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]

[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.

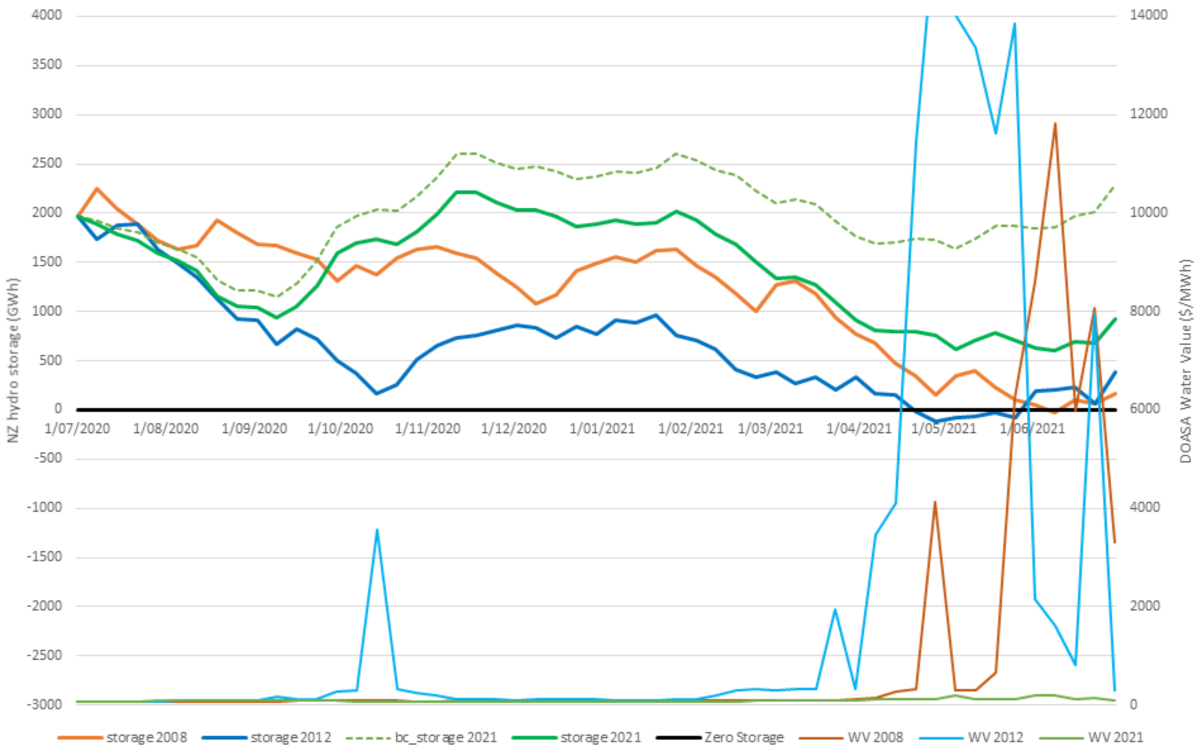
There is no "free lunch" when managing scarce hydro resources; if hydro generators use more water in the short term at lower prices the risk of shortage increases as does the risk of much higher prices in the longer term. Grant Read explores this issue more thoroughly in his attached report.

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.

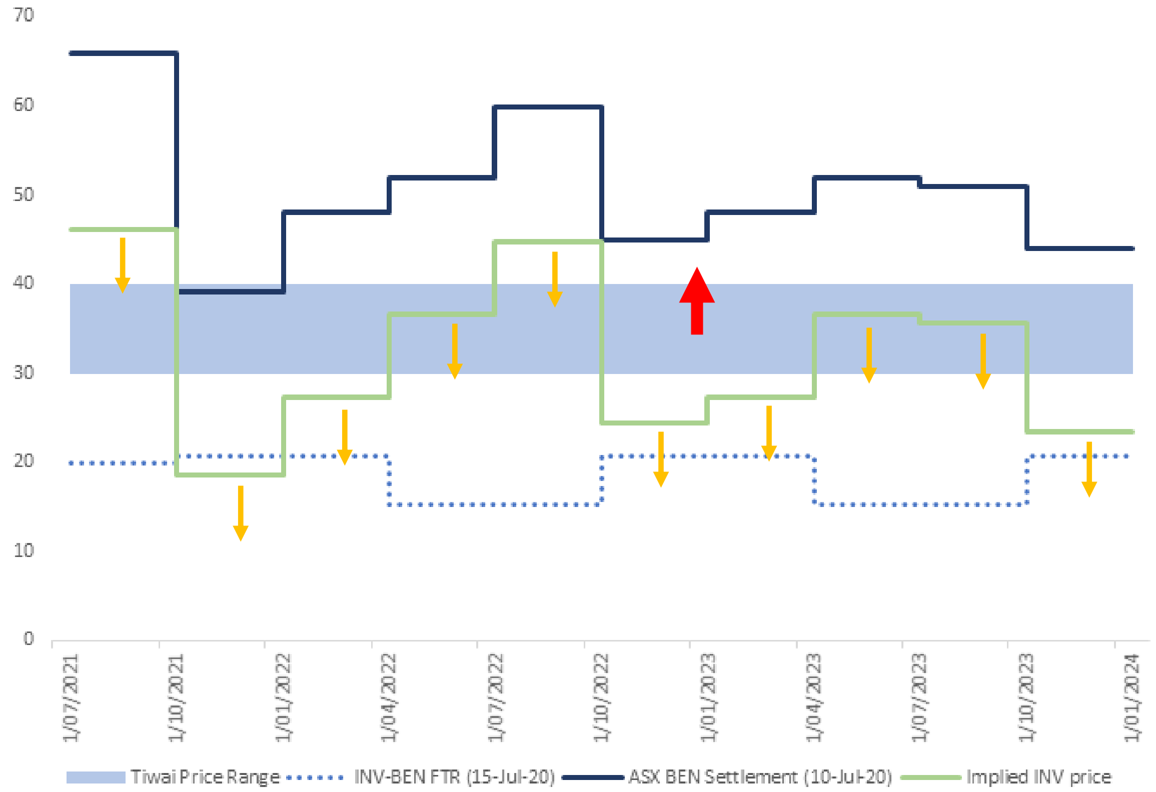
The Authority has not accounted for nodal pricing in its calculations. With transmission constraints limiting transmission out of Southland until completion of the Clutha Upper Waitaki Lines Project (CUWLP), and out of the South Island for much longer in a smelter exit scenario, it is likely that lake 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.

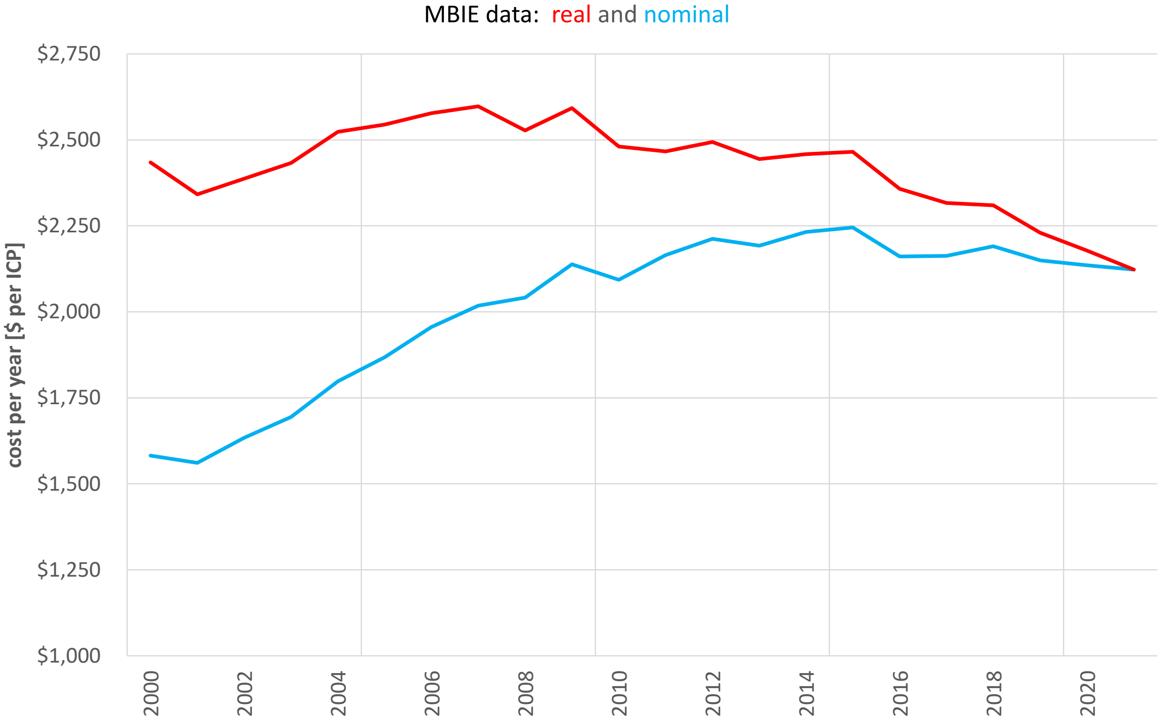
[13] *CSA Report* page 11.
[14] Electricity Price Review *First Report* page 33, available at: https://www.mbie.govt.nz/dmsdocument/3757-first-report-electricity-price-review-pdf.

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

[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."

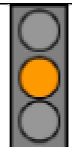
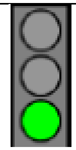
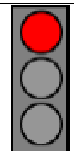
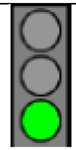
Carl Hansen also notes that to present a balanced set of meaningful indicators requires omitting meaningless or duplicative indicators or including them only for context and not as part of its traffic light summary of competition indicators.

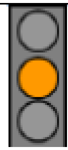
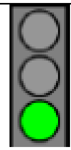
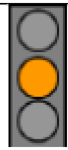
Meridian traffic light summary

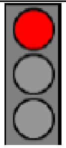
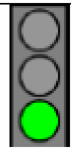
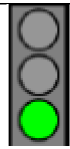
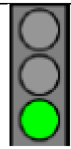
Table x below shows (in blue text) Meridian's suggested adjustments to the Authority's assessment and applies a more appropriate traffic light to each indicator based on those adjustments. The reasons for the suggested adjustments are detailed further in the rest of this section under the Authority's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

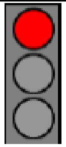
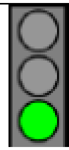
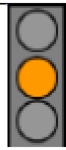
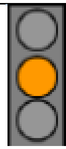
[36] https://www.ea.govt.nz/assets/dms-assets/29/April-June-2021-Quarterly-Report.pdf.
[37] Information paper paragraph 5.160
[38] Information paper pages 71 to 72

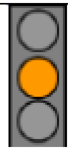
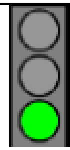
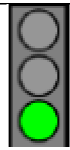
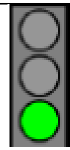
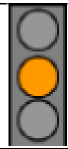
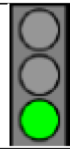
Table x: Meridian adjustments to the Authority's traffic light summary

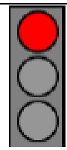
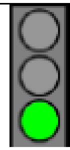
	Measure	Indicators used	What we would expect to see in a workably competitive market	What we observed		
				Authority	Meridian	
Market structure	Seller concentration	Generation HHI	Low concentration reduces risk of any one firm unilaterally affecting prices, or of lasting collusion between groups of 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.

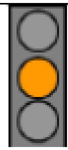
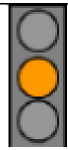
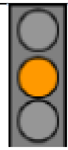
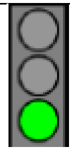
	Barriers to entry	Vertical integration	Low barriers to entry place pressure on incumbents to display competitive pricing behaviour. We would expect to see entry and expansion from a range of business models. [The remainder of this passage is not a description of what the Authority expects to see.] ~~Vertical 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

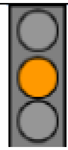
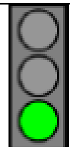
						supply risk for Meridian and New Zealand. It was done to meet what we perceived were regulatory expectations. Meridian and other generators commonly offer in non-clearing tranches to manage security of supply – see details below.]
		Percent of offers above cost	~~To stay the same over time.~~ [There 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.

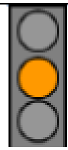
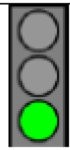
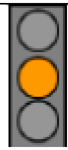
		Relationship of offers to cost	Should be a positive correlation, because we expect generators to increase their offers if their costs increase. However, any estimate of costs must include the costs associated with scarcity risk.			Meridian and Mercury's offers are not correlated with their water values 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

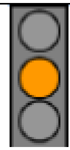
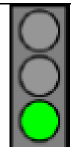
						a South Island generator. This renders the test meaningless for assessing the ability to engage in a sustained period of economic withholding. It rules out the most important aspect of workably competitive markets, which is rivalry.]
		Inter-island price separation	Should change with underlying conditions 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]

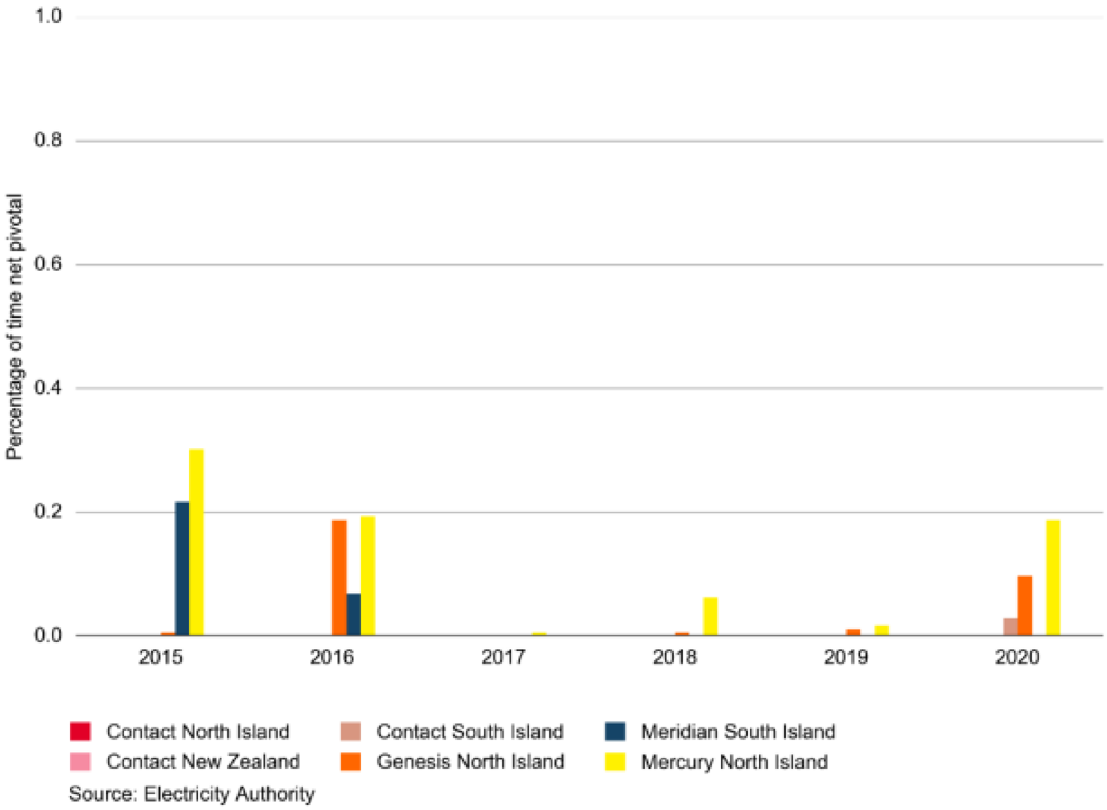
In previous Market Performance Reviews, the Authority has undertaken net pivotal analysis. Figure 4 below is a clipping of the latest net pivotal analysis published by the Authority in February 2021. As can be seen, in 2020 all generators were net pivotal less than 0.2% of the time and the measure shows 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.

[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



Barriers to entry

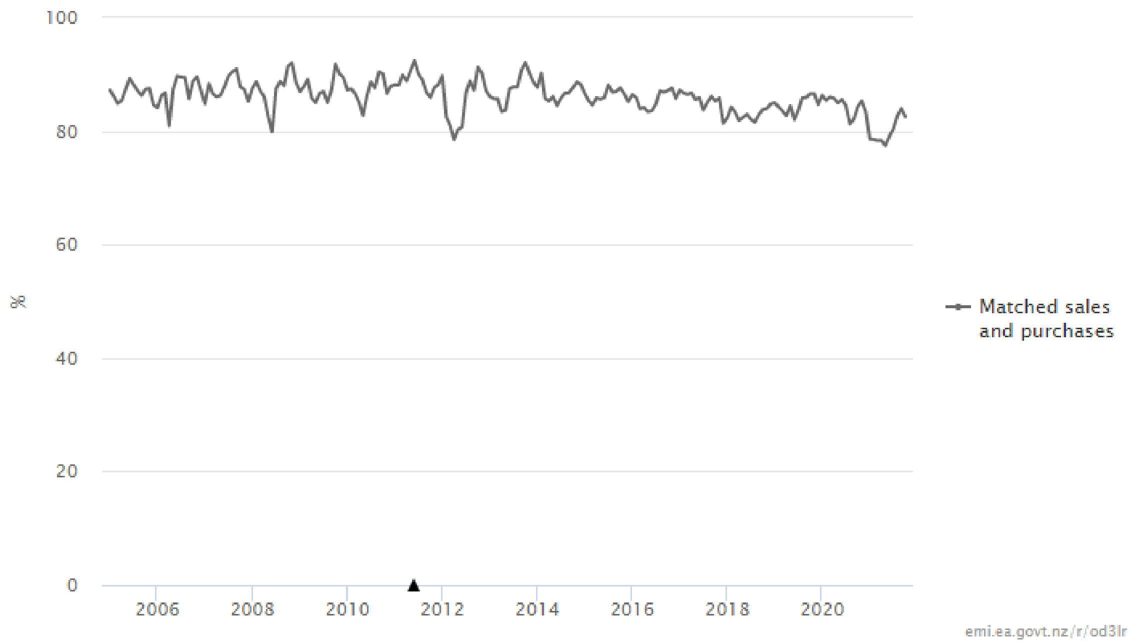
The information paper rightly considers whether there are any barriers to entry in generation. This is one of the most critical considerations to ensure the dynamic efficiency of the market. However, rather than considering this issue fully by assessing a range of potential barriers to entry like access 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.

[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

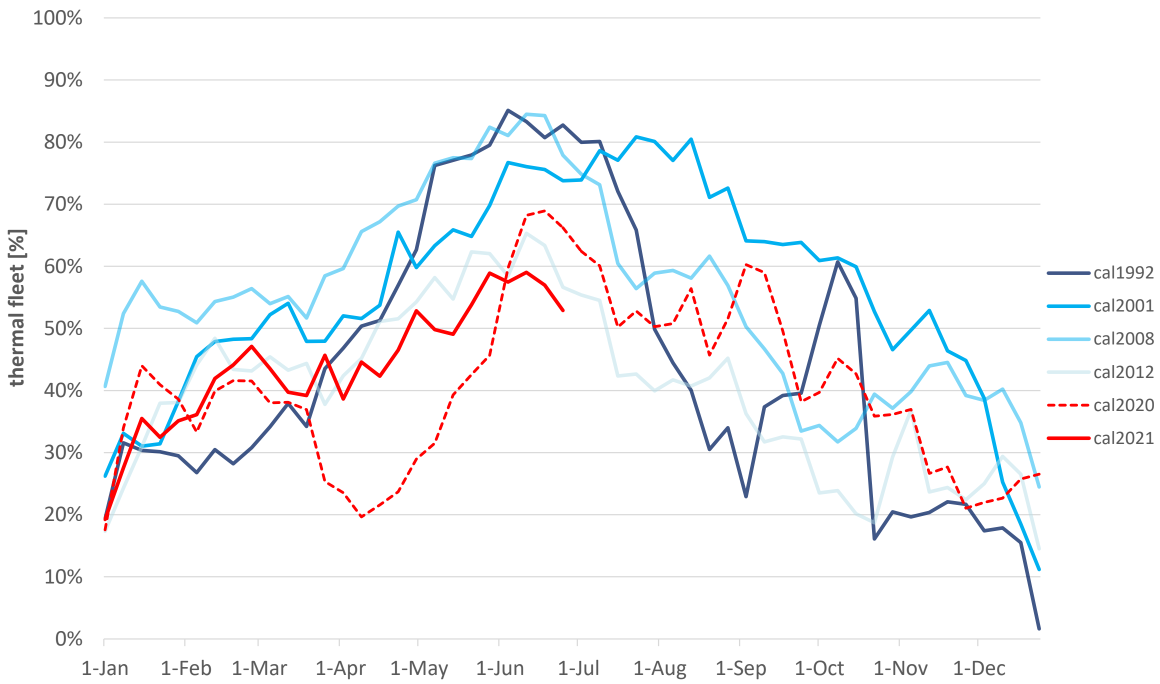
48 *Information paper* paragraph 5.39
49 *Information paper* paragraph 4.38

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.

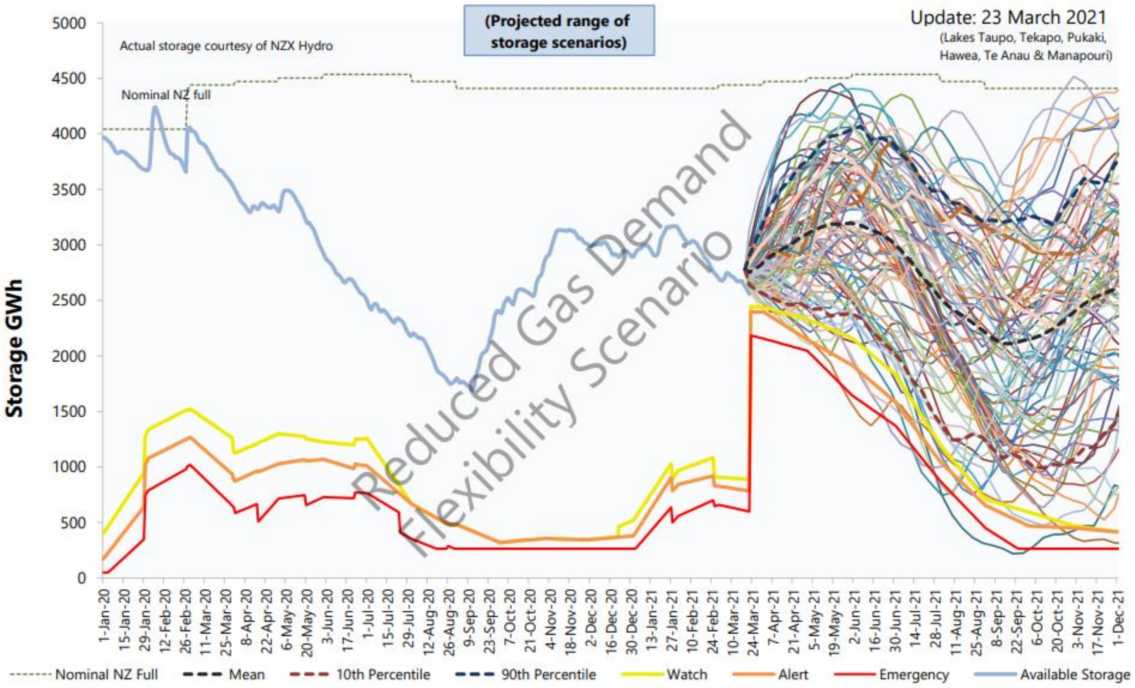
While gas prices have clearly increased, the nature of thermal availability and commitment has also changed markedly, yet the Authority's analysis looks only at offers made and does *not* consider the impact of offers not made and the general lack of thermal commitment. In previous dry-years (1992, 2001, 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.

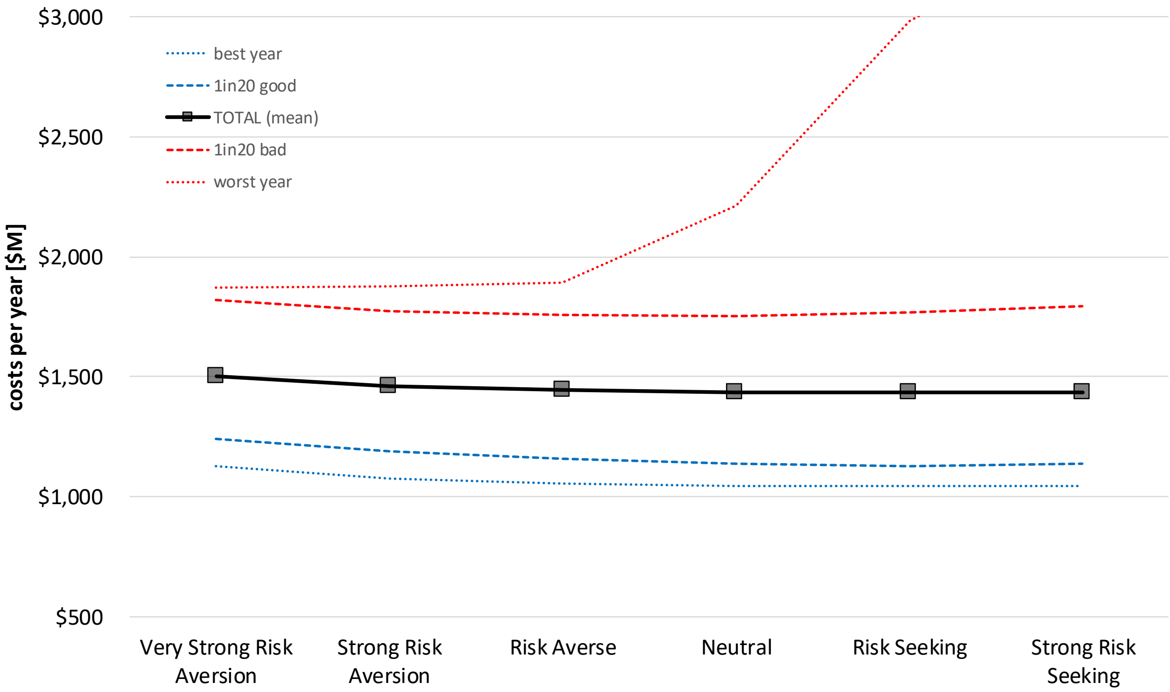
To manage massively uncertain inflows and uncertainty regarding how other market participants will behave, Meridian uses a market model to manage our storage. The model is given 87 historical hydrological inflow sequences to help it predict the range of potential inflows in future and therefore future 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.

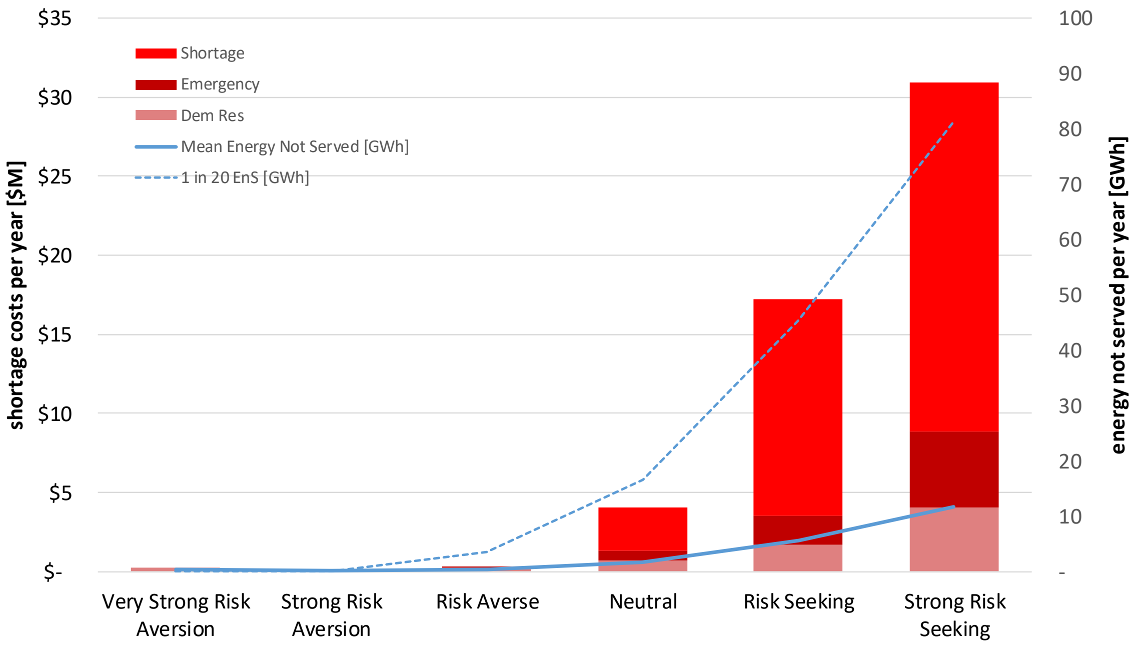
A wide range of storage outcomes are possible and with very similar *average* system costs. However, when we consider the full range of hydrological outcomes, the change in system costs becomes pronounced as shown in figure 8 below. Risks associated with the fear of reaching the bottom of the storage 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.

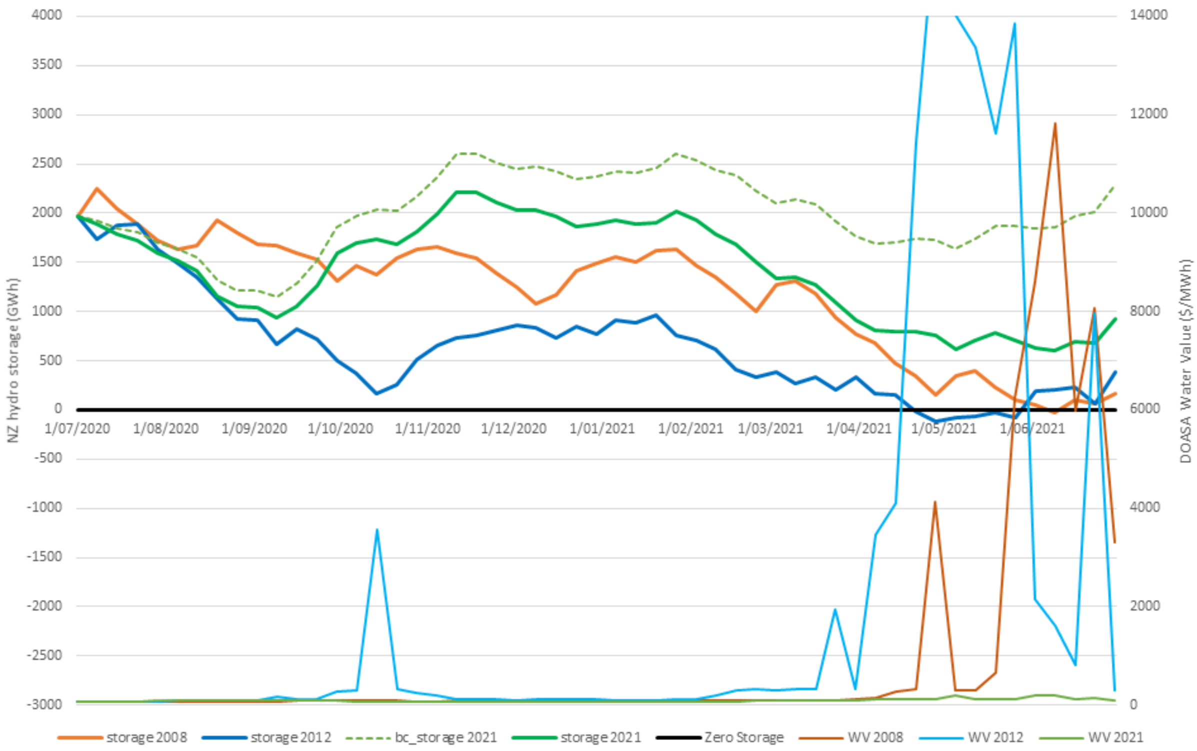
To suggest prudent storage management could be "economic withholding" does not recognise the purpose of non-clearing offers to manage finite stored water, with uncertain supply in future, and uncertain behaviour from other market participants. We find this particularly puzzling given the Authority's 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

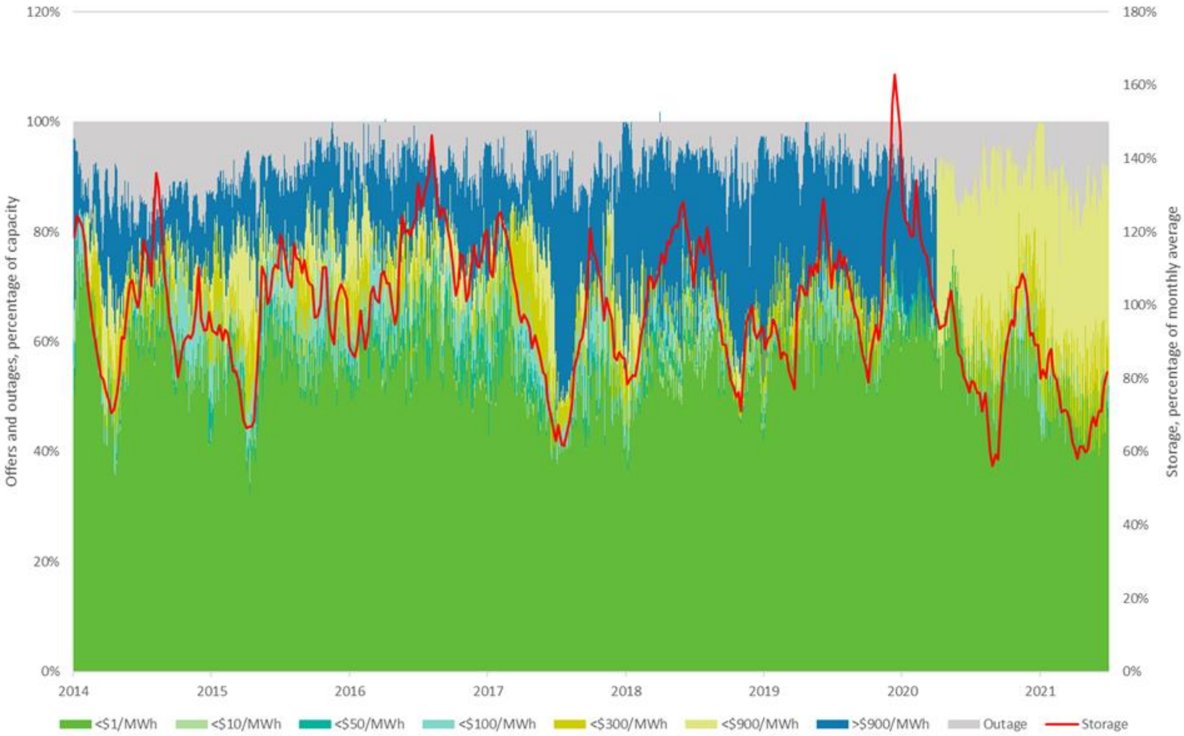
> should be reflected in water values). Additionally, hydro generators that also have thermal generation (Contact and Genesis) may be in a better position to more aggressively draw down available hydro storage, because they are able to cover their contracted load by turning on thermal generation if hydro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

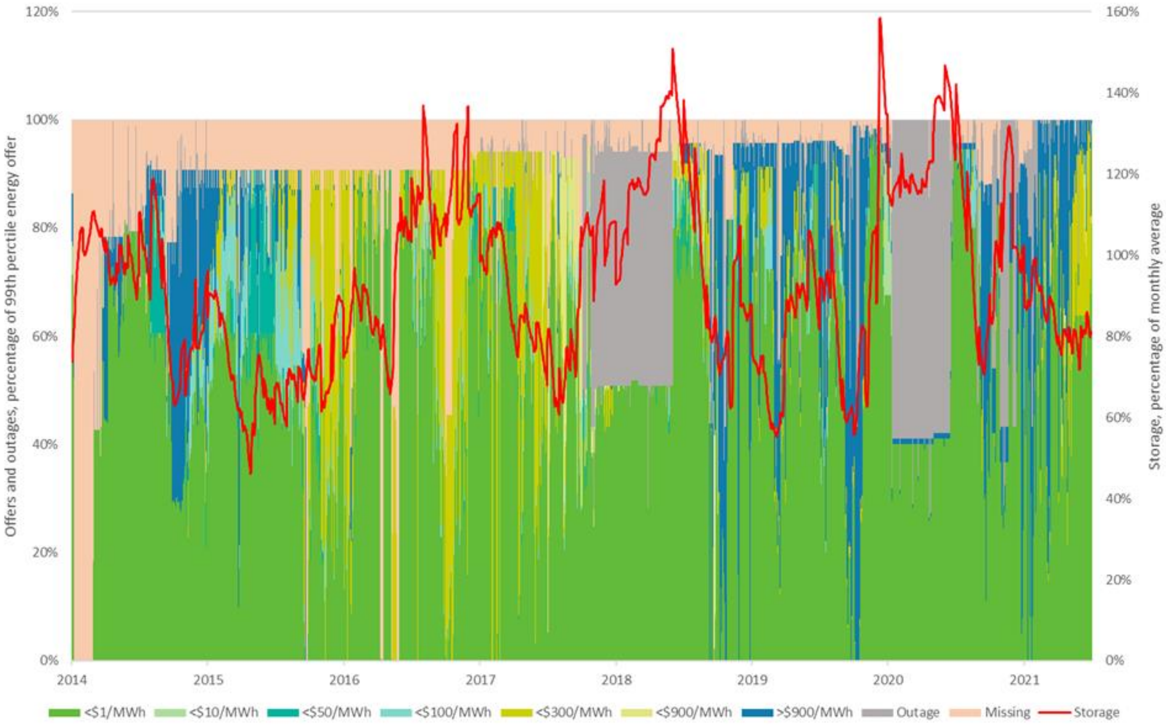
[52] It is worth noting that output from the two Tekapo stations was limited by significant outages during the review period, pushing Genesis to offer more volumes at low prices to the level of Lake Tekapo.

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

Economic Review of the Electricity Authority's Analysis of Spot Prices

A report for Meridian

December 2021

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Contents

1. Introduction

The Information Paper concludes the high spot prices are at least partly due to fuel supply scarcity and high fuel costs.

This report has been prepared by Axiom Economics (Axiom) on behalf of Meridian Energy (Meridian). Its subject is the Electricity Authority's (Authority's) review of 'whether electricity spot prices were determined in a competitive environment for the period from January 2019 until Q2 2021.' The Authority decided to undertake this review in response to the sustained high spot prices that have been observed since the outage at the Pohokura gas field in 2018.

The Authority's Information Paper[1] contains various analyses, including a linear regression of spot prices pre- and post-2018. This analysis indicates that the price increases observed over the period are at least partly attributable to fuel supply scarcity and higher fuel costs. However, the Authority also suggests there has been a sustained upward shift in spot prices that the regression cannot explain. The model could not reveal whether this shift was attributable to (amongst other things):

- limitations in the model itself;[2]
- uncertainty about the gas market influencing bids and prices; and/or
- generators exercising substantial market power.

Various other tests are then performed to look for any signs of the exercise of market power.

The Authority consequently performed a series of other tests to see whether it was able to shed more light on the reasons for the perceived uplift and, in particular, whether it could find any indications of the exercise of market power. Several of these analyses involved comparing generators' offers – and resulting spot prices – with various estimates of short run marginal cost (SRMC). We have been asked to review the robustness of those analyses and, where appropriate, to suggest alternative approaches for assessing the state of competition.

1.1 Key findings

The 'short-term' analyses of the 'price-cost' relationship do not provide any reliable insight into the state of competition.

Our key findings are as follows. First, the Authority's 'short-term' analyses of the relationships between prices and costs are incapable of providing any reliable insights into the state of competition in the New Zealand Wholesale Market (NZWM). Specifically:

- even in the very best of circumstances it is difficult to compare prices with short run costs because, when understood properly, SRMC includes both:
  - the operating and maintenance costs incurred in serving an additional unit of demand; and
  - the *opportunity costs* of *managing* demand when supply is limited (these costs are considerably more challenging to measure, in practice);

1 Electricity Authority, *Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market, Since the Pohokura Outage in 2018*, October 2021 (available: here; hereafter: 'Information Paper').

2 It is nearly impossible for any regression to perfectly capture all relevant variables, in practice.

- those challenges are multiplied manyfold in the NZWM, where the SRMC of generating is influenced by, amongst other things:
  - current lake storage levels (e.g., whether a storage lake is nearly full or nearly empty) and gas availability; and
  - forecast hydrological conditions (which will affect *future* storage levels and also the need to spill) and projected gas supplies; and
- these complexities make it impossible to produce objective estimates of SRMC against which to compare prices and, perhaps unsurprisingly:
  - the analyses of short-term 'price-cost' relationships are problematic in numerous respects, e.g., the SRMC benchmarks are unreliable; and
  - those assessments are consequently incapable of revealing whether generators have been exercising substantial market power.

More insights into the state of competition can be obtained by asking: are prices above long-run entry costs and, if so, why?

Second, in our opinion, more insights into the overall state of competition in the NZWM can be obtained by asking: are prices above long-run entry costs and, if so, *why*? The 'why' is important here because prices *have* been significantly above the *long run marginal cost* (LRMC) of adding new capacity in the NZWM and may remain so for some time yet. However, there appear to be good reasons for this 'gap'. Several factors have diminished incentives to invest in new generation, despite the high spot prices. These include uncertainties surrounding:

- the future of the Tiwai Point aluminium smelter (which accounts for ~13% of total annual demand), i.e., if this large customer had left (which it has threatened to do on multiple occasions) this would lead to near-term spot price *reductions* and a potentially tumultuous adjustment period; and
- government climate change policies, including the future of the natural gas sector, i.e., a prospective investor in, say, a new gas plant would be understandably concerned about obtaining access to a reliable supply of gas at a reasonable price, and the potential for that investment to be stranded.

Several factors have reduced incentives to invest in new generation, but the investment environment is improving.

Much of that uncertainty has now diminished – but in some cases, only relatively recently. For example, the smelter's immediate future has been secured and more clarity is emerging about the government's climate change policies. There has been an enormous recent increase in connection requests, surging development interest in solar farms and around $2 billion of investments either planned or under construction. This should all serve to realign prices with entry costs.

The 'investment deficit' will take time to eliminate but, when it is, prices should realign with entry costs.

However, this adjustment process may not be swift. It will take time for the 'investment deficit' that has built up during the recent period of extreme uncertainty to be erased. Obtaining resource consents, constructing plants and connecting to the grid all take time – such projects are multi-year endeavours. Even so, it would arguably be unnecessary and undesirable to intervene in a market that seems well on the way to addressing the divergence between prices and LRMC.

1.2 Structure of this report

We elaborate on our key findings in the remainder of this report, which is structured as follows:

- **section two** explains the often-misconstrued concept of marginal cost, which is of central relevance to the efficiency of pricing and the identification of substantial market power. It also sets out some key implications for comparisons between 'costs' and 'prices';
- **section three** explores the application of those economic concepts to electricity wholesale generation markets such as the NZWM. We then explain why it is difficult to undertake robust comparisons between prices and SRMC, due to the practical challenges associated with estimating the latter;
- **section four** examines a series of short-term analyses the Authority performed to see if it could find any signs that generators have been exercising substantial market power. Several of these assessments involved comparing generators' offers – and resulting spot prices – with estimates of SRMC; and
- **section five** provides a broader, longer-term assessment comparing spot prices with the long-run cost of adding new capacity. We conclude that there *is* a significant gap between prices and LRMC, but we then identify several potential reasons for this and explain why that gap could well disappear over time.

For the avoidance of doubt, the opinions expressed throughout this report are our own and do not necessarily reflect the views of Meridian.

2. Marginal cost and competition

In competitive markets, there is symbiosis between prices and marginal costs. Many of the *short-term* analyses contained in the Information Paper involve exploring that relationship. However, to be valid, such assessments require properly constructed estimates of marginal cost. These are not easy to produce. Marginal cost is simple enough to define; it is the additional cost that a firm incurs by increasing output by a specified increment. But from there, things quickly get more complicated.

Marginal cost can be estimated in either short run or long run terms.[3] When measuring *short run* marginal cost (SRMC), it is crucial to capture any *opportunity costs* associated with *managing scarcity.* However, these additional costs are very difficult to measure, in practice. This complexity makes it tricky to produce robust estimates of SRMC and diminishes the usefulness of short-run price-cost tests. We explain these challenges and explore some of the implications below.

2.1 Short run marginal cost (SRMC)

SRMC is the cost of meeting an incremental change in demand, holding capacity constant.

In the short run, at least one 'factor of production' is fixed, i.e., a hotel cannot instantaneously add rooms if too many customers want them on any particular day. This means a firm cannot increase the quantity of a product it is supplying by expanding. The only way it can increase supply is to use its existing capacity, i.e., to produce more with what it has already. Short run marginal cost (SRMC) can therefore be thought of as the cost of meeting an incremental change in demand, *holding capacity constant.*

When supply is plentiful, SRMC is equal to the operating and maintenance costs incurred producing additional units.

This is often construed simply as the extra operating and maintenance costs associated with producing more. At times, that is correct, *but not always*. When additional demand can be met by increased supply from existing capacity, SRMC *will* be equal to the operating and maintenance costs associated with producing the additional units. However, at other times, SRMC can be *well above* that level. It is this element of SRMC that is sometimes *not* as well understood.

When supply is scarce, SRMC rises to whatever level is needed to 'choke off' any excess demand.

A crucial but often overlooked element of SRMC is that, if supply *cannot expand* to meet the additional demand (e.g., once a hotel is full, it is full), SRMC rises to whatever level is necessary to 'choke off' any excess demand. In situations where there is an increased risk of shortages, the costs associated with this demand-side component can cause SRMC to rise *significantly above* variable costs. Importantly, it is during these periods of scarcity that firms can recoup some of their *fixed costs* that do not vary with output over the short-term (and are therefore not part of SRMC).

In competitive markets, there is no 'cap' on how high prices can rise during these periods of scarcity and, by extension, on the contribution that can be made to fixed costs during these windows. Professor Alfred Kahn supplied a useful example of this phenomenon. He postulated a scenario in which a bridge is contemplating

[3] The difference being the timeframe under consideration and the extent to which firms can adjust their production processes.

charging a toll on motorists. The incremental operating, maintenance and capital costs caused by each additional vehicle on the bridge were practically zero but, as he observed:[4]

> *'[W]hat if charging a zero toll would, at certain hours of the day, produce such an increase in traffic that cars lined up for miles at the bridge entrance and a crossing took an hour instead of a few minutes? In that event, the SRMC of bridge crossings, at those times,* ***is not zero****. It can be envisaged in terms of congestion: the cost of every bridge crossing at the peak hour is the cost of the delays it imposes on all other crossers. Or it can be defined in terms of opportunity cost: if A uses the bridge at that time, he is taking up space that someone else could use; therefore, the cost of serving him is the value of the space or capacity to others who would use it if he did not.'*

In times of scarcity, the cost of serving one customer must, by definition, include the value foregone by others who might miss out.

In other words, in times of scarcity, the cost of serving one customer must, by definition, include the value foregone by *other customers who consequently cannot be served.* For example, if a city's water supply began to run low, continuing to supply some customers might mean placing restrictions on the usage of others. The costs imposed by those restrictions may be very high and might include costs such as plant losses in residential gardens and parks, reductions in agricultural output, diminished quality of golf courses and higher production costs for breweries. All those costs form a part of the SRMC of serving one customer in circumstances where that implies restricting supply to others.

Although SRMC can be estimated at any particular point in time, it can fluctuate - quite dramatically - from one point to another. Its application to future decisions depends as much on *probability and expectation* as on fact. A forward-looking SRMC is the sum of the various extra costs arising under different scenarios (holding capacity constant), multiplied by the estimated probabilities of those things actually happening. Formally, the expected SRMC is given by:

SRMC depends as much on probability and expectation as on fact.

- the SRMC when supply exceeds demand (i.e., when it is equal only to the operating and maintenance costs of meeting that increment), multiplied by the probability that supply exceeds demand; *plus*
- the SRMC when supplies are less than demand (i.e., operating and maintenance costs *plus* the costs arising from shortages) multiplied by the probability that supply will be less than demand.

By way of simple illustration, suppose that:

- there is a **90%** probability that there will be enough existing capacity to meet an additional unit of demand at time *t* -- **(1)**;
- the short run operating and maintenance cost of supplying that additional unit of demand in that scenario would be **$100** -- **(2)**;
- there is also a **10%** probability that there *will not* be enough existing capacity to meet an additional unit of demand at time *t* -- **(3)**; and
- the opportunity cost to a customer who was unable to buy the product (due to scarcity) at time *t* would be **$1,000** -- **(4)**.

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4 Kahn, A, (1988), *The Economics of Regulation, Principles and Institutions, Volume 1* (MIT Press), p.87.

The SRMC of supplying an additional unit at time *t* would therefore be:

SRMC = [**(1)** x **(2)**] + [**(3)** x (**(2)** + **(4)**)]
= [90% x \$100] + [10% x (\$100 + \$1,000)]
= **\$200**

In other words, in this simple example, the \$200 SRMC at time *t* is *double* the \$100 of operating and maintenance costs incurred producing the unit in question. This simply reflects the non-zero probability of scarcity emerging and the substantial potential *opportunity costs* that scenario would entail. Therefore, in this example, when SRMC is understood properly:

Market prices that signal the opportunity costs of potential scarcity are 'cost-reflective', not 'above cost'.

- a market price of \$200 would not involve *above cost pricing*; rather
- the \$200 price is *cost reflective*, i.e., it reflects both operating and maintenance costs *and* the *opportunity cost* of managing scarcity.

To summarise, SRMC can be defined as the cost of an incremental change in demand, holding capacity constant. Importantly, its estimation takes account of the potential costs of shortages faced by customers. If supply cannot expand to match demand, SRMC rises to whatever price level is necessary to curtail demand to match available supply.

2.2 Long run marginal cost (LRMC)

In the long run, all factors of production are variable and so incremental changes in demand no longer need to be met from current capacity alone. Firms instead have the option of *expanding capacity* to meet additional demand and, equally, of reducing their capacity if patronage tapers off. LRMC can therefore be thought of as the cost of supplying a specified, permanent increment in demand, allowing for future augmentations in supply, i.e., additional capacity.

LRMC is the cost of supplying a permanent increment in demand, allowing for new supply, i.e., additional capacity.

In most industries it is not practicable to add capacity in very small increments.[5] Rather, there are often 'economies of scale' associated with augmentations. For example, once a business has purchased land it may make sense to construct a multi-level office building, even if not all that space will be used right away. This is because adding the extra levels at that time is likely to be cheaper than building them later. Taking this one step further, it is probably even more expensive (in unit cost terms) to add capacity 'room-by-room'.

In other words, in 'real world' markets, capacity is often added in 'lumps' rather than very small increments. The likely effect of a permanent increment in demand is therefore to *bring forward* the time at which a planned future 'lump' of capacity needs to be added – by firms that are already in the market and/or by new entrants. LRMC is therefore the costs – both operating and capital costs – associated with

5 The exception is industries in which assets are highly mobile and capacity can be added in very small increments. In these circumstances, any level of demand can be met by quickly adding (or subtracting) capacity, i.e., there is never any need to curtail demand. Of course, such industries are seldom seen in practice.

undertaking that expansion *sooner than would otherwise be the case* in response to the incremental change in demand, and the associated congestion costs.[6]

This means that when capacity has to be added in 'lumpy units', this gives rise to *time-dependent fluctuations* in LRMC. Specifically, the LRMC of supply will be relatively low when capacity utilisation is low (and the next expansion is some distance in the future). But it will start to rise as utilisation increases and the timing of the next expansion approaches:

Because capacity is often added in 'lumpy units' this gives rise to time dependent fluctuations in LRMC.

- in the period immediately following an expansion, the LRMC of the next increment to capacity is low because the value of any potential deferral of that future investment is relatively low due to discounting (i.e., a dollar spent today is 'worth more' than a dollar spent ten years from now); and
- as spare capacity declines over time and the need to invest in new capacity draws closer the LRMC of the next increment to capacity increases, because the value created through any potential deferral is closer in time and so less (negatively) affected by discounting.[7]

In summary, LRMC reflects the cost of serving an incremental change in demand in a market, assuming all factors of production can be varied. Importantly, because LRMC is a long run concept, it accounts for the fact that firms have the option of *expanding their capacity* in order to meet an incremental increase in demand. Measuring LRMC involves estimating the costs involved with undertaking a capacity expansion *sooner than would otherwise be the case* in response to that change in demand.

2.3 Relationship between SRMC and LRMC

We have seen that SRMC is the cost of an incremental change in demand, *holding capacity constant*, whereas LRMC reflects the cost of meeting that change in demand *assuming capacity can vary*. In competitive markets, unless assets are highly mobile, and capacity can be added in very small increments – conditions that are seldom seen[8] – there is *no reason* to expect SRMC and LRMC to be the same at any particular

6 To be clear, LRMC does *not* equal the total operating and capital costs associated with that expansion. This is because an incremental increase in demand does not generally result in investment that would otherwise never be required; rather it usually serves to *bring forward the timing* of an expansion. LRMC is the additional cost incurred by *bringing forward the timing* of that expansion (that would otherwise have taken place later).

7 In other words, LRMC changes over time as new capacity is added. This is because the cost today of, say, bringing forward by one year a $1m investment that would otherwise have taken place in 12 months' time is much greater than the cost today of that same one-year rescheduling applied to a $1m investment expected to be made in 10 years' time, because of the time value of money. Put another way, the value today of deferring by one year a $1m investment expected to be made in 12 months' time is much greater than the value today of that same one-year deferral applied to a $1m investment expected to be made in 10 years' time.

8 When these conditions are present, there is no distinction between SRMC and LRMC since, by definition, there is no difference between the short run and the long run. Any level of demand can be met by quickly adding (or subtracting) capacity and so the need to curtail demand never arises. In these circumstances, SRMC and LRMC are always equivalent, and constant at all times. Of course, industries exhibiting these characteristics are almost never observed in practice.

point in time. However, there is still a strong 'in principle' link between SRMC, LRMC and capacity expansion decisions over time.

SRMC and LRMC can be different at a particular point in time but, in competitive markets, there is a symbiosis between them over time.

If demand is growing, or subject to short term fluctuations, SRMC will start to increase. In the first instance, that growth can be met only through increased risk of congestion or via demand curtailment, because the existing capacity is fixed. However, as time passes, there will eventually be a 'tipping point' at which the expected SRMC of *curtailing demand* increases beyond the expected LRMC cost of *expanding capacity* to meet it. It is at that point, when LRMC is *less* than SRMC, that new investment *should* ideally occur.[9] Box 2.1 provides a simple example.

Box 2.1: Relationship between SRMC, LRMC and new investment

Imagine there is only one hotel in a small town, but the market is competitive, i.e., there is nothing stopping other hoteliers from entering. In the short run, the number of hotel rooms in the location is fixed. This means the most efficient way for the hotel to deal with excess demand during peak periods over the short term is to increase its room prices.[10] This is because:

In competitive markets, prices cannot exceed SRMC or LRMC for a prolonged period without prompting new investment.

- it is not possible to construct a new hotel or expand the existing building in the near-term, e.g., to find a site, obtain planning approvals, arrange financing, undertake construction, and so on; and
- those investment decisions would not be based solely on one period of high prices in any case – rather, the expected return over a longer time horizon is what is relevant for entry/expansion decisions.

However, if demand kept growing to the point where the hotel was constantly increasing its room prices to curtail demand (i.e., to 'manage congestion') then it may be more efficient to build more, i.e., to expand supply. When competition is effective, this tipping point occurs when the forward looking SRMC of curtailing demand increases beyond the forward looking LRMC of expanding capacity to meet it – either via new firms entering, or existing suppliers expanding.

This means that, in competitive markets, it should not be possible for prices to substantially exceed the forward-looking expected *SRMC of using existing capacity* and the *LRMC of adding new capacity* (which, as we have just seen, are equal on average in the long run) for a prolonged period. If a firm tries to charge prices higher than this level, it should lose market share – either to new providers entering, or existing competitors expanding. This promotes simultaneously:

9 The same principles apply to a market in which demand is declining over time. In the first instance, declining demand can be met by firms continuing to supply the market with their existing capacity. However, there will again be a 'tipping point' at which the long run costs that would be avoided by reducing or redeploying capacity exceed the SRMC of continuing to supply the product at the current level of capacity. At that point, capacity should be redeployed to other markets where returns are more attractive.

10 Similarly, if the hotel experienced a temporary period of low prices due to reduced demand it is hardly likely to respond in the near term by reducing the number of rooms or by exiting the market altogether.

- the efficient use of existing capacity, i.e., customers will only use an additional unit of capacity if the benefits they derive exceed the costs of providing it (the scope for over- or under-consumption is reduced); and
- the efficient investment in additional capacity, i.e., investments should occur when demand has grown to levels where the expected costs of managing congestion (SRMC) exceed the costs of expanding supply (LRMC).

In 'real world' markets there can be periods of disequilibrium where SRMC and LRMC are misaligned, but these should 'correct' in time.

In 'real world' markets, it is difficult to time capacity expansions and reductions to coincide perfectly with the emergence of inefficient levels of demand curtailment, i.e., when scarcity is either too common or too infrequent. This is particularly the case when capacity must be added and withdrawn in large increments that alter substantially the supply/demand balance. Even in the best of circumstances there may therefore be times when:

- forward-looking SRMC is *above* LRMC for a period as the market waits for new capacity to come on-stream; and
- forward-looking SRMC is *below* LRMC for a period as the market waits for redundant capacity to be redeployed elsewhere.

Misalignments between SRMC and LRMC can be prolonged by various factors, e.g., uncertainty over government policy.

These periods of misalignment can be prolonged – potentially by years – by various factors. For example, suppose speculation is rife that new government policy might be introduced that would threaten the financial viability of a particular productive activity. In those circumstances, investors might understandably be reticent to invest until more certainty emerged regarding that policy – even if prices (i.e., SRMCs) exceeded the cost of entry (i.e., LRMC) in the meantime. After all, it is long-term future cashflows that drive investment decisions, not just immediate returns.

Such instances of 'disequilibrium' are neither unexpected, given the imperfections that can affect real markets, nor a cause for concern, *provided they are transitory*. Even accounting for such periods there is no reason to expect SRMC to differ materially from LRMC in competitive markets, on average, provided they are properly defined and assessed over a sufficiently long timeframe. Equally, although both SRMC and LRMC can fluctuate over time, there is no reason to think that either will diverge materially over the long term.

2.4 Implications for comparisons of prices and costs

The preceding discussion has implications for the extent to which comparisons between prices and marginal costs can be used to draw inferences about the state of competition in a market. For the reasons set out above, when estimating SRMC it is crucial to capture any *opportunity costs* associated with *managing scarcity*. However, these additional costs are very difficult to measure. This can diminish the usefulness of *short-run* price-cost tests. More insight into the state of competition in a market can often be obtained by performing *longer run* assessments, i.e., that compare prices with estimates of *LRMC*. We elaborate below.

2.4.1 Short run comparisons

In competitive markets, prices should reflect SRMC. However, we have also seen that, when measured properly, SRMC includes the opportunity costs of *managing scarcity*. This makes it difficult to compare prices with SRMC in practice. The efficacy of such comparisons hinges crucially on (amongst other things) ensuring SRMC estimates incorporate all the relevant opportunity costs of managing scarcity. This is not easy to accomplish. Such analyses should therefore be undertaken sparingly and their results must be interpreted with caution.

This can be illustrated using a straightforward example. Suppose that to supply 'widgets' a producer must make an upfront investment of $100 and that, from then on, it costs $1 to manufacture each unit. Should we be concerned about the state of competition if, say, the market price was observed to be $2 per widget at a particular point in time? Or, put another way, should we be concerned about a price that exceeds short run production costs? The answer is: not necessarily.

If supply at that point of time happened to be *plentiful*, the SRMC for that particular firm of producing each widget would be $1, i.e., equal to its short run production costs – labour, materials and so on. And, if the market is competitive and the firm happens to be the 'marginal supplier' (i.e., the business that supplies the last units that 'clear' the market and therefore determines the market price), then we might expect the price of widgets to also be $1 (or near to it). However, in other circumstances, there are good reasons for the price to be *higher* than $1.

It is difficult to compare prices with SRMC, since the validity of such exercises hinges on capturing all relevant opportunity costs.

First, if the firm in question is *not* the marginal supplier in the market, then *its* short run production costs are irrelevant. If *more expensive* producers are instead needed to meet total market demand, then it is *their* costs that will determine the market-clearing price. If the 'marginal supplier's' short run production costs happen to be $2 per widget, then *that* should be the market price and all firms with *lower costs* ('inframarginal' producers) will then earn positive economic profits.

Second, as we explained earlier, if supply at the pertinent point in time was *scarce*, then *all* producers – marginal or otherwise – would earn positive returns. During those times of potential shortages, the SRMC of producing widgets would rise to whatever level was necessary *to curtail demand to match supply*. Specifically, the price would increase *above $1* until it reached a level at which balance (or 'equilibrium') was restored. During these times of scarcity:

- even the 'marginal' widget supplier could make a contribution to its fixed costs;
- all 'infra-marginal' widget suppliers (i.e., firms with operating costs below $1 per unit) would make *even greater* contributions to their fixed costs; and
- those higher prices would also provide a potential impetus for entry and expansion, i.e., if there was perceived to be profitable opportunities on offer.

Care must therefore be taken when drawing inferences about the state of competition in any market from comparisons of prices and short run cost estimates. Unless SRMC benchmarks incorporate appropriate values for the *demand-side costs of managing scarcity*, they will *underestimate* the prices that would prevail under workable competition. And because it is so difficult to accurately gauge those externality costs[11] this frequently diminishes the usefulness of such comparisons.

2.4.2 Long run comparisons

It is often useful to assess the state of competition in a market by making *longer-term* comparisons. Returning to our 'widget' market, suppose the LRMC of supplying widgets via new entry (or expanding existing capacity) was $2. Should we be concerned about the state of competition if the average market price over a significant period was $3 per widget? Again, the answer is: not necessarily. In real world markets, entry and exit take time and market frictions may abound.

There are *always* factors that impose costs on entry and exit decisions in competitive markets. Because new capacity cannot be added in infinitely small units, prices that depart from SRMC or LRMC will not prompt an immediate supply side response. Such reactions are simply infeasible. Put simply, things take time. Entry and exit decisions are also unlikely to be made simply because prices appear to be temporarily misaligned with underlying supply costs.

It is often useful to assess the state of competition in a market through longer-term comparisons.

For instance, suppose a prospective new entrant into the 'widget' market (or an existing participant considering expansion) saw high prices leading up to the Christmas period (when, for the sake of argument, demand for widgets is at its peak). That firm would not respond by quickly constructing a new production line to take advantage of those high prices. There are two simple reasons for this:[12]

- it would probably not be possible to construct a facility in that timeframe, e.g., to find a site, obtain planning approvals, arrange financing, undertake construction, etc; and
- that investment decision would not be based solely on one period of high prices – rather, the expected returns over a much longer time horizon would be the most germane consideration.

For these reasons, it is unremarkable to observe prices in competitive markets that are separated from LRMC. Various 'real world' frictions mean prices (and SRMCs) can be above the level at which new entry and/or expansion should *theoretically* be profitable (in this example, above $2 per unit), without swiftly prompting a supply side response. There are consequently many potential price outcomes in such markets that are consistent with workable competition *at a particular point in time*.

However, as we have seen, that does not mean there is *no* relationship between the prices that are observed and the underlying costs of production over the long term. Specifically, once firms are able to respond to changes in demand- and supply-side factors by adjusting their capacities, one would not expect to see prices that are

11 This requires the analyst to estimate - in quantitative terms – how much congestion/scarcity is affecting various customers, which is very challenging (and often highly subjective).

12 Equally, existing hotels are not going to respond by adding more rooms.

significantly and persistently *above the LRMC of adding capacity* for a *prolonged period*, i.e., allowing for those 'real world' frictions.

If average prices exceed the LRMC of adding capacity (e.g., because prices frequently increase to reflect the increased risk of congestion, or the need for demand curtailment) then, over the long term, we should see firms expanding and/or new entrants emerging to 'chase' the resulting profits. If that does not happen (e.g., if prices remain above LRMC for prolonged periods), this is a potential indicator of a lack of effective competition (and, on the flip side, of the existence and exercise of substantial market power).

Take our widget market as an example. Suppose entry typically takes a year, at most. If average prices remained at $3 per widget, on average (compared with the $2 per widget LRMC) for, say, *two* years then this gives rise to legitimate questions about the state of competition. In particular, it *might* indicate that incumbent 'widget makers' are insulated from effective competition by significant barriers to entry and expansion (as opposed to, say, minor differences in product attributes).

Before deciding to intervene in a market one should first consider whether a situation is likely to be perpetuating or self-correcting.

However, before any market intervention was contemplated it would first be necessary to consider whether the current market outcomes are likely to be perpetuating or self-correcting. For example, if widget making was characterised by strong economies of scale and scope and insuperable first-mover advantages, then incumbent suppliers may have enduring market power that is unlikely to wane over time. In those circumstances, some form of regulatory redress may be appropriate.

Conversely, if investors have been deferring any capital expansions until they have clarity on government policy likely to impact the economics of the sector, then the current prices may be temporary. Namely, once investors have more certainty, entry and expansion could occur to drive prices back down to levels commensurate with LRMC. Intervention in those circumstances might therefore be unnecessary and could give rise to unintended adverse consequences.

2.5 Summary

Marginal cost is the added cost of producing a specified increment in output. The fundamental difference between SRMC and LRMC is the timeframe under consideration and the implications of this for a firm's ability to adjust its production process. Specifically, SRMC is the cost of an incremental change in demand, *holding capacity constant*. LRMC relaxes this constraint and reflects the cost of an incremental change in demand assuming *everything* can be varied.

An important distinguishing feature of SRMC is that, in the event that current capacity may not be sufficient to meet all demand, SRMC rises to whatever level is necessary to curtail demand to match available supply over the relevant timeframe. It therefore takes account of the costs of shortages faced by customers. It is consequently unremarkable to see *prices rising above the short run production costs* of 'marginal suppliers' in competitive markets. This is quite normal.

The estimation of LRMC accounts for the fact that, in the long run, firms have the option of expanding their capacity in order to meet increased demand. Measuring LRMC therefore involves calculating the costs associated with undertaking a capacity expansion sooner than would otherwise be the case in response to a change in demand. Both SRMC and LRMC can fluctuate over time and there is no *a priori* reason to expect them to be equivalent at any particular moment.

However, there is a strong 'in principle' link between SRMC and LRMC over the long term. Specifically, when demand is growing over time, or subject to short term fluctuations, SRMC can be expected to increase to the point at which the cost of curtailing demand exceeds the cost of expanding capacity to *meet* that demand (i.e., when LRMC < SRMC). At that 'tipping point', one should expect to see new investment taking place by firms 'chasing' the profits on offer.

Of course, market imperfections mean that the timing of capacity expansions will not always be perfect, e.g., SRMC may rise above LRMC for a period if the optimal expansion is particularly lumpy. Entry and expansion take time and be hindered by countless 'real world' frictions. Investment can also be 'chilled' by various external factors, such as uncertainties surrounding government policies and/or the design and application of regulations. All this can lead to periods of 'disequilibrium'.

Nonetheless, provided things are measured over a sufficiently long timeframe, the link between SRMC, LRMC and new investment decisions should mean that, on average, there is no material difference between the value of SRMC and LRMC. This has important implications for the design and application of any price/cost tests intended to assess the state of competition in a market. Comparisons between prices and *SRMC* tend to be fraught, because:

- unless SRMC benchmarks incorporate appropriate values for the demand-side costs of managing scarcity, they will *underestimate* the prices that would prevail under workable competition; and
- in practice, it can be very difficult to accurately gauge these opportunity costs, which often leaves such analyses susceptible to errors (e.g., 'false positives'), diminishing their usefulness.

Longer-term comparisons of prices to *LRMC* are often more instructive. Once firms are able to adjust their capacities, one would not expect to see prices that are significantly and persistently *above the LRMC of adding capacity* for a *prolonged period*, i.e., allowing for those 'real world' frictions. If such a margin has persisted, this may indicate incumbent suppliers are insulated from effective competition by significant barriers to entry and expansion, i.e., it could suggest the existence and exercise of substantial market power.

However, before any intervention was countenanced, it would first be necessary to examine whether the observed market outcome was likely to continue unabated, or to self-correct. For example, if investors had been putting off capital expansions until clarity was obtained on government policy that would impact suppliers' profitability, then current prices may only be temporary. Intervention in such circumstances might be needless and potentially harmful.

3. Application to electricity generation markets

This section discusses the application of the economic principles described hitherto to 'energy only' wholesale electricity generation markets, such as the arrangements that exist in New Zealand. It begins by describing some of the distinguishing characteristics of such markets, and of the NZWM in particular. We then set out some of the key implications for assessing competition and testing for the misuse of substantial market power.

3.1 Characteristics of electricity generation

The electricity sector is characterised by a homogeneous, non-storable commodity-type product that has few (if any) close substitutes. These attributes deprive consumers of some of the usual means for adjusting to variations in price and supply, e.g., storing the product,[13] switching to alternatives and so on. Suppliers are also characterised by significant variation between the costs of the different generation technologies available:

The costs of available generation technologies vary significantly.

- base load plants (such as hydro, coal, solar and wind), have relatively low operating costs, but this intrinsic, short run cost advantage is offset by relatively high capital (fixed) costs (i.e., the cost per unit of potential output) and, often, a reduced ability to vary output in the short term (i.e., 'stopping' and 'starting' certain types of such plants is not straightforward);
- mid-merit plants, typically in the form of combined cycle gas turbines (CCGT) have higher running costs, but mid-range capital (fixed) costs; and
- peaking plants, typically in the form of open cycle gas turbines (OCGT) have relatively low capital costs, a high degree of short-term controllability (i.e., 'stopping' and 'starting' such plants is easy) but relatively high running costs.

The way that prices are set is also a distinguishing characteristic. In most workably competitive markets, prices do not continually change – primarily because of the associated transaction costs[14] and customers' general aversion to volatile, unpredictable prices.[15] The NZWM is an exception. Prices in the NZWM are highly dynamic and are set in a way that reflects the fact that:

- demand for electricity is highly variable and must be met at (almost) all times, i.e., it is highly undesirable for the 'lights to go out';

[13] There are some limited exceptions. For example, battery technology is beginning to become more economic – although very few households have them. Moreover, hydroelectricity is sometimes considered to be a storable form of electricity – although this almost always done by generators, rather than final consumers.

[14] Updating prices for stockkeeping unit codes (SKUs) in computer systems and 're-stickering' inventory takes time and resources.

[15] For example, customers at McDonalds would be unlikely to react favourably if the price of Big Macs fluctuated significantly from day-to-day.

- output must change very rapidly, and by large amounts within the course of a day in order to meet that variable demand; and
- a suite of technologies is required to meet that variability efficiently, i.e., typically a combination of baseload, mid-merit and peaking plant.

Prices in the NZWM are highly dynamic and can change every five minutes.

Scheduled generators in the NEM are required to submit 'offer prices' for their capacity for every 5-minutes of the day. From all offers submitted, the system operator, Transpower, determines through a centralised process the generators that will be called upon to produce electricity based on the principle of meeting demand in the most cost-effective way, i.e., generators are dispatched in 'merit order' (from cheapest to most expensive). Prices are set as follows:

- a 'dispatch price' is determined every five minutes, based on the offer lodged by the most expensive generator that must be dispatched in order to meet prevailing demand in that period – the 'marginal generator'; and
- six dispatch prices are averaged every 30-minutes to determine the 'spot price' for each trading interval for each of the ~285 pricing 'nodes' throughout the NZWM, i.e., nodal spot prices are determined 48 times per day.

Because the NZWM is an 'energy only' market, the only way a generator can be paid for investing in plant is by being dispatched and producing electricity. It cannot be paid for having plant that is not being used, even if the existence of that capacity offers 'security of supply' benefits. This sets the NZWM apart from other wholesale market arrangements that *do* include payments to generators for simply offering capacity, such as the Western Australian market.

3.2 Competition in generation

The unusual features of the NZWM give rise to highly variable SRMCs. The market design is directed towards promoting competition between generators that produces prices that *reflect* those variable SRMCs. Specifically, the expectation is that most of the time generation plant should be 'dispatched' according to its economic merit order, as given by the ascending SRMC of running each type of plant (as determined by the respective operating and maintenance costs – the cost of managing scarcity is discussed subsequently).

The unusual features of the NZWM give rise to highly variable SRMCs.

Although generators in the NZWM are permitted to offer capacity at any price (subject to a 'scarcity pricing' mechanism[16]), the existence of competing offers by alternative plant owners normally constrains the prices that generators can bid. For example, a base load plant that bids capacity substantially above its operating and maintenance costs risks not being dispatched and being forced to incur the expense of shutting down and restarting. It will be foregoing the opportunity to earn positive economic profits in the meantime.

[16] If the weighted average spot price exceeds NZ$20,000/MWh, then prices are adjusted down so that the weighted average price is equal to $20,000/MWh.

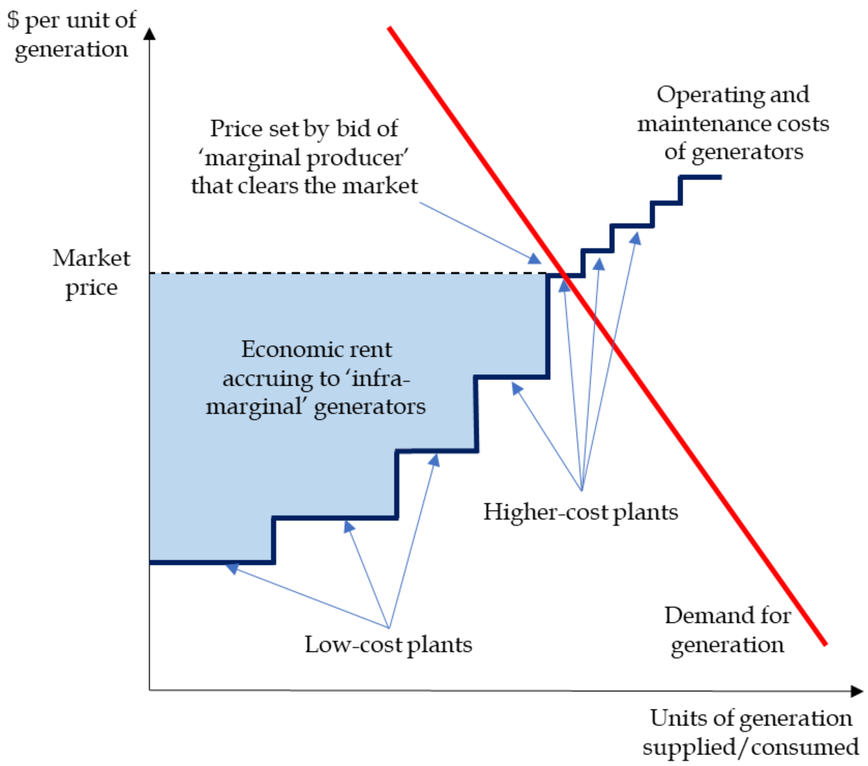
For this reason, provided there is ample generation capacity available to meet demand over the relevant time horizon (this is strong assumption that we will relax shortly when we explore the crucial issue of managing scarcity in the NZWM):

- generators have an incentive to offer to supply the market at prices that reflects their short run operating and maintenance costs; and
- if they do, plants will be scheduled to run in line with their economic 'merit order', i.e., from least-to-most expensive (in terms of $/MWh).

Figure 3.1 illustrates that, even when a generator offers its capacity at a price sufficient to cover only its operating and maintenance cost, the price it *receives* is equal to the offer of the last generator dispatched to meet demand (the 'marginal generator'). This means generators with lower running costs (base load and mid-merit plant that is 'infra-marginal') make a profit from the market price, allowing them to make a contribution to their fixed costs. But how does the *marginal generator* cover its investment costs? The answer is no different from that in any other competitive market.

Competition between generators should drive spot prices towards SRMC.

Figure 3.1: Economic merit order



When there is a possibility that the existing generation capacity will *not* be able to meet demand over the relevant timeframe, prices in the market *must rise* to reflect the increased SRMC of curtailing that excess demand. In situations where there is a risk of shortages, the costs associated with this demand side component can cause prices to rise *well above* the operating and maintenance costs of the marginal generator. It is during these periods that *marginal* generators are able to make a contribution to their fixed costs. We explore this crucial matter of prudently managing scarcity below.

3.2.1 Managing near-term scarcity

When there is enough capacity to meet demand over the relevant timeframe, prices should reflect the operating and maintenance costs of marginal plant.

Just as in any other competitive market, when there is expected to be sufficient capacity to meet demand over the relevant time horizon, prices in the NZWM should reflect operating and maintenance costs. More specifically, the price at each node should reflect the short run operating and maintenance costs of the marginal generator needed to meet demand at those locations. But equally, when there is a possibility that the existing generation capacity will be *insufficient* to meet demand over the relevant period, prices will rise *above* this level.

For the sake of illustration, imagine that generators only needed to supply one location *for a single time period* '*t*' (i.e., there is no need to worry about the future beyond this single point). How would one go about calculating SRMC – and therefore the expected spot price – in this time period? The approach is no different to in any other competitive market. Namely, the expected spot price can be estimated by undertaking a probabilistic assessment of possible future outcomes and the respective costs they entail. The formula is the same as previously; namely:

When there is a possibility that the existing generation capacity will be insufficient to meet demand over the relevant period, prices will rise.

- the SRMC of the marginal generator when supply exceeds demand over the relevant timeframe (i.e., operating and maintenance costs for that *single* period), multiplied by the probability of that scenario occurring; *plus*
- the SRMC of the marginal generator *plus* the SRMC of curtailing excess demand when supply is less than demand during that single period, multiplied by the probability of that scenario eventuating.

In electricity generation markets, the cost of curtailing demand to manage scarcity is termed the 'value of lost load' (VoLL). This reflects the amount customers would be willing to pay to avoid a disruption to their electricity service, i.e., it is the opportunity cost to them of being 'switched off'. For large industrial users (e.g., an aluminium smelter) that amount may be very high. VoLL estimates vary based on many factors – including the type of customer, plus the time and duration of outages.[17] To keep things simple, suppose VoLL is $10,000/MWh. The expected spot price at time *t* can therefore be expressed as follows:[18]

Expected spot price = [(1-LOLP) x OMC] x [LOLP x VoLL]

Where:

LOLP = Loss of load probability

OMC = Operating and maintenance cost of the marginal generator

VoLL = Value of lost load (assumed for simplicity to be $10,000/MWh)

By way of simple illustration, suppose that:

- there is a **98%** probability that there will be enough existing generation capacity to meet an additional unit of demand at time *t* -- **(1)**;

17 For a comprehensive discussion of VoLL estimation issues, *see:* PwC, *Estimating the Value of Lost Load in New Zealand*, March 2018 (available: here).

18 Hunt & Shuttleworth (1996), *Competition and Choice in Electricity*, Wiley, p.173.

- the short run operating and maintenance cost of the marginal generator in that scenario would be **$10/MWh** -- **(2)**;
- there a 2% probability that there *will not* be enough existing capacity to meet an additional unit of demand at time *t* -- **(3)**; and
- the opportunity cost to customers who consequently miss out (due to scarcity) at time *t* would be **$10,000/MWh** (the assumed VoLL) -- **(4)**.

The costs of managing scarcity can have a strong influence on SRMC and, in turn, spot prices.

With these simplifying assumptions, the expected spot price at time *t* would be: (98% x $10/MWh) + (2% x $10,000/MWh) = **$209.50/MWh**. What this example illustrates is the strong influence the costs of managing scarcity can have on SRMC and, in turn, expected spot prices. Even though the probability of a shortage emerging at time *t* is only small (2%), the potential *opportunity costs* that would arise in that scenario are vast. The probability-weighted effect of those 'scarcity' costs is consequently the primary driver of the spot price in this simple example.[19]

Importantly, this example assumes that generators only need to supply in a single period – *t*. And we have seen that, even in this highly simplified world, estimating SRMC is challenging. It depends as much on probability and expectation as on fact – often more so. Of course, in reality, generators do *not* focus only on the current trading period when making supply decisions. They also need to consider the potential implications of *today's* decisions on *tomorrow's* decisions. This complicates matters significantly, as we explain below.

3.2.2 Longer-term intertemporal considerations

Using water or gas to generate now means it cannot be used to generate later. This gives rise to distinct opportunity costs.

Some generation technologies are 'non-depleting'. For instance, using the sun's rays or the wind to produce electricity today does not affect the probability of being able to generate using those same fuel sources tomorrow. However, that is not the case for hydro or gas-fired plants – at least not in today's NZWM. By definition, using water to generate *now* means that same water cannot be used to generate electricity *later*. This is also the case for natural gas (and coal). There are therefore distinct opportunity costs associated with managing those resources through time.

3.2.2.1 Prudent water storage management

Currently, more than half of New Zealand's electricity is generated from hydro-electric plants.[20] As noted above, water is *not* an infinitely renewable resource,[21]

19 More generally, when the probability of shortage is effectively zero, spot prices can be expected to resemble the operating and maintenance costs of the marginal generator. As the probability of a shortage begins to increase (which will happen if demand is approaching the 'outer limits' of the supply curve), spot prices will start to increase and begin approaching VoLL.In the extreme scenario in which a shortage is certain (i.e., if the LOLP=1), the expected spot price *is* VoLL and, under the conditions described above, a price of $10,000/MWh should transpire for the period *t.*

20 The percentages vary year-on-year but, on average, ~60% of total generation is hydro-powered, and nearly all the amount produced in the South Island – where many of New Zealand's hydro lakes are located.

21 As an aside, one frequently hears the claim that it is 'much cheaper' to generate electricity with hydro plants than, say, thermal plants because 'water is free'. This is a fallacy. It is true that hydro

The opportunity cost of using water to generate now rather than saving it for later is an important component of the current SRMC.

since using more now may mean there is less available later (unlike with, say, sunlight and wind). Therefore, one of the short-run costs of using water to generate *now* is the foregone opportunity to generate with it at *another* time. This constitutes an important component of the total *current* SRMC of generating.

The value of this lost opportunity at any given moment – and the extent to which it contributes to the prevailing SRMC – will depend upon a variety of things. For example, it will be influenced by:

- current storage levels, e.g., whether a storage lake is nearly full or nearly empty;
- forecast hydrological conditions which will affect *future* storage levels and also the need to spill, e.g., whether river inflows will be high or low; and
- expected future electricity prices which will, of course, depend upon the same conditions throughout the rest of the country's hydro schemes.

The opportunity cost of water can vary greatly across catchment systems, plants and time.

Hydro generators – especially those without their own thermal firming/back-up plants – will naturally be keenly aware of the potential impacts their offer behaviour *today* may have on *future* storage levels. For example, we understand that at any point in time, there is only a few months' worth of 'supply' stored in Meridian's South Island storage lakes. In other words, if Lake Pukaki is 'full' today and all rain and snowmelt ceased, it would be nearly empty in a matter of months.

This means that even if a storage lake is 'fullish' in, say, September (spring), using all available water to generate then could mean there is a non-zero probability of running out in February (summer). This introduces an *inter-temporal* element into the offer calculus described earlier. Generators – and hydro-generators in particular – are interested not only in the probability of shortages emerging in the *near-term*, but also over the *longer-term*. Put simply, they can be expected:

A storage lake that is full at one point could be empty in a matter of months without prudent storage management.

- to consider the effect that using water to generate *today* may have on the probability of scarcity emerging in the *future*, e.g., of storage running low; and
- to therefore factor the potential costs that would arise from any potential future scarcity (i.e., opportunity costs to customers) into their offers *today.*

These intertemporal effects have a direct impact upon SRMC and expected spot price. If using water to generate *now* increases the probability of shortages emerging *later* (in, say, three-months' time), this *increases* the current SRMC of hydro generation. A hydro generator that incorporates those potential future costs into its offers today – and consequently receives a price above its 'operating and

generators do not have to 'do anything' to make it rain or to make snow melt. But thermal generators also do not have to 'do anything' to make coal and gas exist in underground deposits. We are all used to thinking of gas and coal as having a market value and therefore being 'costly'. Transactions involving water are seen less frequently, which perhaps contributes to the mistaken impression that its use should be free, or near to it. However, this intuition is misleading. There is no economic basis for concluding that water-based generation is less costly than coal or gas-based generation. All these types of generators have to 'do something' to make best use of their fuel resources. As this section explains, there is no economic reason to believe that reservoir management (e.g., deciding whether to use water now or later) is necessarily a lower cost activity than managing gas/coal resources (e.g., deciding whether to burn gas/coal now or later), once all relevant costs (including, most importantly, *opportunity costs*) are considered.

maintenance costs' – is therefore acting *prudently*. Complicating matters further still, different generators may manage those risks in a variety of ways, for example:[22]

Different generators may manage those water storage risks in a variety of ways via their bidding strategies.

- some generators might elect to increase their offer prices for every tranche of capacity offered, i.e., elevate their bids 'across the board';
- others might choose to price a certain percentage of their offers at significantly higher levels, i.e., offer some capacity (a 'baseload' quantity) at a 'lowish' price and a smaller quantity at a much higher price; and
- some might choose simply to physically withhold a portion of their capacity, i.e., to not offer it to the market at all and 'save it for later'.[23]

All these 'scarcity management' strategies have the potential to result in prices that exceed the generators' operating and maintenance costs (i.e., if the plant turns out to be marginal). However, this is not necessarily 'above-cost pricing' (i.e., spot prices in excess of SRMC). Rather, those prices could instead reflect the endogenously determined *opportunity cost of water*. These complex inter-temporal factors make it very difficult to pin down precise SRMC values for hydro plants.

To complicate matters even more, different generators may have contrasting *expectations* about future supply risks, (i.e., these are not 'facts' – there is an unavoidable element of subjectivity). Hydrological conditions, the nature of drought and the intensity of spill *all vary* across the different catchment systems. Generators' approaches to *managing* those perceived risks may also be coloured by a plethora of other factors, including the combination of generation technologies comprising their respective profiles. For example:

Different generators may also have contrasting expectations about future supply risks and varying approaches to managing them.

- hydro generators with discretionary thermal generation (e.g., Genesis and Contact) may have a greater appetite for risk, safe in the knowledge they can rely on those assets as 'back-up' if water levels run low; whereas
- Meridian does not own any thermal 'firming' plants that it can fall back on if its southern storage lakes start to run dry, which may diminish considerably its willingness to needlessly elevate longer-term supply risks.

There is also an important relationship between lake storage levels – and, in turn, the opportunity cost of water – and the availability and flexibility of *gas supplies*. If gas becomes scarcer, or there is less flexibility surrounding its availability, then hydro generators may understandably factor this into their *own* offers. If less gas generation is available then, all other things being equal, hydro generators will be dispatched more regularly and deplete their water supplies more quickly. We explore gas market conditions below.

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22 To be clear, this is a non-exhaustive list of potential approaches.

23 However, as we explain in section 4.3.2, the Electricity Code sets out a number of explicit criteria for a generator to follow when it finds itself in a 'pivotal supplier' situation, i.e., where its capacity (or at least some of it) is needed to meet demand in a location. To stay within the 'high standard of trading conduct' safe harbours (and therefore avoid any possibility of a subsequent regulatory intervention), a generator must – among other things – offer all of its available capacity to the market. In other words, a generator that adopted this strategy when pivotal – i.e., physically withheld some capacity in reserve – would, technically, not be within the trading safe harbours.

3.2.2.2 Tightening gas market conditions

If gas-fired generators were able to access all the natural gas they could ever possibly need in order to run (at reasonable prices), they would not need to worry about managing their fuel-stock. But, like water, gas is in limited supply. And those supplies have declined significantly in recent years. The prolonged outage at the Pohokura field in 2018 exposed the relatively fragile nature of New Zealand's gas supplies and the potential ramifications for spot prices.

There has been a tightening of gas supplies as well as reduced flexibility around delivery.

The deterioration of output from the Pohokura gas field was not anticipated so early in the field's life cycle and has resulted in a marked tightening of supplies and reduced flexibility around delivery. All available gas is contracted and users – including some generators – have been forced to accept a reduction in their contracted quantities. There are strong indications that gas supplies will continue to tighten and may eventually cease altogether. For example:

- the government's 2018 decision to ban all new off-shore oil and gas exploration permits has placed a cap on new domestic off-shore gas supplies;
- the Maui field is diminishing rapidly and, as noted above, supply from the Pohokura field has proved to be less reliable than expected;[24] and
- the Climate Change Commission has recommended eliminating natural gas use in residential, commercial and public buildings[25] – which could also foreshadow the end of its use as a generation fuel stock.[26]

Gas-fired generators therefore face a broadly analogous decision to that confronting hydro generators. Namely, thermal generators have access to a finite amount of fuel (in this case, gas) and they know that any of it they use now will not be available later – including potentially in the colder winter months when demand is highest. And so, just as with hydro plants, decisions about what prices to bid today must be made with a clear eye on the potential implications for future supply. If burning gas now increases the probability of shortages emerging later, then:

Decisions about what prices to bid today must be made with a clear eye on the potential implications for future supply.

- this again increases the *current* SRMC of gas-fired generation, i.e., the SRMC is equal to the operating and maintenance costs *plus* the opportunity costs associated with any increased probability of future scarcity; and
- those (potentially steep) opportunity costs should, ideally, be factored into their bids (and potentially current spot prices, i.e., if gas-plants are 'marginal') to enable more efficient consumption decisions.

Furthermore, as foreshadowed above, one might also expect to see *hydro* generators factoring projected gas market conditions into *their own bids* in some fashion. In the

24 For more detail on the long-term gas supply outlook, *see for example:* Concept Consulting Group Ltd, *Long term gas supply and demand scenarios – 2019 update*, 16 September 2019 (available: here).

25 Climate Change Commission, *Ināia tonu nei: a low emissions future for Aotearoa Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025*, 31 May 2021 (available: here).

26 Any ban on natural gas use in residential, commercial and public buildings would reduce local demand for natural gas, which could result in a significant reduction in domestic production, potentially reducing the availability of the fuel to generators.

NZWM, less thermal generation generally means more hydro generation and, in turn, a heightened probability of water shortages (and vice versa). Consequently, hydro generators can be expected to take these interdependencies into consideration when formulating their bids. There are many ways they might do so.

Hydro generators can be expected to factor gas market conditions into their own bids in some fashion.

For example, one approach would be to offer tranches of hydro capacity at prices commensurate with the estimated SRMC of gas generation. But here again, there is no 'right answer', since different generators may have varying views on (amongst other things), emerging gas market conditions. In addition, if a hydro generator *does not observe* gas-fired plants committing generation at the estimated SRMC of this type of generation, it may be forced to revisit the assumptions underpinning its water values.[27] About all that *is* clear is that any tightening in gas market conditions will flow-through *in some way* to SRMC and, in turn, to spot prices.

The preceding analyses illustrate there is a host of legitimate reasons for spot prices in the NZWM to rise above the *short run operating and maintenance costs* of marginal plants. This may reflect the underlying supply and demand conditions prevailing *in a particular trading period*. Or it may reflect potential *future* conditions, e.g., the probability-weighted average of a shortage emerging over the longer-term. Importantly, in neither scenario would a 'market power' problem exist.

3.2.3 Longer term

We have established that it is unremarkable to see periods of high spot prices in energy-only electricity wholesale markets – including the NZWM. Such periods are necessary to cover generation costs in the aggregate, to manage scarcity and, critically, to provide an *inducement for new investment* by firms chasing those high prices. When scarcity in the market causes spot prices to increase high enough, or frequently enough that the average spot price exceeds the LRMC of constructing additional capacity over that timeframe then:

The period over which spot prices rise to reflect the increased risk of near- or longer-term scarcity should be finite.

- firms already in the market have an incentive to expand their generation capacity so as to take advantage of those periods of high prices; and
- new firms have a stronger incentive to enter the market and offer new generation capacity, chasing those high prices.

In other words, provided that the electricity market is workably competitive, the period over which spot prices rise to reflect the increased risk of near-term congestion, or the need to manage longer-term scarcity, is *finite*. Specifically, once the cost of that curtailment/resource management (as represented by SRMC) has risen to a level that consistently exceeds the costs of adding capacity (as represented by LRMC), entry and expansion can be expected to occur over the longer-term to *meet* that additional demand.

27 This may be *very* difficult when gas generators are observed at times not committing generation *at any price* – which can and does happen (presumably due to restrictions relating to either gas availability and/or deliverability).

Prolonged periods of prices above LRMC should prompt investment in new capacity.

In this respect, a workably competitive wholesale electricity spot market functions no differently from most other competitive markets. Any change in market conditions that results in spot prices significantly and persistently *above LRMC* should, in time, prompt a supply-side response that restores prices to that level. For example, if short-term price spikes (e.g., to manage 'competitive scarcity') occur with sufficient frequency to push average spot prices significantly above LRMC this should, in time, prompt new entry and expansion. This relationship between prices and costs is the same as that described in general terms in section 2.3.

Prices that diverge from LRMC for significant periods of time may still be explicable in an electricity generation market.

Of course, one of the complications discussed in section 2.3 is that this supply-side adjustment process cannot necessarily be expected to be *perfect*. Because new generation capacity cannot be added (or removed) in 1MW increments, it can be difficult to time 'lumpy' capacity expansions (or reductions) to coincide precisely with the theoretical 'trigger points' described earlier. It takes time to plan expansions, obtain resource consents, construct plant, arrange connections and so forth. There may therefore be periods during which:

- average spot prices (and SRMC) are *above LRMC* for periods, as the market waits for the next increment of capacity to come on-stream; and
- average spot prices (and SRMC) are *below* long-run *avoidable* costs for periods, as the market waits for redundant capacity to be redeployed.

In other words, prices that diverge from LRMC (or LRAC) for significant periods of time may *still be explicable* in an electricity generation market. And, just as in any other competitive market, these periods of disequilibrium can be prolonged (or potentially shortened) by a variety of exogenous factors. For instance, investors may be reluctant to invest large sums into new generation plant if significant uncertainty surrounds the availability and cost of a particular fuel source.

SRMC – and average spot prices – should not differ materially from LRMC, provided they are assessed over an appropriate timeframe.

Such instances of 'disequilibrium' are neither unexpected, given the imperfections that can affect real markets, nor a cause for concern, provided they are transitory. Indeed, if such misalignments are likely to be 'self-correcting' (i.e., if it is simply a matter of waiting for any uncertainty arising from exogenous factors to abate), then intervening in the market would be unnecessary and very likely counterproductive.

With those important qualifications in mind, there is no reason to expect SRMC to differ materially from LRMC in competitive markets, on average, provided they are properly defined *and assessed over a sufficiently long timeframe* (i.e., one that allows for the resolution of exogenous factors). Equally, although both SRMC and LRMC can fluctuate over time, there is no reason to think that either will diverge materially over the longer term, when it is defined appropriately.

3.3 Incentives to engineer price increases

Hitherto we have focussed on the demand and supply conditions that can lead to high spot prices in a *well-functioning* competitive spot market. Complicating matters, these conditions are also the most likely to encourage the *exercise of market power*. Specifically, it is in that same environment in which market participants can have the strongest incentives to engineer price spikes through creating – or signalling – *contrived scarcity*.[28] This can be achieved in two principal ways:

- by 'physically' or 'economically' withholding capacity that *would otherwise be dispatched* in order to create *artificial* scarcity in the market (rather than *true* 'competitive scarcity') that must then be curtailed through high prices; or
- by a generator anticipating it will be the marginal supplier in a location, and consequently increasing its offers above its 'true' SRMC (i.e., including opportunity costs) in order to increase the market clearing price.

Generators can sometimes have incentives to engineer price increases by creating – or signalling – artificial scarcity.

In terms of the former strategy, *physical* withholding involves a generator not offering all of its capacity and *economic* withholding is where it offers some of its capacity at a price that exceeds the operating and maintenance costs of the likely marginal generator. The objective of the two types of withholding is the same: to increase the market clearing price by creating *contrived* shortages. There are a number of different withholding strategies that can be employed by generators.

For example, withholding can involve a low-cost producer (e.g., a baseload plant) withholding part of its capacity to increase the price at which *the remainder* is dispatched. It can also involve the coordinated use of multiple generation units. For instance, a generator with both baseload and mid-merit or peaking plant might withhold the latter in order to produce a shortage that benefits the former. Successful implementation of either strategy depends on the concurrence of a number of factors, including:

Strategic withholding involves holding back some capacity in order to change the identify of the marginal plant and increase spot prices.

- whether the slope of the 'merit curve' is 'steep' or 'flat' around the market clearing price, since this determines the magnitude of any price increase;[29]
- the production costs of the low-cost suppliers that potentially could restrict output to increase profits and the total quantities supplied to the market; and
- the extent to which a reduction in supply by a low-cost supplier might be offset by increased supply by other low-cost so as to reduce any price effect.[30] and

The hedging position of the withholding generator is also relevant. If a vertically integrated generator (i.e., with retail load to serve) is:[31]

28 *See:* Joskow, P (2007), 'Competitive Electricity Markets and Investment in New Generating Capacity', *The New Energy Paradigm* (ed: Dieter Helm), Oxford University Press.

29 The shape of the merit curve in electricity markets can therefore be conducive to such conduct at high levels of demand. The shape of the demand curve is less relevant since consumers tend to be very unresponsive to short-term price increases.

30 This is not a possibility when a generator is 'pivotal', i.e., where demand cannot be met without it.

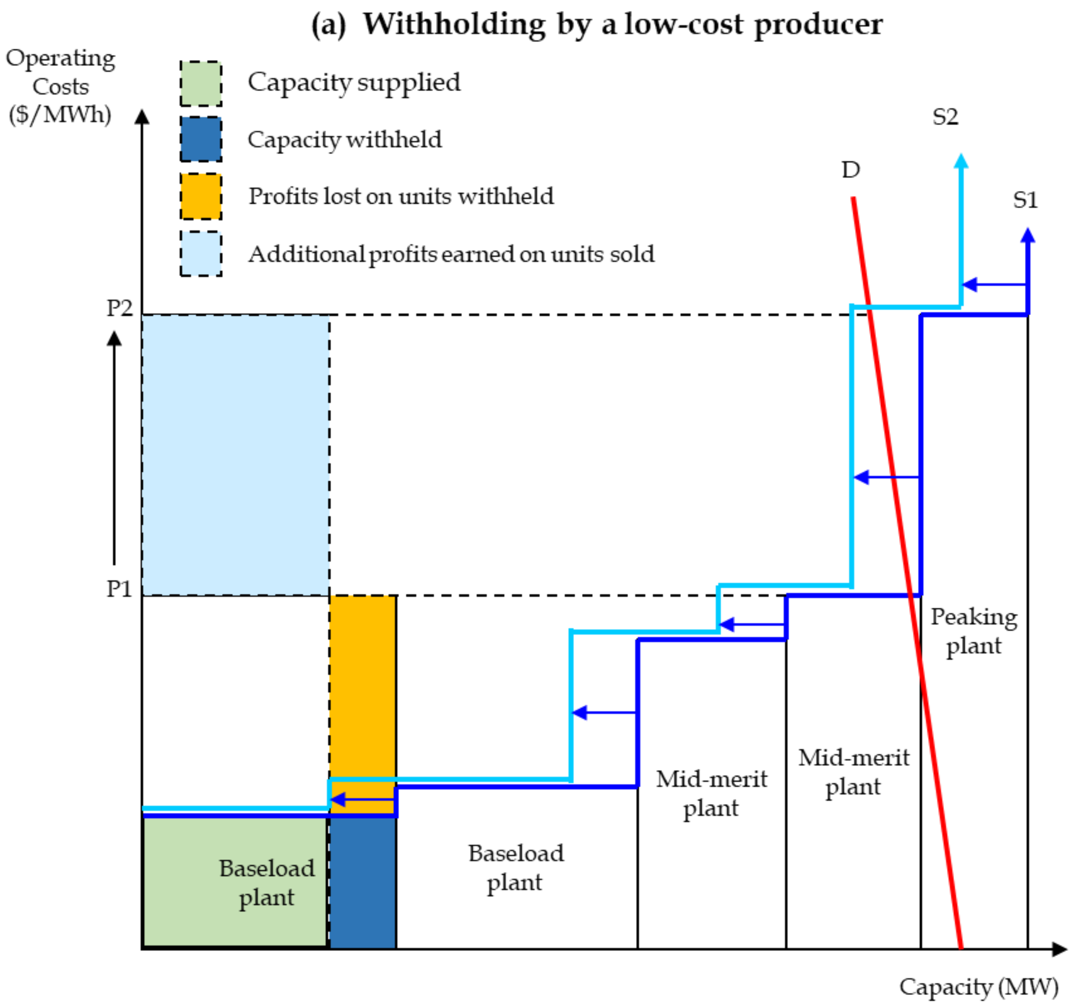
31 In principle, a generator may still have some incentive to withhold capacity and increase the spot price, even if the near-term financial benefit to it from doing so is diminished by its hedging position. The price of hedge contracts is determined primarily by the balance of expectations as to the level and volatility of future spot prices. Consequently, if average spot prices are seen to be increasing – e.g., because of the short-term incentives described above – this can usually be expected to result in higher contract prices, potentially creating a 'longer-term' pay-off.

- 'long' on generation,[32] then in the immediate term, it will only earn more on sales not covered by its existing contracts, i.e., the uplift in price will lead to an increase in profits only on its unhedged capacity; and
- 'short' on generation, then the near-term consequence of engineering the price increase will be that it pays *more* to purchase the additional generation it needs to meet its own commitments.

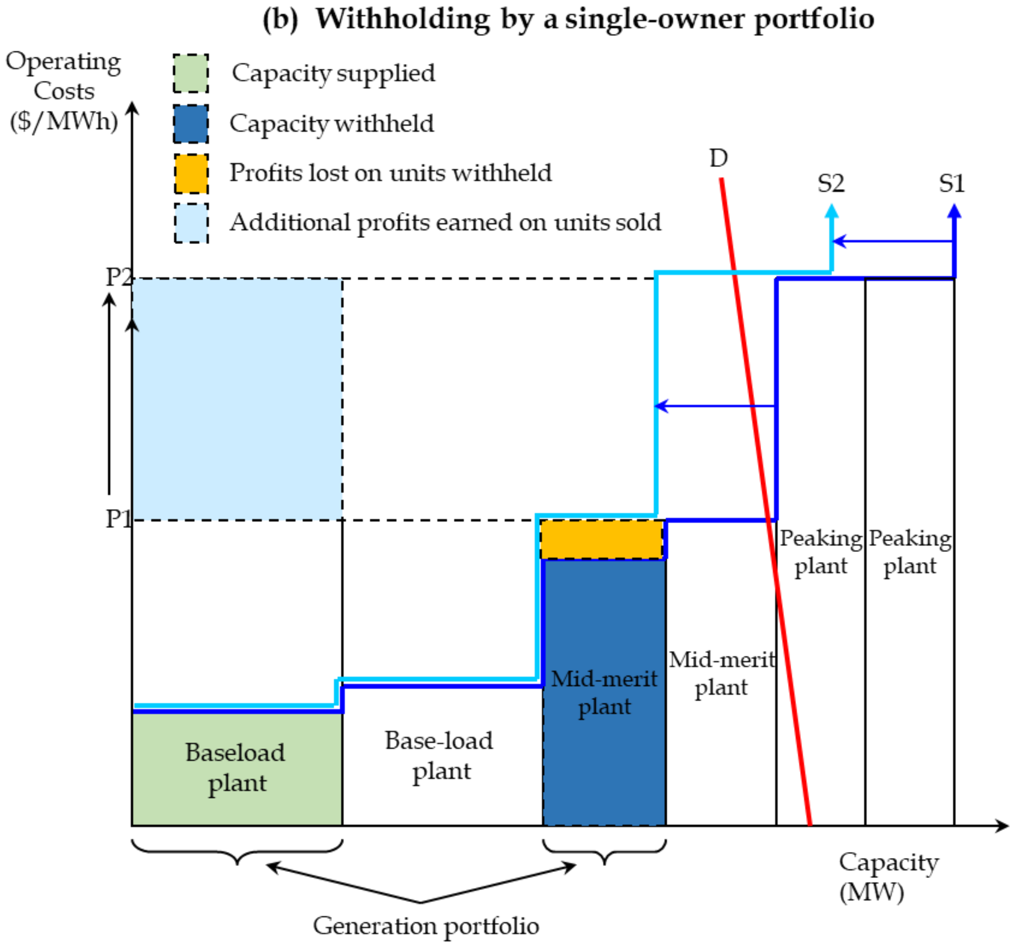
Figure 3.2 illustrates each of these withholding strategies, i.e., withholding by a low-cost producer and by a single-owner portfolio.

Figure 3.2: Strategic withholding

The withholding plant forgoes profits on the capacity it withholds but earns higher profits on the units it supplies.



32 A generator is 'long' if its wholesale revenue from generation and derivatives is greater than its wholesale costs from purchases and derivatives, i.e., if it is a net seller of generation. Conversely, a generator is 'short' if it is a net buyer of generation.



If a generator expects to be marginal, it can potentially increase its profits by increasing its offers above its 'true' SRMC.

The second principal means of engineering prices increases is far simpler. If a generator expects it will be the marginal supplier, then it can potentially increase its profits by increasing its offers above its 'true' SRMC (even if this might result in some of its capacity not being dispatched). Both strategies – strategic withholding and directly increasing marginal prices – can result in higher prices that *do not reflect* the underlying supply and demand conditions.

This begs the question: how can one distinguish *legitimate* price increases from *potentially problematic* ones in the NZWM? As we have seen, short-term price spikes will often reflect underlying supply and demand dynamics, yet they can also be symptomatic of artificial 'engineering'. In our opinion, the best way to draw these distinctions and to gauge the effectiveness of competition is by adopting a *broader, longer-term* perspective. We elaborate below.

3.4 Implications for assessing competition

Section 2.4 described the various challenges typically encountered when trying to compare prices with SRMC and draw inferences about the state of competition in *any* market. Foremost are the difficulties associated with estimating the opportunity costs of managing scarcity. Unless these costs are properly factored in when constructing SRMC estimating, those benchmarks will *underestimate* the prices that would prevail under workable competition. This risks 'false positives', i.e., erroneous findings that competition is less than effective.

There are many legitimate reasons for spot prices to exceed the short run operating and maintenance costs of marginal plants.

These difficulties are magnified manyfold in the context of the NZWM. There is a host of legitimate reasons (i.e., unrelated to the exercise of market power) for spot prices in the NZWM to rise above the *short run operating and maintenance costs* of marginal plants. For example, a temporary price spike may simply reflect the underlying supply and demand conditions:

- prevailing *in that particular trading period*, i.e., there may be a non-zero probability of an immediate or near-term shortage; or
- potential *future conditions*, e.g., the probability-weighted average of a shortage emerging over the longer-term if, say, water supplies wane.

The latter consideration in particular greatly complicates the estimation of SRMC in New Zealand's hydro-centric system. Hydro generators will be mindful of the potential impacts their offer behaviour *today* might have on *future* storage levels. The enormous costs associated with power shortages – and the inevitable negative publicity and scrutiny that follow – will factor heavily into water management strategies. Complicating matters further, as we have seen:

- different generators may have varying expectations about supply risks (these are not observable 'facts') – and hydrological conditions, the nature of drought and the intensity of spill all vary across the different catchment systems; and
- different generators may manage those risks in a variety of ways[33] and those strategies may be affected by a plethora of factors, including the combination of generation technologies comprising their profiles.[34]

It is impossible to produce objective measures of opportunity costs and, in turn, SRMC in the NZWM.

These complexities make it impossible to produce objective measures of opportunity costs and, in turn, SRMC in the NZWM – something the Authority acknowledges.[35] Even the most sophisticated models of SRMC will inevitably struggle to capture all the intricacies and complexities described above. This reduces considerably the utility of comparisons between spot prices and SRMC – regardless of how those benchmarks have been calculated. Such exercises are susceptible to errors (and 'false positives') and, in our opinion, are best avoided.

More reliable insights into the state of competition can be gained by adopting a *broader, longer-term* perspective. If competition is workable, the period over which spot prices can rise to reflect the increased risk of near-term congestion, or the need to manage longer-term scarcity, is *finite*. Once the costs of managing scarcity have risen to a level that consistently exceeds the costs of adding capacity entry and expansion *should* occur. More specifically, once expected *post-entry* wholesale spot prices[36] exceed the *LRMC* of constructing additional capacity then:

33 Some may elect to offer a portion of their capacity at much higher prices to signal to customers the potential scarcity value. Others may choose simply to physically withhold a portion of their capacity, i.e., to not offer it to the market at all and 'save it for later'.

34 For example, a generator with firming thermal generation may perceive and manage water storage risks differently to a generator without such assets in its portfolio.

35 Information paper, p.49.

36 If a firm expects that its entry would cause prices to drop to a substantial degree (e.g., due to the 'lumpy' nature of a capital expansion and the surplus capacity it may create), then it will focus on

More reliable insights into the state of competition can be gained by adopting a broader, longer-term perspective.

- firms already in the market have an incentive to expand their generation capacity so as to take advantage of those high prices; and
- new firms have a stronger incentive to enter the market and offer new generation capacity, chasing 'above normal' profits.[37]

However, those supply-side adjustments are not instantaneous. It takes time to build new plant, which means there may be periods when average spot prices are *above LRMC* for periods, as the market waits for the next increment of capacity. And, just as in any other competitive market, these periods of disequilibrium can be extended (or potentially shortened) by various exogenous factors. For instance, investors may be reluctant to invest in new plant if:

- significant uncertainty surrounds the availability and/or cost of a particular fuel source (e.g., due to potential government policies);
- there is significant 'sovereign risk' (e.g., a chance the government might invest public funds into generation, crowding out private investment);
- uncertainty surrounds the future of certain major customers, the departures of which might lead to near-term price drops and/or asset retirements; and/or
- there is material 'regulatory risk' (e.g., if uncertainty surrounds how regulators may intervene in the contestable and/or network elements of the supply chain).

Misalignments between prices and LRMC are not unexpected or a source of concern, provided they are transitory.

In those circumstances, investors might understandably delay expansions until more certainty emerges – even if prices (i.e., SRMCs) exceed the cost of entry (i.e., LRMC) in the meantime. Such instances of 'disequilibrium' are neither unexpected, given the imperfections that can affect real markets, nor a cause for concern, provided they are transitory. Indeed, if such misalignments are likely to be 'self-correcting' (i.e., if it is simply a matter of waiting for 'uncertainty' to wane), then intervening the in the market is unnecessary and likely to be counterproductive.

With those important qualifications in mind, there is no reason to expect spot prices to differ materially from LRMC in competitive markets, on average, provided they are properly defined and assessed over a sufficiently long timeframe (i.e., one that allows for the resolution of exogenous factors).[38] This suggests the best way to gauge the state of competition in the NZWM is ask two basic questions: 1) have spot prices been persistently above LRMC? And 2) if so, are likely to remain so due to enduring barriers to entry, or are they likely to 'self-correct'?

3.5 Summary

Energy-only electricity generation markets have some characteristics that distinguish them from many other markets. However, despite those differences, a

the expected *post-entry* prices when weighing its entry decision. This is an important nuance in the NZWM, when generator entry can have a significant impact upon prevailing nodal prices.

37 *Ibid.*

38 Equally, although both SRMC and LRMC can fluctuate over time, there is no reason to think that either will diverge materially over the longer term, when it is defined appropriately.

competitive wholesale electricity spot market functions no differently from most other competitive markets. Specifically, with certain limited exceptions, if prices are significantly and persistently *above LRMC* this should, given time, prompt a supply-side response that restores prices to these levels. The best way to gauge the state of competition in the NZWM is therefore to ask two basic questions:

- have spot prices been persistently above LRMC?; and
- if so, are spot prices likely to remain at that level due to enduring barriers to entry, or are they likely to 'self-correct', i.e., revert to LRMC over time?

If spot prices have *not* consistently exceeded LRMC, then this suggests strongly there is no competition problem. If they *have*, the question then becomes: *why?* Specifically, it is necessary to consider whether the observed margin between prices and entry costs is attributable to enduring barriers to entry, or transitory factors that may wane over time, e.g., investor uncertainty. If it is the latter, any perceived 'problem' may be self-correcting. Intervening in the market in such circumstances may therefore be needless and potentially harmful.

Conversely, few insights into the state of competition can be gleaned from comparing spot prices with estimates of SRMC. That is because it is impossible to produce objectively robust estimates of SRMC, given the complexities involved in measuring opportunity costs in New Zealand's hydro-centric system. Despite those challenges, much of the analyses in the Information Paper entail precisely these kinds of assessments. As we explain in the following section, unsurprisingly, those assessments are of little or no probative value.

4. Review of the Authority's short-term analyses

The Information Paper concludes the high spot prices are at least partly due to fuel supply scarcity and high fuel costs.

The Information Paper contains various analyses, including a linear regression of spot prices pre- and post-2018. This analysis indicates that the price increases observed over the period were at least partly attributable to fuel supply scarcity and higher fuel costs. However, the Authority also suggests there has been a sustained upward shift in spot prices that the regression *cannot* explain. The model could not reveal whether this shift was attributable to (amongst other things):

- limitations in the model itself;[39]
- uncertainty about the gas market influencing bids and prices; and/or
- generators exercising substantial market power.

Various other tests are then performed to look for any signs of the exercise of market power.

The Authority then performed a series of *other* analyses to see if it could determine the reasons for the perceived uplift. In particular, it looked for any indications that generators might have been exercising market power by exploring short-term 'price-cost' relationships.[40] However, as we explain below, these assessments exhibit many of the shortcomings foreshadowed in sections 2.4.1 and 3.4. They are consequently incapable of providing meaningful insight into the state of competition.

4.1 Percentage of offers over $300/MWh

The Authority's begins its examination of short-term price-cost relationships by looking at the percentage of offers that have exceeded $300/MWh over time. It reasons that: 'if significant quantities of a generators' capacity are offered at high prices, or above price and cost, this could indicate economic withholding, which is an exercise of market power.'[41] Its analysis reveals a significant increase post-2018 in the percentage of offers at higher prices for both hydro and thermal generators. The Authority then observes that:[42]

The Authority notes the percentage of offers over $300/MWh is higher, post-2018.

> *'The timing of most of these offer price increases seems consistent with the rise in the cost of thermal fuel, the increasing uncertainty surrounding gas supply from Pohokura and hydro storage conditions. However, the steadily increasing percentage of higher priced offers since 2014 at Meridian's (Waitaki) stations, the only slight decrease in 2020 at Contact's (Clutha) stations, and the quantity of higher priced offers at Mercury's (Waikato) stations since 2018 is not immediately explainable by underlying conditions.'*

The Authority notes also that a significant proportion of some hydro generators' capacity – including Meridian's – is consistently not dispatched, even during times of 'high' storage:[43]

> *'… it appears that Meridian (Waitaki) and Mercury* [sic] *(Waikato) higher priced offers are less related to storage than the other hydro generators. Meridian (Waitaki), Contact (Clutha)*

39 It is nearly impossible for any regression to perfectly capture all relevant variables, in practice.

40 Information Paper, p.49.

41 *Op cit.*, p.50.

42 *Ibid.*

43 *Op cit.*, p.51.

and Mercury (Waikato) always have, on average, above 30 percent of their capacity offered at higher prices than the final price (ie, above 30% of their generating capacity is not dispatched).

A simple analysis of the percentage of offers above $300/MWh reveals little – if anything – about competition in the NZWM.

In our opinion, a simple analysis of the percentage of offers above $300/MWh reveals little – if anything – about the state of competition in the NZWM. As we noted earlier, in New Zealand's hydro-centric system water shortages are only ever a few months' away. A storage lake can be full in September, but near-empty come February if an unexpected drought descends. Those risks must be factored into SRMC and into offers in some fashion. As we noted earlier, different generators might manage those supply risks in a variety of ways, for example:

- some generators might elect to increase their offer prices for every tranche of capacity offered, i.e., elevate their bids 'across the board';
- others might choose to price a certain percentage of their offers at significantly higher levels, i.e., offer some capacity (a 'baseload' quantity) at a 'lowish' price and a smaller quantity at a much higher price; and
- some might choose simply to physically withhold a portion of their capacity, i.e., to not offer it to the market at all and 'save it for later'.

Meridian offer a tranche of capacity at ~$300/MWh, but those offers are not intended to clear.

We have been advised that, broadly speaking, Meridian adopts the *second* strategy. Namely, it chooses to offer a tranche of capacity at ~$300/MWh – a volume that *is not intended to clear*. This 'high-priced' tranche is a quantity that Meridian chooses to systematically hold in reserve as part of its overall storage management strategy. The capacity is offered only really *as a back-up*, i.e., so that it is available to the system operator if an unexpected shortage emerges and it is needed (e.g., an event similar to that experienced in the North Island on 9 August).

We understand that Meridian maintains this strategy relatively consistently – even when storage levels are quite high. This is perhaps unsurprising given that, unlike some other generators in the NZWM it has no thermal-firming assets and only a few months' worth of storage available in the Waitaki catchments at any moment. It has consequently chosen to apply a 'smoothed/flattened' water value curve through time. An alternative approach would be for Meridian to have:

Meridian maintains this strategy as part of its storage management practices, i.e., to signal the potential costs of water shortages.

- more periods in which it offered a greater proportion of its capacity at prices below $300/MWh; and
- with this inevitably being offset by more periods with offers *well above $300/MWh* when its storage levels dropped.

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. Another strategy would be for Meridian to *simply not offer* a proportion of its capacity, i.e., to physically withhold it. Ironically, this would serve to *reduce substantially* the proportion of its capacity offered above $300/MWh. We understand that this is precisely the strategy *already* adopted by some generators, which serves to undermine the analysis even further.[44]

If Meridian physically withheld some of its capacity, it would be frequently trading outside the HSOTC safe harbours.

Prior to June 2021, a secondary reason Meridian chose not to withhold a portion of its capacity (and opted instead to offer it at a price not intended to clear) was the 'high standard of trading conduct' (HSOTC) rules that were in place up to that point. As we explain in more detail in section 4.3.2, the Electricity Code set out certain criteria for a generator to follow when it found itself in a 'pivotal supplier' situation, i.e., where its capacity (or at least some of it) was needed to meet demand in a location. To stay within the HSOTC safe harbours, those rules required:

- a generator to offer *all* of its available capacity to the market; and
- when a generator found itself in a pivotal position, its offers had to be (amongst other things) generally consistent with how it bid when it was *not* pivotal.

As section 4.3 explains, in recent years Meridian found itself 'gross pivotal' in the South Island in ~90-95% of trading periods. Consequently, before June 2021, if it chose to manage its water resources by physically withhold a portion of its capacity from the market (one of the strategies described above), it would have been *trading outside* the HSOTC safe harbours ~90-95% of the time. All things considered, it is therefore easy to understand how it arrived upon the strategy of offering *all* its capacity – with some priced at levels *not intended to clear* in most circumstances.

More generally, given the tightening gas market conditions, one might also expect to see *hydro* generators factoring projected gas market conditions into their bids in some fashion. In the NZWM, less thermal generation generally means more hydro generation and, in turn, a heightened probability of water shortages (and vice versa). Consequently, hydro generators can be expected to take these interdependencies into consideration when formulating their bids. There are many ways they might do so.

Tightening gas market conditions may have also resulted in more offers exceeding $300/MWh.

For example, one approach would be to offer tranches of hydro capacity at prices commensurate with the estimated SRMC of gas generation. This would also contribute to a growing percentage of offers in excess of $300/MWh – including from hydro plants. This could be especially the case if there was a growing level of uncertainty about gas market conditions and future gas prices. For those reasons, we do not consider that anything useful can be gleaned from the Authority's examination of offers exceeding $300/MWh, in isolation.

4.2 Comparisons to short run costs

The Information Paper contains a series of analysis comparing generators' offers with two estimates of SRMC – or, rather, what the Authority *characterises* as SRMC. These short-term analyses appear to be beset by the types of problems foreshadowed earlier. For example, the estimates of SRMC do not appear to be

[44] Physically withholding capacity from the market is the economic equivalent of offering that capacity at an infinite price. Yet, the analysis in the Information Paper is incapable of capturing this critical nuance.

objectively reasonable measures of the *true* short-term costs of generation. The way offers have been formulated for comparison purposes is also problematic. This can be illustrated using some simple 'sense checks'. We elaborate below.

4.2.1 Quantity-weighted offer price (QWOP) values

To compare generator's offers to SRMC, the Authority constructs a single 'quantity-weighted offer price' (QWOP) value.

In order to compare generator's *offers* to underlying estimates of their short run costs, the Authority constructs a single 'quantity-weighted offer price' (QWOP) value. This QWOP metric collapses all generation offers across different price and quantity bands into a single, quantity-weighted value. Table 4.1 provides a simple illustration, using a hypothetical hydro generator's offers. The generator is assumed to offer tranches of capacity at four price points. Most relevantly:

- at the bottom end of the range is a 'baseload quantity' of 1,000 units offered at a zero price, intended to (all but) guarantee this volume is dispatched;
- at the top of the range, 20% of the generator's capacity is offered at a 'high' price of $500/MWh, which is *not intended to clear* in ordinary circumstances; and
- to that end, the generator anticipates it will be marginal at ~1,500MW, i.e., beyond that point no more of its capacity is expected to be required.

As we explained above, the $500/MWh price could serve a number of purposes. It could signal the potential future costs of scarcity (and/or represent the 'shadow cost' of thermal plant). Offering that capacity could also allow the generator to stay within the HSOTC safe harbours if it expects to be 'gross pivotal' in the period. It might also serve as a source of 'back-up' capacity if, say, there was an unexpected outage and more supply was suddenly needed.[45] All these purposes are perfectly legitimate in a competitive market.

Table 4.1: Calculation of QWOP value

Price ($/MWh)	Quantity (MW)	% of Quantity	QWOP ($/MWh)
$0	1,000	50%	$0 x 50% = $0
$50	400	20%	$50 x 20% = $10
$100	**200**	**10%**	**$100 x 10% = $10**
$500	400	20%	$500 x 20% = $100
		Overall QWOP value	**$120**

QWOP values and SRMC estimates must incorporate opportunity costs in the same ways for comparisons between them to be valid.

Despite the fact that the generator has no serious intention of supplying 400MW at $500/MWh (the price signal *discourages* customers from using that capacity unless they are prepared to bear those opportunity costs) that tranche has a substantial impact upon the QWOP estimate. Indeed, it accounts for ~*83%* ($100 ÷ $120) of the final value. Consequently, unless this QWOP value is compared to estimates of SRMC that factor in the opportunity costs of managing scarcity *to the same extent*, it is unclear whether any useful information will be conveyed.

45 The recent events of 9 August (when ~20,000 households across the North Island lost power on one of the coldest nights of the year) being a salient example.

The intrinsic volatility of the QWOP value makes this very difficult to achieve. To illustrate, consider how the QWOP value calculated earlier changes if three simple changes are made. First, suppose that instead of offering its 'baseload' quantity of 1,000MW at $0, the generator prices this tranche at $40/MWh. Second, imagine that instead of offering its top tranche at $500/MWh the generator offers it at $5,000/MWh. And, finally, suppose that instead of offering 400MW at $500/MWh the generator decides to not offer that capacity at all, i.e., to physically withhold it from the market. Table 4.2 illustrates these scenarios.

Different bidding strategies designed to achieve the same things can cause large changes in the QWOP value.

Table 4.2: Volatility of QWOP value

Bottom offer tranche increased from $0/MWh to $50/MWh			
Price ($/MWh)	**Quantity (MW)**	**% of Quantity**	**QWOP ($/MWh)**
$40	1,000	50%	$40 x 50% = $20
$50	400	20%	$50 x 20% = $10
$100	200	10%	$100 x 10% = $10
$500	400	20%	$500 x 20% = $100
		Overall QWOP value	**$140 ($20↑)**

Top offer tranche increased from $500/MWh to $5,000/MWh			
Price ($/MWh)	**Quantity (MW)**	**% of Quantity**	**QWOP ($/MWh)**
$0	1,000	50%	$0 x 50% = $0
$50	400	20%	$50 x 20% = $10
$100	200	10%	$100 x 10% = $10
$5,000	400	20%	$5,000 x 20% = $1,000
		Overall QWOP value	**$1,020 ($900↑)**

Top offer tranche removed, i.e., the 400MW is not offered			
Price ($/MWh)	**Quantity (MW)**	**% of Quantity**	**QWOP ($/MWh)**
$0	1,000	50%	$0 x 50% = $0
$50	400	20%	$50 x 20% = $10
$100	200	10%	$100 x 10% = $10
		Overall QWOP value	**$20 ($100↓)**

Crucially, *none of these changes* would be expected to influence the market-clearing price, since neither the bottom nor the top tranche is likely to be 'marginal' in the trading period (under the above assumptions). Furthermore, each bidding strategy is intended to fulfil the *same basic purposes* (described previously). Most notably, these strategies are simply (amongst other things) different ways of managing scarce water resources. Indeed, in each instance, the overall *opportunity cost* that is being signalled through the generator's offers may be *identical*.[46]

The sensitivity of QWOP values to changes means comparisons to SRMC may not be robust, even if opportunity costs are properly captured.

Yet, despite these strategies' uniformity of purpose and their identical impacts upon price, the final QWOP values vary substantially depending upon which of them is being employed. This means that even if the SRMC estimates to which those QWOP values are being compared *are robust* (e.g., appropriately incorporated scarcity values, etc.), the results would still be of little or no use. For example, if a generator's QWOP value was found to have exceeded the underlying estimates of SRMC, it may be difficult to discern whether this is because:

- a generator has been attempting to exercise substantial market power; or
- it has been employing a *legitimate* bidding strategy that inadvertently skewed the calculation of the QWOP value (such as in the examples in Table 4.2).

To reiterate, those challenges exist *even when SRMC has been estimated accurately*. If SRMC benchmarks are *not* robust, this will lead to *further* problems. For instance, even if the QWOP value *does* accurately capture the opportunity cost of managing scarcity (despite the practical problems identified above), unless the underlying SRMC benchmarks *also* appropriately incorporate those opportunity costs, the exercise will be 'comparing apples with oranges'. The Authority's analyses appear to have been affected by this problem, as we explain below.

4.2.2 Estimates of SRMC

In a hydro-centric system such as New Zealand's it is impossible to produce objective measures of the SRMC of generating. We explained why in section 3.4. Most importantly, Hydro generators will be cognisant of the potential impacts their offer behaviour *today* may have on *future* storage levels. The substantial costs associated with power shortages can be expected to weigh heavily on water management strategies. Different generators may also have varying expectations about supply risks[47] and adopt a variety of mitigation strategies in response.[48]

The SRMC benchmarks used throughout the Information Paper do not appear to be reasonable.

We suggested earlier that the difficulties involved in producing robust estimates of SRMC in the context of the NZWM greatly reduced the usefulness of short-term price-cost comparisons. Even the most sophisticated models of SRMC will inevitably struggle to capture all the intricacies and complexities described hitherto and risk producing 'false positives and negatives.' The SRMC benchmarks adopted

46 The differences between the scenarios in which the generator offers its top tranche at $500/MWh and $5,000/MWh, respectively, could be explained by the underlying 'water value curves' guiding their offering behaviour. For example, as noted earlier, one approach would be to 'smooth-out' or 'flatten' the water value curve over time by consistently offering a portion (here, 20%) of capacity at $500/MWh. An alternative might be to offer *much higher* prices with *less frequency* (i.e., at lower storage levels) – here, at $5,000/MWh. These are two different ways of managing scarcity and, ultimately, signalling the same overall opportunity cost (albeit, in different ways over time).

47 Specifically, different generators may have varying expectations about supply risks (these are not observable 'facts') – and hydrological conditions, the nature of drought and the intensity of spill all vary across the different catchment systems.

48 For example, a generator with firming thermal generation may perceive and manage water storage risks differently to a generator without such assets in its portfolio

by the Authority throughout its Information Paper appear to be no exception. Two forms of SRMC estimates are employed:[49]

- water values provided by the generators themselves – in Meridian's case, its so-called 'minimum sell values'; and
- water values produced using a Dynamic Outer Approximation Sampling Algorithm (DOASA) model.

Meridian's 'minimum sell values' do not represent reasonable estimates of the SRMC of hydro generation.

We cannot comment on the water values provided by other generators but, insofar as *Meridian's* are concerned, its 'minimum sell values' are plainly *not* measures of SRMC. We have been advised by Meridian that these values provide *non-binding* guidance for traders as they look to price a *certain sub-set* of its capacity. Crucially, those minimum sell values do *not* influence:

- generation offers that are priced at close to zero to cover Meridian's contracted volumes (i.e., the equivalent of the 'baseload' quantity described in Table 4.1); or
- even more importantly, generation offers that are priced at a level *not intended to clear* (i.e., at $300/MWh and above) in a typical trading period, i.e., offers that:
  - are intended to signal the *opportunity costs* of scarcity (i.e., consistent with prudent management of storage lakes and reservoirs); and
  - are made to assist in the management of unexpected shortages (an alternative being to not offer that capacity at all[50]).

If Meridian offered all its capacity at its 'minimum sell values' the probability of shortages would increase substantially.

In other words, the 'minimum sell values' do not capture one of the chief means by which Meridian signals to customers *the opportunity cost of scarcity* – namely, the prices in its more expensive tranches (i.e., bids $300/MWh and upwards). The resulting SRMC benchmark is consequently almost certainly *too low*. Meridian has advised us that if it (hypothetically) consistently offered *all* its available capacity at these minimum sell values it would be at grave risk of running out of water.

By way of simple illustration, if Meridian's full generation capacity had been offered at the *market-clearing* prices from, say, November last year (i.e., at prices likely to have *systematically exceeded* Meridian's minimum sale values), the potential consequences would have been highly undesirable. Meridian has informed us that the drought experienced in the first half of this year would have seen Lake Pukaki *fully depleted* by late March or shortly thereafter if it had adopted this bidding approach, with forced customer outages inevitably following.

Meridian's 'minimum sell values' consequently *do not represent credible estimates of SRMC.* And, by extension, neither do the estimates produced by the DOASA model. The results reported in the Information Paper indicate the DOASA estimates tend to

49 Information Paper, pp.58-59.

50 Remembering that this would cause Meridian to fall outside the HSOTC safe harbours during the many periods in which it is 'gross pivotal' in the South Island (~90-95% of the time). See further discussion in section 4.3.2.

Using the DOASA model's SRMC estimates as the basis for offers would elevate the risk of shortages further still.

be *even lower* than Meridian's minimum sell values.[51] We understand Meridian has modelled (using the vSPD model[52]) the storage outcomes that would have resulted throughout 2021 if its hydro plants had offered to generate at the water values produced by the DOASA model. Meridian also examined what would have transpired if it had replicated this bidding strategy in 2008 and 2012 – both of which were 'drier years' with a reduced inflow sequence. The results are striking:[53]

- Meridian estimated that, in 2021, storage levels would have come perilously close to the level at which an official conservation campaign would have been triggered, which would have been an extraordinary occurrence given the hydrological conditions (2021 was drier than average, but not overly so); and
- Meridian concluded that, in 2008 and 2012, New Zealand would have run out of controlled hydro storage and there would have been insufficient total thermal generation available to avoid energy shortages, i.e., it is likely that load shedding would have been required over significant periods of time.

The DOASA values and Meridian's 'minimum sell values' appear to underestimate the true SRMC of generation.

Given the severity of the potential consequences in each case, it is implausible to think a prudent hydro generator would contemplate offering its capacity at the DOASA-based prices. If the circumstances described above had actually transpired in any of those years, hydro generators would have undoubtedly faced a sharp backlash from stakeholders, regulators and politicians – and rightly so. In our opinion, it is consequently inaccurate for the Information Paper to characterise the DOASA model as providing 'a lower bound for water values.'[54]

Rather, what these simple 'sense checks' illustrate is that the DOASA values – *and* Meridian's 'minimum sell values' – represent *implausibly low* estimates of the *true* SRMC of generation. In each instance, those benchmarks would *systematically under-signal* the opportunity costs of the scarcity that might emerge if those metrics were used as the basis for Meridian's – and probably any other generator's – offers. As we have just seen, they could have resulted in storage levels dropping to dangerously low levels *earlier this year* – despite it not being especially dry.

Tellingly, the Information Paper notes that Meridian's 'raw' QWOP values are not correlated with the Authority's SRMC benchmarks (i.e., the DOASA values and the 'minimum sell values'). However, it then states that if all of Meridian's offers above $300/MWh *are removed*, then there *is* a positive correlation between the *revised*

51 For example, in Table 12 of the Information Paper application of the DOASA values results in a higher percentage of offers 'above cost' than use of the 'minimum sell values' in all but one scenario (the 'high hydro storage/pre-2018' scenario). And, even then, the difference is minimal (40% versus 38%). *See:* Information Paper, Table 12, pp.62-63.

52 The vectorised Scheduling, Pricing and Dispatch (or 'vSPD') is the market-clearing engine used by Transpower in the administration and operation of the NZWM, i.e., it is used to identify and select the generation units to dispatch at each node.

53 Meridian has explained to us that the fundamental problem in each instance is that the DOASA water values do not rise promptly enough to dispatch enough thermal plant to prudently conserve hydro storage, resulting in substantial reductions in storage lake levels.

54 Information Paper, p.59.

QWOP and the SRMC estimates. This is *exactly what one would expect to see* if, as we suggested above:

- Meridian's 'raw' QWOP values are influenced by the presence of those $300/MWh tranches which, as we explained earlier, are intended to signal to customers the *opportunity costs* of limited water suppliers;[55] but
- the underlying SRMC/water values to which those QWOP values are being compared *do not* adequately incorporate the opportunity costs of potential future shortages (which, as we noted earlier, appears to be the case).

The claim that Meridian's offers priced above $300/MWh are not related to its water values misconstrues how SRMC is set in competitive markets.

One would not expect to observe a strong correlation between these two variables, because the comparison is between 'apples and oranges'. The first metric incorporates opportunity costs (albeit in a sporadic and unpredictable way that reduces its reliability) and the second appears to substantially *underestimate* those costs. Stripping out the opportunity costs (imperfectly) wrapped up in the former by removing all bids above $300/MWh is therefore likely to produce a more 'apples-with-apples' comparison and, in turn, a stronger positive correlation.

In other words, all this is showing is that if two variables are examined – *neither of which account for opportunity costs* (because the $300/MWh prices no longer influence the QWOP value once they are removed) – then a positive correlation emerges. The potential *corollary* of this is that if the QWOP and SRMC estimates had *both* appropriately accounted for opportunity costs (which, currently, they do not), then a similarly strong positive correlation might also be seen. Specifically, if the $300/MWh offers were left untouched, the QWOP figure remained the same 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.

In other words, the Authority's statement that: 'Meridian's offers priced above $300/MWh are not related to its water values'[56] misconstrues how SRMC is set in a workably competitive wholesale market. As we explained at length in section 3.4 and elsewhere, it is precisely *through its offers priced above $300/MWh* that Meridian provides a signal to the market of the *scarcity value* of its water. The simple 'sense checks' described above showed what can happen if these costs are understated or ignored: the probability of *shortages* rises.

55 Remembering that the resulting QWOP value can vary substantially depending on the particular strategy a generator adopts for signalling those opportunity costs, i.e., there is no 'single right way' and many options exist.

56 Information Paper, p.66.

4.2.3 Implications

The short-term comparisons contained in the Information Paper do not establish that generators' offers or resulting spot prices have systematically and significantly exceeded the *true* SRMC of supplying generation, accounting for all relevant opportunity costs (including impacts on storage). In particular:

The short-term comparisons do not establish that offers have systematically exceeded the true SRMC of generation.

- the QWOP methodology is a highly imperfect means of collapsing generators' offers into a single value, since legitimate differences in bidding strategies can result in large divergences in the resulting QWOP value; and
- the SRMC benchmarks used in the Authority's comparisons do not appear to appropriately capture the opportunity costs of managing fuel (water or gas), as reflected by the simple 'sense checks' described above.

These problems also undermine the reliability of the Lerner Index estimates.[57] In our opinion, the spot prices observed over the period may simply reflect the prevailing supply and demand conditions and, potentially, perceived structural shifts in the gas market (e.g., greater uncertainty surrounding future prices).

4.3 Withholding analysis

The Information Paper also contains a series of analyses examining the incentives generators may have had to strategically withhold supply. As we explained in section 3.3, this involves a generator either 'physically' or 'economically' withholding capacity that *would otherwise be dispatched* in order to create *artificial* scarcity (rather than true 'competitive scarcity') that must then be curtailed through higher prices.[58] In other words, this *contrived scarcity* does not reflect the *true* underlying supply and demand conditions in the market.

4.3.1 Incentives to strategically withhold

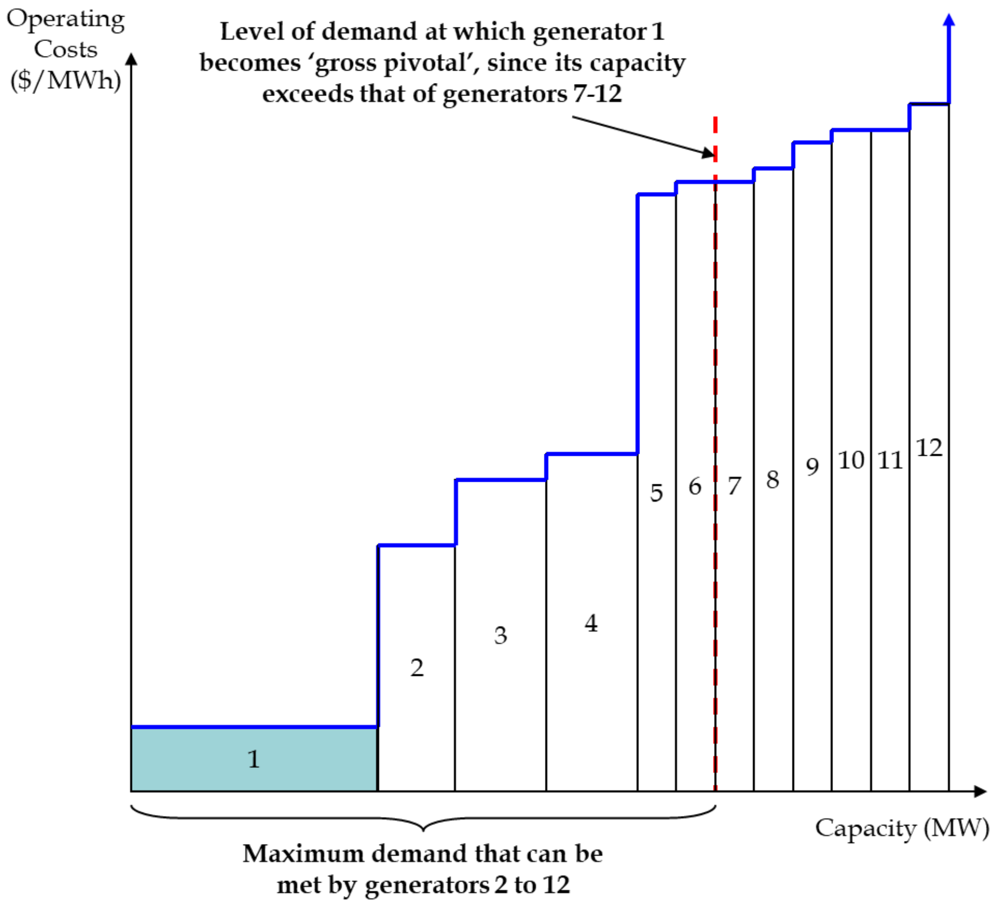
The first metric the Information Paper considers is the 'pivotal suppler index' (PSI). The PSI measures the proportion of time a generator *must* be dispatched (even if only partially) in order to meet demand in a particular location. If a generator becomes 'gross pivotal' this (theoretically[59]) creates an incentive for it to withhold supply to try and boost the market price. Figure 4.1 highlights the level of demand at which a generator becomes pivotal, i.e., for generator 1, this occurs where its capacity exceeds that of generators 7-12.

57 The Lerner Index measures the mark-up a firm is able to charge over its SRMC. The Authority employs the same SRMC benchmarks described above to calculate its Lerner Indices. Ergo, those estimates are equally unreliable. *See:* Information Paper, pp.68-73.

58 Recall that physical withholding involves a generator not offering all of its capacity and economic withholding involves it offering some of its capacity at a price that exceeds the operating and maintenance costs of the likely marginal generator.

59 We explain below some of the practical considerations that may diminish or eliminate a generator's ability to act on that notional incentive.

Figure 4.1: Gross pivotal generation unit



A generator is 'pivotal' when its capacity (or part of it) is needed to meet demand in a particular location.

The fact South Island plants may have had more incentive to withhold capacity in recent years reveals little about the state of competition.

The Information Paper points out that Meridian was 'gross pivotal' in the South Island ~77% of the time from 2016 to 2018, but that this has increased to ~90-95% of trading periods from 2019 to 2021 (to 30 June).[60] In itself this is unremarkable. For example, this uplift could be attributable to a several factors, including:

- increases in South Island load, e.g., electrification of industrial heat and summer irrigation load;
- fuel constraints being experienced by other generators meaning Meridian's generation is needed more frequently, e.g., constraints arising from low North Island hydro inflows and gas supply/delivery constraints; and
- limited recent investment in South Island baseload plant (e.g., new windfarms) due to (amongst other things) the uncertainty surrounding the future of the Tiwai Point aluminium smelter.[61]

The Paper also includes an analysis that suggests the incentives of South Island generators (including Meridian) to strategically withhold may have been higher in

60 Information Paper, p.42.

61 As we explain in more detail in section 5.1.1, if the smelter had exited this would be likely to have resulted in substantial near-term reductions in spot prices – especially in the lower South Island. There is strong evidence that this has significantly delayed a number of new generation investment projects. When those plants come online, this may reduce the number of periods in which Meridian is 'gross pivotal' in the South Island.

recent years, i.e., because the potentially achievable spot price increases appear to have been higher (based on the Authority's simulations).[62] In opinion, in isolation, these analyses reveal little, if anything, about the state of competition in the market.

The 'gross pivotal' metric may overstate the near-term incentives generators have to withhold, since these will be affected by their hedging positions.

First, the 'gross pivotal' metric itself is potentially problematic because it can provide a misleading picture of the near-term incentives a generator may have to withhold supply. The *hedging position* of the withholding generator is also relevant to this near-term withholding calculus. As we explained earlier, if a vertically integrated generator (i.e., with retail load to serve) is:

- 'long' on generation,[63] then in the immediate term, it will only earn more on sales not covered by its existing contracts, i.e., the uplift in price will lead to an increase in profits only on its unhedged capacity; and
- 'short' on generation, then the near-term consequence of engineering the price increase will be that it pays *more* to purchase the additional generation it needs to meet its own commitments.

It follows that a generator may be 'gross pivotal' yet have little or no immediate financial incentive to withhold supply. A more accurate indication of generators' near-term incentives to withhold could potentially be obtained by examining when they were *net pivotal*, i.e., accounting for hedging positions. Indeed, this is the metric the Authority has used when undertaking such assessments previously.[64] However, the Information Paper does not contain such an analysis. But even if it did, and those analyses revealed that generators were frequently *net* pivotal, that may not signify a competition problem, for the reasons we set out below.

4.3.2 No compelling evidence of withholding

The Electricity Code includes explicit provisions relating to pivotal supplier situations.

Just because a generator is *net pivotal* (a metric the Information Paper does not examine) that does not mean it will *act* upon any incentive to withhold capacity. As noted earlier, prior to June 2021, the Electricity Code included explicit provisions relating to pivotal supplier situations. These criteria conveyed to market participants how they could remain within a 'safe harbour' in such scenarios, thereby avoiding an undesirable potential regulatory response. To qualify for a 'high standard of trading conduct (HSOTC) safe harbour':[65]

- a generator had to offer all its available capacity (energy and reserve);

62 The Authority ran simulations of a 2% reduction in demand in the South Island (the equivalent of increasing demand). The average simulated price reduction was higher during the post-2018 period, suggesting that incentives to *withhold* that supply to *increase* the price by that magnitude may have been stronger.

63 A generator is 'long' if its wholesale revenue from generation and derivatives is greater than its wholesale costs from purchases and derivatives, i.e., if it is a net seller of generation. Conversely, a generator is 'short' if it is a net buyer of generation.

64 *See for example:* Electricity Authority, *Market Performance Quarterly Review October-December 2020 Information paper,* 2 February 2021, Figure 12, p.12.

65 Electricity Authority, *Improving the efficiency of prices in pivotal supplier situations*, 4 June 2014, p.2.

- it had to submit, revise, or withdraw an energy or reserve offer in a timely manner after receiving the information that triggered these actions; and
- when a generator found itself in a pivotal position, it had to ensure that either:
  – the prices and quantities in its offers did not result in a material increase in the price in the region where it was pivotal;[66]
  – its offers when pivotal were generally consistent with its offers when it was not pivotal; and
  – it derived no financial benefit from an increase in the price in the region where it was pivotal.

The HSOTC safe harbours have since been superseded by new trading conduct rules set out in 13.5A of the Code. These rules state that it is expected that offers (and reserve offers) will *generally* be subject to competitive disciplines, such that no party has significant market power.[67] However, they then note that, from time-to-time, there may be locations where, or periods when, one or more generators has significant market power.[68] To that end, the Code specifies that:[69]

> *"…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"*

The Authority has considered – and upheld – several complaints arising out of pivotal supplier situations.

Industry participants have displayed a clear willingness to lodge claims with the Authority alleging 'undesirable trading situations' (UTS) whenever they suspect a generator (or group of generators) has strategically withheld supply. The Authority has likewise been prepared to uphold those claims and impose corrective actions when it determines those responses are warranted. For example, a UTS was deemed to have occurred when:

- on 26 March 2011, Genesis found itself in a pivotal supplier situation within the Waikato area and caused spot prices to reach spot prices to reach approximately $20,000/MWh over several hours in and around Hamilton; and
- in December 2019 Meridian responded to heavy flooding by spilling more than the Authority estimated was necessary, pushing up spot prices (an extra 82MW of generation was said to be possible at the Benmore power station).

In both these instances, spot prices during the time of the UTS were 'reset' to considerably lower levels. In other words, even if a generator does find itself 'net pivotal', it may have no real ability to *take advantage* of that situation in practice. Specifically, the Code therefore:

66 Assessed by comparing prices in the immediately preceding trading period or another comparable trading period in which it was not pivotal.

67 Electricity Code, clause 13.5A(1)(a).

68 Electricity Code, clause 13.5A(1)(b).

69 Electricity Code, clause 13.5A(2)(a).

- contains clear *ex-ante* guidelines setting out what generators should do when they find themselves 'pivotal'; and
- allows for a (now reasonably well-traversed) *ex-post* process to address situations where firms stray from those guidelines.

The Code provisions – and the Authority's willingness to enforce them – reduce the ability to profitably withhold supply.

To that end, the Information Paper contains no strong evidence to suggest generators have been engaging in strategic withholding, despite their *ostensibly* strengthened incentives to do so in recent years. For example, the Authority looked at trading periods where there was price separation[70] in pre-dispatch but not in final prices.[71] It observed:[72]

> *'…no evidence of systematic changes in offers in pre-dispatch for these trading periods. Any changes observed in pre-dispatch were consistent with underlying conditions at the time (mainly hydro storage levels). This suggests these generators do not change their offers in pre-dispatch to increase the quantity they economically withhold in these trading periods.'*

The Authority also looked at trading periods with high spot prices (over $300/MWh) to investigate whether these could be attributable to strategic withholding. It concluded that:[73]

The Information Paper found no evidence that generators had been strategically withholding capacity.

> *'All of the changes in prices during these trading periods (compared with surrounding trading periods) could be explained by changes in market conditions at the time. There were no obvious signs that changes made to offers in pre-dispatch during these periods were inconsistent with market conditions. The majority of high priced offers that were dispatched were either priced as they usually were or reflected the fuel scarcity and opportunity cost of operating at the time.*

The Authority does mention again that some generators – particularly Meridian – offer a significant portion of their capacity above $300/MWh *regardless* of the conditions or trading period.[74] However, as we explained in section 4.1, there is no reason to assume this is part of some broader 'withholding' strategy. It may instead simply reflect prudent water storage management. The Authority also concedes that this could be partly symptomatic of gas supply uncertainty.[75]

Taking all this into consideration, the Authority concluded that although there may have been an increased *incentive* over the period to engage in strategic withholding:

70 The Authority also looked at the *frequency* of price separation between the North and South Islands but was unable to draw any robust inferences from this assessment. *See:* Information Paper, p.76.

71 In Meridian's case, this *ostensibly* provides it with an incentive to change its offers to avoid that price separation.

72 Information Paper, p.77.

73 *Op. cit.*, p.79.

74 *Op. cit.*, p.77.

75 Information Paper, p.79. As we noted previously, given the tightening gas market conditions, one might also expect to see *hydro* generators factoring projected gas market conditions into their bids in some fashion. One way to do so would be to offer tranches of hydro capacity at prices commensurate with the estimated SRMC of gas generation. This could result in a larger percentage of offers in excess of $300/MWh – including from hydro plants.

'the evidence to show any generator did this is weak'.[76] We broadly agree with that assessment but we would go further. In our opinion, the analyses contained in the Information Paper do not provide *any* meaningful insights into whether generators have strategically withheld supply over the assessment period.

4.4 Summary

The Information Paper contains a linear regression of spot prices pre- and post-2018. This analysis indicates that the price increases observed over the period were at least partly attributable to fuel supply scarcity and higher fuel costs. However, the Authority also suggests there has been a sustained upward shift in spot prices that the regression cannot explain. It consequently performed a series of other tests to see whether it was able to shed more light on the reasons for the perceived uplift.

In particular, the Authority looked for any indications that generators might have been exercising market power by performing a series of analyses exploring short-term 'price-cost' relationships. However, these assessments exhibit many of the shortcomings that often plague analyses of this nature, which substantially diminishes their usefulness. For example:

- the simple analysis of the percentage of offers above $300/MWh reveals little – if anything – about the state of competition in the NZWM, i.e., those offers may simply be signalling to customers the opportunity costs of managing scarcity;
- the various comparisons to short run costs do not reliably establish that generators' offers or resulting spot prices have systematically and significantly exceeded the *true* SRMC of supplying generation, because:
  - the QWOP methodology is a highly imperfect means of collapsing generators' offers into a single value, since legitimate differences in bidding strategies can result in large divergences in the resulting QWOP value; and
  - the SRMC benchmarks used in the Authority's comparisons do not appear to appropriately capture the opportunity costs of managing fuel (water or gas), as reflected by the simple 'sense checks' described above; and
- even if generators' incentives to strategically withhold supply have increased in recent years, there is no evidence they have been systematically doing so – and the Code sets out clear provisions to deal with 'pivotal supplier' situations.

These short-term analyses are consequently incapable of providing meaningful insights into the state of competition or whether generators have been exercising market power. In our opinion, the spot prices observed in the NZWM over the period may simply reflect the prevailing supply and demand conditions and, potentially, perceived structural shifts in the gas market (e.g., greater uncertainty surrounding future prices).

[76] Information Paper, p.74.

5. A broader, longer-term assessment

The preceding sections have illustrated why it is often inadvisable to focus on short term comparisons between prices and short run costs. In our opinion, more insights into the overall state of competition in the NZWM can be obtained by asking: are prices above long-run entry costs and, if so, *why*? The 'why' is important here because prices undoubtedly *have been* significantly above LRMC in the NZWM and may remain so for some time yet. However, as we explain below, there are many reasons for this, and good reason to think it will change if given time.

5.1 Factors that may have hindered new investment

Prices in the NZWM have been above LRMC for some time, but there appear to be good reasons for this, and cause to think it will change in time.

There is no doubt that average spot prices in the NZWM have outstripped long-run entry and expansion costs for some time. The average monthly spot price is more than twice as high this year as it was three years ago (~$240/MWh vs. ~$110/MWh, nationally).[77] Meanwhile, the Ministry of Business, Innovation and Employment (MBIE) estimates the cost of new wind generation as ~$60/MWh. And new gas peaking plant is said to be ~$175/MWh.[78] This disparity between prices and entry costs is expected to persist (albeit to a diminishing degree) for at least another year – possibly longer.

This begs the question: why has this not spurred a swifter supply-side response to eliminate that differential? There would *appear* to be profitable opportunities for new investment, so why has it not been happening in recent years? Could it be because enduring barriers to entry and expansion exist and have allowed generators to persistently earn 'above normal' returns? Or could it be something else? In our opinion, there are many good reasons for investors to have been reluctant to invest over the last few years, despite the returns ostensibly on offer. These can be expected to have contributed to the 'lag' that we are now observing.

5.1.1 Uncertain status of Tiwai Point aluminium smelter

Uncertainty about the future of a major customer may diminish investment incentives, despite high spot prices.

The characteristics of the NZWM mean that the exit of major load customers can have profound effects on market participants. Because the NZWM is an energy-only market with prices struck at ~285 nodes, the addition or subtraction of large chunks of demand or supply can have profound effects on locational spot prices. If a large user disconnects from a node (or a large generator connects) and there is not enough transmission capacity to transport the surplus power further afield, local nodal prices will fall – perhaps precipitously.

Any uncertainty surrounding the long-term future of a major customer can therefore have a profound impact upon generation investment decisions. New plant that would be profitable at today's prices could be rendered uneconomic if a large customer leaves. If investors are therefore unsure about the future of a major load customer, they might understandably eschew from building new plant, even if

77 Data sourced from the 'Electricity Market information (EMI)' website (available: here).

78 Based on MBIE's 'Interactive Levelised Cost of Electricity Comparison Tool' (available: here).

prices are above the cost of new entry (i.e., LRMC). The seminal case of this in the NZWM is the Tiwai Point aluminium smelter.

The smelter is New Zealand's largest electricity customer. It accounts for ~12-14% of total annual national electricity consumption and ~1/3 of South Island demand (an amount equivalent to around 704,000 households). It currently has 622MW contracted from Meridian (supported by bi-lateral back-to-back contracts with other generators, including Contact and Genesis), of which it is currently consuming 572MW.[79] For nearly a decade, the smelter has repeatedly signalled its willingness to exit the market. For example:

- during the period of Meridian's initial public offering (its partial privatisation) in 2013 the smelter threatened to leave – a move which would have significantly compromised the proceeds from that sale; this resulted in:
  - a renegotiated supply agreement with Meridian at a reduced price (and other revised non-price terms); and
  - a $30m subsidy being paid by the then National government;
- in 2015, the smelter was unable to find an alternative supplier for 172MW of capacity that Meridian was not obligated to supply from 1 January 2017[80] - this could have resulted in the smelter exiting entirely; and ultimately led to:
  - Meridian and the smelter reaching a new commercial agreement for the supply of *all* its electricity requirements (then 572MW); and
  - Meridian striking bi-lateral contracts with Contact (80MW), Genesis (50MW) and others covering 'close to 172MW'; and
- in October 2019 the smelter's owner, Rio Tinto, announced it was commencing a 'strategic review' into whether to exit the market and, in July 2020, it gave notice terminating its electricity contract; but subsequently:
  - in August 2020 (about 1.5 months before the general election) Rio Tinto disclosed that it was still negotiating with the government; and
  - on 14 January 2021, Meridian reached a new supply agreement with the smelter, extending the life of the smelter to at least the end of 2024.

For nearly a decade, the Tiwai point smelter has repeatedly signalled its willingness to exit the market.

Had the smelter exited, prices would have dropped, and a tumultuous transition period might have followed.

The potential exit of the smelter has loomed over the generation sector like a proverbial Sword of Damocles. If it had left, the ramifications would have been substantial. Spot prices – particularly in the South Island – would have dropped sharply. Transpower may have been left scrambling to upgrade the high voltage network to enable surplus power to get further north. Generators may have looked to decommission plant. And, possibly, new energy-intensive customers might have considered moving onto the vacated site.

79 The smelter's fourth potline is not currently being used.

80 This was an element of the renegotiated contract in 2015, i.e., from 1 January 2017, 172MW was scheduled to be 'released'. The smelter also had the right to terminate the contract from 1 July 2015 (giving 12-months' notice).

How this all would have shaken-out in the longer term is unclear. But what *is* clear is the adverse impact this uncertainty has had on generation entry decisions. A recent analysis by Concept Consulting ('Concept') identified several large, consented generation projects (amounting to nearly 1,000MW) that have likely been delayed by the uncertainty surrounding the smelter; namely:

Several large, consented generation projects have been delayed by uncertainty surrounding the smelter's future.

- Tilt Renewables' Kaiwera Downs (240MW) and Mahinerangi II (160MW) wind farms are both in the region that would be most affected if the smelter was to exit – Mercury (which acquired Tilt in August 2021) is said to be currently working on the sequencing of its wind projects;[81] and
- Meridian's Harapaki wind farm (176MW) was only committed *after* greater certainty emerged around the smelter's future, i.e., after the January 2021 announcement that it would continue operating until the end of 2024 (the project was in hiatus prior to that point);[82] and
- Todd Energy's Otorohonga Peaker (360MW) was delayed due to (amongst other things) uncertainty surrounding the potential closure of the smelter.[83]

More generally, it is impossible to know how many other nascent generation projects were cancelled or deferred before they reached even the consenting stage. In our opinion, when faced with such uncertainty it is easy to understand why investors may have been reluctant to commit capital, in spite of the ostensibly attractive spot prices. They would have been aware that, if Tiwai exited, many generators might suddenly be looking to *decommission plant* to mitigate wholesale price *reductions*, rather than build new ones.

5.1.2 Uncertainty over thermal fuels and decarbonisation policies

There has been substantial upheaval in the gas sector in recent years – and considerable uncertainty surrounds the long-term viability of this fuel-source. As we explained earlier, the prolonged outage at the Pohokura field in 2018 exposed the relatively fragile nature of New Zealand's gas supplies. The deterioration of output took the industry by surprise and, when coupled with the rapid diminishment of reserves from the Maui field, casts significant doubt over the level of domestic supply.

There has been upheaval in the gas sector in recent years and uncertainty surrounds the long-term viability of this fuel-source.

The government's 2018 decision to ban all new off-shore oil and gas exploration permits also limits considerably the scope to tap new domestic sources (any fields must, by definition, be on-shore). The potential implications of carbon prices on thermal fuel prices are also a matter of considerable uncertainty – although more clarity is likely to be forthcoming once new targets are announced. More generally, the government's climate change objectives are highly germane. For example:

81 Concept Consulting, *Review of generation investment environment*, August 2021, pp.4, 5 and 12 (hereafter: 'Concept Investment Environment Report').

82 *Op cit.*, p.12.

83 *Op cit.*, p.11.

- the government has a target of reaching 100% renewable electricity by 2030 which, if implemented and enforced, would effectively ban coal and gas generation; and
- separately, the Climate Change Commission has recommended phasing out natural gas use in residential, commercial and public buildings (the initial report recommended a 'hard sunset' of 2050).[84]

This would also have potentially profound ramifications for natural gas transmission and distribution pipeline owners. Those infrastructure owners do not currently know whether there will be enough downstream demand for gas in, say, twenty years' time, for them to be able to cover the ongoing costs of operating their networks. If there is not, and those networks cannot be deployed to alternative uses (e.g., shipping hydrogen or blended fuels), then it quite plausible that they would shut down and be decommissioned. The Commerce Commission and industry working groups are currently grappling with these issues.

These factors can be expected to have weighed on any investor contemplating investing in gas peaking plant. Investors would presumably be asking questions like: will I be able to access a reliable supply of gas (including shipping via a transmission network, if necessary)? How much is that gas likely to cost me over the lifetime of the facility? And, perhaps most importantly of all: is it possible my investment could be stranded due to the impacts of government climate change policies? In recent years, there has not been clear answers to these questions.

At least one gas project has been delayed by uncertainties surrounding government decarbonisation policies.

This is again reflected in Concept's findings. Todd Energy's Otorohonga peaker is a 360MW gas-fired plant. It is consented (until 2027) but has not been committed – in large part because of uncertainties surrounding government decarbonisation policies (and the ongoing status of the smelter).[85] This is unsurprising. As Concept notes, uncertainty around government policy – and the future supply/price of thermal fuels – can delay new investment decisions and cause investors to require a higher rate of return before committing capital.[86]

5.1.3 Other uncertainties

Several other factors could have had a material bearing on generator investment decisions in recent years. For example, the Authority has been reviewing the transmission pricing methodology (TPM) for over a decade (including when it was the Electricity Commission). During that time, five variants of 'benefits-based' charging have been proposed as potential replacements to the current TPM. Each of these methodologies would have had very different ramifications for generators. The status of the HVDC charge under each proposal (i.e., whether it was to remain

84 Climate Change Commission, *Ināia tonu nei: a low emissions future for Aotearoa Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025*, 31 May 2021 (available: here).

85 Concept Investment Environment Report, p.4.

86 *Op cit.*, p.16.

and the form it took), and the proposed times at which each option was intended to come into effect would also have had significant impacts on business cases.

Early variants of the Authorities proposal involved generators being allocated 50% of the so-called 'residual charge', which would have represented a very material impost. More recent versions saw this shift entirely to load customers. Each iteration of the proposal also seen the costs of different groups of existing assets being reallocated amongst generation and load customers – resulting in large swings in projected wealth transfers. This has meant that, until recently, generators are unlikely to have had a good understanding of:

Until recently, generators did not know how much new plants would have to pay to access the transmission network.

- what they would be required to pay to connect to – and use – the transmission grid, i.e., how their connection and 'benefit-based' charges would be set; and
- what the potential financial ramifications might be for certain forms of investment, e.g., batteries and solar investments.[87]

The potential conversion of Lake Onslow into an enormous virtual battery adds another layer of uncertainty to the NZWM. In August 2020, the government announced that it would spend $30m investigating a multi-billion dollar pumped hydro scheme that could be in operation by 2030. The scheme would, in effect, convert the South Island location into a 5,000GW rechargeable battery that could supply electricity during peak periods – including times of little rainfall (and snowmelt) or wind.

Lake Onslow may, at some point, be converted into a huge virtual battery that could supply during peak periods.

In October 2021, a contract was awarded to undertake the engineering, environmental planning and geotechnical feasibility investigations. However, there is no guarantee that the project will proceed. Many crucial questions also remain unanswered, including who might own and operate the scheme if it were to go ahead, and whether it would run on a commercial basis. If the facility was to be publicly owned or operated by, say, Transpower (a state-owned business), this would clearly have widespread ramifications for the NZWM.

Regulatory uncertainty may have also played a role. Certain market participants have long called for substantial regulatory intervention in the NZWM – including the structural separation of the vertically integrated generators[88] – sometimes based on questionable analysis.[89] Until recently, generators did not know whether this lobbying had gained any significant traction with the Authority – including within the context of the current review. Put simply, generators did not know if the Authority would make recommendations that would restrict their ability to contract to manage risk or prompt divestments. These factors may have all served to diminish generators' incentives to invest in new plant.

Regulatory uncertainty may have also diminished generators' incentives to invest.

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87 *See for example:* Concept Investment Environment Report, p.16.

88 For example, earlier this year Flick Energy called upon people to sign a petition calling for the structural separation of the vertically integrated generators.

89 *See for example:* Green., H. 'Analysis of Meridian's profits generates more heat than light', in *Energy News,* 3 September 2021.

5.1.4 Overall implications

Prices in the NZWM have exceeded LRMC in recent years and will continue to do so for some time. But there appear to be good reasons why. Multiple factors may have diminished incentives to invest in new generation capacity. These include uncertainty surrounding the future of the Tiwai point smelter and government decarbonisation policies. These factors may have discouraged investors from committing capital, despite the ostensibly attractive returns on offer. However, as we explain below, investment conditions appear to be improving.

5.2 The investment climate appears to be improving

The near-term future of the smelter was recently secured, which has already prompted new investment.

There are positive signs that some of the uncertainty that has plagued the market in recent years is waning. For example, as noted above, the near-term futures of at least two large customers are now much clearer. Namely, the smelter will remain in business until at least the end of 2024, and the Marsden Point oil refinery will be converted to a terminal storage facility from mid-2022. The greater certainty surrounding the smelter is particularly beneficial. As Concept explains: [90]

> *'More generally, many parties considered the risk of market dislocation from a Tiwai exit was lower now than in the past. This was because there were credible prospects of other forms of demand, such as hydrogen production and data centres, that could offset some (or all) of the reduction in demand if Tiwai exited. In addition, underlying demand growth is expected to quicken in the next few years as decarbonisation gathers pace. This would mean that any temporary supply surplus is absorbed more quickly than in the (former) environment of little or no growth. Finally, many parties considered that Tiwai was more likely to stay than exit at the end of 2024.'*

To that end, as we noted above, shortly following the January 2021 announcement that the smelter would continue operating, Meridian committed to opening the Harapaki wind farm (176MW) – a project that had previously been on hiatus. Following its recent acquisition of Tilt Renewables, Mercury is currently working on the sequencing of its wind projects – including Kaiwera Downs (240MW) and Mahinerangi II (160MW) wind farms. It is reasonable to expect these projects are more likely to proceed now that the smelter's future is clearer. In addition:

- in May, Lodestone Energy unveiled plans to build five solar energy farms in the upper North Island at a cost of $300 million which, collectively, will deliver approximately 400GWh (or ~1% of the country's electricity supply);[91] and
- earlier this month it was announced that the country's largest solar farm – a facility known as Kowhai Park – would be constructed on 400 hectares of land adjacent to Christchurch Airport.[92]

90 Concept Investment Environment Report, p.17.

91 Pullar-Strecker, T., '$300m plan for five solar energy farms, providing 1pc of country's supply', in *stuff.co.nz*, 12 May 2021 (*see*: here. *See also:* here*)*.

92 McDonald, L., '$100m 'world-leading' solar plant will be 50 times bigger than any in New Zealand', in *stuff.co.nz,* 1 December 2021 (*see:* here*)*.

More certainty is also emerging on the government's climate change policies, with a clear focus on renewable forms of generation.

More certainty is also emerging regarding the government's decarbonisation policies. For example, in June, the Climate Change Commission released its final report, in which it recommended (amongst other things) transitioning away from fossil fuel generation. The government is scheduled to release its responding 'emissions reduction plan' in May next year. Meanwhile, it has indicated a commitment to achieving 100% renewable generation by 2030 and reducing net emissions to 50% below gross levels by 2030.

Taken together, these policy announcements suggest the future for *non-renewable* generation in the NZWM could be quite bleak. This is reflected once more in Concept's analysis. Nearly every project mentioned within it is a renewable energy development. And the one gas project listed – Todd Energy's Otorohonga peaker – has been delayed (perhaps indefinitely) by (amongst other things) the government's climate policies. Although this is likely to be unwelcome news to proponents of, say, gas-fired generation, it is beneficial for the investment environment overall, since:

- investors who have been considering investing in new *non-renewable* generation projects, but holding off until greater clarity existed around the government's climate change policies, are likely to have a better idea about the long-term viability of those investments, i.e., they may be unattractive; and
- in turn, this may clear the way for more new investments in *renewable* forms of generation, i.e., if the general expectation is that additional investment in non-renewable power is unlikely (and that existing plants may be decommissioned, e.g., Huntly), then this may result in more capital being committed.

Generators now have a clearer idea of what they are likely to be paying for transmission services.

There are also encouraging signs that the TPM saga is drawing to a close. The Authority is currently consulting on what could very well be the final iteration of the consultation process. A complete methodology – including indicative prices – has been produced and, barring any successful legal challenges, the new methodology will finally be implemented. As such, generators should now have a much clearer idea of what they are likely to be paying for transmission services if the new TPM 'goes live'.

This greater certainty already appears to have had positive effects on the investment environment. For example, Concept highlights that development interest in solar farms is surging and Transpower reports connection enquiries for generation have risen almost tenfold over the past two years.[93] There is also evidence that it may becoming easier for investors to obtain power purchase agreements (PPAs). In particular, Genesis signed PPAs with an independent supplier (Tilt Renewables before it was acquired by Mercury) and a competitor (Contact).[94]

We also understand that, collectively, industry participants (both existing and new) now have around $2 billion of investments either planned or under construction. But, of course, that investment will not happen overnight. It takes a long time to obtain resource consents, to build the plant and to arrange a network connection.

93 Concept Investment Environment Report, p.8.

94 *Op cit.*, pp.5-6.

The 'investment deficit' will take time to eliminate but, when it is, prices should realign with entry costs.

However, as that investment comes on-stream in the coming years, it is plausible – likely, even – that spot prices will realign with the LRMC of new entry, just as one would expect in a competitive market.

To be sure, absent the factors described in the previous section, this new investment might have happened sooner and prices might be lower today. But the important thing is that new investment *does appear to be happening*. In the meantime, prices may continue to be above LRMC. Yet, that does *not* mean there are enduring barriers to entry *or* that generators are exercising substantial market power. Moreover, any significant interventions might not only be unnecessary, but could even serve to disrupt any 'self-correction' currently underway.

5.3 Summary

Spot prices in the NZWM have exceeded LRMC in recent years and will continue to do so for some time. However, there appear to be good reasons why. Multiple factors may have diminished incentives to invest in new generation capacity. These include uncertainty surrounding the future of the Tiwai point smelter and government decarbonisation policies. These factors may have discouraged investors from committing capital, despite the ostensibly attractive returns on offer.

Much of that uncertainty has now diminished – but in some cases, only relatively recently. For example, the smelter's immediate future has been secured and there is much more clarity about the government's climate change policies. This has led to an enormous recent increase in connection requests, surging development interest in solar farms and around $2 billion of investments either planned or under construction. This may all serve to realign prices with entry costs.

However, this adjustment process may not be swift. It will take time for the 'investment deficit' that has built up during the recent period of extreme uncertainty to be erased. Obtaining resource consents, constructing plants and connecting to the grid all takes time – projects are multi-year endeavours. Even so, it would arguably be unnecessary and undesirable to intervene in a market that appears well on its way to addressing the 'gap' between prices and LRMC.

CAPITAL STRATEGIC ADVISORS

Report prepared for

Meridian Energy Limited

Report on the Electricity Authority's competition and price discrimination papers of 27 October 2021

Carl Hansen

16 December 2021

About Capital Strategic Advisors (CSA)

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

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Contents

Summary

This report discusses two papers published by the Electricity Authority on 27 October 2021:

- An issues and options paper regarding inefficient price discrimination in the wholesale electricity market (*Issues paper*).
- A paper reviewing competition in the wholesale electricity market (*Review paper*).

Fundamental problems with the Authority's price discrimination analysis

The Authority has wrongly adopted a static and myopic analysis of the dynamic and long-term relationship between Meridian and New Zealand Aluminum Smelters (NZAS). It has also ignored the implications arising from the irreversibility of an NZAS exit.

As a result, the Authority has made incorrect inferences about NZAS's willingness-to-pay (WTP) and it has ignored economically valuable option values. These mistakes are fundamental for calculating the economic costs and benefits of the Tiwai contract.

Even within its framework, the Authority has adopted incorrect assumptions. For example, it has assumed generators have over-the-top incentives to offer low prices to any large customer. This issue only arises in special cases, such as where a commercial customer is considering entering or exiting the New Zealand market.

The Authority's framework is based on a complete pass-through of lower wholesale prices to lower retail prices. This is a critical assumption in the Authority's price discrimination analysis, but no evidence is provided in support of it.

The Authority's problem definition is flawed

The Authority posits four conditions it says enable *inefficient* price discrimination. But three of those conditions are also needed for firms to undertake *efficient* price discrimination. And the other condition only applies in special circumstances, not more broadly as the Authority suggests.

Unfortunately, the Authority has defined a set of conditions that rule-out all price discrimination. This is problematic because efficient price discrimination is vital for generators and customers to transact in ways that minimise their risks, and so achieve more efficient prices overall.

In section 6 of the Issues paper, the Authority broadens the areas it is concerned about without providing any evidence whatsoever in support of those concerns. Those concerns are not even mentioned in section 5, entitled "Issues the Authority would like to address."

Surprisingly, the broader areas of concern include *discriminatory access pricing*. This should be dealt with separately because the incentives and trade-offs are very different, and the Authority's empirical work from 2017 concluded it had not found any systemic issues in this area.

There are serious problems with each of the Authority's options

Options 2, 4 and 5 reflect the Authority's flawed problem definition, and do not address the source of the problem the Authority is concerned about. These options are like using a shotgun to shoot at a distant target: some pellets will hit their target but there will be considerable collateral damage to efficient price discrimination. The Authority should not progress these options.

Options 6 and 7 have the potential to avoid substantial collateral damage but their information requirements render them impracticable. Long delays are likely for complex and unusual cases, increasing uncertainty and harming planning and hedging activities. These options will create new gaming opportunities, and resourcing requirements are likely to be significant.

Option 3 exceeds the Authority's mandate and could undermine the Authority's independence. If the Authority proceeds with this option, it should request the Government assign responsibility for approving contracts to the Commerce Commission, as it is more distant from the electricity market.

Overall, the options for addressing the price discrimination issue are perfectionist, misguided and pre-emptive.

Concerns with the Authority's analysis of wholesale market competition

The Review paper provides mixed signals on the competition benchmark it is applying. The Authority needs to state it is applying a *workable competition benchmark* and apply it consistently in assessing competition indicators.

Clarity about the competition benchmark is essential because it goes to the issue of what is meant by a sustained exercise of market power. More care is needed to ensure the Authority's competition statistics are not biased by the timeframes chosen for the Review.

The Authority should accept the Waitaki hydro scheme provides energy and capacity services to the spot market, and it should truncate its quantity-weighted offer price (QWOP) indicator when assessing the relationship of Waitaki offer prices with seasonal factors, such as water values.

As New Zealand has small hydro reservoirs, they can severely constrain hydro generators from engaging in any *sustained* exercise of market power. In assessing sustained economic withholding, such as with *the two percent test*, the Authority should calculate the impact on hydro reservoirs.

The competition review contains several biased and meaningless competition indicators

Achieving a balanced set of competition indicators requires the omission of duplicate indicators and the inclusion of indicators that can potentially contradict or nullify other indicators.

For example, the Herfindahl-Hirschmann Index (HHI) and gross pivotal supplier (GPS) indicators are fated to tell pretty much the same story with New Zealand data. Only one of them should be used as a competition indicator. The net pivotal supplier (NPS) indicator potentially nullifies the GPS and should have been presented in the Review paper, instead of the GPS.

The Review paper canvasses multiple indicators of market conduct to identify whether there was a sustained exercise of market power during the review period. Most are meaningful indicators. However:

- Indicators based on the percentage of offers above various benchmarks are meaningless (particularly offers above final prices and above 300 $/MWh)
- Indicators of the correlation of offers with costs can be meaningful provided care is taken to only include relevant offer tranches in the QWOP indicator.
- It is difficult to understand why the Authority expects any of the QWOP indicators to be correlated with DOASA water values as those values are not used in generator offering decisions.

- There are three indicators that essentially duplicate each other: the two percent demand reduction, the two percent demand increase, and the observation of supply curve slopes. A balanced approach would treat all of these as one indicator.

The Authority's interpretations and conclusions are often one-sided

In many respects the Review paper is cautious and avoids inferring too much from its competition indicators. However, there are occasions where the interpretation is one-sided, and in some cases misleading. I am particularly concerned by the summary table on pages 8-13, which provides unbalanced commentary and, in at least one case, contradicts the results shown in the main text.

The Review paper states that no contracts in a competitive market should be priced below cost, and uses that as an indicator suggesting the wholesale market is not competitive. This is incorrect, for two reasons. It is well-known that prices below costs can occur in perfectly competitive markets when entry and exit decisions are irreversible to some degree and there is uncertainty. On the flipside, when there is perfect certainty and reversibility, no contracts in any market structure (whether perfectly competitive, oligopolistic or monopoly) will be priced below cost.

The Issues paper claims Meridian engaged in inefficient price discrimination by subsidising NZAS. However, if that is true then it implies Meridian believed it was unable to engage in the more profitable strategy of economically withholding the generation rather than supplying NZAS. Counter-intuitively, Meridian was acting on the assumption the wholesale market is workably competitive.

The Authority should recognise the inherent limitations of its regression analysis

It is good to see the Authority develop empirical evidence of the drivers of spot market prices. It is also good to see it is included as just one of many competition indicators, as only modest weight can be placed on the results of a single empirical endeavour, irrespective of who undertakes the work.

Unfortunately, the Authority has characterised the unexplained shift in prices (of 39 $/MWh) in the Authority's regression analysis as *a sustained* uplift in spot prices. However, the Authority's structural break analysis suggests there have been three sudden shifts in spot prices since 1 October 2018. This is important because it means plausible explanations of the unexplained price shifts need to be driven by factors that could cause such large and sudden price effects.

1. Introduction

This report provides a high-level review of two papers published by the Electricity Authority on 27 October 2021:

- Inefficient Price Discrimination in the Wholesale Electricity Market: Issues and Options: An Initial Response to the Wholesale Market Review (*Issues paper*, or *IP*).
- Market Monitoring Review of Structure Conduct and Performance in the Wholesale Electricity Market (*Review paper*, or *RP*).

The Issues paper presents the Authority's concerns with the terms and conditions of the Tiwai contract, which is the agreement between Meridian and New Zealand Aluminum Smelter (NZAS), announced on 24 January 2021 (refer to Box 1).

The Authority claims the contract price amounts to inefficient price discrimination. It also posits that price discrimination may be a far wider problem in the electricity market, potentially occurring with any large customer. The Authority presents a wide range of potential solutions that it believes could address not just the Tiwai issue but also these wider issues.

The Review paper presents the results of a review of competition in the wholesale electricity market, motivated by high spot market prices since the Pohokura gas field outage in late 2018. The review considers whether prices from 1 January 2019 to 30 June 2021 (the review period) were determined in a competitive environment. The Authority states it is not able to definitively conclude whether all of the increase in prices is due to underlying conditions or if some of the increase is due to prices not being determined in a competitive environment.

This report first focuses on the Authority's price discrimination analysis and the options it has floated for addressing its concerns about price discrimination, published in the Issues paper. The final two sections discuss concerns with the Authority's analysis of wholesale market competition, published in its Review paper.

Box 1: The Tiwai contracts

The Tiwai agreement is a contract-for-difference (CFD) for 572 MW for every half-hour for four years, with an option after 1 January 2022 to reduce it to 400 MW through to 31 December 2024. The CFD is referenced to spot market prices at Tiwai Point, and is often called *the Tiwai contract*.

As the contract is for a large portion of Meridian's generation capacity in the lower South Island, Meridian secured an offsetting CFD with Contact Energy for 100 MW, which also included an option to reduce quantity from 1 January 2022. Both contracts include use-it-or-lose-it clauses.

2. Problems with the Authority's price discrimination analysis

This section discusses key omissions in the Authority's analysis of the Tiwai contract. These omissions have led the Authority to make unwarranted assumptions in its price discrimination analysis, to omit important option values from its assessment of the efficiency effects of the contract and to float inappropriate and impractical policy solutions to address its concerns.

The Authority's mindset may be one of the reasons for these mistakes. Ronald Coase, widely regarded as the father of contract theory, has remarked:

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

2.1 A static and myopic approach has been used for a dynamic relationship with irreversible actions

A fundamental problem with the Authority's analysis of the Tiwai contract is that it adopts a static and myopic perspective of the Meridian and NZAS relationship. The analysis is static because the Authority takes a one-off approach that ignores uncertainty about future market conditions for both parties, in particular for NZAS. The analysis is myopic because it ignores the irreversibility associated with NZAS exiting New Zealand.

The relationship between Meridian and NZAS is best characterised as a strategic relationship between New Zealand's largest generator and largest consumer, in which a sequence of short-term contracts are agreed over time to cater for the evolving circumstances of each party.

The negotiations at each stage are undertaken in the knowledge NZAS may exit New Zealand. Such an exit is irreversible because it is extremely unlikely NZAS would re-start its plant at Tiwai Point once it had closed it down, paid redundancies, lost experienced workers and managers and incurred large site cleanup costs.[1]

Uncertainty and irreversibility are not just 'bells and whistles' that can safely be ignored by policymakers. They are fundamental for calculating the economic costs and benefits of the Tiwai contract and for formulating feasible policy options.

The Authority's approach is a reflection of the general issue of information asymmetry between regulators and regulated entities,[2] and it highlights the dangers of the Authority's suggestion it become directly involved in individual contract decisions (discussed further in section 3).

The rest of this section discusses some of the implications arising from the realities of the relationship between NZAS and Meridian.

Rationale for bilateral contracts

It is well-known that when a seller has sales opportunities just as good as those available from a bilateral negotiation, the buyer has no bargaining power. Likewise, a seller has no bargaining power when the buyer can access equally good outside opportunities. In these situations, each party will buy and sell in a spot market rather than negotiate bilateral contracts.

In the presence of spot markets, bilateral contracting occurs when the parties bring something to the table that is not available from other parties. In these cases, the parties expect their trading relationship to create a surplus, which they allocate between them through the prices (or pricing rules) specified in the contract.[3]

[1] Technically, an action is totally irreversible if none of the costs of the action can be recovered if the decision maker changes its mind. See Dixit and Pindyck (1994, ch7-8) for introductory analysis of business decisions when exit is irreversible.
[2] Information asymmetry between regulators and regulated entities is widely recognised in the regulatory economics literature. See Laffont & Tirole (1994) for a standard textbook treatment of the issue.
[3] There is considerable economics literature making this point about the role of bilateral contracts and spot markets. See Tirole (1997, pp17-34), Kornhauser & MacLeod (2010) and Bresnahan & Levin (2012) for insightful overviews of the literature.

Bilateral contracts are typically for long periods of time, reflecting the long-lived nature of the investments made by one or more of the parties. However, contracts are often re-negotiated every three or four years to cater for changing circumstances.[4]

Meridian, Contact and NZAS are natural counterparties for bilateral contracts

The Authority acknowledges that Meridian and Contact are natural counterparties for NZAS due to the generators having large generation assets in the lower South Island, close to NZAS's smelter (IP, para 4.25).

To see the implications of location, consider a counterexample in which NZAS seeks a bilateral CFD with one of the North Island generators, such as Genesis Energy or Mercury Energy. If the CFD was referenced to spot prices in the lower South Island then the North Island generators would face the risk of price separation (selling energy in the upper North Island at one price and buying in the lower South Island at another price to cover the CFD with NZAS). Alternatively, if the CFD was referenced to spot prices in the upper North Island then NZAS would face the risk of price separation between the two locations.[5] Contracting with Meridian avoids these risks because Meridian sells generation in the lower South Island.

The scale of generation is also relevant, although not a big issue. If NZAS sought contracts with Genesis, Mercury or Trustpower (soon to be called Manawa), each of them would be far more reliant on the contract than Meridian. For example, Mercury's share of generation over the last five years averaged 13%, roughly matching the 13% of load used by NZAS. Mercury would be reliant on just one customer. The situation would not be much better for Genesis as it had only an 18% market share. A bilateral contract with Trustpower would be untenable, as it has only an 8% market share.[6]

Either NZAS would need to negotiate contracts with three or four generators (excluding Meridian), or the head contractor on the generation side would have to do so. NZAS or the head generator would have to coordinate the multiple counterparties carefully to achieve the volume of cover it wanted. Also, NZAS might have to deal with greater complexity if the different generators insisted on different terms and conditions, and it may face greater risk of its commercial imperatives becoming more widely known in the market.

Contracting with Meridian reduces these transaction costs and it minimises locational price risks for both parties. Meridian subcontracts a portion of its Tiwai contract to Contact Energy for the same reasons; to reduce its reliance on NZAS and because Contact has significant generation in the lower South Island.

Conversely, NZAS brings locational and scale advantages to Meridian and Contact. It enables Meridian to sell a large portion of its output in the lower South Island, avoiding significant locational price risks. Moreover, as Meridian and NZAS have dealt with each other for many years, they each bring valuable familiarity and confidence to the relationship.

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[4] Joskow (1987) provides the seminal analysis of contract duration. Neumann & von Hirschhausen (2004, p178) state that gas contracts are usually revised every three years or so.

[5] Note these risks are not eliminated by the hedge and financial transmission rights (FTR) markets, as monthly and quarterly risks remain. Those markets enable parties to minimise half-hourly spot price risks but they have to pay a premium for that service.

[6] Market share data sourced from Infracom (2021a, p25).

Incorrect inferences have been made about NZAS's willingness to pay (WTP)

It is widely accepted that prices in bilateral contracts are affected by the relative bargaining strength of each party at the time of their negotiation. In a sequential game between buyer and seller, a low price for NZAS reflects a strong short-term bargaining position for NZAS.

The Authority acknowledges NZAS had strong bargaining power (IP, p16). This means it is incorrect to infer an upper bound to NZAS's willingness to pay from decisions to terminate its previous contract, as giving notice can be part of hard-ball bargaining (refer Box 2).

Nevertheless, the Authority infers from statements made at the time of the termination announcement that NZAS's true willingness to pay fell below the price paid under the existing contract (IP, page iv). However, an upper bound on willingness-to-pay can only be inferred from a buyer actually ceasing to buy a good or service. As NZAS has not exited the New Zealand market, no one other than NZAS knows its true willingness to pay.

More generally, NZAS's short-term bargaining power reflects the conditions it faces in the aluminum market. Although Meridian does not know NZAS's true willingness to pay, it knows it will be a function of NZAS's long-run expectations of the aluminum market, and those expectations are likely to be a function of current market conditions.

Hence, it is rational for Meridian to assume NZAS places significant weight on current market conditions when assessing its willingness-to-pay. It therefore makes sense for Meridian to accept lower prices when the aluminum market is depressed and insist on higher contract prices when the aluminum market is buoyant.

> *Box 2: Cheap talk v action*
>
> When Rio Tinto (the majority owner of NZAS) announced it was terminating its contract, it stated it planned to wind down operations. The Authority states that Rio Tinto indicated it was unfortunate that it could not 'secure a power price reduction aimed at making NZAS a financially viable business'.
>
> Clearly, the parties were in contract negotiations, and statements made during negotiations are treated in the bargaining literature as *cheap talk* and are distinguished from *actions*. Lewicki *et al* (1994) explains that communicating a willingness to walk away is a common bargaining tactic. See also Croson *et al* (2003).
>
> Hence, giving notice on a contract is considered to be another phase of the negotiation process, and certainly not the definitive end of the relationship. This reality is, of course, obvious from the fact the parties ended up executing a new four-year contract. And since the new agreement came into effect some investment analysts have questioned whether it will really be the last Tiwai contract, as aluminum prices have strongly rebounded (Rutherford, 2021). The Authority also acknowledges that NZAS may not exit at the end of 2024 (IP, p21, 4.28)

In summary, the Authority's calculations simply reflect historical episodes of short-term bargaining power, not willingness-to-pay which are based on expectations of future market conditions. Those expectations are likely to be influenced by past outcomes, but a single past outcome (eg the previous contract price) should never be adopted as an upper bound on the future.

Care is needed when interpreting business statements about financial viability when there is uncertainty and exit is irreversible

As mentioned above, each short-term agreement incorporates the parties' views about the future long-term benefits of the relationship, which in turn depend on their views of future market conditions in the electricity and aluminum markets. However, there is considerable uncertainty about future conditions in each market.

It is critical to understand the implications for business decisions when there is uncertainty and exit is irreversible. Under the static and myopic approach adopted by the Authority, firms should exit an industry as soon as their revenue falls below their variable costs. But when there is uncertainty and exit is irreversible, firms should not exit unless their revenues fall substantially below their variable costs.[7] This reinforces the point it can be misleading to infer very much from statements that a business was not able to 'secure a power price reduction aimed at making NZAS a financially viable business.'

The irreversibility of exit can create positive option values, which the Authority has omitted from its efficiency calculations

Moreover, 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.

Positive option values arise when deferring the exit avoids costs (or results in benefits) that would otherwise not occur. From a New Zealand-wide perspective, the new Tiwai contract created positive option values due to:

- Avoiding sharp demand reductions in the next four years that would likely lead to the irreversible exit of thermal generation. The Rankine units in particular can provide valuable dry year cover until there is more certainty about what will replace them for the early stages of the transition to a net-zero emissions economy (this is discussed further in the next subsection).
- The prospect the aluminium market may improve over time, as it has since the new contract started, potentially increasing NZAS's true willingness-to-pay for New Zealand electricity.
- The prospect that new technology may become available for NZAS to provide large seasonal demand response services to the New Zealand electricity market, making it a more valuable participant than currently.
- The prospect of lower adjustment costs for workers, businesses and community organisations in the lower South Island. This may occur if the local community had become blasé about repeated threats of exit, leading to a view NZAS was just bluffing. To the extent the new short-term contract is viewed differently from previous contract extensions, then it may provide a crucial period of time for the local community (and central government) to adjust to the new circumstances and search for new opportunities. Note this source of option value runs counter to the first two.

These factors also strengthen Meridian's bargaining position for the contract renegotiation in 2024. For example, if sustained over the new few years, higher aluminum prices increase the threshold electricity price at which a future NZAS threat to exit New Zealand is credible.

Similarly, if it turns out to be economic for NZAS to invest to provide greater seasonal flexibility than it does now, this could be a game-changer for Meridian and Contact because of the sizeable hedge it

[7] See Dixit & Pindyck (1994, p264) for an illustrative example of the potential size of these effects.

would provide them against sustained low inflows into their hydro reservoirs. It could also be a game-changer for the electricity market as a whole. [8]

While NZAS would presumably want to earn a return on such an investment, their size means they will be unable to capture all of the benefits the service would provide to New Zealand. For example, they would not capture the spillover benefits to other consumers that occur in the form of (a) lower average wholesale electricity prices than would otherwise occur and (b) enhancing their confidence in the security of New Zealand's electricity supply. They would also not capture spillover benefits to workers, accruing in the form of higher wages and living standards.[9]

The above discussion ignored the economic benefits of the upgrade of the transmission circuits in the lower South Island, known as the Clutha and Upper Waitaki Lines Project. The economic benefits from that work do not create option value as they would have been undertaken anyway if NZAS had exited the New Zealand market.

Also, Contact and Meridian have incurred significant effort and time investigating opportunities to attract new types of customers to the region, such as hydrogen and ammonia production plants and data centres. If these opportunities come to fruition they may deliver net economic benefits to New Zealand, but they do not create positive option values because the efforts to attract them would also have been made if NZAS had exited the New Zealand market.

Both investments – the transmission upgrade and the efforts to attract new customers to the lower South Island – are likely to improve the generator's bargaining power in future negotiations with NZAS and any other lower South Island customers considering exiting New Zealand. Likewise, to the extent an NZAS exit cannot be taken as a certainty, the new contract with NZAS strengthens the generator's bargaining power with respect to new customers looking to locate in the lower South Island.

Clearly, it made commercial sense for Meridian to agree a low price with NZAS to keep commercial options alive for three to four years.[10] It is also clear a significant portion of the option value extends beyond the commercial value to Meridian, and has economic value to the wider economy. The Authority must include these matters in its efficiency calculations before it can draw conclusions about the efficiency of price discrimination.[11] The Authority engaged Concept Consulting to estimate the incremental cost of supplying NZAS (IP, 5.28), but these calculations ignore possible option values, rendering Concept's estimates unreliable or at best a considerable over-estimate of the inefficiency.

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[8] Concept reports that this flexibility would need a relatively small capital investment but notes there is significant uncertainty over the curtailment opportunity costs and this requires further analysis (Concept Consulting, 2021, pp14-15). This uncertainty could be resolved over the term of the current contract.

[9] Higher wages and living standards could arise if the enhanced security of supply, combined with a highly renewable electricity system, attracted more energy-intensive production to locate here (Infracom, 2021b, pp46-56).

[10] Although the Tiwai contract ends on 31 December 2024, renegotiations typically begin a year prior to contract maturity. Hence, the four-year contract provides less than four years of time to develop options into realizable propositions.

[11] The Authority agrees the Tiwai contract contributed to a wider set of national goals, including regional job creation and supporting cleaner aluminium production, when compared with other Rio Tinto smelters (IP, p31, 5.41). However, it argues that issues such as regional development, employment, foreign direct investment and taxation lie outside of the Authority's remit and are better addressed by other arms of government (IP, p32, 5.42).

There is likely to be option value from retaining thermal generation for a relatively long interim period

The Authority rightly considers whether the charges payable by NZAS exceed the incremental cost of supplying it. However, once again, it applies a static and myopic approach to the issue even though it acknowledges heightened uncertainty regarding generation investment decisions (IP, 5.38-9).

The Authority's analysis suggests that an NZAS exit would likely result in the retirement of thermal plants, such as the Rankine units at Huntly and the Taranaki Combined Cycle (TCC) plant (IP, 3.4, 4.12, 6.16). Hence, the short run marginal costs of operating those units are a significant component of the incremental costs of supplying NZAS.

But once they exit the market, the Rankine and TCC units are very unlikely to return. In other words, their exits are irreversible, and so is the entry of new generation plant.[12] In a period of heightened uncertainty, it makes economic sense to defer the retirement of existing plants and defer investments in new plants.

Heightened uncertainty arises not just from the four-yearly episodes of "will NZAS exit or not" but also from uncertainty about demand growth in the early phases of the transition to net zero emissions, and from the Government's investigation of the Onslow pumped hydro storage scheme.

Although an NZAS exit would eliminate dry year risk for a few years, significant new dry year cover would start to be required by around 2030.[13] At this stage it is not clear what could fill the gap left by TCC and the Rankine units. If the Government proceeded with the Onslow scheme, it is very unlikely to be operational until 2038 at the earliest.[14] Other possible sources of dry year cover, such as a large scale hydrogen and ammonia plant, are highly uncertain at this stage. Retaining the Rankine units, and possibly TCC, provides significant real option value for the electricity system, especially as there is a possibility of converting the Rankines to run on biomass.

The Authority touches only very briefly on the reliability issue and does not consider the possibility of the option value of retaining thermal generation units. It merely states "Higher electricity prices and expectations of elevated prices promote investment in electricity generation and demand response, including the maintenance of high-cost thermal generation to support reliability" (IP, 5.36).

2.2 Even within its framework, incorrect and unsubstantiated assumptions have been adopted

The above discussion identifies significant flaws in the Authority's framework for evaluating the implications of the Tiwai contract. However, even within its own framework it has made some surprising assumptions. Unfortunately, these errors and assumptions lead it to float inappropriate and impractical policy solutions to address its concerns.

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[12] Dixit and Pindyck (1994) provides an introductory discussion of irreversible entry.

[13] The Climate Change Commission is projecting it will take six or seven years for demand to fully recover from an NZAS exit, which would be around 2031-32 (ENZ Scenarios Dataset for 2021 Final Advice, Demonstration tab). However, that would leave New Zealand with the same level of dry year risk as now. Clearly, smaller dry year risk will arise before then.

[14] Fox (2021) states that a government decision on the Onslow scheme is likely to occur late 2023 or early 2024. Assume a decision is made by 1 January 2024. It will take four to five years for construction to begin, as the pre-construction period involves clearing RMA hurdles, tendering such a large and complex project, and time for the successful tenderer to assemble the needed resources. It is likely to take seven to ten years to construct, and three to four years to fill the reservoir. This implies an operational date commencing 2038 – 2043.

The Authority has contradictory views about market power and price discrimination

The Authority's price discrimination analysis rests on the claim generators receive inframarginal revenue gains from NZAS continuing to operate in New Zealand. It argues these inframarginal gains provided Meridian with inefficient incentives to offer discounted prices to NZAS (IP, 4.15).

However, the Authority goes even further, and argues Meridian and Contact had incentives to subsidise NZAS provided those subsidies are less than the inframarginal revenue gains from keeping NZAS in the market (IP, page iii).[15]

But the previous sentence implies the wholesale market is workably competitive.[16] This is because it assumes Meridian would be worse-off adopting the strategy of letting NZAS exit and withholding some portion of the 572 MW of generation to achieve the same inframarginal revenue gains. Absent competition, this strategy would be more profitable because Meridian would achieve the same revenue gains but avoid subsidising NZAS.

But clearly there is competition, and the Authority implicitly assumes it is strong enough to render the withholding strategy less profitable than subsidizing NZAS to keep it in the market.[17] If it assumes otherwise, then it would have to explain why Meridian forwent a more profitable strategy.

> **Box 3: Workably competitive markets**
>
> A workably competitive market is one where no seller can choose its level of profits by withholding output or increasing its offer prices for a sustained period. This is because competitive rivalry will over time generally move the seller closer towards, rather than further away from, efficient outcomes.

More generally, market participants appear to acting on the basis the spot market is workably competitive. This is because the announcement of NZAS's exit reduced futures prices by about 20 $/MWh, which means market participants expected spot market prices to fall by those amounts on average.[18] This means most market participants do not expect any generator can sustainably withhold generation capacity to prevent spot prices falling.

The Authority makes unsubstantiated assumptions about the incentives for generators to find new customers willing to pay more than their existing customers

On one hand

On one hand, the Authority implicitly assumes generators have minimal incentives to find new customers willing to pay more than their existing customers. This assumption is clear from its statement that publicly offered hedge contracts would ensure greater and equal access to sale and purchase

[15] NZAS receives subsidised electricity when the amount it pays for electricity is less than the incremental cost of supplying NZAS, or equivalently, when the contract price is less than the average incremental cost (AIC) of supplying NZAS. This results in production inefficiency. This is in addition to the Authority's claim that generation output may be allocated to the wrong consumers, which results in allocation inefficiency.

[16] The Authority interprets competition to mean workable or effective competition, as discussed by the Commerce Commission in its 2009 publication on input methodologies (EA, 2011a, 2.1, A.15 - A.16).

[17] In Fisher & Paykel Ltd v Commerce Commission, the New Zealand High Court stated: "Workable competition exists when there is an opportunity for sufficient influences to exist in any one market, which must be taken into account by each participant and which constrain its behaviour." Fisher & Paykel Ltd v Commerce Commission, [1990] 2 NZLR 731 citing, Heydon, Trade Practices Law (2nd ed, 1989) Vol 1, p. 1548, paragraph 3.210.

[18] NZAS announced the termination of the Tiwai contract on 9 July 2020 and on 28 August it confirmed it was still negotiating with the Government. The price of long-dated futures contracts fell from around $94/MWh on 8 July 2020 to $72/MWh on 9 July 2020.

opportunities, providing greater assurance electricity is going to consumers with the highest willingness to pay (IP, 6.27 and 6.37).

This is surely an inadvertent mistake by the Authority, as any seller of any product or service wants to attract higher paying customers to their business, after adjusting for additional costs and risks the customer may bring with them.

Sellers, of course, are not perfectly informed of the additional costs and risks, and so discrepancies exist in real world markets, but they have strong incentives to trade-off the costs of better screening methods with the financial benefits of greater screening accuracy.

On the other hand

On the other hand, the Authority assumes generators have over-the-top incentives to offer artificially low prices to win large customers. Without any evidence whatsoever, it expresses a concern this could be a reasonably widespread problem in the New Zealand electricity market.

The error in the Authority's logic arises from the presumption large customers bring inframarginal revenue gains to generators, creating over-the-top incentives for inefficient price discounting. But this will not be the case for the vast majority of large customers. No matter how large a customer is, there are no inframarginal revenue gains from winning them from a competitor because customers switching from one generator to another does not alter total market demand.

It is only when new customers are entering or exiting the New Zealand electricity market that total demand is affected. And it is only when those decisions are materially affected by electricity prices that generators *might* have over-the-top incentives. In reality, the production-location decisions of multinational firms are made on the basis of a wide range of factors, and international evidence suggests electricity prices have minimal impact on their location choices.[19]

Unfortunately, the Authority is showing signs of a perfectionist mindset, which is inimical to good regulatory practice. I discuss these concerns further in section 3.

The Authority's calculation of allocation inefficiency uses an incorrect benchmark

The Authority acknowledges price discrimination can be efficient but it seems to think it relates solely to costs and risks of serving a customer. This is incorrect. *Efficient* price discrimination also involves taking into account the relative price elasticities of demand of customers (Tirole, 1997, p139).

This means it is incorrect for the Authority to calculate allocation inefficiency in relation to a uniform market price, such as the futures price.

Also, it is misleading to state that the low price in the Tiwai contract relative to forward prices at the time it was signed raises the prospect that the generators' motivation for reaching an agreement was to maintain elevated prices paid by other consumers (IP, 5.6). This is because efficient price discrimination inevitably involves some consumers being charged prices lower than the futures price, and other consumers being charged more.

Further, it is clear that 'use-it-or-lose-it' clauses can be efficiency-enhancing, such as when they enable efficient price discrimination.

[19] See Saussay & Sato (2018) for a recent empirical study of the impact of energy prices on foreign direct investment. Arauzo-Carod et al (2009) provides an overview of the literature on industrial location. Of course new domestic startups are another source of new entrants but it is rare for them to be large electricity consumers at the startup stage.

The Authority seems to have an unhealthy fixation with uniform pricing, stating that “If all parties faced a ‘market price’, then inefficiencies of the kind being discussed would be less likely to eventuate. … ‘Use-it-or-lose-it’ clauses may not then be required by the generators to protect their interests, because the prices in the Tiwai contracts would be at market prices (adjusted for the cost and risk of serving) at the time of contracting” (IP, p16, 4.8).

The Authority provides no evidence about pass-through of wholesale prices to retail prices

The Authority claims the contract with Tiwai increases the prices paid by the rest-of-New Zealand consumers, causing inframarginal revenue gains to generators of as much as $850 million per year during the first three years of the contract (IP, p24, 5.13). It acknowledges the estimate depends on the extent to which wholesale prices are passed through to consumers but does not provide any evidence about the rate of pass-through.

However, price smoothing is a key aspect of the service electricity retailers provide to their customers, and so it is not obvious retail charges would fall rapidly and by the magnitude of the fall in futures prices.

If it wishes to adhere to good regulatory practice, the Authority should at a minimum discuss the empirical evidence of key parameters and provide a balanced assessment. If empirical evidence is not available, it should consider a range of scenarios and show their implications for the Authority’s conclusions.

3. Problems with the Authority’s options for addressing its concerns about price discrimination

This section discusses key problems with many of the Authority’s options. Many of them derive from the deficiencies with the price discrimination analysis identified in section 2, but there are also broader concerns with the overall approach adopted by the Authority.

In my view the Authority’s options analysis begins with a flawed problem definition, and so that is where this section starts (section 3.1). Section 3.2 provides a high-level analysis of the risk allocation implications of several options, section 3.3 discusses the impracticality of some options and section 3.4 discusses concerns that some of the options are likely to compromise the Authority’s independence. Section 3.5 discusses concerns with the overall approach adopted by the Authority.

3.1 There are serious flaws in the Authority’s problem definition

In my view the Authority’s options analysis begins with a flawed problem definition. Broadly speaking, the flaws arise from the Authority stating that price discrimination can be efficient but not taking that reality seriously, as it has not embedded that in its problem definition. This leads it to carelessly broaden the areas of concern and to posit four conditions that enable price discrimination, whether efficient or not.

The Authority broadens the areas of concern without providing any evidence whatsoever

The Authority states that the potential price discrimination issue raised by the Tiwai contracts could also arise with any other large purchaser of electricity (IP, page iii). In paragraph 6.10, it identifies three categories of concern:

1) the large generator–retailers' supply agreements with other large industrial loads or independent retailers, including potential for new large-scale demand to be developed in future
2) in long-term power purchase agreements (PPAs) where large purchasers could exert pressure on independent generators to obtain favourable terms[20]
3) in the terms and conditions of OTC derivative agreements between independent retailers and large generator–retailers.

In paragraph 6.11, the Authority notes that individual agreements in categories (1) to (3) may be too small to be of concern but collectively they could raise efficiency and competition concerns.

The Authority presents no evidence whatsoever in support of these broader areas of concern, or of the claim that, collectively, the individual agreements could be inefficient. It does not present any empirical evidence about inefficient price discrimination in bilateral contracts with any other large consumers, in either the Review paper or Issues paper. Nevertheless, the Authority proceeds to float far-reaching changes to market design and industry structure to address these concerns. This is poor regulatory practice, to say the least (refer section 3.5).

Oddly, the above list includes concerns about access pricing for independent retailers

Surprisingly, the above list conflates (standard) price discrimination with *discriminatory access pricing*. Access pricing issues arise when a supplier competes with its own customers. For example, the supplier owns a retailer and supplies other retailers as well as its own retailer.

Discriminatory access pricing is mentioned in category (1) above and it is the sole focus of category (3). The issues in category (2) are solely about standard price discrimination.

Discriminatory access pricing is a form of price discrimination, but it should be dealt with separately from standard price discrimination because the incentives and trade-offs are very different. In particular:[21]

- The theory of standard price discrimination involves a monopoly supplier trading-off forgone profits from causing some higher-priced customers to greatly reduce their demand against higher profits from other high-priced customers reducing their demand only a little.[22]
- In contrast, under discriminatory access pricing, a monopoly supplier could charge the independent retailer a high price to force it out of the market or out of particular segments of the market. If there were only two retailers – an independent one and the supplier's retail business – then the independent retailer's customers become customers of the supplier's retailer and so the monopoly supplier faces no profit trade-off.

The Issues paper provides no empirical evidence about inefficient access pricing to retailers. The Authority has previously undertaken an empirical analysis of the issue by comparing commercial

[20] Note the Authority is presumably referring to virtual PPAs here, as clause 13.25 of the Code requires all generation plants exceeding 10 MW to be sold to the wholesale electricity market. Virtual PPAs are bilateral CFDs with terms specific to particular generation plants.

[21] For simplicity, this discussion is for the case of a monopoly supplier. The results for other markets where there are multiple vertically-integrated suppliers and many independent retailers depend on the particulars of the situation.

[22] This ignores the unrealistic case of perfect price discrimination, in which there are no trade-offs. Under perfect price discrimination the supplier can identify customers that would greatly reduce their demand and would not charge them high prices.

contract prices generator-retailers achieved with consumers relative to the ASX electricity futures prices. It concluded it had not found evidence of systemic discounting by generator-retailers (EA, 2017).[23]

Section 5 of the Review paper considers access pricing issues for independent generators but not access pricing issues for independent retailers. Tellingly, section 5 of the Issues paper is entitled *Issues the Authority would like to address* and runs for 10 pages, but never mentions any concerns about access pricing to independent retailers.

Despite all of that, in section 6 of the Issues paper the Authority refers to some options potentially improving confidence about access pricing to independent retailers (IP, 6.32). It is essential the Authority make clear its position on access pricing. If, despite previous statements to the contrary, the Authority now suspects access pricing for independent retailers to be an issue then it should examine and present the evidence. The Issues paper has failed to do this.

The Authority posits four conditions that enable (inefficient) price discrimination

At paragraph 6.9, the Issues paper identifies four conditions it says enable inefficient price discrimination:[24]

a) generators' ability to offer different prices to different customers without having to justify the difference

b) the capacity to do the deal off-market so as to control which parties can participate

c) the use of use-it-or-lose-it contract clauses thereby effectively prohibiting the re-contracting of that electricity with other consumers who have higher valued uses

d) generators own other generating assets that benefit from the increase in revenues from other customers.

The fundamental problem with conditions (a) – (c) is that they are also needed for firms to undertake efficient price discrimination. Efficient price discrimination is vital in the electricity market, as it allows generators and (large) customers to transact in ways that minimise their risks, and so achieve more efficient prices overall. The flaws in condition (d) were addressed in section 2.2 but will be elaborated below.

More generally, it is poor regulatory practice for the Authority to posit the above conditions without offering any theoretical justification or referencing to the relevant academic literature. I am not aware of any rigorous analytical framework that would lead to using those conditions to separate inefficient from efficient price discrimination.[25] The Authority has unfortunately defined a set of conditions that rule-out all price discrimination.

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[23] The Authority also provided no empirical evidence in its consultation and decision papers for requiring the disclosure of internal transfer prices and it rejected suggestions that independent retailers should be able to buy electricity from generator-retailers at their prevailing internal transfer prices. Refer EA (2021b) and EA (2021c).

[24] Note the Authority seems to view section 5 of the Issues paper as its problem identification (IP, 6.10) section. However, it is clear conditions (a) – (d) constitute the Authority's problem definition because section 5 focuses only on the Tiwai contract, whereas the options presented in the Issues paper reach far further than that contract.

[25] There are many very good technical analyses of price discrimination, such as Laffont & Tirole (1994) and Tirole (1997). A more accessible description is provided in Krylovskiy (2020), which provides a list of the conditions necessary for any price discrimination to occur, which of course includes efficient price discrimination. These conditions are similar to conditions (a) – (c).

Condition (a) is misguided and inimical to efficient markets

In workably competitive markets, sellers (indirectly) justify their price differences to customers. This is because any customer concerned about being over-charged can seek offers from other suppliers and switch if a better deal is available. Any supplier losing its high-priced customers but retaining low-priced ones will suffer reduced profits, harming their return on investment. In essence, rivalry for high-value customers discourages sellers from over-discounting their prices to low-value customers.

As mentioned in section 2.2, discrepancies will exist in real world markets because sellers are not perfectly informed of the costs and risks associated with each customer. But overall, a workably competitive market provides acceptable incentives for careful consideration of those costs and risks.

Suggesting sellers should be justifying their price offers to consumers (other than the customer in question) is misguided and inimical to efficient markets. It ignores the reality that different customers have different load and risk profiles, and it is efficient for them to be matched with suppliers that can best accommodate those features in their overall load and generation portfolio. Suppliers attract those customers, and screen-out poorly-matched customers, by offering low prices to the former and higher prices to the latter. This is fundamental to achieving an efficient electricity market.

For similar reasons, condition (b) is also misguided and inimical to efficient markets

Condition (b) states that inefficient price discrimination occurs because suppliers have the capacity to do the deal “off-market” so as to control which parties can participate. The flaw in this statement is that doing deals “off-market” is also critical to efficient price discrimination, as discussed for condition (a). Condition (b) does not assist the Authority or anyone else to separate efficient and inefficient price discrimination.

It is concerning to see the Authority characterise some methods of transacting as less beneficial because they’re conducted in a so-called “off-market” manner. In any real world market, different types of market platforms are best for different types of transactions.

The spot market is a gross pool, for example, because in 2001 that approach was judged to provide the best means of assuring the close coordination needed for real-time balancing. Prior to those arrangements, about 20% of physical supply was traded bilaterally between parties, including the supply to NZAS. A key argument during the debate over net vs gross pool was that generators and consumers would be free to agree bilateral CFDs to meet their risk management requirements.

In reality, the vast bulk of markets for goods and services comprise bilateral transactions between willing buyers and willing sellers, where each party decides by mutual consent who else can be privy to the deal. Completely open and public markets are the exception, rather than the norm. This reflects the reality that buyers and sellers gain from better matching each other’s requirements, but this comes at the cost of low comparability of prices. Public markets bring greater pricing transparency, but at the cost of less tailoring to specific requirements. One is not necessarily better than the other.

The wholesale electricity market allows both public and closed markets to co-exist. The spot market is a public and highly standardised market, and parties can contract-out of it by mutually agreeing CFDs.

Condition (c) is inherent in the physical supply of electricity and so it can be an efficient provision in financial contracts

Condition (c) states that use-it-or-lose-it clauses prohibit the re-contracting of electricity with other consumers who have higher valued uses. This is not quite correct. CFDs are financial instruments that the counterparties are using to allocate their financial risks, and are not contracts for the physical supply of electricity. This subtly matters, because risk is specific to each counterparty. For that reason, banks and other financiers also prohibit customers from transferring their bilateral loan obligations to other parties without their approval. Both generators and banks value having a contractual right to manage their exposure to credit default risks.

In reality, electricity transmission and distribution systems connect all consumers together. The laws of physics mean electricity cannot be transferred bilaterally between any two connected parties. It also means the physical supply of electricity is a use-it-or-lose-it arrangement. Hence, it can be efficient for CFDs to include clauses that mimic these inherent features of the physical system.

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. But that is what would occur with a prohibition of use-it-or-lose-it clauses.

In conclusion, CFDs and futures contracts allow market participants to contract-out of the spot market to varying degrees. Consumers that elect to stay exposed to the spot market do so for zero additional transaction costs. But those that want to reduce their risks and gain the benefits of transparency and liquidity, can do so through futures contracts, which are available at modest transaction cost. But if greater risk reduction is important, they can incur the higher transaction costs of negotiating a tailored CFD and forgoing the benefits of a high degree of transparency and liquidity.

Condition (d) reflects a flawed understanding of price discrimination in markets with customer choice

Condition (d) reflects the Authority's misunderstanding of when inframarginal revenue gains accrue to generators. As discussed in section 2.2, in markets with customer choice, such as we have in electricity, it is critical to separate customer switching from customer entry or exit from the market. It is obvious switching completely dominates entry and exit, and especially so for large customers.

In customer switching cases, the *size* of the generator's own generating assets is irrelevant, as market demand and spot prices are not affected at all. This is true regardless of the size of the switching customer.[26]

Unfortunately, most textbook analysis of price discrimination is for monopoly situations, where market demand equals the demand for the firm's output. The Authority has carelessly applied monopoly analysis to a market with customer choice.

By definition, in the monopoly supplier situation, any large increase in demand has the potential to increase market prices, and so the size of the generator's own generating assets can be relevant.

But even in this case, the issue is really the entry of new sources of demand to the market, or the inducement of additional demand from an existing customer or the inducement to an existing customer not to exit. In these cases, the size of the generator's own generating assets could potentially provide inframarginal revenue to make it worthwhile to subsidise the entry or forestall exit. This creates production inefficiencies, but as discussed in section 2.1 it is essential the incremental cost of supply takes into account option values when there is uncertainty and irreversibility.

[26] But as discussed earlier, the nature of the generator's other generating assets is relevant for risk and portfolio management reasons.

3.2 Several options reflect the Authority's flawed problem definition

Section 3.1 explained the Authority's problem definition does not provide any basis for separating efficient from inefficient price discrimination. This reflects the Authority's tendency to 'pay lip service' to the risk allocation and efficiency rationales for bilateral contracting in the New Zealand electricity market.[27]

As a result, the Authority suggests three options that would seriously undermine efficient bilateral contracts:

- Option 2: Prohibit use-it-or-lose-it clauses
- Option 4: Require public offering of all (or some percentage of) hedge contracts
- Option 5: Require large hedges to be traded publicly

The problem with each of these options is they do not address the source of the problem the Authority is concerned about. As the problem definition is cast too wide, the options emanating from it are like using a shotgun to shoot at a distant target: some pellets will hit their target but most pellets cause considerable collateral damage to closer objects (efficient price discrimination).

Options 2, 4 and 5 cause too much collateral damage

The Authority seems to be aware of the shotgun nature of options 2, 4 and 5. In its tabular assessment of option 2, it states the option would potentially enable high WTP consumers to unwind inefficient market segmentation by contracting with lower WTP consumers but it also notes it could prevent efficient contracting by large consumers (IP, p37). The list of collateral damage with Options 4 and 5 are more extensive (IP, potential cons, pp 41 & 43).

The Authority notes that the OTC market, and other closed forms of negotiations such as PPAs, would be collateral damage as they would no longer exist under option 4. This is very concerning. Tirole (1997, p139) states that "The elimination of price discrimination may be particularly dangerous if it leads to the closure of markets."

The Authority states that options 4 and 5 would ensure greater and equal access to sale and purchase opportunities, providing greater assurance electricity is going to consumers with the highest willingness to pay (IP, 6.27 and 6.37). This may be the case for the trades that occur, but as indicated in the quote form Tirole it ignores the welfare losses for efficient trades that no longer occur. This once again reflects the poorly specified problem definition adopted by the Authority.

As discussed in section 2.2, there are no theoretical grounds for thinking there are incentives for inefficient price discrimination across large commercial contracts generally in workably competitive markets. It is only where the commercial customer is considering entering or exiting the New Zealand market *due to* electricity prices *and* the party is so large its decision materially affects wholesale market prices. And even in those special cases, the economically optimal contract price depends on the nature of the market at the time, such as the extent and nature of any investment uncertainty.

[27] This is partly reflected in the Authority erroneously treating bilateral contracts as contracts for physical supply. For example, paragraphs 6.10, 6.15, 6.18, 6.20.

3.3 Several options are plainly impracticable or ineffective

The Authority floats several market design options that have the potential to avoid the collateral damage to efficient price discrimination. However, the informational requirements for each of them renders them impracticable or ineffective or both.

Options 6 and 7 are clearly impracticable

Option 6 involves extending the new trading conduct provisions beyond the spot market to hedge markets. This would require all forward offers and contracts to be consistent with the *as if there were competition* principle (IP, p44).[28] Option 7 is very similar, but rather than the vague *as if* principle, specific rules would be introduced to prohibit discriminatory pricing unless those prices can be explained by differences in risks or costs in servicing different customers or other similar reasons (IP, 6.48-9). Both operate on the basis of parties complaining to a third party and the third party investigating the complaint and making a determination.

Unlike with the spot market, where offers for an homogenous product are made every half-hour and are available from the market IT system, offers for bilateral contracts are dispersed among the parties, and are context and time-dependent. Assessing whether a contract satisfied requirements would require significant information transfer from the parties to the decision-maker, including presumably recordings of conversations.

All decision-makers are fallible, and third-party decision-makers face the additional difficulty of information asymmetry. Even with full information transfer to the Authority, information asymmetry occurs because a third-party cannot perfectly observe the hidden attributes of the counterparties. This will create adverse selection incentives for generators, causing them to forgo efficient bilateral contracts where they are unsure of the type of customer they are dealing with. Instead, they will pursue less tailored (and therefore less efficient) arrangements via public markets.

Given the commercial significance of these contracts, regulatory decisions would need to be made by a committee, with a subcommittee of the Authority Board or the Rulings Panel likely the final decision maker. Delays exceeding two to three months are inevitable for complex and unusual cases.

If the contract is kept 'null and void' during the investigation period, and lapses if it is assessed to be non-compliant, then generators will face additional uncertainty around their future contract obligations, affecting their planning and hedging activities. This would be particularly problematic for large contracts. Alternatively, if contracts are allowed to take effect and a washup process or penalty is enforced later, then additional administrative and computational costs would be imposed.

The resourcing requirements will be very significant for the decision-maker, the complainant and the accused party. Legal risks would inevitably lead the accused and decision-maker to lawyer-up, adding real resource costs to the electricity system. Given the commercial issues at stake, some cases would no doubt be litigated to higher level decision-makers, adding further resource costs and delays.

There could also be considerable incentive for parties to game the system, either by threatening to complain to the Authority as part of their bargaining or to actually complain to bring reputational damage to the counterparty. Gaming would add to everyone's resource requirements.

[28] The Authority does not specify whether the hypothetical competition is from other generators or from other commercial customers or both.

Reducing the size of generators will be costly and ineffective

Under this option the Government would require all large generators to divest specified generation assets or divest specified amounts of generation capacity, with the aim of ensuring their inframarginal revenue gains are insufficient to offset any significant subsidies realised through inefficient price discrimination (IP, 6.66).

The Authority rightly identifies the need to consider the productive efficiency losses that would arise from additional transaction costs to industrial consumers, forgone economies of scale and synergies, and the potential for reduced competition at the national level (IP, 6.68).

As discussed in 2.2, there are very few bilateral contracts that affect market prices, as the vast majority of them are switching decisions rather than entry or exit decisions. Those that are entry or exit decisions are overwhelmingly too small to materially affect wholesale market prices. Reducing generator sizes provides no benefit in any of these cases.

The Authority suggests that having a greater number of smaller generators may make it more difficult for generators to collectively bargain and replicate the wealth transfers that it says underpins the Tiwai contracts (IP, 6.67). This is difficult to believe.

For example, suppose Meridian and Contact were each split into two generators, so there would be four major generators in the lower South Island rather than the current two.[29] It is very likely they would all be willing to share the burden of the Tiwai contract, as Tiwai is a natural counterparty because of their location. Failure to share the burden could be very costly for them, whereas sharing the burden would be a continuation of the status quo.

The discussion at para 6.67 suggests the Authority's main concern may be the Tiwai contracts. If that is the case, reducing the size of the North Island generators would be redundant but costly.

Splitting Manapouri off from Meridian is likely to backfire

The Authority floats the idea of requiring Meridian to divest Manapōuri so that it becomes a stand-alone generation company, to decrease industry concentration and increase competition (IP, 6.69). As the Authority notes, this is a specific example of reducing the size of generators, and so the points in the previous subsection apply to this option too.

The Authority may have in mind a requirement that Manapouri carry all of the contract with NZAS but with some backup arrangements in place to cover periods of low storage and/or generation outages at Manapōuri (IP, 6.70). This would create serious bankruptcy risks if NZAS exited, significantly raising Manapouri's cost of capital.

Bankruptcy risks would significantly harm Manapouri's sale value, reducing the revenue it would require from NZAS to earn an acceptable return on capital. It would also undermine Manapouri's bargaining position vis-à-vis NZAS, further increasing the incentives on it to agree to low-price contracts with NZAS. Worse than being ineffective, the option is likely to be counterproductive to meeting the Authority's goals.

Virtual asset swaps would also backfire, as the Authority acknowledges

The Authority also briefly considers the idea of a virtual asset swap in which a proportion of Manapōuri and/or other lower South Island generation could be exchanged for claims on generation elsewhere (IP,

[29] This ignores Genesis, which has only 190 MW generation in the lower South Island.

6.71). The Authority itself thinks this option could be counterproductive because it may socialise the burden of the Tiwai contract (IP, 6.73).

The Authority suggests mitigating these concerns by involving new entrant generators in the virtual asset swap (IP, 6.73). This is plainly speculative – what new entrant generator would want to place itself at the risk of NZAS deciding to exit New Zealand?

3.4 Some options exceed the Authority's mandate and risk compromising its independence

The Authority's mandate is given by its statutory objective in section 15 of the Electricity Industry Act 2010. This requires the Authority to promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.

The Authority was established as an independent Crown entity, with rule-making, market monitoring and enforcement powers.[30] To carry out its market regulation role effectively, the Authority needs to preserve its independence from market participants, not just from Ministers and the Executive.

Option 3 exceeds the Authority's mandate

It is very concerning the Authority, in option 3, has suggested it could grant itself the power to pre-approve large commercial contracts (IP, 6.22-3). In my view this exceeds its mandate to *promote* competition, reliability and efficiency and it risks undermining its role as a truly independent market regulator.

The word *promote* in s15 of the Electricity Industry Act was adopted to prevent the Authority falling into the trap of seeking to ensure particular outcomes occurred. Being aware of these subtleties, the Authority issued its interpretation of s15 shortly after being established (EA, 2011a) . It took care to adopt wording consistent with the wording of the Act.

In regard to competition, paragraph A.28 of the Interpretation document states:

> *The Authority interprets <u>promoting</u> competition to mean exercising its functions to <u>facilitate</u> or <u>encourage</u> 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.* (underlining added)

In regard to efficiency, the same document states at paragraph A.65:

> *The Authority interprets <u>promoting</u> efficient operation to mean exercising its functions in ways that <u>enhance</u> the efficiency of the industry.* (underlining added)

The respective roles of the Electricity Authority and Commerce Commission are described in a memorandum of understanding (MOU).[31] In regard to promoting and monitoring competition:

- clause 10 in the MOU states "the Authority's focus is on the competitiveness of the electricity markets rather than on the conduct of any particular market participant or group of market participants…"

[30] Refer sections 12 and 16 of the Electricity Industry Act 2010, section 7 and Part 3 of Schedule 1 of the Crown Entities Act.
[31] See Electricity Authority and Commerce Commission (2010).

- clause 11 states the Commission's role is "to promote competition in markets for the long term benefit of consumers by prohibiting contracts or arrangements by businesses that could lead to a substantial lessening of competition, the taking advantage of substantial market power to deter or eliminate competition …"

It is therefore very concerning the Authority now believes it should aim to ensure consumers who value electricity above the cost of production can consume the amounts that they desire and that electricity is produced in a least cost manner given available generation (IP, p22, 5.3). This clearly exceeds the Authority's mandate to promote rather than ensure outcomes.

Option 3 risks compromising the Authority's independence

As indicated above, the Authority's role is to regulate the electricity market with broad-based rules, and leave it to the Commerce Commission to prohibit the actions of individual market participants where necessary to meet the Commission's mandate. This approach was designed to avoid the Authority becoming effectively a market participant, which would compromise its independence when undertaking its market monitoring function.

Option 3 is likely to result in the Authority reverting to the situation it inherited from the Electricity Commission in 2010, where it decided offer prices for the Whirinaki power station while it was owned by the Crown. During that time, the Authority was acutely aware that this responsibility compromised its independence.

In my view, if the Authority proceeds with option 3, it should request the Government make it the responsibility of the Commerce Commission. The Commission is an independent economic regulator across all business sectors, and does not have specific responsibilities regarding the wholesale electricity market. It has the economic analysis expertise needed to make these decisions.

As option 8 is a combination of options 3 and 7, the above comments also apply to option 8.

3.5 Overall, the Authority's options analysis is perfectionist, misguided and pre-emptive

The Authority is demonstrating a perfectionist and misguided mindset

The economic rationale for adopting a market approach to electricity rests on the view that, on average over time, it performs better than the next best feasible alternative. This does not require the market to work perfectly or firms to always make efficient decisions, and it does not require there be no market power and no exercise of market power, nor does it require all prices to be efficient.

These realities are why courts have adopted the workable competition standard for competition, as they appreciate competition is a multi-faceted process and third parties, such as the courts, have imperfect information about it.

A similar approach is adopted for fiscal and regulatory interventions, such as tax policy. In theory, an efficient commodity tax system requires tax rates be inversely related to relative demand elasticities, but in practice we have a flat-rate commodity tax called the goods and services tax (GST). This is because adopting the perfect schedule would be very informationally demanding and create tax avoidance incentives.[32] Taking these practical matters into account can result in very large deviations from the theoretical optimum.[33]

It is critical the Authority avoids the trap of seeking near perfect outcomes, such as aiming to *ensure* consumers who value electricity above the cost of production can consume the amounts that they desire and that electricity is produced in a least cost manner given available generation (IP, 5.3). The Authority should definitely promote these outcomes but it should step back from intervening directly in commercial contracts.

The Authority needs to take proper account of the limitations of its powers. It has significant information gathering powers, but it will always face asymmetric information regarding the unobservable actions and attributes of regulated parties. As with competition and tax policy, the Authority should consider the implications of these limitations and consciously avoid over-regulating the electricity industry.

The Authority also needs to consider the wider and longer-term consequences of interventions. It should eschew interventions likely to increasingly politicise regulation of the electricity sector. Decisions about large commercial customers inevitably carry significant implications for other matters government and society care about, such as employment and just transitions for workers.

In my view it is misguided for the Authority to believe it will be sustainable for it to intervene in specific commercial decisions but claim it does not have the mandate to consider the wider economic and social impacts of those decisions (IP, 5.42). This should surely signal to the Authority it does not have the mandate to intervene in the manner it proposes under options 3 and 8.

The pre-emptive move to consider options is very concerning

As mentioned in section 3.1, the Authority does not present any evidence in support of the broader areas of concern identified in paragraph 6.10 of the Issues paper. This leaves the impression they were added belatedly, perhaps to avoid the Authority being cast as anti-Tiwai or to backfill a rationale for considering more far-reaching changes to market design and industry structure than could otherwise be the case. At best, this is poor regulatory practice.

Of course, in practice it is often useful for regulators to present potential solutions contemporaneously with detailed analysis and evidence of the problems to be addressed. However, in doing that the Authority has always presented significant evidence of the problems that the options were intended to address.

In contrast, the Issues paper presents an entirely novel concern about the functioning of broad areas of the electricity market, with no evidence and no effort to assess the magnitude of the issue. Moreover, the concerns the Authority seeks to address are not once mentioned in section 5 entitled “Issues the Authority would like to address” (IP, pp21-31). This is highly unusual.

[32] The widely-held view of tax policymakers around the world is that attempting to set taxes in strict accordance with relative demand and supply elasticities would (1) incur very high administration and compliance costs (2) create endemic opportunities and incentives for tax avoidance and evasion, undermining the integrity of the tax system and (3) could in practice result in a set of taxes that deviate further from efficiency than more straightforward options.

[33] For example, GST applies to domestic spending by foreign tourists while in New Zealand, which in theory should be zero-rated like all other exports. But zero-rating would create significant tax avoidance opportunities for New Zealanders, as foreigners could buy the goods and on-sell them to New Zealanders. Hence, our GST system collects about $1.7 billion per annum from foreign tourists, far in excess of costs tourists impose on New Zealand (Productivity Commission, 2019, p263).

At a minimum the Authority should furnish and consult on the evidence it has about the broader areas of concerns it mentions in paragraph 6.10. Failure to do so will tarnish its reputation for being a balanced and evidence-based decision-maker. It would raise serious concerns about whether the Authority has an open mind about the option it selects.

4. Concerns with the Authority's analysis of wholesale market competition

The Review paper presents empirical analysis of wholesale market competition. It presents a suite of competition indicators and an econometric analysis of the drivers of spot market prices. Doing this well requires in-depth knowledge of the practical realities of our electricity system, and it requires considerable expertise to use that knowledge to settle on meaningful indicators. It also requires attention to detail to ensure inferences, and summaries of those inferences, are correct and balanced.

In my view the Review paper falls short in each area. Section 4.1 discusses broad concerns with the Review paper, regarding lack of clarity about the competition benchmark and the need for the Authority to better understand the implications of hydro generation for interpreting competition indicators. Section 4.2 discusses biases in the choice of competition indicators and section 4.3 identifies occasions where the interpretation of competition indicators is one-sided and potentially misleading. Section 4.4 concludes with concerns about the way the Authority has characterised and used its econometric analysis.

4.1 General concerns with the Authority's competition review

Section 4.1 discusses broad concerns with the Review paper, regarding a lack of clarity about the competition benchmark and the need for the Authority to better understand hydro generation realities and their implications for interpreting competition indicators.

The Authority should be more explicit about its competition benchmark

The Review paper defines market power as the ability of a firm (or group of firms) to raise and maintain prices above the level that would prevail under competition, and it proceeds to state that the concern is with the sustained exercise of market power (RP, 5.7 & 5.35).

Paragraph 1.1 of the Review paper justifies the structure, conduct and performance (SCP) framework for assessing market power by referring to EA (2011b). This implies the Authority interprets competition to mean workable or effective competition, as that is the definition provided in EA (2011b). However, it uses the term only once (RP, 5.187).

The Review paper provides mixed signals on the competition benchmark it is applying. For example, it states that the performance of a competitive market is ultimately one that satisfies the conditions of allocative, production and dynamic efficiency (RP, 5.9). This implies the perfect competition benchmark is being used as only perfectly competitive markets *satisfy* allocation and production efficiency conditions.

Similarly, the paper states that in a competitive market the Lerner Index is equal to zero (RP, 5.82). This also implies the Authority is interpreting competition to mean perfect competition as a zero Lerner index will only occur in a perfectly competitive market.[34]

[34] A similar error is made in EA (2021, p11), which is referenced in the Review paper.

The Authority muddies the water further by referring to transitory episodes of market power, which is irrelevant to the issue of sustained exercise of market power.

Greater clarity and consistency from the Authority would be helpful. This could be achieved by explicitly stating it is applying the workable competition benchmark when assessing its competition indicators, and spell out what that looks like in terms of rivalry in the spot and hedge markets.

A more realistic timeframe is needed to assess competitive rivalry

Clarity about the competition benchmark is essential because it goes to the issue of what is meant by a sustained exercise of market power. The review period is 30 months, from 1 January 2019 to 30 June 2021. Competition indicators for this period are compared to periods (of various lengths) before 2018.

A key problem with the Authority's analysis of the 30--month review period is that many of its statistics are averages over that period. This ignores the reality that competition is a process that occurs over time. As rivalry from competitors takes time to organise and have a material effect, some allowance should be made for a period from 1 January 2019 to reduce bias in the Authority's competition statistics.

Moreover, as most generation investments are irreversible, investor uncertainty (about Tiwai, policies regarding the transition to net zero emissions and future gas supply) may significantly delay the timing of investment reactions to high spot prices, even in perfectly competitive markets.[35] The Authority discusses these factors in some detail, including that investment intentions may have improved since the 'Tiwai stay' decision on 14 January 2021 (RP, 5.185-93).

But the paper is very meek in its discussion of the implications for competition, simply stating "These signs of improvement may be the start of a response to recent high prices" (RP, 5.193). Given what we know about workably competitive markets and irreversible investment under uncertainty, the Authority should have discussed more fulsomely that supply responses to high prices are adaptive and so it can take considerable time for prices to revert to long-run marginal cost. In reality, there is a high likelihood that competitive pressure will intensify significantly over 2022 and 2023. This expectation is supported by movements in the price index for long-dated futures contracts, which had fallen from around 118 $/MWh in March 2021 to around 94 $/MWh in October 2021.[36]

The Authority should also have commented on the implications of these considerations on the timeframe used to assess the competitiveness of the wholesale market. Given the significant uncertainties outlined by the Authority, it is not reasonable to expect the full competitive process to have worked through by 30 June 2021. This implies its competition statistics are likely to be understating the true competitiveness of the spot market.

Some hydro tranches offer capacity services

The Authority acknowledges that generators are managing plant with different characteristics, and mentions the different offer profile for thermal peaker plants versus thermal baseload and for generators managing hydro systems with storage versus those managing run-of-river schemes (RP, 5.44).

[35] Dixit & Pindyck (1994, pp 247-316) show that in perfectly competitive markets it can make commercial sense for firms to raise their hurdle rate of return and defer investment plans until higher prices lift their return on investment above the hurdle rate. But for markets comprising a small number of large competitors, there are also strong incentives for participants to take risks and act pre-emptively to get ahead of their rivals. Delays to investment depend on which force is dominant at the time.

[36] See emi.ea.govt.nz/r/rdrk3. The price index was $118.91 on 1 March 2021 and $96.15 on 1 October 2021.

However, the Authority does not mention the peaking and last-resort roles of some hydro generation plants. Meridian's Waitaki hydro scheme performs these roles because, generally, its capacity significantly exceeds the amount needed to prudently manage the Pukaki reservoir to minimize dry year security of supply risks. This feature reflects the design of the scheme at the time it was built.

Rather than keep the excess capacity out of the market, Meridian offers it at high prices so that it is only dispatched for peaking and last resort purposes. It does this because it knows it will need to use the stored water later and this is not materially compromised by transitory drawdowns to avoid capacity shortages in the market.

In effect, the top tranches on the Waitaki offer schedules are providing capacity services to the market. It does not make economic sense to expect the offers on those tranches to vary in response to changes in seasonal conditions, such as seasonal variations in hydro storage. This is analogous to the Authority not expecting the offer structure for thermal peakers to vary with hydro conditions.

The Authority naturally places significant store on its quantity-weighted offer price (QWOP) indicator. This captures the entire offer structure, and so captures moves to shift offer quantities from low-priced tranches to higher-priced tranches, which could indicate economic withholding (RP, 5.42). However, it also captures the top tranches, which means it can be a misleading indicator for assessing whether offers are correlated with underlying supply and demand reasons.

The Authority appears to have recognised this possibility because it calculated a truncated QWOP, in which all offers exceeding 300 $/MWh were excluded. The truncated QWOP for Meridian had a strong positive correlation with water values, whereas that was not the case for the full QWOP for Meridian (RP, 5.77-8).

However, it is not clear the Authority accepts the reality that the Waitaki scheme provides both energy and capacity services to the market. It does not mention this reality about Waitaki and it ignores the results for the truncated QWOP in its summaries. For example, the Authority states that the only hydro generator with a strong relationship between offer prices and estimated cost is Genesis at Tekapo (RP, 5.73). This is plainly incorrect.

Hydro storage generators are constrained in their ability to exercise *sustained* market power

The Authority states that generators managing hydro storage are likely to have different offer structures than run-of-river generators (RP, 5.44). Although that is correct, the Authority ignores the fact even our largest hydro scheme, Lake Pukaki, has very modest storage capacity relative to annual inflows. This severely constrains Meridian's ability to set offer prices out of sync with its competitors for any length of time.

The Review paper shows some awareness of this because it notes that thermal generation offers affect the offer prices of hydro generators. It states that if hydro generators offer above thermal prices their offers might not be dispatched, potentially leading to the lakes filling up and excessive spill (RP, 5.39). It states that this interaction must be kept in mind when assessing offering behaviour in relation to the level of competition in the market (RP, 5.40).

The problem is the Authority does not appear to keep the interaction in mind when interpreting the competition statistics it produces. It assesses each generator's conduct by looking at the pattern of their offers over time (relative to cost etc) but rarely considers how the offers of one may have affected the other. But the issue is the sustained exercise of market power, not short-term interactions.

The Review paper states there has been a sustained upwards shift in prices after the Pohokura outage in October 2018 that it has not been able to explain by underlying conditions (RP, 2.3). The paper states this may be due to difficulties measuring uncertainty about future gas supply from existing fields, however it also states: "We observed some evidence to suggest that generators have an increased incentive and ability to exercise market power, and may have been doing so over the review period." (RP, page ii)

The problem with this evidence is that it based on the slope of half-hourly offer curves. The Authority does not quantify the extent to which hydro generators could engage in a sustained period of economic withholding sufficient to account for the upward shift in prices without significantly increasing the risk of over-filling their hydro reservoirs. Only generators with a controllable supply of fuel could engage in such behaviour on a sustained basis. However, the evidence shows the reverse: spot prices are higher when thermal generators are uncertain about their fuel supplies.

4.2 The Review paper contains biased and meaningless competition indicators

The Authority states it is looking at all the indicators in the round, so that it can build a picture of the way the market is operating (RP, 5.8). While this is generally a good approach, it is important the Authority presents a balanced set of meaningful indicators. Doing this requires omitting meaningless indicators regardless of their results.

It is appreciated the Authority needs to present various statistics to provide context and assist with presenting its range of competition indicators. Where the Authority needs to do this, it should present them as *context indicators* and not include them in its tabular summary of competition indicators.

Achieving a balanced set of competition indicators requires two things. It requires an understanding of when indicators are effectively measuring the same issue, in which case the duplicates should be omitted from the competition assessment (but they could still be provided as context indicators). Secondly, other indicators should be adopted if they can potentially contradict another indicator.[37] I will refer to these requirements in my discussion below.

The Authority does not provide a balanced set of indicators for market structure

The Herfindahl-Hirschmann Index (HHI) and gross pivotal supplier (GPS) indicators are fated to tell pretty much the same story because our spot electricity market is a reasonably concentrated market, as are many other markets in New Zealand.

The original rationale for examining GPS indicators was that the HHI can be very low and yet generators can still have episodes of substantial market power (Twomey et al, 2005, p12). However, this concern is not relevant for New Zealand because our HHIs are not low. This means the Authority should choose one of them as a competition indicator and include the other as a context indicator.

As discussed below, the net pivotal supplier (NPS) indicator potentially nullifies the GPS indicator and should have been presented in the Review paper, instead of the GPS.

The gross pivotal supplier (GPS) indicator needs to be adjusted to be meaningful

The Review paper rightly states that a market dominated by a few large firms is more susceptible to the exercise of market power than a market with numerous small firms (RP, 5.12). The Authority appreciates

[37] In language the market monitoring team might appreciate, this is analogous with econometricians omitting variables to avoid multicollinearity and including instrumental variables to capture the informative components of a set of variables.

that generation market shares, and indices based on market shares such as the HHI, are not particularly useful indicators of market power in electricity markets. This is because sellers with a relatively small market share may still be able to exercise considerable market power and the indices do not account for the effects of transmission constraints (RP, 5.15).

To address these limitations, the Review paper presents statistics on the prevalence with which each of the four largest generators are gross pivotal. For a given level of market demand, a generator is *gross pivotal* when demand exceeds the maximum dispatchable output of all other generators serving the spot market. In these circumstances, some output from a pivotal generator has to be dispatched for total supply to match demand. When a generator is gross pivotal in a trading period, it has the ability to set the spot price for that period at almost any level it wants.

The Authority calculates that Meridian was gross pivotal in the South Island around 77 percent of the time in each year from 2016 to 2018 and calculates this has increased to around 90 - 95 percent over the review period (RP, 5.19). The Authority notes Meridian was the only generator that was gross pivotal a higher percent of the time in all three review years (2019–2021) compared with previous years. Inexplicably, the Review paper does not mention that Meridian's net pivotal position shows the opposite trend (more on this later).

The Review paper's analysis and commentary is superficial, at best. It presents the South Island statistics regardless of whether transfer limits on the HVDC link (connecting the North and South Islands) become binding. And it does not adjust for the volume of *must-run generation*, such as hydro generation to meet consenting requirements and geothermal and wind generation.[38]

The GPS indicator is misleading when generators have hedge and retail commitments

The Review paper uses the gross pivotal concept without considering its applicability to our system, which has a large share of electricity produced from must-run generation. However, these features of our system can be ignored if a generator has hedge and retail commitments exceeding must-run generation. In those cases, it is sufficient to adjust for retail and hedge volumes.

In fact, Darryl Biggar (2011, p32), which the Authority references for authoritative discussion of market structure, argues it is necessary to adjust for hedge and retail commitments:

> *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.*

In other words, the GPS statistics in the Review paper are misleading on their own and should be dropped, or at a minimum accompanied by net pivotal statistics. I turn to this next.

[38] In principle, the same adjustments should be made to the calculation of market shares and HHIs, as surely it is the shares of controllable generation that matters.

Net-pivotal supplier (NPS) situations need to be examined to determine whether they nullify GPS situations

A generator is net pivotal when some of its uncommitted generation is needed to ensure total supply matches total demand. *Uncommitted generation* equals a generator's potential generation minus its retail and hedge commitments.

GPS analysis identifies how often a generator does not have to compete to be the marginal generator. In effect, it shows how often a generator has the *ability* to set the offer prices for its marginal generator deterring dispatch of that generator.

In contrast, NPS analysis shows how often a generator has the *ability* to use its uncommitted generation to increase spot market prices. This is important because it shows how often it would have been profitable on a half-hourly basis for a generator to set high offer prices. In other words, it measures how often a generator has short-term *incentives* to exploit a GPS situation to raise spot prices. At a minimum, NPS statistics are surely a key consideration for interpreting GPS statistics.

Further, when a generator is gross pivotal but not net-pivotal, it can only engage in pivotal pricing by setting high offer prices for its committed generation. The Authority can check whether generators used their committed generation to do that by identifying (a) whether a gross pivotal generator in each trading period was dispatched for less than its committed generation, and when that was the case, (b) whether the last tranche of its dispatched generation was the marginal generator, setting spot market prices. This would show whether generators potentially engaged in pivotal pricing despite short-term incentives not to do so.[39] Conversely, negative results for (a) or (b) essentially nullify GPS situations.

Why were NPS statistics omitted?

The Authority has reported net pivotal statistics in every annual report since its 2013/14 Annual Report, and it regularly reports them in its market performance quarterly reports. The latest quarterly report presents these statistics for 2019 and 2020. In none of these papers has it reported gross pivotal statistics, for the reasons noted above.

Whereas Meridian is gross pivotal in the South Island for over 90% of the time during the review period, it has only rarely been net pivotal in the South Island since 2016 (EA, 2021d, p12). The same report shows that no generator was net pivotal more than 0.2% of the time in 2019 – 2020. This is surely important information for assessing short-term incentives to exploit gross pivotal situations.

The Review paper is silent about the switch in focus from net to gross pivotal. One reason for the switch may be a view that net pivotal statistics are not useful for considering a sustained exercise of market power. This could be because over the medium-term high spot prices can be expected to translate into higher hedge and retail prices, providing medium-term incentives to exercise market power.

Nevertheless, it is difficult to conclude the Authority has presented a balanced picture. It has presented only one of the pivotal supplier statistics. And it is clear the most-pivotal generator, Meridian, has not engaged in a sustained exercise of market power. It was the marginal generator only 27% of the time (RP, 5.160) and the Lerner index for those trading periods is volatile, even on a monthly-average basis

[39] A third test would need to be added to try to ascertain whether a generator mis-used its pivotal pricing power. This would involve checking, for trading periods satisfying (a) and (b), whether the offer prices for the marginal generator were higher than when the generator was not gross pivotal.

(RP, pp71-2).[40] 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.

As mentioned above, the Authority makes no effort to draw these factors together to provide a balanced interpretation of market structure and conduct.

Most of the indicators for the price-cost relationship are meaningless

The Review paper canvasses multiple indicators seeking to identify whether there was a sustained exercise of market power during the review period. Five measures of the price-cost relationship are discussed:

1. offers over time (charts of offer structures over time)
2. percent of offers above various benchmarks
3. correlation of offers with cost (ie, water values)
4. correlation of storage with cost (ie, water values)
5. the Lerner Index.

Only the Lerner Index actually measures the price-cost relationship. As the price-cost gap carries profit implications, the Lerner Index is potentially a meaningful indicator. The main drawback is that the results hinge on accurate measures of marginal costs, which in practice are not very accurate. It is good to see the Authority calculating Lerner Indices for two different methods of estimating marginal opportunity costs of hydro generation, as this gives some indication of the credibility of the Lerner statistics.

The first three indicators in the above list are about offers, for which considerable care is needed to define meaningful indicators. In particular:

1. *Offers over time*. The charts of offer structures (Figures 26 – 29) are so busy they are largely uninformative. They mostly show changes in offer prices in the top tranches of offer schedules. It is good to show these charts to provide context but they essentially provide the same information covered in the next point.
2. *Percent of offers above various benchmarks*. The Authority states that if *significant* quantities of a generator's capacity are offered at high prices, or above final price and cost, this could indicate economic withholding (RP, 5.46). It assesses consistency with this expectation by examining the percent of offers exceeding six benchmarks:
    a. 300 $/MWh
    b. final prices
    c. futures prices
    d. gas SRMC
    e. "water values" provided by the generators[41]
    f. DOASA water values.

[40] The Lerner index = (spot price - marginal cost)/price, where price is the spot price Meridian received when it was the marginal generator. A volatile Lerner index means the price is volatile relative marginal cost.

[41] Meridian provided the Authority with minimum sell values, not water values. The Review paper refers to that data variously as water values or costs, and this paper does so as well for consistency with the Authority's reports.

Although the concept of economic withholding involves setting higher offer prices, doing so is only meaningful if it increases spot prices. Examining offers above final prices is meaningless and I am not aware of any basis in competition theory for considering such an indicator. The same comments apply to offers above 300 $/MWh, as final prices are rarely above that level.

These concerns also potentially apply to the other four versions of this indicator. This is because, although these versions include offers that potentially affect spot prices, they also include all other offers that will not influence spot prices.

Reflecting the lack of theoretical basis for these indicators, there is no commentary in the Review paper about what would constitute a significant quantity of offers at high prices.[42] Despite that, the Authority states several times the percentages are high (RP, table 2 and para's 2.12 and 5.59).

3. *Correlation of offers with costs*. The Authority states that in a competitive market it expects offer prices to be related to underlying supply and demand conditions (RP, 5.46). It assesses consistency with this expectation by examining correlations between QWOP and water values.

   This approach can be meaningful provided care is taken to only include relevant offer tranches in the QWOP statistic. For example, capacity tranches must be excluded for the reasons discussed in section 4.1. Doing this is critical for assessing Meridian's Waitaki offers.

   Although the Authority calculates results for a truncated QWOP (where offers above 300 $/MWh are excluded), it underplays those results in summarising the results of the correlation analysis. For example, the Review paper states that Genesis is the only hydro generator with a strong positive correlation of offer prices and estimated cost (RP, 5.73), which is plainly incorrect.

   Furthermore, it is difficult to understand why the Authority expects offers might be correlated with a measure of cost (the DOASA water values) that they do not use in their business.[43]

The fourth indicator in the above list is the correlation of storage and cost. The Authority states that in a competitive market it expects to see the opportunity cost of water increase when storage is low, and it reports statistics in line with that expectation (RP, 5.68). But it is unclear why the Authority thinks these correlations provide any indication of whether or not generators have engaged in a sustained exercise of market power.[44] Although it is one of the few indicators given a green light in the summary table, it is not clear it is a meaningful indicator for the Review paper.

Two of the output indicators are meaningless

The Review paper considers five output indicators:

- two percent decrease in demand in the South Island (two percent test)
- price separation
- trading periods where economic withholding might be more likely

[42] There is also no such commentary in earlier Authority papers on this topic, such as EA (2011b) and EA (2021a).

[43] This does not detract from my view the DOASA values are useful for assessing the credibility of the Lerner Indices.

[44] Even a monopoly generator would seek to manage hydro storage in a manner inversely related to cost. Consider a monopoly with a suite of thermal and hydro generation plants. The monopoly maximises profits by generating with its lowest-cost plants and generating at levels where marginal revenue equals marginal cost. As storage declines, marginal cost increases because the monopoly faces increasing risk it will have to draw on more expensive thermal generation if it runs out of water. This leads the monopolist to reduce its hydro generation to increase its marginal revenue to maintain parity with marginal cost.

- trading periods with high spot prices
- the Tiwai contract event.

My primary concern is with the two percent test and the inferences the Authority believes can be drawn from the Tiwai contract event. I discuss the Tiwai contract later below.

The two percent test simulates a two percent reduction in South Island demand to assess the spot price effect of a two percent increase in South Island generation. Unfortunately, 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.

Rather than provide a measure of the incentive to economically withhold, the two percent test is more likely to be measuring the consequence of greater uncertainty about gas supply and tighter hydro conditions. A design feature of the spot electricity market is that generator offers are restricted to five tranches. Any time seasonal or medium term factors require higher prices, the price spread across the middle three tranches will increase because the first tranche is anchored to very low-prices (to offer generation that covers retail and hedge commitments) and the top tranche is for peaking or last-resort generation. The steeper supply curves essentially reflect the design features of the spot market.

More generally, the two percent test is revealing the slope of the (very) short run supply curve rather than a seasonal or medium run supply curve, and it is the latter that will be relevant for assessing incentives for a sustained increase in supply. It is well-known from economic theory that the slope of the former will always be greater than the latter.

A sense of the magnitude of the different slopes can be gleaned from comparing the spot price reductions under the two percent test with the price reductions predicted by futures prices. Under the two percent test, spot prices reduce by 18 – 37 $/MWh during the review period (RP, p75). In contrast, prices for long-dated futures contracts reduced by only 47 $/MWh in response to the announced exit of the Tiwai smelter.[45] The smelter accounts for about 30% of South Island demand, and so an NZAS exit would result in a 15-times larger demand reduction than considered in the two percent test, and yet the price reduction is only double. Clearly, competitor reactions are critical for assessing incentives for sustained economic withholding.

The Tiwai contracts are not an indicator of an uncompetitive wholesale market

The Authority states in the summary table in the Review paper that any contract made in a competitive market should not be below cost, and then takes the Tiwai contracts as a reliable indicator of the state of competition in the wholesale market (RP, p11). This approach is incorrect, for two reasons.

Firstly, if there is uncertainty and if entry, expansion and exit decisions are irreversible to some degree, then it is incorrect to claim no contracts in a competitive market should be priced below cost.[46] The Authority is implicitly assuming perfect certainty and perfect reversibility, which is unrealistic and not a sound basis for making inferences about competitive rivalry between suppliers.[47]

[45] The long-dated futures price was 92.15 $/MWh on 22 October 2019, the day before NZAS announced it was undertaking a strategic review. The price declined to 45.74 $/MW on 6 August 2020, a few days after NZAS announced it had terminated its contract with Meridian. Refer emi.ea.govt.nz/r/i2rxq.

[46] Dixit & Pindyck (1994, pp 247-80) show that in perfectly competitive markets prices can be significantly below marginal cost when there is uncertainty and entry and exit are irreversible to some degree.

[47] Sections 2.1 and 2.2 of this paper discusses some of the implications of uncertainty and irreversible exit decisions.

Secondly, theoretical and empirical models of imperfectly competitive markets, such as oligopoly markets, do not predict prices below cost. Rather, with perfect certainty and reversibility, they predict prices above marginal cost of supply. Hence, any observation of prices below marginal cost is not a meaningful indicator of the degree of competition between suppliers.

The Review paper also states that only a generator about the size of Meridian could sell to a customer at prices below cost (RP, 5.141-3). This claim is too simplistic, for the reasons stated in section 3.3. But it is also undermined by the fact Meridian subcontracted a portion of the obligations and risks to Contact Energy. The important consideration for the Tiwai contract is the availability of sufficient generation units close to Tiwai Point, not the corporate bundling of those units.

It is notable the Authority's expectations and inferences in the summary table are not repeated elsewhere in the Review paper. The main text does not state that the Tiwai contract is evidence of a sustained exercise of market power or that the wholesale market is uncompetitive. The executive summary is also silent on that matter. It appears the claim was added to the summary table with inadequate consideration.

As discussed in section 2.2, we can infer from the Tiwai event that Meridian did not believe it could sustainably withhold generation capacity from the market to prevent prices falling. If it did believe it could do that, then it would have been a more profitable strategy to let NZAS exit the market. Indeed, Meridian's board paper noted that "competition for existing load would increase" if NZAS exited the market (RP, 5.135), reflecting management's view that withholding supply would be unsustainable. The fact Meridian priced its supply aggressively to retain NZAS in the market for another four years reflected the uncertainties it was facing and the option value from deferring the exit.

There are also problems with the market performance indicators

The Review paper considers seven market performance indicators:

- two percent increase in demand in each Island (two percent test)
- observations of spot market supply curves
- marginal analysis
- actual versus predicted prices
- forward prices
- profitability
- investment.

As mentioned at the start of section 4.2, two criteria for formulating a balanced set of competition indicators are (1) omitting indicators that essentially duplicate other indicators and (2) including indicators that can potentially contradict other indicators.

As the two percent increase in demand is essentially a mirror image of a two percent reduction, the two indicators are duplicating each other. If, despite my comments earlier about these tests, the Authority intends to retain them then one of them should be omitted from the list. The second bullet point involves visual inspection of the slope of the spot market supply curves, which is just another version of the two percent tests. This analysis provides useful context and so should be used in that capacity rather than as a separate indicator.

The fourth indicator – actual versus predicted prices – is the most rigorous and scientific of all the indicators in the Review paper. However, it is rightly included as just one of many competition indicators for reasons I discuss in section 4.4.

4.3 The Authority's interpretations and conclusions are often one-sided

In many respects the Review paper is suitably cautious and avoids inferring too much from its competition indicators. However, there are occasions where the interpretation is one-sided, and in some cases misleading. I am particularly concerned by the summary table on pages 8-13 and the executive summary, both of which provide unbalanced commentary and, in at least one case, contradicts the results shown in the main text.

The conclusions of the gross pivotal supplier (GPS) results are misleading

The Authority assigns a red light to the GPS indicator in its summary table, based solely on the fact that Meridian's GPS indicator increased from around 77 percent prior to the review period to 90 – 95 percent for the review period (RP, p8). Similar comments are provided in the main text and in the executive summary.

As discussed above, the GPS indicator is meaningless because Meridian's NPS indicator was zero over the review period, and no generator was net pivotal more than 0.2% of the time.

Technically, an NPS result trumps a GPS result. This is because generators only have an incentive to exploit a GPS when they are net pivotal. The Authority should replace the GPS with the NPS, or at least present both of them and provide context along these lines. If the Authority had considered the NPS indicator it would have assigned a green light.

The conclusions about barriers to entry are not supported by the facts

The Review paper states that, if a high percentage of new generation is from the incumbent vertically integrated firms, this could suggest there are barriers to entry for smaller, independent players (RP, 5.30). However, the sale of Trustpower's retail business to Mercury would suggest Trustpower's former owners do not share those concerns.

Moreover, the evidence cited in the paper does not support a view that vertical integration is resulting in barriers to entry. For example, the paper states that none of the generation projects built over the review period were built by incumbent generator–retailers, including the 133 MW Waipipi wind farm (RP, 5.31). Although it has since changed ownership to a generator–retailer, that is not a sign the original owner (Tilt Renewables) faced barriers to entry. Tilt's major shareholders are Australian, with substantial experience in investing in renewable energy. And by selling Waipipi, they retain strong incentives to build again when their price expectations justify the costs and risks involved.

The paper also raises concerns that over three-quarters of committed projects, and projects that are likely to be committed soon, are owned by generator–retailers, but noted there are encouraging signs this may be changing because of the possibly committed solar projects in the Far North (RP, 5.34). Surely with generator-retailers currently having 80 percent 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 by incumbent generators and their desire to out-compete potential new entrants in the generation-build market.

Contrary to the statement in the Review paper at paragraph 5.192, every investor has access to hydro-firming via the spot market. Presumably this is why Trustpower (now Manawa) has been 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 customers' demand.

In my view, the Authority is being overly cautious and should have concluded there are no significant barriers to entry in the New Zealand generation market (assigning a green rather than orange light). Also, in addition to the four large generators, there are currently over 25 other generators participating in the spot market. Wind and solar generation are modular and easily scalable, there are many locations around the country where they can be installed, backup generation is readily available from the spot market, and significant (but imperfect) cover for spot pricing risks is readily available from the futures market.[48]

Commentary on the percent of offers above cost does not focus on the relevant evidence

The summary table states the Authority expects this indicator to stay the same over time, and acknowledges there are some legitimate reasons for having a non-clearing tranche with a higher offer price (RP, p9). But the assessment in the right-hand-side column does not consider whether the percentages are reasonably steady over time, which they are for Meridian and Mercury (RP, p52).

Instead the table compares Meridian and Mercury with Genesis and Contact, stating the former always have a higher percentage compared with the latter, which is irrelevant given they each have generation plants with rather different characteristics, as discussed in section 4.1.[49]

As mentioned in section 4.2, I am not convinced this indicator is meaningful. But if the Authority is going to report it, then the evidence suggests an orange rather than red light as two of the four observations match the Authority's expectations.

Commentary on the relationship of offers to cost is misleading

The summary table states Meridian and Mercury's offers are not correlated with their water values using some measures, and states that none of the generators' offers appear to be related to the DOASA water values (RP, p9). The paper also states Genesis is the only hydro generator with a strong positive correlation of offer prices and estimated cost (RP, 5.73).

Separately, and taken together, these comments are misleading. There is no reason to expect correlations with a cost measure (the DOASA water values) the generators do not use in their businesses. Conversely, there is a sound basis for the Authority to draw on the correlation results for the truncated QWOP[50] because it excludes the capacity offers in the top tranches of Meridian's offers for the Waitaki hydro scheme.

Rather than a red light, the summary table should be green (or orange at a minimum) because the results for the truncated QWOP for Meridian are strongly positive, and Genesis and Contact also have positive correlations with QWOP. The DOASA results are irrelevant.

[48] Miller (2020) identifies over a hundred sites for utility-scale solar and Roaring40s (2020) identifies over 80 onshore sites for windfarms.

[49] One reason for Meridian's high percentage is that it provided the Authority with minimum sell values (rather than water values) as that is what it used for trading decisions over the review period. Clearly, a high percentage of offers will be above the minimum that traders are allowed to offer.

[50] The truncated QWOP excludes offers exceeding 300 $/MWh.

4.4 The inherent limitations of econometric analysis need to be acknowledged

It is pleasing to see the Authority continue to develop rigorous empirical evidence of the drivers of spot market prices. However, the Authority needs to take care to present and use the results in a manner consistent with scientific discovery.

As disappointing as it is, little weight can be placed on the results of a single empirical endeavour, irrespective of who undertakes the work. It is also important to avoid describing results in ways that are not yet reflected in the empirical results.

No evidence is provided to show the unexplained shift in prices of 39 $/MWh is *a sustained* uplift in spot prices

The Authority states that the dummy variable in its regression analysis reveals *a sustained* upwards shift in spot market prices since the 2018 Pohokura outage (RP, 2.4). However, the Authority's analysis shows there were three structural breaks in spot market prices since 1 October 2018 (RP, 2.7 and Appendix C).

This suggests including multiple dummy variables in the regression equations is likely to produce statistically significant coefficients of materially different magnitudes, and possibly with different signs.[51] If the coefficients are not statistically different, then the Authority would be on firmer ground to refer to the 39 $/MWh figure as a sustained rise in spot prices. It appears the Authority has not undertaken that assessment.

If different coefficients are statistically different, then plausible explanations of factors driving the different sized price shifts would need to be identified and tested. It seems unlikely generator market power is suddenly a key driver of spot market prices, as market structure and concentration in the generation market has remained reasonably steady since 2016.[52] Rivalrous behaviour, such as competing for dispatch, does not seem to have materially altered. In reality, sudden and sizable shifts in market power are unlikely in a market with a steady competitive structure.

The alternative is that sudden and sizeable changes in underlying factors – such as hydro conditions, demand shocks and/or gas supply issues (or in perceptions about these factors) – suddenly alter the ability and incentives for generators to exercise market power. However, if this is the case then it will not be possible to empirically separate market power effects from the underlying factors. This means the Authority is very unlikely to find credible evidence of sizable shifts in the exercise of market power.

Econometric analysis is great but discussion of it should be methodologically sound

The reality is all statistical models are imperfect, and many are very imperfect. In my experience, the size of coefficients on explanatory variables, including dummy variables, typically varies greatly from one regression model to another and when different datasets are used.

For those reasons, the economics literature is replete with thousands of publications questioning the validity of earlier empirical studies. This is all part of the scientific tradition, in which the evidence from any one study is treated with great caution – in fact, largely ignored in public policy analysis – until the

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[51] Khajuria *et al* (2009), for example, identified structural breaks in a timber price time series and recognised this meant it was inappropriate to treat the mean as constant for the entire time series.

[52] Although the gross pivotal supplier (GPS) index has increased since 2018, this is a meaningless result because the net pivotal supplier (NPS) indicator shows that since the end of 2016 no generator has had material incentives to exploit GPS situations.

results have been replicated multiple times by other authors using different data and methods. Meta studies, in which researchers analyse and probe a large body of publications, have become common for those reasons.

Although the empirical work appears to have been undertaken to a high degree of rigor, unfortunately that is not enough to attribute any confidence in the results. Methodologically, it is inappropriate for the Authority to place significant weight on its empirical analysis.

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Interpreting Hydro Offers in the NZEM

Reflections on the Electricity Authority's October2021 Market Monitoring Review

Prepared for

Meridian Energy Ltd

by

E Grant Read

20 December, 2021

DISCLAIMER

EGR Consulting Ltd

Executive Summary

1. This paper has been prepared at the request of Meridian Energy Ltd, to provide an alternative perspective on some of the observations and suggestions made in the Electricity Authority's Market Monitoring Review paper, of October 2021.[1]

2. Although this paper has been prepared at Meridian's request, we have had no involvement whatsoever with Meridian's offer formation process, or modelling, or seen any relevant internal data or documents. Thus, nothing in this report should be construed as reflecting on Meridian's actual offer formation process, or any positions it may have taken, or wish to take in its public or private statements or interactions. Our intent is to contribute to debate within the industry, by drawing out some implications of the established theory of opportunity cost-based valuation of storable resources for the way in which hydro is offered into the NZEM.

3. In particular, we feel that sectoral participants may need to develop a better common understanding, with the Authority, of what hydro offers can reasonably be expected to represent in the NZEM market design, and of how to distinguish between offering strategies that meet the design objectives, vs those that might create harmful distortions.

4. As a general observation, we do not see how to assess the incentives for economic (ie profitable) withholding, without knowing how far the observed dispatch of a participant is from its contract position (including load commitments, hedging etc.), and that does not seem to have been accounted for in these investigations. Similarly, we believe that contracts also need to be netted off when assessing whether generators are "pivotal" in any period and region.

5. More specifically, Chapter 2 of this report offers some perspectives on the Authority's concern about the "steepness" of offers from major hydro operators, including Meridian, which it takes to be evidence of "possible withholding".

6. We query the usefulness of QWOP, and other measures used by the EA, that put a heavy weighting on a lot of high-priced offer bands that actually seem irrelevant because they are not only, "not expected to be called upon in the market", but correspond to capacity that should never be called upon, in those periods, by a centralised optimisation either.

7. In fact, we argue that the proper measure of withholding from the energy market would be to compare the quantity actually cleared with the perfectly competitive quantity. The shape of the offer curve away from that point may indicate withholding of "flexibility", but it does not seem all that relevant to any assessment of withholding from the energy market, per se.

8. That said, we have not attempted to analyse the shape of actual offer curves, so can not comment on whether they are "too steep". But we do discuss several reasons why we should expect aggregate offers from hydro system to be significantly steeper than the offers that might be inferred from the underlying marginal water values in their major reservoirs. (In fact, we sometimes wonder whether some discussions confuse “offer curves”, which are functions of half-hourly release levels, with “marginal water value curves”, which are functions of storage levels, and typically quite flat over the range of storage likely to be covered by weekly, let alone half-hourly, release.)

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[1] Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market, Released by the New Zealand Electricity Authority, October 2021

9. First, even in a centralised optimisation assuming perfect foresight, the effective offer curves implicitly calculated within the optimisation would become steeper than the offer curve implied by the marginal water value, as soon as the generation/storage capacity limits of downstream stations came into play.

10. Second, the NZEM's reliance on "snapshot" market-clearing means that participants are effectively required to make steep offer curves, and then to adjust them dynamically, if they want to maintain some degree of physical control over the intertemporal allocation of resources, including both long- and short-term energy availability.

11. Third, participants can be expected to make their offer curves even steeper, in order to manage both physical and financial risk, in an uncertain environment. Importantly, the narrower the resource base (including storage reservoirs) available to each participant, the more pronounced this effect will be. This particularly applies, now, to the Waitaki system, where neither major reservoir manager can rely on the co-operation of the other to balance output, or storage levels, and the downstream manager is entirely reliant on the unknown intentions of the upstream manager for a significant proportion of their "fuel supply".

12. Then, Chapter 3 of this report discusses the Authority's concern that the marginal water values implied by the observed offers are "too high". Again, we have not attempted to analyse historic offers, or assess how high water values "should" be, but we discuss several reasons why we do not think this should, of itself, be a focus of regulatory concern.

13. First, the real long-term discipline on industry costs, and hence consumer price levels, is not supposed to be spot market competition, but competitive entry. And the evidence collected by the Pricing Review in 2018[2] suggested that observed market price distributions actually conformed remarkably well to that theory. In fact, our own conclusion was that it looked like market power was not being exercised to push long-run average prices above the optimal pattern implied by the entry costs of the various available technologies level, but perhaps to stabilise them from year to year, around that pattern. While that would imply some short-term inefficiency, increasing stability should actually encourage lower cost entry, implying an offsetting downward pressure on consumer prices.

14. Second, raising marginal water values, for whatever reason, has much less effect on outcomes in the real world, or in simulation studies, than is commonly supposed, and does not necessarily imply higher market prices. The effect is mainly to shift the whole probability distribution of storage trajectories to a higher level, often at much the same price.

15. A consistent upward shift must increase the probability of spill, and decrease the probability of a supply shortfall, but whether that is considered to be better or worse depends on the relative cost assigned to those events. All would surely agree, though, that the worst possible policy must be to set marginal water values so low that storage sits near empty all the time, implying frequent shortages, high national costs, and very high average prices.

16. So, it seems clear that lower marginal water value settings do not, of themselves, imply lower costs, or market prices. Conversely, then, a participant setting higher marginal water values can not, of itself, provide prima facie evidence of an attempt to raise market prices.

17. Clearly, some marginal water value setting methods will perform better than others, by minimising both shortage and spill, and/or achieving a more consistent (and hence more efficient) scheduling of resources over time. But the impact on cost and prices can really

[2] *Electricity Price Review: First Report* Released by the New Zealand Ministry of Business Industry and Enterprise (MBIE), October 2018

only be determined by consistently simulating the effect of using each method, over a broad set of hydrologies.

18. Chapter 4 of this report the focuses specifically on the way the Authority has used DOASA. We believe that models like DOASA could be used to perform studies on various aspects of market performance. But simulations would need to be done, carrying through the release recommendations of the model being tested, to form an internally consistent set of storage trajectories, with the model being used to determine marginal water values along each one.

19. What the Authority seems to have done, though, is to use DOASA to assess marginal water values along the storage trajectories observed in the market. This shows that DOASA consistently estimates marginal water values that are lower, for the same storage levels, than Meridian (and perhaps other participants) believe to be appropriate.

20. But that does not tell us whether the nation would have considered itself better or worse off if DOASA's release recommendations had been systematically followed. All we can say is that that we would have seen a lower set of storage trajectories than those observed in the market, with lower spill and higher shortage probabilities, and probably greater price volatility. But average prices may have been higher or lower, or maybe not significantly different.

21. Finally, we offer some reflections on broader market design and development issues implicitly raised by the Authority's analysis, namely:

- Would it be helpful to allow some more direct representation of inter-temporal constraints in the NZEM?
- Is hydro now becoming "the new thermal", and should that change expectations with respect to the way in which it is offered into the market?
- Is there, or should there be, an expectation that major generators should act to some extent as market makers, by offering relatively flat curves indicating a willingness to flex production so as to accommodate output variations from other participants?
- If that kind of offering behaviour is believed to be desirable, should it not really be seen as providing a kind of extended ancillary service, for which providers should be compensated?

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Reflections on the Electricity Authority's October2021 Market Monitoring Review

1. Introduction

1.1. Context

This paper has been prepared at the request of Meridian Energy Ltd, to provide an alternative perspective on some of the observations and suggestions made in the Electricity Authority's recent *Market Monitoring Review* paper.[3] That paper covers a wide range of complex and potentially contentious issues, and rightly raises questions that should be openly debated. Thus, our intent is merely to contribute to that debate, and perhaps illuminate a few specific points, with a view to finding more common ground between the Authority and generator participants, at least at a theoretical level.

Over the last 25 years, industry participants and analysts have gradually developed their own understandings of how the market works, or how it should work. But those understandings may not always align with each other, or with the original intent. By raising some entirely valid questions about observed market behaviour, their recent analysis implicitly highlights the possibility that the Authority's understanding of how market participants should be expected to behave might differ significantly from the understanding of some participants.

The original WEMS market design study was done 30 years ago, now.[4] At the time, many theories were advanced about what markets could do, and various parties formed views about what they should do. But it should be recognised that there was very little international experience to draw on, none of which pertained to a market of this exact form, or in a comparable context.

It was understood that no one market design could simultaneously meet all expectations, and deliver all possible benefits, and that choices had to be made. But probably no one participant or analyst clearly understood what, out of all the possible outcomes discussed, could or should be expected from the specific design chosen. Common understandings about how the market should operate may have influenced behaviour for many years, but were not necessarily codified, or an inherent feature of the chosen design, or perhaps even sustainable in it.

So, having been closely involved in that study, we have gone right back to some of the fundamental market design choices made at that time, and the implications of those choices for the way in which major hydro systems, in particular, should be expected to offer their capacity into the market. In part,

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3 Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market, Released by the New Zealand Electricity Authority, October 2021

4 *Towards a Competitive Wholesale Electricity Market*, New Zealand Wholesale Electricity Market Study Report, WEMS/5 October 1992

our discussion draws on an earlier paper, prepared for a generator's consortium, and released in 2018,[5] to which the reader is referred for a discussion of the underlying theory. While the balance of the power system may be changing, the theory outlined in the earlier paper has not changed. Indeed, much of it is rooted in analyses of the optimal management of electricity systems, going back as far as the work of Masșé in the1940's.[6]

Most of that theoretical development occurred in pre-market environments but, in theory, the same results should be expected to apply identically in a perfectly competitive market. Real world outcomes will deviate from that ideal, due to factors such as rick aversion, market power, not to mention the everyday limitations on knowledge and analytical, and imperfect organisational structures. The idealised framework still provides the best reference point, though, so our intent here is mainly to draw out some implications of that theory for the way in which hydro offers should be interpreted in the real NZEM, the impact that real-world factors might reasonably be expected to have on those offers, and the implications for "market monitoring" activities.

We also believe, though, that the Authority's analysis implicitly highlights some widely held assumptions, and possibly some subtle mis-conceptions, about the way in which the NZEM market is supposed to work. Thus, we go right back to consider some of the fundamental market design choices made by the original WEMS market design study. We suggest that those choices have implications for any assessment of whether the market is doing what it was designed to do, or hydro is being offered in a way that allows hydro to play the role that was expected then, or should be expected now.

1.2. Disclaimer

Although this paper has been prepared at Meridian's request, it has been prepared independently, and reflects our personal views, which they may, or may not share. We have had no involvement whatsoever with Meridian's offer formation process, since market start.[7] We have not had access to the data supplied by Meridian to the EA, either, and nor would we be in a position to analyse it, if we did. Thus, nothing in this report should be construed as reflecting on Meridian's actual offer formation process, or any positions it may have taken, or wish to take in its public or private statements or interactions.

1.3. Scope

As noted above, the Authority's report is very comprehensive, but we will not attempt a comprehensive critique of it. In particular:

- We will not comment on the extensive discussion in that report on the implications that recent contract negotiations with NZAS might have had on the NZEM.
- Nor will we comment on the Authority's extensive statistical analyses, except to note that the potential for market power to be exercised does not depend on the ability of any generator to shift market prices, because, theoretically, any generator, anywhere in the merit order will be able to do that, when the supply/demand balance is critical.

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5 *An Economic Perspective on the New Zealand Electricity Market* Prepared by EGR Consulting ltd for a broad generator consortium, and submitted by Meridian in response to MBIE's *Electricity Price Review: First Report* , October 2018 https://www.mbie.govt.nz/dmsdocument/4195-meridian-energy-electricity-price-review-first-report-submission.

6 P Masșé Les Réserves et la régulation de l'avenir dans la vie économique. Hermann & Cie. Paris, 1946

7 We have had occasional discussions with Meridian personnel, and with others in the industry, around specific modelling issues, mainly in the context of public forums such as EPOC, but not worked for, or with, them on his topic either.

- We believe that the real test (and definition) of market power is whether a generator can systematically increase its profits by shifting prices. And we know of no way to assess that without accounting for the generator's contract position, including load commitments, hedges, FTRs, “swaptions” and so on. In particular, even a generator that is locally dominant, when measured by its gross generation, will have little incentives to move prices in either direction, unless its optimal perfectly competitive optimal generation differs significantly from its contract position. And it will have incentives to push prices down, not up, in any period when it is locally over-contracted. So, we would have thought it necessary to net off contracts when determining whether generators are "pivotal" in any period and region.
- In fact, we understand that the Authority has extensive access to contract data, and routinely performs a “met pivotal” analysis of this type. So, we do not really know what to make of analyses that, while impressive in many respects, do not seem to account for this factor at all.

Leaving that aside, though, this report focuses on:

- The concern the Authority has expressed with respect to the shape of hydro offer curves, and particularly "steepness" of offers from major hydro operators, including Meridian;
- The way in which hydro offers should be interpreted, given that the NZEM design relies upon dynamic participant offering strategies as a means of dealing with intertemporal optimization requirements over both long- and short-term planning horizons;
- The implications of that design for the analysis of participant offers; and particularly for the way in which simulations need to be conducted, if they are to properly compare the implications of alternative marginal water value estimation methods; and
- Finally, some reflections on broader market design issues implicitly raised by the Authority analysis.

2. Perspectives on Offer Curve Shape

2.1. Introduction

One over-arching theme emerging from the Authority's report is a general concern that some offer curves may be "too steep", and perhaps that marginal water values are being set "too high".

The Authority's report focuses on the "Quantity Weighted Offer Price" (QWOP), and other measures that put a heavy weight on high-priced offers which, in the words of the report, are "not expected to be cleared by the market". At first glance that seems inappropriate, because one would think that offers that are not expected to be cleared by the market can not, of themselves, affect market prices or outcomes. Naively, the more obvious issue would seem to be the impact that those parts of the offer that <u>are</u> expected to be cleared may have on market prices. In principle, a participant might provide vertical offer curves for the precise quantity they wished to generate, in each market interval, and have the same effect as offering a nearly flat curve that went through the same point. The "withholding" issue would then become how far the quantities being offered might deviate from the perfectly competitive optimum, irrespective of QWOP.[8]

We accept the difficulty of coming up with an ideal measure, though, and speculate that perhaps the Authority's concern about offer shape, as opposed to position, is not entirely about "withholding" from the energy market. One possible concern could be that these offer tranches might actually be called upon, and set prices in some circumstances. Or perhaps the concern is more that they may never be called upon, but that their existence might suggest that there is more MW capacity available that could have been offered more flexibly. Thus, we don't imagine the Authority has any concerns about inflexible generators using offers of this form, because there is no flexibility to be offered, except possibly as spill. The Authority may not have a problem with small hydro generators using this offer form, either, because that has little impact at the national level. But there does seem to be concern about the offer forms used by major hydro generators presumably because their offering behaviour is deemed to have an impact at the national level.

One way of expressing this concern could be in terms of a feeling that perhaps significant capacity might effectively have been "withheld" from what we might term the "market for flexibility". We explore the concept of a market for flexibility in a Section 5.5. But we note that, beyond the very short timeframes covered by defined ancillary services, there actually is no market for flexibility in New Zealand, thus making the concept of "withholding" from such a market somewhat moot.

The Authority presents extensive statistical analyses of participant offer data, and we do not have the resources to reproduce or critique that kind of analysis.[9] Instead, the discussion in this section focuses on some of general reasons why market offer curves from major hydro chain operators might be steeper than often seems to be assumed. This will be followed, in Chapter 3, by a more specific discussion of the way the NZEM market design's reliance on "snapshot" offers inevitably requires at we believe participants towards making steeper offer curves than might otherwise have been expected.

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8 Note that all Cournot models assume that participants make offers of exactly that form, so the issue for gaming analysis of that kind is not the form of the offer, but how close the quantity offered is to the perfectly competitive market clearing quantity.

9 Meridian's offers have been discussed as being of particular concern. The Authority notes that the "guidance" data provided by Meridian was explicitly tagged as not representing marginal water values. As discussed above, though, we have no inside knowledge of Meridian's offer formation process, or trading strategies. Accordingly, we will leave the interpretation of all that data as a matter for discussion between Meridian and the Authority.

2.2. Optimal valuation of storable resources

The Authority's report acknowledges the need to manage energy limited thermals by setting what is effectively an "opportunity cost" price to ration the quantum of fuel available to be used optimally over some daily, annual, or other cycle.

We are in full agreement but note that, as explained in our 2018 paper, it is also necessary to do this for any energy limited resource, including running down limited hydro resources stored in large annual reservoirs, or part way down a river chain, or in a small hydro scheme. So, the true economic Short Run Marginal Cost (SRMC) of such resources should always be determined by an "opportunity cost", reflecting the best available use of that resource over some horizon irrespective of any historical accounting cost.

As discussed in that paper, the optimal management of hydro chains, accounting for tributary flows, delay times and other restrictions, is quite a complex problem. And, once constraints threaten to bind, it implies a complex set of marginal water values, differing between stations, and over the day, with no necessary linkage to the long-term marginal water value of the head reservoir.[10] Thus, it is quite possible to have both very high and very low hydro SRMCs in the same chain at the same time.

Consequently, the optimal aggregate SRMC "offer curve" for a hydro chain can be a lot steeper than is perhaps commonly supposed, even under deterministic centrally optimisation assumptions.[11] In particular, we should not necessarily expect to see the bulk of generation capacity offered at the Marginal Water Value (MWV) of the head reservoir, right across the day.

Later sections discuss reasons to expect such offer curves to become steeper, once risk is accounted for. But first, we should note one possible mis-conception that can easily creep into discussion about the relative “steepness of offer curves. We find it very easy, in our own discussions to slip into the habit of talking about perfectly competitive “offer curves” as if they were analogous to “MWV curves”, and perhaps should align with them. But they are not actually comparable at all. MWV curves are functions of storage levels. For large reservoirs, they are typically quite flat over the range of storage likely to be covered by weekly releases, and virtually constant over the range covered by half-hourly, release. By way of contrast, offer curves, are functions of half-hourly release levels. They relate to MWV curves inasmuch as they assume some (nearly constant) MWV for the head reservoir in a chain. As discussed below, though, their “steepness” is determined by different factors, including downstream station efficiencies and limitations, and the need, or desire, to maintain some degree of physical control over storage levels etc, both in the downstream river chain and the head reservoir itself.

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10 Strictly speaking, the marginal cost of release from a station in a river chain will reflect the MWV difference between upstream and downstream MWVs, but that complication does not really affect this discussion.

11 As we will see, the shadow price structure implicitly determined by a centralised inter-temporal optimisation is not strictly comparable with a set of single-period offer curves submitted to a spot market like the NZEM, but the general effect still applies.

2.3. Optimal accounting for investment cost

The discussion in our 2018 paper dealt extensively with the issue of optimally accounting for investment cost. But we briefly discus it again here, in order to inform our later discussion of "Entry Limit Pricing" (ELP) in a market context.[12]

In principle, we could apply a large centralised deterministic model to optimise investment and operational decisions simultaneously. If investment could be made continuously, at linear cost, such a model would find an equilibrium, in which the marginal contribution of each investment type, in terms of reducing operational costs across the system,[13] was continuously aligned with its marginal expansion cost. That logic has been commonly applied to expansion of conventional thermal generation capacity, but also applies to the expansion, and indeed the design, of renewable options like hydro. For example, cumulative MWV differences between high- and low- priced periods in storage cycles, over short/long term storage capacity investment lifetimes would continuously align with the marginal cost of expanding such storage capacity, in a hydro scheme.

We will take this picture as a broad guide to the influence of investment cost on short-term prices, and hence water values, even though it is obviously unrealistic, even in a centrally planned scenario, and even if continuous expansion was available at linear cost:

- First, short-term volatility in inflows, demand etc, mean that there will be a whole probability distribution (pdf) of short-term "shadow prices"[14] arising from the operational sub-model, that should align with the cost of investment.[15]
- Second, any change to long term demand forecast, or technology will disrupt any equilibrium. So, we should expect to see potentially quite long "catch up" periods, during which the optimal short-term (shadow) price pdf will be either higher or lower than the marginal expansion cost.[16]
- And then, of course, investment has, at least traditionally, been quite "lumpy", with strong scale economies, implying potentially quite long periods of (shadow) prices being higher/lower than investment cost, even under certainty.

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[12] That is, the theory that market prices will ultimately be capped at the price levels would induce competing providers to enter the market.

[13] Including shortage/DSM costs.

[14] An optimisation model will internally determine "shadow prices", or "dual variables", which measure the marginal value that would be delivered if any constraint (such as a capacity limit) could be increased by one unit. Given some common assumptions about convexity, etc, these are equivalent to the prices that would be observed in an idealised "perfectly competitive" market, and in fact all NZEM prices are "shadow prices" produced by optimisation model that clears the market.

[15] That is, the expected value should align, if we ignore any risk aversion by the nation, (in a centralised optimisation, or the agents in a perfectly competitive market.

[16] On the upside, prices should be expected to stay high during the period required to plan, consent, build and commission new plant. On the downside, prices may stay low, because we can not expect existing /committed plant to be instantly "unbuilt".

2.4. Implications of market decomposition

When the decision was made to break up the assets of ECNZ into several competing firms, the hope was that this would create a competitive entry market that would both discipline costs and achieve better long-term supply/demand alignment than had occurred under the previous centralised, but highly politicised, regime.[17] But it was recognised that, despite best efforts with respect to spot market design, there would probably be some offsetting losses, in terms of less efficient short-term coordination. Some aspects of that concern about efficiency losses may be reflected in the form of offer curve effects, as discussed below.

2.4.1. Physical risk management

One aspect of particular concern when market developments were first considered, was risk management. Specifically, there was concern that national hydro storage would be run down too fast, because each individual hydro operator would have short-term incentives to make a quick profit by releasing too much to the market. But our view was that, if anything, collective storage management was likely to be more conservative, because:[18]

- Each participant would have their own set of contractual and/or load commitments to meet;
- But none of them would be able to rely on fully utilising a comprehensive national portfolio of storage options; and
- Each would see themselves as being vulnerable to exploitation by their competitors should it become evident, at any time, that they were reliant on buying in from the spot market to cover their commitments.[19]

We have not seen a recent study on this, but evidence from the first decade seemed to confirm that intuition. Tipping[20] analysed spot market outcomes over that period to determine the MWV surface implicitly being applied by hydro generators, in aggregate, to a notional national reservoir, and then simulated the pdf of storage trajectories using that inferred MWV surface. They then compared the results with those from previous epochs, and concluded that the market's storage management was about as conservative as the Ministry of Energy's. But both were more conservative than ECNZ, which had full control of most hydro resources, like the MoE, but stronger cost minimisation incentives.

The implication is that we should expect to see market participants expressing their aversion to the risk of physically running out of water by setting higher MWVs[21] than might be implied by MWVs

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[17] For an analysis of electricity sector performance over the previous decades See J.G. Culy, E.G. Read & B. Wright: "Structure and Regulation of the New Zealand Electricity Sector", in R Gilbert & E Kahn (eds.) *International Comparison of Electricity Regulation*, Cambridge University Press, 1996, p. 312-365

[18] E.G. Read: *Management of Hydro Storage*. Released by the New Zealand Government Task Force on Electricity Sector Structure, 1989

[19] As a result, we were not too concerned about the nation "running out of water", and more concerned that there might not be sufficient incentives or mechanisms to achieve a balanced release of the last of that extra stored water, should a crisis actually develop.

[20] See Chapter 7 in J. Tipping "*The Analysis of Spot Price Stochasticity in Deregulated Wholesale Electricity Markets*" PhD thesis, University of Canterbury, 2007

[21] `And probably also using steeper offer curves, as discussed below.

calculated in a centralised optimisation model.[22] That expectation of a conservative (i,e. high MWV) bias in reservoir management was reinforced, even then, by the additional fear that a generator who actually "ran the nation out of water" would suffer a significant public/political backlash. That threat has since been made more explicit, and arguably strengthened, by the national storage management regime, which now includes provisions for an official conservation campaign linked to hydro risk curves, a customer compensation scheme, stress testing, and scarcity pricing.

This sort of "physical/societal" risk aversion applies also to short-term storages in hydro chains, and we expect that it has since been exacerbated by a general tightening of water consent conditions, operational requirements, and perhaps social expectations, forcing more conservative operation of hydro chains.[23] So, we should expect that to have further steepened hydro offers.

One major change, since market start, has been splitting management of the two largest national storages between Genesis and Meridian. Given the impact which this structural change was predicted to have on the combined Waitaki offering strategy,[24] it seems perhaps surprising that we have not seen any public analysis of what the actual impact might have been. We were quite surprised, though, by the Authority's comment that Meridian had significant flexibility in managing the Waitaki river in the form of lakes Pukaki and Benmore.[25] Physically, we understand the point that the Waitaki river could potentially be managed more flexibly than most others in New Zealand, but is that physical flexibility actually available to be utilised by Meridian?

- Historically, when the entire river chain was controlled by Meridian, Pukaki did provide flexibility, part way down the chain, but it is surely now just a head reservoir in a very similar position to Taupo, where the inflow is partly natural and partly controlled by a competing generator. At the time, there was extensive discussion of possible schemes to retain some part of the coordination/flexibility benefits traditionally provided by having Pukaki and Tekapo managed as part of the same river chain, or at least to align incentives between the two generators operating within that catchment.[26] But our understanding is that none of those proposals was actually adopted.
- Thus, whatever the overall benefits may have been from creating a physical (rather than virtual) generation split on the Waitaki, the obvious implication was that Meridian was going to be placed in a much riskier and less flexible position.[27] Estimates at the time were that 32% of the Waitaki energy system storage would be in Tekapo, with two thirds of that stored energy, effectively 21% of Meridian's energy supply, being directly controlled by a competitor, whose intentions can only be guessed. So, inevitably, Meridian should now be expected to operate in a more cautious fashion, both in terms of its long-term storage management (mainly in Pukaki), and its short-run river chain management (without any flexibility in Pukaki).

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[22] Noting that the two MWV concepts are not quite comparable. A centralised multi-reservoir optimisation will implicitly compute a multi-dimensional MWV surface, with a strong component effectively based on the national storage position, assuming balanced access to all storages. A sophisticated operator of a single hydro reservoir might, in principle, do some similar analysis, but is unlikely to assume balanced access to all resources, and so must put a higher MWV on their own storage, to achieve a more conservative management of the resource they actually can control.

[23] The ability to utilise extra "contingent" storage in major reservoirs does not really increase this kind of short-term flexibility, but it will have increased long-term flexibility.

[24] See *The Economics of Upstream/Downstream Interactions in Hydro Power Systems*: *The Waitaki Case:* EGR Consulting report for Meridian, July 2010.

[25] See p.6 of the Authority's report.

[26] *WMA Options: Energy Banks and Virtual Reservoirs* EGR Consulting report for Meridian, February 2010

[27] Our report, at the time, acknowledged benefits in terms of increased competition in South Island retail and spot markets, but predicted a significant reduction in the aggregate ability of the catchment to efficiently provide storage or other capacity to the market, unless some form of water management agreement was put in place.

- The situation with Benmore is a little different. The lake certainly does have enough physical storage capacity to manage intra-day variations, and more. Generation efficiency drops off, though, as the storage level falls, and it was traditionally only operated in the upper part of its storage range, with the lower part being reserved as a national "last resort" precautionary stock. An independent generator like Meridian may no longer be expected to hold any precautionary stock in that location, or have any commercial motivation to do so. But our understanding is that the operating regime of Benmore has not greatly changed in the market era, and we suspect that the local community would not react well if Meridian were now to start cycling storage to anything like its physical limits.

Meridian may wish to comment further but, since there is not really all that much flexibility in the rest of the Waitaki system, we suggest that Meridian probably has much less operating flexibility than this quote from the Authority's report might seem to suggest.

2.4.2. Financial risk management and "gaming"

The discussion of risk management in the previous section relates primarily to the fear of physically running out of (or possibly spilling) water. But we also mentioned concern about not being able to meet contractual commitments, including both formal and explicit contracting, whether physical or financial, and less precise commitments made to meet the loads of retail consumers.

Irrespective of what mix of implicit or explicit contracting any particular participant might commit to, the general effect of contracts is to incentivise participants to align their generation with contract quantities. In a physical market this might be considered a fairly hard constraint, but our spot market design allows participants to implicitly sell additional power, and buy in enough to cover deficits, with negligible transaction costs. So, concern about meeting a physical delivery requirement is translated into a fear of losing money, through having to dump any excess at too low a price, or pay too much for any extra.[28]

The theory involved is too well known to worth repeating here, but the implications are that we should expect to see:

- The offered price for production at the contract quantity pegged somewhere near SRMC;
- Prices for production above the contract quantity rising above the participant's SRMC curve, to limit the likelihood that the offerer will be called upon to produce substantially more than they are contracted for; and
- Prices for production below the contract quantity falling below the participant's SRMC curve, to limit the likelihood that the offerer will be called upon to produce substantially less than they are contracted for, and hence buying-in from other producers.

In other words, we expect this concern to further steepen offer curves.[29] Irrespective of the reasons participants might have to move their offer curves away from SRMC like this, though, the aggregate effect will be:

- To put upward pressure on prices in periods where real-time demand exceeds contracted supply; and

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[28] This discussion again highlights the critical importance of a participant's net contract position (including hedges bought and sold, along with load commitments) in any assessment of the gains they might make from offering in such a way as to move prices in either direction. As noted in Section 1.3, we are puzzled that contract position does not seem to feature in any of the analyses reported by the Authority, because we don't think that any conclusions can be reached about "gaming" or "withholding" incentives without it.

[29] In the limit, very risk averse participants, or those who are tightly constrained, might even provide vertical offer curves, exactly matched to contract quantities.

- To put downward pressure on prices in periods where the real-time demand falls below contracted supply.

Accordingly, the tricky issue, from a market monitoring point of view, is that exactly the same effects can be expected, no matter whether market participants believe they have sufficient "market power" to profitably influence prices, and deliberately set out to do so, or not. Basically:

- The further the generation determined by market clearing rises above a generator's contractual commitments, the more incentives they have to pull generation down from the perfectly competitive ideal towards the contract quantity, so as to get a higher price for the extra they do sell.
- Conversely, the further the generation determined by market clearing falls below a generator's contractual commitments, the more incentives they have to push generation up from the perfectly competitive ideal towards the contract quantity, so as to get a lower price for the deficit they do buy.

These effects will be small, if a generator's commitments are close to their perfectly competitive output quantity, and they will also tend to cancel each other. But they can be significant if the discrepancy between perfectly competitive output and contractual commitments is large. And it can be relatively large, at times, for hydro operators whose effective generation capacity fluctuates over time.

In fact, we expect that, unless artificial measures are introduced to incentivise construction of (uneconomic) capacity in excess of any possible load requirement, there will be times when not just one, but many generators can withdraw enough capacity to cause prices to spike temporarily. Many generators contracted for less than their maximum output capacity could profit from that strategy, too. Further, the opportunities for this kind of gaming are increased when a few participants may find themselves operating in a part of the network where competition from other areas is limited by transmission constraints, and/or the availability of reserve to support transmission.

Our own view, though, is that while the extensive literature on short run gaming in electricity markets is technically very interesting, much of it misses a key point; namely that, especially in a largely renewable system such as ours, the ultimate level of national cost, and consumer prices, is mainly determined by entry costs, with a relatively modest contribution from operational costs. In our view, the real focus of concern should be on how the level and kind of gaming that does occur affects three things, all of which really could increase long run equilibrium costs:

- Decreasing competitive pressure to improve productive efficiency within organisations;
- Reducing allocative efficiency, in the sense that the wrong plant is generating at the wrong time, or that consumers see the wrong price signal;
- Reducing dynamic efficiency by reducing the returns or increasing the risk seen by potential entrants (or of course by direct obstruction).

We are certainly not proposing to analyse, or even discuss, all those issues here. To do so would require a major study, in its own right. But we note that, while the Authority has done a very thorough analysis of many aspects of the situation, it does not really seem to have focussed on directly assessing these overall efficiency impacts, either. The next section discusses one aspect of "gaming" that may be considered relevant to the shape of offer curves, though.

2.4.3. Market design goals and entry limit pricing

As discussed above, the primary goal of the WEMS/NZEM market design was to provide a competitive market for entry, so as to maintain competitive pressure on costs, and improve alignment between demand and supply over time. Implicit in that statement is the belief that the prices charged by incumbents will ultimately be disciplined by investment costs. In principle, this "Entry Limit Pricing" theory is really the same as for the centralised planning model discussed in Section 2.3 above.

As in that case, if investment could be made continuously at linear cost, a market with perfectly competitive entry should find an equilibrium in which the marginal profitability of each investment type, as determined by spot prices in the wholesale market, was continuously aligned with its marginal expansion cost. As above, though, short-term volatility in inflows, demand etc, mean that it is really the whole pdf of spot prices arising from the market that should turn out to be aligned with the investment cost.[30] Real-world investment is lumpy, too, and any change to long term demand forecasts, or technology, will again disrupt any equilibrium. So, we should really expect to see potentially quite long "catch up" periods, during which the optimal operational spot price pdf will be either higher or lower than the long run marginal expansion cost (LRMC) set by entry costs.

The application of this theory is not quite as simple as seems sometimes to be assumed by analysts, and perhaps by market participants too:

- First, there is not really a single LRMC, because each technology has its own entry price, and particular niche in the system portfolio. Thus, there is a whole vector of entry prices, and that vector controls the shape of the equilibrium PDC.[31] Traditionally, this has been by limiting the operating profit available to a set of possible future thermal entrants with defined SRMCs to match their investment costs.[32]

- Second, participants are sometimes modelled as just pricing a section of their offer curve at some kind of ELP, assuming that to be a well-defined single value. That may be a useful heuristic approximation, or an actual practice. In principle, though, incumbents should really be thinking in terms of the impact that any offers they make might have on the whole pdf of prices faced by each possible type of entrant, weighted for the expected generation pattern of that type of entrant. Up to that level they may indeed try to offer above their own SRMC, in an effort to push the pdf of prices up towards a level just below what might trigger entry.[33]

If market power is defined as pricing above SRMC, then this latter behaviour is clearly an exercise of some degree of market power. But pricing above SRMC is clearly also the norm, rather than the exception, across the vast bulk of businesses and sectors.[34] While the standard business practice of applying a "mark-up" may well be considered necessary for business survival, it is also always an exercise of market power, according to this SRMC-based definition. And it should be recognised that it really does imply some regrettable, if inevitable, distortion of incentives, at some level. But it is not normally regarded as an abuse of market power, in any other sector.

On the other hand, we do agree that pricing closer to SRMC would certainly help to minimise distortion in short run markets. And it would be nice to do that if it can be done without unduly damaging long term investment efficiency. But WEMS believed that the capital intensity of the sector argued for a strong focus on efficient signalling for capacity investment, 30 years ago. So, this seems even more likely to be true, now that no new capacity will have any fuel costs to save by more efficient

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[30] That is, the expected value should align, given the commercial risk implied by the rest of the pdf.

[31] So, the traditional LRMC of meeting load does not correspond to the entry cost of any particular plant type, and should be taken as the LWAP over the whole equilibrium PDC.

[32] This can be generalised, but seems sufficient for the current discussion.

[33] This implies that we may see major one-time downward shifts in the profitability of incumbents, if new technologies emerge, and upward shifts if old technologies are banned, for whatever reason. But this is just the same kind of revaluation as would occur in a centrally optimised system, or in any other market.

[34] Perhaps the most common exception would be free downloads of apps, whose marginal cost is truly zero, albeit often with strings attached. But there is only muted criticism, if any, of all the other software developers who actually charge for their products, even though the marginal cost of another download is zero for them, too.

coordination. Thus, we are not convinced that there will necessarily be much net gain from forcing the sector towards a more volatile, “pure SRMC” pricing profile.[35]

SRMC vs LRMC

The common assumption, in some discussions seems to be that SRMC is consistently lower than LRMC, and that prices could perhaps be "pushed down towards SRMC" to the benefit of consumers. But that can not actually be true, on average, in long term equilibrium. If we take LRMC as the long-run reference price level, it may well be possible to push prices down to SRMC during periods of relative surplus. Theoretically, though, the quid pro quo should be to allow prices to rise above LRMC, up to an SRMC level which will at least sometimes be a shortage cost of some kind, during periods of relative scarcity. Otherwise, the long run optimal trade-off between expected operational and investment costs would no longer hold.[36]

The upside of forcing prices to SRMC ((in both directions) should be improved allocative efficiency, but the extent of that improvement seems debatable. If all participants scaled up their offer prices proportionately, the optimal dispatch would hardly be affected, only the trade-off between spill and shortage, and signalling to consumers. Sadly, though, the value of that signalling seems quite limited, in practice, because few retail consumers actually face tariffs set at anything like the SRMC level, or reflecting anything more than the crudest approximation to the SRMC price structure, let alone changing hour by hour to reflect the subtle difference between gamed and un-gamed spot prices. The downside seems clear, though: Increased price volatility clearly increases risk for all parties, and particularly for potential entrants. That should logically be expected to raise their required rate of return, and that must increase sector costs, which have always been dominated by investment costs, thus raising prices and reducing system reliability by delaying/reducing capacity investment relative to load growth.

Although the 208 MBIE *Pricing Review* referred to earlier did not focus on it, our own interpretation of their analysis was that the observed market price pdfs conformed remarkably well with the predictions of ELP theory.[37] Moreover, the fact that the year to year variations seemed less than night have been expected, given the significant variations in the underlying demand/supply balance, suggested that market power might indeed have been exercised, not so much to raise prices (which theoretically can not be raised above ELP on average) but to stabilise returns from year to year.[38]

So, returning to the topic of offer curve shape, we are inclined to think that some participants' offers, across the sector, may well be consciously shaped to sculpt the pdf toward the long run equilibrium

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[35] Unless that delivers major gains from better DSM coordination, in the emerging environment. But possible institutional designs for DSM coordination lie well outside the present scope, as does then social acceptability of having the prices consumers actually see and respond to fluctuating strongly from year to year.

[36] Obviously, we can not have an equilibrium where prices are "below average" part of the time, and only just "average" the rest. So, from a regulatory point of view, it does not really make sense to see Entry Limit Prices as setting a "cap" on the market price pdf. As in the national optimisation scenario, we should optimally expect to see the real price pdf fluctuate both above and below entry costs. Even the threat of truncating the upside of the price pdf in such a way must increase the risk faced by entrants, causing them to hold off investing until the pdf they expect to see (after accounting for possible capping) does rise to a level providing an acceptable risk-adjusted rate of return. In other words, truncating the price pdf at any level (including at a supposed long run entry cost level) can only sustain an equilibrium in which the mean of the price pdf rises, reflecting higher real entry costs, and hence consumer prices, in the long run.

[37] See, particularly, Appendix C of *An Economic Perspective on the New Zealand Electricity Market* EGR Consulting report, October 2018

[38] If so, that would be a distinctly different motivation for exercising market power, driven by long-term strategic considerations and/or shareholder profit expectations, and not directly related to short run profit maximisation, or loss minimisation, when deviating from contract positions, as described in Section 2.4.2.

ELP/LRMC "ideal"…... and hence away from the more volatile SRMC "ideal". We suspect, too, that other participants, who may not do their own analysis in such terms, are likely to follow what they believe others are doing, and/or adopt heuristics like pricing at ELP, without necessarily doing much deep analysis.

Where we may differ from other commentators is just that, rather than seeing the resultant inter-temporal stability as a failure of the market design, we are more inclined to think that it would actually encourage competitive entry, and probably thereby reduce long run average costs, despite the implied loss of short run efficiency.[39]

Indeed, year to year pricing stability was always seen as a desirable goal, in pre-market times, and we should be cautious about concluding that what was thought to be good public policy then would necessarily be an unmitigated public disaster now. In fact, the observed market outcomes broadly correspond to a typical pragmatic regulatory resolution of a very long running debate, back in the public sector days (in the New Zealand Ministry of Energy, for example) between proponents of LRMC vs SRMC pricing, which was:

- To set the benchmark pricing level to LRMC;
- While flexing somewhat towards SRMC levels as the supply/demand balance changes from year to year;
- And also reflecting typical SRMC patterns (e.g. day/night) in the retail price structure.[40]

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39 For discussion of the potentially large impact of risk on entry costs, particularly for peaking capacity in a hydro dominated market, see E. G. Read, M. Thomas & D. Chattopadhyay "The Impact of Risk on Capacity Investment in Electricity Markets" Keynote Address, *IAEE Proceedings*, Wellington, 2007.

40 WEMS hoped to see an alternative resolution emerge, with long run hedges priced at LRMC, complemented by a volatile spot market which, with a high level of long-term contracting in place, should not be unduly distorted by gaming.

3. Perspectives on Storage Management

3.1. Introduction

Storage management is a critical issue in power systems, particularly over two main time horizons:

- The intra-day horizon, over which hydro resources play a significant role in matching power available from natural sources, including hydro, geothermal, and now wind and solar, to the time-varying load; and
- The intra-year horizon, over which larger hydro reservoirs play a critical role in matching natural resources available in various seasons to the load, which has its own seasonal pattern of variation.

Rather similar market design issues arise in both timeframes, and it will be seen that the New Zealand electricity market design differs from others that could have been implemented, and/or have been implemented overseas. In this section we will discuss the implications of those design choices for the kind of offers we should expect to see from participants, and for the way in which those offers might be expected to shift and respond to unfolding market events. In Chapter 4, we will look in more detail at some of the issues that arise when trying to compare actual offers made in the NZEM context with hypothetical offers inferred from models implicitly assuming an alternative market design paradigm, such as global inter-temporal optimisation.

3.2. Managing Intra-day Storage

3.2.1. Global optimisation option

Before discussing the interpretation of offers in the NZEM, we need to discuss an alternative design that was seriously considered by WEMS. At the time there was really very little international experience to draw on, in terms of implemented electricity markets in any setting, let alone in hydro dominated power systems. One possible model was the original UK power market, and that market employed a significantly different form of offers from that eventually implemented in the NZEM.

In that market, each power station submitted a multi-part offer, which not only specified an SRMC-like supply curve, but a number of other parameters such as start-up costs, minimum run times, ramping restrictions etc. These offers were then processed and "cleared" by a semi-optimizing package inherited from the CEGB, which performed an inter-temporal optimization over the daily horizon, including determination of start-up times etc. Unlike in the NZEM, though, the SRMC curve in the multi-part offer was not allowed to change from period to period, within a day, unless there was a major breakdown, for example.

Inter-temporal optimisation to determine thermal start-ups was not considered to be such a major issue in New Zealand, but inter-temporal optimisation to determine optimal river chain management was. So, WEMS considered a variation of that UK paradigm under which:

- Each market participant would provide a multi-part offer, essentially describing their plant characteristics.
- For thermal generators that description might have been similar to that employed in the UK.[41]
- For hydro generators, though, the proposed description of system capabilities was to be a set of parameters incorporating a detailed description of the generation plant available

[41] Although the treatment of integer start-up costs was not fully resolved.

downstream of the main reservoir, including generation capacity limits, river flow limits, efficiency curves, tributary flow forecasts, storage limits, and time delays.

- Those parameters would be used to define a set of Linear Programming (LP) sub-models, representing each hydro chain in the context of a global inter-temporal LP optimisation.[42]
- In addition, each participant would specify a "fuel" supply curve which, for hydro, would have represented the marginal water value to be assumed in each major reservoir, generally the head reservoir(s) in river chains.
- The daily market would have then been cleared using an LP optimisation, incorporating all of the participants' sub-models, and covering 48 half-hourly intervals with full inter-temporal linkage of storage levels, etc.
- And that optimisation would be re-run regularly, as new information came to hand throughout the day, and then at some point switching to extend the optimisation into the next day.[43]

The expectation, at that time, was that the offered marginal water value curves for major reservoirs would be stable, within each day, and (expect when close to storage bounds) fairly flat across the range of release likely to occur within a day.[44] But it was clearly understood that the effective offers from each downstream power station, as implicitly determined within the LP optimisation, would not have been directly set by those relatively flat MWV curves.

There could have been days on which the requirement to vary release rates between downstream head ponds was relatively mild, implying optimal storage levels in those head ponds that did not threaten to reach any storage or flow bound. Stations down a river chain are seldom perfectly balanced, though, in terms of the ratio of storage to flow/generation capacity, delay times mean that optimal management can not involve all stations just ramping up and down in synch, and whatever balance there is will be disrupted by constantly changing tributary flows.

So, some flow and/or storage bounds will ultimately come into play, at which point we would expect to see marginal water values varying significantly over time, and differing significantly between head ponds at any point in time.[45] The implied "steepness" of (effective) aggregate "offer curves" for catchment-wide generation was not investigated, but it was certainly expected that they could be much steeper than the MWV "fuel offer" curves from the long-term head reservoirs.[46]

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[42] Such LP river chain models already existed within ECNZ, so it did not seem too difficult to require offers of that sort. Especially since, apart from tributary flows, the system description would have been fairly much the same each day, unless there was a breakdown or maintenance requirement.

[43] So "48" periods, on average, might really have been 24 to 72 periods, in practice.

[44] Although that expectation may have been somewhat naïve. See further discussion on long-run storage management below.

[45] Although, again, it is actually the upstream/downstream MWV difference that drives release strategy.

[46] As discussed in Section 2.2, there is actually almost no connection between the shape of the two curves, one being a function of release, and the other of storage.

At the time, some analysts with a strong optimisation background favoured this proposal, and its potential merits might still be debated.[47] But the point is that, for various reasons, it was abandoned.[48] So, the market was designed to instead rely on dynamic re-offering by participants, each of which was left responsible for managing inter-temporal optimisation of their own system in response to changing conditions over the day. In doing so, though, it was recognised that participants would be offering release/generation curves that were only indirectly related to the MWV curve in the main reservoir, as discussed in Section 2.2 above, and could become quite steep, for reasons discussed further below.

3.2.2. WEMS NZEM market design

Under the regime actually adopted by WEMS the market relies on participants not only to specify offers for every power station in their portfolio, but to adjust those offers dynamically over the day, in response to changing market conditions. (Not just physical changes, such as plant availability or forecast flows, in their own systems.) One obvious implication is that, unlike markets in which generators are allowed to specify start-up costs, and are compensated for them, the NZEM assumes that thermal participants, in particular, will recover such costs by increasing their offers above SRMC, and massage offers so as to make sure they generate for long enough to recover them over each operational cycle. But there are significant implications for the management of hydro chains, too.

Managing the ever-changing situation in river chains can actually be quite tricky. A flow regime needs to be established for the day, and varying that regime at short notice may not be easy, particularly due to flow delays, and explicit or implicit environmental and/or social limits on rates of change for flow/storage levels. A centralised inter-temporal optimisation would have to include all such limits, and dynamically re-assess shadow prices on those limits that turn out to be binding, and hence implicitly adjust effective offers, every time it was re-run. Instead, though, the core NZEM design relies on participants providing relatively steep offer curves, designed to give fairly close control over

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[47] Many overseas markets do employ inter-temporal optimisation, and less elaborate implementations of the concept would be possible. For example, participants could be allowed to specify a simple energy limit, or perhaps a limit for each of the morning and evening peaks. The point is that imposing any inter-temporal constraint in an optimisation means that market prices are no longer set directly by participant offers. Typically, an additional shadow price component will be computed and applied internally, forming a higher implicit offer, which optimally sets market prices for all participants. In fact, this lack of a transparent connection between participant offers and market outcomes was one of the reasons why inter-temporal optimisation was rejected in New Zealand, and in some other markets. (Although, ironically, ancillary service co-optimisation was accepted, and that also means that market prices are set by effective energy offers adjusted to include the cost of forgoing ancillary service profits, as determined internally by the optimisation.)

[48] Extensive experiments were actually done on this market design, to determine how easy it might be to find an equilibrium between all of hydro chains in New Zealand. The main technical problem turned out to be setting starting and ending levels for downstream storages. If it were not for flow delays, we would have expected to find a particular time, probably around 4 AM, at which all storages in the chain might be expected to reach a maximum level, before running down for the morning peak, replenishing during the day, then running down again for the evening peak to return to a similar storage level by the next 4 AM. With delays, though, it is more difficult, and insisting on a 4 AM market day start would find some storages part-way through a filling cycle, making it much more difficult, and perhaps undesirable, to pin down exactly what storage level should be aimed at.

That problem did not really seem too difficult to work around. But the experiment was abandoned anyway, because it was believed that potential participants were likely to require a higher degree of physical control over their own systems, in an environment where they could become liable for breaching the provisions of resource consents, health and safety regulations, etc.

physical flows, and then shifting those offer curves, as necessary, to respond to changing circumstances during the day.[49]

In fact, it can be shown that the presence of correlation in the price forecasts may imply that, when a participant observes higher prices early in the day, they should (from a national benefit maximisation perspective) actually reduce output.[50] The reason is that higher prices early in the day will often indicate tight market conditions that are likely to persist all day. And the optimal response to that forecast will typically involve conserving water in some storages, in order to be in a position to meet even tighter system requirements later in the day. A centralised optimisation would do that automatically, as updated information was received. In our market design, though, a participant specifying offers in advance should really be making those offer curves bend backwards, in some periods. That is not really possible in any market, let alone one cleared by an LP optimisation. So, the best approximation that a participant can give the market is to offer a vertical curve, indicating the quantity they are prepared to commit to releasing in those particular hours, and then respond dynamically with less or more generous offers, as the situation unfolds over the day.

More generally, there is a trade-off between the steepness of offer curves, and the frequency with which they are adjusted. We have not attempted to analyse actual market offers, or discussed the matter with any market participant, but it is not hard to see the attraction of a cautious "set and forget" offering strategy, under which a participant might:

- Set offers so as to fairly reliably meet their own contractual commitments; while
- Specifying a relatively narrow window within which they stand ready to be flexible, at something like their own estimate of SRMC (which may differ significantly from hour to hour, and from station to station, as discussed above); and
- Pricing any further capacity high enough to make it effectively out of bounds, unless an unexpected market crisis occurs.

To be truly "set and forget", though, the offered flexibility bounds might have to be quite tight. The problem is that the participant does not know how situations elsewhere in the market, and outside of their control, might change. So, if they offer capacity in a series of moderately priced tranches across the day, they just do not know if those tranches will be called upon for only one hour, or none, or perhaps several. If the tranches represent storage-based generation that can only be sustained for an hour, and that hour is called upon early in the day, they would have to rapidly react by withdrawing all corresponding offers for the rest of the day, or until the storage could be recharged. And they might then face recriminations for their apparently capricious market behaviour, and perhaps also from locals seeing unexpected flow patterns.

In the extreme, one could imagine participants being attracted to the idea of simply planning a schedule to meet their own commitments, implying largely predictable flow/storage patterns, without providing much flexibility to meet the fluctuating needs of other (competing) participants at all. After all, that would be entirely normal in most business sectors. We discuss the valuation and trading of "flexibility" below. But we expect that current reality must lie between the extremes of predictable rigidity and unpredictable flexibility. Specifically, we would expect to see that, if all MW capacity is being offered in every period:

- Much of that capacity, being surplus to any likely system requirement in most hours, should be expected to stay safely out of play in high-priced offer tranches that truly are never expected to be called upon in most (off-peak) periods. Thus, QWOP, and other similar measures just do not seem appropriate for assessing the appropriateness of offers in those hours.
- Some further capacity might often appear in "precautionary" tranches, that are more moderately priced, but possibly quite narrow. These would be set so that, when prices rise

[49] Although, to be fair, block dispatch arrangements do somewhat mitigate the situation.

[50] E.G. Read, P. Stewart, R. James & D. Chattopadhyay "Offer Construction for Generators with Inter-temporal Constraints via Markovian DP and Decision Analysis" *EPOC Winter Workshop,* Auckland, 2006

high enough to bring that resource into play, management (and the market) are alerted to the fact that a rapid response may be required:

- Either to conserve limited storage resources by withdrawing (or pricing up) later offers in that band;
- Or to profit by releasing more, while attractive prices are available.

The overall conclusion is that, while we might have expected something like pure marginal water value curves as 'fuel offers" in the experimental multi-part design, we really did not, and should not, expect that to happen, in the market design actually adopted. As noted above, nothing that has happened since then seems likely to have increased the flexibility available to river chain managers, reduced their risk, or increased their incentives to provide flexibility to support competitors.

Deliberate "gaming" is always a possibility, on both large and small scales. Even without it, though, the combined effect of uncertainty interacting with limiting downstream constraints, and participant nervousness about violating explicit or implicit environmental/regulatory guidelines, is likely to lead to conservative offer curves that are significantly steeper than the underlying marginal water value curve for the main reservoir in a chain.

3.3. Managing Intra-year Storage

3.3.1. Global optimisation option

Although the WEMS market design team could only refer to very limited international experience with hydro dominated electricity markets, there actually was an alternative design already operating in Chile. That market employed a global optimisation approach to intra-year hydro storage management, and many similar markets have subsequently been developed in Latin America. In all of those markets:

- Market participants submit their plant characteristics, but without specifying any MWV for hydro;[51]
- A large-scale long-term stochastic optimization model is run regularly to determine the release from each major hydro station;[52] and
- In doing so, that model also determines a marginal water value for every hydro storage modelled.[53]

Accordingly, the "offers" from each hydro participant are effectively determined internally to the model, and these markets do not really rely on a competitive "spot market" coordinating hydro releases in the short term. Thus, the focus of competition in that environment is really on the long-term provision of generation capacity, and storage facilities, rather than on day-to-day or week-to-week generation strategy. It should be recognised that some of these Latin American markets have to coordinate releases in complex river catchments involving large reservoirs controlled by different companies, and sometimes lying in different jurisdictions. So, we would not presume to argue over whether their global optimisation paradigm is better or worse than our own market-clearing approach, in their environment or ours.

The point is, though, that the WEMS team rejected that kind of model.[54] So the remainder of this section discusses what sort of offering patterns we might expect in the WEMS NZEM market design environment, and how they might differ from those that might have been implicit in a global optimisation environment. Later, Chapter 4 will discuss how a global optimisation model such as DOASA might, or might not, be validly used to provide a point of comparison.

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51 Some of those markets have significant thermal capacity, but the regulation of their fuel price offers is not really relevant to this discussion.

52 Originally, the Chilean market used a simple single reservoir Stochastic Dynamic Programming model, somewhat like SPECTRA, but we understand that all of these markets now use the Brazilian SDDP software, employing as similar methodology to DOASA.

53 The basis for actual payments to generation capacity owners is another complex matter, but is not really relevant to this discussion, either.

54 Despite the fact, or perhaps because of the fact, that it was actually quite similar to the model-based regime that ECNZ was operating at the time, using SPECTRA.

3.3.2. WEMS NZEM market design

The NZEM market paradigm is quite different from global optimisation, and handles optimisation of storage management over the annual horizon in very much the same way as for the daily storage optimisation discussed above. It does not impose a top-down assessment of optimal generation strategies or MWVs. Nor does it perform a forward-looking optimization of any kind. Instead, NZEM participants are solely responsible for managing their own storage over time. The market does not expect participants to submit a whole range of contingent offers, up front, to be applied in a variety of scenarios. Instead, it expects that they will adjust their offers dynamically, as circumstances change, either in terms of their own supply capabilities, or their perceptions of how market outcomes are developing.

This creates difficulties for market monitoring because what we observe in the market is a particular sequence of offers, reflecting the circumstances actually experienced within a particular year, as perceived by each participant. What the market monitor cannot observe is:

- The actual perspective of any particular participant;
- The extent to which any participant's offers are driven by particular goals; or most importantly
- The way in which the sequence of offers might have evolved, over the wide range of hydrological (and/or other) scenarios that could have occurred.

The next chapter discusses quantitative comparison of observed market offers/outcomes with possible benchmarks is discussed in some detail. But one of the strengths of the market paradigm is that it allows an equilibrium to be reached between the wide variety of opinions that might be held, at any time, about the most likely future market situation. Some of this diversity will be driven by real differences in what is known, or believed, by particular participants, with regard to the likely future performance of various system elements about which they may have special knowledge, or not. But some will be driven by more subjective elements, including the participant's personality, and preferred management style. And that may follow through to the shape of their offers.

The Authority's report seems to reflect a broad concern that certain offers, particularly from hydro participants, may be "too high", or "too steep".[55] The implications of hydro offers being higher or lower that some observer may think proper is discussed in Section 4.3.1. Here we focus simply on the "shape" issue.

First, note that the influence of long-term considerations on offer shape may be difficult to untangle from all of the short-term influences discussed in the previous section. Because participants can only make short-term offers to the spot market, there is no way to directly express their views about MWV, or to specify any overall inter-temporal limits on energy availability, etc.[56]

Still, a major reservoir manager's perception of the long-term situation must shape the overall guidance given to those making short-term offers. Long-term reservoir management is, in some respects less complex than short-term river chain management, but it involves much greater uncertainty. And it seems likely to us that long-term reservoir managers will not just be thinking about MWV, but about limiting their risks with respect to physical storage management. So, we expect they will run forward simulations of how much water might be carried forward in various hypothetical scenarios, then form a view about how much they should be releasing and, for example, about how much storage should be allowed to fall, in each week of the critical winter period. Then, having done so, they will want to

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[55] By way of contrast, pre-market concerns that participants would take an unduly cavalier attitude to managing the nation's vital storage would have been reflected by concern that they might make offers that were "too low", and perhaps "too flat".

[56] In fact, investigation of market performance in dealing with such issues might more logically be focused on the hedge market.

provide guidance about an acceptable range of aggregate weekly release, or perhaps of end-of-week storage levels.

The issue is, again though, that our market design does not allow for any direct representation of inter-temporal limits other than to make spot offers quite steep, and/or to dynamically adjust them. We have not discussed the practicalities of offer formation with any participant but, traditionally, long term MWV/storage targets for major reservoirs were reviewed on a weekly basis, and we suspect that may not have changed greatly, over the years of market operation. We also suspect that, at least in larger participant organisations, offers are made and adjusted by a team that does not, itself, determine weekly targets or MWVs. One could imagine that team dynamically adjusting offers within a week. Perhaps they might start out relatively open (ie moderately sloped) then firm up (becoming steeper), around the quantities required to meet targets over the rest of the week, given what has already been released. But one could also imagine that it might be easier just to use steeper curves to set tighter bands from the outset, thus avoiding the need for much intra-week adjustment.

As we say, we have not been involved, but note that whatever the above discussion might be seen to imply about incentives to narrow the offer bands participants think are likely to be called upon around physical targets, those incentives would be layered on top of all the shorter term effects discussed in previous sections, because all must be expressed through a single sequence of half-hourly offers.

Whether the combination of all these factors adds up to explaining the observed offer shapes and/or patterns of offer shifts, we can not say. But we should say that we are not aware of any market rule that precludes a participant from deciding to manage their storage position in this way, by making steeper offer curves, designed to provide better physical control of the storage position. In the limit, one can imagine they might even offer near vertical curves, implying that they will be generating to meet contract requirement commitments, but quite reluctant to deviate from that position.

If that storage management style is adopted, though, it is not the steepness of the offer curves that indicates whether they are "withholding", at least from the energy market.[57] What matters, in that market, is really the quantity being offered, as indicated by the position of the curve, or specifically the expected market-clearing point. And it is the way in which those curves shift in response to changing market conditions that would indicate the offering strategy of any particular participant, and perhaps shed some light on their perceptions and intent. We have already noted that this management style might be seen as "withholding" from a "flexibility market", the possibility of which is discussed in Section 5.5. Before that, though, we should discuss the surprisingly tricky business of making valid comparisons between observed offers and objective benchmarks.

[57] We have already noted that this management style might be seen as "withholding" from a "flexibility market", the possibility of which is discussed in Section 5.5.

4. Perspectives on Offer Comparisons

4.1. Introduction

The previous sections discuss how the short- and long-run offering patterns arising in the actual NZEM market environment might be expected to differ from what might have arisen in different market environments, particularly those based on global optimisation. But that raises a problem for market monitoring, because an obvious benchmark for comparison, relatively free from subjective manipulation, would be a global optimisation, such as DOASA. And, of course, the Authority actually has used DOASA to perform such a comparison.

Quite apart from anything already discussed above, though, we are aware that there has been ongoing debate, over many years now, between the proponents of:

- What we might call "Sampling" implementations of the "Dual Dynamic Programming" optimisation paradigm, including SDDP, and more recently DOASA; and
- "Constructive" implementations of that same general concept in models such as SPECTRA, and more recent models developed and used by Meridian, in particular, to explore the MWV space and support offer formation.

We are aware that models of the DOASA type have consistently produced lower water value estimates, and hence recommended higher releases, than models of the constructive type, and that there is no broad agreement over all the reasons for that discrepancy. We understand that Meridian may make some submissions in that regard, and it would certainly be good to see progress made toward a common understanding. But, while we obviously have an historical interest in the debate, all we can say, at this point in time, is that both have their strengths and weaknesses, and we are not well enough informed with respect to recent developments to attempt any judgement, either way. Section 4.2 discusses some possible issues, though.

Far more importantly, we are concerned that the Authority seems to have used DOASA in a way that can not provide a valid benchmark for comparison with real market offers, or outcomes.[58] Specifically, and perhaps surprisingly, we will argue that the fact that a model produces lower MWV estimates, of itself, tells us nothing about whether consistently using that model would lower market prices, or raise them. Conversely, the fact that any market participant consistently makes offers reflecting higher MWV levels, actually says tells us nothing about whether that participant is trying to push market prices higher, or lower, or perhaps not trying to do either.

58 The Authority's report actually says very little about how DOASA has been used, so the discussion in this chapter very much rests on Meridian's interrelation of the more detailed information they have subsequently obtained from the Authority.

4.2. Issues that may affect DOASA results

A truly comprehensive global optimisation model for hydro dominated power systems remains an elusive goal. Having done a relatively recent review of the state of that art, we can say that even the best, and most expensive, modelling systems are still struggling to achieve a balanced, integrated and internally consistent optimisation across all timeframes. Thus, we would hesitate to criticise any model, and have never reviewed DOASA in enough detail to really critique it. Still, we believe that the most important things to be aware of, when using any such model, are:

- The input data, including fuel costs and generation/storage capacity limits, but also
- The structural approximations and compromises that have inevitably been made in order to make it computationally tractable; and
- The direction in which each approximation can be expected to bias the results.

Among the most difficult aspects to model accurately, even from a risk-neutral national benefit perspective, is the wide range of both short and long run uncertainties, and the ability of the system to respond to them in real time, given that electricity has, at least traditionally, been un-storable. We have already discussed a wide range of factors that make both the short- and long-term storage management problems quite difficult, in their own right. But models like DOASA effectively have to try to deal with a very large number of instances of each problem, all within the one optimisation.

For example, a comprehensive stochastic optimisation of the short-term river chain management problem is complex enough that, so far as we know, no New Zealand hydro operator actually attempts it. We suspect that many of the risks we have discussed above are actually dealt with by heuristic approximations like maintaining top and bottom "buffer zones" in storage ranges. The managers will know that those zones are probably not "optimal", and so can be expected to err on the side of caution when setting them, thus further restricting the effective flexibility of the chain. A deterministic river chain optimisation, on the other hand, would see no need for such buffers at all, believing it could safely utilise the full range, thus modelling the chain as being more flexible than it really is. And that optimistic bias would remain intact, and bias the results of all scenarios, even when embedded in a global optimisation rightly labelled as "stochastic", because it models the management of week-to-week uncertainty in inflows to major reservoirs.

Even a deterministic optimisation of river chain management requires the modelling of a chronological intra-day load pattern, though. And few, if any, long-term optimisation models will remain computationally tractable if that kind of detail is included. So, we inevitably get to a level at which heuristic approximations have to be adopted, and the tuning of those approximations to "match reality" becomes a matter of debate. So, without suggesting any criticism of DOASA, as such, we suspect there may still be some calibration to be done with respect to a whole range of internal assumptions, before it can be relied upon to produce a generally accepted "perfectly competitive" base case.

Of course, if each manager or analyst believes that their MWV estimate is "optimal", they must also believe, at some level, that anything else must be "sub-optimal". So, each will tend to believe that national welfare would be improved if their models and judgment were applied to manage all reservoirs. Each may run the others' strategies through their models and, if their models are internally consistent, each may be able to prove their point by showing that their own strategy is the best, according to their own model. And the same will be true if a market monitor runs a model to determine their own "benchmark" MWV policy, as the Authority has done. But, of themselves, those self-tests do not really give us any reason to prefer one manager's opinion, or model, over another. At best, they will just show that each method is internally consistent.

For example, we understand that such studies have, in fact, been done by the DOASA developers and led them to conclude that following their model's recommendations could produce significantly more efficient outcomes than those observed in the market.[59] We also understand, though, that those conclusions have not been universally accepted by other modellers. And there is a fundamental problem here, in that we expect that the simulations used to verify DOASA will have been, to some extent, reliant upon modules and assumptions shared in common with DOASA. And the same will be true of other models.

So, a comparison of those shared modules and assumptions with those employed by others may reveal some reasons for the observed differences. At least, we believe that it could be productive to bring modellers together for an in-depth investigation into why these discrepancies, and differences of opinion seem to persist. To be clear, the developers of DOASA are acknowledged experts in that type of modelling, and we have no reason to think there is anything fundamentally wrong with the model. So, we expect that the debate would be mainly about data, and assumptions. But, at this stage, we are not in a position to reach any conclusions, either way, based on the limited evidence we have seen.

We should stress, though, that our own experience with side-by-side comparison of much, much simpler models, long, long ago is that apparently reasonable models can produce very different looking MWV surfaces.[60] Also, it turns out that quite subtle details, like the assumed frequency with which decisions are reviewed, and eh data available to the decision-maker at that time, can make a major difference to MWV estimates, along with factors like the assumed cost of shortage that may be more obvious, but perhaps indeterminate. That may seem worrisome. But it is equally important to note that the same study also showed that large observed differences in the MWV estimated for particular storage levels can have surprisingly little impact on real world outcomes, for reasons discussed in the next section.

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[59] A.B. Philpott and Z. Guan *Benchmarking wholesale electricity markets*: *2017 update*, November 26, 2020 https://www.epoc.org.nz/

[60] E.G. Read & J.F. Boshier: "Biases in Stochastic Reservoir Scheduling Models", in A.O. Esogbue (ed.) *Dynamic Programming for Optimal Water Resources System Management*, *Prentice* Hall NY, 1989, p.386-398

4.3. Issues relating to the way DOASA has been used

4.3.1. Properties of reservoir systems

One of the most obvious things that can be said about reservoirs is that they are basically natural systems, obeying one simple law, that outflow equals inflow, on average over time. Human intervention can significantly increase the lag between inflow and outflow, but does not change that basic law. And that is true, no matter what management regime is pursued, and what MWVs may be computed. Changing the management regime may transition a reservoir from one stochastic equilibrium to another, but reservoirs will always settle into a stochastic equilibrium in which outflow equals inflow, on average over time.[61]

That observation may be thought so obvious that it is not worth saying, but it does have important consequences, because it implies that, no matter what MWVs are set, a reservoir manager ultimately must either release or spill whatever water arrives, and a hydro generator can ultimately only "withhold" generation from the market by spilling water or perhaps, to a lesser extent, by generating inefficiently.

4.3.2. "Withholding" and stochastic equilibrium

In fact, there is a theorem in the literature that asserts that a monopolist reservoir manager can not exercise market power at all, and that the monopolist's optimal release pattern turns out to be identical to the perfectly competitive release pattern.[62] The problem with that theorem, though, is that it assumes that the reservoir manager faces a consistent constant elasticity demand curve for water. In reality, the elasticity of electricity demand varies from period to period, and the net elasticity, after accounting for all other suppliers varies much more. Importantly, electricity demand is not the same thing as water demand, because a hydro generator will ultimately be forced to spill, and could choose to do so voluntarily, without being forced to dump cheap electricity on to the electricity market. Still, there is a sizable kernel of truth in the proposition.

Our own experience suggests that placing a higher value on water, whether motivated by an attempt to influence electricity prices or not, can end up making surprisingly little difference to simulated outcomes, as in the Boshier and Read study above. To understand why, imagine a manager deciding to consistently raise their whole MWV curve. Irrespective of their motivation for doing that, and the mechanism they employ, the result will be that releases from that storage move up the merit order. So, release falls, and the storage trajectory rises to a higher level on the new MWV surface, causing the MWV to start falling again.

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[61] By "stochastic equilibrium" we are not referring to the equilibrium of a stochastic game, or of a market (although, as it happens, both may be thought applicable in this case). We merely mean the whole set of storage trajectories, generation levels, prices etc that might be traced out by simulating market operations over a large set of hydrological/meteorological/load years in a continuous loop, assuming the physical transmission system plant/ portfolio, fuel costs, load levels, MWV surface etc, either observed or forecast to exist for one particular year.

[62] P.C. Dalziel "Optimal water storage and pricing: The effect of Monopoly" *New Zealand Economic Papers* Volume 21, Issue 1 Pages 3-16, 1987

But how far will it fall?

Well, the other fundamental equation at work here is that, over the annual cycle:

Demand (minus any shortage) is met by the sum of generation from two sources:

1. *Plant whose total energy is basically fixed, plus*
2. *Plant with access to flexible energy sources*

Traditionally, the first category has often been referred to as "energy-limited" plant, and that category has been dominated by hydro, while all thermal has been thought of as being in the second category.[63] And the point is that the total annual generation from any plant in the first category can not actually rise above what is available over any particular year.[64] Nor can it fall below that level, unless it is wasted, either through "spill", or unnecessarily inefficient generation.

We can not know how much generation will be available from the energy-limited plant in Category 1 at the start of the year, and hence we can not know how much generation will be required from flexible thermal in Category 2. But we do know that, whatever that quantity turns out to be, no amount of re-scheduling of energy-limited plant could have changed it unless there was:

- Some degree of supply shortfall (possibly including price-induced DSM); or
- Some degree of spill (possibly including inefficient operation).

Traditionally, hydro has been thought of as the main component of Category 1, and hence the main potential contributor to spill.[65] And the implication of the above discussion is that, at least over this period, the main impact of pricing hydro releases at higher levels will be just to move the whole pdf of hydro storage trajectories up to a higher level, with:

- A somewhat higher probability of spill; and
- A somewhat lower probability of shortage.

The future may be different, but the historical record, including for the period analysed by the Authority, shows the total volume of spill and lost load both being quite small, as a proportion of total load. So, we can be reasonably confident in saying that, in retrospect, the total generation called upon from flexible thermals must have been at (or at least quite close to) the levels it inevitably had to be in each of those years. And that seems to imply that market price levels must have been just high enough to induce that level of generation from those sources, irrespective of any gaming or also mis-estimate or game offers, mis-estimation of MWVs by hydro storage managers.[66]

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63 Our 2018 paper argued that at least some thermal may actually be more in the first category. But that does not change the discussion of hydro here.

64 We are ignoring some limited flexibility to carry water over from year to year, but that just means that we have to think about stochastic equilibrium over a slightly longer timeframe, and makes no difference to the argument here.

65 The relevant spill measure also includes geothermal spill and some wind spill, but only when that spill is due to market prices falling so low that some party must spill because the combined wind/ geothermal/solar/hydro minimum running capacity exceeds market demand. But the volume involved is not large over this historical period.

66 Thermal generators might also mis-estimate or game offers, but consideration of that possibility lies outside our scope, here.

4.3.3. Comparing management policies

Whether the stochastic equilibrium implied by higher MWV curves is deemed to be better or worse, from a national cost benefit perspective, will depend significantly on rather subjective judgements about the relative weight that should be given to the "cost" of spill vs shortage. Different individuals will weight them differently, and different modellers reservoir managers will too. Consequently, different managers may settle on quite different MWV curves as being "optimal".

Fortunately, as discussed above, we are dealing with an essentially natural system, with strong self-equilibrating properties. So, these differences of opinion matter much less than might have been supposed. Indeed, one of the main advantages of a market is that it allows a variety of managers to each follow their own management strategy over the part of the national resource portfolio they control, and to find an equilibrium balancing these diverse opinions.

In particular, the manager who values water more highly than others do, and offers accordingly, will find that the market calls for his/her generation less, and relies more on that offered by others, at lower prices. But this will cause storage to rise in the more highly valued reservoir, and fall in those whose managers assigned lower values. And that will continue until the probability of spill has risen to a point where the manager's estimated MWV for that water, and market offers, fall low enough to bring releases back up to a level establishing a new equilibrium (i.e. with releases balancing inflows), with that reservoir running at rather higher storage levels, and the others perhaps a little less. Or,

It does not mean that MWV mis-estimation has no impact at all, though. Even if plausible MWV policies are all likely to produce stochastic equilibria with roughly the same generation from flexible thermal, there are real issues at stake. For example, a poor enough MWV policy might do a bad enough job of coordinating production over time and space, that imposes significant costs on society by:

- Raising or lowering the MWV surface by so much as to shift the spill/shortage balance too far in one direction or the other;
- Flattening the MWV surface by so much as to actually increase both spill and shortage;
- Steepening the MWV surface by so much as to unduly limit the reservoir's ability to arbitrage effectively between high- and low- priced periods, thus creating extra costs due to alternating too much between high- and low-cost flexible thermal generation, rather than keeping the rate of such generation as constant as possible, and as similar as possible between day and night, Summer and Winter;
- Creating extra demand for flexible thermal to meet, by recommending too much inefficient hydro generation;
- And so on.

Importantly, though, we see no reason to think that consistently setting lower MWV levels will, of itself, lower cost or market prices. Perhaps ironically, the very worst MWV policy, producing the highest costs and prices, would probably be to set MWV to zero, so that storages were always held empty. Hydro could still operate, in a run-of-river mode, and prices might actually be lower over Summer. But they would surely be much higher over Winter, with heavy use of the most expensive thermal options, and very frequent non-supply events implying very high national costs, and prices. Of course, no-one, and no model, would recommend such an extreme policy, but the clear implication is that raising MWVs above that level would lower both cost and prices.

Accordingly, we see no reason to think that following a policy of setting higher MWVs will necessarily lead to higher market prices. In principle, there will be an optimal MWV, for each storage level.[67] But

[67] This is true, in principle, although our experience suggests that, in practice there can actually be a wide range of MWV curves that are "more-or-less optimal". So, the choice between them may often come down to the degree of risk aversion some particular manager believes is appropriate.

the thought experiment above just tells us that the optimum must normally be greater than zero, without telling us how much greater than zero it should be. Therefore, while raising MWV may temporarily raise market prices, while the system moves into a new equilibrium, we have no a priori reason to think that the new equilibrium market price distribution will be higher, or lower.

Accordingly, the fact that a participant is believed to have opted for a higher MWV reservoir management strategy should not, of itself, be interpreted as providing evidence that they are trying to raise market prices. So, if that simple and perhaps obvious seeming test provides no useful basis for comparison, we must ask: How can MWV estimation policies be fairly compared, if we are to determine which is "best"?

Simulation

In principle, one would like to have a simulation model that had been calibrated and agreed by all parties as being sufficiently detailed and accurate as to form a reliable testbed. Then the performance of each model could be simulated across a wide range of scenarios, and assessed in terms of the end results that actually matter, like shortage frequency, system cost, and price level/volatility, rather than by essentially subjective determination that MWVs are "too low", "too high", and so forth. Or, at least, we would like to think that a model's simulated performance could be compared with actual market outcomes.

Unfortunately, no agreed benchmark simulation testbed currently exists in New Zealand, and it is actually not very easy to do a proper comparison with market outcomes, either. Suppose we want to compare actual market outcomes with the policies recommended by some model, using a weekly time step:

- We need to start by choosing an observed market storage level (or more likely a vector of storage levels across multiple reservoirs).
- Then we can use our model to estimate an MWV and/or release recommendation for that storage level (or more likely a vector of MWVs and releases across multiple reservoirs).
- If we have a model which tends to estimate lower MWVs than the ones used by market participants, it can be expected to report lower MWVs for this initial point.
- And those lower MWVs must then be used to form offers, which should be at lower prices than the actual observed offers, for one or more market participants.
- Those lower offers will then imply higher releases, when cleared along with the offers of other participants (assuming those remain as they were in the market).
- Thus, the simulated storage level (vector) for the end of the week, assuming the historically observed inflows and these higher releases, will certainly be lower than that observed in the market.
- So, we can use our model to determine an MWV (vector) for that storage point, and that will definitely be higher than the (hypothetical but irrelevant) MWV (vector) we might have determined by running our model starting with storage at the observed market level.
- Then, in principle, all we need to do, from there on, is to keep simulating the trajectory implied by the MWVs determined by our optimisation model, re-running the model each week from our simulated storage level, and adopting its release recommendations to determine the next.

If such a simulation process were to be set up, it could, in principle, provide a legitimate basis for conclusions to be reached about better, or worse, approaches to MWV setting. If, for example it was established that consistent application of DOASA produced stochastic equilibria that were broadly agreed to be superior, the question would then become one of determining whether the modelled gains were due to:

- A flawed market design; or
- Participants acting sub-optimally (for whatever reason) in the context of a basically sound market design.

Unfortunately, some tricky issues would need to be resolved before implementing this conceptually simple simulation process, though. For example:

- At one extreme, we could be trying to determine the consequences of a particular participant using their own model and offer formation process rather than our models, in which case we would presumably just substitute our hypothetical offers for theirs. The difficulty is, though, that our chosen participant will presumably control a significant reservoir, and the observed offers from other participants will presumably have been conditioned on their knowledge of the storage level in that reservoir, so this kind of simulation will be unrealistic because we do not know how all those other offers would have changed.
- A more sensible goal might be to compare the simulated performance of our model, assuming <u>all</u> participants accepted its recommendations, with actual market performance. Actual market conditions will have been significantly different from those assumed in our model, though, and the model may not optimise strategies for some participants, such as thermal generators managing limited fuel stocks.
- In part, the discrepancies will be due to unexpected events, like breakdowns, or weather affecting load and most renewable generation. But there is a more fundamental problem if the only intra-week model we have is the highly simplified approximation incorporated into our annual optimisation model. We can't really compare market outcomes with the output of that approximate model, unless we can calibrate it carefully against market outcomes, as discussed in Section 4.2 above.
- And, of course, even if they are not trying to “game” system prices, real participants really will be averse to a wide range of risks, as discussed in various sections above, and the form of that risk aversion is unlikely to conform to the one mathematical form that can be handled by (some) convex optimisation models.[68]

Accordingly, we can understand the difficulties the Authority has faced in attempting to provide a valid benchmark for comparison. Nonetheless, we believe that some kind of simulation would actually be required in order to provide a consistent basis for any sound conclusions about whether the MWV levels chosen by participants are too high, or otherwise inappropriate. In particular:

- We can legitimately compare the MWVs estimated by one method along a storage trajectory formed by following the release policy determined by that method.
- But we can not legitimately compare the MWVs estimated by one method along a storage trajectory formed by following the release policy determined by a different method or, in this case, along an observed market storage trajectory.

Unfortunately, though, this last bullet describes exactly what the Authority seems to have done, in this study.[69] And, if so, we are forced conclude that:

- All of these reported DOASA runs really only serve to confirm that models of that type consistently recommend lower water values than the kind of models or processes Meridian and others appear to have been using.
- So, we are not surprised to see DOASA consistently recommending low MWVs when storage is assumed to be at the levels observed in reality, because DOASA never would have recommended holding that much water in storage.
- But we believe that DOASA must also be recommending higher release levels, at the observed storage levels, than market participants actually made, and we are not seeing how much lower storage levels would actually have fallen if, if DOASA’s higher release recommendation had been adopted, week after week.

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[68] Conditional Value at Risk (CVaR)

[69] This discussion is based on Meridian’s analysis of detailed information published by the Authority subsequent to the review paper. See: https://emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2021/20211115_WaterValuesFor2016To2021CompetitionReview

- Nor are we seeing how much higher DOASA's MWV estimates would have been along all those lower storage trajectories, as a consequence.
- And we really can not tell whether national costs, or market prices, would have been higher or lower, on average across all hydrologies, if that had been done.
- Nor can we tell what the spill and shortage probabilities would have been,

Conversely, we believe what would be required, in order to answer the questions the Authority seems to be asking, is a systematic and consistent simulation, to establish a different stochastic equilibrium for the national reservoir system, with lower storage trajectories, and lower spill probabilities, but higher probabilities of non-supply. The question then would be whether that alternative equilibrium was deemed to be better, or worse than the status quo.

We have simply not seen the evidence to judge that question, either way. But we have already argued that there is no *a priori* reason to assume that this "low MWV equilibrium" would produce lower costs, or prices, on average. And it is also far from clear that the nation actually would be comfortable with the apparent loss of security, and probably increased price volatility, even if that strategy did promise to lower costs.

5. Concluding Reflections

5.1. Introduction

The Authority's study focuses entirely on analysis of past market data, without attempting any future projection, and we have mainly tried to do the same. Some trends and issues seem to be emerging from the report, though, and/or from our discussion. So, we will conclude by briefly canvassing a few of those issues here.

5.2. Inter-temporal optimisation

One theme emerging across our discussion of storage management over both intra-day and intra-year timeframes is the possibility that relying on participants maintaining control over inter-temporal linkages like delay times and storage limits by making, and adjusting, relatively steep offers may not be ideal. Many other markets do employ inter-temporal optimisation, and some, such as Singapore, have gradually moved away from "snapshot" approach like New Zealand's, towards inter-temporal optimisation over recent years.

One reason for adopting the snapshot approach in New Zealand, and in Singapore, was simply the fear that it might prove to challenging to solve the inter-temporal market-clearing problem in real time, but that should be far less challenging now, given hardware and software advances over the last 20 years. So, without going so far as to implement the kind of detail inter-temporal optimisation discussed in Section 3.2.1 above, it may well be possible to allow participants to express simple inter-temporal limits, including rate-of-change limits, or energy limits on particular plant or aggregate release, so as to link the current daily set of half hourly snapshot optimisations into, say, a single day-ahead optimisation.[70]

We are not arguing for, or against, such a development, but do note that it could allow participants to make flatter offer curves, indicating more flexibility to respond to period-to-period changes in requirements, than they do at present.

5.3. Changing role of hydro

Perhaps the most interesting observation in the Authority's report is that there now seems to be little to no correlation between hydro and thermal generation, on average.[71]

At first sight that seems incredible. After all, load must be met by the sum of hydro and thermal generation, so a unit increase in hydro generation should be expected to imply a unit decrease in thermal generation, in meeting the same load. Thus, from a very short-term perspective, we should expect to see a correlation of minus one between hydro and thermal generation.

On the other hand, if we expected hydro and thermal to be peaking together, to follow load in a balanced way, we might expect a correlation of plus one. So, if we actually observe no correlation at all, over some period, it could be that we are observing a transitional phase, in which sub-periods of negative correlation approximately balance sub-periods of positive correlation. And/or it could be that natural fluctuations in output from some hydro sources are being accommodated by counteracting

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70 Or perhaps to run such an inter-temporal optimisation instead of the current set of look-ahead snapshots, while also running quicker snapshot optimisations, with steeper dynamically updated offers in real time.

71 See discussion on p31&32 of the Authority's report.

managed fluctuations in output from other hydro sources. In other words, it could be that (some) hydro is already taking over thermal's traditional role of smoothing out fluctuations in the net supply/demand balance caused by variations in the load and/or increasingly by (other) renewable generation.

If so, we might expect to see, and may already be seeing, hydro offer curves looking more and more similar to traditional offers from thermal generators operating within strict daily energy limits. That is, with significant high-priced components, representing offers to use flexible capacity to meet extreme peaks in the supply/demand balance, and respond to short-term fluctuations in that balance, but to use it quite sparingly, due to limited "fuel stocks". Again, the ability to specify inter-temporal restrictions might assist.

5.4. Market making obligations?

We have pointed out that it is really the position of an offer curve: That is, how the expected quantity cleared in the market compares with a perfectly competitive market-clearing quantity; that determines whether an offer curve should be seen as withholding anything from the energy market, in any particular period. After all, no other characteristic of the curve normally determines market-clearing prices or quantities for any other participant, or consumer.[72]

The Authority does seem to be concerned about the shape of hydro offer curves, though. And that raises the question of whether the Authority believes there is, or should be, an implied obligation for some or all generators to offer curves that are as flat as they can be, or perhaps as close to SRMC as they can be, across the whole range of physically possible generation levels.

As we recall it, ECNZ did give some kind of undertaking, when it controlled all major generation stations, that it would "act like a perfect competitor". And that could be interpreted to include offering an SRMC curve into a (then hypothetical) market. We also recall a general feeling that large incumbents would/should be supporting entry of a "competitive fringe". That was expected to involve offering available response to the ancillary service market, and perhaps also offering energy in such a way as to allow smaller entrants (who would not be able to call on their own diversified plant portfolio) to readily, and almost costlessly, buy/sell power to balance their own output in meeting contractual commitments. There was also argued to be significant self-interest in all major generators doing this, because even major generators would each frequently need to call on each other, due to a fluctuating hydro/thermal balance, if nothing ese.

On the other hand, this report has argued that the realities of the current situation imply that:

- The true hydro SRMC curve may actually be much steeper than the head reservoir MWV curve that some commentators seem to be thinking of, and perhaps there is less accessible physical flexibility, too.
- There are also quite a few factors, including some aspects of market design, that should be expected to make risk averse participants provide offer curves that are significantly steeper than raw SRMC curves.
- And the situation is perhaps not all that symmetric, in that, especially with thermal's role diminishing, one or two hydro generators may be providing most of the flexibility, mostly for the benefit of others.

So, it seems timely to ask whether there are any market rules, or understandings, that would prevent, or penalise, a market participant deciding to only provide steep offer curves, because (for whatever reason) they wanted to adopt a more quantity-focussed approach to storage management?

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[72] The only exception being when a step of the offered curve happens to set market price directly.

We imagine the Authority would not be concerned if a small-scale operator were to do this. But the focus of the recent support suggests that maybe there is some underlying expectation that a large generator, such as Meridian, "should" provide offer curves that allow other participants to freely buy in power at prices that are not too much higher than those pertaining at the expected dispatch point, and to sell power at prices that are not too much lower than those pertaining at the expected dispatch point. We are not aware of any such rule, though, or of any recent commitment by the major hydro operators to do this.

5.5. A market for flexibility?

Looking at this another way, while a steep offer curve might not (of itself) imply any intent to exercise market power in the energy market, it might be interpreted as possibly representing some kind of gaming with regard to the availability of flexibility to accommodate fluctuations in the supply/demand balance due to variation in load, and/or other generation.

That is not the same thing as withholding energy from the market, and not necessarily the same as withholding MW capacity either. But it could arguably be interpreted as withholding capacity from the "flexibility market", if there was one.

We understand that the possibility of a market providing flexibility to cover fluctuations in wind etc has been discussed in New Zealand, and we can imagine a market for flexibility being developed, as an extension of the ancillary services framework. But there is no such market in New Zealand, at this point in time.[73] Even if such a market were to be developed, we can imagine market power problems developing if there turns out to be only one participant, or perhaps one in each island.

So, we are not arguing for, or against, establishment of a formal competitive market for some such service. With or without such a market, though, the imposition or expectation of protocols that limit the form of offers from one or two participants, must surely raise the question of compensation and/or incentivisation. Or, in other words, the price at which those participants would, or should, be prepared to "sell" that service to the broader market.

73 Ideally, we have often argued that a coherent market design should have ancillary services defined out to the energy market trading interval. That is not the point here, though, because we are talking about the shape of offer curves that are actually only applied at the trading interval level, rather than within trading intervals. If the flexibility provided by these snapshot offer curves is to be thought of as an ancillary service, then it is an ancillary service delivered over multiple periods, not just within a single period.

Efficient price discrimination in the wholesale electricity market

Response to the Electricity Authority Market Monitoring Review

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22 December 2021

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In its discussion paper, *Inefficient Price Discrimination in the wholesale electricity market – issues and options,* the Electricity Authority (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.

Little weight, however, should be given to the specific results from applying the Authority's assumptions, as many of those assumptions are questionable and abstract from elements of the contracts that produce value for New Zealand but which are not considered in the Authority's analysis (for example, locational prices, demand response, transmission costs).

This report discusses two sources of error in the approach taken by the Authority.

Firstly, the Authority did not arrive at a clear problem definition—its descriptions of the problem differ from its reviewers and the reviewers differ among themselves. In its discussion paper and supporting peer reviews, the Authority published three different views as to what constitutes inefficient price discrimination:

- prices that differ between customers for reasons other than quantifiable differences in costs (Authority)
- charging some consumers lower prices when other customers, who place a higher value on electricity, consume less or not at all because they face higher prices and/or the cost of producing electricity is higher than the value of its use (Mr Duignan)
- the sale of electricity at prices below the economic cost of supply (Mr Hunt).

Without a clear problem definition, there was no solid foundation for the Authority's analysis.

Second, the analysis undertaken by the Authority was not grounded in the extensive literature on the issue it was investigating—price discrimination. Economic research provides elegant and powerful results showing that discriminatory prices can enhance output and increase economic welfare.

The key test from the literature is whether price discrimination increases output (either by serving more customers or increasing the amount they consume), rather than merely shuffling prices paid by pre-existing customer groups without an increase in output. The tests applied by the Authority, for distinguishing efficient and inefficient price discrimination, are at odds with this established literature.

As the Tiwai contracts unambiguously lead to a large increase in electricity output relative to the Authority's counterfactual scenario of the smelter exiting New Zealand, one of two possibilities arise:

- the received economics literature is wrong, and the Authority has shown that price discrimination can expand output and be welfare reducing
- the Authority is mistaken.

We show the Authority wrongly interprets its own analysis and Appendix B of its discussion paper provides an example of welfare enhancing price discrimination, not inefficient price discrimination as the Authority concludes.

Even under the Authority's own calculations, the increase in aluminium prices since the contracts were finalised, means the Authority would determine that the contracts result in an increase in economic welfare were it to repeat the calculation with current knowledge. The Authority, in effect, is proposing regulatory options in its Discussion Paper that would have precluded a contract that it now knows to be welfare enhancing on the grounds that it (the Authority) would not have foreseen that benefit when it applied its proposed regulatory tests.

There is no economic foundation to the Authority's claims that generators have subsidised the price of electricity to the smelter. The Authority's claim was based on an analysis that compared the price paid under a commercially agreed contract by a low-cost supplier (hydro generation), with the cost of the highest cost existing supplier (approximated by thermal generation). The Authority's definition of a subsidy would imply that an efficient new entrant should not enter into a contract at prices below that charged by the incumbents; a test that would make it very difficult for the Authority to pursue its objective of promoting competition for the long-term benefit of consumers.

The Tiwai contracts do result in a significant net gain to producer surplus under the Authority's characterisation of the contracts and its assumptions. In of itself, this observation is nothing more than the 'invisible hand of the market' at work; generators were incentivised to negotiate a contract that resulted in a net benefit to New Zealand.

1. Introduction

The Electricity Authority (Authority) makes a number of strong claims in its discussion paper, *Inefficient Price Discrimination in the wholesale electricity market – issues and options* (Discussion Paper) (Electricity Authority, 2021). The Authority claims price discrimination implicit in the 'Tiwai contracts' between Meridian Energy, Contact Energy, and the New Zealand Aluminium Smelters (NZAS) provide a potential illustration of price discrimination not in the longer-term interests of consumers and result in (Electricity Authority, 2021, p. ii):

- potential inefficiency costs of around $57 million to $117 million per year
- subsidies from electricity generators to NZAS of $500 million over the contract's four-year term
- generators being willing to subsidise NZAS because the Tiwai contracts result in other consumers paying an additional $850 million per annum
- market prices that distort signals for investment in generation and electrification, thereby compromising the efficient transition to a low emissions economy.

We test the validity of the Authority's claims. Our report is structured into four sections:

- Section 1 introduces our report and outlines its scope.
- Section 2 summarises the Authority's view of what constitutes efficient and inefficient price discrimination and assesses whether the Authority's view accords with the findings of relevant economic literature.
- Section 3 reviews whether the Tiwai contracts, when assessed against the tests in the economic literature of efficient and inefficient price discrimination, give rise to economic efficiency losses or efficiency gains.
- Section 5 concludes.

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2. Economics of price discrimination

2.1 The Authority's view

The Authority explains that its focus is primarily on the allocative inefficiencies that can arise from price discrimination (Electricity Authority, 2021, para 5.2). It notes, almost in passing, that price discrimination can enhance economic efficiency (Electricity Authority, 2021, p. ii). However, there is no clear statement from the Authority as to what it considers distinguishes efficient price discrimination from inefficient price discrimination.

One interpretation of the Authority's view can be gleaned from an option it contends would counter inefficient price discrimination. In describing its option 7 (non-discriminatory pricing rules), the Authority explains it could write a rule that prevents "generators or other electricity market participants from offering electricity hedges at lower (or higher) prices to different customers absent a credible and quantifiable justification." (Electricity Authority, 2021, para 6.47). The Authority elaborates that sellers (Electricity Authority, 2021, 6.52):

> would not have to offer the same electricity price to all parties, but rather would be required to attribute price differences directly to differences in the costs of services … These differences might include aspects such as timing of offer, node, volume economies, duration of contract, credit rating of counterparty, consumption profiles, demand response provisions and other terms and conditions.

The implication is that the Authority views efficient price discrimination occurring only when the difference in price reflects a "quantifiable" difference in the cost of supply.[1] However, the Authority suggests it would permit prices to vary for reasons other than cost when the sale is for an activity the Authority views favourably; the Authority gives the example of a discount to a retailer supplying vulnerable customers (Electricity Authority, 2021, para 6.52). The Authority does not explain how it will select those customers who would be permitted to benefit from price discrimination for reasons other than economic efficiency.[2]

In his peer review, Mr Duignan comments on the Authority's summary of its problem definition which states (Electricity Authority, 2021, pg 22):

> With inefficient price discrimination, the right consumers are no longer consuming the right amounts of electricity – the allocation of electricity to different consumers may be inefficient or the cost of producing electricity may be higher than people value it at.

As Mr Duignan observes, the Authority's statement does not define the right consumers or the right amount (nor, we would add, does it define what it means by the cost of producing electricity).

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[1] The Authority seems to overlook that price discrimination could be present even when all consumers are charged the same price; this is a surprising omission given its efforts in recent years to explain that uniform transmission pricing inefficiently discriminates amongst transmission customers.

[2] This selection criterion would be important as the Authority says that, under its rules based approach, penalties should at a minimum exceed the private benefits the deal bestows on the parties to the contract and ideally should approximate the social harm done (Electricity Authority, 2021, para 6.56).

However, Mr Duignan suggests other sections of the Authority's paper do provide a more precise explanation which he summarises as (Duignan, 2021, pg 2):

> inefficient price discrimination results in some consumers being favoured with lower prices who have a lower valued use for the electricity than other consumers or potential consumers who consume less or not at all because they face higher prices and/or the cost of producing electricity may be higher than the value of its use.

Mr Duignan does not reference the sections of the Authority's paper he is referring to in arriving at his summary of the Authority's views. However, as the Authority published its Discussion Document after receiving Mr Duignan's review and did not amend its summary, it seems reasonable to assume that the Authority agrees that Mr Duignan's expansion encapsulates one of its views (along with its incompatible view that inefficient price discrimination occurs when prices vary for reasons other than differences in quantifiable costs to serve).

The Authority's second peer reviewer, Mr Hunt, also comments on the Authority's discussion of its problem definition and summarises the Authority's views as (Hunt, 2021, pg 22):

> The issues paper focuses on the potential for economic efficiency losses to arise from price discrimination, particularly allocative inefficiency effects including from the sale of electricity at prices below the economic cost of supply.

Hence, the Authority, in its discussion paper and supporting peer reviews, has published three different views as to what constitutes inefficient price discrimination:

- prices that differ between customers for reasons other than quantifiable differences in costs (Authority)
- charging some consumers lower prices when other customers, who place a higher value on electricity, consume less or not at all because they face higher prices and/or the cost of producing electricity is higher than the value of its use (Mr Duignan)
- the sale of electricity at prices below the economic cost of supply (Mr Hunt).

Neither the Authority nor its reviewers cite any economic literature in support of their contentions. Though the Authority and Mr Hunt both state that price discrimination may be efficient, neither explain the circumstances in which price discrimination is efficient.

2.2 Price discrimination in economics literature

Price discrimination has long been studied in economics. We provide below an overview of the key conclusions from the literature. In Appendix A, we present a simple theoretical model to illustrate when a price discrimination strategy may give rise to economic inefficiencies and when it gives rise to economic efficiency gains.

In her seminal book "The Economics of Imperfect Competition", originally published in 1933, (Robinson, 1969), argues that some degree of discrimination will almost certainly be desirable. Following (Pigou, 1920), economists generally distinguish between three types of price-discrimination (Varian, 1989):

- First-degree (or perfect) price discrimination— involves the seller charging a different price for each unit of the good in such a way that the price charged for each unit is equal to the maximum willingness to pay for that unit.
- Second-degree price discrimination (or nonlinear pricing)—occurs when prices differ depending on the number of units of the good bought, but not across consumers. That is, each consumer faces the same price schedule, but the schedule involves different prices for different amounts of the good purchased. Quantity discounts or premia are the obvious examples.
- Third-degree price discrimination—occurs when consumers are charged different prices but each consumer faces a constant price for all units of output purchased. This is probably the most common form of price discrimination. The textbook case is where there are two separate markets, where the firm can easily enforce the division. An example would be discrimination by age, such as youth discounts at the movies.

(Robinson, 1969) observes that under conditions of perfect competition, price discrimination cannot exist.[3] However, if there is some degree of market imperfection, some degree of price discrimination becomes feasible. When markets are imperfect (as all real-world markets are), and customers do not have perfect information and cannot always move without cost from one seller to another, price discrimination becomes practicable.

Writing nearly 90 years ago, (Robinson, 1969) argued that price discrimination depends on customers having different elasticities of the demand. If all customers changed their demand by the same amount in response to a price change, then suppliers would charge the same price to all their customers as they would gain nothing from price discrimination. If customers differ in their elasticity of demand, suppliers have an incentive to charge higher prices to the least elastic (least price sensitive) customers, and lower prices to the most elastic (most price sensitive) customers.

Writing more recently, initially for a chapter in the Handbook of Industrial Organisation and then a standalone article, (Varian, 1996) concludes that if price differentiation allows more consumers to be served or increases output, it will generally increase welfare. However, price differentiation that merely shuffles prices paid by pre-existing customer groups and that does not result in an increase in the number of customers served, or the amount that they consume, will tend to reduce overall welfare (Varian, 1996). Therefore, (Varian, 1996) concludes that:

> the key concern in examining the welfare consequences of differential pricing is whether or not such pricing increases or decreases total output.

(Baumol, 2005) demonstrates why, under competitive conditions, a firm will normally be forced to adopt discriminatory pricing wherever that is feasible. He argues that uniform pricing is not to be taken as the normal characteristic of equilibrium of the competitive firm. Rather, Baumol maintains that discriminatory pricing is the normal attribute of equilibrium wherever customers have different

[3] Textbook models of perfect competition include assumptions of perfect information, homogeneous products, an infinite number of buyers and sellers, the absence of economies of scale, independence of action, and free movement of resources.

willingness to pay, and it is possible for the firm to prevent consumers in separable groups from reselling products to one another.

(Baumol, 2005) argues that discriminatory pricing is not a sign of a breakdown of contestability but rather a manifestation of its normal functioning. If the constraint on profit imposed by entry is potent, the only way for firms with large fixed and continuing sunk costs to survive will be to engage in price discrimination of the most sophisticated variety that is workable. Firms that are more efficient in finding and carrying out better pricing strategies will survive against less creative firms (Baumol, 2005).

2.3 Authority's view of efficient and ineffective price discrimination conflicts with the literature

It has long been known that discriminatory prices can enhance output and increase economic welfare. Researchers such as (Hausman & MacKie-Mason, 1988), (Varian, 1996), and (Baumol, 2005), have provided elegant and powerful results that confirm this observation. The tests set out by the Authority and its peer reviewers, for distinguishing efficient and inefficient price discrimination, are at odds with this established literature. A simple, every day, example may help illustrate the difference by comparing the Authority and its peer reviewers' characterisation of price discrimination with Varian's, (1996), touchstone—whether or not such pricing increases or decreases total output.

Most movie theatres offer discounted ticket prices for children. Community theatres would not appear to be earning monopoly profits, and indeed might be better characterised as a declining industry; [4] hence the ubiquity of price discrimination in this industry is unlikely to be evidence of the use of market power.[5]

Were the Authority regulating movie theatres, its proposed rule (option 7 discussed above) would deem price discounts for children inefficient as there is no material cost difference in making a seat in a theatre available to a child, relative to an adult.

It is not clear what Mr Hunt means by a 'price below the economic cost of supply'. From the appendix to his letter, it seems Mr Hunt considers the relevant measure of economic cost is the price or cost of the marginal unit (the last unit sold to meet demand).[6] For a theatre, this cost may be the full priced seat. A discounted price for children would therefore be deemed an inefficient price discount under Mr Hunt's rule.

Mr Duignan would be interested in whether any other movie goer, who would have been prepared to pay more than the child's discount price, but less than the full fare, had been 'crowded out' and missed out on seeing the movie. As Varian shows, that question falls short of the analysis required to assess whether the discount is inefficient price discrimination, as account needs to be taken of the additional output (in this example, the seats sold to the family).

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[4] See for example, https://www.forbes.com/sites/enriquedans/2020/12/05/imagine-a-world-without-movie-theaters.

[5] For the origin of the argument that discriminatory pricing need not require monopoly power, see (Levine, 2002).

[6] We show below that Mr Hunt's test misreads theory; a profit-maximising price discriminator would set prices in each sub-market at levels at which its marginal cost is equal to its marginal revenue.

A family that could not purchase discounted prices for children (because those tickets were sold to a movie goer willing to pay more than the discounted fare but not the full price) may choose not to view the movie and to undertake some other family activity. Mr Duignan's test would require the theatre owner to forgo the custom of an entire family to avoid crowding out a customer who might have been willing to pay more than the child's discounted price. The test from the literature (e.g., Varian) would allow an assessment of whether more tickets are sold when some prices are discounted, than are sold at a uniform price, which is the reason why profit-seeking theatres discount prices for some customers; put simply, theatres do not charge lower prices to older customers and to children out of charity but because economic welfare enhancing market conditions force them to do so.

This simple example helps illustrate three conceptual foundations from the literature on efficient and inefficient price discrimination:

- the relevant test is whether or not such pricing increases or decreases total output (Varian, 1996); society is better off, in the simple example, if the whole family can attend the movie rather than the individual who would have paid a little more than the child's ticket price.
- efficient price discrimination (that is welfare enhancing) requires customers to be segmented in a way they cannot resell to others willing to pay more (Baumol, 2005); that is, welfare-enhancing markets include measures such as 'use-it-or-lose-it' contracts, and do not prohibit them as proposed by the Authority under its Option 2 (Electricity Authority, 2021, pg 36 -37).
- efficient price discrimination involves complex considerations that cannot be determined centrally but are discovered in market processes.

2.4 Subsidy-free prices

As an input to its Discussion Paper, the Authority asked Mr Hunt to "estimate the size of any subsidy that NZAS receives under the new supply agreement" (Hunt, 2021, pg 6). Mr Hunt says prices are subsidy-free if they lie between the incremental and stand-alone costs of supplying the relevant service. In support of this statement Mr Hunt cites the Commerce Commission's Input Methodologies Reasons Paper, (2010, para 7.2.5).

The statement referred to by Mr Hunt is in a footnote to the cited paragraph. This footnote refers the reader to Chapter 3 of the Input Methodologies for further discussion. In Chapter 3 the Commerce Commission discusses the incremental cost and stand-alone cost by a single entity supplying two or more services in combination (see for instance, paragraph 3.2.8).

In economic regulation of a monopoly, a subsidy-free price for a specific service lies between the incremental cost to the entity of providing that service, and the efficient standalone cost of that supply. The standalone cost is usually estimated in regulatory setting from the efficient costs of a hypothetical new entrant.[7]

[7] For a fuller explanation of the application of incremental cost and standalone cost in price setting, (Mayo & Willig, 2018).

Mr Hunt explains that his analysis focussed on whether the price paid by NZAS is below the incremental cost of supply as that would indicate a subsidy is being provided (Hunt, 2021, pg 6). He adopts, as a measure of incremental cost of supply, the cost of meeting additional supply from thermal power stations in the North Island. If the price charged to NZAS is below the cost of thermal generation in the North Island, Mr Hunt concludes that the difference is a subsidy.

There is no economic validity to Mr Hunt's approach. At best, his comparator of the cost of thermal generation in the North Island might be some proxy of standalone cost—that is, the amount the smelter might have to pay for supply from a hypothetical efficient new entrant. It is not a measure of the incremental cost of supply from Meridian's and Contact's hydro stations.

Mr Hunt's test would imply that an efficient new entrant should not enter into a contract at a price below the cost of the highest cost existing supplier, which is approximated by thermal generation cost, as that lower price would be a subsidy. Mr Hunt's view of a price subsidy would make it very difficult for the Authority to pursue its objective of promoting competition for the long-term benefit of consumers.

There is therefore no economic foundation to the Authority's claims that generators have subsidised the price of electricity to the smelter (Electricity Authority, 2021, p. ii).

2.5 Efficient prices

The Authority claims that the Tiwai contracts (which result in other consumers paying more than they would had the smelter closed production) distort signals for investment in generation and electrification, thereby compromising the efficient transition to a low emissions economy (Electricity Authority, 2021, p. ii). The Authority makes these claims from an analysis of static efficiency; however, the implications it draws for dynamic efficiency from its static analysis are incorrect.

Standard welfare economics provides economists with tests for whether marginal prices are (Pareto or statically) efficient—that is, where no consumer could be made better off without making some other consumer worse off. Marginal pricing refers to the price of an additional unit of service. A *necessary* condition for Pareto efficiency is that the *marginal willingness to pay* must equal *marginal cost*.

Each of the italicized terms has a formal meaning in economics. The phrase, 'marginal willingness to pay', refers to the willingness of the customer to pay for an incremental unit of the service. 'Marginal cost" refers to the cost of providing an incremental unit of the service. A 'necessary' condition means that the condition must hold for the situation to be economically efficient, but the condition may hold in circumstances without implying that the situation is efficient.

The static efficiency requirement—that the price for the marginal unit equate marginal willingness to pay and marginal cost—does not mean that every unit of the good or service be sold at marginal cost. This is a key conclusion from the literature on efficient price discrimination discussed above. Consider, for example, the illustration provided by Varian (1996). In this example, a supplier offers a service that has fixed costs of $10 and marginal costs of $2 per unit supplied. Two customers each want to purchase one unit of the service. Customer A is willing to pay $12 for the service; customer B is willing to pay $5.

A number of pricing scenarios are possible, including:

a) The service could be sold at marginal cost—in this case the producer would sell the service at a price of $2 to each of the customers, but would fail to recover its fixed costs, which is not economically viable.

b) The service could be sold at a flat price—in this case the supplier would find it most profitable to set a price of $12 and sell only to customer A. Customer B would not purchase the service even though it would be willing to pay a price that covers marginal cost.

c) Different prices could be charged to A and B—the supplier could set a price of $12 for customer A and $2 for customer B. Each customer would be served, and the supplier would be able to cover its full costs.

The variation in prices under scenario (c) is consistent with the condition for static efficiency, as the price at the margin equals the marginal willingness of customer B to pay. As customer A pays a price less than its willingness to pay, resulting in a consumer surplus, the pricing structure also meets the requirements of efficient price discrimination.

Price discrimination of this nature is ubiquitous in industries that exhibit large fixed costs; airlines, for example, operate sophisticated yield management systems whereby two passengers flying at the same time and in the same cabin class may have paid very different prices for their tickets. According to (Geradin & Petit, 2006):

> A key insight of economics is that price discrimination is most likely to expand output where the seller has declining average total costs. Expanding output through price discrimination is an essential strategy for firms facing problems of fixed cost recovery. Price discrimination allows firms facing large fixed costs (in practice all firms that make substantial investments) to expand their output and thus spread fixed costs over a large number of units.

3. The Authority's testing for inefficient price discrimination

3.1 The Authority observed output increasing from differentiated pricing

The Authority uses the 'Tiwai contracts' to illustrate its view of inefficient price discrimination (Electricity Authority, 2021, Appendix B). These contracts are a curious example for the Authority to select in its Discussion Paper for two reasons.

First, an increase in aluminium prices since the contracts were finalised means the contracts resulted in an increase in economic welfare relative to a scenario in which the smelter hypothetically exited, under the Authority's own approach to estimating economic impacts.[8] The Authority, in effect, is proposing regulatory options in its Discussion Paper that would have precluded welfare enhancing contracts on the basis that it (the Authority) would not have foreseen that benefit when it applied its proposed tests and precluded the contract.

Second, the Tiwai contracts led to a large increase in electricity output relative to the Authority's counterfactual scenario of the smelter exiting New Zealand, as illustrated by the Authority in its figure 7, scenario (Electricity Authority, 2021, pg 55). The Authority's conclusion (supported by its peer reviewers) that this increase in output would have been anticipated to reduce welfare is clearly at odds with the expectation from the economics literature (e.g., Varian's touchstone discussed above).

One of two possibilities arise:

- the received economics literature is wrong, and the Authority has shown that price discrimination can expand output and be welfare reducing
- the Authority is mistaken.

In the following section, we show the Authority wrongly interprets its own analysis and Appendix B of its discussion paper provides an example of welfare enhancing price discrimination, not inefficient price discrimination as the Authority concludes.

3.2 Measuring an increase in total welfare

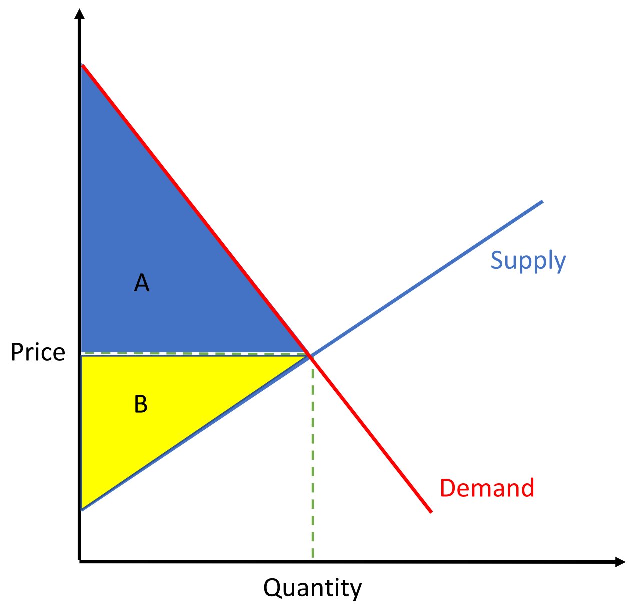
(Samuelson & Nordhaus, 1989) defined economics as the study of how societies use scarce resources to produce valuable commodities and distribute them among different people. Economists measure the total wellbeing of all participants in a market from the sum of consumer surplus and producer surplus.

[8] This means the willingness-to-pay by the smelter is likely to be higher now compared to what is assumed under the Authority's calculation of overall efficiency gain (loss).

Consumer surplus is the difference between the price a consumer is willing to pay for a good and the price they actually pay. In a textbook supply and demand diagram, consumer surplus is measured as the area above the market price and below the demand curve—the blue area A in Figure 1 below.

Producer surplus represents the difference between the price a seller receives for a good and the price they would be prepared to sell at. In a textbook supply and demand diagram, producer surplus is measured as the area above the supply curve and below the market price—the yellow area B in Figure 1 below.

Figure 1 Total welfare = producer plus consumer surplus



Hence, price discrimination that increases the sum of the producer and consumer surplus increases total welfare and therefore is efficiency-enhancing. An increase in the sum of producer and consumer surplus might result, for example, from a pricing strategy that shifts either (or both) the demand curve or the supply curve to the right in Figure 1.

3.3 Analysis undertaken by Authority

In its analysis set out in Appendix B of its Discussion Document, the Authority presents a series of stylized supply and demand diagrams.

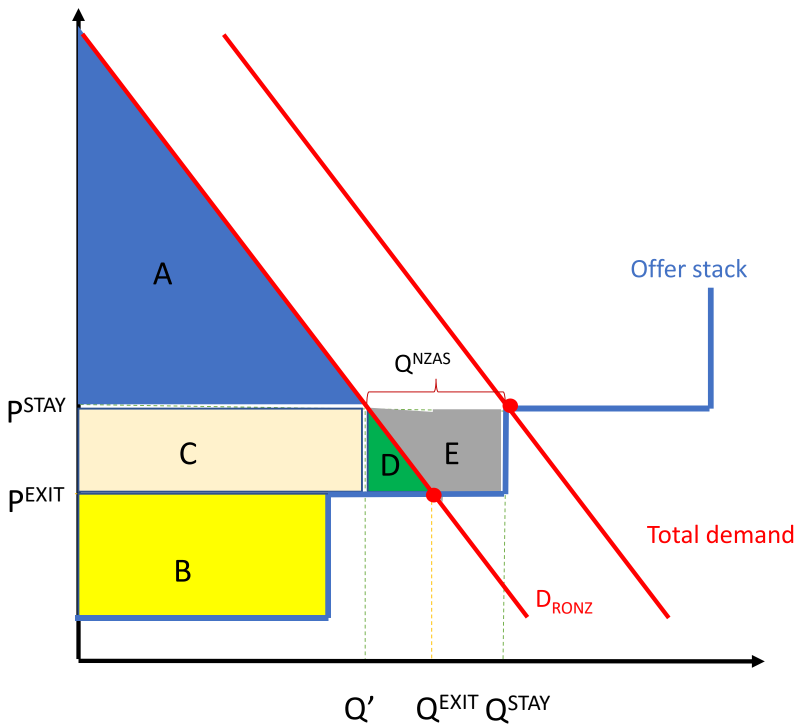
The Authority's analysis makes a number of simplifying assumptions. It assumes a normal year, and hence does not account for the benefit of load reduction provided by the smelter nor the prospect that additional high-cost generation might need to be run to maintain supply. Other attributes of the contracts and spot markets that are important to assessing the costs and benefits for New Zealand are not considered by the Authority (notably transmission charges paid by the smelter and locational pricing are excluded from the analysis).

The effect the Authority seeks to illustrate in its figures 7 to 13 is the impact on a market when commercial entities enter agreements at different prices. The Tiwai contracts give rise to this effect in the Authority's characterisation as:

- the quantity and price for electricity supplied to the smelter is determined under a contract-for-difference (CFD)[9]
- the quantity and price for electricity supplied to the 'rest of New Zealand' (R_{ONZ}) is determined by the intersection of the supply and demand curve after allowing for the supply to Tiwai.[10]

Figure 2 reproduces figure 7 from the Authority's Appendix B, with some areas coloured to assist in describing changes in consumer and producer surplus. As with the Authority's chart, the market price is shown as P^{EXIT} in the scenario the smelter exits, and at P^{STAY} in the scenario that the smelter remains. P^{STAY} is higher than P^{EXIT}, because a quantity of electricity, Q^{NZAS}, is supplied to the smelter (that is, supplied under the CFD) and hence higher cost generation is run to meet the demand by the rest of New Zealand, labelled R_{ONZ}. Because of the higher price, R_{ONZ} demands less electricity in the scenario where the smelter stays, consuming Q' rather than Q^{EXIT}.

Figure 2 Change in producer and consumer surplus



As with the Authority's diagrams, the supply curve is shown as steps, rather than a straight line, to represent the step changes in the operating cost of electricity generation plant as demand increases.

The Authority locates the exit price and the stay price on an unchanged offer curve, marked with red dots in Figure 2. This representation is incorrect as the Authority accepts some water would be

[9] The economic effect of a contract-for-difference is that the parties pay and receive the price negotiated in the contract for the quantity specified in contract.

[10] In reality, there would be many sub-markets (under the Authority's characterisation) as most wholesale electricity sales are governed by CFDs and other forms of contracts.

stranded—that is, the water could not have been used for generation—had the smelter exited. Hence, the offer curve under the exit scenario cannot be the same as the offer curve for stay. The likely implication (within the simplified structure of the Authority's analysis) is that the exit price would have been closer to the stay price, had the Authority correctly adjusted the offer curves under the exit and stay scenarios respectively.

The following areas of producer and consumer surplus are coloured in Figure 2:

- the blue triangle, labelled A, shows consumer surplus (this is the area above P^{STAY} and below the demand curve); this area A is unchanged whether the smelter stays or exits and therefore need not be considered further in an efficiency analysis
- the yellow rectangle, labelled B, shows producer surplus (this is the area below the P^{EXIT} and above the supply curve); this area is impacted by the lower willingness to pay by the smelter, as discussed below
- a loss in consumer surplus, because demand is 'crowded out' by the higher price, is represented by the green triangle and labelled D[11]
- an increase in producer surplus, coloured grey and labelled E; this area of producer surplus was excluded from the Authority's calculation as discussed below
- an increase in producer surplus matched by a decrease in consumer surplus, shown as the light yellow rectangle, labelled C, between P^{STAY} and P^{EXIT}; as the decrease in consumer surplus is matched by an increase in producer surplus, the total surplus illustrated by this area is unchanged and need not be considered further in an efficiency analysis.

3.4 Changes in producer and consumer surplus

We comment on four areas of the Authority's presentation of changes in producer and consumer surplus.

First, not shown on Figure 2, but accepted in the Authority's analysis, is additional producer surplus from using water for generation in the smelter stays scenario, when that water would have been stranded in the exit scenario. This additional value is measured by the volume of generation from stranded water multiplied by the difference between P^{STAY} and the marginal operating cost of hydro generation plant, P^{MC}.

Second, the Authority excludes from its analysis the producer surplus marked as E on Figure 2. This is not a correct treatment. Sufficient generation is dispatched to meet total demand, identified as Q^{STAY} in Figure 2. Generation that is dispatched is paid P^{STAY}. The area above the offer curve and below the market price is additional producer surplus—the producer surplus created from the increase in output.

[11] This triangle is often referred to as the 'deadweight loss', or Harberger triangle. The loss is a 'deadweight' because no-one benefits from the price distortion; Arnold Harberger first defined how to quantify the loss for price distortions due to taxation, see (Harberger, 1964).

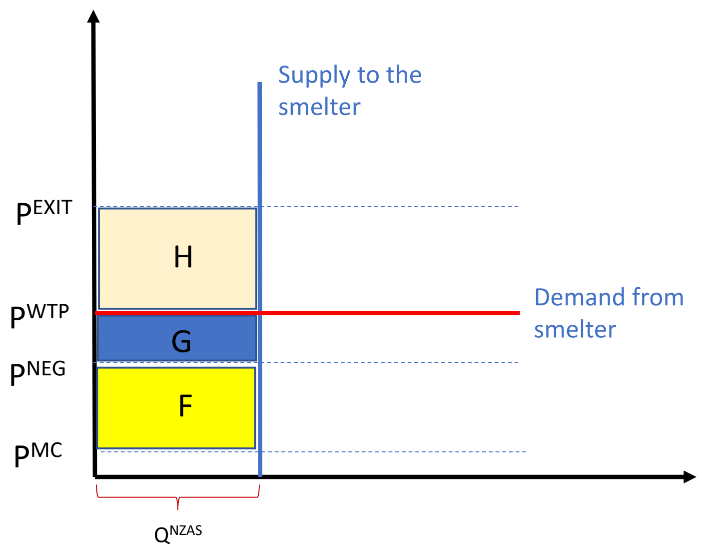
Third, the chart as drawn overstates the producer surplus, and understates the consumer surplus, from the supply to the smelter. To help illustrate these impacts, Figure 3 Change in producer and consumer surplus – smelter

shows prices and quantities in the supply of electricity to the smelter.

In Figure 3 Change in producer and consumer surplus – smelter

, P^{WTP} is the price the smelter is assumed to be willing to pay. P^{NEG} is the price negotiated between the smelter and the generators; that is, the CFD price. P^{MC} is operating costs to generators in meeting the electricity supplied to the smelter. As the price and quantity in this sub-market are set by the CFD, the demand curve is horizontal and the supply curve is vertical.

Figure 3 Change in producer and consumer surplus – smelter



The area of consumer and producer surplus from the supply to the smelter shown in Figure 3 Change in producer and consumer surplus – smelter

are:

the yellow rectangle, labelled F, in Figure 3 Change in producer and consumer surplus – smelter

- shows the producer surplus from the electricity supplied to the smelter; this an area above the cost to the generator of producing the output (P^{MC}) and below the sale price negotiated in the CFD, P^{NEG}. This area is already encapsulated in Figure 2 and need not be considered further
- the blue rectangle, labelled G, shows the consumer surplus from the electricity supplied to the smelter; this is the area above the price paid by the smelter, P^{NEG}, and below the smelter's willingness to pay, P^{WTP}; this surplus is not shown in Figure 2 because it is located in the area below the market price, and therefore needs to be accounted for explicitly in an assessment of efficiency changes

- the light yellow rectangle, labelled H, shows the opportunity cost, or lost producer surplus, incurred by generators in supplying the smelter; this areas equals the benefit the producers would have received by using the same water to supply R_{ONZ} in the exit scenario.

Finally, the Authority includes in its production cost estimates an allowance for transmission charges (hence, the producer surplus from electricity generated using stranded water is reduced by an allowance for additional payment of transmission costs). However, in the exit scenario, the Authority makes no allowance for the approximately $57 million per annum paid by the smelter for the cost of transmission, which if Transpower is to meet its revenue requirement, would be allocated to other transmission customers in the exit scenario.

3.5 Quantification of efficiency gains using the Authority's assumptions

Having identified the changes in producer and consumer surplus, we can quantify these changes using the same assumptions adopted by the Authority. These assumptions were set out by the Authority in its Discussion Paper and in the appendix to Mr Duignan's review. We list the assumptions in our Appendix B. Our calculations are shown in Table 1. In Appendix B we reproduce the sensitivity analysis presented by the Authority in its table 2.

Table 1 Change in total producer and consumer surplus $ million

Authority's table 2 assumptions	**Formulae**	**Lower bound Value**	**Upper bound**
Element			
Gain in producer surplus on additional volumes	$(Q^{STAY}-Q') \times (P^{STAY}-P^{EXIT})-(P^{STAY}-P^{EXIT}) \times (Q^{EXIT}-Q')/2$	92.11	8.10
Producer surplus on stranded water	$(P^{STAY}-P^{MC}) \times Q_{stranded\ water}$	$ 100.56	$ 100.56
Smelter consumer surplus	$(P^{WTP}-P^{NEG}) \times Q_{NZAS}$	$ 50.11	$ 50.11
Total gain in surplus		$ 242.79	$ 158.77
Less			
Opportunity cost on sales to smelter	$(P^{EXIT}-P^{NEG}) \times Q_{NZAS}$	-175.38	-175.38
Net efficiency gain		$ 67.41	-$ 16.60
Consistent treatment of transmission costs		$ 57.00	$ 57.00
Net efficiency on consistent application of Authority's approach		**$ 124.41**	**$ 40.40**

Hence, rather than an efficiency loss of $54 million to $117 million as arrived at by the Authority (Electricity Authority, 2021, pg 27),[12] the better measure of the total efficiency gains from the Tiwai contracts (relative to the exit scenario) is around $40 million to $120 million per annum, applying the Authority's assumptions consistently. This result is consistent with the expected outcome from output enhancing price discrimination.

[12] As we note in footnote 8, the willingness-to-pay by the smelter is likely to be higher now compared to what is assumed under the Authority's calculation of overall efficiency gain (loss). This means that if P^{WTP} is now $70 rather than $45, as assumed in the Discussion Paper, the Authority's analysis would result in efficiency gains between $6 million and $68 million.

The Tiwai contracts do result in a significant net gain to producer surplus under the Authority's characterisation of the contracts and its assumptions. In of itself, this observation is nothing more than the 'invisible hand of the market' at work;[13] generators were incentivised to negotiate a contract that resulted in a net benefit to New Zealand.

[13] The invisible hand is an economic concept that describes the social benefits and public good brought about by individuals acting in their own self-interests. The concept was first introduced by Adam Smith in The Theory of Moral Sentiments, written in 1759.

4. Conclusion

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.

There appear to be two sources of error in the Authority's approach:

- The Authority did not arrive at a clear problem definition—its descriptions of the problem differ from its reviewers and the reviewers differ among themselves; without a clear problem definition, there was no solid foundation for its analysis
- The analysis undertaken by the Authority were not grounded in the extensive literature on the issue it was investigating—price discrimination. The tests from the literature are not mentioned at all, and the Authority seemed unaware that it was arriving at conclusions at odds with the relevant literature.

There is no economic foundation to the Authority's claims that generators have subsidised the price of electricity to the smelter. The Authority's claim was based on an analysis that compared the price paid under a commercially agreed contract by a low-cost supplier (hydro generation), with the cost of the highest cost existing supplier (approximated by thermal generation). The Authority's definition of a subsidy would imply that an efficient new entrant should not enter into a contract at prices below that charged by the incumbents; a test that would make it very difficult for the Authority to pursue its objective of promoting competition for the long-term benefit of consumers.

The Tiwai contracts do result in a significant net gain to producer surplus under the Authority's characterisation of the contracts and its assumptions. In of itself, this observation is nothing more than the 'invisible hand of the market' at work; generators were incentivised to negotiate a contract that resulted in a net benefit to New Zealand.

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Appendix A Simple model of price discrimination

Inefficient price discrimination

We present here a simple theoretical model of a scenario where price discrimination strategy may give rise to inefficiencies, measured as a loss of total surplus, compared to the adoption of uniform price. Using an example from (Viscusi, Vernon, & Harrington, 2001), let us assume there are two types of customers in the market (A and B), with their demand curves expressed respectively as:

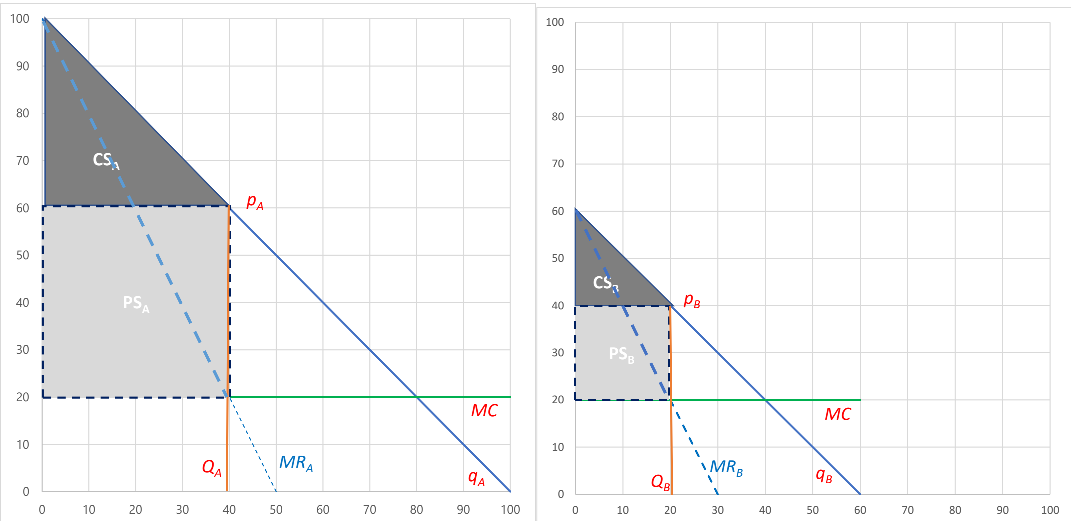
$$q_A = 100 - p_A$$

$$q_B = 60 - p_B$$

We further assume, for simplicity, that the marginal cost (MC) is constant at $20. Under normal profit-maximisation solution, the producer sets the marginal revenue for customer A (MR_A) equal to the marginal revenue from customer B (MR_B), and both equal to the marginal cost (*MC*). Given the above demand curves for customers A and B, the profit-maximisation solution requires to sell 40 units to customer A at a price of $60 per unit and 20 units to customer B at a price of $40 per unit.

The higher price is charged to the customer with lower elasticity of demand.[14] As (Viscusi, Vernon, & Harrington, 2001) note, if the elasticities were not different, the prices would be the same and discrimination would not be profitable.

The graphs below show the demand and marginal revenue curves[15] respectively for customers A (left-hand side) and B (right-hand side), with the corresponding total surplus, as a sum of consumer surplus (CS) and producer surplus (PS).[16]



[14] The elasticity of demand for customer A is 1.5, while the elasticity of demand for customer B is 2.

[15] MR_A = 100-2q_A and MR_B = 60-2q_B

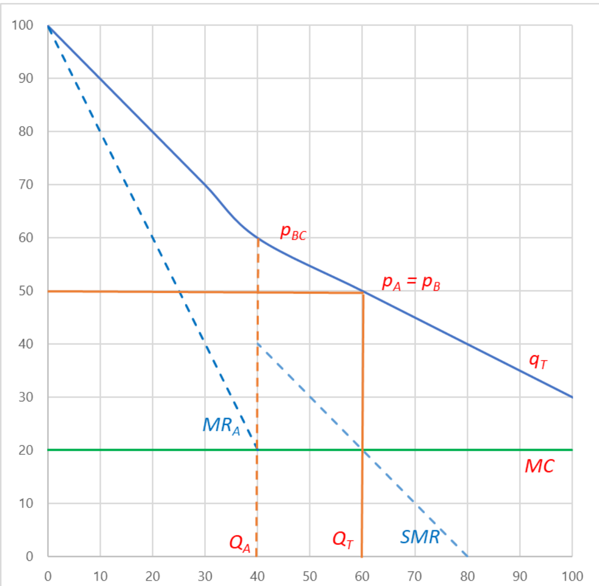
[16] Consumer surplus is represented by the triangle CS and producer surplus is represented by the square PS.

Table below shows the breakdown of consumer surplus (CS), producer surplus (PS) and total surplus (TS) per each customer, under the price discrimination strategy adopted by the producer:

	Customer A	**Customer B**
Price	P_A = $60	P_B = $40
Quantity consumed by each customer	$Q_A = 40$	$Q_B = 20$
TOTAL quantity consumed	$Q_T = 60$	
Consumer surplus	CS_A = $800	CS_B = $200
Producer surplus	PS_A = $1,600	PS_B = $400
Total surplus	TS = $3,000	

Total surplus (TS) under the price discrimination strategy is therefore $3,000.

Let us now assume that the supplier is not allowed to price-discriminate between the two customers. In this case, the supplier offers the same product to both customers at uniform price of $50 per unit sold. The uniform price is obtained at intersection of the simple marginal revenue (SMR)[17] curve associated with the total demand curve (q_T) and the marginal cost MC, as illustrated in the graph below.



Given the uniform price is set below the choke price of $60 for customer B ($p_{BC}$), the customer B is willing to buy 10 units. At the same time, the customer A is willing to buy 50 units at the uniform price of $50.

[17] See footnote 53 in (Viscusi, Vernon, & Harrington, 2001) and pages 196-197 in (Robinson, 1969).

The graphs below show the demand curves respectively for customers A (left-hand side) and B (right-hand side), with the corresponding total surplus, as a sum of consumer surplus (CS) and producer surplus (PS), under this uniform price scenario.

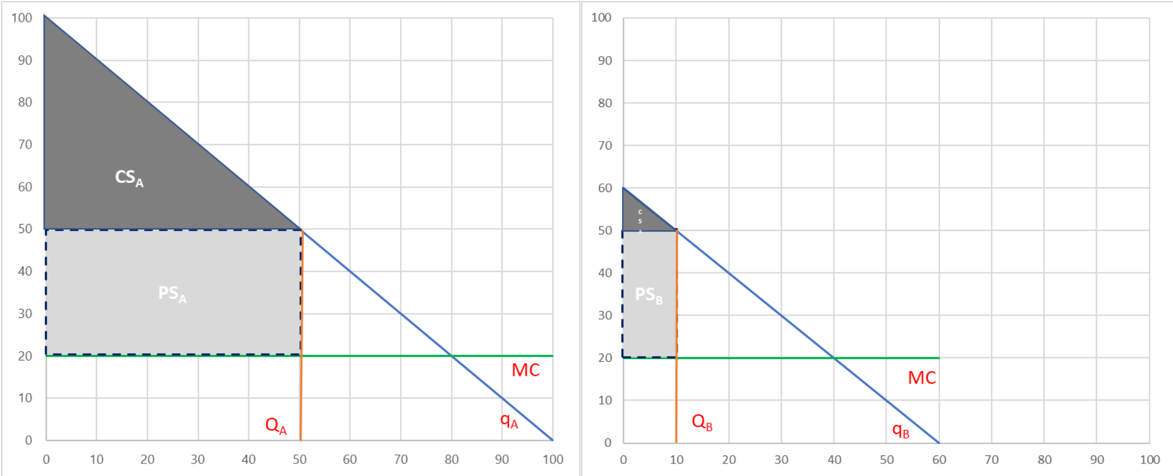


Table below shows the breakdown consumer surplus, producer surplus and total surplus per each customer, under the uniform price scenario:

	Customer A	**Customer B**
Price	P_A = \$50	P_B = \$50
Quantity consumed by each customer	Q_A = 50	Q_B = 10
TOTAL quantity consumed	Q_T = 60	
Consumer surplus	CS_A = \$1,250	CS_B = \$50
Producer surplus	PS_A = \$1,500	PS_B = \$300
Total surplus	TS = \$3,100	

The analysis above shows that total surplus under the price discrimination scenario is lower than the total surplus under the uniform price scenario. This means that the price discrimination strategy, in this case, would give rise to inefficiencies (i.e., reduction of \$100 in total surplus).

Efficient price discrimination

We now assume that the demand from customer B is smaller than before, with the choke price for customer B (p_{BC}) at \$40, and it is represented by the following demand curve:

$$q_B = 40 - p_B$$

Under normal profit-maximisation solution, the producer sets again the marginal revenue for customer A (MR_A) equal to the marginal revenue from customer B (MR_B), and both equal to the marginal cost (*MC*). Given the change in demand curve for customer B, the profit-maximisation solution requires to sell 40 units to customer A at a price of $60 per unit and 10 units to customer B at a price of $30 per unit. The higher price is again charged to the customer with lower elasticity of demand.[18]

The graphs below show the demand and marginal revenue curves[19] respectively for customers A (left-hand side) and B (right-hand side), with the corresponding total surplus, as a sum of consumer surplus (CS) and producer surplus (PS).

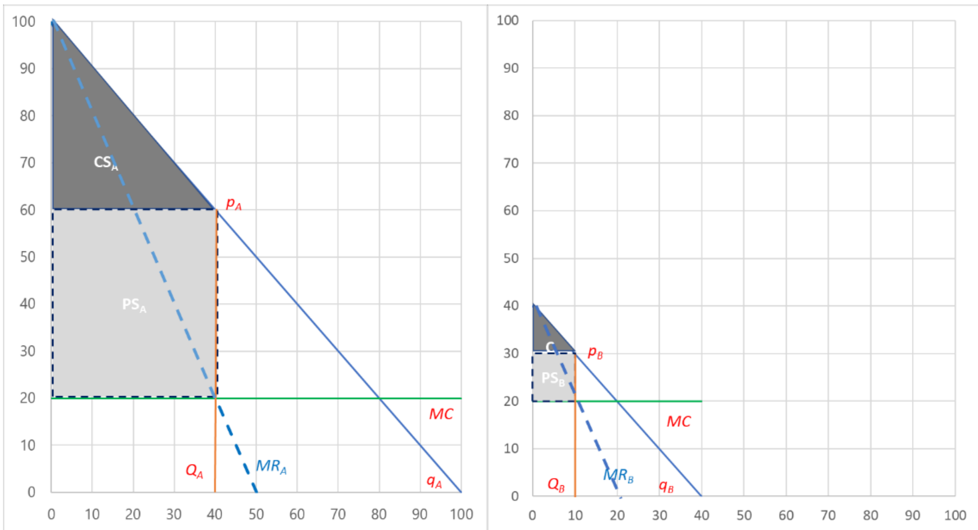
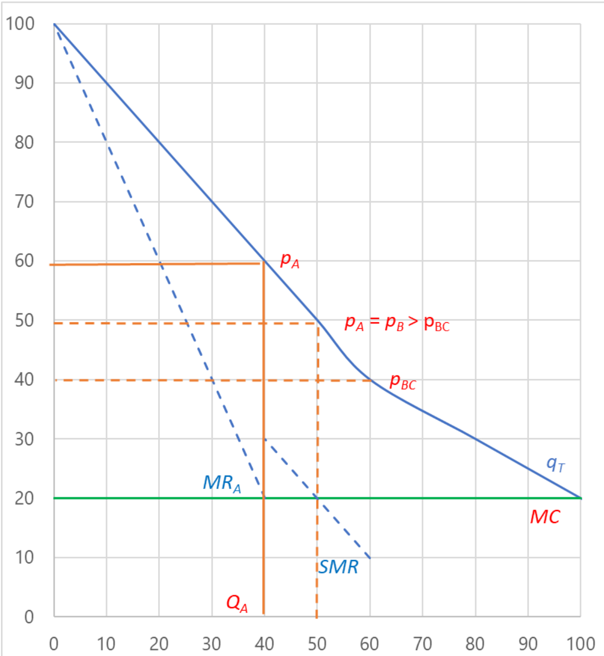


Table below shows the breakdown of consumer surplus, producer surplus and total surplus per each customer, under the price discrimination scenario:

	Customer A	**Customer B**
Price	P_A = \$60	P_B = \$30
Quantity consumed by each customer	Q_A = 40	Q_B = 10
TOTAL quantity consumed	Q_T = 60	
Consumer surplus	CS_A = 800	CS_B = 50
Producer surplus	PS_A = 1,600	PS_B = 100
Total surplus	TS = 2,550	

18 The elasticity of demand for customer A is 1.5, while the elasticity of demand for customer B is now 3.
19 $MR_A = 100\text{-}2q_A$ and $MR_B = 40\text{-}2q_B$

Let us now assume that the supplier is not allowed to price-discriminate between the two customers. In this case, the supplier is prepared to offer the same product to both customers at uniform price of \$50 per unit sold. This uniform price is obtained at intersection of the simple marginal revenue (SMR)[20] curve associated with the total demand curve (q_T) and the marginal cost MC, as illustrated in the graph below.



However, as shown on the graph above, this uniform price sits above the choke price for customer B. This means that the customer B will exit the market under the uniform price, so the equilibrium price in the market is now determined solely by the demand curve from customer A. Given the demand curve from customer A, and therefore the marginal revenue MR_A, the profit-maximisation solution requires to sell 40 units to customer A at a price of \$60 per unit.

Table below shows the breakdown consumer surplus, producer surplus and total surplus under the uniform price scenario:

	Customer A	**Customer B**
Price	P_A = \$60	P_B = \$60
Quantity consumed by each customer	$Q_A = 40$	$Q_B = 0$
TOTAL quantity consumed	$Q_T = 40$	
Consumer surplus	CS_A = \$800	$CS_B = 0$

[20] Given the demand curves for customers A and B, the marginal revenue associated with total demand is now $MR = 7 - Q_T$

Producer surplus	PS_A = $1,600	PS_B = 0
Total surplus	TS = $2,400	

The above scenario shows that by adopting price discrimination strategy, the producer is able to expand the output, and increase the total welfare by $150 (from $2,400 under uniform price to $2,550 under price discrimination).

Price discrimination, in this case, gives rise to efficiencies, compared to the uniform price.

Appendix B Quantification of producer and consumer surplus

Assumptions adopted from the Discussion Document and Mr Duignan's review:

Table 2 Assumptions and area calculations

Parameter	Assumed value
P^{STAY}	\$90 / MWh
P^{EXIT}	\$70 / MWh
P^{WTP}	\$45 /MWh
P^{NEG}	\$35 /MWh
P^{MC}	\$ 8 /MWh
Q^{NZAS}	5.011 TWh = 572 MW x 8,760 / 1,000,000
Q^{EXIT}	37.264 TWh = 36.454 TWh x (1+(-0.1) x (\$70-\$90)/\$90)
Q'	36.454 TWh
Area C (Figure 2)	(P^{STAY}-P^{EXIT}) x Q' = (\$90-\$70) x 36.454 TWh = \$729.08 million
Area D (Figure 2)	(Q^{EXIT}-Q') x (P^{STAY}-P^{EXIT})/2 = (37.264 TWh - 36.454 TWh) x (\$90-\$70)/2 = \$8.10 million

Table 3 Reproducing Authority sensitivity analysis from its Table 2

	Net efficiency gain (lower bound)	Net efficiency gain (upper bound)
Baseline	**124.41**	**40.40**
Exit price = \$60/MWh	214.50	100.63
Stay price = \$80/MWh	67.86	22.31
RoNZ Elasticity ε= -0.05	128.46	36.35
Average stranded water = 120 MW	110.04	26.03
WTP = \$55/MWh	174.52	90.50

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independence, integrity and objectivity

Regulatory uncertainty and long-term harm to consumers

Part of the response to the Electricity Authority Market Monitoring Review

Kieran Murray and Veronica Jacobsen

22 December 2021

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Appendices

Executive summary

The Electricity Authority's review into the wholesale electricity market is consulting on a number of policy options intended to ensure that future contracts between electricity generators and large consumers are efficient. The review finds that New Zealand Aluminium Smelter Limited at Tiwai Point was offered a low electricity price by Meridian Energy New Zealand to encourage it to stay in New Zealand and this may have resulted in other consumers having to pay more. Although the analysis and conclusions are centred on this contract, the Authority emphasises that it is concerned to address future potential outcomes that could be inefficient.

The policy options identified span the range from retaining the status quo, various amendments to the Electricity Industry Participation Code to far-reaching structural or financial separation outside the remit of the Authority. The Authority seeks additional options from submitters in addition to the ones it lists in the review for comment. It provides a brief outline of the possible changes to the Code, together with some pros and cons. However, it provides no detail on the structural or financial separation options that would need to be taken forward by other government entities.

The New Zealand electricity sector is vulnerable to regulatory uncertainty. The sector is characterised by large, long-lived, location-specific, irreversible investments in fixed infrastructure that require long lead times in construction. Changeable and unpredictable regulation over the investment cycle can result in under-investment, especially where there are high sunk costs. Also, small economies such as New Zealand are characterised by high industrial concentration levels, high entry barriers, and suboptimal levels of production. These features create a tension between the efficient scale of production and competition and make the costs of policy error high. In addition, electricity is consumed by almost everyone and is an essential input to industry, making it inherently political, as consumers and politicians alike take an interest in how it is regulated.

The Authority does not acknowledge that the review creates considerable and prolonged regulatory uncertainty for the sector that will have a potential negative effect on firms' investment decisions. The extensive literature on regulatory uncertainty shows that in an uncertain and unpredictable policy environment firms delay investment if they can, particularly if the investment is irreversible, or make suboptimal investments. The higher the uncertainty, the greater the value of delay and the more cautious firms become. Regulatory intervention, or the threat of intervention, that creates uncertainty results in underinvestment, with negative effects on long-run industry performance and flow-on effects of deterioration in services for consumers.

The Authority has not followed good regulatory practice in its analysis and development of options for change, creating more uncertainty than is inevitable in policy changes. It is not clear that the Authority has in fact determined that there is a problem substantial enough to warrant intervention. The proposed changes to the Code are underdeveloped and no details are provided for the far-reaching structural and financial separation options. The Authority's proposals create considerable regulatory uncertainty for the sector that threatens both the value of existing investments and the potential payoff to future investments. It also creates opportunity for rent-seeking behaviour by third parties. Until the uncertainty is resolved, firms' attention will be diverted from business as usual and investment activity is likely to be put on hold.

1. Introduction

The Electricity Authority (the Authority) is authorised to undertake inquiries into any matter related to the electricity industry and has recently published a review *Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market since the Pohokura Outage in 2018* (the review) into competition in the wholesale electricity market (Electricity Authority, 2021d). A key finding of the review is that New Zealand Aluminium Smelter Limited at Tiwai Point was offered a low electricity price by Meridian Energy New Zealand (Meridian) to encourage it to stay in New Zealand and, in the Authority's view, this may have resulted in other consumers having to pay more. The Authority notes that its analysis of the Tiwai contracts is not part of any compliance investigation and that the Commerce Commission has decided not to undertake an enquiry under the Commerce Act.

The Authority's initial response to the review *Inefficient price discrimination in the wholesale electricity market – Issues and options: An Initial Response to the Wholesale Market Review* (the response) identifies possible options to ensure that similar, future contracts between electricity generators and large consumers are efficient (Electricity Authority, 2021b). The options are explored prematurely given the lack of evidence of a problem and ongoing consultation on the supposed problem identified. The policy options identified span the range from retaining the status quo, various amendments to the Electricity Industry Participation Code (2010) (the Code) to options that require implementation through other branches of government, including legislative change to limit the size of generators, to split the Manapōuri Power Station (Manapōuri) from Meridian's other assets, and to require virtual asset swaps. The response seeks further options in public submissions.

The extensive literature on regulatory uncertainty, also known as policy uncertainty or economic policy uncertainty (EPU), concludes that an uncertain and unpredictable policy environment affects firms' investment decisions with flow-on effects on consumers. The electricity sector is no exception.

The policy process followed by the Authority in developing its proposals for consultation itself creates more regulatory uncertainty than is inevitable in policy changes. The problem definition is tentative at best and itself subject to consultation, and the number, scope and underdeveloped nature of the Authority's proposals create considerable regulatory uncertainty for the sector about the future policy environment, that threatens both the value of existing investments and the potential payoff to future investments.

This report proceeds as follows:

Section 2 identifies the characteristics of the electricity sector that makes it susceptible to both politicisation and regulatory uncertainty and outlines New Zealand's reforms of the sector.

Section 3 presents the literature on the impact of regulatory uncertainty on firm's investment decisions and the flow-on effects on consumers.

Section 4 assesses the policy process followed by the Authority against principles of best practice regulation and discusses its shortcomings as sources of regulatory uncertainty that are likely to have a negative impact on investment in the sector.

Section 5 concludes.

2. The New Zealand context

The electricity sector in New Zealand has a number of characteristics that make regulatory changes particularly challenging for it. The nature of the sector, with large, long-lived investments in fixed infrastructure providing a service which is consumed by and necessary to almost everyone, makes it susceptible to regulatory uncertainty that affects its investment decisions and to politicisation that gives consumers and politicians alike an interest in how it is regulated. Also, the small size of the economy creates a tension between efficient production and competition and makes the costs of policy error high.

Electricity sector

The electricity sector is particularly vulnerable to regulatory uncertainty and politicisation. It is characterised by long-lived, location-specific generation and distribution assets with few alternative uses. It displays significant economies of both scale and scope. The economies of scale imply that there will be few suppliers in each locality. Investments in the sector are large-scale, lumpy and demand significant lead times in construction.[1] Electricity is massively consumed, is critical to the operation of the economy and may be regarded as an essential service. The result is that consumers, politicians and interest groups are all sensitive to price and service levels. These features have traditionally raised the need for governmental regulation.

Massive consumption, economies of scale and sunk investments also make the electricity sector inherently susceptible to political interest and third party opportunism in regulatory processes (Evans & Meade, 2005; Spiller, 2010). Equity considerations of regulatory changes are unavoidable giving rise to ongoing political interest and ever-present political input into the regulation of the sector. Policy or administrative changes (or the threat of changes) that alter the implied contract between the sector and the regulator can reduce the value of firm's sunk investment. Governments can face incentives to expropriate the value of sunk assets if the direct costs (such as reputation loss vis-à-vis other regulated industries or lack of future investments in other sectors) are small compared to the short-term benefits of such action (such as achieving re-election by reducing prices paid by consumers), and if the indirect institutional costs (such as not following the proper administrative procedures) are not too large (Spiller, 1996).

In the face of politicisation and regulatory uncertainty firms will take actions to protect their investments. In particular, they will delay investment, require higher returns from any investments they do make to take account of the risks, invest in less specific assets and invest less in innovation. These effects are discussed further in section 3.

[1] The growth in distributed energy resources is unlikely to eliminate the need for investment at scale in the medium term.

Small, open economy

New Zealand is a small, open economy, and leading economists, including Nobel Laureate Michael Spence, have long recognised the effects of the small size of a domestic economy on the economic characteristics and performance of markets. The fundamental structural traits of small economies are so pronounced they belong to a "different class of market economies" (Caves et al., 1980, p. 5). There are several characteristics of small market economies like New Zealand that have implications for policy making.

First, small economies are characterised by high industrial concentration levels, high entry barriers, and suboptimal levels of production.[2][3] These features are explicitly recognised in the Regulatory Charter for New Zealand's competition system (MBIE, 2018a, p. 7). These economic features create a basic tension between productive efficiency and competitive conditions—if a given number of firms can operate efficiently in a market of a certain size, then productive efficiency requires the market contain only this number of firms.

This basic tension means market studies in small economies should give greater weight to long-term dynamic considerations and recognise that high market concentration is often necessary to achieve efficiency (Evans, 2004). However, these welfare benefits may also be adversely affected by higher concentration levels. Finding the right balance in this trade-off inherently involves judgement and requires more complex analysis than that needed in a large economy (where the decision-maker can assume the market is sufficiently large for a number of firms to achieve productively efficient size) (Gal, 2012). Complex decisions involving judgement have a higher probability of error.

Second, the relative costs of a false-positive error in policy-making (overstating harm) in a small market economy are likely to be higher than the costs of 'false negatives' (failing to prevent an activity that harms consumers). The relative price paid by a small economy for a false-positive error is higher than that paid by a large economy, because in large economies the 'invisible hand of markets'[4] has more corrective power, given the size of the market and the number of entities in the market (Gal, 2012).

Third, in small economies, the interdependencies in the interests of various stakeholders are likely to be more significantly affected by a regulatory intervention. Hence, the "risk of costly interest-group-affected industrial policy in the guise of competition law becomes high" (Gal, 2006, p. 9). This effect is particularly relevant for a sector prone to politicisation and third-party opportunism in policy-making.

This risk of rent-seeking behaviour increases with regulatory uncertainty (Giertz & Mortenson, 2014). When economic policies are uncertain, firms divert resources to lobbying politicians and regulators to obtain more clarity or more favourable policy. Rent-seeking is not confined to firms or industries that

[2] For an explanation of these characteristics and their implications for competition policy, see Gal (2006).

[3] See Evans and Hughes (2003) for discussion of the issues arising from the New Zealand economy's small size, geographic isolation and openness.

[4] The invisible hand is an economic concept that describes the social benefits and public good brought about by individuals acting in their own self-interests. The concept was first introduced by Adam Smith in The Theory of Moral Sentiments, written in 1759.

are threatened by regulatory uncertainty. Rent-seeking is used by firms, who see advantages from the change, to consolidate potentially beneficial policies.

Institutional arrangements

Sound institutions are of primary importance to economic outcomes in any country because they influence incentives and the decisions of firms and individuals, in particular their investments in physical and human capital (North, 1990). North defines institutions as "rules of the game", including formal institutions such as laws and regulations enforced by regulatory bodies. The capability and performance of regulators is therefore intrinsic to the quality of a country's institutions.

Good regulatory practice can be compromised in a number of ways. Regulators are typically subject to information asymmetry; regulated parties know more about their businesses, activities and objectives than the regulator does so the regulator acts on imperfect information. Regulators are subject to lobbying and susceptible to "capture" by the regulated industry – unintentionally acting in its interest rather than the wider good (Stigler, 1971). They can also be subject to political over-reach, when politicians seek to influence their independent decisions. In addition, regulators may lack the capacity and capability to carry out their functions effectively and to a high standard.

Hence, a regulator acting in a manner that increases uncertainty, including failing to recognise that it is making decisions with imperfect information and therefore imposing the costs of error on the community, creates powerful incentives for firms to postpone or reduce investment and hiring. Investment that does occur will require higher rates of return to compensate for increased regulatory risk or will be undertaken from entities well connected 'politically'.

Because of the high cost to society from regulatory uncertainty, reforms to New Zealand's institutions in recent decades sought to reduce erratic and unpredictable changes in policy by providing institutional constraints (Evans et al., 1996, p. 1862). Important examples include the Reserve Bank Act 1989, the Public Finance Act 1989, and the Fiscal Responsibility Act 1994 (Barker et al., 2008). Together, these reforms create constraints to "structure political, economic and social interaction" (North, 1991, p. 97) and thereby determine New Zealand's incentive structure for savings, investment, trade and production. The reforms were supported by policy work to define the attributes of best practice regulation developed by the Treasury (2015a) and applied to the Energy Markets Regulatory Charter (MBIE, 2018b) laid out in Appendix B. A recent careful study concludes the reforms were successful in reducing uncertainty from institutional sources (Ryan, 2020b).

The regulation of New Zealand's electricity sector

The electricity sector was not immune to the 1980s reform agenda that included putting state-owned business activities set on a more commercial footing, and using market-based mechanisms rather than state planning (Evans & Meade, 2005).

The New Zealand electricity market has been subject to a steady succession of ongoing services and structural reforms since the early 1980s, based a number of clear principles including the need for a reliable power pool; financial contracts governing the sale and distribution of energy; competition; the capacity to address market failure when required and providing regulatory certainty for investment; (Beri & O'Reilly, 2017, p. 12).

The creation of the wholesale market, and related measures to open the sector to private investment, was intended to solve several problems that had emerged under the arrangements that prevailed in the 1970s and 1980s including:

- considerable cost overruns from the construction of generation capacity, with these costs met either by consumers or by taxpayers (see Galvin, 1985)
- a lack of price signals and financial incentives for generators and consumers to increase/decrease generation/demand in response to low hydro inflows until the shortage actually existed, and as a result, recurring shortages (Davidson, 1992)
- electricity pricing had become a political rather than an economic exercise[5]
- a desire to replace investment by the government with private investments (Galvin, 1985).

In proposing options that would re-instate centralised control over contract pricing decisions, the Authority appears to have given little weight to experience in New Zealand and elsewhere of such decision processes.

In 2010, the Electricity Commission was abolished, and the Electricity Authority was established. The objectives of Parliament in making this change included (Electricity Industry Bill, explanatory notes, 2009):

- focusing the Authority on a single statutory objective, whereas the Commission had multiple objectives including "fairness" (the Ministerial Electricity Review had concluded fairness was best considered by Ministers)
- improving the Authority's focus on developing the market by reducing the overlap with other government agencies and to take advantage of synergies in performing closely-related functions
- making the Authority independent from government to:
    - provide greater certainty and predictability about how the market will operate
    - reduce incentives for lobbying by industry participants
    - improve investor perceptions about market risk.

[5] Prices were supressed for times and then hiked – prices increased 55% following the 1975 election for example (other significant price increases included, 1954 by 46% and 1959 by 42%).

3. Impact of uncertainty

The Authority does not seem to recognise the potential future impact of its proposals on firms not just in the electricity sector, but also on consumers of electricity.

When firms understand the rules under which they operate and are confident that any unforeseen future rule changes will not be materially adverse, they enjoy an environment conducive to long-term planning and investment. For the electricity sector, with long-lived and irreversible investments for which payoffs accrue over many years, a certain regulatory environment is an important determinant of investment decisions. But regulatory intervention that creates uncertainty deters investment, with negative effects on long-run industry performance and flow-on effects of deterioration in services for consumers.

Threatened, as opposed to actual, regulatory intervention that reduces the value of past private investments or materially affects likely returns from future investments, has additional effects. Firms tend to focus on managing the risks, investing time and resources in rent-seeking behaviour to avoid or ameliorate the impact of the threatened intervention.

There is an extensive literature on regulatory uncertainty, discussed below, that concludes that an uncertain and unpredictable policy environment affects firms' investment decisions. Firms delay investment if they can, particularly if the investment is irreversible, and may hold liquid assets instead or switch to other investments with a lower, but more certain rate of return. The higher the uncertainty, the greater the value of delay and the more cautious firms become. The negative impact of regulatory uncertainty on investment flows through to consumers in terms of reduced service levels, and also has a chilling effect on regulated firms in the wider economy.

Time inconsistent regulation

Firms make investment decisions based on the existing regulatory environment and their expectations of the future policy state, although rules can change and not all future contingencies can be foreseen and factored into investment decisions (Klein et al., 1978; Levy & Spiller, 1994; Williamson, 1975, 1985).

The long-lived nature of electricity investments means that their costs must be recovered over a long period in which the regulatory environment might change. But once an investment is made, it is 'sunk', in the sense that it cannot be removed and used elsewhere or sold at its original cost, making it hard for a firm to exit the sector if the rules change. It will be willing to continue production as long as operating revenues exceed operating costs, since operating costs do not include a return on sunk investments. As a result, the bargaining position of the sector vis-à-vis the government is limited, making it particularly exposed to policy or administrative changes by politicians and regulators (Bergara et al., 1998a; Holburn & Spiller, 2002; Levy & Spiller, 1994). This form of regulatory decision making is often referred to as 'opportunistic' behaviour (the seminal article is Levy & Spiller, 1994).

Such regulatory changes from one period to another are described as time-inconsistent. According to Ergas (2009, p. 153) time consistency issues arise in:

> …situations where a policy that is optimal (from the point of view of the policymaker) ex ante turns out not to be the optimal policy ex post. If the policymaker cannot commit to a policy, it may then find itself wanting to change its policy ex post (say, after a regulated firm has made an irreversible investment decision), regardless of what it promised ex ante. Such an approach to policy is said to be time inconsistent.

Time consistency is a component of regulatory predictability. Predictability allows firms to make inter-temporal investment decisions (i.e. based on the complete investment cycle, rather than a particular point in time) based on what they anticipate the future regulatory environment to be after the investment (Guthrie, 2006).

A time-inconsistency problem in regulation often results in under-investment, especially where there are high sunk costs. The risk of unpredictable changes in the regulatory environment can harm regulated firms' investment incentives. They may be reluctant to invest at all, delay investment, underinvest, or invest sequentially when an immediate or single large investment may be better. Spiller (2011) notes that investors may demand up-front compensation for that risk or stronger safeguards when dealing with the state than they would in contracts with others that can be bound by credible commitments, for example with private agents. Awareness of the regulatory risk will drive up the required rate of return and the cost of capital, resulting in underinvestment or higher prices, contrary to the long-term benefit of end-users (see Levy & Spiller, 1997).

Time consistency issues in regulation arise in situations where a regulator does not have mechanisms to commit to a policy through time, and finds itself wanting to change its policy after a regulated firm has made an irreversible investment decision. The key challenger for a regulator is the extent to which it can credibly commit to regulation over the investment cycle.

Investment decisions of firms

There is an extensive and growing literature on the impact of economic regulatory uncertainty on firms' decisions and behaviours (see for example Al-Thaqeb & Algharabali, 2019; Baker et al., 2016; Bernanke, 1983). The primary prediction of this real options literature is that firms will delay investments in long-lived irreversible assets when there is regulatory uncertainty because uncertainty increases the value of the option to wait.

Economic regulatory uncertainty arises when where the future path of government policy is unknown, unclear or unpredictable. The review, and the breadth of policy proposals in the response create a great deal of uncertainty about the nature, scope and timing of any policy changes.

Uncertainty[6] affects both the level and timing of investment. Firms invest in anticipation of future returns. A firm's expectations are informed by its analysis of the future market context, as well as by the possible impact of government policy. Increased uncertainty tends to lower investment because most major investments by firms are irreversible: the firm cannot disinvest, so the expenditure is a

[6] We use a broad definition of uncertainty that includes risk (something that is not certain to happen but for which it is possible to assign probabilities to the possible outcomes – the 'known unknowns') and uncertainty (the 'unknown unknowns').

sunk cost. Also, the investment, such as branding, is often firm- or industry-specific; it cannot be used by another firm or industry (Pindyck, 1988).

Regulatory uncertainty negatively affects economic performance through the reduction in investment and employment. In the face of increased uncertainty firms also delay investment. If there is some choice about the timing, and the investment is irreversible, there is value in waiting until the uncertainty has been resolved (Dixit & Pindyck, 1994). Holding off investment allows firms to gain more information about the possible future state. The higher the uncertainty, the greater the value of delay and the more cautious firms become (Bloom, 2009; Gulen & Ion, 2016; Vural-Yavaş, 2020). But decision paralysis ('wait and see') and resource misallocation are avenues through which uncertainty contributes to economic harm (Giertz & Feldman, 2012).

This caution is also reflected in firms' employment decisions. In periods of high uncertainty, firms hire less (Baker et al., 2016; Jurado et al., 2015). Firms may 'wait and see' instead of engaging in activities, such as new job creation, that create sunk costs (job creation costs are not refundable). In aggregate, unemployment rises.

Uncertainty also affects firms' access to capital. Banks are reluctant to lend when uncertainty is high, this might mean finance is harder to obtain or is more costly (Alessandri & Bottero, 2020; Bloom, 2014).

Sustained underinvestment from decision paralysis is likely to flow through to higher costs in the future, supply shortages, and other symptoms of a deterioration in service levels for consumers. New investment by large electricity consumers, such as data farms, is also likely to be delayed at least or moved to other jurisdictions with a more certain and predictable policy environments.

There are likely to be even wider effects. Firms in other regulated sectors of the economy entering into supply contracts may be concerned by the ability of government to examine their relationships and formulate policy that constrains their ability to enter into private contracts between willing buyers and sellers. Mechanisms to act as checks on regulatory uncertainty are discussed below.

The New Zealand evidence

There is a paucity of empirical studies on the impact of economic regulatory uncertainty on firms' decisions and behaviour in New Zealand, but studies that do exist point to the same conclusion: regulatory uncertainty depresses investment and consumption.

Sense Partners (2020) develop an economic uncertainty index for New Zealand based on media articles related to uncertainty and examine its impact on investment. Their results mirror those in the literature: firms delay investment and hiring decisions until the outlook is clearer and households reduce their spending. These impacts persist: the economy is much weaker several quarters after the uncertainty shock hits. Ryan (2020a) examines the effects of regulatory uncertainty using measures derived from New Zealand's parliamentary record from 1975 to 2017. The results show that uncertainty has a large negative impact on output and share prices, consistent with declines in investment and consumption.

Investment decisions in the electricity sector

Policy uncertainties in the electricity sector are particularly important, as they are highly idiosyncratic and therefore impossible to hedge perfectly (Ehrenmann & Smeers, 2011). A challenge for firms when considering new investments is to balance expected financial gains against potential risks, including changes to policy and how regulations are administered. Firms will be less willing to invest when they anticipate that future changes to the policy environment could reduce the value of their investments.

A number of studies find that an uncertain policy environment makes firms less willing to invest in new electricity assets. Fabrizio (2013) examines how the perceived risk of future regulatory change affected firm responses to a policy initiative designed to increase investment in location-specific long-lived electricity assets in the USA. He finds that policies were followed by significant increases in investments in renewable resource generation assets in states with a stable policy environment. However, there was no increase in investments in states with regulatory policy instability.

Ishii and Yan (2004) investigate how uncertainty surrounding possible comprehensive regulatory restructuring has affected US generation investment decisions since 1996. They find that greater restructuring enactment uncertainty is associated with lesser aggregate generation investment. They conclude that regulatory uncertainty can contribute to an 'investment slowdown' by creating an incentive for firms to delay their investment decision so they can acquire more regulatory information to enable them to make a better-informed decision.

Meyer and Koefoed (2003) examine the impact on investors of changing a decades-long, stable wind promotion policy in Denmark, in particular the impact of delayed implementation of the new policy, and find that it caused a well-established wind industry to stall.

Liang and Fiorino (2013) analyse the relationship between policy stability and patent applications for renewable energy technologies. They find that incremental, predictable, and credible federal R&D expenditures facilitate renewable energy technology development. Conversely, a boom-bust cycle of resource support fails to translate policy goals into intended results.

Expectations can affect investment decisions. Ambrosius et al (2019) show that expectations that policy change will make the market more efficient (and therefore has an expected benefit to firms) can have a positive effect on investment in the electricity sector.

Regulatory uncertainty can also influence the level of energy consumption. A number of studies emphasise the importance of policy stability for encouraging energy conservation or a shift to renewable energy by consumers (Pirgaip & Dinçergök, 2020; Shafiullah et al., 2021; Zeng & Yue, 2021).

The Authority discusses the importance of distortions to firms' investment decisions in generation and electrification and the impact on the efficient transition to a carbon-neutral economy in its response document (Electricity Authority, 2021b, p. 30). It also acknowledges that "uncertainty around government policy" may create a barrier to investment in new generation (Electricity Authority, 2021b, p. 31). However, it does not recognise the impact that its policy proposals will have on the decisions and behaviour of firms in sector and beyond, or that the impact is likely to be most severe for the far-reaching separation proposals it makes that are outside its remit.

Innovation in the energy sector

Without certainty about government policies, firms are unable to assess risk and opportunity and make the trade-offs necessary for investment in new technologies. Investment in innovation may be slowed or delayed, or firms may choose less efficient, but more flexible technologies, limiting overall dynamic efficiency (Bergara et al., 1998a citing Zelner, 1997).

The value of the option to wait is particularly important for investments in research and development (R&D), given that innovation is the exploration of unknown approaches and untested methods that requires considerable investments in intangible assets with a long-term payoff. The value of the option to wait is even more important for innovation in an uncertain political environment because the payoff to the investment in innovation will be influenced by the future policy environment.

In a study of 43 countries Bhattacharya et al. (2017) show that regulatory uncertainty matters more than the policy environment for innovation. Regulatory uncertainty hurts the economy's incentive to innovate, and adversely affects a country's innovation quantity, quality, and originality. The effect is stronger for more innovative industries.

Innovation is particularly important in the transition to low-carbon electricity generation; a number of studies illustrate that regulatory uncertainty depresses innovation into alternative technologies. Schleich et al. (2017) explores factors driving innovation in wind power technologies in OECD countries and find that a more stable policy environment is favourable for patenting wind technologies. In a study of low-carbon innovation in the transition of the German electricity system towards renewable energy, Rogge and Schliech (2018) conclude that policy credibility stimulates green innovation and suggest that policymakers need to recognise this relationship and better understand the formation (and loss) of such credibility. A study by Verdolini et al. (2015) analyses the impact of regulatory uncertainty on innovation in the wind industry in 18 OECD countries over the years 1995-2009. They show that a higher level of policy commitment in EU countries is associated with higher innovation in wind energy technologies.

Regulatory uncertainty is not compatible with private investments in innovation which involve large capital expenditures, are often made on a long-term horizon and are irreversible or quasi-irreversible. Regulatory uncertainty reduces dynamic efficiency, implying higher costs to abate emissions.

Checks on regulatory uncertainty

The time inconsistency problem derived from the existence of sunk investments in network industries has been historically alleviated through the design of various forms of commitment to time consistent behaviour. These include policy rules that remove discretion (Kydland & Prescott, 1977) and the delegation of responsibility to authorities independent of political influence (Rogoff, 1985). The empirical literature provides evidence that regulatory independence (as a means of ensuring commitment and raising credibility) has a positive impact on investment (Levine et al., 2005).

Levine et al (2005) acknowledge that regulators need to balance their role in supporting investment with their role of protecting consumers against monopolistic exploitation. They point out that investment and innovation is generally beneficial to end-users. Providing a predictable regulatory environment that supports firms' incentives to invest is important for the promotion of competition in the industry for the long-term benefit of end-users.

There is a rich empirical literature that examines policy risk and the constraints on policy-makers that can reduce its negative impact on investment (see for example Soroush et al., 2021). This literature, based in new institutional economics, emphasises the value of checks and balances in the institutional environment to protect investments. When institutions effectively constrain arbitrary or opportunistic actions by policymakers and regulators, they reduce the risk of ex post expropriation and create conditions under which firms are more willing to make sunk investments.

Seminal studies by Levy and Spiller (1994) (amongst others) identified achieving regulatory commitment (sometimes referred to as policy credibility) as the single most important characteristic if regulation is to benefit consumers in the long-term. Restraints on regulators that ''reduce the potential for administrative expropriation or a manipulation'' foster private investment. Absent credible and predictable policies, firms will invest less. To illustrate, a study of investment in telecommunications infrastructure across 147 countries over the period 1960 – 1994 finds that the higher the degree of regulatory commitment, the greater the investment by private firms (Henisz & Zelner, 2001).

In the electricity sector, Bergara et al. (1998b) undertake a cross-nation analysis on the role of political institutions and the ability of governments to commit to stable and non-opportunistic regulatory policies, and its impact on electricity sector's performance. They find that credible independent constraints on executive power and an effective regulator create a better environment for investment.

Holburn (2012) focuses on differences in the institutional processes governing policy-making in Ontario and Texas and their impact on investment. He found that policy instability is a major factor that accounts for why investment levels in Ontario have fallen short. In Ontario, renewable policy had exhibited significant instability and unpredictability since inception. In contrast, renewable investment in Texas surpassed its goal with a more certain policy environment in which regulatory agencies have greater autonomy from politicians and where policies are formulated through more 'rigid' policy-making processes. In general, therefore, the more that regulators are able to resist political pressures, the less the level of regulatory risk for investors.

Finally, Levy and Spiller (1994) stress the importance of administrative capability. The higher the regulatory capability of a nation, the higher the potential sophistication of the regulatory regime, and hence the higher the performance of the sector.

4. Uncertainty from the EA's proposals

The review and the Authority's response create considerable and prolonged regulatory uncertainty. The Authority has not followed good regulatory practice in its analysis and development of options for change, creating more uncertainty than is inevitable in policy changes.

Not only is the evidence and analysis inconclusive, but it is not clear that the Authority has in fact determined that there is problem substantial enough to warrant intervention. The Authority has proposed a series of policy options from underdeveloped changes to the Code to undeveloped, highly disruptive proposals for structural or financial separation without any details as to how they will address the purported problem, all based on a somewhat tentative conclusion that "the current incentives and market design *could* result in inefficient future outcomes … and it is worth exploring options to address this *potential* outcome" emphasis added, (Electricity Authority, 2021b, p. vi). The response seeks feedback on a number of questions, including whether a problem in fact exists, and seeks further proposals in submissions.

The uncertainty is likely to continue for some time because the next steps following the closure of submissions is not clear. While the Authority can make changes to the Code, any structural changes would need to be developed and taken forward by other government departments, subject to the agreement of the responsible Minister(s) and are likely to require legislation that would need to be balanced against other Government priorities on the legislative agenda. The lengthy hiatus between the consultation process and the eventual implementation of any policy changes creates a period of uncertainty for the sector with a chilling effect on investment decision-making until there is clarity about the outcome.

While the Authority's reports acknowledge the impact of various commercial arrangements on investment incentives in the sector, it does not consider the potential impact of the uncertainty arising from its own policy process and policy proposals, not only on investment in the electricity sector, but on consumers and industry more broadly.

Good regulatory practice

Many factors are important for ensuring the effectiveness of regulation, none more so than the practices of the agency charged with implementing the regulatory regime (Productivity Commission, 2014). Formal guidance for best practice regulation is provided in the Treasury's "Best Practice Regulation" (The Treasury, 2015a), the "Regulatory Charter: Energy Markets Regulatory System" from the Ministry of Business, Innovation and Employment (MBIE, 2018b) and the "Government Expectations of Good Regulatory Practice" (New Zealand Government, 2017). The Authority has proposed criteria for evaluating policy options but has not used them in assessing the options it proposes and is seeking feedback on them (Electricity Authority, 2021b, p. 51).

Sound public policy processes in government departments typically involve analysis to answer a number of key questions, illustrated in Table 1, that guide the process from initially identifying whether there is, in fact, a problem through to identifying the best options for addressing the problem, if one exists (see for example Scott, 2006). The analysis needs to be underpinned by sound evidence and robust analysis at every stage. The processes also generally involve public consultation on significant policy changes.

These steps in the policy process are reflected in the Government expectations for good practice by regulators for the analysis and implementation of change to regulatory systems shown in Appendix A, which should have been followed by the Authority (New Zealand Government, 2017).

Table 1: Key questions in policy analysis

Key questions	Issues
Is there a problem?	What is the nature of the problem? What is the underlying cause of the problem? How big is the problem? Who does it affect, how and how much? Is it a big enough problem that's it's worth addressing?
What are the options for addressing the problem?	What is the status quo option i.e. what would happen without intervention? What are the options for addressing the problem, including doing nothing?
Will the options work?	How will the options work in practice? What other changes are needed to make them success e.g. skills, money? Will they actually address the problem, and if so to what extent? How will the outcomes be measured and monitored?
What are the effects?	What are the other effects e.g. on industry, consumers, environment, trade? How big are these effects, who do they affect and by how much?
Are the options worthwhile?	What are *all* the direct and indirect costs and benefits of each option? For each option, do the benefits outweigh the costs (CBA)? Are there additional criteria and how are they weighted? What are the trade-offs between the criteria? How well does each option meet the criteria (MCA)? How efficient (productive, allocative and dynamic) and equitable is each option?
What is the best option?	Which option (including the status quo), best meets the criteria?

Note: CBA – Cost Benefit Analysis
MCA – Multicriteria Analysis

A key feature of public policy analysis is that it takes a national perspective, identifying *all* the national costs and benefits, rather than being limited to sectoral or regional effects. Any proposals for structural or vertical separation that would be taken forward by other government agencies would involve an assessment of all the costs and benefits, both direct and indirect, from a national perspective as well as all the impacts of market concentration (Evans, 2004). Such an analysis would typically comprise part of a Regulatory Impact Assessment accompanying any proposal for legislative change.

Inconclusive evidence and analysis

At best, the evidence presented is indicative rather than conclusive. The wording in the Authority's own documents implicitly reveals the uncertainty of its analysis and conclusions, as shown in a sample of quotations below (emphasis added):

> …the price discrimination implicit in the 'Tiwai contracts' between Meridian Energy, Contact Energy and New Zealand Aluminium Smelters (NZAS) *raises the possibility* that electricity may not have been allocated efficiently. (Electricity Authority, 2021b, p. ii)

> there *appears to be evidence* to *indicate* that inefficiencies are *potentially* significant, with material implications for consumers and generators. (Electricity Authority, 2021b, p. ii)
>
> The Tiwai contracts were negotiated and structured in a way that *may* increase the *likelihood* of inefficient price discrimination occurring (Electricity Authority, 2021b, p. v)
>
> There is *some* evidence that suggests prices *may* not be being determined in a competitive environment. We have looked at many different indicators. *None in isolation provide concrete evidence* to establish whether spot prices are being determined in a competitive environment. However, taken as a complete picture, there *appears to be some evidence* that spot prices may not have been determined in a competitive environment over the review period. (Electricity Authority, 2021c, p. 2)
>
> There is *some evidence* of economic withholding, but different indicators provide *conflicting evidence* (Electricity Authority, 2021c, p. 6)
>
> ….Genesis and Contact, whose offers *appear to* better reflect storage. For thermal*, as far as we can tell,* the percent of offers above estimated cost reflect underlying conditions. (Electricity Authority, 2021c, p. 6)
>
> This *might suggest* economic withholding has been increasing, or it *could be reflecting* other conditions. At the least, it *may* show that there has been an increased incentive to economically withhold in recent years.(Electricity Authority, 2021c, p. 7)
>
> …interpretation of the data indicates that economic withholding *may* have been taking place over the review period. (Electricity Authority, 2021c, p. 7)
>
> New Zealand Aluminium Smelters is *potentially* paying below the opportunity cost for energy, and its presence increases energy costs for the rest of the country. (Electricity Authority, 2021c, p. 7)
>
> It is *not possible to definitively conclud*e whether all of the increase in prices is due to underlying conditions, including uncertainty about future gas supply from existing fields, or if some of the increase is due to prices not being determined in a competitive environment. This is because, *given the data available* to the Authority, it is difficult to account perfectly for all underlying conditions. (Electricity Authority, 2021d, p. ii)
>
> Steeper supply curves in recent years *suggest* an increased incentive and ability to economically withhold. (Electricity Authority, 2021d, p. iii)

A core tenet of policy making is that it should be informed by robust evidence in order to produce better quality decisions (see for example Gluckman, 2018; Productivity Commission, 2009; Superu, 2018). However, policy decisions are often made with a less-than ideal evidence base. But the greater the expected impact of the policy decision, such as splitting Manapōuri from Meridian's other assets, the more important it is to have robust evidence on which to base it. It behoves advisors to be clear about the limitations and boundaries of their knowledge and analysis and to inform decisionmakers about the degree of certainty underpinning their recommendations.

It is by no means clear that the evidence presented in the review reports is definitive enough to support the policy interventions proposed by the Authority. This is particularly true of the more interventionist proposals. Such far-reaching changes should be based on strong, complete and unambiguous evidence to support decision-making because the cost of being wrong is high.

Undefined problem

The Authority does not seem to have yet come to a firm view on the existence of a problem to be addressed. In its own assessment, it has at best identified a "*potential* for an inefficiency that might be worth addressing" (emphasis added) without having reached a concluded view of whether a problem exists (Electricity Authority, 2021b, p. iv). The tentative nature of its views is reflected in the language of the response document, as shown in the sample below (emphasis added):

> 3.2 While the Review is being consulted on, the initial Authority observations have highlighted the market impact of the Tiwai contracts and the *potential* consequences for other consumers. The evidence, to date, *indicates* the arrangements for the supply of electricity to the Tiwai Point smelter *may* not necessarily be efficient because electricity *may* not be supplied to the parties that have the highest valued uses, that is, have the highest willingness to pay (WTP). The Tiwai contracts *seem* to provide preferential pricing in a way that is unique in the industry, even in contrast to the terms available to other large industrial consumers. The Authority considers that inefficient price discrimination *could potentially* have a material impact on the market and warrants being explored in greater depth at an early point. (Electricity Authority, 2021b, p. 12)

Without a clear problem definition, neither the Authority nor any stakeholder can assess whether the proposals will in fact fix the (ill-defined) problem, and whether the benefits will outweigh the costs. The risks associated with a false positive (i.e., a conclusion that a problem exists, when it doesn't) are high, as discussed in section 2, leading to that worst of policy choices: 'a solution that won't work for a problem that doesn't exist'.

The Authority is tentative in the definition of a problem to be addressed. The language it uses does not provide confidence that a problem exists, or if it is potential problem, what would trigger it. Moreover, the Authority is seeking "feedback from stakeholders on whether discriminatory pricing is a problem of sufficient scale to warrant intervention", suggesting that it has not yet reached a firm view on the issue (Electricity Authority, 2021b, p. 32).

While the review identifies the possible existence of a potential future risk, it provides no assessment of its likelihood or magnitude. This gap in analysis makes it impossible to determine whether and which of the proposed interventions would be worthwhile and proportionate in addressing the potential problem. With no assessment of the size (and likelihood) of the problem, the Authority does not appear to have considered the balance of risks between false positives (overstating the harm) and false negatives (failing to prevent a harm to consumers) in its analysis and proposals (Gal, 2012). Sound policy analysis seeks to minimise the effects of both kinds of error over time.

Risk-based regulation frameworks focus on identifying and assessing the risk of harm (based on the gravity of the potential event and the probability of the event occurring) and on developing interventions to address the highest priority risks (Department of Finance, Services and Innovation, 2016). The central idea of risk-based regulation is that regulators cannot, and should not, prevent all possible harms, but should focus on controlling the greatest potential threats to achieving their regulatory objectives.

The costs imposed by regulatory uncertainty suggest that the Authority should first reach a firm, clear view on the nature and size of the problem, rather than a tentative view that may change, before embarking on a public discussion of policy options, including far-reaching measures beyond its remit such as structural and financial separation. The next step should be to establish that the potential harm is substantial, so that there is at least the prospect of net beneficial outcome from the proposals. The Authority has done neither.

Underdeveloped policy options

The Authority identifies a number of policy options, including those that it could potentially advance through Code amendments, as well as more far-reaching structural or financial separation solutions outside its remit that would require implementation through other branches of government (Electricity Authority, 2021b, p. vi). In the invitation for public submissions, it acknowledges that the options are not fully developed, and that additional options may exist, some of which could be outside changes to the Code.

Code changes

The Authority presents a multiplicity of options that are neither complete nor fully developed. The high-level description of the potential changes to the Code and the associated lists of pros and cons is not sufficient to provide a detailed understanding of how each option would work in practice to address the purported problem. There are many loose ends – "key considerations and choices to be worked through" – adding further uncertainty to each proposal. It is simply not possible from the information provided to assess which options are best targeted to the issue that the Authority has identified.

The purported problem identified by the Authority is inefficient price discrimination. There is insufficient information provided in the description of the proposed changes to the Code to be sure that they would first, in fact address inefficient price discrimination effectively and secondly, *only* address inefficient price discrimination. It appears that several of the proposed options would restrict efficient price discrimination. Contemplation of options that go beyond or are unrelated to the supposed problem cannot be justified and create considerable uncertainty.

While pros and cons of each change to the Code are listed, there is no sense of the magnitude of the costs and benefits of each. Because there is no assessment of the likely size of the potential problem it is of course hard to estimate the benefits of reducing or eliminating it. There is therefore no way of assessing which policy options satisfy the cost-benefit test, which ones are most worthwhile, and which are proportional to the issue. Nor is there any indication of the weightings of the pros and cons or the trade-offs involved with each proposal. In the discussion of the options, the Authority focusses on the steady state costs and benefits, i.e., those that would be expected to occur once the policy had been implemented. It seems blind to the costs of regulatory uncertainty imposed on the sector through the consultation and development process as discussed in section 3. The discussion of the cons of some of the options do acknowledge the impact on "potential negative impacts on investor sentiment towards New Zealand". But they do not go beyond this in looking at the impact on the investment decisions of domestic firms, or the flow-on effects of a lack of investment on consumers.

It is not clear how the effectiveness of the changes to the Code, if implemented, will be monitored. Nor is it clear how the counterfactual will be considered. Both are likely to be hard to measure – the averting of *potential* opportunities for inefficient price discrimination and the loss of *potential* opportunities for investment. The inability to monitor the effectiveness of the policy makes it likely that, if implemented, it will be hard to undo because the evidence to support change will be lacking, raising the problem of false positive error.

Structural changes

In addition to changes to the Code, the Authority also proposes profound structural changes to the sector including limiting the size of generators, splitting Manapōuri off from Meridian's other assets and virtual assets swaps. Changes such as these are outside the Authority's remit, and would require carrying forward by other Government agencies, most likely leading to legislative changes.

The options for structural and financial separation are not well-developed, although some of the key changes and implications are discussed at a high level.

The Authority is proposing heavy-handed regulatory interventions (that is, interventions involving direct regulatory control over core pricing, output, or investment decisions by firms), without first assessing whether more limited interventions might be suitable.

The proposed structural changes could have more profound impacts on the sector than the Code changes, but they are not as fully developed. No detail is provided on how they could work or how they address the purported problem. The costs, benefits and trade-offs are not identified, although the Authority does acknowledge, in limiting the size of generators, that "6.68 One difficulty with this proposal is that there may be fixed costs or overheads that create economies of scale, and these economies could be lost." (Electricity Authority, 2021b, p. 49).

Raising the very possibility of these unformed and unclear structural and financial changes itself creates uncertainty for the sector. There is no indication at all that central government would even contemplate these changes. But while they remain as threats on the table, they undermine the confidence of the sector in the predictability of the future regulatory environment and are likely to engender caution in firms' investment decisions.

Unclear assessment criteria

The Authority identifies eleven criteria to be used when assessing the options it proposes, including the cost-benefit analysis criterion required by section 39 of the Electricity Industry Act 2010 (Electricity Authority, 2021b, p. 51). It is not clear why these criteria are included, or why submissions are sought on them. If they differ from criteria used to analyse previous changes to the Code, the reasons should be made clear, because inconsistent application of criteria to policy changes across time could lead to different outcomes. If they are indeed different, would they have led to different conclusions about the desirability of previous changes to the Code? It is not clear how the various criteria will be weighted in decision-making, nor how trade-offs will be handled.

The Authority lists the high-level pros and cons of each of the options to change the Code, but they are not lined up against the Authority's own proposed evaluation criteria, making it more difficult than necessary for submitters to assess the potential outcomes of each option against the criteria. A structured list of the pros and cons in a multi-criteria assessment matrix would at least have helped submitters consider the information provided in an organised way.

Consultation process

The Authority's consultation is very wide, inviting submissions on 42 questions, as well as requesting further options from submitters. The scope of the invitation creates an opening for third-party opportunism by those seeking to promote their commercial or political interests.

The Authority has established the *Innovation and Participation Advisory Group (IPAG)* and the *Market Development Advisory Group (MDAG)* to provide advice and recommendations to the Authority on the development to the Code. It is not clear whether or not these bodies have provided input into the development of the proposed changes to the code. It would seem to be desirable to have had their expert input into testing and further developing and refining the options before submitting them to broad public consultation.

The documentation for the review of competition in the wholesale electricity market was released for consultation on 27 October 2021 (Electricity Authority, 2021a, 2021c, 2021b, 2021d). The initial deadline for submissions was 8 December 2021, but this has been pushed back to 22 December 2022. Given the complexity of the analysis underlying the Authority's review, the scope of the options it identifies and the significance of their impact, and the large number of questions posed of submitters, this timeframe limits the ability of submitters to undertake thorough analysis of the issues and to provide well-evidenced feedback. This timeframe exacerbates the Authority's challenge of making policy changes in an environment of imperfect information. Submissions made under time pressure could provide a less-than-ideal basis for making decisions about policy changes, creating a risk of poor-quality policy.

The Authority did not release all of its supporting analysis when the consultation papers were published. Information has been slowly released over the consultation period. The Authority has also chosen to withhold the full peer review comments, making it harder than necessary for submitters to review and compare the analyses of the Authority and peer reviewers. It is unclear what the next steps will look like, and the Authority has not confirmed whether there will be cross submissions. This lack of process clarity creates further uncertainty.

Consistency with other government priorities

The interface between the issues identified in the review and response and other Government priorities, such as climate change, are not clear. Comment on climate change is relegated to a footnote:

> The 2020 amendments to the Climate Change Response Act 2002 have committed New Zealand to mitigate climate change. The Authority recognises these broader objectives and aims to ensure that the resulting changes in the electricity market are efficiently accommodated.(Electricity Authority, 2021b, p. 30)

Exactly how Government priorities for climate change will be accommodated is unspecified, creating significant scope for additional regulatory uncertainty.

Policy process uncertainty

The process followed by the Authority in undertaking the review has been ad hoc, as it describes (Electricity Authority, 2021c, p. 1):

> Since the review of spring 2018, the Authority has announced several reviews with a common research question: 'Do spot prices reflect underlying fundamentals?'. In December 2019 we announced a review into wholesale prices. And in July 2020 we announced a review of issues surrounding the Tiwai Point smelter closure.
>
> In early 2021 we decided that, because these reviews all had a common research question, we would combine these reviews into one based on the logic that if prices are competitively determined, then spot prices must reflect underlying market fundamentals. This report is the output from this combined review.

This ad hoc approach has not provided the sector with the transparency, predictability and opportunity for engagement normally associated with reviews of regulation. There was no set scope for the review and no terms of reference has been published. There were no set timeframes for the review. Nor was there any process for engagement with the sector to obtain information and understand transactions, test the analysis, provide feedback and inform findings before the publication of drafts for consultation. The Authority briefed the Minister on at least one occasion prior to completion of the review, raising questions about its independence.

The process that the Authority has followed does not provide confidence that the evidence and analysis is based on the best available information. Regulatory uncertainty arises not just because the evidence base is not robust, but also because the problem is not well-defined, there is a large number of possible policy changes, the details of each policy option are not clear, and which ones will be progressed, how they interact, and how and when they will be implemented is unknown at this stage. Uncertainty also arises from the lack of clarity about the criteria to be used, the consistency of policy with other government priorities and the compressed timeframe for submissions. In addition to the uncertainties associated with the pre-implementation period (not knowing if, when, or what type of policy will be implemented), some uncertainty may remain even after policies have been put in place, as firms learn how they will work in practice.

The undeveloped nature of the Authority's problem definition and its options widens the space for opportunistic behaviour by third parties seeking to influence the outcome, as discussed in section 2. Interested parties will be emboldened to promote options that are equally undeveloped and without consideration of the costs of their proposals.

The number and underdeveloped nature of the Authority's proposals create considerable regulatory uncertainty for the sector. The Authority's proposals threaten both the value of existing investments and the potential payoff to future investments because whether, how and when they will be implemented is simply unknown. Until the uncertainty is resolved, firms' attention will be diverted from business as usual and investment activity may be put on hold as firms focus on ameliorating and managing the risks inherent in the proposals, to the detriment of dynamic efficiency and long-term consumer benefit.

5. Conclusion

The Authority does not seem to recognise the future potential impact of the review on the investment decisions of firms in the electricity sector and the long-run impact of underinvestment on consumers.

Sunk investments make the electricity sector particularly susceptible to regulatory change, and the threat of regulatory change. Uncertainty about the future regulatory environment reduces the value of past private investments and materially affects likely returns from future investments. Firms ameliorate the impact of the threatened intervention by delaying investment, holding liquid assets, switching to other investments with a lower, but more certain rate of return or investing sequentially when a single investment might have been better. Uncertainty also drives up the required rate of return and the cost of capital so that finance is harder to obtain or is more costly.

The regulatory uncertainty arising from the review arises not just because the Authority canvasses a number of policy changes. The process the Authority has followed has created more uncertainty than necessary about the future regulatory environment; the problem is not clearly defined; the options to change the Code are underdeveloped and the structural and financial separation options that would be likely to have profound impact on the sector are undeveloped.

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Appendix A: Government expectations for good regulatory practice

Robust analysis and implementation support for changes to regulatory systems

Before a substantive regulatory change is formally proposed, the government expects regulatory agencies to provide advice or assurance on the robustness of the proposed change, including by:

- assessing the importance of the issue in relation to the overall performance and condition of the relevant regulatory system(s), and how it might fit with plans, priorities or opportunities for system improvement already identified
- clearly identifying the nature and underlying cause of the policy or operational problem it needs to address, drawing on operational intelligence and available monitoring or review information
- undertaking systematic impact and risk analysis, including assessing alternative legislative and non-legislative policy options, and how the proposed change might interact or align with existing domestic and international requirements within this or related regulatory systems
- making genuine effort to identify, understand, and estimate the various categories of cost and benefit associated with the options for change
- identifying and addressing practical design, resourcing and timing issues required for effective implementation and operation, in conjunction with the regulator(s) who will be expected to deliver and administer the changes,
- providing affected[1] and interested parties with appropriate opportunities to comment throughout the process and, in the right circumstances, to participate directly in the regulatory design process (co-design), and
- use of "open-book" exercises to allow potential fee or levy paying parties to scrutinise the case for, and structure and level of, proposed statutory charges.

[1] Affected parties include people and organisations whose obligations, rights or powers will be directly affected by the proposed change

Source: New Zealand Government (2017)

Appendix B: Regulatory Charter Energy markets regulatory system

Regulatory Principles: Energy Markets Regulatory System

This section describes the high level principles that underpin the design and operation of the energy markets regulatory system.

The left hand column of the table describes the general intent of each principle. The right hand column explains how each principle is given effect in the energy markets regulatory system, with illustrative examples where relevant.

The Electricity Authority [EA] has also adopted further regulatory strategy principles to guide its approach to regulation through the Code and other market facilitation measures, for example avoiding a 'one size fits all' approach.

Regulatory principles for the energy market regulatory system

Principles	Description of the design or operational approach
Growth compatible: economic objectives are given an appropriate weighting relative to other specified objectives, including other factors contributing to higher living standards	Legislation governing the energy markets regulatory system has the primary objective of promoting the long-term interests of consumers. Emphasis is given to promoting competition, achieving outcomes consistent with workably competitive markets, efficient operation of markets, reliability, and incentives to invest. This is in recognition of energy as an essential input to all sectors underpinning our economy.
Proportional: the burden of rules and their enforcement should be proportional to the benefits that are expected to result	The economic regulation of monopoly electricity and gas pipeline businesses strives to balance the costs and benefits of such regulation by combining lower cost default price-quality regulation with provision for 'customised' regulation where necessary. In addition, of the 29 electricity lines businesses in New Zealand, 12 firms are subject only to information disclosure regulation on the grounds that their ownership and governance limits the potential benefits of price-quality regulation. Other elements of the electricity and gas regulatory systems give priority to non-regulatory measures, such as model contracts, principles, guidelines and other 'market facilitation' measures.
Certain and predictable: regulated entities have certainty as to their legal obligations, and the regulatory regime provides predictability over time	'Input methodologies' (IMs) are a key input to the price-quality regulation of electricity lines and gas pipeline businesses under Part 4 of the Commerce Act. The purpose of IMs is to provide certainty to regulated suppliers and consumers about the rules, requirements and processes applying to Part 4 regulation. IMs are reviewed at least every seven years. This regime therefore promotes stability and predictability by providing suppliers and investors in regulated firms the confidence to invest in the long-lived infrastructure underpinning these services.
Flexible and durable: regulated entities have scope to adopt least cost and	The EA and [Commerce Commission] CC have discretion to develop and evolve their regulatory measures over time in response to changing circumstances, subject to following

Principles	Description of the design or operational approach
innovative approaches to meeting legal obligations. The regulatory system has the capacity to evolve in response to changing circumstances	rigorous statutory process and guided by high level objectives. For example, the EA has complete discretion regarding the Code and the CC has the ability to review and change IMs. The GIC [Gas Industry Company] has more limited regulatory tools available, but flexibility is afforded by the ability to regulate via tertiary rules, made by the Minister of Energy and Resources on the GIC's recommendation.
Transparent and accountable: rules development, implementation and enforcement should be transparent	Rules and regulations applying to the electricity and gas sectors are only introduced after comprehensive consultation and evaluation of the costs and benefits. Minimum energy performance standards and labelling regulations are developed in conjunction with relevant Australian agencies, and are subject to New Zealand's regulatory impact assessment conventions. All agencies in the energy markets regulatory system undergo significant consultations with stakeholders as part of their decision making processes. Accountability regarding economic regulation is promoted by provision for merits appeal of input methodologies in the High Court.
Capable regulators: the regulator has the people and systems necessary to operate an efficient and effective regulatory regime	Capacity assessments are undertaken at regular intervals and subject to independent input and review.
Understanding behavioural responses: regulatory requirements are designed with the likely behavioural responses of market participants in mind	[Energy Efficiency and Conservation Authority] EECA's energy efficiency programmes are designed and reviewed with information from market research about the behaviour of individuals, households, businesses and suppliers. The EA's market facilitation measures, especially those seeking to inform and empower consumers, are equally informed by market research to enhance their effectiveness.

Note: These principles are taken from the Treasury's principles for best practice regulation (The Treasury, 2015b)

Source: Ministry of Business, Innovation and Employment (2018b, p. 17)

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independence, integrity and objectivity

Vertical integration and consumer benefit in the New Zealand electricity sector

Kieran Murray, Toby Stevenson, Michael Young

20 December 2021

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Executive summary

On the evening of 9 August 2021, the electricity sector failed to 'keep the lights on' as electricity was cut to thousands of households during one of the coldest nights of the year. Several inquiries into this event have been undertaken. Before the results of these investigations were known, several commentators were quick to suggest the cause was due to vertical integration (that is, common ownership) of electricity generation and retail activities. In fact, there has been a pattern of commentators pointing to vertical integration as a contributor to a number of market events since the Authority was formed. To our knowledge, none of the commentators who suggest vertical integration is a problem has published any supporting analysis, either conceptual or empirical. The Authority has not released a study dedicated to the competitive impacts of vertical integration but the recently released Market Monitoring Review raises vertical integration as a potential barrier to entry that may have been restricting entry of independent generators. It notes a number of developments which lead it to the conclusion that:

> VI [Vertical integration] as a barrier to entry may be becoming less of an issue. ((Electricity Authority, 2021) 5.29

Our understanding of the Authority's thinking has been gleaned from what may amount to similar passing comments in consultation papers on rule change proposals.

This report reviews key conclusions and findings from theoretical and empirical studies into the causes and consequences of vertical integration. Virtually all theories of vertical integration turn in one way or another on the presence of market imperfections; that is, on deviations from the long list of explicit and implicit assumptions associated with textbook models of perfect competition. A view of whether vertical integration is beneficial or harmful to consumers therefore must be grounded in an assessment of whether vertical integration is an efficient means of navigating the real-world imperfections of the electricity sector, or a means of exploiting those imperfections.

We reviewed numerous studies into the hazards for ex-ante investment commitment and ex-post performance in the electricity sector. The overwhelming conclusion from this large body of literature is that specific features of electricity markets are both statistically and economically important causal factors influencing the decision of firms to vertically integrate, both in New Zealand and internationally; there may be few other areas in economic research where there is such an abundance of empirical and theoretical work supporting a theory of firm or market structure.

We draw two conclusions:

- vertical integration of electricity generation and retail activities has emerged as an economically efficient organisational form to overcome real-world imperfections in the wholesale and retail electricity markets; if regulatory interventions were to impede efficient vertical integration, the cost of electricity to consumers would increase, potentially substantially
- market reform which reduces market imperfections, including bargaining frictions, will increase competition and lead to a reduction in vertical integration; that is, an increase in competition will reduce the need for firms to vertically integrate (but a decrease in vertical integration imposed through regulation will not increase competition).

1. Introduction

Vertical integration between electricity generators and retailers has become somewhat of a 'lightening rod' for commentators unhappy with the performance of the electricity sector. Government intervention to separate, to varying degrees, generation activities from retail activities would, in the view of some commentators, lead to better outcomes for consumers.[1] To our knowledge, the Electricity Authority (Authority) has not published a paper evaluating vertical integration in the New Zealand electricity sector. However, the Authority does appear to have formed views that are influencing its regulatory actions. An indication of the Authority's thinking is available from a recent consultation paper, *Internal transfer prices and segmented profitability reporting* (Electricity Authority, 8 April 2021) and, more recently, the Market Monitoring Review. (Electricity Authority, 2021).

The Authority views vertical integration of generation and retail electricity businesses as having the potential for economies of scale where fixed costs can be spread over the consolidated business. It also views vertical integration as enabling efficient risk mitigation. However, the Authority considers control by integrated generator-retailers of the bulk of electricity generation raises competition concerns (Electricity Authority, 8 April 2021, para. 2.1). The same possibility was raised in the Market Monitoring Review in the context of the potential for vertical integration to form a barrier to entry for independent generators

In explaining its competition concerns, the Authority had previously referred to comments heard by the Electricity Price Review that generator-retailers may stifle competition by advantaging their own retail arms via preferential pricing of electricity and/or cross subsidisation (Electricity Authority, 8 April 2021, para. 2.2). The Authority considers that it is largely the size of vertically integrated generator-retailers, rather than their vertical integration per se, that is the primary driver of its competition concerns—the Authority states that small integrated firms do not raise competition concerns (Electricity Authority, 8 April 2021, para. 2.3).

While it is difficult to be confident of the Authority's reasoning around vertical integration, given its limited explanation, it seems the Authority accepts there is a trade-off. Vertical integration allows economic efficiencies, which presumably increase with the size of the integrated entity. However, offsetting these benefits are economic inefficiencies due to a belief that integrated entities could raise the costs of their competitors and advantage their own retail arms. In the Market Monitoring Review it states:

> VI can often be efficient because it can reduce transaction costs, lower the cost of capital for building new generation, or facilitate better risk management. However, we are interested in VI because low barriers to entry place pressure on incumbents to display competitive pricing behaviour. (Electricity Authority, 2021) 5.27

[1] See for example, https://www.stuff.co.nz/business/opinion-analysis/300383610/power-blackout-highlights-nzs-electricity-problem; https://www.energynews.co.nz/news/electricity/95733/nz-lacks-basic-power-competition-rules-octopus; https://www.pundit.co.nz/content/has-our-electricity-system-burnt-itself-out

It is not clear whether the Authority perceives their concern as arising when an integrated entity supplies a large share of the market, or when the bulk of the market is supplied by vertically integrated entities, or whether its concern results from some combination of entity size and the proportion of the market supplied by vertically integrated firms.

In this paper we test the views expressed by the Authority. Our paper unfolds in four sections as follows:

- *This section* introduces our report.
- *Section two* draws out the key conclusions and findings from theoretical and empirical studies into vertical integration.
- *Section three* applies these findings to electricity markets to explain why vertical integration emerged as a feature of existing electricity markets, not just in New Zealand but in competitive electricity markets worldwide.
- *Section four* brings the analysis together to assess whether the views expressed by the Authority in relation to impacts and risks of vertical integration are soundly based, and whether forced vertical disintegration as advocated by some commentators would likely benefit or harm the long-term interests of consumers.

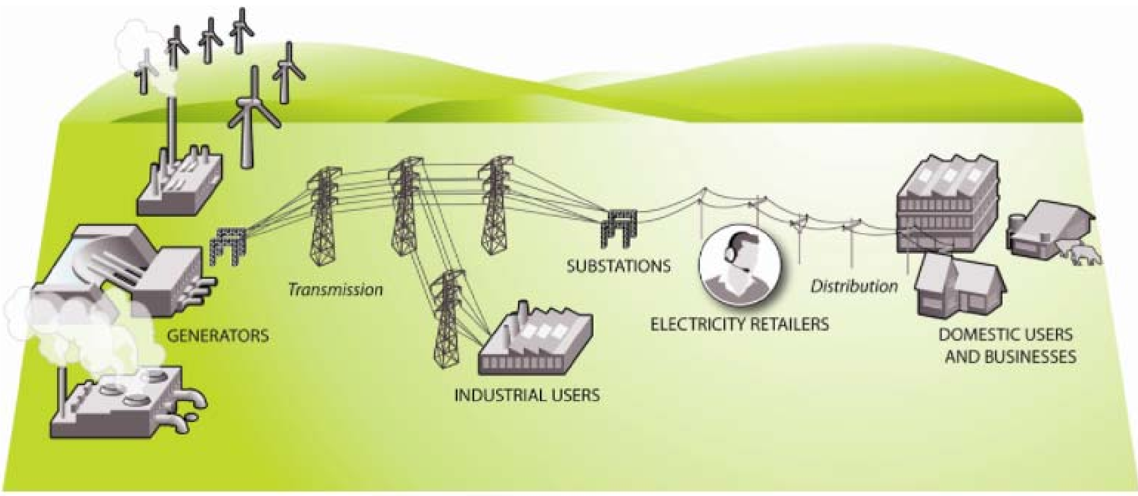
2. Economics of vertical integration

2.1 Vertical integration

Many goods or services involve a series of steps, or functional levels, to produce and supply the product to consumers. The term "vertical integration" refers to a situation where the production or supply of two or more of these functional steps in providing a good or service are owned by the same firm.

The Ministry of Business Innovation and Employment (MBIE) provides the following illustration of the four main components of the New Zealand electricity industry:[2]

Figure 1 The four main components of the New Zealand electricity industry



Source: MBIE

The components of interest in this report are the wholesale electricity market (governing the supply and price of energy and instantaneous reserves) and retail market (where retailers buy from the wholesale market and supply to end consumers). The network components, transmission and distribution, have been required to be owned (with some limited exceptions) and operated separately from the competitive elements of generation and retail for over 20 years.[3]

Oddly, some commentators have suggested the comparatively recent split of Telecom into a network company, Chorus, and a telecommunications and digital service provider, Spark, as providing a model for reform of the electricity sector, seemingly unaware that both industries are subject to similar

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[2] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-generation-and-markets/electricity-market/electricity-industry/

[3] Electricity Industry Act 2010.

legislation separating (and revenue regulating) the network component from the content and retailing activities.[4]

Currently, about 89.4 per cent of residential and small-to-medium businesses are served by vertically integrated electricity retailers, when market share is measured by ICP.[5]

2.2 Analysis more complicated than horizontal integration

Vertical integration is inherently more complex to analyse than horizontal integration (Shapiro, 2019, para. 6). When two firms integrate in the same market (horizontal integration), competition is eliminated between the merging parties and the integrated entity would typically have a stronger incentive to raise prices; competition analysis then proceeds by assessing whether pressure from competitors would be sufficient to thwart that incentive (or the integration produces other offsetting benefits) (Slade, 2019, p. 9).

An analysis of vertical integration involves considering two functional markets—in this case the wholesale and the retail electricity markets—and, importantly, the interface between those two markets. The term "market" is a technical term in competition economics to describe a relevant range of activity by reference to economic and commercial realities. A market is the field of exchange (or potential exchange) in which the services being considered are substitutable. It is this possibility of substitution in response to changing prices or output that limits the ability of a firm 'to give less and charge more' (Re Queensland Co-operative Milling Association Ltd, 1976).

Generally, the Commerce Commission (and equivalent competition bodies internationally) identify separate markets at each functional level (Commission, 2019(a), pp. 21-22). It is sometimes possible for firms in different levels of a supply chain to be in the same market if firms could easily, profitably and quickly (the Commission generally uses a period of one year) move from one level to another in response to a small, but significant, non-transitory, price increase.[6]

Firms in the electricity sector are unlikely to move from one level in the chain of supply to another in response to a small change in price. An electricity retailer would need to invest in generation assets to compete in the wholesale market, and a generator is not equipped to compete effectively with retailers for mass-market customers without investing in systems and marketing etc. Firms operating at one level in the supply chain—either generation or retail—are currently not a sufficient threat to constrain pricing in the other level of the supply chain.[7]

As the wholesale and retail markets are separate markets for the purposes of competition analysis, vertical integration in the electricity sector refers to circumstances where activities competing in

[4] https://www.stuff.co.nz/business/opinion-analysis/300383610/power-blackout-highlights-nzs-electricity-problem; https://www.pundit.co.nz/content/has-our-electricity-system-burnt-itself-out.

[5] This figure includes Trustpower that supplies 11.8 per cent of mass market consumer and has agreed to sell its retail assets to Mercury, subject to regulatory approvals.

[6] Typically abbreviated to SSNIP; the Commission generally uses a SSNIP of 5 per cent, but for some markets, such as frequently purchased, low value products, a lower figure might be adopted (for example, 2 per cent for retail groceries).

[7] Distributed energy resources (for example, small scale solar) are blurring some of these market boundaries, a point we pick up further below.

separate markets are owned by the same entity. A situation where one entity invests in an existing activity in a separate market does not in-of-itself reduce competition in either market—the same number of entities compete in each market with the same market shares. Where an entity enters a separate market by establishing a new entity (e.g., a generator establishes a retail arm), that entry increases competition in the separate market (in this example, retail) without reducing competition in the original market (in this case generation).

An analysis of vertical integration therefore requires an assessment of the interface between activities operating in two separate markets and is inherently more complicated than an analysis of competition within a single market.

2.3 Studies of shipping between integrated entities

2.3.1 Industrial organisation focused on physical integration

Explanations of the cause and consequences of vertical integration that emerged from the study of industrial organisation following World War II tended to assume vertically integrated entities ship goods between their divisions (Carlton & Perloff, 2015). Industrial theorists like Bain (1959) viewed the boundaries of a firm narrowly as encompassing activities that were clearly physically related to one another; an upstream division was assumed to supply inputs to a downstream division, and the downstream division supplied the customer.[8]

This assumption of an upstream entity supplying a downstream entity led to three theories for why firms vertically integrate. Two of these theories—sharing fixed costs and eliminating double marginalization—conclude that vertical integration reduces costs; the third theory 'raising rivals costs' would lead to reduced competition. None of these reasons are likely to hold in the New Zealand electricity market because generators do not ship to retailers in the manner assumed in the industrial organisation literature. We touch on these 'traditional' reasons, as comments by the Authority suggest its thinking may have been influenced by this literature.[9]

2.3.2 Spreading fixed costs

As noted above, the Authority views vertical integration of generation and retail electricity businesses as having the potential for economies of scale where fixed costs can be spread over the consolidated business (Electricity Authority, 8 April 2021, para. 2.1). The explanation by the Authority is limited but

[8] Economics literature tends to refer to entities supplying inputs into a production process as "upstream firms" and the firms producing goods as "downstream". Historically in Europe and the United States, firms used the flow of rivers to ship goods downstream to be processed and on-sold to consumers.

[9] We do not discuss a fourth reason discussed in the industrial organisation literature, third degree price discrimination, as the requirements for this behaviour to be profitable fit neither the Authority's explanation of its concerns nor the characteristics of the electricity sector. Third degree price discrimination would involve charging customers with less elastic derived demand a higher price and customers with more elastic derived demand a higher price, with vertical integration used to prevent the elastic (low price) customer on-selling to the customer charged higher prices.

we think the Authority intended to write ‘economies of scope’ rather than ‘economies of scale’.[10] It is possible there are economies of scope from jointly owning generation and retail. Managing wholesale risk involves developing skills and dedicating resources to forecasting, monitoring the market, updating forecasts and positions, trading and ensuring compliance with risk management policies. A vertically integrated generator-retailer might achieve economies of scope from, for instance, integrating its risk teams, and using the same team to provide risk management to both its generation and retail activities.

While the potential for economies of scope may exist, it is not clear to us why such economies would be vertical-integration specific in the electricity sector; that is, why non-integrated firms might not be able to achieve similar efficiencies, say, through contract. Further, it is not obvious to us that the retail entities that have entered and expanded in the New Zealand market in recent years without investing in generation assets—including national retailers Ecotricity, Electric Kiwi, Flick Electricity and Vocus—have a higher operating cost structure than vertically integrated retailers.[11]

We are aware that our argument conflicts with (Simshauser, 2020, p. 8), who cites several authors as concluding that partitioning generation from retail results in cost efficiency losses of 20 per cent to 40 per cent. However, on our reading, the studies cited by Simshauser in support of this finding reviewed the separation of generation from distribution and transmission, not a separation of retail from generation.

In short, absent further explanation of a theoretical or empirical basis for the Authority’s view that vertical integration has the potential for economies of scope (or scale) not available to non-integrated entities, we consider it unlikely that economies of scope or scale are a substantive explanation for the high proportion of the wholesale market served by vertically integrated firms.

2.3.3 Eliminating double marginalization

A classic explanation for vertical integration is that it can eliminate “double marginalization”, and hence lower prices for consumers (Slade, 2019, p. 5). The idea that vertical integration creates an incentive to lower prices to consumers was first formalized by Spengler (1950) . An integrated firm will set the downstream price based on the firm’s combined upstream and downstream profits. The entity will have an incentive to lower its prices to consumers (relative to what the downstream entity would have charged if not vertically integrated), if a lower price attracts more customers and if those extra customers generate extra profits at the upstream division of the merged firm, as the upstream division increases the volume of inputs supplied to the downstream division to meet the extra demand.

A large body of empirical work shows that vertical integration tends to be efficient and benefits consumers by removing double marginalisation (Lafontaine & Slade, 2007). However, we are sceptical that the benefits identified in many of these studies can be assumed to apply to the New Zealand electricity sector. In the New Zealand electricity market, vertically integrated generators cannot sell

[10] Economies of scope arise when it is cheaper to produce two or more goods using the same infrastructure. Economies of scale arise when it is cheaper to produce more of the same good.

[11] In a recent submission to the Commerce Commission, Electric Kiwi stated “we believe we are among the most efficient retailers in the market” (Electric Kiwi , 31 August 2021).

electricity directly to their retail arms. Under the gross pool design, all vertically integrated firms are obliged to sell electricity into the wholesale market pool as generators and buy it back as retailers to serve their customers. As no vertical shipments occur, eliminating double marginalization is lessened as a motive for vertical integration (we turn to the effects of financial contracts and derivatives, including retail as a physical hedge, below).

2.3.4 Raising rivals' costs

Similarly, when no vertical shipments occur the primary mechanism by which vertical integration can lessen downstream competition is also weakened. Vertical integration can harm competition when an integrated entity can use its control over an upstream input to weaken its downstream rivals, either by denying them access to that input – "total foreclosure" – or by raising the price charged for that input – "partial foreclosure" (Shapiro, 2019, para. 7). From an economic perspective, total foreclosure is just a special (and extreme) case of partial foreclosure. For simplicity, we refer to both effects as "raising rivals' costs".

Vertical shipments can raise the economic cost to the integrated firm of selling inputs to its rivals, because access to the input, or a lower price for that input, may make those rivals stronger competitors. Integrated suppliers could try to use key inputs strategically to advantage their downstream operations. Economists and regulators refer to these key inputs as "bottlenecks"—inputs that must be obtained to compete in a downstream market but which are controlled (typically) by a single entity. Ensuring access to a 'bottleneck' facility is the reasoning that led the government to separate Chorus (network) from Spark in the telecommunications sector, and Transpower (network) from ECNZ in electricity sector.[12]

As a general rule, the potential for vertical practices to harm competition occurs only under specific assumptions, with seemingly "only minor perturbations to these assumptions" reversing the predicted welfare effects (Cooper, Froeb, O'Brien, & Vita, 2005, p. 3). In the New Zealand electricity sector, the mechanism for raising rivals' costs via vertical integration is not available to generators trading through the wholesale electricity spot market. A generator does not sell into the wholesale spot market at different prices to different customers, and a generator cannot prevent a retailer becoming a purchaser from the wholesale pool.

A generator may, or may not, have market power in the wholesale market, but owning a retailer does not provide the generator with an additional means to raise the costs to its rivals of purchasing electricity in the gross pool. Indeed a generator owning a retailer is generally considered to have a reduced incentive to raise prices in the wholesale market (relative to a generator in a similar position but without a retail position), because the generator-retailer is also a purchaser in the same market (Australian Competition & Consumer Commission, 2018); we discuss further below how retail and forward contract positions alter incentives for generators to offer capacity into the wholesale market.

[12] The separation of Telecom into Chorus and Spark was proposed by the Telecom Board as a condition for the Government to accept its proposal to build the majority of the Ultra Fast Broadband network: https://company.chorus.co.nz/file-download/download/public/1467

In a variant on this argument, the Authority suggests, in its *Internal transfer pricing* consultation paper, the possibility generator-retailers may sell at prices below what is economic with the intent of forcing competitors to exit (Electricity Authority, 8 April 2021, p. 4). Such a strategy would involve generator-retailers choosing to transfer shareholder funds to consumers, which is the effect of pricing below cost, in the hope of squeezing competitors out of the market. Economic theory sets out the conditions necessary for such behaviour to be rational (Carlton & Perloff, 2015, pp. 352-353). The generator-retailer would need to be confident that:

- competitors would exit the market or reduce market share until they were ineffective as competitors
- the generator-retailer could subsequently raise retail prices above competitive levels to recoup the losses
- competitors would not re-enter or expand (including other generator-retailers) when the generator-retailer attempted to raise prices above competitive levels to recoup its losses.

The Authority offers no analysis or explanation of how an integrated generator-retailer could be confident of these outcomes. Taking just the last point, no generator-retailer can deny access to the 'gross pool' for retailers seeking to re-enter, nor deny those retailers access to exchange traded futures.

In the more recent MMR the Authority raises the issue of whether VI provides barriers to entry in generation, and the effect such barriers can have on wholesale prices. Low barriers to entry place pressure on incumbents to display competitive pricing behaviour. The Authority notes the possibility that

> VI may increase costs for new entrants by reducing liquidity in the forward market and reducing the demand for PPAs that can support new-entrant generation. This is because it can be hard for non-VI generators to obtain PPAs from generator–retailers or obtain hedges elsewhere. Vertically integrated firms may be incentivised to grow their supply and retail shares in parallel, thereby constraining PPAs with independent generators by the rate at which they grow their retail books. (Electricity Authority, 2021) 5.28

The Authority notes a number of developments in the market in recent years which lead it to the conclusion that:

> VI as a barrier to entry may be becoming less of an issue. (Electricity Authority, 2021) 5.29

The Authority reports the percent of new generation built by new entrants versus incumbent vertically integrated firms in recent years and repeats the conclusion above:

> Over three-quarters of committed projects and projects that are likely to be committed soon are owned by generator–retailers. This suggests there may be barriers to entry for smaller, independent firms, although there are encouraging signs (the possibly committed solar projects are all from independent companies) that this may be changing. (Electricity Authority, 2021) 5.34

2.4 Vertical integration as a means of navigating market imperfections

A limitation in the theories outlined above is that, in the real world, the motivation for vertical integration does not require product flows. In a study of vertical integration in United States manufacturing sector, Atalay, Hortacsu, & Syverson (2014), found that one half of upstream establishments do not ship to their downstream divisions. In electricity markets with gross pools, there is of course no physical supply between generators and retailers. Instead, the motivation for vertical integration involves intangibles.

Transaction cost theories pioneered by Nobel Laureate, Oliver Williamson (1975), and the work of those who built on his insights both theoretically and empirically, have changed the way economists think about vertical integration. An important conceptual lesson from Williamson's work is that it is not particularly useful to think about a sharp dichotomy between vertical integration and market transactions; rather, there is a continuum of governance arrangements between spot transactions (anonymous sales and purchases) through to bringing activities in-house. These hybrid forms include various types of long-term contracts, non-linear pricing arrangements, joint ventures, and so on.

The foundation of transaction cost theories is the recognition that contracts are incomplete (it may be impractical or prohibitively costly to write a contract that covers every possible contingency and to stipulate appropriate responses). Because contracts are incomplete, contractual hazards arise—one or other party might undertake actions that do not suit the other party after the contract has been agreed.

Modern theories of vertical integration turn in one way or another on the presence of these market imperfections; that is, on deviations from the long list of explicit and implicit assumptions associated with textbook models of perfect competition. Vertical integration provides a means of navigating these real-world imperfections. Internal organisation mechanisms provide the potential to better harmonize conflicting interests and can provide for a smoother and less costly adaptation process, thereby facilitating more efficient ex-ante investment and more efficient adaptation to changing supply and demand conditions over time (Joskow P. L., April, 2010, p. 23). As Williamson observed (Williamson O. E., 1971, p. 61) :

> The advantages of integration thus are not that technological (flow process) economies are unavailable to non-integrated firms, but that integration harmonizes interests (or reconciles differences, often by fiat) and permits an efficient (adaptive, sequential) decision process to be utilized...

Against these benefits, vertical integration risks costs of increased bureaucracy and dulled incentives of in-house production. A view of whether vertical integration is beneficial or harmful to consumers therefore must be grounded in an assessment of whether vertical integration is an efficient means of navigating the real-world imperfections of the sector under study, in this case the electricity sector; that is, whether the gains from over-coming real-world imperfections exceed the costs of dulled incentives and increased bureaucracy.

The theoretical literature has identified numerous ways through which organizational design through vertical integration affects firm performance. We briefly introduce several forms of contract hazards below. In the following section, we consider whether some these hazards are likely to be material when evaluating vertical integration in the New Zealand electricity markets.

Relationship-specific investments can be especially problematic in making bilateral trading relationships susceptible to ex-post bargaining and contractual performance problems (Williamson, O. E.,1975, 1985; Klein, Crawford, & Alchian, 1978; Joskow, 1987). A relationship-specific investment may have little value outside of its use in a specific trading relationship. Once the investment is made, a risk of 'hold-up', a form of opportunistic behaviour, occurs. The investing party's bargaining power is reduced once they have made an investment, because the value of the investment becomes dependent on another party for either sale of their output or a source of inputs. This exposure reduces the incentive to undertake an otherwise efficient investment. An example of this outcome is where an investment in long-term assets is required, but only short-term sales commitments are available in the market.

Where recurrent bargaining is required as market circumstances change, internal organisation has an advantage over market exchange in that it permits adaptation and forecloses future haggling. In contrast, recurrent contracting can be impaired as each party seeks to adjust the terms to their advantage as market conditions change.

Contracting for an item whose final cost or quality is subject to uncertainty raises issues about incentives. The supplier could bear the uncertainty but would charge a risk premium. If the buyer regards the premium as excessive and prefers to bear the risk, they may seek a cost-plus contract. Under this type of contract, the supplier has less incentive to achieve least cost performance, so the buyer may therefore wish to monitor the supplier and, where external monitoring is difficult, integration may become the most effective option. Typically, incentives to behave opportunistically are reduced and monitoring costs are lower where firms are vertically integrated.

Property rights theories identify alignment of investment incentives with better performance (Grossman and Hart, 1986; Hart and Moore, 1990). Hart (2017) argues that integration will occur between firms in response to incomplete contracts if it is more efficient for one of the firms to hold the residual control rights than for these to be shared between the firms. The firm with residual control rights has the power to make decisions about things that are left out of the contract. Offsetting these benefits, divisions within an integrated firm lose control rights and may have less incentive to innovate or invest, because they are unable to capture all the benefits of innovation. Whether integration is efficient depends on which distortion is more important (Hart, 2017, p. 1734). Commercial entities have strong incentives to strive for the optimum balance between these incentives.

Vertical integration can also incentivize multi-tasking (Holmstrom and Milgrom, 1991), and improve coordination (Hart and Holmstrom, 2010), by reducing transaction costs. Moral hazard models highlight productivity gains due to alignment of incentives to exert effort and the rewards of those efforts (Lafontaine & Slade, 2007).

In the following section, we consider some of the contracting hazards arising in electricity markets and whether vertical integration is likely to be an efficient response to those market imperfections.

3. Vertical integration in electricity markets

3.1 Vertical integration a feature of electricity markets

Vertical integration of electricity generation and retail activities has emerged as the prevailing organisational form in most electricity markets in which the wholesale and retail sectors have been opened to competition. For example, in Singapore the largest 6 vertically integrated generator retailers supply 90 per cent of the retail market.[13] In Australia, the four largest vertically integrated participants in each region accounted for the majority of generation output and at least half of all retail load (AER, 2021, p. 249). These four vertically integrated firms account for:

- 79% of generation output and 65% of load in NSW
- 83% of generation output and 50% of load in Victoria
- 69% of generation output and 63% of load in South Australia.

NERA report consolidation and vertical integration as a common experience of deregulated electricity markets in Great Britain, Ireland, the Netherlands, and PJM) (NERA Economic Consulting, 2019). The structure of the market in Great Britain has recently become less vertically integrated. Some analysts suggest a primary motivation for reduced vertical integration has been the regulator shifting the risk of new investment from generators to consumers (via-feed in tariffs and capacity payments) reducing the need for vertical integration as a means for managing investment risk (Helm). NERA observe that the regulator also raised the cost of vertical integration by imposing the cost of market-making obligations on integrated firms and withdrawing those obligations upon divestment.

As outlined above, vertical integration can be an efficient response to market imperfections. In this section we discuss four reasons why vertical integration emerged as the predominant organisational form in competitive electricity markets. In the following section, we consider whether further market evolution may lead to a greater diversity of organisational forms becoming economically efficient, and therefore consistent with the long-term interest of consumers.

3.2 Incentives to invest

In the wholesale market, generators make investments in large, long-lived assets. Prior to committing, the generator needs to be confident that it will be able to sell the output of the plant at a price that makes the investment profitable. In concept, spot price fluctuations have opposite effects on retailer and generator profits; an increase in the spot price affects positively the revenue of the generator to the detriment of the retailer, and a decrease in spot price benefits the retailer to the detriment of the generator.[14] As the price risk profile of a retailer and generator are negatively correlated, long-term fixed price forward contracts should, in principle, align the hedging needs of both parties.

[13] Energy Market Authority, Singapore Energy Statistics 2020.

[14] In New Zealand, the vast majority of mass-market customers are on contracts that allow the consumer to vary the volume of electricity they consume at a fixed monthly price.

However, when contract prices are fixed, the ex-post distribution of risks across the parties depends on the duration and magnitude of the periods during which the spot price will be above or below the contractual fixed price. In the electricity sector, the duration and magnitude of these periods is not foreseeable, especially in the New Zealand electricity sector with its reliance on hydro-electricity generation and electrical isolation from other markets (unlike, for example, Europe).

As entry costs into the retail sector are comparatively low,[15] any period of sustained spot prices below the contract fixed price may induce profitable new entries into the retail market. Retail firms sell electricity on short-term fixed price contracts with their customers. Retailers with a significant level of sourcing through long-term fixed-price contracts would be exposed to a risk of price-squeeze from the new entrant retailers; retailers on long-term fixed-price contracts and exposed to a risk of price-squeeze would, in turn, expose generator counterparties to the risk of default by thinly capitalised retail entities. Anticipating this risk of opportunism, generators would require a higher contractual premium, making long-term contracts more expensive, and therefore less attractive, for retailers. Absent long-term alignment of parties' interests, long-term contracts between generators and retailers that would support investment in new generation are not ''self- enforcing'' (Klein, 2000).

By contrast, vertically integrated generators rely on the internalised incentive to maintain their retail base, eliminating hold-up risk and enabling investment in generation. It is not a coincidence that since the inception of the wholesale electricity market 25 years ago, almost all new investment in new generation of scale has been under-taken by vertically integrated generator-retailers.[16] The notable exceptions are Whirinaki (which was commissioned by the government and paid for by a regulated levy on consumers), several geo-thermal plant built by lines companies, and most recently the Waipipi windfarm, built by Tilt.[17] (We discuss further below how distributed energy resources alter the risk profile and may impact on the efficient organisational form for new investment).

To date, vertical integration has lowered the total risk, and hence the cost, of financing investment in generation relative to what could be achieved via contracting. Consumers have benefited from a lower cost of capital for investment in electricity generation through lower wholesale prices and higher reliability than would otherwise have been experienced. Appendix A explains why the bulk of cost reduction due to a lower cost of capital can be expected to have been passed through to consumers.

As we mention earlier, the Authority tested the whether the degree to which new entrants and vertically integrated firms are investing in generation from the perspective of the impact on competitive pricing behaviour. They confirm that non vertically integrated generators are entering the market even though the majority of upcoming projects are still being initiated by vertically integrated

[15] In comparison to the cost of building new generation plant. In addition to systems and marketing costs, retailers must also fund prudential requirements in the wholesale market, lodge deposits with the network companies, and potentially fund prudential requirements in the futures market.

[16] Ecotricity, (2020, p. 1) argue that "gentailers" have controlled the development of new generation capacity into the market with the gentailer's retail base providing an internal hedge for the new generation volumes. The better view is that vertical integration improves incentives to invest by reducing hold-up risk and improving access to capital; this is a benefit of vertical integration.

[17] Energy News reports (18 November 2020) the Tilt Waipipi output is all sold through a PPA to Genesis, that is, a vertically integrated portfolio generator: "Under the PPA, Tilt Renewables owns and operates the wind farm and Genesis purchases the electricity generated".

firms. In the MMR section on dynamic efficiency, the Authority states that uncertainties and incentives on existing players may have impeded timely investment but the investment environment is improving. It describes the current state of investment as "encouraging".

3.3 Reduced credit and re-contracting risk

A standalone generator could be expected to enter into a series of wholesale finite term financial contracts with independent retailers. A vertically integrated generator substitutes these contract arrangements with a large, diverse, group of contracts directly with retail consumers. The bundle of retail customer contracts reduces both credit and re-contracting risk exposure.

In terms of credit risk, retail customers are more diverse than wholesale customers and their default risk is more easily and cheaply managed (for example via credit checks, bonds, and prepayment meters). In contrast, a non-integrated generator may have limited ability to assess the creditworthiness of the retailer (or other wholesale customer) and little ability to monitor the impact of their behaviour on their credit risk. Counterparty risk on a bilateral contract is managed by the parties themselves and by the exchange in exchange traded contracts. The generator or the exchange may impose some prudential requirement on the wholesale customer to reduce the generator's risk exposure. Ultimately prudential requirements increase cost to the consumer, by increasing the cost of hedging to retailers.

Re-contracting risk is also reduced by vertical integration. A non-integrated generator is exposed when contracts expire (or if a purchaser fails). This re-contracting risk is relatively more significant, although less frequent, than the equivalent risk associated with retail contracts and switching rates. Re-contracting risk is likely to be a significant concern for generators with long-term investments. Diversifying across a range of sales methods, including vertical integration with a retailer, may mitigate this risk, reducing capital costs.[18]

3.4 Incentive to offer competitively to ensure dispatch

As noted earlier, New Zealand's wholesale gross pool market means vertically integrated generators sell their electricity through the spot market: they cannot sell it directly in an internal transaction to their affiliated retailer. This market structure differs from other some markets such as the United Kingdom.[19] In a gross pool, the generator wants to ensure its generation is dispatched so that they earn revenue from generation to offset the cost of their retail purchases. This incentive is likely to be at least as strong as the incentive created by a hedge contract between a generator and non-affiliated retailer since the internal hedge position (i.e., the proportion of generation committed to its retail base) is likely to be at least as great as that which would be committed to an external hedge position.

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[18] An alternative strategy is for the output to be sold through a power purchase agreement (PPA). In this case the entire volume is sold, usually on a long-term basis, to a single party. In reality the single buyer is often a portfolio generator and, oftentimes, a vertically integrated portfolio generator. The price for PPAs reflects the fact that the buyer takes the risk on the variability of the generator's output.

[19] The National Electricity Market (NEM) of Australia, Singapore and the Philippines also operate gross pool markets.

Thus, vertical integration is likely to be at least as effective as hedge contracts in limiting the exercise of market power in the wholesale market (Australian Competition & Consumer Commission, 2018).

Vertically integrated generator retailers have the same, additional incentive, as stand-alone generators to offer generation capacity so if demand is higher than expected and prices commensurately higher they can capitalise on those opportunities.[20] However, a vertically integrated generator is likely to act in a more conservative way—offer additional generation at dispatchable prices—because they have to cover an unknown retail volume. In contrast, the stand-alone generator knows their contract position.[21]

Because a vertically integrated generator faces greater demand uncertainty than a non-integrated generator, the integrated generator is more likely to offer at prices closer to marginal cost than a stand-alone generator. This result arises because competition in the wholesale electricity market most closely corresponds to Cournot quantity competition (Hogan, 2011). Cournot, or quantity competition, is one of the two key models applied in competition economics to understand how firms interact and compete for market share in markets that are not perfectly competitive (that is, almost all real-world markets); the other model is "Bertrand" or price competition. Under Cournot quantity competition, firms behave as though they set quantities based on their knowledge of demand and the quantities they expect other firms to set.

Where a market exhibits Cournot-like competition, an increase in capacity will typically lead to increased competitive pressure, and hence lower prices and increased trade. However, a generator faces many different possible demand levels even when it has a good level of knowledge about its competitors' production levels. Uncertain demand means that the market outcome will move away from the Cournot equilibrium to an outcome that has smaller price-cost margins (Borenstein, Bushnell, Kahn, & Stoft, 1995). Demand uncertainty means that wholesale prices are expected to be closer to the perfectly competitive outcome than in a market with more certain demand.

Consistent with the prediction from economic theory, empirical analysis of the Australian NEM shows that vertical integration increases the amount of capacity offered into the market at competitive prices. Frontier Economics (2017, paragraph 12) explained:

> We found that vertically integrated generators in fact behave more competitively on average than when they were operating as stand-alone generators.... This statistically significant, robust and striking result is contrary to claims that vertically integrated generators will bid at higher prices than stand-alone generators.[22]

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[20] There are nuances around this incentive including where a generator may not want to face the warm-up cost and some 8-10 hours warm up period for a thermal unit. Another case is where hydro capacity may be offered from storage reservoirs but priced at the opportunity cost of releasing today compared with the value of being available to manage risk in the future. In the latter case the capacity is offered but the price might be more associated with scarcity value.

[21] To date, this has been a hypothetical construct as all generators of scale have been vertically integrated. We understand that the sale by Trustpower of its retail base will be accompanied by relatively long-term hedge contracts to the purchaser of the retail base.

[22] In the NEM, generators are said to 'bid' into the market, whereas the NZEM uses the term 'offer' (to sell and bid to buy) consistent with commodity and other exchange traded markets.

Frontier's conclusions are consistent with our expectations: generation only provides a hedge if it is dispatched and the risk of not being dispatched constrains offer behaviour.

3.5 Managing residual volume risk

Retailers generally sell electricity to their customers on a fixed price variable volume contract. This form of contract means that there is uncertainty about both the volume of electricity the retailer will require and the intraday shape of the load. Some of this uncertainty resolves as the time gets closer (for example the weather becomes more predictable), but it is not fully resolved until real time (or once meters are read).

Due to the correlation of retail quantities and spot prices, electricity retailer price and quantity risks have been described as having ''flat hills and deep valleys'' (Boroumand & Zachmann, 2012). In periods of high wholesale prices their customers are likely to demand more electricity than the retailer expects and has provided for; this higher-than-expected demand is one of the reasons prices may be high—this was well illustrated by peak demand during cold weather in August 2021. Thus, in the absence of vertical integration or contracts, a retailer's losses in periods where wholesale prices are above retail prices are over proportional. In periods of low wholesale prices (say, a summer holiday evening) retail customers demand less electricity so that a retailer's gain from the positive retail-wholesale price differential is under proportional. This payoff-structure of retail contracts is almost perfectly mirrored by call options and peak generation assets. Thus, those assets are essential for hedging a retailer's joint price and volume risk. This 'residual volume risk' explains why forward contracts alone are not sufficient for hedging a retail commitment.

A vertically integrated generator may mitigate this risk by offering a larger quantity into the spot market at a more competitive price to cover short-term retailer volume risk, as discussed above. Volume risk could, in theory, be managed by an option contract, but it is likely to be costly to find a form of option that suits more than one party, particularly compared to the cost of managing uncertain outputs through vertical integration.

3.6 A simulation model

To test formally our conclusion that vertical integration is an efficient means for mitigating residual risk in the New Zealand electricity market we adapted a simulation model published by Boroumand & Zachmann (2012). Whereas the Boroumand & Zachmann study simulates the outcomes for an electricity retailer holding 1 MW of *retail* contracts, we simulate the outcomes of a *generator* holding 1 MW of generation assets. Our adaptation of the work of Boroumand & Zachmann (2012) for this analysis is described in detail in Appendix B.

Our simulation model estimates the benefits of different risk management portfolios (potentially) available in the New Zealand electricity market. It compares the risk for a North Island and a South Island generator under 7 separate strategies choosing between full market exposure, entering into retail contracts and/or forward contracts and/or call options and/or put options.

The results show that the least risk strategies include the use of options. The results show that a combination or retail and forward contracts are more risky than using options, but not as risky as spot exposure. For generators with access to only retail and forward contracts—as is effectively the case in the New Zealand market as option contracts are limited—a combination of the two is the least risky strategy. That is, a combination of vertical integration and trading in forward markets, is the least risk strategy available to generators in the New Zealand market.

4. Recent commentary on vertical integration

4.1 Drawing from the theory and empirical research

In section 2, we reviewed key conclusions and findings from theoretical and empirical studies into the causes and consequences of vertical integration. Virtually all theories of vertical integration turn in one way or another on the presence of market imperfections. In section 2, we discuss four reasons why vertical integration emerged as an efficient organisational response to the hazards for ex-ante investment commitment and ex-post performance in the electricity sector. In this section we draw from the preceding analysis to assess the views expressed by the Authority in relation to impacts and risks of vertical integration, and whether forced vertical disintegration as advocated by some commentators would likely benefit or harm the long-term interests of consumers.

4.2 A comment on the Authority's perspective

4.2.1 Economies of scale and efficient risk mitigation

As noted in the introduction, the Authority views vertical integration of generation and retail electricity businesses as having the potential for economies of scale where fixed costs can be spread over the consolidated business. It also views integration as enabling efficient risk mitigation.

As discussed in section 2.4 above, we are sceptical that vertical integration provides significant economies of scope or scale in operating costs not available to non-integrated entities. We therefore consider it unlikely that these economies are a substantive explanation for the high proportion of the wholesale market served by vertically integrated firms.

The Authority's comment that vertical integration enables efficient risk mitigation, while correct, grossly understates the importance of choosing the most efficient organisational form for the long-term benefit of consumers. In the current market, vertical integration:

- has underpinned almost all new investment of scale in generation plant in New Zealand over the past 25 years (see section 3.2)
- reduces both credit and re-contracting risk, leading to lower costs to serve consumers (see section 3.3)
- increases the amount of capacity offered into the market and at lower prices than would be expected from stand-alone generators (see section 3.4)
- lowers residual volume risk relative to a standalone generator with forward contracts (see section 3.5).

Given the scale of investment in the sector and the significance of the risks being managed, vertical integration can be expected to have resulted in substantial long-term benefits to consumers through lower prices and increased reliability—relative to what would have occurred, had generation been separated from retail.

4.2.2 Competition concerns

The Authority considers control by integrated generator-retailers of the bulk of electricity generation raises competition concerns in the retail market (Electricity Authority, 8 April 2021, para. 2.1). As we noted in our introduction, it is not clear whether the Authority perceives this concern as arising when an integrated entity supplies a large share of the market, or when the bulk of the market is supplied by vertically integrated entities, or whether its concern results from some combination of entity size and the proportion of the market supplied by vertically integrated firms. The MMR focusses on barriers to entry in generation and the effect such barriers can have on wholesale prices, thought the MMR sees the basis for any concerns as improving and "becoming less of an issue".

Although we cannot be confident that we understand the Authority's thinking on vertical integration, given its limited explanation, the concerns as expressed by the Authority are not supported either in theoretical literature or the applied experience of competitive electricity markets. We respond briefly to each aspect of the Authority's comments below.

4.2.3 Market structure is not determinative of competitive behaviour

An entity with either a large share of the wholesale market, or a large share of the retail market, may or may not give rise to competition concerns in the market in which it holds a large share; however, vertical integration does not add to those competition concerns; the gross wholesale pool structure is not conducive for an entity to leverage market power from one market into the other market. The MMR considers VI from the perspective of whether it imposes barriers to entry for non-vertically integrated firms. It posits the view that barriers to entry in new generation may limit price competition. The literature and applied experience of competitive electricity markets does not support the Authority's concern that integration combined with significant market concentration confers the ability for the largest firm or firms to act without competitive constraint in either the generation or retail markets. The Australian Competition Tribunal, in its decision to authorise AGL Energy to acquire Macquarie Generation addresses this point at some length (Application for Authorisation of Macquarie Generation by AGL Energy Limited, 2014); it makes a number of comments that reinforce points that we have already made:

- Market structure is not determinative of competitive behaviour (paragraph 369).
- Integrated companies have an incentive to ensure that they are dispatched, which limits their incentive to withhold generation or raise prices; generators that have entered hedge contracts have a similar incentive. While prices may rise somewhat in periods of capacity constraint, the generator will still have an incentive to ensure it is not displaced (paragraphs 314-315).

The Tribunal's observation that it is competitive conduct, not market structure, that determines outcomes for consumers bears citing in full:

> There is nothing inherently wrong with a market in which three large firms compete vigorously for market share where there are incentives to steal customers away from rivals. It is behaviour that matters, not structure per se. It appears to the Tribunal that it

> has been invited to assume that the "Big 3" will not constitute a competitive market principally on the basis of their combined market share immediately post-acquisition on an assumption that competition between them would become muted over time. In the opinion of the Tribunal, oligopolies should not be thus prejudged.
>
> The Tribunal does not consider that any shift to an uncompetitive oligopoly is likely. It is accepted that AGL will be long in generation and will have a real commercial incentive to achieve some level of balance between its generation capacity and its retail load in the longer term. It can only do so by winning customers from [the other gentailers, which] can be expected to resist. The competitive environment that is likely to exist in that situation may be hostile to small, non-integrated retailers or it may present niche opportunities. However, the Tribunal cannot conclude that a more atomistic market structure that favours a particular class of competitors is intrinsically better for consumers in the long run. It is the competitive mindset that matters, not market structure.
>
> …In a product as homogeneous as electricity it is hard to conceive that independent action could be taken successfully to give less and charge more, as this Tribunal put it in *Re QCMA* many years ago. If one gentailer sought to do this, the potential gains to a rival by not doing this would be commercially obvious. (Application for Authorisation of Macquarie Generation by AGL Energy Limited, 2014, paragraphs 369-70, 372)

4.3 Commentators seeking forced separation

Vertical integration between electricity generators and retailers has become somewhat of a 'lightening rod' for commentators unhappy with the performance of the electricity sector. Government intervention to separate, to varying degrees, generation activities from retail activities would, in the view of some commentators, lead to better outcomes for consumers.[23] To our knowledge, none of the commentators who suggest vertical integration is a problem has published any supporting analysis, either conceptual or empirical.

4.3.1 Anomalous analogy

Several of these commentators have suggested the comparatively recent split of Telecom into a network company, Chorus, and a telecommunications and digital service provider, Spark, as providing a model for reform of the electricity sector, seemingly unaware that both industries are subject to similar legislation separating (and revenue regulating) the network component from the content and retailing activities.[24] Analysis by analogy is prone to error, especially when the analogy is anomalous.

[23] See for example, https://www.stuff.co.nz/business/opinion-analysis/300383610/power-blackout-highlights-nzs-electricity-problem; https://www.energynews.co.nz/news/electricity/95733/nz-lacks-basic-power-competition-rules-octopus; https://www.pundit.co.nz/content/has-our-electricity-system-burnt-itself-out

[24] https://www.stuff.co.nz/business/opinion-analysis/300383610/power-blackout-highlights-nzs-electricity-problem; https://www.pundit.co.nz/content/has-our-electricity-system-burnt-itself-out.

4.3.2 Vertical integration and liquidity in contract markets

A notion repeated recently by commentators is that vertical integration results in less liquidity in contract markets. The Electricity Price Review set this argument out as follows (Electricity Price Review, 2018):

> Another drawback of vertical integration is that it can result in less use of contract markets – where companies buy and sell electricity ahead of time to lessen their exposure to wholesale price volatility. Vertically integrated companies have no inherent need for contract markets, whereas independent generators and retailers rely on them heavily. If large portions of the generation and retailing sectors have little use for contract markets, there will be low liquidity and muffled price signals, making it difficult and costly for independent companies to manage electricity price risks. An effective contract market, in contrast, supports ready access to contracts on reasonable terms, and sends clear price reference points for buyers and sellers.

In the early stages of the evolution of competitive wholesale and retail markets, some writers postulated what they referred to as a vicious cycle (Boroumand & Zachmann, 2012):

> [A]s long as derivative markets are not sufficiently liquid, retailers will strive to vertically integrate to better hedge their risk exposure … The more retailers are vertically integrated the less likely is the development of a liquid contract market, thus forcing non-integrated retailers to leave the market or to move towards physical integration.

We doubt that this proposition was ever valid for electricity markets, and if it were, the changing market dynamics place it amongst yesterday's problems.

We agree that liquidity is a beneficial feature of any derivatives market. Liquidity is characterised by frequent trading where prices are stable when trading occurs and contracts are readily available. Liquidity in electricity futures markets is particularly valuable for smaller firms as it provides the ability for them to adjust their risk position using futures contracts—larger firms are more likely to be able to diversify their volume risk reducing the benefit to them of liquidity.

Establishing liquidity in electricity markets presents special challenges. In most futures markets, liquidity is created by the presence of speculators, that is, traders prepared to take on outright risk. Liquidity in electricity futures markets is restricted because the underlying commodity cannot be stored so pricing cannot be linked directly to future physical supply. Trading in electricity futures is dominated more by expectations and risk premiums than in many other commodities. In New Zealand the restraint on liquidity is being addressed through the use of market making schemes.

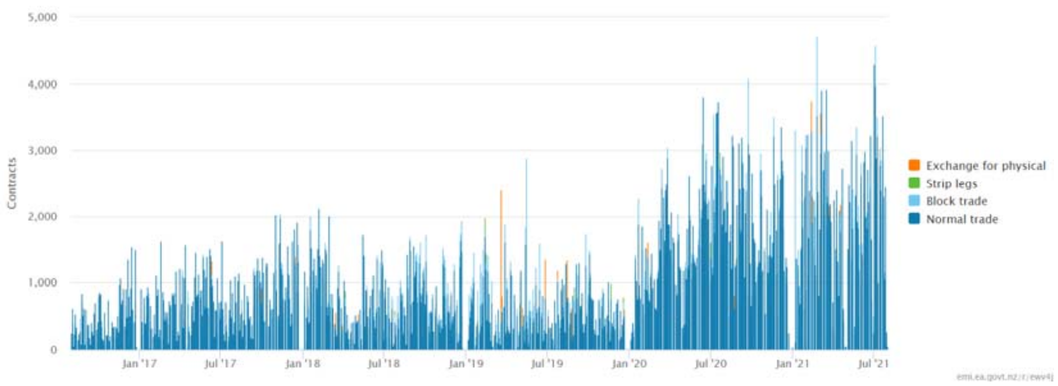
However, vertical integration is not a restraint on liquidity. Opponents of vertical integration suggest that it reduces the need for a financial hedge to manage price or revenue risk because the generator arm is earning the same price that the retail arm pays on the spot market; the argument is that generators no longer have an incentive to participate in futures markets. This argument ignores the (usually) fixed price, variable volume, contracts that the retailer has with their customers. If the retail arm has to pay a higher wholesale price than is embedded in their retail contracts, they lose money. This is the same as the contracting loss suffered by an independent generator when the price rises above the hedge contract price. Therefore, the incentive to participate in futures markets is the same for vertically integrated entities as it is for standalone entities.

The Australian Competition Tribunal reached the same conclusion (Application for Authorisation of Macquarie Generation by AGL Energy Limited, 2014):

- Competition is by its nature challenging. The relevant question is whether the challenge confronting competitors is made more difficult by vertical integration as a result of an impediment to securing suitable hedge contracts to enable them to participate in the market (paragraph 261).
- Individual generators have no incentive to withhold supply of hedge contracts (or raise prices) from competitive retailers because this would reduce revenue and advantage a competitor generator (paragraph 321). It is not feasible to recoup losses later: For a strategy of withholding contracts against generation capacity to be profitable in the long run, AGL would need to be able to recoup the revenue lost by charging higher retail prices in the future. However, the Tribunal was provided no analysis of how this could occur…The commercial reality is that AGL faces substantial retail competition, principally from its vertically integrated gentailer rivals. It cannot manipulate to its own advantage the level and type of competition from these competitors (paragraphs 358-359).
- The fact that from time to time some buyers cannot get the product they want at the price they are prepared to pay does not indicate an illiquid market (paragraph 328).

In any event the four major generator retailers have operated under a voluntary market making scheme since 2011. From Jan 2020 this scheme has operated under more stringent provisions incorporated into the Code including metrics for market making and penalties for failure to meet them. This could be seen as a belts and braces approach to the liquidity question raised by critics of vertical integration or a move by the Authority to remove any niggling doubt. Volumes in the New Zealand electricity futures contract have stepped up accordingly.

Figure 2 All New Zealand Electricity futures products, all maturities, daily volumes 01 Aug 2016 - 31 Jul 2021



Source EMI Electricity Authority

4.4 Market dynamics are changing

More recent theory on vertical integration observes that as competition increases, the incidence of vertical integration reduces. Vertical integration decreases because increased competition reduces bargaining frictions, one of the reasons firms integrate (Acemoglu et al., 2010). Modern organizational economic theory proposes that shocks to product market competition led firms to reorganize production chains and that this effect is transmitted through market prices. In a study of a natural experiment in the United States' coal mining industry, McGowan (2017) shows that an exogenous increase in product market competition due to deregulation of the railroad sector caused a 30 per cent reduction in vertical ownership.

Competition in the New Zealand retail sector has increased significantly over the past decade. It is conceivable that this increase in competition will alter the most efficient organisational form, leading to less vertical integration. More generally, the dynamic changes to the electricity sector are likely to lead to changes to the most efficient corporate form, or at least new experimentation in organizational structure. Trustpower's move to sell its mass-retail base and establish a standalone generation business may be anecdotal evidence of the change in efficiency of different organisation forms. Trustpower is reported as saying changes to the retail energy markets were the "primary" driver of the sale:[25]

> Electrification and decarbonisation, decentralised energy, digital trends in service provision and utilities convergence are all shaking up traditional operating models.

The position the MMR takes is also consistent with encouraging signs in new investment by non-vertically integrated firms.

4.5 Concluding comment

The overwhelming conclusion from the large body of literature we reviewed in preparing this report is that specific features of electricity markets are both statistically and economically important causal factors influencing the decision of firms to vertically integrate, both in New Zealand and internationally. Viewing the New Zealand electricity market through the lens provided by this empirical and theoretical work we draw two primary conclusions:

- vertical integration of electricity generation and retail activities has emerged as an economically efficient organisational form to overcome real-world imperfections in the wholesale and retail electricity markets; if regulatory interventions were to impede efficient vertical integration, the cost of electricity to consumers would increase, potentially substantially
- market reform which reduces market imperfections, including bargaining frictions, will increase competition and lead to a reduction in vertical integration; that is, an increase in competition will reduce the need for firms to vertically integrate (but a decrease in vertical integration imposed through regulation will not increase competition).

[25] https://www.nzherald.co.nz/business/energy-industry-shake-up-trustpower-says-it-could-sell-its-retail-business/OMY3UCZBJU2HXBD73VADUHB2SY/

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Appendix A Risk reduction passes through to lower costs for consumers

The analysis set out above conduces that risk reduction enabled by vertical integration allows a reduction in risk premium. In a workably competitive market, end consumers can expect to benefit from that risk reduction.

Economic theory finds that the extent to which a cost saving (in this case, the reduction in risk premium) is passed on to a consumer depends on the competitive pressure in a market. In the extreme case of perfect competition, there are many sellers of a homogenous product and all firms are price takers with no power to influence or set prices; the market price of an additional unit exactly equals the cost of producing that unit. In this situation, a change in costs will result in all of the cost change being translated into market prices, and consumers would receive the full benefit or incur the full impost of the change in costs.

The other extreme case is a monopoly (a single seller). If we assume that demand can be represented by a linear demand curve,[26] then the monopoly would pass through half the change in costs. This result is shown in a stylised form in Figure 3 below.

A profit maximising monopoly will produce a quantity such that marginal revenue (MR) is equal to marginal cost (MC). A monopoly will target this quantity as a lower level of production would reduce profits as the revenue lost would exceed the cost reduction; similarly, a higher level of production would reduce profits as the additional cost would exceed the additional revenue.

In Figure 3, the quantity where MR is equal to MC is represented by Q_1 (before a change in costs). When a monopolist produces the quantity determined by the intersection of MR and MC, it can charge the price determined by the market demand curve at that quantity, represented by price P_1 in Figure 3.

With a linear demand curve, the marginal revenue curve is twice as steep as the demand curve. To sell more, a monopolist must reduce its prices, therefore the net additional revenue from the last unit sold is less than its average revenue on all units sold.[27] Hence, for any shift in the marginal cost curve, the change in price will be half that of the change in costs. This effect is demonstrated in Figure 1; that is, the reduction in price from P_1 to P_2 is equal to half the reduction in marginal cost from MC_1 to MC_2.[28]

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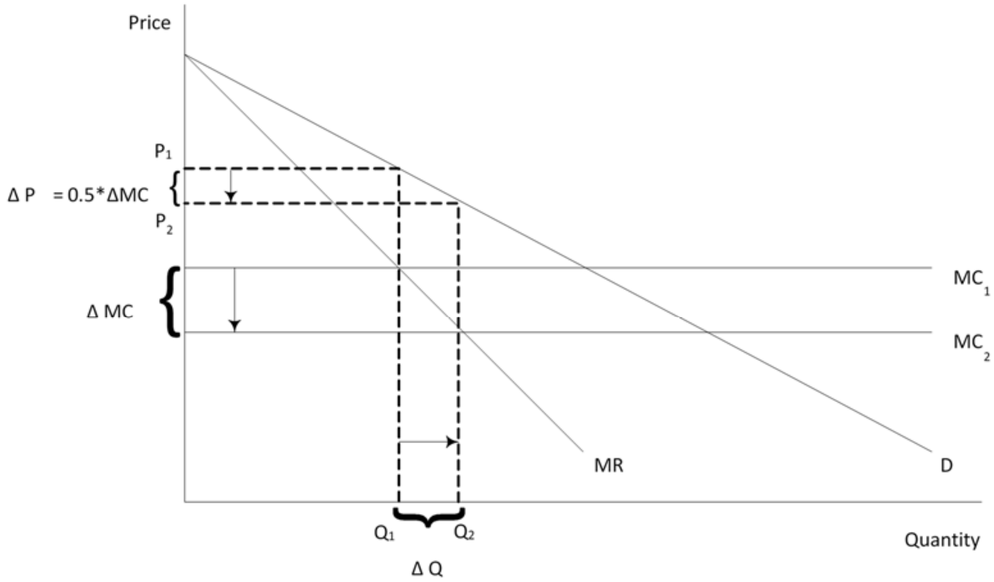
[26] A demand curve is the graphical representation of the relationship between the price of a good and the quantity of that good consumers are willing to pay at a certain price at a point in time. In reality, demand curves are rarely linear.

[27] For example, if a monopolist could sell 1 unit for \$10 and 2 units for \$9, the change in average revenue is \$1 and the change in marginal revenue is \$18-\$10 = \$2.

[28] For ease of illustration, a flat marginal cost curve (MC) is shown, but the result is the same for a shift of any shape marginal cost curve.

Figure 3 Cost pass-through by a monopoly



Hence, the greater the competitive pressure, the greater the portion of any cost savings that can be expected to be passed through to consumers. The two cornerstone economic models for understanding how firms interact and compete for market share in markets that are not perfectly competitive (that is, almost all real world markets) are "Cournot" or quantity competition, and "Bertrand" or price competition. Under price competition, each firm sets price given its belief about how the other firms will price. Under quantity competition, firms may behave as though they set quantities based on their knowledge of demand and the quantities they expect other firms to set.

Most academic analysis of the wholesale electricity market we are aware of concludes that the market has a Cournot-like structure, as suppliers simultaneously submit a schedule of quantities (willingness to supply at a range of prices) – see for example (Hogan, 2011). In concept, retail electricity markets exhibit some of the conditions necessary for Bertrand competition—the product sold is largely homogeneous and on a casual analysis the costs to supply might be thought to be more or less similar. However, because the five main retailers are vertically integrated with generation—an organisational form which has emerged in all competitive electricity retail markets to efficiently manage price and quantity risk—all retailers are subject to capacity constraints. This feature of the electricity retail market distinguishes it from textbook Bertrand competition; in Bertrand (or price competition), each firm can potentially take all the market.

Suppliers with physical generation assets face capacity constraints. Economic theory shows that when limits exist on the production capacities of competitors, markets that might otherwise exhibit Bertrand competition yield Cournot outcomes (Scheinkman, 1983). Literature on competition in the British and Norwegian markets (Boroumand D. F., 2011), and observations from the New Zealand market, tend to support a conclusion that electricity retail markets exhibit Cournot competition.

In New Zealand, retailers appear to compete over the number of consumers/ICPs. Annual reports released by retailers suggest that the number of ICPs is a critical success factor, as are measures of churn (gains and losses of consumers). For example, Meridian Energy's annual report lists customer ICPs as a key statistic, and Contact Energy's annual report provides information on churn relative to market average. Importantly, companies note that there is an optimum balance of consumers to generation capacity (Energy, June 2017):

> We aim for a volume of contracted retail sales that optimises our overall earnings relative to market risk.

Additionally, methodologies adopted by investment banks in valuing the retail electricity supply businesses internationally use customer numbers as a key variable in determining the long-term value of the business.

An oligopolistic market, that exhibits Cournot competition, produces a level of cost pass through that is between the monopoly and perfectly competitive outcomes. In a study often cited, (Niels, 2005) found that the price change in an oligopolistic market, with linear demand and a homogenous product, will be equal to N/(N + 1) of the cost change, where N is equal to the number of firms in the market. In the case of the retail energy market, if N is assumed to equal to five (the number of retailers that supply nearly 89% of all consumers), the expected pass through would be 5 / 6 or 83%. If N is larger, to reflect the smaller retailers in the market, the pass-through percentage would increase. For example, if N is assumed to be 10—the number of retailers that compete in every region in New Zealand, the pass-through would be 10/ 11 or 91%.

Appendix B Risk management optimisation model

Model details

The model simulates the payoff outcomes of a generator with 1MW of generation assets (in either the NI or SI) using a variety of different risk management contracts and hedges. These include, retail contracts, forward contracts and call and put options. We run six combinations of these risk management mechanisms (scenarios) for both a NI and SI generator.

There are two important (and related) assumptions for this modelling:

1. there are no transaction costs (or risk premia) for contracting
2. each contract is assumed to have net zero payoff on average.

Under each scenario, the generator is assumed to be minimising their exposure to 'worst case' risk. This is defined as the 95th percentile value at risk (VAR[95]). This measure represents the value of the payoff received by the generator at which 95 per cent of the simulated payoffs will be greater than or equal. Alternatively, only five per cent of outcomes will be worse than this value. As VAR(95) represents a loss, this number is negative. Therefore, a value that is closer to zero (less negative) represents a lower exposure to worst case risk.

The volume of retail contracts (measured in MW) are constrained to be positive. The retail load profile is load following. Retail contracts are normalised such that the average load for a 1 MW retail contract is also equal to 1 MW. The volume of all forwards and options (measured in MW) may be positive or negative. The volume of forwards and options are modelled as constant over the course of a year, that is, a 1 MW forward contract is modelled as 1MW for each trading period in a year.

Results

Table 1 shows the results of the modelling. The VAR(95) column is the main column of interest. As described above, the closer this value is to zero, the less risk the generator is exposed to in a 'worst-case' scenario. It is immediately apparent that any risk management portfolio results in a large reduction in the VAR(95) faced by a generator.

For both NI and SI generators, the portfolios where options are available to use (rows highlighted in grey) to hedge risk create the optimal scenarios. Indeed, the difference in VAR(95) from adding other contracts to the portfolio when using options is minimal. However, liquidity in options in New Zealand is limited.

The remaining scenarios consider the benefits of using retail and forward contracts. For both NI and SI generators, retail contracts provide a smaller VAR(95) than forward contracts alone, while a combination of the two provides even further benefit. The model estimates that the residual risk for a North Island (NI) generator that manages risk with a combination of retail contracts and forward contracts is 19 per cent lower than a generator that only manages risk with forward contracts. The equivalent reduction in risk for a South Island (SI) generator is 14 per cent.

Table 1 Results of VAR(95) optimisation

	VAR(95)	Retail contracts		Forward		Call option		Put Option	
		NI	SI	NI	SI	NI	SI	NI	SI
North Island generation assets									
All contracts	-411	0.02	0.00	-1.29	1.98	0.31	-2.00	-1.06	1.95
Forwards and options	-411			0.25	-0.38	-1.25	0.35	0.47	-0.40
Options only	-411					-1.00	-0.03	0.22	-0.02
Retail and forward contracts	**-1,327**	0.29	0.31	-0.64	0.43				
Retail only	-1,548	0.73	0.00						
Forwards only	**-1,637**			-0.96	0.10				
Generation only	-8,191								
South Island generation assets									
All contracts	-383	0.01	0.05	1.61	-0.66	-1.59	-0.30	1.62	-0.50
Forwards and options	-387			-0.14	0.31	0.14	-1.33	-0.13	0.53
Options only	-387					0.00	-1.02	0.01	0.22
Retail and forward contracts	**-1,307**	0.07	0.72	0.09	-0.09				
Retail only	-1,320	0.00	0.80						
Forwards only	**-1,523**			-0.03	-0.83				
Generation only	-6,233								

Explanation

The net payoff for all contracts/assets (including the retail contract) is zero in expectation. This is the same assumption that Boroumand & Zachmann (2012) use, which allows non-biased comparison between contracts/assets.

> We assume that in a perfect market (no market power, no transaction costs, full transparency, etc.) arbitrage would not allow for the existence of systematic profits. Without this postulate, the method for the evaluation of contracts and assets would drive our results. Indeed, the net loss calculated for each portfolio would be strongly determined by the valuation method of the assets or contracts within the portfolio.

Net payoff functions for each trading period, t, which represents each half hourly period:

$$\pi_{plant,t} = \max(P_t - mc, 0) \times V_{plant} - E\left[\max(P_t - mc, 0) \times V_{plant}\right]$$

$$\pi_{retail,t} = -P_t \times V_{retail,t} + E\left(P_t \times V_{retail,t}\right)$$

$$\pi_{forward,t} = P_t \times V_{foward} - E\left(P_t \times V_{forward}\right)$$

$$\pi_{call,t} = \max(P_t - X, 0) \times V_{call} - E[\max(P_t - X, 0) \times V_{call}]$$

$$\pi_{put,t} = \max(X - P_t, 0) \times V_{put} - E\left[\max(X - P_t, 0) \times V_{put}\right]$$

Where:

$$P_t \; is \; thespot \; price \; for \; period \; t$$

$$mc = marginal \; cost \; of generation \; for \; a \; marginal \; generator$$

$$V_{plant/forward/call/put} \; is \; the \; volume \; of \; each \; contract/asset \; purchased \; or \; sold$$

$$V_{retail,t} \; is \; the \; stochastic \; demand \; for \; electricity \; for \; period \; t$$

$$X = strike \; price \; of \; call/put$$

For simplicity of modelling, the volume of non-retail contracts/assets is assumed constant, and set prior to the start of the year.[29] Retail volume varies with each time period, t, and is estimated such that the optimised volume of retail contact(s) is the expected value of the yearly average load. For instance,

[29] It is likely that risk could be further minimised by employing a strategy that alters the volume of contracts/assets purchased or sold during different periods e.g. peak/off-peak, weekday/weekend, season etc. and the various combinations. However, the same relative trends in risk mitigation between the combinations of contracts/assets will remain.

a 1 MW contract would be expected to have an average load of 1 MW for the year. We assume that the distribution of demand volume for each time-period in our simulation follows the same distribution as historic load (for each island), i.e. it is directly sampled from the historic time series data.

The net annual payoff for a generator is simply the sum of each of the individual payoffs of each contract/asset employed:

$$\pi = \sum_{t=1}^{17520} \begin{array}{c} V_{plant,island} \times \{\max(P_{island,t} - mc_{island}, 0) - \mathrm{E}[\max(P_{island,t} - mc_{island}, 0)]\} + \\ V_{retail,NI,t} \times (P_{retail,NI} - P_{NI,t}) + \\ V_{retail,SI,t} \times (P_{retail,NI} - P_{NI,t}) + \\ V_{forward,NI} \times (P_{NI,t} - X_{NI}) + \\ V_{forward,SI} \times (P_{SI,t} - X_{SI}) + \\ V_{call,NI} \times \{\max(P_{NI,t} - X_{NI}, 0) - \mathrm{E}[\max(P_{NI,t} - X_{NI}, 0)]\} + \\ V_{call,SI} \times \{\max(P_{SI,t} - X_{SI}, 0) - \mathrm{E}[\max(P_{SI,t} - X_{SI}, 0)]\} + \\ V_{put,NI} \times \{\max(X_{NI} - P_{NI,t}, 0) - \mathrm{E}[\max(X_{NI} - P_{NI,t}, 0)]\} + \\ V_{put,SI} \times \{\max(X_{SI} - P_{SI,t}, 0) - \mathrm{E}[\max(X_{SI} - P_{SI,t}, 0)]\} \end{array}$$

Where

$$mc_{island} = median(P_{island,t})$$

$$P_{retail,island} = \frac{E(V_{retail,island,t} \times P_{island,t})}{E(V_{retail,island,t})} = load\ weighted\ average\ price\ for\ 1MW\ contract$$ [30]

$$X_{island} = E(P_{island,t})$$

mc, P_{retail}, and X are estimated separately for each island using 3,000 simulations of yearly data (see below).

Setting the marginal cost of plant generation, mc, at the median price, assumes a marginal plant. That is, the plant will generate, on average, during 50 per cent of the periods. For simplicity we assume that when the plant generates, it generates at capacity. This also differentiates plant assets from the put option, where the strike price is set at the mean price. If $mc_{island} = X_{island}$, then the payoffs between generation and put options would be identical in the model.

The definition for P_{retail} sets the price to customers (i.e. retailer income) to a level where the net payoff for a retail contract is zero in expectation. Due to the multiplicative effect of the positive correlation between load and price, the 'load weighted' average price, is higher than the average. A stylised example of this is shown in Figure 4.

This depicts a scenario where price and demand are perfectly (linearly) correlated. Due to the multiplicative effect, cost increases at an increasing rate with price and demand (it follows a quadratic function in this stylised case). This results in the average cost and weighted average price being higher than the product of the mean price and mean demand.

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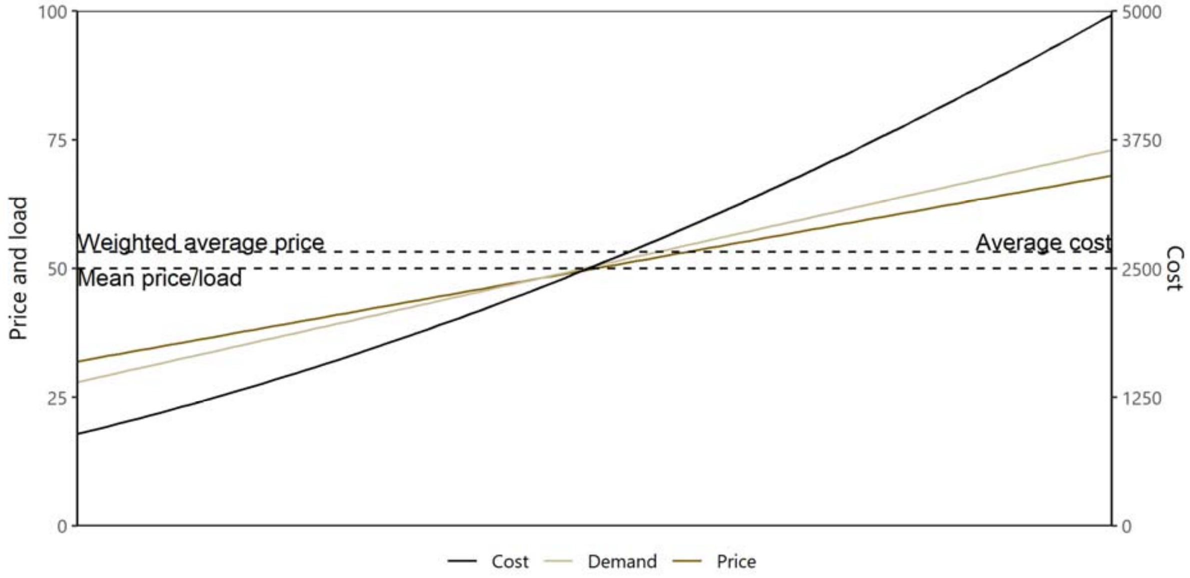
[30] Differs from Boroumand & Zachmann (2012) who assume a fixed payment to offset the difference between the arithmetic and weighted average price.

Figure 4 Impact of load-price correlation on load weighted average price



Source: Sapere analysis

Methodology

Data from Electricity Authority's (EA) Electricity Market Information (EMI). Two file sets with all available (final) data files between 2011 and 2020 inclusive:

- Load Generation Price (LGP). Provides load data which is used to simulate electricity demand.
- Final Prices (FP). Provides pricing data which is used to simulate electricity prices.

Load data from LGP files are aggregated by each half hourly trading period, and island. Price data are extracted from the FP files. The OTA2201 node is used as the reference node for prices for the North Island (NI), while BEN2201 is used for the South Island (SI). Load and price data are combined by trading period, constructing a sampling set with load and price pairs for each island. Some files are missing from LGP therefore only 174,624 rows of data (theoretically should be 175,344).

From these rows, 3,000 sets of 17,520 (the number of half hourly trading periods in a year) load and prices (by island) are randomly drawn, for each island (with replacement and uniform probability). While the sampling could be stratified by time of day, weekday/weekend, season etc, due to the uniform nature of the selection process, selection should be unbiased, and normally select a generally realistic sample. Any additional variation is also useful to highlight potential risks and uncertainties.[31]

[31] Differs from Boroumand & Zachmann (2012) who use an alternative sampling method. The method that we have chosen generates a more 'realistic' situation, rather than forcing variation in the mean/median of the samples. Our methodology also allows for both extreme highs and lows (along with more 'normal' values) with a year/simulation, rather than the truncated nature of the windowed sampling by Boroumand & Zachmann (2012)

Optimisation of the VaR(95) based on the profit function defined early was completed using the DEoptim optimisation function from the R package, RcppDE.[32] Volumes of retail contracts (in MW) were constrained to be positive (or zero). Volumes of other contracts could be positive or negative (or zero), representing the ability to be a buyer or seller of each.

Sample statistics

Table 2 compares the summary statistics of the observed data (historic data from EA's EMI) compared to the samples used in the models. We can see that the observed and sample data are very similar in nature.

Table 2 Observed vs sample statistics

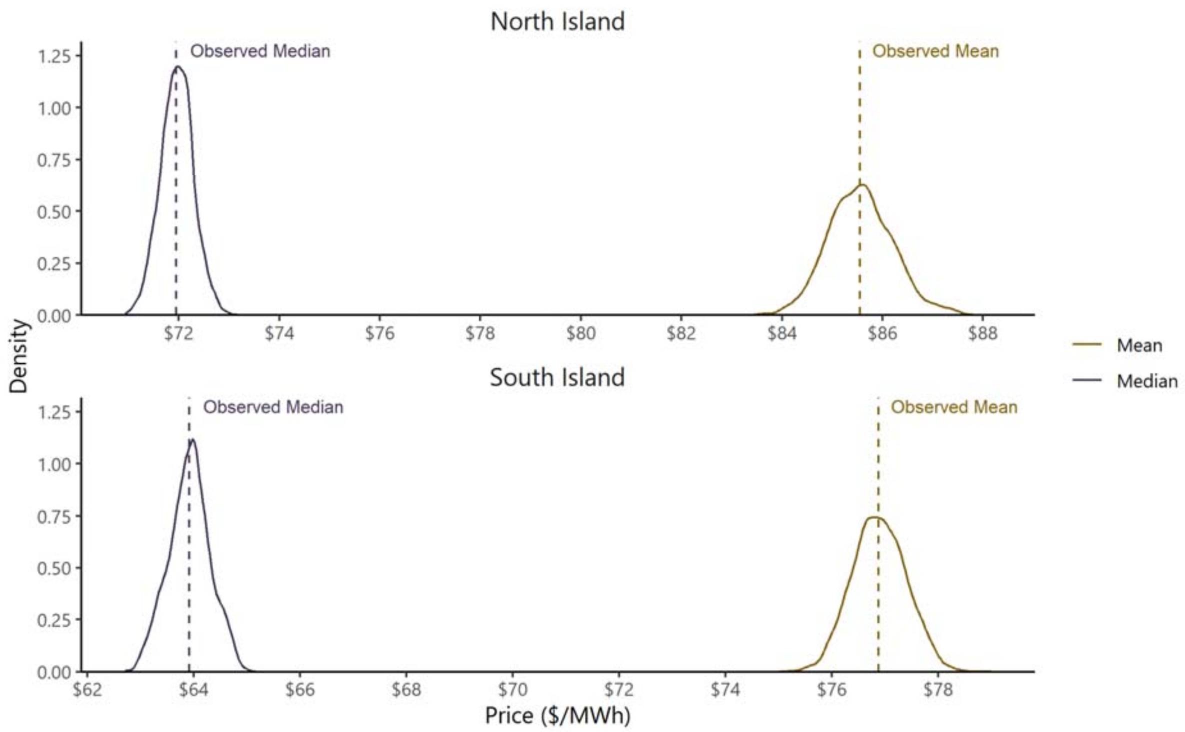
		North Island		South Island	
		Observed	Sample	Observed	Sample
Price ($/MWh)	Median	72.0	72.0	63.9	63.9
	Mean	85.5	85.6	76.9	76.9
	Standard deviation	84.1	84.0	65.6	65.7
Demand (MW)	Median	2,745	2,746	1,650	1,650
	Mean	2,684	2,684	1,640	1,640
	Standard deviation	614	614	205	205

Source: Sapere analysis

Figure 5 shows the distribution of the mean and median price of the 3,000 simulated years. The distributions are roughly centred on the observed values. A similar picture is shown for the mean and median price in Figure 6.

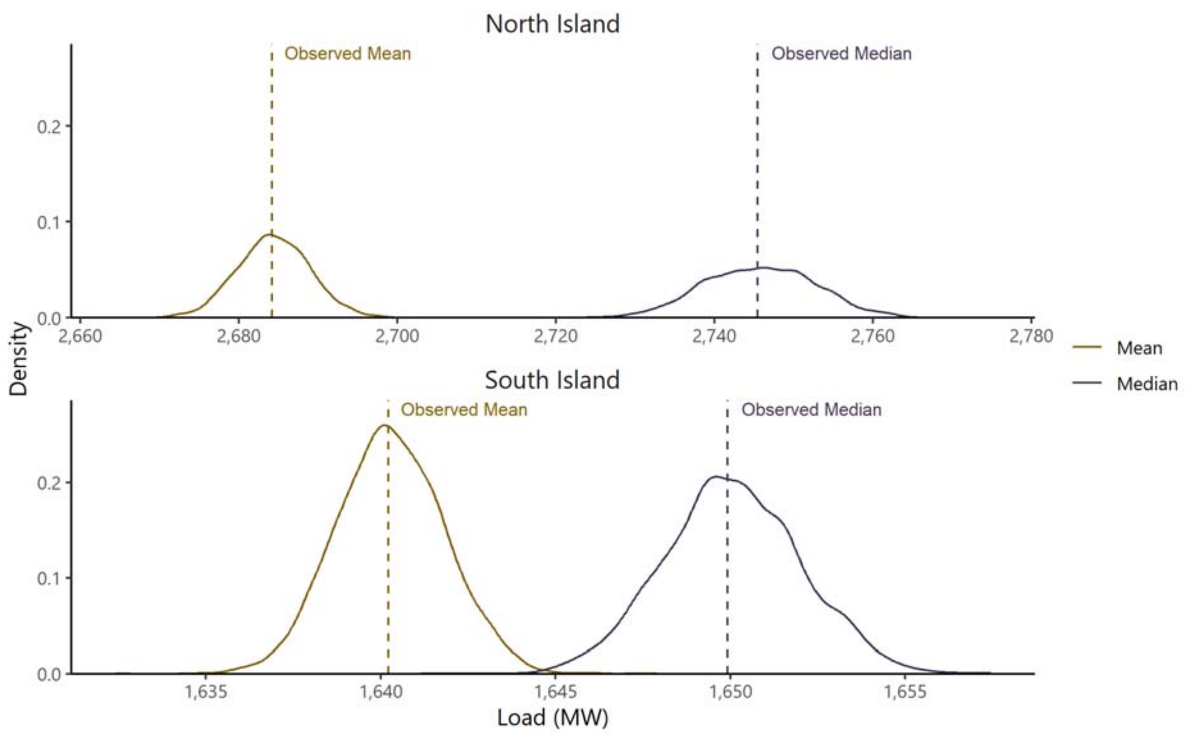
[32] This package uses the Differential Evolution optimisation methodology for non-linear constrained optimisation. Further information on the function and its underlying model can be found at: https://cran.r-project.org/web/packages/RcppDE/RcppDE.pdf

Figure 5 Distribution of sample mean and median price



Source: Sapere analysis

Figure 6 Distribution of sample mean and median load



Source: Sapere analysis

About Sapere

Sapere is one of the largest expert consulting firms in Australasia, and a leader in the provision of independent economic, forensic accounting and public policy services. We provide independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

'Sapere' comes from Latin (to be wise) and the phrase 'sapere aude' (dare to be wise). The phrase is associated with German philosopher Immanuel Kant, who promoted the use of reason as a tool of thought; an approach that underpins all Sapere's practice groups.

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