ELECTRICITY AUTHORITY
TE MANA HIKO

MARKET MONITORING REVIEW OF STRUCTURE, CONDUCT AND PERFORMANCE IN THE WHOLESALE ELECTRICITY MARKET

SINCE THE POHOKURA OUTAGE IN 2018

INFORMATION PAPER

Executive summary

Prices have been higher since the Pohokura gas field outage in 2018, and some of the increase may not be explained by underlying conditions

The Electricity Authority (Authority) is reviewing whether electricity spot prices were determined in a competitive environment for the period from January 2019 up to and including the first two quarters of 2021 (this review).

The Authority decided to undertake this review in response to the sustained high spot prices since the Pohokura outage. Prices rose in response to the Pohokura outage and have been, on average, above $100/MWh since then. The average spot price for 2019 was $127/MWh. This is the highest yearly average since 2008, when there was a severe hydro shortage during the winter. For comparison, the average spot price from 2009 to the Pohokura outage in 2018 was $67/MWh.

Prices over the review period have, at least to some extent, reflected underlying supply and demand conditions, which is a sign of a competitive market. Over the review period, demand has been higher; hydro inflows and storage have often been low; there have been a number of gas production outages; and all fuel costs — including the value of stored water and the cost associated with carbon dioxide emissions — have been rising. These have all affected electricity spot prices.

However, some of the price increases since the Pohokura outage appear to be unexplained by the underlying conditions. This observation is supported by two statistical tests presented in this paper.

It is not possible to definitively conclude whether all of the increase in prices is due to underlying conditions, including uncertainty about future gas supply from existing fields,[1] 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.

However, we observed some evidence to suggest that prices may not have been determined in a competitive environment. If firms who have market power exercise it in a sustained way, this can mean spot prices are not being determined in a competitive environment. 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.

The ability to engage in economic withholding — offering some quantity at higher prices with the intention that it not be dispatched, to reduce supply and increase the spot price — is the main form of market power analysed in this review. We also look at offer prices at the margin and compare these with costs. Offering at a higher price to avoid dispatch can be an appropriate response to surrounding demand and supply conditions, operating constraints and resource consent obligations. But if offers appear unrelated to underlying conditions this could indicate that the generator is using these offers to influence the price.

Our observations are as follows.

[1] In this paper, we refer to gas supply risk and gas supply uncertainty. This is a reference to the fact that there has been supply disruption from some fields and, while we understand some initiatives are under way to improve production from those fields, some residual uncertainty remains in the market about potential output from those fields.

- The market is dominated by a few large firms, with Meridian needed to meet demand over 90 percent of the time.
- Offer prices have increased since the Pohokura outage, and there is often a large proportion of offers above cost (regardless of the cost estimate used) for some generators. However, these observations could be consistent with gas supply uncertainty.
- Some offers do not reflect underlying conditions.
- Steeper supply curves in recent years suggest an increased incentive and ability to economically withhold.
- Differences in price between the North Island and South Island have been subdued over the review period when storage has been high. This suggests some generators may have been economically withholding so the price they pay to cover their retail books in one island is not much higher than the price they receive for their generation in the other.
- The Lerner Index (the mark-up of price over cost) is sometimes high, so these offers above cost appear to be resulting in prices above costs, although this result is sensitive to the cost estimate used.
- Previous instances have occurred where the Authority was concerned about economic withholding. These are discussed in section 5.

The New Zealand Aluminium Smelter is potentially paying below opportunity cost for energy, and its presence increases energy costs for the rest of the country

On 14 January 2021, a new contract was announced relating to the electricity supplied to the New Zealand Aluminium Smelters Limited (NZAS) at Tiwai Point. The smelter consumes about 13 percent of New Zealand's electricity demand, so these contracts have an impact on the wholesale electricity market.

If NZAS had exited and the smelter had closed, that electricity would have been available to the rest of New Zealand and the increased supply would have reduced prices. If the smelter has stayed open only because NZAS is paying a significantly lower price for electricity than the rest of New Zealand, this raises concerns about whether that electricity is going to the highest value use, and if not, what cost (an efficiency cost) that might impose on consumers.

Meridian can afford to sell to the smelter at low prices because its scale means it profits more from the higher prices of electricity sold into the grid than it loses on the electricity sold to NZAS at Tiwai Point at the lower price. Meridian's generating capacity is significantly greater than the other three main generators: close to one-third of New Zealand's total generating capacity.[2]

It is important to note that, in this context, scale is not referring to the fact that Meridian is a vertically integrated generator–retailer; rather, it is referring to its large generation capacity and concentration of generation in the South Island.

We estimate that the result of the smelter staying open means spot market costs to purchasers are higher by between an estimated $1.6 billion and $2.6 billion over 3 years, an increase that will translate into spot prices over the next 3 years. Any effect on prices will ultimately be borne

[2] Meridian's importance within the electricity market is larger than its size suggests: our analysis showed that Meridian's South Island generation has been needed to meet demand across the New Zealand market for over 90 percent of the time since 2019.

by consumers, with an impact first on commercial and industrial consumers, because their contracts are more closely linked to spot prices than residential consumers' contracts. The efficiency cost to the New Zealand economy of the low price paid by the smelter has been estimated at between $57 million and $117 million per annum.

Our observations are as follows.

- The contracts made between Meridian and Contact and NZAS in January 2021 (the Tiwai contracts) caused a sharp increase in the forward price. Based on that increase, spot market purchasers could be expected to pay between $1.6 billion and $2.6 billion more over the 3 years 2021–2023.
- The price in the Tiwai contracts (which is between $30/MWh and $40/MWh[3]) does not provide assurance that the electricity is going to the highest value use.[4]
- The estimate of the scale of the potential inefficiency of the Tiwai contracts is significant and raises concerns that the institutional arrangements are creating incentives for this.

Investment may have been impeded over recent years

Investment in efficient and low carbon technology needs to displace legacy technology, but the rate of new investment in generation has been slow in recent years. Significant investment will be required to effect the transition to renewables. Concept Consulting Group Limited (Concept) estimates that New Zealand could need investment of between $27 billion and $37 billion by 2050 to meet demand growth, replace thermal plant and maintain existing renewable generation.

A reasonable number of signalled projects remain unbuilt, but only a small number of projects seem likely to proceed to the commissioning stage. A variety of reasons exist for this, including: delays in the consenting process; a reported need to update consents for new technology; the need for transmission connections; and some reported delays while firms await certainty around government policy. Additionally, Concept found that generator–retailers may still be making investment decisions with regard to maximising returns on their existing assets.

These factors, combined with the uncertainty surrounding the Tiwai Point smelter, are likely to have contributed to delays in investment. The total quantity of definitely committed investment projects is not enough to replace existing thermal generation. And at least 75 percent of this committed generation is from generator–retailers.

However, more recently, the uncertainty surrounding the Tiwai Point smelter appears to be much less of an issue for investment in new generation, perhaps because of increased expectations of demand growth (from decarbonisation and the prospect of other demand sources in the lower South Island). There are also some signs that factors impeding investment by independent developers may be improving. Respondents to Concept's investment environment interviews (see Dynamic efficiency for further details) told us that large electricity users have historically had limited appetite for power purchase agreements (PPAs) but that this might now be changing. Two large industrial users recently collaborated to obtain PPAs with Contact. Genesis's recent request for proposal process was also seen as a positive for the industry, enabling more diversity and options.

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3 The effective price is even lower because of the rebate for the reduced term at the previous contract price.

4 The user with the highest willingness to pay is used as a proxy for the highest value use.

Next steps

These are complex issues. We are seeking feedback on our analysis, including the indicators used.

The two main issues arising out of this review that the Authority will consider further are:

- the incentives on industry that allow the potential for inefficiencies, such as via the Tiwai contracts, to take place. This is discussed in the companion paper *Inefficient price discrimination in the wholesale market – Issues and options*
- whether the recently amended trading conduct rules will address some of the conduct issues noted in this paper.

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1 Introduction

1.1 This review looks at competition in the electricity wholesale market since the unplanned Pohokura outage in the spring of 2018. To do this, we have used the structure, conduct and performance (SCP) framework as set out in the 2011 Electricity Authority (Authority) information paper: *Industry and market monitoring: Competition*.[5] This review does not look at the high-voltage, direct current (HVDC) outage from 7 January 2020 to 28 March 2020 and the undesirable trading situation (UTS) investigation period from 10 November 2019 to 16 January 2020, because these periods have been reviewed elsewhere.[6] However, the findings from these previous reviews contribute to our overall observations.

1.2 The Authority decided to undertake this review in response to the sustained high spot prices since the Pohokura outage. This review looks at whether prices over the review period (January 2019 to June 2021) were determined in a competitive environment, for the long-term benefit of consumers.

1.3 Since the review of spring 2018,[7] 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.

1.4 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.

1.5 In undertaking this review, the Authority sought specific information from the four largest generator–retailers under section 46 of the Electricity Industry Act 2010, as well as using information in the public domain. Along with Concept, we also interviewed most market participants about investment issues. A list of firms we interviewed is included in the Concept report (see *Review of generation investment environment*).

1.6 While this review considers the conduct of participants as part of the SCP framework, the Authority is not looking to attribute blame to any participant for any particular outcomes or factors identified. Rather, this review is seeking to establish whether prices have been determined in a competitive environment. It is also important to note that the Authority is not investigating any breaches of competition law by participants: this is the role of the Commerce Commission.

1.7 This review comprises two parts: this review paper, which sets out observations on the current state of the market based on the information and analysis the Authority has done to date, and an issues paper. We are seeking feedback on the content and methodology of this review paper, and the options discussed in the issues paper. In particular, we are aware that a number of possible indicators can be used to assess competition in the

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5 Electricity Authority, "Industry and market monitoring:Competition – Information paper," 2011, https://www.ea.govt.nz/assets/dms-assets/11/11525Industry-market-monitoring-information-paper.pdf.

6 See: Electricity Authority, "Final decision – Actions to Correct 2019 – Undesirable Trading Situation," August 2021, https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/10-november-2019/, and Electricity Authority, "Market Performance Quarterly Review Q1 2020: Information paper," April 2020, https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2019-2020/market-performance-quarterly-review-april-2020/.

7 See Electricity Authority, "Market performance review of Spring 2018: Market performance review," March 2020, https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2018/review-of-wholesale-market-issues-during-spring-2018/.

electricity market. Our 2011 paper sets out several these under the SCP approach. In determining which indicators to use for present purposes, we took into account issues including the availability of reliable data, measures that are tracked regularly so that trends can be observed, and timeliness. We are interested to hear feedback on:

- the structure, conduct and performance approach to assessing competition in the market
- the indicators we have used under this approach
- whether we have left out any important indicators
- any other issues you think we should consider.

1.8 We are also seeking feedback on the policy options described in the issues paper.

How to make a submission

1.9 The Authority prefers to receive submissions in electronic format (Microsoft Word). Submissions in electronic form should be emailed to reviewconsultation2021@ea.govt.nz with 'Consultation on the Market Monitoring Review of structure, conduct and performance in the wholesale electricity market' in the subject line.

1.10 If you cannot send your submission electronically, post one hard copy to the address below, or fax it to 04 460 8879.

1.11 Postal address: Submissions Electricity Authority PO Box 10041 Wellington 6143.

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

(a) indicate which part should not be published

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

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

1.13 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether or not to publish that part of your submission. However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act 1982 to withhold it. We would normally consult with you before releasing any material that you said should not be published.

1.14 When to make a submission: Please deliver your submissions by 5pm on Wednesday 8 December 2021. We will acknowledge receipt of all submissions electronically. Please contact the Authority at reviewconsultation2021@ea.govt.nz or 04 460 8860 if you don't receive electronic acknowledgement of your submission within two business days.

2 Summary

Spot prices appear to have reflected underlying supply and demand conditions, but a sustained upwards shift has occurred since the Pohokura outage

2.1 Since the Pohokura outage in 2018, the spot market has experienced high prices, higher demand, continuing uncertainty surrounding future gas supply from Pohokura and other fields, and high gas spot prices. The climate has also generally been drier, with periods of quite low storage. The cost of carbon emissions has also increased significantly.

2.2 During the review period, changes in underlying market fundamentals have been reflected in spot price movements. This is confirmed by our regression analysis (see Appendix A for details). Table 1 sets out the underlying conditions for different months from January 2019 to June 2021.

2.3 While spot price movements appear to have reflected underlying conditions, there has been an overall increase in the level of spot prices above the level explained by the market fundamentals in the regression. The regression analysis shows that there has been a sustained upwards shift in prices after the Pohokura outage in October 2018. Since then, the market has continued to experience uncertainty around gas supply from Pohokura and other fields.

2.4 This sustained upwards shift is indicated by the statistically significant coefficient for a dummy variable in the regression analysis.[8] The dummy variable equals zero before the 2018 Pohokura outage, and one from October 2018 onwards. Since other underlying fundamentals are controlled for in this regression analysis, the significant dummy variable shows that the price is higher for other reasons.[9] However, what the regression analysis does not show is whether this upwards shift is due to the uncertainty surrounding gas supply from Pohokura and other fields (above that reflected in the gas spot price) or if there is some other reason for the upwards shift, such as the exercise of market power.

2.5 We tested one variable as a possible indicator of gas supply risk in our regression (Ahuroa quarterly storage levels) and found that it was not significant once we adjusted for non-stationarity.[10] This does not rule out that supply disruption from Pohokura and other fields is driving the sustained upwards shift in prices, because Ahuroa storage is an imperfect indicator of this underlying supply condition (and is only quarterly data). Additionally, it was significant if we did not adjust for non-stationarity and the dummy variable was not included in the regression. This is because the trend in this variable is very similar to the dummy variable, that is, a significant drop around the time of the Pohokura outage. We also tried variations of a smoothed gas spot price as a possible better indicator of expected future gas costs and uncertainty about supply from existing fields, because it has less noise than the daily gas spot price. This was sometimes significant and sometimes not significant, but again, is an imperfect indicator. The

8 This is a commonly used way to test for a structural break (or shift) in the data. A statistically significant coefficient means that we are 95 percent confident the variable is related to the dependent variable (in this case, the spot price). We have also used the Bai and Perron test to test for structural breaks, see Appendix C.

9 For more details of the regression analysis and the explanatory variables included, see Appendix A.

10 See Appendix A for details.

dummy variable remained significant regardless of which variation in the gas spot price we used.

2.6 We also obtained information on gas supply agreements (GSAs). This data shows that GSA value weighted average prices (VWAPs) are similar to the emsTradepoint gas spot price VWAP.[11] Analysis of this data gives us confidence that the emsTradepoint VWAP that we have used in our analysis is a good proxy for the cost of fuel for gas generators. We also think that this suggests the emsTradepoint VWAP might be a good indicator of expectations of gas supply risk, given the opportunity to store gas at the Ahuroa underground gas storage. However, we still cannot conclude definitively that gas supply risk (or indeed, some other underlying condition that we have missed from the regression analysis) is not contributing to the sustained upwards shift in prices indicated by the significant dummy variable. Linear regression analysis is an imperfect approximation of the interactions that occur between supply and demand in the electricity market. However, our concern about not representing gas supply risk adequately has been somewhat allayed.

2.7 The indication from the significant dummy variable of a sustained upwards shift in prices, since the Pohokura outage in late 2018, is supported by statistical testing for structural breaks (see Appendix C for details). The structural break tests also suggest a break in late 2019 (probably due to the UTS, followed by the HVDC outage and COVID-19 lockdown, all of which decreased prices relative to 2019), and a break in late 2020, when prices began to increase again.

2.8 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.

2.9 This sustained upwards shift in spot prices is also reflected in a comparison of forward prices with spot prices. The forward price reflects the expected value of the final spot price for a future period. Previous Authority analysis concluded that there has been a bias in the forward price over the past 3 years, with the forward price underestimating the spot price.[12] Before 2018, the forward price predicted the spot price with no evident bias. This observation of higher than expected spot prices over the past few years may be consistent with underlying supply conditions being persistently worse than anticipated, whether this is gas supply or hydro inflows.

2.10 This sustained upwards shift is also evident in an increase in the steepness of the supply curve over recent years. Again, it is not possible to know how much of this steepness is explainable by underlying conditions, but, as discussed in section 5, there may be increased incentive and ability to exercise market power when the supply curve is steeper.

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11 Our calculated gas supply agreements (GSA) value weighted average prices (VWAPs) include a carbon price (see Appendix B for source) but exclude escalation, locational differences and inflation.

12 See Electricity Authority, “Market insight – accuracy of the forward price curve,” April 21, 2021, https://www.ea.govt.nz/about-us/media-and-publications/market-commentary/market-insights/accuracy-of-the-forward-price-curve/.

Table 1: Summary of market conditions, by month

Period	Summary
January–February 2019	Ongoing gas supply disruption following the 2018 Pohokura outage, another Pohokura outage in February, hydro storage below mean in January and declining in February, high summer demand
March 2019	Low wind and low hydro storage — hitting the 1 percent Electricity Risk Curve, high thermal generation
April–June 2019	High hydro storage with spilling occurring in the South Island
July 2019	Continuing high SI hydro storage and improving North Island hydro storage
August–October 2019	Decreasing hydro storage, high thermal generation, Kupe unplanned outage late September–early October, high demand
November–December 2019	Undesirable trading situation period. Refer to: https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/10-november-2019/. Spilling in the SI, NI hydro generators were trying to increase and conserve storage for the upcoming high-voltage, direct current (HVDC) outage
January–March 2020	HVDC outage. Refer to: https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2019-2020/market-performance-quarterly-review-april-2020/. Storage levels reverted to mean, demand was higher than average, and the HVDC outage caused price separation
April 2020	COVID-19 level 4 lockdown, demand very low
May 2020	Historically low NI inflows, delayed scheduled maintenance outages, start of declining output from Pohokura
June 2020	NI hydro storage low (fifth lowest on record), thermal generation high
July 2020	Cold weather, low wind generation, low lake levels, thermal generation high, NZAS terminates electricity contract, Kupe outage
August 2020	Auckland COVID-19 level 3 lockdown, warmer temperatures, low wind generation, low lake levels
September 2020–December 2020	Improving — but fluctuating — lake levels, Pohokura outage finished, decreasing Pohokura output, constrained output from the lower SI due to transmission outage
January–March 2021	NZAS contract announced, decreasing hydro storage, high gas spot prices, high carbon prices, decreasing Pohokura output, low wind generation, Rankine outages
April–June 2021	Very low hydro storage, constrained gas supply, weak wind conditions, Kawerau outage in June

Generators appear to have behaved within the parameters of the Code

2.11 Our analysis of conduct in the spot market does not currently show any definitive evidence that generators are operating outside the rules of the Electricity Industry Participation Code 2010 (the Code).[13] There is some suggestion that economic withholding has occurred, on occasion. By way of example, the UTS in 2019 found some evidence of this. Further, even though it is outside the review period, another useful example of possible economic withholding was observed in the market performance review of high prices on 2 June 2016. In reaching its findings, the market performance review noted Meridian's response that it had modified its offers to reduce the likelihood of price separation. The market review also identifies other instances of this behaviour.[14] Another example from outside the review period was on 8 December 2016 when Mercury withdrew reserves, although the Authority did not lay a formal complaint with the Rulings Panel in that instance.[15]

2.12 Meridian (Waitaki) has always had a high percentage of offers priced at over $300/MWh, and this proportion has been increasing steadily over the years. This proportion does not change with underlying supply conditions as much as for other hydro generators.

2.13 Meridian, Contact and Mercury tend to have a large percent of offers above final price at their hydro stations, whereas Genesis's offers at its Tekapo stations during times of high storage decrease substantially. Contact (Clutha) and Mercury (Waikato) have little storage and can be considered run-of-river schemes. This means they need to manage flows through their systems so that water is in head ponds when it is needed. Meridian has a lot more latitude, due to the storage capacity of Pukaki and Benmore, although as the largest storage lake in New Zealand, Pukaki needs to be managed prudently to ensure security of supply.

2.14 Offer prices of both hydro and thermal generators have risen in recent years to reflect the fuel supply situation (both hydro storage and gas supply). Given the subjective nature of the costs involved, it is difficult to determine if these offer price increases are reflecting this scarcity alone or other factors are at play (which might include the potential exercise of market power).

Outcomes for consumers have been affected

2.15 While behaviour in the spot market has largely been consistent with the rules of the spot market, we have seen evidence suggesting that electricity may not be going to the highest value use, at the expense of other consumers. Meridian and Contact entered into contracts in relation to the supply of electricity to the aluminium smelter at Tiwai Point. Price movements in response to announcements regarding the Tiwai contracts imply spot market purchasers could be impacted by between $1.6 billion and $2.6 billion over 3 years.

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13 This is based on analysis by the Authority Market Monitoring team, not the Authority Compliance team. We note also that participants were subject to the High Standard of Trading Conduct Rule over the review period and not subject to the new trading conduct rule that came into force on 30 June 2021.

14 See Electricity Authority, "Market performance review: High prices on 2 June 2016," last updated February 20, 2018, https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2016/high-energy-prices-2-june-2016/.

15 See Electricity Authority, "Notification of the Authority's decision under regulation 29 of the Electricity Industry (Enforcement) Regulations 2010," no date, https://www.ea.govt.nz/assets/dms-assets/22/2278431October17-Mercury-discontinue-investigation.pdf.

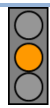
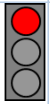
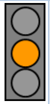
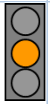
2.16 Efficient investment may also have been affected by the structure of the market. Some small participants interviewed by Concept suggested that established players face different incentives to new (or smaller) participants because they will, rationally, consider the effect of new investment on the earnings of their existing portfolio. New investment is likely to be more efficient and this should reduce market prices and/or reduce utilisation of legacy assets. This could incentivise incumbents to delay investment in new assets. Further, because the large generators are vertically integrated, costs for new entrants may be higher due to the low availability of power purchase agreements (PPAs) at attractive prices. Several parties considered that generator–retailers were not incentivised to provide good terms for PPAs. Historically, there has also been a lack of PPAs in New Zealand entered into from other sources, such as industrial power users, but this situation may be changing.

Summary of observations using structure, conduct and performance indicators

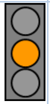
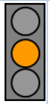
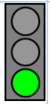
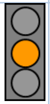
2.17 Table 2 summarises the observations we made from the suite of indicators we have used. More detail is in section 5.

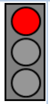
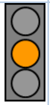
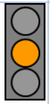
2.18 The results we have observed from these indicators do not tell us definitively whether prices have been competitively determined. However, we have included all the indicators we have used in this analysis. While, when viewed in isolation, any particular indicator may not be insightful, the idea of this analysis is to build a picture of the market based on the set of indicators rather than focusing on any indicator individually.

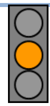
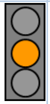
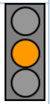
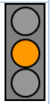
Table 2: Summary of structure, conduct and performance observations

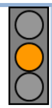
	Measure	Indicators used	What we would expect to see in a competitive market	What we observed	
Market structure	Seller concentration	Generation HHI	Low concentration reduces risk of any one firm unilaterally affecting prices, or of lasting collusion between groups of firms. A lower HHI means lower seller 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.
		Gross 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.		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.
	Barriers to entry	Vertical integration	Low barriers to entry place pressure on incumbents to display competitive pricing behaviour. 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.		While Mercury and Contact's level of vertical integration has decreased (based on our measure), Meridian's has increased. The level of vertical integration remains high in the New Zealand market. Some indication of increased use of PPAs and potential PPAs means vertical integration is less of a barrier than it might have been.
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.

	Measure	Indicators used	What we would expect to see in a competitive market	What we observed
				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).
		Percent of offers above cost	To stay the same over time. Offer prices should reflect costs (including opportunity costs) but there are some legitimate reasons for having a tranche with a higher offer price – ie, a "non-clearing" tranche.	Meridian and Mercury always have a higher percentage of offers above cost compared with Genesis and Contact, regardless of the storage situation. However, some of this may be explainable by gas supply uncertainty or hydro operating constraints.
		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.	Meridian and Mercury's offers are not correlated with their water values using some measures. None of the generators' offers appear to be related to the DOASA water values.
		Lerner Index	To 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

	Measure	Indicators used	What we would expect to see in a competitive market	What we observed	
					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.
	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).
		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.
		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.
		Trading periods with high prices	Offers consistent with underlying conditions, revisions in pre-dispatch consistent with underlying conditions (no obvious manipulation). Prices		These higher prices compared with surrounding trading periods could be explained by changes in market conditions at the time. There were no obvious signs that the changes made to

	Measure	Indicators used	What we would expect to see in a competitive market	What we observed	
			reflect the marginal generator as determined by underlying conditions.		offers in pre-dispatch during these 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.
		Tiwai contracts event analysis	Any contract made in a competitive market should not be below cost.		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.
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.
		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.

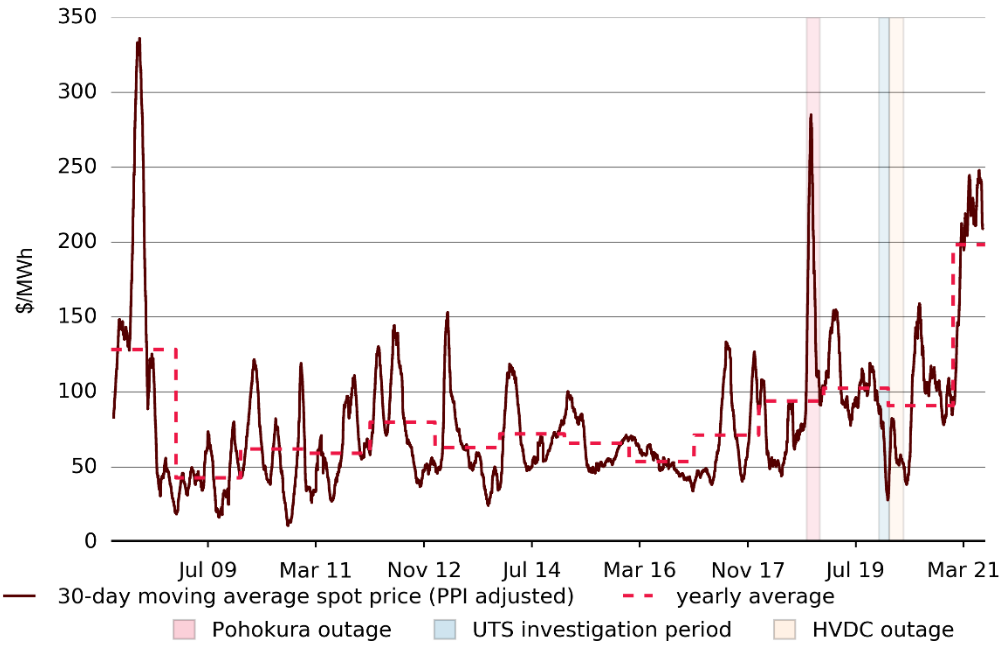
	Measure	Indicators used	What we would expect to see in a competitive market	What we observed	
		Marginal analysis	No big changes in the percent of time any one generator is marginal (before 2018 and after), especially in higher priced trading periods. Any changes are consistent with underlying conditions.		Percentages of time each generator is marginal are similar to previous years, and any changes during the review period are consistent with underlying conditions. 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.		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.
		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.
	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.

	Measure	Indicators used	What we would expect to see in a competitive market	What we observed
	Dynamic efficiency	Investment	Has there been investment in least-cost generation technology? (As supply tightens, expect an increase in investment.)	 The pipeline of build-ready investment projects has become very thin. There has also been uncertainty of various types in the investment environment, which has likely 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.

3 Prices have been high since the 2018 Pohokura outage

3.1 For much of the time since the 2018 Pohokura outage, the average daily spot price has been above $100/MWh.[16] The average spot price for 2019 was $119/MWh. This is the highest yearly average since 2008, when a severe hydro shortage occurred during the winter.[17] The average spot price for 2020 was $105/MWh, and for 2021 to 30 June it was $239/MWh. For comparison, the average price from 2009 to the Pohokura outage in 2018 was $67/MWh.[18]

Figure 1: Thirty-day moving average spot price, inflation adjusted



Sources: Electricity Authority, Stats NZ

3.2 Figure 2 shows price duration curves for calendar years back to 2014. It shows that 2019, 2020 and 2021 all had higher prices for most of the year compared with the previous five years.[19] For around 65 percent of 2019 and 60 percent of 2020, prices were higher than $100/MWh. The first two quarters of 2021 have seen prices higher than $100/MWh for around 90 percent of trading periods. For the previous 5 years, this figure was less than 30 percent. Some higher prices occurred during October to December 2018 due to a gas shortage caused by the Pohokura outage, a shortage of water in

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16 The average daily spot price has been higher than $100/MWh for 63 percent of days over the review period (or 70 percent of days, if we exclude the undesirable trading situation (UTS) investigation and high-voltage, direct current (HVDC) outage periods).

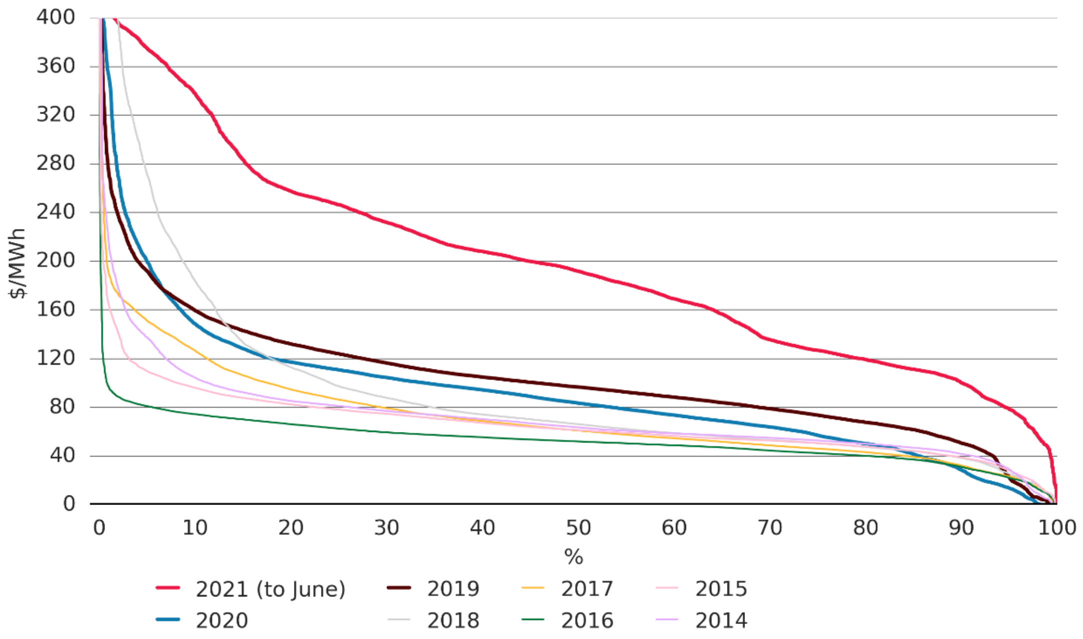
17 Even when inflation adjusted.

18 Throughout this report, we use the average New Zealand spot price unless otherwise stated.

19 We also ran this comparison (and the comparison in Figure 3) using only the first 6 months of each year. This showed similar results for 2021 against the comparator years for f, but that the first 6 months of the comparator years in Figure 3 had price duration curves that were more similar to — but still mainly below that of — 2021. See Appendix G for charts.

hydro generation schemes, and increased demand.[20] The effects of these market issues were exacerbated by planned outages that occurred during this period as there were not expected to be any supply concerns.

Figure 2: Price duration curves compared with previous five years (inflation adjusted)



Sources: Electricity Authority, Stats NZ

3.3 Prices over the review period have also been amongst the highest since the market began. Average yearly prices during the review period were ranked in the top ten since the market began, with 2019 and 2021 in the top five. Figure 3 shows price duration curves for the review period years compared with previous years that had the highest yearly average prices (since the market began in 1996). These years include 2018 (with the Pohokura outage pushing up the yearly average price), and three very dry years (2008, 2003 and 2001) during which conservation campaigns were called for. Figure 3 shows that prices during 2019 to 2021 were similar to these years, although 2019 and 2020 had extreme high prices for a lower proportion of the time compared with these previous years. However, in 2019, prices remained higher for a greater proportion of the year, prices were above $80/MWh for around 70 percent of the year, compared with around 55 percent of the year or lower for the previous years.

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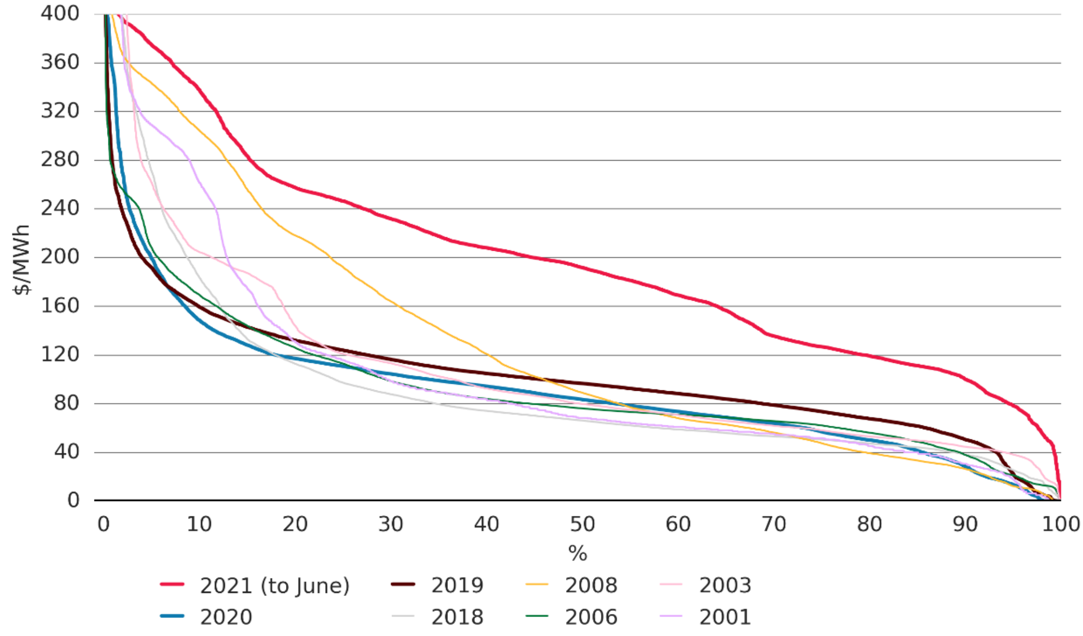
20 See Electricity Authority, "Market performance review of Spring 2018," March 2020, https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2018/review-of-wholesale-market-issues-during-spring-2018/.

Figure 3: Price duration curves compared with previous years with the highest yearly averages (inflation adjusted)

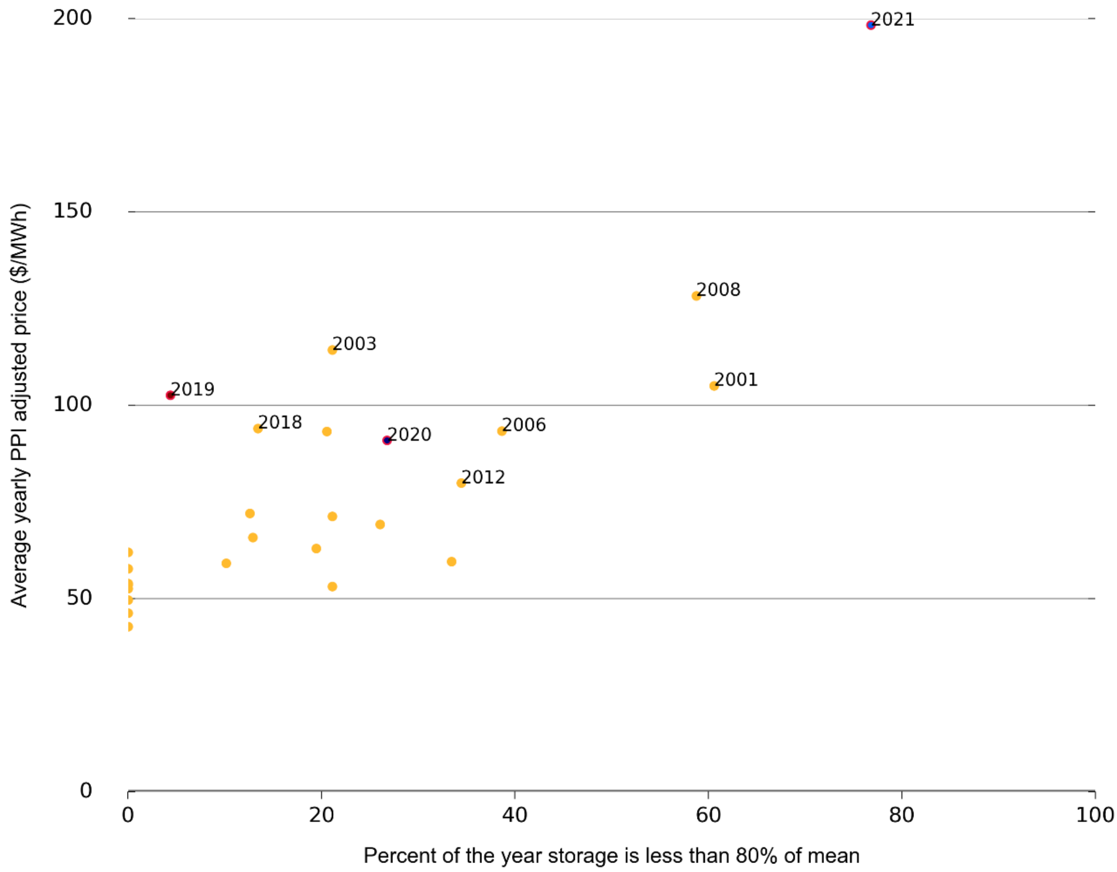


Sources: Electricity Authority, Stats NZ

3.4 Figure 4 plots the duration of low relative storage in each year against the average yearly price (2019, 2020 and 2021 are shown in red).[21] It shows a positive relationship between high prices and longer durations of low relative storage. For 2019, the year looks like somewhat of an outlier from this relationship, with low relative storage for only about 4 percent of the year but an average yearly price of above $100/MWh. Of course, underlying conditions other than the duration of low storage levels can influence prices (including gas prices, what time of year the low storage occurred, and if it was nearing the electricity risk curves, as well as other factors unrelated to storage).

[21] Storage as a percent of mean monthly storage over all available data is used in all analysis, unless otherwise stated.

Figure 4: Price versus low storage



Sources: Electricity Authority, Stats NZ, NZX Hydro

3.5 A previous quarterly review (first quarter 2019 review) published by the Authority discussed the high prices in February and March of 2019.[22] During this period, lake levels were low and Pohokura was on partial outage. However, the report states that 'When South Island storage increased in April 2019 the spot price decreased rapidly in response, but prices have not fallen to the average prices seen historically.'[23]

3.6 The first quarter 2019 review goes on to say that there are some possible reasons why the price has remained high – including low lake levels in the North Island, gas spot prices remaining high, and gas supply disruptions – but that further investigation is needed to fully identify the contributing factors and ensure that no undue use of market power exacerbated the situation. This review sets out the further investigation the Authority has undertaken.[24]

22 See Electricity Authority, "Market performance quarterly review – First quarter 2019," October 2019, https://www.ea.govt.nz/assets/dms-assets/25/25823Market-performance-quarterly-review.pdf.

23 Electricity Authority, "Market performance quarterly review – First quarter 2019," 1.

24 Note that this review was planned before receiving the 2019 UTS claim. The review was subsequently delayed due to the UTS investigation.

4 Underlying supply and demand conditions

4.1 In this section, we look at underlying supply and demand conditions over the review period to investigate whether prices may have been higher due to these conditions. We also use regression analysis (see section 5) to further support this analysis. If prices are being determined in a competitive environment, they will reflect underlying supply and demand conditions. In particular, we look at demand levels, gas supply uncertainty from existing fields, thermal plant costs, hydro storage and levels of wind generation, to assess the contribution each might have been making to prices over the review period.

Demand has been higher

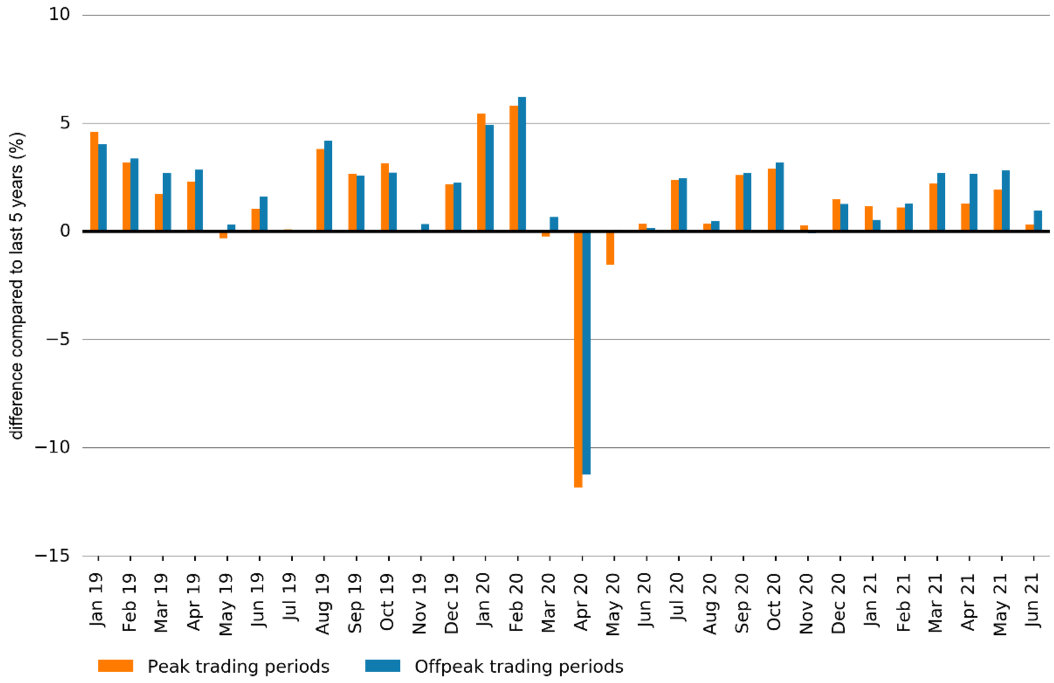
4.2 If demand is higher, the spot price will be higher because more expensive generation needs to be dispatched to meet the higher demand. We therefore assess whether demand may have contributed to the higher prices in the review period.

4.3 Demand has been higher by around 2 percent or more in most months of the review period compared with demand in the previous 5 years. Demand was higher in almost every month of 2019 and for 7 months in 2020, compared with mean monthly demand for 2014–2018, for both peak and off-peak trading periods. Demand in January and February 2021 was similar to the mean demand for 2014–2018, but higher than this mean in March to June 2021. This higher demand in 2021 is despite some demand response due to higher spot prices and hydro storage concerns during this time.

4.4 Demand was significantly lower during the COVID-19 lockdowns, especially during April 2020 when the country was in level 4, but also in May when the country was in level 3 and in August when Auckland was in level 3.[25] However, despite the pandemic reducing total demand over 2020, there are early indications that demand has been starting to grow over the past few years. NZAS reopened its fourth pot-line at the Tiwai Point smelter in December 2018, which contributed to the increase in demand in 2019, but the pot-line was closed again in March 2020 due to the COVID-19 lockdown, and has remained closed up until the time of writing.

25 See Electricity Authority, "Market Performance Quarterly Review Q1 2020," April 2020, https://www.ea.govt.nz/assets/dms-assets/26/26718Quarterly-Review-April-2020.pdf and Electricity Authority, "Market Performance Quarterly Review Q2 2020: Information paper," no date, https://www.ea.govt.nz/assets/dms-assets/27/27142Quarterly-Review-July-2020.pdf for a discussion on the impact on the electricity market of level 4 lockdown.

Figure 5: Difference in monthly demand compared with past 5 years



Sources: Electricity Authority

There have been many gas outages and ongoing uncertainty about gas supply from Pohokura

4.5 Gas supply disruption and uncertainty of future supply from Pohokura and other fields may affect electricity spot prices because it means gas generation is either unable to run (or unable to run at maximum capacity) and/or the opportunity cost of thermal generators may increase (see the box 'Opportunity cost in the New Zealand electricity market' in section 5 for an explanation of opportunity cost). In this section, we assess whether this has been an issue in the electricity market over the review period.

4.6 In line with advice previously provided to the Minister of Energy, because of the effect gas availability can have on electricity prices, and as New Zealand transitions to 100 percent renewable generation, information on the gas sector will be increasingly important for the Authority to manage, monitor and understand market impacts and security of supply.[26]

The Pohokura outage illuminated gas supply concerns

4.7 In spring 2018 (14 September to 11 December), there was a major unplanned outage at Pohokura. Pohokura is New Zealand's highest producing gas field, supplying 35 percent to 40 percent of gas market demand. During the 2018 outage, output at Pohokura reduced by close to a half. Subsequent to this outage, there have been other outages and an ongoing decline has occurred in Pohokura output.

26 Electricity Authority, "Ministerial Briefing: Dry Year Risk Update: Spot market review and other related Authority initiatives," June 2021, https://www.ea.govt.nz/assets/dms-assets/28/BR-21-0024-Dry-Year-Risk-Update-Spot-market-review-and-other-related-Authority-initiatives.pdf.

4.8 As discussed in an Authority quarterly review and market commentary publication, there were several periods of gas outages in 2019.[27] Pohokura had reduced gas supply for 12 days in February 2019 as an intervention campaign was initiated. Supply was reduced again in May when the work was wrapped up, as well as a few individual days in between. An unplanned reduced production also occurred at Kupe in late September–early October 2019, and a planned outage of Kupe from 30 October to 27 November 2019.

4.9 Pohokura had a full planned outage in 2020 from 11 March to 24 March. Onshore production restarted on 25 March and offshore production on 6 April. This overlapped with the HVDC outage that finished on 27 March. After this outage was finished, Pohokura's production increased to the normal production range. However, from May 2020, there was a steady decline in output from Pohokura, potentially due to scaling or water ingress.[28] Further outages occurred in August and September to commission a compression plant, which increased Pohokura's output but did not stop the decline (see Figure 6). Pohokura production reduced from 164 TJ/day to 133 TJ/day during the last quarter of 2020.

4.10 A Ministry of Business, Innovation and Employment report states that annual production levels for Pohokura were around 76 PJ from 2007 (the first full year of production) to 2017. In 2018, this fell to 53 PJ then bounced back again in 2019 to 68 PJ.[29] Both the outages and production decline resulted in annual production of 55 PJ in 2020. Annual production is expected to be around 39 PJ for 2021, a 25 percent drop in projections (as of 4 March 2021).[30]

4.11 Other major gas outages that occurred in 2020 include two unplanned outages at Kupe, the first from 3 to 5 July and the second from 2 to 11 December, and an unplanned outage at Maui from 2 to 5 August.

4.12 Transpower (in December 2020) estimated the potential future impact of gas supply issues.[31] Its calculations showed that – if no adjustment was made in consumption – there would be clear production shortfalls in 2021. That is, if there was no change in demand for gas from Methanex or other, predominantly industrial, users, thermal electricity generation would be curtailed. Since this Transpower report was released, Methanex and some other large industrial users have indeed curtailed demand. Methanex is now consuming less than 50 percent of the gas it consumed back at the start of 2020.

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27 Electricity Authority, "Market performance quarterly review," January 2020, https://www.ea.govt.nz/assets/dms-assets/26/26273Market-Performance-Quarterly-Review-January-2020.pdf, and Electricity Authority, Market insight - wholesale spot prices, November 14, 2019, https://www.ea.govt.nz/about-us/media-and-publications/market-commentary/market-insights/market-insight-wholesale-spot-prices/.

28 Scaling refers to wells being able to carry progressively less gas.

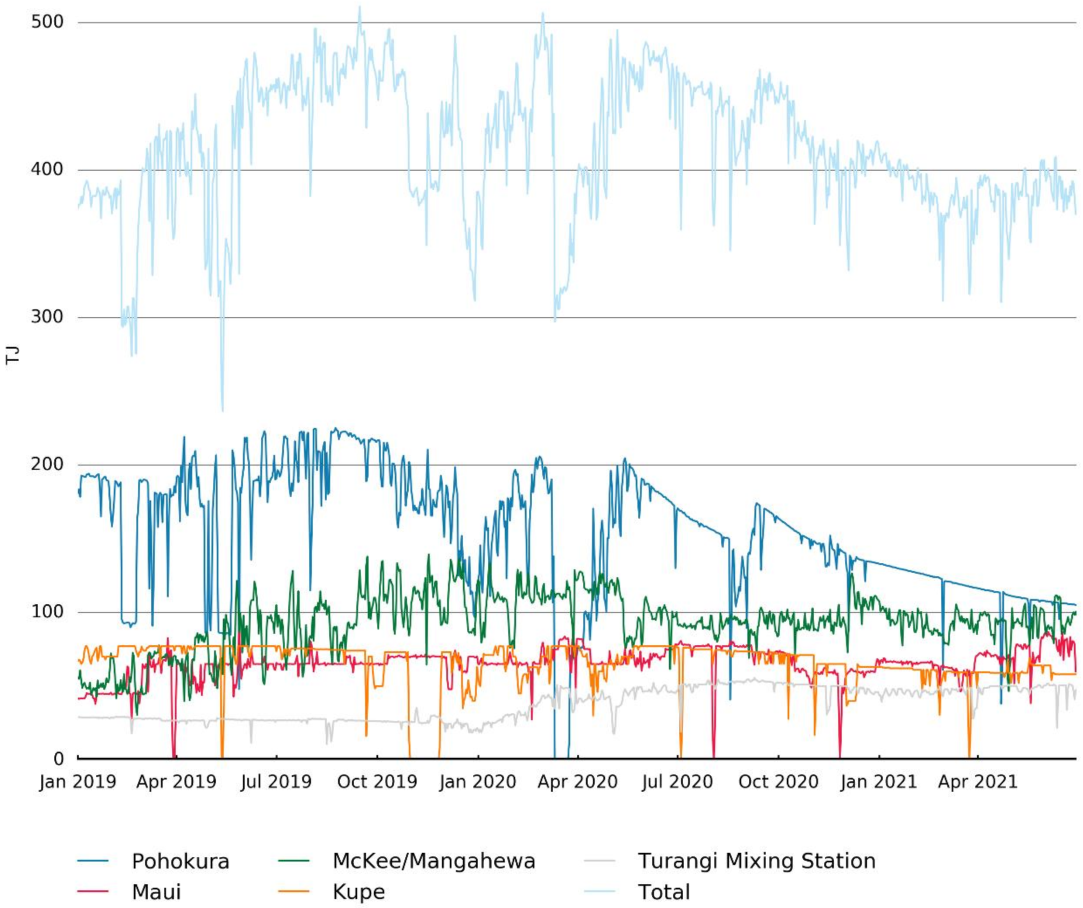
29 Ministry of Business, Innovation and Employment, "Gas statistics," last updated October 14, 2021, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics/.

30 See Industry Notifications, "000277 – Pohokura Update," March 4, 2021, https://industrynotifications.gasindustry.co.nz/home/show/277. At the time of writing, we could not find any more recent estimates of this figure.

31 Transpower, "Gas Outlook for Electricity Generation and Security of Supply 2021", December 2020, https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/Gas%20Outlook%20for%20Electricity%20Generation%20and%20Security%20of%20Supply%202021.pdf

4.13 Contact's gas storage net movement figures show that, over June 2018 to March 2021, it extracted more gas from Ahuroa (the only gas storage facility in New Zealand) than it injected over this time (3.5 PJ of extraction compared with 1.7 PJ of injection).[32] Figure 7 shows the decline in Ahuroa gas storage over time.

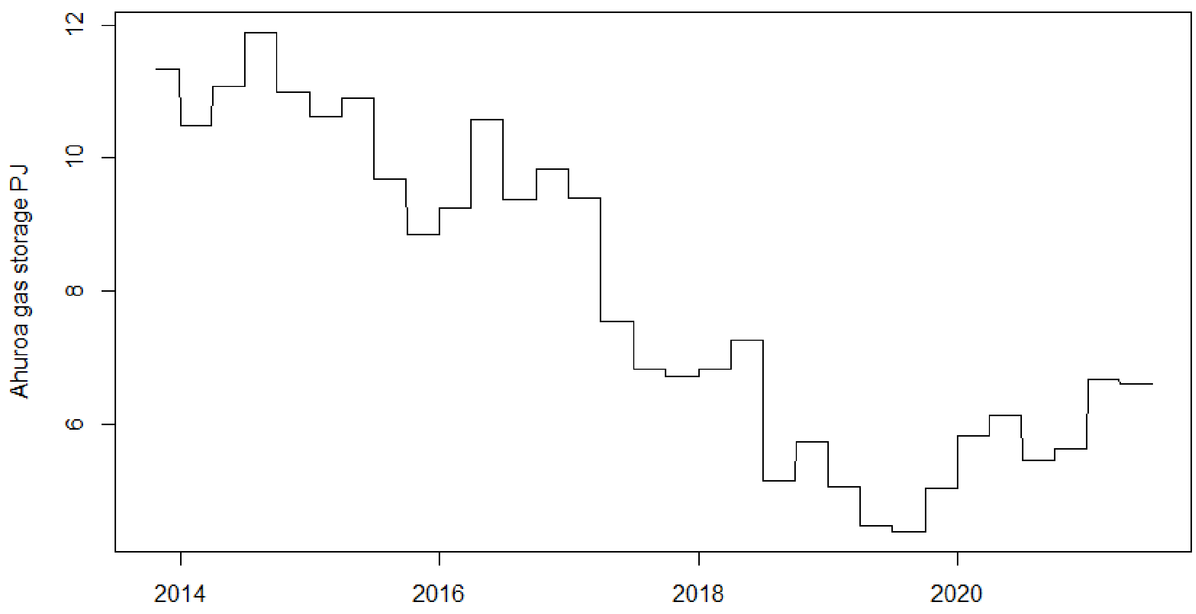
Figure 6: Daily gas production by major fields



Sources: Gas Industry Company Limited

32 Contact, "Operating reports," https://contact.co.nz/aboutus/investor-centre/reports-and-presentations#Operating-reports.

Figure 7: Quarterly Ahuroa gas storage



Source: Concept Consulting Group Ltd

Gas supply issues have affected spot prices

4.14 As discussed above, there has been a sustained upwards shift in electricity spot prices since the Pohokura outage in 2018. It is possible that this upwards shift in prices could be due to the Pohokura incident shining a spotlight on gas supply issues (in conjunction with the gas industry outlook for the next 1-to-2 years, discussed below).

4.15 It also appears that gas outages have increased spot prices at the time they occurred (see Table 3 and Figure 8). So not only may gas supply issues be affecting the level of prices over the medium term, they may also trigger short-term fluctuations in price. The average price over the February 2019 Pohokura outage was \$194.53/MWh, compared with \$128.42/MWh for the rest of the month. The average prices during other major gas outages in 2019 and 2020 are listed in Table 3. These prices compare to an average spot price during the rest of 2019 and 2020 of \$107.76/MWh.

4.16 Table 3 also shows the gas spot price during these outages. These gas spot prices compare to an average gas spot price during all other times of 2019 and 2020 of \$10.22 /GJ.

Table 3: Average electricity spot prices during major gas outages

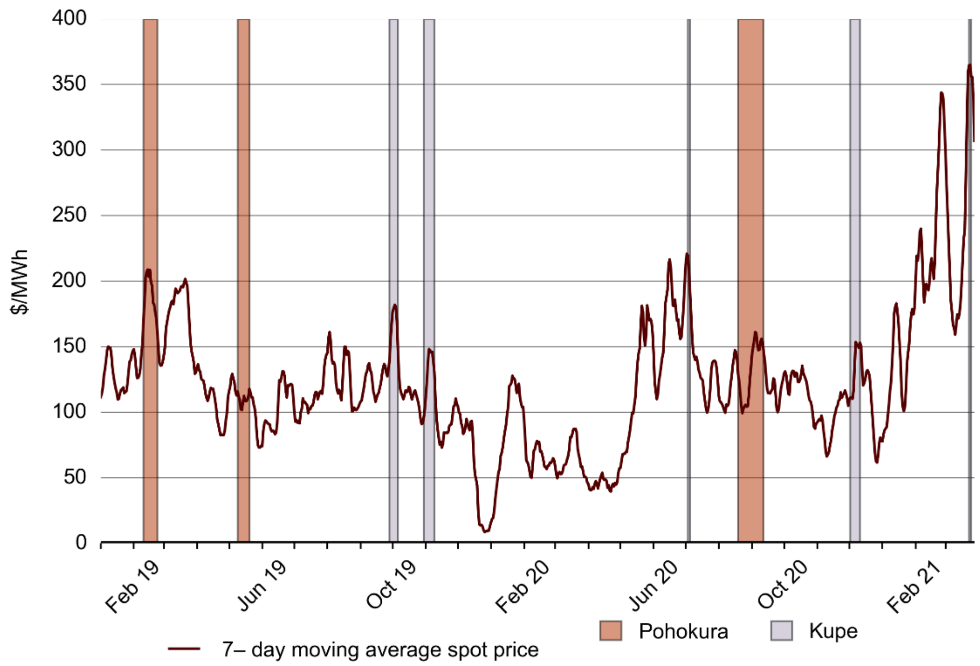
Year	Outage	Approximate reduction in gas production	Average electricity price (\$/MWh)	Average gas spot price (\$/GJ)
2019	February Pohokura	90 TJ/day	194.53	11.00
	May Pohokura	90 TJ/day	106.67	18.85
	September–October Kupe	25 TJ/day	162.03	11.97

Year	Outage	Approximate reduction in gas production	Average electricity price ($/MWh)	Average gas spot price ($/GJ)
	October–November Kupe*	73 TJ/day	134.44	12.09
2020	July Kupe	50–70 TJ/day	205.18	19.23
	August–September Pohokura	20–110 TJ/day	132.00	12.36
	December Kupe	25 TJ/day	137.47	11.30

*This outage went until 27 November, here the average price is calculated to 9 November, because the undesirable trading situation (UTS) investigation period began on 10 November and other factors may have had a larger impact on price during the UTS period.

Sources: Gas Industry Company Limited, Electricity Authority, EMS Tradepoint

Figure 8: Spot electricity price and gas outages



Sources: Electricity Authority

Coal use has increased

4.17 Also, due to gas supply issues, electricity generation from coal increased in 2019 by 43 percent and in 2020 by 47 percent, compared with 2018.[33] The first quarter of 2021 saw the highest quarterly coal usage for electricity since 2012.[34] Figure 9 shows the

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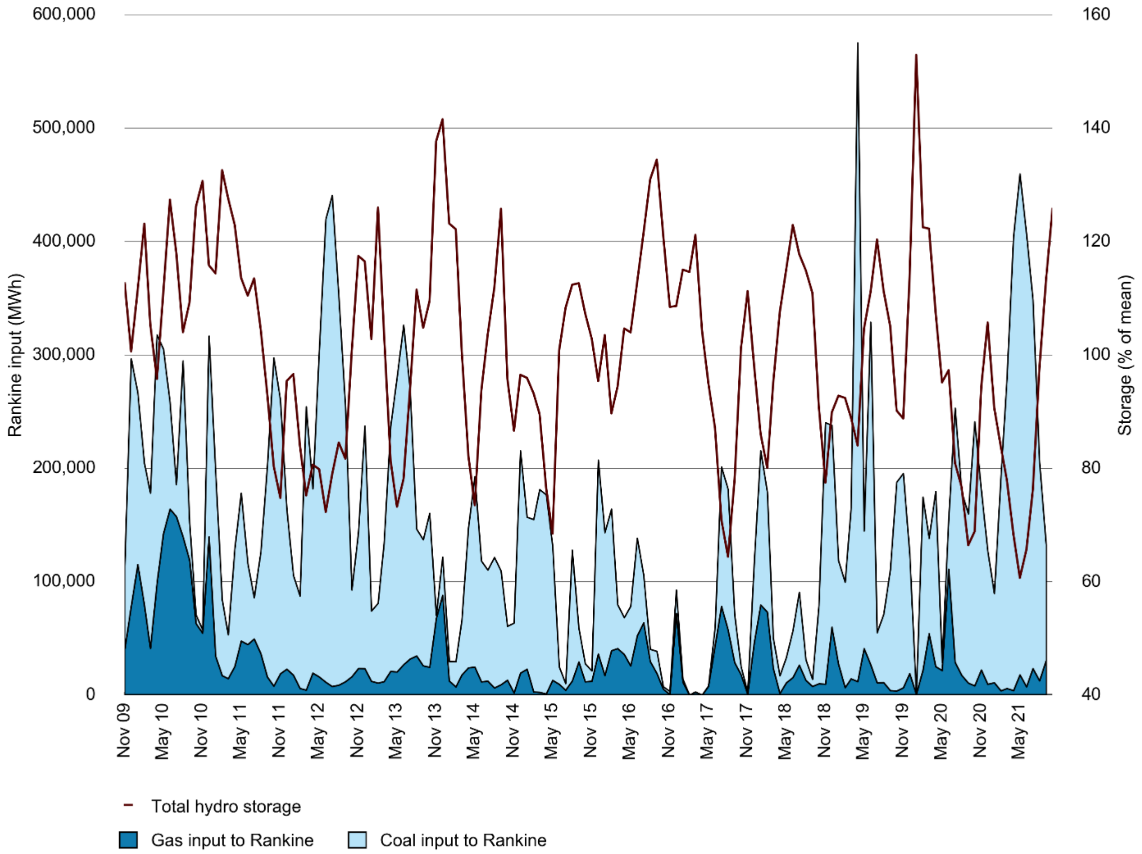
33 Ministry of Business, Innovation and Employment, "Electricity statistics," last updated September 10, 2021, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/.

34 Ministry of Business, Innovation and Employment, "New Zealand Energy Quarterly," last updated June 10, 2021, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/new-zealand-energy-quarterly/.

estimated monthly coal and gas use of the Huntly Rankine units since 2010.[35] The increase in coal use compared with the previous few years is visible, with the highest monthly usage since 2012 (when hydro storage was very low) occurring at the end of 2018 and the start of 2019, and the first three months of 2021. This is relevant for electricity prices because both the price of coal and the price of carbon have been increasing (see below). While this shift to coal shows that the market is able to nimbly substitute fuel sources when needed (as in times of low hydro inflows and uncertain gas supply) this has an obvious negative impact on the climate.

Figure 9: Huntly Rankine Units monthly coal and gas usage



Sources: Electricity Authority, NZX Hydro, OATIS, MBIE

Gas supply issues could continue for at least another 2 years, and this could be affecting both spot and forward electricity prices now

4.18 The tight supply conditions being experienced this year appear likely to continue into 2022 and this is expected to contribute to high wholesale gas prices. There is more confidence that tight conditions should ease from 2023–2024. This reflects an expectation that planned work programmes at Pohokura, Kapuni, Kupe, Mangahewa,

35 Figure 9 is based on estimates of coal use, not actual coal use data. These estimates have been calculated by comparing Genesis's daily gas use with its daily generation and calculating how much coal is needed to make up the shortfall. For this analysis, we assumed Huntly 6 and Huntly's E3P only run on gas, that the Rankines can run on both gas and coal, and that the heat rates are the same as those given in Table 3-13 of the 2020 Thermal generation stack update report (https://www.mbie.govt.nz/assets/2020-thermal-generation-stack-update-report.pdf). These heat rates are a median of a range, so our coal estimates will not be 100 percent accurate. We compared our estimates with the quarterly data on coal use published by the Ministry of Business, Innovation and Employment and found that we more often underestimated coal use, especially from 2018 onwards.

Maui and Turangi will have been undertaken by then, which should result in more gas being brought to market. In addition, committed new renewable electricity generation projects are expected to be on stream, reducing the thermal back-up required.

4.19 Expectations of similar (or higher) electricity demand are now firmly set, due to confirmation that the aluminium smelter at Tiwai Point will likely remain open until at least 2024. Expectations are therefore that current levels of thermal generation will be required to meet this demand until new renewable generation can come online. The two recently announced renewable generation builds — Harapaki and Tauhara — will not come online until at least early 2024, but approximately 100 MW of Turitea wind farm generation is due to come online in late 2021, with a further 100 MW in 2022.

4.20 This year, additional supply for electricity generation has been procured from Methanex. Methanex is New Zealand's largest consumer of natural gas. Recently, Genesis entered into an agreement with Methanex to obtain more gas.[36] Methanex will provide Genesis with up to 4.4 PJ of gas over the winter period. To provide this gas, Methanex will temporarily idle one of its Motunui trains for close to 3 months and release gas to support the New Zealand electricity sector. If run through Huntly Unit 5, an efficient baseload gas generator, 4.4 PJ of gas could provide up to around 570 GWh of energy to New Zealand over the winter. Genesis and Methanex also agreed to a summer winter gas swap for 2022 and 2023, with Genesis providing gas to Methanex in summer months that is swapped back to Genesis in the winter months.[37] Since this deal, Genesis has used some of this gas to '…supply critical gas supply to industrial customers and other market participants'.[38]

4.21 It is also possible that the price of gas from Methanex is more expensive than through long-term contracts (this is discussed in the next section). Additionally, Methanex indicated to us that its ability to alter its gas utilisation is limited, because large reductions could require shutting down a whole production train.[39] This year is the first time Methanex has shut down a train to provide flexibility.

4.22 Additionally, the Government recently updated its target of 100 percent renewable electricity to 2030 (instead of 2035). This has been — and will continue to be in the future — reflected in increasing carbon costs for thermal generators (see paragraph 4.29).

4.23 It is highly likely that continued gas supply disruption will affect forward prices. It is also possible that expectations of future gas supply disruptions affect the current spot prices through water values, which in some cases use the cost of gas and/or coal generation as a proxy for future market prices or generation cost. Hydro generators may, therefore, have already been more conservative in their storage management if higher gas prices or continued gas supply disruption suggest higher future spot prices. Thermal generators may find it difficult to rebuild gas storage quantities in these circumstances, increasing the electricity systems' reliance on continued gas field output.

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36 Genesis, "Genesis and Methanex work together to improve energy security," May 28, 2021, https://www.genesisenergy.co.nz/about/media/news/genesis-and-methanex-work-together-to-improve-ener.

37 Transpower, "Market Summary for the week ended 30 May 2021," https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/Weekly%20Market%20Summary%20-%20Week%20Ended%2030%20May%202021.pdf.

38 Genesis, "Genesis Delivers Earnings of $358 million and Dividend of 17.4 cents per share," August 26, 2021, https://www.genesisenergy.co.nz/about/media/news/genesis-delivers-earnings-of-$358-million.

39 Methanex has three methanol producing trains, two at Motunui and one at Waitara Valley.

Thermal plant costs have been increasing

4.24 Most gas for generation is bought through long-term contracts. However, the gas spot price can affect thermal generation costs in four ways:

1. price volatility reflects the uncertainty surrounding gas supply from existing gas fields
2. price level is indicative of fuel supply disruptions
3. price level reflects the opportunity cost of using gas to generate rather than the (potential) alternative of selling it
4. price level is an indication (among other factors) of how much it might cost to buy gas from industrial users.

4.25 The fourth point is particularly relevant, given the recent contract Genesis has made with Methanex (discussed in the previous section) to obtain more gas. Because the gas spot price has been increasing, it is reasonable to assume that the gas Genesis obtained from this contract was more expensive than gas it has obtained through long-term contracts. To the extent that this gas substitutes for cheaper gas previously obtained from Pohokura, the marginal cost of fuel for generating for Genesis has increased. Enerlytica estimates that the cost of the gas Genesis obtained from Methanex is somewhere in the $20/GJ to $30/GJ range.[40] This implies a short-run marginal cost (SRMC) for Huntly 5 of between $150/MWh and $230/MWh. For a Rankine running on gas, this gas price implies an SRMC of between $230/MWh and $340/MWh (SRMC estimates assume that the cost of emissions is included in the gas price). These figures compare to an average estimated SRMC (based on the gas spot price) for Huntly Unit 5 of $92/MWh during the review period, and for the Huntly Rankine units running on gas of $137/MWh.[41]

4.26 Following the gas shortage at the end of 2018, the gas spot price remained high throughout most of 2019. The average gas spot price from 2014 to September 2018 was $5.56/GJ. For October to December 2018 (during the Pohokura outage), it was $14.05/GJ, and in 2019 it was $11.07/GJ, almost double the price pre-October 2018. The average price during 2020, at $8.75/GJ, was slightly lower than 2019 but still high compared with historical prices. The price then increased again to a record high for the first half of 2021 to $16.30/GJ. Figure 11 shows this increase in recent years.

4.27 These high gas spot prices are a good indicator of genuine concern about scarcity of gas supply from existing fields. To the extent this scarcity means that non-generator gas users are willing to pay more for gas, the opportunity cost of using gas to generate electricity has been increasing.

4.28 We also obtained information on GSAs. This information suggests that the gas spot price is a good proxy for the cost of fuel for gas generators.

4.29 The price of carbon is another cost faced by thermal generators that has been increasing. The average carbon price was $12 ($NZ/tonne CO2) from 2010 to September 2018, but jumped up to an average of $25 in 2019. It increased further in 2020 to $31, and again in the first 6 months of 2021 to $38. It is currently trading at around $50. The 1-for-2 surrender obligation was phased out over 3 years from 1 January 2017. In totality, this translates to a material increase between 2017 and the

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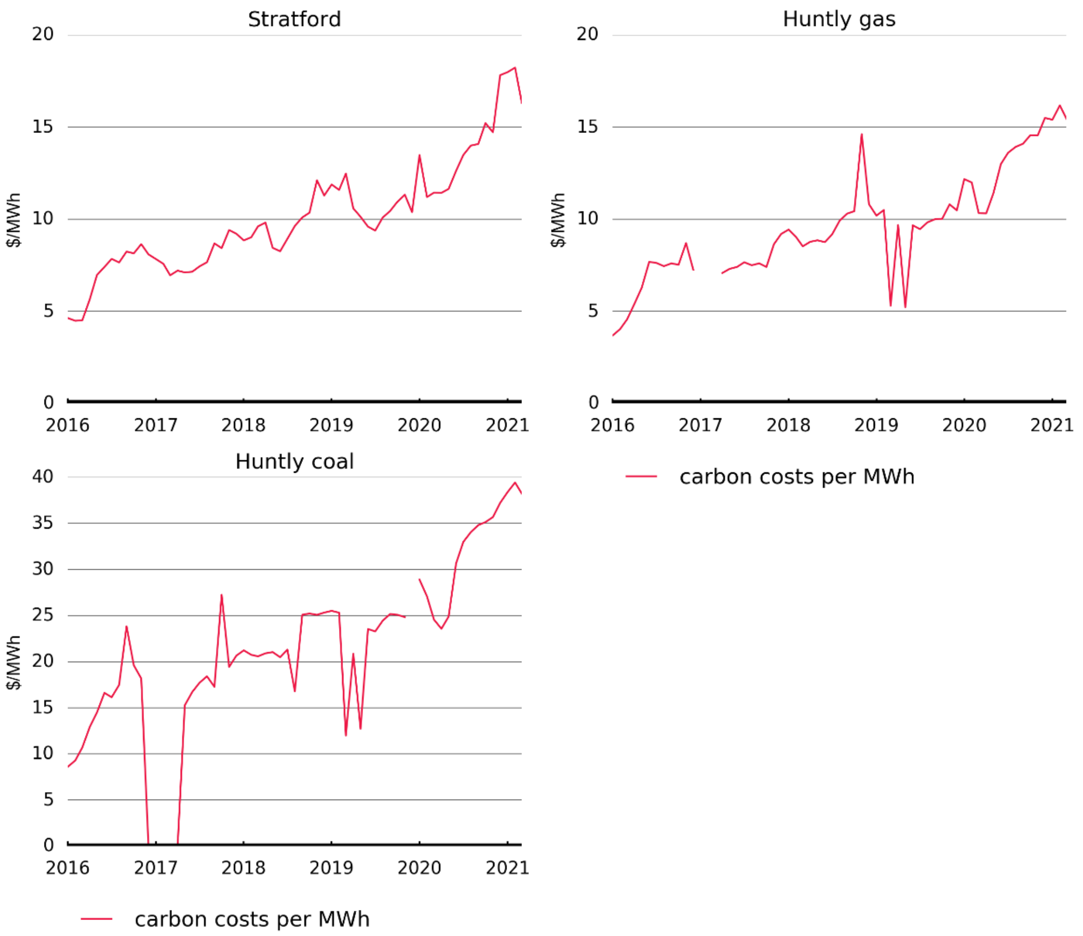
40 Enerlytica, "NZ Gas – May 2021", May 31, 2021, https://www.enerlytica.co.nz/.

41 See Appendix B for how we have calculated short-run marginal costs (SRMCs) for thermal generation.

present time in carbon costs for gas-fired generators, and, in particular, coal generation. Figure 10 shows these increases in carbon costs (total monthly emissions multiplied by the average monthly carbon price, divided by total monthly generation in MWh).[42]

Figure 10: Total monthly carbon costs per MWh for thermal generation



4.30 These higher input costs and the uncertainty around gas supply from Pohokura and other fields appear to be reflected in the offer prices of thermal generation. Figure 11 shows that the average gas generation quantity weighted offer price (QWOP) (excluding offers from all Huntly Rankine units, which have mainly been running on coal) has been increasing alongside the price of gas. The very high QWOP at the end of 2018 reflects the unavailability of gas during the Pohokura outage. Offer prices not only reflect the cost of fuel, including opportunity cost, but also whether generators can obtain fuel. Operators of gas peakers may offer in higher priced tranches (rather than not offering capacity into the market) if they are unable to run the plant for a sustained period of time due to gas unavailability.

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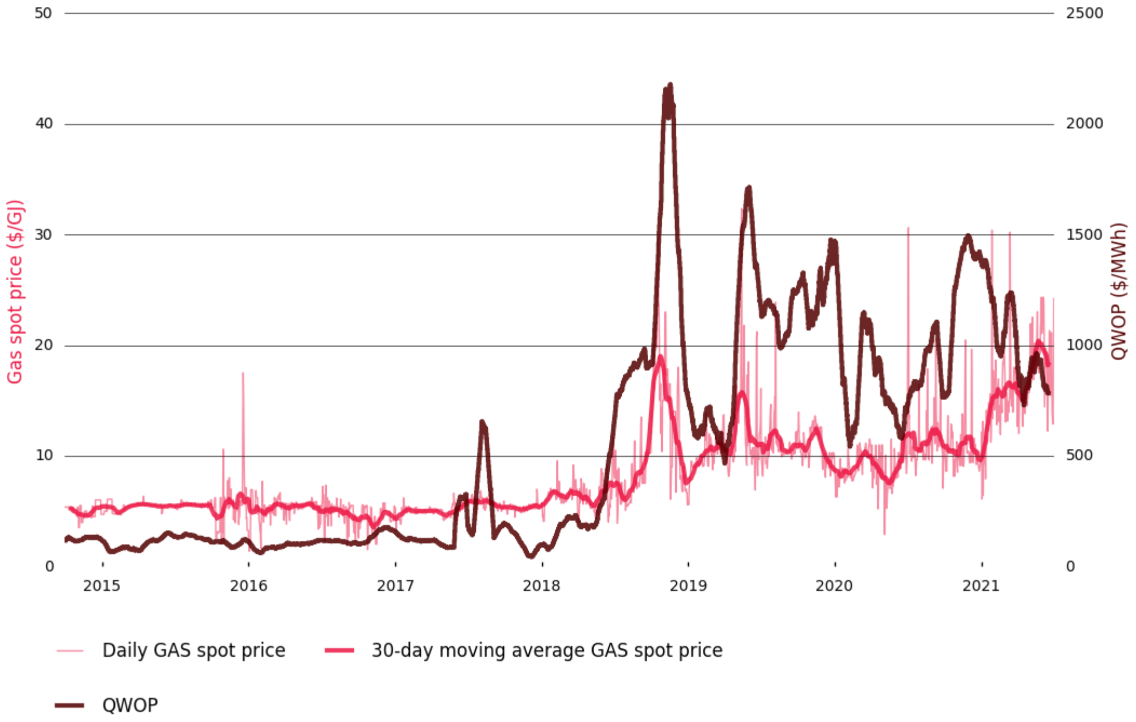
42 This uses the same methodology as in Figure 9 to estimate the Rankines monthly coal and gas usage. Emissions factor (tonnes carbon dioxide per terajoule) is sourced from: table A4.1 (gas) and table A4.2 (coal), Ministry for the Environment, *New Zealand's Greenhouse Gas Inventory 1990–2018*, Vol 2, Annexes, April 2020, https://environment.govt.nz/assets/Publications/Files/new-zealands-greenhouse-gas-inventory-1990-2018-vol-2-annexes_July2020.pdf. We use the weighted average figure for gas of 53.97, and the latest (2018) figure for coal of 92.18. The heat rate (GJ/MWh) is sourced from: table 3-13 of Ministry of Business, Innovation & Employment, *2020 Thermal Generation Stack Update Report*, October 29, 2020, https://www.mbie.govt.nz/assets/2020-thermal-generation-stack-update-report.pdf. The carbon price is sourced from: https://github.com/theecanmole/nzu.

4.31 The Huntly Rankine units can run on both gas and coal. Figure 12 shows that the price of coal has also been increasing over recent years. It also shows that Huntly's generation weighted average price (GWAP) reflects SRMCs closely (including the cost of fuel, coal or gas, and the carbon price), although at times the GWAP is significantly above the SRMC for gas.

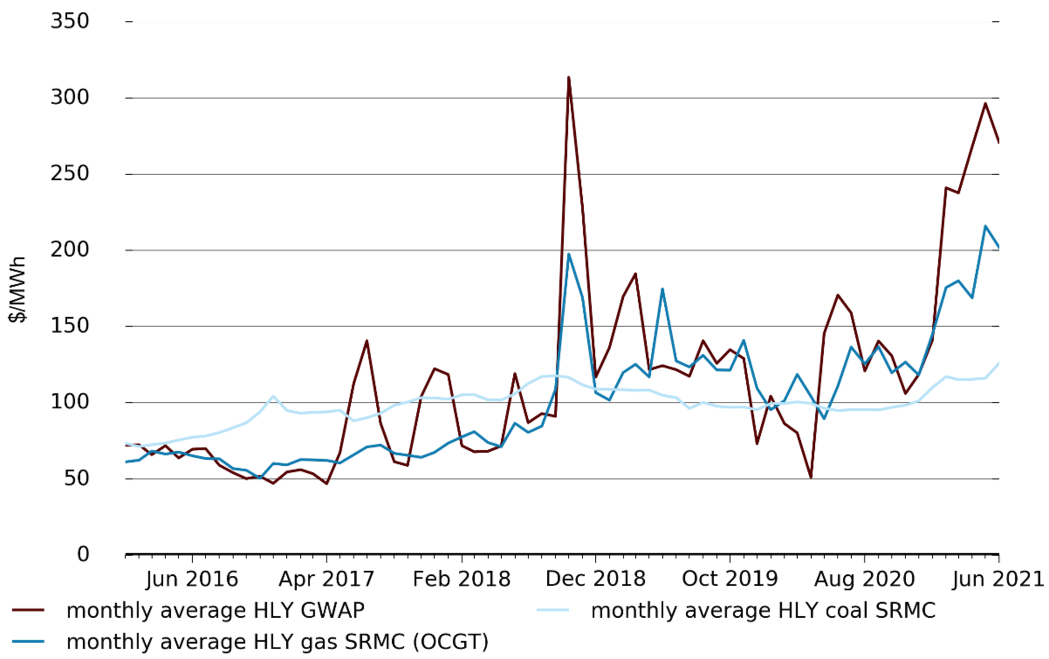
4.32 The observations in this section generally support the proposition that the sustained upwards shift in prices reflect, at least in part, the ongoing gas supply risk and increases in fuel and carbon costs, but generator offers are explored in more detail in section 5.

Figure 11: Gas prices and average gas generation QWOP (excluding Huntly Rankine units)



Sources: Electricity Authority, EMS Tradepoint

Figure 12: Huntly GWAP and coal and gas SRMCs



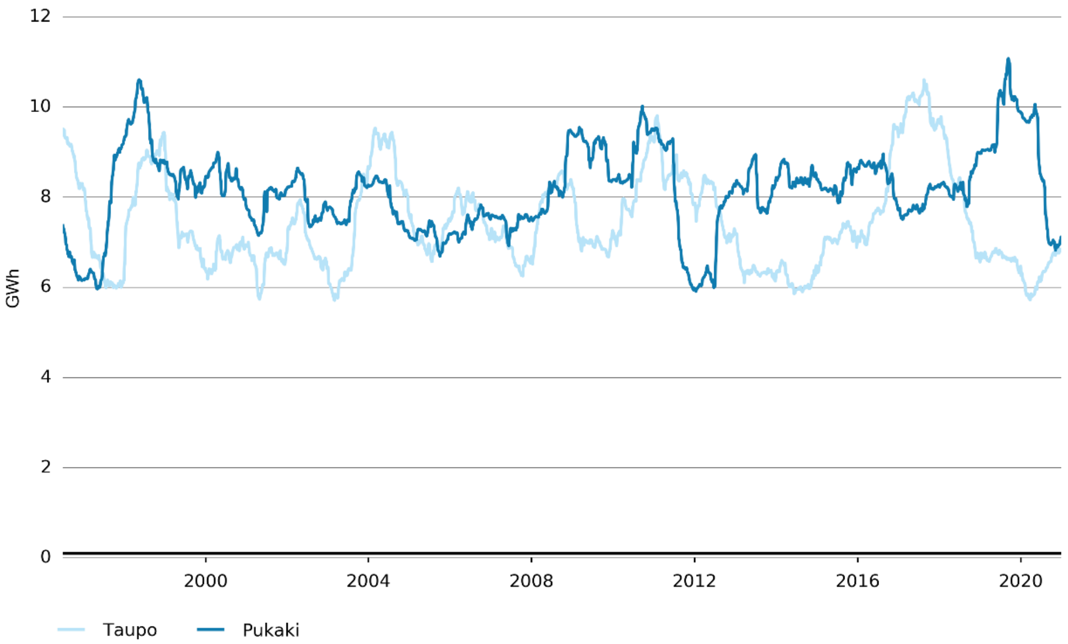
Sources: See Appendix B

Hydro storage has been low generally, and very low at times

4.33 Hydro storage has a big impact on spot electricity prices in the New Zealand market, because a large proportion of generation in New Zealand is hydro generation. If storage is low relative to the expected or desired level for the time of year, the hydro generators want to conserve water so they do not run out. They therefore increase their offer prices accordingly, which flows through to spot prices if they are dispatched, or other, more expensive, types of generation (such as thermal generation) are dispatched instead. In this section, we look at what hydro storage has been like over the review period.

4.34 Figure 13 shows that Taupo inflows have, on average, been very low over the review period, while Pukaki inflows have been high on average most of the time, but low in 2021.

Figure 13: Annual rolling mean inflows



Sources: NZX Hydro

4.35 Hydro storage has fluctuated significantly in both islands over the past few years, although sometimes in opposite directions.

(a) March 2019 — storage in both islands was declining, and New Zealand storage hit the 1 percent Electricity Risk Curve (ERC).[43]

(b) April to June 2019 — South Island storage increased and there was spilling in South Island lakes in May and June, but storage in the North Island was still low.

(c) July to October 2019 – storage in the South Island was decreasing but increasing in the North Island. Mercury may have been beginning to store water in preparation for the upcoming HVDC outage period.

(d) UTS investigation period — record high inflows in the South Island with spilling occurring in all South Island catchments, and North Island hydro generators conserving water for the upcoming HVDC outage period.

(e) HVDC outage period — South Island storage remained high, but due to the reduced capacity for imports to the North Island, North Island storage decreased, with North Island hydro generators generating more and low North Island inflows.

(f) April to September 2020 — decreasing South Island storage and continuing low North Island storage. The North Island had the lowest inflow sequence for the first 9 months of 2020, since records began in 1926.

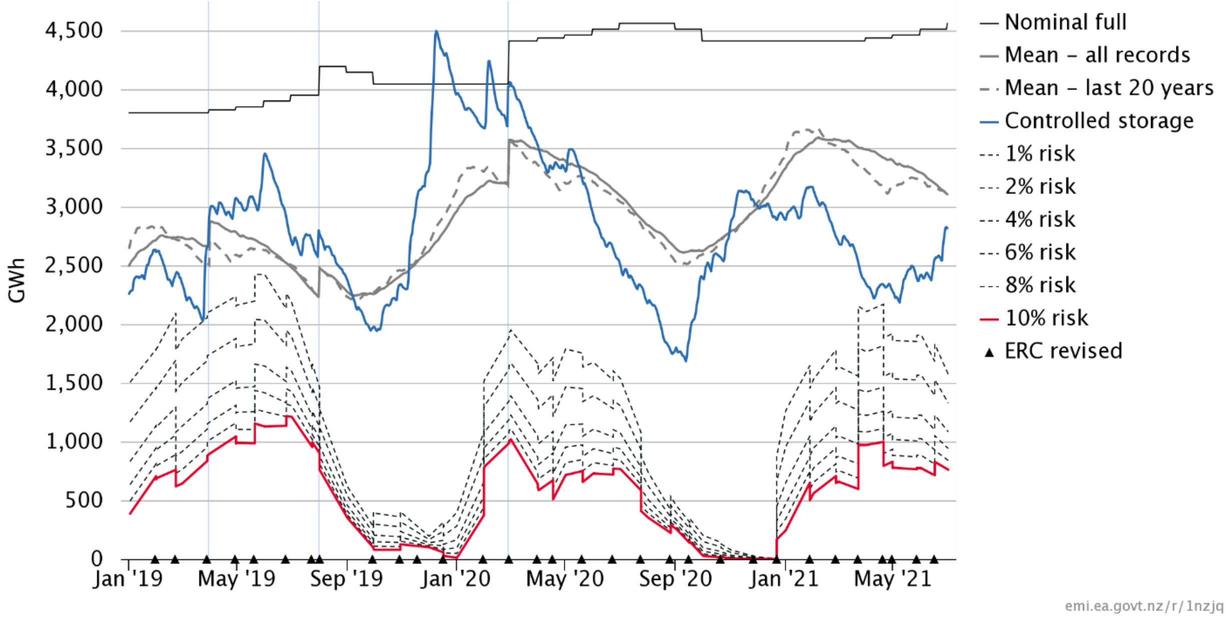
(g) October 2020 to January 2021 — increasing, but fluctuating, storage in both islands, but restricted export from the lower South Island.

43 The electricity risk curves show how stored hydro energy is tracking relative to a calculated risk of energy shortage, for more, information see the Authority's Electricity Market Information website at: https://www.emi.ea.govt.nz/MemberDashboards/Public/b5197237-33a4-4295-8c33-dc52c06415d3.

(h) February to March 2021 — decreasing storage in both islands, with the lowest total New Zealand inflow sequence since the market began in 1996. North Island storage in the first 3 months of 2021 fell to levels not seen since 2014 for this time of the year.

(i) April to June 2021 — storage was hovering near the 1 percent risk curve until early May, after which the storage trend turned upwards. By the end of June, storage was 91 percent of mean storage.

Figure 14: New Zealand hydro storage and risk curves



Thermal has reduced flexibility to firm hydro generation

4.36 Traditionally, when hydro storage has been low, thermal generation has stepped in to fill the gap. This is referred to as 'firming'. In the New Zealand power system, wind requires firming over timeframes of about a day or week, while hydro generation requires firming over monthly timeframes. Thermal generation is one of the most useful generation types to provide this firming, due to its controllability, so long as the generators can secure fuel for the firming timeframe. As hydro storage decreases, hydro generators offer at higher prices to conserve water and, as offer prices reach thermal SRMC levels, it becomes economic for thermal generators to run.

4.37 This is reflected in the historical negative correlation between thermal generation and hydro generation and storage, and the positive correlation between thermal generation and the spot price (see Table 4).

4.38 However, more recently, thermal generation has had diminished flexibility to firm hydro generation due to the reduction in Pohokura's output (discussed in the previous section). This has meant that hydro generators have needed to keep generating, despite lower storage levels, leading to higher hydro offer prices. This is reflected in the near zero correlation, that is, no relationship, between hydro generation and thermal generation in recent years, which in turn has resulted in no relationship between hydro generation and the spot price in recent years.[44] Instead of thermal generation stepping in, that is, offer tranches from hydro generators, which are priced to conserve water, were dispatched.

Table 4: Correlations

	1 June 2011 to 30 September 2018	**2019 to June 2021**
Thermal generation and hydro storage	-0.64	-0.61
Thermal generation and spot price	0.62	0.65
Thermal generation and hydro generation	-0.37	-0.04*
Hydro generation and spot price	-0.25	-0.02*

*Significantly different from the 2011–2018 correlation at the 5 percent level.

The correlations are based on daily data, because storage data is only available daily. Generation is the daily sum, and price the daily load weighted average. We use Spearman's rank correlation, which does not assume normality, is robust to outliers and does not assume a linear relationship.

4.39 Gas generators' reduced flexibility to firm hydro generation is also reflected in which generation types have been marginal over recent years (shown in Figure 15). From January 2014 to September 2018, gas generators were marginal on average 9 percent of the time. This decreased in 2019 (to 9 November, when the UTS investigation period began) to 4 percent, 7 percent in 2020 (after the HVDC outage ended) and 6 percent for the first 6 months of 2021.[45] Coal and diesel fired generation, on the other hand, have been marginal more often in recent years, because they have stepped in to meet the firming required in the system.[46]

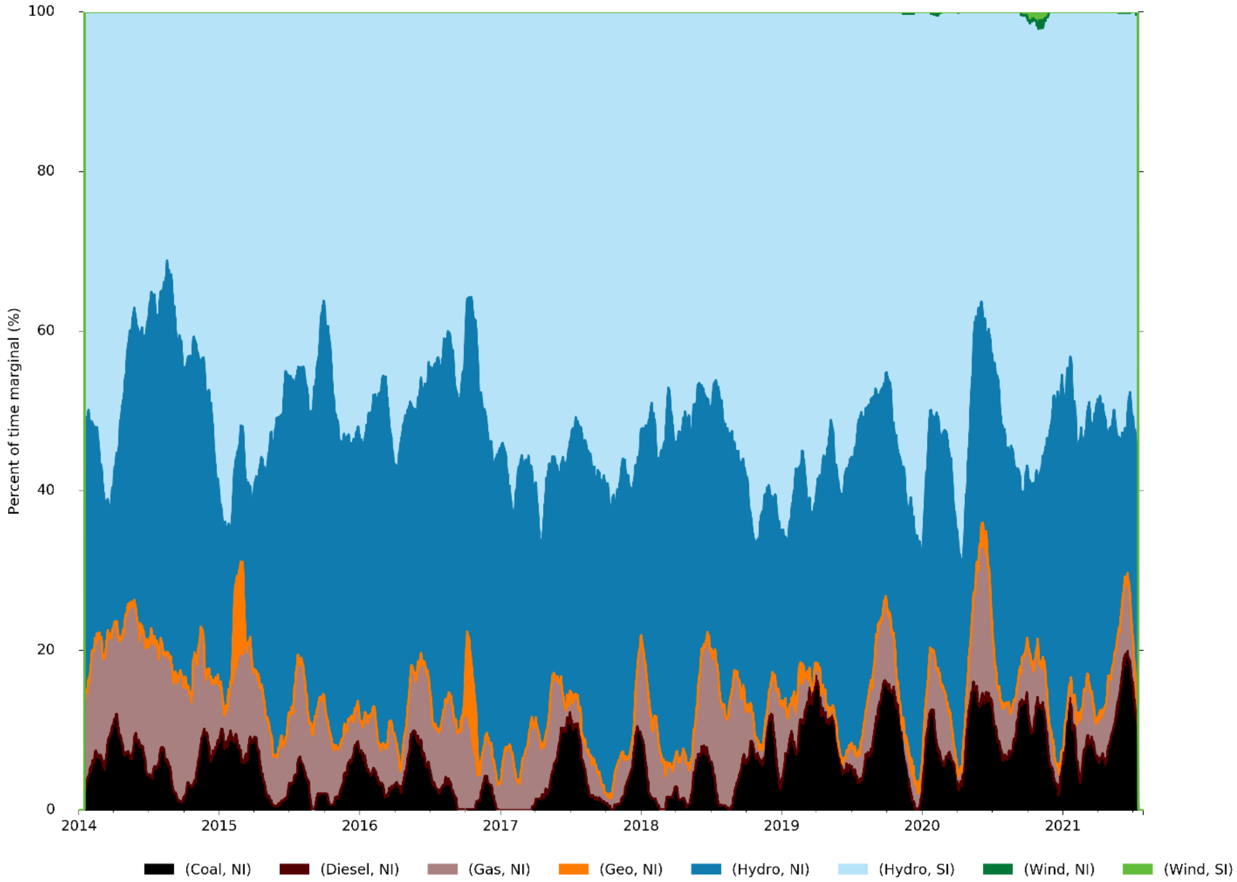
4.40 Note the marginal generator may be affected by thermal unit commitment issues where a station needs a minimum price to generate, but, once this occurs, may offer its minimum load at very low prices to ensure dispatch. This may lead to circumstances where the highest priced plant that is running is not marginal.

44 This is also discussed in an Authority quarterly review. Electricity Authority, "Market Performance Quarterly Review: January-March 2021," April 27, 2021, https://www.ea.govt.nz/assets/dms-assets/28/Market-Performance-1st-Quarter-Review-2021.pdf.

45 The difference between this percent for 2014–2018 and this percent for the review period (2019 to June 2021) was statistically significant.

46 This analysis assumes the Huntly Rankine units always operate on coal. Although this is not strictly true, Figure 9 shows that they have run more often on coal in recent years.

Figure 15: Marginal generators by fuel type (30-day rolling average)

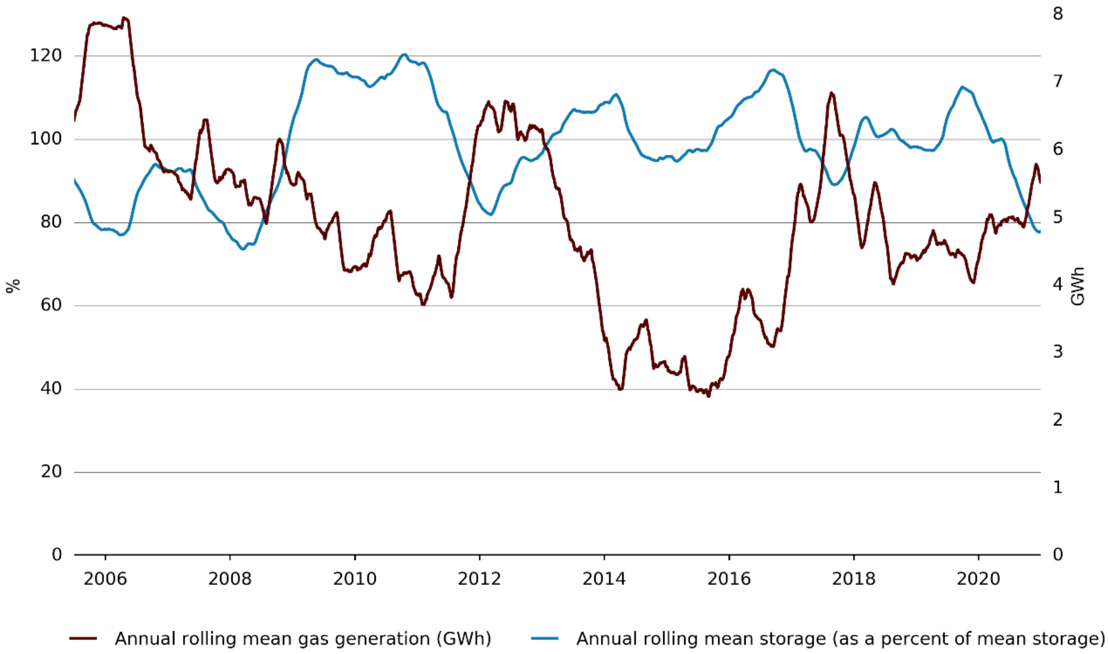


Sources: Electricity Authority

4.41 Additionally, Figure 16 shows that gas generation (excluding Huntly) has been lower than in previous instances of low hydro storage.[47] Total gas generation (excluding Huntly) for the first 3 months of 2021 was 2.5 percent of demand, compared with 5.8 percent of demand in June to August 2008 (when hydro storage was lowest) and 7.0 percent in June to August 2012.

47 Huntly is excluded because generation data by plant is unavailable before 2009. Only gas generation that was available at the end of the period is included: Stratford, McKee and Junction Road.

Figure 16: Gas generation and hydro storage



Sources: Electricity Authority, NZX Hydro

Prices reflect levels of both hydro and gas fuel availability

4.42 Historically, electricity spot prices have been high when hydro storage has been low (particularly South Island storage, because South Island storage makes up approximately 83 percent of total New Zealand hydro storage).[48] This has continued to be the case in recent years, with the highest prices occurring in times of low hydro storage. The average spot price for March 2019 — when New Zealand hydro storage hit the 1 percent ERC — was the highest of any month in 2019 at $176/MWh. Similarly, for 2020, the highest average monthly spot price was in June at $158/MWh. The average monthly spot prices for February, March and April 2021 were $241/MWh, $250/MWh, and $267/MWh, respectively.

4.43 Figure 17 shows the long-term relationship between hydro storage and price. It highlights the upwards shift in prices in recent years, evident by the following.

(a) Prices in recent years have increased when storage has been low, but to levels similar to those in previous years with even lower storage.

(b) Prices in recent years have decreased when storage recovered, but not to the levels seen in previous years.

4.44 Prices in recent years have been similar to prices back in 2006 and 2008, when storage in the South Island was very low. So even though storage in the review period did not get as low as in these previous years, the higher prices recently could be exacerbated by the Pohokura outage and gas supply issues (and also the time of year for the low storage, storage usually increases in January and February before the higher winter demand).

48 Calculated using all storage, controlled and uncontrolled, from 1996 to June 2021.

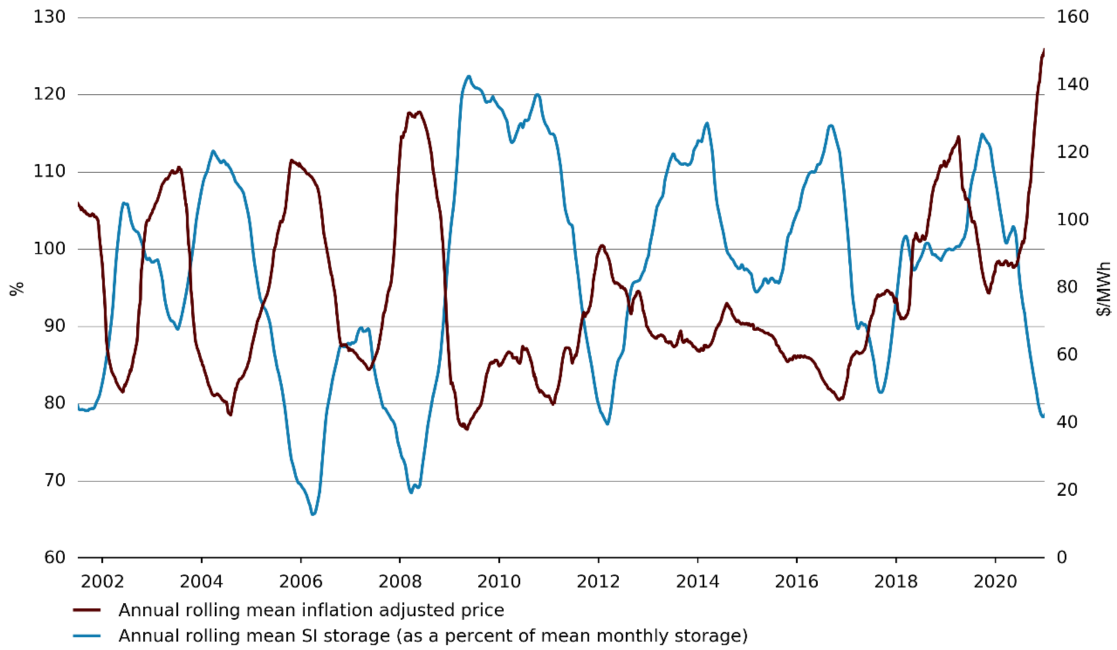
4.45 Prices did not decrease as much as previously when hydro storage recovered. Some of this could also be due to the gas supply issues. Additionally, we understand that Mercury was conserving water for some of this period due to the HVDC outage at the beginning of 2020. The Authority also found that prices should have been lower during the UTS period. At similar levels of storage in both islands back in 2013–2015, average prices were around $70/MWh to $90/MWh. In contrast, the average price in 2019–2020 did not drop below $100/MWh except for a brief period when the UTS occurred.

4.46 However, this sustained upwards shift in prices could also be due to a change in behaviour. A previous Authority review has shown that hydro generators may already have been offering more conservatively due to changes in regulation.[49] Analysis undertaken for this previous review found evidence consistent with greater risk aversion by hydro generators post the 2009 Ministerial Review of Electricity Market Performance (the catalyst for the Code changes). This was the objective of these policy changes because the 2009 review was in response to a series of dry seasons where the management of hydro reservoirs was not conservative enough. These Code changes — the official conservation campaign linked to the hydro risk curves, customer compensation scheme, stress testing and scarcity pricing — were already in force back in 2013–2015 when storage was at similar levels to 2019–2020. But prices remained higher still in 2019–2020 compared with 2013–2015.

4.47 These high prices could be because thermal fuel pressure may be compounding this more conservative offering approach. Water values calculated using the gas price as the opportunity cost of water would result in higher water values and therefore higher offer prices. Analysis of whether the sustained upwards shift in prices is also due to a change in behaviour is explored in more detail in section 5.

49 Electricity Authority, "Winter 2017 review," last updated September 21, 2018, https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2017/winter-2017-review/.

Figure 17: Long-term hydro storage and price



Sources: Electricity Authority, Stats NZ, NZX Hydro

Wind generation has increased overall, but has been low at crucial points

4.48 One feature of the market that has changed over time is the contribution of wind to electricity generation. Here we outline these changes and explore the impact on pricing.

4.49 Total wind generation has been increasing over time, making up, on average, 5.1 percent of total generation over the first 6 months of 2021, compared with 4.3 percent of total generation back in 2017. However, wind generation was low in March 2019 when hydro storage hit the 1 percent ERC. This meant thermal generation was high in this month. Wind generation was also low in February and March 2021 while hydro storage was declining, gas supply issues remained, and NZAS announced (in mid-January) that the Tiwai Point smelter would remain running until at least 2024. Including Waipipi (a wind farm that began operation in early 2021), wind generation was down by 7 percent, compared with 2017, and 11 percent, compared with 2018. Ignoring Waipipi, wind generation was down about 25 percent in these months, compared with the same months in 2017 and 2018. Wind generation in the first quarter of 2021 was the lowest it has been in the past 7 years. Again, this meant thermal generation made up a higher proportion of overall generation in these months and contributed to higher prices.

4.50 Overall, while total wind generation in 2019 and 2020 was higher than previous years, it was not enough to make up for the drop in hydro generation. This meant that the total share of renewables fell from 84 percent in 2018 to 82.4 percent in 2019. It continued to fall in 2020 to 80.8 percent.[50] In the first quarter of 2021, it dropped further to

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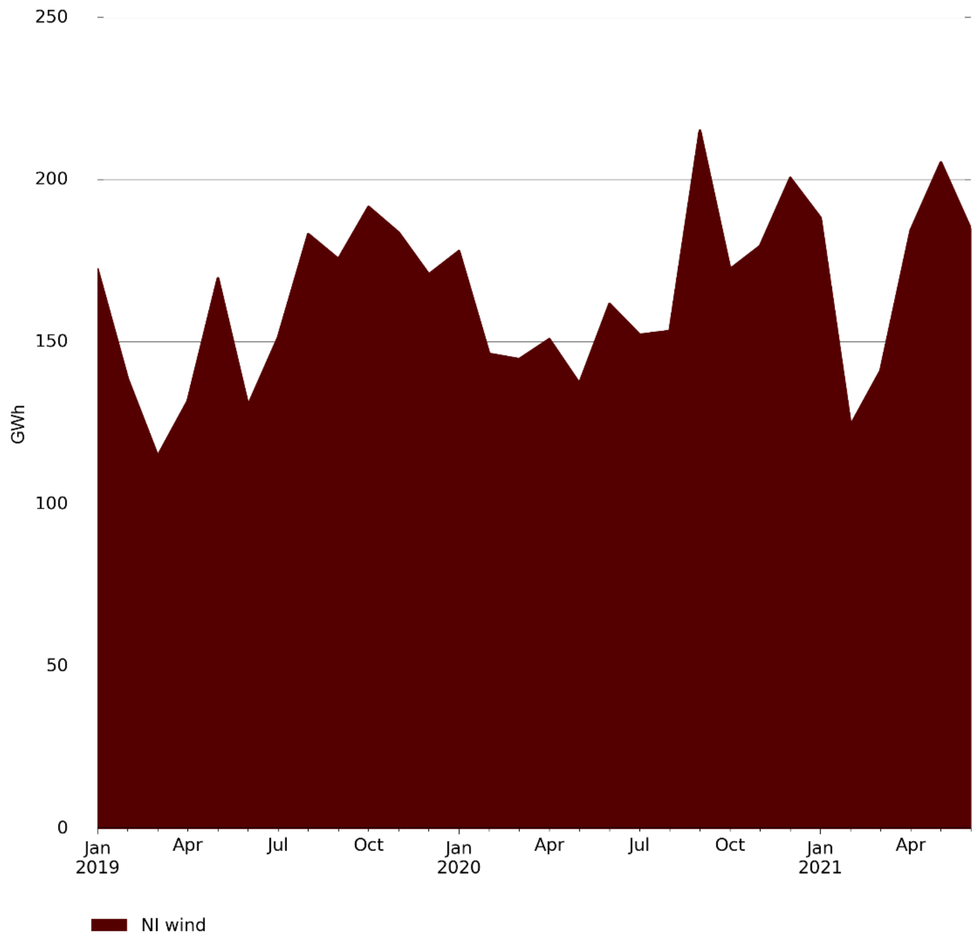
50 Ministry of Business, Innovation and Employment, "Electricity statistics," https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/

78.8 percent, and in the June quarter, it dropped to an eight-year low of 75 percent, despite near-record wind generation in this quarter.

4.51 The correlation of wind generation with price is usually negative, that is, when wind generation increases, the spot price decreases. From 2014 to the end of September 2018, this correlation was –0.30. In the first 6 months of 2021, it was –0.41.[51]

4.52 A recent Transpower market summary report discusses how the spot price may have been relatively more sensitive to changes in wind generation over the first few months of 2021 because of the comparatively steep offer stack (the steeper offer curve is discussed in section 5).[52] This means price has been more sensitive (higher volatility) to changes in wind generation over the review period, that is, some of the peaks in prices during the review period, when wind has been low, have been exacerbated by a steeper offer curve.

Figure 18: Monthly total wind generation



Sources: Electricity Authority

51 Daily data was used to calculate these correlations.

52 Transpower, March 2021, https://www.transpower.co.nz/system-operator/weekly-summary-and-security-supply-reporting

5 Structure, Conduct and Performance analysis: Are prices being determined in a competitive environment?

5.1 As noted, the purpose of this review is to assess whether prices over the review period (January 2019 — June 2021) were determined in a competitive environment. In the previous sections, we looked at underlying supply and demand conditions, because prices determined in a competitive environment will reflect these underlying conditions.

5.2 While the spot price may appear to reflect underlying supply and demand conditions, this analysis alone does not determine definitively whether spot prices have been determined in a competitive environment. The question remains as to whether all of the increase in the spot price in recent years is due to supply and demand conditions (including gas supply uncertainty), or whether some of this increase also reflects prices that are not determined in a competitive environment.[53] In this section, we use the SCP framework to address this question.

5.3 As set out in an Authority information paper, the Authority's monitoring of competition in the electricity industry plays a key role in supporting development of the Electricity Industry Participation Code 2010 (Code) by 'giving the Authority and wider industry participants a robust evidentiary basis upon which to identify the need for Code amendments and to assess proposals'.[54]

5.4 That information paper discusses how the SCP framework is an internationally accepted way of examining a sector's competitiveness, and how this provides a starting point for the Authority's monitoring framework. The simple premise is that the structure of the market determines the conduct of its participants. The more competitive the structure, the more competitive the conduct of participants and the more efficient their performance.

5.5 Market structure can be analysed using several factors, such as the number of competitors in an industry, barriers to entry and the level of vertical integration.[55]

5.6 Conduct refers to specific actions taken by firms. Measures of market conduct include analysis of offers and the relationships between offers, prices and cost. Analysis of these measures (amongst others) can indicate whether market power is being exercised.

5.7 Market power refers to the ability of a firm (or group of firms) to raise and maintain prices above the level that would prevail under competition. In this review, we are concerned with the sustained exercise of market power. This review is not concerned with the occasional exercise of market power, although the Authority may allege a breach under the new trading conduct rules if it considers such an exercise of market power has occurred.[56]

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53 See discussion of our regression analysis and structural break analysis in Appendix A and Appendix C, respectively.

54 Electricity Authority, "Industry and market monitoring: Competition," August 31, 2011, https://www.ea.govt.nz/monitoring/market-performance-and-analysis/what-we-monitor-in-the-industry-and-market/.

55 Vertical integration is where a firm owns both retail and generation businesses.

56 Electricity Authority, "The Authority's approach to monitoring the new trading conduct rule," June 1, 2021, https://www.ea.govt.nz/operations/wholesale/trading-conduct/.

5.8 If firms that have market power exercise it in a sustained way, this can mean spot prices are not being determined in a competitive environment. While it is difficult to determine definitively whether market power has been exercised, we can examine a set of indicators to determine if sustained market power has or is being exercised. We do not expect any of these indicators in isolation to unequivocally show market power has been exercised. Rather, we are looking at all the indicators in the round, so we can build a picture of the way the market is operating.

5.9 The performance of a competitive market is ultimately one that satisfies the conditions of allocative, production and dynamic efficiency. Given our focus on long-term benefits to consumers, we assess pricing trends, because this is a key determinant in influencing investment within the sector (ie, dynamic efficiency). Because current spot prices reflect past decisions, we also look at whether forward prices reliably reflect expectations of future spot prices and signal an appropriate investment and innovation mix.

5.10 This section examines indicators of competition using this SCP framework, including:

(a) indicators of market structure:

(i) indicators of seller concentration, pivotal supplier indicators

(ii) indicators of barriers to entry, including degree of vertical integration (eg, retail sales as percent of own generation); percent of new generation built by new entrants versus incumbent vertically integrated firms

(b) indicators of market conduct:

(i) offers over time

(ii) price–cost relationship (Lerner Index)

(iii) economic withholding analysis (including 2 percent decrease in demand simulation, price separation analysis, 2016 event, 2019 UTS)

(iv) an event analysis surrounding the Tiwai Point smelter announcement in January 2021

(c) indicators of market performance:

(i) profitability

(ii) price monitoring:

1. compare market price with underlying conditions

2. price trends

3. price setting: correlation between the frequency with which a supplier sets the market price and market conditions.

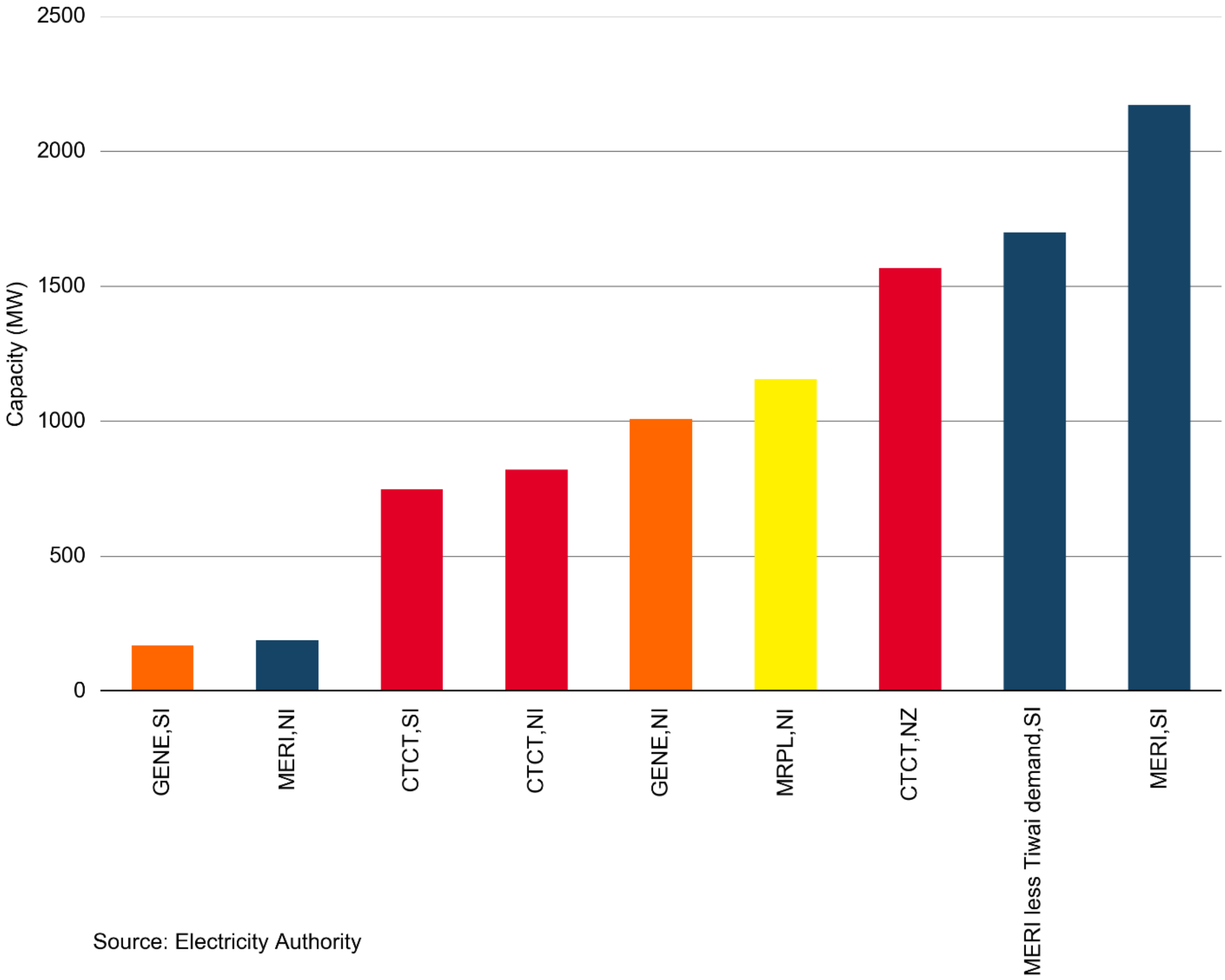
As discussed above, we are interested in feedback on whether there are other indicators you consider we should also be looking at.

Market structure

5.11 Generation in the New Zealand electricity market is supplied primarily by four large vertically integrated generator–retailers. They supply about 80 percent of generation to the market. Figure 19 shows the generating capacities of these generators split by South Island and North Island generation. For comparison, this chart also includes the amount of generating capacity from Meridian available to meet demand for the rest of New

Zealand after subtracting its contracted NZAS demand (472 MW). This shows that, even once NZAS demand is accounted for, Meridian still has the largest generating capacity. Contact's generation over the whole of New Zealand (which includes hydro generation in the South Island and thermal and geothermal in the North Island) is the next largest.

Figure 19: Generation capacities



Source: Electricity Authority

Seller concentration

5.12 A market dominated by a few large firms is more susceptible to the exercise of market power than a market with numerous relatively small firms. In this section, we assess — using two different measures — the concentration of generation in the New Zealand market.

Herfindahl–Hirschman Index has not changed since 2014

5.13 The Herfindahl-Hirschman Index (HHI, the sum of squares of each firm's share) is a widely used measure for market concentration, where higher scores indicate higher concentration and scope for market power. The maximum HHI score is 10,000, when a monopolist has 100 percent of the market (100×100=10,000). The US Federal Trade Commission broadly categorises an HHI above 2,500 as highly concentrated.[57] The US Federal Energy Regulatory Commission uses a standard of 1,800 to indicate a

57 US Department of Justice and the Federal Trade Commission, "Horizontal merger guidelines," August 19, 2010, pp. 18–19, https://www.justice.gov/atr/horizontal-merger-guidelines-08192010.

concentrated market.[58] The Australian Competition and Consumer Commission's (ACCC's) merger guidelines indicate it is generally less likely to identify competition concerns when the post-merger HHI is less than 2,000.[59] Biggar (2011) discuss how an HHI of less than 1,000 is usually taken as an indication that a market is broadly competitive in competition policy analysis, but if the elasticity of demand is low enough (which it could be in electricity markets), even an electricity market with an HHI of 1,000 could give rise to significant market power.[60] The Authority has not determined its own HHI concentration thresholds, but rather uses the HHI as a tool to look at trends over time.

5.14 The HHI for generation in New Zealand has been hovering around 2,000 since 2014, with slight decreases when storage has been low (see Figure 20). However, it may increase with the recent announcements by Contact and Meridian regarding investment in Tauhara and Harapaki, respectively, and Mercury developing Puketoi and Turitea, and acquiring Tilt's New Zealand generation assets.

5.15 While the HHI is commonly used to measure market concentration, it has been suggested that this measure has limited usefulness for electricity markets.[61] This is because, even for electricity markets where the most dominant net seller has a relatively small market share, they may still be able to exercise market power. Additionally, transmission constraints — which can create separate geographic markets where concentration may differ from the national market — are not taken into account.

5.16 Finally, the HHI for the generation market is driven somewhat by hydro storage levels in the New Zealand market, where most generation is hydro. The HHI falls when water is scarce and climbs when water is abundant (large hydro generators produce more when water is abundant). However, the trend is still apparent through the use of moving averages.

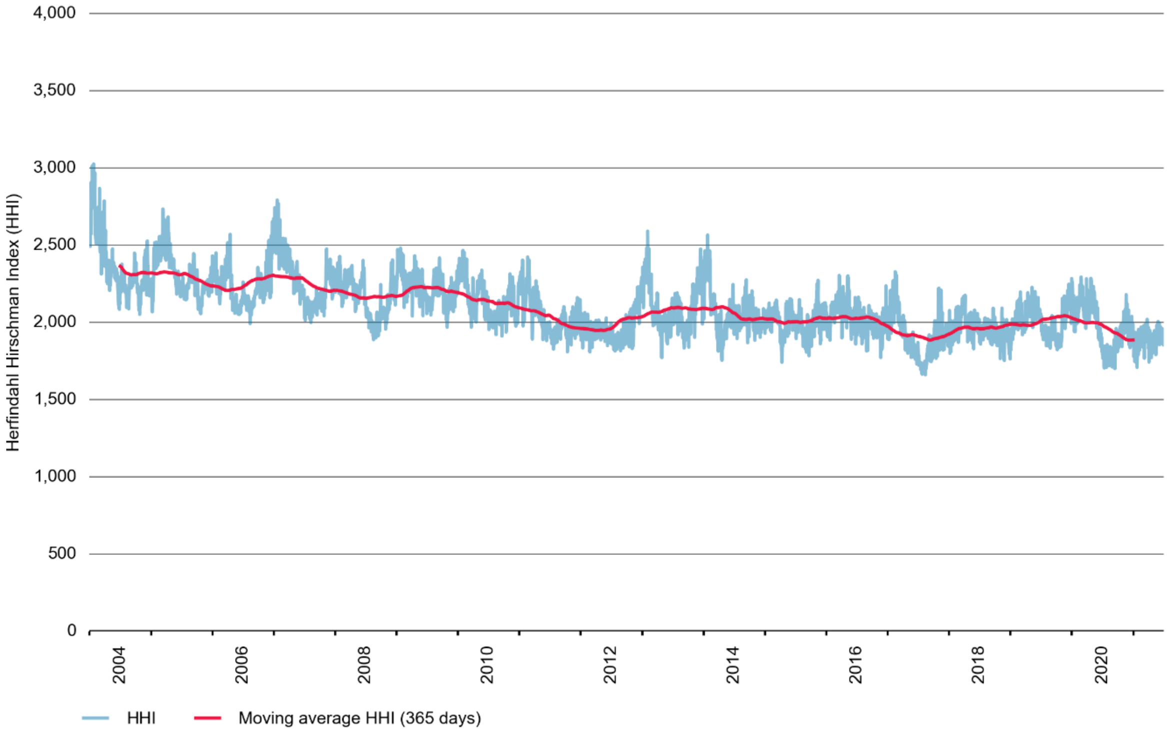
58 https://www.ferc.gov/industries-data/natural-gas/intrastate-transportation/market-based-rate-standards

59 Australian Competition and Consumer Commission, "Merger guidelines," updated 2017, p. 35, https://www.accc.gov.au/system/files/Merger%20guidelines%20-%20Final.PDF

60 D Biggar, "The theory and practice of the exercise of market power in the Australian NEM," 2011, https://www.aemc.gov.au/sites/default/files/content/1b0947b4-930f-449a-be21-4cf009b2fe7a/AER-Attachment-1.PDF.

61 See, for example: Penn State Collage of Earth and Mineral Sciences, "Measuring market power", https://www.e-education.psu.edu/ebf483/node/732, Paul Twomey, Richard Green, Karsten Neuhoff, and David Newbery, "A Review of the Monitoring of Market Power: The Possible Roles of TSOs in Monitoring for Market Power – Issues in Congested Transmission Systems," February 2005. https://www.researchgate.net/publication/4998936_A_Review_of_the_Monitoring_of_Market_Power_The_Possible_Roles_of_TSOs_in_Monitoring_for_Market_Power_Issues_in_Congested_Transmission_Systems.

Figure 20: Generation Herfindahl–Hirschman Index



Source: Electricity Authority

Pivotal supplier indicators: Meridian is needed to meet demand 90 percent of the time

5.17 Another measure that has been developed to overcome these criticisms is the pivotal supplier index (PSI). This measure takes into account both the supply side and demand conditions. It examines whether a given generator is necessary (ie, pivotal) in serving demand. A participant is pivotal if market demand exceeds the capacity of all other participants. In these circumstances, the participant must be dispatched (at least partly) to meet demand. The basic idea is to evaluate whether any firm is large enough relative to the market to allow it the ability to change its own output in a way that will affect the market price.

5.18 The Authority's annual report uses a pivotal analysis using simulations in vectorised scheduling, pricing and dispatch (vSPD) (instead of the PSI).[62] This gives a more accurate measure because market constraints are more fully taken into account (although still not perfectly accounted for). All offers for a trader (both energy and reserve) are changed to $30,000/MWh. If there are any trading periods where the generation from this trader is needed to meet demand, then this trader is gross pivotal in those trading periods.[63]

5.19 Meridian is the only generator–retailer that was gross pivotal a higher percent of the time in all three review years (2019–2021), compared with previous years. It was gross pivotal in the South Island around 77 percent of the time in each year from 2016 to 2018. This increased to around 90 percent to 95 percent in 2019 to 2021 (to 30 June). Genesis

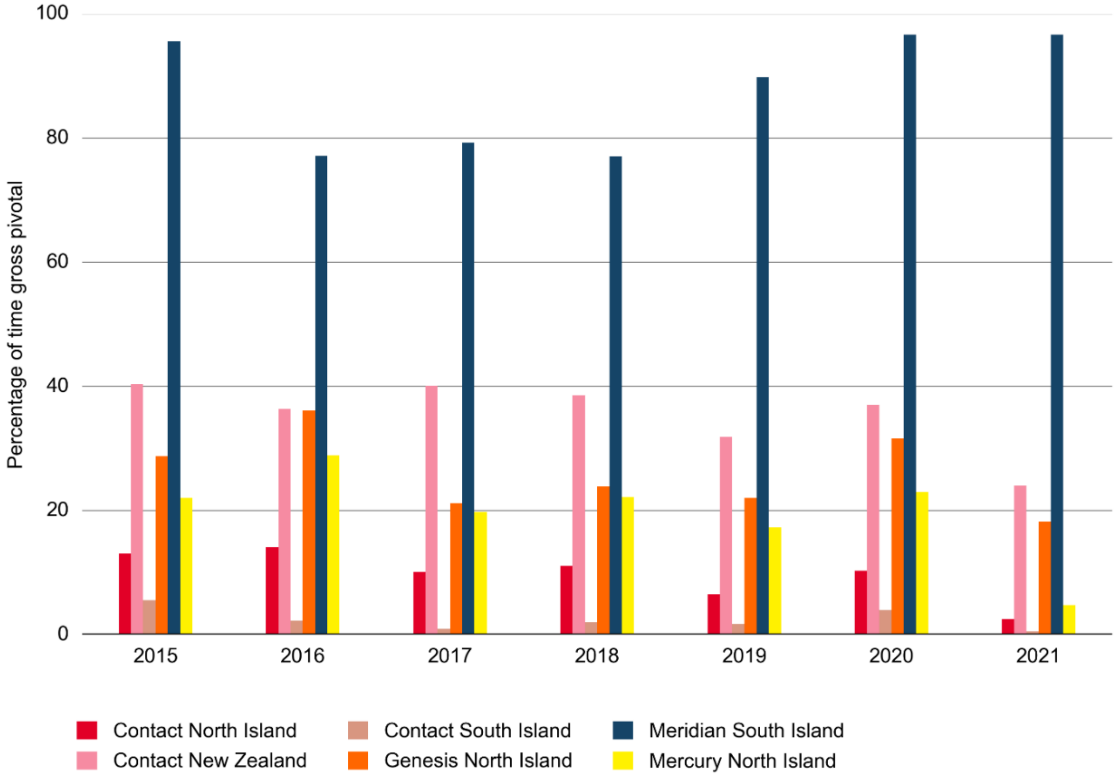
62 Note that, since the last annual report, the model used to calculate when generators are pivotal has been updated to improve the estimation of DC Extended Contingent Event Net Free Reserve for the South Island. As a result of this update, South Island generators are now calculated to be pivotal less frequently when the high-voltage, direct current (HVDC) is transferring southwards.

63 This analysis is split by island.

(in the North Island) was gross pivotal a higher percentage of the time in 2020, compared with 2017 and 2018, but had a similar or lower percentage for 2019 and the first 6 months of 2021, compared with previous years. Contact and Genesis were gross pivotal between them in 2020 in the North Island (ie, thermal generation) about 40 percent of the time.

5.20 A comparison of Figure 19 and Figure 21 shows that, while Meridian is not much larger in terms of generating capacity compared with the next largest generator (Contact), its importance to the market, in terms of meeting demand, is much larger. Meridian has 30 percent of the market-generating capacity (from its South Island hydro generation) but is needed to meet demand over 90 percent of the time. Contact has 22 percent of the market-generating capacity but is only needed to meet demand less than 40 percent of the time.

Figure 21: Gross pivotal



Source: Electricity Authority

Barriers to entry

5.21 If it is hard for a new generator to enter the market, this protects incumbent firms and restricts competition. Barriers to entry in new generation may limit price competition.

5.22 This review is concerned only with barriers to entry in generation, and the effect such barriers can have on wholesale prices. While this in turn affects entry into the retail market, it is not the focus of this review. We note that the Authority has recently decided to mandate the disclosure of internal transfer prices by vertically integrated generator–retailers, and retail gross margins by retailers, with the aim of increasing transparency.

Vertical integration may have been restricting entry of independent generators

5.23 In the context of electricity markets, vertical integration (VI) refers to firms that have both generation and retail businesses. The level of VI is calculated using reconciled sales and purchase volumes in the wholesale electricity market:

$$VI = 100 \times \frac{2 \times \min(S, P)}{S + P}$$

Where S denotes sales and P denotes purchases.[64]

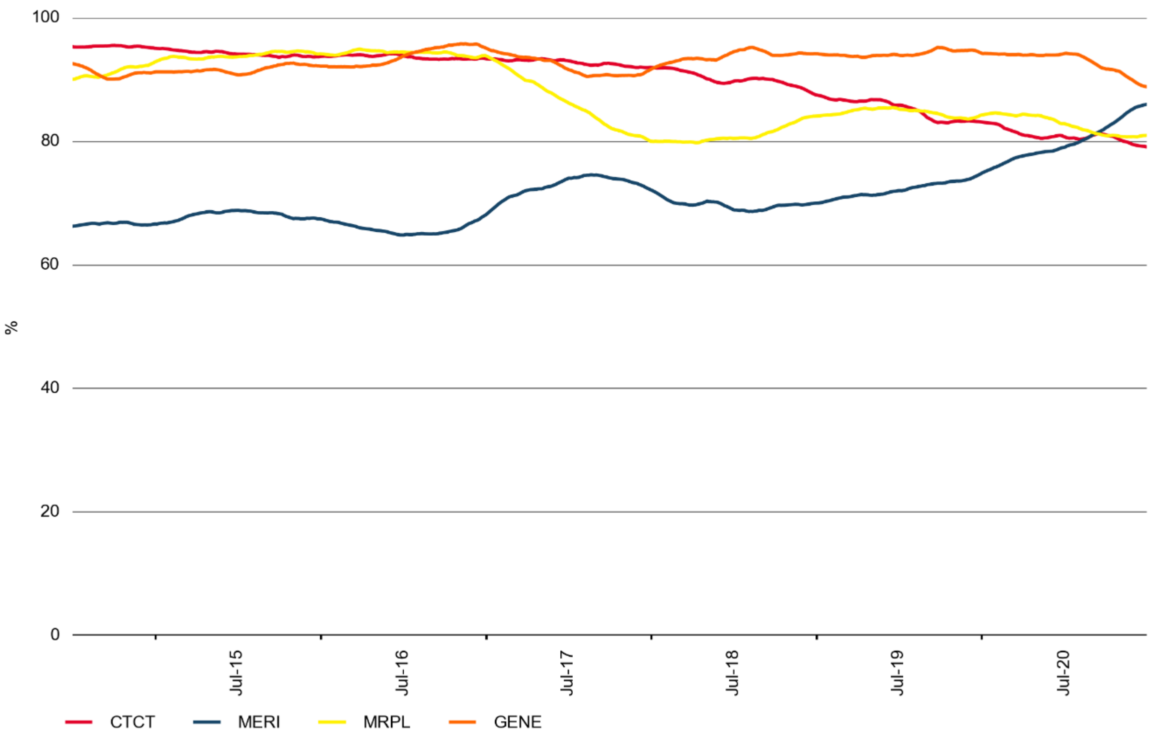
5.24 As with the HHI measure discussed above, VI can be heavily influenced by variations in hydrology in New Zealand because most of the large generator–retailers have a high proportion of hydro generation, and sales during periods of low inflows will affect this measure. However, as Figure 22 shows, while levels move around a bit, the overall degree of VI in the New Zealand market has remained high.

5.25 Also similarly to the HHI, this measure may change with the recent announcements by Contact and Meridian regarding new generation investment in Tauhara and Harapaki, respectively, and with Mercury acquiring the New Zealand assets of Tilt Renewables and the residential and SME customer base of Trustpower.

5.26 Figure 22 shows the yearly moving average (of daily volume weighted VI) for the largest four vertically integrated firms. It shows that Contact's average level of VI has been decreasing from 2018. Mercury's level of VI decreased in 2017 to a new average level of around 80 percent to 85 percent. This is because Mercury's retail book has decreased. Genesis's level has remained about the same as in previous years, except for a decrease in 2021. Meridian's level of VI has been broadly increasing since the middle of 2018, surpassing the yearly averages of Mercury and Contact in 2021. This is because Meridian has increased its share of retail sales.

64 As on Electricity Authority, "EMI: Vertical integration trends," https://www.emi.ea.govt.nz/Wholesale/Reports/BLKL4U?DateFrom=20190101&DateTo=20191231&RegionCode=NZ&TimeScale=D&Include=RPC&Entity=CTCT&Show=MWP&_si=v|3.

Figure 22: Vertical integration (rolling yearly average)



Source: Electricity Authority

5.27 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.

5.28 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. Sources for contracts other than from incumbent generator–retailers could include:

- hedges from the ASX — which does not have products that are long enough to cover revenue certainty for investment projects
- other forms of agreements (including PPAs) with independent retailers — who are small
- other forms of agreements (including PPAs) with larger electricity users. Respondents interviewed by Concept suggested that large electricity users have historically had limited appetite for PPAs, although this might be changing.

5.29 One respondent to Concept's investment environment interviews (see Dynamic efficiency for further details) said that the chance of obtaining PPAs with industrial users may be improving. Respondents told us that industrials are now starting to engage with advisors to understand and help manage the risks around intermittent generation. Two large industrials recently collaborated to obtain PPAs with Contact. These types of deals have become more prevalent overseas. For example, in Australia, Tilt Renewables has signed a deal with the Aldi supermarket chain. Genesis's recent request for proposals process was also seen as a positive for the industry, because it enables more diversity and options.[65] Genesis has entered into two PPAs for wind farms (Kaiwaikawe and Waipipi) with Tilt Renewables and one with Contact to support development of Tauhara. Genesis has also announced its plan to develop grid-scale solar, and we understand is currently finalising the terms of a joint venture with two shortlisted international solar developers. All of these developments could indicate that VI as a barrier to entry may be becoming less of an issue.

Percent of new generation built by new entrants versus incumbent vertically integrated firms: most has been from generator–retailers, but this could be changing

5.30 If a high percentage of new generation built or committed has been from the incumbent vertically integrated firms, this could suggest that there are barriers to entry for smaller, independent players.

5.31 During the review period, three new generation investment projects were built (shown in Table 5). Of these, none were built by generator–retailers, but the largest one (Waipipi) has since changed ownership to a generator–retailer. There was no evidence from our interviews that generator–retailers have been constrained by ownership structures to access capital for new investment, nor that this will be a problem for many years to come.

Table 5: Generation built during the review period (January 2019 to June 2021)

Project name	Party	MW	Generator–retailer?
Waipipi wind farm	Tilt Renewables	133	N (but now owned by Mercury)
Ngawha S4	Top Energy	32	N (distribution company)
Rakaia	Barrhill Chertsey Irrigation Ltd	3	N

5.32 It is not straightforward to calculate the percentage (by MW capacity) of committed but unbuilt new generation that is owned by generator–retailers, because it is not always clear which projects have been officially committed. This is the case particularly for smaller investors, for example, it's not clear whether Lodestone Energy's Kaitaia solar farm and LightYears Solar Naumai solar farm have been committed yet (although according to Concept they all seem reasonably likely to go ahead). Committed projects will also exclude solar projects that are not yet consented, but, due to the relative ease to be consented, are likely to be commissioned earlier than most of the committed windfarms.

5.33 Table 6 and table 7 show estimates of the percentage (in MW terms) of committed projects owned by generator–retailers: 97 percent for the projects that are definitely committed and 90 percent if Kaitaia and Naumai are included. If we also include the projects commissioned and built during the review period, these figures change to 75 percent and 71 percent respectively.

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65 Genesis Energy, "Genesis assessing 6,000 GWh of renewable generation options for development by 2025," 12 February 2021, https://www.genesisenergy.co.nz/about/media/news/renewable-generation-options-feb-2021.

5.34 Over three-quarters of committed projects and projects that are likely to be committed soon are owned by generator–retailers.[66] 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. See Dynamic efficiency for more details.

Table 6: Committed generation investment

Project name	Developer	MW	Generator–retailer?
Definitely committed			
Tauhara 1	Contact	152	Y
Harapaki	Meridian	176	Y
Turitea North	Mercury	119	Y
Turitea South	Mercury	103	Y
Pukenui	Far North Solar Farm	16	N
Possibly committed			
Kaitaia	Lodestone Energy	39	N
Naumai	LightYears Solar	3.4	N

Table 7: Percentages of commissioned and recently built generation that is generator–retailer owned

Including	Percent
Committed generation (%)	
Only including definitely committed projects	97
Including possibly committed projects	90
Committed and recently built generation (%)	
Only including definitely committed projects	75
Including possibly committed projects	71

Note: Waipipi is not included in generator–retailer numbers because it was owned by Tilt Renewables when investment was committed and commissioned.

Market conduct in relation to the spot market

5.35 Generators interact with the spot market by offering generation. Therefore, conduct is embodied in offers. This section accordingly focuses on offer behaviour, and in particular

66 This is based on information in the public domain. It is likely there are projects that we haven't captured. These projects are most likely small and not owned by the large generator–retailers. Therefore, the true percentage of projects that are generator–owner owned may be slightly lower.

whether offer behaviour suggests market power is being exercised.[67] Market power refers to the ability of a firm to raise and maintain prices above the level that would prevail under competition.

5.36 The information paper that sets out the Authority's approach to monitoring competition in the electricity market states that 'Market conduct is perhaps the most challenging part of the SCP framework. The measures are clear in principle but practically difficult to implement'. It goes on to say that 'These difficulties are pronounced in the context of how electricity markets operate in the short run. In the short run, electricity markets are characterised by both inelastic supply and inelastic demand. Under these conditions, strategic pricing becomes prevalent and some degree of strategic pricing, which may be undesirable in other markets, is unavoidable'.[68]

5.37 Accordingly, offering at higher prices does not necessarily mean a breach of the Code or the exercise of market power. The rules of the New Zealand electricity market do not prohibit prices from being high when they reflect competitive outcomes and the underlying supply and demand conditions. In the New Zealand wholesale electricity market, there are many fuel-constrained generators that have the option of using fuel to generate now or later. This means that any consideration of whether behaviour is consistent with competition must take into account opportunity cost. For hydro generation and thermal generation with storage, this can represent the return it may make by generating at a different point in time.

5.38 The structure of the New Zealand market also affects offering behaviour. Thermal generation offers are affected by the gas price and, since the Pohokura outage, disruption in the supply of gas. If fuel supply is constrained or highly priced, thermal generators can on-sell gas — if the returns are greater than from using it to generate, or in some cases store it for future generation — if generators believe future spot prices will be higher. In either case, this will mean higher offer prices or plant not being offered.

5.39 This in turn affects offer prices of hydro generators. In the New Zealand market, hydro generators must manage their storage levels within the context of volatile thermal fuel prices and thermal fuel availability. In some cases, this is done by including the thermal fuel price as a proxy for the opportunity cost of water. Hydro generators may also sometimes adjust the opportunity cost of water to account for thermal generation that is not able to run due to fuel availability. If hydro generators offer above thermal prices, their offers might not be dispatched, potentially leading to the lakes filling up and excessive spill. If they offer below thermal prices, the lakes will empty out faster. This also applies to hydro generators with little or no storage: they will price their offers to avoid being asked to dispatch water they have not got (rather than water they wish to store).

5.40 This interaction of gas and hydro generation offer prices must be kept in mind when assessing offering behaviour in relation to the level of competition in the market. In this review, conduct has been assessed by looking at the pattern of offers over time and how they relate to underlying supply and demand conditions; the relationship of offers to estimates of cost (including opportunity cost); the relationship of price to cost (using the

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67 For all of the analysis of offers in this review, we use effective offers, that is, offers available after accounting for cleared reserves and frequency keeping.

68 Electricity Authority, "Industry and market monitoring: Competition," August 31, 2011, https://www.ea.govt.nz/monitoring/market-performance-and-analysis/what-we-monitor-in-the-industry-and-market/, 13.

Lerner Index); output, again in the context of underlying supply and demand conditions; and specific events, such as the 2019 UTS and the contracts recently entered into by Meridian and Contact in relation to the Tiwai Point smelter (referred to in this document as the Tiwai contracts).

Opportunity cost in the New Zealand electricity market

Opportunity cost is the cost of the foregone use of a resource.

Opportunity cost is part of the short-run economic costs of generation. Hydro inflows can be stored or used to generate. Gas can be stored at the Ahuroa underground gas storage or sold to industrial users. By generating, wind and geothermal are incurring maintenance costs and the alternative is to neither generate nor incur the maintenance costs.

Opportunity cost for a hydro generator needs to balance the probability of spilling water with the probability of running out. So the opportunity cost for hydro generators can vary from zero, for a spilling generator, to the Value of Lost Load (a dollar-value measure of the impact of outages on electricity users) for a situation where it is anticipated that consumers will be deprived of service. Models of the opportunity cost of water include a probability distribution over the full set of possible outcomes — many with significant levels of thermal generation, where the costs of that thermal generation will heavily increase the spot price — given current storage and possible inflows.

Decisions to store fuel for later use, or generate now, are intertemporal, so the opportunity cost depends on perceptions of the future spot price. These perceptions must be subjective. So it is not possible to have an objective measure of opportunity cost.

Price–cost relationship

5.41 In this section, we consider 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.

5.42 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).

5.43 While a significant amount of data is presented here — in the interests of transparency we have included all data we looked at — much of it is inconclusive. Further, in this section, we are often looking at the same data but measuring the relationships in different ways (percent of offers over a benchmark; ratio of price to cost) to build as complete a picture as possible of the market.

5.44 We acknowledge also 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.

5.45 While much of the data presented here is inconclusive, there seems to be a significant quantity of high offers for some generators that are not always related to underlying supply and demand conditions, including storage and thermal fuel costs.

Offers over time: offer prices have increased in the review period

5.46 In a competitive market, we expect offer prices to be related to underlying supply and demand conditions. If they are not, this could suggest the exercise of market power. In this section, we look at trends in offers over time and the percentage of offers for each generator that are offered above \$300/MWh.[69] 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.

5.47 Figure 23 reveals a marked increase in the percentage of offers at higher prices for both hydro generators and thermal generators. For some generators, in particular Meridian (Waitaki), the percentage of offers at higher prices does not change much in relation to changes in underlying conditions.

5.48 We observe:

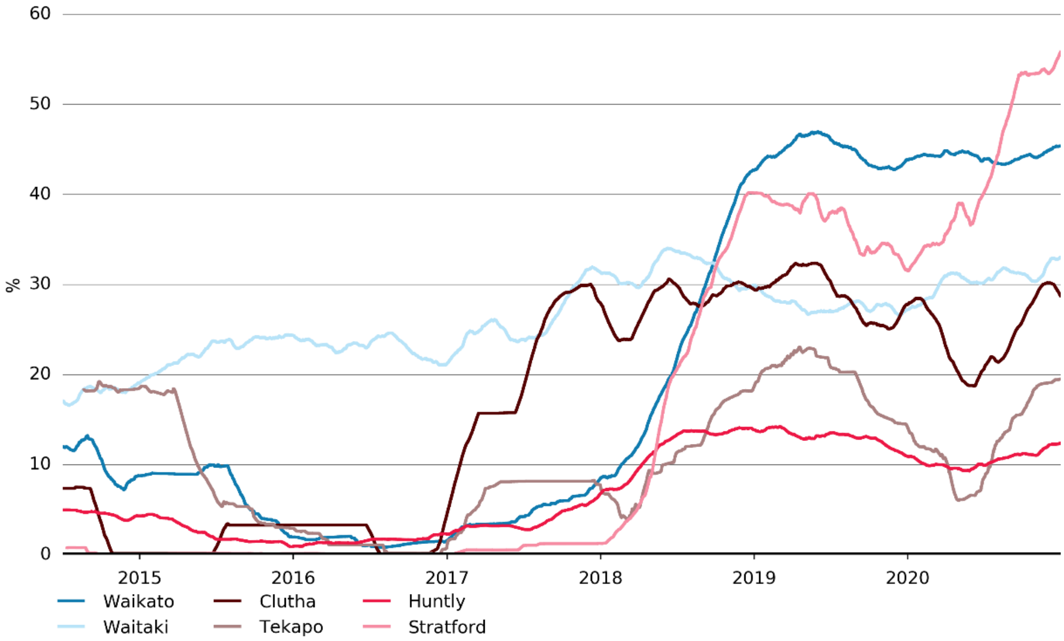
- there has been a larger increase for Contact's offers at Stratford (which runs solely on gas) than for Genesis's offers at Huntly (where the Rankine units can run on gas or coal)
- the increase in Mercury's offer prices at its Waikato hydro generation plants has been consistent with the increases at Contact's Stratford gas plants, although higher at times
- Contact's percentage of higher priced offers at its hydro generation plants on the Clutha increased before the gas situation (when there was low hydro storage in the Clutha catchments), but came down a little in 2020, although not back to levels seen before 2017
- the percentage of higher priced offers for Meridian's Waitaki hydro stations has been increasing gradually since 2014.

5.49 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

69 We use \$300/MWh because the spot price is rarely above this (around 1.6 percent of the time) but is low enough to incorporate the change in behaviour observed from Meridian and Contact following the UTS in 2019 (discussed more below).

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. While Genesis’s (Tekapo) percentage of higher priced offers has increased since 2018, its percent decreased to less than 10 percent on average at one stage during the review period. No other hydro generators’ offers decreased by this much.

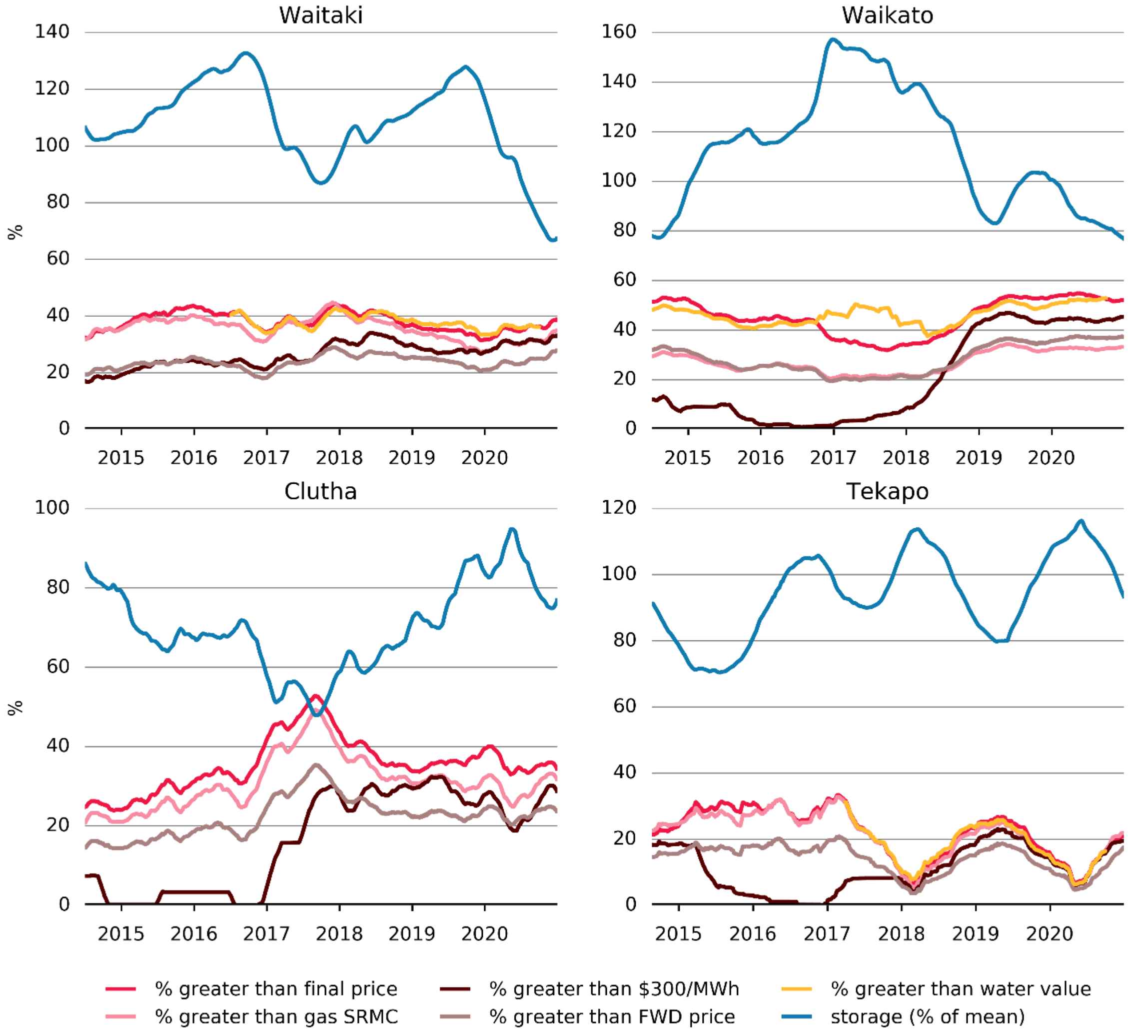
Figure 23: Percent of offers above $300 /MWh (yearly moving average)



Sources: Electricity Authority

5.50 Figure 24 compares storage levels to the percent of offers above $300/MWh and, in addition, the percentage of offers above various estimates of cost and above final price. As we would expect to see, in most cases, there is a negative relationship between storage and high offers, that is, as storage improves, the percent of high offers should come down. However, it appears that Meridian (Waitaki) and Mercury (Waikato) higher priced offers are less related to storage than the other hydro generators. Meridian (Waitaki), Contact (Clutha) and Mercury (Waikato) always have, on average, above 30 percent of their capacity offered at higher prices than the final price (ie, above 30 percent of their generating capacity is not dispatched). For Genesis (Tekapo), this gets down to an average of below 10 percent during times of high storage. For all hydro generators, the percent of offers above final price, gas SRMC, and water values are all similar.

Figure 24: Percent of offers above final price, and estimated cost (yearly moving averages)[70]

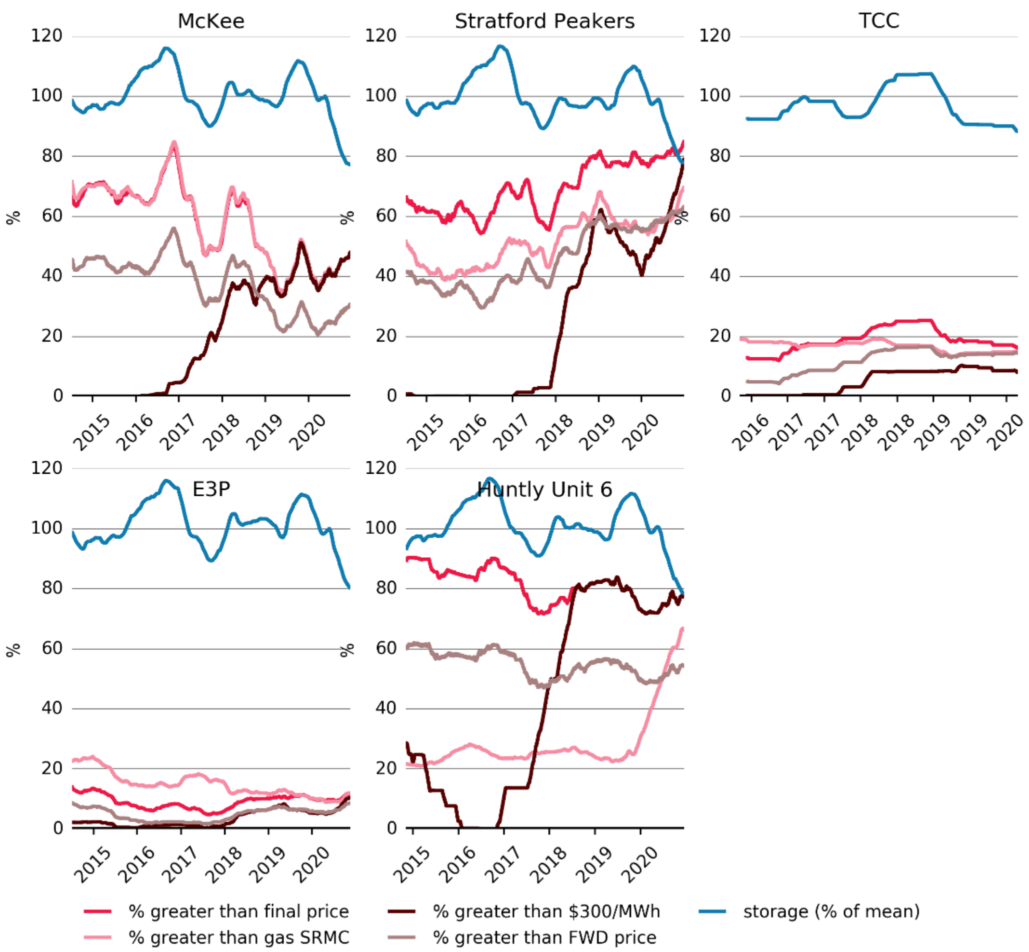


Sources: Electricity Authority, NZX Hydro, Generators, see Appendix B

5.51 Figure 25 shows these same measures for gas generation plants. It shows that the peaking plants (the Stratford peakers, Huntly Unit 6 and McKee) always have a higher percentage of higher priced offers than the (essentially) baseload plants (Huntly unit 5 (e3p) and Taranaki Combined Cycle (TCC)). This is what we would expect to see because peaking plants, which cannot easily run continuously, incur costs associated with being idle for longer periods. However, the Stratford peakers and Huntly Unit 6 (faster start open cycle gas turbines) show a dramatic increase in the percentage of offers above $300/MWh since late 2017. This timing does not fit with the timing of the Pohokura outage and associated uncertainty, or with storage.

70 Storage data is from NZX Hydro. We use storage for the relevant catchments (including some seasonal contingent storage: Taupo for Mercury, Pukaki for Meridian, Tekapo for Genesis and Hawa, Wakatipu and Wanaka for Contact) for the hydro generators, and total New Zealand storage (including uncontrolled storage and some seasonal contingent storage) for thermal generators. Storage is calculated as a percent of mean monthly storage over all available data (1926 to 3 September 2021).

Figure 25: Gas generation plants percent of offers above final price and cost (yearly moving averages)



Sources: Electricity Authority, NZX Hydro, see Appendix B

5.52 Figure 26 shows Meridian's (Waitaki) offers since 2014. We are interested in the high-priced bands, because if a generator was going to withhold capacity it could simply increase the quantity offered in these high-priced bands. However, high offer prices for some quantity of a generators' capacity can also be an appropriate response to surrounding demand and supply conditions, operating constraints and resource consent obligations, so it can be hard to tell if higher priced offers are being used for these reasons or to economically withhold.

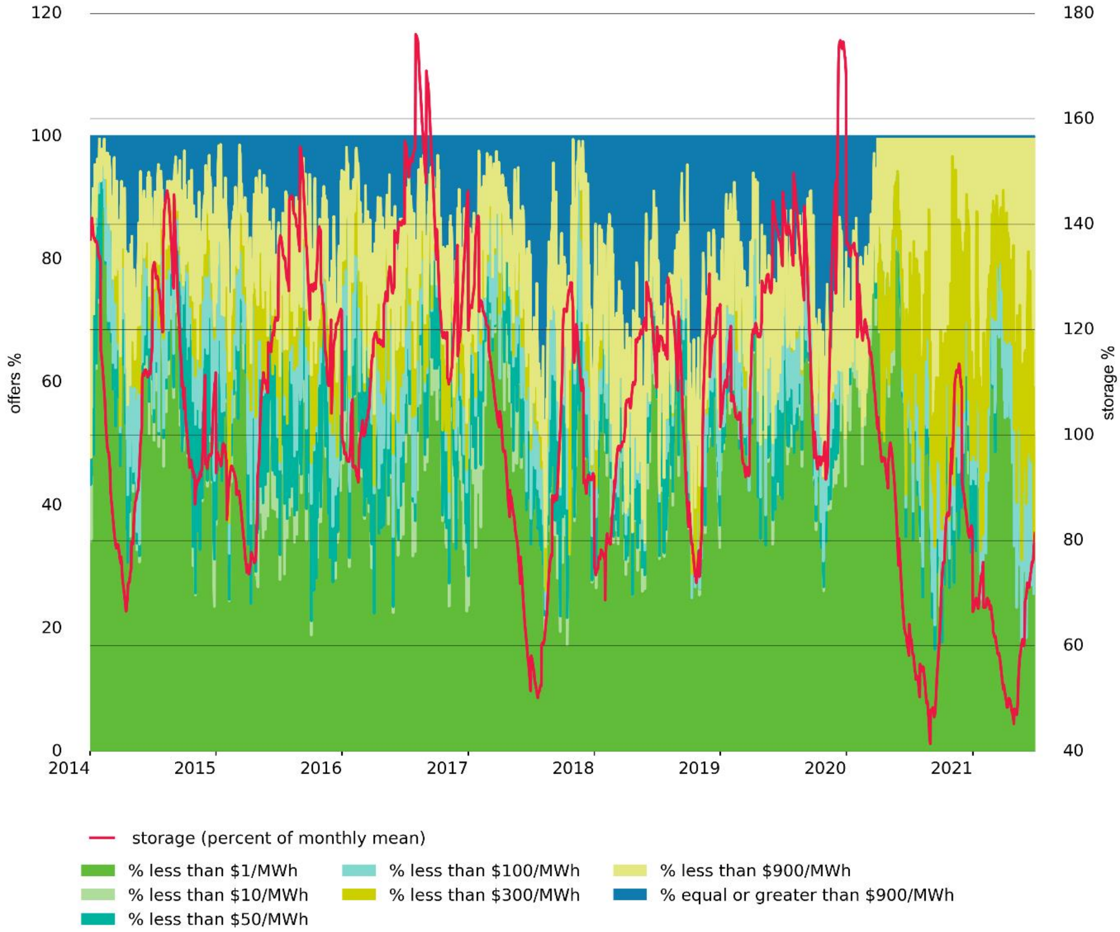
5.53 Figure 26 shows the increase in Meridian's (Waitaki) offers at higher prices over time. In early 2020, Meridian repriced its highest priced tranche from over $900/MWh to between $300/MWh and $900/MWh.[71] This reinforces our approach of analysing offers priced above $300/MWh.

5.54 Meridian also repriced some of its offers in lower tranches so that it now has offers priced between $100/MWh and $300/MWh (down from $300/MWh to $900/MWh).

71 Up to the UTS at the end of 2019, the average price in its highest priced band for its Waitaki stations was $1,725/MWh. From the end of the HVDC outage in early 2020 to the end of June 2021, this average price was $455/MWh.

However, this change has not slowed the increase overall in the percentage of offers over $300/MWh (as shown in Figure 23).

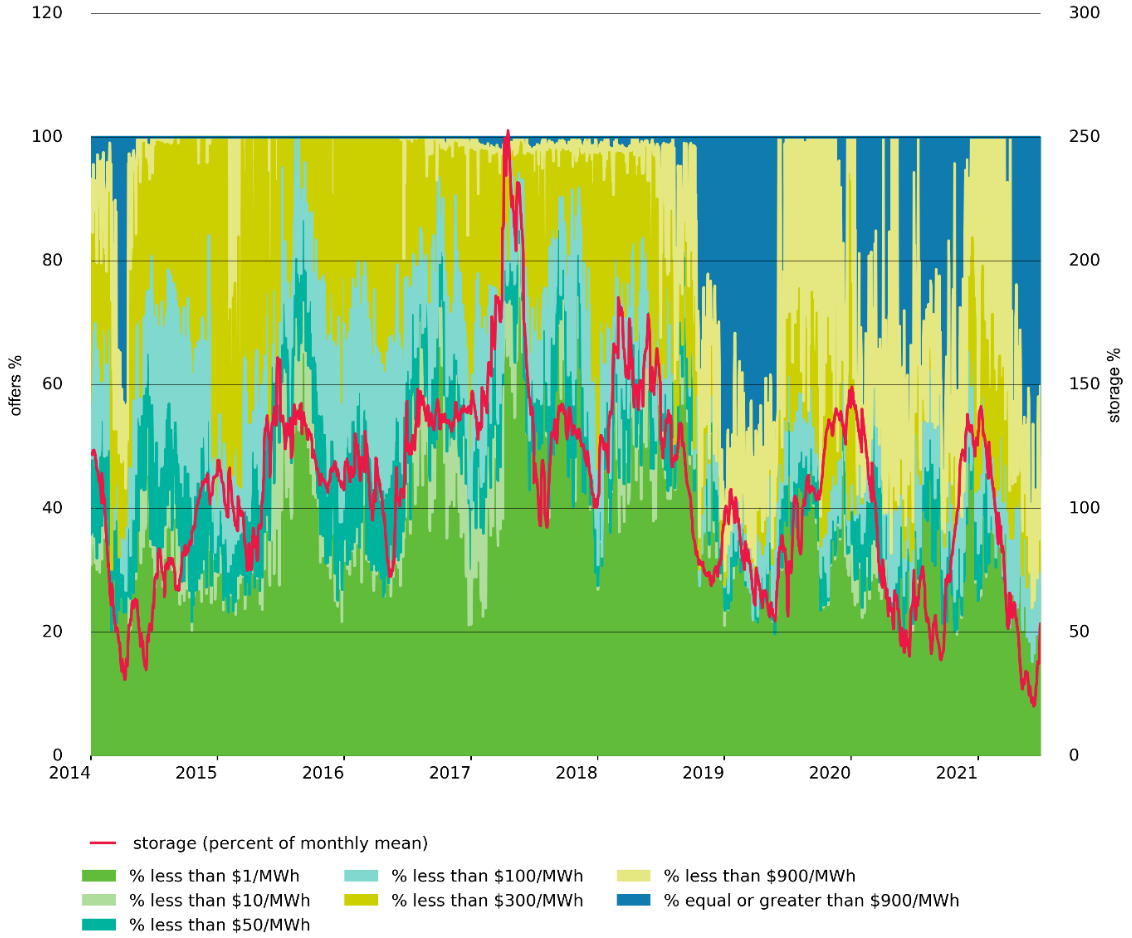
Figure 26: Waitaki offers (daily)



Sources: Electricity Authority, NZX Hydro

5.55 Figure 27 shows offers since 2014 for Mercury's (Waikato) stations. It shows the increase in offer prices at these stations since late 2018, and very high offer prices (above $900/MWh) during times of low storage. Previously to 2018, Mercury often had 100 percent of offers (or close to 100 percent) priced at less than $300/MWh.

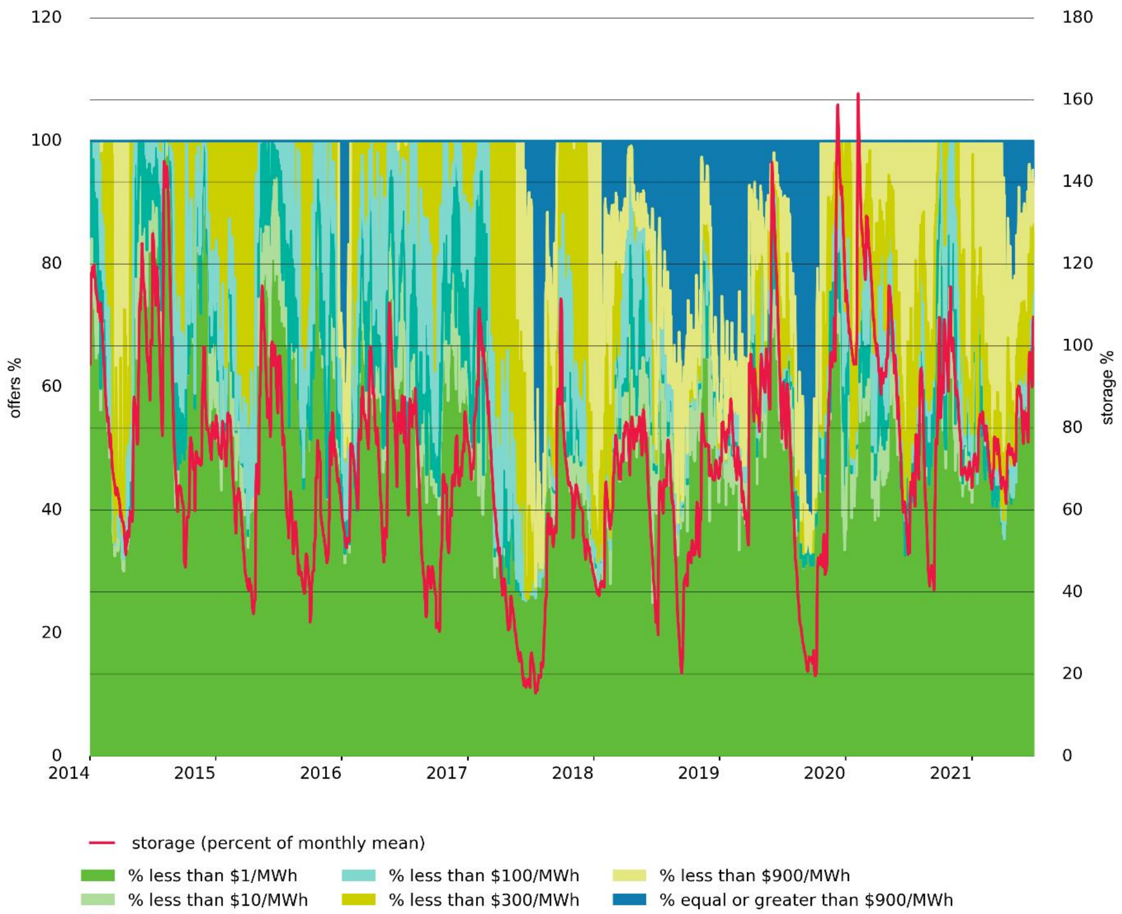
Figure 27: Waikato offers (daily)



Sources: Electricity Authority, NZX Hydro

5.56 Figure 28 shows that Contact has also changed its offering behaviour on the Clutha since late 2019, similar to Meridian's, lowering the price of its highest priced tranche. Similar to Mercury, the overall increase in higher priced offers since 2018 is evident, before 2018, Contact often had 100 percent of offers priced at less than $300/MWh. But Contact does appear to have changed its offers somewhat in response to underlying conditions during the review period.

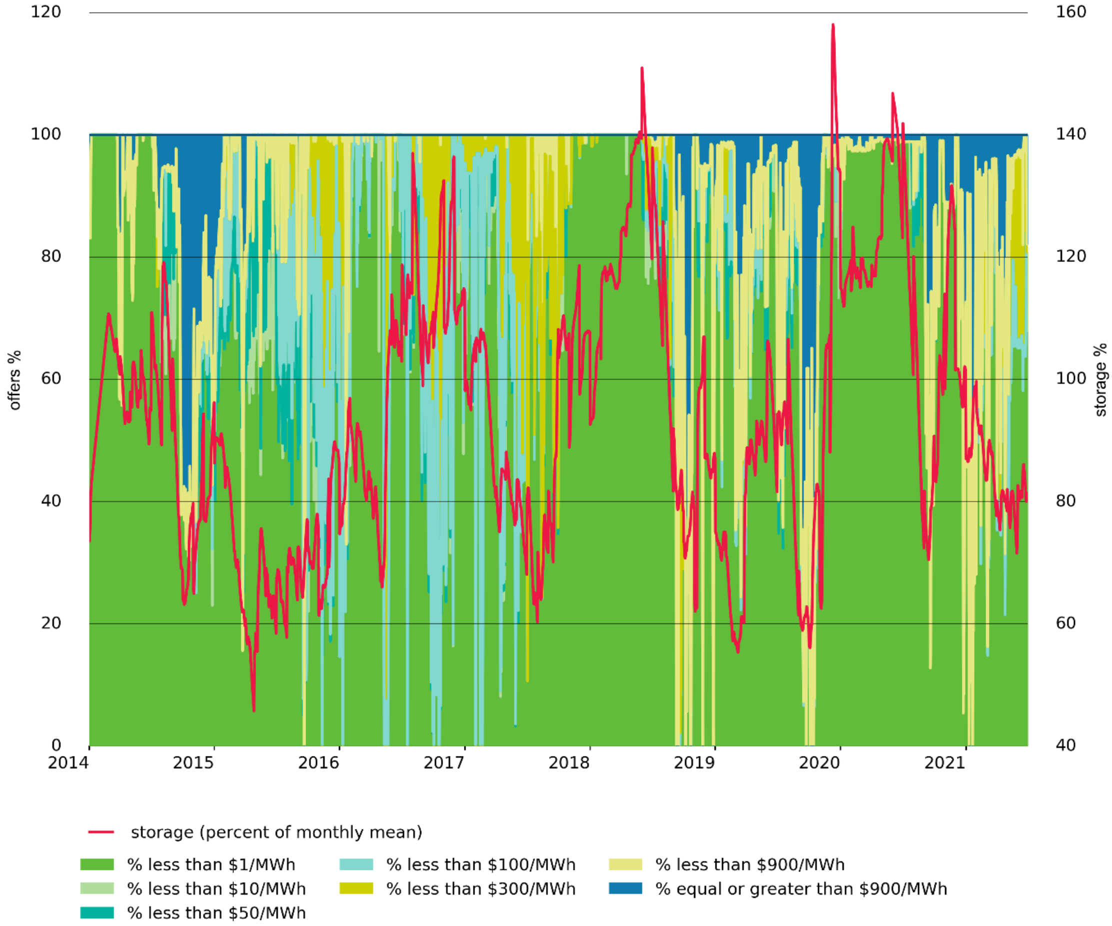
Figure 28: Clutha offers (daily)



Sources: Electricity Authority, NZX Hydro

5.57 Genesis (Tekapo) has a high percent of very low-priced offers when hydro storage is high. More recently (2021), Genesis appears to have increased the offer prices in its top tranches compared with previous years.

Figure 29: Tekapo offers (daily)



Sources: Electricity Authority, NZX Hydro

5.58 Table 8 shows that all hydro generators had a lower percent of offers over $300/MWh in times when hydro storage was higher, as expected. However, both Meridian (Waitaki) and Mercury (Waikato) did not decrease their percentages by much in times of higher hydro storage during the review period, while Genesis (Tekapo) and Contact (Clutha) decreased the proportion of their higher offers to 10 percent or less of their total offers.

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	29	14	15	1	5
	High hydro storage (greater than or equal to	6	23	2	0	1	4

Period	Storage level	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	Stratford	Huntly
	100% of mean)						
2019 to June 2021	**Low hydro storage (less than 80% of mean)***	50	33	29	40	39	11
	High hydro storage (greater than or equal to 100% of mean)	41	25	4	10	37	13

*Storage for the relevant catchments is used for the hydro generators, while total New Zealand storage (including uncontrolled storage) is used for the thermal generators (storage data is from NZX Hydro and includes some seasonal contingent storage). We ran sensitivity analysis using different storage thresholds for all analyses presented in this report, with similar results. Storage is calculated as a percent of mean monthly storage over all available data (1926 to 3 September 2021).

Trading periods are only included for the calculation when the generator has offered greater than zero megawatts. This means that not all trading periods over the period are included for thermal generators because they often have zero offered megawatts.

Percentage of offers above cost: a high percentage of offers are above cost in the review period

5.59 In a competitive market, offer prices should reflect economic costs, including opportunity costs. The results from the indicators we use to assess this are set out in Table 9, Table 10, Table 11 and Table 12. The results show that generators with thermal peaker plants have increased the percentage of offers above estimated cost in the review period, compared with previous years, in times of low hydro storage. Mercury (Waikato) has increased its percentage of offers above estimated cost in the review period, compared with previous years, in both high and low storage periods. Contact (Clutha) has also increased its percentage of offers above estimated cost in times of high hydro storage, although still has a lower percentage compared with Mercury (Waikato) and Meridian (Waitaki).

5.60 We have used water values provided by the generators as a measure of opportunity cost, as well as water values obtained from DOASA.[72] Each generator will take a range

72 We use the average water value over all of New Zealand from DOASA rather than the water values for individual reservoirs because the individual reservoir water values are very volatile. This is due to the following.

1. DOASA does a forward solve (linear programming), so as long as the objective values are the same, it is likely to use all water from one reservoir first until it hits some constraint, before moving to the next

of factors into account in deciding their water values, including storage and security of supply. Meridian provided us with minimum sell values when water values were requested (alongside modelled generation guidance). Therefore, when we refer to water values provided by generators throughout this report, we are referring to these minimum sell values for Meridian.[73] Genesis provided us with different water values for different quantities (price quantity tranches). We have created a quantity weighted average of these water values to provide a single point estimate of opportunity cost. While single point estimates may not completely capture the full dynamics between water values and offers (because generators may offer different price quantity tranches to reflect the probabilities of different scenarios, from wet to dry, and the opportunity costs associated with these different scenarios), this makes Genesis's value consistent with the single point estimates provided by the other generators (noting that Meridian's single point estimate is a minimum sell value, not a water value), and enables summary statistics and comparisons to be computed.

5.61 DOASA is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto[74] developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[75] A version of DOASA has been used by EPOC for analysis of the New Zealand electricity market for many years, and SDDP is a well known and widely accepted modelling tool for electricity markets. DOASA gives a consistent measure of the opportunity cost of water. The DOASA model seeks a policy of electricity generation that meets demand and minimises the expected fuel cost of thermal generation and value of lost load. In this sense, it provides a lower bound for water values.[76] However, both water values obtained from generators and DOASA water values are sensitive to assumptions,[77] and, as such, should be treated like any estimate.

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reservoir. This leads to the likely extreme usage of small reservoirs (ie, not using water proportional to total national storage by either holding back or letting it all go).

2. Therefore, small (constrained) reservoirs in DOASA are expectedly more likely to hit maximum or minimum levels or constraints, and this will be reflected in the water values (high price if likely to hit minimum level and low price if likely to hit maximum level).
3. National water values are calculated based on absolute total national storage, not absolute individual reservoir storage, which tends to make the water values less volatile. That is, if we had two reservoirs with the same capacity and one had storage at 10 percent of capacity and the other at 90 percent, the national water value is based on total storage of 50 percent of total capacity.

73 Meridian advised us that these minimum sell values are not modelled water values nor are they a measure of costs. They are a result of a weekly process that considers several inputs (one of which is modelled water values) and makes a judgement about how to guide traders. They are values that inform real-world offer construction in a way that ensures not too much water from storage is dispatched, for security of supply. Meridian advised that appropriate volume guidance through time can be more important than the minimum sell value in this regard.

74 M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," *Mathematical Programming* 52, (1991): 359–375.

75 Electricity Authority, "Doasa overview," https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa.

76 Additionally, the estimated thermal fuel costs used in DOASA (the estimated SRMCs as set out in Appendix B) may not accurately represent what hydro generators face (in terms of thermal generator offers) in reality. That is, as pointed out in paragraph 5.39, hydro generators must manage their storage levels within the context of volatile thermal fuel prices and availability, and the thermal fuel cost estimates may not perfectly represent these.

77 Assumptions include:

- load forecasts (not relevant to estimating past water values using DOASA because we can use reconciled data, but would have been used as input for the generator water values)

5.62 Note that Contact does not use water values for the majority of generation from the Clutha scheme. Contact has advised the Clutha is essentially a run-of-river scheme with very low storage. Generation attributable to stored water in Hawea accounts for only 10 percent to 15 percent of total generation volumes. We have used DOASA water values for Contact, to paint a complete picture, but note that any analysis for Contact based on DOASA water values is unlikely to be particularly meaningful.

5.63 For thermal plant, cost is calculated using estimated SRMCs excluding the opportunity cost of storage. These SRMCs are based on the foregone opportunity of selling gas on the spot market. However, they could also be based on the foregone opportunity cost of storing gas and generating later, which would yield a different number.[78] The electricity forward price (the average over the following 3 years) is used as an estimate of the opportunity cost of storing gas.

5.64 We observed that the percentages above SRMC are higher in the review period than in previous years for the thermal peakers (McKee, Stratford peakers and Huntly Unit 6). This is probably because they offer some capacity at higher prices (rather than not offering at all) when they are unable to run for sustained periods, but could run in peak periods. This behaviour is broadly consistent with gas supply risk. But, as noted above, the timing of the changes to offers is earlier than expected.

5.65 The percentages above the forward price are similar in the review period for all thermal plants except the Stratford peakers, which had a large increase in the percent of offers above the forward price. This is despite higher forward prices in the review period.

5.66 Similar to the analysis of offers over $300/MWh, both Meridian (Waitaki) and Mercury (Waikato) have a higher percent of offers greater than the estimated maximum gas SRMC when hydro storage is higher, compared to Genesis (Tekapo) and Contact (Clutha). This could reflect the fact that both Contact and Genesis have non-baseload thermal capacity, so may be prepared to let hydro run more than Mercury and Meridian. Mercury's (Waikato) and Meridian's (Waitaki) percentages fall only slightly during periods of high hydro storage, although Meridian's percentage in both high and low storage periods has decreased in the review period compared with previous years. Genesis (Tekapo) only had 4 percent of offers higher than the gas SRMC in times of higher hydro storage.

- forecast plant and HVDC outages (similarly, not relevant to estimating past water values with DOASA because we derived these for past periods from scheduling, pricing and dispatch outages)
- modelling around how the HVDC is limited due to reserve requirements
- load response
- thermal fuel costs and other running costs
- flexibility and/or limits of hydro station head ponds and major reservoirs
- inflow probability distribution and how stagewise dependence is represented (ie, flows in one period tend to be correlated with flows in recent periods)
- for DOASA water values, the effect of operating in a market setting versus centrally planned (affects assumptions and modelling around opportunity costs)
- how non-dispatchable plant is modelled, for example, wind is actually stochastic but is modelled as constant power output
- how many load blocks are modelled, DOASA uses three: peak, shoulder and off-peak, and how many hours are modelled in each block.

78 In the short run, the opportunity cost of using gas to generate will be whichever is higher: the price they could sell the gas today or the value of storing it.

5.67 In looking at the hydro plant offers greater than water values given to us by the generators, the observations are similar to using the gas SRMC. Using water values from DOASA also shows a similar story: Genesis (Tekapo) has a low percent of offers greater than the DOASA water value in times of higher hydro storage, but percentages from Meridian (Waitaki) and Mercury (Waikato) are still high. Contact (Clutha) also has a higher percent in times of high storage post-Pohokura (but not as high as Meridian and Mercury).

Table 9: Percent of offers greater than SRMCs, by storage level, for thermal plants

Period	Storage level	McKee	Huntly OCGT	Stratford peakers	Rankines (coal)	E3p	TCC
2014 to September 2018	**Low hydro storage (less than 80% of mean)**	22	23	45	26	22	14
	High hydro storage (greater than or equal to 100% of mean)	84	23	49	20	15	19
2019 to June 2021	**Low hydro storage (less than 80% of mean)**	46	63	74	20	13	19
	High hydro storage (greater than or equal to 100% of mean)	52	29	61	27	11	15

Note: Total New Zealand storage (as a percent of mean monthly storage over all available data) is used. Only includes trading periods where any offers were made for the plant (ie, total megawatts offered were greater than zero).

Table 10: Percent of offers greater than the average forward price, by storage level, for thermal plants

	Storage level	McKee	Huntly OCGT	Stratford peakers	Rankines	E3p	TCC
2014 to September 2018	**Low hydro storage (less than 80% of mean)**	10	49	26	19	4	5
	High hydro storage (greater than or equal to 100% of mean)	55	60	45	18	4	12

	Storage level	McKee	Huntly OCGT	Stratford peakers	Rankines	E3p	TCC
2019 to June 2021	**Low hydro storage (less than 80% of mean)**	30	50	60	15	9	16
	High hydro storage (greater than or equal to 100% of mean)	31	54	59	22	7	16

Note: Total New Zealand storage is used (as a percent of mean monthly storage over all available data).

Table 11: Percent of offers greater than the maximum gas short-run marginal cost, by storage level, for hydro plants

Period	Storage level	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)
2014 to September 2018	**Low hydro storage (less than 80% of mean)**	28	45	31	38
	High hydro storage (greater than or equal to 100% of mean)	23	34	14	4
2019 to June 2021	**Low hydro storage (less than 80% of mean)**	36	36	33	41
	High hydro storage (greater than or equal to 100% of mean)	31	28	4	18

Note: storage levels relate to the relevant catchment (Taupo for Mercury, Pukaki for Meridian and Tekapo for Genesis) and we use storage as a percent of mean monthly storage over all available data. The gas short-run marginal cost (SRMC) relates to the maximum SRMC over all gas stations.

Table 12: Percent of offers greater than water values, by storage level, for hydro plants

Period	Storage level	Mercury (Waikato) using Mercury's water values	Meridian (Waitaki) using Meridian's water values	Genesis (Tekapo) using Genesis's water values	Mercury (Waikato) using DOASA water values	Meridian (Waitaki) using DOASA water values	Genesis (Tekapo) using DOASA water values	Contact (Clutha) using DOASA water values
	Low hydro	47	40	34	57	46	34	44

2016 to September 2018*	**storage (less than 80% of mean)**							
	High hydro storage (greater than or equal to 100% of mean)	43	40	15	37	38	16	17
2019 to June 2021**	**Low hydro storage (less than 80% of mean)**	54	37	34	62	47	39	46
	High hydro storage (greater than or equal to 100% of mean)	49	34	5	55	35	5	29

Note: storage levels relate to the relevant catchment (Taupo for Mercury, Pukaki for Meridian, Tekapo for Genesis, and Hawea, Wakatipu and Wanaka for Contact), and we use storage as a percent of mean monthly storage over all available data.

We also ran this analysis using water values plus a South Island Mean Injection (SIMI) charge ($6.42) for the South Island generators and an operating and maintenance charge for all hydro generators. The results were similar. The biggest difference was for Mercury for high storage periods during 2016 to September 2018, where the percentage changed from 43 to 37. All other percentages were only different by 1 percent or 2 percent (if different at all).

* Water values provided by Genesis start from 1 October 2016. Water values provided by Meridian start 6 January 2016. Water values provided from Mercury start from 1 January 2014, but we have only used data from 1 January 2016, to be consistent with the other generators.

** Water values obtained from the generators were only requested up to 31 March 2021.

Relationship of hydro storage to cost: water values increase when storage decreases

5.68 In a competitive market, we would expect to see the opportunity cost of water increase when storage is low. Our evidence shows a strong relationship between estimated cost and storage for all hydro generators.

5.69 The water values provided from the three hydro generators (Meridian, Mercury and Genesis) had strong negative correlations with storage (see Table 13).[79] These correlations were stronger before the Pohokura outage, most noticeably for Mercury (Waikato). This weaker correlation in 2020 for Mercury (Waikato) could be due to the HVDC outage at the beginning of the year (meaning more North Island generation was needed regardless of Taupo storage levels) and reduced demand during lockdowns (unexpectedly affecting storage levels).

5.70 The weaker correlations post-Pohokura could be explainable by the increased awareness of the gas supply situation, that is, water values calculated using a gas price to inform the opportunity cost will be affected by gas supply disruptions.

5.71 For water values obtained from DOASA, the correlations with storage were stronger after the Pohokura outage, and near zero (indicating no relationship) before Pohokura for both Taupo and Tekapo.[80] Despite the HVDC outage and reduced demand during lockdowns in 2020, the DOASA water value is still strongly correlated with Taupo storage in 2020.

5.72 Figure 30 shows the water values from the generators and from DOASA alongside storage. This shows that the water values obtained from the generators are much more variable than the water values from DOASA.

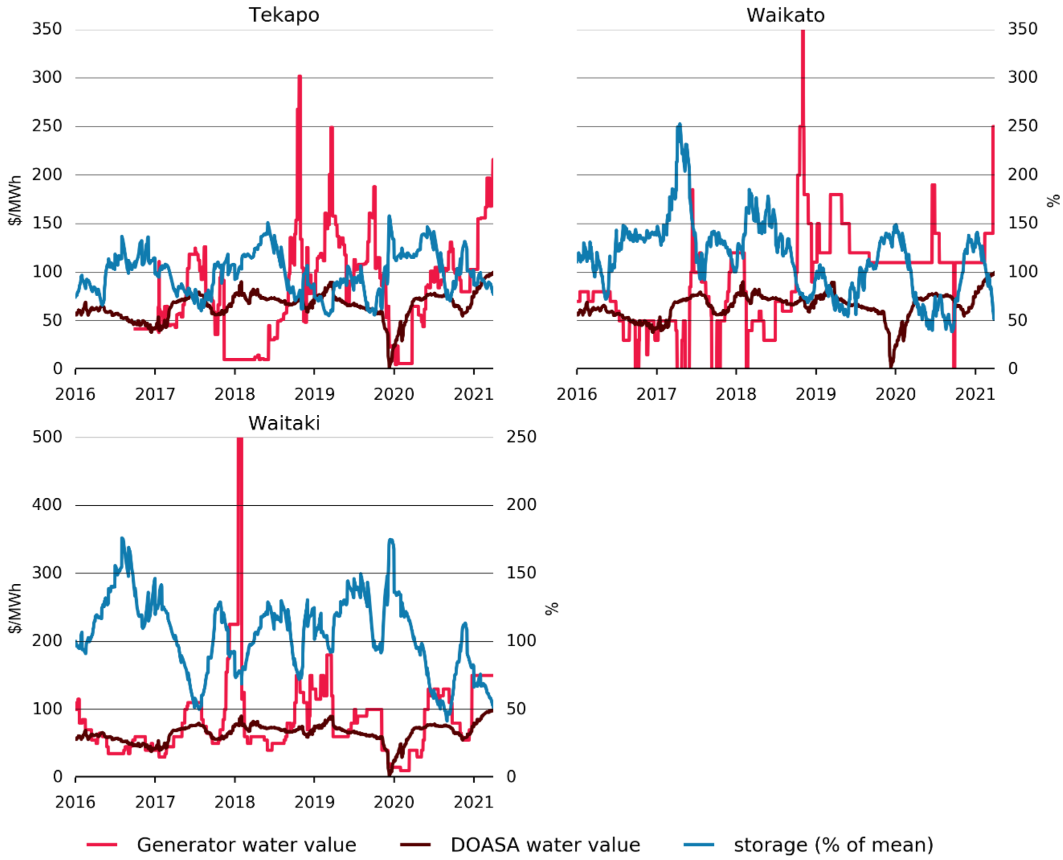
Table 13: Correlations of water values with storage

Period	Mercury (Waikato) using Mercury's water values	Meridian (Waitaki) using Meridian's water values	Genesis (Tekapo) using Genesis's water values	Mercury (Waikato) using DOASA water values	Meridian (Waitaki) using DOASA water values	Genesis (Tekapo) using DOASA water values	Contact (Clutha) using DOASA water values
2016 to September 2018	-0.72	-0.79	-0.73	0.08	-0.68	-0.12	-0.41
2019 to March 2021	-0.34	-0.62	-0.74	-0.66	-0.73	-0.35	-0.33

79 We use storage as a percent of mean monthly storage over all available data, where storage relates to the relevant catchment (Taupo for Mercury, Pukaki for Meridian, Tekapo for Genesis, and Hawea, Wakatipu and Wanaka for Contact).

80 This was true even if using water values for each individual reservoir from DOASA.

Figure 30: Water values and storage (daily)



Sources: Electricity Authority, Generators, NZX Hydro

Relationship of offers to cost: only Genesis's offers are strongly related to its water values

5.73 In a competitive market, we would expect generators' offers to be related to their costs. Our indicators suggest that the only hydro generator with a strong relationship between offer prices and estimated cost is Genesis (Tekapo) (see Table 14, Table 15 and Table 16).

5.74 Meridian (Waitaki) and Mercury's (Waikato) costs (using the water values they provided) are not correlated with the percent of offers they have over $300/MWh. In contrast, Genesis (Tekapo) has a positive correlation of offers over $300/MWh with its water value, and the correlation is slightly stronger post-Pohokura outage.

5.75 For Mercury (Waikato):

- the correlation between QWOP and water values is higher than the correlation between its percentage of offers over $300/MWh and water values, but neither correlation is as high as those for Genesis (Tekapo)
- the QWOP correlation with water values is stronger post-Pohokura
- removing offers above $300/MWh, post-Pohokura, the QWOP is no longer correlated with water values.

5.76 This suggests Mercury is making all of its changes in the plus-$300/MWh range of its offers in relation to water values and storage levels (which is not the case pre-Pohokura).

5.77 For Meridian (Waitaki):

- QWOP is not correlated with its water values
- removing offers priced over $300/MWh, Meridian has a strong positive correlation between its QWOP and its water values post-Pohokura.

5.78 This suggests that Meridian's offers priced over $300/MWh are not related to its water values or storage levels, but it appears to change its offers under $300/MWh in response to changes in water values and/or storage levels. This is also evident in Figure 27. Given prices seldom clear above $300/MWh, this should have an effect on prices in more trading periods than Mercury's apparent practice over the review period of changing offers priced above $300/MWh.

5.79 The difference between the relationships for Meridian (Waitaki) and Mercury (Waikato) are consistent with the observations above. That is, it appears that both do not change their percentage of higher offers much with changes in storage and cost. But this analysis shows that Mercury (Waikato) decreases the price of its higher priced offers during times of higher storage. Mercury's behaviour is consistent with it being marginal more often in higher priced trading periods (see paragraph 5.159).

5.80 Using DOASA water values, Mercury's (Waikato) percent of offers over $300/MWh and its QWOP are more highly correlated to the DOASA water value pre-Pohokura, but, as noted above, this water value is uncorrelated with Taupo storage in this period. Genesis (Tekapo) has weaker correlations of offers to the DOASA water value, but also weaker correlations of this water value with Tekapo storage. Overall, none of the generators' offers appear to be related to the DOASA water values, despite the DOASA water values being correlated with storage during the review period.

5.81 Figure 31 shows QWOPs alongside water values (both DOASA and those provided by the generators) over time.

Table 14: Correlations of water values with percent of offers over $300 /MWh

Period	Mercury (Waikato) using Mercury's water values	Meridian (Waitaki) using Meridian's water values	Genesis (Tekapo) using Genesis's water values	Mercury (Waikato) using DOASA water values	Meridian (Waitaki) using DOASA water values	Genesis (Tekapo) using DOASA water values	Contact (Clutha) using DOASA water values
2016 to September 2018	0.08	0.02	0.46	0.44	0.18	0.20	0.68
2019 to March 2021	0.13	0.04	0.49	0.11	-0.01	0.06	0.33

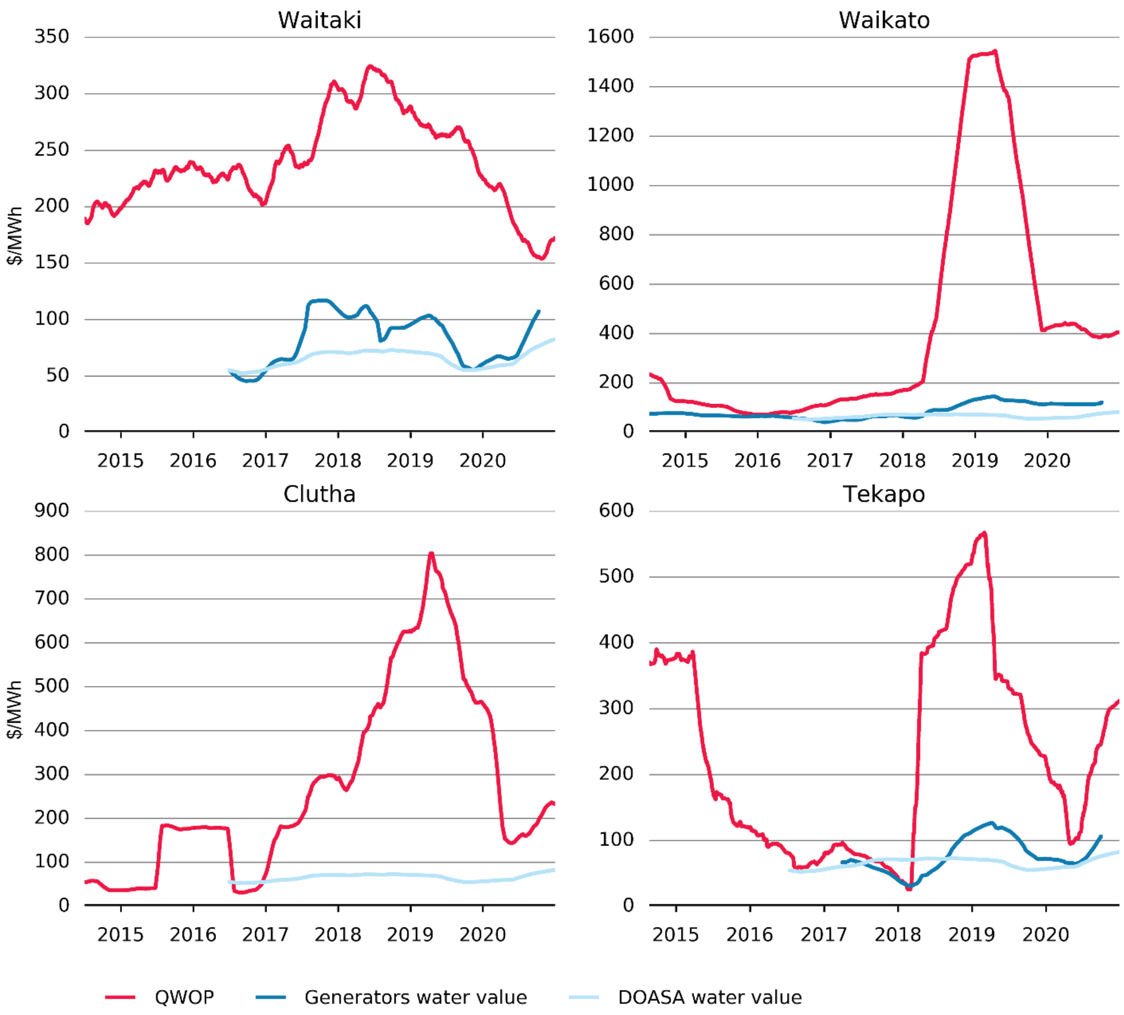
Table 15: Correlations of water values with QWOP

Period	Mercury (Waikato) using Mercury's water values	Meridian (Waitaki) using Meridian's water values	Genesis (Tekapo) using Genesis's water values	Mercury (Waikato) using DOASA water values	Meridian (Waitaki) using DOASA water values	Genesis (Tekapo) using DOASA water values	Contact (Clutha) using DOASA water values
2016 to September 2018	0.15	0.03	0.73	0.32	0.19	-0.22	0.58
2019 to March 2021	0.40	-0.09	0.55	0.14	-0.22	0.09	0.27

Table 16: Correlations of water values with QWOP excluding offers priced over $300/MWh

Period	Mercury (Waikato) using Mercury's water values	Meridian (Waitaki) using Meridian's water values	Genesis (Tekapo) using Genesis's water values	Mercury (Waikato) using DOASA water values	Meridian (Waitaki) using DOASA water values	Genesis (Tekapo) using DOASA water values	Contact (Clutha) using DOASA water values
2016 to September 2018	0.19	0.26	0.55	-0.11	0.09	-0.31	-0.13
2019 to March 2021	-0.02	0.51	0.64	0.09	0.23	0.34	-0.07

Figure 31: Water values and QWOPs (yearly moving averages)



Sources: Electricity Authority, Generators

Lerner Index: Mercury and Meridian have high Lerner indices during the review period using DOASA water values

5.82 The Lerner Index is an indicator of market power. Essentially, it measures the mark up that a firm is able to charge over its marginal cost. It is calculated as:

$$LI = \frac{Price - Marginal\ Cost}{Price}$$

where price is the market spot price set by the firm. The Lerner Index lies between zero and one. In a competitive market, the Lerner Index is equal to zero (when price equals marginal cost), implying that the marginal benefit of a good (the price) just equals the marginal cost. Values closer to one indicate strong market power.

5.83 In electricity markets, generators often offer a proportion of their capacity at prices below their marginal cost to meet their contracted volumes. When demand is low, the marginal offer (and therefore final price) can sometimes be these low-priced offers. This means that the Lerner Index can be negative. We have included negative values here. But we also show results when we exclude the HVDC outage period (because the South Island generators were limited in how much they could export to the North Island, so effectively demand was a lot lower) and the level 4 lockdown in April 2020 when demand was very low nationally.

5.84 Note that this indicator is only measuring market power when the generator is marginal (ie, the generator is directly setting the price). However, generators can exercise market power (ie, effect the price) even when they are not marginal through economic withholding. Indicators of economic withholding are analysed in the next section.

5.85 It is difficult to make any firm observations from the evidence below because the Lerner Index is very sensitive to the estimate of cost used. However, both Mercury (Waikato) and Meridian (Waitaki) have higher Lerner indices during the review period using DOASA water values. This is because both Mercury and Meridian value their water more highly than the DOASA model does, even in times of high storage. As noted, the DOASA water values can be considered a lower bound cost estimate for hydro generators.

5.86 Again, water values obtained from generators or from DOASA are used as an estimate of the marginal cost of a hydro generator, and the estimated SRMC for thermal generation or the forward price curve as the opportunity cost for thermal generators. See Appendix B for a description of how the SRMCs for thermal generators were calculated. See paragraph 5.60 above for more detail about water values.

5.87 Table 17 and Table 18 show average Lerner indices for Contact (Stratford), Genesis (Huntly), Genesis (Tekapo), Meridian (Waitaki) and Mercury (Waikato). These were calculated for months (average monthly price and average monthly cost) where the average monthly price is calculated using only trading periods when the point(s) of connection was/were marginal.

5.88 Before the Pohokura outage, all thermal plants had a higher Lerner Index (regardless of the cost estimate used) when storage was lower. This is what we would expect to see and is consistent with thermal generation being needed to firm hydro generation when hydro storage is low. That is, thermal generators have less competition when hydro storage is low. However, since 2019, Contact (Stratford) has had a higher Lerner Index when storage is higher (compared with previous years). This could be because when we calculate cost as an input into the Lerner index calculation, we are aware that gas prices may not perfectly take gas supply uncertainty into account. Genesis (Huntly) has had very low Lerner indices since 2019 using a gas SRMC as the cost estimate, due to the ability to use coal instead. Using a coal SRMC or the forward curve, Genesis's (Huntly) average Lerner Index is very similar to previous years.

5.89 Using water values obtained from the generators, Genesis (Tekapo) had a high Lerner Index in times of high storage before the Pohokura outage, but very low values since 2019 regardless of storage level. Meridian's (Waitaki) Lerner Index in times of high storage has increased slightly from 2019 compared with previous years, especially if we exclude the HVDC outage and level 4 lockdown periods.[81] All hydro plants had lower Lerner indices since 2019 in times of low storage, compared with thermal plants.

5.90 Using water values obtained from DOASA, all three hydro generators had high Lerner indices when storage was low, and higher values in the review period, compared with previous years. Mercury (Waikato) also had a higher Lerner Index in periods of higher storage in the review period, compared with previous years, as did Meridian (Waitaki)

81 This is still true if we include the SIMI charge plus $1.00 for operating and maintenance costs when the HVDC outage and lockdown periods are excluded, but not if these periods are included. Results for Genesis were very similar if we include the SIMI and operation and maintenance costs.

and Genesis (Tekapo) if we exclude the HVDC outage period and level 4 lockdown. Mercury (Waikato) had a higher Lerner Index during high storage periods than during low storage periods over the review period (although excluding the HVDC outage period and level 4 lockdown its index becomes very similar in both high and low storage periods).

5.91 Figure 32 shows average monthly Lerner indices over time. It shows that Meridian (Waitaki) had a high monthly average Lerner Index during the Pohokura outage in 2018 and during the UTS period in 2019 (despite the water values given to us never getting as low as zero), and a low Lerner Index during the HVDC outage period (January to March 2020) and level 4 lockdown (April 2020). In previous years, it has also had a low Lerner Index over summer months. Mercury (Waikato) had a high average Lerner Index in February and March 2021 (when storage was low), and a low Lerner Index during the HVDC outage period and level 4 lockdown (April 2020). Genesis (Tekapo) and Mercury (Waikato) had some very high average monthly values in 2017 and 2018. Contact (Stratford), consistent with Table 17, has had some high monthly averages since the Pohokura outage. Figure 32, however, highlights that the Lerner Index is very sensitive to the estimate of cost used.

Table 17: Average Lerner indices for thermal plants

Period	Storage level	Stratford (using forward curve)	Stratford (using OCGT SRMC)	Huntly (using forward curve)	Huntly (using Rankines gas SRMC)	Huntly coal
2016 to September 2018	**Low hydro storage (less than 80% of mean)**	0.24	0.40	0.34	0.38	0.22
	High hydro storage (greater than or equal to 100% of mean)	-0.10	0.08	-0.13	-0.09	-0.50
2019 to June 2021	**Low hydro storage (less than 80% of mean)**	0.48	0.30	0.29	-0.11	0.28
	High hydro storage (greater than or equal to 100% of mean)	0.25	0.12	0.05	-0.33	-0.07

Note: this uses storage for the whole of New Zealand (as a percent of mean monthly storage over all available data). Lerner indices are calculated as price less cost (using SRMC or forward price) divided by price, using average monthly values (average price over trading periods where the generator is marginal). If the generator is not marginal in a month, the monthly value for the Lerner Index is NA. Hence, the averages in the tables only apply to periods when the generator is marginal.

Table 18: Average Lerner indices for hydro plants

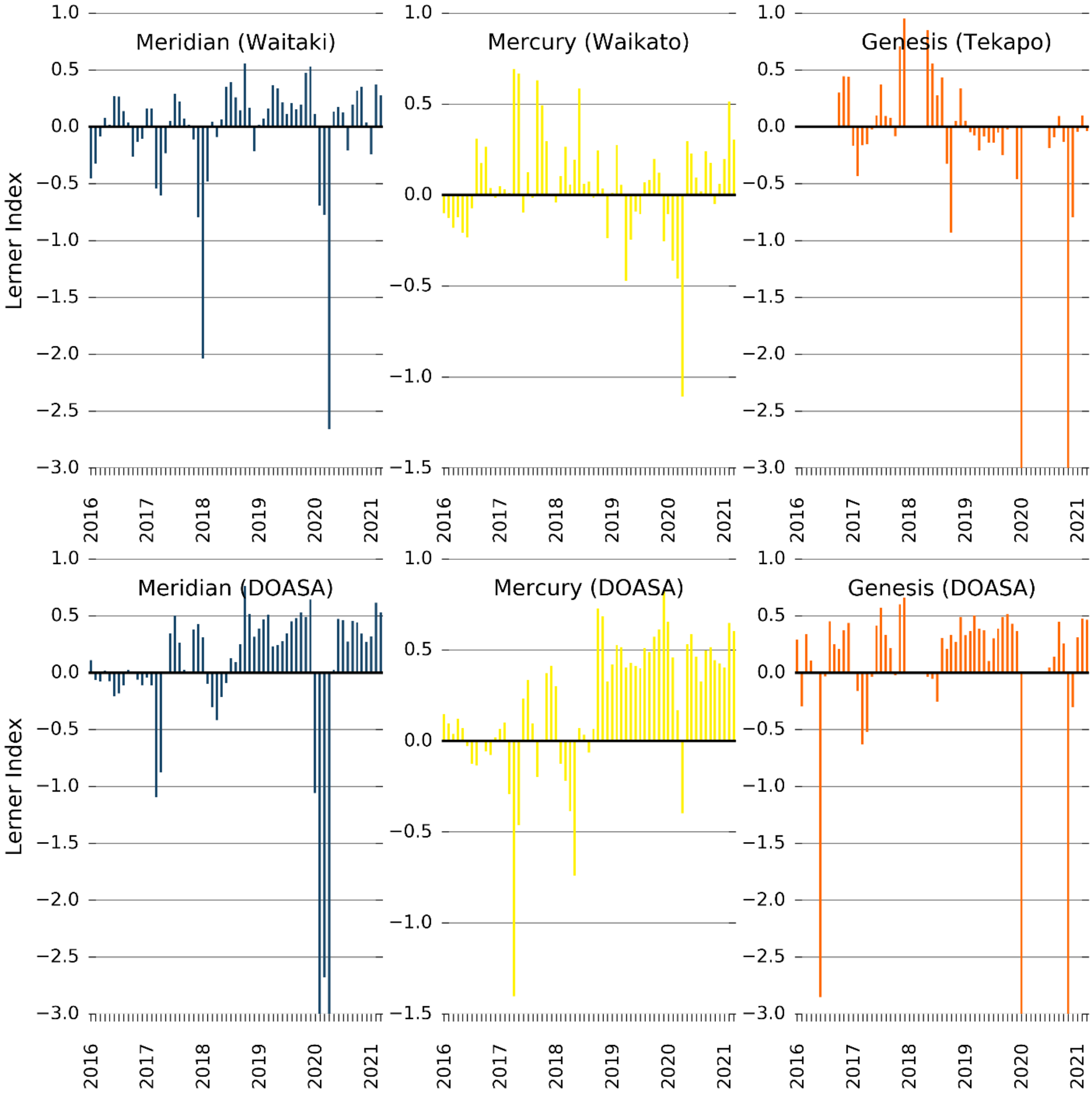
	Storage level	Mercury (Waikato) using Mercury's water values	Meridian (Waitaki) using Meridian's water values	Genesis (Tekapo) using Genesis's water values	Mercury (Waikato) using DOASA water values	Meridian (Waitaki) using DOASA water values	Genesis (Tekapo) using DOASA water values
2016 to September 2018	**Low hydro storage (less than 80% of mean)**	-	-0.37	0.19	-	0.36	0.35
	High hydro storage (greater than or equal to 100% of mean)	0.13	0.05	0.36	-0.06	-0.09	-0.01
2019 to June 2021* (results in brackets exclude January—April 2020, and November 2020 for Genesis)**	**Low hydro storage (less than 80% of mean)**	-0.06 (0.06)	0.14	-0.04	0.45 (0.52)	0.50	0.47
	High hydro storage (greater than or equal to 100% of mean)	0.04 (0.10)	0.11 (0.26)	-2021.12 (-0.33)	0.54 (0.54)	-0.41 (0.40)	-1463.34 (0.21)

Note: this uses storage for each relevant reservoir (Taupo for Mercury, Pukaki for Meridian and Tekapo for Genesis) and we use storage as a percent of mean monthly storage over all available data. Lerner indices are calculated as price less water value divided by price, using average monthly values (average price over trading periods where the generator is marginal). If the generator is not marginal in a month, the monthly value for the Lerner Index is NA. Hence, the averages in the tables only apply to periods when the generator is marginal.

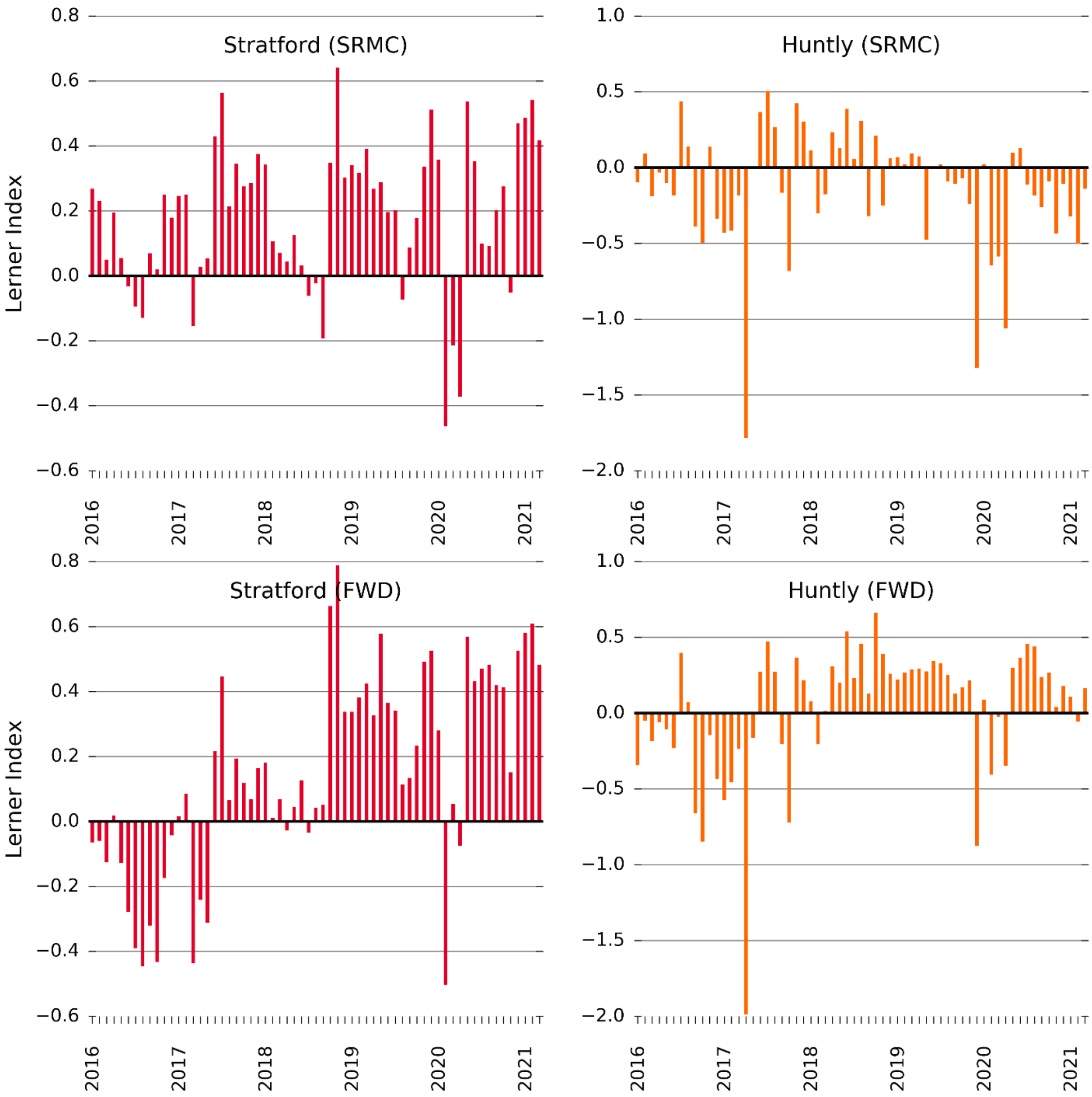
*Water values obtained from generators were only requested up to 31 March 2021.

** This is to exclude the HVDC outage period and level 4 lockdown when demand was very low. We also exclude November 2020 for Genesis because the average price in this month when Genesis was marginal was $0.01/MWh, which has a large impact on the results.

Figure 32: Lerner indices over time



Note: Meridian and Genesis axes have been clipped at -3.



Sources: Electricity Authority, Generators, see Appendix B

Economic withholding

5.92 The Lerner Index above only applies when a generator sets the price (ie, is marginal). However, being marginal is not a precondition for economic withholding to occur. We therefore look beyond the Lerner Index.

5.93 A generator engages in economic withholding when it offers a proportion of its capacity at a higher price, in theory any price higher than the wholesale spot price, with the intention of influencing the price.[82] By doing so, this portion of its capacity is not dispatched and the supply curve is shifted, potentially resulting in a higher spot price.[83]

82 Commerce Commission, "Investigation Report: Commerce Act 1986, S 27 S 30 and S 36 Electricity Investigation," May 22, 2009, https://comcom.govt.nz/__data/assets/pdf_file/0025/219094/Electricity-investigation-Investigation-report-21-May-2009.PDF.

83 This differs from physical withholding, which is when a proportion of a generator's technically available capacity — that is, capacity that would have been offered under competitive conditions — is simply not available to the market at any price.

5.94 In this section, we use four separate analyses to assess whether economic withholding might have occurred. We observe that there has been increased incentive over the review period to economically withhold, but the evidence to show any generator did this is weak.

5.95 There are also other reasons why a hydro generator may offer a proportion of its capacity at a higher price, such as to conserve water for a later date, temporary outages or maintenance, uncertainty around forward gas supply from existing fields, resource consent obligations, or avoiding changes in dispatch due to restrictions on plant flexibility. Generators have often used higher priced tranches in this way instead of removing capacity due to the high standard of trading conduct provisions. To be considered as a safe harbour under the old provisions, generators were required to offer all available capacity, and, since July 2021, the new rule requires offers to reflect what would occur in a competitive market. It is therefore hard to determine at first glance whether the generator has, in fact, exercised economic withholding.

5.96 The measures presented below provide an indication of whether generators are exercising or are incentivised to exercise economic withholding.

Two percent decrease in demand in the South Island: simulations suggest an increased incentive to economically withhold in the review period

5.97 To investigate whether South Island generators had an incentive to economically withhold, we looked at what the change in price would have been had they increased supply at lower prices in the South Island. Increasing supply in the South Island is equivalent to decreasing demand. We therefore ran simulations with a 2 percent decrease in demand in the South Island.

5.98 This analysis does not definitively confirm whether South Island generators withheld output to increase prices. As discussed above, they may have had valid reasons (other than to influence prices) as to why they had generation available at higher prices.[84] But the analysis does show if the South Island generators had an incentive to economically withhold.

5.99 The simulations are equivalent to increasing South Island generation at lower prices by approximately 40 MW (or 20 MWh per trading period). The average price decrease from the simulations was higher in the review period years compared with previous years, in both $/MWh and as a percentage change (see Table 19). This was true for both low storage and high storage periods. This means that South Island generators have had a higher incentive to economically withhold in recent years. In the review period, during times of higher storage, South Island generators have increased prices on average by $18/MWh by offering 20 MWh of capacity at higher prices, but may have been offering this generation at higher prices for a reason other than to influence prices. Figure 33 shows the average price difference from this simulated change in demand has been increasing over time.

5.100 The results of this analysis — the higher average price decrease in recent years — are a consequence of a steeper supply curve in recent years (discussed in more detail below).

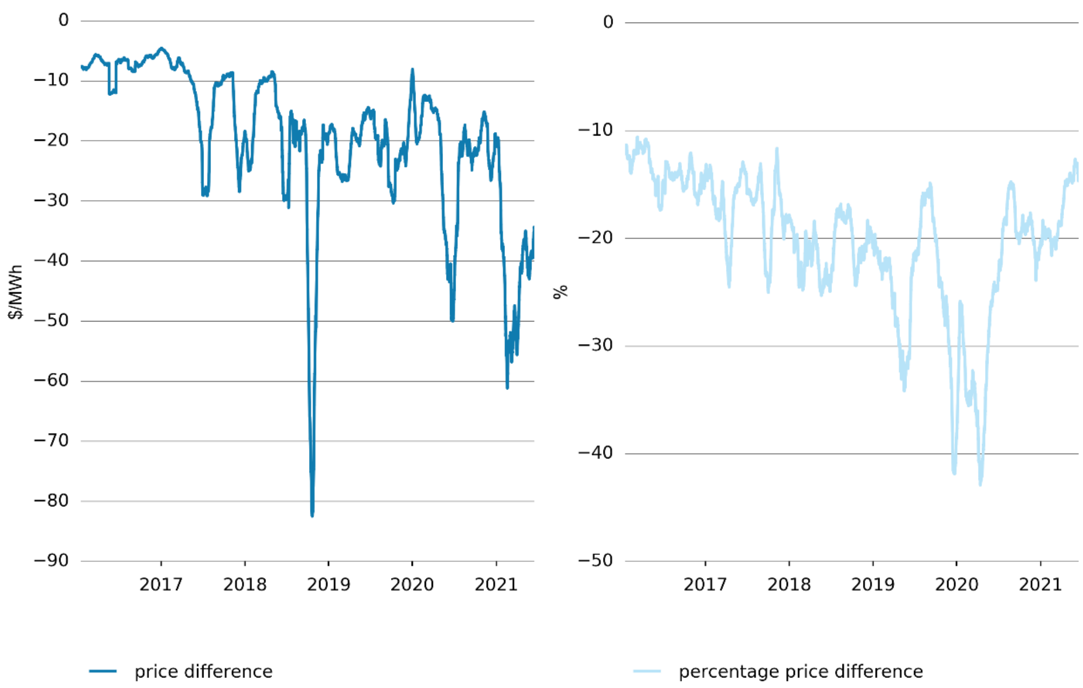
84 The simulations also do not take into account any competitor response that may have occurred due to the change.

Table 19: Simulated price changes for a 2 percent decrease in South Island demand

Period	Storage level	Average price change ($/MWh)	Average price change (percent)
2016 to September 2018	**Low hydro storage (less than 80% of mean)**	-22	-16
	High hydro storage (greater than or equal to 100% of mean)	-10	-17
2019 to June 2021	**Low hydro storage (less than 80% of mean)**	-37	-18
	High hydro storage (greater than or equal to 100% of mean)	-18	-28

Note: this uses storage for the whole of New Zealand (as a percent of mean monthly storage over all available data).

Figure 33: Simulated average price decrease over time (30-day rolling average)



Sources: Electricity Authority

Price separation: was subdued in the review period during times of high storage, suggesting some economic withholding (or withholding for other reasons)

5.101 Another indication of economic withholding would be subdued price separation between the islands, although subdued price separation can also result from hydro generators trying to conserve water in periods of low hydro storage or for other reasons.

5.102 The Authority's understanding is that Meridian and Contact offer in such a way as to try to avoid the HVDC and lower South Island constraints binding.[85] They do this to avoid price separation between the islands,[86] because it would mean receiving a lower price for their generation in the South Island than they would pay in the North Island for their retail purchases. This is an example of economic withholding, that is, altering offers in such a way as to reduce generation.

5.103 Mercury has the opposite incentive, if the HVDC binds, it will receive a higher price for its generation in the North Island while paying a lower price for its retail purchases in the South Island. It could try to achieve this by economically withholding generation, but it can achieve the same effect by changing its reserve offers instead and still get paid for producing more generation in the North Island (at the higher price). In the case of the HVDC, reserve constraints can act like a transmission constraint. Often the limitation of the HVDC has little to do with the physical capability of the HVDC itself, but more to do with an inability to procure sufficient reserves in the receiving island to cover the loss of one pole of the HVDC. Thus, Mercury, by increasing its offer prices for reserves or physically withholding reserves, decreases the amount of reserves available at a price that would get dispatched (when optimising energy and reserves in scheduling, pricing and dispatch) and therefore constrain the HVDC.

5.104 Price separation between the islands was lower in the review period years when hydro storage was higher, compared with previous years. This supports the hypothesis of economic withholding, because there is less reason for hydro generators to withhold generation when storage is higher. However, as mentioned previously, this economic withholding could be due to reasons other than trying to influence the price, such as Mercury trying to conserve water before the HVDC outage at the beginning of 2020. The finding of higher price separation in previous years during periods of high hydro storage is also driven to a large extent by many trading periods of very low Benmore prices (ie, less than $0.05/MWh). If these trading periods are removed, the price ratio for 2014–2018 in high storage periods becomes 1.11.

Table 20: Average ratio of Haywards to Benmore price

Period	Storage level	Ratio
2014 to September 2018	**Low hydro storage (less than 80% of mean)**	1.04
	High hydro storage (greater than or equal to 100% of mean)	1.68

85 See the 2019 UTS decision paper. Electricity Authority, "Final Decision – Actions to Correct Undesirable Trading Situation," December 2019, https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/10-november-2019/.

86 Large price differences, or price separation, indicate where transmission is constrained. These prices are important investment signals. When large amounts of South Island generation are exported north, we would expect transmission to become constrained. This should lead to lower prices in the South Island than in the North Island.

Period	Storage level	Ratio
2019 to June 2021	**Low hydro storage (less than 80% of mean)**	1.03
	High hydro storage (greater than or equal to 100% of mean)	1.07

Note: This excludes high-voltage, direct current outages as listed on https://pocp.redspider.co.nz/search/, where the outage was for longer than a trading period. It also only counts trading periods where the Haywards nodal price was larger than the Benmore nodal price, and the Benmore nodal price was greater than zero.

Note: this uses storage for the whole of New Zealand (as a percent of mean monthly storage over all available data).

Trading periods where economic withholding might be more likely: no increased evidence of economic withholding compared with other trading periods

5.105 We also looked at trading periods where there was price separation in pre-dispatch but not in final prices.[87] If Meridian, Contact or Mercury see price separation in pre-dispatch, they may be incentivised (as discussed above) to change their offers (generation or reserve) to avoid (in the case of Meridian and Contact) or solidify (in the case of Mercury) this price separation.[88]

5.106 We observed 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 offers in pre-dispatch to increase the quantity they economically withhold in these trading periods.

5.107 Table 21 shows summary statistics for these trading periods versus all other trading periods. It shows that both Meridian and Contact usually had a lower QWOP and a lower percent of offers above $300/MWh in trading periods with price separation in pre-dispatch but not in final prices (compared with all other trading periods). This suggests there was no economic withholding — or no increase in economic withholding compared with other trading periods — in response to pre-dispatch prices in these trading periods. Even controlling for hydro storage levels (by dividing QWOP by water values) this remains true, that is, Meridian usually has a lower ratio in trading periods with price separation in pre-dispatch but not in final prices. However, as mentioned previously, regardless of the conditions or trading period, Meridian always has a large percent of offers above $300/MWh.

5.108 Table 21 also shows that Mercury's reserve offers are not systematically priced higher or that they offer less capacity as reserves in these trading periods compared with other trading periods. Again, this suggests Mercury is not changing reserve offers to influence the price of electricity.

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87 Trading periods with a price difference in any runtime of the price response schedule short between Haywards and Benmore of greater than $10/MWh and a ratio of Haywards nodal price to Benmore nodal price greater than 1.2, and a ratio of between 1 and 1.15 in final prices.

88 We also ran the same analysis for trading periods where the HVDC had little spare capacity (less than 50 MW based on a contingent event) with similar results.

Table 21: Average QWOPs and ratios of QWOPs to water values in trading periods (TPs) with price separation in pre-dispatch

		Meridian (Waitaki)			Contact (Clutha)		Mercury (Waikato)	
		Average QWOP ($/MWh)	**Ratio of QWOP to cost**	**Percent of offers above $300/MWh**	**Average QWOP ($/MWh)**	**Percent of offers above $300/MWh**	**Average reserves QWOP ($/MWh)**	**Percent of total offers that are offered as reserves**
2019	**Other TPs (to 9 Nov)**	257	2.97	26	808	34	1553	20
	Price separation in pre-dispatch but not final	248	2.93	25	543	22	2412	21
2020	**Other TPs (from 29 March)**	157	2.11	32	159	22	340	18
	Price separation in pre-dispatch but not final	64	1.49	13	68	6	146	19
2021	**Other TPs (to 30 June)***	170	0.97	32	322	38	377	17
	Price separation in pre-dispatch but not final	143	0.96	28	156	24	324	17

*The ratios of QWOP to cost are only using data up to 8 March 2021, because water value data was only requested to this date.

Trading periods with high spot prices: changes in pre-dispatch offers are consistent with underlying supply and demand, but generators still had a high percent of offers above final price in these trading periods

5.109 We also looked at trading periods with high spot prices, to investigate whether these high spot prices could have been due to economic withholding. We looked at trading periods in days that averaged over $300/MWh from 1 January 2019 to 31 May 2021. We investigated whether these prices were a fair representation of the cost of generation, including fuel supply uncertainty and opportunity cost. We did this by examining the market conditions at the time, including what mix of fuels were used to meet national demand, national hydro storage levels, available gas production, the pattern of offers leading up to the marginal generator plant dispatching, whether the marginal generator knew they would be marginal pre-dispatch, outages and line constraints.

5.110 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.

5.111 There were no obvious signs that the 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.

5.112 However, all hydro generators had an increased percent of offers priced above final price during the review period in these high-priced trading periods, compared with previous years. Genesis (Tekapo) had 9 percent of offers priced higher than final price, Meridian (Waitaki) 22 percent, Contact (Clutha) 30 percent and Mercury (Waikato) 37 percent. Mercury (Waikato) also had a higher percentage above its water value in these trading periods, at 40 percent. This could, however, be reflecting gas supply uncertainty.

Previous events suggested the ability to raise prices above costs

5.113 Three previous events have suggested that generators may have the ability to raise prices above costs.

5.114 Even though it is outside the review period, another useful example of possible economic withholding was observed in the market performance review of high prices on 2 June 2016.[89] In reaching its findings, the market performance review noted Meridian's response that it had modified its offers to reduce the likelihood of price separation.

5.115 On 8 December 2016 Mercury withdrew reserves, which resulted in high final prices for energy and reserves in the North Island. The Authority's view was that Mercury's offering behaviour did not comply with a high standard of trading conduct but did not lay a formal complaint with the Rulings Panel.[90]

5.116 Following a market review initiated in December 2019, the Authority found that a UTS had occurred during November and December 2019. Although South Island inflows were high, and both Meridian and Contact were spilling water, prices remained high.[91] Prices relating to this UTS have been excluded from this review because they will be 'corrected' following the Authority's decision on the actions to correct the 2019 UTS.

The Tiwai contracts event analysis

5.117 From early 2020 the Authority noticed significant movement in the forward price of electricity. This section analyses the events surrounding the announcement made by Rio

89 Electricity Authority, "High Prices on 2 June 2016, Market Performance review", 18 December 2017, https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2016/high-energy-prices-2-june-2016/

90 Electricity Authority, "Notification of the Authority's decision under regulation 29 of the Electricity Industry (Enforcement) Regulations 2010," no date, https://www.ea.govt.nz/assets/dms-assets/22/2278431October17-Mercury-discontinue-investigation.pdf.

91 Details can be found at Electricity Authority, "Final Decision – Actions to Correct Undesirable Trading Situation," December 2019, https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/10-november-2019/.

Tinto, as majority owner of NZAS, in January 2021 that the Tiwai Point smelter would remain open until at least 2024. We also discuss the contracts made between Meridian, Contact and NZAS relating to that aluminium smelter (the Tiwai contracts).

The Tiwai Point smelter adds between $1.6 billion and $2.6 billion to spot market costs over 3 years

5.118 The result of the Tiwai contracts has meant spot market costs to purchasers are higher by between $1.6 billion and $2.6 billion over the next 3 years, an increase that will translate into spot prices over the next 3 years. In a competitive market, we would expect actual or anticipated entry of new generation to discipline prices (see the section on Dynamic efficiency below).

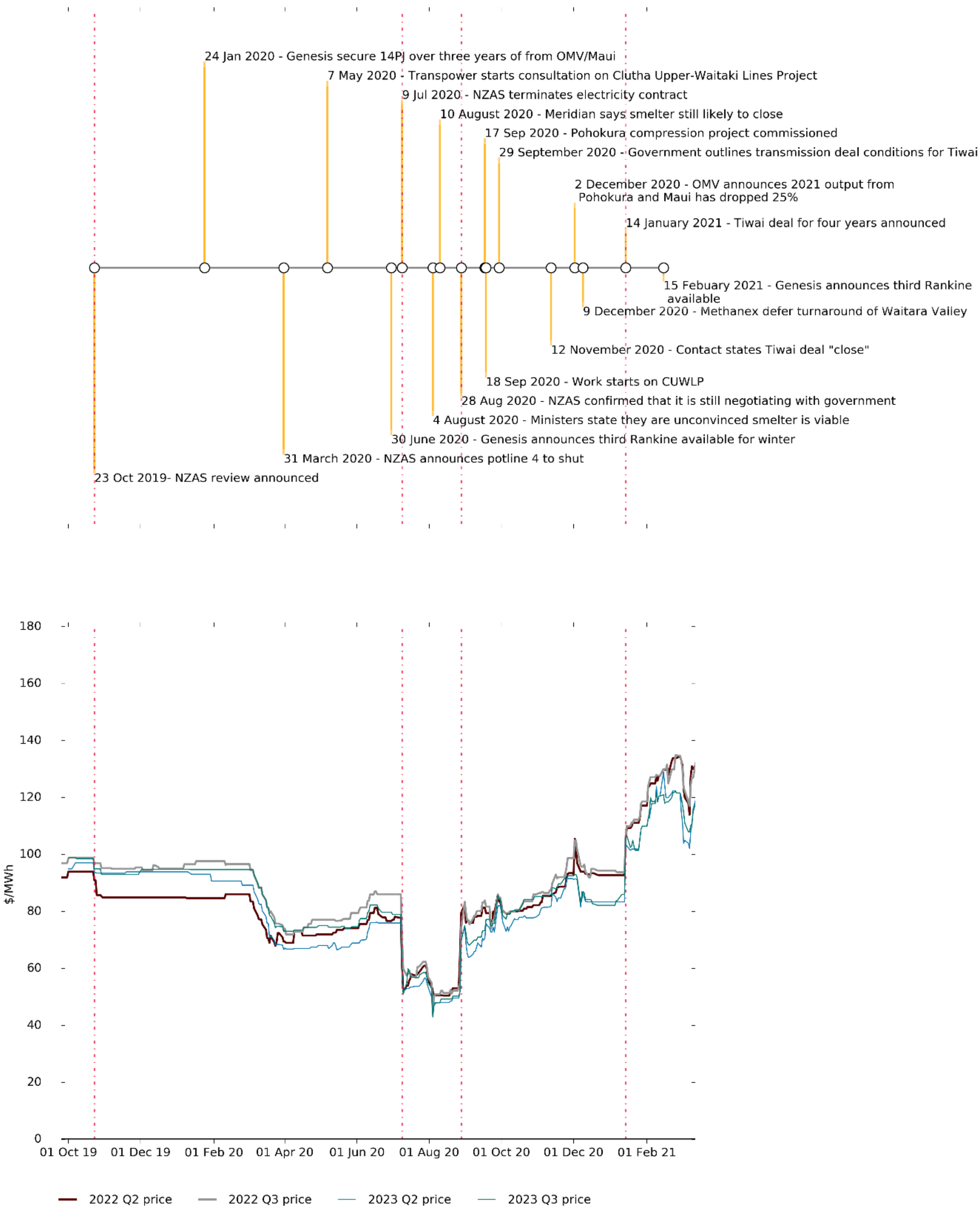
5.119 On 14 January 2021 Rio Tinto announced that the Tiwai contracts had been agreed, which meant the smelter would stay operational until 2024. The smelter is about 13 percent of New Zealand's electricity demand (and about 30 percent of South Island demand on average over the review period), so the announcement had an impact on the wholesale electricity market. The price paid by NZAS is between $30/MWh and $40/MWh (the effective price is even lower because of the rebate for the reduced term at the previous contract price).

5.120 Figure 34 shows a timeline of Tiwai Point smelter announcements and four forward contracts, both winter quarters in 2022 and 2023 at Benmore. The timeline also includes different announcements about Pohokura and other gas supply issues. We use 2022 and 2023 prices because the forward price is not affected by inflows between years but issues like the Tiwai Point smelter and Pohokura can affect these longer term prices.

5.121 Figure 34 has four red, dashed vertical lines showing four large step changes in forward price coinciding with:

1. Rio Tinto announcing a review of the Tiwai Point smelter (23 October 2019)
2. Rio Tinto giving notice it is terminating its electricity contract (9 July 2020)
3. Rio Tinto announcing it is still negotiating with the Government regarding a new contract (28 August 2020)
4. a new contract being announced (14 January 2021).

Figure 34: The Tiwai contracts timeline and Benmore futures



5.122 Figure 34 also shows the effect the four events have on these winter quarter forward prices. The review announcement by NZAS coincided with a small fall in the forward price. The notice of termination shifted the winter forward price a significant amount, an average of just under $23/MWh over the 3 years we have forward prices for. Note this is consistent with the Ministry of Business, Innovation and Employment EDGS Tiwai Point smelter off scenario, which is the lowest spot price scenario of the five modelled, around $18/MWh lower than the highest priced scenario.[92]

5.123 The gas-related events shown in figure 34 do not have the same level of impact on the forward price that the Tiwai Point smelter announcements have.

5.124 We tested the impact of the Tiwai Point smelter announcements on the forward price statistically, using tests for structural breaks. This analysis is set out in Appendix D.

5.125 Table 22 sets out the main Tiwai Point smelter announcements and the structural break tests that identify these. This confirms what the chart suggests that Tiwai Point smelter announcements resulted in large price shifts.

Table 22: Identifying structural breaks

Date	Announcement	Identified in test
23 Oct 2019	NZAS review announced	
3 March 2020	Meridian starts to sell forward contracts at Benmore in anticipation of NZAS exit	Level, Trend and Polynomial
31 March 2020	NZAS announces potline 4 to shut	
9 Jul 2020	NZAS terminates electricity contract	Level and Trend
28 Aug 2020	NZAS confirmed it is still negotiating with the Government	AR model
14 January 2021	Tiwai contracts for 4 years announced	Level, Trend and Polynomial

The forward price predicts a spot market impact of between $1.6 billion and $2.6 billion over 3 years from the Tiwai contracts

5.126 This observed impact on forward prices suggests an impact on future spot prices. The impact on spot market purchasers is set out in Table 23. It is calculated using the forward price increases that coincided with the NZAS statement that it was still negotiating with the Government (August 2020), and the new contract announcement (January 2021). These price changes are combined with 2019 demand, excluding the Tiwai Point smelter (2020 demand is excluded due to the effects of the COVID-19 lockdown), to calculate the implied spot market impact of the Tiwai contracts.

5.127 The assumptions used are:

(a) 2019 demand in 2021, 2022 and 2023 excluding Tiwai Point smelter demand

[92] https://www.mbie.govt.nz/dmsdocument/2809-electricity-demand-and-generation-scenarios-2016-pdf

(b) the forward price change as the difference between the day prior and the day after the two announcements for 2021, 2022 and 2023: We use the two announcements because the August 2020 announcement makes NZAS staying more likely, and the January 2021 announcement makes it certain.

5.128 We have done the following sensitivity analysis on the impact of the Tiwai Point smelter announcements. This includes a comparison with the July price fall that coincided with NZAS terminating its electricity contract.

Table 23: Sensitivity analysis of impact of Tiwai Point smelter announcements

Scenario		Spot market difference
Day before and day **after** announcement(s)	Both announcements	**$2.589 billion**
	August only	$1.467 billion
	January only	$1.121 billion
	July price fall	–$2.155 billion
Day before and day **of** announcement(s)	Both announcements	**$1.567 billion**
	August only	$0.610 billion
	January only	$0.956 billion
	July price fall	–$2.248 billion

5.129 This analysis shows that, assuming it takes two days for news to be fully reflected in the forward price, and that the August and January announcements are independent, up to an extra $2.589 billion dollars could be added to the spot purchase costs of electricity over 3 years, a cost borne by spot purchasers other than NZAS. We use one day of forward changes and the price fall in July by way of sensitivity analysis. This gives a spot market impact of between $1.6 billion and $2.6 billion over 3 years.

5.130 These higher prices will flow through to consumers, depending on when existing contracts were due to be renewed. Because contracts in the commercial and industrial market are linked tightly to the ASX price, these prices will shift quickly, as will any other prices indexed to the ASX. For residential consumers, the timing of price increases will depend on the term of their existing contract.

5.131 We built a simple model of the spot market value of the smelter to Meridian. We did sensitivity analysis on the amount of spill that might occur if the smelter exited, and the increase in spot price estimated using the forward price data above. This suggests that, in terms of spot market receipts, the smelter is worth up to $253 million per year to Meridian.

5.132 If a contract is made at a significantly lower price to other users, this at least raises the possibility that the electricity is not going to the highest value use. This raises potential concerns about the way the market is operating because it may suggest a potentially inefficient outcome. The low price paid by NZAS suggests that the electricity may not be going to the highest value use. While between $1.6 billion and $2.6 billion is a transfer, **if** the smelter would have exited if it had to pay the market price, then there is an efficiency cost associated with this transfer.

5.133 This efficiency cost is estimated at between $57 million and $117 million per year.

Meridian's objectives included avoiding the price fall that would accompany an NZAS exit

5.134 Meridian provided the Authority with its Board decision-making documents for the Tiwai contracts. These documents include the following statement as to Meridian's rationale for offering a price sufficient to keep the smelter at Tiwai Point operating.

> *The rationale for the offer [to NZAS] was straight forward. At the price captured in the offer, a 450MW and a 622 MW smelter was more valuable to Meridian shareholders than either a smelter that exits in 12 months (or stages that exit over 4 years).*
>
> *The reason for that was that if the smelter exits, the resulting depression in prices primarily in the South Island alongside loss of production at Manapouri power station for three years has a material impact on EBITDAF.*[93]

5.135 Meridian also anticipated that "competition for existing load would increase" and estimated the effect on households if the smelter were to exit. It also identified a risk that it would cause lower retail prices if it tried to sell into the retail market too aggressively. The Authority notes that, based on the forward market changes in July when NZAS cancelled the supply contract, the Authority estimates that a household in the South Island could expect to pay $208 less per year if the smelter exited, once wholesale price changes filtered through to the retail market. An Auckland household would expect to pay $136 less per year on the same basis.

The forward price at Benmore was well above the NZAS price

5.136 Figure 35 shows the forward curve changes that resulted from the 9 July termination of the supply contract by NZAS. The forward curve is an unbiased predictor of future spot prices.

5.137 Figure 35 shows that the new contract price is lower than the predicted spot price. This suggests that the price NZAS pays is below the price that Meridian could have got for the same energy on the wholesale market at Benmore.

5.138 Figure 35 uses the Benmore price, which is on average within 0.6 percent of the Tiwai price (using data from 2017 to 2020 inclusive). If the smelter had closed, it is likely that there would have been more price separation and more spill. However, this is difficult to estimate given the potential for increased overnight generation from the lower South Island generators and engineering options for increased utilisation of existing transmission capacity.[94] It would also depend heavily on hydrology.

5.139 Financial Transmission Rights (FTRs) for Invercargill-Benmore traded between the date of the termination notice and the new contract being announced were between $5.93 and $20.98, with most trading around $10.00. The FTR picture was made complex by a series of announcements regarding the Clutha, Upper Waitaki lines project which affects the prices of the FTRs on this segment of the grid. This range of prices is not surprising

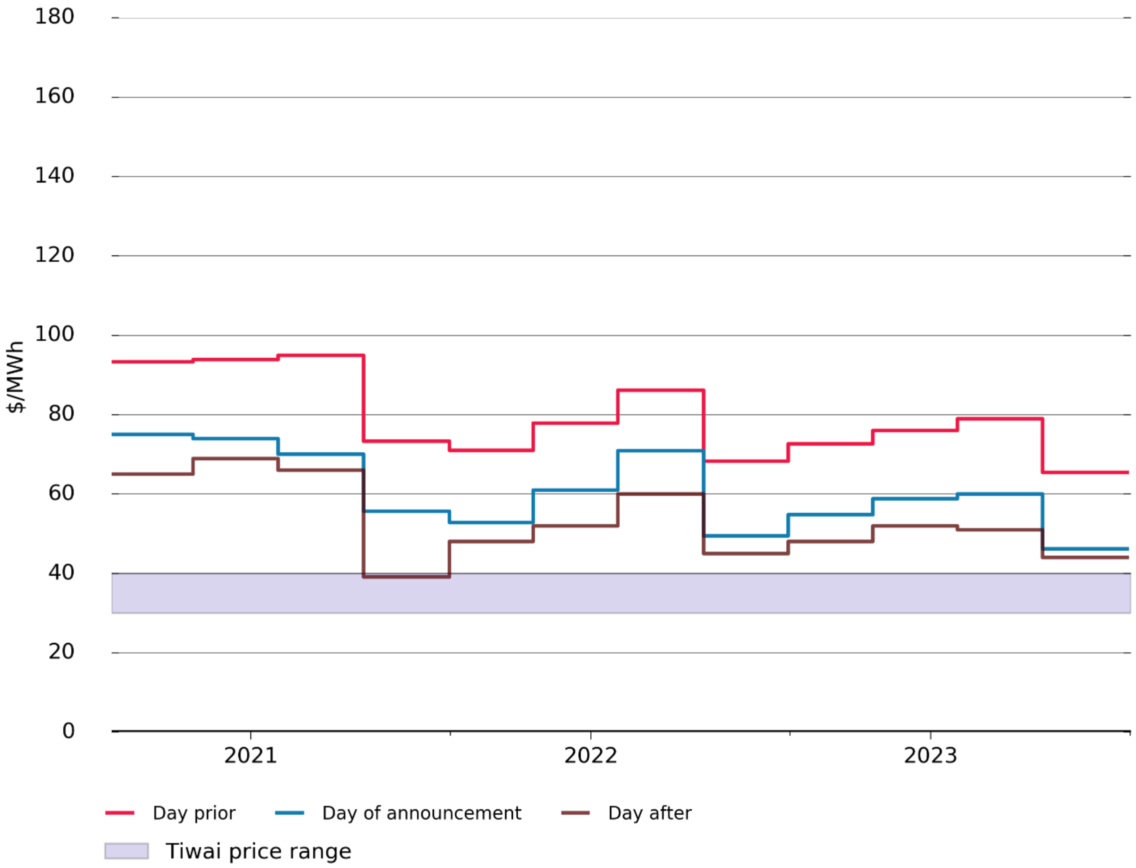
93 Meridian, "NZAS offer update" presentation at Special Board meeting 9 July 2020.

94 Such as special protection schemes and generation runback agreements.

as the FTR market is generally thin due to each auction releasing limited quantities of FTRs. It is therefore a shallower market than the forward market.

5.140 Regardless this suggests that there is a possibility that Meridian is selling energy to NZAS at below its opportunity cost.

Figure 35: Forecast prices versus the Tiwai contract price



Source: ASX and Meridian Energy

Both Meridian and Contact were able to profit from selling to NZAS because they benefit from increased revenue from the rest of New Zealand

5.141 Both Meridian and Contact profit from the presence of the smelter, despite the very low electricity price NZAS pays. This is because the market price increase caused by the smelter’s volume of consumption more than makes up for the low price the smelter pays. This price increase applies to the energy that Meridian and Contact produce that is not supplied to the smelter.

5.142 Because the price increase applies to all energy sold into the market, all generators benefit from the presence of the smelter. This creates the incentive for Meridian to supply to the smelter at a price potentially below its opportunity cost.

5.143 However, only a generator about the size of Meridian could sell to a customer on those terms, the rest of its generation sold into the wholesale market has to be large enough to make up for the loss. In this context, scale is not referring to the fact that Meridian is a vertically integrated generator–retailer; rather it is referring to its large generation capacity and concentration of generation in the South Island. That is to say, these issues arise from the scale of generation (particularly in the South Island), not because of vertical integration.

Contact was concerned that NZAS would resell the energy it supplied to Meridian

5.144 Contact identifies the risk that:

> *As a purely financial transaction, it is possible that NZAS can reduce its physical operations and trade the electricity in the wholesale market.*[95]

5.145 This is indicative of how low the price of the contract between Meridian and Contact was, and how much higher the prevailing spot price would be. Contact is identifying the risk that the price paid by NZAS makes it potentially more profitable for the smelter to on-sell the electricity than to produce aluminium.

Market performance

Pricing trends

Two percent increase in demand: simulations indicate prices in the review period have been more responsive to changes in demand

5.146 In a competitive market, large price increases from a change in demand suggest tight supply, and should attract new entry. In the interim, the incumbents have an increased incentive to economically withhold. Our results show that prices have been more responsive to changes in demand over the review period. This analysis is similar to that presented under the conduct section (see paragraphs 5.97 to 5.100), but is intended to provide a more general analysis of the affect of demand changes on pricing trends.

5.147 This section analyses the impact a change in demand would have had on prices. This analysis is not intended to predict future prices if demand increases but to understand past offer behaviour by analysing the effect of higher demand on a given trading period. All trading periods from 2016 to end of March 2021 have been included for this analysis.

5.148 The box plots in Figure 36 show the distribution of the price changes by island and year, if demand had been 2 percent higher. The blue line indicates the median price change, the orange box shows the 25th to 75th percentile range and the orange line shows the 1st to 99th percentile range, with the black crosses representing the top 1 percent of price increases (price increases have been capped at $1,000/MWh).

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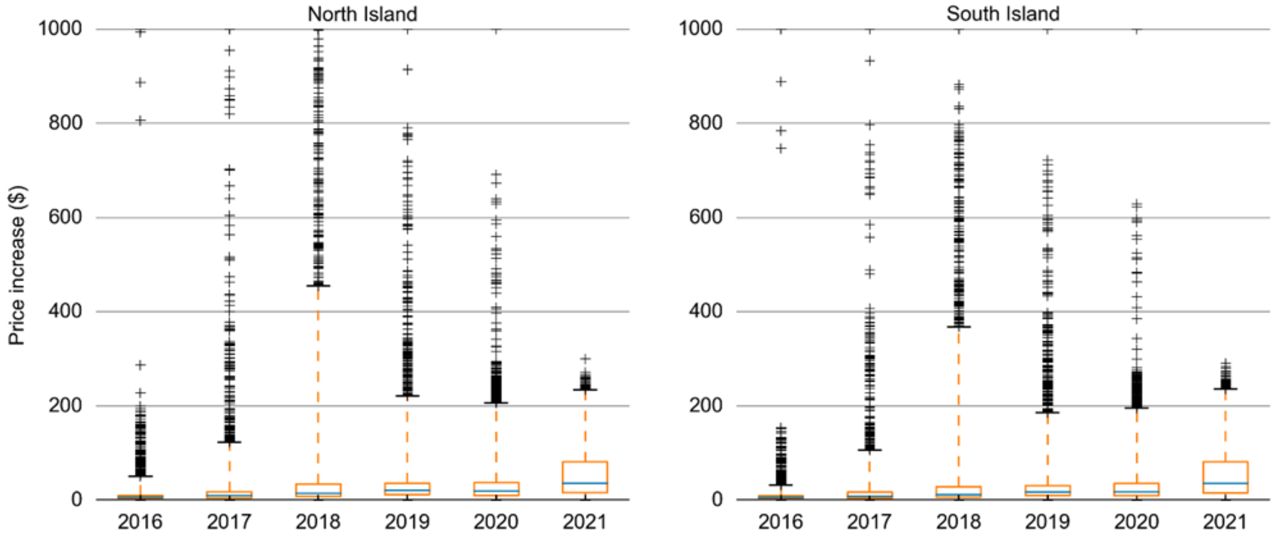
95 Contact, Board paper number 11952.

Figure 36: Distribution of price change from 2 percent increase in demand



5.149 In 2016, the median price increase was around $6/MWh, and was less than $11/MWh in 75 percent of trading periods. Price increases of more than $100/MWh would have occurred during less than 1 percent of trading periods, though a handful of those resulted in large price increases.

5.150 2017 was similar to 2016, though the market was tighter due to low inflows. This resulted in most of the top 1 percent of price increases being higher compared with 2016. The median price increase was around $9/MWh, and 75 percent of trading periods had less than a $18/MWh increase in both islands.

5.151 In 2018 there was a jump in the number of trading periods with high price increases, with 1 percent of trading periods having an increase of over $450/MWh in the North Island. Most of these trading periods occurred during the Pohokura gas outage, which reduced the availability of thermal generation. The median price increase was around $14/MWh in the North Island and $12/MWh in the South Island.

5.152 In 2019 and 2020 the price increases for most trading periods has increased: the median increase in prices was $17/MWh or higher, close to the 75th percentile in 2017. The top 1 percent of trading periods had an increase of $200/MWh or more, though the number of trading periods with an increase higher than $800/MWh dropped, compared with 2017 and 2018.

5.153 The first half of 2021 has a much wider range of price increases, compared with the previous 5 years. In the first 6 months of 2021, only 25 percent of price increases were below $15/MWh, with a mean increase of $50/MWh in the North Island. Conversely, there would not have been any trading periods where the price increase was more than $300/MWh.

5.154 Since 2018, prices have been more responsive to changes in demand. This could be because the price is being cleared at a steeper part of the curve, or because the supply curve itself is steeper (or a combination of both). This is discussed in more detail in paragraphs 5.155 to 5.157 below. This is consistent with the identification of a sustained upwards shift in prices in our regression analysis.

Supply curve: has become steeper in the review period, which may have increased the incentive to exercise market power

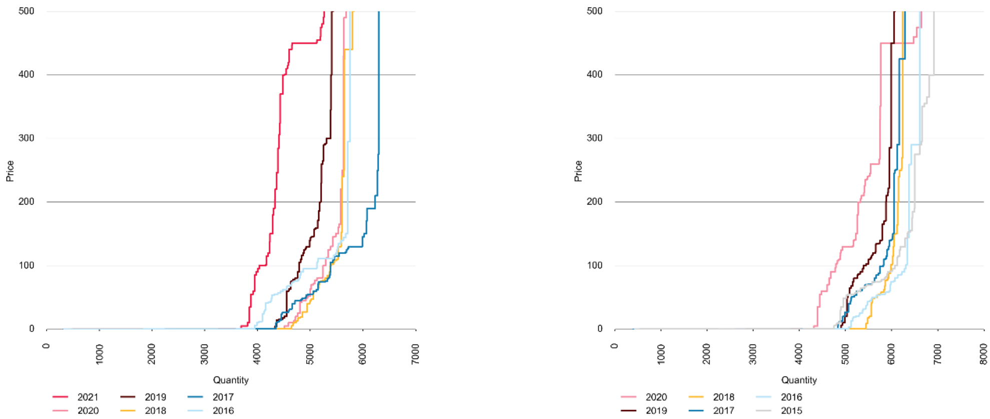
5.155 Figure 37 shows two examples of offer curves for the same day and trading period in different years.[96] Wind generation has been excluded from the supply curve in all years. The amount offered at very low prices is likely a factor of demand, expected wind generation, outages and lake levels. Between 2015 and 2021, there has been an increase in the steepness of the supply curve's slope, especially between $1/MWh and $200/MWh. The first chart is from 6 March and shows that, in 2019 and 2021, the supply curve was steeper than 2016 and 2017. Even 6 March 2020 is steeper than 2016 and 2017, despite high lake levels at the time (although the HVDC outage was still in effect, so more North Island generation was needed to meet demand in the North Island). The difference is less pronounced for 6 September, early spring, due to 2016 and 2017 being steeper (compared with March) but recent years are still steeper. This indicates that the changes seen in Figure 36 are not just due to being at the steeper part of the supply curve but also due to the curve getting steeper.

5.156 The increase in the steepness of the supply curve can be explained, at least in part, on the changes in the market, such as supply disruption due to issues at Pohokura and lake levels. However, it is also important to consider the impact this increased steepness has on competition. When a lot of offers are close to the cleared price (ie, a flatter supply curve), the marginal generator has a smaller range that they can change their price within without losing their position as the marginal generator. There is also less incentive to withhold generation (economically or physically) to push up the price because the small price increase that results would not make up for the lower quantity dispatched.

5.157 However, when the curve is steeper and fewer generators are offering around the cleared price then either the marginal generator can increase the price by a greater amount and still be dispatched, or a generator may be able to withhold generation and push up the price significantly enough that their revenue increased even though their dispatch decreased.

Figure 37: Example supply curves for same day and trading period across several years

6 March ***6 September***



96 For analysis of more dates see Appendix G.

Marginal analysis

5.158 When a generator is marginal and setting the price, it may have a stronger incentive and ability to exercise market power, because it has the potential to directly influence the price it receives. In a competitive market, this ability would be constrained because a generator would face competition from other generators further up the stack, constraining its ability to raise prices and be dispatched. The extent of competitive constraint will tend to reduce as prices increase and the quantity of unused capacity decreases. We therefore also considered the frequency of price setting when prices were greater than $200/MWh.

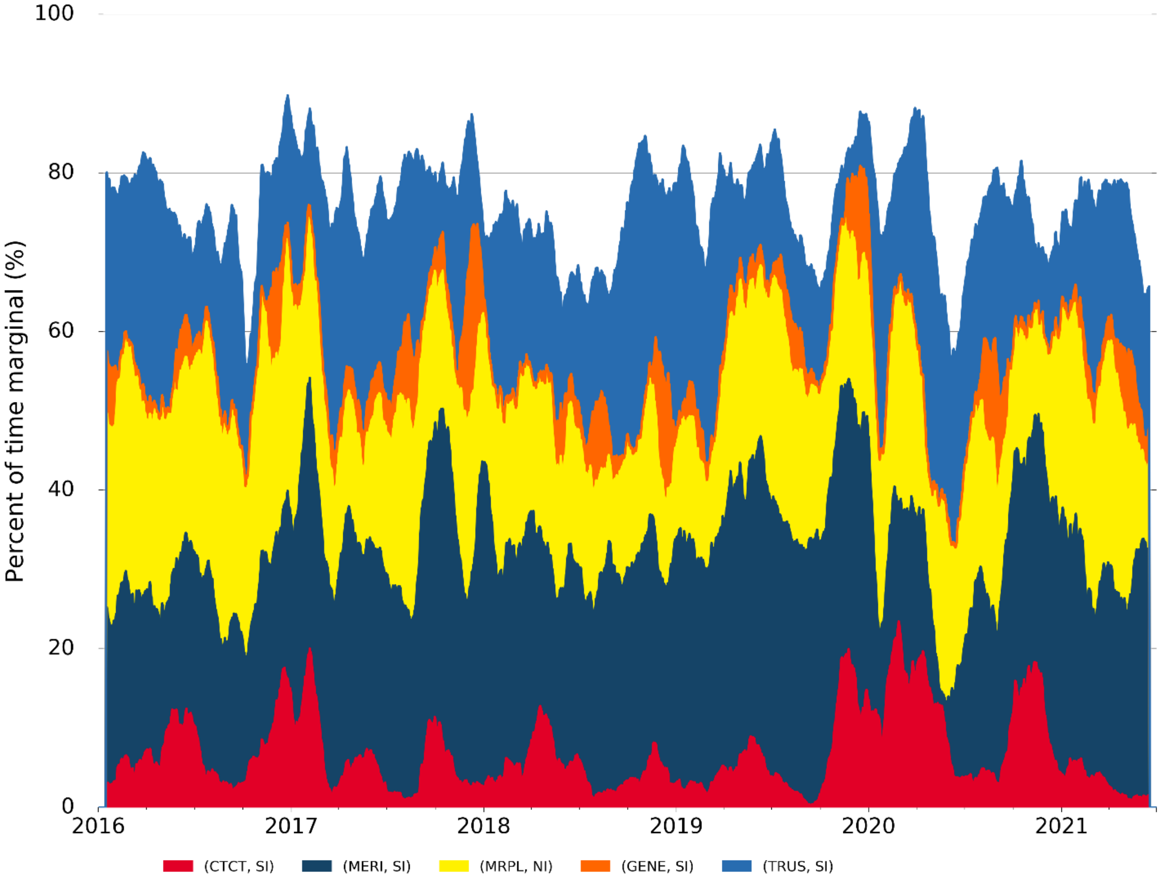
5.159 We observed that Mercury has been marginal more often during the review period in higher priced trading periods, increasing from 9 percent in previous years, to 31 percent in the review period. This is consistent with gas supply issues (gas generation, McKee and Stratford, were marginal less often in these trading periods) and dry conditions. Genesis was also marginal from its North Island generation slightly more often in these higher priced trading periods (18 percent in the review period compared with 12 percent in previous years), consistent with coal-fired generation being needed more often.

5.160 Meridian remains the generator that is marginal the most often over all trading periods. It was marginal 27 percent of the time over the review period. Mercury was marginal in 20 percent of all trading periods over the review period. Contact was marginal with its South Island generation in 7 percent of trading periods, and 5 percent of trading periods with its North Island generation. Genesis remained marginal in 15 percent of trading periods from its North Island generation. These figures are all similar to previous years. Figure 38 and Figure 39 show monthly rolling averages of these percentages.[97]

5.161 As set out above, the marginal generator may be affected by thermal unit commitment issues where a station needs a minimum price to generate, but once this occurs may offer in its minimum load at very low prices to ensure dispatch. This may lead to circumstances where the highest priced plant that is running is not marginal. As a consequence, it is difficult to deduce anything about market power from this analysis.

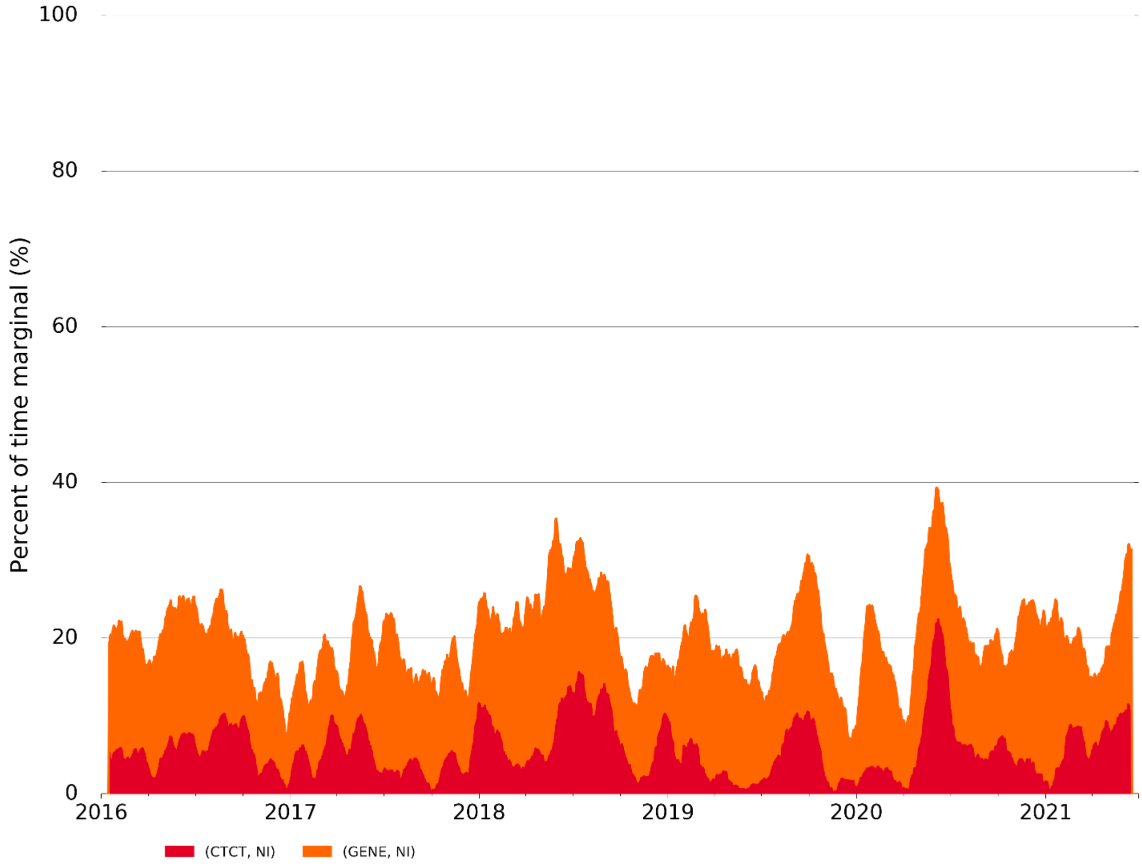
97 These two figures may not add up to 100 percent, due to the approximate nature of the estimates.

Figure 38: Hydro marginal generators (30-day rolling average, all trading periods)



Sources: Electricity Authority

Figure 39: Thermal marginal generators (30-day rolling average, all trading periods)



Sources: Electricity Authority

Actual versus predicted prices: spot price movements reflect underlying supply and demand conditions, but a sustained upwards shift in prices has occurred since 2018

5.162 In a competitive market, spot prices should reflect underlying supply and demand conditions. To analyse this, we discussed the underlying supply and demand conditions over the review period in section 4. Here, we also assess whether underlying supply and demand fundamentals predict the spot price accurately using regression analysis. The model confirms that price movements are related to underlying supply and demand conditions, but also shows a sustained upwards shift in prices after the 2018 Pohokura outage not explained by the underlying fundamentals in the model.

5.163 In a Market Performance Quarterly Review, we discussed a preliminary linear model of the drivers of the spot price.[98] Here, we discuss an extended approach that applies a time series model to the same data. This offers greater flexibility when analysing time series data. The model and diagnostics are discussed in more detail in Appendix A. However, we note that a linear regression model of the electricity market is an imperfect approximation of the interactions that occur between supply and demand in the electricity market. Therefore, the results observed must be treated with caution.

98 Electricity Authority, "Market Performance Quarterly Review: Q2 2020," last updated August 4, 2020, https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2019-2020/market-performance-quarterly-review-july-2020/.

5.164 The time series model confirms there have been higher prices following the 2018 Pohokura outage, which are not explained by the underlying supply and demand conditions in the model. The model — that is, the significant coefficient on the dummy variable — predicts that prices have been $39/MWh higher on average after the 2018 Pohokura outage, even when controlling for other fundamentals such as the gas price (including carbon price) and hydro storage. As mentioned previously, this dummy variable could be picking up other impacts on the price, including gas supply uncertainty, that we cannot control for perfectly in the model.[99]

5.165 While the gas price reflects some of the uncertainty surrounding gas supply from Pohokura and other fields, it may not reflect all of this uncertainty. We therefore also used quarterly Ahuroa storage as an indicator of gas supply risk. When we first differenced this variable to adjust for non-stationarity, it was not significant as an explanatory variable in the model.

5.166 This does not rule out that gas supply risk is affecting prices, because this variable is also an imperfect indicator of gas supply risk. It only measures Contact's ability or otherwise to obtain gas for storage, and it is only quarterly (not daily) data. We also tried variations of the smoothed gas spot price[100] as a possible better indicator of expected future gas costs and uncertainty, because it has less noise than the daily gas spot price. This was sometimes and sometimes not significant, but, again, is an imperfect indicator. The dummy variable was always significant regardless of which gas spot price variation we used.

5.167 We also obtained information on GSAs and found that the gas spot price VWAP appears to be very similar to VWAPs based on these GSAs. We are therefore confident that the daily gas spot price is a good indicator of the cost of fuel and also of gas supply risk.

5.168 Our structural break tests[101] confirmed a structural break in prices around the time of the Pohokura outage in late 2018 (see Appendix C). This lends support to the argument that some of the increase in prices is due to uncertainty surrounding gas supply from Pohokura and other fields. But, again, it is not conclusive evidence.

5.169 Aside from the increase in prices not explained by underlying fundamentals in the model, the model does confirm that price movements are otherwise related to underlying supply and demand conditions. The model shows that, when storage, wind generation and the quantity of offers in the market increase, the spot price decreases, while when demand and the gas price increase, the spot price increases. The model therefore confirms that market fundamentals have driven some of the increase in the spot price in recent years.

Forward prices: were pricing in certain scarcity for 2022 for a period before falling

5.170 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. The forward price is subjective in the sense that traders are taking a view of the future. That is, forward prices should reflect the collective expectations of future supply and demand conditions.

5.171 Figure 40 shows the average forward price (for 1 year) as a percent of the average spot price for the previous year. This shows the recent spike in forward prices is consistent

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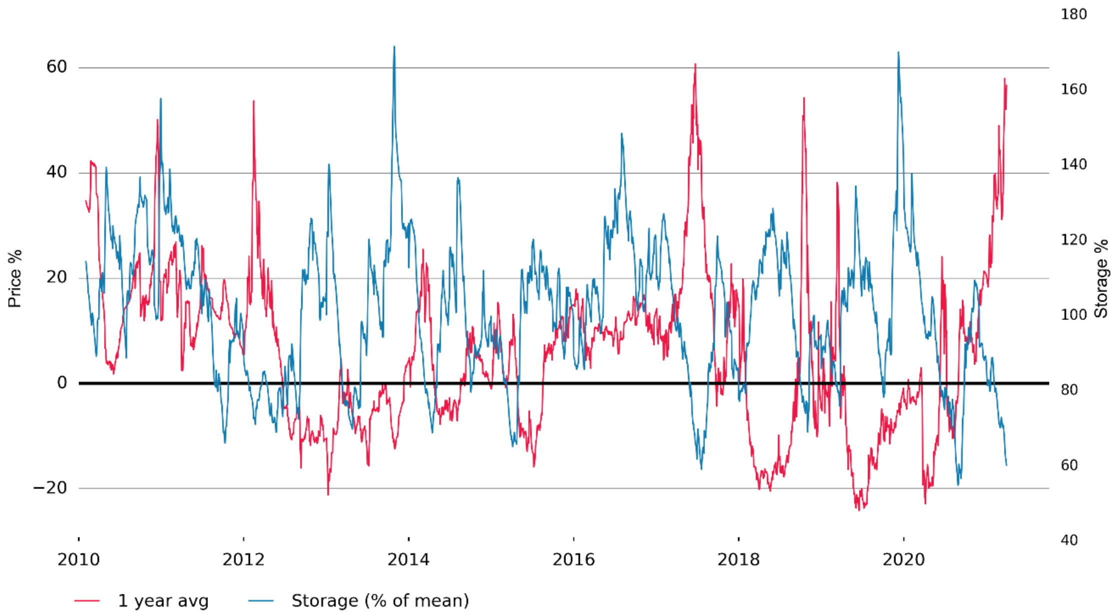
99 The dummy variable equals zero before the 2018 Pohokura outage and one from October 2018 onwards.

100 A weekly average and a rolling weekly average.

101 A structural break is when a time series abruptly changes at a point in time. Structural break tests help us to determine when and whether there is a significant change in the data.

with hydro storage levels. The percent (of average forward price to average spot price) was similar to the percent in 2012, where average forward prices for the next year got up to 60 percent of the average spot price for the previous year and storage was low.

Figure 40: Forward versus spot price, with hydro storage (daily)



Sources: Electricity Authority, ASX, NZX Hydro

5.172 However, the average spot price for the previous year in 2021 incorporates spot prices determined in relatively dry conditions (storage got down to below 60 percent of mean storage in 2020). This implies that the forward price is pricing in continued dry conditions.

5.173 The forward price for the next 3 years is above the mean spot price since June 2020, despite these spot prices being determined in a dry period with gas supply issues. To try to understand the very high forward prices in 2022, we looked at the 3 years 2018—2020. We used a regime switching model to understand the states that the spot market was in over 3 years. The details are contained in Appendix E. This type of model describes data in terms of regimes. For example, in previously published work by the Authority, a regime switching model described storage in terms of either high or low and either extreme or not extreme, giving four states: high extreme, low extreme and so on.

5.174 The results we are interested in are shown in Table 24. The model produces two states. State 1 occurs around 40 percent of the time, and the mean price in this state is $64.28/MWh. State 2 occurs around 60 percent of the time, and the mean spot price in this state is $140.94/MWh.

Table 24: States from the regime switching model

	Percentage of adjusted spot prices in each state	Mean spot price (/MWh)
state 1	39.60	$64.28
state 2	60.40	$140.94

5.175 When we started this work, we were hoping to use the mean spot prices in each state to calculate the market expectations for 2022 using $P_H * High\ price + (1 - P_H) * Low\ price = Forward\ price$, where P_H is the expectation that the spot price will be in a high priced regime: state 2.

5.176 This did not work because the forward price, Benmore or Otahuhu, was higher than the mean state 2 price and the equation cannot produce a probability between zero and one.

5.177 This raises the question as to what was driving the 2022 forward price at that time?

5.178 The mean forward price for Q1–3 2022 was $176/MWh at Otahuhu and $156/MWh at Benmore in early June. The mean spot price in the year to June 2021 is $176/MWh at Otahuhu and $165/MWh at Benmore. During this time, national storage was below average for 11 months, and Taupo storage was below average for 8 months. In addition, Pohokura's output declined from around 200 TJ/day to just over 100 TJ/day during this time.

5.179 The forward market was pricing in fuel scarcity as a certainty for Q1–3 2022. Inflows have been low in both islands over the past 12 months and supply disruption from Pohokura is ongoing.

5.180 The forward price was suggesting these supply conditions would extend into 2022 with certainty. While we would expect the forward market to be pricing scarcity as one scenario, it is surprising it was the only scenario. This may reflect that the context was novel in the sense that there has not been another La Niña event where gas supply has been disrupted.

The forward price will not accurately predict the spot price at all times

5.181 In early August 2021, the forward price was more explainable, with storage just over mean (but falling). The 2022 prices were more like the state 2 price. This is consistent with previously published analysis that shows, over the long run, the forward price is an unbiased predictor of the spot price.[102]

Profitability

5.182 The Authority engaged Concept to review electricity-related earnings of the four largest generator–retailers, to help build the picture of industry performance. In particular, if there has been a sustained exercise of market power, we would expect this to show in net earnings. Concept used earnings before interest tax depreciation amortisation and fair value (EBITDAF) to measure company earnings, and reviewed the financial years ending June 2016 to June 2020,[103] to assess whether there was any change in earnings that might coincide with the start of the structural break in prices observed by the Authority; around the time of the 2018 Pohokura outage.[104]

5.183 Concept observed that, for the financial years June 2016 up to June 2018, aggregate EBITDAF was fairly stable for the combined companies. If we look across the pre-2018

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102 Electricity Authority, "Market insight – accuracy of the forward price curve," April 21, 2021, https://www.ea.govt.nz/about-us/media-and-publications/market-commentary/market-insights/accuracy-of-the-forward-price-curve/.

103 We engaged Concept Consulting Group Limited to review the financial years ending June 2016 to June 2020. Although the 2020/21 results have since become available, because we were only looking for change over the pre- and post-Pohokura period, it is not necessary to include the 2020/21 results.

104 See Concept Consulting Group Limited, *Analysis of generator retailer financial data*.

and post-2018 periods, there were modest differences in earnings for most companies. Meridian was the exception with an earnings increase of 24 percent in 2019. Based on transfer prices reported by each company, the increase in earnings for the industry as a whole, since 2018, has resulted from wholesale market operations, with retail remaining reasonably flat.[105]

5.184 For Meridian, the 2019 increase was driven by greater revenue and little change in operating costs, with the revenue change largely attributable to increased volume of sales to commercial and industrial customers, and gains on derivatives purchased. As another check, Concept also compared 2016 with 2020 earnings. This comparison showed that Meridian has benefitted from increasing volumes in higher value sale channels, such as residential customer sales.

Dynamic efficiency

Investment: uncertainties and incentives on existing players may have impeded timely investment, but the investment environment is improving

5.185 Competition means convergence to an efficient price over time. For this to occur, investment in efficient technology needs to displace legacy technology. In New Zealand over the next few years, transitioning to a low–zero carbon electricity system means renewables replacing thermal generation. So we can expect that the long term efficient price is something like firmed wind or some equivalent firm renewable technology.

5.186 Significant investment will be required to effect the transition to renewables. Concept has advised that New Zealand could need investment of between $27 billion and $37 billion by 2050 to meet demand growth, replace thermal plant and maintain existing renewable generation.[106]

5.187 Concept found that forward prices have been above the cost of new electricity supply by about 50 percent, and this has been the case for longer than we would expect to see in a workably competitive market. This gap would suggest, to a casual observer, that more generation investment is signalled, at least over the term of the forward curve. It appears some investment is now happening, but because the signalled projects will not come on stream before 2023, the forward curve remains elevated.

5.188 Concept found that the divergence between forward prices and the cost of new supply exists primarily because the pipeline of build-ready projects has become very thin. In other words, while a number of projects are past the scoping (and sometimes consent) stage, they are not progressing to the final decision or commitment stage. The total quantity of definitely committed projects is 566 MW (see Table 6), which is not enough to replace existing thermal generation.

5.189 We commissioned Concept to talk to potential generation investors (both generator–retailers and independent developers, as well as Transpower) to understand the answer to the question: ‘Has investment in new renewable generation been restrained due to an uncertain investment environment?’.[107] Interviews with market participants highlighted a number of reasons for this, including the need to update consents for newer technology,

105 Concept Consulting Group Limited, August 2021, *Analysis of generator retailer financial data*, 12.

106 Concept Consulting Group Limited, unpublished research paper.

107 Concept Consulting Group Limited, August 2021, *Review of generation investment environment*.

time taken to obtain consents, the need for transmission connections, uncertainty around government policy and uncertainty around demand growth.

5.190 While we have noted the uncertainty around the cycle of decision making about the Tiwai Point smelter, some respondents are now seeing this as less of an issue following the NZAS announcement in January this year that the smelter would stay until 2024. This is possibly because of the prospect of other demand sources in the lower South Island and the signalling by Meridian and Contact to proceed with investment projects immediately after signing the contracts with NZAS (Harapaki and Tauhara, respectively). Both these projects were restarted around a month after the Tiwai contracts were signed.

5.191 The Climate Change Commission's recent report also attributes delayed investment in renewable generation to the Tiwai Point smelter situation and uncertainty about government policy. The Commission notes that these "… can create uncertainty in the market and result in generators delaying investment in new renewable generation, transmission and distribution infrastructure".[108]

5.192 Other factors that respondents considered may be inhibiting new investment are as follows.

- The existing large generator–retailers in New Zealand have access to hydro generation to firm any intermittent wind or solar generation build, an advantage that new entrant generators of wind or solar (the cheaper and easier generation options available) do not have.
- Incumbents may be making investment decisions with regard to their existing portfolio, and they may be less inclined to invest if a delay will increase returns on existing plant, unless spurred by competition (ie, the prospect that others will invest in newer more efficient generation).

5.193 However, Concept concludes that there are some signs that the investment environment is improving. Development interest (especially in solar farms) is increasing, concern about the Tiwai Point smelter exit may have reduced, and the demand outlook is strengthening with decarbonisation. Further, Transpower has indicated increased enquiries over the past year or so about grid connections. These signs of improvement may be the start of a response to recent high prices.

[108] 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*. (Wellington: Climate Change Commission), 281, https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf.

Appendix A Dynamic regression analysis of spot price drivers

A.1 We have used a linear regression to analyse the drivers of the spot price in the July 2020 quarterly review.[109] We found increasing demand and gas prices lead to higher spot prices. Increases in storage, wind generation, and generation Herfindahl-Hirschman Index (HHI) lead to lower spot prices. We found autocorrelation in the residuals but we also found evidence of stationarity. This gives us confidence in the results.

A.2 This study applies a time series model to the same data, but on a daily basis. The model is an extended autoregressive integrated moving average (ARIMA) model with covariates (known as ARIMAX). This model offers great flexibility in analysing time series data. The details of the model are described below.

A.3 However, this is still a linear model and, as such, may not capture the full dynamics of the electricity market. The explanatory variables used may also not be capturing some effects sufficiently, such as gas supply concerns (because future gas supply concerns may affect current spot prices, and the gas spot price probably does not capture future concerns perfectly). We tried another two variables — Ahuroa storage and the weekly average of the gas spot price — as possible improved indicators of future gas supply concerns. This is discussed in more detail below.

A.4 Our research question is the same as the one in the quarterly review: 'What is the relationship between the spot price and storage, demand, wind generation, gas price, competition in generation, coal price, carbon price, and gas supply risk?'.

Data

A.5 We use daily average data from 1 January 2014 to 30 June 2021. The response variable is adjusted daily average spot prices. We adjusted the spot price for inflation using the electricity component of the New Zealand producers price index (PPI). Then, we applied trend adjustments for the PPI adjusted prices based on Thomson's 2013 paper.[110] Figure 41 shows the spot price in black and adjusted spot price in red. The Augmented Dicky-Fuller (ADF) test suggests the adjusted spot prices are stationary.

A.6 Figure 42 shows autocorrelation function (ACF) and partial autocorrelation function (PACF) are present in the adjusted spot prices. The ACF of the adjusted prices is slow-decaying. The PACF plot shows the spike at lag 3 and the first cut-off at lag 6. This indicates an autoregressive model with more than one lag.

[109] Electricity Authority, "Market Performance Quarterly Review Q2 2020," last updated August 4, 2020, https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2019-2020/market-performance-quarterly-review-july-2020/.

[110] P J Thomson, *An exploratory analysis of the relationship between electricity spot price and hydro storage in New Zealand (2013)*. Report commissioned by the New Zealand Electricity Authority. (Wellington, Electricity Authority, 2013).

Figure 41: Spot price and adjusted spot price

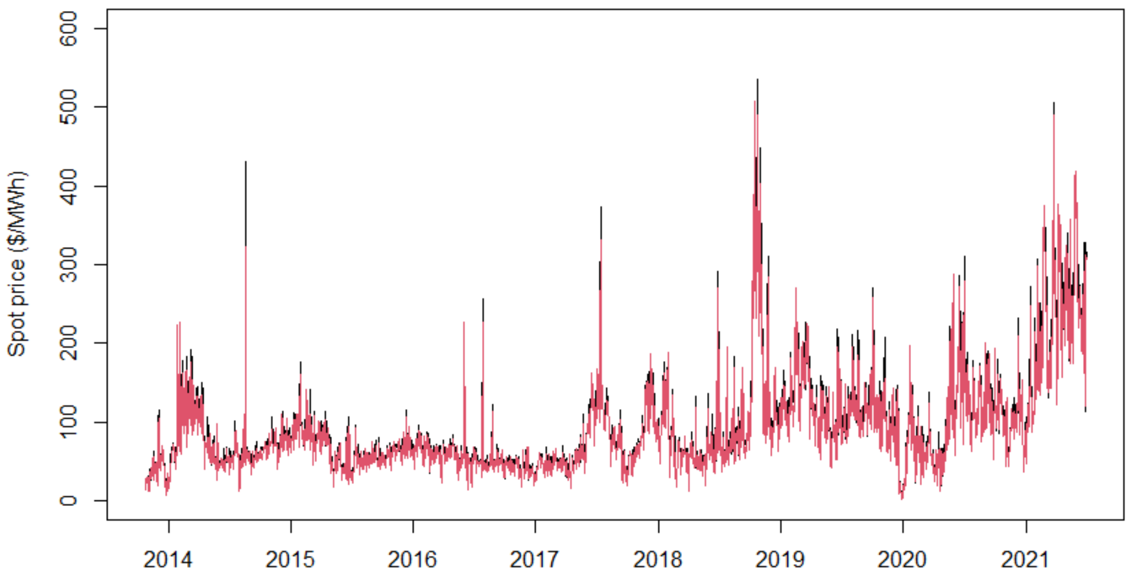
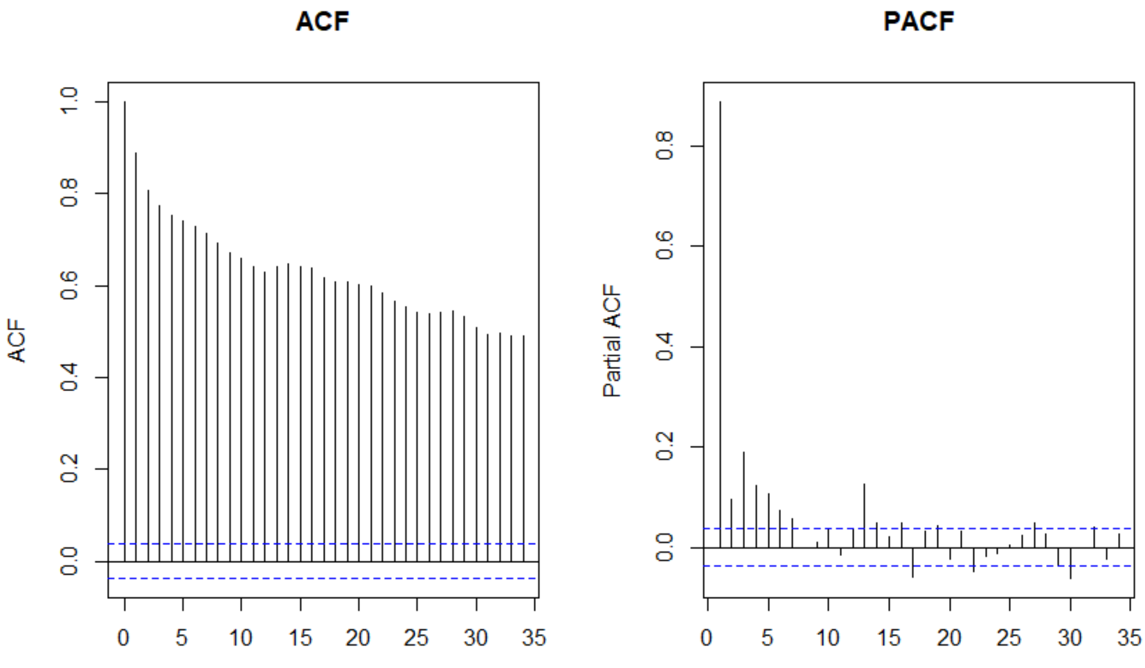


Figure 42: Autocorrelation function (ACF) and partial autocorrelation function (PACF) of adjusted spot prices



A.7 The covariates are adjusted storage, demand, gas price, wind generation, the HHI for generation (as a measure of competition in generation), the ratio of offers to generation (a measure of excess capacity in the market), Ahuroa gas storage, coal price, carbon price, and a dummy variable for the period since the 2018 unplanned Pohokura outage started. The adjusted storage variable is total New Zealand daily storage minus the mean day-of-year storage (where the mean is calculated using the past 20 years of data). This is to adjust for the seasonal impact on storage. Coal prices are monthly data interpolated to daily data, and Ahuroa gas storage is quarterly data. The rest of the variables are daily data.

A.8 The units for the raw data are: storage and demand are in GWh, spot price is $/MWh, gas price is $/GJ (from emsTradepoint), wind generation is in MW, gas storage is in PJ, coal price is the Indonesian HBA coal price in $/GJ with transport cost to Huntly added (transport within New Zealand and international freight and insurance), and the carbon price is the New Zealand emissions unit (NZU) in $/tonnes of CO2.

A.9 We used the ADF test for all variables to see if they are stationary. If not, we need to take differences to make a variable stationary. To start, we use the first difference. If the ADF test shows the data is still not stationary, we take the second difference. The first difference of a time series is the series of changes from one period to the next. For example, if the demand variable is not stationary, we use $demand_t - demand_{t-1}$.

A.10 Table 25 shows the ADF test results for stationarity. Comparing test-statistic values with critical values at 1 percent, 5 percent and 10 percent levels of significance, if the test-statistic value is less than the critical value, the variable is stationary. Demand, generation HHI, Ahuroa gas storage, weekly average gas price, coal price, and the carbon price are non-stationary, so we need to take the first difference of these variables. We test them using the ADF test again. For the ratio of offers to generation, we use the first difference for total generation and for total offered, then take the ratio of these first differenced variables. The test results show the adjusted variables are stationary.

Table 25: Test for stationarity

Augmented Dicky-Fuller test unit root test results		
Critical values at 1%	**Critical values at 5%**	**Critical values at 10%**
-2.58	-1.95	-1.62
	Test statistic	**Stationary? (Y/N)**
Adjusted spot price	-5.9093	Y
Adjusted storage	-2.9936	Y
Demand	-1.3915	N
Wind generation	-11.1441	Y
Gas price (daily)	-3.913	Y
Gas price (weekly average)	-1.4177	N
Generation HHI	-0.7004	N
Ratio offer to generation	-1.6848	N, stationary only at 10%
Ahuroa gas storage	-1.1815	N
Carbon price	4.3632	N
Coal price	0.4389	N
Take first difference for non-stationary variables		
Diff(demand)	-54.0386	Y
Diff(generation HHI)	-47.7214	Y

Augmented Dicky-Fuller test unit root test results		
Critical values at 1%	**Critical values at 5%**	**Critical values at 10%**
Ratio diff(offer) to diff(generation)	-36.9671	Y
Diff(Ahuroa gas storage)	-36.9527	Y
Diff(carbon price)	-29.6606	Y
Diff(coal price)	-5.1196	Y
Diff(weekly gas price)	-37.0297	Y

A.11 For the dummy variable, a value of 0 is given for all periods before 28 September 2018, and a value of 1 is given for the data from 28 September 2018 onwards. This is to cover the period since the unplanned Pohokura outage that started in late September 2018. Since this outage, the deliverability of gas from Pohokura has been increasingly uncertain. This uncertainty has persisted. The 2020 outage was partly to determine whether further remedial work was required on the undersea pipeline, and, since this outage ended, output from Pohokura has drifted downwards, creating further uncertainty.

Model

A.12 An ARMA model is an autoregressive model (AR) combined with a moving average model (MA). AR is a regression of the variable against its own lagged values (past values). MA uses lagged errors as a regressor. It captures shock effects (unexpected events) affecting the observation process. So if a time series data is denoted by $y_1, \ldots, y_n$, the ARMA(p,q) model will be $y_t = \varphi_1 y_{t-1} + \cdots + \varphi_p X_{t-p} + Z_t + \theta_1 Z_{t-1} + \cdots + \theta_q Z_{t-q}$ where p and q are the order (number of lags) of the autoregressive and moving average components respectively.

A.13 An ARMA model relies on the assumption that the underlying process is weakly stationary. Weakly stationary means the data has no systematic change in mean and variance and has no periodic fluctuations. If the data is non-stationary, we need to take first differences ($y_t - y_{t-1}$) to transform the data. The differencing process can be performed several times until the data achieves stationary. This model is called an ARIMA model. 'I' indicates the differencing process.

A.14 An ARIMAX model is an ARIMA model with added covariates on the right-hand side of the ARIMA equation: $\beta_1 x_{1.t} + \beta_2 x_{2.t} + \cdots + \beta_i x_{i.t}$, where $x_{1.t} \ldots x_{i,t}$ are covariates at time t and $\beta_1, \ldots, \beta_i$ are their coefficients. A disadvantage using an ARIMAX model is that the covariate coefficients are hard to interpret. This is because the covariate coefficients (βs) are not the marginal effect on y_t when the x_t is increased by one unit. This is because of the lagged response variable on the right-hand side of equation. So the coefficient βs can only be interpreted conditional on the value of previous values of the response variable.

A.15 Dynamic regression is a method to transform the ARIMAX model and make the coefficients of the covariates interpretable. The form of dynamic regression is:

$$y_t = intercept + \beta_1 x_{1,t} + \cdots + \beta_i x_{i,t} + \eta_t$$
$$\nabla \eta_t = \varphi_1 \eta_1 + \cdots + \varphi_p \eta_{t-p} + \cdots + \theta_1 Z_{t-1} + \cdots + \theta_q Z_{t-q} + Z_t$$

$where\, x_{1,t}, \ldots, x_{i,t}\ are\ covariates;\ and\ \nabla\eta_t = \eta_t - \eta_{t-1}$

A.16 The model can be treated as a regression model (first equation) with ARIMA errors with first order differencing (second equation). The errors η_t in the first equation are assumed to be white noise. White noise is the simplest description of a stationary process. If the variables are independent and identically distributed with a mean of zero, we say these variables are white noise. Note if there is no differencing process, the second equation becomes ARMA errors: $\eta_t = \varphi_1\eta_1 + \cdots + \varphi_p\eta_{t-p} + \cdots + \theta_1 Z_{t-1} + \cdots + \theta_q Z_{t-q} + Z_t$.

A.17 Dynamic regression requires all variables to be weakly stationary so we need to test this by applying the ADF test to all variables.

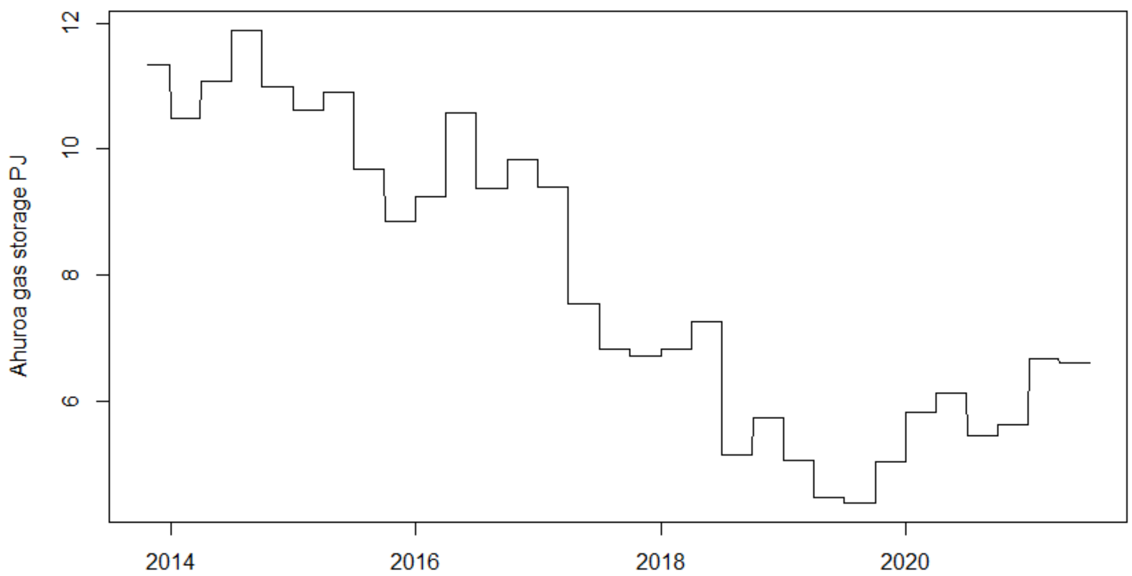
Results

A.18 We fit the data using the Dynamic model. We compared the Akaike information criterion (AIC) between models with different numbers of lags. The lowest AIC indicates the best fit of the model, which is an autoregression model with five lags.

A.19 The first difference of the coal price and the first difference of the carbon price were not significant in the model, even when we excluded the carbon price from the gas spot price. We therefore dropped both of these variables (one by one, based on the p-values) from the model. Once these variables were dropped, the ratio of offers to generation was also not significant at the 5 percent level, so we dropped this variable also.

A.20 The Ahuroa gas storage variable was only significant at the 10 percent level (indicating very weak significance) when we took the first difference of this variable (which was needed to make it stationary). We therefore also dropped this variable from the model. It was significant using raw data (ie, if we did not take the first difference) and the dummy variable was not included in the model. Since the Ahuroa storage data is quarterly, it picks up a similar trend to the dummy variable (shown in Figure 43). That is, it exhibits a significant drop around the time of the Pohokura outage, which dominates other fluctuations in the Ahuroa storage data. Therefore, it is very similar to including a dummy variable, and 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.

Figure 43: Ahuroa gas storage



A.21 We also tried using the weekly average and a rolling 7-day average of the gas spot price as a potentially improved indicator of future gas prices (compared with the daily gas spot price, because this has a lot of noise). The weekly gas spot price was not stationary, and when we adjusted for this, the first difference was not significant in the model. The first difference of the rolling 7-day average was significant. The dummy variable was always significant regardless of the gas spot price variation used (smoothed or daily). We also observed that the gas spot price value weighted average price (VWAP) was similar to VWAPs of gas supply agreements. We therefore present, as our final model, the model including the daily gas spot price (ie, using the same frequency as the dependent variable).

A.22 We expected a positive coefficient sign on the concentration measure variable HHI, because an increase in market concentration (increasing HHI) should suggest a reduction in competitive pressure and therefore higher prices. However, our models have a negative coefficient on this variable.

A.23 HHI is the sum of the squared market shares. The HHI for the generation market is driven somewhat by hydro storage levels in the New Zealand market, where most generation is hydro. The HHI falls when water is scarce and climbs when water is abundant (large hydro generators produce more when water is abundant). But when storage is low, the spot price will be high. This gives the negative sign for the HHI coefficient in our regression, suggesting a fall in concentration (increased competitive pressure) leads to higher prices.

A.24 This negative sign in our regression results suggests that the storage effect dominates any market concentration effect. This results in an inverse correlation between hydro generators market shares and high spot prices in contrast to the normal correlation. Additionality, the influence on the HHI of the storage factor results in daily variability of the HHI being far greater than is normally encountered.

A.25 Therefore, we consider that HHI is not an appropriate variable to include in the regression. We dropped it from the model and refit the regression.

A.26 The final fitted dynamic regression is:

$$y_t = 67.15 - 0.06 \times \ adj.storage + 0.68 \times diff(demand) - 6.27 \times \ wind.generation + 3.1 \times \ gas.price + \ 38.74 \times dummy + \eta_t$$

$$\eta_t = 0.7 \times \eta_1 - 0.02 \times \eta_2 + 0.05 \times \eta_3 + 0.08 \times \eta_4 + 0.04 \times \eta_5 + \varepsilon_t$$

A.27 Table 26 shows the estimated coefficients from the fitted model.

Table 26: Results from the regression

	Coefficients	p-values	Significant?
AR1	0.6908	0	Y
AR2	-0.0222	0.3	N
AR3	0.0492	0.04	Y, at 5%
AR4	0.0788	0	Y
AR5	0.0422	0.03	Y, at 5%
Intercept	67.1522	0	Y

Adjusted storage	-0.0613	0	Y
Diff(demand)	0.6843	0	Y
Wind generation	-6.2694	0	Y
Gas price	3.0827	0	Y
Dummy	38.7416	0	Y

A.28 All estimated coefficients have the expected signs:

(a) when storage and wind generation increase, the spot price decreases

(b) when demand and the gas price increase, the spot price increases

A.29 The coefficient on the dummy variable suggests that the spot price has increased since September 2018.

A.30 The results are consistent with the linear regression fitted in the quarterly review.

Interpretation

A.31 Dynamic regression allows the regression coefficients to be interpreted in a similar way to a linear model.

Adjusted storage: a unit increase in adjusted daily storage causes on average a $0.06/MWh decrease in the daily adjusted spot price, holding other variables constant.

Difference of demand: a unit increase in difference of daily demand causes on average a $0.68/MWh increase in the daily adjusted spot price, holding other variables constant.

Wind generation: a one MW increase in daily wind generation causes on average a $6.27/MWh decrease in the daily adjusted spot price, holding other variables constant.

Gas price: a dollar per GJ increase in the daily gas price causes on average a $3.1/MWh increase in the daily adjusted spot price, holding other variables constant.

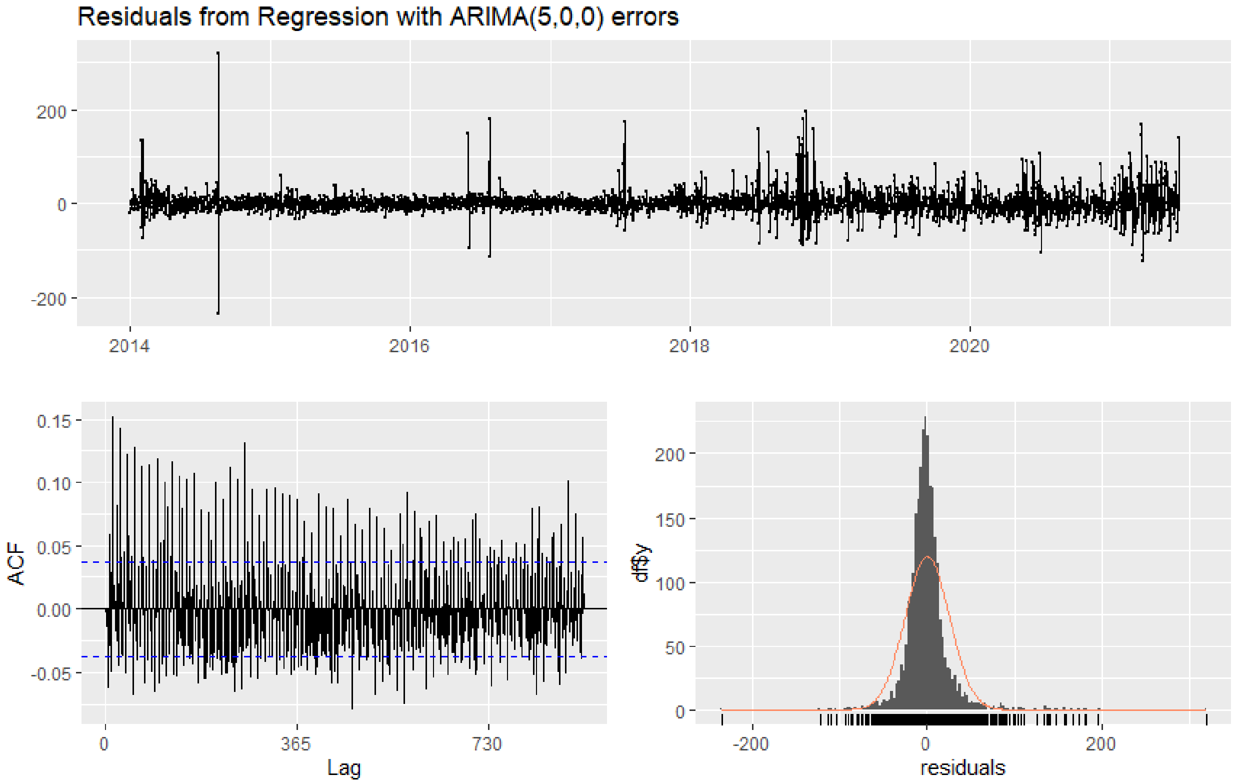
Dummy variable: For the period from 28 September 2018 onwards, the daily adjusted spot price is on average $38.74/MWh higher than the daily adjusted spot price before 28 September 2018, holding other variables constant.

Checking residuals

A.32 Figure 44 shows the residuals of ARMA errors are not significantly different from white noise. The bottom left graph, autoregression plot ACF shows no autocorrelation for the residuals. The bottom right graph of histogram for residuals shows the residuals have mean at zero. All these indicate white noise for the residuals. So the assumption of ARMA errors are white noise is satisfied.

A.33 Box test is a statistical test for whether the autocorrelation of a time series is different from zero. The p-value for the test is 0.87 suggesting there is no evidence that the residuals are autocorrelated.

Figure 44: Plots for residuals



Note: ACF = autocorrelation.

Conclusion

A.34 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.

A.35 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.

Appendix B Calculating thermal short-run marginal costs

B.1 The following steps describe the calculation of the coal and gas short-run marginal cost (SRMCs).

(a) Historical series of the spot gas price, coal price and carbon price were obtained from the following sources:

(i) emsTradepoint: gas price (average daily volume weighted market price)

(ii) http://www.imining.id/solutions/coal-price-calculator: coal price (HBA 6322 series)

(iii) https://github.com/theecanmole/nzu: carbon price (NZU daily prices – business days).

(b) The coal price above is in $US/tonne, so we obtained an exchange rate series and the heat value (GJ/tonne) to convert to $NZ/GJ from:

(i) https://www.rbnz.govt.nz/statistics/key-graphs/key-graph-exchange-rate : monthly exchange rate (US$:NZ$)

(ii) Enerlytica's (https://www.enerlytica.co.nz/user/login) 'NZ Energy Daily': Heat value (1,000 times the ratio of the Huntly coal stockpile in PJ and kt)

(c) We add NZ$20/tonne (NZ$9.90/MWh) domestic freight for transporting the coal from the port to Huntly, and US$15/tonne (NZ$10.50/MWh) international freight and insurance for transporting the coal to the New Zealand port.

(d) The coal and exchange rate series are monthly, so we converted the other series to monthly averages for consistency.

(e) Interpolated to fill any gaps in the data.

(f) Obtained parameters for different plants:

(i) fuel type (gas, coal, diesel)

(ii) heat rate (HR) (GJ/MWh) (source: Table 3-13 of https://www.mbie.govt.nz/assets/2020-thermal-generation-stack-update-report.pdf)

(iii) emission factor (EF) (tonnes CO_2 per TJ) (source: Tables A4.1 (gas) and A4.2 (coal) of https://environment.govt.nz/assets/Publications/Files/new-zealands-greenhouse-gas-inventory-1990-2018-vol-2-annexes_July2020.pdf)

(iv) variable operation and maintenance costs (VOM) ($/MWh) (source: Table 3-15 of https://www.mbie.govt.nz/assets/2020-thermal-generation-stack-update-report.pdf).

(g) Created a nested dictionary of the parameters.

(h) For each station, we calculated the SRMC as: VOM + HR*(fuel_cost + EF/1000*carbon_price) where:

(i) SRMC is a series in $/MWh

(ii) Fuel_cost is the price series for the relevant fuel type in $/GJ

(iii) carbon_price is the price series in $/tonne of CO_2 (only added for coal since the gas spot price includes the carbon price)

(iv) VOM, HR, EF as above.

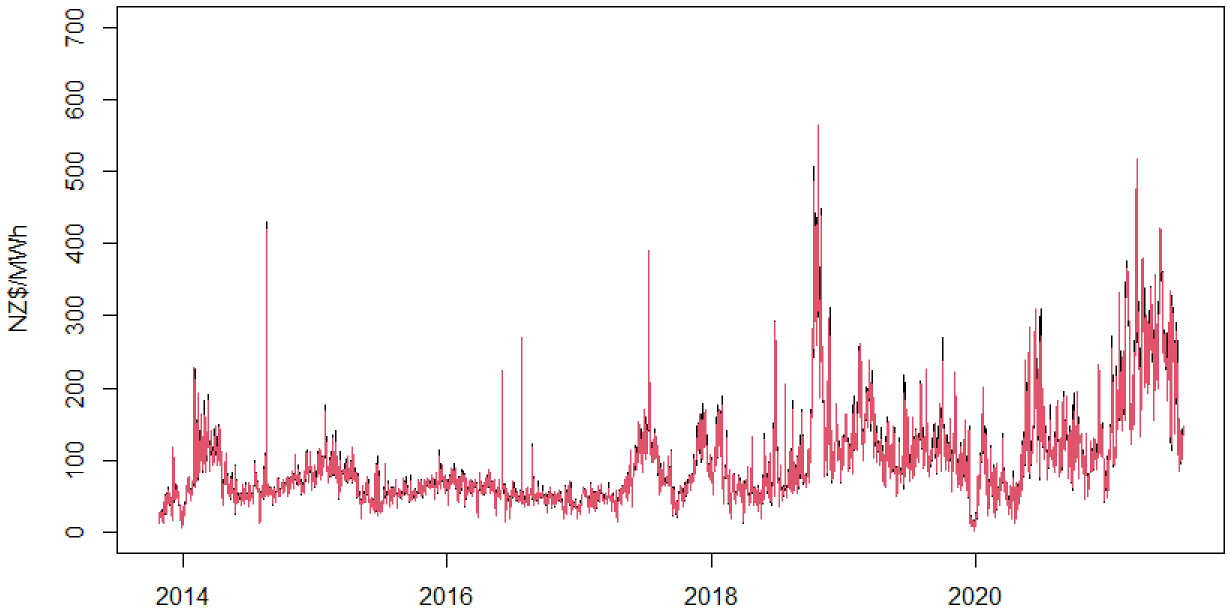
Appendix C Details of structural break analysis for the spot price

Introduction

C.1 In this report, we use structural break tests to investigate and examine how the pricing trend changes in the electricity spot price time series.

C.2 Figure 45 shows the daily average spot prices (black) and the adjusted daily spot prices (red) from 24 October 2013 to 31 July 2021. The adjusted daily spot prices are adjusted inflation to common dollars using the electricity component of the New Zealand producers price index (PPI). We then applied trend adjustments for the PPI adjusted prices based on Thomson's 2013 paper.[111]

Figure 45: Spot prices and adjusted spot prices



C.3 Our research question is: are there any structural breaks in the adjusted daily spot price?

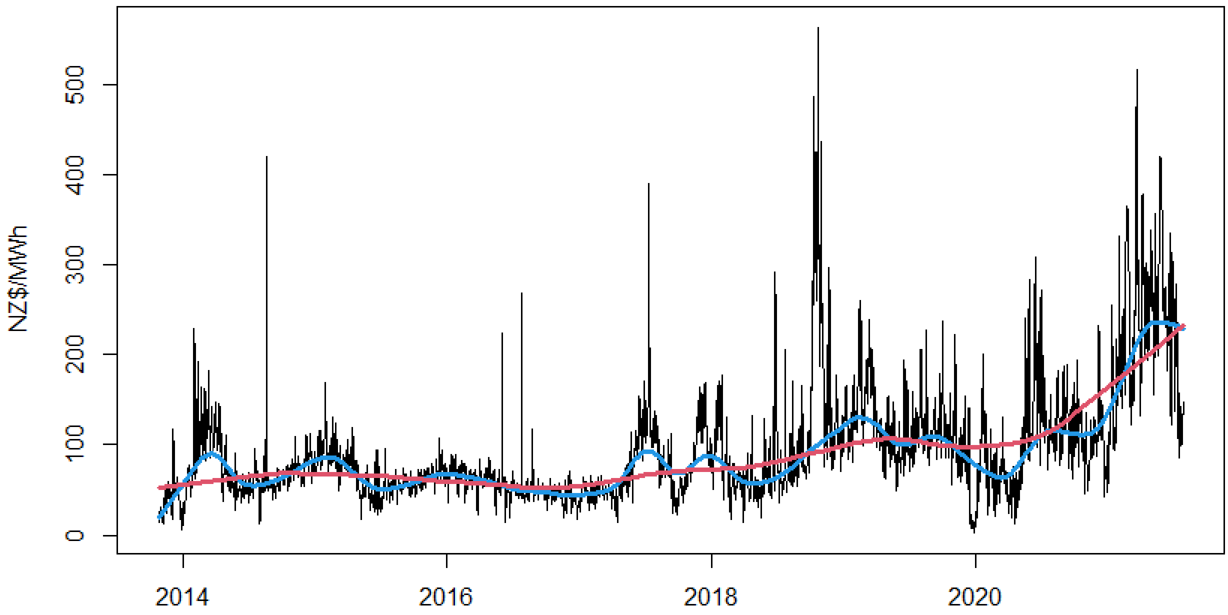
Data

C.4 Figure 46 shows the adjusted daily spot price (black line) and two loess regressions (red and blue lines). An inter-annual trend (red) provides a view of the long-term trend while the intra-annual trend (blue) provides seasonal levels of the daily time series.

C.5 The inter-annual trend (red) shows an overall increasing trend, especially from mid-2020. The intra-annual trend (blue) provides a quarterly view of the data. In general, the adjusted daily spot price is relatively low in summer and high in winter, due to high demand and low hydro inflows.

111 P J Thomson, *An exploratory analysis of the relationship between electricity spot price and hydro storage in New Zealand (2013)*. Report commissioned by the New Zealand Electricity Authority. (Wellington, Electricity Authority, 2013).

Figure 46: Adjusted daily spot prices and pricing trends



C.6 We use the Augmented Dicky-Fuller (ADF) test for the spot price time series to see if it is stationary. If the test statistic value is less than the critical value, we can conclude that the spot price is stationary. The ADF test results suggest the adjusted daily price is stationary at significance levels of 1 percent, 5 percent and 10 percent. The full R outputs are shown in appendix A.

Method

C.7 In time series analysis, structural changes represent a time series abruptly changing at a point or multiple points in time. Chow (1960) applied an F-statistic for regime changes at priori known dates.[112] Quandt (1960) modified Chow's framework to consider the F-statistics for all possible break dates.[113] Bai and Perron (1998, 2003) extend the framework by allowing for multiple unknown breakpoints.[114]

C.8 The basic idea of Bai and Perron's method is through a classical linear regression model employing dynamic programming, to find a number of breakpoints (m) that minimize the residual sum of squares (RSS). The number of breakpoints (m) is unknown. It is therefore necessary to compute the optimal breakpoints for m=0,1, 2,…N break points and choose the model with the lowest Bayesian information criterion (BIC).

C.9 We use Bai and Perron's method to detect the points of possible structural changes, and then use the Chow test to confirm the changes.

---

112 G C Chow, "Tests of Equality Between Sets of Coefficients in Two Linear Regressions," *Econometrica* 28, (1960): 591–605.

113 R C Quandt, "Tests of the Hypothesis that a Linear Regression Obeys Two Separate Regimes," *Journal of the American Statistical Association* 55, (1960): 324–330.

114 J Bai and P Perron, "Estimating and Testing Linear Models with Multiple Structural Changes," *Econometrica* 66, (1998): 47–78. J Bai and P Perron, "Computation and Analysis of Multiple Change Models," *Journal of Applied Econometrics* 18, (2003): 1–22.

Results

C.10 We use four scenarios: level, trend, polynomial fit and autoregressive model (AR) to estimate structural breaks.

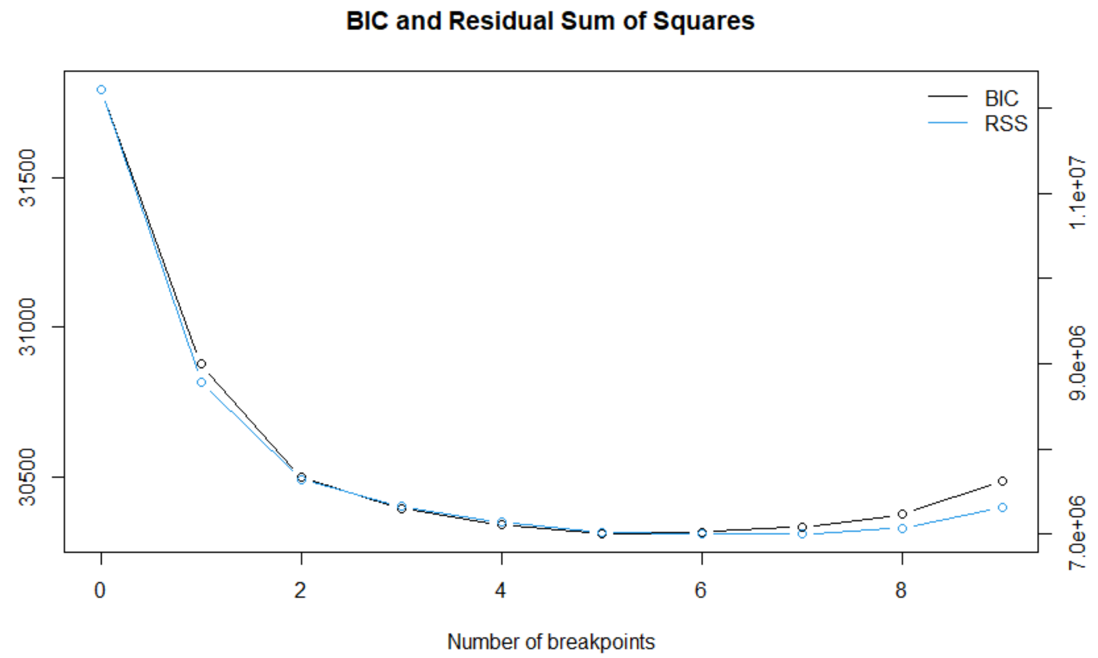
Level structural changes

C.11 This method models the adjusted daily spot prices using a linear model, then applies Bai and Perron's method to this linear model to find the breakpoints.

C.12 Figure 47 shows that BIC reaches its minimum value when there are 5 breakpoints. The breakpoint dates are:

Dates	2015-04-30	2017-05-30	2018-10-02	2019-10-11	2020-10-21

Figure 47: Bayesian information criterion (BIC) and residual sum of squares (RSS) for level structure changes

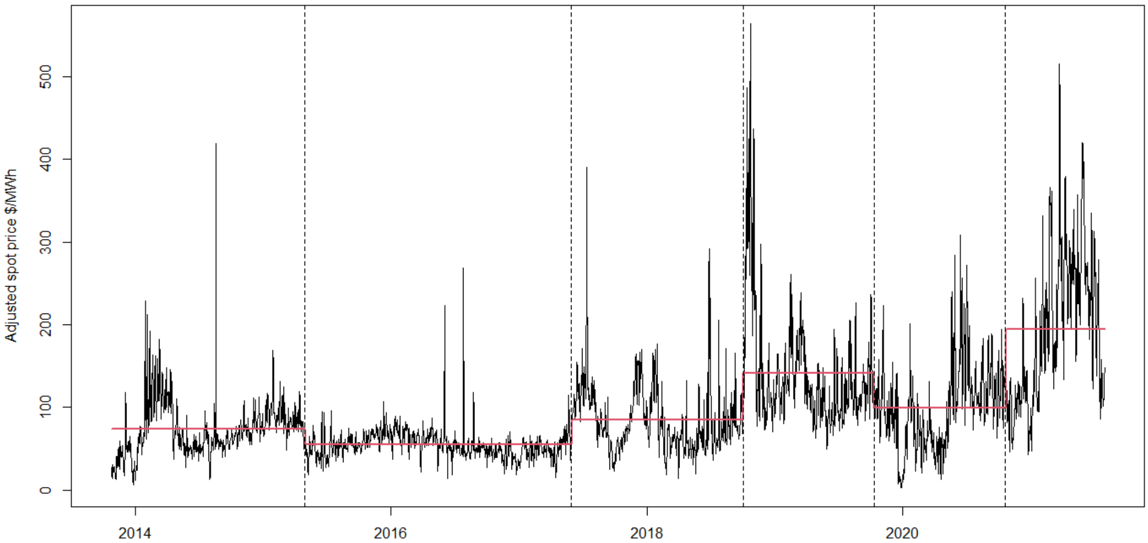


C.13 We then run the Chow test to confirm these breakpoints. The results of the Chow test are shown below. The p-value is very small. The null hypothesis of the Chow test is that there are no structural breaks in the data. We therefore have very strong evidence against the null hypothesis.

```
supF test
data: test2
sup.F = 1109.6, p-value < 2.2e-16
```

C.14 Figure 48 shows the adjusted daily spot prices, with the vertical dashed lines indicating different segments based on the estimated structural break dates. The red horizontal lines are the trend fitted by Bai and Perron's method in each segment.

Figure 48: Adjusted daily spot prices with possible structure breaks (level scenario)



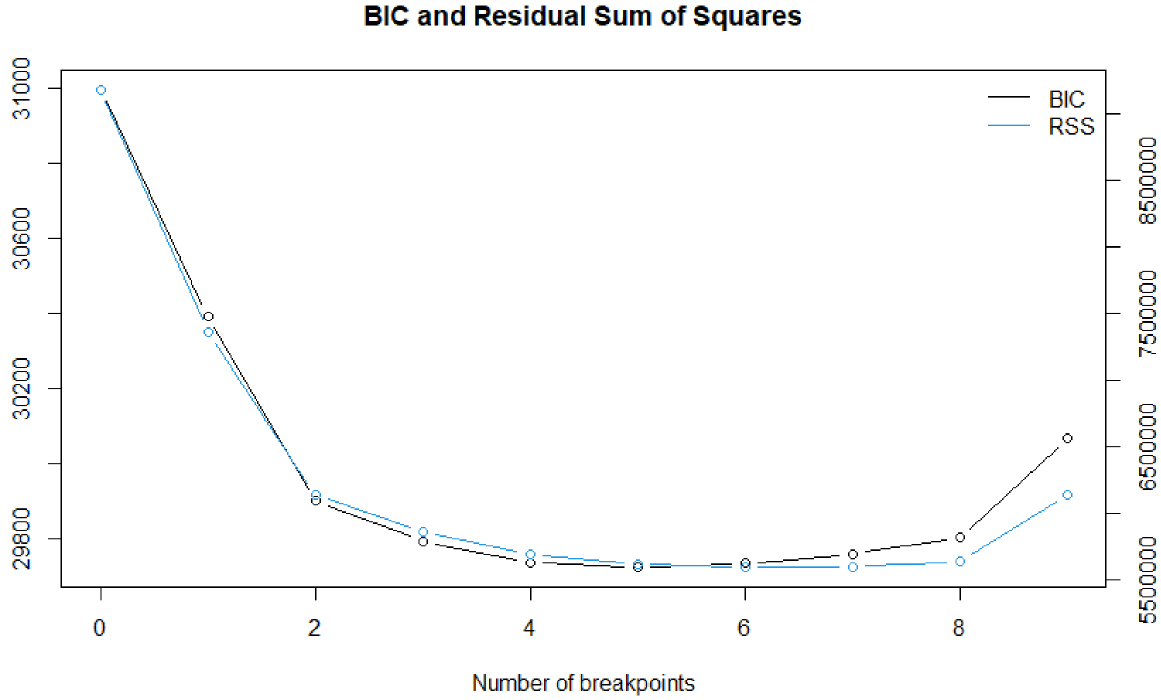
Trend structural changes

C.15 This method models the adjusted daily spot prices against time in a linear model, then applies the same method (Bai and Perron) to estimate breakpoints.

C.16 Figure 49 shows that the BIC reaches its minimum value when there are 5 breakpoints. The breakpoint dates are:

Dates	2015-04-24	2017-05-30	2018-10-04	2019-07-17	2020-05-04

Figure 49: Bayesian information criterion (BIC) and residual sum of squares (RSS) for trend structure changes

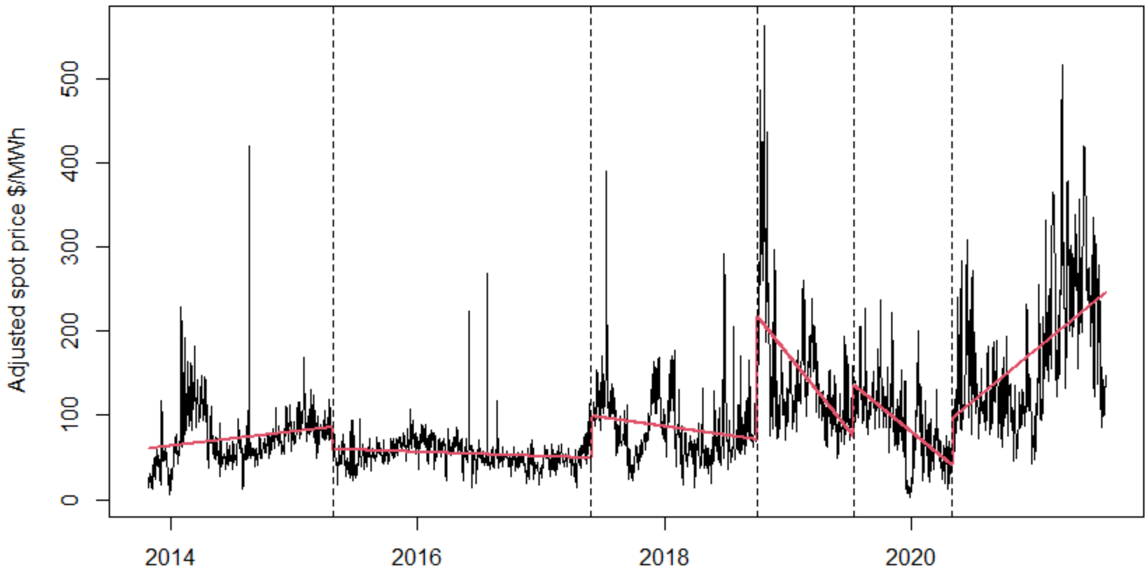


C.17 The Chow test results are shown below. The p-value is very small suggesting there are structural breaks.

```
supF test
data: test3
sup.F = 702.09, p-value < 2.2e-16
```

C.18 Figure 50 shows the adjusted daily spot prices with the estimated break dates. The red lines are the pricing trends fitted by Bai and Perron's method in each segment.

Figure 50: Adjusted daily spot prices with possible structure breaks (trend scenario)



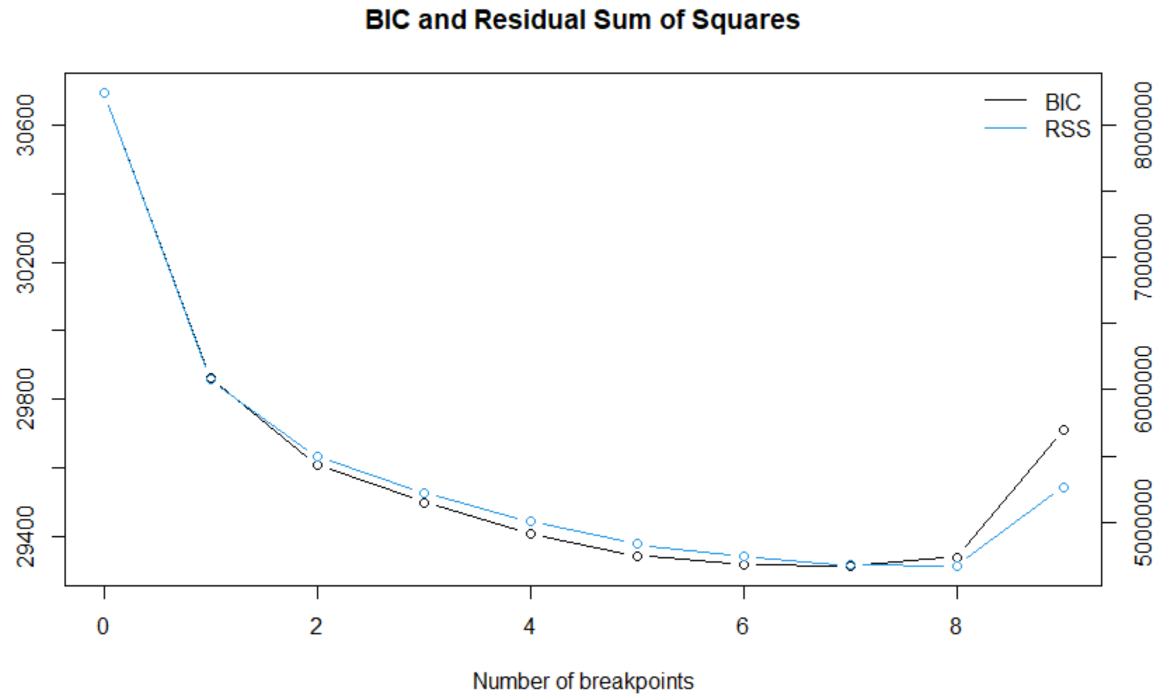
Polynomial fit structural changes

C.19 This method models the adjusted daily spot prices against time and time squared, then applies the same method as above.

C.20 Figure 51 shows that BIC reaches its minimum value when there are 7 breakpoints. The breakpoint dates are:

Dates	2014-08-03	2015-07-08	2017-02-11	2017-11-22	2018-11-07	2019-12-17	2020-10-21

Figure 51: Bayesian information criterion (BIC) and residual sum of squares (RSS) for polynomial fit structure changes

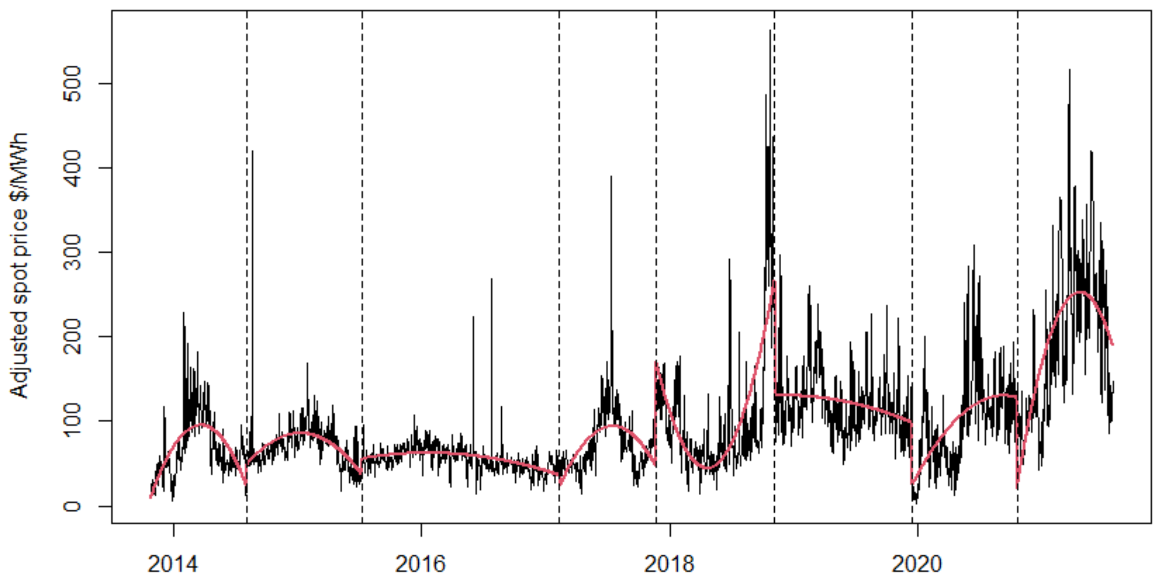


C.21 The Chow test results are shown below. The p-value is very small suggesting there are structural breaks.

```
supF test
data: test4
sup.F = 1005.2, p-value < 2.2e-16
```

C.22 Figure 52 shows the adjusted daily spot prices with the estimated break dates. The red lines are the pricing trends fitted by Bai and Perron's method in each segment.

Figure 52: Adjusted daily spot prices with possible structure breaks (polynomial scenario)

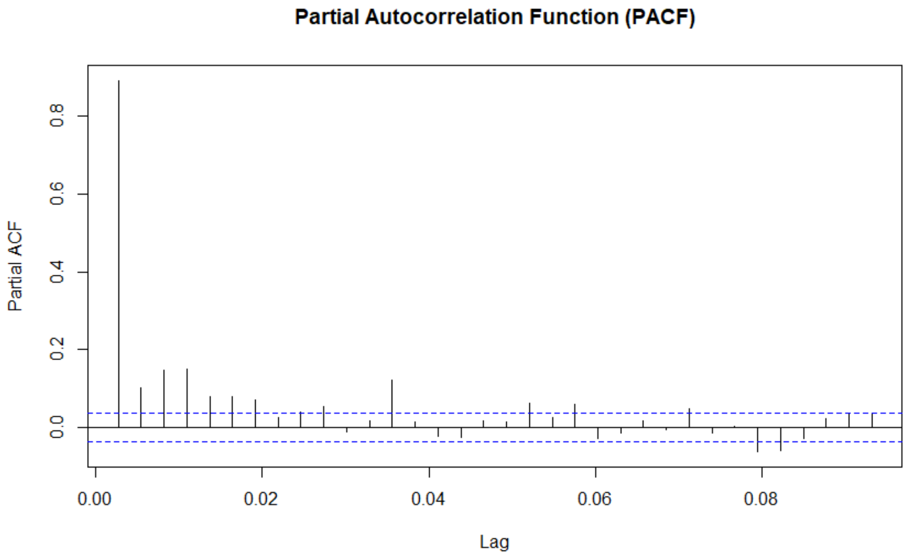


Autoregressive model structural changes

C.23 The adjusted daily spot prices are time series data. We can apply a time series AR statistical model to them. This process is very similar to the analysis in appendix A. An AR model is a regression of the variable against its own lagged values (past values).

C.24 Figure 53 shows the partial autocorrelation function (PACF) representing the adjusted daily spot prices. This provides a suggestion of how many lags need to be used in the model. The PACF plot shows spikes at lags 2 and 3, and the first cut-off at lag 6.

Figure 53: Partial autocorrelation function (PACF) of the adjusted daily spot prices



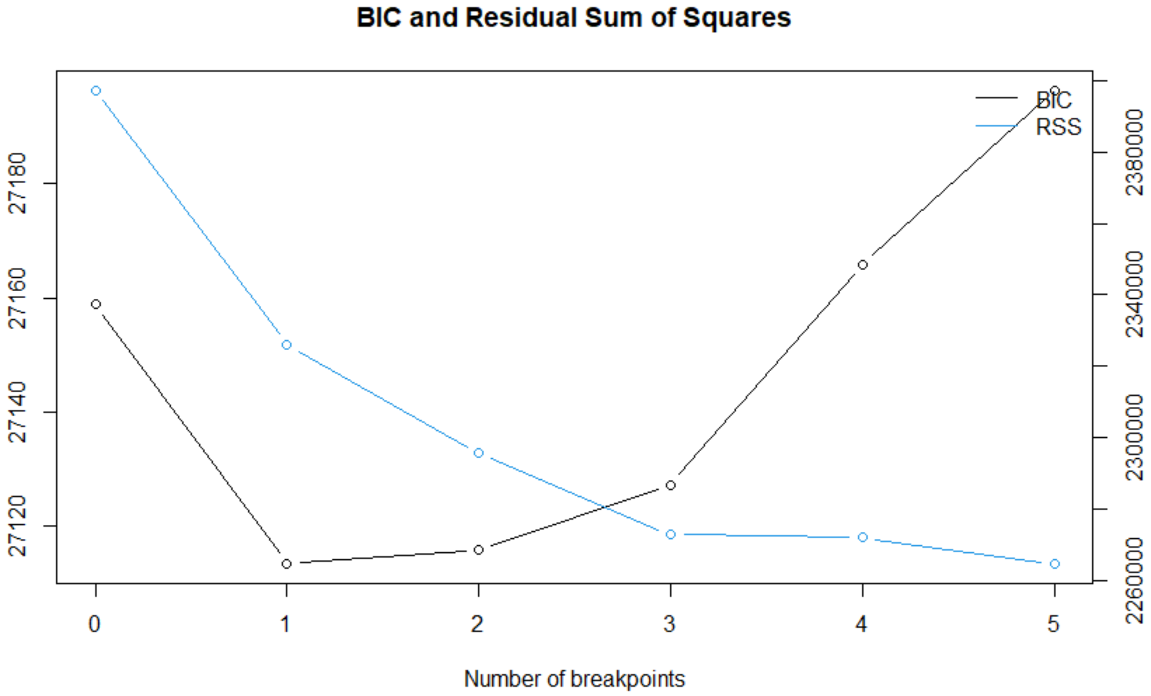
C.25 We compared Akaike information criterion (AIC) among models with different numbers of lags. The lowest AIC indicates the best fit is an autoregression model with five lags (AR(5)). This is consistent with the results from the dynamic regression model in appendix A.

Autoregressive model with five lags using adjusted daily spot prices

C.26 We apply five lags to the structural break test. Figure 54 shows that BIC reaches a minimum when there is 1 breakpoint. The breakpoint date is:

Date	2016-07-22

Figure 54: Bayesian information criterion (BIC) and residual sum of squares (RSS) for autoregressive model structure changes

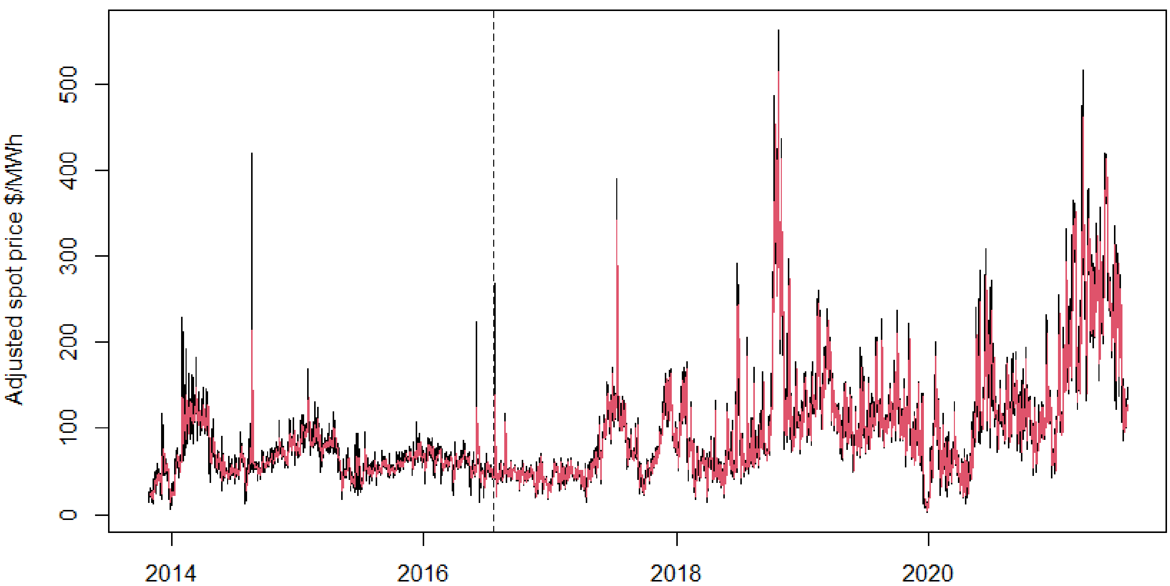


C.27 The Chow test results are shown below. The p-value is very small suggesting there are structural breaks.

```
supF test
data: fw_Fstats
sup.F = 101.83, p-value < 2.2e-16
```

C.28 Figure 55 shows the adjusted daily spot prices with the estimated break date. The red lines are the pricing trends fitted by Bai and Perron's method in each segment.

Figure 55: Adjusted daily spot prices with possible structural breaks (AR(5))

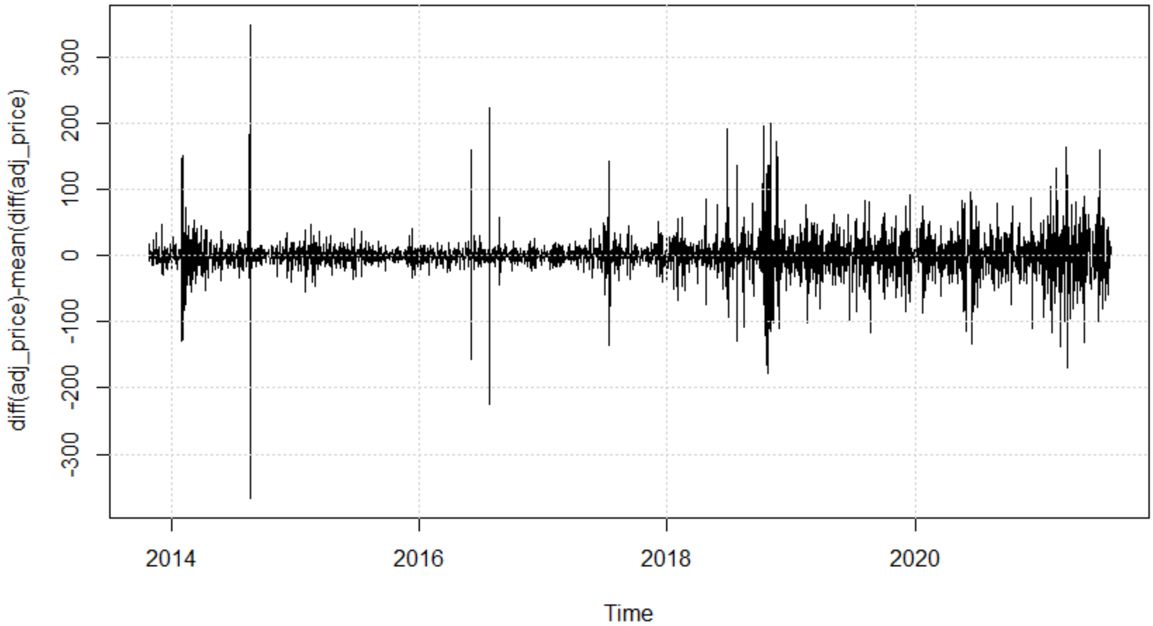


Autoregressive model with five lags using zero centred prices

C.29 Recall from Figure 46 that there is an overall increasing trend in the adjusted spot price. That is, the adjusted spot price time series is non-stationary. To make the series stationary, we can take the first difference of the time series and then subtract the mean of the difference to have the resulting price series centred around zero. This method is used to adjust the pricing trend. The first difference is calculated using:

$adjusted_{price_t} - adjusted_{price_{t-1}}$. The formula is: $difference(adjusted_{price_t} - mean(difference\left(adjusted_{price_t}\right)))$. Figure 56 shows the zero-centred prices.

Figure 56: Zero-centred prices

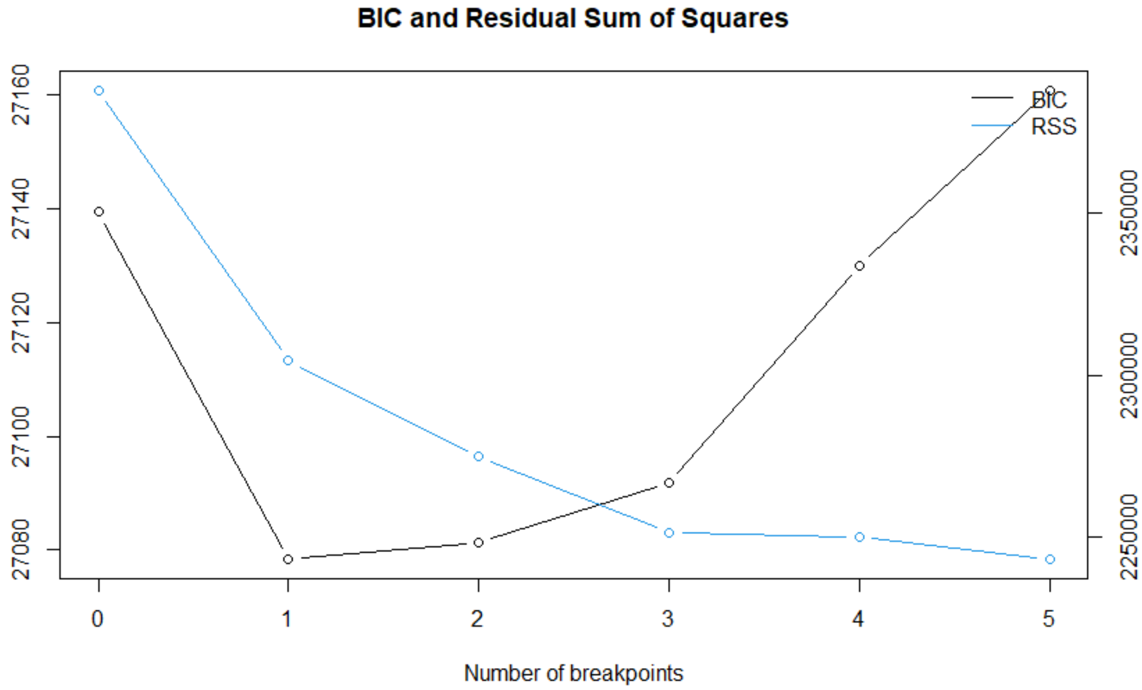


C.30 We run the ADF test again on the zero-centred prices. The result confirms the data is stationary.

C.31 The structural break test results are very similar to the results using the AR(5) model with adjusted daily spot prices. By comparing AIC, the minimum AIC suggests five lags. Using the AR(5) model to test for structural breaks, the BIC reaches a minimum value with 1 breakpoint (see Figure 57). The breakpoint date is:

Date	2016-07-21

Figure 57: Bayesian information criterion (BIC) and residual sum of squares (RSS) for autoregressive model structure changes



C.32 The Chow test results are shown below. The p-value is very small suggesting there are structural breaks.

```
supF test
data: fw_Fstats
sup.F = 113.76, p-value < 2.2e-16
```

Conclusions

C.33 We use the Chow test to confirm there are structural breaks in the adjusted daily spot prices. When reviewing the break dates under four scenarios, we observe some break dates that are overlapping or similar. These are:

2015 late-April	2017 late-May	2018 October–November
late-2019	2020 – October	

Appendix A: R outputs of Augmented Dicky-Fuller test for the adjusted daily spot prices

```
###############################################
# Augmented Dickey-Fuller Test Unit Root Test #
###############################################
Test regression none
Call:
lm(formula = z.diff ~ z.lag.1 - 1 + z.diff.lag)
Residuals:
 Min 1Q Median 3Q Max
-307.06 -7.84 2.03 12.37 354.32
Coefficients:
 Estimate Std. Error t value Pr(>|t|)
z.lag.1 -0.029963 0.004929 -6.079 1.37e-09 ***
```

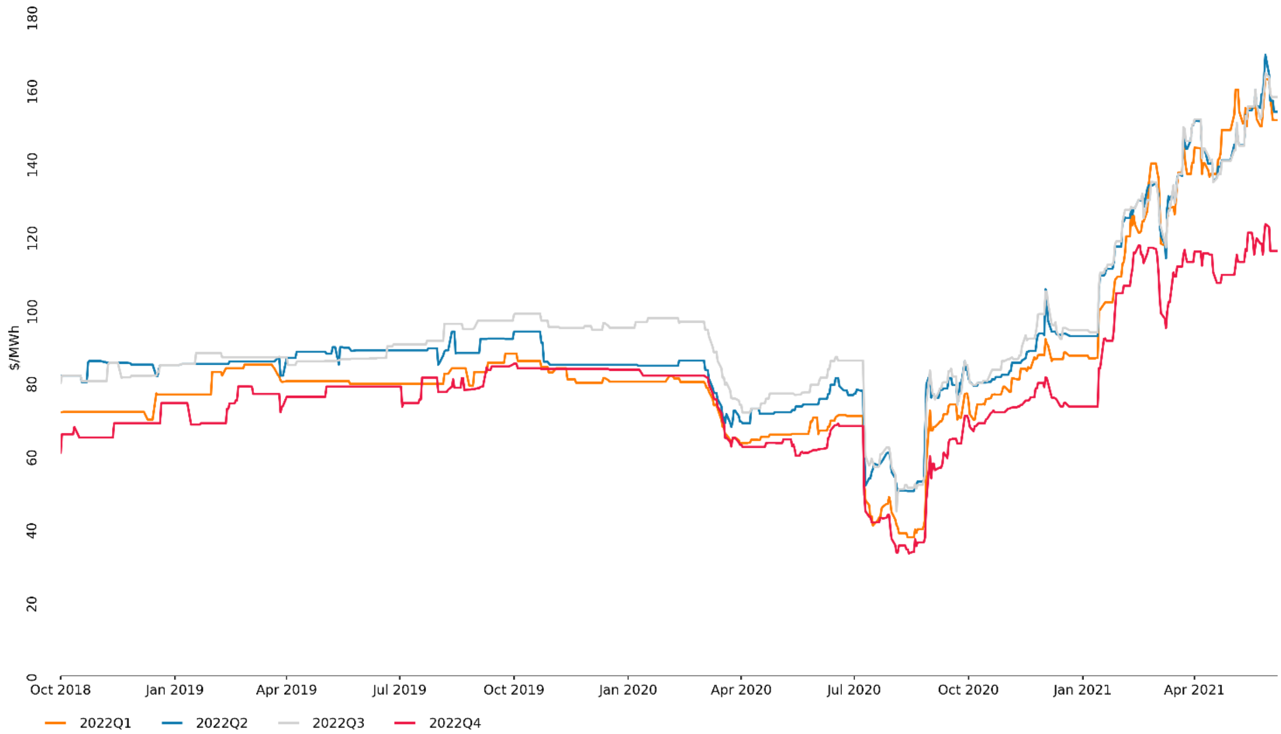
```
z.diff.lag -0.135564 0.018623 -7.279 4.32e-13 ***
---
Signif. codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
Residual standard error: 29.98 on 2832 degrees of freedom
Multiple R-squared: 0.03528,    Adjusted R-squared: 0.0346
F-statistic: 51.79 on 2 and 2832 DF, p-value: < 2.2e-16
Value of test-statistic is: -6.0791
Critical values for test statistics:
 1pct 5pct 10pct
tau1 -2.58 -1.95 -1.62
```

Appendix D Details of structural break analysis for forward prices

Introduction

5.194 Electricity forward prices suggest the expectation and indication of the future market. Figure 45 shows Benmore daily forward prices from 1st October 2018 to 7th June 2021 for Quarter 1, 2, 3 and 4 of 2022. The overall trend of four quarters forward prices is similar. The forward prices are relatively flat until April 2020, decreasing in the following months until August 2020, and then increasing from then onwards.

Figure 58: Benmore forward prices



5.195 We investigated and examined how the pricing trend changed in the quarterly forward price series (time series data). We applied structural break tests to understand this.

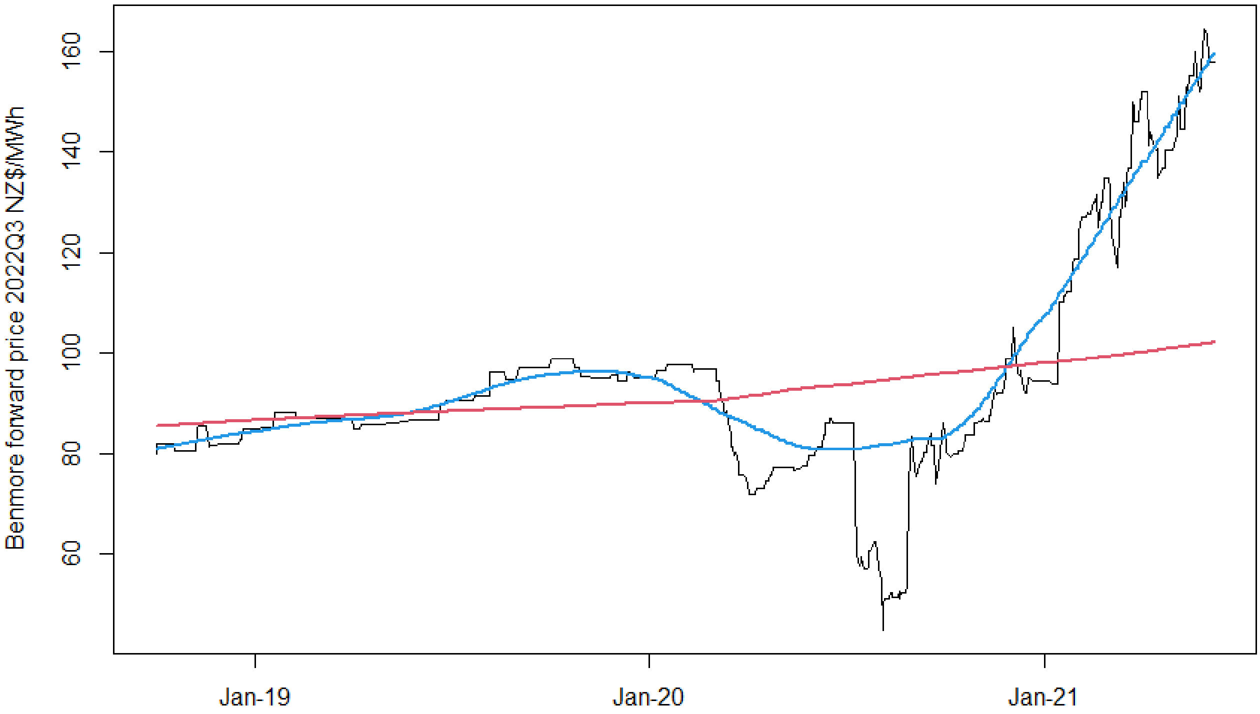
5.196 Our research question is: are there any structural breaks in the forward prices?

Data

5.197 We used Benmore daily forward prices for Quarter 3 of 2022 in the following analysis. Figure 46 shows the forward prices (black line) and two loess regressions (red and blue lines). An inter-annual trend (red) provides a view of the long-term trend of the forward prices, and the intra-annual trend (blue) provides seasonal levels of the daily time series.

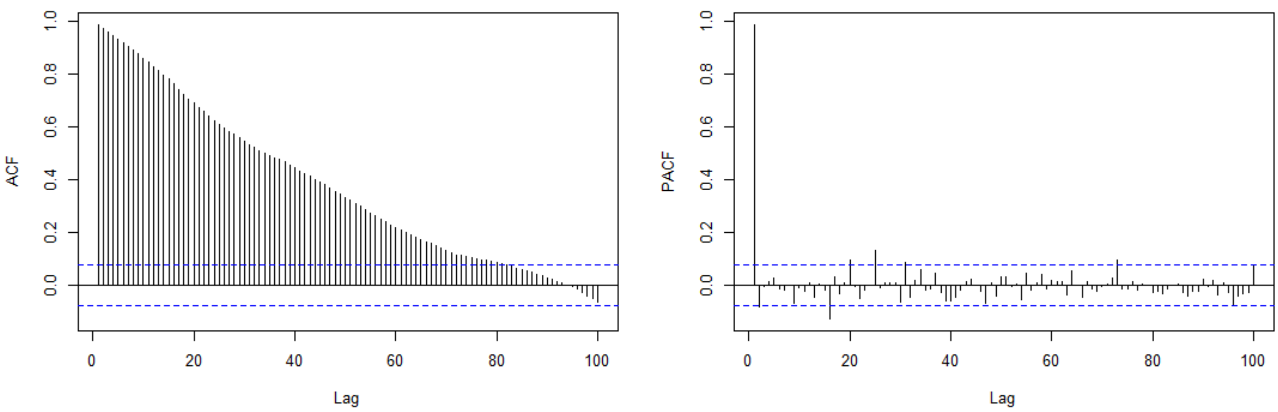
5.198 The inter-annual trend (red) shows an overall increasing trend. The intra-annual trend (blue) provides a quarterly view of the data. The forward prices are relatively low in late 2018 and beginning of 2019, then increasing until late 2019. In 2020 and 2021, the prices did not follow the same pattern. The pricing trend in 2020 is lower comparing to 2019 and 2021. This was due to Covid-19 and possible Tiwai Point smelter exit resulting in the market expectation of lower prices for the future. The pricing trend in 2021 keeps increasing. This is due to the uncertainty of gas supply and the dry year effect. The increasing pricing trend reflects the expectation of higher prices in the future.

Figure 59: Benmore forward prices Q3 2022 and pricing trend



5.199 Figure 60 shows the Autocorrelation Function (ACF) and Partial Autocorrelation Function (PACF) plots of the forward prices. The ACF shows the time series data slowly decaying. The PACF shows there are possible auto regressors at lag 17 and 23. Both plots indicate the data are not stationary. The Augmented Dicky-Fuller (ADF) test confirms the prices are non-stationary. This is due to the trends in the data. And these pricing trends are what we are aiming to examine.

Figure 60: ACF and PACF of forward prices



Method

5.200 In time series analysis, structural changes represent a time series abruptly changing at a point or multiple points in time. Chow (1960)[115] applied an F-statistic for regime changes at a priori known dates. Quandt (1960)[116] modified Chow's framework to consider the F-statistics with all possible break dates. Bai and Perron (1998, 2003)[117] extend the framework by allowing for multiple unknown breakpoints.

5.201 The basic idea of Bai and Perron's method is through a classical linear regression model employing dynamic programming, to find a number of breakpoints *m* that minimize the residual sum of square (RSS). The number of breakpoints *m* is unknown. So it is necessary to compute the optimal breakpoints for m=0,1, 2,… breaks and choose the model with the lowest Bayesian Information Criterion (BIC).

5.202 We use Bai and Perron's method to detect the points of possible structural changes, and then use the Chow test to confirm the changes.

Results

5.203 We use four scenarios: level, trend, polynomial fit and Auto-regressive model (AR) to estimate structural breaks.

Level structural changes

5.204 This method models the forward prices using a linear model, then applies Bai and Perron's method to find breakpoints.

5.205 Figure 47 shows that the BIC reaches a minimum when the breakpoints are 6. The dates and forward prices at the breakpoints are:

Date	2019-01-08	2019-08-05	2020-03-12	2020-07-08	2020-10-16	2021-01-26
Forward prices ($/MWh)	85.2	91.5	88.55	86.1	80.5	113.5

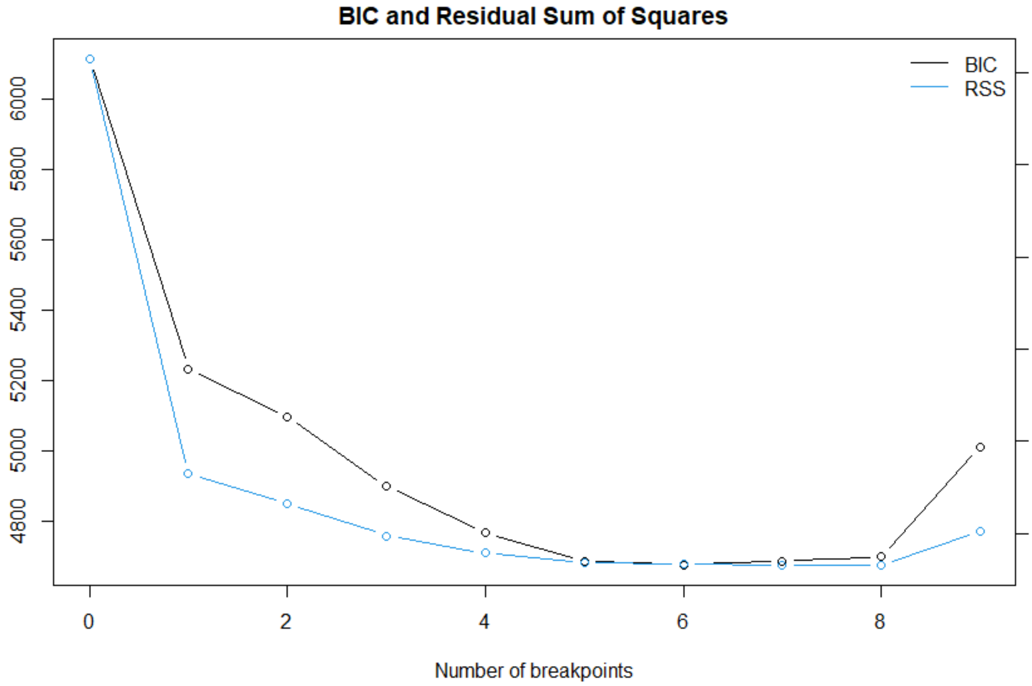
[115] Chow, G.C. (1960). Tests of Equality Between Sets of Coefficients in Two Linear Regressions. Econometrica, (28), 591-605.

[116] Quandt, R.E. (1960), Tests of the Hypothesis that a Linear Regression Obeys Two Separate Regimes, Journal of the American Statistical Association, (55), 324-330.

[117] Bai, J. and P.Perron (1998), Estimating and Testing Linear Models with Multiple Structural Changes, Econometrica, (66), 47-78.

Bai, J. and P.Perron (2003), Computation and Analysis of Multiple Change Models, Journal of Applied Econometrics, (18), 1-22.

Figure 61: BIC and RSS for level structure changes

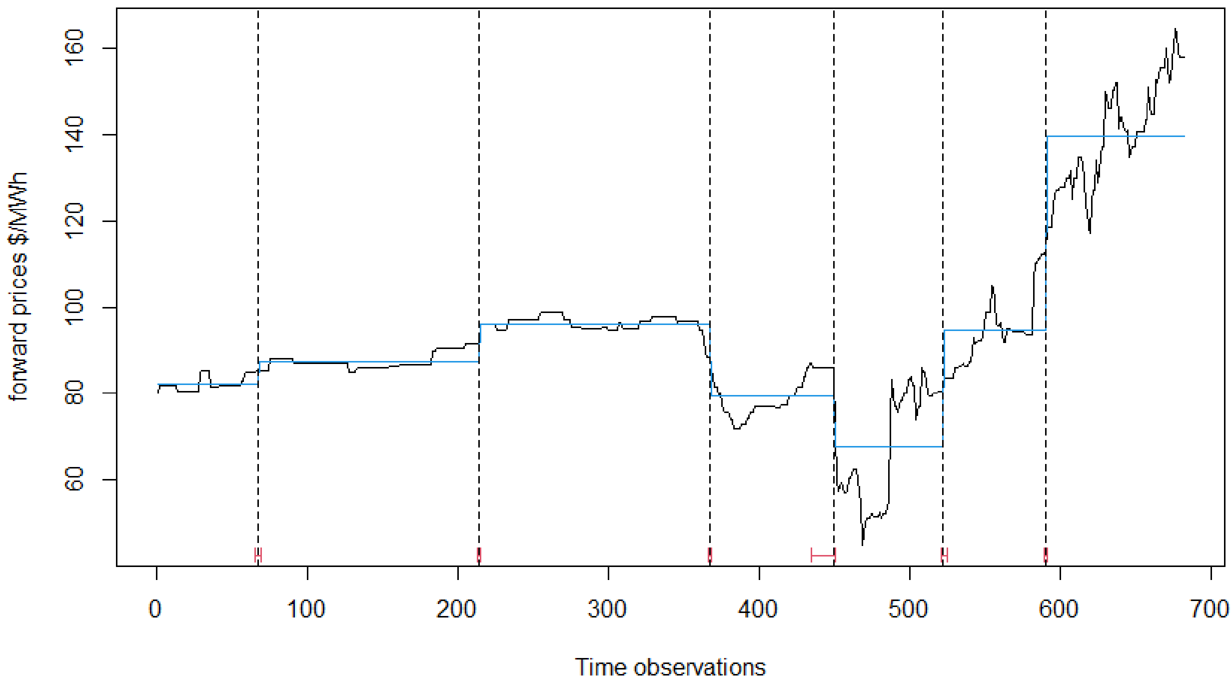


5.206 Then we run the Chow test, the results of which are shown below. The p-value is very small. The null hypothesis of the Chow test is that there are no structural breaks in the data. So we have very strong evidence against the null hypothesis.

```
        supF test
data:  test2
sup.F = 1763.4, p-value < 2.2e-16
```

5.207 Figure 48 shows the forward prices with the dashed vertical lines at the estimated break dates. The red lines at the bottom are 95% confidence intervals at each estimated structural break. The blue lines are the trend fitted by Bai and Perron's method in each segment.

Figure 62: Forward prices with possible structure breaks (level scenario)



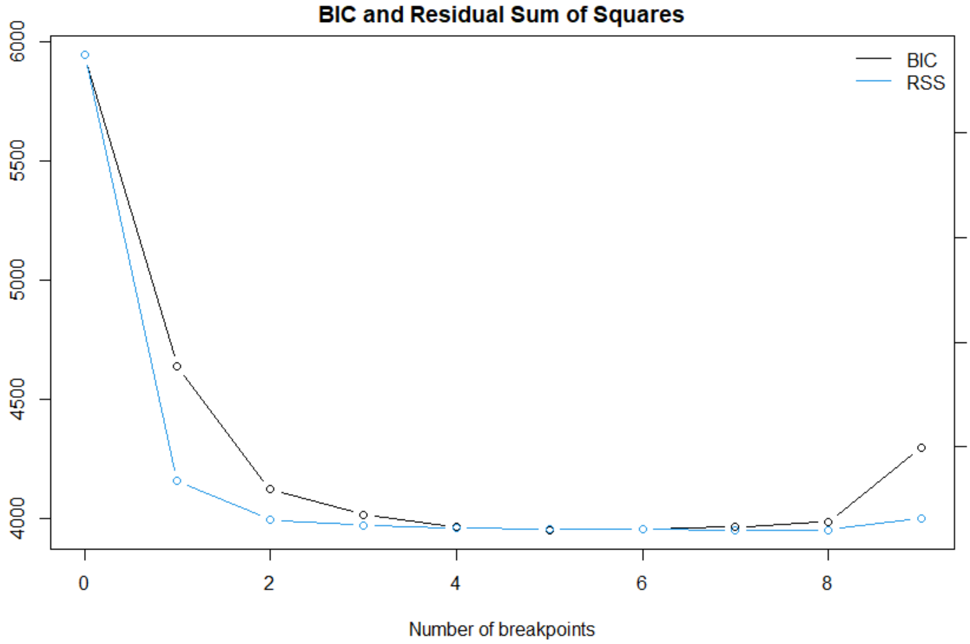
Trend structural changes

5.208 This method uses forward prices against time in a linear model, then applies the same method to estimate breakpoints as before.

5.209 Figure 49 shows that the BIC reaches a minimum when the breakpoints are 5. The dates and forward prices at the breakpoints are:

Date	2019-08-05	2020-03-13	2020-07-09	2020-10-13	2021-01-21
Forward prices ($/MWh)	91.5	86	88.55	80.6	112.25

Figure 63: BIC and RSS for trend structure changes

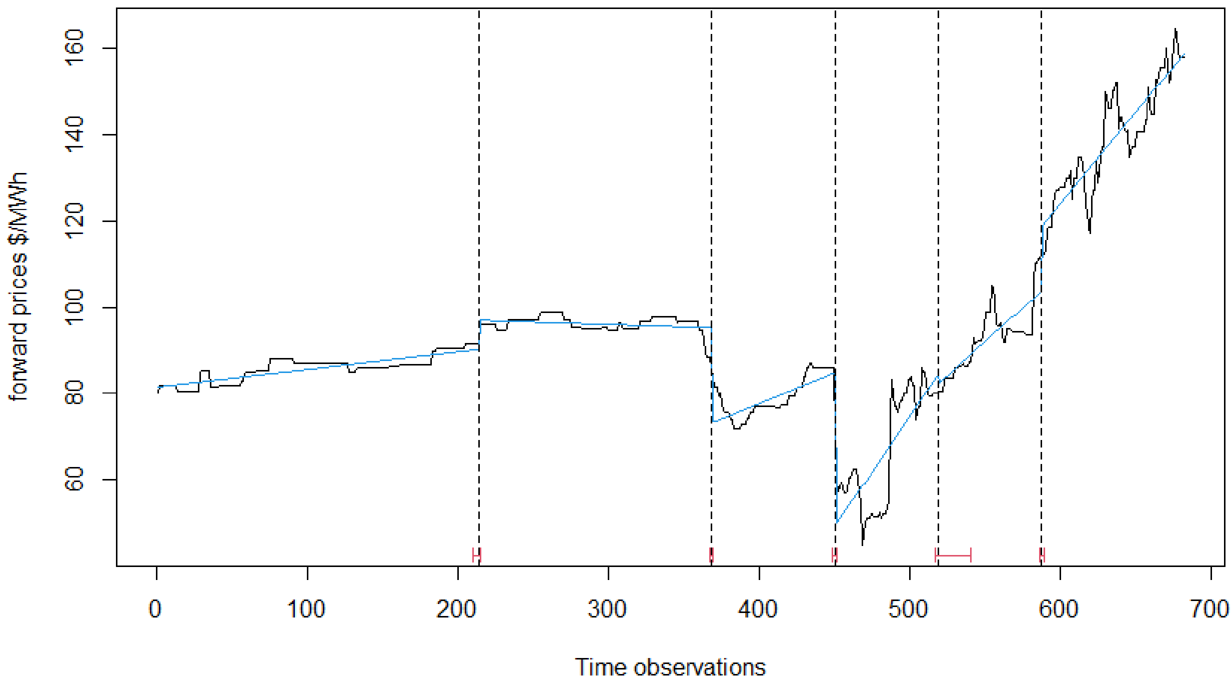


5.210 The Chow test results are shown below. The p-value is very small suggesting there are structural breaks.

```
        supF test
data:   test3
sup.F = 4081.6, p-value < 2.2e-16
```

5.211 Figure 50 shows the forward prices with the estimated break dates and 95% confidence intervals (red). The blue lines are the pricing trend fitted by Bai and Perron's method in each segment.

Figure 64: Forward prices with possible structure breaks (trend scenario)



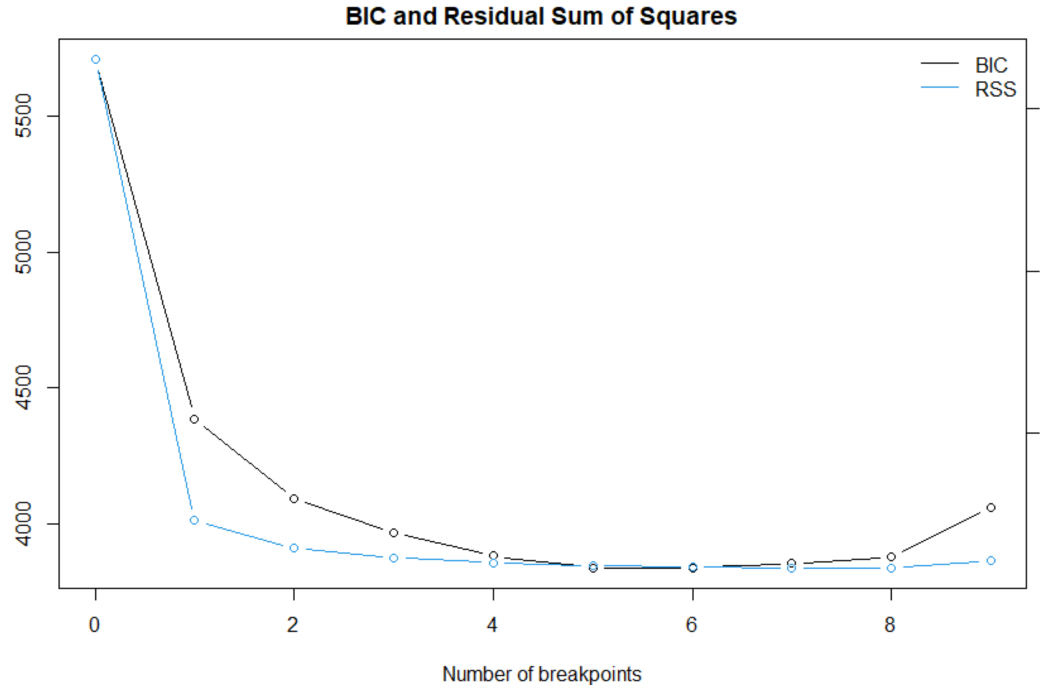
Polynomial fit structural changes

5.212 This method uses forward prices against time and time squared in a regression model, then applies the same method as before.

5.213 Figure 51 shows that the BIC reaches a minimum when the breakpoints are 6. The dates and forward prices at the breakpoints are:

Date	2019-01-17	2019-09-09	2020-03-06	2020-06-17	2020-09-21	2021-01-13
Forward prices ($/MWh)	85.2	97	92.7	87.1	81.75	93.8

Figure 65: BIC and RSS for polynomial fit structure changes

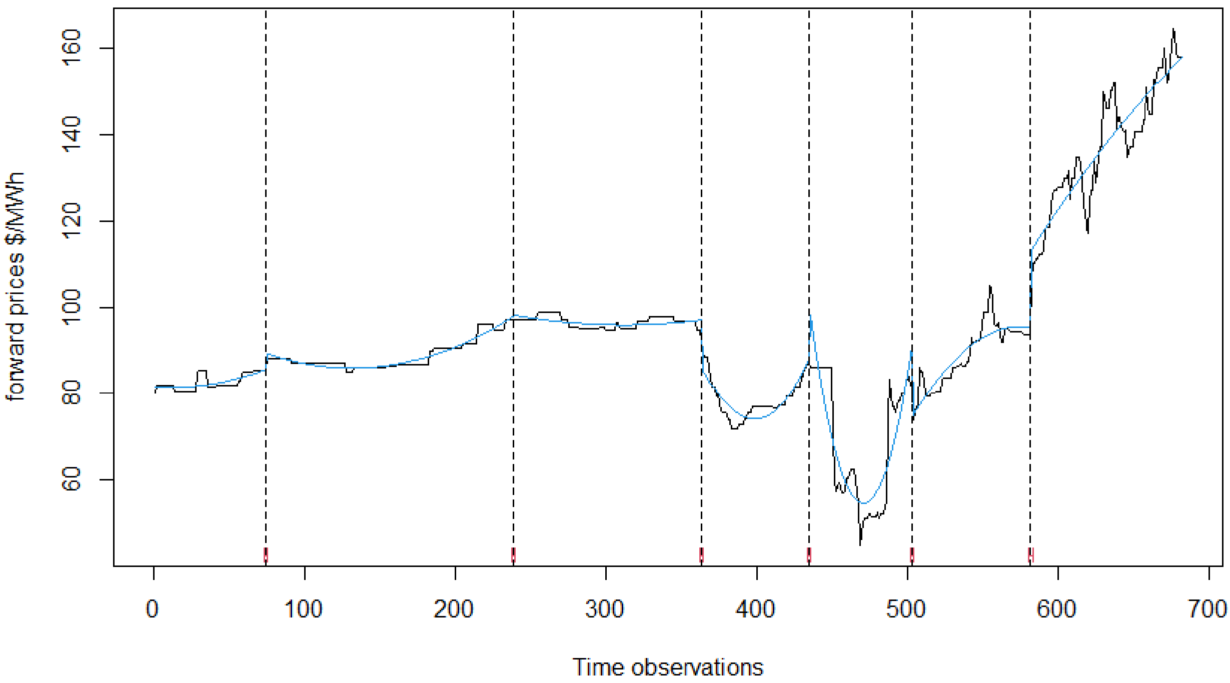


5.214 The Chow test results are shown below. The p-value is very small suggesting there are structural breaks.

```
        supF test
data:  test4
sup.F = 4177.8, p-value < 2.2e-16
```

5.215 Figure 52 shows the forward prices with the estimated break dates and 95% confidence intervals (red). The blue lines are the pricing trend fitted by Bai and Perron's method in each segment.

Figure 66: Forward prices with possible structure breaks (polynomial scenario)



Auto-regressive (AR) model structural changes

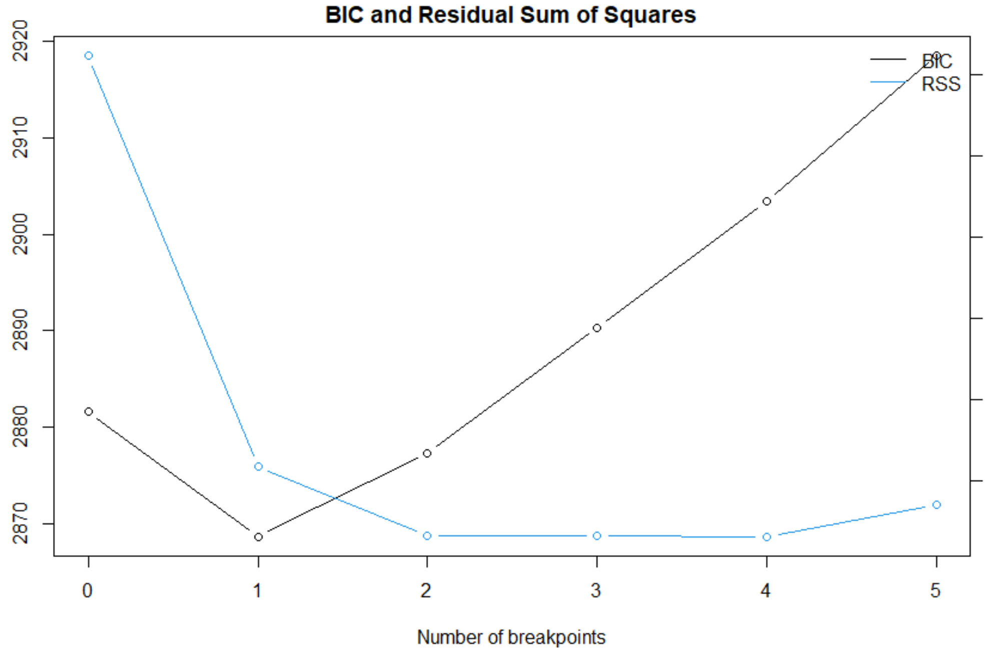
5.216 When we examined the future prices in the Data section above, the ADF test suggests the data is non-stationary. If we want to apply an AR model, we need to take the first difference of the data to make it stationary. The difference is done by $forward\_price_t - forward\_price_{t-1}$, then subtracting its mean to get zero-centered data. We run the ADF test again on the differenced prices. The result confirms the data are stationary.

5.217 Then, we evaluated a linear regression model with two time lags (lag1 and lag2) as regressors to fit the prices. However, lag2 was not statistically significant. We therefore dropped lag2 and used only one time lag to inspect if any structural changes occurred in the AR model.

5.218 Figure 54 shows that the BIC reaches a minimum when the breakpoint is 1. The date and forward price at the breakpoints are:

Date	2020-08-27
Forward prices ($/MWh)	55

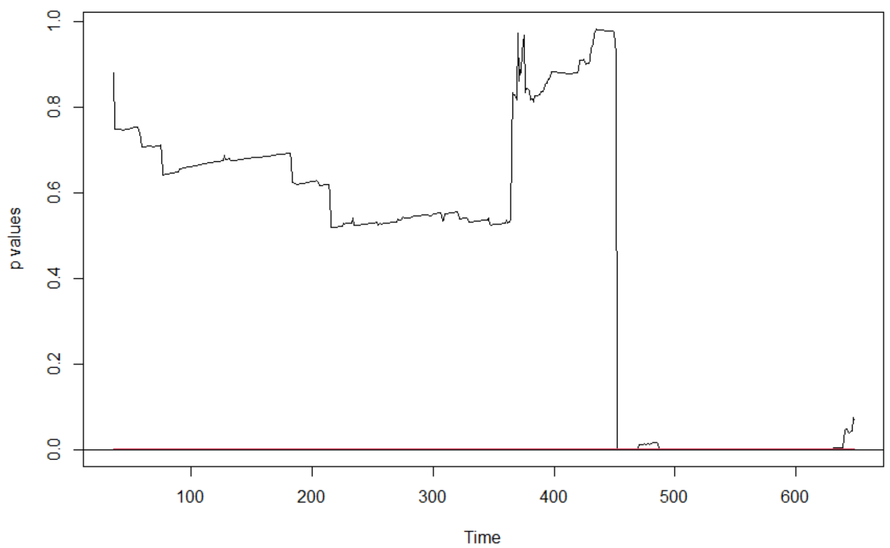
Figure 67: BIC and RSS for AR model structure changes



5.219 The Chow test results are shown below. The p-value is very small suggesting there are structural breaks. Figure 55 shows the Chow test p-values against time observations. When the observation is 488 (or date 2020-08-27), the p-value reaches 0 (indicating statistical significance) suggesting the date is a structural break date.

```
    supF test
data:  fw_Fstats
sup.F = 26.402, p-value = 1.392e-05
```

Figure 68: P-values from Chow test against time for AR model structural breaks



Conclusions

5.220 We used the Chow test to confirm there are structural breaks in forward prices. When we reviewed the break dates in our four scenarios, we observed some break dates that are overlapping or similar:

2019 mid-January	2019-08-05	2020-03-12 or 13
2020 early March	2020-07-08 or 09	2020 mid-October
2020 late-January		

Appendix E Details of the regime switching model

Introduction

E.1 We applied a Hidden Markov model (HMM) for the spot prices to determine how the spot prices switch between regimes (different level of prices). In 2014, Thomson (2014)[118] developed and fitted a non-homogeneous HMM for Waitaki weekly average storage. The model used in this report is based on this methodology.

E.2 Our research question asks how the spot prices switch (transit) between regimes and examines the performance of the spot prices in each regime.

Data

E.3 We use daily average spot prices from 1 January 2018 to 31 December 2020. Using three full years of data allows us to capture complete seasonal patterns. We adjusted spot prices for inflation using the electricity component of the New Zealand producers price index (PPI). Then we make trend adjustments for the PPI adjusted prices. The method is based on Thomson's 2013 paper.[119]

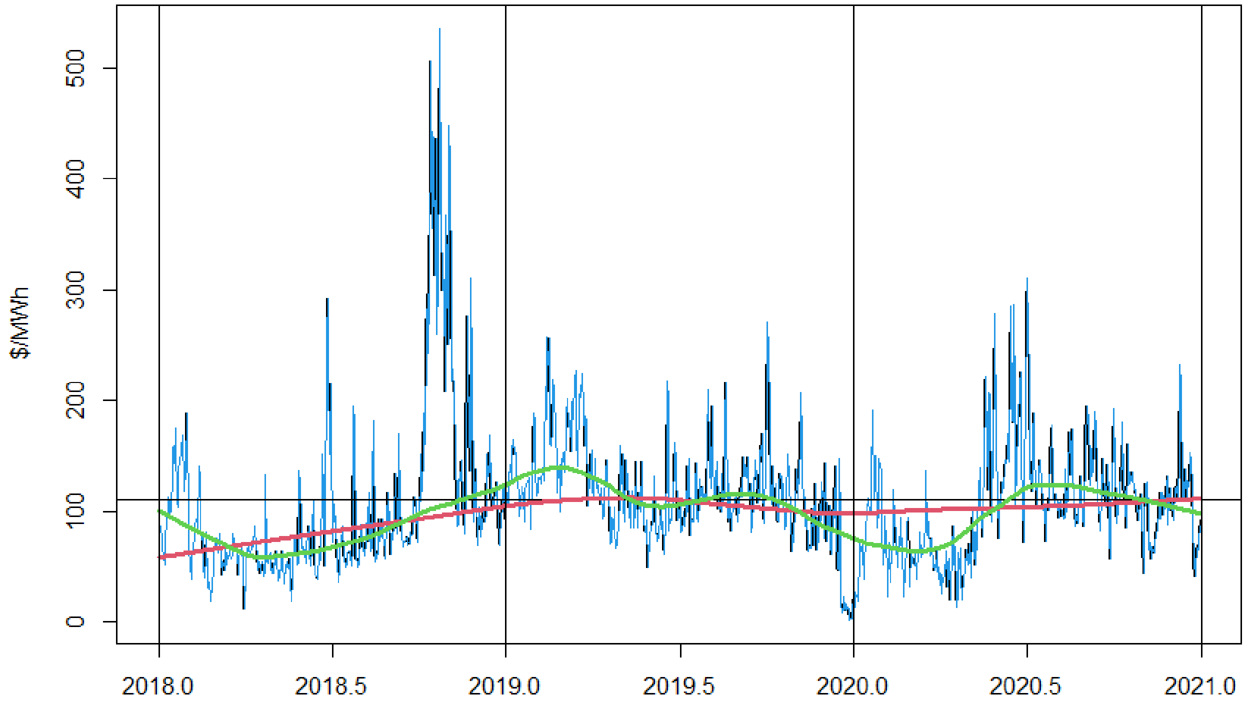
E.4 Figure 69 shows nominal daily average spot prices (black line) and PPI and trend adjusted spot prices (adjusted spot prices, blue line). The black horizontal line shows the mean of the adjusted prices is $150/MWh.

E.5 Red and green lines in Figure 69 are two loess regressions. They provide views of inter-annual trend (red) and intra-annual trend in quarterly view (green) respectively. Inter-annual trend shows long-term levels and intra-annual shows seasonal levels of the daily time series of adjusted prices. We can see the overall trend is upwards over 3 years. The trend also shows seasonal patterns, relatively low early in the year and higher in the following months.

[118] P J Thomson, *A seasonal regime switching model for South Island hydro storage (2014)*. Report commissioned by the New Zealand Electricity Authority. (Wellington: Electricity Authority, 2014).

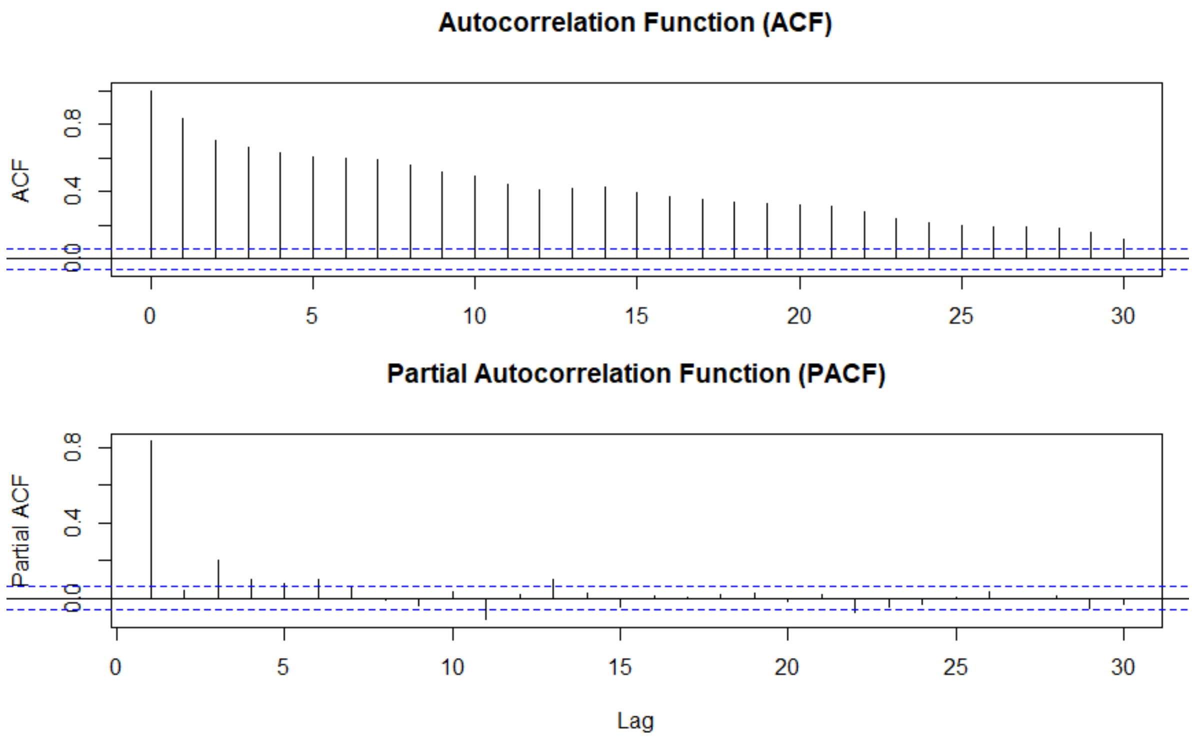
[119] P J Thomson, *An exploratory analysis of the relationship between electricity spot price and hydro storage in New Zealand (2013)*. Report commissioned by the New Zealand Electricity Authority. (Wellington: Electricity Authority, 2013).

Figure 69: Pricing trends for adjusted spot prices



E.6 Figure 70 shows the autocorrelation function (ACF) and partial autocorrelation function (PACF) for the adjusted spot prices. PACF implies two lags suggesting an autoregressive AR(2) process if we were to model the data using the autoregressive-moving-average model. The Augmented Dicky-Fuller test suggests the adjusted spot prices are stationary.

Figure 70: Autocorrelation function and partial autocorrelation function of adjusted spot prices



E.7 Our objective is to transform the prices so they are normally distributed. Because if we make the data more Gaussian (normally distributed), we can apply conventional statistical and time series techniques. Log transformation is not propriate in this case.

E.8 Figure 71 shows four plots of adjusted spot prices: a histogram, a probability density function, a boxplot and a quantile-quantile (Q-Q) plot. These suggest that the adjusted prices are right skewed. This implies the data needs to be transformed. A simple transformation is a log transform of the adjusted spot prices. However, the diagnostic plots in Figure 72 show this results in left-skewed data.

Figure 71: Diagnostic plots for adjusted spot prices

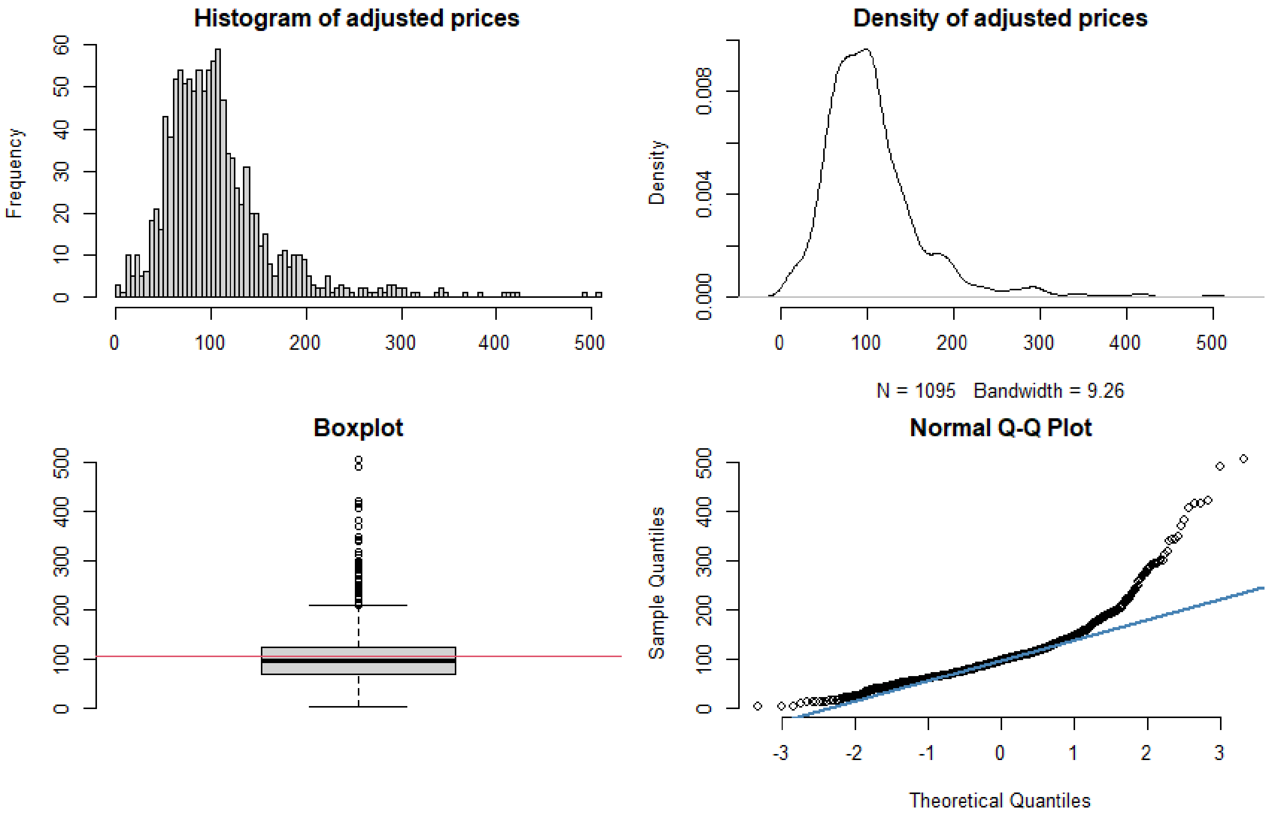
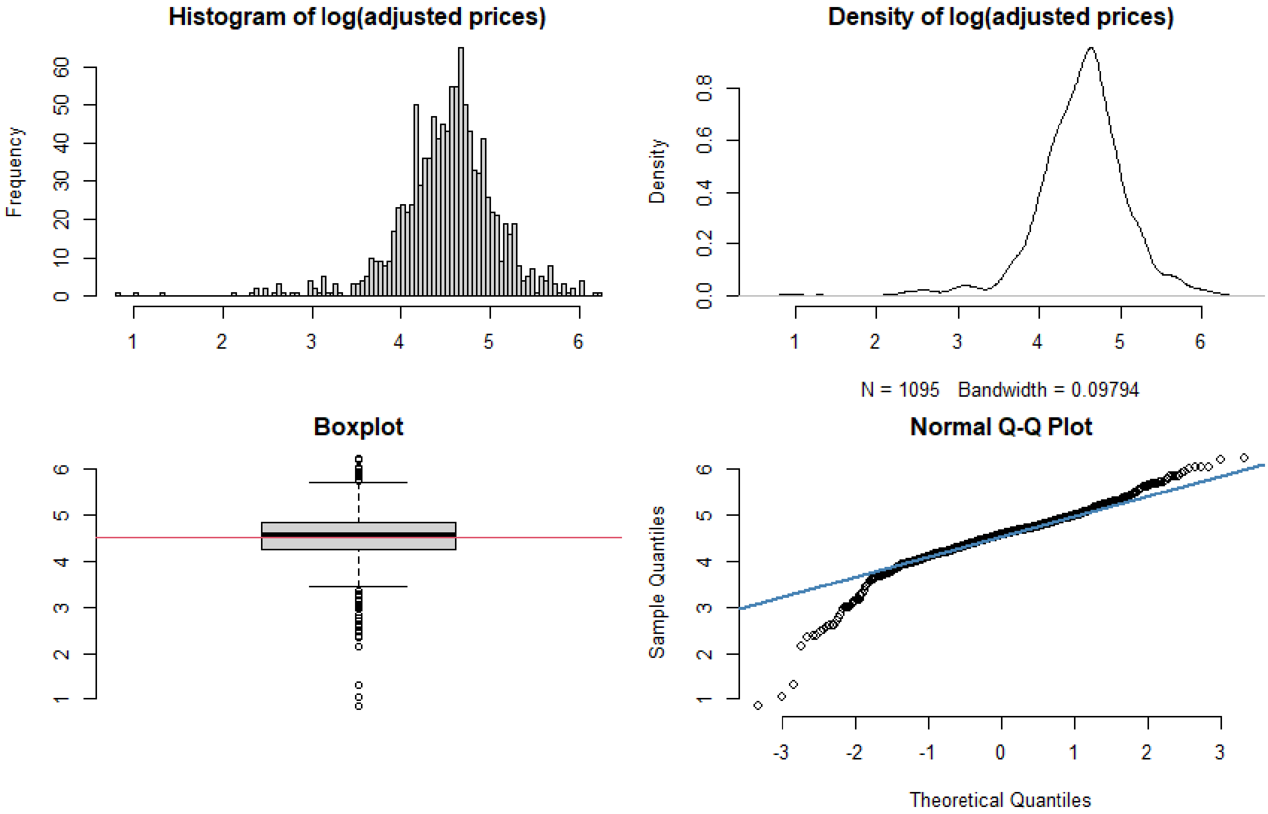


Figure 72: Diagnostic plot for log adjusted spot prices



E.9 Thomson, in his 2014 paper, uses a Johnson transformation. When we use this, our data is normally distributed. When comparing the density plot of adjusted spot prices with the density plot of Johnson transformed prices in Figure 73, the Johnson transformed data is more normally distributed and close to a bell shape. Figure **74** shows the Johnson transformed prices are bounded by –3 and 3. The Augmented Dicky-Fuller test suggests the transformed prices are stationary. So we use the transformed data in the following analysis.

Figure 73: Density plots

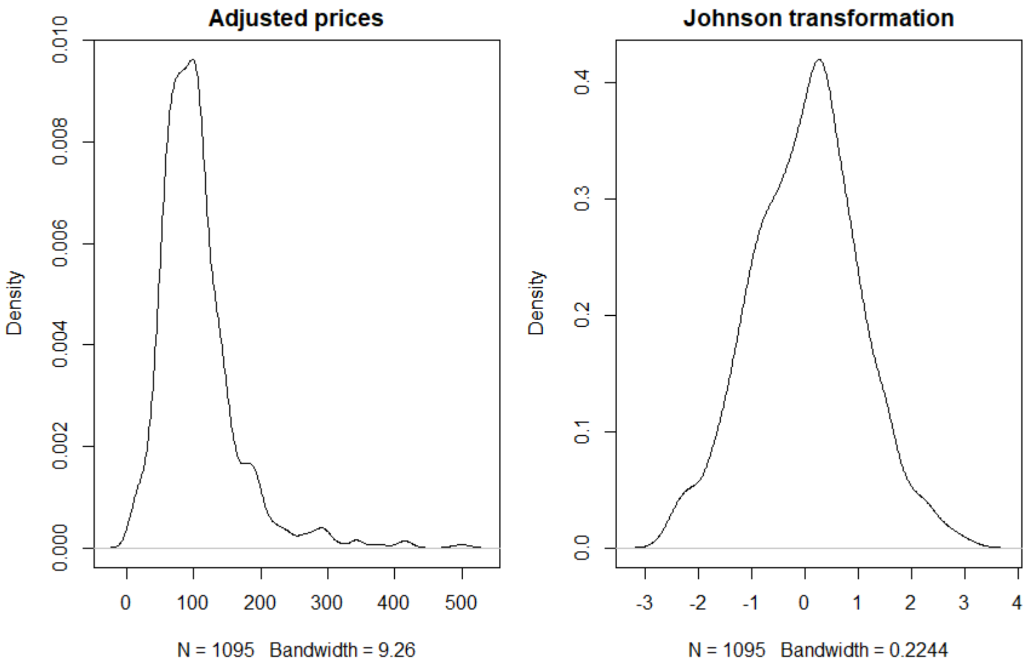
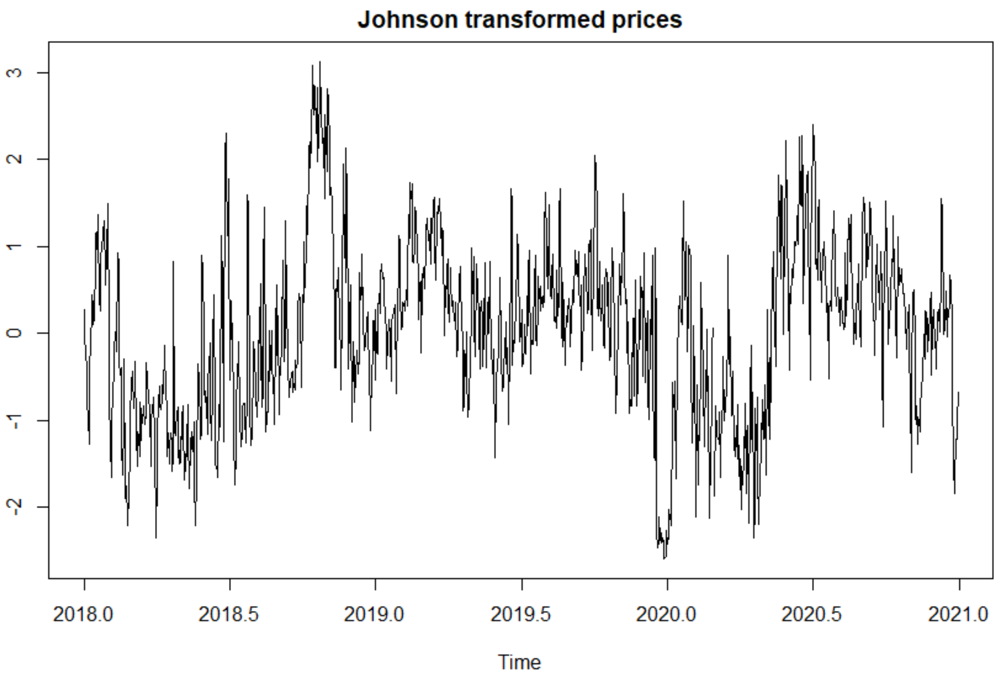


Figure 74: Johnson transformed prices



Model

E.10 We applied an HMM to the transformed prices to see how the prices transit between regimes and how they perform in different regimes. HMMs are based on the Markov Chain model. A Markov Chain model consists of a set of transitions, which are determined by probability distribution, that satisfies the Markov property. The model is a sequence of observable events transiting from one event to another. For example, if a sequence of time series data (such as daily average spot prices) is high in winter then low in the following spring, we say it transits from one state to another.

E.11 The Markov property means the probability that the chain is in one state at time *t* only depends on the state at the previous time *t-1*. Each probability in a transition probability matrix represents a probability of moving from one state to another.

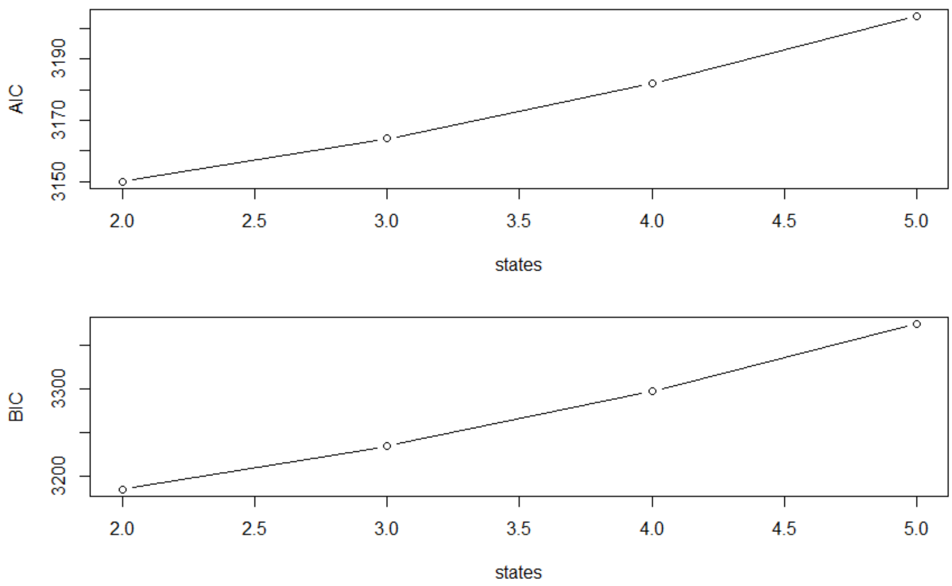
E.12 The HMMs allow the probability distribution of each event to depend on the unobserved (hidden) state of a Markov Chain. HMMs are flexible general-purpose models for univariate and multivariate time series data. The models can accommodate both overdispersion and serial dependence.

E.13 The HMMs are fitted by maximum likelihood using an expectation maximisation algorithm, and the best fit model is selected by Akaike information criterion (AIC) and Bayesian information criterion (BIC).

Results

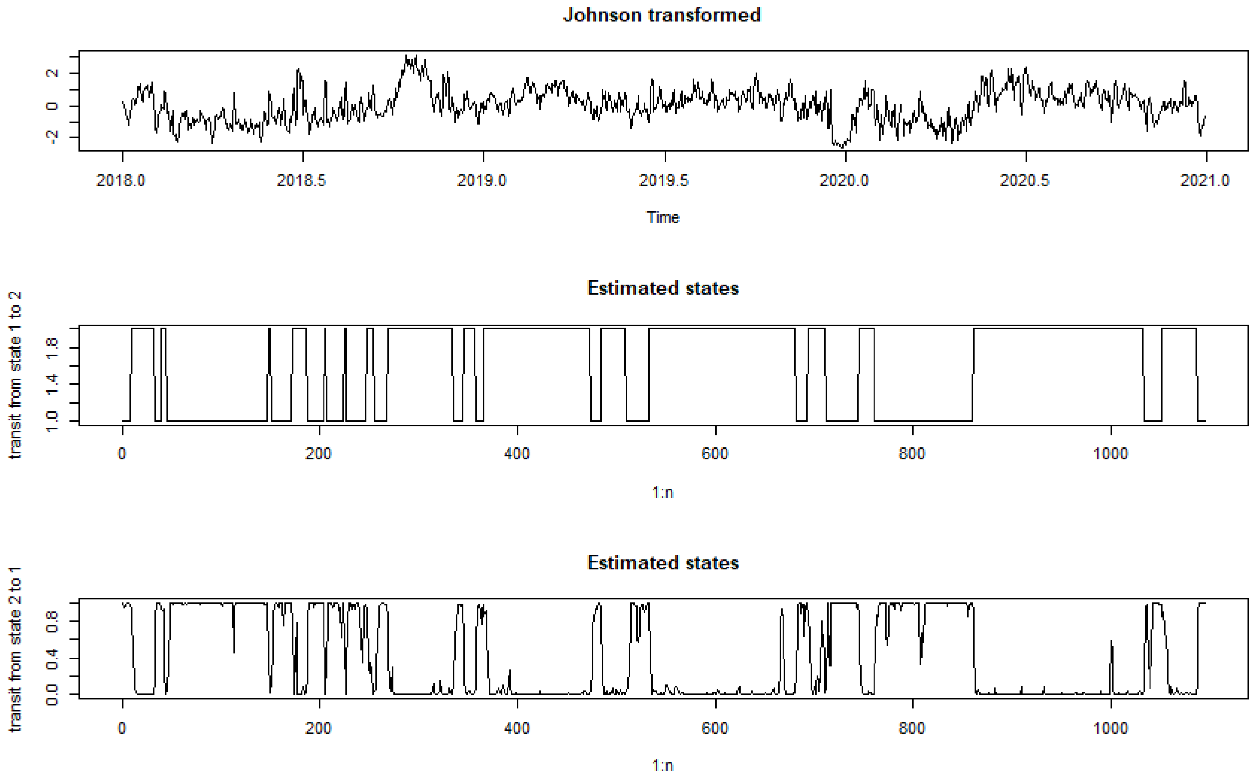
E.14 Figure 75 shows AICs and BICs if we fit the transformed data using HMMs by 2, 3, 4 and 5 states. The two state model is where both the AIC and BIC are at their minimum. So we use two states for our transformed data.

Figure 75: Akaike information criterion (AIC) and Bayesian information criterion (BIC)



E.15 Figure 76 shows the transit from state 1 to state 2 or vice versa. For example, in the second graph, at the beginning of 2018, the transformed prices transit from state 1 to state 2 and stay for some days then transit back to state 1.

Figure 76: Transformed prices transit between two states



E.16 Table 27 shows the transition probability matrix. Interpretation of the matrix in an HMM only focuses on off-diagonal probability. In this case, the probability transit from state 1 to state 2 is 0.044, and the probability transit from state 2 to state 1 is 0.029.

Table 27: Transition probability matrix

Transmission probability matrix

		To	
		state 1	state 2
From	state 1	0.956	0.044
	state 2	0.029	0.971

E.17 Rather than looking at the transition probability matrix, we are more interested in how the spot prices perform in each state. We mapped the states back to the adjusted spot prices. Table 28 shows about 39.6 percent of adjusted spot prices in state 1 and 60.4 percent of them in state 2. The mean adjusted price in state 1 is $64.28/MWh, indicating that state 1 is a low price state, and state 2's mean adjusted price is $140.94/MWh, indicating that state 2 is a high price state. Most of the adjusted spot prices are in a high price state, indicating spot prices are relatively high based on 3-year data.

Table 28: Percentage and mean of adjusted spot prices in two states

	Percentage of adjusted spot prices in each state (%)	Mean adjusted spot prices (/MWh)
State 1	39.60	$64.28
State 2	60.40	$140.94

Conclusions

E.18 We use a two-state HMM, one state with high spot prices and another with low spot prices. About 60 percent of the adjusted spot prices are in a high price state from 1 January 2018 to 31 December 2020.

Appendix F Water value data from generators

Meridian

F.1 Meridian provided us with minimum sell values, which we refer to as Meridian's water values throughout this document, although modelled water values are only one input to these minimum sell values. Meridian advised us that these minimum sell values are informed by a range of different factors including:

(a) consent conditions

(b) regulatory requirements

(c) safe operation of plant

(d) modelled generation volumes and prices

(e) recent spot prices

(f) the offer stack in market schedules

(g) forward market prices

(h) recent contract sales prices.

F.2 [redacted]

F.3 [redacted]

F.4 The minimum sell values are therefore a simplified view of the weekly trading guidance and do not convey the full range of matters taken into account in trading decisions.

F.5 Meridian also provided the Authority with modelled generation guidance, because it advised us that Meridian's offers are structured to be consistent with the generation of prudent volumes from a security of supply perspective.

F.6 Meridian provided us with data that is approximately weekly. We resampled the data to daily data and back filled the values.

Genesis

F.7 Genesis provided us with data that had more than one entry for each trading date; we used the most recent effective date for each trading date. The data provided is daily, although some days were missing. We forward filled these dates. Genesis provided us with price-quantity pairs (ie, different tranches, similar to how offers are structured). From this, we calculated a quantity-weighted water value.

F.8 Genesis did not send us data prior to 1 October 2016 because its record keeping before this date was not in a centralised database and would take time to collate.

F.9 In regards to the data Genesis sent us, it told us the following.

(a) The process of deriving water values takes inputs such as ASX prices, hydro storage levels, cost of carry, and assumptions around longer term uncertainty, overlaid against an approximated future generation programme (based on P50 inflows). It looks at where finite future generation would come from if additional generation volume was deployed 'now' and what the associated water value is. This could, for example, be based off a future peak, off peak or baseload value.

Such values can be used to consider if and when future generation volume could or should be used ‘now’. The usefulness, or otherwise, of water values changes, however, at extremes of lake levels.

(b) Water values can be used as one input into Genesis’s offer decision-making. The use of water values has varied over time, ranging between being prescriptive in nature to a theoretical value for information purposes.

(c) Genesis does not employ water values for the Tongariro Scheme because, for all intents and purposes, it is a run-of-river scheme.

Mercury

F.10 Mercury did not provide any supporting documentation for the data. We queried the water values for a particular period in 2020, because the values were zero while surrounding values were not. Mercury told us that the water value of zero reflects Mercury moving to volume trading for 5 days to manage the level in Lake Taupo, which it was concerned was getting too low.

F.11 Mercury provided us with data that is approximately monthly (although often with more than one value in a month, but also often a few months between some values). We resampled the data to daily data and forward filled the values.

Appendix G Price duration curves for six months, and supply curves for different dates

Price duration curves for the first six months of each year

G.1 Figure 77 and Figure 78 show price duration curves as in Figure 2 and Figure 3, but using only the first 6 months of each year.

Figure 77: Price duration curves compared with previous five years (inflation adjusted)

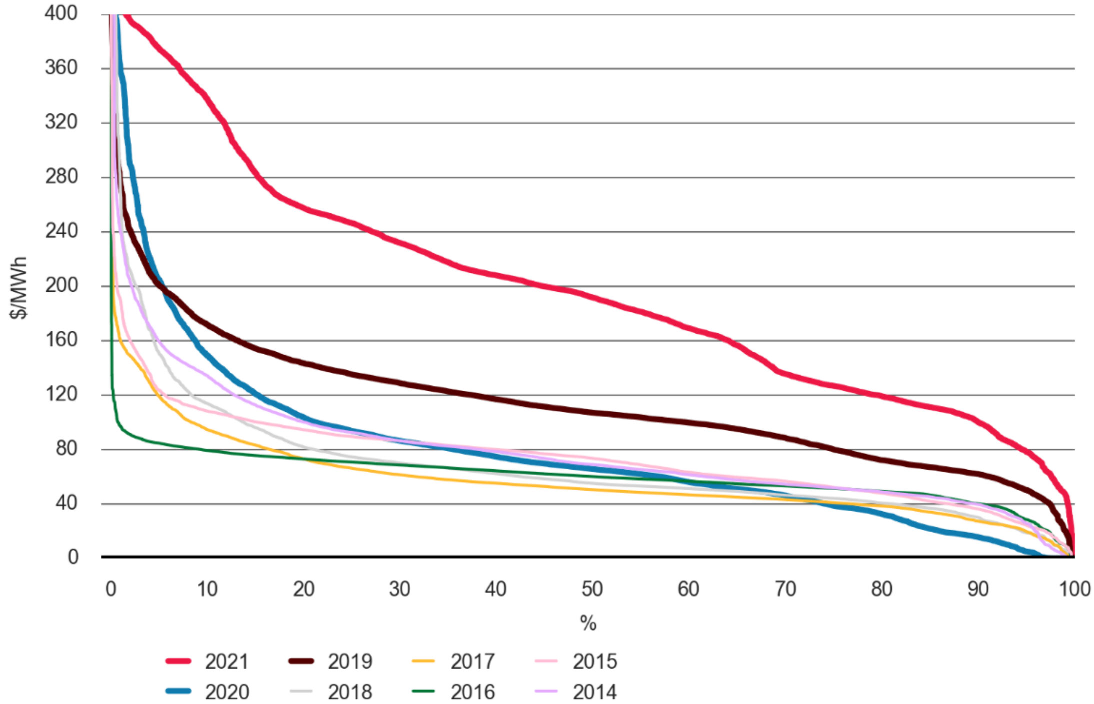
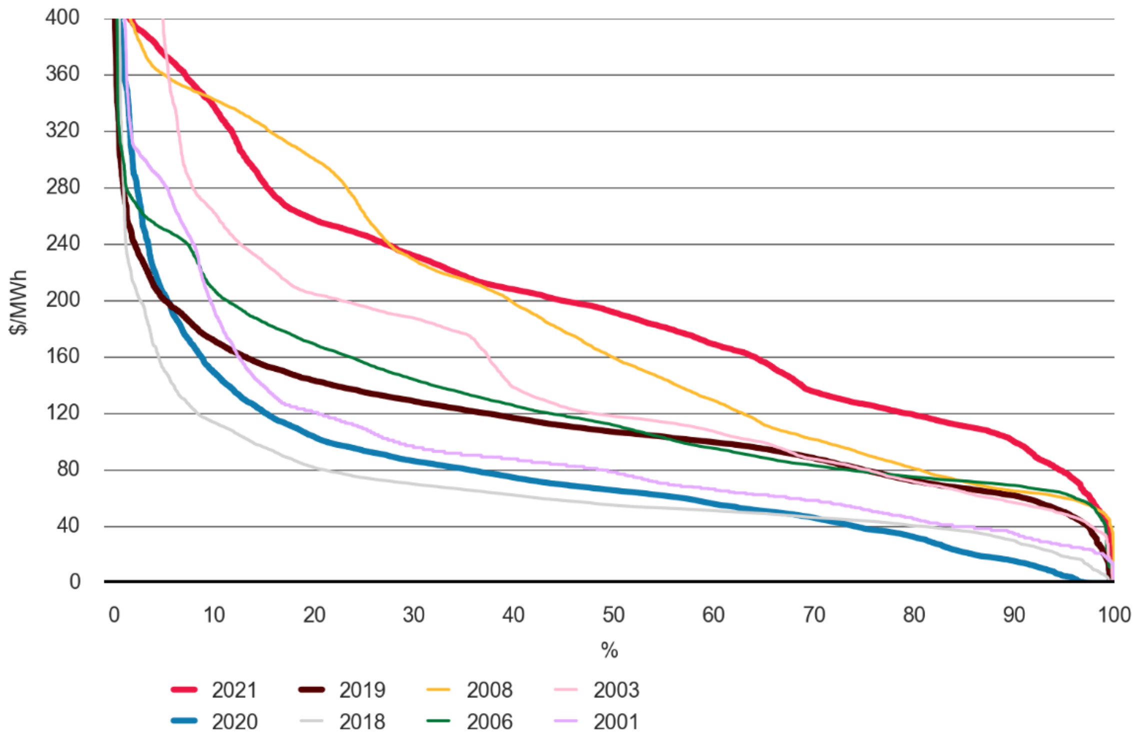


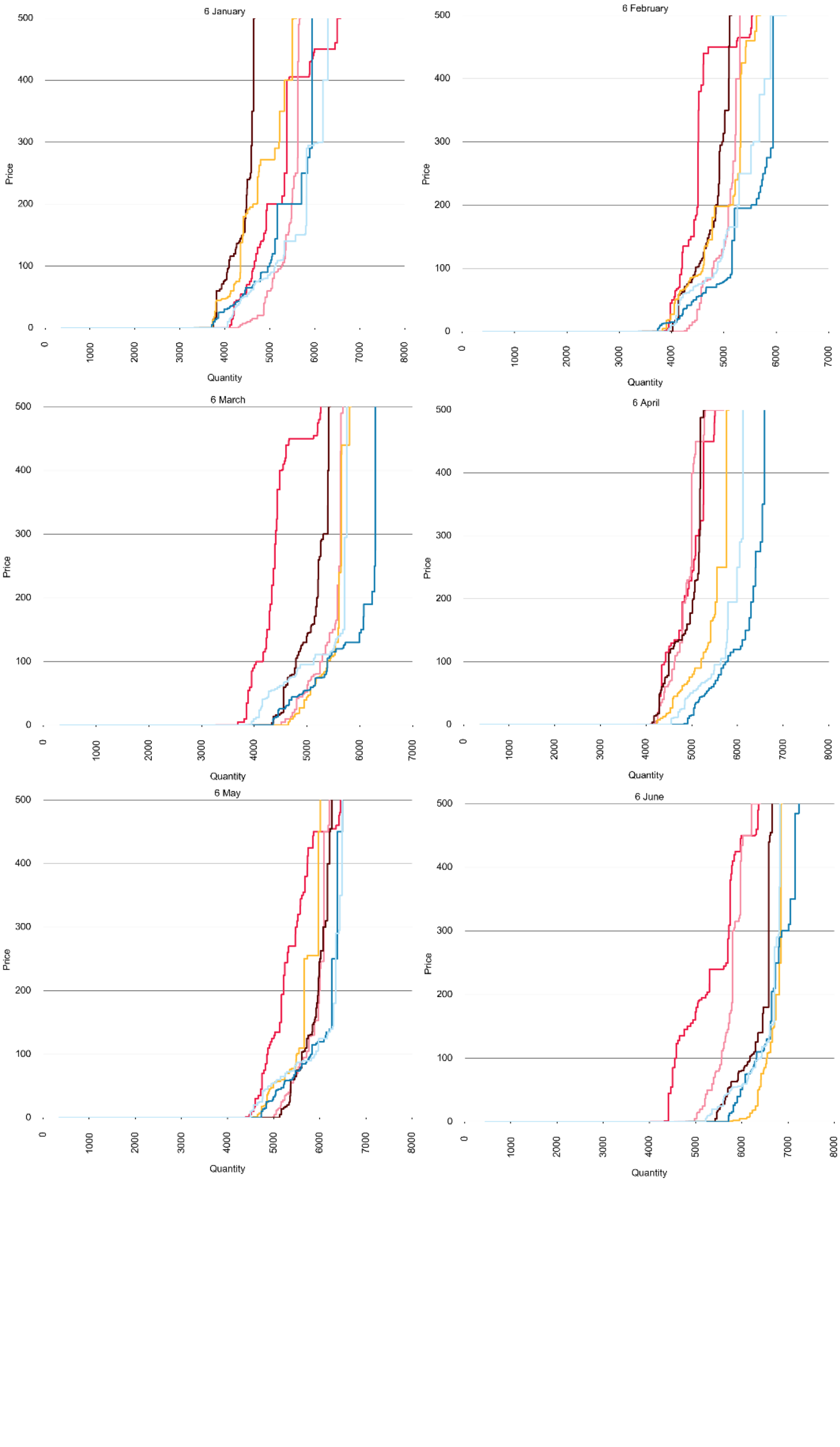
Figure 78: Price duration curves compared with previous years with the highest yearly averages (inflation adjusted)

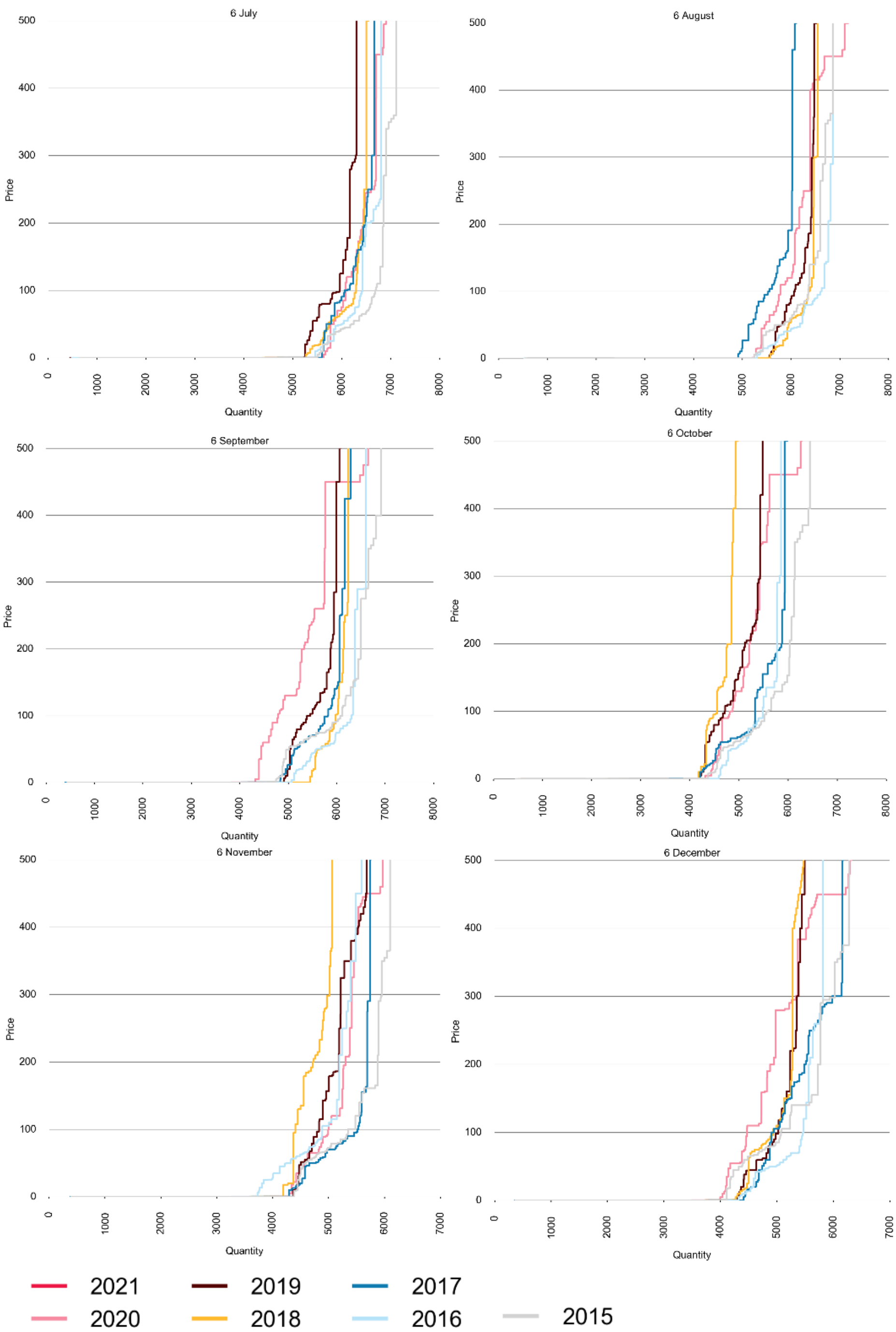


Supply curves for different dates

G.2 Figure 79 shows the offer curves for the same day and trading period for each month across several years. All these offer curves are for trading period 36, which is during the evening peak. Wind generation has been excluded from the supply curve in all years. The amount offered at very low prices is likely a factor of demand, expected wind generation, outages and lake levels. Between 2015 and 2021, the trend has been towards an increase in the steepness of the supply curve's slope, especially between $1/MWh and $200/MWh. This is particularly noticeable from March to June, with the offer curves for July and early August (when demand is usually highest) steep in all years. The curve was particularly steep in October and November 2018, when the Pohokura outage occurred.

Figure 79: Supply curves for different dates




6 July
6 August
6 September
6 October
6 November
6 December
Price
Quantity
0
100
200
300
400
500
1000
2000
3000
4000
5000
6000
7000
8000
2021
2020
2019
2018
2017
2016
2015

Appendix H Consultation questions

5.221 On 27 October 2021 the Authority released an Information Paper and an Issues Paper as part of the Wholesale Market Review. The Authority is seeking feedback on both papers. The Issues paper focuses on just one key observation highlighted by the review.

5.222 In addition, The Authority has published an extended set of consultation questions for the Information Paper. After receiving initial feedback, the Authority considers that providing more specific consultation questions will help stakeholders prepare more targeted responses.

5.223 The Authority expects to develop additional workstreams following submissions on both papers. Those workstreams need to support the transition to a low carbon future and maintain security of supply, while enhancing competitive tension in the wholesale market to support efficient outcomes.

5.224 As noted on page 2 of the Information Paper, the Authority is seeking feedback on:

- the structure, conduct and performance approach to assessing competition in the market;
- the indicators we have used under this approach;
- whether we have left out any important indicators and;
- any other issues you think we should consider.

5.225 In addition, the Authority is seeking specific feedback on the following questions related to the Information Paper:

(a) What are you views on the structure, conduct, performance approach used to assess competition in the wholesale market?

(b) Is there any other methodology or framework that the Authority should be using instead of structure, conduct, performance? (If so, please describe.)

(c) Are the indicators used in this information paper appropriate to inform the Authority's assessment of wholesale market competition?

(d) Do you agree with the Authority's interpretation of the indicators presented in the information paper. (If not, please explain.)

(e) What other indicators should the Authority use to inform its assessment of wholesale competition?

(f) Are there any additional competition issues that the Authority should consider?

(g) Are there any interventions that the Authority should consider, to improve competition in the wholesale market?

(h) Are there any future workstreams that the Authority should develop to transition red and orange indicators outlined in Table 2 of the Information Paper to green?

(i) How should any proposed interventions be monitored and evaluated?

Glossary of abbreviations and terms

ACCC	Australian Competition and Consumer Commission
ACF	autocorrelation function
ADF	Augmented Dicky-Fuller
Ahuroa	gas storage facility at Ahuroa
AIC	Akaike Information Criterion
ARIMA	autoregressive integrated moving average model
AR	autoregressive model
ARMA	autoregressive moving average model
ASX	Australian Securities Exchange
Authority	Electricity Authority
Benmore	(as in prices at Benmore)
BIC	Bayesian Information Criterion
CFD	Contract for Differences
CO2	Carbon dioxide
Code	Electricity Industry Participation Code 2010
Contact	Contact Energy Limited (CTCT)
DOASA	model of system-wide scheduling
E3P	Unit 5 at Huntly
EBITDAF	earnings before interest, tax, depreciation, amortisation and fair value adjustments
Economic withholding	offering some quantity at higher prices with the intention that it not be dispatched, thus reducing supply and increasing the spot price
EPOC	Electric Power Optimisation Centre
ERCs	Electricity Risk Curves: these show how stored hydro energy is tracking relative to a calculated risk of energy shortage
EMI	Electricity Market Information, a website maintained by the Authority
FTR	Financial Transmission Rights
Genesis	Genesis Energy Limited (GENE)
Gross pivotal	If there are any trading periods where the generation from a trader is needed to meet demand, then this trader is gross pivotal in those trading periods
GJ	gigajoule
GSAs	gas supply agreements
GW	gigawatt
GWh	gigawatt hour
GWAP	generation weighted average price
HHI	Herfindahl-Hirschman Index for assessing seller concentration
HLY	Huntly
HMM	Hidden Markov model
HSOTC	High Standard of Trading Conduct Provisions
HVDC	high voltage direct current connection between the South Island and North Island (or Cook Strait Cable)
Lerner Index	index of marginal price above cost
MA	moving average, also called rolling average. A series of averages of different subsets of the full data is created. For example, a series of 30-day moving averages is calculated using the first 30 days of the original data, then the next 30 days (excluding the first day) of the original data

	and so on. Where the original data is in trading periods, we take the first average as the average over all trading periods in the first 30 days, then the second average in the series will exclude the first trading period of the first day. All moving averages are centred, that is, the value presented on a chart for a specific date represents the average of the subset of data both before and after that date.
Mercury	Mercury NZ Limited (MRPL)
Meridian	Meridian Energy Limited (MERI)
MW	megawatt
MWh	megawatt hour
NI	North Island
Non-stationarity	non-stationary data is time series data that has a mean, variance or covariance that changes over time
NZAS	New Zealand Aluminium Smelters Limited
OCGT	open cycle gas turbine
Otahuhu	(as in prices at Otahuhu)
PACF	partial autocorrelation function
Pohokura	the Pohokura gas field
PPA	power purchase agreement
PPI	producer price index
PSI	pivotal supplier index
PJ	petajoule
QWOP	quantity weighted offer price
RMA	Resource Management Act
RSS	residual sum of squares
SCP	structure, conduct and performance
SDDP	Stochastic Dual Dynamic Programming
SI	South Island
SIMI	South Island Mean Injection
SPD	scheduling, pricing and dispatch
SRMC	short-run marginal cost
Tiwai	the aluminium smelter at Tiwai Point
Tiwai contracts	the Contract for Differences contracts between Meridian and NZAS, and between Contact and Meridian, relating to the supply of power to the Tiwai Point smelter for 2021 to 2024
TJ	terajoule
TCC	Taranaki Combined Cycle
UTS	Undesirable trading situation
VI	vertical integration: in the electricity market this refers to where a firm is both a generator and a retailer
vSPD	vectorised scheduling, pricing and dispatch — the vSPD model is a precise replica of scheduling, pricing and dispatch
VWAPs	value weighted average prices

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

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