Market Performance Quarterly Review

October-December 2022

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1 Purpose of this report

1.1 This document covers a broad range of topics in the electricity market. It is published quarterly to provide visibility of the regular monitoring undertaken by the Electricity Authority (Authority).

1.2 This report also includes a brief yearly analysis of the reliability of the network, and a 6-monthly update of structure, conduct and performance (SCP) indicator analysis. The findings are summarised in section 7 and section 8, respectively.

2 Highlights

2.1 Throughout October, weekly load was slightly higher than the historical average. Weekly demand peaked for the week of 1-7 October, while demand for the week of 19-25 November was a lot lower than the historical average.

2.2 Peak demand often exceeded the historical average, and many of these instances were related to cold snaps. The highest peak demands of the quarter occurred on the mornings of 6 and 7 October, reaching around 90 percent of that seen on 9 August 2021.

2.3 The market share of larger retailers marginally increased in this quarter. It also slightly increased for small-medium sized retailers. Similar to the previous quarter, Genesis had the largest increase in market share, while Contact had the biggest decline. Trader switches and move-in switches per month decreased month on month throughout the quarter.

2.4 Average wholesale electricity prices fell throughout the quarter, influenced by increased hydro storage and periods of high wind generation. The average spot price for the quarter was $43/MWh (compared to $68/MWh for the same quarter last year), also a decrease compared to the previous quarter. Thermal generation decreased significantly due to increased hydro, and low demand.

2.5 Nationally hydro storage decreased in October but increased significantly in November. However, in December storage decreased slightly due to reduced inflows and high hydro generation. This decline was most dramatic at lakes Te Anau and Manapōuri.

2.6 Gas production by major fields decreased slightly at the end of the quarter. Methanex Motunui consumed around 185 TJ/day. However, Huntly’s gas consumption fell due to a gas swap arrangement with Methanex. Gas spot prices hovered around $10/GJ throughout the quarter, like the previous quarter. Contact informed the market that the Ahuroa gas storage facility’s working storage capacity had fallen from 18 PJ to between 10 PJ and 12 PJ.

2.7 Short-term forward prices decreased, while long-term forward prices increased over the quarter. The change in short-term futures was likely due to improved hydro storage in this quarter. Uncertainties in the gas supply, forecasted high coal and carbon prices, increasing costs of running fossil-fuelled plants, and delay in new renewable plants, likely contributed to the higher long-term futures prices.

3 Demand

3.1 Figure 1 shows total daily demand between October and December 2022 against the historical average demand from 2017-2021. Note that the historical average is based on the date, so the average for any day will likely include weekends (which have different demand profiles). Annotations display the weekly percentage difference between the 2022 load and the 2017-2021 historical average load.

3.2 Reconciled demand for October, November, and December 2022 was 3,518 GWh, 3,228 GWh, and 3,229 GWh, respectively. This compares to historical average demands for October, November, and December of 3,457 GWh, 3,284 GWh, and 3,285 GWh, respectively. These values show that total demand was higher in October compared to the historical average but lower in November and December (61 GWh higher in October, 56 GWh lower in both November and December).

3.3 During October, total weekly load was higher during cold snaps. The highest difference to the historical average occurred in the first week of October, when weekly average demand was 4.1 percent above the historical average. Throughout November and December, the decline in average weekly demand was likely due to moderate temperatures as expected. Average weekly demand was lower than the historical average for these months.

3.4 Daily peak demand repeatedly exceeded the historic average successively between 3-7 October 2022 (Figure 2). During that time the country was experiencing unseasonably cold weather. The highest peak demand occurred on the morning of Friday 7 October, reaching 6,546 MW. This was 90% of that experienced on 9 August 2021.

Figure 1: Daily load, December 2022 quarter with historic average

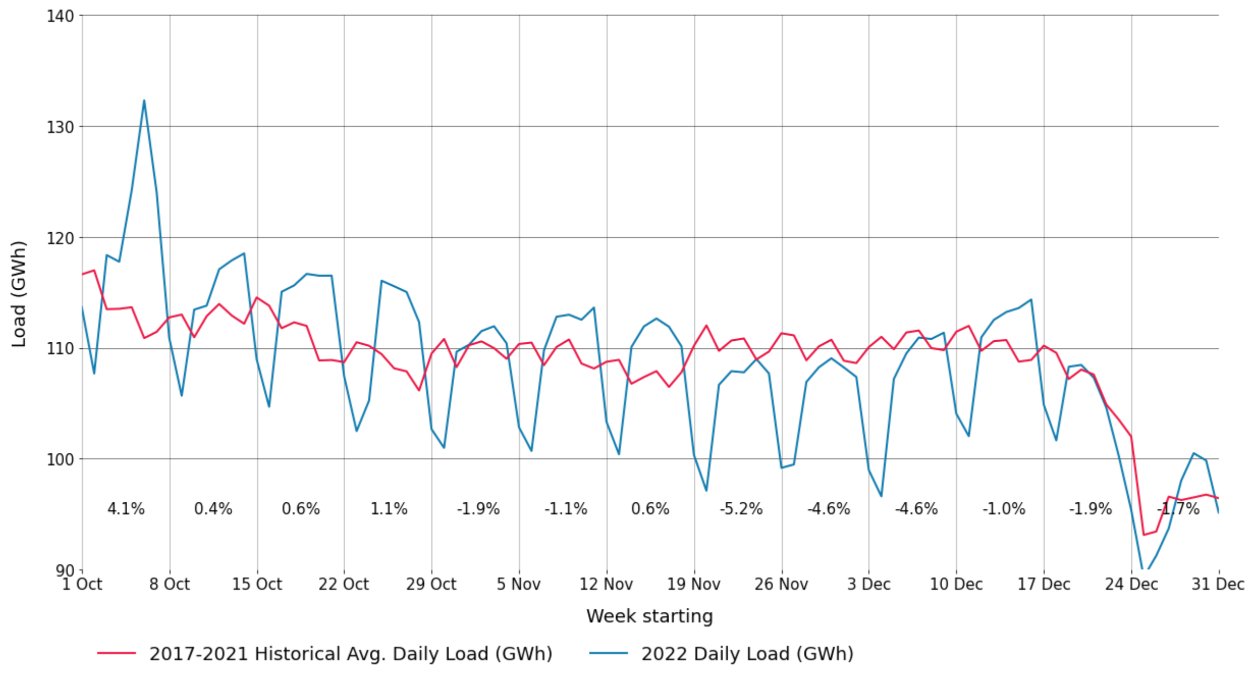


Figure 2 : Half hourly load compared to the historical average for 3-7 October

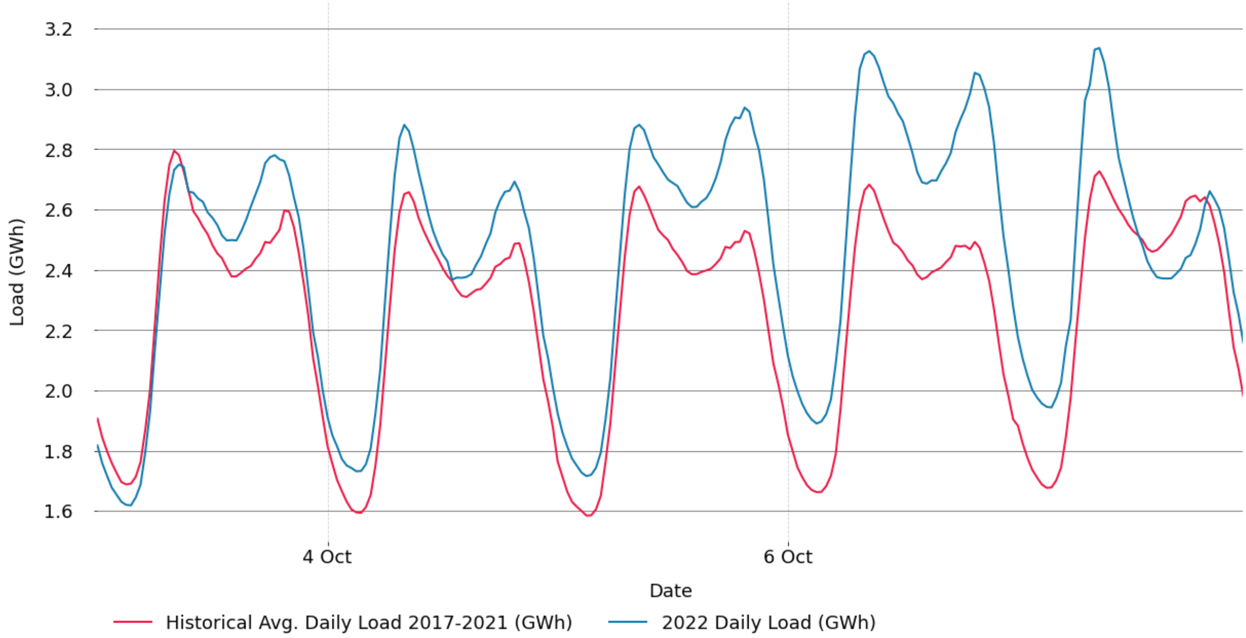
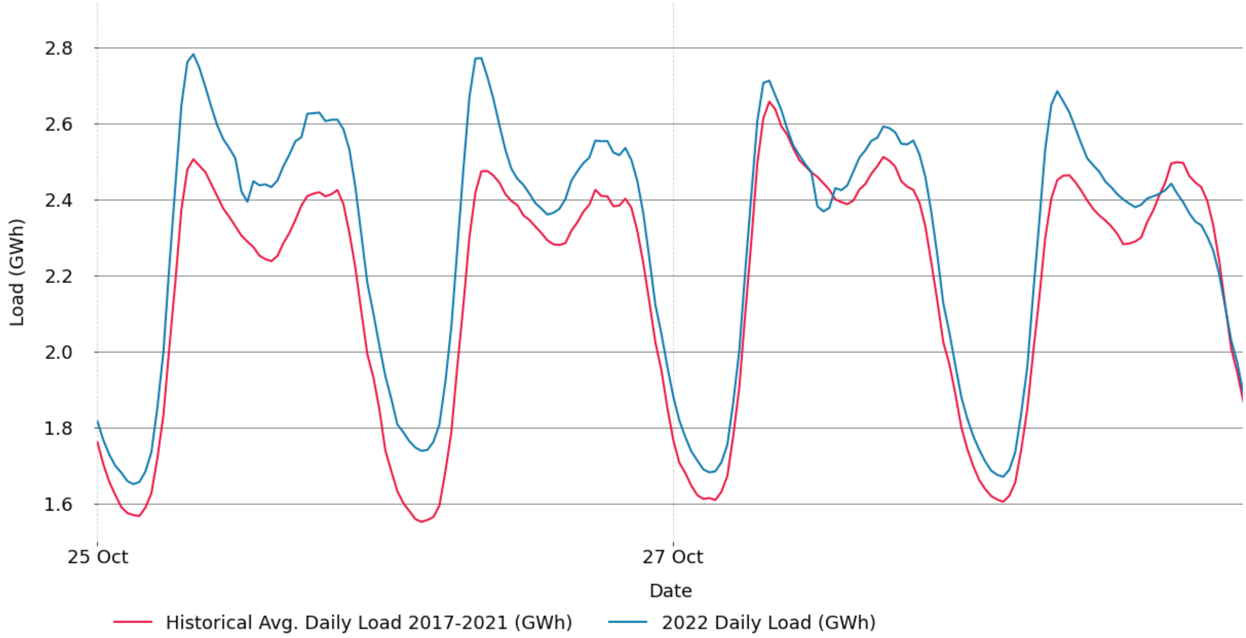


Figure 3: Half hourly load compared to the historical average for 25-28 October



4 Retail

4.1 Over the December 2022 quarter, the collective market share of the four[1] largest retailers, Contact, Genesis, Mercury, and Meridian was 84.19 percent (a decrease of 0.11 percent in this quarter).

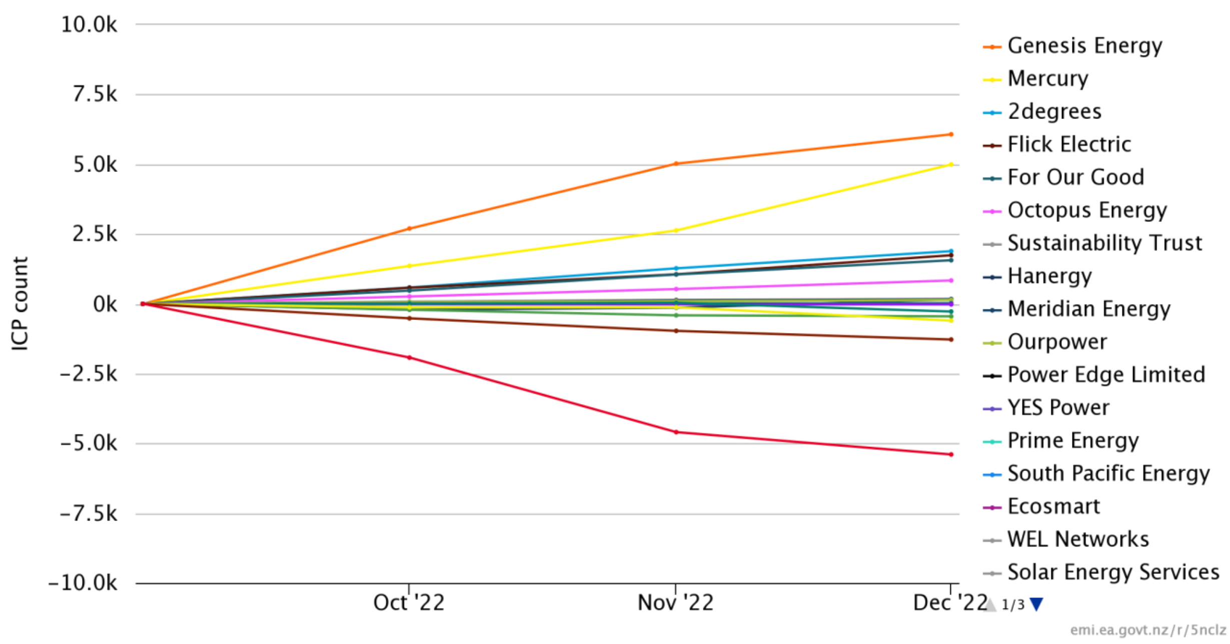
[1] As of 1 May 2022, Trustpower sold part of its business to Mercury and changed its name to Manawa Energy. In the future Electricity Authority reports, it will not be bundled with the other large retailers as it has sold its retail assets to Mercury.

4.2 On 31 December 2022, the four largest retailers collectively held 1,906,041 ICPs between them, by gaining 5,873 ICPs over the quarter. Small-medium sized retailers held 357,834 ICPs between them, gaining 3,839 ICPs.

4.3 Figure 4 shows the changes in market share of each retailer from 1 October to 31 December 2022. Genesis Energy had the largest increase in market share of 6,074 ICPs, and Mercury gained 4,994 ICPs. Some smaller retailers also made gains, including For Our Good and Octopus Energy who gained 1,564 and 838 ICPs, respectively. Contact Energy had the greatest decline in market share by losing 5,395 ICPs.

4.4 The largest regional change in ICPs came from Genesis's gains in Auckland, with an increase of 2,965 ICPs over the quarter.

Figure 4: Changes in retailer market share[2]

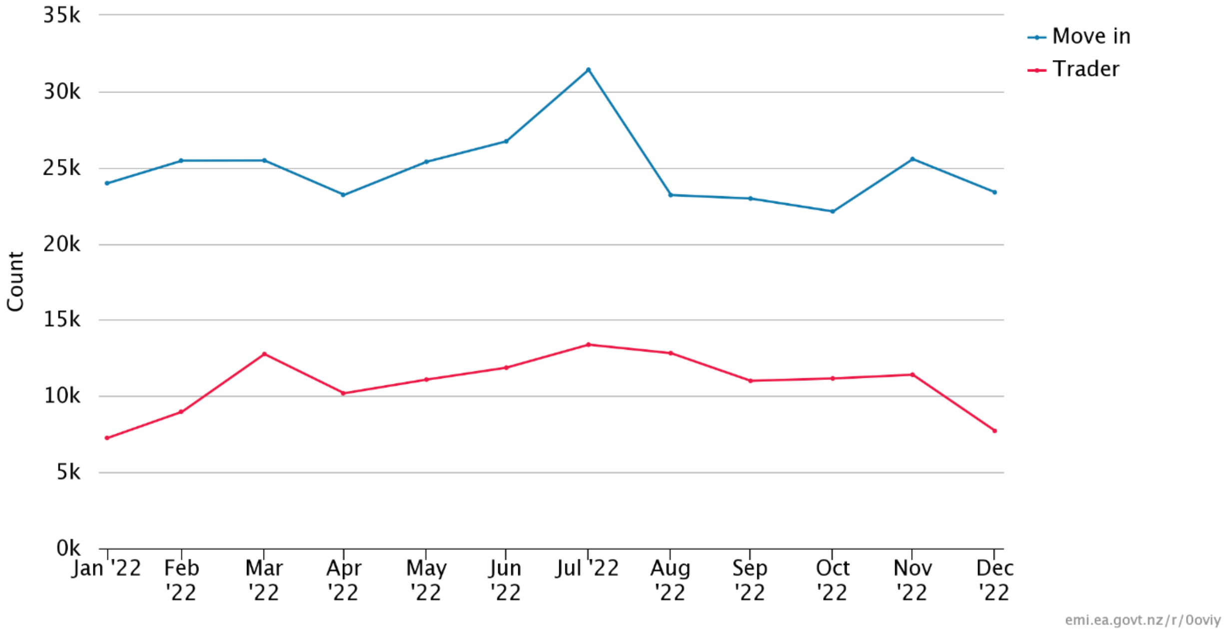


4.5 Figure 5 shows the number of electricity connections (ICPs) that have changed electricity suppliers from 1 January 2022 to 31 December 2022 categorised by type 'move in', and 'trader'. Move in switches are switches where the customer does not have an electricity provider contract with a trader at a particular ICP, and subsequently obtains a contract. In contrast, trader switches are switches where the customer does have an existing contract with a trader, and the customer obtains a new contract with a different trader.

4.6 Over the quarter, trader switches decreased from 11,154 per month in October to 7,696 per month in December. Move in switches slightly increased from 22,115 in October 2022 to 23,316 in December 2022. Move in switches are slightly higher than they were this quarter last year.

[2] Please note that not all traders fit in the key. Please go to emi.ea.govt.nz/r/2a110 to view the key with all traders.

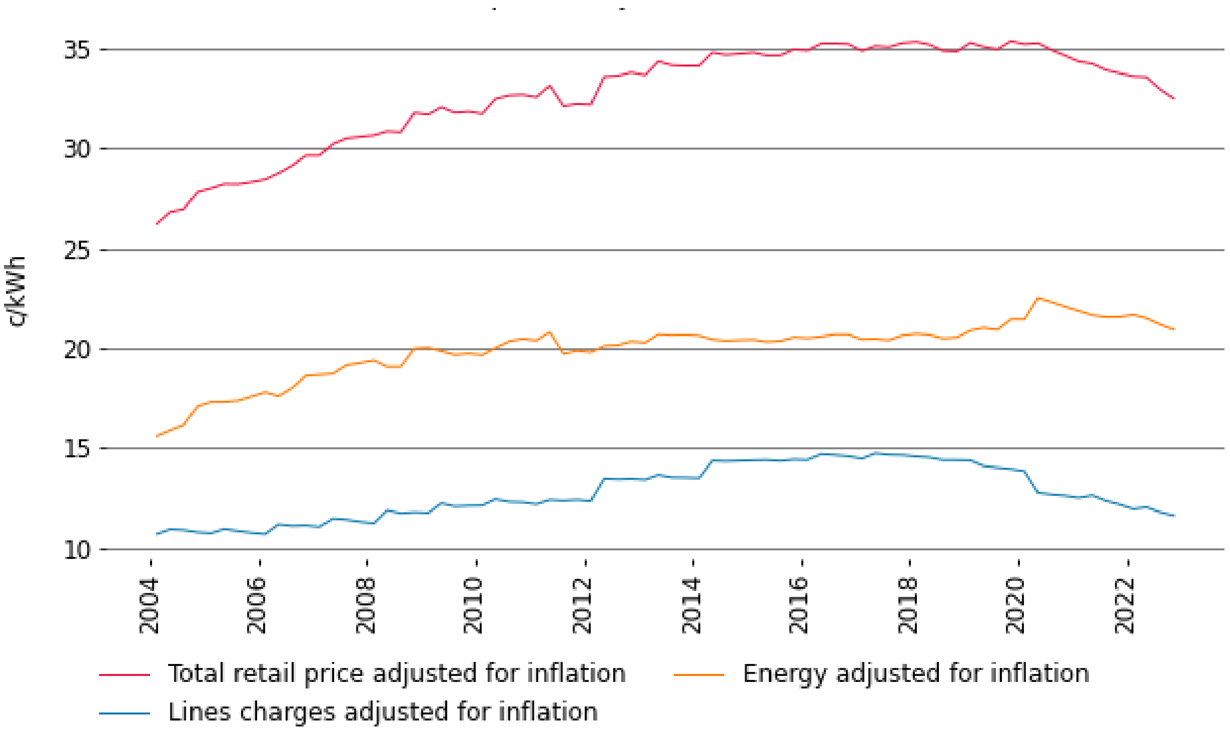
Figure 5: ICP switches by type 2022



4.7 The Quarterly Survey of Domestic Electricity Prices (QSDEP) indicator is an average price series based on publicly advertised tariffs in the retail market. The series estimates costs based on an average household consumption of 8,000 kWh per year to calculate a per energy unit charge. It does not capture actual costs to households, which may vary based on type of tariff and total electricity use.

4.8 Figure 6 shows the QSDEP adjusted for inflation between 2004 and 2022. It shows that between 2015 and 2020 retail costs, including for each component, were stable and in line with inflation. From 2020 the energy component of the cost of electricity has been decreasing (once adjusted for inflation). There has also been a decrease in transmission and distribution costs since 2020, with a drop in the cost of these two components from 1 April 2020 when the new price-quality paths set by the Commerce Commission came into effect.

Figure 6: Domestic Electricity Prices by component (QSDEP)



5 Wholesale

5.1 Half hourly nationally averaged wholesale electricity spot prices across New Zealand are shown in Figure 7. Average spot prices fell this quarter, with the average spot price being $43/ MWh. However, there were a few notable price spikes.

5.2 As hydro storage increased from November, prices fell dramatically. However, during times of low wind, high thermal usage and/or peak demand, prices rose usually to between $100-$200 /MWh but sometimes much higher.

5.3 The largest price spikes between 6-7 October were associated with cold weather and low wind. On the evening of Thursday (6 October 2022), prices reached $1500/MWh at Benmore, and $1900/MWh at Ōtāhuhu. On Thursday afternoon a low residual situation was issued for Friday morning (7 October 2022) between 7:30 and 9:00 am.

5.4 On Friday 7 October, an unexpected outage at the Haywards substation on the HVDC led the system operator to first issue a Customer Advice notice at 5:24 am, notifying participants of the HVDC issue, which restricted electricity from the South Island from reaching the North Island. At 5:37 the HVDC ran back causing an under-frequency event.

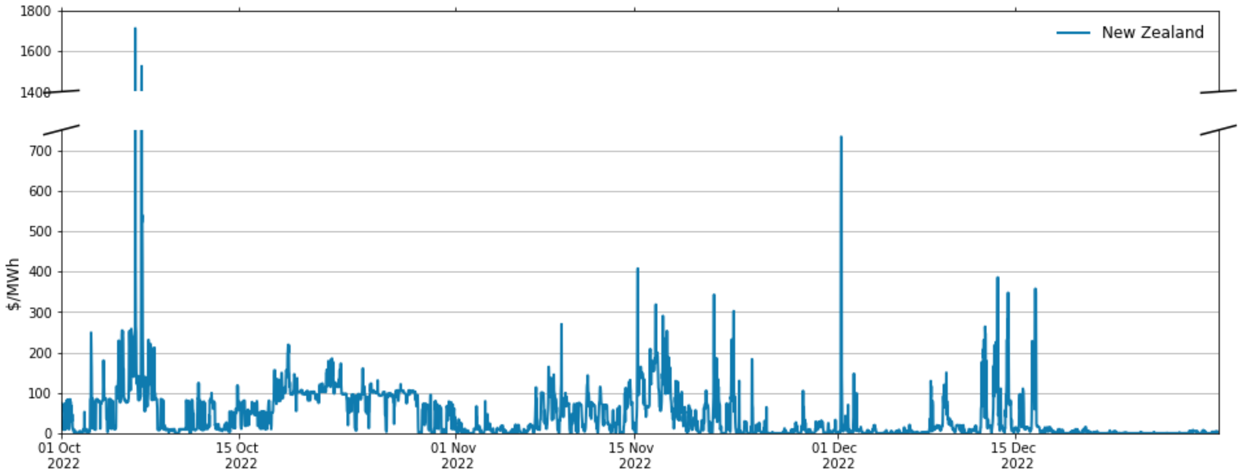
5.5 At 5:39 am a Warning Notice was sent as there were insufficient North Island offers to meet expected demand between 7:30-10:00 am. A Grid Emergency was announced at 7:15 am. As a result, North Island spinning reserves were dispatched as generation. Also, controllable load such as hot water systems was turned off. Prices reached $2,372/MWh in the North Island and were $18/MWh in the South Island. The issue was resolved by 8:00 am. This grid emergency was unrelated to the low residual situation, however, the impact of the unplanned HVDC outage was exacerbated by the unseasonably high demand due to the cold weather.

5.6 Real-time pricing (RTP) went live at midnight on 1 November 2022. Prices are now driven directly by live conditions on the power system, rather than calculated separately the next day using different information. This removes a source of uncertainty about the price parties pay or receive for the electricity they buy and sell in the wholesale spot market.

5.7 A price spike of $1,162/MWh occurred on 1 December at 8:00 am at Ōtāhuhu (North Island). At the same time, the price at Benmore (South Island) was $80/MWh and high volumes were transferring northwards. The observed price separation was likely due to the tighter energy and reserve market, and low wind generation in the North Island. Also, the outage of E3P at Huntly (Genesis's most efficient gas fired unit) contributed to price separation between the North and South Islands.

5.8 During the Christmas and New Year holidays, spot prices were mostly low as demand was low. Between 18 and 31 December, the average spot price was $26/MWh less compared to this period last year. It was $107/MWh less compared to the average over the previous 5 years for the same time of year.

Figure 7: Half hourly wholesale electricity spot prices



5.9 Figure 8 shows the daily averaged spot price against national hydro storage. Increasing hydro storage meant hydro generation was offered at lower prices, reducing average spot prices in this quarter. Figure 8 displays this relationship. Decreasing hydro storage throughout the first half of the quarter kept prices comparatively high. Due to an increase in storage from November average prices decreased.

5.10 Prices were also impacted by high wind generation (eg, 1-6 November 2022), which reduced the need for thermal generation. Generally, outside of unusual circumstances, spot prices increased when grid demand increased, wind generation decreased, and thermal powered generation increased. The relationship between wind generation and prices can be seen in Figure 9. Mostly, low prices occurred when wind generation was high and thermal generation was low.

5.11 Outages of note include TCC, and E3P at Huntly. E3P was on annual planned outage for three weeks from 1 November. One Stratford peaker was on outage until mid-November. Huntly 4 was on outage in mid-November.

Figure 8: Daily national storage and daily average spot price

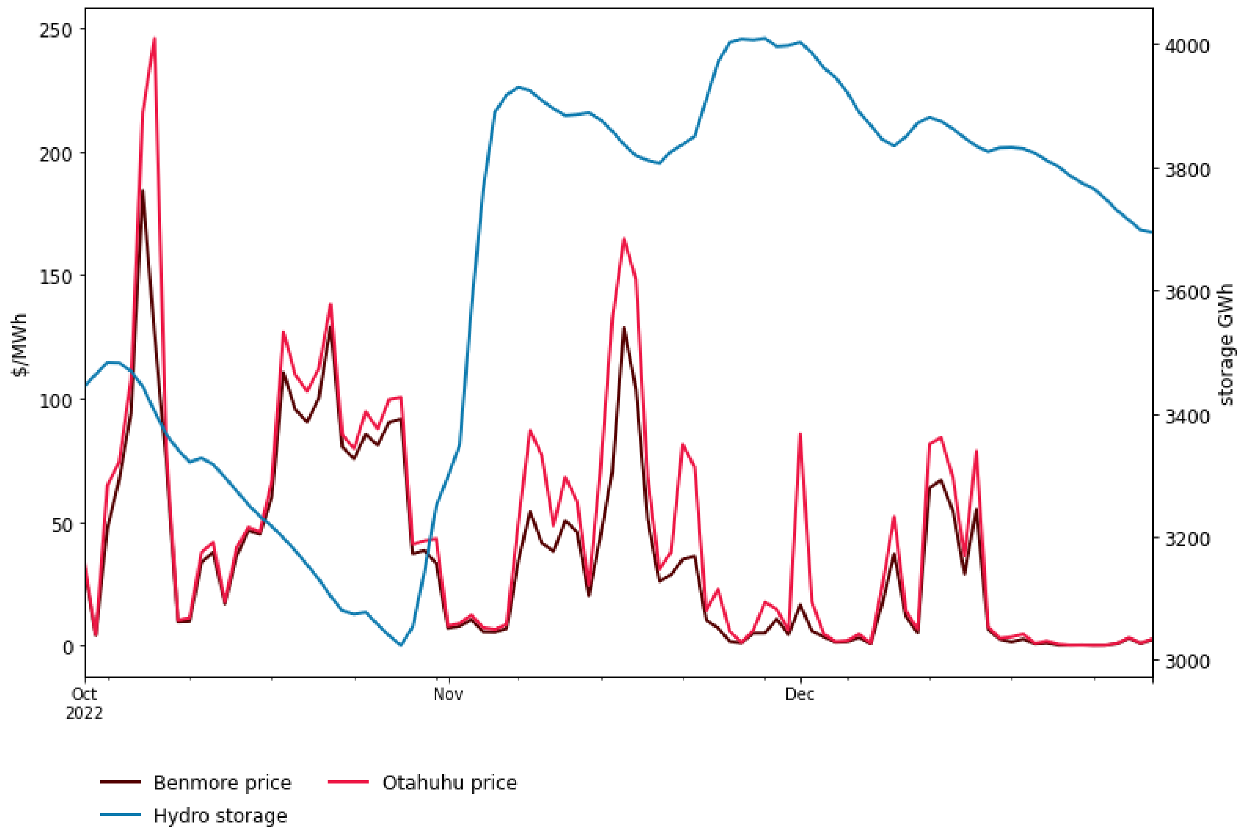
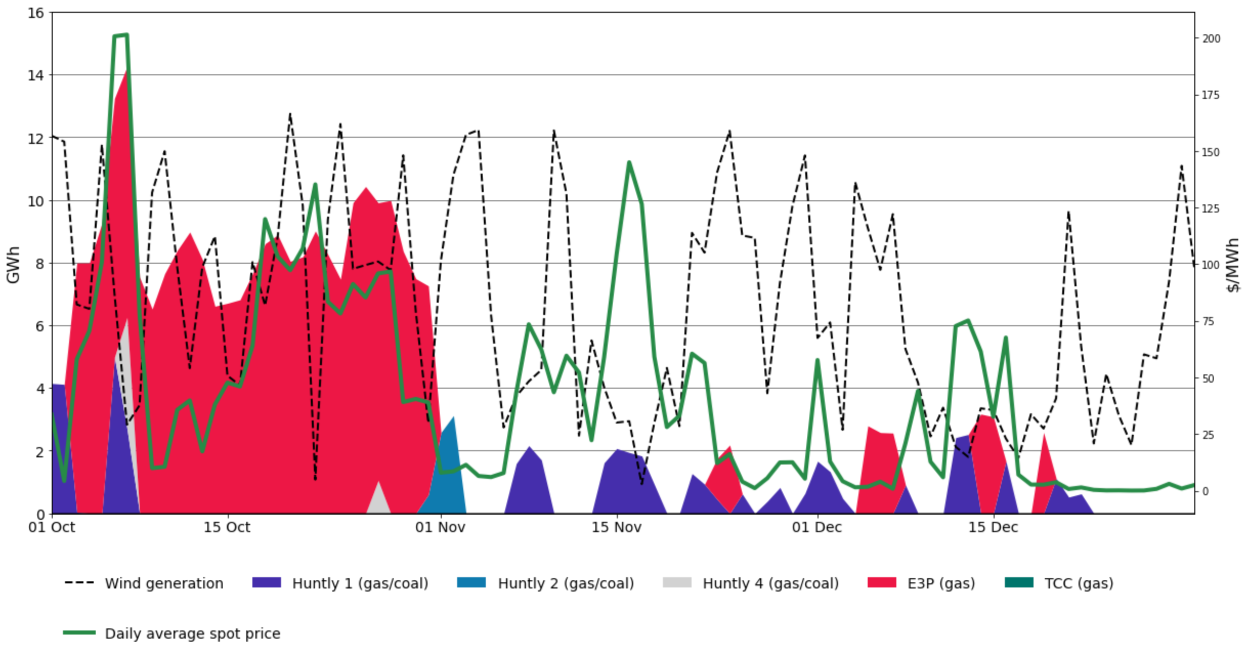
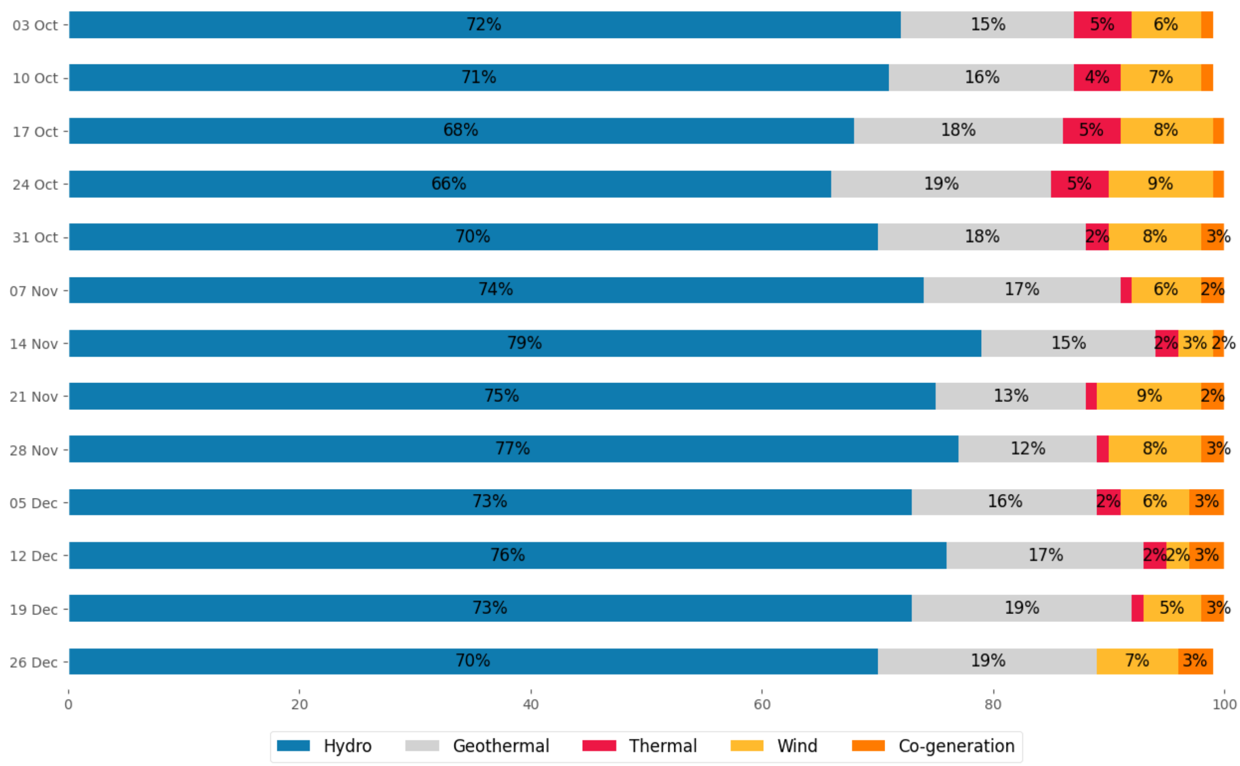


Figure 9: Daily average spot price and daily total generation, in GWh, at Huntly (coal/gas fired units), TCC and from wind, between 1 Oct – 31 Dec 2022



5.12 The proportion of generation from renewable sources increased significantly in this last quarter, averaging 95 percent of total generation. This compares to just over 90 percent for the same quarter last year and 88 percent for the same quarter in 2020. Weekly variation can be seen in Figure 10. As hydro generation increased, thermal generation dramatically declined from five percent of weekly generation to zero percent at the end of December (due also to low demand). Generation from wind varied between 2 - 9 percent of weekly generation throughout the quarter.

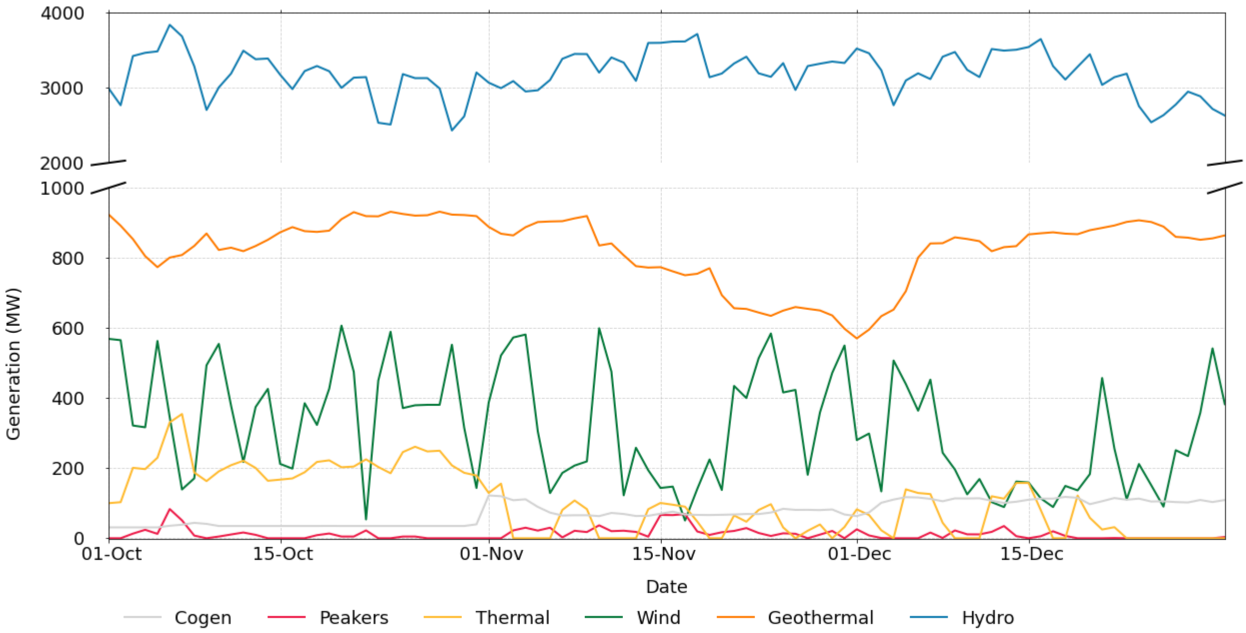
Figure 10: Weekly generation by fuel breakdown



5.13 Figure 11 shows daily generation for the quarter by fuel type. Throughout October to December, due to relatively high hydro storage, generation from hydro was high overall. Large, slow start thermal generation supported a proportion of baseload - with hydro ramping up and down throughout the day to match load. In October, hydro storage slightly decreased, as did hydro generation.

5.14 Average wind generation was 320 MW for the quarter and averaged 7 percent of total generation. Hydro generation averaged 3,185 MW or 71 percent of total generation. Half hourly thermal generation averaged 101 MW or 2 percent of total generation. Thermal generation decreased by 9 percent compared to the previous quarter due to lower demand and healthy hydro storage.

Figure 11: Average Daily Generation by Fuel Type

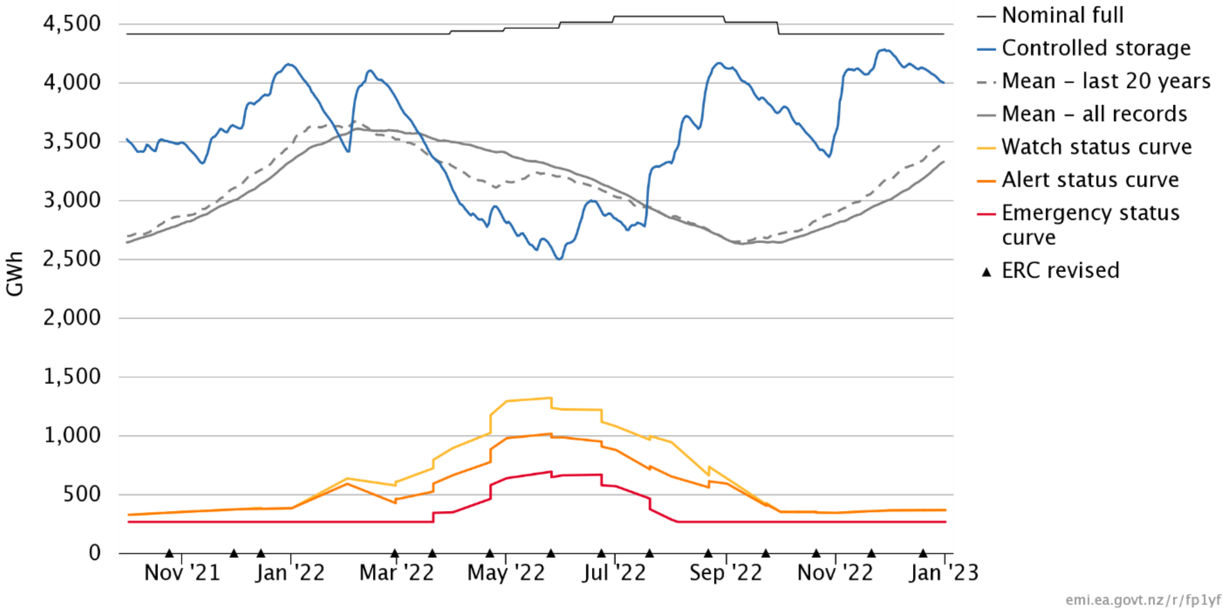


5.15 Figure 12 shows total national controlled hydro storage up to 31 December 2022. Over the December quarter hydro storage increased by 235 GWh, from 3,763 GWh on 1 October 2022 to 3,998 GWh on 31 December 2022.

5.16 On 1 October 2022 hydro storage was 2,641 GWh (142 percent of the historical mean for that time of year)). On 31 December 2022 storage was 3,326 GWh (120 percent of the historical mean for that time of year).

5.17 Hydro inflows were slightly higher than the historical mean for this quarter. Total national inflows between October and December were 7,915 GWh, which is close to the historical average of 7,615 GWh.

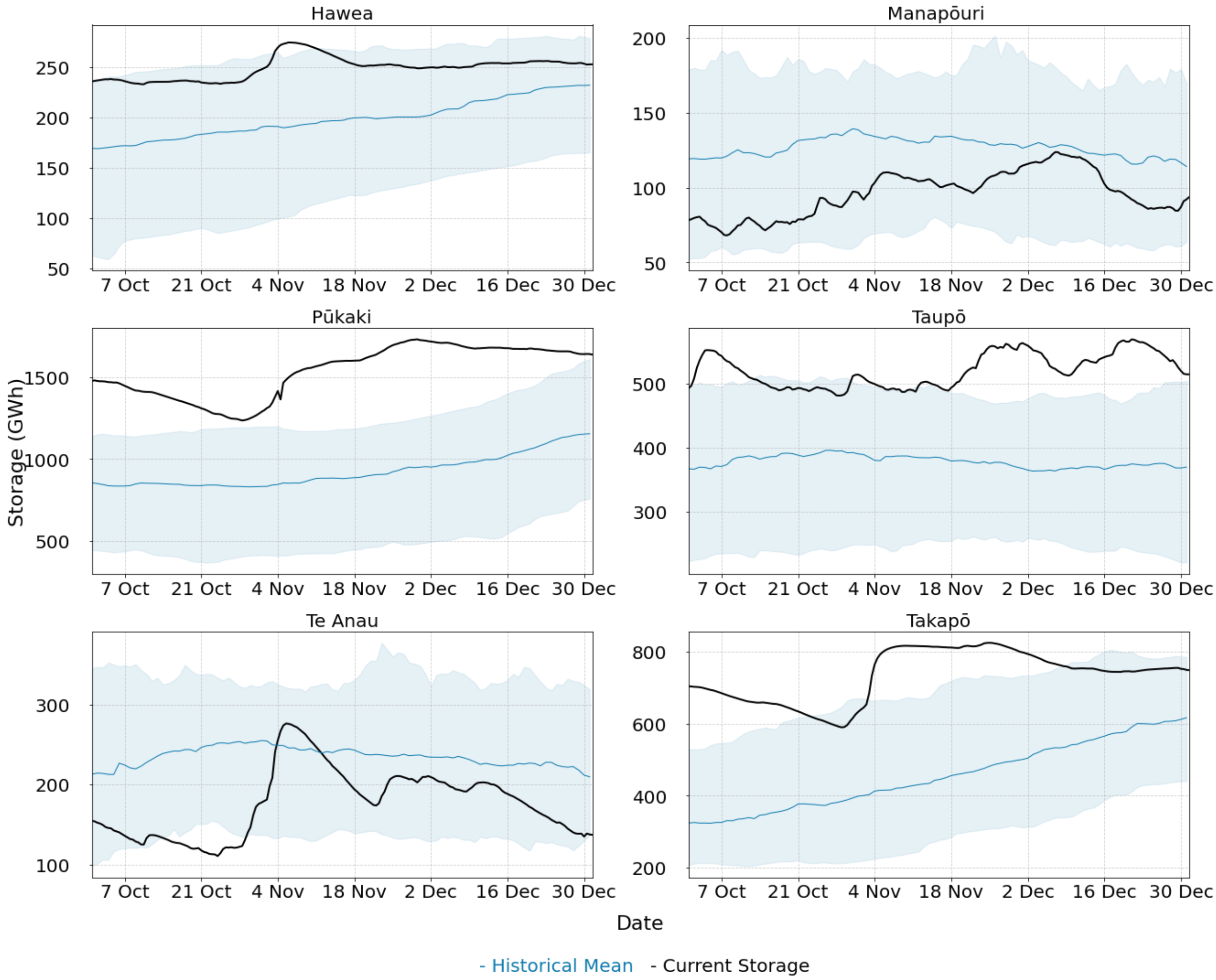
Figure 12: Controlled National Hydro Storage 2021/2022



5.18 Figure 13 shows the storage of major catchment lakes Pūkaki, Taupō, Takapō, Hawea, Manapōuri and Te Anau for the quarter against their historical means and 10th -90th percentiles based on data from 1926-2021. At the end of December, storage levels at lakes Pūkaki, and Taupō remained above their respective 90th percentile. Lakes Takapō, and Hawea were slightly below their respective 90th percentile but above their historical averages.

5.19 In contrast, by the end of quarter, storage at both lakes Te Anau, and Manapōuri remained below their respective historic mean.

Figure 13: Major Lake Storage vs. mean, 10th-90th percentile



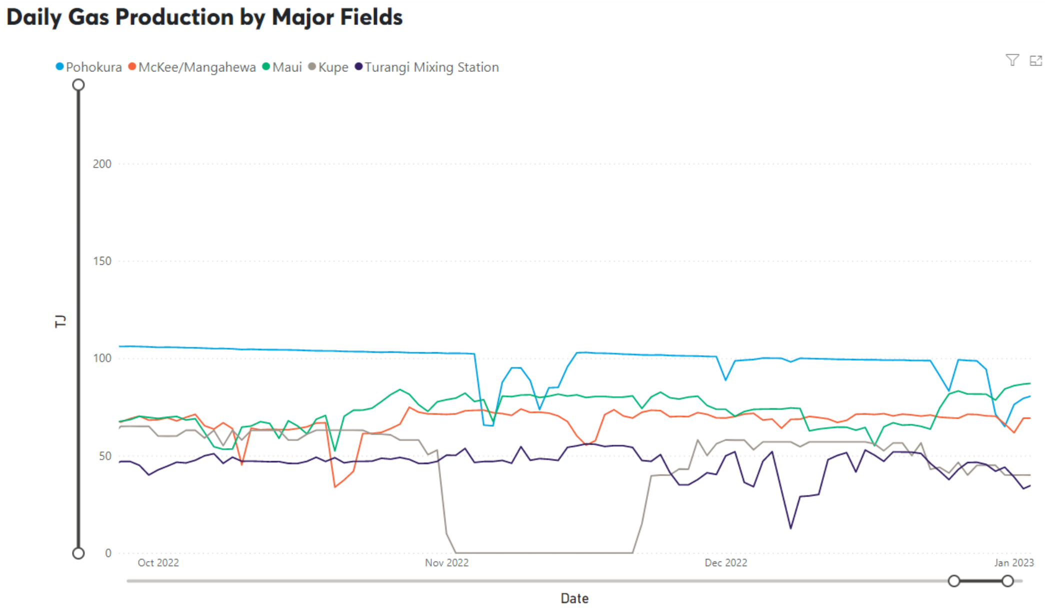
5.20 Figure 14 shows gas production by major fields and gas consumption by major users from October 2022 to December 2022. Total gas production for the December quarter decreased by 46 TJ/day, from 346 TJ/day on 1 October 2022 to 300 TJ/day on 31 December 2022 with some volatility. Kupe was on annual schedule outage for three weeks from 1 November 2022.

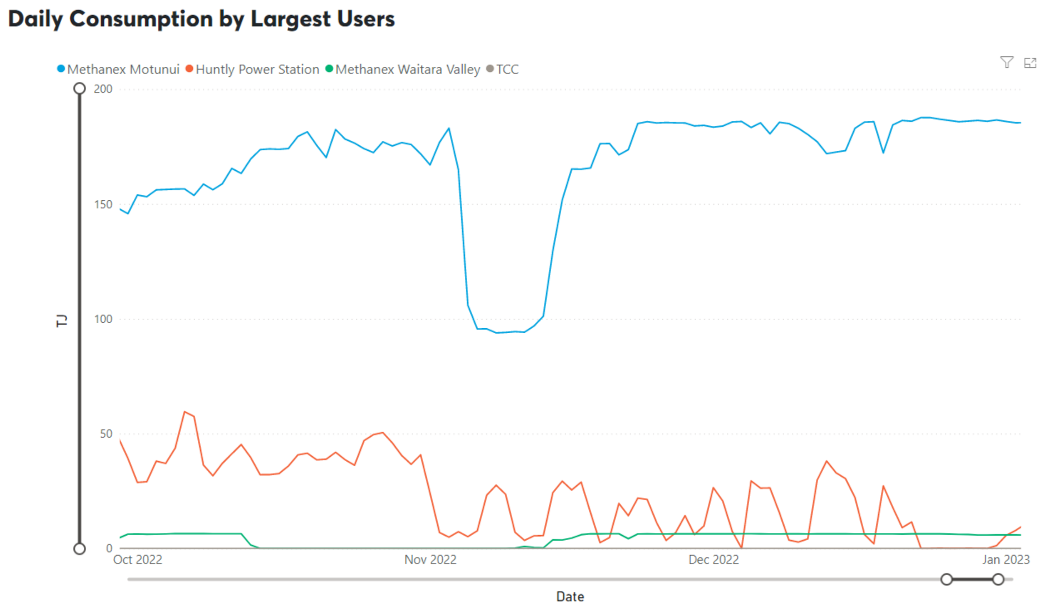
5.21 Overall, gas consumption from the largest users slightly increased, from 189 TJ/day on 1 October 2022 to 194 TJ/day on 31 December 2022. Reduced consumption at Methanex Motunui at the beginning of November suggests that one of the Motunui plants was shut down. TCC was not run during the quarter. Due to excess hydro generation, gas consumption at Huntly also decreased. E3P at Huntly was on outage for three weeks in November.

5.22 During the Motunui shut-down, large volumes were pumped into the Ahuroa underground gas storage (AGS) facility. At the end of December 2022, the total closing balance of AGS was 10 PJ, the highest of the year.

5.23 In December, Contact announced that working storage capacity at Ahuroa gas storage facility had fallen from 18 PJ to between 10 PJ and 12 PJ. Additionally, to maintain extraction and injection rates at contracted levels, Contact needs to retain 4 PJ of working gas in the reservoir, effectively reducing accessible gas by a further 4 PJ. This reduces estimated working gas storage to between 6 to 8 PJ, and of this stored gas Contact can immediately access about 2.5 PJ. When combined with Contact's contracted gas, the 12-month forward gas available to Contact totals about 15 PJs. Contact has advised that it has "several mitigations available" to limit the reduced Ahuroa capacity.

Figure 14: Daily Gas Production and Consumption[3] October – December 2022





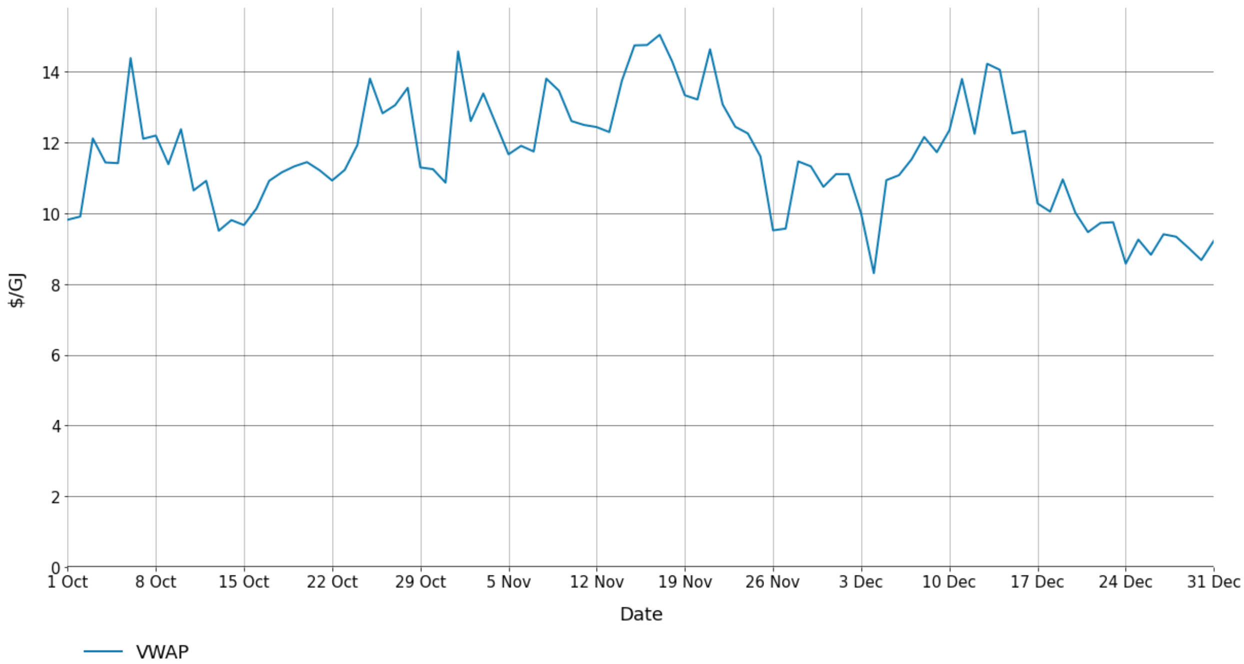
[3] Gas production and consumption - Gas Industry

5.24 Figure 15 shows the daily gas volume weighted average price (VWAP) from emsTradepoint.[4] Gas spot prices hovered around $12/GJ from October to December. Prices generally decreased from July, as supply increased due to the Motunui outage. Prices levelled off throughout the quarter as the Motunui plant returned, but overall gas used by thermal generators was lower.

5.25 Figure 16 shows estimated gas and coal usage at Huntly. From mid-July coal use dramatically dropped close to zero. Only a few days in late July and throughout August saw coal burning in the Rankines.

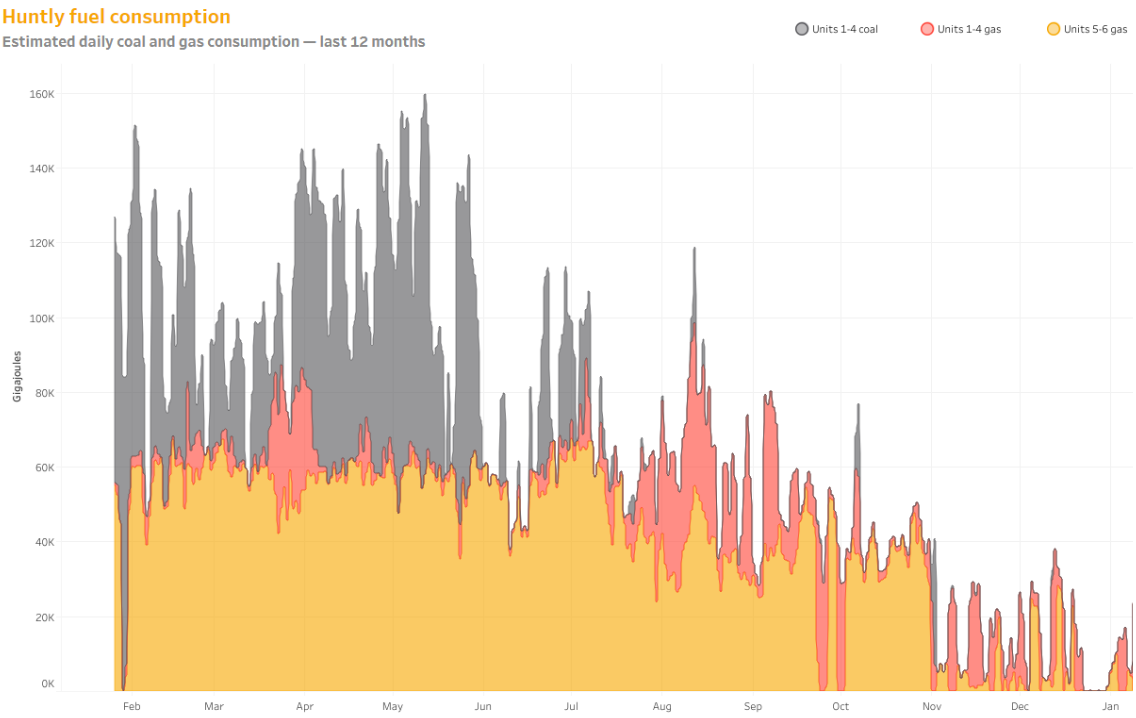
5.26 The latest coal numbers from Genesis put Huntly's coal stockpile at 998,000 tonnes on 31 December 2022 which is the highest stockpile since September 2014. High hydro generation, relatively low demand, and excess gas in this quarter helped in the growth of coal storage.

Figure 15: Daily Spot Gas Prices



[4] The daily VWAP is based on trades done via emsTradepoint. Daily VWAP is the volume weighted average price for trades delivered on that day.

Figure 16: Estimated fuel usage at Huntly 2021/22



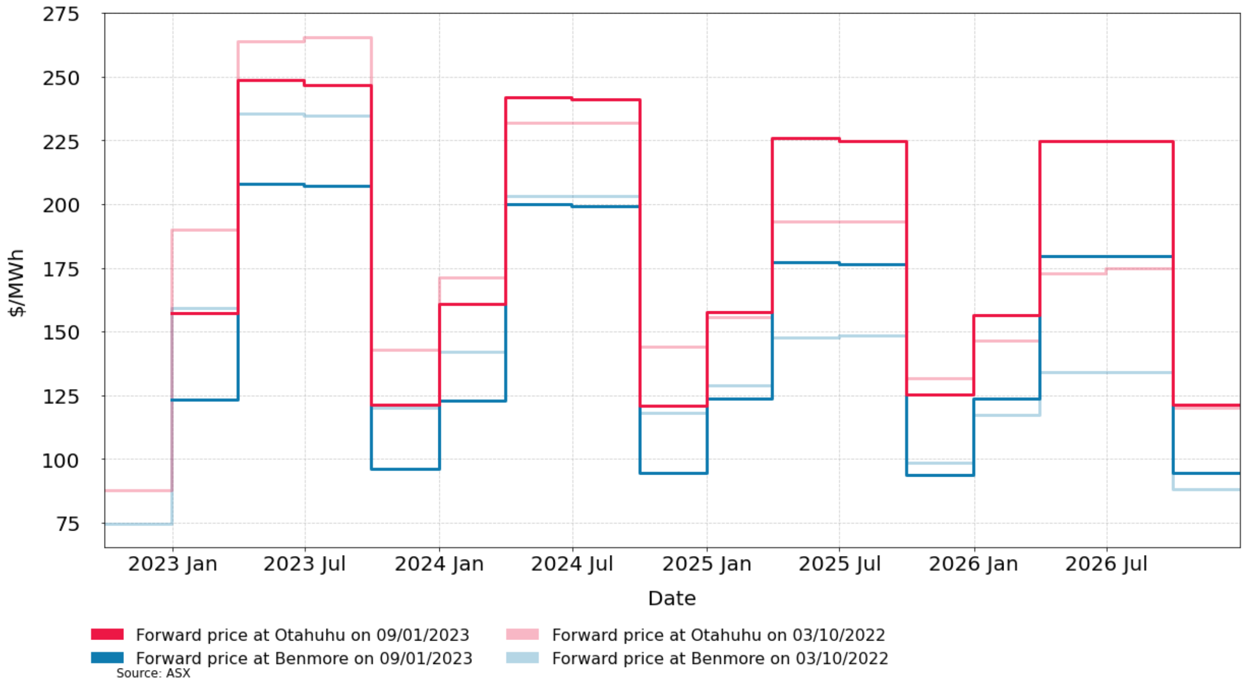
6 Forward Market

6.1 The ASX forward price curve provides a view of future wholesale spot prices. Figure 17 shows forward prices for Ōtāhuhu and Benmore at the beginning and end of the quarter, to illustrate how forward prices have changed.

6.2 In this quarter, the future prices for all 2023 quarters decreased between $15/MWh and $36/MWh. March 2024 futures fell by up to $19/MWh, and June 2024 and September 2024 futures decreased around $4/MWh at Benmore and increased by $10/MWh at Ōtāhuhu. December quarters for all years up to 2025 fell by up to $24/MWh. However, future prices for winter quarters in 2025 and 2026 rose between $28/MWh and $52/MWh.

6.3 The fall in 2023 futures is likely due to increases in hydro storage and a general excess of gas supply over the quarter. The long term forward prices are likely to reflect Tiwai uncertainty, carbon price increases, and uncertainty about how renewables that are being built will integrate into the power system.

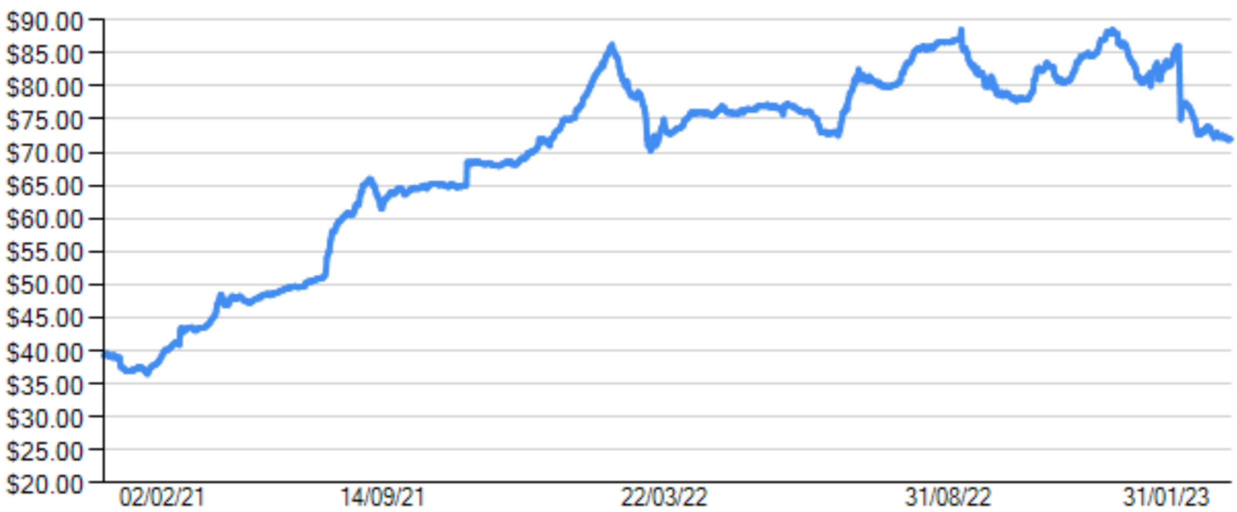
Figure 17: Future Prices



6.4 One factor that contributes to the higher long-term forward prices compared to five years ago is increasing carbon prices, which increases the costs of running thermal generation. Figure 18 shows spot NZ carbon unit prices since the first ETS auction began in 2020, taken from CommTrade's (a platform for buying and selling NZ ETS carbon credits owned by Jarden Securities Limited) website.

6.5 Overall carbon prices rose by 81 percent in 2021, and 16 percent in 2022. During the December 2022 quarter, carbon units (NZUs) were cleared at $79 per unit, and 4.825 million NZUs were sold. After the triggering of the cost containment reserve at $70 no additional NZUs were sold.

Figure 18: New Zealand Carbon Unit Spot Price[5]



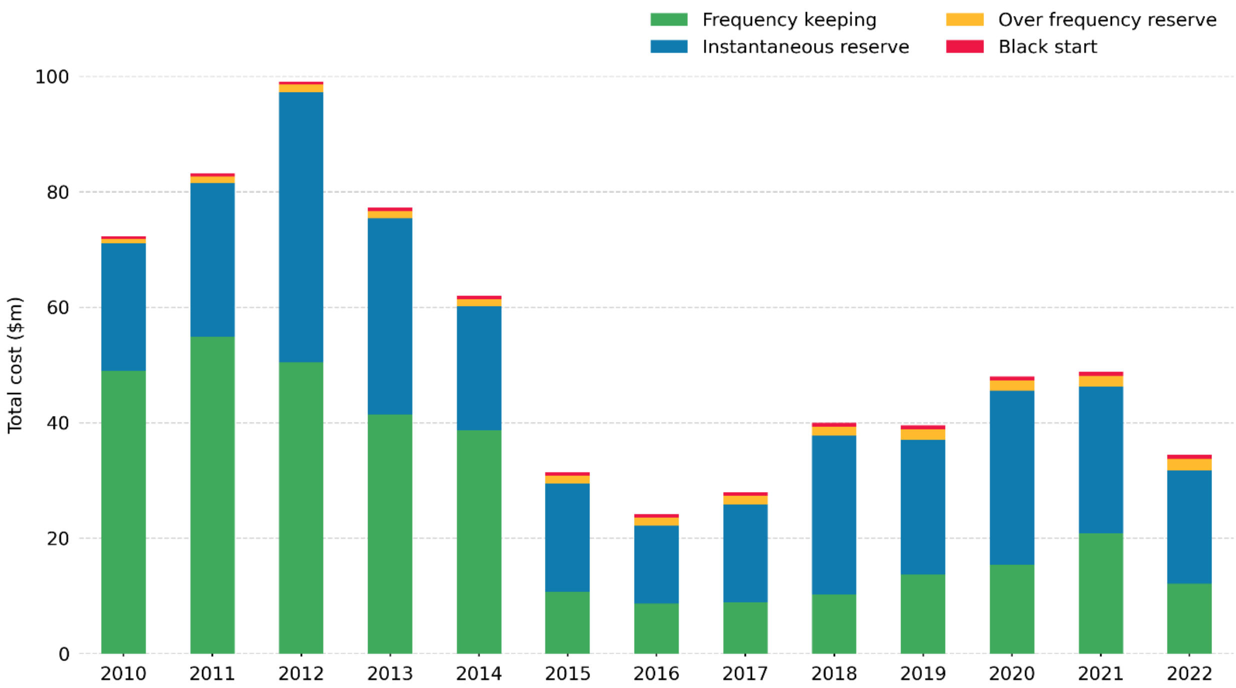
[5] https://www.commtrade.co.nz/

7 Reliability

7.1 The statistics presented in this section are reported for a full calendar year and are included in our fourth quarter review for each year.

7.2 Four main ancillary services maintain the reliability of the network. The total costs of these are shown in Figure 19. Frequency keeping is done by one or more generators able to vary their generation to maintain frequency within the acceptable band. This is needed to match load with generation between dispatches. The cost of frequency keeping dropped in 2015 when the system operator began using Frequency Keeping Control (FKC) which reduced the amount of frequency keeping services required. There was an increase in frequency keeping costs between 2018 and 2021, partially due to increased energy costs, then costs dropped in 2022.

Figure 19: Yearly ancillary service costs

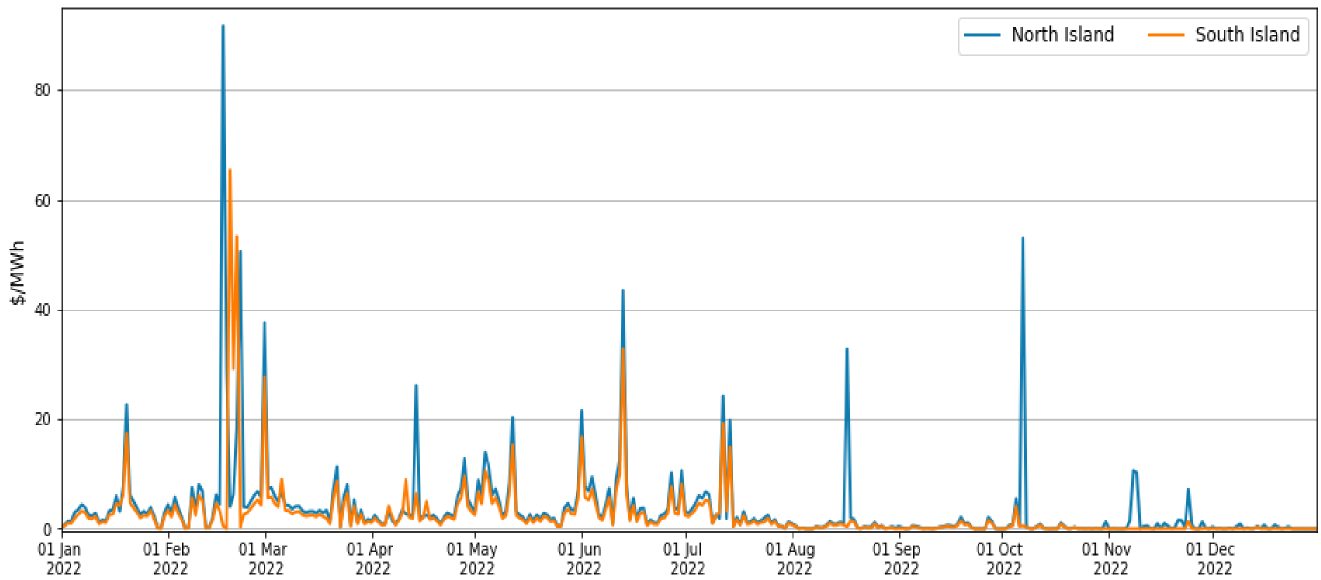


Source: System Operator (Transpower New Zealand Limited)

7.3 In the event of the sudden loss of generation or transmission assets the system needs instantaneous reserves which respond quickly to prevent cascade failure. Instantaneous reserves (IR) can be provided by both generators and large industrial users who are willing to have load interrupted. The price of reserve is co-optimised with energy as available generation can either be used for energy or reserve but not both at the same time. Figure 20 shows the half hourly price for fast instantaneous reserves (FIR).

7.4 The cost of IR is usually low (below $5/MWh), increasing when supply is tight and energy prices are high. The cost of IR was particularly high in February 2022. This was mostly due to the HVDC outage in February and March which limited sharing of both energy and reserves between the islands. As supply was more abundant in the South Island at this time, there was an increase in North Island prices of FIR up to $92/MWh. Prices dropped very low from August as rainfall increased supply. IR prices occasionally spiked in the North Island due to high HVDC flows northward, which required increased reserves in the North Island to cover a trip of the HVDC.

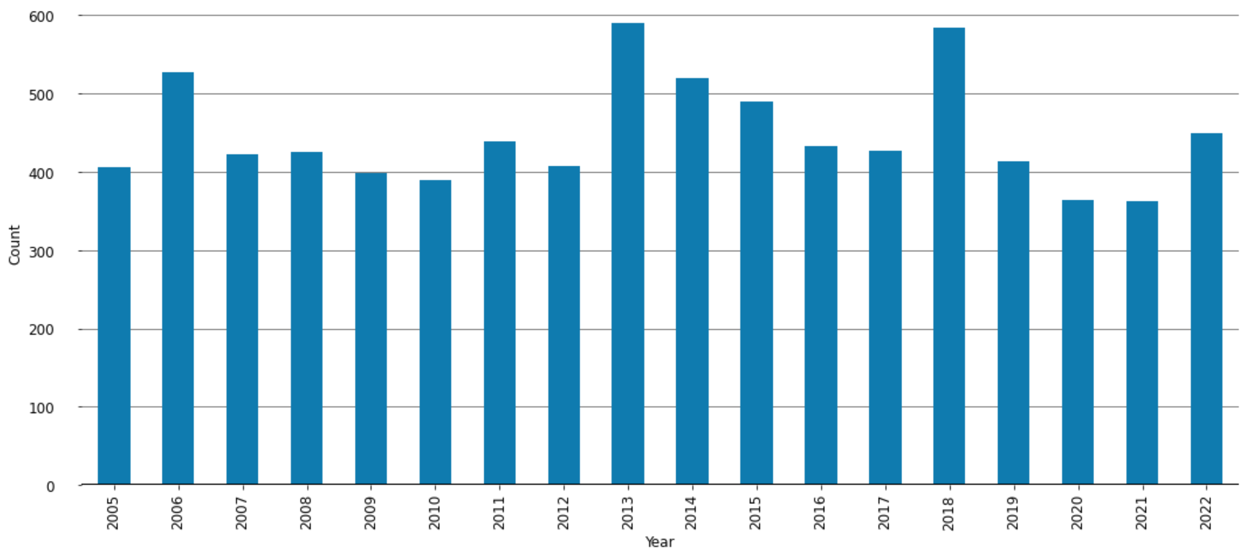
Figure 20: Price of FIR in the North and South Island 2022



7.5 Transpower monitors both voltage and frequency of the grid and sends excursion notices when voltage or frequency measures fall outside of stated limits. Figure 21 and Figure 22 show an estimate of the number of times excursions occurred based on the number of excursion notices issued each year. Tracking excursion notices can help indicate the state of transmission and generation and inform if more in-depth investigation is needed.

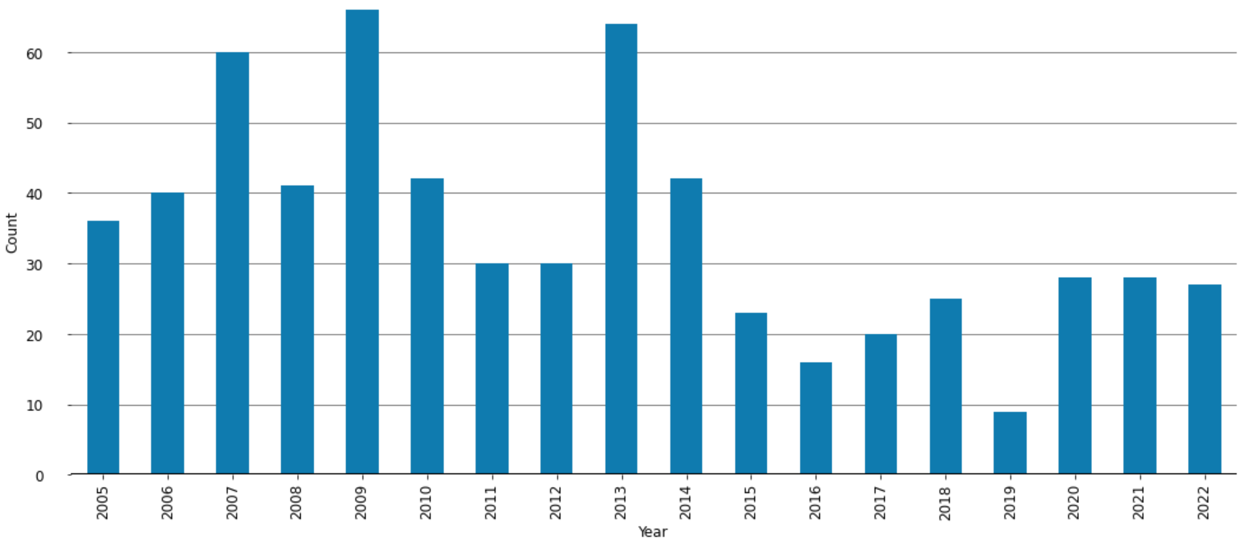
7.6 Voltage excursions are usually around 400 per year, with some high years reaching up to 600. In 2022 over 400 excursion notices were issued, an increase from 2021, but still well within the normal range.

Figure 21: Annual number of voltage excursions (estimated)



7.7 Frequency excursions happen much less frequently than voltage excursions. The number of excursions has been less than 30 excursions per year since 2015.

Figure 22: Annual number of frequency excursions (estimated)



8 Structure, conduct and performance (SCP) indicator analysis

8.1 In this section we assess whether observed outcomes in the market are consistent with competitive outcomes. The approach used is the same as that used in the post implementation review of the trading conduct provisions (the post implementation review).[6] That is, we use the Structure-Conduct-Performance (SCP) framework. The simple premise of the framework 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. As structure is not expected to have changed much since the post implementation review was published, we do not revisit the structural indicators here.

8.2 In the post implementation review we looked at the period 1 July 2021 to 31 July 2022. Here we look at the 6 months 1 July 2022 to 31 December 2022, ie, two quarters of data. We will include 6-monthly updates of these indicators in every second quarterly review going forward.

8.3 For the period 1 July 2022 to 31 December 2022, we find that price separation has continued to be more pronounced since the introduction of the provisions. The frequency of very low prices has continued to be higher and the percentage of high-priced offers lower than in previous years. Offer prices also appear to have continued to reflect underlying conditions and economic costs more closely. Based on our assessment of the conduct and performance indicators presented here and the findings in the Authority's proactive regular monitoring, we continue to conclude that the new provisions appear to be having an impact on generator behaviour

8.4 The indicators we have used to assess competitive outcomes in the market are as follows:

(a) The frequency of **very low prices**. If prices are being determined in a competitive environment, we would expect very low prices in off-peak trading periods to occur more frequently (ie, prices should reflect underlying conditions).

(b) **Price separation**. If prices are being determined in a competitive environment, we would expect price separation to occur more frequently (ie, prices should reflect underlying conditions).

(c) How generators are offering into the market over time. If offer prices are not related to underlying supply and demand conditions, this could suggest the exercise of market power.

(d) The **percent of offers above $300/MWh and above final price**. If these higher priced offers are not related to operational or underlying supply and demand reasons, it could indicate economic withholding.[7]

6 https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2022/wholesale-market-competition-review-oct2022/

7 Offering some quantity at higher prices with the intention that it not be dispatched, to reduce supply and increase the spot price

(e) The **percent of offers above cost**, using various estimates of cost. In a competitive market, offer prices should reflect economic costs, including opportunity costs.[8]

(f) The **relationship of storage and offers to cost**. In a competitive market, we expect an inverse relationship of storage to cost, because the value of stored water for hydro generators increases when storage is low relative to what is expected. We expect a positive relationship between offers and cost, as we expect generators to increase their offer prices if their costs increase.

Very low prices

8.5 If prices are being determined in a competitive environment, we would expect very low prices in off-peak trading periods to occur more frequently than in a market where participants are exercising market power. If participants are economically withholding generation (in a manner that is consistent with the exercise of significant market power), very low prices would be less likely to occur. It is important to note this is an indicator only, as fewer low prices could also arise from prudent hydro storage management.

8.6 shows the distribution of prices for each year from 2018 to 2022 for 1 July to 31 December in each year. Each bar represents a $10/MWh interval. While the mean for these 6 months in 2022 is somewhat lower compared to the previous four years, the median is quite a lot lower, with a high frequency of prices at the bottom end of the distribution.[9] 2022 shows an increase in the frequency of low prices in the second half of 2022. We discussed a similar finding for the 13 months from 1 July 2021 to 31 July 2022 in the post implementation review. That is, since the introduction of the new trading conduct provisions, there has been an increase in the frequency of very low prices.[10]

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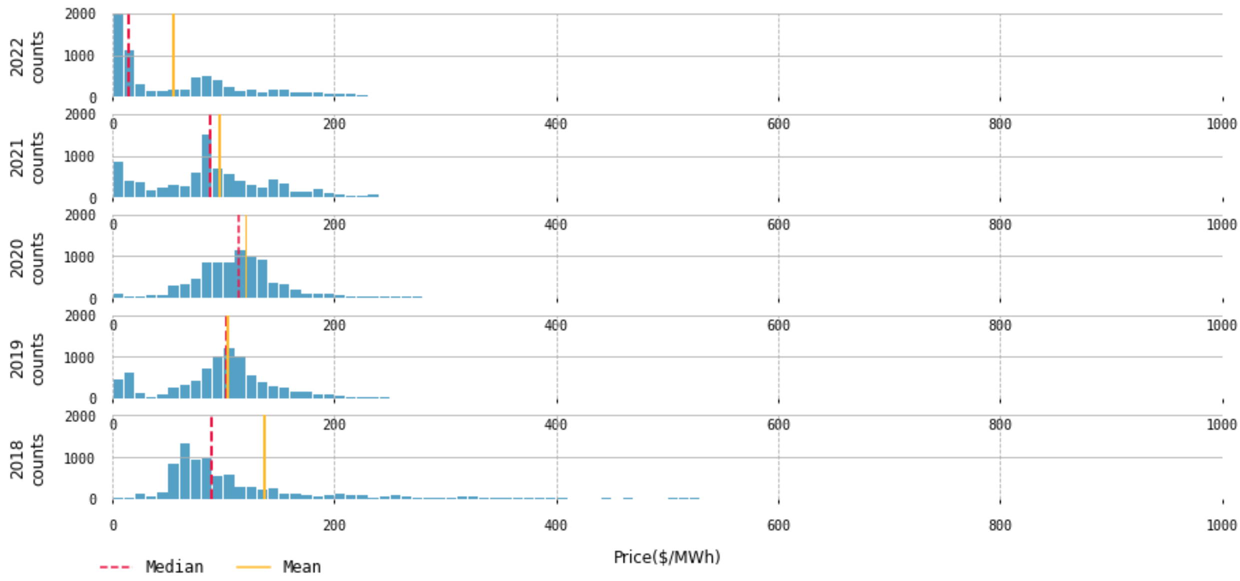
8 Opportunity cost is the cost of the foregone use of a resource. For a fuller definition see page 49 in: https://www.ea.govt.nz/assets/dms-assets/29/Monitoring-Review-of-structure-conduct-and-performance-in-the-wholesale-electricity-market-updated-paper.pdf

9 We are interested in both the mean and median to get a fuller picture. The median can be defined as the number that is found in the middle of the set of data, so is not affected as much as the mean is by some very large values in the data.

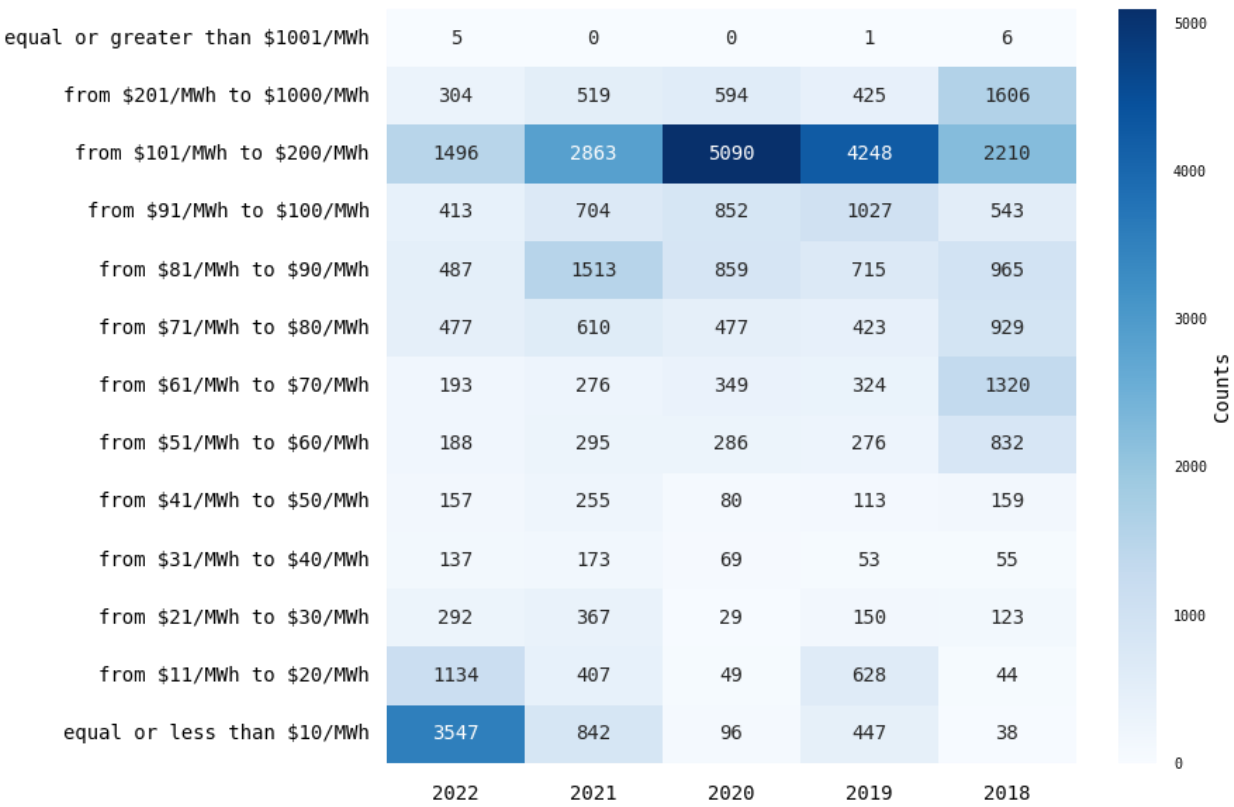
10 Note that 2019 also had a relatively higher frequency of lower prices. This was the year in which spilling occurred from November in the South Island and a UTS was found between 3 to 27 December. Prices were corrected for this UTS (corrected prices shown here).

Figure 23: Histogram of spot prices by year 2018-2022, 1 July to 31 December



8.7 Figure 24 shows a heatmap of the half-hourly spot prices in the different pricing bands for 2018 to 2022 1 July to 31 December in each year. 3547 trading periods in 2022 were less than or equal to $10/MWh (or 40 percent of all trading periods from 1 July to 31 December). Compared to 2022 previous years have a significantly lower number of trading periods less than $10/MWh and between $11/MWh and $20/MWh. The period 1 July 2021 to 31 December 2021 had the next highest number of trading periods less than $10/MWh, which was the first 6 months of the new trading conduct provisions.

Figure 24: Heatmap of spot prices by year 2018-2022, 1 July to 31 December



8.8 Very low prices have occurred more often during the day in 2022 and 2021 (since the new trading conduct provisions came into effect) and are on average lower than in previous years.

8.9 Table 1 shows the percent of prices less than or equal to $10/MWh that occurred in off-peak trading periods during the day, and the median price of these prices. 30 percent of these prices occurred in off-peak trading periods during the day in July to December 2022. In comparison in 2021 this was 21.1 percent and between 2015 and 2020 this was 12.9 percent.

8.10 50 percent of prices less than or equal to $10/MWh in July to December 2022 were less than $0.56/MWh, which is similar to the median of low prices in July to December 2021 and quite a lot lower than the median of low prices in July to December between 2015 and 2020.

Table 1: Very low prices, 1 July to 31 December

Year	Percent of very low prices that occurred in off-peak times during the day (9am to 4.30pm)	Median price of the very low prices (all trading periods)
2022	30.0	0.56
2021	21.1	0.43
2015-2020	12.9	4.93

8.11 Overall, the frequency of prices less than or equal to $10/MWh for July to December 2022 compared to previous years is much higher. There has been an increase in the proportion of these very low prices occurring in off-peak times during the day, rather than just occurring overnight. These observations suggest that prices - and therefore offering behaviour - are following underlying conditions more closely than in previous years, which is indicative of competitive behaviour. This is the same finding as in the post implementation review.

Price Separation

8.12 An indication of economic withholding (consistent with the exercise of significant market power) would be subdued price separation, although subdued price separation can also result from hydro generators trying to conserve water in periods of low hydro storage or for other reasons. 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

8.13 In the wholesale market competition review (WMR),[11] we found that differences in price between the North Island and South Island were subdued over the review period when hydro storage was 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.

[11] https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2021/wholesale-market-competition-review-2/

8.14 In the post implementation review, we found that price separation had become more pronounced since the new trading conduct provisions came into effect (from 1 July 2021 to 31 July 2022).

8.15 Table 2 shows that price separation has continued to be slightly more pronounced over the period 1 July 2022 to 31 December 2022, compared to previous years (for price separation between Benmore and Haywards, and between Manapouri and Benmore). This suggests that economic withholding may be occurring less frequently since the trading conduct provisions came into effect.

Table 2: Price separation, for periods of high hydro storage (1 July to 31 December)

	Ratio of Haywards to Benmore price		Ratio of Benmore to Manapouri price	
Year	**Mean**	**Median**	**Mean**	**Median**
2022	12.19	1.04	9.77	1.06
2021	68.72	1.06	26.92	1.09
2015-2020	1.35	1.04	8.43	1.09

Note: this only includes trading periods when hydro storage is high (ie., where total New Zealand storage is greater than or equal to 100 percent of mean). We have also excluded periods for the Haywards/ Benmore ratio where one or more of the HVDC poles has been on outage, and periods for the Benmore/Manapouri ratio where there was an outage for the CUWLP (ie, the Naseby to Livingston line or the Naseby to Roxburgh line was on outage). It also excludes 9 August 2021 when demand was cut.

Percent of offers above $300/MWh, final price, and various estimates of cost

8.16 In the WMR, we discussed how we were 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). The WMR observed that there seemed to be a significant quantity of high offers for some generators that are not always related to underlying supply and demand conditions, including hydro storage and thermal fuel costs, during the WMR period.

8.17 The post implementation review found that for the period 1 July 2021 to 31 July 2022, generator offers were more closely related to underlying supply and demand conditions, with low percentages of high-priced offers and offers above estimates of cost for all hydro generators, except Mercury's Waikato offers.

8.18 Hydro plant offer tranches, with reservoir storage overlayed, from 1 July 2022 to 31 December 2022, are shown in Figure 25 to Figure 29.

8.19 Meridian's Waitaki offers appear to have followed storage quite closely over this period (see Figure 25). Between July-September, the majority of offers in the Waitaki scheme were either less than $1/MWh or between $100-$300/MWh as storage increased from ~85 per cent of mean to over 160 per cent. Between September and December, as storage remained high, at over 140 per cent of mean, nearly all offers at Waitaki were below $100/MWh. In December, even as storage began to fall, most offers were below $50/MWh.

Figure 25: Meridian Waitaki plant offers.

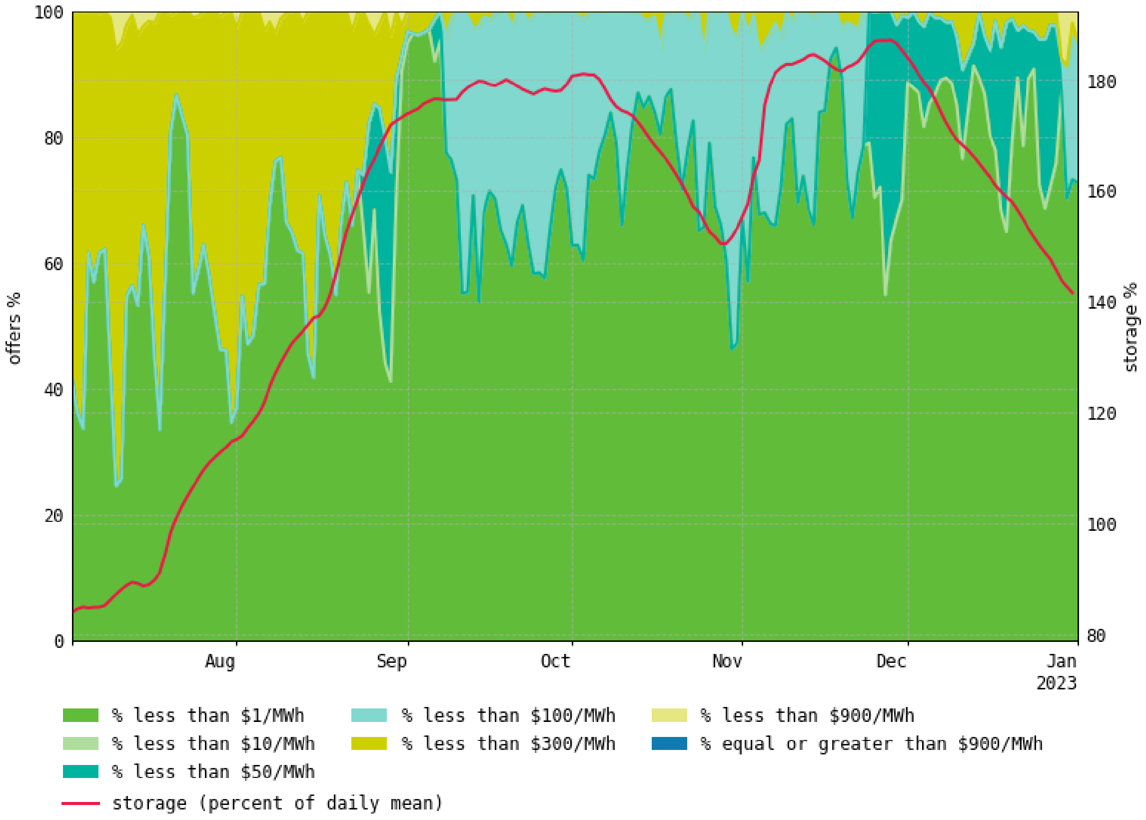
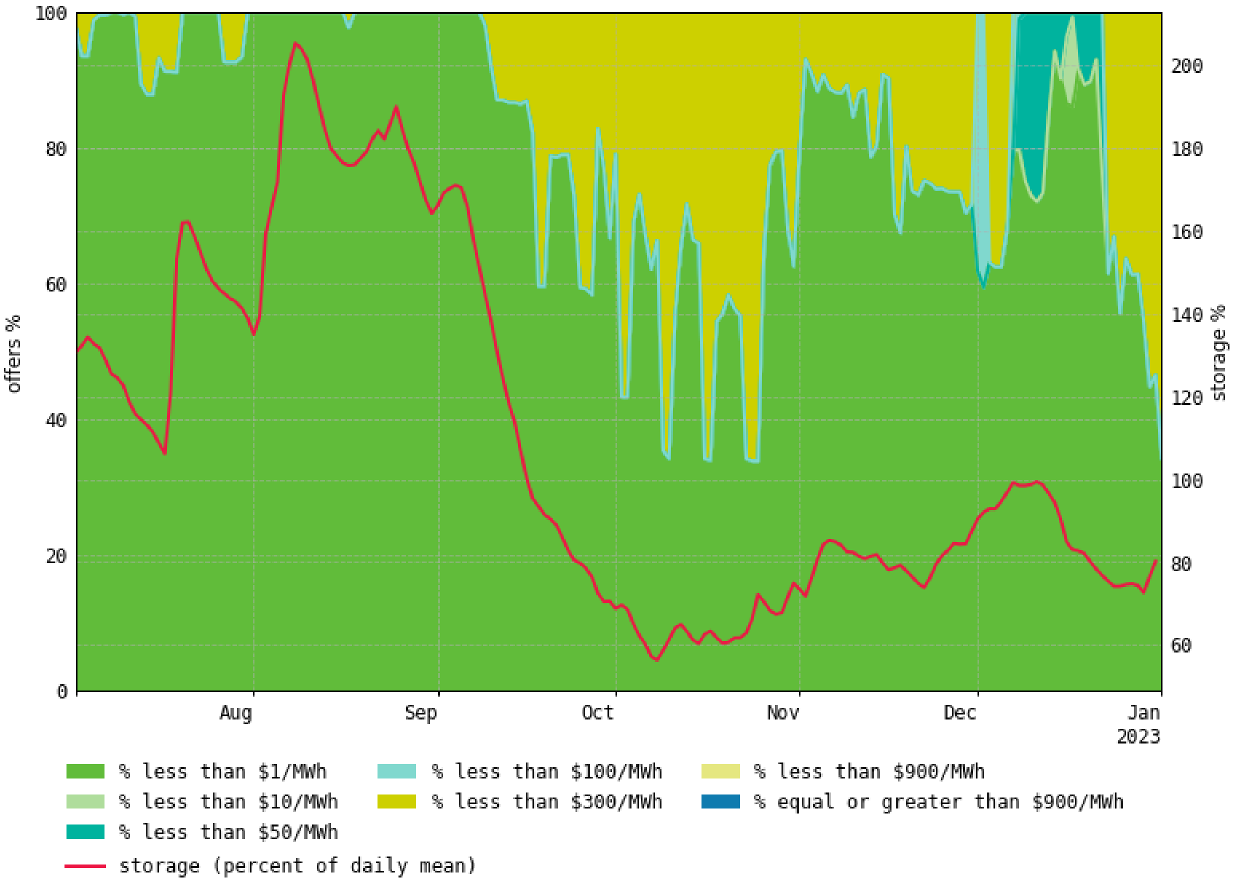
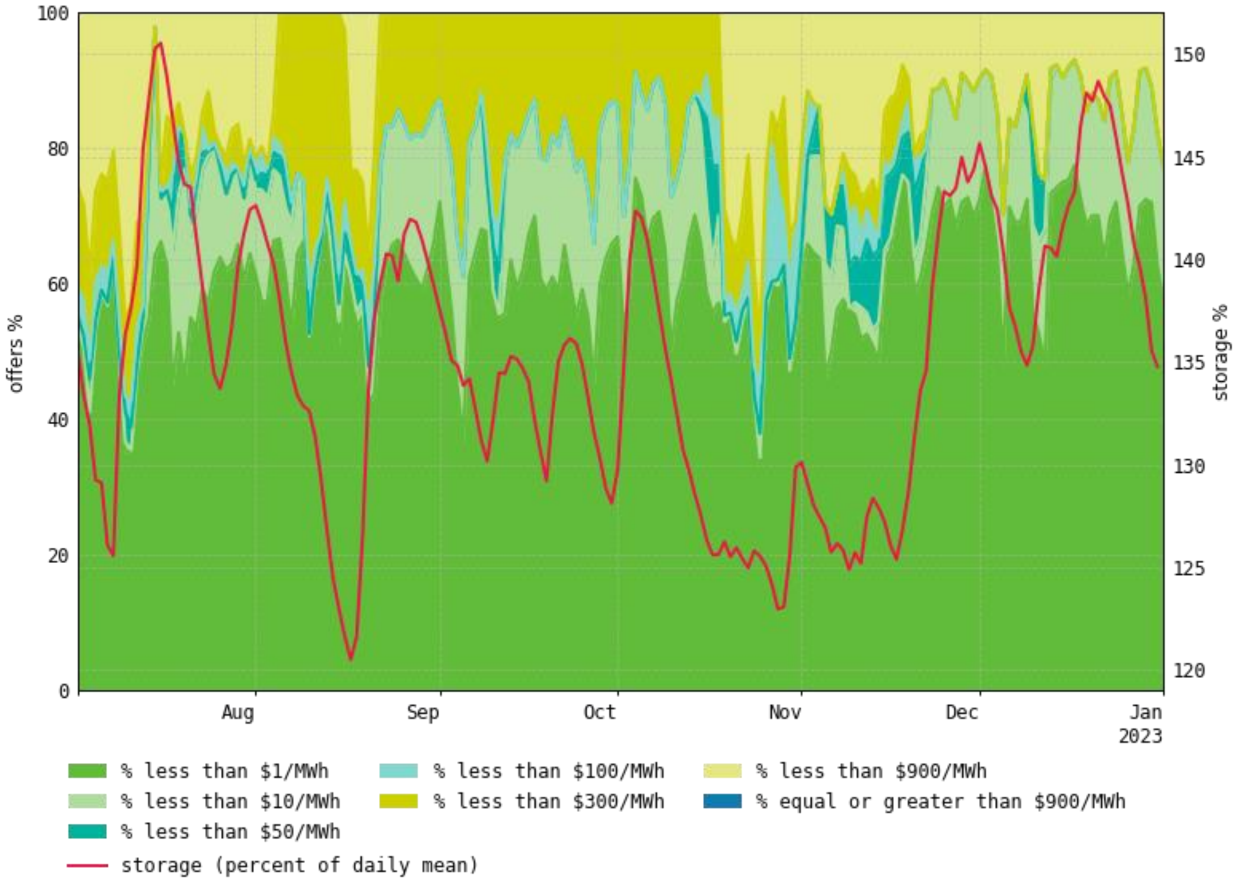


Figure 26: Meridian Manapouri offers.



8.20 Offers at Manapouri have also changed alongside fluctuating storage (see Figure 26). Between July and August, as storage was above 100 per cent of mean, nearly all offers were below $1/MWh. Between September and October, as the lake level fell to between 60-80 per cent of mean, offers priced between $100-300/MWh increased. Between November and December, as lake levels at Manapouri remained rather consistent between 80-100 per cent of mean, a larger volume of offers were priced lower than $1/MWh.

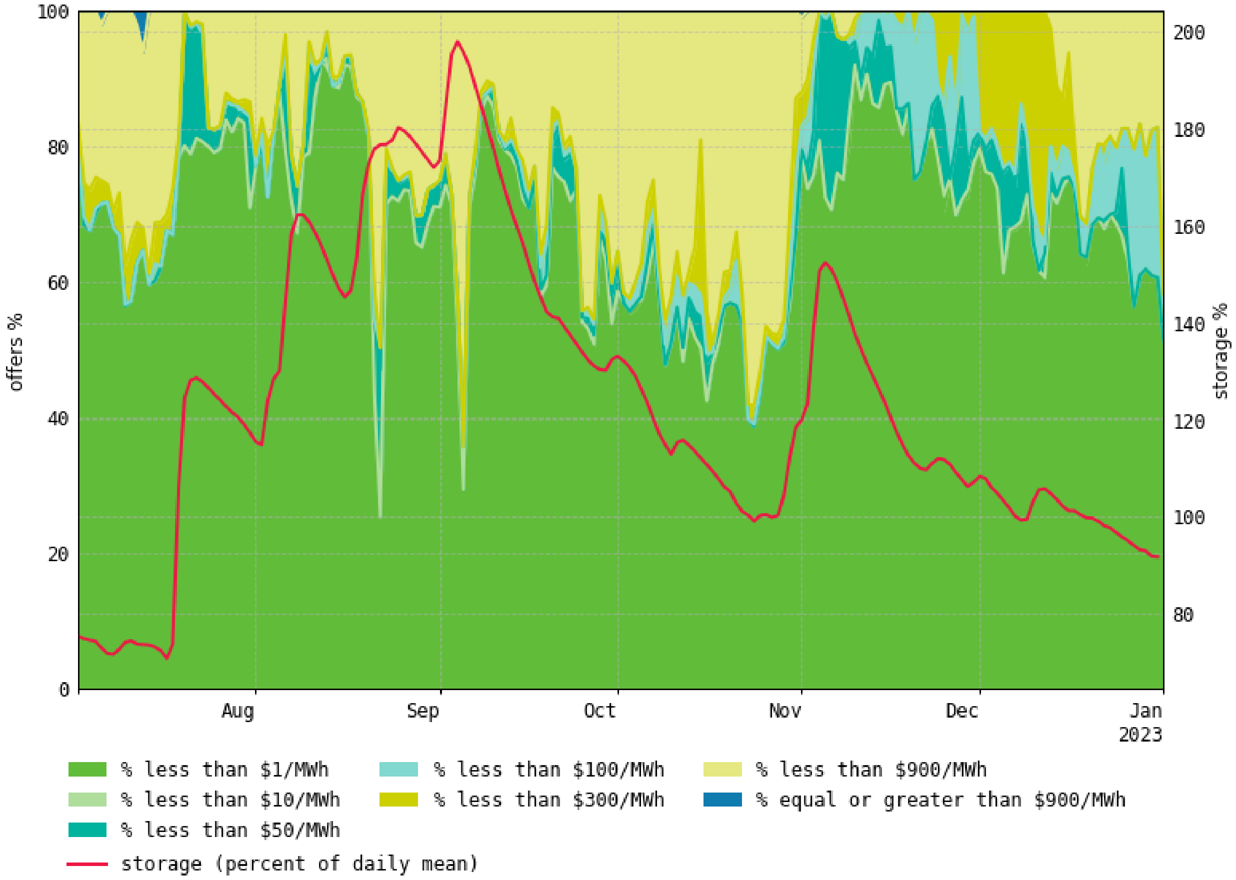
Figure 27: Mercury Waikato plant offers



8.21 For offers along the Waikato, Mercury's offer prices followed storage somewhat, although the offer price variation was small (See Figure 27). The Waikato has less ability to store water than the Tekapo and Waitaki schemes – that is, it is essentially a run-of-river scheme. This means Mercury needs to manage flows through their system to that the water is in head ponds when it is needed. This gives them less flexibility to change offers with changing Taupo storage levels.

8.22 We also looked at Mercury's offer prices for peak trading periods and off-peak trading periods separately. During peak trading periods when storage was high, Mercury often had close to 100 percent of offers priced at less than $10/MWh. Offers in the $300-900/MWh price range occurred less between August – mid October when storage was more consistently higher, and more from mid-October onwards when storage decreased. When storage rebounded in late November Mercury increased its offers priced at less than $10/MWh, especially during peak trading periods although still had some quantity offered in off-peak trading periods at above $300/MWh. This may have been partly driven by conservation of water for the HVDC outage scheduled at the end of February and lower demand during December.

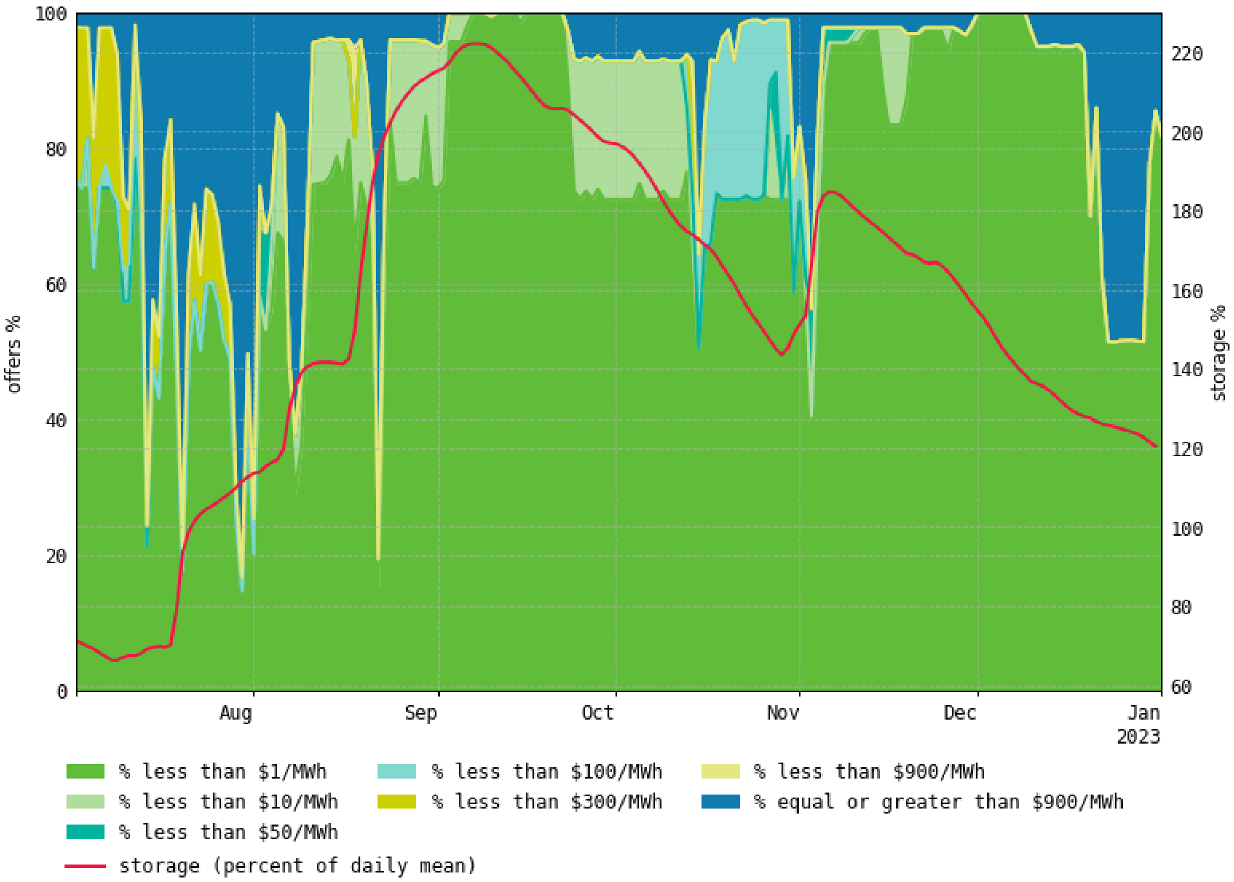
Figure 28: Contact Clutha plant offers



8.23 Contact's Clutha scheme also has little controllable storage and can be considered a run-of-river scheme. Despite having less flexibility, Contact's offers on the Clutha have followed lake levels quite closely over the period examined (see Figure 28). Between July and August, as storage increased, most offers were priced below $1/MWh. However, there appear to be days in late August and early September, when storage was very high, where the amount of low-priced offers suddenly dips. Our weekly trading conduct monitoring found over this period that spot prices were consistent with underlying conditions, and did not pick up at the time any trading periods where these dips in low-priced offers from the Clutha scheme may have contributed to increases in the spot price. We may re-visit our analysis to check this finding.

8.24 As storage fell throughout September and October the volume of offers priced between $300-900/MWh increased. After the bump in storage in early November, Contact offered near to 100 percent of quantity at less than $100/MWh until December, when it began reducing lower-priced offers again as storage continued to decline.

Figure 29: Genesis Takapō plant offers



8.25 The volume of low-priced offers at Takapō increased as storage approached over 200 percent of the mean in early September. However, before then (when storage was lower but recovering), there were instances where most of the energy at Takapō was offered in at above $900/MWh. Our weekly trading conduct monitoring found that spot prices were generally consistent with underlying conditions over this period, and did not pick up at the time any trading periods where higher offer prices from Genesis's Takapō scheme may have contributed to higher spot prices. From September onwards most energy was offered at below $1/MWh.

8.26 Table 3 to Table 7 show the percent of offers above $300/MWh, final price, and various measures of cost, for 1 July to 31 December compared to previous years, when hydro storage was high [12]. These tables show that high priced offers decreased along the Waikato and the Waitaki when compared to the same time in previous years. Takapō and the Clutha scheme had a higher percentage of higher offers when compared to most previous years, but these plants have historically had very low percentages of higher priced offers. The percentages of higher priced offers at the thermal plants Stratford and Huntly both increased when compared to previous years. During this time Contact had issues with both the Stratford peakers and TCC. The second Stratford peaker was on outage from the start of August until mid-November. TCC was also on

[12] Only trading periods when hydro storage was high are included for each table – ie, where total New Zealand storage or storage for the relevant catchment is greater than or equal to 100 percent of mean. This is to control for storage. Only periods of high hydro storage are included because there were no trading periods where total New Zealand storage, Pukaki, Tekapo or Clutha storage were low (ie, less than 80 percent of mean) in these months in 2022.

outage from mid-August to early September. Additionally, after the outage TCC remained off due to restrictions on running hours ahead of more maintenance scheduled for early 2023.

8.27 These results continue the trend seen in the post implementation review of offer prices following conditions and economic costs more closely than in previous years.

Table 3: Percent of offers above $300/MWh (1 July to 31 December)

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	Stratford	Huntly
2022	10	0	13	12	89	26
2021	35	4	9	5	67	19
2019-2020	40	25	6	6	36	17
2014-2018	6	24	6	0	2	4

Table 4: Percent of offers above final price (1 July to 31 December)

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	Stratford	Huntly
2022	26	24	15	28	98	40
2021	53	33	11	17	82	30
2019-2020	49	34	8	31	59	25
2014-2018	37	39	22	7	64	20

Table 5: Percent of offers above the average forward price (1 July to 31 December)

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	McKee	Huntly OCGT	Stratford peakers	Rankines (coal)	E3P	TCC
2022	12	5	12	15	90	84	97	32	20	42
2021	30	11	7	8	60	55	62	24	14	21
2019-2020	31	22	5	12	35	61	62	27	9	11
2014-2018	21	22	13	2	60	63	45	16	4	9

Table 6: Percent of offers above thermal SRMCs (1 July to 31 December)

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	McKee	Huntly OCGT	Stratford peakers	Rankines (coal)	E3P	TCC
2022	7	1	13	11	92	81	98	11	24	48
2021	24	8	10	6	87	52	42	23	20	15
2019-2020	30	27	6	14	56	28	64	19	13	9
2014-2018	20	31	18	3	87	22	49	21	14	19

Table 7: Percent of offers above water values (16 September[13] to 31 December)

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)
2022	15	15	11	25

Relationship of storage and offers to cost

8.28 Table 8 to Table 10 show the relationships between the average water values for each associated reservoir and hydro storage and offers, for 16 September to 31 December 2022, when hydro storage was high. Figure 30 shows the relationship between these water values and offers for 16 September to 31 December 2022.

8.29 Table 8 shows that between 16 September to 31 December 2022, the JADE water values were strongly negatively correlated with storage across all the Clutha, Waikato, Waitaki and Takapō schemes.

8.30 The Waitaki, Takapō and Clutha schemes had positive correlations between offers and the JADE water values (both for the daily percentage of offers greater than $300/MWh and for QWOP). However, the Waikato scheme had a negative correlation. Note again that the Waikato and Clutha schemes have less flexibility due to the run-of-river nature of the schemes.

8.31 These correlations are weaker than those found in the post implementation review period - although not directly comparable due to changes in the water value methodology used. However, both Mercury and Genesis (for the Waikato and Takapō schemes) had a low percentage of offers above water values and other estimates of cost.[14] That is, the overall picture provided by all of the indicators suggests a

[13] Note that we only have data using our new calculations of water values from 16 September 2022. These water values are calculated at the beginning of each week for the following week. Previously (for the wholesale market review and the post implementation review) we have calculated water values using a backwards looking approach (using actual fuel input costs, actual plant and HVDC outages, and reconciled load data to calculate historical water values). Our new water values are now also reported for individual reservoirs whereas previously we used an average over all reservoirs. Due to this change we have not compared to previous years results here. Details of how the water values are calculated can be found on this page: https://www.ea.govt.nz/monitoring/market-performance-and-analysis/monitoring-trading-conduct/market-monitoring-weekly-reports-2022/ (Appendix B JADE water value model).

[14] Additionally, we only have data for 3.5 months for the water values, which is a relatively short period for looking at correlations.

continuation of the new trading conduct provisions having an impact on generator behaviour.

Figure 30: QWOPs and average water values

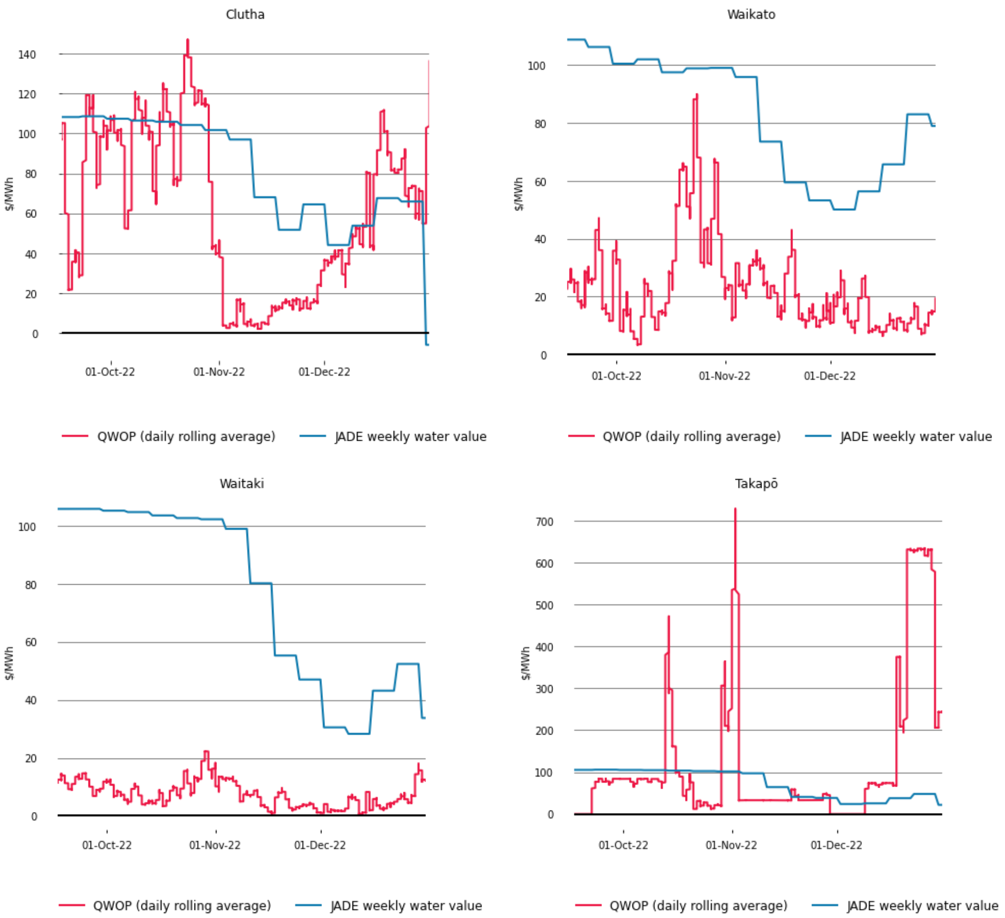


Table 8: Correlations of water values with hydro storage (16 September to 31 December)

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)
2022	-0.48	-0.76	-0.56	-0.61

Table 9: Correlations of water values with percent of offers above $300/MWh (16 September to 31 December)

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)
2022	-0.46	0.19	0.13	0.69

Table 10: Correlations of water values with QWOP (16 September to 31 December)

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)
2022	0.18	0.38	-0.12	0.005