Market performance quarterly review

April - June 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

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1. Purpose

1.1 This is a review of the performance of New Zealand's energy market from 1 April to 30 June 2025. It aims to provide visibility of the monitoring of the market undertaken by the Electricity Authority Te Mana Hiko (Authority) during this period.

1.2 This review seeks to assess whether spot electricity prices were reflective of underlying energy supply and demand conditions faced by the sector for quarter 2 (Q2) 2025. It also analyses changes in the retail and forward market. This review also includes our six-monthly structure, conduct, performance (SCP) review which assesses whether observed outcomes in the market are consistent with competitive outcomes. The approach used is the same as that for the post implementation review of the trading conduct provisions.

1.3 We want to provide visibility of previous market conditions, and of the Authority's market monitoring, to give the energy sector confidence that prices are being set in a competitive market. This reflects the expectations set out in paragraph 29 of the Government Policy Statement to the Electricity Authority (October 2024) that "effective competition is essential for our electricity system to deliver reliable electricity at lowest possible cost to consumers".

2. Highlights

2.1 Spot prices rose from January to April due to a decline in hydro storage, with prices sitting mostly above $250/MWh. The latter part of Q2 saw a significant dip in daily average spot prices due to a combination of increased gas supply from Methanex and an increase to hydro inflows. The mean spot price during this quarter was $217/MWh.

2.2 Daily demand was above the historic average (last five years) for most of Q2. Cool temperatures drove up demand towards the end of the quarter.

2.3 Meridian and the New Zealand Aluminium Smelter agreed to shorten the demand response deal that was in place since March, with the smelter ramping up from 16 June.

2.4 Hydro storage increased during this quarter with national storage going above mean from the end of June for the first time since late January. However, storage remained below mean in some South Island lakes.

2.5 Thermal generation was high at the start of the quarter accounting for around 17-20% of weekly generation. This reduced to between 8 and 14% for the latter half of the quarter once hydro generation increased to above 50%.

2.6 The gas spot price increased slightly from quarter 1 to $19/GJ. The carbon unit price dipped to $50/NZU during the quarter before increasing to $56/NZU by the end of June.

2.7 Meridian again topped the list for biggest gain in ICPs this quarter (mostly due to growth in Powershop customers). Genesis had the biggest net loss of ICPs again, mostly due to its subsidiary Frank Energy consolidating into the Genesis brand.

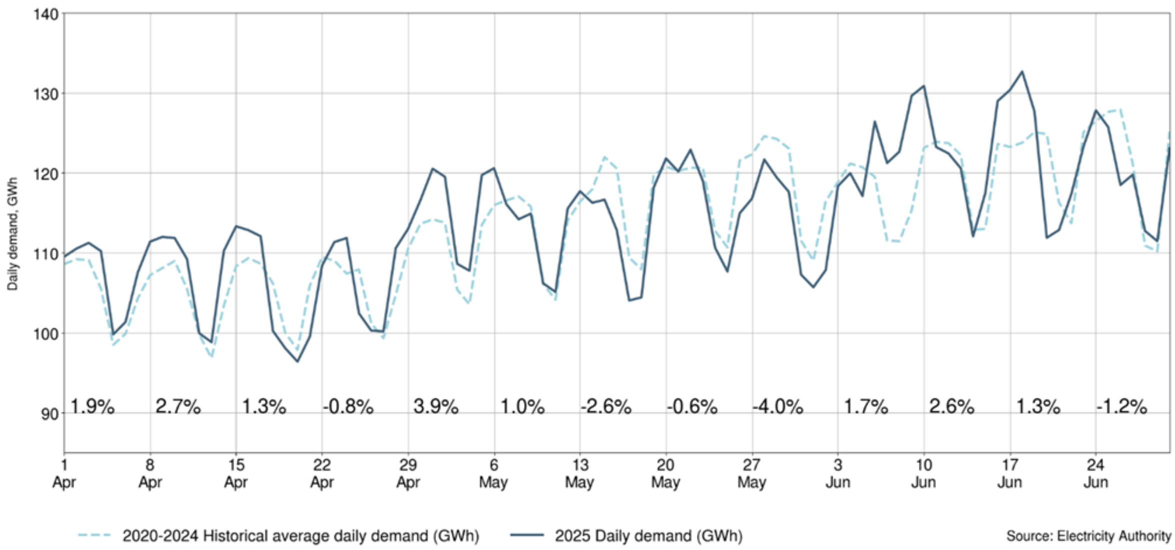
2.8 There was a significant increase to retail electricity prices this quarter mainly from increases to lines charges. In inflation adjusted terms, the increase compared to the same quarter last year is around $290 per year for an average household using 8000kWh/year. Note there are large regional differences in tariff rises, with regions seeing monthly increases from $7 to $29 per household.

3. Electricity demand

Demand across the quarter

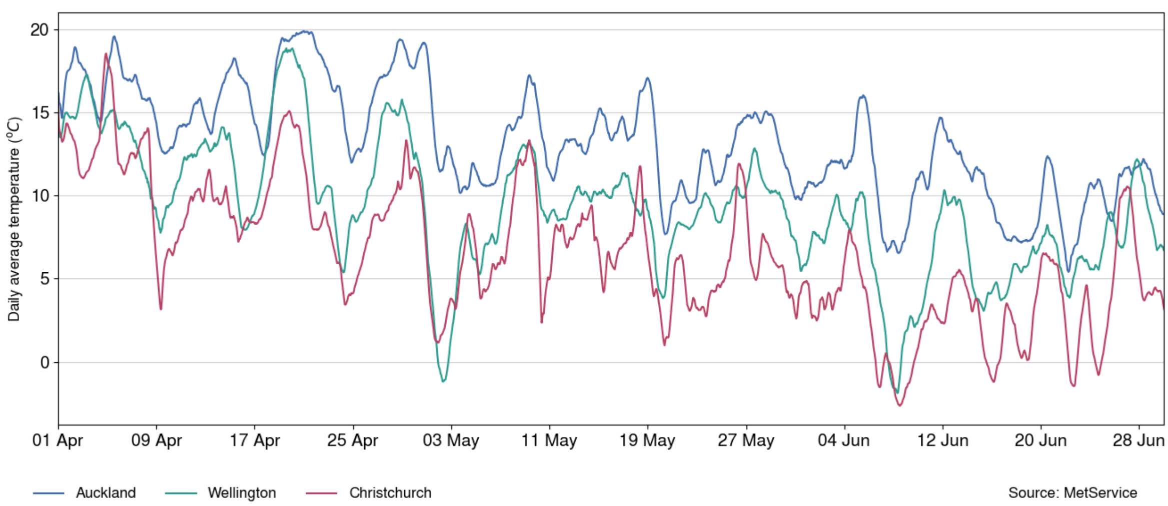
3.1 Figure 1 shows the total daily electricity demand 2025 and the 2020-24 historic average demand between April and June.

Figure 1: New Zealand daily demand compared to historical average, April to June 2025



3.2 Daily demand trends were higher through most of April apart from the Easter weekend. A milder May than last year saw daily demand sit mostly below historical average. Cold conditions drove the uptick in demand over June. This can be seen in the daily rolling average temperature trends across Auckland, Wellington and Christchurch in Figure 2.

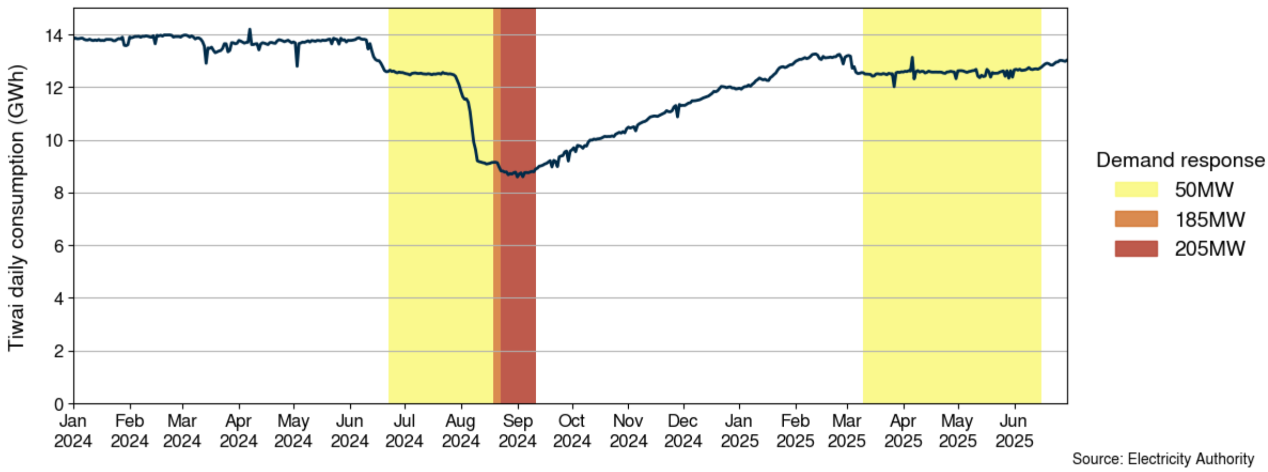
Figure 2: Daily rolling average temperatures for the 3 main centres, April- June 2025



3.3 As well as cold weather impacting demand, from mid-June the demand response deal between Meridian and NZAS[1] ended earlier than planned. The aluminium smelter at Tiwai began to ramp up production again from 16 June (Figure 3).

[1] NZX, New Zealand's Exchange - Announcements, Meridian And Nzas Agree To Shorten Current Demand Response

Figure 3: New Zealand Aluminium Smelter consumption profile from January 2024-June 2025

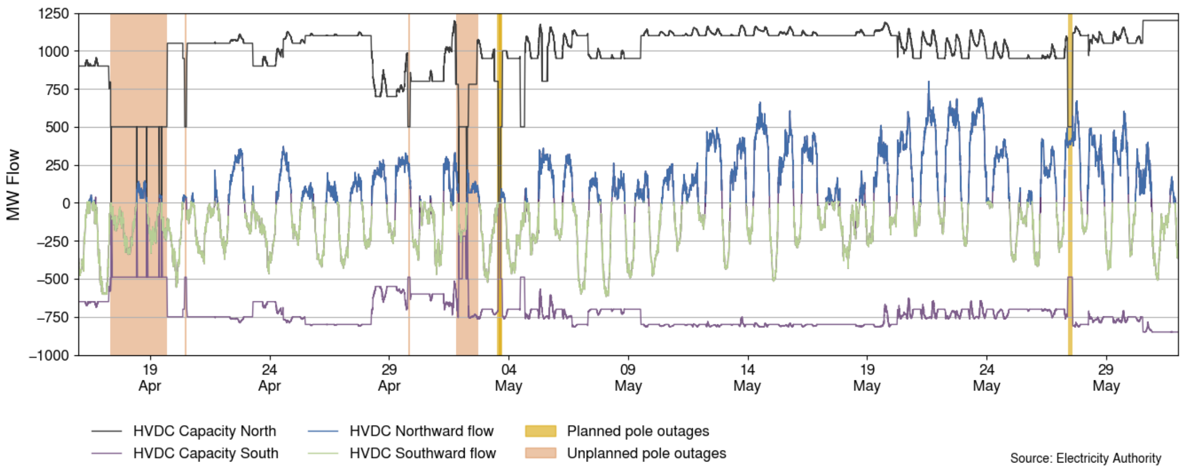


3.4 Figure 4 shows the [high-voltage direct current cables] (HVDC) flows from mid-April to the end of May. Over the end of April and beginning of May there were six HVDC pole outages. When a pole is on outage this can limit reserve sharing between the two islands and can also lead to price separation between the islands.

3.5 Most of the unplanned pole outages were short except for the one on 17 April which saw several CAN (Customer Advice Notice) revisions and was extended to 19 April. The impact of this pole outage was minimal due to the holiday weekend where demand across the country was lower.

3.6 The 1 May outage was due to contamination of insulation caused by some extreme weather. Voltage was reduced to improve resilience and system security. Live line water blasting was used to clean the insulators[2].

Figure 4: HVDC flow and capacity



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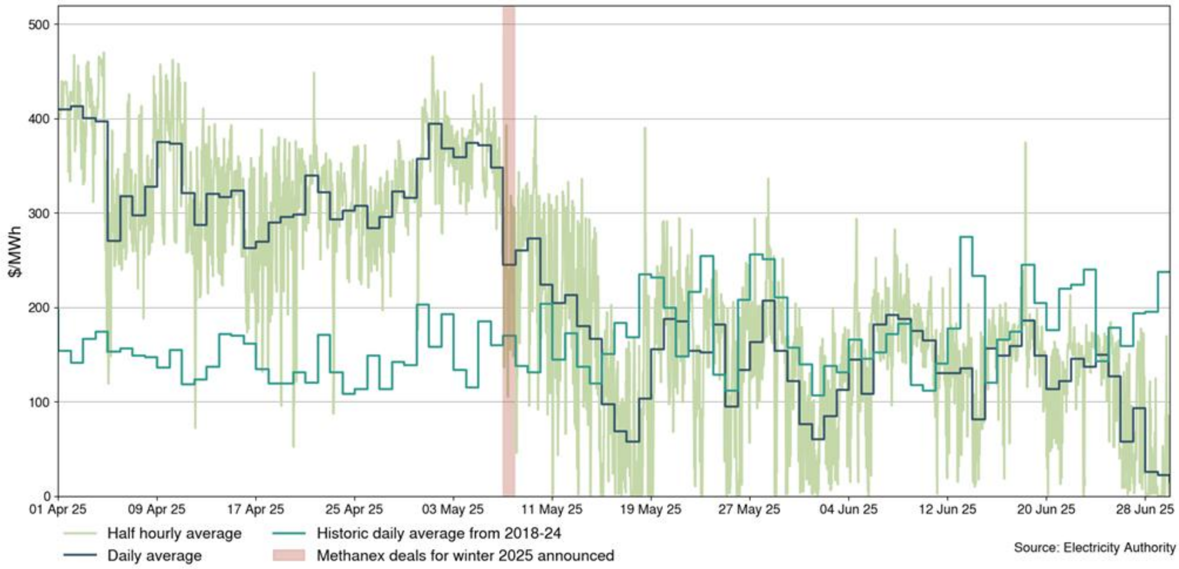
2 System operator forum slides 13 May

4. Wholesale electricity price and consumption

4.1 Figure 5 shows the half hourly and daily national wholesale electricity spot prices between April and June 2025. The historic daily average between 2018 and 2024 adjusted for inflation is also displayed.

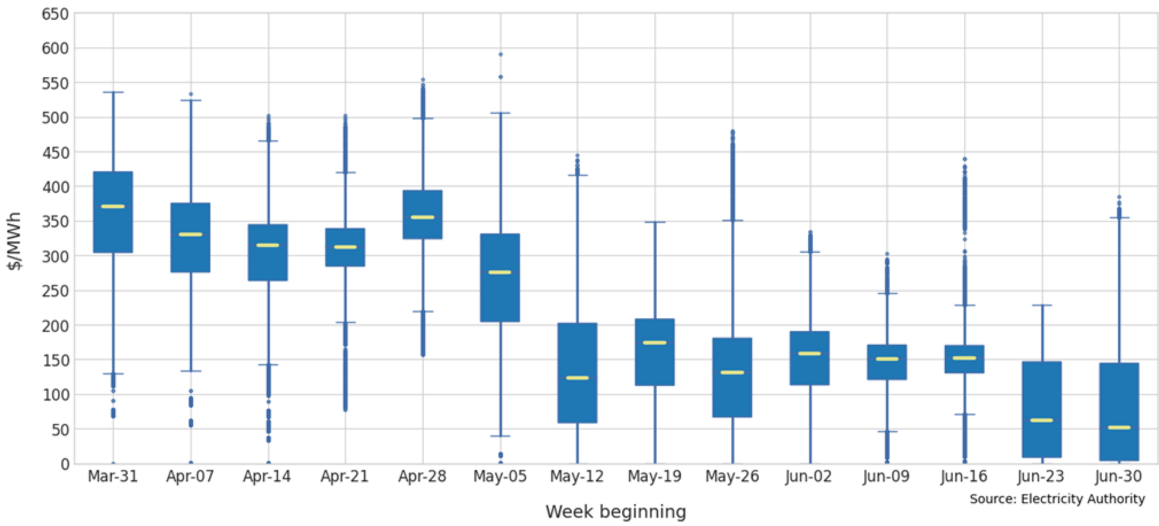
4.2 Daily average prices dropped during May, particularly around the time a deal was struck between Methanex, Genesis Energy and Contact Energy. This deal saw Methanex Motunui reduce production and make gas available to generators. There were also some increases to hydro inflows in mid-May which contributed to the decrease in spot prices.

Figure 5: Half hourly, daily and daily historic average wholesale electricity prices, April to June 2025



4.3 Figure 6 shows the weekly spot price distributions between April and June 2025. The middle 50% of weekly price distributions dropped from sitting within $304-$420/MWh at the beginning of the quarter to $4-$144/MWh at the end of the quarter.

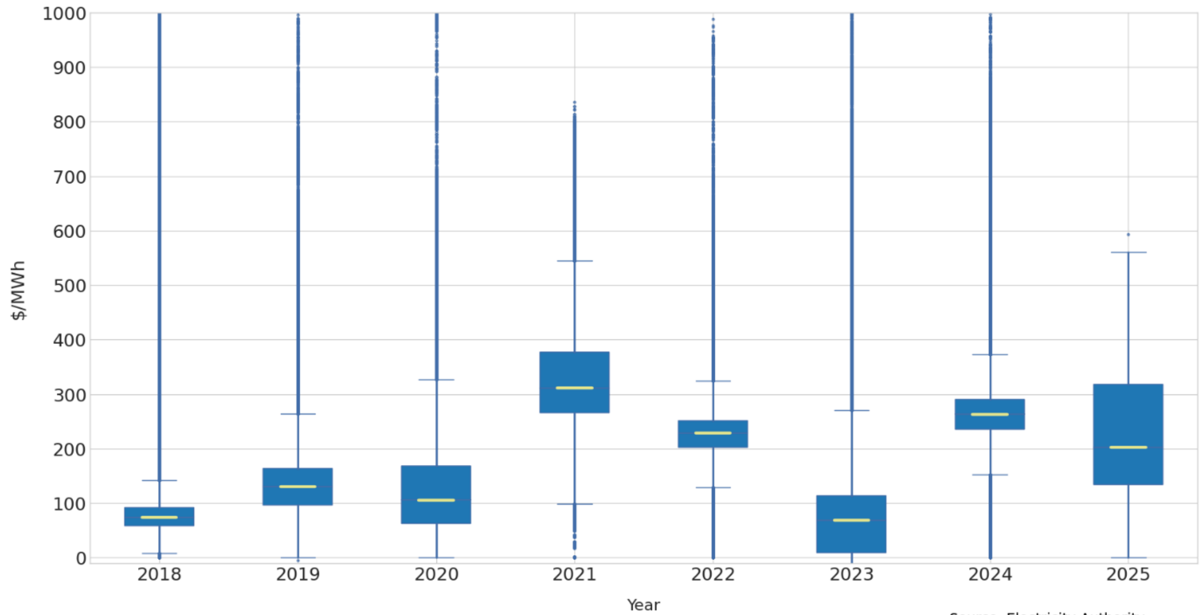
Figure 6: Box plot distributions of weekly spot prices between, April to June 2025



4.4 Figure 7 shows the distribution of spot prices across the quarter compared to previous years. The middle 50% prices in Q2 2025 were between $134/MWh and $318/MWh. The average wholesale spot price for Q2 2025 was around $217/MWh with a median of $202/MWh. Comparing to Q2 spot prices in previous years, the position of the upper 50% of prices over $200/MWh is consistent with the hydro conditions and comparable to previous years where there were lower inflows.

4.5 There are fewer high prices than previous years, which is likely due to less tight periods where spot prices get very high for a short period of time. These tight periods typically occur during cold snaps or during unexpected equipment failure and often result in low residual notices being issued by the System Operator. There were five and four low residual notices issued during Q2 2023 and Q2 2024 respectively, but zero low residual notices issued during Q2 2025.

Figure 7: Quarter 2 spot price distributions, 2018-2025



Source: Electricity Authority

Generation composition influence on price

4.6 While instantaneous demand is one of the key drivers of wholesale prices, the average wholesale market price is affected by a broad range of factors. The source of electricity generation plays a role in price, as different sources have different prices and generation characteristics.

4.7 The effects of the factors are visible at different time scales. Wind and demand have the most impact on half-hourly prices as these elements change the most quickly. Thermal generation is typically on for hours or days at a time and affects daily average prices. Hydro storage levels take days or weeks to change significantly so they can affect prices for weeks or months.

4.8 Figure 8 shows the total monthly wind generation between April and June for 2021-2025. The total volume of wind generation has been increasing over the last few years due to the commissioning of more wind farms such as Turitea (221MW, May 2023) and Harapaki (176MW, July 2024). However, wind has also been operating with a higher capacity factor[3] in Q2 2025 as seen in Figure 9.

[3] The capacity factor refers to the ratio of actual energy produced relative to the maximum energy that could be produced if it was operating continuously at full capacity. The higher the capacity factor the more effective the power plant is.

Figure 8: Monthly total wind generation Q2 2021-2025

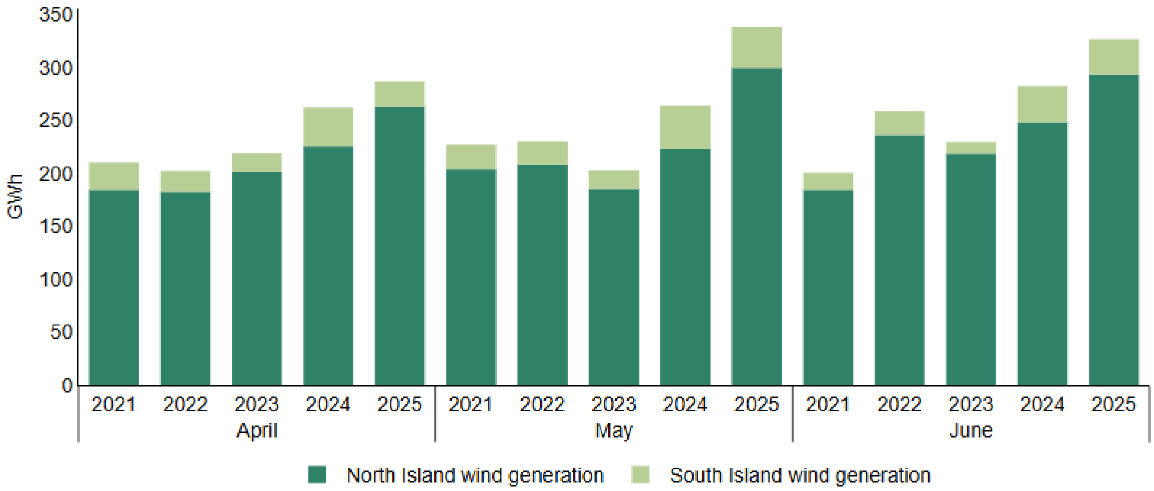
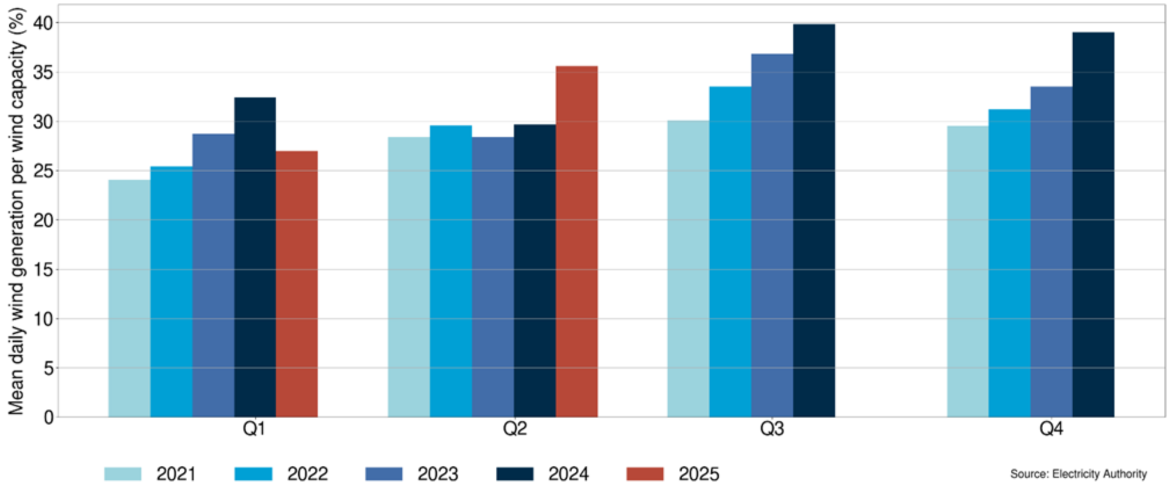


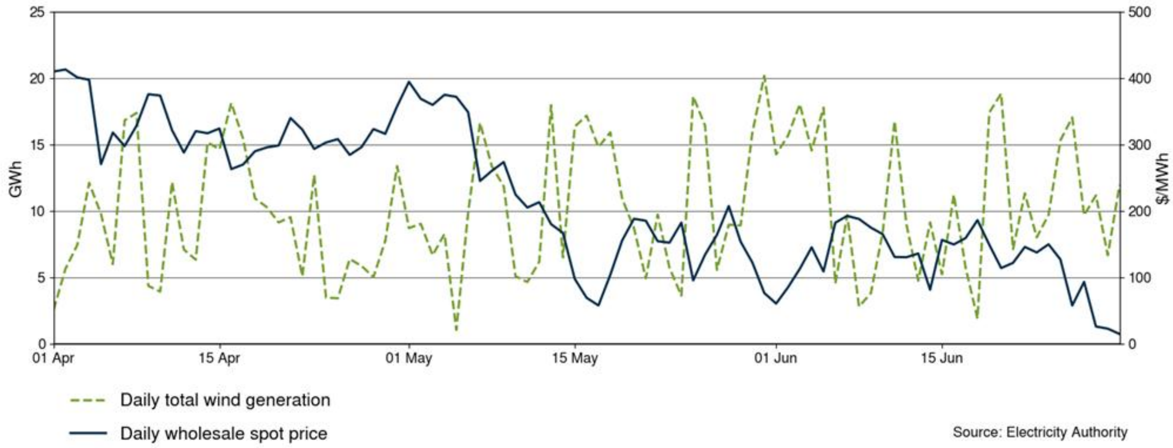
Figure 9: Average daily wind generation by quarter relative to capacity



4.9 Figure 10 shows the daily wind generation against the daily average spot price. Days with larger volumes of wind generation, which contributes to a high overall percentage of renewable generation, help to lower spot prices since there is no fuel cost associated. Wind generators can offer a lot of generation at low prices, which can displace more expensive generation.

4.10 This trend is most obvious towards the end of the quarter where days of higher wind generation tended to have a lower average spot price. The trend is less obvious at the start of the quarter when spot prices were higher due declining hydro storage.

Figure 10: Daily wind generation vs daily average spot prices, April-June 2025

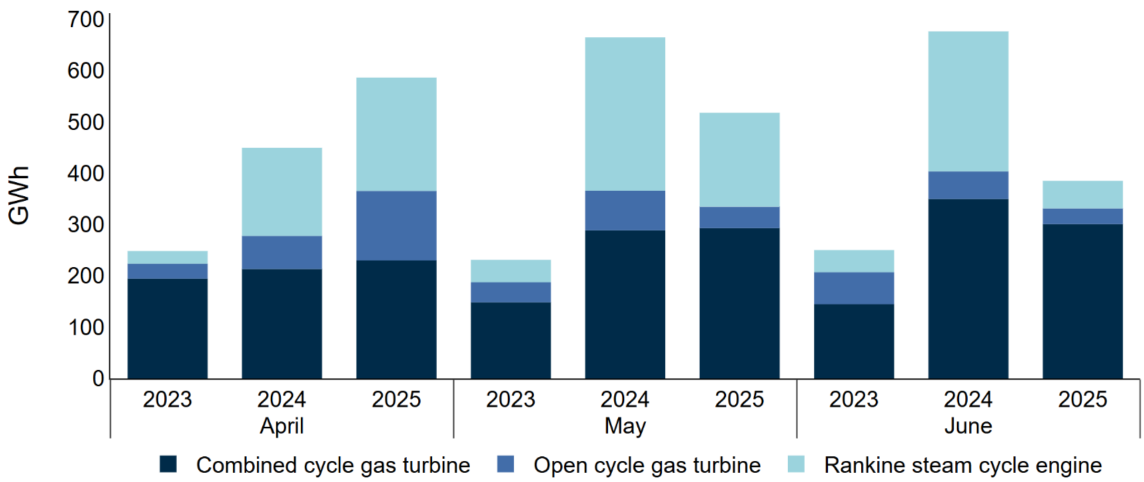


4.11 Figure 11 shows the total thermal generation by type and month in Q2 for the past three years. Thermal generation in April was higher than the previous two years due to record low inflows during Q1.

4.12 Thermal commitment was still high in May, however there was lower generation compared to May 2024 mainly due to demand being a slightly lower due to milder weather than the previous year. There was significantly less Rankine generation in June compared to 2024 due to higher hydro generation and some reasonable wind generation volumes.

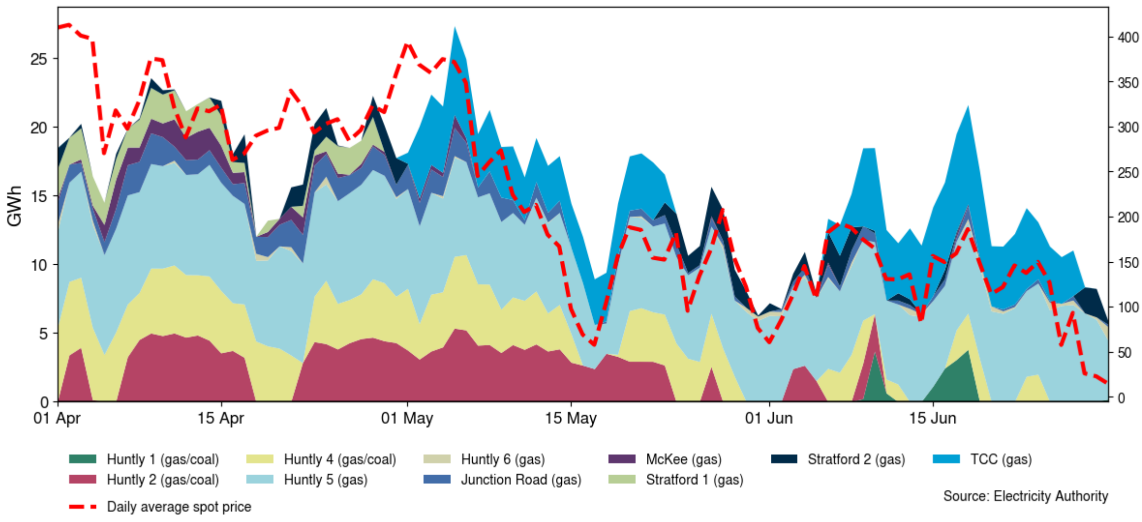
4.13 Figure 12 shows the daily total thermal generation and daily average spot price between April and June 2025. There was a high amount of thermal commitment during the first half of Q2 whilst hydro storage levels continued to fall. Thermal generation began to drop off from mid-May when inflows to hydro catchments increased. Although some low wind generation days saw some increased thermal generation in the middle two weeks of June.

Figure 11: Monthly total thermal generation, Q2 2023-25



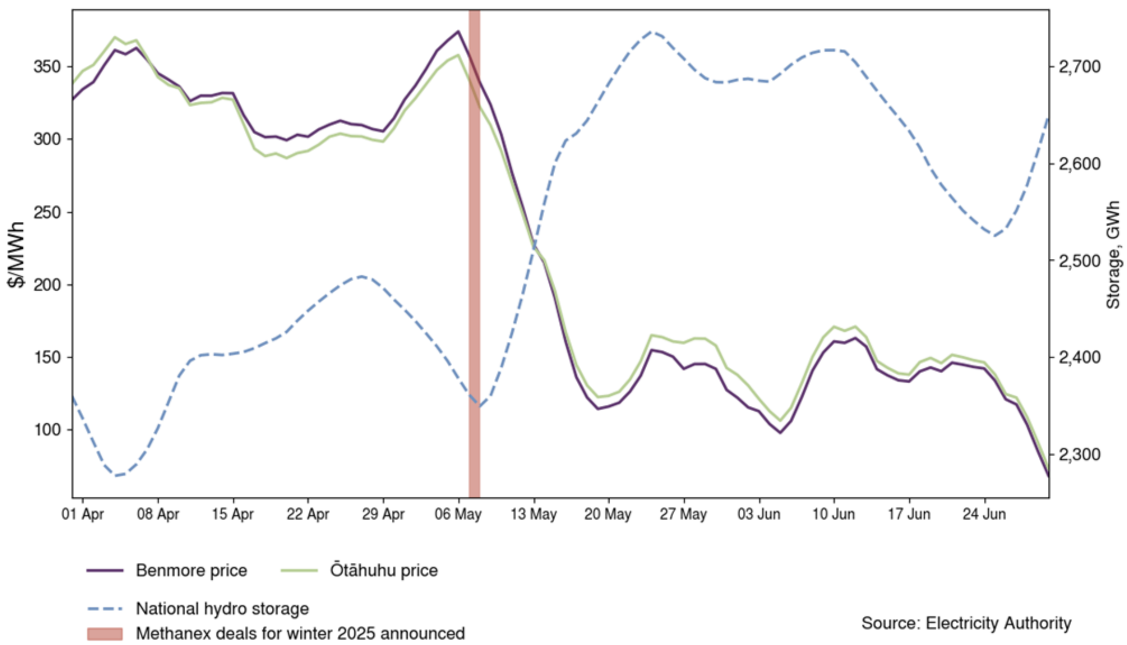
4.14 The amount of hydro energy in storage is the final element that affects wholesale electricity prices. High amounts of hydro storage keep prices lower, while low storage levels typically correlate with higher prices as hydro offers are increased to incentivise more thermal generation and conserve storage. This is not always clear on a day-to-day basis, but is easier to see over a rolling average, as in Figure 13 which shows the rolling seven-day average wholesale prices at Benmore and Ōtāhuhu and the daily national hydro storage.

Figure 12: Daily total thermal generation and average wholesale price, April to June 2025



4.15 Prices at both island reference nodes illustrate the sustained higher prices mostly above $300/MWh until the first week of May, see Figure 13. From early May, hydro storage and gas supply for electricity increased and prices dropped to be consistently below $200/MWh.

Figure 13: Rolling seven-day average of wholesale price versus hydro storage April to June 2025



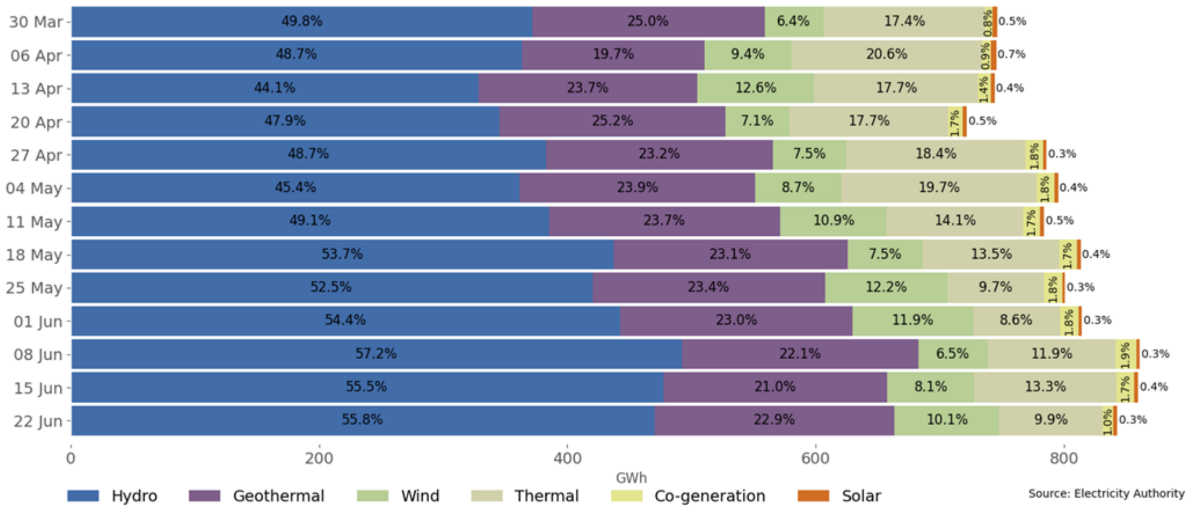
Generation by fuel type

4.16 Figure 14 shows the weekly breakdown of electricity generation by fuel type. The weekly share of thermal generation was lowest generally when wind is over 10% and hydro generation is over 50%. When the proportion of wind or hydro generation decreases, thermal generation generally increases to compensate.

4.17 The proportion of generation from hydro gradually increased over the quarter and was above 50% from the end of May. There were occasions where weekly wind generation was above 10%, reaching 12.6% one week.

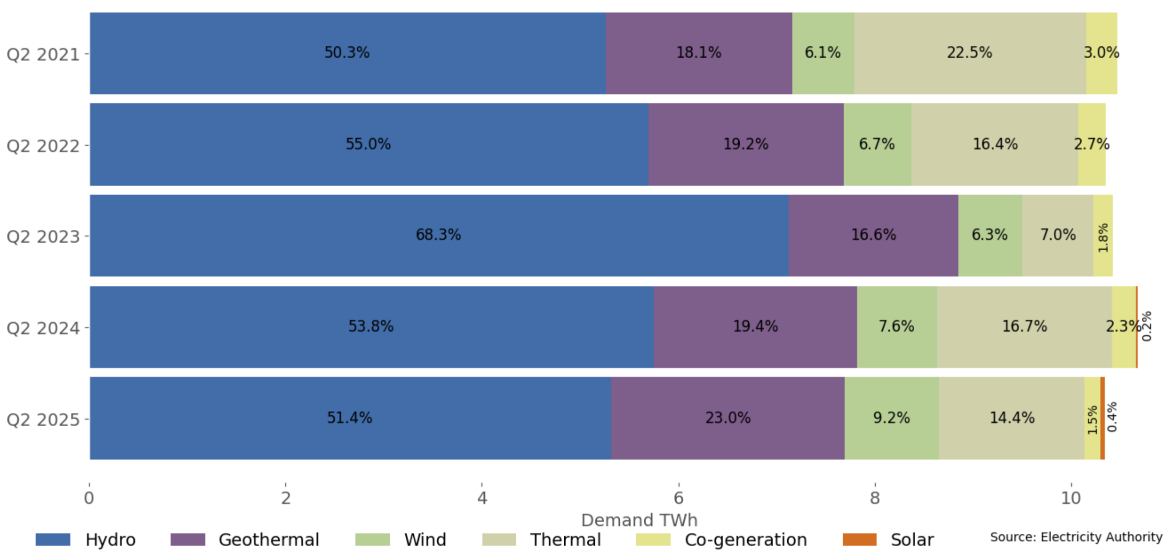
4.18 Although overall weekly demand was lower at the start of the quarter, the proportion of thermal generation was consistently above 17%, reaching 20.6% the week of 6 April. As hydro conditions improved the proportion of thermal generation dropped below 15% for the latter half of the quarter.

Figure 14: Weekly generation share by fuel type, April to June 2025



4.19 Demand was lower in Q2 2025 compared to Q2 2024, but similar to Q2 2021-2023. Figure 15 shows the quarterly breakdown of electricity generation by fuel type relative to the quarterly demand. The higher proportion of geothermal generation is due to the increased geothermal capacity on the grid after the commissioning of Tauhara and Te Huka 3.

Figure 15: Generation by fuel type for Q2, 2021-2025

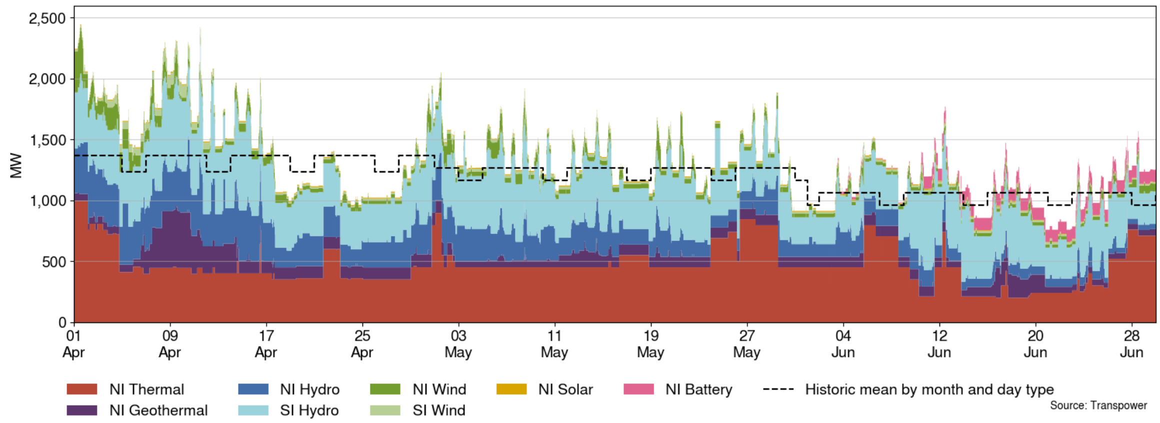


4.20 The proportion of hydro generation this quarter is similar to Q2 2021. This is reflective of the dry year conditions in both years. However, compared to 2021 there was less thermal generation due to wind and geothermal generation capacity increasing.

Outages

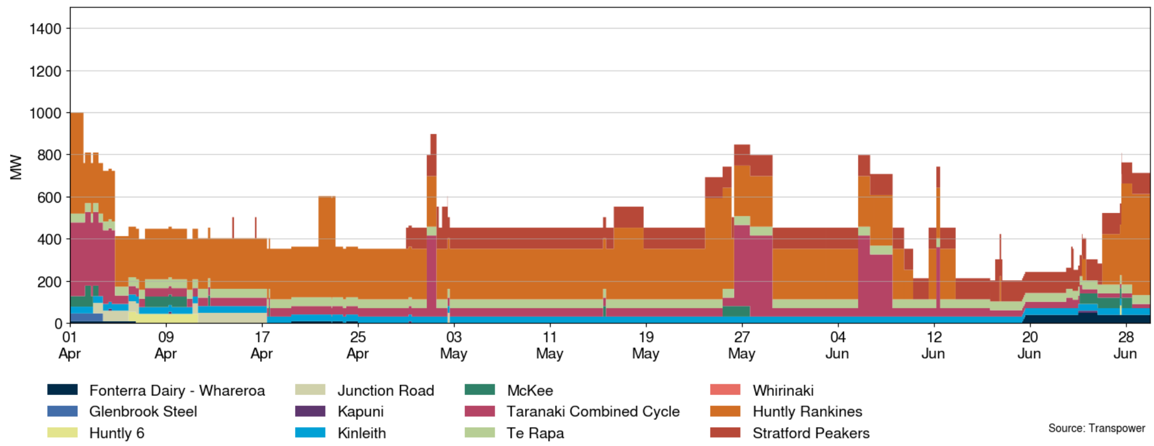
4.21 Figure 16 shows how much generation was on outage in Q2 2025. Generation outages were mostly below historic average values for the time of year, although some large thermal and geothermal outages at the start of the quarter saw outages sit above this for a time.

Figure 16: Total MW loss from generation outages, Q2 2025



4.22 Figure 17 highlights the thermal outages with all three Rankine units having multiple outages logged for across the quarter at different times. One Stratford unit went on outage at the end of April with a return date in mid-August. The other Stratford unit had multiple short outages logged over the quarter.

Figure 17: Total MW loss from thermal generation outages, Q2 2025

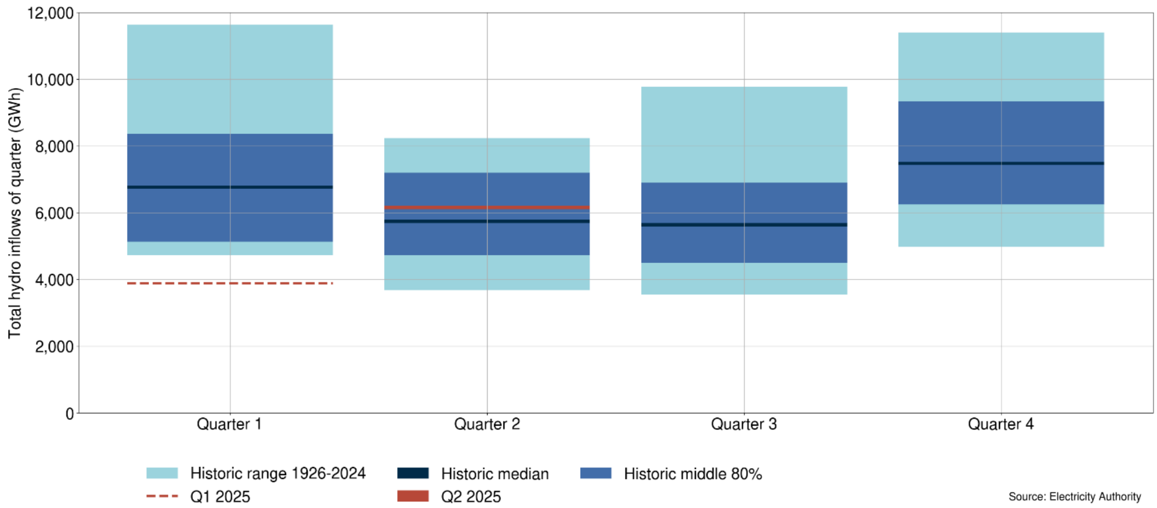


5. Hydro storage levels

National hydro storage levels

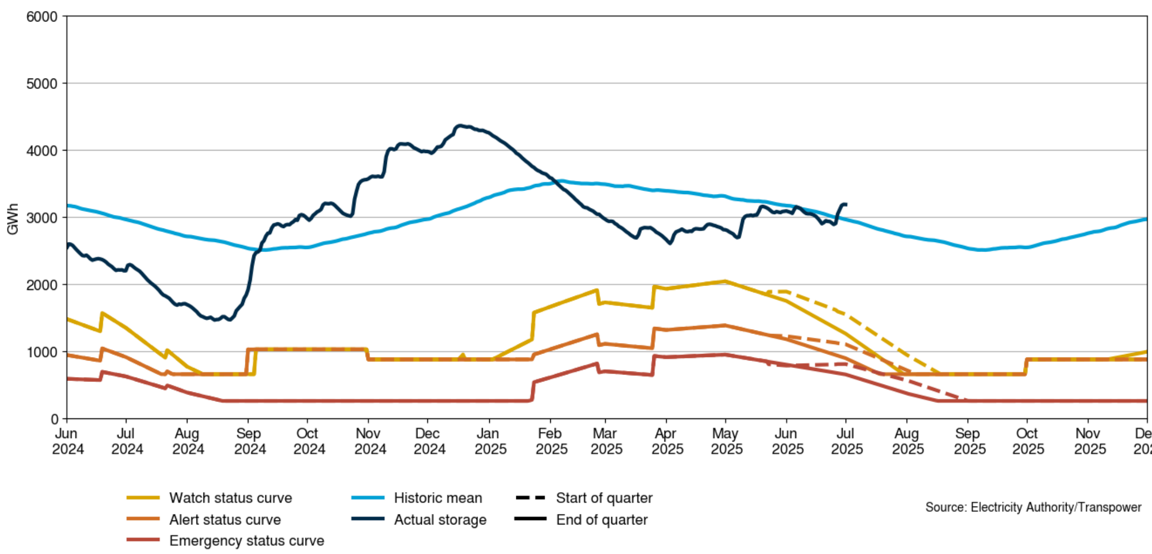
5.1 Figure 18 show the inflows to hydro catchment areas for Q2 2025. Following the lowest inflows on record for Q1, total inflows during Q2 were ~6100GWh; this is around 500GWh higher than historic median levels.

Figure 18: Total national hydro inflows for Q2 2025 compared to historic quarters, 1926-2024



5.2 Figure 19 shows the national hydro storage levels from June 2024 to December 2025. Changes in gas supply, coal availability and planned outages through May and June have seen the emergency risk curves (ERCs) decrease as we head into the latter half of winter. National hydro storage increased to above mean for the first time since January with storage on 30 June 2025 at 101% of historic mean and 68.5% nominally full.

Figure 19: National hydro storage levels, June 2024 to December 2025



Lake storage levels

5.3 Figure 20 shows individual lake levels for April to June 2025 and the difference location can have on hydro inflows. Although, overall, we have seen national hydro storage increase, the story for each hydro catchment varies.

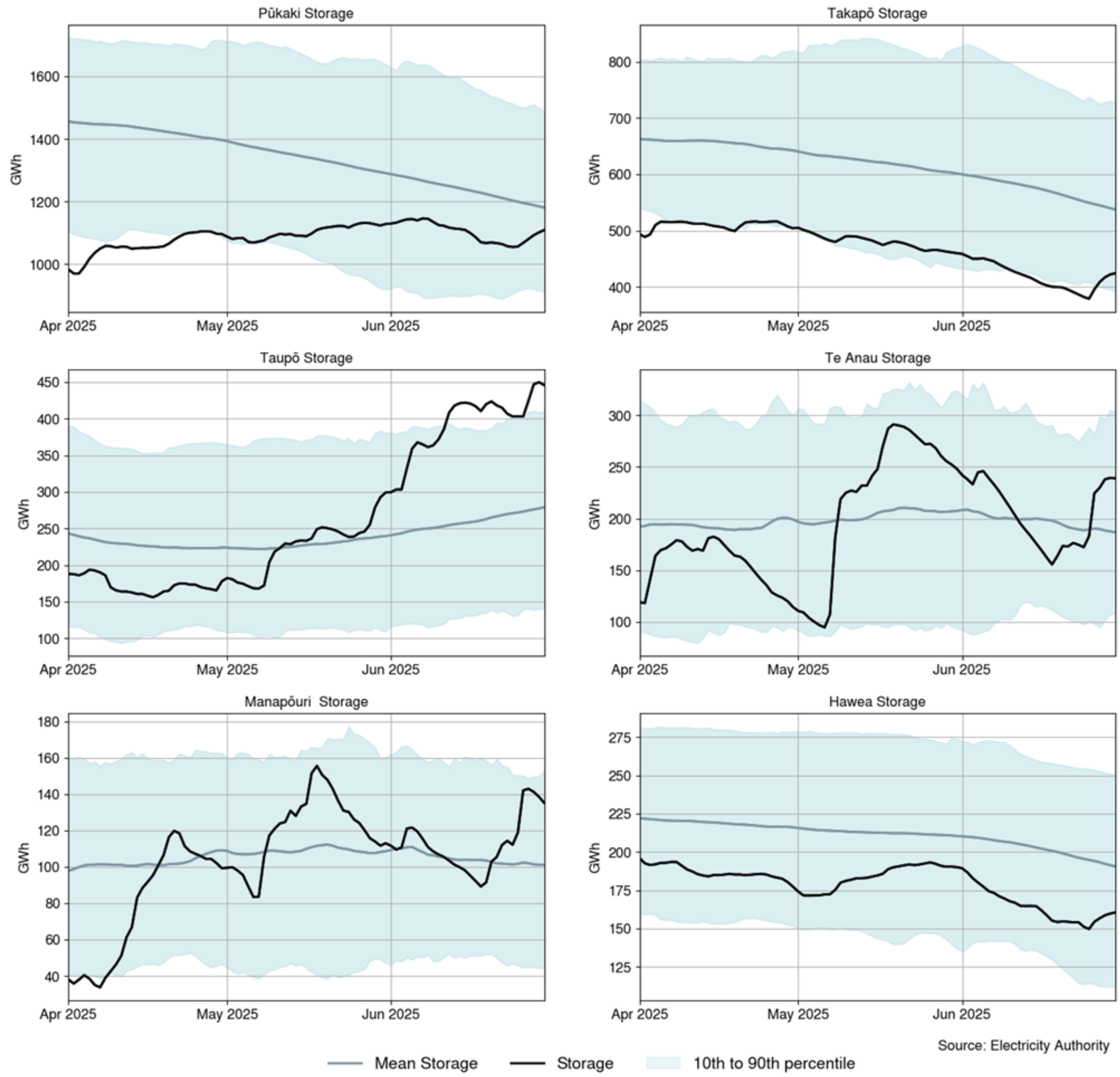
5.4 In the North Island, Taupō saw large increases to storage, initially going above historic mean values in the middle of May. Consistent wet conditions in the region saw storage at Lake Taupō increase to above its 90th percentile by the end of Q2 sitting close to 450GWh of storage. The NZX hydrological summary as of 30 June reported Lake Taupō storage at 78% full.

5.5 Manapōuri and Te Anau saw increases to storage over the quarter, fluctuating in their usual patterns. Both lakes were sitting above mean at the end of Q2, and at 86% and 90% full respectively.

5.6 All other South Island catchment lakes remained below mean for the duration of Q2 2025. Hawea, although seeing some increases generally trended downwards in overall storage finishing the quarter at 57% full.

5.7 Pūkaki storage remained within 1,000-1,200GWh, approaching historic mean storage values and finishing the quarter at 65% full. Takapō storage trended downwards for most of the quarter remaining close to its historic 10th percentile region, with a small uptick in storage in late June taking the lake to 48% full.

Figure 20: Lake storage levels for April to June 2025 versus historical average and 10th and 90th percentiles



6. Wholesale gas prices, production and consumption

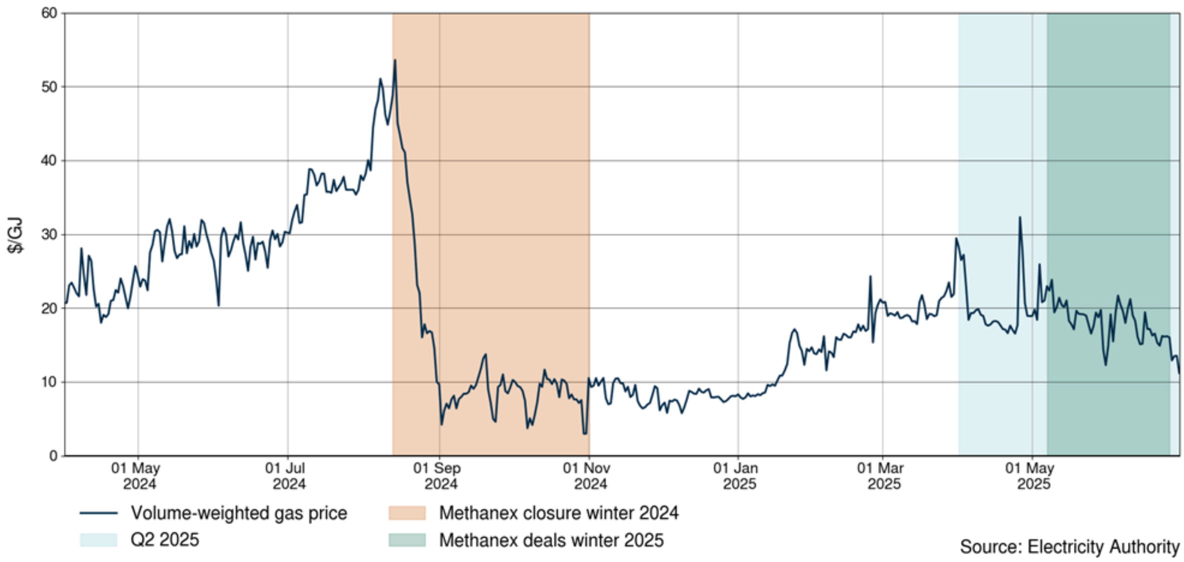
Gas prices

6.1 Figure 21 shows the daily volume-weighted average gas price for April 2024 to June 2025.

6.2 The average daily volume-weighted average price (VWAP) for gas in Q2 2025 was $19/GJ. This is a slight increase of $3/GJ compared to Q1 2025 and a decreased of around $7/GJ compared to Q2 2024.

6.3 After some fluctuations in April, gas prices began to trend downwards in May, particularly after the Methanex deals were announced. At the end of the quarter the daily VWAP reached $11/GJ, with the maximum price during the quarter at $32/GJ.

Figure 21: Daily volume-weighted average price for gas and NZ carbon unit price, April 2024 to June 2025

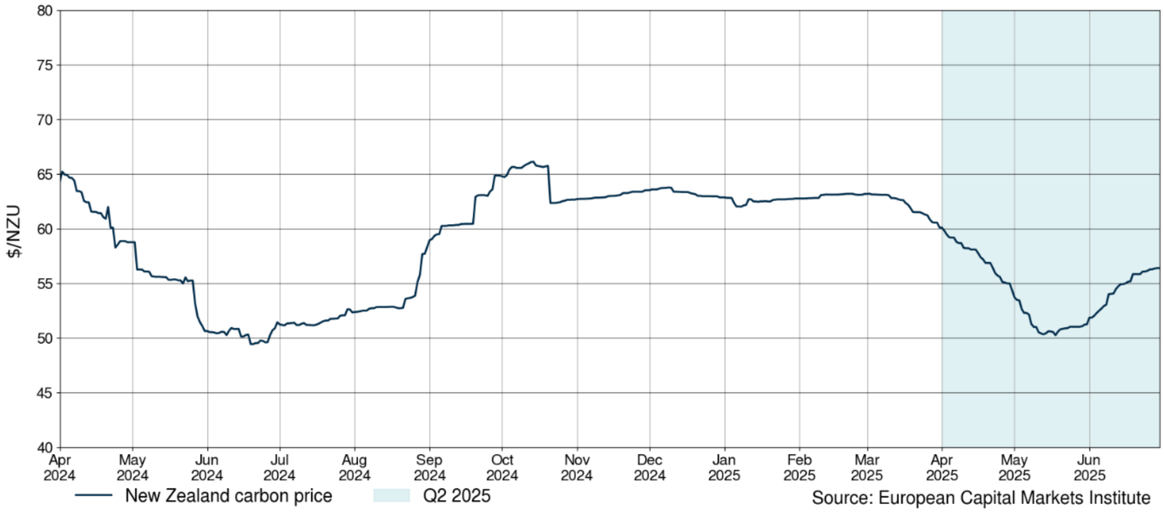


Carbon pricing

6.4 Figure 22 shows the New Zealand carbon unit price between April 2024 and June 2025 as recorded by the European Capital Markets Institute. Carbon costs have significance in the electricity market due to the impact on the cost of thermal generation.

6.5 At the beginning of Q2 2025, carbon unit prices were around $60/NZU, dropping to nearly $50/NZU during May. Through June carbon prices have begun to rise again, reaching $56/NZU by the end of the quarter.

Figure 22: New Zealand Units price, April 2024 and June 2025



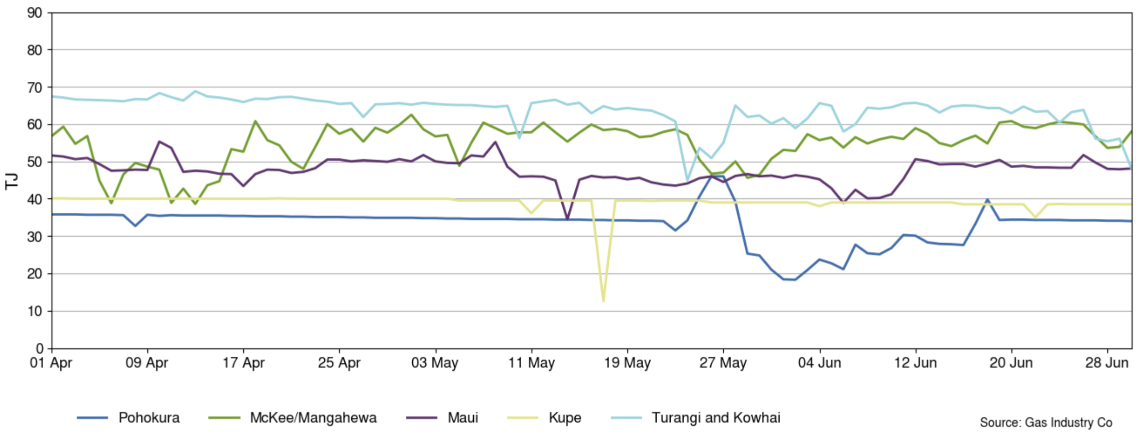
Gas production

6.6 Figure 23 shows daily gas production at major fields between April to June 2025.

6.7 Total gas production for Q2 2025 ranged from 210-254TJ/day. Minimum total production was 23TJ/day higher than last quarter's minimum and maximum total production was around 2TJ/day lower than last quarter.

6.8 Pohokura had one of the largest variations in production, particularly towards the end of May, with production in the range of 18.3-46.0TJ/day. Kupe production was generally steady at around 40TJ/day apart from a dip in mid-May to around 12.6TJ/day.

Figure 23: New Zealand gas production, April to June 2025

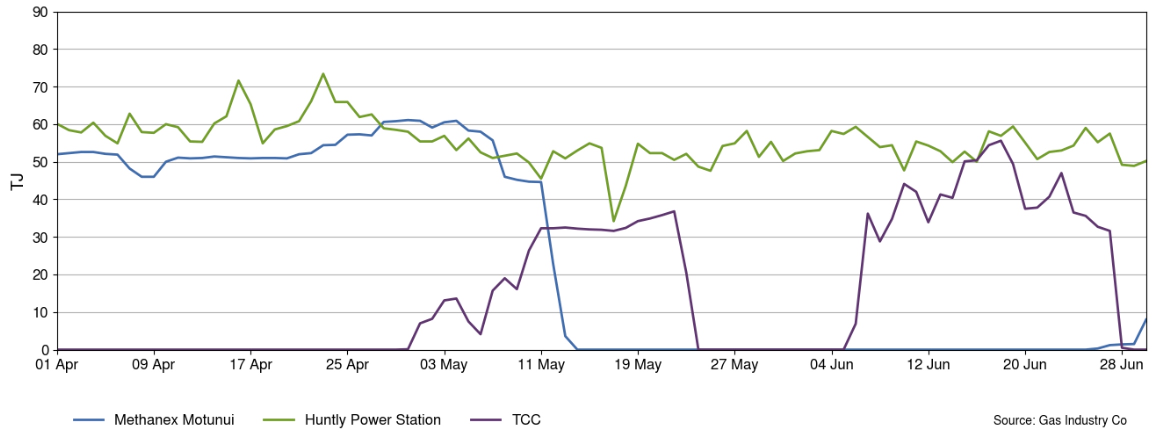


Gas consumption

6.9 Figure 2424 shows the daily gas consumption by major users between April to June 2025.

6.10 Methanex Motunui consumption was mostly within 50-60TJ/day through April before dropping to 0TJ/day in mid-May after a gas deal was struck with electricity generators. This deal lasted until the end of June.

Figure 24: New Zealand gas consumption, April to June 2025



6.11 There was gas consumption from TCC (Taranaki Combined Cycle) during May and June when it was generating. Huntly gas consumption ranged from 34-73TJ/day across the quarter.

6.12 Figure 25 shows the estimated daily total energy consumption across all Huntly units between April to June 2025.

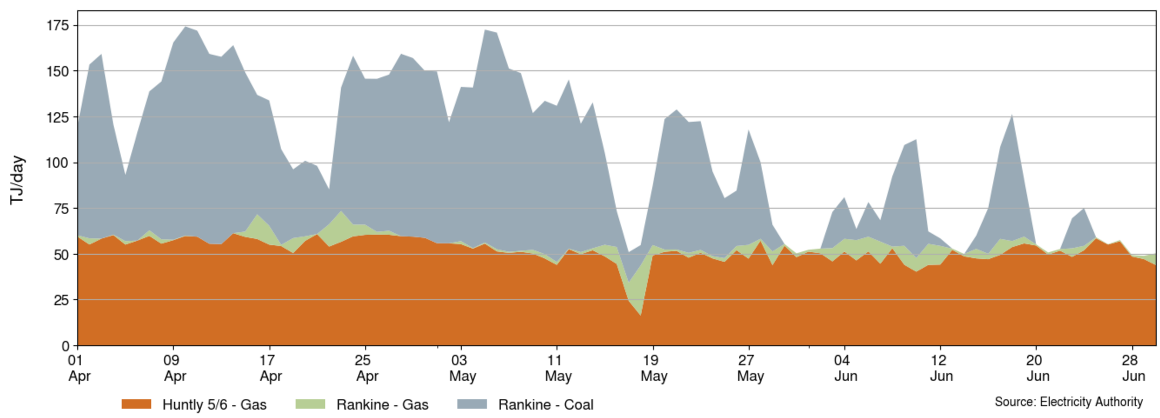
6.13 Gas consumption at Huntly was relatively consistent across the quarter with the only significant dip when Huntly 5 turned off on a Saturday morning in mid-May.

6.14 Coal consumption was higher at the beginning of the quarter where Rankine generation was mainly using coal. This was also when thermal generation overall was higher prior to inflows arriving in the hydro catchments.

6.15 The Rankine units were also used less towards the end of May and into June likely due to increased hydro generation and gas availability.

6.16 The coal stockpile has been increasing through the end of Q2 and reached ~684kt as of 29 June 2025. Thermal fuel storage information including contracted gas ranges can be found on our website - [Thermal fuel information | Electricity Authority](#).

Figure 25: Estimated Huntly fuel consumption, April to June 2025



7. Retail electricity

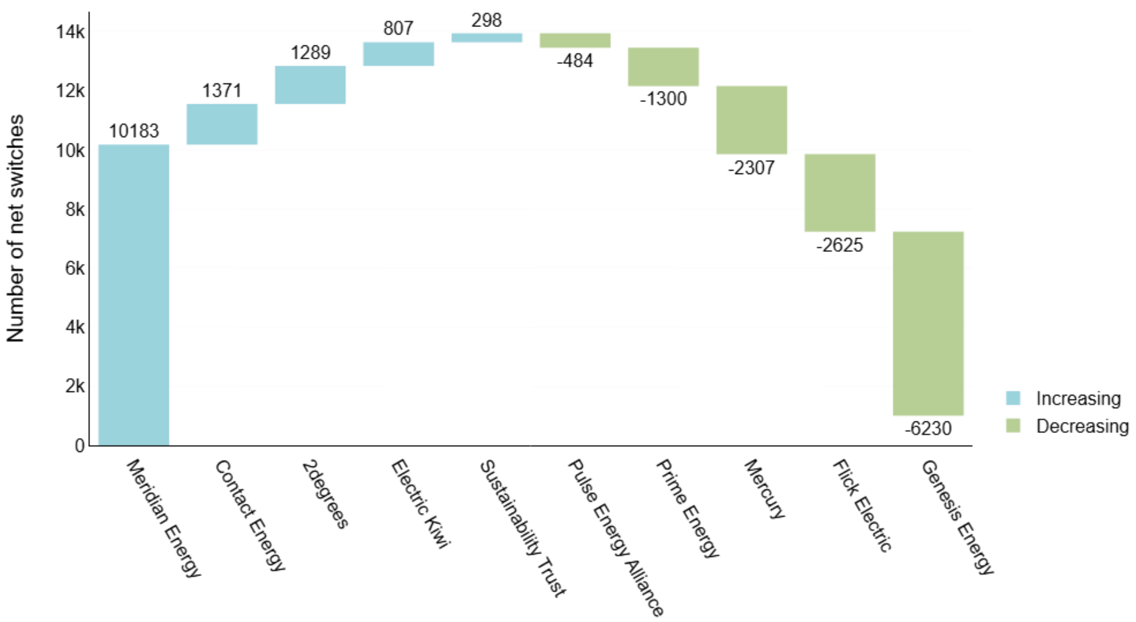
Retailer switching

7.1 Figure 26 shows the top five retailers who gained and the five who lost the most electricity connections (ICPs) between April and June 2025.

7.2 Meridian again has the largest net gain in ICPs this quarter at 10,183 net switches (mostly due to an increase in Powershop customers). Contact and 2Degrees had the next highest net gain of 1,371 and 1,289 respectively. Both Contact and 2Degrees last quarter were one of the five retailers who lost the most ICPs, with each retailer gaining more ICPs than they each lost last quarter.

7.3 The retailer with the biggest net loss of ICPs in Q2 2025 was Genesis (6,230). Most of these losses are from its subsidiary brand Frank Energy, which announced in June 2025 that it would be consolidated into the Genesis brand.

Figure 26: Top 5 increases and decreases in ICP net switching by retailer parent company, April to June 2025

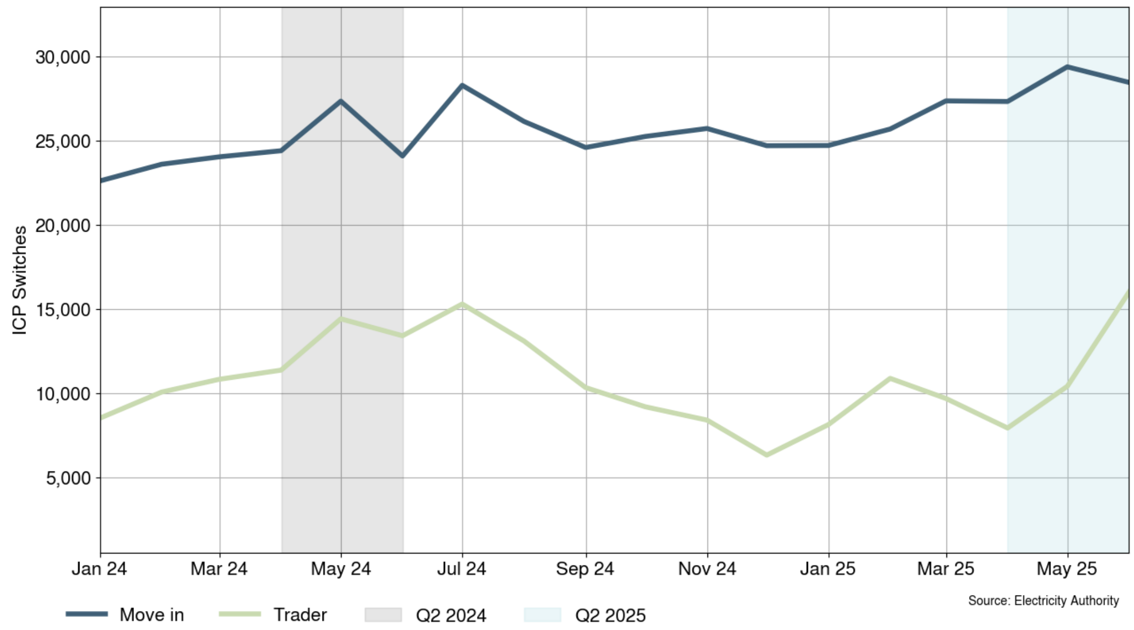


7.4 Figure 27 shows the number of ICPs that have changed electricity suppliers between January 2024 and June 2025 categorised by 'move in' and 'trader' type. Move in[4] switches are where the customer does not have an electricity provider contract. In contrast, trader switches are where the customer does have an existing contract, and the customer obtains a new contract with a different trader.

7.5 The light blue highlighted section shows switches across the most recent quarter from April to June 2025, with the grey highlight showing the same quarter for 2024. At the beginning of the quarter, trader switches were lower than at the same time last year. However, there was a steep increase in switches from May to June, likely due to the usual seasonal trend during winter.

[4] At an ICP.

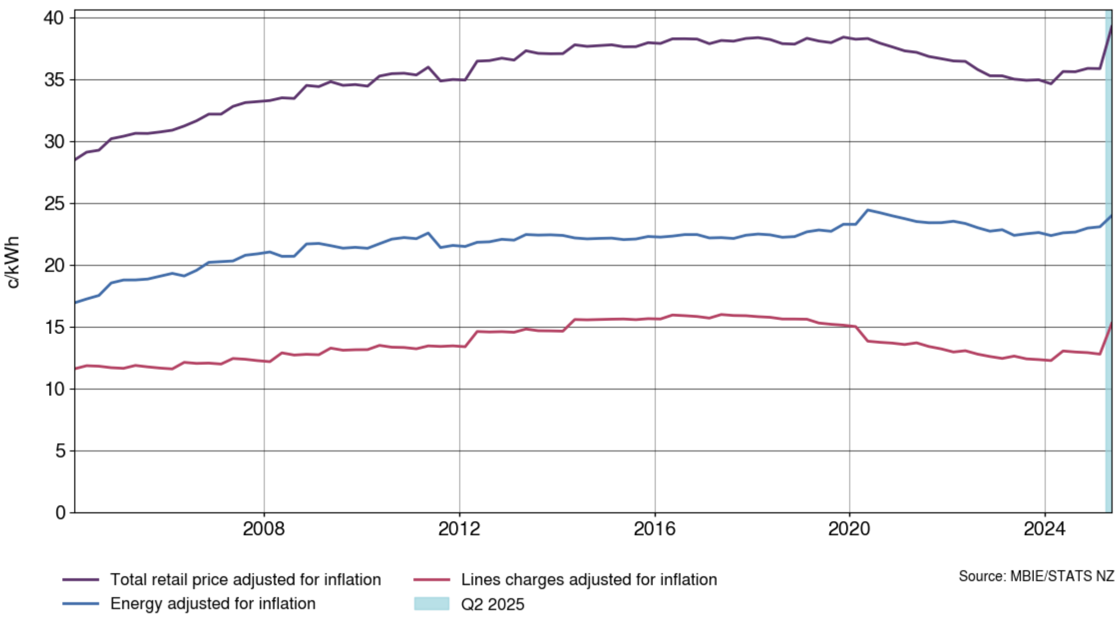
Figure 27: Breakdown of monthly ICP switching by type, between January 2024 and June 2025



Retail prices

7.6 Figure 28 shows the domestic electricity price by component (QSDEP) adjusted for inflation from 2004 to June 2025. The increase this quarter is mostly related to increased lines charges following changes to revenue limits regulated by the Commerce Commission[5].

Figure 28: Domestic electricity prices by component adjusted for inflation (base Q2 2025 CPI)



7.7 Figure 29 shows the domestic electricity prices by component without adjusting for inflation. In the last 12 months nominal values have risen 13%.

7.8 For a typical household using 8,000kWh annually, this increase equates to an extra $290 per year, adjusted for inflation, on their bill compared to one year ago.

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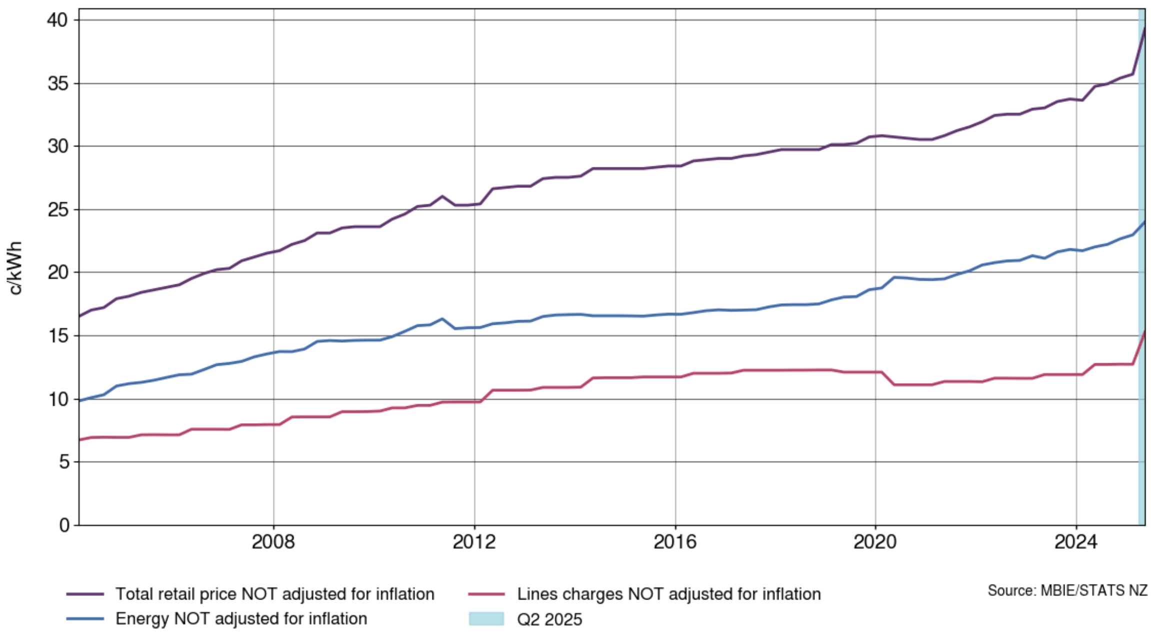
[5] Commerce Commission - Electricity Lines and Transmission Charges: What are they, why are they changing and what does this mean for your electricity bill?

Figure 29: Domestic electricity prices by component without inflation adjustment

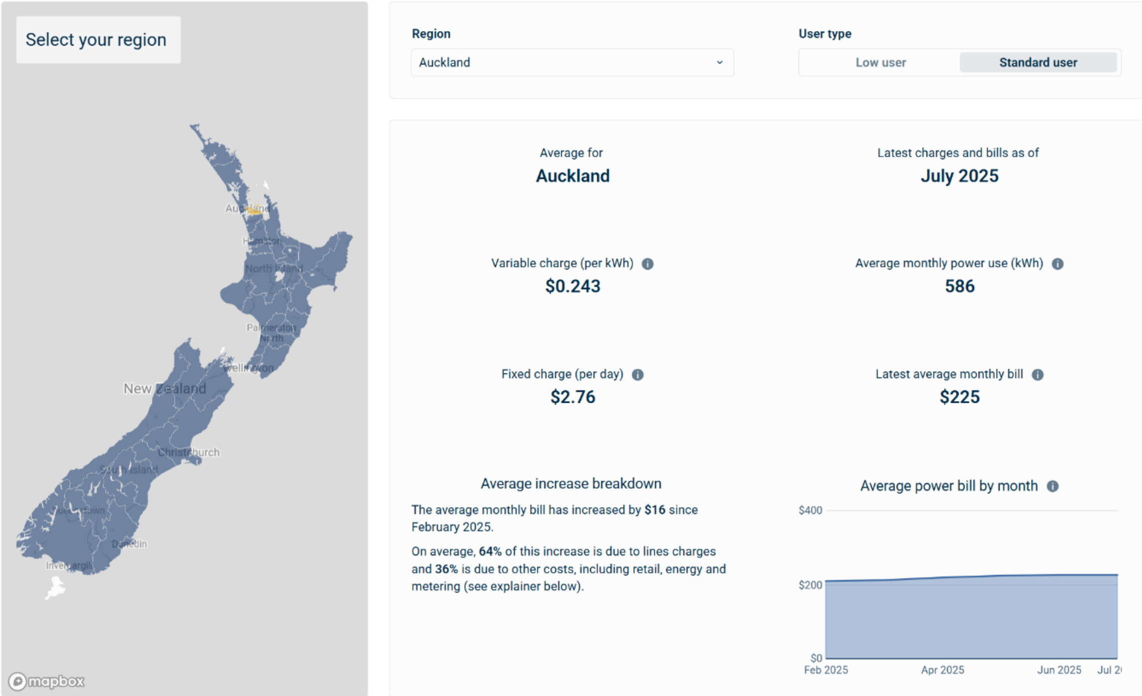


7.9 The Authority sought price increase information from retailers in response to this year's increased in lines charges. This was released in a new retail price dashboard[6] showing average monthly power bills by region across New Zealand, see example in Figure 30. This provides price transparency and encourages New Zealanders to get more engaged in choosing their power plan and provider.

7.10 There are large regional differences in these increases, with average households seeing $7 per month increases and some regions facing increases of up to $29 per month. Note these numbers have been obtained using the Authority's S46 powers, which are based on the price changes (including legacy plans) between February and July 2025, and has not been adjusted for inflation.

[6] Regional power prices | Electricity Authority

Figure 30: Retail price dashboard for Auckland July 2025



8. Forward market and carbon pricing

Forward pricing

8.1 Figure 31 shows the quarterly forward prices up to 2028, with the first snapshot (dashed lines) at the beginning of April 2025 and second snapshot at the end of June 2025 (solid lines).

8.2 Quarter 2 started with future prices for June 2025 around $296-312/MWh, dropping to ~$215/MWh by the end of the quarter. This was due to a combination of the gas deals with Methanex in mid-May and the hydro storage situation improving as we headed into winter. September 2025 prices also saw a significant decrease of around $148/MWh by the end of Q2.

8.3 Long-term (2026 and after) futures saw increases to summer contracts (quarters one and four) but decreases to winter contracts (quarters two and three). A range of market announcements and trends over this time could have influenced these changes, including:

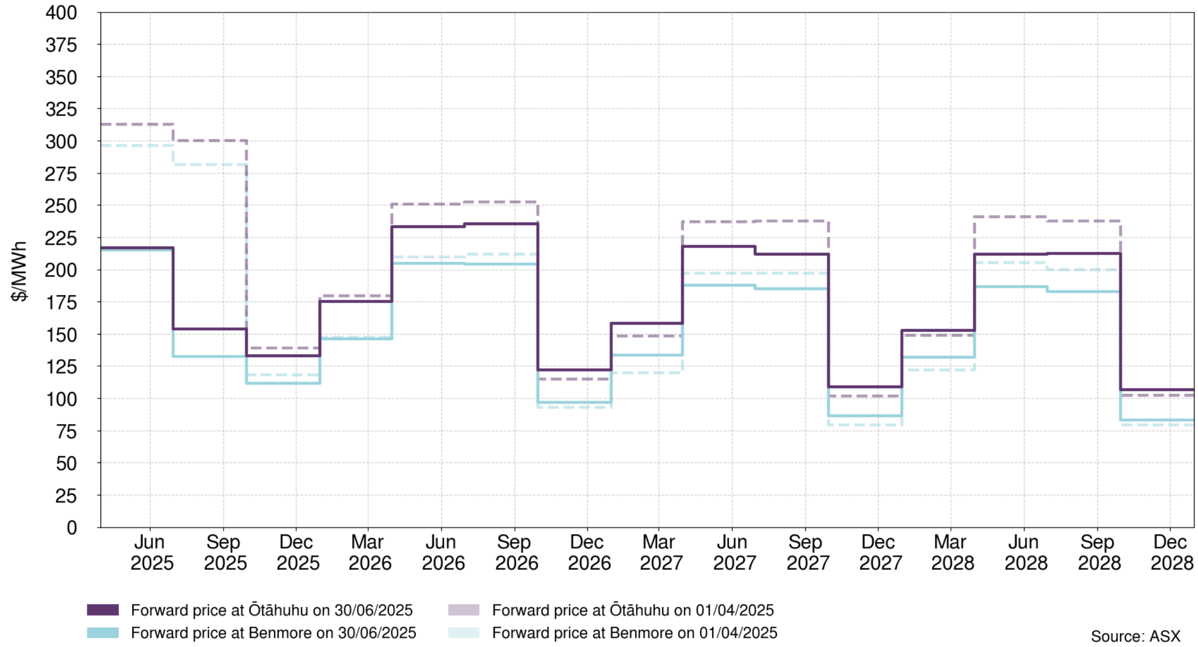
(a) Long-term gas supply agreement between Greymouth and Contact[7]

(b) Gentailer deals to support national energy security with Huntly power station[8]

(c) Commerce Commission clearing the Contact acquisition of Manawa Energy[9].

[7] NZX, New Zealand's Exchange - Announcements, Greymouth Gas Deal
[8] NZX, New Zealand's Exchange - Announcements, Huntly Capacity To Support National Energy Security
[9] NZX, New Zealand's Exchange - Announcements, Commerce Commission Clears Manawa Acquisition

Figure 31: ASX forward prices for the start and finish of Q2 2025



Source: ASX

8.4 Measures relating to the futures market can also be found on the Electricity Authority's Competition Dashboard.

9. Regression analysis review

9.1 In our wholesale market review (2021), we presented the results of a regression analysis to determine the key drivers of wholesale electricity spot price. This regression utilised a dummy variable to represent the gas uncertainty following the 2018 Pohokura gas outages. At the time this dummy variable was significant while a range of other variables that were tested to represent gas supply risk were not significant, including carbon price.

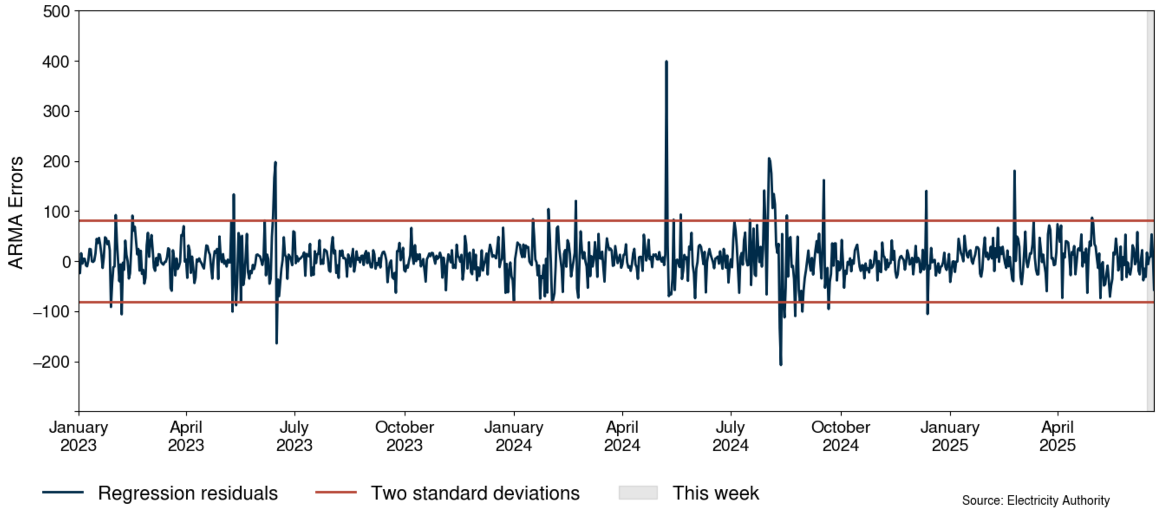
9.2 With several more years of data to work with, the results have changed. Recently when the carbon price is included in the regression model, the carbon price is significant, showing a positive relationship between the carbon price and spot price, while the Pohokura dummy variable is not significant.

9.3 The coefficients for relationships between the spot price and the other variables (hydro storage, demand, wind generation and gas price excluding carbon price) remain significant with the same positive and negative signs and similar magnitudes. This indicates that carbon price is now a better explanation for spot price changes than the dummy variable.

9.4 The weekly trading conduct report uses a modified daily average version of these past regressions. More details on this regression can be found in our trading conduct appendix A. While it used to include the Pohokura dummy variable, the inclusion of the gas price including the carbon price made this dummy insignificant and it is no longer included.

9.5 Every week we look at the error in this regression to see if any of the errors are especially large. Figure 32 is an example of the regression errors from the 15-21 June 2025 report. If an error for a day is very large, it implies that the day's prices may not reflect market conditions and we may need to analyse that day's prices further.

Figure 32: Plot of errors from using linear regression to estimate daily average spot prices, 1 January 2023 - 21 June 2025



9.6 In our quarterly report for 2020 Q2, we introduced a dummy variable into our regression model to represent the gas supply risk introduced after the Pohokura outages. The key date chosen for this dummy variable was 28 September 2018 because that is the date we believed gas supply risk began to contribute more to the spot price. The dummy variable was given a value of 0 for all time periods before that date and 1 from 28 September 2018 onwards.

9.7 In our 2020 Q2 and Wholesale Market Review regressions, we found that the dummy variable was significant. This implied that the Pohokura gas outages had a significant impact on spot prices going forward.

9.8 The wholesale market review tested a range of other variables to capture the increased gas supply risk. One of these variables was carbon price. During the 2021 market review, the carbon price was not a stationary variable so the difference of carbon price was used instead. We found that the carbon price was not significant in the model at this time.

9.9 Figure 33 shows carbon price from 2015-20 was mostly below $30/NZU. In the last few years, carbon prices have been higher and more varied. Recently when carbon price is included in the regression model, carbon price is significant while the Pohokura dummy variable is not. This indicates that carbon price is now a better explanation for spot price changes than the dummy variable. In our current regression models, rather than the Pohokura dummy variable we use either gas price (excluding carbon price) and carbon price, or gas price that includes carbon price.

Figure 33: New Zealand Carbon unit price, January 2015 to June 2025

9.10 The other key relationships in our regression model have not changed. Our current model used in the weekly trading conduct report shows that lower hydro storage, higher demand, lower wind generation, the higher gas price (including carbon) and lower generation HHI[10] contribute to higher wholesale electricity spot prices.

9.11 All coefficients are significant and all variables are stationary or transformed to be stationary. The Ljung-Box test[11] was used to report if there was serial correlation of residuals. The Ljung-Box P-value for our model was insignificant, indicating that there was not likely to be serial correlation for the residuals. This lends some confidence to the performance of the model.

[10] Herfindahl-Hirshman Index – measure of market concentration that helps assess the level of competition

[11] Ljung-Box Test: Definition + Example

10. Structure Conduct Performance Analysis

10.1 This section assesses 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 using 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.

10.2 The period considered is 1 January to 30 June 2025, ie, two quarters of data. The Authority includes six-monthly updates of these indicators in every second quarterly review.

10.3 Six key indicators are used to assess the competitive outcomes:

10.4 The first two of these are the frequency of both very low prices and price separation, which should reflect underlying market conditions.

10.5 Offers are also tested against supply and demand conditions; prices above $300/MWh or final price may indicate economic withholding if they cannot be related to underlying conditions.

10.6 Finally, investigating offers in relation to known costs, including opportunity costs, the percentage of offers above cost and the relationship of storage and offers to cost.

10.7 From the period 1 January to 30 June 2025:

10.8 Price separation has reflected underlying conditions, consistent with competition. Hydrological conditions saw price separation in both directions.

10.9 The frequency of low prices occurring during off peak increased when compared to pre-Trading Conduct years. The median low price also remains lower.

10.10 The high share of prices between $200-400/MWh reflected a shift to reliance on thermal generation, during low hydro inflows. Prices declined once gas availability increased and hydro storage stabilised.

10.11 Thermal offers were reflective of changing market conditions. Thermal gas generators were constrained in their output due to reduced gas production. Once gas was secured from Methanex, most of this was used to fill Ahuroa for winter.

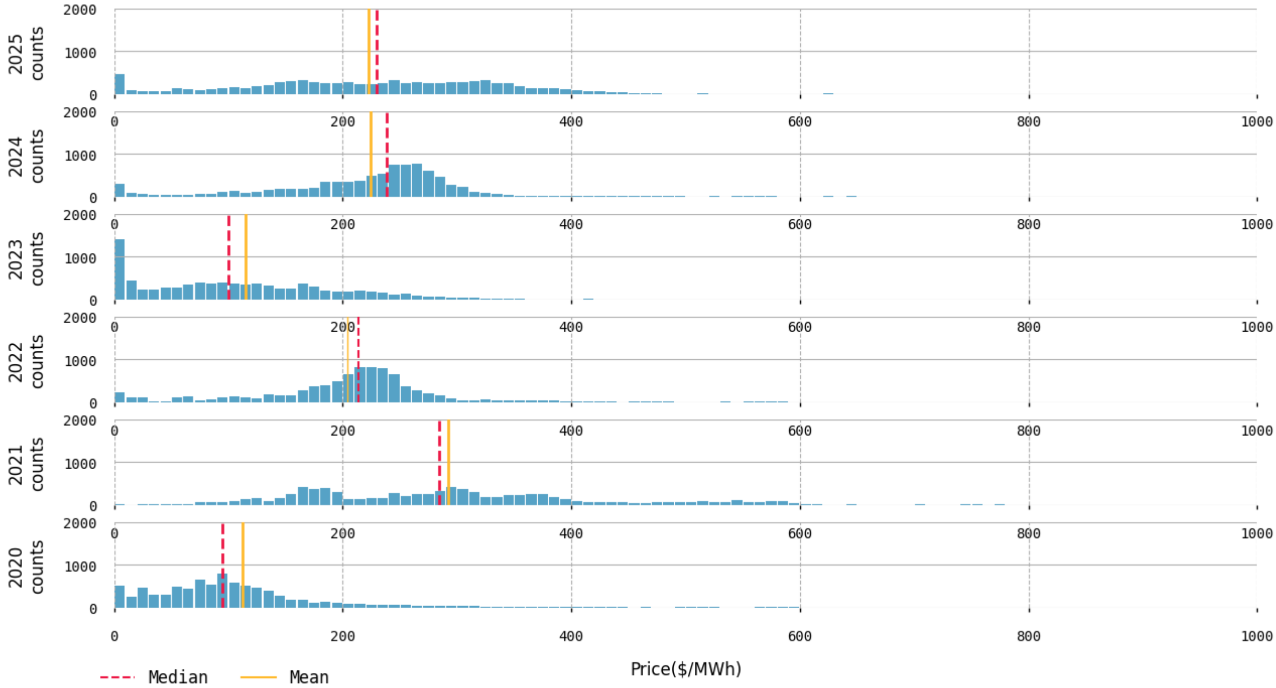
Very low prices

10.12 If prices are being determined in a competitive environment, one 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 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 during times of declining hydro storage.

10.13 Figure 34 and Table 1 give insight into the distribution of prices between January - June 2025. Between January and April 2025 hydro storage declined. During this time spot prices increased to reflect increasing scarcity of water heading into winter. However, storage increased slightly and stabilised throughout May and June, and spot prices fell.

10.14 These two hydro sequences have resulted in the distribution of prices in 2025 to be very spread out, with prices mainly clustering between $200-300/MWh. This is similar to what occurred in 2021, when hydro storage was similarly declining. However, in 2025 there were less prices above $300/MWh and the mean and median price were lower ($222/MWh and $229/MWh in 2025 compared to $292/MWh and $284/MWh in 2021). There was also a higher proportion of prices below $10/MWh in 2025, compared to 2021.

Figure 34: Histogram of price counts for the January – June of each year 2020-25



10.15 Additionally, of the 'very low' prices in 2025 occurring during daytime off peak, the median price continues to be lower compared to pre trading conduct (2015-2021) ($0.26/MWh and $1.34/MWh respectively).

10.16 The frequency of low prices occurring during daytime off peak continues to be between 20-30%, as it has been in the years since trading conduct. Both are indicative of less economic withholding.

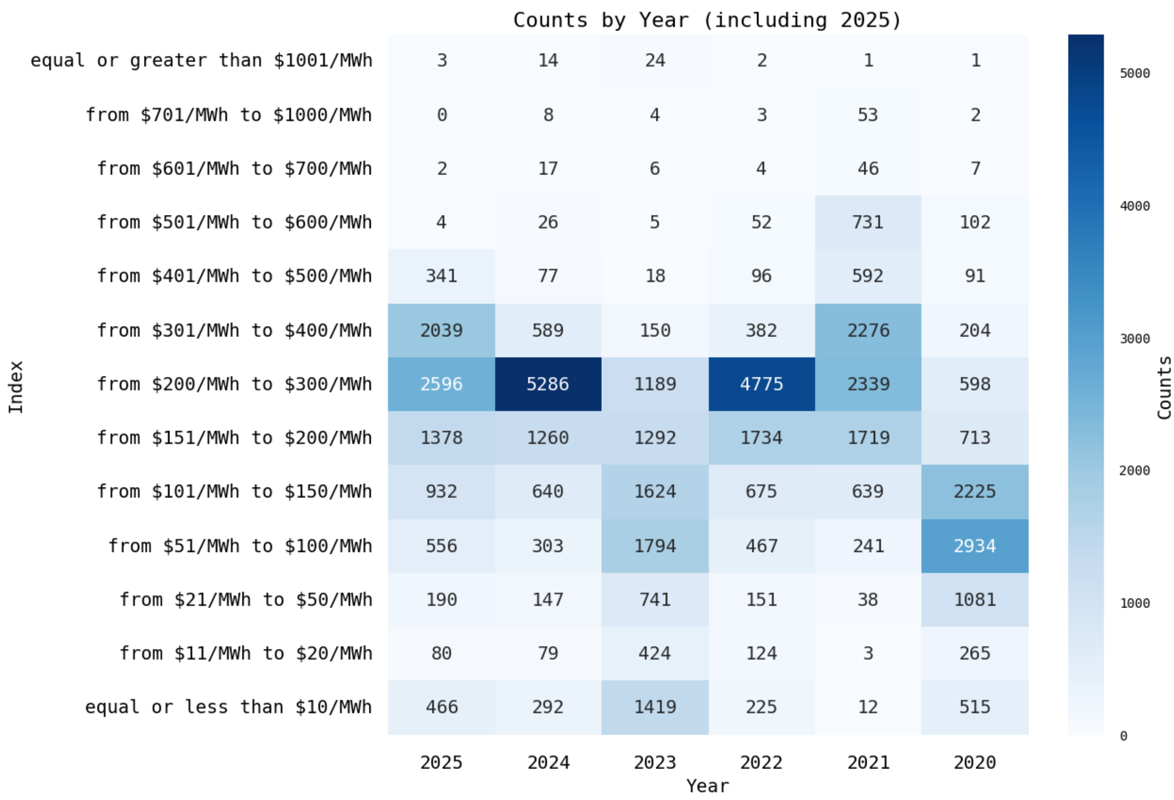
Table 1: Very low prices 1 January to 30 June

Year	Share of very low prices occurring during daytime off-peak times (9am – 4:30pm)	Median price of all very low prices (all trading periods)
2025	29.3%	0.26
2024	25.5%	0.51
2023	28.9%	1.98
2022	23.1%	0.02
2021-2015	8.8%	1.34

10.17 Figure 35 shows a heatmap of price distribution for January – June since 2020. The January-June 2025 period was dominated by prices in the $200-$300/MWh range which is similar to the distributions in 2024, 2022 and 2021.

10.18 However, this year there were more prices in the $300-$400/MWh band, which also occurred in 2021. This pricing reflected both increasing hydro scarcity heading into winter as hydro lakes dropped and increased gas scarcity during this period.

Figure 35: Heat map of price distribution for January – June of each year



Price separation

10.19 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 is exported north, transmission could become constrained. This should lead to lower prices in the South Island than in the North Island.

10.20 The mean price separation of the Haywards to Benmore price, for times when storage was above mean, was much lower this year when compared to previous years. However, national hydro storage was only above mean 17% of the time, and only throughout January, compared to 25% and 99% of the time in 2024 and 2023, as seen in Table 3. Both 2022-23 had periods of high inflows which led to greater instances of very low South Island prices – with the HVDC binding and creating price separation. This did not occur in the January-June period in 2024 or 2025.

10.21 In brackets, the same statistics have been calculated for when storage was above 80% of the mean. For these times, the mean price separation of the Haywards to Benmore price was closer to 20, which is more consistent with the separation than the previous year.

10.22 Traditionally with price separation, prices are higher in the North Island due to South Island hydro generation being exported North along the HVDC. However, as South Island hydro storage was declining over January, there were several prolonged instances where South Island prices were higher than those in the North. This led to ratios lower than one, which were often balanced out by ratios greater than one, which is how the ratio averages to roughly one.

10.23 The mean ratio of the Benmore to Manapōuri price is low again this year. This was due to low South Island hydro storage resulting in more southward HVDC transfer. Also the upgraded CUWLP has continued to allow better import and export between the lower and middle South island.

Table 2:Price separation January - June 2015-25[12], values for times when storage greater than 80% in brackets

Year	Ratio of Haywards to Benmore price		Ratio of Benmore to Manapōuri price	
	Mean	Median	Mean	Median
2025	1.11[20.5]	1.04[1.04]	1.02[1.05]	1.01[1.04]
2024	34.18	1.04	1.03	1.02
2023	187.3	1.05	1.09	1.06
2022	351.5	1.04	116.8	1.01
2015-2021	22.27	1.06	49.3	1.09

Table 3: Percentage of times in 2021-25 January – June when national and induvial lake levels were above 100% and 80% of daily means

Storage above		National	Waikato	Waitaki	Manapōuri	Takapō	Hawea
2025	100% of mean	17	65	21	39	12	1
	80% of mean	66	88	65	53	41	50
2024	100% of mean	25	70	9	68	0	13
	80% of mean	77	79	84	91	12	42
2023	100% of mean	99	100	89	42	98	19
	80% of mean	100	100	100	59	100	77
2022	100% of mean	35	83	41	17	41	6
	80% of mean	85	98	71	35	61	35
2021	100% of mean	0	29	0	16	0	3
	80% of mean	23	41	1	56	76	27

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

10.24 Between January-April several lakes experienced their lowest inflow sequences on record, as shown in Figure 18. From late April the combined effect of less hydro generation, higher thermal generation and high inflows saw most lakes increase in storage, however, only Taupō recovered to above mean by the end of June.

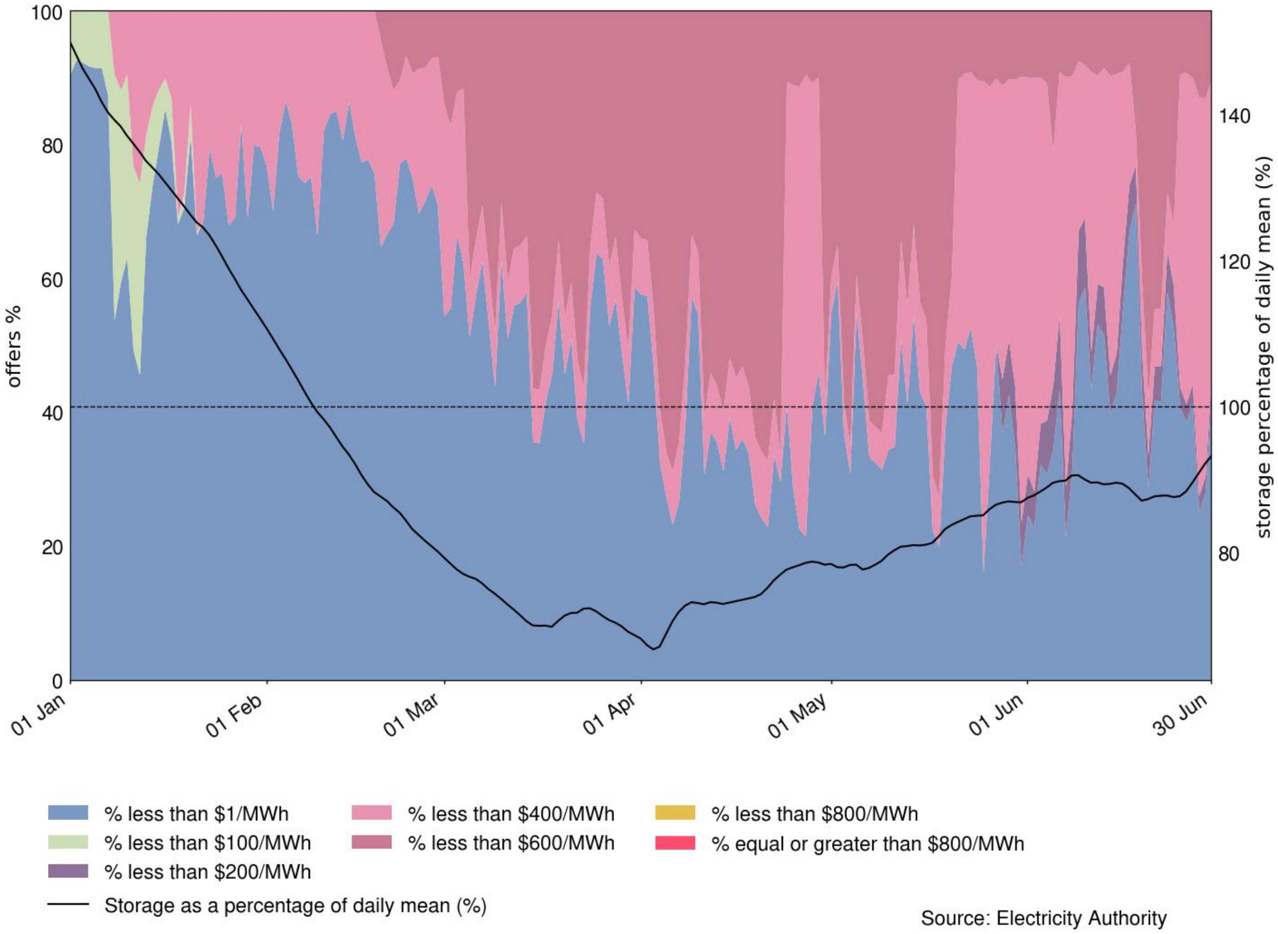
[12] This only includes trading periods when hydro storage is high (ie., where total New Zealand storage is greater than or equal to 100 percent of mean). Periods for the Haywards/ Benmore ratio where one or more of the HVDC poles has been on outage have been excluded, as have periods for the Benmore/Manapōuri 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.

10.25 Figure 36 shows Meridian's adjusted offer changes at Waikato over January-June 2025. Over the summer holiday period Meridian had all energy priced below $100/MWh as storage remained above 140% of mean.

10.26 However, storage at Pukaki rapidly fell when inflows reduced. Meridian priced its upper tranche of Waitaki generation between $200-400/MWh from mid-January, with between 70-80% of generation remaining below $1/MWh.

10.27 After storage fell below 100% of mean this tranche was again priced up, with some generation remaining in the $200-400/MWh band. When storage reached its lowest point in early April ~50% of generation was priced above $400/MWh. Then as storage steadily increased the pricing of the higher tranches mostly reverted back to the $200-$400/MWh band.

Figure 36: Adjusted offers vs available storage for Meridian Waitaki for January to June 2025



Source: Electricity Authority

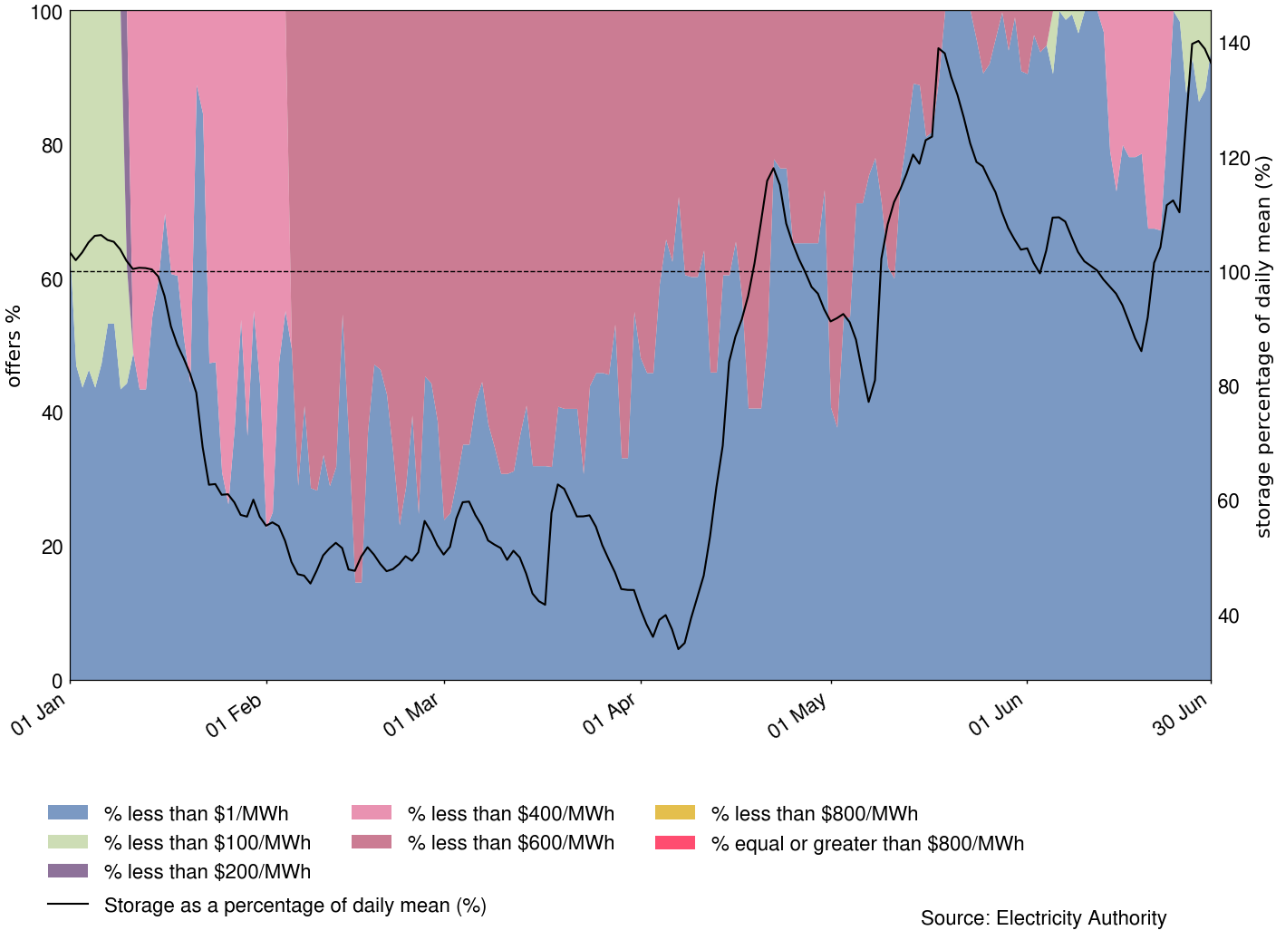
10.28 Figure 37 shows Meridian's adjusted offers from the Manapōuri scheme and storage (as a percentage of daily mean) at lakes Manapōuri and Te Anau from January-June 2025.

10.29 Allowable storage in the Manapōuri reservoir is not deep and fluctuates quickly in comparison to other locations. As a result, Meridian Manapōuri offers followed their storage levels closely. Manapōuri quickly sank below 100% of mean in January. Following this an increasing amount of energy was priced above $200/MWh. As this decline continued, and Meridian was operating in the 'low operating range' until mid April, the majority of energy was priced between $400-600/MWh to preserve the minimum allowable lake levels.

10.30 Storage rapidly increased from early April and the percentage of offers below $1/MWh increased to roughly 70-80% (on weekdays). Throughout May offers were at times 100%

below $1/MWh. Storage then waned between 140-80% full, with the minimum storage at this time seeing the return of offers between $200-400/MWh.

Figure 37: Adjusted offers vs available storage for Manapōuri, January to June 2025



Source: Electricity Authority

10.31 The adjusted offers from the Waikato scheme and storage (as a percentage of daily mean) at lake Taupō is shown in Figure 38.

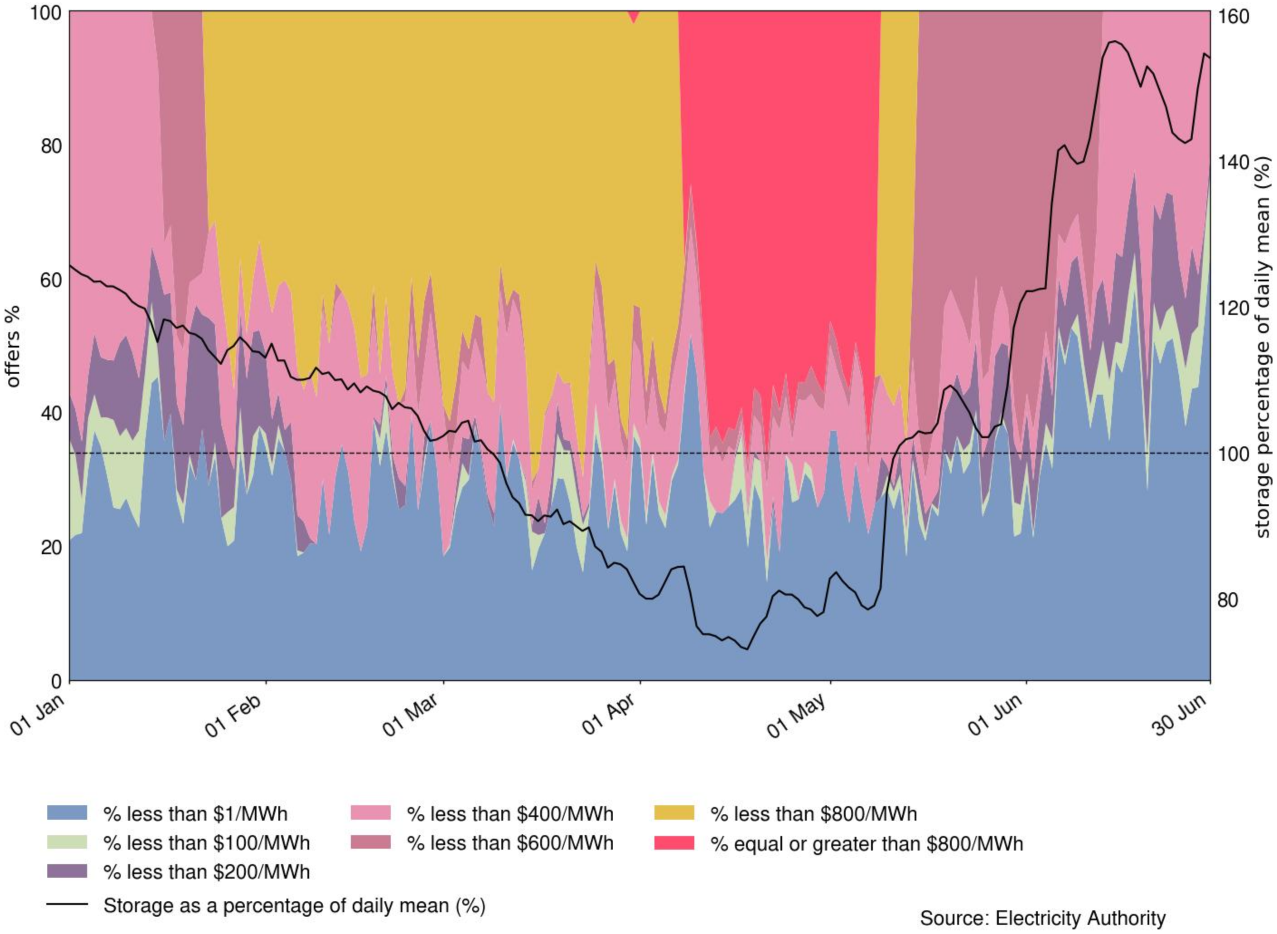
10.32 The Mercury Waikato scheme is the largest hydro scheme on the North Island but does not have the depth of some of the southern hydro schemes. As such, its offers are more directly correlated with weekly demand patterns than overall storage levels.

10.33 Over the January to May period, the quantity of offers priced below $1/MWh remained roughly stable, between 20-40% (higher on weekdays than weekends). This increased in June after storage reached 120% of mean. Taupō like many other lakes this year also experienced some of its lowest inflows on record. The pricing of its higher tranches reflects this.

10.34 As storage declined from ~120% of mean to ~75% of mean in April, the pricing of over 40% of its energy increased from $200-400/MWh to $400-600/MWh to $600-800/MWh.

10.35 In mid-April when storage reached its lowest levels this energy was priced above $800/MWh (mostly between $800-899/MWh). This water value reflected the increased value of this remaining water, especially heading into winter. Once inflows increased and storage rapidly increased to above 100% of mean, the pricing of the upper tranches was brought back down to the $200-$400/MWh range.

Figure 38: Adjusted offers vs storage for Mercury Waikato for January to June 2025



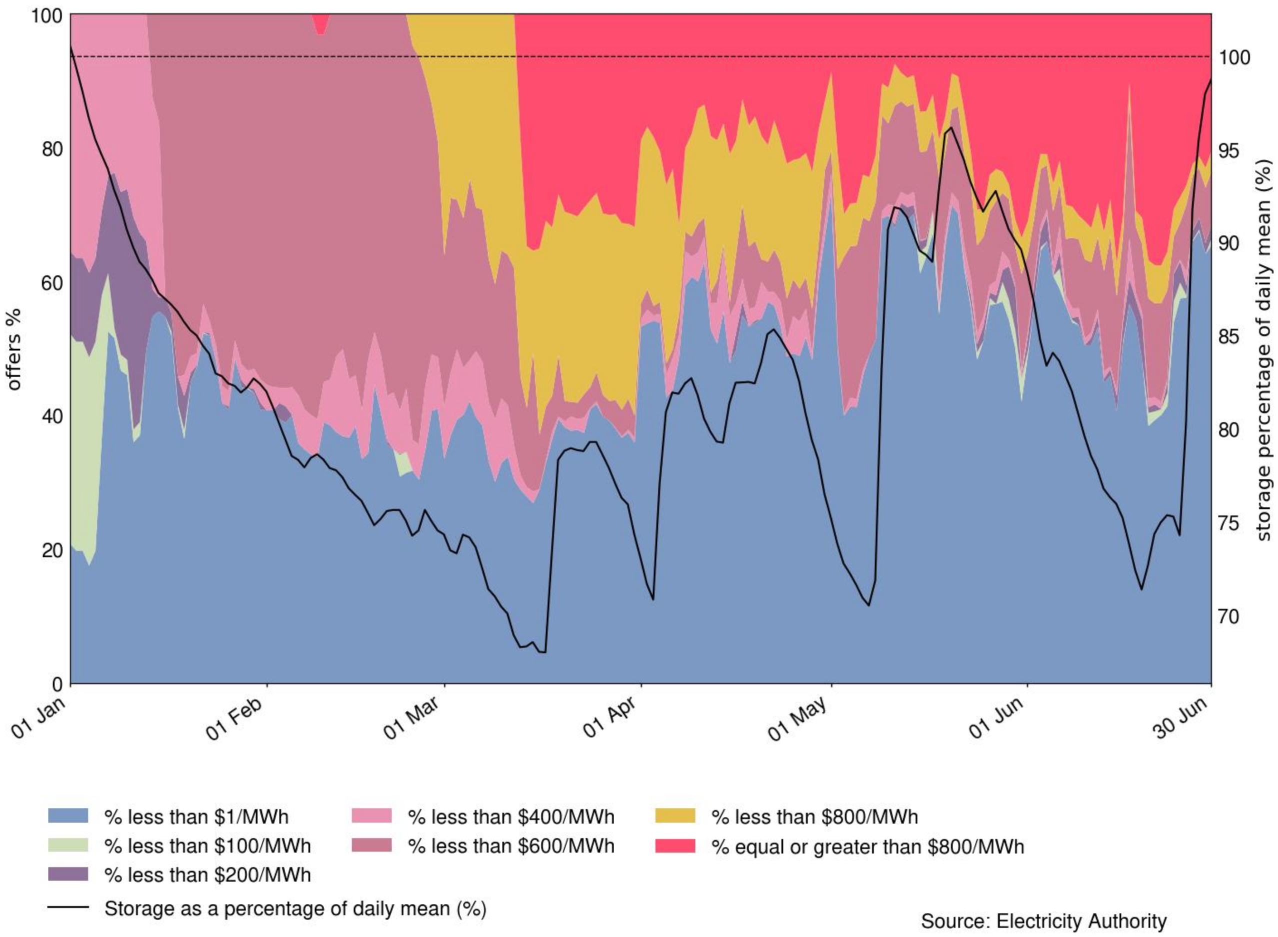
Source: Electricity Authority

10.36 The adjusted offers from the Clutha scheme and storage (as a percentage of daily mean) at lake Hawea is shown in Figure 39.

10.37 The Contact Clutha scheme also does not have much storage and runs mostly as a run of river scheme, with uncontrolled inflows from Wakatipu and Wanaka. However, despite this offer changes followed Hawea storage.

10.38 Hawea spent nearly the entirety of January-June 2025 below 100% full. As a result, Contact moved roughly 50% of Clutha energy into the $400-600/MWh band in January. From early March as Hawea storage reached its lowest value a proportion of this was moved to be priced $600-800/MWh. The increases in Hawea storage from April saw increases in low priced energy, but the tranches priced above $800/MWh remained.

Figure 39: Adjusted offers vs storage for Contact Clutha for January to June 2025



Source: Electricity Authority

10.39 The adjusted offers from the Takapō scheme and storage (as a percentage of daily mean) at lake Takapō are shown in Figure 40. Takapō is the second largest storage lake, however, the generation attached is only 190MW, so Genesis have more flexibility with their offering.

10.40 Genesis's offer changes at Takapō do not follow storage as closely as the other lakes. Over February-May, offers stayed somewhat stable despite declining storage with energy priced into coarse tranches of below $1/MWh, $200-400/MWh and over $800/MWh. Genesis priced down energy in June despite storage remaining below 80% of mean. However, towards the end of June this was again priced up at the time storage was increasing – although storage remained below mean. The monitoring team are enquiring further with Genesis regarding this. The drops in February in low priced generation occurred when Genesis was pricing generation at Takapō high overnight, but lower during the day on Sundays.

10.41 As part of our market monitoring the Authority contacted some hydro generators throughout January-June to question the rationale behind their hydro offer prices. We found that despite some generators having their own storage mostly at or above mean, other factors impacted offer prices:

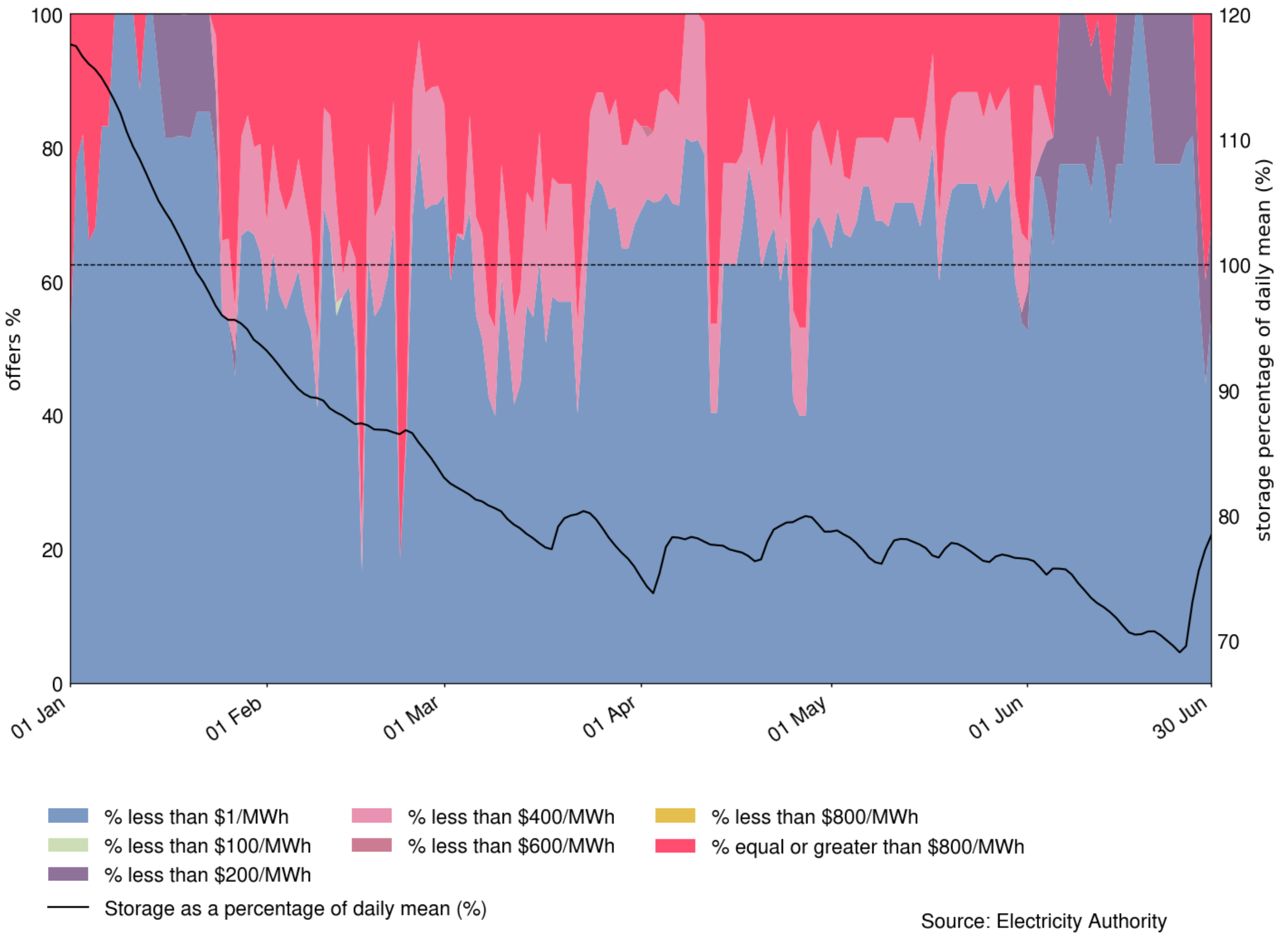
(a) national storage being below mean;

(b) gas uncertainty;

(c) periods of record low inflows; and

(d) the price of quarterly winter future prices.

Figure 40: Adjusted offers vs storage for Genesis Takapō for January to June 2025



Source: Electricity Authority

10.42 Table 4 to Table 8 cover the dates when the reservoir storage was above its long-term average. Clutha spent all of January to June 2025 below this threshold, but most other major storage locations had limited periods of high storage in the first half of the year. Manapōuri and Taupō also had higher levels later in the 6-month period. Huntly and Stratford offers are only considered when total hydro storage was above its daily mean, which only occurred in January. Because of this these percentages are also calculated for times when storage was above 80% of mean, shown in brackets.

10.43 These tables consider the percentage of offers above $300/MWh, and above the final price or above various measures of cost.

Table 4: Percentage of offers over $300/MWh, January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2025	55% [59%]	17% [36%]	10% [31%]	NA [37%]	61% [47%]	44% [34%]
2024	36%	2%	NA	19%	64%	24%
2023	25%	4%	5%	16%	74%	23%
2022	44%	0%	7%	15%	42%	13%
2019-2021	44%	25%	2%	12%	34%	10%
2014-2018	7%	23%	2%	0%	0%	5%

10.44 The percentage of offers above final prices and various measures of cost has increased for the Waikato. However, while the Waikato enjoyed the longest portion of time with storage above mean out of all of the lakes, this portion of time was still lower than in the last three years. As mentioned above, other factors impacted offer prices, including very low inflows until May for the Waikato.

10.45 For the thermal units, for which the un-bracketed number only considers January, the percentage of offers above final price and $300/MWh reflects the lower running of these units in January when compared to the other months of the year. When more dates are considered, i.e. the numbers in the brackets, these percentages fall as these units were running more often which brings down their cost. This is also reflected when comparing offers to thermal costs in Table 7. However, these numbers do overall remain higher than pre-2021 figures and reflects the increased gas scarcity. The monitoring team is considering carefully how these percentages have changed.

Table 5: Percentage of offers above final price, January to June 2024

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2025	59% [60%]	20% [38%]	12% [31%]	NA [47%]	64% [46%]	52% [37%]
2024	43%	37%	NA	21%	69%	27%
2023	34%	22%	8%	27%	83%	35%
2022	55%	16%	7%	31%	56%	23%
2019-2021	54%	32%	2%	30%	61%	19%
2014-2018	42%	38%	8%	13%	62%	20%

Table 6: Percentage of offers above the average forward price January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2025	44% [42%]	35% [24%]	20% [17%]	NA [27%]	42% [33%]	22% [25%]
2024	32%	21%	NA	15%	44%	20%
2023	19%	9%	4%	12%	56%	23%
2022	38%	10%	6%	8%	42%	15%
2019-2021	35%	20%	1%	16%	42%	13%
2014-2018	25%	20%	5%	3%	37%	11%

Table 7: Percentage of offers above thermal SRMCs January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)	Stratford	Huntly
2025	59% [62%]	18% [36%]	15% [33%]	NA [45%]	71% [51%]	56% [38%]
2024	42%	37%	NA	19%	69%	24%
2023	25%	10%	5%	17%	76%	26%
2022	32%	7%	7%	16%	19%	16%
2019-2021	32%	28%	2%	21%	33%	14%
2014-2018	24%	31%	7%	3%	27%	13%

10.46 In previous SCP analysis we noted that sometimes the JADE model under-valued hydro costing. Despite some improvements in the modelling there appears to still be some under evaluation when hydro storage is declining.

Table 8: Percentage of offers above water values January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2025	58% [62%]	22% [39%]	6% [31%]	NA [43%]
2024	48%	37%	NaN	22%
2023	32%	17%	8%	17%

Relationship of storage and offers to cost

10.47 Table 9 to Table 11 show the relationships between the average water values for each associated reservoir and hydro storage and offers. Figure 41 shows the relationship between these water values and offers.

10.48 For January to June 2025, all schemes had a water value which was negatively correlated with storage (as shown in Table 9), ie, water values increased as storage decreased, which is consistent with competition.

10.49 Figure 41 shows an increase in quantity weighted offer prices (QWOP) between January and June, which as shown above was correlated with storage declines in these schemes. It is not unexpected for generators to price water high when storage is low/declining, and many lakes were below average heading into winter 2025.

10.50 While the JADE water value also increased, for all schemes except the Waitaki, the QWOP was much higher than the marginal water values in each scheme. This seems to be due to hydro generators offering steeper tranches. Generation seems to be placed into three buckets, very low priced generation to cover existing obligations, then mid-tier generation which is often cleared in the wholesale market, then capacity which is priced out of the market to enable storage to be conserved. When tranche five (priced to conserve storage) from each scheme is removed, as in Figure 42, the JADE water value is more reflective of the QWOP from each generator.

Figure 41: Quantity weighted offer prices for January - June 2024

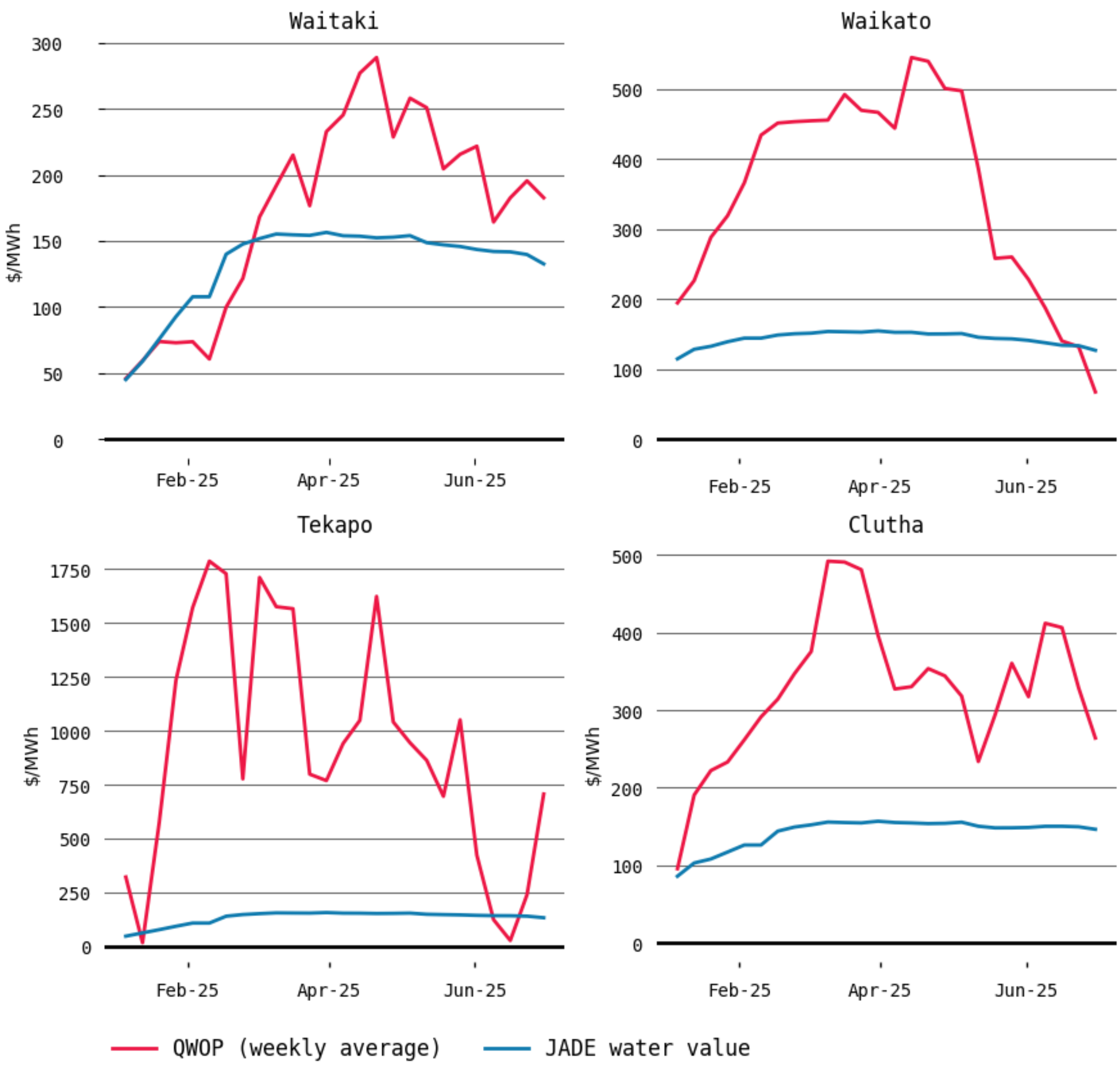
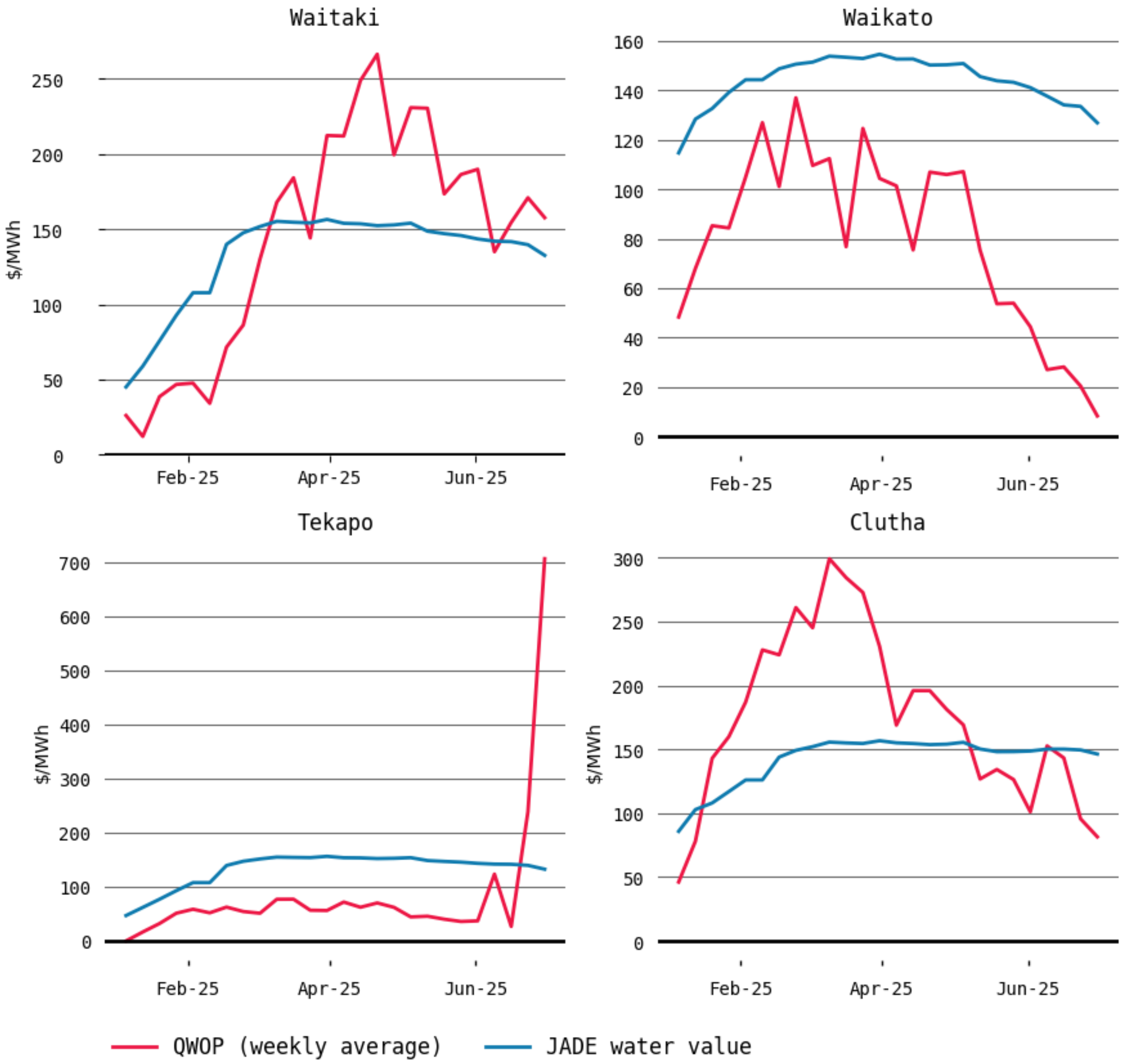


Figure 42: Quantity weighted offer prices for January - June 2024 where tranches five offers are removed



10.51 All schemes had negative correlations between hydro storage and water values ie, water values decreased when storage increased and vice versa, which is what we would expect under competitive outcomes.

10.52 All schemes also had a positive correlation of water values with the percent of offers above \$300/MWh, and with QWOP, meaning that as water values increased the proportion of offers above \$300/MWh, and the QWOP increased, as expected under competitive outcomes

10.53 The overall picture presented by the indicators suggests a continuation of the trading conduct provisions having a positive impact on generator behaviour.

Table 9: Correlations of water values with hydro storage - January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2025	-0.84	-0.92	-0.46	-0.59
2024	-0.87	-0.72	-0.59	-0.29
2023	0.49	-0.32	0.17	-0.41

Table 10: Correlation of water values with percentage of offers above $300/MWh - January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2025	0.76	0.69	0.47	0.37
2024	0.52	0.57	0.44	0.50
2023	0.13	-0.18	-0.30	-0.04

Table 11: Correlation of water values with QWOP - January to June

Year	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Takapō)	Contact (Clutha)
2025	0.87	0.76	0.21	0.78
2024	0.86	0.70	0.79	0.41
2023	0.28	0.05	0.15	0.05