Market performance quarterly review

January – March 2024

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1. Purpose

This document is a review of the performance of New Zealand's energy market from 1 January to 31 March 2024. It aims to provide visibility of the monitoring of the market undertaken by the Electricity Authority Te Mana Hiko (Authority) during this period.

2. Highlights

National electricity demand was higher this quarter than the 2019-2023 historic average, especially throughout early to mid-January.

Huntly 5 returned from outage on 20 January and ran as baseload for most of the quarter. Taranaki Combined Cycle (TCC), Huntly 2 and Huntly 4 also provided baseload, as did Huntly 1, before it went on outage on 31 January for the remainder of the quarter.

National controlled hydro storage increased in mid-January due to high inflows, then gradually declined over the rest of the quarter.

HVDC outages took place in February and March for scheduled annual maintenance, leading to price separation between the North and South islands.

Daily volume weighted average gas prices were mostly between $15-$19/TJ, with prices rising over the quarter.

Genesis Energy lost the largest number of electricity connections (ICPs) this quarter, with the largest gainer being Frank Energy.

While electricity prices increased at below inflation (ie, in real terms), in nominal terms (ie not adjusted for inflation) prices have increased since last year with power bills approximately $56 per year higher for an average household.

The price of New Zealand carbon unit price (NZUs) decreased this quarter, dropping to $64.27 per unit by the end of March. The first successful carbon auction since December 2022 took place on 20 March.

3. Electricity demand

Demand across the quarter

Figure 1 shows the total daily electricity demand in 2024 and the 2019-23 historic average electricity demand between January and March.

National demand was mostly above the historic average this quarter. It was low at the beginning of the quarter, as is expected during the holiday period, but was still significantly higher than usual for the time of year. In the first week of January, demand was 17.5% higher than the historic average. Note, however, that this comparison matches week and weekday, so comparisons during the early January holiday period include years where major holidays fell both during weekdays and weekends. Demand began to decrease from February onwards as temperatures fell.

One customer advice notice (CAN) was issued in Q1 2024 for low reserve supply[1] from 24-25 February[2]. However, there were no CANs issued for low residual supply[3]; as compared to the four CANs issued in Q1 2023.

The relatively high number of CANs issued in Q1 2023 resulted from low temperatures leading to high demand during HVDC outages. Although scheduled HVDC outages also took place in Q1 2024, demand during the outages was typical for the time of year.

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[1] https://static.transpower.co.nz/public/interfaces/can/CAN%20Potential%20Short%20Fall%20or%20Low%20Residual%20Situation%205230612368.pdf?VersionId=Y8msJ8L5oVCqeHx02l_Rn1IGbUFSVdO6

[2] In this case the system operator was advising of a South Island reserve shortfall in the week ahead schedule (WDS)

[3] These are issued when national residual generation is less than 200MW in the forward schedules

Figure 2 shows monthly total demand for January to March. Total demand for each month in Q1 2024 was higher than for the same month the previous two years. February demand increased the most significantly, at around 200GWh higher than in 2023 or 2022.

Figure 1: New Zealand daily demand compared to historical average, January to March 2024

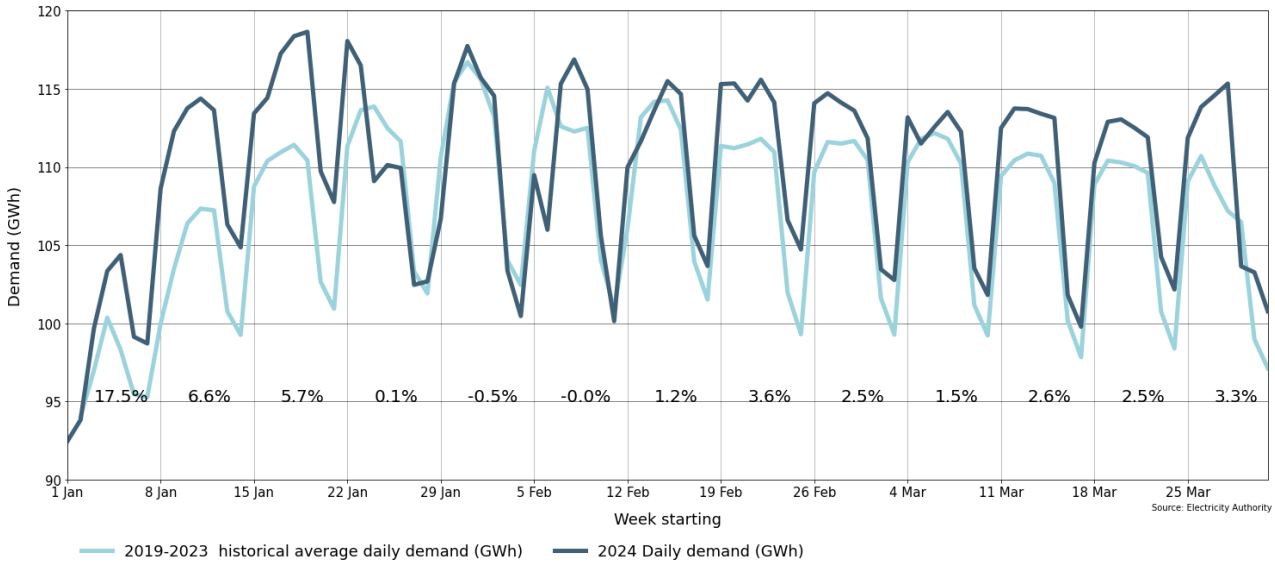
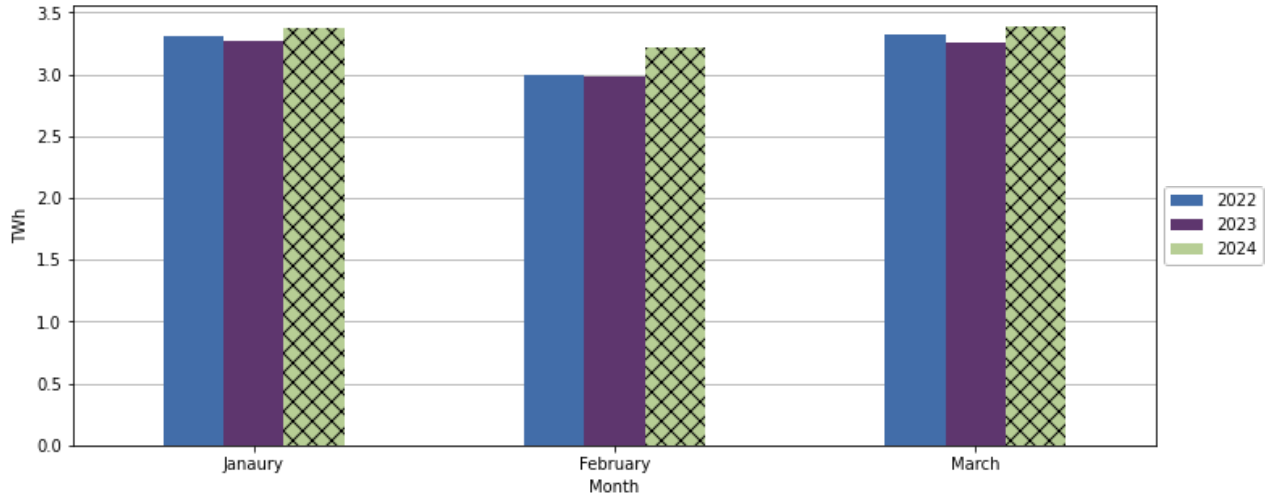


Figure 2: Monthly total demand, January to March 2022-24



4. Wholesale electricity price and composition

Figure 3 shows the half hourly and daily national wholesale electricity spot prices between January and March 2024. Also shown are the historic daily average prices adjusted for inflation (1999-2023).

Prices in Q1 2024 gradually increased until mid-January, at which point hydro storage increased significantly. This caused prices to decrease, with the daily average spot price dropping from $341/MWh on 18 January to $7/MWh by 4 February. Prices then began to rise again and by the end of March were similar to the prices seen in mid-January.

Prices were fairly stable at the beginning of the quarter but became more volatile from late January. From late January to late February, there were several prices over $500/MWh as well as many near-zero prices. Most of the price spikes were due to demand and wind forecasting inaccuracies, while the near-zero prices resulted from a combination of high hydro or wind generation and low demand. Prices became higher but more stable towards the end of the quarter.

The maximum half-hourly average price for the quarter was $955/MWh on the afternoon of Thursday 22 February. HVDC Pole 3 was on outage at this time, limiting transfer between islands. Very low wind generation despite the optimistic wind forecast generation required three baseload generators and four peakers, including Whirinaki, to be dispatched to meet North Island demand.

Figure 4 shows the weekly price distributions between January and March 2024. The average wholesale spot price for Q1 2024 was $188/MWh, which is higher than both the average Q4 2023 price ($145/MWh) and the Q1 2023 price ($135/MWh). The median and middle 50% of prices seen in the last weeks of January were lower than for the rest of the quarter, but had a wider range of prices with more high outliers. The weekly median price gradually increased from February onwards, while the range of prices each week – particularly the range of the middle 50% - tended to become smaller.

Figure 3: Half hourly, daily and daily historic average wholesale electricity prices, January to March 2024

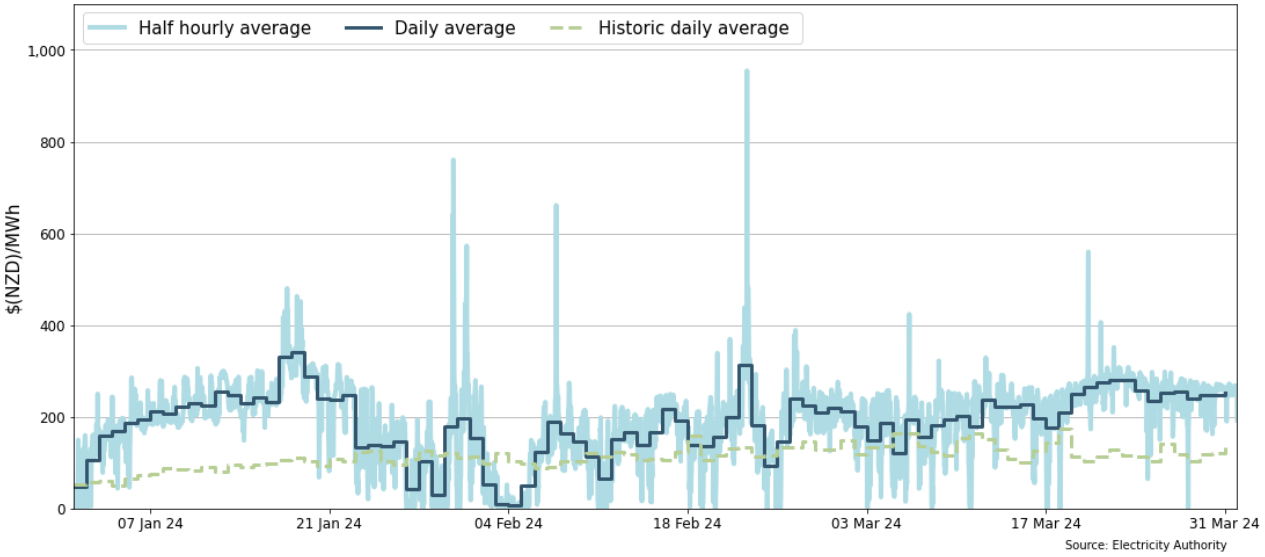
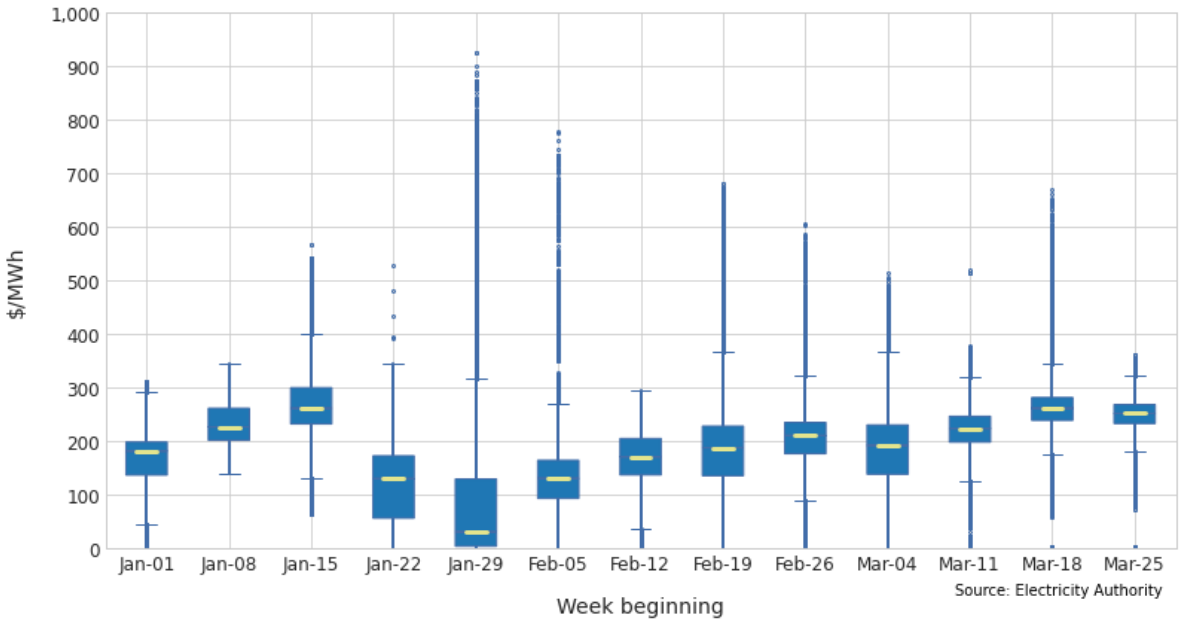


Figure 4: Box plot distributions of weekly spot prices between, January to March 2024



Generation composition influence on price

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. These include the source of the electricity generation, as different sources have different prices and generation characteristics.

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 and so affects longer-term average prices.

Figure 5 shows the daily total wind generation and the daily average national spot prices between January to March. Wind generation typically has an inverse relationship with average wholesale price. Since wind generation has no fuel costs, when the wind is blowing it has no reason not to offer all its generation into the market. With these low operating costs, it can offer a lot of generation at low prices, which displaces more expensive generation.

The inverse relationship between wind generation and wholesale electricity prices in Q1 2024 can be seen in Figure 5. For example, in early February high levels of wind generation and high hydro storage helped push the daily average price down to $7/MWh. Conversely, the daily average spot price reached $341 when total daily wind generation dropped to just 2.5GWh in January. However, as hydro storage decreased, wind generation began to displace hydro generation rather than thermal generation. This led to prices remaining high despite high wind generation in late March.

Figure 5: Daily wind generation and average wholesale price, January to March 2024

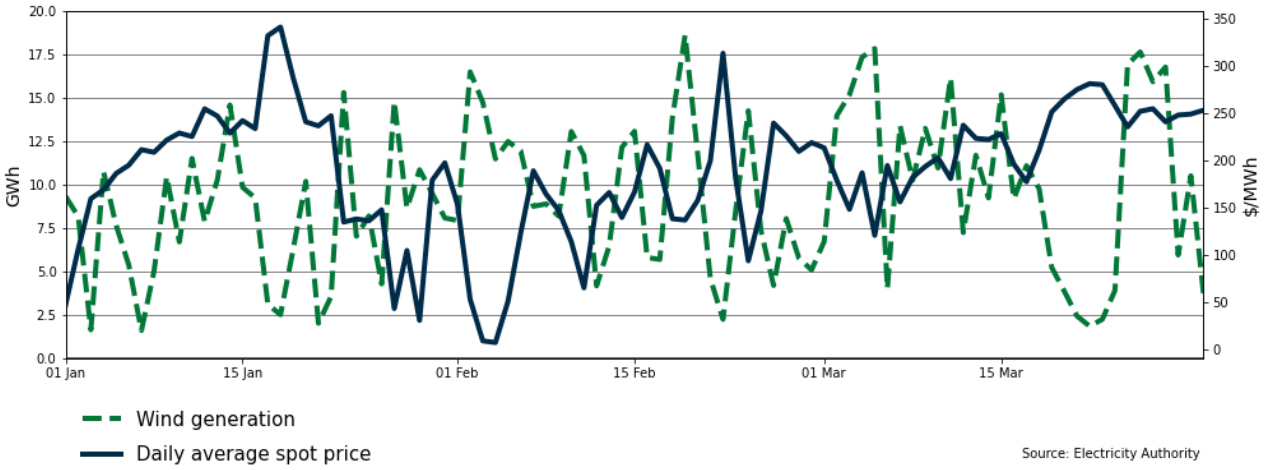
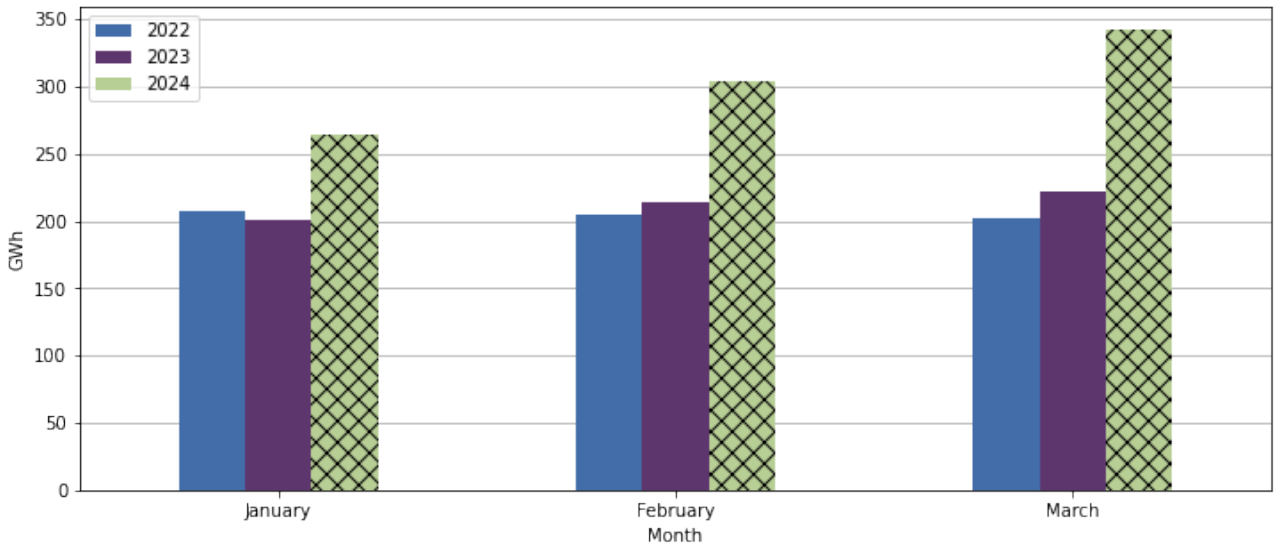


Figure 6 shows the total wind generation by month in Q1 for the past three years. Wind generation capacity has increased by 44% between 2020 and 2023, and wind generation has risen with it. Total wind generation in Q1 2022 was 614GWh; in Q1 2024 it was 910GWh.

Figure 6: Monthly wind generation in Q1, 2022-24



The amount of thermal generation required also affects wholesale prices. Thermal generation includes fuel costs and carbon prices, so it is more expensive. At times of higher demand, a

thermal generator is often the marginal generator. As a result, it often sets or influences the wholesale prices.

Figure 7 shows the daily total thermal generation and daily average spot price between January to March 2024. Thermal generation decreased late in late January as hydro storage increased and TCC turned off. From this point until mid-February, E3P was often the only thermal generator running and the daily average spot price was consistently below $200/MWh. E3P continued to run consistently the rest of the quarter, with TCC and other thermal units joining as hydro storage began to decline again. As can be seen in Figure 7, the daily average spot price increases as the daily total thermal generation does over the last half of the quarter.

Figure 7: Daily total thermal generation and average wholesale price, January to March 2024

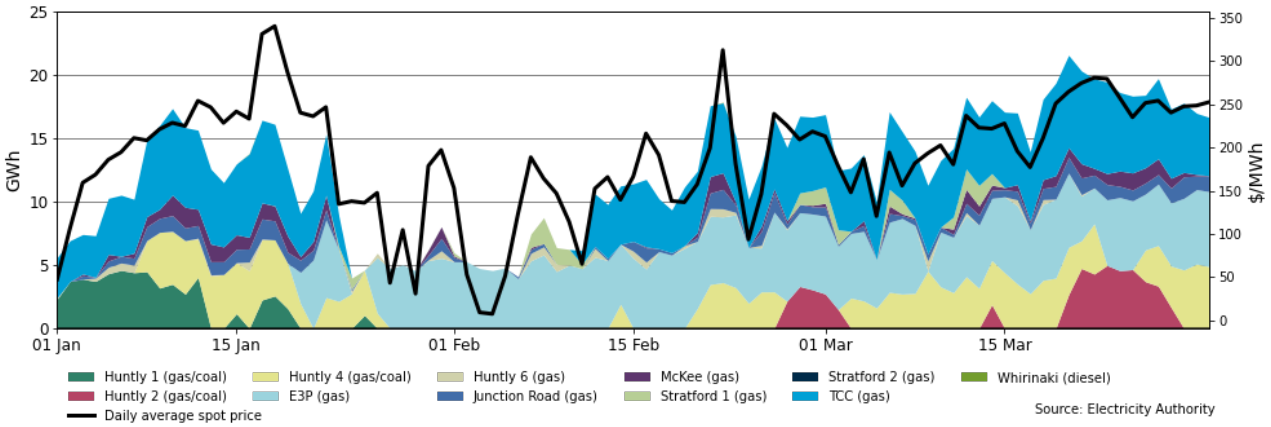
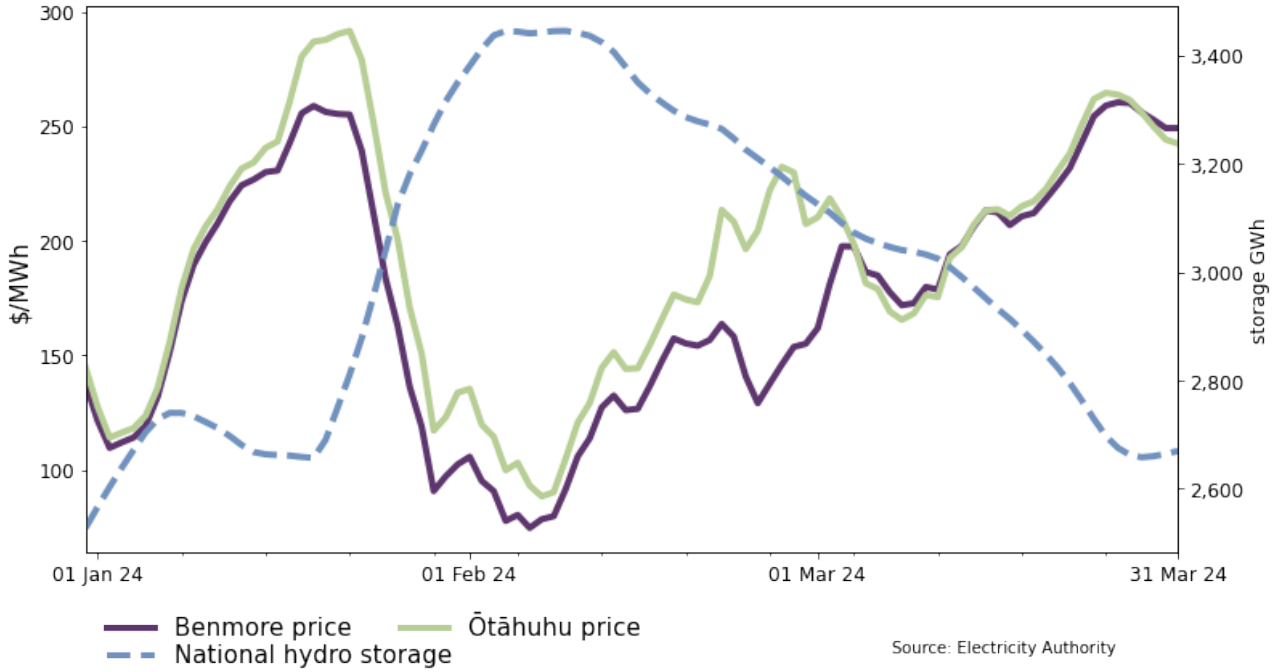


Figure 8 shows the rolling seven-day average wholesale prices at Benmore and Ōtāhuhu and the daily national hydro storage.

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. This is not always clear on a day-to-day basis, but is easier to see over a rolling average, as in Figure 8.

Figure 8 shows that hydro storage levels increased slightly overall in Q1 2024, with a significant increase in mid-January that drove wholesale prices down, and a gradual decline over the rest of the quarter that caused prices to increase again. The separation between the Ōtāhuhu and Benmore spot prices in late February is due to the HVDC Pole outages limiting transfer between islands, preventing the use of South Island hydro generation to meet North Island demand.

Figure 8: Rolling seven-day average of wholesale price versus hydro storage, January to March 2024



Generation by fuel type

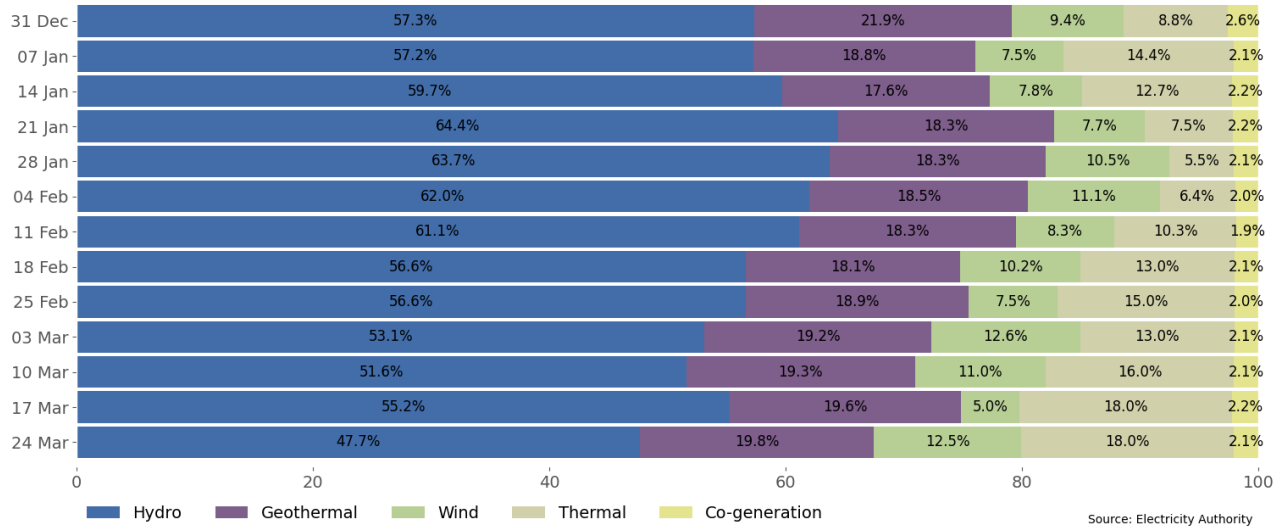
Figure 9 shows the weekly breakdown of electricity generation by fuel type.

Hydro generation increased over the first few weeks of the quarter as hydro storage improved, making up 64.4% of total weekly generation at its peak in late January. Storage then began to decline, and hydro generation gradually decreased for the rest of the quarter, dropping to just 47.7% of total weekly generation by the end of March.

Average wind generation this quarter was 9.3%, a decrease from the previous quarter but an increase compared to the same quarter last year. Wind generation made up 9.6% of total generation in Q4 2023 compared to 5.6% in Q1 2023.

Overall, the share of thermal supply increased compared to both the previous quarter and Q1 2023. The average weekly share of thermal supply in Q1 2024 was 12.2%, up from 7.5% in Q4 2023 and 9.4% in Q1 2023. The inverse relationship between renewable and thermal generation can be seen in Figure 9. The weekly share of thermal generation was lowest when wind or hydro generation were high. When wind or hydro generation were low, thermal generation generally increased to compensate. Thermal generation remained high even when wind was also high in late March, as hydro storage was low enough that wind generation was compensating for decreased hydro generation.

Figure 9: Weekly generation share by fuel type, January to March 2024



5. Water storage levels

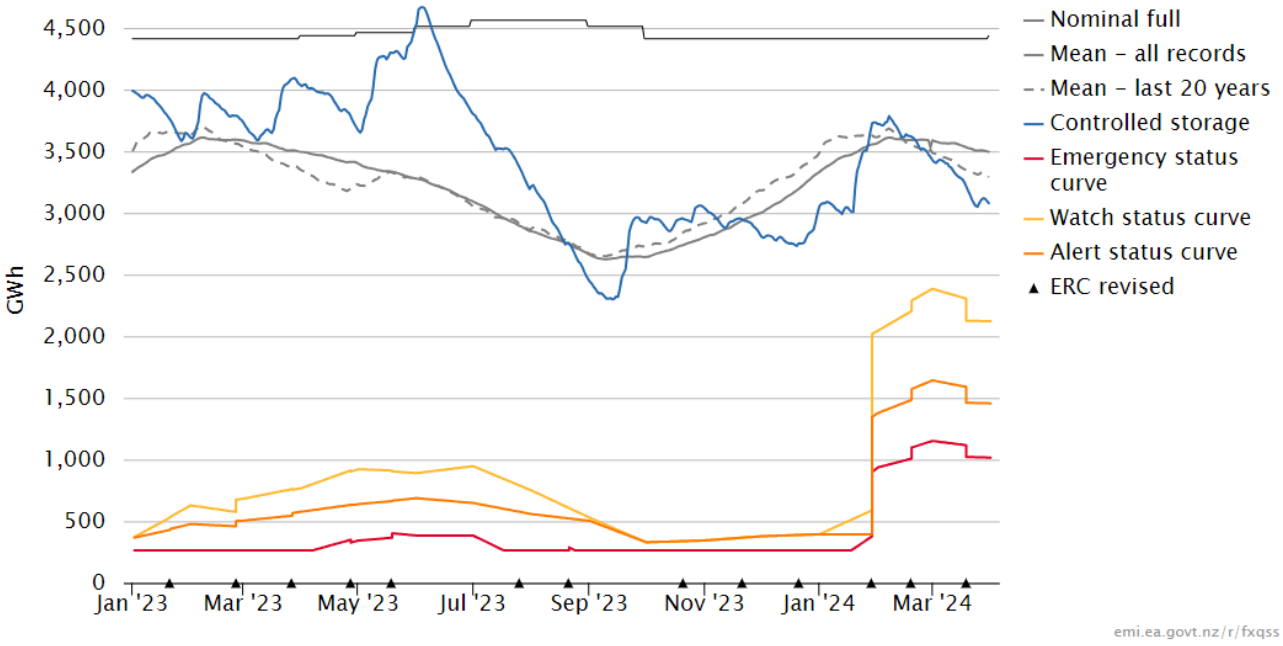
National hydro storage levels

Figure 10 shows the national hydro storage levels from January 2023 to March 2024.

Hydro storage increased slightly overall across Q4 2023. At the beginning of Q1 2024, national storage was 3,055GWh. High inflows in mid-January led to a sharp increase, with storage reaching a peak of 3,786GWh. However, storage gradually declined from early February onwards, and dropping back down to 3,079GWh by the end of March. Storage at the end of the same quarter the previous year was 4,041GWh.

After being revised on 29 January, the Electricity Risk Curves increased significantly due to decreased gas production forecasts[4].

Figure 10: National hydro storage levels, January 2023 to March 2024



[4] https://static.transpower.co.nz/public/bulk-upload/documents/ERC%20update%20log%20-%20January%202024.pdf?VersionId=u1jFNjyzxj4A06qhcXy2J4LqGlaHzX.E

Lake storage levels

Figure 11 shows individual lake levels in Q1 2024 and the difference location can have on hydro inflows.

At the start of the quarter, storage at Hawea was below its historical 10th percentile. By the end of the quarter, it was above its 10th percentile but still below mean.

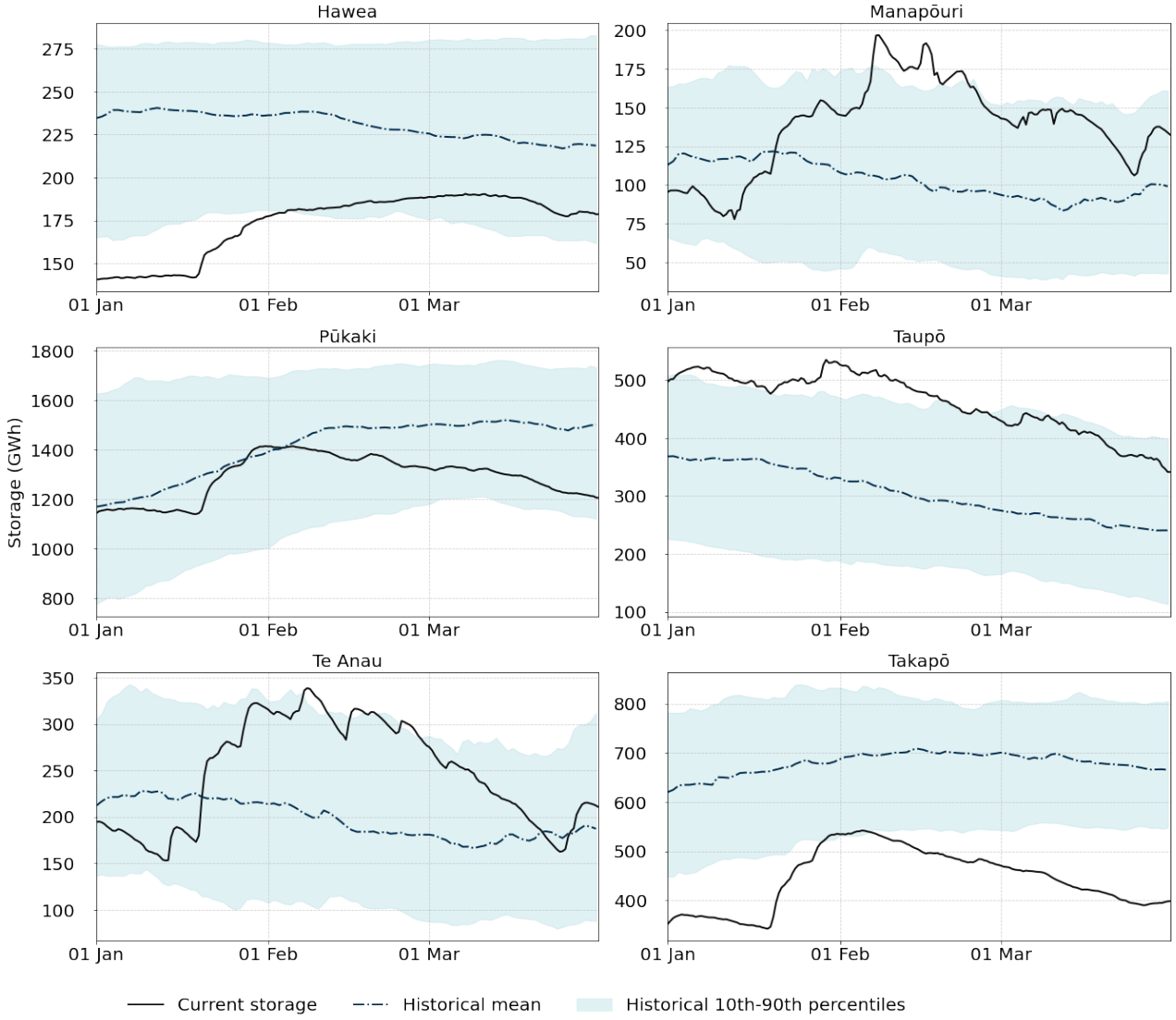
Pūkaki storage rose above its mean after the significant hydro inflows in mid-January, but declined throughout the rest of the quarter to near its 10th percentile.

Storage was below mean at Te Anau and Manapōuri at the beginning of January, but above the 90th percentile for each lake by early February. Storage at both lakes declined across the rest of the quarter but remained above mean by the end of March.

Taupō storage was close to its historical 90th percentile throughout Q1 2024, though it continued to fall further below it from the start of March.

Storage at Takapō was very low this quarter, only rising above its 10th percentile for a brief period in late January/early February before declining again.

Figure 11: Lake storage levels for January to March 2024 vs historical average and 10th and 90th percentiles



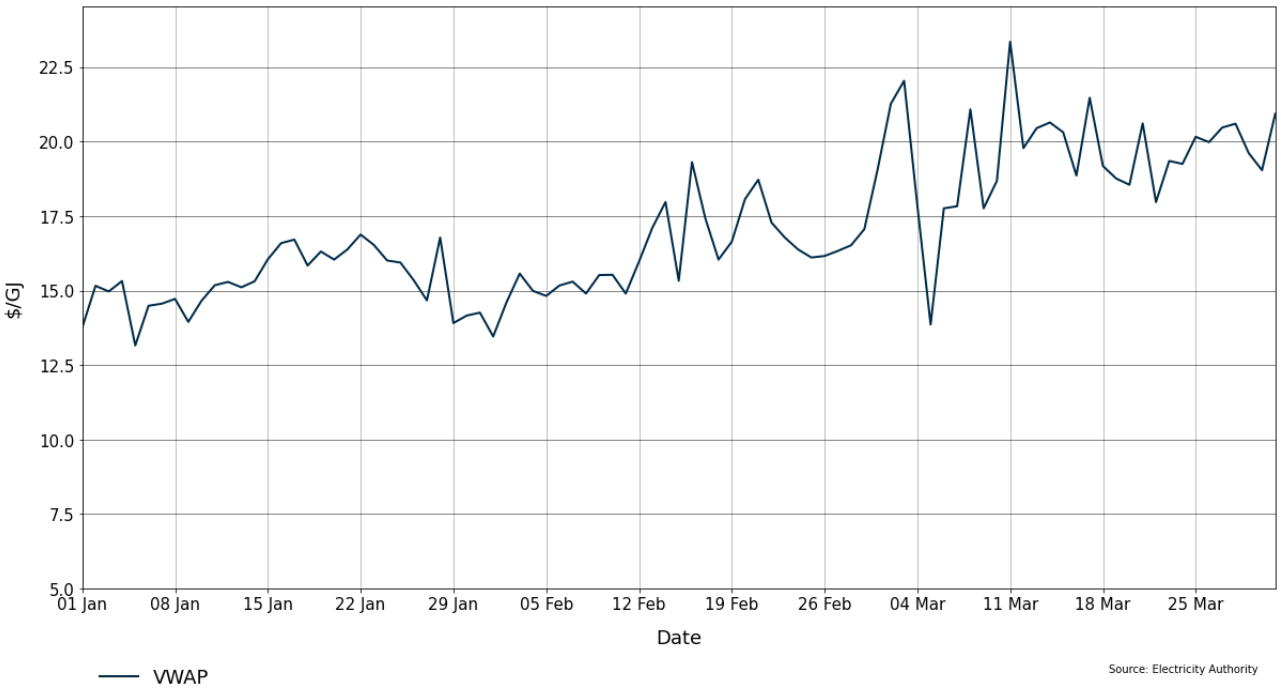
6. Wholesale gas prices, production and consumption

Gas prices

Figure 12 shows the daily volume-weighted average gas price for January to March 2024.

The volume-weighted average price (VWAP) for gas in Q1 2024 was $17.04/GJ. This is an increase of around $4.33/GJ on the previous quarter and $5.95/GJ on Q1 2023. VWAP prices peaked on 11 March 2024, shortly after the Pohokura field outage began. Gas prices increased over the quarter, as production fell and increased thermal generation led to a rise in demand.

Figure 12: Daily volume-weighted average price for gas, January to March 2024



Gas production

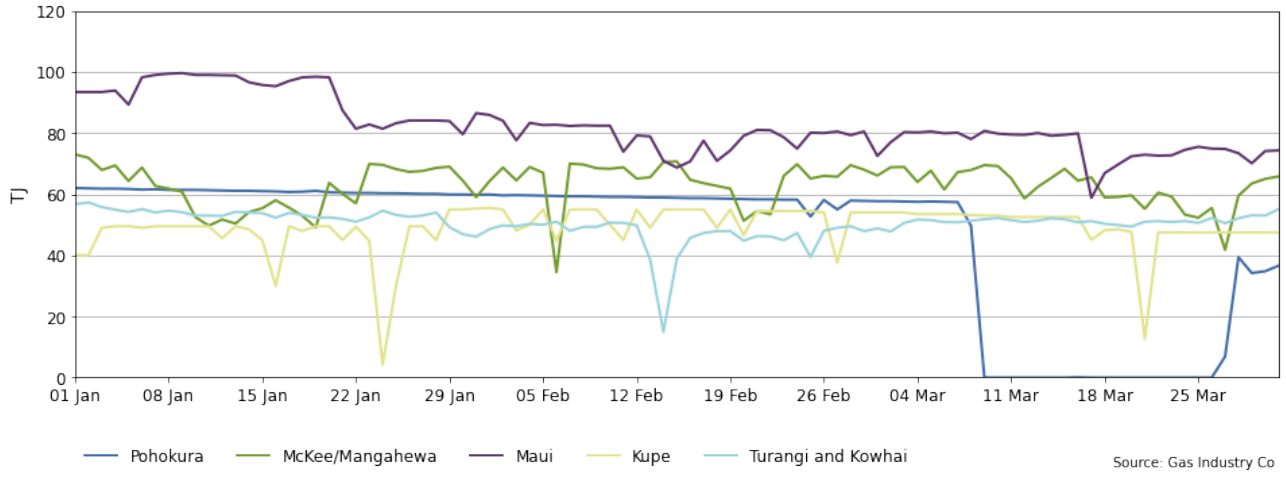
Figure 13 shows daily gas production at major fields between January to March 2024.

Total gas production decreased across Q1 2024, dropping from an average 326TJ/day in the first week of January to 274TJ/day after Pohokura returned from outage at the end of March. Production at all major fields except Kupe decreased over the quarter.

The planned outage at Pohokura took place from 9-27 March. Production did not return to the level seen before the outage, decreasing by ~20TJ/day.

Brief unplanned outages occurred at Kupe on 21 March and at Maui on 17 March.

Figure 13: New Zealand gas production, January to March 2024 from Gas production and consumption



Gas consumption

Figure 14 shows the daily gas consumption by major users between January to March 2024. Gas consumption in Q1 2024 decreased significantly compared to the previous quarter.

Consumption at Methanex Motunui decreased over the quarter, as one of its production trains shut down due to the Pohokura outage.

Figure 14: New Zealand gas consumption, January to March 2024 from gas production and consumption

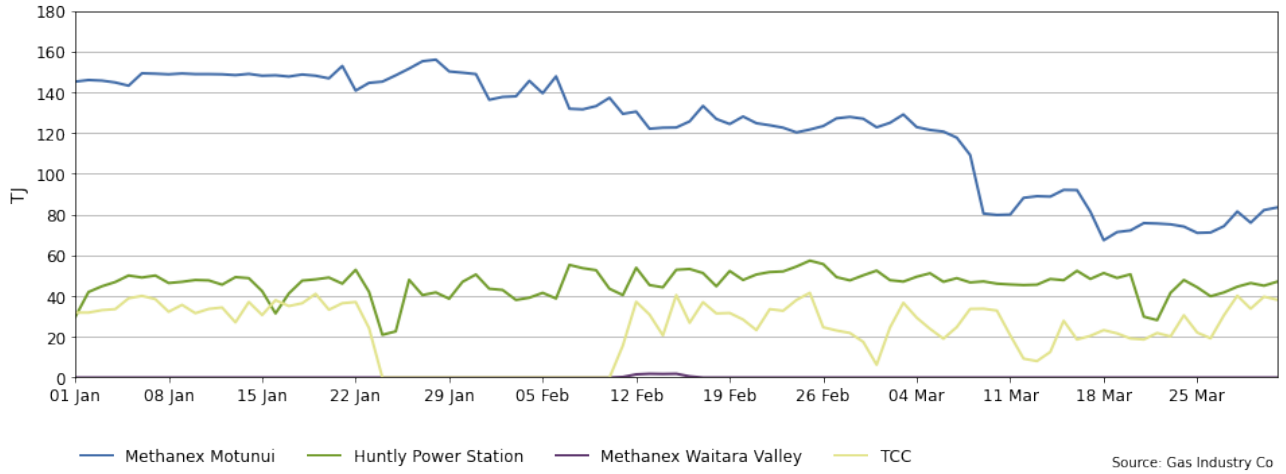
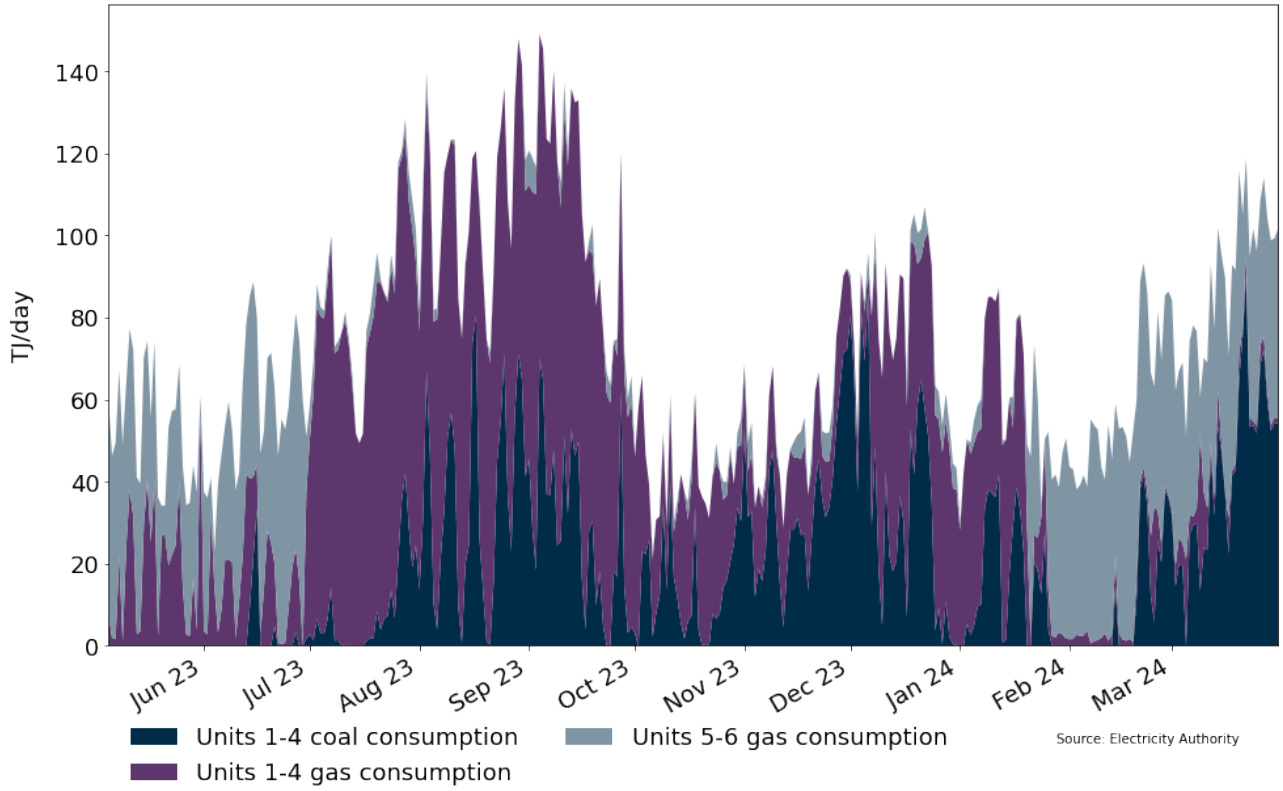


Figure 15 shows the estimated daily total energy consumption across all Huntly units between May 2023 and March 2024.

Huntly fuel consumption increased compared to the previous quarter. Consumption dropped in mid-January due to the increase in hydro storage but began to increase from early February as hydro storage declined again. At the beginning of February, the fuel consumed was almost entirely gas, but as thermal generation increased the consumption of coal increased with it. The proportion of coal consumption increased over the rest of the quarter, likely due to the limited availability of gas after the Pohokura outage. Additionally, the short run marginal cost (SRMC) of coal fell below that of gas in March 2024.

Figure 15: Estimated Huntly fuel consumption, May 2023 to March 2024



7. Retail electricity

Retailer switching

Figure 16 shows the 20 retailers who either gained or lost the most electricity connections (ICPs) between January and March 2024.

Frank Energy experienced the greatest net gain in ICPs by a significant margin at 4,281. Flick Electric continued to gain market share for the fourth quarter in a row, with a net gain of 879 IPCs this quarter.

Genesis Energy experienced the greatest net loss in ICPs, losing 4,712 over the quarter.

After purchasing Trustpower in May 2023, Mercury Energy transitioned all Trustpower customers to Mercury by the end of Q2 2023. Mercury have experienced net ICP losses since this switch, which is likely due to former Trustpower customers seeking a new retailer. However, Mercury's net losses have again decreased from the last quarter, at 4,385 ICP losses compared to 6,869 in Q4 2023.

Figure 16: Top 20 movements in ICP net switching by retailer, January to March 2024

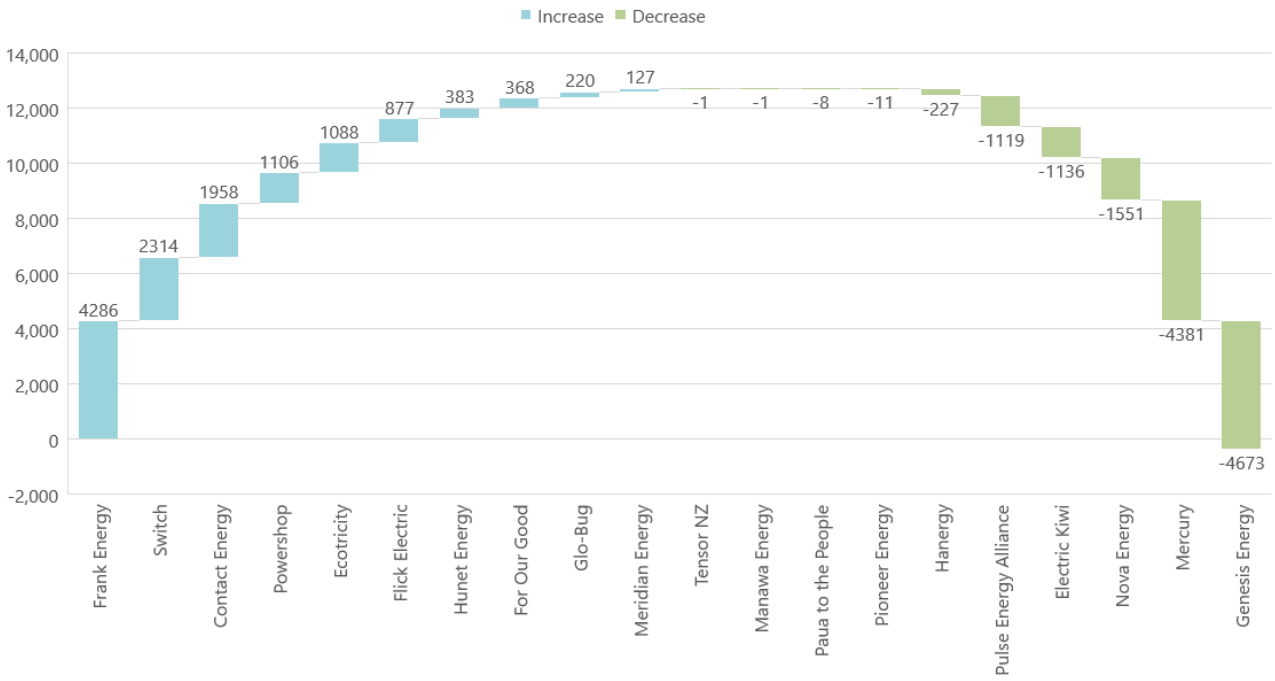
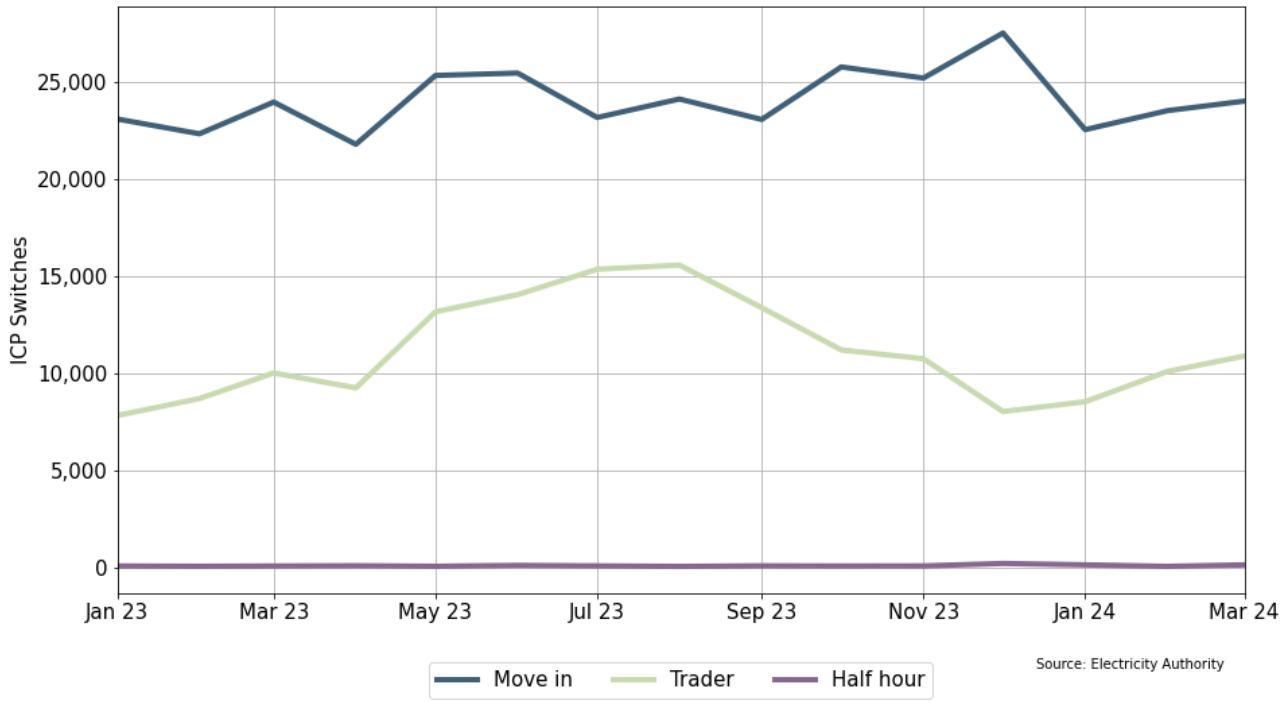


Figure 17 shows the number of ICPs that have changed electricity suppliers between 1 January 2023 and 31 March 2024 categorised by type 'move in', 'trader' or 'half hour'. Move in[5] switches are switches where the customer does not have an electricity provider contract with a trader. In contrast, trader 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.

Move-in and trader switching rates both increased over Q1 2024. Both rates were similar to those seen in Q1 2023, though move-in trader rate increased consistently across this quarter rather than declining in March as they did in 2023.

Figure 17: Breakdown of monthly ICP switching by type, January 2023 to March 2024



[5] At an ICP

Retail prices

Figure 18 shows the domestic electricity price by component (QSDEP) adjusted for inflation from 2004-24. Based on the trends in Figure 18, energy retail prices tracked below the rate of inflation. Changes in prices were driven by the line charges as adjusted for inflation, which continued to decline. After adjusting for inflation, costs for electricity declined marginally from the 2020 peak.

Figure 18: Domestic electricity prices by component adjusted for inflation (base 2024 Q1 CPI)

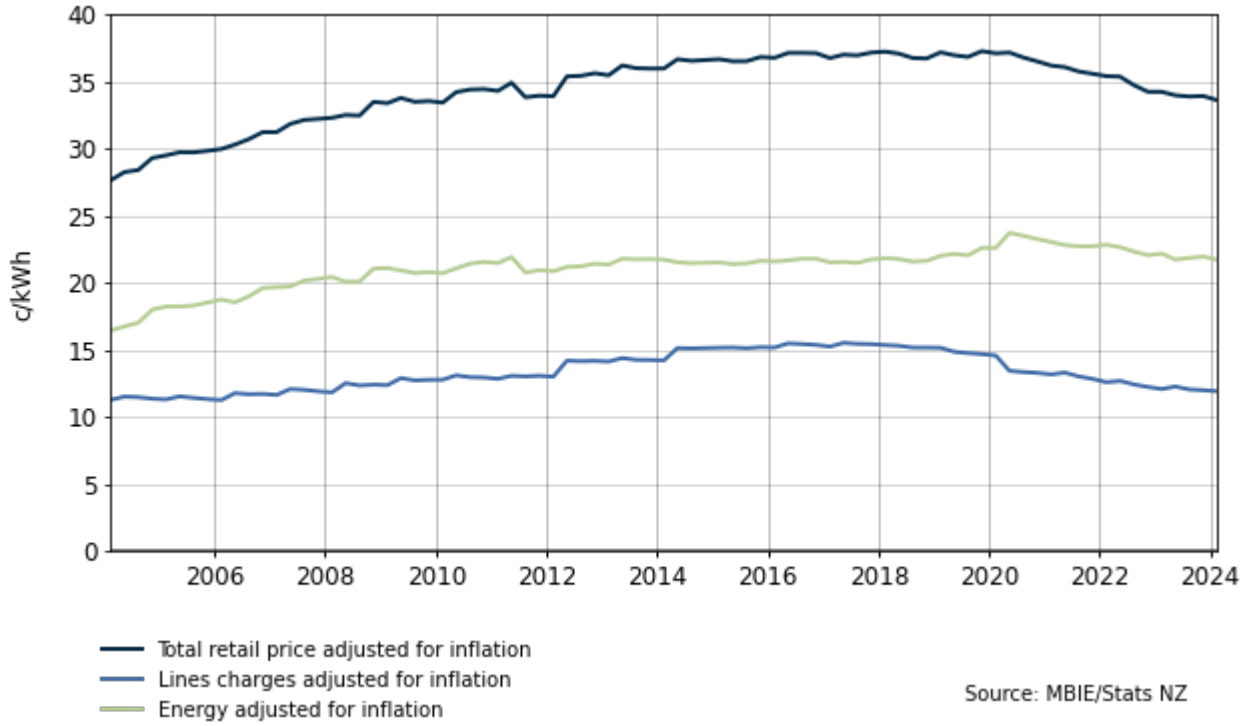
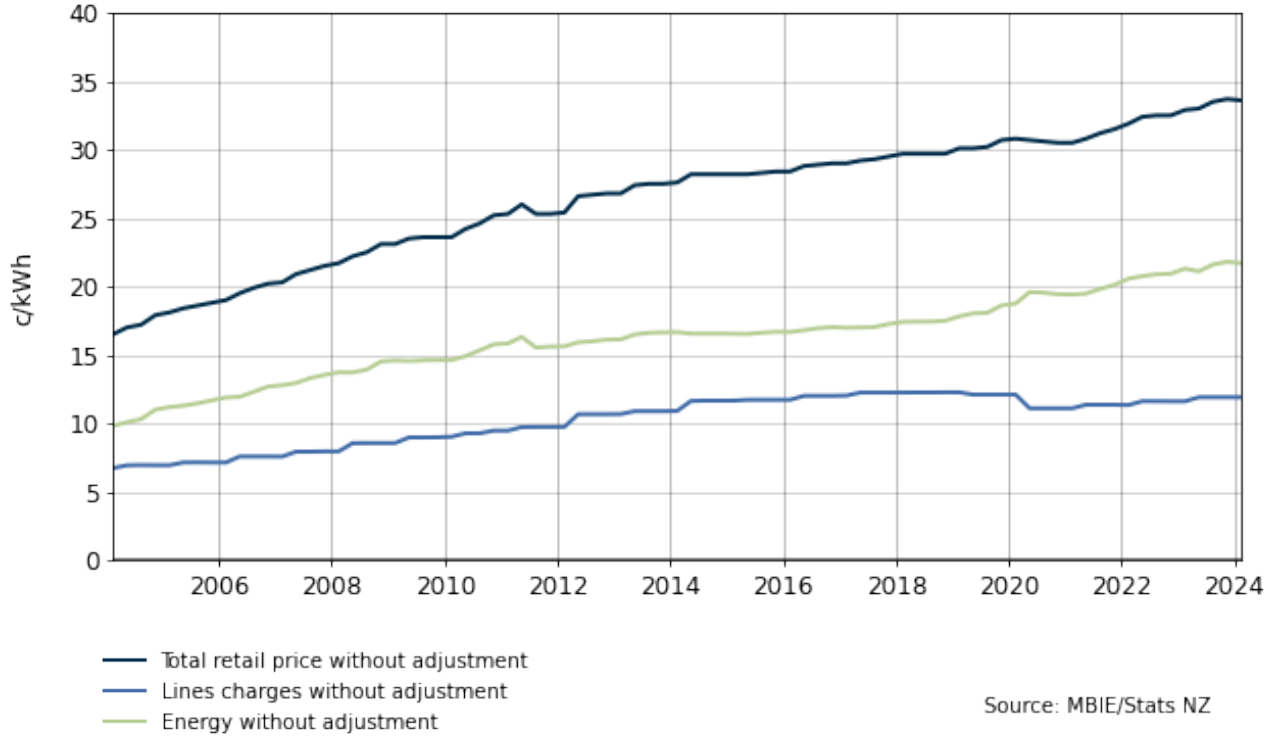


Figure 19 shows the domestic electricity prices by component without adjusting for inflation. While electricity prices are increasing at a rate below inflation (as per Figure 19), Figure 19 this makes it clear that in nominal terms, electricity prices have increased with energy costs being one of the main factors. In the last 12 months, nominal values have risen by 2.1%. For a typical household using 8,000kWh annually, this equates to an extra $56 per year on their electricity bill compared to one year ago.

Figure 19: Domestic electricity prices by component without inflation adjustment



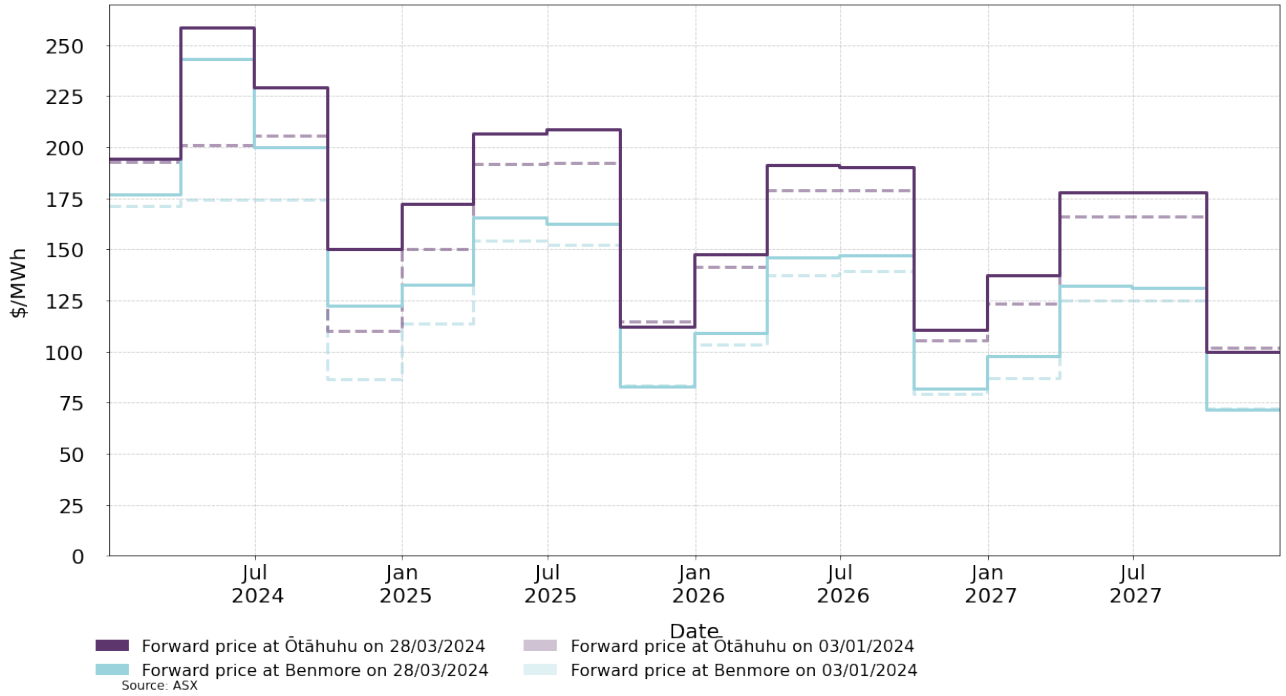
8. Forward market and carbon pricing

Forward pricing

Figure 20 shows the quarterly forward prices up to 2027, with the first snapshot being at the beginning of January 2024 and the other snapshot being at end of March 2024.

In Q1 2024, forward prices increased for all contracts except December 2025 and December 2027, which decreased slightly (likely as these contracts are for summer months with low price risk). June 2024 contracts saw the most significant increase in price, possibly reflecting concerns around winter security of supply due to decreased gas production and low hydro storage.

Figure 20: ASX forward prices for the start and finish of Q1 2024



Carbon pricing

Figure 21 shows the New Zealand carbon unit price between September 2022 to March 2024 as recorded by the European Capital Markets Institute.

To try to minimise the impacts on the cost of living, the Government did not adopt the New Zealand Unit (NZU) floor prices recommended by the Climate Change Commission in 2022. Following this action, NZU prices dropped in 2023. The sharpest drops coincided with the scheduled NZU auctions, which failed to clear. Prices reached a low of $35 per unit in early August 2023.

In mid-July 2023, the High Court issued a judgment saying the Government's December 2022 action was ultra vires[6]. The Government then made changes in line with the pricing recommended by the Climate Change Commission and NZU prices began to return to previous levels. The Climate Change Commission recommended prices step up gradually in coming years.

In early September 2023, the third NZU auction took place and failed to reach minimum levels. All unsold NZUs were rolled into the final auction in December 2023, which had 15 million NZUs available[7], but no NZUs were sold.

The market reset in 2024, without 2023 NZUs rolling over. At the beginning of the quarter, the carbon price was $72 per unit. The price decreased until late January, dropping to $67 per unit before rising back above $70 per unit, then continuing to gradually decrease. The first carbon auction since December 2022 took place on 20 March, with 2.97 million units out of the 3.53 million available being sold[8]. Prices continued to decrease after the March auction, finishing the quarter at $64 per unit.

[6] https://www.capitalletter.co.nz/news/climate-change-response-act-2002/142596/climate-change-lawyers-climate-action-v-minister

[7] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/090623-new-zealands-carbon-auction-fails-on-lower-bids-lifts-spot-price-slightly

[8] https://www.beehive.govt.nz/release/first-nz-ets-auction-2024-partially-clears

Figure 21: New Zealand Units price, September 2022 to March 2024

9. Financial Transmission Rights analysis

This section assesses whether there is evidence of trading misconduct in the FTR market. Similar analysis was previously carried out on bid data dating back to January 2015. The Authority will repeat this analysis in every second quarterly review going forward.

Analysis was conducted on awarded option contracts and bids relative to specific sink-source pairs (FTR paths) with end dates between October 2023 to March 2024 (Q4 2023 to Q1 2024). Both buy and sell trade types were included.

Four key factors were specifically considered:

- prices and volumes of awarded FTR contracts,
- market participants' bid behaviour, and
- the generation outage schedule.

Contracts awarded at unusually high prices or volume were identified as requiring further analysis to assess whether suspicious activity had taken place. Only contracts belonging to physical participants were assessed further, as they would be most likely to have access to confidential information relating to generation conditions.

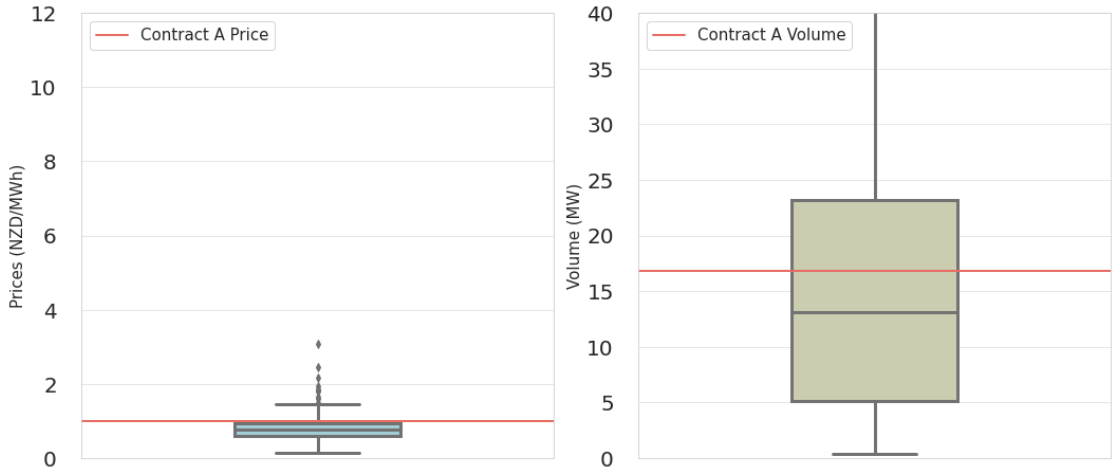
Of the 2,682 contracts considered, only nine (0.3%) were identified as being potentially suspicious:

- Two of these nine contracts were excluded from further analysis as they belonged to non-physical participants.
- Two were the only contracts for a specific FTR path between Q4 2023 and Q1 2024. The prices and volumes of these two contracts were not suspicious when compared to other contracts previously traded for the same FTR path.
- Three contracts were identified due to their relatively high volume but had low prices compared to other contracts for the same FTR path.
- One contract, for a relatively uncommon FTR path, was identified as having a high price and volume compared to other contracts traded for the same path between Q1 2023 and

Q4 2024. When also compared to contracts that were traded before Q4 2023, the price and volume were not found to be unusually high.

- One contract had both a high price and high volume compared to other contracts for the same path, as shown in Figure 22. This contract, referred to as Contract A, was identified as requiring further analysis.

Figure 22: Price and volume for Contract A and other contracts for the same FTR path



The bidding behaviour of the owner of Contract A was analysed. The bid curve for Contract A was compared to the bid curves of contracts bought by the same participant for the same FTR path. The bid curve for Contract A was found to be consistent with the participant's previous bidding behaviour.

Market conditions for the period covered by Contract A were also examined, including outages scheduled for the contract owner's generation units. No evidence of suspicious activity was found.

When compared only to other contracts bought by the same participant, as well as for the same FTR path, the price and volume of Contract A were not unusually high.

Overall, no evidence of suspicious activity on the FTR market between Q4 2023 to Q1 2024 was found. The results of this analysis do not reveal any suspicious bidding behaviour that would indicate insider trading, or other forms of trading misconduct from FTR market participants.