Market performance quarterly review

July - September 2023

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1. Purpose

1.1. This document is a review of the performance of New Zealand's energy market from 1 July to 20 September 2023 (Q3 2023). 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

2.1. New Zealand experienced high levels of electricity demand in Q3 2023. August was very cold – the only month with below average temperatures in the last 6 years.

2.2. The cold weather caused six top 10 demand events, including a maximum of 7122MW, which was 7MW short of the highest demand ever recorded. This reflected an increase in peak demand on previous years.

2.3. Despite these high demand levels, only one low residual customer advice notice (CAN) was issued for the whole quarter, compared with seven CANs in the previous quarter.

2.4. A higher share of thermal generation contributed to higher wholesale prices, which averaged $124/MWh for the quarter.

2.5. Thermal and wind generation had a higher share of generation than the same quarter last year, due to increased wind capacity and declining hydro storage levels.

2.6. Below average inflows caused hydro levels to decline for the first ten weeks of the quarter, reducing hydro contribution to generation.

2.7. Gas prices were similar to the same quarter last year, at an average of around $10.16/GJ.

2.8. Retail switching was dominated by installation control points (ICPs) transferring away from Mercury following the rebranding of Trustpower to Mercury in June 2023.

2.9. While electricity prices increased at below inflation (ie, real terms), in nominal terms prices have increased since last year – bills are approximately $80 per year higher for an average household.

2.10. Total debt (more than 30 days late) held by retailers lifted by approximately $10 million across the quarter, which is consistent with seasonal billing trends.

2.11. The price of New Zealand Units (NZUs) reached a minimum of $35 in early July, before recovering to $73 before the end of the quarter, after pricing was reinstated in line with the Climate Change Commission's recommendation.

3. Electricity demand

Demand across the quarter

3.1. July 2023 was a mild month with electricity demand lower than average. In comparison, August 2023 was very cold – the first month in six years where temperatures were below average. This is evident in Figure 1, where demand is well above the long-term average for the month. Some days had demand close to 140GWh: an average demand of 5.8GW across 24 hours. Total demand for August was 196GWh up on the same time last year, while July and September were down 31GWh and 42GWh respectively.

3.2. Across the quarter, there were six new top 10 demand trading periods for New Zealand. However, there was only one customer advice notice (CAN) for low residual supply, which was issued on 11 August 2023. This was remarkable, given that Huntly 5 was on outage for the entire quarter.

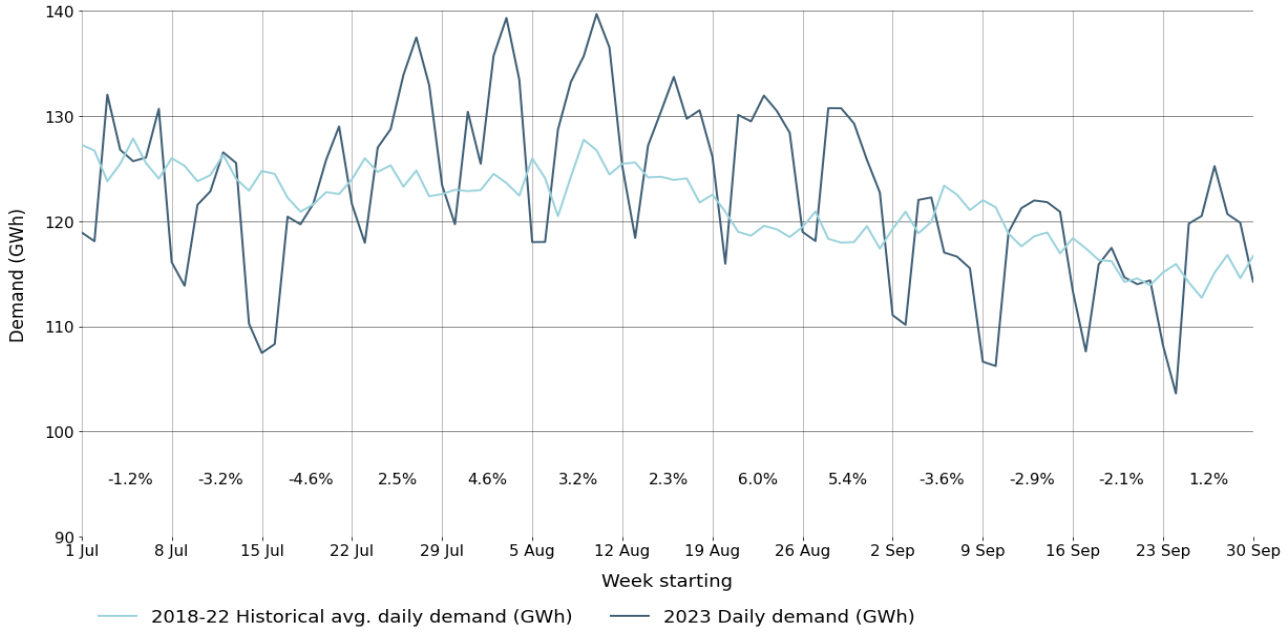

Figure 1: New Zealand daily load compared to historical average for July to September

Demand highlights

3.3. Q3 2023 was notable for particularly high electricity demand. Five of the highest peak demand days in the last 10 years (see Figure 2) happened in this quarter (shown in dark blue in the graph below). Four of these days occurred in the first two weeks of August. The morning and evening of 3 August were both top 10 peak demand events, visible in Figure 3.

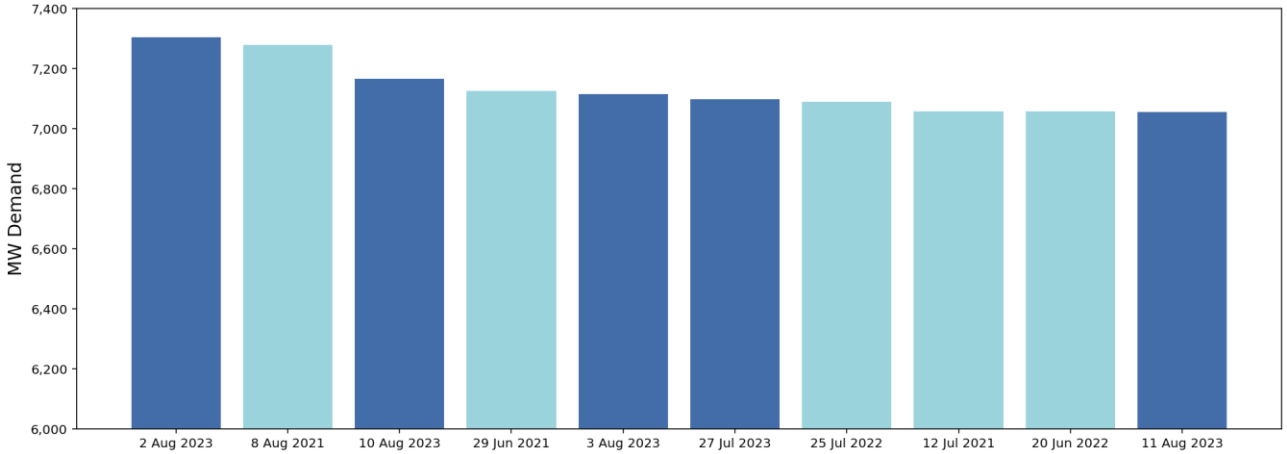

Figure 2: Top 10 days by maximum demand in the last 10 years

3.4. Demand on Wednesday 2 August 2023 was 7,122MW, almost equal to the record demand reached on Monday 9 August 2021 of 7,129MW. Temperatures were well below average in all regional centres from Wednesday 2 to Friday 4 August. Figure 3 shows that this resulted in demand well above average for this time of year.

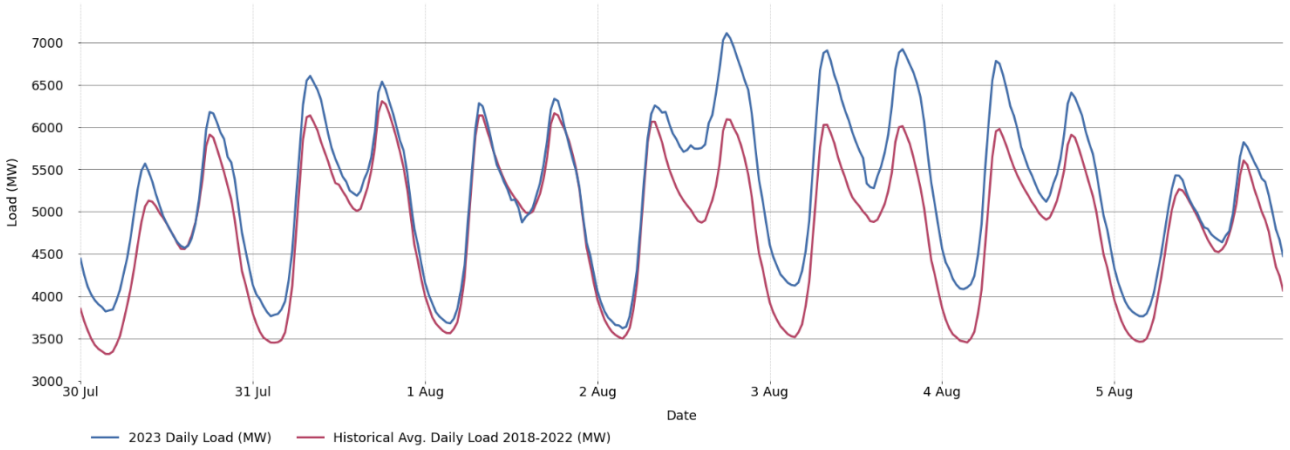

Figure 3: Half-hourly load for 30 July to 5 August 2023 versus historical demand

3.5. The only low residual customer advice notice (CAN) for Q3 2023 was issued for the morning of 11th August 2023, when North Island residuals were forecast to be under 200MW. Higher wind than forecast and a good market response to the CAN helped prevent any escalation. As visible in Figure 4, demand on the evening of 10 August 2023 was higher than on 11 August 2023, reaching 6,980MW – the third highest peak on record after 9 August 2021 and 2 August 2023.

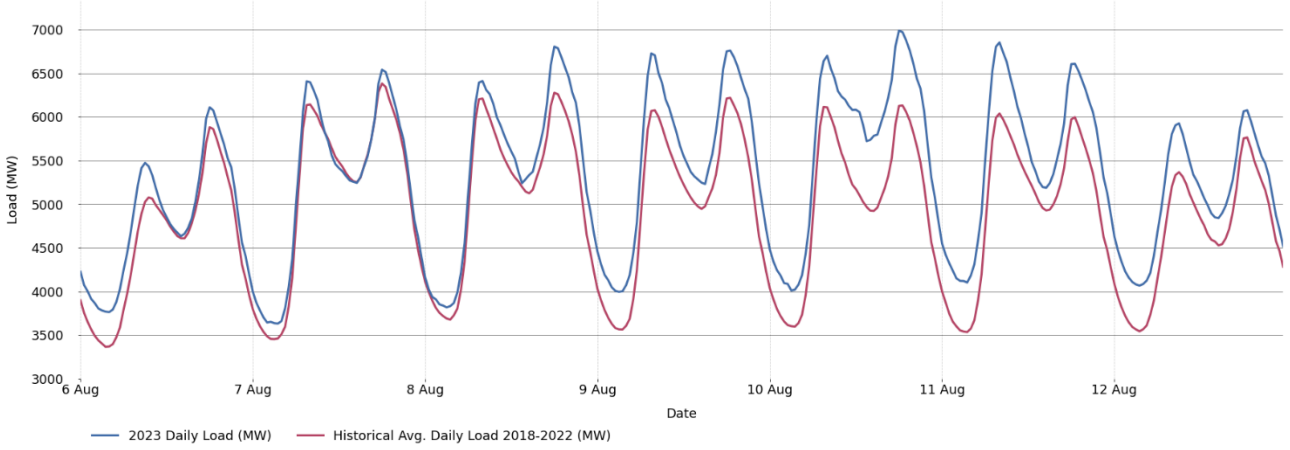

Figure 4: Half-hourly load for 6 to 12 August 2023 versus historical demand

5. Wholesale electricity price and composition

5.1. Q3 2023 prices were less volatile than Q2 2023, but average prices were higher, due to a much higher share of thermal generation. The average wholesale market price for Q3 2023 was $124/MWh, higher than both the average Q2 2023 price ($79/MWh) and the same quarter last year, when prices averaged $66/MWh due to high hydro inflows and low thermal generation contributions.

5.2. Elevated demand across most of August 2023, coupled with declining hydro storage for most of the quarter, contributed to the higher prices shown in Figure 5. Prices eased at the end of the quarter when large hydro inflows led to spilling in some locations.

5.3. The maximum half-hourly average price for the quarter was $765/MWh, corresponding with one of the exceptionally high demand peaks of the quarter.

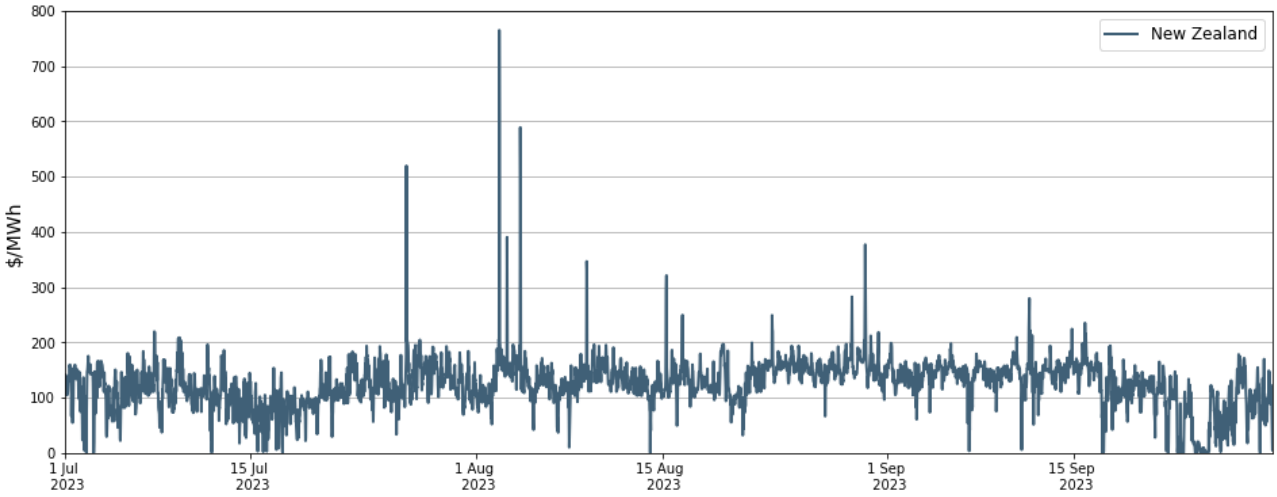

Figure 5: Average New Zealand wholesale price per half hour, July to September 2023

Generation composition influence on price

5.4. 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.

5.5. 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.

5.6. As evident in Figure 6, wind generation typically has an inverse relationship with average wholesale price. It has no fuel costs, so 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.

5.7. Figure 6 shows the correlation between high wind and low wholesale electricity prices in Q3 2023. For example, in mid-July 2023, an extended period of high wind kept prices below the quarterly average for most of a week. Similarly, in late September, record levels of wind generation and moderate demand helped push the daily average price down to $8/MWh.

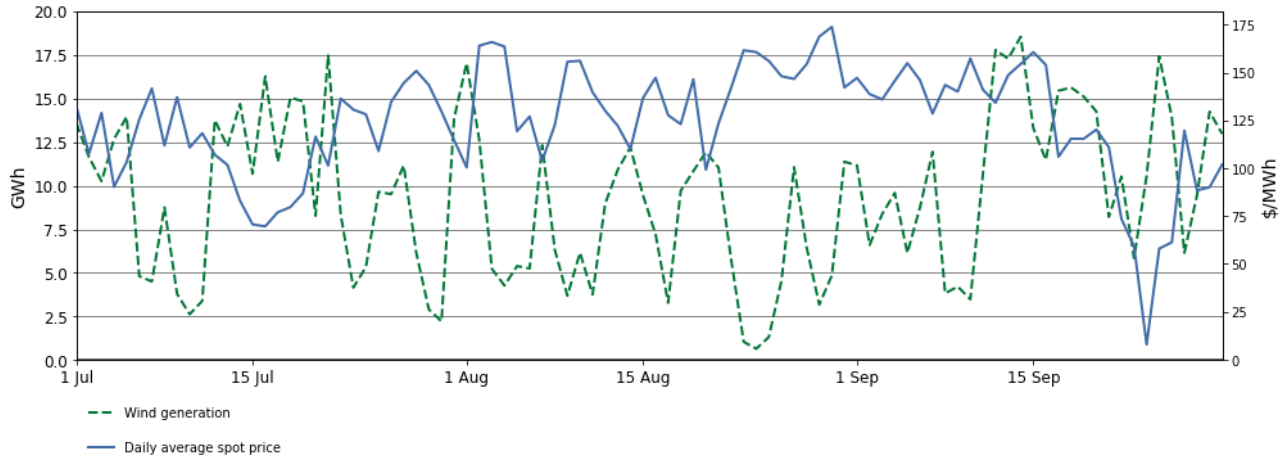

Figure 6: Daily wind generation and average wholesale price, July to September 2023

5.8. 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 like most of Q3 2023, a thermal generator is often the marginal generator. As a result, it often sets or influences the wholesale prices. As clear in Figure 7, the more thermal generation, the higher the average wholesale price.

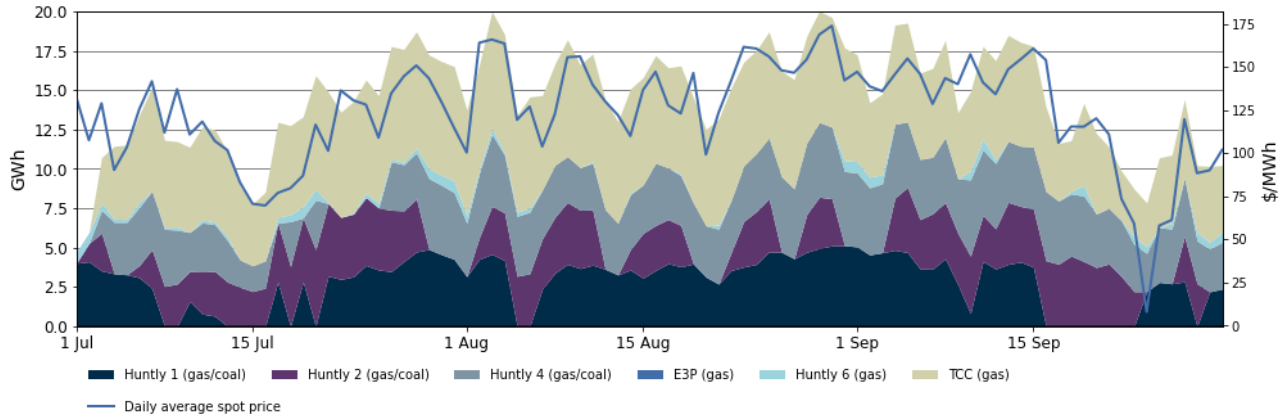

Figure 7: Daily peaking generation and average wholesale price, July to September 2023

5.9. 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.

5.10. Figure 8 shows that hydro storage levels steadily declined across most of Q3 2023 due to below average hydro inflows. There was a large amount of rain in late September which lifted hydro storage levels, pushing average wholesale prices down. The exception to the inverse pricing relationship was in mid-July, where high amounts of wind displaced other forms of generation and kept average prices lower for several days.

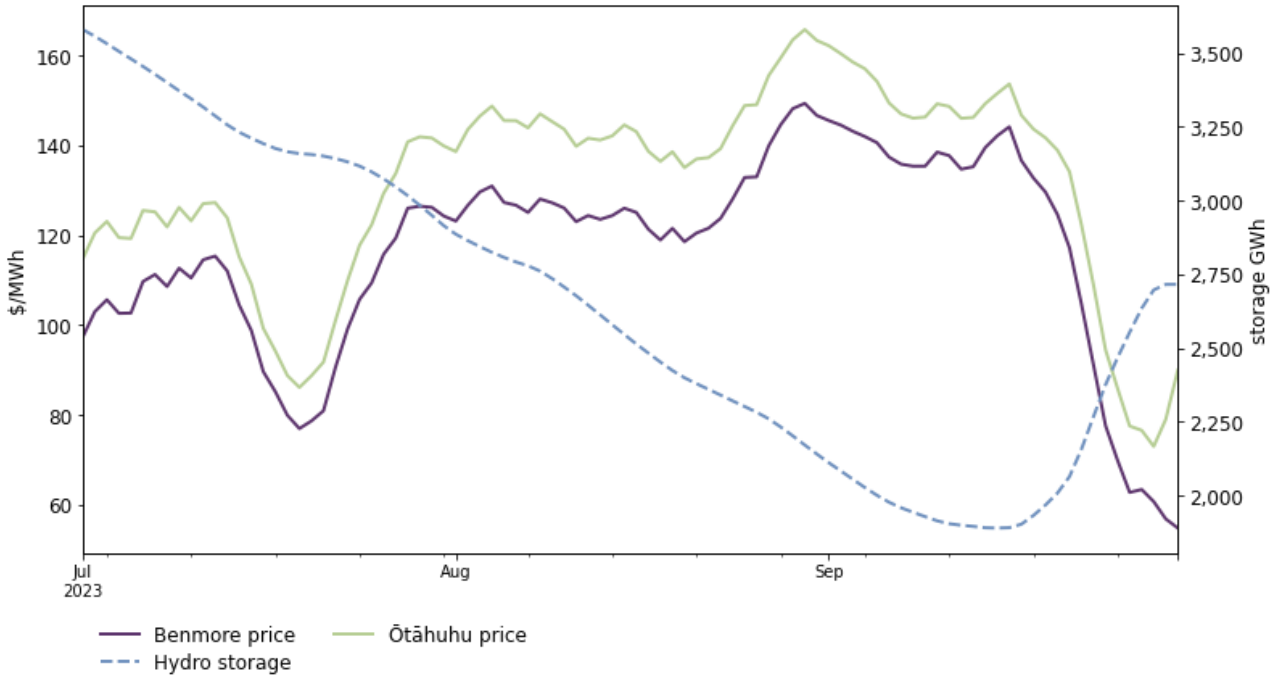

Figure 8: Rolling seven-day average of wholesale price versus hydro storage, July to September 2023

Generation by fuel type

5.11. Following Huntly 5's outage on 30 June 2023, Taranaki Combined Cycle Power Station (TCC) came online and operated as baseload for the quarter. This increased the overall share of thermal supply in all weeks compared to the previous quarter. Below average hydro inflows also increased the need for thermal generation.

5.12. The declining levels of hydro supply are evident in the shrinking share of hydro generation shown in Figure 9, starting at around 61% and dropping to 51.7%. High inflows then lifted the share of hydro generation in the last two weeks. Overall, the average share of hydro generation was 58%, which was lower than Q1 2023 (63%) and Q2 2023 (70%).

5.13. Turitea wind farm reached full operational capacity in late June and Kaiwera Downs Stage 1 began sending power to the grid in Q3 2023. Their contribution to supply is visible in Figure 9. Wind share of generation ranged from 4.3% to 12.2% – a notable increase on previous quarters and the same time last year. In late September, the records for average wind offered in a 24-hour period were broken several times, with one day averaging 830MW.

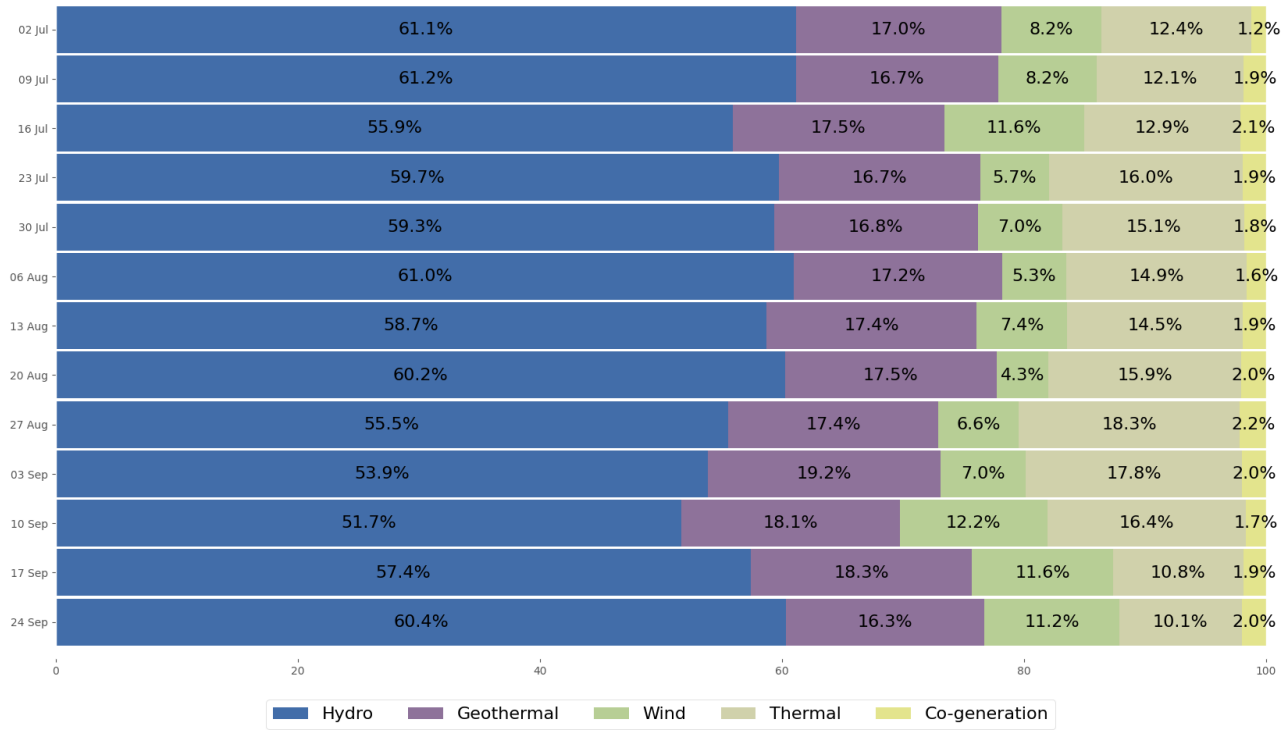

Figure 9: Weekly generation share by fuel type, July to September 2023

6. Water storage levels

National hydro storage levels

6.1. Q3 2023 started with hydro storage at 3500GWh and dropped to a minimum of 2300GWh on 13 September, before lifting to 2900GWh by the end of the quarter. This was 800GWh lower than Q3 last year (seen in Figure 10), which was an unusually wet quarter.

6.2. Having reached record fill levels in early June, hydro storage steadily declined across most of Q3 2023 due to below average inflows. Inflows increased in the last two weeks of September, including a large rain event on the South Island which led to spilling in the southernmost locations.

6.3. El Niño conditions were confirmed for New Zealand during the quarter. This is expected to contribute to higher hydro inflows in coming months.

6.4. Hydro levels are improving and expected to continue to lift throughout the next quarter as snow melt is added to other inflow sources.

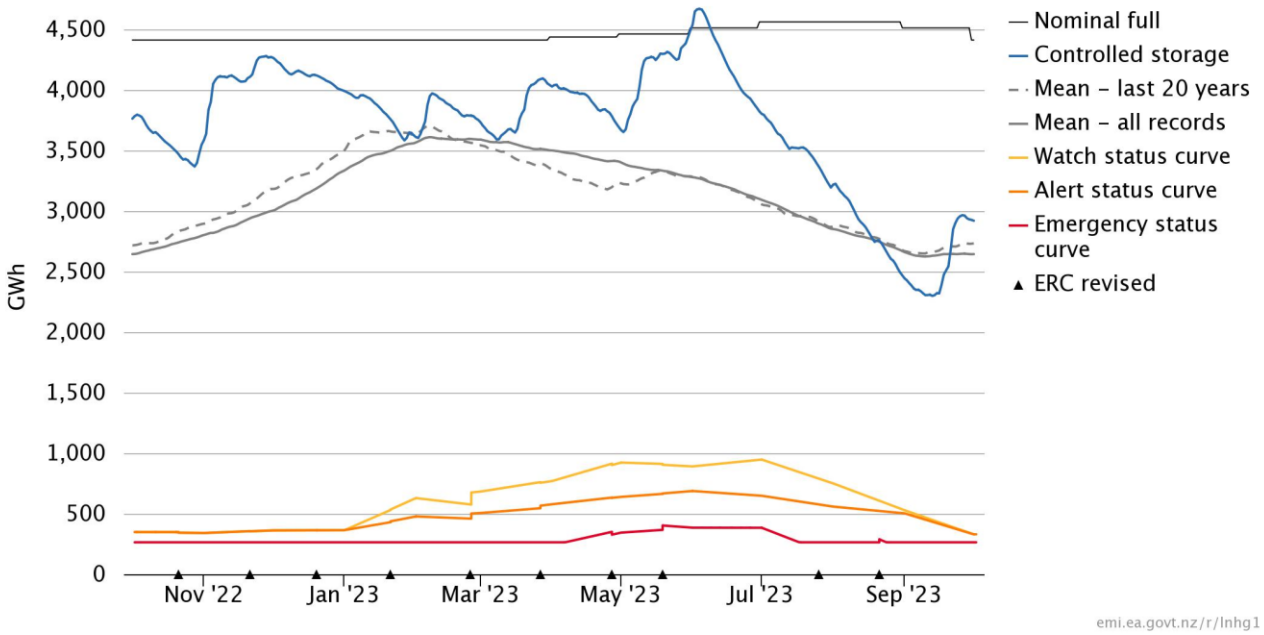

Figure 10: National hydro storage levels, October 2022 to September 2023 from ea.govt.nz/t/vqlya

Lake storage levels

6.5. Figure 11 shows individual lake levels in Q3 2023 and the difference location can make to hydro inflows. The southernmost lakes received consistent rainfall, keeping their storage levels close to or above average for most of the quarter.

6.6. Lakes Manapōuri and Te Anau also received high inflows in late September, which led to spilling for more than a week in both locations.

6.7. In contrast, all the other lakes received below average inflows, resulting in a slow and steady decline in hydro storage levels across the quarter.

6.8. All locations saw an uplift in storage levels at the end of September, as a band of rain worked its way up New Zealand over several days.

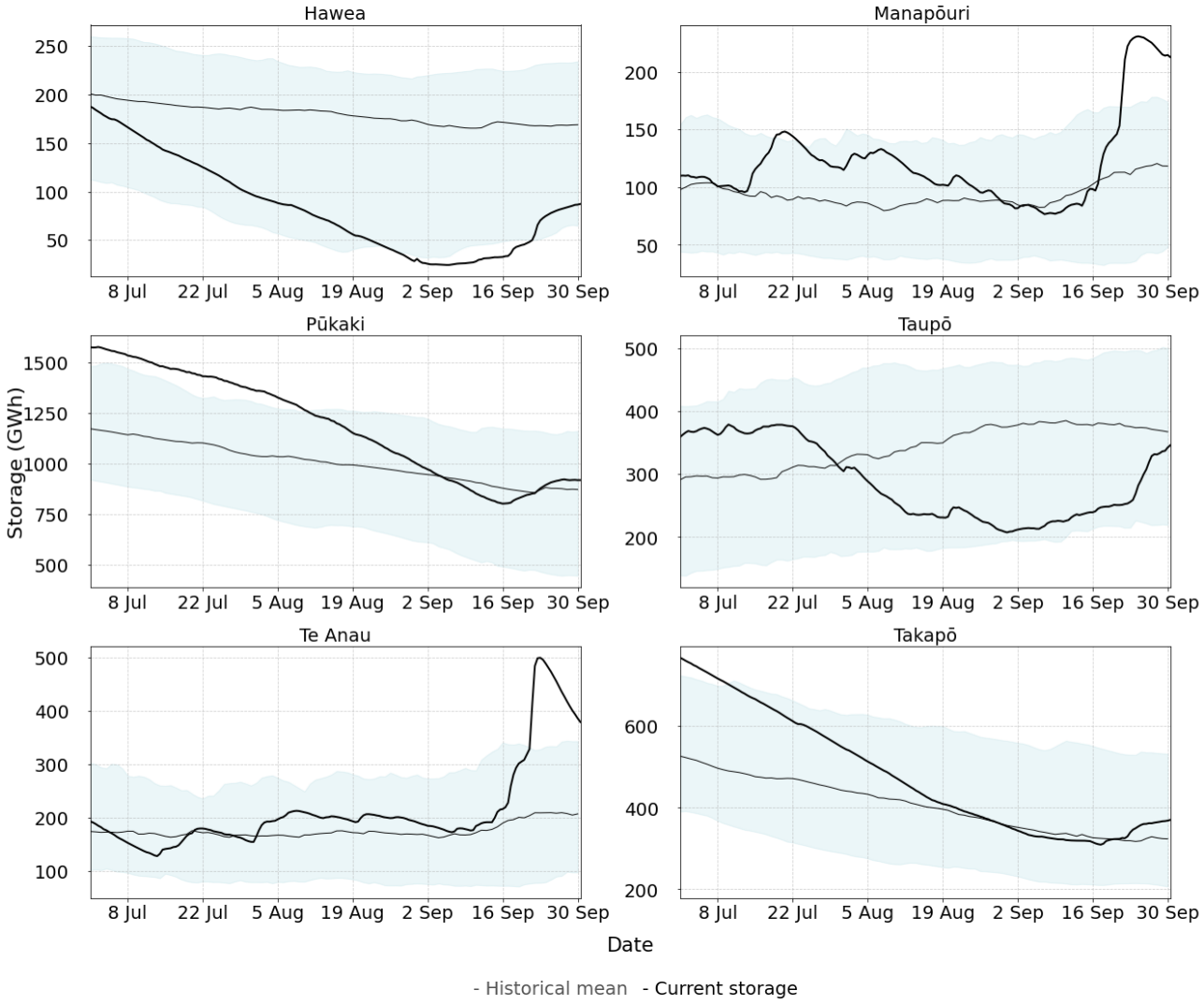

Figure 11: Lake storage levels for July to September 2023 vs typical historical storage levels

7. Wholesale gas prices, production and consumption

Gas prices

7.1. The volume-weighted average price (VWAP) for gas in Q3 2023 was $10.16/GJ. This is an increase of around $1.30/GJ on the previous quarter and similar to prices in Q3 2022. Price volatility continued to decline compared with the previous quarters, reducing gas price shocks.

7.2. Across the quarter, global gas prices gradually eased upward as the Northern Hemisphere prepares for winter conditions. New Zealand prices followed a similar trajectory (see Figure 12).

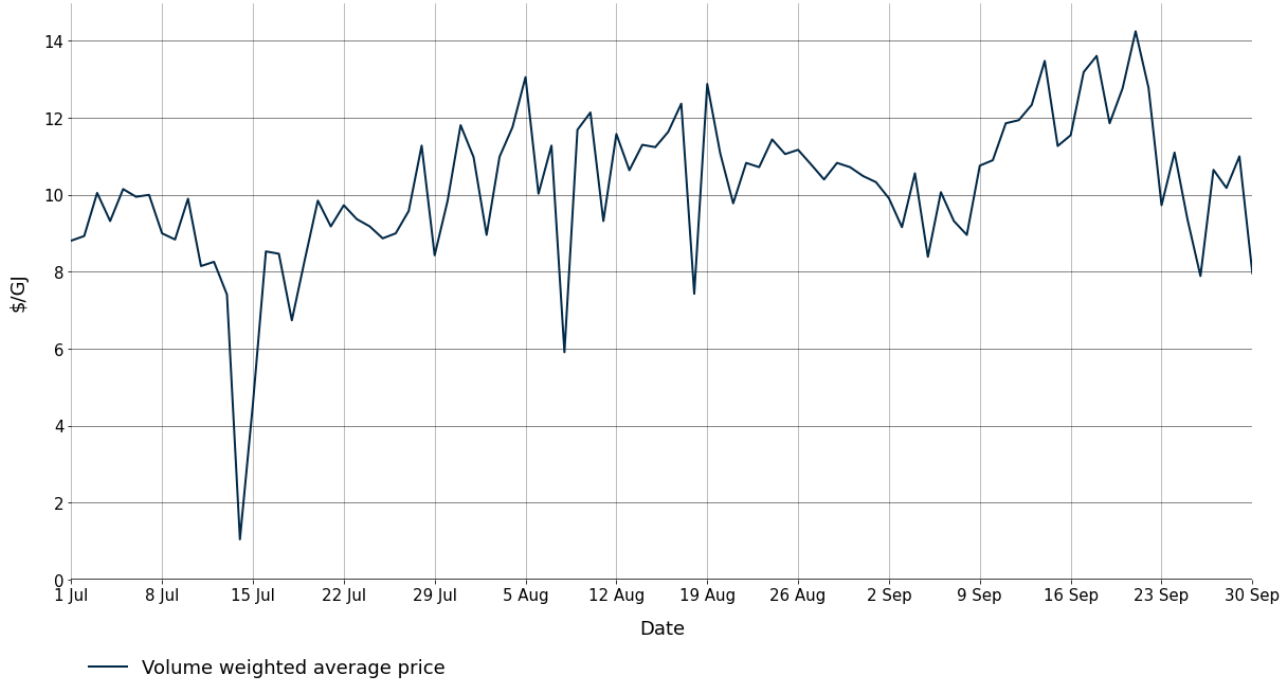

Figure 12: Daily volume-weighted average price for gas, July to September 2023

Gas production

7.3. In Q3 2023, total gas production decreased gradually. Gas production in early July was variable but based on typical output in the first week of July, gas production started the quarter at 372TJ/day and finished at 365TJ/day. An increase in gas production by the Kupe, Turangi and Kowhai gas fields was offset by a decline in production from Pohokura, Maui and Kupe.

7.4. Maui had two short scheduled outages which reduced output during the quarter, but most other producers maintained a steady output, as visible in Figure 13.

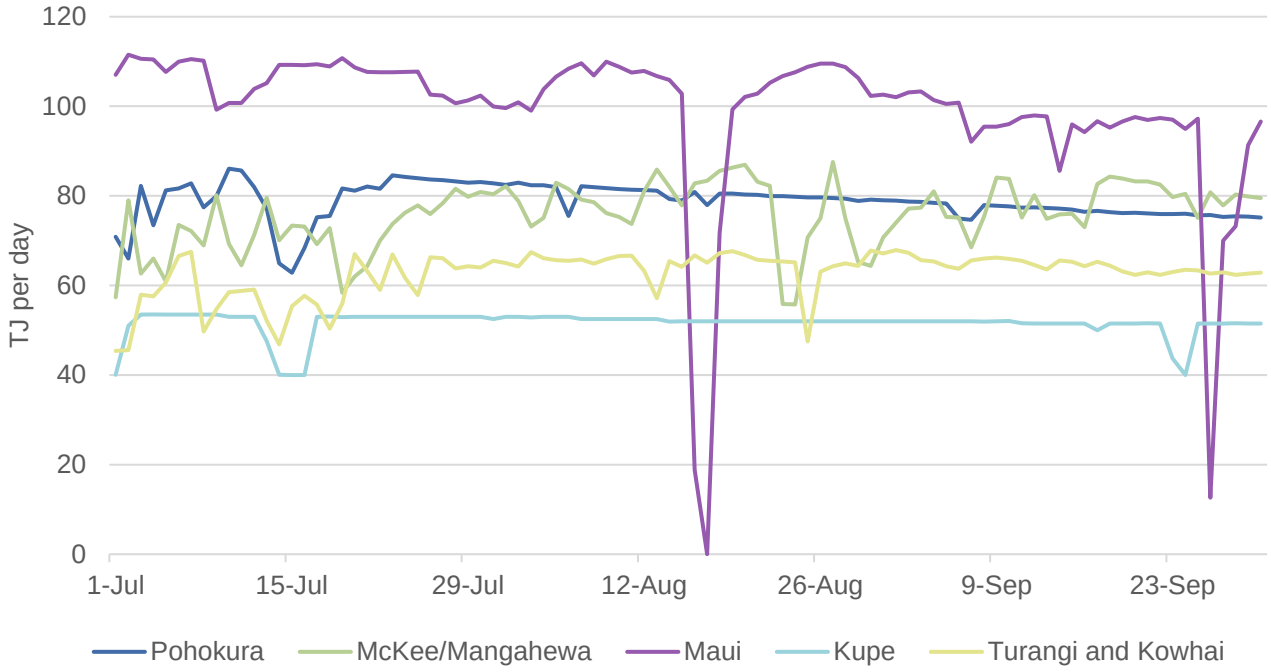

Figure 13: New Zealand gas production, July to September 2023

Gas consumption

7.5. From 30 June 2023, Methanex Motunui (a methanol production facility) had a planned outage lasting most of Q3 2023. This reduced its gas consumption by around 85TJ/day. At the end of the quarter, it began ramping back to capacity but did not reach its previous operating levels by the end of Q3.

7.6. Gas generation was high in Q3 2023, as the quarter experienced the highest electricity demand of the year. TCC ran from 3 July to 6 October, filling the gap left by the Huntly 5 outage. Most weeks Huntly had at least two Rankine units operating, as Huntly 5 was offline. These units have a lower efficiency than Huntly 5 and used more gas, so consumption was higher than the same time last year.

7.7. The Taranaki Combined Cycle Power Station (TCC) used a share of the gas that would have otherwise gone to Methanex Motunui across the quarter. Figure 14 shows that when Methanex Motunui returned to service, TCC and Huntly gas consumption dropped.

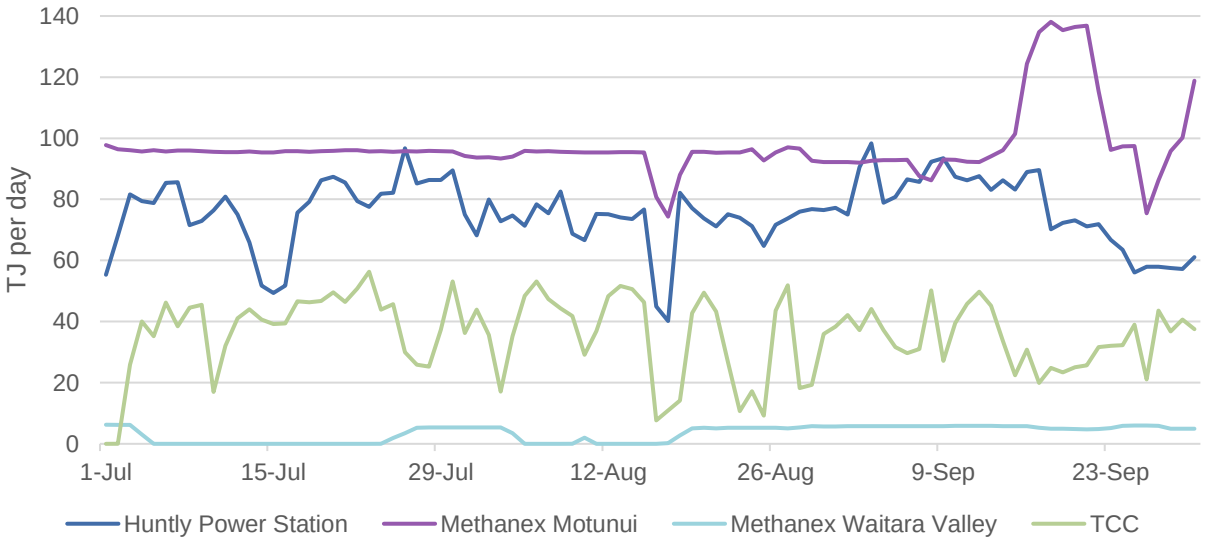

Figure 14: New Zealand gas consumption by major consumers, July to September 2023

7.8. Figure 15 shows how the distribution of gas consumption at Huntly power station changed after Huntly 5's outage on 30 June 2023. The combined output from Huntly 5 and 6 was reduced to near zero for Q3 2023, except when peaking generation was supplied by Huntly 6. The balance of generation was largely made up by the Huntly Rankine units, ensuring no shortfalls across the quarter. Huntly 5 is currently expected to return to service in February 2024.

7.9. The contribution of Huntly to high demand in August is evident in Figure 15, as coal generation supplemented the existing gas generation. Easing demand and increased hydro contribution to supply is visible as generation from Huntly dropped away during September, barring a cold snap at the end of the month while Stratford was on outage.

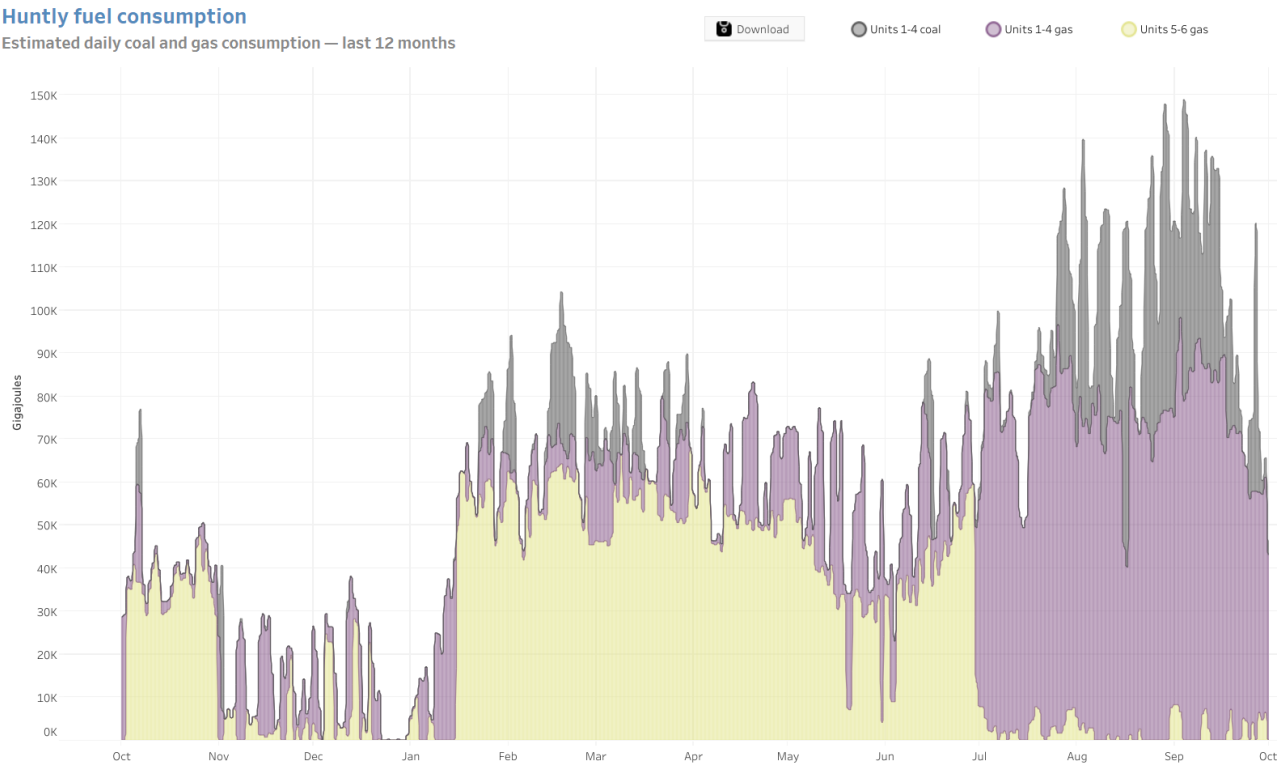

Figure 15: Huntly fuel consumption for the last 12 months to 30 September 2023

8. Retail electricity

Retailer switching

8.1. After purchasing Trustpower in May 2023, Mercury transitioned all Trustpower customers to Mercury by the end of Q2 2023. Mercury experienced particularly high ICP losses this quarter. The very high movement of customers away from Mercury visible in Figure 16 is likely to be led by former Trustpower customers moving to a new retailer of choice.

8.2. Small retailers continued to gain market share. Flick Electric and Frank Energy made strong ICP gains for the second quarter in a row.

8.3. The major retailers suffered a net loss of 6,300 ICPs across the quarter – dominated by Mercury's net loss of 7,450 ICPs.

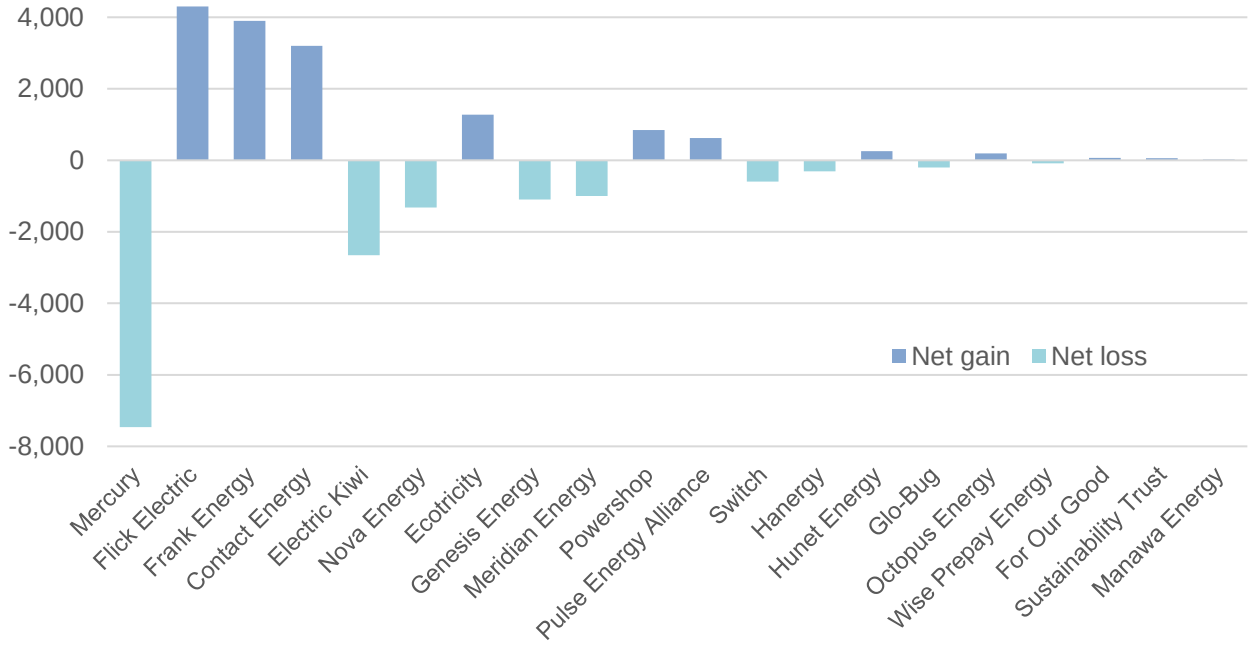

Figure 16: Top 20 movements in ICP net switching by retailer, July to September 2023

8.4. Consumer switching in Q3 2023 was 15-20% higher than the last two years (see Figure 17). Switching rates were lower than average over the last two years, compared to the last 10 years. It is not clear if the last two years were a new normal or if switching rates were suppressed due to the pandemic.

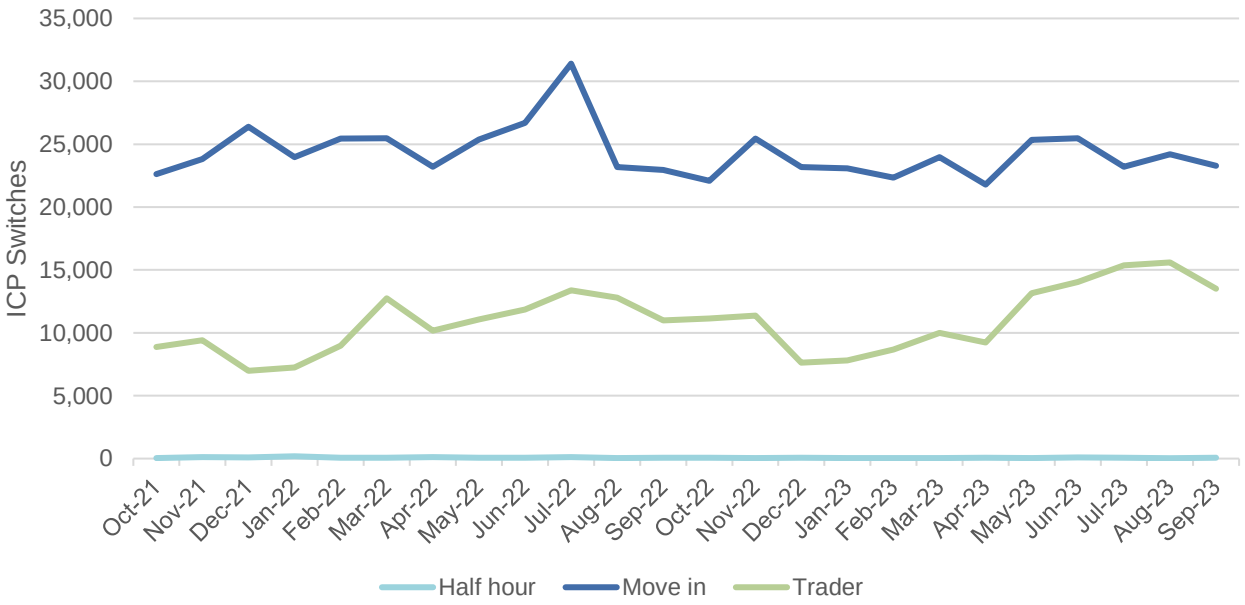

Figure 17: Breakdown of monthly ICP switching by type from emi.ea.govt.nz/r/14qr

Retail prices

8.5. Based on the trends observable 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.

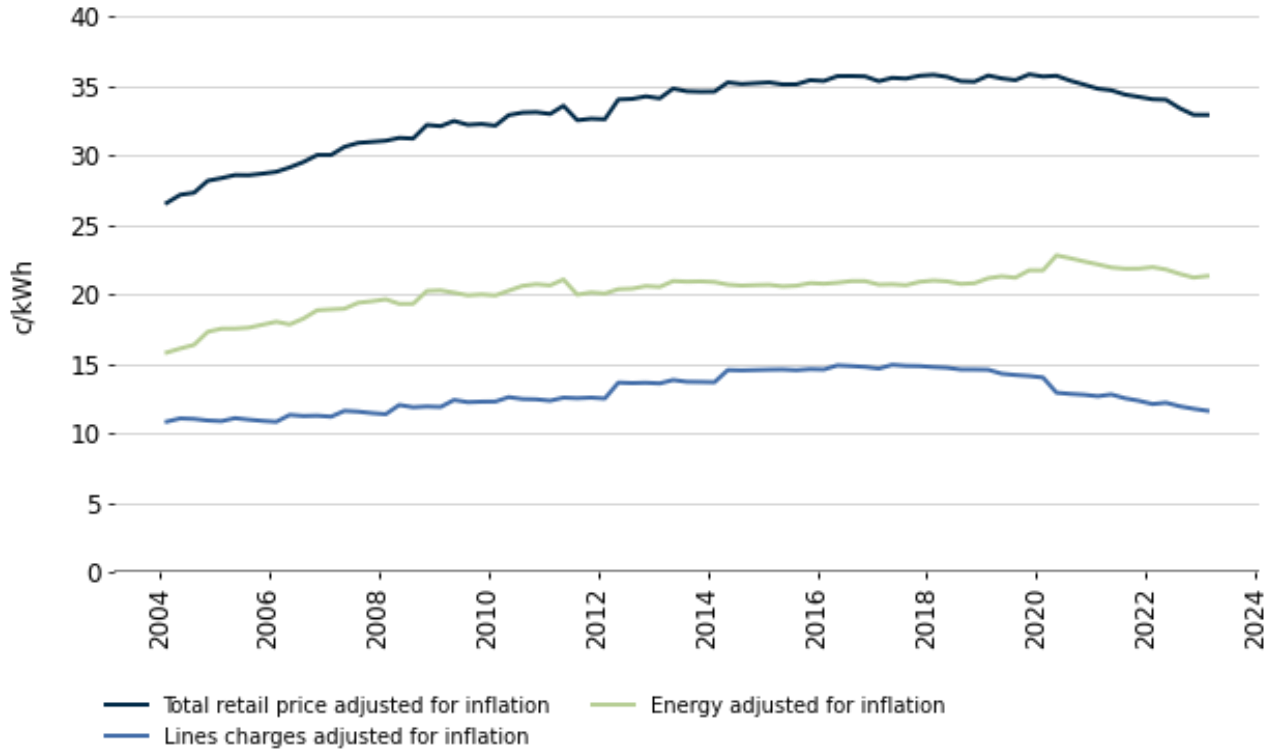

Figure 18: Electricity prices by component adjusted for inflation to mid-2023

8.6. While it's technically correct electricity prices are increasing at a rate below inflation (as per the previous figure), Figure 19 shows that electricity prices have increased in nominal terms. In the last 12 months, nominal values have risen by 3%. For a typical household using 8,000kWh annually, this is an extra $80 per year on their electricity bill compared to one year ago.

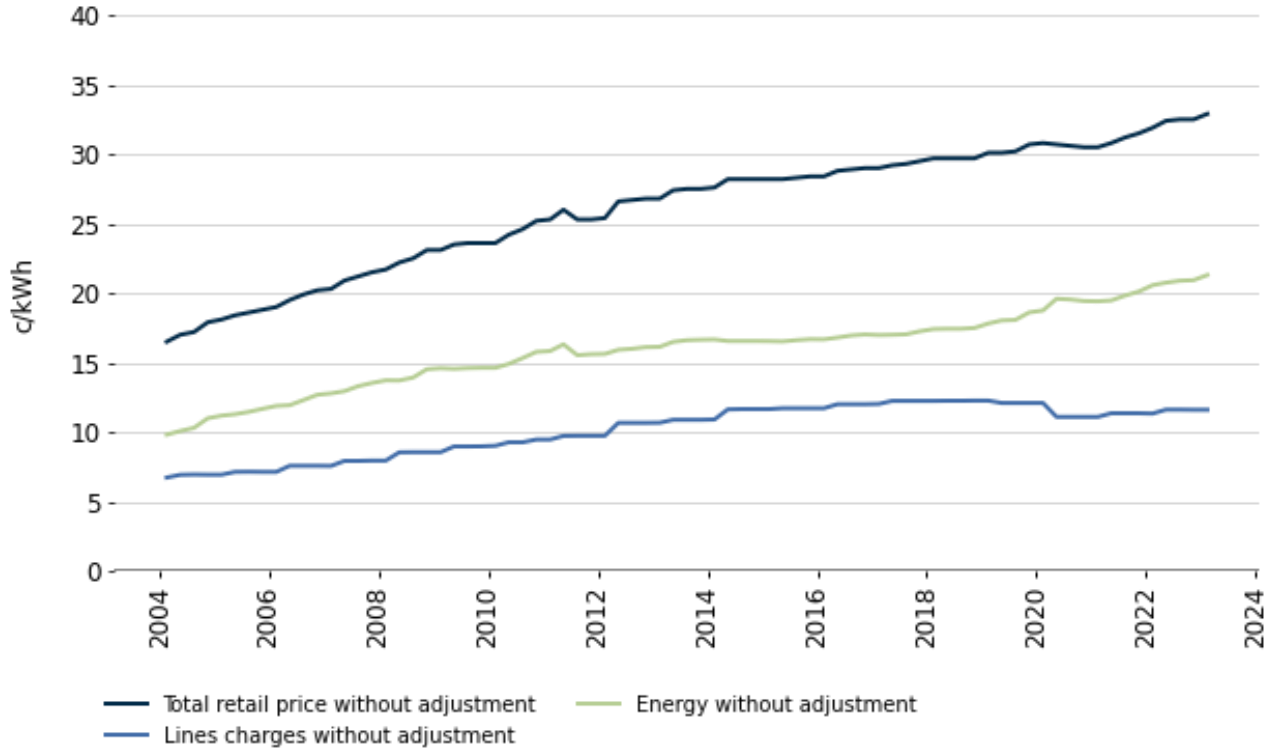

Figure 19: Electricity prices by component to mid 2023 not adjusted for inflation

Retailer financial stress

8.7. In August 2022, the Electricity Authority amended the Electricity Industry Participation Code to add a retailer financial stress notice data request to monitor financial stress faced by consumers. The Authority monitors the correlation between payment flexibility enquiries and debt owed to retailers. This replaces the data request implemented in response to Covid-19 and requires a different set of retailers selected under a new criterion to answer slightly different questions. This amendment means that new stress notice data starts from October 2022 and is not directly comparable to previous data.

8.8. Across the last 9 months shown in Figure 20, there has been a gradual uplift in the number of customers requesting payment flexibility or payment deferral. This allows retailers and consumers to work together to minimise the risk of disconnection. There were approximately 15,500 payment flexibility requests in December 2022. In September 2023 it was close to 22,000.

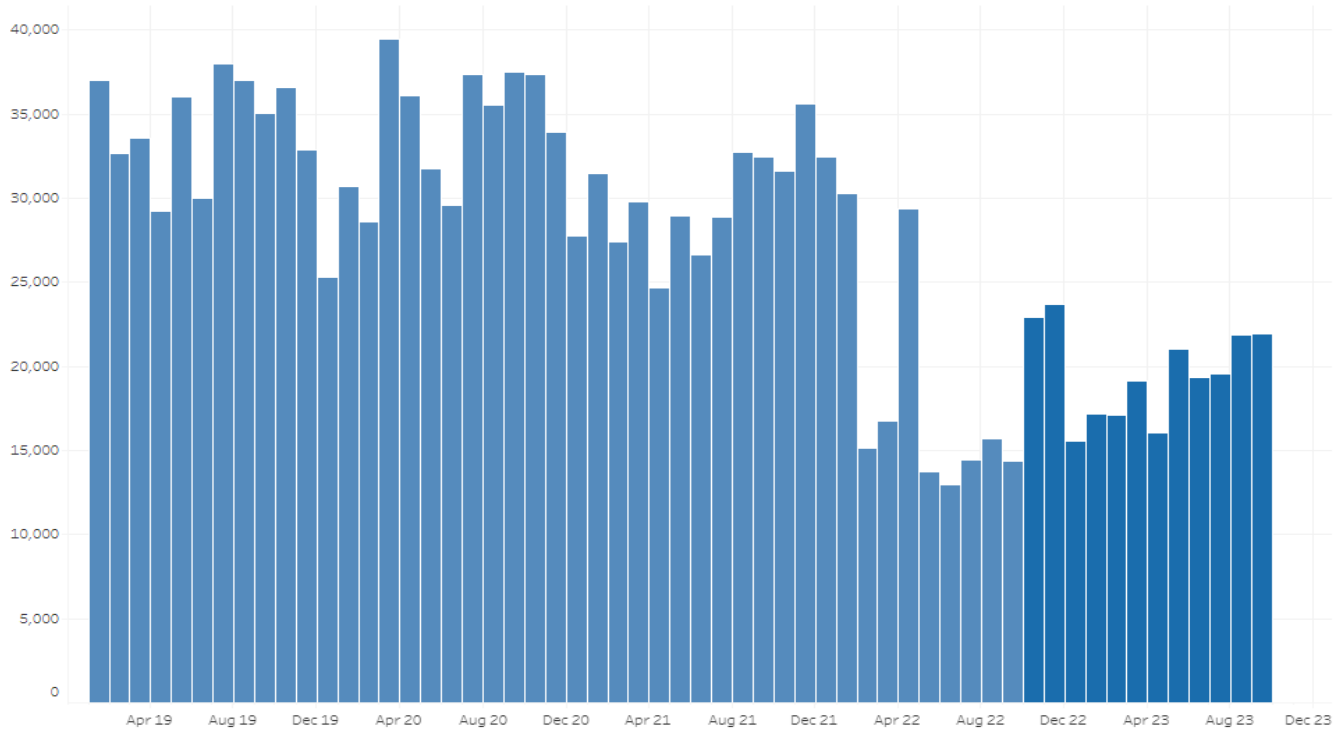

Figure 20: Customer enquiries for payment flexibility, January 2019 to September 2023

8.9. Debt more than 30 days in arrears is an early indicator of both customer and retailer stress. Figure 21 indicates the total debt in this category increased across Q3 2023, but was consistent with seasonal trends. Higher energy consumption in winter corresponds with higher energy bills and leads to higher levels of debt being carried by retailers. The Authority is monitoring this debt to check it eases.

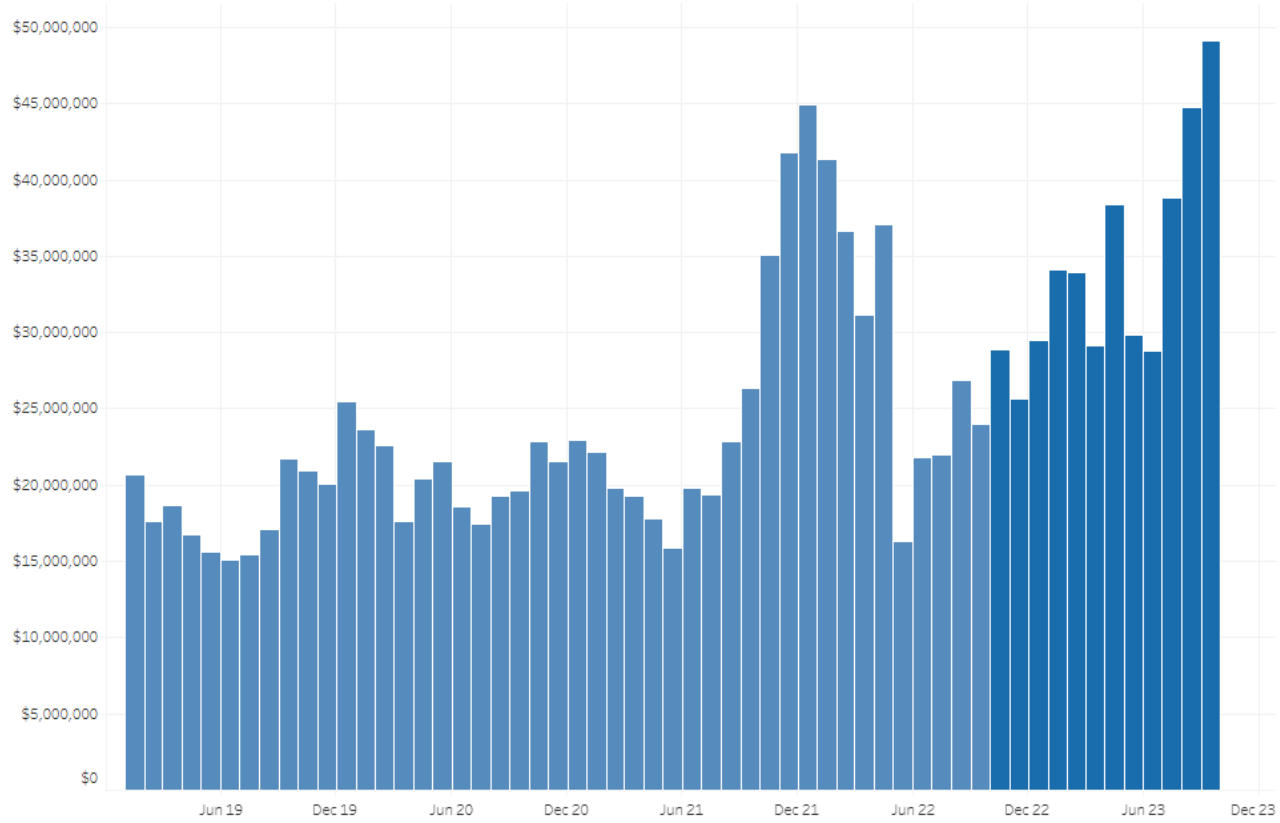

Figure 21: Total debt from customers 30+ days overdue and not scheduled for disconnection, January 2019 - October 2023

8.10. Figure 22 shows the ICPs disconnected for more than 24 hours as a result of non-payment. These ICPs either haven't paid their invoice(s) or have been unable to reach an agreement through the retail credit management process. This degree of non-payment is connected to long term debt where the next step is typically disconnection, as the debt is regarded as being harder to recover. The number of affected ICPs has dropped by over 30% in the last two months – it is not clear if this is a delayed seasonal impact or if credit management strategies are improving.

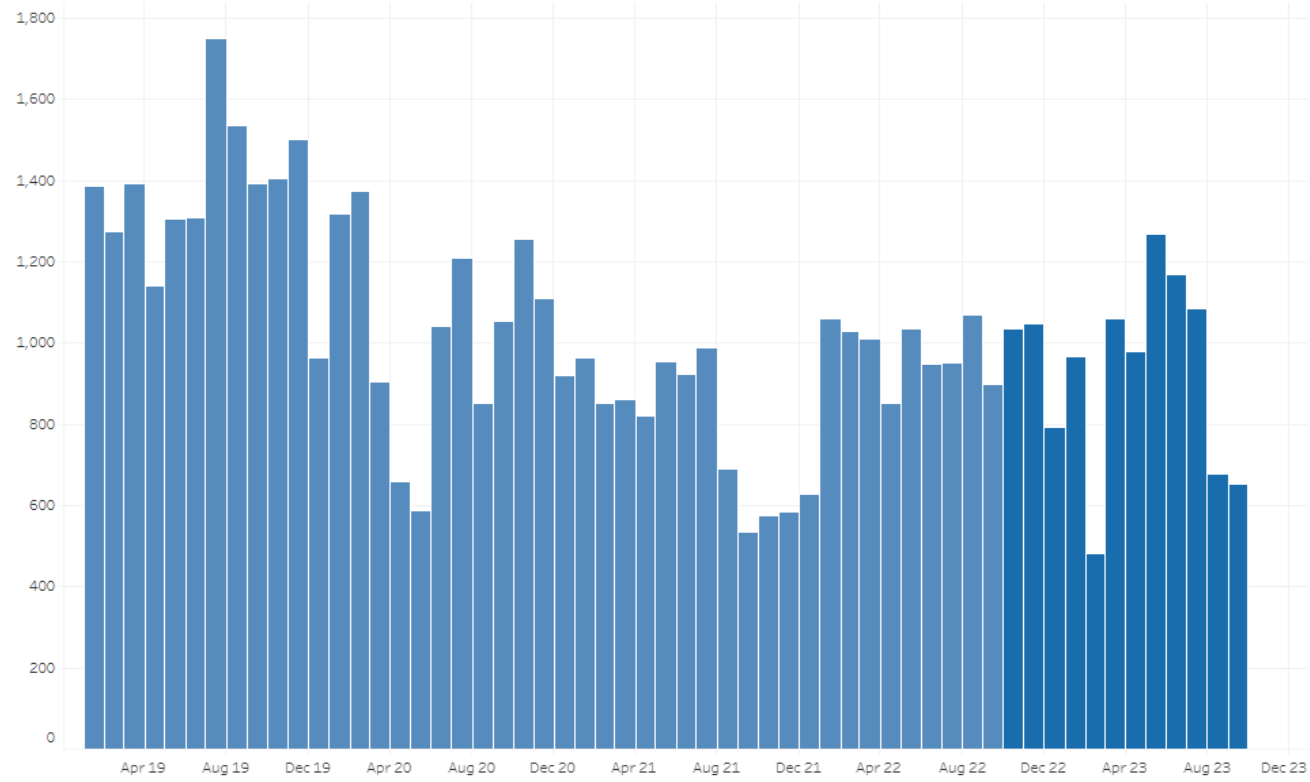

Figure 22: Total ICPs disconnected for non-payment for more than 24 hours

9. Forward market and carbon pricing

Forward pricing

9.1. In Q3 2023, all forward prices increased, except September 2023 prices and winter 2024 prices in Ōtahuhu, as evident in Figure 23. In all cases, the cheapest quarters are in the next 12 months and futures prices are higher in later years. Extended thermal and hydro outages from Huntly, Stratford and Manapōuri may contribute to higher prices being sustained.

9.2. In the current market composition, prices are most likely to be set by either thermal or hydro generation. Three consecutive months of below average inflows has lifted the value of hydro generation. Thermal generation costs have also increased across the quarter due to a gradual increase in fuel costs and an increase in the New Zealand Unit (NZU) floor prices. As discussed in the next section, NZU prices are unlikely to decline below current levels in coming years, keeping prices higher in later years.

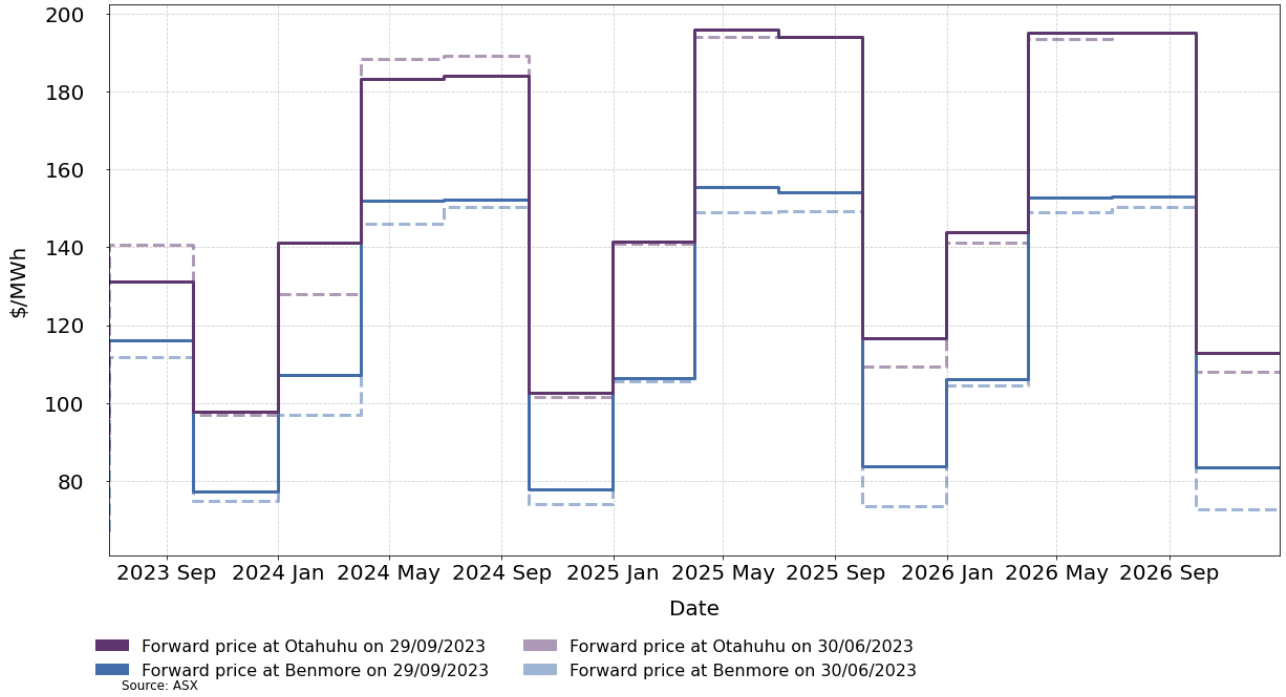

Figure 23: ASX forward prices for the start and finish of Q3 2023

Carbon pricing

9.3. To try to minimise 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 July 2023.

9.4. In mid-July 2023, the High Court issued a judgment saying the Government's December 2022 action was ultra vires[1]. 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. At the close of Q3 2023, prices were $66 per unit, down slightly from $73 per unit in early September (see Figure 24). The Climate Change Commission recommended prices will step up gradually in coming years.

9.5. In early September 2023, the third NZU auction took place and failed to reach minimum levels. This was expected and did not cause the same sharp drop of NZU prices seen at the March and June auctions[2]. All unsold NZUs have been rolled into the final auction in December 2023, which will have 15 million NZUs available[3].

9.6. Government NZU auctions have a minimum reserve price. If the auction clearing price is below the reserve price, no NZUs will be sold at that auction[4]. Due to the high volumes of NZUs available in December 2023, it is not certain if the reserve price will be met. If the December auction is not successful, all NZU carbon credits for 2023 will be cancelled, but volumes for the Q1 2024 auction will not be affected.

Figure 24: New Zealand Units price, July 2022 - September 2023

[1] https://www.capitalletter.co.nz/news/climate-change-response-act-2002/142596/climate-change-lawyers-climate-action-v-minister
[2] 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
[3] https://www.etsauctions.govt.nz/public/auction_noticeboard/35
[4] https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/ets/nz-ets-market/emission-unit-prices-and-controls/