28 April 2025

Trading conduct report 20-26 April 2025

Market monitoring weekly report

Trading conduct report 20-26 April 2025

1. Overview

1.1. The average spot price increased by $10/MWh this week to $307/MWh, with most prices above the historical 90th percentile for this time of year. Total demand was lower this week due to public holidays. The proportion of wind generation also reduced this week, with hydro generation making up most of the difference. National hydro storage has held steady this week at ~64% nominally full and ~83% of the historical average for this time of year.

2. Spot prices

2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.

2.2. Between 20-26 April 2025:

(a) The average spot price for the week was $307/MWh, an increase of around $10/MWh compared to the previous week.

(b) 95% of prices fell between $182/MWh and $388/MWh, with most prices above the historical 90th percentile for this time of year.

2.3. Spot prices were volatile on Sunday morning, Ōtāhuhu reached a minimum of $49/MWh at 2.00am before increasing to its maximum of $360/MWh at 6.30am and then back down to $118/MWh at 7.30am. Wind forecast errors contributed to this volatility, with wind generation 237MW higher than forecast at 2.00am, 198MW lower than forecast at 4.30am and 120MW lower than forecast at 6.30am.

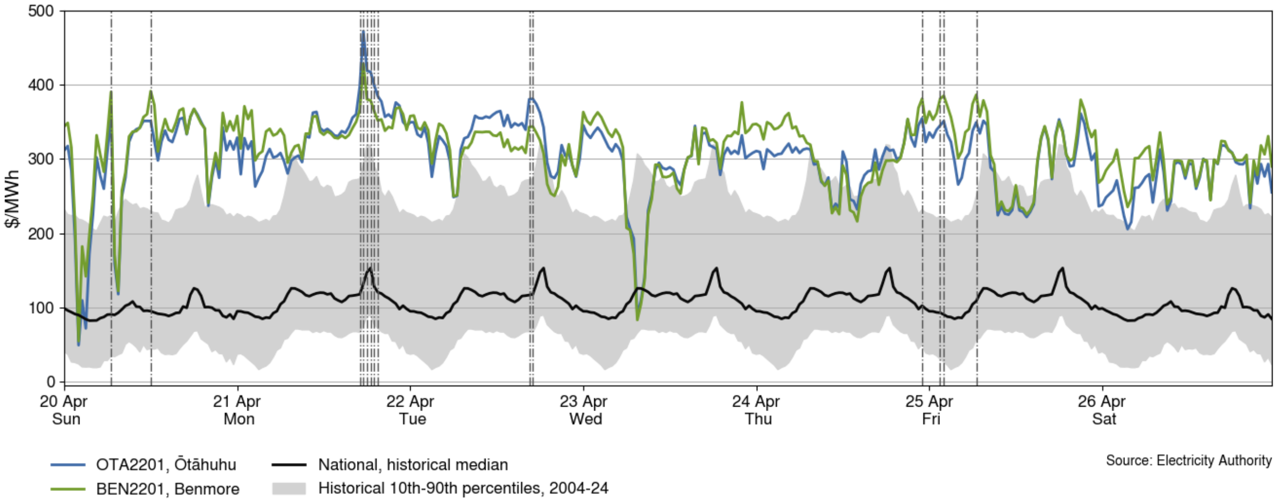
2.4. The highest spot price at Ōtāhuhu was $472/MWh at 5.30pm on Monday when demand was near its evening peak and 143MW higher than forecast, wind was 56MW lower than forecast and following the Huntly 4 trip at 4.43pm. The Benmore spot price at the same time was $428/MWh.

2.5. Spot prices dropped below $100/MWh at 7.30am on Wednesday morning when wind generation was 287MW higher than forecast and demand was 47MW lower than forecast.

2.6. Spot prices increased above $380/MWh for periods from 11.00pm Thursday to 6.30am Friday. During this period, wind generation was less than 150MW and demand was up to 67MW higher than forecast.

2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices greater than $380/MWh are marked with black dashed lines.

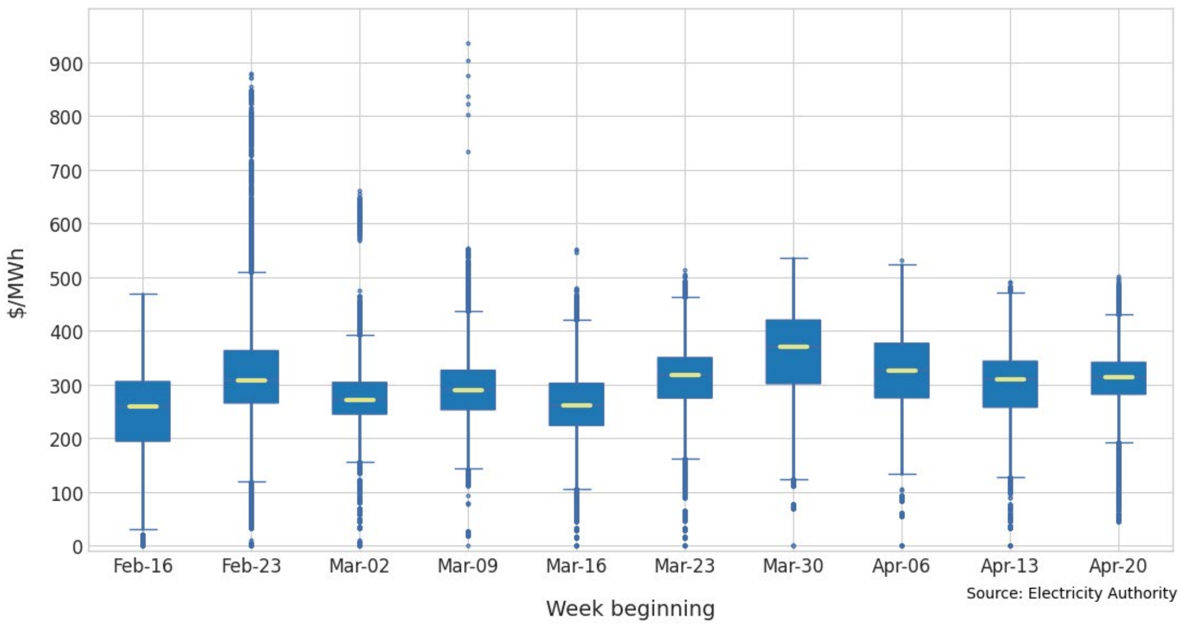
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 20-26 April 2025



2.8. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.9. The distribution of spot prices this week was narrower than last week, with a similar median price of $314/MWh. Most prices (middle 50%) fell between $282/MWh and $342/MWh.

Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks

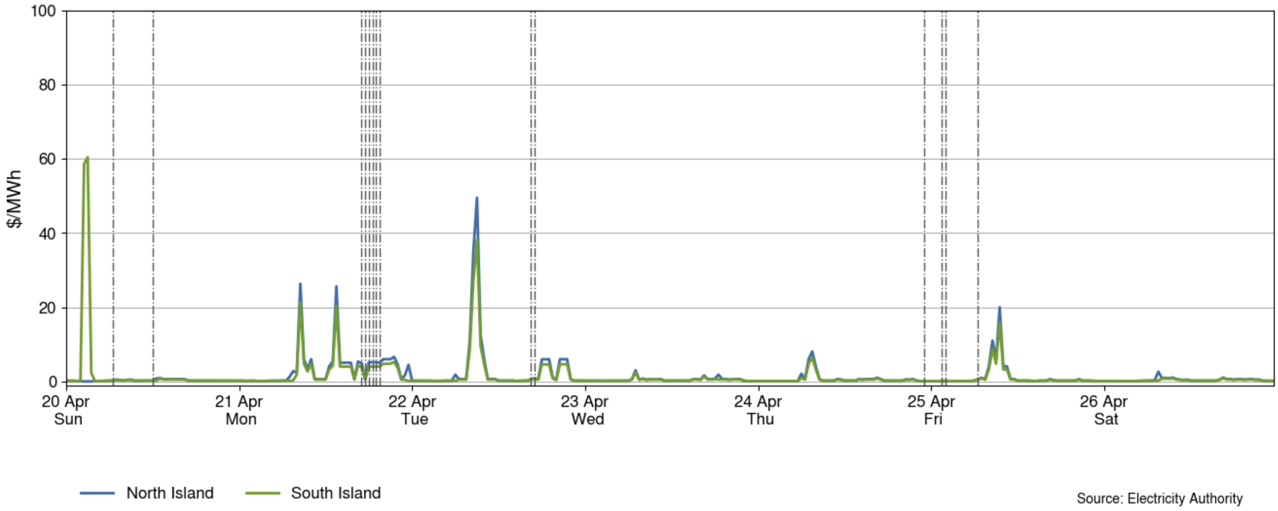


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices separated early on Sunday morning from 2.30am-3.00am when the HVDC became the binding South Island risk – South Island FIR was ~$60/MWh and North Island FIR was $0/MWh.

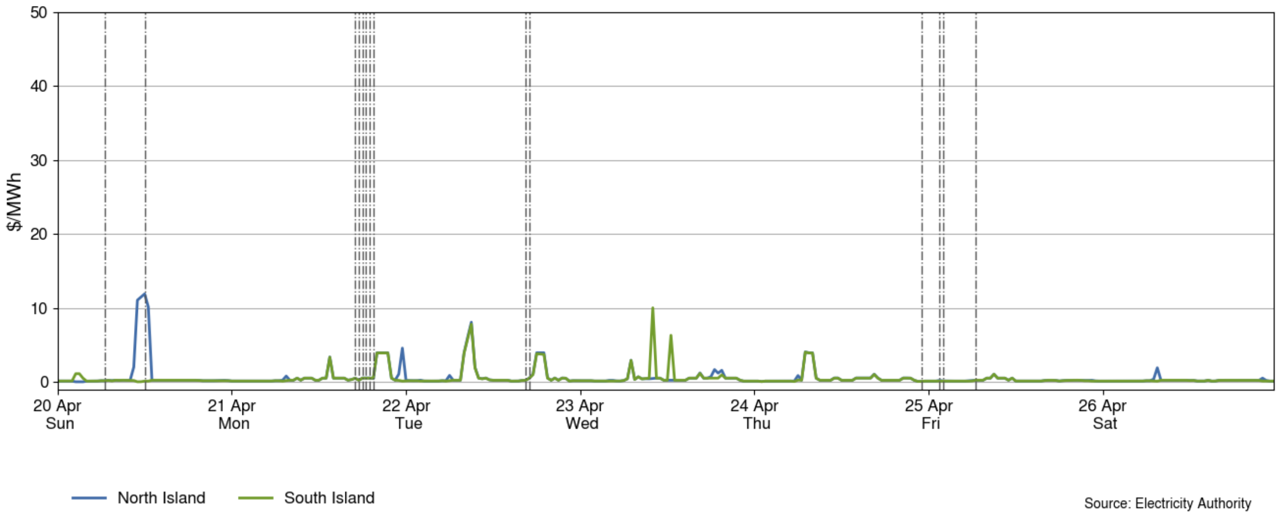
3.2. FIR prices spiked at 9.00am on Tuesday to $38/MWh in the South Island and $49/MWh in the North Island when the instantaneous load reserve offers for both FIR and SIR reduced.

Figure 3: Fast instantaneous reserve price by trading period and island, 20-26 April 2025



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices separated from 11.00am to 12.30pm during the HVDC pole 3 outage, with North Island SIR prices reaching $12/MWh while South Island SIR prices remained below $1/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 20-26 April 2025



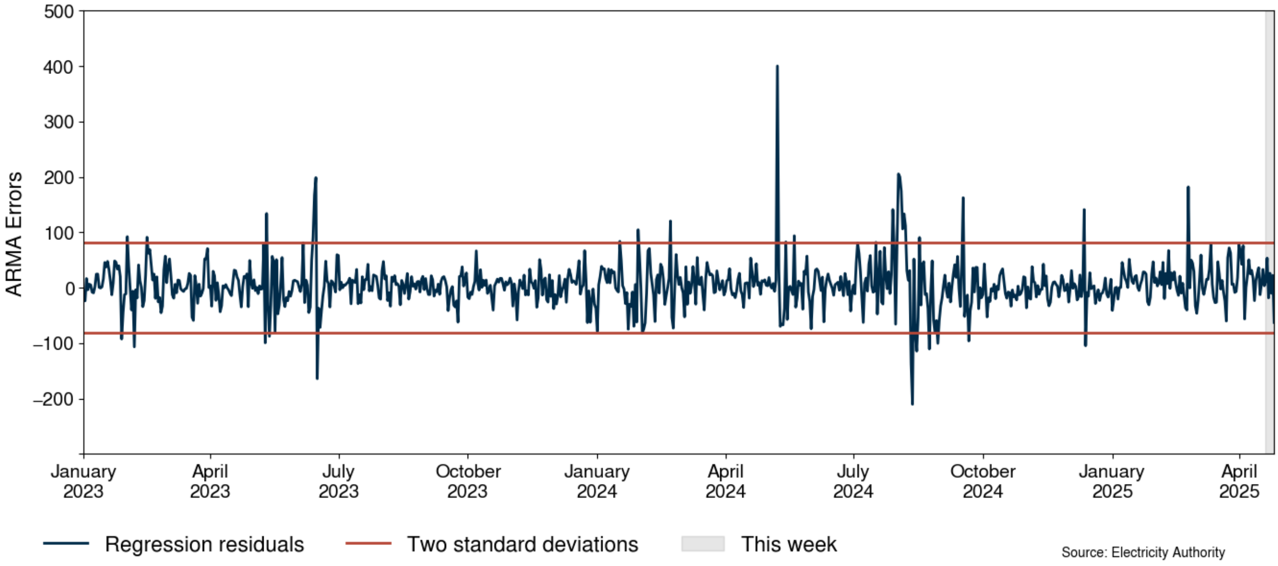
4. Regression residuals

4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in Appendix A.

4.2. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than the actual average daily price and vice versa. When residuals are small this indicates that average daily prices are likely largely aligned with market conditions. These small deviations reflect market variations that may not be controlled in the regression analysis.

4.3. This week, there were no residuals above or below two standard deviations, indicating that prices were similar to those predicted by the model.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 26 April 2025



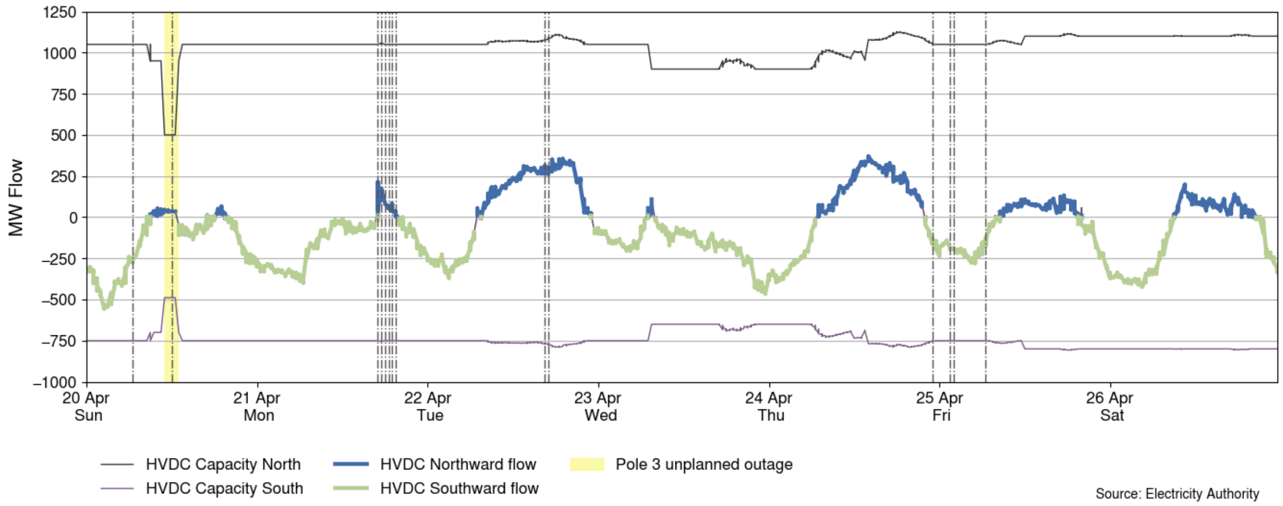
5. HVDC

5.1. Figure 6 shows the HVDC flow between 20-26 April 2025. HVDC flows were mostly southward this week, with northward flow during periods of low wind generation and higher demand.

5.2. Pole 3 was on outage from 11.00am-1.00pm on Sunday[1].

[1] CAN Unplanned Outage HVDC Pole 3 6195179511.pdf

Figure 6: HVDC flow and capacity, 20-26 April 2025

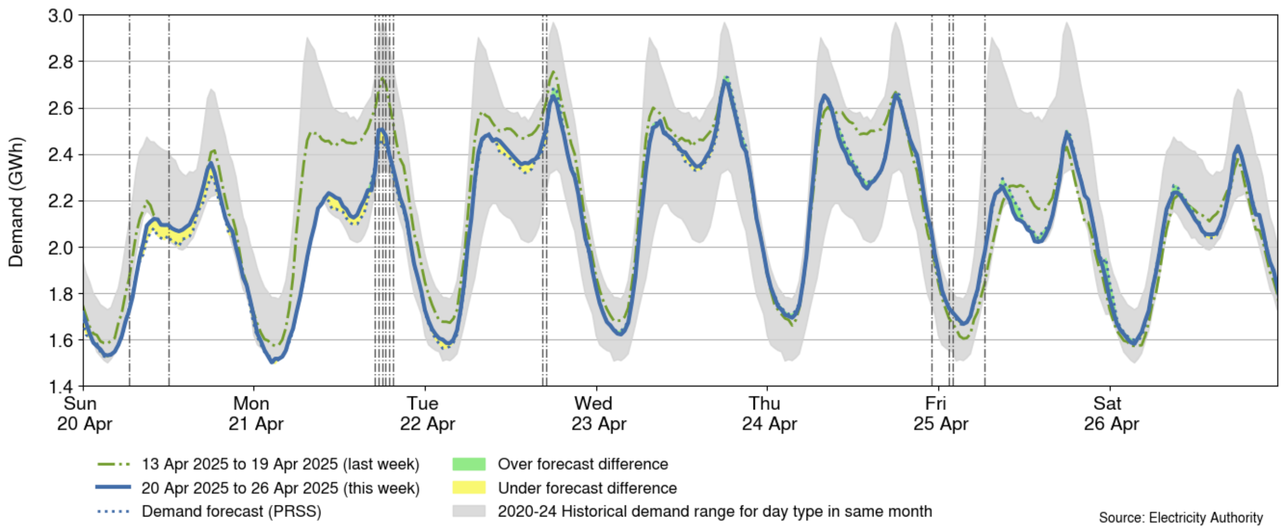


6. Demand

6.1. Figure 7 shows national demand between 20-26 April 2025, compared to the historic range and the demand of the previous week. Demand was lower on Monday and Friday due to public holidays.

6.2. Midday demand was higher than forecast from Sunday to Tuesday. Forecast errors were largest at 5.30pm on Sunday when demand was 143MW higher than forecast.

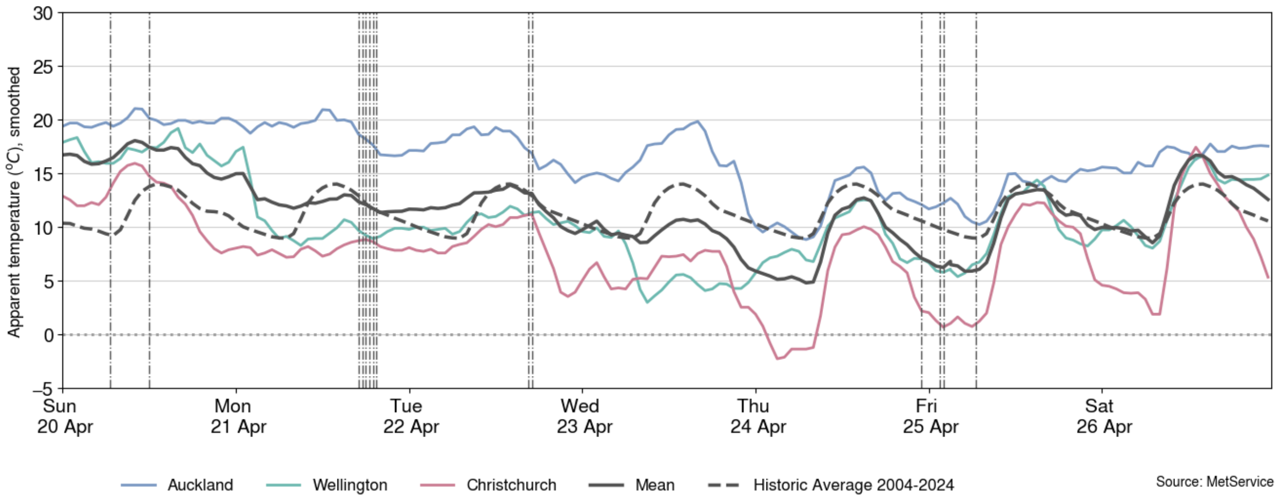
Figure 7: National demand, 20-26 April 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 20-26 April 2025. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.4. Apparent temperatures were above average on Sunday and Monday, and below average on Wednesday and Thursday, ranging from 9°C to 22°C in Auckland, 3°C to 19°C in Wellington, and -3°C to 18°C in Christchurch.

Figure 8: Temperatures across main centres, 20-26 April 2025

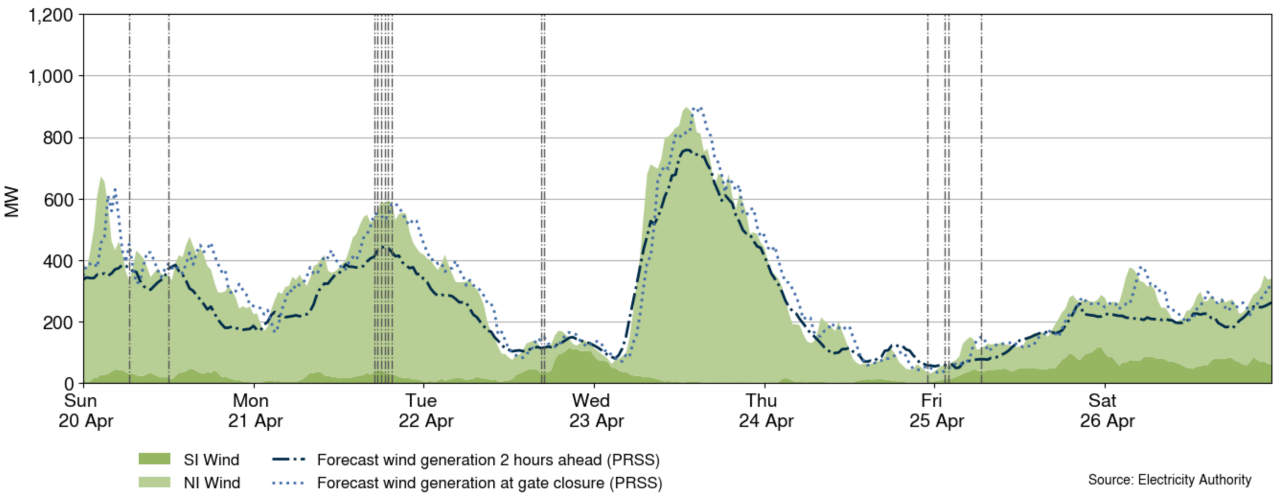


7. Generation

7.1. Figure 9 shows wind generation and forecast from 20-26 April 2025. This week wind generation varied between 32MW and 898MW, with a weekly average of 305MW. Wind generation was highest on Wednesday and lowest on Thursday.

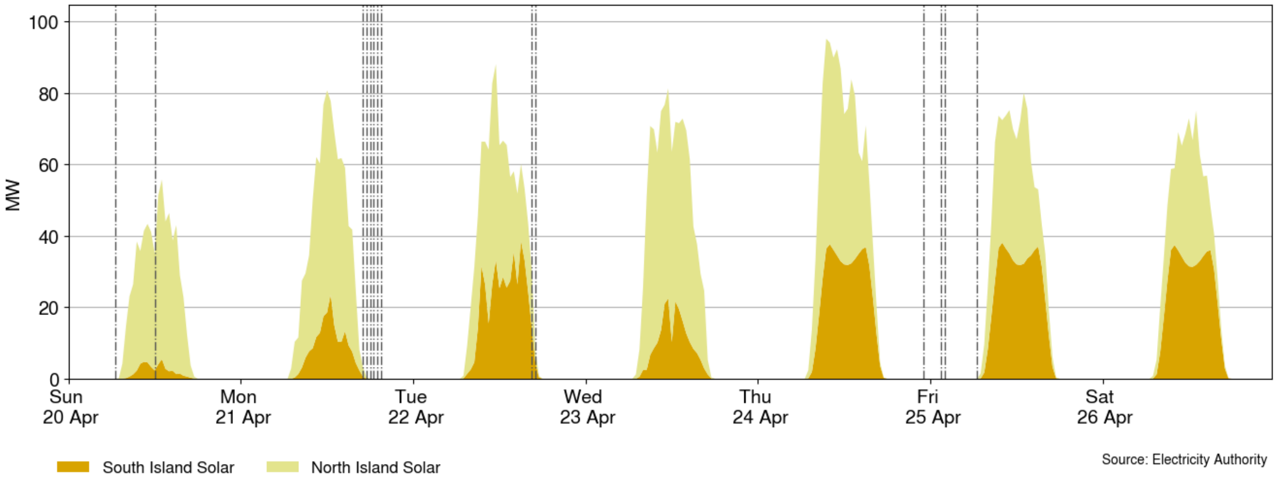
7.2. The largest negative discrepancy between generation and the gate closure forecast was at 4.30am on Sunday when wind generation was 198MW lower than forecast.

Figure 9: Wind generation and forecast, 20-26 April 2025



7.3. Figure 10 shows grid connected solar generation from 20-26 April 2025. Solar generation was highest on Thursday, with a maximum of 95MW at 9.30am.

Figure 10: Grid connected solar generation, 20-26 April 2025



7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.5. The largest marginal price differences this week were:

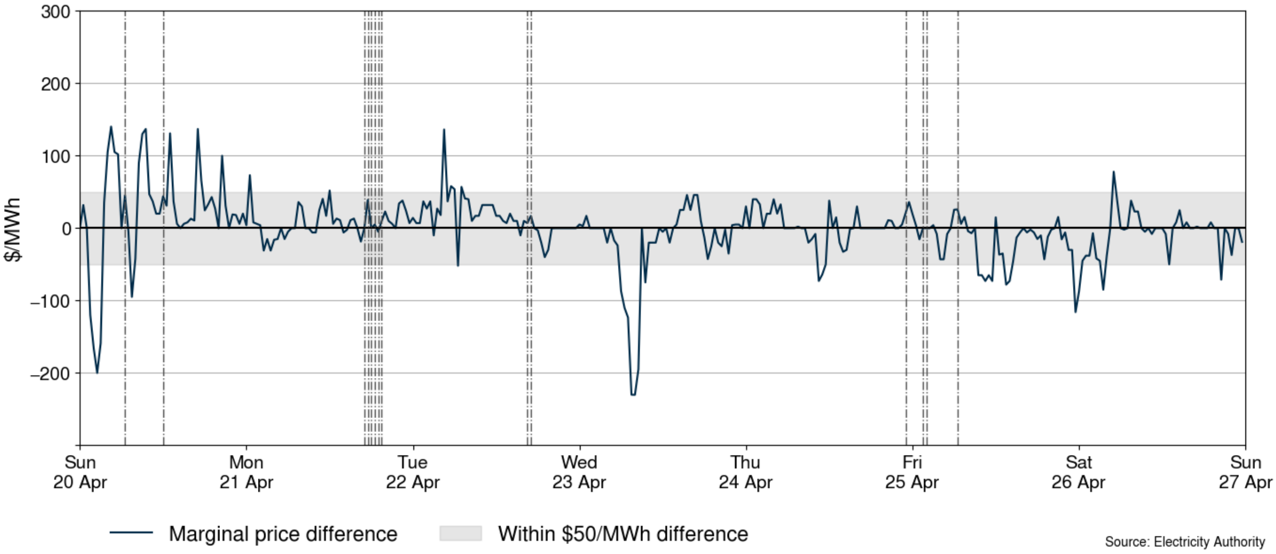
(a) -$200/MWh at 2.30am on Sunday when wind generation was 217MW higher than forecast.

(b) +$140/MWh at 4.30am on Sunday when wind generation was 198MW lower than forecast.

(c) -$230/MWh at 8.00am on Wednesday when wind generation was 299MW higher than forecast and demand was 34MW lower than forecast.

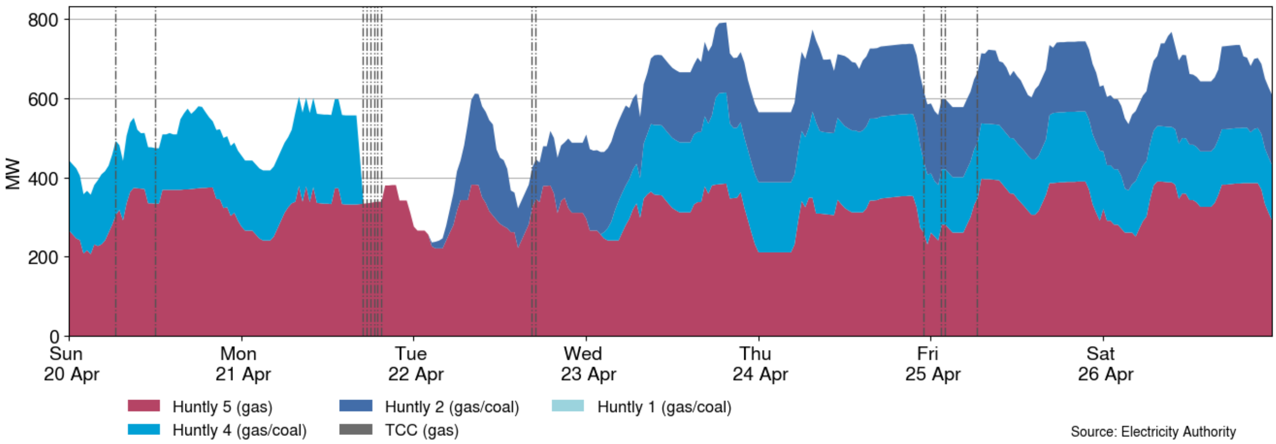
[2] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 20-26 April 2025



7.6. Figure 12 shows the generation of thermal baseload between 20-26 April 2025. Baseload generation was provided by Huntly units 2, 4 and 5. Huntly 4 tripped at 4.43pm on Monday[3], leaving only Huntly 5 generating for the evening peak before Huntly 2 started on Tuesday.

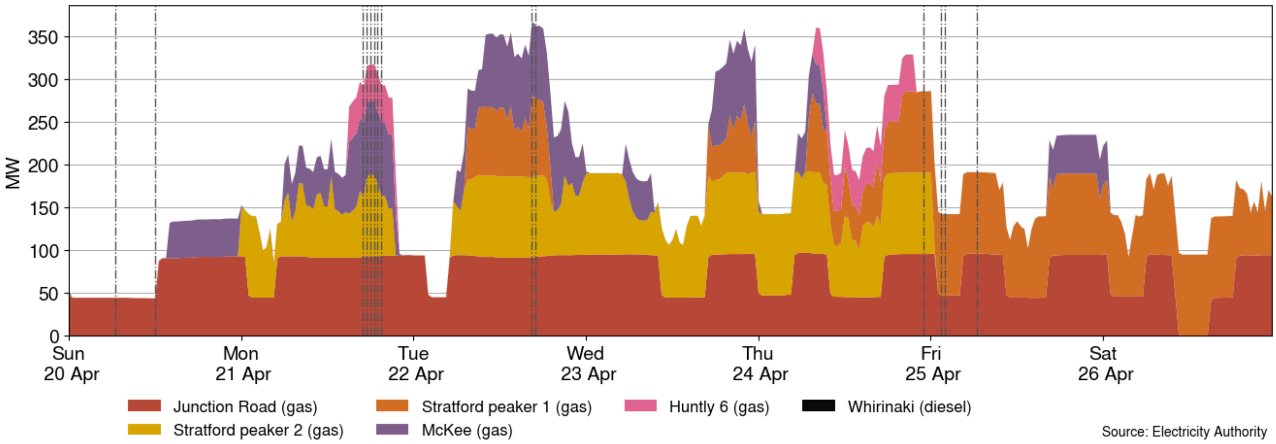
Figure 12: Thermal baseload generation, 20-26 April 2025



7.7. Figure 13 shows the generation of thermal peaker plants between 20-26 April 2025. Junction Road ran continuously, except for a short period on Saturday and McKee ran most days. At least one Stratford peaker ran every day except for Sunday, and both Stratford peakers ran during periods of lower wind generation from Tuesday. Huntly 6 ran on Monday afternoon and during the day on Thursday.

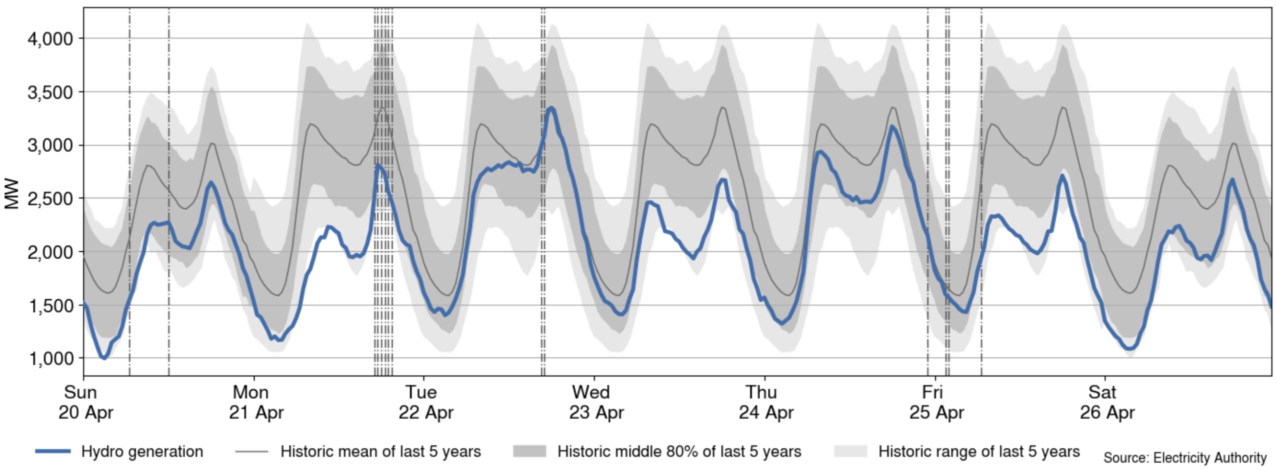
[3] EXN Frequency National Huntly generation tripped 6199271521.pdf

Figure 13: Thermal peaker generation, 20-26 April 2025



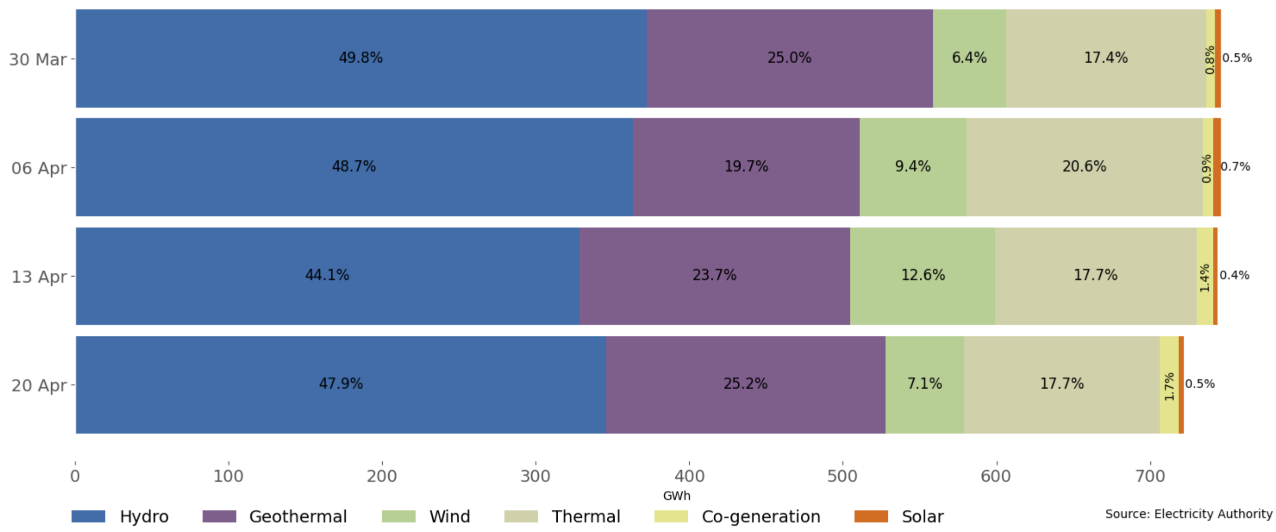
7.8. Figure 14 shows hydro generation between 20-26 April 2025. Hydro generation was at the low end of the historic range for most of the week, except for Tuesday and Thursday when wind generation was low.

Figure 14: Hydro generation, 20-26 April 2025



7.9. As a percentage of total generation, between 20-26 April 2025, total weekly hydro generation was 47.9%, geothermal 25.2%, wind 7.1%, thermal 17.7%, co-generation 1.7%, and solar (grid connected) 0.5%, as shown in Figure 15. Total generation was lower during the last week due to public holidays.

Figure 15: Total generation by type as a percentage each week, between 30 March and 26 April 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 20-26 April 2025 was below the average for this time of year, likely related to the public holidays, and ranged between ~923MW and ~1,380MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 1 is on outage until 2 June.

(b) Huntly 4 was on outage from 21-23 April.

(c) Manapōuri unit 4 is on outage until 12 June 2026.

(d) Clyde has a unit on outage until 23 May.

Figure 16: Total MW loss from generation outages, 20-26 April 2025

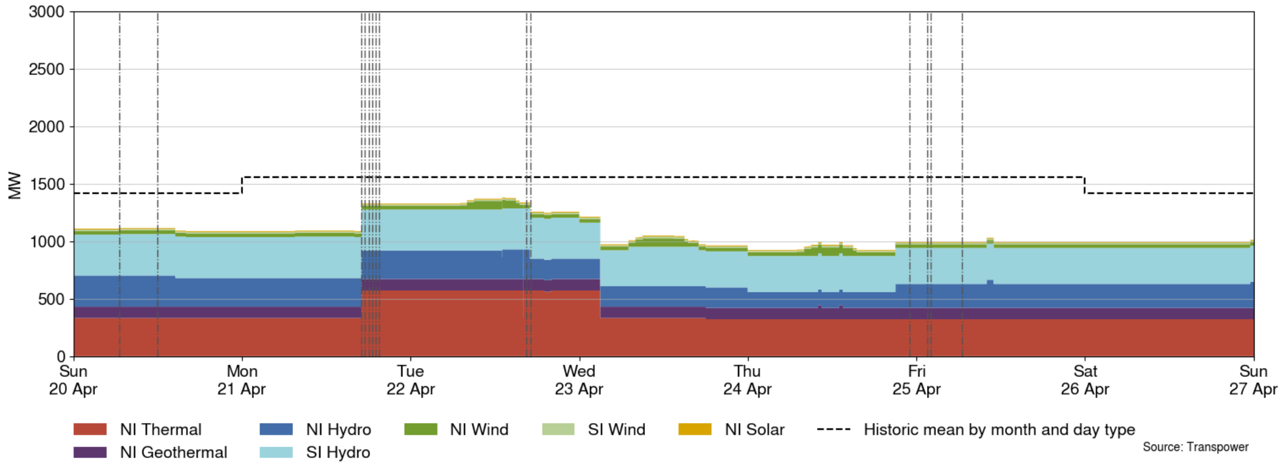
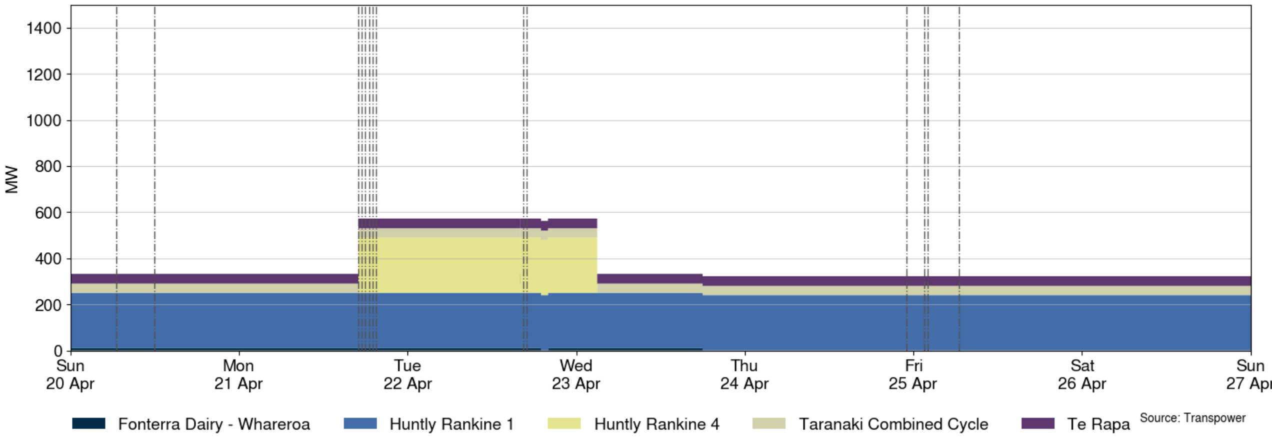


Figure 17: Total MW loss from thermal outages, 20-26 April 2025

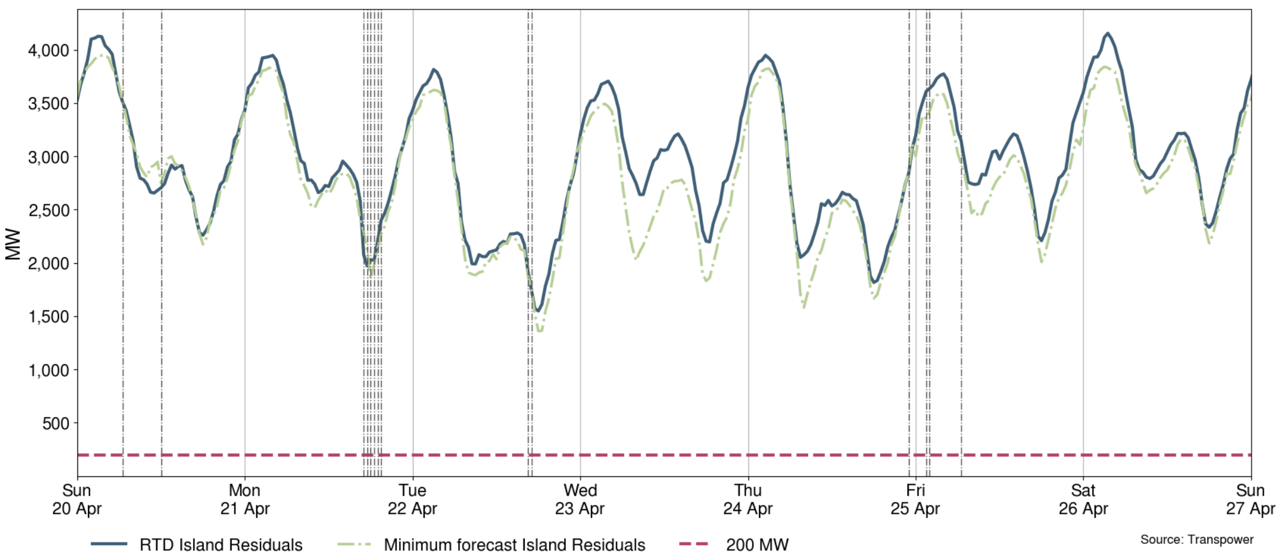


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 20-26 April 2025. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. Residuals were healthy this week. The minimum North Island residual was 697MW at 6.00pm on Tuesday.

Figure 18: National generation balance residuals, 20-26 April 2025



10. Storage/fuel supply

10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

10.2. National controlled storage has held steady in the last week and was ~64% nominally full and ~83% of the historical average for this time of the year.

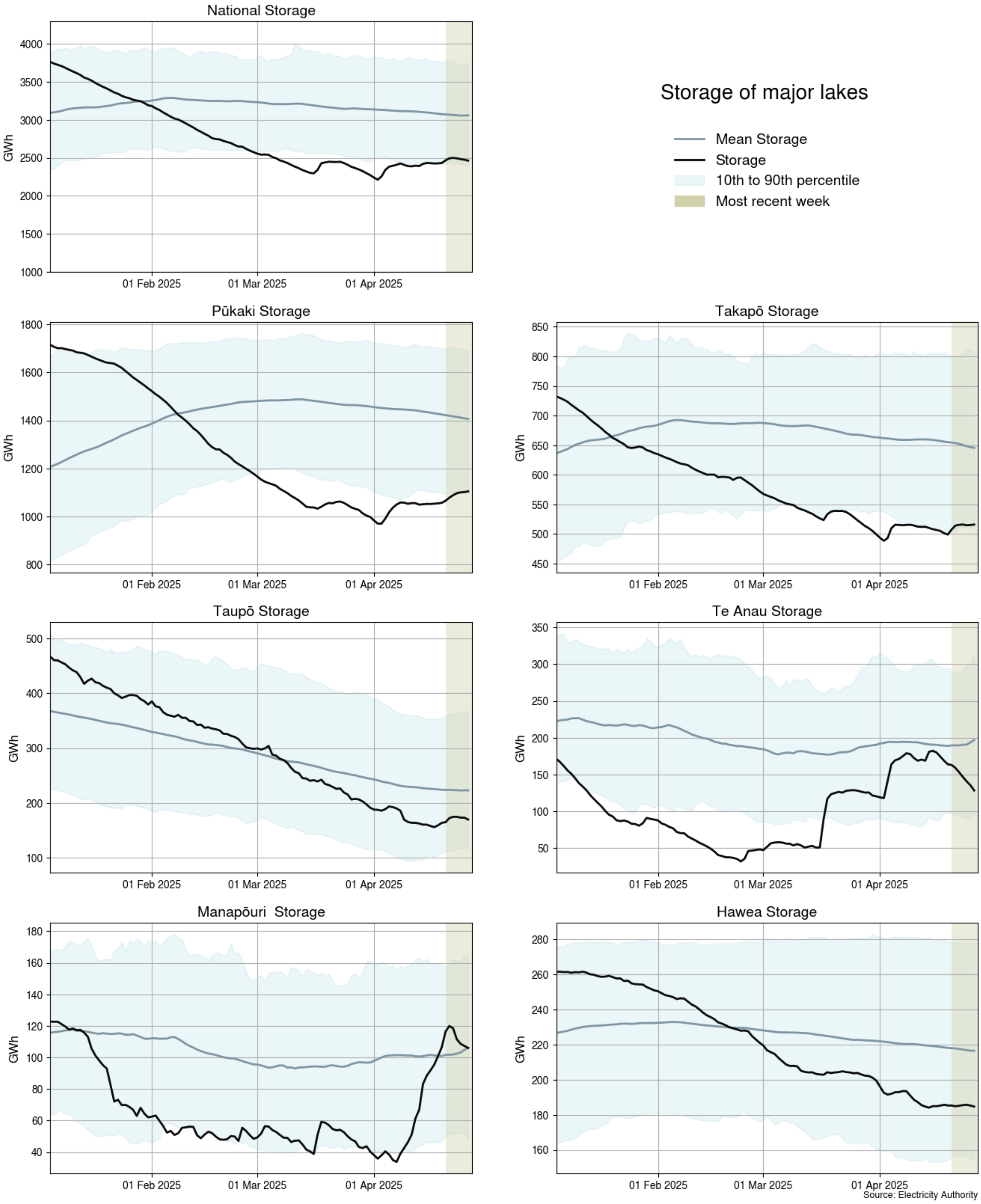
10.3. Storage at lakes Pūkaki (63% full)[4] and Takapō (63% full) increased in the last week, both lakes are now at their historical 10th percentiles.

10.4. Storage at lakes Taupō (29% full) and Hawea (64% full) held steady between their respective historical 10th percentile and mean.

10.5. Storage at Lake Te Anau dropped to between its historical mean and 10th percentile. Storage at Lake Manapōuri also dropped and is now at its historical mean.

[4] Percentage full values sourced from NZX Hydro.

Figure 19: Hydro storage



11. Prices versus estimated costs

11.1. In a competitive market, prices should be close to (but not necessarily at) the short-run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).

11.2. The SRMC (excluding opportunity cost of storage) for thermal fuels is estimated using gas and coal prices, and the average heat rates for each thermal unit. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal.

11.3. Figure 20 shows an estimate of thermal SRMCs as a monthly average up to 1 April 2025. The SRMC for gas fueled generation has increased compared to last month. The SRMC for coal fueled generation has reduced slightly and the SRMC diesel fueled generation remains similar.

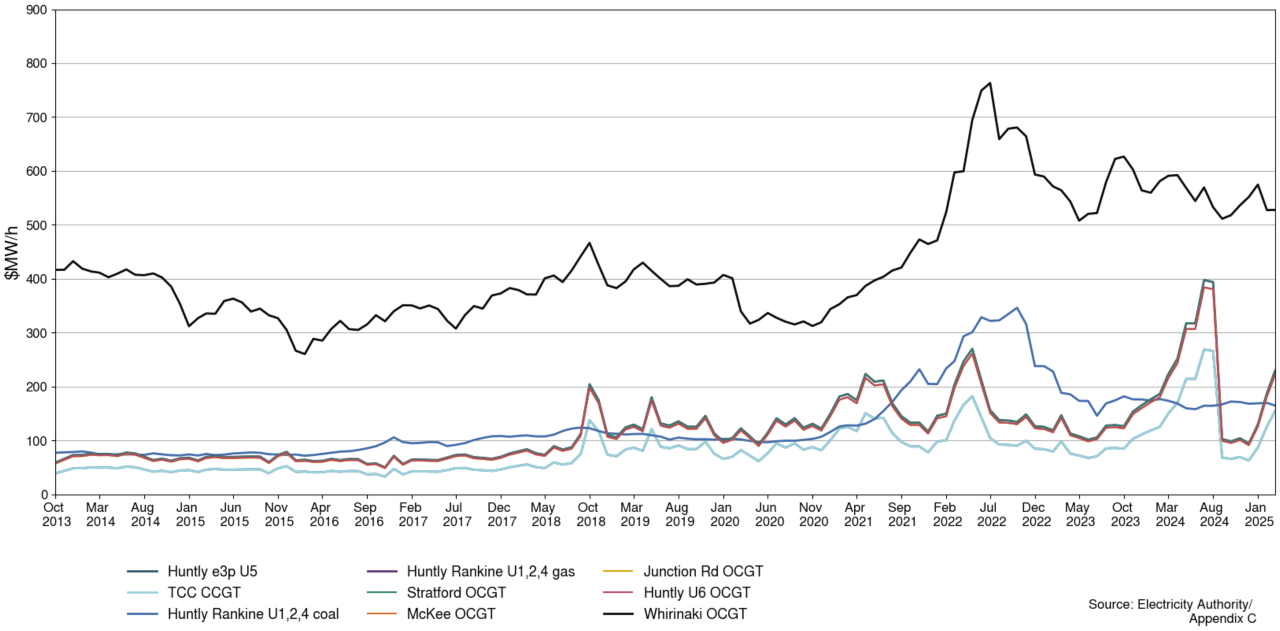
11.4. The latest SRMC of coal-fueled Rankine generation is ~$160/MWh, with the cost of running the Rankines on gas more expensive at ~$250/MWh.

11.5. The SRMC of gas fueled thermal plants is currently between $168/MWh and $250/MWh.

11.6. The SRMC of Whirinaki is still ~$528/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

Figure 20: Estimated monthly SRMC for thermal fuels

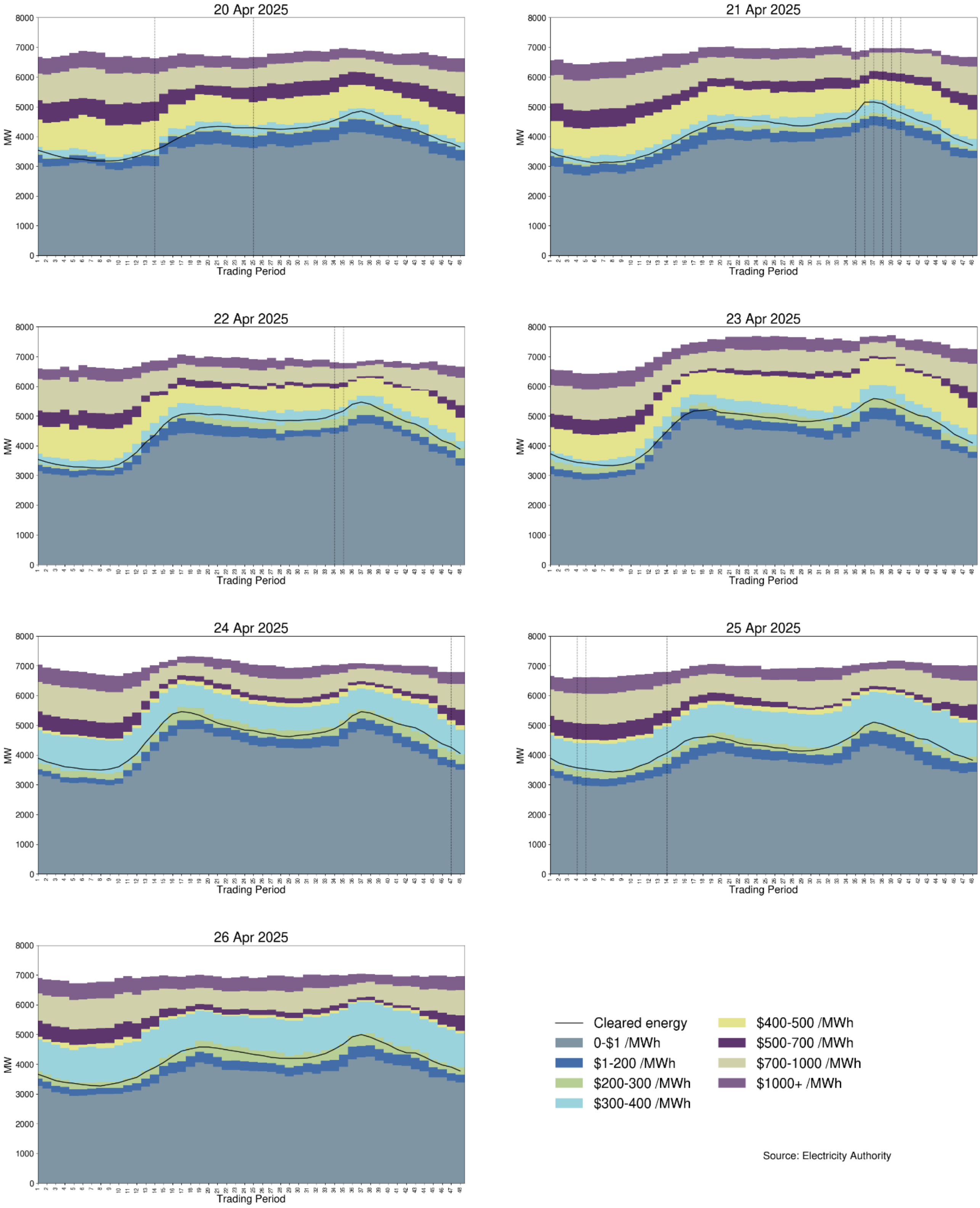


Source: Electricity Authority/ Appendix C

12. Offer behaviour

12.1. Figure 21 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price. The increase in offer volume in the $300-400/MWh band from 24 April is mostly a reduction in the price of hydro offers.

Figure 21: Daily offer stacks

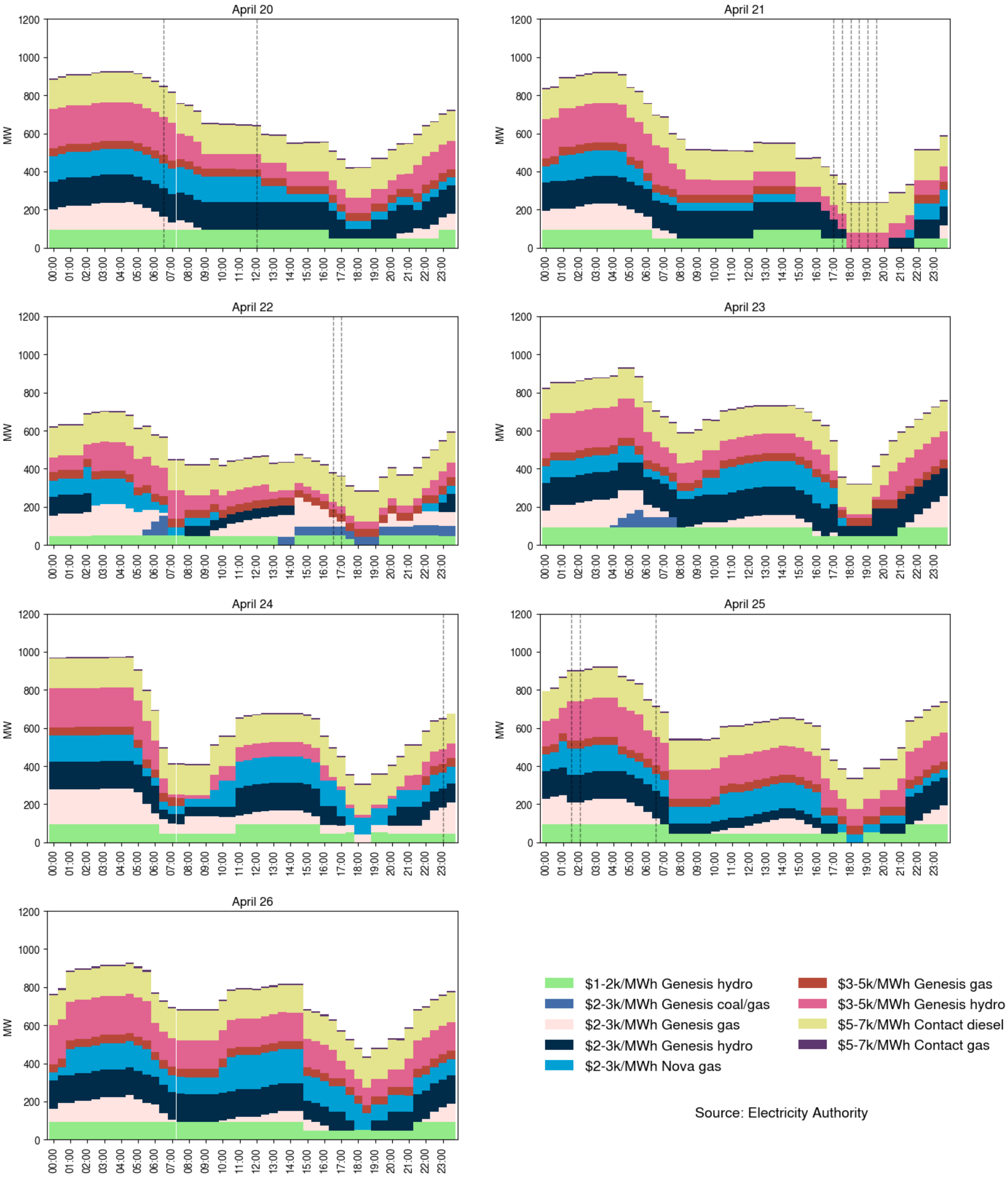


12.2. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.3. If forecast prices are lower than thermal operating costs, this signals some generators may not be needed in that half-hourly trading period. Thermal generators may then price their units high, as they aren't expecting to run. These high prices reflect increased operating costs of running for only a short time. So, if demand is unexpectedly high, wind generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.4. On average 638MW per trading period was priced above $1,000/MWh this week, which is roughly 10.6% of the total energy available and similar to last week.

Figure 22: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions. We are enquiring with several hydro generators regarding their recent hydro offers.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

Table 1: Trading periods identified for further analysis

Date	Trading period	Status	Participant	Location	Enquiry topic
14/06/2023- 15/06/2023	15-17/ 15-19	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023- 30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13- 18/09/2024	Several	Further analysis	Contact	Clutha scheme	Hydro offers
18/03/2025	23-27	Further analysis	Genesis	Huntly	Unplanned outage
27/03/2025	20-28	Further analysis	Contact	Stratford peakers and TCC	Offers
4/04/2025	Several	Further analysis	Genesis	Huntly	Offers removed
2/04/2025- 4/04/2025	Several	Further analysis	Genesis	Takapō and Tokaanu	Offers
1/03/2025- 26/04/2024	Several	Further analysis	Meridian	Waitaki	Hydro offer pricing
1/03/2025- 26/04/2024	Several	Further analysis	Genesis	Takapō	Hydro offer pricing
1/03/2025- 26/04/2024	Several	Further analysis	Mercury	Waikato	Hydro offer pricing