

8 June 2026

# **Trading conduct report**

## **31 May-6 June 2026**

Market monitoring weekly report

# Trading conduct report 31 May-6 June 2026

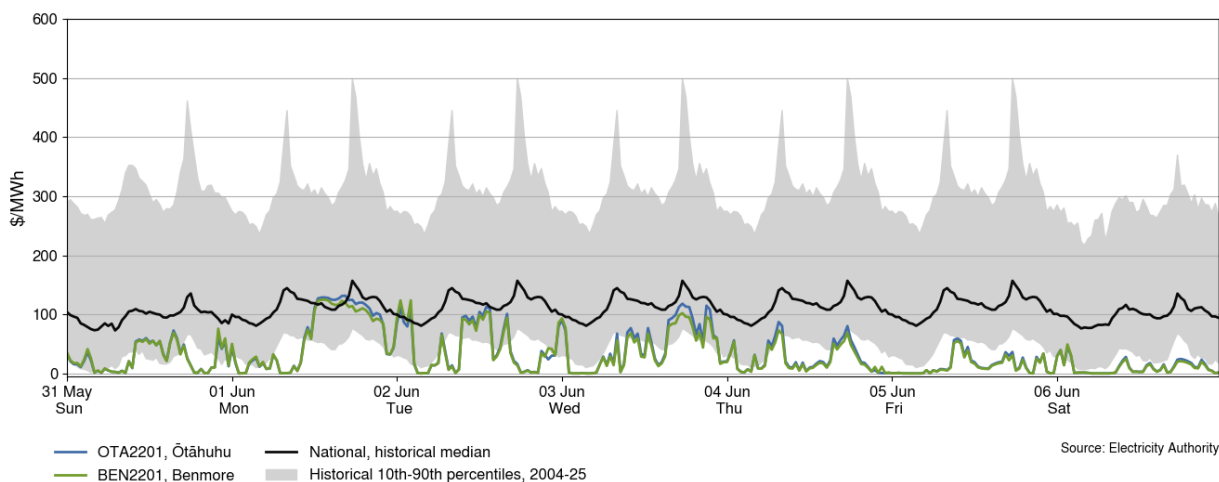
## 1. Overview

- 1.1. This week the average spot price decreased from \$99/MWh to \$32/MWh. Prices have been low this week due to lower demand and higher wind generation. National controlled storage has increased to 84% nominally full and 117% of the historical average for this time of year.

## 2. Spot prices

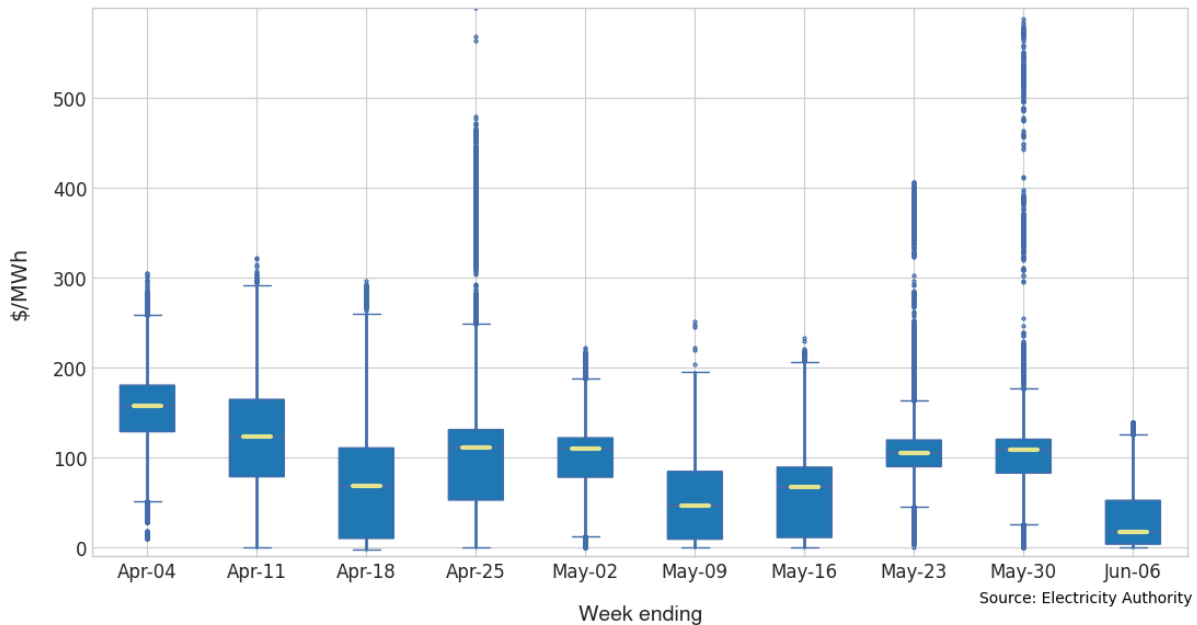
- 2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.
- 2.2. Between 31 May-6 June:
  - (a) The average spot price for the week was \$32/MWh, a decrease of around \$67/MWh compared to the previous week.
  - (b) 95% of prices fell between \$0.02/MWh and \$120/MWh.
- 2.3. Prices have been low this week due to lower demand because of King's Birthday and warmer temperatures, and higher wind generation.
- 2.4. The highest price at Ōtāhuhu was \$131/MWh at 4.30pm on Monday, while prices at Benmore were \$119/MWh.
- 2.5. The highest price at Benmore was \$125/MWh at 1.30pm on Monday, while prices at Ōtāhuhu were \$129/MWh.
- 2.6. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90<sup>th</sup> percentiles adjusted for inflation. Prices greater than quartile 3 (75<sup>th</sup> 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 generally highlighted with a vertical black line, however, this week there were none.

**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 31 May-6 June**



- 2.7. 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.
- 2.8. The distribution of spot prices this week was lower compared to last week, with a much lower maximum price. The median price was \$18/MWh and most prices (middle 50%) fell between \$3/MWh and \$53/MWh.

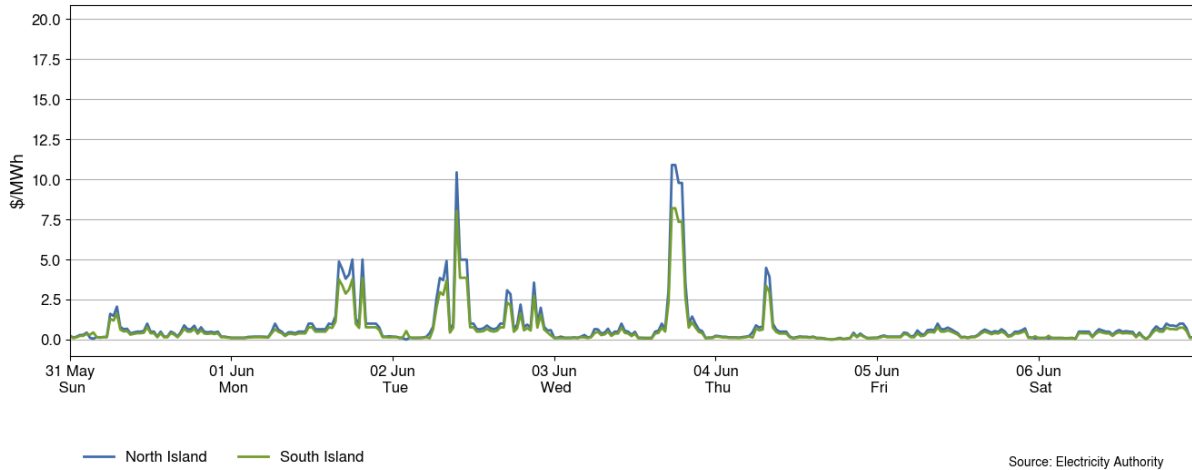
**Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks**



### 3. Reserve prices

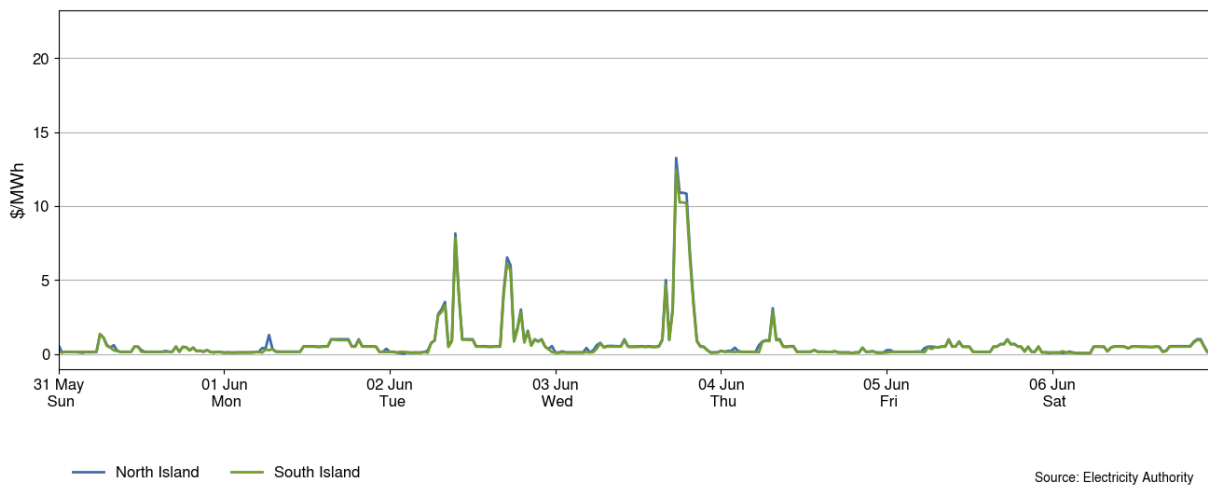
- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices remained mostly below \$1/MWh, with two spikes reaching above \$10/MWh in the North Island.
- 3.2. The largest FIR prices for the week occurred at 5.30pm on Wednesday, with FIR prices in the North Island reaching \$11/MWh and FIR prices in the South Island reaching \$8/MWh.

**Figure 3: Fast instantaneous reserve price by trading period and island, 31 May-6 June**



- 3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices remained mostly below \$1/MWh, with one price spike over \$10/MWh on Wednesday.
- 3.4. The largest SIR prices for the week occurred at 5.30pm on Wednesday, with SIR prices in the North Island reaching \$14/MWh and SIR prices in the South Island reaching \$13/MWh.

**Figure 4: Sustained instantaneous reserve by trading period and island, 31 May-6 June**

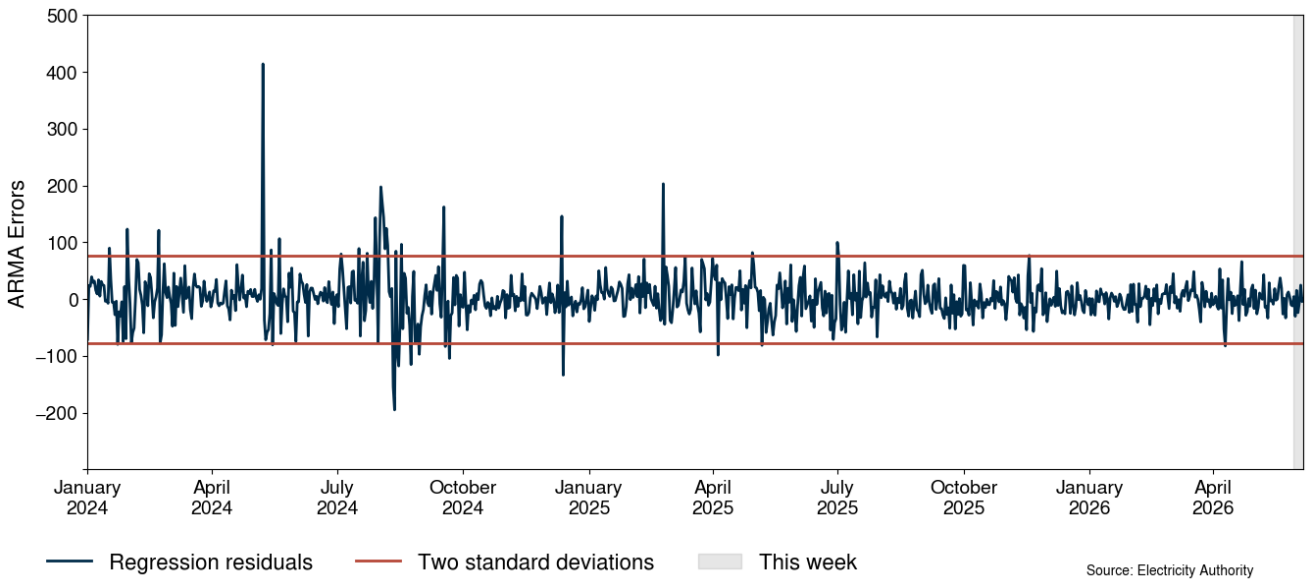


## 4. Regression residuals

- 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.

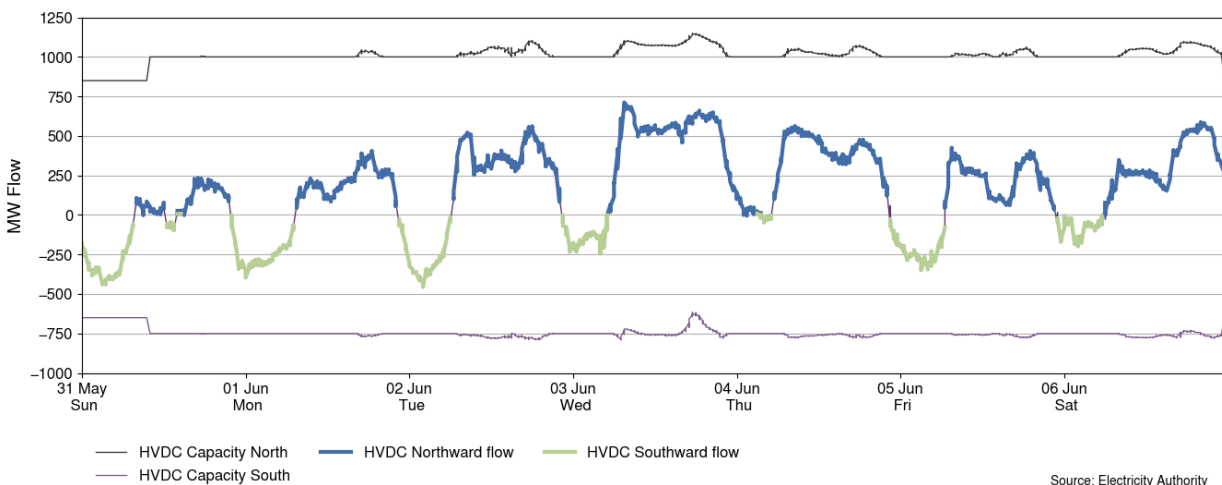
**Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 6 June 2026**



## 5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 31 May-6 June. This week, HVDC flows were mainly northward with southward flows occurring overnight.
- 5.2. The highest northward flow reached 712MW on Wednesday at 7.30am.
- 5.3. The highest southward flow reached 455MW on Tuesday at 2.00am.

**Figure 6: HVDC flow and capacity, 31 May-6 June**

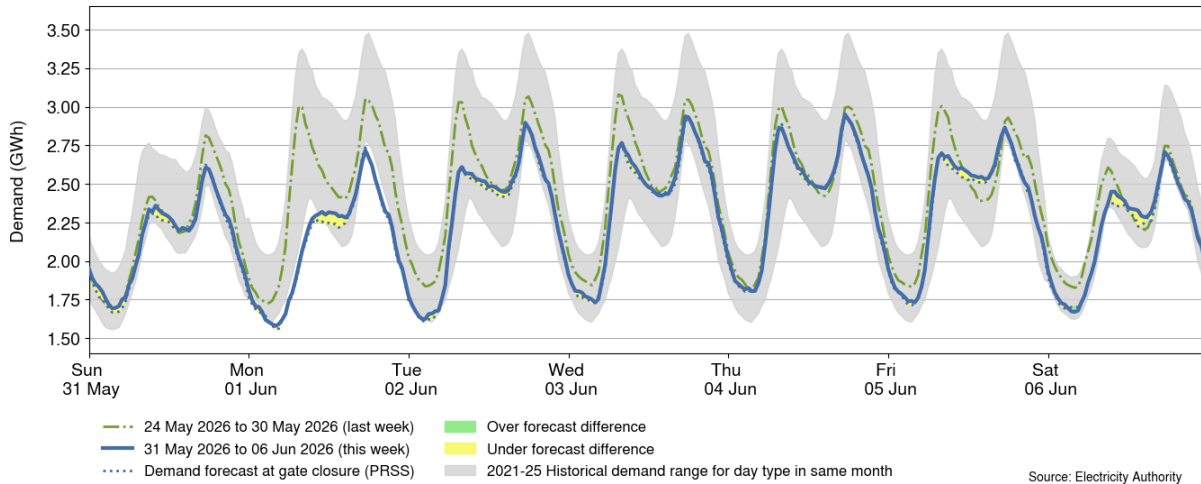


## 6. Demand

- 6.1. Figure 7 shows national demand between 31 May-6 June, compared to the historic range and the demand of the previous week. Demand was significantly lower than last week, due to warmer temperatures and King’s Birthday on Monday.

- 6.2. The maximum demand this week was around 2.95GWh (5.9GW) at 5:30pm on Thursday.
- 6.3. This week, there were some notable periods where demand was over 100MW more than forecast. These occurred on Monday from 10.30am to 2.00pm, on Friday from 11.00am to 11.30am, and on Saturday from 9.30am to 10.30am and from 1.30pm to 2.00pm.

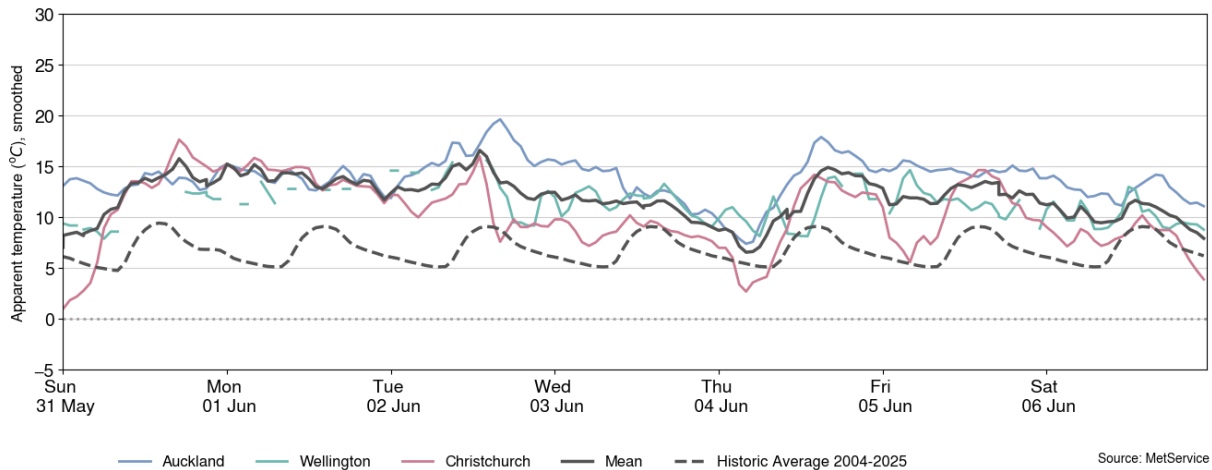
**Figure 7: National demand, 31 May-6 June compared to the previous week**



- 6.4. Apparent temperatures ranged from 7°C to 20°C in Auckland, 8°C to 16°C in Wellington, and 1°C to 18°C in Christchurch.
- 6.5. From Sunday to Tuesday, much of the Wellington data is missing. Some Wellington data is also missing on Thursday and Friday.
- 6.6. **Figure 8** shows the hourly apparent temperature at main population centres from 31 May to 6 June. 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.

- 6.7. Apparent temperatures ranged from 7°C to 20°C in Auckland, 8°C to 16°C in Wellington, and 1°C to 18°C in Christchurch.
- 6.8. From Sunday to Tuesday, much of the Wellington data is missing. Some Wellington data is also missing on Thursday and Friday.

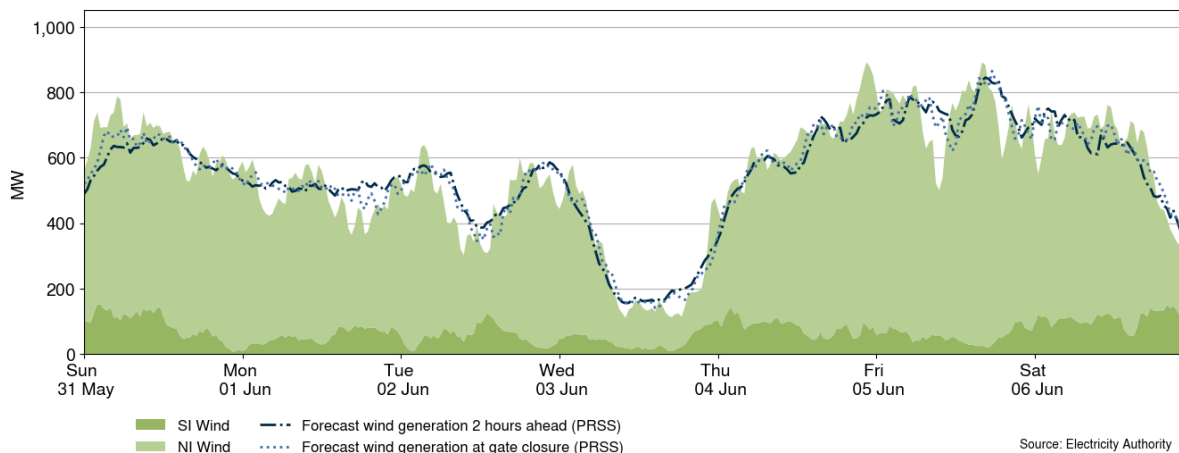
**Figure 8: Temperatures across main centres, 31 May-6 June**



## 7. Generation

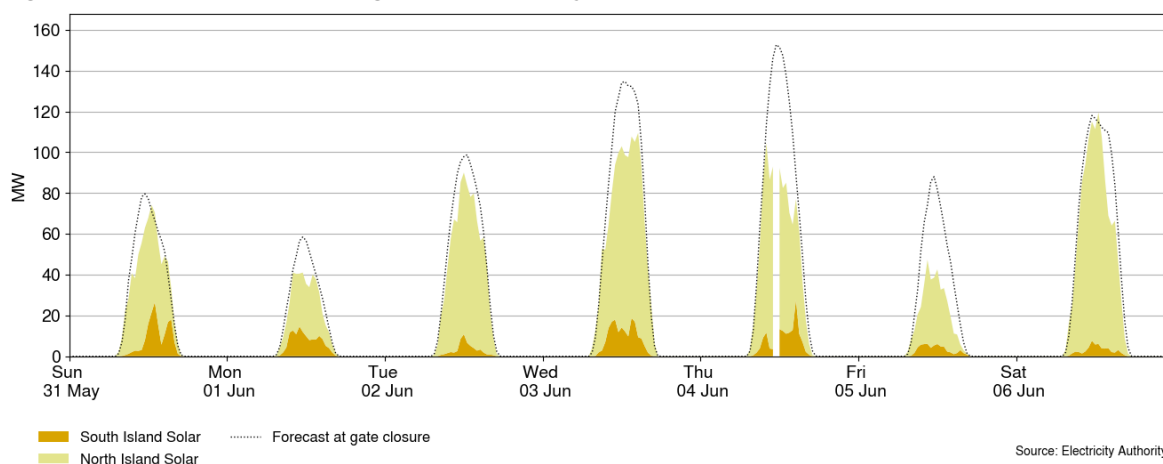
- 7.1. Figure 9 shows wind generation and forecast from 31 May to 6 June. Wind generation was high this week, varying between 110MW and 892MW, with a weekly average of 550MW.
- 7.2. Daily average wind generation exceeded 450MW every day except for Wednesday where it averaged 261MW. The maximum daily average of 737MW occurred on Friday.
- 7.3. The largest over forecasting error occurred on Saturday at 12.30am, where wind generation was 208MW below forecast. In addition, on Friday from 7.30am to 10am, wind generation between 75MW and 205MW below forecast.
- 7.4. Frequent forecasting errors throughout the week were an amalgamation of errors at multiple wind farms, especially Harapaki, Kaiwera Downs 2, Tararua 3, Te Āpiti, Turitea, and Waipipi.

**Figure 9: Wind generation and forecast, 31 May-6 June**



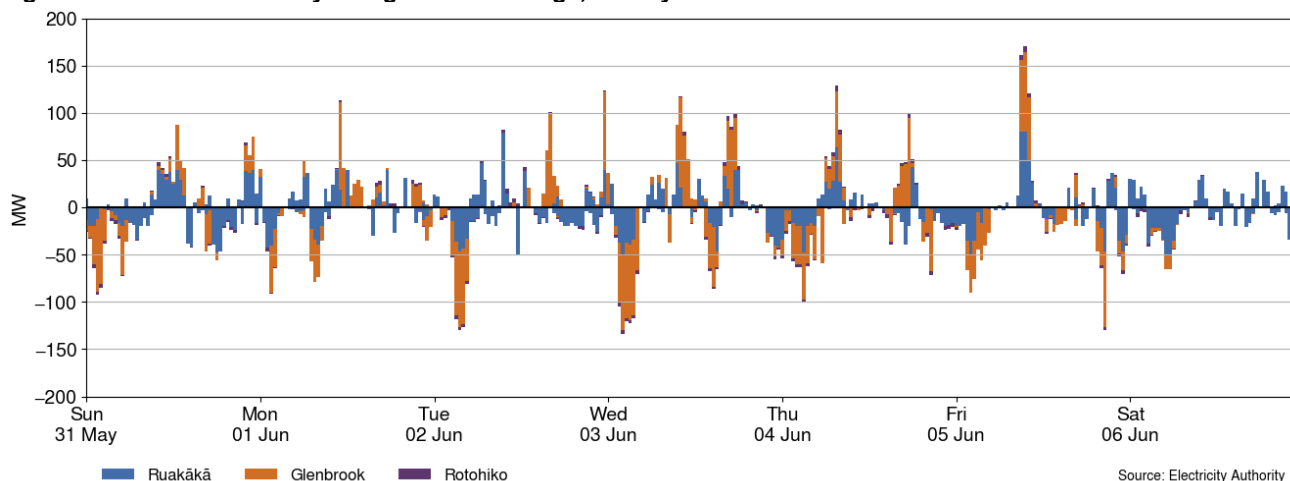
- 7.5. Figure 10 shows grid connected solar generation from 31 May-6 June. Solar generation was low this week, peaking at 119MW at 12.30pm on Saturday.
- 7.6. On Thursday at 11.30am both North Island and South Island data is missing.
- 7.7. There were large over forecasting errors on Wednesday, Thursday, and Friday. The largest error of 65MW occurred on Thursday at 12.30pm.
- 7.8. The forecasting errors were a result of an amalgamation of farms, in particular Omeheu, Papareireiā, Taiohi, and Twin Rivers solar farms.
  - (a) Omeheu did not generate on Wednesday and Thursday and had low generation on Friday and Saturday. Omeheu appears to be still commissioning.
  - (b) Papareireiā solar farm did not generate on Thursday and Friday, despite not logging an outage. The monitoring team is looking further into this.

**Figure 10: Grid connected solar generation, 31 May-6 June**



- 7.9. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.
- 7.10. This week, the batteries generally charged when prices were relatively low, at below ~\$30/MWh, and discharged when prices were higher, at above ~\$30/MWh.

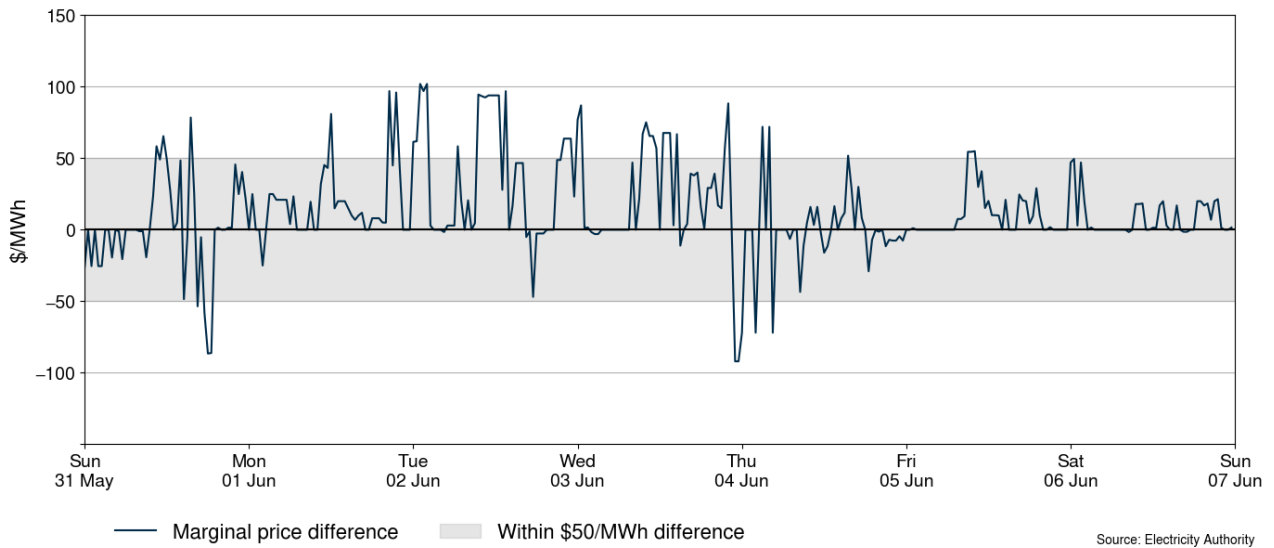
**Figure 11: Grid scale battery charge and discharge, 31 May-6 June**



- 7.11. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS<sup>1</sup>) 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 intermittent generation is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and intermittent generation forecasting, the 1-hour ahead and the RTD intermittent generation 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.
- 7.12. There were some marginal price differences over \$50/MWh this week.
- 7.13. The maximum positive difference of \$102/MWh occurred on Tuesday at 1.00am. At this time, wind generation was 50MW below forecast, and demand was 3MW below forecast. Additionally, on Monday and Tuesday there were several instances of large wind forecasting errors.
- 7.14. The maximum negative difference of \$92/MWh occurred on Wednesday at 11.00pm. At this time, wind generation was 180MW above forecast, and demand was 56MW above forecast.

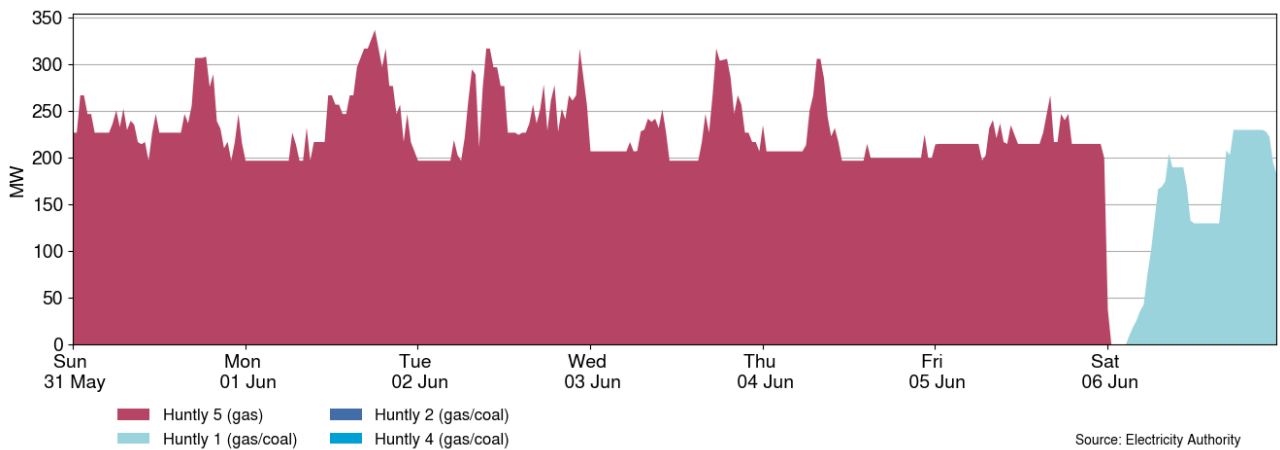
<sup>1</sup> Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

**Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 31 May-6 June**



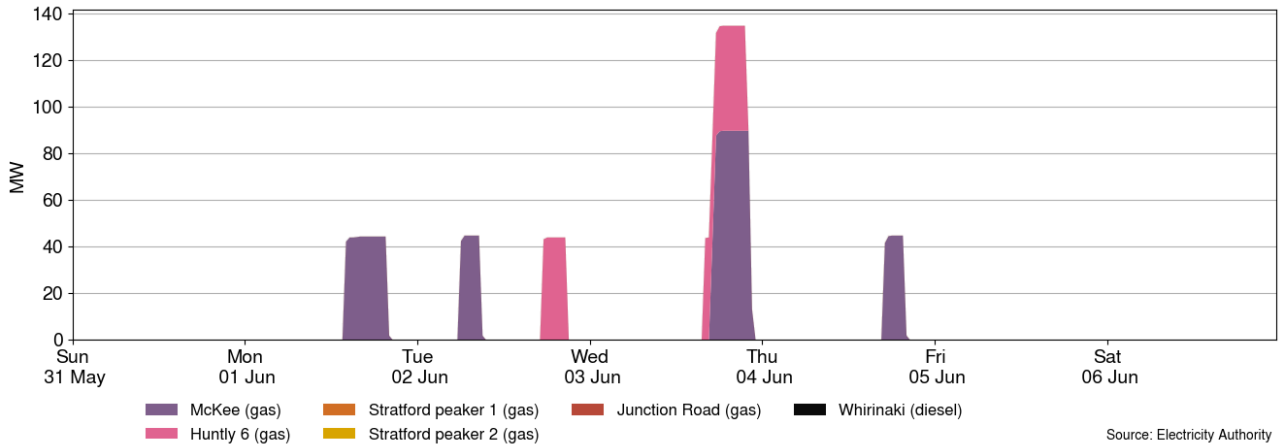
7.15. Figure 13 shows the generation of thermal baseload between 31 May-6 June. Huntly 5 ran continuously until Friday night, and Huntly 1 ran on Saturday.

**Figure 13: Thermal baseload generation, 31 May-6 June**



7.16. Figure 14 shows the generation of thermal peaker plants between 31 May-6 June. McKee ran at times from Monday to Thursday, and Huntly 6 ran at times on Tuesday and Wednesday.

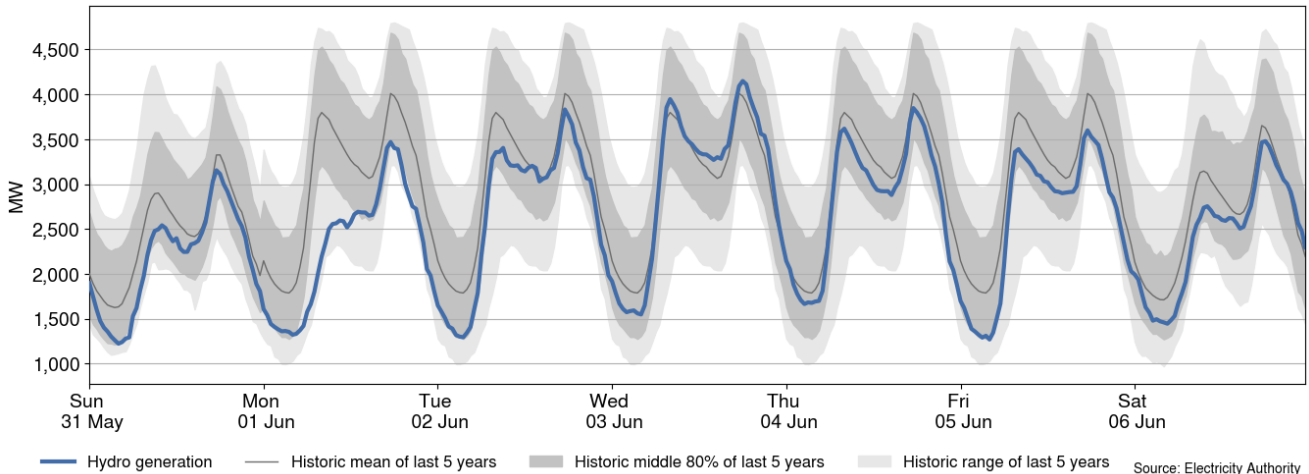
**Figure 14: Thermal peaker generation, 31 May-6 June**



Source: Electricity Authority

7.17. Figure 15 shows hydro generation between 31 May-6 June. Hydro generation was mostly lower than the historic mean this week, due to lower demand and higher levels of wind generation. When wind generation was lower on Wednesday, hydro generation was higher.

**Figure 15: Hydro generation, 31 May-6 June**



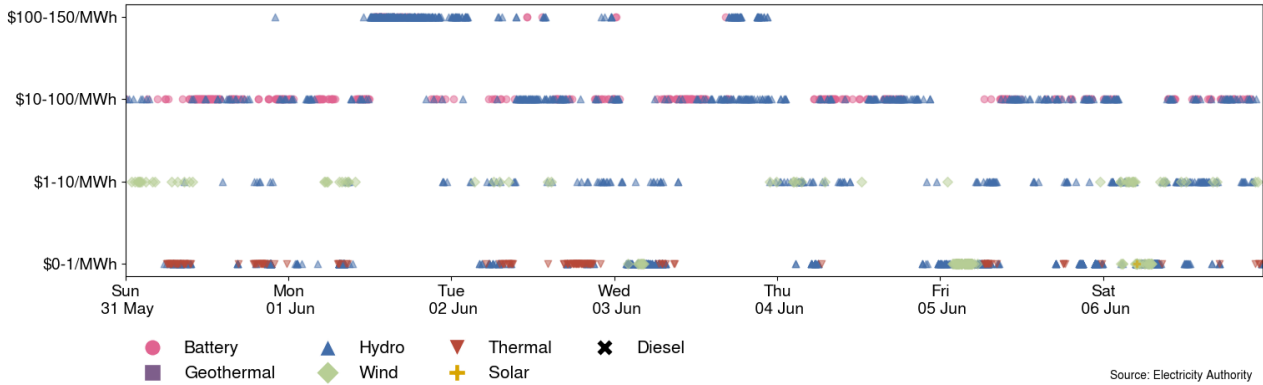
Source: Electricity Authority

7.18. The highest prices this week were set by the Ruakākā battery. The most common technology setting prices was hydro, with batteries the second most common. Most marginal prices were between \$10-100/MWh.

7.19. Figure 16 shows the distribution of marginal prices this week and what generation technology produced each marginal price. Note there can be multiple marginal plants for each 5-minute period.

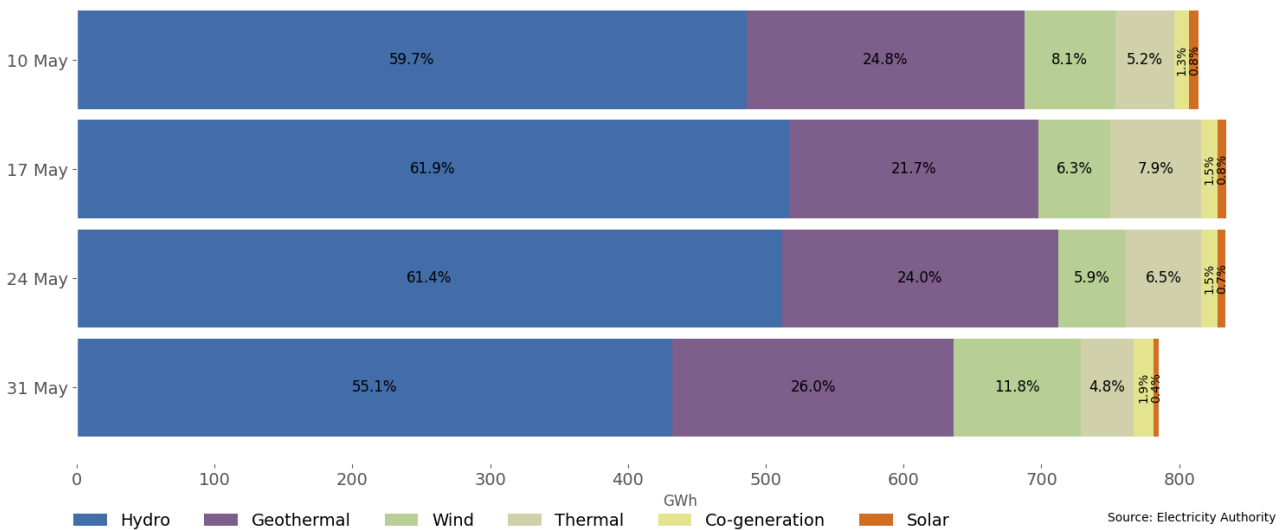
7.20. The highest prices this week were set by the Ruakākā battery. The most common technology setting prices was hydro, with batteries the second most common. Most marginal prices were between \$10-100/MWh.

**Figure 16: Prices of marginal generation, 31 May-6 June**



7.21. As a percentage of total generation, between 31 May-6 June, total weekly hydro generation was 55.1%, geothermal 26.0%, wind 11.8%, thermal 4.8%, co-generation 1.9%, and solar (grid connected) 0.4%, as shown in Figure 17.

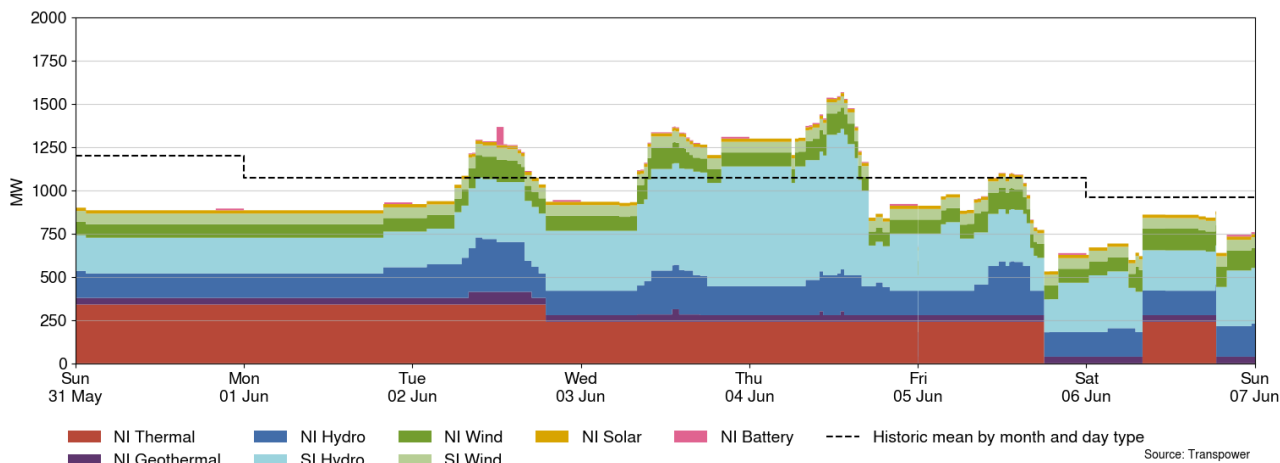
**Figure 17: Total generation by type as a percentage each week, between 10 May and 6 June**



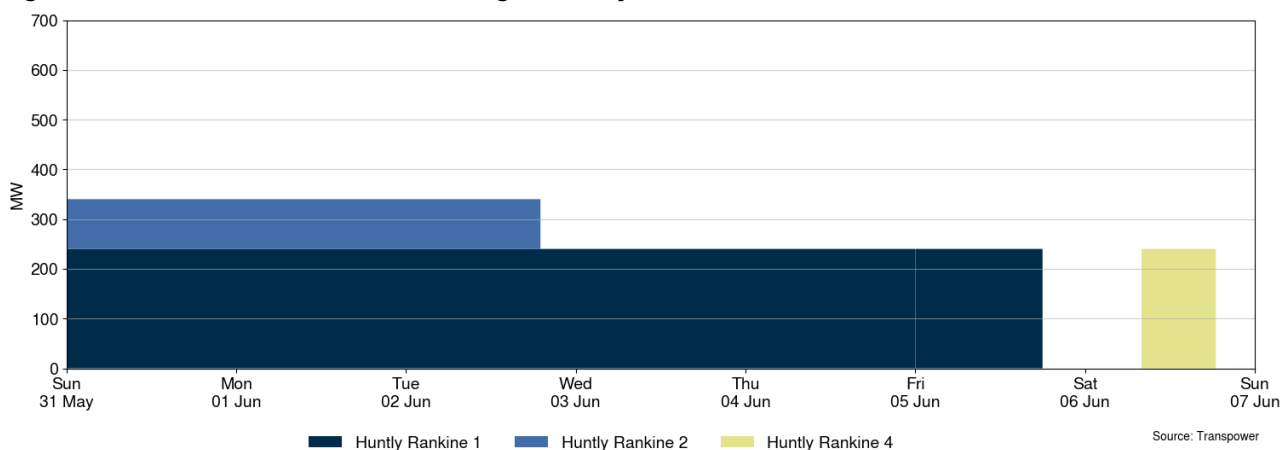
## 8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 31 May-6 June ranged between ~531MW and ~1,567MW. Figure 19 shows the thermal generation capacity outages.

**Figure 18: Total MW loss from generation outages, 31 May-6 June**



**Figure 19: Total MW loss from thermal outages, 31 May-6 June**



8.2. Notable outages include:

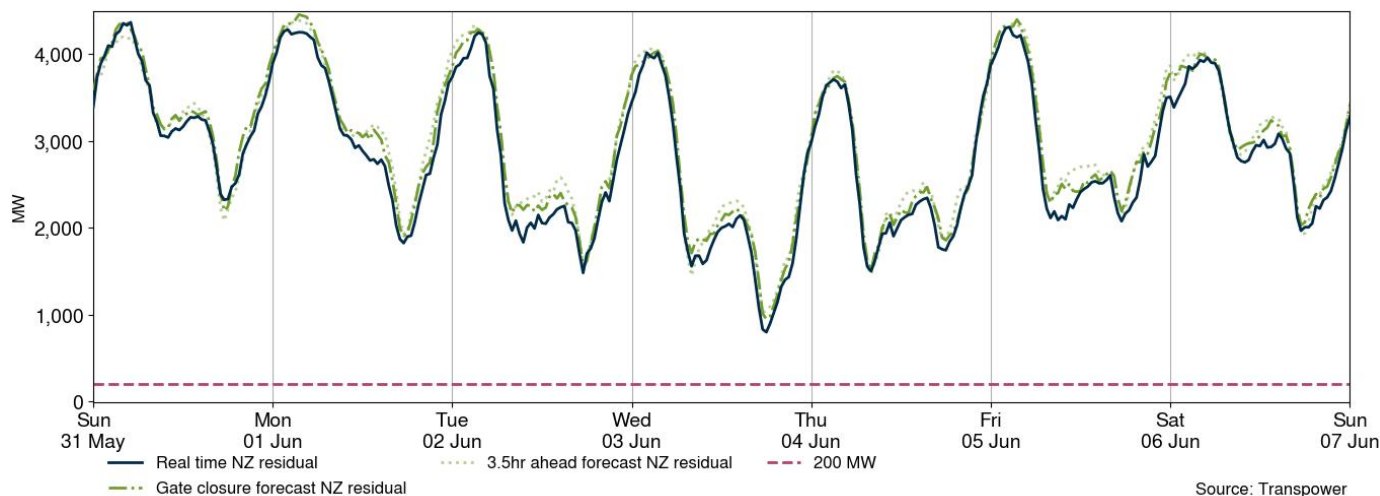
Plant	Partial or Full	End Date
Huntly 2	Full	2 June 2026
Manapouri unit 2	Full	4 June 2026
Clyde 3	Full	4 June 2026
Huntly 1	Full	4 June 2026
Kaiwera Downs	Partial	11 June 2026
Manapouri unit 4	Full	21 July 2026
Roxburgh unit 8	Full	2 September 2026

## 9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 31 May-6 June. 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 forecast low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. The national residual has been healthy this week. The lowest national residual was 801MW at 6.00pm on Wednesday.

**Figure 20: National generation balance residuals, 31 May-6 June**

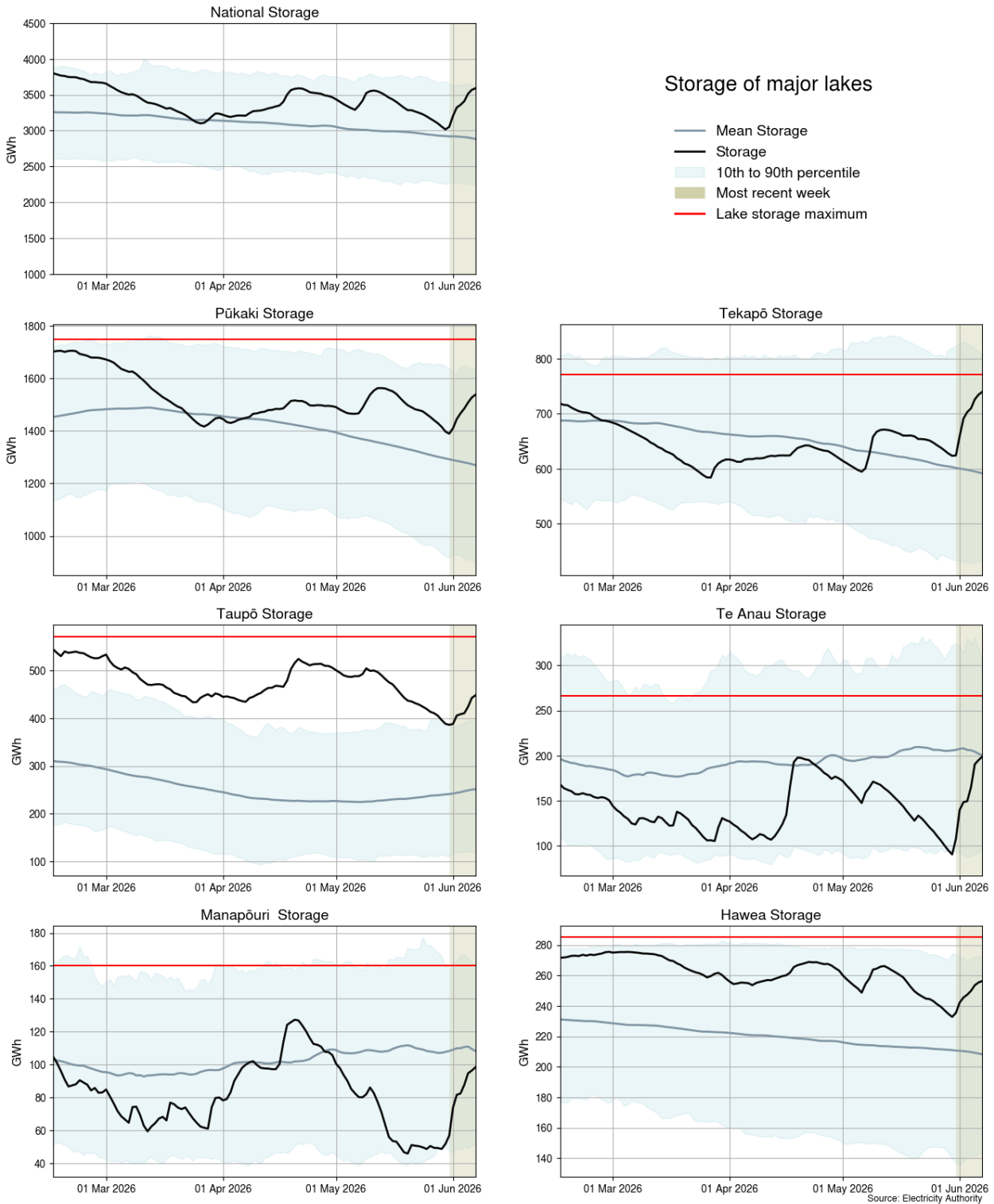


Source: Transpower

## 10. Storage/fuel supply

- 10.1. As of 6 June, national controlled storage was 84% nominally full and ~117% of the historical average for this time of the year.
- 10.2. Storage at Lake Pūkaki (85% full) and Lake Tekapō (82% full) remain above their historic mean.
- 10.3. Storage at Lake Te Anau (75% full) has increased to above its historic mean, while storage at Lake Manapōuri (63% full) has increased to near its historic mean.
- 10.4. Storage at Lake Taupō (78% full) remains above its historic 90th percentile for this time of year.
- 10.5. Storage at Lake Hawea (90% full) is below its historic 90th percentile but remains above its historic mean.
- 10.6. Figure 21 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10<sup>th</sup> to 90<sup>th</sup> percentiles.
- 10.7. As of 6 June, national controlled storage was 84% nominally full and ~117% of the historical average for this time of the year.
- 10.8. Storage at Lake Pūkaki (85% full) and Lake Tekapō (82% full) remain above their historic mean.
- 10.9. Storage at Lake Te Anau (75% full) has increased to above its historic mean, while storage at Lake Manapōuri (63% full) has increased to near its historic mean.
- 10.10. Storage at Lake Taupō (78% full) remains above its historic 90th percentile for this time of year.
- 10.11. Storage at Lake Hawea (90% full) is below its historic 90th percentile but remains above its historic mean.

**Figure 21: Hydro storage**

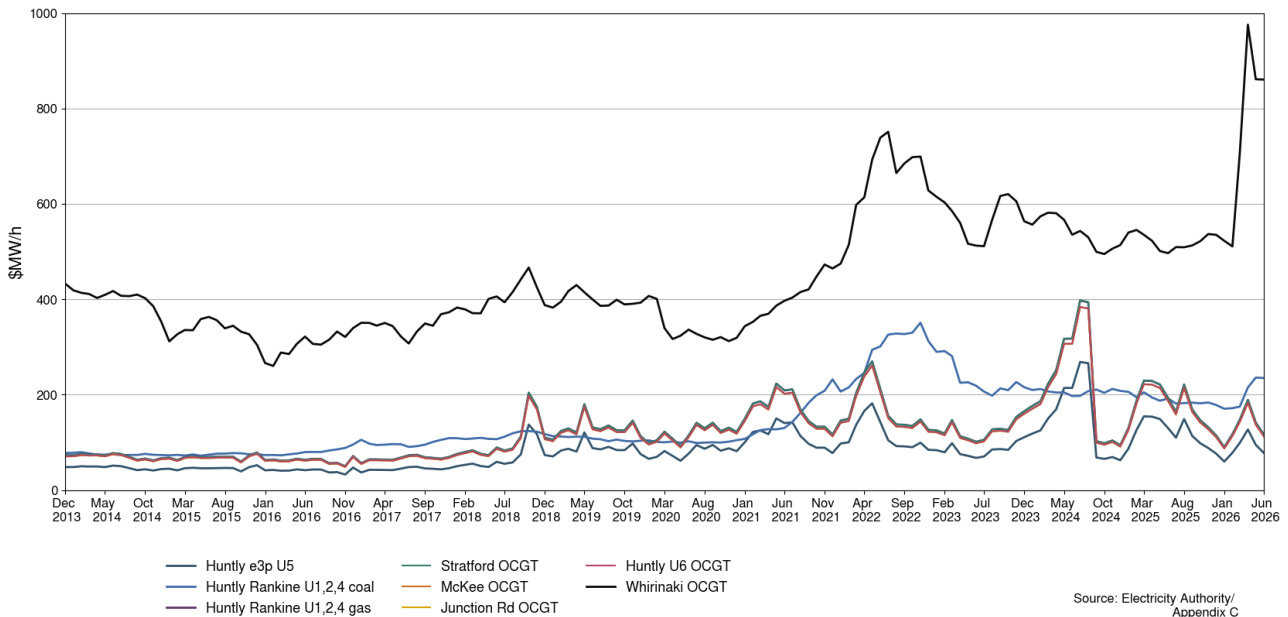


## 11. Prices versus estimated costs

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 22 shows an estimate of thermal SRMCs as a monthly average up to 1 June 2026. The SRMCs for gas generation has decreased, with SRMCs for coal and diesel fuelled generation remaining steady.
- 11.4. The latest SRMC of coal-fuelled Rankine generation is ~\$235/MWh, while the cost of running the Rankines on gas is ~\$116/MWh.
- 11.5. The SRMC of gas fuelled thermal plants is currently between \$78/MWh and \$116/MWh.
- 11.6. The SRMC of Whirinaki is ~\$861/MWh.
- 11.7. Note that coal prices have been rolled forward from May.
- 11.8. More information on how the SRMC of thermal plants is calculated can be found in [Appendix C](#).

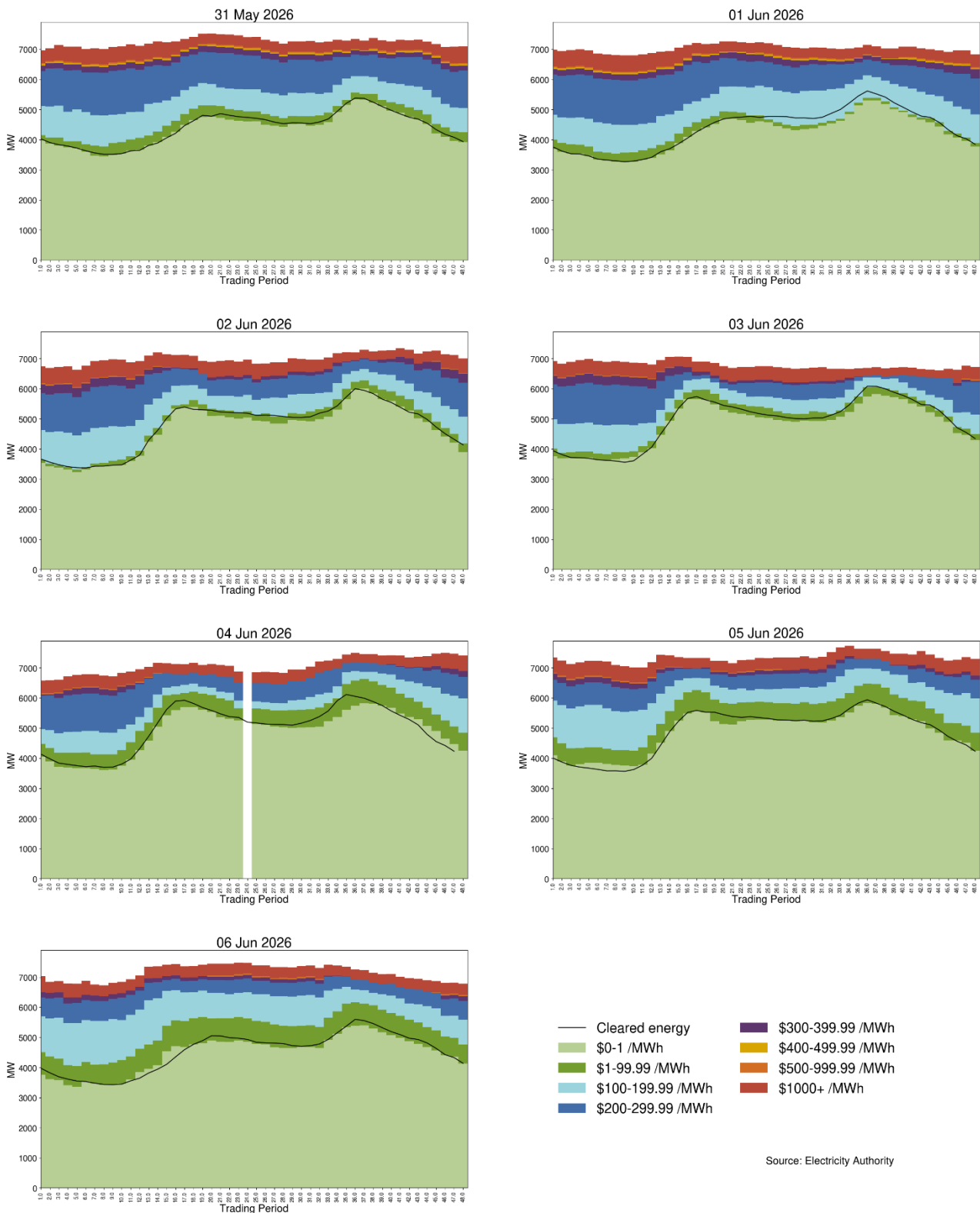
**Figure 22: Estimated monthly SRMC for thermal fuels**



## 12. Offer behaviour

- 12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.
- 12.2. On Monday afternoon and Tuesday morning, Mercury hydro priced up offers from \$1-99/MWh to \$100-199/MWh.
- 12.3. From Thursday, Meridian hydro priced down offers from its Ōhau chain from \$100-199/MWh to \$1-99/MWh.
- 12.4. From Thursday afternoon, Mercury hydro priced down offers from \$200-299/MWh to \$100-199/MWh.

**Figure 23: Daily offer stacks**



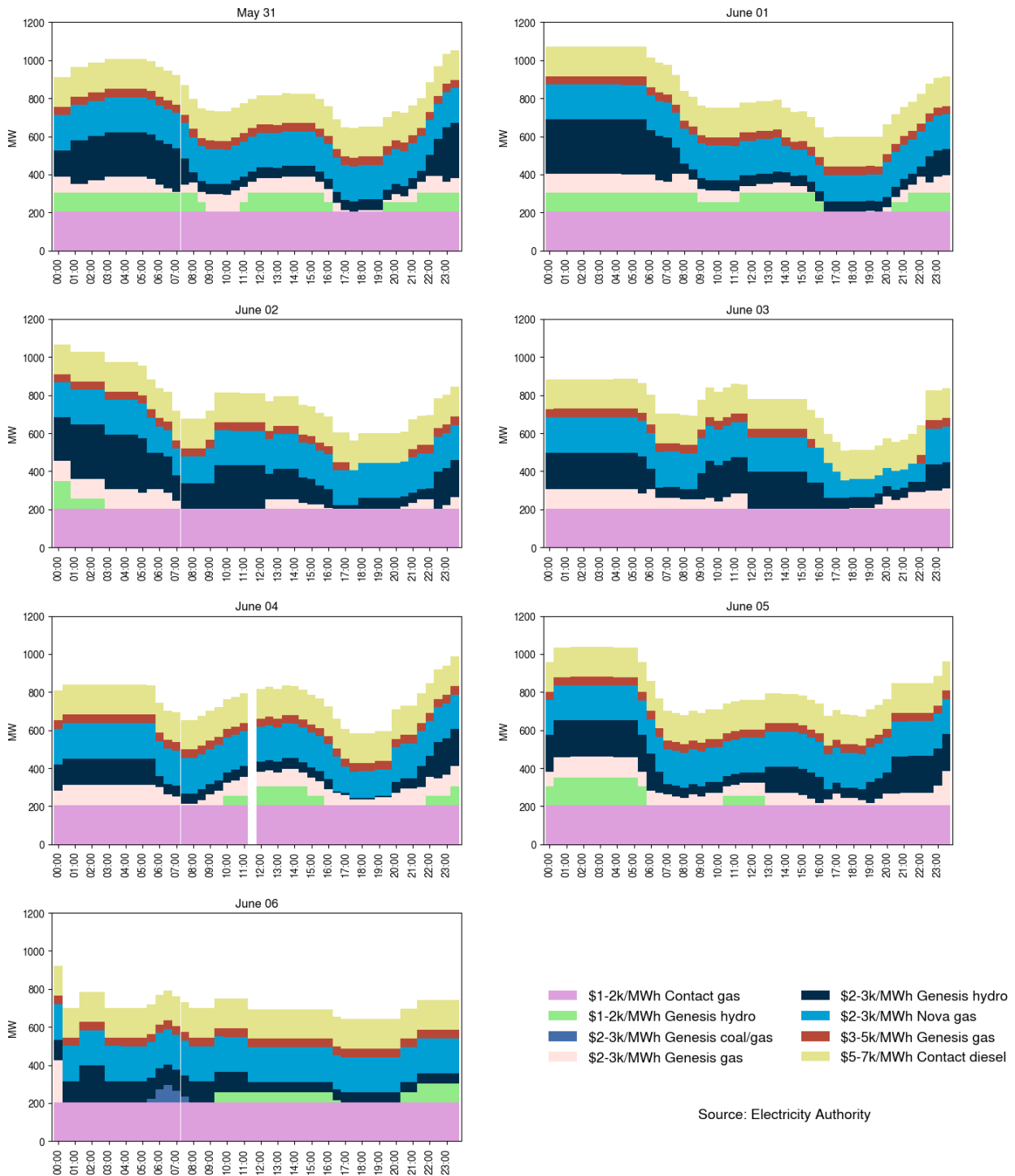
12.5. Figure 24 shows offers above \$1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.6. 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, intermittent generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.7. On average 789MW per trading period was priced above \$1,000/MWh this week, which is roughly 13.8% of the total energy available.

Figure 24: High priced offers



## 13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions. The monitoring team is looking into Papareireiā solar farm generation this week.

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
8/12/2025-11/12/2025	Several	Further analysis	Contact/Manawa	Coleridge, Cobb, and Matahina	Offers
22/04/2026-24/04/2026	Several	Further analysis	Genesis	Tokaanu	Offers
26/04/2026-02/05/2026	Several	Further analysis	Contact	Roxburgh	Offers
r02/05/2026	Several	Further analysis	Genesis	Tokaanu	Offers
07/05/2026-08/05/2026	Several	Further analysis	Genesis	Tekapō	Offers
27/05/2026	Several	Further analysis	Genesis	Huntly 5	Offers
04/06/2026-05/06/2026	Several	Further analysis	Harbour Infrastructure	Papareireiā solar farm	Reason for no generation