9 June 2025

Trading conduct report 1-7 June 2025

Market monitoring weekly report

Trading conduct report

1. Overview

1.1. The average price decreased by $9/MWh this week to $127/MWh. National hydro storage slightly increased to 69% nominally full and ~96% of the historical average. Demand was higher compared to the previous week due to colder temperatures. Wind generation was low on Friday and Saturday, and demand was high, which elevated prices.

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 1-7 June 2025:

(a) the average wholesale spot price across all nodes was $127/MWh.

(b) 95% of prices fell between $3/MWh and $254/MWh.

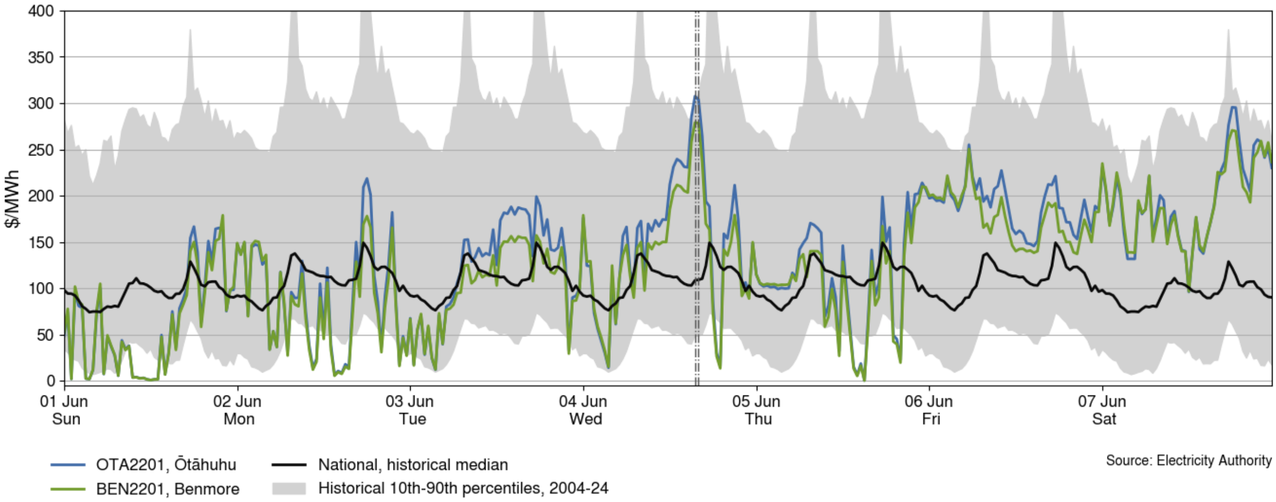
2.3. Overall, the majority of spot prices were within $78-$175/MWh, meaning the weekly average price decreased by around $9/MWh compared to the previous week.

2.4. The highest price of the week occurred on Wednesday at 3:30pm, with prices of $308/MWh at Ōtāhuhu and $279/MWh at Benmore. During this time, demand forecast was underestimated by 88MW and wind was 164MW lower than forecast.

2.5. On Friday and Saturday, prices were relatively high due to high demand and low wind generation.

2.6. 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 are marked with black dashed lines.

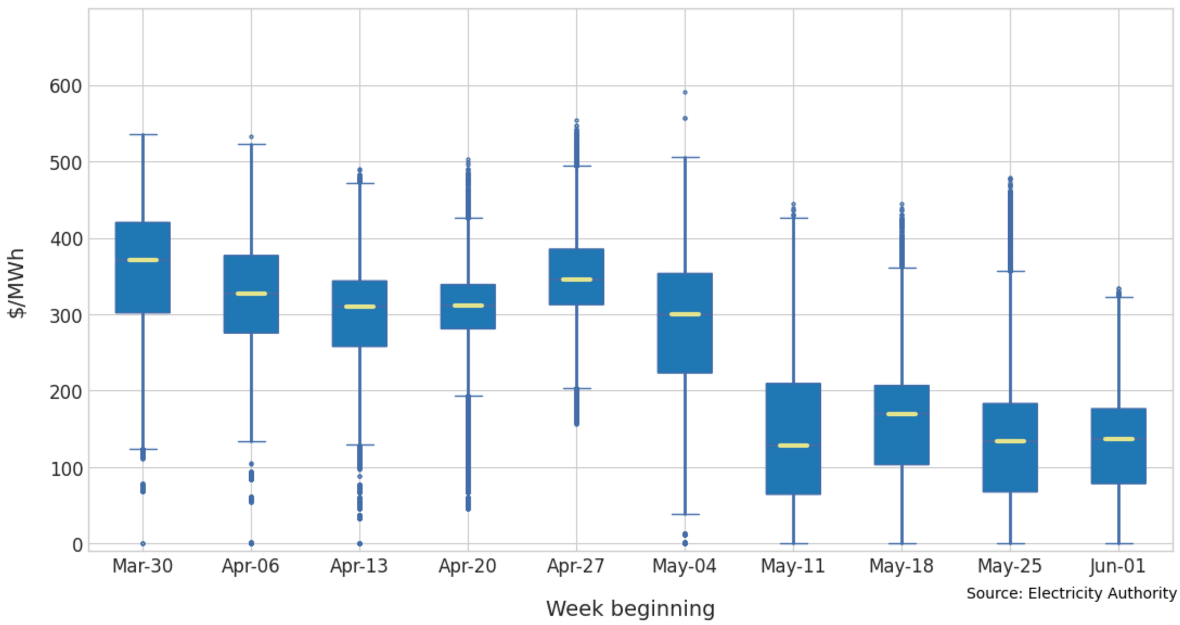
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 1-7 June 2025



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 median spot prices this week was similar compared to last week and most prices (middle 50%) fell between $78/MWh and $176/MWh. The distribution shows fewer outliers (high prices) this week.

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

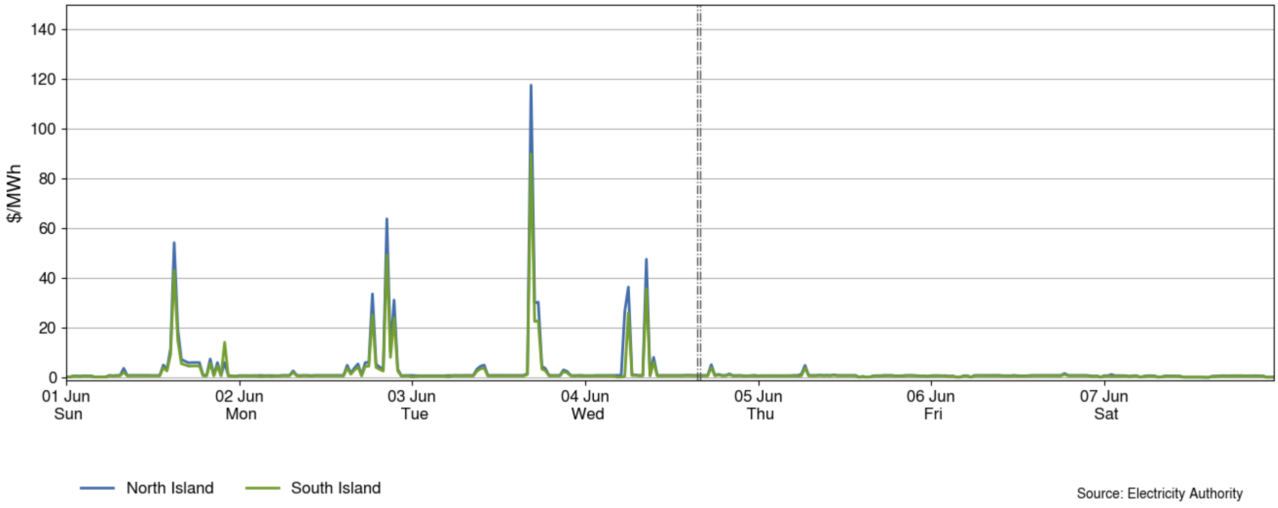


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh with a few spikes between Sunday and Wednesday. The highest FIR prices spiked at 4:30pm on Tuesday to $118/MWh in the

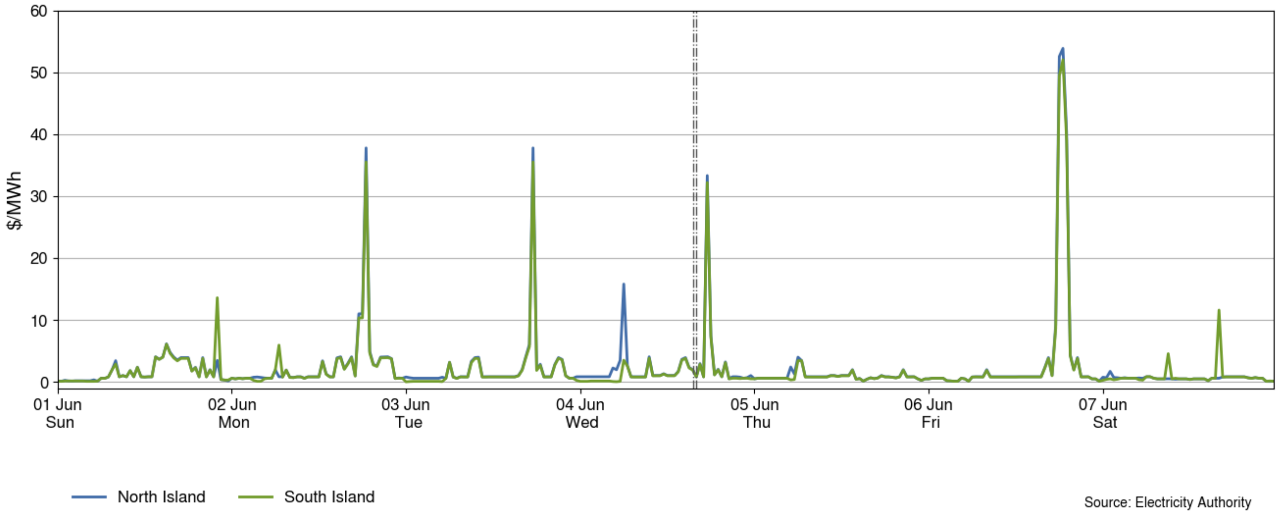
North Island and $90/MWh in the South Island generally during peak demand periods, and or when the amount of reserve required increased due to frequency keeping.

Figure 3: Fast instantaneous reserve price by trading period and island, 1-7 June 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh with a few spikes. SIR prices spiked at 6:30pm on Friday to $54/MWh in the North Island and $52/MWh in the South Island. Spikes in SIR generally occurred during evening peak times when the total quantity of reserve available 'reduces' due to more capacity being dispatched for energy.

Figure 4: Sustained instantaneous reserve by trading period and island, 1-7 June 2025



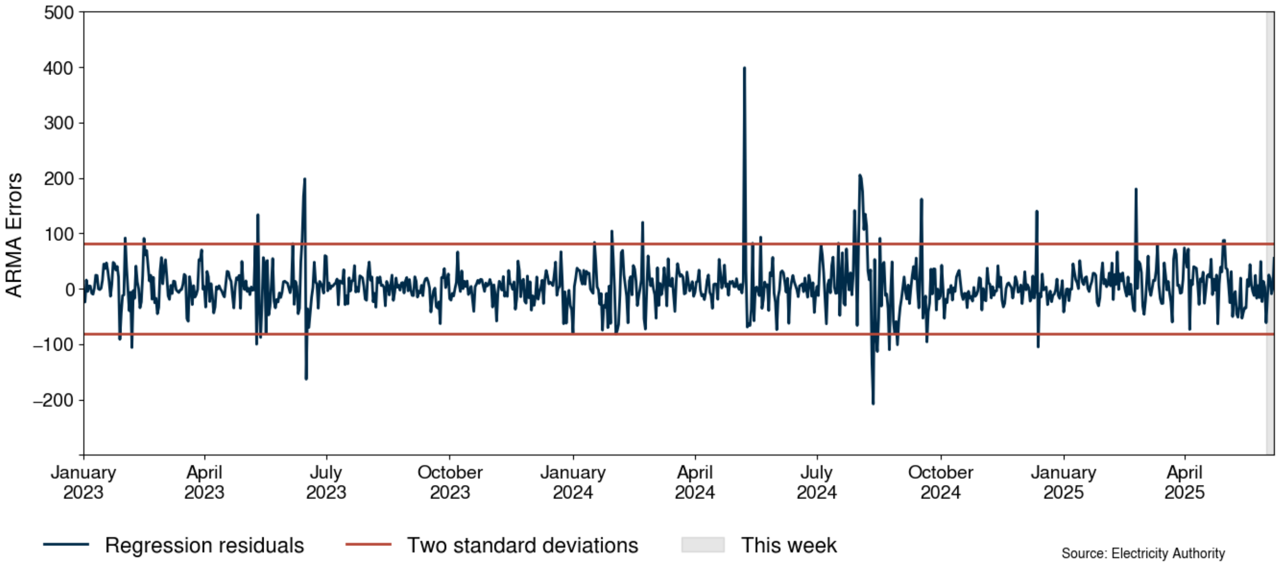
4. Regression residuals

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.

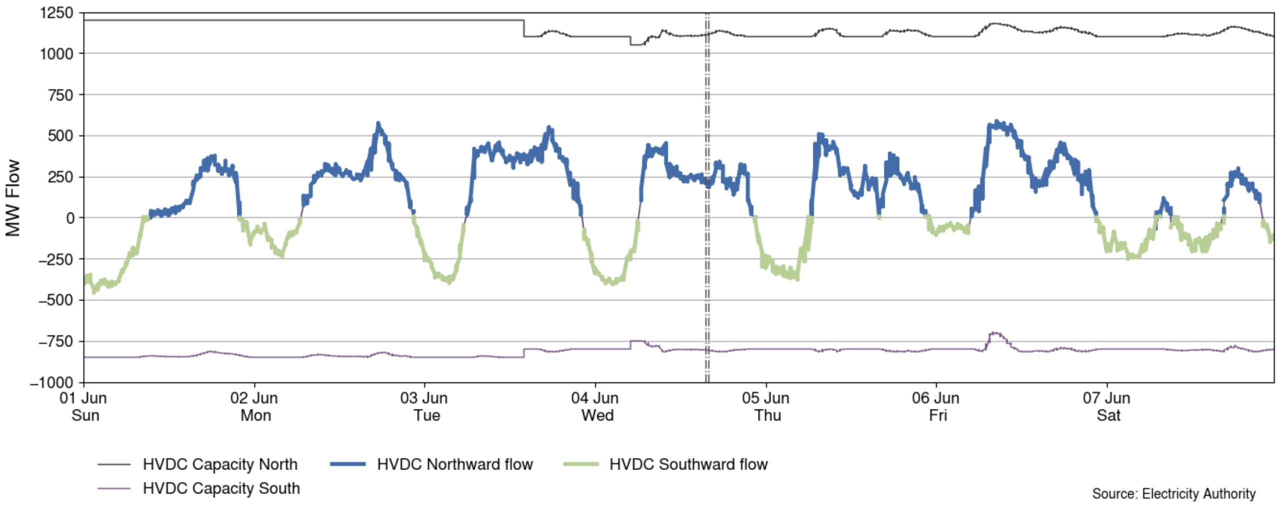
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 7 June 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 1-7 June 2025. HVDC flows were mostly northward during the day and southward overnight. Northward flows reached over 580MW on Friday when wind generation was low.

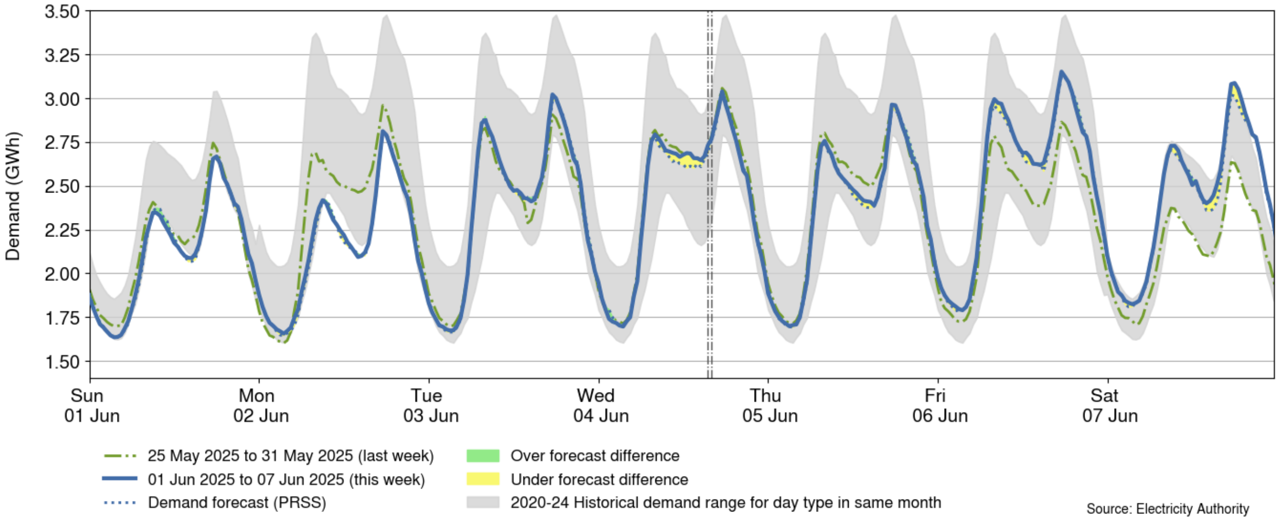
Figure 6: HVDC flow and capacity, 1-7 June 2025



6. Demand

6.1. Figure 7 shows national demand between 1-7 June 2025, compared to the historic range and the demand of the previous week. Demand was higher compared to the previous week due to colder temperatures. The highest demand of the week was 3.15GWh at 5:30pm on Friday.

Figure 7: National demand, 1-7 June 2025 compared to the previous week

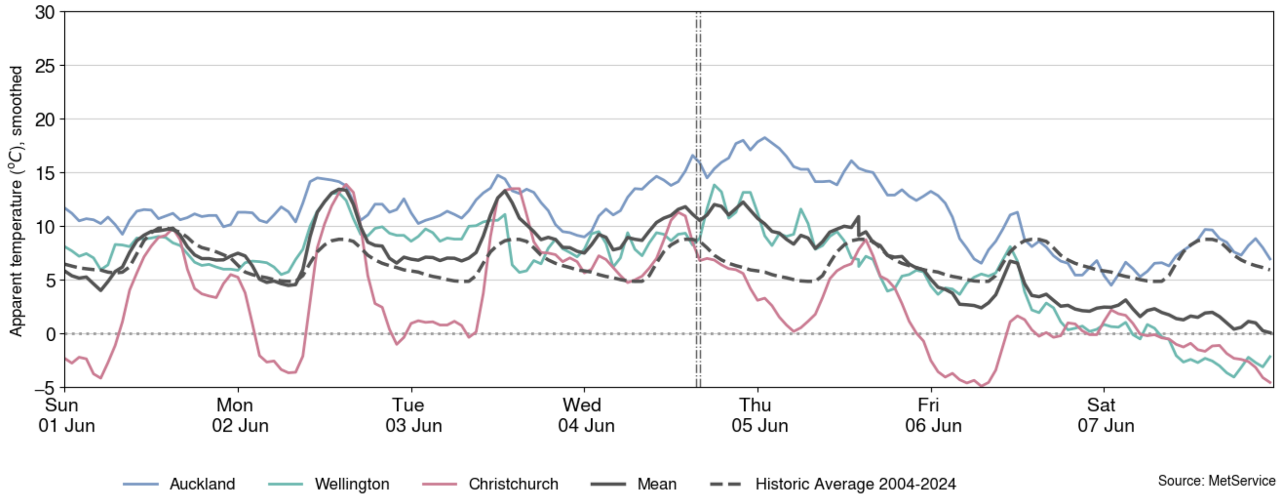


6.2. Figure 8 shows the hourly apparent temperature at main population centres from 1-7 June 2025. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures declined through the week, with Wellington experiencing an apparent temperature of 0°C on Friday night. Christchurch experienced below freezing temperatures on most mornings.

6.4. Apparent temperatures ranged from 5°C to 19°C in Auckland, 0°C to 15°C in Wellington, and -5°C to 14°C in Christchurch.

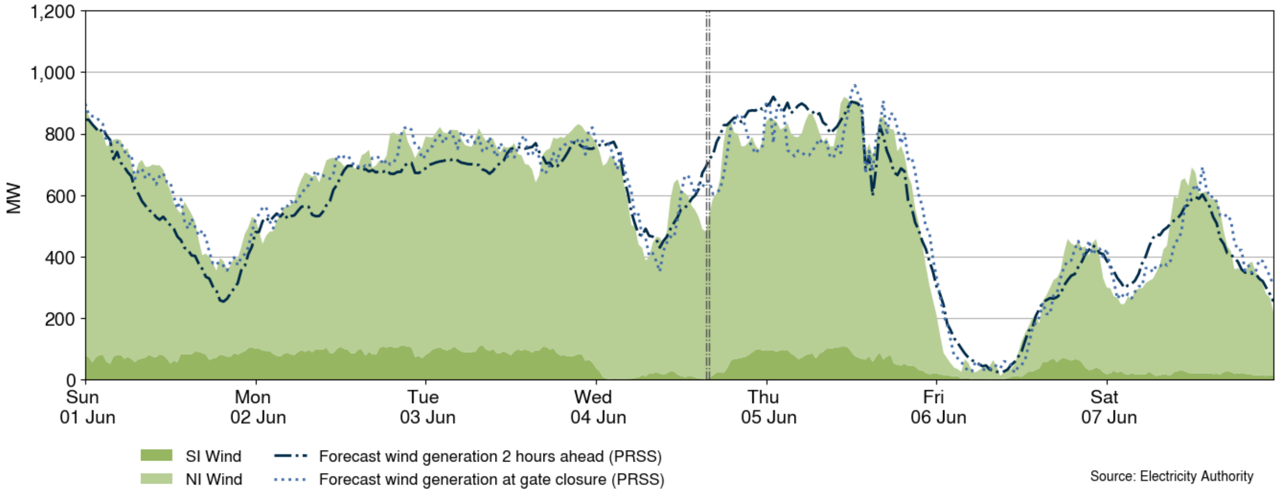
Figure 8: Temperatures across main centres, 1-7 June 2025



7. Generation

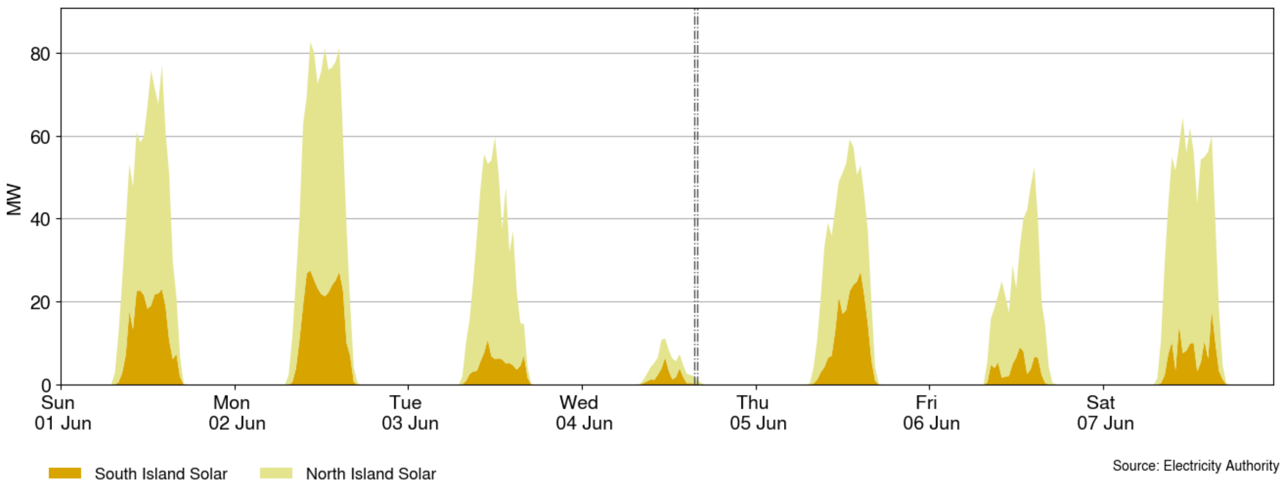
7.1. Figure 9 shows wind generation and forecast from 1-7 June 2025. This week wind generation varied between 12MW and 920MW, with a weekly average of 577MW. Wind generation was relatively high at the start of the week but significantly low on Friday. During the price spike on Wednesday, wind was 164MW lower than forecast.

Figure 9: Wind generation and forecast, 1-7 June 2025



7.2. Figure 10 shows solar generation from 1-7 June 2025. Solar generation was low on Wednesday. The rest of the week generation was mostly above 40MW.

Figure 10: Solar generation, 1-7 June 2025



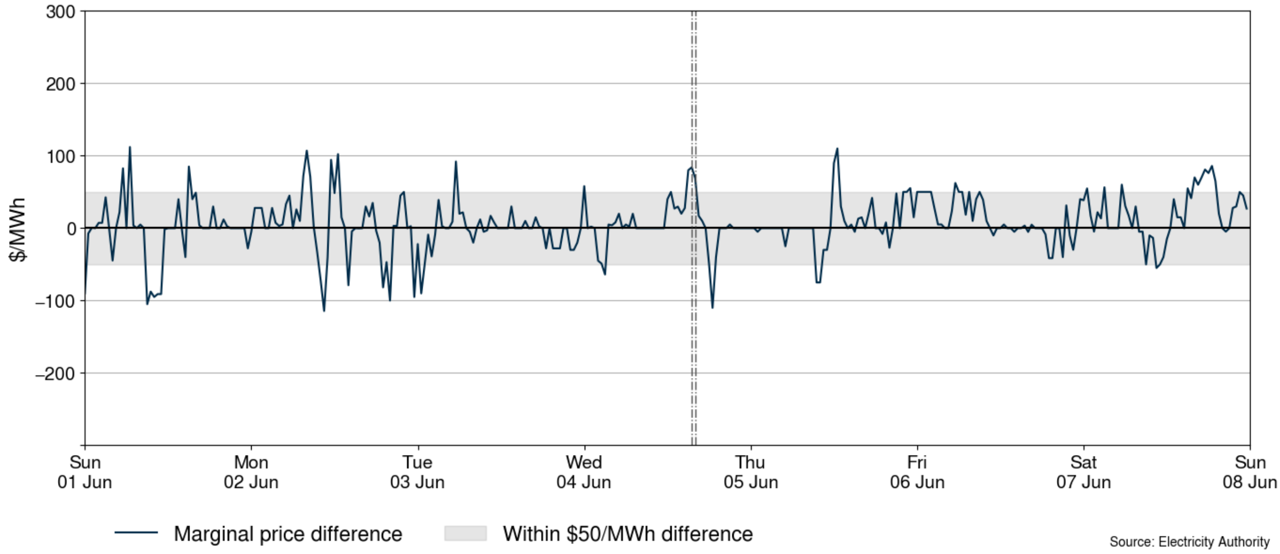
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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

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

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.

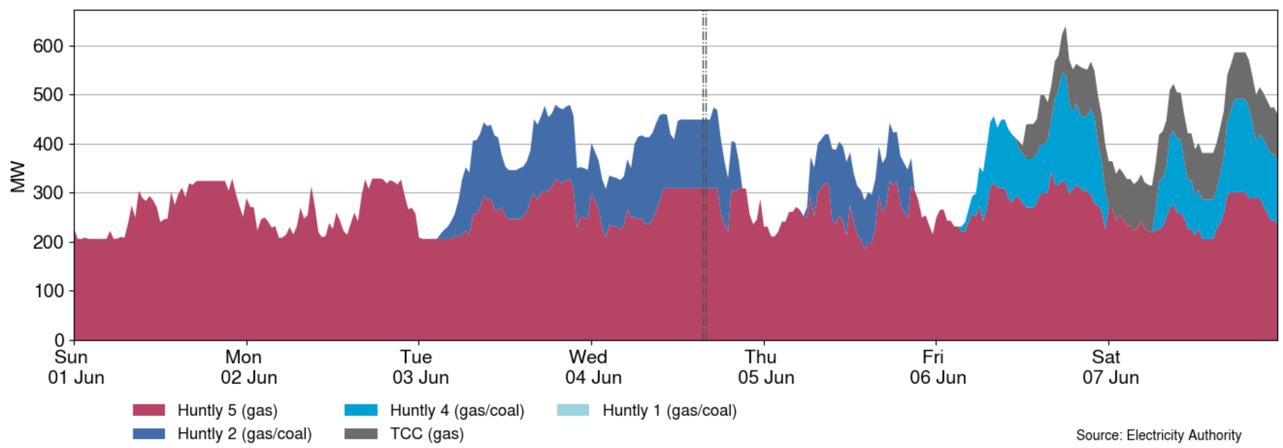
7.4. Several trading periods on Sunday and Monday had positive marginal price differences which were driven by the wind and demand forecasting errors. Another large positive price difference occurred on Thursday when demand was over 88MW higher than expected and wind was 164MW lower than expected.

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, 1-7 June 2025



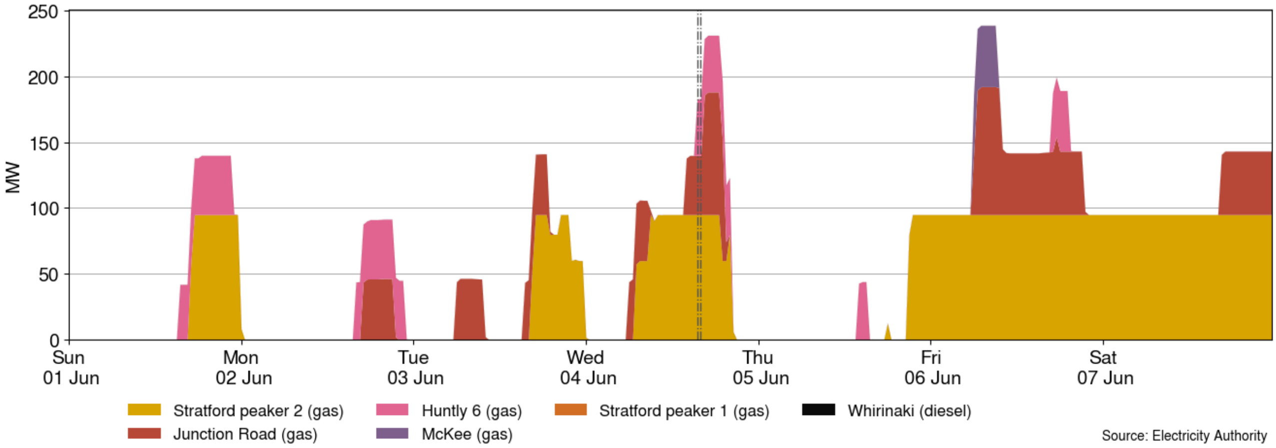
7.5. Figure 12 shows the generation of thermal baseload between 1-7 June 2025. Huntly 5 ran this week as a baseload. Huntly 4 ran from Tuesday to Wednesday, and on Thursday from the afternoon. Furthermore, Huntly 1 supported the baseload on Friday and Saturday due to low wind generation and high demand. TCC started on Friday with a reduced capacity of 95MW.

Figure 12: Thermal baseload generation, 1-7 June 2025



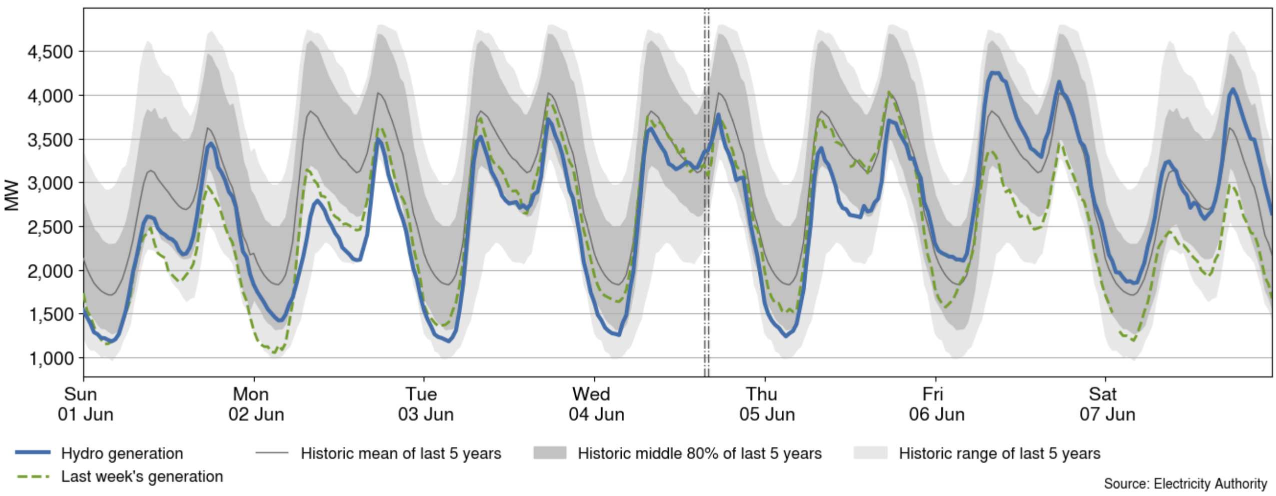
7.6. Figure 13 shows the generation of thermal peaker plants between 1-7 June 2025. Stratford peaker 2 ran on Sunday and Tuesday during the evening peak periods, on Wednesday during both morning and evening peaks, and continuously from Thursday night to Saturday. Junction Road and Huntly 6 also ran to cover some peak periods. McKee only ran on Friday during the morning peak.

Figure 13: Thermal peaker generation, 1-7 June 2025



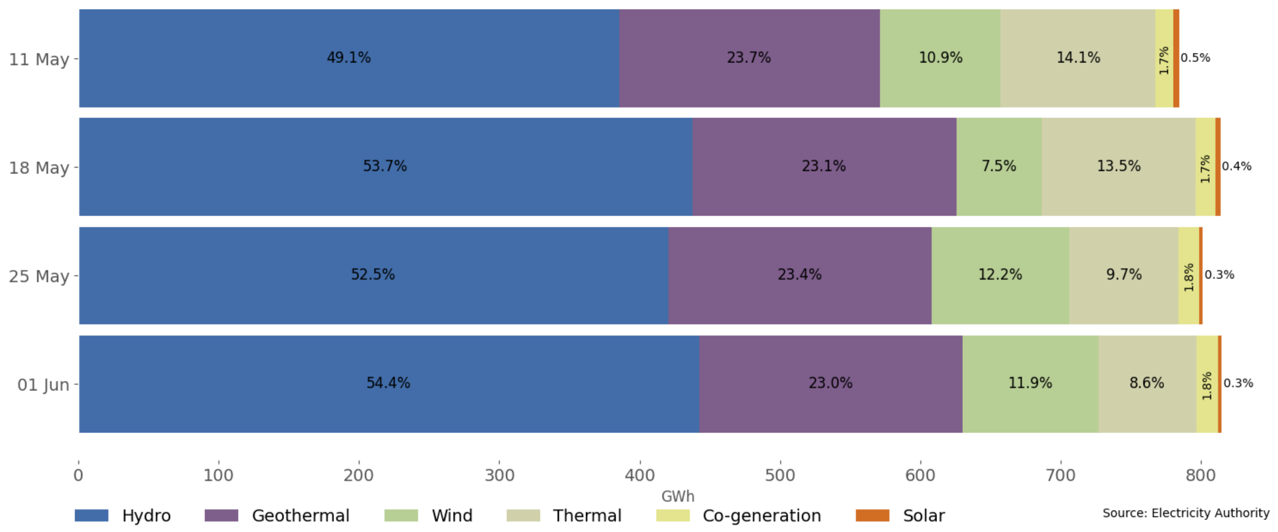
7.7. Figure 14 shows hydro generation between 1-7 June 2025. Hydro generation this week was higher compared to the previous week. On Thursday, hydro generation was lower due to high wind generation. However, on Friday and Saturday, due to high demand and low wind, hydro generation was significantly higher compared to the previous week.

Figure 14: Hydro generation, 1-7 June 2025



7.8. As a percentage of total generation, between 1-7 June 2025, total weekly hydro generation was 54.4%, geothermal 23%, wind 11.9%, thermal 8.6%, and co-generation 1.8%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, 11 May 2025 and 7 June 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 1-7 June 2025 ranged between ~677MW and ~1528MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC was on partial outage between 5-8 June.

(b) Huntly 1 outage was extended until 9 June.

(c) Stratford peaker 1 is on outage until 30 June.

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

(e) Ohaaki geothermal is on outage until 12 June 2025.

(f) Mokai geothermal was on outage between 3-4 June 2025.

(g) Nga Awa Purua was on outage on 4 June 2025.

Figure 16: Total MW loss from generation outages, 1-7 June 2025

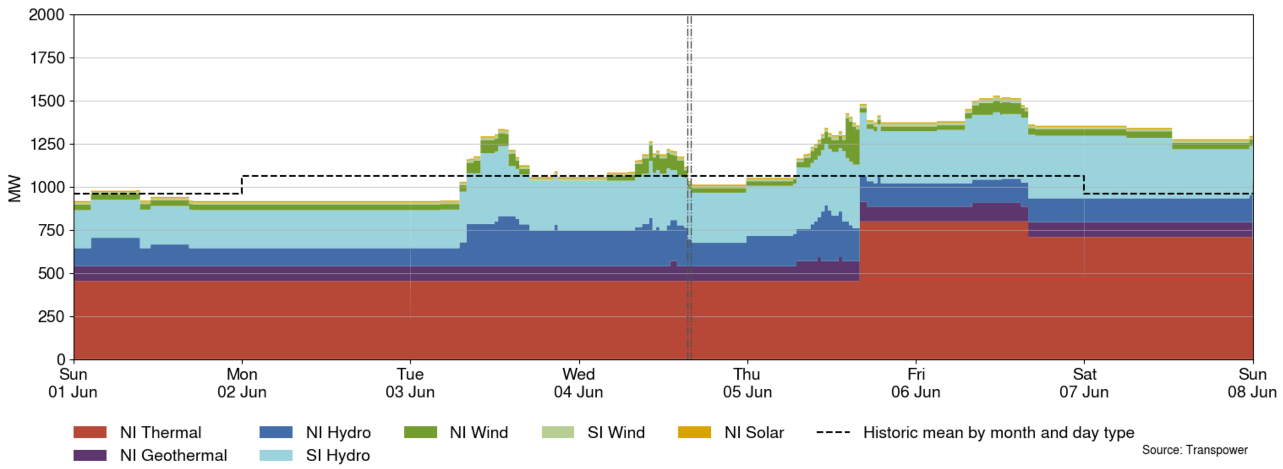
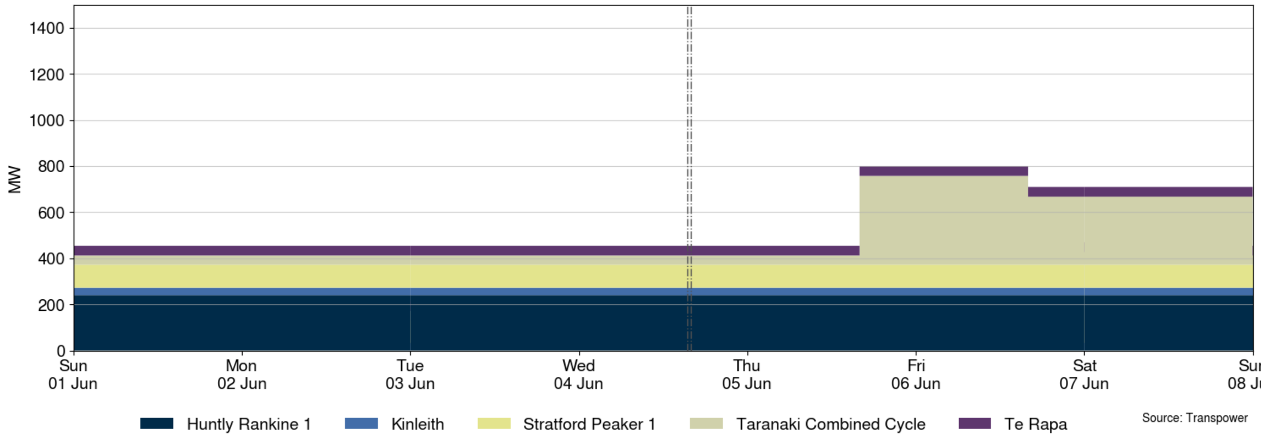


Figure 17: Total MW loss from thermal outages, 1-7 June 2025

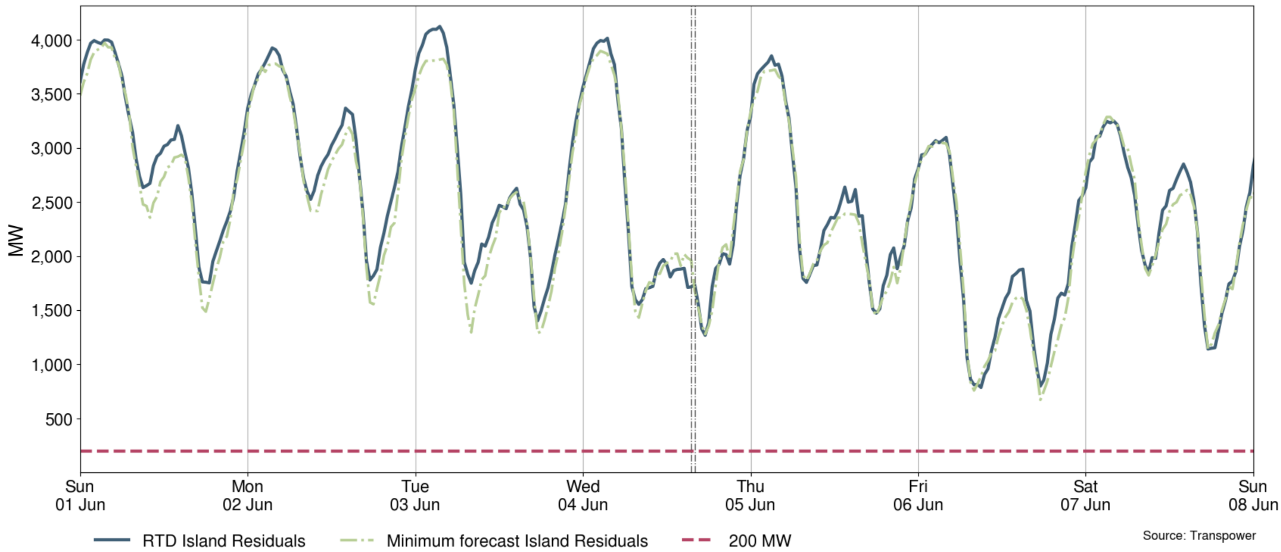


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 1-7 June 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 lowest national residual was 785MW on Friday at 7.30am.

Figure 18: National generation balance residuals, 1-7 June 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. As of 7 June 2025, national controlled storage was 69% nominally full and ~96% of the historical average for this time of the year.

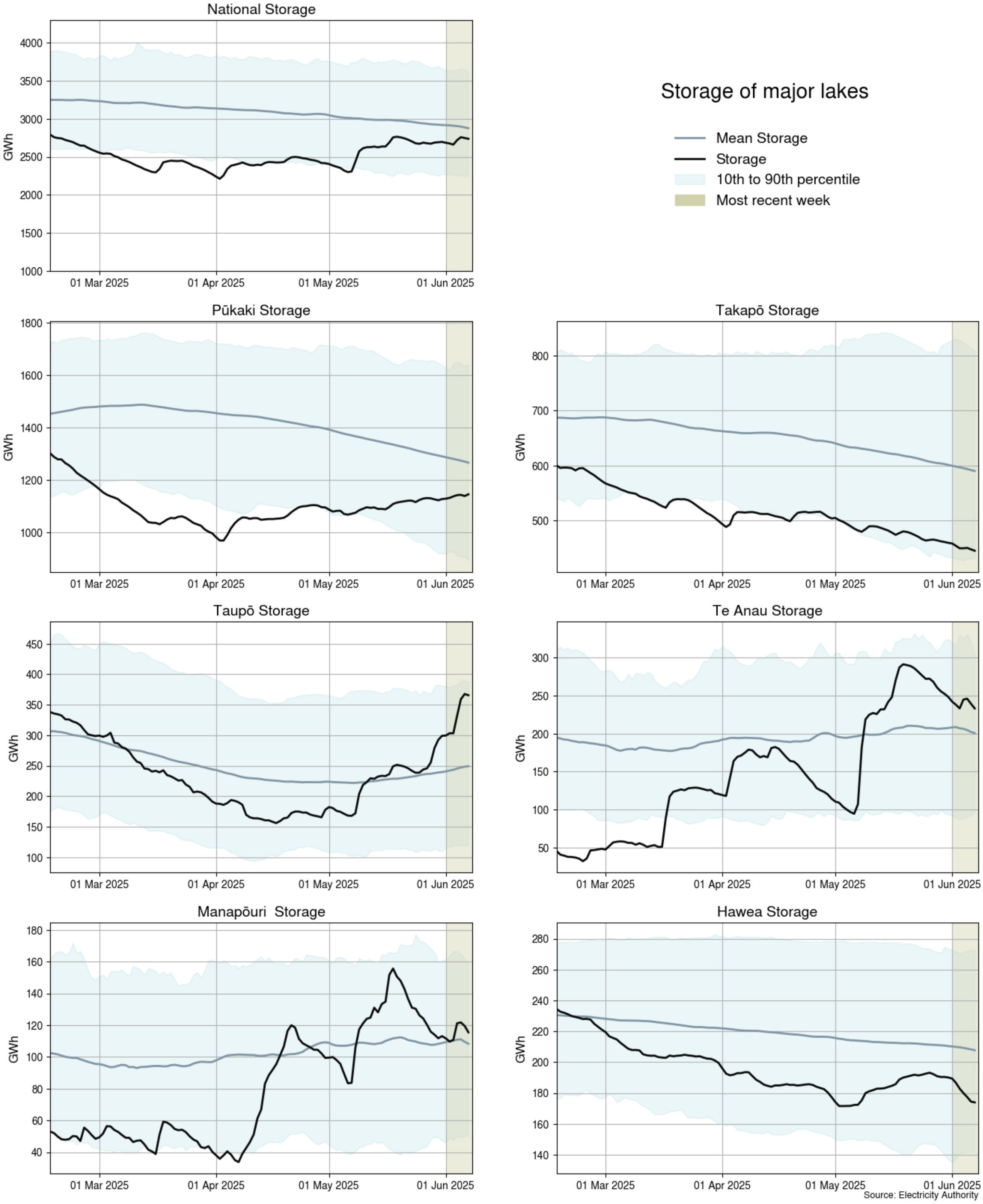
10.3. Storage at lakes Pūkaki (63% full) and Takapō (49% full) are above their historical 10th percentiles.

10.4. Lakes Te Anau and Manapōuri decreased during the week but are both still above their respective means.

10.5. Storage at Lake Taupō (63% full) is well above its historic mean.

10.6. Lake Hawea storage (60% full) decreased and is still between its historical 10th percentile and mean.

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 May 2025. The SRMCs for gas powered generation have increased slightly while coal and diesel fuelled generation decreased. As was the case last month, it is likely cheaper to run the Rankines on coal.

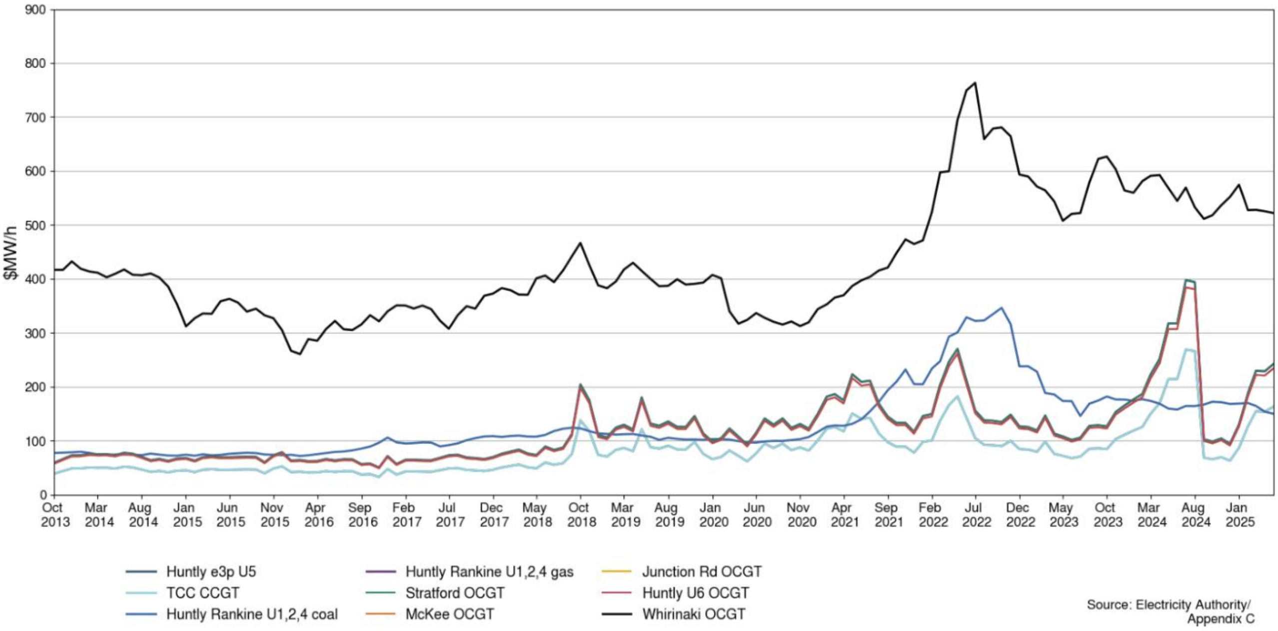
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$242/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $163/MWh and $242/MWh.

11.6. The SRMC of Whirinaki is ~$522/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

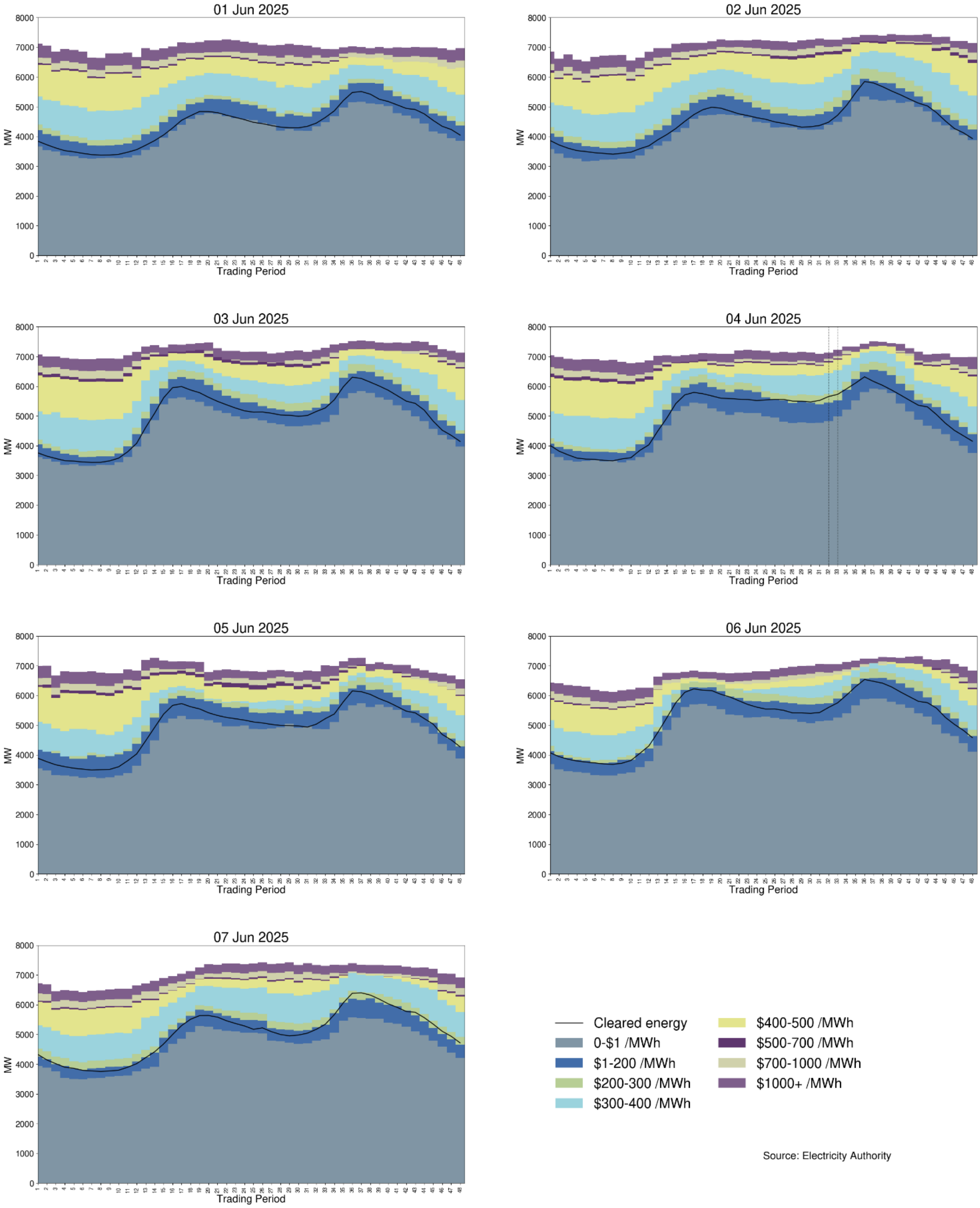


12. Offer behaviour

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.

12.2. This week most offers cleared in the $1-$200/MWh. The demand forecasting errors on Wednesday tipped the cleared energy into higher band. On Saturday, high demand and low wind resulted in cleared energy moving into the next band of $200-$300/MWh.

Figure 21: Daily offer stacks



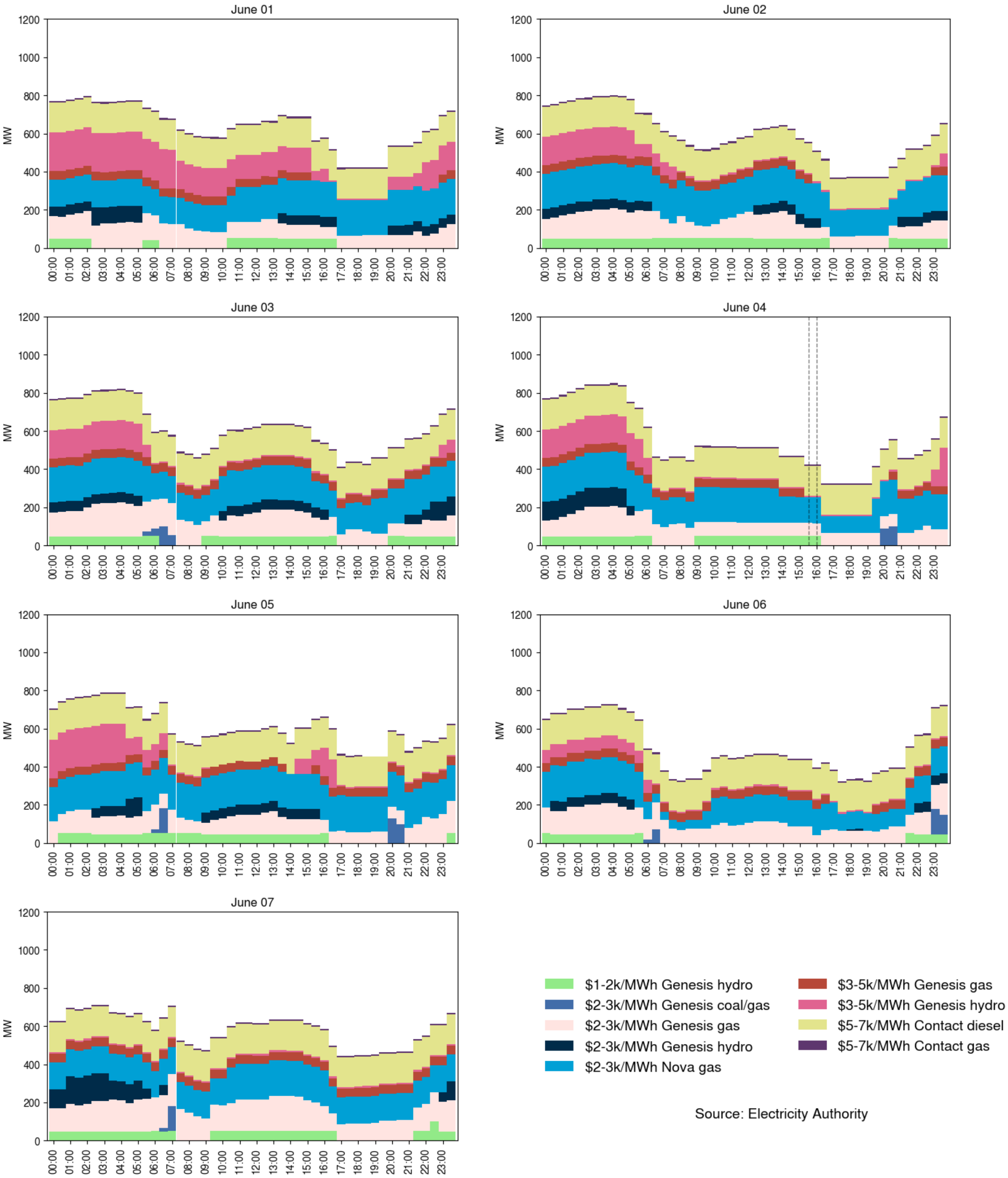
Source: Electricity Authority

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

12.4. 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 reflects 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.

12.5. On average 585MW per trading period was above $1,000/MWh this week, which is roughly 10% of the total energy available.

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.

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
15/05/2025	46-47	Further analysis	Genesis	Huntly	Rankine offers
23/05/2025	31	Further analysis	Contact	TCC	Offers