3 June 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

# Trading conduct report 25-31 May 2025

Market monitoring weekly report

# Trading conduct report 25-31 May 2025

## 1. Overview

1.1. The average price decreased by $24/MWh this week to $136/MWh. National hydro storage remained stable at 68% nominally full and ~93% of the historical average. Wind generation increased this week compared to the previous week. The HVDC was on outage on Tuesday, which resulted in the price spike and price separation between the North and South Islands.

## 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 25-31 May 2025:

(a) the average wholesale spot price across all nodes was $136/MWh

(b) 95% of prices fell between $0.04/MWh and $270/MWh.

2.3. Overall, the majority of spot prices were within $85-$189/MWh, meaning the weekly average price decreased by $24/MWh compared to the previous week.

2.4. Price spikes on Tuesday between 10:00am and 11:00am were due to the planned HVDC outage[1]. The outage started at 9:30am and ended at 2:30pm. During this time price separation occurred, with Ōtāhuhu reaching a peak price of $456/MWh at 10:00am. Wind was also low at this time.

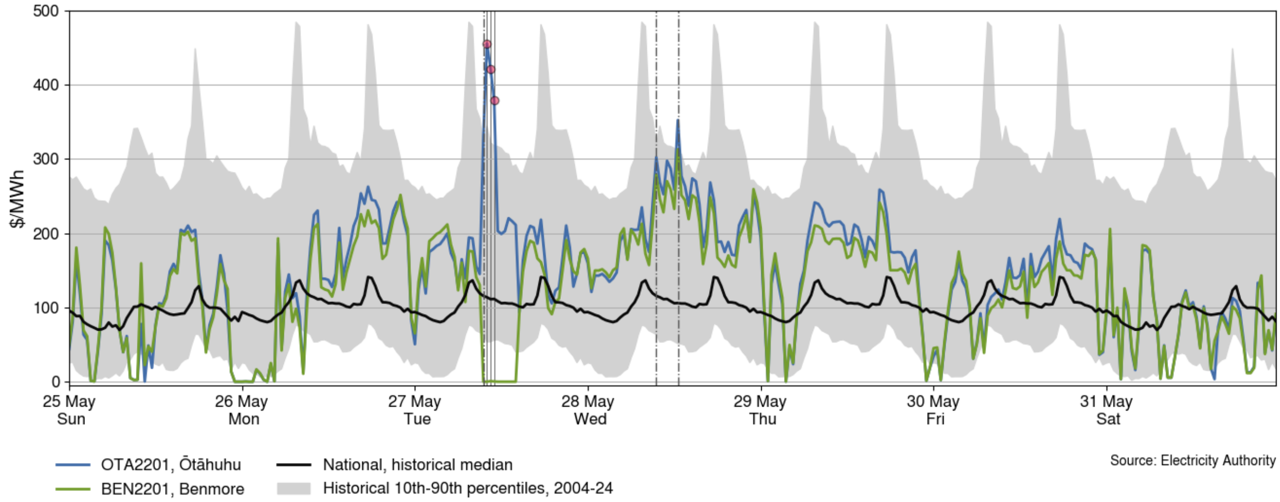
2.5. Other high prices occurred on Wednesday at 9:00am with prices of $302/MWh at Ōtāhuhu and $279/MWh at Benmore, and at 12:30pm the Ōtāhuhu price was $352/MWh and the Benmore price was $313/MWh. During these times, demand forecast was underestimated by 174MW and 259MW, respectively.

2.6. High wind on Sunday and Saturday depressed prices in both islands.

2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90$^{th}$ percentiles adjusted for inflation. Prices greater than quartile 3 (75$^{th}$ 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.

[1] Customer Advice Notices (CAN) | Transpower

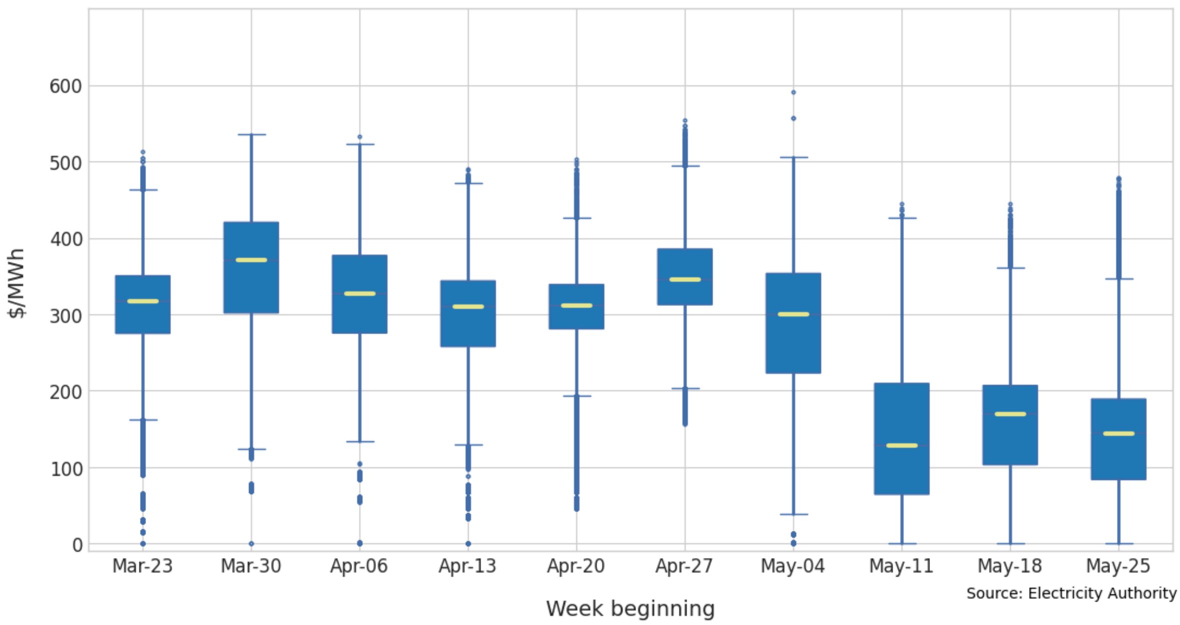
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 25-31 May 2025**




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 median spot prices this week decreased slightly compared to last week and most prices (middle 50%) fell between $84/MWh and $190/MWh.

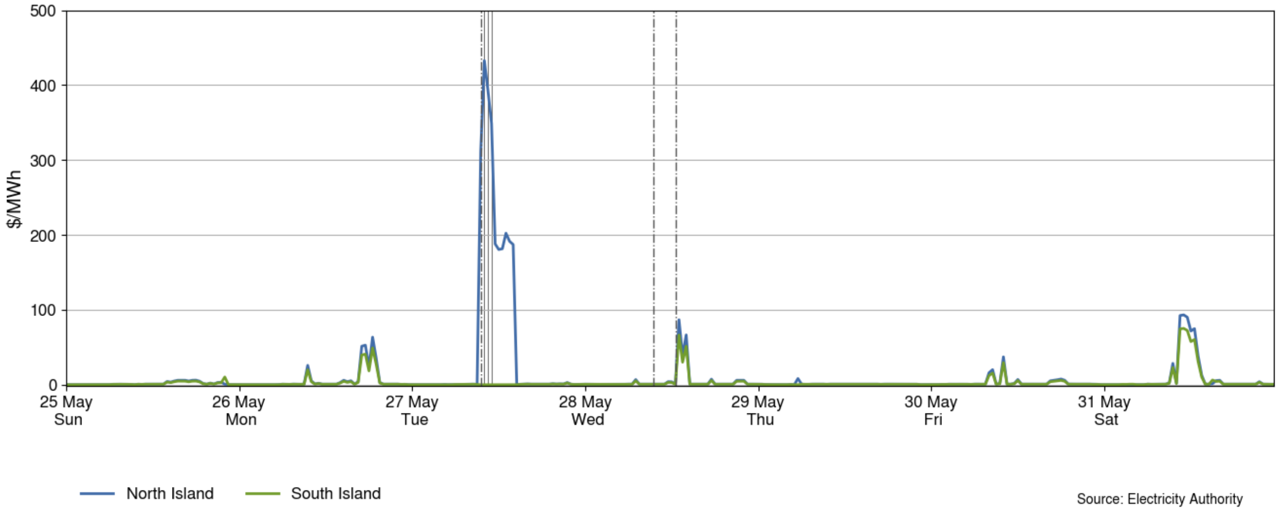
**Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks**



# 3. Reserve prices

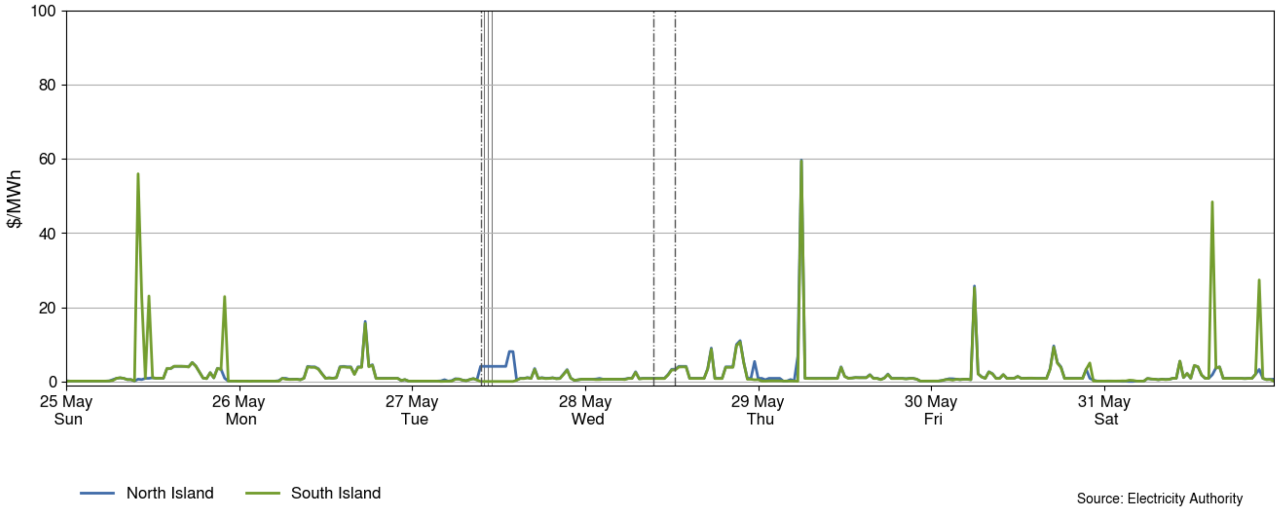
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. The highest FIR prices for the North Island were $432/MWh on Tuesday at 10:00am during the HVDC outage.

**Figure 3: Fast instantaneous reserve price by trading period and island, 25-31 May 2025**




3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. South Island SIR prices were high when the HVDC was switching directions.

**Figure 4: Sustained instantaneous reserve by trading period and island, 25-31 May 2025**



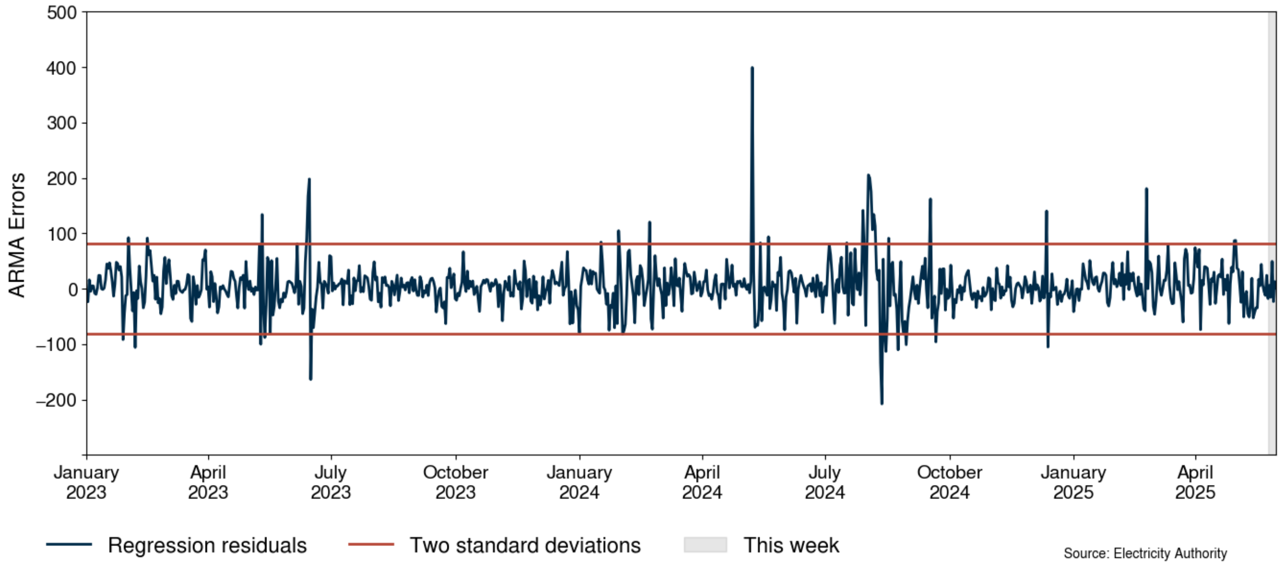

# 4. Regression residuals

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.

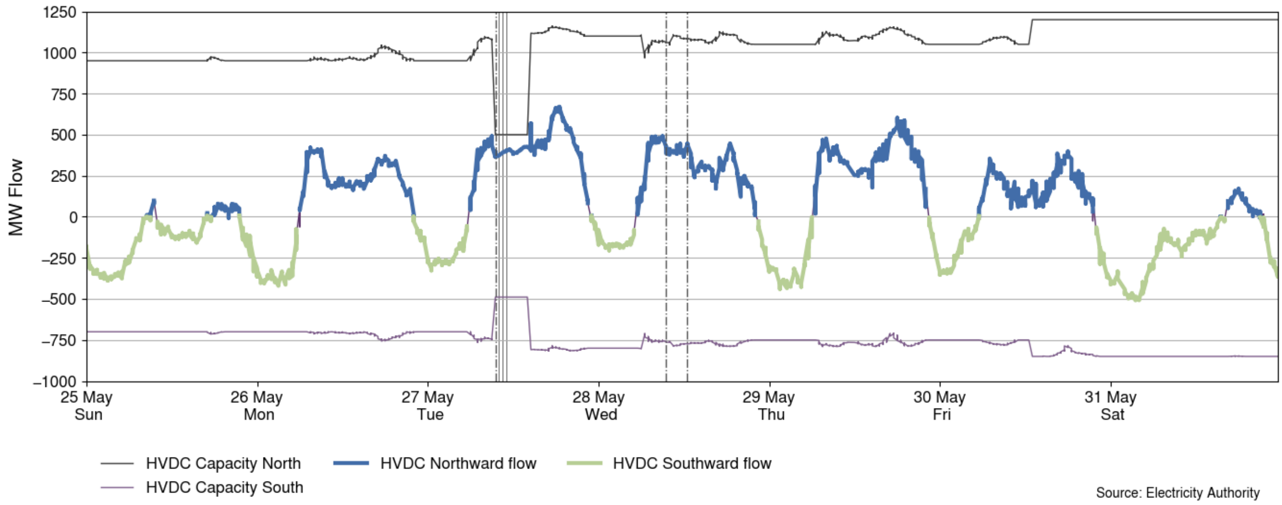
**Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 31 May 2025**




## 5. HVDC

5.1. Figure 6 shows the HVDC flow between 25-31 May 2025. HVDC flows were mostly northward during the day and southward overnight. On Sunday, the flow was southwards except at 9:30am when 87MW were flowing northwards. HVDC Pole 3 was on outage on Tuesday from 9:30am to 2:30pm, which reduced the capacity. Northward flows reached over 750MW on Tuesday when wind generation was low.

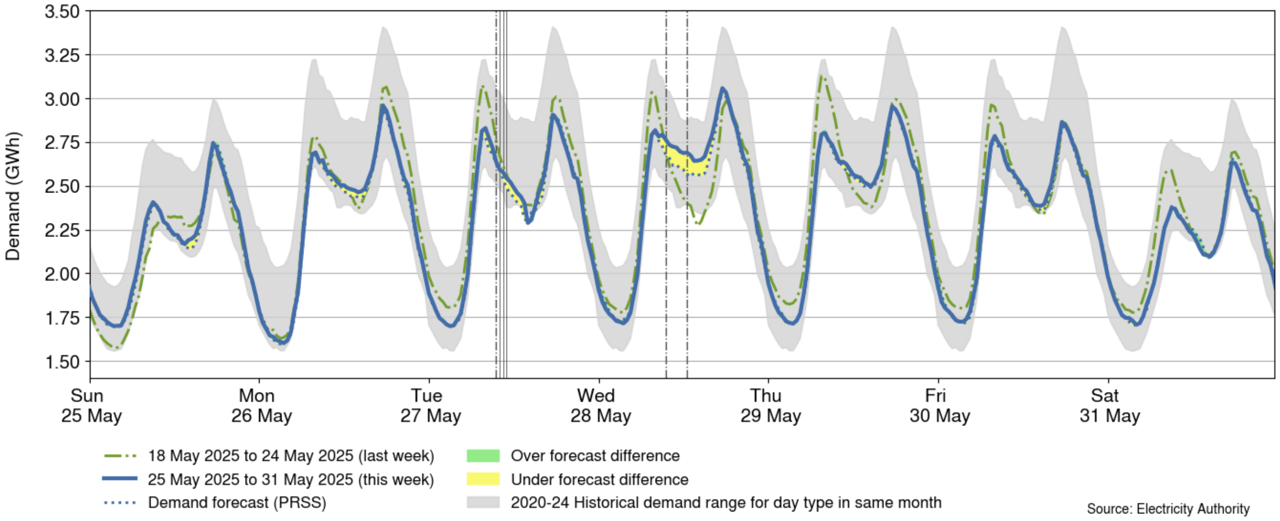
**Figure 6: HVDC flow and capacity, 25-31 May 2025**



# 6. Demand

6.1. Figure 7 shows national demand between 25-31 May 2025, compared to the historic range and the demand of the previous week. Demand was lower compared to the previous week due to mild temperatures. Demand was significantly higher than forecast on Wednesday.

**Figure 7: National demand, 25-31 May 2025 compared to the previous week**

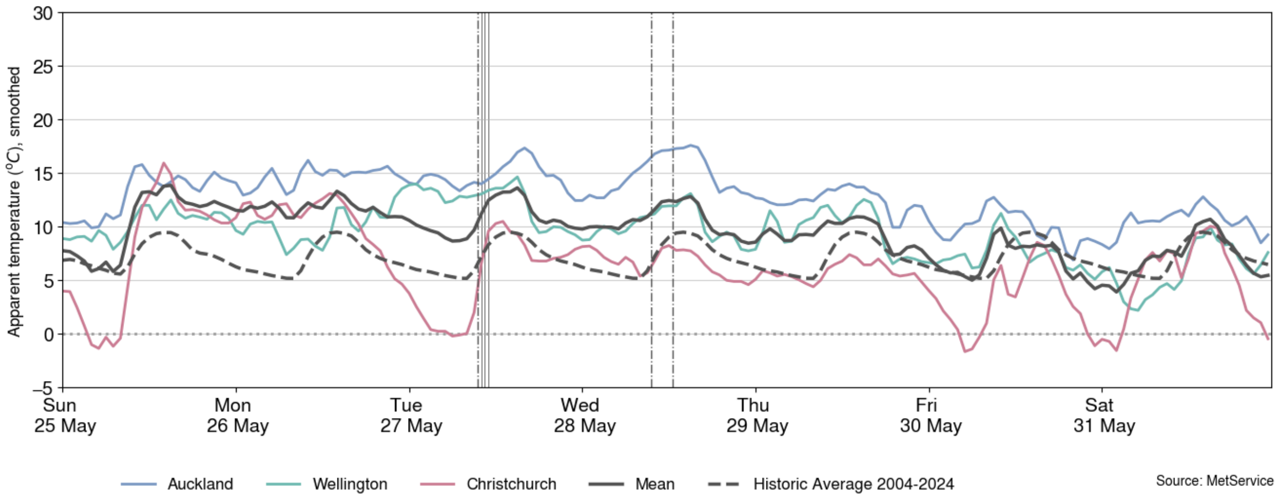



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 25-31 May 2025. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature 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. Mean temperature was above average at the start of the week and hovered around the mean at the end of the week. However, Christchurch experienced some cold mornings.

6.4. Apparent temperatures ranged from 6°C to 18°C in Auckland, 2°C to 15°C in Wellington, and -3°C to 17°C in Christchurch.

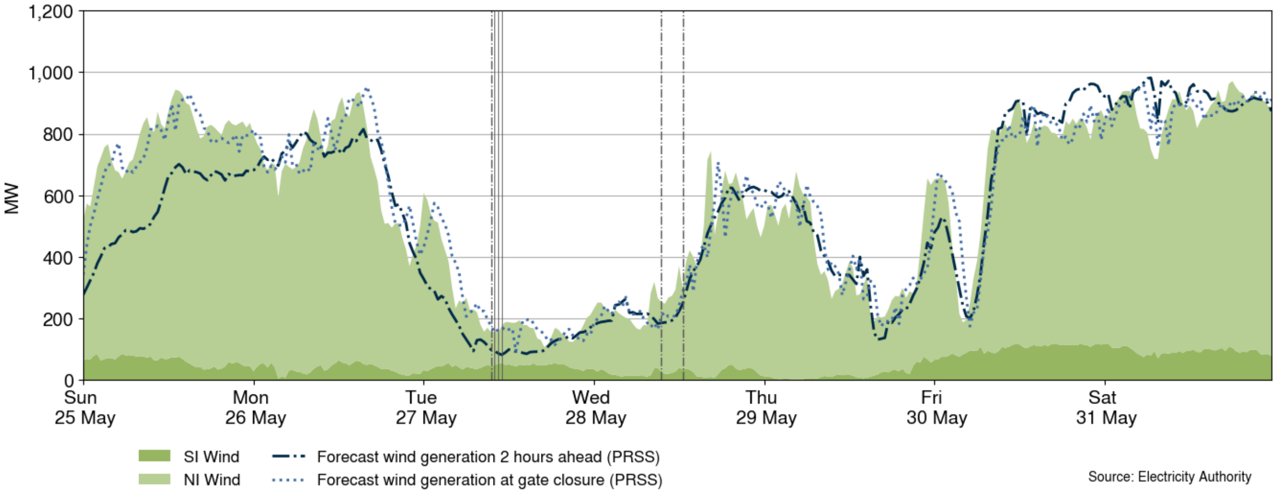
**Figure 8: Temperatures across main centres, 25-31 May 2025**



## 7. Generation

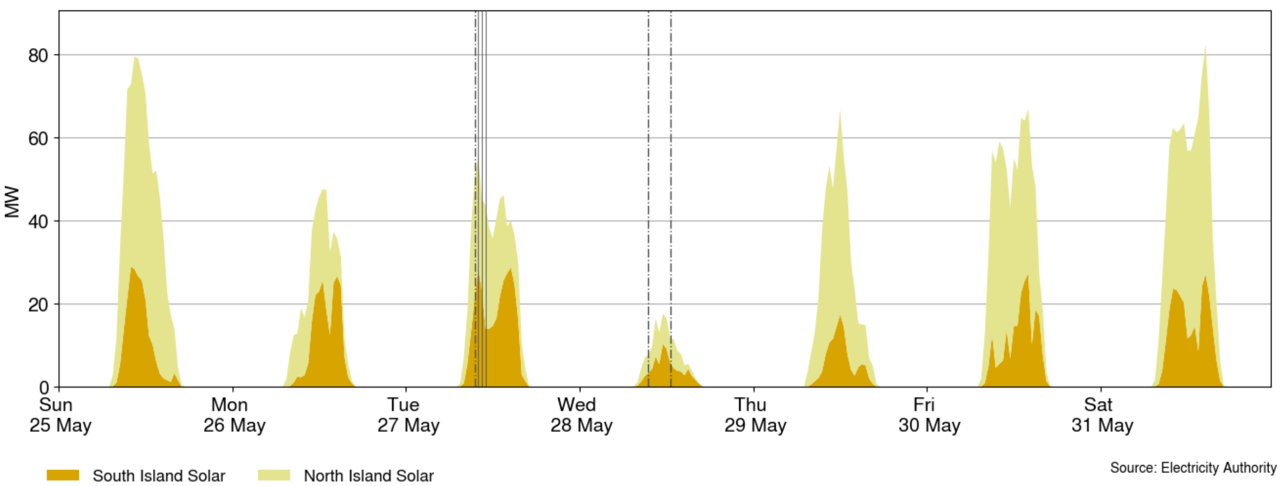
7.1. Figure 9 shows wind generation and forecast from 25-31 May 2025. This week wind generation varied between 107MW and 971MW, with a weekly average of 583MW. Wind generation was high at the start of the week but gradually decreased on Tuesday. On Wednesday wind started to increase but dropped on Thursday night. Wind generation was high on Friday afternoon and Saturday.

**Figure 9: Wind generation and forecast, 25-31 May 2025**




7.2. Figure 10 shows solar generation from 25-31 May 2025. Solar generation was low on Wednesday. The rest of the week generation was mostly above 40MW.

**Figure 10: Solar generation, 25-31 May 2025**



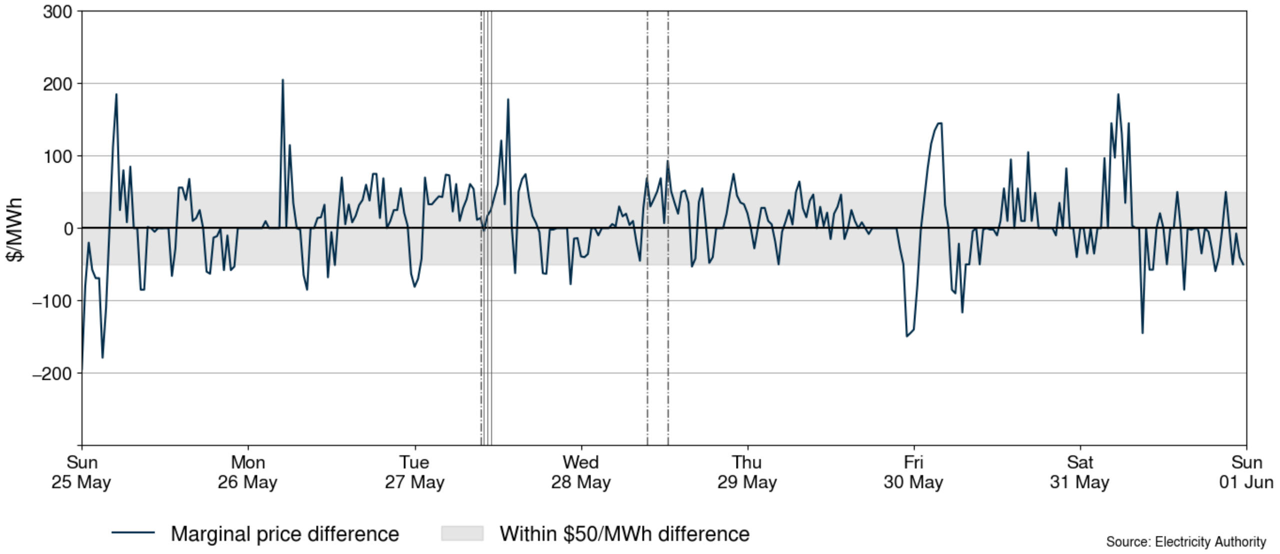

7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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

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

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.

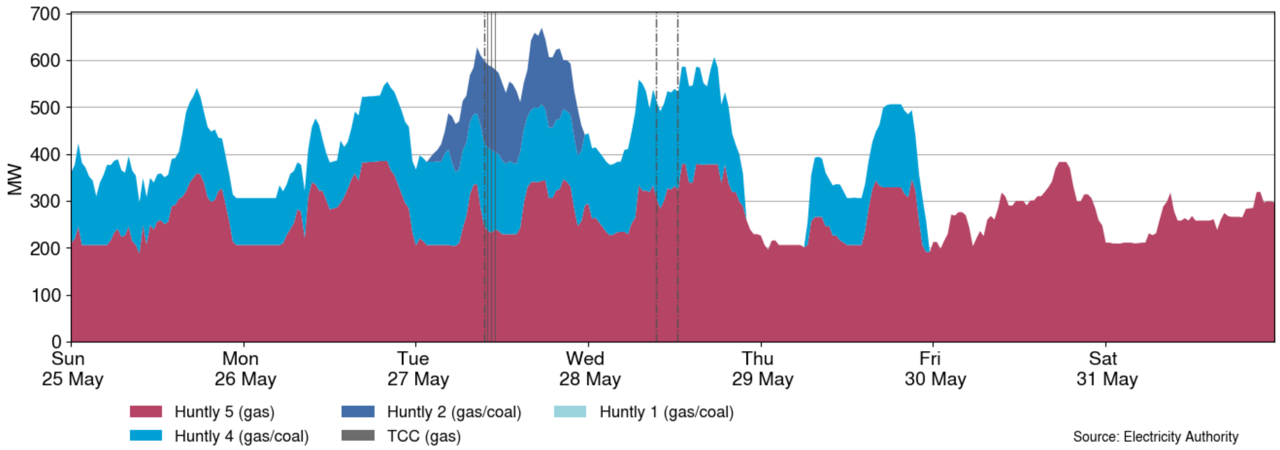
7.4. Several trading periods on Sunday had positive marginal price differences which were driven by the wind and demand forecasting errors. Another large positive price difference occurred on Monday, when the difference was $205/MWh. Similarly, there were a few trading periods on Friday and Saturday mornings when the differences were high due to errors when wind generation dropped off.

**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, 25-31 May 2025**



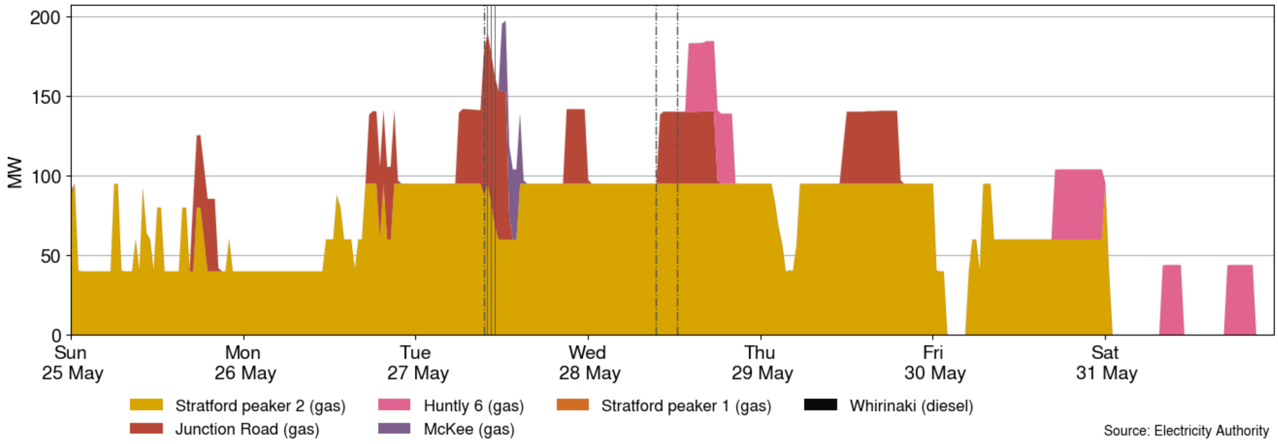

7.5. Figure 12 shows the generation of thermal baseload between 25-31 May 2025. Huntly 5 ran this week as a baseload. Huntly 4 ran from Sunday to Wednesday, and on Thursday from the afternoon. Furthermore, Huntly 2 supported the baseload on Tuesday.

**Figure 12: Thermal baseload generation, 25-31 May 2025**



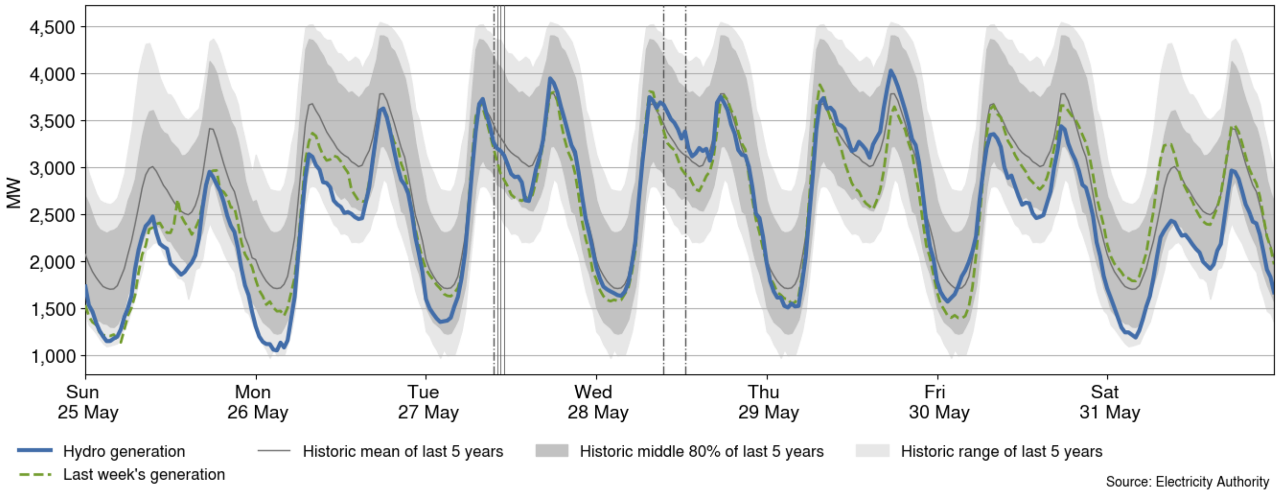

7.6. Figure 13 shows the generation of thermal peaker plants between 25-31 May 2025. Stratford peaker 2 ran from Sunday to Friday (turned off on Friday night). Junction Road ran this week, mostly to cover peak periods. Huntly 6 ran during Wednesday and Friday evening peak periods and on Saturday. McKee only ran on Tuesday during the HVDC outage.

**Figure 13: Thermal peaker generation, 25-31 May 2025**



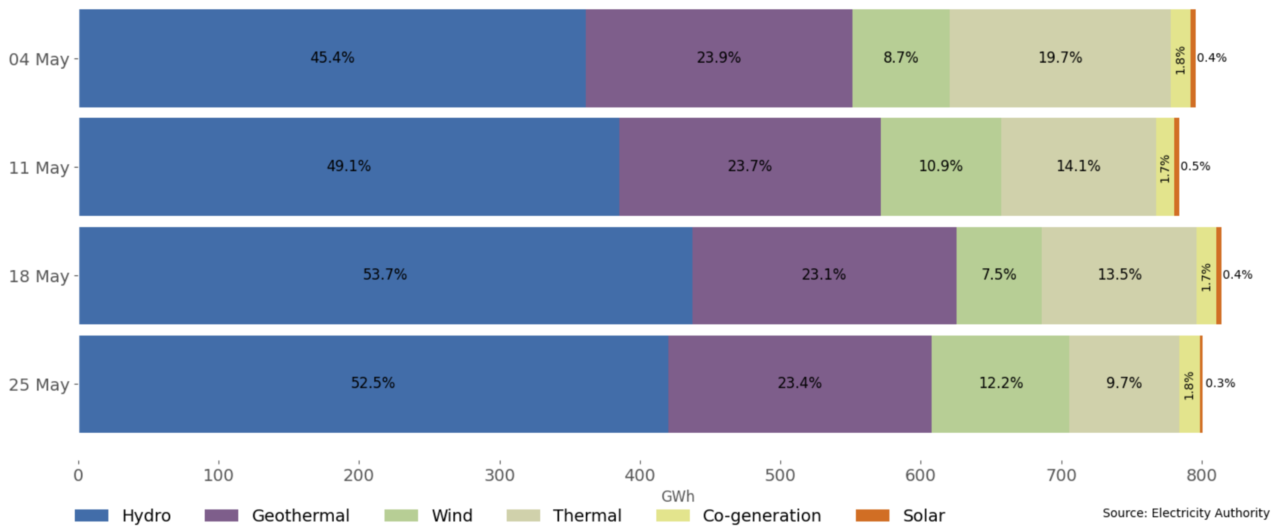

7.7. Figure 14 shows hydro generation between 25-31 May 2025. Hydro generation this week was higher during the off-peak periods compared to the previous week. At the start and end of the week, hydro generation was below the historic mean, as wind generation was high, and from Tuesday to Thursday it was around the historic mean.

**Figure 14: Hydro generation, 25-31 May 2025**




7.8. As a percentage of total generation, between 25-31 May 2025, total weekly hydro generation was 52.5%, geothermal 23.4%, wind 12.2%, thermal 9.7%, and co-generation 1.8%, as shown in Figure 15.

**Figure 15: Total generation by type as a percentage each week, 4 May 2025 and 31 May 2025**




## 8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 25-31 May 2025 ranged between ~918MW and ~1883MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

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

(b) Huntly 2 was on outage until 26 May.

(c) TCC was on outage between 26-29 May.

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

**Figure 16: Total MW loss from generation outages, 25-31 May 2025**

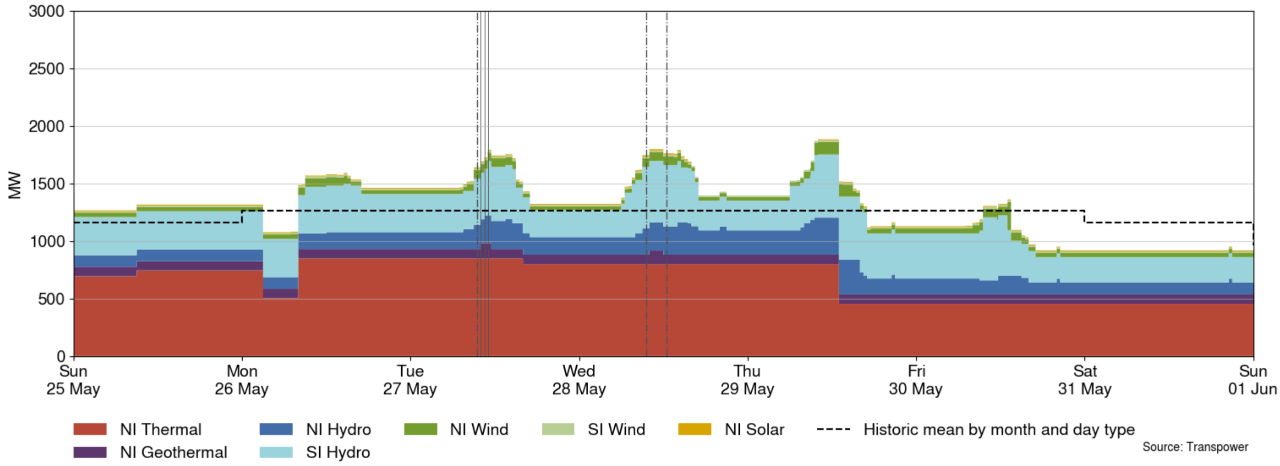
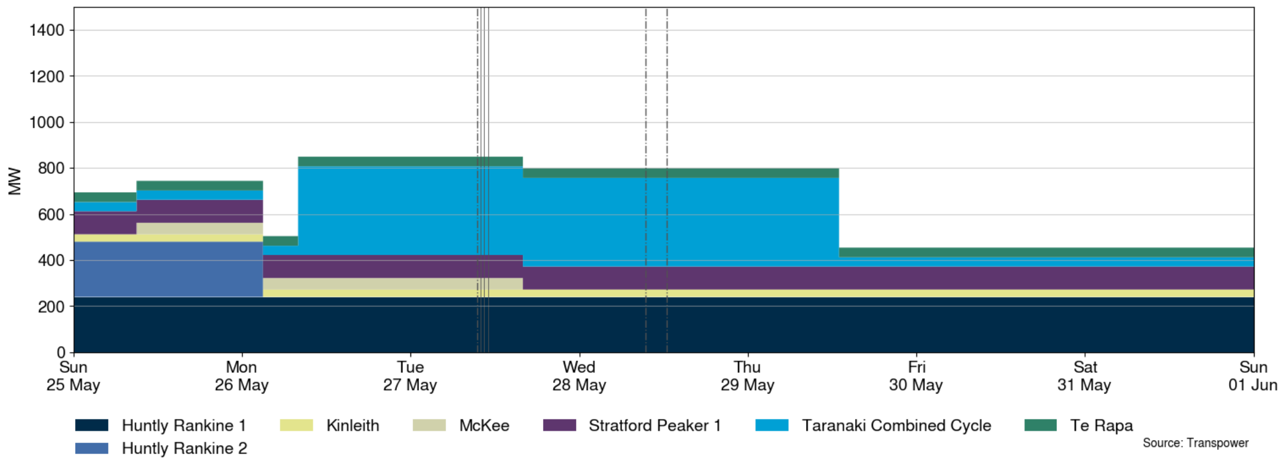


**Figure 17: Total MW loss from thermal outages, 25-31 May 2025**

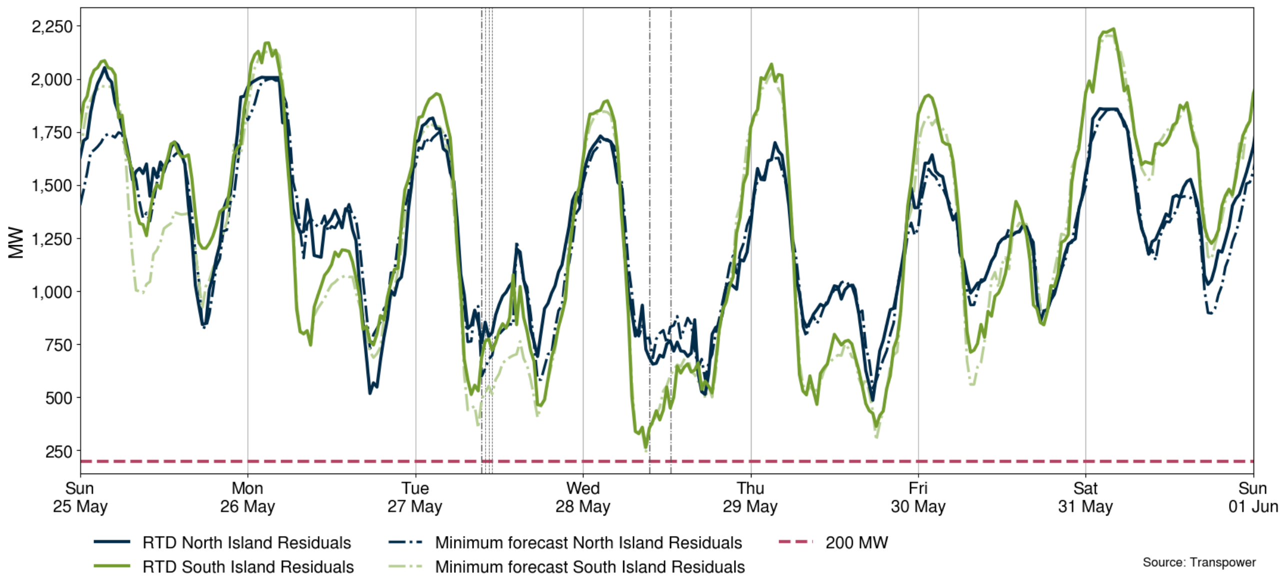



# 9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 25-31 May 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 910MW on Thursday at 5:30pm. However, the lowest South Island residual was 264MW on Wednesday at 9:00am.

**Figure 18: National generation balance residuals, 25-31 May 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 1 June, national controlled storage was 68% nominally full and ~93% of the historical average for this time of the year.

10.3. Storage at lakes Pūkaki (63% full)[3] and Takapō (51% full) are above their historical 10th percentiles.

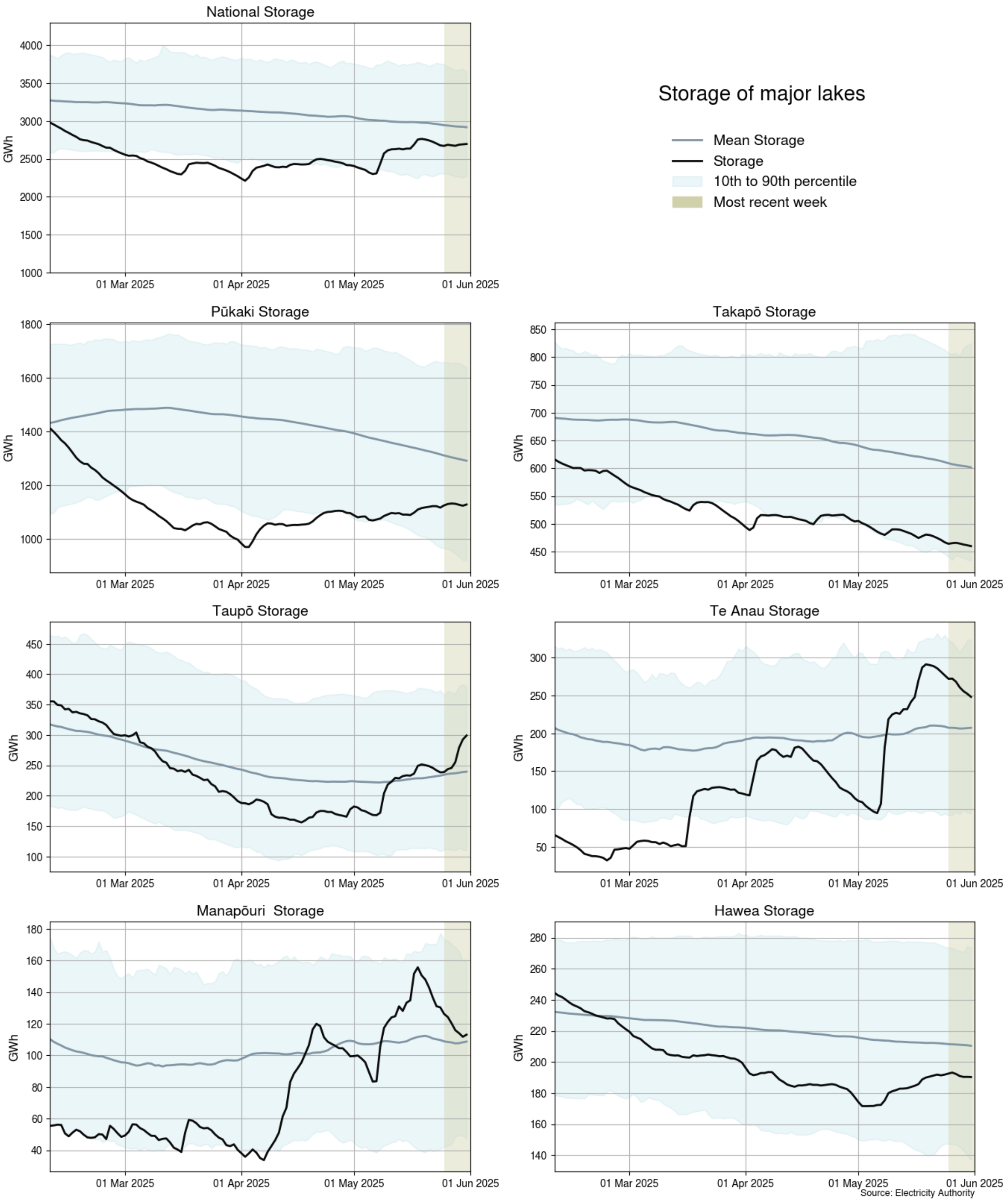
10.4. Lakes Te Anau and Manapōuri decreased during the week but are both still above their respective means.

10.5. Storage at Lake Taupō (53% full) is above its historic mean.

10.6. Lake Hawea storage (66% full) increased and is still between its historical 10th percentile and mean.

[3] Percentage full values sourced from NZX Hydro (2 June 2025).

**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.

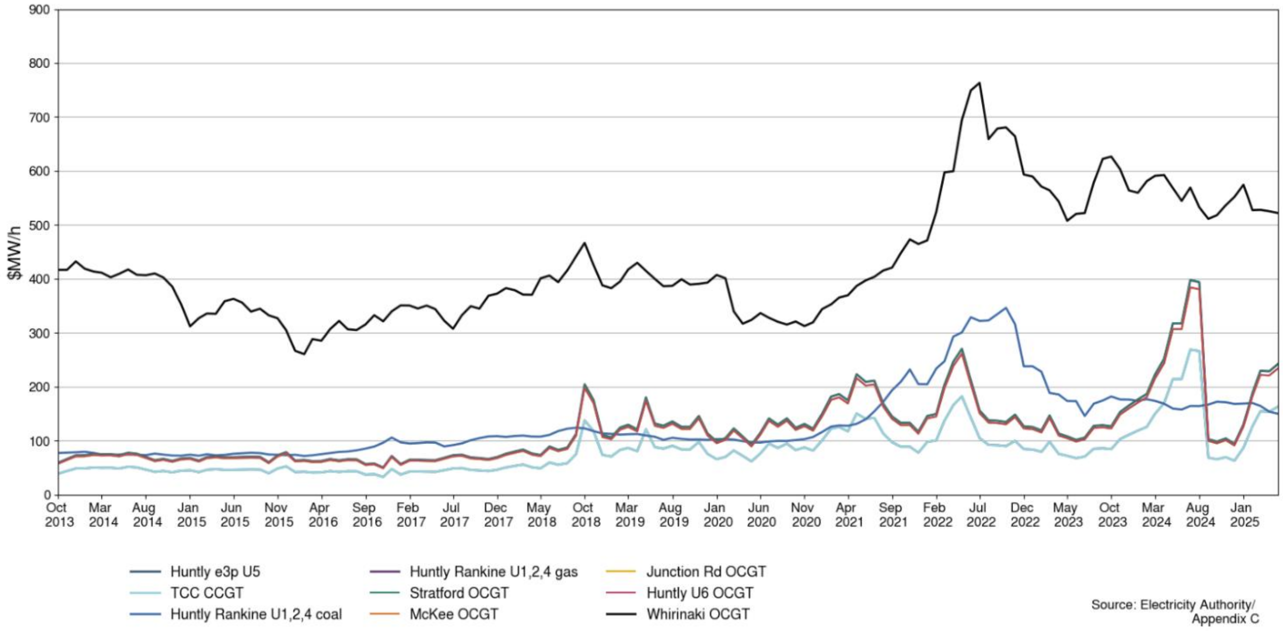
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$242/MWh.

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**

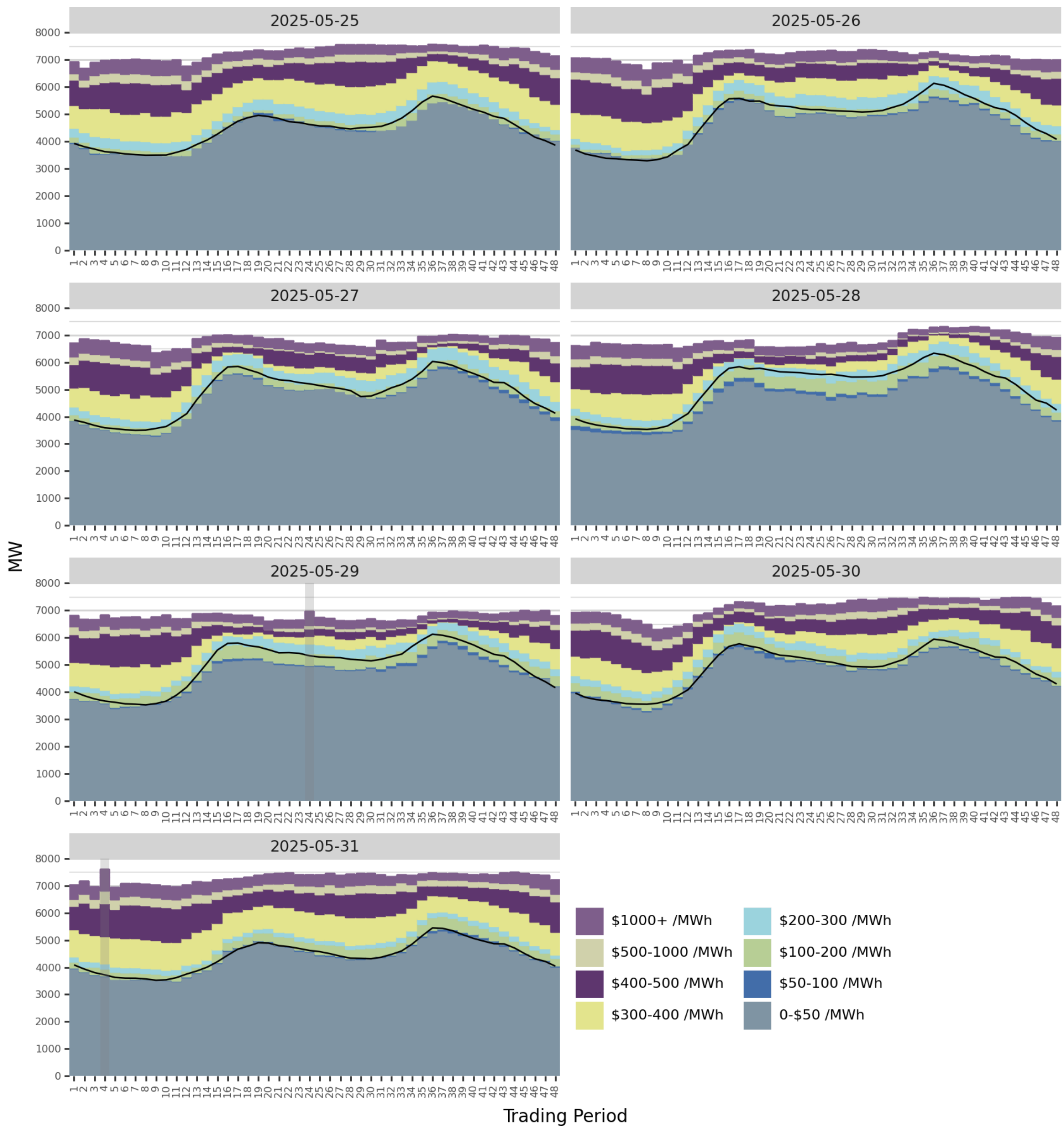



## 12. Offer behaviour

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 bands.

**Figure 21: Daily offer stacks**[4]



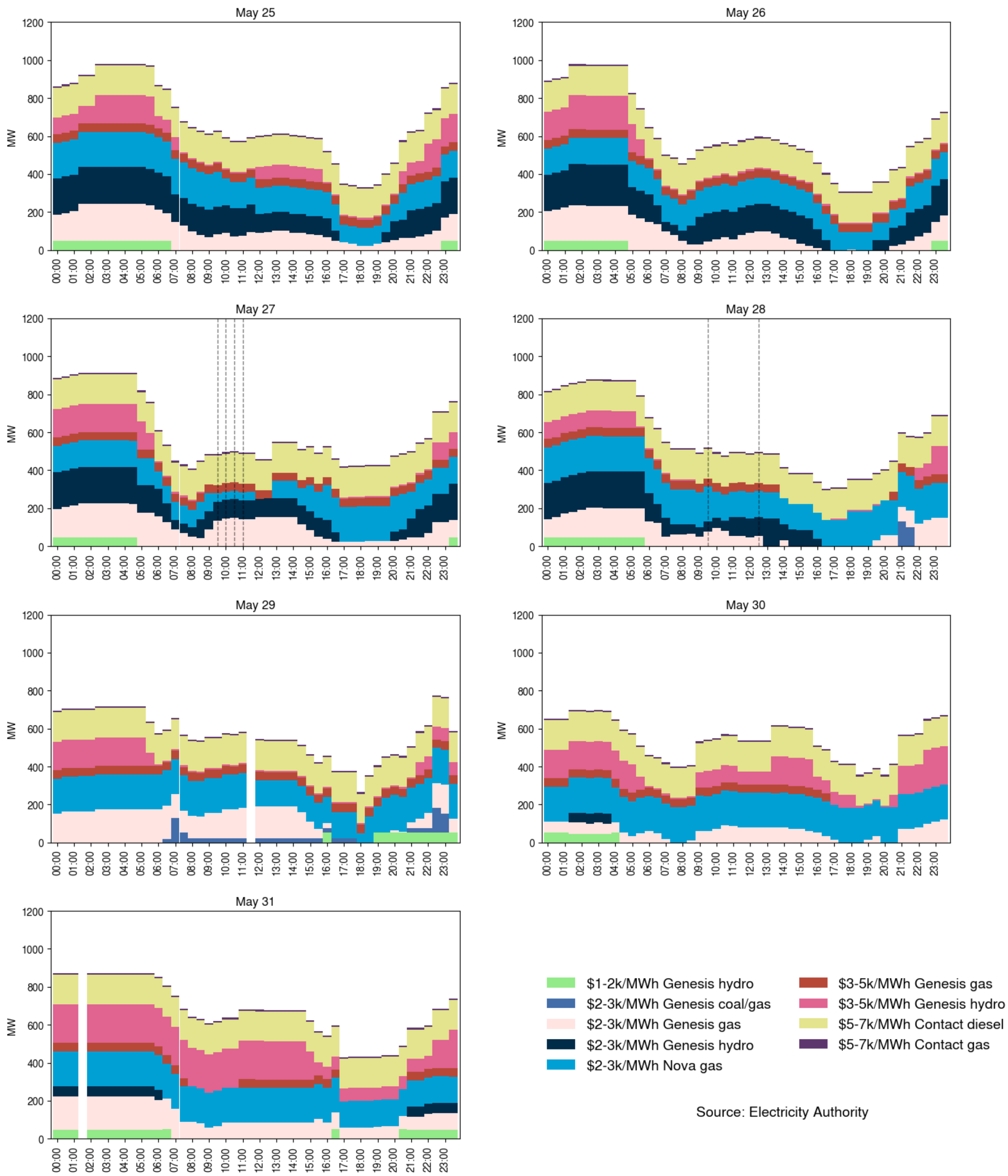

12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

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 reflect the 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.

[4] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

12.5. On average 608MW per trading period was above $1,000/MWh this week, which is roughly 11% of the total energy available. There are two periods on Thursday and Saturday with missing offer data.

**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-<br>15/06/2023 | 15-17/<br>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 |