24 November 2025

Trading conduct report 16-22 November 2025

Market monitoring weekly report

Trading conduct report 16-22 November 2025

1. Overview

1.1. This week the average spot price decreased by $17/MWh to $58/MWh. The proportion of hydro generation increased above 70% this week, whereas geothermal generation was lower due to outages. HVDC flows were entirely northward throughout the week, and periods of price separation occurred when HVDC flows approached its limit. National hydro storage increased to 96% nominally full and around 142% of the historical average. However, this includes storage at Manapōuri and Te Anau, which is expected to spill.

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 16-22 November 2025:

(a) The average spot price for the week was $58/MWh, a decrease of around $17/MWh compared to the previous week.

(b) 95% of prices fell between $0.30/MWh and $181/MWh.

2.3. This week, prices remained mostly below $250/MWh at Ōtāhuhu and $150/MWh at Benmore. Prices were particularly low on Saturday and Sunday, driven by low demand and high hydro generation, despite low wind generation. On Friday, prices were also low due to strong hydro and wind generation.

2.4. Some price spikes also occurred between Monday and Thursday, mostly due to wind and/or demand forecast errors. Between Monday and Thursday, HVDC flow was high and close to the northward capacity limit.

(a) On Monday, between 6.00pm-6.30pm, wind was 69MW-96MW below forecast.

(b) On Tuesday, wind was 25MW-148MW below forecast, and between 1.30pm-5.00pm demand was 37MW-113MW higher than forecast.

(c) On Wednesday, wind was 31-64MW below forecast, and demand was higher than forecast by 35MW at 11.00am and 46MW at 11.30am.

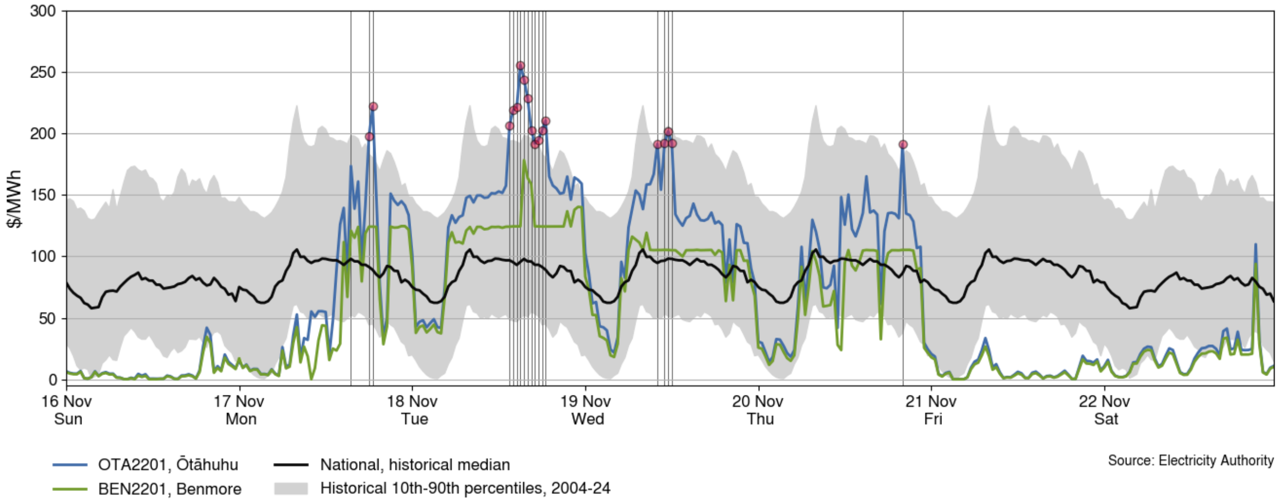
(d) On Thursday wind was 54MW below forecast, and demand was 41MW higher than forecast.

2.5. Some price separation was observed between Monday and Thursday during periods of high northward HVDC flow, at times this approached $100/MWh. However, price separation averaged $16/MWh this week between the Ōtāhuhu and Benmore.

2.6. The highest price of the week occurred on Tuesday at 3.00pm, reaching $256/MWh at Ōtāhuhu and $124/MWh at Benmore. At this time, demand was 43MW above forecast, and wind was 107MW below forecast. Also, HVDC northward flow was close to its capacity limit.

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.

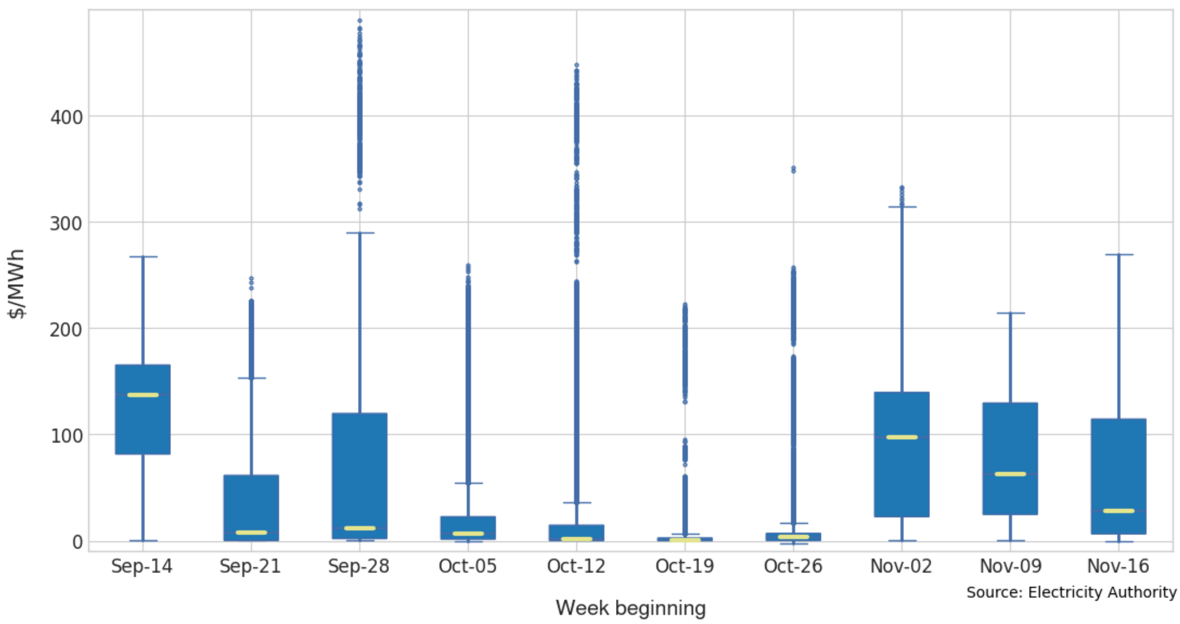
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 16-22 November 2025



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 similar to last week. The median price was $28/MWh and most prices (middle 50%) fell between $6/MWh and $114/MWh.

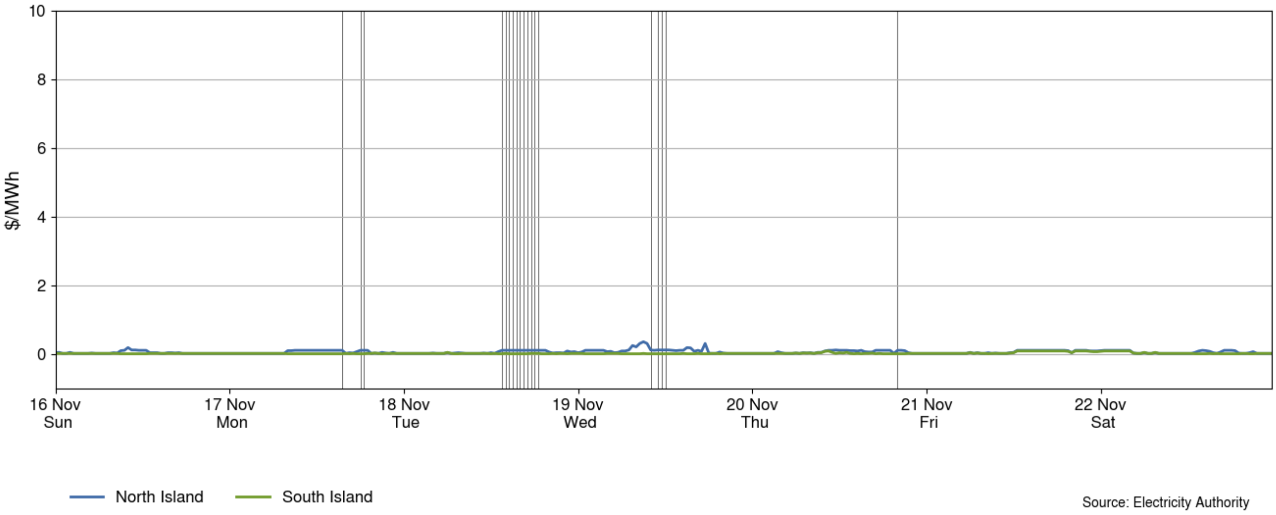
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

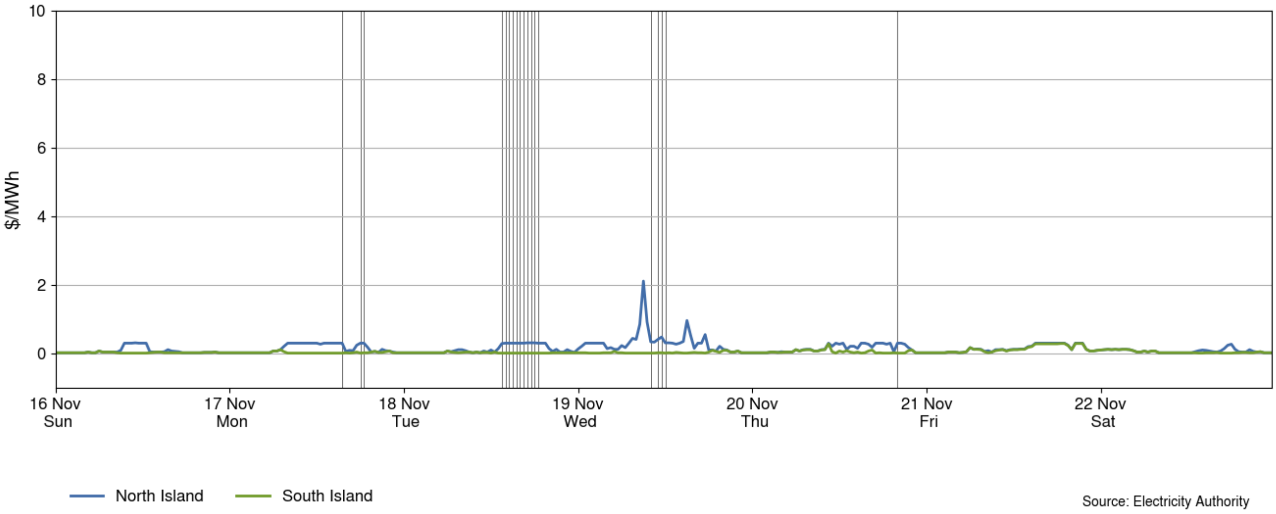
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week, FIR prices were below $1/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 16-22 November 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were below $3/MWh throughout the week.

Figure 4: Sustained instantaneous reserve by trading period and island, 16-22 November 2025



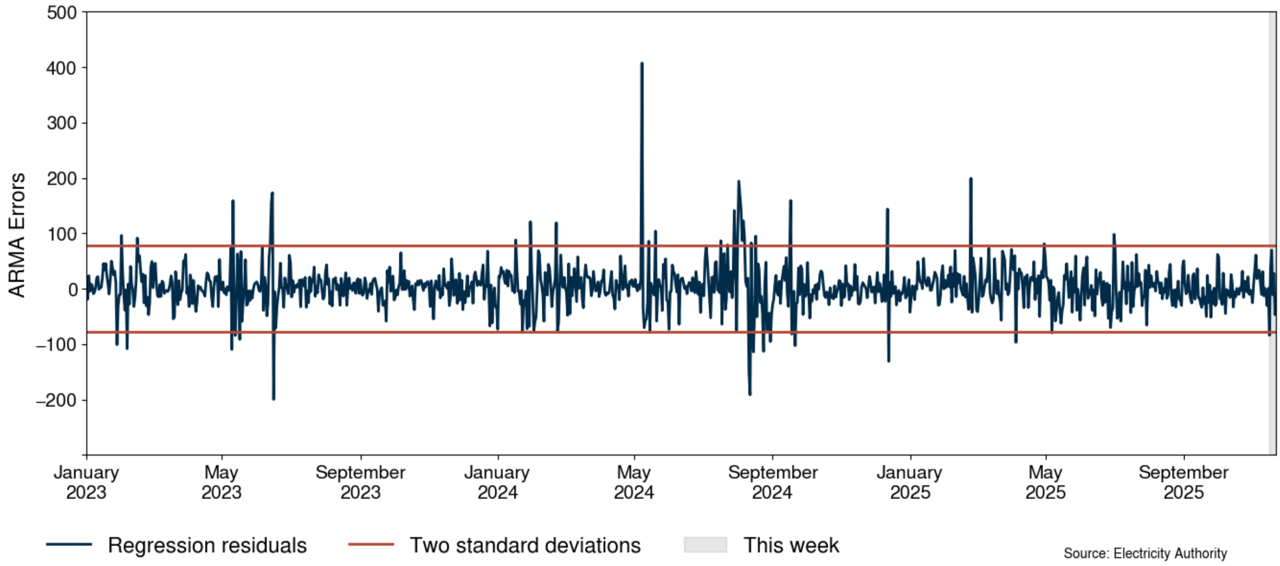
4. Regression residuals

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 two standard deviations, indicating that prices were consistent with those predicted by the model. On Sunday, the residual was below two standard deviations when prices were significantly low.

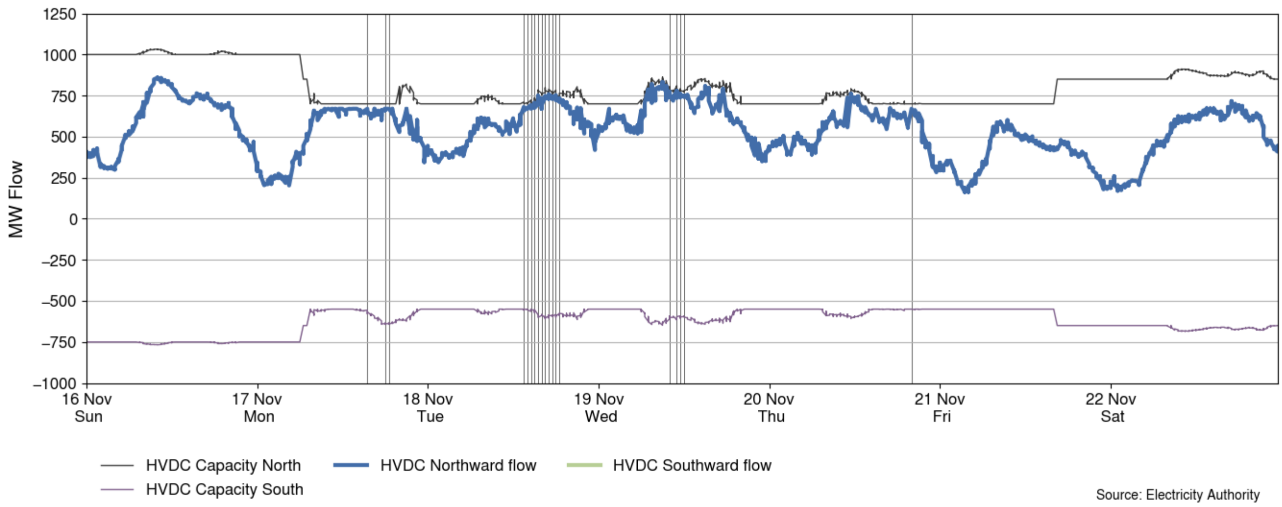
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 22 November 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 16-22 November 2025. HVDC flows were entirely northward this week due to high hydro generation in the South Island. The highest northward flow occurred at 10.00am on Sunday with a flow of around 860MW. HVDC northward flows were consistently near their capacity limit for several periods between Monday and Thursday.

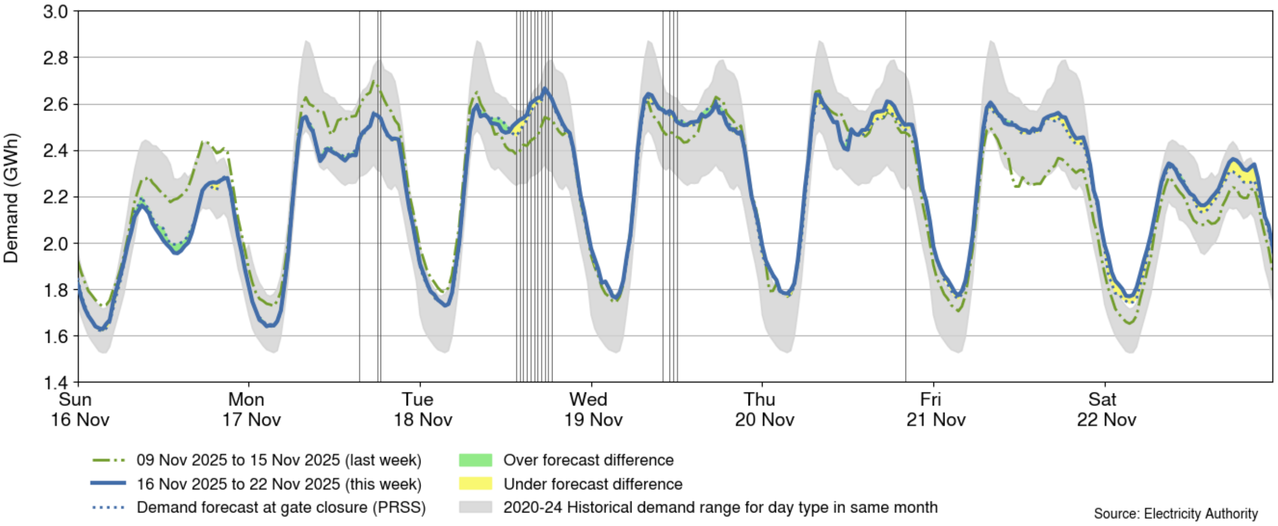
Figure 6: HVDC flow and capacity, 16-22 November 2025



6. Demand

6.1. Figure 7 shows national demand between 16-22 November 2025, compared to the historic range and the demand of the previous week. On Monday, demand was lower than last week, while on Friday it was higher. On Tuesday, during the price spikes, demand was higher than last week and was underforecast. The highest demand of the week was around 2.67 GWh at 5.30pm on Tuesday.

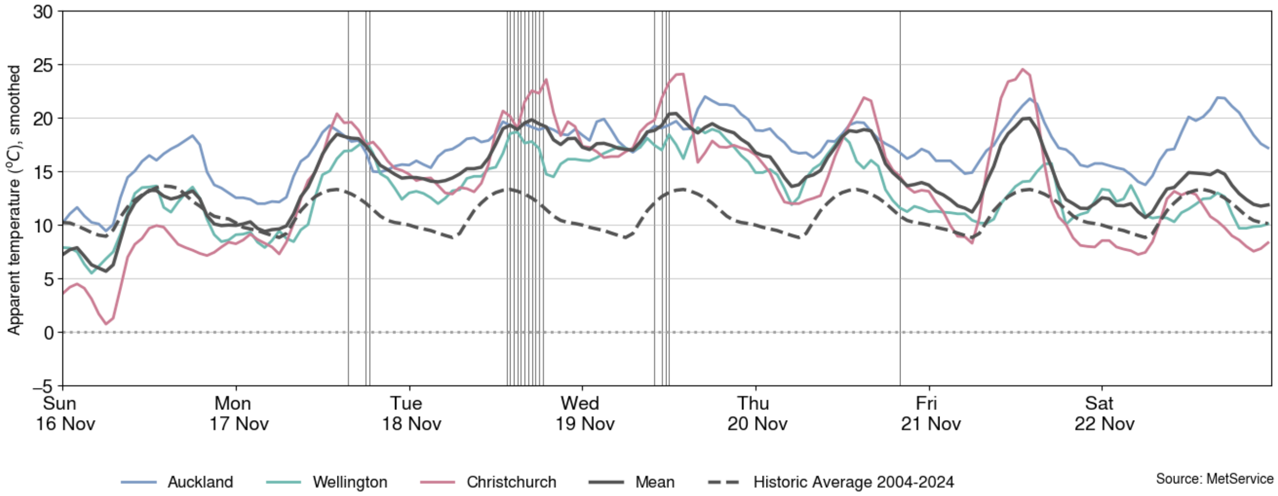
Figure 7: National demand, 16-22 November 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 16-22 November 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. Apparent temperatures ranged from 9°C to 23°C in Auckland, 6°C to 20°C in Wellington, and 0°C to 25°C in Christchurch.

Figure 8: Temperatures across main centres, 16-22 November 2025

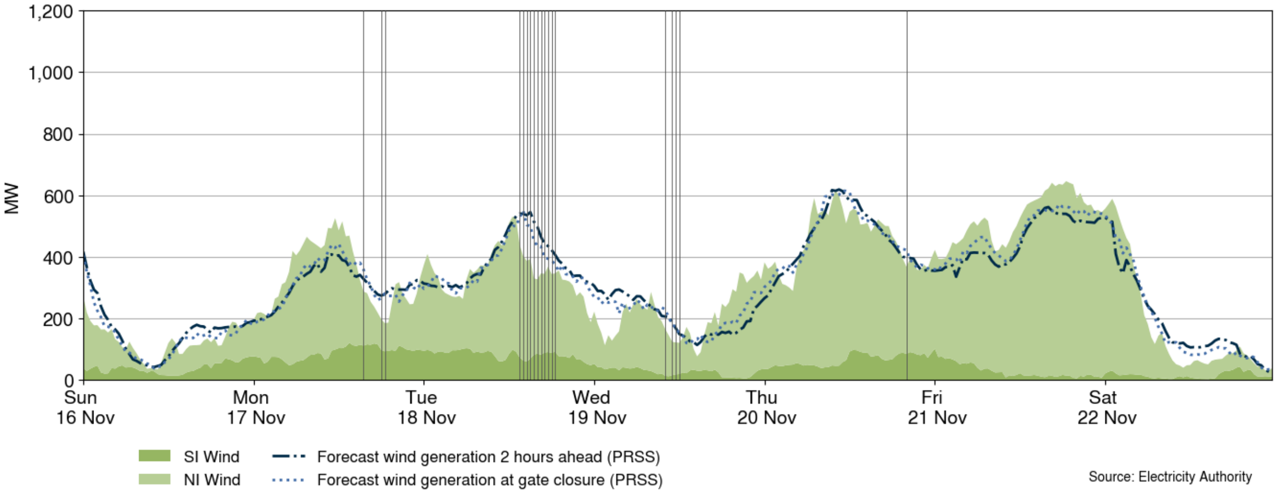


7. Generation

7.1. Figure 9 shows wind generation and forecast from 16-22 November 2025. This week wind generation varied between 30MW and 646MW, with a weekly average of 311MW.

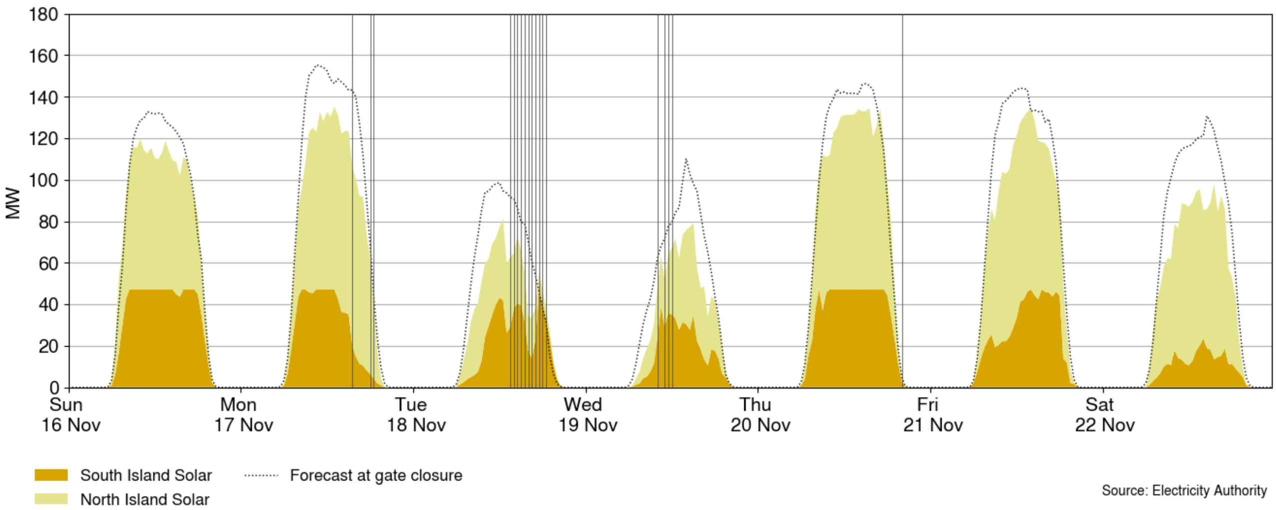
7.2. Wind generation was relatively low throughout the week. On Sunday, wind was low, increased gradually but remained under 500MW before declining again on Wednesday. Between Thursday and Friday, wind generation was mostly below 600MW, and on Saturday it dropped further to under 100MW. The wind errors on Tuesday and into Wednesday were an amalgamation of errors across multiple wind farms.

Figure 9: Wind generation and forecast, 16-22 November 2025



7.3. Figure 10 shows grid connected solar generation from 16-22 November 2025. Solar generation peaked above 100MW daily, except on Tuesday and Wednesday. Solar generation peaked at around 135MW on Monday at 1.00pm.

Figure 10: Grid connected solar generation, 16-22 November 2025



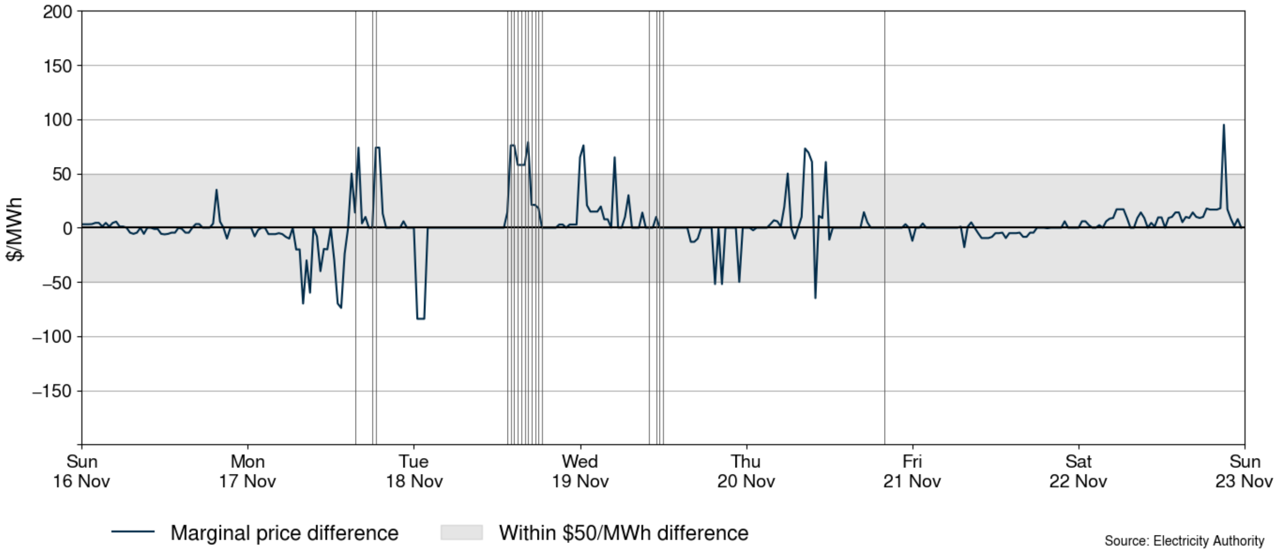
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting

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

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.

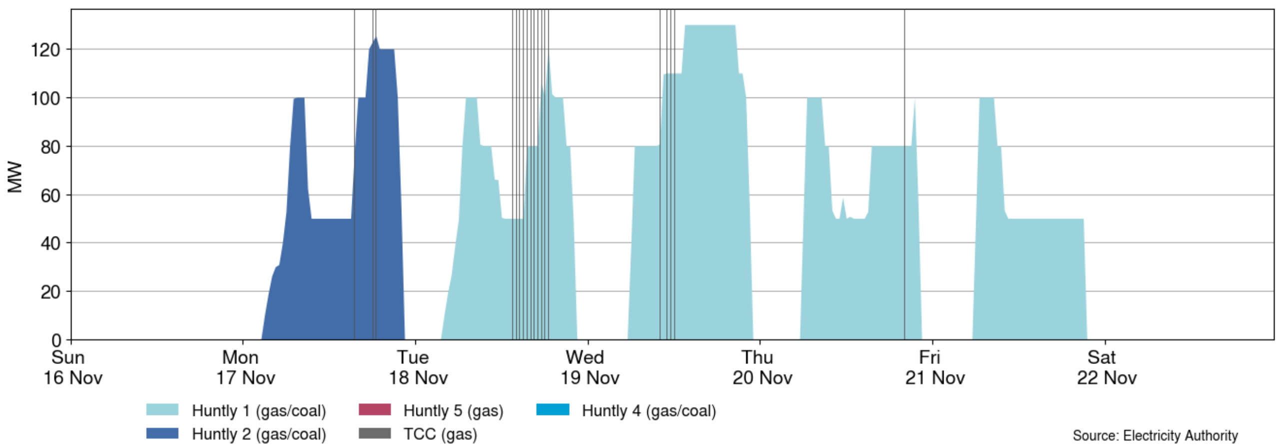
7.5. A few trading periods this week had positive marginal price differences above $50/MWh which were driven by wind and demand forecasting errors. The largest positive price difference of +$95/MWh occurred at 9.00pm on Saturday during a price spike, when demand was 138MW higher than forecast and wind was 20MW lower than forecast.

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, 16-22 November 2025



7.6. Figure 12 shows the generation of thermal baseload between 16-22 November 2025. Huntly 2 ran on Monday, while Huntly 1 ran from Tuesday to Friday. There was no thermal generation overnight during the week.

Figure 12: Thermal baseload generation, 16-22 November 2025

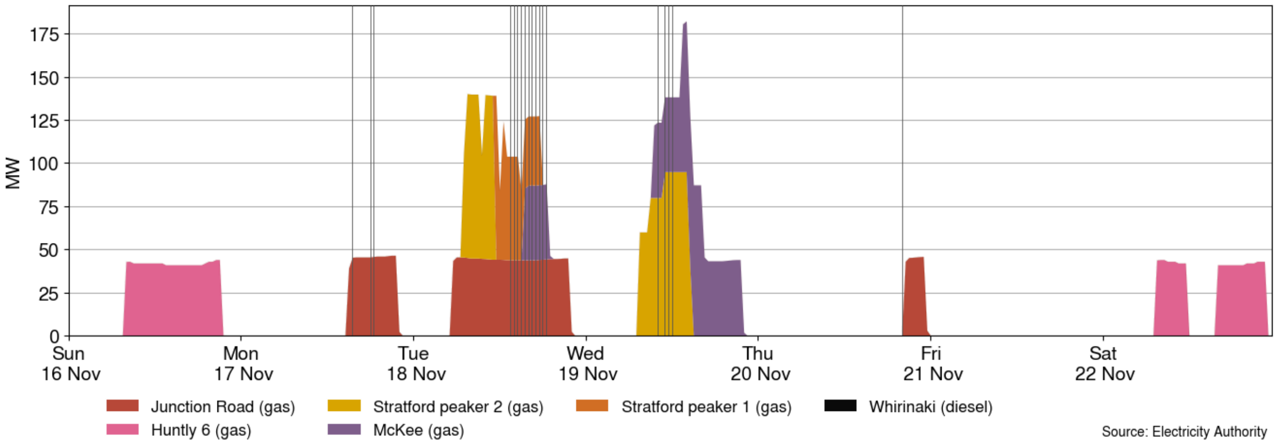


7.7. Figure 13 shows the generation of thermal peaker plants between 16-22 November 2025. Junction Road ran on Monday and Thursday during the evening peak. On Tuesday, it ran continuously between the morning and evening peaks.

7.8. Huntly 6 ran on Sunday and Saturday. Stratford peaker 1 was dispatched on Tuesday during the price spikes, while Stratford peaker 2 was dispatched on Tuesday and Wednesday to meet demand.

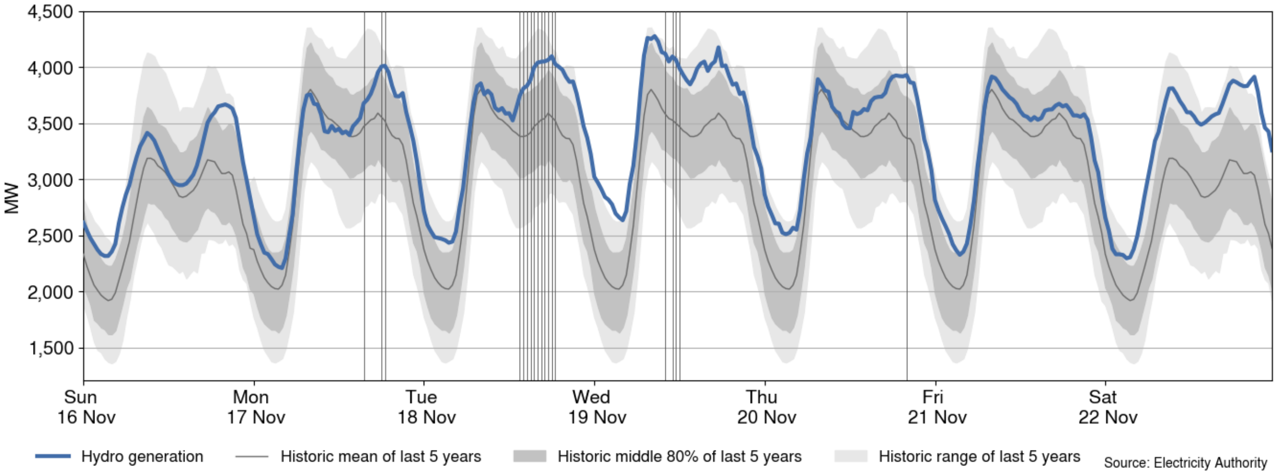
7.9. McKee ran on Tuesday during the price spikes and on Wednesday between the morning and evening peaks.

Figure 13: Thermal peaker generation, 16-22 November 2025



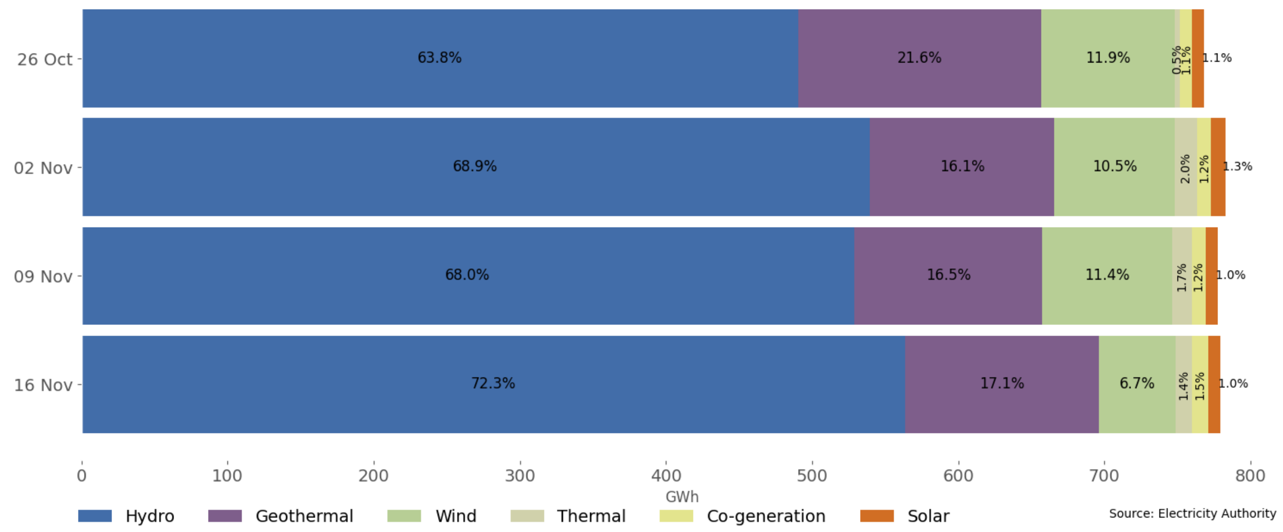
7.10. Figure 14 shows hydro generation between 16-22 November 2025. Overall, hydro generation was high throughout the week. It was elevated during the evening peaks on Monday and Tuesday, coinciding with the price spikes. The highest hydro generation was on Wednesday during the morning peak. On Saturday, hydro generation remained relatively high, likely due to low wind generation.

Figure 14: Hydro generation, 16-22 November 2025



7.11. As a percentage of total generation, between 16-22 November 2025, total weekly hydro generation was 72.3%, geothermal 17.1%, wind 6.7%, thermal 1.4%, co-generation 1.5%, and solar (grid connected) 1.0%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 26 October and 22 November 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 16-22 November 2025 ranged between ~1,720MW and ~2,578MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 5 is on extended outage until 30 November 2025.

(b) Huntly 4 was on extended partial outage until 26 November 2025.

(c) Nga Awa Pūrua geothermal is on outage until 28 November 2025.

(d) Tauhara geothermal is on outage until 22 December 2025.

(e) Ruakākā battery was on partial outage during the week.

(f) Clyde unit 2 was on outage between 19-20 November, and unit 4 was on outage between 17-18 November 2025.

(g) Benmore unit 3 is on outage 19 November – 12 December 2025.

8.3. Some longer-term outages include:

(a) Ōhau A is on partial outage until 4 February 2026.

(b) Ōhau C is on partial outage until 16 January 2026.

(c) Roxburgh unit 5 is on outage until 25 February 2026.

(d) Rangipo unit 6 is on outage until 29 March 2026.

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

Figure 16: Total MW loss from generation outages, 16-22 November 2025

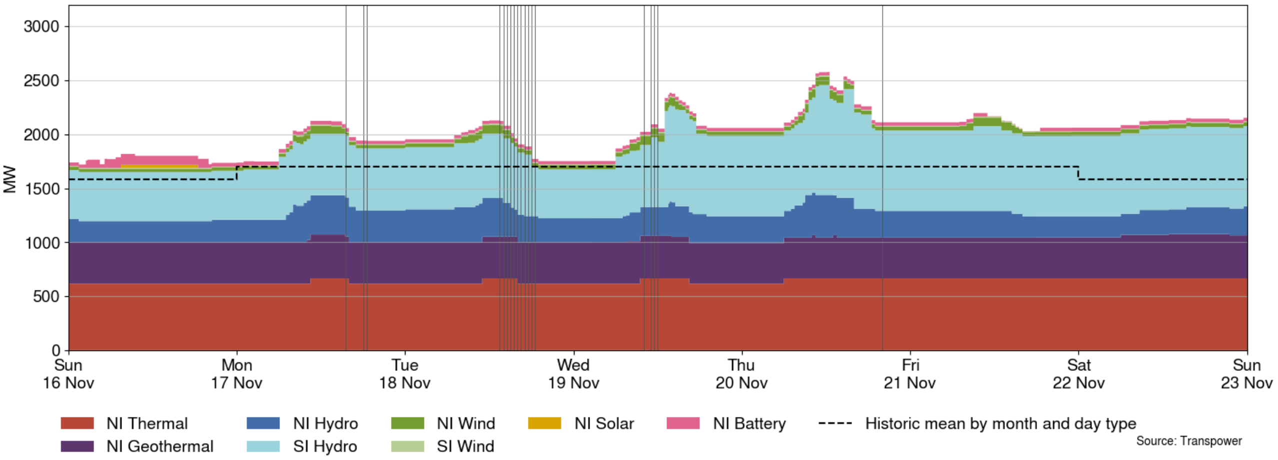
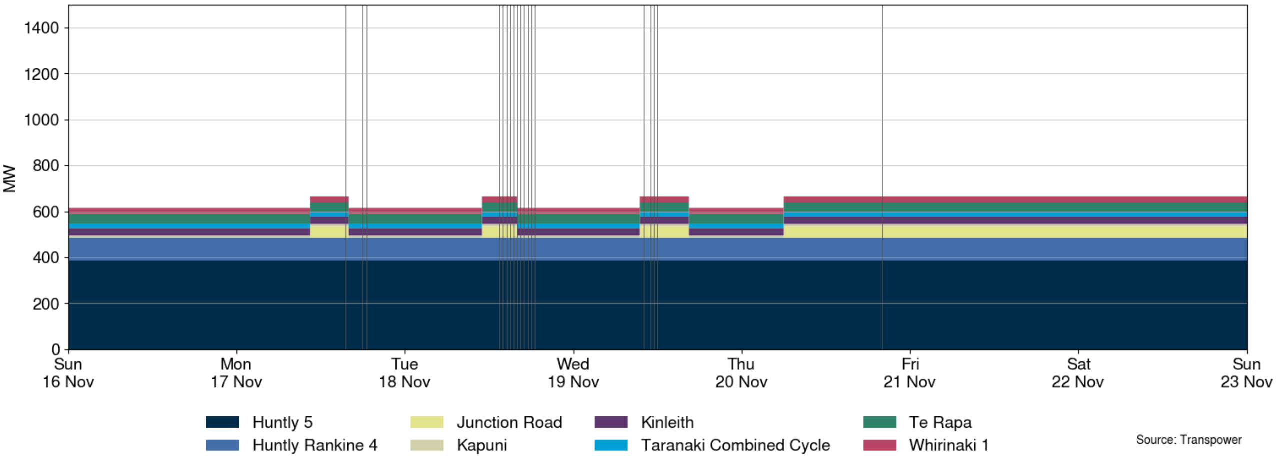


Figure 17: Total MW loss from thermal outages, 16-22 November 2025

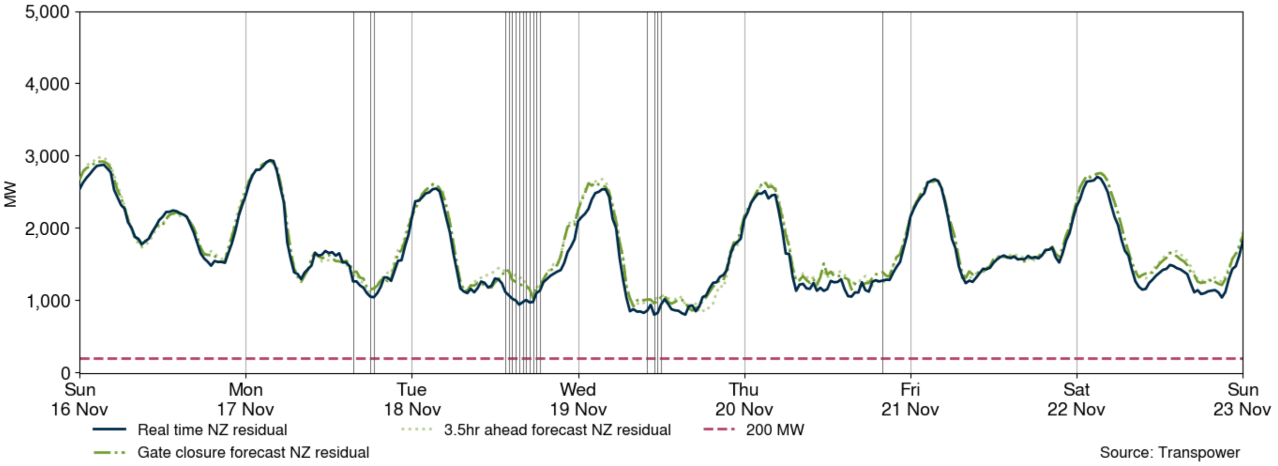


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 16-22 November 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. Overall, residuals were healthy this week. The lowest national residual was 800MW on Wednesday at 11.00am.

Figure 18: National generation balance residuals, 16-22 November 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 22 November 2025, national controlled hydro storage increased to 96% of nominal full and ~142% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (87% full[2]) and Lake Takapō (101% full) are above their respective 90th percentile.

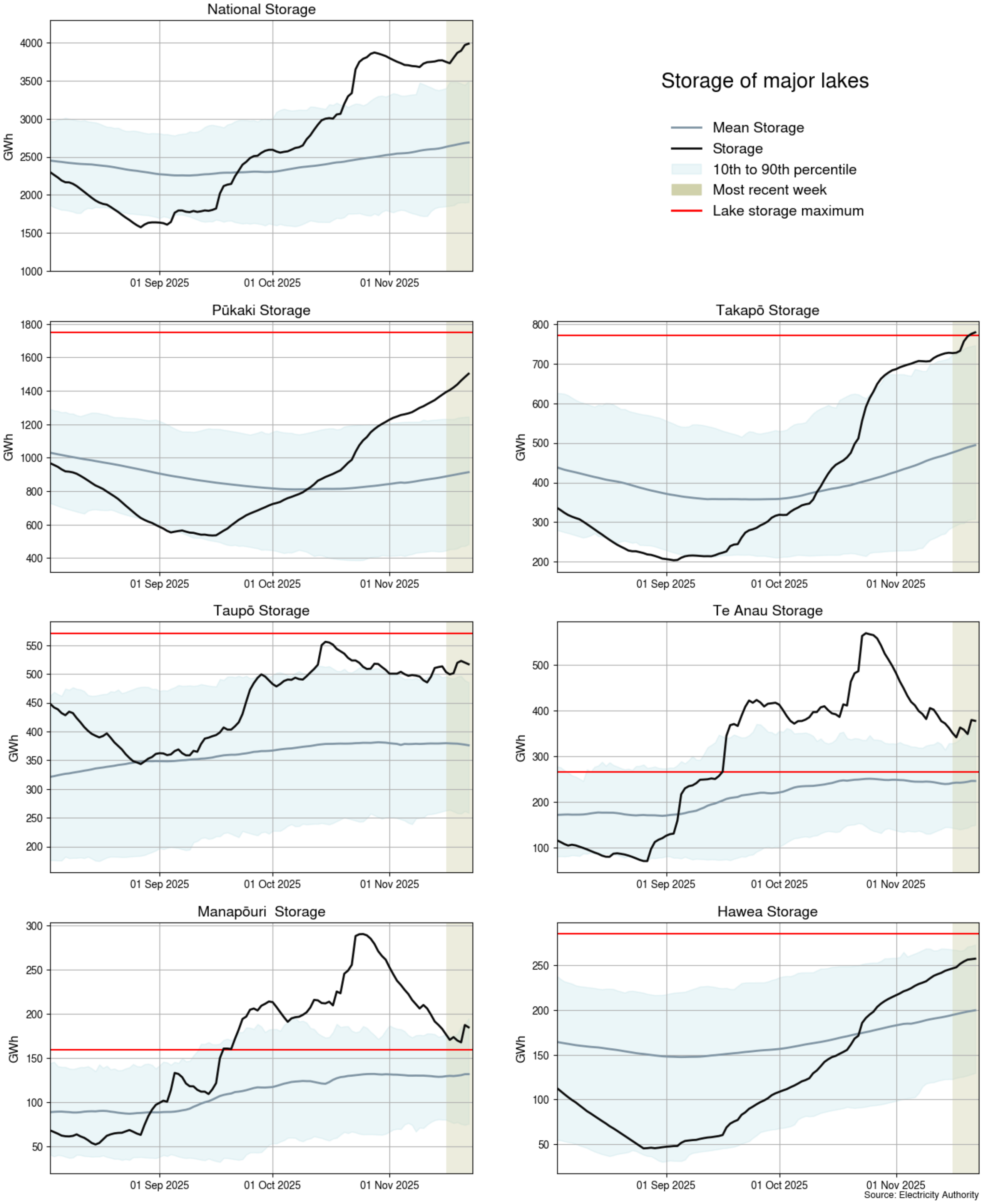
10.4. Storage at Lake Te Anau (138% full) and Lake Manapōuri (115% full) is above their respective historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (90% full) is slightly above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (90% full) is close to its historic 90th percentile.

[2] Percentage full values sourced from NZX hydrological summary 23 November 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 November 2025. The SRMCs for gas-powered and coal-powered generation decreased, while the SRMC for diesel-fuelled generation increased.

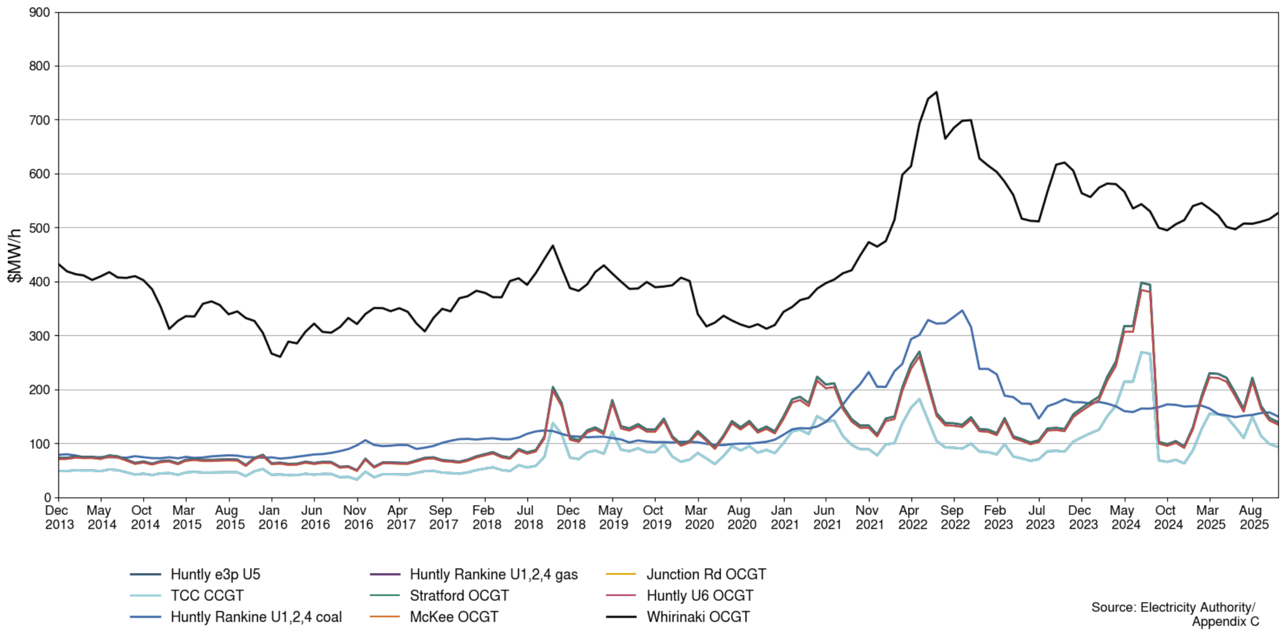
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$184/MWh. The cost of running the Rankines on gas is ~$138/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $92/MWh and $138/MWh.

11.6. The SRMC of Whirinaki is ~$526/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



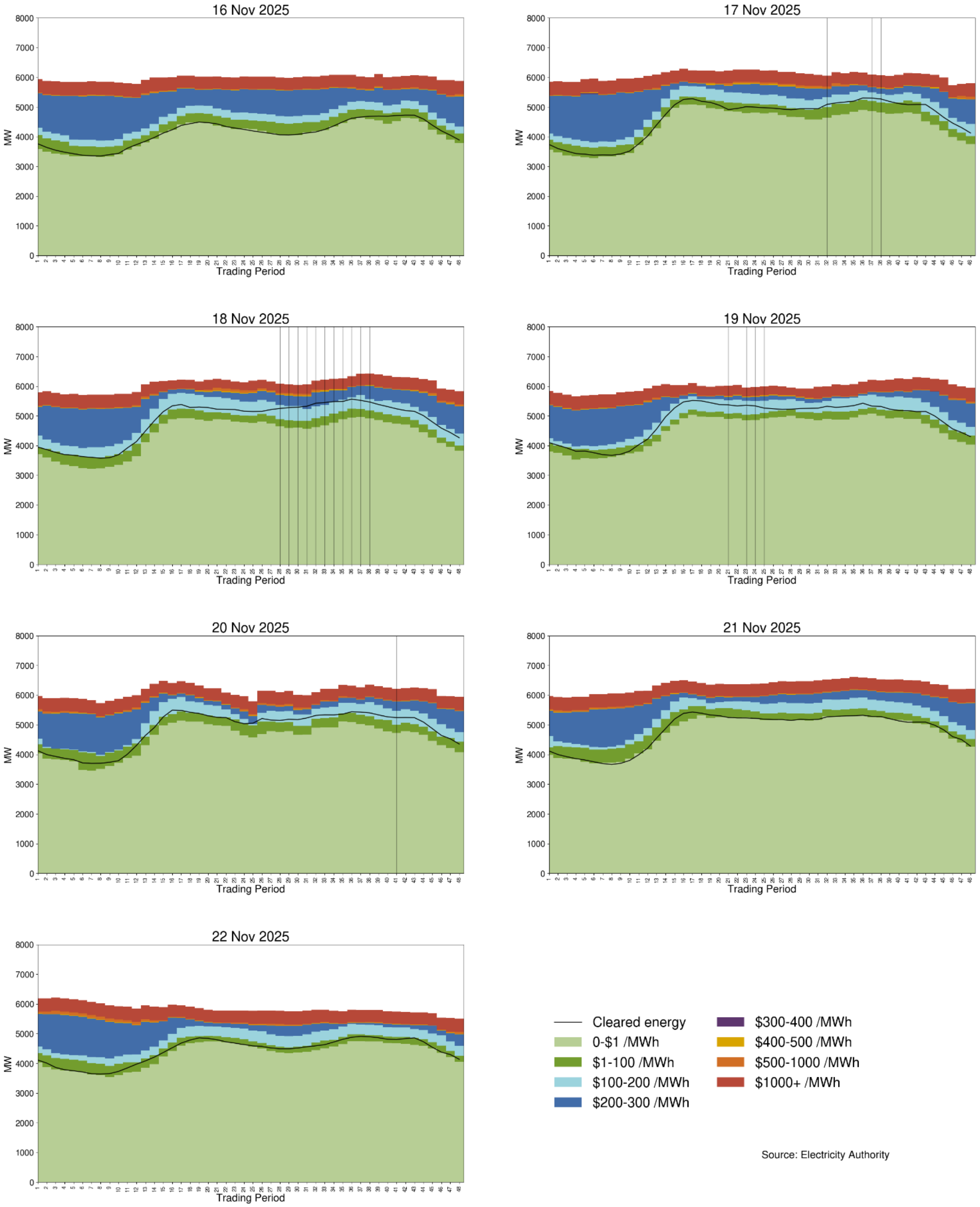
12. Offer behaviour

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 below $100/MWh on Sunday, Friday, and Saturday, and within the $0–$200/MWh range on the remaining days. During periods of high northward HVDC flow, wind and/or demand forecast errors pushed some offered energy into the next band of $200–$300/MWh.

12.3. On Thursday from TP26, the increase in available energy occurred when New Zealand's Aluminium Smelter (NZAS) reduction line was restored.

Figure 21: Daily offer stacks

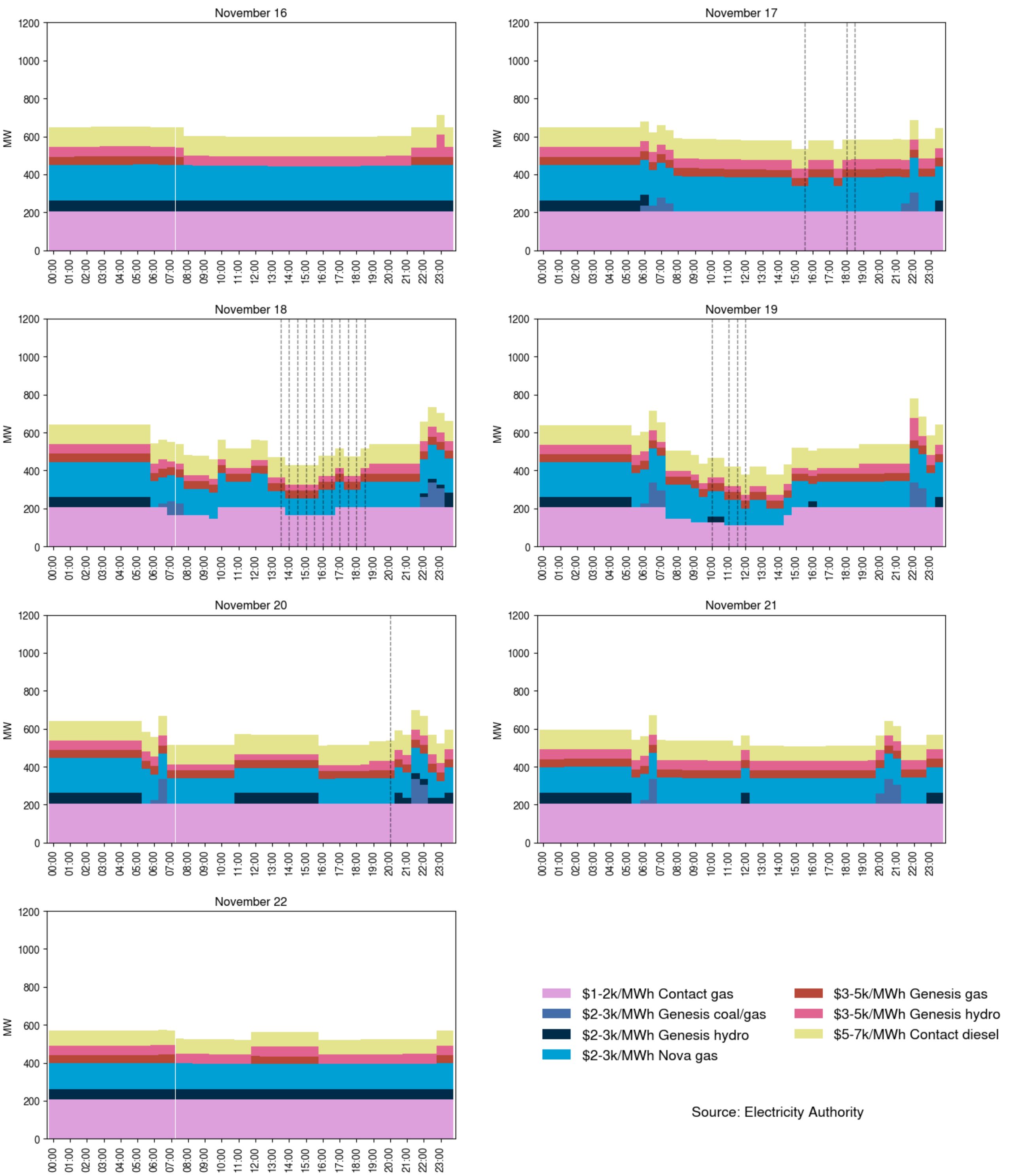


12.4. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.5. 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.

12.6. On average 572MW per trading period was priced above $1,000/MWh this week, which is roughly 11% 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. This week the monitoring team is looking further into offers at Ruakākā and at the Clutha scheme.

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
8/05/2025-9/05/2025	Several	Further analysis	Genesis	Waikaremoana	Offers
21/10/2025-1/11/2025	Several	Further analysis	Contact	Clyde	Offers
5/11/2025	23-24	Further analysis	Contact	Stratford	Offers
19/11/2025	21-30	Further analysis	Meridian	Ruakākā	Offers
18/11/2025	Several	Further analysis	Contact	Clutha Scheme	Offers