

20 October 2025

Trading conduct report 12-18 October 2025

Market monitoring weekly report

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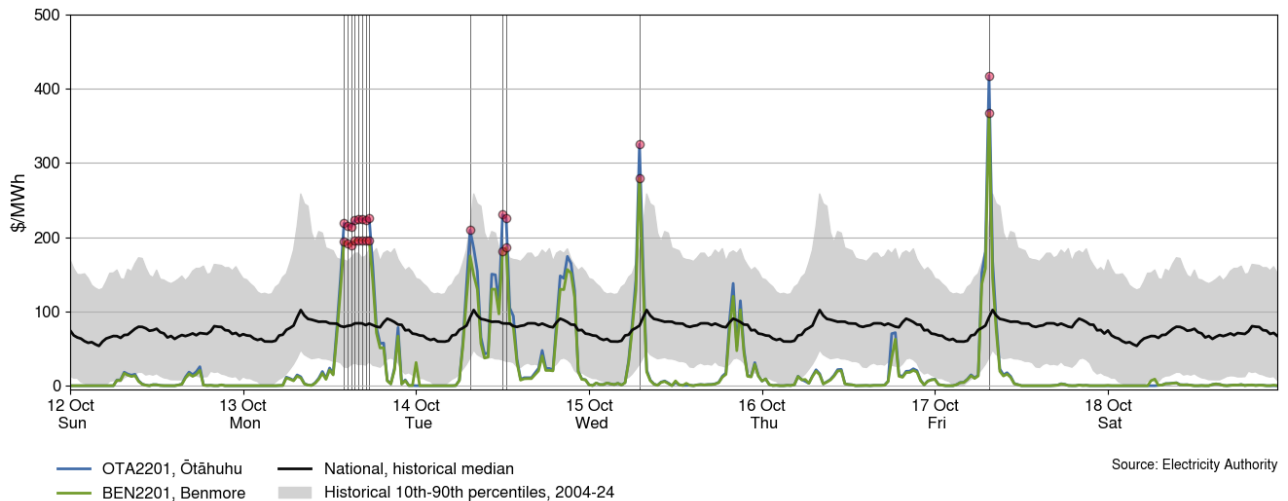
1. Overview

- 1.1. This week the average spot price decreased by \$12/MWh to \$25/MWh, likely due to increased hydro storage. Hydro generation was relatively high throughout the week, while thermal generation remained low. National hydro storage increased to 75% nominally full and around 120% of the historical average.

2. Spot prices

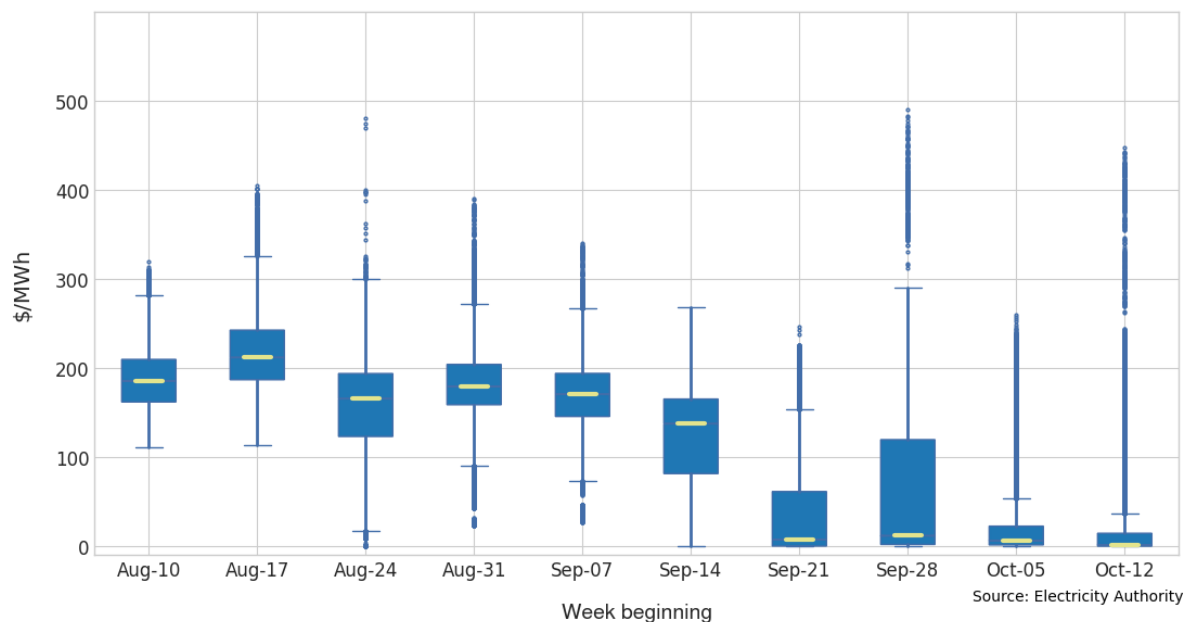
- 2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.
- 2.2. Between 12-18 October 2025:
 - (a) The average spot price for the week was \$25/MWh, a decrease of around \$12/MWh compared to the previous week.
 - (b) 95% of prices fell between \$0.01/MWh and \$203/MWh.
- 2.3. Spot prices were low and volatile throughout the week, while weekend and overnight prices were mostly low. Demand and wind forecast errors contributed to most of the price spikes this week.
- 2.4. On Monday afternoon, high prices were observed between 2.00pm-5.30pm. Prices ranged between \$214-\$226/MWh at Ōtāhuhu, and \$189-\$196/MWh at Benmore. During this period, demand was 128MW-170MW higher than forecast and wind was 18MW-161MW lower than forecast.
- 2.5. At 7.30am on Tuesday during the morning peak, prices reached \$210/MWh at Ōtāhuhu and \$175/MWh at Benmore. At this time, demand was 89MW above forecast. Between 12.00pm-12.30pm prices ranged between \$226-\$230/MWh at Ōtāhuhu and \$181-\$186/MWh at Benmore and demand was 84MW-110MW higher than forecast.
- 2.6. On Wednesday at 7.00am, prices reached \$325/MWh at Ōtāhuhu and \$279/MWh at Benmore. At this time, demand was 15MW above forecast and wind was 23MW below forecast.
- 2.7. The highest price of the week observed on Friday at 7.30am during peak demand for the week. Prices reached \$418/MWh at Ōtāhuhu and \$367/MWh at Benmore. During this time, wind was low (~119MW) and Stratford peaker 1 was dispatched to meet demand for one 5-minute interval.
- 2.8. 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, 12-18 October 2025



- 2.9. 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.
- 2.10. The distribution of spot prices this week was similar to last week, but with some high-priced outliers above \$300/MWh. The median price was \$1.70/MWh and most prices (middle 50%) fell between \$0.05/MWh and \$15/MWh.

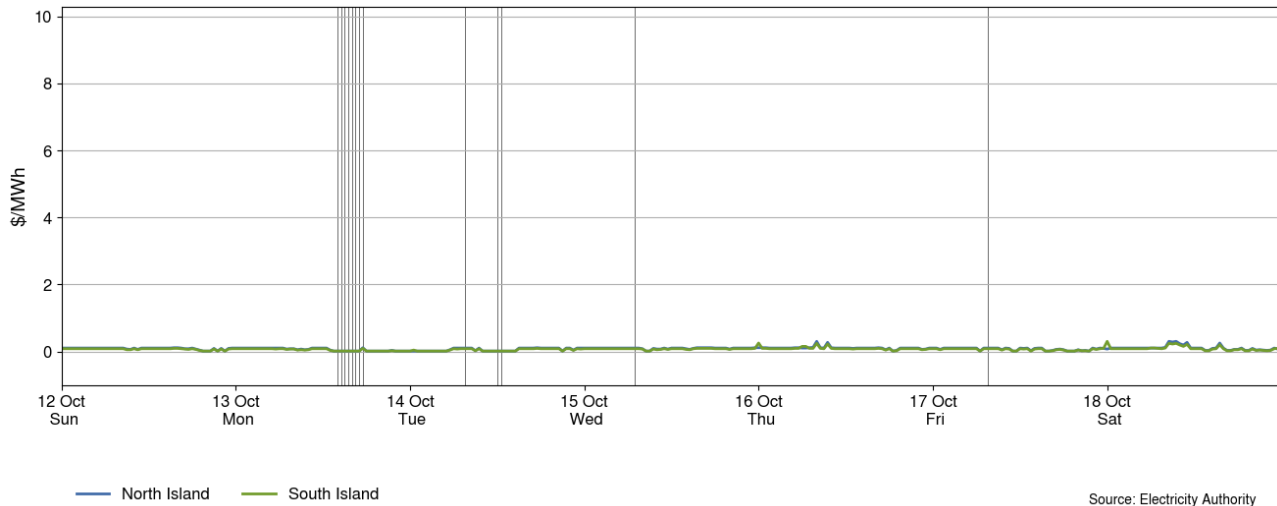
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

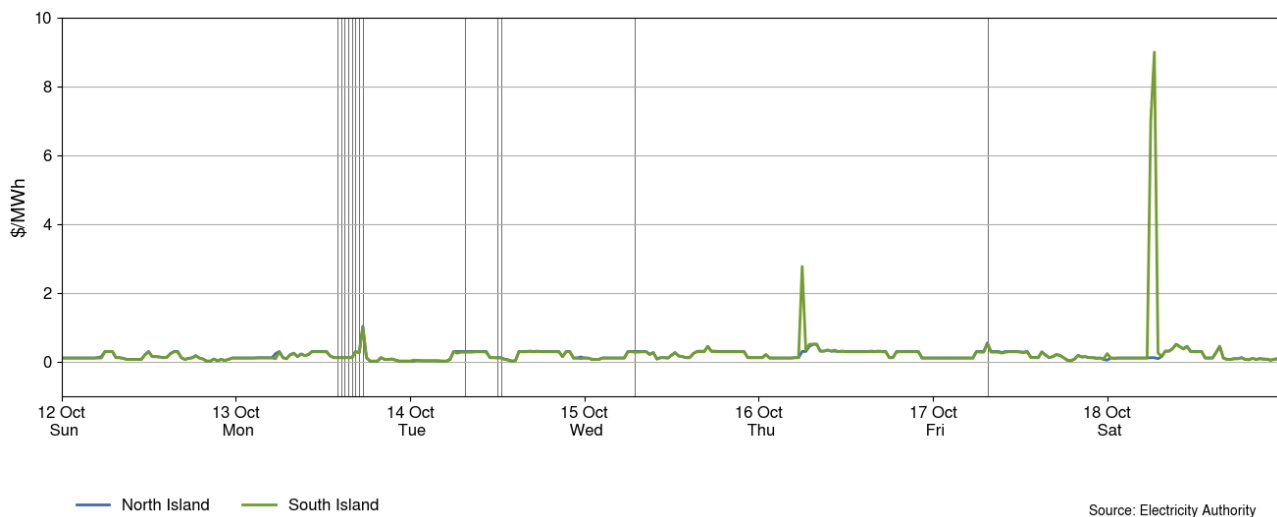
- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week, FIR prices across both the North and South Island were under \$0.30/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 12-18 October 2025



- 3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly under \$1/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 12-18 October 2025



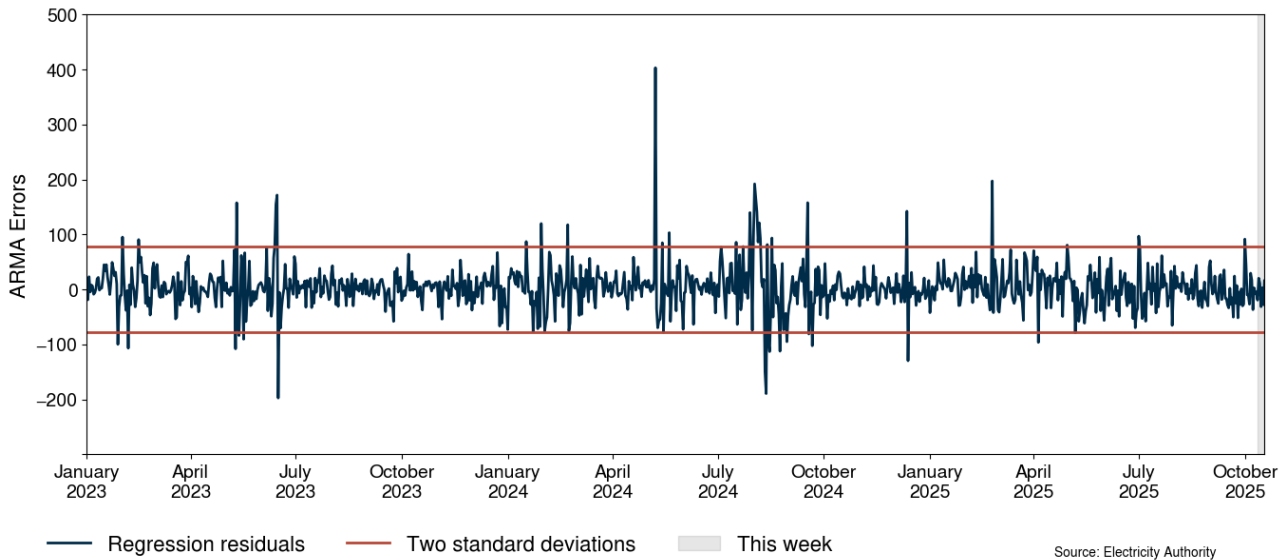
4. Regression residuals

- 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.

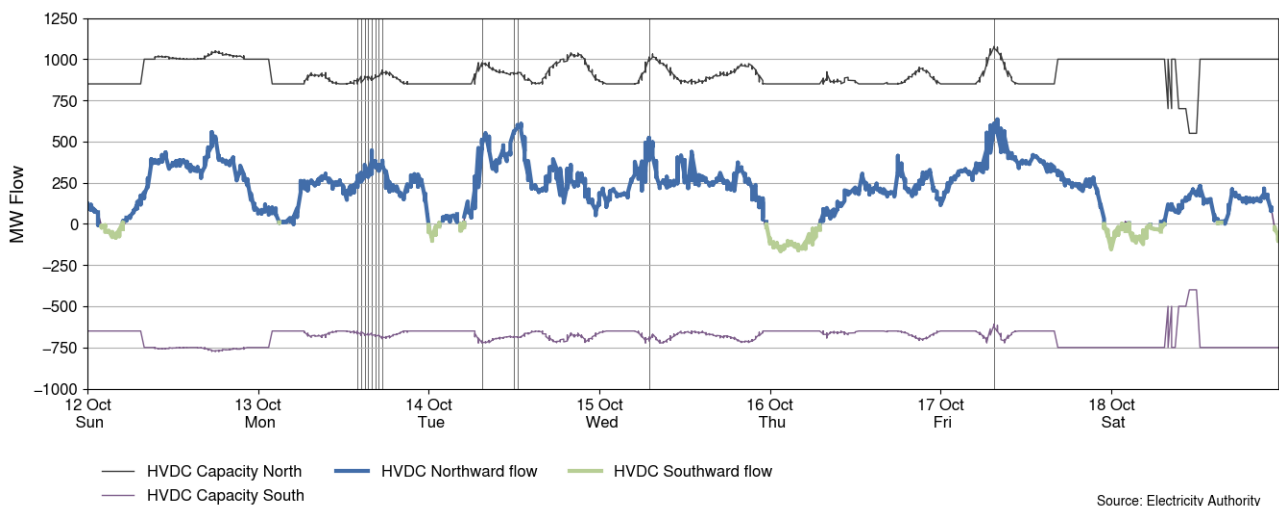
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 18 October 2025



5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 12-18 October 2025. HVDC flows were mostly northward with some periods of overnight southward flow. Northward flows peaked around 635MW on Friday at 8.00am.

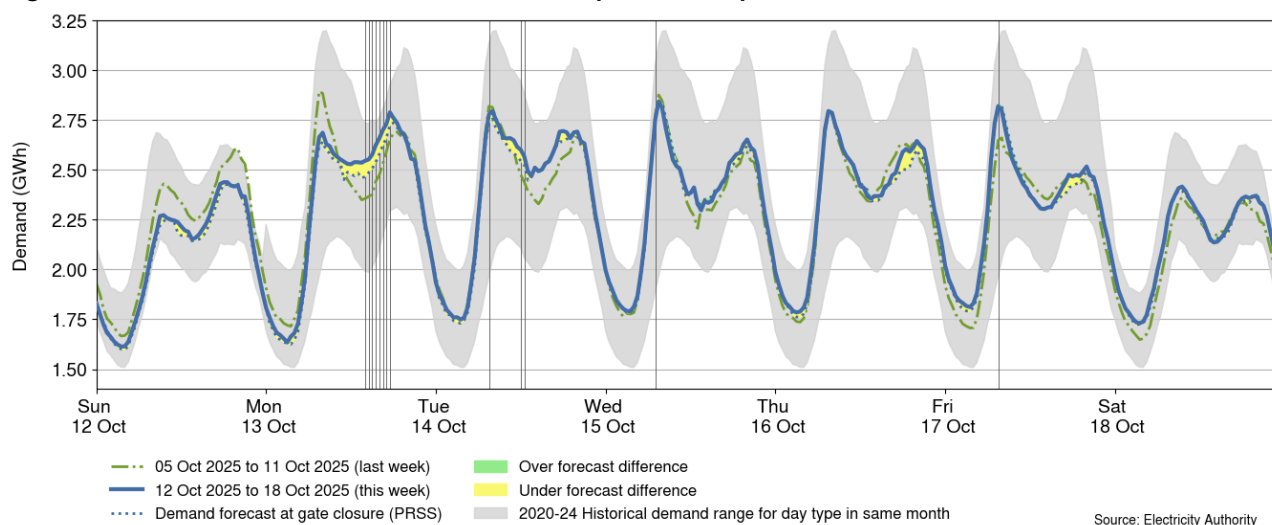
Figure 6: HVDC flow and capacity, 12-18 October 2025



6. Demand

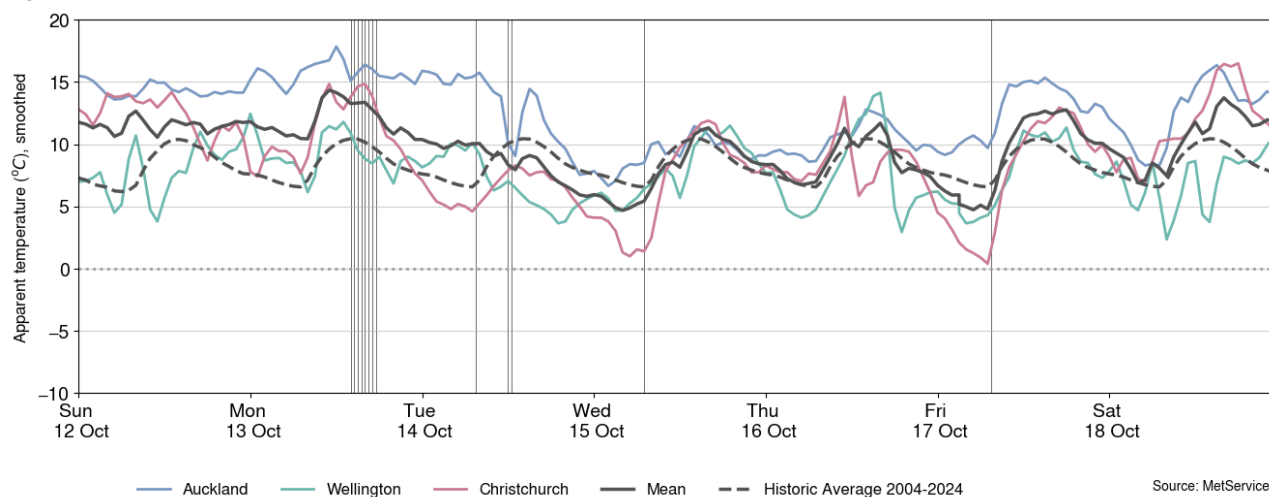
- 6.1. Figure 7 shows national demand between 12-18 October 2025, compared to the historic range and the demand of the previous week. From Tuesday, morning peak demand was higher than evening demand. The highest demand of the week was around 2.84GWh at 7.30am on Wednesday.
- 6.2. Demand was lower than forecast during several trading periods throughout the week. The largest error in the demand forecast was at 6.30pm on Thursday when demand was 206MW higher than forecast.

Figure 7: National demand, 12-18 October 2025 compared to the previous week



- 6.3. Figure 8 shows the hourly apparent temperature at main population centres from 12-18 October 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 ranged from 7°C to 19°C in Auckland, 2°C to 15°C in Wellington, and 0°C to 17°C in Christchurch.

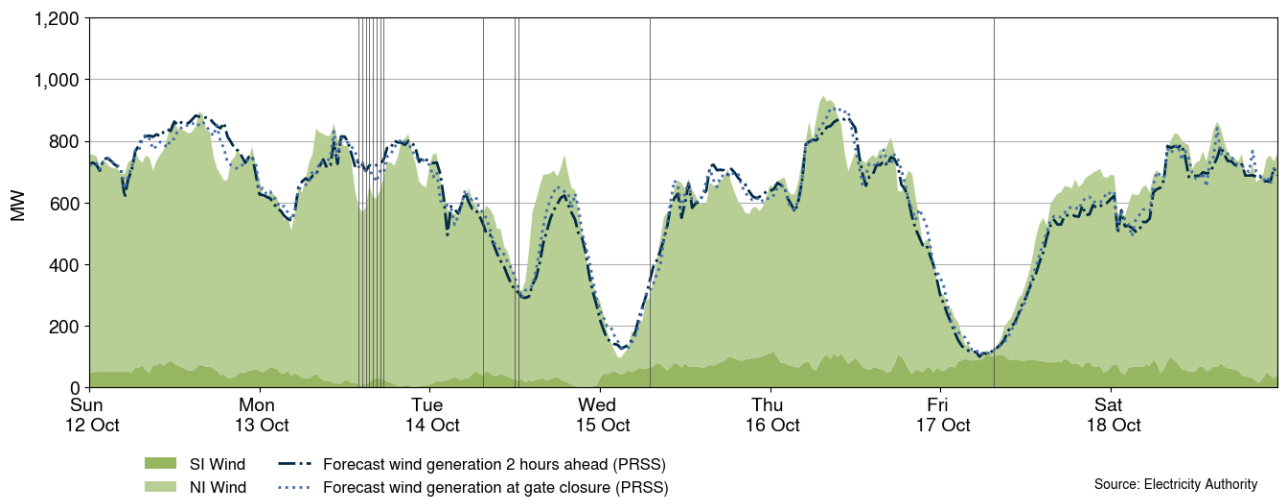
Figure 8: Temperatures across main centres, 12-18 October 2025



7. Generation

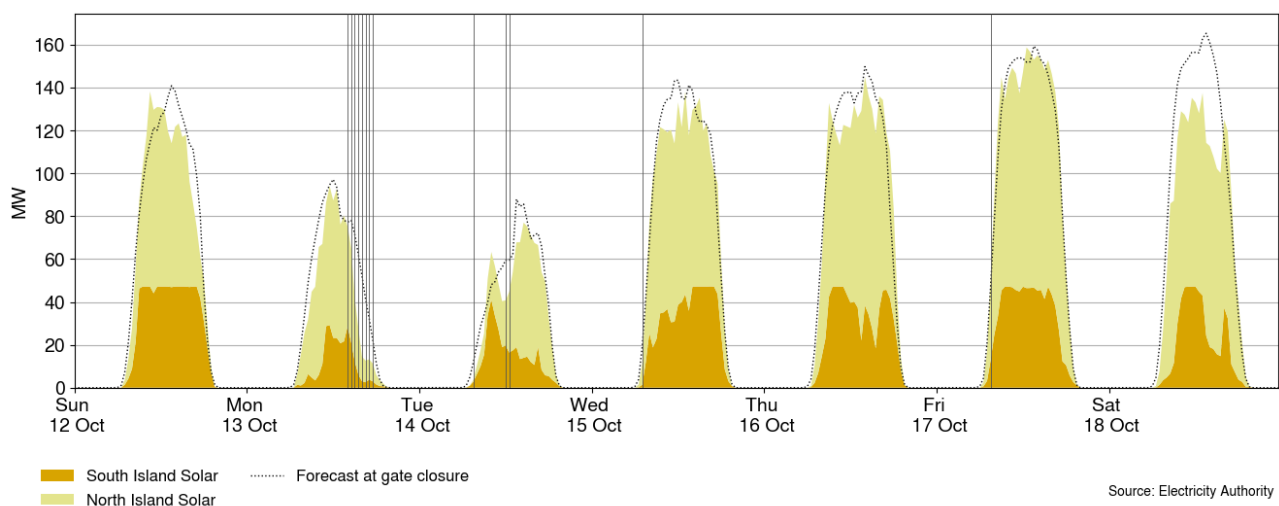
- 7.1. Figure 9 shows wind generation and forecast from 12-18 October 2025. This week wind generation varied between 97MW and 947MW, with a weekly average of 617MW.
- 7.2. Wind generation remained mostly high through Sunday and Monday. It began to decline gradually from Tuesday and was low on Wednesday morning. From Wednesday morning, wind generation increased steadily. Wind was high on Thursday, declined on Friday, and was relatively high again on Saturday.
- 7.3. Wind generation was mostly steady at, or above 600MW this week, with drops below 400MW occurring around midday on Tuesday and on Wednesday and Friday mornings.

Figure 9: Wind generation and forecast, 12-18 October 2025



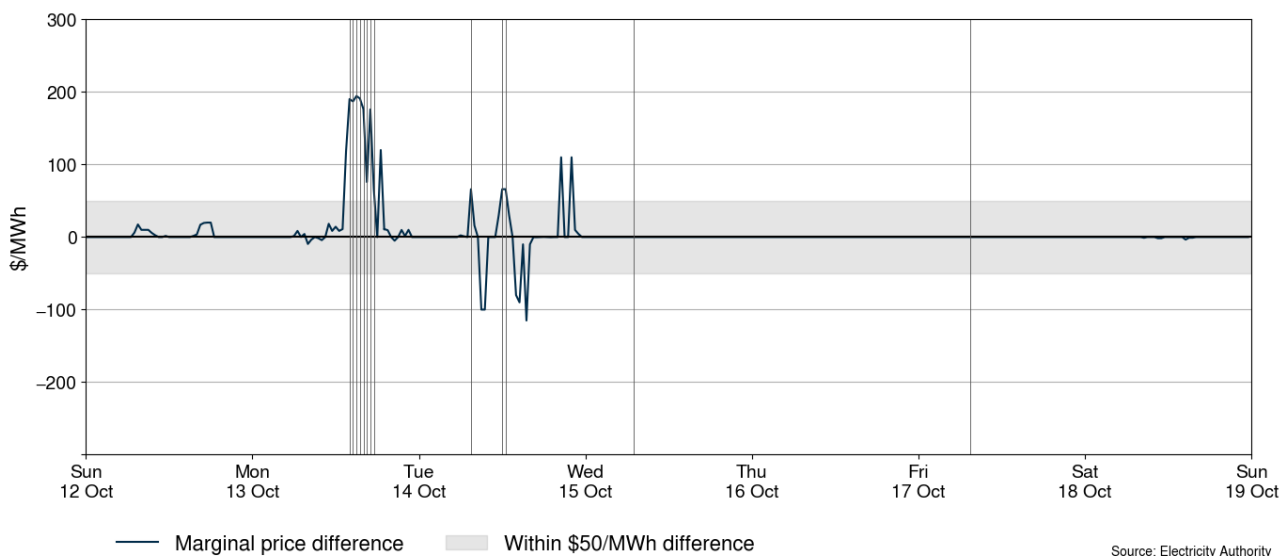
- 7.4. Figure 10 shows grid connected solar generation from 12-18 October 2025. Solar generation peaked above 120MW most days, except on Monday and Tuesday when it was low. Solar generation reached a maximum of around 159MW on Friday at 12.30pm.

Figure 10: Grid connected solar generation, 12-18 October 2025



- 7.5. 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 (PRSS¹) 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.
- 7.6. 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 +\$194/MWh occurred at 3.00pm on Monday during one of the spot price spikes, when demand was 140MW higher than forecast, and wind was 120MW lower than forecast.

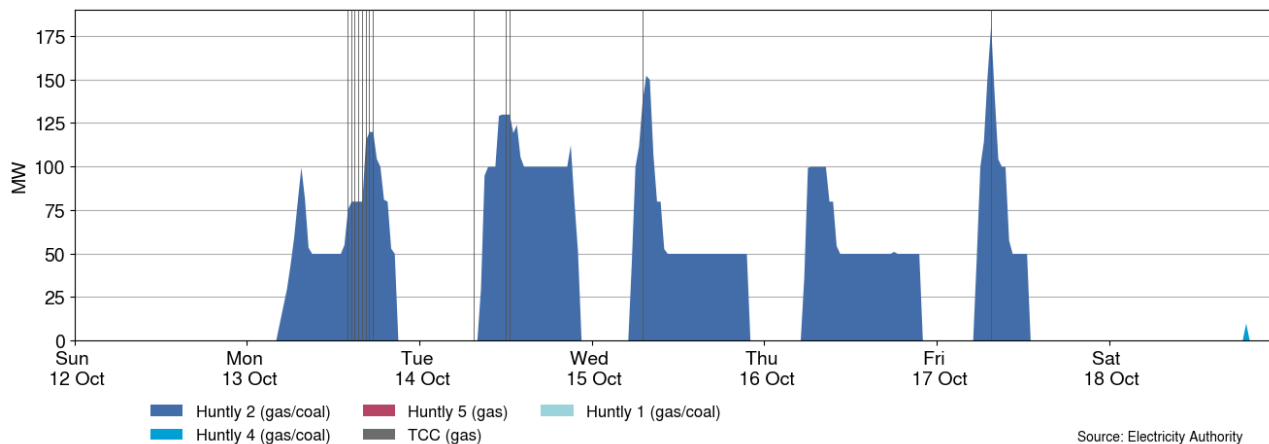
Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 12-18 October 2025



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

7.7. Figure 12 shows the generation of thermal baseload between 12-18 October 2025. Huntly 2 generated during the daytime from Monday to Friday.

Figure 12: Thermal baseload generation, 12-18 October 2025



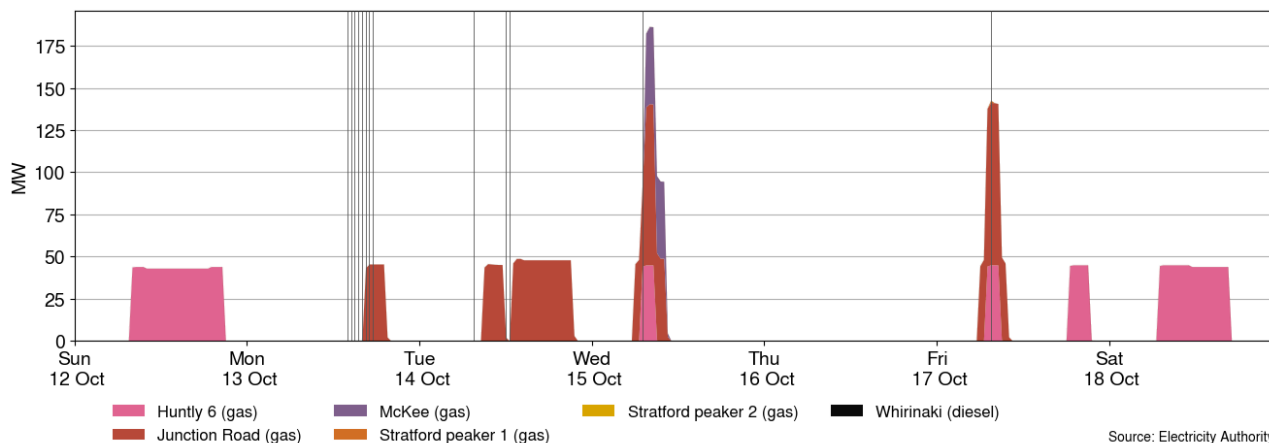
7.8. Figure 13 shows the generation of thermal peaker plants between 12-18 October 2025.

7.9. Junction Road ran on Monday during the evening peak demand, on Tuesday between the morning and evening, and on Wednesday and Friday during the morning peak demand period.

7.10. Huntly 6 ran continuously between the morning and evening peaks on Sunday and Saturday, during the morning peak on Wednesday, and during both morning and evening peaks on Friday.

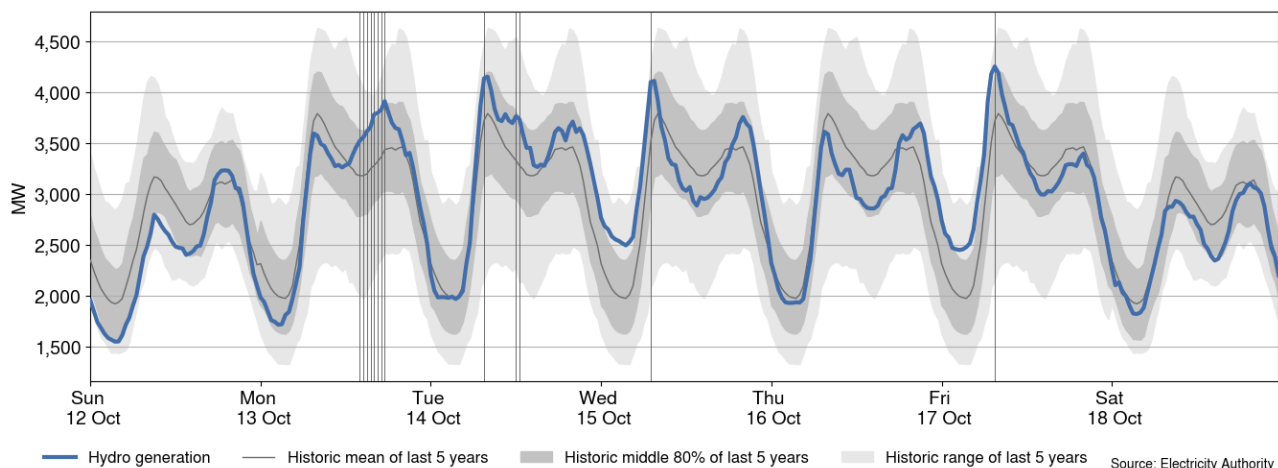
7.11. McKee ran only on Wednesday during the morning peak demand period. Stratford peaker 1 ran for one 5-minute interval during the Friday morning peak.

Figure 13: Thermal peaker generation, 12-18 October 2025



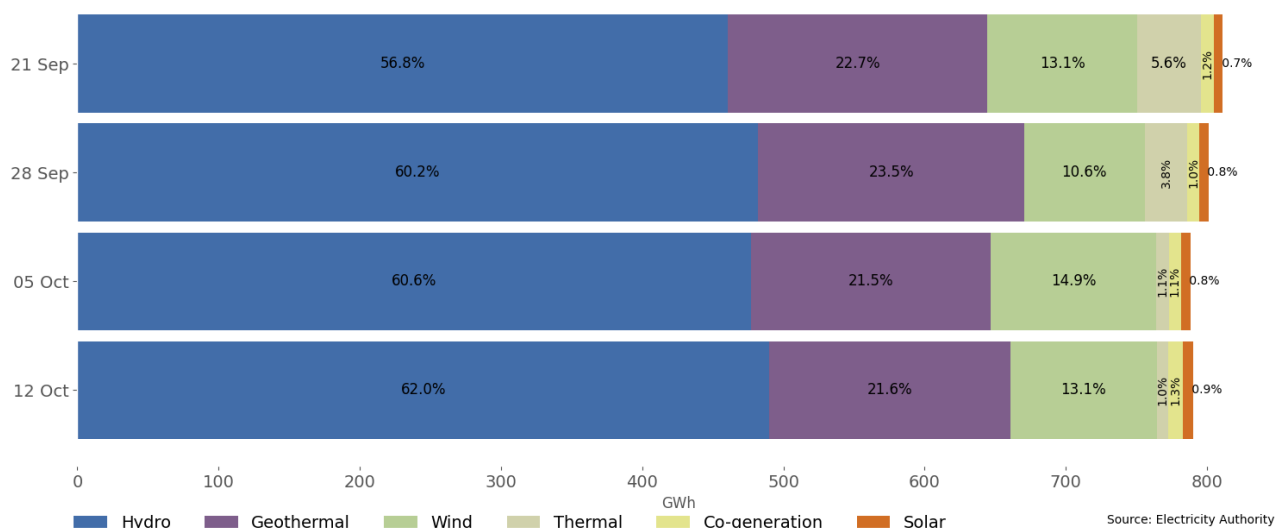
7.12. Figure 14 shows hydro generation between 12-18 October 2025. Hydro generation remained mostly within the middle 80% of historic generation. Hydro generation during the Friday morning peak demand period was the highest for the week.

Figure 14: Hydro generation, 12-18 October 2025



7.13. Hydro generation increased and wind generation reduced compared to last week. As a percentage of total generation, between 12-18 October 2025, total weekly hydro generation was 62.0%, geothermal 21.6%, wind 13.1%, thermal 1.0%, co-generation 1.3%, and solar (grid connected) 0.9%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 21 September and 18 October 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 12-18 October 2025 ranged between ~1,594MW and ~2,726MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

- (a) TCC was on outage until 15 October 2025.
- (b) Huntly 4 is on extended partial outage until 22 October 2025.
- (c) Huntly 1 is on outage until 31 October 2025.
- (d) Ruakākā battery was on full or partial outage for most of the week.

- (e) Manapōuri unit 5 was on outage between 14-16 October 2025.
- (f) Kawerau geothermal is on outage until 23 October 2025.
- (g) Benmore unit 6 is on outage until 10 November 2025.
- (h) Ōhau B is on partial outage until 17 October 2025.

8.3. Some long-term outages include:

- (a) Ōhau A is on partial outage until 4 February 2026.
- (b) Ōhau C is on partial outage until 13 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, 12-18 October 2025

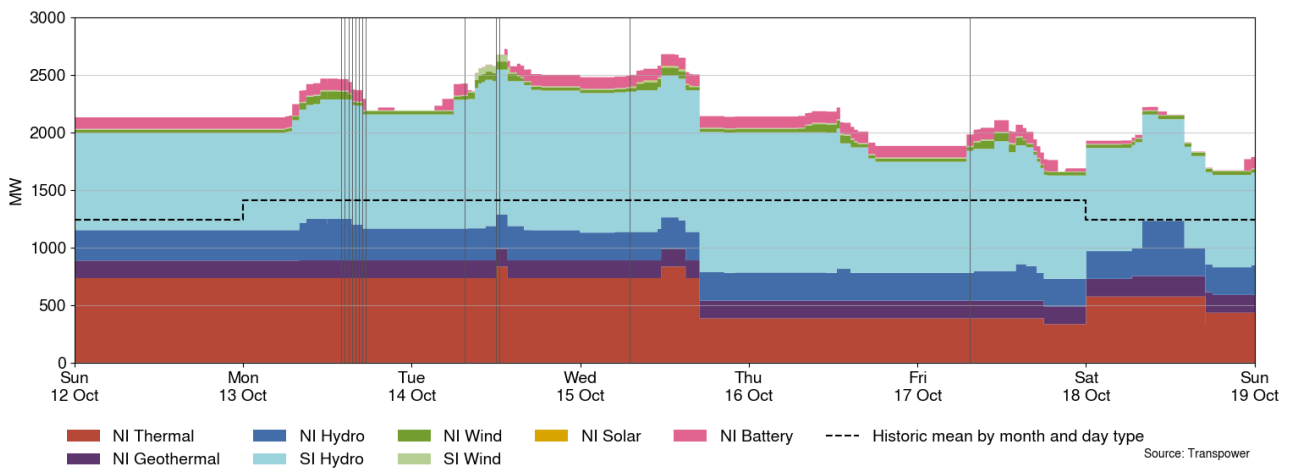
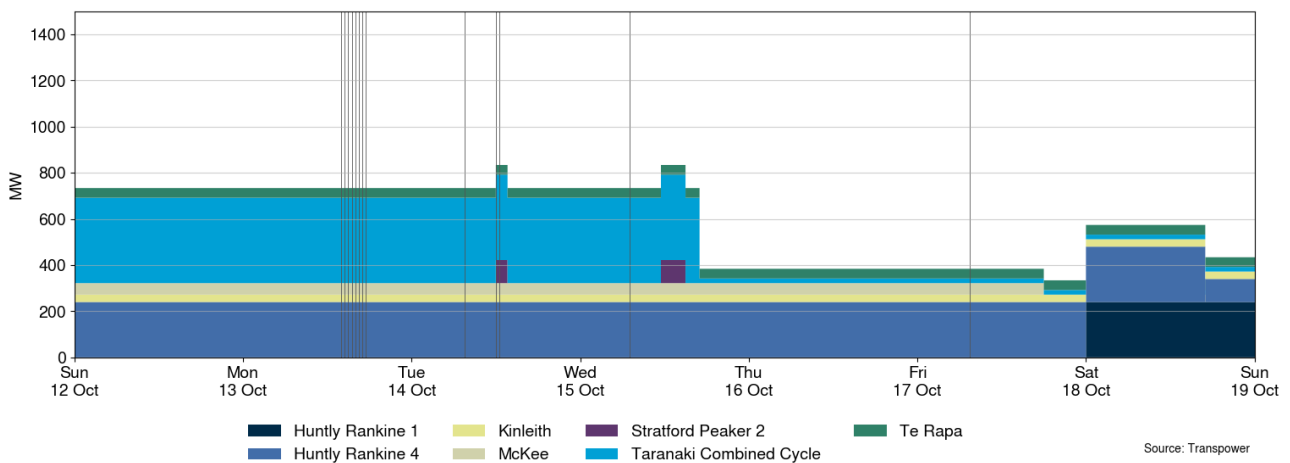


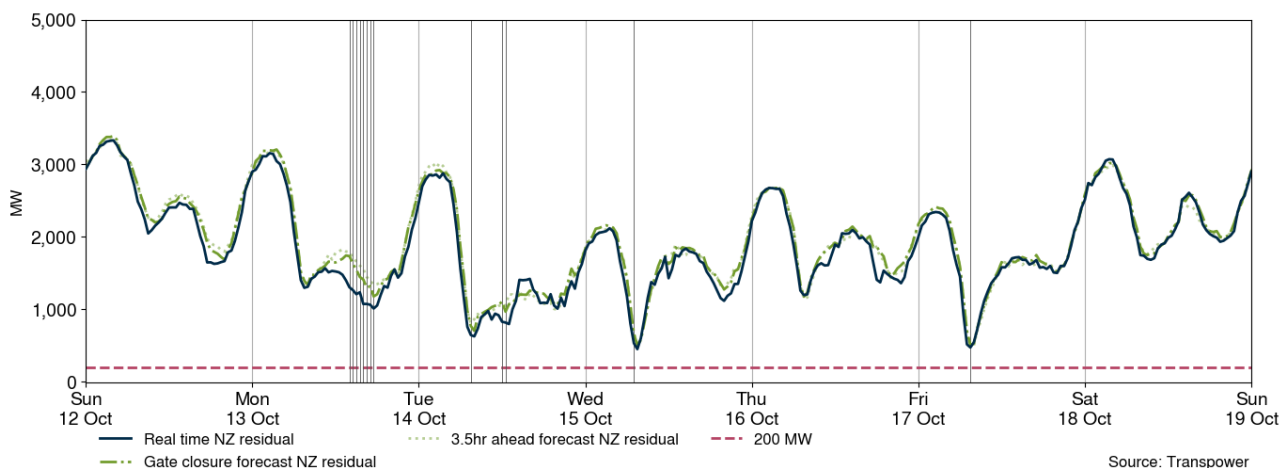
Figure 17: Total MW loss from thermal outages, 12-18 October 2025



9. Generation balance residuals

- 9.1. Figure 18 shows the national generation balance residuals between 12-18 October 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 451MW on Wednesday at 7.30am.

Figure 18: National generation balance residuals, 12-18 October 2025

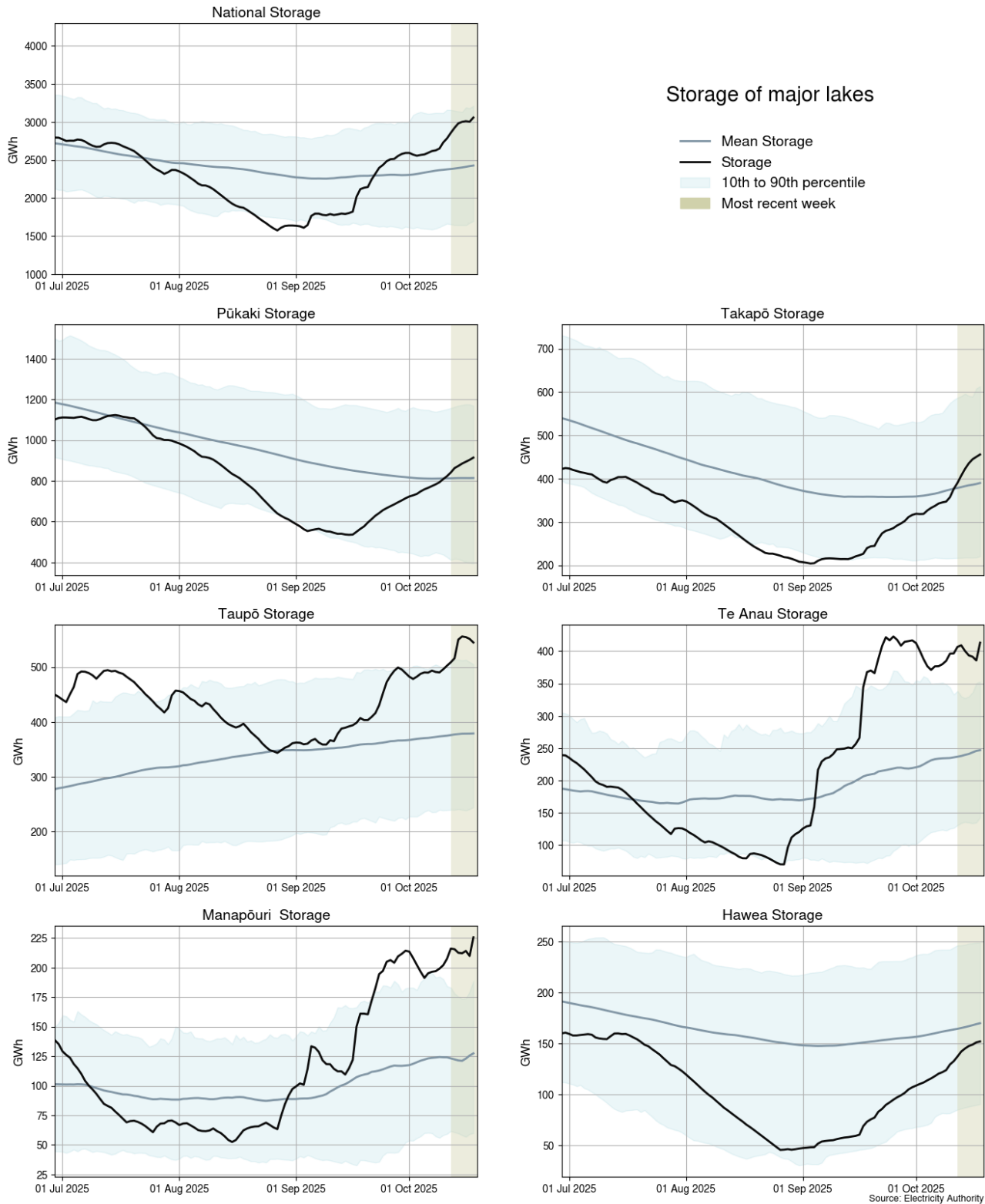


10. Storage/fuel supply

- 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 18 October 2025, national controlled hydro storage increased to 75% of nominal full and ~120% of the historical average for this time of the year.
- 10.3. Storage at Lake Pūkaki (53% full²) and Lake Takapō (60% full) is above their respective historic mean.
- 10.4. Storage at Lake Te Anau (154% full) and Lake Manapōuri (142% full) is above their respective historic 90th percentile. Both lakes have exceeded their respective storage capacities.
- 10.5. Storage at Lake Taupō (94% full) is above its historic 90th percentile for this time of year.
- 10.6. Storage at Lake Hawea (54% full) is between its historic mean and 10th percentile.

² Percentage full values sourced from NZX hydrological summary 19 October 2025.

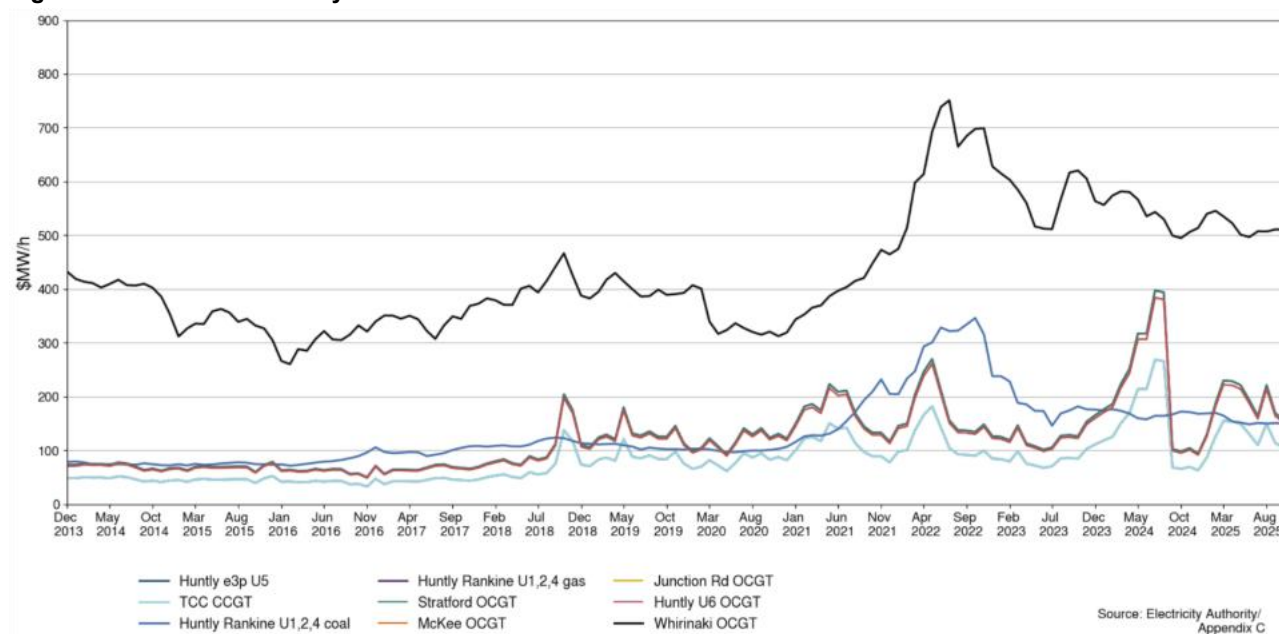
Figure 19: Hydro storage



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 October 2025. Coal was last updated on 1 August so the previous prices were carried forward. The SRMCs for gas powered generation have decreased, while the SRMC for diesel fuelled generation has remained stable.
- 11.4. The latest SRMC of coal-fuelled Rankine generation is ~\$150/MWh. The cost of running the Rankines on gas is ~\$157/MWh.
- 11.5. The SRMCs of gas fuelled thermal plants are currently between \$105/MWh and \$157/MWh.
- 11.6. The SRMC of Whirinaki is ~\$510/MWh.
- 11.7. More information on how the SRMC of thermal plants is calculated can be found in [Appendix C](#).

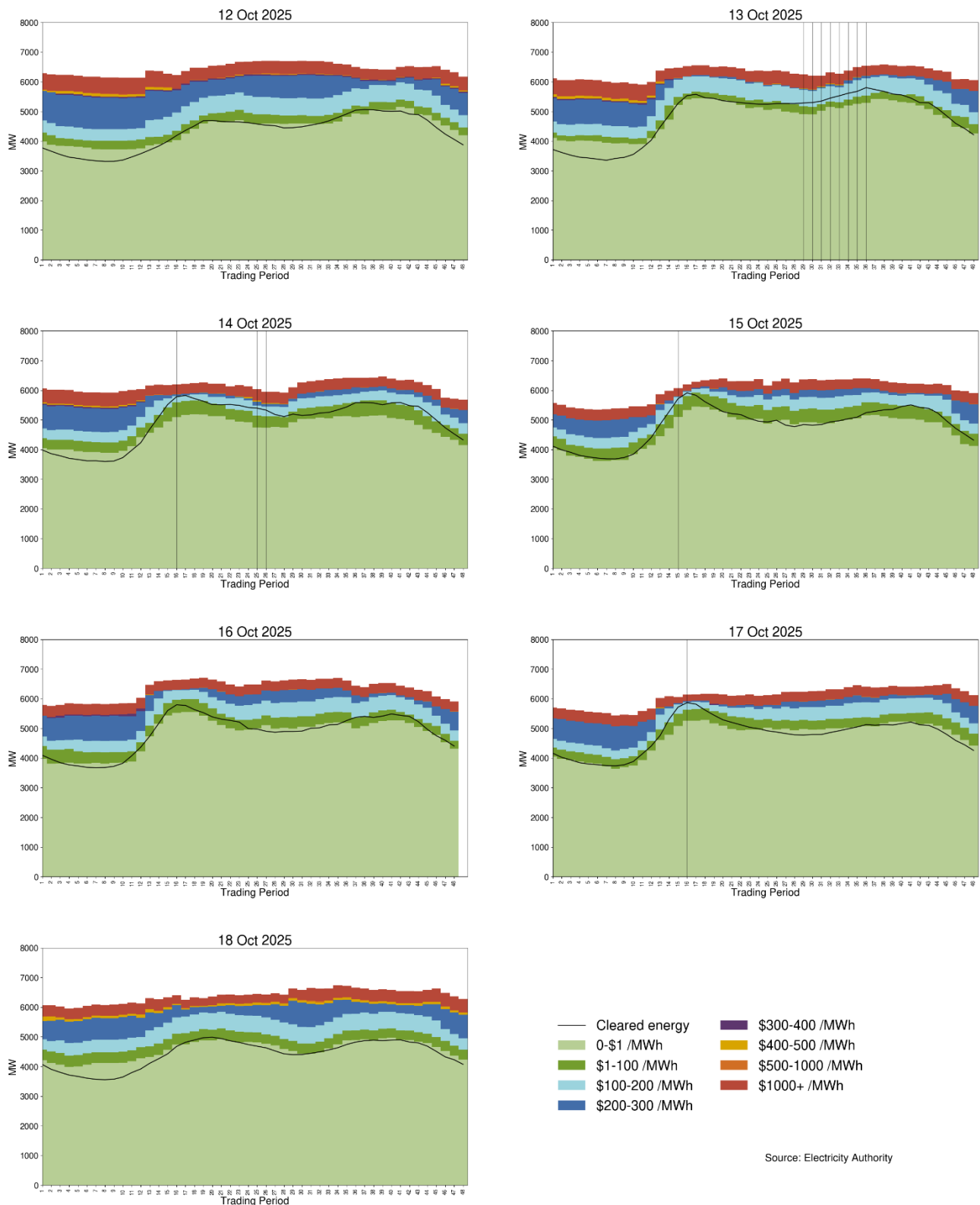
Figure 20: Estimated monthly SRMC for thermal fuels



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. Most energy cleared below \$100/MWh on the weekend. On weekdays most offers cleared in the <\$200/MWh range. Due to wind and/or demand forecast errors, some energy cleared into the next pricing band of \$200-\$300/MWh.

Figure 21: Daily offer stacks³

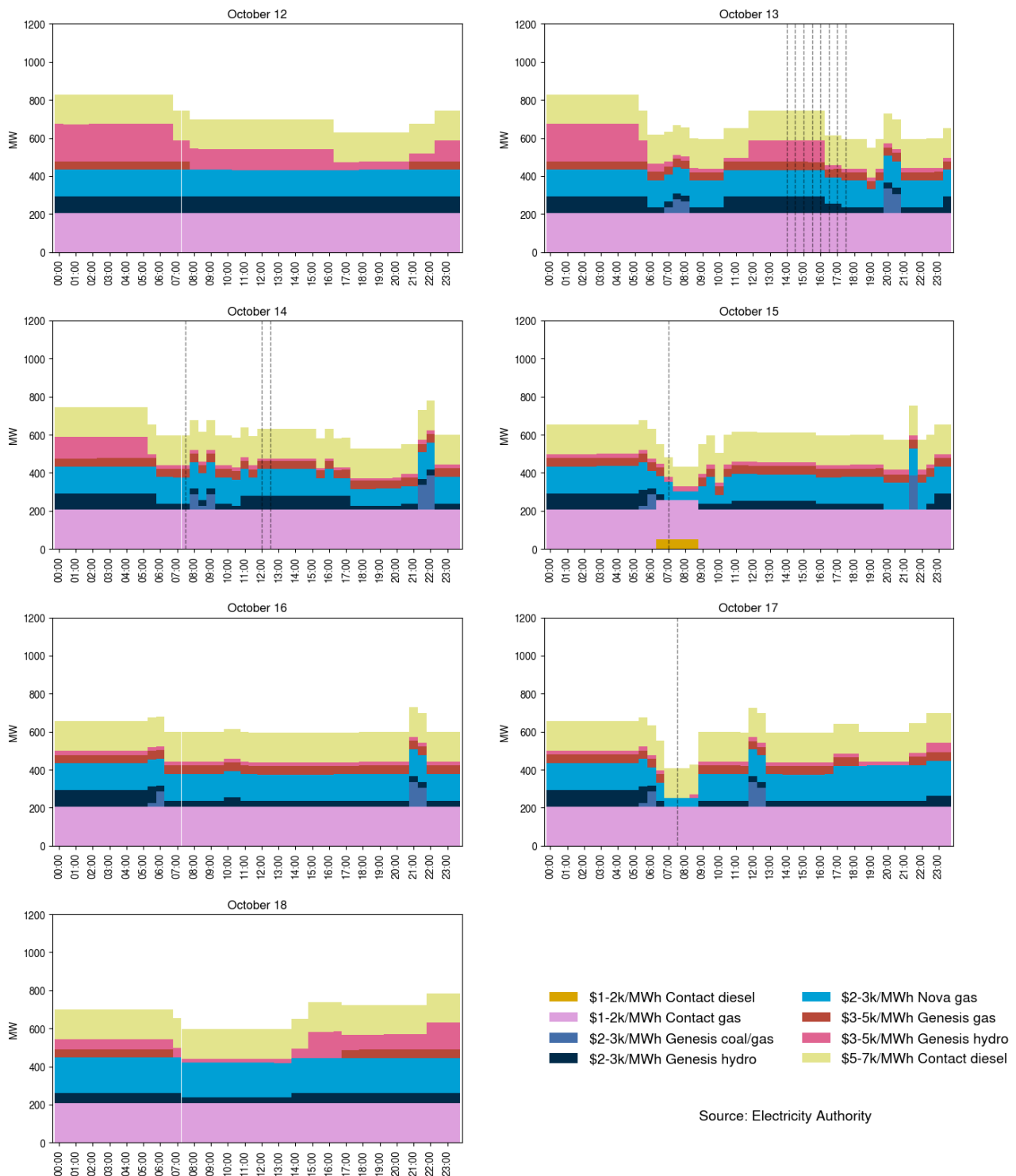


12.3. Figure 22 shows offers above \$1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

³ RTD data for TP24 was unavailable on Thursday.

- 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 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 654MW per trading period was priced above \$1,000/MWh this week, which is roughly 13% of the total energy available.

Figure 22: High priced offers



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
8/05/2025-9/05/2025	Several	Further analysis	Genesis	Waikaremoana	Offers
01/10/2025-04/-10/2025	Several	Further analysis	Genesis	Huntly	Offers