

13 October 2026

Trading conduct report 4-10 October 2026

Market monitoring weekly report

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1. Overview

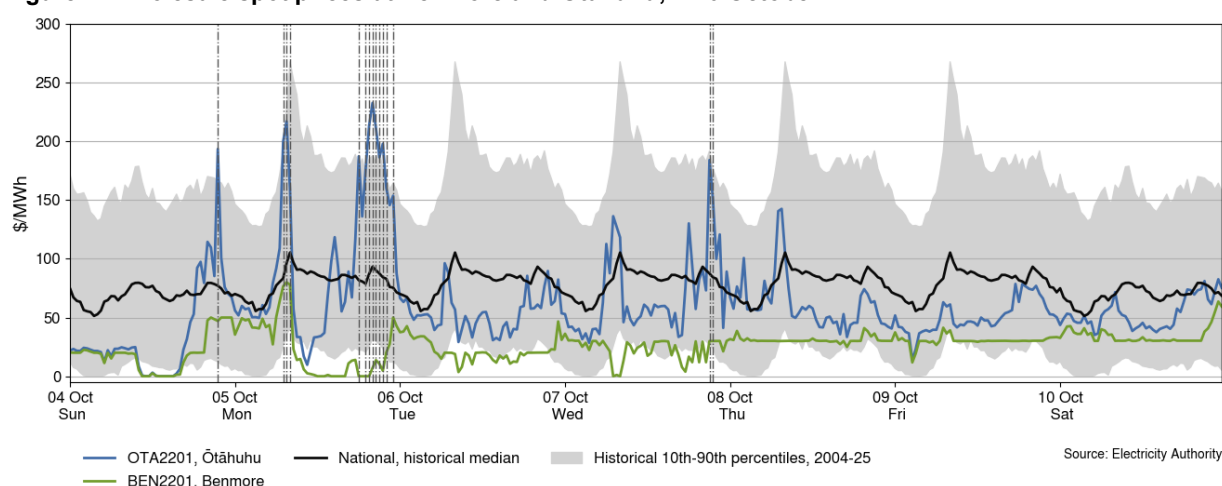
- 1.1. Spot prices have increased this week due to low wind generation, reducing the availability of cheap energy, and high northward HVDC resulting in periods of North Island price separation. Hydro and thermal generation increased this week. National hydro storage decreased to 78% nominally fully and 121% of the historic 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 4-10 October:
 - (a) The average spot price for the week was \$46/MWh, an increase of around \$16/MWh compared to the previous week.
 - (b) 95% of prices fell between \$0.02/MWh and \$148/MWh.
- 2.3. Prices have increased this week due to low wind generation decreasing the availability of cheap energy, and high northward HVDC flows leading to extended periods of elevated prices and price separation.
- 2.4. From 6.00pm to 11.00pm on Monday the spot price at Ōtāhuhu was above \$150/MWh, reaching a maximum of \$232/MWh at 8.00pm. At this time the spot price at Benmore was \$7/MWh. During this time:
 - The HVDC was binding, having reached its northward flow capacity.
 - Demand was higher than forecast at times, up to 120MW.
- 2.5. At 9.30pm on Sunday the spot price at Ōtāhuhu spiked up to \$193/MWh. At this time the spot price at Benmore was \$47/MWh. During this time:
 - North Island fast instantaneous reserve (FIR) prices were high, spiking up to \$102/MWh.
 - Demand was 117MW higher than forecast.
 - Intermittent generation was 48MW lower than forecast.
 - National residual generation was 252MW lower than forecast.
- 2.6. At 7.30am on Monday the spot price at Ōtāhuhu spiked up to \$217/MWh. At this time the spot price at Benmore was \$80/MWh. During this time:
 - North Island FIR prices were high, spiking up to \$91/MWh.
 - Total wind generation was less than 50MW.

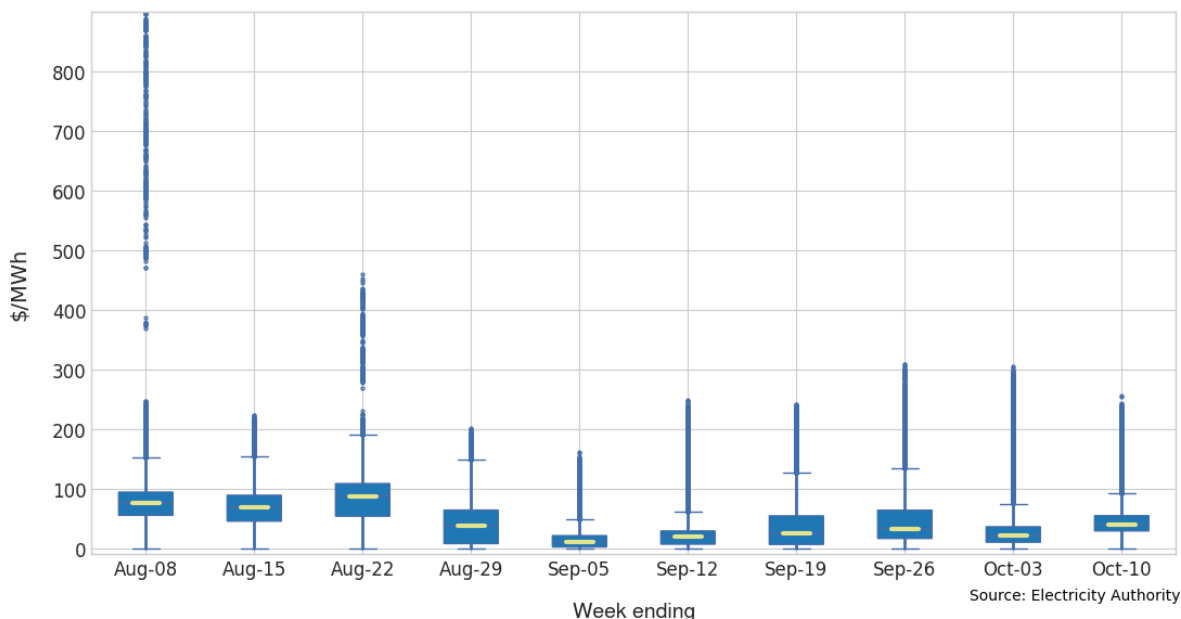
- National residual generation was very low at 287MW due to low wind generation and peak demand for the week, likely caused by cold weather.
- 2.7. At 9.00pm on Wednesday the spot price at Ōtāhuhu spiked up to \$184/MWh. At this time the spot price at Benmore was \$29/MWh. During this time:
- North Island FIR prices were high, spiking up to \$109/MWh.
 - Demand was 56MW higher than forecast.
 - Intermittent generation was 60MW lower than forecast.
- 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. Other notable prices are marked with black dashed lines.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 4-10 October



- 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 wider than last week. The median price was \$46/MWh and most prices (middle 50%) fell between \$29/MWh and \$55/MWh.

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



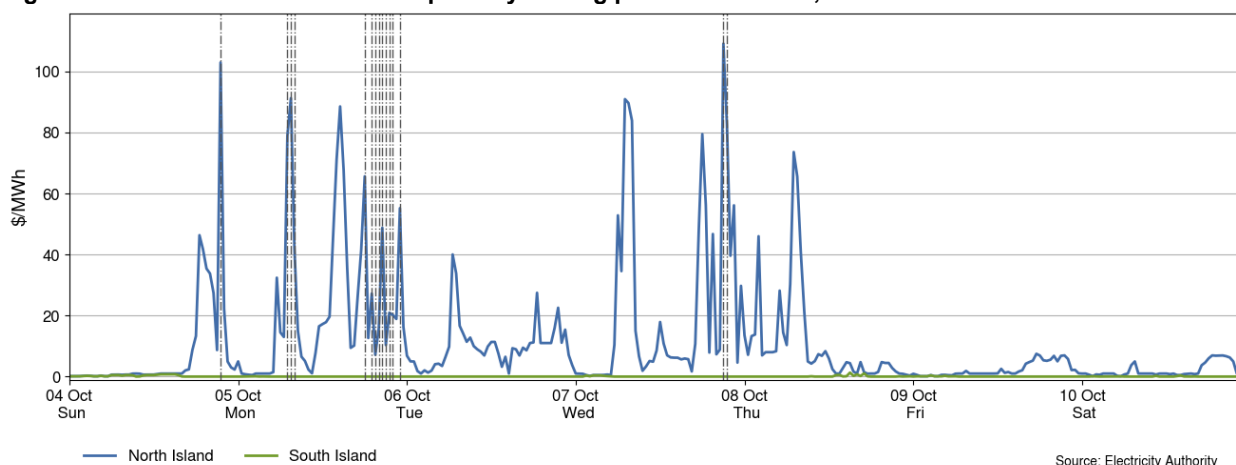
3. Reserve prices

- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below \$10/MWh this week. Due to high HVDC flows throughout the week, the HVDC set the risk for much of the week increasing demand for FIR.
- 3.2. At 9.30pm on Sunday, the North Island FIR price spiked up to \$102/MWh. During this time the HVDC was setting the risk and the amount of FIR offered between \$1-10/MWh decreased by ~100MW.
- 3.3. At 7.30am on Monday, the North Island FIR price spiked to \$91/MWh. At this time the HVDC was setting the risk, and national residual generation was 67MW lower than forecast. This meant that plants that would have been able to provide reserve were dispatched for energy instead, decreasing the volume of FIR available.
- 3.4. From 6.00-11.00pm on Monday, FIR prices were elevated as northward HVDC flows were extremely high, being maintained at 30MW below the northward flow limit. The HVDC was setting the risk during this time.¹
- 3.5. From 6.00-8.00am on Wednesday, North Island FIR prices were above \$40/MWh, peaking at \$91/MWh at around 7.00am. The HVDC was setting the risk during this time and battery FIR offers reduced significantly during this time as Ruakākā and Glenbrook were dispatched for energy.
- 3.6. At 9.00pm on Wednesday, the North Island FIR price spiked up to \$109/MWh. At this time the HVDC was setting the risk, national residual generation had a sharp

¹ Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these being the one that determines the required quantity of instantaneous reserve. Reserve to cover generator risks can be shared between the North and South Islands. However, reserve to cover HVDC risks must be located in the receiving island. Because SPD (scheduling, pricing and dispatch) co-optimises energy and reserve, when an HVDC risk binds it can cause both energy and reserve price separation between the islands.

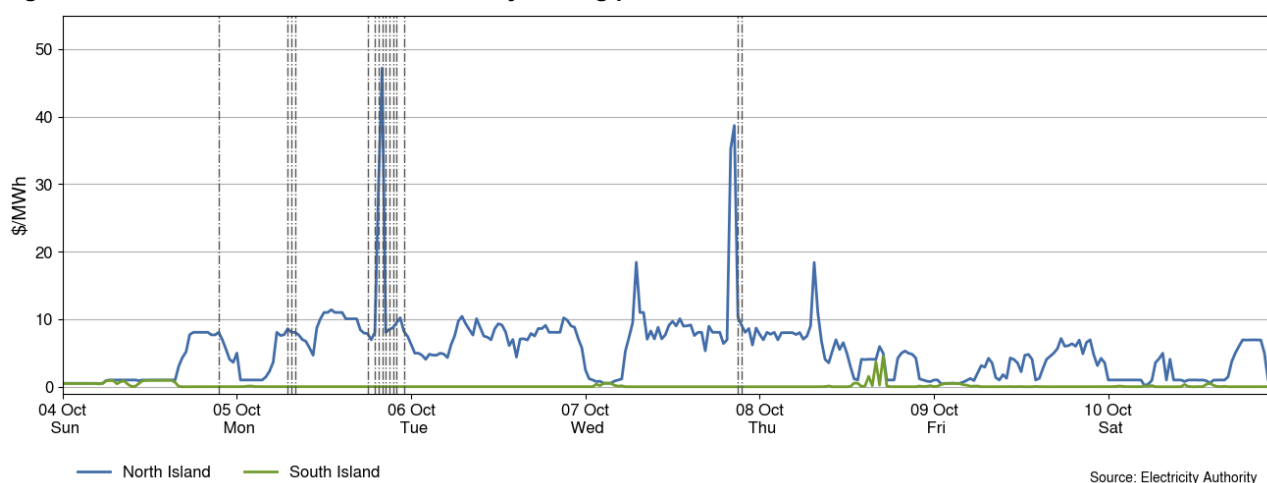
decrease of 156MW which was not forecast. This meant that plants that would have been able to provide reserve were dispatched for energy instead, decreasing the volume of FIR available.

Figure 3: Fast instantaneous reserve price by trading period and island, 4-10 October



- 3.7. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below \$8/MWh this week.
- 3.8. At 8.00pm on Monday, the North Island SIR price spiked to \$47/MWh. At this time the HVDC was setting the risk, and the Glenbrook and Ruakākā batteries were unable to provide reserve due to a low state of charge.
- 3.9. At 8.30pm on Wednesday, the North Island SIR price spiked to \$38/MWh. At this time the HVDC was setting the risk, the volume of required SIR increased, and the volume of SIR available decreased.

Figure 4: Sustained instantaneous reserve by trading period and island, 4-10 October



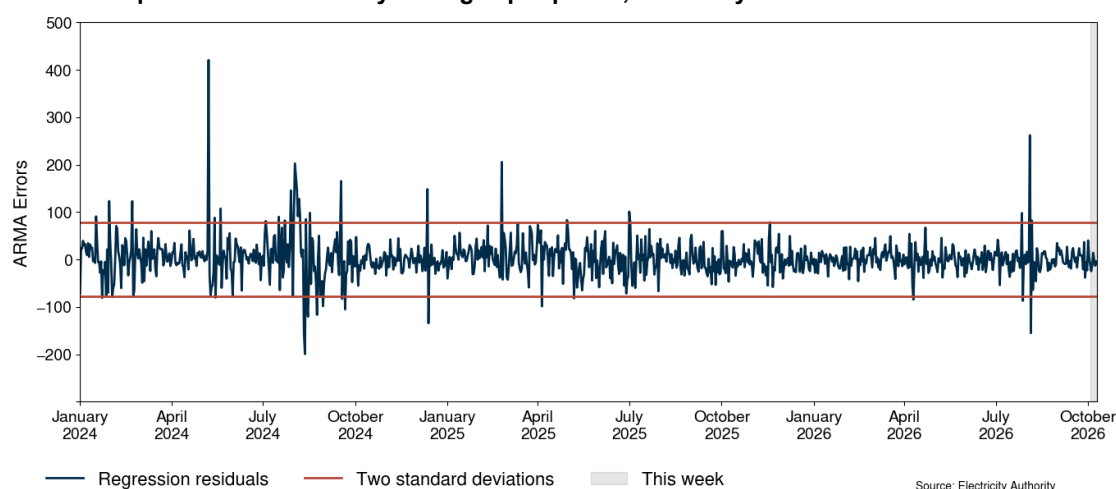
4. Regression residuals

- 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.

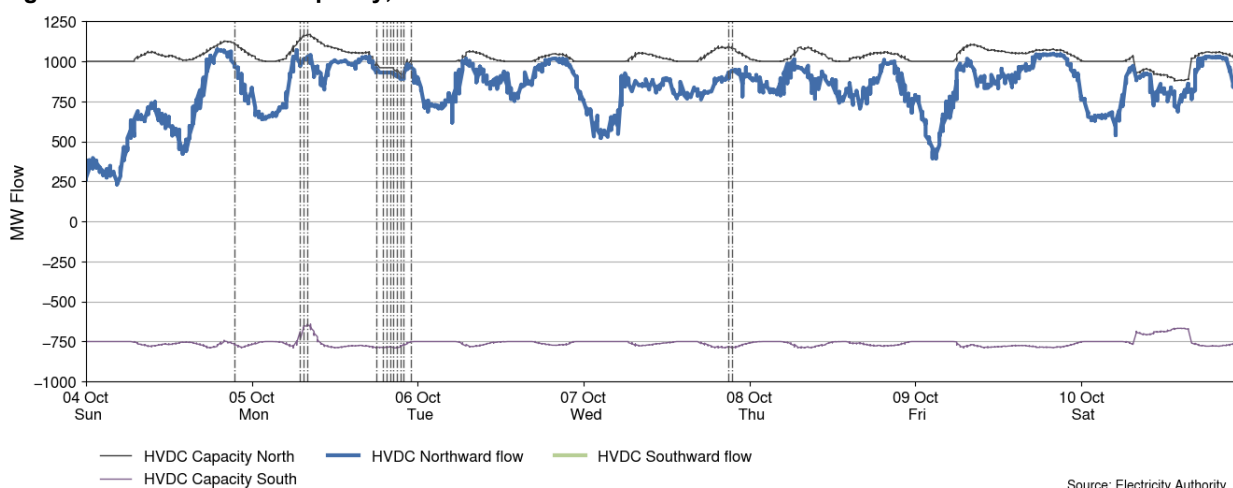
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 10 October 2026



5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 4-10 October. Due to low wind generation, lower North Island hydro generation, and high South Island hydro generation, northward HVDC flows were high this week.
- 5.2. The highest northward HVDC flow this week was 1,073MW which occurred at 7.00pm on Sunday. No southward HVDC flow occurred this week.

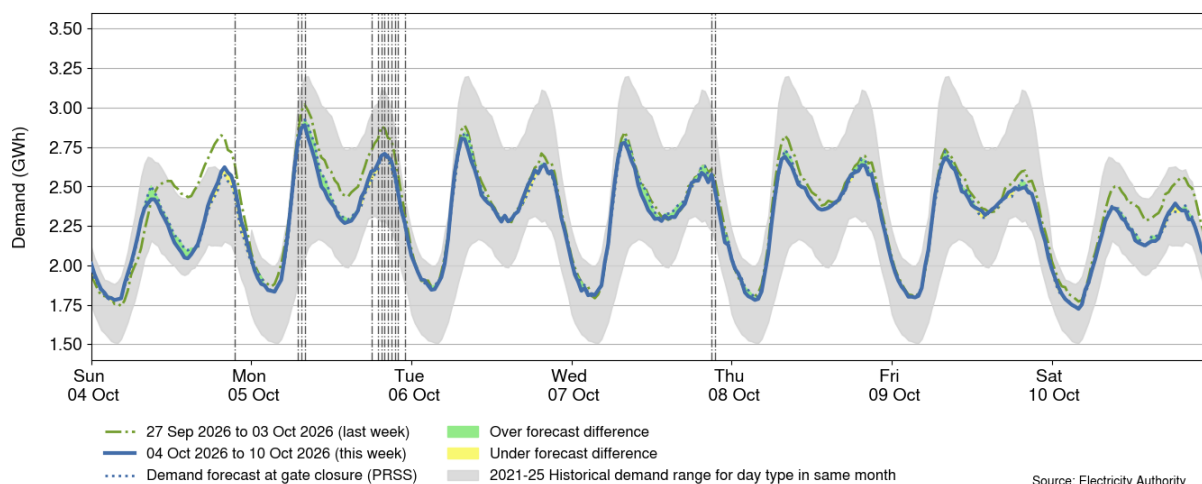
Figure 6: HVDC flow and capacity, 4-10 October



6. Demand

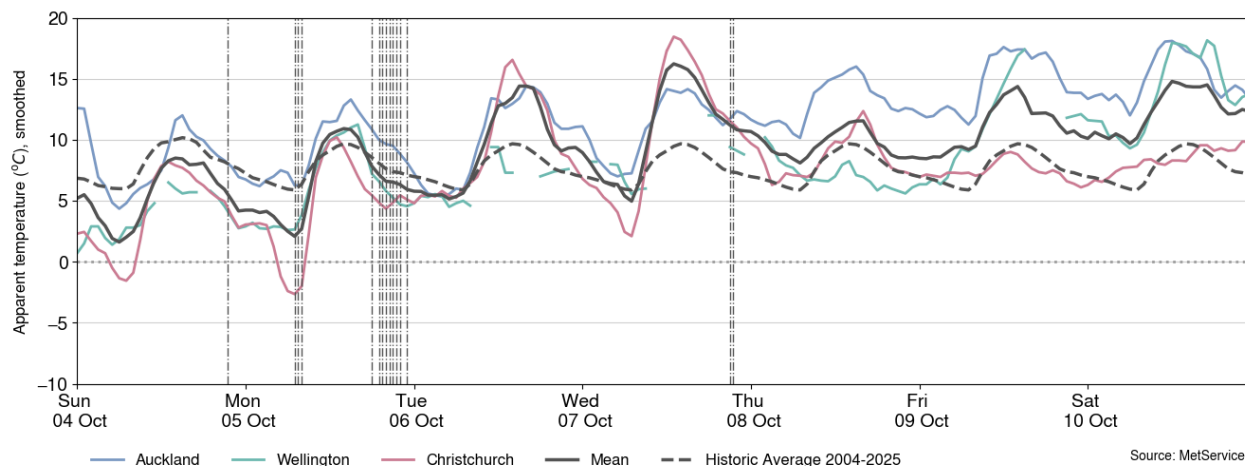
- 6.1. Figure 7 shows national demand between 4-10 October, compared to the historic range and the demand of the previous week. Demand was lower than last week on Sunday, Monday and Saturday, and similar to last week from Tuesday to Friday.
- 6.2. The maximum demand this week was around 2.89GWh (5.78GW) at 8.00am on Monday.

Figure 7: National demand, 4-10 October compared to the previous week



- 6.3. Apparent temperatures ranged from 4°C to 18°C in Auckland, 1°C to 19°C in Wellington, and -3°C to 19°C in Christchurch.
- 6.4. Figure 8 shows the hourly apparent temperature at main population centres from 4-10 October. 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.
- 6.5. Apparent temperatures ranged from 4°C to 18°C in Auckland, 1°C to 19°C in Wellington, and -3°C to 19°C in Christchurch.

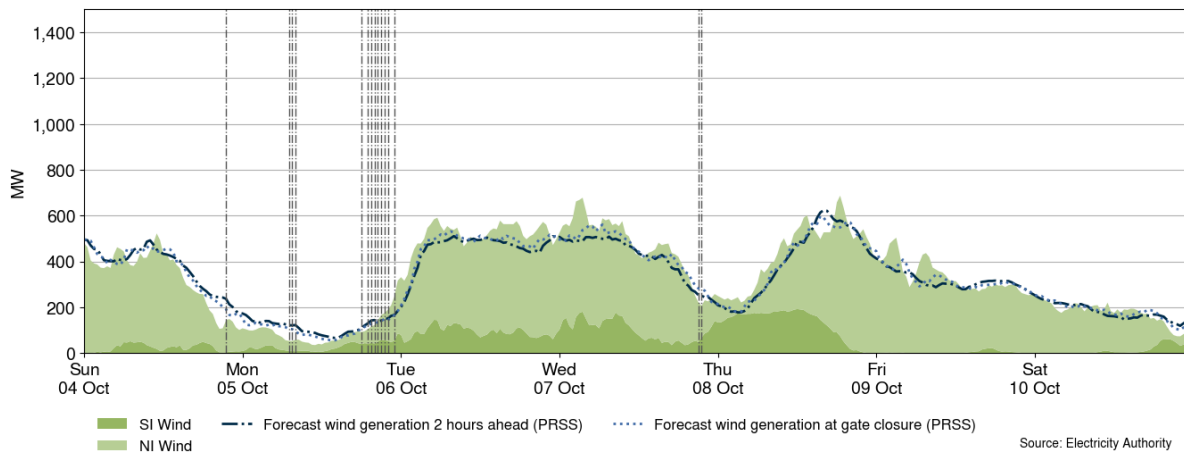
Figure 8: Temperatures across main centres, 4-10 October



7. Generation

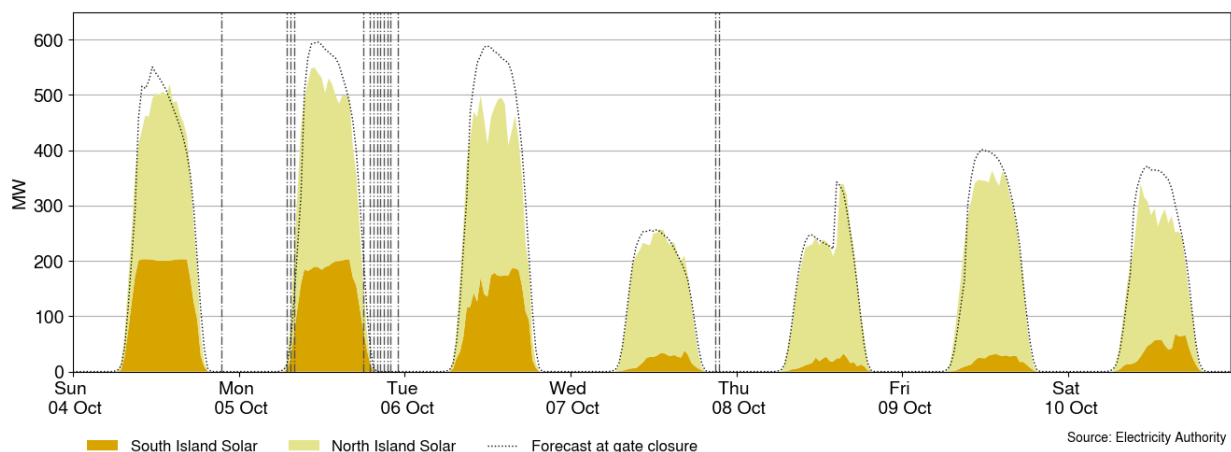
- 7.1. Figure 9 shows wind generation and forecast from 4-10 October. This week wind generation was low, varying between 35MW and 687MW, with a weekly average of 337MW.
- 7.2. Wind generation was lower than forecast from Sunday night to Monday morning. This forecasting error was due to differences at Turitea wind farm and an accumulation of errors at other wind farms.

Figure 9: Wind generation and forecast, 4-10 October



- 7.3. Figure 10 shows grid connected solar generation from 4-10 October. Solar generation was high but lower than last week. Mean daytime solar generation this week was 267MW, peaking at 549MW on Monday at 11:00am.
- 7.4. Kōwhai Park solar farm went on outage from Wednesday this week, with Tauhei solar farm also on outage from Wednesday to midday Thursday.
- 7.5. Forecasting errors on Monday and Tuesday are due to Tauhei and Kōwhai Park solar farms.

Figure 10: Grid connected solar generation, 4-10 October



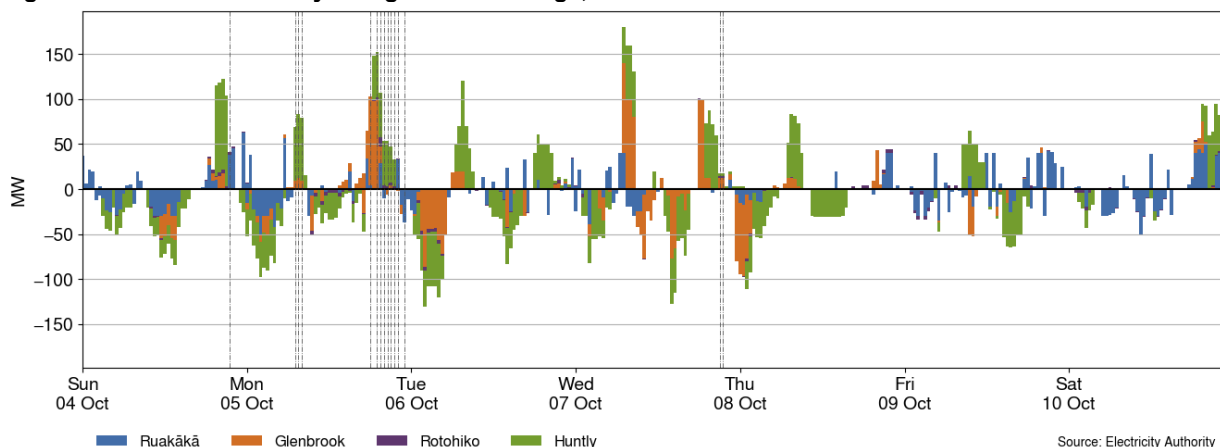
- 7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale

battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.7. This week batteries charged overnight and during the middle of the day when demand was lower and discharged during morning and evening peak demand.

7.8. Both Glenbrook and Ruakākā reached zero state of charge around 9:30pm on Monday during high prices.

Figure 11: Grid scale battery charge and discharge, 4-10 October



7.9.

7.10. The largest positive price difference of \$65/MWh occurred at 7.00am on Monday. At this time demand was 108MW higher than forecast and intermittent generation was 48MW lower than forecast.

7.11. The largest negative price difference of \$70/MWh occurred at 8.30am on Monday. At this time demand was 161MW lower than forecast and intermittent generation was 75MW lower than forecast.

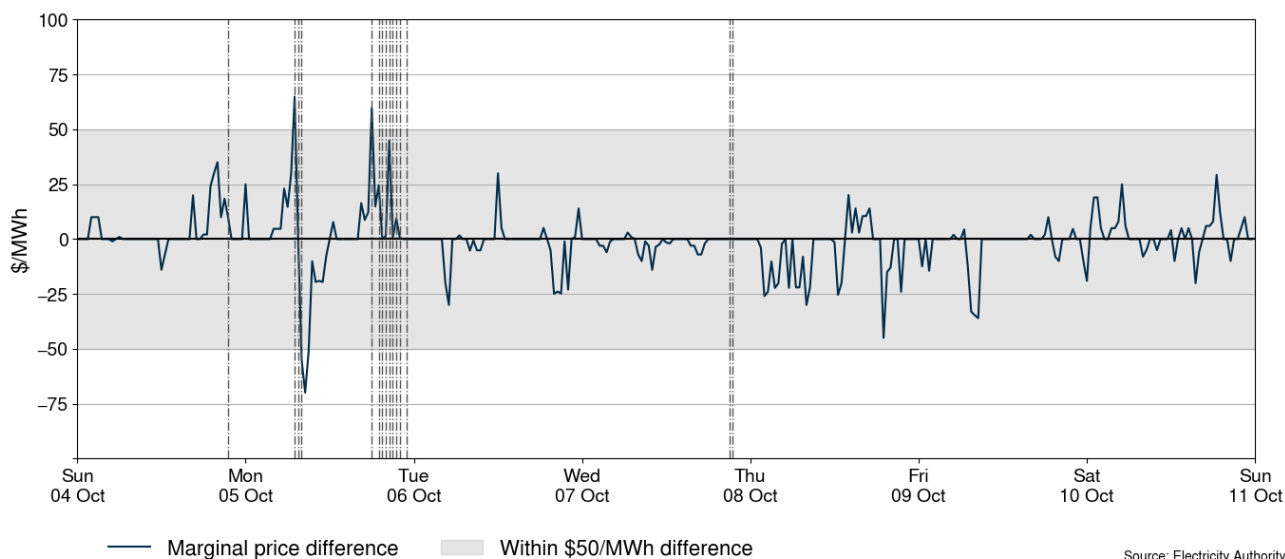
7.12. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS²) projections. The figure highlights when forecasting inaccuracies are causing 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.

7.13. The largest positive price difference of \$65/MWh occurred at 7.00am on Monday. At this time demand was 108MW higher than forecast and intermittent generation was 48MW lower than forecast.

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

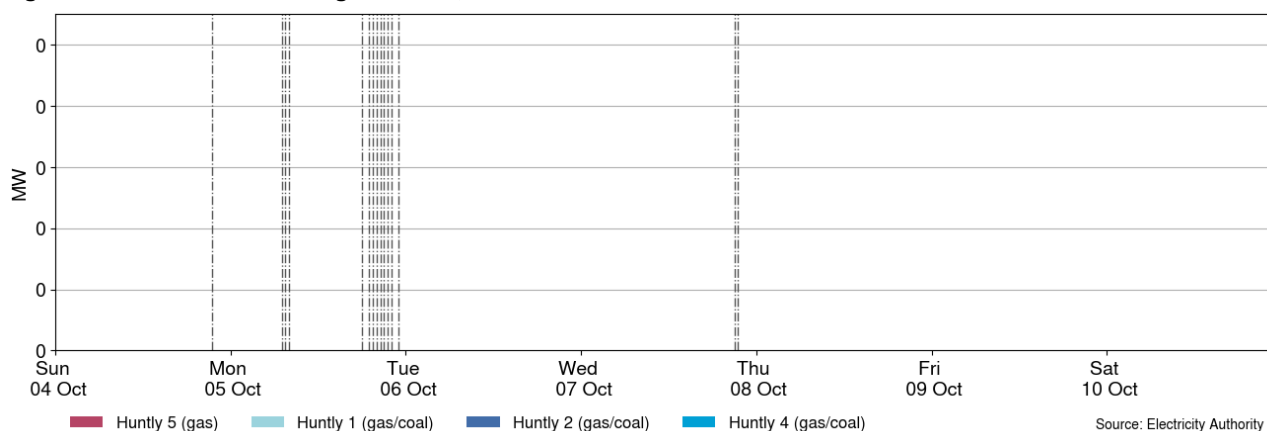
7.14. The largest negative price difference of \$70/MWh occurred at 8.30am on Monday. At this time demand was 161MW lower than forecast and intermittent generation was 75MW lower than forecast.

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, 4-10 October



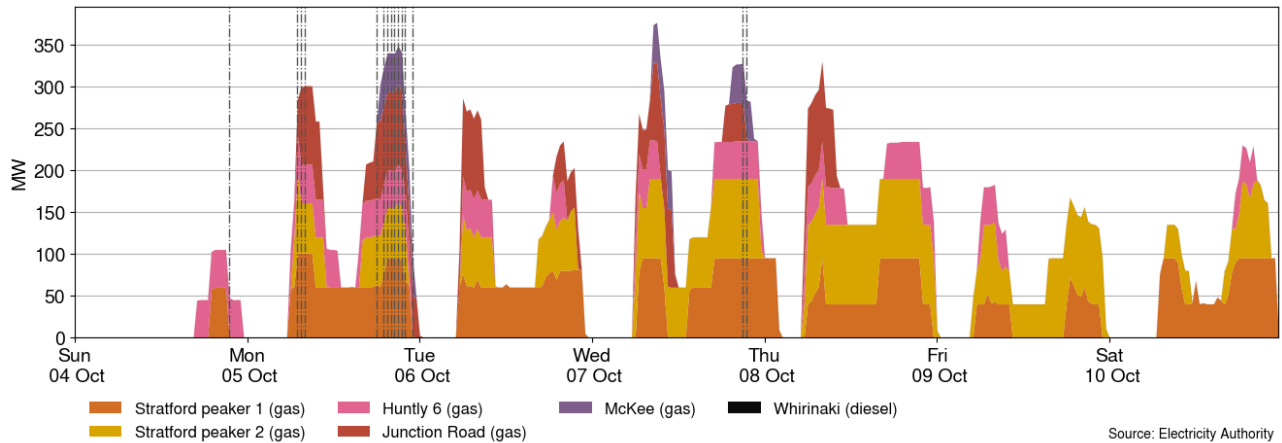
7.15. Figure 13 shows the generation of thermal baseload between 4-10 October. There was no thermal baseload generation this week.

Figure 13: Thermal baseload generation, 4-10 October



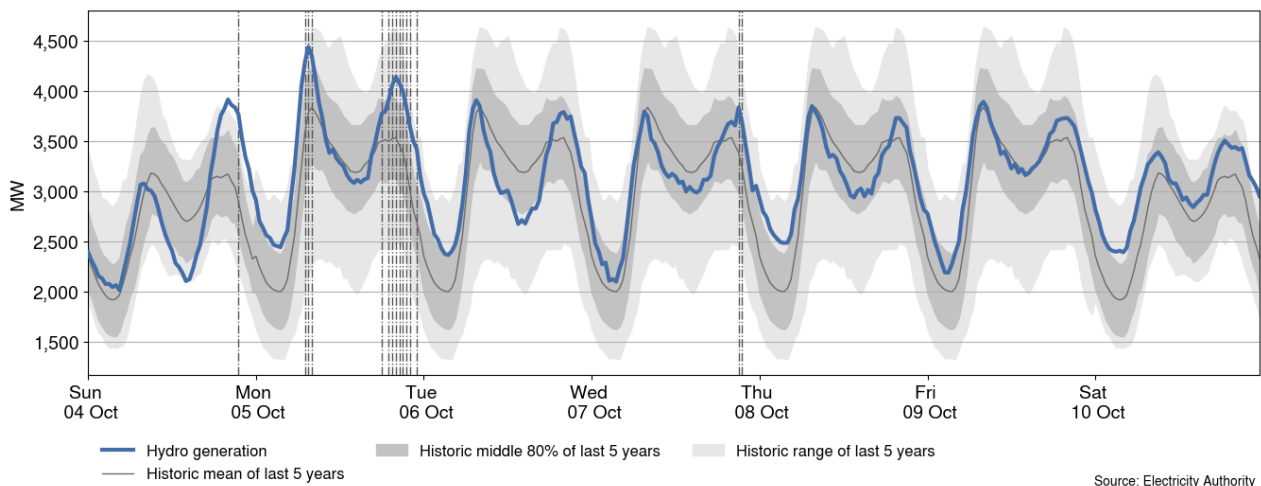
7.16. Figure 14 shows the generation of thermal peaker plants between 4-10 October. Peaker generation this week was higher than the previous week.

Figure 14: Thermal peaker generation, 4-10 October



7.17. Figure 15 shows hydro generation between 4-10 October. Hydro generation was near average from Tuesday onwards. However, Sunday evening and Monday morning saw very high hydro generation, exceeding the historic range for the past five years on Sunday evening.

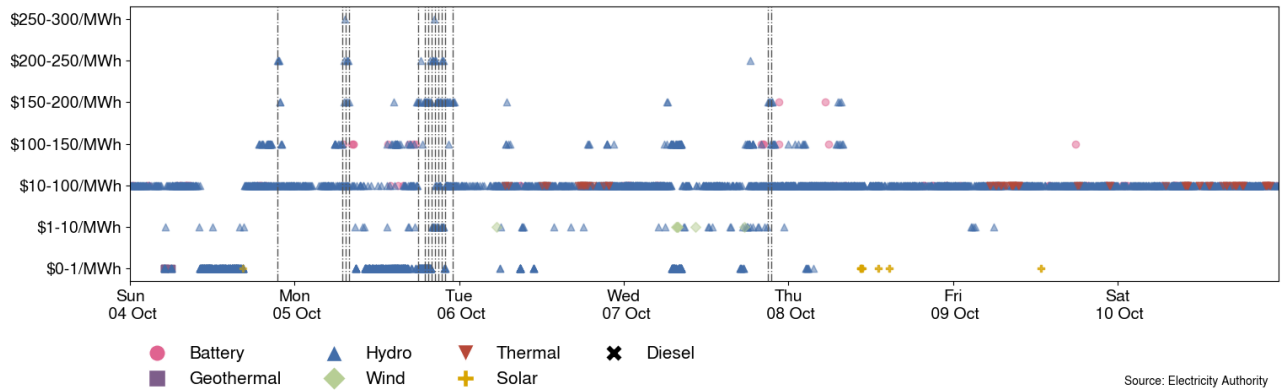
Figure 15: Hydro generation, 4-10 October



7.18. 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.

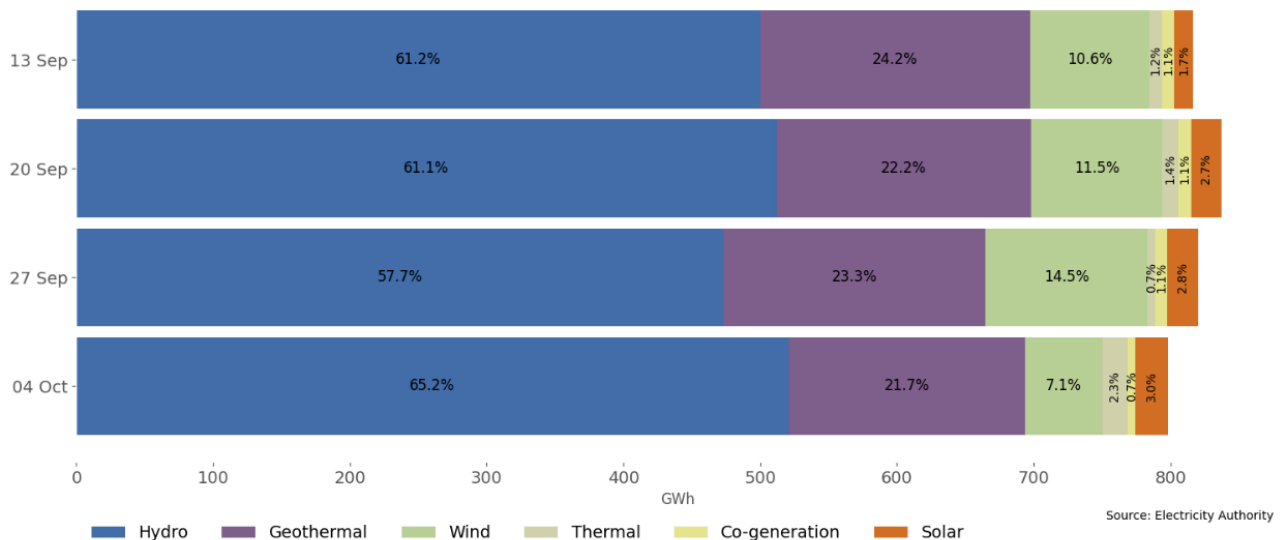
7.19. The highest marginal price of \$260/MWh was set by Karāpiro at 7:00am on Monday. The most common marginal technology was hydro and the second most common technology was battery. Most marginal prices were between \$10-100/MWh.

Figure 16: Prices of marginal generation, 4-10 October



7.20. As a percentage of total generation, between 4-10 October, total weekly hydro generation was 65.2%, geothermal 21.7%, wind 7.1%, thermal 2.3%, co-generation 0.7%, and solar (grid connected) 3.0%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 13 September and 10 October



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 4-10 October ranged from ~1,272MW to ~2,440MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 4-10 October

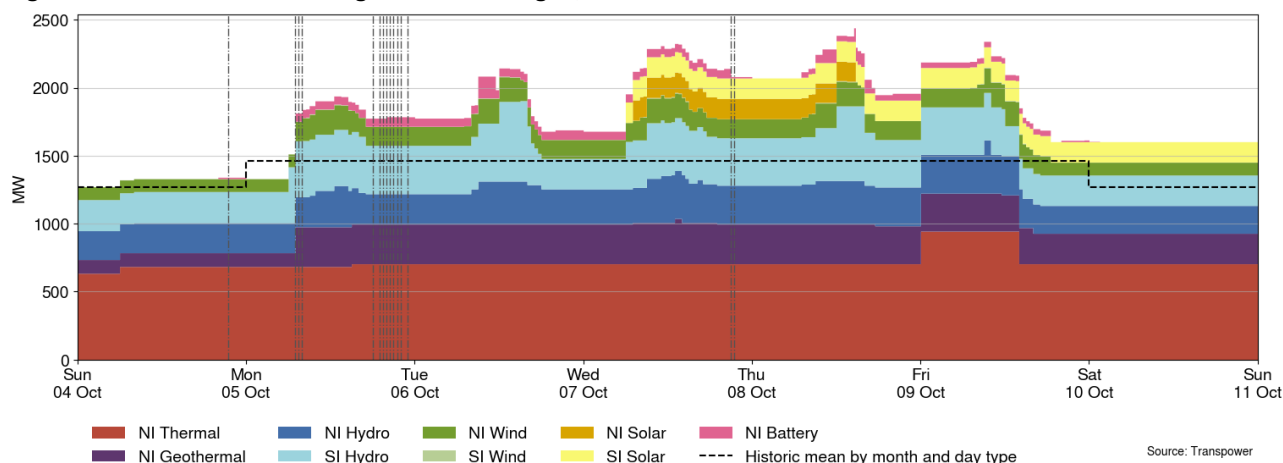
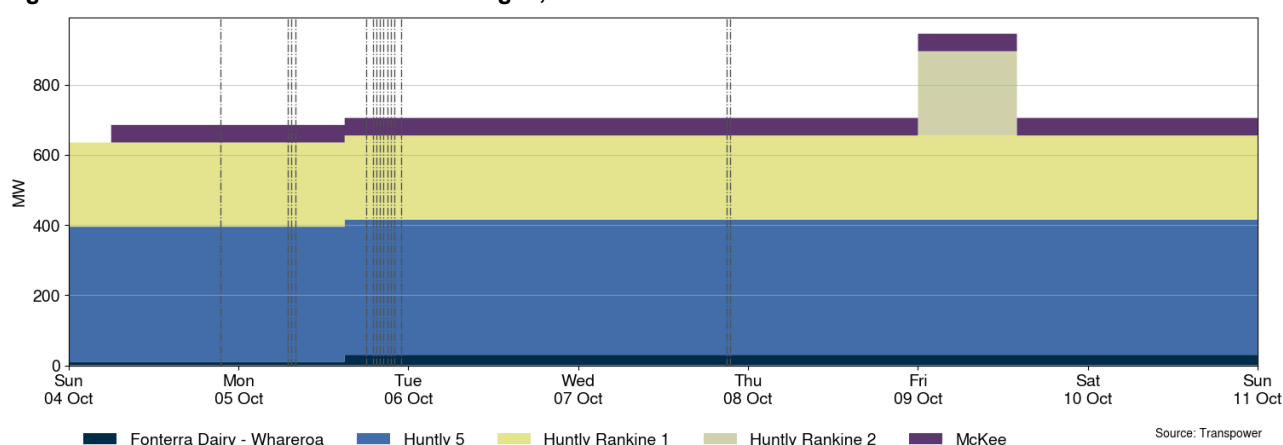


Figure 19: Total MW loss from thermal outages, 4-10 October



8.2. Notable outages include:

Plant	Partial or Full	End Date
Manapōuri unit 5	Full	6 October 2026
Huntly BESS	Full	6 October 2026
Tauhei	Full	8 October 2026
Ruakākā	Full	8 October 2026
Manapōuri unit 4	Full	9 October 2026
Huntly 2	Full	9 October 2026
Huntly 1	Full	11 October 2026
Kōwhai Park	Full	13 October 2026
Huntly 5	Full	28 October 2026
Kaiwaikawe wind farm	Partial	30 November 2026
Manapōuri unit 2	Full	2 July 2027

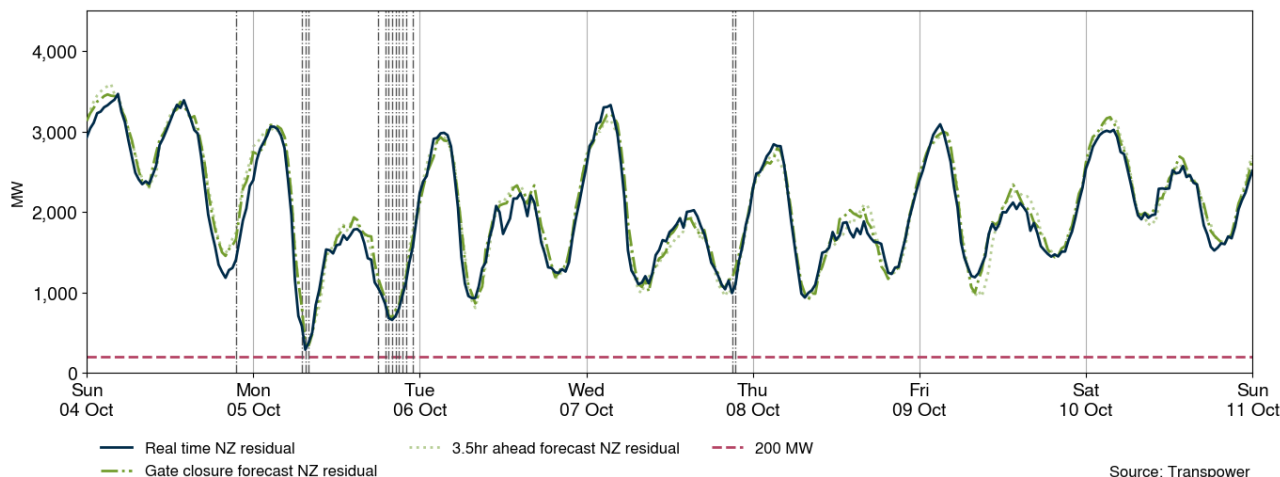
9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 4-10 October. 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. There were no residuals below 200MW this week. However, national residual generation reached a low for the week of 287MW at 7.30am on Monday.

Figure 20: National generation balance residuals, 4-10 October

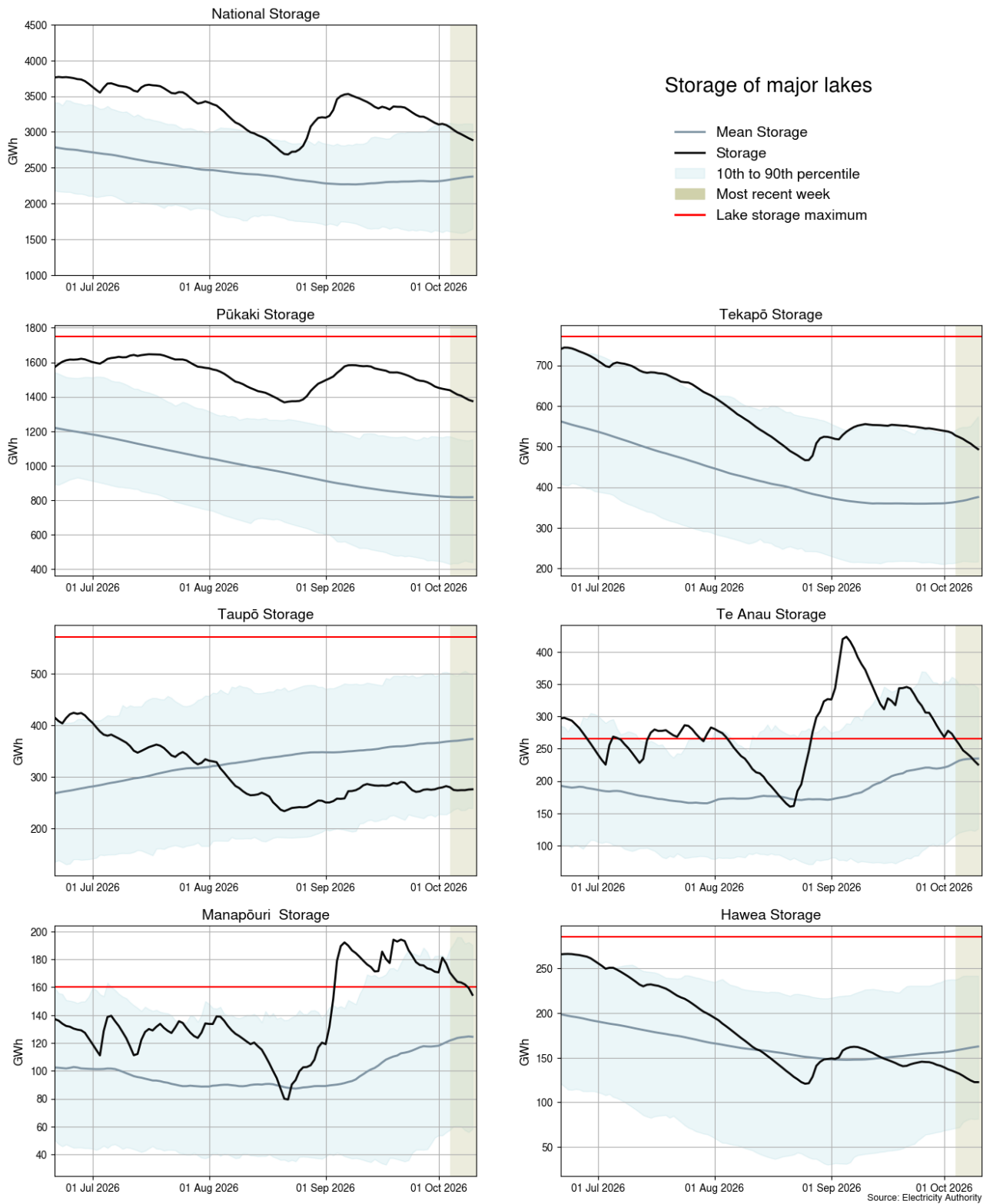


10. Storage/fuel supply

- 10.1. Storage at Lake Pūkaki (80% full) is significantly higher than the historic 90th percentile for this time of year.
- 10.2. Storage at Lake Tekapō (64% full) is above average for this time of year.
- 10.3. Storage at Lake Taupō (49% full) is below average for this time of year.
- 10.4. Storage at Lake Te Anau (83% full) is slightly below average for time of year.
- 10.5. Storage at Lake Manapōuri (95% full) is above average for this time of year.
- 10.6. Storage at Lake Hawea (44% full) is below average for this time of year.
- 10.7. Figure 21 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.
- 10.8. National controlled storage was 74% nominally full and ~121% of the historical average for this time of the year.
- 10.9. Storage at Lake Pūkaki (80% full³) is significantly higher than the historic 90th percentile for this time of year.
- 10.10. Storage at Lake Tekapō (64% full) is above average for this time of year.
- 10.11. Storage at Lake Taupō (49% full) is below average for this time of year.
- 10.12. Storage at Lake Te Anau (83% full) is slightly below average for time of year.
- 10.13. Storage at Lake Manapōuri (95% full) is above average for this time of year.
- 10.14. Storage at Lake Hawea (44% full) is below average for this time of year.

³ Percentage full values sourced from NZX Hydro.

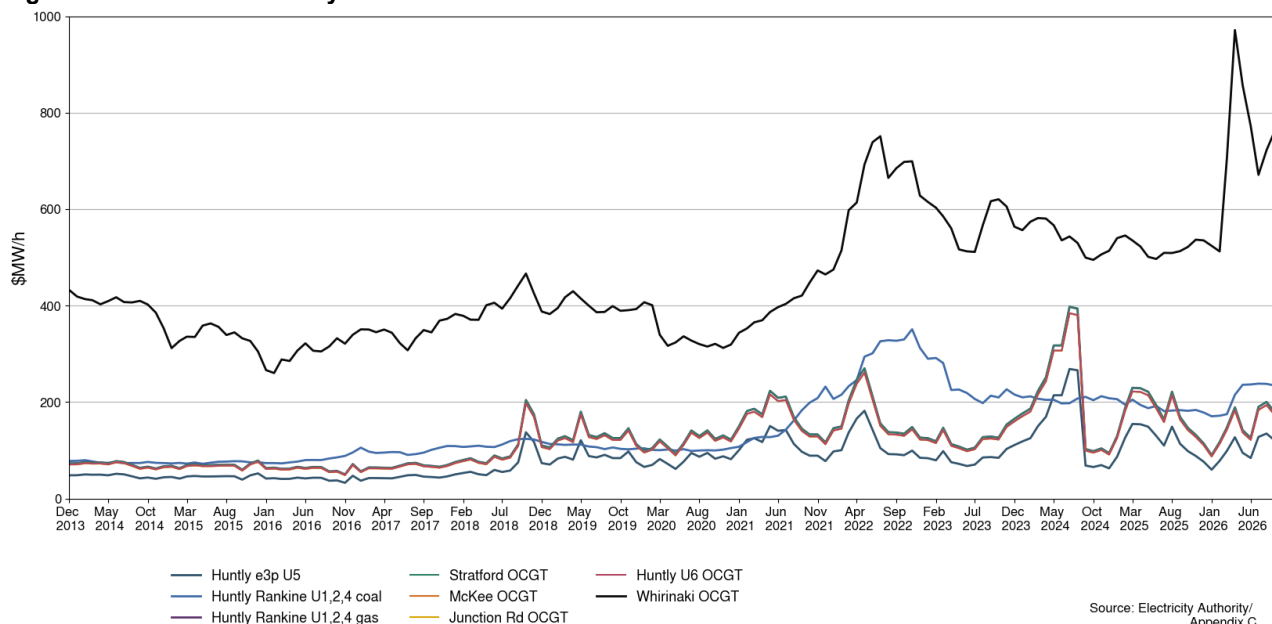
Figure 21: Hydro storage



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 23 shows an estimate of thermal SRMCs as a monthly average up to 1 October 2026. The SRMCs for gas generation have decreased, the SRMC for diesel generation has increased, with the SRMC for coal 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 ~\$112/MWh.
- 11.5. The SRMC of gas fuelled thermal plants is currently between \$74/MWh and \$112/MWh.
- 11.6. The SRMC of Whirinaki is ~\$762/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

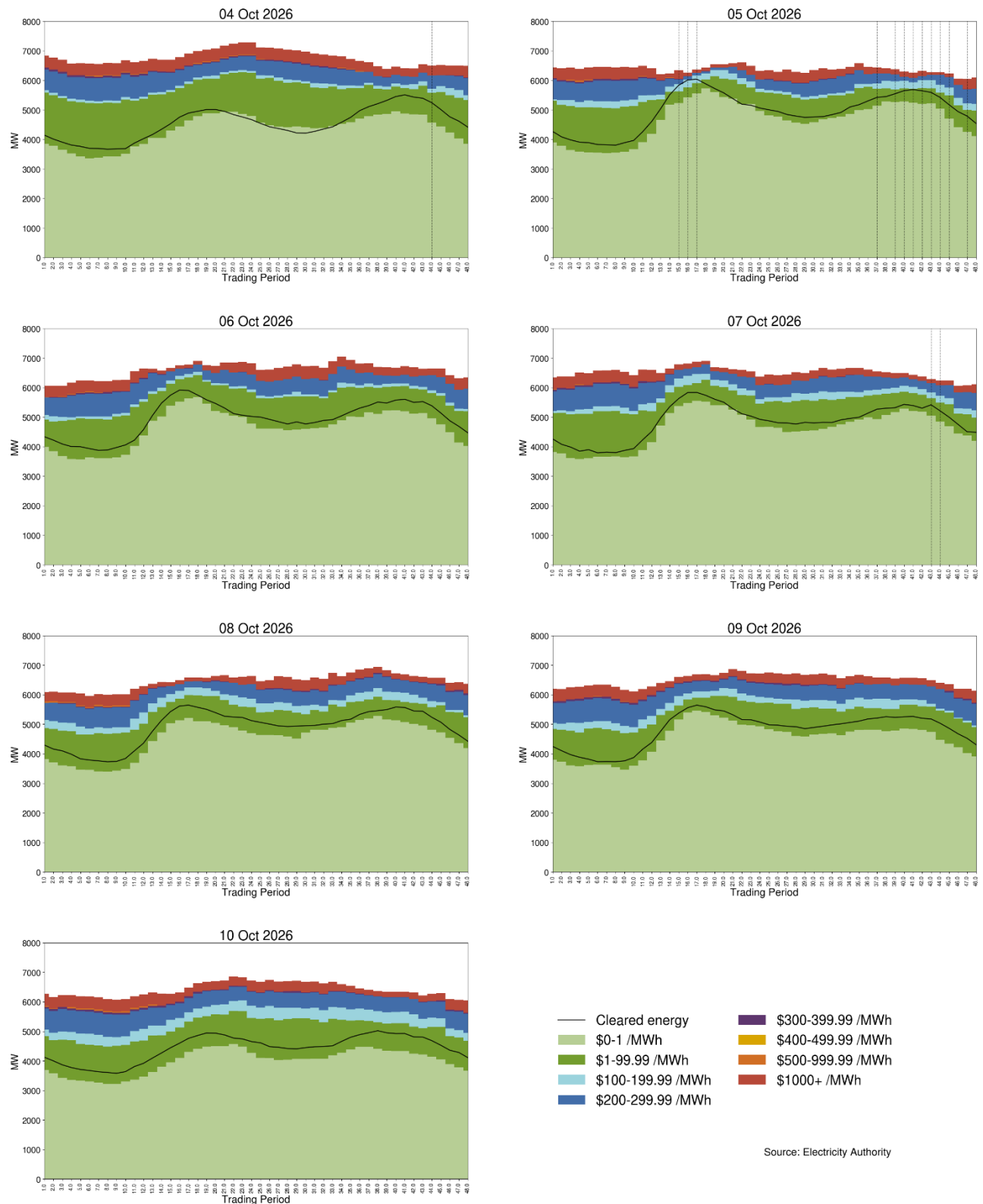


12. Offer behaviour

- 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. Most energy cleared between \$1-99/MWh this week, except for times on Monday morning when energy cleared between \$100-199/MWh.

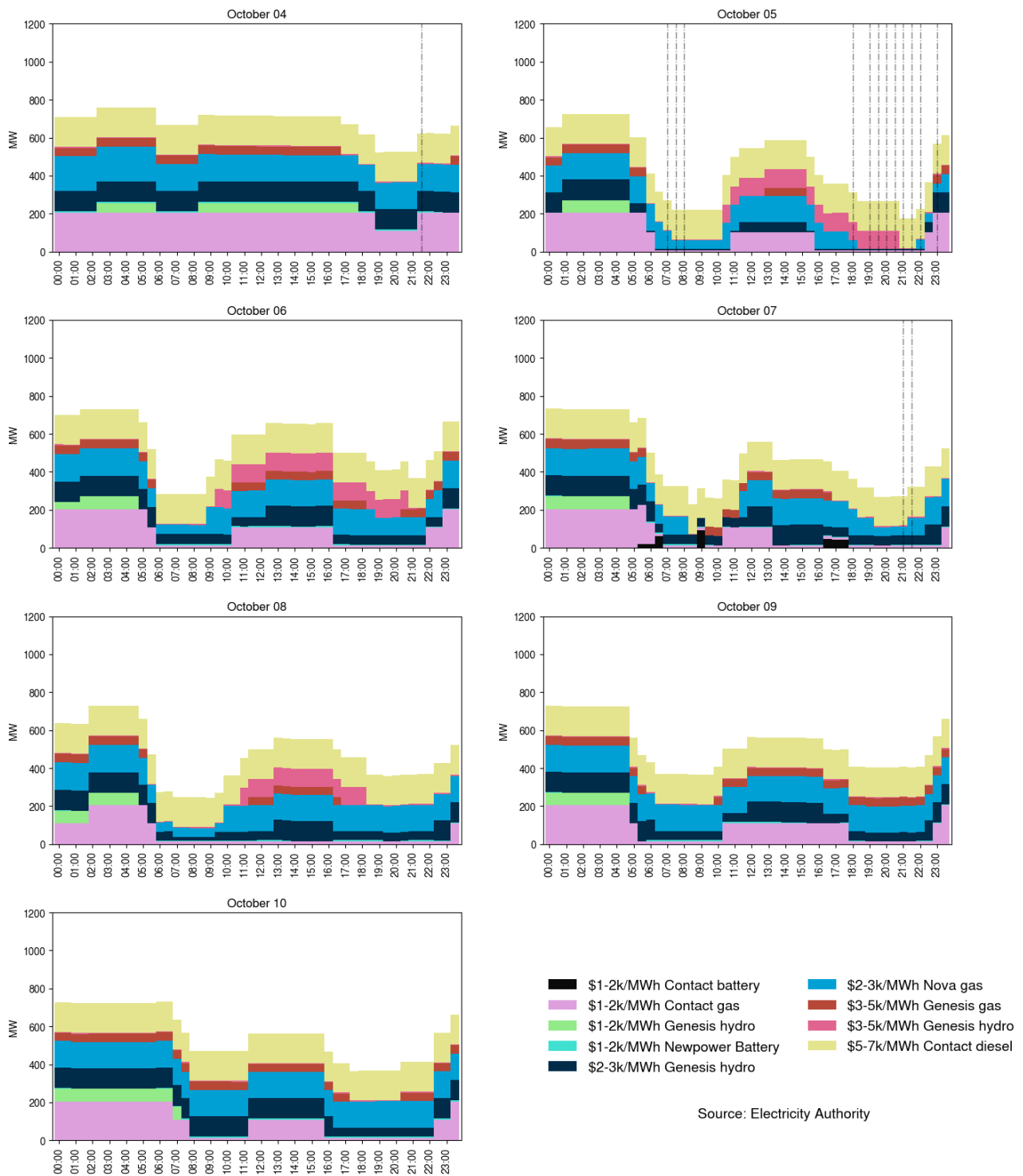
Figure 23: Daily offer stacks



12.3. 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.

- 12.4. 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, intermittent 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 546MW per trading period was priced above \$1,000/MWh this week, which is roughly 10% 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.

13.2. We will be looking further into Stratford Peaker 1 offers this week.

13.3. 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
07/05/2026-08/05/2026	Several	Further analysis	Genesis	Tekapō	Offers
27/05/2026	Several	Further analysis	Genesis	Huntly 5	Offers
27/09/2026	Several	Further analysis	Meridian	Ruakākā BESS	Bids
04/10/2026	44	Further analysis	Contact	Stratford Peaker 1	Offers
05/10/2026-08/10/2026	Several	Further analysis	Genesis	Tekapō	Offers