28 October 2026

Trading conduct report 18-24 October 2026

Market monitoring weekly report

Trading conduct report 18-24 October 2026

1. Overview

1.1. Spot prices have decreased slightly this week due to higher apparent temperatures leading to decreased demand throughout the week. However, HVDC constraints lowered HVDC capacity, and periods of high Northward HVDC flow led to frequent North Island price separation. Wind and hydro generation decreased this week, while solar increased. National hydro storage decreased to 72% nominally fully and 114% 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 18-24 October:

(a) The average spot price for the week was $54/MWh, a decrease of around $3/MWh compared to the previous week.

(b) 95% of prices fell between $0.02/MWh and $185/MWh.

2.3. Spot prices decreased slightly this week due warmer weather leading to decreased demand for electricity. There was frequent price separation between the North and South Island, with HVDC capacity reduced due to the continuation of planned transmission equipment outages near Benmore and Haywards substations.

2.4. Between 7.30-11.00pm on Wednesday the spot price at Ōtāhuhu was above $200/MWh, reaching a maximum of $312/MWh at 9.00pm. At this time the price at Benmore was $35/MWh. During this period:

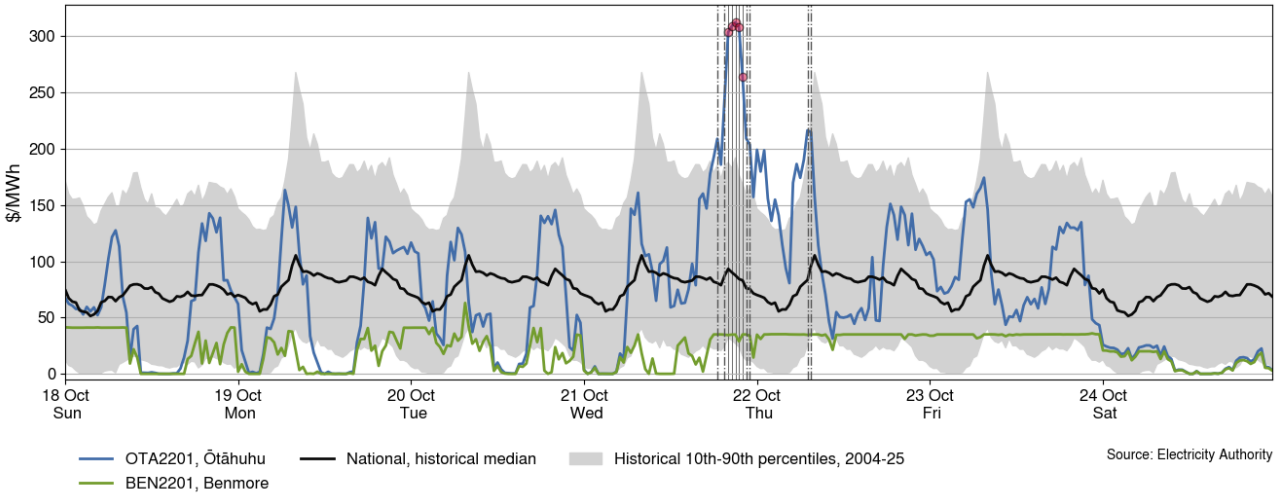
- Wind generation was very low, below 200MW, and there was no solar generation as the sun had just set, decreasing the availability of cheap energy.
- The HVDC was constrained, increasing the need for thermal and North Island hydro generation. Currently most North Island hydro generation is priced high compared to South Island hydro generation due to low North Island hydro storage levels.
- Demand was up to 85MW higher than forecast.
- National residual generation was up to 393MW lower than forecast.
- Batteries were running low during this period, and Huntly BESS was on outage.
- Additional peaker generation was dispatched.

2.5. At 7.00am on Thursday the spot price at Ōtāhuhu spiked up to $216/MWh. At this time the price at Benmore was $35/MWh. During this period:

- The HVDC was constrained, along with high North Island demand.
- Additional thermal generation was dispatched.

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.

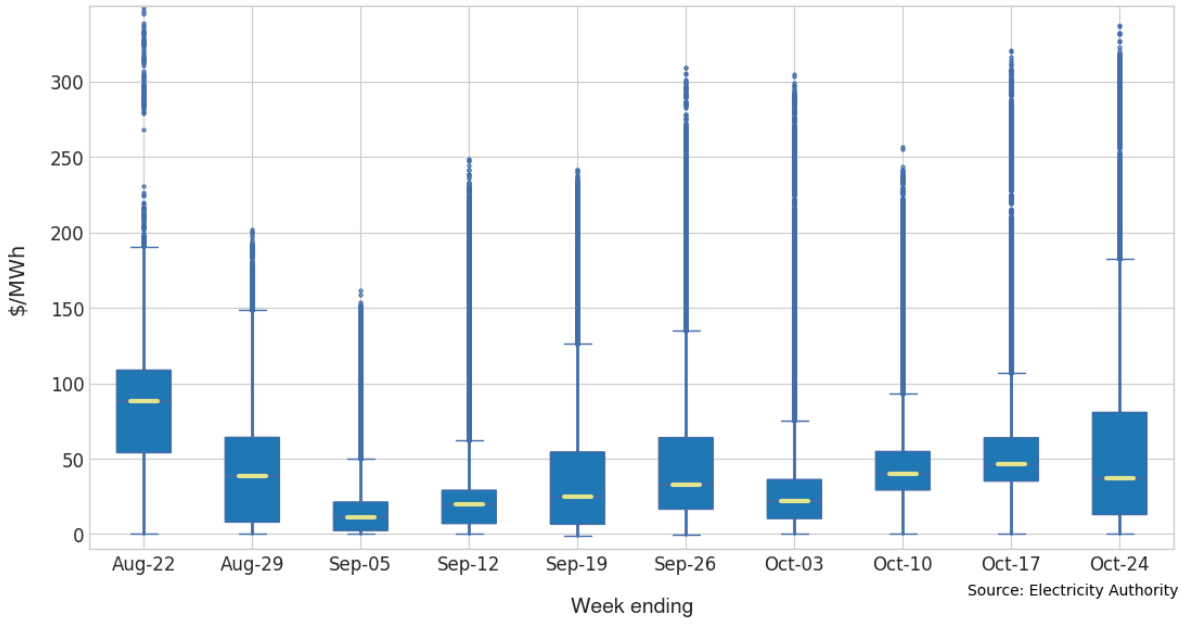
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 18-24 October



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 distribution of spot prices this week was wider than last week with fewer high price outliers. The median price was $54/MWh and most prices (middle 50%) fell between $13/MWh and $81/MWh.

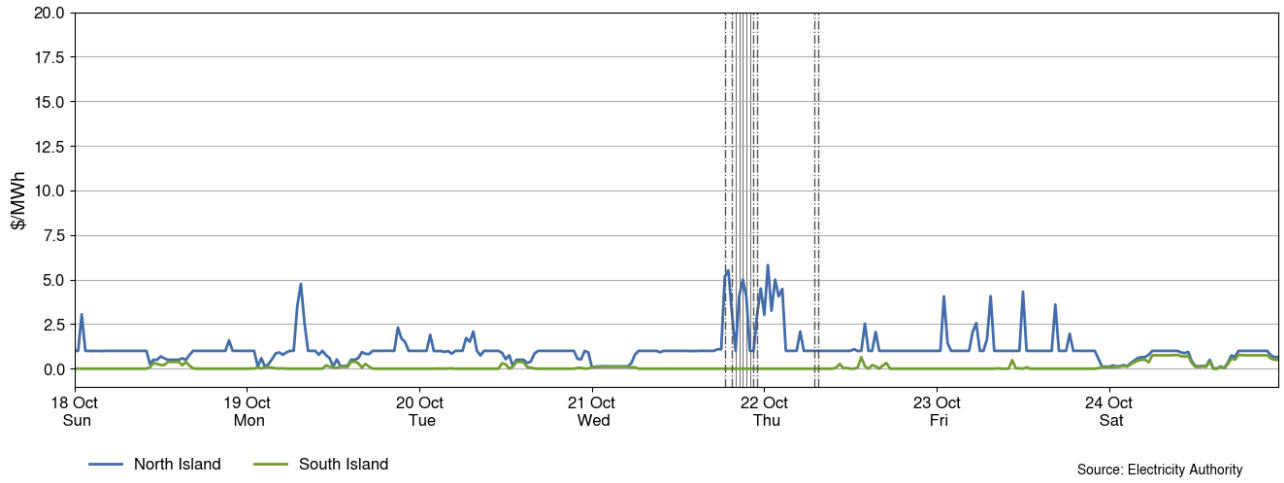
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

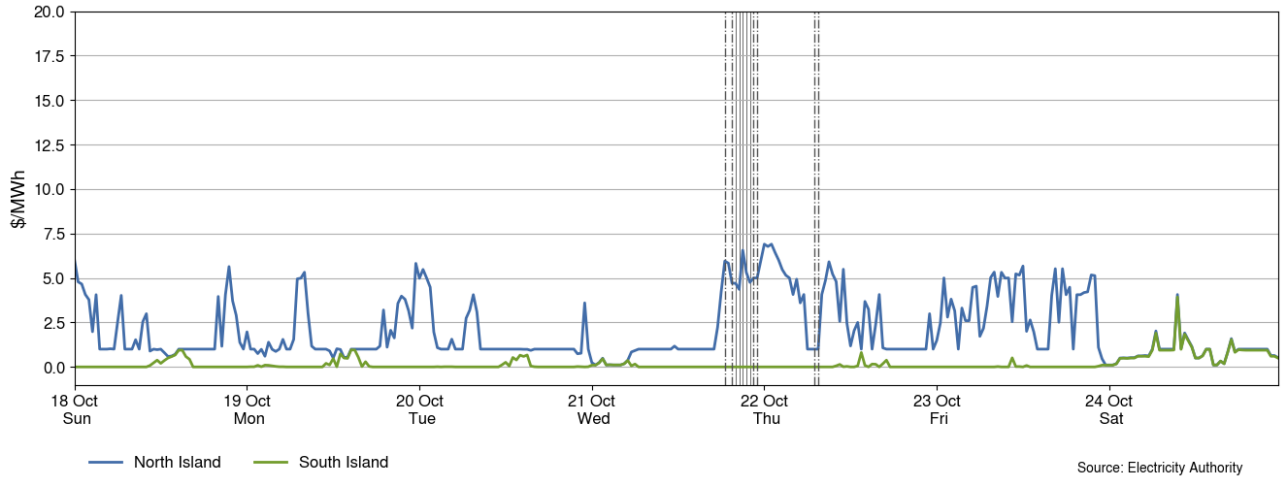
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week.

Figure 3: Fast instantaneous reserve price by trading period and island, 18-24 October



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

Figure 4: Sustained instantaneous reserve by trading period and island, 18-24 October



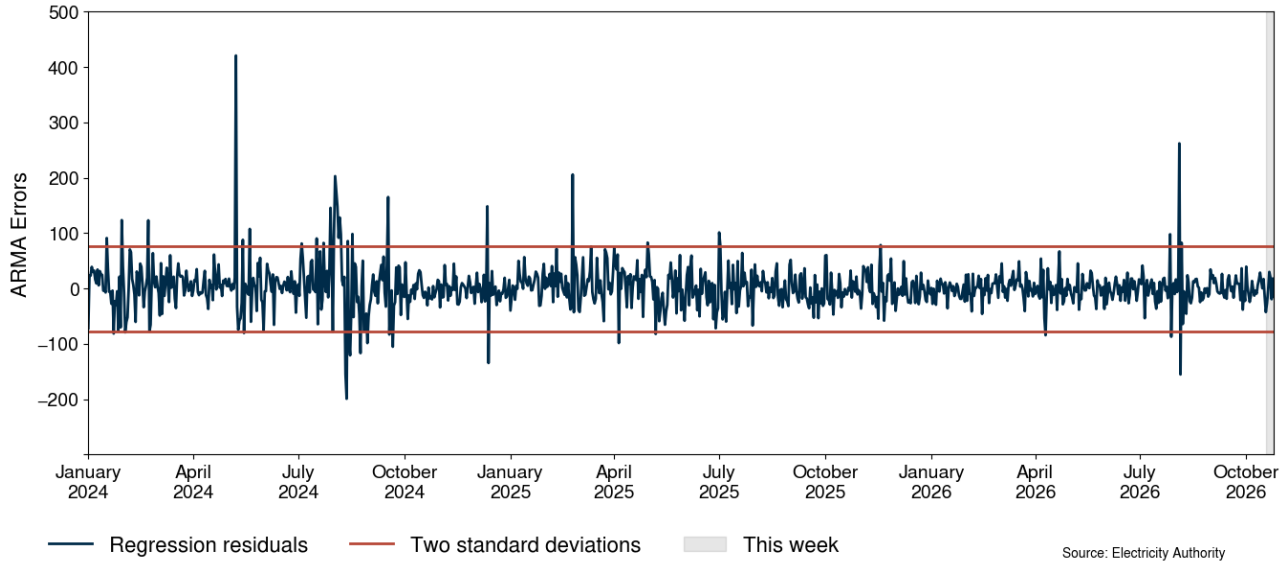
4. Regression residuals

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 - 24 October 2026



5. HVDC

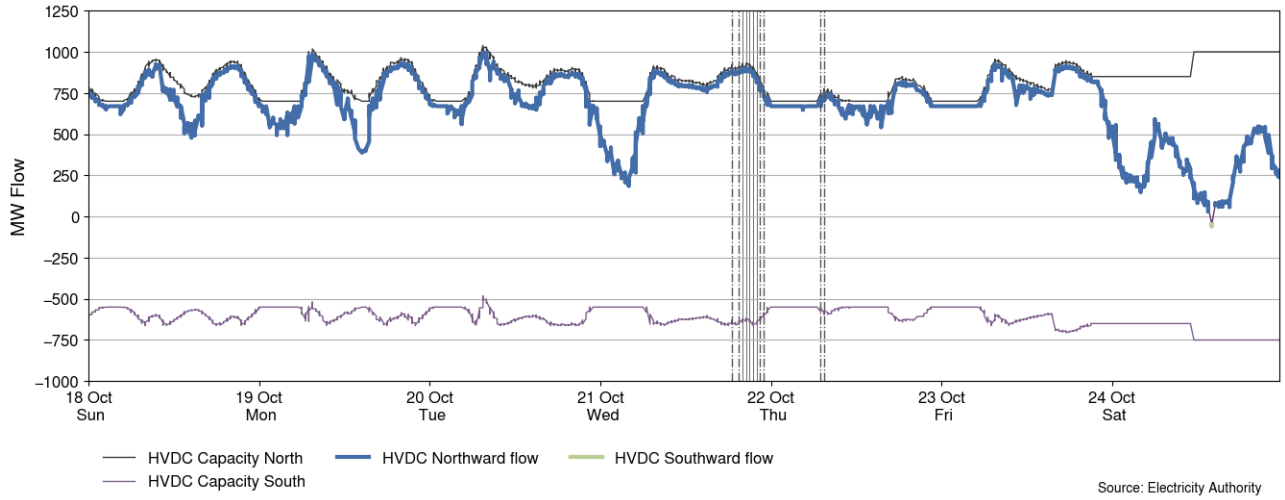
5.1. Figure 6 shows the HVDC flow between 18-24 October. HVDC[1] flows were almost entirely northward this week.

5.2. The HVDC had reduced capacity until Saturday afternoon due to planned transmission equipment outages around Haywards and Benmore substations this week.

5.3. The highest northward HVDC flow this week was 995MW which occurred at 8.00am on Tuesday.

5.4. The highest southward HVDC flow this week was 60MW which occurred at 2.00pm on Saturday.

Figure 6: HVDC flow and capacity, 18-24 October



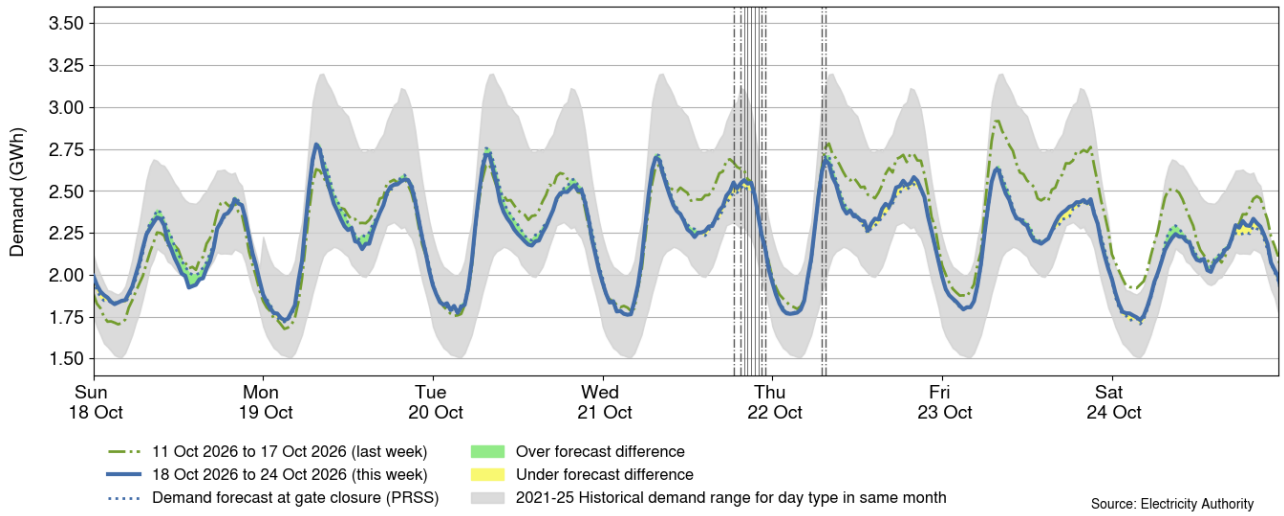
[1] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these being the one that determines the required quantity of instantaneous reserve. 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.

6. Demand

6.1. Figure 7 shows national demand between 18-24 October, compared to the historic range and the demand of the previous week. Demand was similar to last week until Tuesday afternoon. From Tuesday afternoon onward demand tended to lower than last week, particularly in the evenings.

6.2. The maximum demand this week was around 2.78GWh (5.56GW) at 7.30am on Monday.

Figure 7: National demand, 18-24 October compared to the previous week

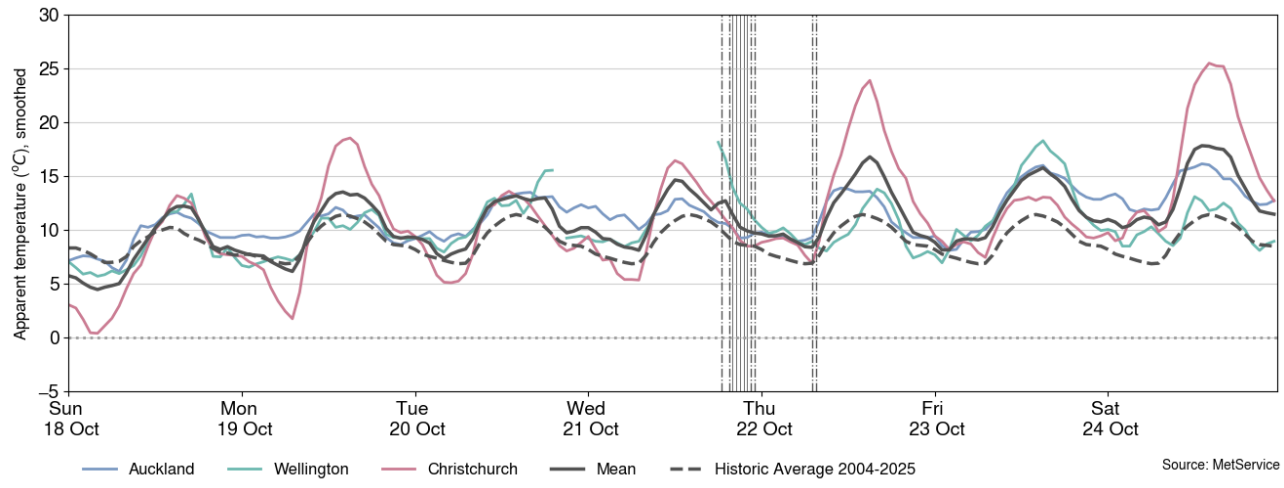


6.3. Figure 8 shows the hourly apparent temperature at main population centres from 18-24 October. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.4. Apparent temperatures ranged from 6°C to 17°C in Auckland, 5°C to 19°C in Wellington, and 0°C to 26°C in Christchurch. Temperatures increased throughout the week, likely leading to a corresponding decrease in electricity demand.

6.5. Some data is missing for Wellington on Tuesday and Wednesday due to data issues at MetService.

Figure 8: Temperatures across main centres, 18-24 October

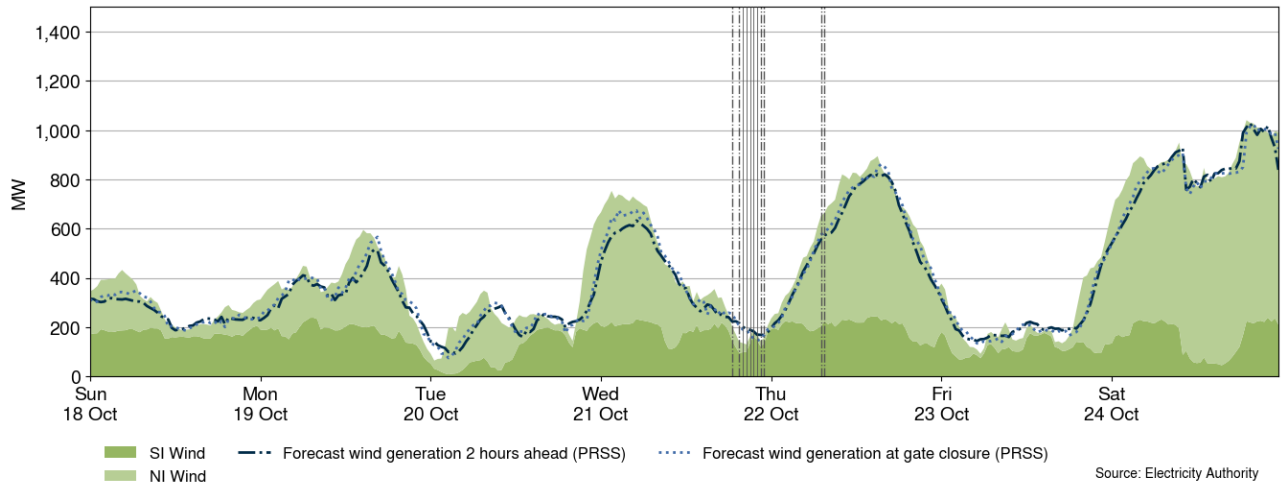


7. Generation

7.1. Figure 9 shows wind generation and forecast from 18-24 October. This week wind generation varied between 65MW and 1040MW, with a weekly average of 443MW. Wind generation was low early in the week, being mostly below 400MW, before picking up at times on Wednesday and Thursday. Wind generation was then mostly below 200MW on Friday, before increasing to above 800MW on Saturday.

7.2. Wind generation was lower than forecast at times on Wednesday evening. This was due to forecasting differences at Kaiwera Downs, and West Hill wind farms.

Figure 9: Wind generation and forecast, 18-24 October

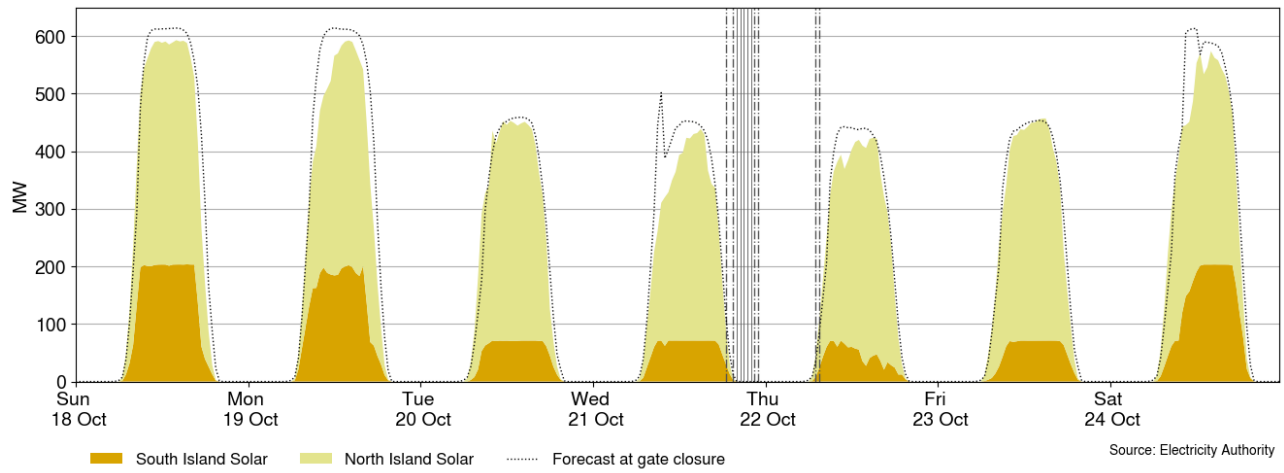


7.3. Figure 10 shows utility-scale solar generation from 18-24 October. This week, mean daytime solar generation was 329MW, peaking at 593MW on Sunday at 2:00pm. Solar generation continues to increase with the commissioning of new farms and the approach of summer. This Sunday peak is currently the highest solar generation across one trading period seen to date.

7.4. Forecasting differences on Sunday, Monday, and Wednesday are due to forecasting errors at Kōwhai Park solar farm.

7.5. Forecasting differences on Saturday are due to an accumulation of forecasting errors at various solar farms.

Figure 10: Utility-scale solar generation, 18-24 October



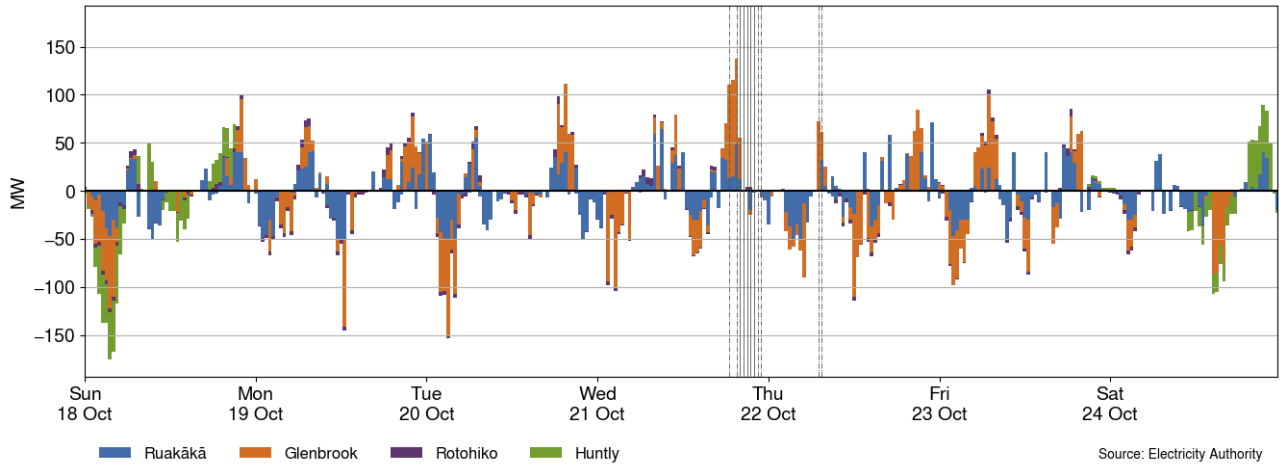
7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.7. This week batteries typically charged at night and during the middle of the day when demand was lower and discharged during the morning and evening at times of high demand.

7.8. The Huntly BESS was on a full outage from Monday to Friday this week.

7.9. During the period of high prices on Wednesday evening, Glenbrook and Ruakākā batteries reached a low state of charge.

Figure 11: Grid scale battery charge and discharge, 18-24 October



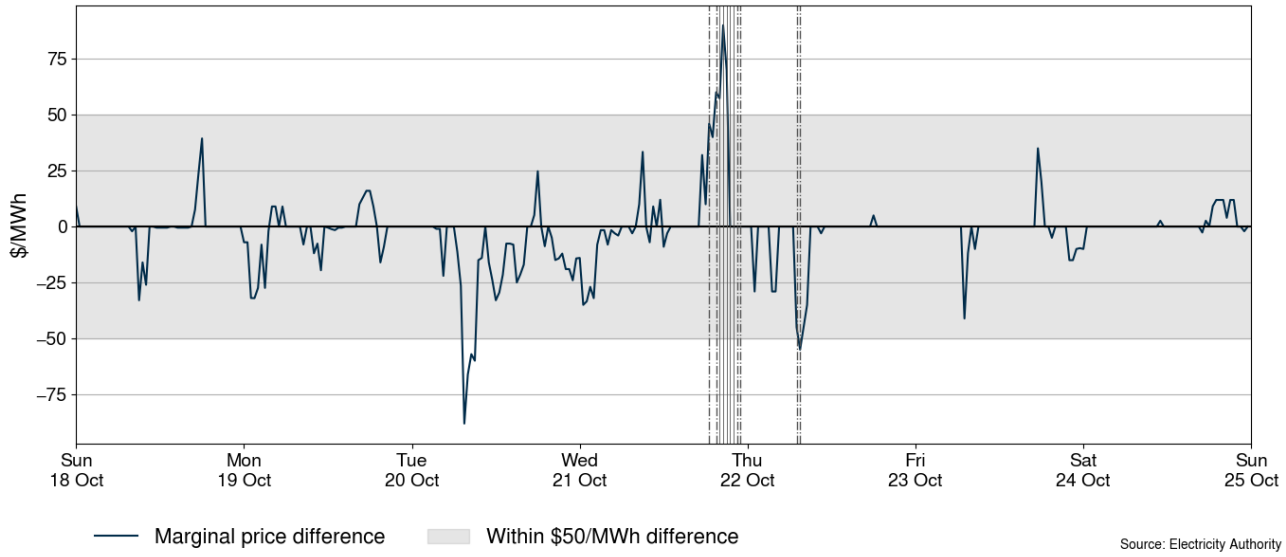
7.10. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing 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 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.

7.11. The highest positive marginal price forecast difference of $90/MWh occurred at 8.30pm on Wednesday. At this time demand was 68MW higher than forecast and intermittent generation was 60MW lower than forecast.

7.12. The highest negative marginal price forecast difference of $88/MWh occurred at 7.30am on Tuesday. At this time demand was 81MW lower than forecast and intermittent generation was 102MW higher than forecast.

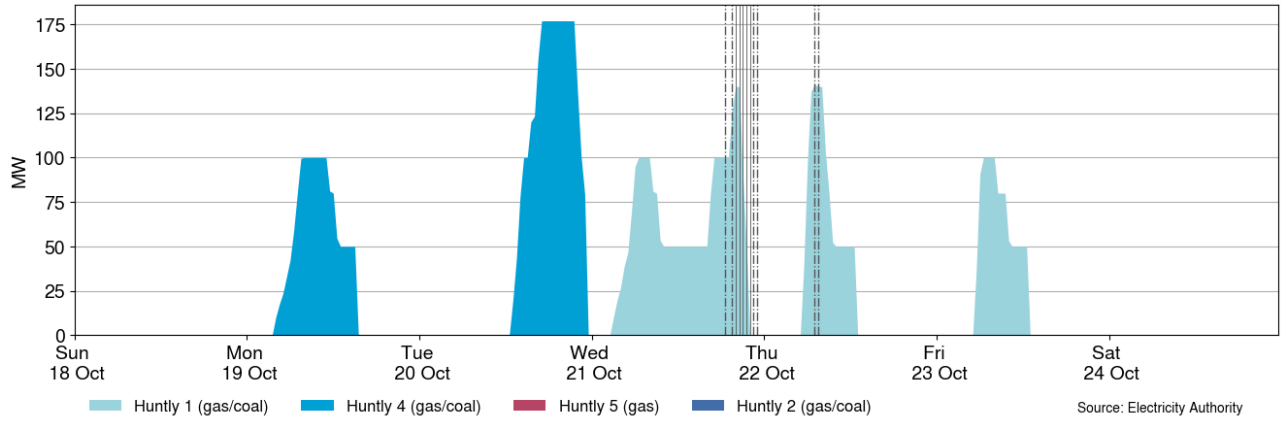
[2] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 18-24 October



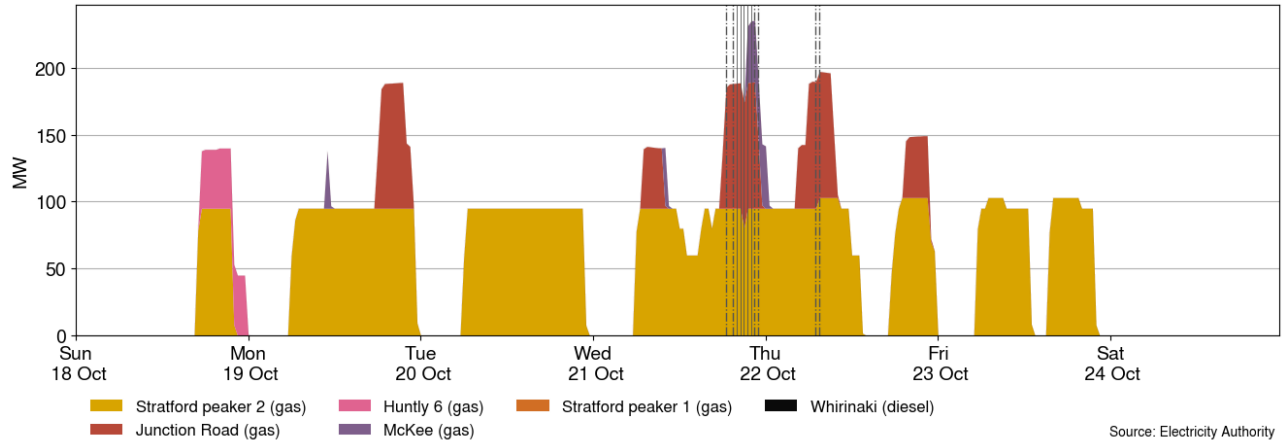
7.13. Figure 13 shows the generation of thermal baseload between 18-24 October. This week Huntly 1 and Huntly 4 provided thermal baseload generation. There was no thermal baseload generation on Sunday or Saturday.

Figure 13: Thermal baseload generation, 18-24 October



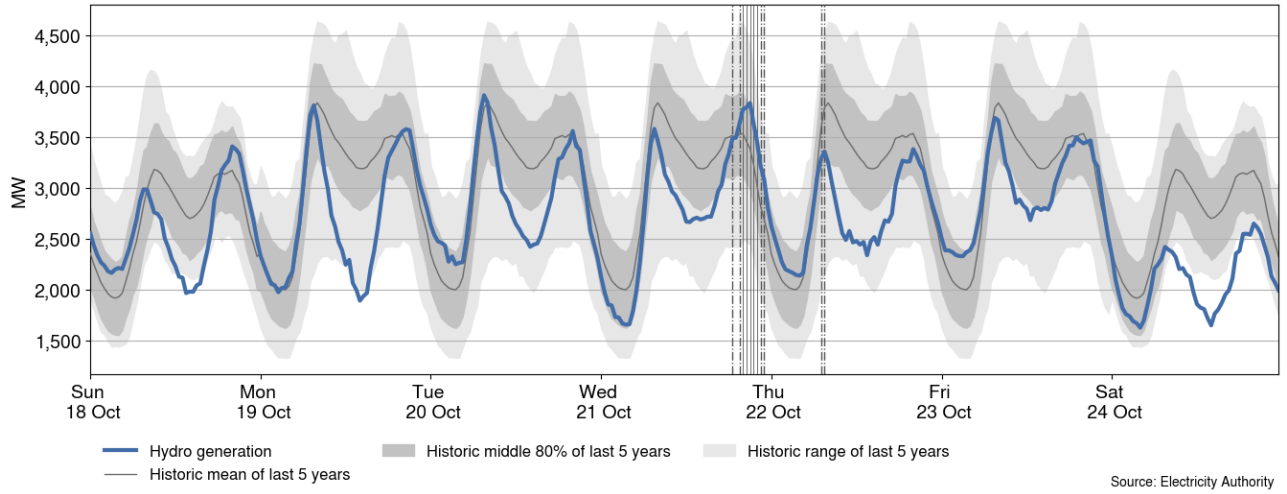
7.14. Figure 14 shows the generation of thermal peaker plants between 18-24 October. Peakers ran throughout the week. Additional peaker generation was dispatched during high prices on Wednesday evening. There was no peaker generation on Saturday.

Figure 14: Thermal peaker generation, 18-24 October



7.15. Figure 15 shows hydro generation between 18-24 October. Hydro generation was generally lower than average throughout the week, particularly during midday periods when it reached below the historic range of the last five years on Sunday, Monday and Saturday. Hydro generation was above average on Sunday and Wednesday evenings.

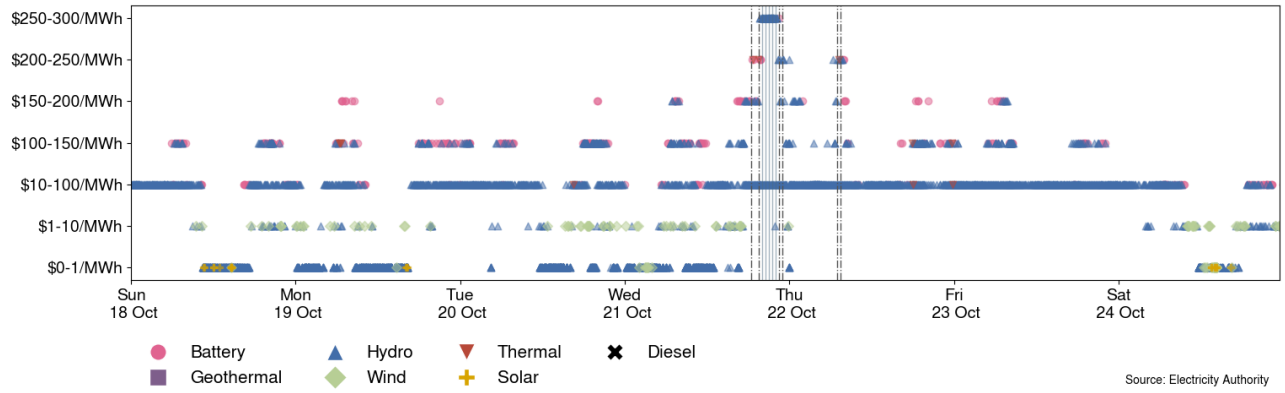
Figure 15: Hydro generation, 18-24 October



7.16. 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.

7.17. The highest marginal price of $290/MWh was set by Karāpiro at 7:30pm on Wednesday. The most common marginal technology was hydro, and the second most common technology was battery. Most marginal prices were between $10-100/MWh.

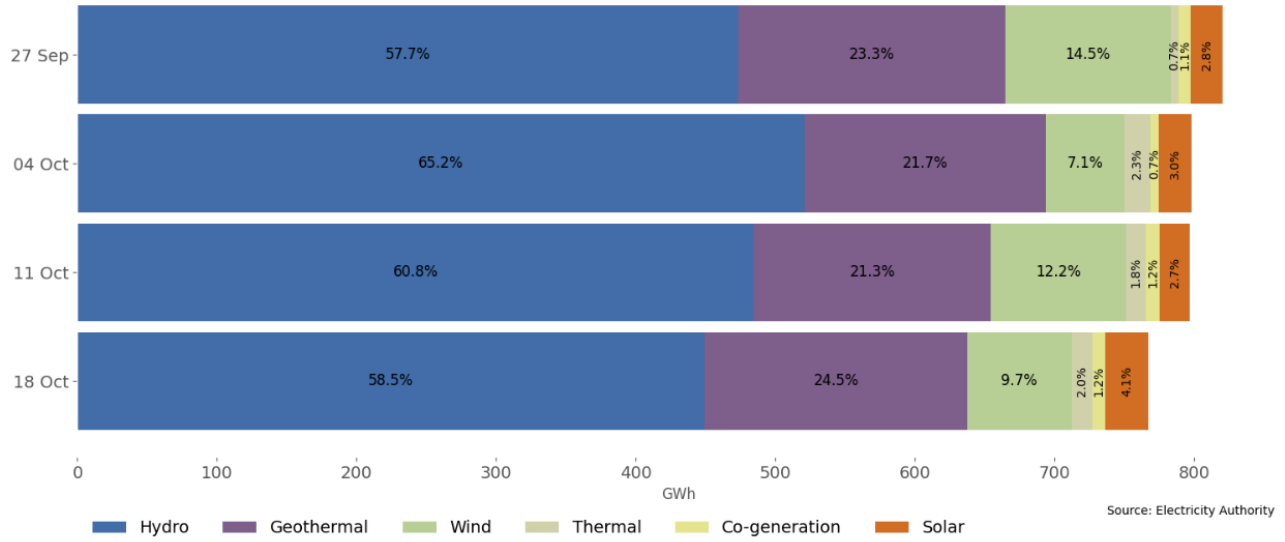
Figure 16: Prices of marginal generation, 18-24 October



7.18. As a percentage of total generation, between 18-24 October, total weekly hydro generation was 58.5%, geothermal 24.5%, wind 9.7%, thermal 2.0%, co-generation 1.2%, and solar (utility-scale) 4.1%, as shown in Figure 17.

7.19. 4.1% is the highest portion of the weekly generation mix solar has been to date.

Figure 17: Total generation by type as a percentage each week, between 27 September and 24 October



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 18-24 October ranged from ~1,339MW to ~2,566MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 18-24 October

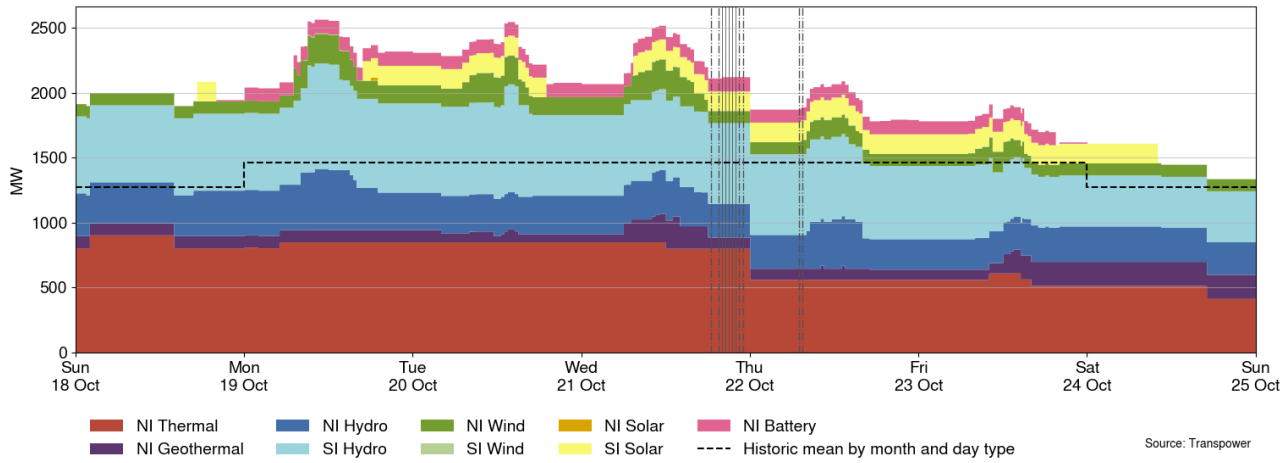
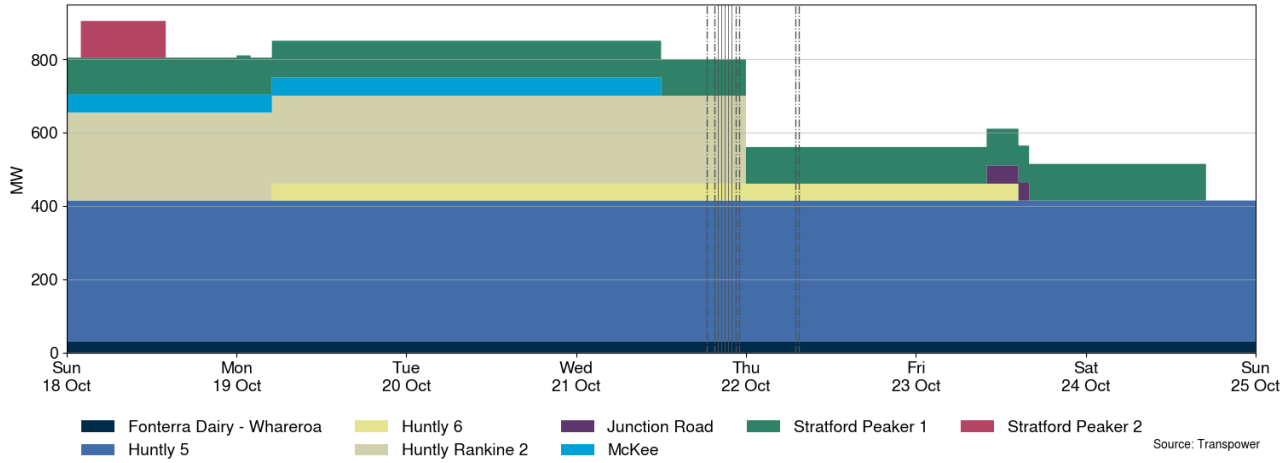


Figure 19: Total MW loss from thermal outages, 18-24 October



8.2. Notable outages include:

Plant	Partial or Full	End Date
Maraetai units 1,2,3,8,9	Full	19 October 2026
Manapōuri unit 7	Full	20 October 2026
Aviemore unit 4	Full	21 October 2026
Ōhau A unit 5	Full	23 October 2026
Huntly BESS	Full	23 October 2026
Kōwhai Park	Full	24 October 2026
Stratford Peaker 1	Full	24 October 2026
Huntly 2	Partial	25 October 2026
Huntly 5	Full	28 October 2026
Stratford Peaker 2	Full	15 November 2026
Kaiwaikawe wind farm	Partial	30 November 2026
Manapōuri unit 7	Full	4 December 2026
Manapōuri unit 2	Full	2 July 2027

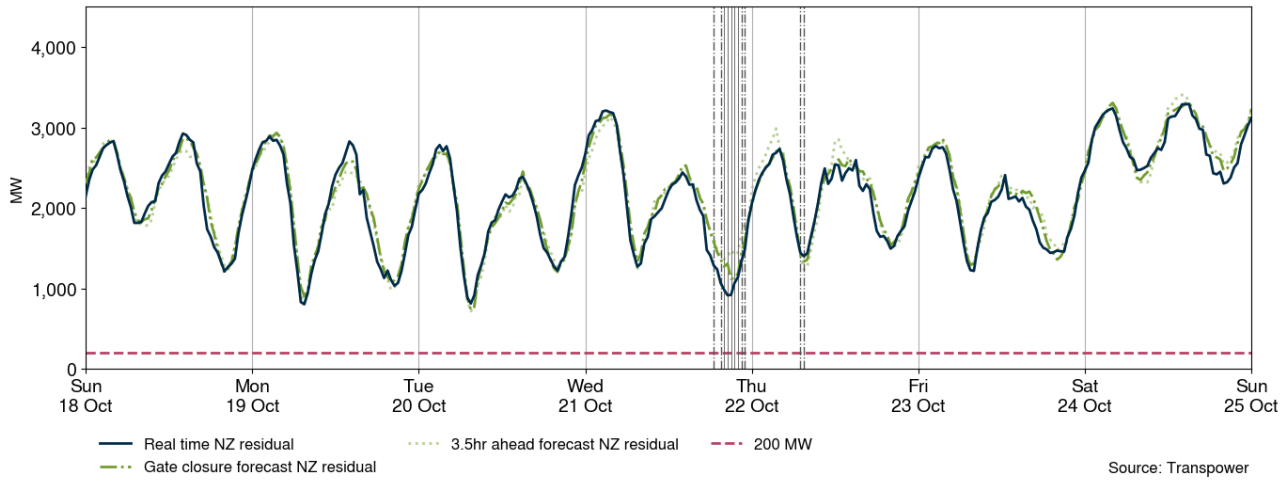
9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 18-24 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.

Figure 20: National generation balance residuals, 18-24 October



10. Storage/fuel supply

10.1. 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.

10.2. National controlled storage was 72% nominally full and ~114% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (82% full[3]) is significantly higher than the historic 90th percentile for this time of year.

10.4. Storage at Lake Tekapō (59% full) is above average for this time of year.

10.5. Storage at Lake Taupō is (51% full) is below average for this time of year.

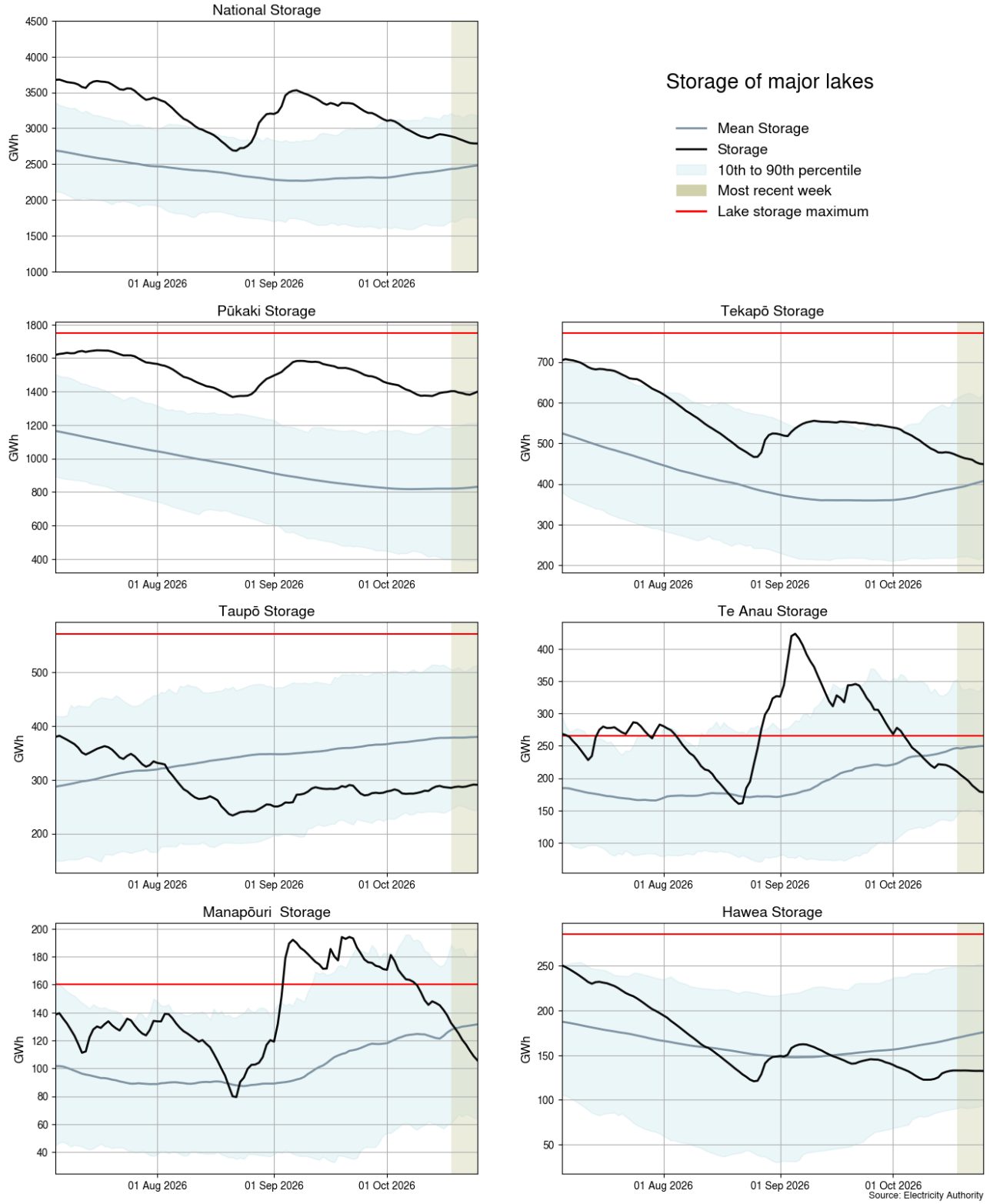
10.6. Storage at Lake Te Anau (108% full) is below average for time of year.

10.7. Storage at Lake Manapōuri (93% full) is below average for this time of year.

10.8. Storage at Lake Hawea (47% 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 ~$143/MWh.

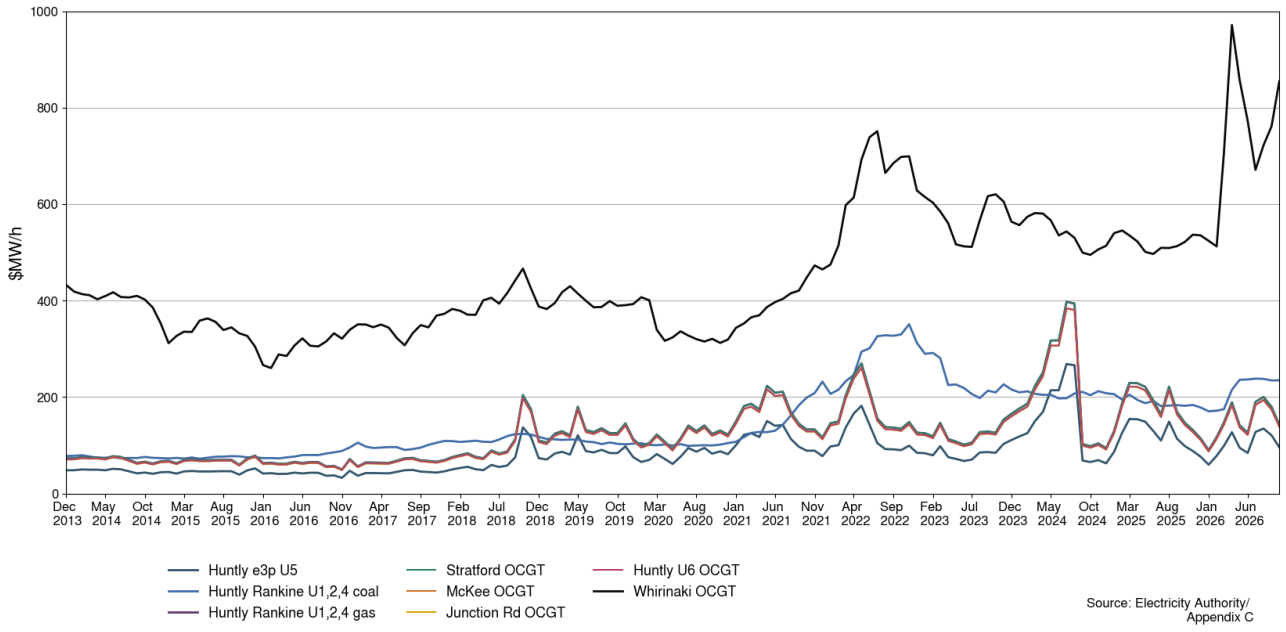
11.5. The SRMC of gas fuelled thermal plants is currently between $138/MWh and $143/MWh.

11.6. The SRMC of Whirinaki is ~$854/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

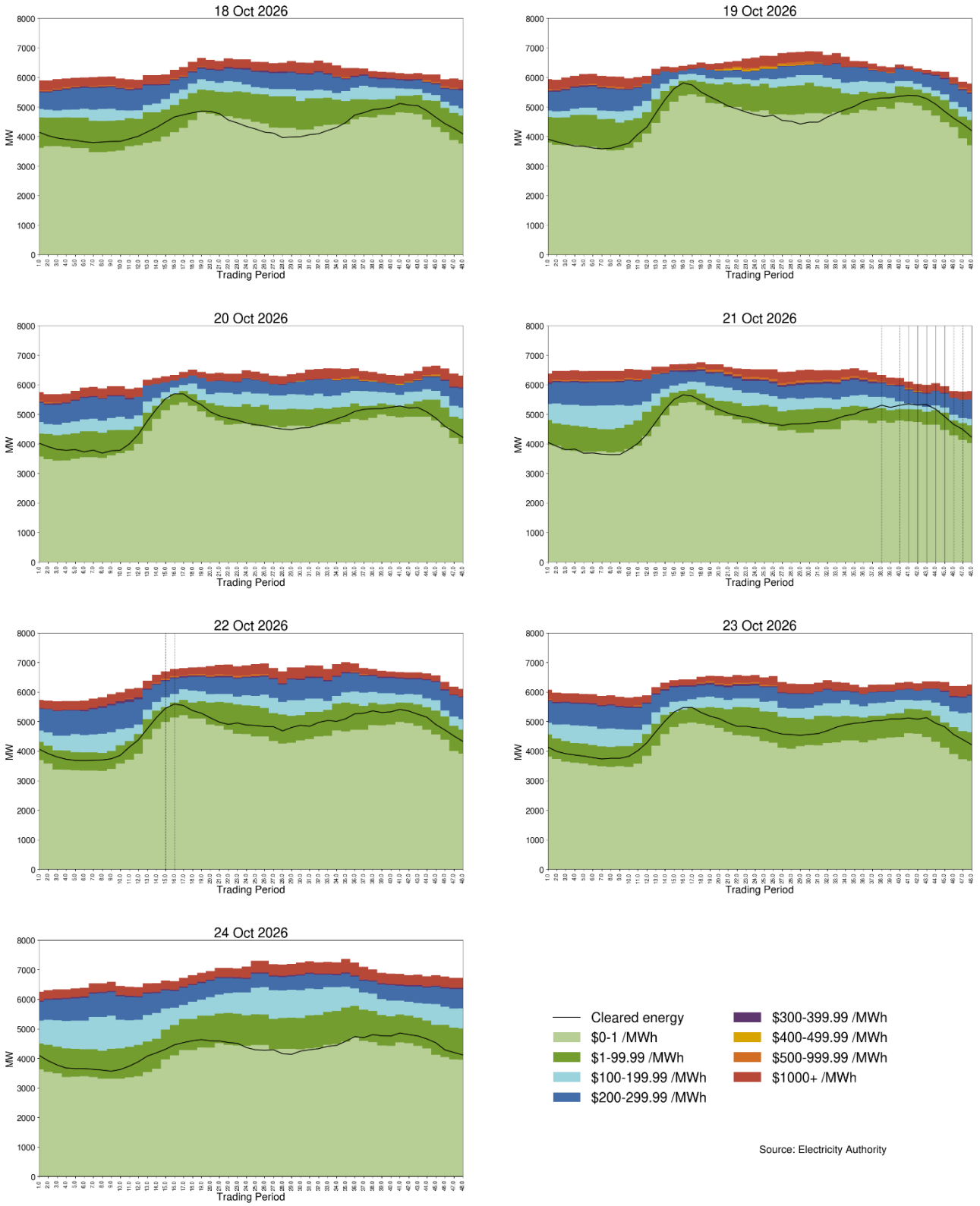


12. Offer behaviour

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. This week most energy cleared between $1-99/MWh, except for times on Tuesday and Friday mornings when energy cleared between $100-199/MWh, and Wednesday evening when energy cleared between $100-299/MWh.

Figure 23: Daily offer stacks



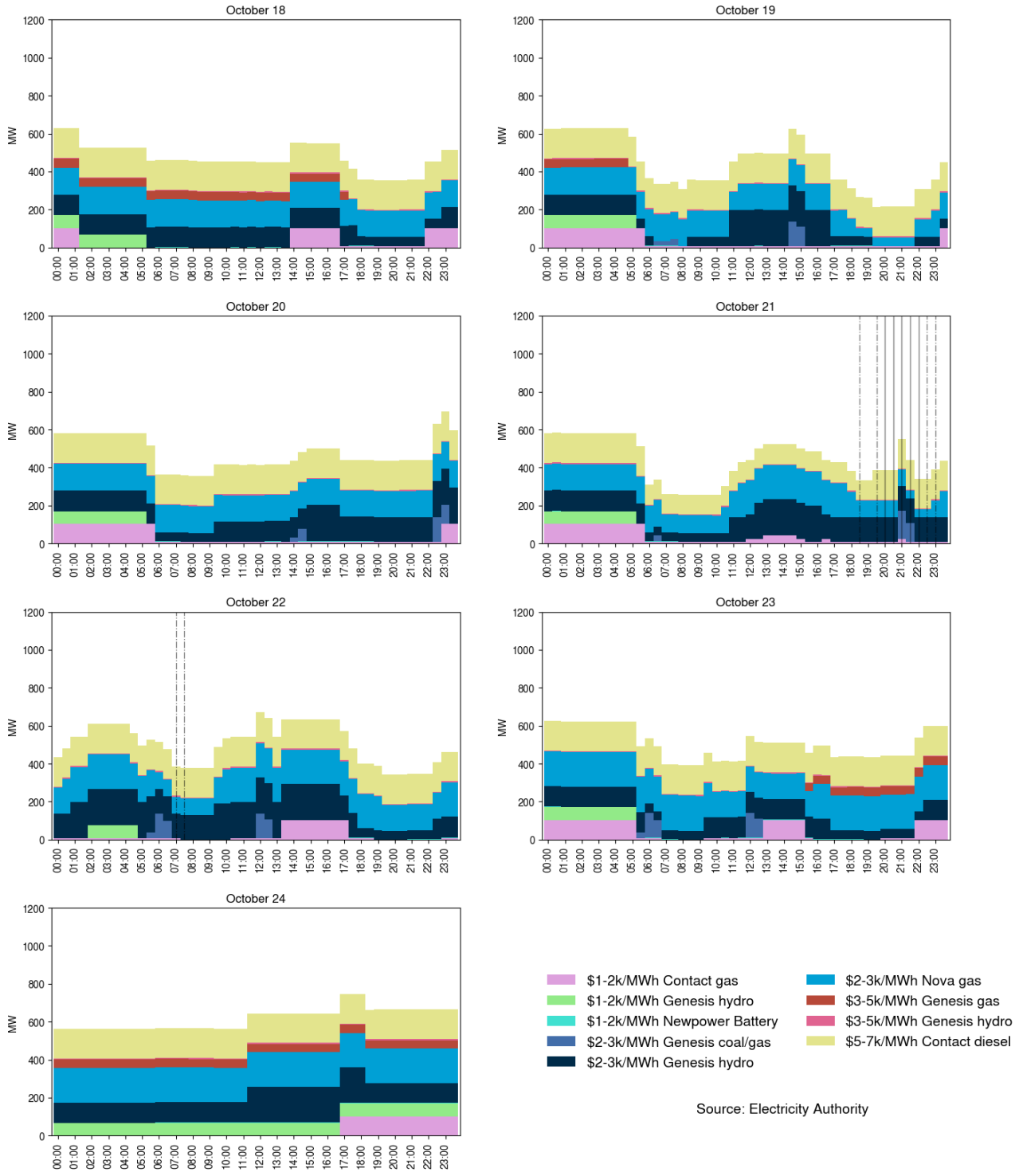
12.3. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 520MW 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. However, we are looking further into Genesis Huntly 1 offers this week.

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
8/12/2025-11/12/2025	Several	Further analysis	Contact/Manawa	Coleridge, Cobb, and Matahina	Offers
22/04/2026-24/04/2026	Several	Further analysis	Genesis	Tokaanu	Offers
12/10/2026	37-43	Further analysis	Genesis	Huntly battery	Offers
21/10/2026	42-48	Further analysis	Genesis	Huntly 1	Offers