13 October 2025

Trading conduct report 5-11 October 2025

Market monitoring weekly report

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1. Overview

1.1. This week the average spot price decreased by $19/MWh to $37/MWh. This was largely due to hydro inflows, high wind generation and decreased demand due to above average temperatures.

1.2. There was a large price spike to above $1,192/MWh at Ōtāhuhu on Monday at 8.00am due to demand forecast inaccuracies, geothermal generation tripping and high reserve prices.

1.3. National hydro storage increased to 68% nominally full and ~112% 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 5-11 October:

(a) The average spot price for the week was $37/MWh, a decrease of around $19/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $194/MWh.

2.3. Prices were mostly below $200/MWh this week due to increasing hydro storage, consistently high wind generation, decreased demand and lower thermal generation.

2.4. However, prices spiked to $1,192/MWh at Ōtāhuhu on Monday at 8.00am while the price at Benmore was $975/MWh. Prices were also high at 7.30am that same day, with the Ōtāhuhu price at $923/MWh and the Benmore price at $776/MWh. These extreme prices were due to a combination of factors.

(a) Demand was 102MW higher than forecast for 7.30am and 69MW higher than forecast for 8.00am. The highest demand of the week also occurred at 7.30am and was similarly high at 8.00am.

(b) At 7.51am Mokai geothermal generation tripped and 73MW was removed.

(c) Huntly 1 generation ramped up to maximum output, and total required sustained instantaneous reserve (SIR) increased from 7.00am to 7.30am, leading to generation residuals dropping to 302MW at 7.30am.

(d) The price of SIR spiked to $851/MWh in the North Island and $783/MWh in the South Island at 8.00am, contributing to the high price at that time.

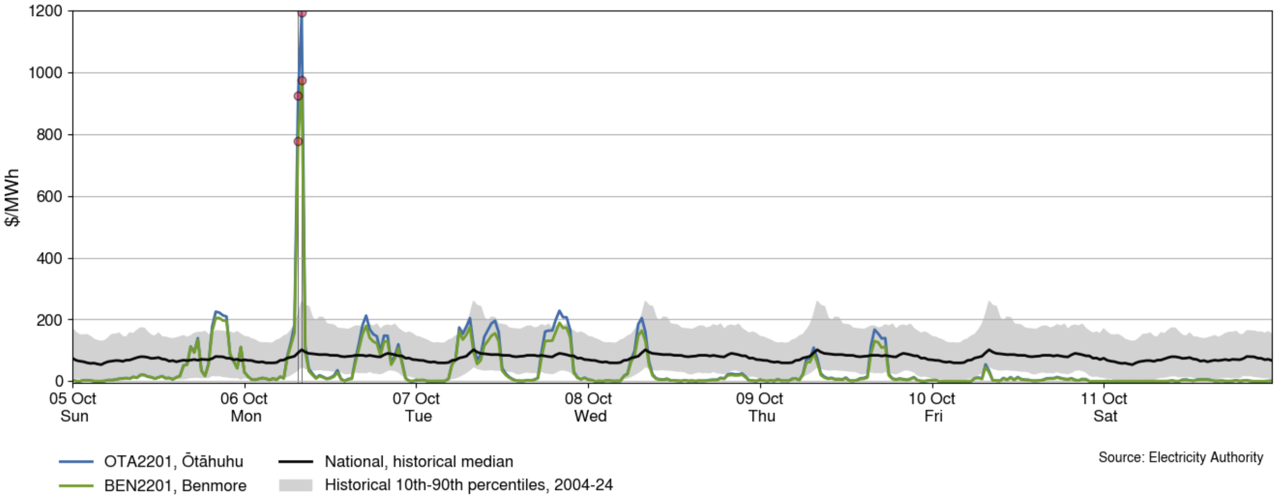
(e) Expensive thermal peaker generation had to be dispatched, leading to the Stratford Peakers setting the price for this high-priced period.

(f) Wind generation was also low at this time and there has been an above average amount of generation on outage this week.

2.5. Other prices throughout the week that reached above $200/MWh were largely due to wind and demand forecasting inaccuracies.

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.

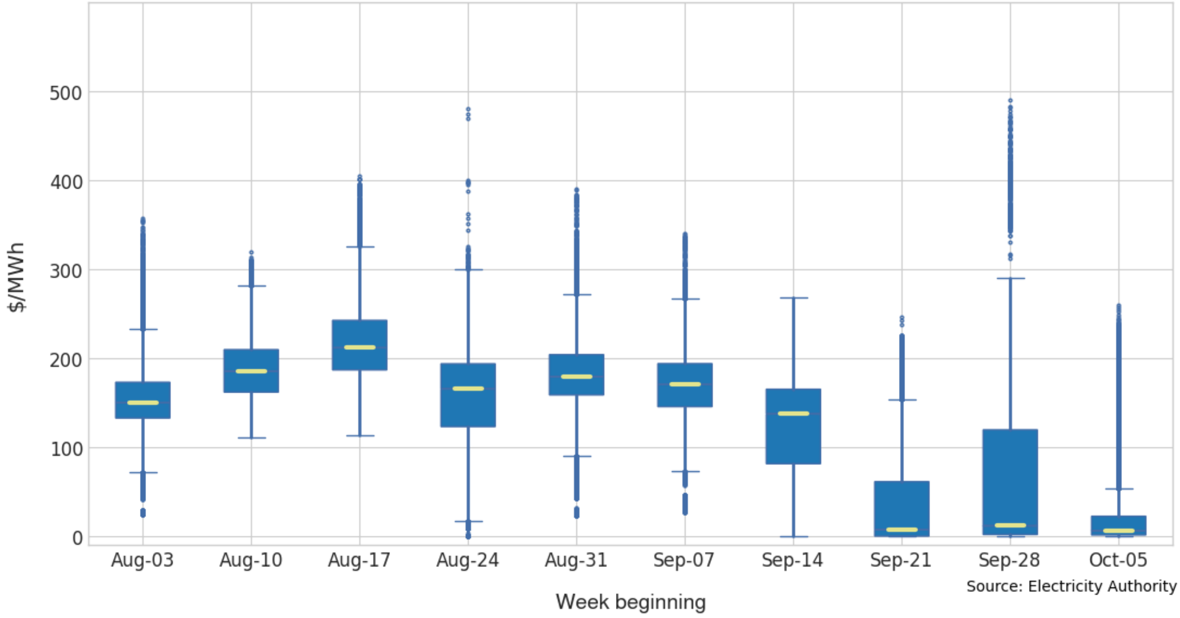
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 5-11 October



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 skewed lower and less volatile compared to last week. The median price was $6/MWh and most prices (middle 50%) fell between $1/MWh and $23/MWh.

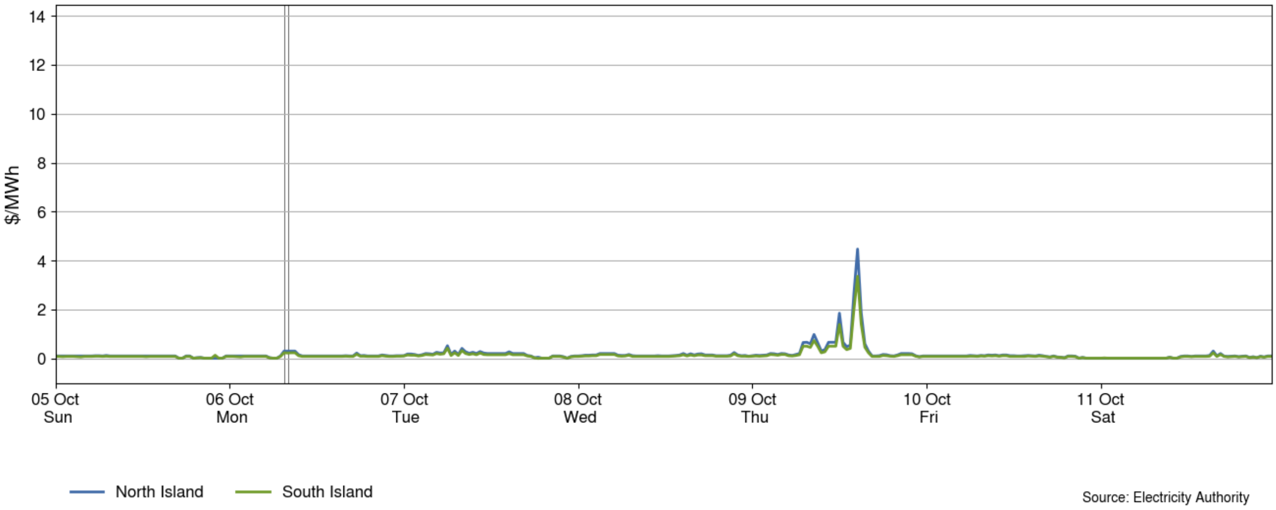
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

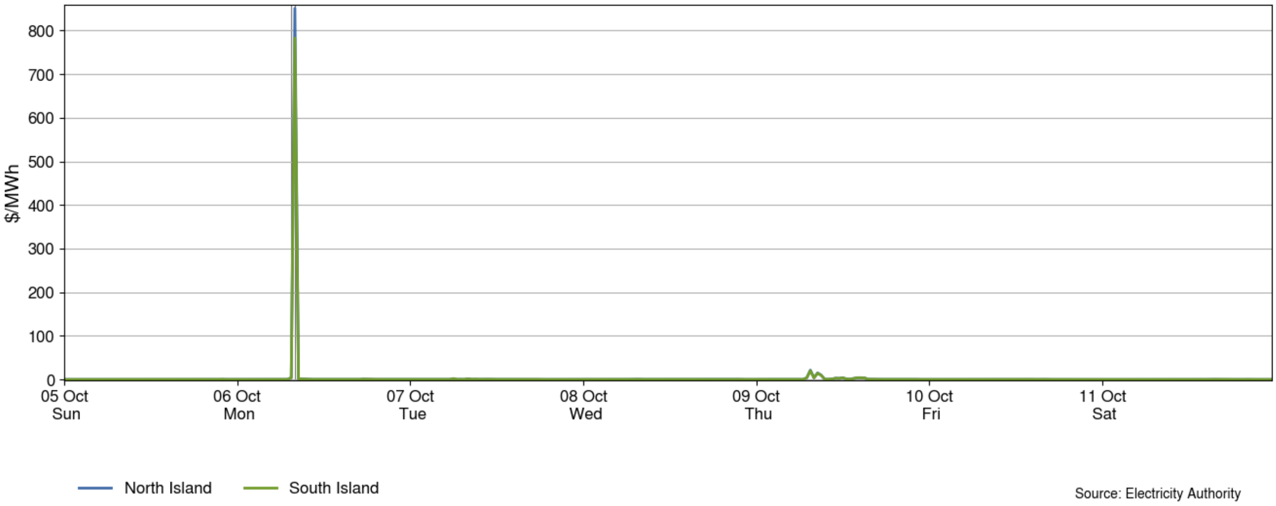
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh and did not reach above $5/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 5-11 October



3.2. SIR prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh. However, prices spiked to $851/MWh in the North Island and $783/MWh in the South Island at 8.00am on Monday during the time of the highest spot price this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 5-11 October



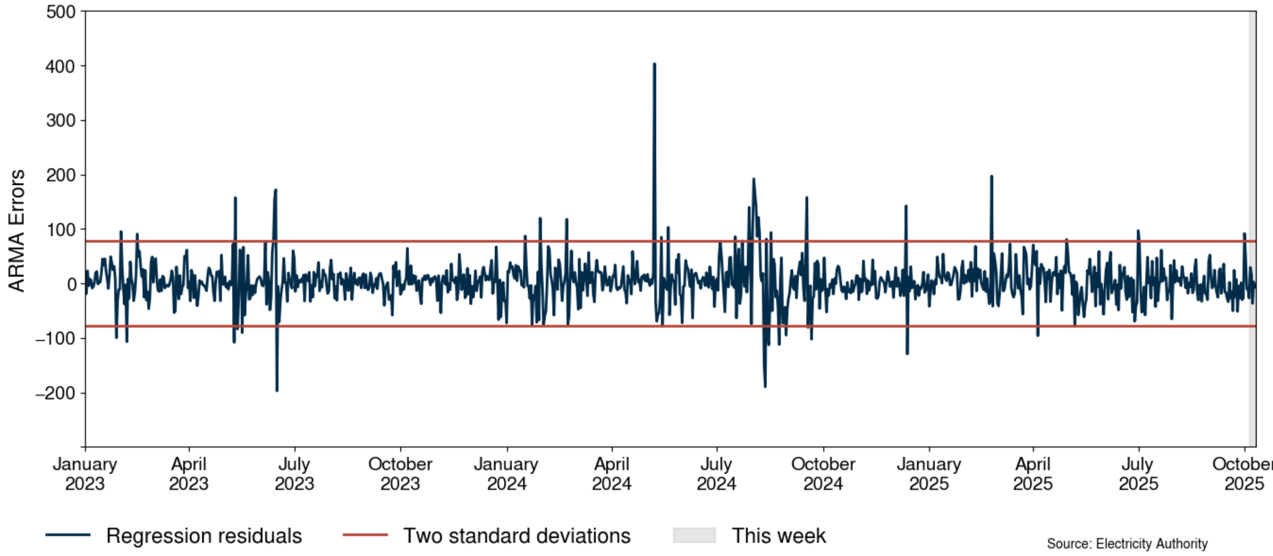
4. Regression residuals

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. However, with the added data from this week and the reconciled data from last month becoming available, the 1 October price is now outside of 2 standard deviations despite being within 2 standard deviations in last week's analysis. This was the day when prices increased, after being extremely low after Huntly 5 turned off and wind generation was lower.

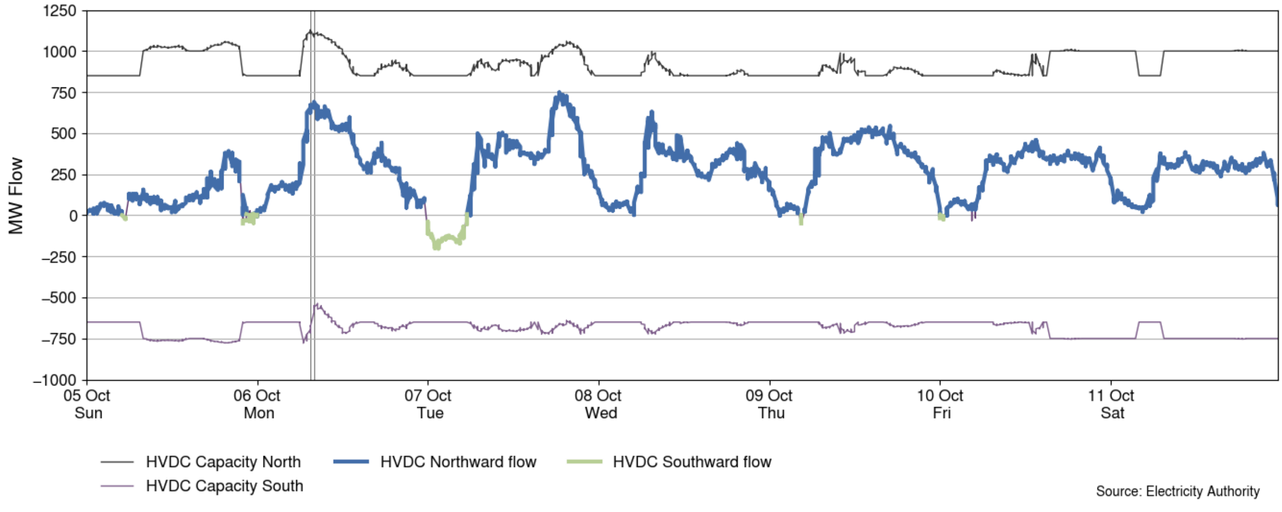
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 11 October 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 5-11 October. HVDC flows were mostly Northward this week despite high wind generation due to high hydro generation and low thermal generation. Northward HVDC flow was highest at 6.30pm on Tuesday with a flow of 748MW.

Figure 6: HVDC flow and capacity, 5-11 October

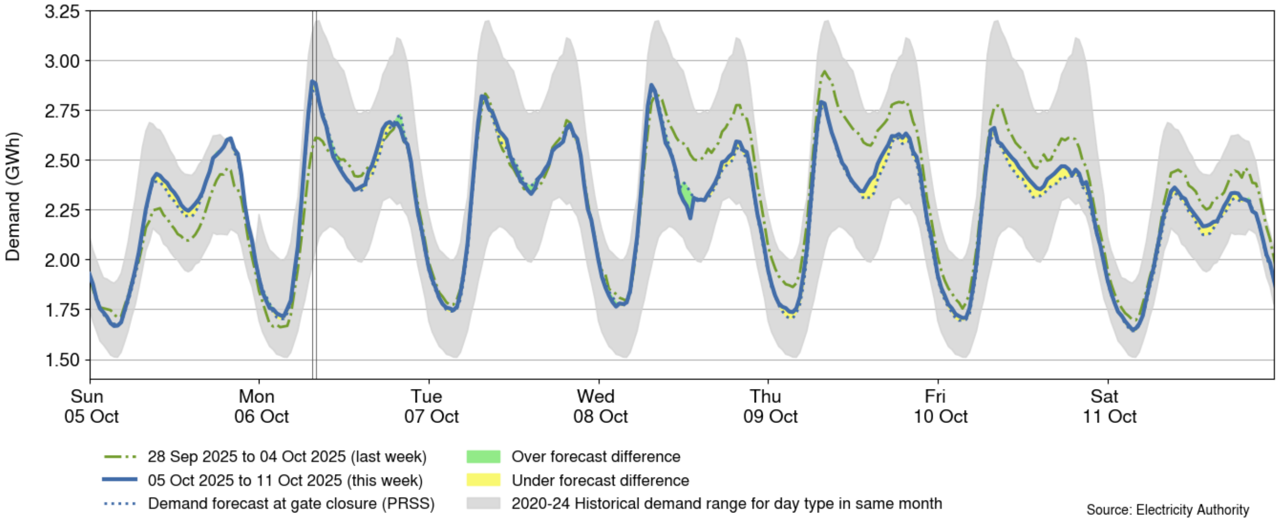


6. Demand

6.1. Figure 7 shows national demand between 5-11 October, compared to the historic range and the demand of the previous week. Overall demand was lower this week compared to last week due to above average temperatures. The highest demand this week was around 2.89GWh at 7.30am on Monday during the period of very high prices. Demand was overforecast on Wednesday when there was a trip at Tiwai[1].

[1] EXN Voltage North Island Tiwai reduction line tripped 6713818824.pdf

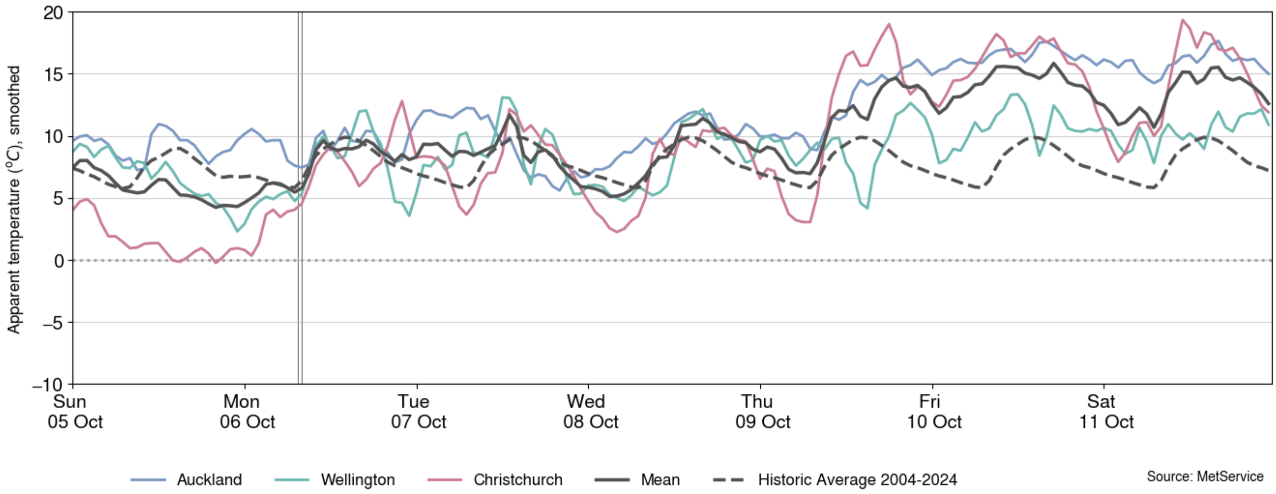
Figure 7: National demand, 5-11 October compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 5-11 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.

6.3. Apparent temperatures ranged from 6°C to 18°C in Auckland, 2°C to 14°C in Wellington, and 0°C to 21°C in Christchurch. Temperatures were above average in the latter part of the week.

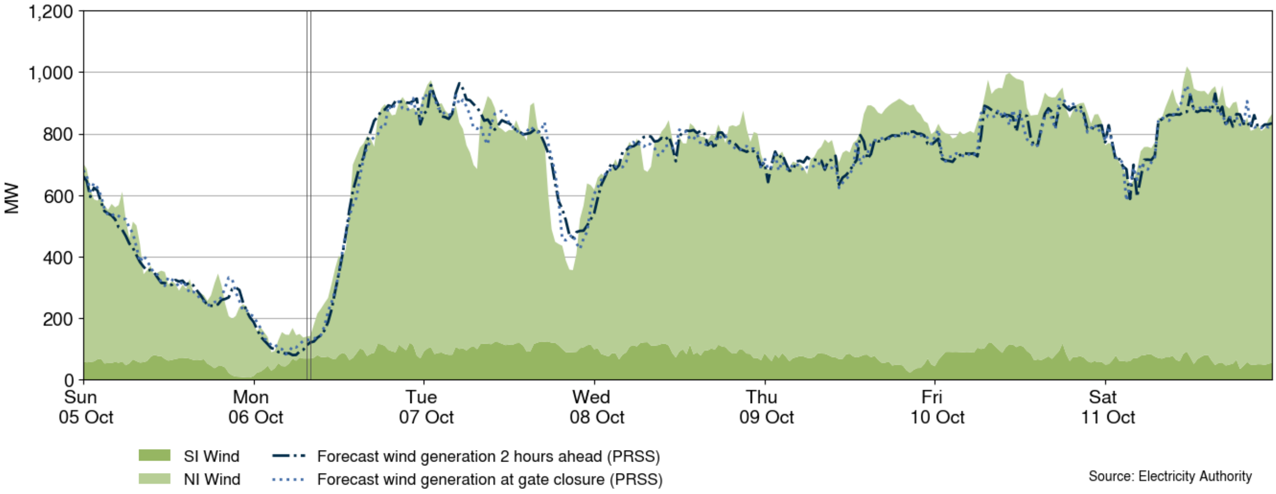
Figure 8: Temperatures across main centres, 5-11 October



7. Generation

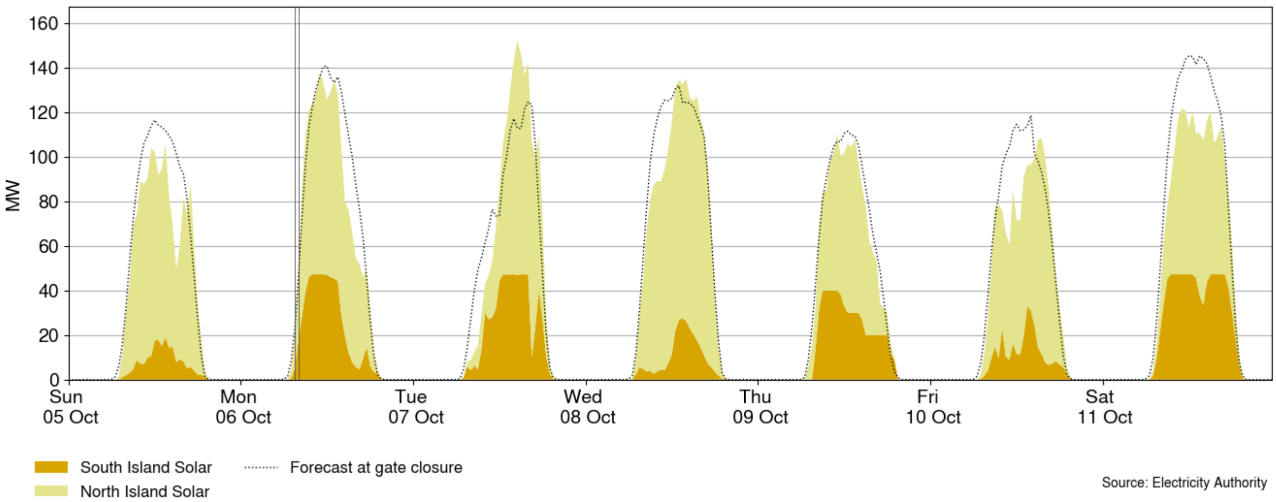
7.1. Figure 9 shows wind generation and forecast from 5-11 October. This week wind generation varied between 89MW and 1,018MW, with a weekly average of 699MW. Wind generation was high this week from Monday afternoon, remaining mostly above 600MW.

Figure 9: Wind generation and forecast, 5-11 October



7.2. Figure 10 shows grid connected solar generation from 5-11 October. Solar generation reached above 100MW every day this week. The highest solar generation was 152MW at 2.30pm on Tuesday. This is a new record for national grid connected solar generation.

Figure 10: Grid connected solar generation, 5-11 October

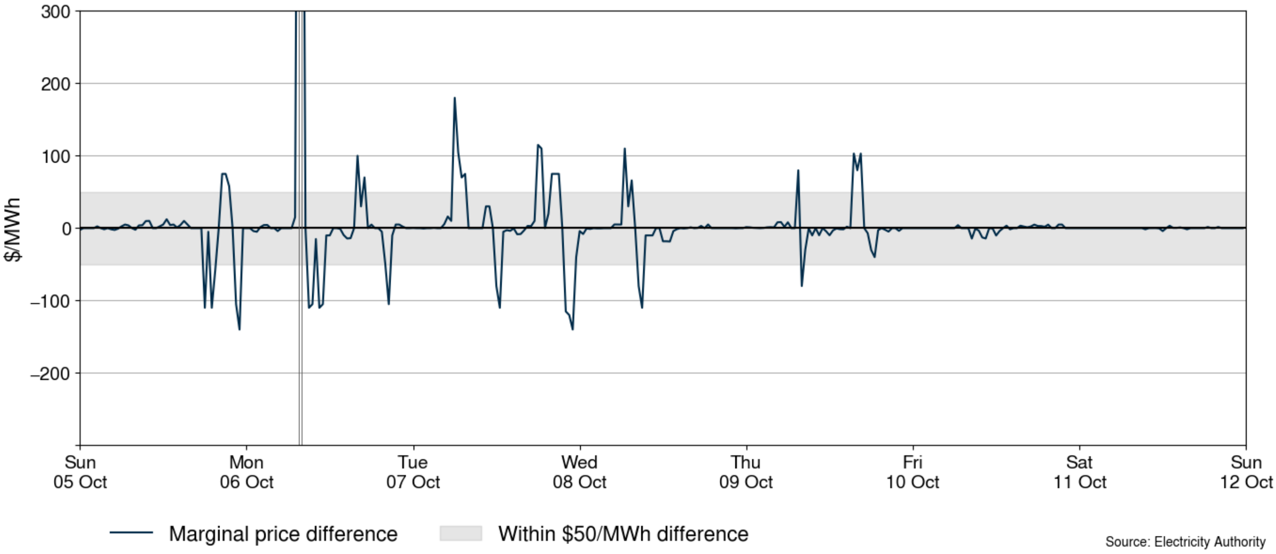


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of 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.

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

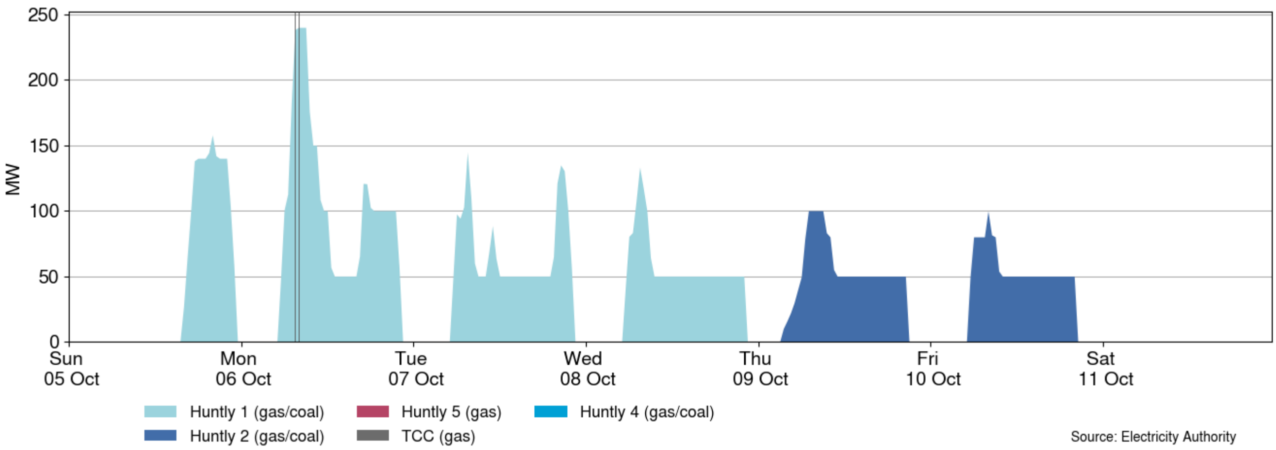
7.4. There were several trading periods with marginal price differences above $50/MW. The largest marginal price difference was $1,055/MWh at 7.30am on Monday during the period of very high prices. This was related to demand being 102MW higher than forecast.

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, 5-11 October



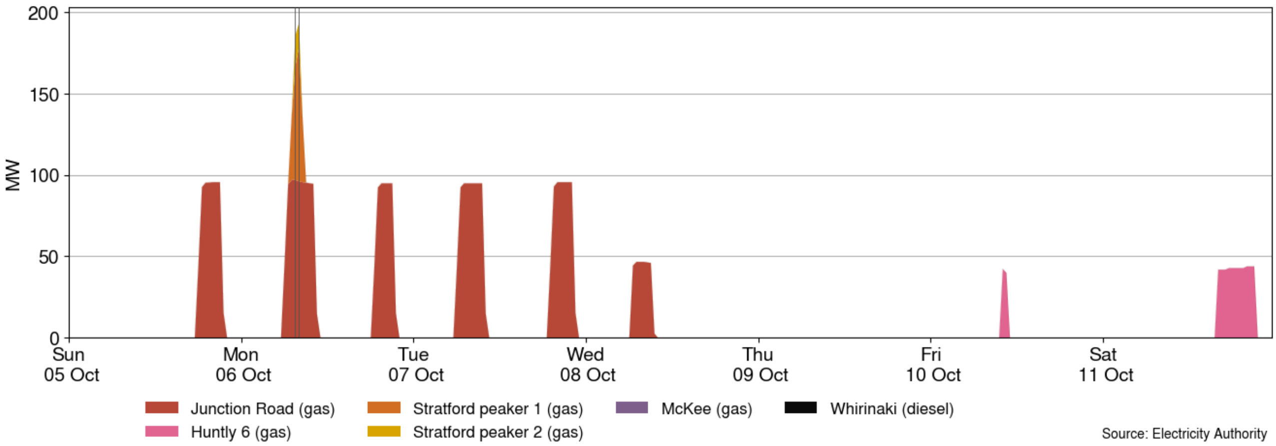
7.5. Figure 12 shows the generation of thermal baseload between 5-11 October. Huntly 1 generated Sunday to Wednesday and Huntly 2 generated Thursday and Friday. Huntly 1 ramped up to its full capacity between 7.30am and 9.00am on Monday when prices started spiked.

Figure 12: Thermal baseload generation, 5-11 October



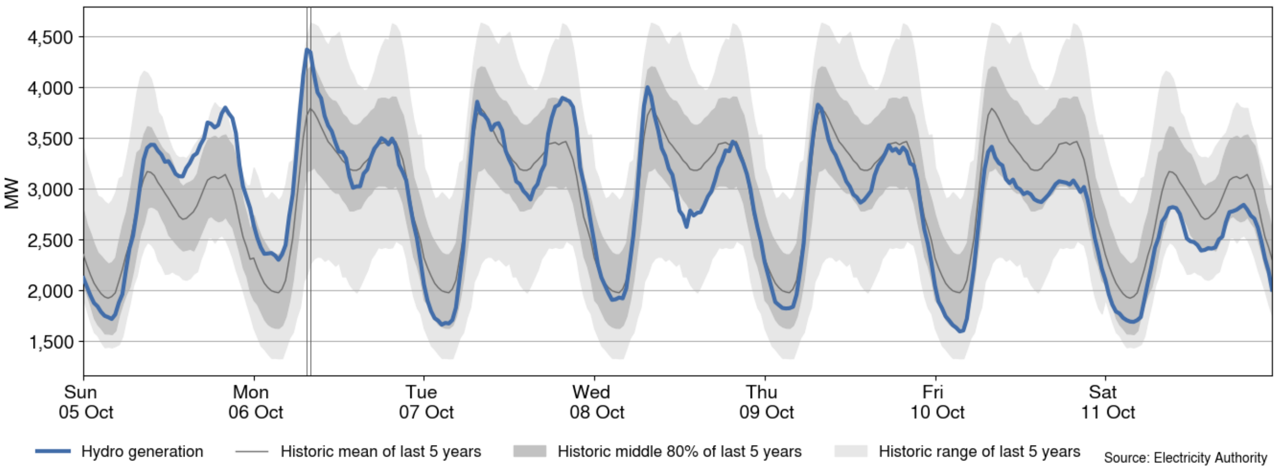
7.6. Figure 13 shows the generation of thermal peaker plants between 5-11 October. Junction Road generated morning and evening peaks from Sunday's evening peak to Wednesday's morning peak. Stratford Peaker 1 and 2 generated during the period of very high prices on Monday, setting the price. Huntly 6 generated on Friday and Saturday.

Figure 13: Thermal peaker generation, 5-11 October



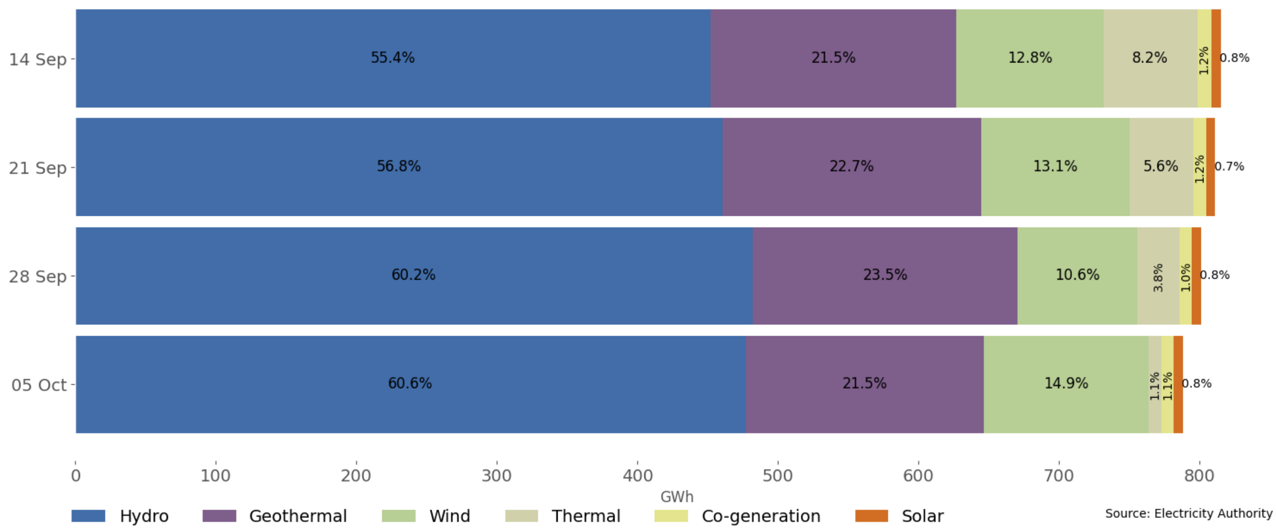
7.7. Figure 14 shows hydro generation between 5-11 October. Hydro generation remained mostly within the middle 80% of historic generation. It was above the historic 90th percentile on Sunday afternoon and during the very high prices on Monday morning. The hydro generation on Monday morning was the highest for the week.

Figure 14: Hydro generation, 5-11 October



7.8. As a percentage of total generation, between 5-11 October, total weekly hydro generation was 60.6%, geothermal 21.5%, wind 14.9%, thermal 1.1%, co-generation 1.1%, and solar (grid connected) 0.8%, as shown in Figure 15. Wind generation increased, allowing thermal generation to decrease despite some geothermal generation being on outage.

Figure 15: Total generation by type as a percentage each week, between 14 September and 5 October 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 5-11 October ranged between ~1,797MW and ~2,500MW. Figure 17 shows the thermal generation capacity outages. Generation on outage was above average this week.

8.2. Notable outages include:

(a) TCC is on outage until 15 October 2025.

(b) Huntly 4 is on outage until 17 October 2025.

(c) West Wind farm was on outage 9 and 10 October 2025.

(d) Ōhau B is on partial outage until 17 October 2025.

(e) Kawerau geothermal is on outage until 23 October 2025.

(f) Tauhara geothermal was on partial outage 7 October 2025.

(g) Te Mihi geothermal went on unplanned partial outage 5-9 October 2025.

(h) Ruakākā battery was on outage between 3-6, 9 and 11-13 October 2025.

(i) Benmore unit 6 is on outage until 21 November 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, 5-11 October

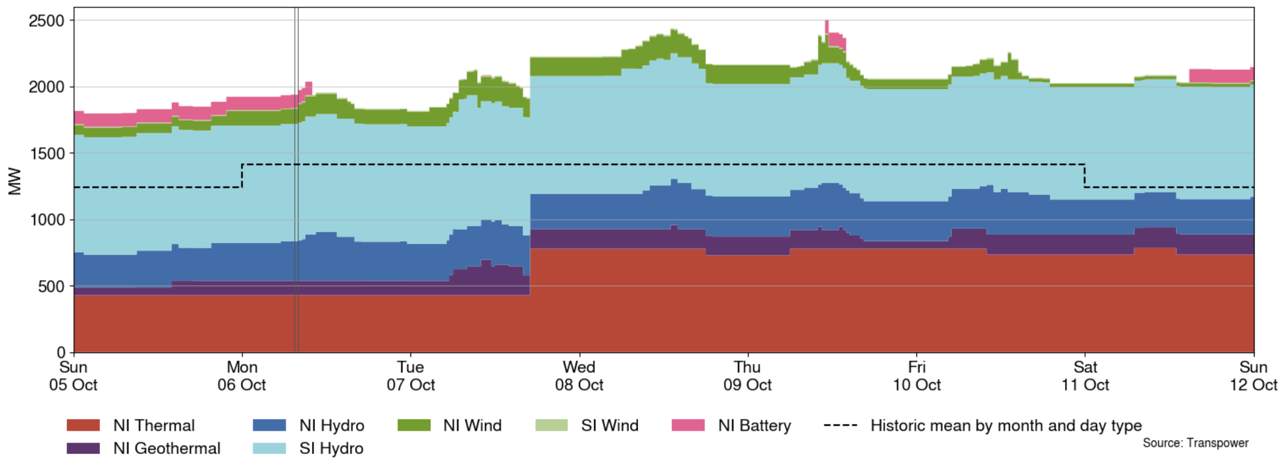
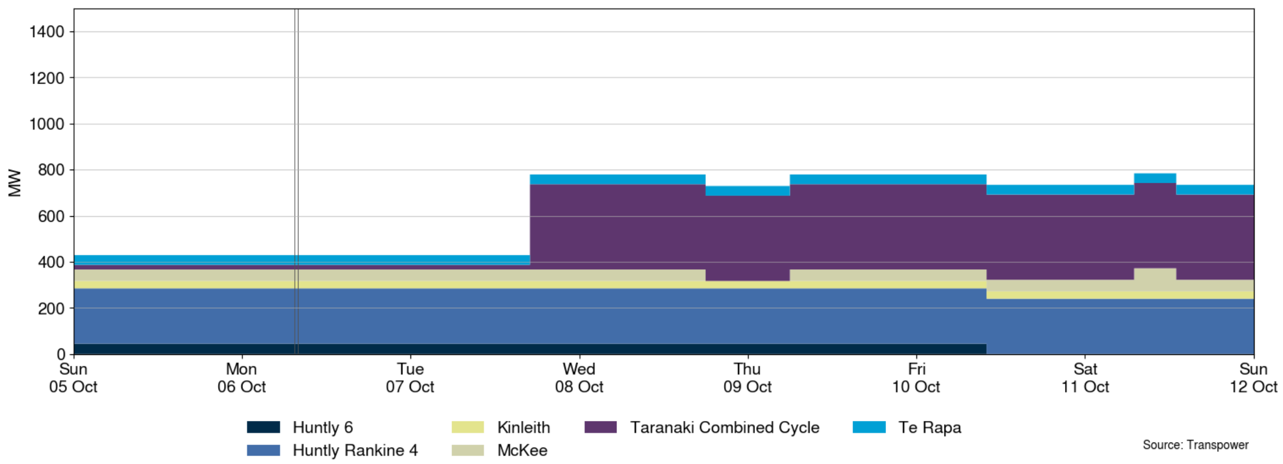


Figure 17: Total MW loss from thermal outages, 5-11 October

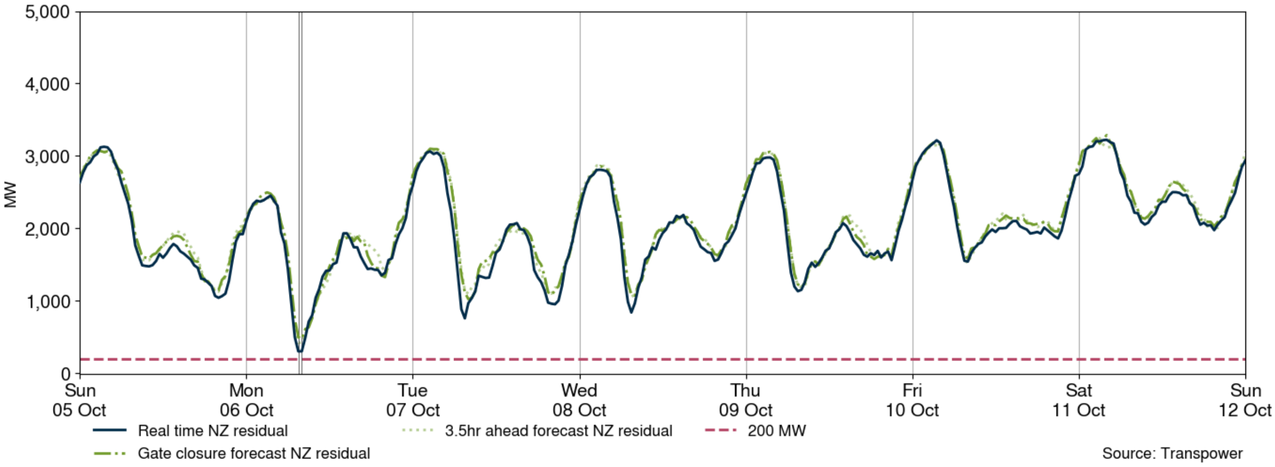


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 5-11 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 low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. The minimum residual generation this week was 304MW on Monday at 7.30am during the very high price period.

Figure 18: National generation balance residuals, 5-11 October



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 10^{th} to 90^{th} percentiles.

10.2. National controlled storage increased to 68% nominally full and ~112% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (50% full[3]) and Lake Takapō (51% full) have increased to around their historic means.

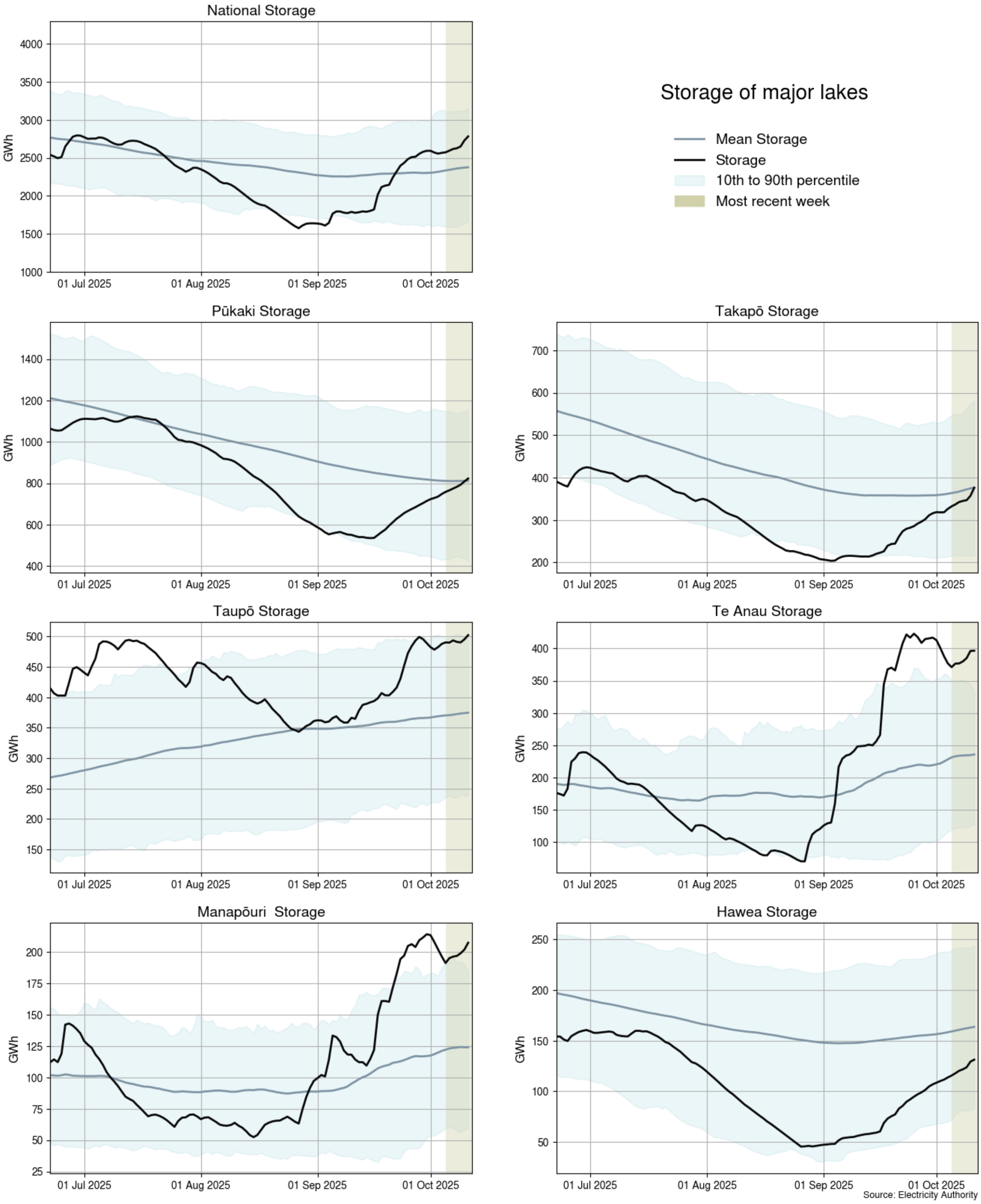
10.4. Storage at Lake Te Anau (153% full) and Lake Manapōuri (137% full) are above their respective historic 90th percentiles. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (89% full) is close to its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (48% full) is between its historic mean and 10th percentile.

[3] Percentage full values sourced from NZX Hydro.

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.

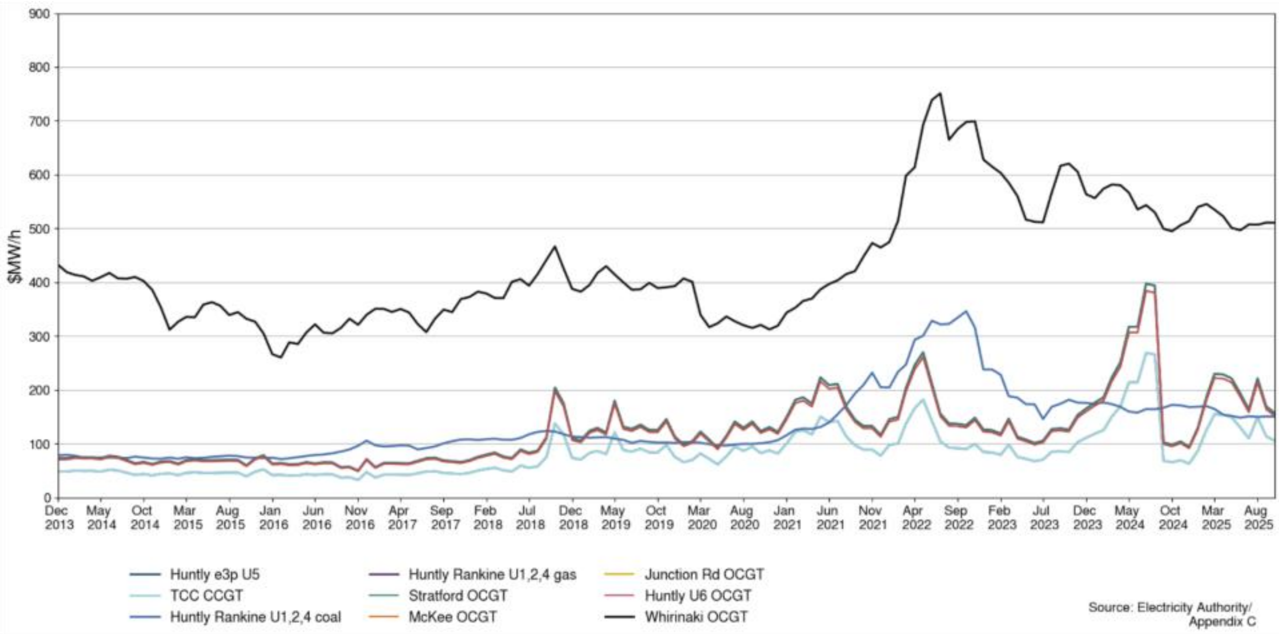
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$157/MWh.

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



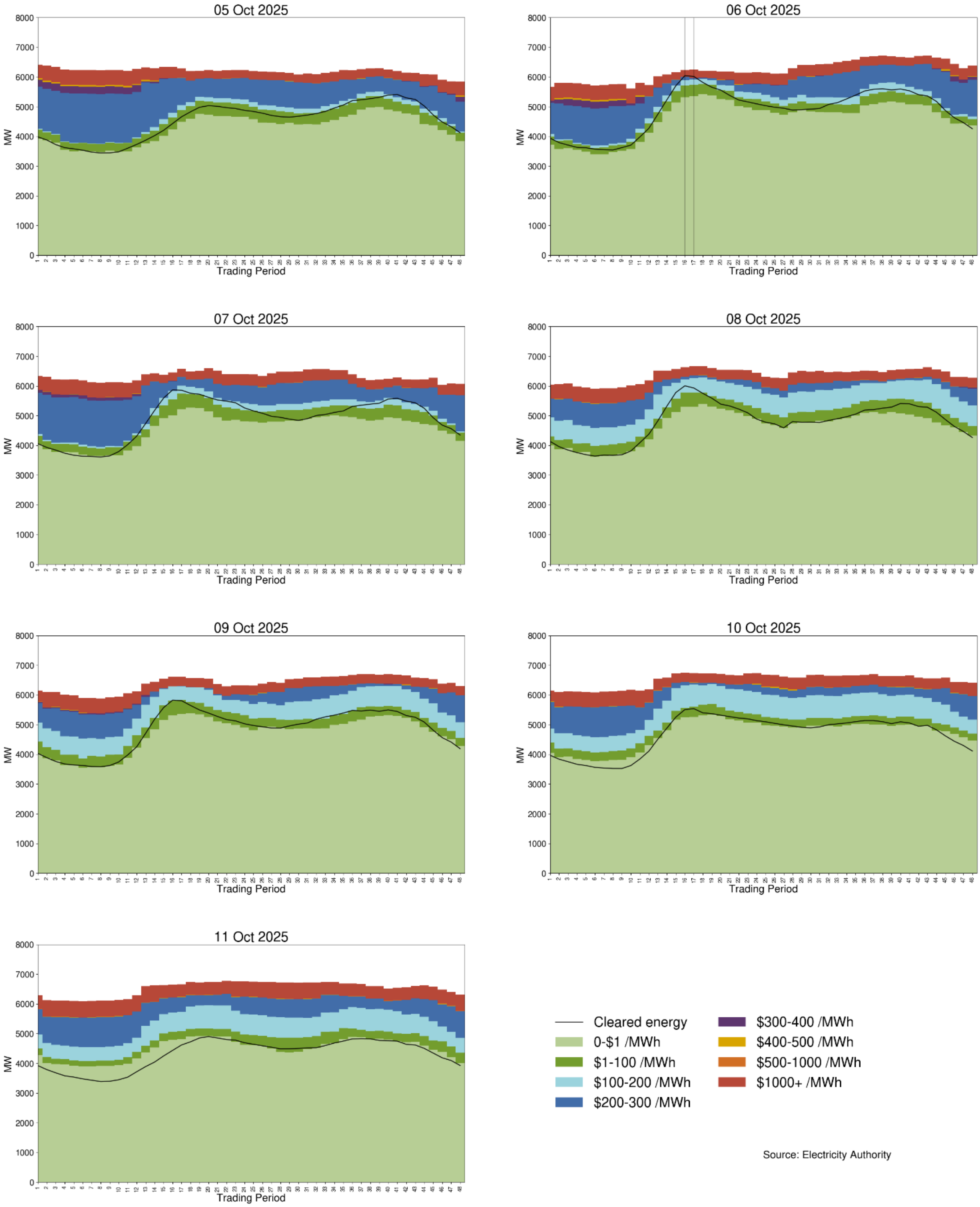
12. Offer behaviour

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 offers cleared in the bands under $200/MWh this week. A portion of Meridian hydro generation in the $200-300/MWh band was priced down into the $100-200/MWh band from 8 October.

12.3. The stack remains very steep with little generation priced between $300-$1,000/MWh.

Figure 21: Daily offer stacks

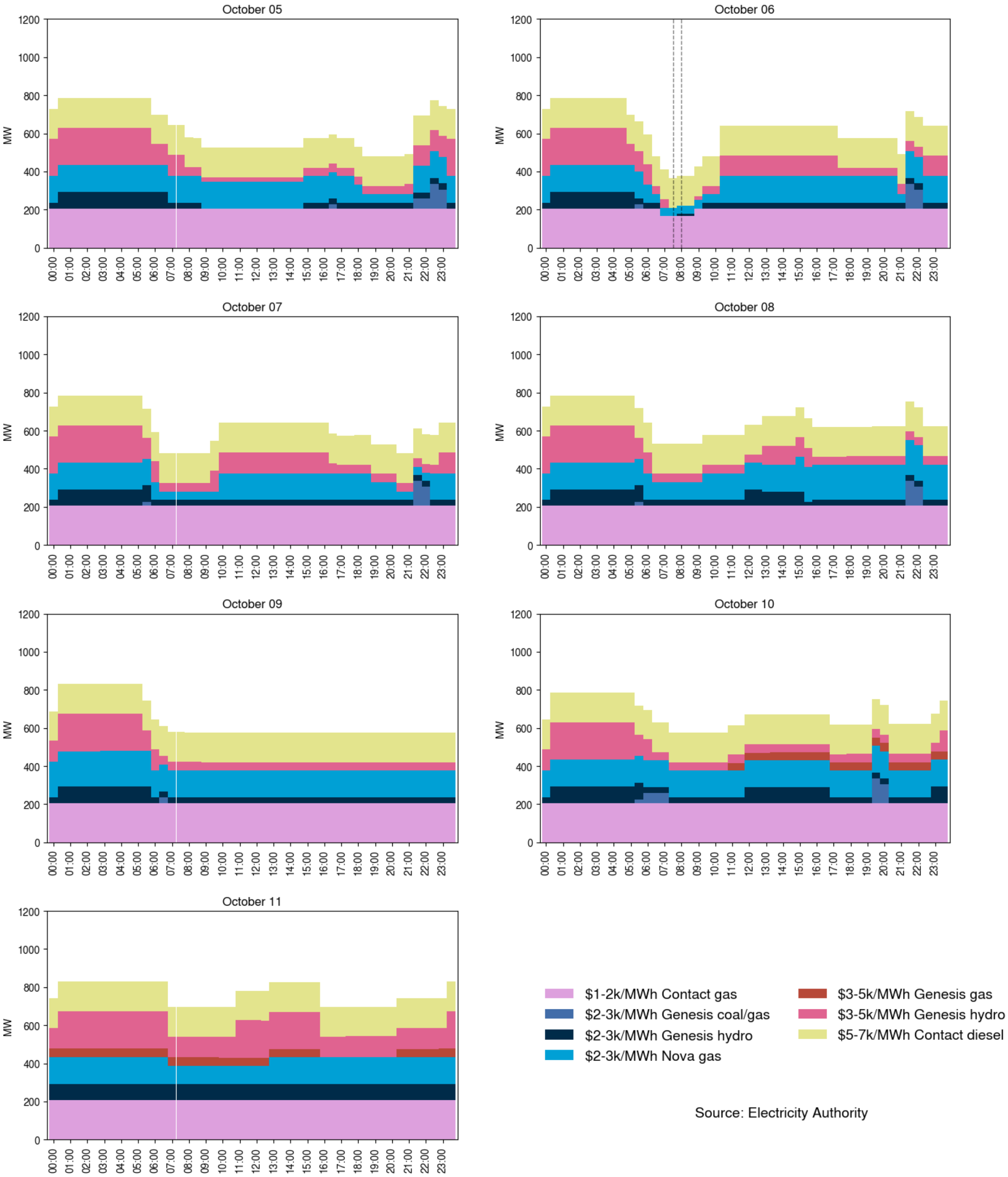


12.4. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 658MW per trading period was priced above $1,000/MWh this week, which is roughly 12% of the total energy available. This is a slight decrease from last week.

Figure 22: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

Table 1: Trading periods identified for further analysis

Date	Trading period	Status	Participant	Location	Enquiry topic
8/05/2025-9/05/2025	Several	Further analysis	Genesis	Waikaremoana	Offers
01/10/2025-04/-10/2025	Several	Further analysis	Genesis	Huntly	Offers