

29 September 2026

Trading conduct report 20-26 September 2026

Market monitoring weekly report

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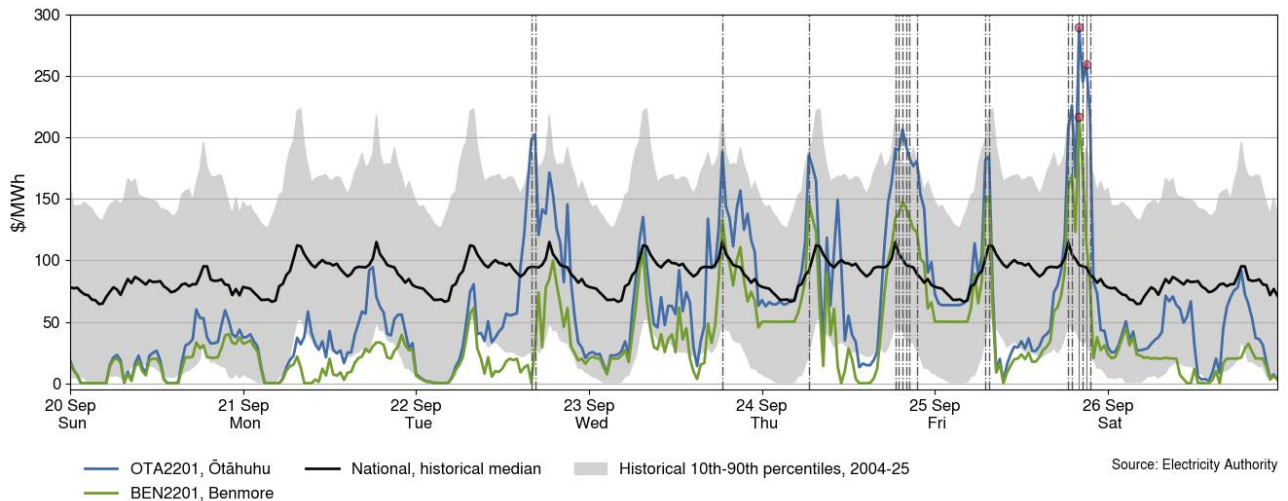
1. Overview

- 1.1. Prices have increased this week due to higher demand driven by colder weather, and lower wind generation. Solar generation is at an all-time high with two new solar farms generating semi-regularly from Thursday. National hydro storage has decreased to 80% nominally full and is 133% of the historic mean for this time of year.

2. Spot prices

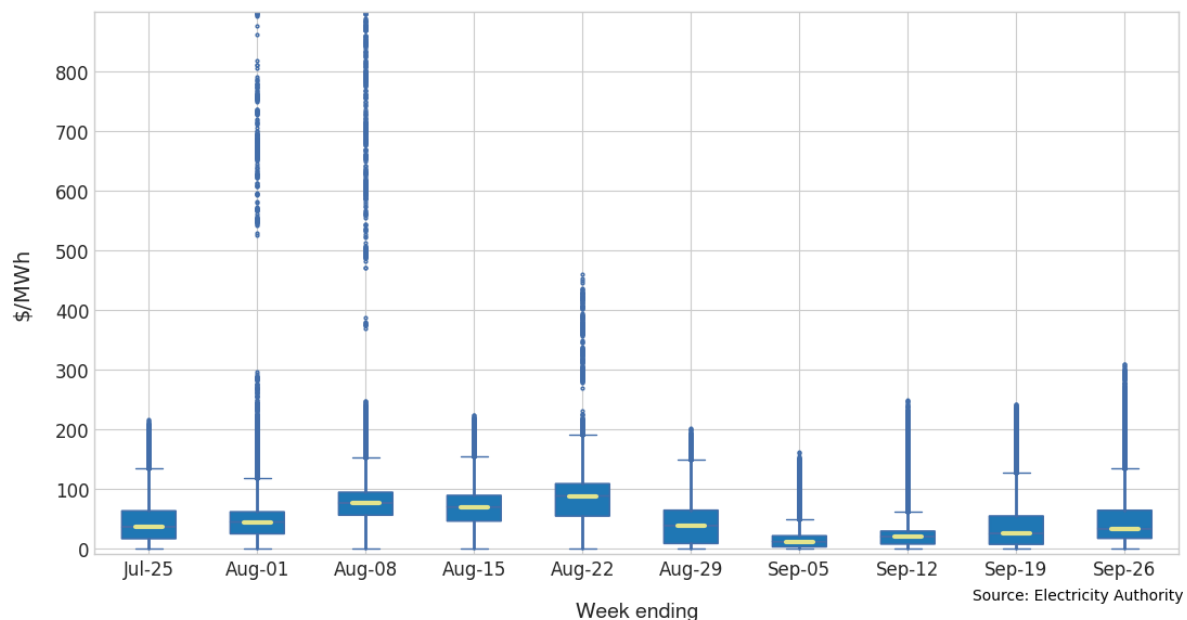
- 2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.
- 2.2. Between 20-26 September:
 - (a) The average spot price for the week was \$48/MWh, an increase of around \$9/MWh compared to the previous week.
 - (b) 95% of prices fell between \$0.02/MWh and \$180/MWh.
- 2.3. Prices this week are slightly higher than last week due to increased demand and lower wind generation in the second half of the week, increasing price volatility and spot prices overall.
- 2.4. The highest price at Ōtāhuhu was \$290/MWh at 8:00pm on Friday. At this time the price at Benmore was \$216/MWh. Intermittent generation was 112MW lower than forecast, and the batteries very likely had little to no energy left to discharge.
- 2.5. At 4.30pm on Tuesday, the price at Ōtāhuhu spiked up to \$202/MWh. At this time the price at Benmore was \$29/MWh. During this time the HVDC had 79MW of northward flow capacity remaining, demand was 56MW higher than forecast, intermittent generation was 119MW lower than forecast and continuing to decline, and demand was increasing toward its peak for the evening. These factors caused North Island FIR prices to increase to \$128/MWh, compounding already higher energy prices.
- 2.6. At 7.30am on Thursday, the price at Ōtāhuhu spiked up to \$206/MWh. At this time the price at Benmore was \$148/MWh. During this time demand was 50MW higher than forecast, and intermittent generation was low, decreasing the availability of cheap energy.
- 2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 20-26 September



- 2.8. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.
- 2.9. The distribution of spot prices this week was slightly wider than last week with more high-priced outliers. The median price was \$48/MWh and most prices (middle 50%) fell between \$17/MWh and \$64/MWh.

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

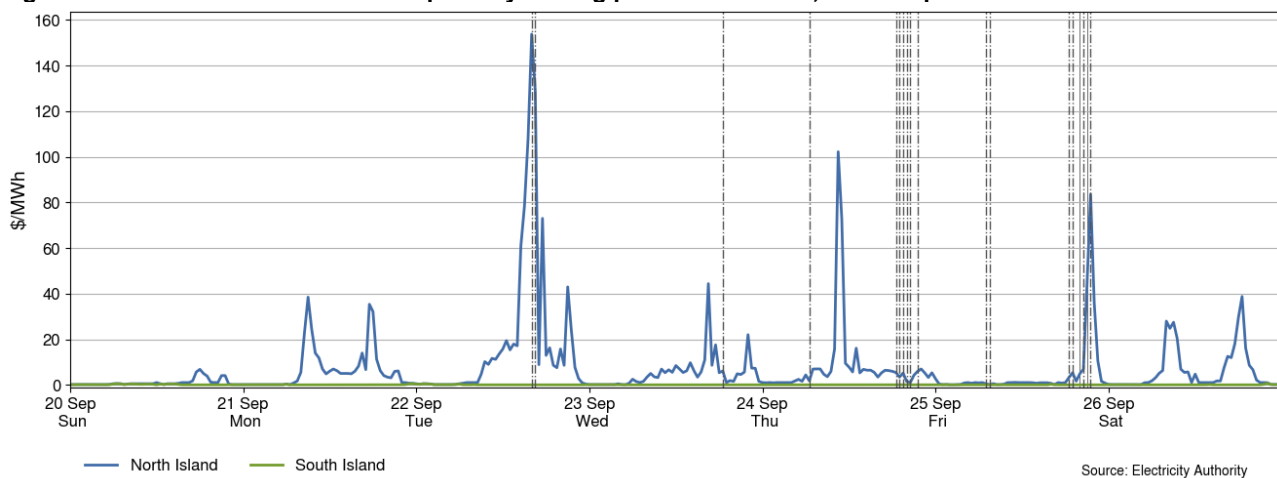


3. Reserve prices

- 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.

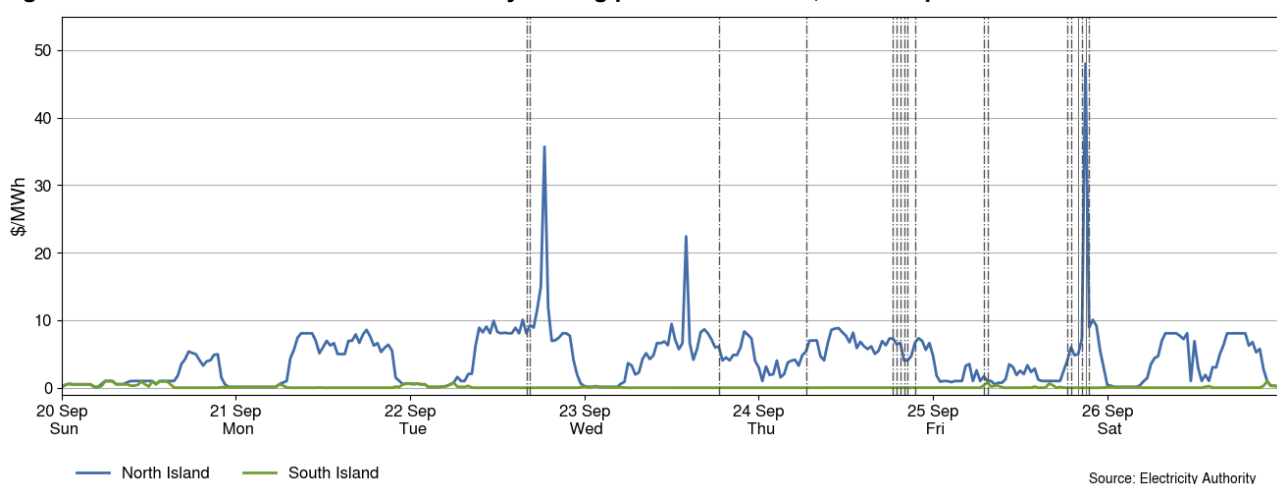
- 3.2. At 4.00pm on Tuesday, North Island FIR prices spiked up to \$153/MWh. At this time the HVDC was setting the risk and had 79MW of its northward flow capacity remaining. Additionally, wind and solar generation was decreasing.
- 3.3. At 10.30am on Thursday, North Island FIR prices spiked up to \$102/MWh. At this time the HVDC was setting the risk and had 68MW of its northward flow capacity remaining. The volume of FIR available during this period decreased significantly compared to the previous trading period.
- 3.4. At 9.30pm on Friday, North Island FIR prices spiked up to \$83/MWh. At this time the HVDC was setting the risk and had 170MW of its northward flow capacity remaining. The volume of FIR available during this period decreased significantly compared to the previous trading period.

Figure 3: Fast instantaneous reserve price by trading period and island, 20-26 September



- 3.5. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below \$10/MWh this week.
- 3.6. At 6.30pm on Tuesday North Island SIR prices spiked to \$35/MWh. At this time the HVDC was setting the risk and had 209MW of its northward flow capacity remaining.
- 3.7. At 9.00pm on Friday, North Island SIR prices spiked up to \$48/MWh. At this time the HVDC was setting the risk and had 206MW of its northward flow capacity remaining.

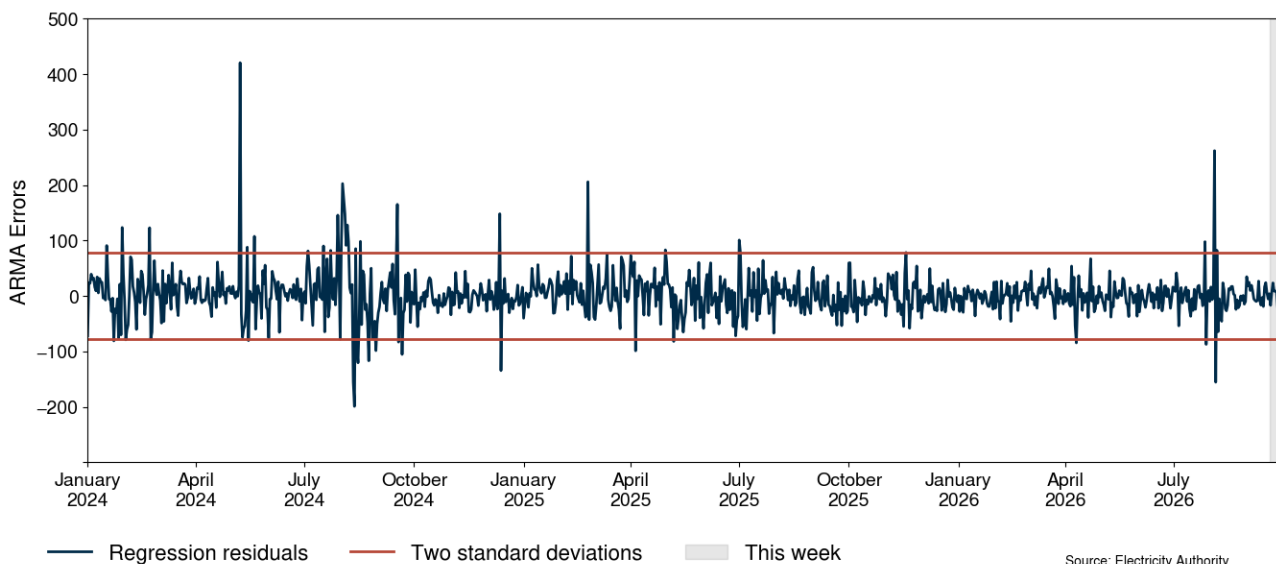
Figure 4: Sustained instantaneous reserve by trading period and island, 20-26 September



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.

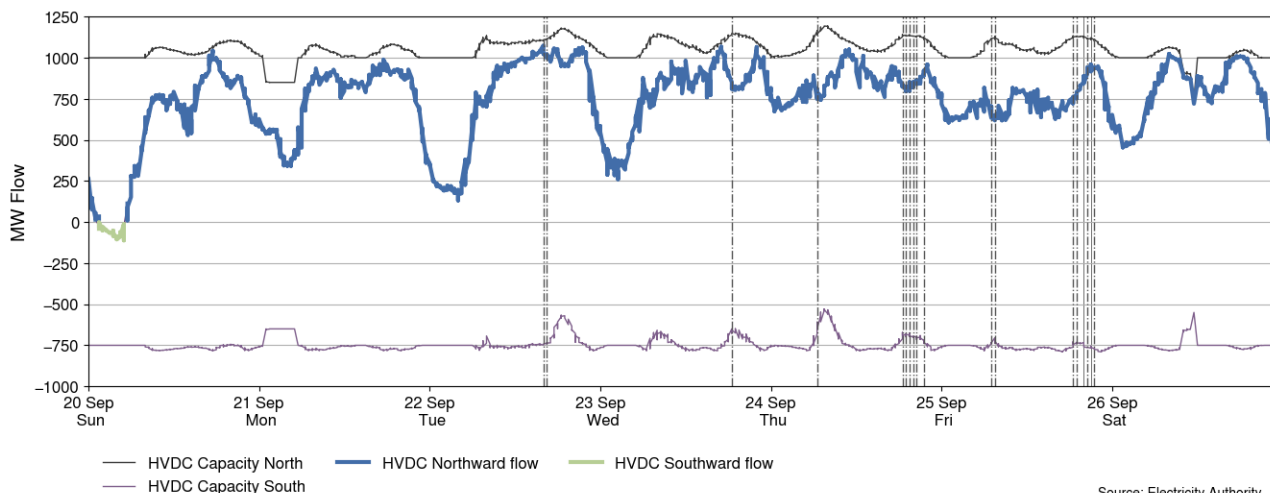
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 26 September 2026



5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 20-26 September. HVDC flows were mostly northward this week.
- 5.2. The highest northward HVDC flow this week was 1,075MW which occurred at 4.00pm on Tuesday.
- 5.3. The highest southward HVDC flow this week was 112MW which occurred at 5.00am on Sunday.

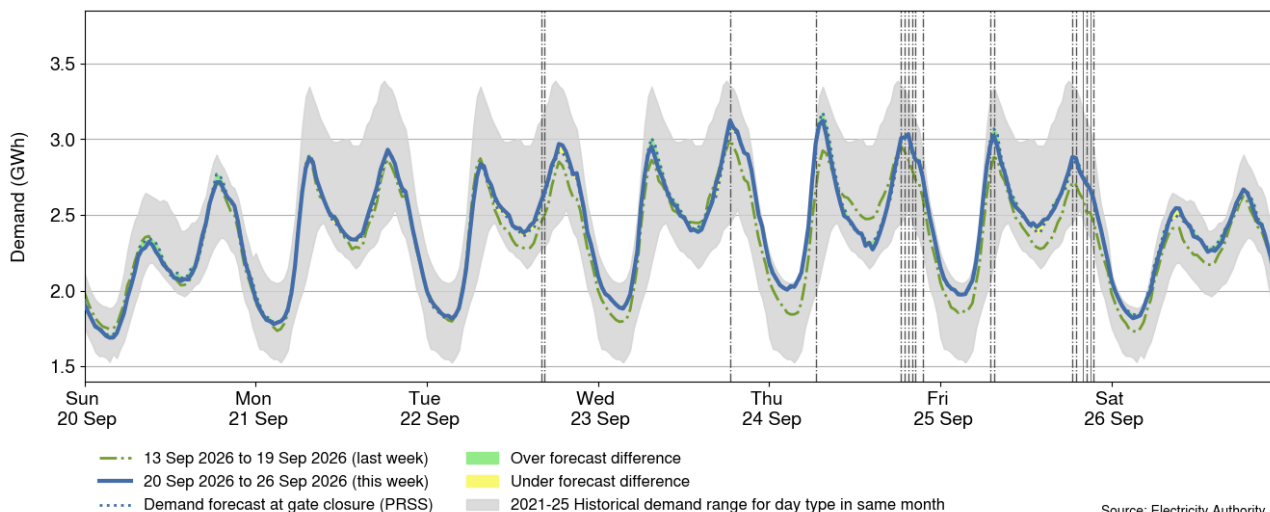
Figure 6: HVDC flow and capacity, 20-26 September



6. Demand

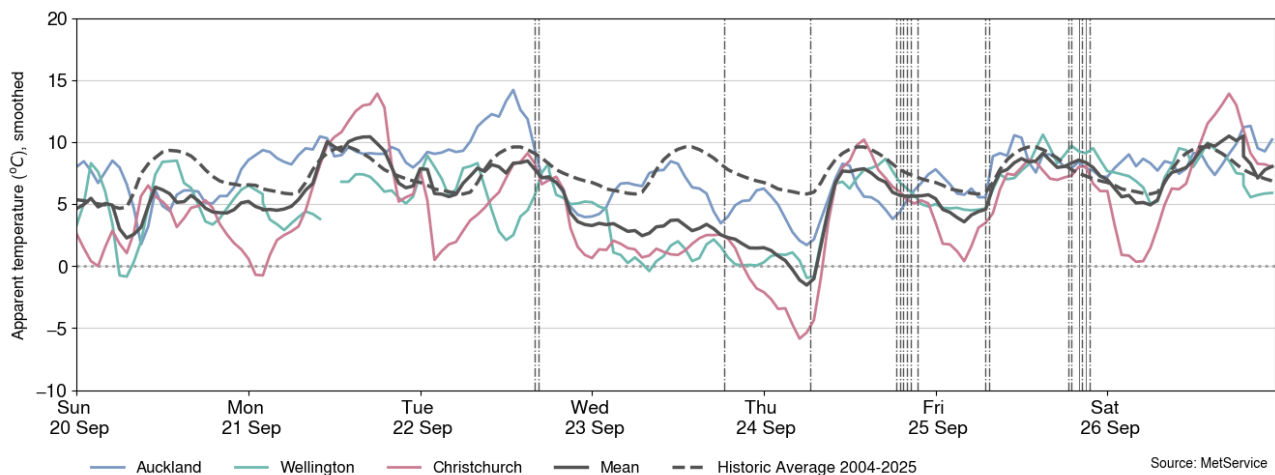
- 6.1. Figure 7 shows national demand between 20-26 September, compared to the historic range and the demand of the previous week. Demand was similar to last week until midday Tuesday when demand was generally higher due to colder weather.
- 6.2. The maximum demand this week was around 3.12GWh (6.25GW) at 6:30pm on Wednesday.

Figure 7: National demand, 20-26 September compared to the previous week



- 6.3. Figure 8 shows the hourly apparent temperature at main population centres from 20-26 September. 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 0°C to 15°C in Auckland, -2°C to 11°C in Wellington, and -6°C to 15°C in Christchurch.

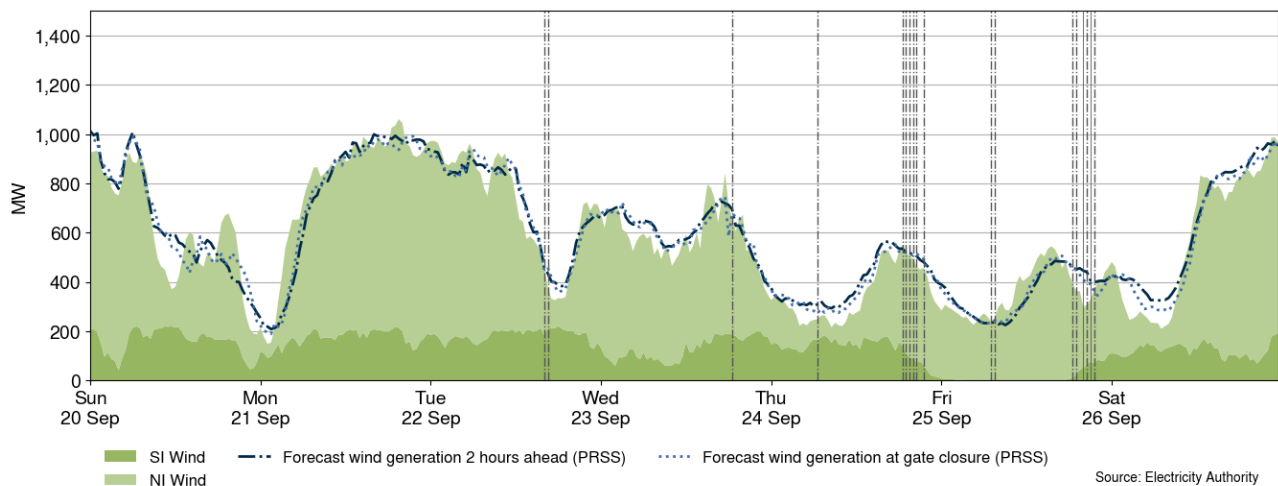
Figure 8: Temperatures across main centres, 20-26 September



7. Generation

- 7.1. Figure 9 shows wind generation and forecast from 20-26 September. This week wind generation varied between 148MW and 1,060MW, with a weekly average of 572MW. Wind generation was higher from Monday to Wednesday, then dropping to below 600MW until Saturday evening.
- 7.2. Forecasting differences on midday Sunday were due to Waipipi, Turitea, and Harapaki wind farms.
- 7.3. Forecasting differences on Saturday morning were due to Turitea, Tararua stage 3, and various Meridian wind farms.

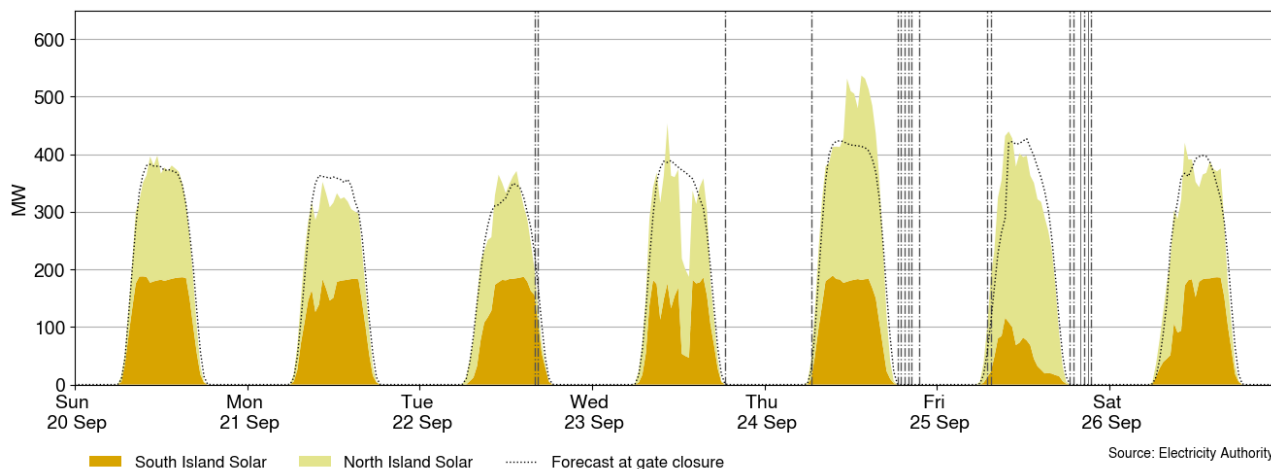
Figure 9: Wind generation and forecast, 20-26 September



- 7.4. Figure 10 shows grid connected solar generation from 20-26 September. Solar generation was high this week. Mean daytime solar generation this week was 257MW, peaking at 537MW on Thursday at 1:30pm.
- 7.5. Kōwhai Park, and Tauhei solar farms have been commissioned recently. Thursday morning marks the first time that both 150MW farms have generated at full capacity at the same time. These farms now provide just under half of New Zealand's solar generation capacity.
- 7.6. Forecasting differences on Wednesday are due to Kōwhai Park solar farm.

7.7. Forecasting differences on Thursday are due to Tauhei solar farm.

Figure 10: Grid connected solar generation, 20-26 September

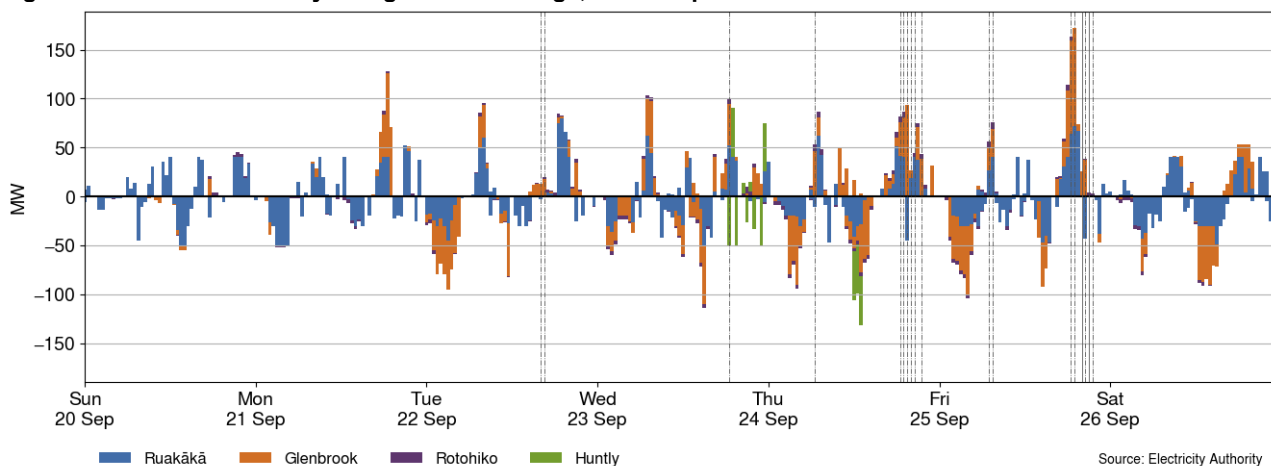


7.8. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh, commissioning) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy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

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

7.10. Huntly BESS charged at 50MW during peak demand for the week on Wednesday at 6.30pm.

Figure 11: Grid scale battery charge and discharge, 20-26 September



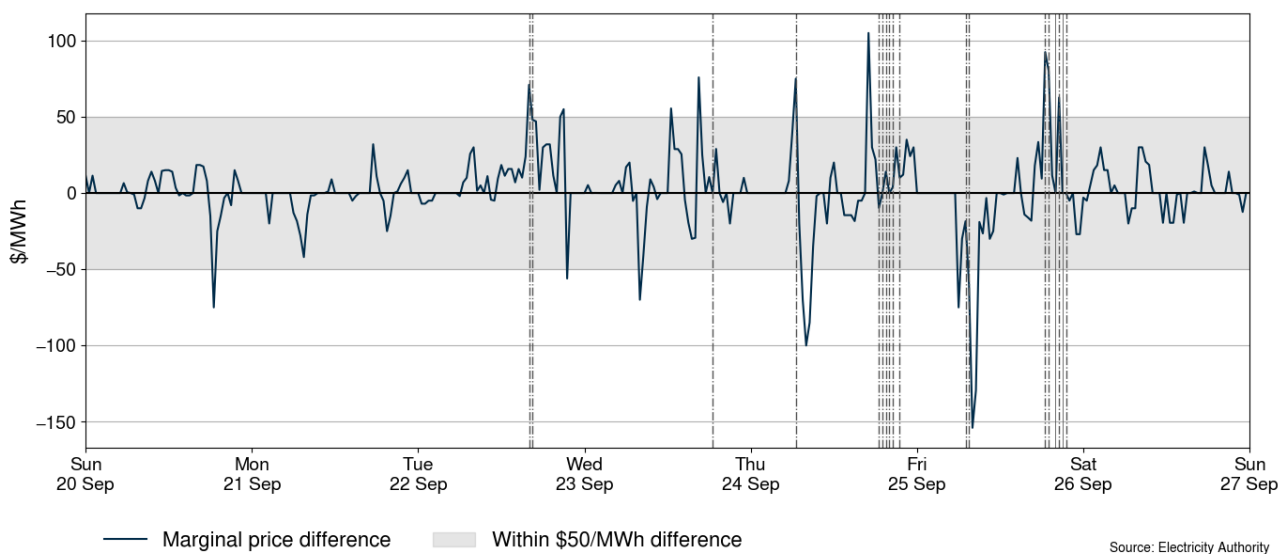
7.11. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS¹) projections. The figure highlights when forecasting inaccuracies are causing 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

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

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.

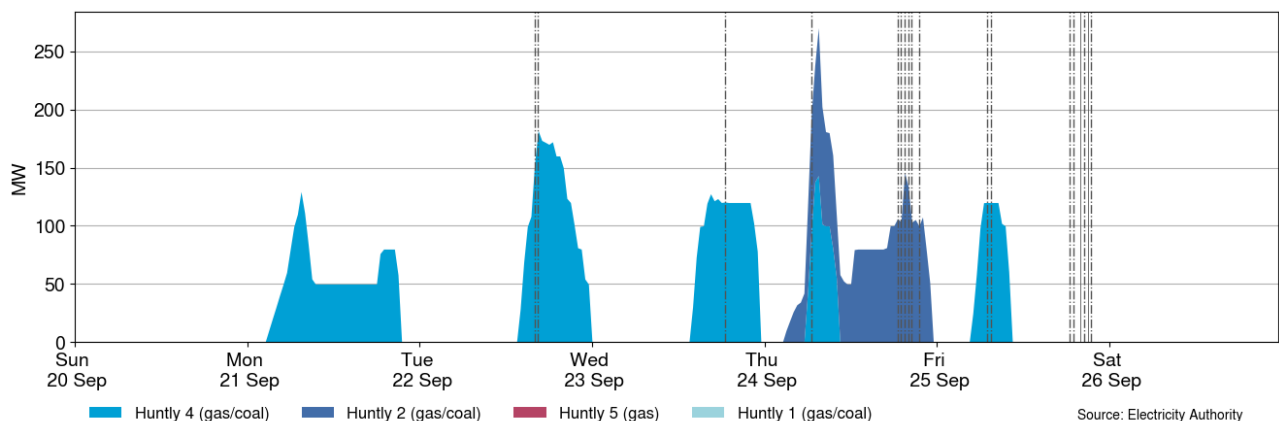
- 7.12. The largest positive forecast difference of \$105/MWh occurred on Thursday at 5.00pm. At this time demand was 84MW higher than forecast, and intermittent generation was 87MW lower than forecast.
- 7.13. The largest negative forecast difference of \$154/MWh occurred on Friday at 8.00am. At this time demand was 161MW lower than forecast, and intermittent generation was 114MW higher 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, 20-26 September



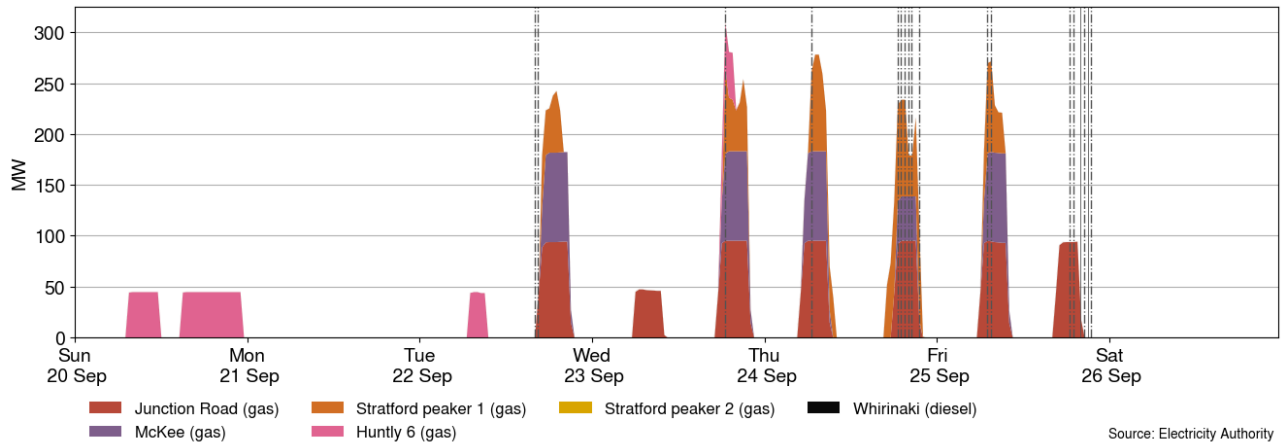
- 7.14. Figure 13 shows the generation of thermal baseload between 20-26 September. This week thermal baseload generation was provided by Huntly 2 and 4.

Figure 13: Thermal baseload generation, 20-26 September



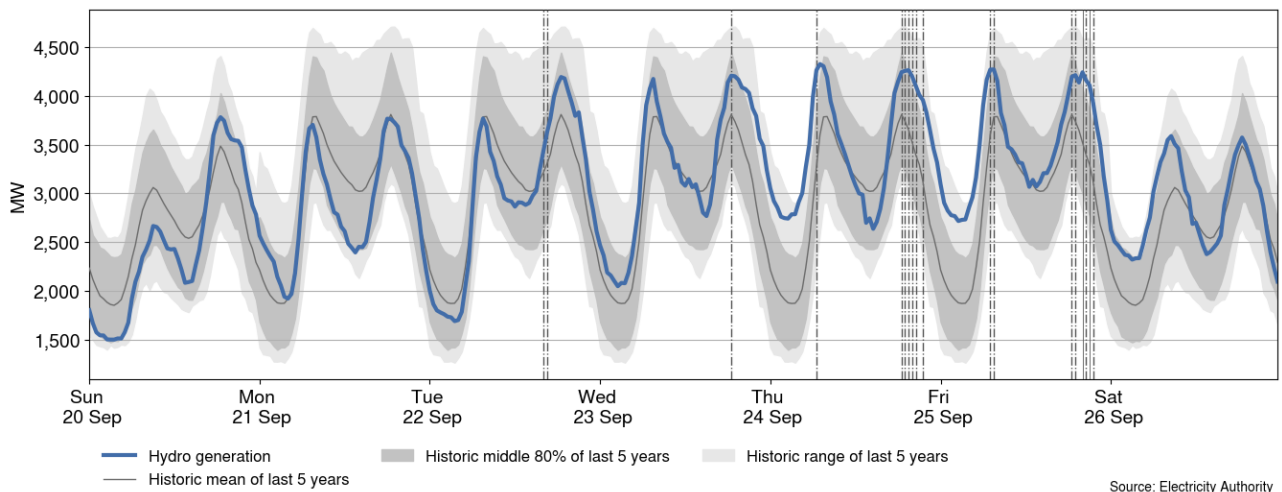
- 7.15. Figure 14 shows the generation of thermal peaker plants between 20-26 September. Peaker generation this week was low on Sunday and Monday when demand was low and wind generation was higher. Peaker generation increased from Tuesday evening onward as wind generation decreased and demand increased.

Figure 14: Thermal peaker generation, 20-26 September



7.16. Figure 15 shows hydro generation between 20-26 September. Hydro generation was near average up to Tuesday evening when it increased during peak periods when demand increased due to colder weather.

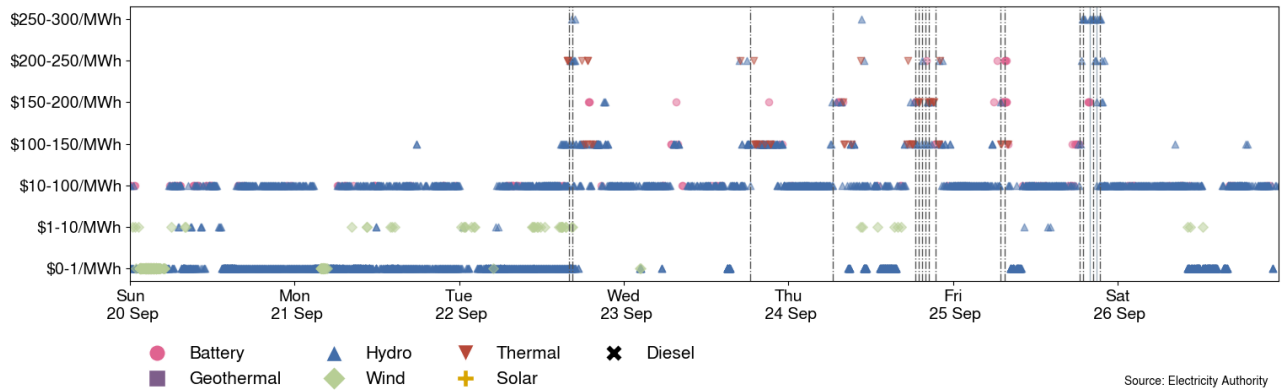
Figure 15: Hydro generation, 20-26 September



7.17. 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.

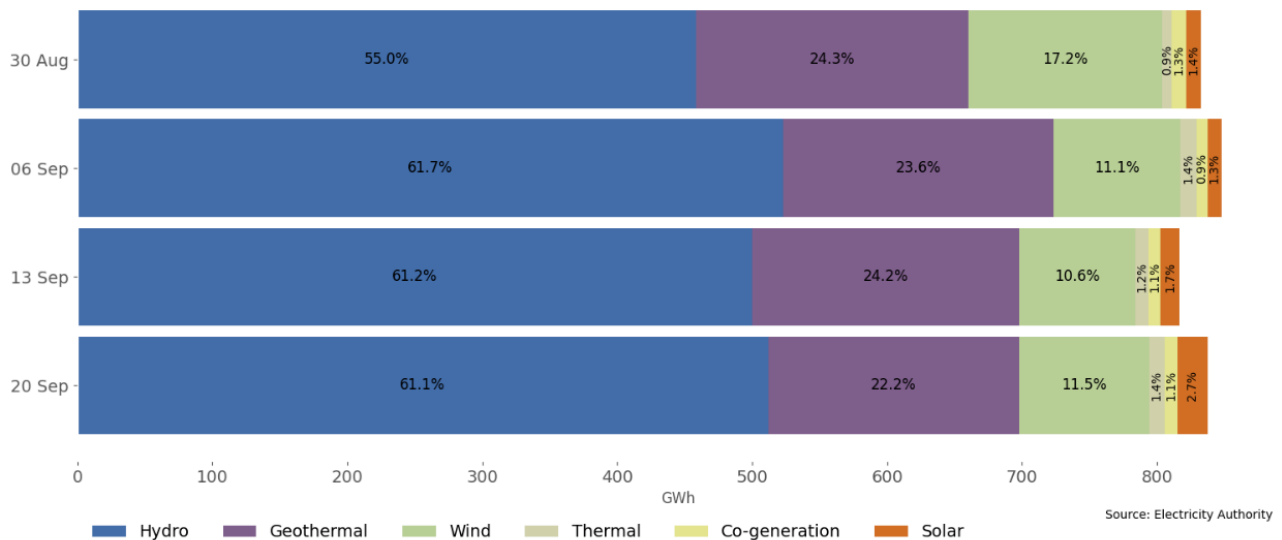
7.18. The highest marginal price of \$260/MWh was set by Karāpiro at 4:00pm on Tuesday. The most common marginal technology was hydro and the second most common technology was wind. Most marginal prices were between \$10-100/MWh.

Figure 16: Prices of marginal generation, 20-26 September



7.19. As a percentage of total generation, between 20-26 September, total weekly hydro generation was 61.1%, geothermal 22.2%, wind 11.5%, thermal 1.4%, co-generation 1.1%, and solar (grid connected) 2.7%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 30 August and 26 September



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 20-26 September ranged between ~1,085MW and ~1,907MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 20-26 September

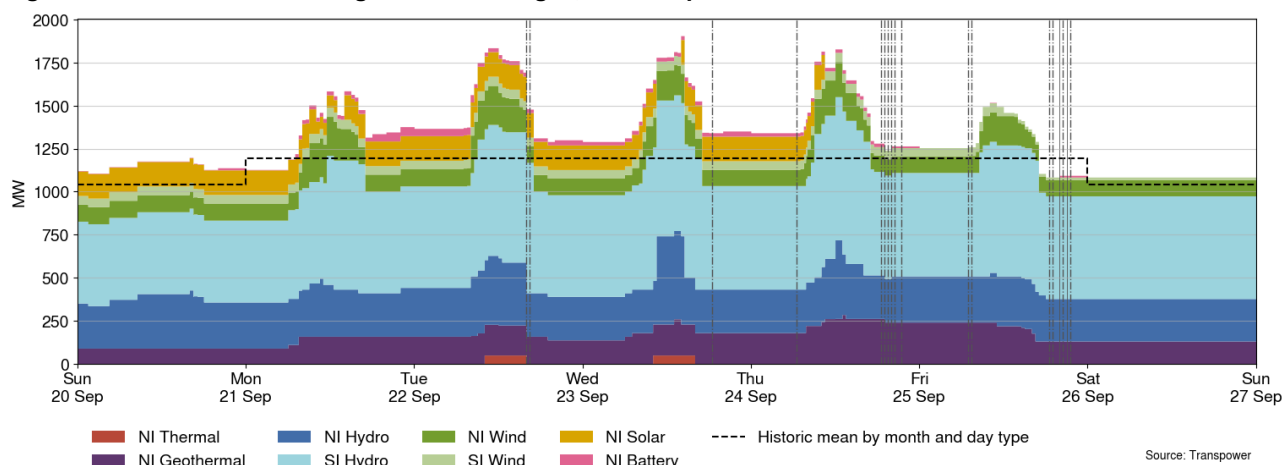
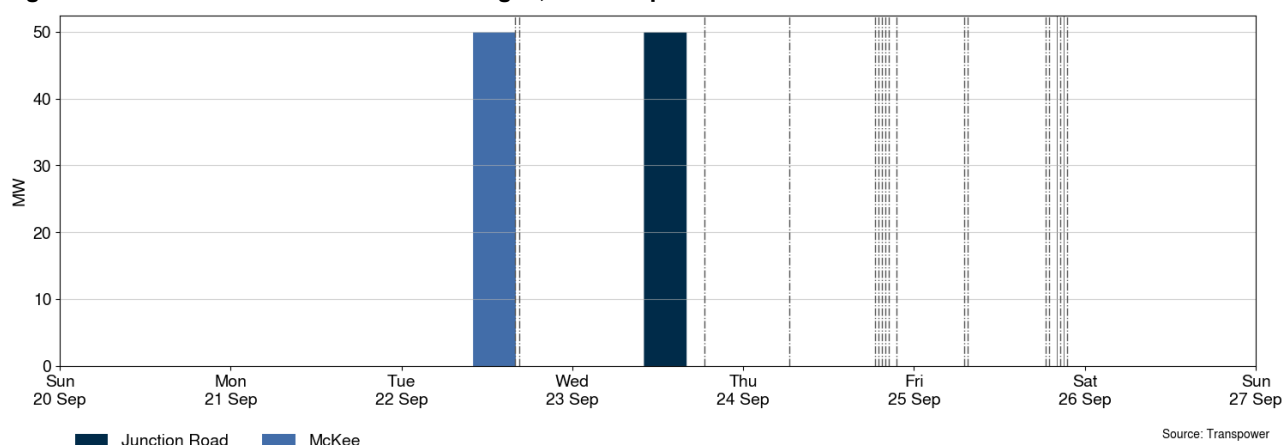


Figure 19: Total MW loss from thermal outages, 20-26 September



8.2. Notable outages include:

Plant	Partial or Full	End Date
Tokaanu Station	Full	23 September 2026
Tauhei Solar Farm	Partial	23 September 2026
Roxburgh units 1,2,3,4,6,7	Partial	25 September 2026
Mokai 10	Full	25 September 2026
Benmore unit 2	Full	28 September 2026
Te Huka 3	Full	28 September 2026
Kaiwaikawe Wind Farm	Partial	30 November 2026
Takapō B unit 2	Full	6 October 2026
Huntly 1	Full	11 October 2026
Manapōuri unit 2	Full	2 July 2027

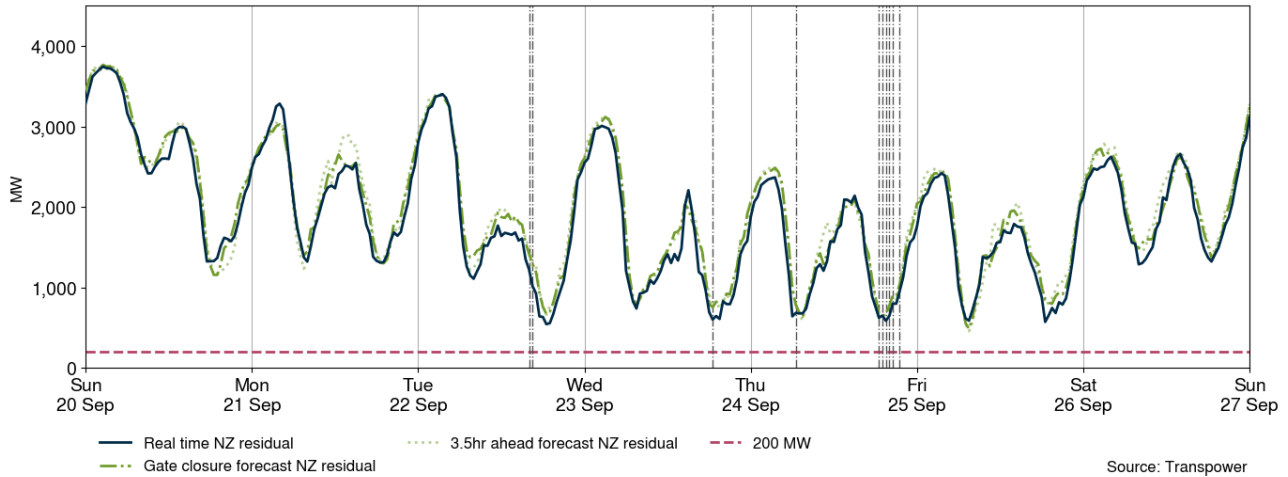
9. Generation balance residuals

- 9.1. Figure 20 shows the national generation balance residuals between 20-26 September. 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, 20-26 September



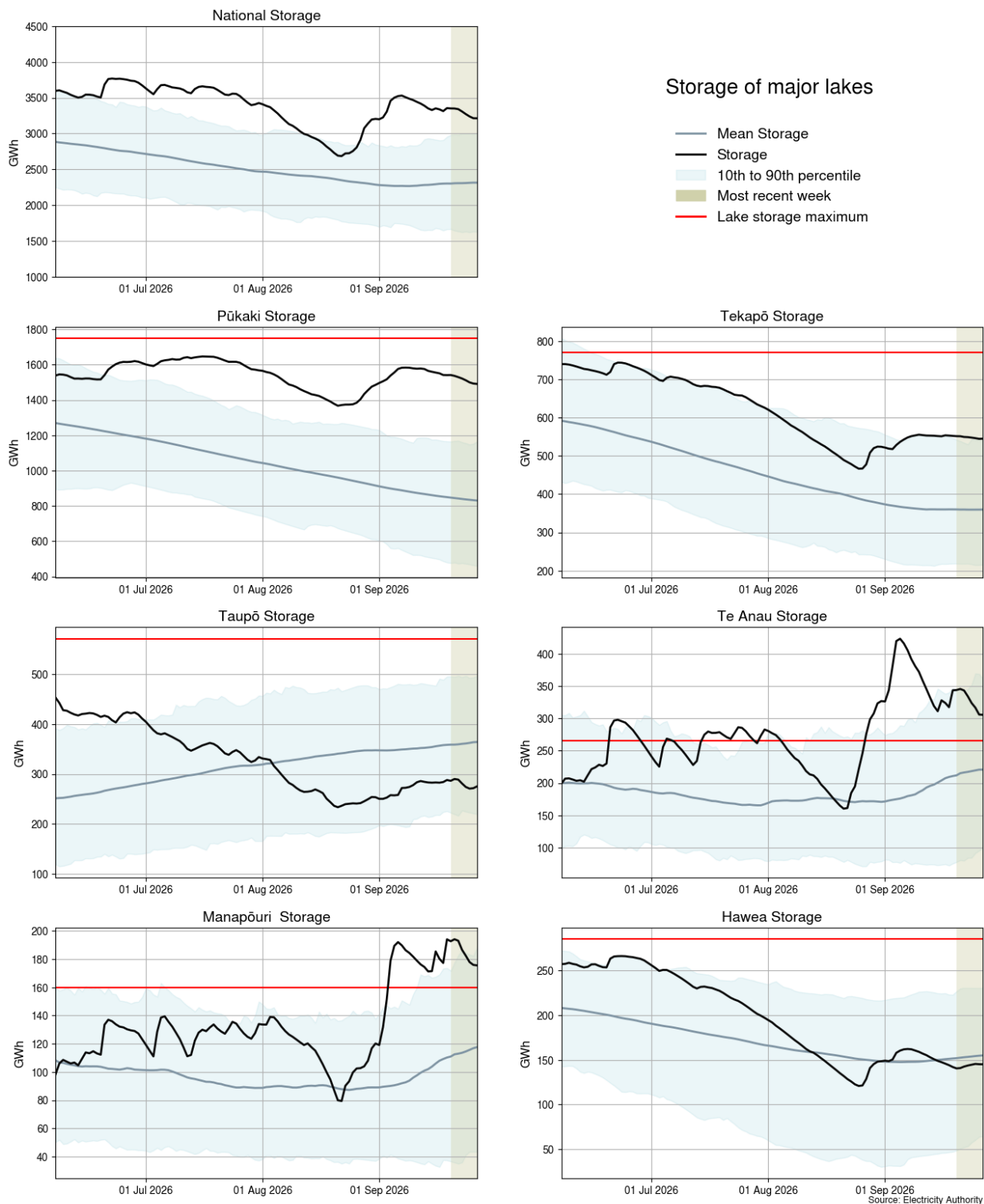
10. Storage/fuel supply

- 10.1. National controlled storage was 80% nominally full and ~133% of the historical average for this time of the year.
- 10.2. Storage at Lake Pūkaki (86% full) is significantly higher than the historic 90th percentile for this time of year.
- 10.3. Storage at Lake Tekapō (71% full) is at the historic 90th percentile for this time of year.
- 10.4. Storage at Lake Taupō is (48% full) is below average for this time of year.
- 10.5. Storage at Lake Te Anau (115% full) is well above average for this time of year and remains above nominal full level.
- 10.6. Storage at Lake Manapōuri (112% full) is at the historic 90th percentile for this time of year and remains above nominal full level.
- 10.7. Storage at Lake Hawea (51% full) is slightly below average for this time of year.
- 10.8. 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.
- 10.9. National controlled storage was 80% nominally full and ~133% of the historical average for this time of the year.
- 10.10. Storage at Lake Pūkaki (86% full²) is significantly higher than the historic 90th percentile for this time of year.
- 10.11. Storage at Lake Tekapō (71% full) is at the historic 90th percentile for this time of year.
- 10.12. Storage at Lake Taupō is (48% full) is below average for this time of year.

² Percentage full values sourced from NZX Hydro.

- 10.13. Storage at Lake Te Anau (115% full) is well above average for this time of year and remains above nominal full level.
- 10.14. Storage at Lake Manapōuri (112% full) is at the historic 90th percentile for this time of year and remains above nominal full level.
- 10.15. Storage at Lake Hawea (51% full) is slightly below average for this time of year.

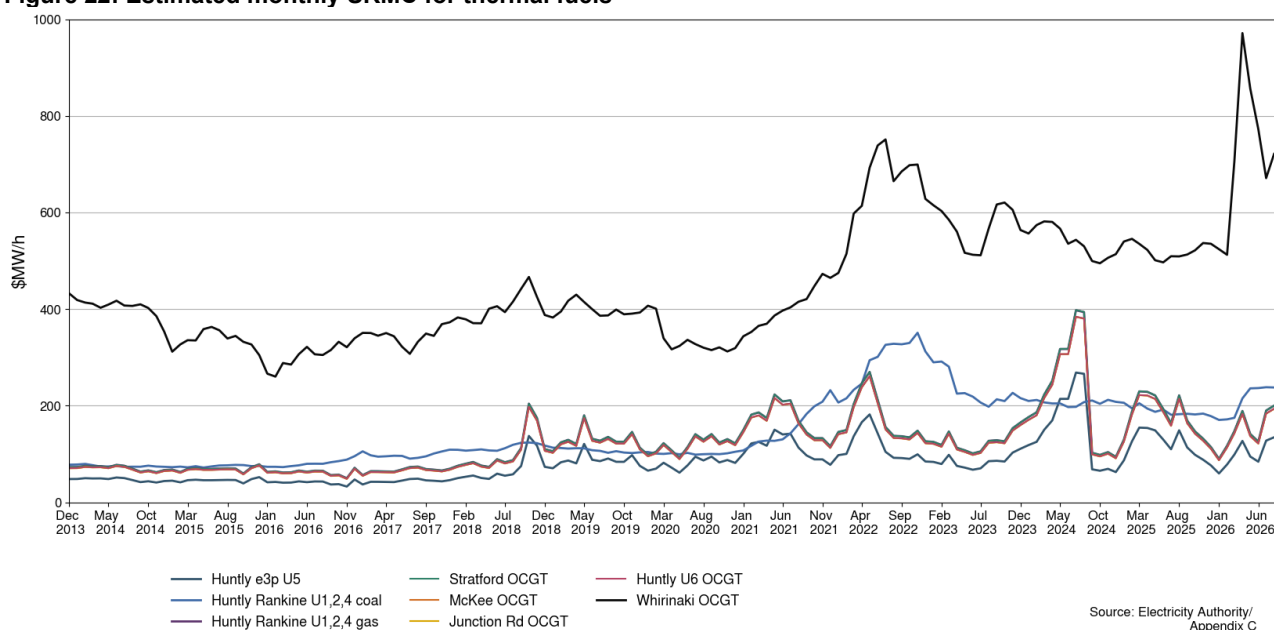
Figure 21: Hydro storage



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 September 2026. The SRMCs for gas generation have decreased, with SRMCs for coal and diesel 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 ~\$177/MWh.
- 11.5. The SRMC of gas fuelled thermal plants is currently between \$118/MWh and \$177/MWh.
- 11.6. The SRMC of Whirinaki is ~\$720/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](#).

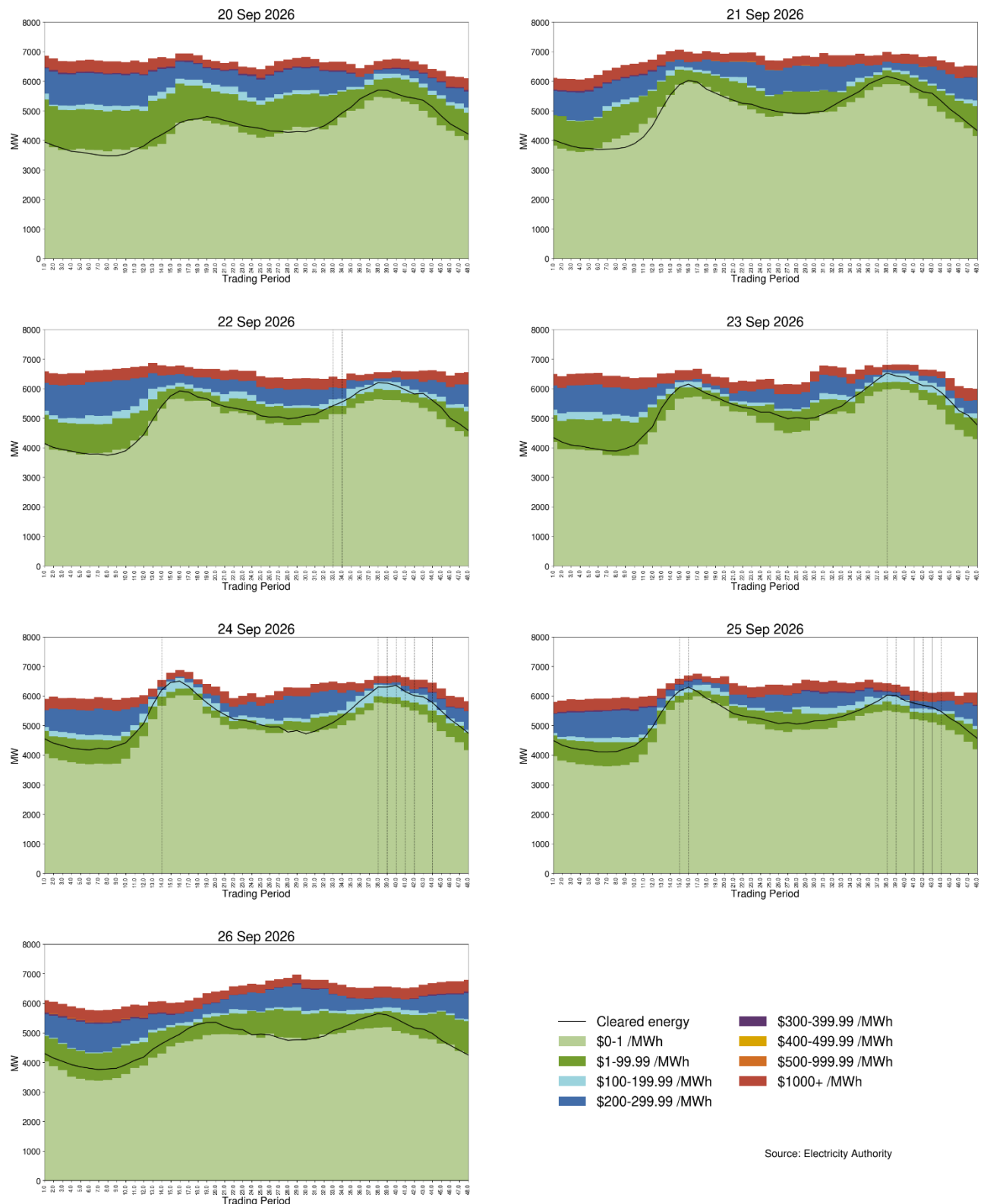
Figure 22: Estimated monthly SRMC for thermal fuels



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. Prices mostly cleared between \$1-99/MWh this week.

Figure 23: Daily offer stacks



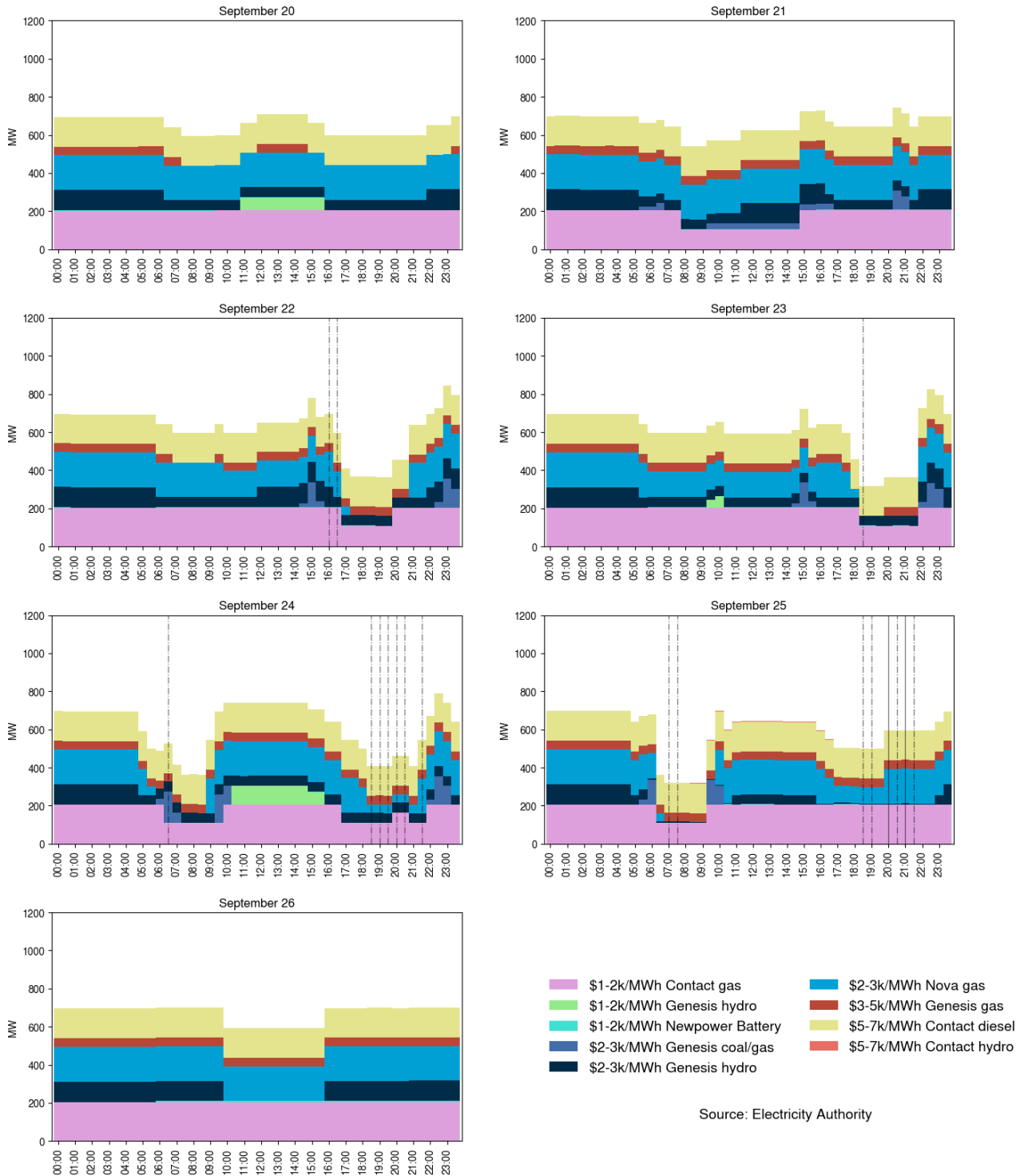
12.3. Figure 24 shows offers above \$1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 633MW per trading period was priced above \$1,000/MWh this week, which is roughly 12% 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. 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
02/08/2026-08/08/2026	Several	Further analysis	Contact/Manawa	Matahina	Offers