18 August 2026

Trading conduct report 9-15 August 2026

Market monitoring weekly report

Trading conduct report 9-15 August 2026

1. Overview

1.1. This week is characterised by high hydro generation and lower wind generation contributing to almost entirely northward HVDC flows. Declining, but still high, hydro storage has seen some hydro offers priced up above $200/MWh. Overall prices decreased this week as warmer weather led to lower demand.

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 9-15 August:

(a) The average spot price for the week was $71/MWh, a decrease of around $52/MWh compared to the previous week.

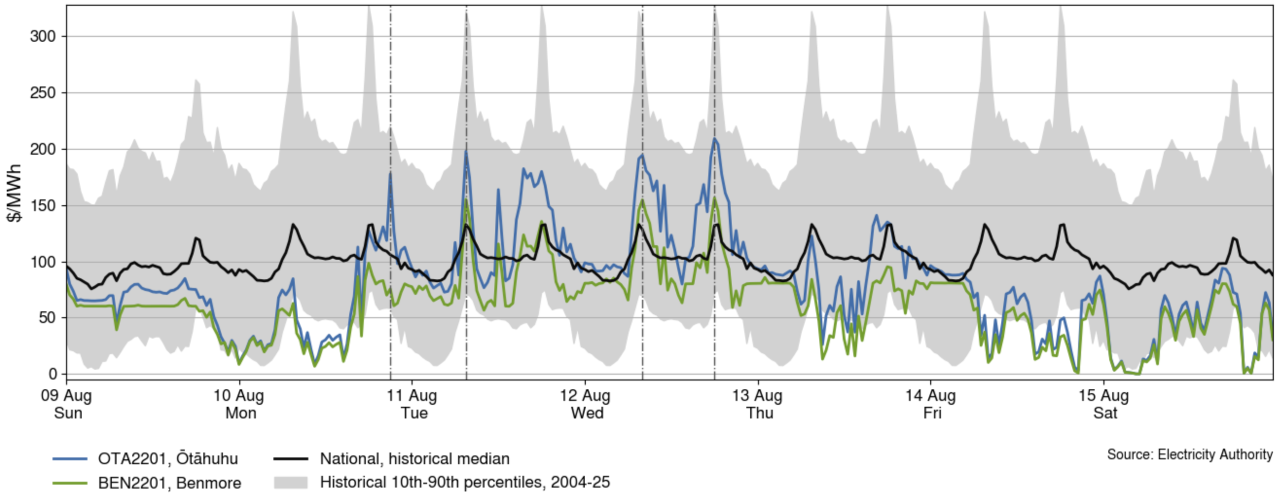
(b) 95% of prices fell between $3/MWh and $165/MWh.

2.3. Demand has declined significantly compared to last week, likely due to warmer temperatures this week. This contributed to prices decreasing overall despite lower wind generation and declining hydro storage.

2.4. The highest price at Ōtāhuhu was $209/MWh at 6:00pm on Wednesday. At this time prices at Benmore were $156/MWh. This was a peak demand period. Wind generation was 38MW lower than forecast at the time and national residual generation was at its lowest point for the week (416MW).

2.5. 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.

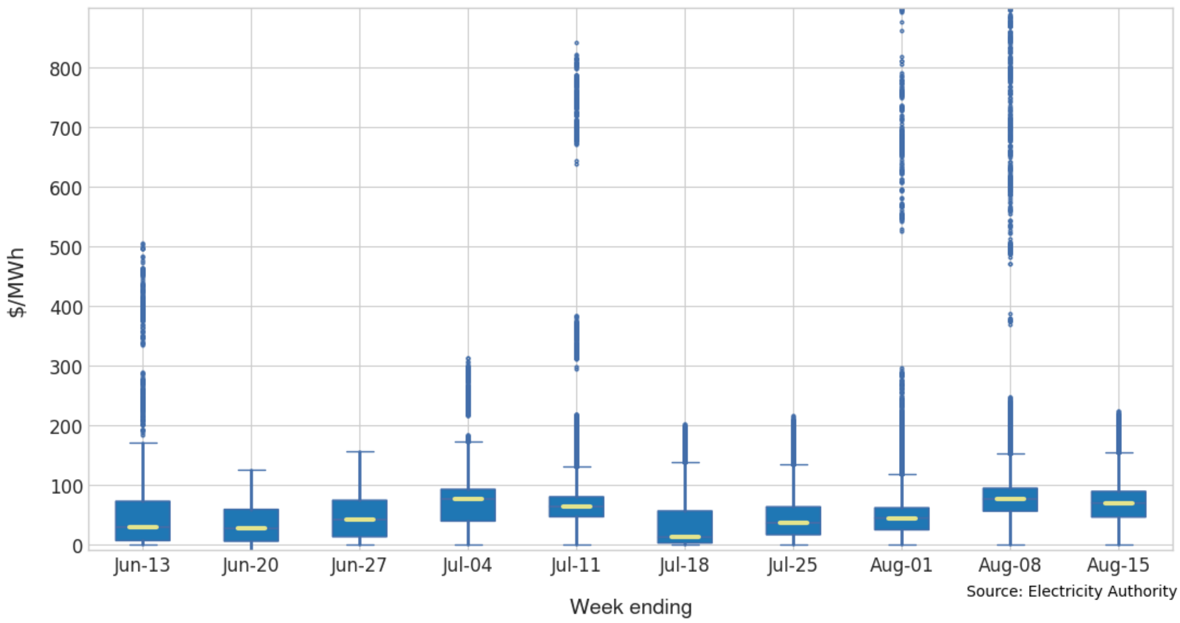
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 9-15 August



2.6. 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.

2.7. The distribution of spot prices this week was similar to last week with fewer high priced outliers. The median price was $71/MWh and most prices (middle 50%) fell between $46/MWh and $89/MWh.

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

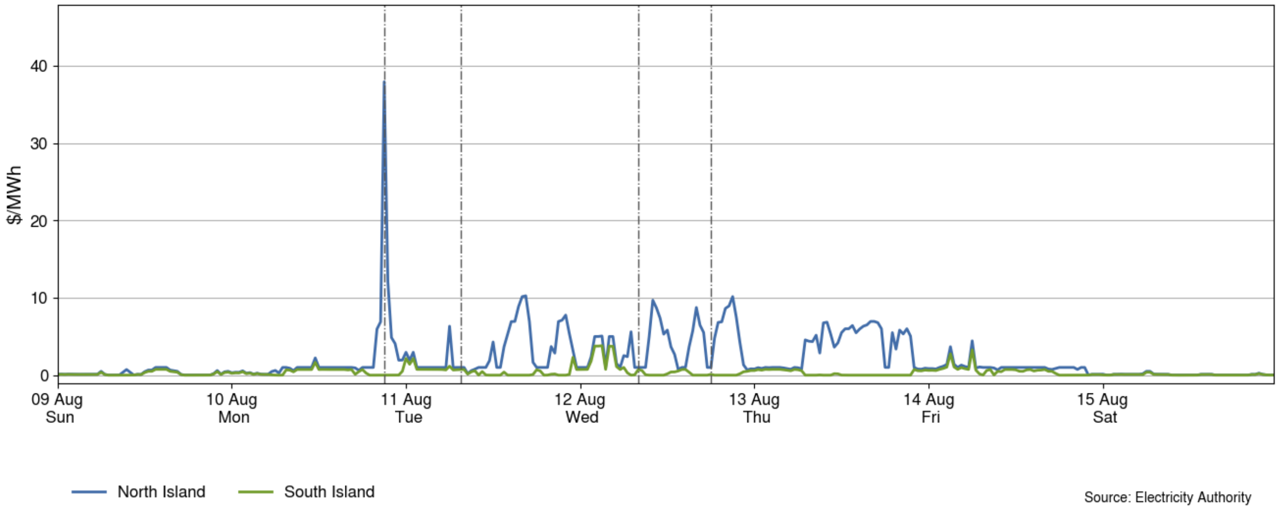


3. Reserve prices

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.

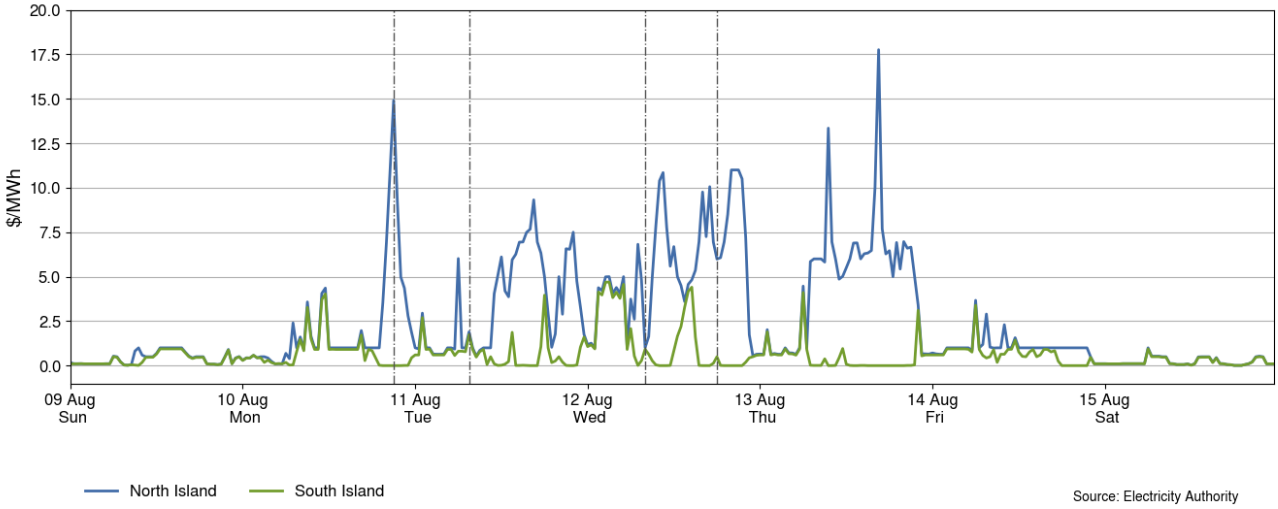
3.2. North Island FIR prices spiked up to $38/MWh at 9.00pm on Monday. At this time South Island FIR prices were $0/MWh. This separation in FIR prices is likely due to the HVDC only having 44MW of northward flow capacity remaining during this period.

Figure 3: Fast instantaneous reserve price by trading period and island, 9-15 August



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $15/MWh this week. SIR prices also separated this week when the HVDC was flowing northward near its capacity.

Figure 4: Sustained instantaneous reserve by trading period and island, 9-15 August



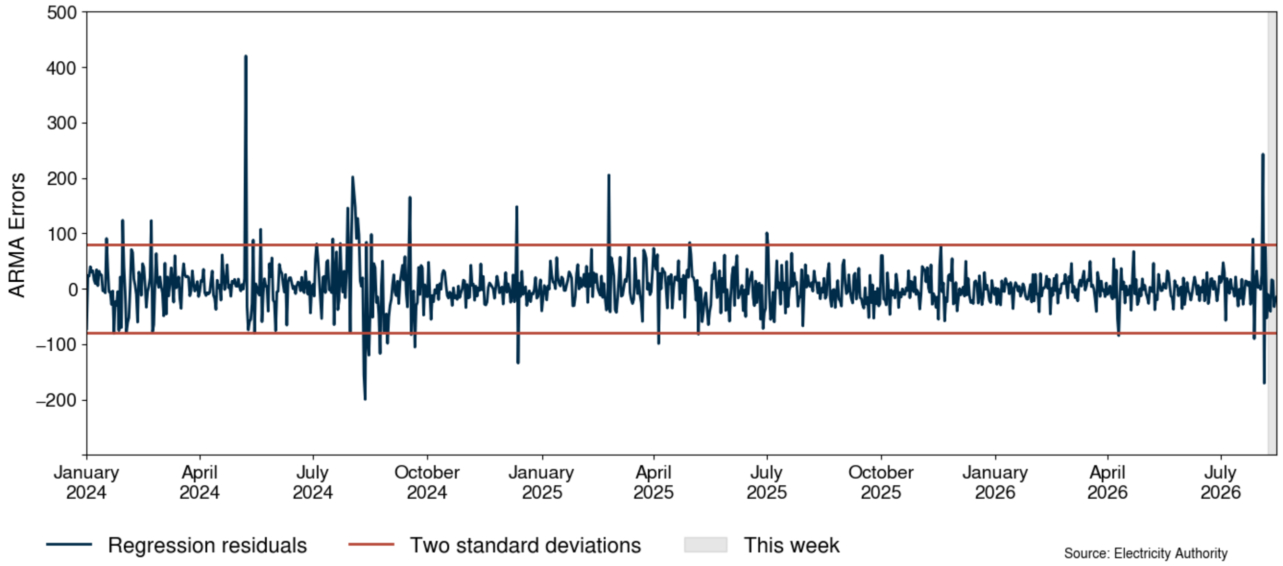
4. Regression residuals

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 - 15 August 2026



5. HVDC

5.1. Figure 6 shows the HVDC flow between 9-15 August. HVDC[1] flows were almost entirely northward this week, with one period of southward flow occurring overnight on Sunday.

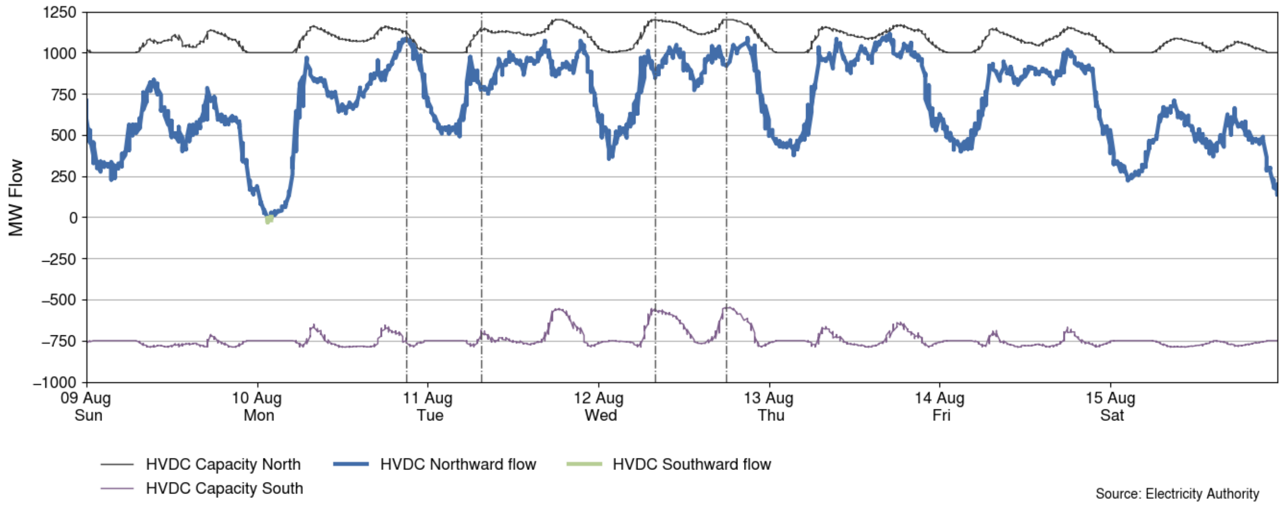
5.2. The highest northward HVDC flow this week was 1,114MW which occurred at 5.00pm on Thursday.

5.3. The highest southward HVDC flow this week was 32MW which occurred at 1.30am on Monday.

5.4. At various times the HVDC was close to its northward flow capacity. The lowest remainder of 30MW occurred at 9.30pm on Monday, when HVDC flow was 1,061MW northward and the capacity was 1,091MW.

[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.

Figure 6: HVDC flow and capacity, 9-15 August

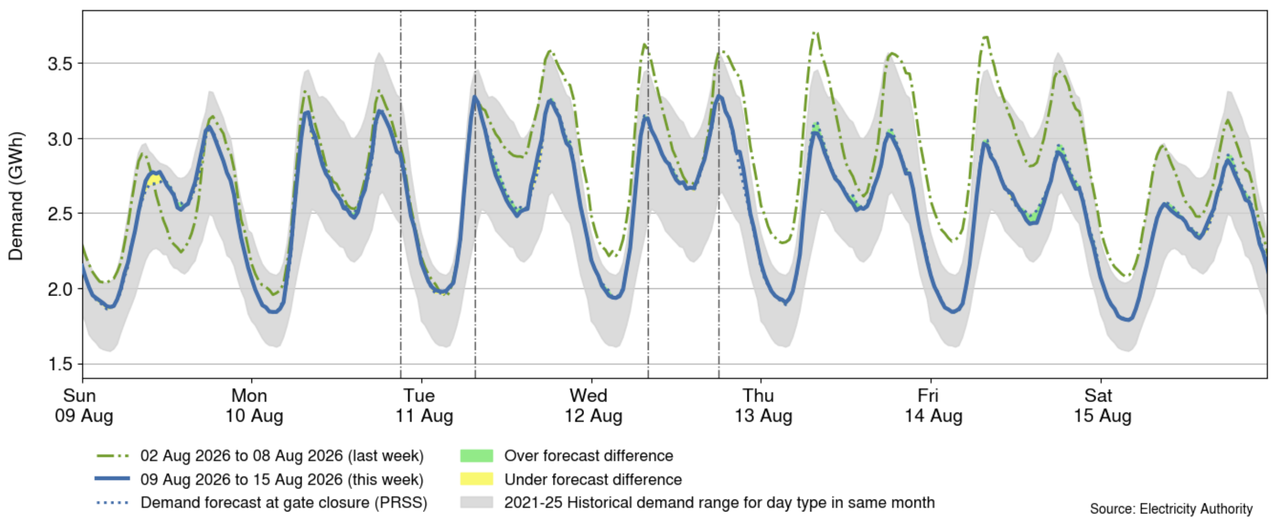


6. Demand

6.1. Figure 7 shows national demand between 9-15 August, compared to the historic range and the demand of the previous week. Demand was generally lower than last week. This difference is more pronounced from midday Tuesday to Saturday evening, whereas demand was more similar to last week from Sunday to Tuesday morning.

6.2. The maximum demand this week was around 3.28GWh (6.56GW) at 6.00pm on Wednesday.

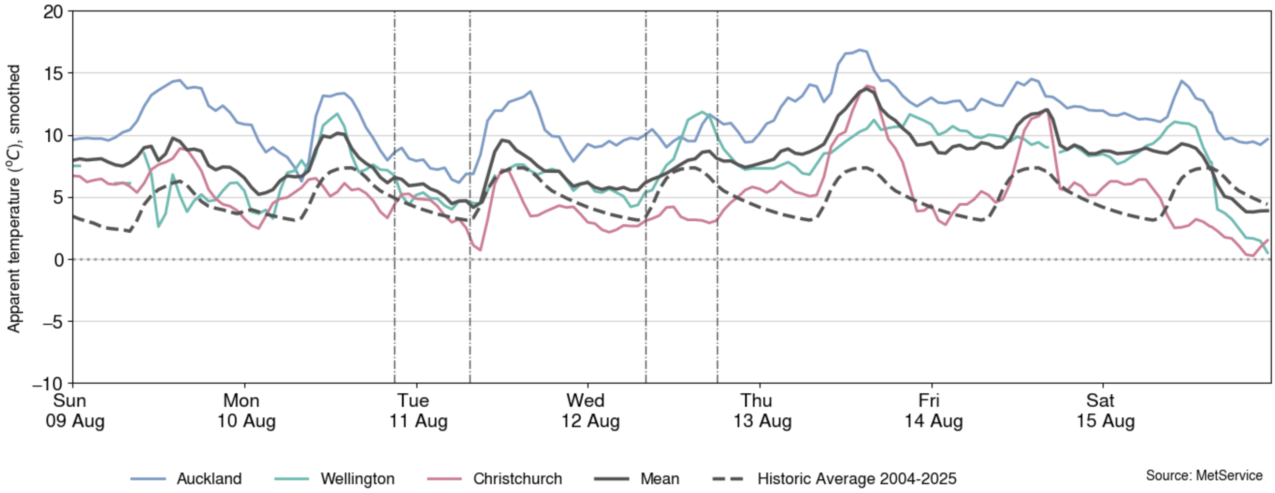
Figure 7: National demand, 9-15 August compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 9-15 August. 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. This week the mean temperature has mostly been above the historic average at main centres for this time of year. Apparent temperatures ranged from 6°C to 17°C in Auckland, 0°C to 12°C in Wellington, and 0°C to 14°C in Christchurch.

Figure 8: Temperatures across main centres, 9-15 August



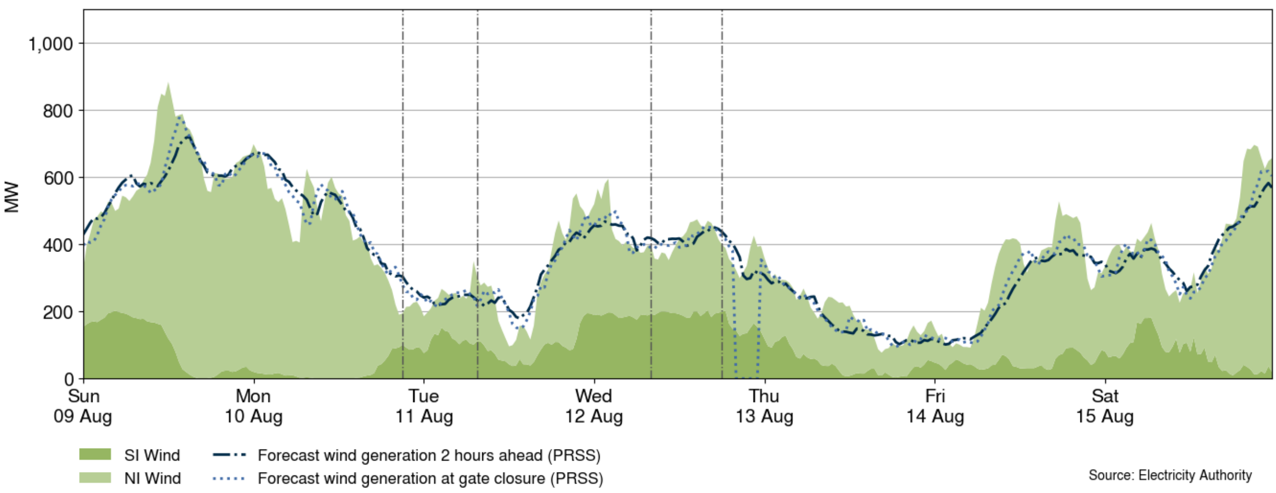
7. Generation

7.1. Figure 9 shows wind generation and forecast from 9-15 August. This week wind generation varied between 77MW and 884MW, with a weekly average of 383MW. This week wind generation was low at times, with higher generation on Sunday, Monday, and Saturday, then remaining mostly below 600MW for the rest of the week.

7.2. Forecasting errors on Monday, Tuesday, and Wednesday are caused by Waipipi, Harapaki, and West Wind 1 wind farms.

7.3. Note on Wednesday there is a period from 8.30-11.00pm where the forecast at gate closure shows as zero. This is due to a data error from 6.30-8.30pm, so one-hour ahead forecasts aren't available for the following 6 trading periods.

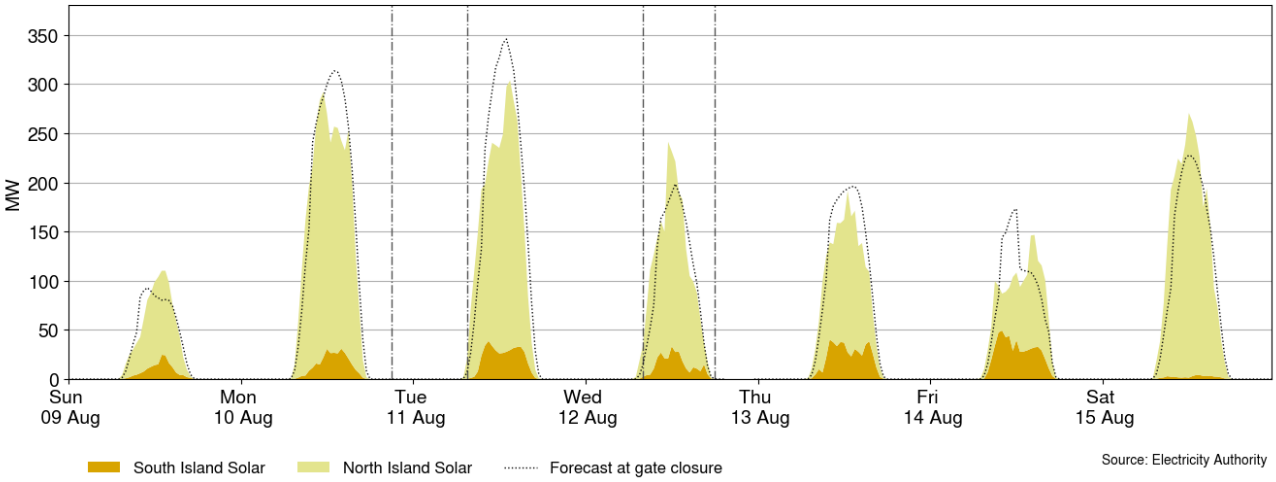
Figure 9: Wind generation and forecast, 9-15 August



7.4. Figure 10 shows grid connected solar generation from 9-15 August. Solar generation was high this week as Tauhei solar farm is nearing the end of its commissioning process and has begun generating daily. Tauhei solar farm's output will continue to vary as it commissions with forecasting errors this week being largely caused by this farm.

7.5. South Island solar generation was particularly low on Saturday, remaining below 5MW, due to particularly cloudy weather and snow.

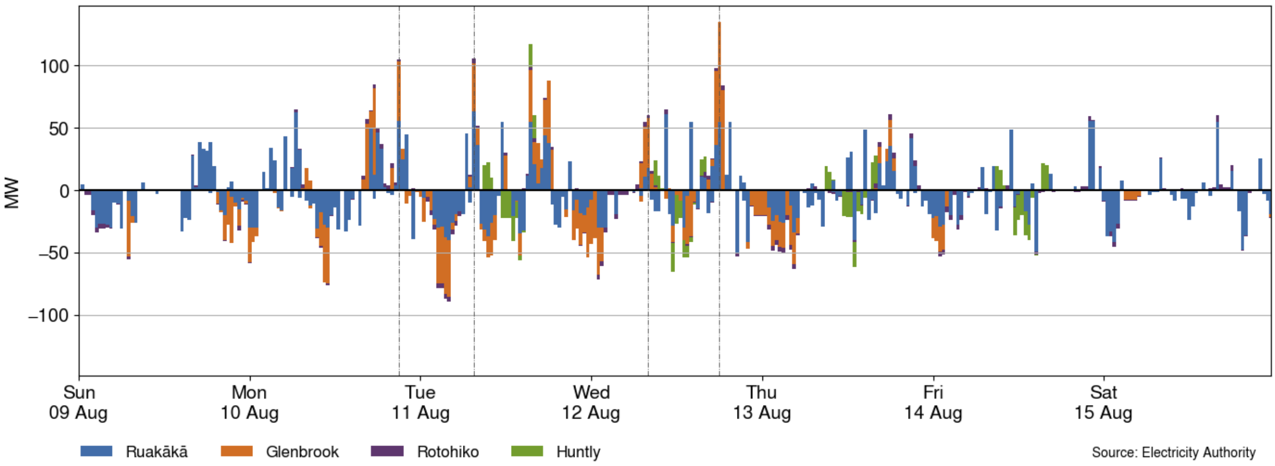
Figure 10: Grid connected solar generation, 9-15 August



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 generally charged overnight and the middle of the day when prices were lower and discharged during the morning and evening peaks.

Figure 11: Grid scale battery charge and discharge, 9-15 August



7.8. 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

[2] 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.

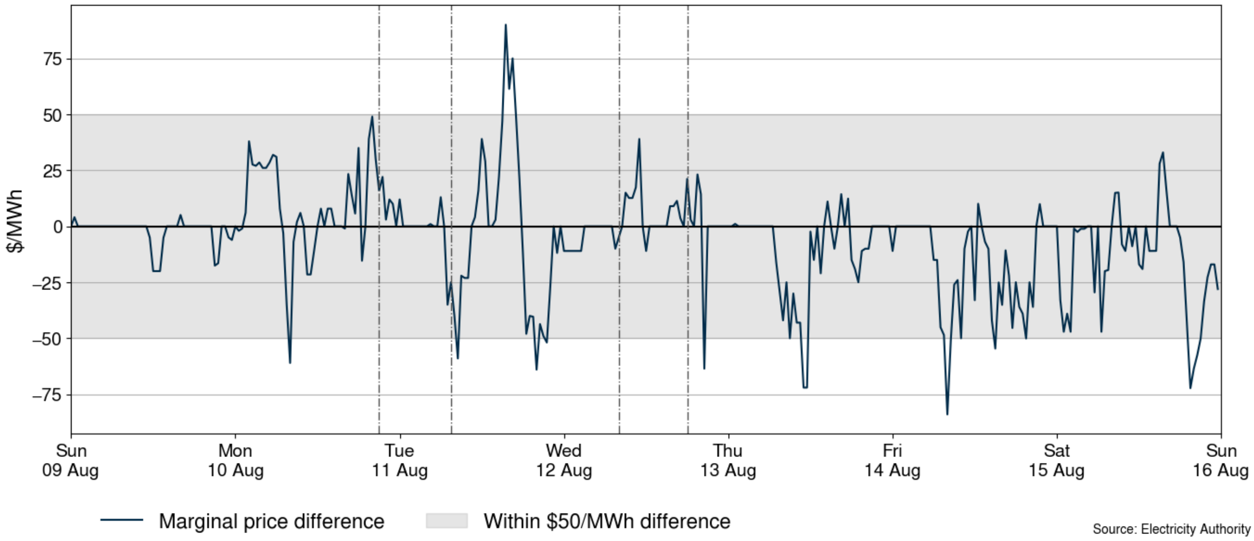
7.9. This week there were 17 periods with a price forecast difference greater than $50/MWh.

7.10. The largest positive difference was $90/MWh which occurred at 3.30pm on Tuesday. At this time intermittent generation was 126MW lower than forecast and demand was 98MW (49MWh) higher than forecast.

7.11. The largest negative difference was $83/MWh which occurred at 8.00am on Friday. At this time intermittent generation was 119MW higher than forecast and demand was 70MW (35MWh) lower than forecast.

7.12. Prices tended to be lower than forecast from Thursday onwards, as there were several periods with overforecast demand and underforecast wind.

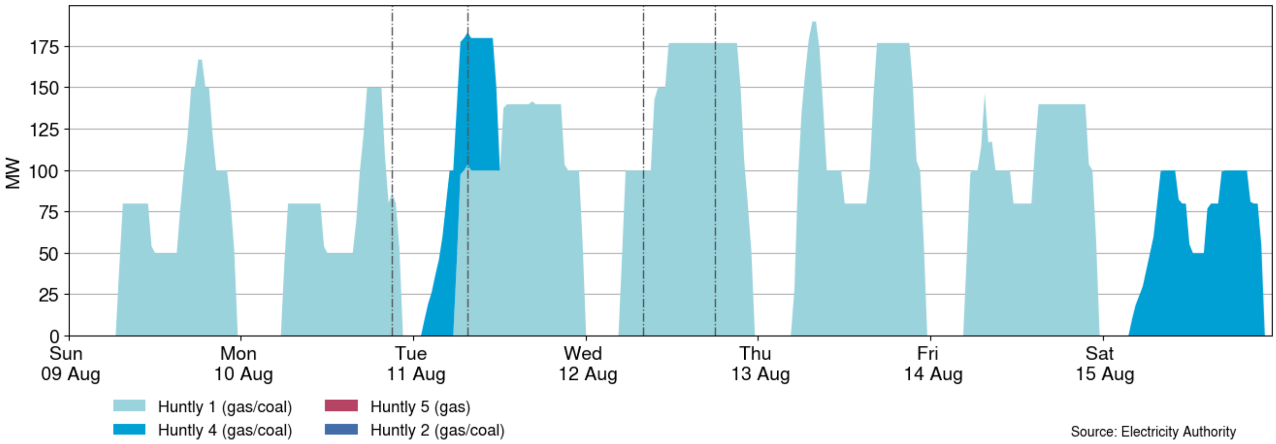
Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 9-15 August



7.13. Figure 13 shows the generation of thermal baseload between 9-15 August. Huntly 1 and Huntly 4 ran this week, with Huntly 1 providing the majority of the thermal baseload generation.

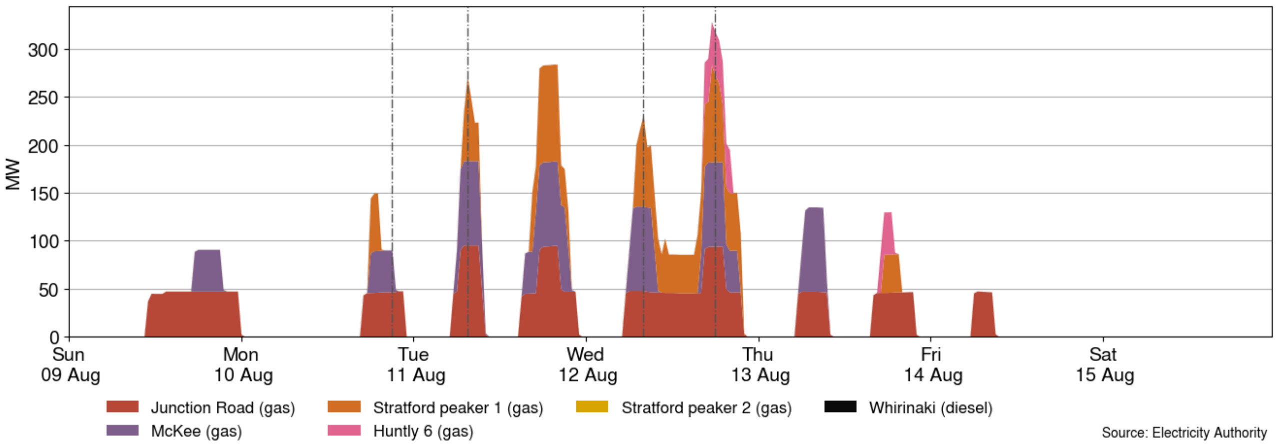
7.14. On Tuesday Huntly 4 attempted to ramp up to 190MW just before the morning peak but was forced to ramp down to 80MW at 6.30am, due to a pump failure in the 6.00am trading period.

Figure 13: Thermal baseload generation, 9-15 August



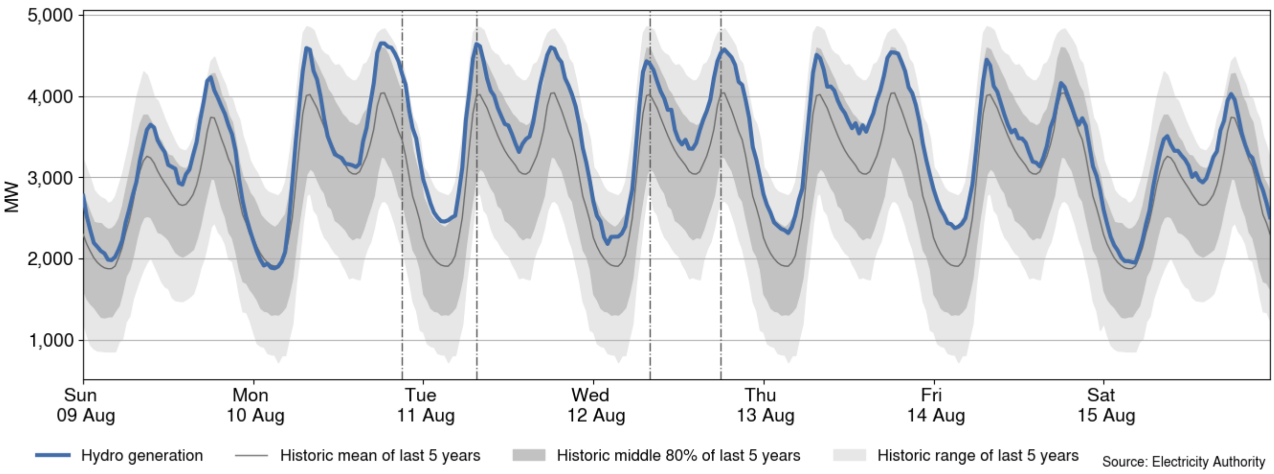
7.15. Figure 14 shows the generation of thermal peaker plants between 9-15 August. Peaker generation this week was greatest on Tuesday and Wednesday. There was no peaker generation on Saturday.

Figure 14: Thermal peaker generation, 9-15 August



7.16. Figure 15 shows hydro generation between 9-15 August. Hydro generation was above average or average at times this week.

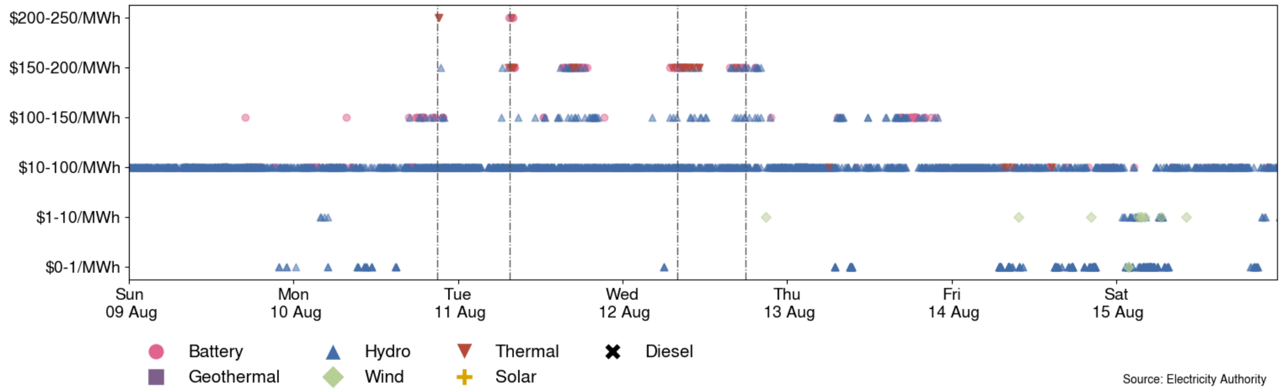
Figure 15: Hydro generation, 9-15 August



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.

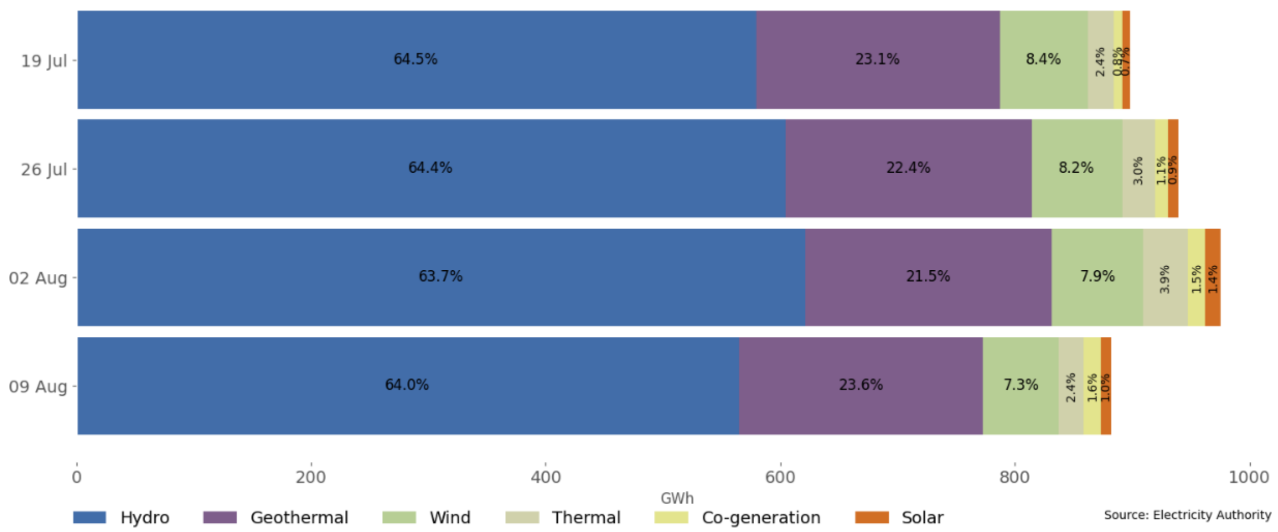
7.18. The highest prices of $206/MWh were set by Ruakākā Energy Park at 8.00am on Tuesday. The most common marginal technology was hydro and the second most common technology was batteries. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 9-15 August



7.19. As a percentage of total generation, between 9-15 August, total weekly hydro generation was 64%, geothermal 23.6%, wind 7.3%, thermal 2.4%, co-generation 1.6%, and solar (grid connected) 1.0%, as shown in Figure 17. Total weekly demand has fallen substantially this week compared to last.

Figure 17: Total generation by type as a percentage each week, between 19 July and 9 August



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 9-15 August ranged between ~894MW and ~1,948MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 9-15 August

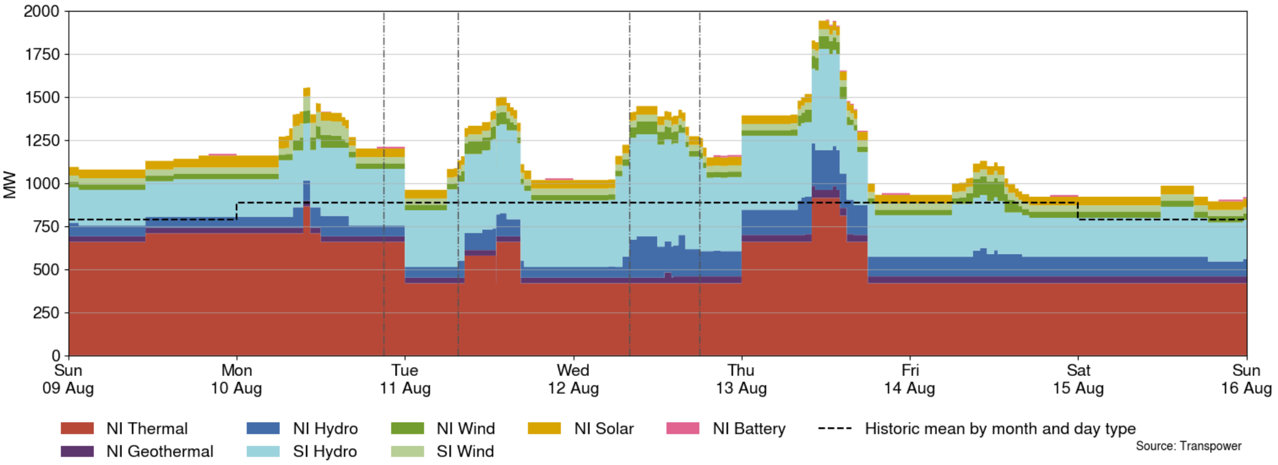
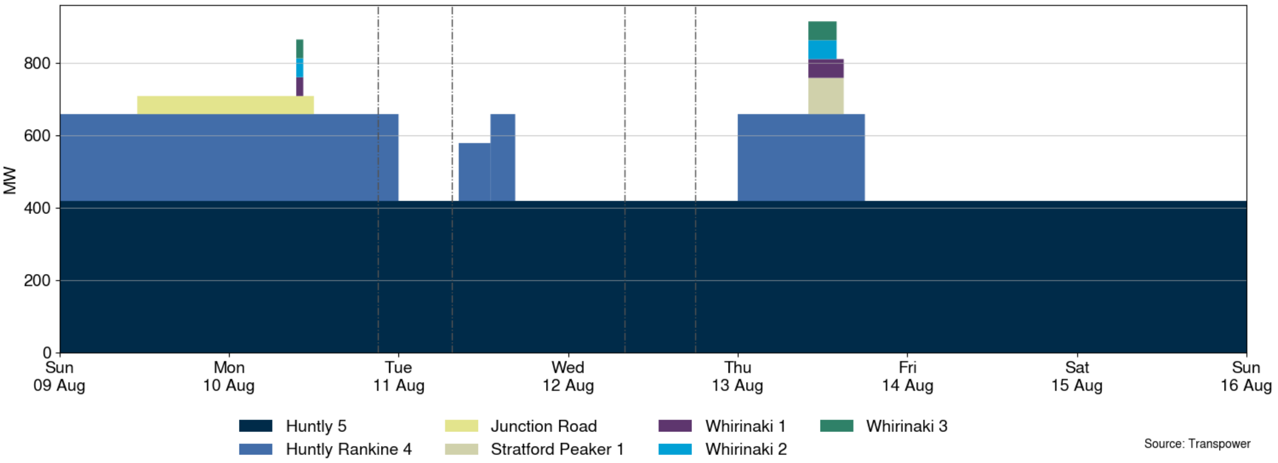


Figure 19: Total MW loss from thermal outages, 9-15 August



8.2. Notable outages include:

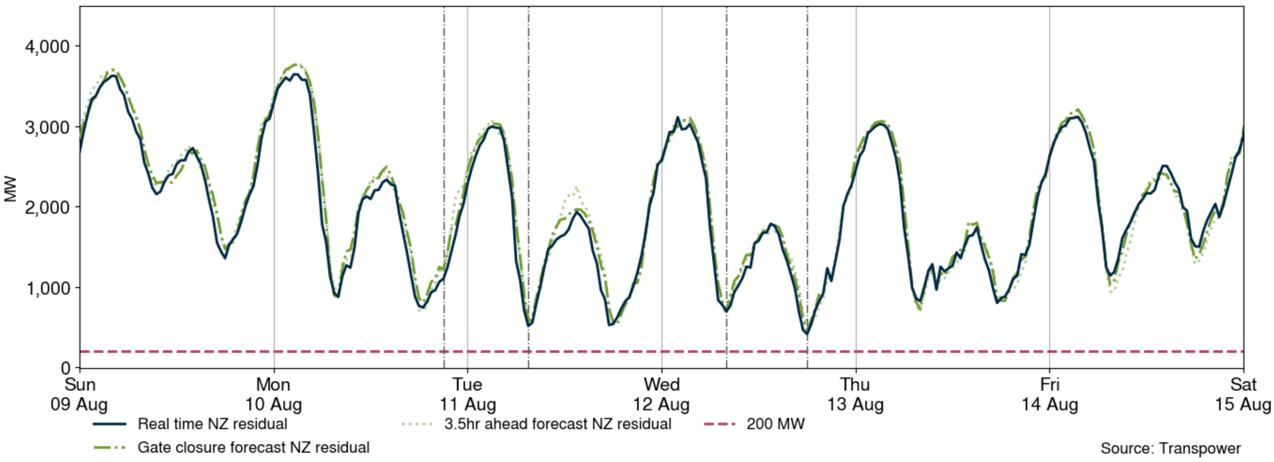
Plant	Partial or Full	End Date
Manapōuri unit 2	Full	13 August 2026
Stratford Peaker 1	Full	13 August 2026
Huntly 4	Full	13 August 2026
Huntly 5	Full	18 August 2026
Manapōuri unit 7	Full	18 August 2026
Kaiwaikawe Wind Farm	Partial	30 November 2026
Roxburgh unit 8	Full	24 September 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 9-15 August. 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, 9-15 August



10. Storage/fuel supply

10.1. Storage at Lake Pūkaki (79% full) is significantly higher than the historic 90th percentile for this time of year.

10.2. Storage at Lake Tekapō (63% full) is slightly below the historic 90th percentile for this time of year.

10.3. Storage at Lake Taupō is (46% full) is below average for this time of year.

10.4. Storage at Lake Te Anau (72% full) is just above average for this time of year.

10.5. Storage at Lake Manapōuri (70% full) is below the historic 90th percentile for this time of year but above average.

10.6. Storage at Lake Hawea (53% full) is slightly 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 73% nominally full and ~119% of the historical average for this time of the year.

10.9. Storage at Lake Pūkaki (79% full[3]) is significantly higher than the historic 90th percentile for this time of year.

10.10. Storage at Lake Tekapō (63% full) is slightly below the historic 90th percentile for this time of year.

10.11. Storage at Lake Taupō is (46% full) is below average for this time of year.

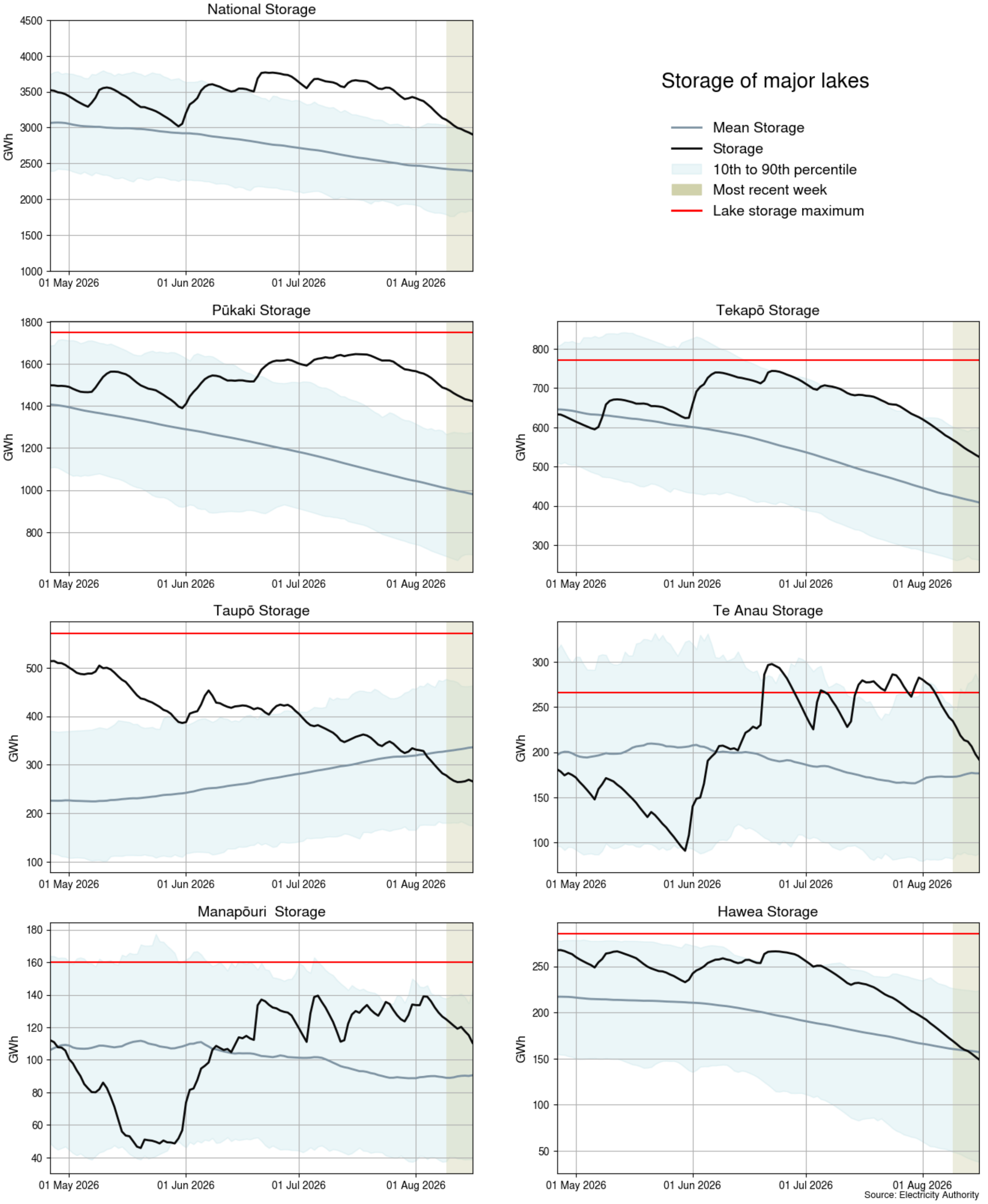
10.12. Storage at Lake Te Anau (72% full) is just above average for this time of year.

10.13. Storage at Lake Manapōuri (70% full) is below the historic 90th percentile for this time of year but above average.

10.14. Storage at Lake Hawea (53% full) is slightly below average for this time of year.

[3] Percentage full values sourced from NZX Hydro.

Figure 21: Hydro storage



Source: Electricity Authority

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 August 2026. The SRMCs for gas generation have increased, with SRMCs for coal and diesel fuelled generation remaining steady.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$238/MWh, while the cost of running the Rankines on gas is ~$203/MWh.

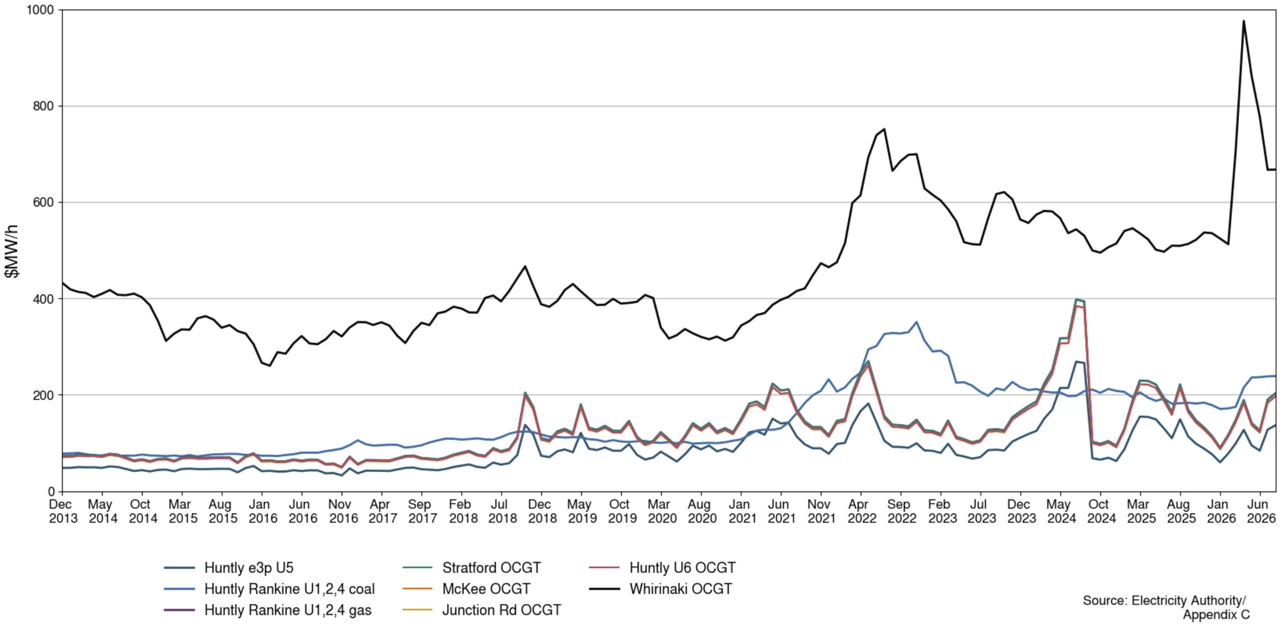
11.5. The SRMC of gas fuelled thermal plants is currently between $136/MWh and $203/MWh.

11.6. The SRMC of Whirinaki is ~$667/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

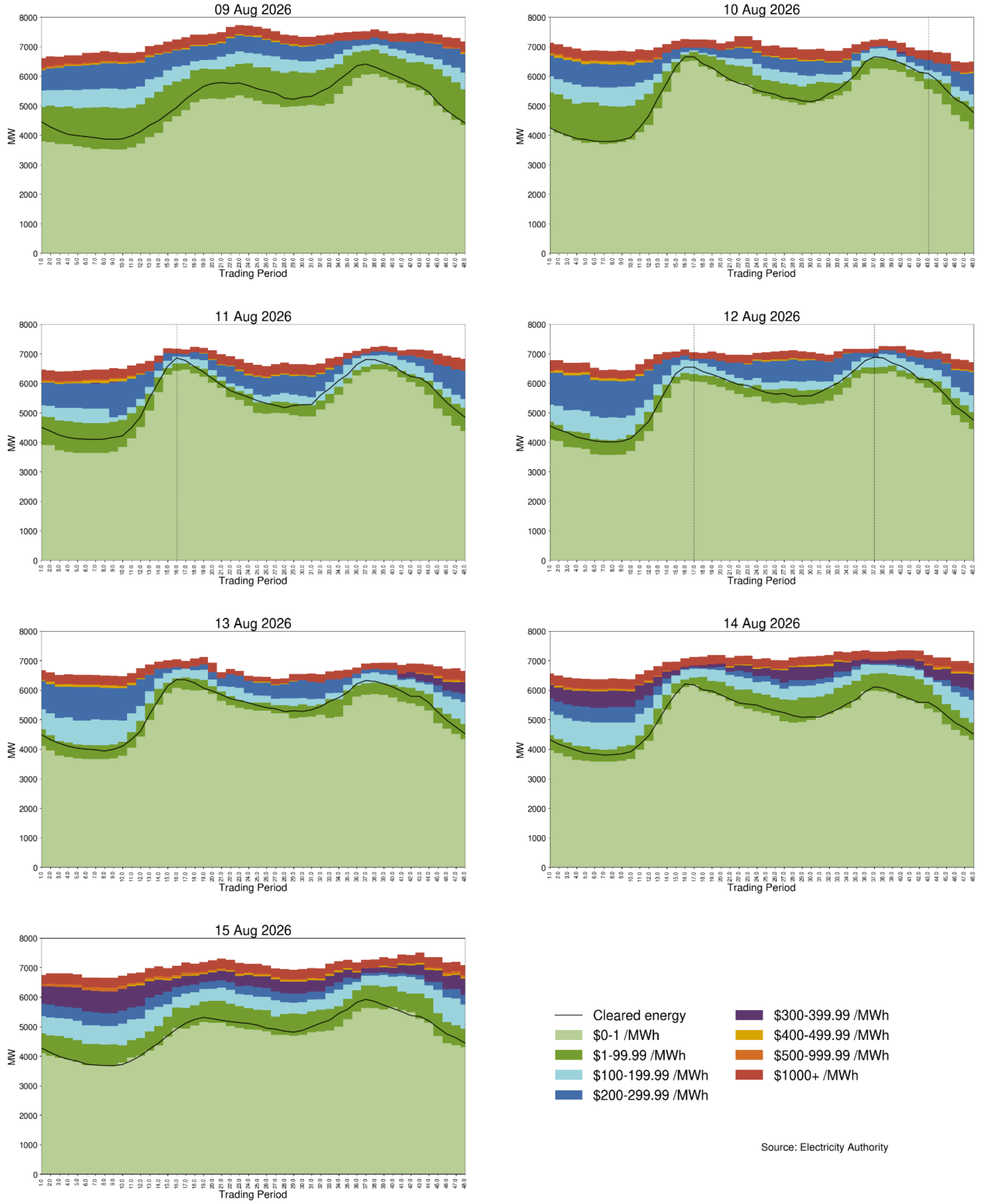


12. Offer behaviour

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. Contact hydro priced up some offers from $100-199/MWh to $200-299/MWh at 8.30am on Tuesday. Some Mercury hydro offers were priced up from $200-299/MWh to $300-499/MWh from 7.30pm on Thursday.

Figure 23: Daily offer stacks



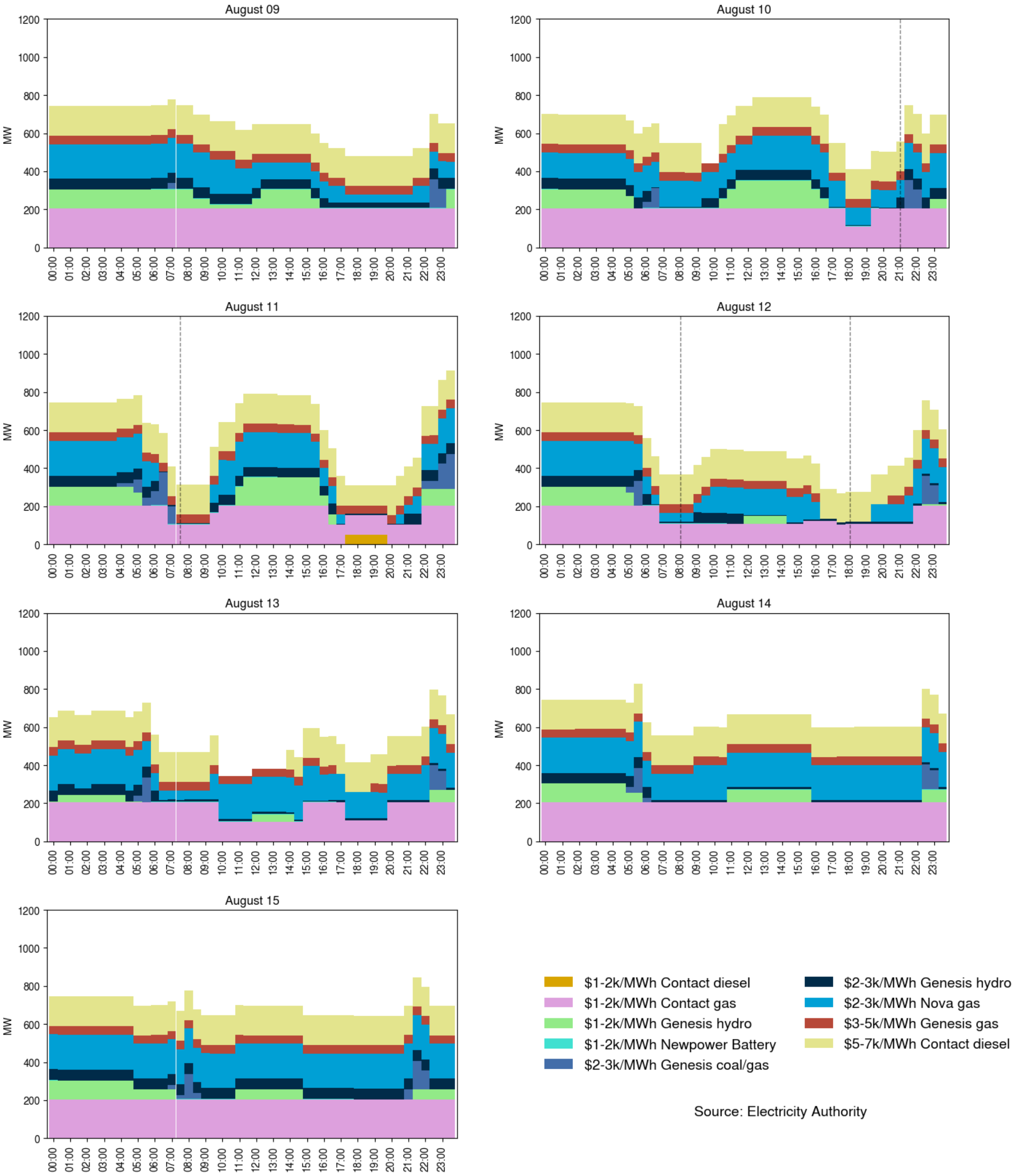
Source: Electricity Authority

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 614MW per trading period was priced above $1,000/MWh this week, which is roughly 11% of the total energy available.

Figure 24: 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. The monitoring team is looking into Genesis hydro offers further 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
02/05/2026	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
13/08/2026	28-32	Further analysis	Genesis	Tekapō	Offers