1 September 2026

Trading conduct report 23-29 August 2026

Market monitoring weekly report

Trading conduct report 23-29 August 2026

1. Overview

1.1. Spot prices have decreased compared to the previous week, as intermittent generation was high. Prices remained near or below the historic average for this time of year. Hydro storage has increased to 76% nominally full and ~127% of the historical average for this time of the 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 23-29 August:

(a) The average spot price for the week was $42/MWh, a decrease of around $40/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $119/MWh.

2.3. Prices were lower this week as wind generation was high increasing the availability of cheap energy. Increased hydro storage also led hydro generators to decrease their value of water.

2.4. The highest price at Ōtāhuhu was $189/MWh at 7:30am on Monday. At this time the price at Benmore was $145/MWh. This period also saw peak demand for the week, which was 48MW higher than forecast. Additionally, 1,630MW of capacity was on outage, approximately double the historic average of 884MW for this time of year as Manapōuri was on outage following an excursion notice.

2.5. At 12.07pm on Sunday the system operator issued an excursion notice (EXN)[1] advising multiple trippings at 11.24am on Sunday, including Manapōuri units 1-7, and loss of supply to Brydone, Edendale, and North Makarewa. These trips followed a lightning strike in the area. This event had limited price impact but creates a notable dip in demand which propagates throughout the graphs presented in this report.

2.6. At 2.37pm on Sunday the system operator issued a grid emergency report (GEN)[2] for a grid emergency period from 11.52am-12.27pm on Sunday. The report advised that during this period the system operator reconfigured the grid to restore electricity supply to Brydone, Edendale, and North Makarewa.

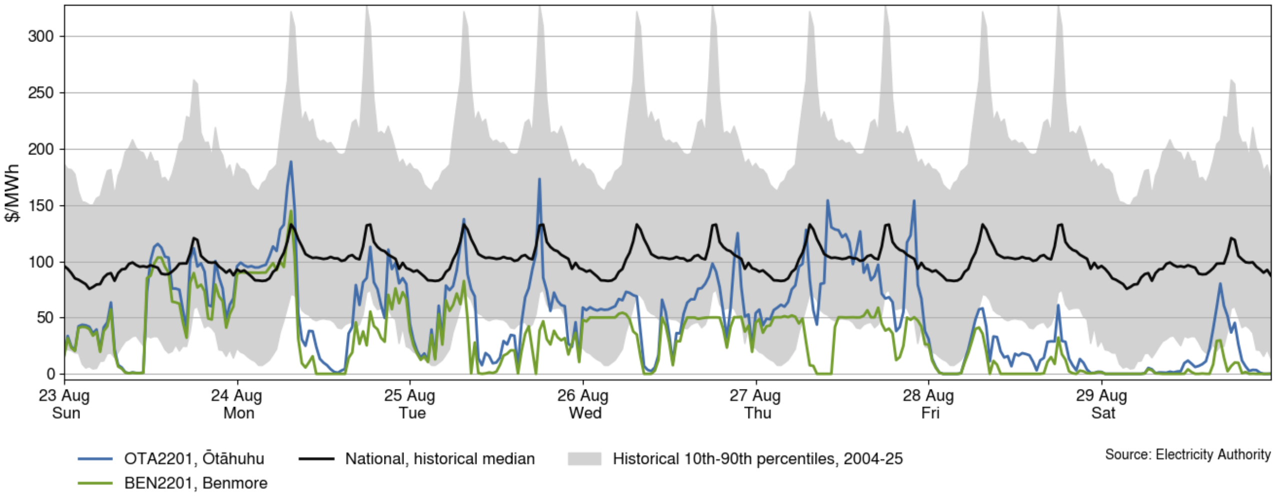
2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the

[1] EXN Frequency National Brydone Edendale 1 Tripped, Edendale Invercargill 1 Tripped, Invercargill North Makarewa 1 Tripped, Invercargill Tiwai 1 Tripped, Kaiwera Gore North Makarewa 1 Tripped, 800000331.pdf

[2] GEN RPT for Unplanned Outage North Makarewa, Brydone, Edendale 800000332.pdf

difference between this week's median and the historic median, are highlighted with a vertical black line.

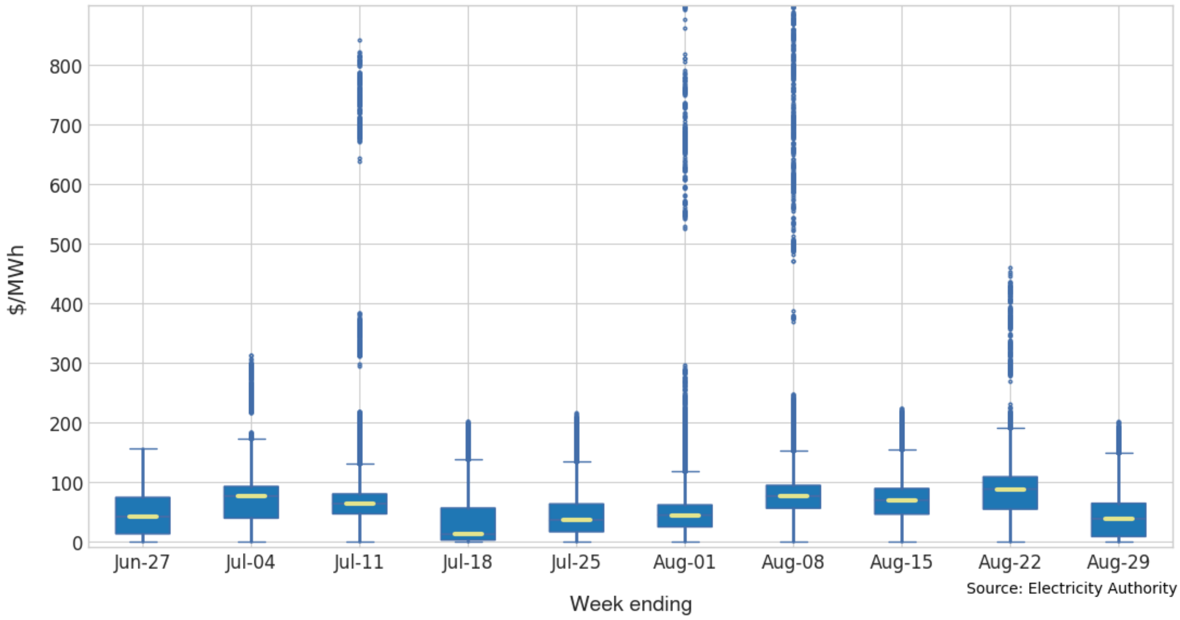
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 23-29 August



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 narrower than last week with fewer high-priced outliers. The median price was $42/MWh, and most prices (middle 50%) fell between $8/MWh and $64/MWh.

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

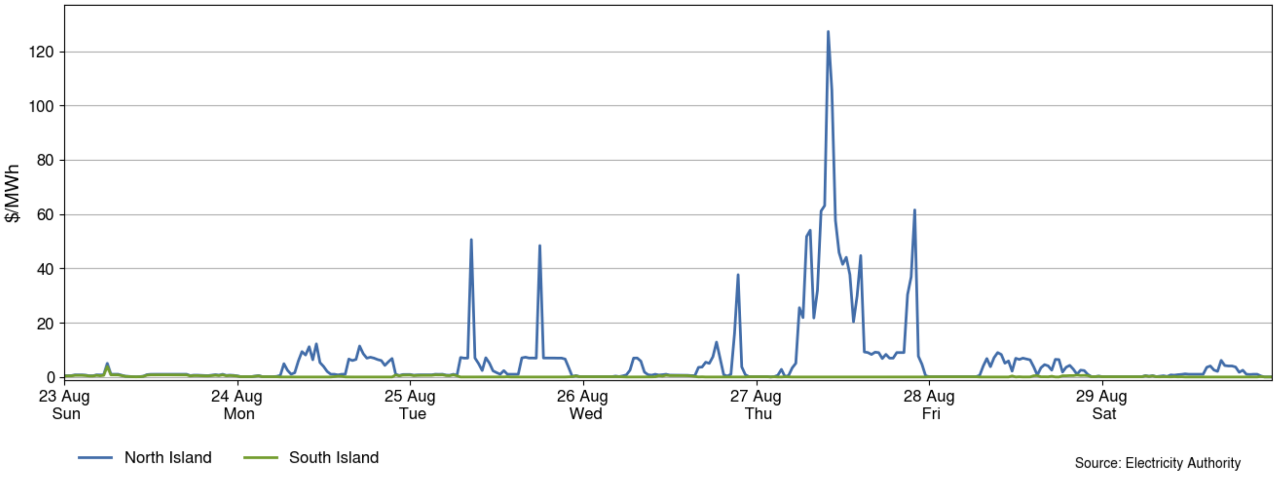


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $15/MWh. North Island FIR prices were elevated on

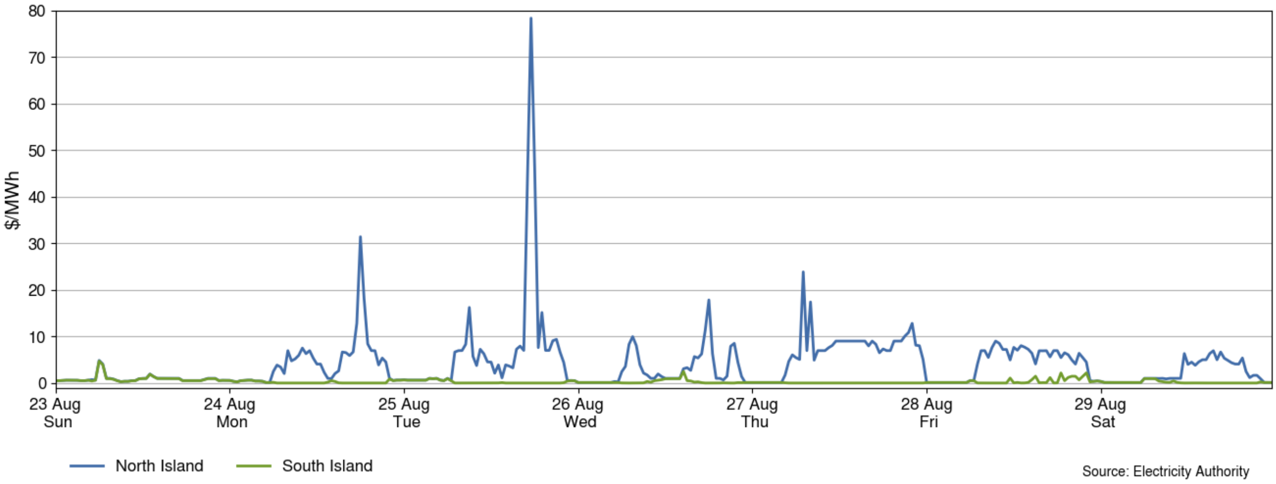
Thursday a combination of low wind generation, which required greater north island hydro dispatch, no Ruakākā battery reserve offers and high northward HVDC transfer requiring North Island reserve coverage. The HVDC was setting the risk at this time. The monitoring team is looking further into why reserve wasn't offered by Ruakākā during this time.

Figure 3: Fast instantaneous reserve price by trading period and island, 23-29 August



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh. The highest North Island SIR price of $78/MWh occurred at 5.30pm on Tuesday. At this time Junction Road failed to start due to an unforeseen breaker issue, hence more hydro was dispatched which reduced the reserve available.

Figure 4: Sustained instantaneous reserve by trading period and island, 23-29 August



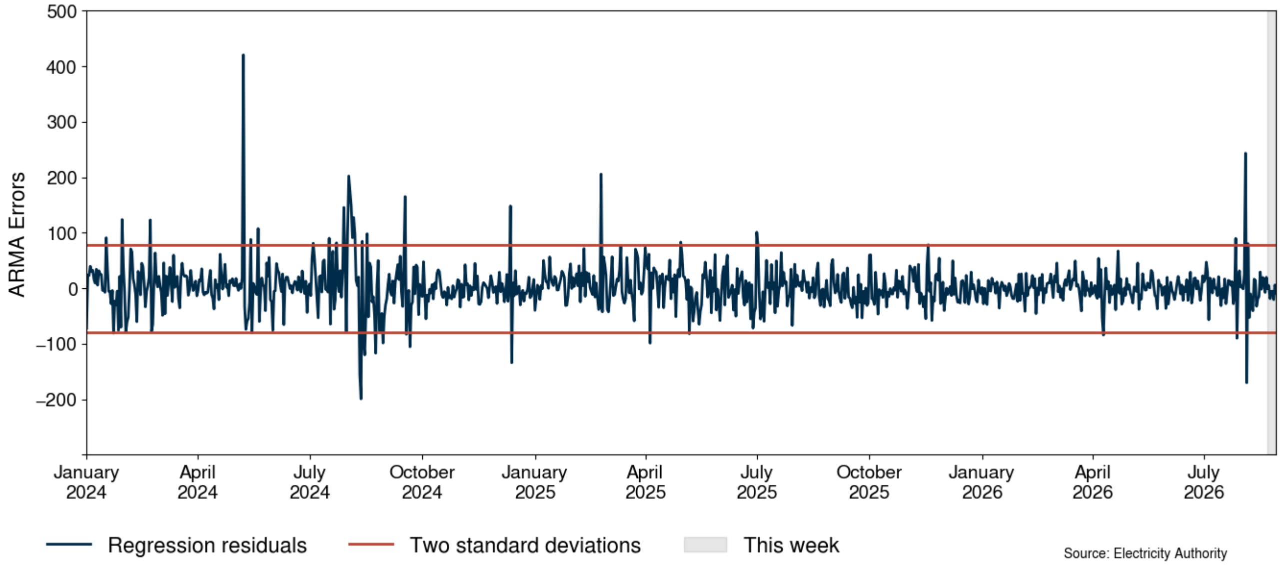
4. Regression residuals

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 - 29 August 2026



5. HVDC

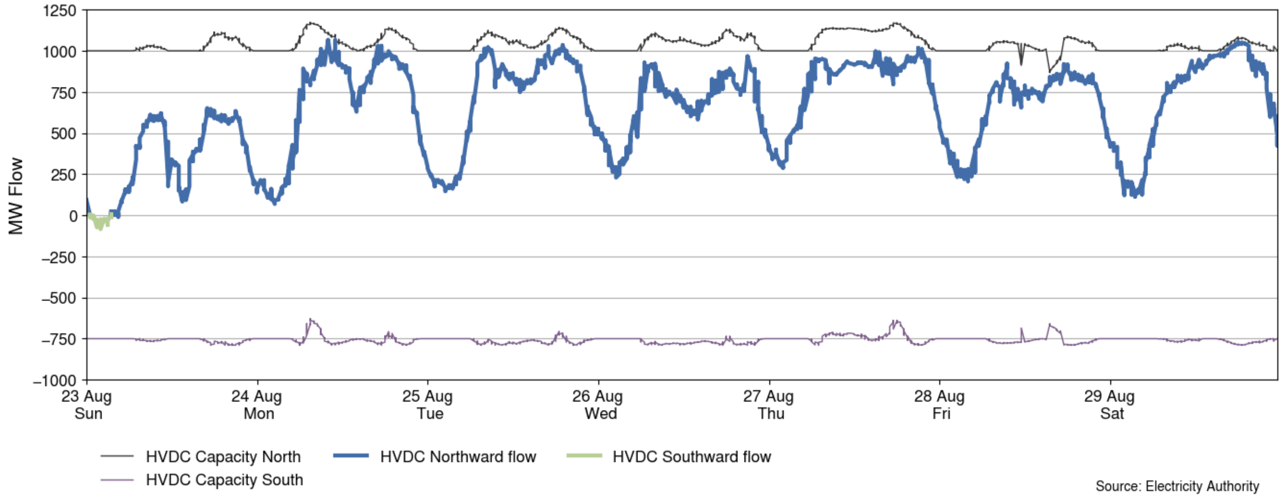
5.1. Figure 6 shows the HVDC flow between 23-29 August. HVDC[3] flows were mostly northward this week, with southward flow occurring early on Sunday Morning.

5.2. The highest northward flow of 1,067MW occurred at 10.00am on Monday.

5.3. The highest southward flow of 84MW occurred at 2.00am on Sunday.

[3] 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, 23-29 August

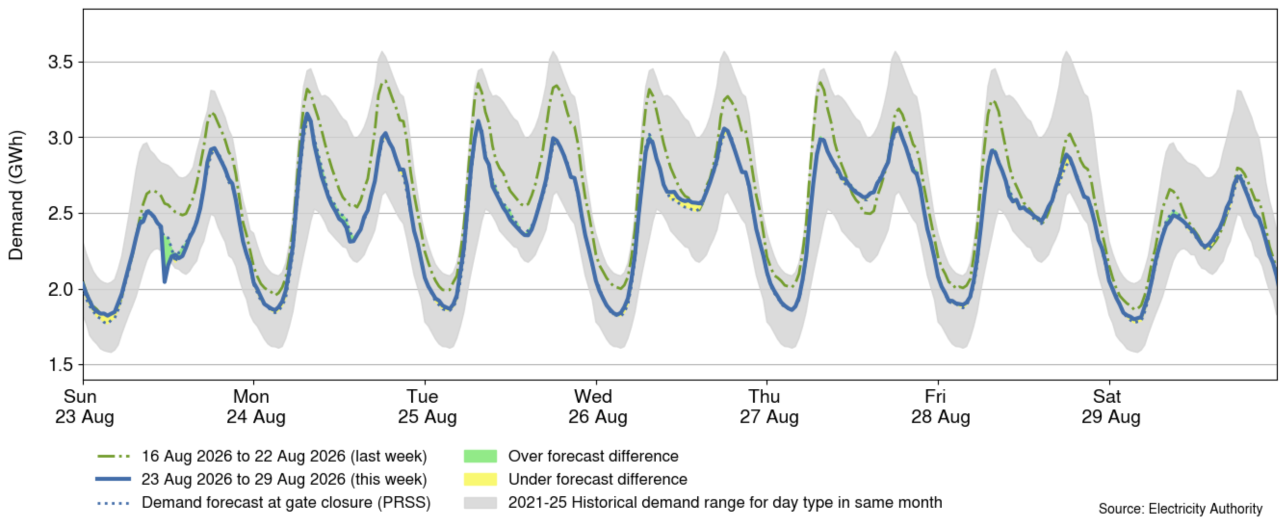


6. Demand

6.1. Figure 7 shows national demand between 23-29 August, compared to the historic range and the demand of the previous week. Demand was overall lower than last week. Peak demand was lower than last week throughout the week, and midday demand was similar or higher than last week from Wednesday onwards.

6.2. The maximum demand this week was around 3.16GWh (6.31GW) at 7:30am on Monday.

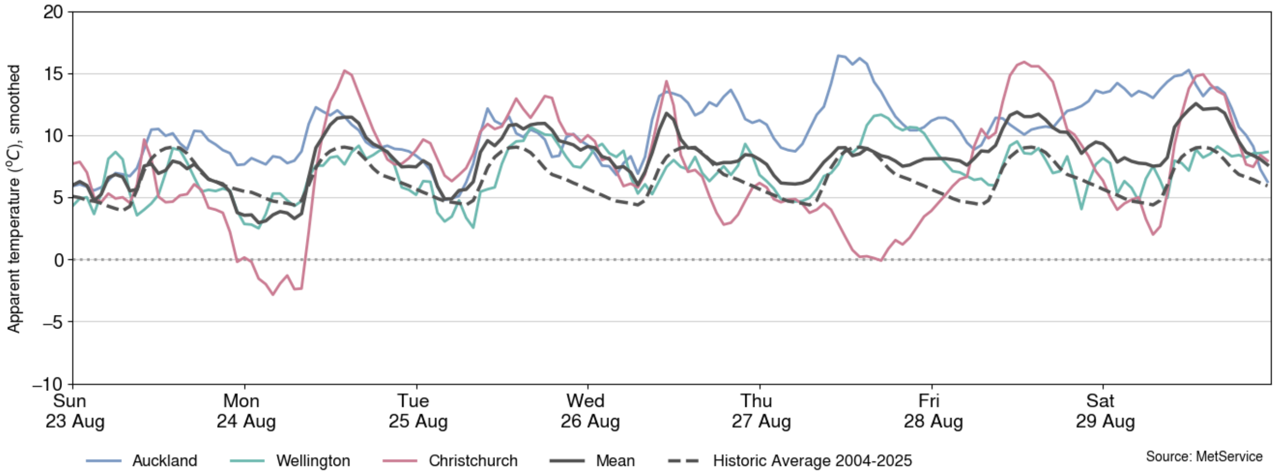
Figure 7: National demand, 23-29 August compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 23-29 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. Apparent temperatures ranged from 4°C to 17°C in Auckland, 2°C to 12°C in Wellington, and -3°C to 16°C in Christchurch.

Figure 8: Temperatures across main centres, 23-29 August



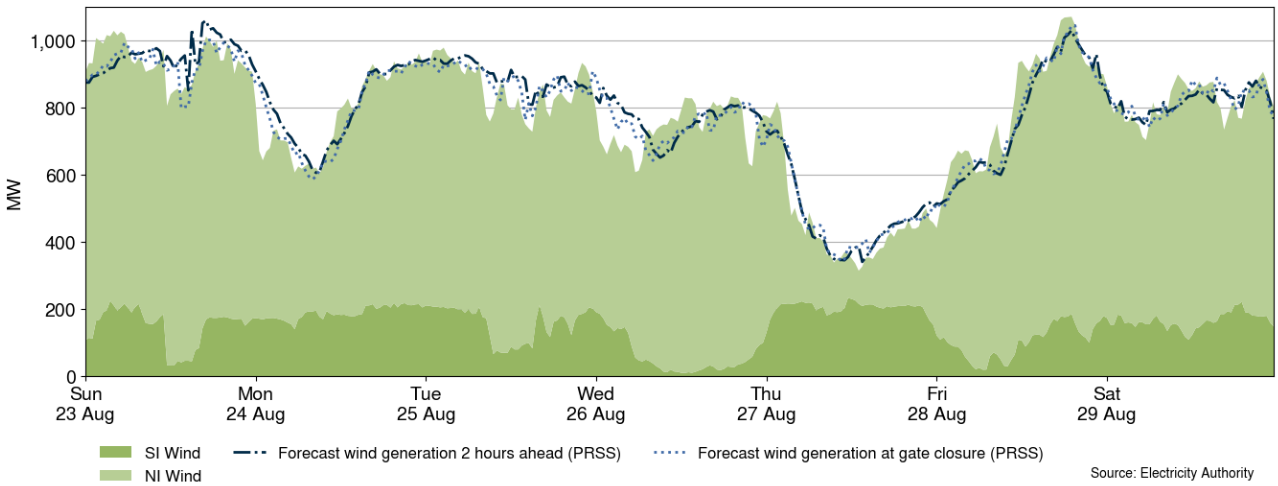
7. Generation

7.1. Figure 9 shows wind generation and forecast from 23-29 August. This week wind generation varied between 315MW and 1,071MW, with a weekly average of 774MW. Wind generation was mostly above 700MW this week, dropping to ~600MW on Monday morning and dropping below 400MW on Thursday.

7.2. Wind generation was lower than forecast on Sunday night, this forecast difference was due to Harapaki wind farm.

7.3. Wind generation was lower than forecast early Wednesday morning, this forecast difference was due to Waipipi and Harapaki wind farms.

Figure 9: Wind generation and forecast, 23-29 August

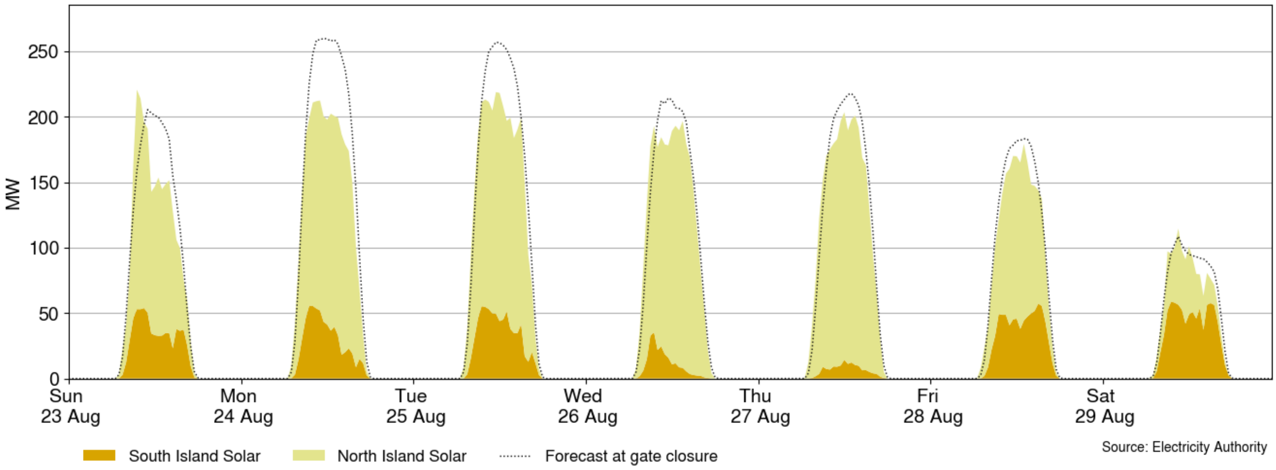


7.4. Figure 10 shows grid connected solar generation from 23-29 August. Solar generation was mostly above 150MW this week. Generation was particularly low on Saturday, staying below 115MW.

7.5. The average solar generation this week was 111MW, peaking at 221MW on Sunday at 9:30am.

7.6. Solar forecasting errors this week are an accumulation of errors at various solar farms.

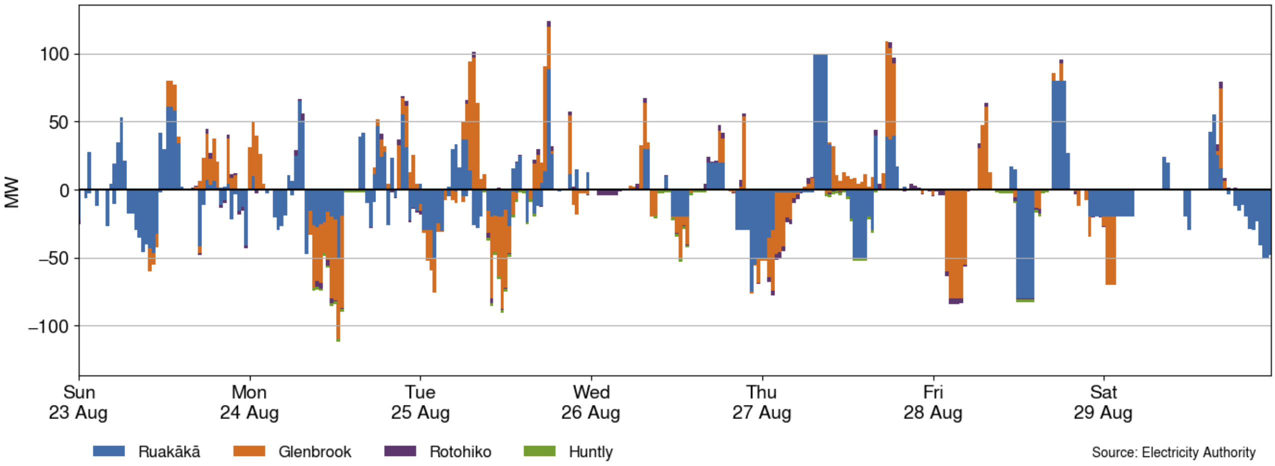
Figure 10: Grid connected solar generation, 23-29 August



7.7. 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.

7.8. This week batteries generally charged at night and during the middle of the day, and discharged during peak demand periods.

Figure 11: Grid scale battery charge and discharge, 23-29 August



7.9. 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[4]) 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.

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

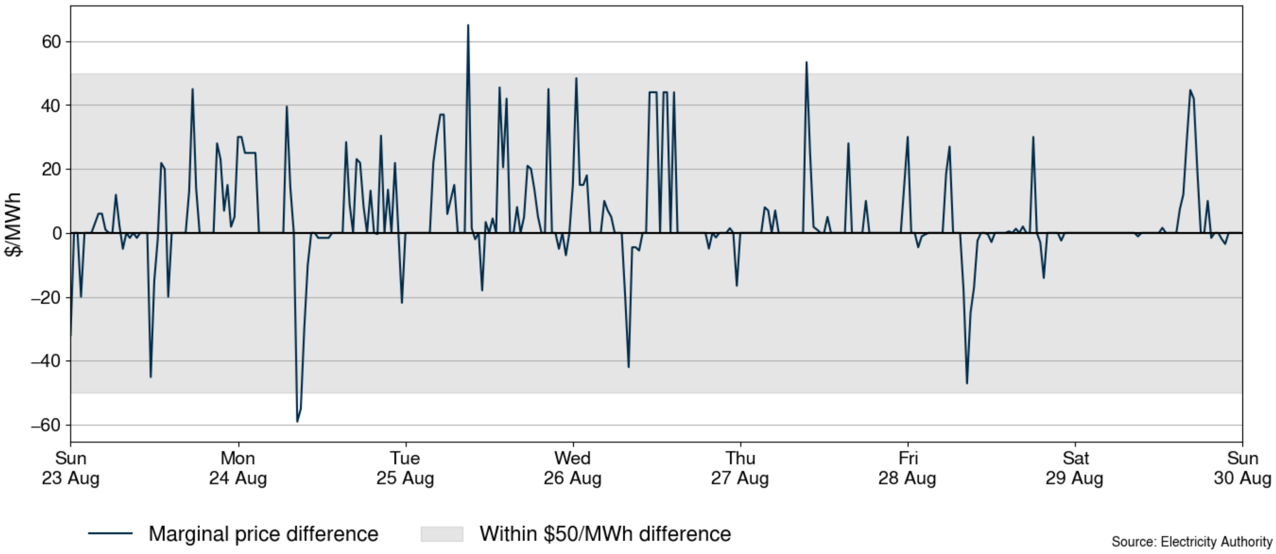
Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.10. There were four periods with price forecast differences greater than $50/MWh.

7.11. The largest positive difference was $65/MWh at 9.00am on Tuesday. At this time demand was 19MWh higher than forecast and intermittent generation was 100MW lower than forecast.

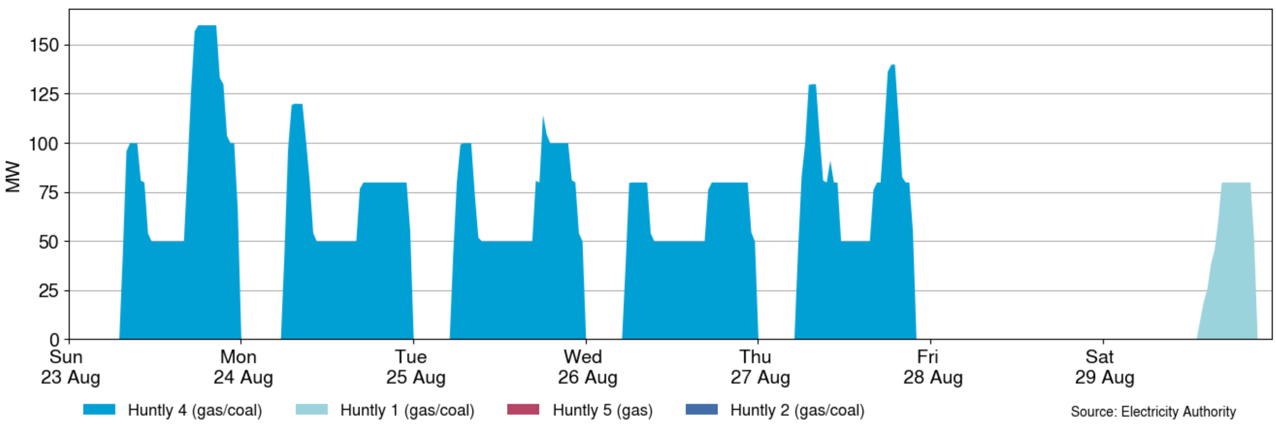
7.12. The largest negative difference was $59/MWh at 8.30am on Monday. At this time demand was 38MWh lower than forecast, and intermittent generation was 33MW higher than forecast.

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, 23-29 August



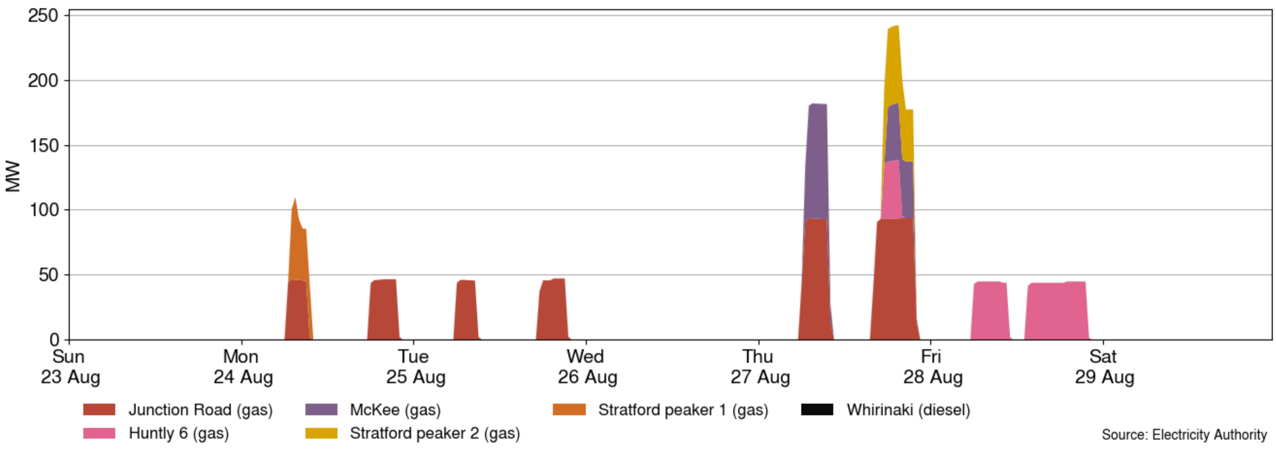
7.13. Figure 13 shows the generation of thermal baseload between 23-29 August. Thermal baseload generation this week was provided by Huntly 4, and Huntly 1.

Figure 13: Thermal baseload generation, 23-29 August



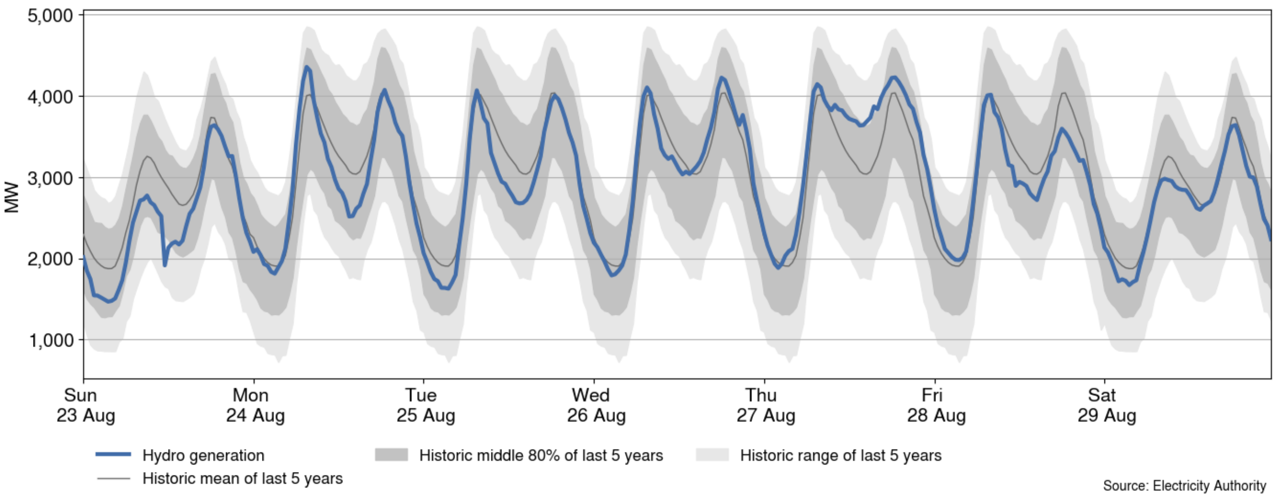
7.14. Figure 14 shows the generation of thermal peaker plants between 23-29 August. Peaker generation this week was low throughout the week, except for Thursday when North Island wind generation was low.

Figure 14: Thermal peaker generation, 23-29 August



7.15. Figure 15 shows hydro generation between 23-29 August. Hydro generation has been close to average throughout the week. Notably midday hydro generation on Thursday was much higher than the historic mean.

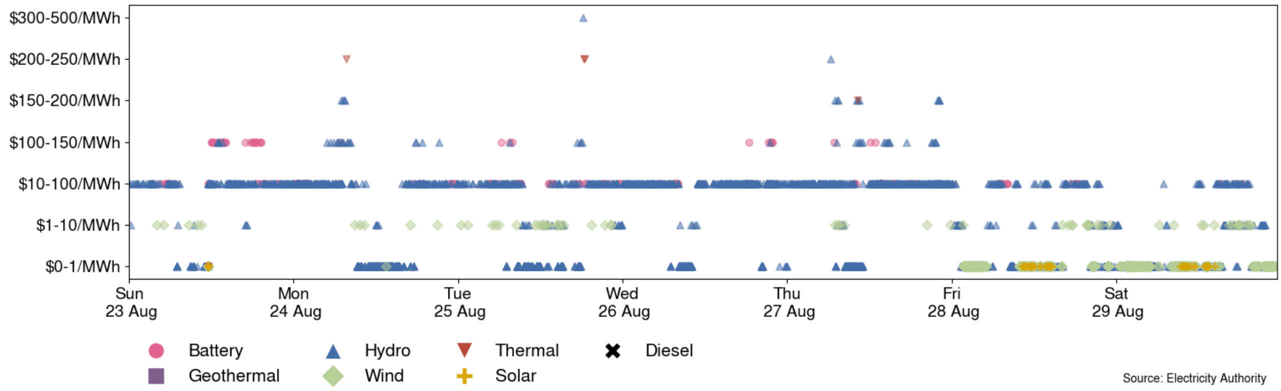
Figure 15: Hydro generation, 23-29 August



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.

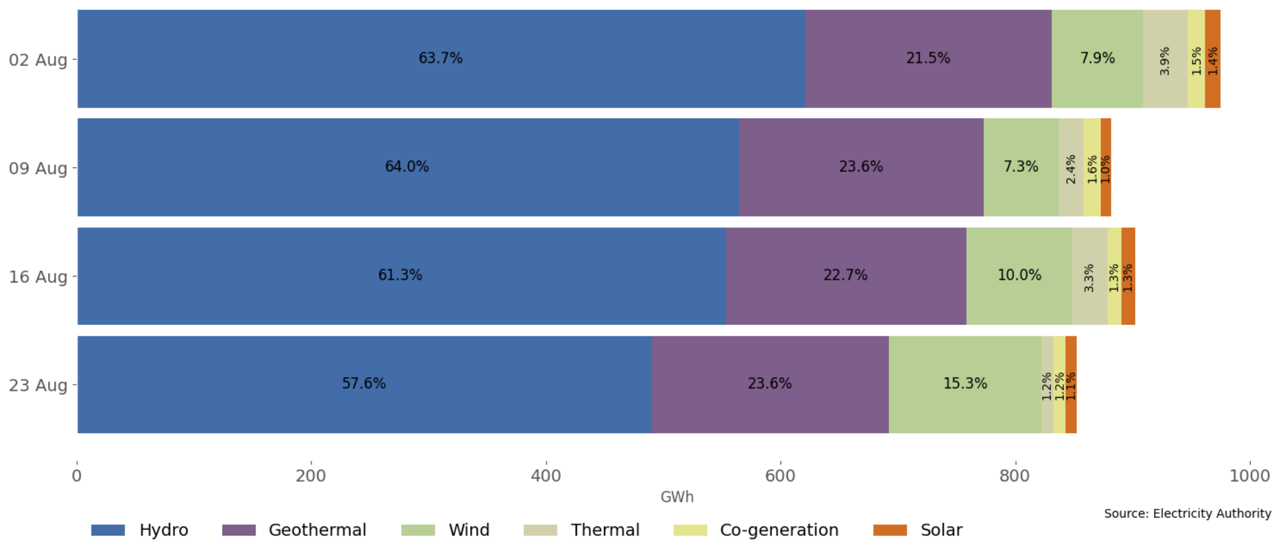
7.17. The highest marginal price of $310/MWh was set by Karāpiro at 6:00pm on Tuesday. The most common marginal technology was hydro, and the second most common technology was wind. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 23-29 August



7.18. As a percentage of total generation, between 23-29 August, total weekly hydro generation was 57.6%, geothermal 23.6%, wind 15.3%, thermal 1.2%, co-generation 1.2%, and solar (grid connected) 1.1%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 2 August and 29 August



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 23-29 August ranged between ~408MW and ~1,898MW. Figure 19 shows the thermal generation capacity outages.

8.2. At 11.00am on Monday ~1,898MW was on outage, over double the historic average of 884MW for this time of year as Manapouri unit 1-7 were on outage following an excursion notice.

Figure 18: Total MW loss from generation outages, 23-29 August

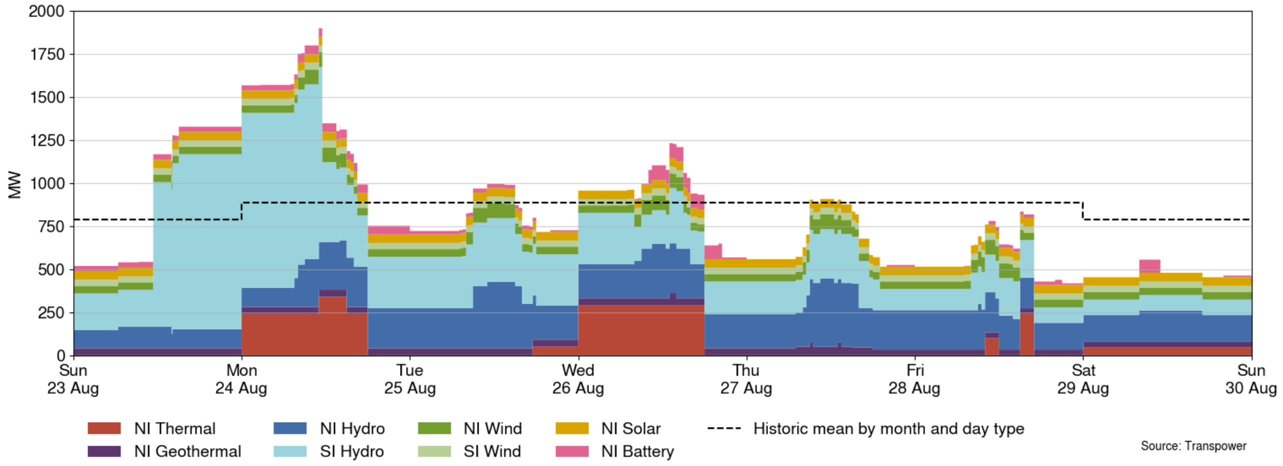
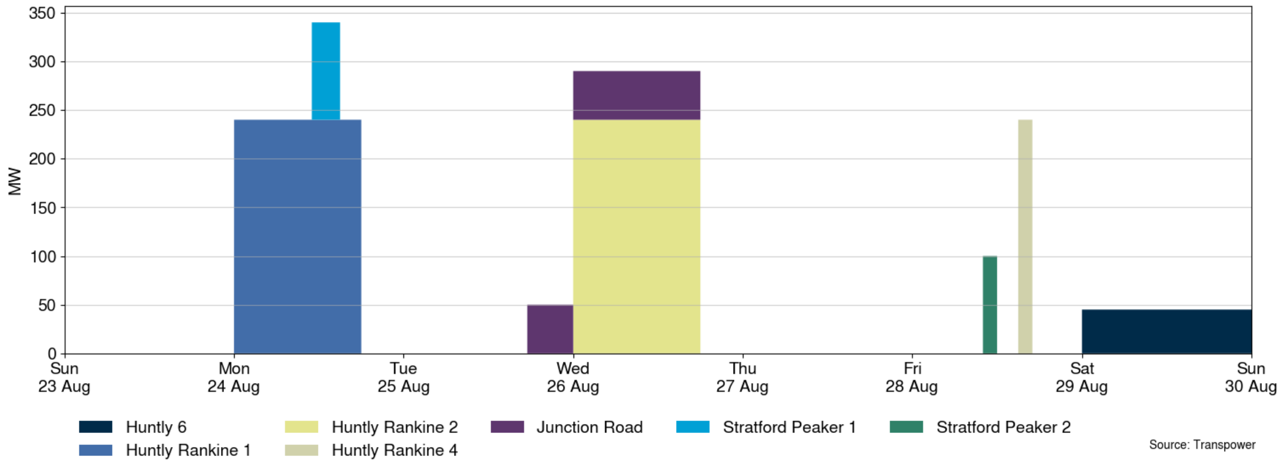


Figure 19: Total MW loss from thermal outages, 23-29 August



8.3. Notable outages include:

Plant	Partial or Full	End Date
Huntly 1	Full	24 August 2026
Stratford Peaker 1	Full	24 August 2026
Manapōuri units 1 - 6	Full	24 August 2026
Huntly 2	Full	26 August 2026
Manapōuri unit 7	Full	26 August 2026
Huntly 4	Full	28 August 2026
Stratford Peaker 2	Full	28 August 2026
Kaiwaikawe Wind Farm	Partial	1 September 2026
Tauhei Solar Farm	Full	4 September 2026
Roxburgh unit 8	Full	24 September 2026

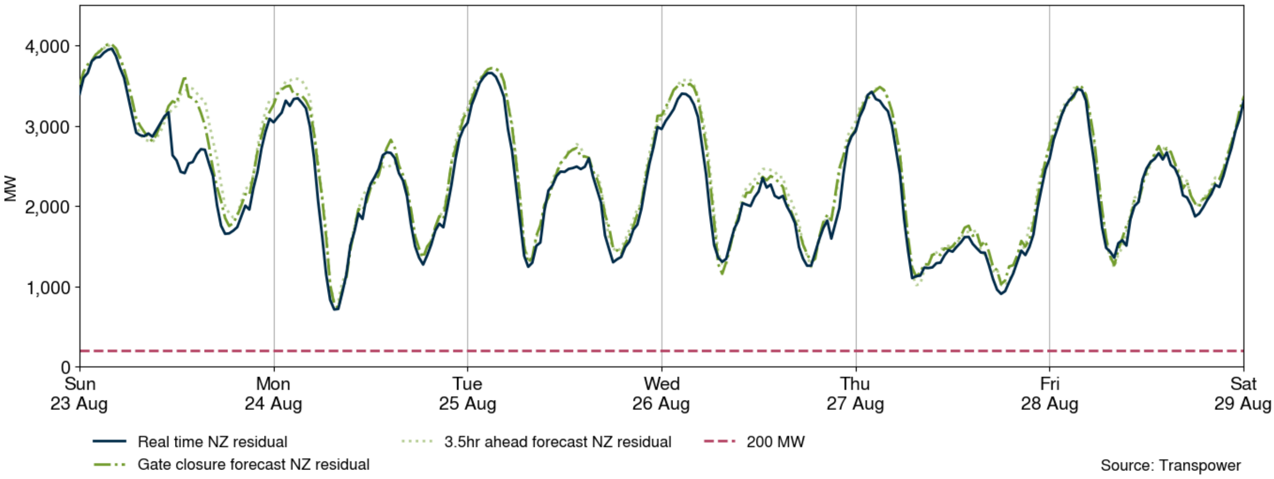
9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 23-29 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. From 11.30am to 3.30pm on Sunday national residual generation ranges from 305MW to 1,216MW lower than forecast. This forecast difference is due to Manapōuri units 1-7 going on outage following an excursion notice.

9.3. The minimum residual generation this week was 711MW at 7.30am on Monday.

Figure 20: National generation balance residuals, 23-29 August



10. Storage/fuel supply

10.1. Storage at Lake Pūkaki (81% full) is significantly higher than the historic 90th percentile for this time of year.

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

10.3. Storage at Lake Taupō is (44% full) is below average for this time of year.

10.4. Storage at Lake Te Anau (122% full) is higher than the historic 90th percentile for this time of year.

10.5. Storage at Lake Manapōuri (74% full) is above average for this time of year.

10.6. Storage at Lake Hawea (52% 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 76% nominally full and ~127% of the historical average for this time of the year.

10.9. Storage at Lake Pūkaki (81% full[5]) is significantly higher than the historic 90th percentile for this time of year.

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

10.11. Storage at Lake Taupō is (44% full) is below average for this time of year.

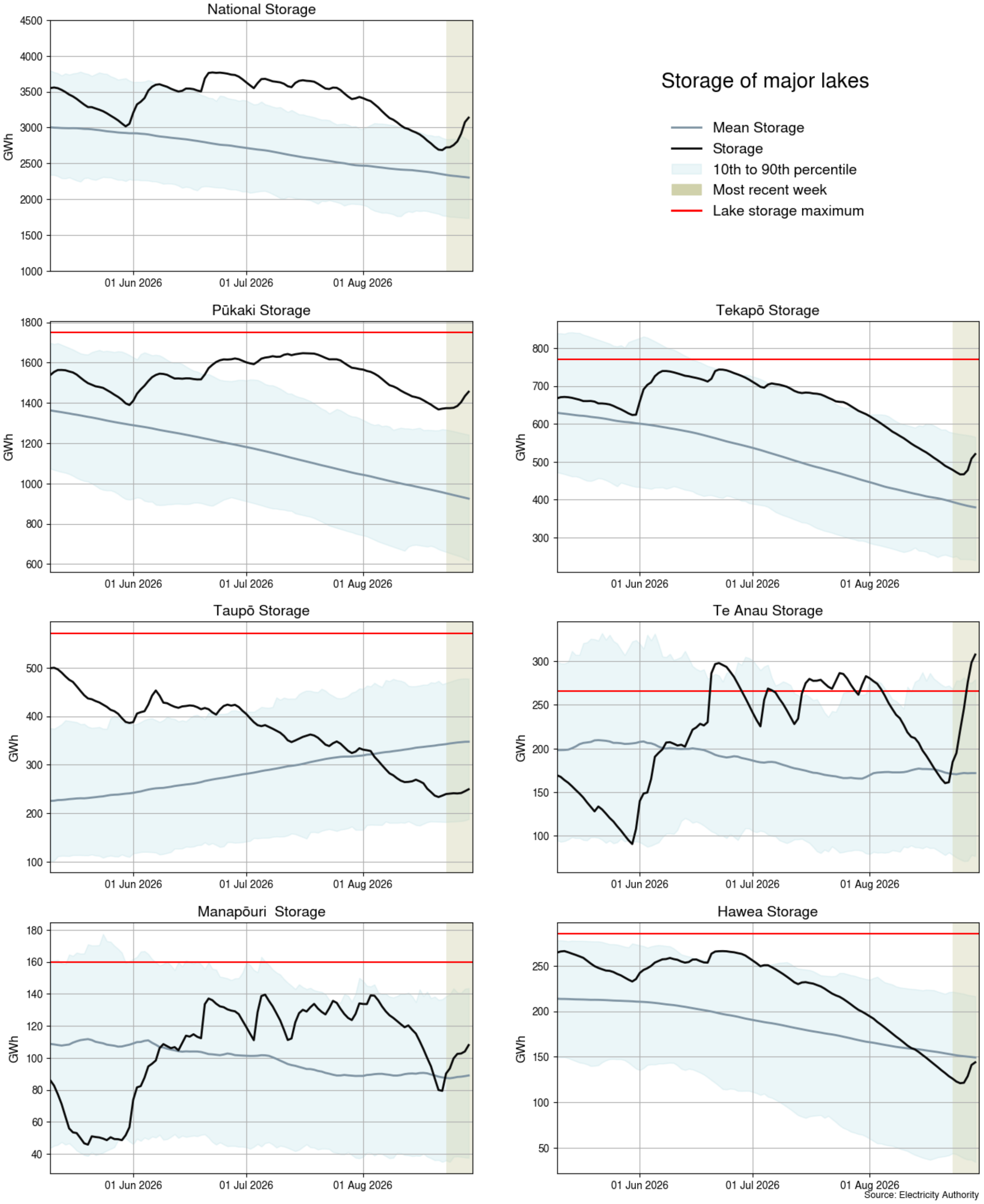
[5] Percentage full values sourced from NZX Hydro.

10.12. Storage at Lake Te Anau (122% full) is higher than the historic 90th percentile for this time of year.

10.13. Storage at Lake Manapōuri (74% full) is above average for this time of year.

10.14. Storage at Lake Hawea (52% 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 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.

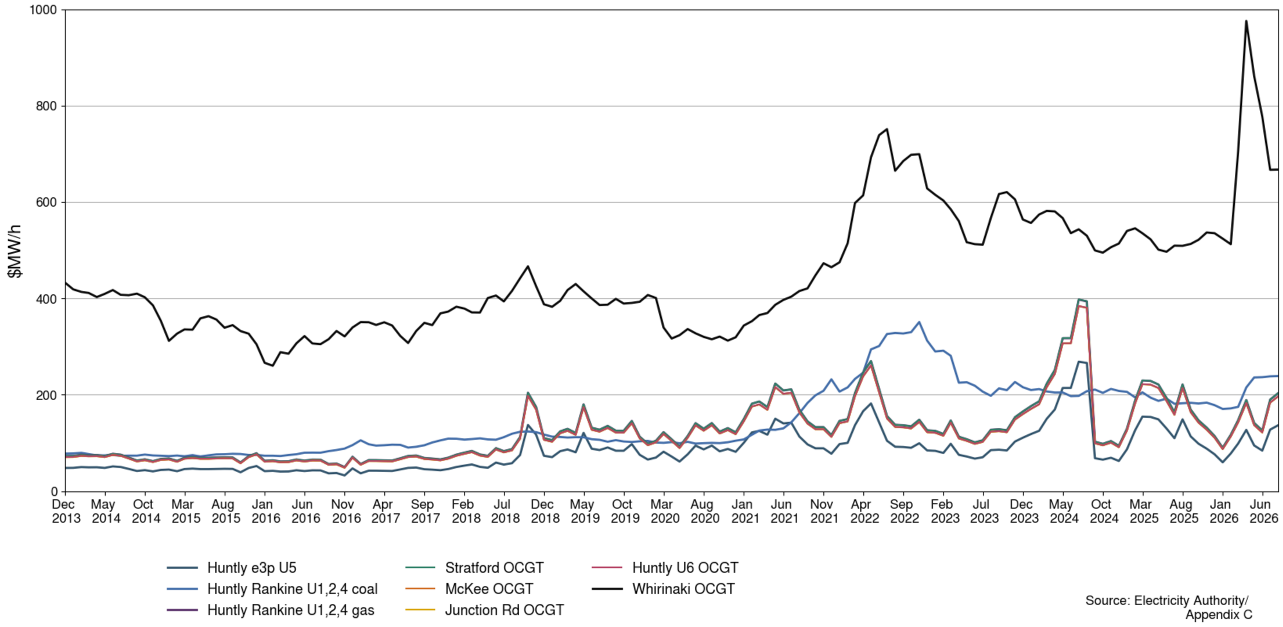
11.5. The SRMC of gas fuelled thermal plants is currently between $136/MWh and $203/MWh.

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.

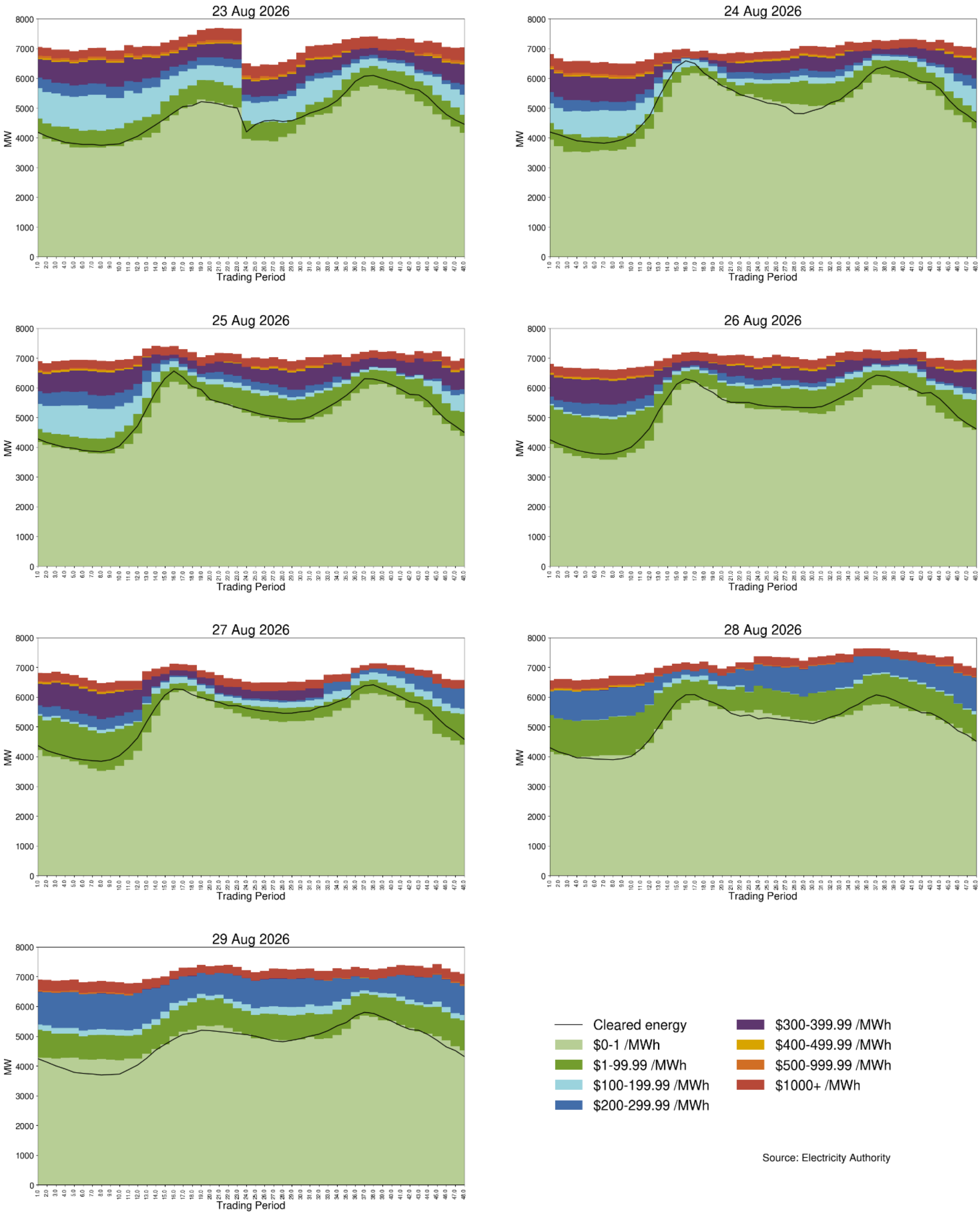
12.2. Meridian priced down hydro offers from $100-199/MWh to $1-99/MWh on Wednesday.

12.3. Contact priced down hydro offers on Friday night as Clyde began spilling.

12.4. Mercury priced down hydro offers from $300-499/MWh to $200-299/MWh on Thursday afternoon.

12.5. Manawa priced up offers from hydro offers on Friday.

Figure 23: Daily offer stacks



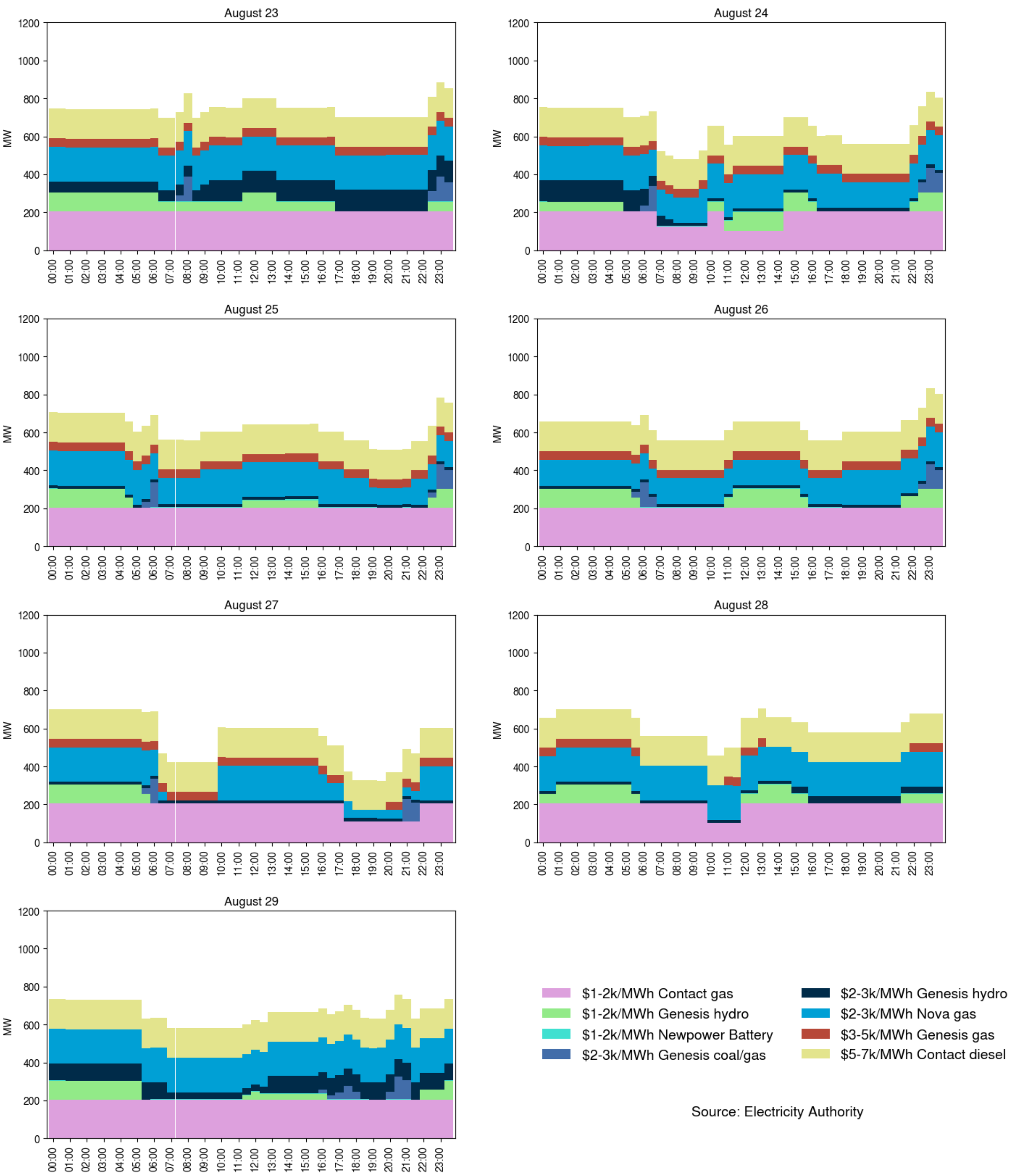
Source: Electricity Authority

12.6. 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.

12.7. 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.

12.8. On average 640MW 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

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
26/08/2026-29/08/2026	Several	Further analysis	Meridian	Ruakākā	Reserve offers