1 September 2025

Trading conduct report 24-30 August 2025

Market monitoring weekly report

Trading conduct report 24-30 August 2025

1. Overview

1.1. The average price decreased by $61/MWh this week to $155/MWh. Invercargill experienced elevated prices and price separation due to transmission constraints.

1.2. Wind generation was low at the start of the week, with an average across Monday-Tuesday of approximately 72 MW. It increased sharply from Thursday, reaching an average of 854 MW across Friday and Saturday.

1.3. Demand was lower than the previous week, primarily due to warmer temperatures.

1.4. National hydro storage declined to ~ 45% nominally full and around 77% of the historical average.

1.5. Hydro generation decreased as a result of declining hydro storage. Thermal generation increased, with the rise more pronounced during periods of low wind generation to meet the 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 24-30 August 2025:

(a) The average spot price for the week was $155/MWh, a decrease of around $61/MWh compared to the previous week.

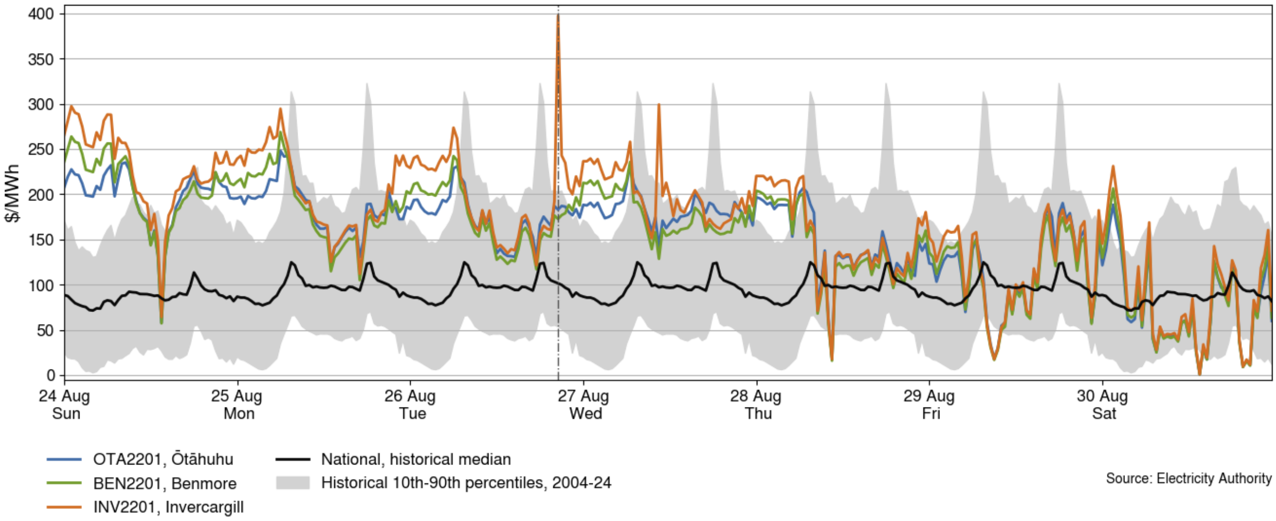
(b) 95% of prices fell between $26/MWh and $249/MWh.

2.3. Spot prices hovered between $200-$250/MWh from Sunday to Wednesday, due to low wind generation and high thermal generation. Spot prices decreased from Thursday onwards, driven by increased wind generation.

2.4. Invercargill observed high prices and price separation on Tuesday and Wednesday. During these times there was low Southland wind generation and reduced hydro generation. The highest price of $398/MWh at Invercargill occurred on Tuesday at 8.30pm. Another price spike at Invercargill occurred on Wednesday at 10:30 am, with a price of $299/MWh. Across Tuesday and Wednesday there were several instances or binding or near binding import constraints in Southland.

2.5. Figure 1 shows the wholesale spot prices at Benmore, Ōtāhuhu, and Invercargill 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 above $300/MWh are marked with black dashed lines.

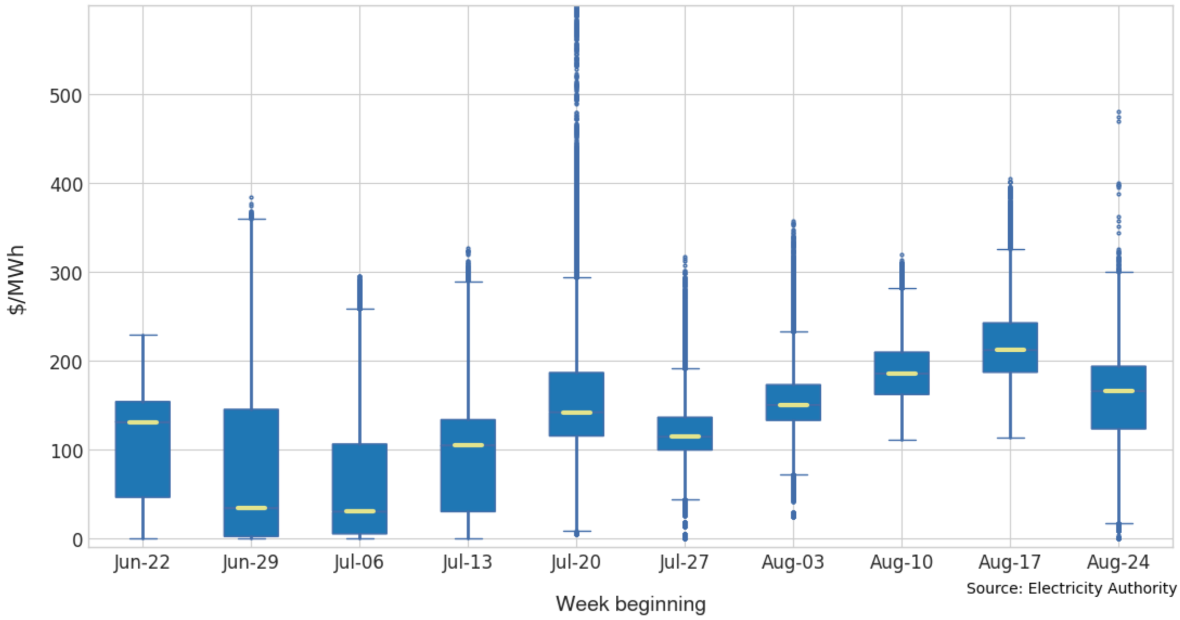
Figure 1: Wholesale spot prices at Benmore, Ōtāhuhu and Invercargill, 24-30 August 2025



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 slightly wider than last week, with a few high-priced outliers above $400/MWh. However, the median price was lower than last week ($166/MWh), and most prices (middle 50%) fell between $123/MWh and $194/MWh.

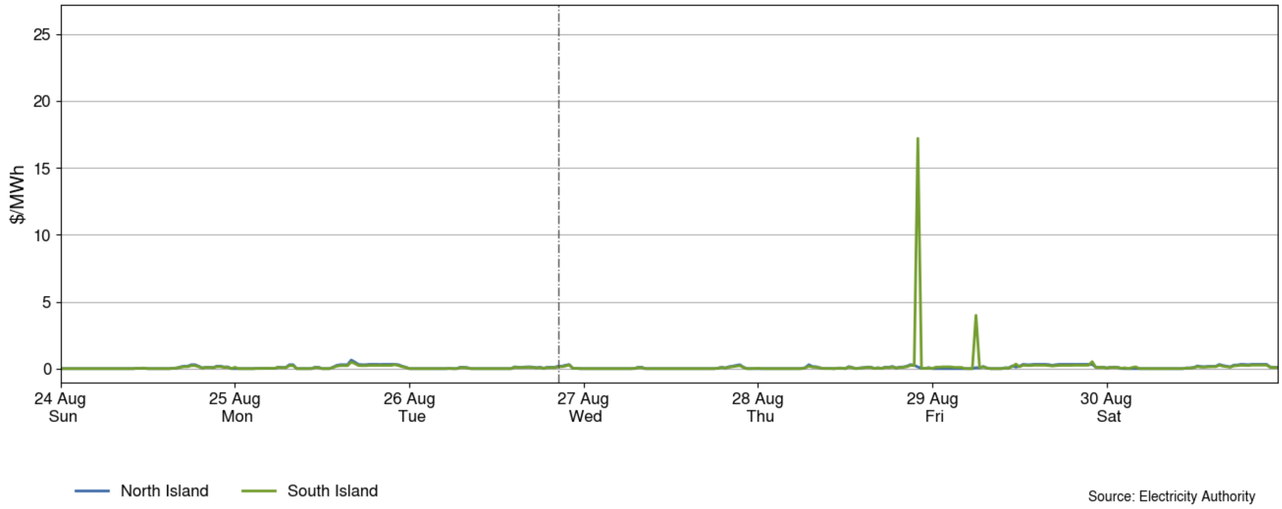
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

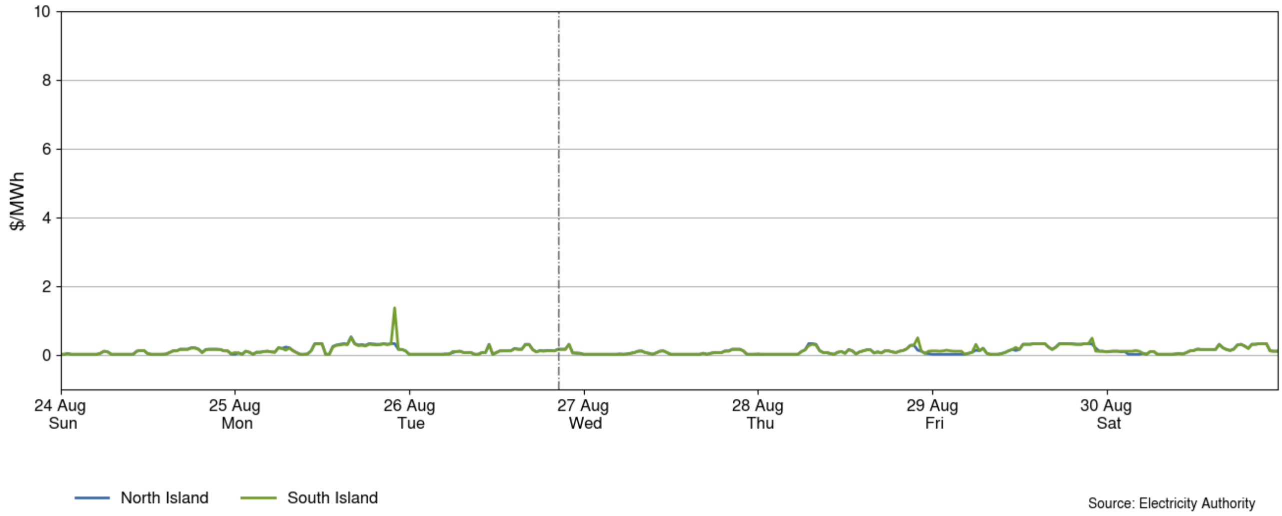
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were below $5/MWh, except on Thursday at 10.00pm, with prices reaching around $17/MWh in the South Island and $0.31/MWh in the North Island. During that time, HVDC was setting the South Island risk for two dispatch intervals within Trading Period 45.

Figure 3: Fast instantaneous reserve price by trading period and island, 24-30 August 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were below $2/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 24-30 August 2025



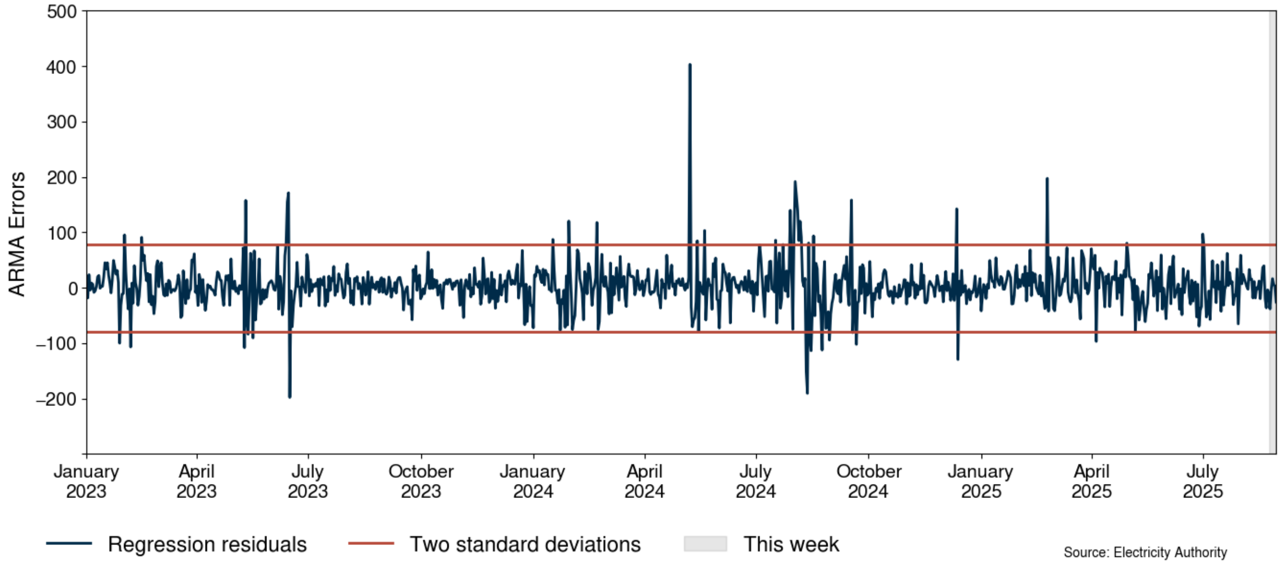
4. Regression residuals

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.

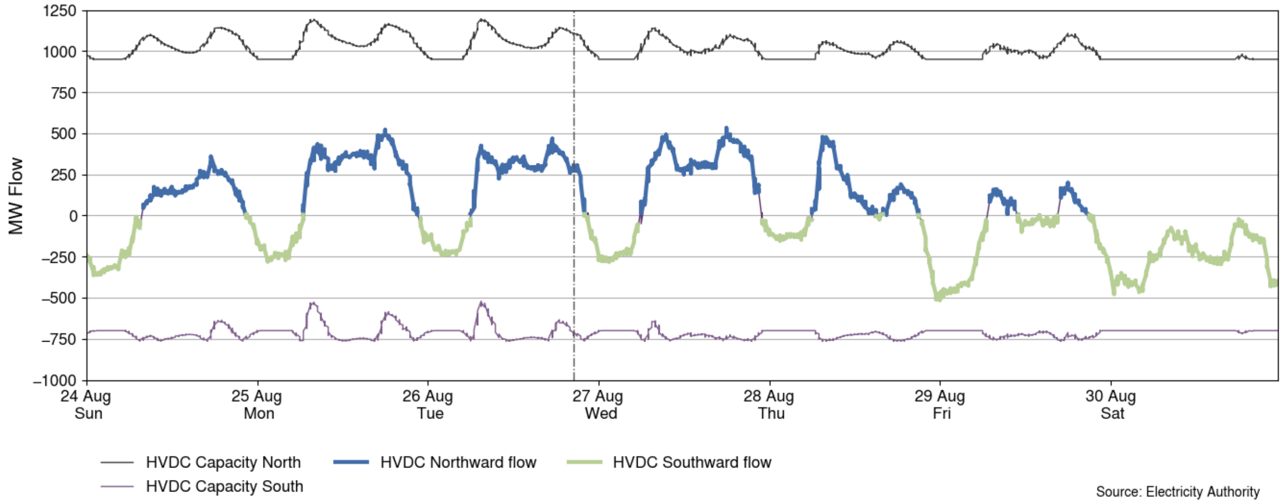
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 30 August 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 24-30 August 2025. HVDC flows were mostly northward during the day and southward overnight. Northward flow was reduced, likely due to declining hydro storage (maximum of 531MW northward flow). On Saturday, flow was entirely southward, due to high wind. Southward flows reached a maximum of 514MW around midnight on Friday, when North Island wind generation was high.

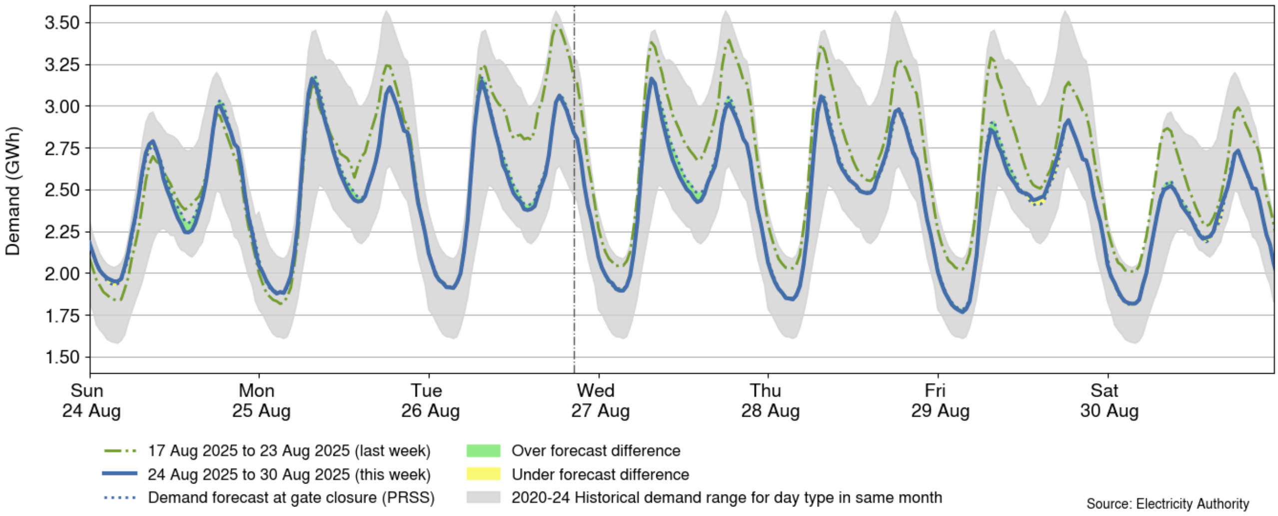
Figure 6: HVDC flow and capacity, 24-30 August 2025



6. Demand

6.1. Figure 7 shows national demand between 24-30 August 2025, compared to the historic range and the demand of the previous week. Demand was lower from Tuesday due to warmer temperatures. The highest demand of the week was around 3.16GWh at 7.30am on Wednesday during the morning peak.

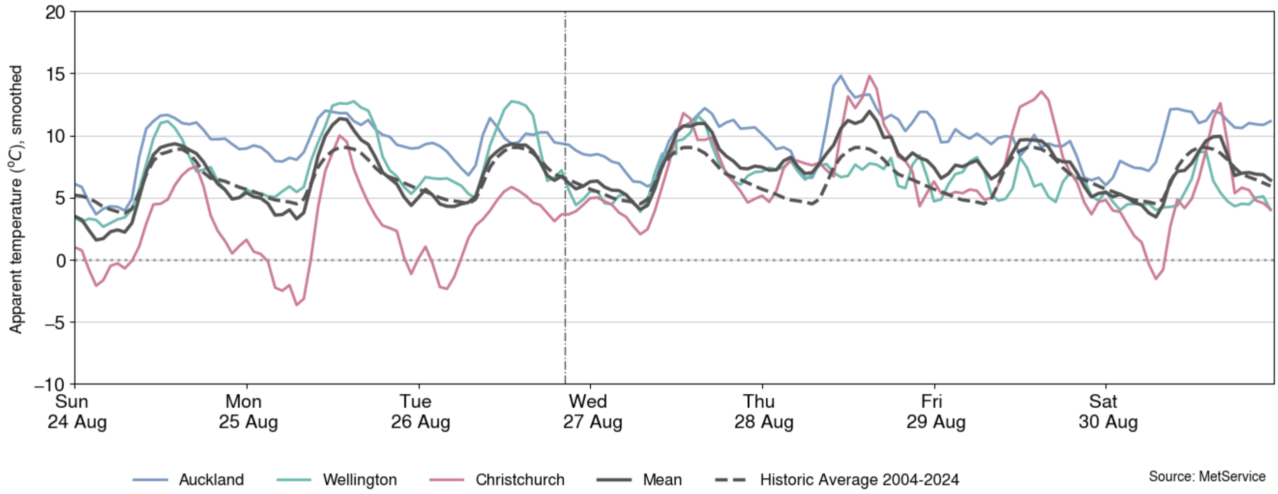
Figure 7: National demand, 24-30 August 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 24-30 August 2025. 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 4°C to 16°C in Auckland, 2°C to 13°C in Wellington, and -4°C to 15°C in Christchurch. Temperatures were mild from Tuesday, which helped reduce demand.

Figure 8: Temperatures across main centres, 24-30 August 2025

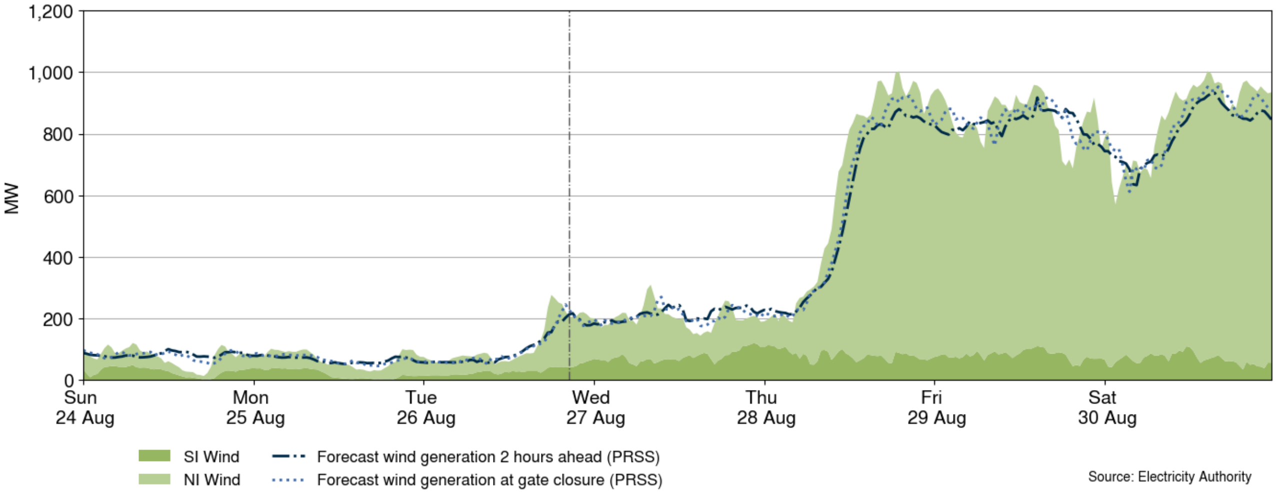


7. Generation

7.1. Figure 9 shows wind generation and forecast from 24-30 August 2025. This week wind generation varied between 13MW and 1003MW, with a weekly average of 400MW.

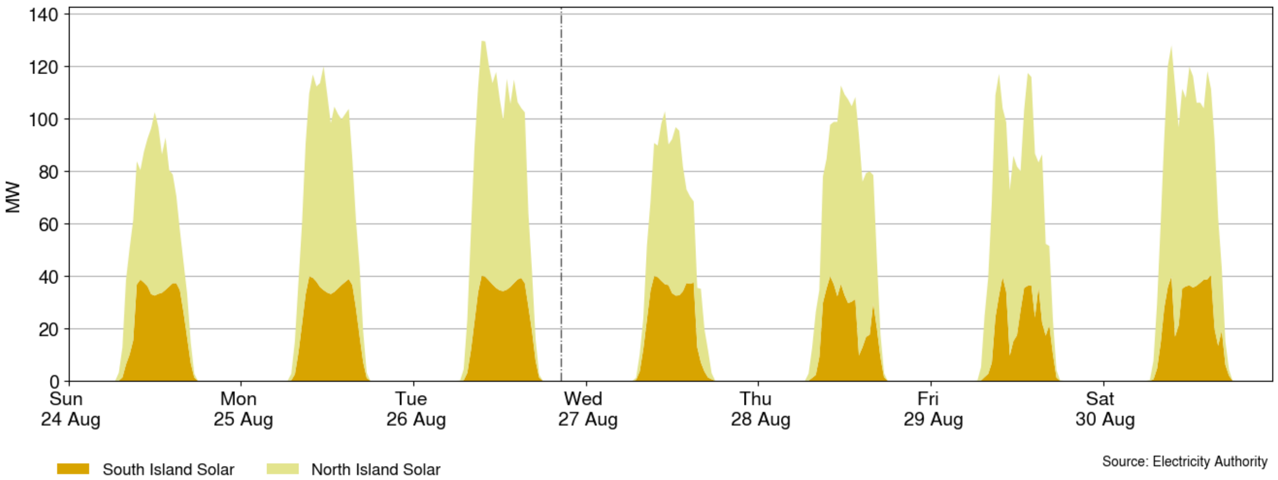
7.2. Wind generation was very low on Sunday and Monday, with an average of around 72MW. On Wednesday, wind remained mostly under 200MW. Wind generation sharply increased on Thursday. The average wind generation on Friday and Saturday was very high (average ~ 854MW).

Figure 9: Wind generation and forecast, 24-30 August 2025



7.3. Figure 10 shows grid connected solar generation from 24-30 August 2025. Solar generation typically peaked above 100MW, with a maximum of 130MW at 9.30am on Tuesday.

Figure 10: Grid connected solar generation, 24-30 August 2025



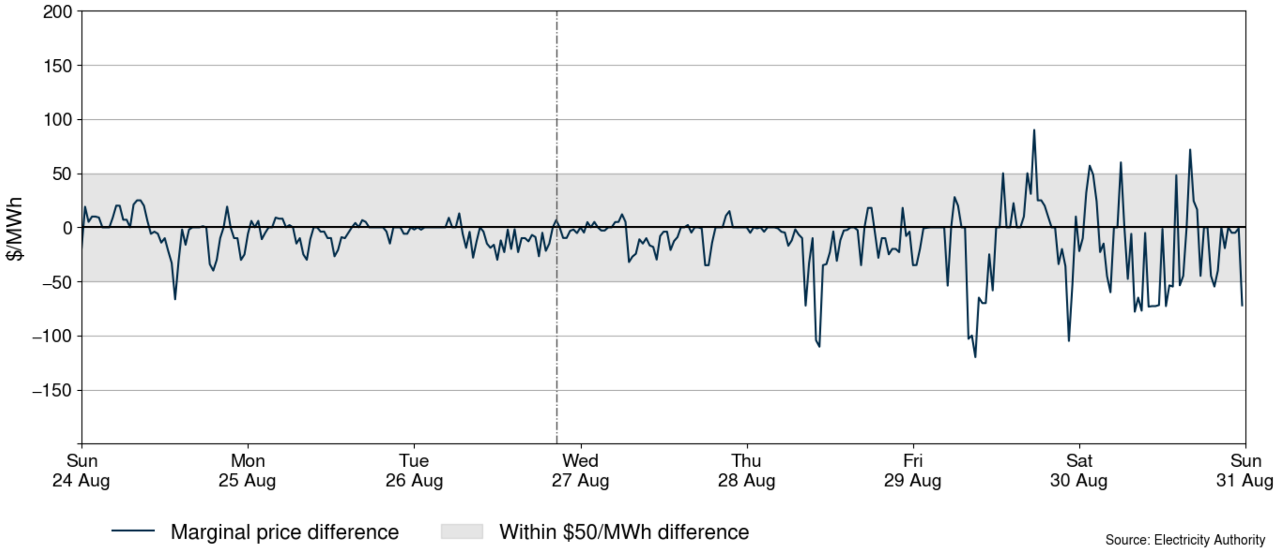
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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

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

signal that forecasting inaccuracies had a large impact on the final price for that trading period.

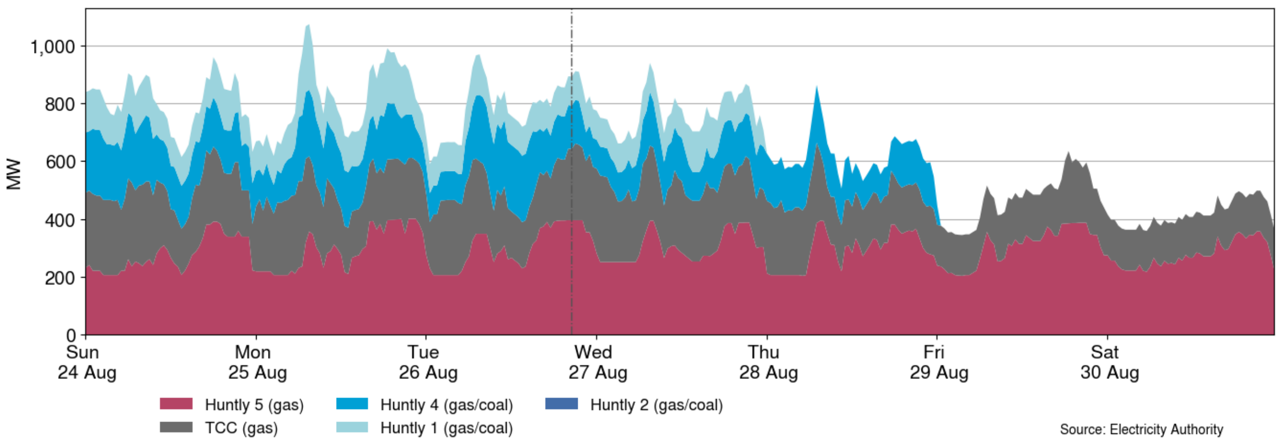
7.5. The volatility in the real versus simulated prices was low at the start of the week when wind generation was low, but increased in magnitude once wind generation increase from Thursday onwards. The largest differences show the real prices being lower than the simulation, likely due to wind being higher than expected.

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, 24-30 August 2025



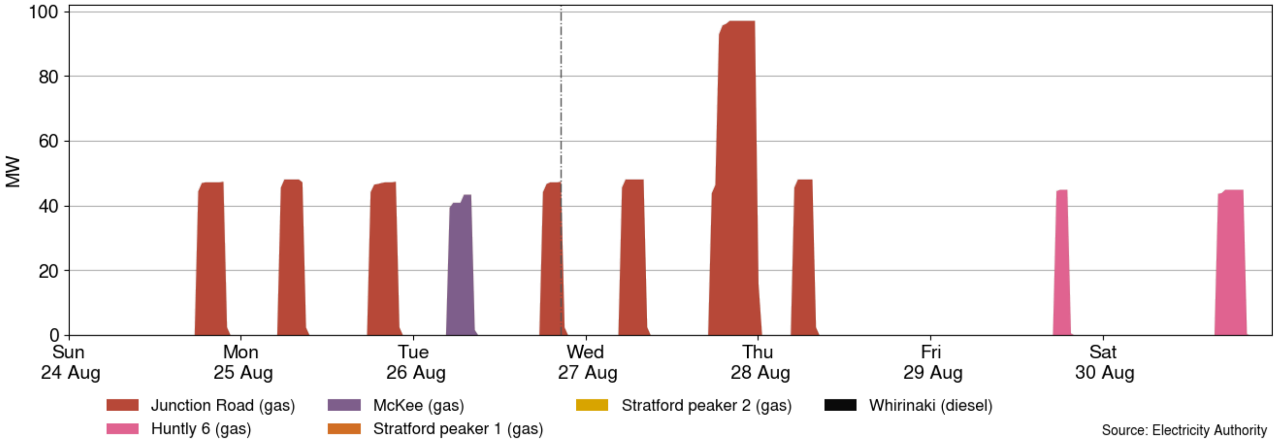
7.6. Figure 12 shows the generation of thermal baseload between 24-30 August 2025. Huntly 5 and TCC ran as baseload this week. Huntly 4 ran from Sunday to Thursday, and Huntly 1 ran from Sunday to Wednesday when wind generation was low. No Rankine units ran on Friday and Saturday, due to high wind generation.

Figure 12: Thermal baseload generation, 24-30 August 2025



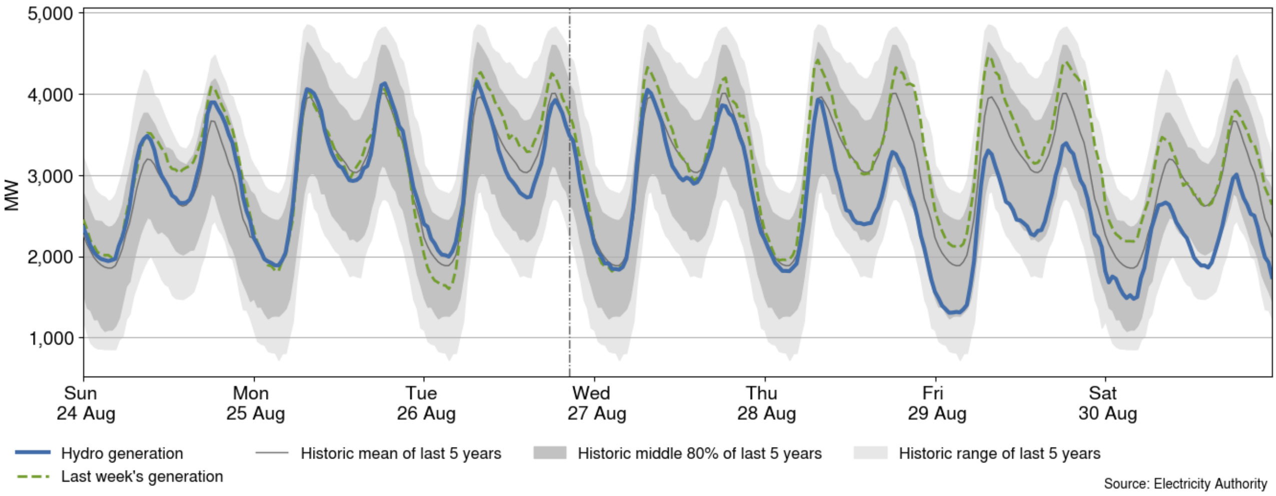
7.7. Figure 13 shows the generation of thermal peaker plants between 24-30 August 2025. Junction Road ran from Sunday to Thursday during peak demand periods. McKee ran on Tuesday during the morning peak. Huntly 6 also generated during the evening peak on both Friday and Saturday.

Figure 13: Thermal peaker generation, 24-30 August 2025



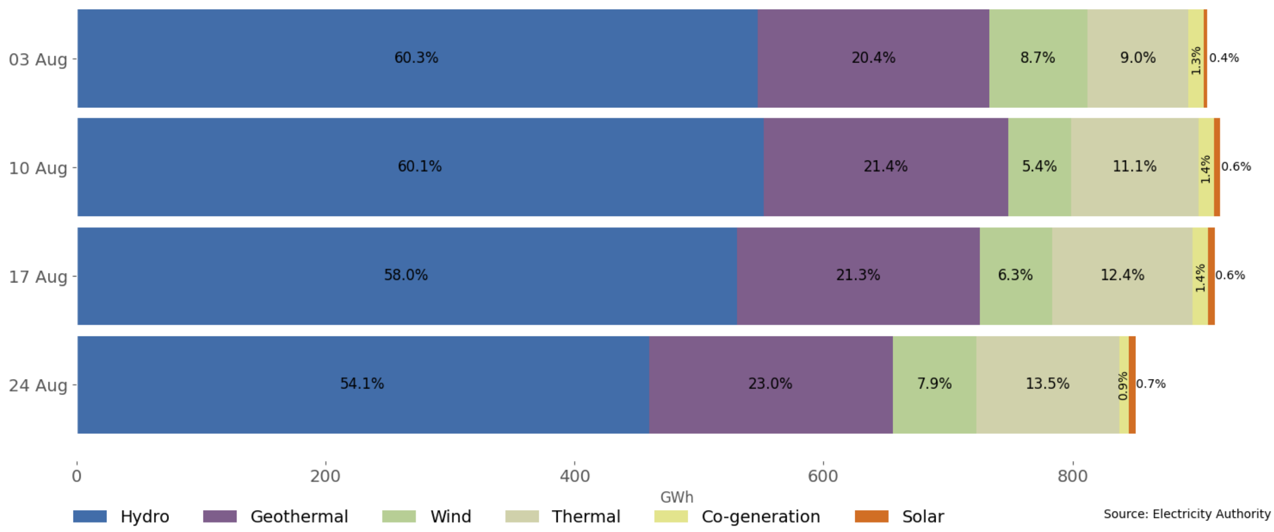
7.8. Figure 14 shows hydro generation between 24-30 August 2025. Hydro generation was around the historic mean from Sunday to Wednesday, as wind was low during those days. From Thursday onwards, hydro generation decreased as wind generation increased significantly.

Figure 14: Hydro generation, 24-30 August 2025



7.9. As a percentage of total generation, between 24-30 August 2025, total weekly hydro generation was 54.1%, geothermal 23.0%, wind 7.9%, thermal 13.5%, co-generation 0.9%, and solar (grid connected) 0.7%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 3-30 August 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 24-30 August 2025 ranged between ~540MW and ~1,239MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 extended outage end date from 31 August to 7 September 2025.

(b) Manapōuri unit 4 is on outage until 12 June 2026.

(c) Roxburgh unit 5 is on outage until 25 February 2026.

Figure 16: Total MW loss from generation outages, 24-30 August 2025

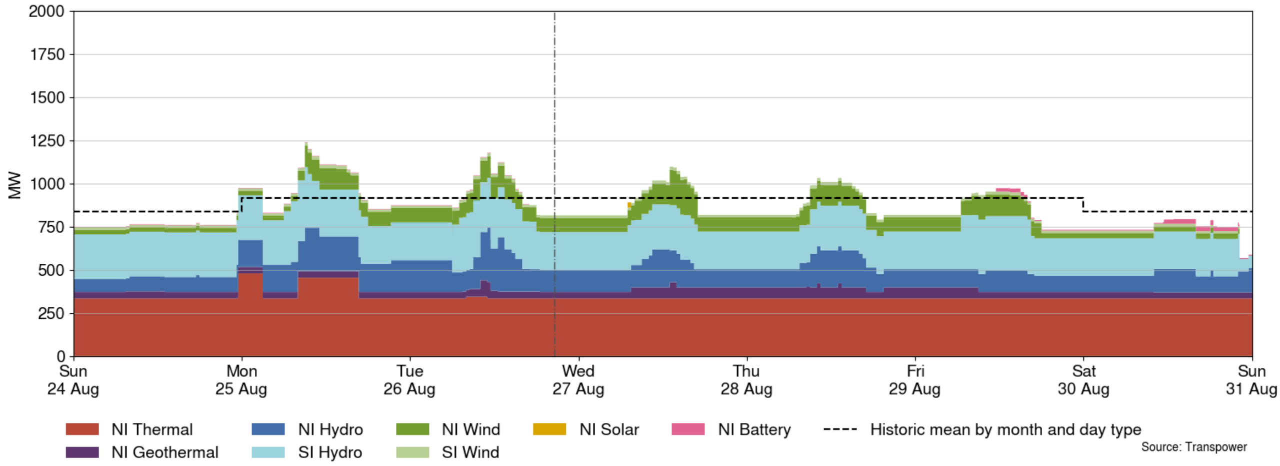
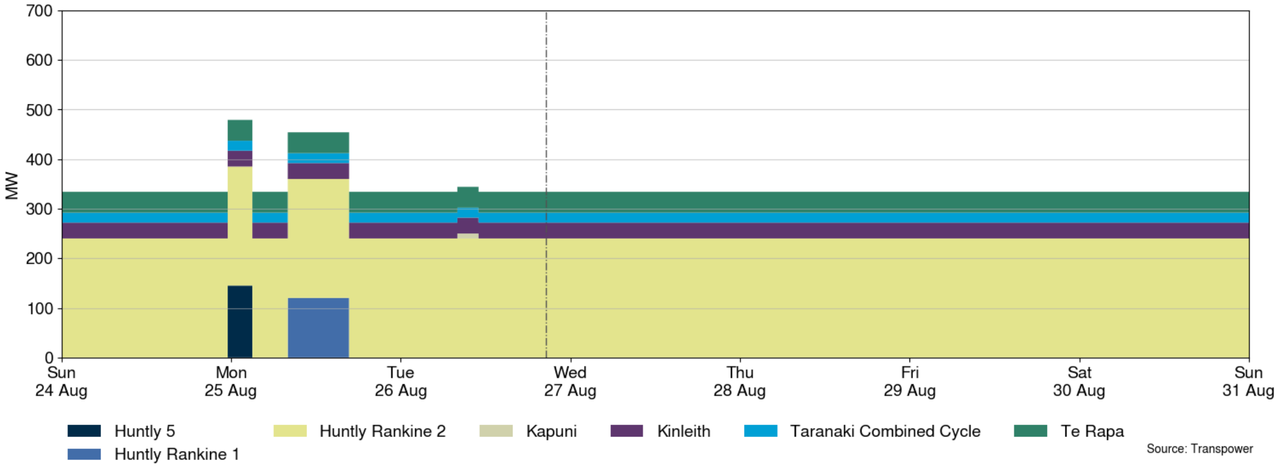


Figure 17: Total MW loss from thermal outages, 24-30 August 2025

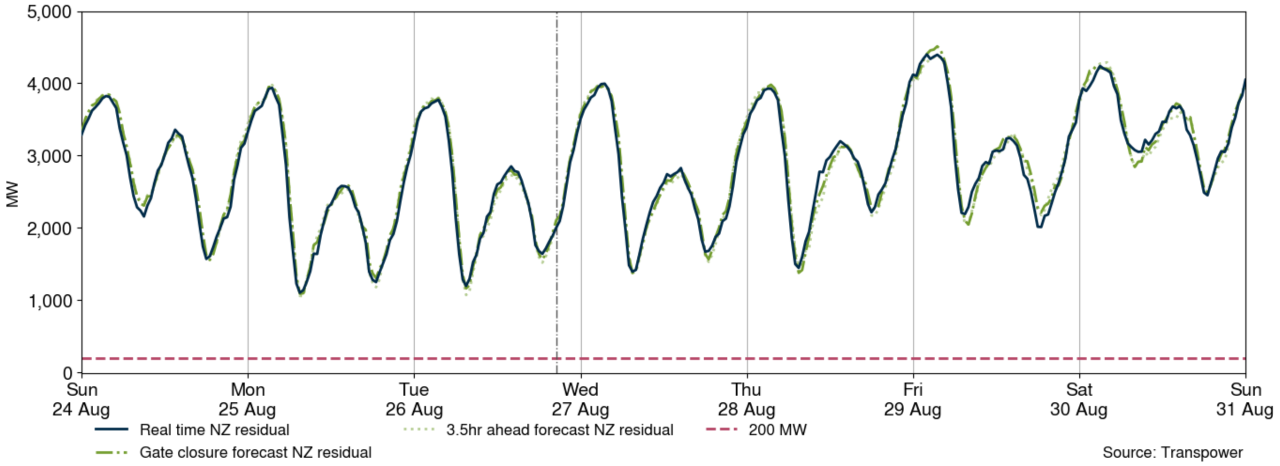


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 24-30 August 2025. 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. Residuals were healthy this week. The lowest national residual was 1105MW on Monday at 7.30am.

Figure 18: National generation balance residuals, 24-30 August 2025



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 10th to 90th percentiles.

10.2. As of 30 August 2025, national controlled hydro storage had decreased to 45% of nominal full and ~77% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (34% full[2]) is touching its historic 10th percentile, while storage at Lake Takapō (27% full) is below its historic 10th percentile.

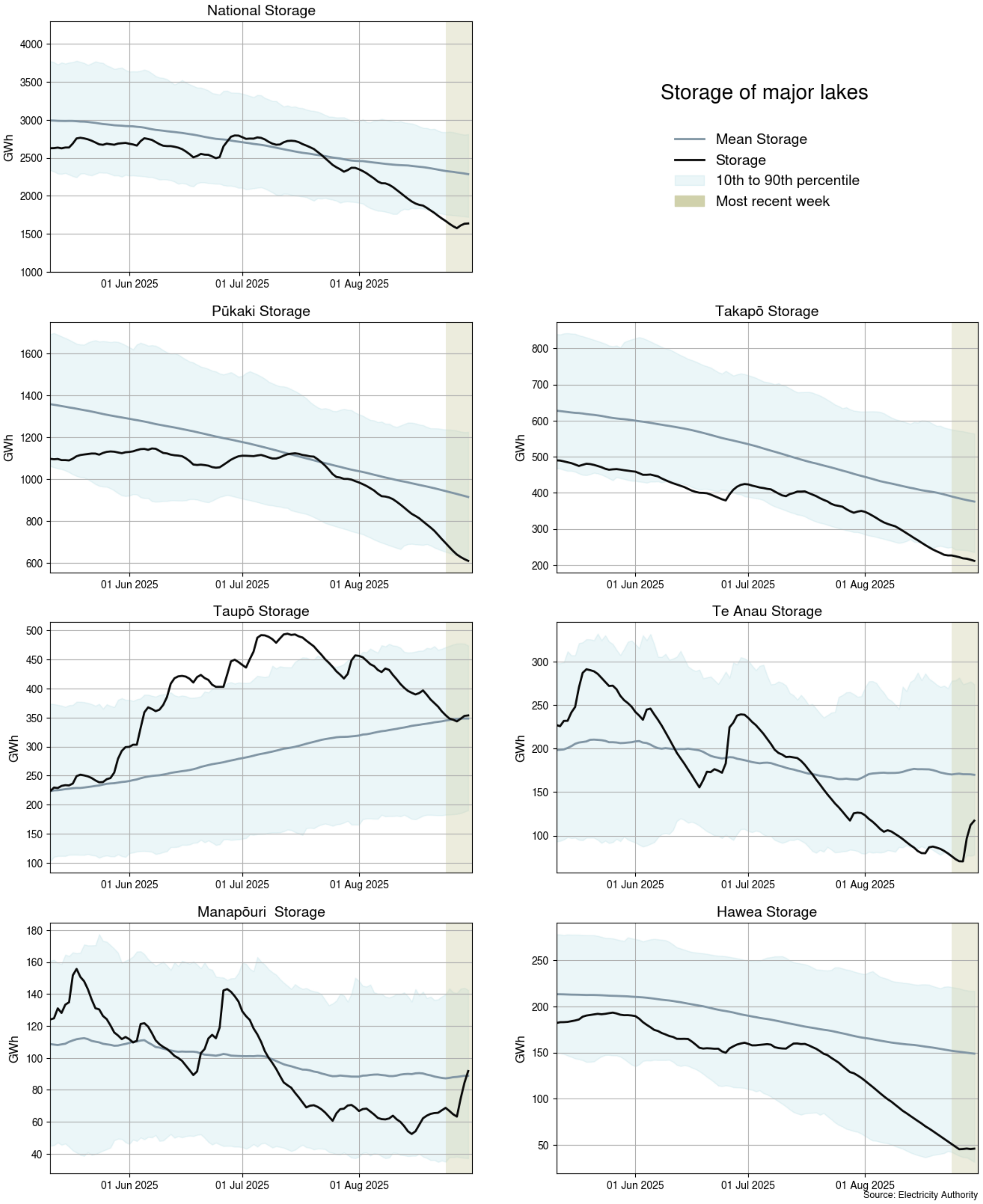
10.4. Storage at Lake Te Anau (45% full) is slightly above its historic 10th percentile, and storage at Lake Manapōuri (62% full) is around its historic mean.

10.5. Storage at Lake Taupō (63% full) is around its historic mean for this time of year.

10.6. Storage at Lake Hawea (16% full) remains close to its historic 10th percentile.

[2] Percentage full values sourced from NZX hydrological summary 31 August 2025.

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 August 2025. The SRMCs for gas powered generation have increased, while the SRMC for diesel fuelled generation has remained stable.

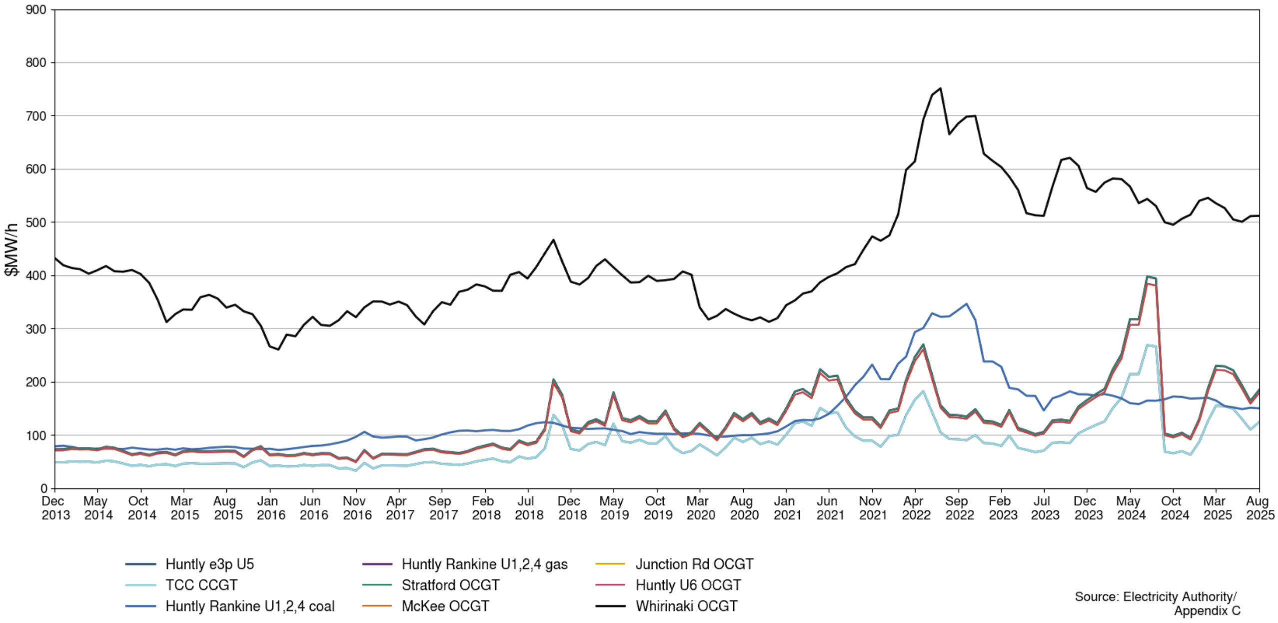
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$184/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $124/MWh and $184/MWh.

11.6. The SRMC of Whirinaki is ~$512/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



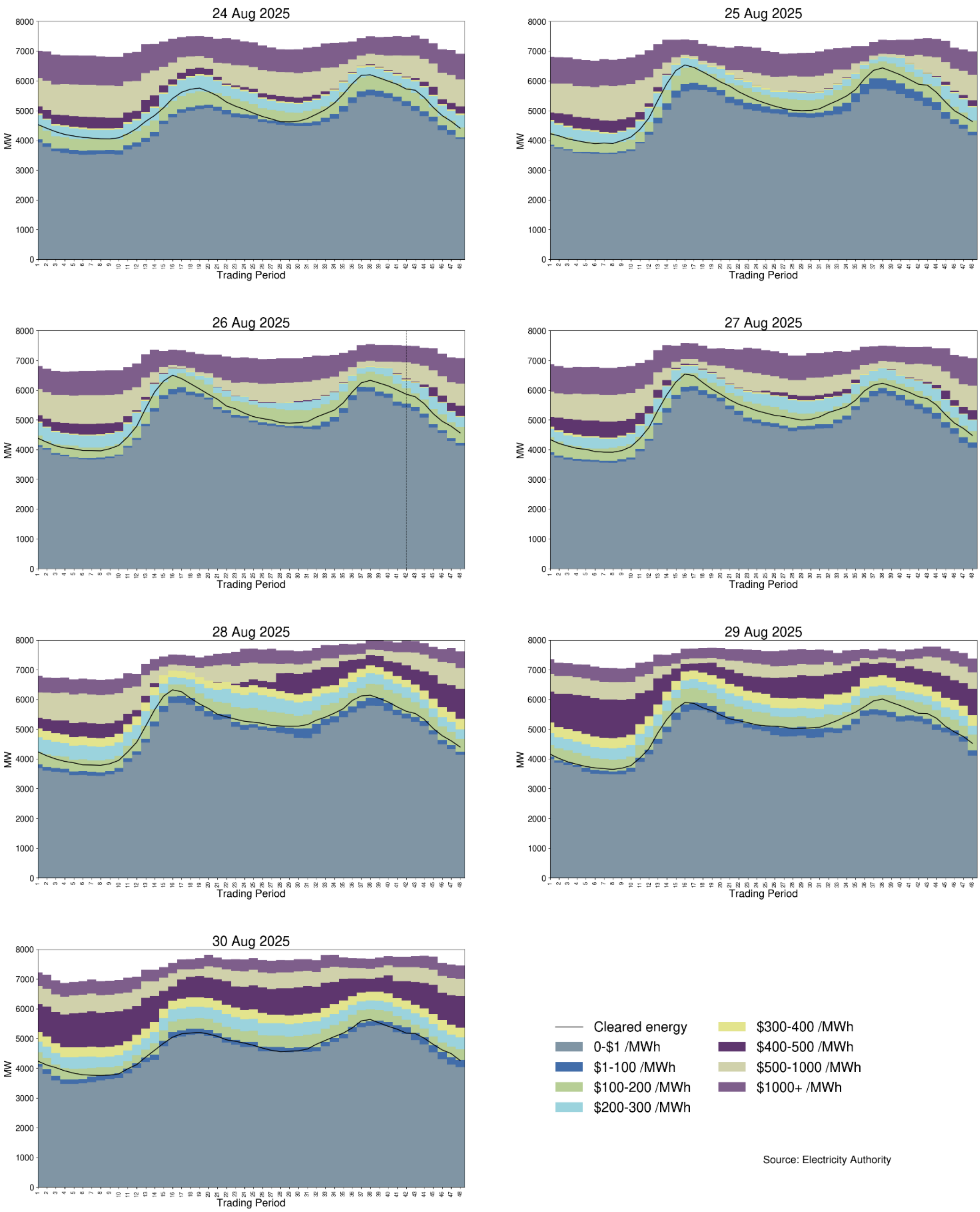
12. Offer behaviour

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. This week most offers cleared in the $100-$300/MWh range. However, on Friday and Saturday, offers cleared in the lower band due to high wind generation.

12.3. Hydro generation was offered into higher priced tranches to signal the increasing value of stored water, due to declining hydro storage. However, from Thursday some hydro offers were priced down to lower bands.

Figure 21: Daily offer stacks

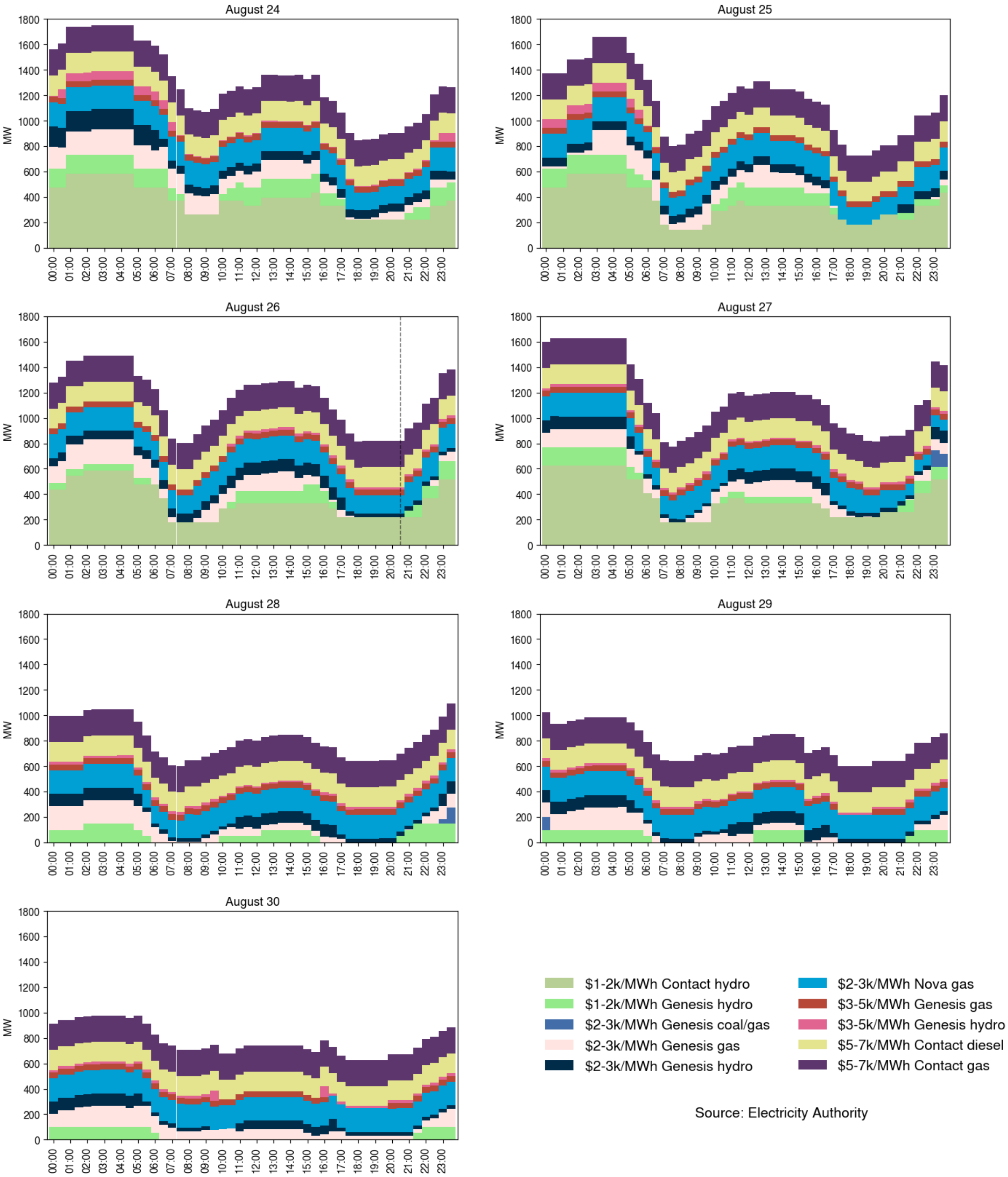


12.4. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 1023MW per trading period was priced above $1,000/MWh this week, which is roughly 15.7% of the total energy available. The amount of high priced generation decreased from Thursday onwards as Contact hydro offers were priced down.

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
22/09/2023-30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact	Clutha scheme	Hydro offers
8/05/2025-9/05/2025	Several	Further analysis	Genesis	Waikaremoana	Offers
1/08/2025-9/08/2025	Several	Further analysis	Mercury	Waikato	Hydro offers