11 August 2025

Trading conduct report
3-9 August 2025

Market monitoring weekly report

Trading conduct report 3-9 August 2025

1. Overview

1.1. The average price increased by $35/MWh this week to $154/MWh. Demand increased due to colder temperatures. Thermal generation increased to meet the demand. National hydro storage declined to ~ 56% nominally full and around 91% of the historical average.

2. Spot prices

2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.

2.2. Between 3-9 August 2025:

(a) The average spot price for the week was $154/MWh, an increase of around $35/MWh compared to the previous week.

(b) 95% of prices fell between $133/MWh and $173/MWh.

2.3. Spot prices were mostly under $200/MWh with a few price spikes.

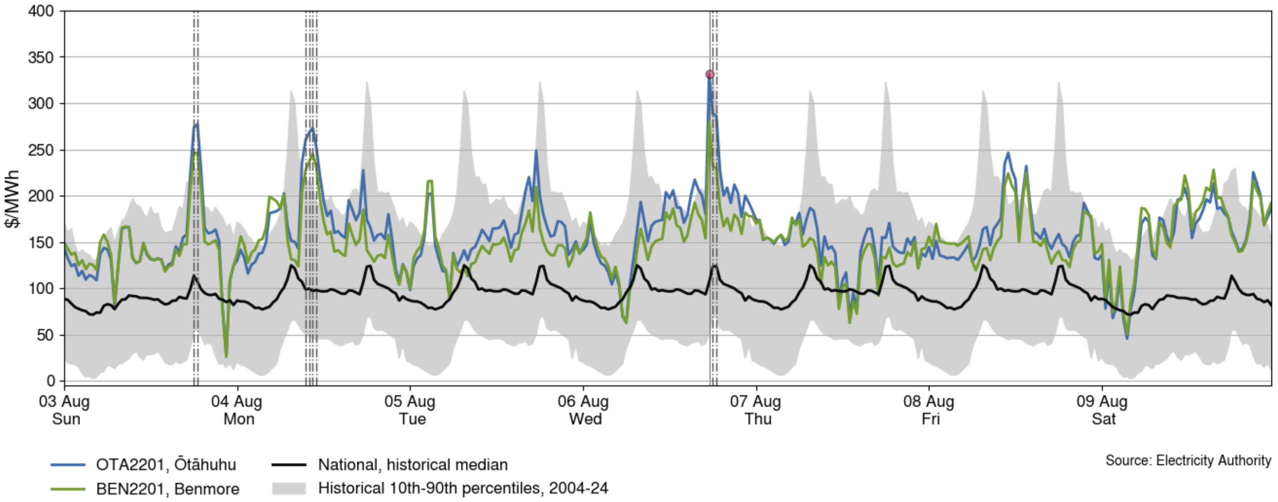
2.4. On Sunday, during the evening peak (6.00pm-6.30pm), prices reached up to $277/MWh at Ōtāhuhu and $246/MWh at Benmore. During these times, national demand was 123MW-162MW higher than forecast.

2.5. Another price spike occurred on Monday between 9.30am-11.30am, with prices ranging from $252-$273/MWh at Ōtāhuhu and $227-$245/MWh at Benmore. Demand was higher than forecast by 116MW-204MW, and wind was 24MW-97MW lower than forecast.

2.6. The highest price of the week occurred during the evening peak on Wednesday between 5.30pm-6.30pm, with a maximum of ~$332/MWh at Ōtāhuhu and ~$280/MWh at Benmore. During these times, demand was higher than forecast by 35MW-65MW. Demand was also high (3.3GWh at 6.00pm). Wind was also up to 100MW underforecast.

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 above $250/MWh are marked with black dashed lines.

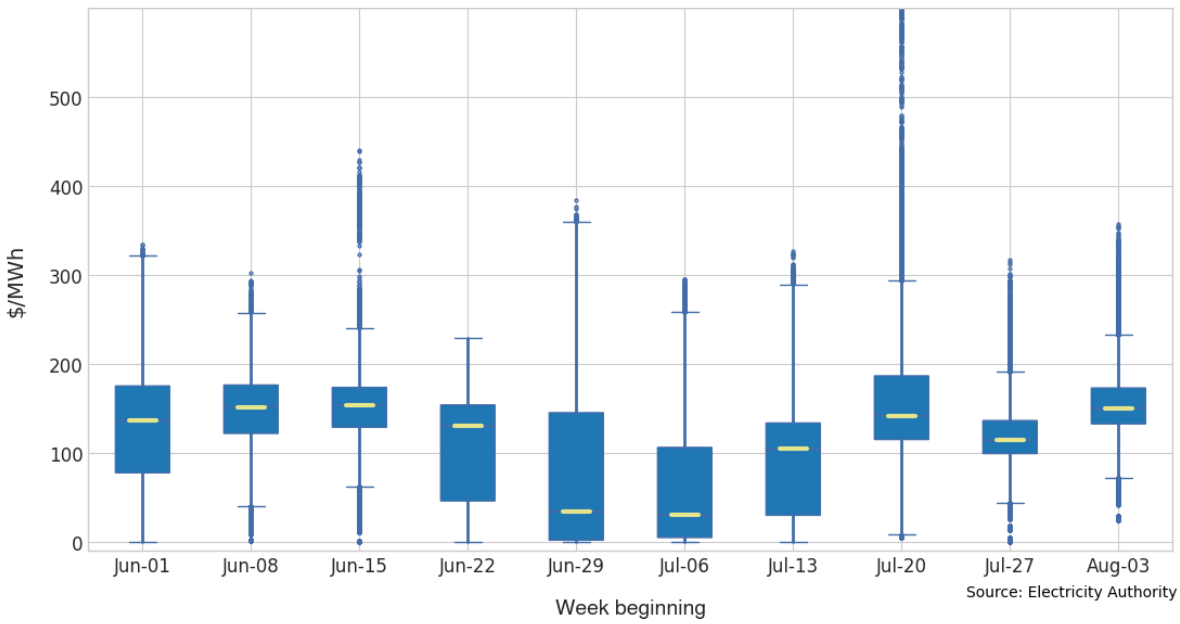
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 3-9 August 2025



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 similar to last week, with no significant high-priced outliers but high median prices. The median price was $151/MWh and most prices (middle 50%) fell between $133/MWh and $173/MWh.

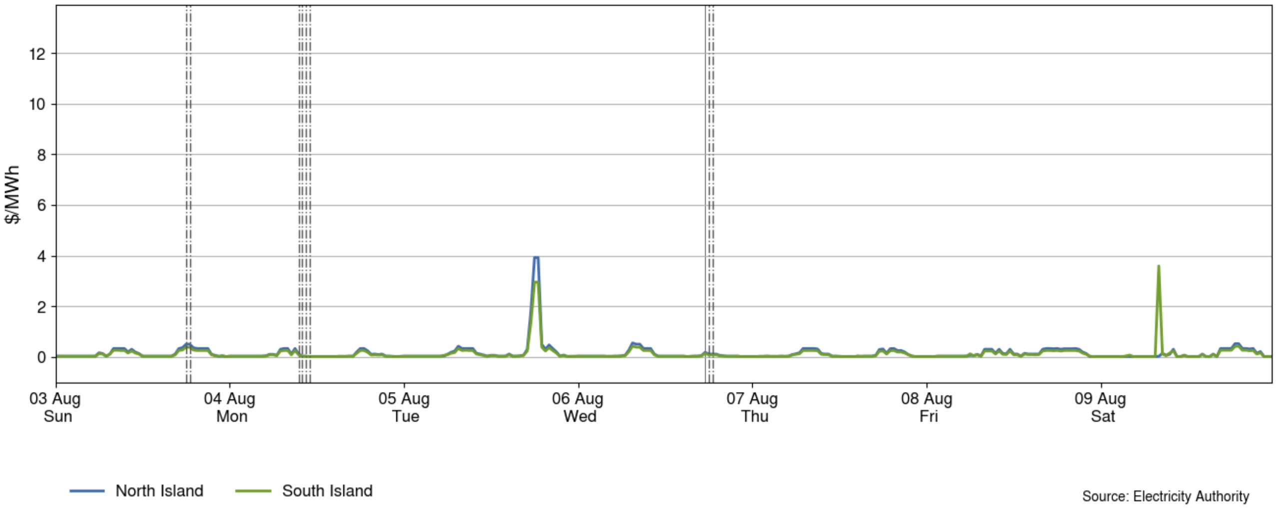
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week, FIR prices across both the North and South Island were below $5/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 3-9 August 2025

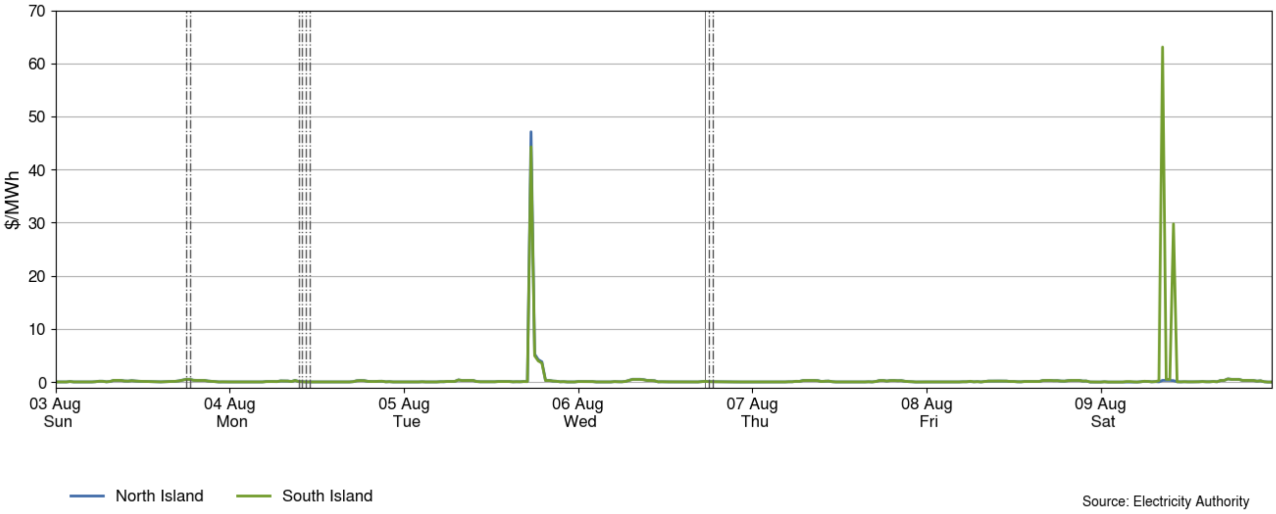


3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh with price spikes on Tuesday, and Saturday.

3.3. A SIR price spike occurred on Tuesday at 5.30pm, with prices reaching around $47/MWh in the North Island and $44/MWh in the South Island., At that time, Huntly 5 was the risk setter, and its generation increased, requiring more reserves to be cleared to cover the risk.

3.4. On Saturday, South Island SIR prices spiked to $63/MWh (North Island SIR prices ~$0.32/MWh), when the HVDC was flowing North and round power was disabled[1].

Figure 4: Sustained instantaneous reserve by trading period and island, 3-9 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

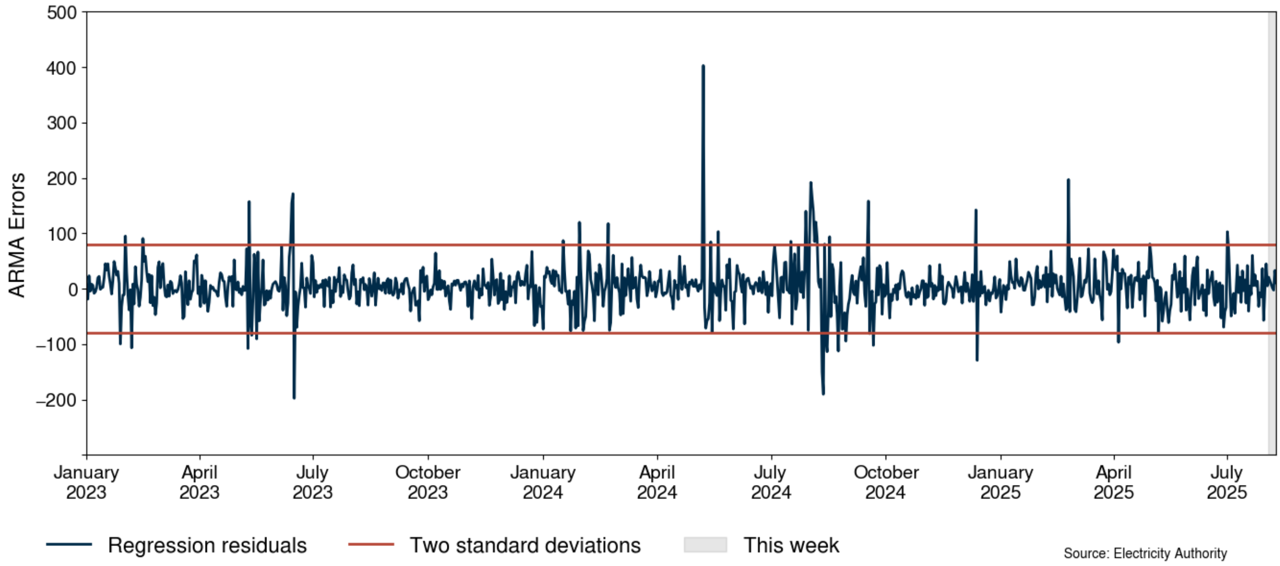
[1] Which limited the reserve available in the South Island. Frequency keeping control and roundpower information | Transpower

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.

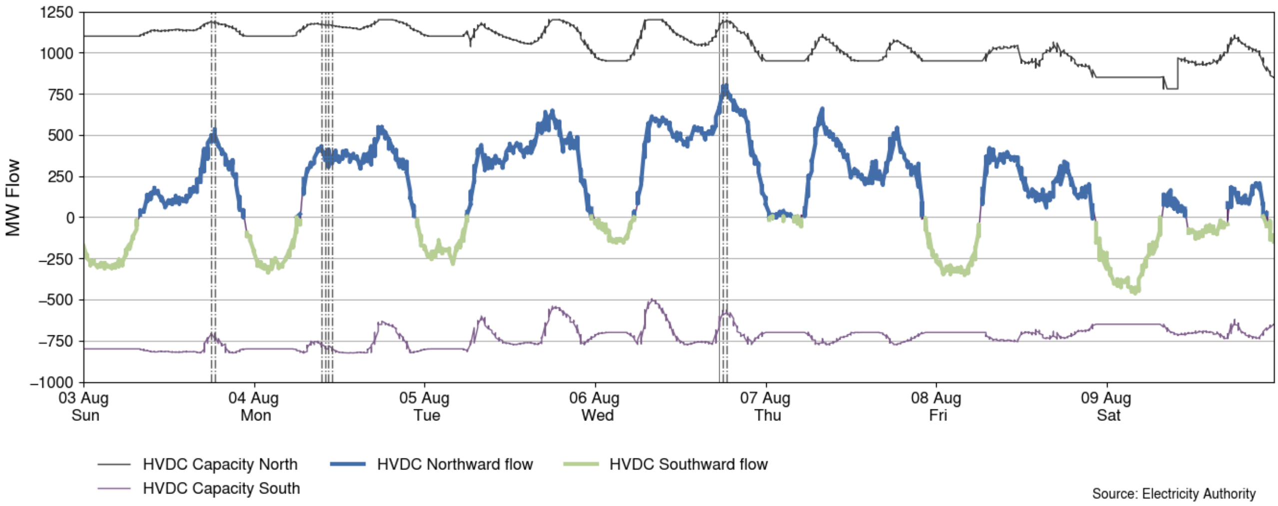
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 9 August 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 3-9 August 2025. HVDC flows were mostly northward during the day and southward overnight. On Thursday, southward flow was minimal due to low wind generation. However, on Saturday, flow was southward during the day as wind was mostly above 550MW. Northward flows reached around 800MW on Wednesday at 6.30pm during the price spikes.

Figure 6: HVDC flow and capacity, 3-9 August 2025

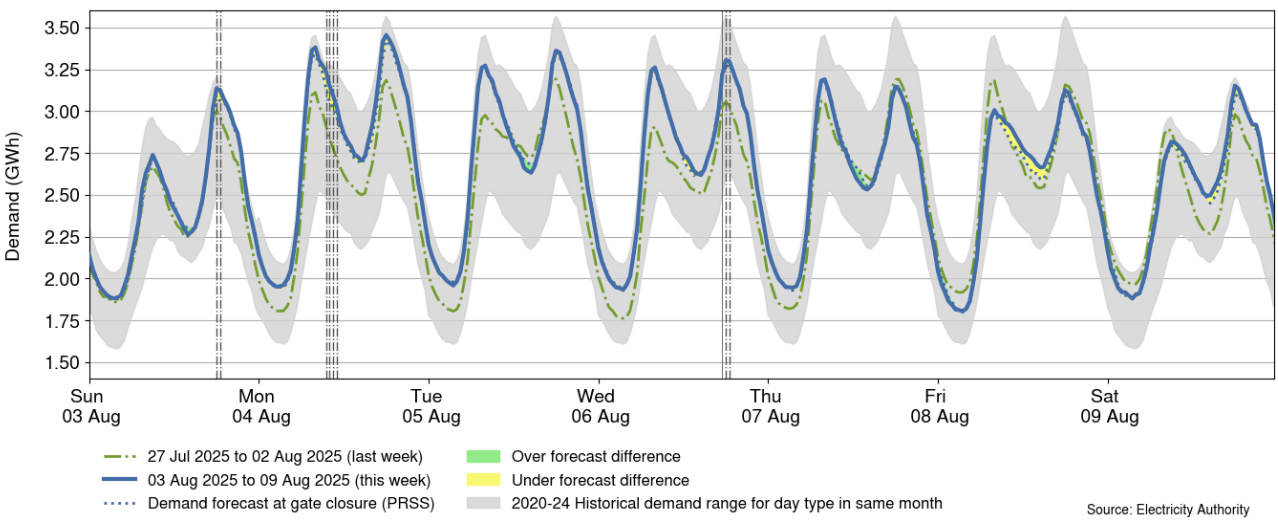


6. Demand

6.1. Figure 7 shows national demand between 3-9 August 2025, compared to the historic range and the demand of the previous week. Demand was consistently underforecast on Monday mid-morning and Friday post-peak to early afternoon.

6.2. Overall, demand was high this week compared to the previous week due to relatively low temperatures. The highest demand of the week was 3.45GWh at 6.00pm on Monday.

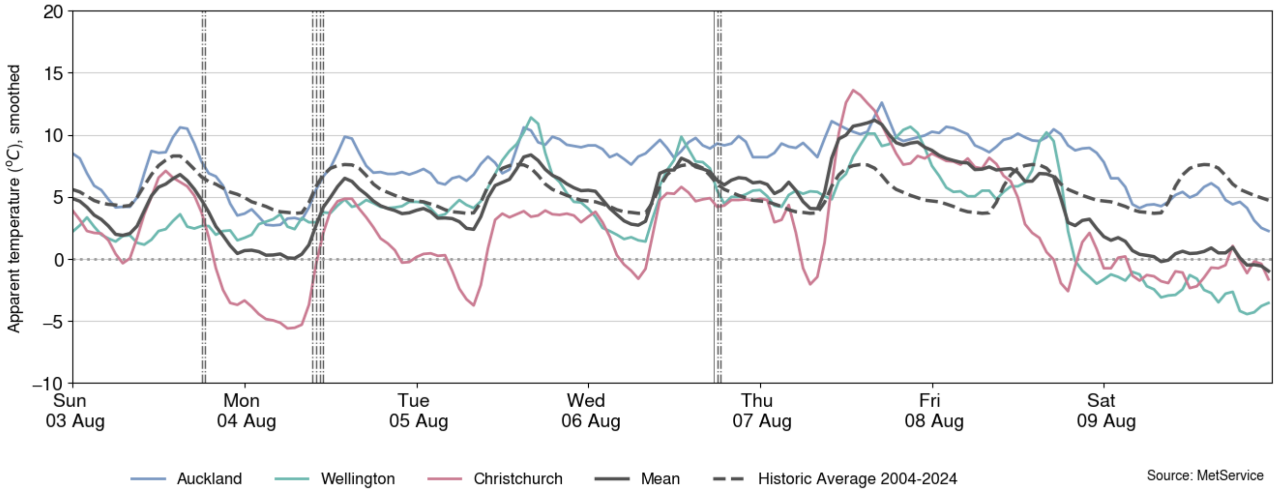
Figure 7: National demand, 3-9 August 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 3-9 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.

6.4. Apparent temperatures ranged from 2°C to 13°C in Auckland, -4°C to 12°C in Wellington, and -6°C to 14°C in Christchurch. Christchurch experienced freezing mornings most of the week.

Figure 8: Temperatures across main centres, 3-9 August 2025



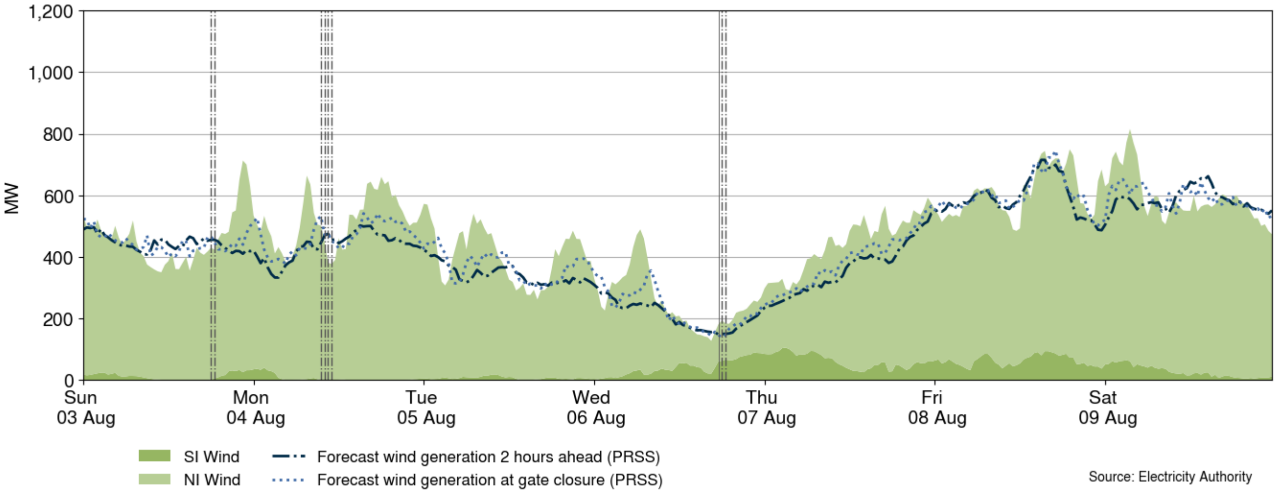
7. Generation

7.1. Figure 9 shows wind generation and forecast from 3-9 August 2025. This week wind generation varied between 127MW and 816MW, with a weekly average of 468MW.

7.2. Wind generation was relatively steady around 400-500MW at the start of the week, with a few peaks, followed by a sharp dip on Wednesday to near the weekly minimum.

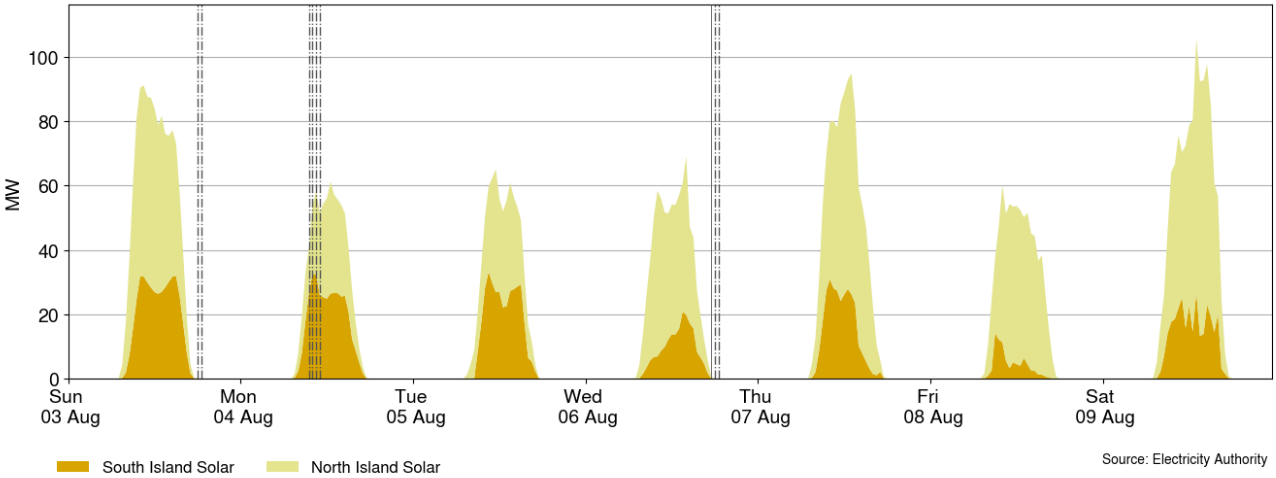
7.3. From Thursday onwards, wind steadily increased, reaching higher sustained levels between Friday and Saturday. There was up to 100MW error in wind forecasting during the Monday morning price spike.

Figure 9: Wind generation and forecast, 3-9 August 2025



7.4. Figure 10 shows grid connected solar generation from 3-9 August 2025. Solar generation typically peaked above 50MW, with a maximum of 106MW at 1.30pm on Saturday.

Figure 10: Grid connected solar generation, 3-9 August 2025

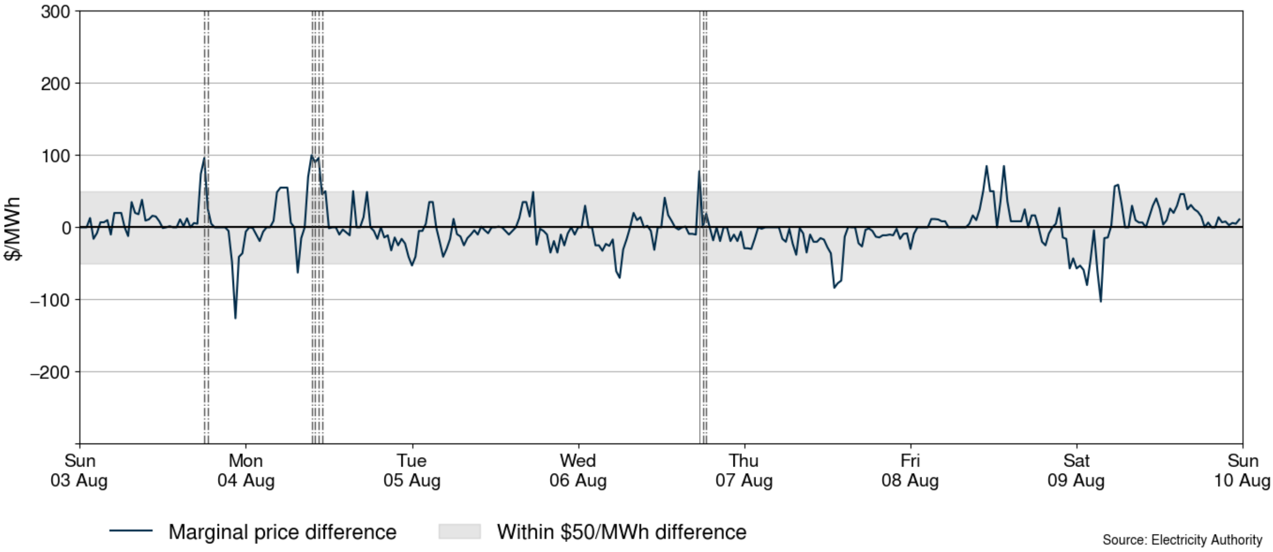


7.5. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

7.6. A few trading periods this week had positive marginal price differences above $50/MWh which were driven by wind and demand forecasting errors. The largest positive price difference of +$100/MWh occurred during the price spike at 9.30am on Monday, when demand was 204MW, and wind was 31MW lower than forecast.

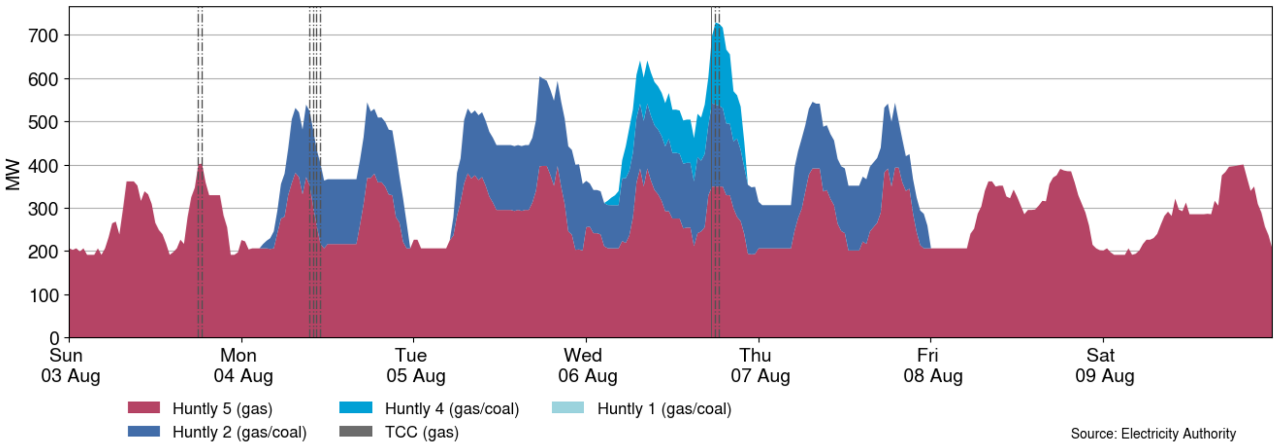
[2] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 3-9 August 2025



7.7. Figure 12 shows the generation of thermal baseload between 3-9 August 2025. Huntly 5 ran as baseload this week. Huntly 2 ran from Monday to Thursday, except on Tuesday night. Huntly 4 ran on Wednesday when wind generation was low and Tauhara was on outage.

Figure 12: Thermal baseload generation, 3-9 August 2025

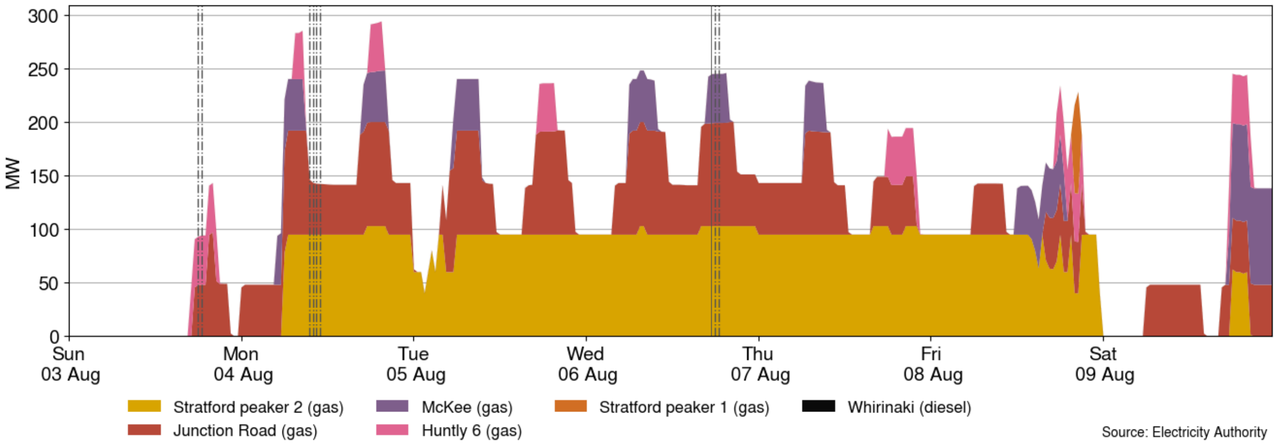


7.8. Figure 13 shows the generation of thermal peaker plants between 3-9 August 2025. Stratford Peaker 2 generated continuously from Monday to Friday, and on Saturday during the evening peak period. Junction Road ran daily this week.

7.9. McKee ran from Monday to Saturday during peak demand periods. Huntly 6 ran on Monday during the morning and evening peaks, on Tuesday during the evening peak, and from Thursday to Saturday during the evening peak.

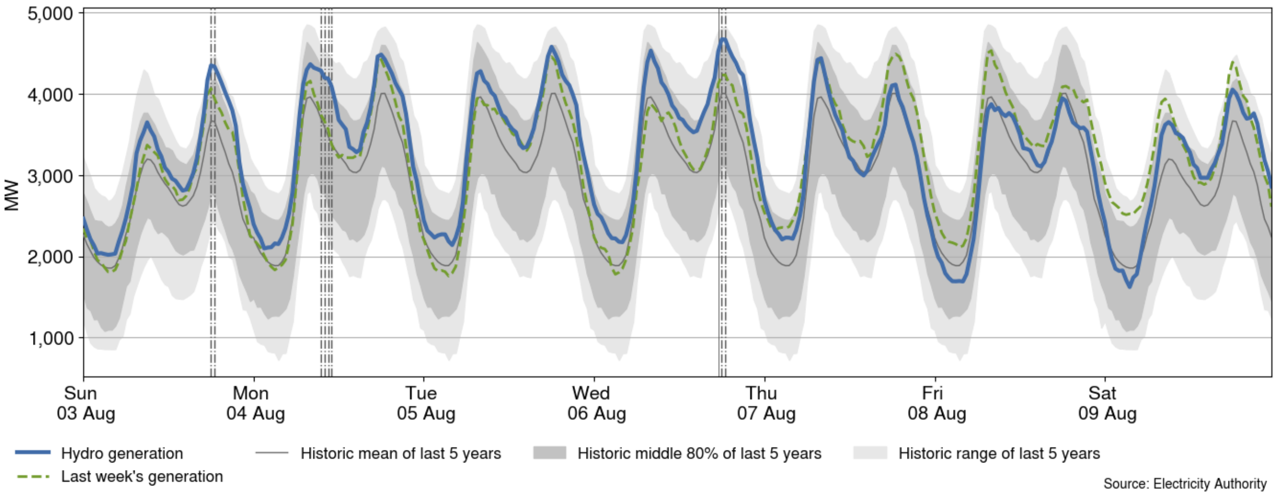
7.10. Stratford Peaker 1 ran briefly on Friday during the evening peak following its outage.

Figure 13: Thermal peaker generation, 3-9 August 2025



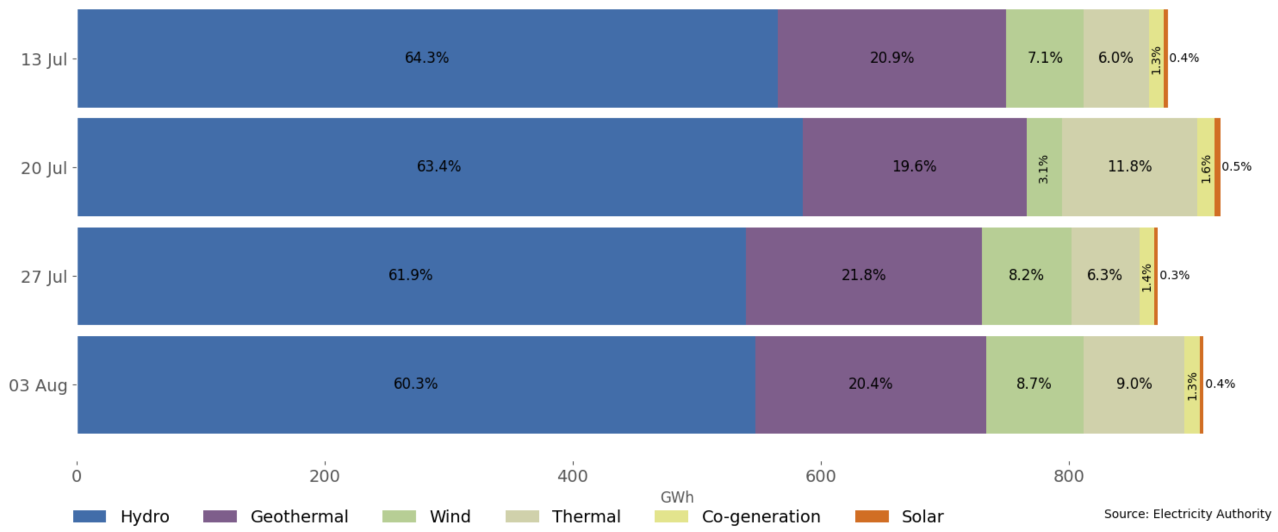
7.11. Figure 14 shows hydro generation between 3-9 August 2025. Overall, hydro generation was higher than the historic mean. During the times of high demand, hydro generation increased to meet elevated demand.

Figure 14: Hydro generation, 3-9 August 2025



7.12. As a percentage of total generation, between 3-9 August 2025, total weekly hydro generation was 60.3%, geothermal 20.4%, wind 8.7%, thermal 9.0%, co-generation 1.3%, and solar (grid connected) 0.4%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 13 July – 9 August 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 3-9 August 2025 ranged between ~474MW and ~1,373MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford peaker 1 was on outage until 9 August 2025.

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

(c) Manapōuri unit 1 was on outage between 5-6 August 2025.

(d) Tauhara geothermal was on outage between 5-7 August 2025.

Figure 16: Total MW loss from generation outages, 3-9 August 2025

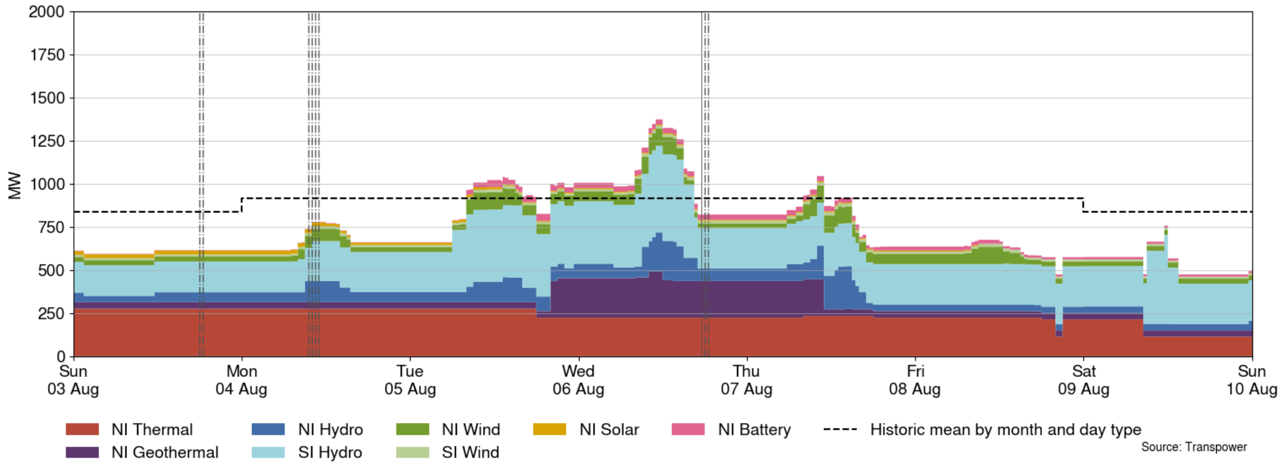
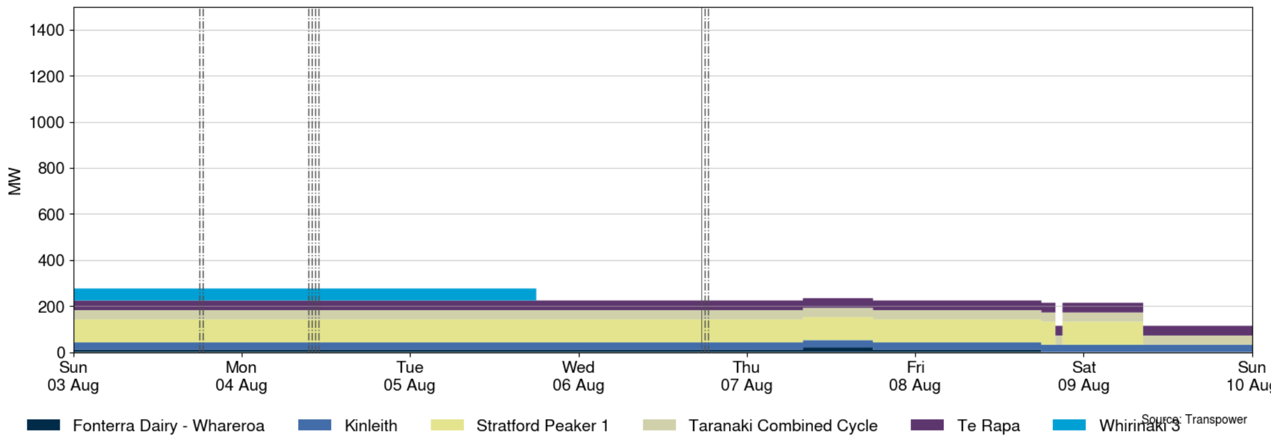


Figure 17: Total MW loss from thermal outages, 3-9 August 2025

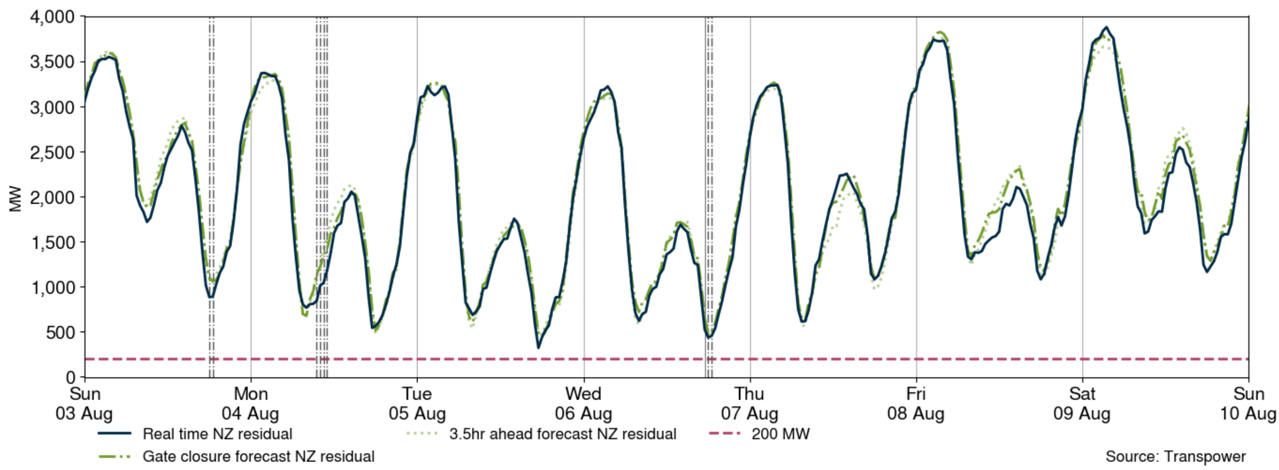


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 3-9 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 320MW on Tuesday at 5.30pm.

Figure 18: National generation balance residuals, 3-9 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 9 August 2025, national controlled hydro storage had decreased to 56% of nominal full and ~91% of the historical average for this time of the year.

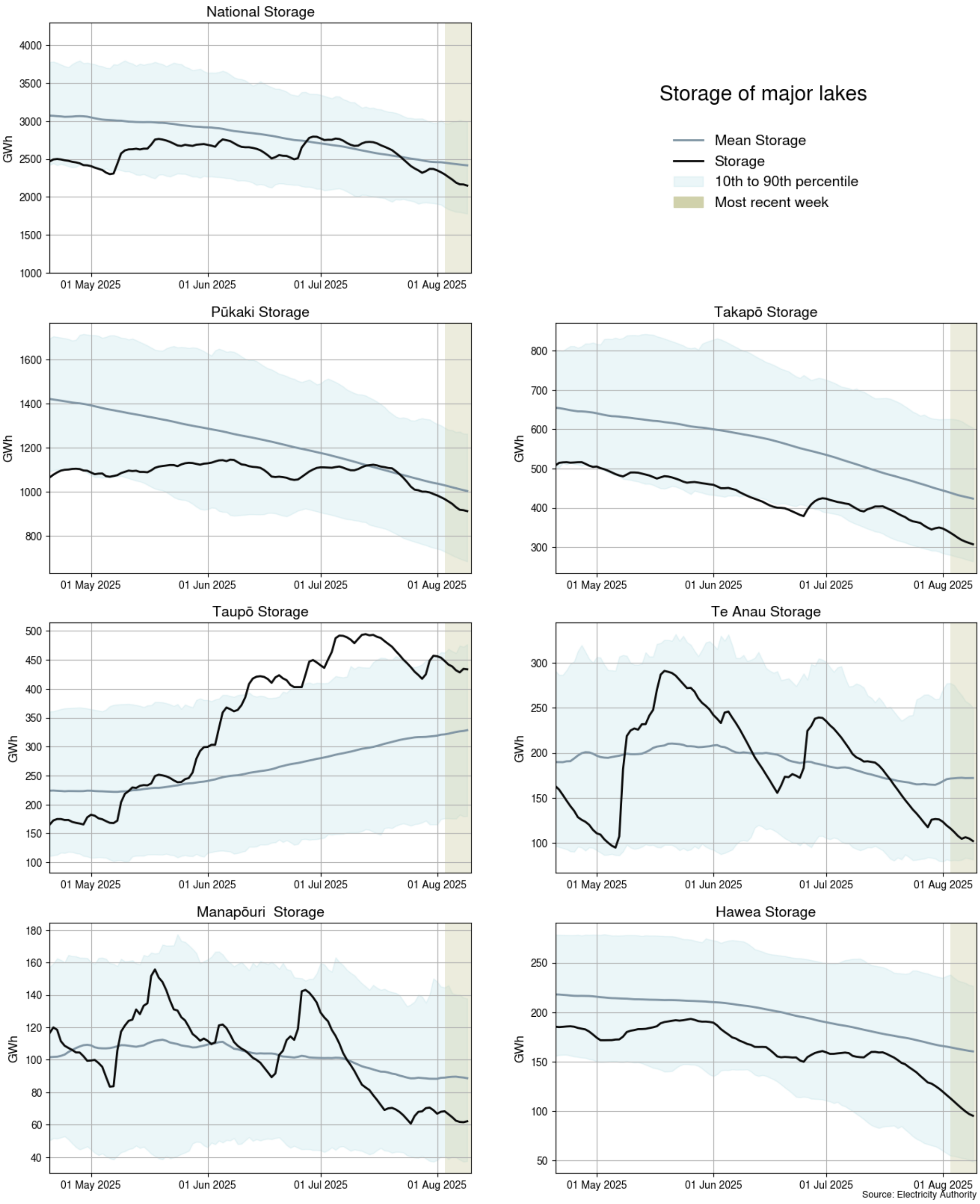
10.3. Storage at Lake Pūkaki (50% full[3]) is below its historical average, and storage at Lake Takapō (36% full) is between its historic mean and 10th percentile.

10.4. Storage at Lake Te Anau (37% full) and Lake Manapōuri (41% full) is currently below their respective historical mean.

10.5. Storage at Lake Taupō (78% full) is touching its historical 90th percentile.

10.6. Storage at Lake Hawea (32% full) remains between its historical 10th percentile and mean.

Figure 19: Hydro storage



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[3] Percentage full values sourced from NZX hydrological summary 10 August 2025.

Prices versus estimated costs

10.7. 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).

10.8. 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.

10.9. 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.

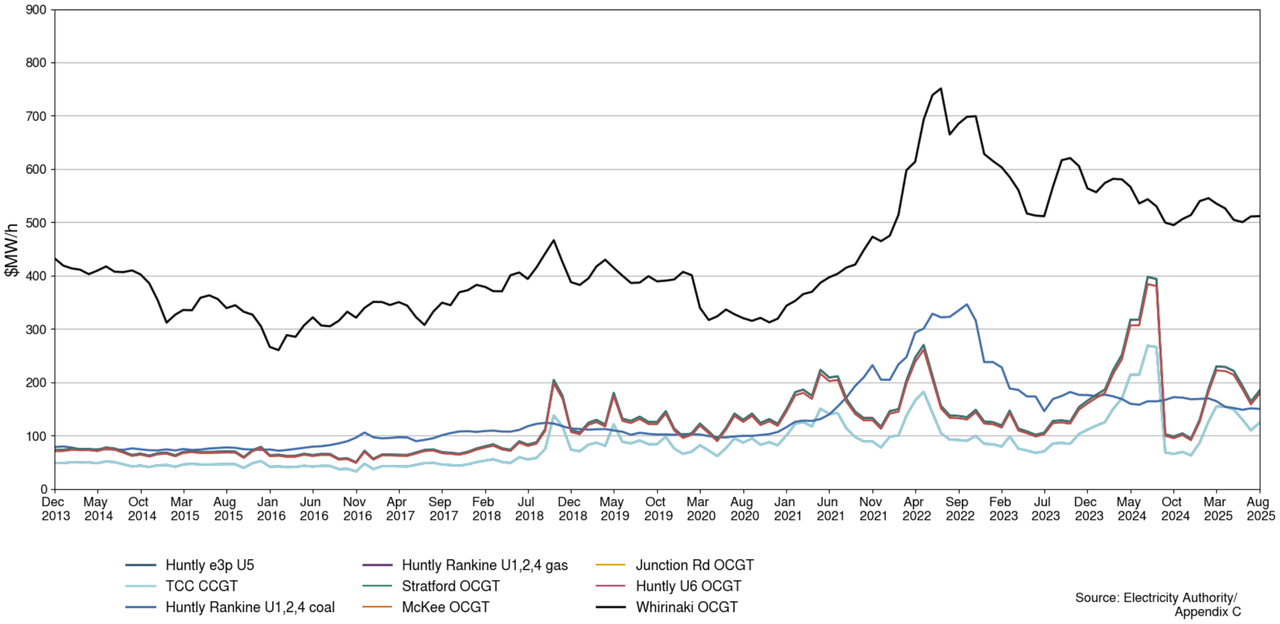
10.10. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$184/MWh.

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

10.12. The SRMC of Whirinaki is ~$512/MWh.

10.13. 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

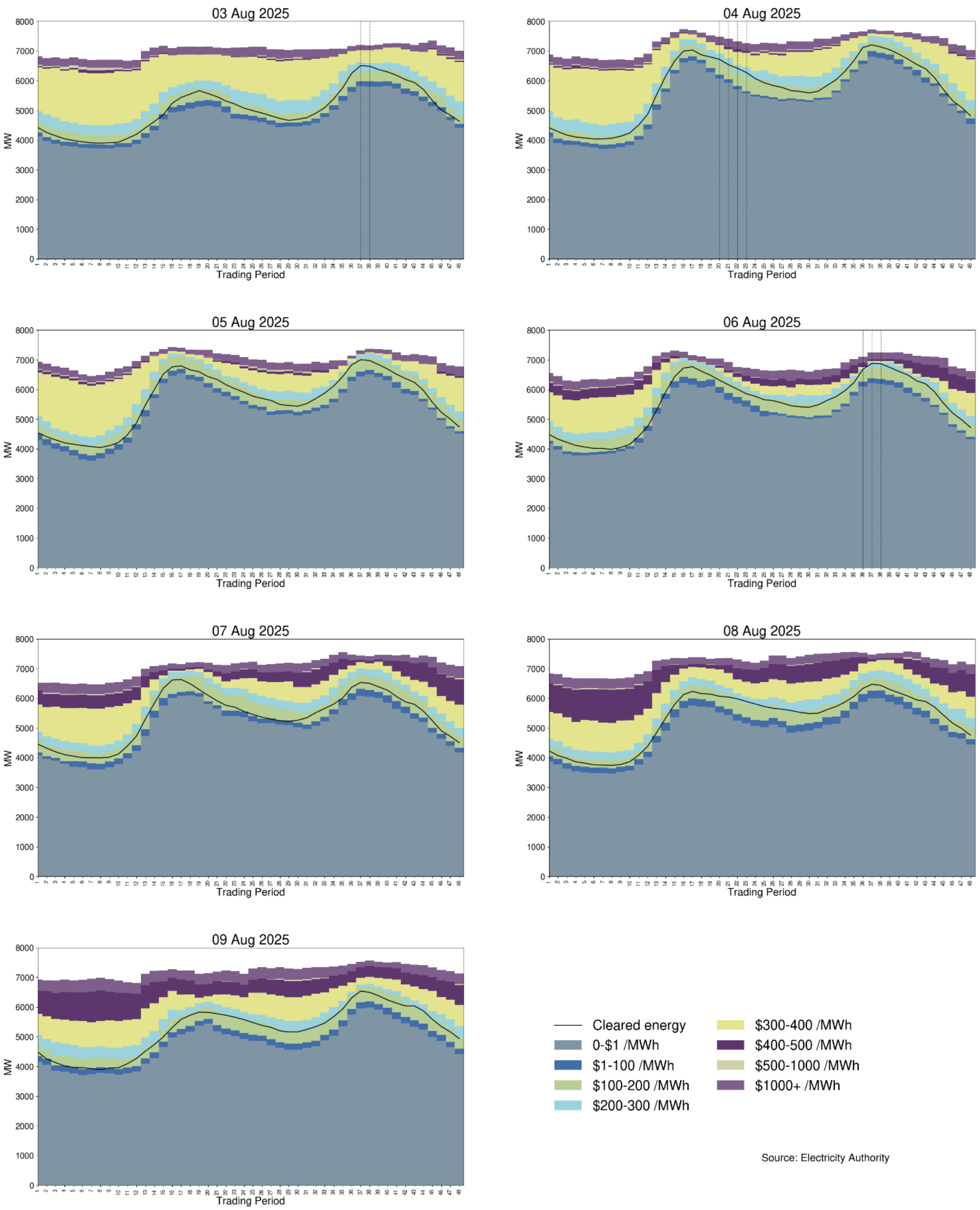


11. Offer behaviour

11.1. Figure 21 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

11.2. This week most offers cleared in the $100-$200/MWh range. During a few trading periods, high demand, demand forecast inaccuracies, and low wind generation contributed to cleared energy shifting into higher price bands. A significant amount of generation was shifted into the $400-500/MWh band this week. The monitoring team is looking further into these changes.

Figure 21: Daily offer stacks



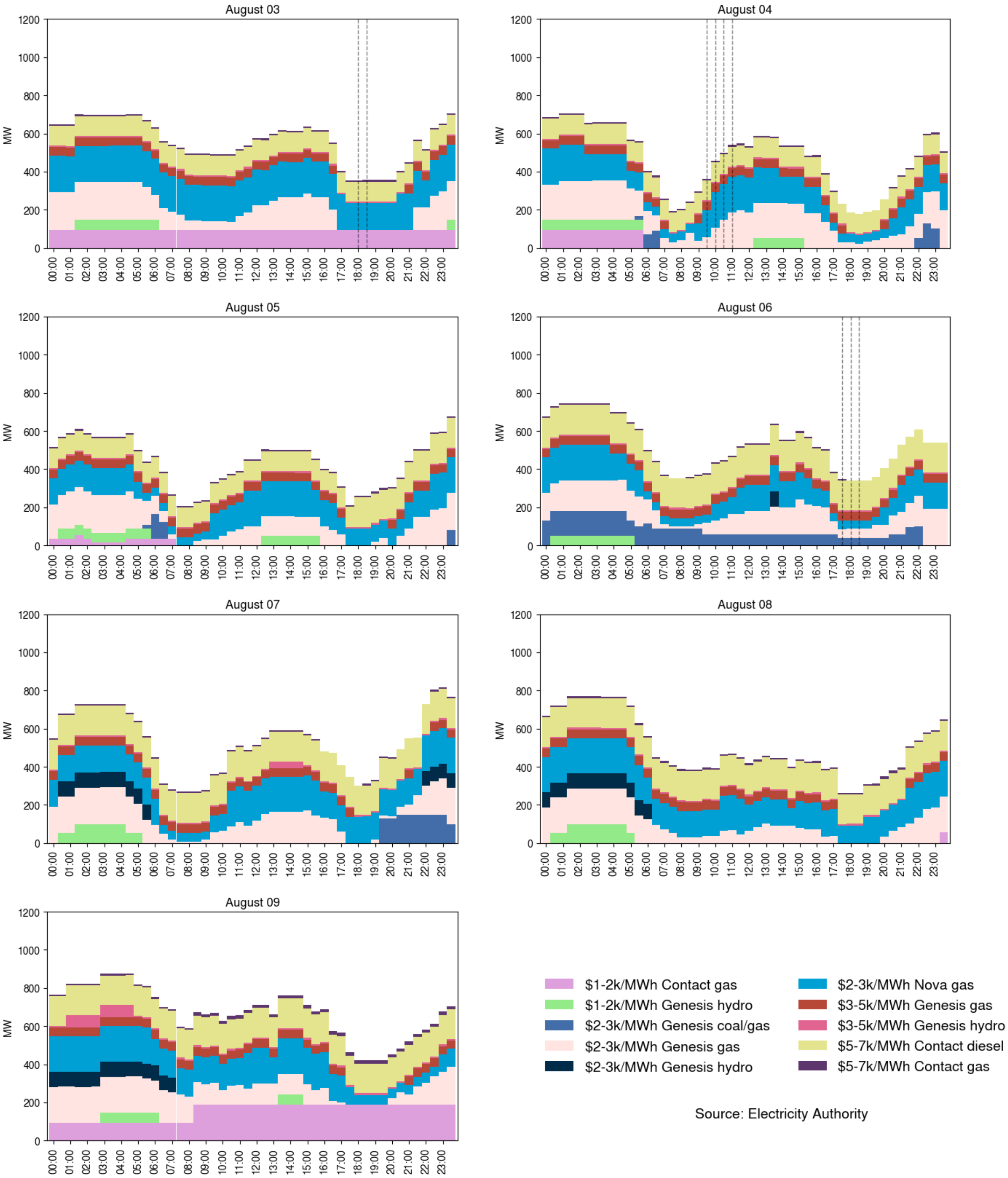
Source: Electricity Authority

11.3. 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.

11.4. 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, wind generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

11.5. On average 528MW per trading period was priced above $1,000/MWh this week, which is roughly 8.8% of the total energy available.

Figure 22: High priced offers



Source: Electricity Authority

12. Ongoing work in trading conduct

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

12.2. 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