14 July 2025

Trading conduct report 6-12 July 2025

Market monitoring weekly report

Trading conduct report 6-12 July 2025

1. Overview

1.1. The average price decreased by $20/MWh this week to $56/MWh. National hydro storage remains stable at ~67% nominally full and ~101% of the historical average. A few high prices were observed on Wednesday, mainly due to the wind and demand forecast errors. On Friday, at 1.00pm the HVDC tripped[1], resulting in a price spike of $1,001/MWh at Ōtāhuhu, as the HVDC flow was northward at that time.

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 6-12 July 2025:

(a) The average spot price for the week was $56/MWh, a decrease of around $20/MWh compared to the previous week.

(b) 95% of prices fell between $0.02/MWh and $167/MWh.

2.3. Spot prices between Sunday and Tuesday were mostly under $150/MWh, with instances of low prices below $1/MWh during the nighttime periods.

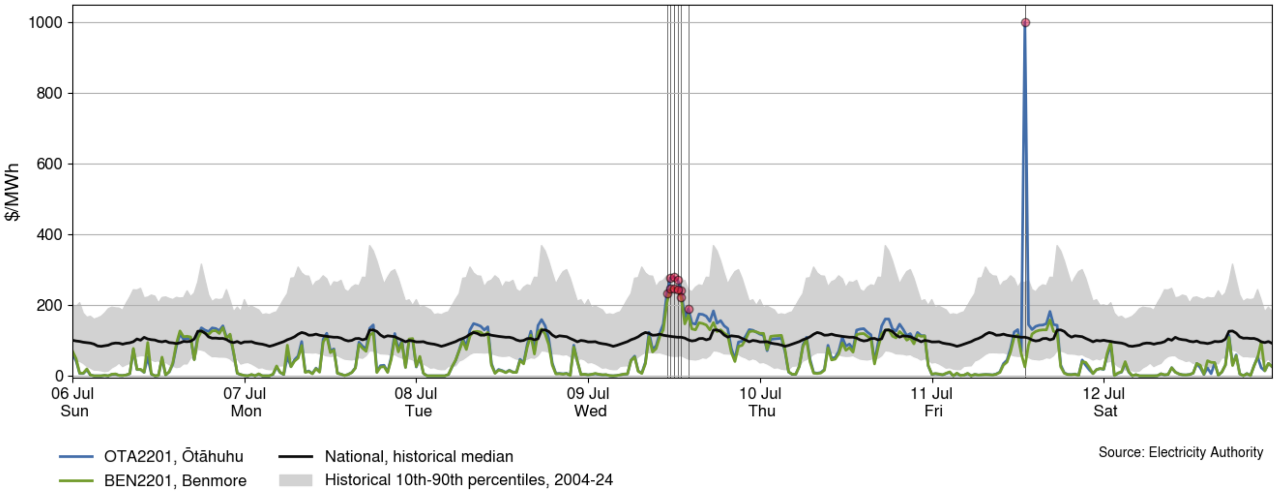
2.4. On Wednesday, between 11.00am and 1.00pm there were a few price spikes. The spot prices were $234-279/MWh at Ōtāhuhu, and $206-247/MWh at Benmore. During these times, demand was 101MW-214MW higher than forecast and wind was 33MW-190MW lower than forecast.

2.5. The highest price of the week occurred on Friday at 1.00pm, with prices of $1,001/MWh at Ōtāhuhu and $25/MWh at Benmore. During this time, the HVDC tripped[1], which restricted the power sharing from the South Island to the North Island.

2.6. 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.

[1] EXN Frequency Voltage National HVDC Equipment Tripped 6441028361.pdf

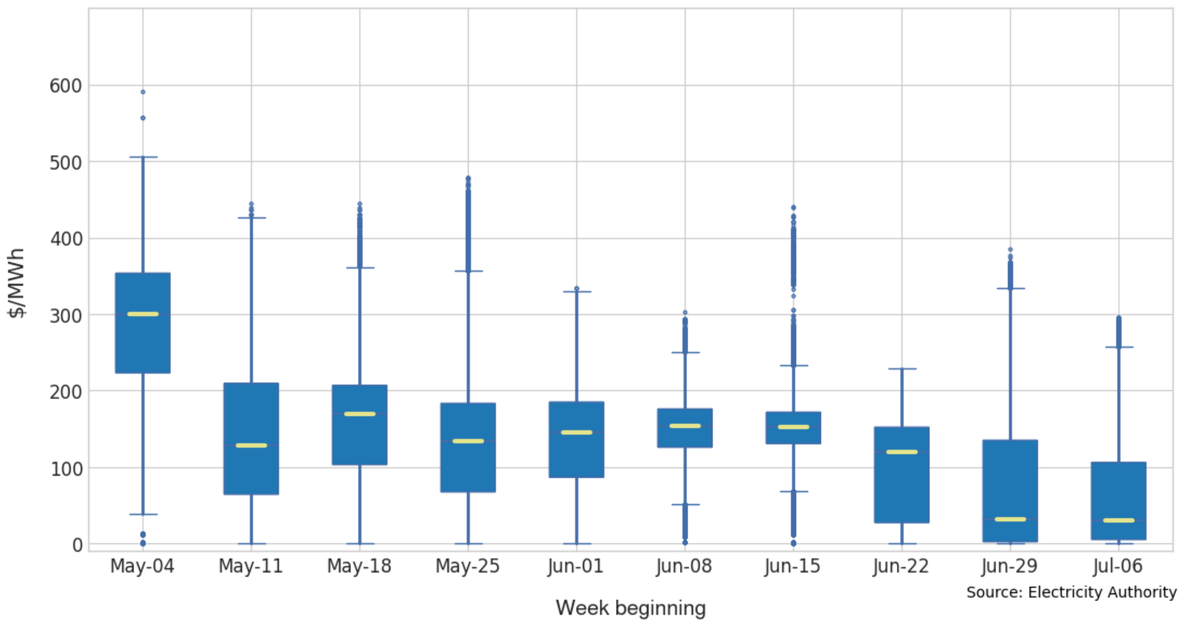
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 6-12 July 2025



2.7. 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.

2.8. The distribution of spot prices this week was narrower than last week. The median price was $30/MWh and most prices (middle 50%) fell between $5/MWh and $106/MWh.

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

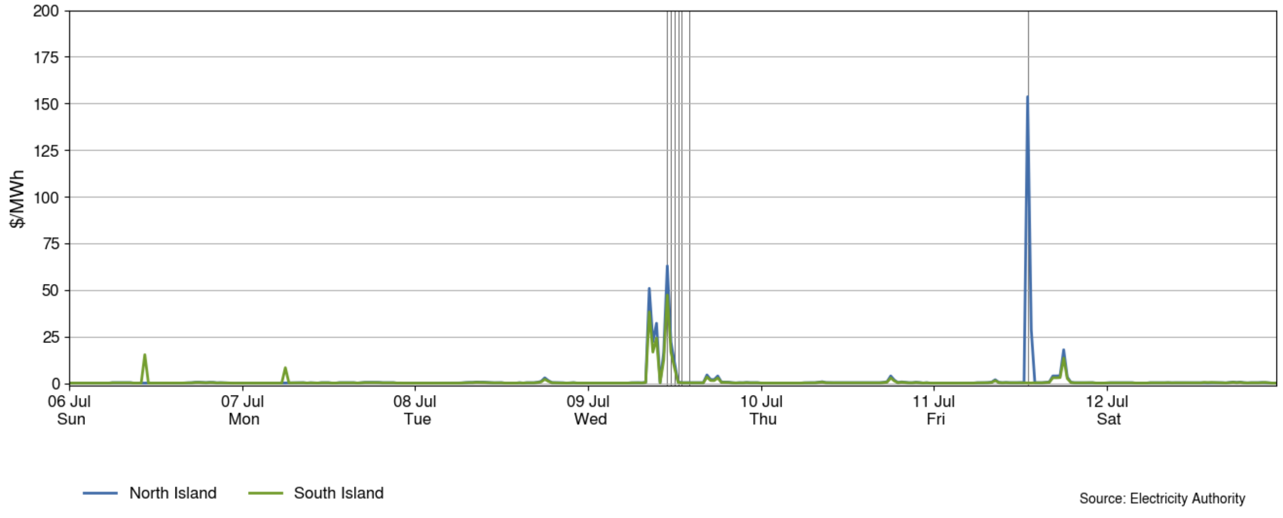


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh with a few spikes on Wednesday between 8.30am and 11.00am. At these times, Huntly 5 was the risk setter, and required more reserves to be cleared.

3.2. A significant FIR price spike occurred on Friday at 1.00pm, with FIR prices reaching around $154/MWh in the North Island, and prices in the South Island were $0.18/MWh. This was due to the HVDC trip.

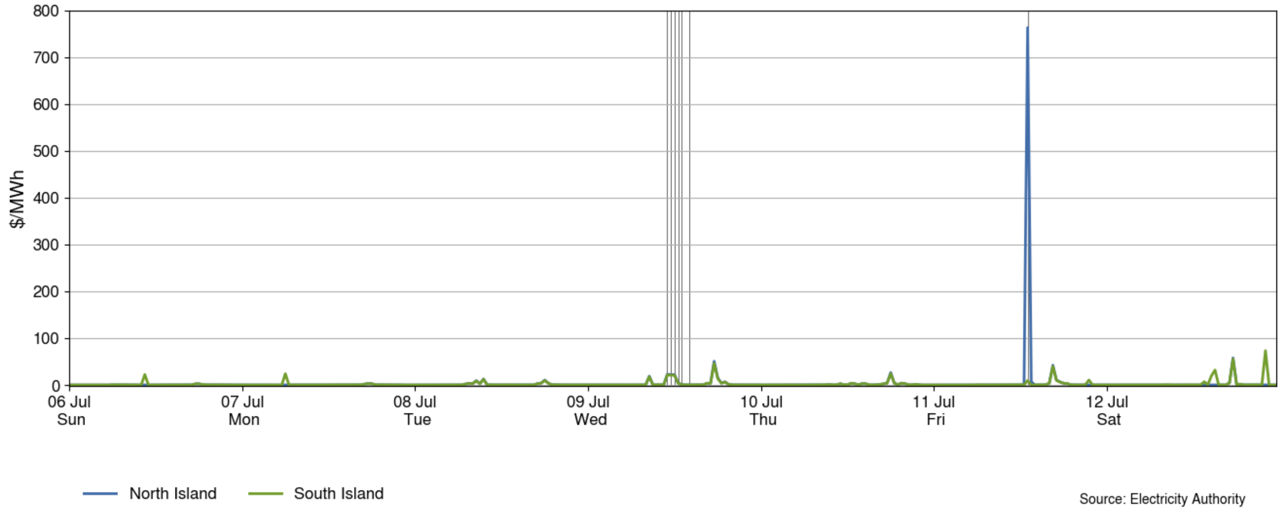
Figure 3: Fast instantaneous reserve price by trading period and island, 6-12 July 2025



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh with a few spikes. The highest SIR price was at 1.00pm on Friday with prices of $763/MWh in the North Island and $9.51/MWh in the South Island during the HVDC trip.

3.4. On Saturday, at 10.00pm the SIR prices were $73/MWh in the South Island and $0.24/MWh for the North Island. At this time, the HVDC was contributing to setting the SIR risk in the South Island.

Figure 4: Sustained instantaneous reserve by trading period and island, 6-12 July 2025



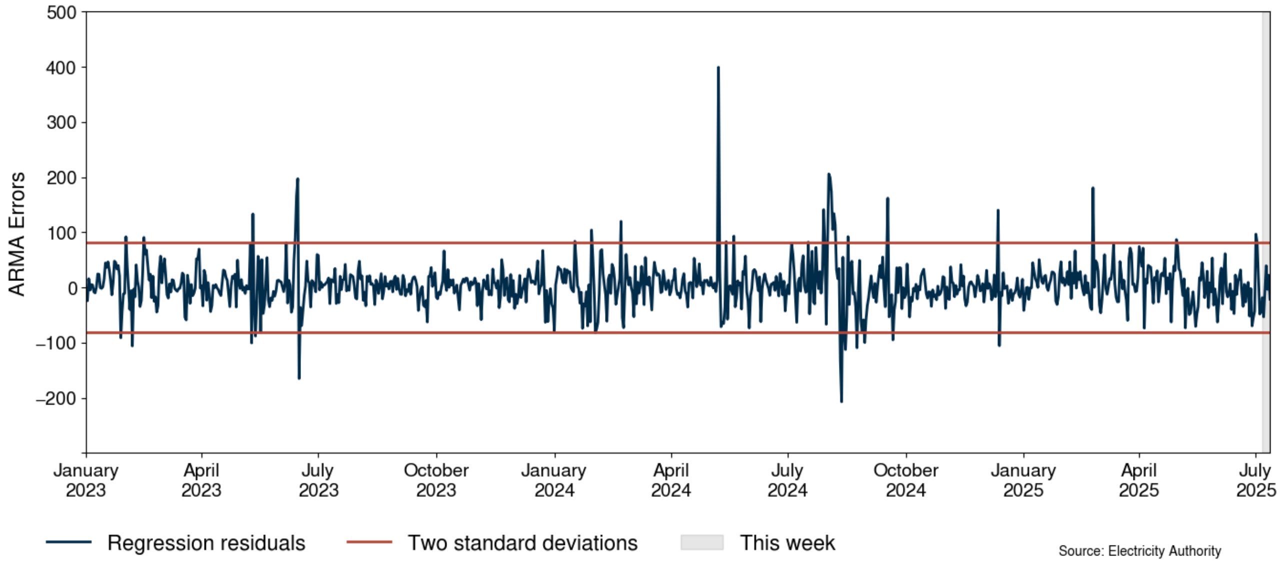
4. Regression residuals

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.

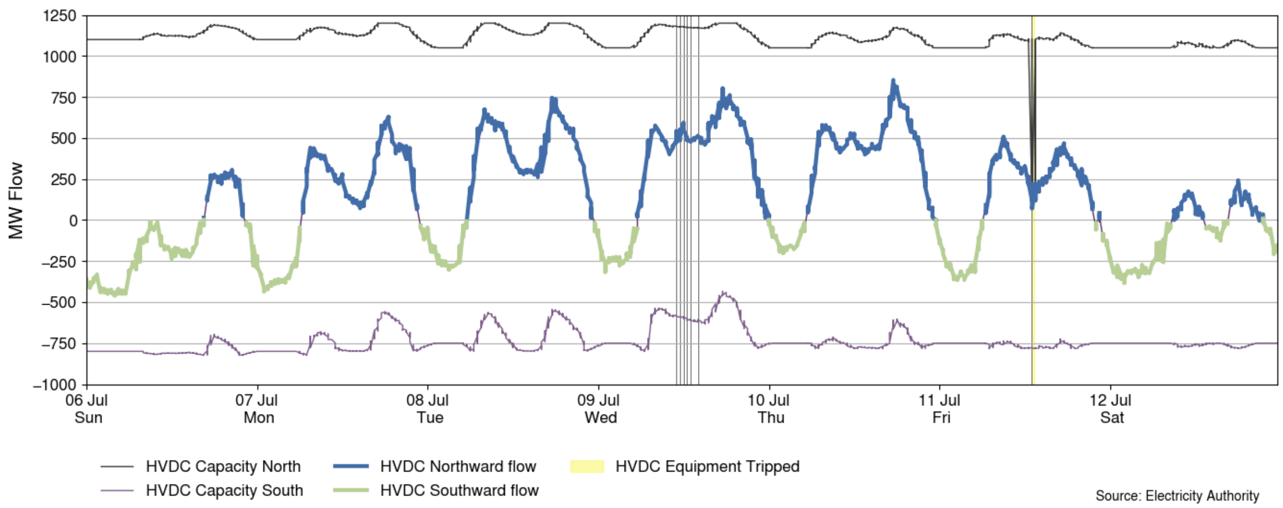
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 12 July 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 6-12 July 2025. HVDC flows were mostly northward during the day and southward overnight. Northward flows reached around 853MW on Thursday at 5.30pm during the evening demand peak when wind generation was low.

Figure 6: HVDC flow and capacity, 6-12 July 2025

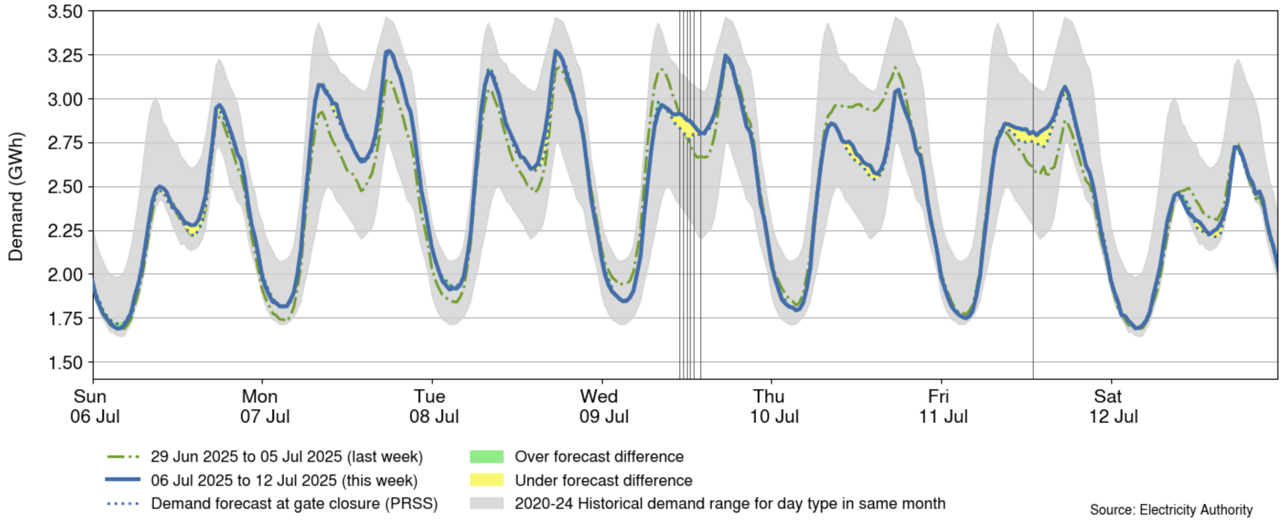


6. Demand

6.1. Figure 7 shows national demand between 6-12 July 2025, compared to the historic range and the demand of the previous week. Overall, demand was high this week compared to the previous week. The highest demand of the week was 3.27GWh at 6.00pm on Monday.

6.2. This week, demand was frequently higher than forecasts. The maximum demand error occurred on Wednesday at 12.30pm during the period of higher prices, when demand was 214MW higher than forecast.

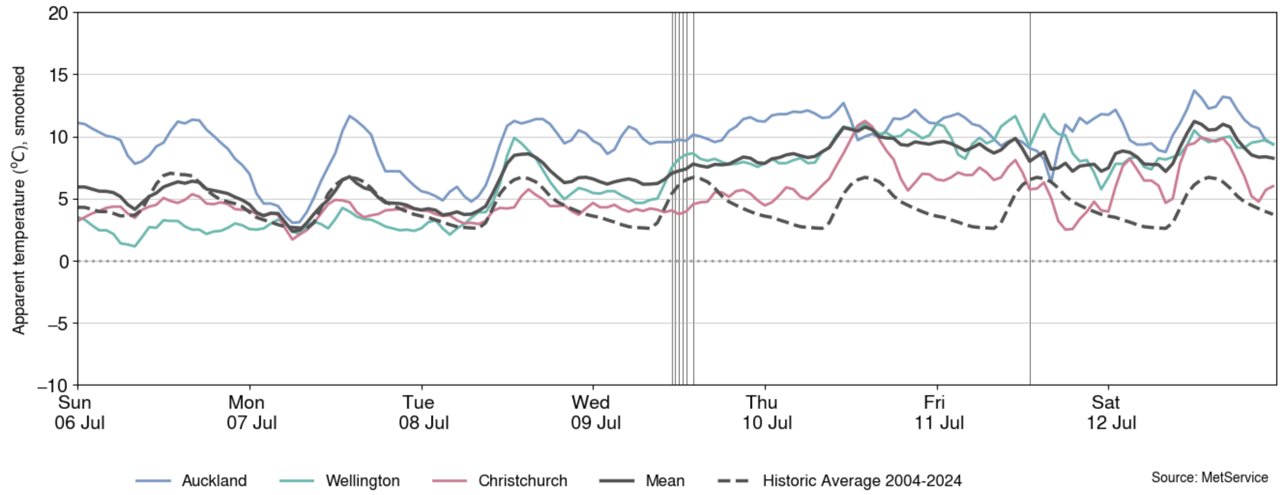
Figure 7: National demand, 6-12 July 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 6-12 July 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 were mostly above average and ranged from 3°C to 14°C in Auckland, 1°C to 12°C in Wellington, and 2°C to 11°C in Christchurch.

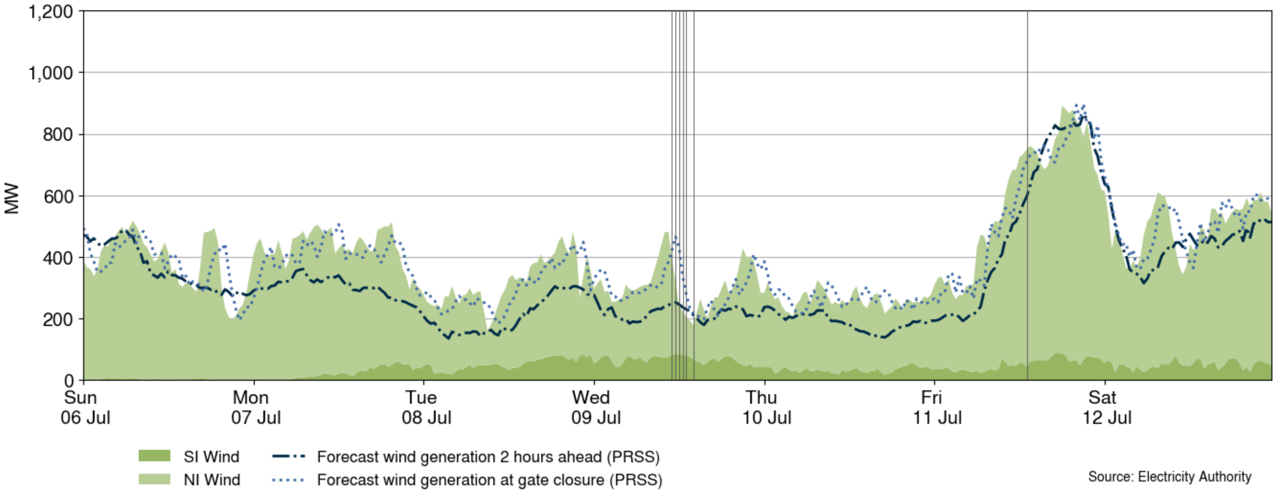
Figure 8: Temperatures across main centres, 6-12 July 2025



7. Generation

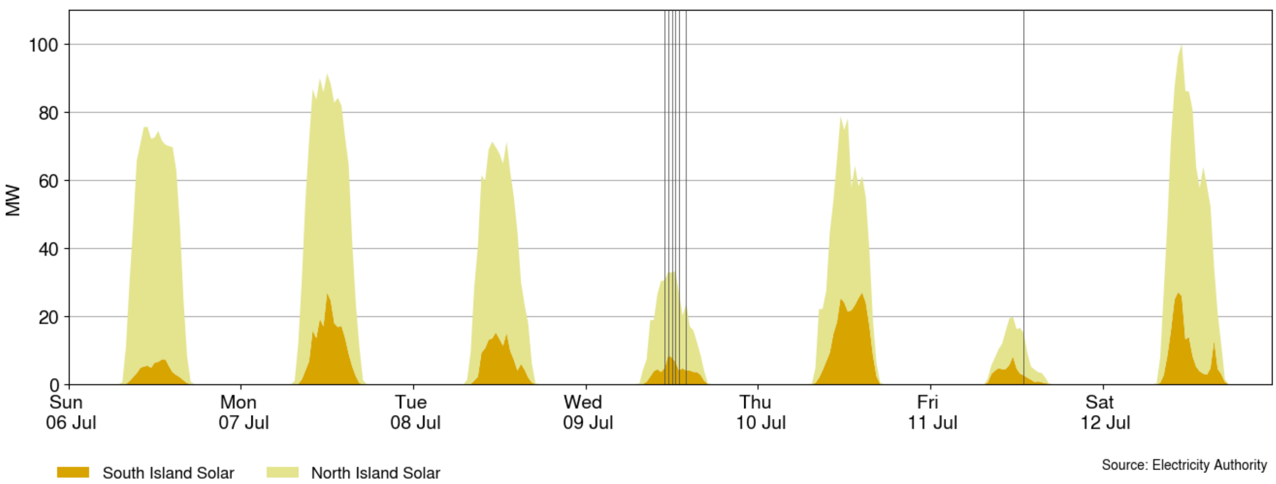
7.1. Figure 9 shows wind generation and forecast from 6-12 July 2025. This week wind generation varied between 160MW and 891MW, with a weekly average of 399MW. Wind generation was below 400MW most of the week, except on Friday when wind generation reached a maximum of 891MW at 6.00pm.

Figure 9: Wind generation and forecast, 6-12 July 2025



7.2. Figure 10 shows grid connected solar generation from 6-12 July 2025. Solar generation was low on Wednesday and Friday, but peaked above 60MW all other days. It reached a maximum of 100MW at 11.00am on Saturday.

Figure 10: Grid connected solar generation, 6-12 July 2025



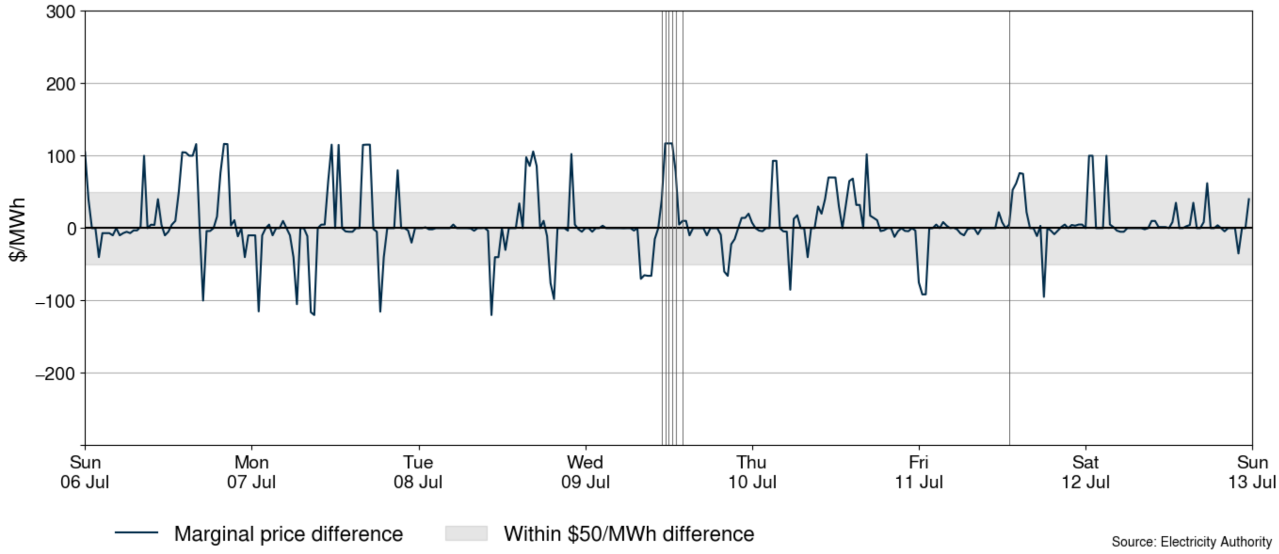
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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

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

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.

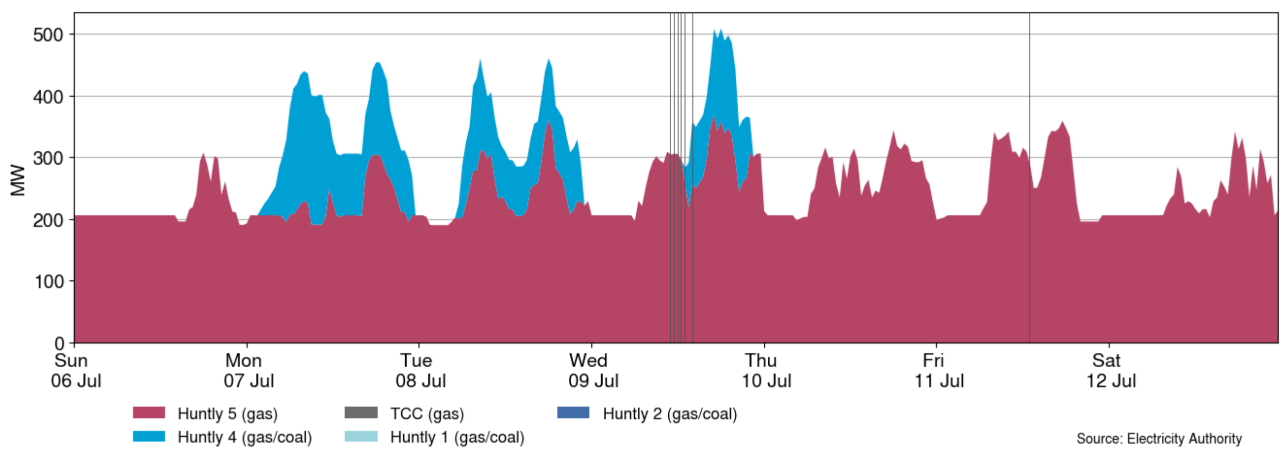
7.4. Many trading periods throughout the week had positive marginal price differences above $50/MWh. The largest positive price difference of +$117/MWh occurred at 11.30am on Wednesday when demand was over 195MW higher than forecast, and wind was 144MW lower than forecast.

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, 6-12 July 2025



7.5. Figure 12 shows the generation of thermal baseload between 6-12 July 2025. Huntly 5 generated baseload this week. Huntly 4 generated between Monday and Wednesday.

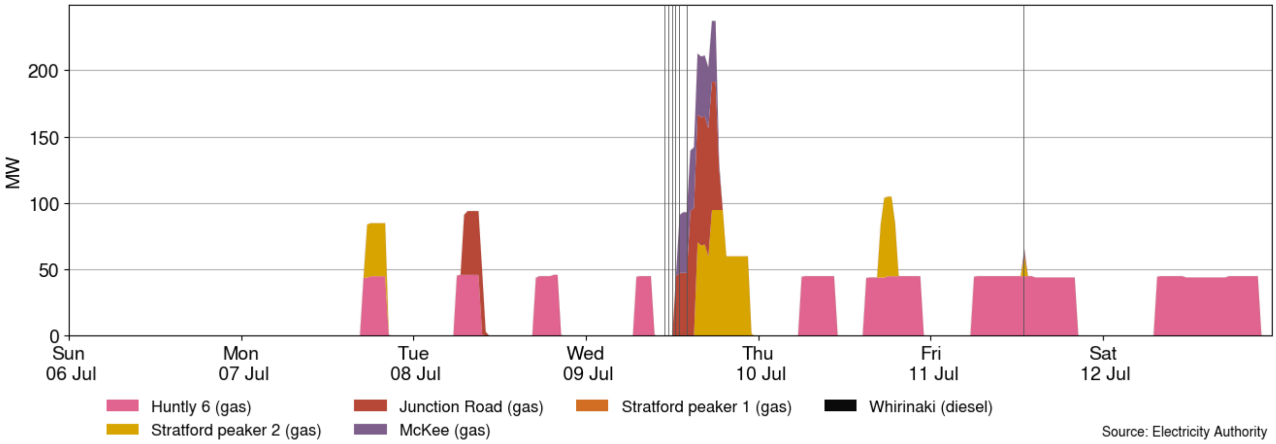
Figure 12: Thermal baseload generation, 6-12 July 2025



7.6. Figure 13 shows the generation of thermal peaker plants between 6-12 July 2025. Huntly 6 generated daily during most peak periods, except on Sunday, and ran continuously from morning to evening peak on both Friday and Saturday. Junction Road generated on Tuesday during the morning peak and again on Wednesday during the evening peak.

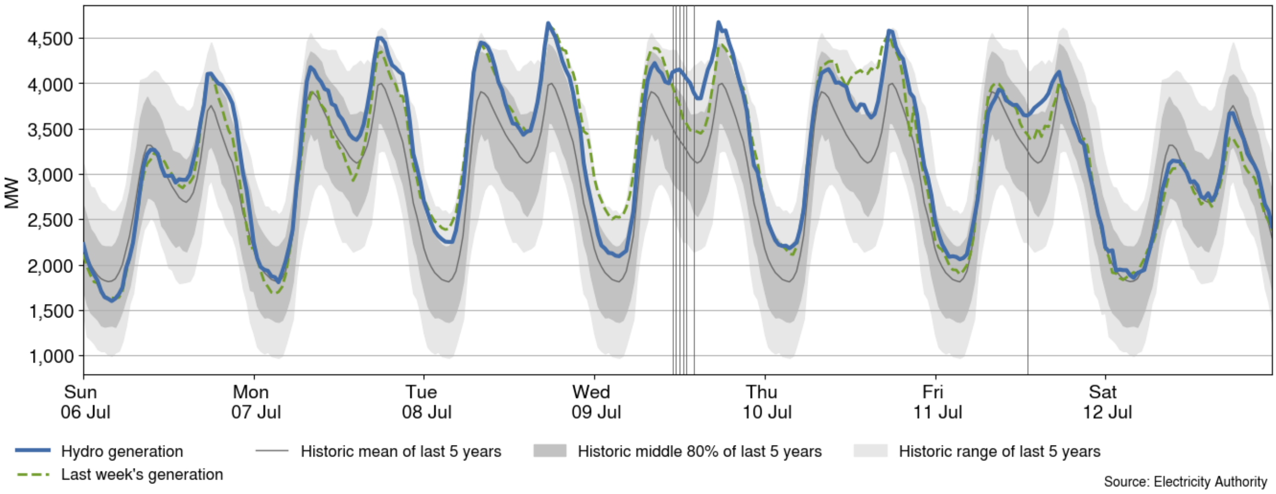
Stratford Peaker 2 generated during the evening peaks on Monday, Wednesday, and Thursday. McKee also generated on Wednesday.

Figure 13: Thermal peaker generation, 6-12 July 2025



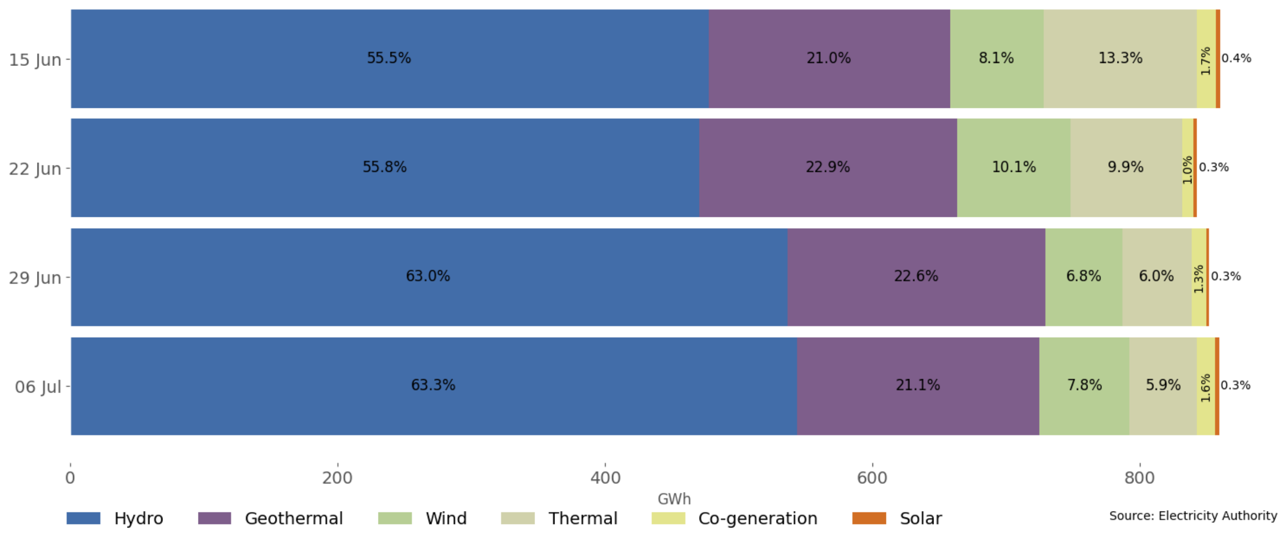
7.7. Figure 14 shows hydro generation between 6-12 July 2025. Overall, hydro generation was higher than the historic mean. On Wednesday, during the price spikes, hydro generation increased to meet elevated demand.

Figure 14: Hydro generation, 6-12 July 2025



7.8. As a percentage of total generation, between 6-12 July 2025, total weekly hydro generation was 63.3%, geothermal 21.1%, wind 7.8%, thermal 5.9%, co-generation 1.6%, and solar (grid connected) 0.3%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 15 June 2025 and 12 July 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 6-12 July 2025 ranged between ~691MW and ~1,049MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford peaker 1 is on outage until 10 August 2025.

(b) Manapōuri unit 3 was on outage between 8-9 July 2025.

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

(d) Roxburgh unit 4 is on outage until 30 July 2025.

(e) Tauhara geothermal is on outage between 9-14 July 2025.

(f) Ruakākā battery outage has been extended to be until 18 July 2025.

Figure 16: Total MW loss from generation outages, 6-12 July 2025

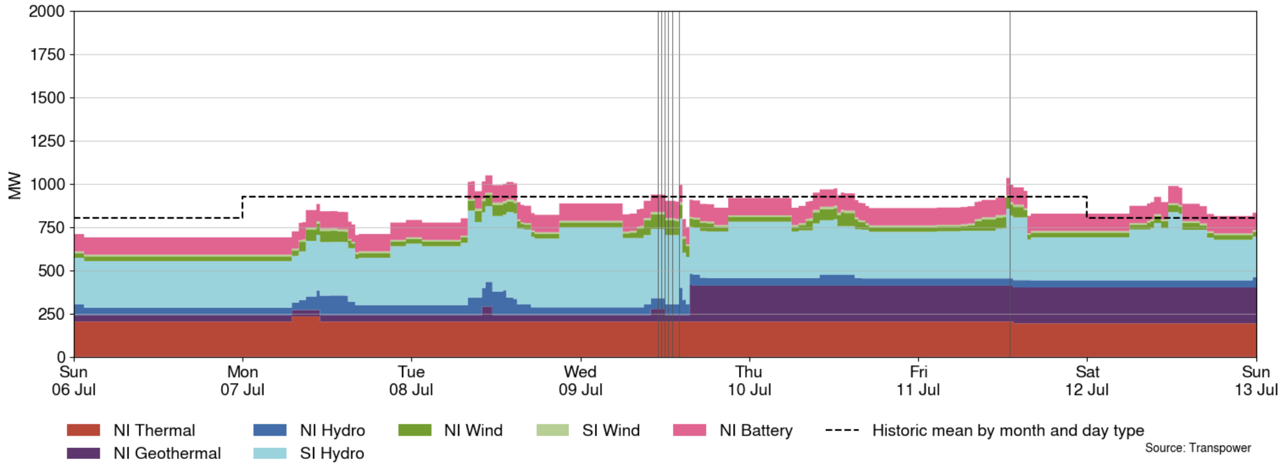
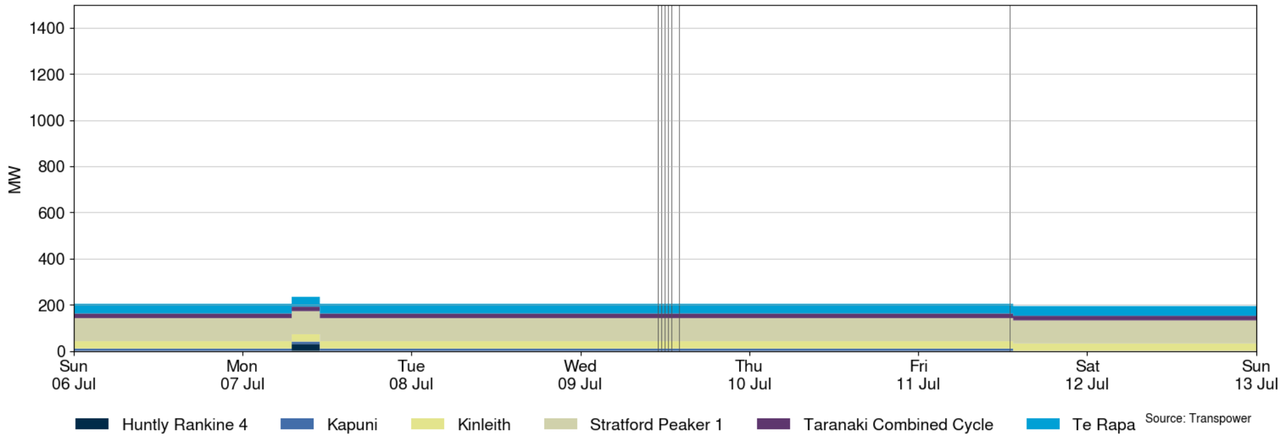


Figure 17: Total MW loss from thermal outages, 6-12 July 2025

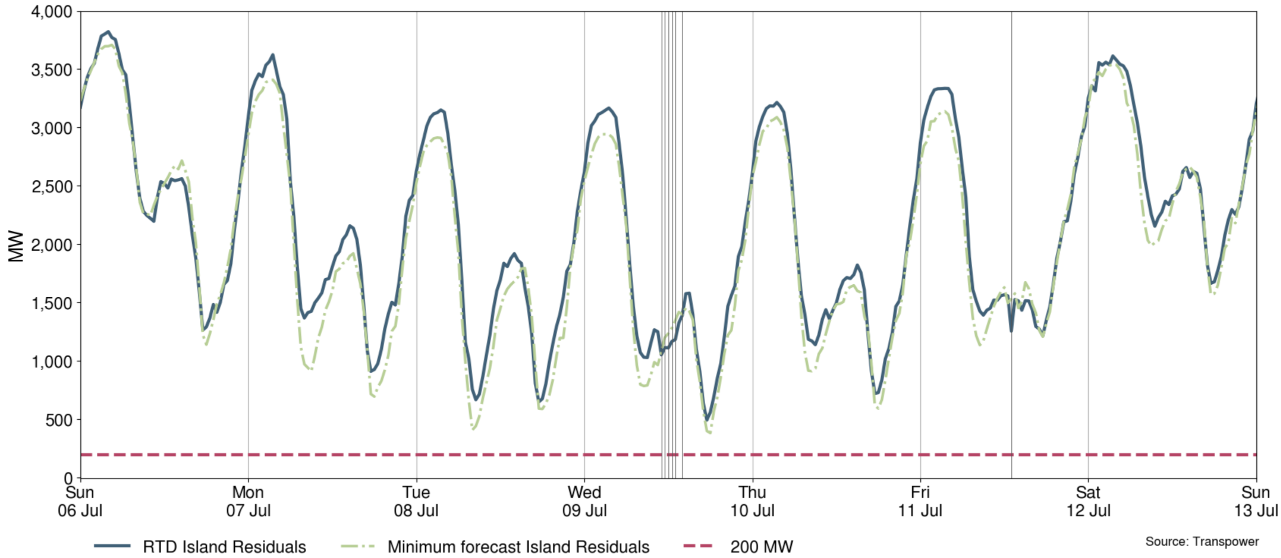


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 6-12 July 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 494MW on Wednesday at 5.30pm.

Figure 18: National generation balance residuals, 6-12 July 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 10^{th} to 90^{th} percentiles.

10.2. As of 12 July 2025, national controlled storage was 67% nominally full and ~101% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (62% full)[3] is close to its historic average, and storage at Lake Takapō (44% full) is between its historic mean and 10th percentile.

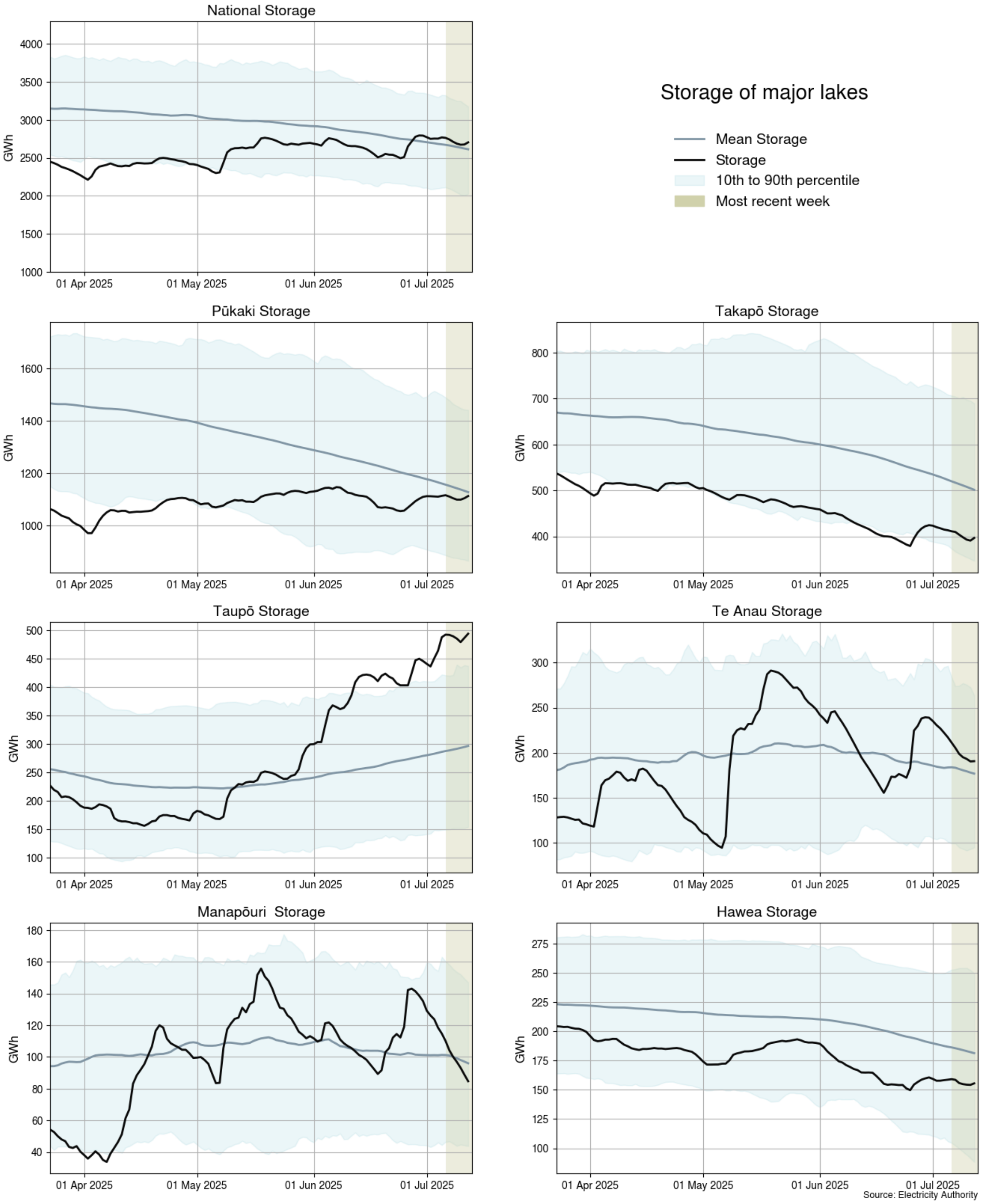
10.4. Storage at Lake Te Anau (71% full) decreased but remains above its historic mean, and storage at Lake Manapōuri (53% full) also declined during the week and is below its historic mean.

10.5. Storage at Lake Taupō (86% full) remains above its historical 90th percentile.

10.6. Storage at Lake Hawea (55% full) remains between its historical 10th percentile and mean.

[3] Percentage full values sourced from NZX hydrological summary 14 July 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 July 2025. The SRMCs for gas powered generation have decreased, while the SRMC for diesel fuelled generation slightly increased.

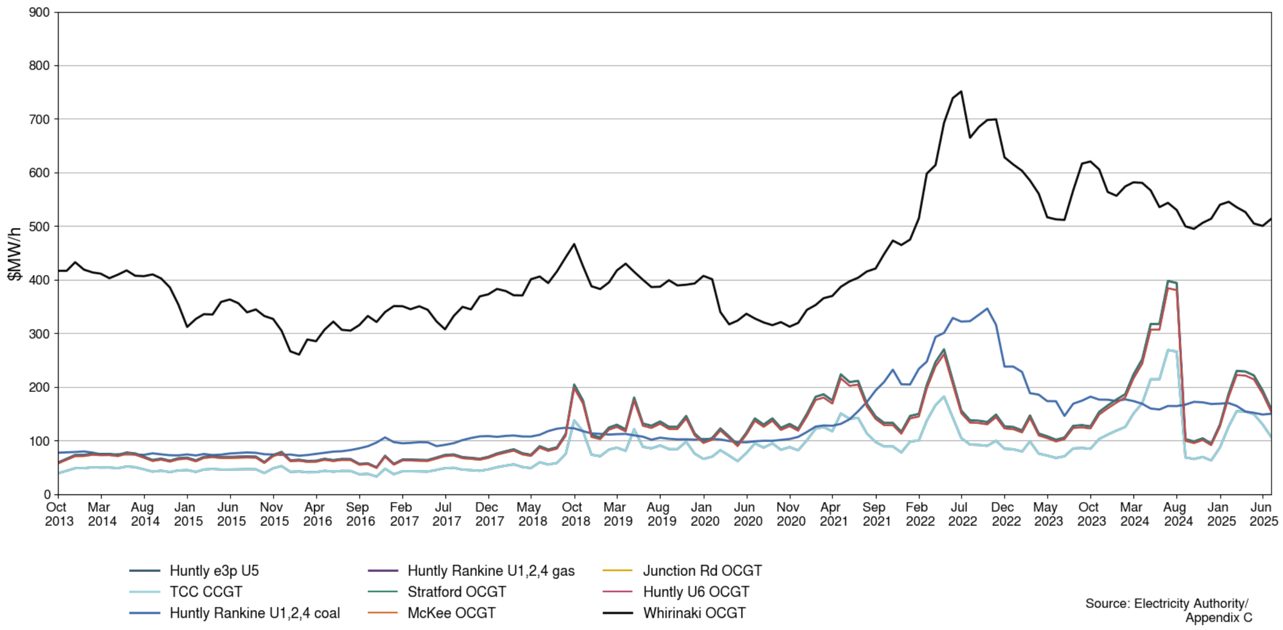
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$159/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $106/MWh and $159/MWh.

11.6. The SRMC of Whirinaki is ~$513/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

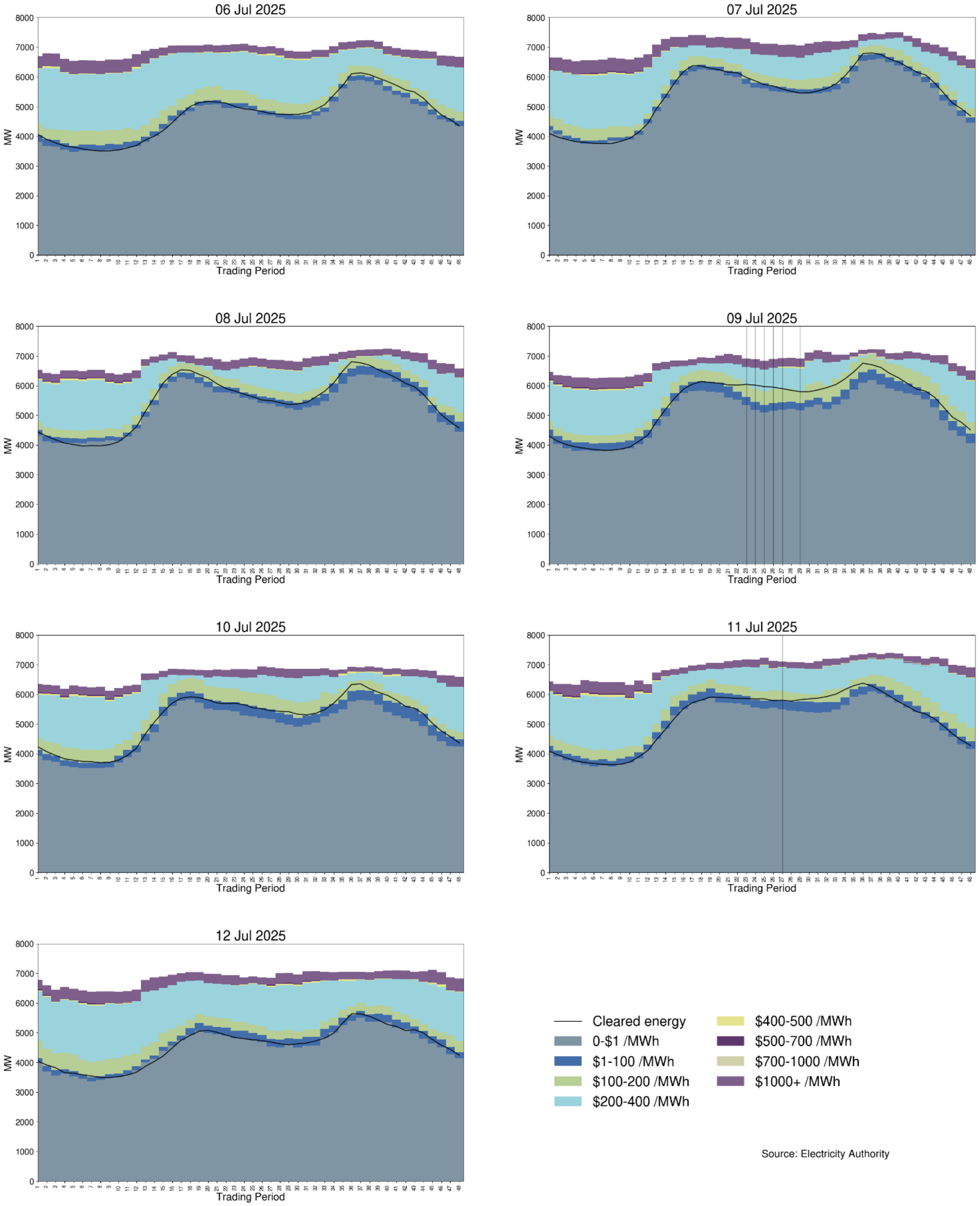


12. Offer behaviour

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 $1-$200/MWh range. The volume of offers in the $200-$400/MWh range remains notably high. On Wednesday, energy cleared into the $200-400/MWh band due to demand and wind forecast errors.

Figure 21: Daily offer stacks



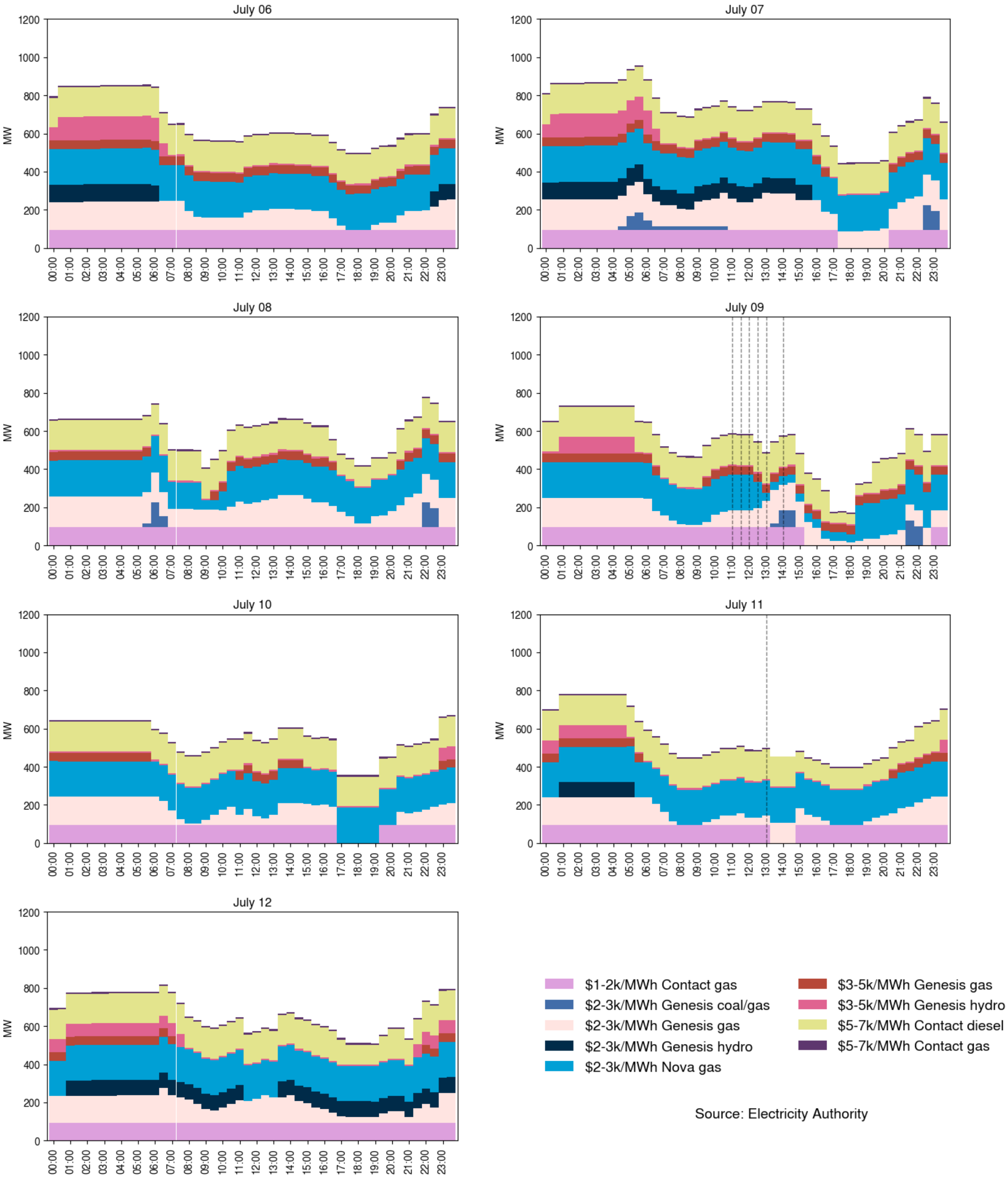
Source: Electricity Authority

12.3. 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.

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, wind 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 10.5% of the total energy available.

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
14/06/2023- 15/06/2023	15-17/ 15-19	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
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