28 July 2025

Trading conduct report 20-26 July 2025

Market monitoring weekly report

Trading conduct report 20-26 July 2025

1. Overview

1.1. The average price increased by $71/MWh this week to $161/MWh. Demand increased due to colder temperatures, and peak demand periods were significantly higher. During the Monday morning peak, prices were high due to high demand, demand underforecasting, low wind generation and high reliance on peaking generation. Due to low wind generation, hydro and thermal generation increased this week. National hydro storage declined to ~ 60% nominally full and around 96% 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 20-26 July 2025:

(a) The average spot price for the week was $161/MWh, an increase of around $71/MWh compared to the previous week.

(b) 95% of prices fell between $39/MWh and $301/MWh.

2.3. Spot prices were mostly under $300/MWh with price spikes on each morning from Monday to Friday.

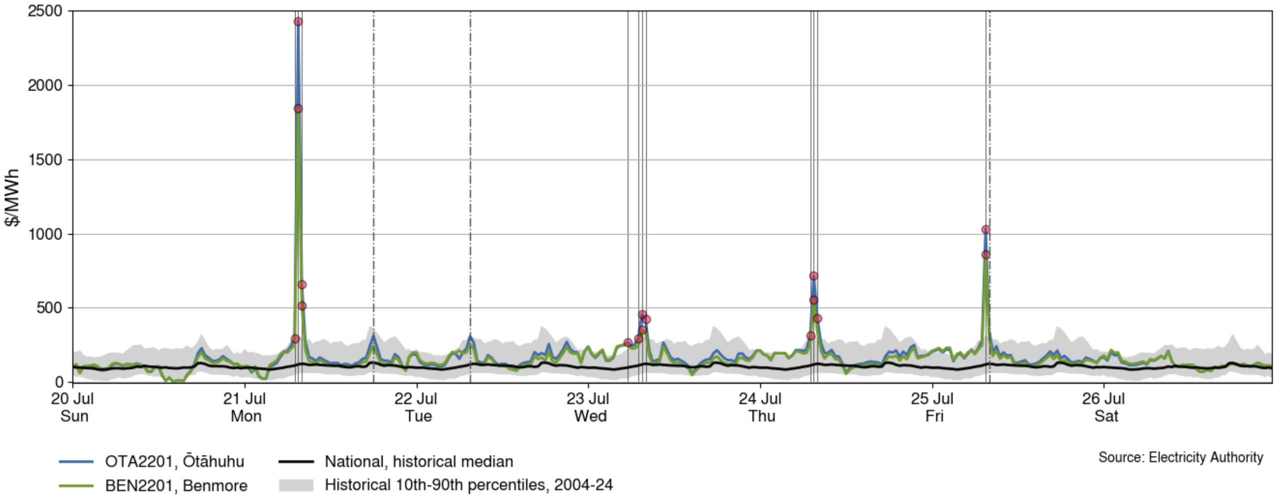
2.4. On Monday, during the morning peak at 7.30am, prices reached $2,431/MWh at Ōtāhuhu and $1,841/MWh at Benmore. During this time, national demand was high and 151MW higher than forecast. Wind was also low, at around 108MW. Additionally, 50-60MW of generation from McKee was bona fide out in the 7:00-7:30 periods, further reducing generation available to meet demand. During this time only Huntly 5 was online providing thermal baseload energy, and additional energy was needed from peaking plants. Sustained instantaneous reserve (SIR) prices also spiked during this time to $2,021/MWh in the North Island, and $1,797/MWh in the South Island. In real time the national residual reached 65MW.

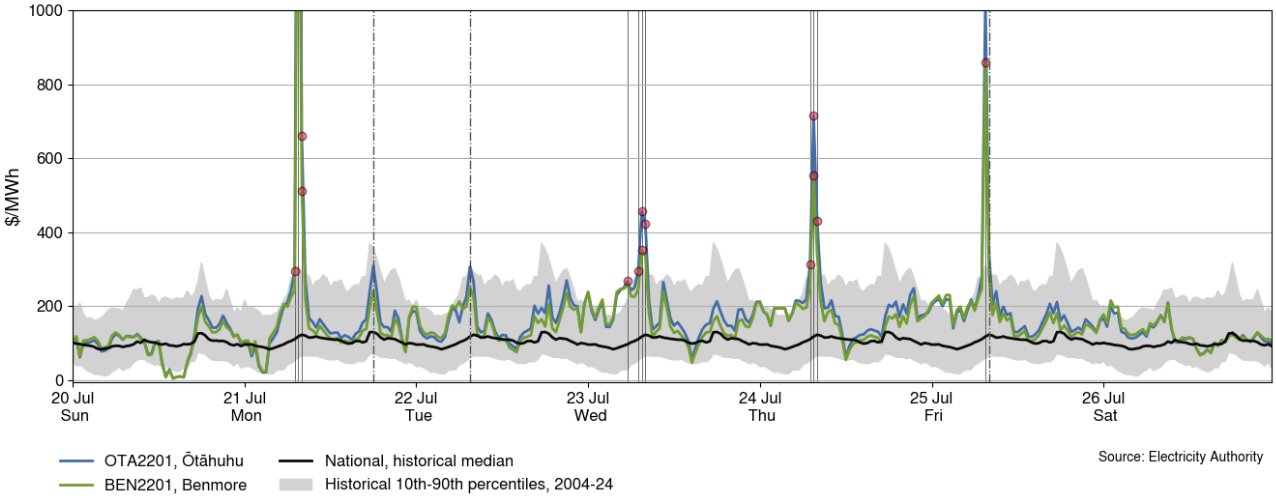
2.5. Another significant price spike occurred during the morning peak at 7.30am on Friday, with prices reaching around $1,031/MWh at Ōtāhuhu and $858/MWh at Benmore. At this time, national demand was highest of the week (3.52GWh), and 120MW higher than forecast. Wind generation was relatively low at around 115 MW. SIR prices also spiked to $562/MWh in the North Island, and $528/MWh in the South Island.

2.6. Other high morning prices on Tuesday-Thursday were also due to a combination of high and underforecast demand, low wind and high amounts of peaking generation.

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 $300/MWh are marked with black dashed lines.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 20-26 July 2025

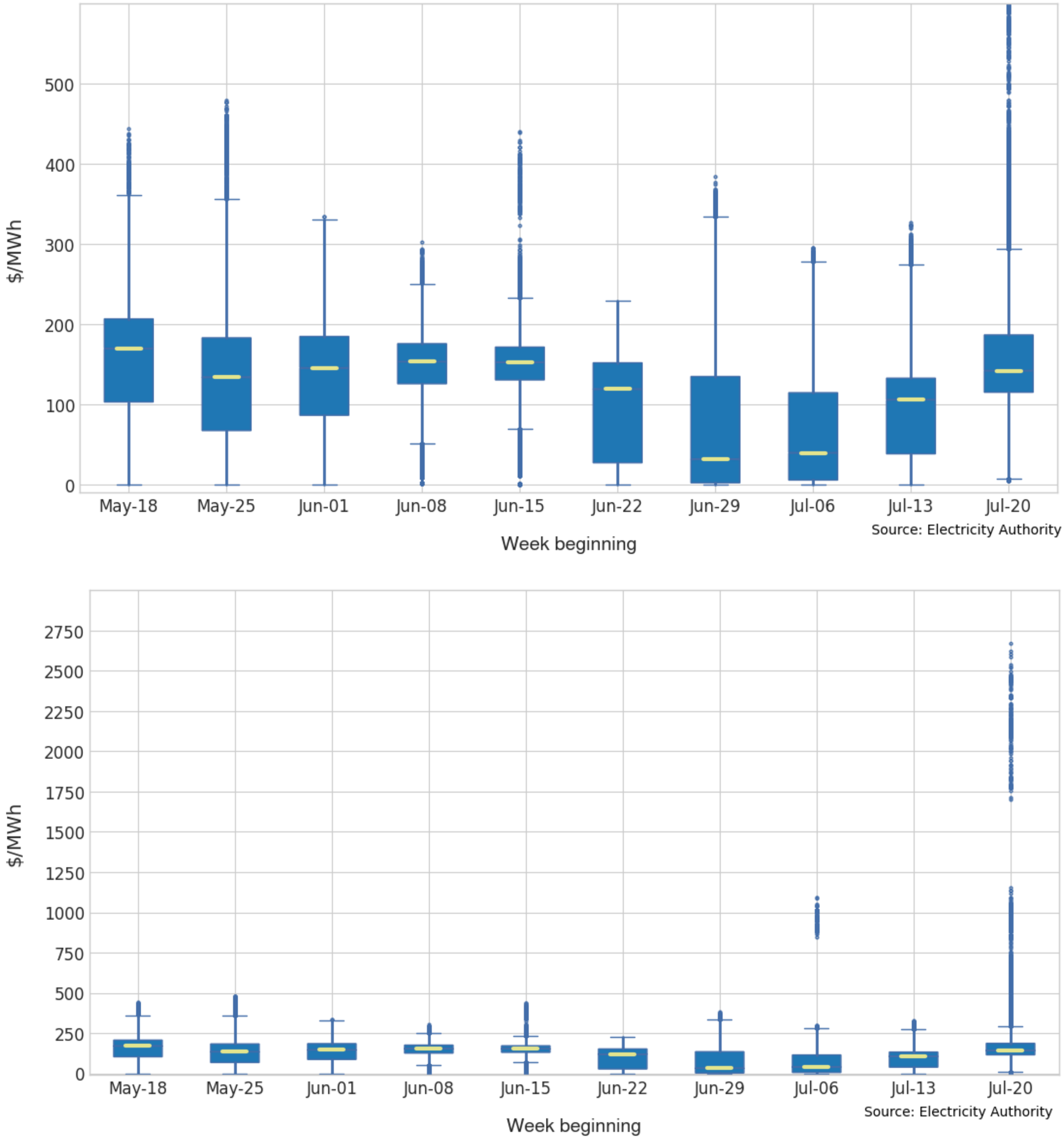




2.8. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times 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 moved up this week compared to the previous week, with significant high-priced outliers. The median price was $142/MWh, which is higher compared to the previous week, and most prices (middle 50%) fell between $115/MWh and $187/MWh.

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



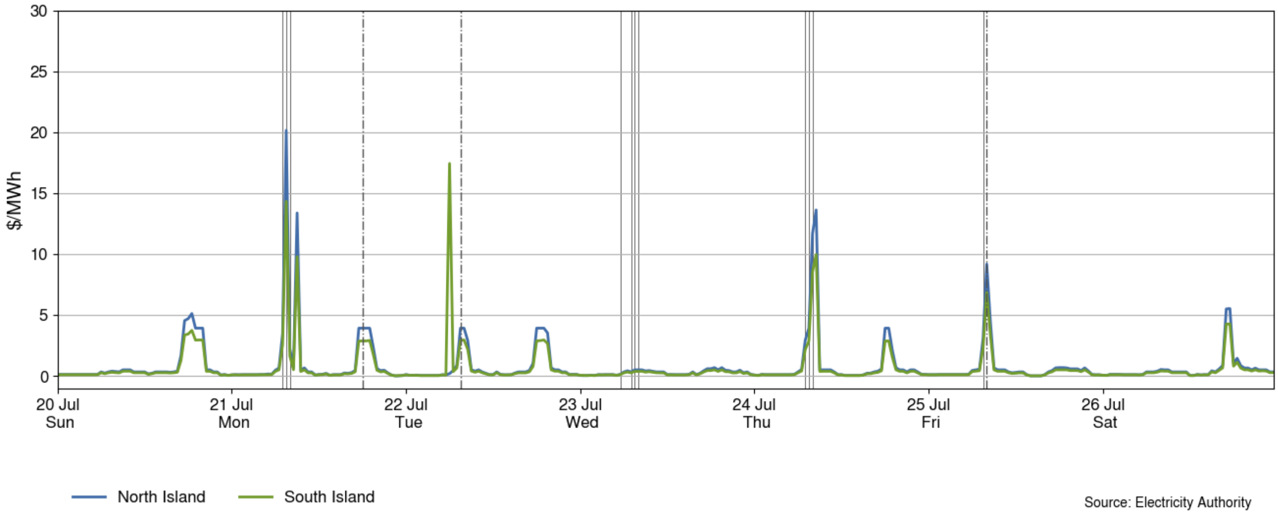
3. Reserve prices

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.

3.2. A FIR price spike occurred on Monday at 7.30am, with prices reaching around $20/MWh in the North Island and $14/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.

3.3. On Tuesday, South Island FIR prices spiked to $17/MWh, when the HVDC was flowing South and setting the risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 20-26 July 2025

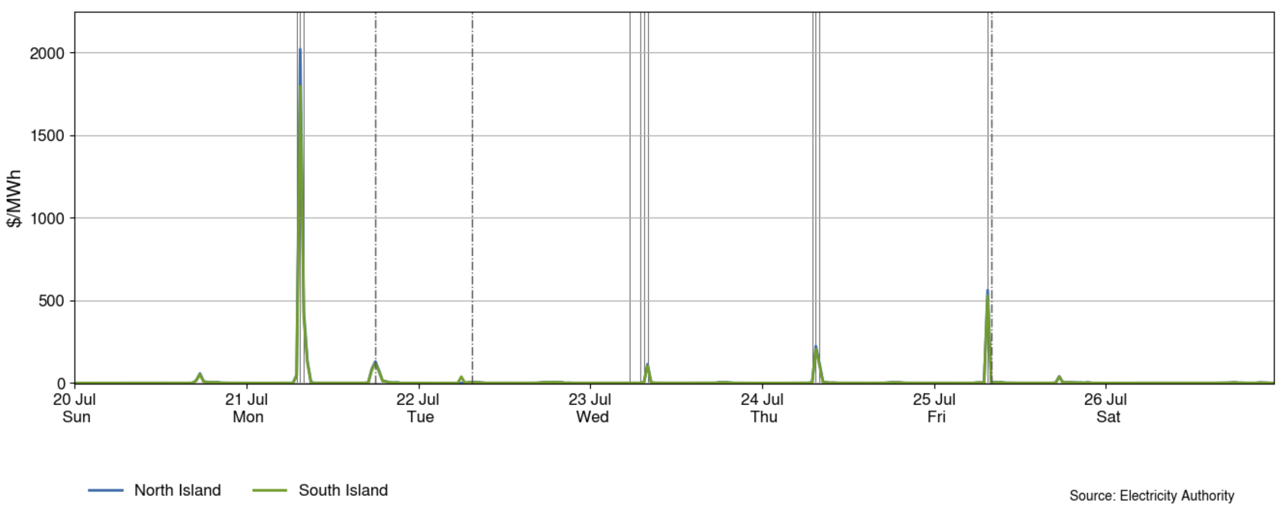


3.4. SIR prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh, with a few notable spikes during periods of high demand and high spot prices.

3.5. A significant SIR price spike occurred on Monday during the morning peak period at 7.30am, coinciding with a spike in spot prices. During that time SIR prices reached $2,021/MWh in the North Island and $1,797/MWh in the South Island. Huntly 5 was the risk setter. Whirinaki was cleared for reserve, which set the reserve price over $2,000/MWh. In general when thermal commitment is low there is an overall reduction in reserve available, and reserve prices can spike when higher amounts of reserve are required.

3.6. Another SIR price spike appeared during the morning peak period at 7.30am on Friday, with prices of around $562/MWh in the North Island and $528/MWh in the South Island. Huntly 5 was again the risk setter, and spot prices also spiked during this period.

Figure 4: Sustained instantaneous reserve by trading period and island, 20-26 July 2025



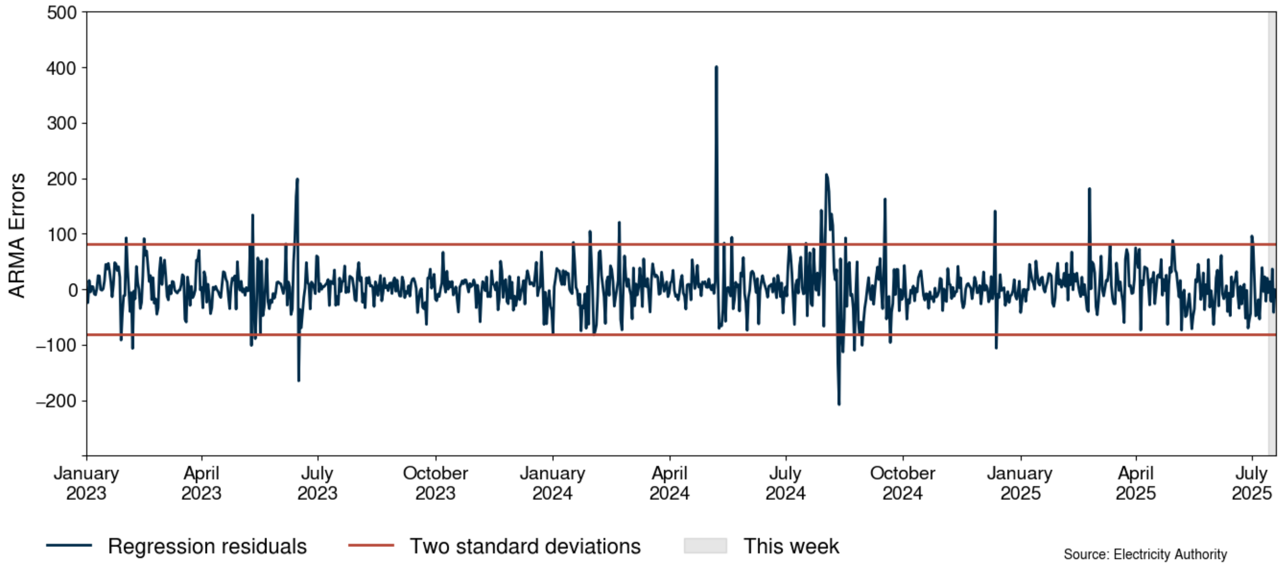
4. Regression residuals

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.

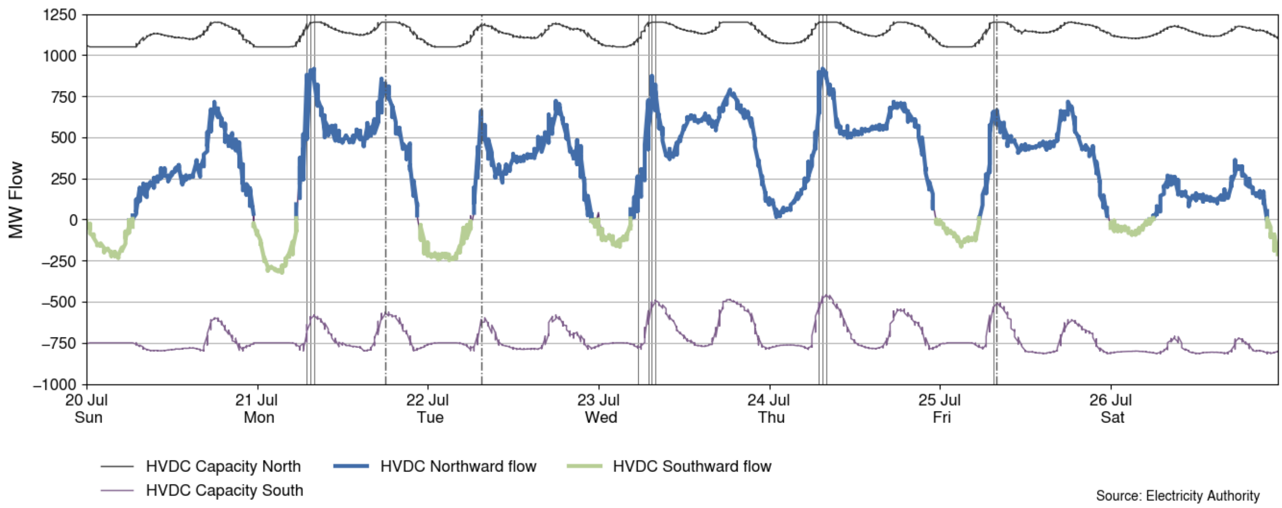
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 26 July 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 20-26 July 2025. HVDC flows were mostly northward during the day and southward overnight. Northward flows reached around 917MW on Thursday at 7.30am during the morning demand peak when demand was high.

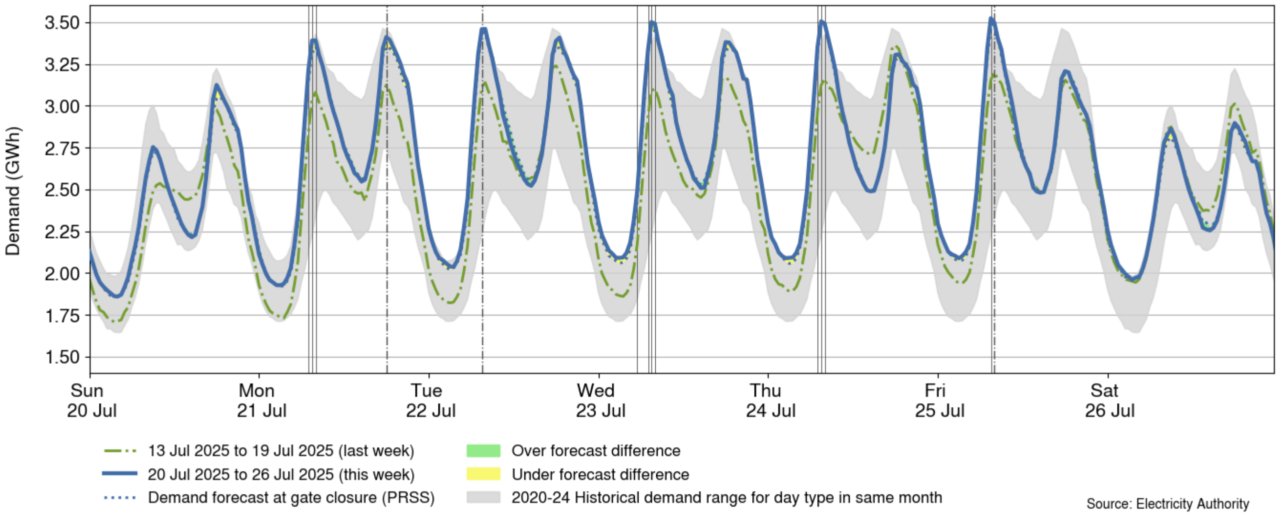
Figure 6: HVDC flow and capacity, 20-26 July 2025



6. Demand

6.1. Figure 7 shows national demand between 20-26 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 due to colder temperatures. The highest demand of the week was 3.52GWh at 7.30am on Friday. The morning peak demand was mostly higher than the evening peak.

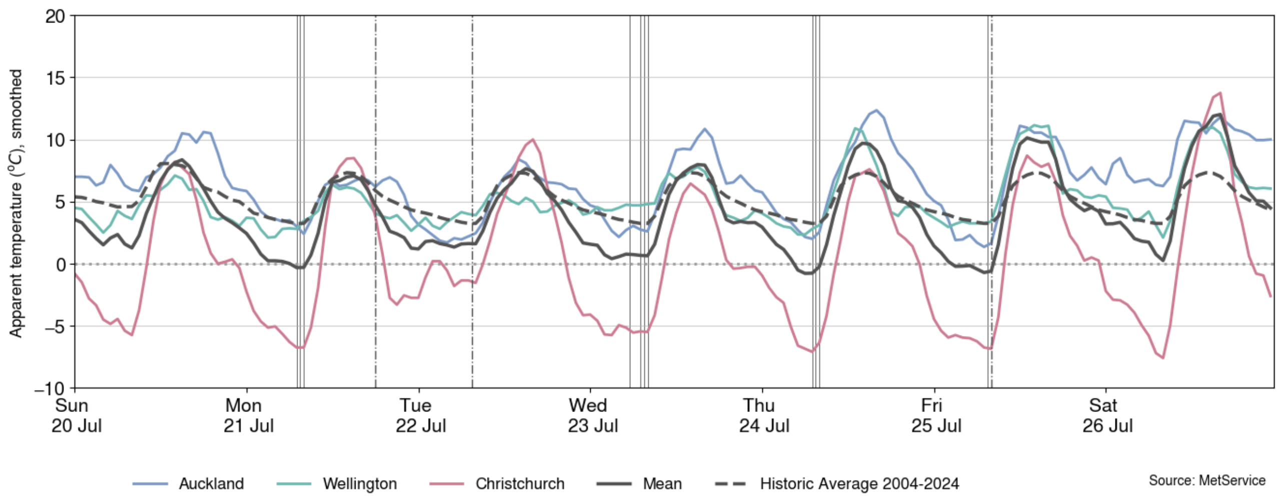
Figure 7: National demand, 20-26 July 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 20-26 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.

6.3. Apparent temperatures ranged from 1°C to 12°C in Auckland, 2°C to 11°C in Wellington, and -8°C to 14°C in Christchurch. Christchurch experienced freezing mornings this week. These low temperatures contributed to higher demand.

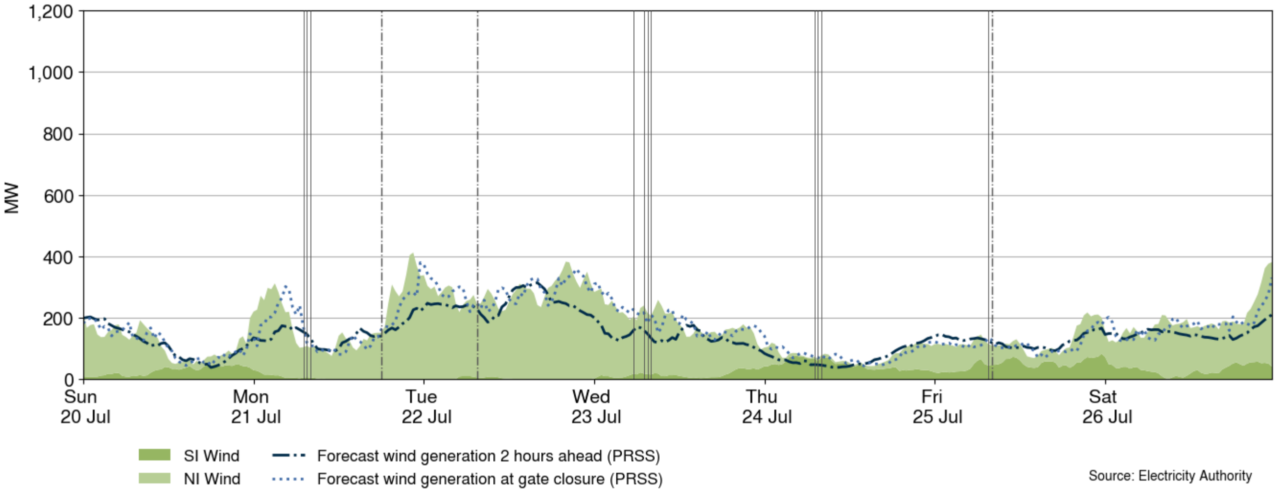
Figure 8: Temperatures across main centres, 20-26 July 2025



7. Generation

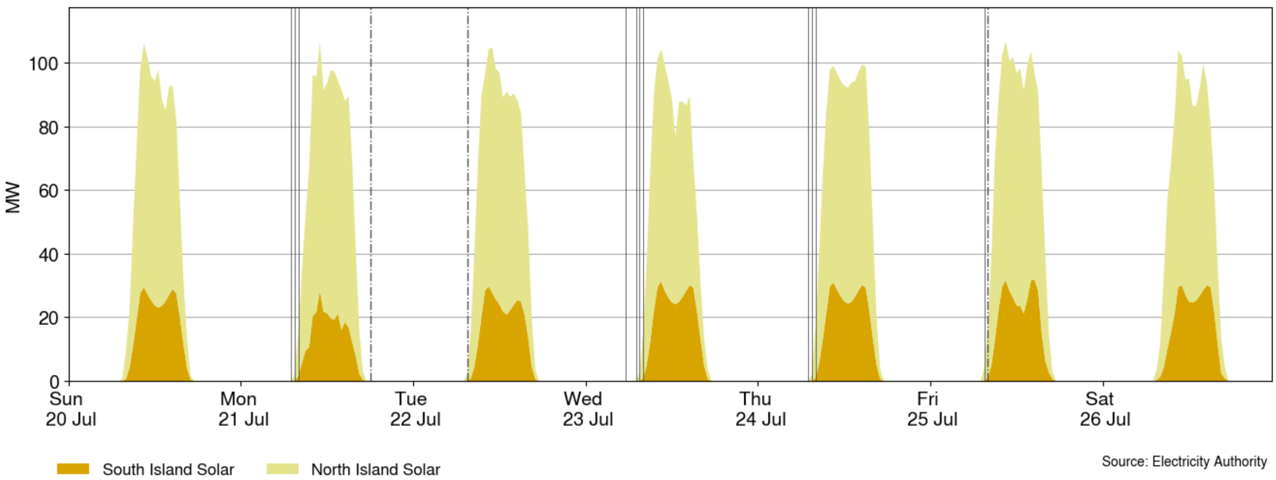
7.1. Figure 9 shows wind generation and forecast from 20-26 July 2025. Wind generation varied between 43MW and 412MW, with a weekly average of 169MW. Wind generation remained relatively low throughout the week, mostly under 200MW.

Figure 9: Wind generation and forecast, 20-26 July 2025



7.2. Figure 10 shows grid connected solar generation from 20-26 July 2025. Solar generation typically peaked around 100MW, with a maximum of 107MW at 10.30am on Friday.

Figure 10: Grid connected solar generation, 20-26 July 2025



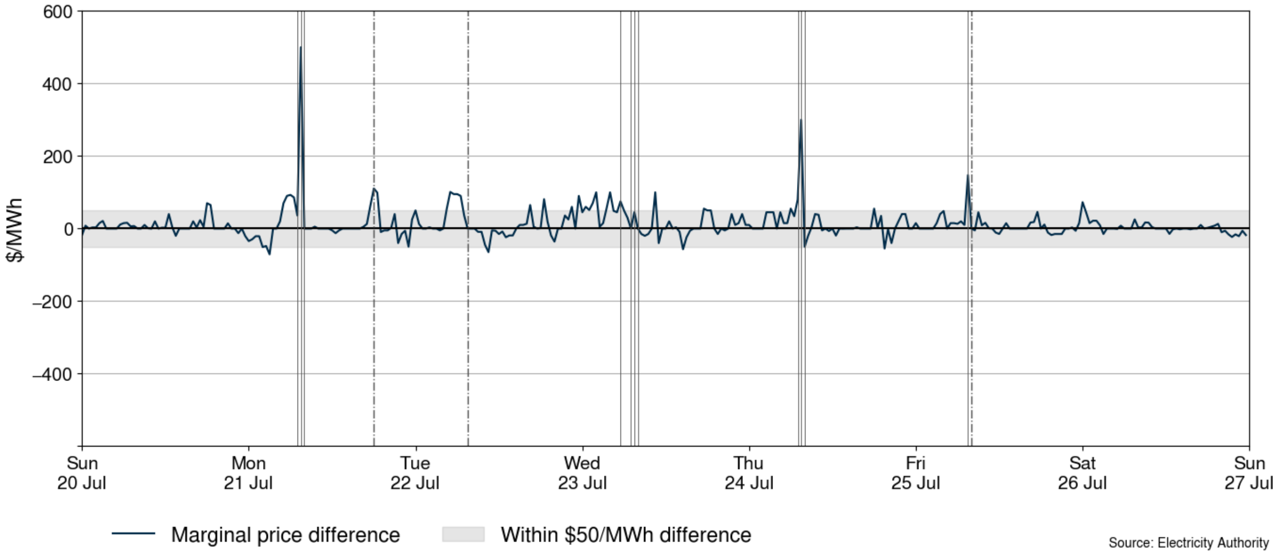
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

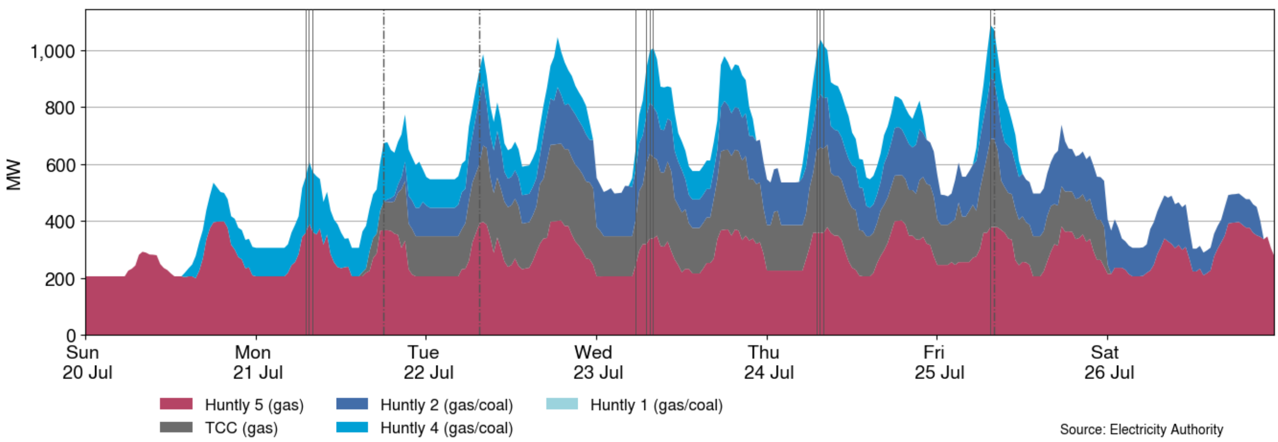
7.4. Many trading periods throughout the week had positive marginal price differences above $50/MWh which were driven by wind and demand forecasting errors. The largest positive price difference of +$500/MWh occurred during the price spike at 7.30am on Monday, when demand was over 151MW higher than forecast.

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, 20-26 July 2025



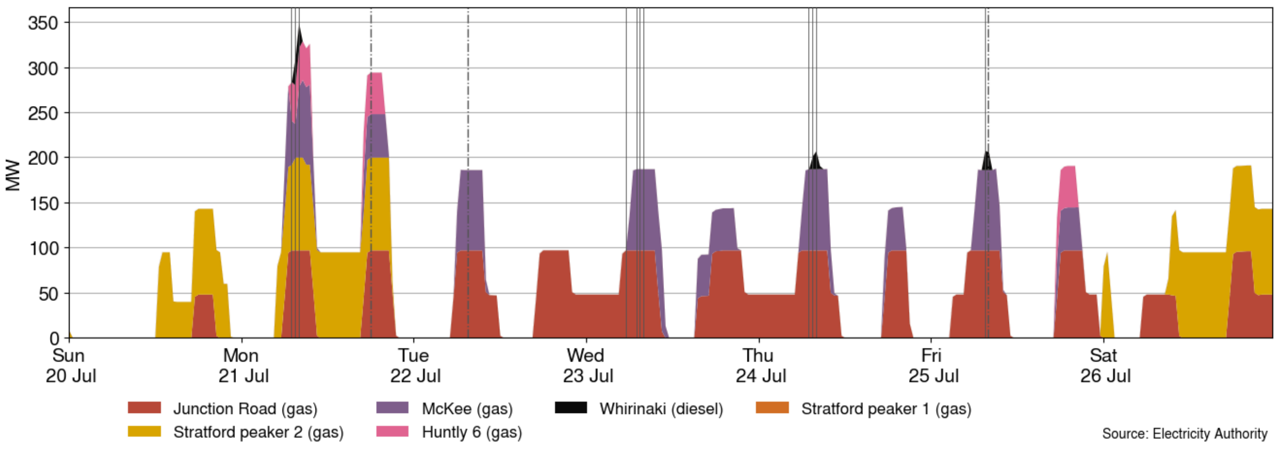
7.5. Figure 12 shows the generation of thermal baseload between 20-26 July 2025. Huntly 5 ran as baseload this week. TCC ran from Monday evening to Friday. Huntly 2 ran from Monday afternoon until Saturday. Huntly 4 supported the baseload from Sunday evening to Friday afternoon, turning off occasionally overnight.

Figure 12: Thermal baseload generation, 20-26 July 2025



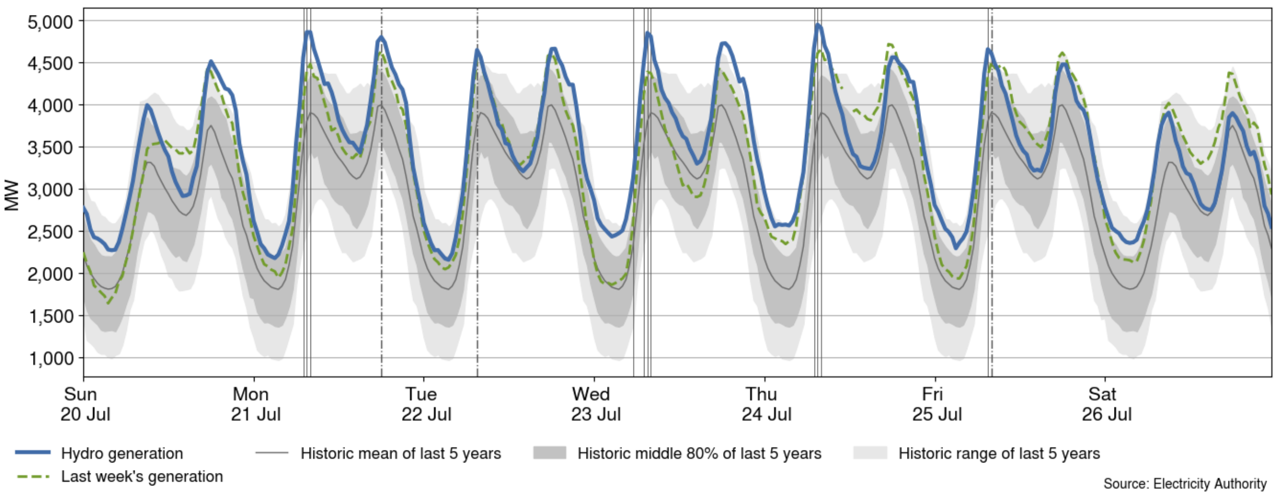
7.6. Figure 13 shows the generation of thermal peaker plants between 20-26 July 2025. Junction Road ran this week from Sunday evening, covering peak periods but overnight on Wednesday and Thursday as well. Stratford Peaker 2 generated on Sunday, Monday, and Saturday. McKee ran from Monday to Friday during peak demand periods. Whirinaki also ran during the Monday morning peak, Thursday evening peak, and on Friday morning peak.

Figure 13: Thermal peaker generation, 20-26 July 2025



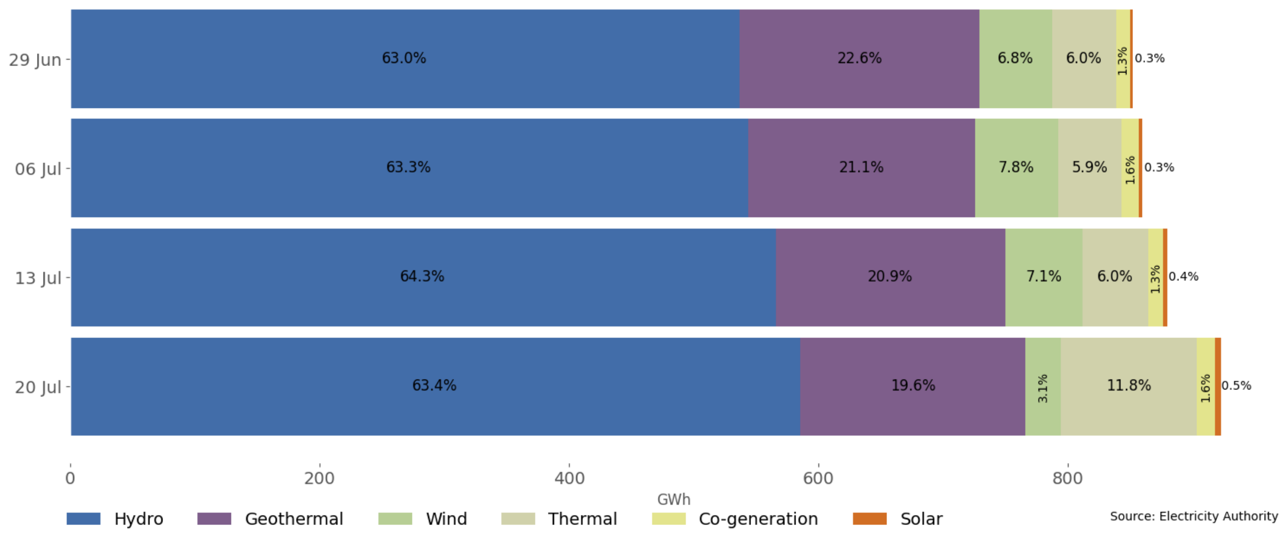
7.7. Figure 14 shows hydro generation between 20-26 July 2025. Overall, hydro generation was higher than the historic mean. During the times of high demand, hydro generation increased to meet elevated demand.

Figure 14: Hydro generation, 20-26 July 2025



7.8. As a percentage of total generation, between 20-26 July 2025, total weekly hydro generation was 63.4%, geothermal 19.6%, wind 3.1%, thermal 11.8%, co-generation 1.6%, and solar (grid connected) 0.5%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 29 June 2025 and 26 July 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 20-26 July 2025 ranged between ~689MW and ~1,376MW. 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) Huntly 1 was on outage between 20-24 July 2025.

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

(d) Manapōuri unit 1 was on outage between 24-26 July 2025.

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

(f) Tauhara geothermal was on outage between 22-24 July 2025.

(g) Ruakākā battery outage ends on 25 July 2025 but still partial outage until 29 July 2025.

Figure 16: Total MW loss from generation outages, 20-26 July 2025

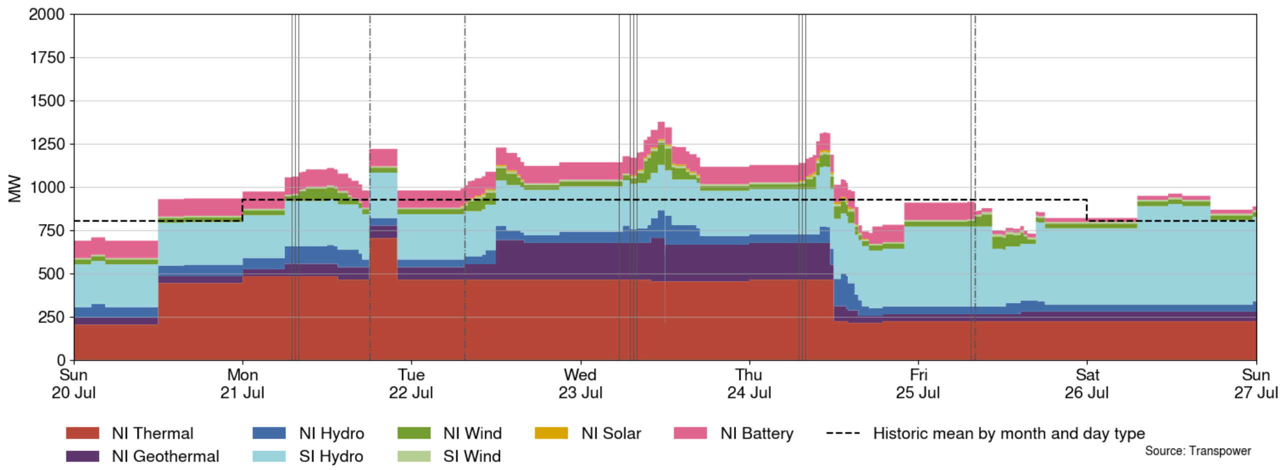
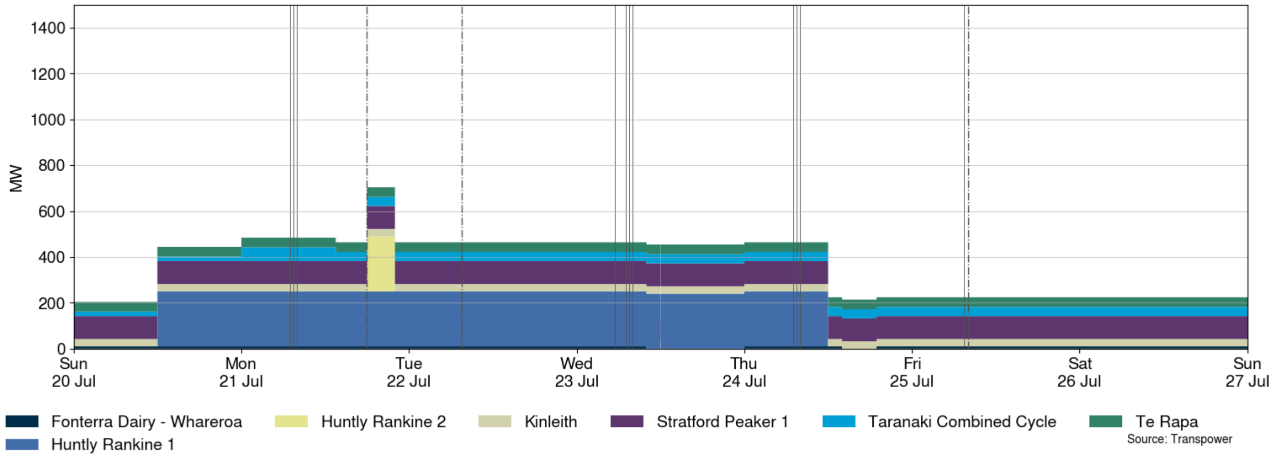


Figure 17: Total MW loss from thermal outages, 20-26 July 2025

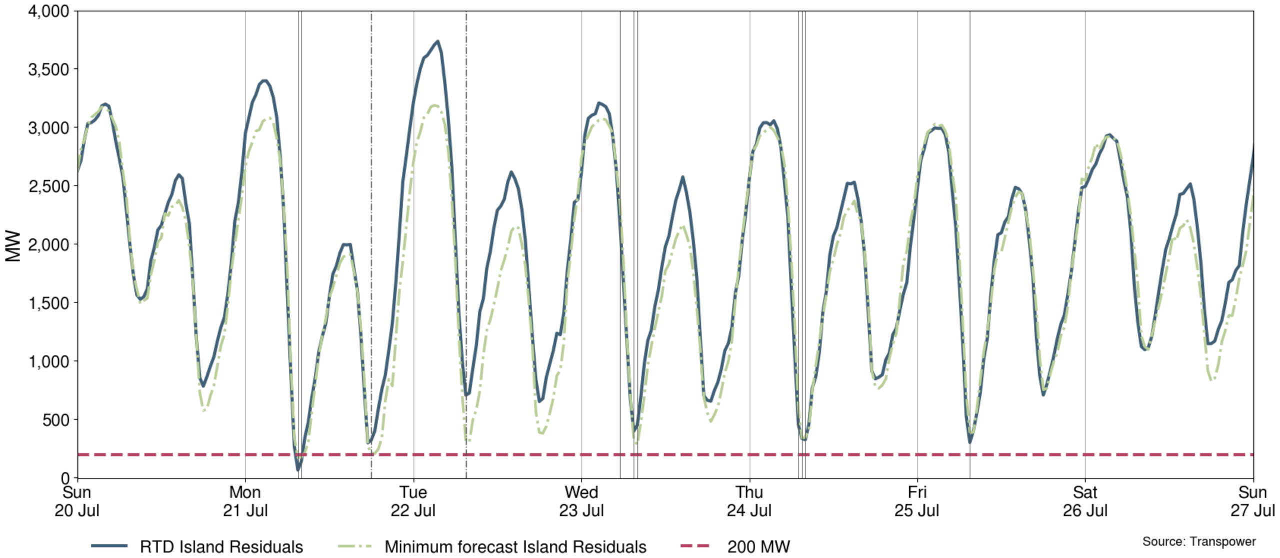


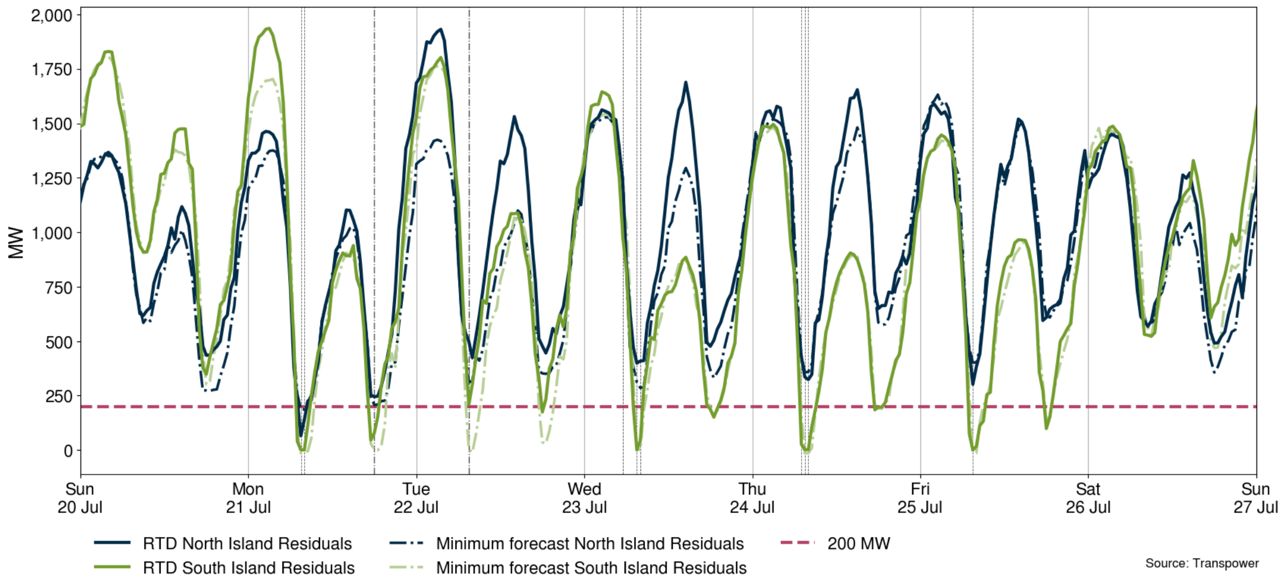
9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 20-26 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 low during the peak demand period this week. The lowest national residual this week was 65MW on Monday at 7.30pm.

Figure 18: National generation balance residuals, 20-26 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 10th to 90th percentiles.

10.2. As of 26 July 2025, national controlled hydro storage had decreased to 60% of nominal full and ~96% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (56% full[2]) is below its historical average, and storage at Lake Takapō (39% full) is between its historic mean and 10th percentile.

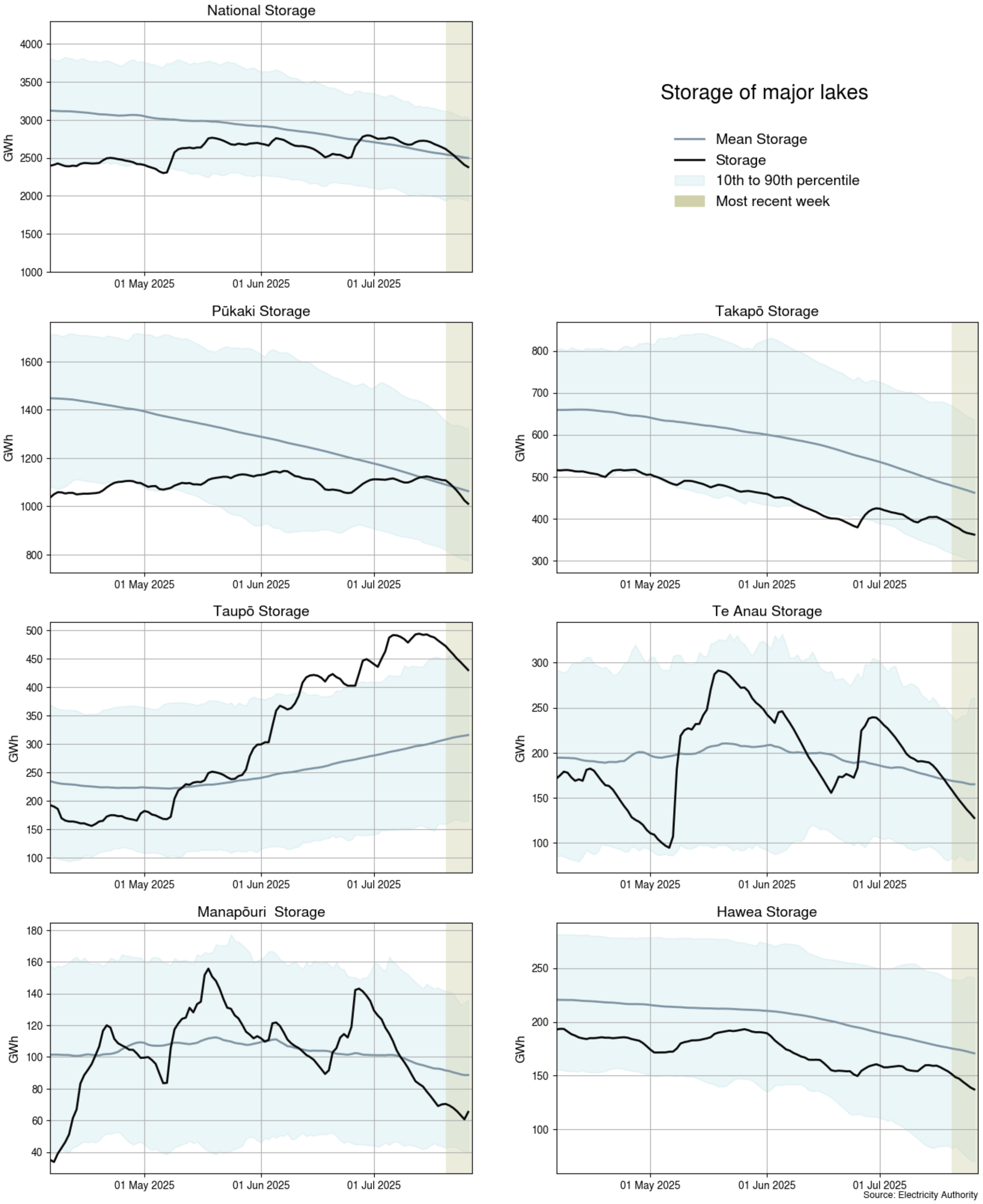
10.4. Storage at Lake Te Anau (46% full) and Lake Manapōuri (43% full) has decreased, with both currently below their respective historical mean.

10.5. Storage at Lake Taupō (74% full) is touching its historical 90th percentile.

10.6. Storage at Lake Hawea (47% full) remains between its historical 10th percentile and mean.

[2] Percentage full values sourced from NZX hydrological summary 27 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.

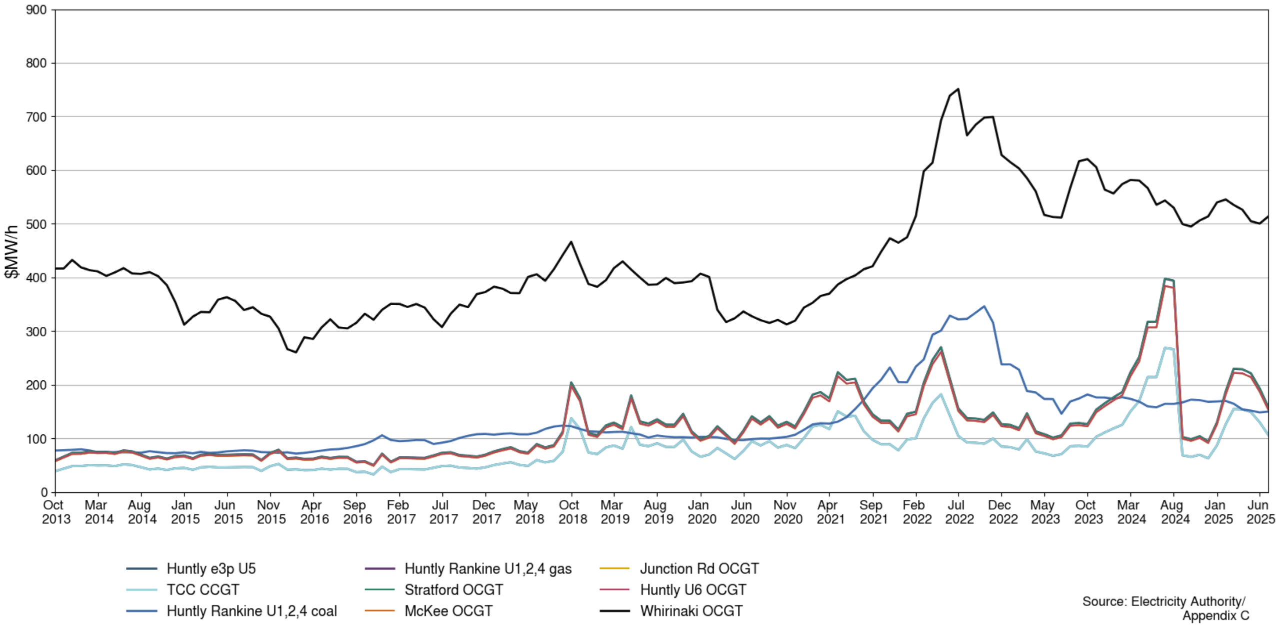
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$159/MWh.

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



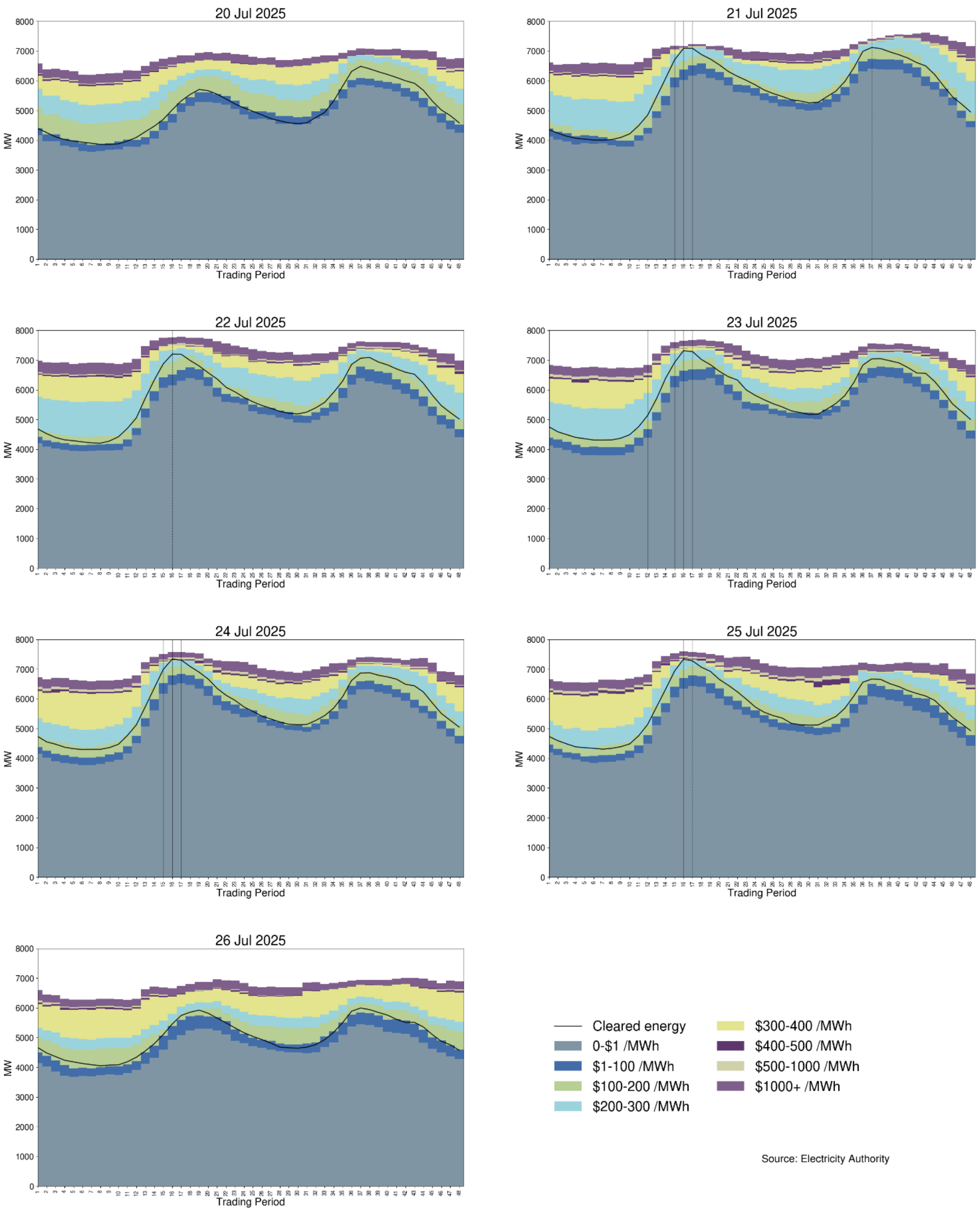
12. Offer behaviour

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 $100-$200/MWh range. During a few trading periods in the peak demand times, high demand and low wind conditions led to cleared energy moving into higher price bands.

12.3. On Monday, during the morning peak, energy from the highest price band also cleared to meet demand.

Figure 21: Daily offer stacks

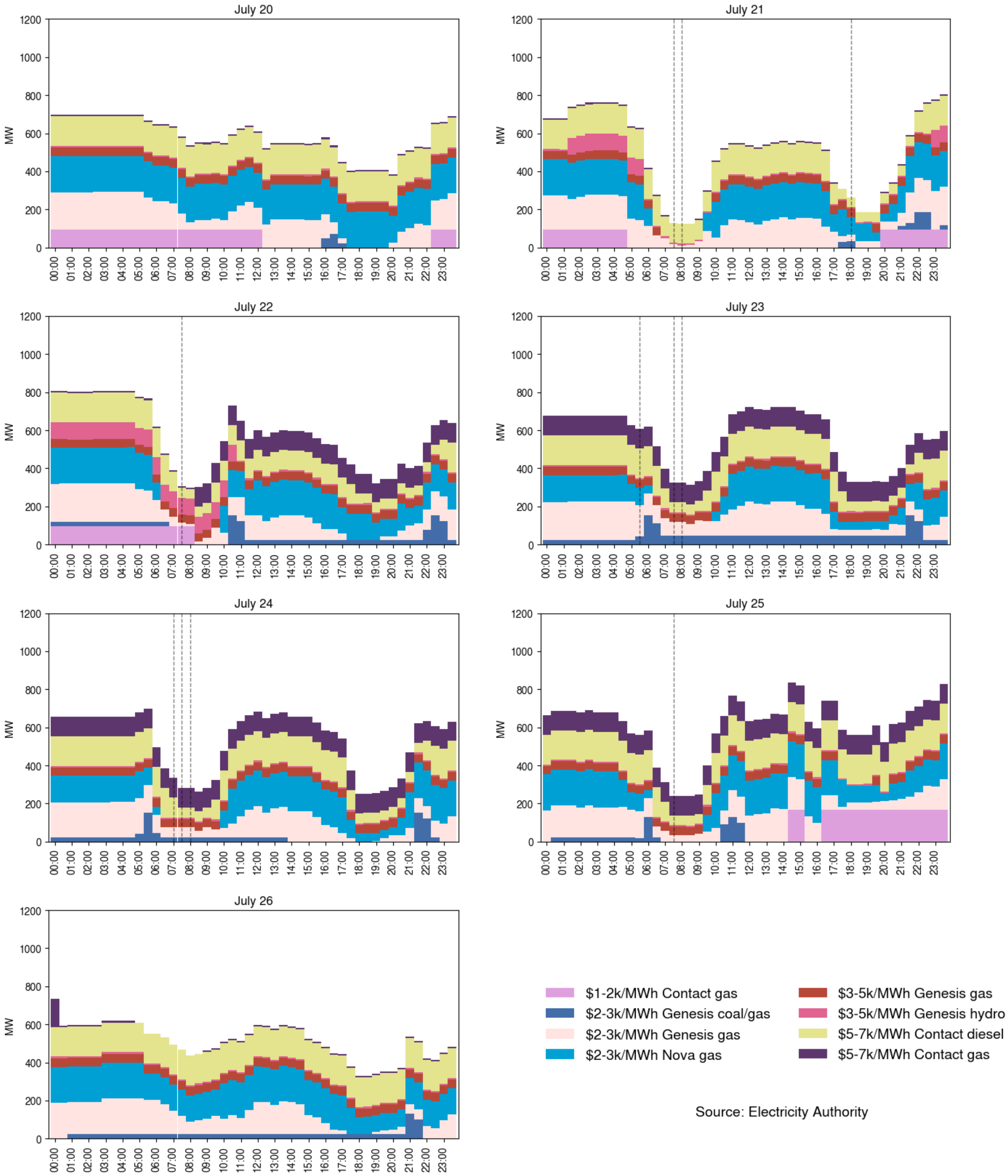


12.4. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 552MW per trading period was priced above $1,000/MWh this week, which is roughly 8.7% of the total energy available. During times of peak demand the proportion of highly priced generation decreases as expected.

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. The monitoring team will be further analysing Rankine offers for 21 July.

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
15/07/2025-16/07/2025	Several	Further analysis	Contact	Stratford and Whirinaki	Offers
21/07/2025	16	Further analysis	Genesis	Huntly Rankine	Offers