27 July 2026

Trading conduct report 19-25 July 2026

Market monitoring weekly report

Trading conduct report 19-25 July 2026

1. Overview

1.1. This week is characterised by a combination of high hydro generation and higher demand causing the HVDC to be frequently close to its northward capacity. This led to frequent price separation with North Island spot prices exceeding South Island prices by up to $201/MWh.

1.2. The average spot price for the week was $46/MWh, an increase of around $17/MWh compared to the previous week. Prices have increased as a result of North Island price separation due to high northward HVDC transfer, higher demand, and lower wind generation this week. National hydro storage has decreased this week to 85% nominally full and 133% 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 19-25 July:

(a) The average wholesale spot price across all nodes was $46/MWh, an increase of around $17/MWh.

(b) 95% of prices fell between $0.02/MWh and $142/MWh.

2.3. The highest price at Ōtāhuhu was $202/MWh at 4:30pm on Wednesday. At this time the HVDC was close to its northward capacity and wind generation was low. At the same time, prices at Benmore were $0.02/MWh.

2.4. There was frequent North Island price separation this week due to the HVDC regularly being near its northward flow capacity as a result of high hydro generation.

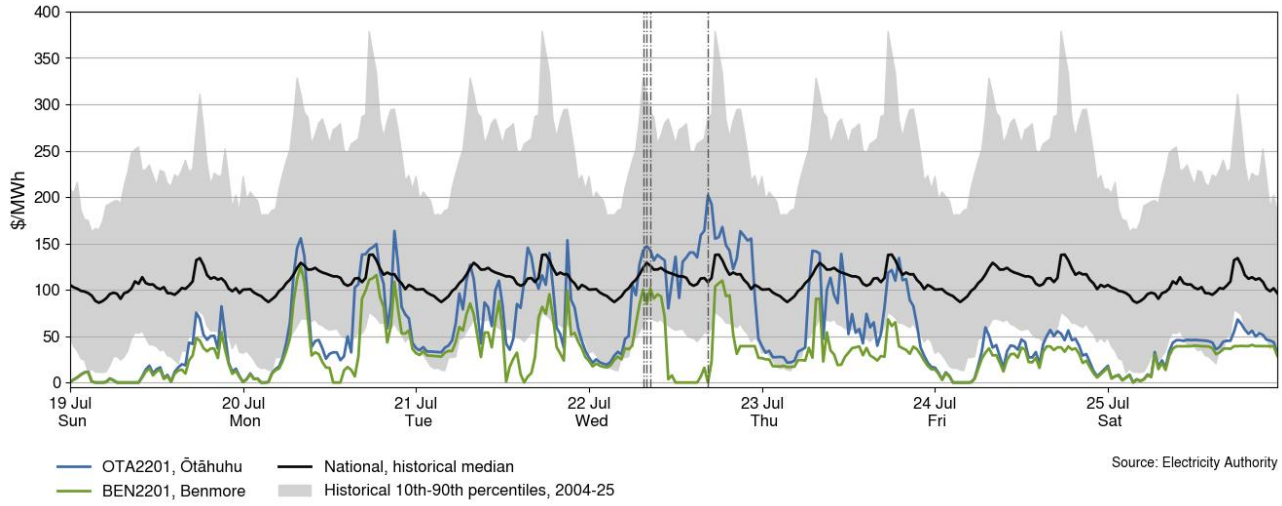
2.5. At 3.30pm on Tuesday, the System Operator issued a low residual customer advice notice (CAN) for 7.30-8.30am on Wednesday as the NRSL schedule showed residual generation was close to 200MW. [1] In real time, the lowest North Island residual was 331MW during this period and Ōtāhuhu prices reached up to $147/MWh.

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. Other notable prices, including the

[1] CAN Low Residual Situation 800000252.pdf

CAN period and highest Ōtāhuhu price this week are marked with black dashed lines.

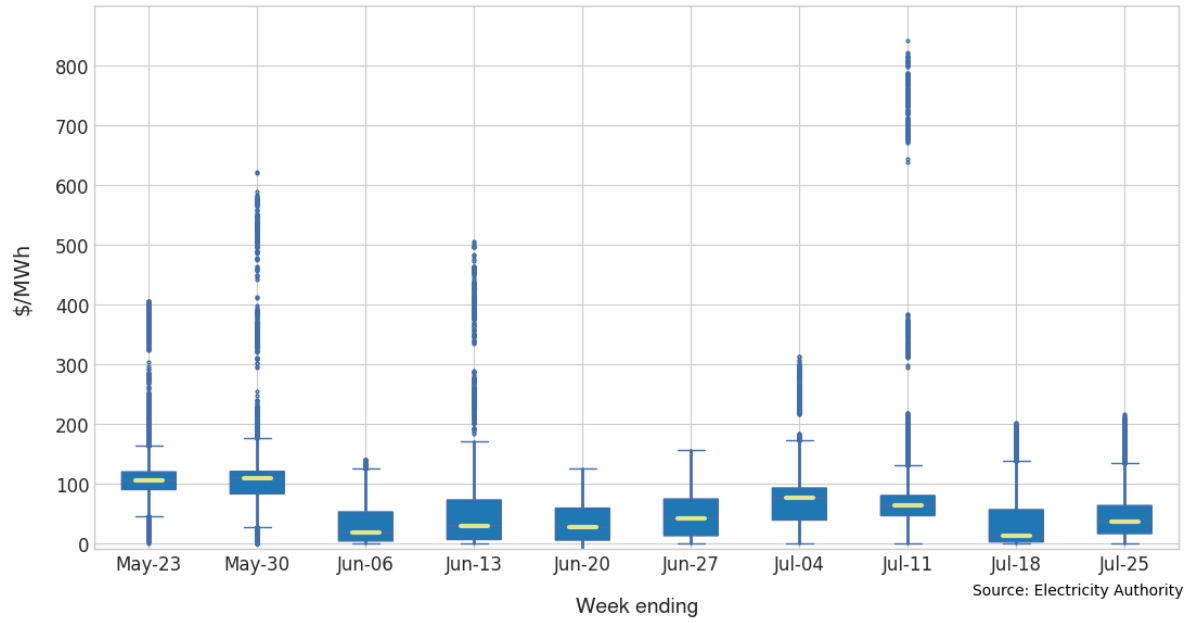
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 19-25 July



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 slightly narrower than last week with more high price outliers. The median price was $46/MWh and most prices (middle 50%) fell between $16/MWh and $63/MWh.

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

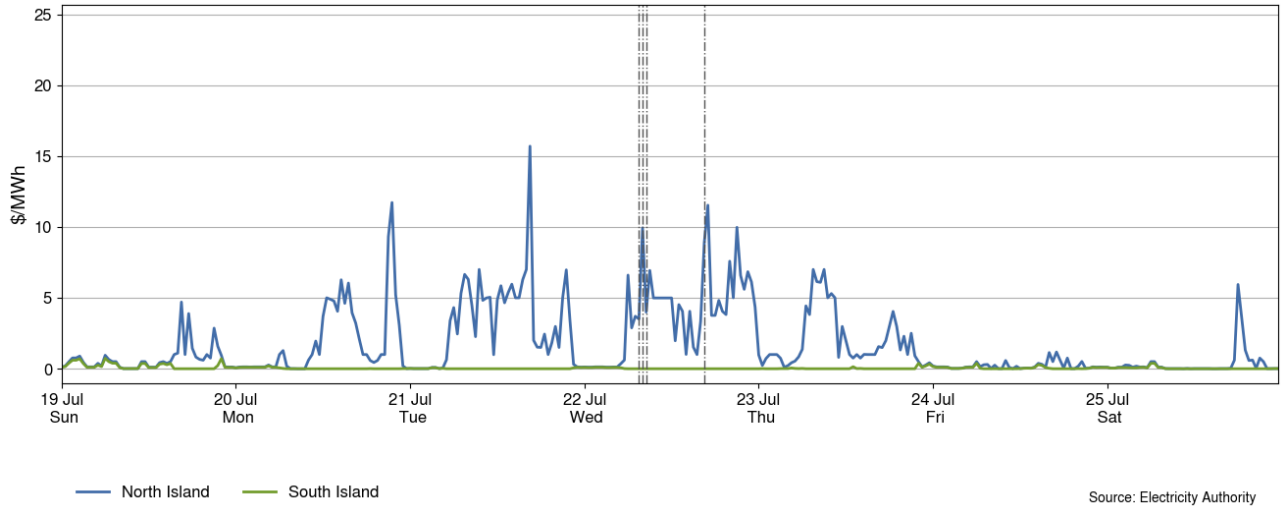


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh this week.

3.2. There was frequent separation between North and South Island FIR prices as the HVDC as regularly near or at its northward flow capacity.

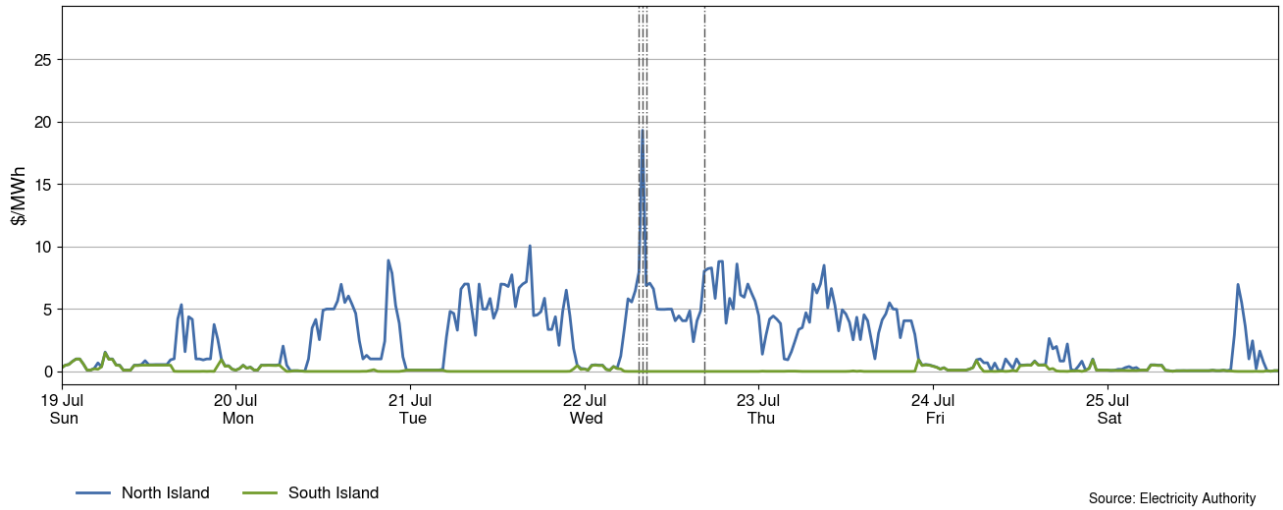
Figure 3: Fast instantaneous reserve price by trading period and island, 19-25 July



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh this week. There was frequent separation between North and South Island SIR prices as the HVDC was regularly near or at its northward flow capacity.

3.4. During Wednesday's CAN period, North Island SIR prices spiked up to $19/MWh at 8.00am. During this time the HVDC was setting the risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 19-25 July



4. Regression residuals

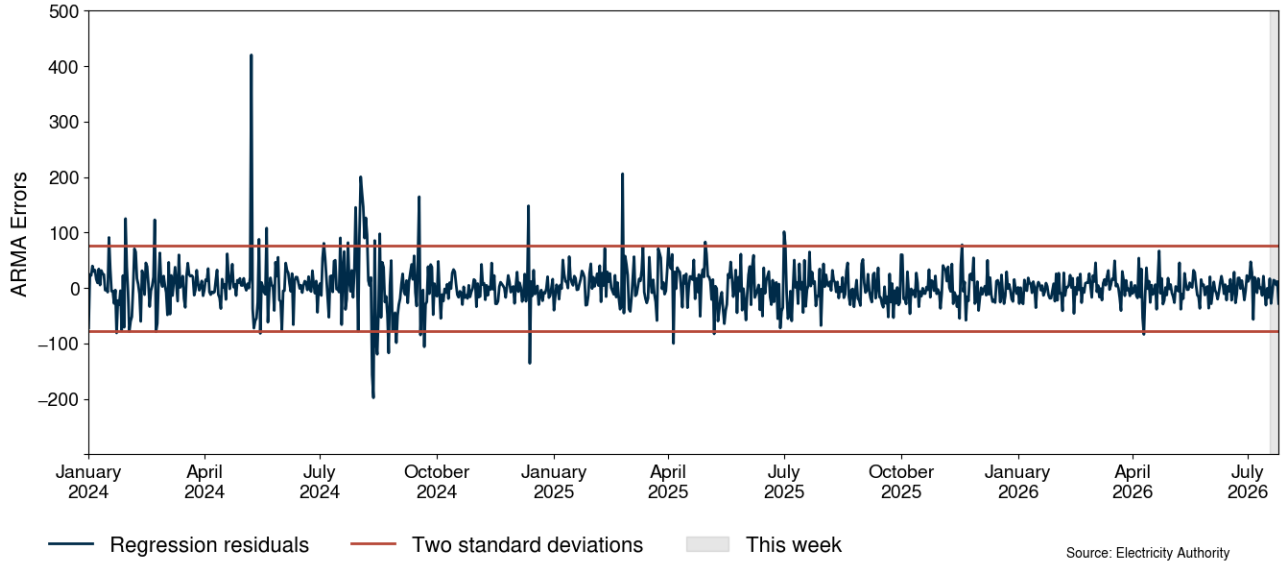
4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and

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 - 25 July 2026



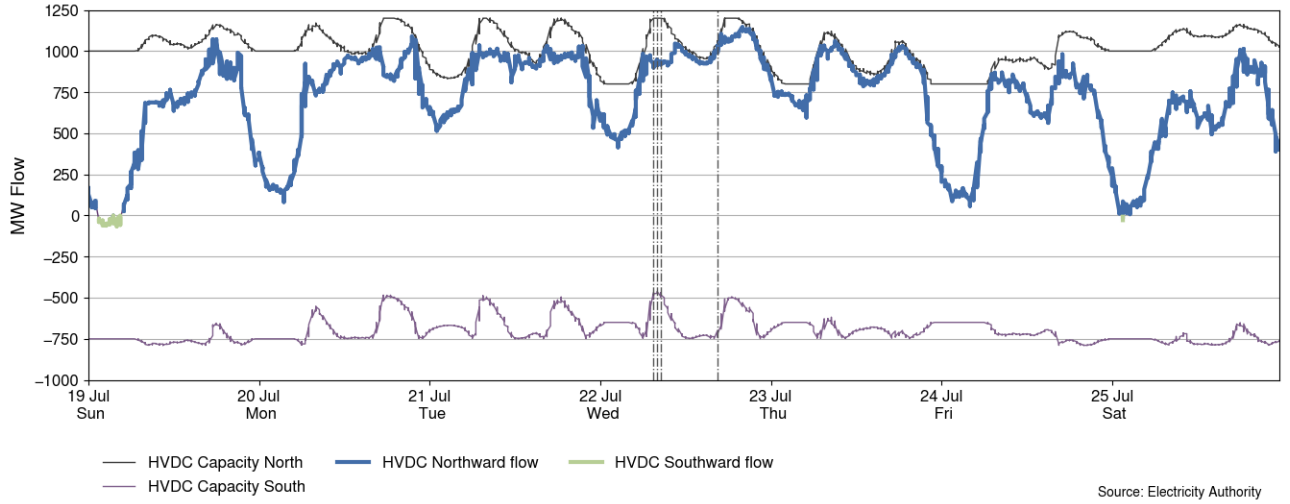
5. HVDC

5.1. Figure 6 shows the HVDC flow between 19-25 July. Due to high hydro generation, HVDC[2] flows have been almost entirely northward this week except for two short periods early Sunday morning and Friday night.

5.2. Throughout the week, the HVDC was often near or at its northward flow capacity.

[2] 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, 19-25 July



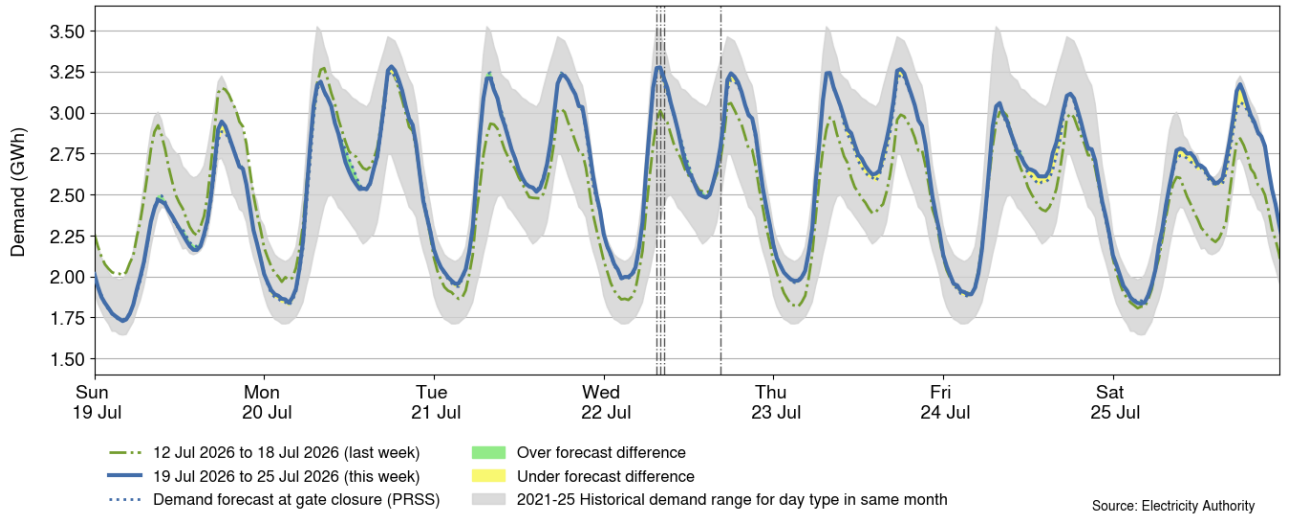
6. Demand

6.1. Figure 7 shows national demand between 19-25 July, compared to the historic range and the demand of the previous week.

6.2. Demand was higher than last week during peak periods on Tuesday, Wednesday, Thursday, and Saturday. It was lower than last week on Sunday, and around the same as last week on Monday. Demand was higher than last week during midday on Thursday, Friday, and Saturday.

6.3. The maximum demand this week was around 3.28GWh (6.56GW) at 6:00pm on Monday.

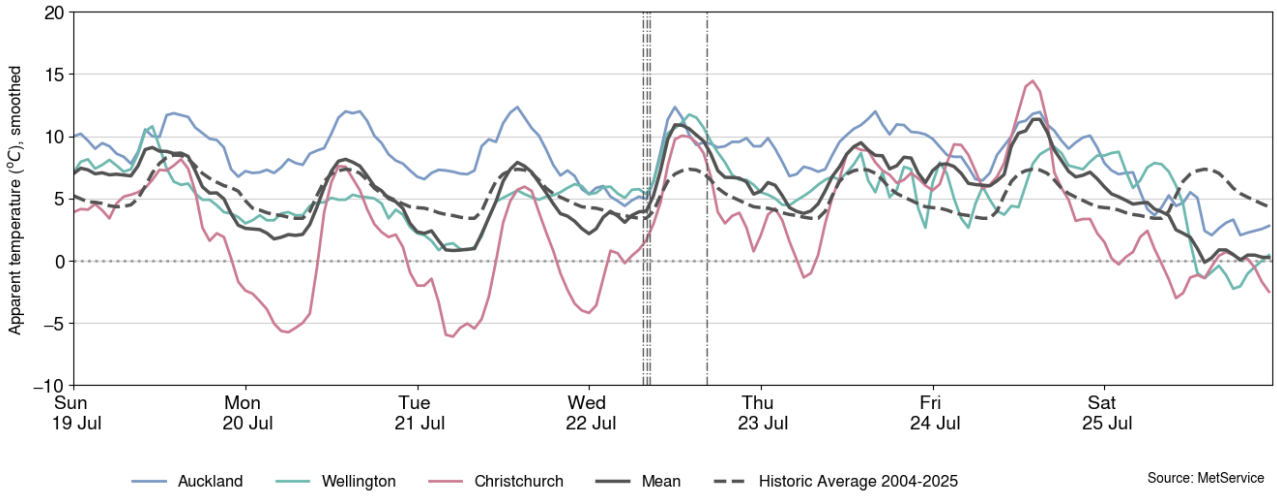
Figure 7: National demand, 19-25 July compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 19-25 July. 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.

6.5. Apparent temperatures ranged from 0°C to 13°C in Auckland, -2°C to 12°C in Wellington, and -6°C to 15°C in Christchurch.

Figure 8: Temperatures across main centres, 19-25 July



7. Generation

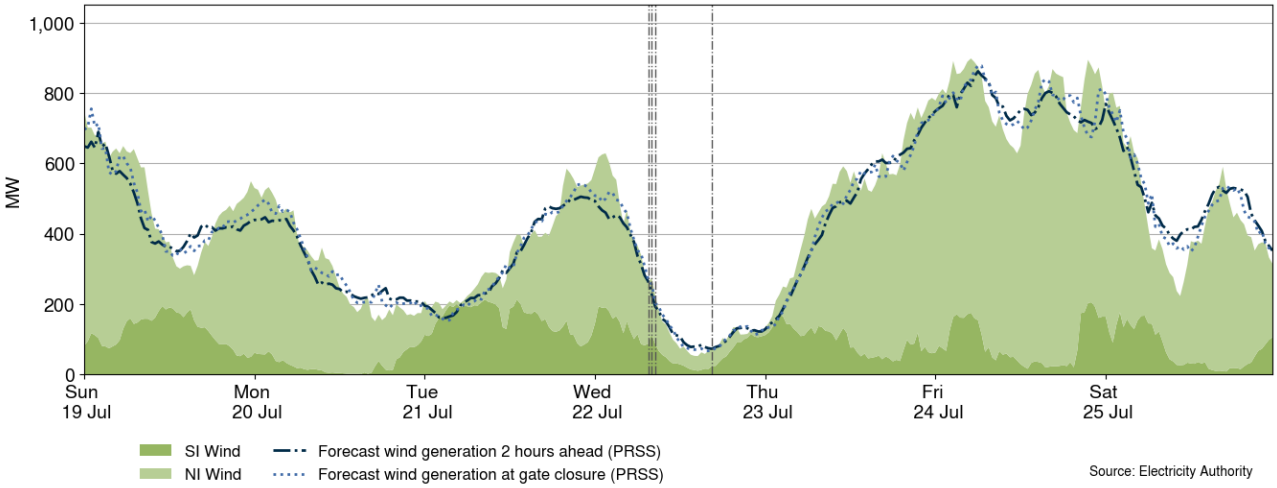
7.1. Figure 9 shows wind generation and forecast from 19-25 July. This week wind generation varied between 52MW and 898MW, with a weekly average of 448MW.

7.2. Wind generation was lower overall than last week, with the highest generation occurring between Thursday morning and Saturday morning.

7.3. Over-forecasting errors on Saturday were caused by Harapaki, Kaiwera Downs, Waipipi, and West Wind 1 wind farms.

7.4. Under-forecasting errors on Tuesday night/Wednesday morning were caused by Kaiwera Downs, Waipipi, and Kaiwaikawe wind farms.

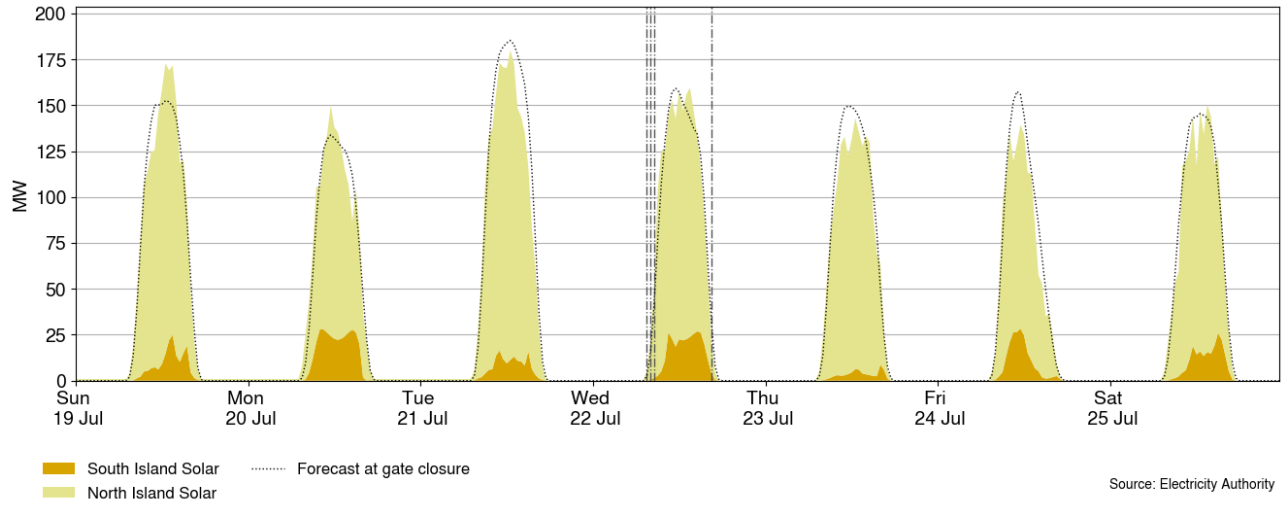
Figure 9: Wind generation and forecast, 19-25 July



7.5. Figure 10 shows grid connected solar generation from 19-25 July.

7.6. Solar generation reached over 135MW each day this week, peaking at 180MW on Tuesday at 12.30pm.

Figure 10: Grid connected solar generation, 19-25 July

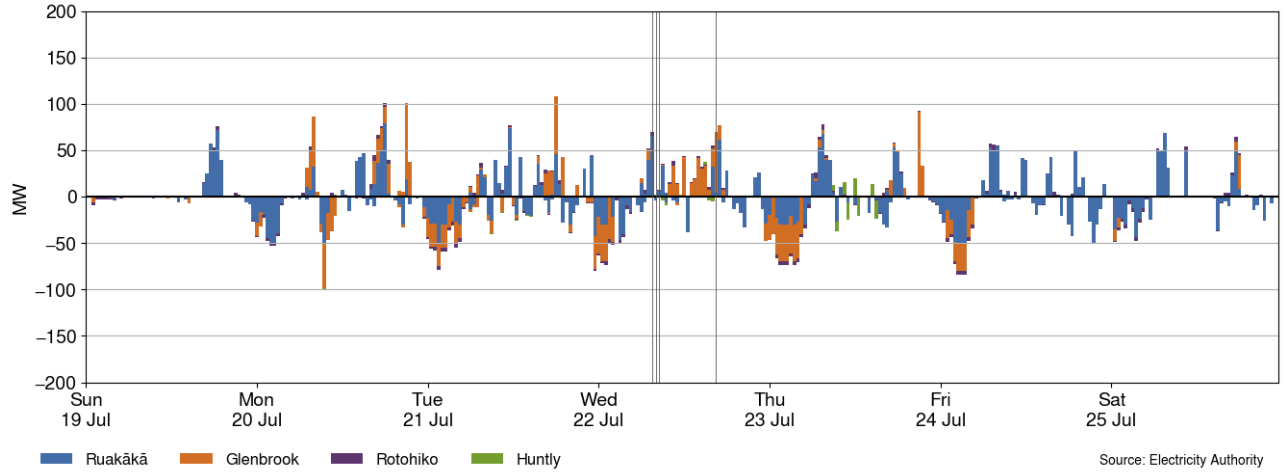


7.7. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh), Glenbrook (100MW/200MWh), and Huntly (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.8. Genesis' 100MW/200MWh Huntly BESS has been generating this week, peaking on Thursday. The output of the battery will vary as it commissions.

7.9. This week the batteries mostly charged overnight during lower prices and discharged during the day. The batteries did not charge or discharge much during low prices on Sunday.

Figure 11: Grid scale battery charge and discharge, 19-25 July



7.10. 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[3]) 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 -

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

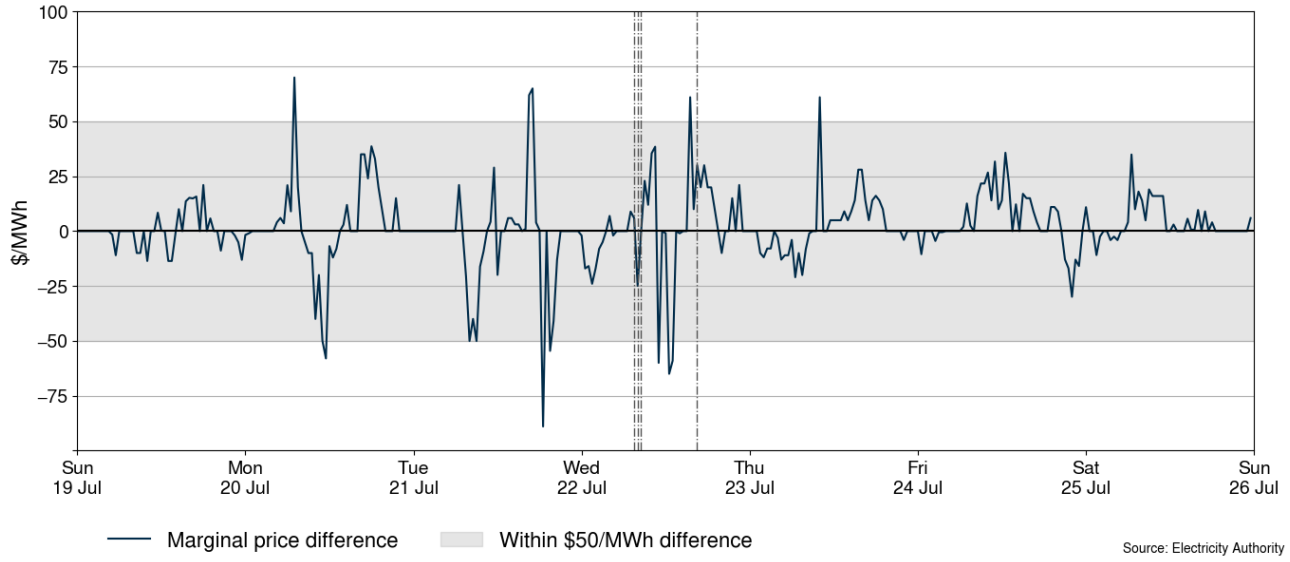
usually here demand is under forecast and/or intermittent generation is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and intermittent generation forecasting, the 1-hour ahead and the RTD intermittent generation and demand forecasts will rarely be the same. 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.

7.11. There were 13 trading periods with forecast differences greater than $50/MWh.

7.12. The greatest positive forecast difference was $70/MWh over-forecast at 7.00am on Monday. At this time demand was ~150MW higher than forecast and intermittent generation was ~6MW higher than forecast.

7.13. The greatest negative forecast difference was $89/MWh under-forecast at 6.30pm on Tuesday. At this time demand was ~4MW lower than forecast and intermittent generation was ~9MW lower than forecast.

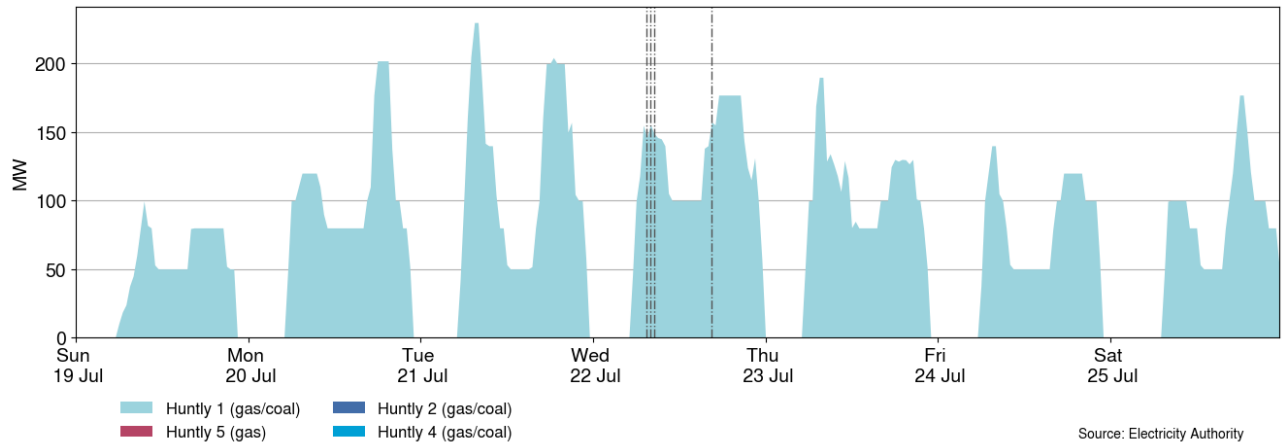
Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 19-25 July



7.14. Figure 13 shows the generation of thermal baseload between 19-25 July.

7.15. Baseload thermal generation this week was entirely provided by Huntly 1.

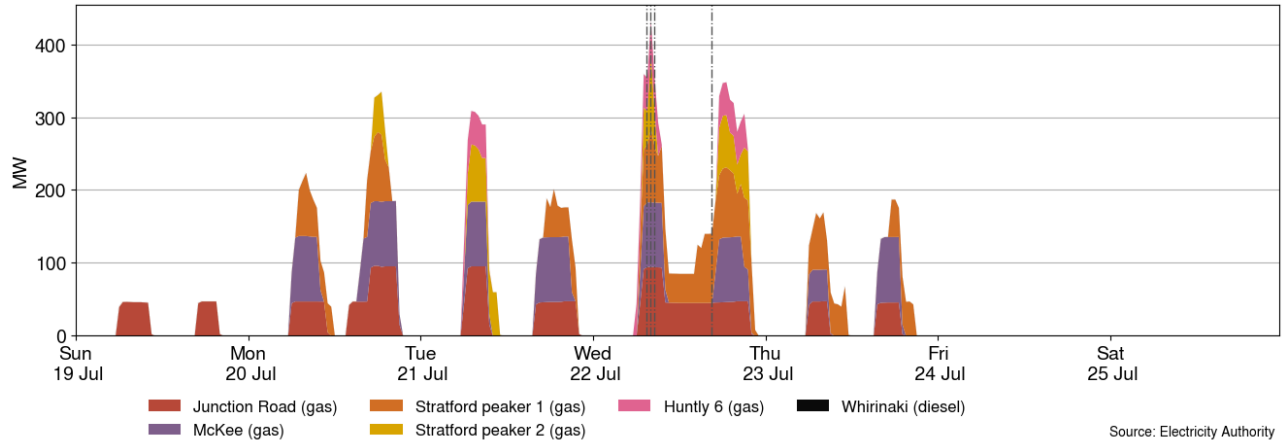
Figure 13: Thermal baseload generation, 19-25 July



7.16. Figure 14 shows the generation of thermal peaker plants between 19-25 July.

7.17. Peaker generation this week was greatest during the Wednesday morning peak demand, with all peakers aside from Whirinaki providing generation. No peaker generation ran on Friday and Saturday.

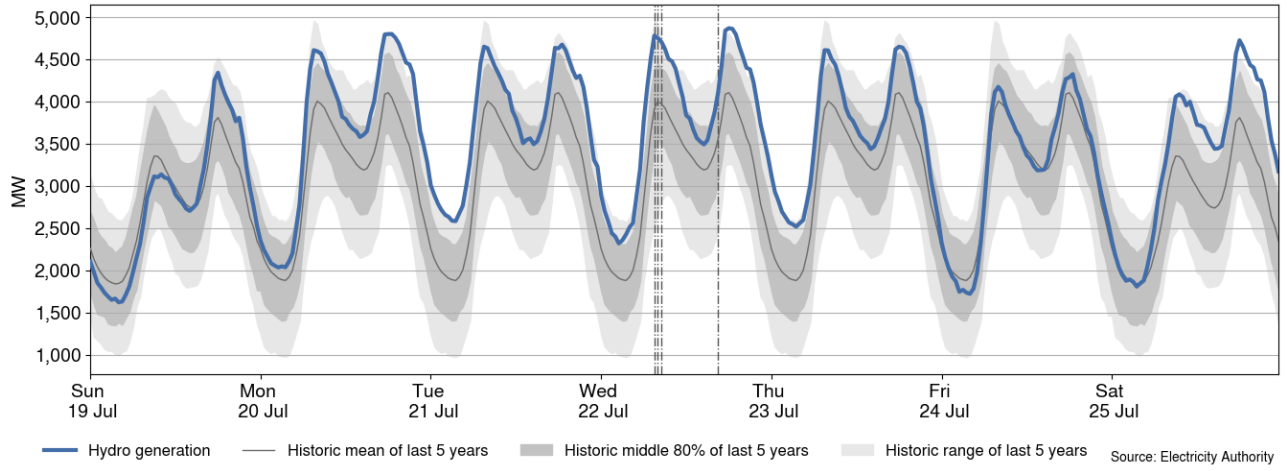
Figure 14: Thermal peaker generation, 19-25 July



7.18. Figure 15 shows hydro generation between 19-25 July.

7.19. Hydro generation was above the historic mean on Monday, Tuesday, Wednesday, Thursday, and Saturday. Generation was near the mean on Sunday and Friday.

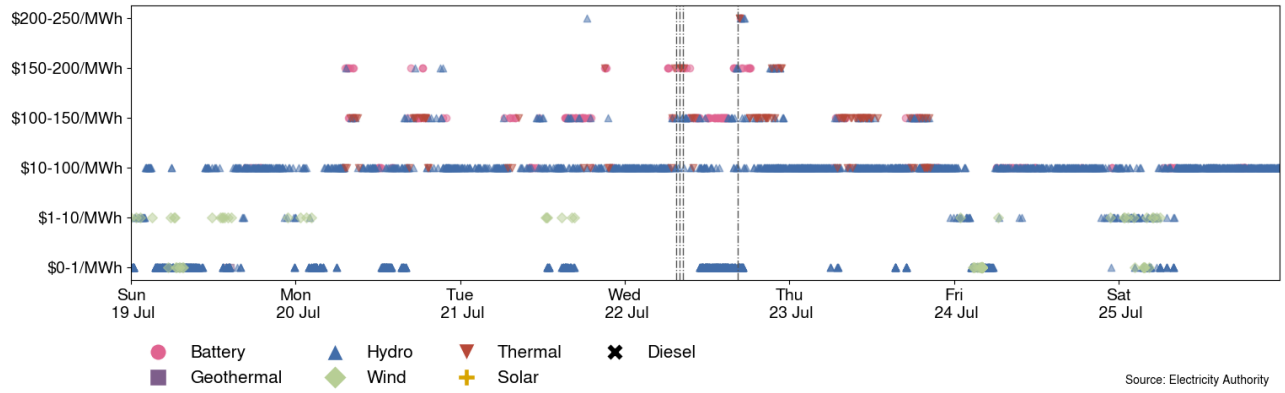
Figure 15: Hydro generation, 19-25 July



7.20. 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.

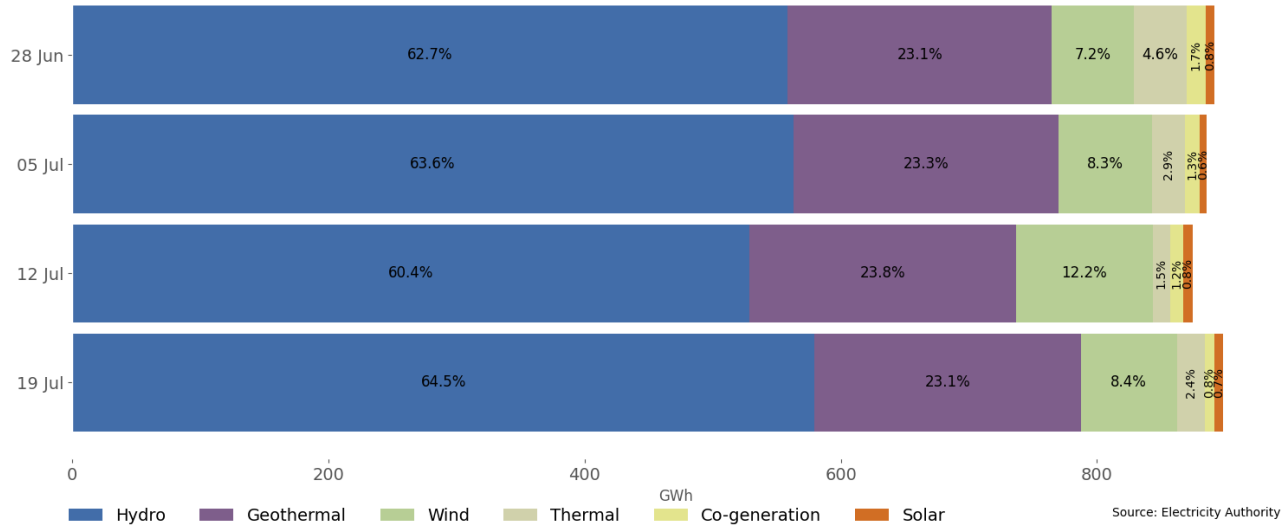
7.21. The highest marginal price was set by Ruakākā Energy Park on Wednesday evening. Most common technology setting prices this week was hydro, with batteries the second most common. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 19-25 July



7.22. As a percentage of total generation, between 19-25 July, total weekly hydro generation was 64.5%, geothermal 23.1%, wind 8.4%, thermal 2.4%, co-generation 0.8%, and solar (grid connected) 0.7%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 28 June and 19 July



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 19-25 July ranged between ~718MW and ~1,621MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 19-25 July

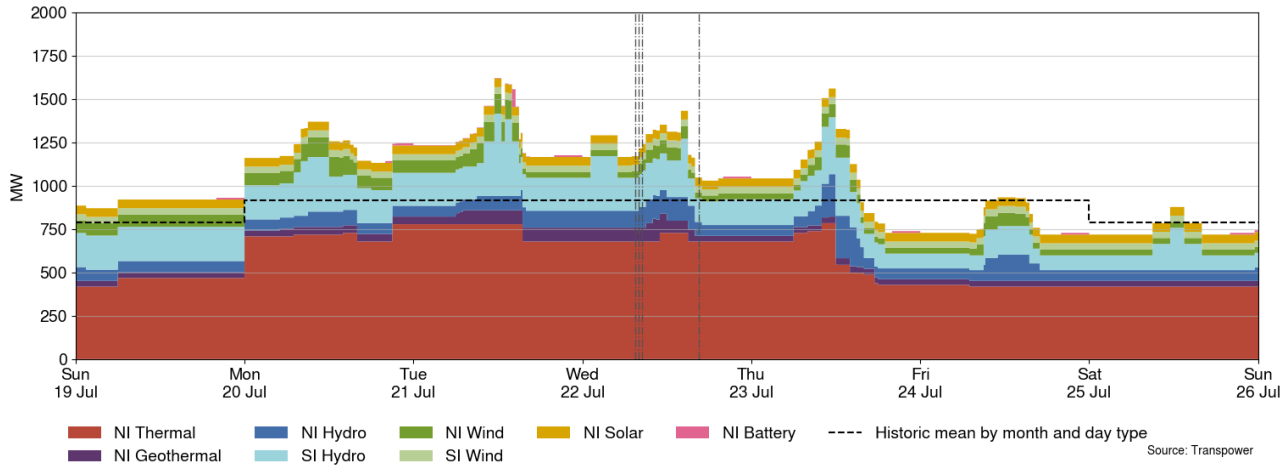
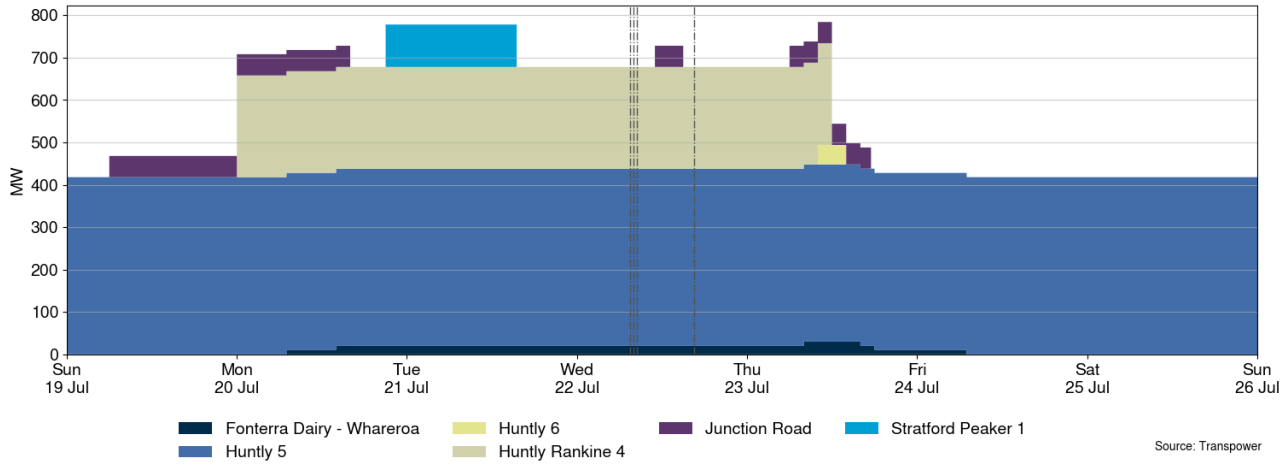


Figure 19: Total MW loss from thermal outages, 19-25 July



8.2. Notable outages include:

Plant	Partial or Full	End Date
Manapōuri unit 6	Full	20 July 2026
Stratford peaker 1	Full	21 July 2026
Roxburgh Station	Full	21 July 2026
Huntly 4	Full	23 July 2026
Huntly 5	Full	2 August 2026
Tauhei Solar Farm	Partial	31 August 2026
Roxburgh unit 8	Full	24 September 2026
Kaiwaikawe	Partial	30 November 2026

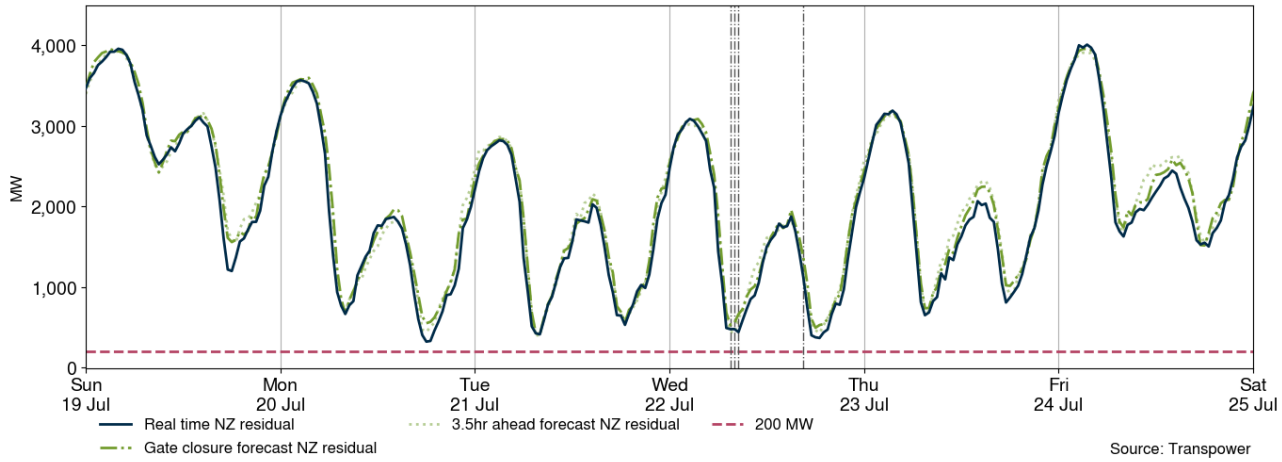
9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 19-25 July. 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. On Tuesday at 3.30pm, the System Operator issued a CAN advising low residual generation for Wednesday between 7.30am to 8.30am as the long non-responsive schedule (NRSL) showed residual generation was close to 200MW. In real time, the lowest North Island residual was 331MW during this period.

9.3. The lowest national residual of 324MW occurred at 6.00pm on Monday.

Figure 20: National generation balance residuals, 19-25 July



10. Storage/fuel supply

10.1. 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.

10.2. As of 25 July, national controlled storage was 85% nominally full and ~133% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (89% full[4]) is significantly higher than the historic 90th percentile for this time of year.

10.4. Storage at Lake Tekapō (73% full) is at the historic 90th percentile for this time of year.

10.5. Storage at Lake Taupō is (60% full) is above average for this time of year.

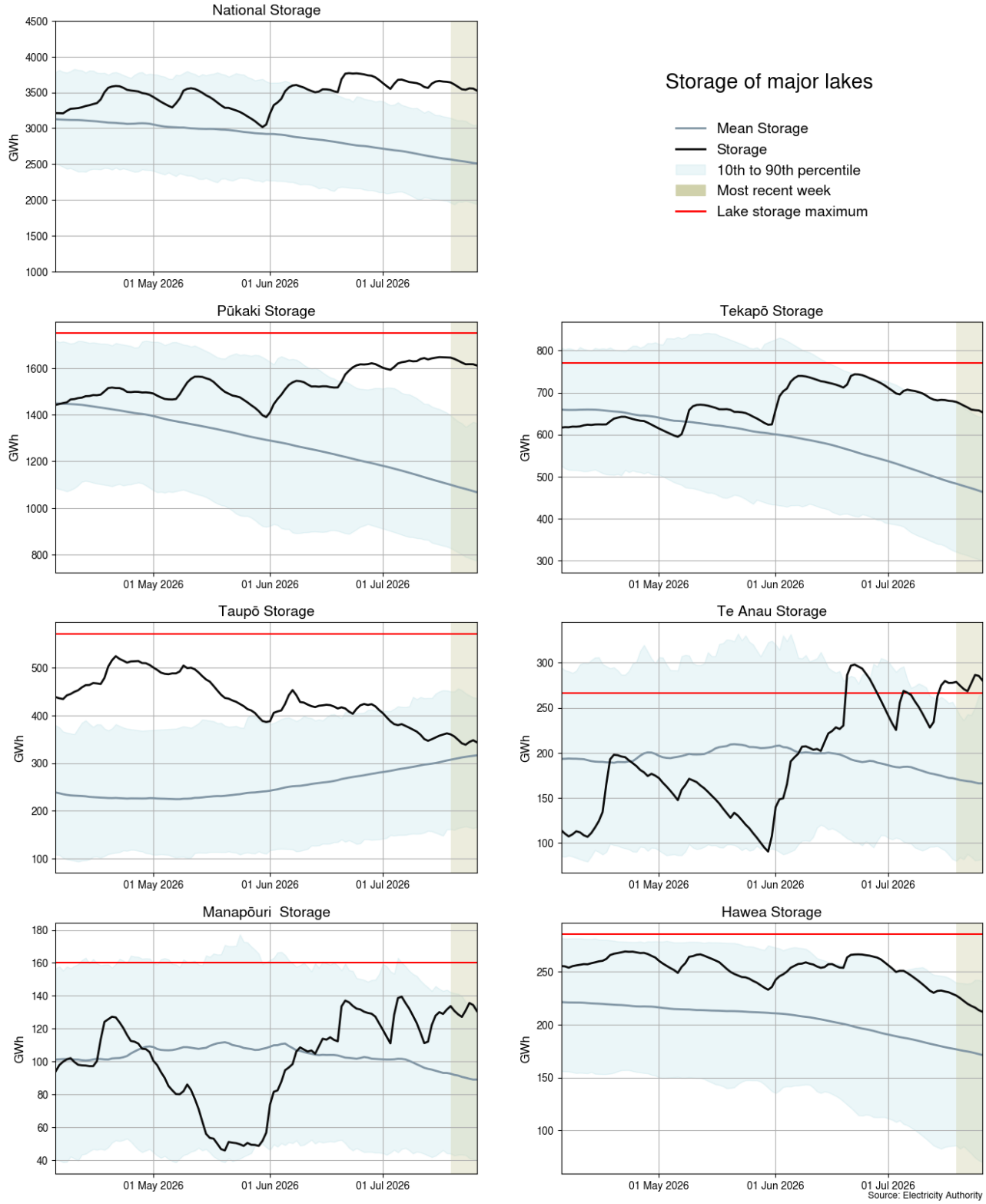
10.6. Storage at Lake Te Anau (105% full) is above its storage maximum and above the historic 90th percentile for this time of year.

10.7. Storage at Lake Manapōuri (83% full) is slightly below the historic 90th percentile for this time of year.

10.8. Storage at Lake Hawea (74% full) remains slightly below the historic 90th percentile for this time of year.

[4] Percentage full values sourced from NZX Hydro.

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 July 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 ~$181/MWh.

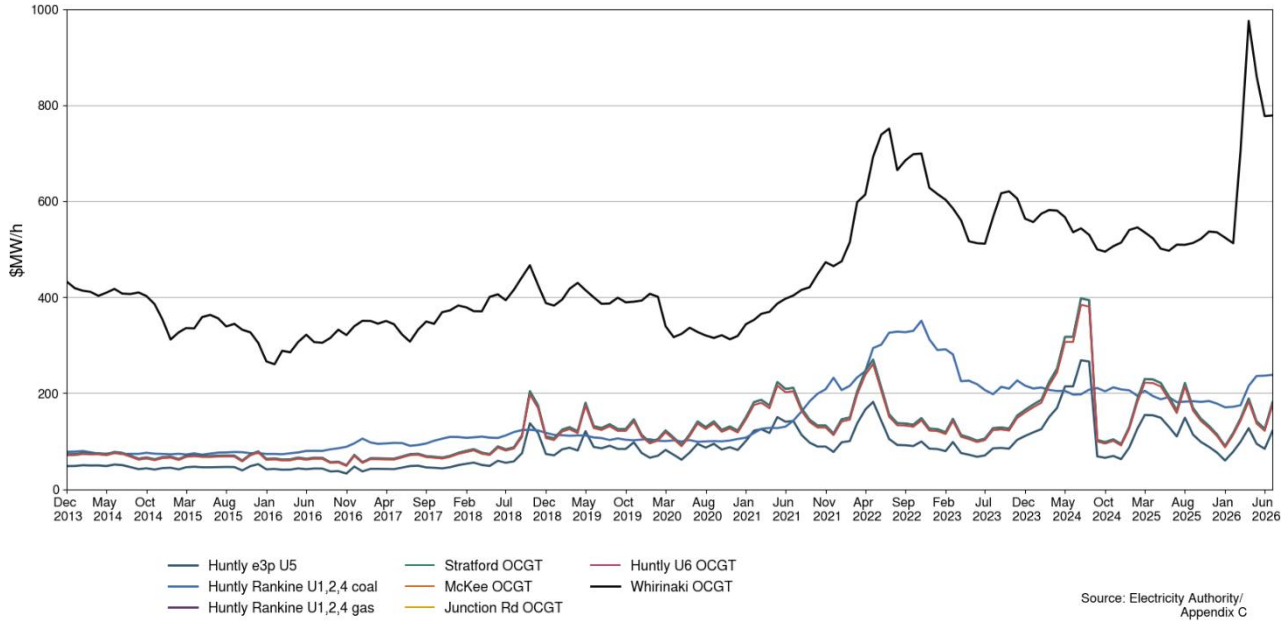
11.5. The SRMC of gas fuelled thermal plants is currently between $122/MWh and $181/MWh.

11.6. The SRMC of Whirinaki is ~$778/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. **Error! Reference source not found.** shows this week's North and South Island daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. In the North Island, most offers cleared below $200/MWh, although some offers cleared between $200-299/MWh on Tuesday and Wednesday during the evening peaks. In the South Island, most energy cleared below $200/MWh this week.

Figure 23: North Island daily offer stacks

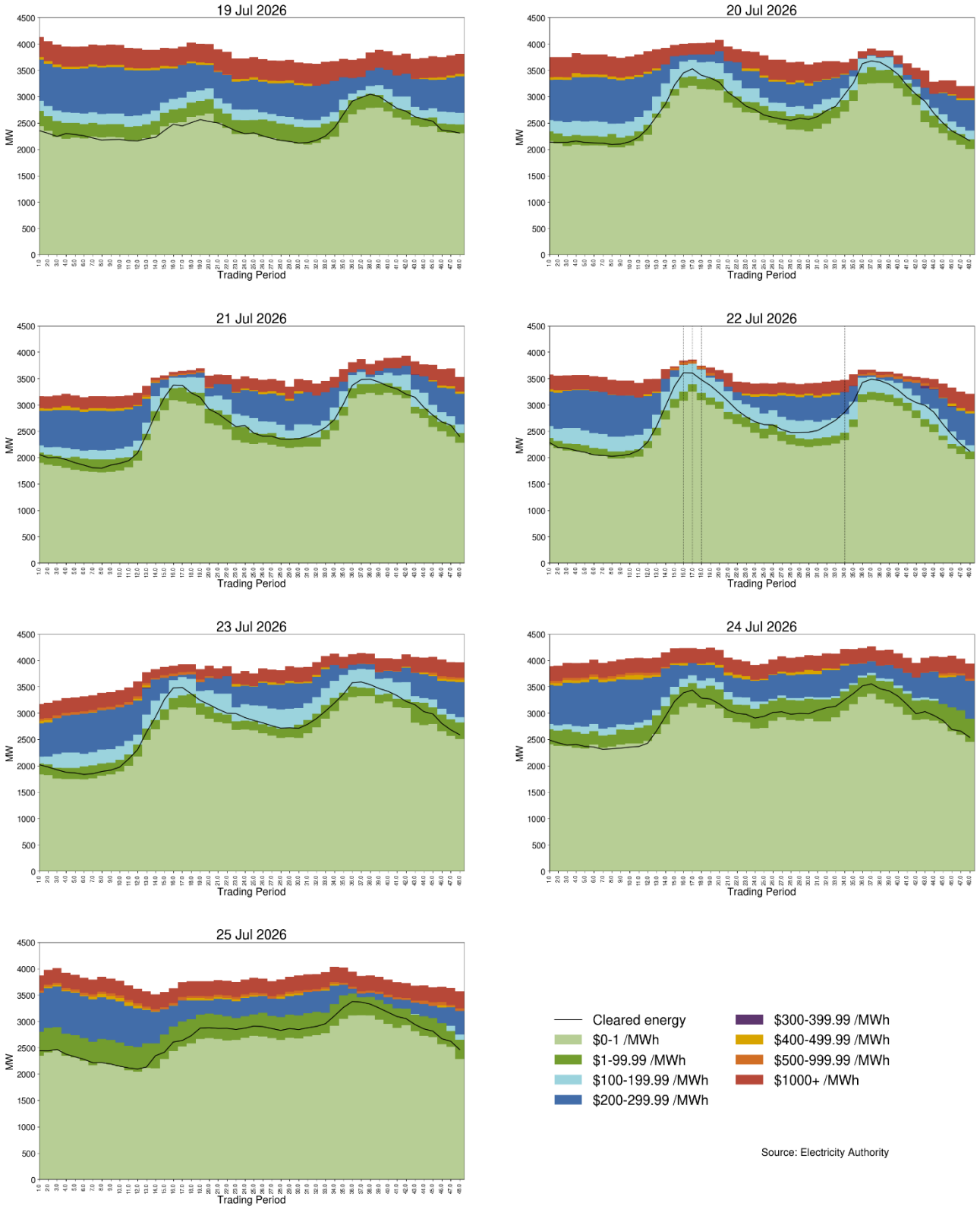
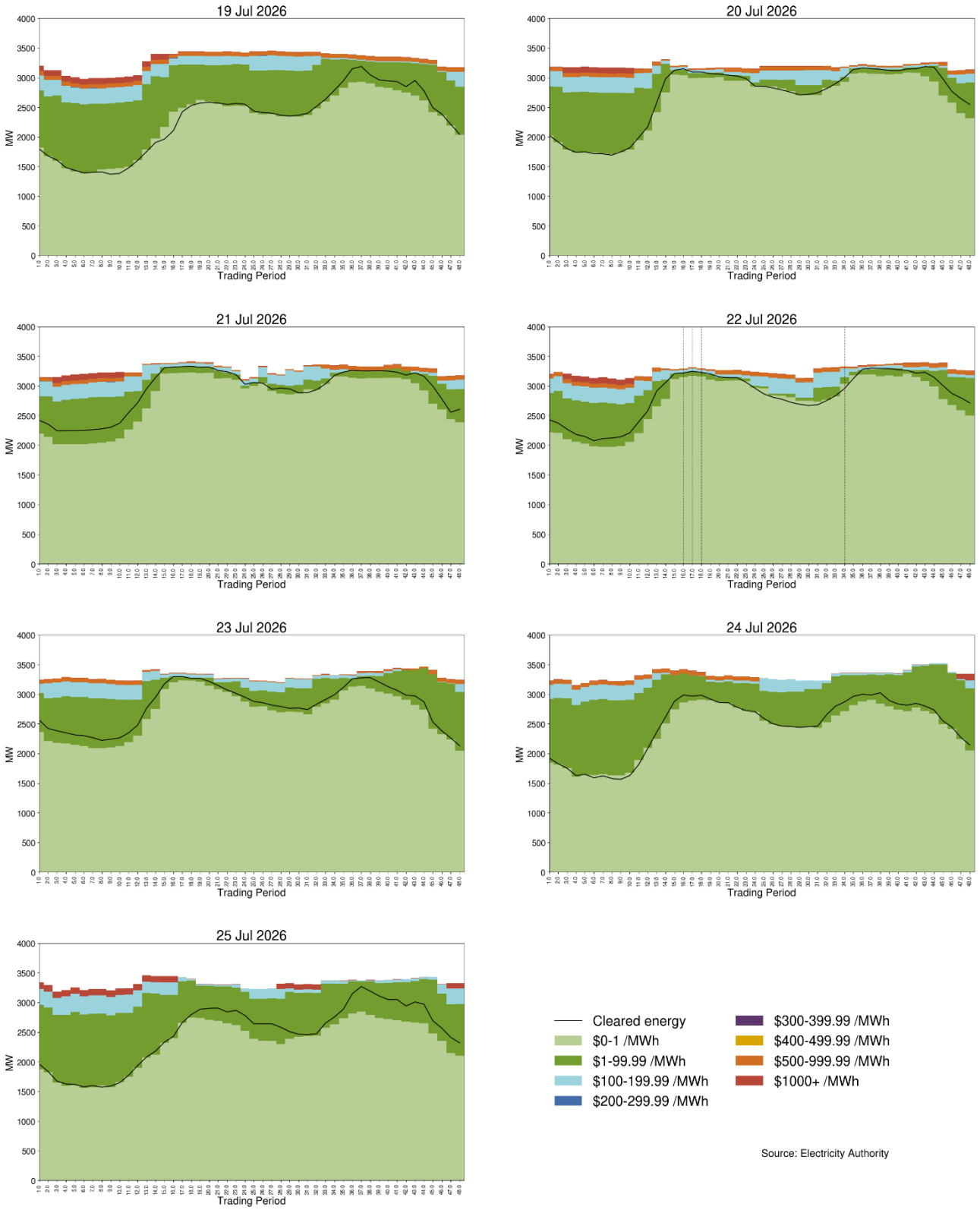


Figure 24: South Island daily offer stacks



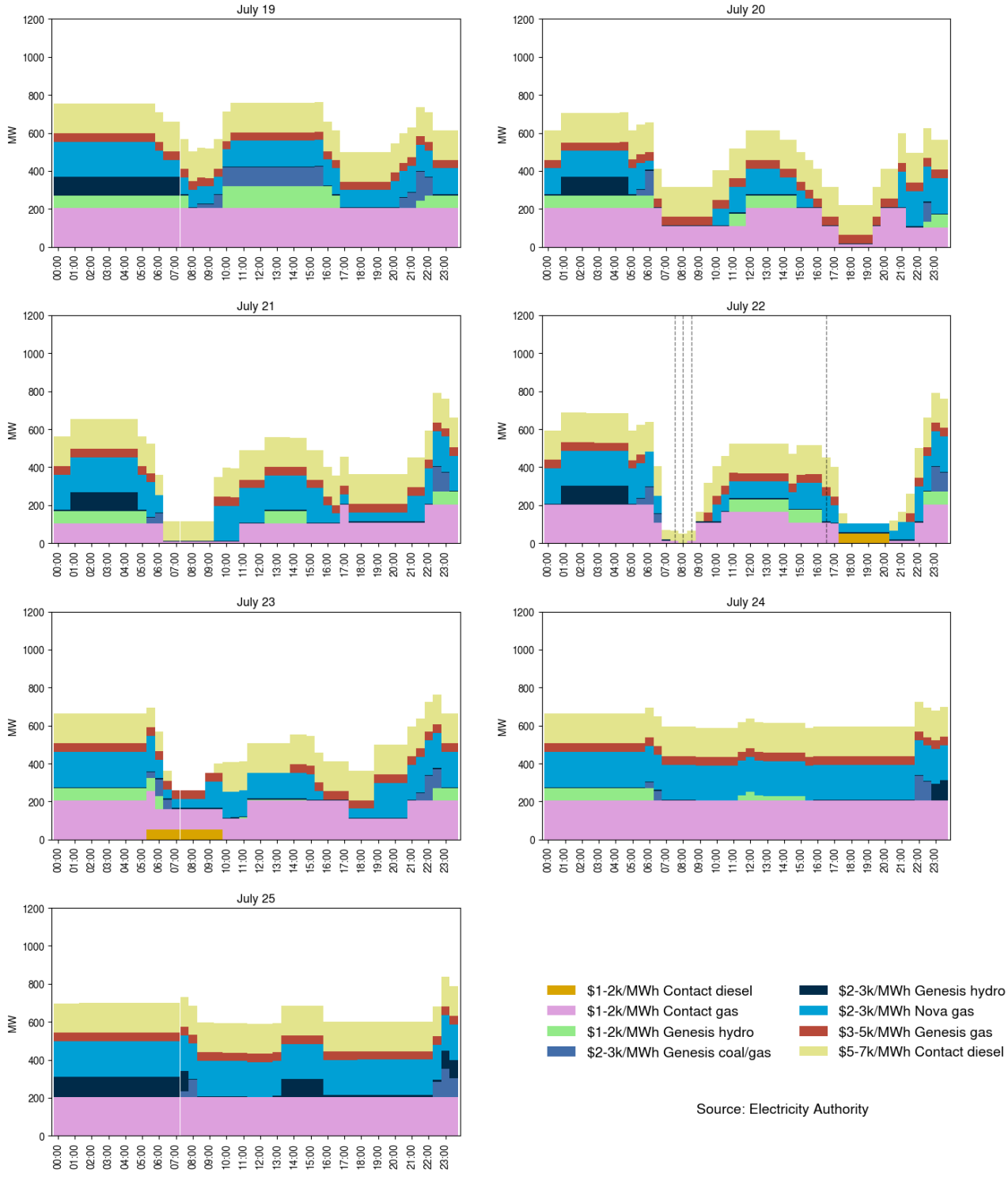
12.3. Figure 25 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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, intermittent 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 533MW per trading period was priced above $1,000/MWh this week, which is roughly 9.77% of the total energy available.

Figure 25: High priced offers



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 looking into Contact peaker offers further this week.

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
02/05/2026	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
04/06/2026-05/06/2026	Several	Further analysis	Harbour Infrastructure	Papareireiā solar farm	Reason for no generation
24/06/2026	Several	Further analysis	Contact	Stratford peakers	Offers
22/07/2026	16-18	Further analysis	Contact	Stratford peakers	Offers