22 June 2026

Trading conduct report 14-20 June 2026

Market monitoring weekly report

Trading conduct report 14-20 June 2026

1. Overview

1.1. This week the average spot price decreased from $39/MWh to $33/MWh. Prices have remained low due to high wind generation and high hydro storage. National controlled storage has increased to 85% nominally full and is 120% of the historical average for this time of here.

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 14-20 June:

(a) The average spot price for the week was $33/MWh, a decrease of around $6/MWh compared to the previous week.

(b) 95% of prices fell between $5/MWh and $59/MWh.

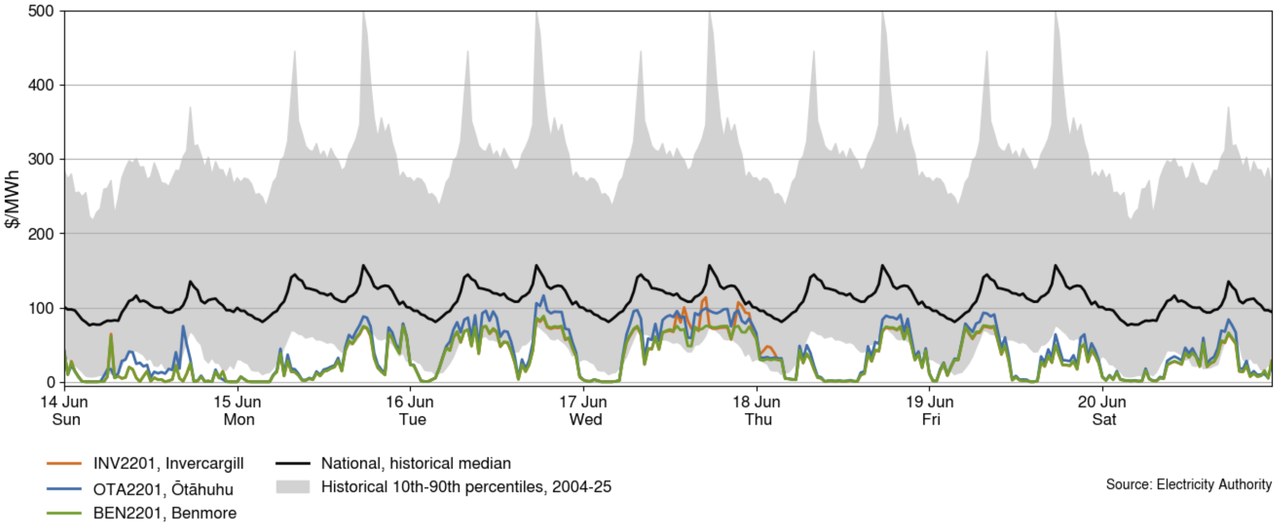
2.3. Prices have remained low this week because of high wind generation and high levels of hydro storage.

2.4. On Sunday at 4.30pm, there was significant price separation, with the spot price reaching $75/MWh at Ōtāhuhu and $0.83/MWh at Benmore. At this time, North Island reserve prices spiked due to an increase in northward HVDC flow driven by increased demand.

2.5. At times on Wednesday and Thursday, the spot price at Invercargill was much higher than at Benmore, peaking at a difference of ~$50/MWh. At this time, some Transpower assets in the region were on outage, and transmission lines from North Makarewa to Invercargill were at capacity. Due to the spring washer effect, this also led to the spot price at North Makarewa briefly dropping below zero.

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 generally highlighted with a vertical black line, however, this week there were none.

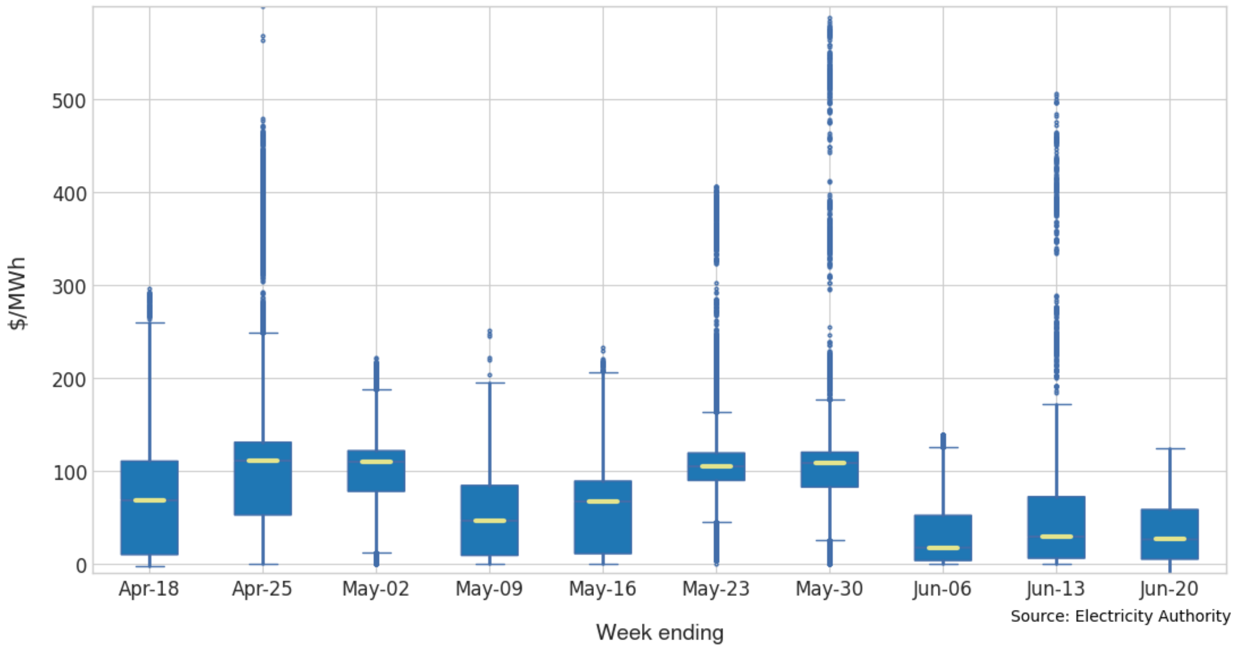
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 14-20 June



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 $26/MWh and most prices (middle 50%) fell between $5/MWh and $59/MWh.

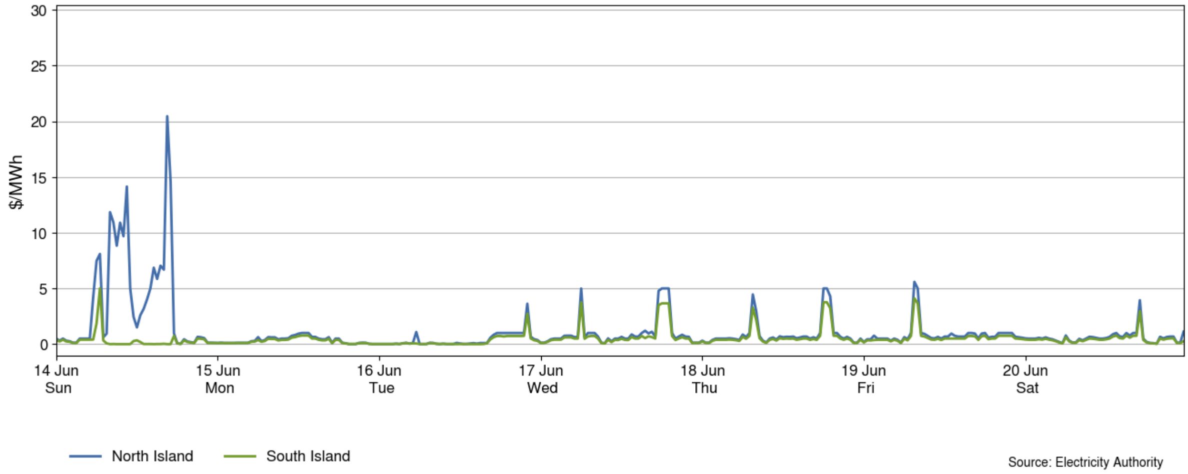
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



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 low this week, aside from some higher North Island reserve prices on Sunday when the HVDC's Pole 3 was on outage.[1]

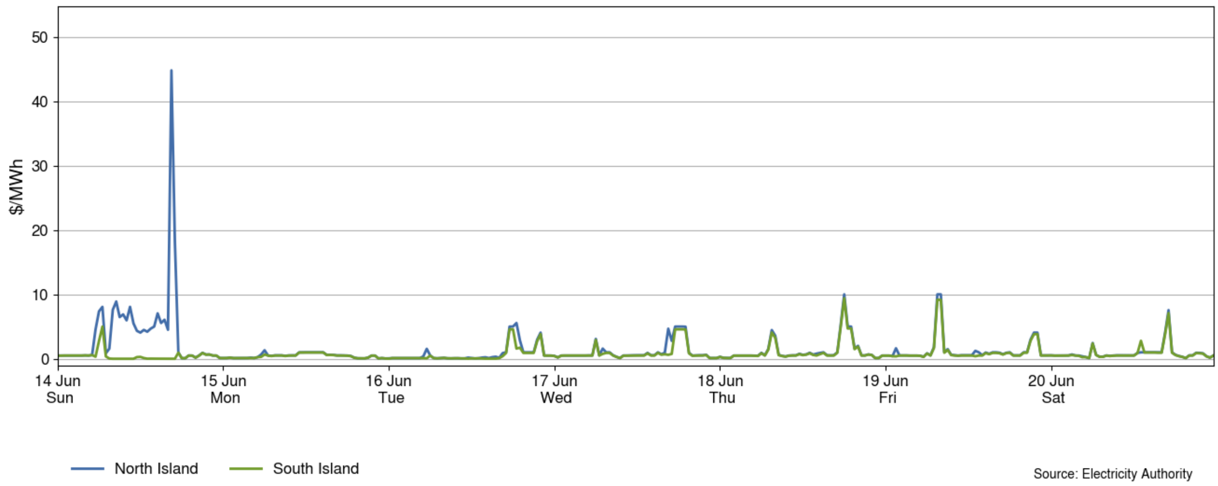
Figure 3: Fast instantaneous reserve price by trading period and island, 14-20 June



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly low this week, aside from some higher North Island reserve prices on Sunday when the HVDC's Pole 3 was on outage.

3.3. At 4.30pm on Sunday, SIR prices spiked to $45/MWh in the North Island. At the same time, SIR prices were $0/MWh in the South Island. At this time, the North Island risk setter changed from the Turitea Wind Farm to the HVDC, as the load across the HVDC increased by over 100MW due to an increase in demand. This meant more reserve was needed to cover this risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 14-20 June



[1] CAN Planned Outage HVDC Pole 3 800000177.pdf

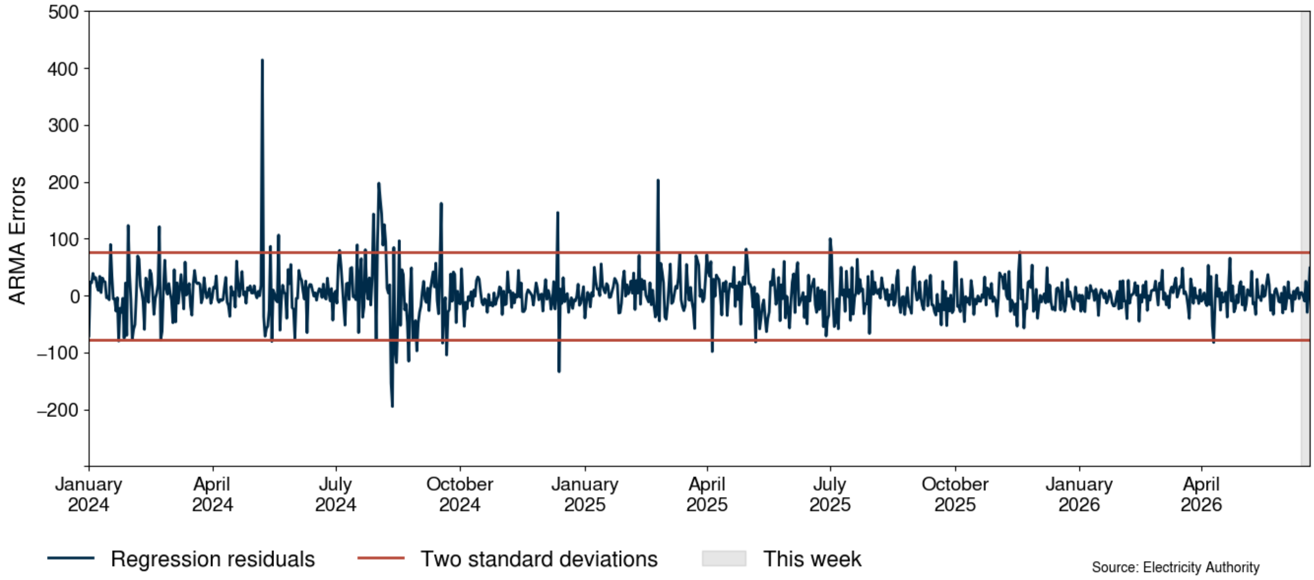
4. Regression residuals

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 - 20 June 2026



5. HVDC

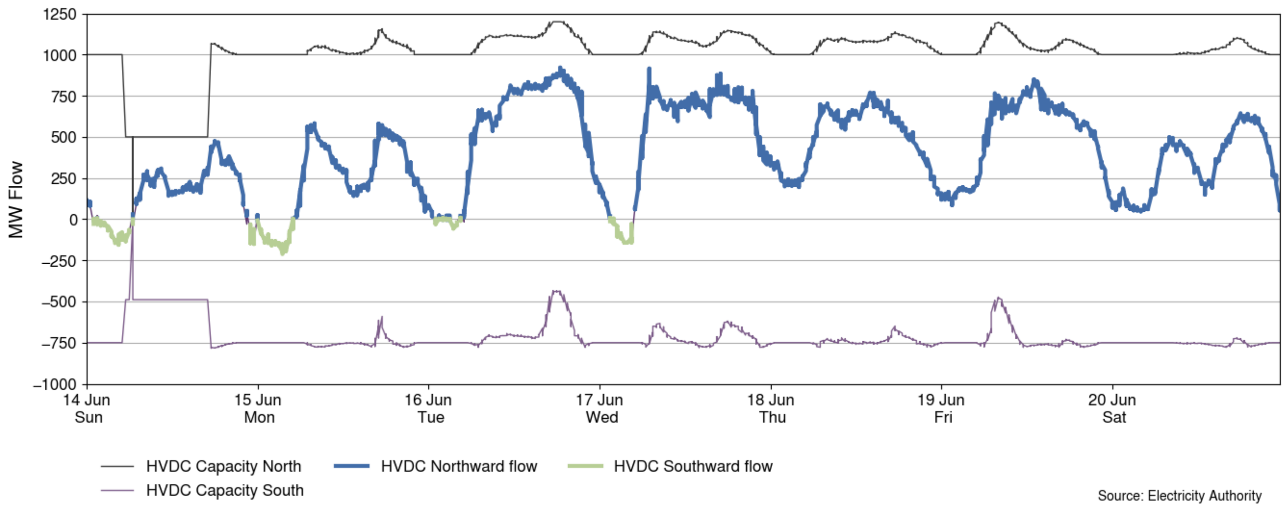
5.1. Figure 6 shows the HVDC flow between 14-20 June. HVDC flows were mainly northward this week, due to continued high demand.

5.2. On Sunday from 5.30am to 5.30pm, Pole 3 was on outage. This meant that when the HVDC switched directions at 6.30am, it briefly had no capacity.

5.3. The highest northward flow was 921MW at 6.30pm on Tuesday.

5.4. The highest southward flow was 212MW at 3.30am on Monday.

Figure 6: HVDC flow and capacity, 14-20 June

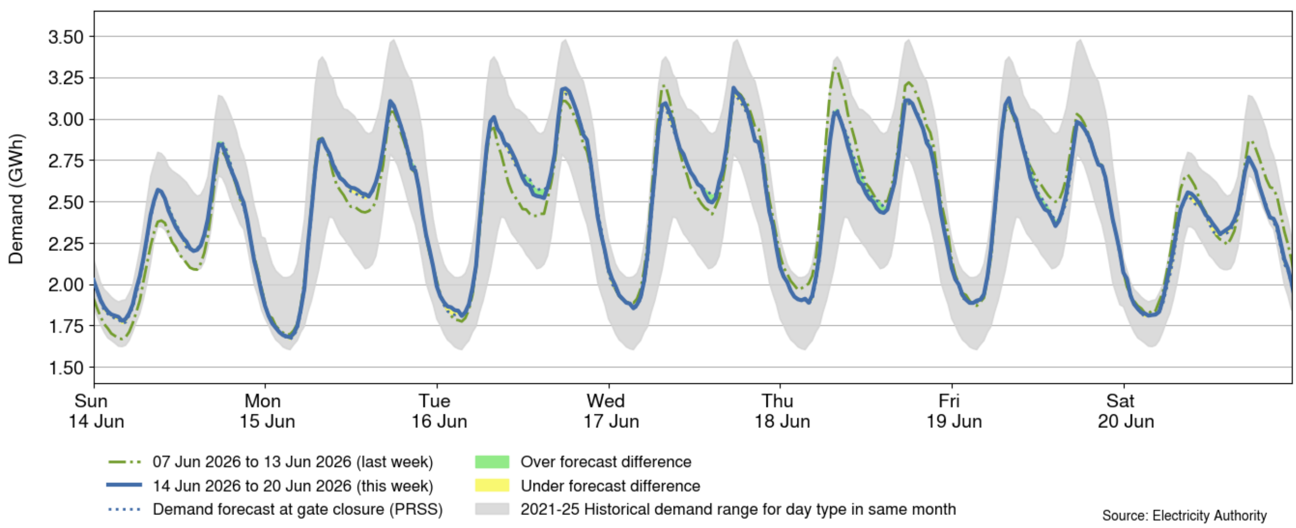


6. Demand

6.1. Figure 7 shows national demand between 14-20 June, compared to the historic range and the demand of the previous week. Demand was higher than last week from Sunday to Tuesday, similar to last week on Wednesday and Friday, and lower than last week on Thursday and Saturday.

6.2. The highest demand for the week was 6,370MW at 5.30pm on Wednesday.

Figure 7: National demand, 14-20 June compared to the previous week



6.3. Apparent temperatures ranged from 4°C to 16°C in Auckland, 4°C to 14°C in Wellington, and -5°C to 21°C in Christchurch.

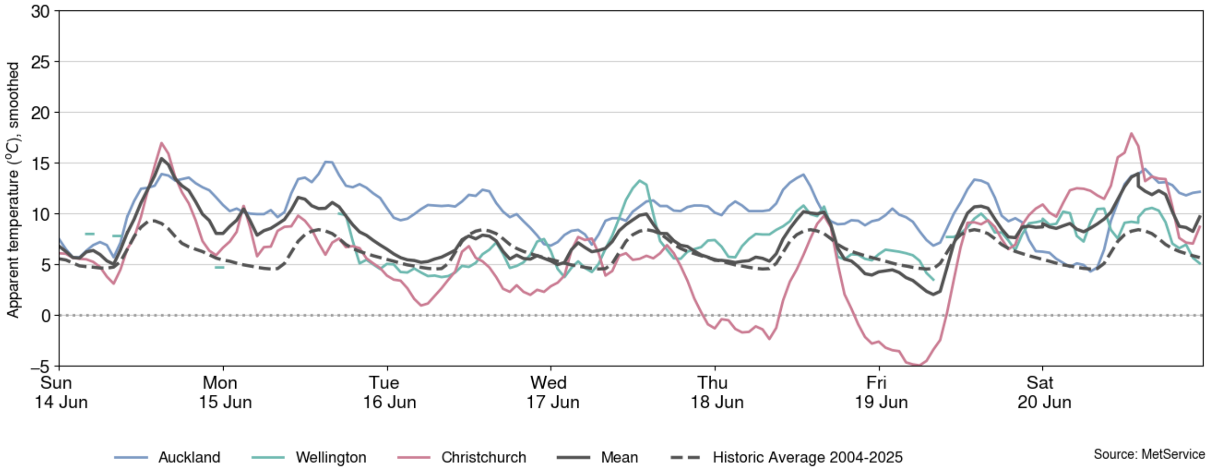
6.4. Note that temperature data is missing at times throughout the week for Wellington.

6.5. Figure 8 shows the hourly apparent temperature at main population centres from 14-20 June. 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.

6.6. Apparent temperatures ranged from 4°C to 16°C in Auckland, 4°C to 14°C in Wellington, and -5°C to 21°C in Christchurch.

6.7. Note that temperature data is missing at times throughout the week for Wellington.

Figure 8: Temperatures across main centres, 14-20 June



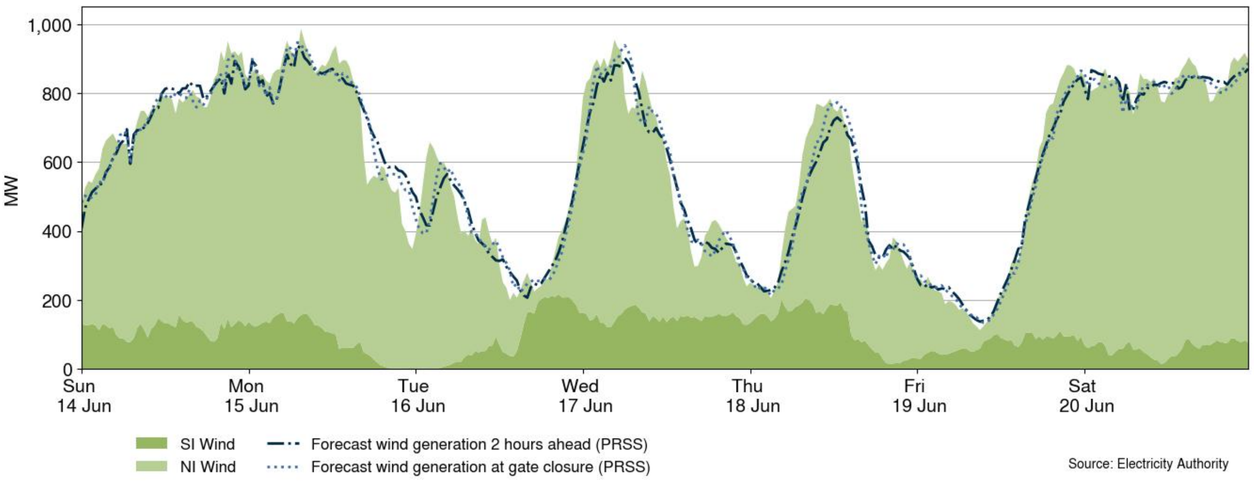
7. Generation

7.1. Figure 9 shows wind generation and forecast from 14-20 June. This week wind generation varied between 112MW and 986MW, with a weekly average of 600MW. Wind generation was mostly high this week, with some periods of lower generation from Tuesday to Friday.

7.2. Forecasting errors on Monday evening and on Wednesday are primarily a result of forecasting errors at Tararua and Turitea wind farms.

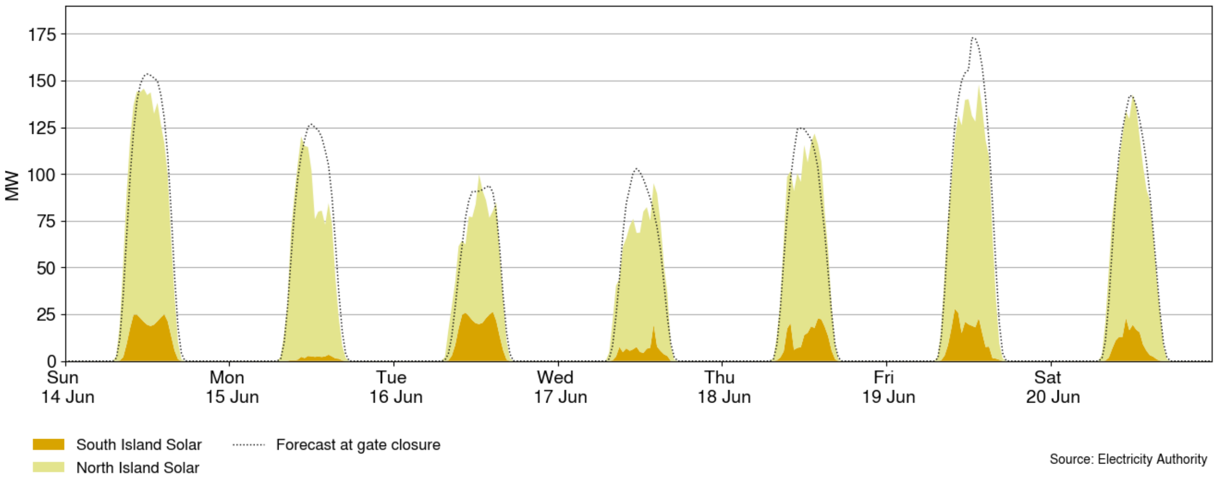
7.3. Forecasting errors on Tuesday are primarily a result of forecasting errors at Tararua wind farm.

Figure 9: Wind generation and forecast, 14-20 June



7.4. Figure 10 shows grid connected solar generation from 14-20 June. Solar generation varied this week, peaking at 148MW at 1.30pm on Friday, but reaching just 95MW on Wednesday.

Figure 10: Grid connected solar generation, 14-20 June

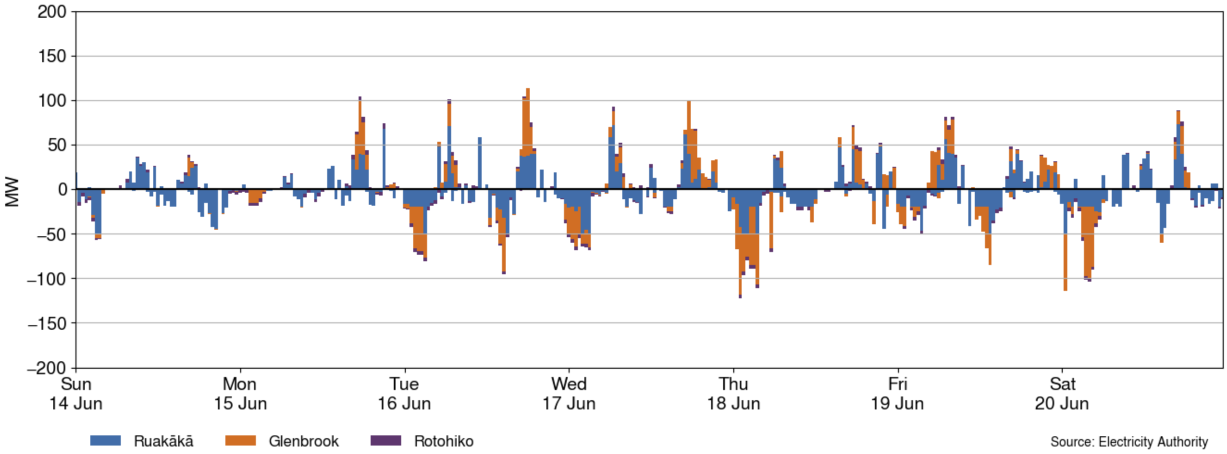


7.5. This week, the batteries generally charged when prices were lower, and discharged when prices were higher. On Sunday and Monday, the batteries generally charged when prices were below ~$15/MWh, and discharged when prices were above ~$15/MWh. From Tuesday onwards, the batteries generally charged when prices were below ~$40/MWh, and discharged when prices were above ~$40/MWh.

7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (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.

7.7. This week, the batteries generally charged when prices were lower, and discharged when prices were higher. On Sunday and Monday, the batteries generally charged when prices were below ~$15/MWh, and discharged when prices were above ~$15/MWh. From Tuesday onwards, the batteries generally charged when prices were below ~$40/MWh, and discharged when prices were above ~$40/MWh.

Figure 11: Grid scale battery charge and discharge, 14-20 June



7.8. 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[2]) projections. The figure highlights

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

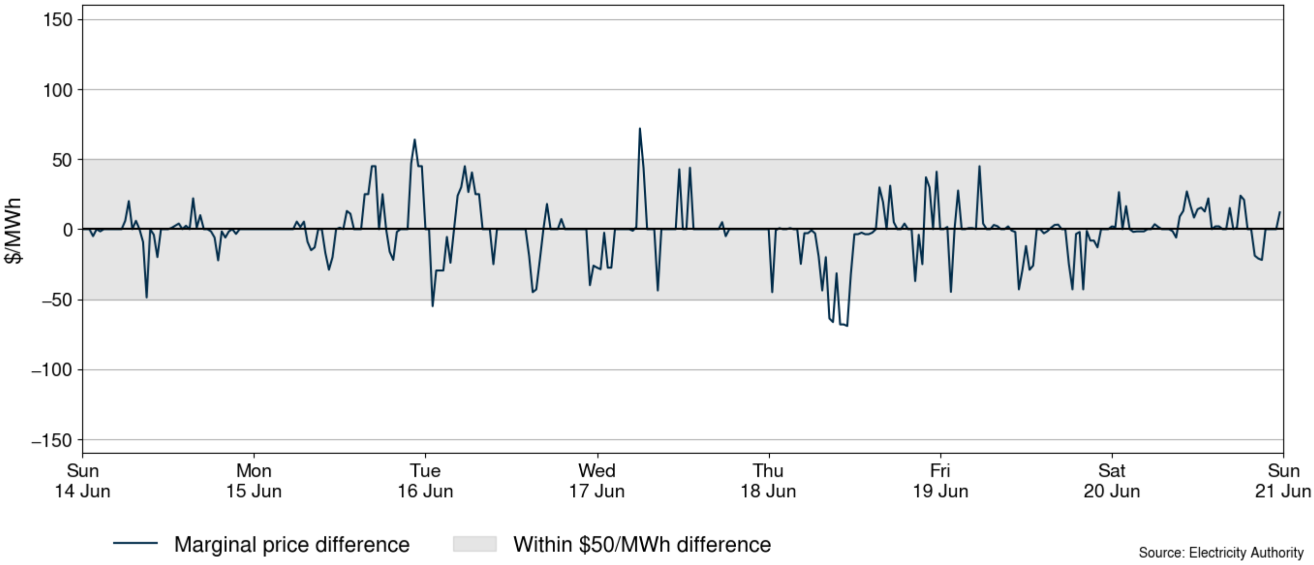
when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or intermittent generation is over 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.

7.9. There were some periods with a marginal price difference over $50/MWh.

7.10. The maximum positive difference of $72/MWh occurred at 6.00am on Wednesday. At this time, wind generation was 146MW below forecast, and demand was 85MW above forecast.

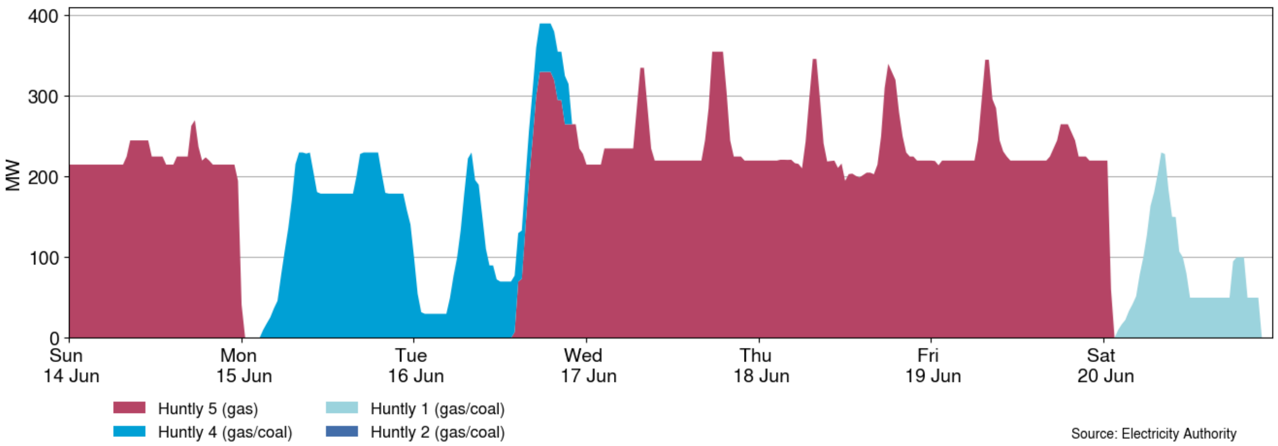
7.11. The maximum negative difference of $69/MWh occurred at 11.00am on Thursday. At this time, wind generation was 23MW above forecast, and demand was 141MW below forecast.

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, 14-20 June



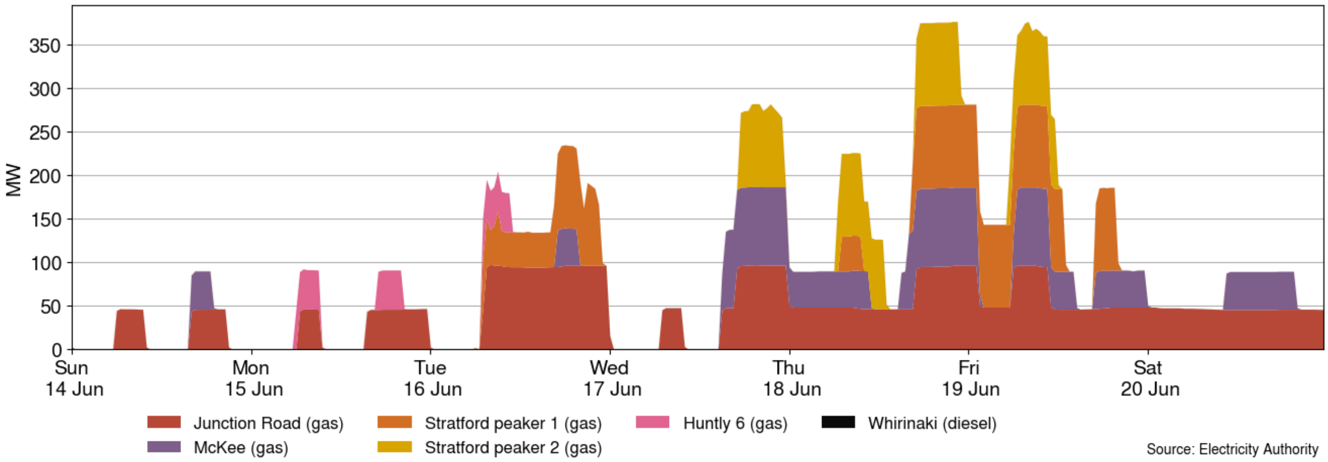
7.12. Figure 13 shows the generation of thermal baseload between 14-20 June. Huntly 5 ran continuously on Sunday, and from Tuesday afternoon to Friday, while Huntly 4 ran continuously on Monday and Tuesday. Huntly 1 ran on Saturday.

Figure 13: Thermal baseload generation, 14-20 June



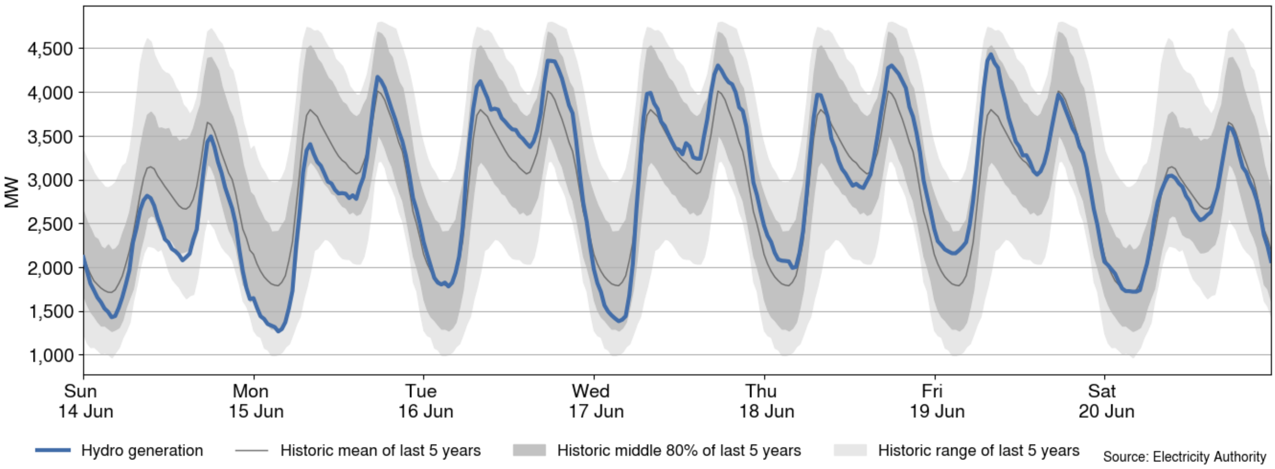
7.13. Figure 14 shows the generation of thermal peaker plants between 14-20 June. Junction Road ran at times every day this week, while McKee ran at times every day except Monday. The Stratford Peakers ran at times from Tuesday to Friday, while Huntly 6 ran at times on Monday and Tuesday.

Figure 14: Thermal peaker generation, 14-20 June



7.14. Figure 15 shows hydro generation between 14-20 June. Hydro generation was lower than the historic mean on Sunday and Monday, when wind generation was high. Hydro generation was higher than the historic mean from Tuesday to Friday, and close to the historic mean on Saturday.

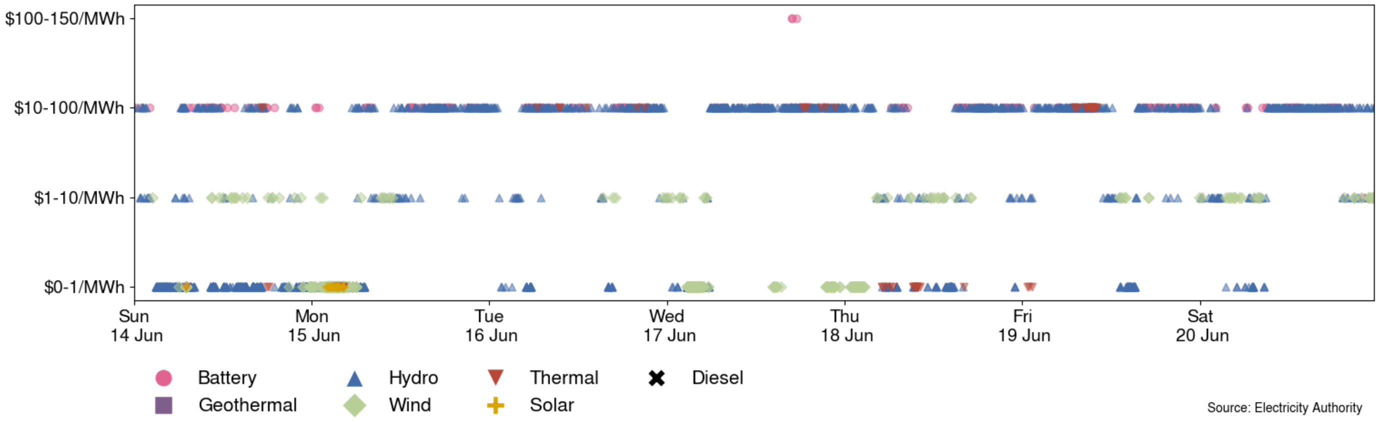
Figure 15: Hydro generation, 14-20 June



7.15. 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.

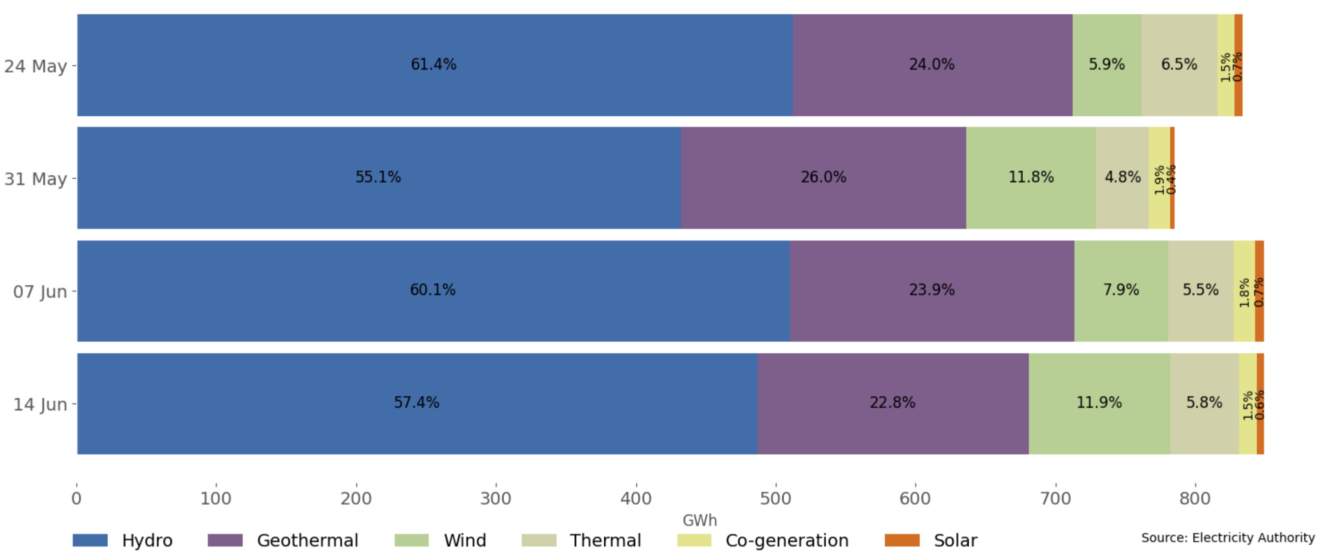
7.16. The highest prices were set by the Glenbrook battery. The most common technology setting prices was hydro, with wind the second most common. Most marginal prices were between $10-100/MWh.

Figure 16: Prices of marginal generation, 14-20 June



7.17. As a percentage of total generation, between 14-20 June, total weekly hydro generation was 57.4%, geothermal 22.8%, wind 11.9%, thermal 5.8%, co-generation 1.5%, and solar (grid connected) 0.6%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 24 May and 20 June



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 14-20 June ranged between ~615MW and ~1,203MW. Several geothermal outages began on 18 June. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 14-20 June

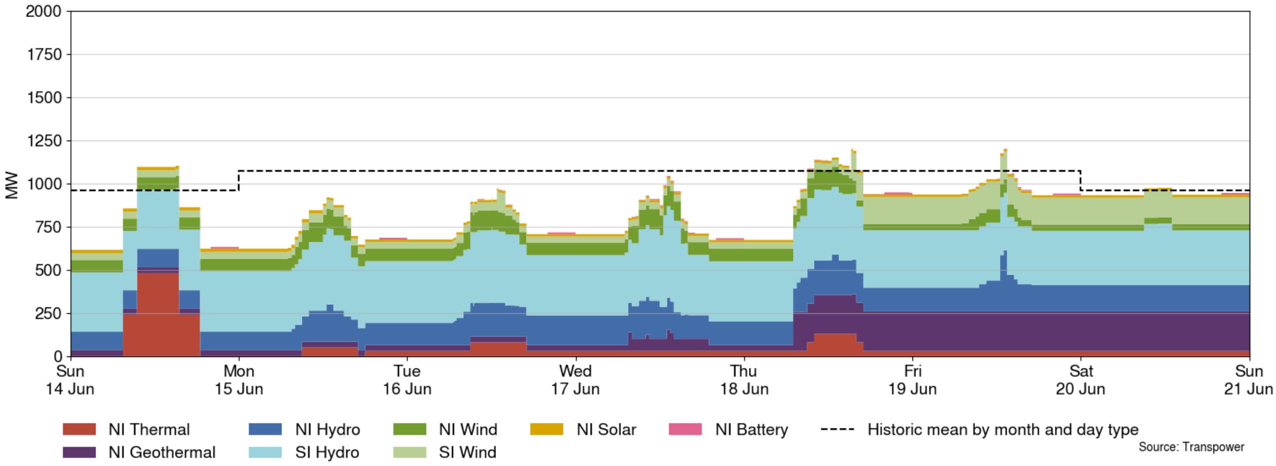
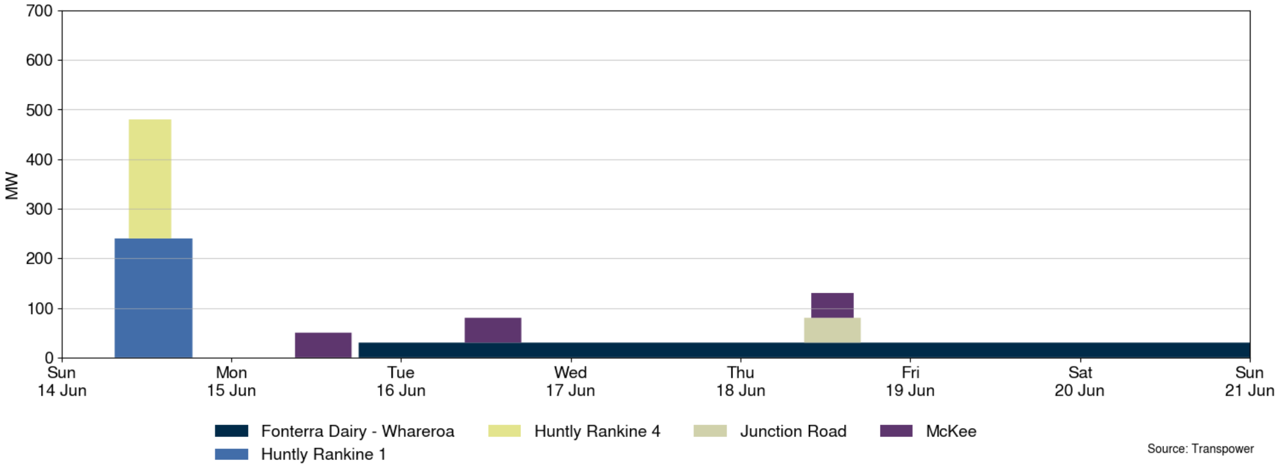


Figure 19: Total MW loss from thermal outages, 14-20 June



8.2. Notable outages include:

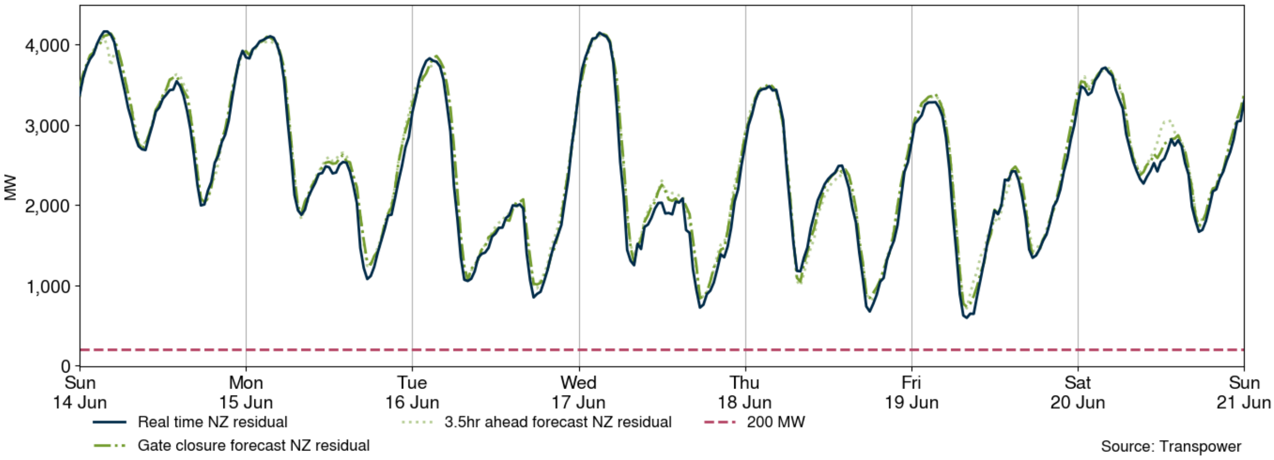
Plant	Partial or Full	End Date
Huntly 1	Full	14 June 2026
Huntly 4	Full	14 June 2026
Clyde unit 2	Full	17 June 2026
Manapōuri unit 2	Full	30 June 2026
Kaiwera Downs	Full	1 July 2026
Manapōuri unit 4	Full	21 July 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 14-20 June. 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. The national residual has been healthy this week. The lowest national residual of 596MW occurred at 8.00am on Friday.

Figure 20: National generation balance residuals, 14-20 June



10. Storage/fuel supply

10.1. As of 20 June, national controlled storage was 85% nominally full and ~120% of the historical average for this time of the year.

10.2. Storage at Lake Pūkaki (87% full) is at its historic mean, while storage at Lake Tekapō (82% full) remains well above its historic mean.

10.3. Storage at Lake Te Anau (112% full) has increased to above its historic 90th percentile, while storage at Lake Manapōuri (87% full) remains above its historic mean.

10.4. Storage at Lake Taupō (72% full) remains above its historic 90th percentile for this time of year.

10.5. Storage at Lake Hawea (93% full) is at its historic 90th percentile for this time of year.

10.6. Figure 21 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.

10.7. As of 20 June, national controlled storage was 85% nominally full and ~120% of the historical average for this time of the year.

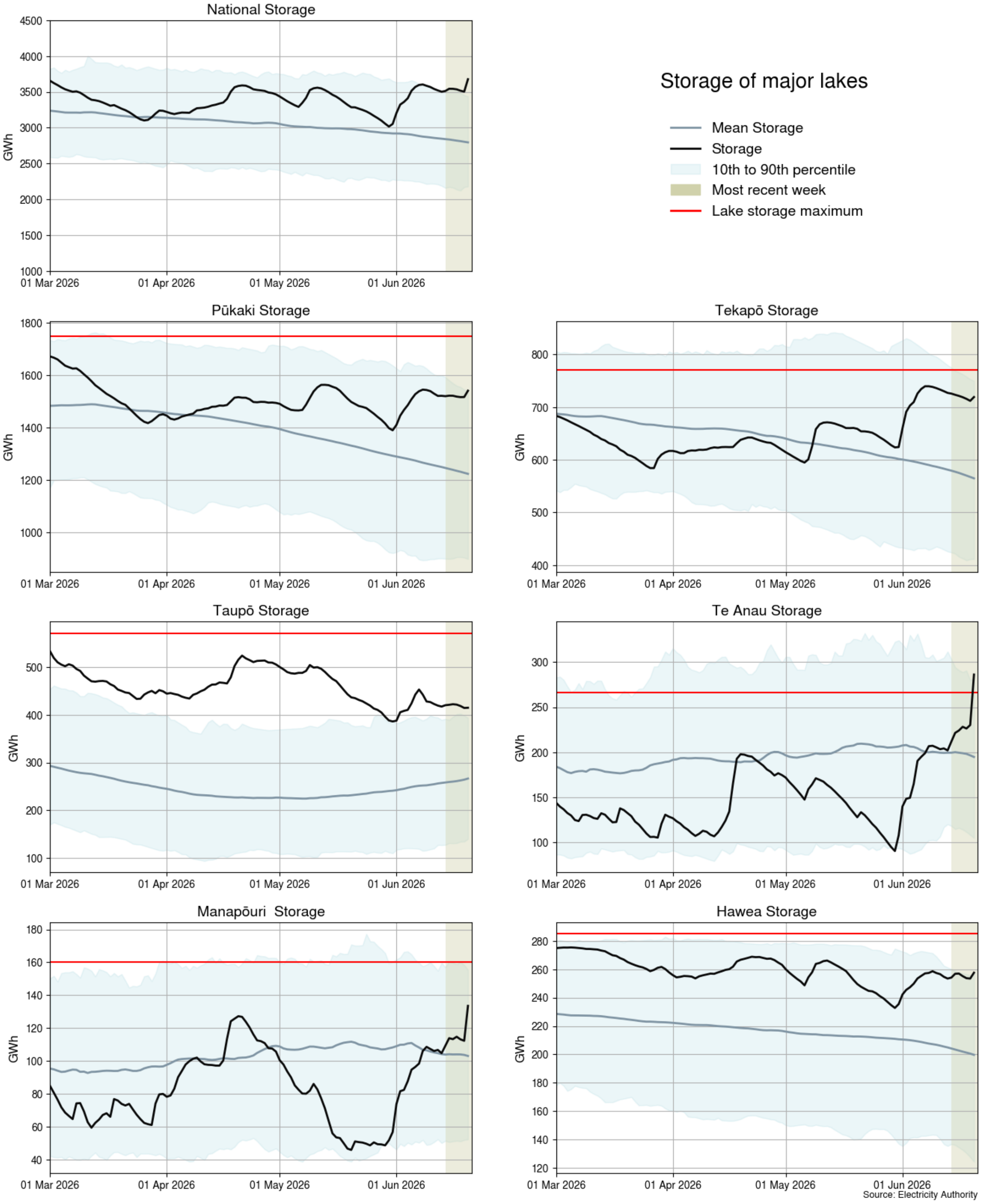
10.8. Storage at Lake Pūkaki (87% full) is at its historic mean, while storage at Lake Tekapō (82% full) remains well above its historic mean.

10.9. Storage at Lake Te Anau (112% full) has increased to above its historic 90th percentile, while storage at Lake Manapōuri (87% full) remains above its historic mean.

10.10. Storage at Lake Taupō (72% full) remains above its historic 90th percentile for this time of year.

10.11. Storage at Lake Hawea (93% full) is at its historic 90th percentile for this time of year.

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 22 shows an estimate of thermal SRMCs as a monthly average up to 1 June 2026. The SRMCs for gas generation has decreased, with SRMCs for coal and diesel fuelled generation remaining steady.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$235/MWh, while the cost of running the Rankines on gas is ~$116/MWh.

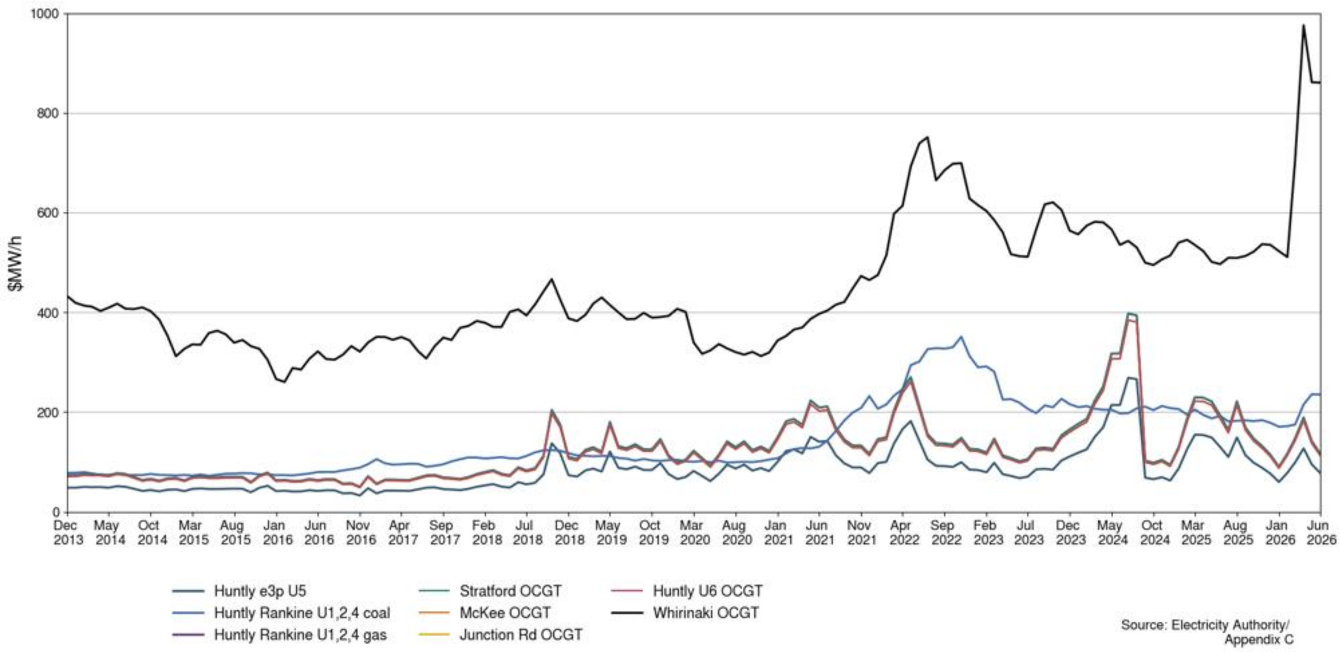
11.5. The SRMC of gas fuelled thermal plants is currently between $78/MWh and $116/MWh.

11.6. The SRMC of Whirinaki is ~$861/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](#).

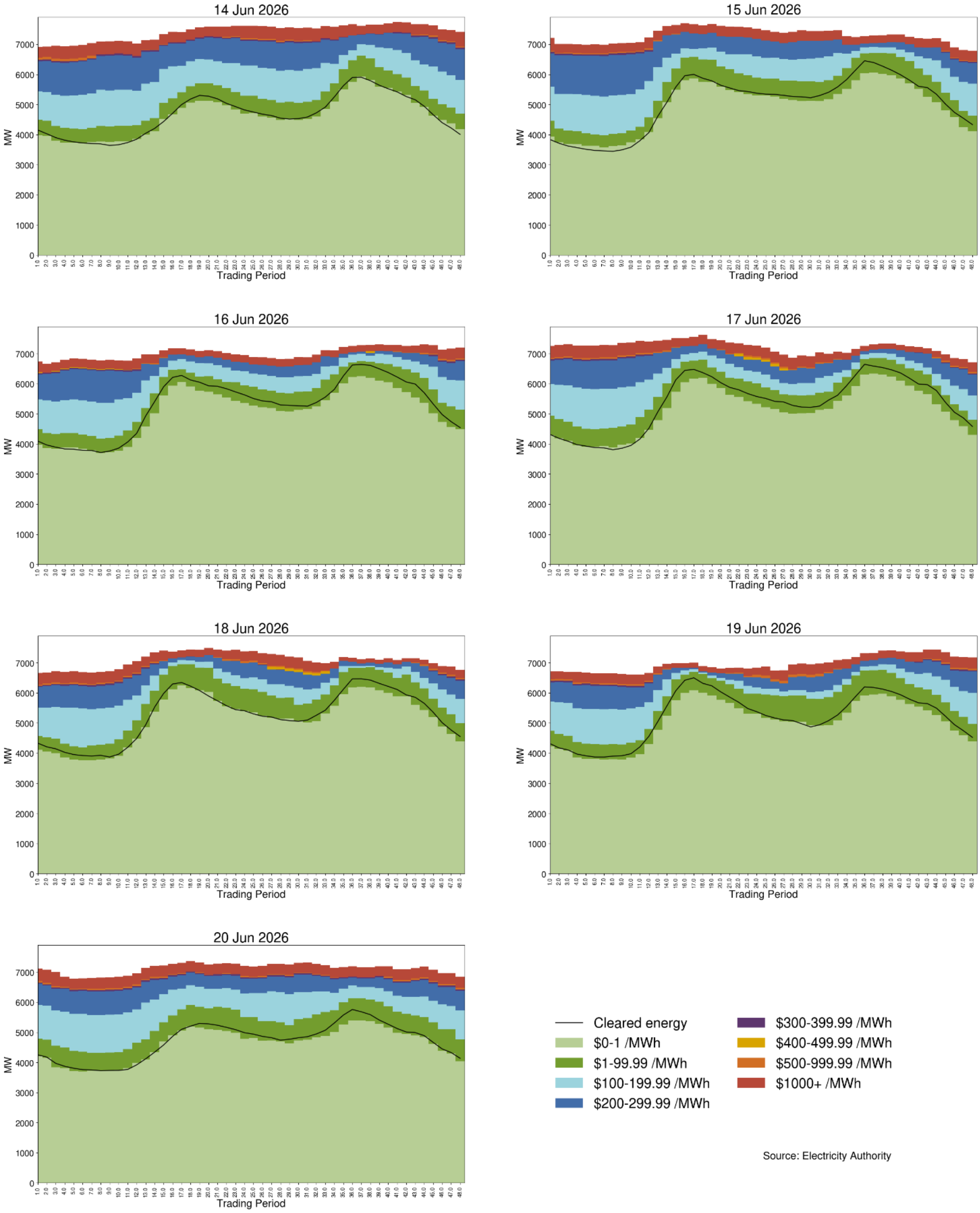
Figure 22: Estimated monthly SRMC for thermal fuels



12. Offer behaviour

12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price. Meridian priced down Manapōuri generation as hydro storage increased. Mercury also increased its percentage of low priced offers this week.

Figure 23: Daily offer stacks

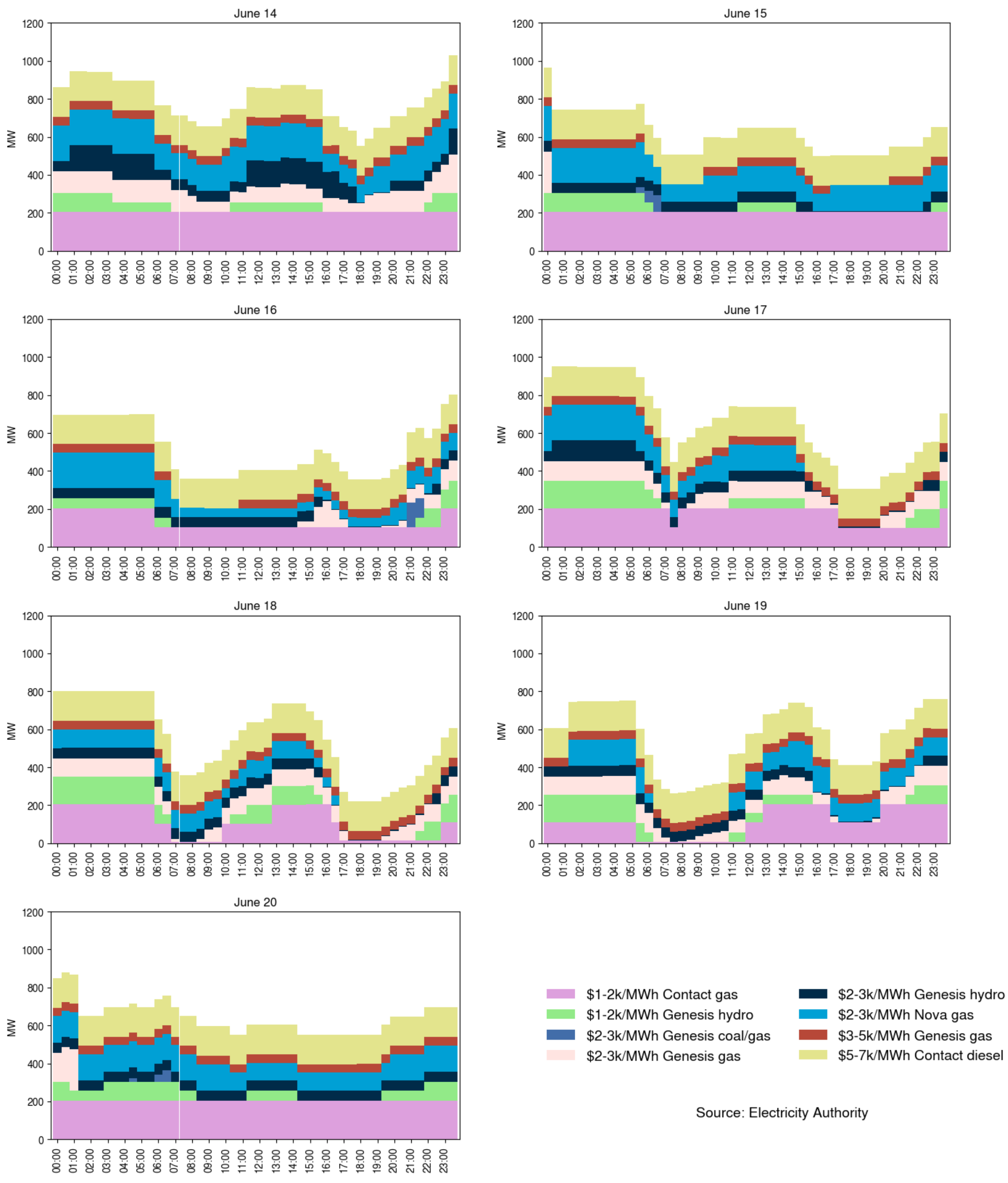


12.2. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.3. 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.

12.4. On average 620MW per trading period was priced above $1,000/MWh this week, which is roughly 11% of the total energy available.

Figure 24: 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 is looking into Huntly 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
r02/05/2026	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
20/06/2026	24-32	Further analysis	Genesis	Huntly 1	Offers