10 June 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 2-8 June

1.1. This week, spot prices were mainly above the historical median and mostly between $200-$300/MWh. Despite the high prices. no energy price spikes occurred this week. Reserve prices spiked on a few occasions this week related to HVDC flows and energy/reserve co-optimisation. This week TCC, Huntly 1, Huntly 5, and Huntly 4 provided baseload generation. Hydro storage decreased to around 77% of the historical average. Geothermal generation increased likely due to the contribution of the new Tauhara geothermal plant.

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, we also single 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 2-8 June:

(a) the average wholesale spot price across all nodes was $259/MWh.

(b) 95% of prices fell between $23/MWh and $347/MWh.

2.3. Overall, the majority of spot prices were above the historical median this week, but there were no spikes. Most prices highlighted this week occurred overnight when one would expect slightly lower prices due to lower demand. This is because last week many hydro generators altered their offers to reflect their hydro storage, and these hydro generators were often marginal overnight this week.

2.4. Low inflows and a continued decline in hydro storage kept prices above $250/MWh for a large portion of the week. However, the average price decreased by around $7/MWh compared to the previous week.

2.5. On Tuesday and Wednesday, there were instances of overnight Benmore prices which were higher than Ōtāhuhu prices and some separation in these prices. This occurred when there was high southward flow on the HVDC when wind generation was high in the North Island.

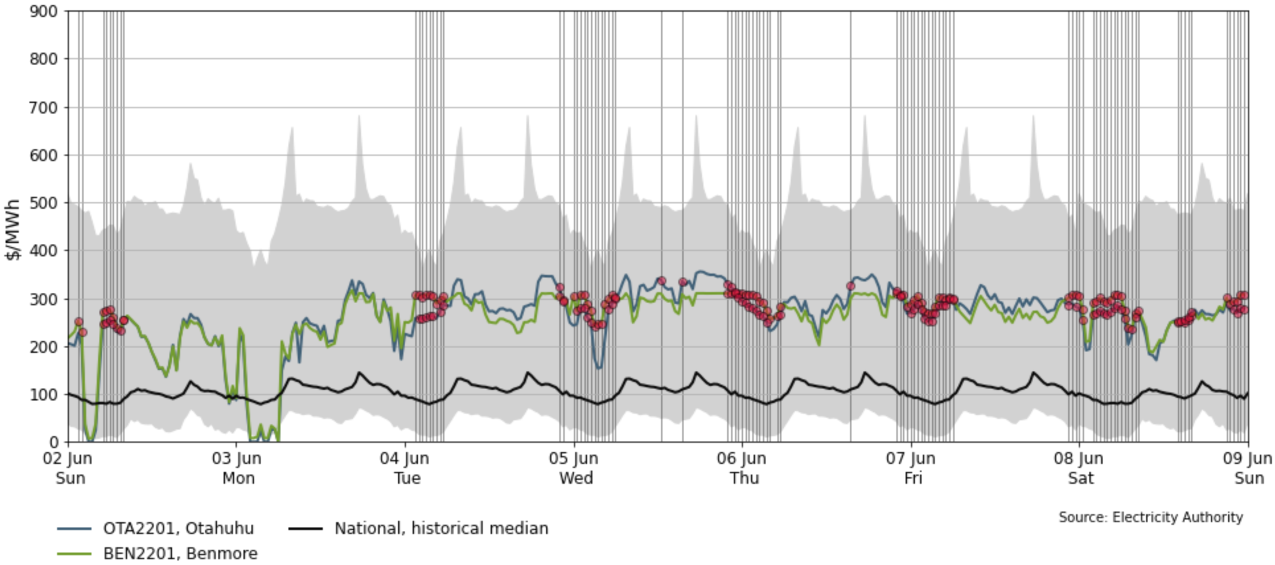
2.6. The low prices seen overnight on Sunday and Monday are related to wind generation being high at those times.

2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10th-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range[1] of historic prices are

[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day and looking for prices that lie 1.5 times the interquartile range above the 75th percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 2-8 June

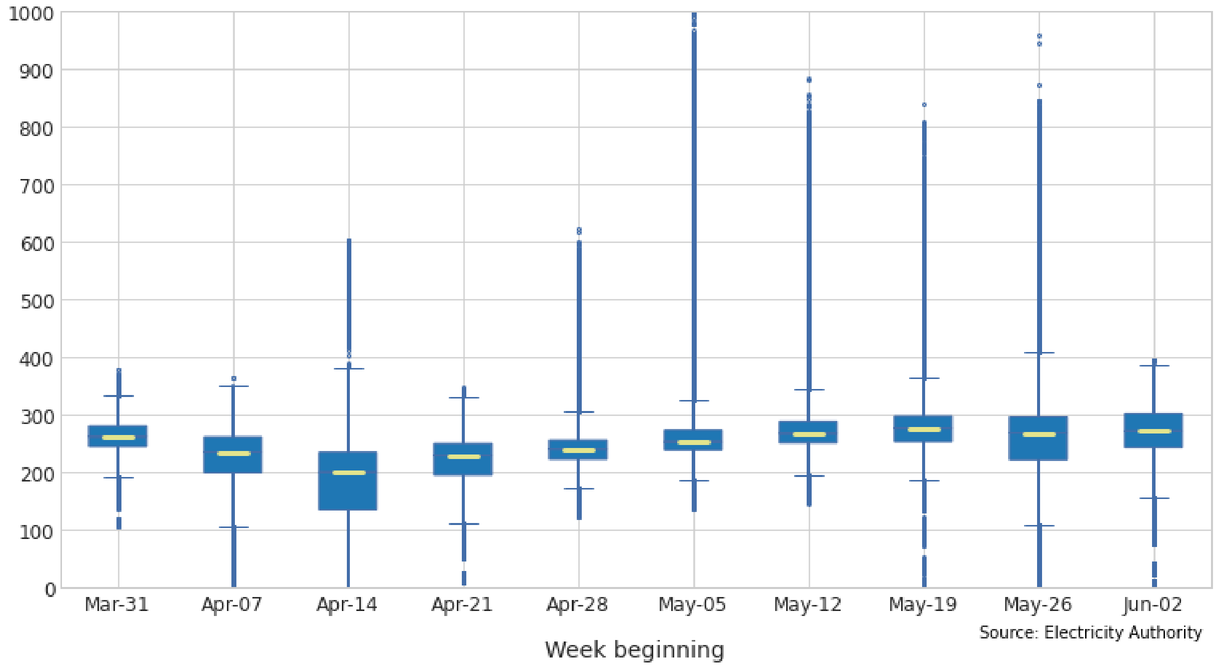


2.8. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the box part shows the lower and upper quartiles (where 50% of prices fell). The "whiskers" extend to points that lie within 1.5 times the inter-quartile range (IQR) of the lower and upper quartile, and then observations that fall outside this range are displayed independently.

2.9. The distribution of prices this week is aligned with the last four previous weeks, related to declining hydro storage. The median price increased slightly from $268/MWh[2] in the previous week to $272/MWh this week, a $4/MWh increase. The middle 50% of the prices were between $243-$302/MWh.

[2] Last week we mistakenly reported the median price at $275/MWh, and not at $268/MWh, as it should be.

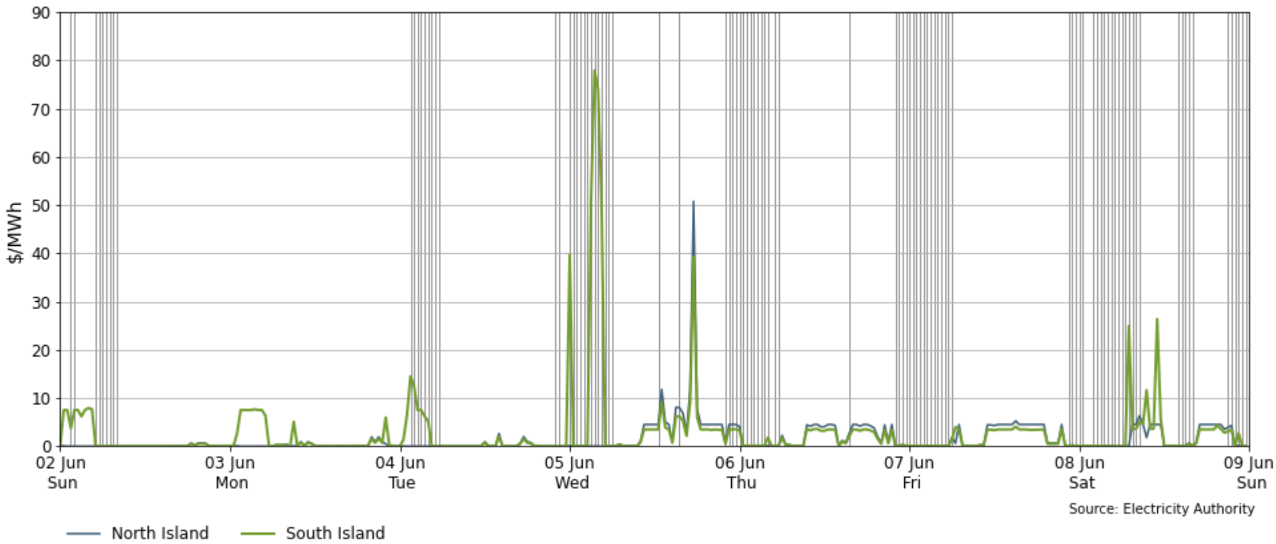
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

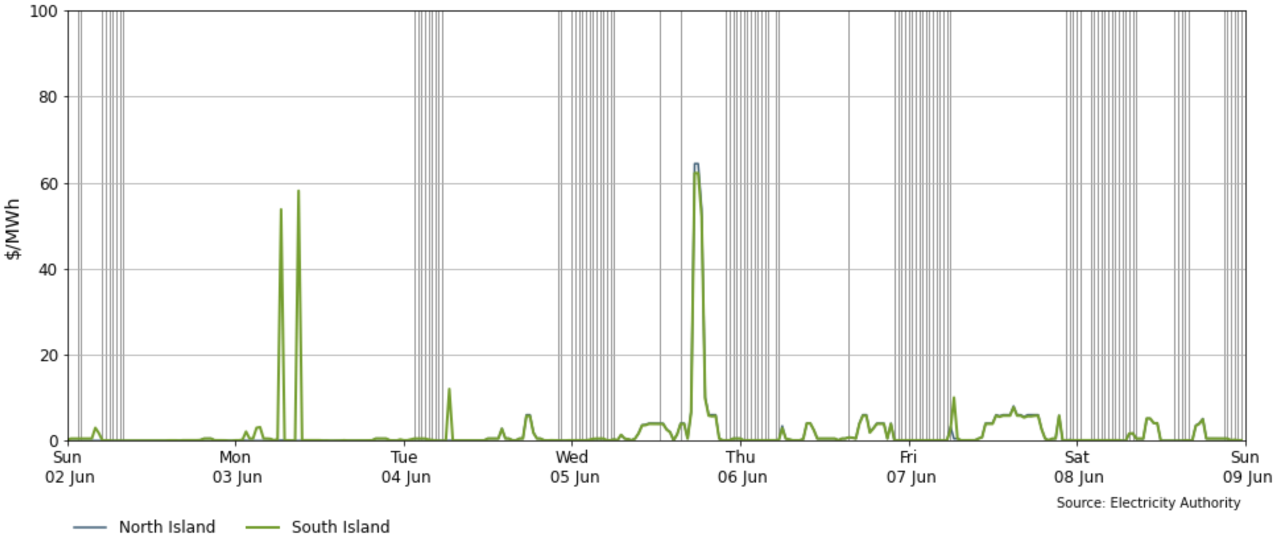
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh, but a few North and South Island FIR spikes occurred this week. On Wednesday morning, a spike in the South Island FIR prices is likely related to high HVDC southward flow, which required reserves in the receiving island to cover the HVDC risk. On Wednesday afternoon, FIR spiked at both islands during the demand peak, likely reflecting energy and reserve co-optimisation. On Saturday, South Island FIR spiked around the time when HVDC transfers were low or close to zero.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 2-8 June



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh. South Island SIR spikes occurred on Monday when wind generators were setting the risk in the North Island and the HVDC was flowing South and setting the South Island risk, requiring reserves in the receiving island to cover the risk. On Wednesday afternoon SIR spiked at both islands during the demand peak, reflecting energy and reserve co-optimisation.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 2-8 June



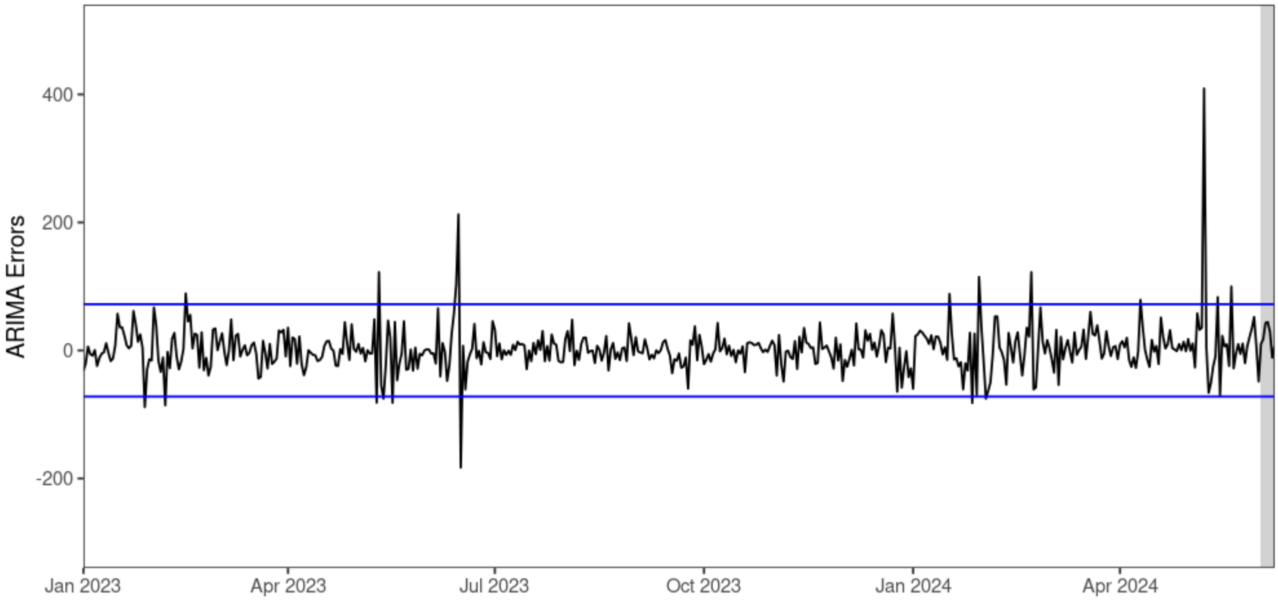
4. Regression residuals

4.1. The Authority’s monitoring team uses a regression model to model spot price. The residuals show how close the predicted 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 on the trading conduct webpage.

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 for in the regression analysis. The area shaded in grey in the figure represents the current week.

4.3. This week, there were no residuals above or below two standard deviations of the data, indicating that the actual and modelled prices were similar.

Figure 5: Residual plot of estimated daily average spot prices from 1 January 2023 to 8 June 2024

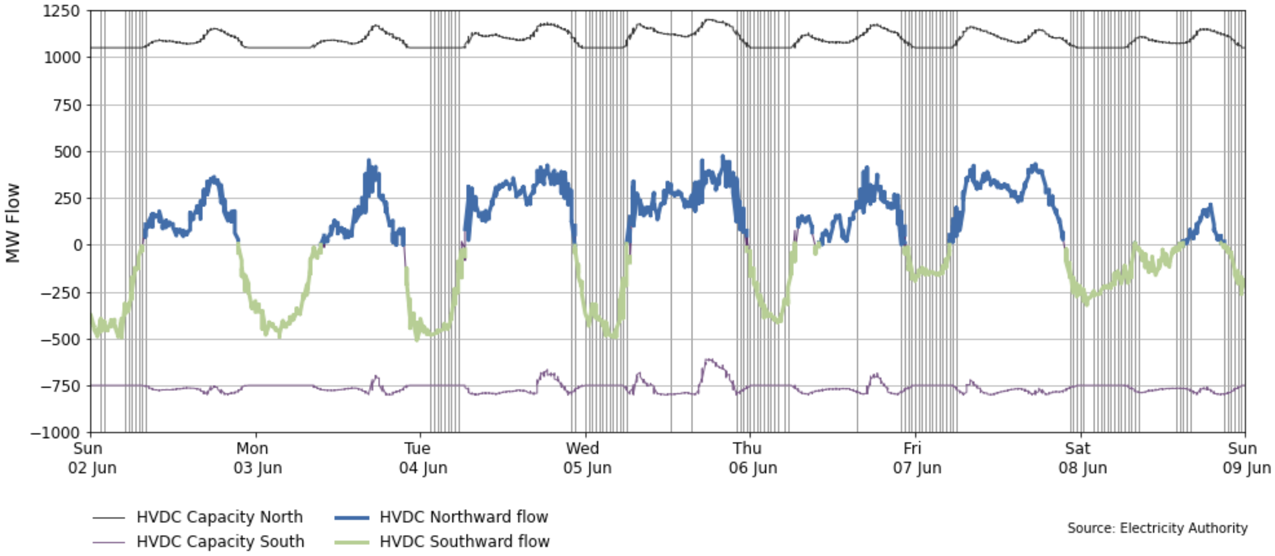


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 2-8 June. This week HVDC southward flows occurred mostly overnight and when wind generation was high or increasing its output. Northward flows occurred during the day with the higher flows corresponding to times of low or decreasing wind generation.

Figure 6: HVDC flow and capacity between 2-8 June

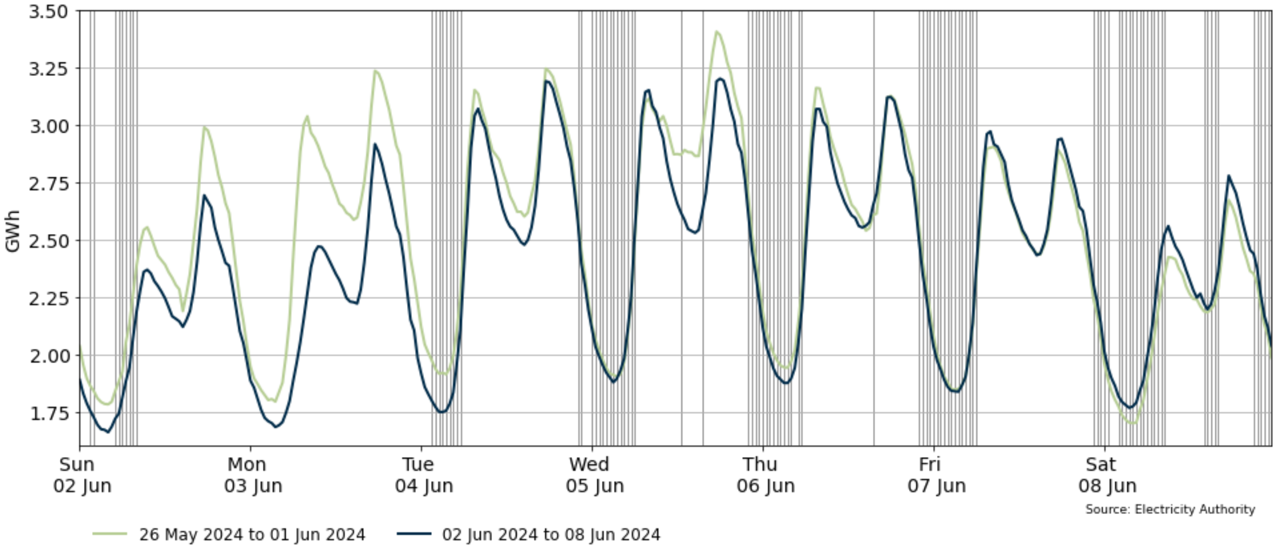


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 2-8 June, compared to the previous week. Demand was lower than the previous week until Thursday afternoon, likely related to milder temperatures during daytime midweek. On Monday, demand was considerably lower than the previous week due to the King's birthday holiday. From Thursday afternoon onwards, demand was similar to or slightly higher than the previous week.

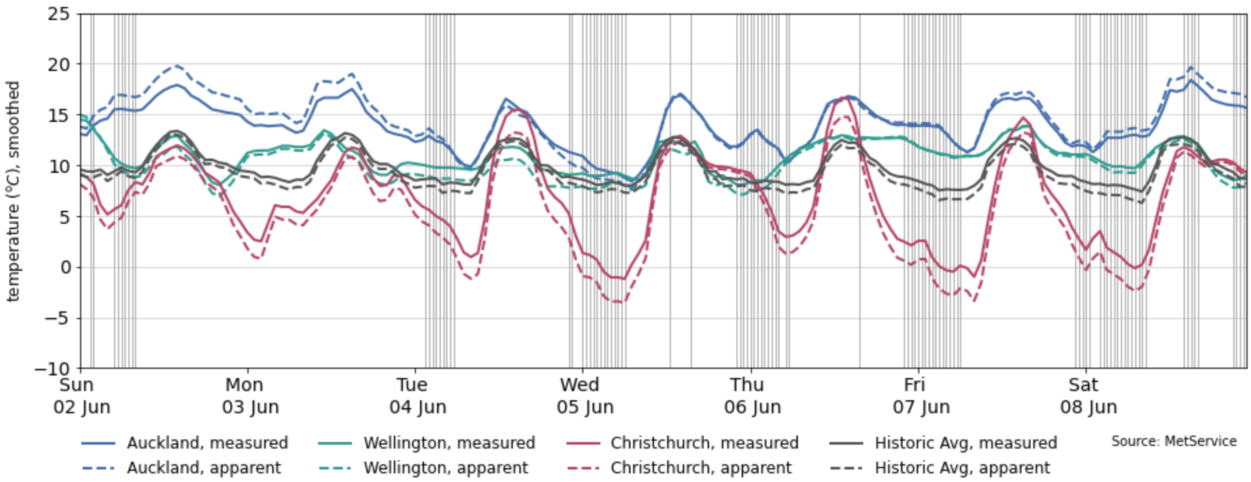
Figure 7: National demand between 2-8 June compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 2-8 June. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures in Auckland were all above the historical average this week, with apparent temperatures varying between 8ºC and 20ºC. Temperatures in Wellington were mostly at or above the historical average with apparent temperatures between 7ºC and 15ºC this week. In Christchurch, apparent temperatures were between -4ºC and 15ºC.

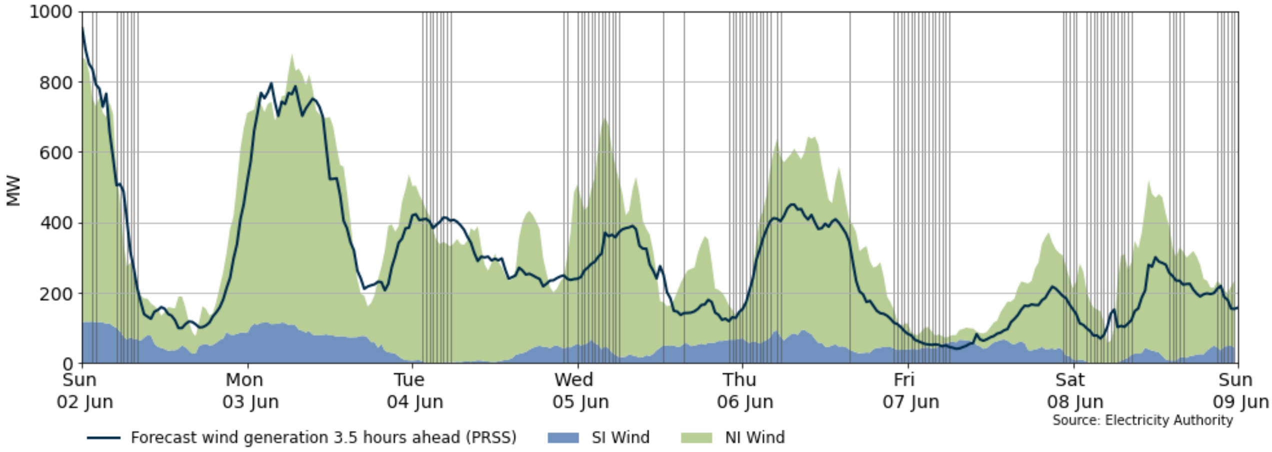
Figure 8: Temperatures across main centres between 2-8 June



7. Generation

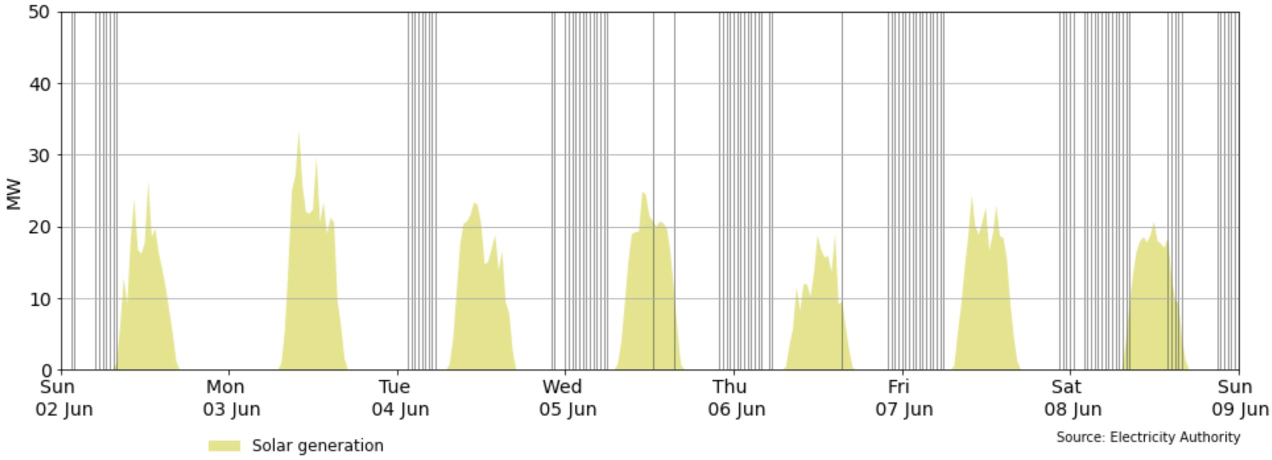
7.1. Figure 9 shows wind generation and forecast from 2-8 June. This week wind generation varied between 58MW and 880MW, with a weekly average of 354MW. Wind generation was high during parts of Sunday and Monday this week when wind was above 600MW. During the rest of the week, wind was more variable, with a few cases of generation lower than 200MW at times, especially on Friday and parts of Saturday. On Wednesday, wind generation was under-forecast by more than 200MW between midnight and 6:00am, which likely contributed to lower North Island spot prices during those times.

Figure 9: Wind generation and forecast between 2-8 June



7.2. Figure 10 shows solar generation from 2-8 June. Solar generation was between 19MW and 33MW this week. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource, as we approach the winter solstice.

Figure 10: Solar generation between 2-8 June

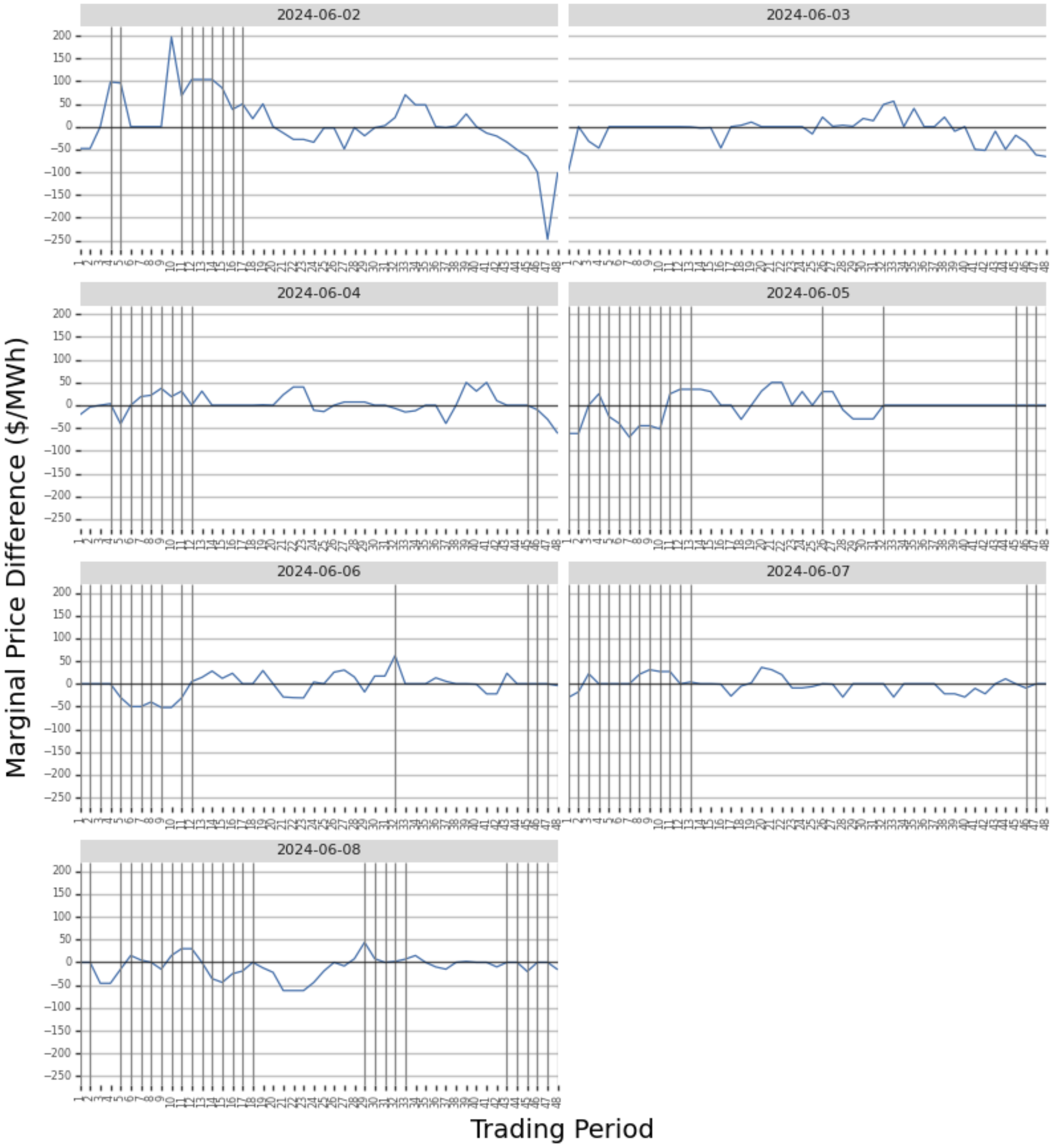


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS) projections. The figure highlights when forecasting inaccuracies are causing large differences in 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, but 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. This week the most notable positive (marginal prices higher than simulation) and negative differences occurred on Sunday. On Sunday morning, between 1:30am and 6:30am, the differences were at or above $100/MWh Monday and Tuesday, when wind over-forecast and demand under-forecast combined were close to 100MW. On Sunday night the negative differences are related to wind generation being under forecast by more than 100MW.

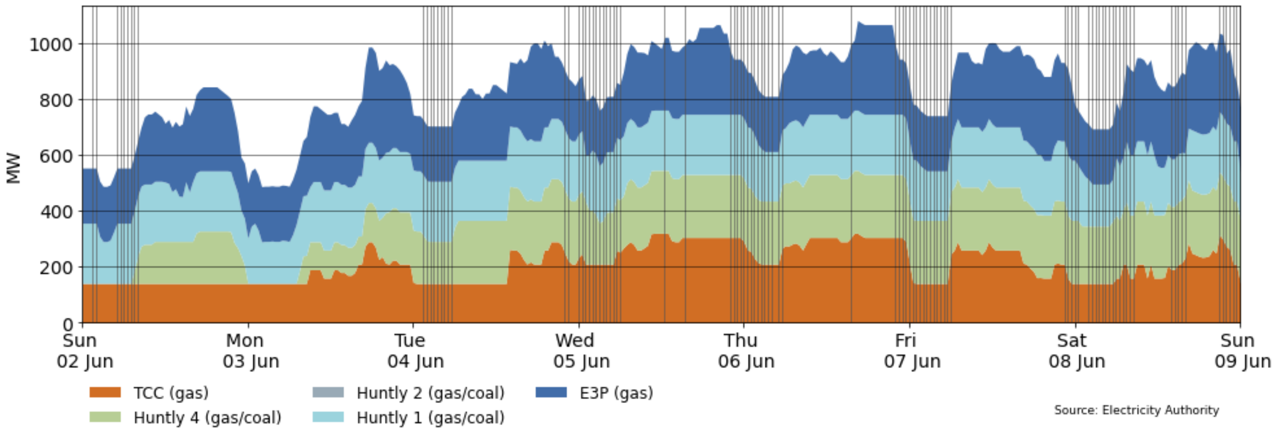
7.5. During the rest of the week, price differences were mostly between the +/-$50/MWh range.

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 between 2-8 June



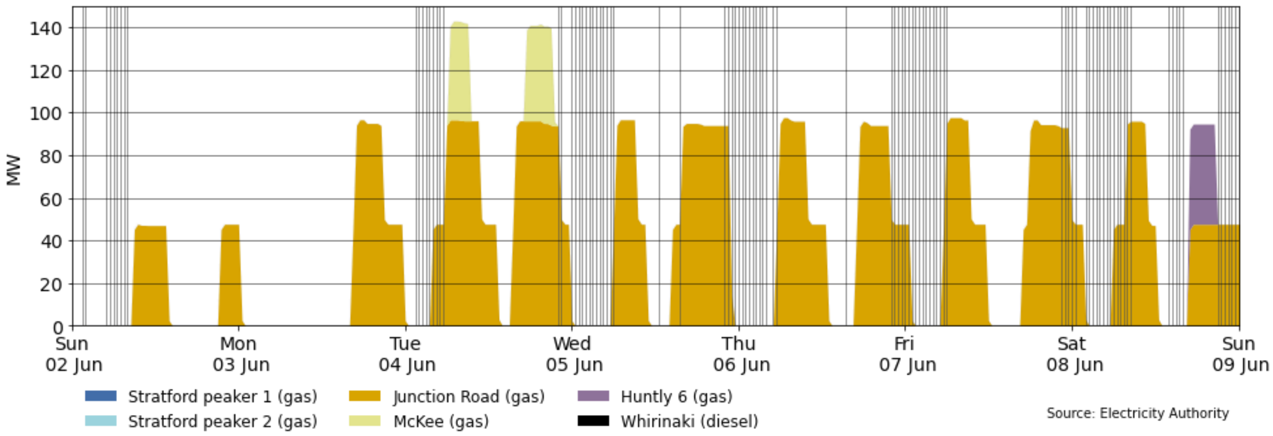
7.6. Figure 12 shows the generation of thermal baseload between 2-8 June. This week TCC, Huntly 1, and Huntly 5 (E3P) ran continuously providing baseload generation. Huntly 4 ran most of Sunday and continuously from Monday morning onwards.

Figure 12: Thermal baseload generation between 2-8 June



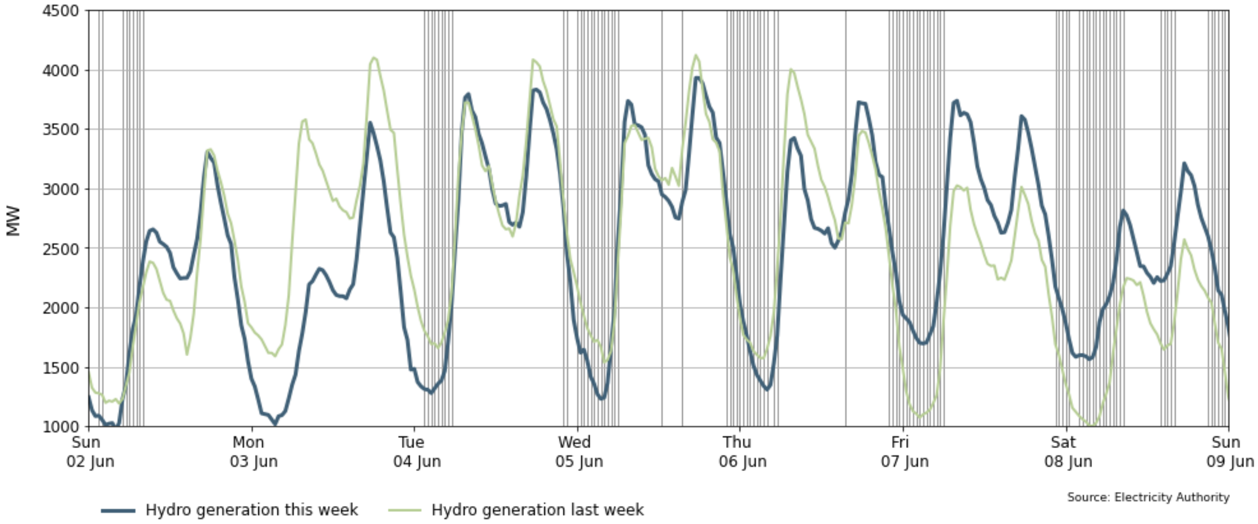
7.7. Figure 13 shows the generation of thermal peaker plants between 2-8 June. Junction Road ran every day this week, often during times of high demand. McKee ran during the shoulder period on Tuesday, while Huntly 6 ran during the demand peak on Saturday afternoon.

Figure 13: Thermal peaker generation between 2-8 June



7.8. Figure 14 shows hydro generation between 2-8 June. Hydro generation was generally similar or higher than the previous week this week due to comparatively lower wind generation this week. Hydro generation was notably lower than the previous week on Monday, due to the King's Birthday holiday.

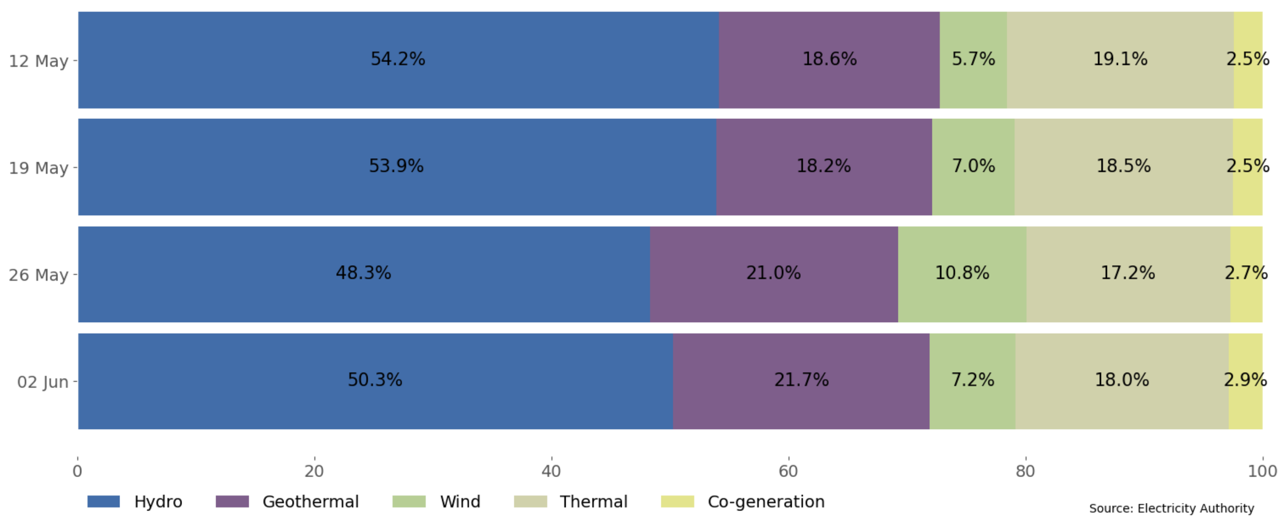
Figure 14: Hydro generation between 2-8 June



7.9. As a percentage of total generation, between 2-8 June, total weekly hydro generation was 50.3%, geothermal 21.7%, wind 7.2%, thermal 18.0%, and co-generation 2.9%, as shown in Figure 15. This week the relative contribution of hydro and thermal generation increased due to the decrease in wind generation compared to the previous week.

7.10. It is also worth noting that geothermal generation has been above 20% over the last two weeks, likely due to the contribution from the new Tauhara geothermal unit, running continuously at around 155MW since late May.

Figure 15: Total generation by type as a percentage each week between 12 May and 8 June



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 2-8 June ranged between ~1070MW and ~1530MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 outage was extended until 19 July 2024

(b) Stratford 2 outage was extended until 5 August 2024.

(c) McKee is on partial outage until 18 June 2024.

(d) Kawerau geothermal plant was on outage on 8 June.

(e) Various North and South Island hydro units were on outage.

Figure 16: Total MW loss due to generation outages between 2-8 June

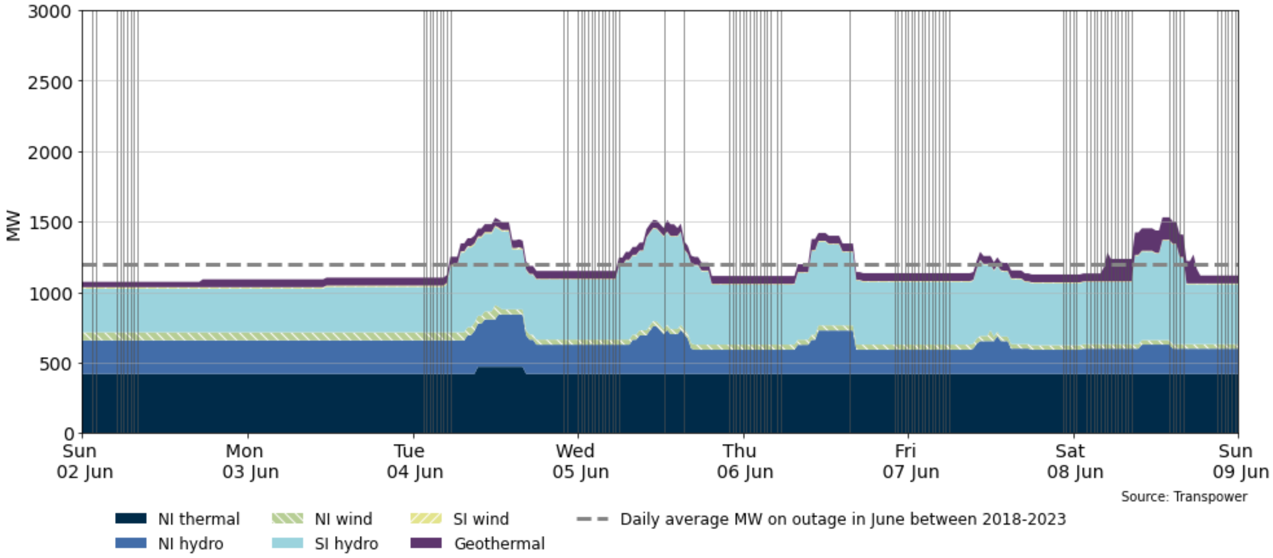
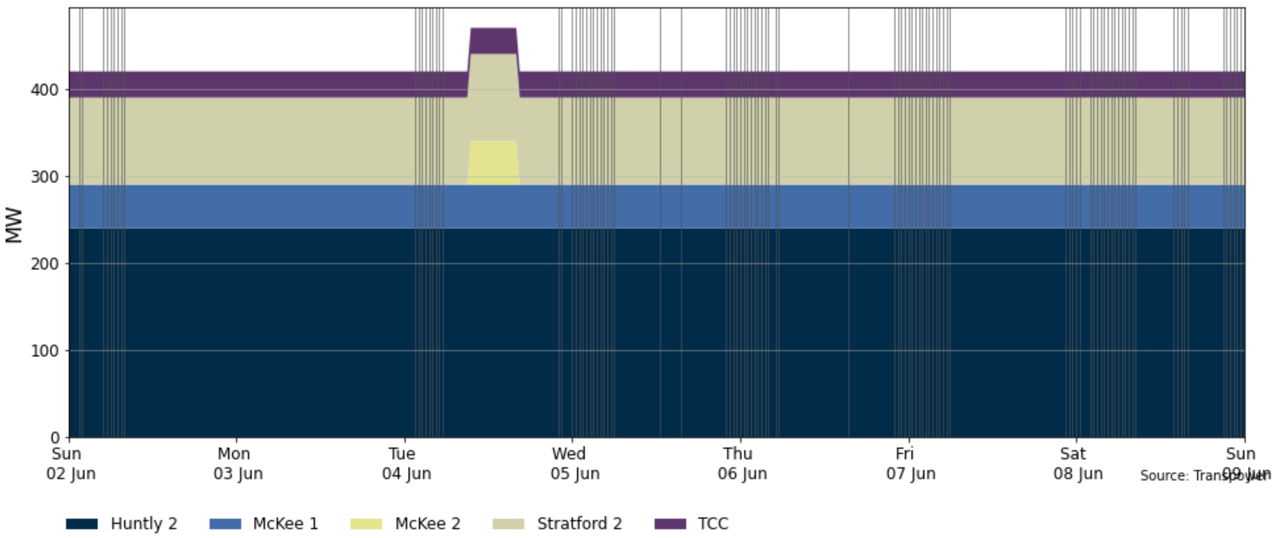


Figure 17: MW loss from thermal outages between 2-8 June

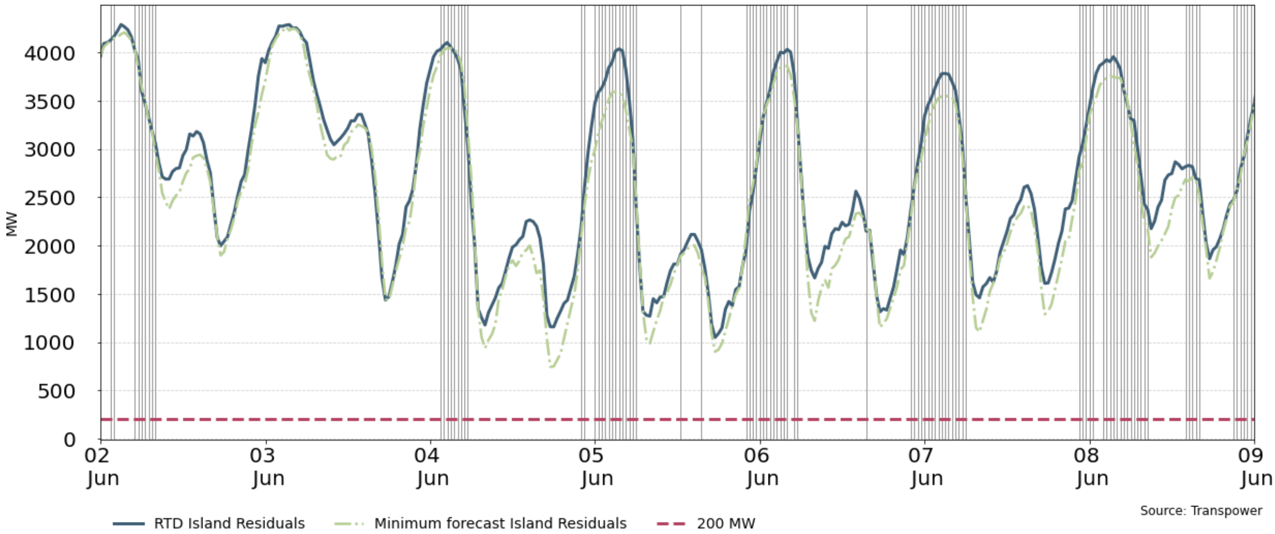


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 2-8 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 low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. Generation residuals were healthy this week. The minimum North Island residual was around 600MW, also on Wednesday afternoon.

Figure 18: National generation balance residuals 2-8 June



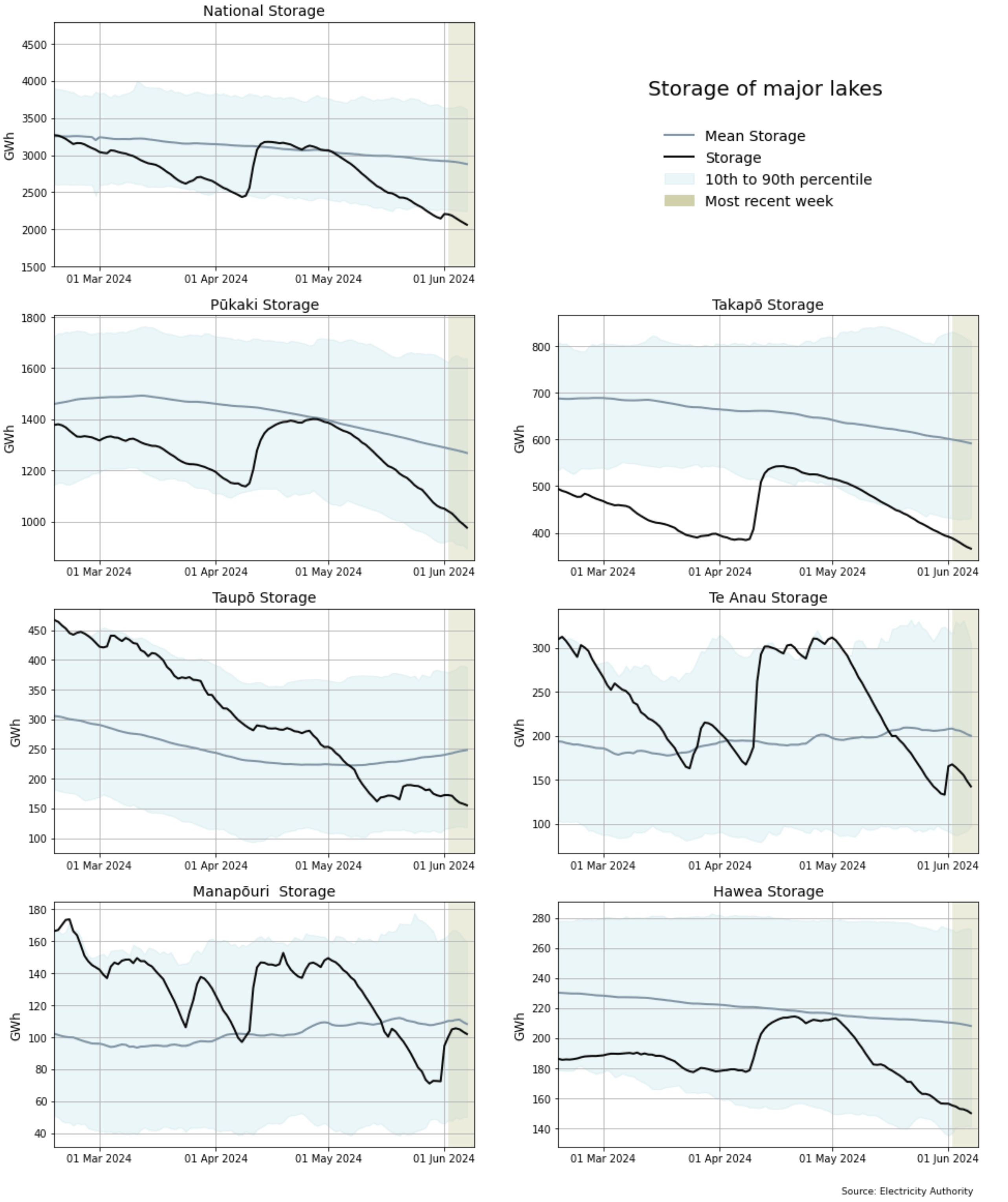
10. Storage/fuel supply

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. National controlled storage declined this week, and it is now at 55% nominally full and ~77% of the historical average for this time of the year (as of 8 June).

10.3. Storage decreased at all major lakes except for Manapōuri this week, which remained approximately stable. Takapō remains below its 10th percentile. Levels at all other lakes are above their 10th percentiles but below their historical means.

Figure 19: Hydro storage

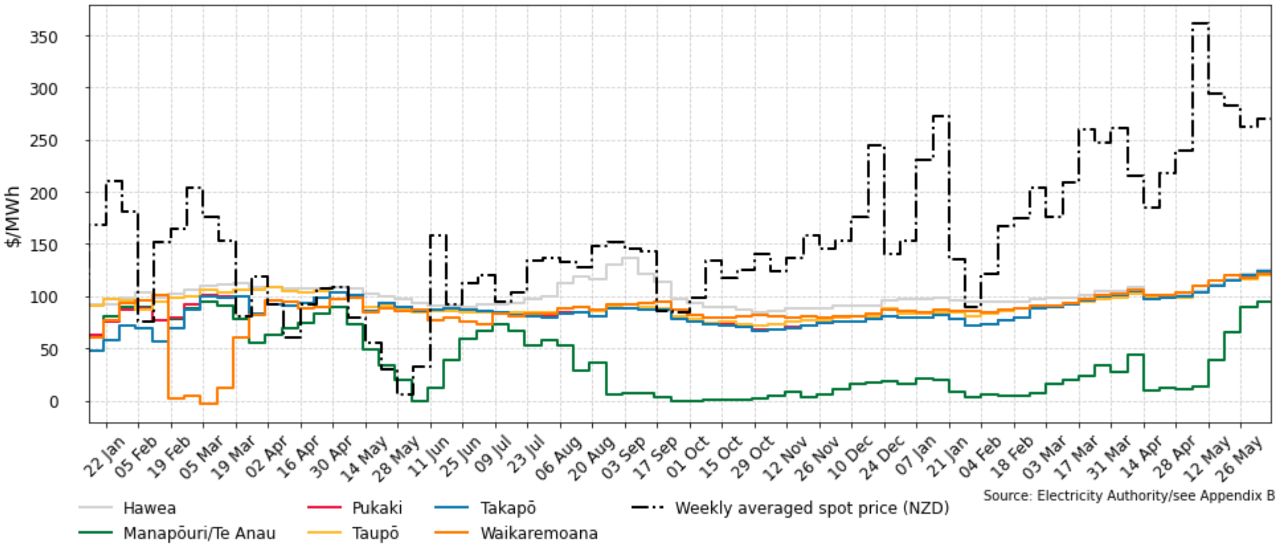


11. JADE water values

11.1. The JADE[3] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 20 shows the national water values between 8 January 2023 and 8 June 2024 obtained from JADE calculated at the start of the week. These values are used to estimate the marginal water value at the actual storage level. More details on how water values are calculated can be found in Appendix B.

11.2. Compared to the previous week there was an increase in water values across all lakes between ~$3.60/MWh (Taupō) to ~$4.60/MWh (Manapōuri/Te Anau).

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 8 June 2024



12. Prices versus estimated costs

12.1. 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).

12.2. 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.

12.3. Figure 21 shows an estimate of thermal SRMCs as a monthly average up to 1 May 2024. The SRMCs for coal and diesel have seen small changes from the previous month, both decreasing slightly. The gas SRMCs have increased this month, likely due to current gas availability and demand.

12.4. The latest SRMC of coal-fuelled Rankine generation is ~$163/MWh. The cost of running the Rankines on gas remains more expensive at ~$287/MWh.

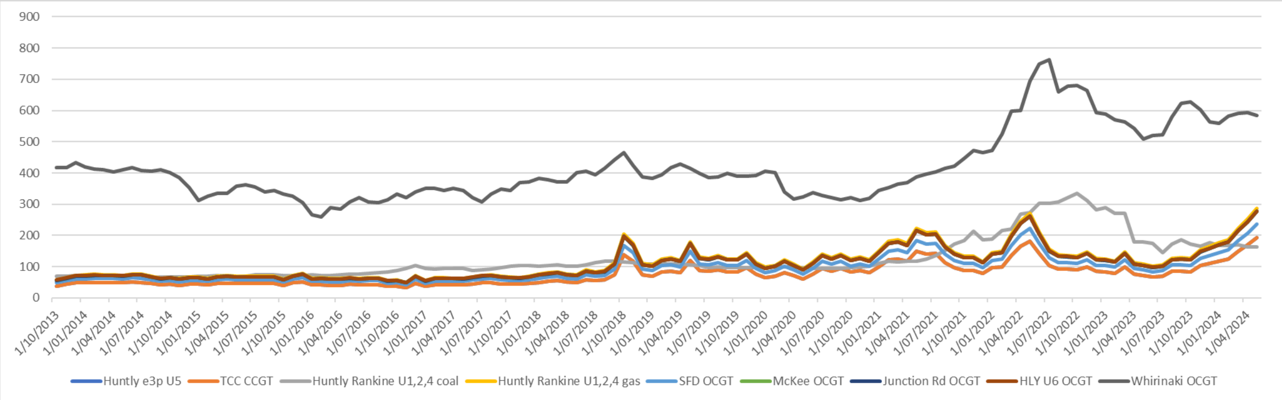
[3] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

12.5. The SRMC of gas-fuelled thermal plants is currently between ~$194/MWh and ~$287/MWh.

12.6. The SRMC of Whirinaki is ~$584/MWh.

12.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C on the trading conduct webpage.

Figure 21: Estimated monthly SRMC for thermal fuels



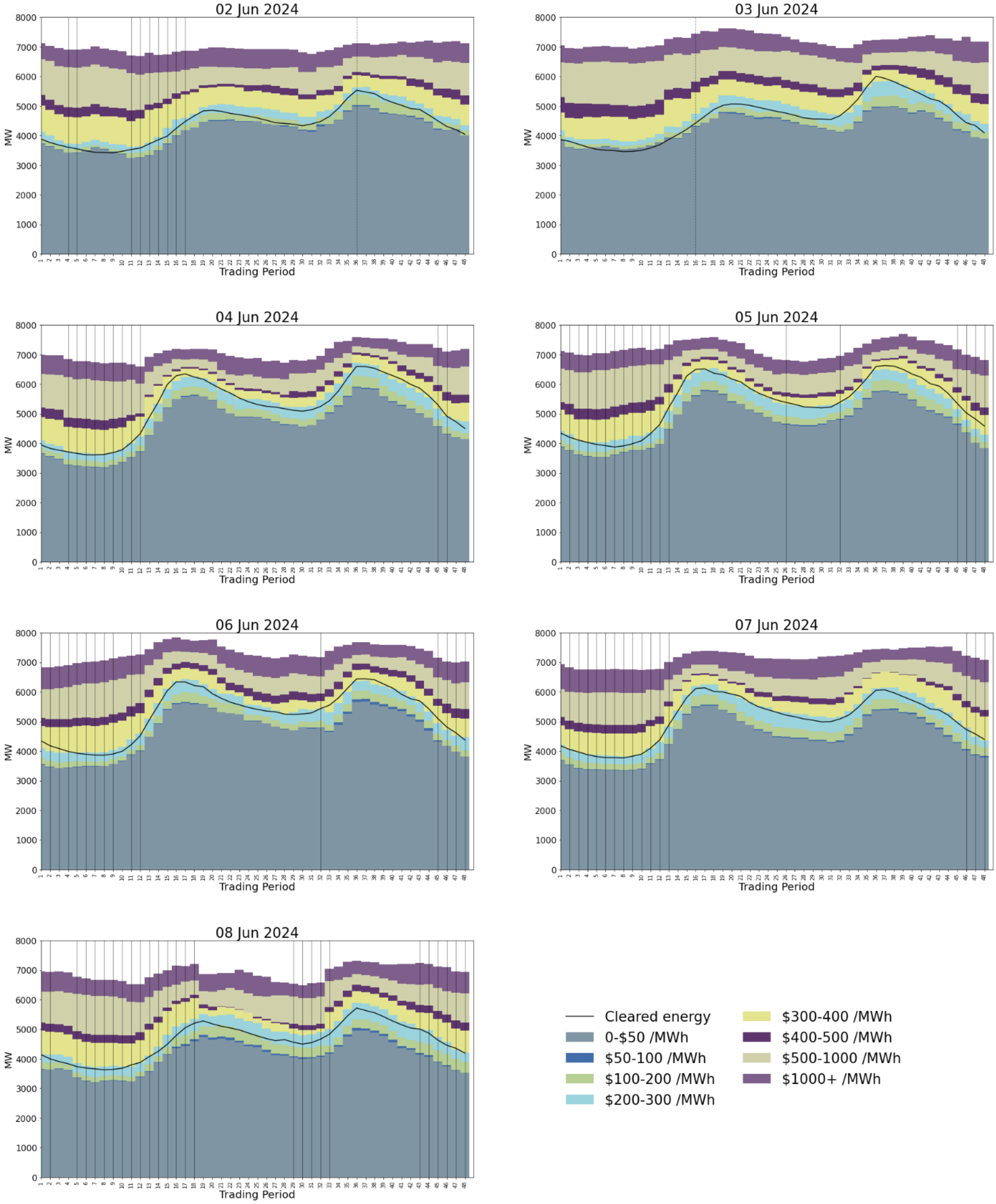
Source: Electricity Authority/see Appendix C

13. Offer behaviour

13.1. Figure 22 shows this week’s national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

13.2. Most offers cleared in the $200-$300/MWh, but during the weekdays several offers cleared within the $300-$400/MWh band, due to a thinner $200-$300/MWh band compared to previous weeks.

Figure 22: Daily offer stacks[4]



Source: Electricity Authority

[4] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

14. Ongoing work in trading conduct

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

14.2. Further analysis is being done on the trading periods in Table 1 as indicated.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Participant	Location	Enquiry topic
14/06/2023-15/06/2023	15-17/ 15-19	Passed to Compliance	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Further analysis	Contact	Multiple	High hydro offers
21/01/2024-27/01/2024	Several	Further analysis	Mercury	Waikato hydro dams	Energy offers
15/03/2024-16/03/2024	Several	Further analysis	Mercury	Waikato hydro dams	Energy offers
19/05/2024-24/05/2024	Several	Further analysis	Genesis	Tuai	East Coast price separation