4 June 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 26 May-1 June

1.1. Spot prices were mainly above the historical median this week and mostly between $200-$300/MWh, although a few days saw prices in the $300-$400/MWh. There were some price spikes related to high demand and wind being over-forecast, the highest of these during the Wednesday evening peak when prices reached $799/MWh at Ōtāhuhu. Higher wind generation this week saw less hydro generation, especially from Thursday onwards. This week, TCC, Huntly 1, Huntly 5, Huntly 4, and then Huntly 2 provided baseload generation. Hydro storage decreased to around 80% 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, 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 26 May-1 June:

(a) the average wholesale spot price across all nodes was $266/MWh.

(b) 95% of prices fell between $40/MWh and $489/MWh.

2.3. Overall, the majority of spot prices were above the historical median this week, with a few spikes occurring during the afternoon peaks between Monday and Wednesday. The average price decreased by around $20/MWh compared to the previous week.

2.4. On Monday, price spikes reached as high as $697/MWh in Ōtāhuhu at 6:00pm, related to high demand, decreasing wind generation and almost 100MW of wind forecast inaccuracies. On Tuesday, prices in Ōtāhuhu reached $645/MWh at 5:30pm, again related to high demand, decreasing wind generation, and more than 100MW of over-forecast wind generation.

2.5. On Wednesday, prices were high between 4:00pm and 5:30pm, reaching $799/MWh at 5:00pm. The high prices on Wednesday were due to record demand and a combination of high wind and demand forecast inaccuracies, often above 200MW during the peak.

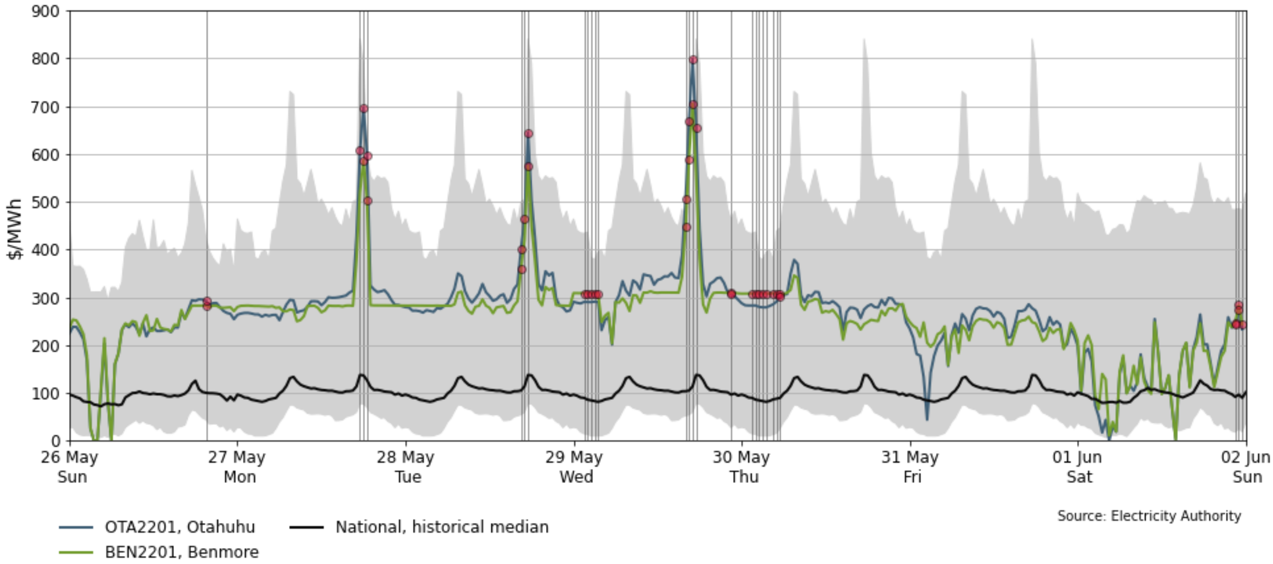
2.6. Low demand and high wind generation saw prices drop below $5/MWh on Sunday and Saturday. Early on Friday, the Ōtāhuhu price dropped to $44/MWh while the Benmore price remained at $205/MWh, again while wind generation was high and overnight demand was low.

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

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 26 May-1 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 spot price distribution this week was less condensed compared to the previous week, partially due to the decrease in spot prices from Friday onwards, related to high wind generation. The median price decreased slightly from $279/MWh in the previous week to $275/MWh this week, a $4/MWh decrease. The middle 50% of the prices were between $233-$301/MWh.

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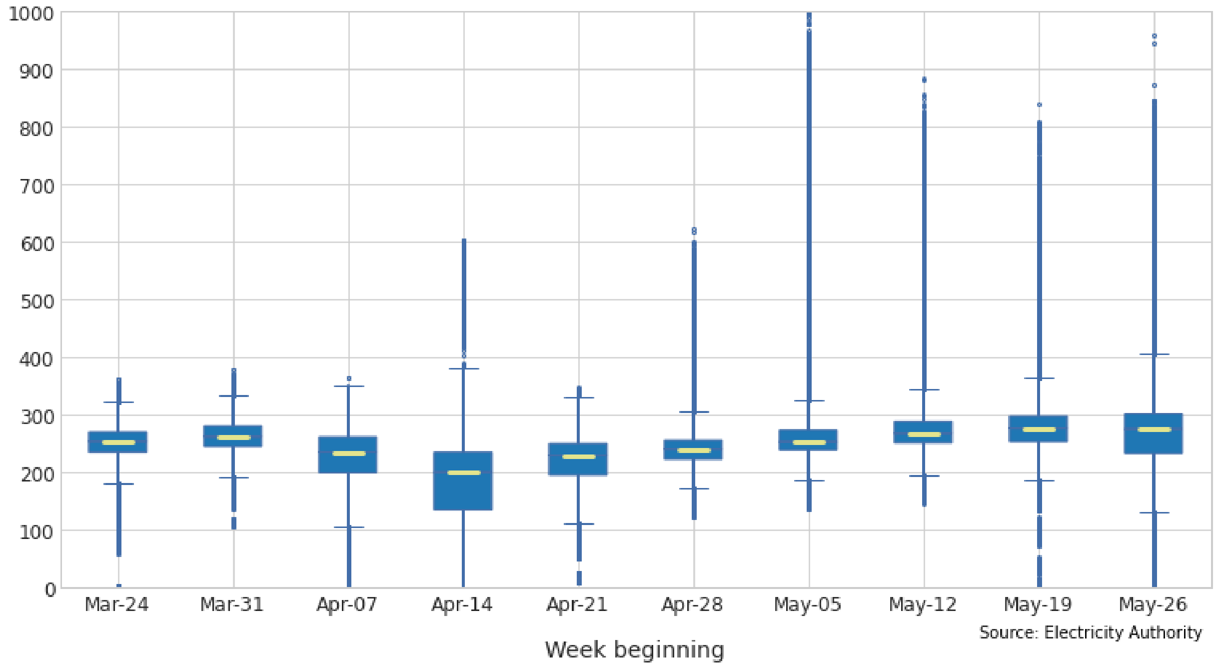
distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

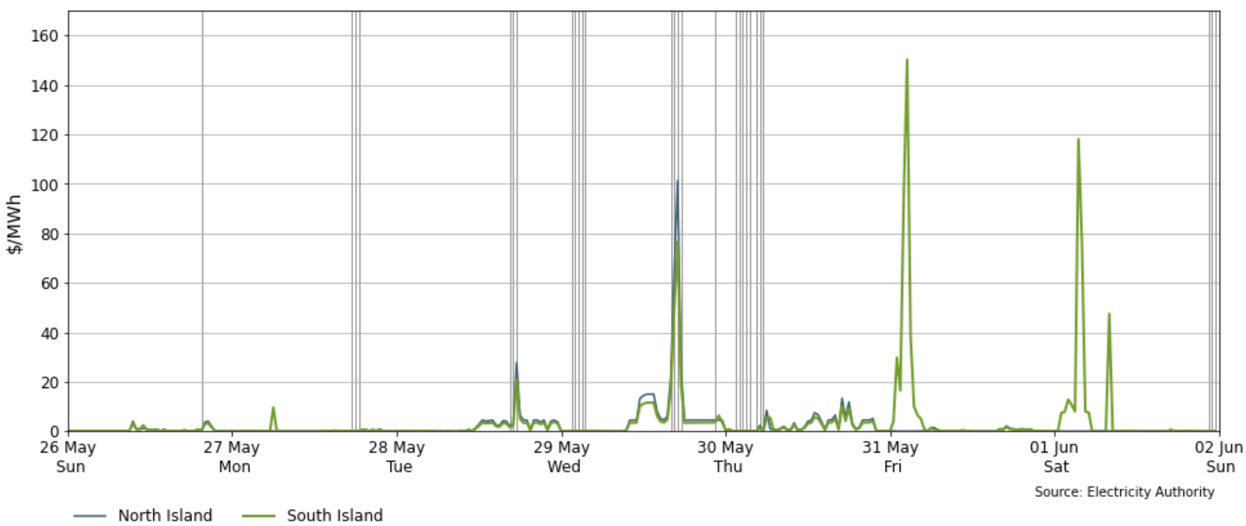
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

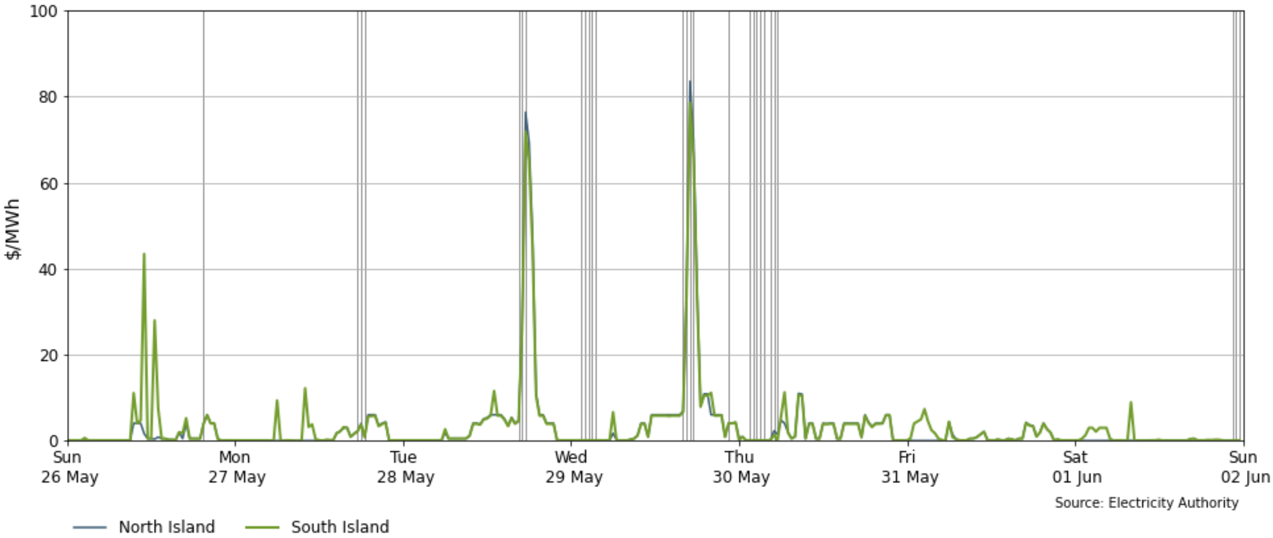
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh this week. A few FIR spikes occurred this week. On Tuesday and Wednesday the spikes are likely related to spot prices and reserve co-optimisation. On Friday and Saturday South Island FIR spiked during times of high HVDC southward transfer, increasing the reserve requirements of the receiving island.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 26 May-1 June



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh. On Sunday, South Island SIR had some small spikes related to reserves needed to cover South Island risk. The spikes seen on Tuesday and Wednesday are in line with the spot price spikes and likely related to spot price and reserves co-optimisation.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 26 May-1 June



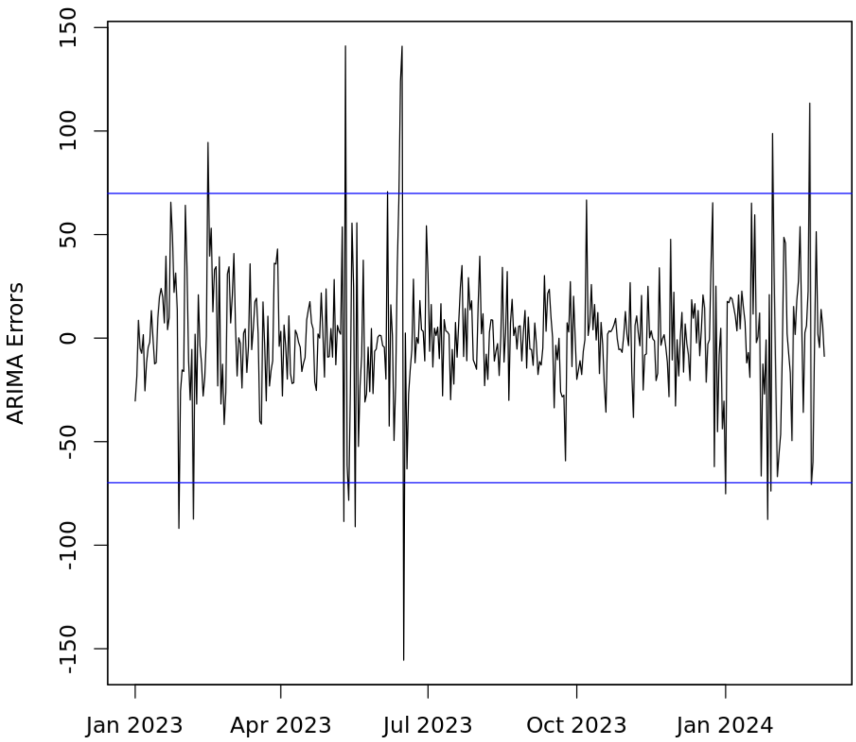
4. Regression residuals

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.

4.3. The residual on Tuesday was above two standard deviations of the data indicating that prices were higher than the model expected.

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

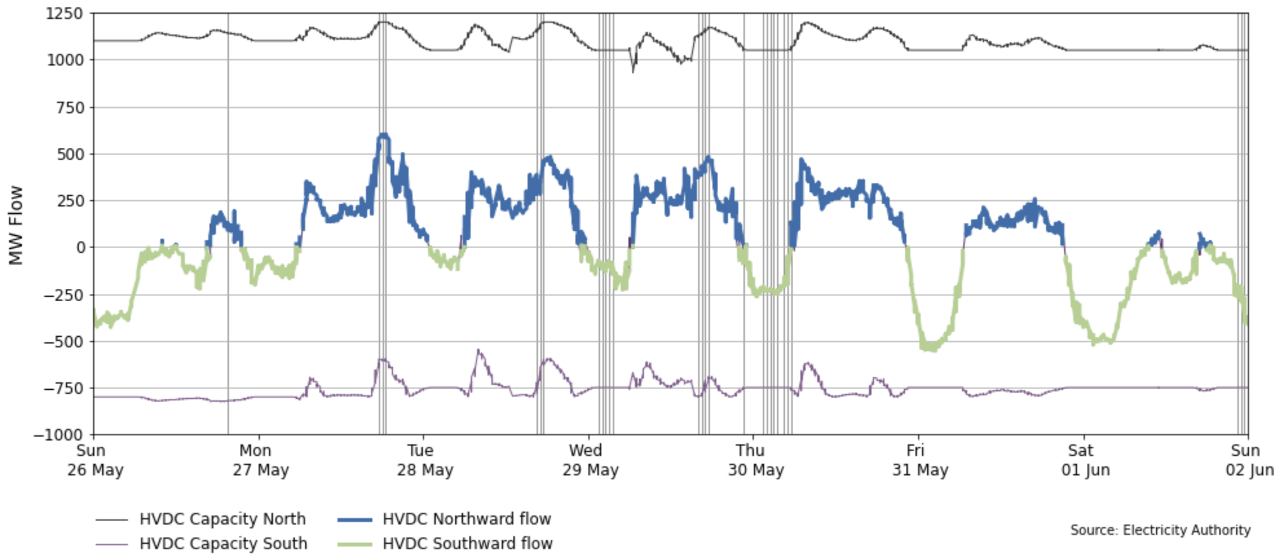


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 26 May-1 June. High wind generation this week saw high southward HVDC flows, particularly in the early hours of Friday and Saturday morning. Northward flows occurred during the day with the higher flows corresponding to times of decreasing wind generation.

Figure 6: HVDC flow and capacity between 26 May-1 June

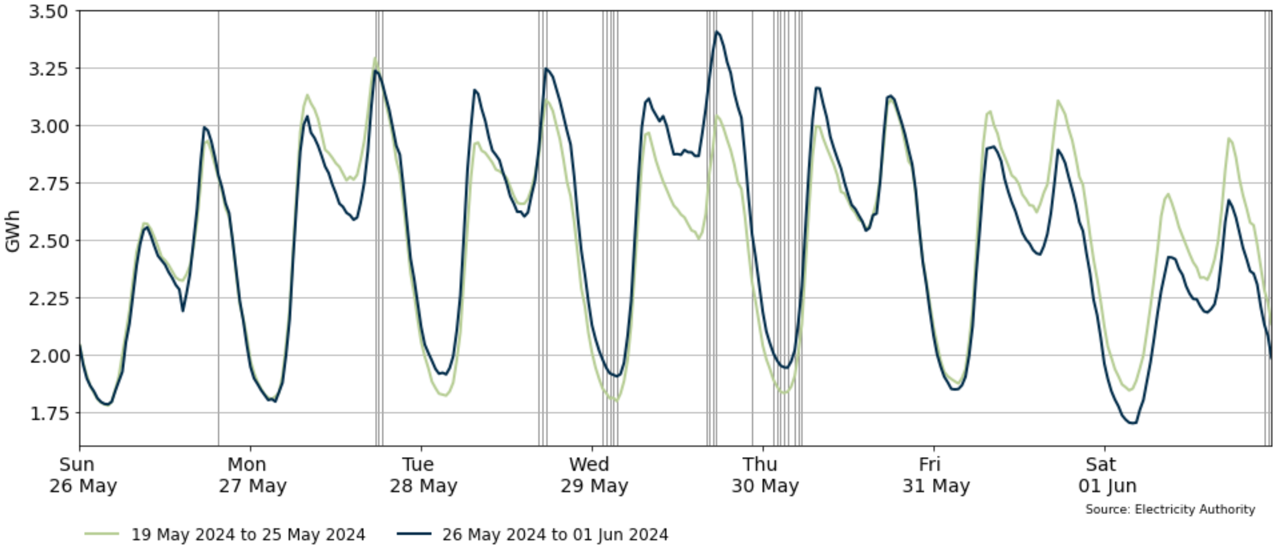


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 26 May-1 June, compared to the previous week. Demand was significantly higher than the previous week on Wednesday, reaching 3.41GWh (6.81GW) that evening, the highest peak this year so far. Demand was lower than the previous week on Friday and Saturday, likely due to warmer temperatures on these days.

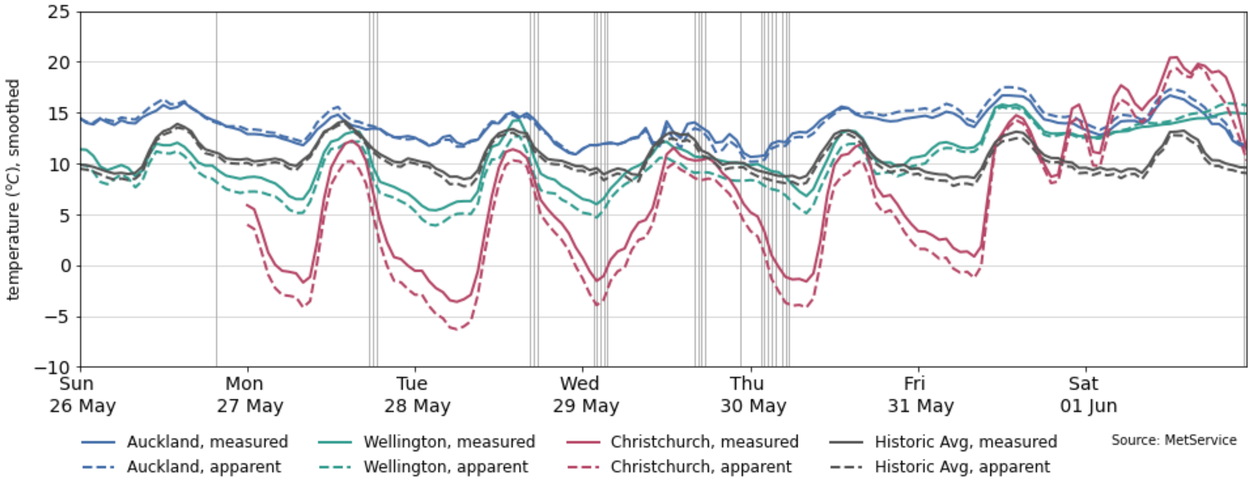
Figure 7: National demand between 26 May-1 June compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 26 May-1 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 mostly above the historical average this week, with apparent temperatures varying between 10ºC and 18ºC. Temperatures in Wellington and Christchurch were mostly below the historical average until Friday when temperatures increased significantly. Apparent temperatures in Wellington were between 4º and 16ºC this week. In Christchurch, apparent temperatures were between -6ºC and 20ºC. Temperature data for Sunday and part of Monday in Christchurch was not available this week.

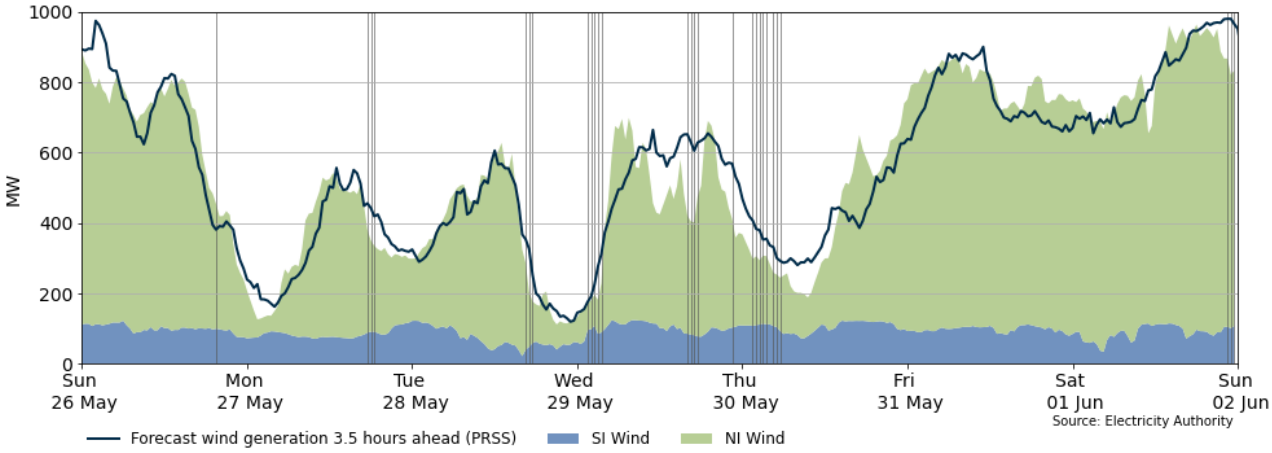
Figure 8: Temperatures across main centres between 26 May-1 June



7. Generation

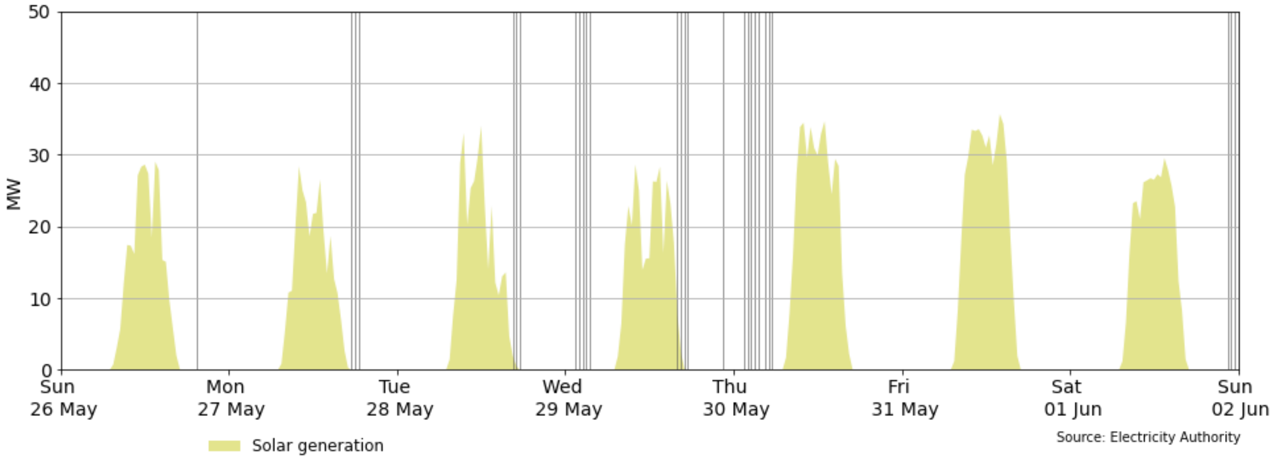
7.1. Figure 9 shows wind generation and forecast from 26 May-1 June. This week wind generation varied between 112MW and 963MW, with a weekly average of 552MW. Wind generation was high this week, although forecasting inaccuracies likely contributed to the high prices seen on Monday, Tuesday, and Wednesday. At the time of the highest Ōtāhuhu spot price, wind generation was 230MW below forecast.

Figure 9: Wind generation and forecast between 26 May-1 June



7.2. Figure 10 shows solar generation from 26 May-1 June. Solar generation was between 28MW and 36MW 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 26 May-1 June

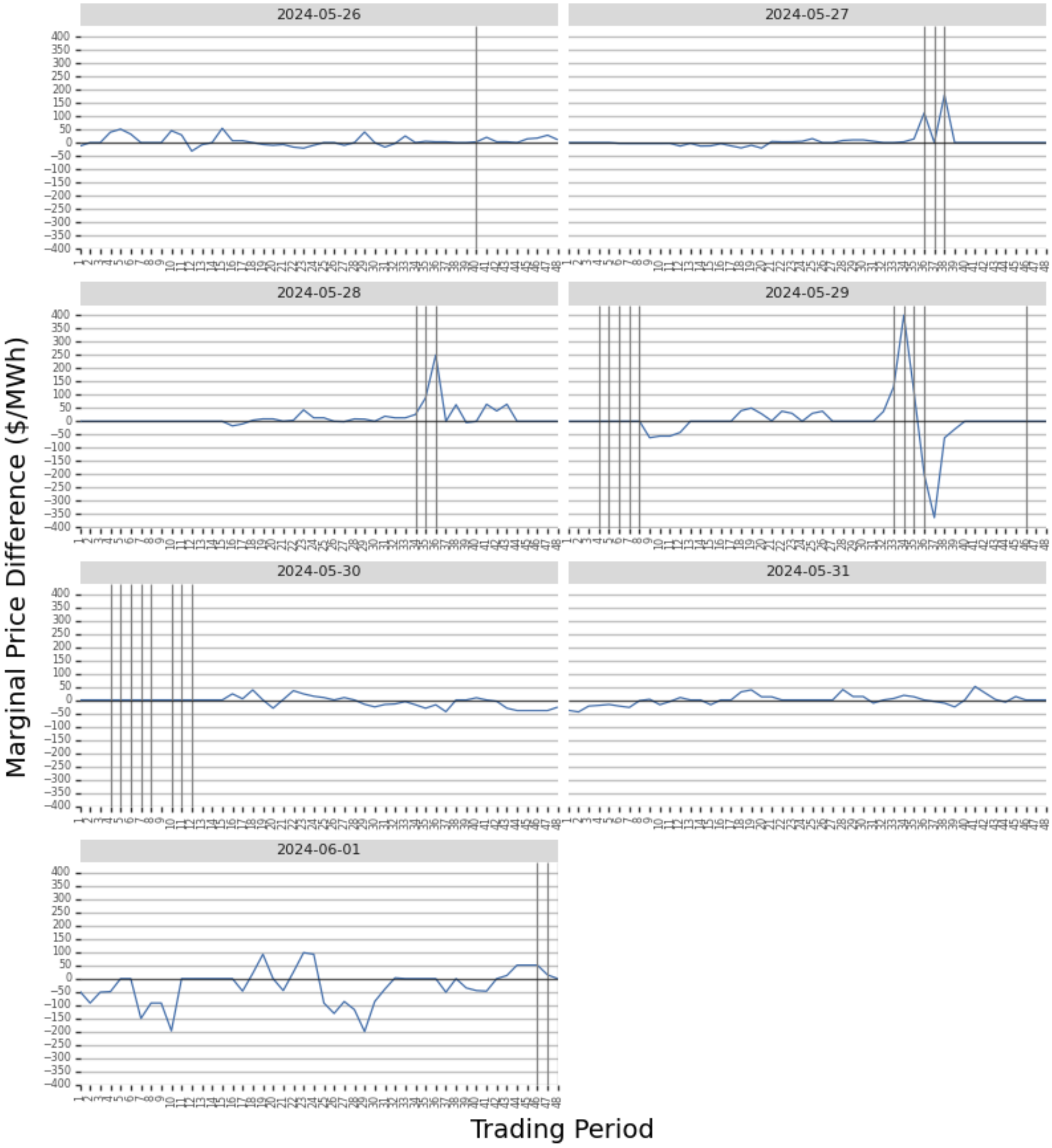


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS) projections. The figure highlights when forecasting inaccuracies are causing large differences in 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 differences (marginal prices higher than simulation) occurred where the majority of this week's price spikes occurred. On Monday and Tuesday, the high price differences occurred during several trading periods in the afternoon on both days, when wind generation was over-forecast more than 100MW at times.

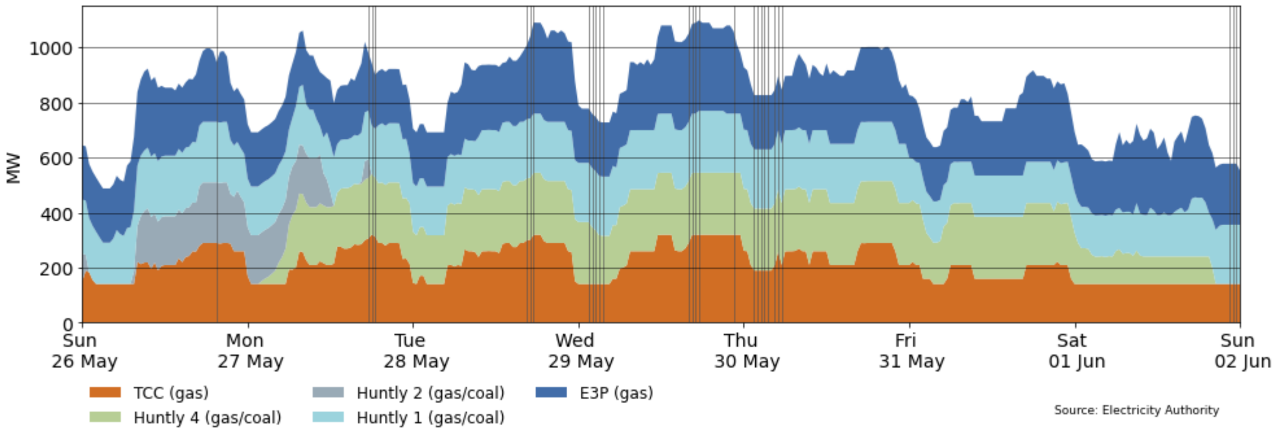
7.5. The largest positive differences were seen on Wednesday afternoon, during trading periods 33-34 (4:00pm-4:30pm) when the difference in marginal price reached ~$400/MWh at 4.30pm. Both wind and demand forecasts were out by more than 200MW.

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 26 May-1 June



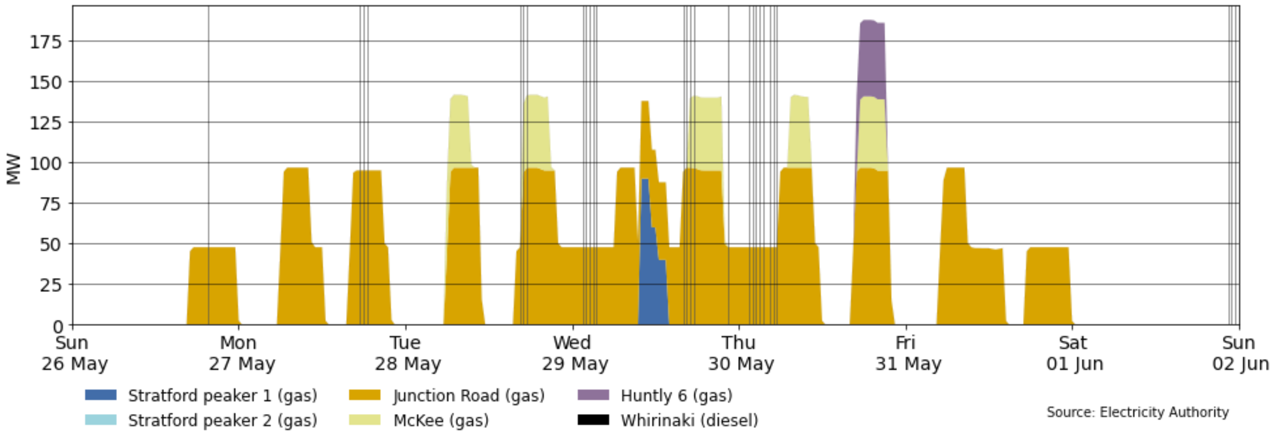
7.6. Figure 12 shows the generation of thermal baseload between 26 May-1 June. This week TCC, Huntly 1, and Huntly 5 (E3P) ran continuously providing baseload generation. Huntly 2 ran on Sunday and Monday before going on outage, while Huntly 4 ran from Monday to Saturday.

Figure 12: Thermal baseload generation between 26 May-1 June



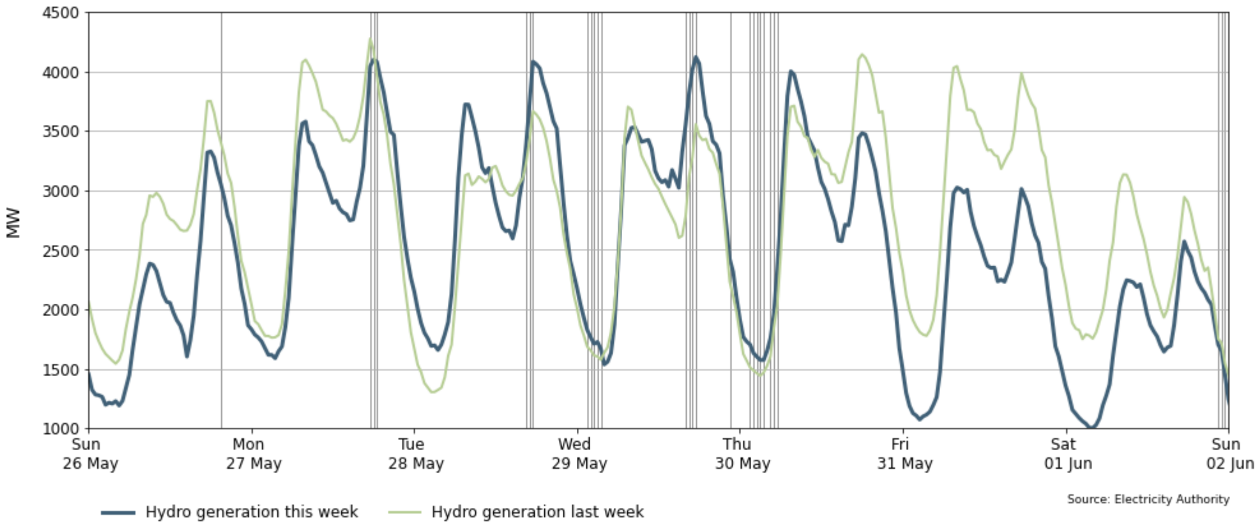
7.7. Figure 13 shows the generation of thermal peaker plants between 26 May-1 June. Junction Road ran every day except for Saturday. McKee ran on Tuesday, Wednesday, and Thursday during times of peak periods. Stratford 1 ran for a few hours during Wednesday, while Huntly 6 ran during the demand peak on Thursday afternoon.

Figure 13: Thermal peaker generation between 26 May-1 June



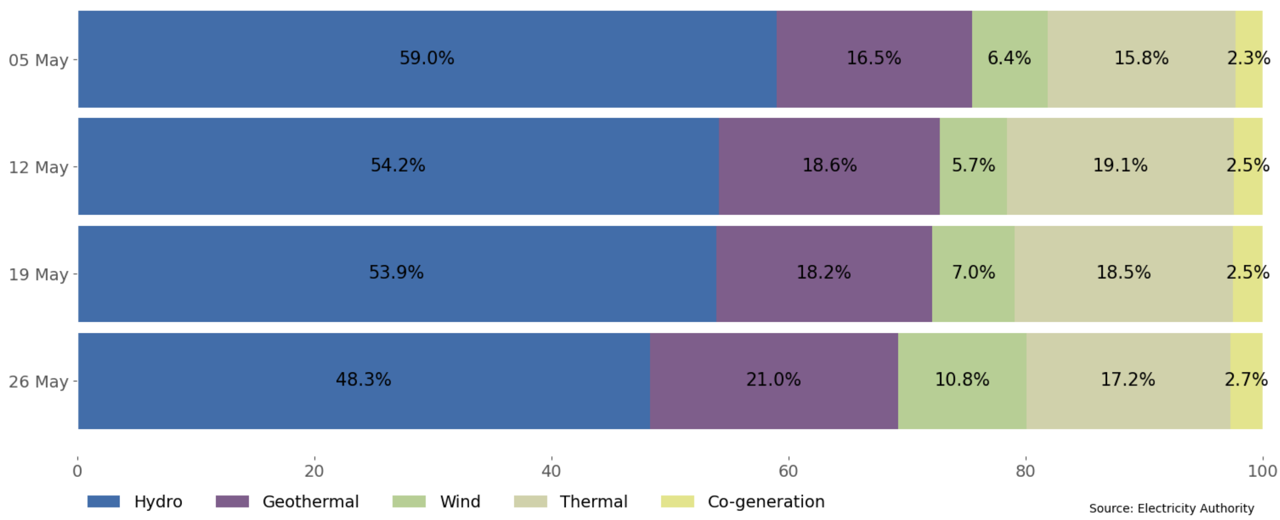
7.8. Figure 14 shows hydro generation between 26 May-1 June. Hydro generation was generally lower than the previous week but was higher over the high peak demand periods from Tuesday to Thursday. From Thursday afternoon onwards, hydro generation was lower compared to the previous week when wind generation was high.

Figure 14: Hydro generation between 26 May-1 June



7.9. As a percentage of total generation, between 26 May-1 June, total weekly hydro generation was 48.3%, geothermal 21.0%, wind 10.8%, thermal 17.2%, and co-generation 2.7%, as shown in Figure 15. The decrease in the proportion of hydro generation this week is related to relatively high wind generation as well as milder temperatures driving down demand later in the week.

Figure 15: Total generation by type as a percentage each week between 5 May and 1 June



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 26 May-1 June ranged between ~800MW and ~1600MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford 2 is on outage until 30 June.

(b) Huntly 2 is on outage until 4 June 2024.

(c) Huntly 4 was on outage until 27 May.

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

(e) Stratford 1 was on outage until 28 May.

(f) Turitea wind farm was on outage on 27 May.

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

Figure 16: Total MW loss due to generation outages between 26 May-1 June

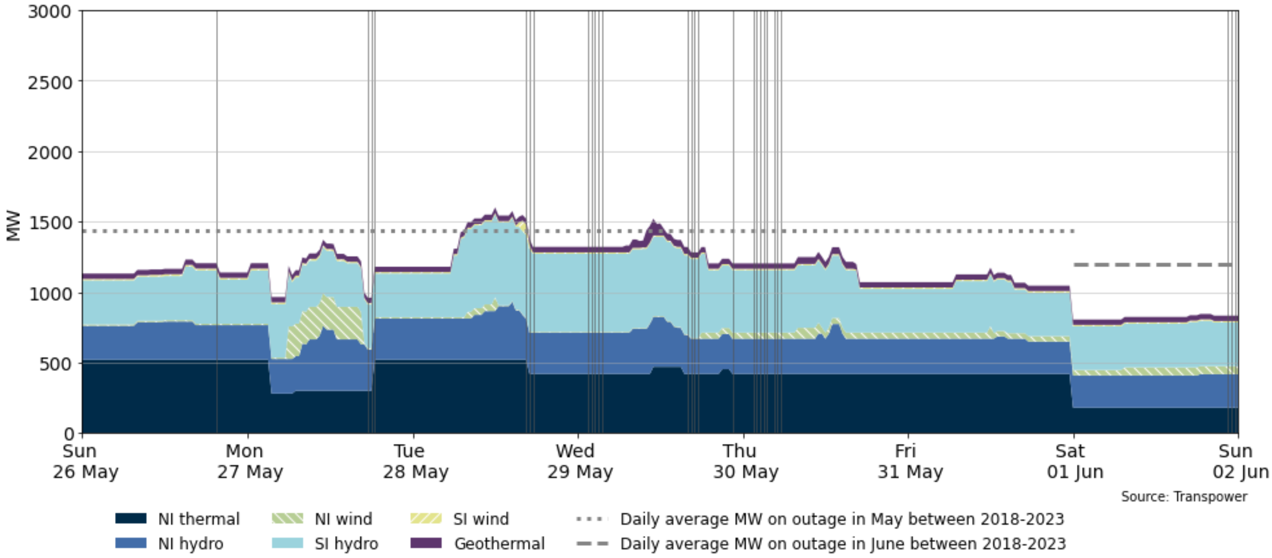
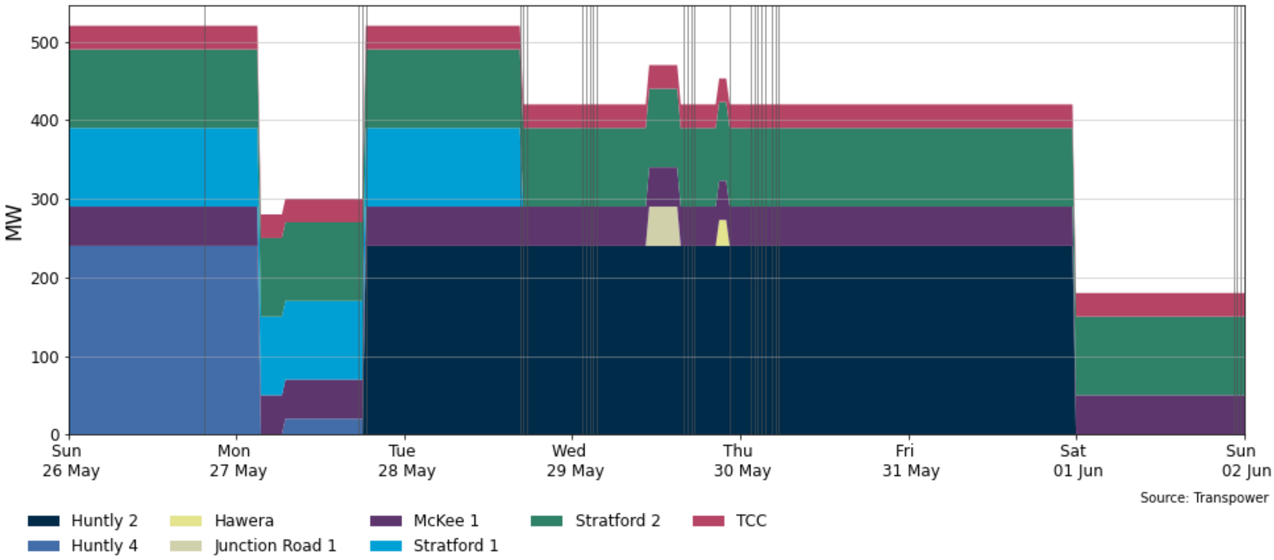


Figure 17: MW loss from thermal outages between 26 May-1 June

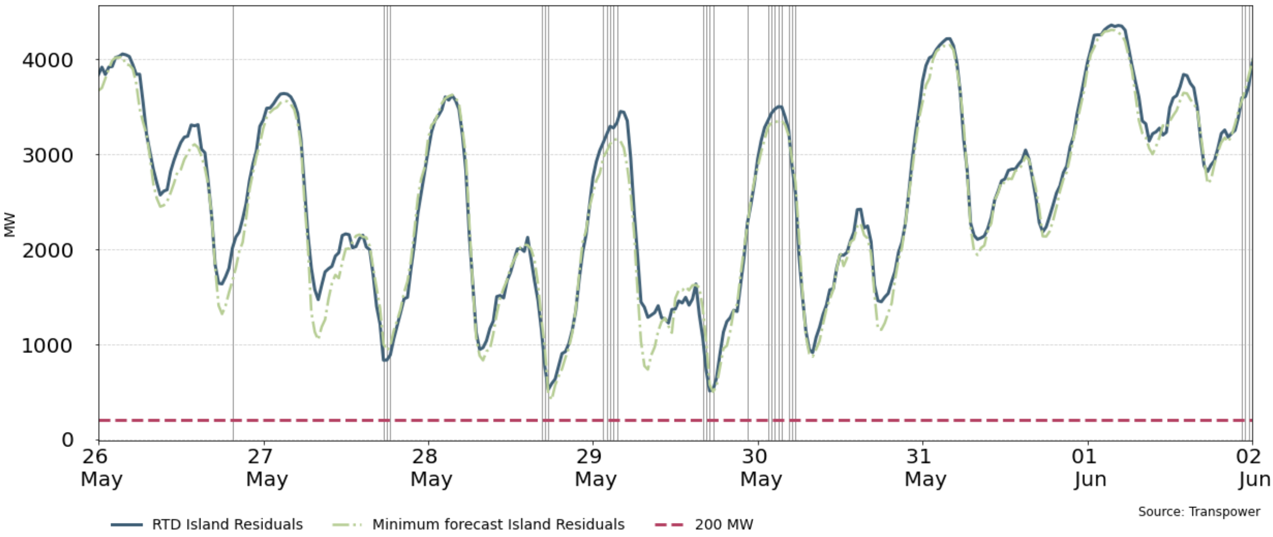


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 26 May-1 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 national residual was 509MW on Wednesday afternoon, and the minimum North Island residual was 354MW, also on Wednesday afternoon.

Figure 18: National generation balance residuals 26 May-1 June



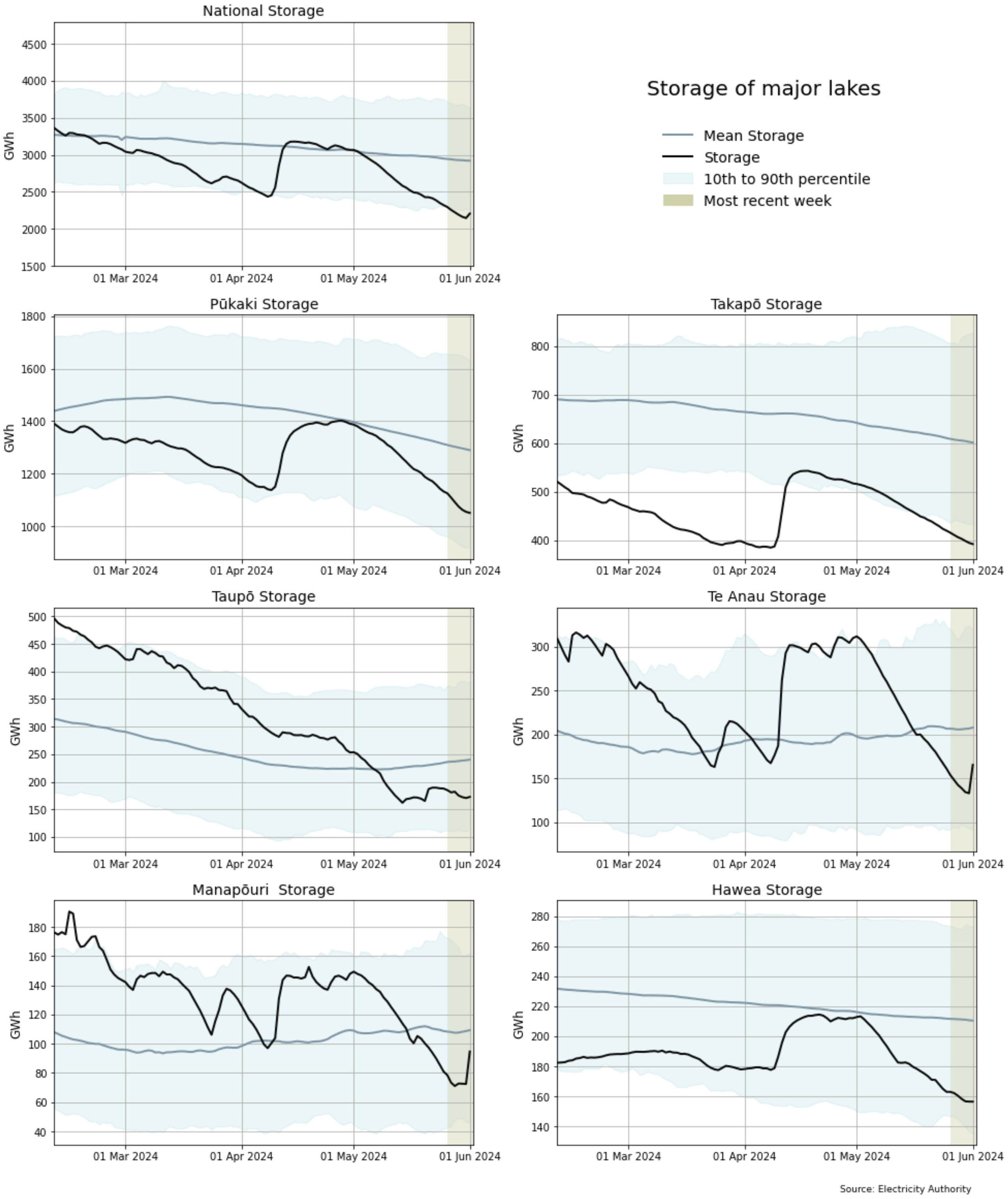
10. Storage/fuel supply

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 58% nominally full and ~80% of the historical average for this time of the year (as of 1 June).

10.3. Storage decreased at all major lakes except Te Anau and Manapōuri this week, which have both seen an increase but remain below mean. Takapō is below its 10th percentile. Levels at all other lakes are above their 10th percentiles, but below their historical means.

Figure 19: Hydro storage

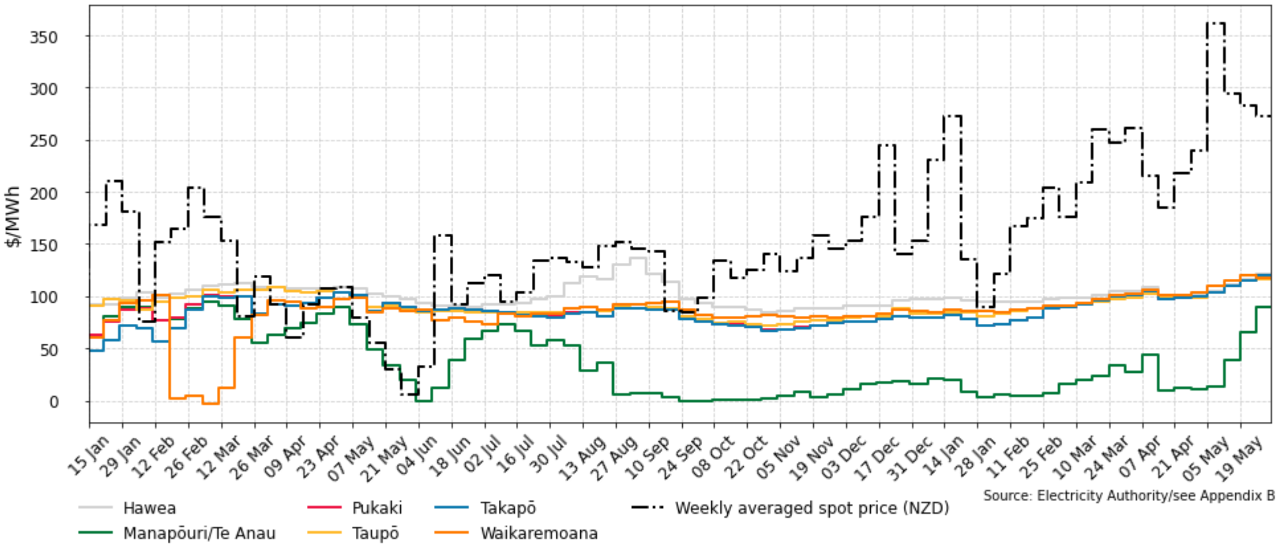


11. JADE water values

11.1. The JADE[2] 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 1 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 except for one, Waikaremoana, which saw a decrease of around $3.00/MWh in its water value. The water values at other lakes increased between ~$2.50/MWh (Taupō) to ~$24.50/MWh (Manapōuri/Te Anau).

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 1 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.

[2] 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.

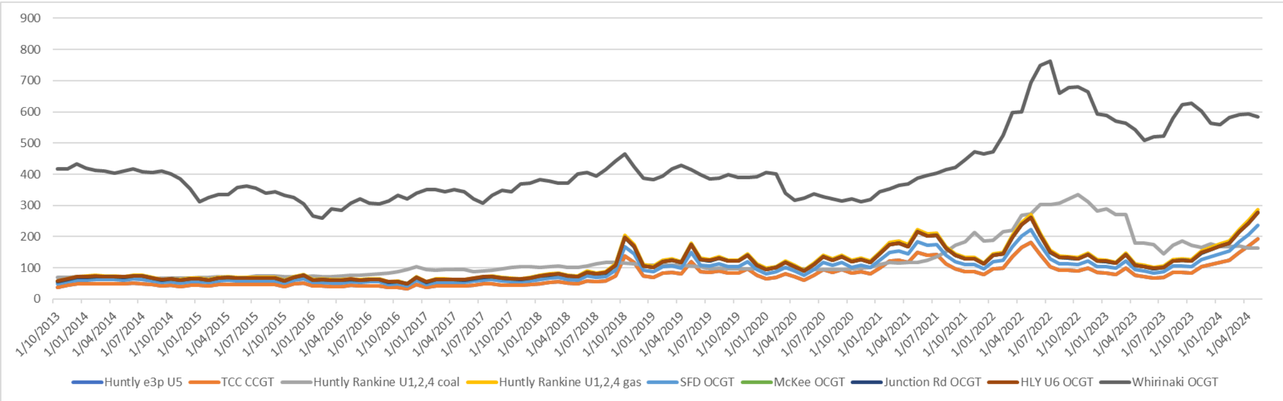
12.4. The latest SRMC of coal-fuelled Rankine generation is ~$163/MWh. The cost of running the Rankines on gas remains more expensive at ~$287/MWh.

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



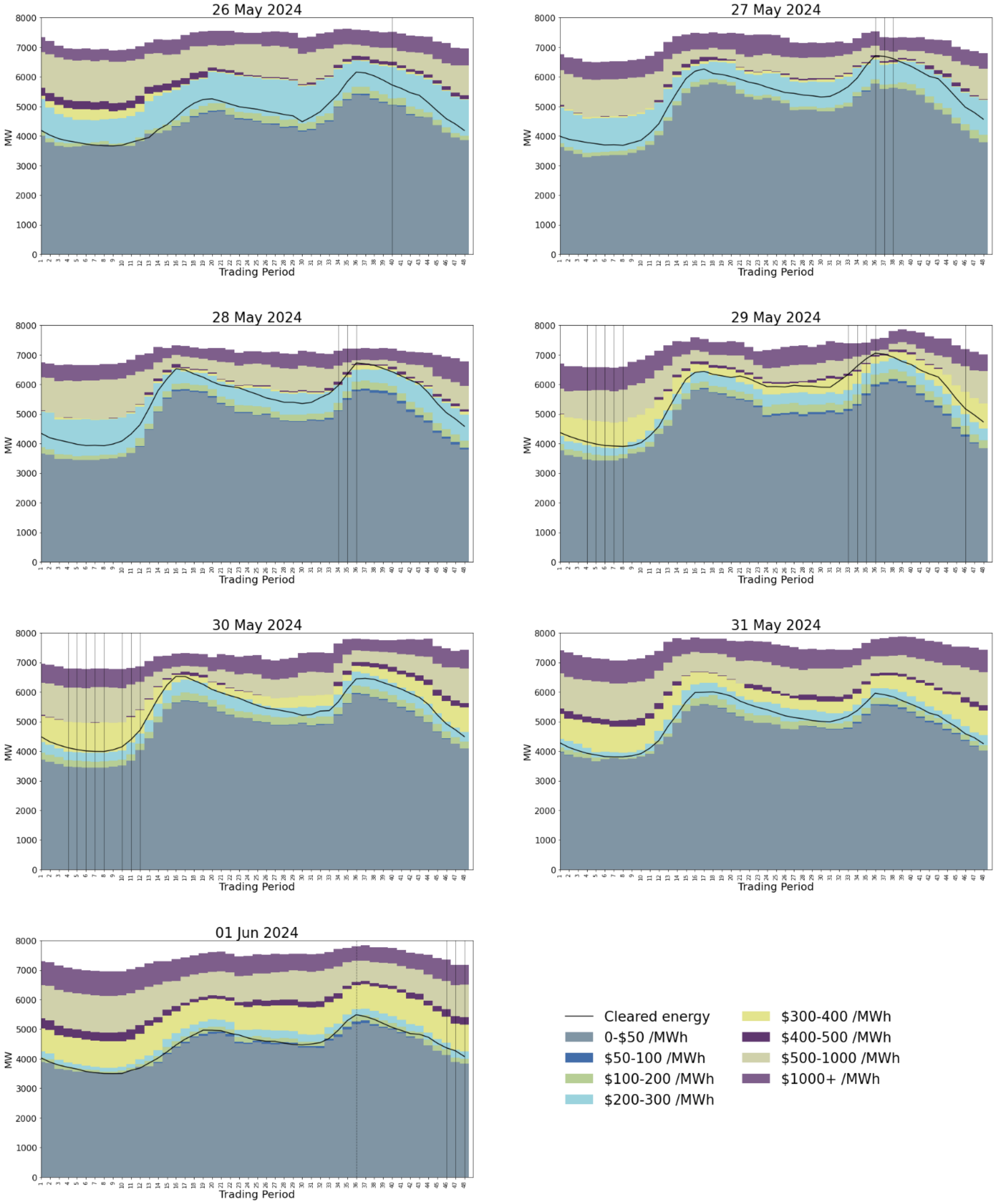
Source: Electricity Authority/see Appendix C

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 region except for Wednesday and Thursday, when several offers cleared within the $300-$400/MWh band. From Wednesday onwards there were less offers in the $200-$300/MWh band with a notable increase to the $300-$400/MWh band. Thin offer bands during the peak demand periods from Monday to Wednesday saw some prices clear above $400/MWh.

Figure 22: Daily offer stacks[3]



Source: Electricity Authority

[3] PRSS data is used for trading periods where RTD data is not available, if any. 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
8/05/2024-10/05/2024	Several	Further analysis	Genesis	Multiple	Energy offers
14/05/2024	16-17	Further analysis	Contact	Several	Energy offers
19/05/2024-24/05/2024	Several	Further analysis	Genesis	Tuai	East Coast price separation