24 June 2024

Trading conduct report 16-22 June 2024

Market monitoring weekly report

Trading conduct report

1. Overview for week of 16-22 June

1.1. Spot prices were consistently above the historical median this week and mostly between $200- $300/MWh. Overnight prices were often higher at Benmore than Ōtāhuhu, likely due to South Island hydro prices increasing as lake levels continue to decline. TCC, Huntly 5 and two Rankines provided baseload generation this week. Hydro storage decreased to around 74% 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. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside their historic average 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 highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 16-22 June:

(a) The average wholesale spot price across all nodes was $265/MWh.

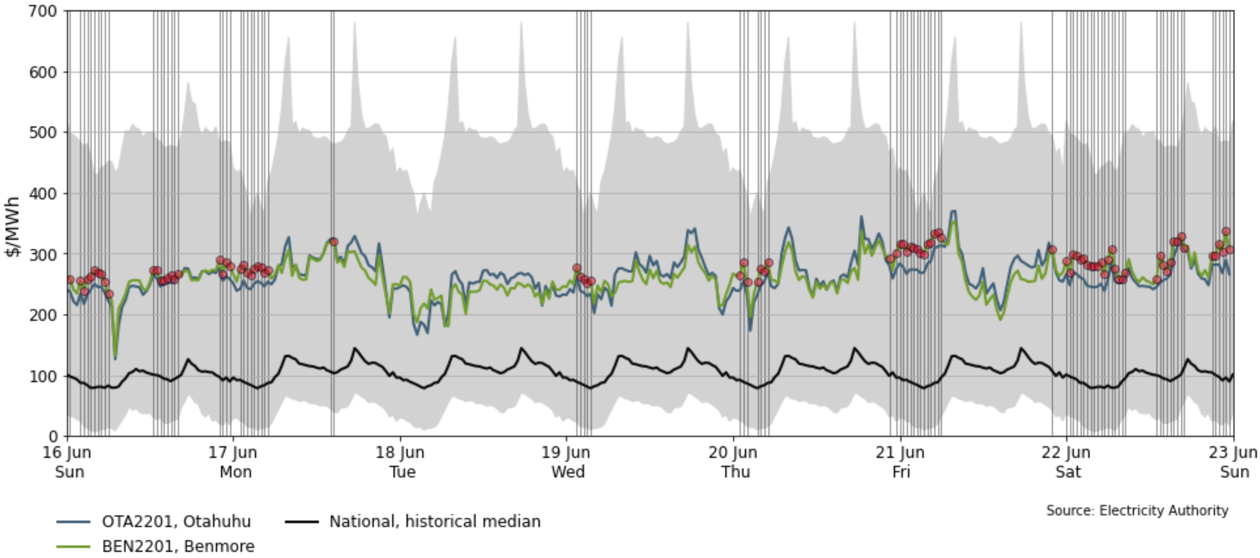
(b) 95 percent of prices fell between $194/MWh and $342/MWh.

2.4. The majority of spot prices were between the historical median and 90th percentile this week. The Ōtāhuhu spot price reached a maximum of $370/MWh on Friday morning at 8:00am, when wind generation was low and demand was high.

2.5. Most of the highlighted prices in Figure 1 occurred when the price at Benmore was higher than the price at Ōtāhuhu. This mostly occurred overnight, when the HVDC was flowing south, and in the context of continued declining hydro storage.

[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.

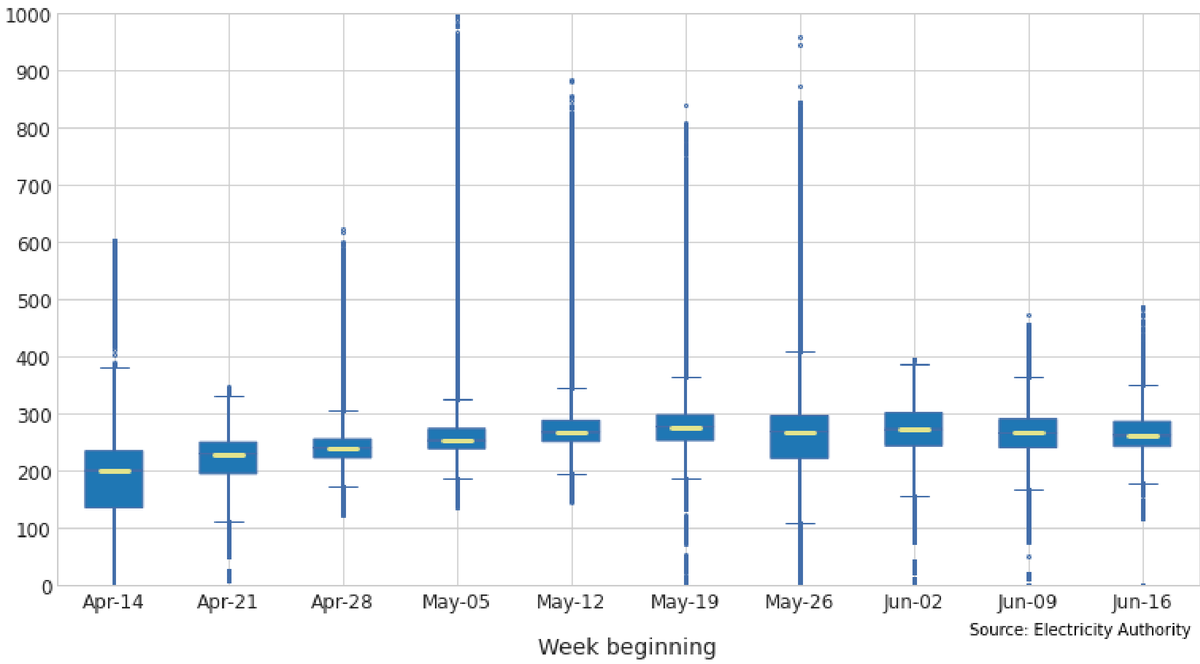
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 16-22 June



2.6. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The green line shows each week's median price, while the box part shows the lower and upper quartiles (where 50 percent 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.

2.7. The distribution of prices this week was similar to the previous week, though there were fewer low outliers. The median price decreased by $3/MWh to $262/MWh, and the middle 50% of prices were between $242/MWh and $286/MWh.

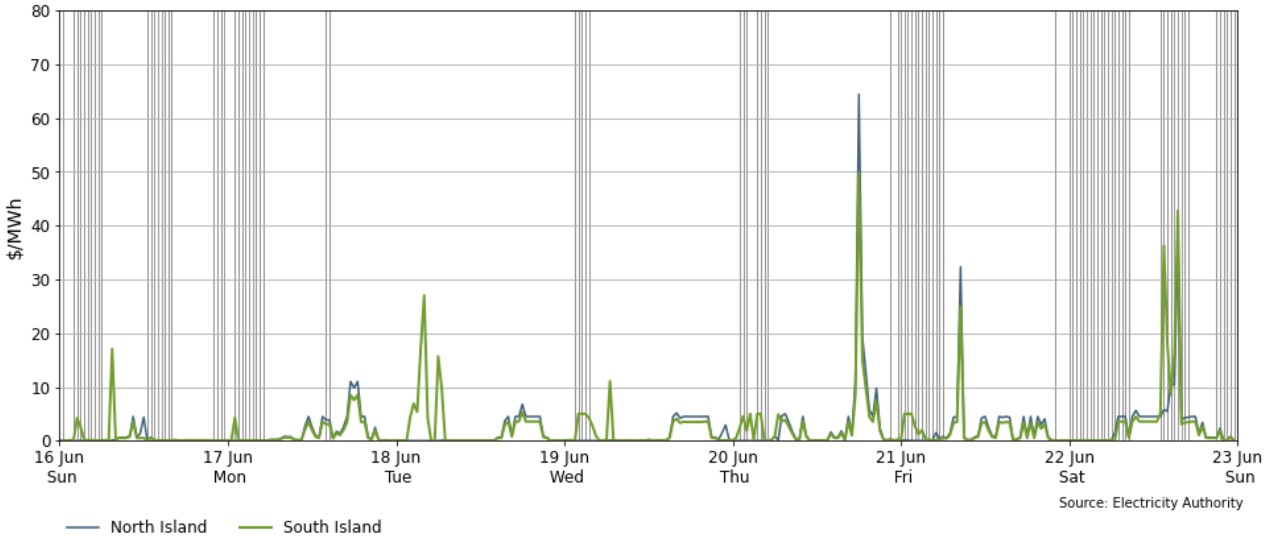
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

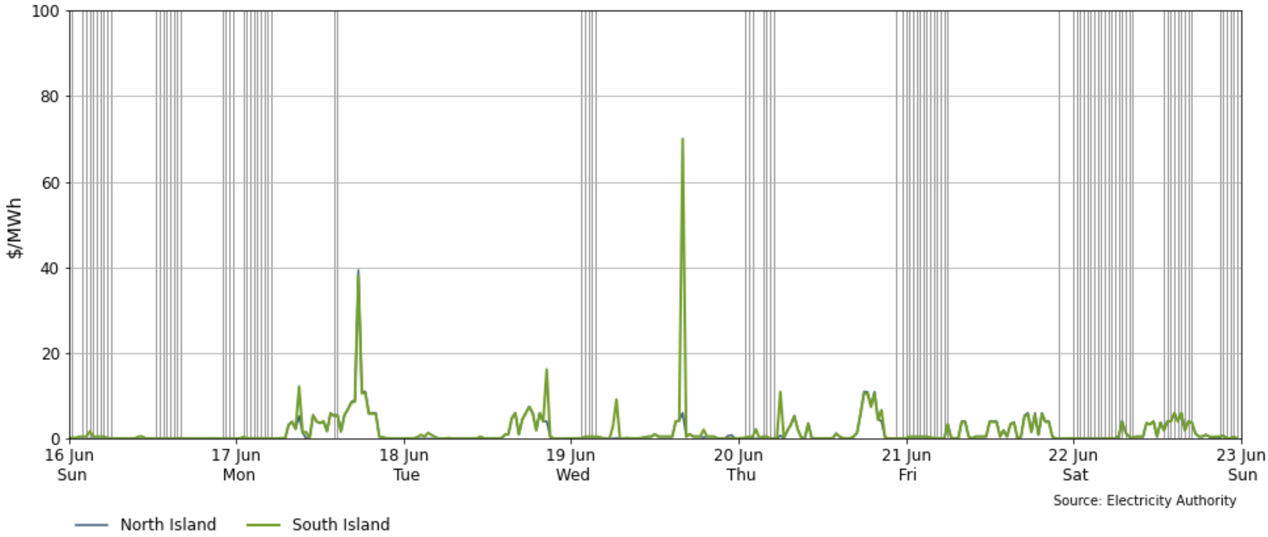
3.1. FIR prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week, but spiked over $25/MWh in the South Island on Tuesday, and over $30/MWh in both islands on Thursday, Friday and Saturday. The high FIR prices on Thursday and Friday occurred during peak periods. While the Tuesday South Island spike occurred when the HVDC was flowing south and setting the South Island risk. During the price spikes on Saturday the reserve requirements in the North Island increased, which also causes South Island FIR spikes due to there being less North Island reserve available to share across the HVDC.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 16-22 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 this week, but spiked over $35/MWh in both islands on Monday, during the evening peak demand period. The South Island SIR price spiked again on Wednesday, reaching $70/MWh while the North Island SIR price remained at $6/MWh. During the South Island SIR spike on Wednesday the reserve requirements in the North Island increased, which can cause South Island SIR spikes due to there being less North Island reserve available to share across the HVDC.

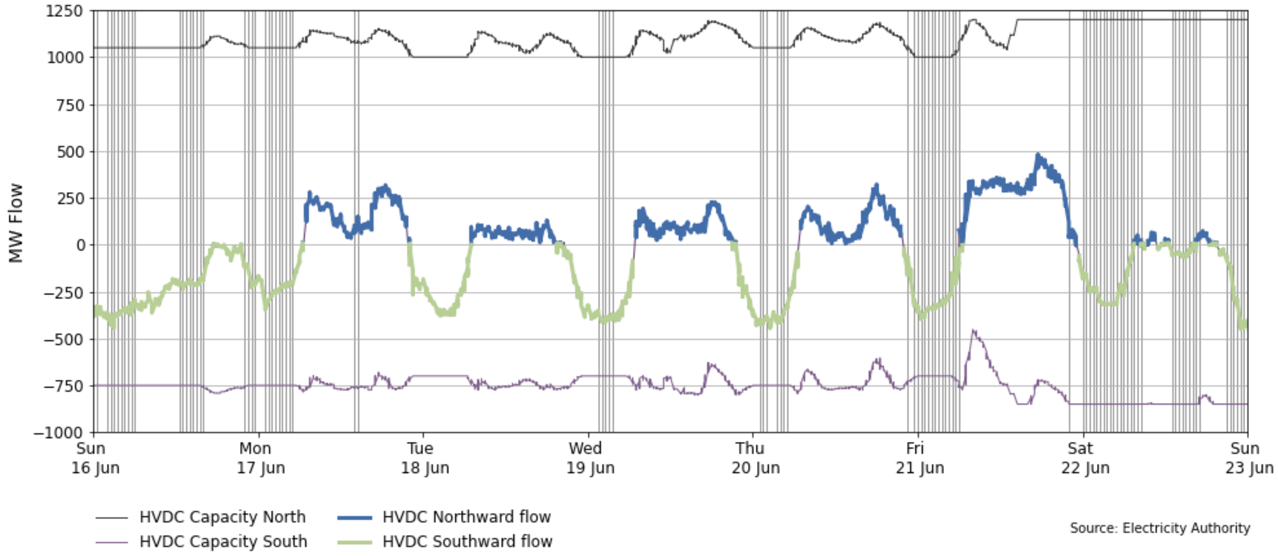
Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 16-22 June



4. HVDC

4.1. Figure 5 shows HVDC flow between 16-22 June. HVDC flow was mostly southward this week, with some northward flow occurring during the day from Monday to Saturday. This is likely a result of relatively low South Island hydro generation due to low lake storage levels. Lower northward flow during the day between Tuesday and Thursday occurred during times of high North Island wind generation.

Figure 5: HVDC flow and capacity between 16-22 June



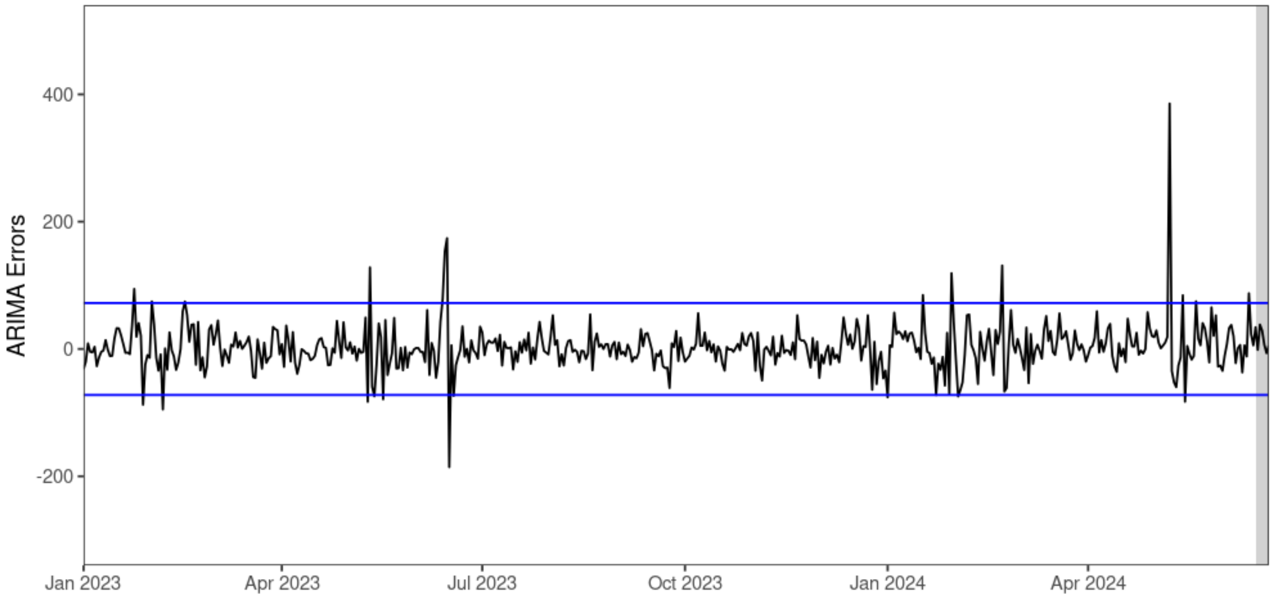
5. Regression residuals

5.1. 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.

5.2. Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than 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.

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

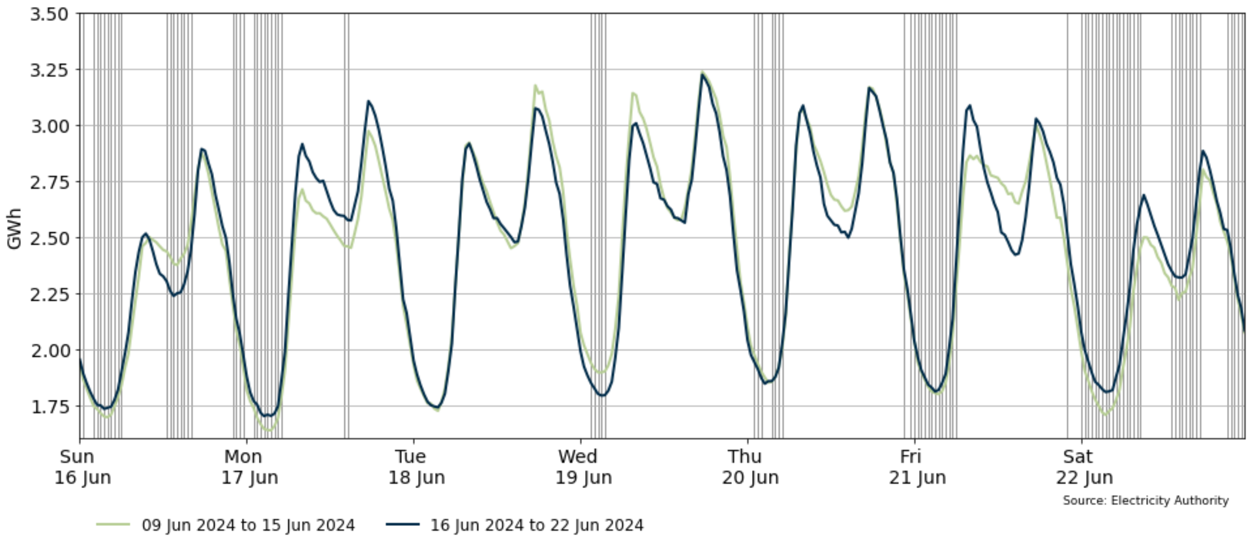
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 to 22 June 2024



6. Demand

6.1. Figure 7 shows national demand between 16-22 June, compared to the previous week. Overall, demand was lower than or similar to the previous week, though it was higher on Monday and Saturday. The maximum demand this week was 3.22GWh at 5:30pm on Wednesday.

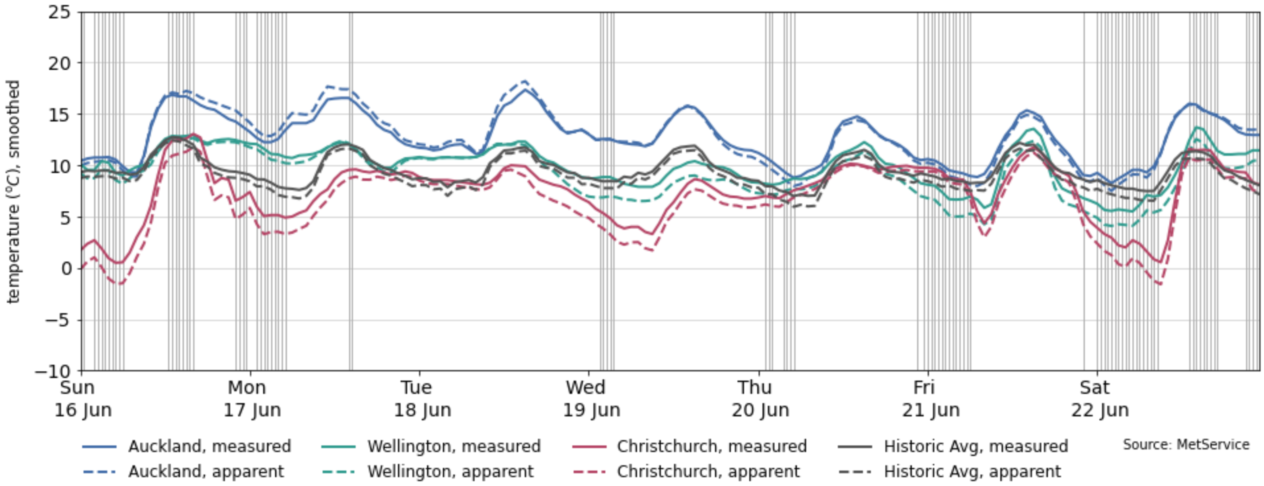
Figure 7: National demand between 16-22 June compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 16-22 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 were above average in Auckland, ranging from 7ºC to 18ºC. In Wellington, temperatures were close to average, ranging from 4ºC to 13ºC. Christchurch temperatures were generally close to or below average, ranging from -2ºC to 12ºC.

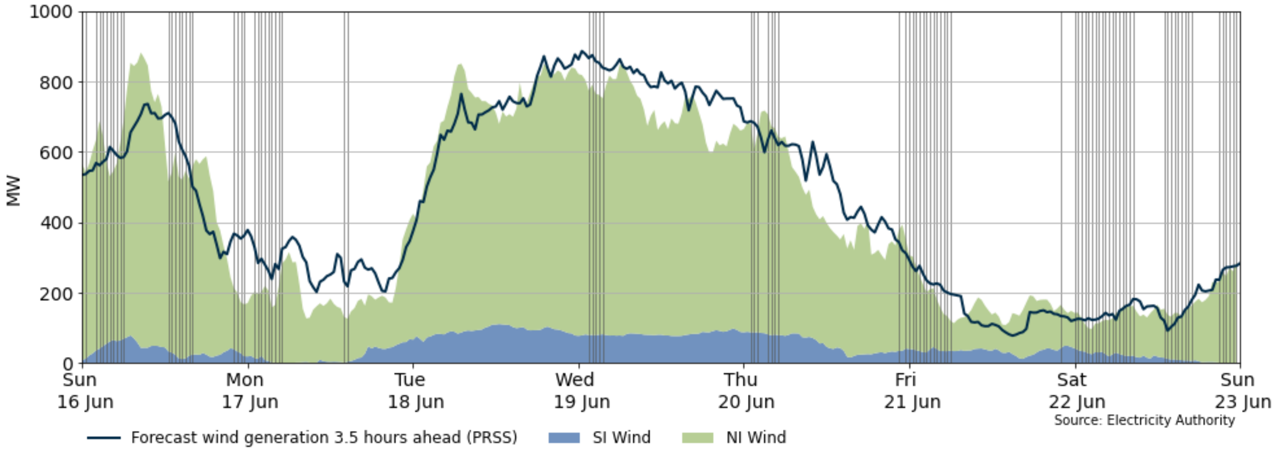
Figure 8: Temperatures across main centres between 16-22 June



7. Generation

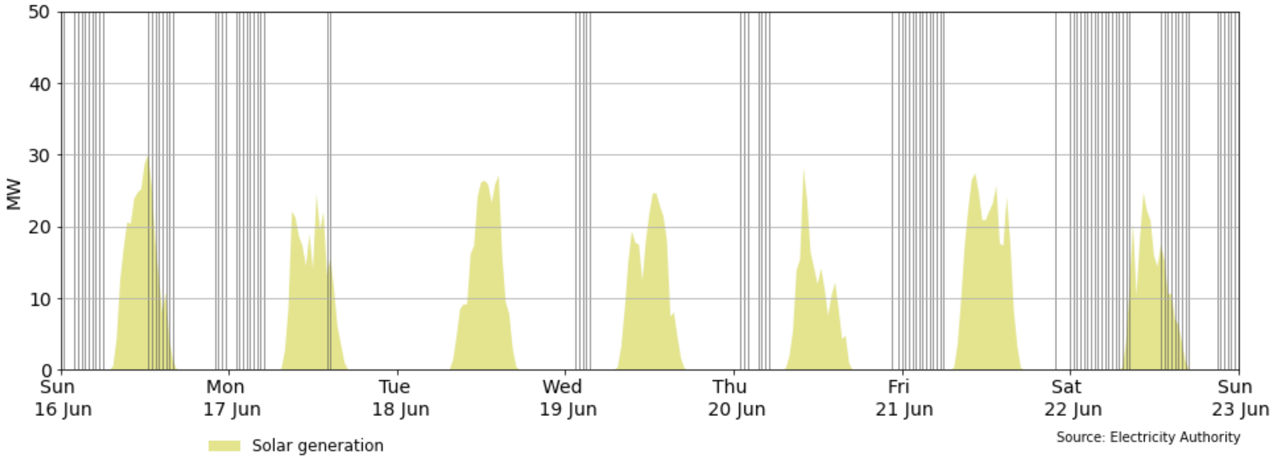
7.1. Figure 9 shows wind generation, from 16-22 June. Average wind generation was 432MW this week, ranging from 98MW-882MW. Wind generation was low and/or over-forecast during some of the times highlighted prices occurred. During the period of high prices on Sunday evening, wind generation was up to 210MW below forecast.

Figure 9: Wind generation and forecast between 16-22 June



7.2. Figure 10 shows solar generation from 16-22 June. Maximum daily solar generation was low this week due to overcast conditions, between 12MW and 30MW. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource, as we approach the winter solstice.

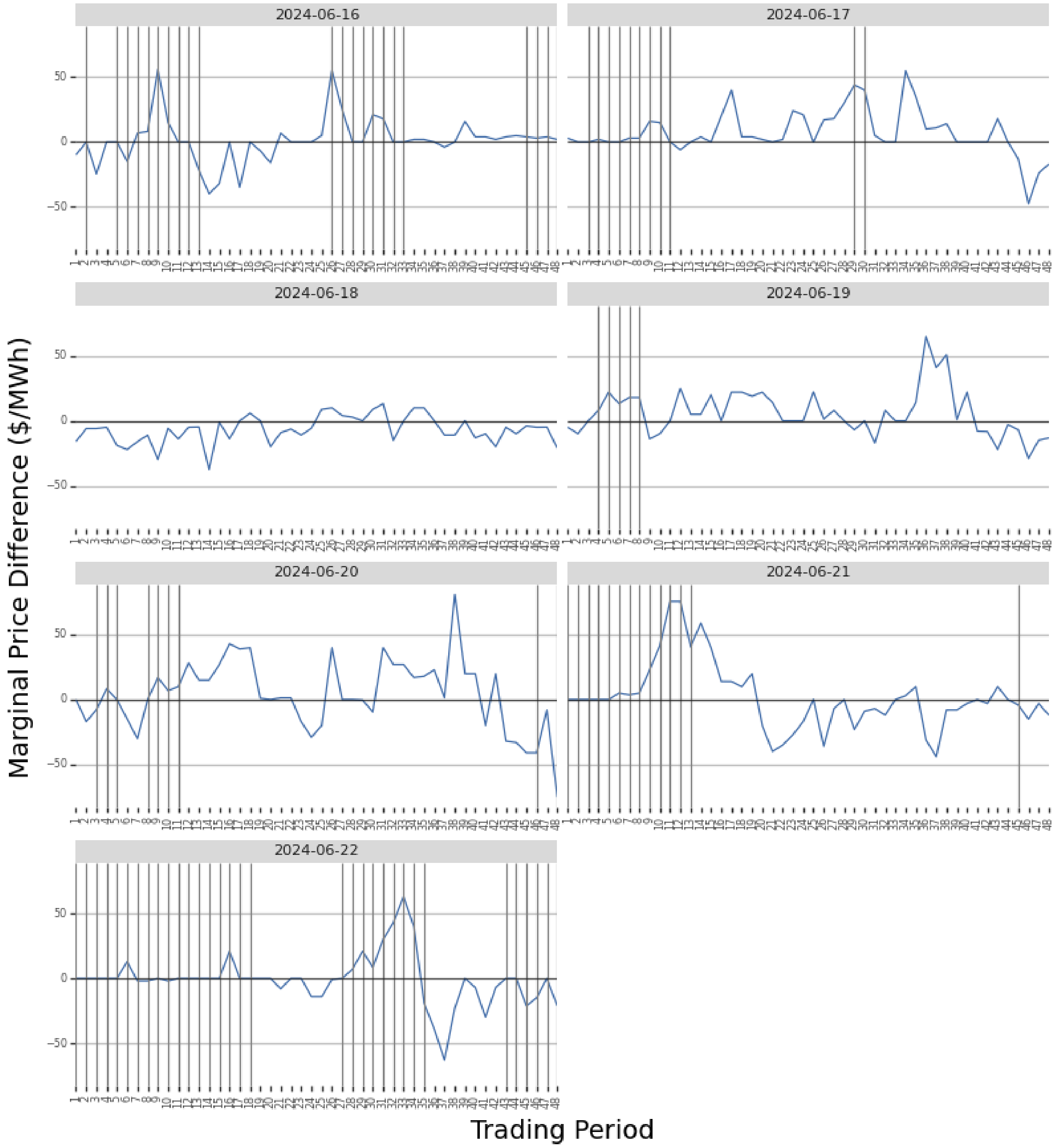
Figure 10: Solar generation between 16-22 June



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.

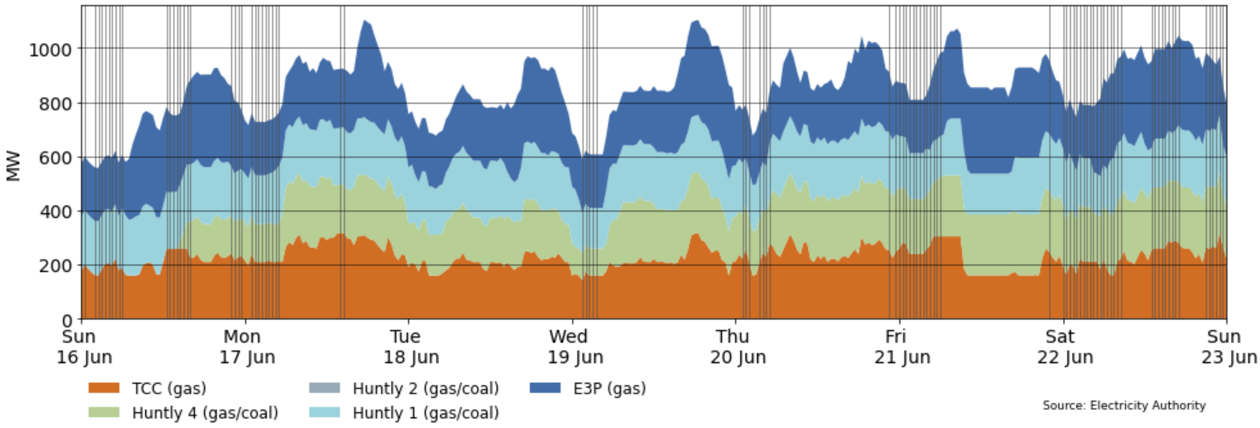
7.4. The most notable positive (marginal prices higher than simulation) difference this week was $81/MWh at 6:30pm on Saturday. Prices were also consistently higher than the simulation on Friday morning, during this time wind generation was lower than expected and demand was higher than expected. Other positive differences were generally less than $50/MWh.

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 16-22 June



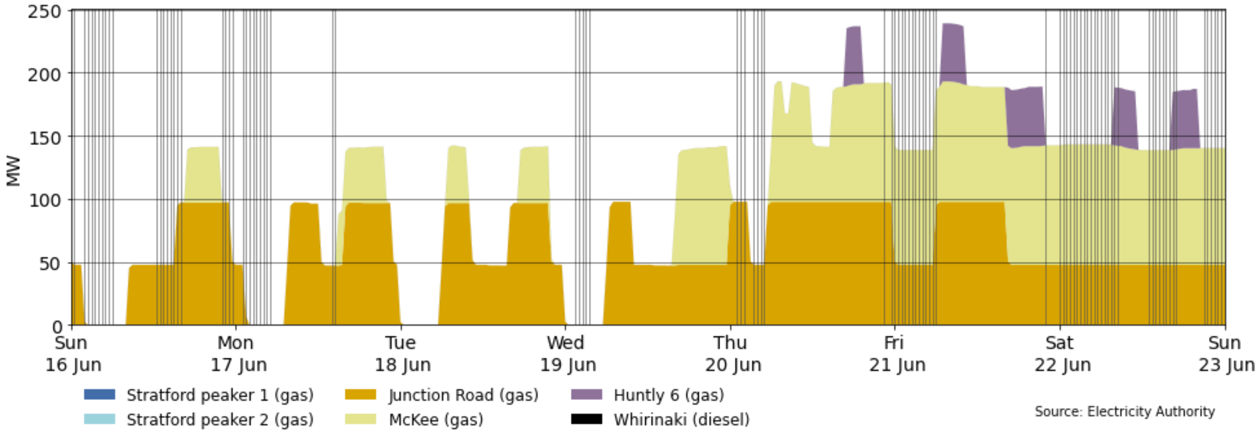
7.5. Figure 12 shows the generation of thermal baseload between 16-22 June. TCC, Huntly 5 (E3P), Huntly 4, and Huntly 1 ran continuously this week.

Figure 12: Thermal baseload generation between 16-22 June



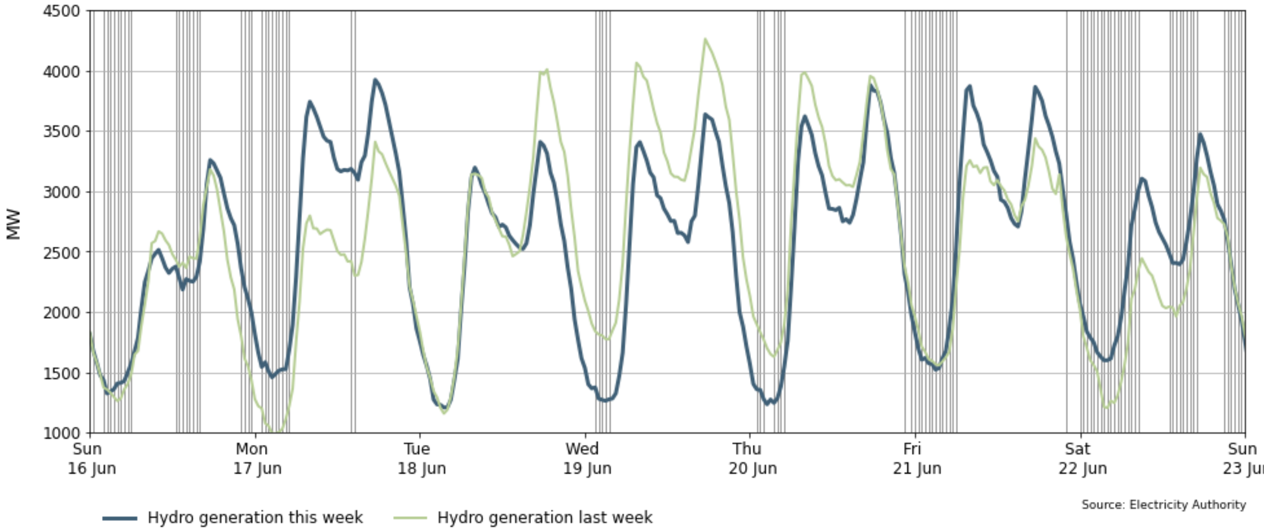
7.6. Figure 13 shows the generation of thermal peaker plants between 16-22 June. Junction Road ran during peak and shoulder periods each day, usually with McKee, with both running continuously from Wednesday onwards. Huntly 6 also ran during peak periods from Thursday.

Figure 13: Thermal peaker generation between 16-22 June



7.7. Figure 14 shows hydro generation between 16-22 June. Hydro generation was generally lower than the previous week, but was higher on Monday, Friday and Saturday due to low wind generation.

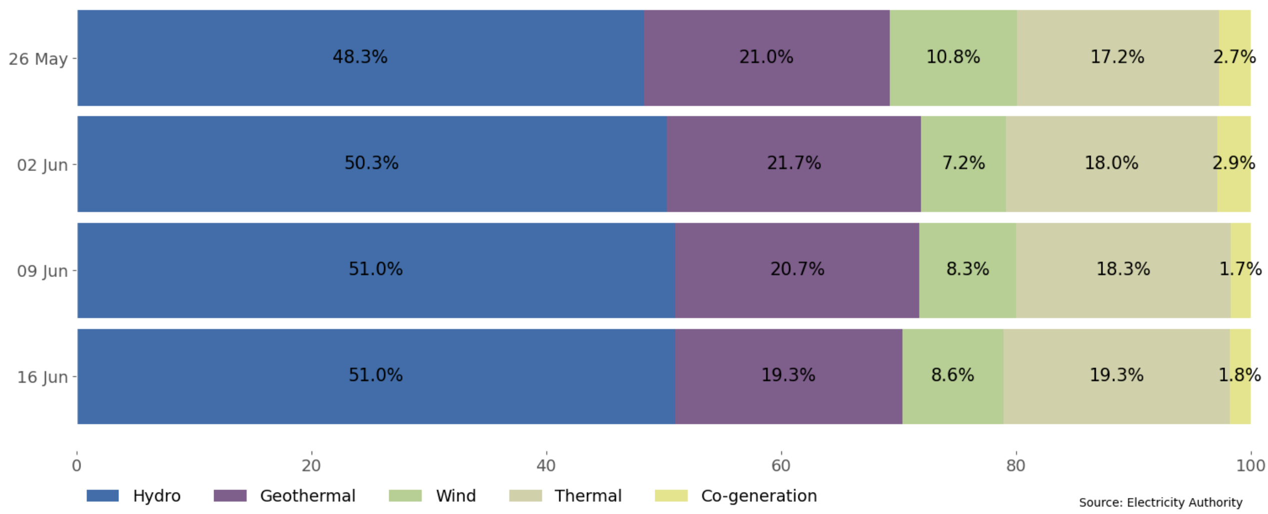
Figure 14: Hydro generation between 16-22 June



7.8. As a percentage of total generation, between 16-22 June, total weekly hydro generation was 51%, geothermal 19.3%, thermal 19.3%, wind 8.6%, and co-generation 1.8%.

7.9. The proportion of geothermal generation decreased this week due to some geothermal units being on outage, as listed below. As a result of increased generation from peakers towards the end of the week, the proportion of thermal generation increased.

Figure 15: Total generation by type as a percentage each week between 26 May-22 June



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 16-22 June ranged from ~1,000-1,500MW, generally below or close to the long-term average for June. Figure 17 shows the thermal capacity outages.

Figure 16: Total MW loss due to generation outages between 16-22 June

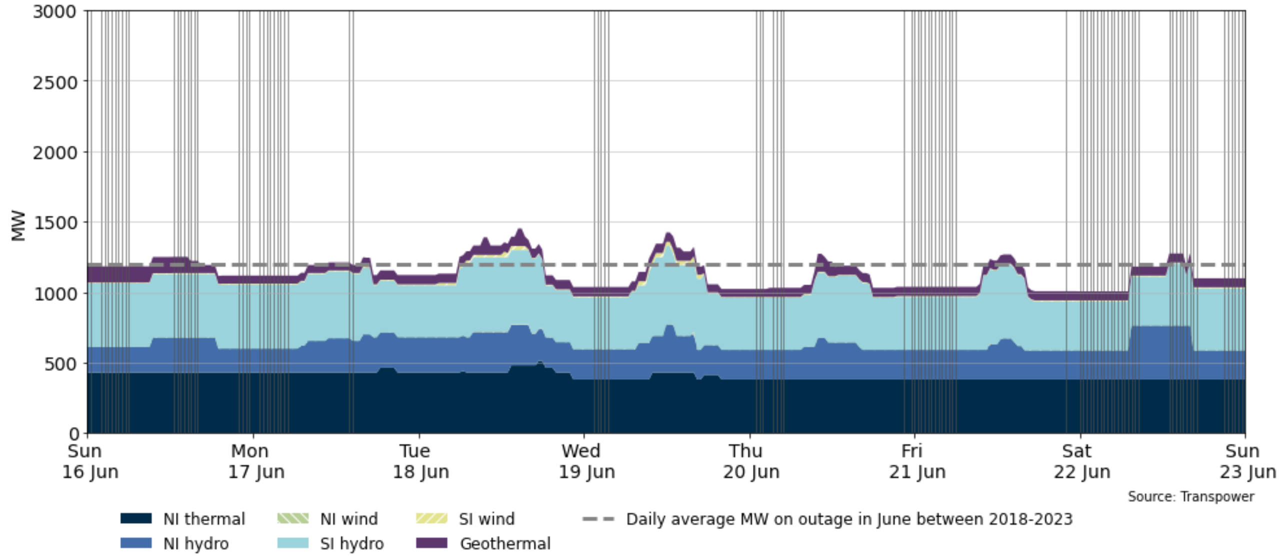
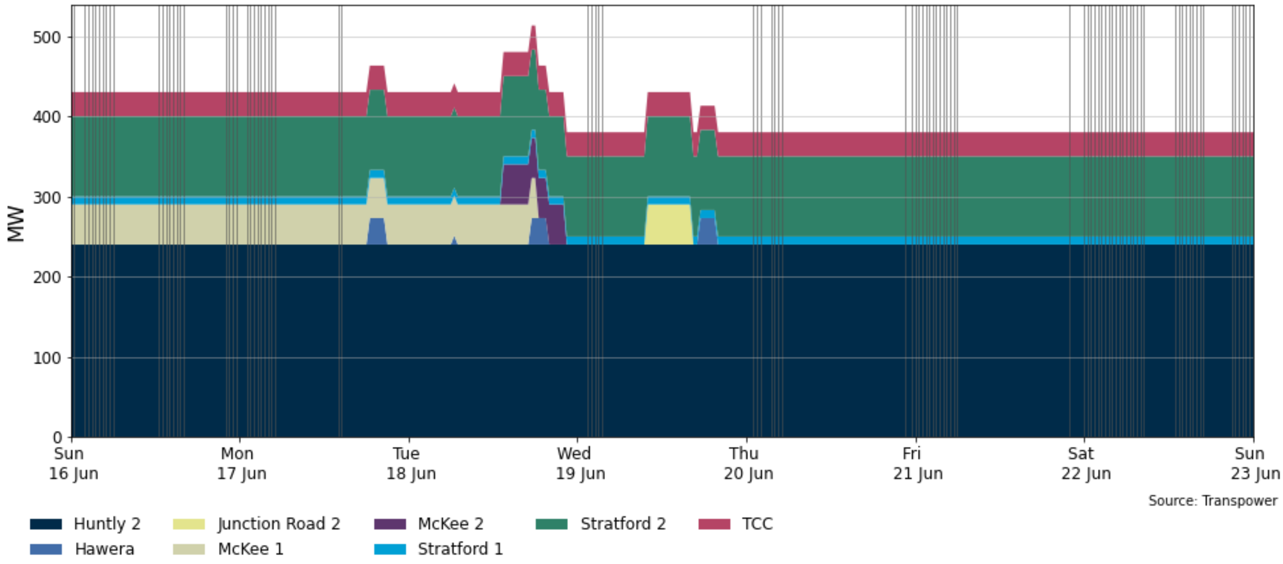


Figure 17: MW loss from thermal outages between 16-22 June



8.2. Notable outages include:

(a) Huntly 2 is on outage until 19 July 2024.

(b) Stratford 2 is on outage until 5 August.

(c) McKee was on partial outage until 18 June.

(d) Junction Road was on outage on 19 June.

(e) Mokai geothermal plant is on partial outage until 25 June.

(f) Te Mihi geothermal unit 2 was on partial outage on 18 June.

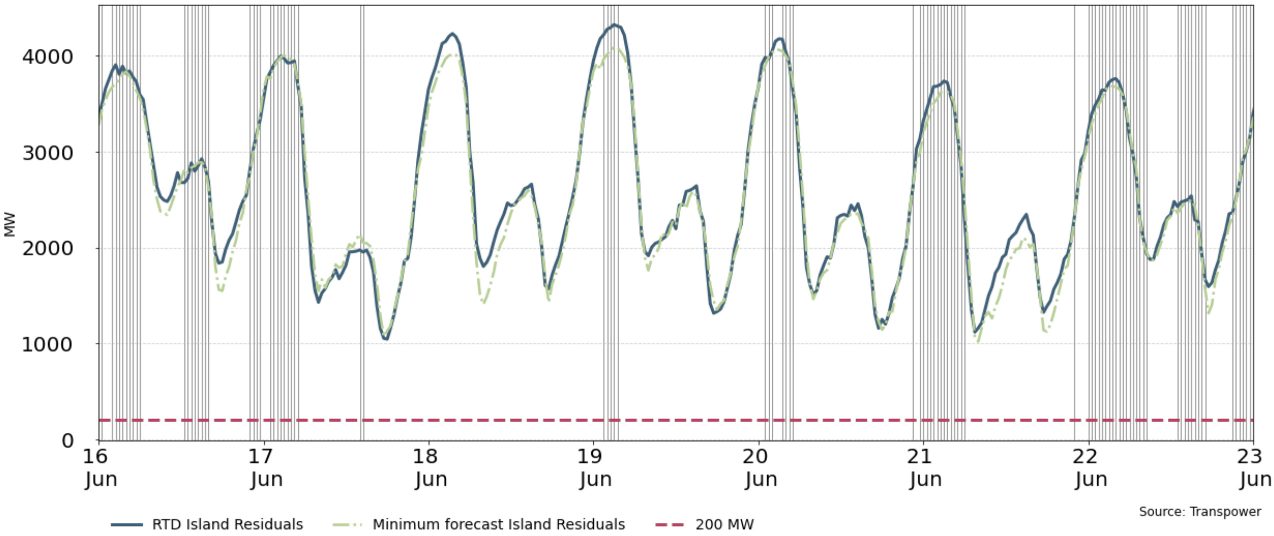
(g) Various North and South Island hydro units were on outage.

9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 16-22 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 450MW on Monday evening.

Figure 18: National generation balance residuals 16-22 June



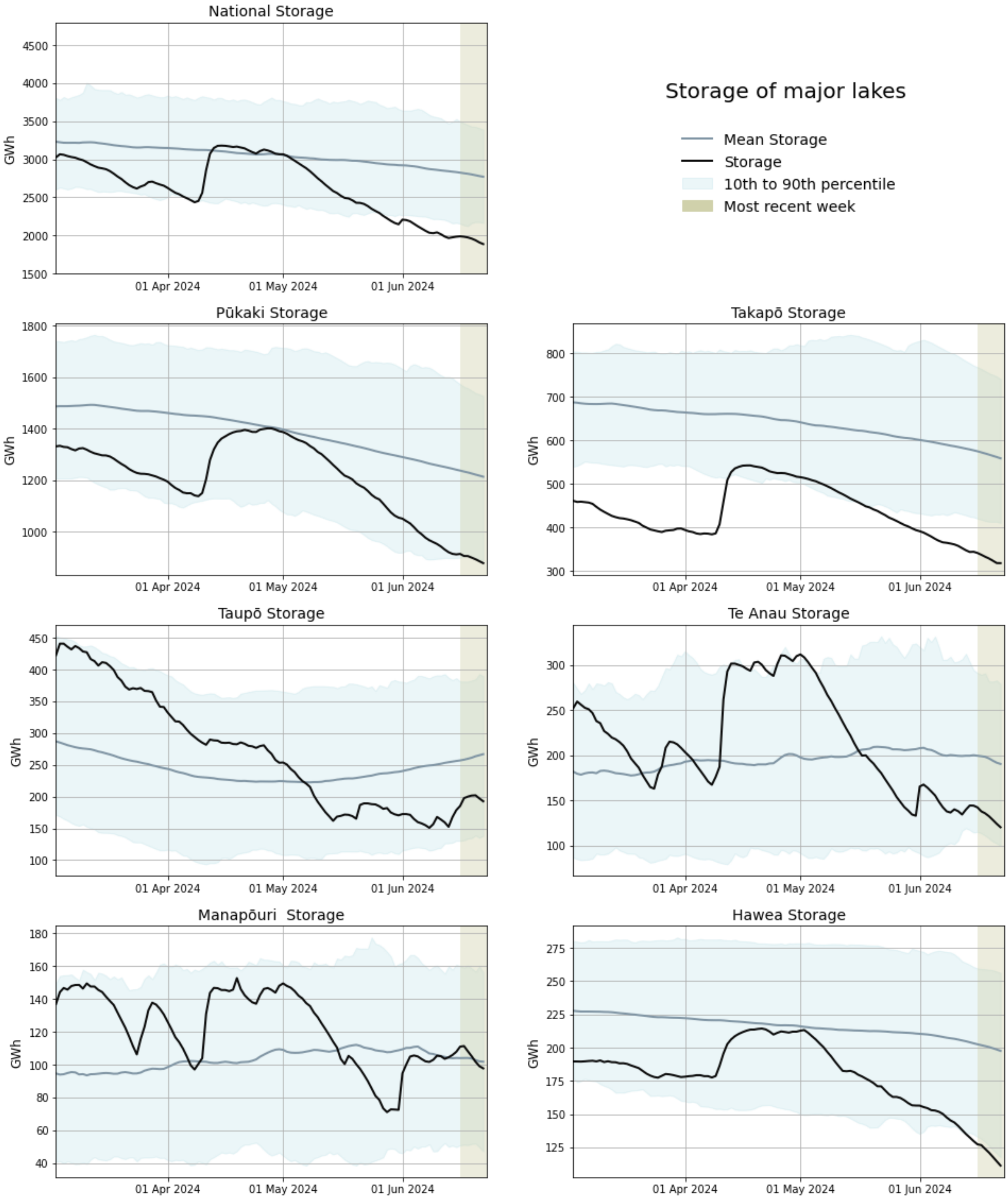
10. Storage/fuel supply

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 hydro storage levels decreased this week, to ~52% nominally full and ~74% of the historical average for this time of the year (as of 22 June).

10.3. Storage increased slightly at Taupō over the week but decreased at all other major lakes. Levels at all lakes are now below mean. Pūkaki, Takapō and Hawea are below their 10^{th} percentiles.

Figure 19: Hydro storage



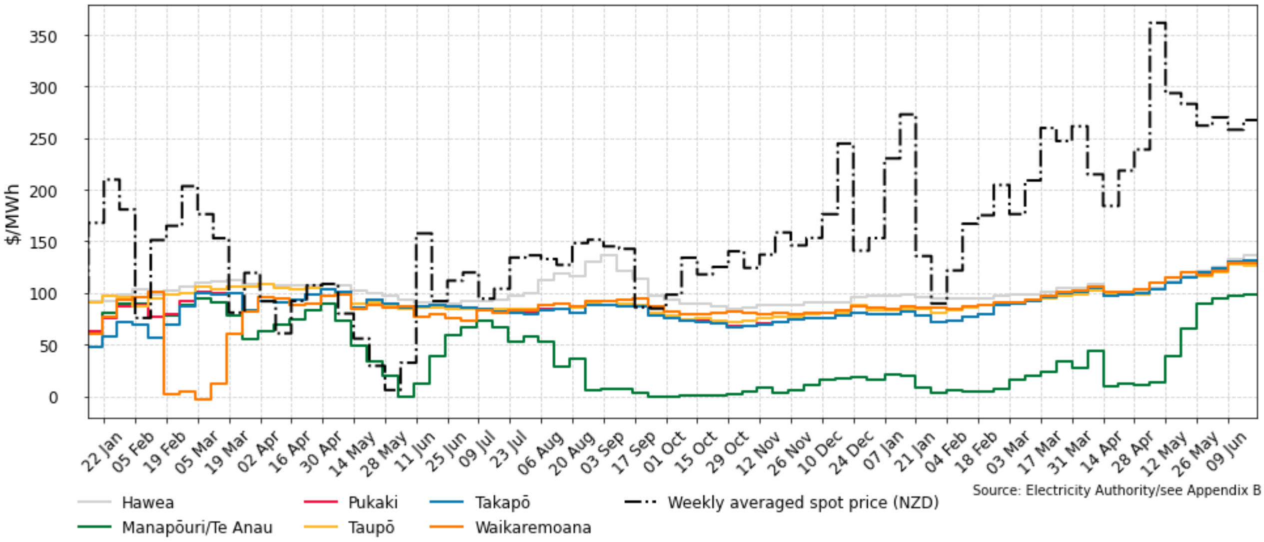
Source: Electricity Authority

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 15 June 2024 obtained from JADE calculated as 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. Water values did not change significantly compared to the previous week, with changes ranging from a decrease of ~$0.70/MWh (Waikaremoana) to an increase of ~$3.30/MWh (Hawea).

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 15 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 June 2024. The SRMCs for coal and diesel have seen small changes from the previous month, both decreasing slightly. The gas SRMCs decreased slightly this month, possibly due to a lower carbon price.

12.4. The latest SRMC of coal-fuelled Rankine generation is ~$159/MWh. The cost of running the Rankines on gas remains more expensive at ~$312/MWh.

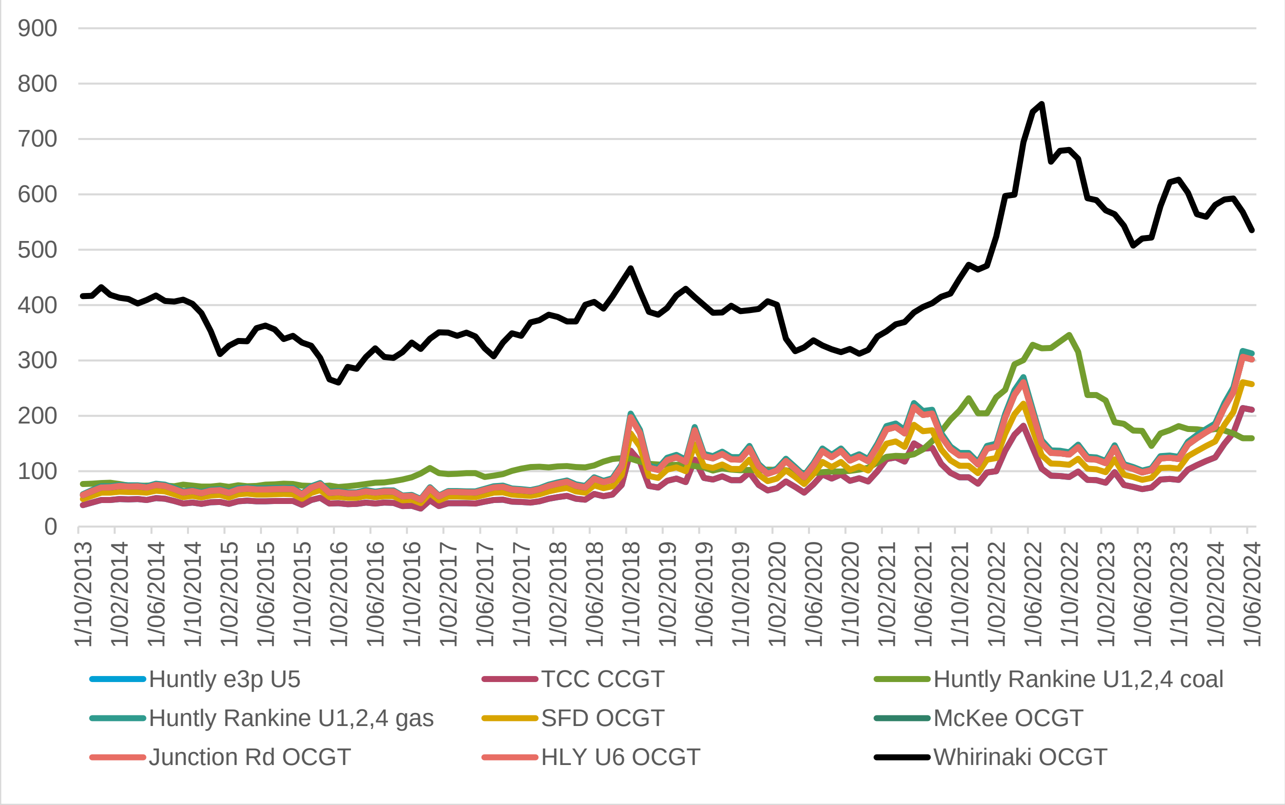
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

12.5. The SRMC of gas fuelled thermal plants is currently between ~$210/MWh and ~$312/MWh.

12.6. The SRMC of Whirinaki is ~$535/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

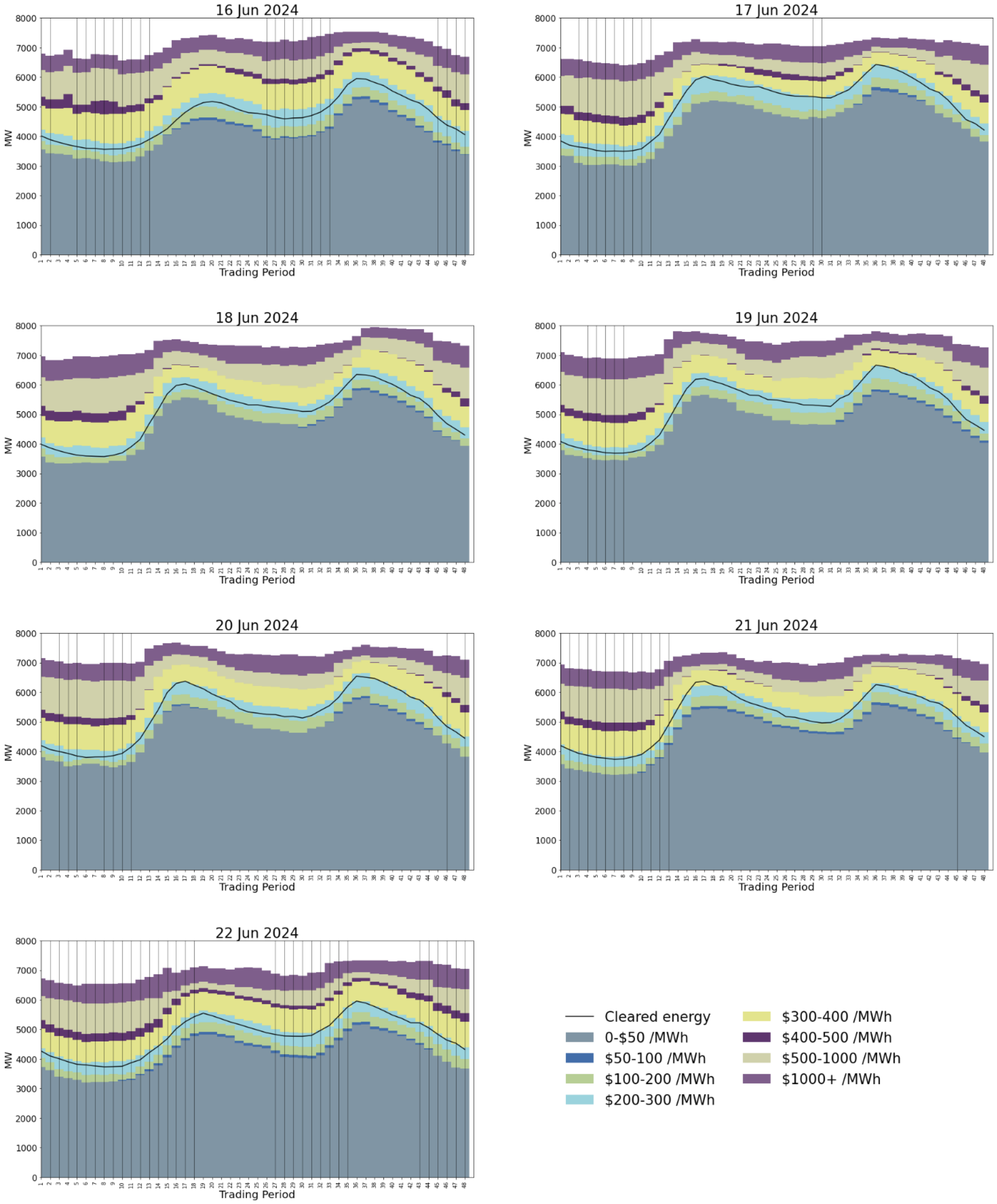


13. Offer behaviour

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. Hydro generation pricing has increased as lake levels have declined, and there were an increased number of offers in the $300-$400/MWh band this week, especially on Sunday.

13.2. Most offers cleared in the $200-$300/MWh region, which includes overnight prices, with some daytime prices clearing in the $300-$400/MWh.

Figure 22: Daily offer stacks



Source: Electricity Authority

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	Trading period	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	Passed to Compliance	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