27 May 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 19-25 May

1.1. Prices were mainly above the historical median this week and mostly between $200-$300/MWh. On Monday, prices spiked over $490/MWh, and went as high as $740/MWh, during a number of trading periods. Friday also saw a few instances of prices above $400/MWh. The spikes were related to high demand, low wind generation and under-forecast demand on both days. High demand and periods of low wind generation this week required more expensive thermal and hydro generation to meet increased demand. This week, TCC, Huntly 5, Huntly 2, and Huntly 1 provided baseload generation, with their combined output often around 1,000MW. Hydro storage decreased to 84% 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 19-25 May:

(a) the average wholesale spot price across all nodes was $286/MWh.

(b) 95% of prices fell between $104/MWh and $556/MWh.

2.3. Overall, the majority of spot prices were above the historical median this week, with a few spikes occurring mainly on Monday and Friday. The average spot prices decreased $7/MWh compared to the previous week.

2.4. On Monday, price spikes reached as high as $740/MWh, and were at or above $490/MWh for 18 trading periods at Ōtāhuhu. Monday’s price spikes are related to high demand and low wind generation. Large demand forecast inaccuracies also contributed to the high prices. Between 09:30am and 5:00pm, demand was under-forecast by more than 100MW, often close to or above 200MW, and spot prices were at times over $200/MWh higher than forecast. The monitoring team will be further analysing these prices.

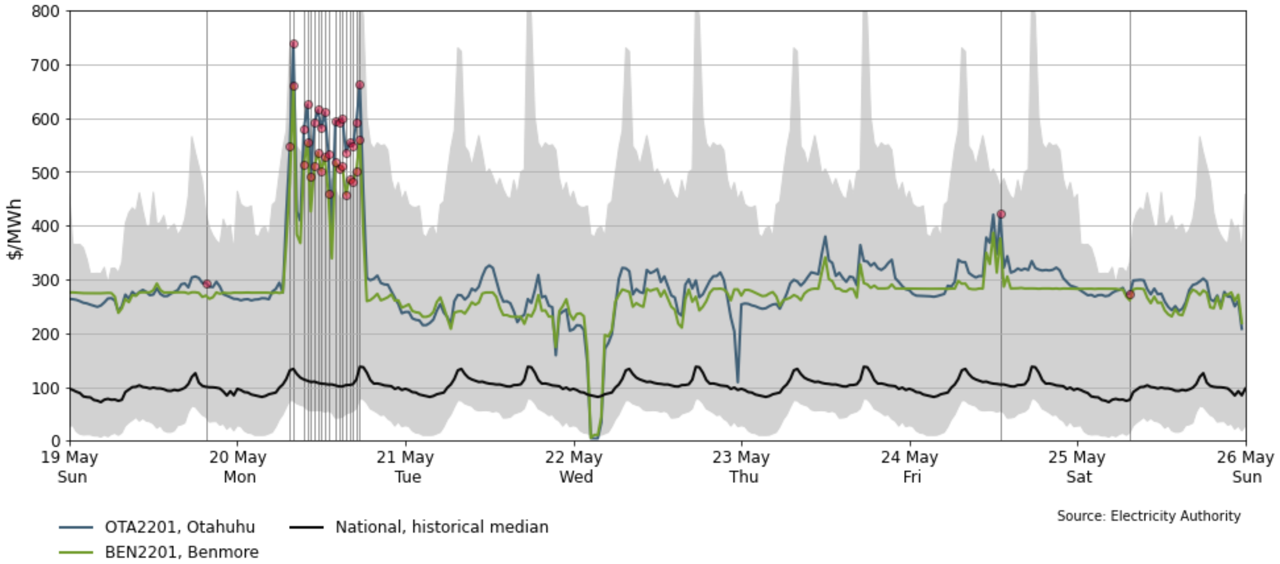
2.5. On Friday, Ōtāhuhu prices spiked as high as $423/MWh at around noon due to a combination of high demand, low wind generation and more than 100MW of demand forecast inaccuracies.

2.6. 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×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.

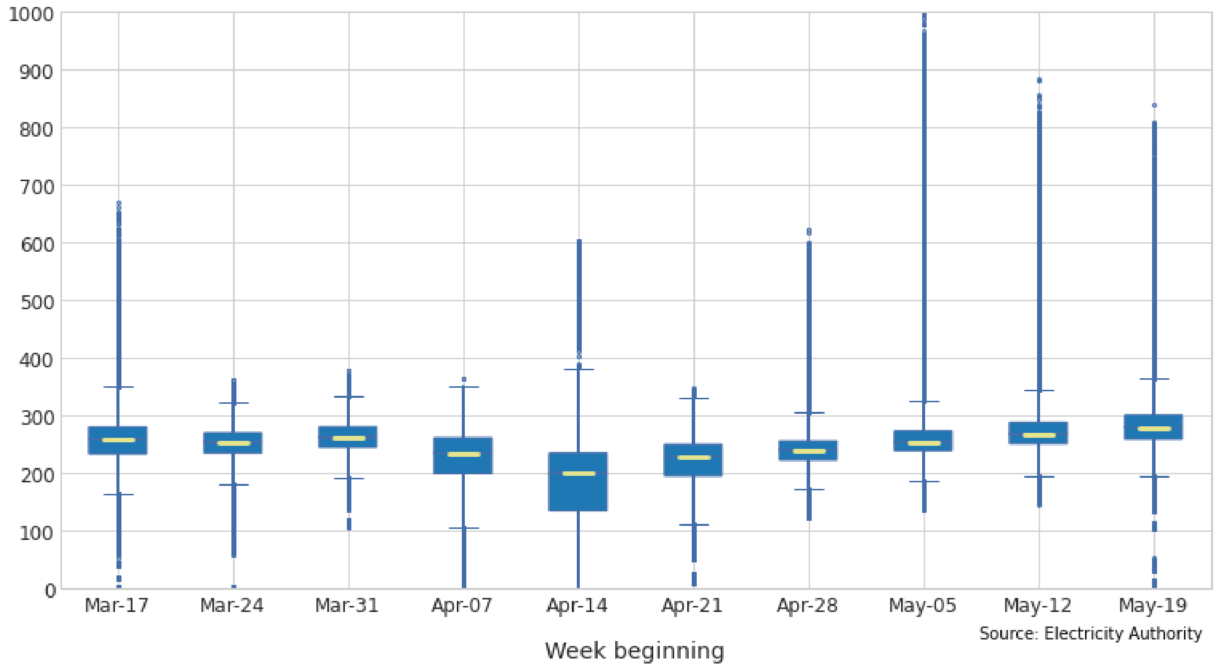
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 19-25 May



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 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.

2.8. The spot price distribution this week was similar to the previous week, however, a period of low overnight prices means there are more outlier prices at the lower end of the distribution. The lower overnight prices decreased the average price this week by $7/MWh while the median price increased from $265/MWh in the previous week to $279/MWh this week, a $14/MWh increase. The middle 50% of the prices were between $259-$301/MWh.

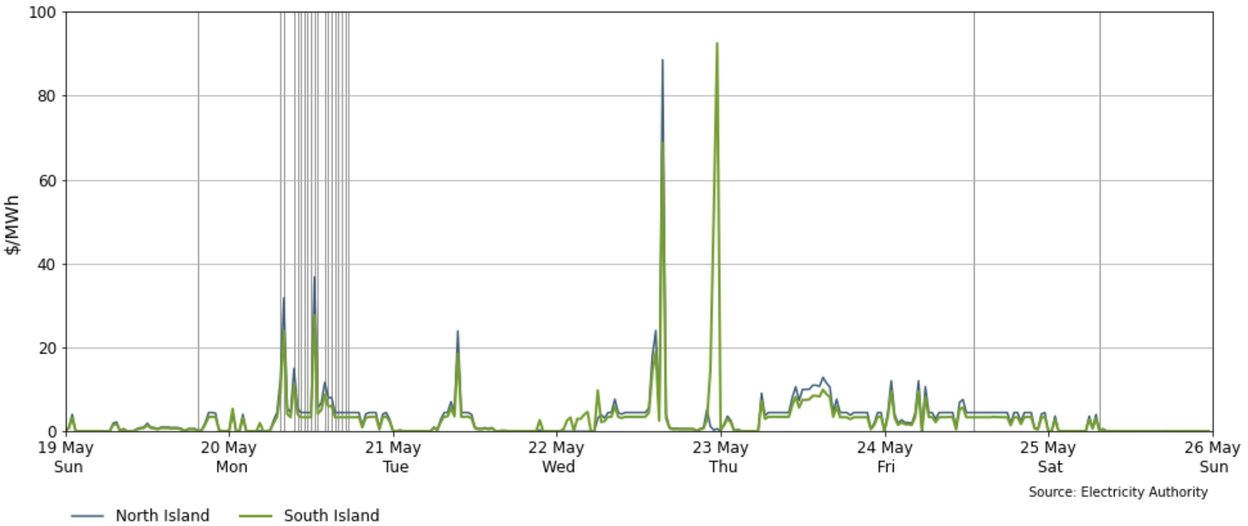
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

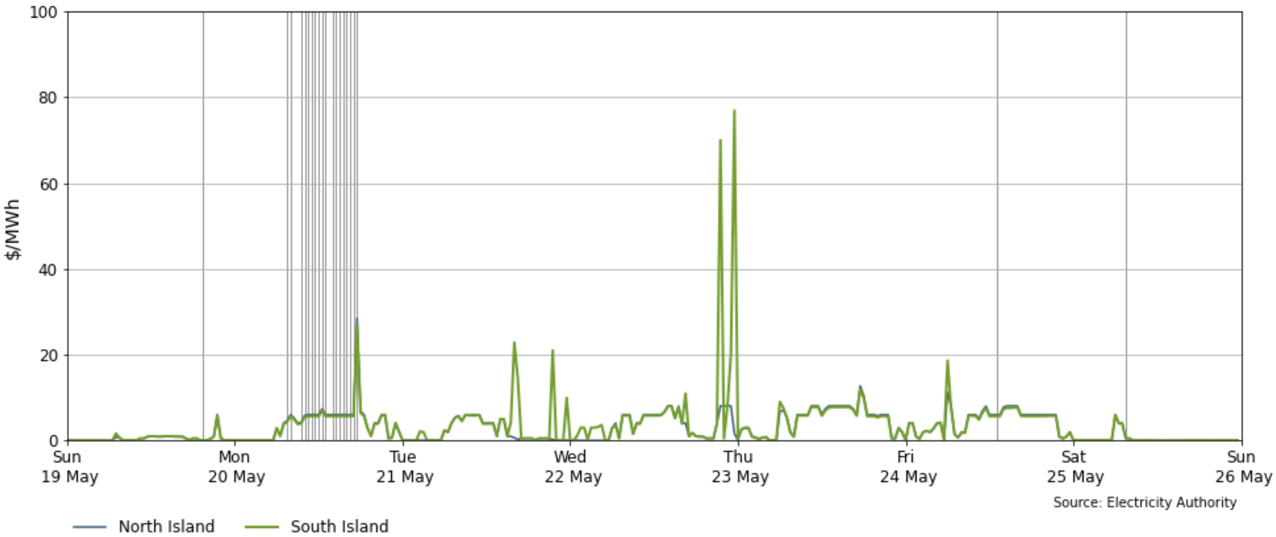
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh this week with a few price spikes occurring on Monday, Tuesday, and Wednesday. The spike on Wednesday afternoon at 3:30pm is related to an increase in the amount of reserve needed to cover the FIR risk in both islands. The second spike, which was only for South Island FIR, was related to the HVDC outage.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 19-25 May



3.2. 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. The most pronounced SIR spikes occurred on Wednesday in the South Island. The first spike was at 9:30pm, related to an increase in SIR needed to cover South Island risk. The second spike was related to the planned HVDC outage.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 19-25 May



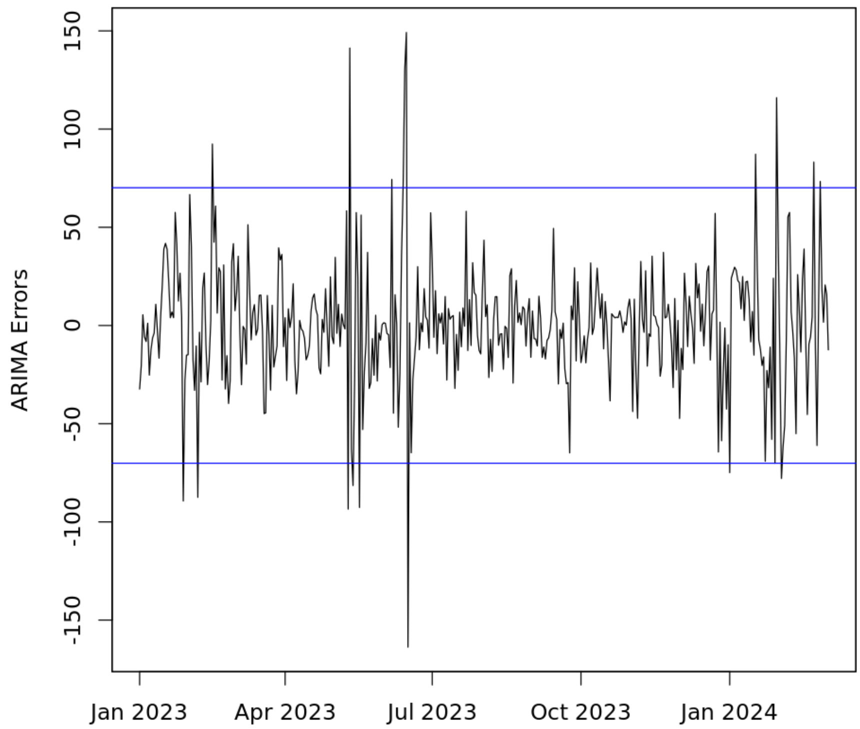
4. Regression residuals

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 Monday was above two standard deviations of the data indicating that prices were higher than the model expected. The monitoring team will be further analysing these prices.

Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 to 25 May 2024

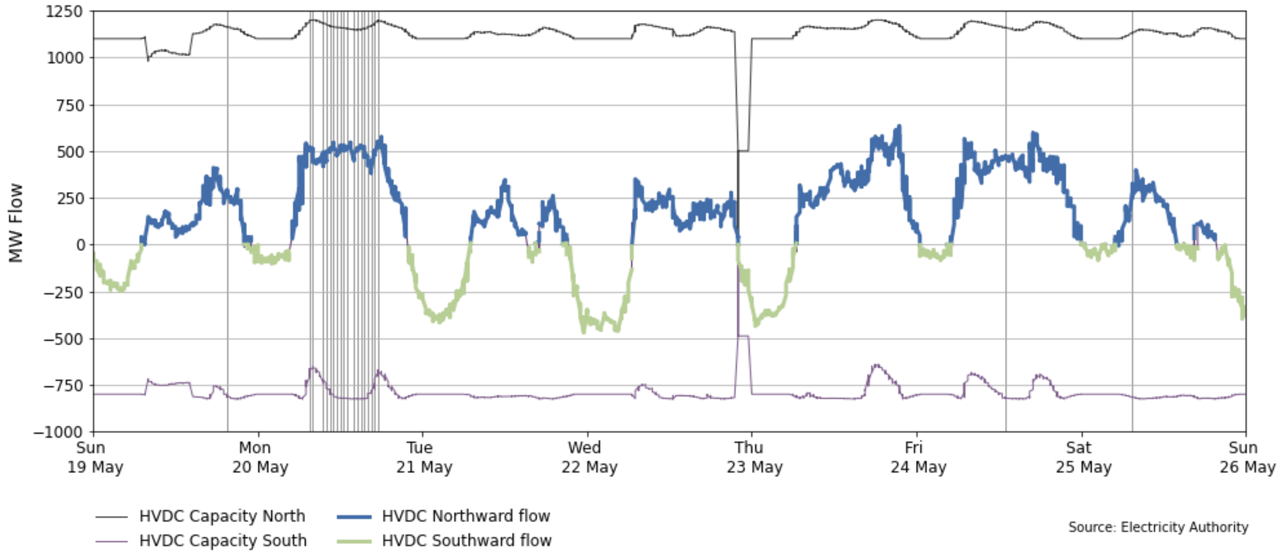


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 19-25 May. This week, HVDC was flowing northward during the day and southward overnight, aligned with the decreasing hydro storage levels in the South Island and high overnight wind generation between Monday and Thursday. The HVDC was sending around 500MW to the North Island during the high prices on Monday. Also this week, a planned HVDC Pole 3 outage limited its flow between 22 May at 10:00pm and 23 May at midnight.[2]

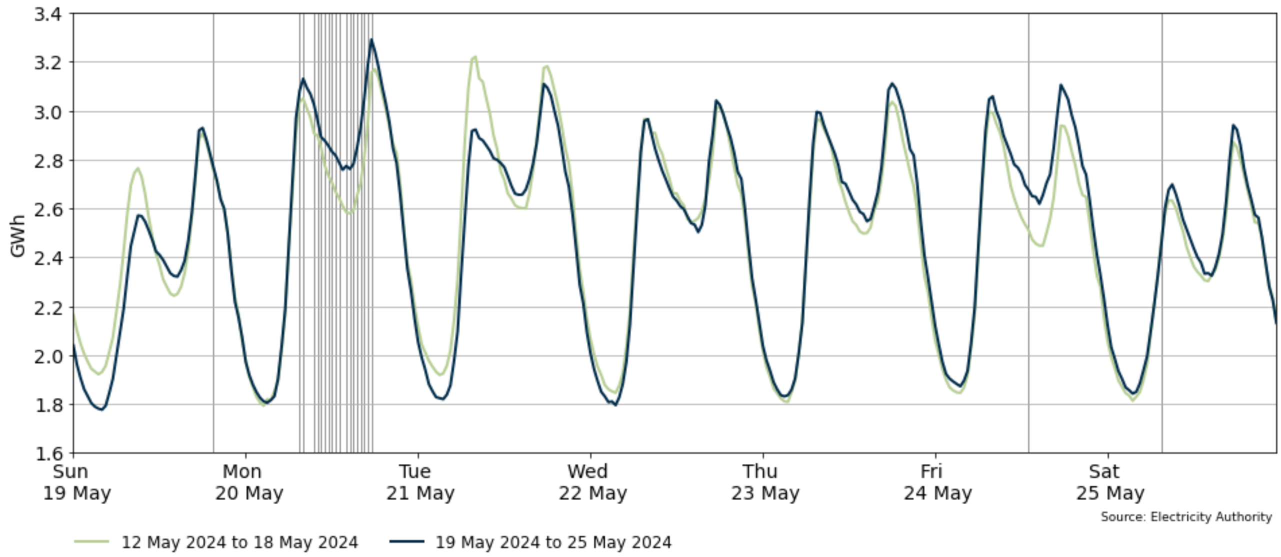
Figure 6: HVDC flow and capacity between 19-25 May



6. Demand

6.1. Figure 7 shows national demand between 19-25 May. This week except for Sunday morning and Tuesday, all other days saw demand being higher than the previous week. The highest demand, ~3.3GWh, occurred on Monday at 5:30pm, marking the highest demand on record this year. Large demand forecast inaccuracies on Monday contributed to the high prices on that day. Between 09:30am and 5:00pm, demand was under-forecast between roughly 136MW and 250MW. On Friday, demand was under-forecast by more than 100MW during the price spike.

Figure 7: National demand between 19-25 May compared to the previous week

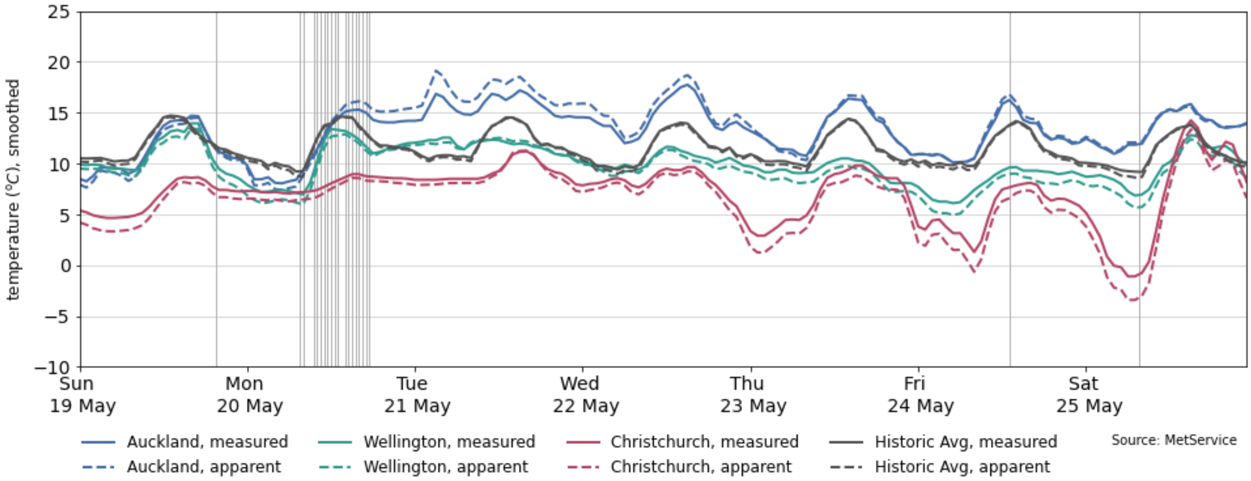


[2] See: https://static.transpower.co.nz/public/interfaces/can/CAN%20Planned%20Outage%20HVDC%20Pole%203%205400364723.pdf?VersionId=8mgIBN_Oownk71woX8C2NzrBkR5oUA7.

6.2. Figure 8 shows the hourly temperature at main population centres from 19-25 May. 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. The week began with low temperatures across the country which persisted until Monday afternoon. Auckland saw temperatures below historical levels on Sunday and Monday, increasing to above that mark from Monday afternoon onwards. Apparent temperatures in Auckland fluctuated between 7ºC and 19ºC. Temperatures in Wellington were mostly below the historical average mark this week, with apparent temperatures ranging from 5ºC to 13ºC. In Christchurch, apparent temperatures were between -1ºC and 13ºC, mostly below the historical average.

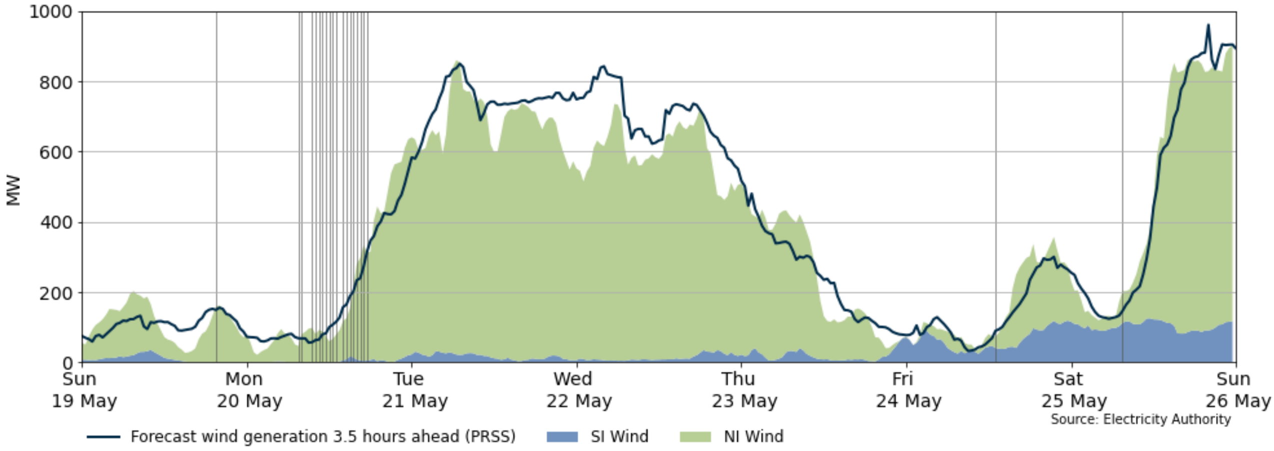
Figure 8: Temperatures across main centres between 19-25 May



7. Generation

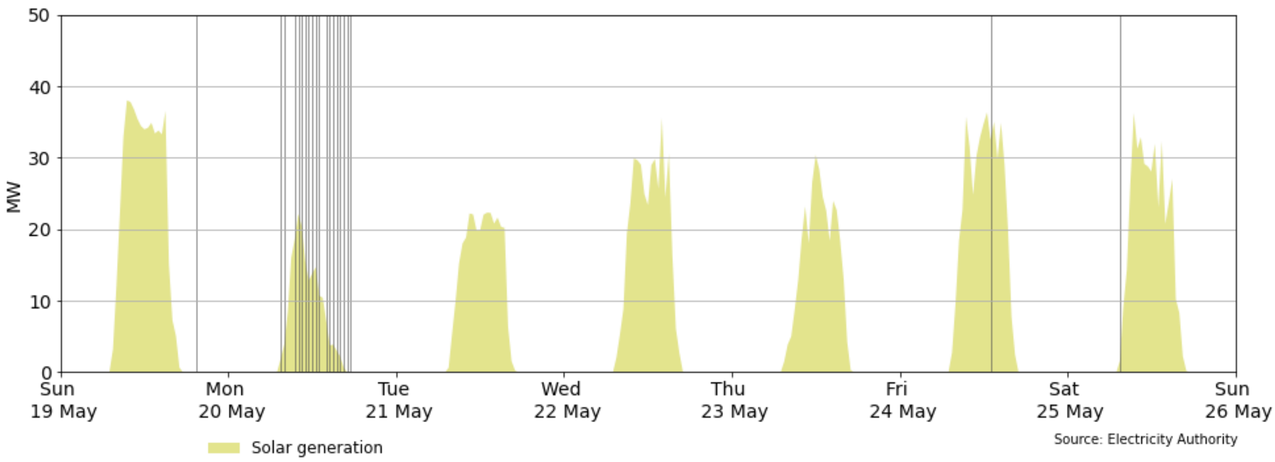
7.1. Figure 9 shows wind generation and forecast from 19-25 May. This week, wind generation varied between 22MW and 900MW with an average of 358MW. Wind generation was low at the start of the week, remaining below 200MW until Monday afternoon. Between Monday afternoon and Thursday morning, wind generation was above 400MW. Wind generation decreased again between Thursday afternoon and Saturday morning, when it increased, reaching its maximum for the week.

Figure 9: Wind generation and forecast between 19-25 May



7.2. Figure 10 shows solar generation from 19-25 May. Solar generation was between 22MW and 38MW this week. On Monday and Tuesday solar generation was lower compared to the rest of the week due to overcast situations.

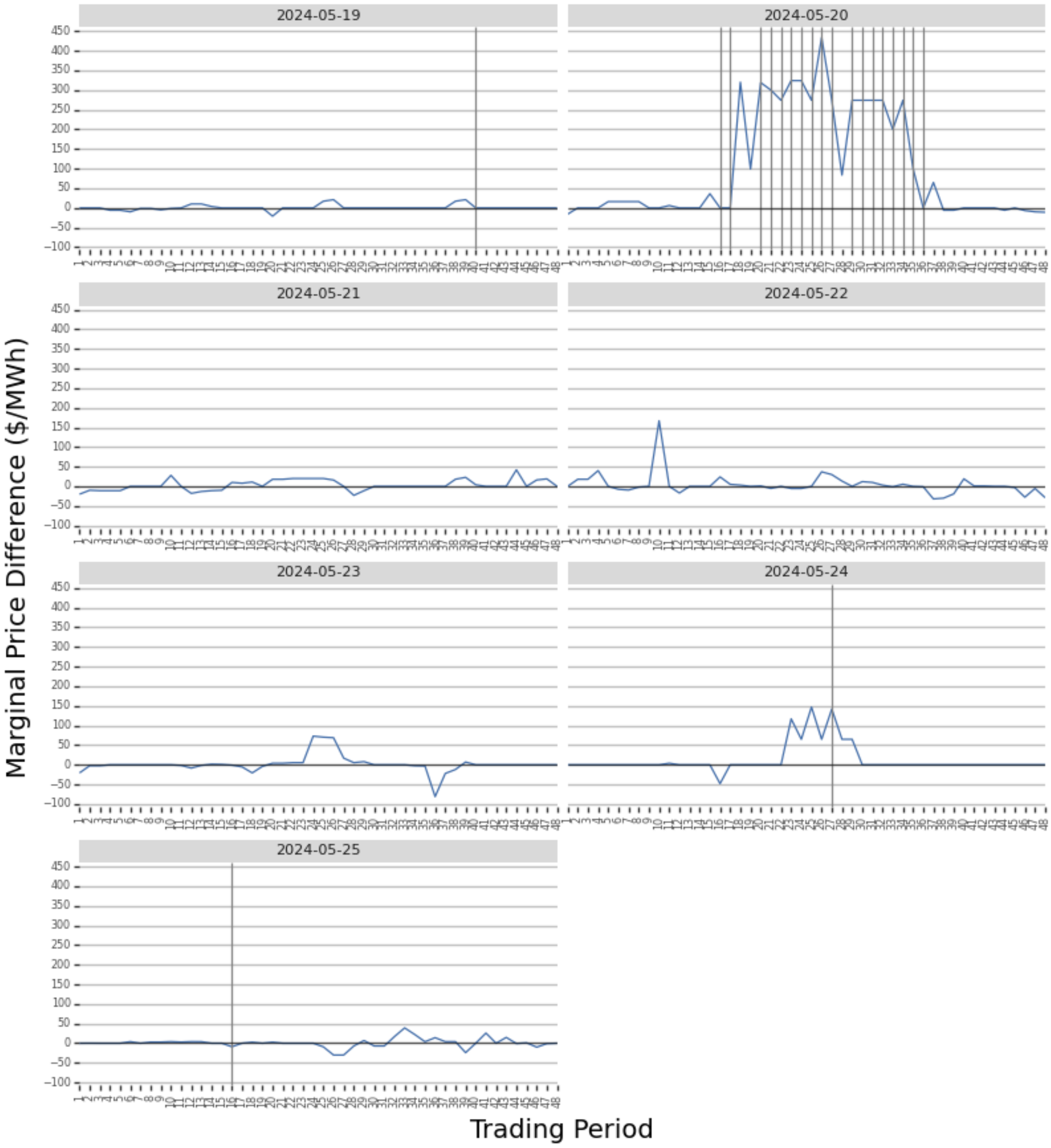
Figure 10: Solar generation between 19-25 May



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.

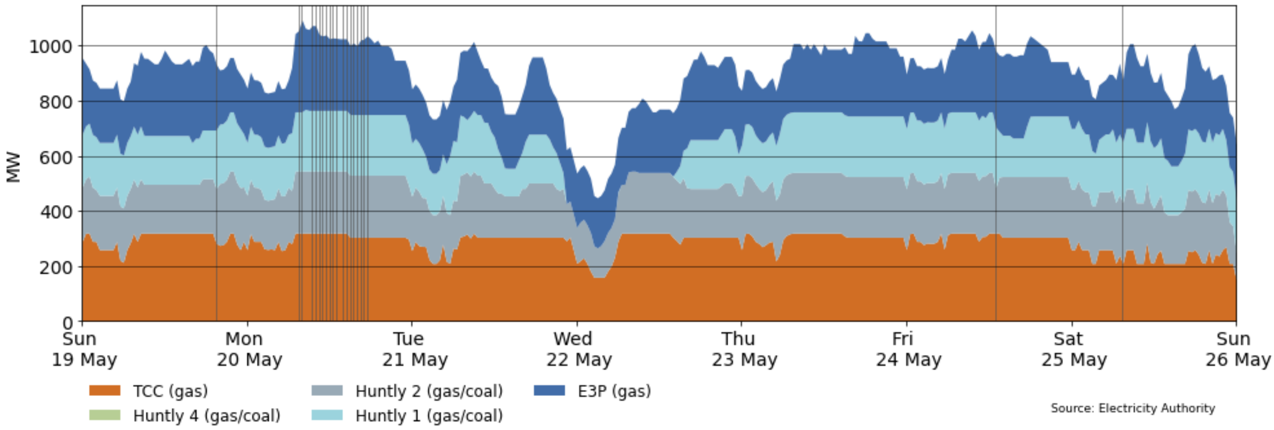
7.4. This week the most notable positive differences (marginal prices higher than simulation) occurred on Monday and Friday. On Monday the high price differences occurred on several trading periods in the morning between 07:30am and 11:30am (trading periods 16-24) and in the afternoon, between 12:00pm and 5:30pm (trading periods 25-36). The high differences on Friday occurred during trading periods 22-30 (10:30am-2:30pm). These differences in marginal prices, which were over $100/MWh, and sometimes above $400/MWh were mostly related to demand being under-forecast.

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 19-25 May



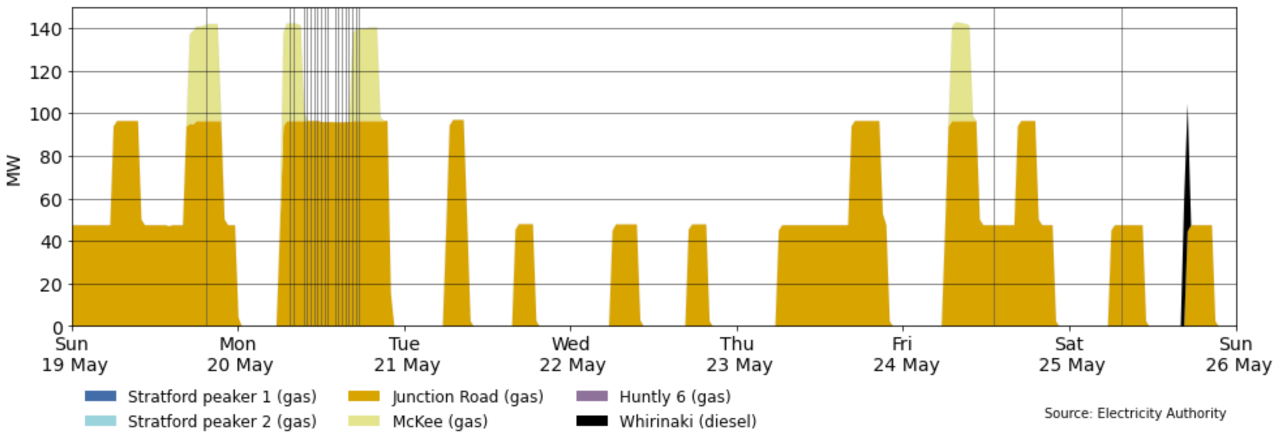
7.5. Figure 12 shows the generation of thermal baseload between 19-25 May. This week TCC, Huntly 2, and Huntly 5 (E3P) ran continuously providing baseload generation. Huntly 1 also ran for most of the week except for some hours between Tuesday and Wednesday.

Figure 12: Thermal baseload generation between 19-25 May



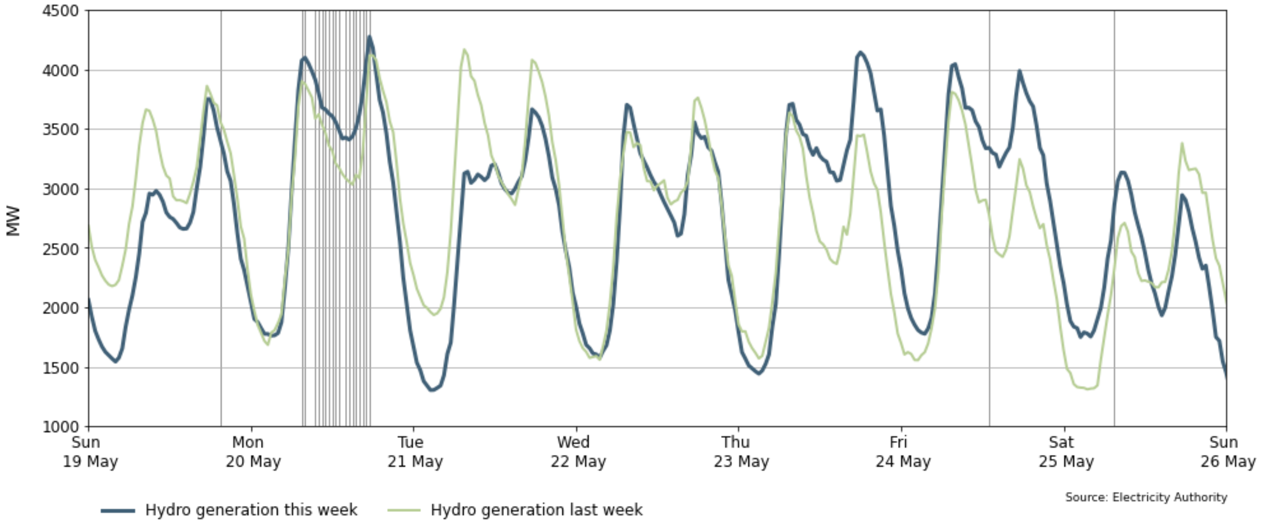
7.6. Figure 13 shows the generation of thermal peaker plants between 19-25 May. Peaker generation this week occurred during times of high demand. This week Junction Road ran every day during shoulder periods and when demand was high and wind generation was low. McKee ran on Sunday afternoon, Monday during the shoulder period, and Friday morning. Whirinaki ran for one hour on Saturday between 4:30pm and 5:30pm.

Figure 13: Thermal peaker generation between 19-25 May



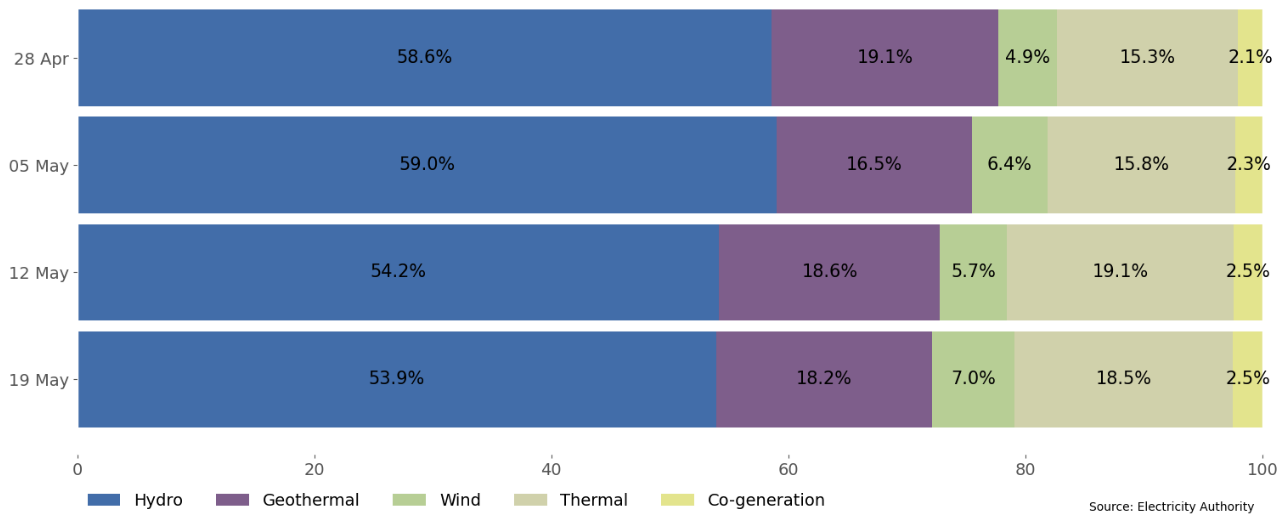
7.7. Figure 14 shows hydro generation between 19-25 May. Hydro generation followed demand and wind generation this week. On Monday when wind generation was low and demand was high, hydro generation was high, decreasing between Tuesday and Thursday when wind generation increased. Hydro generation then increased again between Thursday afternoon and Saturday morning when wind generation was low, ramping back down on Saturday afternoon due to an increase in wind.

Figure 14: Hydro generation between 19-25 May



7.8. As a percentage of total generation, between 19-25 May, total weekly hydro generation was 53.9%, geothermal 18.2%, wind 7.0%, thermal 18.5%, and co-generation 2.5%, as shown in Figure 15. An increase in wind generation and the relatively high thermal participation in the energy mix contributed to the slight decrease in hydro generation this week.

Figure 15: Total generation by type as a percentage each week between 28 April and 25 May



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 19-25 May ranged between ~1,130MW and ~1,760MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford 1 was on outage until 27 May 2024

(b) Stratford 2 is on outage until 30 June 2024

(c) Huntly 4 was on outage until 27 May 2024

(d) McKee is on partial outage until 22 June 2024

(e) Waipipi wind farm was on outage on 19 May for several hours

(f) West Wind wind farm was on outage on 20 May for several hours

(g) Several North and South Island hydro units were on outage this week.

Figure 16: Total MW loss due to generation outages between 19-25 May

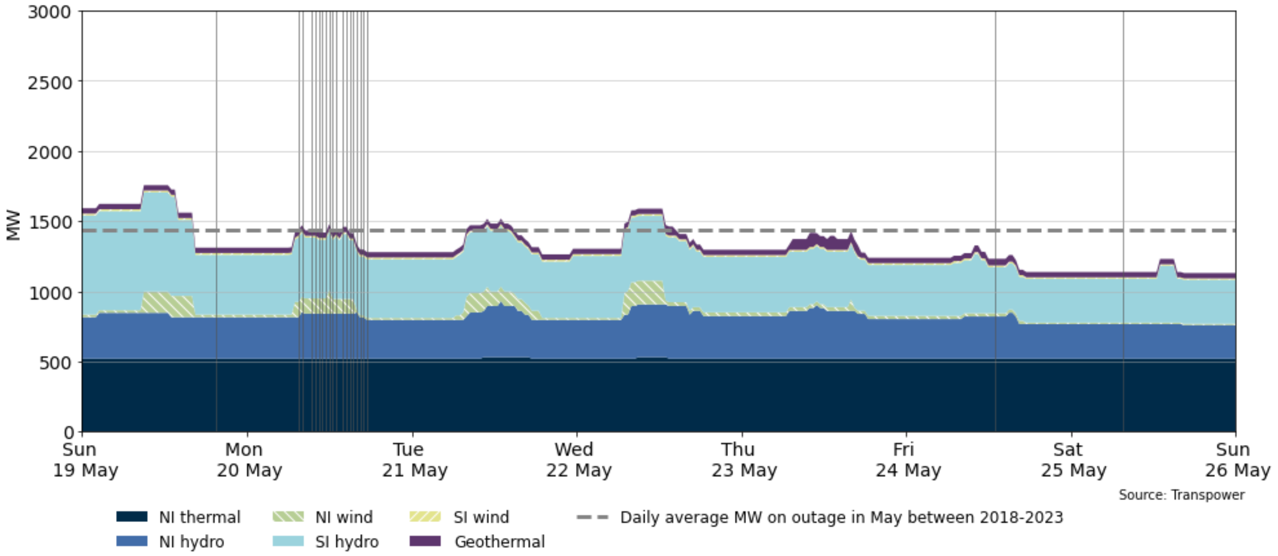
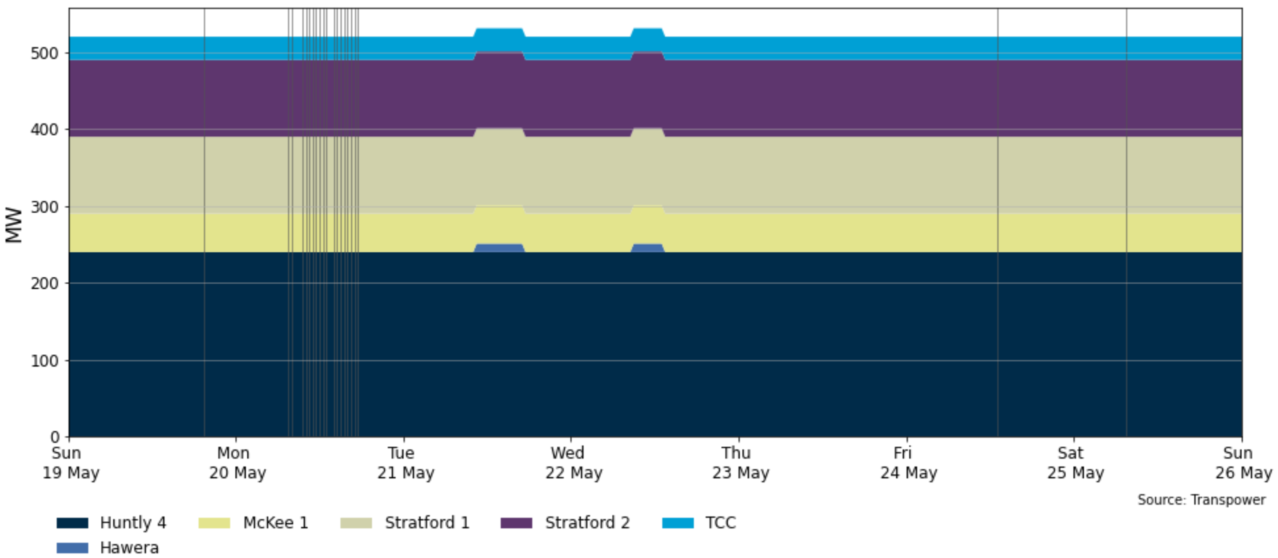


Figure 17: MW loss from thermal outages between 19-25 May

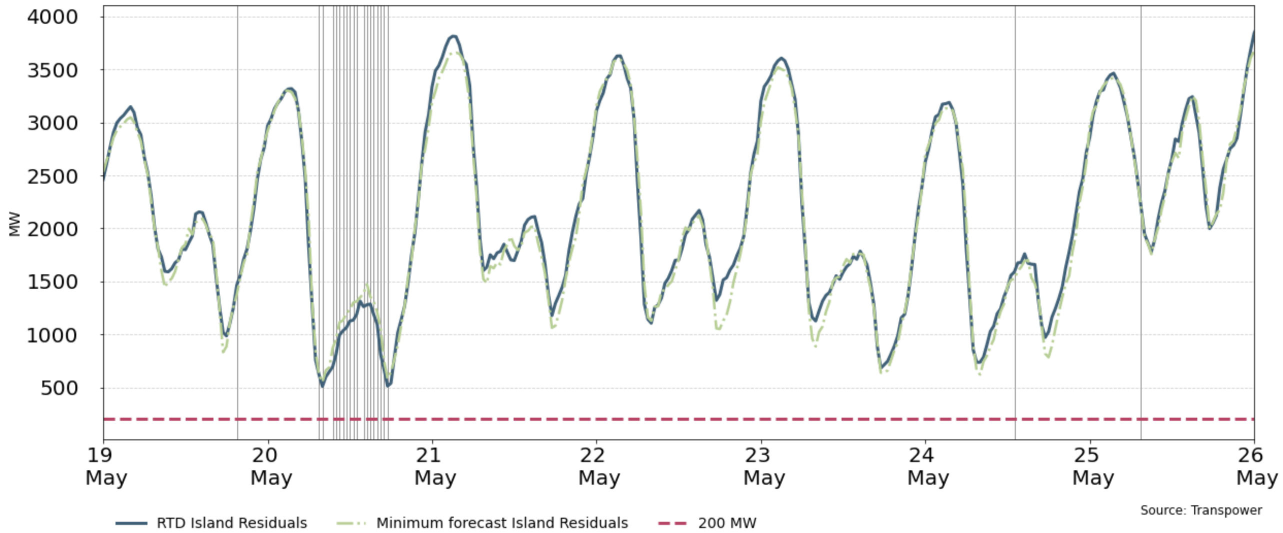


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 19-25 May. 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 Monday morning, and the minimum North Island residual was 315MW, also on Monday morning.

Figure 18: National generation balance residuals 19-25 May



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 62% nominally full and ~84% of the historical average for this time of the year (as of 25 May).

(a) Lake Pūkaki is above its 10th percentile.

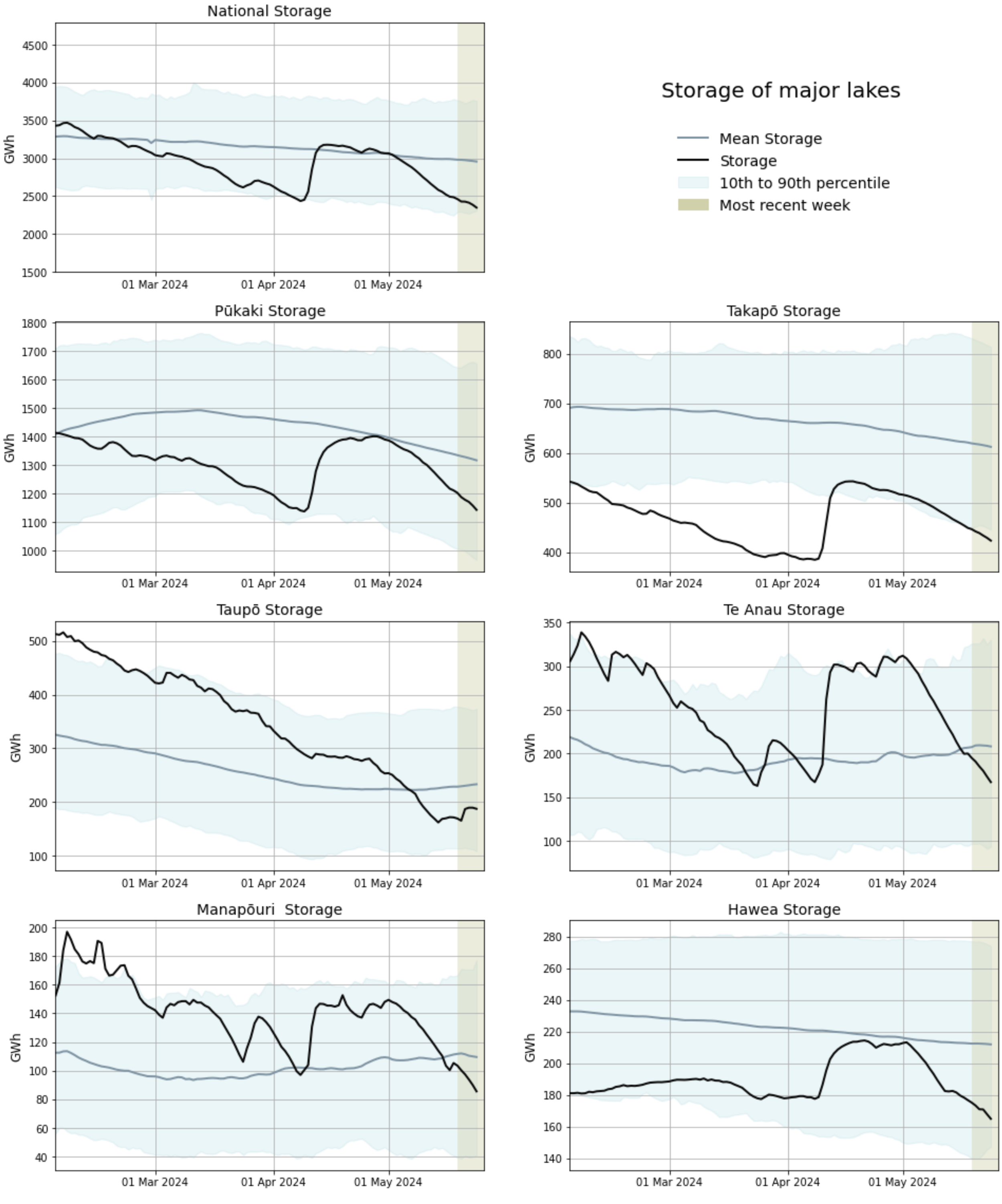
(b) Takapō is now below its 10th percentile.

(c) Taupō is above its 10th percentile and saw a slight increase in storage.

(d) Te Anau and Manapōuri are sitting between their mean and 10th percentile.

(e) Hawea is above its 10^{th} percentile.

Figure 19: Hydro storage



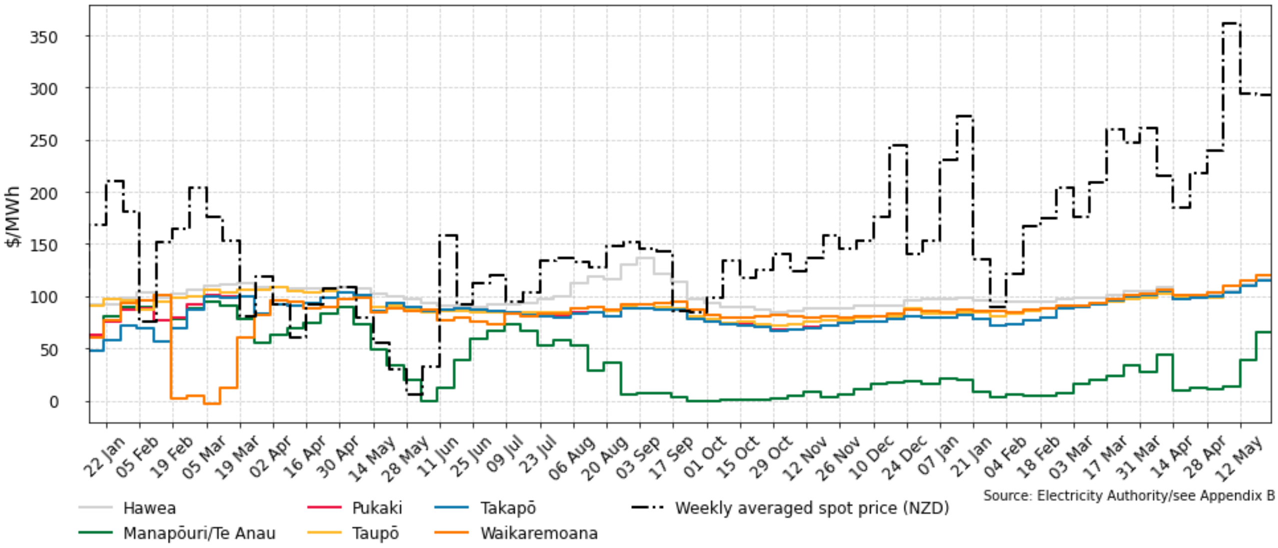
Source: Electricity Authority

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 25 May 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, from ~$4/MWh (Taupō) to ~$27/MWh (Manapōuri/Te Anau).

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 25 May 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.

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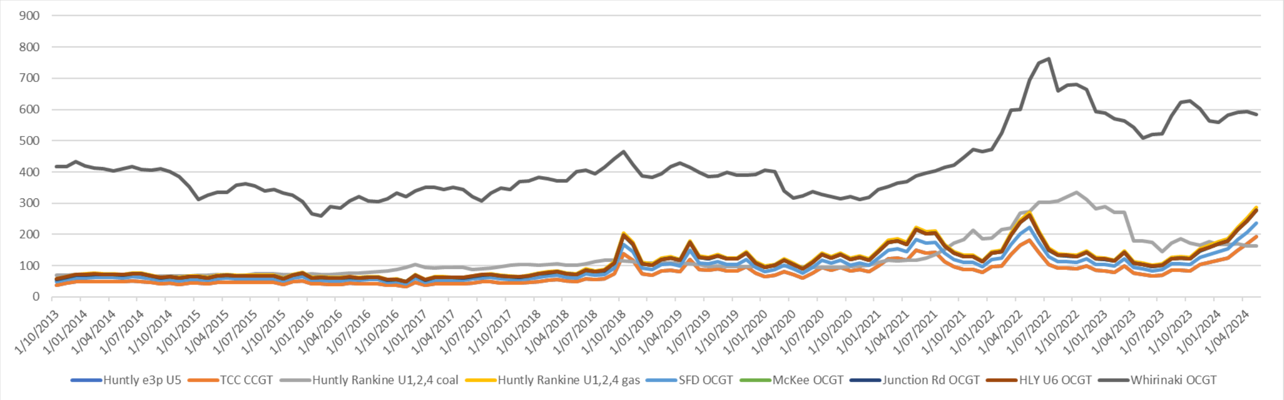
[3] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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



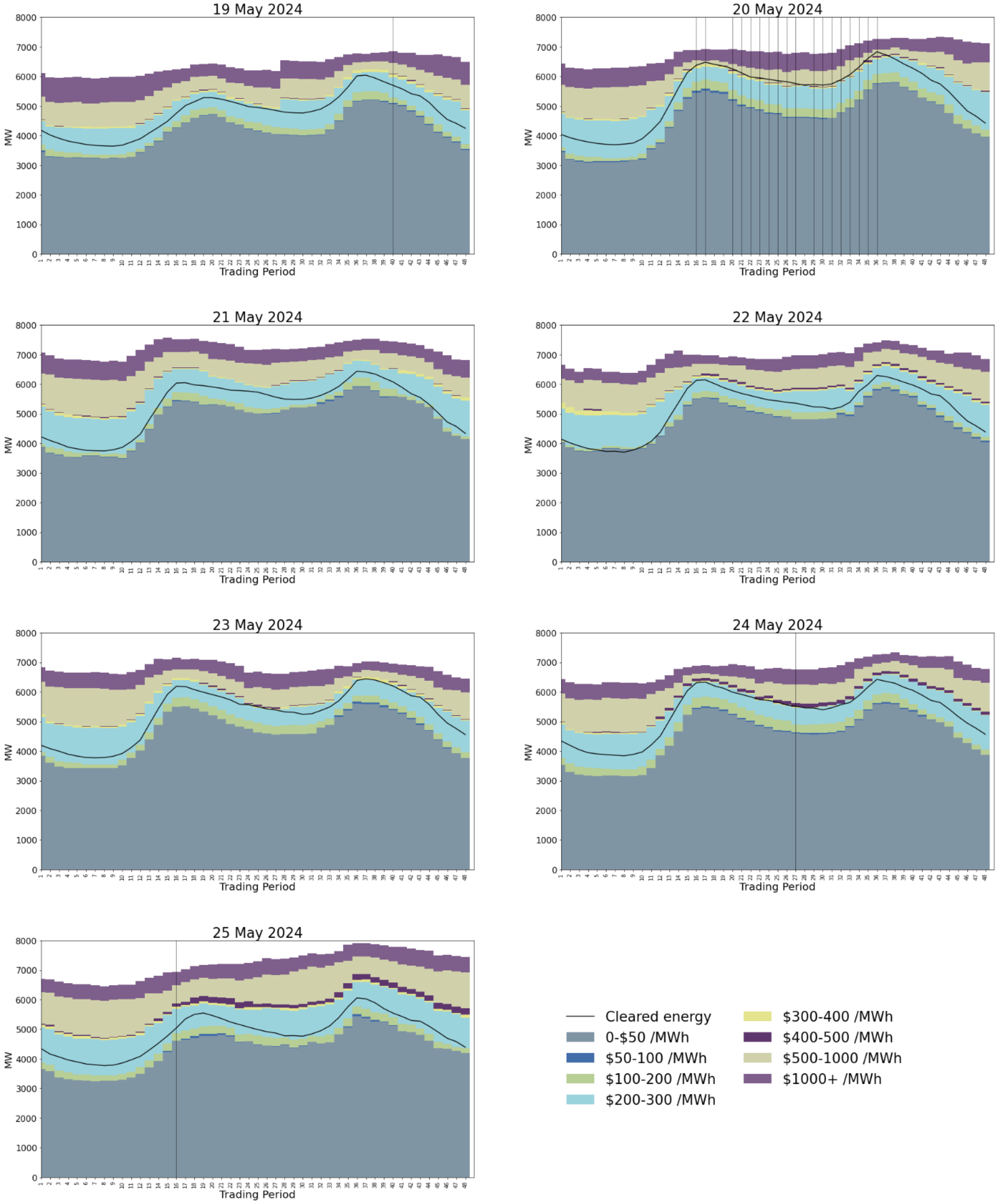
Source: Electricity Authority/see Appendix C

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. This week, most offers were cleared in the $200-$300/MWh region except for Monday when prices reached the $500-$1000/MWh band during the high demand period. The slight decline in the position of the clearing curve seen between Tuesday and Thursday compared to the other days is likely due to the increase in wind generation during those days.

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
8/05/2024-10/05/2024	Several	Further analysis	Genesis	Multiple	Energy offers
14/05/2024	16-17	Further analysis	Contact	Several	Energy offers
20/05/2024	15-35	Further analysis	N/A	N/A	Energy offers
19/05/2024-24/05/2024	Several	Further analysis	Genesis	Tuai	East Coast price separation