Date: 19 June 2023

TRADING CONDUCT REPORT

Market Monitoring Weekly Report

TRADING CONDUCT REPORT

1. Overview for week of 11 – 17 June 2023

1.1. This week once again saw increased price volatility, with high hydro generation. Demand was high due to low temperatures across the country. Significant price spikes occurred when additional thermal generation was necessary due to low wind generation to meet high demand. Prices exceeded the 90th percentile of the historic average several times from Monday to Thursday, when demand was particularly high due to low temperatures. There will be further analysis of offers during the high priced periods to ensure they comply with trading conduct.

2. Spot Prices

2.1. This report monitors underlying wholesale price drivers to assess whether there are trading periods that require further analysis for the purpose of identifying 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 at any node exceed their historical 90th percentiles. Prices above the historic 90th percentile are highlighted with a black line. Other notable prices, but which did not exceed the 90th percentile, are marked with black dashed lines.

2.2. Between 11 – 17 June:

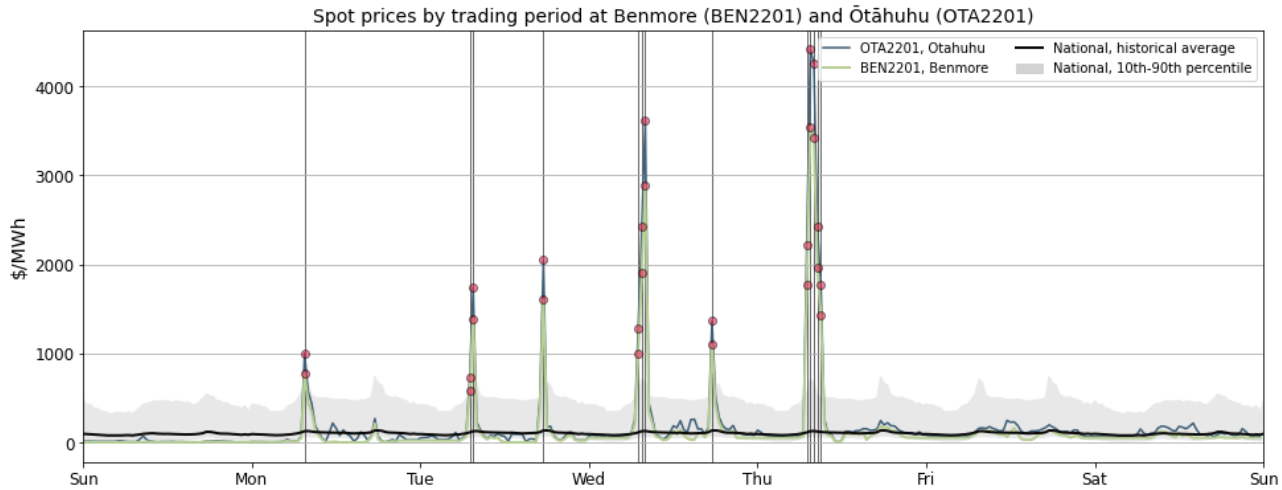
(a) The average wholesale spot price across all nodes was $152/MWh.

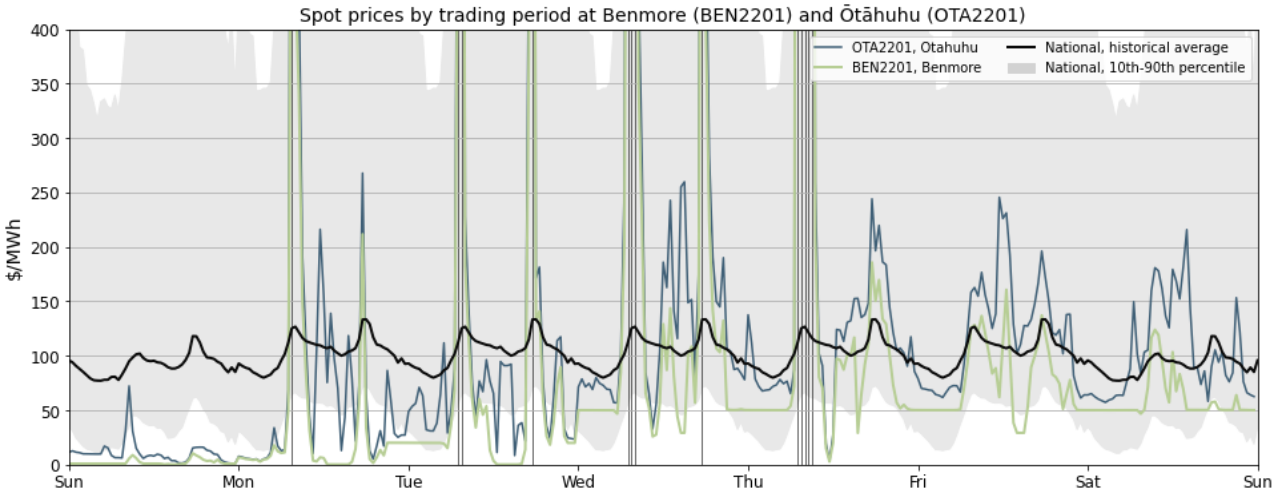
(b) 95 percent of prices fell between $1/MWh and $1550/MWh.

2.3. Figure 1 shows spot prices at Benmore and Ōtāhuhu alongside their historic median and historic 10th - 90th percentiles adjusted for inflation.

2.4. Price volatility was significant compared to last month, with prices both below the 10th percentile and above the 90th percentile. Most prices hovered around the historic average, however, there were significant price spikes during the peak demand periods due to low temperatures.

Figure 1: Wholesale Spot Prices between 11 June (Sunday) – 17 June (Saturday) 2023.





2.5. This week the price spikes above the 90th percentile were observed on:

(a) Monday, 12 June at 7:30 am during the morning peak demand. The price at Ōtāhuhu was $1,000/MWh and the price at Benmore was $774/MWh. The demand was significantly high at that time.

(b) Tuesday, 13 June there were three price spikes, the first two were between 7:00 am and 7.30 am during the morning peak. The price at Ōtāhuhu was $1,739/MWh and the price at Benmore was $1,390/MWh. At 5.30 pm, another spike saw the price at Ōtāhuhu reach $2,048/MWh and the price at Benmore was $1,601/MWh. Demand was particularly high due to low temperatures, and wind was low around 50 MW which resulted in additional thermal generation being dispatched.

(c) Wednesday, 14 June experienced the same pattern with the price spikes between 7:00 am and 8:00 am with prices of $3,620/MWh at Ōtāhuhu, and the price of $2,892/MWh at Benmore. During this time temperatures across both islands were low and there was very little wind. At 5.30 pm, another spike saw the price at Ōtāhuhu reach $1,366/MWh and the price at Benmore reach $1,099/MWh.

(d) The highest price spikes occurred on 15 June during the morning peak between 7.00 am and 9:00 am for each 30-minute trading period, which saw a price at Ōtāhuhu of $4,411/MWh and $3,543/MWh at Benmore at 7:30 am. This coincided with a large ramp down of the HVDC northward flow. Wind generation during this time was below 100 MW, meaning more peakers were required to cover peak demand requirements due to cold conditions.

2.6. Figure 2a 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. Figure 2b shows this week's high volatility.

2.7. This week, the median and upper quartile prices were higher than last week, as hydro storage declined and prices rose closer to the long term average. However, there were also a large number of outliers during peak demand periods, with higher prices than seen even in recent weeks. While high demand and low wind generation were a factor, further analysis will be done to ensure offers during these trading periods have complied with trading conduct.

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

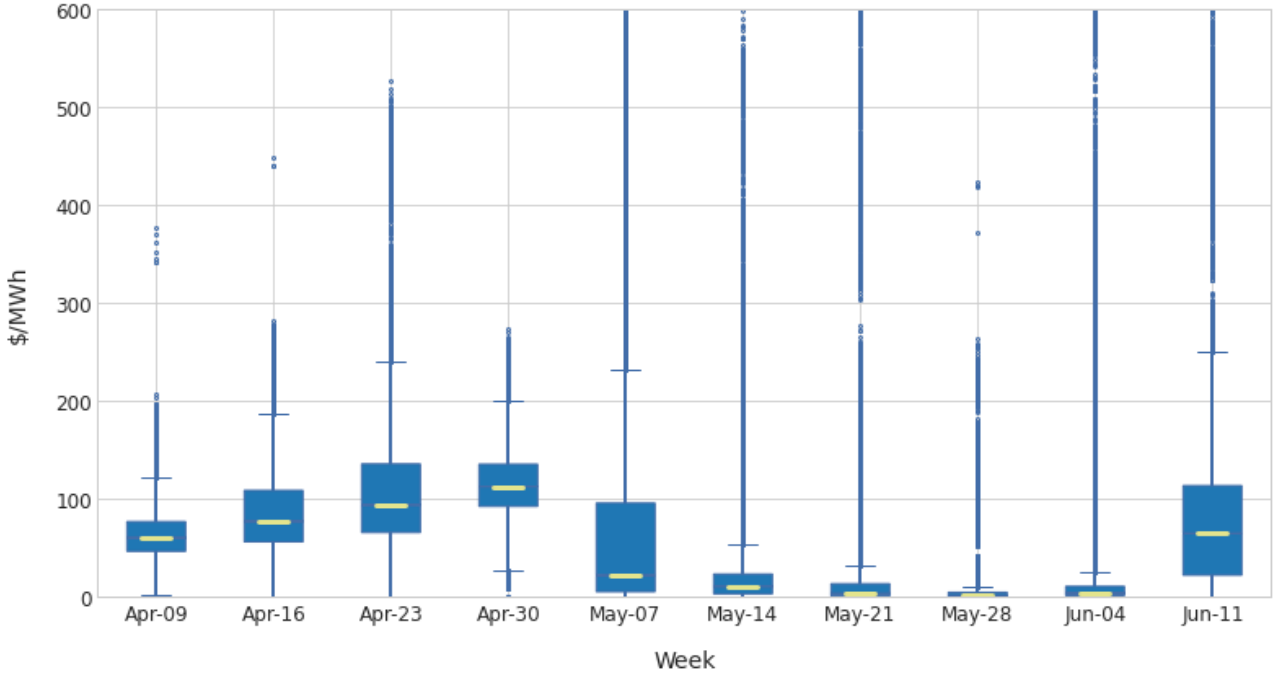
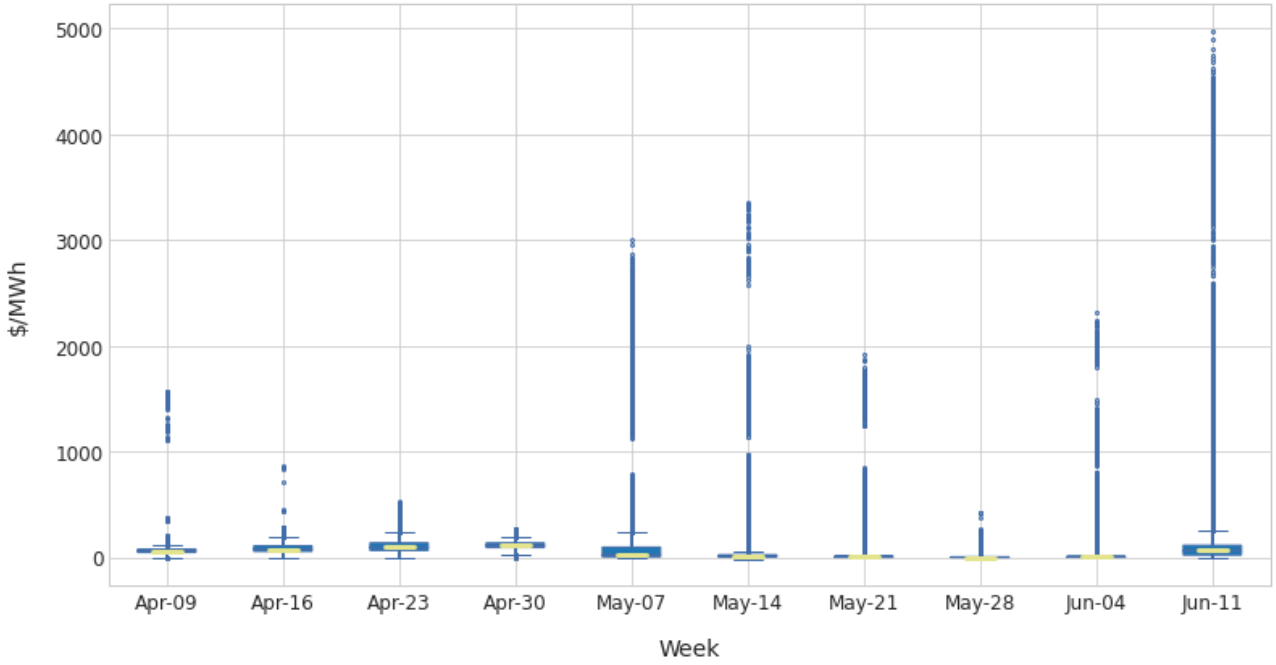


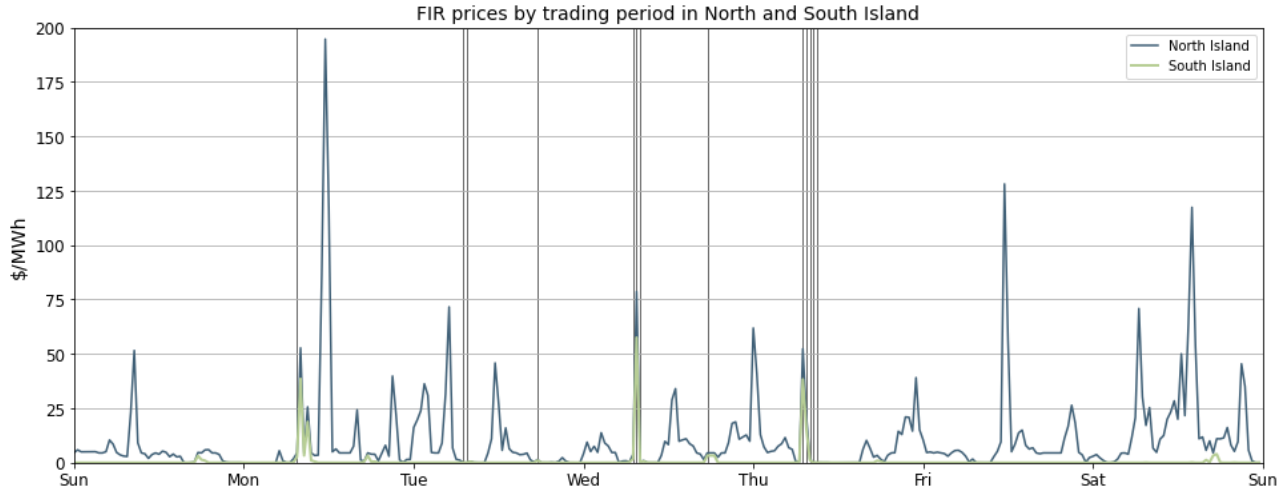
Figure 2b: Boxplots showing the volatility in spot prices this week compared to the previous nine weeks.



3. Reserve Prices

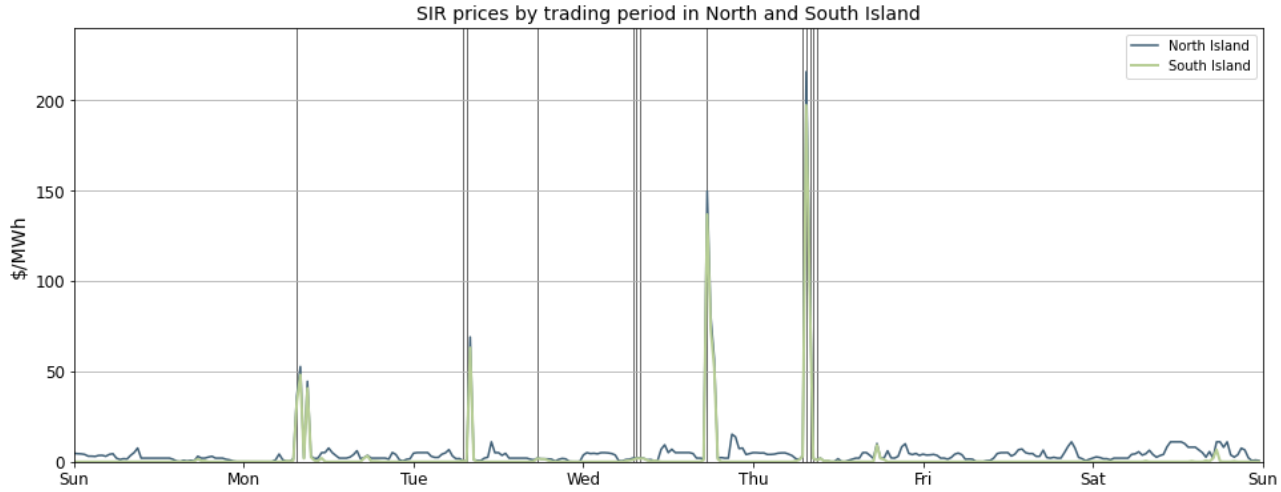
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week the FIR prices were mostly $0/MWh for the South Island with a few instances of price spikes of up to $58/MWh. Meanwhile, the FIR prices for the North Island were volatile and slightly higher, but mostly below $50/MWh. The highest FIR price occurred on Monday, 12 June at 11:30 am, with the price reaching $195/MWh in the North Island, which coincided with high HVDC transfer.

Figure 3: Fast instantaneous reserve (FIR) prices by trading period and Island.



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 this week, with occasional price spikes. The highest SIR price occurred on Thursday, 15 June at 7:30 am, when the price reached $216/MWh in the North Island and $197/MWh in the South Island and coincided with the highest energy prices.

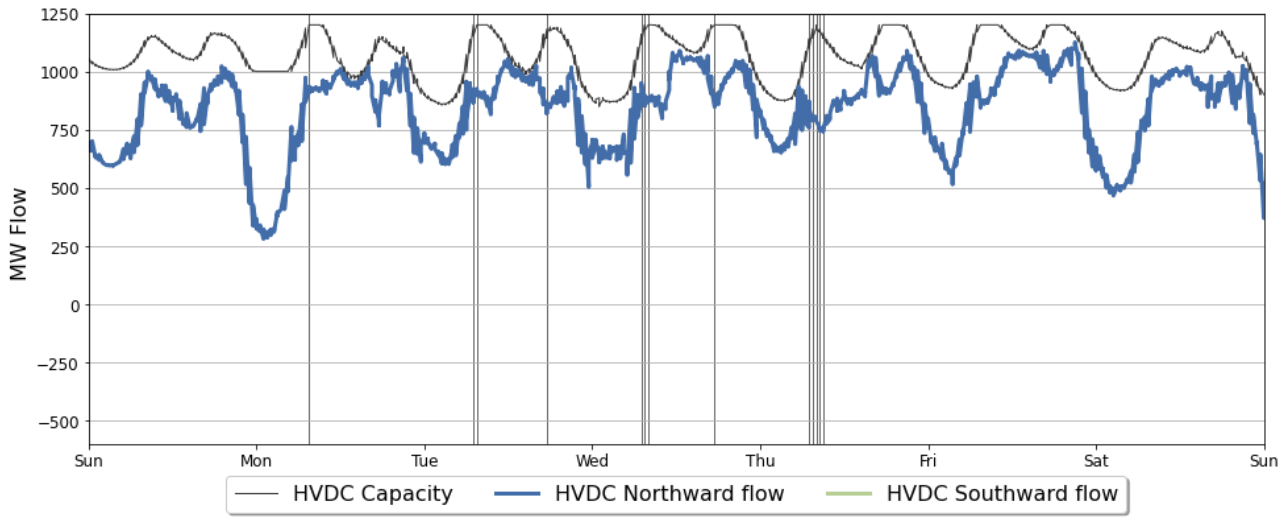
Figure 4: Sustained instantaneous reserve (SIR) prices by trading period and Island.



4. HVDC

4.1. Figure 5 shows HVDC flow between 11 – 17 June, which were northwards for the whole week. HVDC flows were relatively high during the day, due to high hydro generation in the South Island. The high prices coincided with a drop in the northward flow across the HVDC. This drop required additional North Island generation (mainly thermal) to be dispatched to meet the requirement.

Figure 5: HVDC northward flow and capacity.

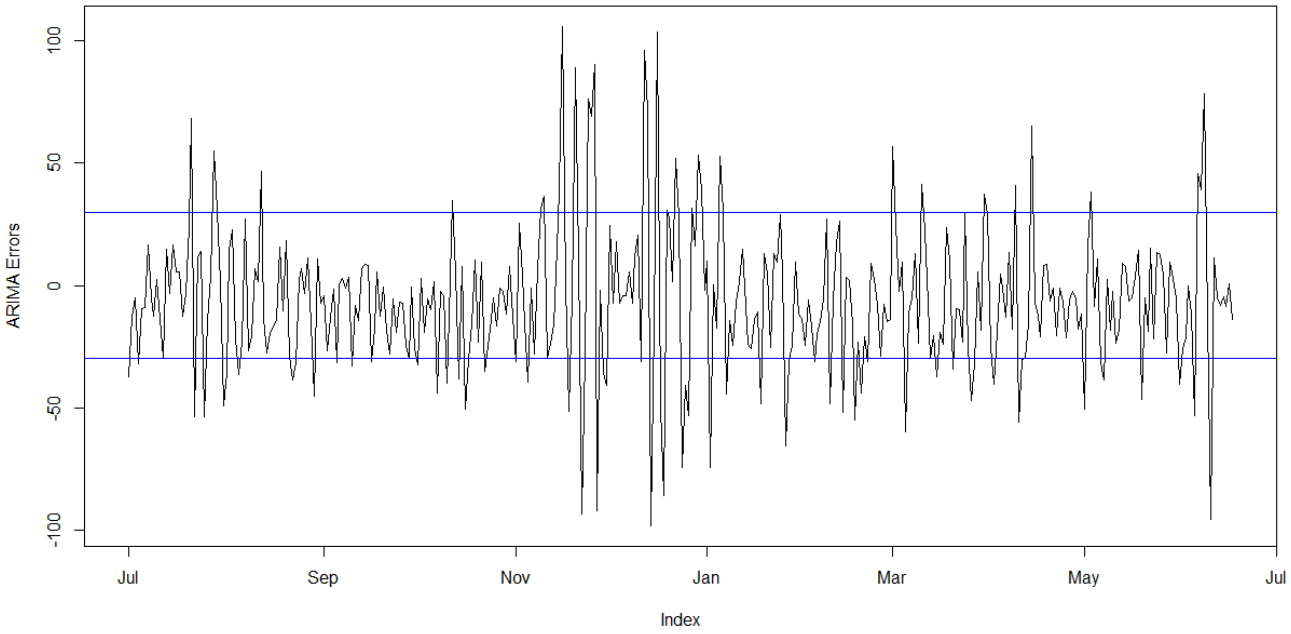


5. Regression Residuals

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. Residuals were mostly relatively small, suggesting that average daily prices on those dates appear to be largely aligned with market conditions. These small deviations reflect market variations that may not be controlled for in the regression analysis. Despite the price spikes this week, there were no residuals above or below the one standard deviation of the data as the daily average prices were relatively low.

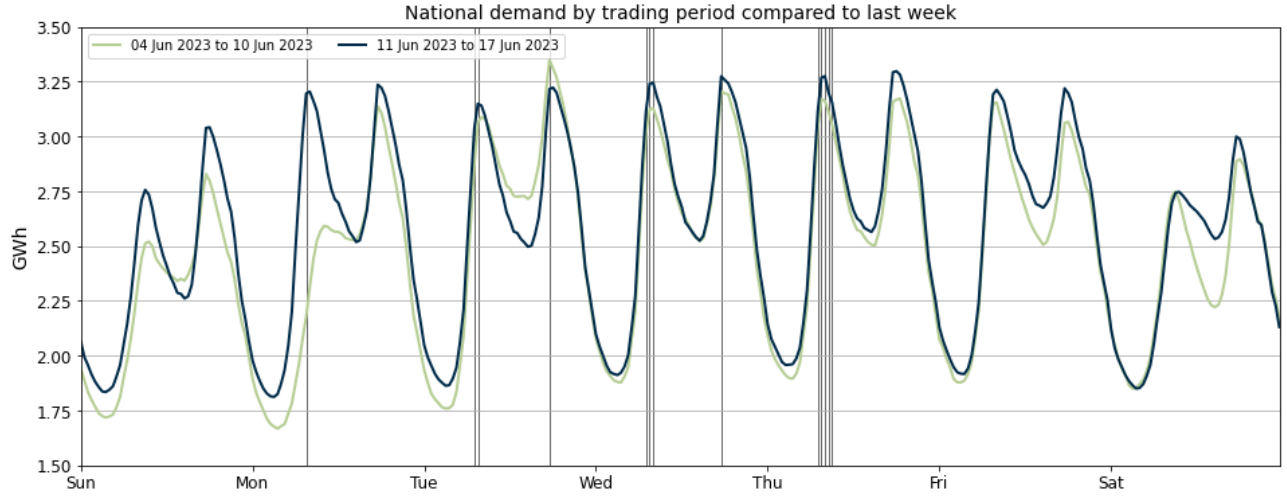
Figure 6: Residual plot of estimated daily average spot prices from 1 July 2022 – 17 June 2023. The blue lines show two standard deviations of the ARMA errors.



6. Demand

6.1. Figure 7 shows national grid demand between 11 – 17 June, compared to the previous week. Overall, demand increased compared to the previous week as temperatures dipped across the country. On Wednesday and Thursday, where we saw multiple price spikes in the morning, demand reached around 3.25 GWh.

Figure 7: National demand by trading period compared to the previous week.

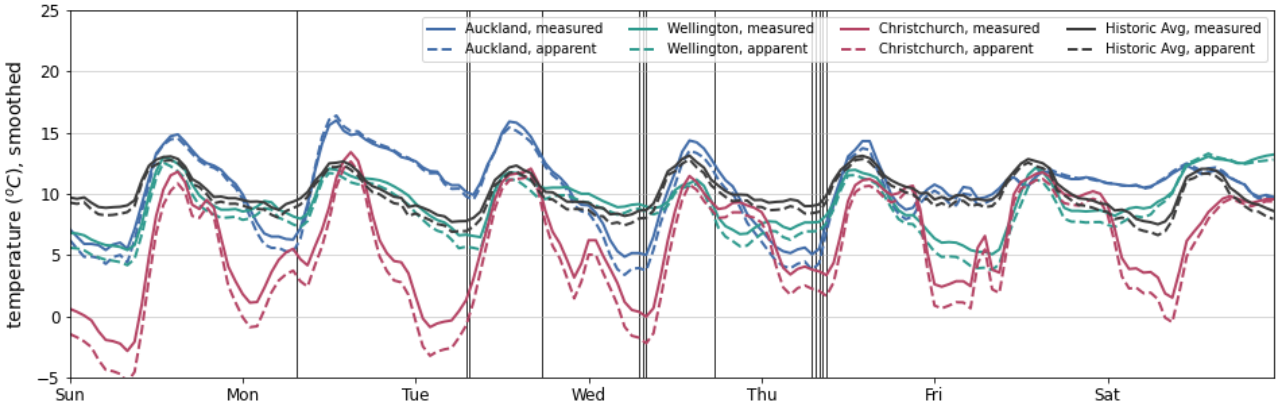


6.1. Figure 8 shows hourly temperatures at the three main population centres between 11 – 17 June. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.2. Temperatures frequently dropped overnight, resulting in cold mornings this week. Auckland and Wellington temperatures dipped to around the 5 degrees mark several times, though Auckland was typically warmer during the day, reaching 15 degrees. Wellington

temperatures were particularly cold, 10 degrees for most of the latter half of the week. Christchurch's apparent temperatures ranged from -5 degrees to 13 degrees, with the beginning of the week seeing some very cold morning temperatures.

Figure 8: Temperatures across main centres.



7. Outages

7.1. Figure 9 shows generation capacity on outage. Total capacity on outage between 11 – 17 June ranged between ~900MW and 1300MW.

7.2. Notable outages include:

(a) Huntly 4 was on outage until 11 June.

(b) Stratford station was on a short outage on 14 June in the afternoon.

(c) Huntly 1 was on a short outage on 15 June in the afternoon.

(d) Huntly 5 had a partial outage during the day on 14 June reducing generation capacity by 145 MW.

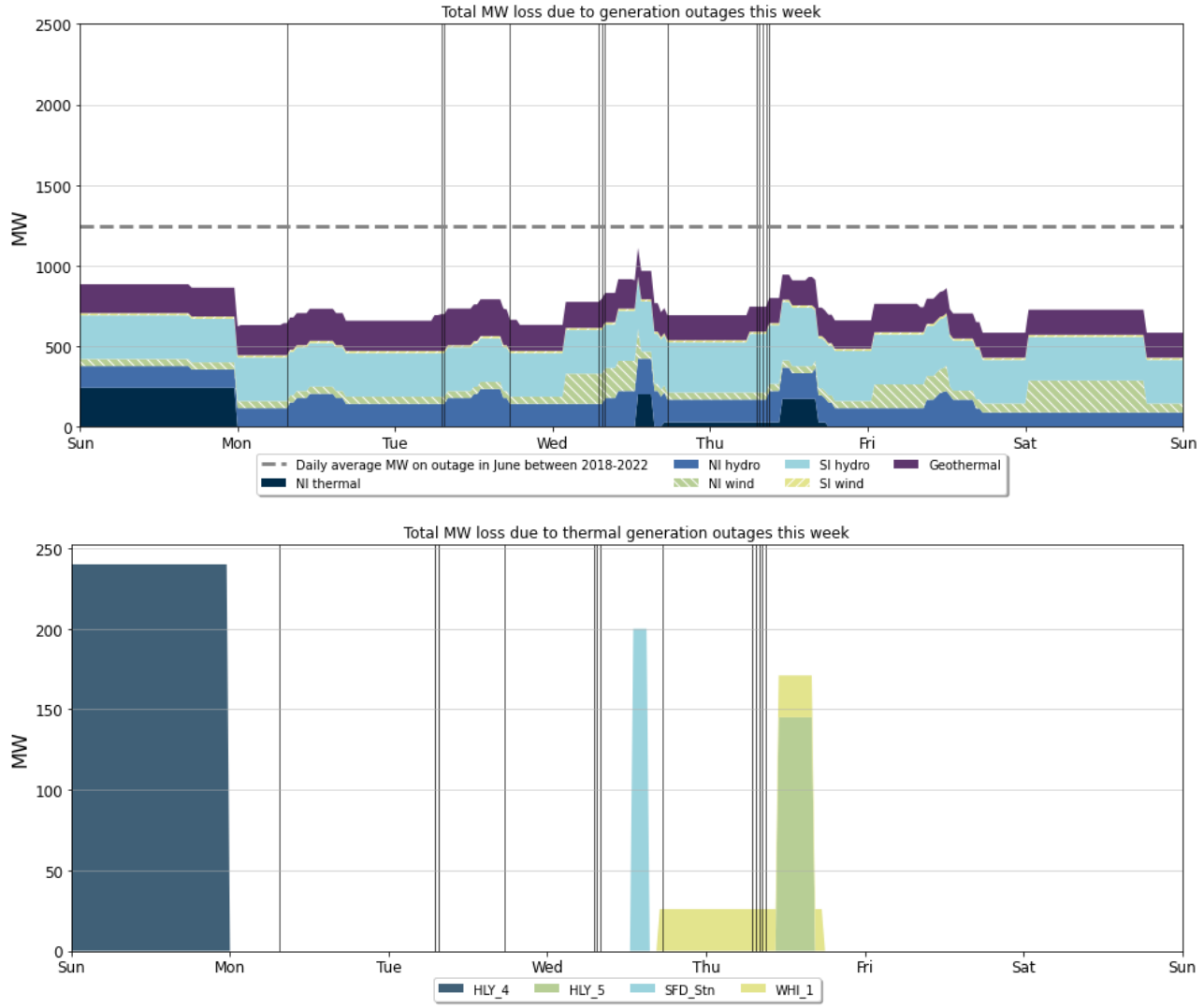
(e) Whirinaki unit was on outage between 14-15 June.

(f) Kawerau geothermal unit on extended outage until 19 June.

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

(h) West Wind is partly on outage until 24 November.

Figure 9: Total MW loss due to generation outages.

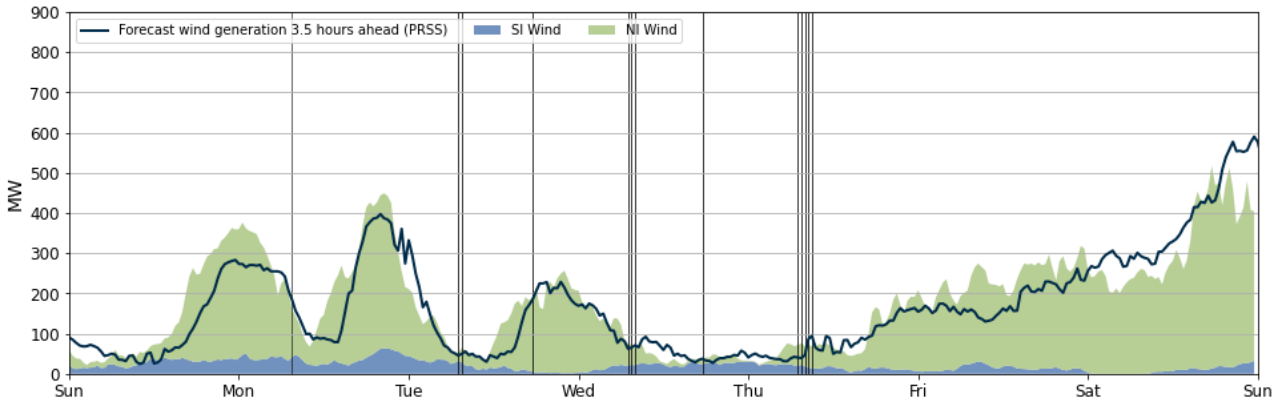


8. Generation

8.1. Figure 10 shows wind generation, from 11 – 17 June, ranged from 20 - 500 MW across the week. Wind generation was around 50 MW at the start of the week and increased to around 380 MW on Monday and peaked to 450 MW on Tuesday. Wind generation was low on Wednesday evening and Thursday morning. Wind steadily increased from Friday and reached to 500 MW on Saturday.

8.2. Several of the price spikes this week coincided with low wind generation that was below 100 MW. This would have contributed to high prices when the market was already tight as it would have required additional generation to be dispatched to make up for the shortfall in wind generation.

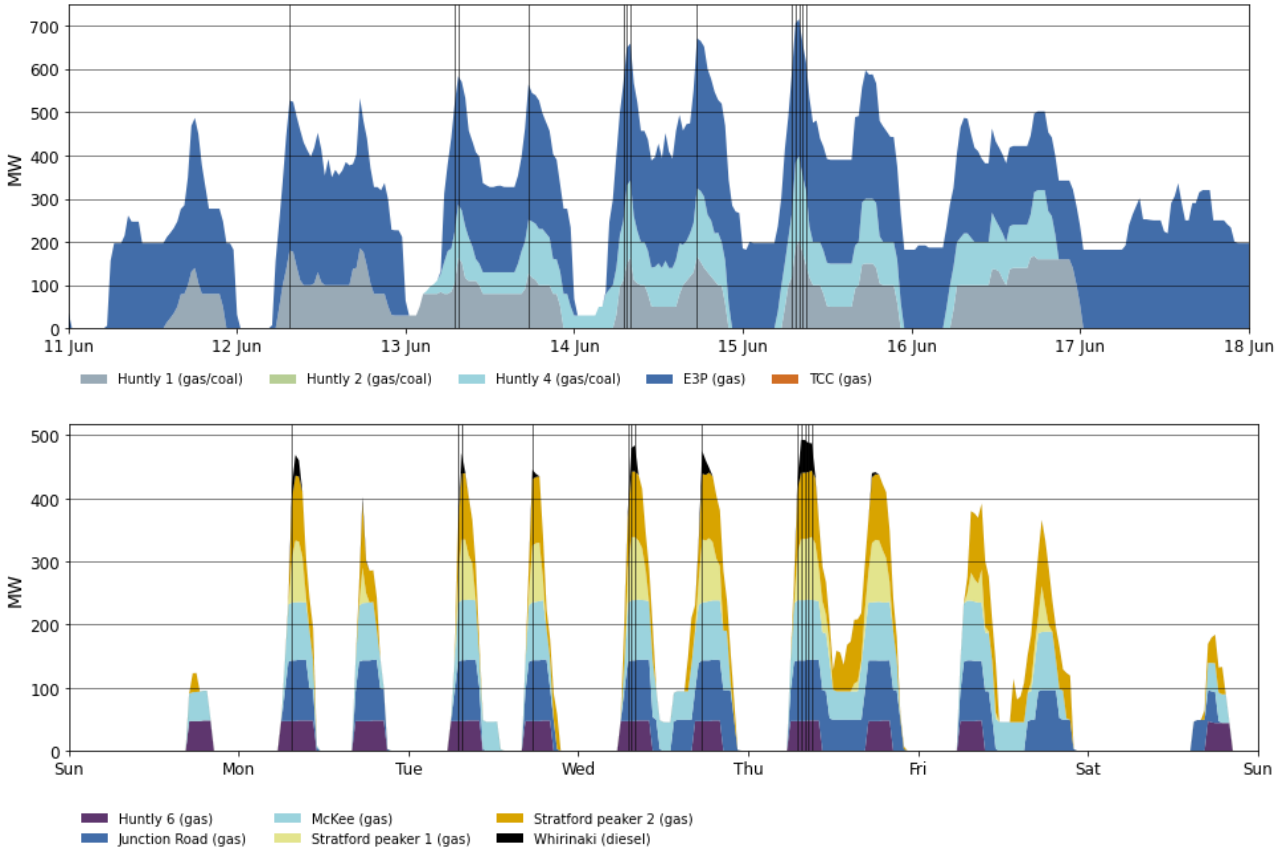
Figure 10: Wind Generation and forecast.



8.3. Figure 11 shows the generation of thermal baseload and thermal peaker plants between 11 – 17 June. E3P (Huntly 5) started the week with a similar pattern to the previous two weeks, turning on in the morning and off overnight. From mid-week when demand was high and wind generation low, E3P ran continuously as baseload. Huntly 1 supported baseload from Sunday afternoon to Friday, with Huntly 4 running from Tuesday to Friday after returning from outage.

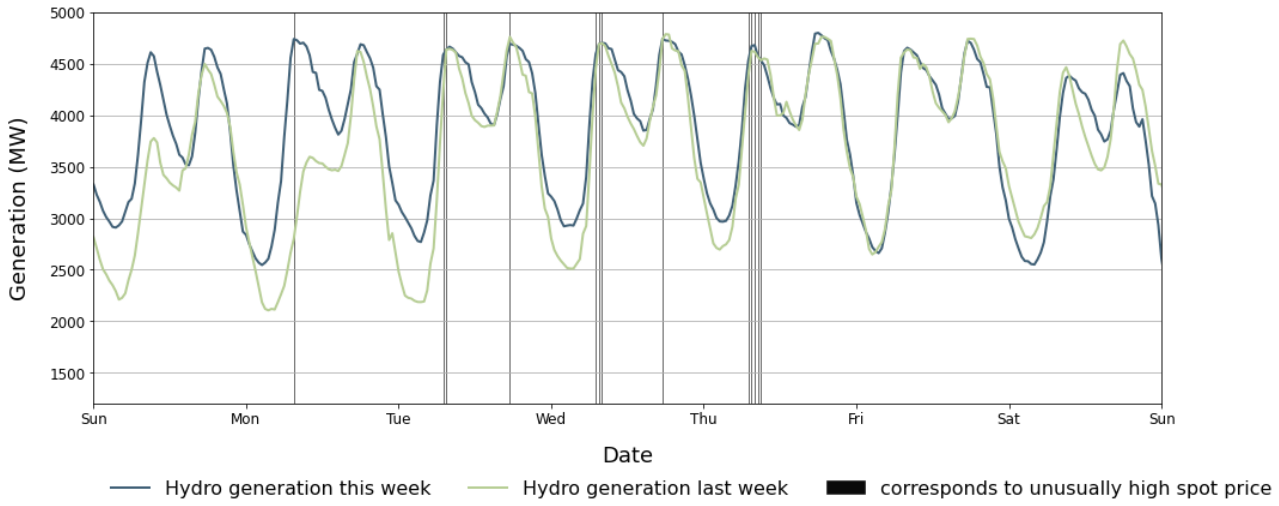
8.4. All thermal peakers run from Monday to Thursday due to high demand, including Whirinaki, resulting in almost 500MW of peaker generation. Stratford 2, Junction Road and McKee also ran during the shoulder period on Thursday when wind generation was particularly low.

Figure 11: Thermal Generation.



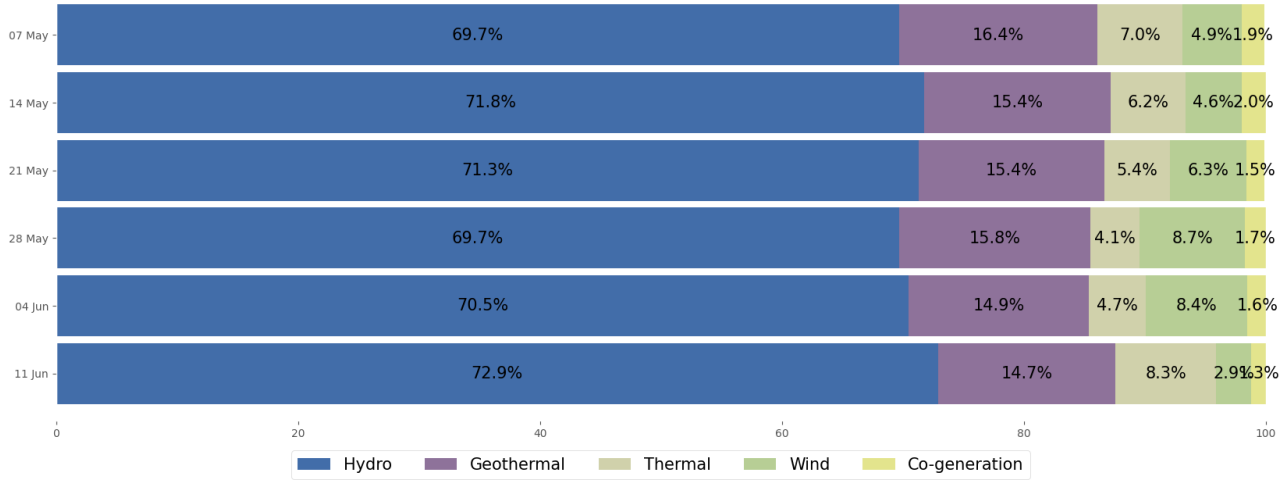
8.5. Figure 12 shows hydro generation between 11 – 17 June. Hydro generation increased compared to the previous week in line with the increased demand.

Figure 12: Hydro generation between 11 – 17 June compared to the previous week.



8.5. As a percentage of total generation, between 11 – 17 June, total weekly hydro generation was 72.9 percent, geothermal 14.7 percent, thermal 8.3 percent, wind 2.9 percent, and co-generation 1.3 percent. Thermal generation was higher than last week, due to low wind and high demand.

Figure 13: Total generation as a percentage each week between 7 May and 17 June 2023.



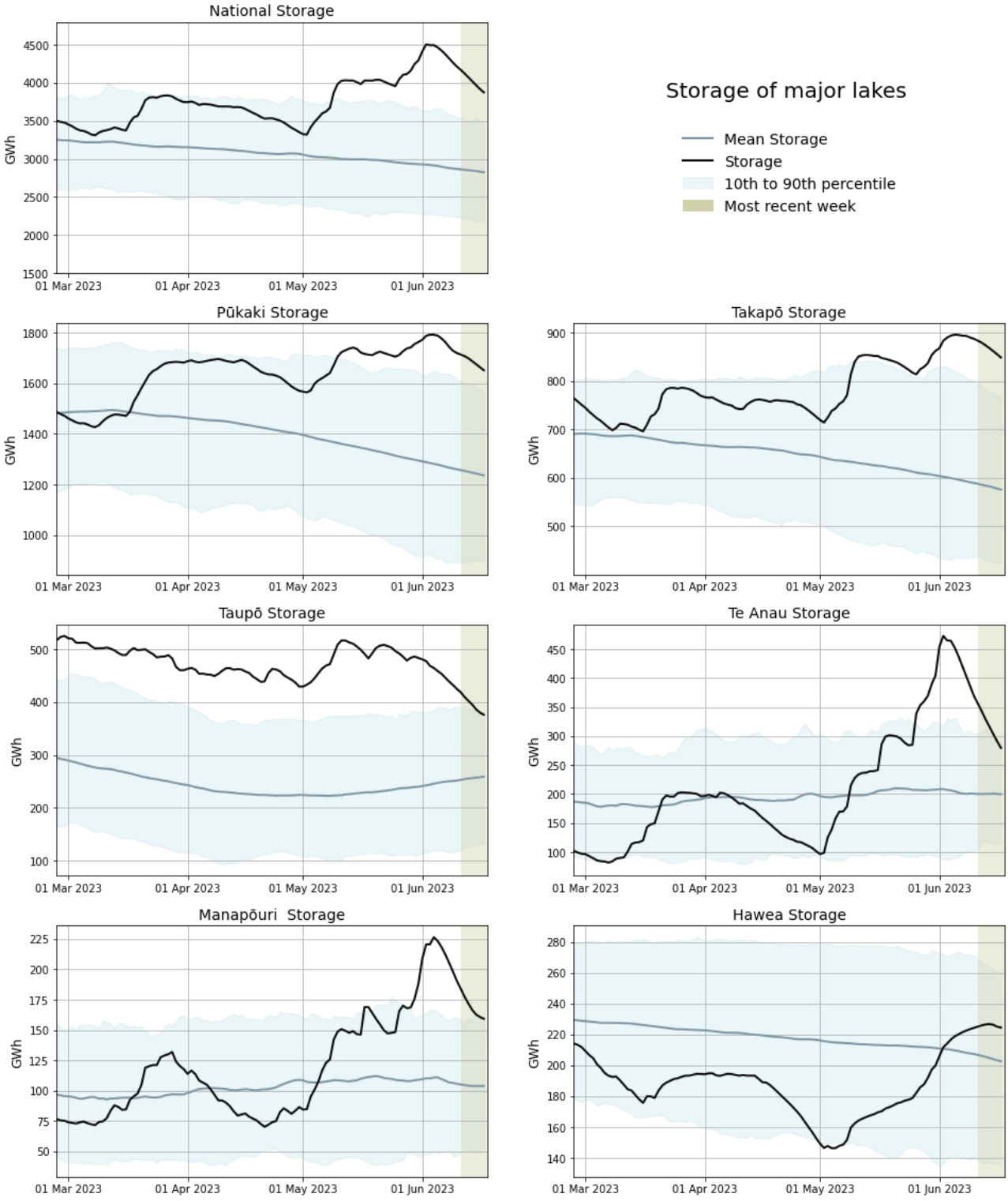
9. Storage/Fuel Supply

9.1. Figure 12 shows total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

9.2. National hydro storage levels have decreased this week. However, controlled storage is still high at 92.4 percent of nominal full as of 17 June.

9.3. All lakes levels decreased this week. Lakes Pūkaki and Takapō have been steadily decreasing but still remain above their 90th percentiles. The steepest drop in lake levels was at Manapōuri and Te Anau, these lakes touched their respective historic 90th percentile. Storage level at Taupō also dropped and touched its historic 90th percentile. Hawea still remains above its historic mean for this time of year, although after a small increase at the beginning of the week, its levels have dropped slightly.

Figure 12: Hydro Storage.

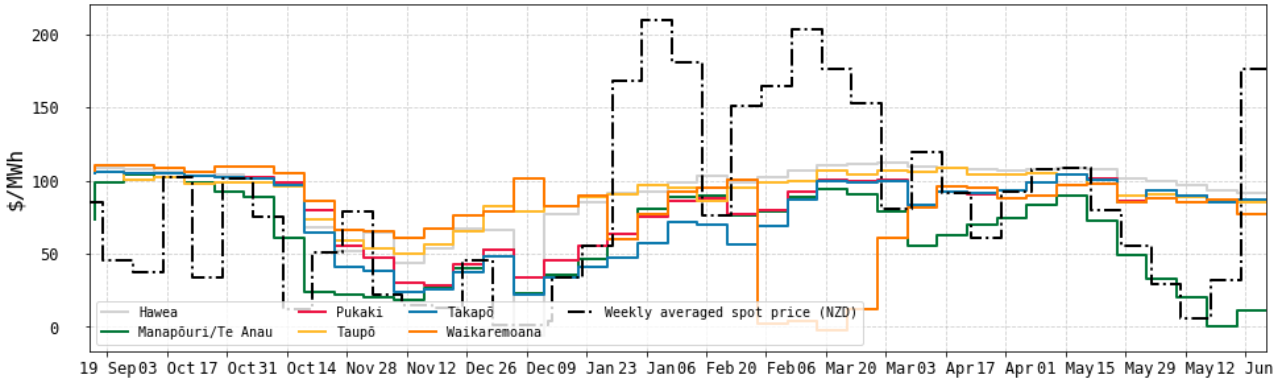


10. JADE Water Values

10.1. The JADE[1] 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 13 shows the national water values between 15 September 2022 and 17 June 2023 using values obtained from JADE. 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.

10.2. Since the beginning of February, the water values at most lakes have been relatively steady, with a small drop in March as lake levels rose. This week water values in all lakes slightly decreased. However, water values at Te Anau and Manapōuri experienced a drastic drop from May and slightly raised last week.

Figure 13: JADE water values across various reservoirs between 15 September 2022 and 17 June 2023.



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 14 shows an estimate of thermal SRMCs as a monthly average up to 1 June 2023. The SRMC of diesel plants has significantly decreased from March, and the SRMC of gas-fuelled and coal plants has also slightly decreased. A reduction in carbon prices has contributed to the decline in SRMCs.

11.4. In early June, Indonesian coal stayed at around ~$466/tonne (NZD) putting the latest SRMC of coal-fuelled Huntly generation at ~$260/MWh.

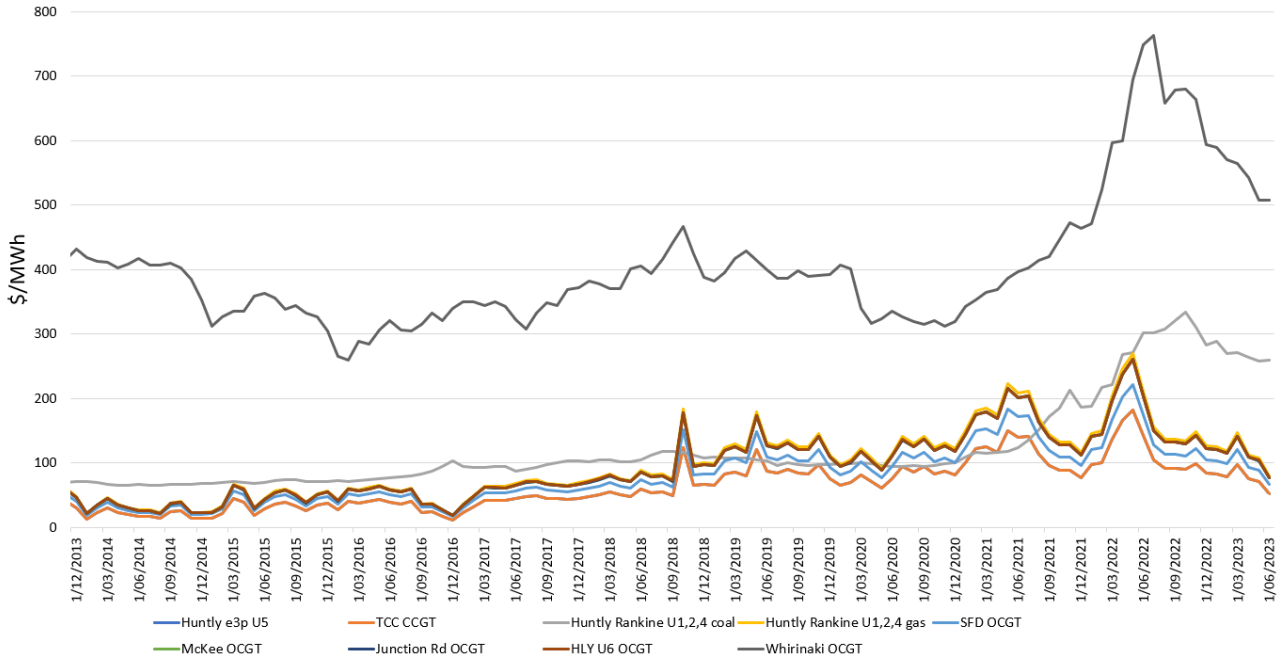
11.5. The SRMC of Whirinaki has decreased to ~$508/MWh.

11.6. The SRMC of gas fuelled thermal plants decreased and is between $53/MWh and $80/MWh, likely due to a decrease in gas demand as well as carbon prices.

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

[1] 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.

Figure 14: Estimated monthly SRMC for thermal fuels.



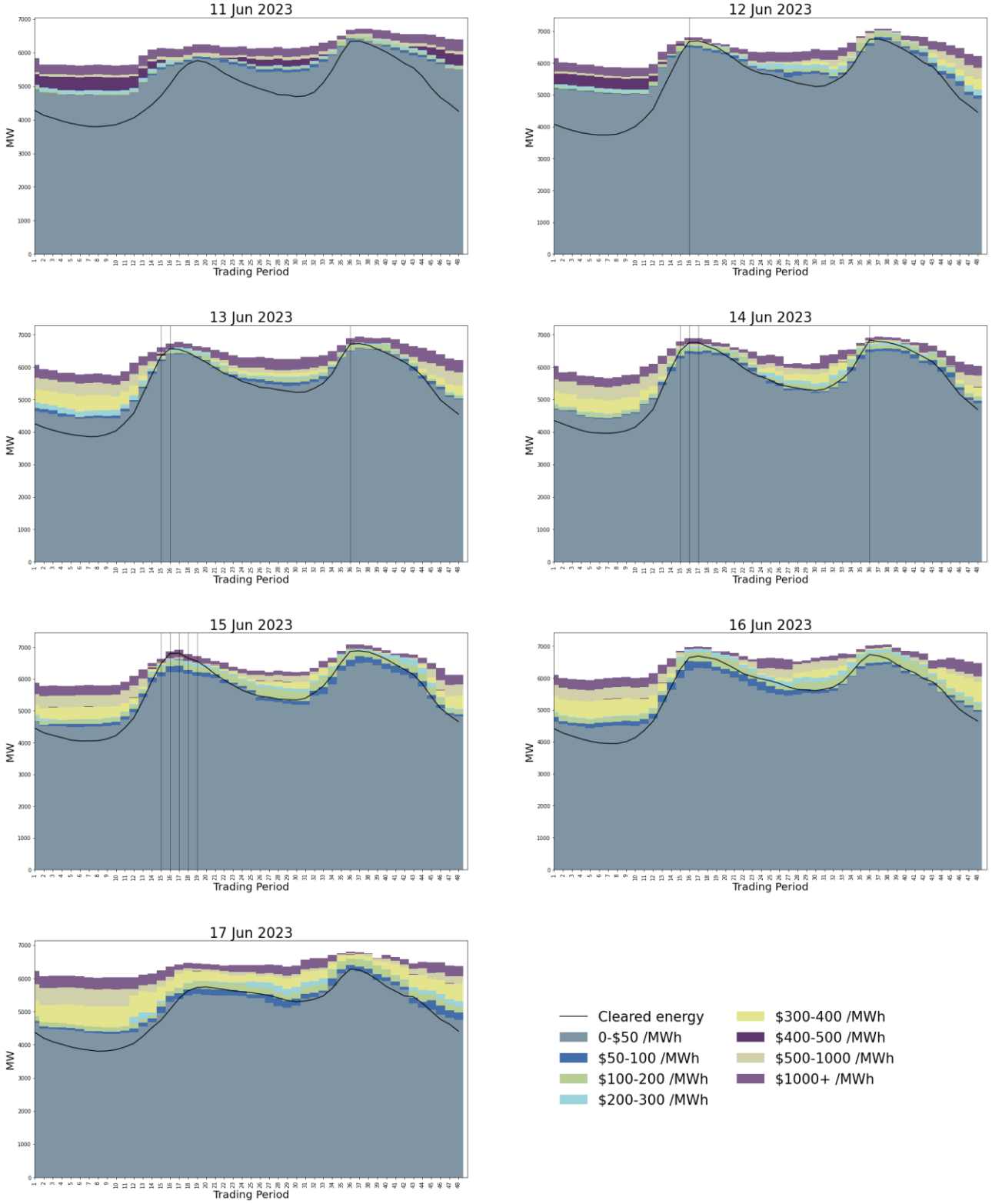
12. Offer Behaviour

12.1. Figure 15 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. There continues to be a high quantity of generation offered between $0 and $50/MWh due to high hydro storage. However, this has declined slightly from last week with an increase in offers between $50-$200/MWh, which resulting in higher average prices this week, particularly Wednesday onwards.

12.3. As the demand significantly increased during the peak periods there was an increase in the quantity of generation offered in the higher bands. However, the stack remains thin above the $50/MWh, contributing to volatile prices. During Thursday morning peak, significant amount of the energy cleared in the higher bands as the demand was higher.

Figure 15: Daily offer stacks



13. Ongoing Work in Trading Conduct

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

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	TP	Status	Participant	Location	Enquiry Topic
07/10/2022	15-16	Further analysis	Genesis	Huntly 5	Prices change for final energy tranche.
15/1/2023 4/2/2023	Several	Further analysis	N.A.	Multiple	High energy prices associated with high hydro offers.
17/4/2023	48	Further analysis	Contact	Clyde and Roxburgh.	Offer changes.
19/4/2023	27	Further analysis	Contact	Clyde and Roxburgh.	Offer changes.
11/5/2023	37-40	Further analysis	Genesis	Huntly 4	Offer changes.
15/5/2023	36-37	Further Analysis	Genesis	Huntly 2,4,5	Offer changes.
18/05/2023	Several	Further Analysis	N.A.	Multiple	Market conditions which led to higher off-peak prices.
13/06/2023	14-16	Further Analysis	Genesis	Takapō	Offer changes.
14/06/2023	15-17	Further Analysis	N.A.	Multiple	High energy prices associated with high energy offers.
15/06/2023	15-19	Further Analysis	N.A.	Multiple	High energy prices associated with high energy offers.