Date: 4 September 2023

ELECTRICITY AUTHORITY
TE MANA HIKO

TRADING CONDUCT REPORT

Market Monitoring Weekly Report

TRADING CONDUCT REPORT

1. Overview for week of 27 August to 2 September 2023

1.1. This week saw spot prices sit above the historic average and slightly higher than recent weeks. There were a few instances of price spikes in the early part of the week during cold mornings when demand was high. Milder temperatures in the latter part of the week saw national demand drop, in particular during the evening peak periods. Hydro generation significantly decreased this week with increased thermal meeting national demand requirements. National controlled hydro storage continues to decline and is currently around 91% of historical mean.

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 at any node exceed their historical 90th percentiles.

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 above the historic 90th percentile are highlighted with a vertical black line. Other notable prices that did not exceed the 90th percentile, are marked with black dashed lines.

2.3. Between 27 August – 2 September:

a) The average wholesale spot price across all nodes was $153/MWh.

b) 95% of prices fell between $107/MWh and $215/MWh.

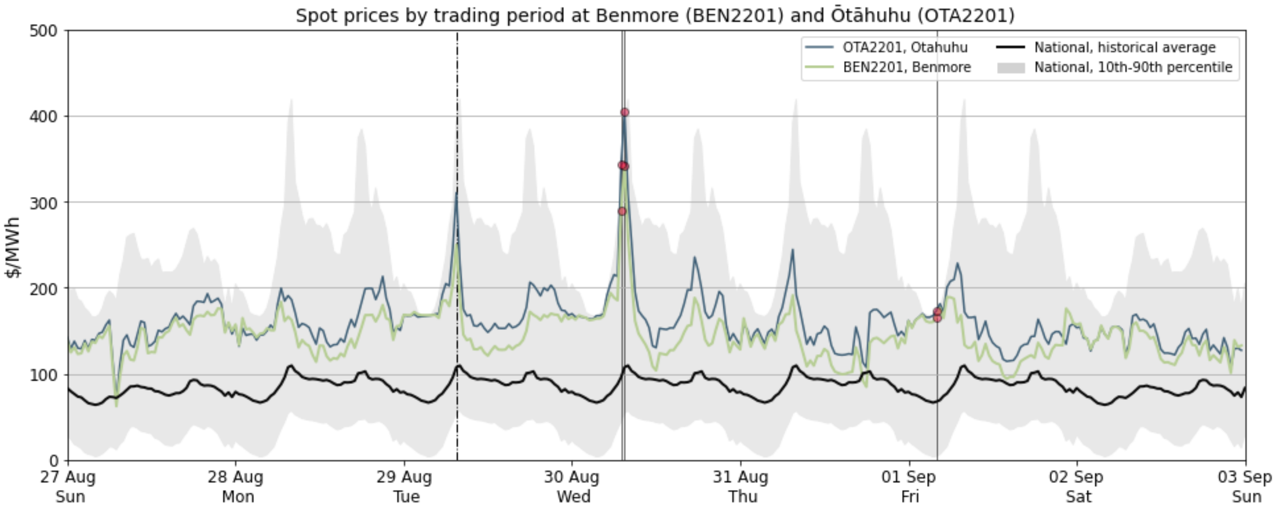
2.4. The majority of spot prices sat above the historic average for the week with an increase to the average spot price compared to the previous week of around $11/MWh.

2.5. There was a spike in spot prices during the 7.30am trading period on Tuesday morning. However, both Benmore and Ōtāhuhu prices remained below the 90th percentile with prices of $250/MWh and $310/MWh respectively. Apparent temperatures across the three main centres dropped below 5 degrees that morning. National demand reached around 3.4GWh. This high demand resulted in a large increase in northward HVDC flow, from 606MW at 7:00 am to 712MW by 7:30.

2.6. On Wednesday morning there was another, higher, price spike at 7.00am and then again at 7.30am. The Benmore prices at these times were $290/MWh and $341/MWh, and the Ōtāhuhu prices were $343/MWh and $405/MWh respectively. During the first of these trading periods demand was around 100MW higher than forecast (50MW in both islands), and the second spike occurred when South Island demand was close to 50MW higher than forecast. There was also under 200MW of wind generation at this time.

2.7. The third price highlighted on the graph was an overnight price at Ōtāhuhu which was around $4/MWh above the 90th percentile. This high overnight price occurred whilst temperatures were low, wind was lower than forecast by around 77MW, and thermal peakers were running continuously overnight. There have been several instances of higher overnight prices this week, especially on Sunday and Tuesday. This is consistent with declining hydro storage.

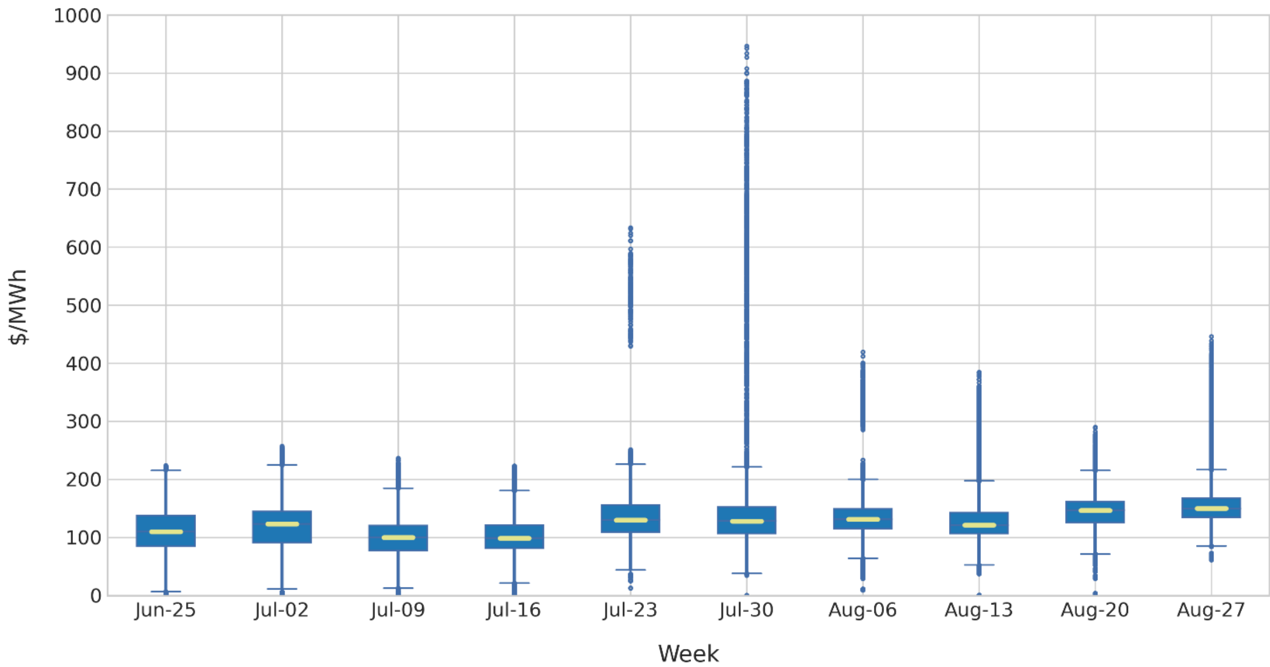
Figure 1: Wholesale Spot Prices between 27 August (Sunday) and 2 September (Saturday) 2023



2.8. 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% 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 spot prices remains small with the middle 50% of prices in the range of $134/MWh to $167/MWh. There were a few outliers given the small IQR, which were the price spikes seen on Tuesday and Wednesday morning. Some of the 5-minute prices during these price spikes went above $300/MWh. Overall, the distribution is showing a slight elevation in prices compared to recent weeks which could be due to the declining hydro storage and increasing thermal costs.

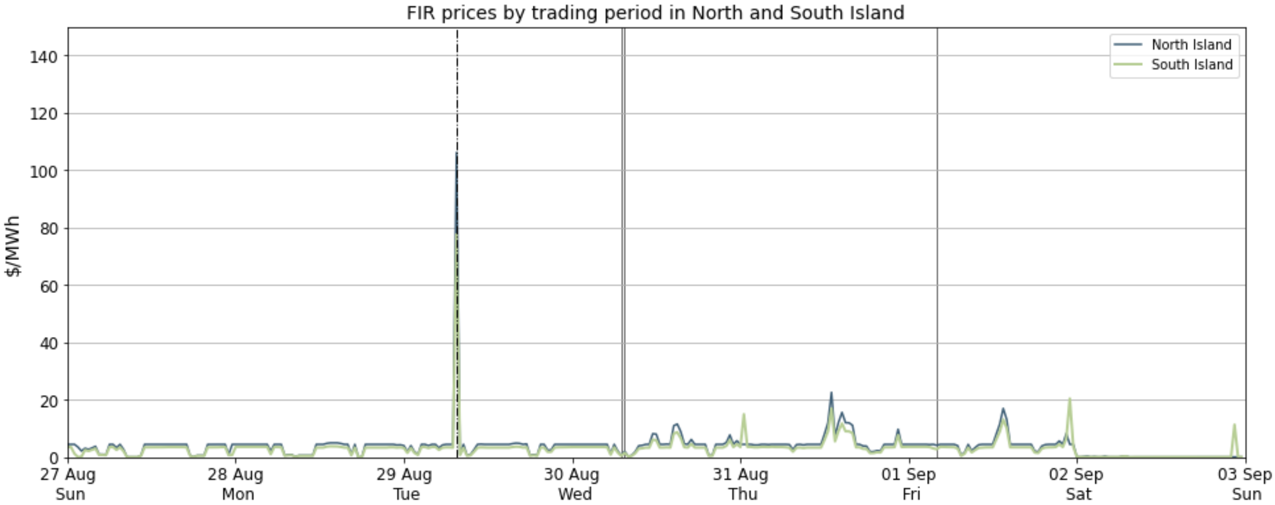
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve Prices

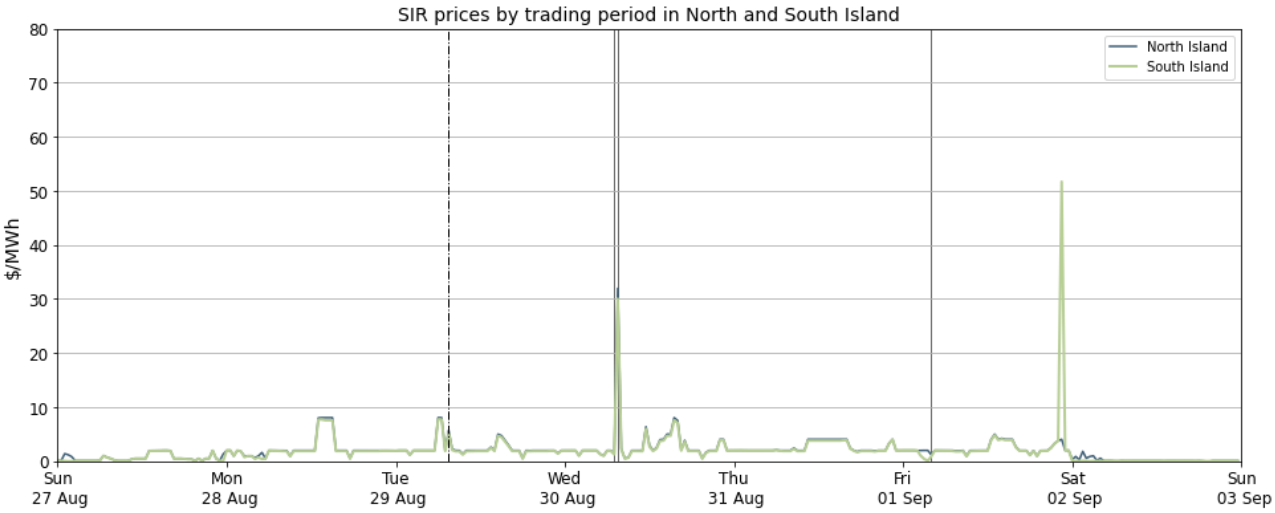
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were mostly below $10/MWh for both islands. There was a spike in FIR prices in both islands at 7.30am on 29 August, where the North Island price reached $106/MWh and the South Island price reached $78/MWh. This coincided with the price spike in spot prices during a period of higher demand.

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 $10/MWh this week. There were a couple of spikes where SIR price went above $30/MWh. The first instance of this was during the 7.30am trading period on Wednesday where the North Island price was $32/MWh, and the South Island price was $30/MWh. The biggest SIR spike occurred on Friday evening at 10.30pm, where South Island SIR reached around $52/MWh. The spike on Friday occurred due to a change in flow direction on the HVDC which caused a binding risk meaning more reserve was required for the South Island in this trading period.

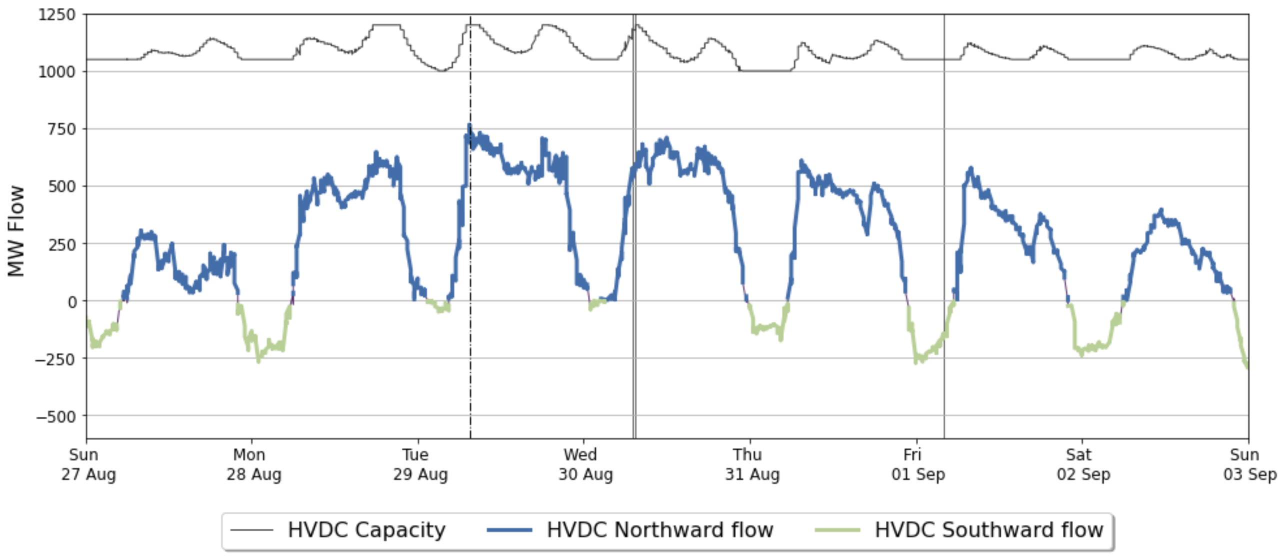
Figure 4: Sustained instantaneous reserve (SIR) prices by trading period and Island



4. HVDC

4.1. Figure 5 shows HVDC flows between 27 August – 2 September. HVDC flows were mainly northwards with some overnight southward flow. Northward flow was mainly below 750MW except for on Tuesday morning where it reached around 766MW during the 7.30am trading period. Southward overnight flow was a bit higher than we have seen in recent weeks with the maximum flow southwards going above 250MW on a few occasions.

Figure 5: HVDC northward flow and capacity



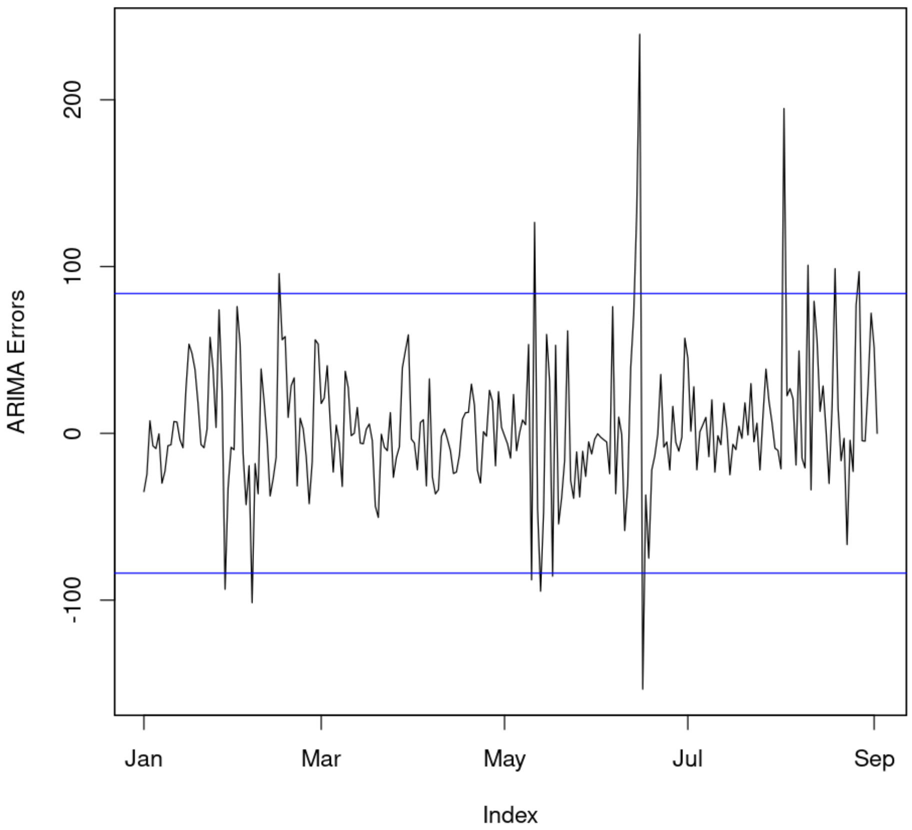
5. Regression Residuals

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. 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 was one residual above two standard deviations, indicating prices on Sunday were higher than the model expected. This is likely due to higher overnight prices which reflect higher overnight hydro offers, as generators aim to conserve more water.

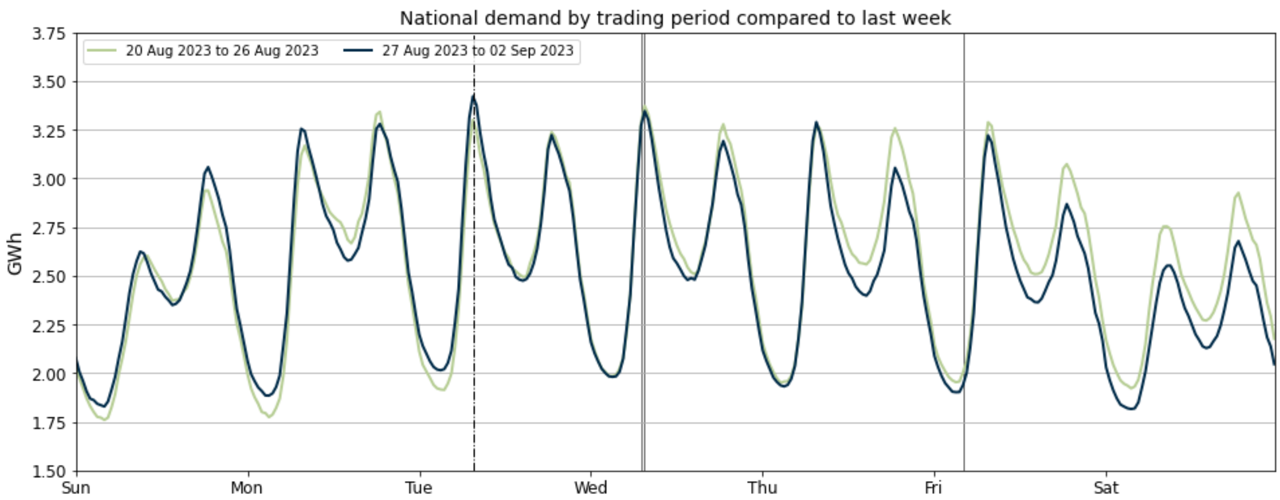
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 - 2 September 2023. The blue lines show 2 standard deviations of the ARMA errors.



6. Demand

6.1. Figure 7 shows national demand between 27 August – 2 September, compared to the previous week. Overall, demand was similar to the previous week with higher morning peaks than evening peaks. The evening peak demand dropped in the second half of the week as milder weather conditions hit the country. Instances of higher than forecast demand occurred during some of the colder mornings, which likely contributed to the Wednesday price spikes.

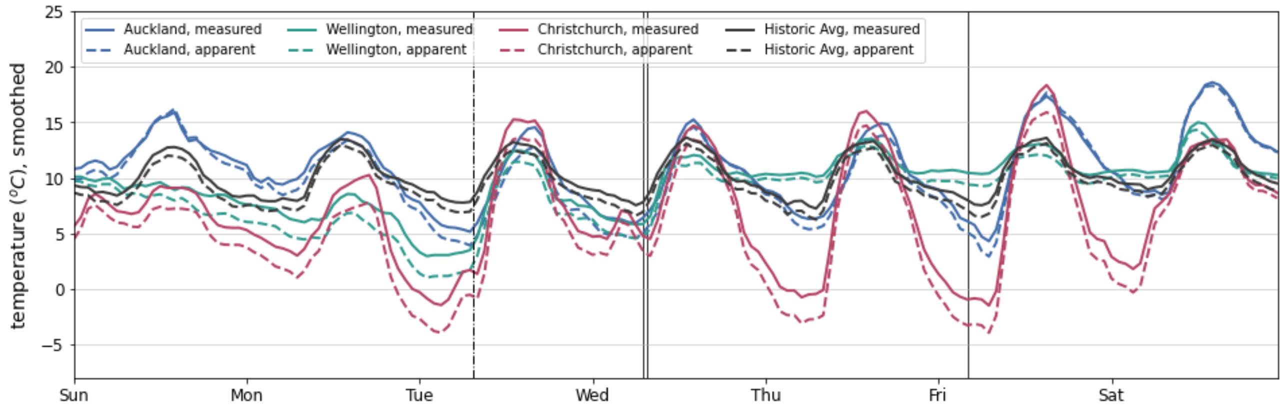
Figure 7: National demand by trading period compared to the previous week.



6.2. Figure 8 shows the hourly temperature at main population centres from 27 August – 2 September. 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 cooler at the beginning of the week, particularly on Tuesday morning where most regions saw apparent temperatures below 5 degrees. In general, Auckland temperatures were mostly on or above average. Wellington saw temperatures consistently below average at the start of the week, before lifting to range between 10 -14 degrees for the second half of the week. Christchurch saw a big range in apparent temperatures across the week from around -4 degrees to 16 degrees.

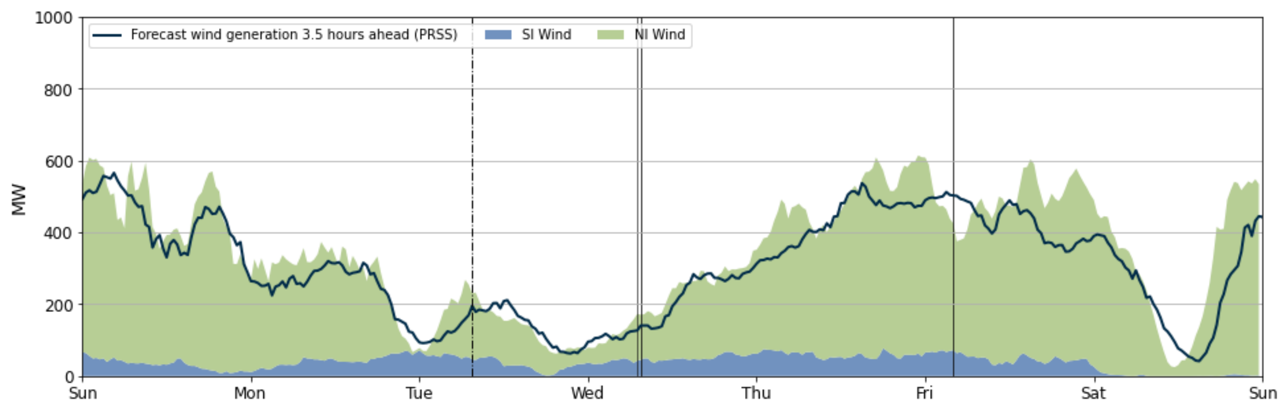
Figure 8: Temperatures across main centres



7. Generation

7.1. Figure 9 shows wind generation, from 27 August – 2 September. Wind generation varied across the week ranging between 25MW and ~600MW. The price spikes on Tuesday and Wednesday morning occurred during some of the lower wind generation periods this week, although in both instances wind generation was slightly higher than forecast.

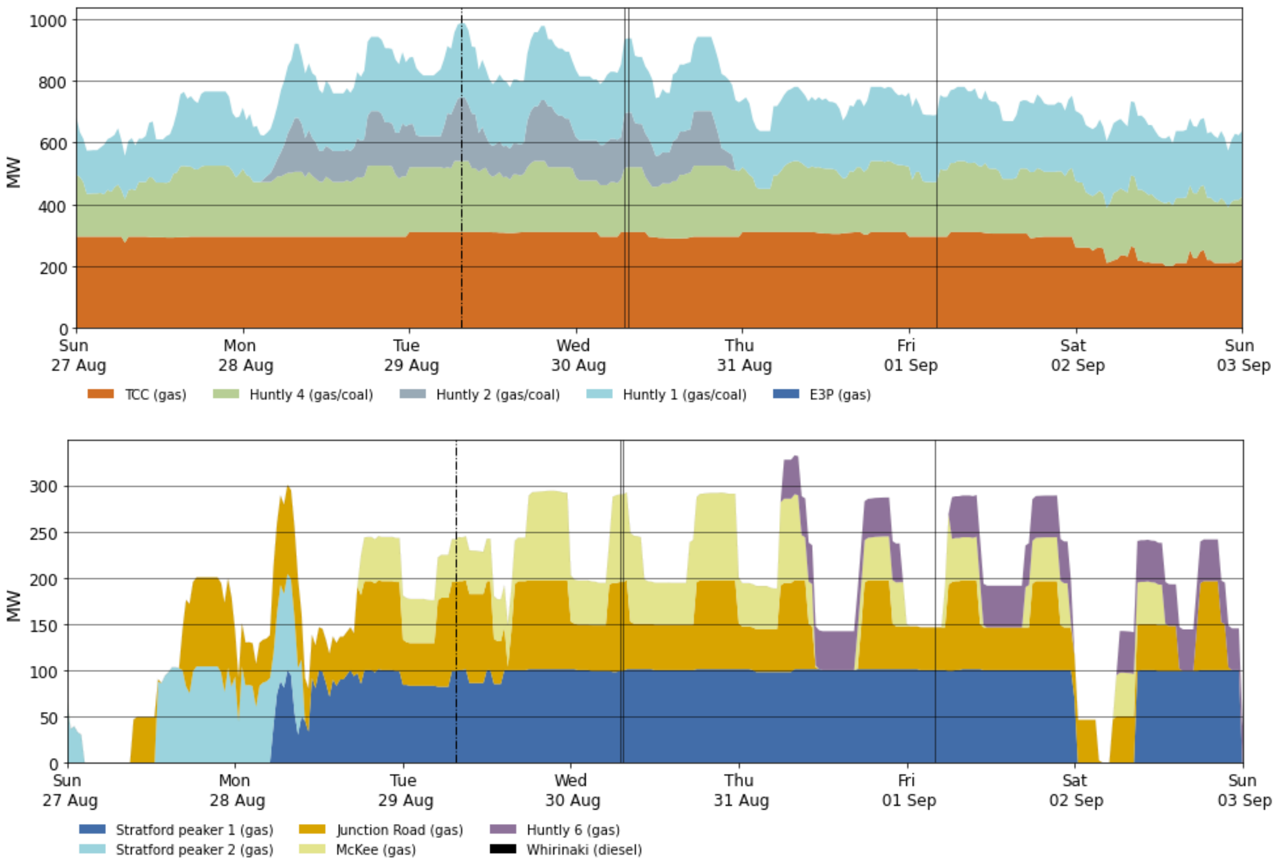
Figure 9: Wind generation and forecast



7.2. Figure 10 shows the generation of thermal baseload and thermal peaker plants between 27 August – 2 September. TCC continues to run as continuous baseload with the Huntly Rankines in support. Huntly 2 ran from Monday through Wednesday, with Huntly 1 and 4 running all week. The three days with all 3 Rankines running coincided with the colder days last week when demand was highest.

7.3. A number of the peaker units ran for continuous periods this week. Before going on outage Stratford 2 ran from around midday on Sunday through to the end of the Monday morning peak. Stratford 1 ran from the Monday morning peak continuously until around midnight Friday before coming on again late morning on Saturday. Junction road also had continuous generation from Sunday through to Thursday late morning. It then came back on for the Thursday evening peak and ran until early Saturday, going off shortly and then running for the rest of Saturday. McKee also ran most days with continuous generation from the Monday evening peak until around Thursday midday. Huntly 6 ran over the peak and shoulder periods from Thursday to Saturday.

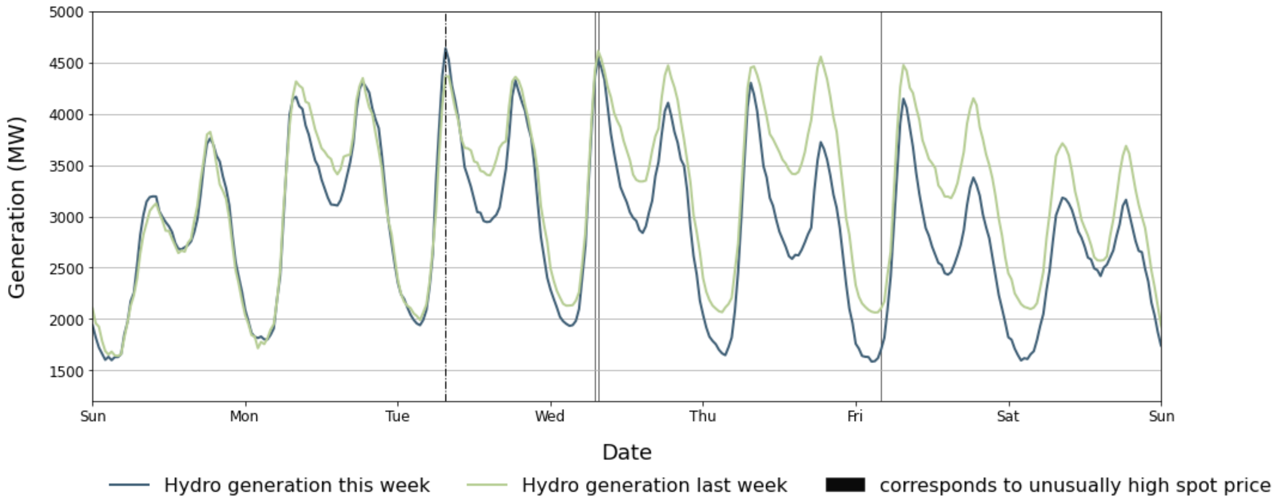
Figure 10: Thermal generation



7.4. Figure 11 shows hydro generation between 27 August – 2 September. Generation from hydro has been decreasing coinciding with the decline in storage. The early part of the week saw similar peak generation to the previous week, with a noticeable decrease during the shoulder periods. In the latter half of the week there was also a noticeable decrease during the evening peak periods. This overall drop in hydro generation reflects the increasing need to reduce outflow from storage lakes as many continue to decline. Some regions are also anticipating a dry start to spring (see latest NIWA Outlook[1]).

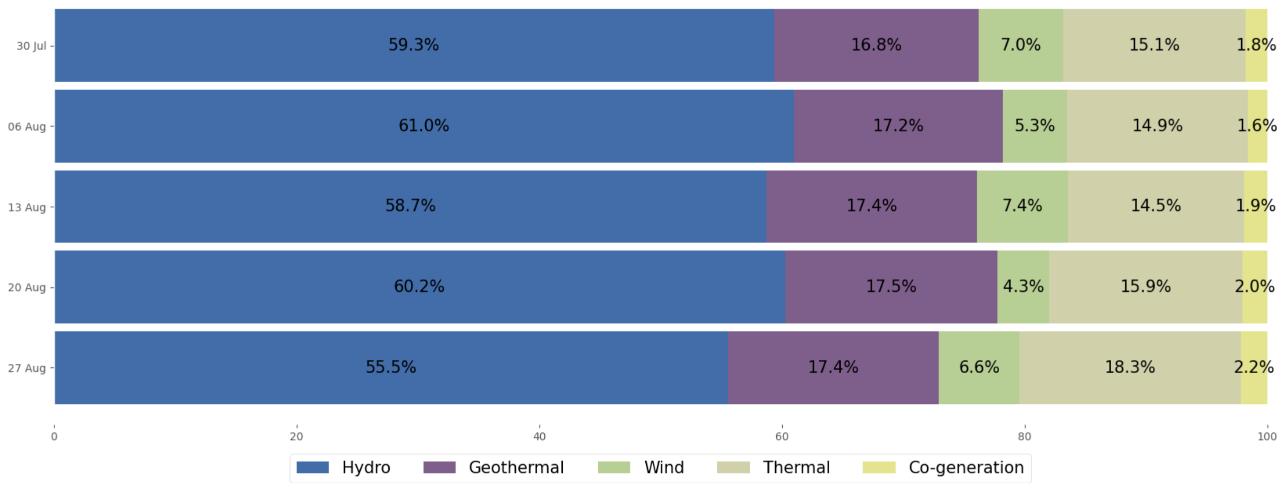
[1] Seasonal climate outlook September-November 2023 | NIWA

Figure 11: Hydro generation



7.5. As a percentage of total generation, between 27 August – 2 September, total weekly hydro generation was 55.5%, geothermal 17.4%, wind 6.6%, thermal 18.3%, and co-generation 2.2%.

Figure 12: Total generation as a percentage each week between 30 July and 2 September 2023.



8. Outages

8.1. Figure 13 shows generation capacity on outage. Total capacity on outage between 27 August – 2 September ranged from ~990 MW to 1680 MW.

8.2. Notable outages include:

a) Huntly 5 remains on outage until 20 May 2024.

b) Huntly 2 was on outage from 30 August (11pm) to 2 September.

c) Stratford 2 is on outage from 28 August 2023 – 28 February 2025.

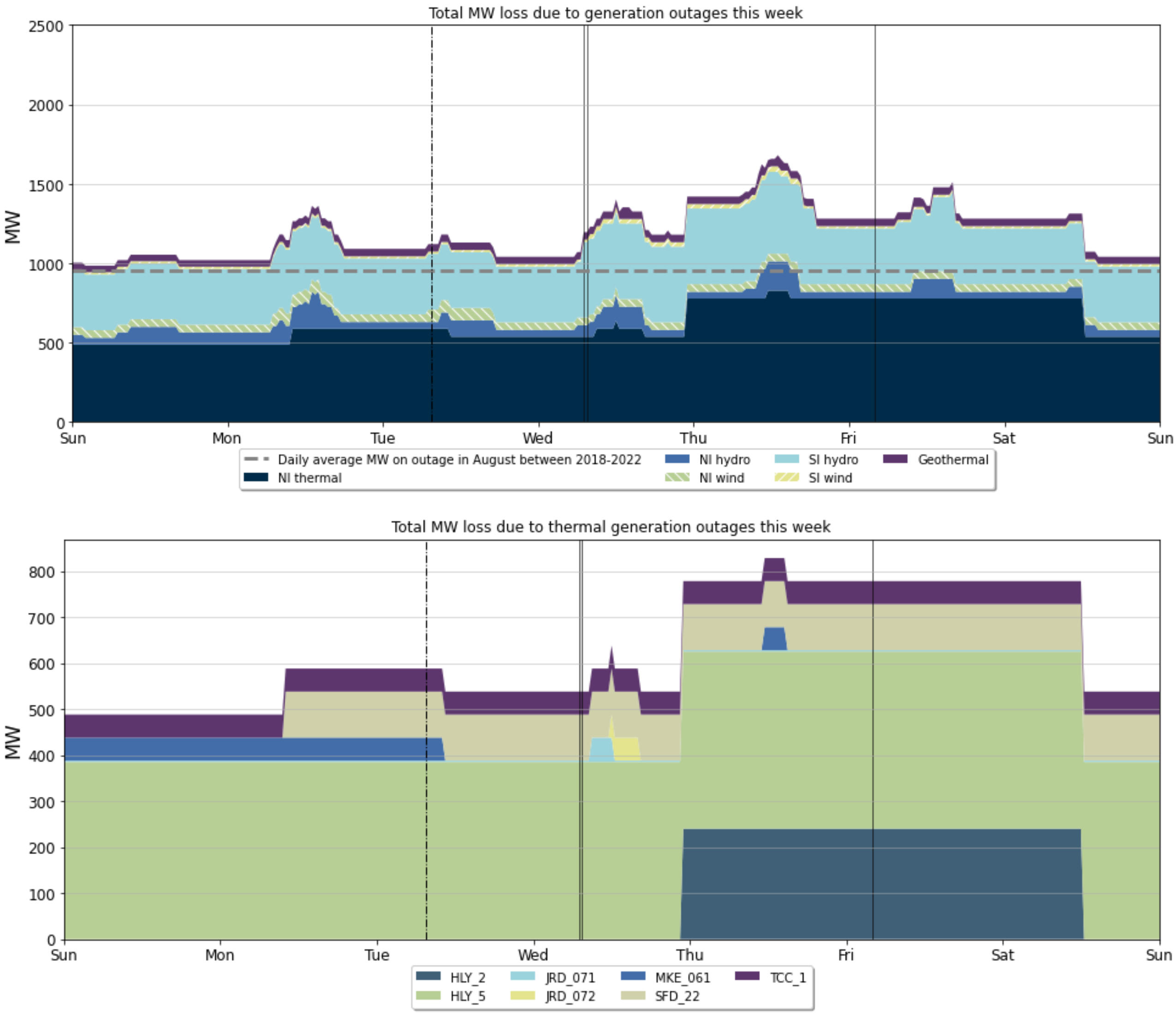
d) McKee was on outage from 25 - 29 August.

e) Junction Road was on outage on 30 August (one unit out in the morning and the other in the afternoon.)

f) Various North and South Island Hydro remain on outage.

g) West Wind Station is on outage until 24 November (44MW).

Figure 13: Total MW loss due to generation outages.



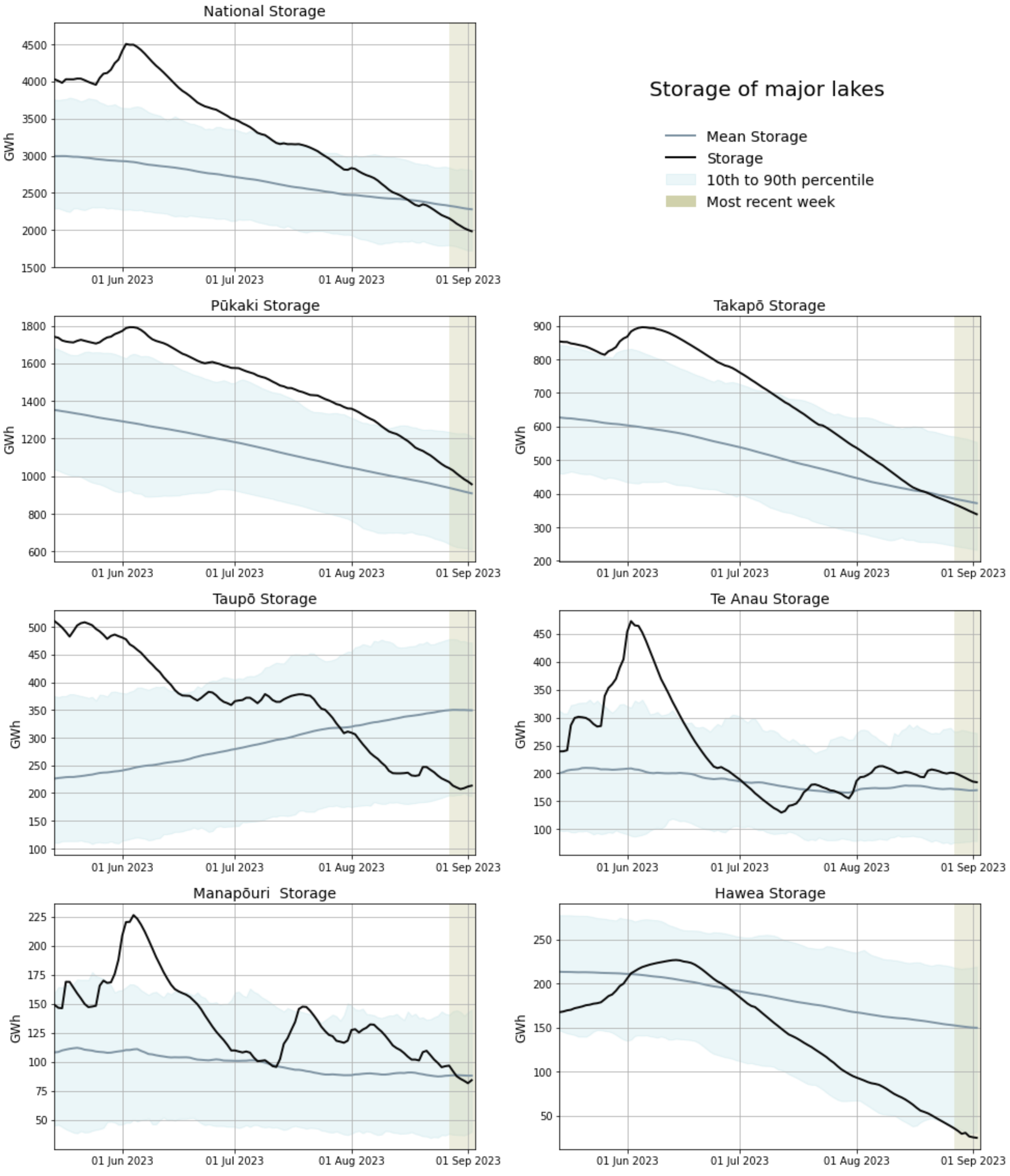
9. Storage/Fuel Supply

9.1. Figure 14 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.

9.2. National hydro storage levels continue to decline with controlled storage now 53.8% of nominally full and around 91% of the historic mean.

9.3. Pūkaki continues to steadily decrease but remains above its historic mean. Takapō is currently below its historic mean and is showing less of a steep decline compared to previous weeks. Taupō storage is currently close to its historic 10th percentile and after continuing to decrease at the start of the week, had a slight increase in the latter part of the week. Hawea storage has continued to decrease and is now around the historic 10th percentile. Manapōuri storage decreased and storage now sits just below the historic mean. Te Anau storage has been generally steady with only a small decrease this week and remains just above its historic mean.

Figure 14: Hydro storage

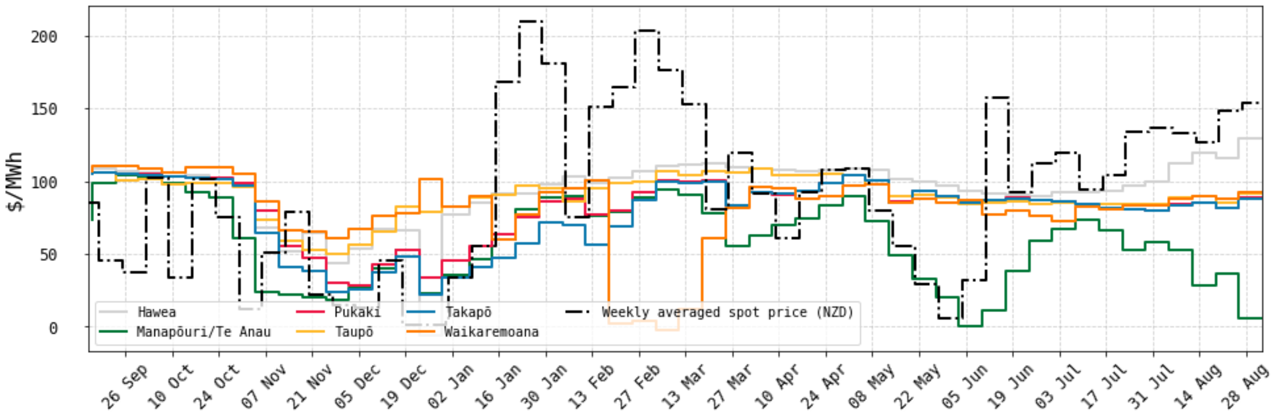


10. JADE Water Values

10.1. 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 15 shows the national water values between 15 September 2022 and 2 September 2023 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.

10.2. Water values for most lakes slightly increased, with only Hawea and, Manapōuri and Te Anau seeing any significant changes. Hawea water values have increased around $14/MWh compared to the previous week as its lake levels continue to decline. Manapōuri and Te Anau water values dropped below $10/MWh, possibly due to unit outages at Manapōuri.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 2 September 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 16 shows an estimate of thermal SRMCs as a monthly average up to 1 September 2023. The SRMC of diesel plants has been increasing since May, and the SRMC of coal-fuelled plants has started to increase again, with gas-fuelled plants continuing to decrease slightly. An increase in carbon prices has contributed to the increase in the diesel and coal fired plant SRMCs, while a reduction in gas prices has curtailed this increase in gas plant SRMCs.

11.4. The latest SRMC of coal-fuelled Huntly generation is ~$168/MWh. With two or three Rankines often running simultaneously this winter Genesis has been using more coal recently.

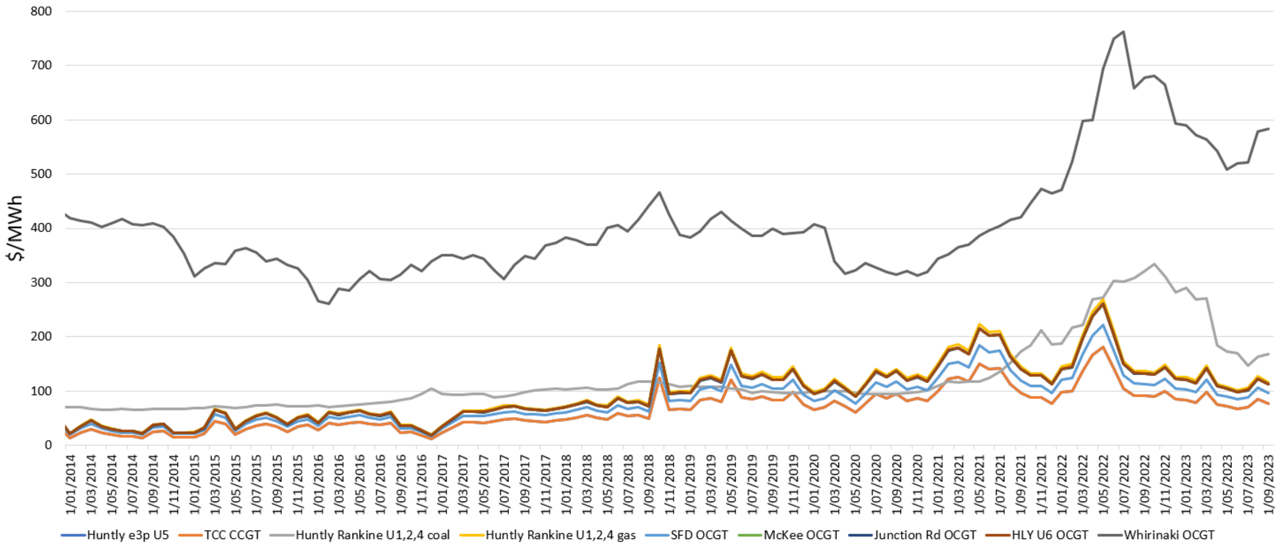
11.5. The SRMC of Whirinaki has increased to ~$583/MWh.

[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.

11.6. The SRMC of gas fuelled thermal plants is currently between $78/MWh and $116/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C on the trading conduct webpage. This appendix was recently updated to reflect the changes made to coal price indices by the Indonesian government. These changes have had the effect of decreasing the coal SRMC from April 2023.

Figure 16: Estimated monthly SRMC for thermal fuels

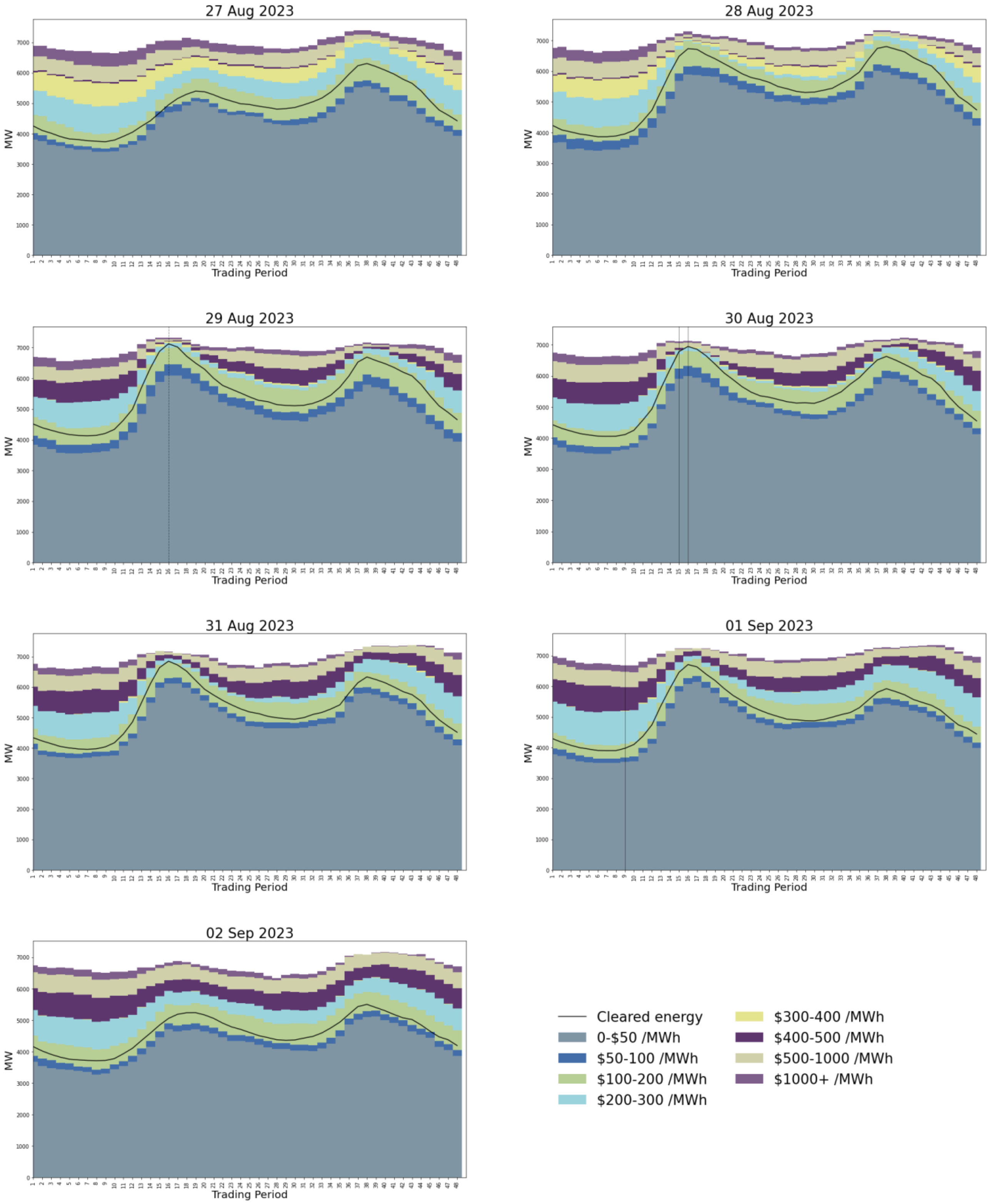


12. Offer Behaviour

12.1. Figure 17 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Through the week most generation cleared in the $100-$200/MWh price range. However, there were a few trading periods where generation cleared in the $200-$400/MWh offer price range which resulted in the Tuesday and Wednesday morning price spikes.

Figure 17: 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.
13/06/2023	14-16	Further Analysis	Genesis	Takapō	Offer changes.
14/06/2023	15-17	Further Analysis	Genesis	Multiple	High energy prices associated with high energy offers.
15/06/2023	15-19	Further Analysis	Genesis and Contact	Multiple	High energy prices associated with high energy offers.