Date: 21 August 2023

ELECTRICITY AUTHORITY
TE MANA HIKO

TRADING CONDUCT REPORT

Market Monitoring Weekly Report

TRADING CONDUCT REPORT

1. Overview for week of 13 – 19 August 2023

1.1. Over the week, prices mainly remained above the historical average. There were no price spikes above the 90th percentile range but there were a few that came close to it. The first instance of price spikes was during the Tuesday morning peak with the next occurring during Wednesday's shoulder period. These price spikes were driven by higher than forecast demand occurring alongside drops in wind generation. The proportion of weekly electricity generation from hydro was slightly lower than the previous week as hydro storage continues to decline. National controlled storage is 99.5 percent of historic mean as of 19 August.

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 13 – 19 August:

a) The average wholesale spot price across all nodes was $130/MWh.

b) 95 percent of prices fell between $78/MWh and $200/MWh.

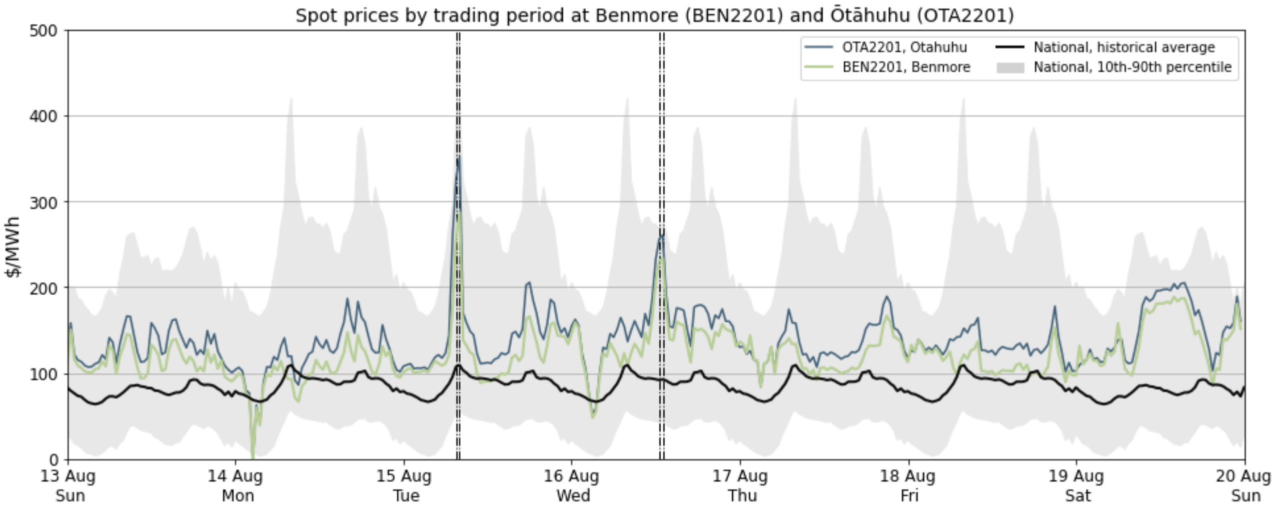
2.4. Spot prices this week generally fell below $200/MWh but hovered above the historic average, with the mean price only $4/MWh lower than the previous week. There was a continuous $20-$30/MWh price separation with Ōtāhuhu prices higher than Benmore as well as a few spikes above $200/MWh but below 90th percentile during this week.

2.5. On 15 August during the 7.30am and 8.00am trading periods there were price spikes close to the 90th percentile. Prices at Ōtāhuhu were $326.37/MWh and $351.68/MWh, whilst Benmore prices at these times were $258.78/MWh and $287.27/MWh. Demand was under forecast for both trading periods with the 7.30am trading period under forecast by around 150MW. There was also lower wind generation than had been expected.

2.6. The other higher prices this week occurred during Wednesday's shoulder period where again demand was higher than had been expected. Actual wind generation was also approximately 200MW lower than forecast. At 12.30pm the price at Ōtāhuhu was $255.90/MWh and the price at Benmore was $230.61/MWh. The following trading period saw prices at these nodes increase slightly with the Ōtāhuhu price at $260.52/MWh and the Benmore price $233.72/MWh.

2.7. There was also a period on Saturday between 10.00am and 4.00pm where prices were between ~$170/MWh and ~$200/MWh. The demand across the shoulder period was higher than the previous week, with demand also higher than forecast. Huntly 2 was on outage and several thermal peaker units were running to meet the increased demand along with an increase in hydro generation.

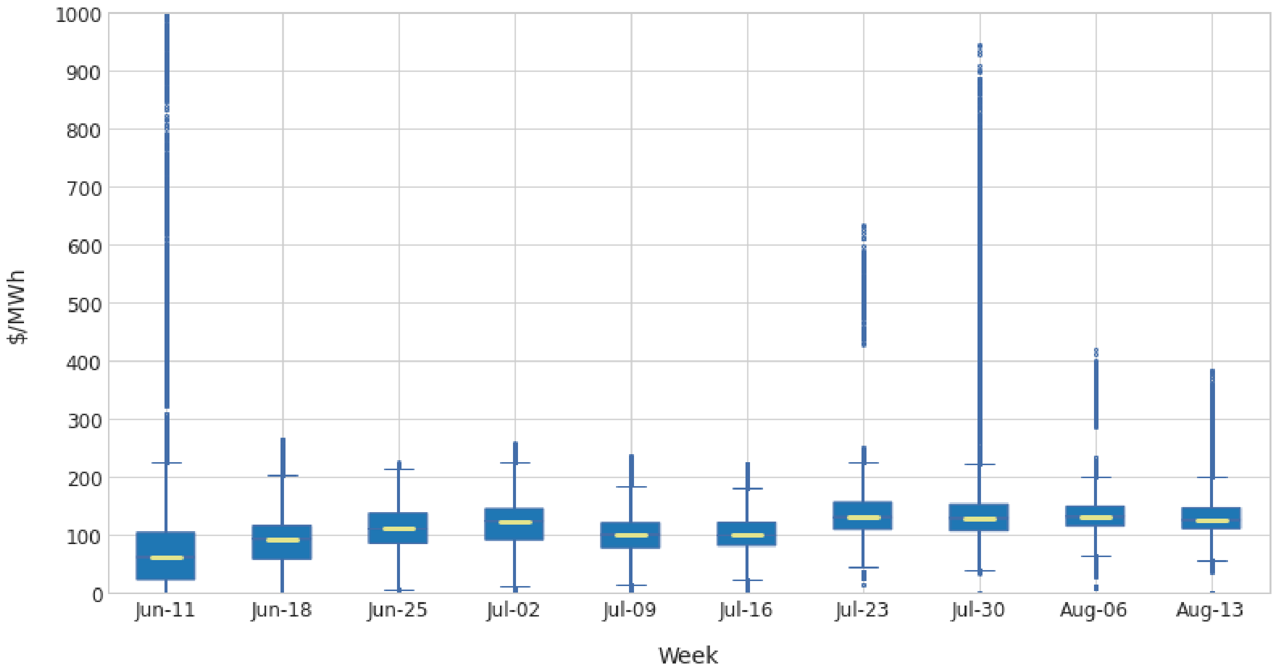
Figure 1: Wholesale Spot Prices between 13 August - 19 August 2023



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 percent of prices fell). The "whiskers" extend to points that lie within 1.5 times the <u>inter-quartile range (IQR)</u> of the lower and upper quartile, and then observations that fall outside this range are displayed independently.

2.9. The distribution of spot prices for last week was in a similar region to the previous week with a median price of around $125/MWh compared to $131/MWh the previous week. The middle 50 percent of prices were within $110/MWh and $146/MWh, similar to previous weeks through the end of July and into August. This continued condensed IQR distribution saw some outliers occurring, but all were below $400/MWh.

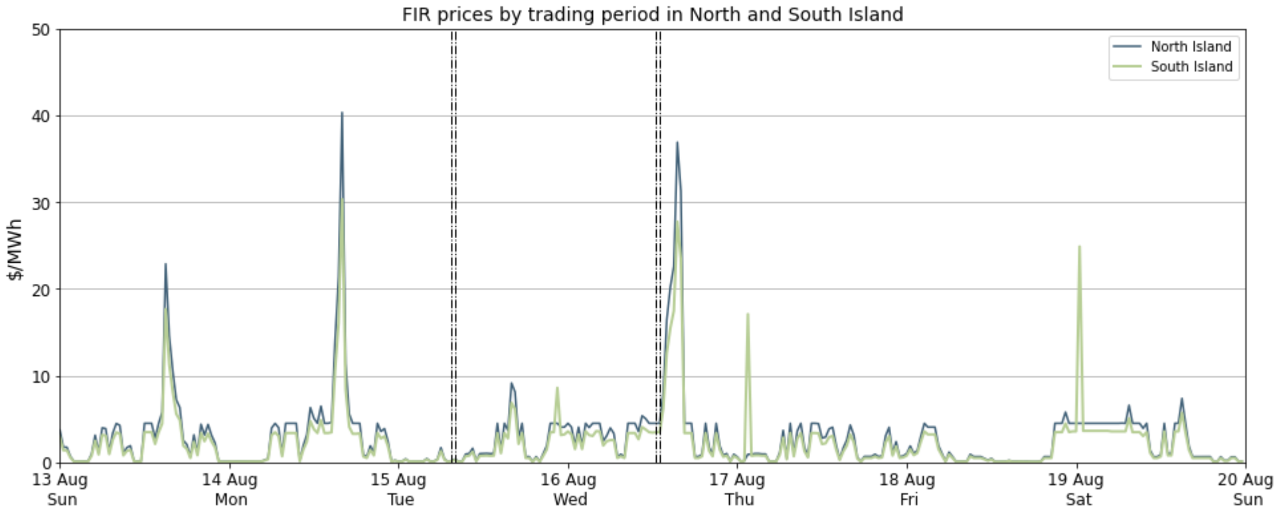
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve Prices

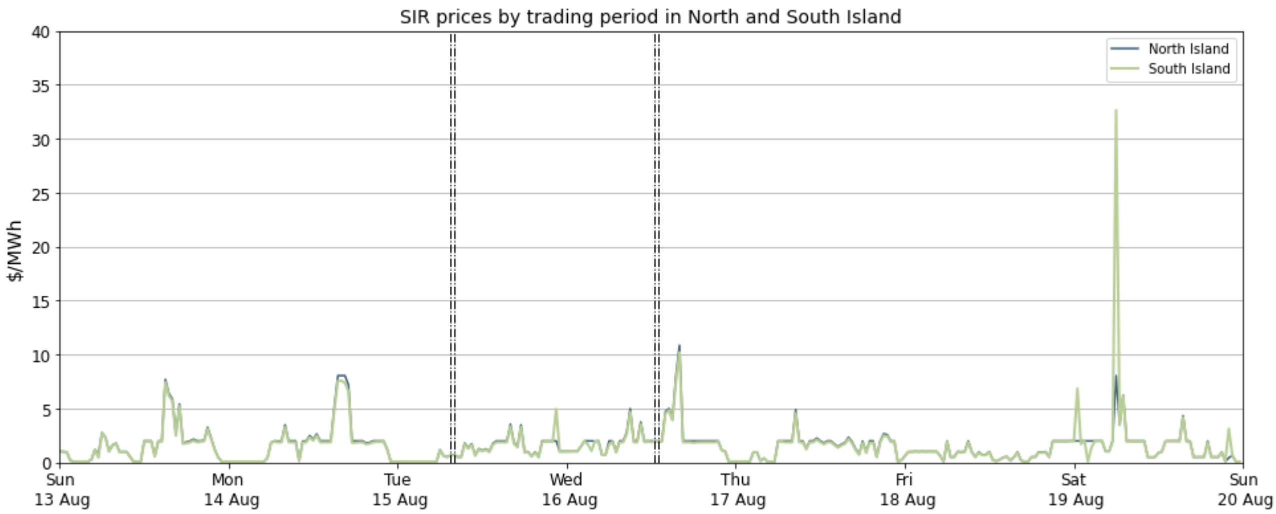
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were mostly under $20/MWh for both islands. There were a few spikes that occurred, the highest was on 14 August at 4.00pm where North Island FIR was $40/MWh and South Island FIR was $30/MWh. There was also a spike on 16 August where North Island FIR was $37/MWh and South Island FIR was $23/MWh. Both times the increase in FIR prices coincided with an increase in reserve requirements, resulting in higher prices.

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 with only one significant spike in South Island SIR of around $33/MWh. The North Island SIR price at this time remained below $10/MWh.

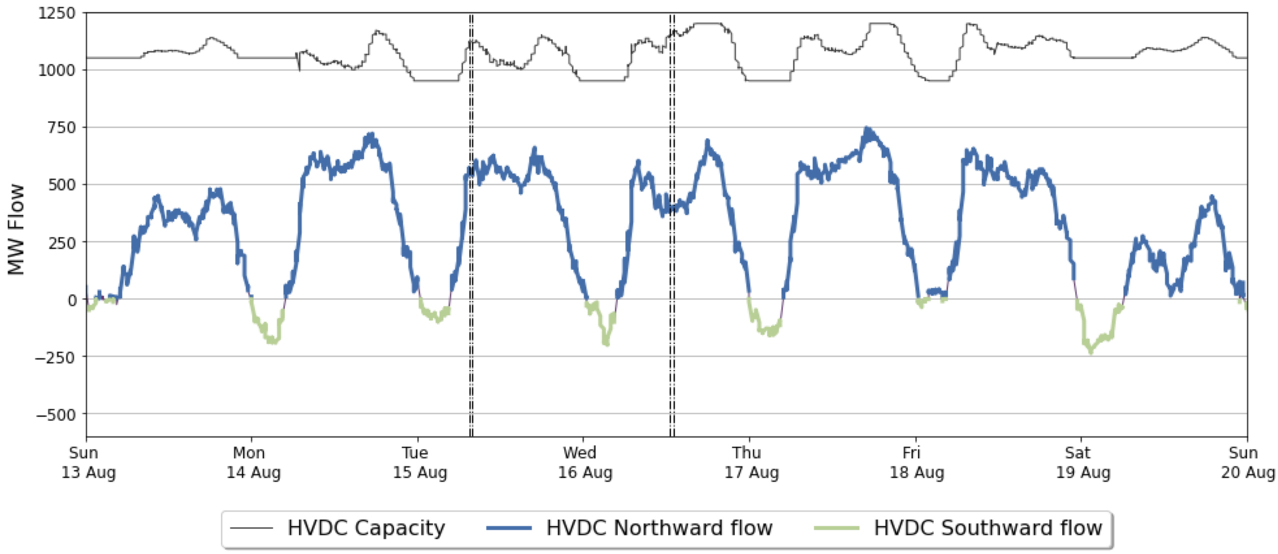
Figure 4: Sustained instantaneous reserve (SIR) prices by trading period and island.



4. HVDC

4.1. Figure 5 shows HVDC flow between 13 – 19 August. HVDC flows were northwards during the day with some southward flow overnight. Northward flow was below 750 MW and well below capacity limits, with the maximum southward flow of around 240 MW.

Figure 5: HVDC northward flow and capacity.



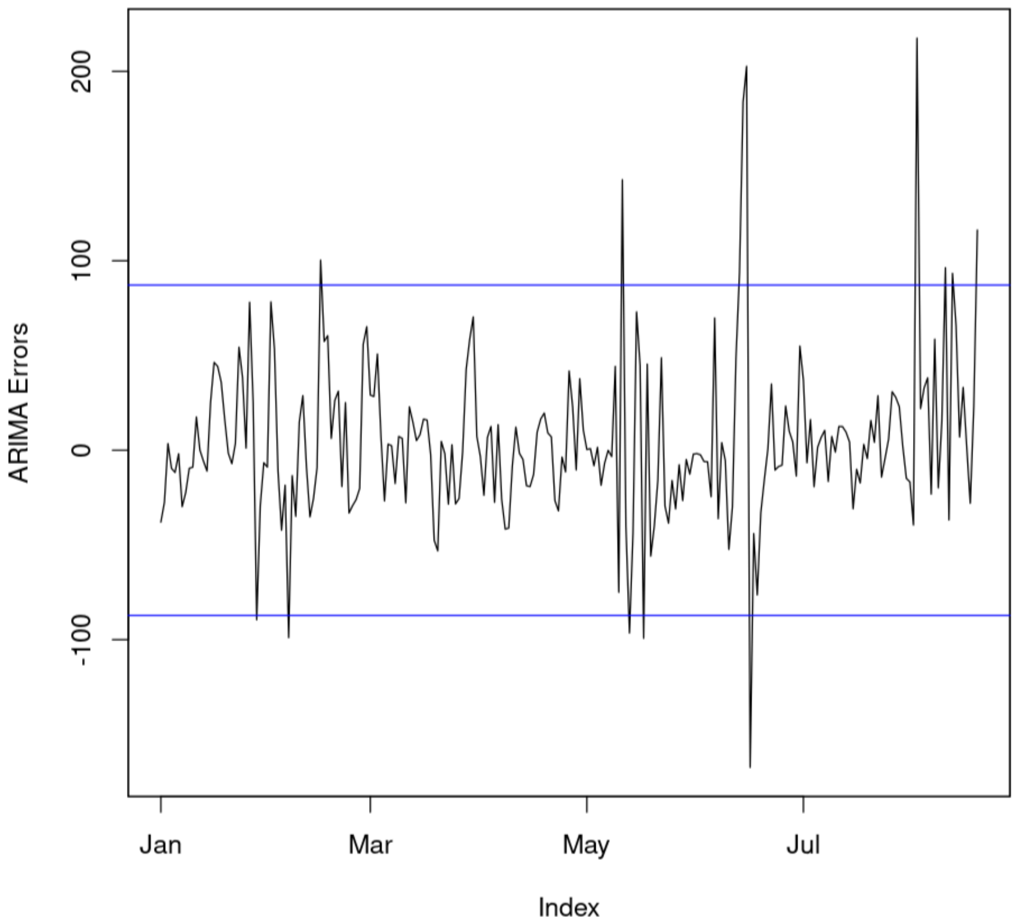
5. Regression Residuals

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 only one residual was two standard deviations above, showing prices on Saturday were higher than the model predicted. This was analysed further and found to be likely due to conditions not captured by the model as it only captures average conditions for each day. Overall, demand was lower than the previous day, which the model expects to reduce prices. However, demand stayed elevated during the shoulder periods and was higher than forecast, which resulted in prices remaining elevated for most of the day and increased the average daily price. All other prices in the model fell within two standard deviations of the mean.

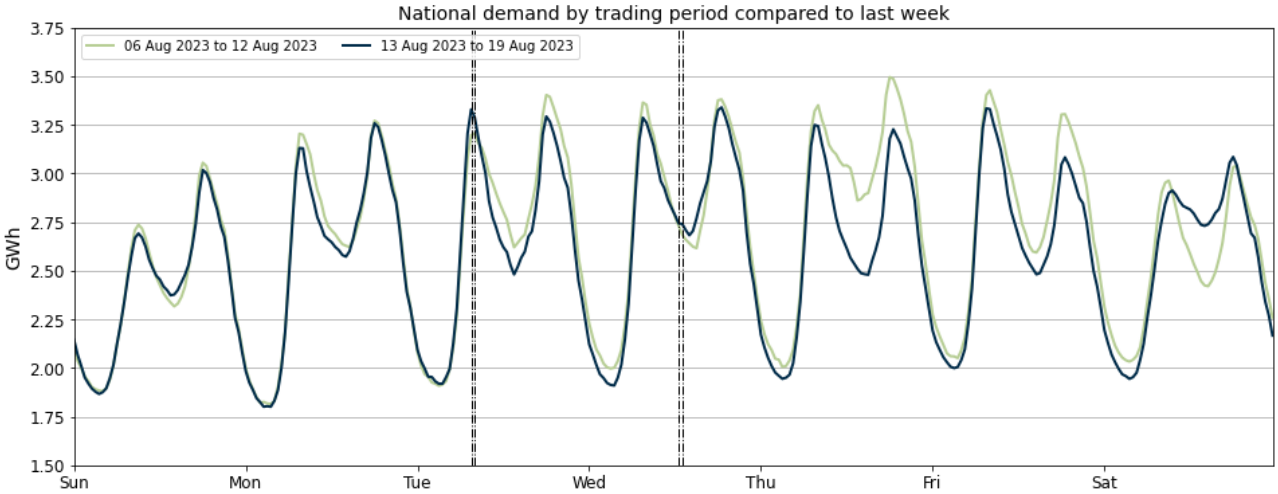
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 to 19 August 2023. The blue lines show two standard deviations of the ARMA errors.



6. Demand

6.1. Figure 7 shows national demand between13 – 19 August, compared to the previous week. Overall, demand was lower than the previous week, particularly during Thursday and Friday's peak periods, due to milder weather conditions. However, Tuesday morning peak saw slightly higher demand than the previous week as well as the shoulder period on Saturday.

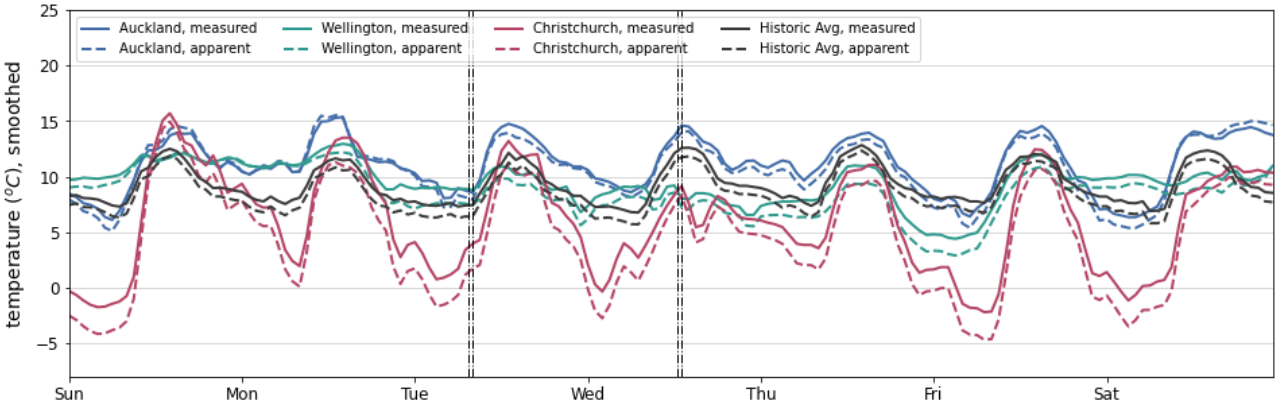
Figure 7: National demand by trading period compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 13 -19 August. 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. Temperature in Auckland was mainly on or above average with apparent temperatures ranging between 5 and 15 degrees. Wellington temperatures were mainly around historic average, although Friday morning apparent temperatures dipped to around 3 degrees. Christchurch temperatures were variable, with morning apparent temperatures reaching close to -5 degrees.

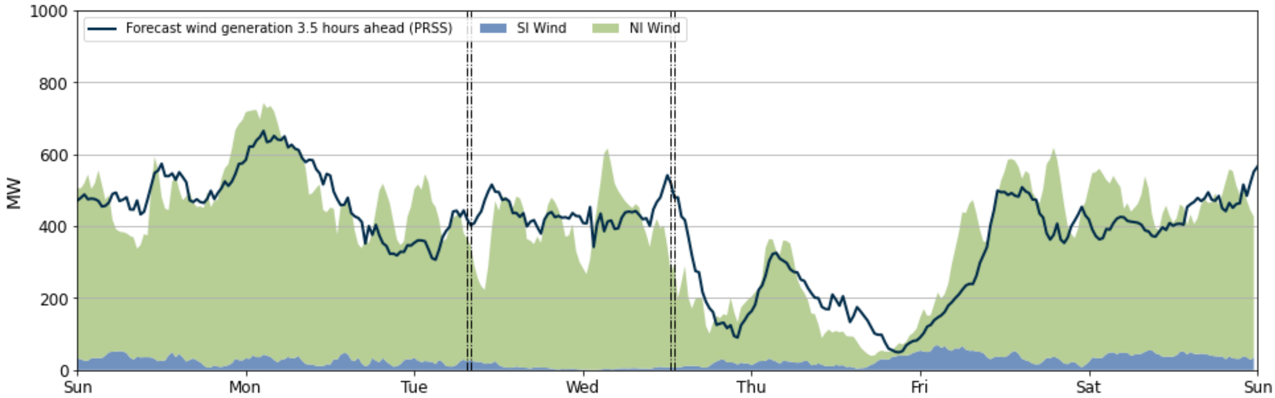
Figure 8: Temperatures across main centres



7. Generation

7.1. Figure 9 shows wind generation, from 13 – 19 August, varied from around 40 MW to 740 MW across the week. Both instances of price spikes this week occurred when wind generation dropped unexpectedly resulting in a significant difference between forecast and actual wind generation. On average, wind generation was slightly higher compared to the previous week.

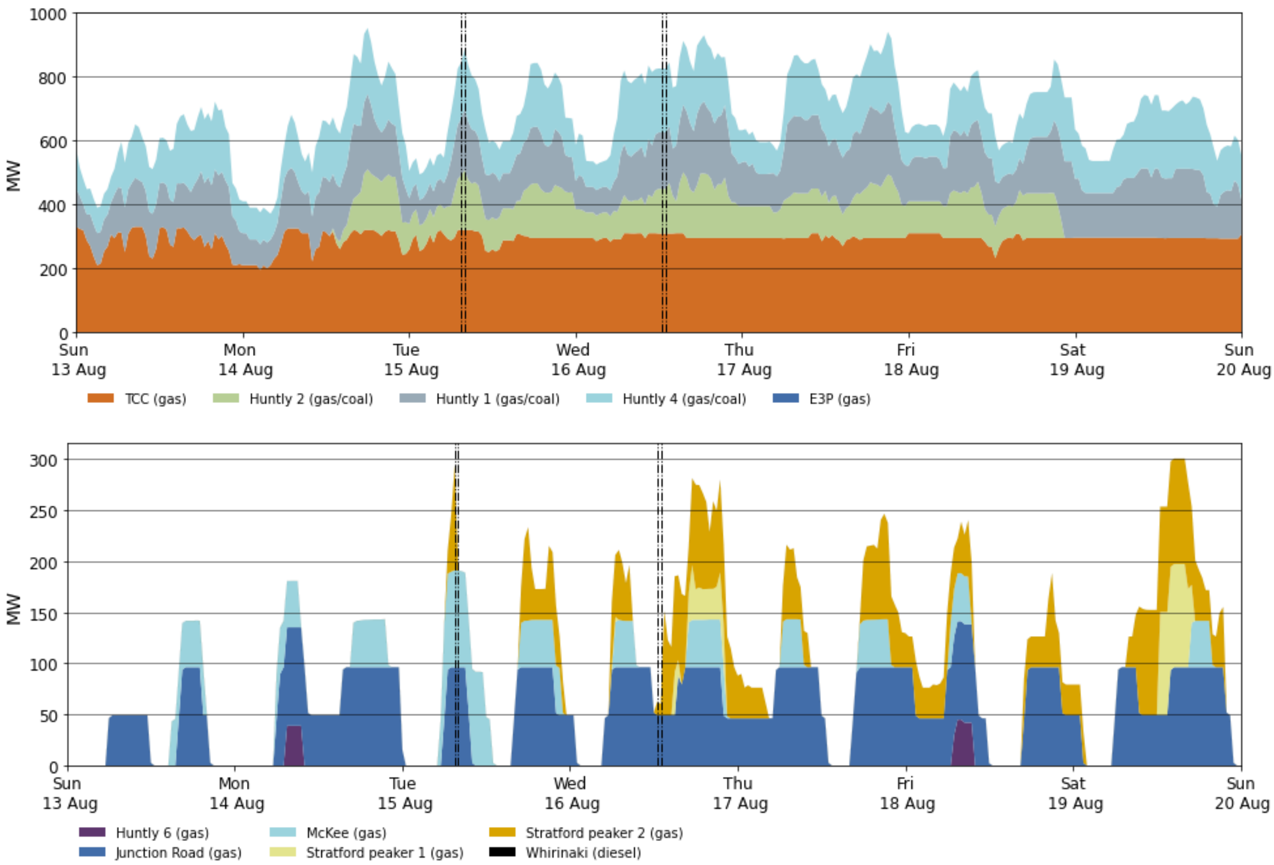
Figure 9: Wind generation and forecast



7.2. Figure 10 shows the generation of thermal baseload and thermal peaker plants between 13 – 19 August. During the working week from early Monday afternoon, TCC along with all three Rankine units ran as baseload. Sunday and Saturday only Huntly 1 and Huntly 4 ran with TCC, as Huntly 2 went on outage over the weekend.

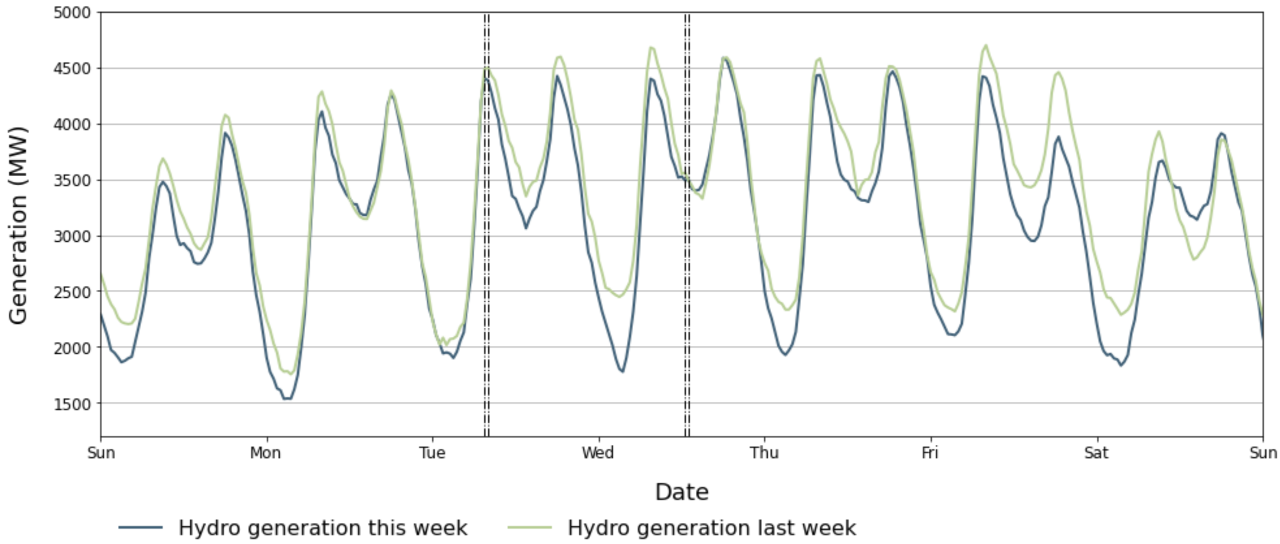
7.3. Junction Road ran every day, sometimes running over the shoulder period as well as the peaks. McKee covered peak periods from Sunday afternoon to Friday morning and then again on Saturday afternoon. Huntly 6 only ran during the Monday and Friday morning peaks. Stratford 1 only ran during the Wednesday and Saturday evening peaks, with Stratford 2 covering the peak periods from Tuesday morning through to Saturday. Stratford 2 also ran continuously from around midday Wednesday to early Thursday morning before coming on again in the morning peak, as well as running over the shoulder period on Friday and Saturday. This was likely covering the drop off in wind generation that occurred.

Figure 10: Thermal generation



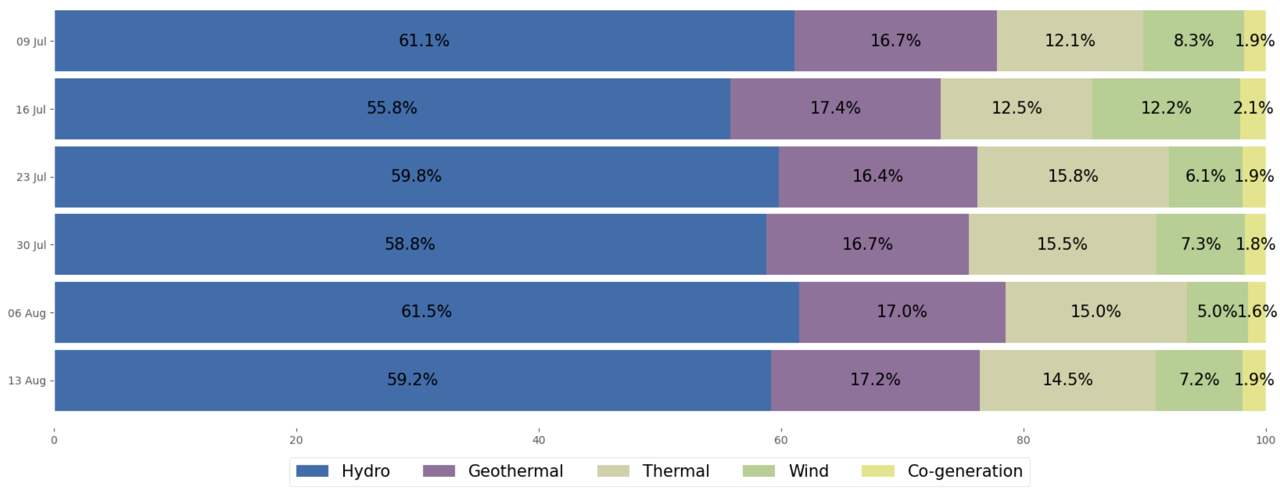
7.4. Figure 11 shows hydro generation between 13 – 19 August. Overall, there was less generation from hydro compared to the previous week. Monday and Wednesday evening peaks saw similar amounts of hydro generation to the previous week, whereas during most other peaks hydro generation was lower. The shoulder period on Saturday saw an increase to hydro generation compared to the previous week in line with higher than forecast demand during this period.

Figure 11: Hydro generation between 13 - 19 August compared to the previous week



7.5. As a percentage of total generation, between 13 – 19 August 2023, total weekly hydro generation was 59.2 percent, geothermal 17.2 percent, thermal 14.5 percent, wind 7.2 percent, and co-generation 1.9 percent. The proportion of hydro and thermal generation dropped slightly this week likely due to the small increase in wind generation along with overall lower demand.

Figure 12: Total generation as a percentage each week between 9 July and 19 August 2023



8. Outages

8.1. Figure 13 shows generation capacity on outage. Total capacity on outage between 13 – 19 August 2023 ranged between ~900 MW and ~1500 MW.

8.2. Notable outages include:

a) Huntly 5 remains on outage until May 2024.

b) Huntly 2 was on outage from 18 – 21 August.

c) Huntly 6 was on outage from 16 – 17 August.

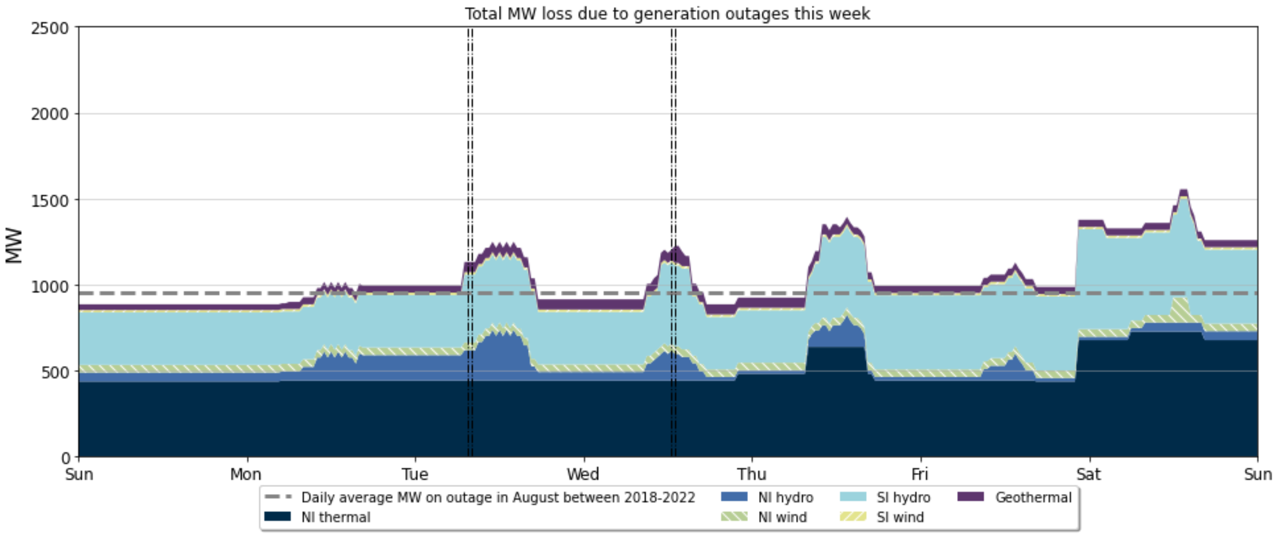
d) Whirinaki station was on outage 17 August.

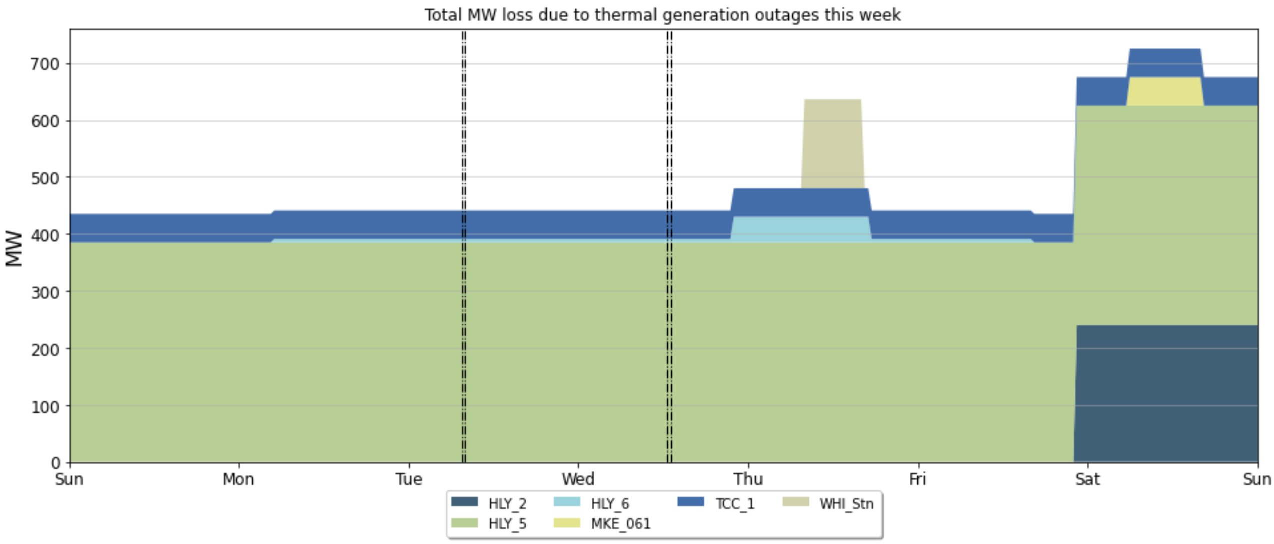
e) West Wind station is on a partial outage until 24 November.

f) Turitea wind farm was on partial outage on 19 August.

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

Figure 13: Total MW loss due to generation outages





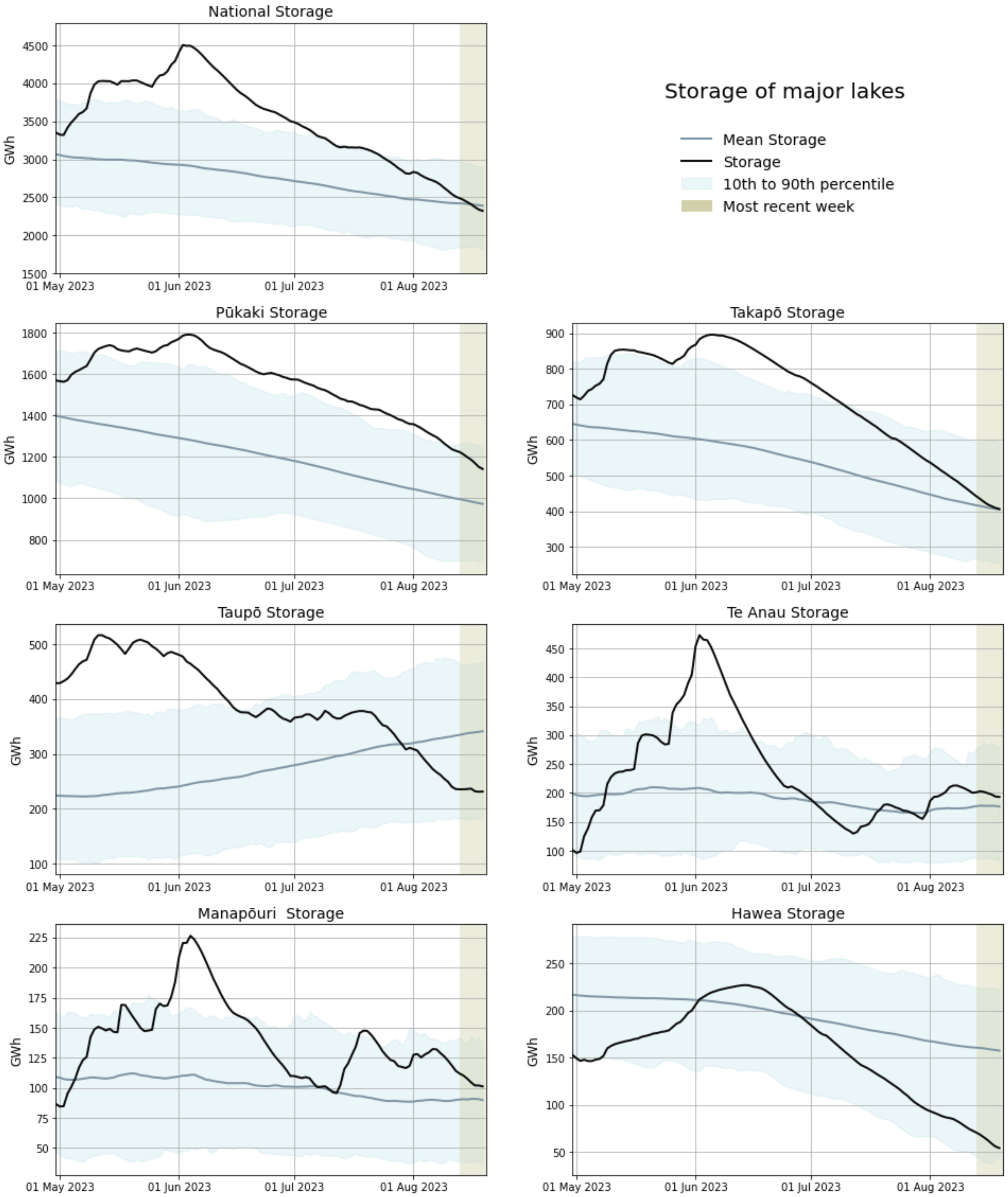
9. Storage/Fuel Supply

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 at 60.2 percent nominally full and 99.5 percent of historic mean, as of 19 August 2023

9.3. All lakes are showing some decrease in storage over the week. Pūkaki storage continues to drop below its historic 90th percentile but remains above its mean. Storage at Takapō has continued to decline and now sits around its historic mean and just above 400 GWh. After a steep decline over the last couple of weeks Taupō storage was relatively steady but still remains well below its historic mean and close to its 10th percentile. Manapōuri storage decreased but remains above its historical mean and Te Anau storage only decreased slightly, with storage remaining steadily above its mean. Hawea storage continued to decline with its storage approaching its historic 10th percentile.

Figure 14: Hydro Storage

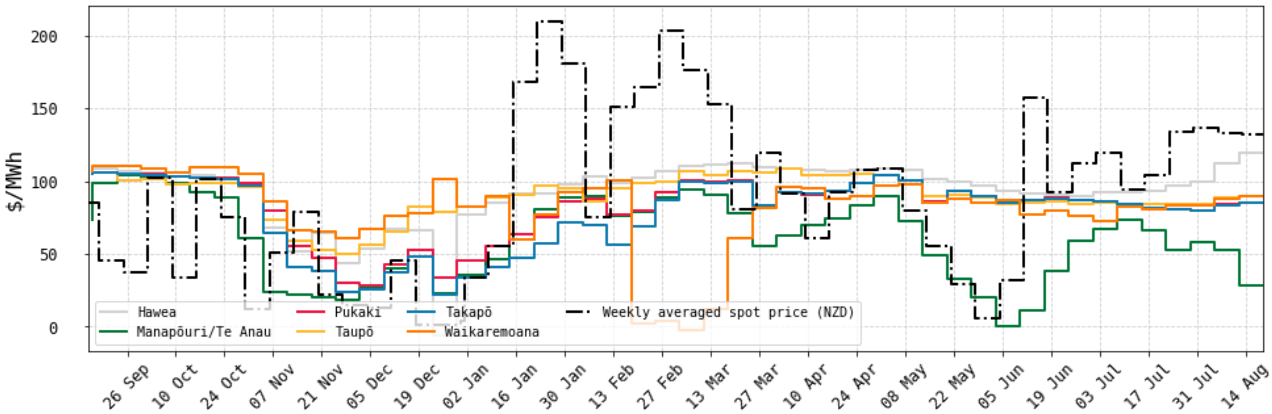


10. JADE Water Values

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 15 shows the national water values between 15 September 2022 and 19 August 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 of most lakes remained relatively steady with only noticeable changes to Hawea and, Manapōuri and Te Anau. Hawea water values have increased slightly on the previous week as storage continues to decline. Manapōuri and Te Anau saw some increases to storage the previous week, which in turn has seen a decrease to their water value of ~$25/MWh.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 19 August 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 August 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. Due to a dramatic drop in coal prices from April 2023, the latest SRMC of coal-fuelled Huntly generation is ~$165MWh.

11.5. The SRMC of Whirinaki has decreased to ~$536/MWh.

11.6. The SRMC of gas fuelled thermal plants increased again and is currently between $86/MWh and $129/MWh, likely due to increased demand for gas.

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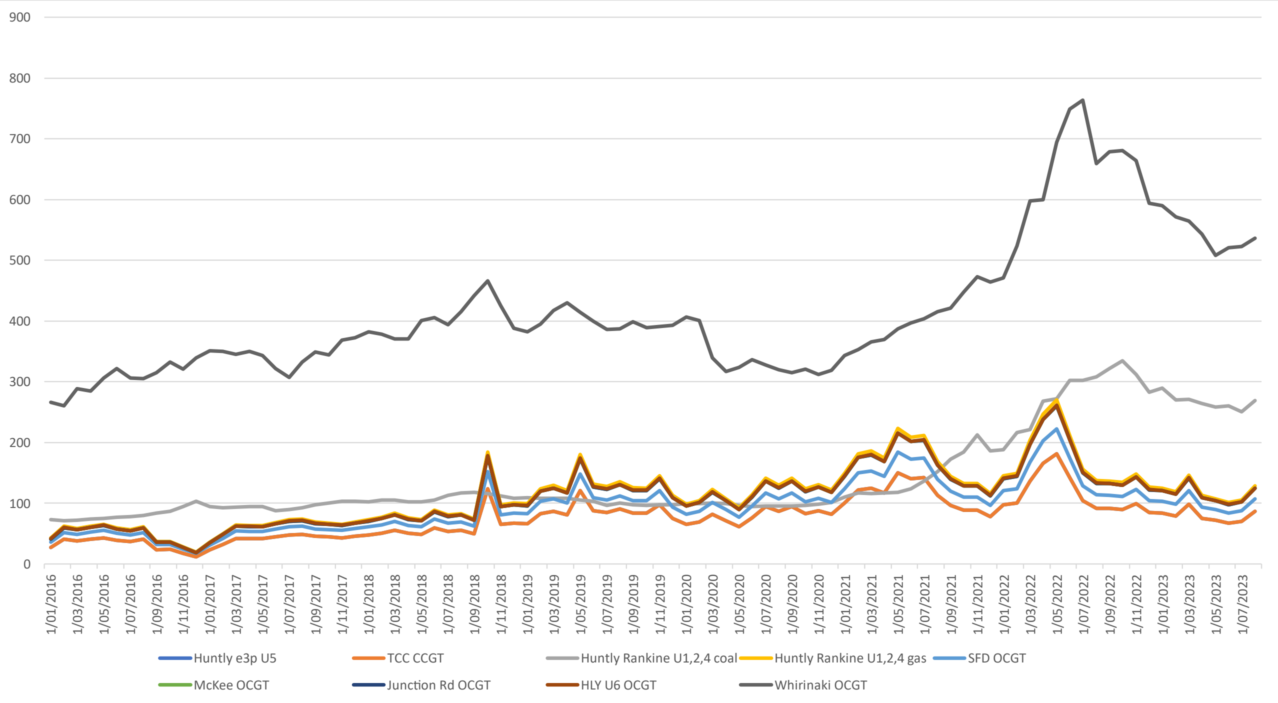
[1] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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



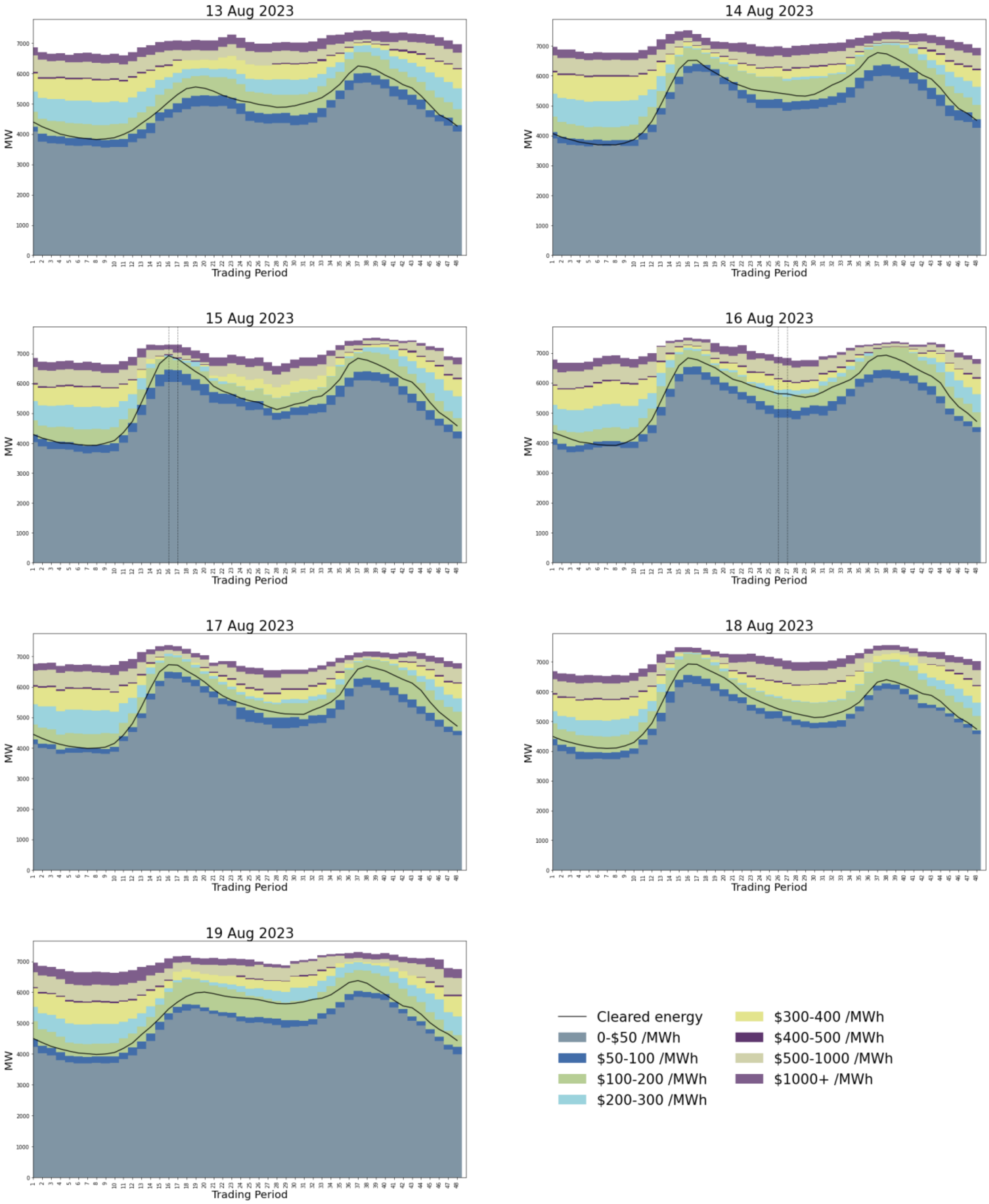
12. Offer Behaviour

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. Throughout the week, most generation cleared in the $100 - $200/MWh price range. During the Tuesday and Wednesday price spikes generation was clearing within the $200 - $400 price range, mainly due to the higher than expected demand along with over forecast wind.

12.3. As hydro storage continues to decline there was a small decrease in generation offered at very low prices and an increase in the quantity of generation offered between $200 and $400/MWh. However, otherwise this week's offers appear to be similar to the previous week.

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.
18/05/2023	Several	Further Analysis	Contact	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	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.
09/08/2023	16-17	Resolved	N.A.	Multiple	High energy prices due to high demand and low wind. No trading conduct issues identified