Date: 31 July 2023

TRADING CONDUCT REPORT

Market Monitoring Weekly Report

TRADING CONDUCT REPORT

1. Overview for week of 23 – 29 July 2023

1.1. During this week, prices remained slightly above the historic average, with two occasions where prices exceeded the 90th percentile. One notable price spike occurred on Wednesday during the evening peak, when demand was unexpectedly high, and actual demand was higher than forecasted demand. As a result, some relatively high tranche offers were dispatched to meet the increased energy requirements. Overall, this week saw a rise in demand, particularly during peak times, attributed to the colder temperatures experienced nationwide. Notably, wind generation halved compared to the previous week. To compensate for this, a combination of high hydro generation and thermal generation was employed to meet high demand. Also, national hydro storage continued to decline.

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. 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 23 – 29 July:

a) The average wholesale spot price across all nodes was $134/MWh.
b) 95 percent of prices fell between $78/MWh and $202/MWh.

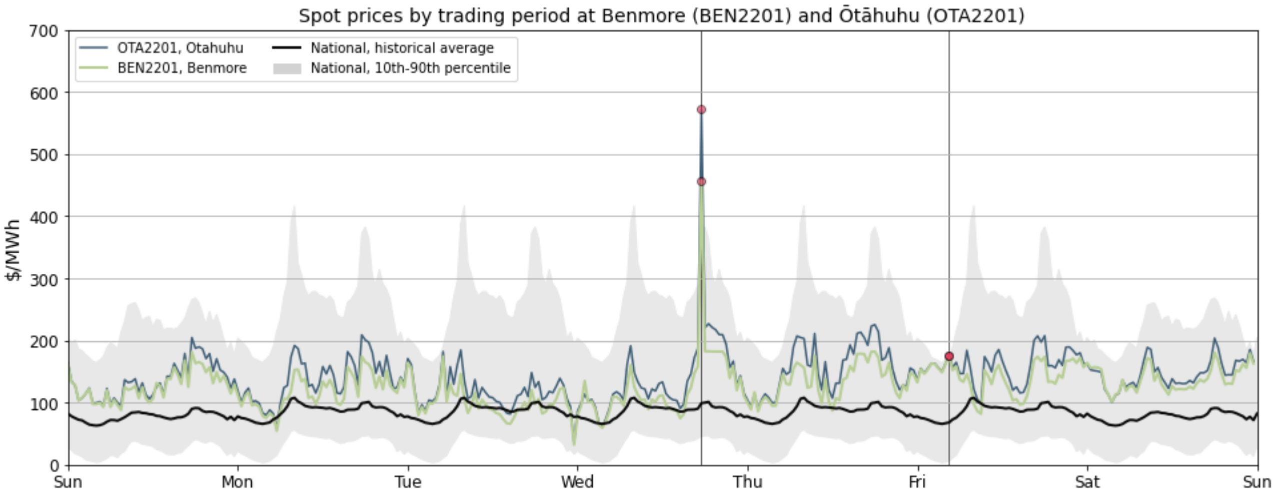
2.3. Figure 1 shows wholesale spot prices at Benmore and Ōtāhuhu alongside their historic average and historic 10th - 90th percentiles adjusted for inflation.

2.4. Prices during this week remain close to or slightly above the historic average. Toward the latter part of the week, prices saw a minor increase, primarily due to lower wind generation and relatively higher thermal generation. The majority of spot prices remained within the range of $100/MWh to $200/MWh. These average price levels can be attributed to the declining hydro storage, which resulted in an increased reliance on thermal generation.

2.5. This week there are two instances when prices reached above the historic 90th percentile. The first occurred on Wednesday, 26 July, at 5:30 pm, resulting in prices of $572/MWh at Ōtāhuhu and $457/MWh at Benmore, with sustained instantaneous reserve (SIR) prices around $80/MWh. This price spike can be attributed to the increase in peak demand, leading to the dispatch of high tranche offers. Additionally, the actual demand surpassed the forecasted demand.

2.6. The second price, slightly above the 90th percentile, occurred on Friday, 28 July, at 4:30 am. Overnight demand was higher than usual which likely contributed to prices remaining high. Note that historic percentiles for this quarter are relatively low compared to the previous quarter.

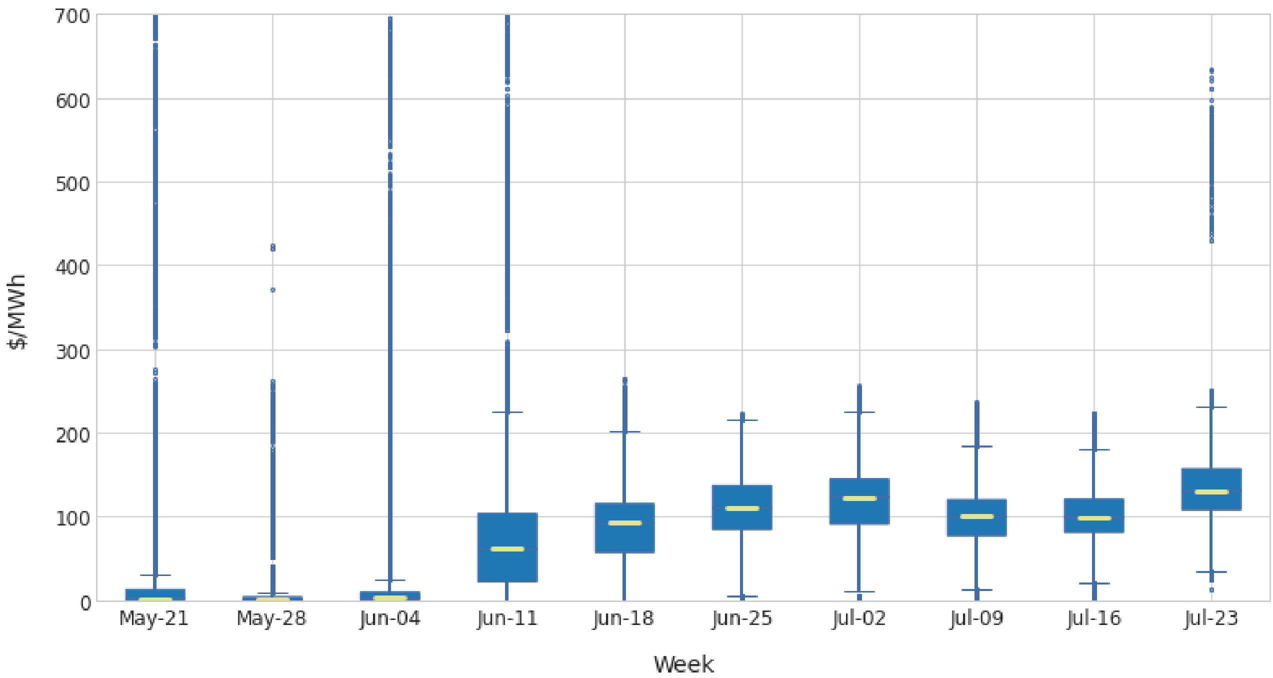
Figure 1: Wholesale Spot Prices between 23 July (Sunday) – 29 July (Saturday) 2023.



2.7. 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.

2.8. During this week, the median and quartile prices experienced a slight increase compared to the previous week. There were a few instances of high prices observed above the third quartile on Wednesday.

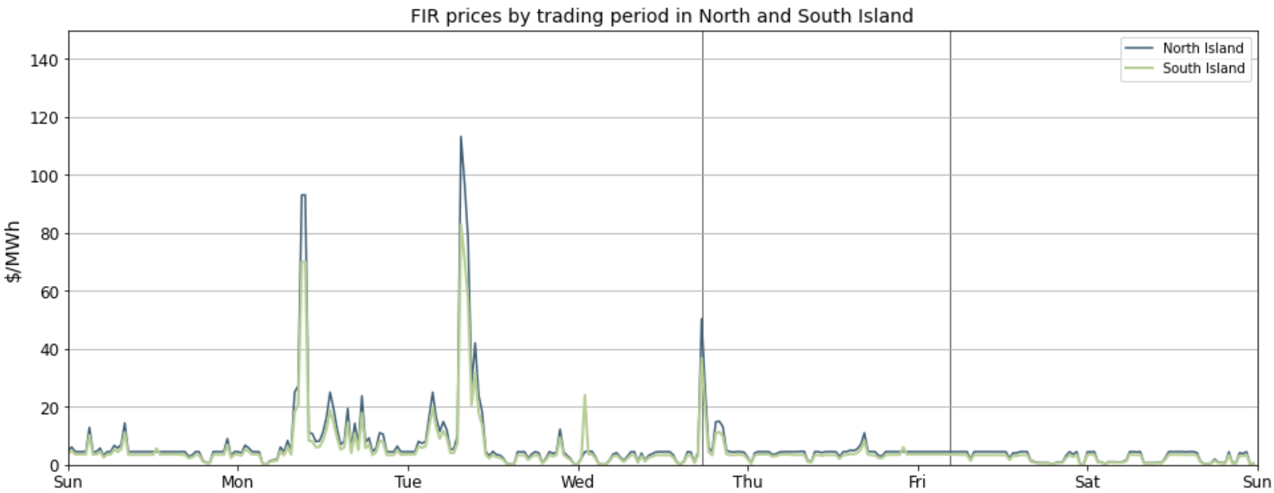
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks.



3. Reserve Prices

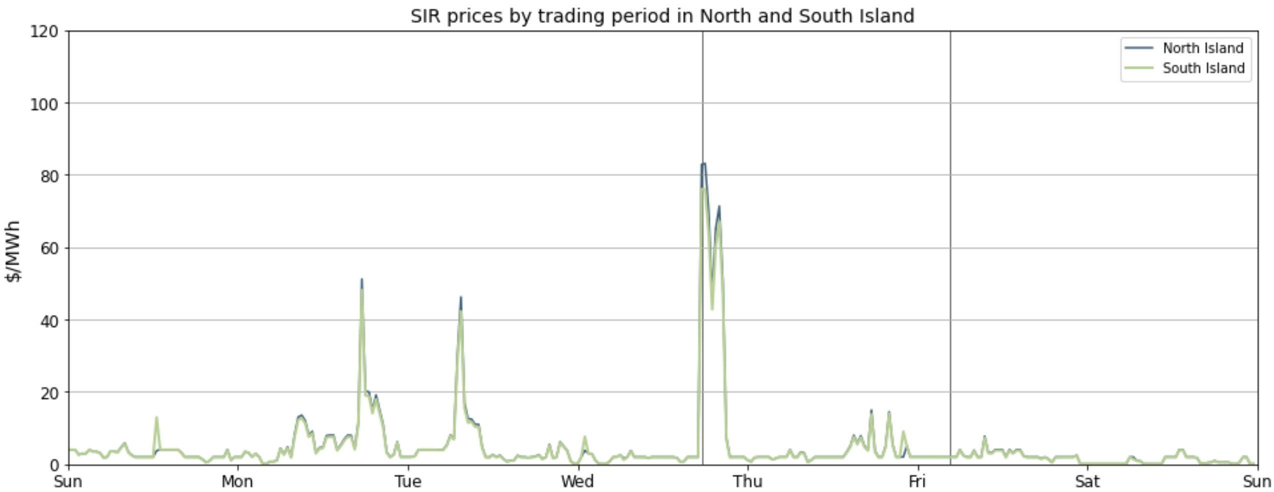
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week the FIR prices were mostly below $20/MWh for both islands, with a few price spikes. The highest FIR price spike occurred on Tuesday, 25 July at 7:30 am when the North Island price reached $113/MWh, with the South Island price of $83/MWh. At that time the HVDC northward flow was high, increasing reserve requirements, and the wind generation was significantly low.

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



3.2. SIR prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh this week, with a few price spikes but all below $85/MWh. The highest peak occurred on Wednesday, 26 July and was in line with the spot price spike, with high HVDC northwards flow. This spike was primarily due to a relatively high demand coupled with limited wind generation. During this period, prices in the North Island reached $83/MWh, while the South Island prices of $76/MWh.

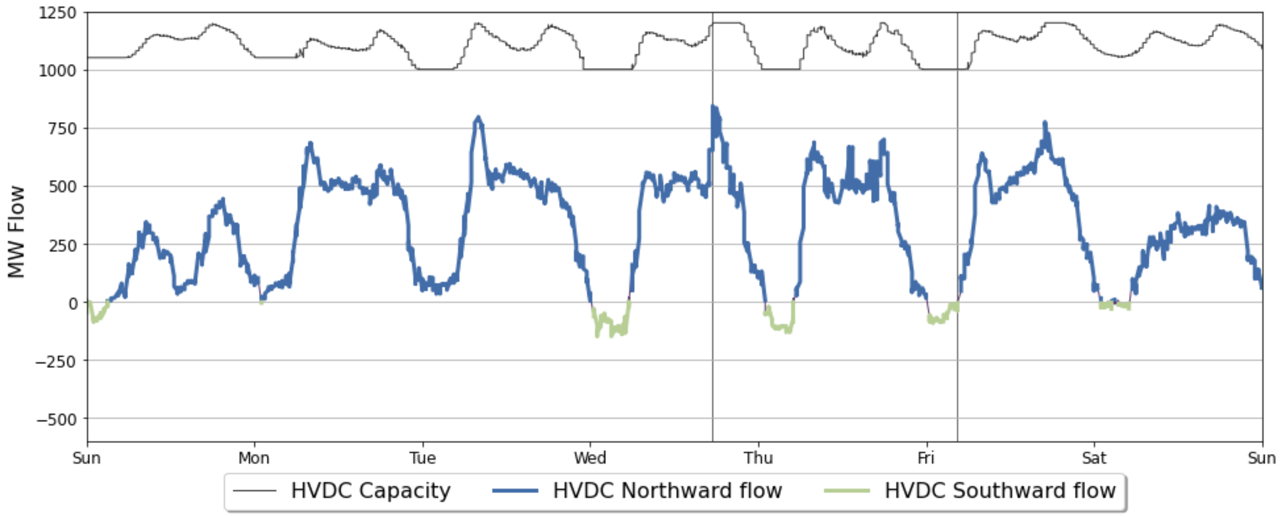
Figure 4: Sustained instantaneous reserve (SIR) prices by trading period and Island.



4. HVDC

4.1. Figure 5 shows HVDC flow between 23 – 29 July. At the start of the week, HVDC flows were northward with no southward overnight flow due to low wind generation. However, during the latter half of the week, HVDC flows were northward during the daytime and southward during the nighttime. The northward HVDC flow reached up to 850 MW during the daytime, while the southward flow during the nighttime remained below 150 MW. HVDC flow was well below the maximum limits. The northward HVDC flow reached the highest peak of around 850 MW during the price spike. On Sunday the HVDC flow followed the peak demand pattern as the thermal was running to support the North Island load.

Figure 5: HVDC northward flow and capacity.

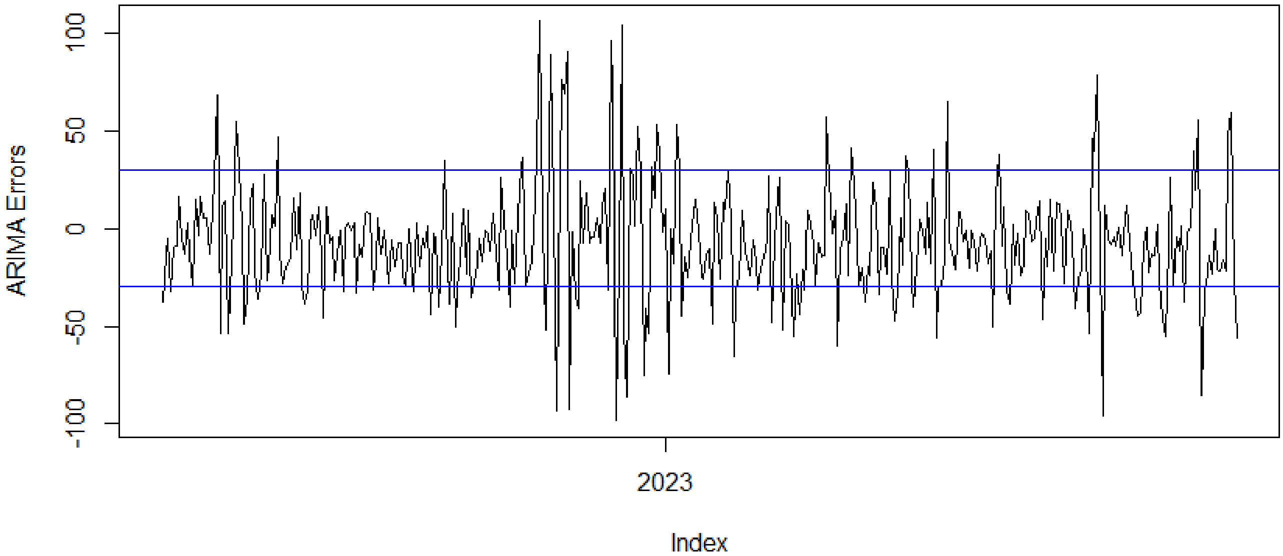


5. Regression Residuals

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. This week, there was one residual above the one standard deviation of the data on Thursday. Another residual but below the one standard deviation was observed on Sunday. The negative residual indicates that the modelled daily price was higher than the actual average daily price and vice versa.

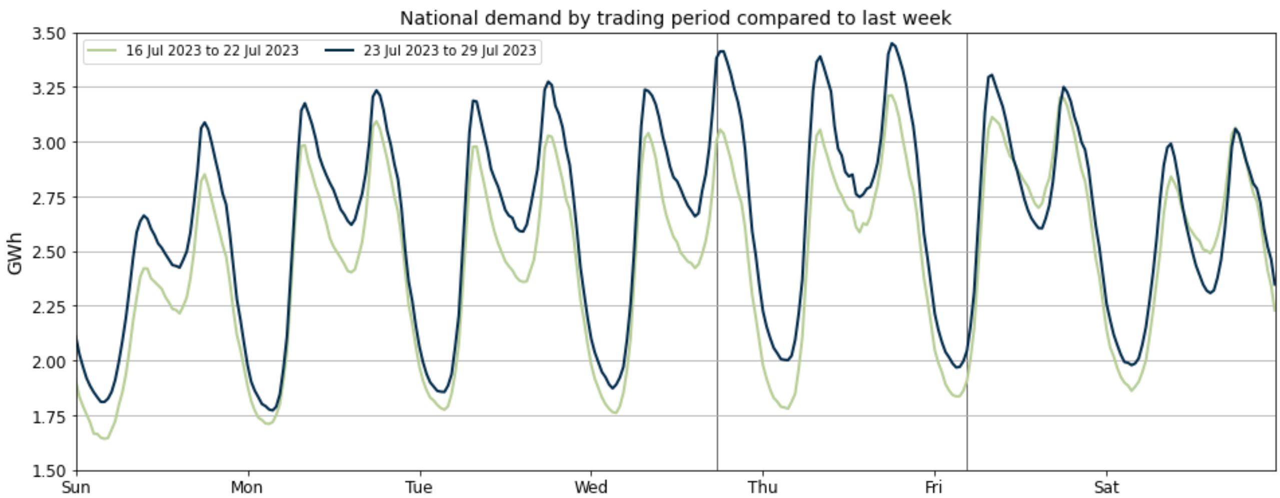
Figure 6: Residual plot of estimated daily average spot prices from 1 July 2022 – 29 July 2023. The blue lines show two standard deviations of the ARMA errors.



6. Demand

6.1. Figure 7 shows national grid demand between 23 – 29 July, compared to the previous week. Overall, demand was higher compared to the previous week due to relatively colder temperatures. In particular, peak demand significantly increased this week. On Wednesday, the evening peak was higher than the morning peak. However, on Thursday the morning peak was also higher due to lower temperatures. On Friday and Saturday, the off-peak demand was slightly lower than last week.

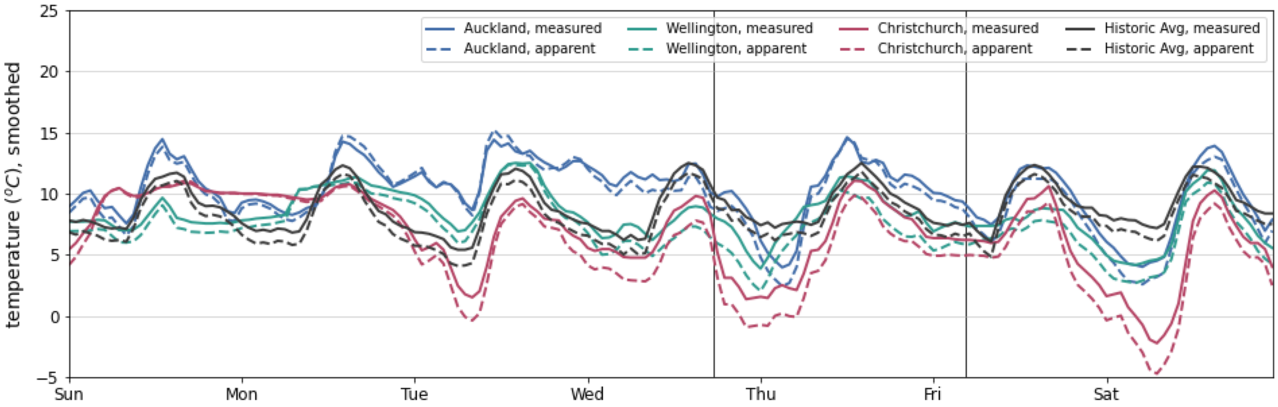
Figure 7: National demand by trading period compared to the previous week.



6.2. Figure 8 shows hourly temperatures at the three main population centres between 23 – 29 July. 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 across all regions. Auckland temperatures were around or above the historic average at the start of the week. The temperature went below the historic average on Thursday and Saturday, with the highest temperature only around 15 degrees. Wellington temperatures were mainly around average for this week with some colder mornings towards the end of the week. Christchurch temperatures fell mainly below average, especially from Wednesday evening, and apparent temperatures ranged from -5 degrees and 11 degrees.

Figure 8: Temperatures across main centres.



7. Outages

7.1. Figure 9 shows generation capacity on outage. Total capacity on outage between 23 – 29 July ranged between ~900 MW and 1300 MW.

7.2. Notable outages include:

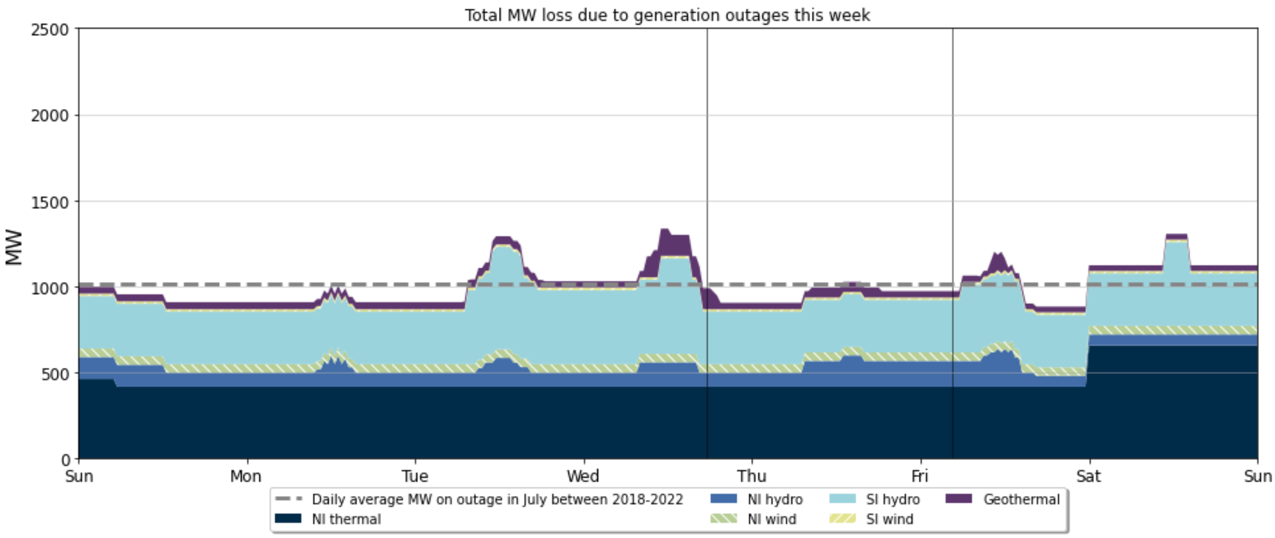
(a) Huntly 5 extended outage from until 31 July to 31 August.

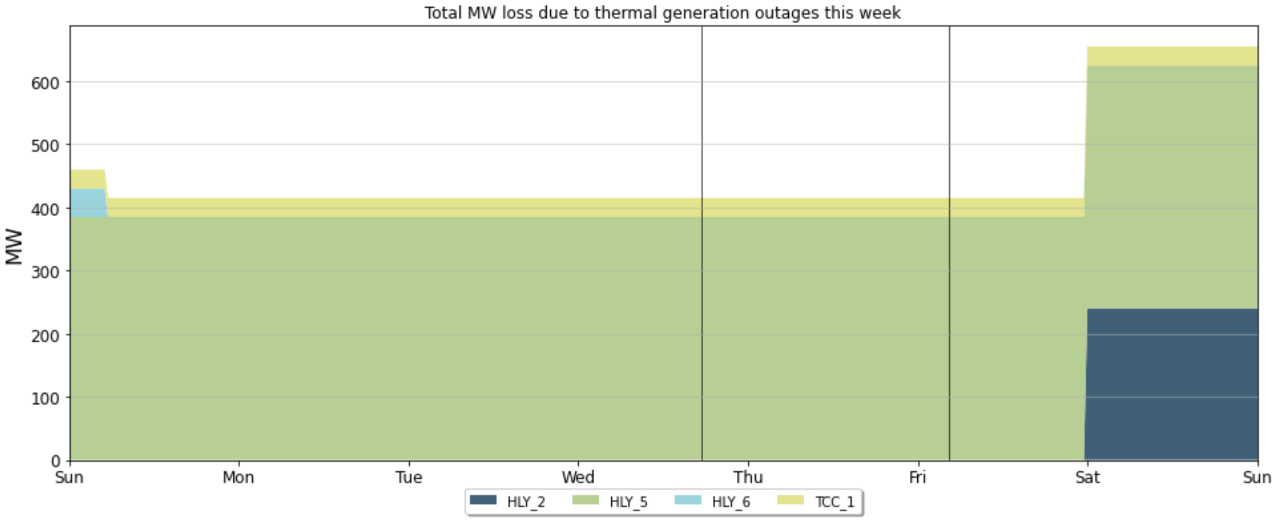
(b) Huntly 2 is on outage from 28 July to 2 August.

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

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

Figure 9: Total MW loss due to generation outages.

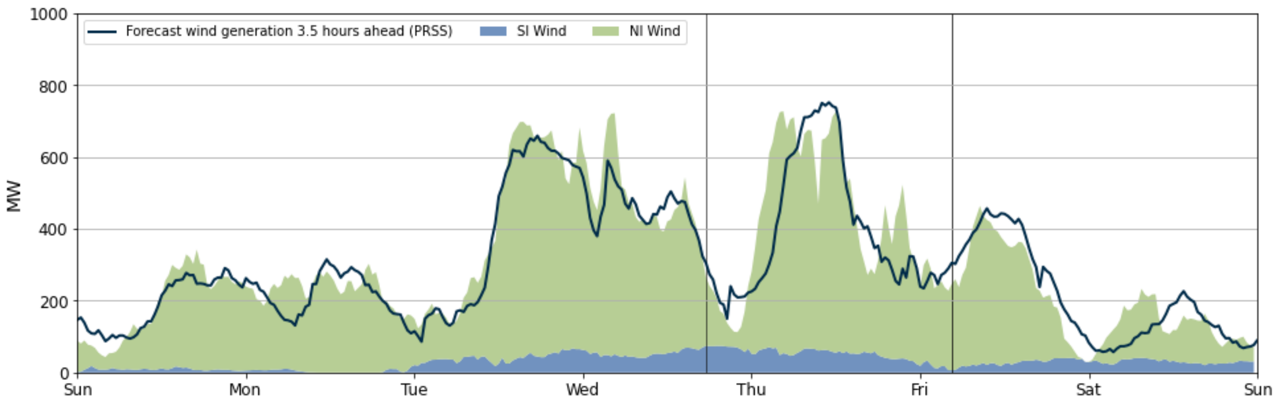




8. Generation

8.1. Figure 10 shows wind generation, from 23 – 29 July, ranged from 30 - 730 MW across the week. At the start of the week, wind started low mostly below 300 MW. From Tuesday, wind generation gradually increased to around 700 MW until it experienced a notable drop again on Wednesday, falling below 100 MW and deviating from the predicted levels. However, on Thursday, wind generation rebounded, reaching up to 730 MW but dropped to 300 MW till Friday morning. On Friday, wind generation remained low and further declined to around 30 MW by Saturday. On Saturday, wind was mostly below 200 MW.

Figure 10: Wind Generation and forecast.

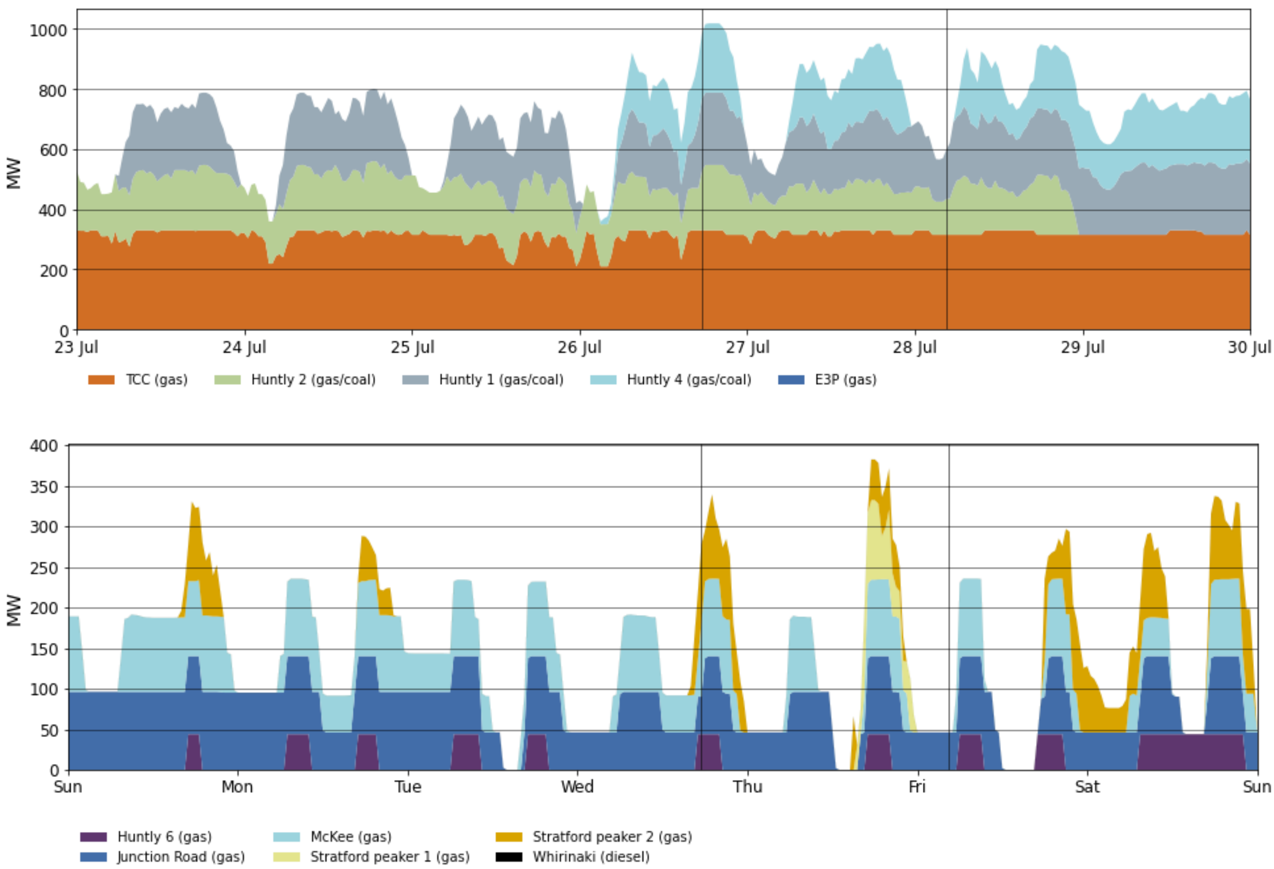


8.2. Figure 11 shows the generation of thermal baseload and thermal peaker plants between 23 – 29 July. E3P (Huntly 5) remains on outage, resulting in the remaining three Rankine units to cycle on and off to support baseload requirements. Huntly 2 ran as baseload until Friday after that it went on outage. From Wednesday until Friday all three Rankine units were running during the day due to high demand, which is a rare occurrence. Furthermore, TCC ran continuously as baseload throughout the week.

8.3. Due to relatively low wind generation and high demand, the load was supported by the thermal peakers. Junction Road and McKee ran daily, with Junction Road also running continuously from Sunday to Tuesday and also overnight Wednesday to Thursday. McKee mainly ran during the peak periods although at the beginning of the week also ran across some shoulder periods as well. Stratford 1 only ran on the Thursday evening peak with

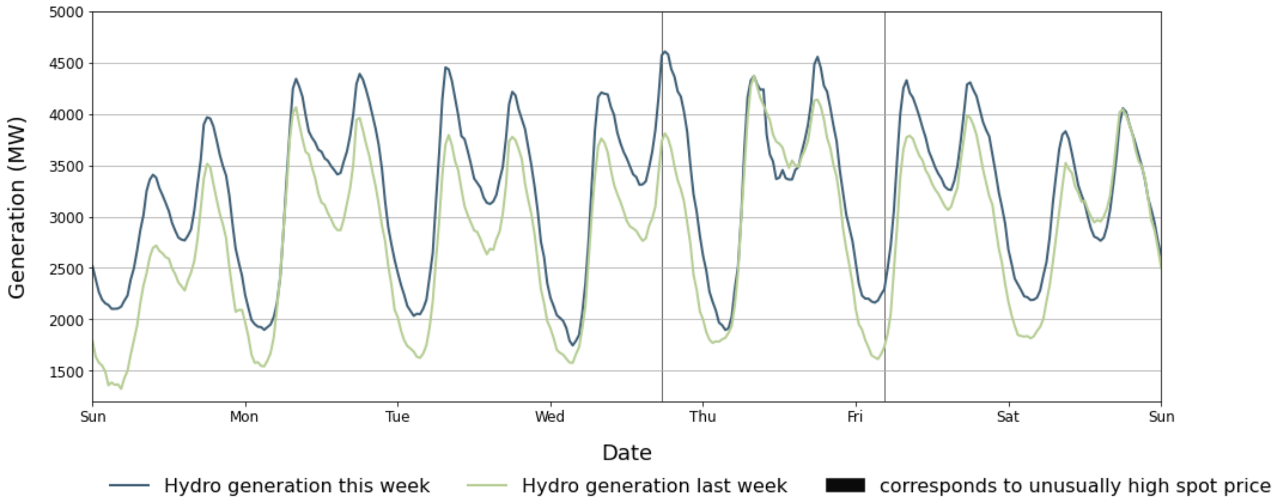
Stratford 2 running mostly in the latter half of the week. Huntly 6 ran during the peak demand periods throughout the week.

Figure 11: Thermal Generation.



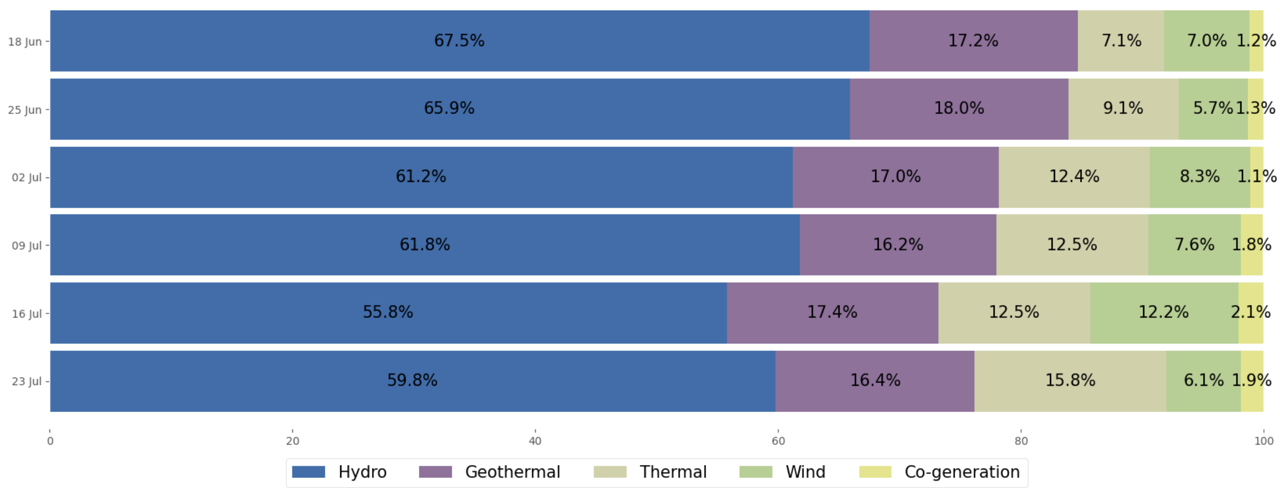
8.4. Figure 12 shows hydro generation between 23 – 29 July. Overall, there was an increase in hydro generation compared to the previous week. The increased demand along with lower wind generation are likely reasons for this increase. The highest hydro generation occurred during the Wednesday price spike. Also, on Tuesday, there was a notable increase in morning peak generation.

Figure 12: Hydro generation between 23 – 29 July compared to the previous week.



8.5. As a percentage of total generation, between 23 – 29 July, total weekly hydro generation was 59.8 percent, geothermal 16.4 percent, thermal 15.8 percent, wind 6.1 percent, and co-generation 1.9 percent. This week due to high demand and low wind generation, the load was covered by the increased thermal and hydro generation.

Figure 13: Total generation as a percentage each week between 18 June and 29 July 2023.



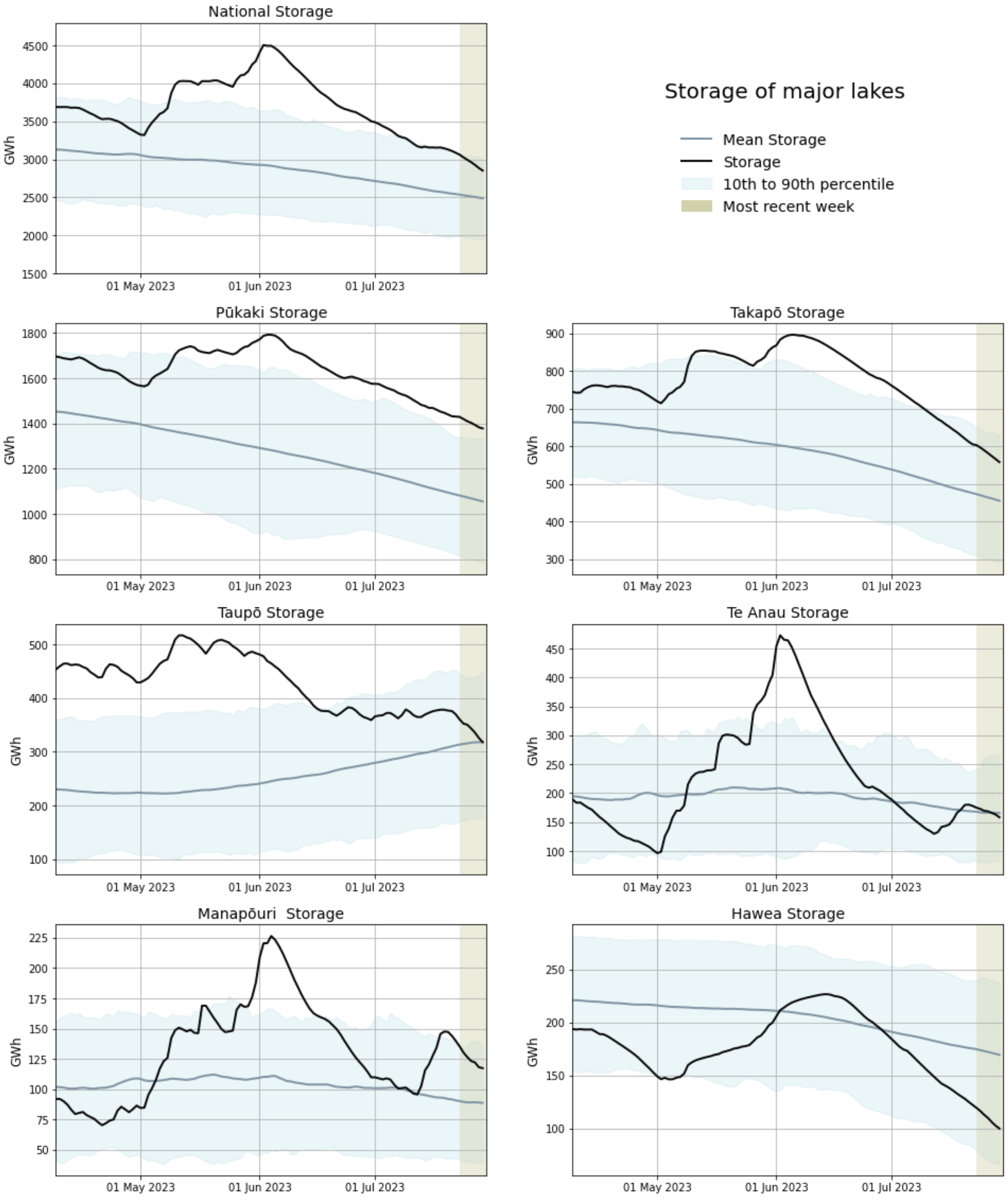
9. Storage/Fuel Supply

9.1. Figure 14 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 to 71 percent of nominal full as of 29 July. However national controlled storage is still high at 113 percent of the historic mean for this time of year.

9.3. During this week, all lake levels experienced a decline. Lake Pūkaki is slightly above its historic 90th percentile and Takapō just under its historic 90th percentile. Storage at lake Te Anau is slightly below its historical average, while Manapōuri is above its historic average but below its respective 90th percentile. The storage level at Taupō is touching its historic mean. Hawea storage also decreased and is currently below its historic mean for this time of year.

Figure 14: Hydro Storage.

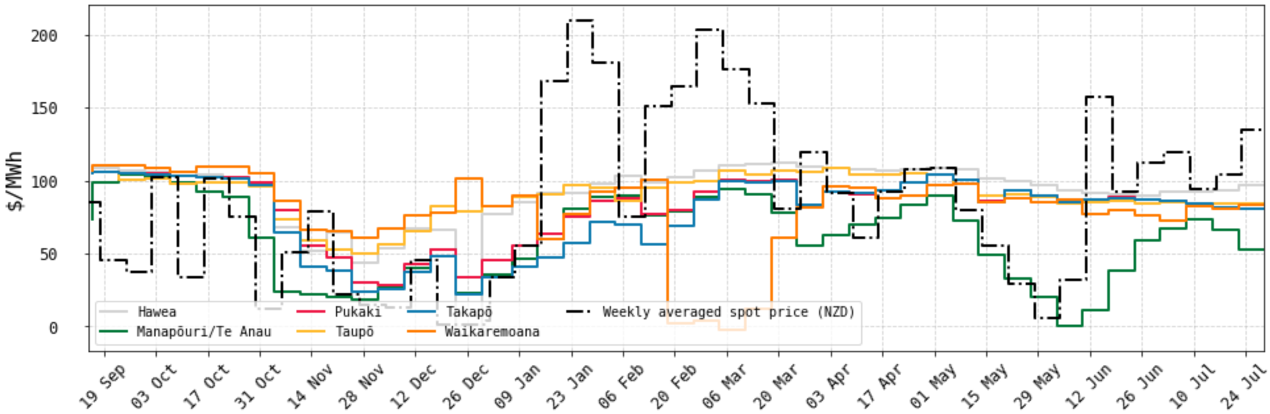


10. JADE Water Values

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 29 July 2023 obtained from JADE calculated as at 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. Recently the water values in most of the lakes remained relatively steady, except for Hawea and Manapōuri/ Te Anau. Water values at Te Anau and Manapōuri have been increasing since June as storage decreased, with a small decrease in the water value from the last two weeks. Water values at Hawea increased as the hydro storage decreased significantly.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 29 July 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 July 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 July, Indonesian coal was at around ~$456/tonne (NZD) putting the latest SRMC of coal-fuelled Huntly generation at ~$247/MWh.

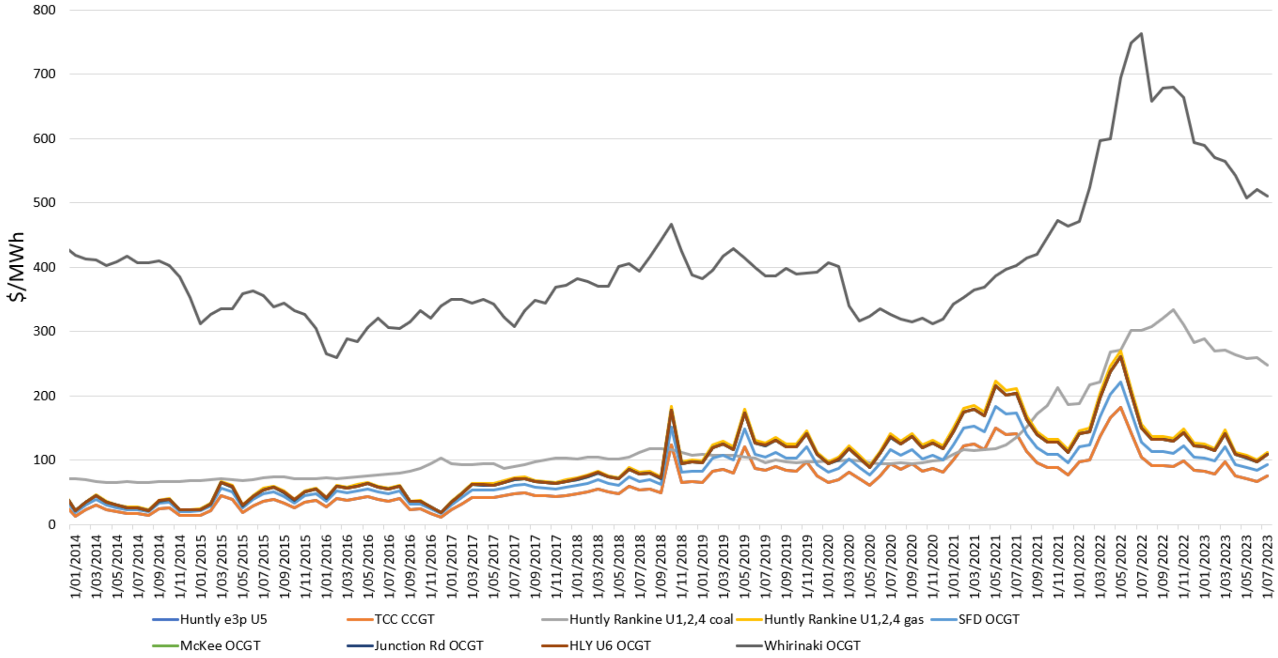
11.5. The SRMC of Whirinaki has decreased to ~$511/MWh.

11.6. The SRMC of gas fuelled thermal plants increased slightly and is between $75/MWh and $113/MWh, likely due to an increase in thermal generation.

[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.

Figure 16: Estimated monthly SRMC for thermal fuels.



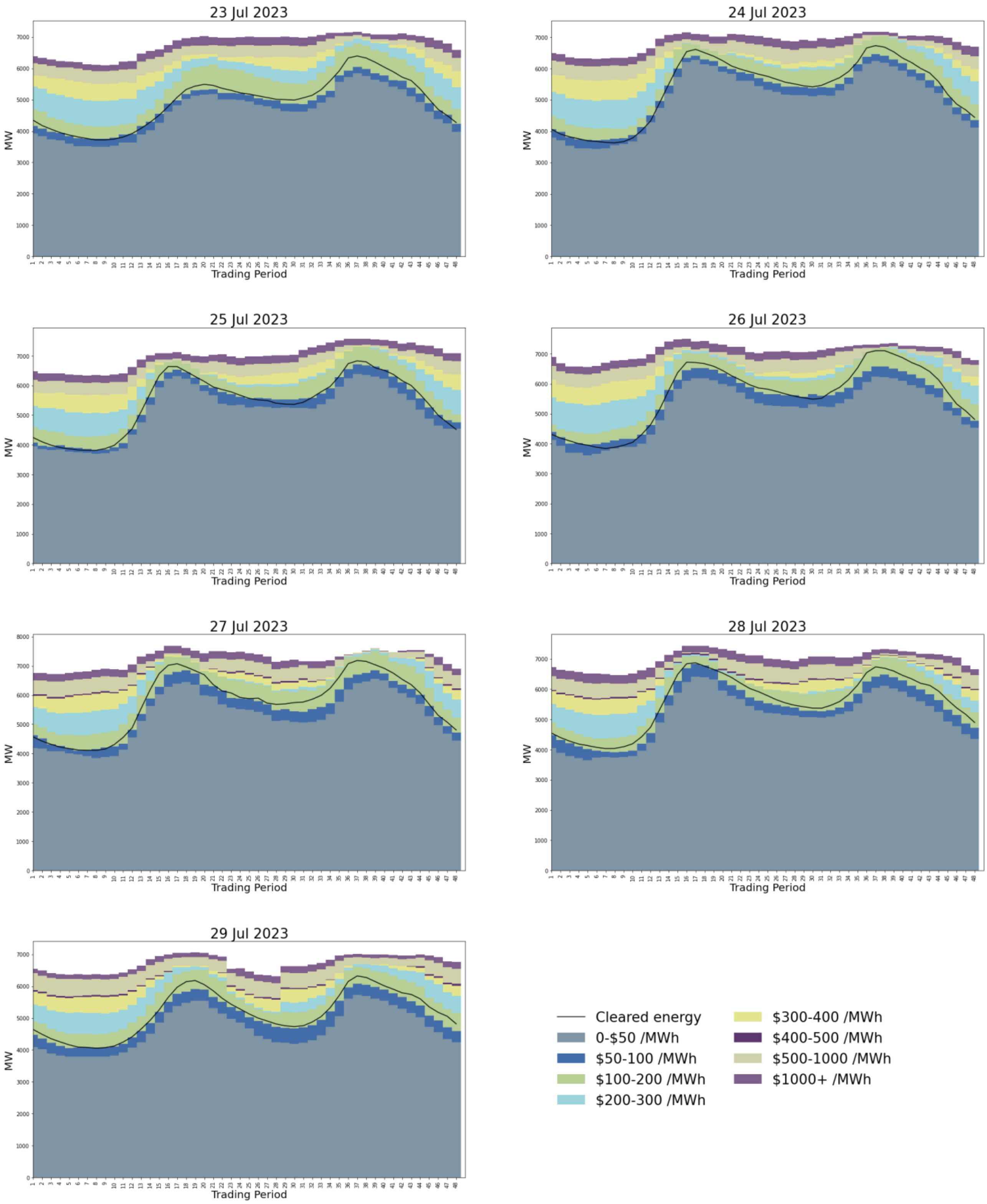
12. Offer Behaviour

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 price range of $0-$100/MWh or in the $100-$200/MWh price range. This week relatively low wind participated in the increased thermal generation. Also, hydro generation increased 5 percent compared to previous week as well.

12.3. On Wednesday and Thursday evenings, when demand was highest, the majority of offers were below $200/MWh, with a relatively thin stack above this price. Total generation offered was also lower compared to morning peaks, likely due to lower wind generation. These likely contributed to the price spike on Wednesday evening.

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.