Date: 18 September 2023

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 10-16 September 2023

1.1. Prices this week were usually above the historic average and within $100-$200/MWh range. The middle of the week saw some record daily wind generation with an average of over 750MW for Tuesday through to Thursday. Hydro generation was similar to the previous week with storage remaining steady at around 88% of historic mean due to inflows in some regions. All three Rankines as well as TCC continued to provide baseload during the week though. Less thermal peakers ran midweek due to increased wind generation as well as units being on outage

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 10-16 September:

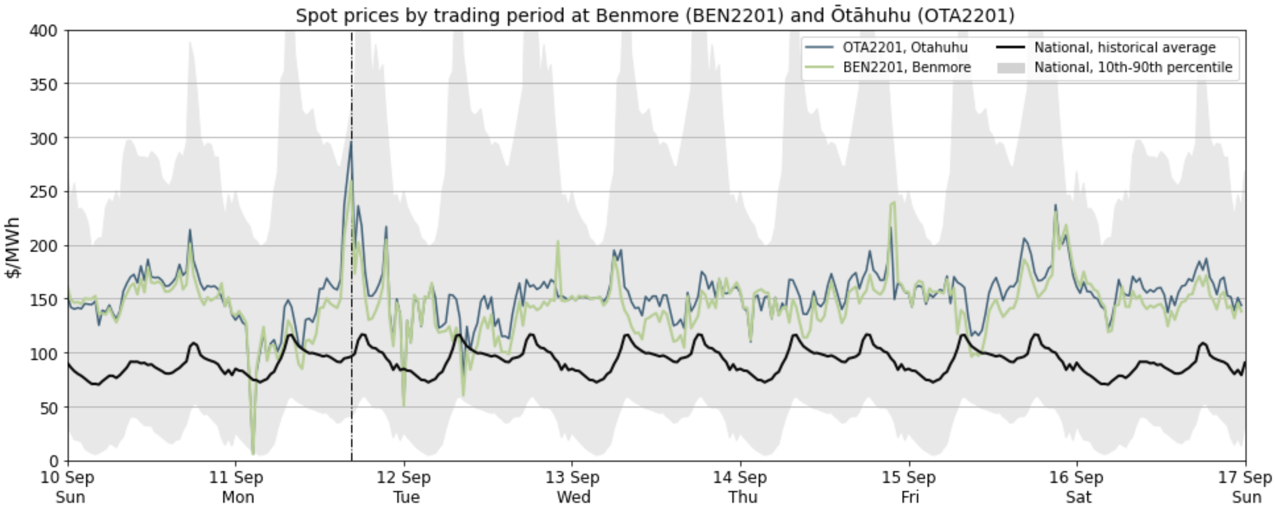
(a) The average wholesale spot price across all nodes was $150/MWh.

(b) 95 percent of prices fell between $97/MWh and $211/MWh.

2.4. The majority of spot prices were below $200/MWh and mostly sat above the historic average for the week. The average spot price was around $6/MWh higher than the previous week.

2.5. There was a spike in prices at 4.30pm on 11 September but prices did not breach the historic 90th percentile. The price at Ōtāhuhu was around $296/MWh and $259/MWh at Benmore. This spike occurred during a period of wind generation being lower than forecast by around 100MW and three thermal peakers running. Demand was also under forecast close to 250MW.

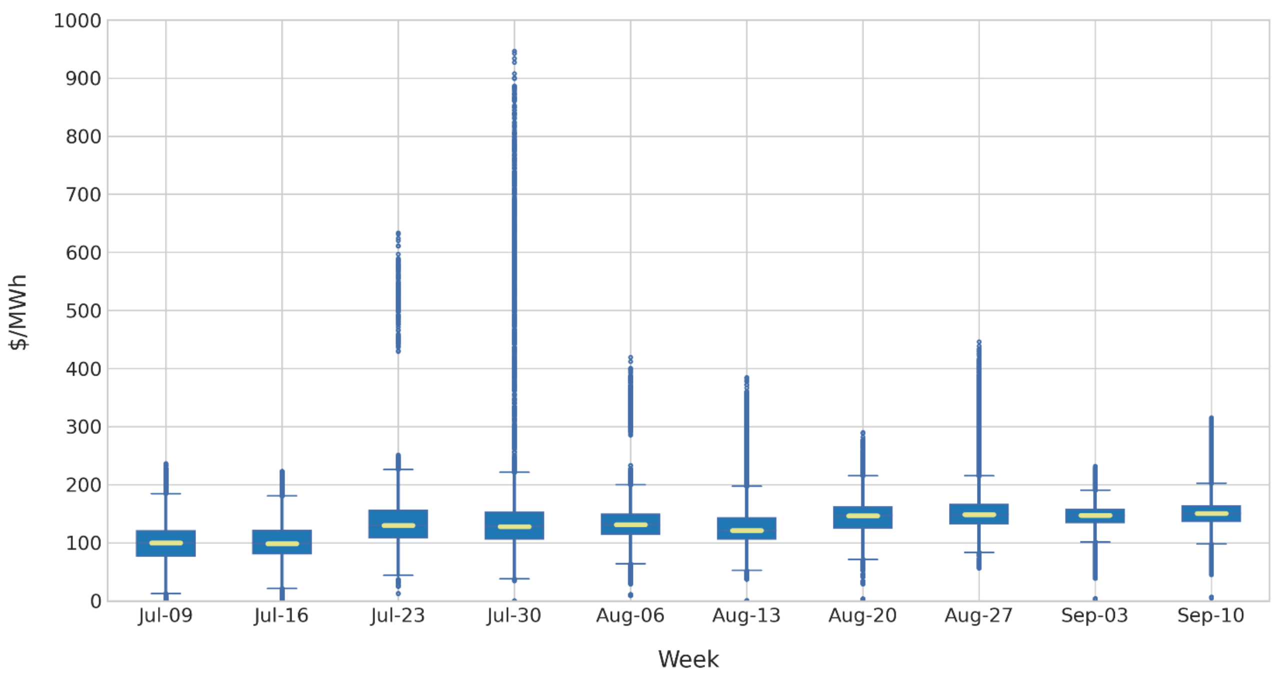
Figure 1: Wholesale spot prices between 10 September (Sunday) and 16 September (Saturday) 2023



2.6. 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.

2.7. The range of spot prices was similar to the previous week with the bulk of prices in a condensed and reasonably symmetrically distribution, although there were some outliers sitting within $250-$315/MWh. The middle 50% of prices were in the $137/MWh to $163/MWh range.

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

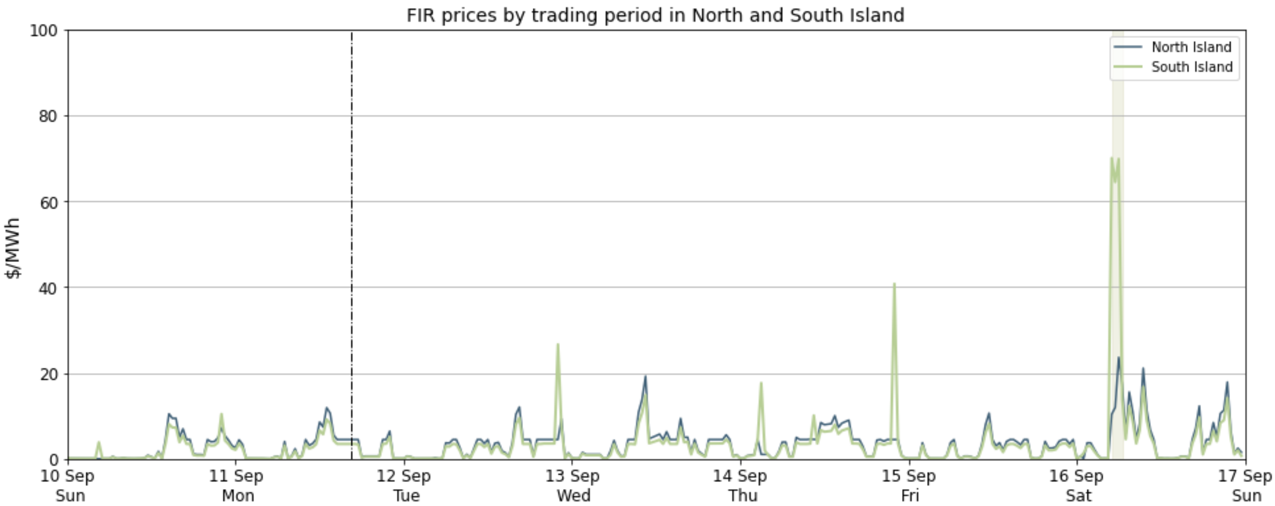


3. Reserve prices

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 $10/MWh. There were a few spikes to South Island FIR prices. The first two were at around 10.00pm on both the Tuesday and Thursday evening where FIR prices were $27/MWh and $41/MWh, respectively.

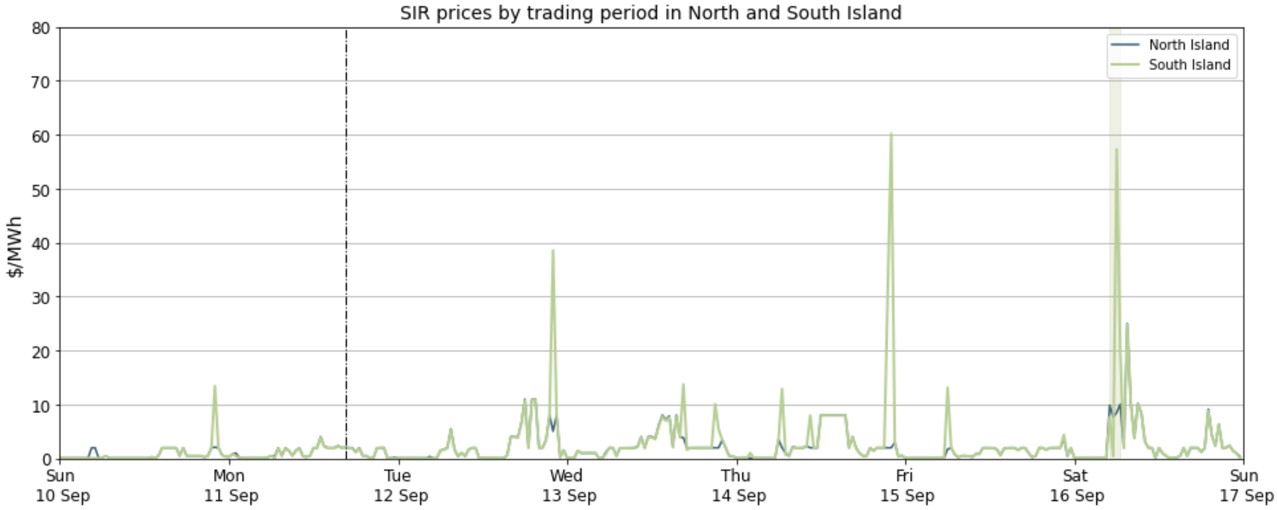
3.2. The largest spike in South Island FIR occurred between 5.00am and 6.00am on Saturday. South Island FIR prices during these three trading periods were $70/MWh, $64/MWh, and $70/MWh, respectively. At this time there was a planned outage to pole 3 on the HVDC. This pole outage reduced reserve sharing between the North and South Islands which meant that more reserves were needed in the South Island to cover the risk of a large generator or transmission line tripping.

Figure 3: Fast Instantaneous Reserve (FIR) prices by trading period and island



3.3. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mainly under $10/MWh. There were South Island SIR spikes that coincided with the FIR spikes mentioned in the previous paragraph. Tuesday at 10.00pm saw a South Island SIR price of ~$39/MWh and at 10.00pm on Thursday evening the price spiked to $60/MWh. During the HVDC pole outage it was only the 6.00am SIR price on Saturday that spiked and was at $57/MWh. North Island SIR prices mainly remained below $20/MWh during these times.

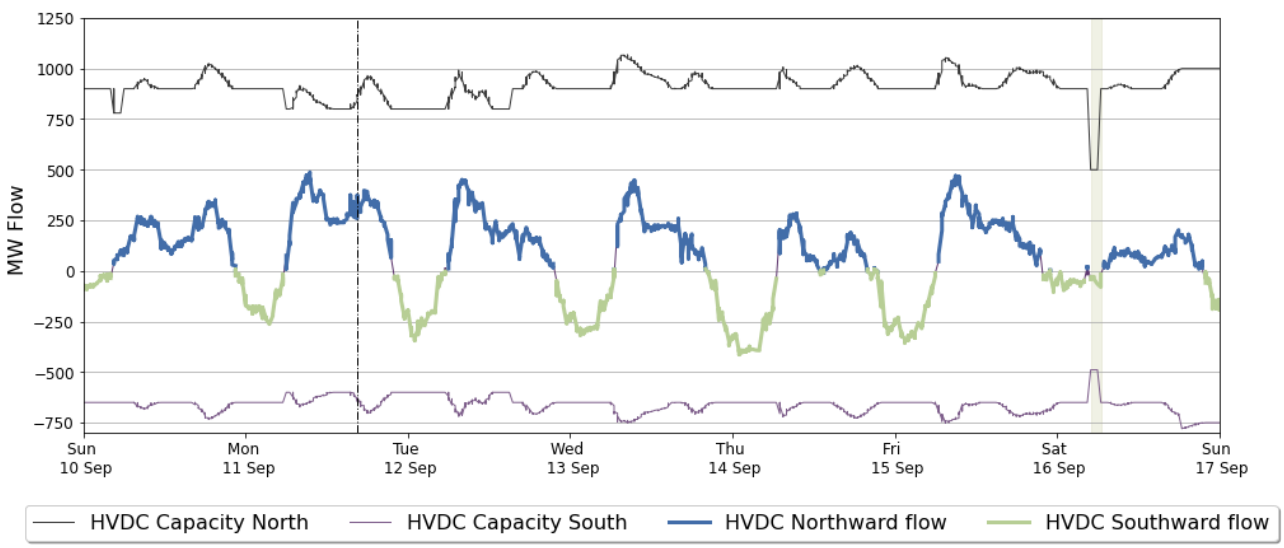
Figure 4: Sustained Instantaneous Reserve (SIR) prices by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC flow between 10-16 September. HVDC flows northwards stayed below 500MW this week with some increased southward flow at times. The maximum flow south was around 400MW overnight on the 14 September. There was also a drop in the HVDC capacity for a short period on Saturday morning as the HVDC pole outage work began.

Figure 5: HVDC flow and capacity



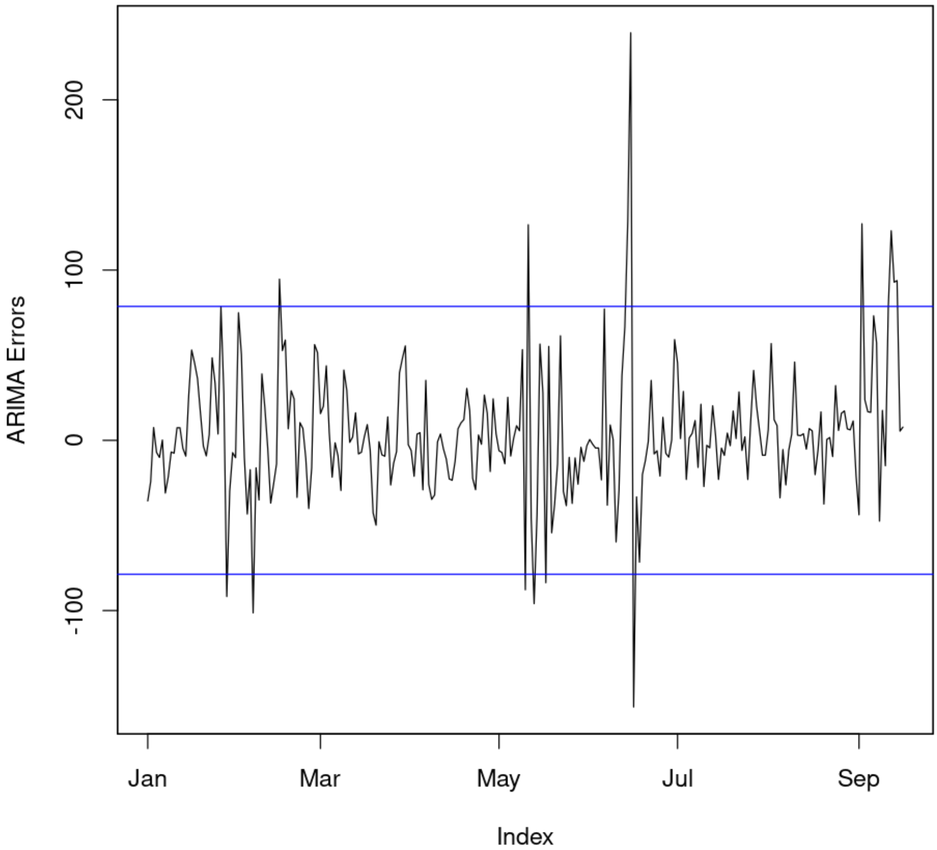
5. Regression residuals

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 were three residuals above two standard deviations, indicating prices on Tuesday, Wednesday and Thursday were higher than the model expected. This is likely due to the high wind generation, which the model correlates with lower prices. However, with thermal generation outages and below average hydro storage, prices did not drop as significantly as they may have otherwise.

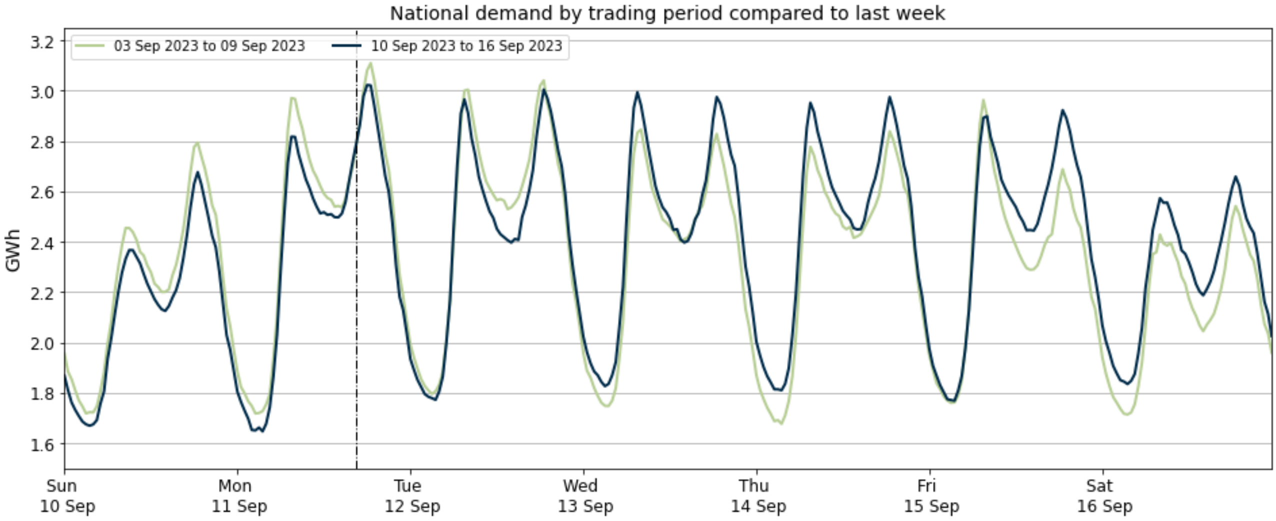
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 - 16 September 2023



6. Demand

6.1. Figure 7 shows national demand between 10–16 September, compared to the previous week. Peak demand was usually below 3GWh, reaching 3.02GWh on Tuesday. Overall, there was a slight increase in peak demand from Wednesday onwards compared to the previous week, possibly due to windy conditions making it feel cooler.

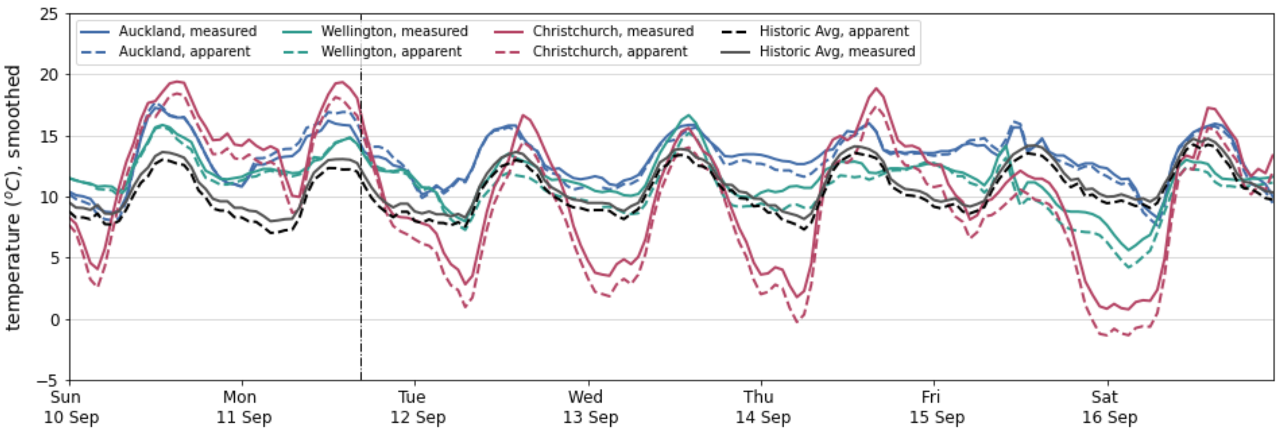
Figure 7: National demand by trading period compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 10-16 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. Temperature was mainly on or above average in Auckland and Wellington. Wellington temperatures did dip below average on Friday afternoon and through to Saturday morning. Christchurch apparent temperatures across the week ranged from around -1°C to 18°C.

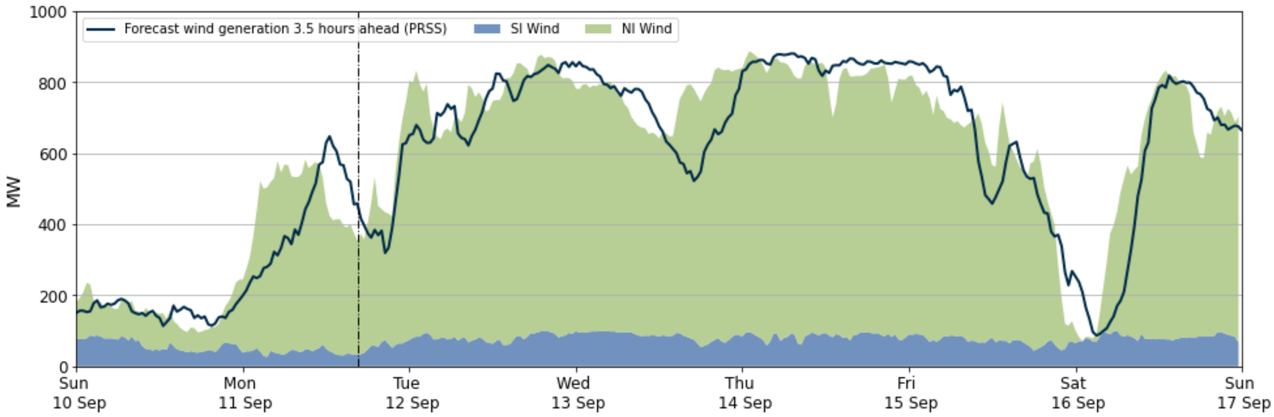
Figure 8: Temperatures across main centres



7. Generation

7.1. Figure 9 shows wind generation, from 10-16 September. Wind generation ranged between 72MW to 888MW across the week, with only Sunday and a period early Saturday morning seeing under 200MW of wind. Wind was around 100MW lower than forecast at 4.30pm on Monday which may have contributed to the higher spot prices during this trading period. From Tuesday to Thursday daily average wind generation was above 750MW.

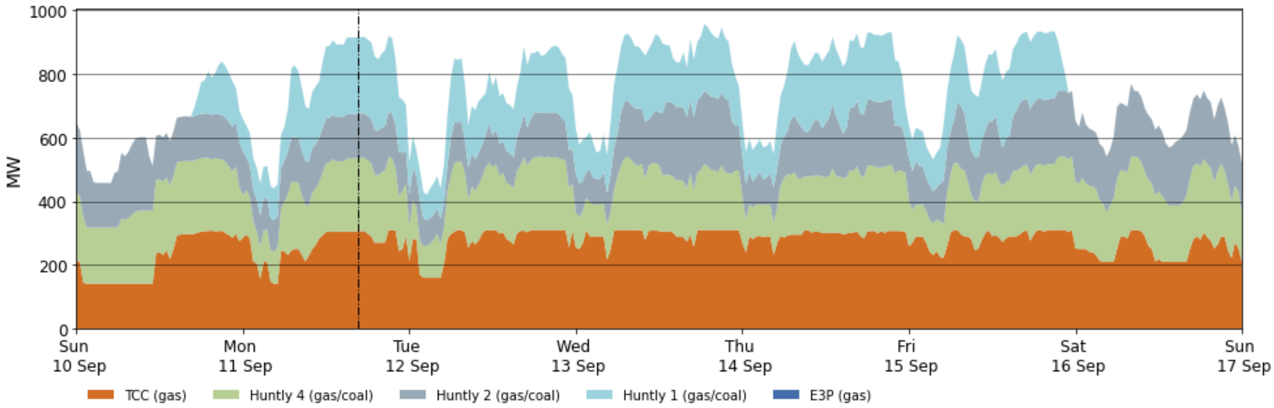
Figure 9: Wind generation and forecast between 10-16 September

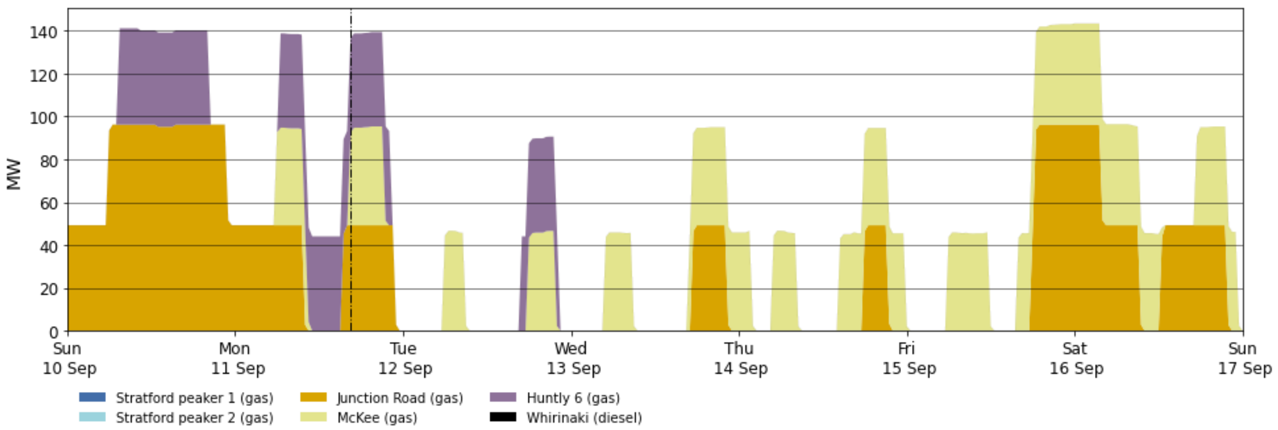


7.2. Figure 10 shows the generation of thermal baseload and thermal peaker plants between 10-16 September. TCC ran as baseload with the three Rankines supporting the majority of the week. The only time Huntly 1 did not run was on Sunday morning and all day Saturday likely due to lower weekend demand combined with the continuous running of Junction Road.

7.3. Overall, there were less thermal peakers running this week with both Stratford units being on outage. Junction Road ran continuously through Sunday ramping up during the peak and shoulder period, through to around midday Monday. It then only ran the Monday evening peak, Wednesday and Thursday evening peaks, and then ran overnight from Friday evening into Saturday. McKee mainly ran over the daily peak periods from Monday to Friday, before generating for a continuous period from Friday evening though to Saturday. Huntly 6 ran over Sunday and Monday peak and shoulder as well as the Tuesday evening peak.

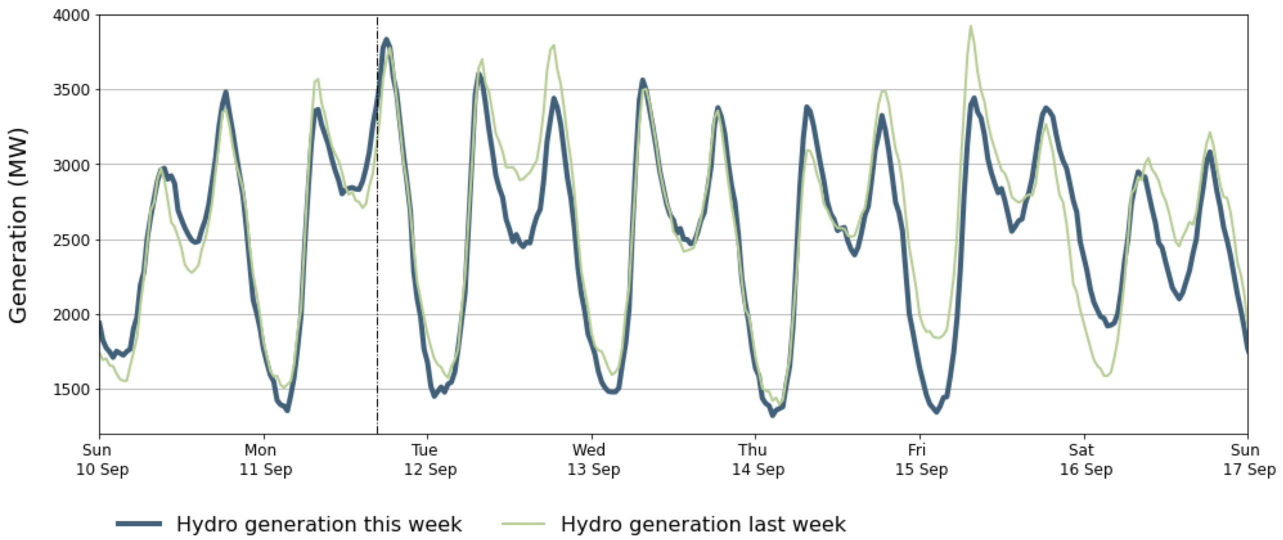
Figure 10: Thermal generation between 10-16 September





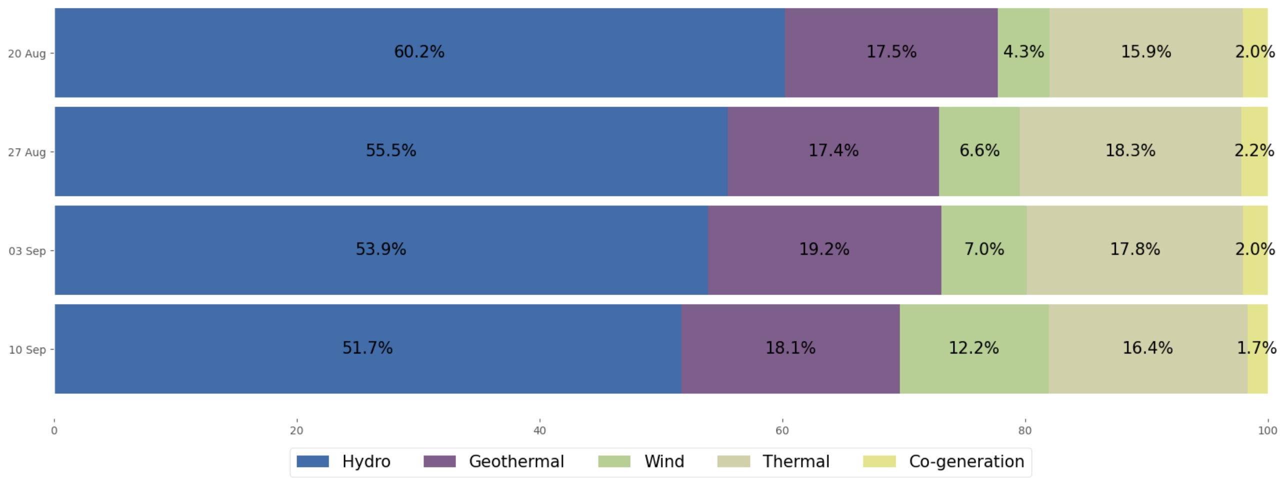
7.4. Figure 11 shows hydro generation between10-16 September. Most days saw a similar volume of generation from hydro this week with the only significant decreases seen on Tuesday during the shoulder and evening peak periods and the Friday morning peak. At these times there was around 700MW of wind generation.

Figure 11: Hydro generation between 10-16 September compared to the previous week



7.5. As a percentage of total generation, between 10-16 September, total weekly hydro generation was 51.7%, geothermal 18.1%, thermal 16.4%, wind 12.2%, and co-generation 1.7%. An increase in the amount of generation from wind caused a drop in the thermal and hydro proportions this week.

Figure 12: Total generation by type as a percentage each week between 10-16 September



8. Outages

8.1. Figure 13 shows generation capacity on outage. Total capacity on outage between 10-16 September ranged from around 1300MW to ~1800MW.

8.2. Notable outages include:

(a) Huntly 5 is on outage until 31 January 2024.

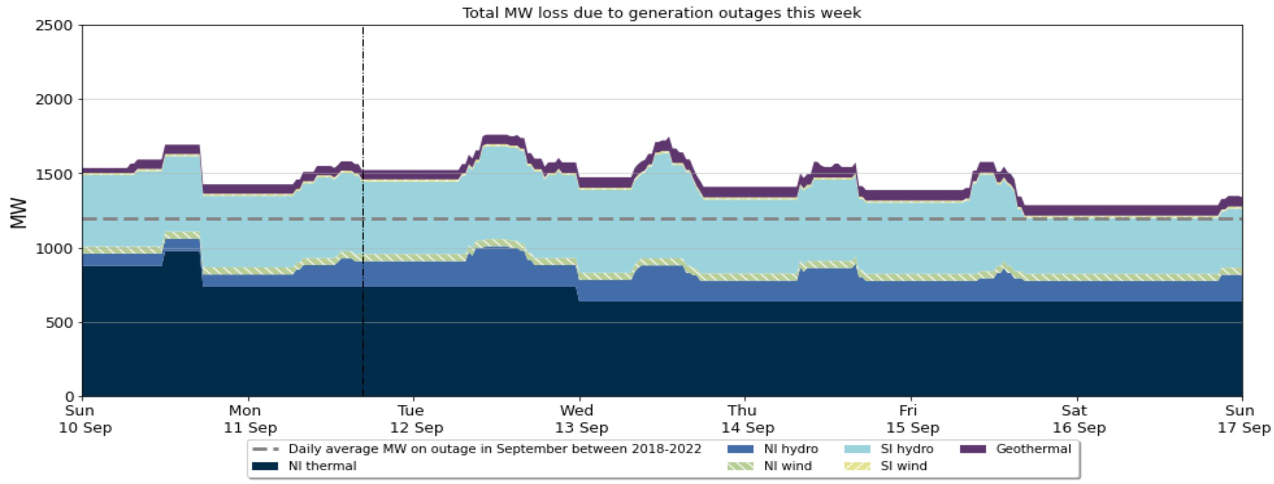
(b) Stratford 1 is on outage from 8 September to 1 October 2023.

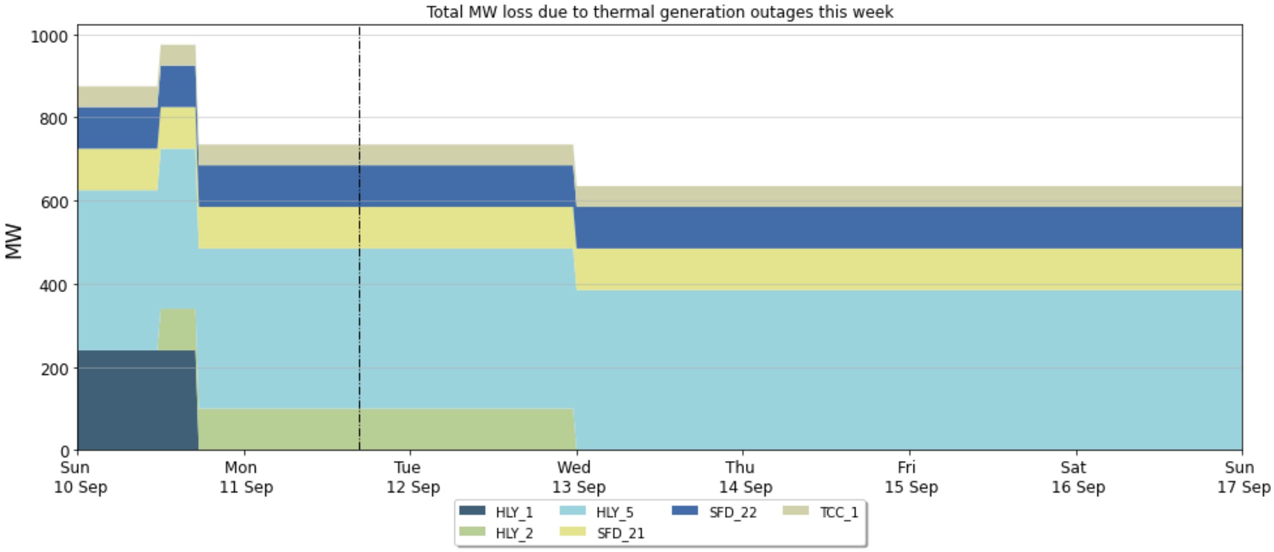
(c) Stratford 2 is on outage until 28 February 2025.

(d) West Wind Station is on outage until 30 September 2024.

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

Figure 13: Total MW loss due to generation outages





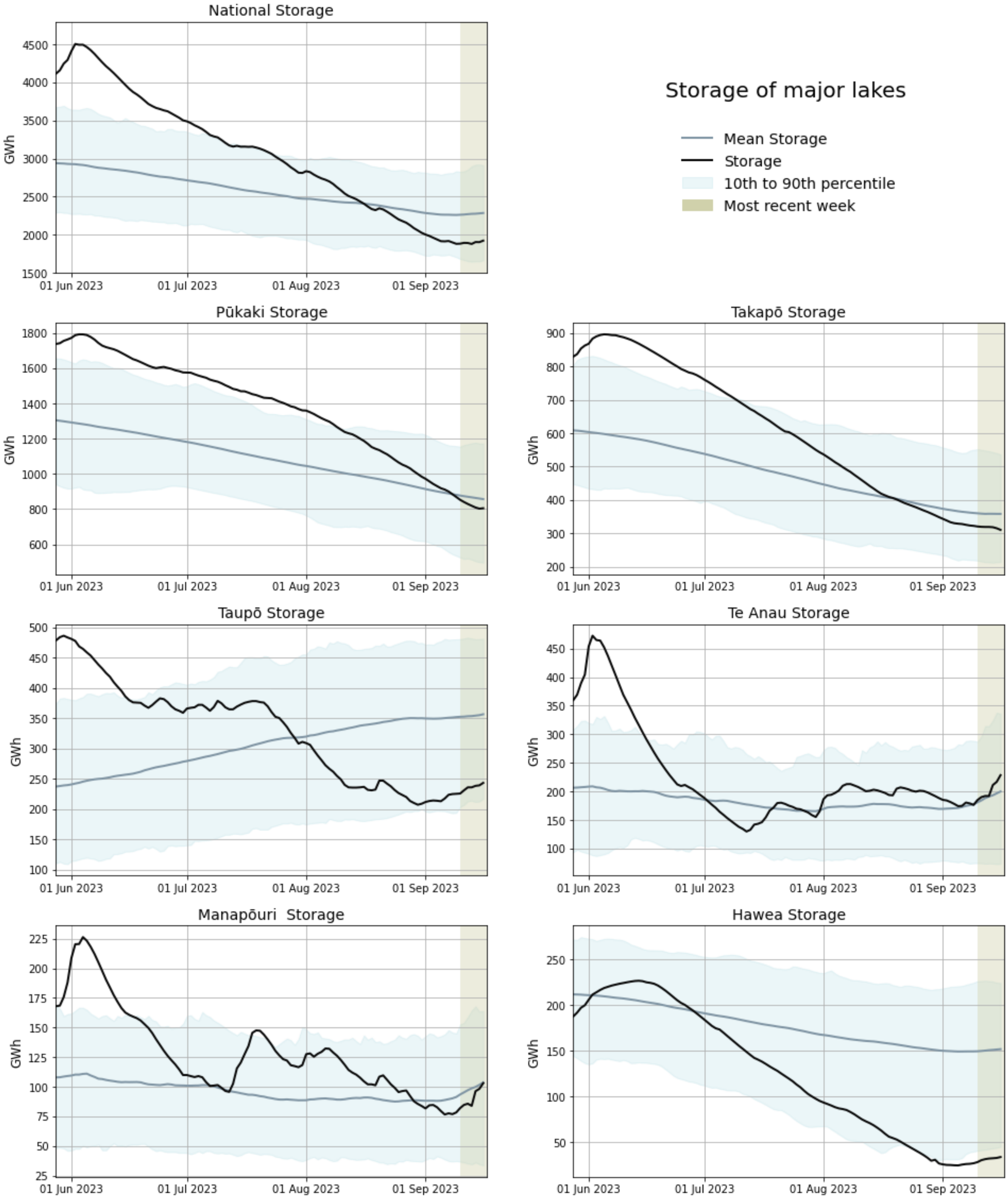
9. Storage/fuel supply

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 remained around 51.4% nominally full and 88% of the historic mean as some lakes experienced inflows over the week.

9.3. Most lakes saw a small uptick in storage this week. Taupō storage showed a steady increase, approaching 250GWh, but still remains close to its historic 10th percentile. Pūkaki continued to decrease below its mean storage, although levelled off toward the end of the week. Takapō decreased slightly and remains below its mean. Hawea storage increased slightly but is still below its historic 10th percentile. Manapōuri storage saw a steep increase approaching its historic mean and Te Anau remains above its mean, also seeing a storage increase over the week.

Figure 14: Hydro storage

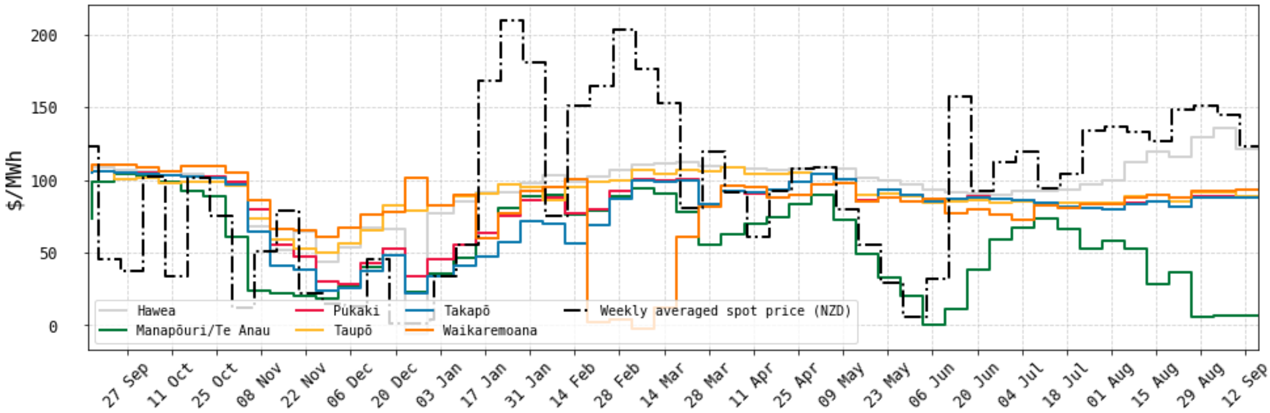


10. JADE water values

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 16 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. Manapōuri/Te Anau values remain low at ~$6.70/MWh with increased inflows over the last couple of weeks. Hawea has had some inflows over the last week and its water values have decreased by around $15/MWh to ~$121/MWh. All other water values remained steady.

Figure 15: JADE water values across various reservoirs between 15 September 2022 and 16 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.

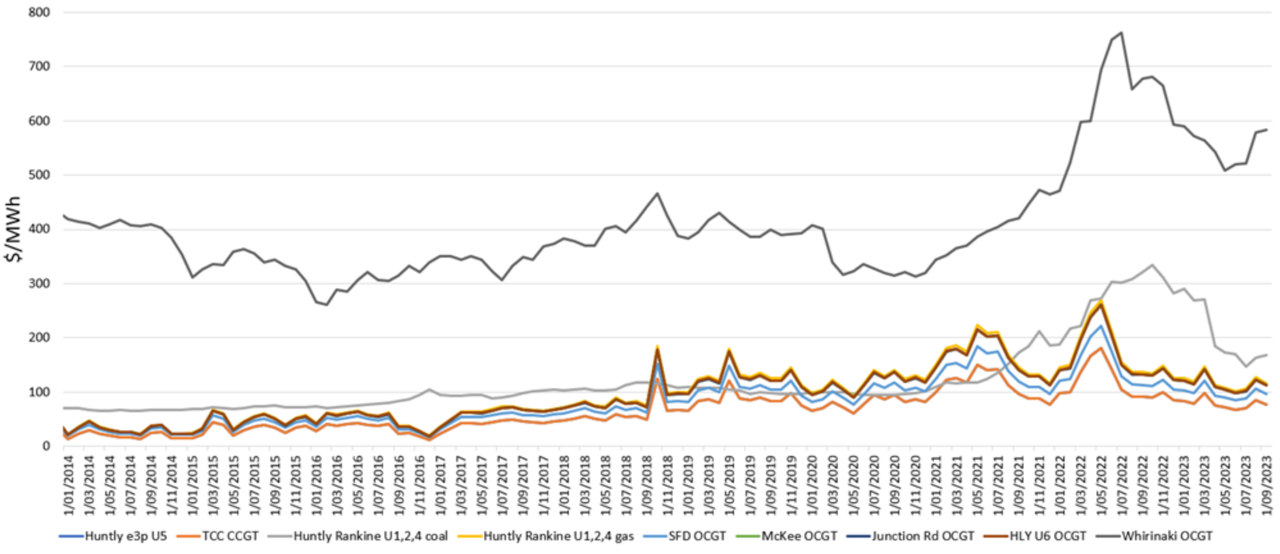
[1] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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

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

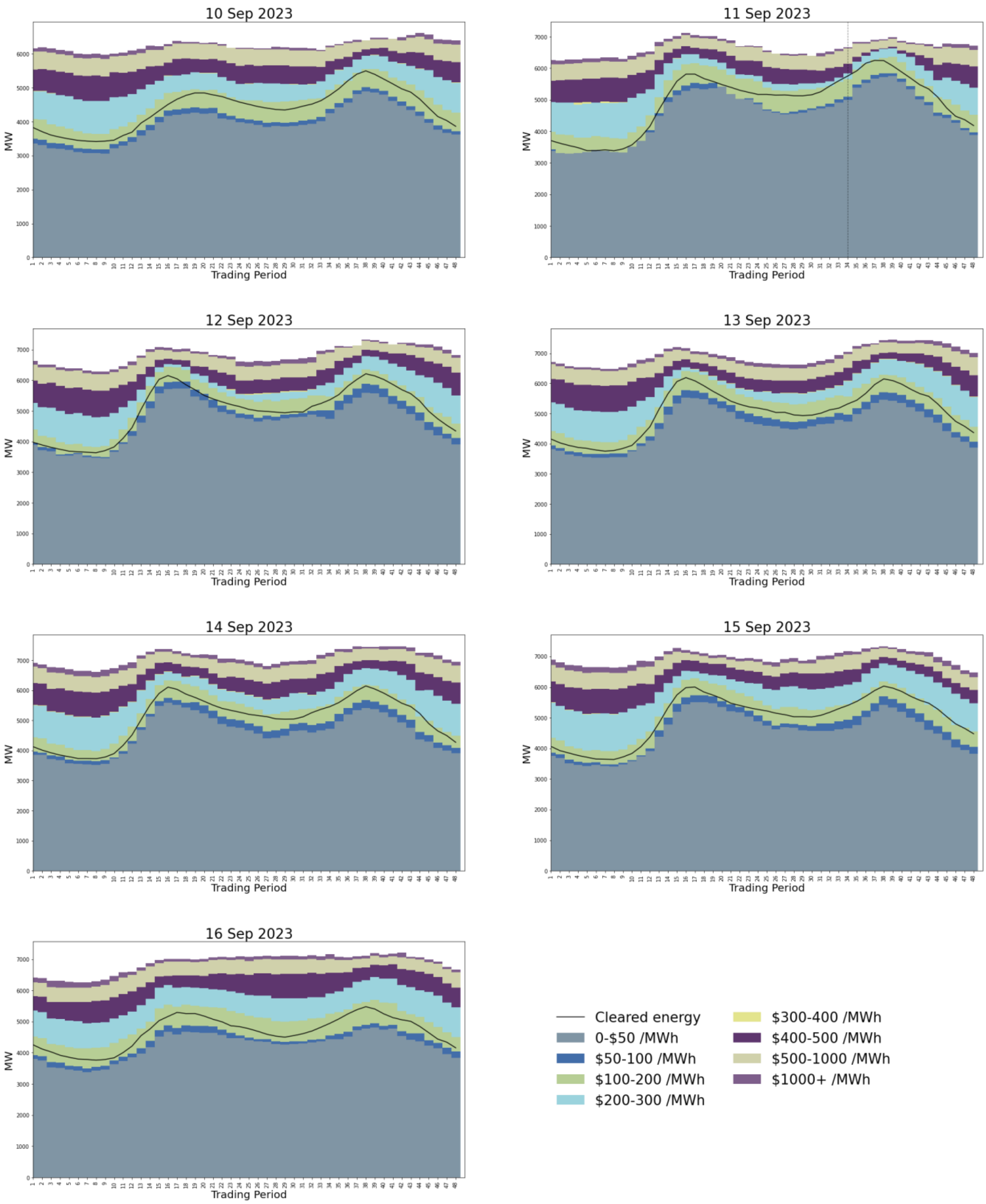


12. Offer behaviour

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. Currently the $50-$100/MWh offer band is quite thin, but otherwise the offer bands are relatively wide. The majority of offers cleared in the $100-$200/MWh price range, which is consistent with estimated marginal costs. The spike in prices on Monday afternoon was the only time offers cleared in the $200-$300/MWh price range and coincided with lower than forecast wind generation.

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. There are no further new analysis cases this week.

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.