8 January 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 31 December 2023 – 6 January 2024

1.1. Throughout this week, spot prices mostly ranged between $90-$190/MWh. Instances of price spikes were observed during periods of low wind generation when load was supported by thermal generation. TCC with Huntly 1 continues to run as baseload. As of January 6, hydro storage was approximately 91% of its 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 are outliers compared to historic prices for the same time of year.

2.2. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10^{th} -90^{th} percentiles adjusted for inflation. Prices greater than quartile 3 (75^{th} percentile) plus 1.5 times the inter-quartile range[1] of historic prices, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 31 December 2023 – 6 January 2024:

(a) The average wholesale spot price across all nodes was $133/MWh.

(b) 95 percent of prices fell between $0.06/MWh and $249/MWh.

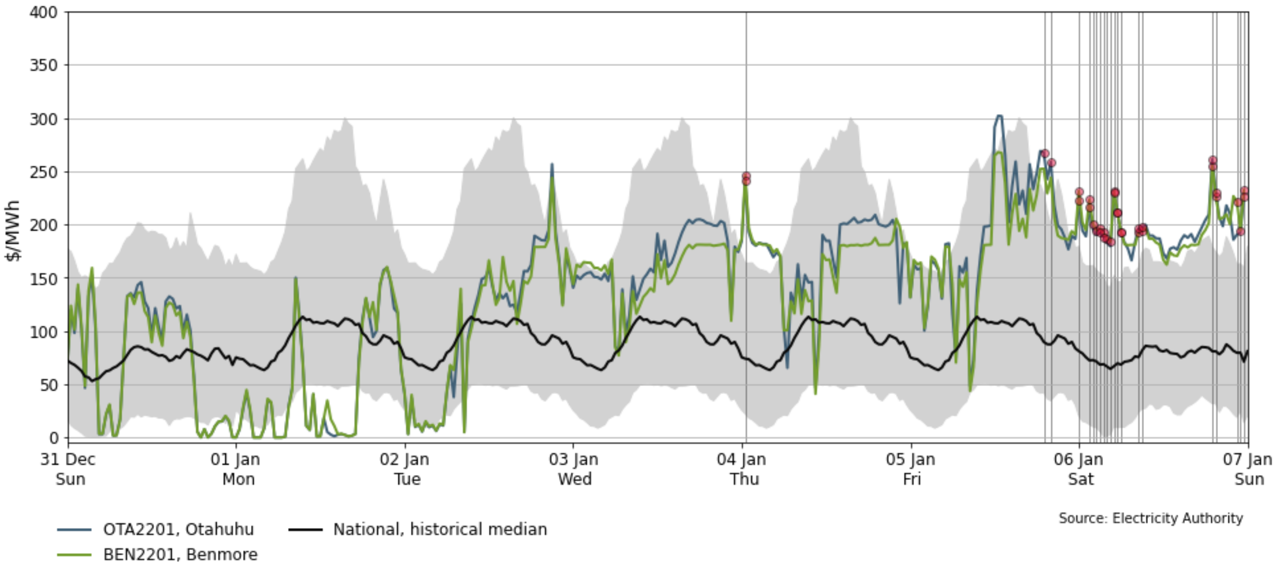
2.4. Overall, spot prices are still sitting mainly below $300/MWh but above the historic average for this time of year. There were a number of price spikes across the week but these were mostly under $300/MWh. Most of these spikes were due to relatively higher priced energy being dispatched to cover wind or demand forecast discrepancies.

2.5. The first instance where the spot price went above the 90^{th} percentile was on Thursday morning at 12:30am. Prices at Ōtāhuhu were $241/MWh and $246/MWh at Benmore.

2.6. On Saturday, prices were higher than the 90^{th} percentile for the whole day, mainly due to low wind generation. Load was supported by thermal generation.

[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day, and looking for prices that lie 1.5 times the interquartile range above the 75^{th} percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75^{th} percentile (or third quartile value) and IQR is your inter-quartile range.

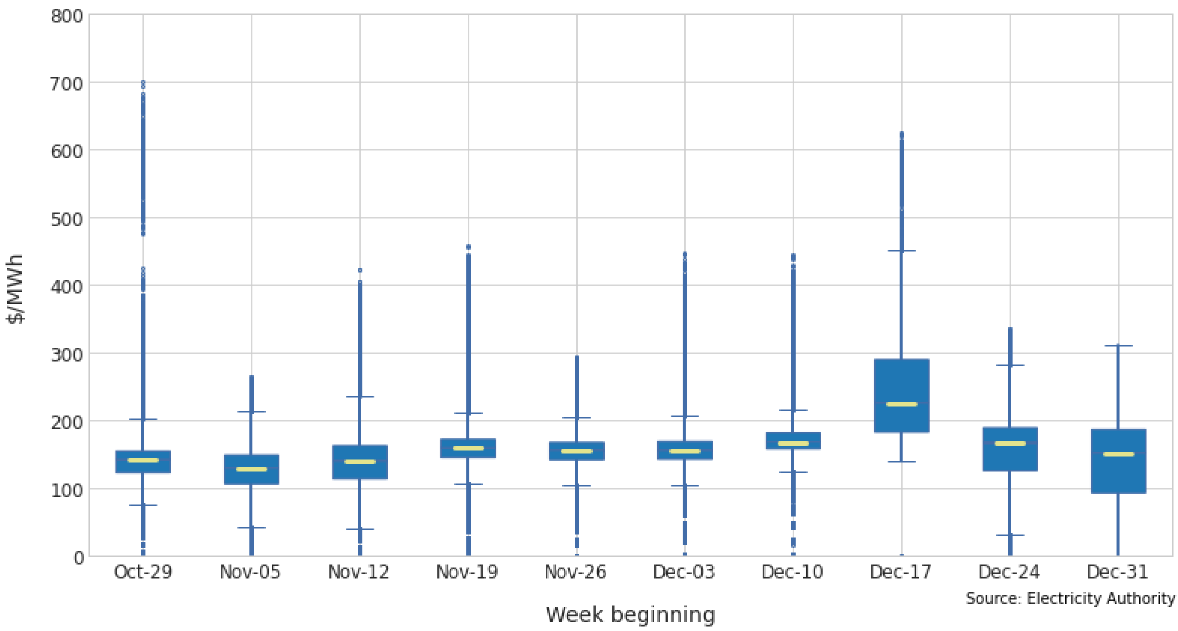
Figure 1: Wholesale spot price at Benmore and Ōtāhuhu between 31 December – 6 January



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. There was a wide distribution of prices this week, with the middle 50% of prices between \$92/MWh and \$186/MWh. The median price was \$152/MWh. This week there weren't any outlier prices.

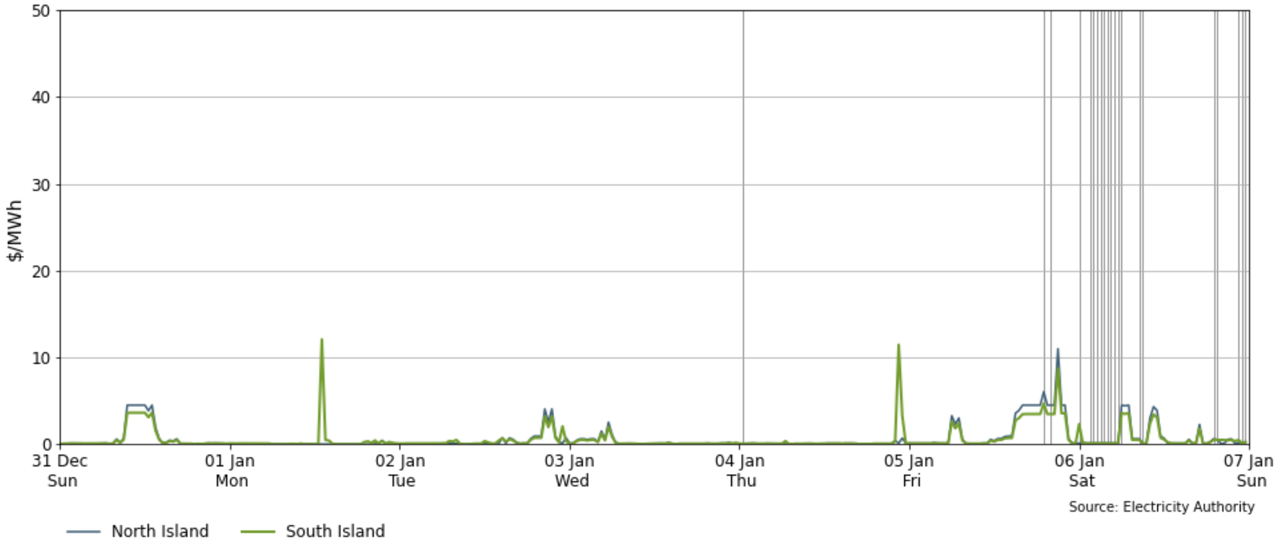
Figure 2: Boxplots showing the distribution of the spot prices this week and the previous nine weeks



3. Reserve prices

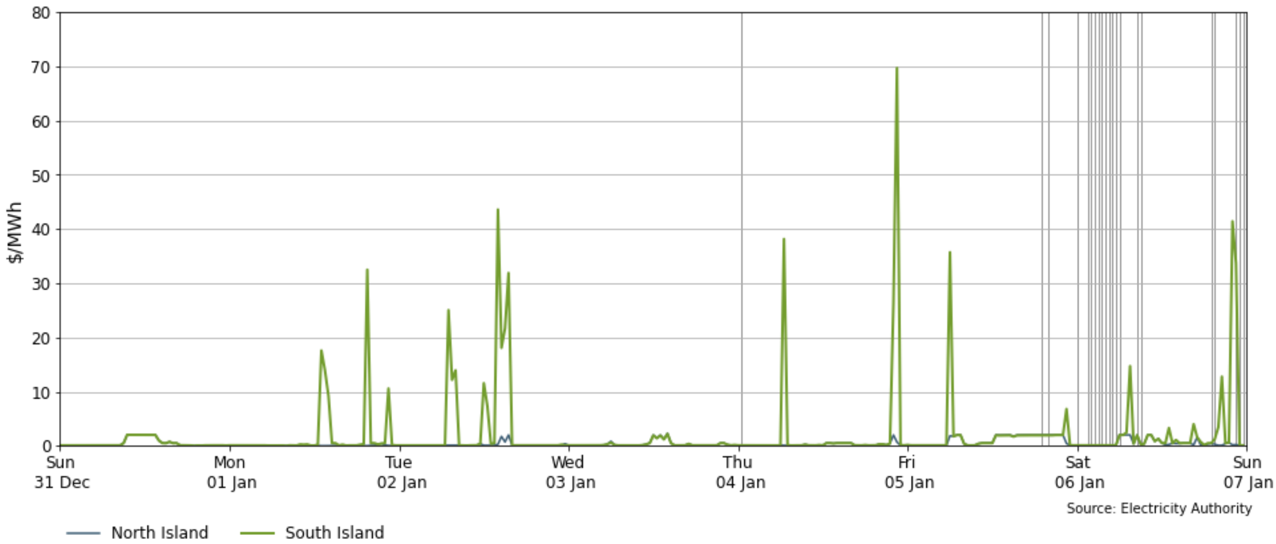
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week FIR prices were mostly below $10/MWh.

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. There were some spikes in the SIR prices this week. The largest spike occurred at 10:30pm on Thursday in the South Island. The South Island price reached around $70/MWh while the North Island price was $0.7/MWh, which might be due to the HVDC becoming the binding risk in the South Island. When the HVDC changes direction, for a short period there is only one pole operating which means there is no redundancy. Once the second pole changes direction, the HVDC will no longer be the binding risk.

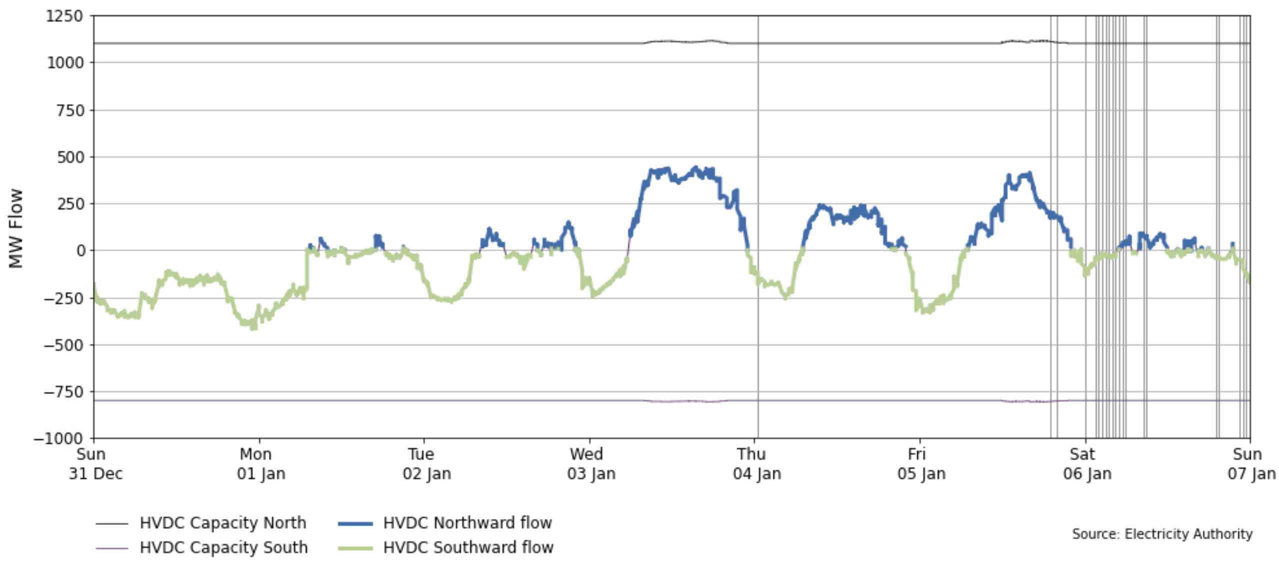
Figure 4: Sustained Instantaneous Reserve (SIR) prices by trading period and island



4. HVDC

4.1. Figure 5 shows HVDC flow between 31 December – 6 January. HVDC flows were mainly southwards at the start of the week due to high wind generation. From Wednesday, flows were northwards during the day with southward flow overnight. On Saturday the HVDC flows were variable and changing direction. Northward flow was below 500MW, while the maximum southward flow was around 327MW.

Figure 5: HVDC flow and capacity



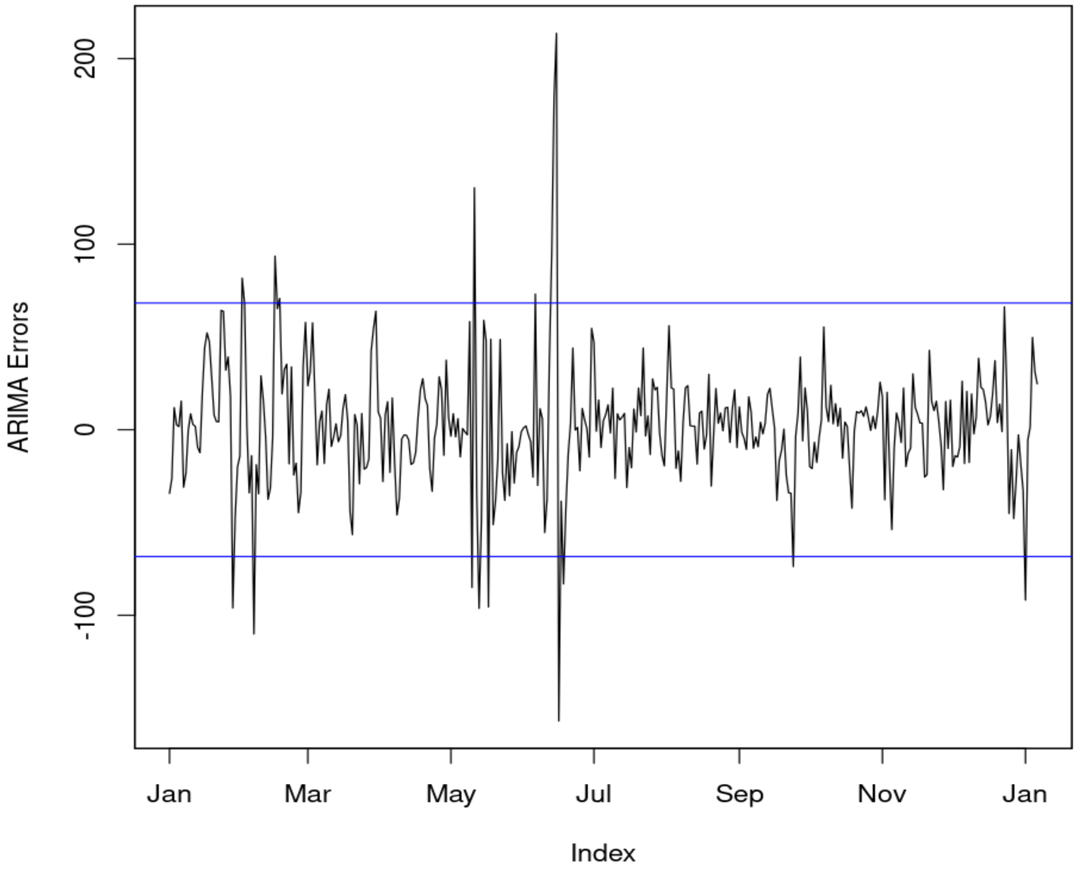
5. Regression residuals

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 the 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 below the two standard deviations on 1st January due to a relatively low average price for a usual Monday. The model does not account for public holidays.

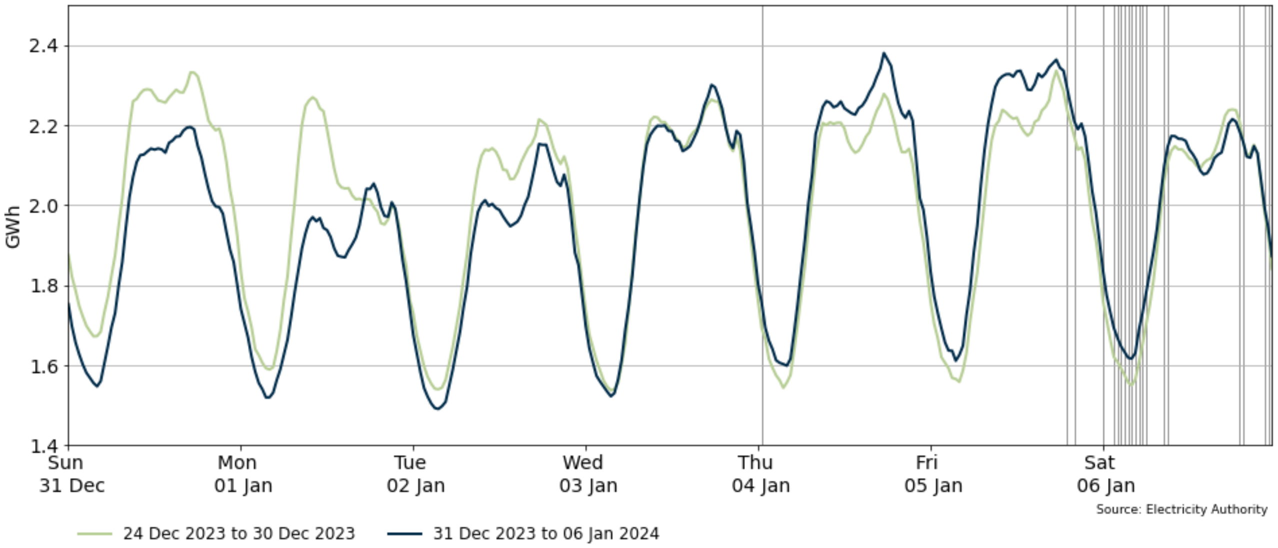
Figure 6: Residual plot of estimated daily average spot prices from 1 January 2023 – 6 January 2024



6. Demand

6.1. Figure 7 shows national demand between 31 December – 6 January, compared to the previous week. Due to public holidays, demand during the first three days of the week was lower compared to the previous week, returning to similar levels to the previous week from 3rd January. Demand was higher on Thursday and Friday with maximum demand on Thursday evening. Demand was slightly higher than forecast on Saturday morning, which also contributed to the higher prices during that time.

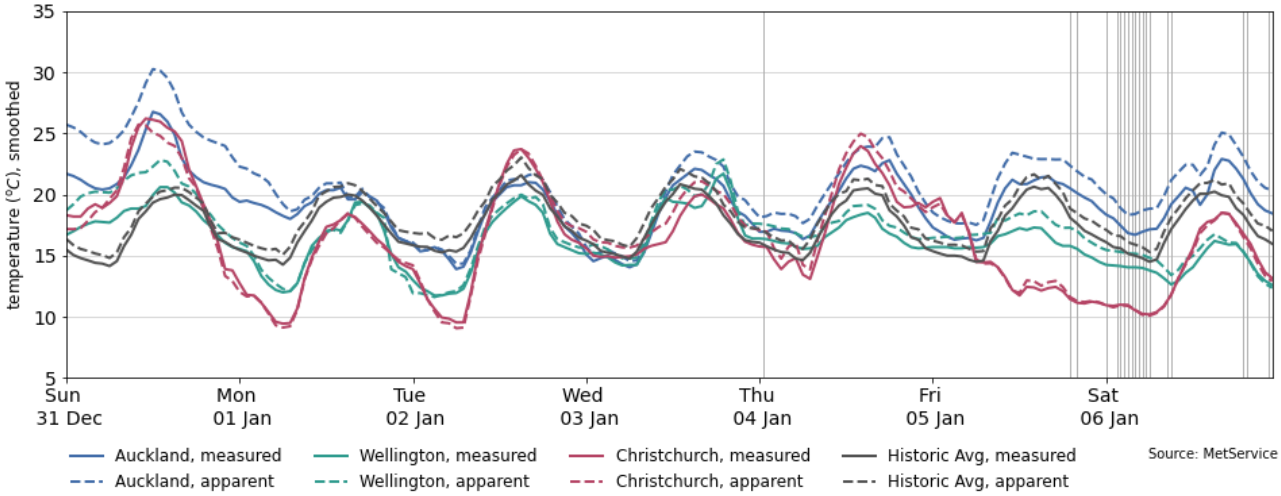
Figure 7: National demand by trading period compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 31 December – 6 January. 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 generally close to average for most of the week, except for a hot day at the beginning of the week (on Sunday) and a couple of cool periods for this time of year for Christchurch and Wellington.

Figure 8: Temperatures across main centres

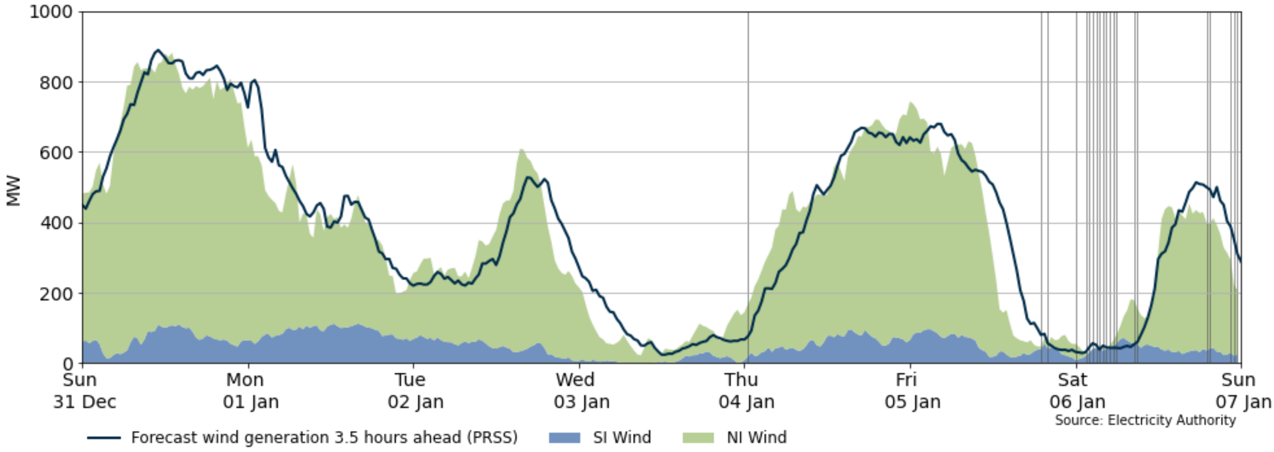


7. Generation

7.1. Figure 9 shows wind generation, from 31 December – 6 January, ranging from ~22MW to 881MW. At the start of the week, wind started high above 800MW but dropped to around 210MW on Monday night. On Tuesday, wind generation gradually increased to around 600MW until it experienced a notable drop that night. Wind remained low throughout Wednesday before increasing on Thursday to around 700MW. Between Friday and

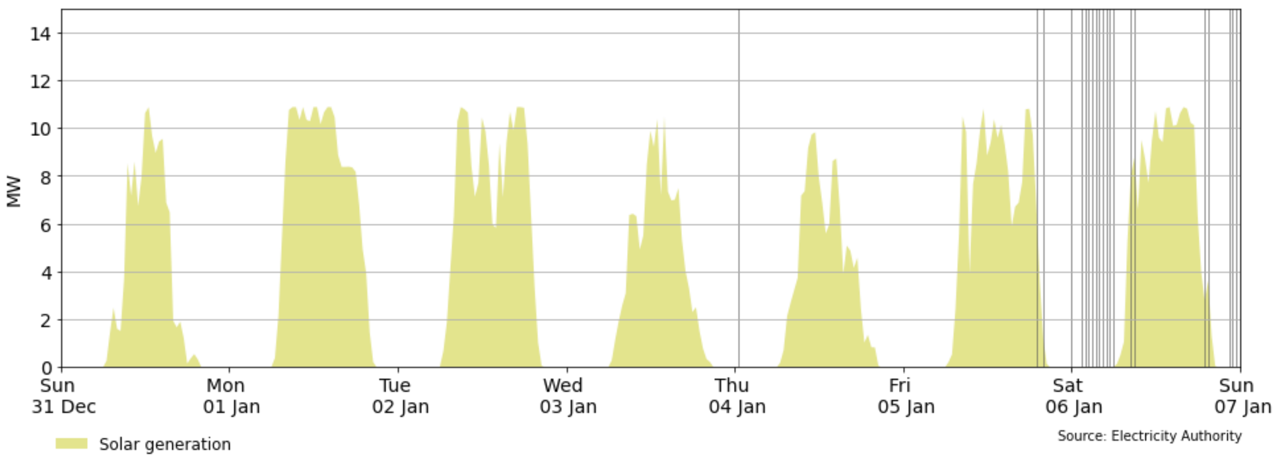
Saturday, relatively high overnight prices were observed due to low wind generation. Later on Saturday wind generation was higher but lower than forecast, which also contributed to the price spikes at that time.

Figure 9: Wind generation and forecast between 31 December – 6 January



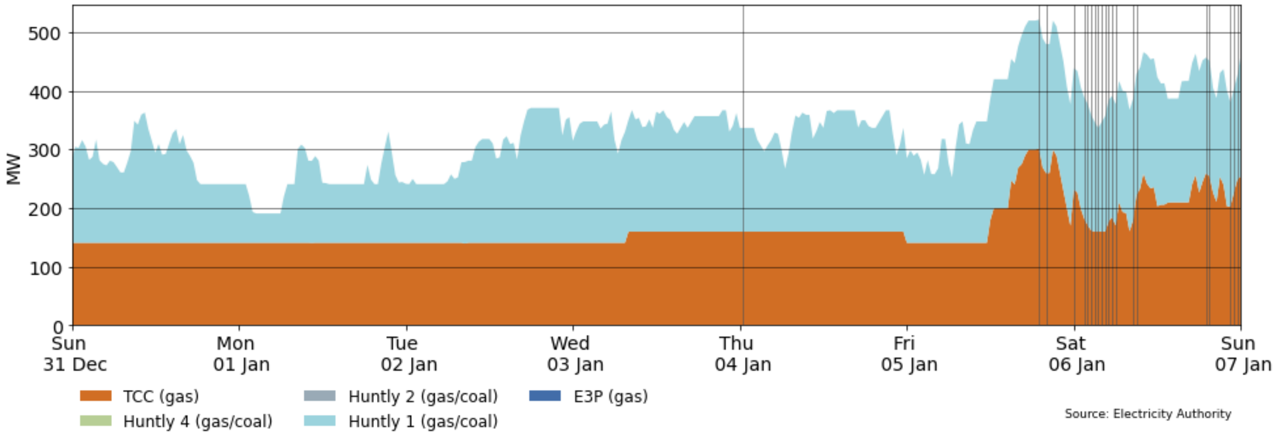
7.2. Some solar generation also occurred this week as the commissioning process continues at Kaitaia Solar Farm.

Figure 10: Solar generation between 31 December – 6 January



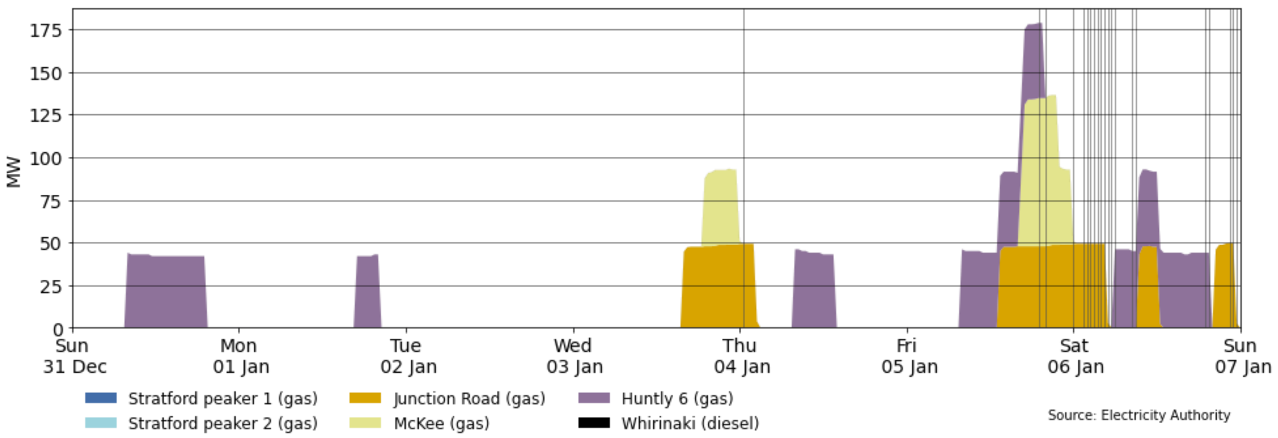
7.3. Figure 11 shows the generation of thermal baseload and thermal peaker plants between 31 December – 6 January. Both TCC and Huntly 1 ran continuously as baseload this week.

Figure 11: Thermal baseload generation between 31 December – 6 January



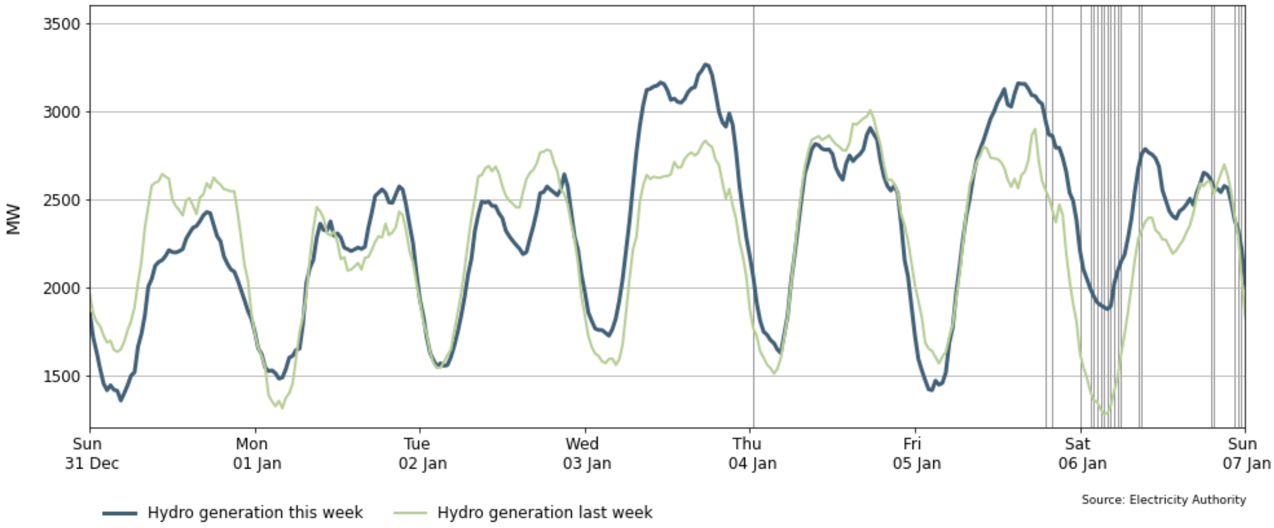
7.4. Figure 12 shows the generation from peaking plants between 31 December – 6 January. During the holidays, only Huntly 6 ran during a few hours on Sunday and on Monday. Junction Road ran on Wednesday and on Friday/Saturday. Friday was when peaking generation was most needed due to low wind and hydro generation, with three plants running (Huntly 6, McKee, and Junction Rd), reaching more than 175MW of supply in some trading periods.

Figure 12: Thermal peakers generation between 31 December – 6 January



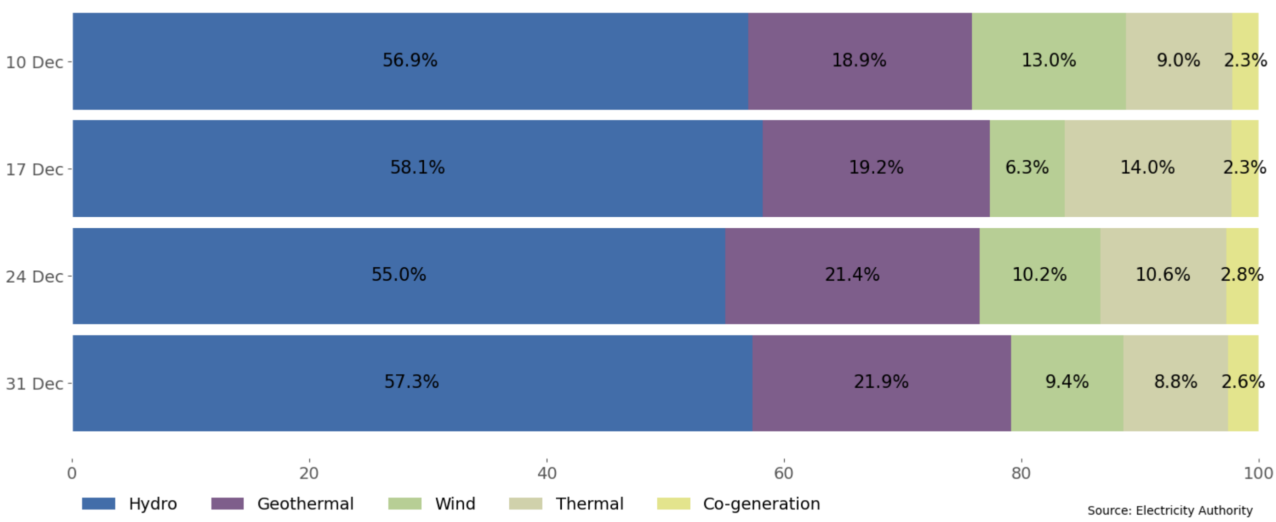
7.5. Figure 13 shows hydro generation between 31 December – 6 January. Hydro generation was mostly lower compared to the previous week during the public holidays, and higher than the previous week from Wednesday and onwards. However, on Thursday hydro generation was slightly lower due to high wind generation.

Figure 13: Hydro generation between 31 December – 6 January compared to the previous week



7.6. As a percentage of total generation, between 31 December – 6 January, total weekly hydro generation was 57.3%, geothermal 21.9%, wind 9.4%, thermal 8.8%, and co-generation 2.6%.

Figure 14: Total generation by type as a percentage each week between 10 December 2023 – 6 January 2024



8. Outages

8.1. Figure 15 shows generation capacity on outage. Total capacity on outage between 31 December – 6 January ranged from 1300MW to 1500MW and was mainly lower than the average for this time of year.

8.2. Notable outages include:

(a) Huntly 5 on outage until 20 January 2024

(b) Stratford 2 outage until 28 February 2025

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

Figure 15: Total MW loss due to generation outages

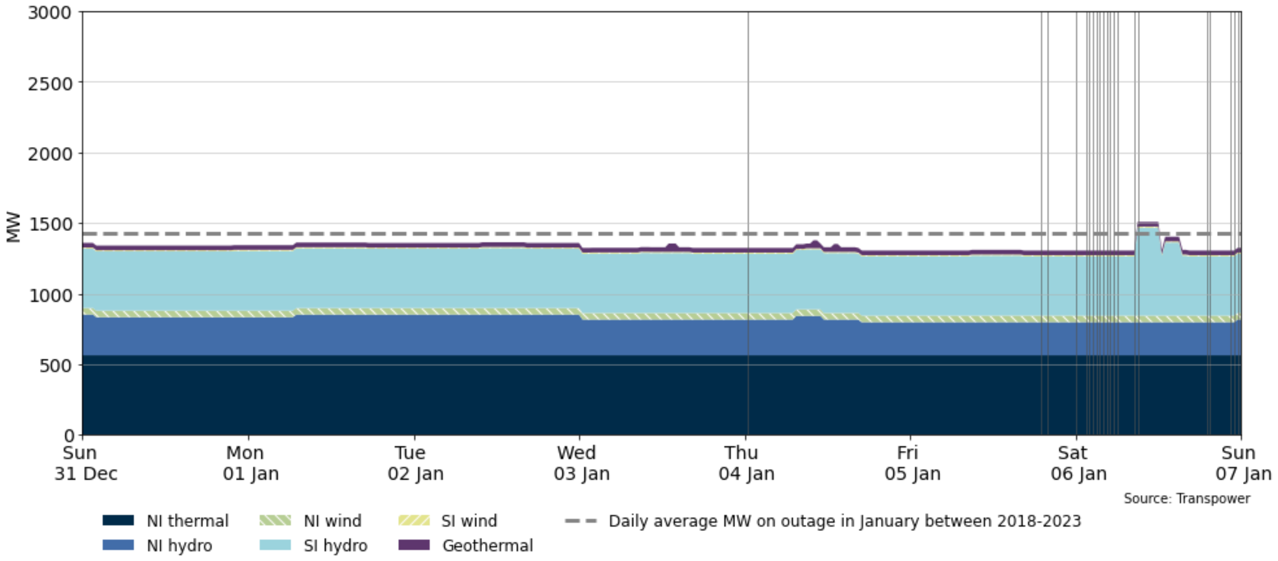
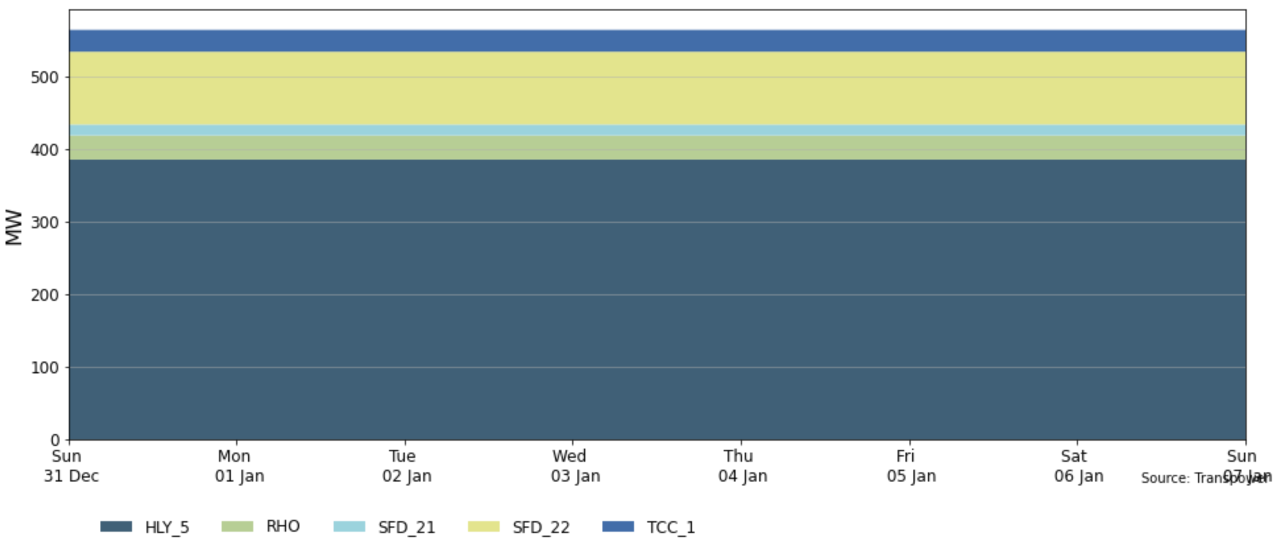


Figure 16: MW loss from thermal outages



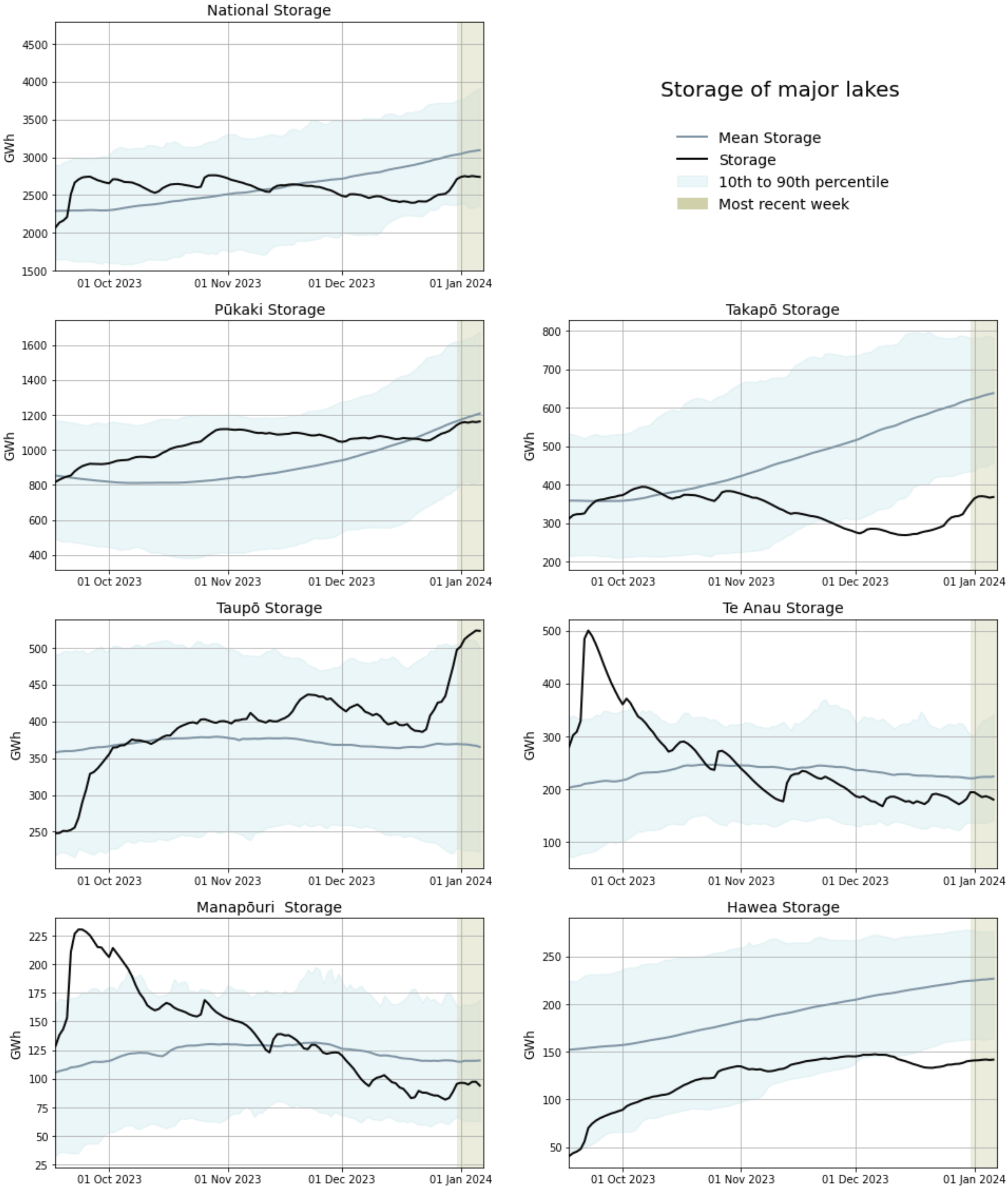
9. Storage/fuel supply

9.1. Figure 17 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 are below their historical average for this time of year, as of 6 January at 91% of historic mean and 70% of nominal full.

9.3. During this week, national hydro storage remained steady. Pūkaki storage is slightly below its historic mean, while Takapō storage is still below its historic 10th percentile. Manapōuri and Te Anau storage also remain below the historic mean for this time of year but above their 10th percentile ranges. Taupō storage increased significantly and is above its 90th percentile. However, Hawea storage is below its 10th percentile range.

Figure 17: Hydro storage

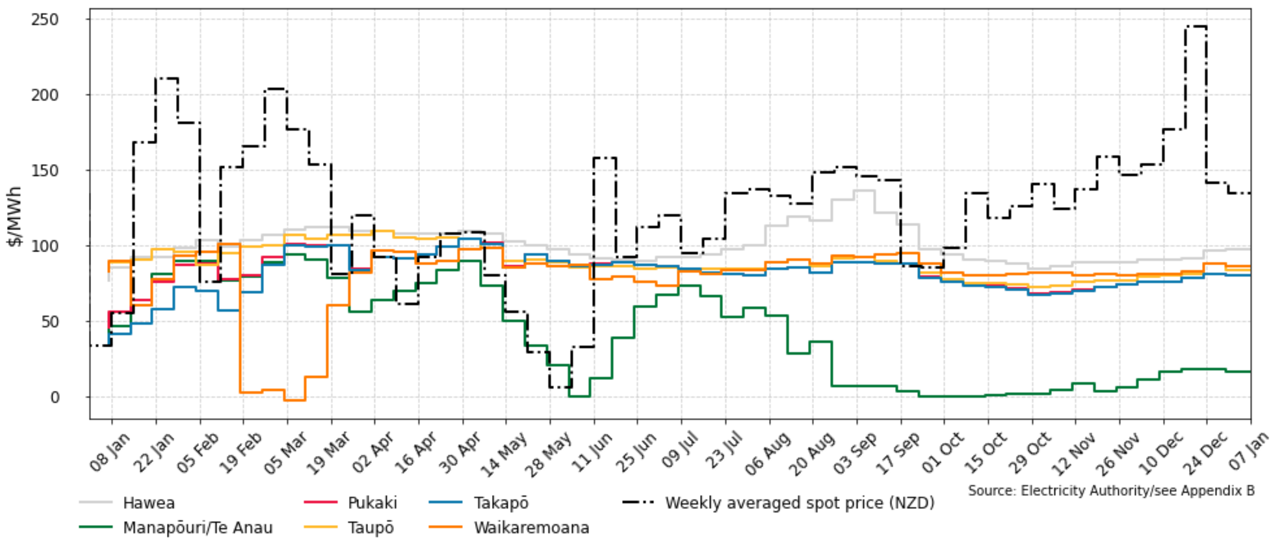


Source: Electricity Authority

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 18 shows the national water values between 1 January 2023 and 6 January 2024 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. The water values of most lakes remained steady.

Figure 18: JADE water values across various reservoirs between 1 January 2023 and 6 January 2024



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 19 shows an estimate of thermal SRMCs as a monthly average up to 1 January 2024. The SRMC for diesel decreased slightly compared to the previous month. The coal SRMC also continued its slightly decreasing trend, while the gas SRMC continued to slightly increase.

11.4. The latest SRMC of coal-fuelled Rankine generation is ~$154/MWh. This is now lower than the cost of running the Rankines on gas at ~$168/MWh.

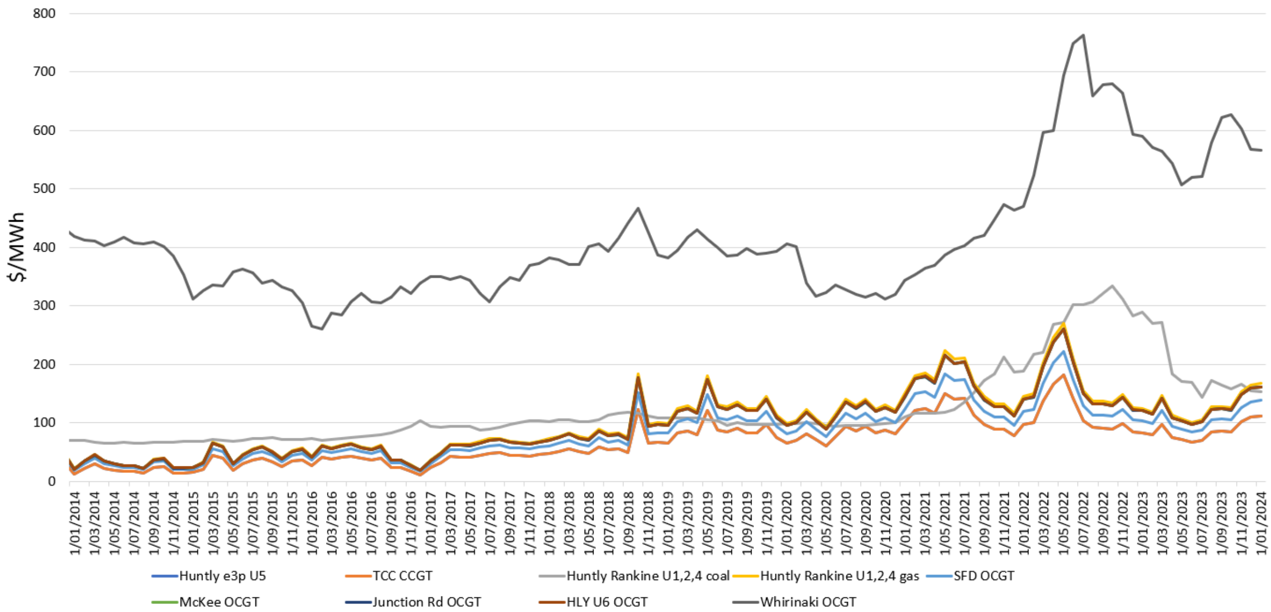
11.5. The SRMC of gas fuelled thermal plants is currently between $112/MWh and $168/MWh.

11.6. The SRMC of Whirinaki has decreased to ~$566/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.

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

Figure 19: Estimated monthly SRMC for thermal fuels



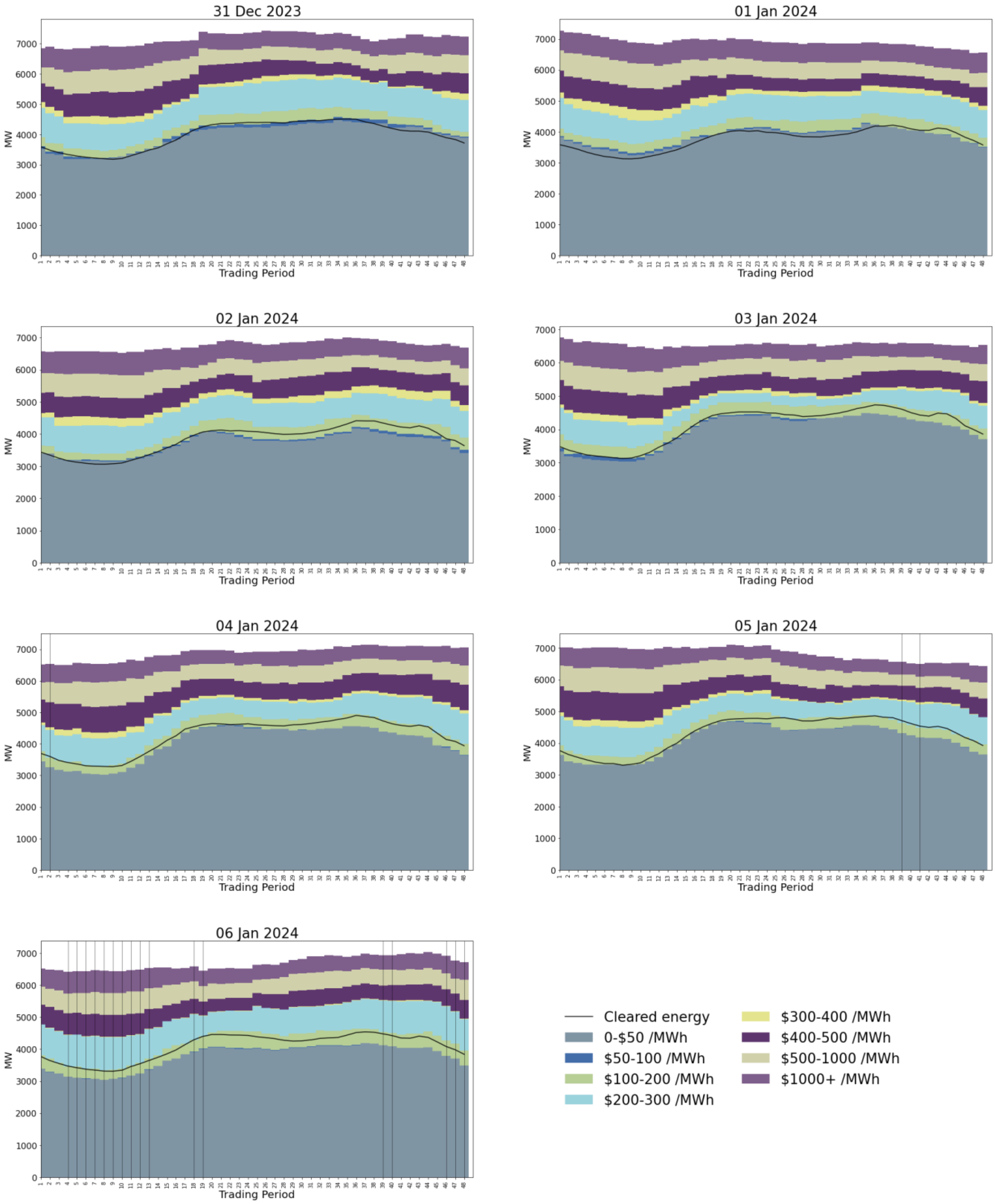
Source: Electricity Authority/see Appendix C

12. Offer behaviour

12.1. Figure 20 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Most offers cleared in the $100-$200/MWh price band this week. There was only a very small (and sometimes none) amount of generation offered between $50-$100/MWh. The amount of generation offered between $200-$300/MWh increased this week. Small changes in conditions can result in price spikes, as the cleared energy moves to the next price band.

Figure 20: Daily offer stacks[3]



Source: Electricity Authority

[3] Offer stacks were generated using PRSS data 30 minutes before gate closure due to unavailable RTD data.

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
14/06/2023-15/06/2023	15-17/ 15-19	Passed to Compliance	Genesis	Multiple	High energy prices associated with high energy offers.
22/09/2023-30/09/2023	Several	Further analysis	Contact	Multiple	High hydro offers.