8 April 2024

# Trading conduct report

Market monitoring weekly report

# Trading conduct report

## 1. Overview for the week of 31 March-6 April

1.1. Spot prices remained relatively stable this week, with prices mostly between $200-$300/MWh. No spot price spikes occurred this week, but there were several reserve price spikes. On Monday multiple reserve price spikes occurred during an unplanned HVDC Pole 3 outage. After this outage, the HVDC flowed North during the day and South overnight. Hydro storage declined this week and is now at ~84% of its historical average. Several thermal units ran to support the baseload, including TCC, Huntly 5, Huntly 4, and then Huntly 2. Junction Road also supported baseload generation. Lower wind generation this week increased reliance on hydro.

## 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 10th-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th 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 March-6 April:

(a) The average wholesale spot price across all nodes was $261/MWh.

(b) 95% of prices fell between $172/MWh and $318/MWh.

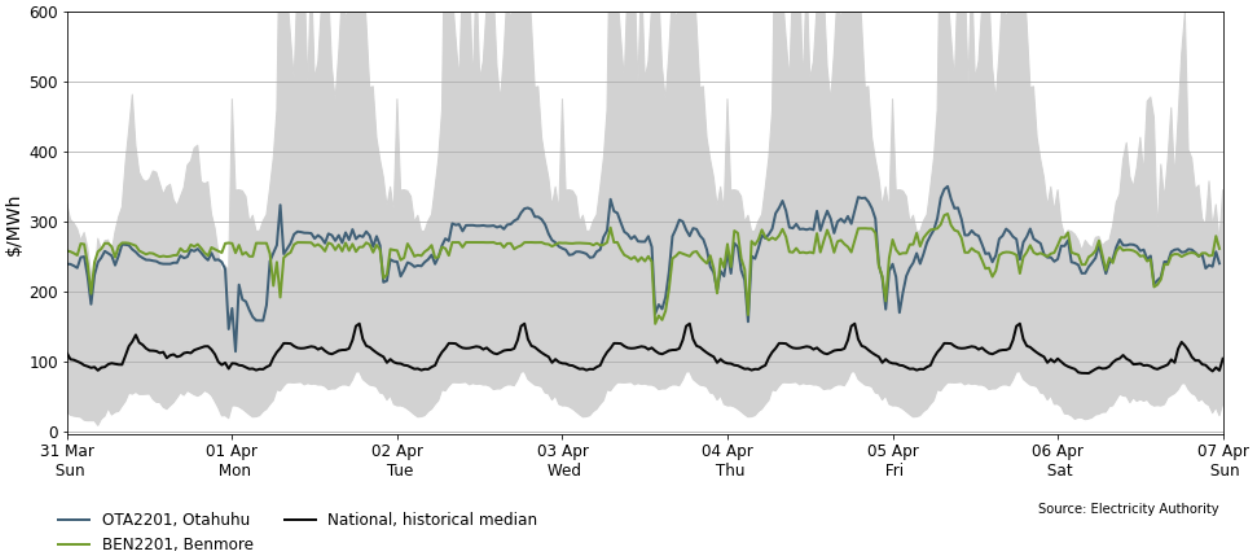
2.4. This week, the spot prices were all above the national historical median and mostly above $200/MWh. There were a few cases of prices above $300/MWh, although no price spikes occurred this week. The consistently high prices are influenced by declining hydro storage and high thermal generation levels. The average price increased by $13/MWh compared to the previous week.

2.5. On Monday, an unplanned HVDC Pole 3 trip caused Ōtāhuhu prices to drop below Benmore prices for a portion of the day. Once the outage concluded, the North and South Island prices re-converged.

2.6. The dips in prices seen between Wednesday and Thursday are likely related to an increase in wind generation during times of lower demand.

[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×IQR, where $Q_3$ is the 75$^{th}$ percentile (or third quartile value) and IQR is your inter-quartile range.

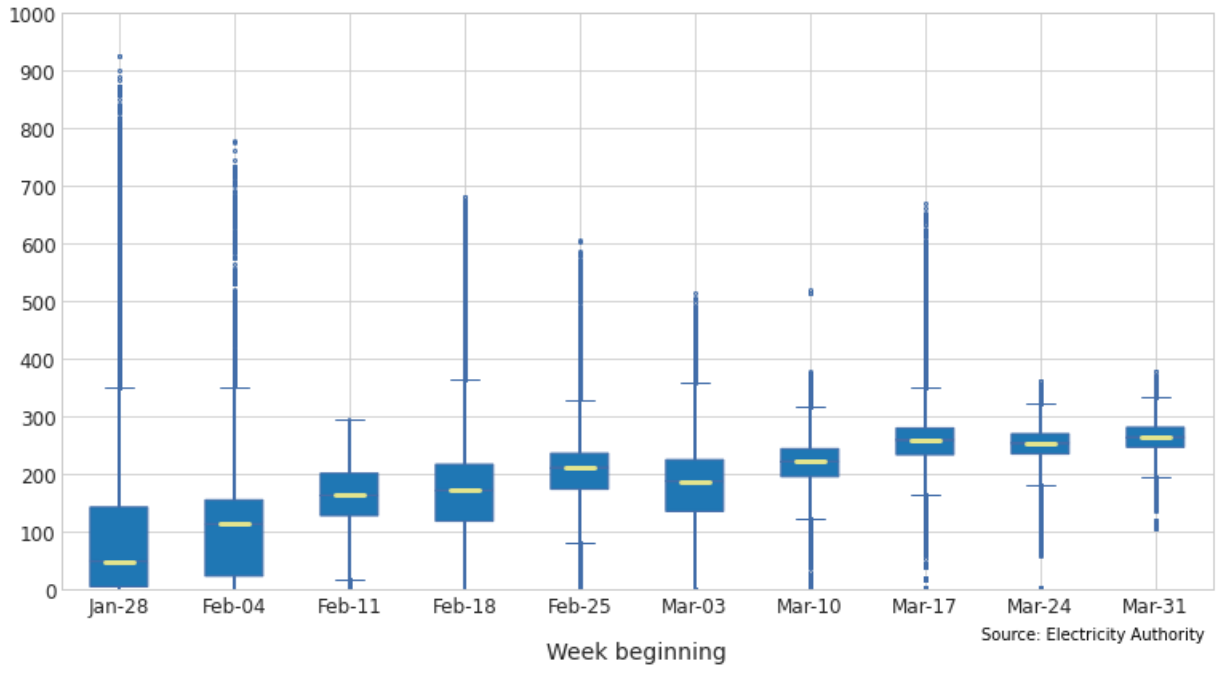
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 31 March-6 April**




2.7. 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.

2.8. Spot prices remained condensed this week. The median price was $263/MWh this week, compared to $253/MWh in the previous week, a $10/MWh increase. The middle 50% of the prices were between $246-$281/MWh.

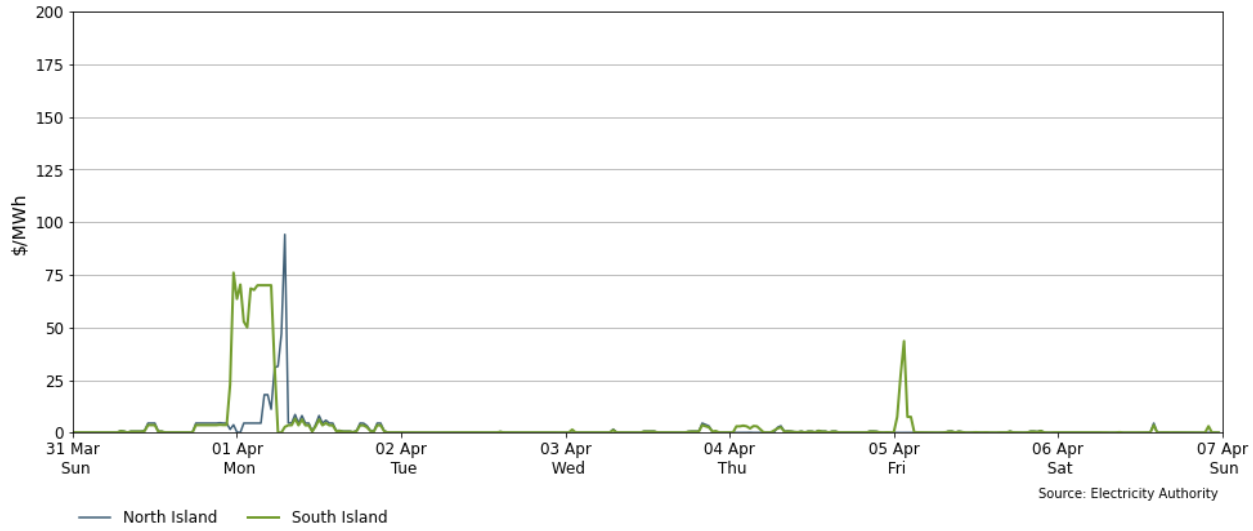
**Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks**



# 3. Reserve prices

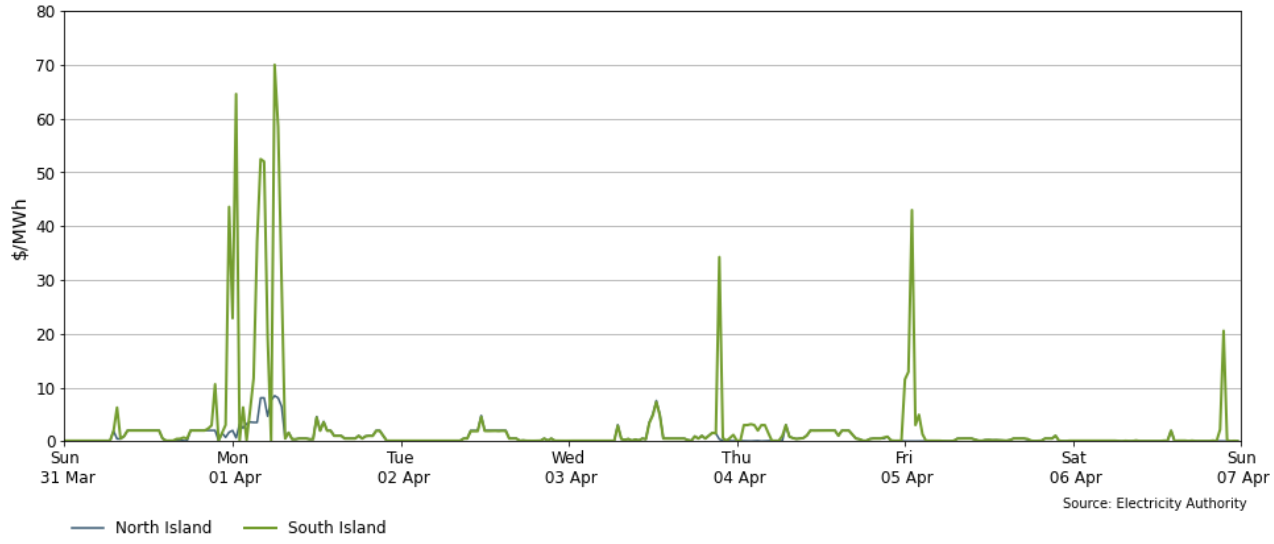
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh, except for a few spikes late Sunday and Monday, related to the HVDC Pole 3 unplanned outage, with the HVDC risk needing to be covered by South Island reserves when it was operating in monopole. The North Island price spike on Monday morning was also influenced by the HVDC outage, as reserves cannot be shared in the opposite direction during monopole operation, and the HVDC was flowing south. The South Island price spike on Friday was related to high southward HVDC flow.

**Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 31 March-6 April**




3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. The SIR prices on both islands were mostly below $5/MWh this week. The South Island saw some spikes in the SIR prices, reaching a maximum of 70/MWh on Sunday and Monday during the unplanned HVDC Pole 3 outage. The Thursday and Saturday South Island SIR spikes occurred close to when the HVDC was reversing its flow. Finally, the Friday spike is related to high HVDC southward transfer.

**Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 31 March-6 April**



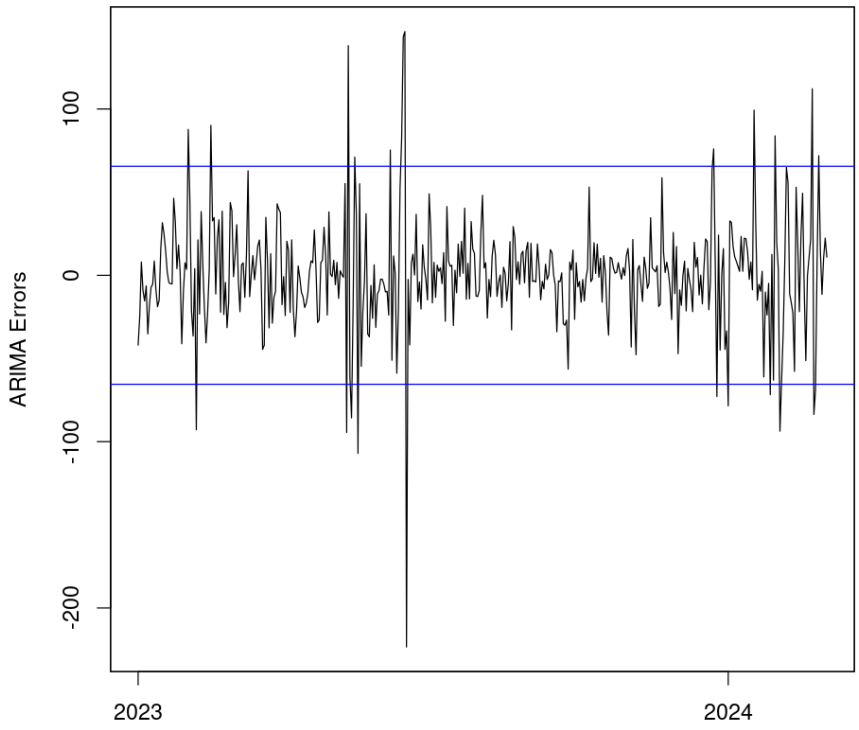
# 4. Regression residuals

4.1. 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.

4.2. Figure 5 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.

4.3. This week there were no residuals above or below two standard deviations of the data, indicating actual and modelled prices were similar.

**Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 to 6 April 2024**

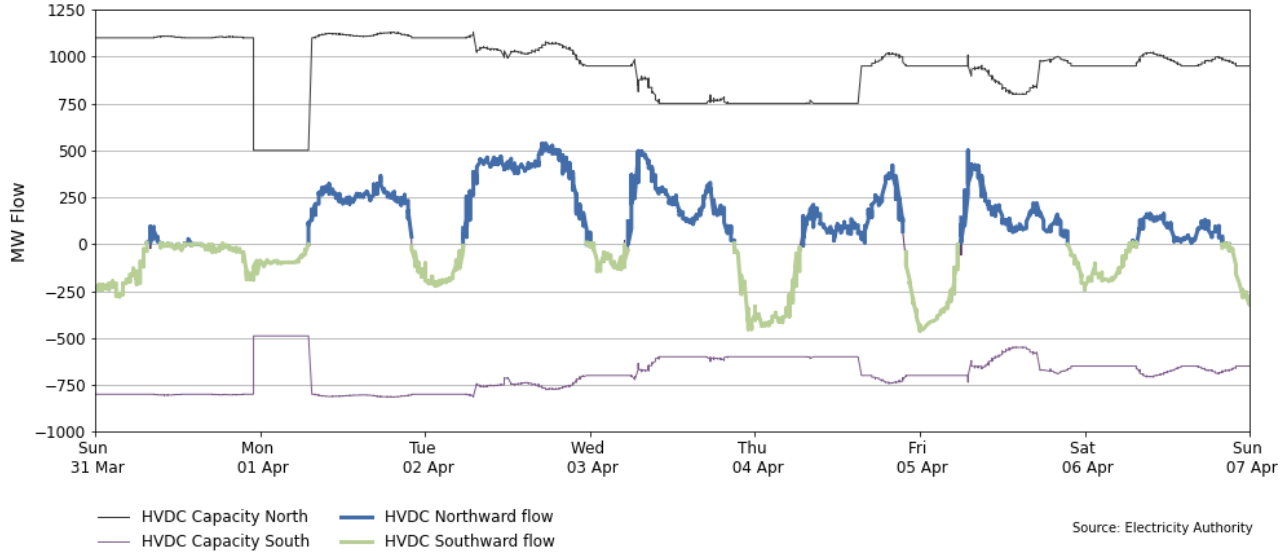



Source: Electricity Authority/see Appendix A

# 5. HVDC

5.1. Figure 6 shows the HVDC flow between 31 March-6 April. The HVDC capacity was reduced on Monday for several trading periods due to an unplanned fault on Pole 3. The HVDC flows were mostly northwards during the day and southwards overnight this week. The northward flow was higher on Monday and Tuesday when wind generation was low. From Wednesday onwards, the southward flow increased as wind generation improved.

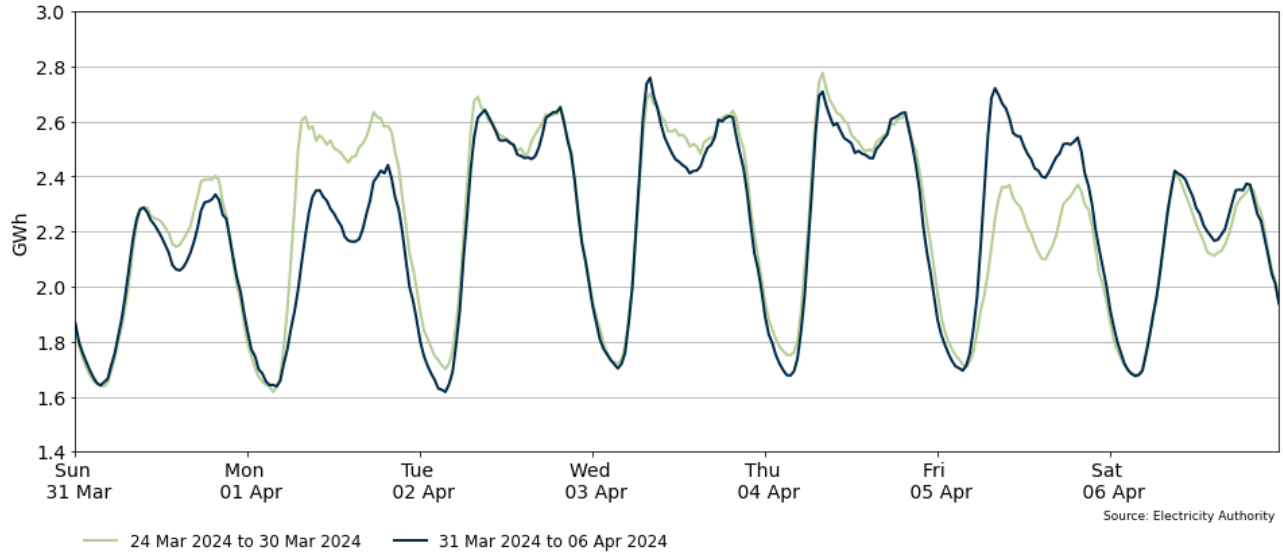
**Figure 6: HVDC flow and capacity between 31 March-6 April**




# 6. Demand

6.1. Figure 7 shows national demand between 31 March-6 April, compared to the previous week. Demand was similar to last week except for Monday and Friday. On Friday demand was higher compared to the previous week due to the Good Friday holiday. The Easter Monday holiday caused demand to be lower compared to the previous week.

**Figure 7: National demand between 31 March-6 April compared to the previous week**

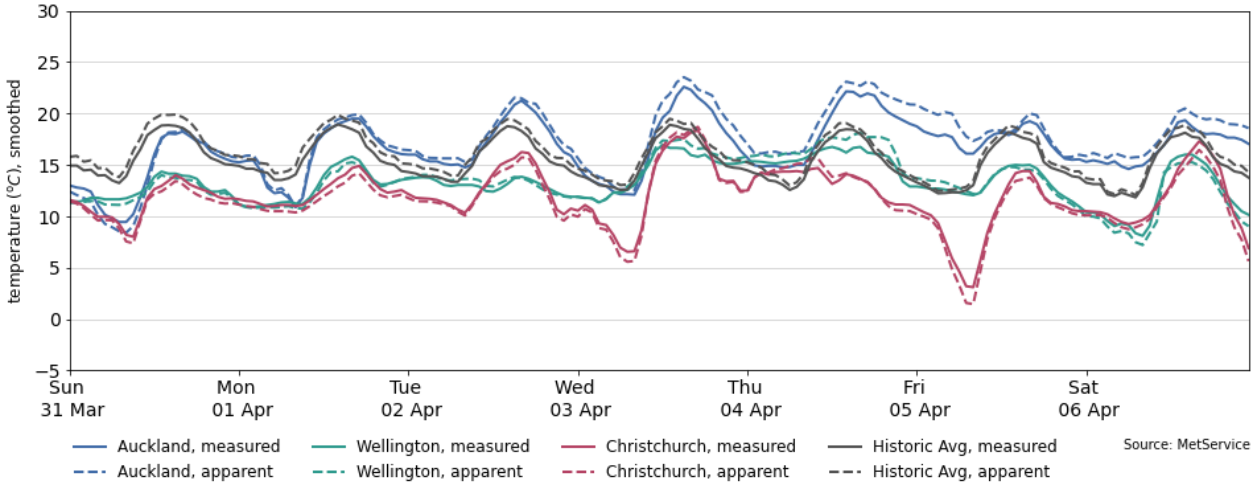



6.2. Figure 8 shows the hourly temperature at main population centres from 31 March-6 April. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures were mostly at or above the historical average for Auckland, while in Wellington and Christchurch, the temperatures were mostly below the historical average but mainly above 10ºC.

6.4. Temperatures in Auckland varied between 8ºC and 24ºC. Wellington temperatures fluctuated between 7ºC and 18ºC. Christchurch temperatures were between 2ºC and 19ºC this week.

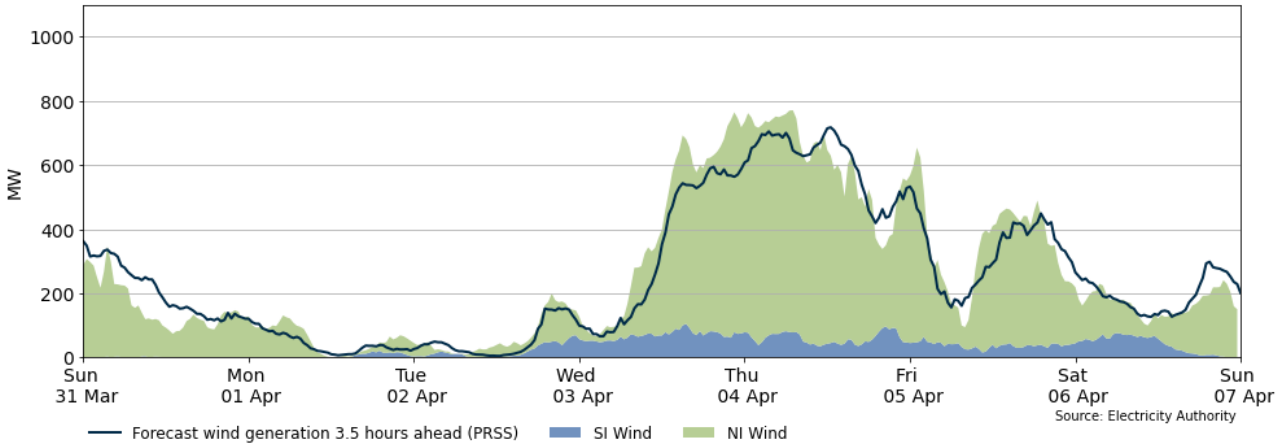
**Figure 8: Temperatures across main centres between 31 March-6 April**




# 7. Generation

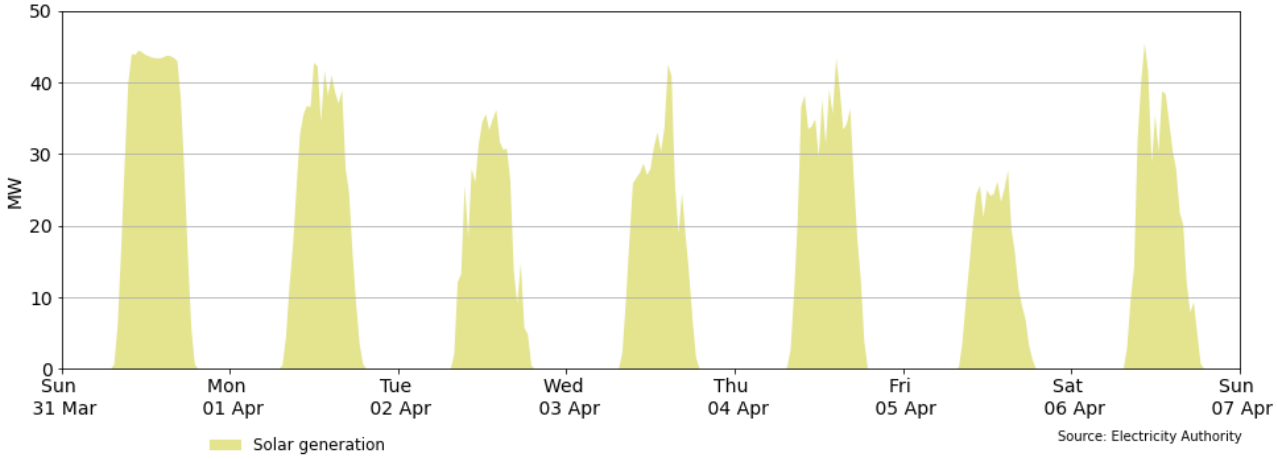
7.1. Figure 9 shows wind generation and forecast from 31 March-6 April. Wind generation varied between 1MW and 771MW this week, with an average of 260MW. Wind generation was mainly below 200MW this week up to Wednesday. From Wednesday until Friday, the wind was close to or above 400MW. From Friday onwards, wind once again decreased to around 200MW.

**Figure 9: Wind generation and forecast between 31 March-6 April**




7.2. Figure 10 shows solar generation from 31 March-6 April. Solar generation was high on Sunday, indicating little or no overcast over the solar arrays on that day. The remaining days saw solar generation impacted by overcast events, especially on Friday.

**Figure 10: Solar generation between 31 March-6 April**



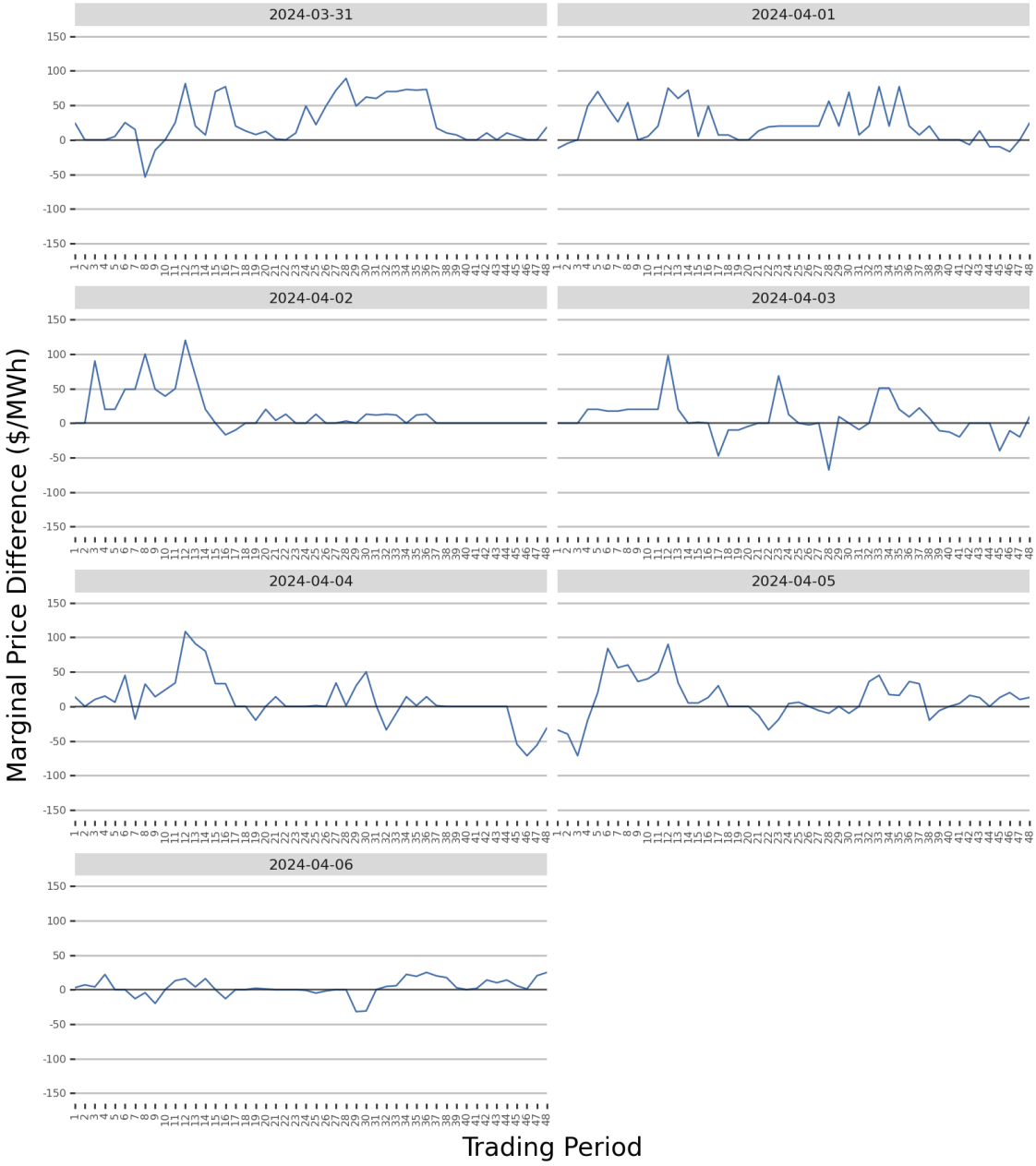

7.3. Figure 11 shows the difference between the real-time dispatch (RTD) marginal price, and what the marginal price would have been based on the 1-hour ahead (PRSS) demand and wind forecasts at the national level. This plot highlights when forecasting inaccuracies are causing large differences between pre-dispatch and final prices. When the difference is positive this means that the 1 hour out forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting the 1 hour ahead and the RTD price will rarely be the same, but trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.4. This week the differences between the RTD and PRSS prices were mostly between negative $50/MWh and $100/MWh. Most of the time prices were under-forecast, meaning the prices were higher than forecast. During these times wind and/or demand were under forecast.

7.5. The RTD prices were consistently higher than forecast between Sunday and Tuesday morning. This is likely due to a combination of low wind and demand being, at times, higher than forecast.

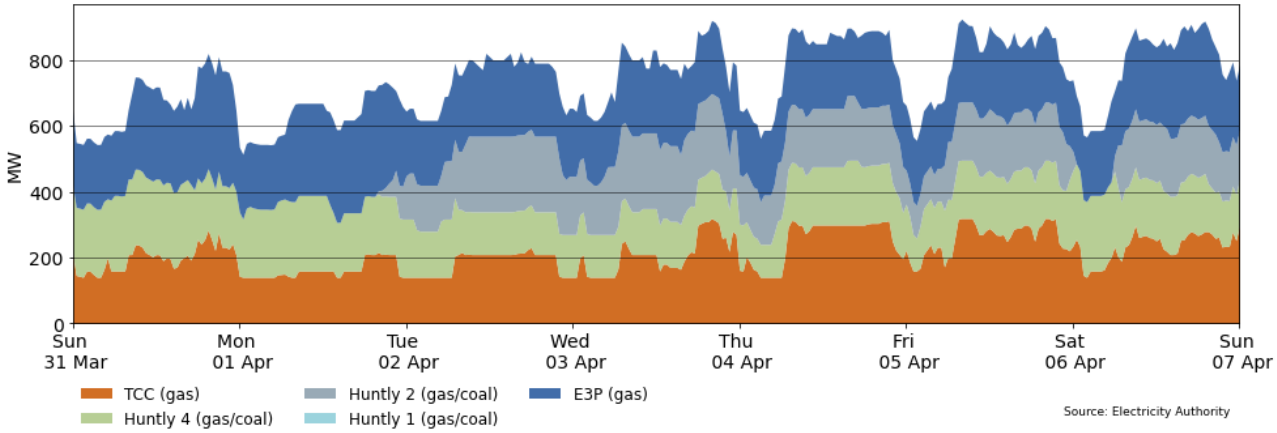
7.6. Compared to the previous week, PRSS prices were slightly more accurate this week, as there were no price differences close to or above $150/MWh.

**Figure 11: Difference between national marginal RTD price and gate closure PRSS prices, with the difference due to one-hour ahead wind and demand forecast inaccuracies between 31 March-6 April**



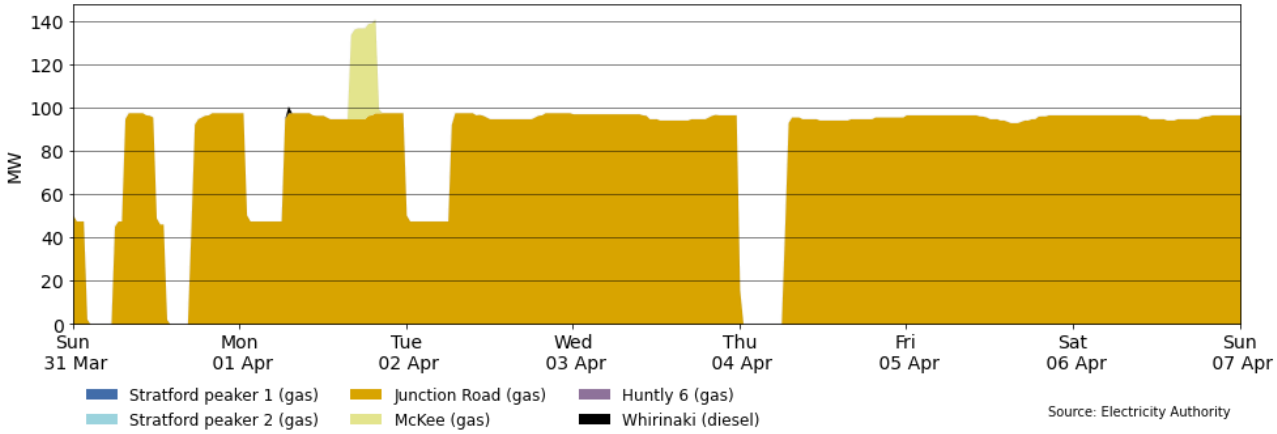

7.7. Figure 12 shows the generation of thermal baseload between 31 March-6 April. This week TCC, Huntly 4, and Huntly 5 (E3P) provided the baseload, with Huntly 2 also running continuously from late Monday onwards. Declining hydro storage this week contributed to the high levels of thermal baseload.

**Figure 12: Thermal baseload generation between 31 March-6 April**



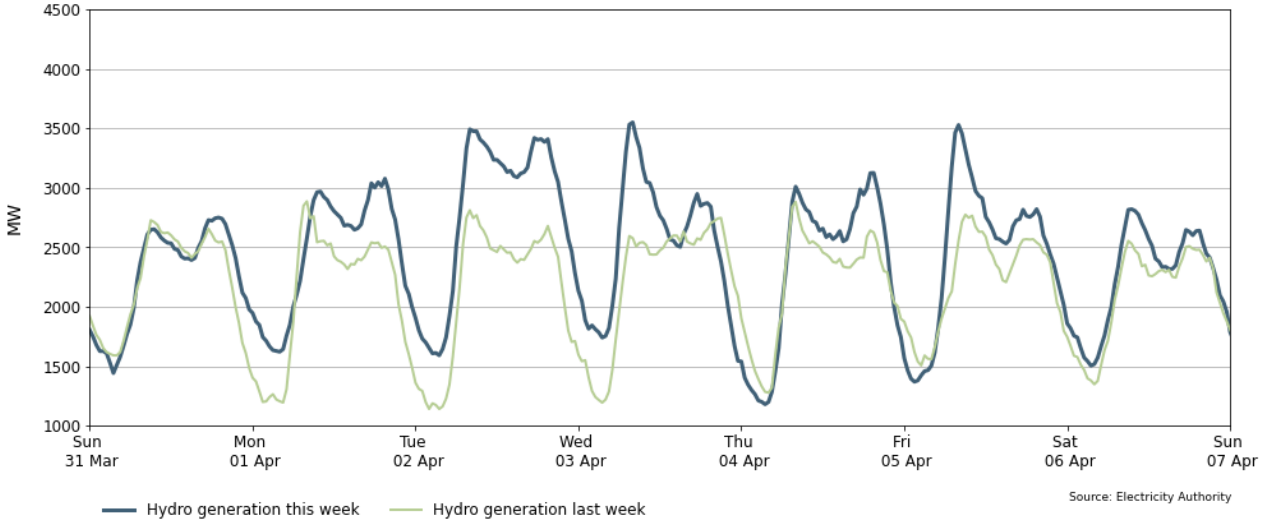

7.8. Figure 13 shows the generation of thermal peaker plants between 31 March-6 April. This week, Junction Road supported baseload as hydro storage levels declined. On Monday, Whirinaki generated a few MWs at 7:00am during trading period 15, likely to provide reserves during the unplanned HVDC pole 3 outage. On Monday, McKee also ran for a few hours in the evening.

**Figure 13: Thermal peaker generation between 31 March-6 April**



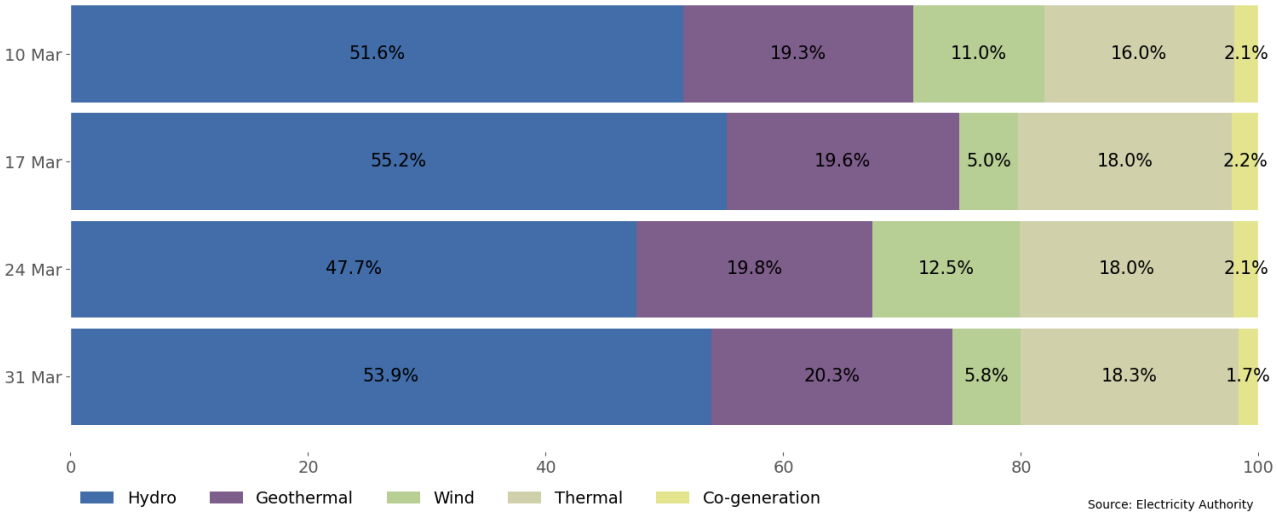

7.9. Figure 14 shows hydro generation between 31 March-6 April. Hydro generation was at or above the levels seen in the previous week due to lower wind generation this week. The impact of low wind generation is especially noticeable on Tuesday when wind generation was minimal and hydro generation was high.

**Figure 14: Hydro generation between 31 March-6 April**




7.10. As a percentage of total generation, between 31 March-6 April, total weekly hydro generation was 53.9%, geothermal 20.3%, wind 5.8%, thermal 18.3%, and co-generation 1.7%, as shown in Figure 15. There was a relative increase in hydro generation this week compared to the previous week due to the relative decrease in wind generation. Co-generation decreased this week due to an outage at Glenbrook between Monday and Friday.

**Figure 15: Total generation by type as a percentage each week between 10 March and 6 April**




# 8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 31 March-6 April ranged between ~1300MW and ~2000MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 1 is on outage until 29 April 2024

(b) Stratford 2 is on outage until 1 May 2024

(c) McKee is on partial outage until 30 April 2024

(d) Huntly 4 was on partial outage between 2-3 April

(e) Poihipi geothermal plant was on outage on 2 April

(f) Several North and South Island hydro units were on outage this week.

**Figure 16: Total MW loss due to generation outages between 31 March-6 April**

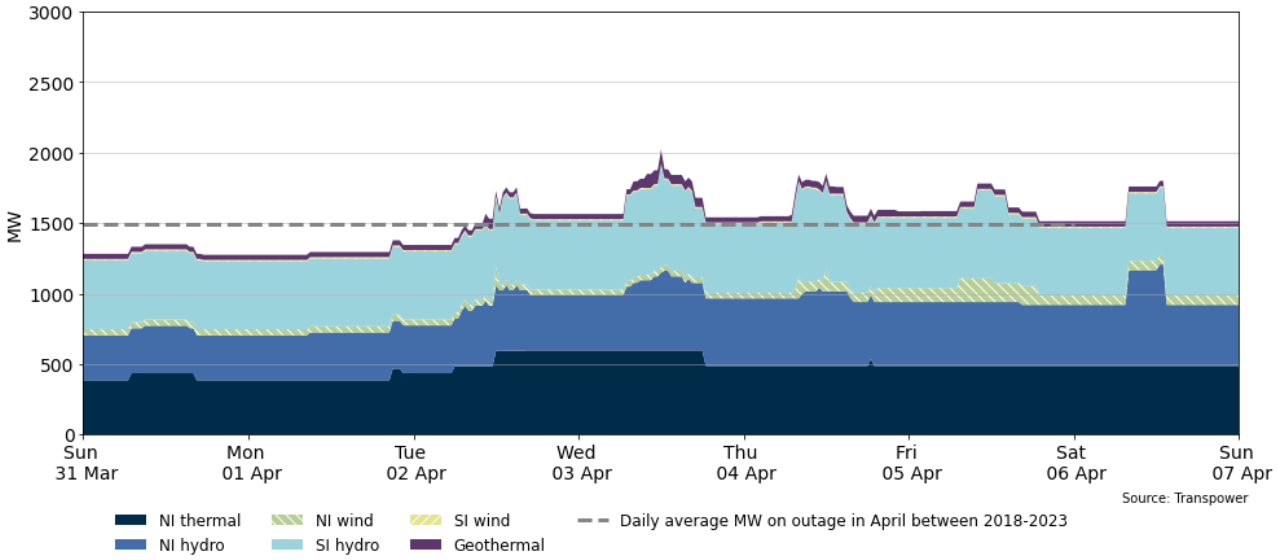
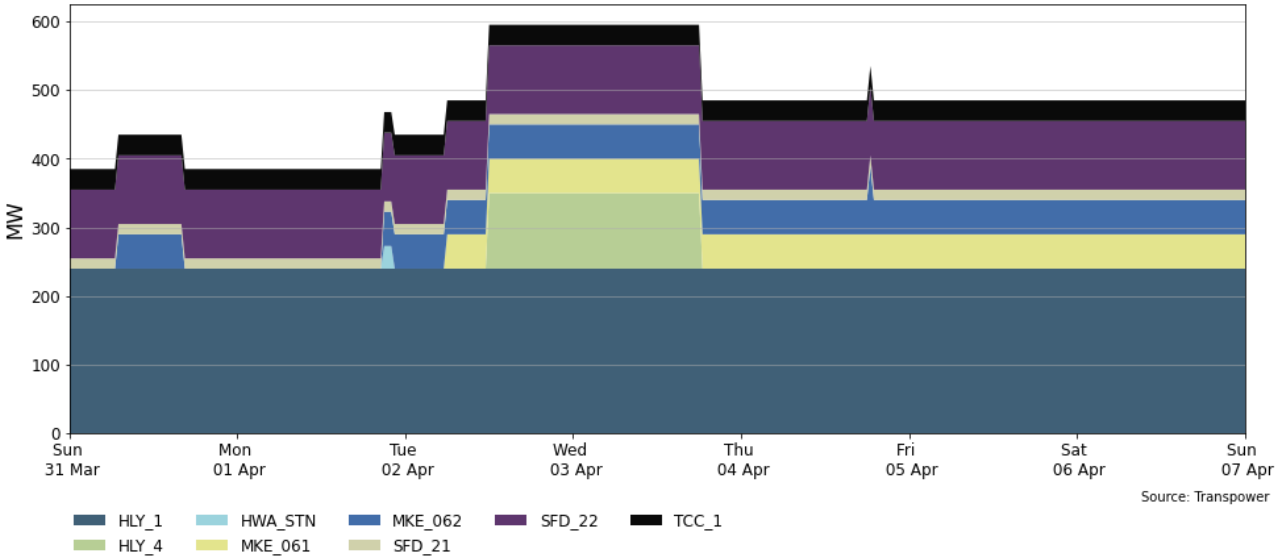



**Figure 17: MW loss from thermal outages between 31 March-6 April**

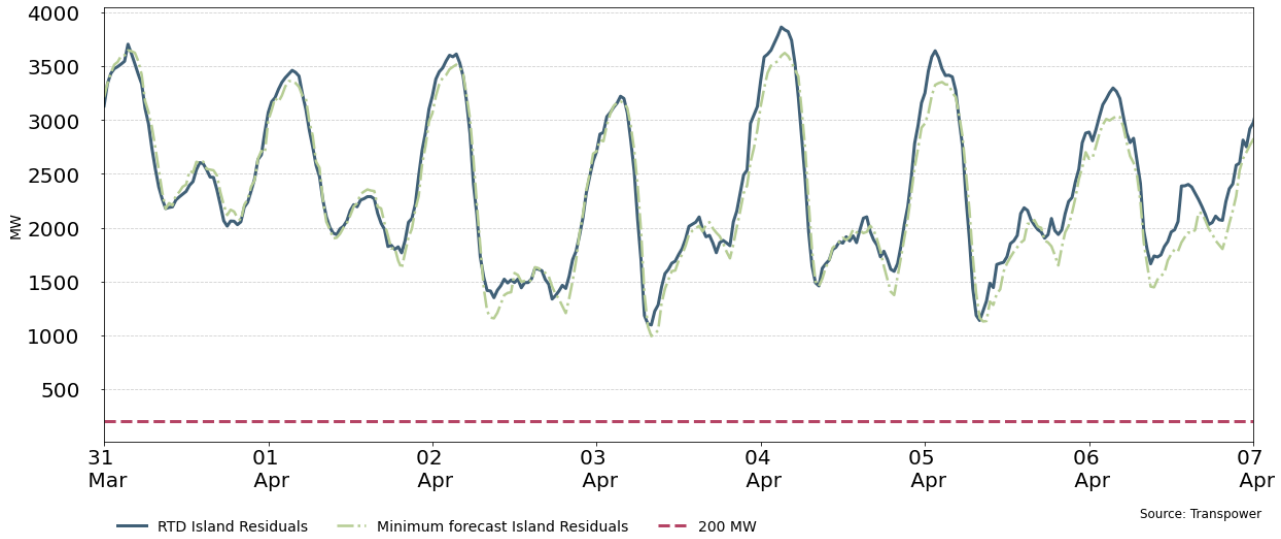



# 9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 31 March-6 April. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. Generation residuals were healthy this week, with the minimum national residual levels above 1000MW and the minimum North Island residual levels at around 720MW.

**Figure 18: National generation balance residuals 31 March-6 April**




# 10. Storage/fuel supply

10.1. Figure 19 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.

10.2. National controlled storage decreased this week and is now sitting at 66% of nominally full and ~84 % of the historical average for this time of the year (as of 6 April).

10.3. Hydro storage declined at most of the lakes this week except for Hawea. As of 6 April:

(a) Lake Taupō is now sitting between its 90th percentile and its historical average.

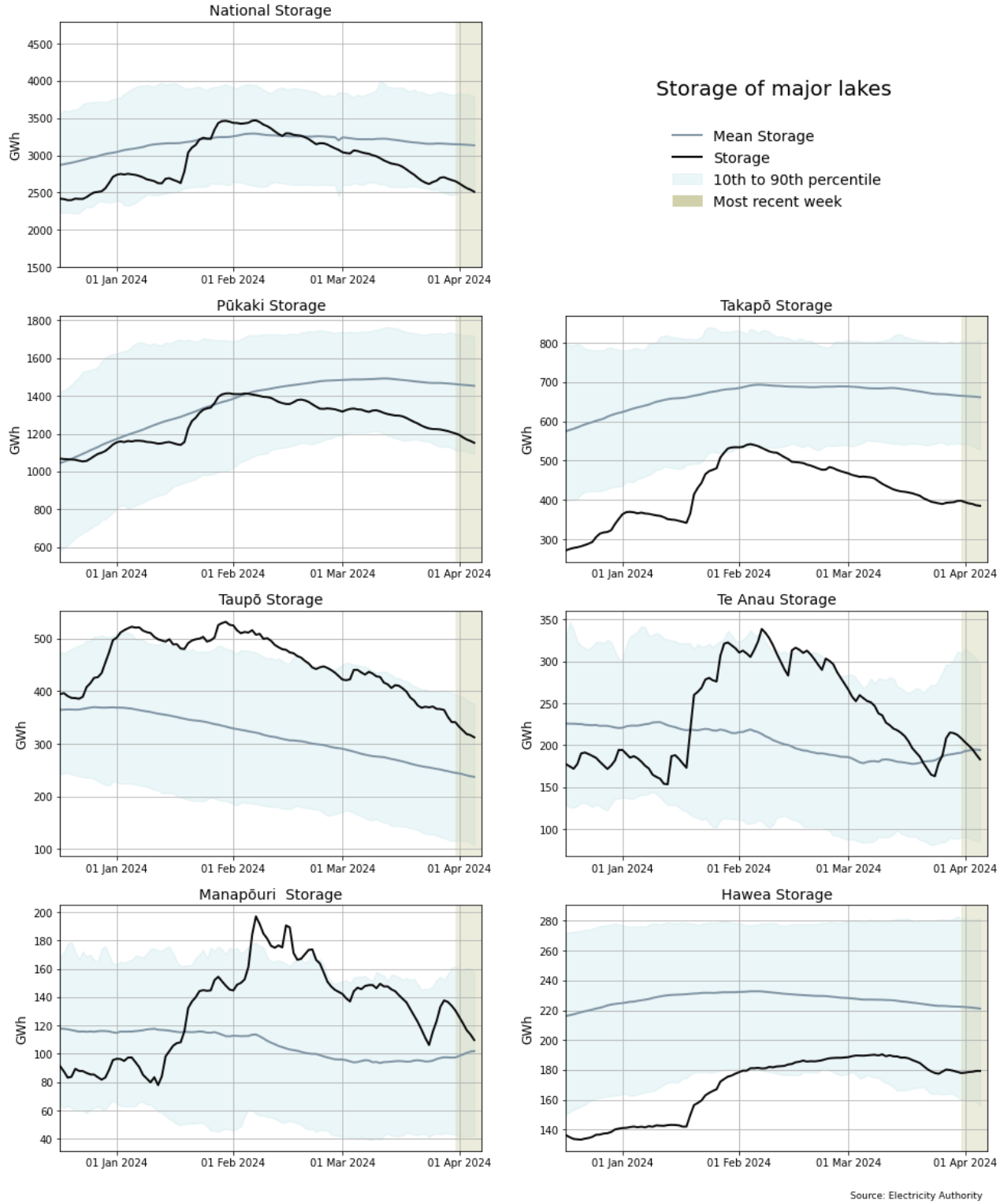
(b) Lake Pūkaki declined and its storage is now close to its 10th percentile.

(c) Lake Takapō storage decreased slightly this week, remaining below its 10th percentile.

(d) Lake Manapōuri and Te Anau both saw a decline in storage. Te Anau is now below its historical average, while Manapōuri is at its historical average.

(e) Lake Hawea storage was relatively stable this week, remaining above its 10th percentile.

**Figure 19: Hydro storage**

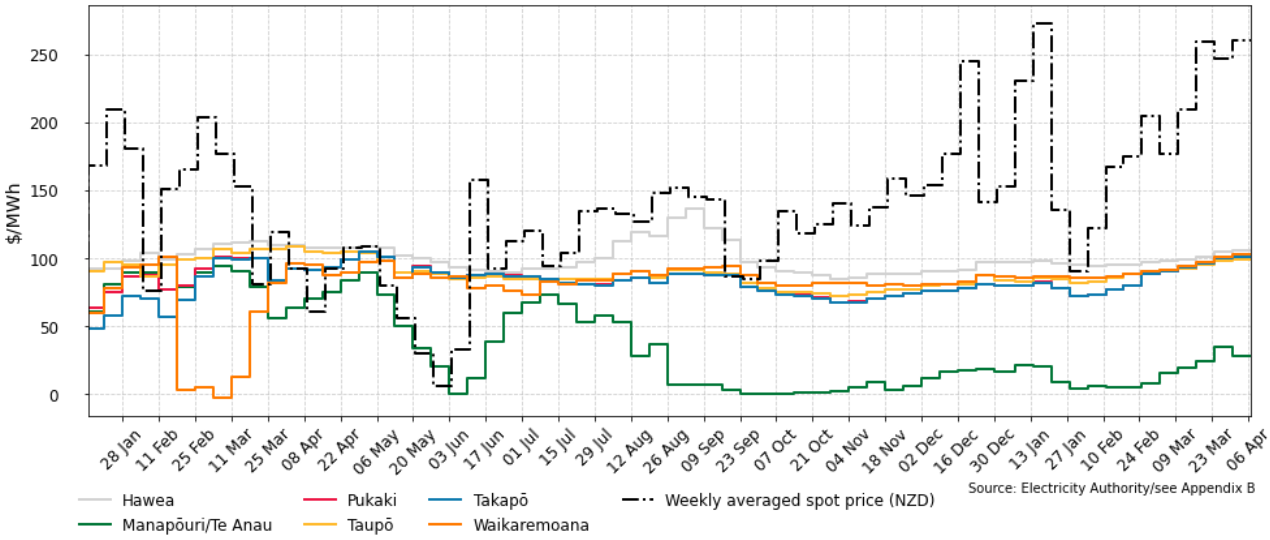


# 11. JADE water values

11.1. 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 20 shows the national water values between 8 January 2023 and 6 April 2024 obtained from JADE calculated 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.

11.2. Compared to the previous week, all lakes, except Manapōuri/Te Anau, saw an increase in their water values of around $1.50/MWh. Manapōuri/Te Anau saw a decrease in water values of around $6/MWh, after a $10/MWh increase in the previous week.

**Figure 20: JADE water values across various reservoirs between 8 January 2023 and 6 April 2024**




# 12. Prices versus estimated costs

12.1. 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).

12.2. 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.

12.3. Figure 21 shows an estimate of thermal SRMCs as a monthly average up to 1 March 2024. The SRMCs for coal and diesel have seen small changes from the previous month. The gas SRMC has increased this month, likely due to current gas availability and demand.

12.4. The latest SRMC of coal-fueled Rankine generation is ~$156MWh. The cost of running the Rankines on gas is now more expensive at ~$236/MWh.

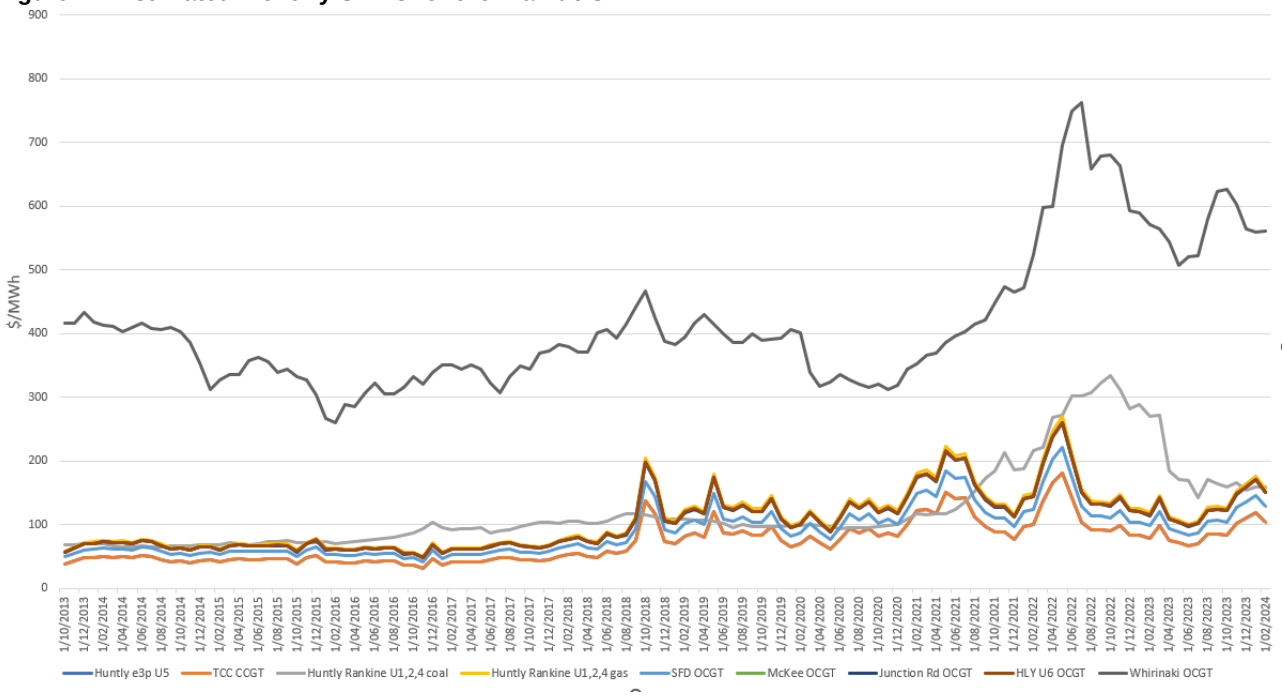
12.5. The SRMC of gas-fueled thermal plants is currently between ~$159/MWh and ~$236/MWh.

[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.

12.6. The SRMC of Whirinaki is ~$578/MWh.

12.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C on the trading conduct webpage.

**Figure 21: Estimated monthly SRMC for thermal fuels**



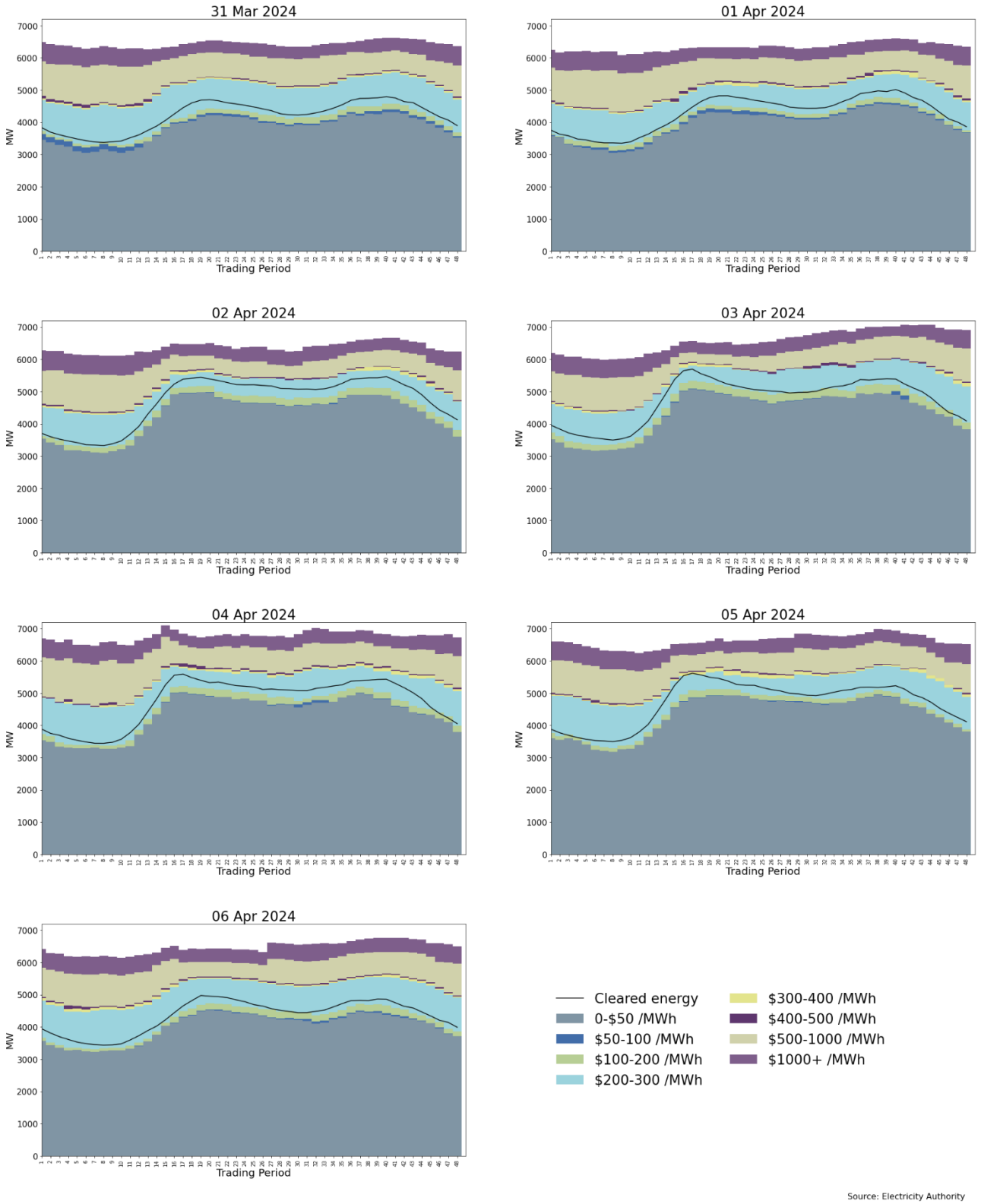

Source: Electricity Authority/see Appendix C

# 13. Offer behaviour

13.1. Figure 22 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

13.2. Most offers this week cleared in the $200-$300/MWh region, consistent with the currently lower-than-average hydro storage levels and current gas prices.

**Figure 22: Daily offer stacks[3]**




Source: Electricity Authority

[3] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

# 14. Ongoing work in trading conduct

14.1. This week, prices generally appeared to be consistent with supply and demand conditions.

14.2. 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 |
| **21/01/2024-27/01/2024** | Several | Further analysis | Mercury | Waikato hydro dams | Hydro offers |
| **15/03/2024-16/03/2024** | Several | Further analysis | Mercury | Waikato hydro dams | Hydro offers |