2 April 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 24-30 March

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 South Island reserve price spikes. During these reserve spikes the HVDC was operating with just one pole. High wind generation displaced hydro generation this week, with HVDC flows mostly going south. Hydro storage remained stable this week, still at ~88% of its historical average as of 30 March. Several thermal units ran to support baseload including TCC, Huntly 5, Huntly 2, and then Huntly 4. Junction Road and McKee also supported baseload generation.

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 24-30 March:

(a) The average wholesale spot price across all nodes was $248/MWh.

(b) 95% of prices fell between $159/MWh and $310/MWh.

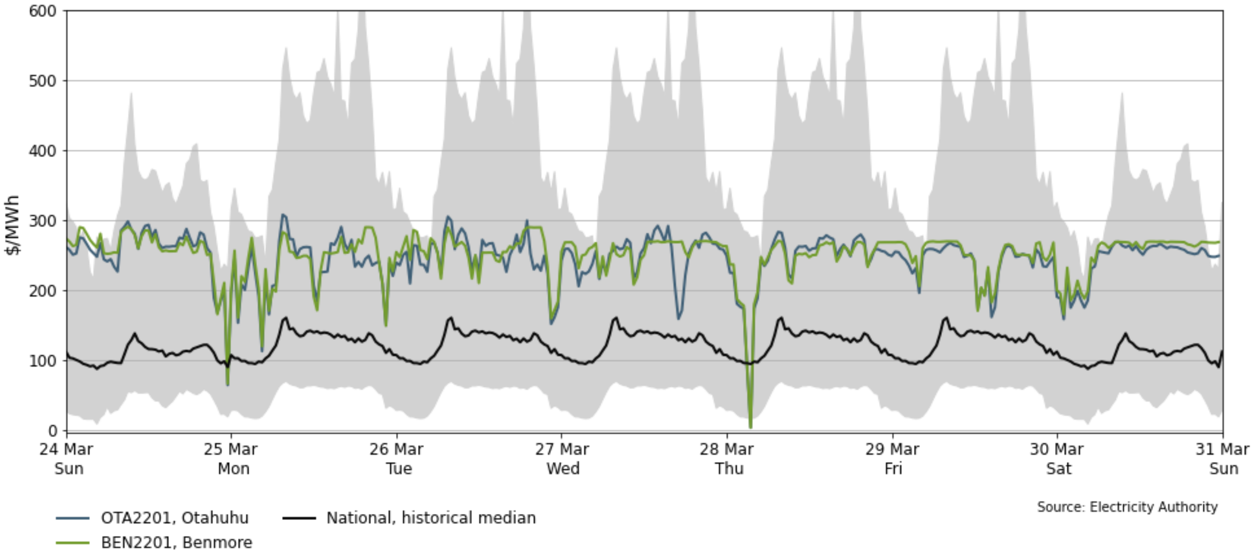
2.4. The spot prices were largely above the national historical median, and mostly above $200/MWh, influenced by the lower-than-average hydro storage levels and high thermal generation. The average price was $248/MWh, the same as the previous week.

2.5. There were no price spikes this week but there were a few occasions where Benmore prices were higher than Ōtāhuhu, mostly during evening or early morning hours. During several of these instances, the HVDC was flowing southward, and the South Island reserve prices were high.

2.6. A few dips in prices occurred this week, most notably on Thursday morning, likely related to wind generation being under forecast.

[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 75th percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

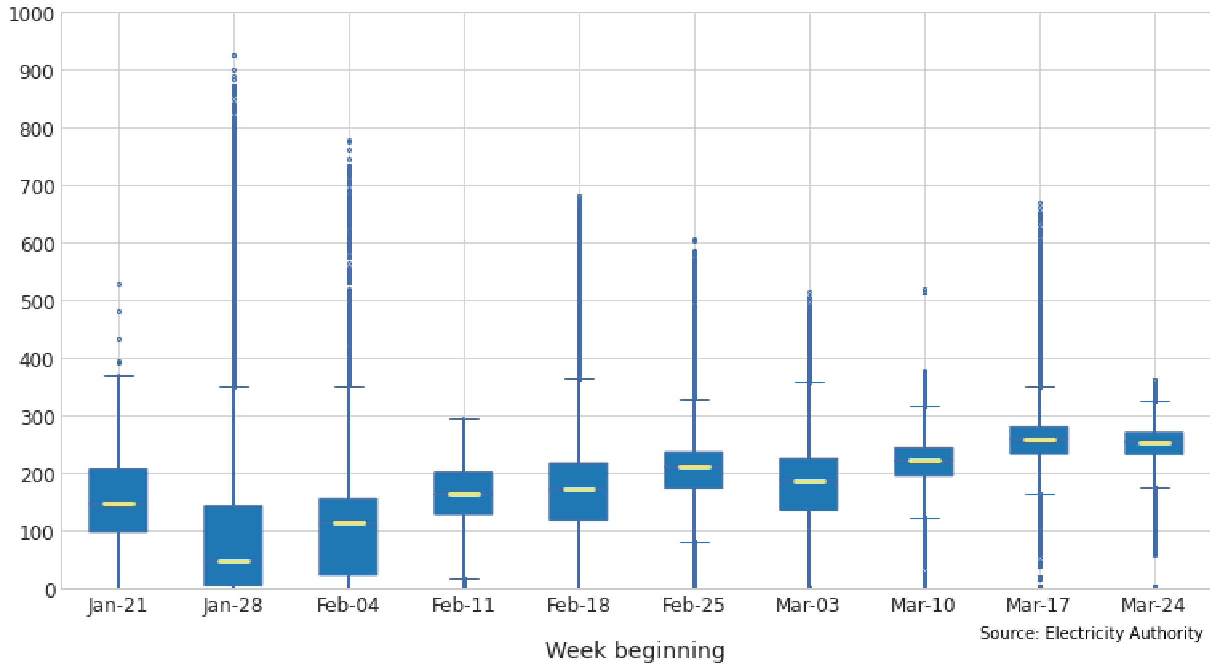
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 24-30 March



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. The spot prices this week were similar compared to the previous week. The median price was $253/MWh, compared to $258/MWh in the previous week, a $5/MWh decrease. The middle 50% of the prices were between $233-$270/MWh. This week saw an even more condensed price distribution compared to the previous week.

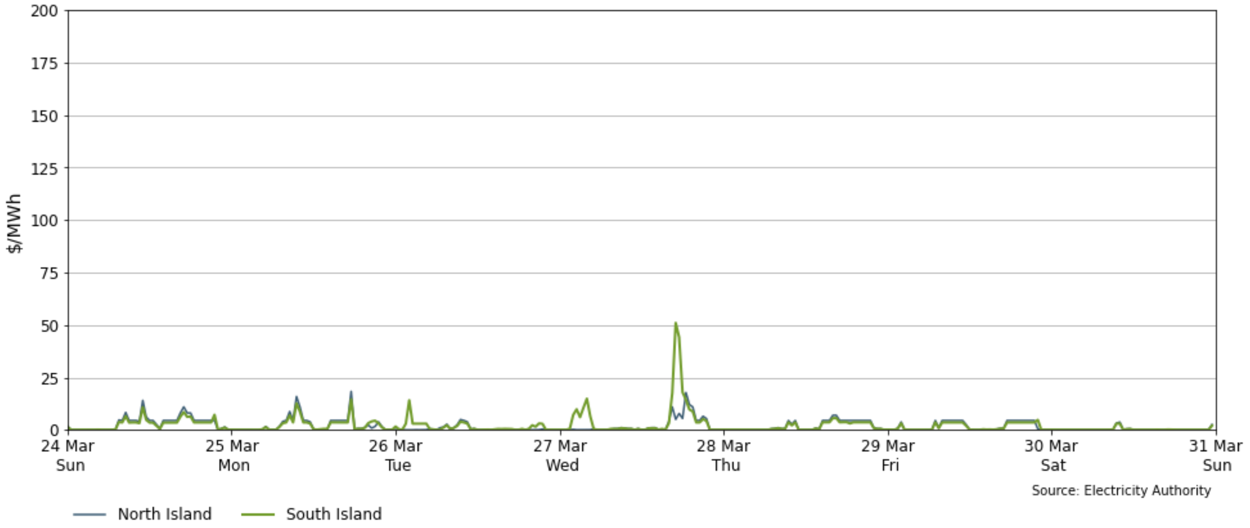
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



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 $10/MWh, except for a South Island price spike on Wednesday evening, close to the time when the HVDC was reversing its flow.

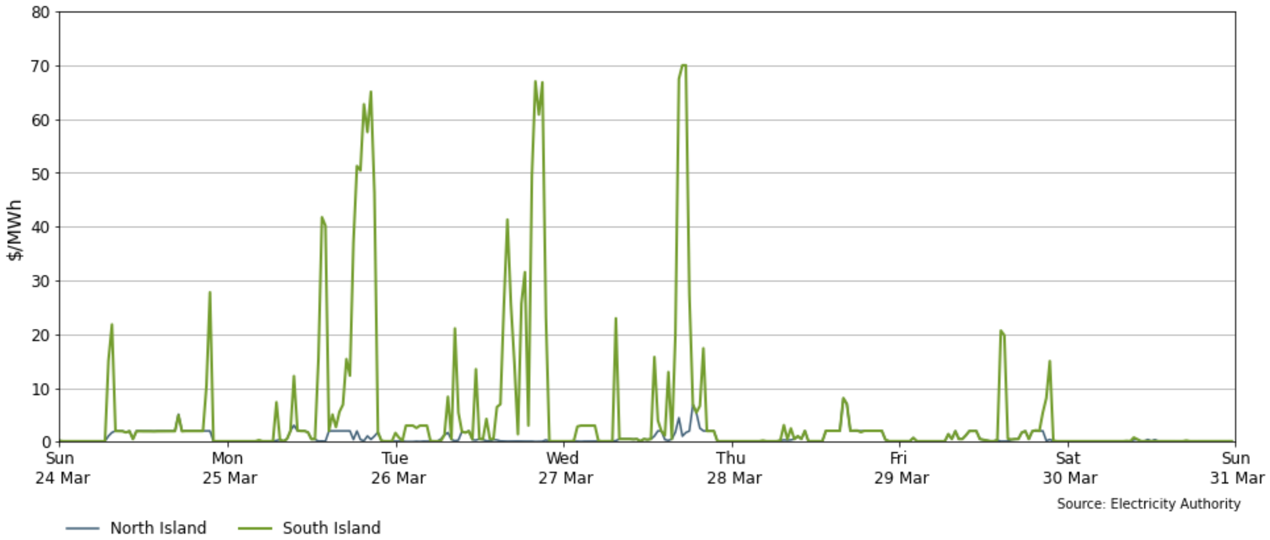
Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 24-30 March



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices in the North Island were mostly below $5/MWh this week. The South Island saw some spikes in the SIR prices this week, reaching a maximum of 70/MWh.

3.3. The spikes seen on Sunday occurred close to the time the HVDC was reversing its flow. The spikes between Monday and Wednesday occurred when the HVDC operated in monopole mode, likely due to low transfer levels in the forward schedule. When this occurs, the HVDC operates with one pole, and hence there is no redundancy. The HVDC risk must then be covered by South Island reserves, causing higher reserve prices. These prices were highest during peak times when energy and reserve markets were tighter.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 24-30 March



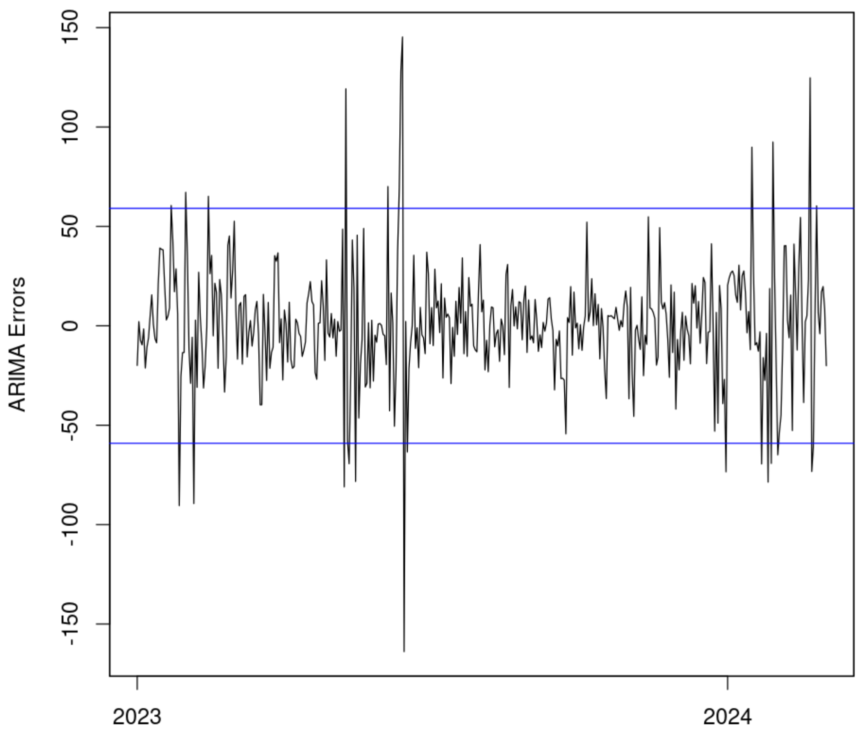
4. Regression residuals

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, the Monday price was above the threshold, indicating that prices were higher than expected on that day. On Monday at 7:30am Ōtāhuhu spot prices reached around $307/MWh. This is likely due to high wind generation offsetting hydro generation rather than thermal, as lake levels remain below average.

Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 to 30 March 2024

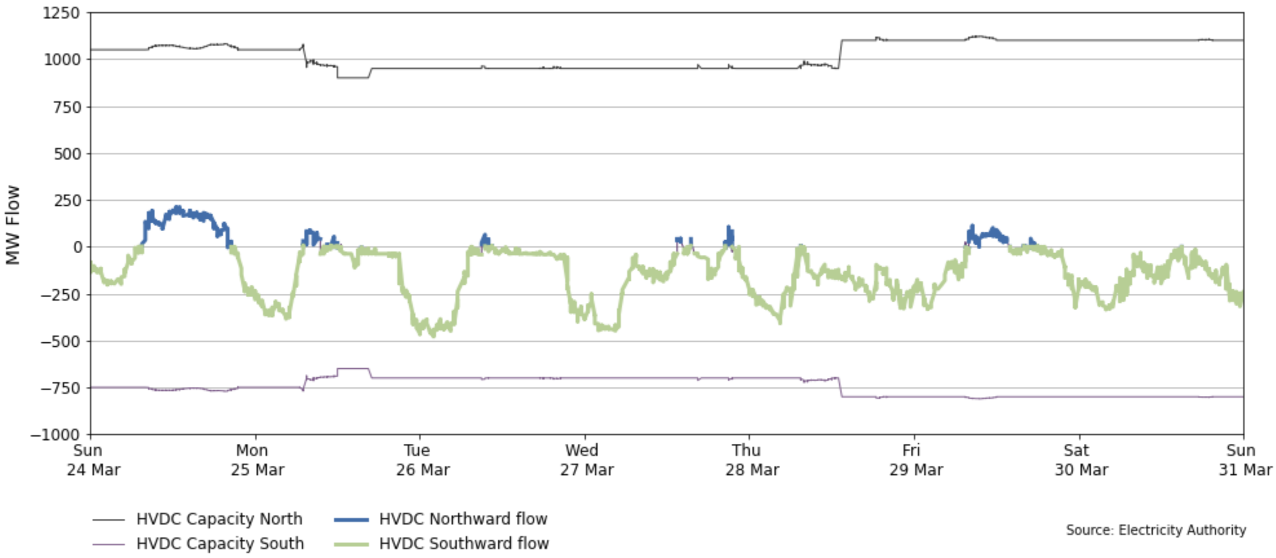


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 24-30 March. HVDC flows this week were mostly southwards, reflecting high North Island wind generation this week. Northward flow occurred mostly on Sunday and Friday, during daytime, when wind generation was low. Southward overnight flow reached nearly 500 MW at times. However daytime flow between Monday and Wednesday was at times very low, as the HVDC operated in monopole due to low transfers in the forward schedule. From Thursday onwards daytime southward transfer increased.

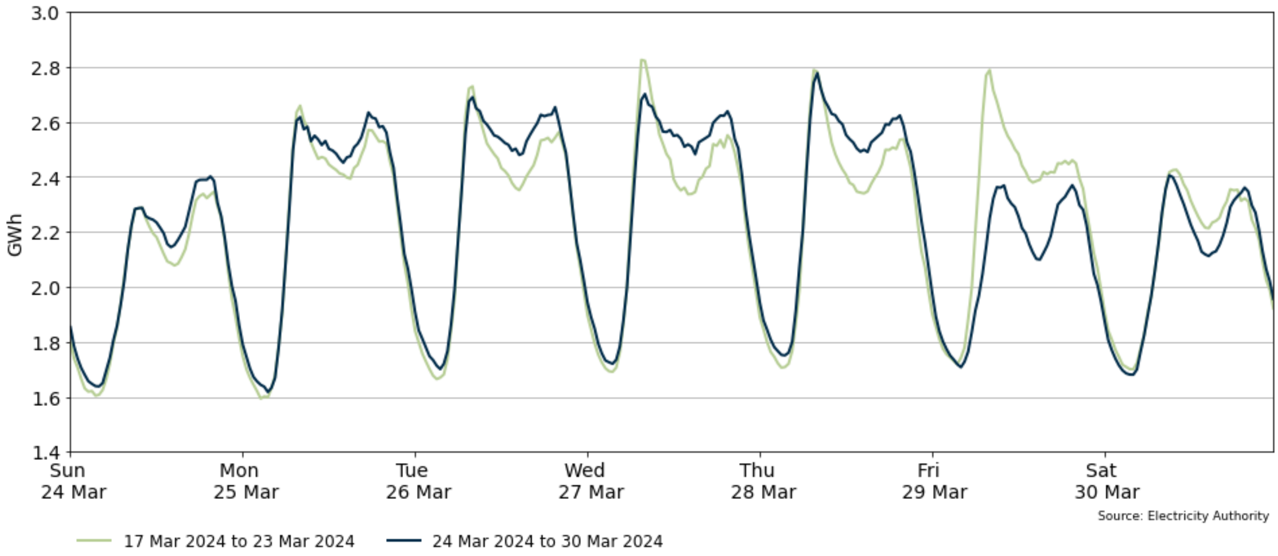
Figure 6: HVDC flow and capacity between 24-30 March



6. Demand

6.1. Figure 7 shows national demand between 24-30 March, compared to the previous week. Demand was high during weekdays from Monday to Thursday, similar to or above the previous week's levels. Friday demand was considerably lower than the previous week, as expected due to the Good Friday holiday. Weekend demand was similar to the previous week.

Figure 7: National demand between 24-30 March compared to the previous week



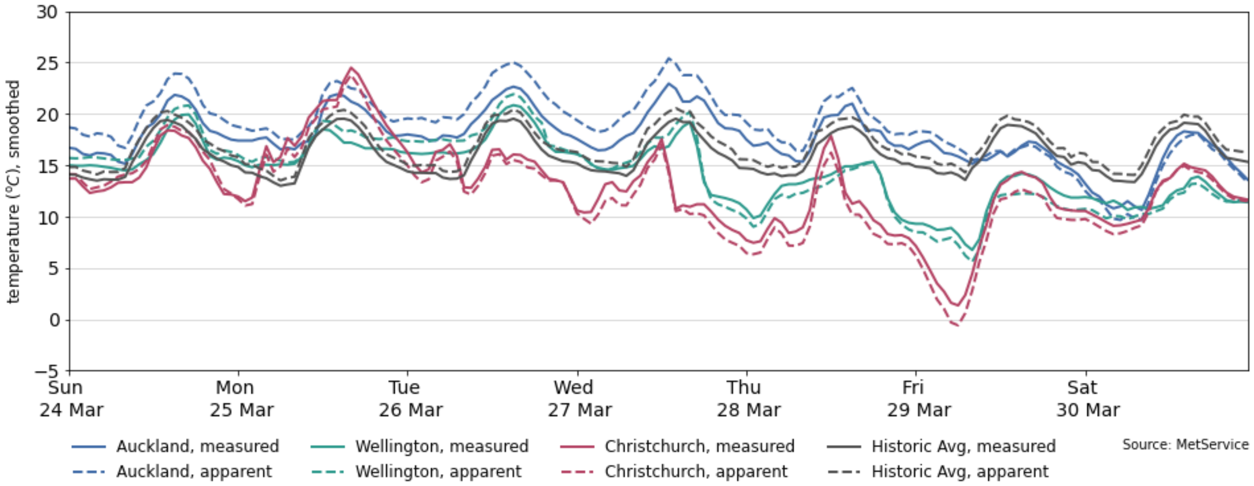
6.2. Figure 8 shows the hourly temperature at main population centres from 24-30 March. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures were mostly around the average until Tuesday when they began to decrease. The drop was gradual, starting with Christchurch on Tuesday, then Wellington on

Wednesday, and Auckland on Friday, with the temperatures of three cities remaining below the historical average from Friday onwards.

6.4. Temperatures in Auckland varied between 10ºC and 25ºC. Wellington temperatures fluctuated between 6ºC and 22ºC. Christchurch temperatures were between -1ºC and 24ºC this week.

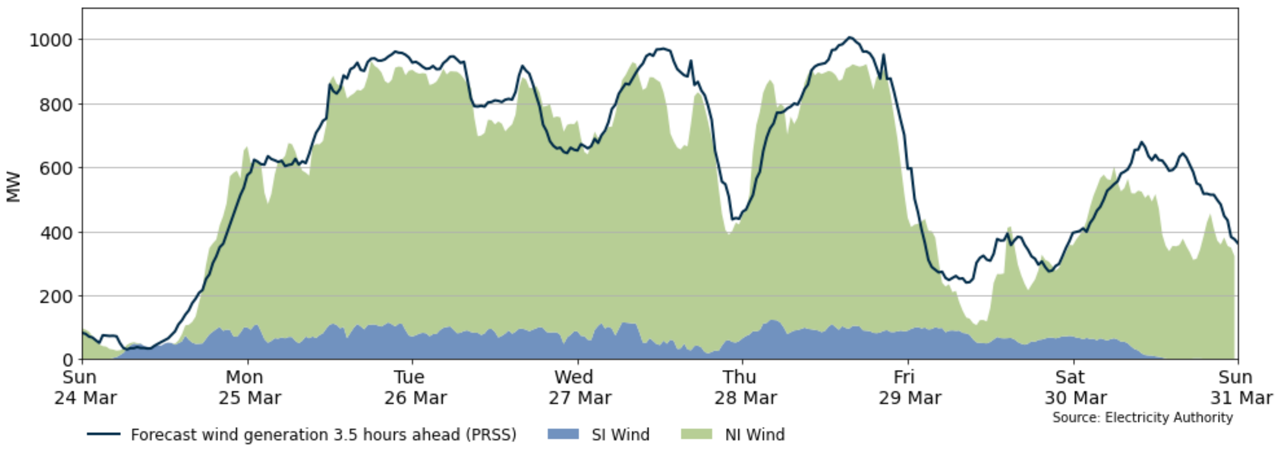
Figure 8: Temperatures across main centres between 24-30 March



7. Generation

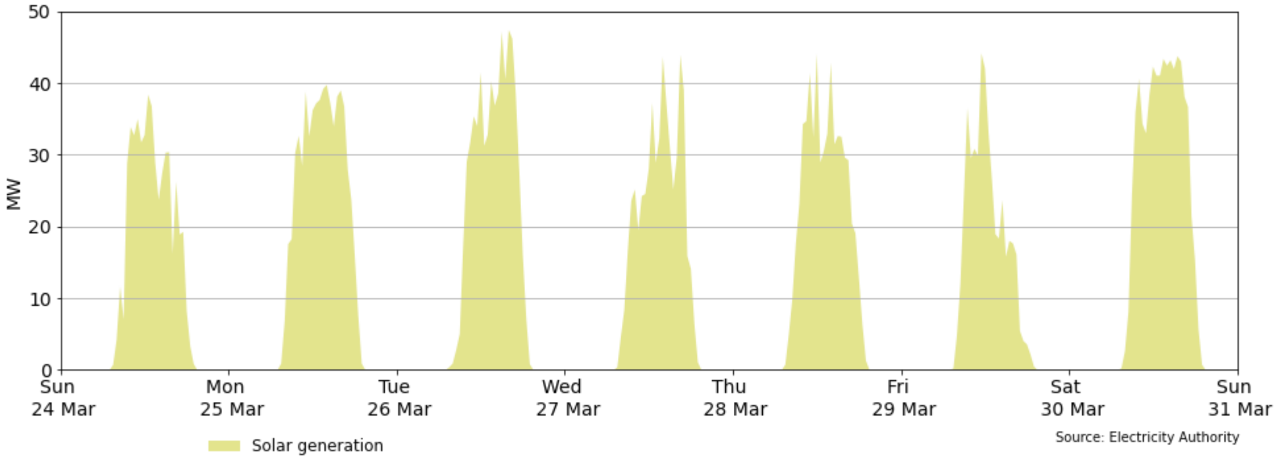
7.1. Figure 9 shows wind generation and forecast from 24-30 March. This week, wind generation varied between 27MW and 932MW, with an average of 566MW. Wind generation was consistently high this week from late Sunday to early Friday and for parts of Saturday. Several wind forecast inaccuracies occurred this week, although with limited impact on the spot prices, except for Thursday morning, when under-forecast wind likely contributed to the price dip.

Figure 9: Wind generation and forecast between 24-30 March



7.2. Figure 10 shows solar generation from 24-30 March. The Lodestone Edgecumbe solar farm is closer to the end of its commissioning process. The 32MW(DC)/24MW(AC) solar array is now capable of generating its maximum nameplate capacity (weather dependent). Solar generation this week saw a few overcast days impacting its generation, as shown in Figure 10, but reached above 60% of the installed capacity every day.

Figure 10: Solar generation between 24-30 March



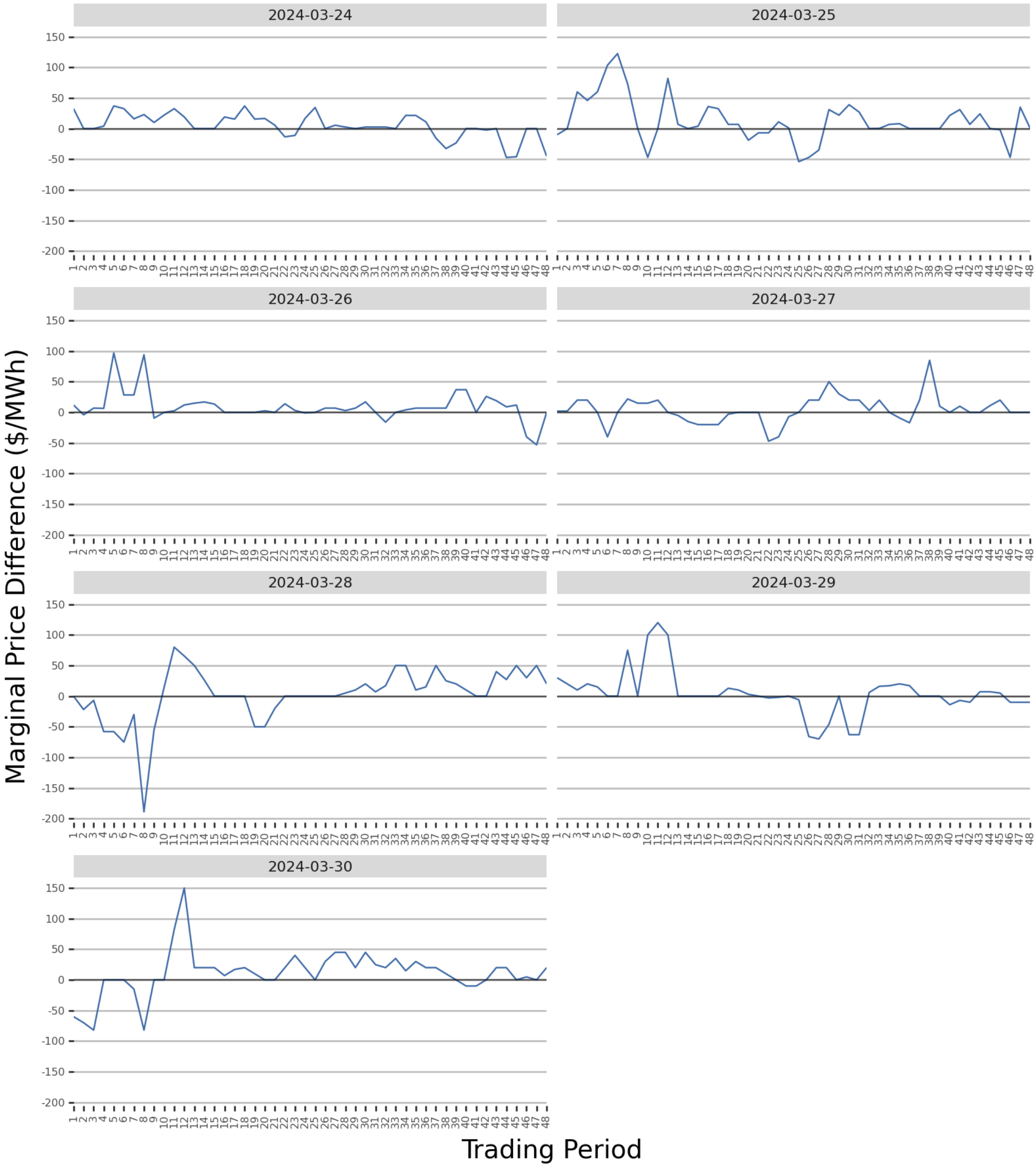
7.3. Figure 11 shows the difference between the real-time dispatch (RTD) marginal price, and what the marginal price would have been based on the 1-hour ahead (PRSS) demand and wind forecasts at the national level. This plot highlights when forecasting inaccuracies are causing large differences between 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 largest under-forecast differences between the RTD and PRSS prices occurred early on Monday and Saturday, when prices were higher than forecast. During these times wind was generally over forecast and or demand was under forecast.

7.5. On Thursday, around 3:30am, the RTD price was ~$200/MWh lower than the 1-hour ahead PRSS price. During this trading period, wind generation was higher than forecast.

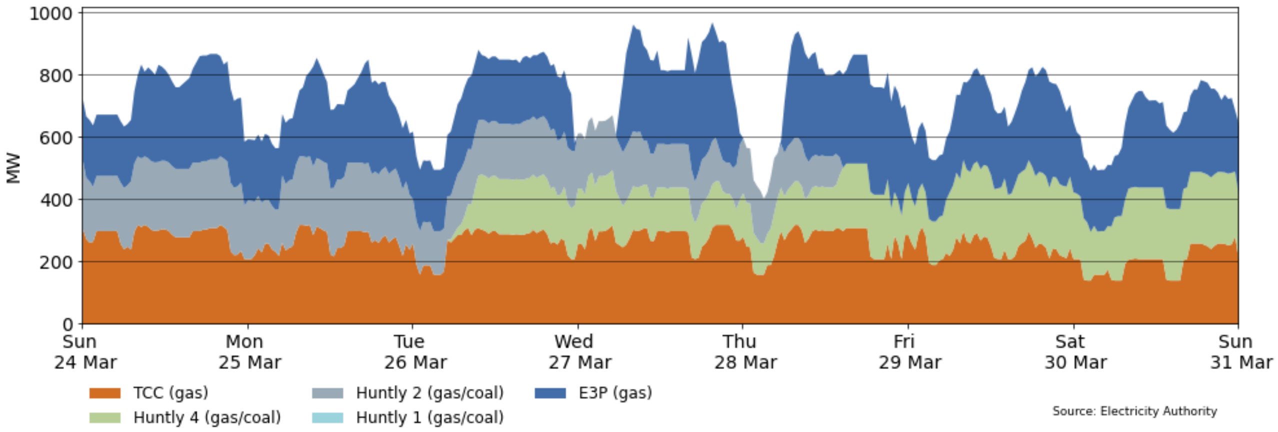
7.6. For most of the week the differences between PRSS and RTD marginal prices within the +/- $50/MWh range. Compared to the previous week, PRSS prices were slightly less accurate.

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 24-30 March



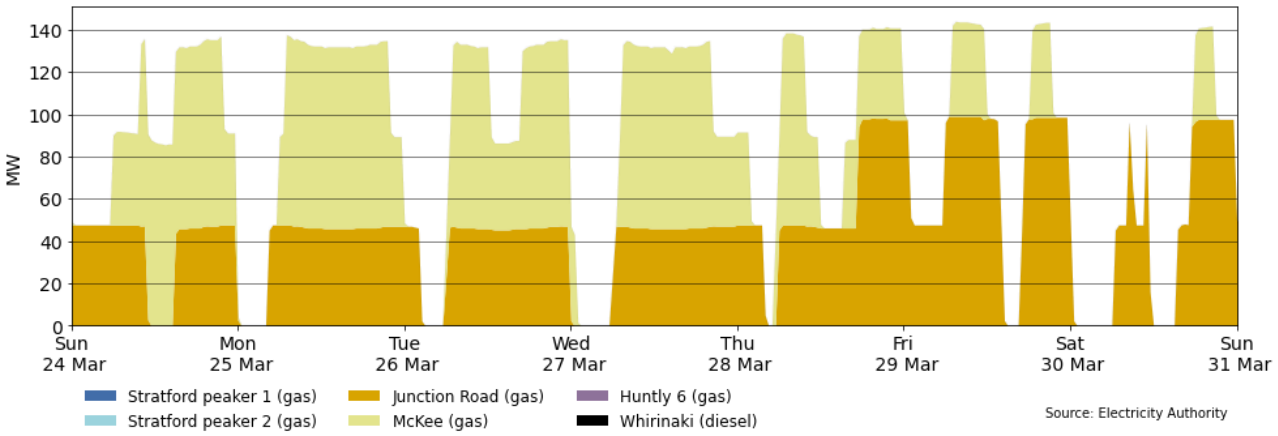
7.7. Figure 12 shows the generation of thermal baseload between 24-30 March. Below-average hydro storage sees continued high levels of thermal baseload running. TCC provided the baseload this week with Huntly 5 (E3P) also running during most of the week except for a few trading periods during early hours on Thursday, when wind generation was high, and demand was low. Huntly 2 ran continuously between Sunday and the middle of Thursday. Huntly 4 ran continuously from Tuesday morning onwards.

Figure 12: Thermal baseload generation between 24-30 March



7.8. Figure 13 shows the generation of thermal peaker plants between 24-30 March. This week, Junction Road and McKee ran every day. The plants have been supporting baseload as hydro storage levels remain below average.

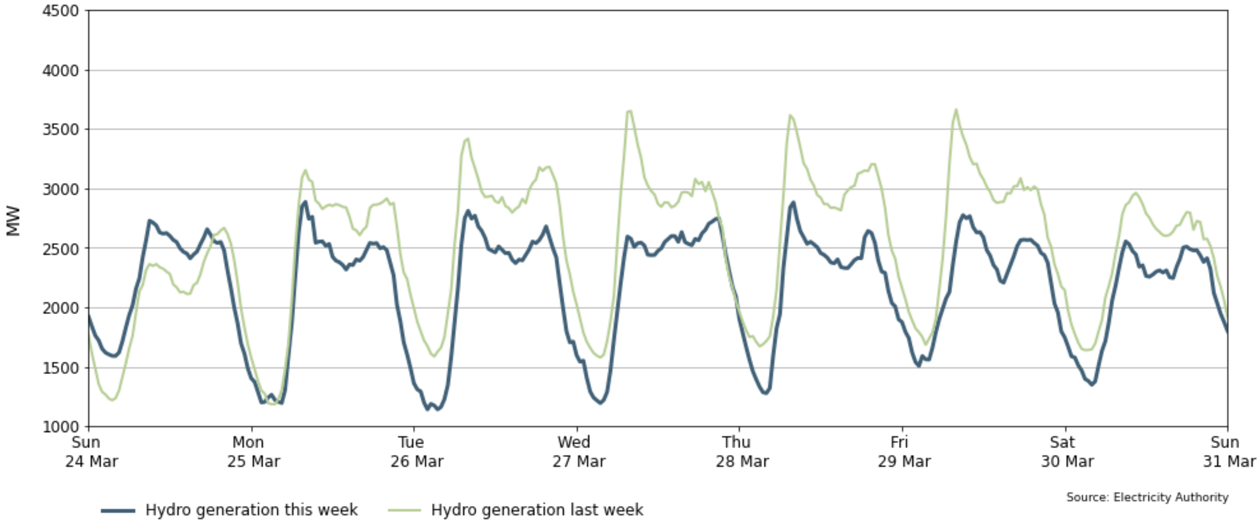
Figure 13: Thermal peaker generation between 24-30 March



7.9. mix.

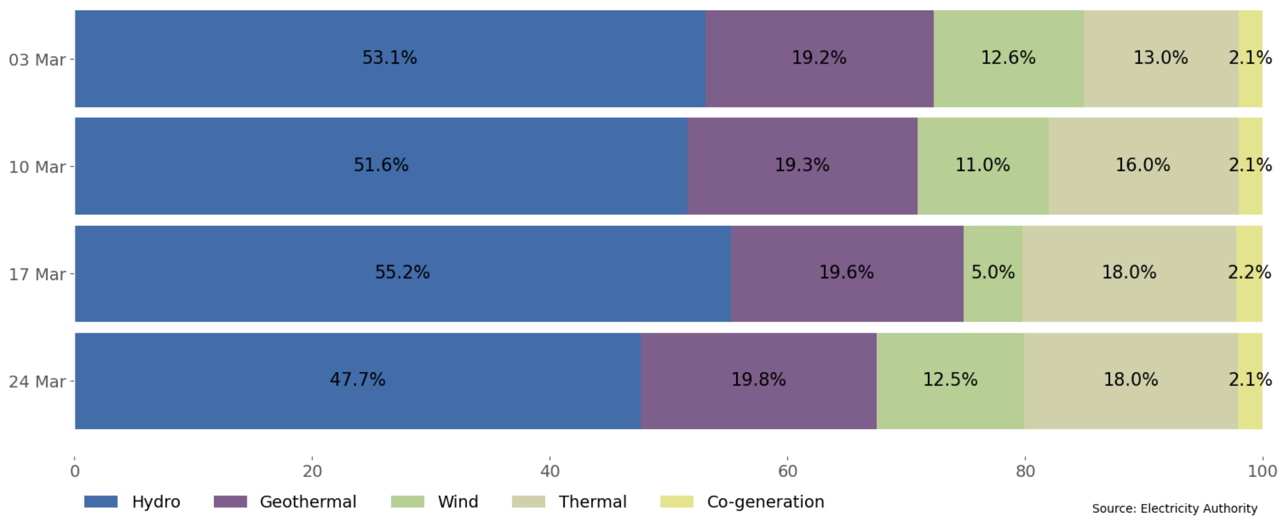
7.10. Figure 14 shows hydro generation between 24-30 March. Hydro generation was mostly lower than the previous week except on Sunday when wind generation was low. This is due to high wind generation displacing hydro in the energy mix.

Figure 14: Hydro generation between 24-30 March



7.11. As a percentage of total generation, between 24-30 March, total weekly hydro generation was 47.7%, geothermal 19.8%, wind 12.5%, thermal 18.0%, and co-generation 2.1%, as shown in Figure 15. This week, the inverse wind-hydro relationship saw hydro generation decrease during periods of high wind generation, whilst thermal and geothermal remained relatively constant when compared to the previous week.

Figure 15: Total generation by type as a percentage each week between 3-30 March



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 24-30 March ranged between ~1280MW and ~2230MW. 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) Stratford 1 was on outage between 28-30 March

(d) Poihipi geothermal plant was on outage until 28 March

(e) West Wind Wind Farm was on outage until 25 March

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

Figure 16: Total MW loss due to generation outages between 24-30 March

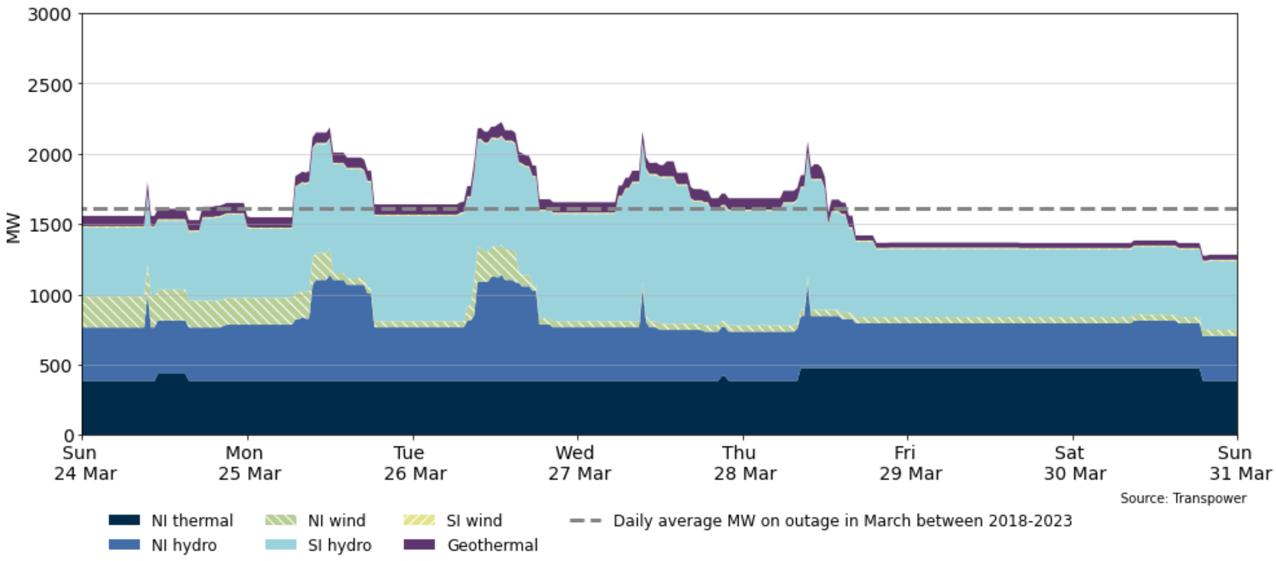
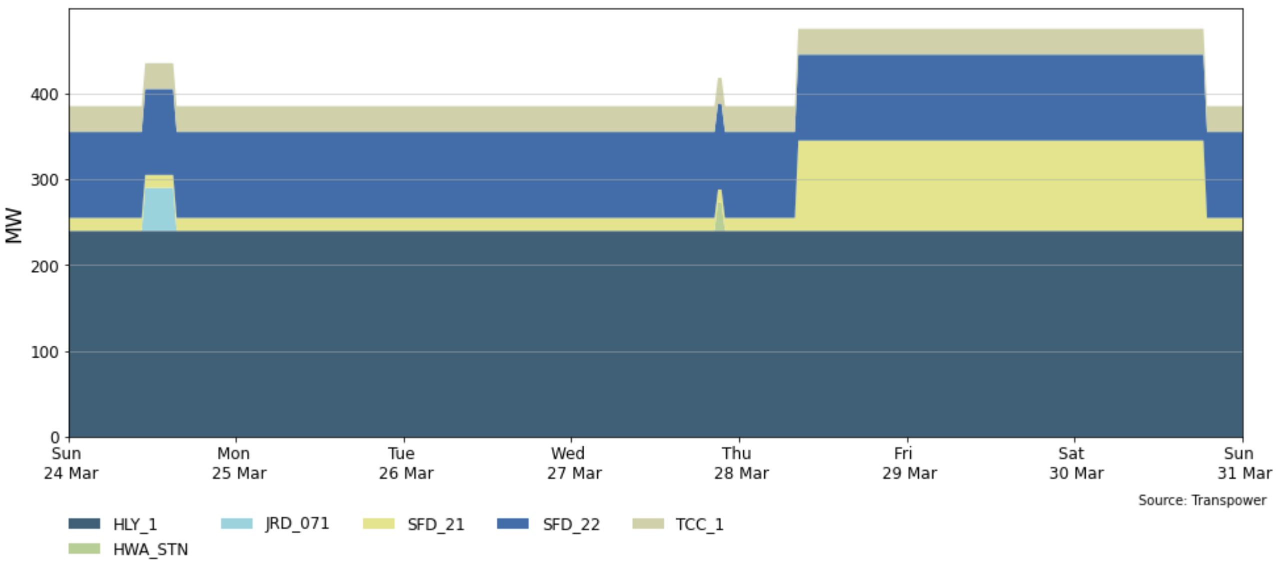


Figure 17: MW loss from thermal outages between 24-30 March

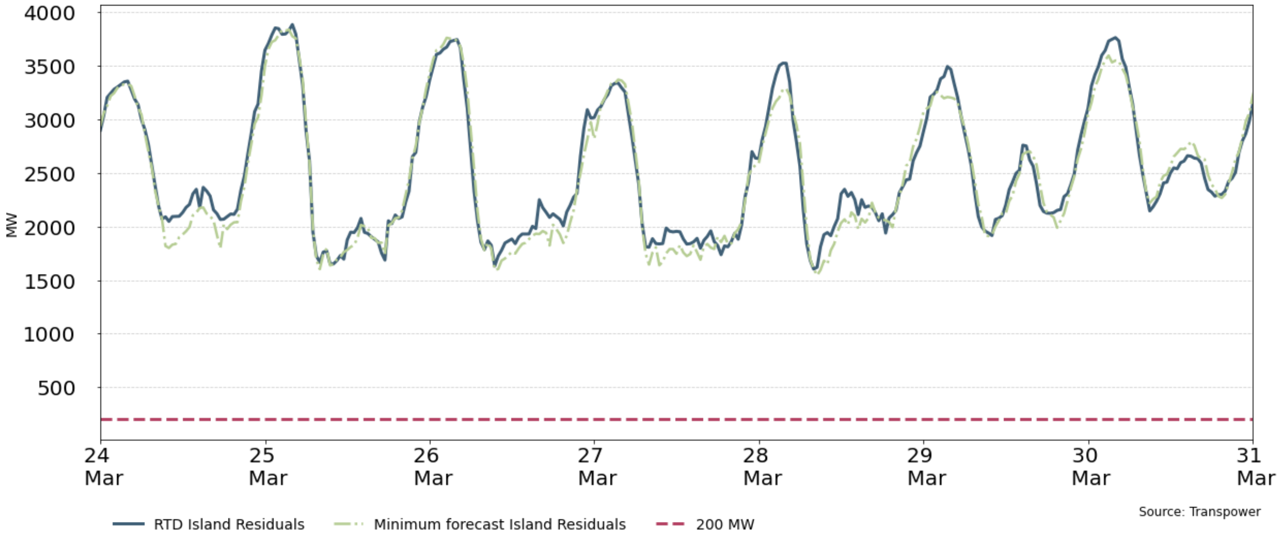


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 24-30 March. 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 1500MW and the minimum North Island residual levels at around 760MW.

Figure 18: National generation balance residuals 24-30 March



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 remained at around 70% of nominally full and ~88% of the historical average for this time of the year.

10.3. Hydro storage saw small changes this week; some lakes increased slightly while others decreased or remained stable. As of 30 March:

(a) Lake Taupō is below its 90th percentile but still above its historical average.

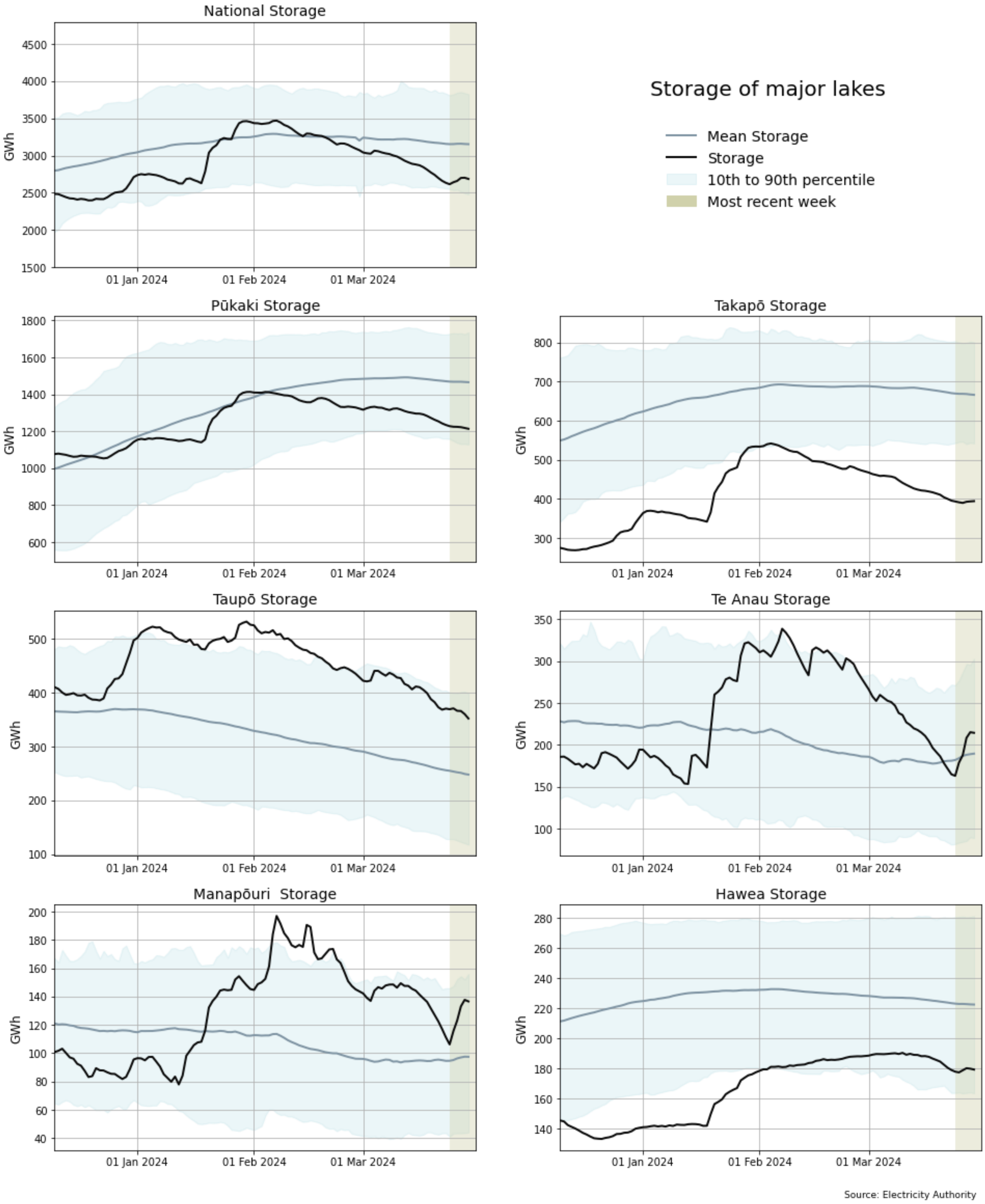
(b) Lake Pūkaki is still trending towards its 10th percentile after a slight decline.

(c) Lake Takapō storage increased slightly this week, but it is still below its 10th percentile.

(d) Lake Manapōuri and Te Anau both saw an increase in storage. Te Anau is now between its historical average and 90th percentile while Manapōuri is closer to its 90th percentile.

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

Figure 19: Hydro storage

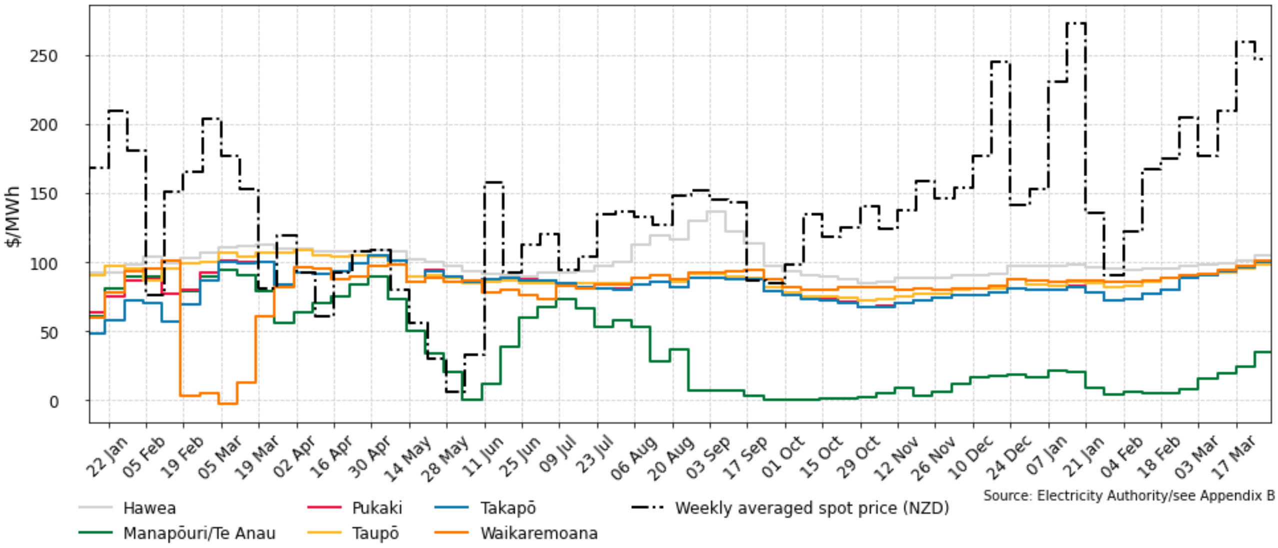


11. JADE water values

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 30 March 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. The water values increased this week compared to the previous week, between $3-$4/MWh at all lakes except for Te Anau/Manapōuri, which saw an increase of around $10/MWh.

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 30 March 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.

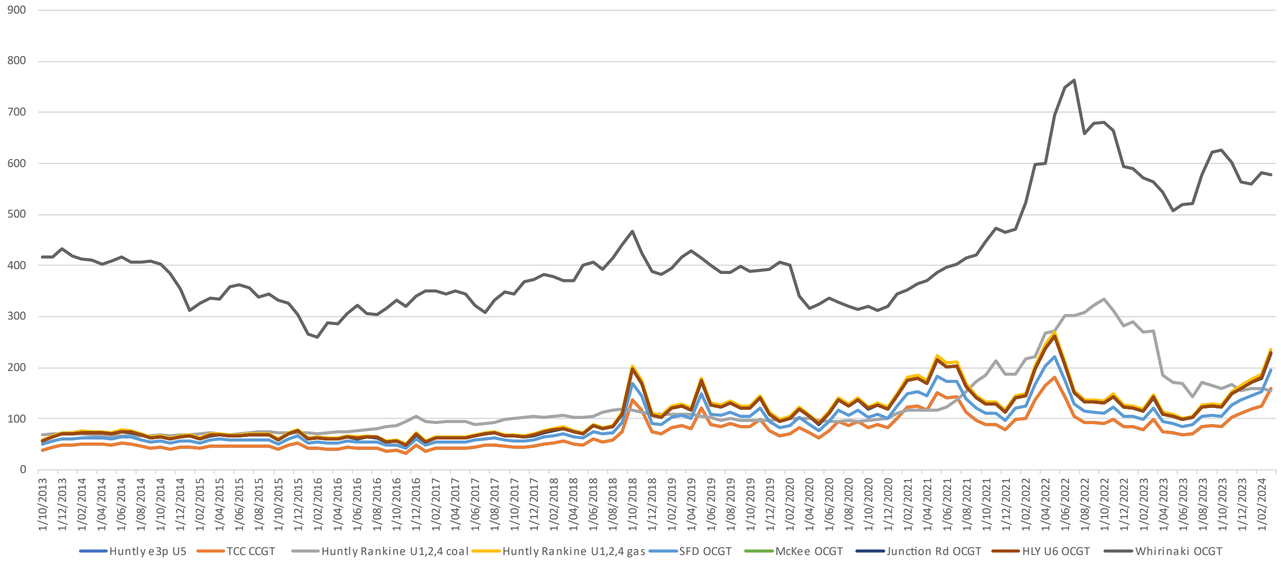
12.5. The SRMC of gas-fueled thermal plants is currently between ~$159/MWh and ~$236/MWh.

[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



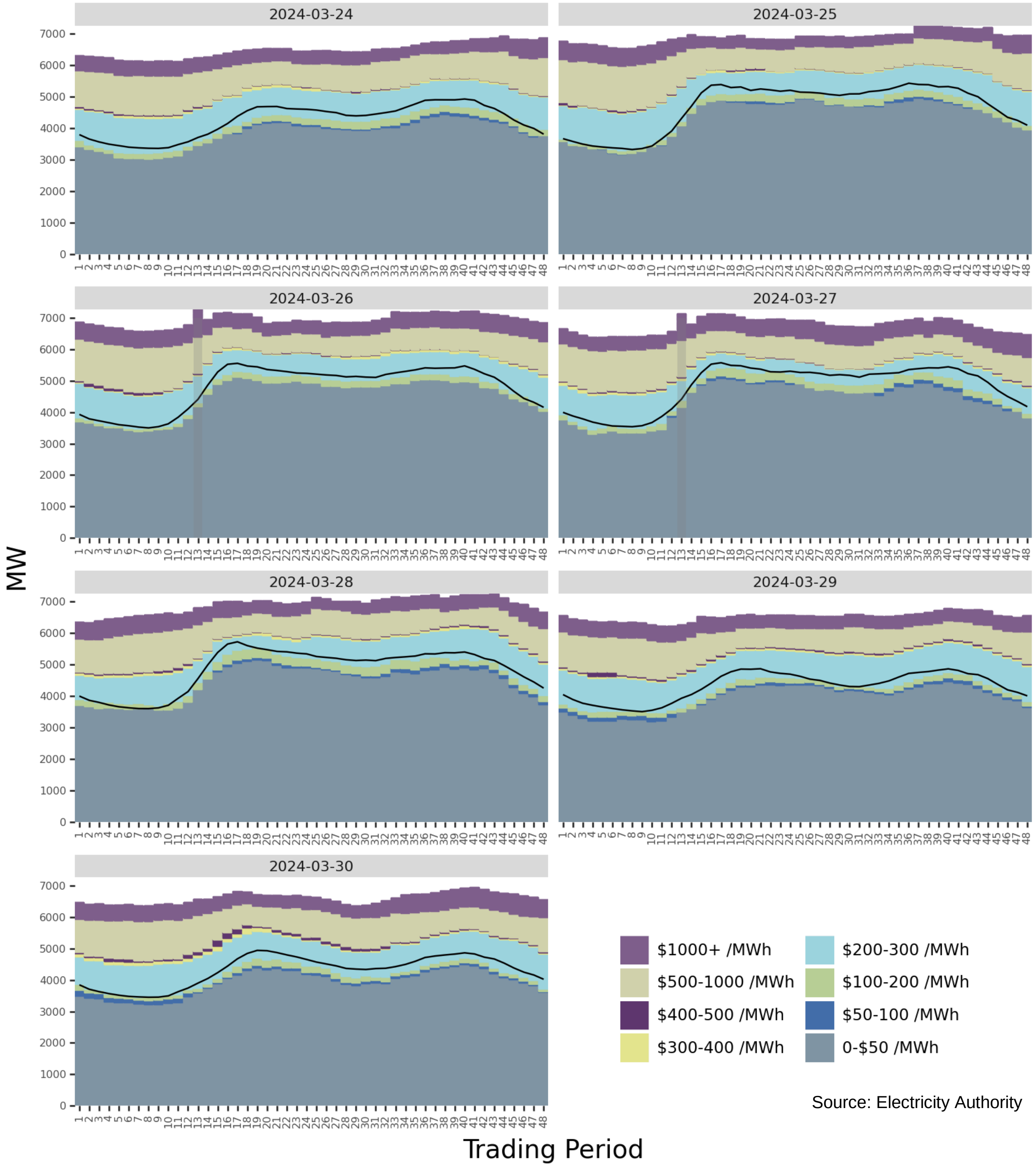
Source: Electricity Authority/see Appendix C

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. Mainly all the offers during the week were 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]



[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