4 March 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 25 February–2 March

1.1. Spot prices were mostly above the historical average this week. There were North Island price spikes on Sunday and Monday due to a combination of low wind generation and planned HVDC outages. There were also several periods of price separation and reserve price spikes across the week. Reserve price spikes were related to the HVDC outages, which limited the reserve sharing capacity between the islands. TCC, Huntly 5, and Huntly 4, then Huntly 2 ran as baseload this week. Hydro storage decreased and is currently at ~95% of mean as of 2 March.

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 25 February-2 March:

(a) The average wholesale spot price across all nodes was $204/MWh.

(b) 95% of prices fell between $0.01/MWh and $361/MWh.

2.4. Similar to the previous week spot prices were affected by the planned HVDC outages. On Sunday a bi-pole outage prevented any transfers between the islands, while from Monday onwards HVDC Pole 2 went on outage.

2.5. The spot prices this week were mainly above the national historical median for this time of the year, with only a few low prices in the South Island earlier in the week. The average spot price increased by $30MWh compared to the previous week.

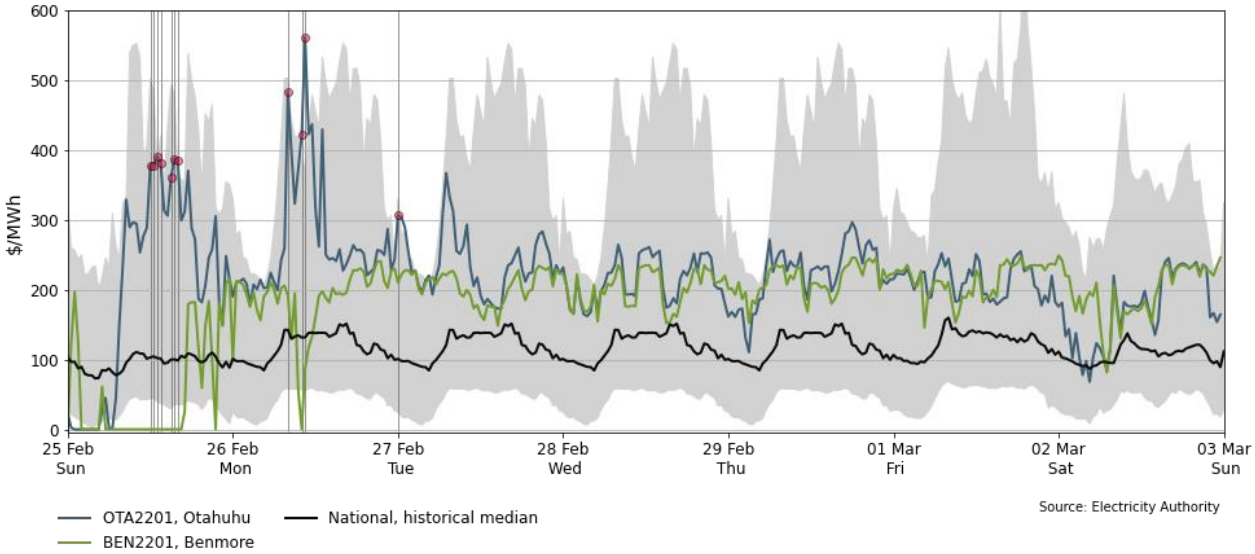
2.6. There were multiple price spikes and price separation in the North Island on Sunday and Monday. The highest price at Ōtāhuhu was on Monday at 10:30am, reaching $562/MWh. These high prices and price separation were related to low wind generation and times of energy-reserve co-optimisation due to the planned HVDC outages. On Sunday demand forecast inaccuracies also contributed to the high prices.

[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.

2.7. On Tuesday, North Island prices spiked over $300/MWh during the first two trading periods. This was possibly related to demand and wind forecasting errors as well as some thermal generation turning off, meaning some higher priced generation needed to be dispatched. We will be looking into these unusually high overnight prices.

2.8. Overnight Friday to Saturday, and on Saturday evening, Benmore prices were higher than Ōtāhuhu prices. South Island demand was higher than forecast during these times with the HVDC also flowing southward. This saw some higher priced hydro dispatched in the South Island.

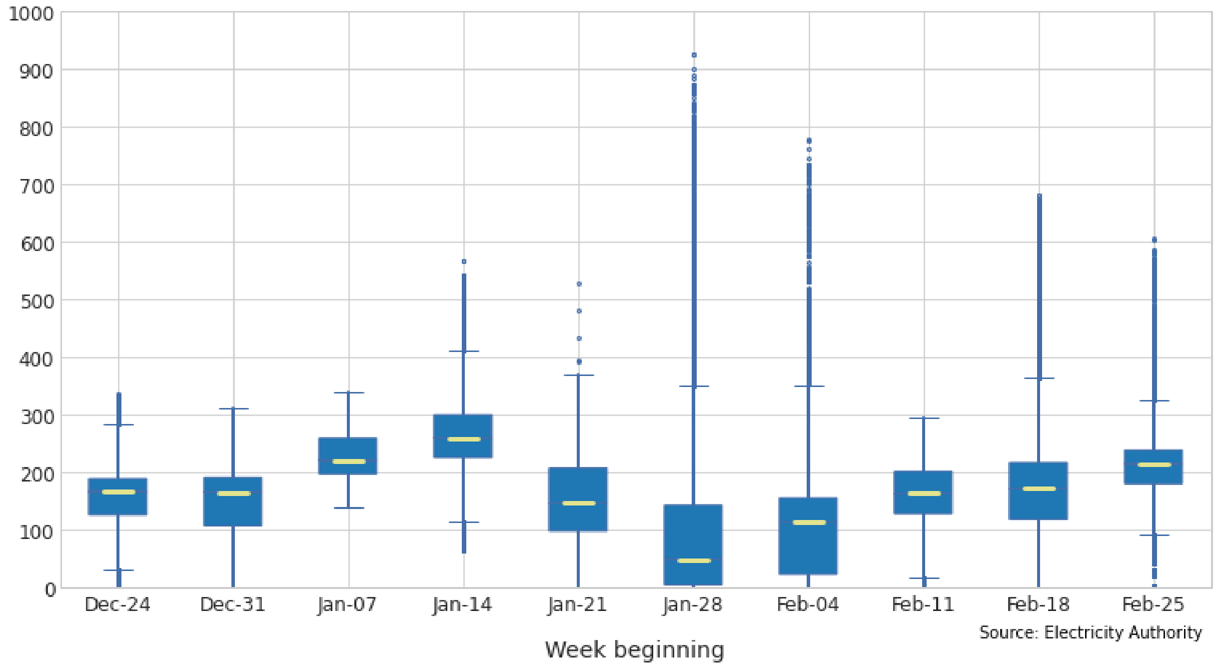
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 25 February-2 March



2.9. 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.

2.10. This week saw a more condensed distribution with higher prices than the previous week. The median price this week increased to $214/MWh compared to $172/MWh last week. The middle 50% of the prices were between $180-$238/MWh.

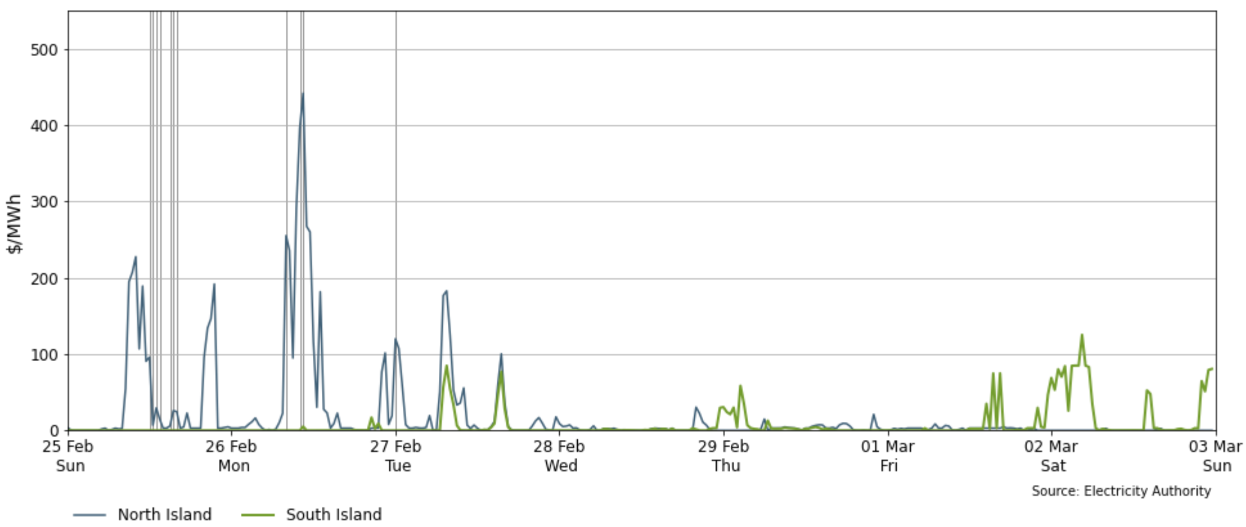
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

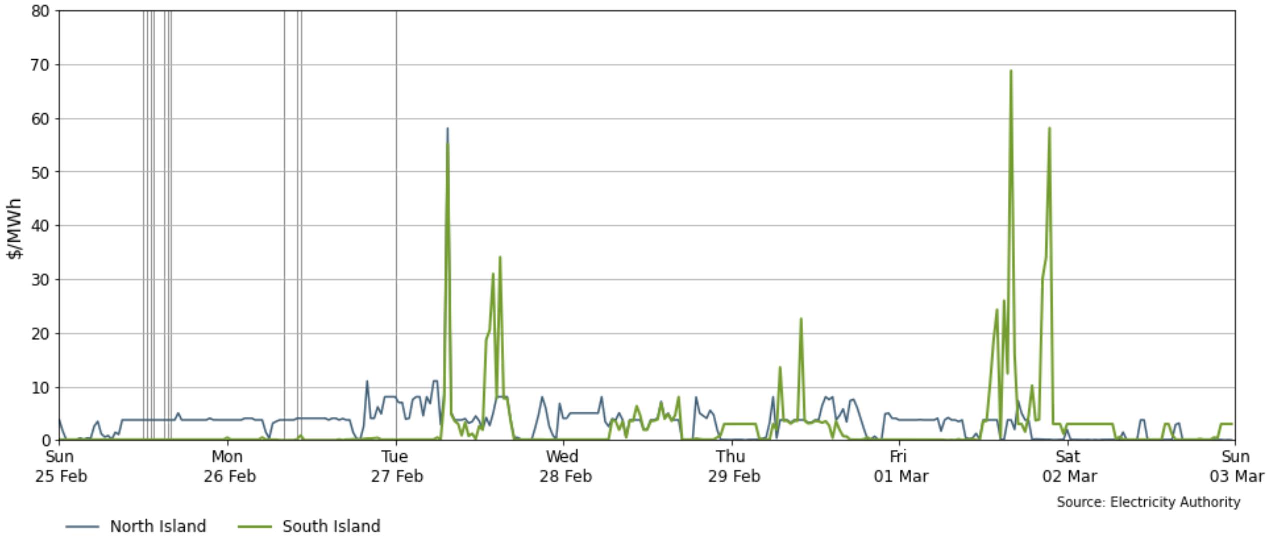
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. The high North Island FIR price seen on Sunday and Monday were caused by the HVDC outages and energy and reserve balancing being impacted by low wind generation on those days. On Sunday, the planned HVDC planned bi-pole outage demanded North Island reserves to cover the North Island risk, since there were no energy transfers between the islands. On Monday, the HVDC was operating as a single pole and its capacity was set by the amount of North Island FIR available. The North Island FIR prices reflect an energy-reserve co-optimisation. Thus, during times of North Island spot price spikes, North Island FIR prices also spiked.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 25 February-2 March



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly within the $0-$10/MWh range. Price separation between Tuesday and Friday was related to the planned HVDC outages. On Tuesday morning, Thursday afternoon and Friday morning SIR prices spiked when higher priced reserves were dispatched to cover larger risk in both islands. Because of the HVDC outage, the South Island reserve stack is very steep – so a small increase in reserve needed can cause a much higher price. On Friday evening, South Island SIR and FIR spikes were related to high Southward HVDC flows, which caused a larger SIR risk, requiring more South Island reserves.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 25 February-2 March



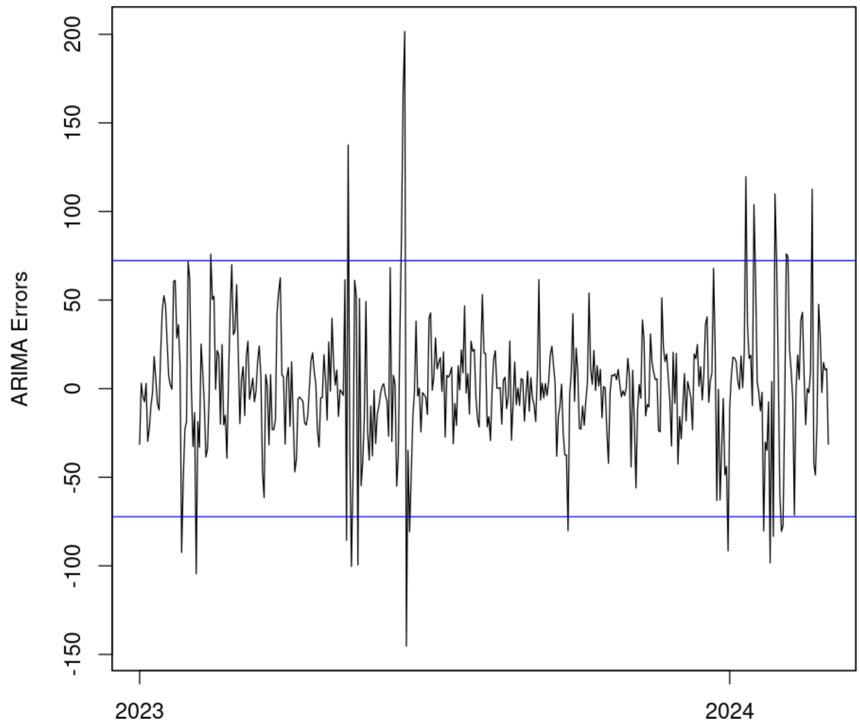
4. Regression residuals

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. The regression analysis does not take transmission outages into consideration.

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 2023-2 March 2024

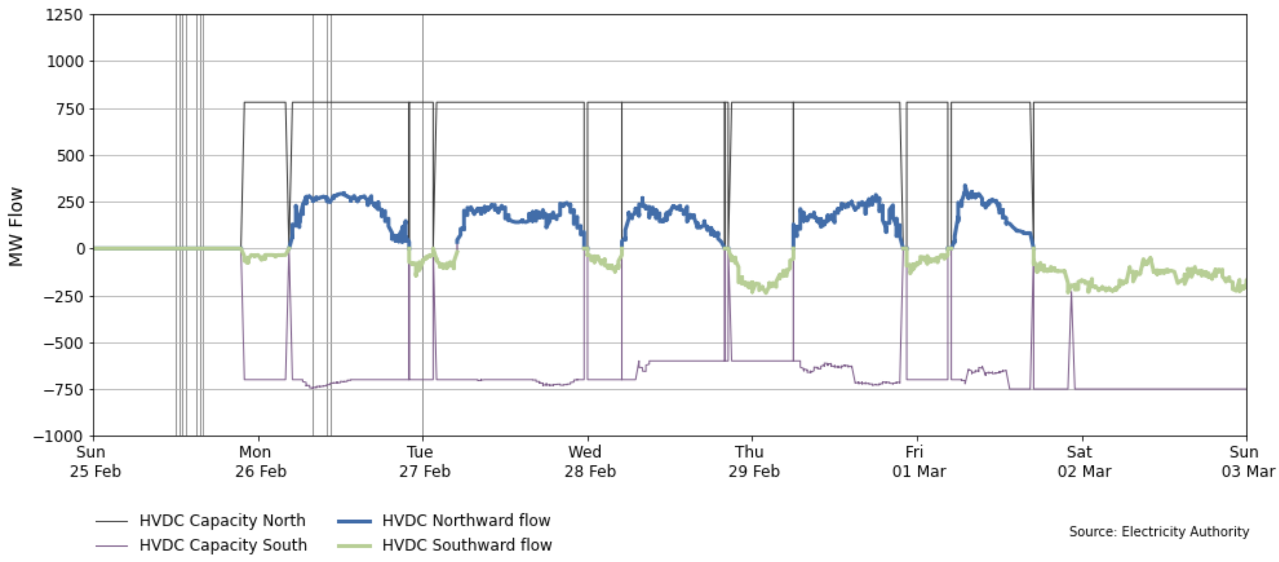


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows HVDC flow between 25 February-2 March. HVDC flows this week were limited by two planned HVDC outages. On Sunday 25 February, the planned bi-pole outage prevented any electricity transfers between the North and South islands. From Monday onwards, the planned HVDC Pole 2 outage began, limiting the flow capacity to 780MW. However, flow remains limited by the reserve availability.

Figure 6: HVDC flow and capacity between 25 February-2 March

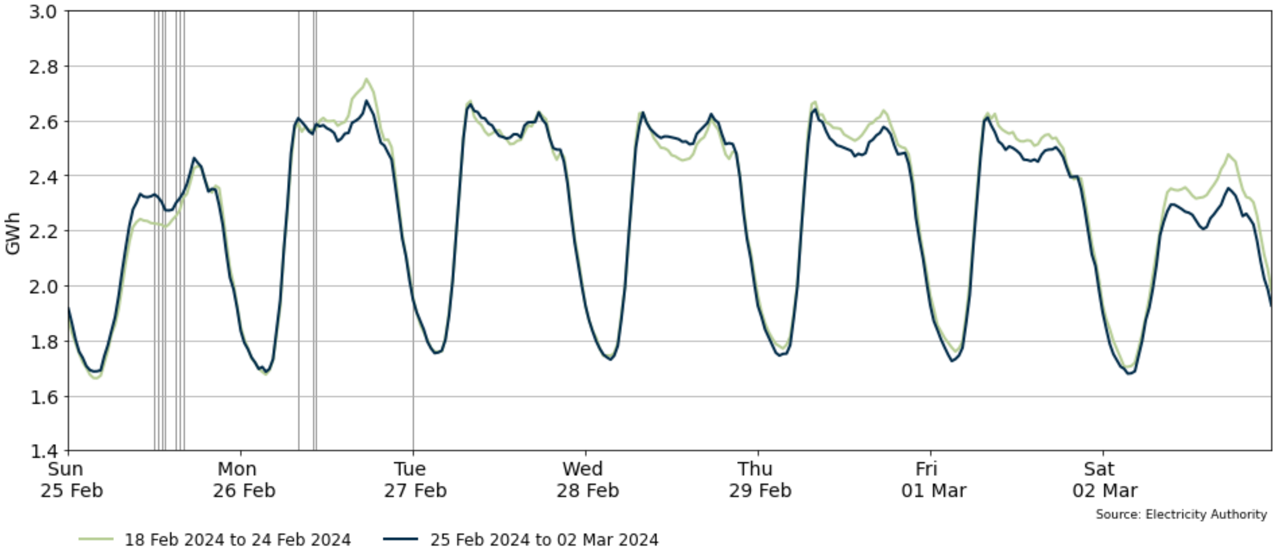


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 25 February-2 March, compared to the previous week. Demand this week was mostly similar to the previous week up to Wednesday. Demand from Thursday onwards was lower compared to the previous week.

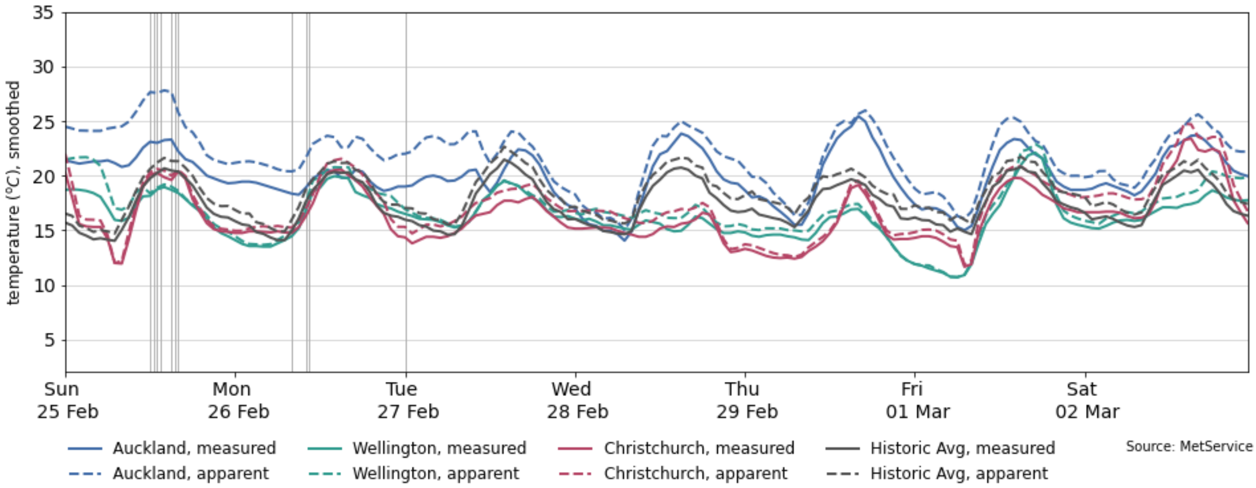
Figure 7: National demand between 25 February-2 March compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 25 February-2 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 fluctuated around the historical averages this week, varying between 12ºC and 28ºC across the country.

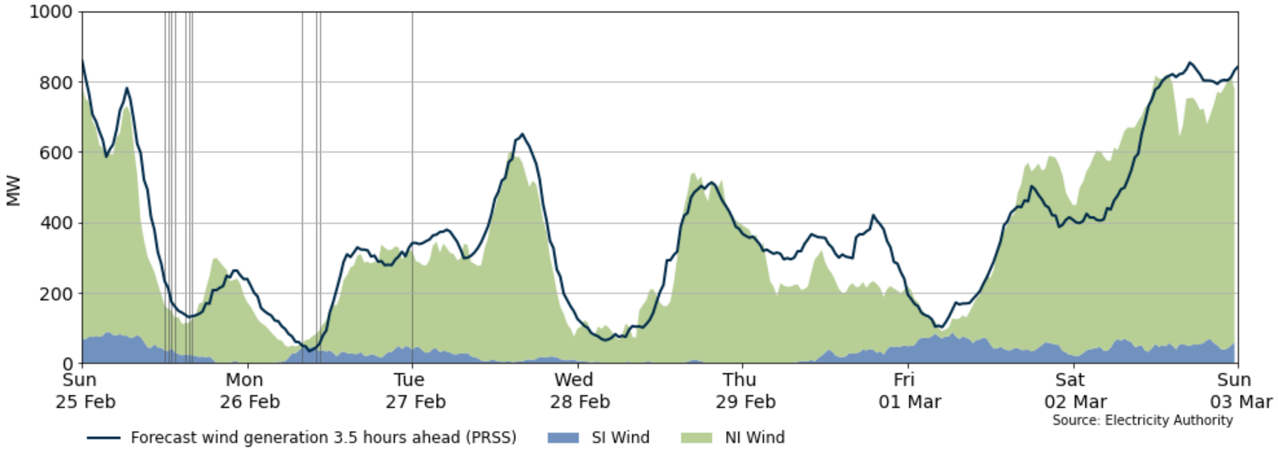
Figure 8: Temperatures across main centres between 25 February-2 March



7. Generation

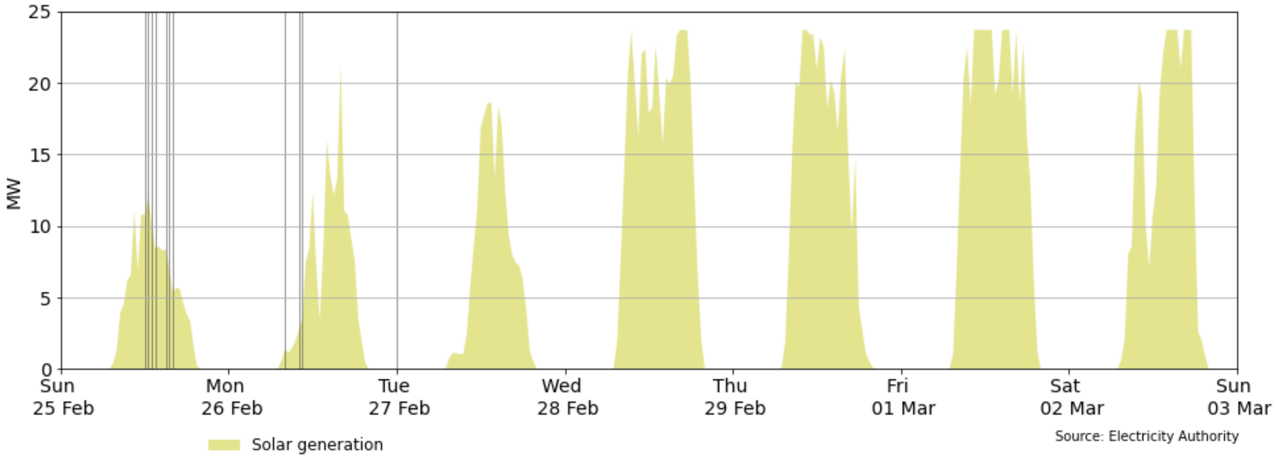
7.1. Figure 9 shows wind generation and forecast from 25 February-2 March. This week wind generation varied between 46MW and 818MW, with an average of 346MW. Wind generation was more variable this week, reaching its lowest on Monday morning and remaining relatively low until Friday, when it increased to more than 400MW.

Figure 9: Wind generation and forecast between 25 February-2 March



7.2. Figure 10 shows solar generation from 25 February-2 March. Solar generation was lower earlier in the week compared to the rest of the week. Overcast conditions earlier in the week contributed to lowering the output of the solar farm.

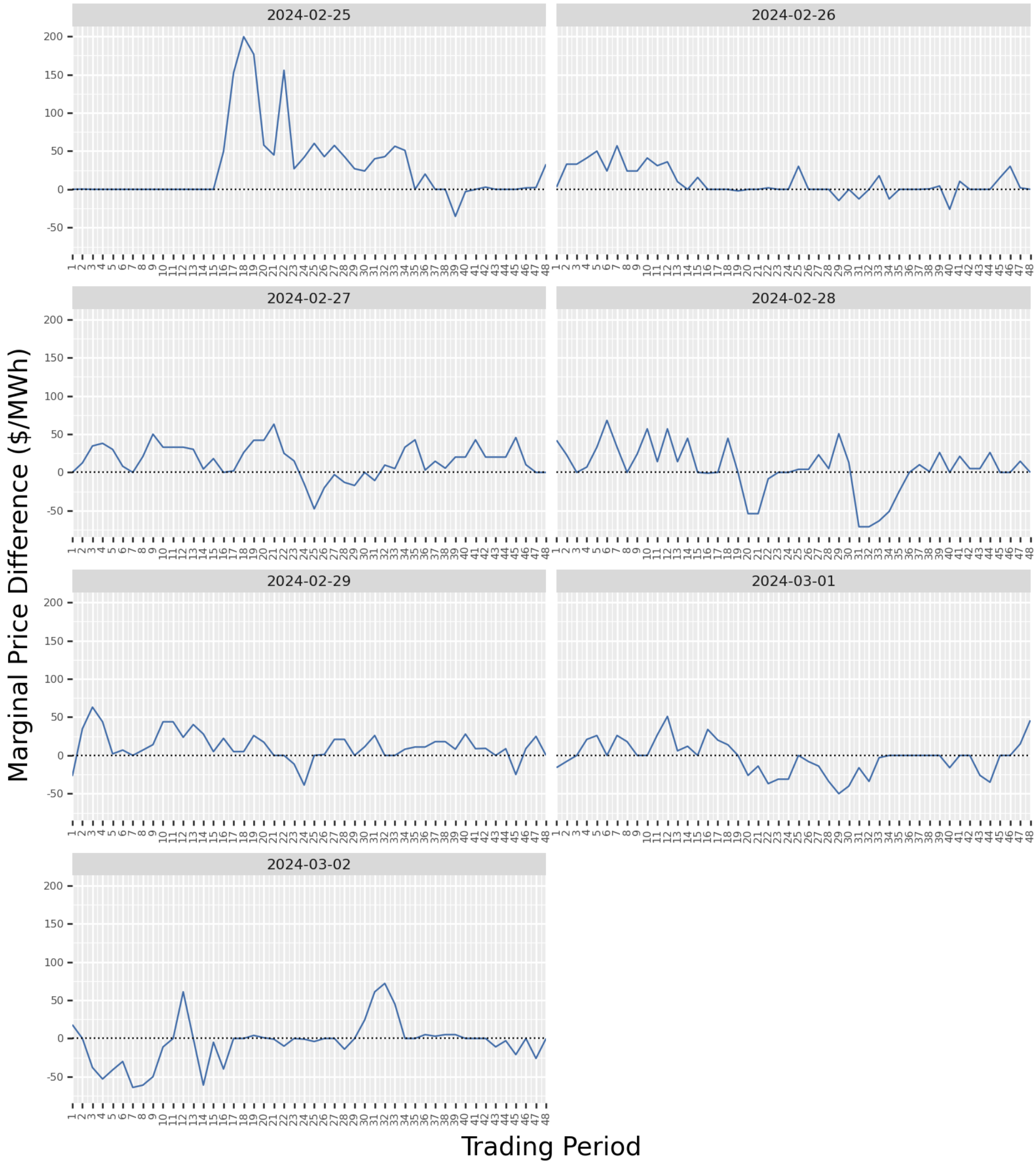
Figure 10: Solar generation between 25 February-2 March



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 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. While 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.

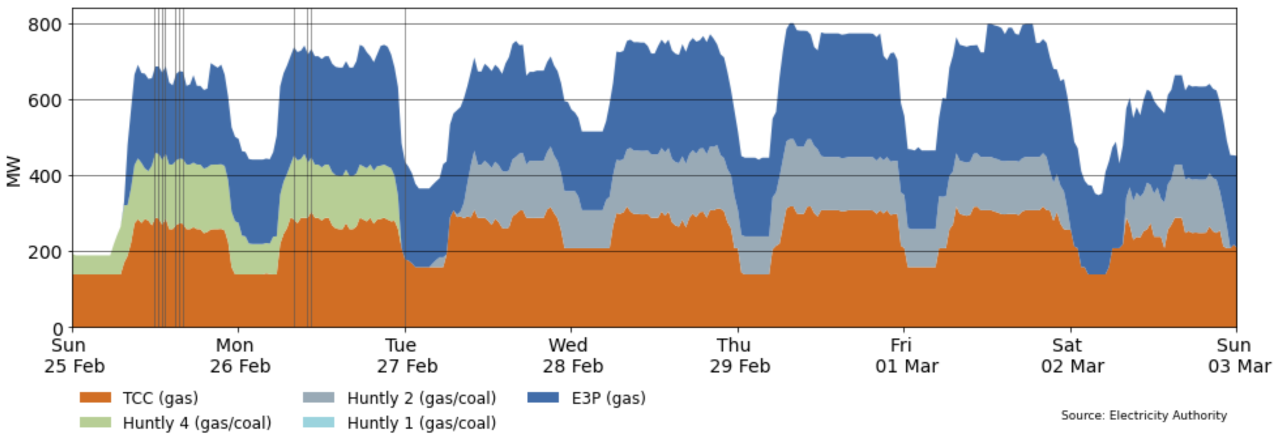
7.4. This week the main difference between the RTD and PRSS prices happened on Sunday, when the RTD prices were over $100/MWh higher than the 1-hour ahead PRSS prices for a few trading periods between 8:00am and 11:30am. Those were times when wind generation or demand (or both) was lower than expected. On the remaining days, the differences mostly stayed between positive and negative $50/MWh, reflecting more accurate pre-dispatch prices on those days.

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 25 February-2 March



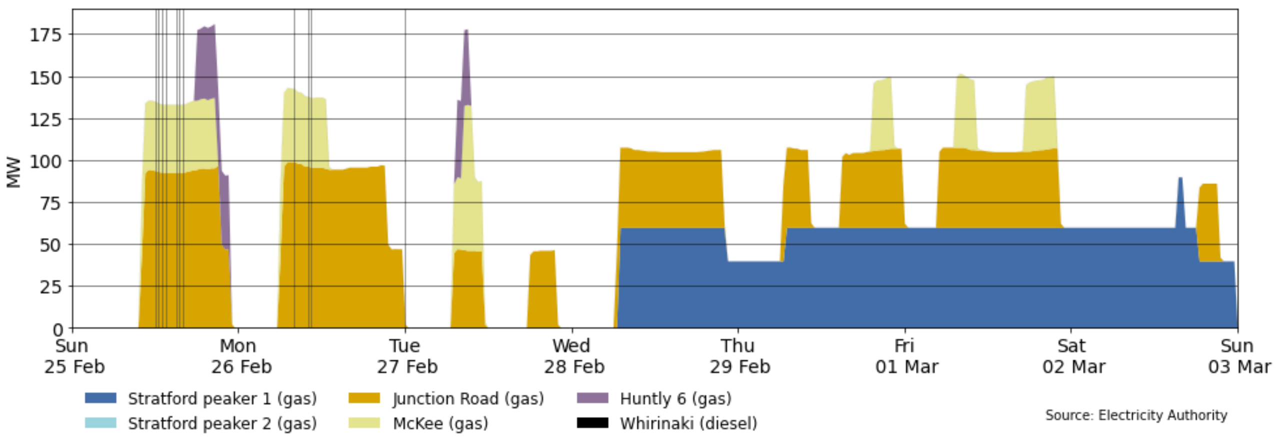
7.5. Figure 12 shows the generation of thermal baseload between 25 February-2 March. TCC and Huntly 5 (E3P) provided baseload this week. A Rankine unit also contributed to baseload generation with Huntly 4 running on Sunday and Monday, and Huntly 2 generating from Tuesday onwards.

Figure 12: Thermal baseload generation between 25 February-2 March



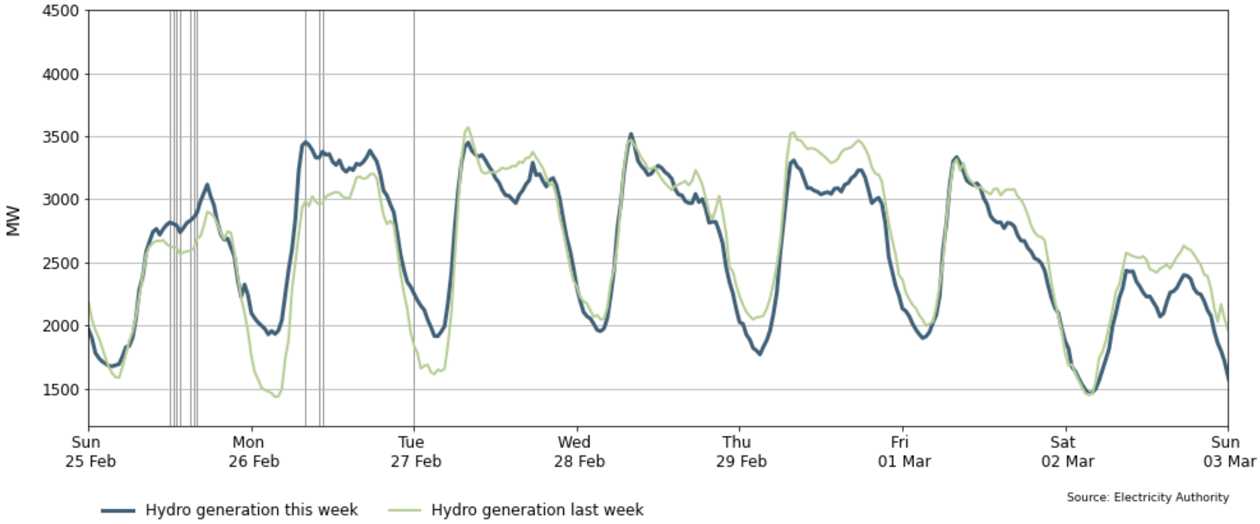
7.6. Figure 13 shows the generation of thermal peaker plants between 25 February-2 March. This week Junction Road ran every day during peak and shoulder periods. McKee also ran during peak periods most days except Wednesday and Saturday. Stratford ran continuously from Wednesday to Saturday.

Figure 13: Thermal peaker generation between 25 February-2 March



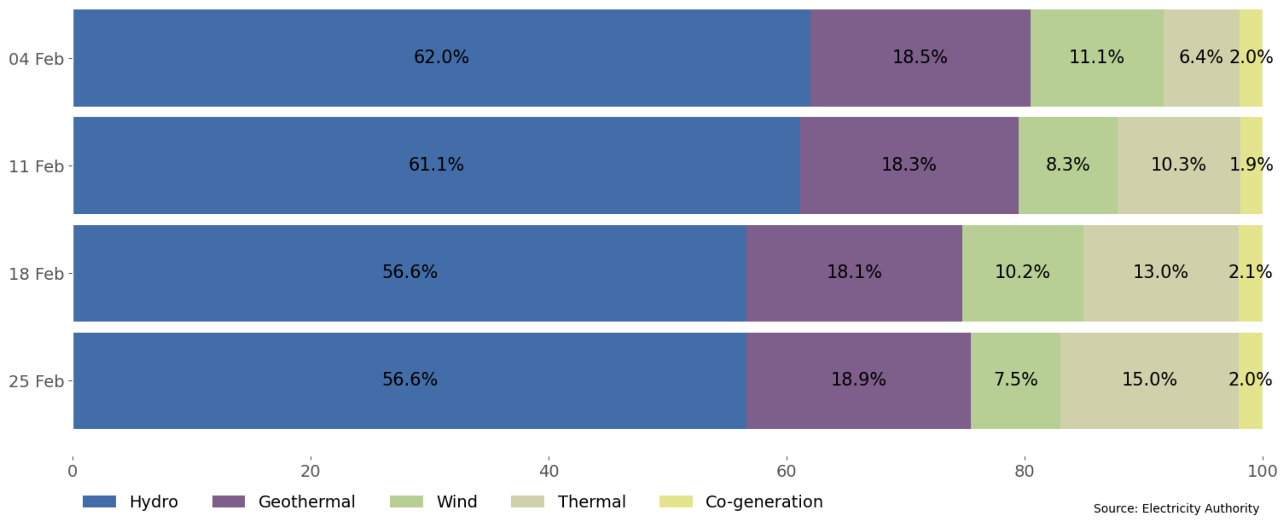
7.7. Figure 14 shows hydro generation between 25 February-2 March. Compared to the previous week, hydro generation was lower most days, except on Sunday and Monday. This was likely due to low wind requiring increased hydro generation to meet demand.

Figure 14: Hydro generation between 25 February-2 March



7.8. As a percentage of total generation, between 25 February-2 March, total weekly hydro generation was 56.6%, geothermal 18.9%, wind 7.5%, thermal 15%, and co-generation 2%, as shown in Figure 15. The proportion of generation from thermal increased this week in line with the decrease to the proportion of generation from wind.

Figure 15: Total generation b type as a percentage each week between 25 February-2 March



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 25 February-2 March ranged between ~1600MW and ~2100MW. Figure 17 shows the thermal generation capacity on outage.

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) Huntly 2 was on partial outage for a few hours on 29 February

(d) Huntly 4 is on partial outage from 28 February to 3 March

(e) Poihipi geothermal plant is on outage until 22 March 2024

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

Figure 16: Total MW loss due to generation outages between 25 February-2 March

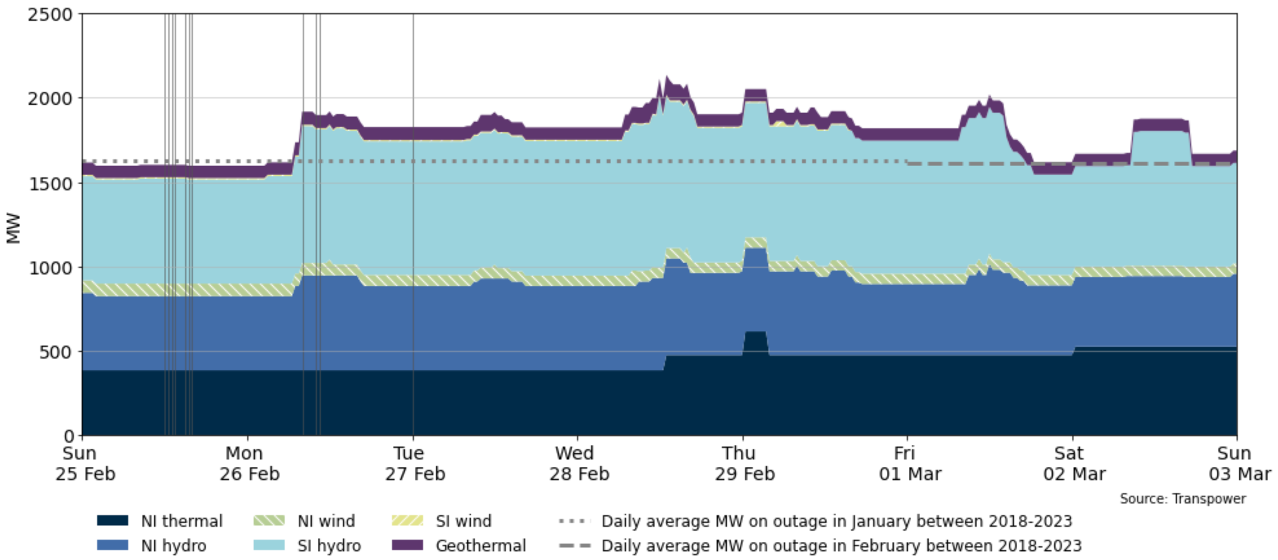
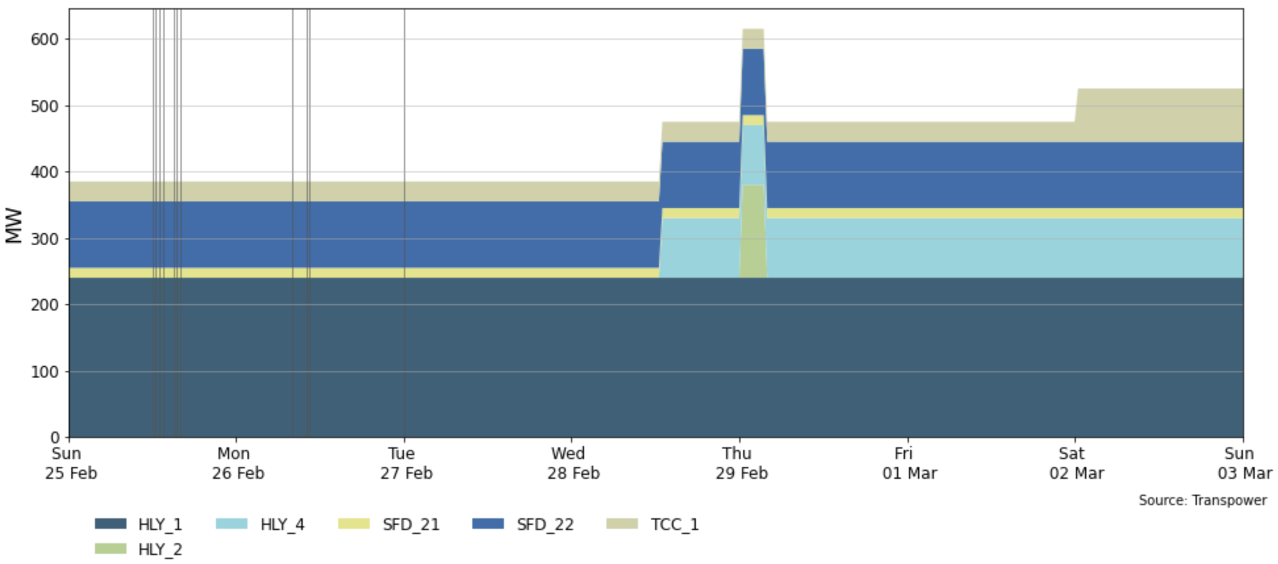


Figure 17: MW loss from thermal outages between 25 February-2 March

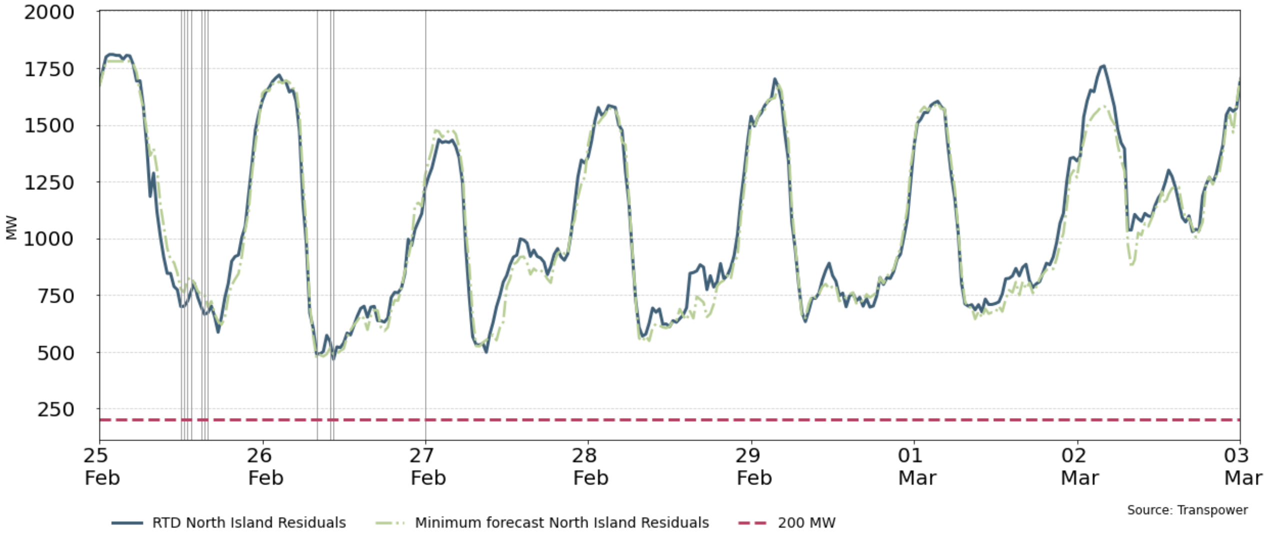


9. Generation balance residuals

9.1. Figure 18 shows the North Island generation balance residuals between 25 February-2 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 the real time dispatch (RTD) residuals.

9.2. National generation residuals were healthy this week, with a minimum of 851MW. Despite the planned HVDC outages and a few price spikes happening this week, the North Island generation residuals were also healthy, as shown in Figure 18, with a minimum of 467MW on Monday morning.

Figure 18: Generation balance residuals 25 February-2 March – North Island



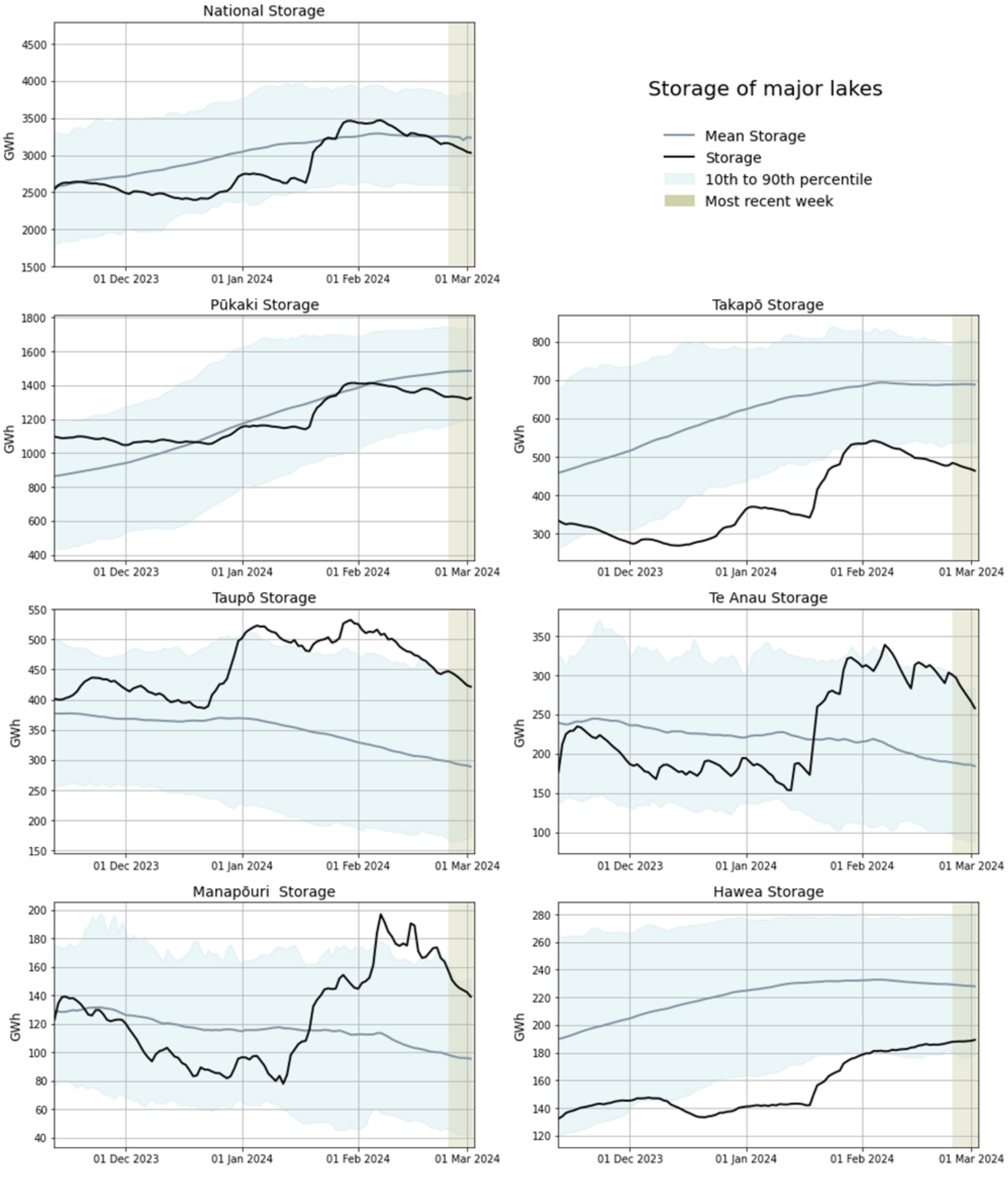
10. Storage/fuel supply

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 compared to the previous week, now at ~77% nominally full and ~95% of the historical average for this time of the year (as of 2 March).

10.3. Most lakes saw a decrease in their storage levels this week. Storage at lake Taupō is now below its 90th percentile but still above the historical average. Storage at lake Pūkaki remained steady, still sitting between its historical average and the 10th percentile. Lake Takapō remains below its 10th percentile as its storage continues to decrease. Lakes Manapōuri and Te Anau saw a decrease in their storage levels and are now just below their respective 90th percentile. Hawea storage continued to increase steadily, now sitting above its 10th percentile.

Figure 19: Hydro storage



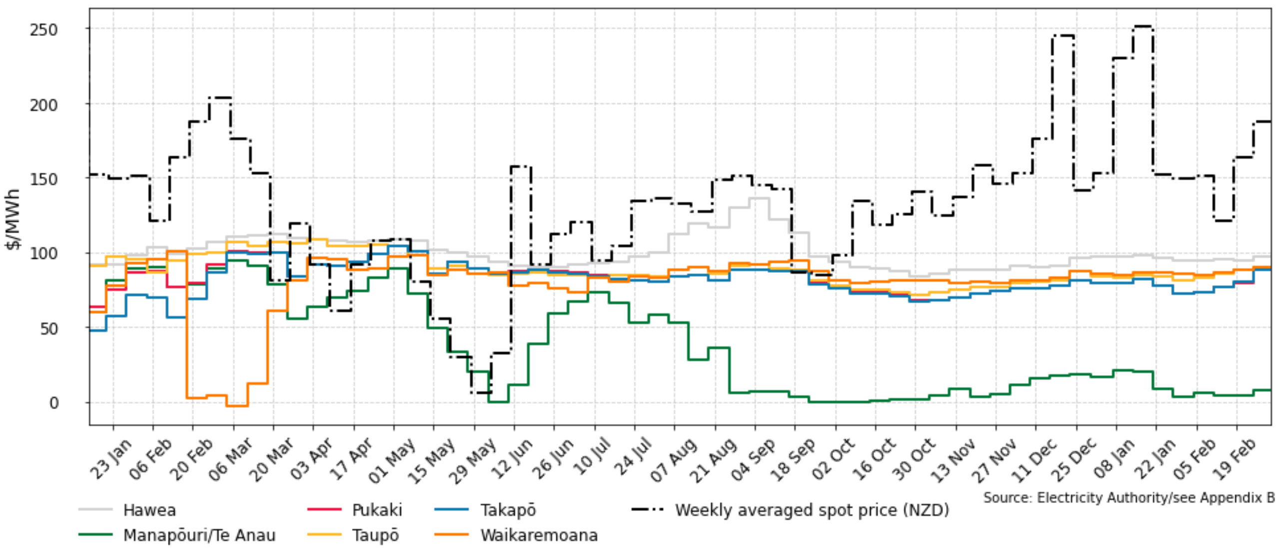
Source: Electricity Authority

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 2 March 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.

11.2. Compared to the previous week the water values increased between around $2-8/MWh at all lakes; the lowest increase being at Lake Taupō and the largest at Lake Pūkaki.

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 3 February 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 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.

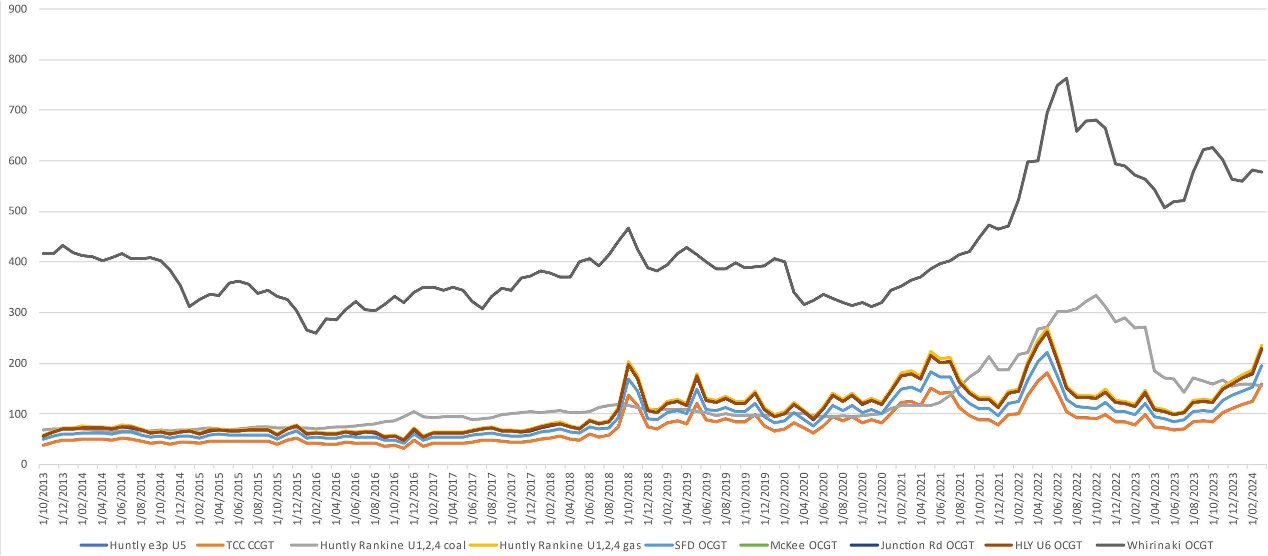
12.5. The SRMC of gas fueled thermal plants is currently between ~$159/MWh and ~$236/MWh.

[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

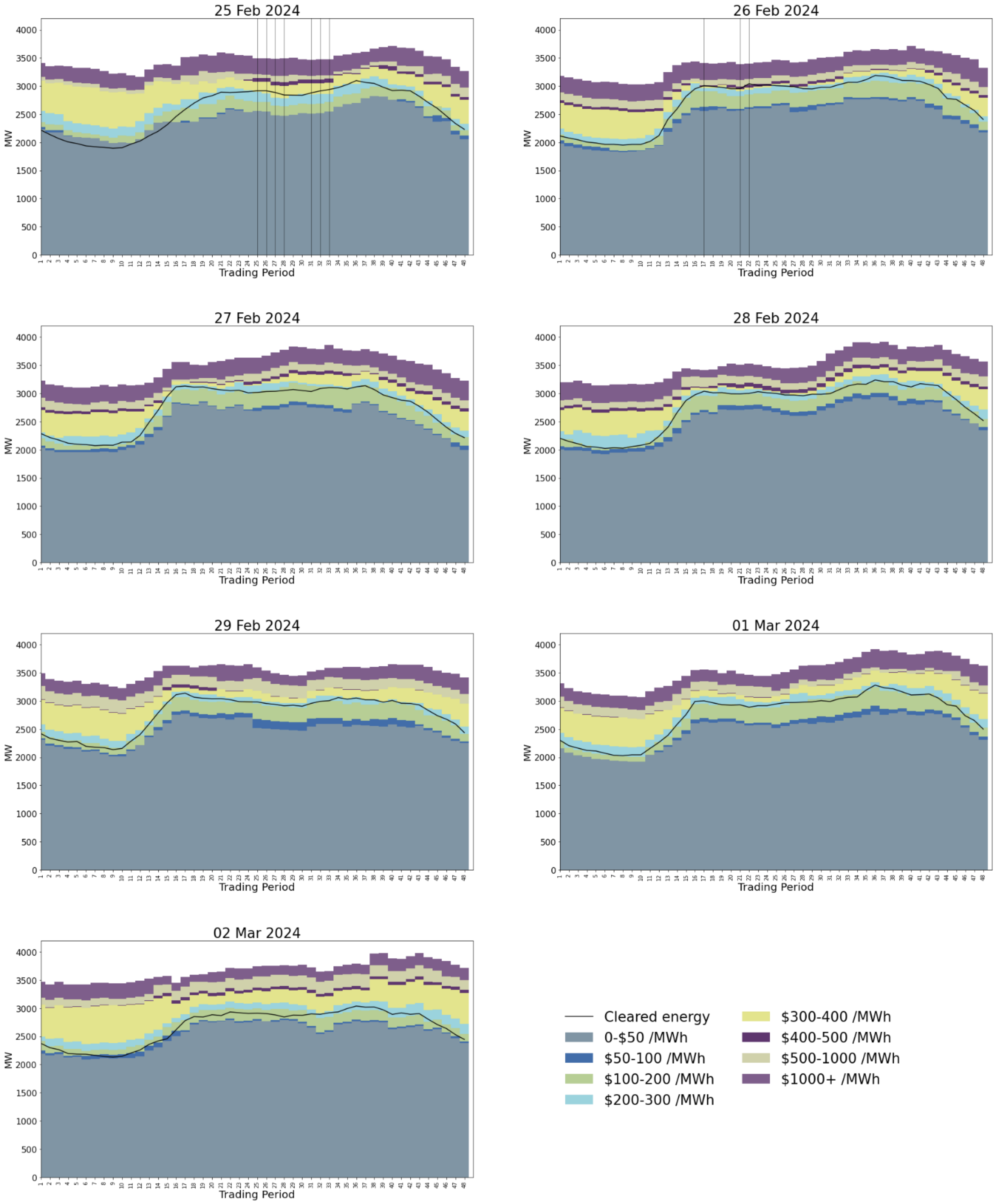
13. Offer behaviour

13.1. This week we split the national daily offer stacks between the two islands due to the planned HVDC outages. Figure 22 and Figure 23 show this week's offer stacks for the North and South islands respectively. The black lines in the figures show cleared energy, indicating the range of the average final price.

13.2. In the North Island most of the offers during the week were cleared either in the $100-$300/MWh region. At the beginning of the week some North Island prices cleared over $300/MWh due to higher priced North Island energy needing to be dispatched to meet demand conditions during the HVDC outage.

13.3. In the South Island most of the offers were cleared within $100-$300/MWh across the week. except for Sunday when the offers were often cleared in the lower bands. Offers in the $0-$200/MWh stacks reduced at the end of the week which saw prices in the South Island clear between $200-$300/MWh for a period from Friday afternoon into Saturday.

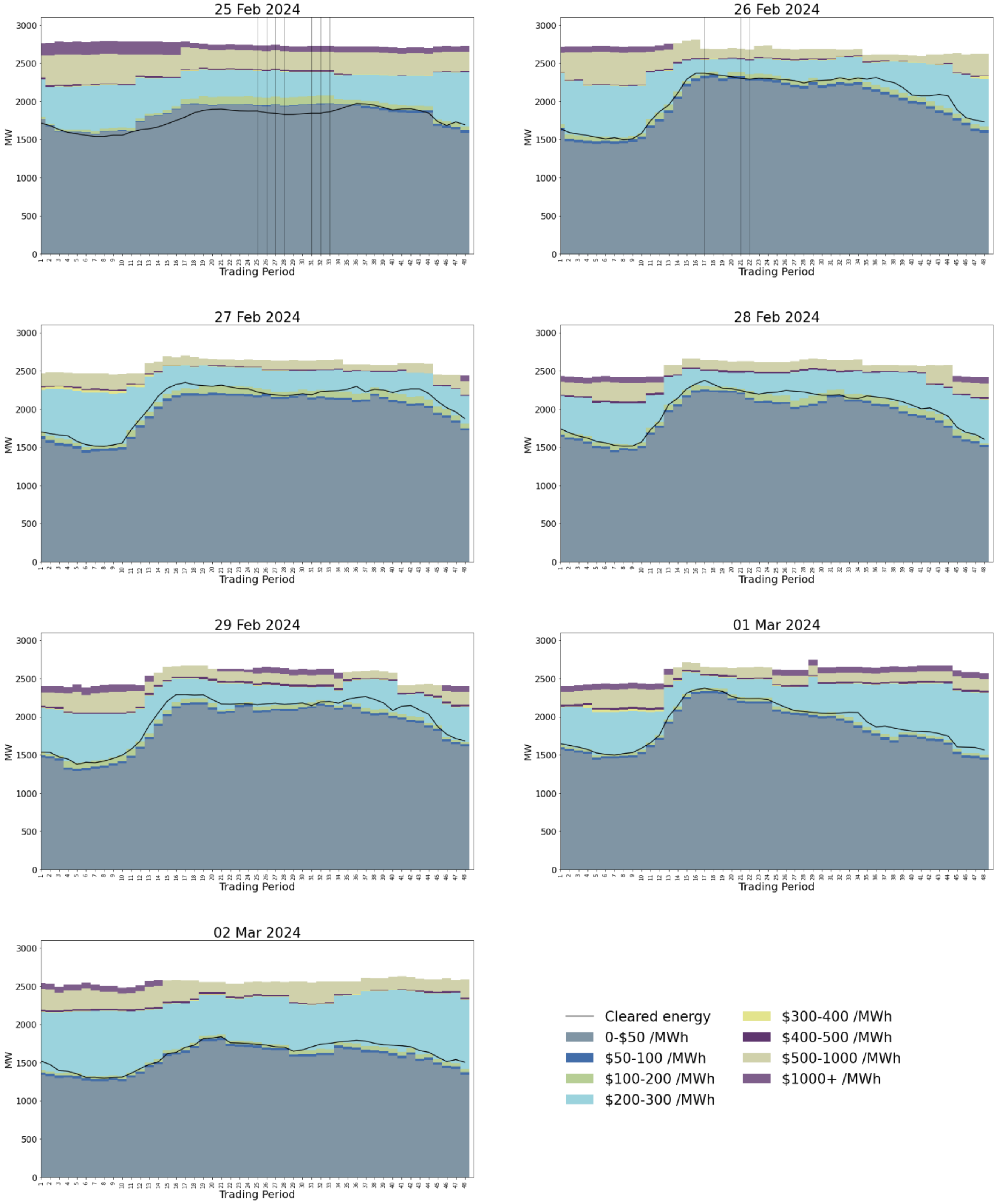
Figure 22: North Island Daily Offer stacks[3]



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.

Figure 23: South Island Daily Offer stacks[4]



Source: Electricity Authority

[4] 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. We are looking further into Meridian hydro offers on Friday.

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	High hydro offers.
30/01/2024-01/02/2024	Several	Further analysis	Several	Multiple	High reserve prices related to reserve offers.
22/02/2024	32	Further analysis	Genesis	Tokaanu	Offer prices
27/02/2024	1-2	Further analysis	Genesis	Huntly	Huntly start up
01/03/2024	Several	Further analysis	Meridian	Ohau and Waitaki	Hydro offers