26 February 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 18-24 February

1.1. Prices were mostly above the historical average this week, but still within the 10th-90th percentile range.

1.2. On Thursday, North Island price spikes occurred when a combination of limited HVDC transfer capacity, low wind generation, along with demand and wind forecasting errors caused prices to spike above $1000/MWh during one trading period.

1.3. This week also saw several periods of price separation and Fast Instantaneous Reserve (FIR) and Sustained Instantaneous Reserve (SIR) price spikes, related to the planned HVDC outage.

1.4. TCC, Huntly 5, and Huntly 4 ran as baseload during most days. The peakers ran from mid-week during times of low wind generation. Hydro storage decreased this week and is currently at ~98% of mean as of 24 February.

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 18-24 February:

(a) The average wholesale spot price across all nodes was $174/MWh.

(b) 95 percent of prices fell between $0.03/MWh and $452/MWh.

2.4. This week there were two HVDC planned outages. HVDC Pole 3 was on outage from 21-24 February. On Saturday HVDC bi-pole outage prevented any HVDC transfers.

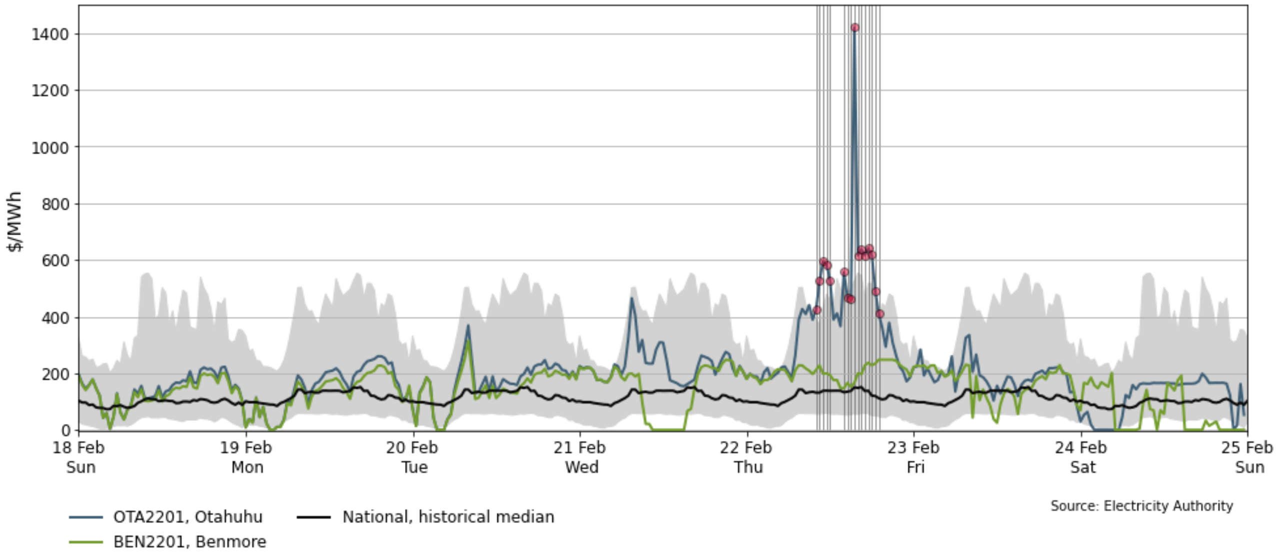
2.5. Prices fluctuated between $0-$200/MWh for most of the week but were often above the historical average for this time of the year. Prices spiked above the 90th percentile on Thursday, when Ōtāhuhu prices were above $400/MWh several times, reaching $1,420/MWh at 3:30pm. Price separation also occurred on Wednesday, Thursday and Saturday.

[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.

2.6. The Thursday price separation and high prices were related to the planned HVDC pole 3 outage, which occurred from 21-24 February. Additionally, there was also low wind generation, tight North Island energy and reserve supply (due to the pole 3 outage), and wind and demand forecast inaccuracies. All these factors combined caused the Scheduling, Pricing, and Dispatch (SPD) model to dispatch more expensive North Island generators. The monitoring team will be looking further into North Island offers during the 3:30 price spike.

2.7. The weekly average price increased by around $17/MWh compared to the previous week.

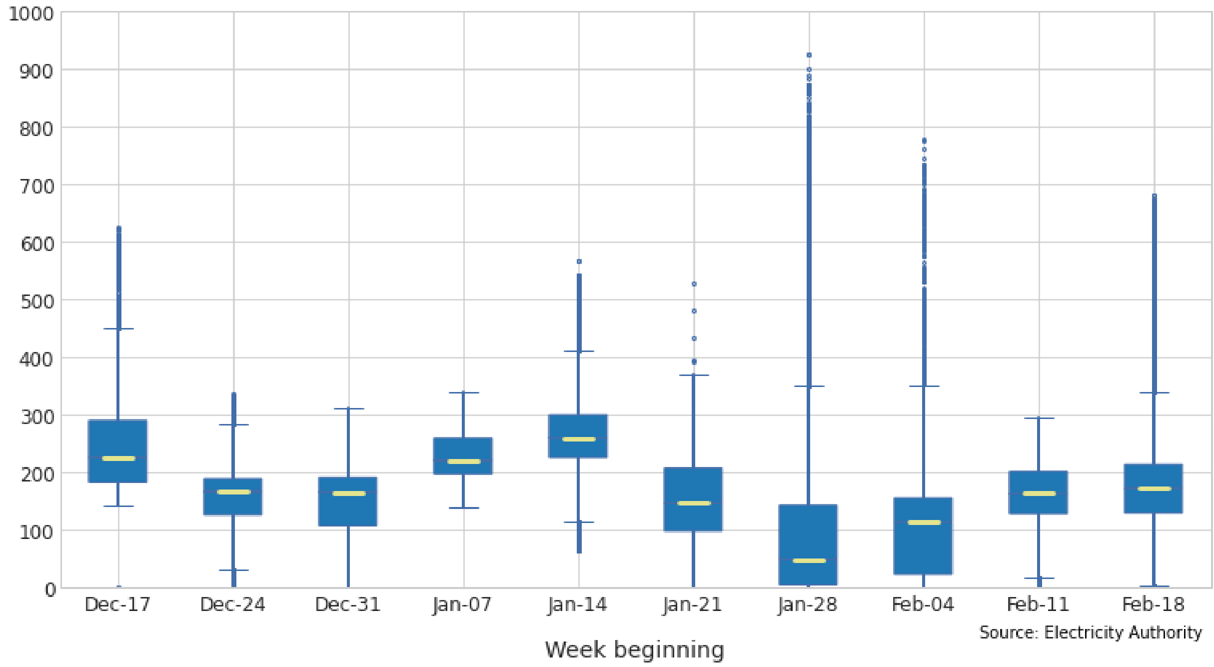
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 18-24 February



2.8. 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.

2.9. This week's price distribution was similar to the previous week, except for several high price outliers this week. The middle 50% of prices were between $129-$213/MWh. The median price increased slightly: $172/MWh this week versus $168/MWh last week.

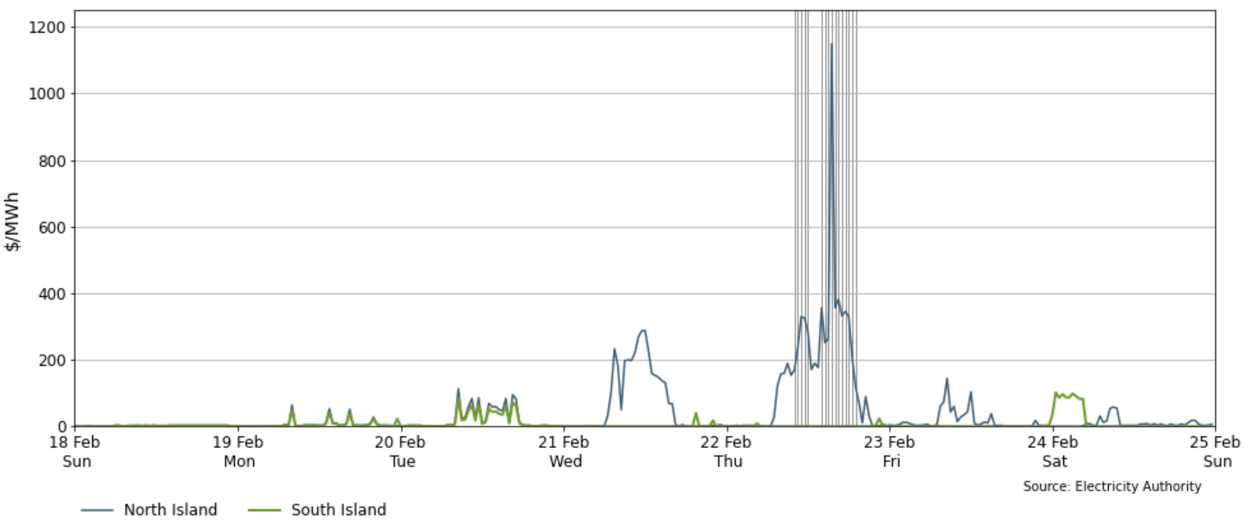
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

3.1. FIR prices for the North and South Islands are shown below in Figure 3. North Island FIR prices on Wednesday and Thursday were reflective of the HVDC outage and low wind generation. Since the HVDC was operating as a single pole during those days, its capacity was set by the amount of North Island FIR available. The North Island FIR prices reflect an energy-reserve co-optimisation, as more energy was required to reduce the HVDC transfer and hence reduce the North Island reserves needed. So, during times of North Island spot price spikes, North Island FIR prices also spiked.

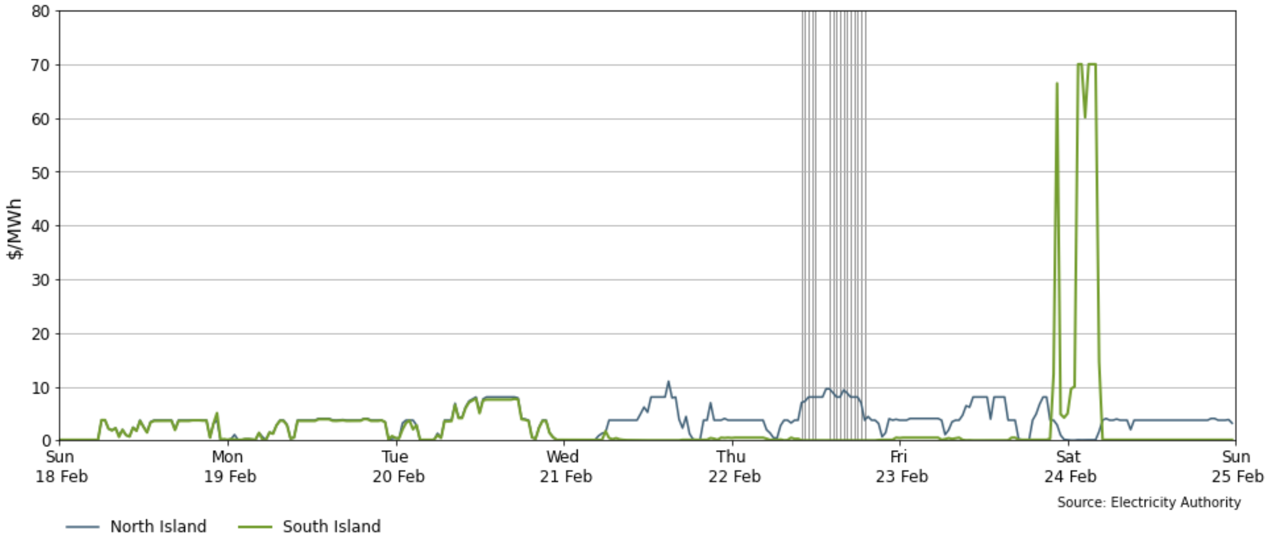
Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between18-24 February



3.2. 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 from Wednesday onwards was related to the planned HVDC outages.

3.3. Between Friday and Saturday, before the bi-pole outage, South Island SIR prices spiked as high Southward HVDC flows caused a larger SIR risk, requiring more South Island reserves.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between18-24 February



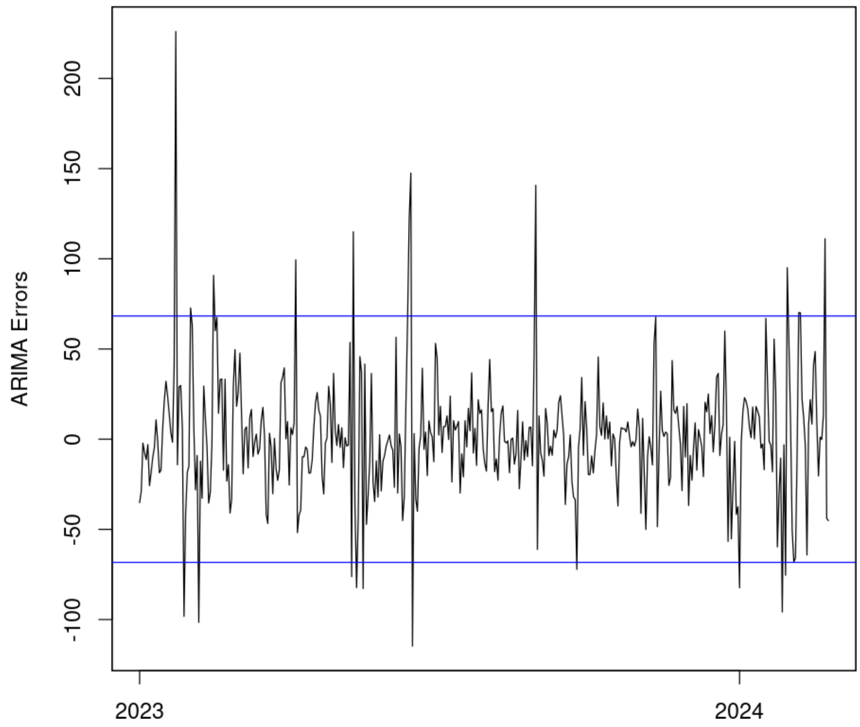
4. Regression residuals

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 was one residual above the two standard deviations of the data on Thursday, meaning prices were higher than the model expected. On Thursday spot prices were high due to a combination of the HVDC Pole 3 outage, low wind generation and high wind forecast inaccuracies.

Figure 5: Residual plot of estimated daily average spit prices from 1 January 2023 - 24 February 2024

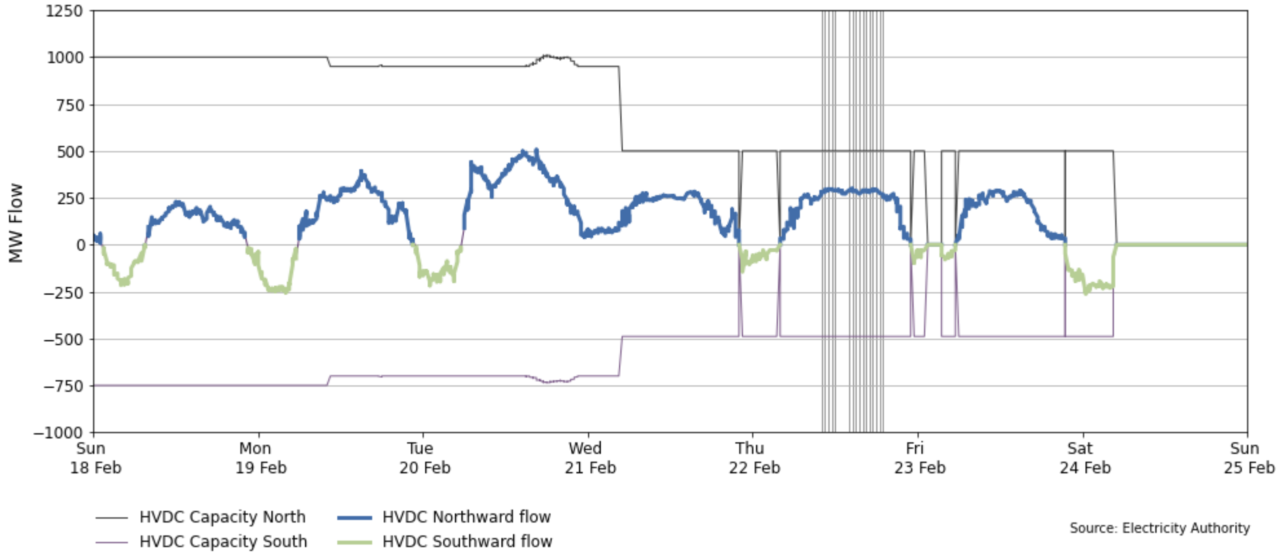


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows HVDC flow between 18-24 February. This week there were two HVDC planned outages. HVDC Pole 3 was on outage from 21-24 February which limited the north flow capacity to around 500MW, also reducing the HVDC reserve sharing capacity. On Saturday the planned HVDC bi-pole outage effectively prevented any HVDC transfers during that day.

Figure 6: HVDC flow and capacity between 18-24 February

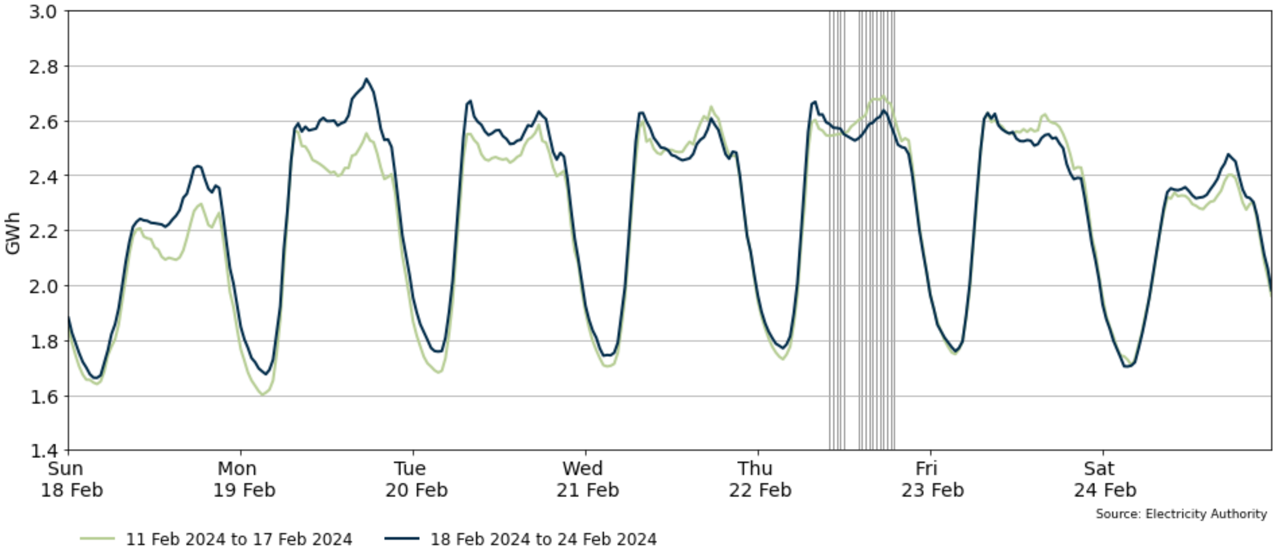


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 18-24 February, compared to the previous week. Demand was higher than last week until Wednesday, and especially on Monday. The high demand on Monday compared to the previous week is likely related to high temperatures and higher irrigation loads. From Wednesday onwards demand was similar to the previous week, including during the price spike on Thursday.

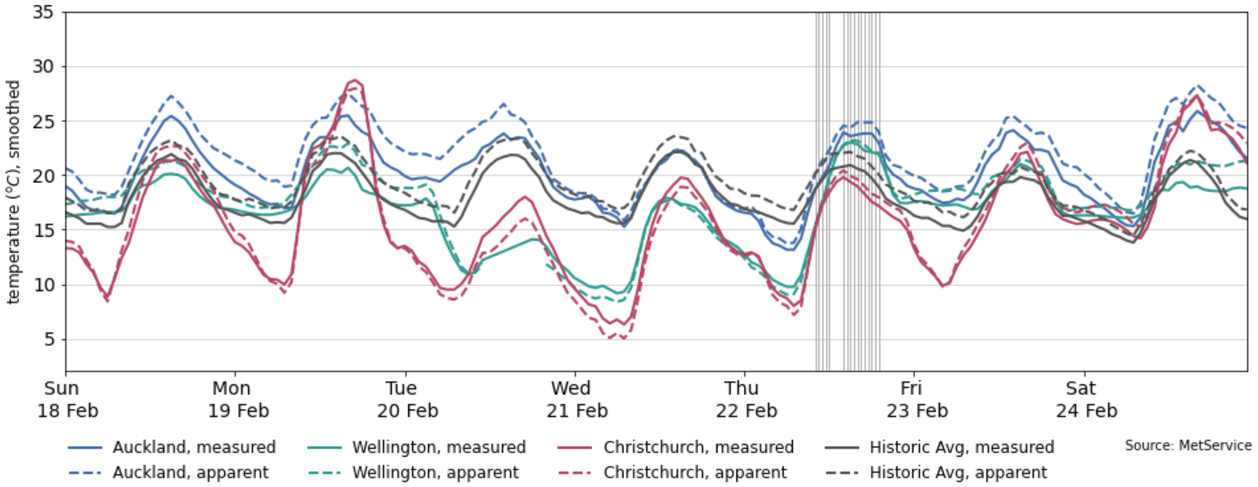
Figure 7: National demand between 18-24 February compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 18-24 February. 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 historical average earlier in the week, changing to mostly lower-than-average temperatures from Tuesday to Thursday. Monday afternoon saw high temperatures across the country. Temperatures went back to mostly around the average later in the week. Apparent temperatures in Auckland varied between ~14ºC and ~28ºC. In Christchurch apparent temperatures varied between ~5ºC and ~28ºC, with the maximum happening on Monday.

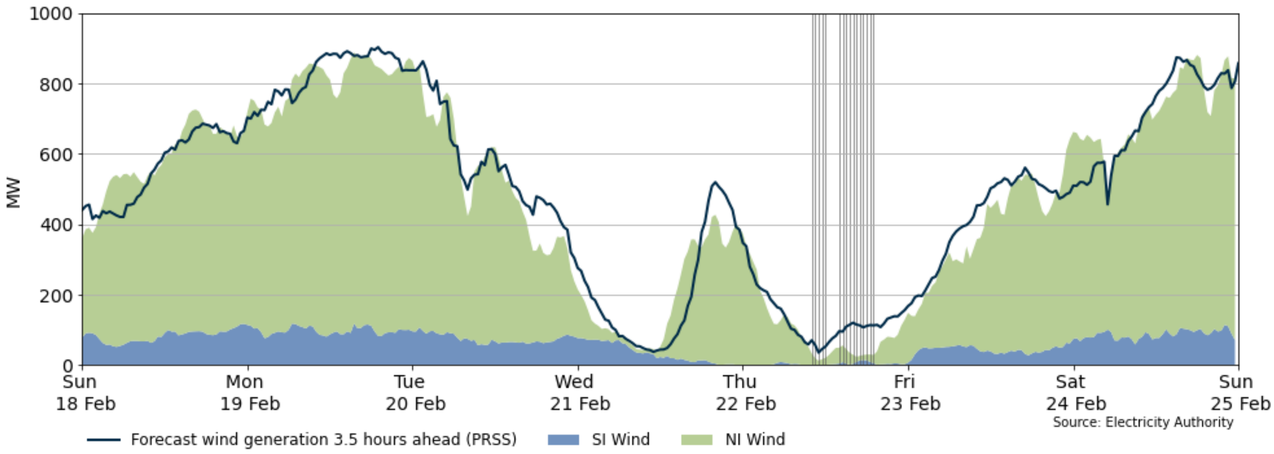
Figure 8: Temperatures across main centres between 18-24 February



7. Generation

7.1. Figure 9 shows wind generation and forecast from 18-24 February. This week wind generation varied between 13MW and 887MW, with an average of 475MW. Wind generation was consistently above 400MW between Sunday to Tuesday, and from Friday afternoon onwards. Between Wednesday and Thursday, however, there were several periods of low wind generation, especially during Thursdays' price spike. Wind forecast inaccuracies during the price spike reached around 90MW[2].

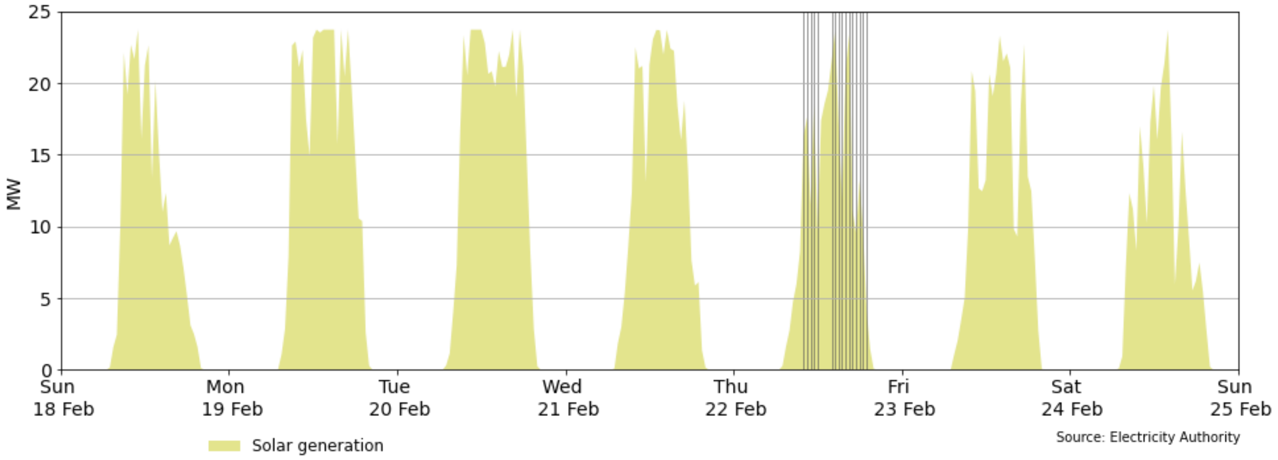
Figure 9: Wind generation and forecast between 18-24 February



7.2. Figure 10 shows solar generation from 18-24 February. Solar generation was somewhat stable this week with some increased variability from Thursday onwards, likely due to overcast conditions later in the week.

[2] Difference between RTD and 3.5 hour ahead PRSS offers

Figure 10: Solar generation between 18-24 February

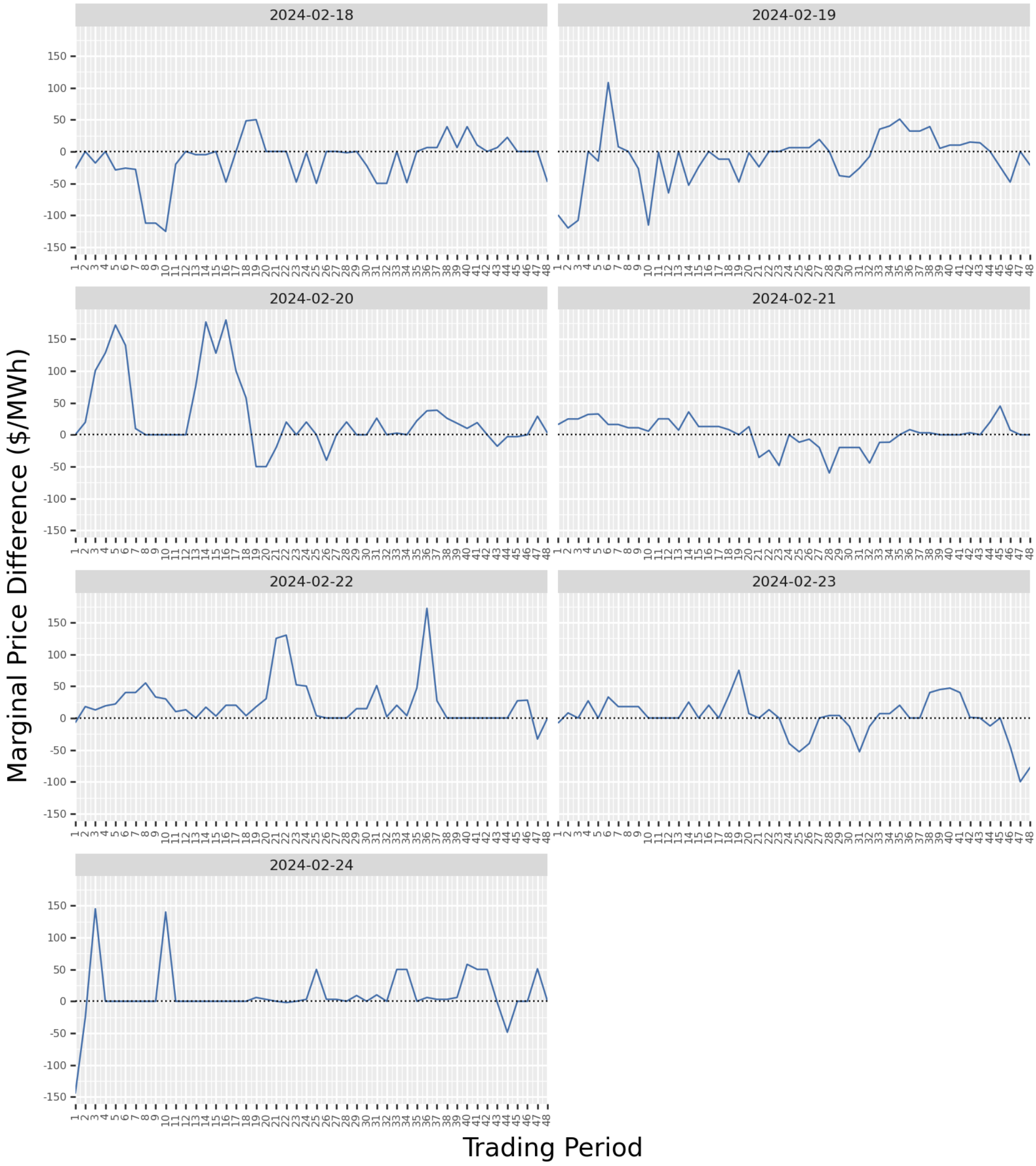


7.3. Figure 11 shows the difference between the real time nationally averaged dispatch (RTD) marginal price, and what the marginal price would have been based on the 1 hour ahead (PRSS) demand and wind forecasts. This plot highlights when forecasting inaccuracies are causing large differences between 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. There were a few trading periods earlier and later in the week when the RTD price was at or over $100/MWh less than the 1 hour ahead PRSS price (negative values in the plot). These were times when wind generation was over forecast, meaning there was more wind generation than expected and / or less demand than expected, causing lower prices.

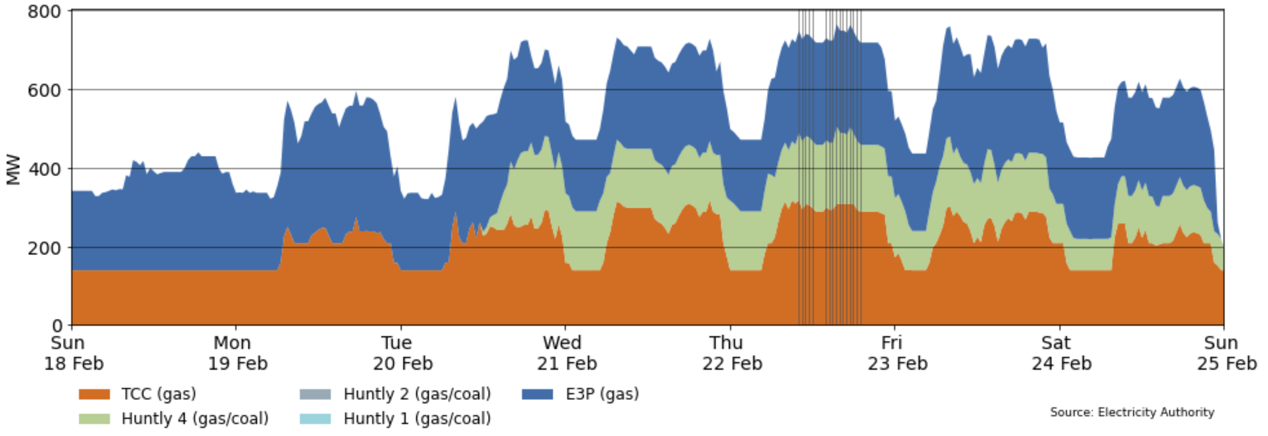
7.5. On Thursday the nationally averaged RTD price was over $100/MWh greater than the 1 hour ahead PRSS price, during several trading periods between 10am-7pm (positive values in the plot). Those were times when wind generation was lower than expected, coinciding with the spikes in spot prices. During the Thursday North Island price spike, the difference between the RTD and 1 hour ahead PRSS price at Ōtāhuhu was over $1000/MWh.

Figure 11: Difference between nationally averaged RTD price and gate closure PRSS prices, with the difference due to one-hour ahead wind and demand forecast inaccuracies between 18-24 February



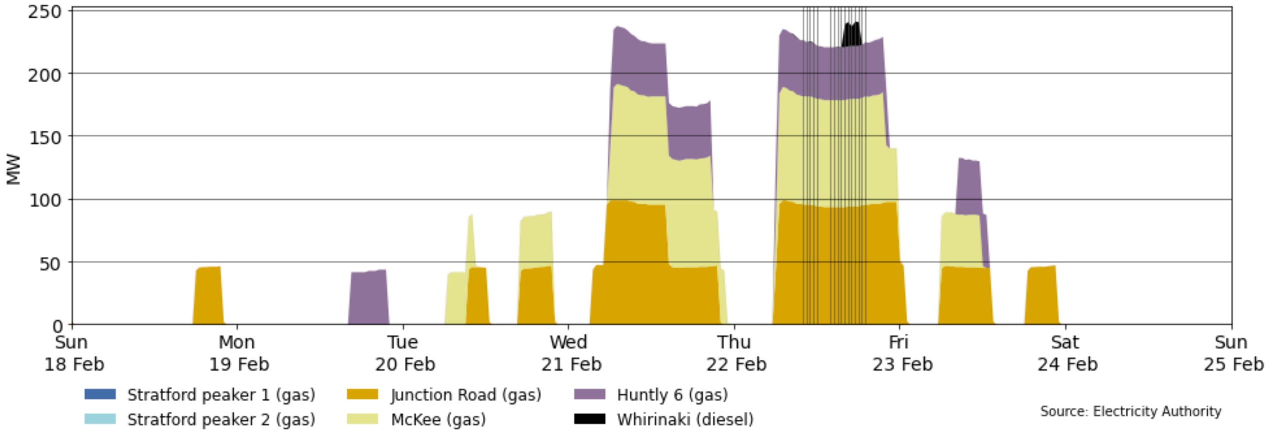
7.6. Figure 12 shows the generation of thermal baseload between 18-24 February. Similar to last week, this week Huntly 5 and TCC ran all week providing baseload. Huntly 4 ran from Tuesday onwards generating between ~100-200MW.

Figure 12: Thermal baseload generation between 18-24 February



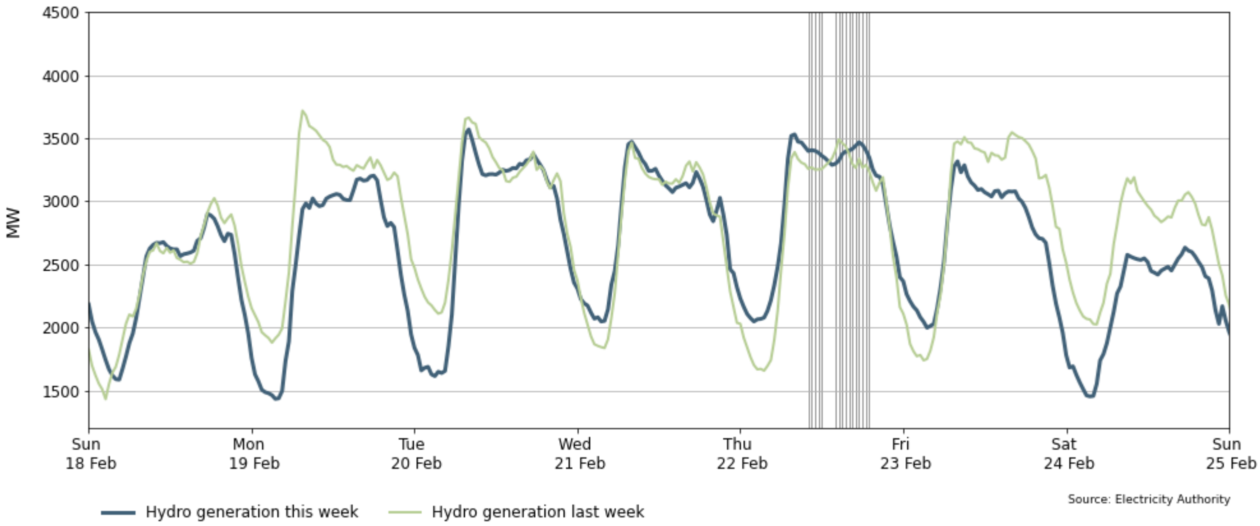
7.7. Figure 13 shows the generation of thermal peaker plants between 18-24 February. Peaker generation was higher on Wednesday and Thursday this week, compared to the other days, and occurred during the HVDC pole 3 outage and low wind generation. On Wednesday and Thursday McKee, Junction Road, and Huntly 6 ran for several trading periods, generating more than 200MW combined. On Thursday Whirinaki ran for a few trading periods during the afternoon spot price spike.

Figure 13: Thermal peaker generation between 18-24 February



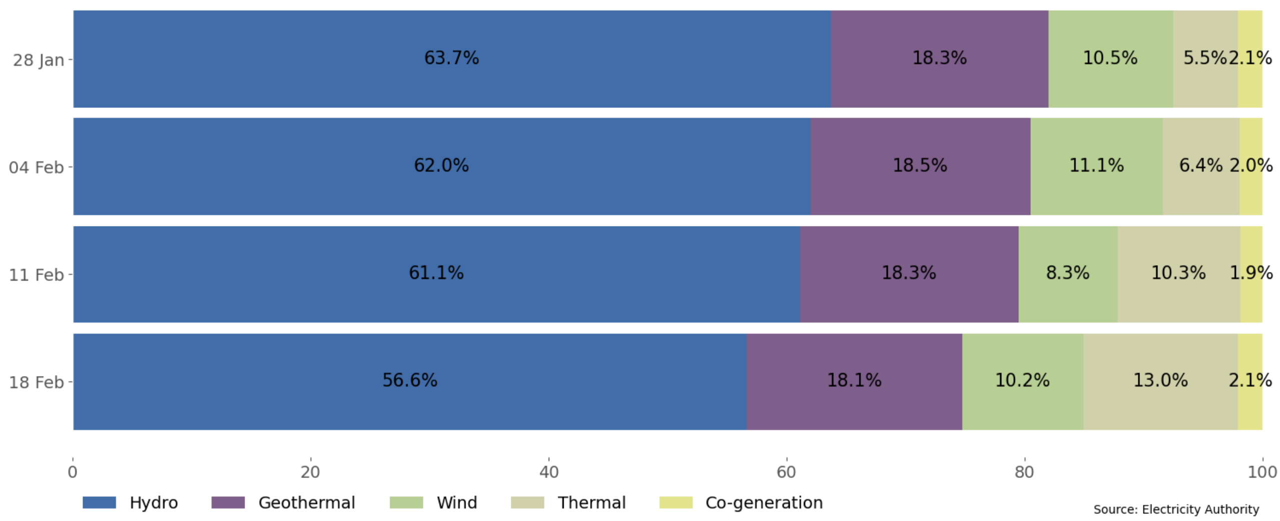
7.8. Figure 14 shows hydro generation between 18-24 February. Hydro generation was mostly similar to the previous week except for Monday, Friday, and Saturday. Several South Island hydro outages began this week, coinciding with the HVDC outages. On Monday high wind generation reduced the need for hydro generation. On Friday and Saturday hydro generation was lower as South Island hydro was limited in its capacity to be sent North.

Figure 14: Hydro generation between 18-24 February



7.9. As a percentage of total generation, between 18-24 February, total weekly hydro generation was 56.6%, geothermal 18.1%, wind 10.2%, thermal 13%, and co-generation 2.1%, as shown in Figure 15.

Figure 15: Total generation b type as a percentage each week between 18-24 February



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 18-24 February ranged between ~ 1550MW and ~2120MW. 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 outage on 21 February

(d) McKee was on outage on 18 February

(e) Kawerau geothermal had units on outage between 20-23 February

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

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

Figure 16: Total MW loss due to generation outages between 18-24 February

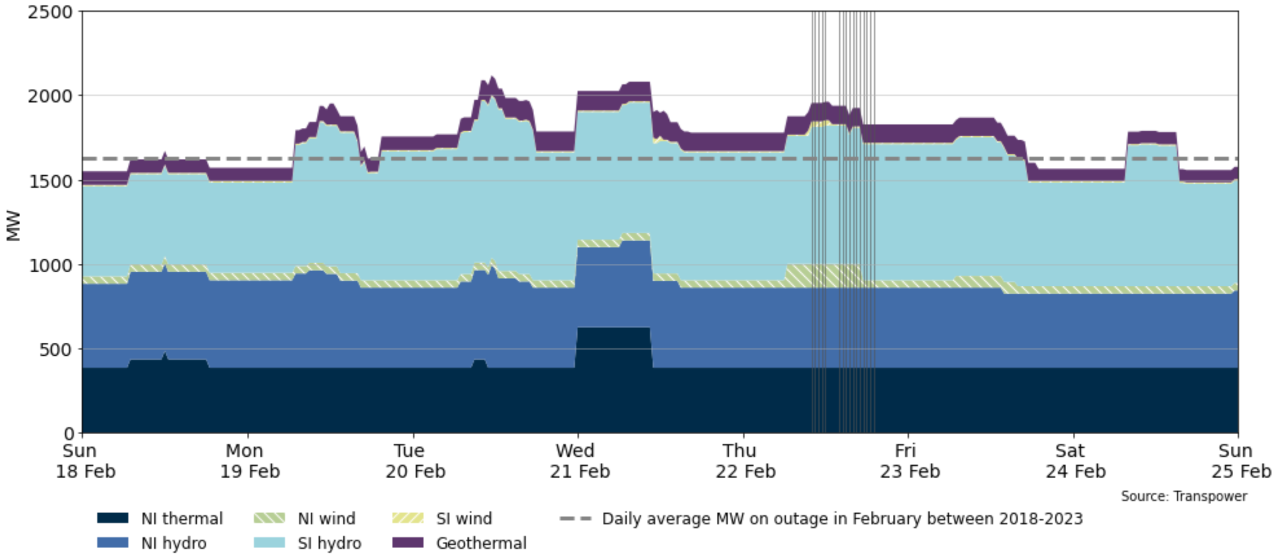
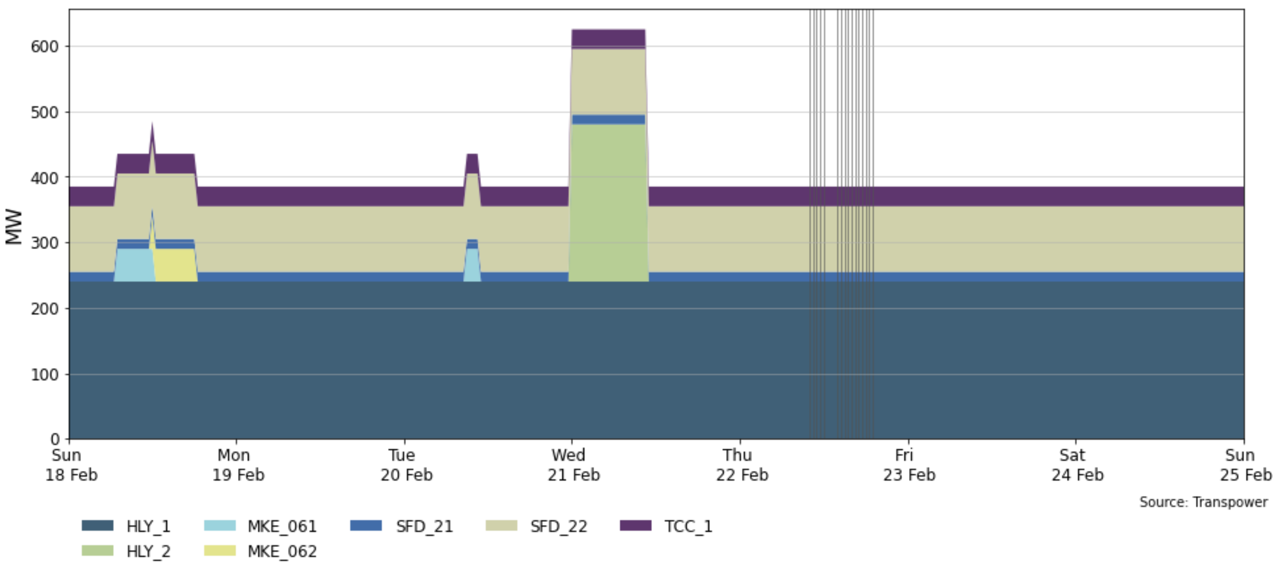


Figure 17: MW loss from thermal outages between 18-24 February



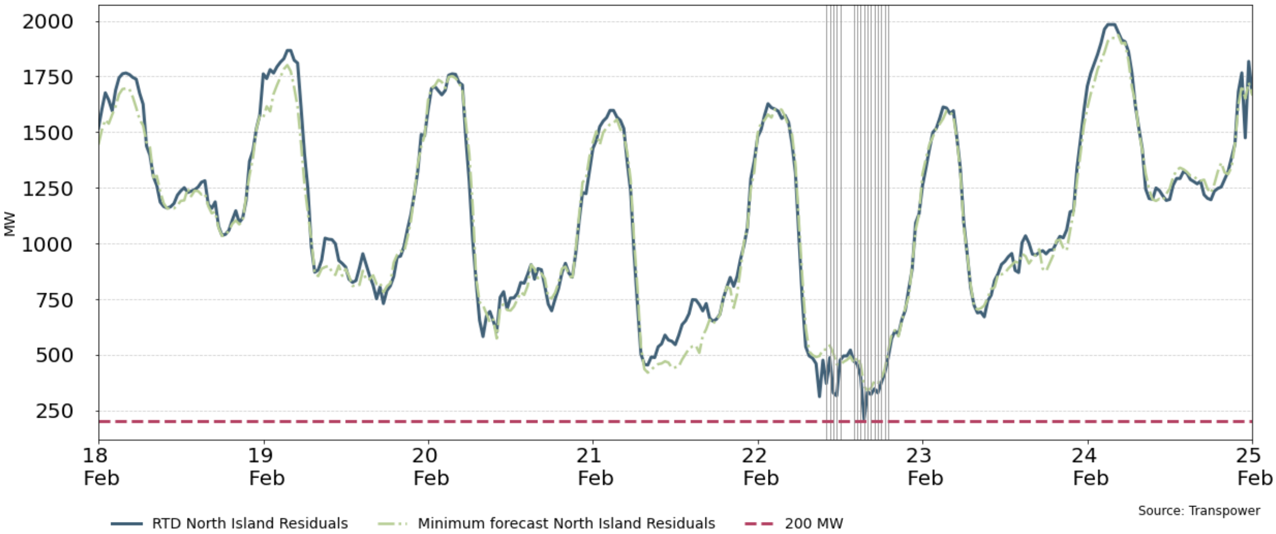
9. Generation balance residuals

9.1. Figure 18 shows the generation balance residuals between 18-24 February. 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 RTD residuals.

9.2. This week the national generation residuals were healthy, with a minimum of 611MW on Thursday, well above the 200MW mark. When looking at the North Island residuals (Figure

21), however, we can see that residual levels were low on Thursday, reaching 209 MW, indicating North Island energy supply was tight during that trading period.

Figure 18: Generation balance residuals between 18-24 February – North Island



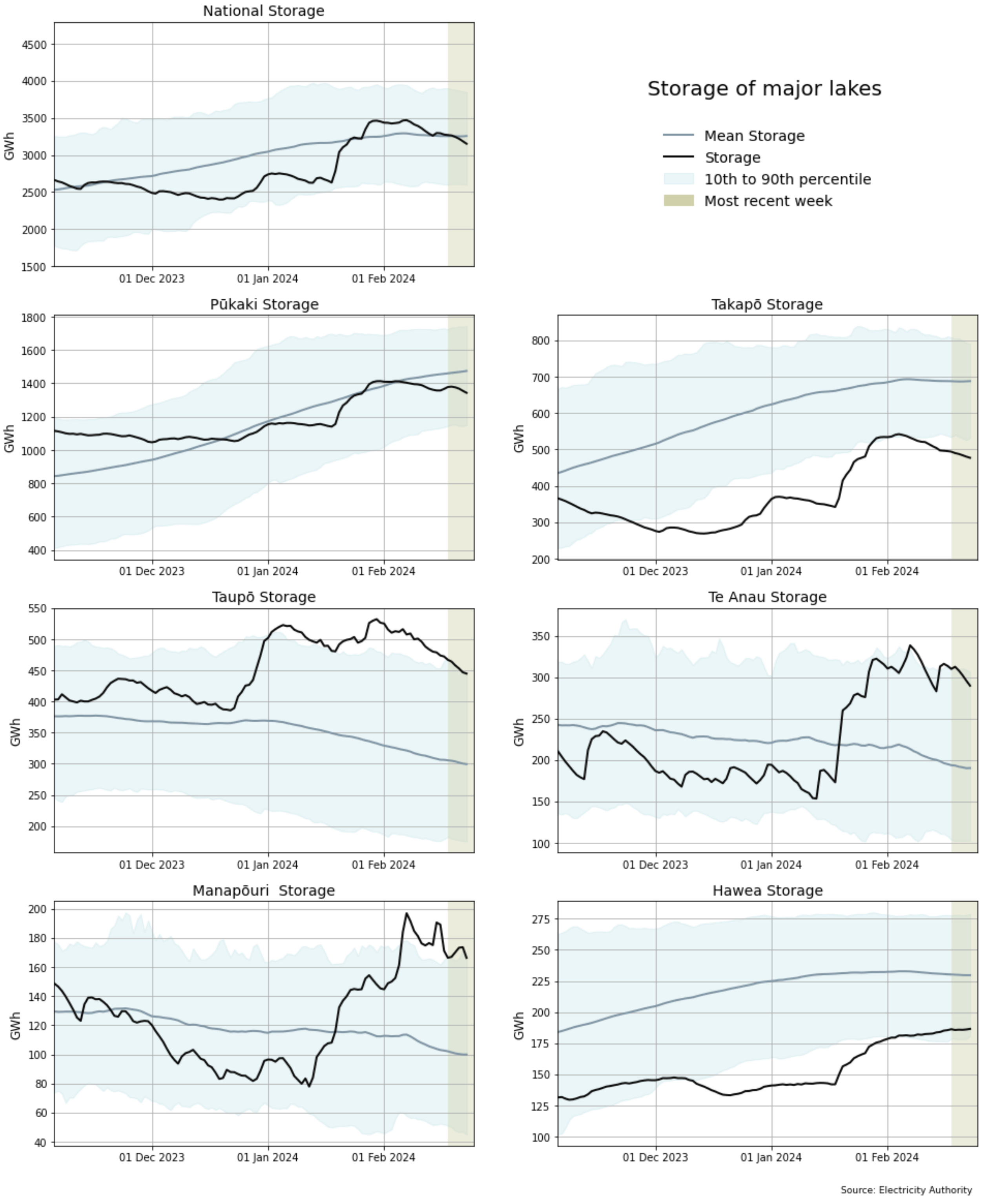
10. Storage/fuel supply

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 80% of nominally full and ~98% of the historical average for this time of the year (as of 24 February).

10.3. Similar to the previous week, most lakes saw a decrease in their storage levels. Storage at lake Taupō is now at its 90th percentile at around 450 GWh. Pūkaki storage is sitting between its historical average and the 10th percentile, trending downwards. Lake Takapō remains below its 10th percentile. Lakes Manapōuri and Te Anau saw a small decrease and are now at their 90th percentile. Hawea had a small increase this week.

Figure 19: Hydro storage

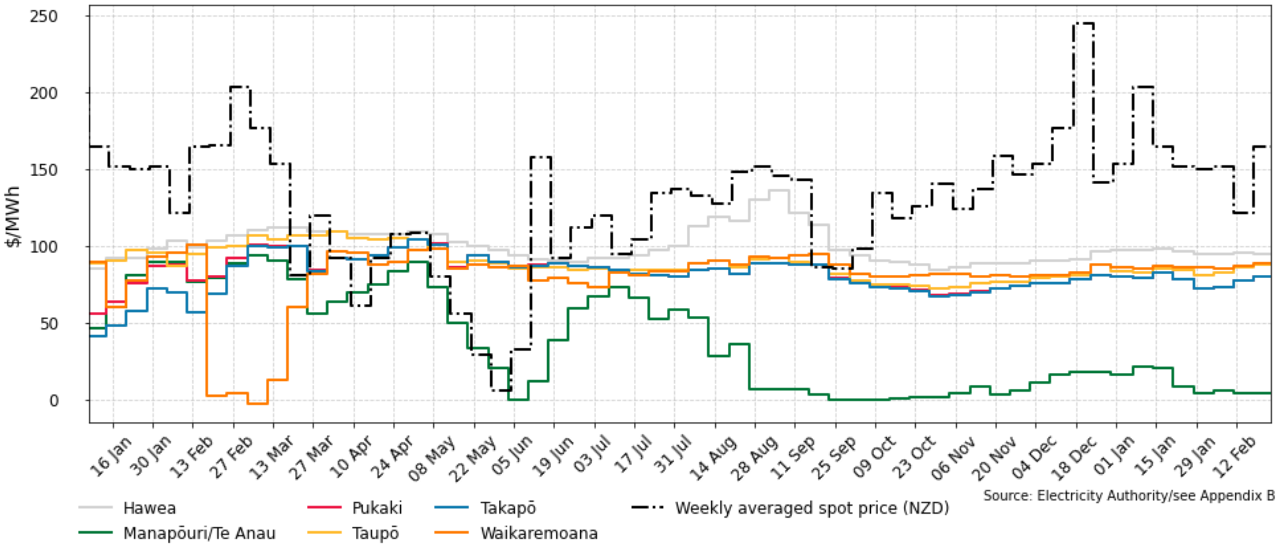


11. JADE water values

11.1. The JADE[3] 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 24 February 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 around $3/MWh at all lakes except Manapōuri/Te Anau which did not change significantly from the previous week.

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 24 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 February 2024. The SRMC for coal and diesel has not seen much change from the previous month. The gas SRMC has seen some decreases although it remains relatively high.

12.4. The latest SRMC of coal-fueled Rankine generation is ~$159MWh. This is now similar to the cost of running the Rankines on gas at ~$156/MWh, whereas the coal SRMC was lower than gas the previous month.

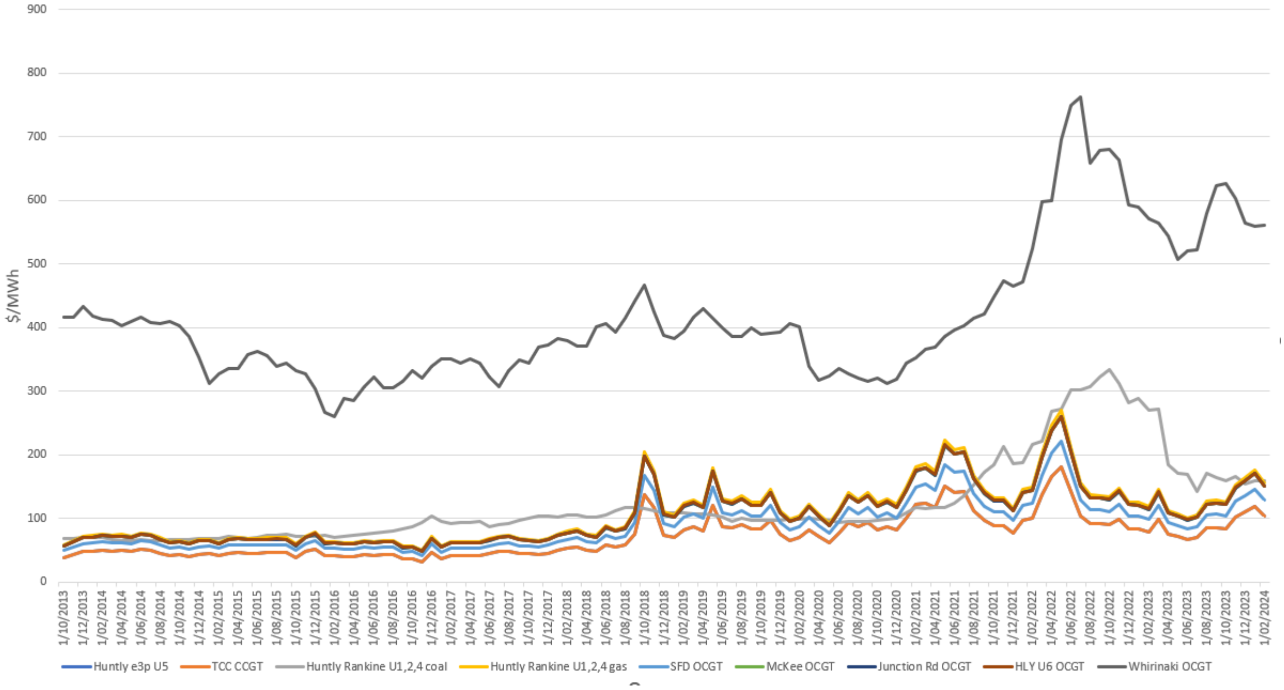
[3] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

12.5. The SRMC of gas fueled thermal plants is currently between $105/MWh and $156/MWh.

12.6. The SRMC of Whirinaki is ~$560/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

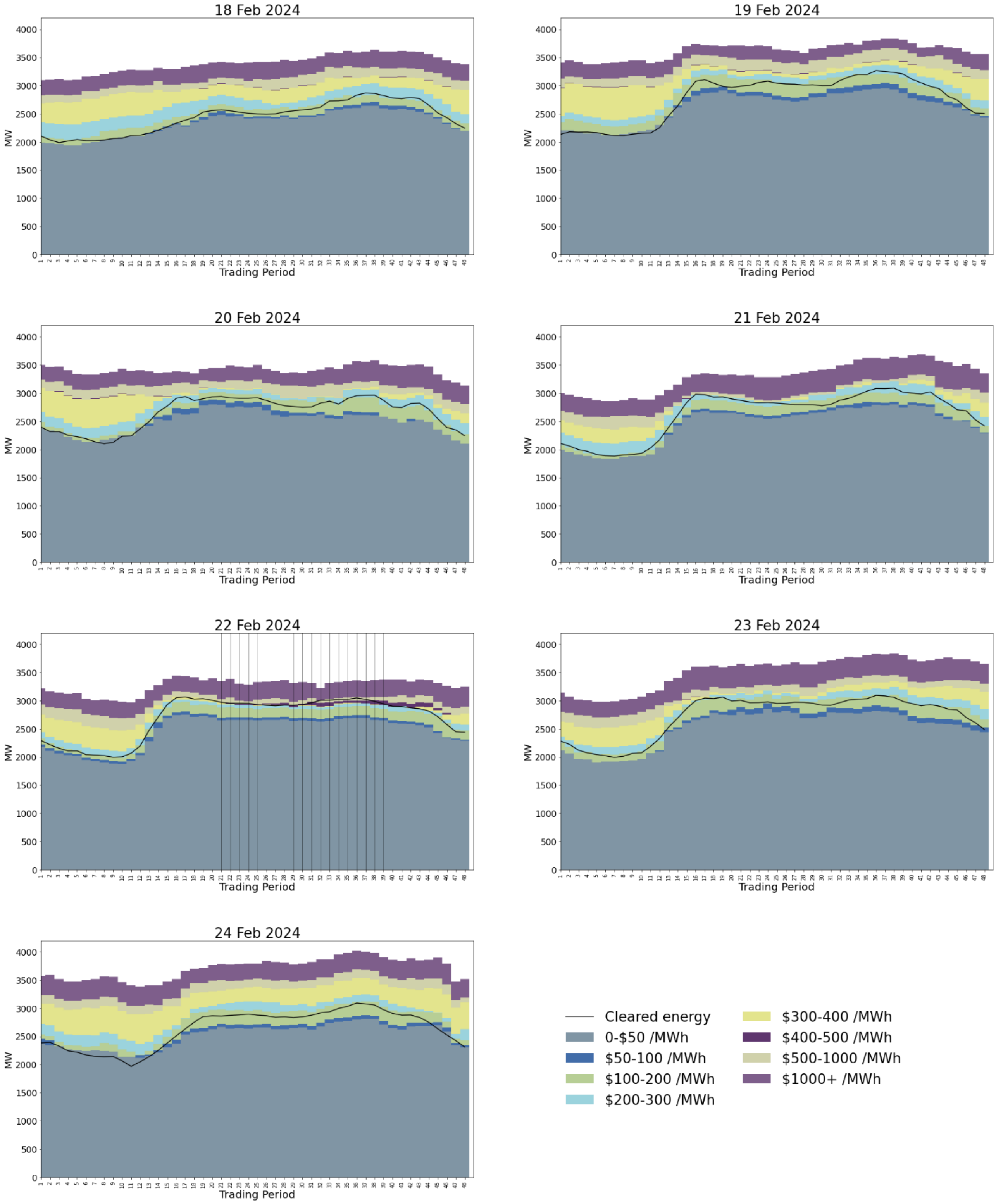
13. Offer behaviour

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-$200/MWh or in the $200-$300/MWh ranges, except for Thursday when offers were cleared in the more expensive ranges during the price spike.

13.3. In the South Island most of the offers during the week were cleared in the $100-$200/MWh range. On a few trading periods the South Island offers were cleared in the $200-$300/MWh range, including some trading periods matching the price spike on Thursday. On Saturday, Aviemore was on outage during the day, causing a drop in South Island offers.

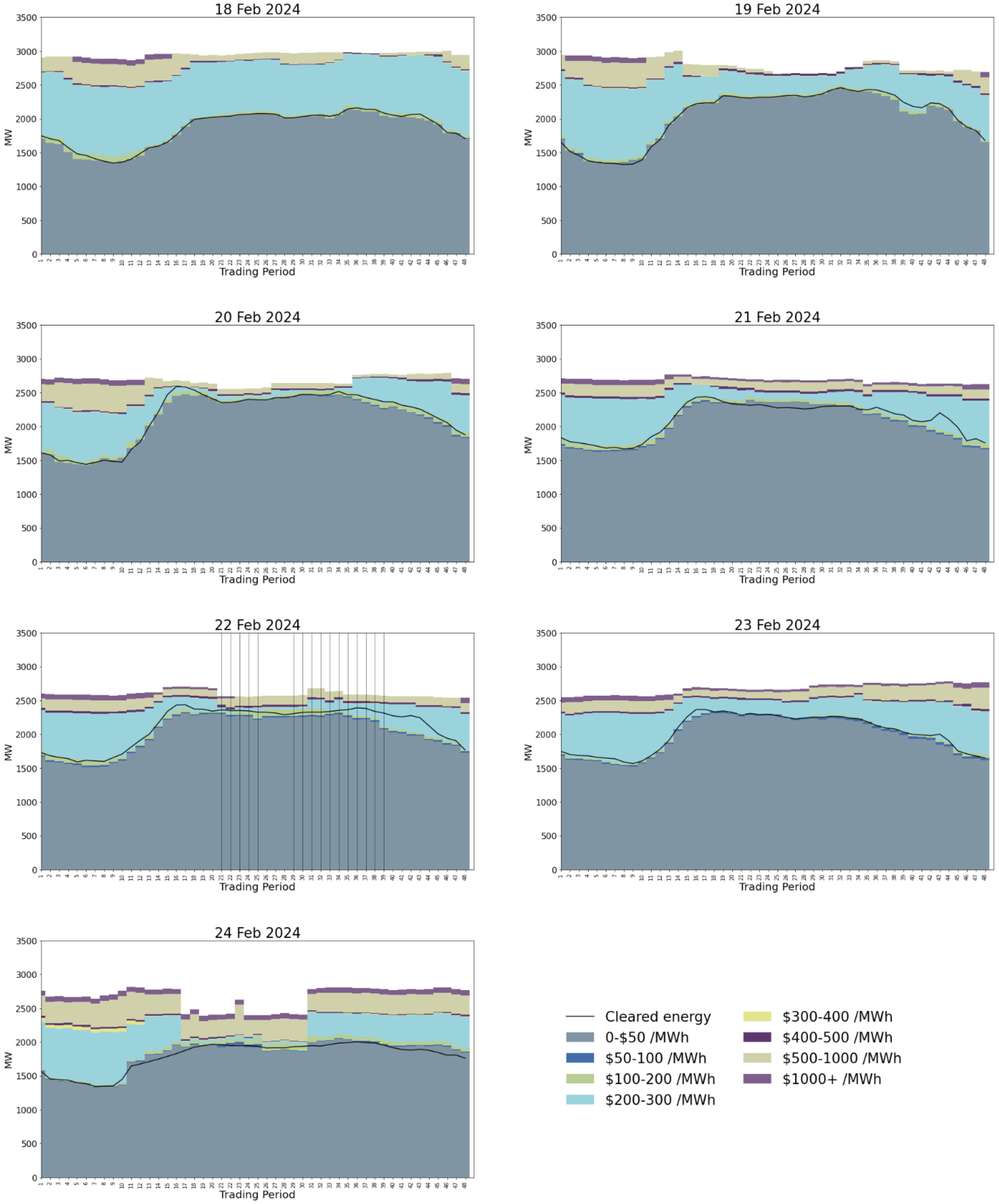
Figure 22: Daily Offer stacks – North Island[4]



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.

Figure 23: Daily Offer stacks – South Island[5]



Source: Electricity Authority

[5] 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 Genesis offers at Tokaanu during the Thursday price spike.

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.
17/01/2024-19/01/2024	Several	Further analysis	Genesis, Contact	Multiple	High energy prices associated with high energy 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.
22/02/2023	32	Further analysis	Genesis	Tokaanu	Offer prices