11 March 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for week of 3-9 March

1.1. Spot prices this week were mostly around \$150-\$250/MWh during the day, with a dip in prices overnight. There were price spikes on Wednesday and Friday due to a combination of low wind generation, wind forecast inaccuracies, 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 energy and reserves co-optimisation and the HVDC outages, which limited the reserve sharing capacity between the islands. TCC, Huntly 5, and Huntly 4 ran as baseload this week. High wind generation at the start and end of the week displaced hydro generation. Hydro storage remained steady at ~95% of mean as of 9 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 3-9 March:

(a) The average wholesale spot price across all nodes was \$170/MWh.

(b) 95% of prices fell between \$9/MWh and \$267/MWh.

2.4. The spot prices this week were mainly above the national historical median, mostly around \$200/MWh during the day, with a dip in prices overnight, influenced, in part, by the ongoing planned HVDC Pole 2 outage. However, the average spot price decreased by \$34/MWh compared to the previous week.

2.5. There were two noticeable price spikes this week:

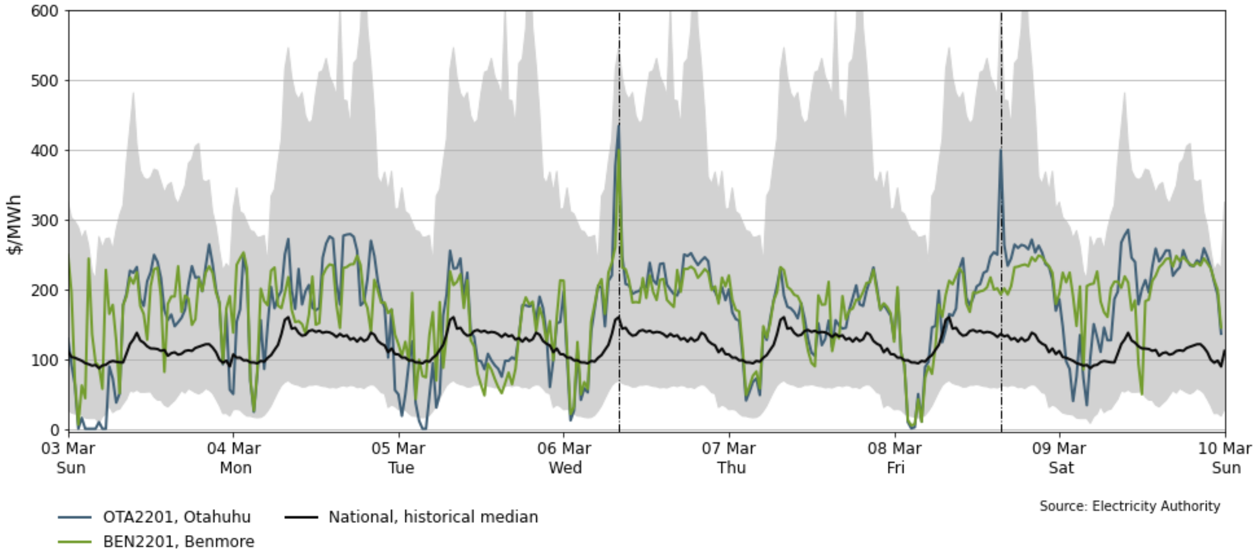
(a) On Wednesday at 08:00am, prices reached \$434/MWh at Ōtāhuhu and \$400/MWh at Benmore.

(b) On Friday at 3:30pm, prices reached ~\$400/MWh at Ōtāhuhu and ~\$190/MWh at Benmore.

[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. These high prices and price separation were related to low wind generation, wind forecast inaccuracies, and times of energy-reserve co-optimisation due to the planned HVDC Pole 2 outage. The price spike on Wednesday also coincided with high morning demand due to low temperatures.

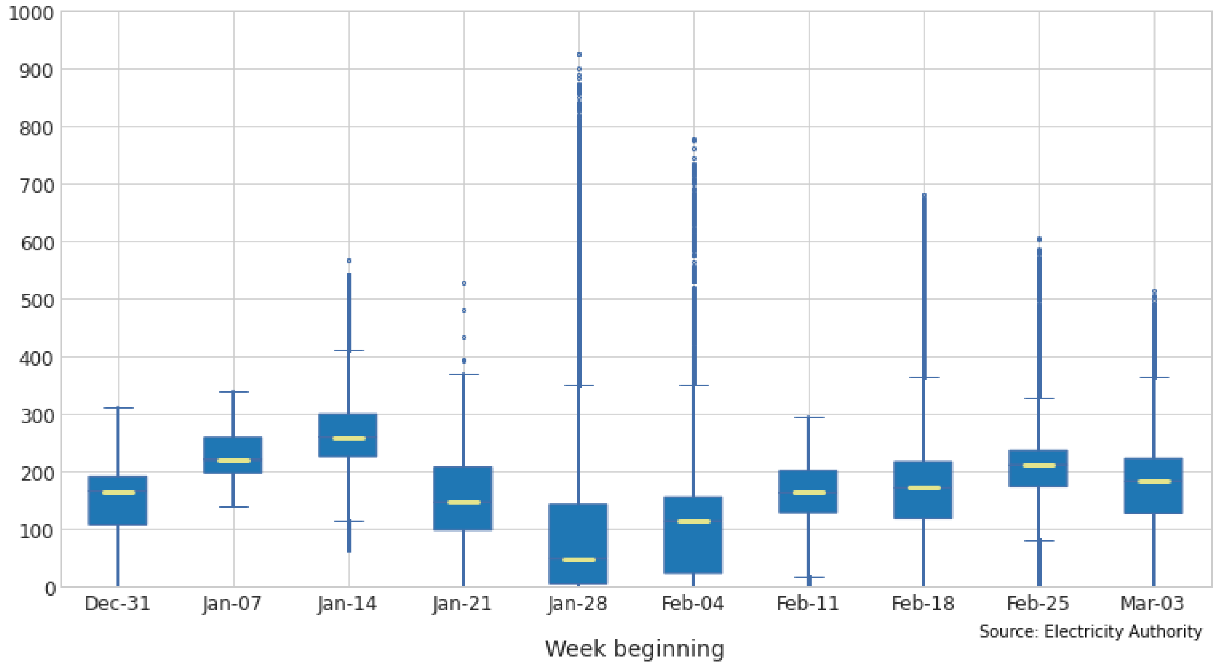
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 3-9 March



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. This week prices were lower compared to the previous week, with the median this week at $183/MWh, compared to $214/MWh in the previous week, a $31/MWh decrease. The middle 50% of the prices were between $135-$225/MWh.

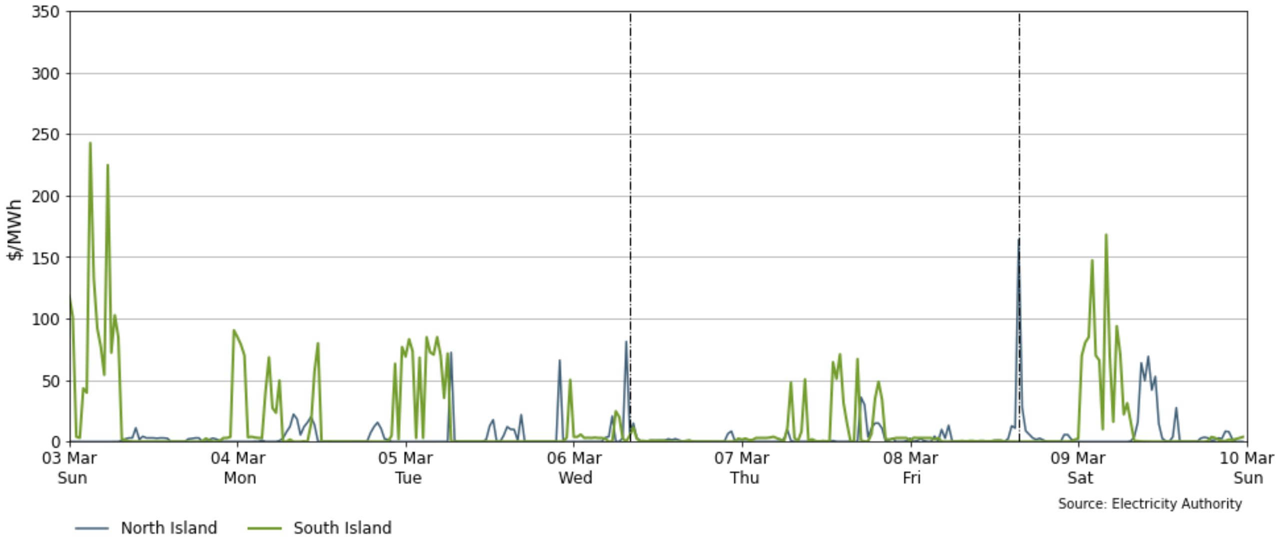
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

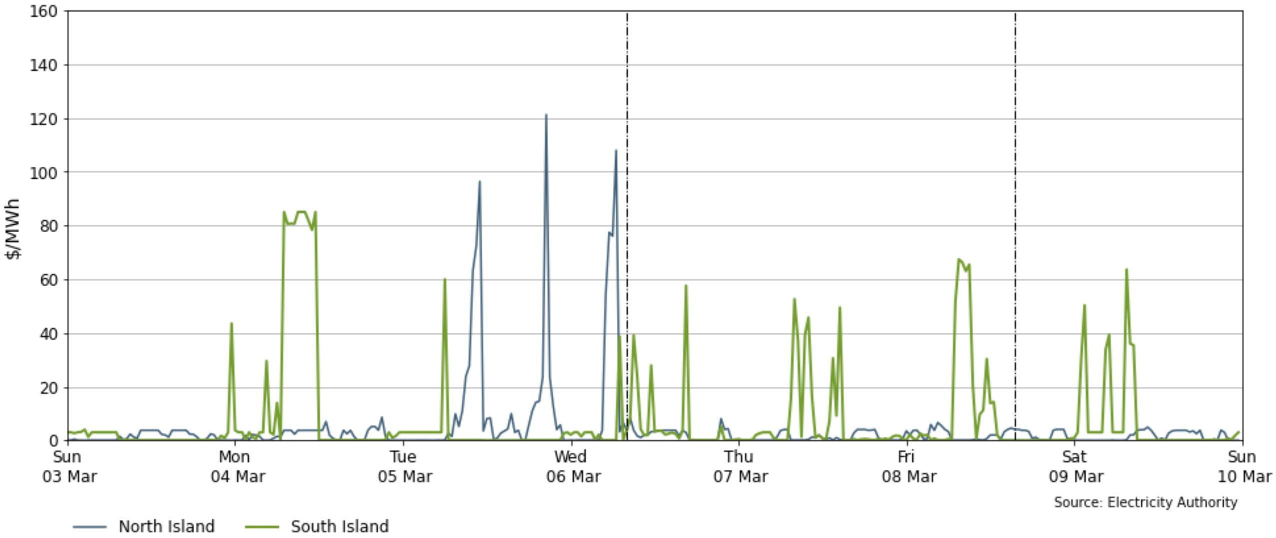
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. The spikes in FIR prices seen this week reflect the HVDC operating as a single pole due to its planned outage. The HVDC capacity was dependent on the amount of North and South islands FIR available depending on its flow direction. The FIR prices reflect an energy-reserve co-optimisation – with a period of low wind requiring higher Northward flow of the HVDC, and hence more North Island reserves. Thus, during times of North Island spot price spikes, North Island FIR prices also spiked. High North Island wind saw extended periods of high Southward HVDC flow which calls for higher reserve requirements when the HVDC is setting the South Island risk.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 3-9 March



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. Price separation occurred during the week, related to the planned HVDC Pole 2 outage. Because of the HVDC outage a small increase in reserve needed can cause a much higher price. On Saturday morning, South Island SIR and FIR spikes were related to high Southward HVDC flows, which caused a larger SIR risk, requiring more South Island reserves. Some of the peaks in SIR prices also occurred close to the times when HVDC was being reversed. The monitoring team is looking further into North Island SIR spikes between Tuesday and Wednesday.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 3-9 March



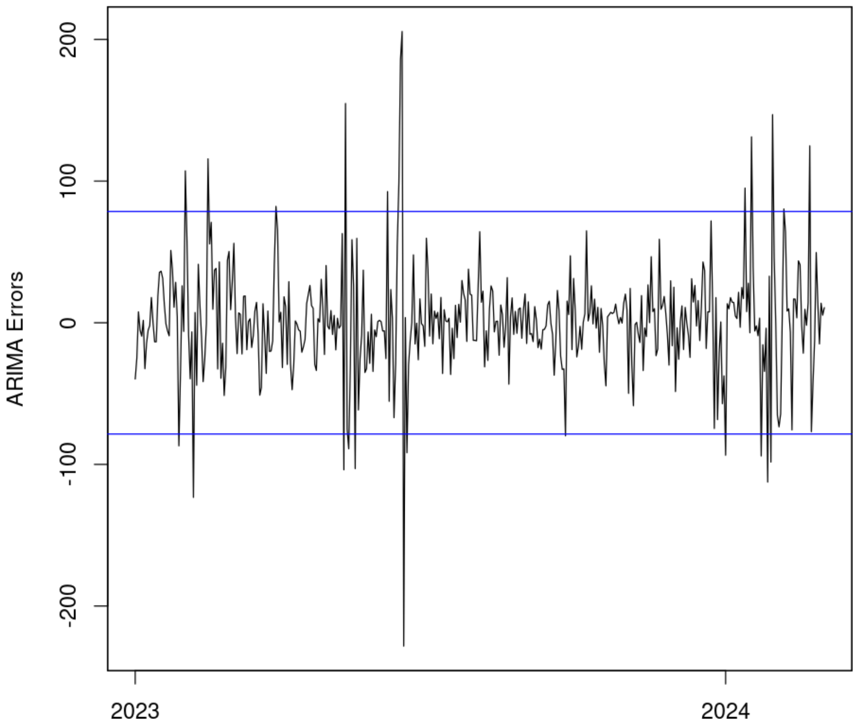
4. Regression residuals

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 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 2023-9 March 2024

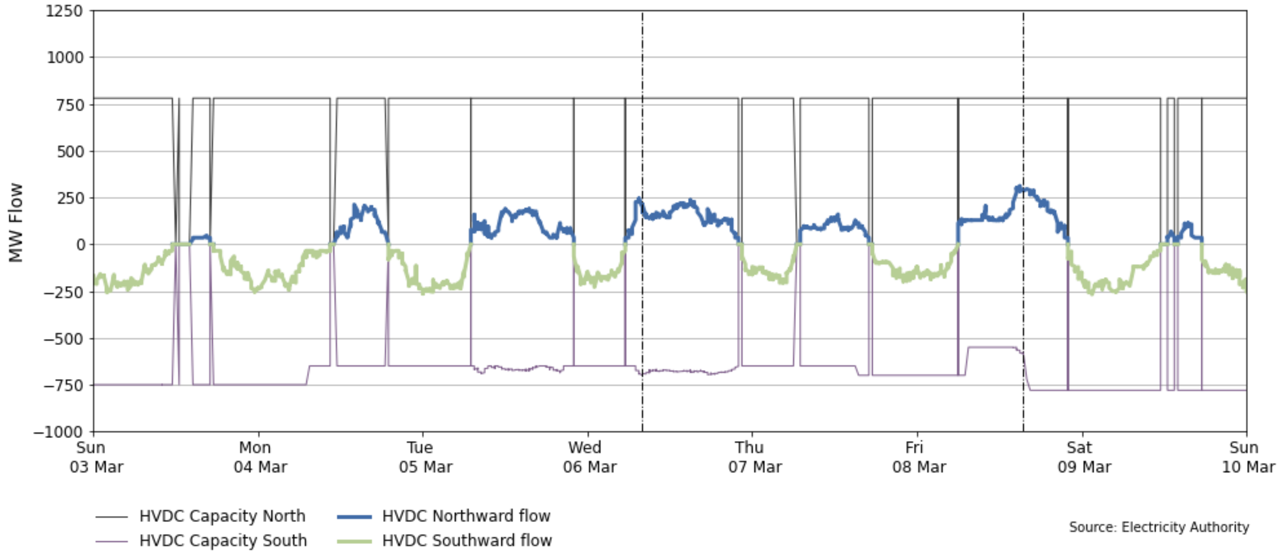


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows HVDC flow between 3-9 March. HVDC flows this week were limited by the planned HVDC Pole 2 outage, limiting the flow capacity to 780MW. However, flow remains limited by the reserve availability. The HVDC was flowing south for most of the time this week, due to high wind generation. Northwards flow happened mostly on weekdays during daytime, coinciding with times of increased demand.

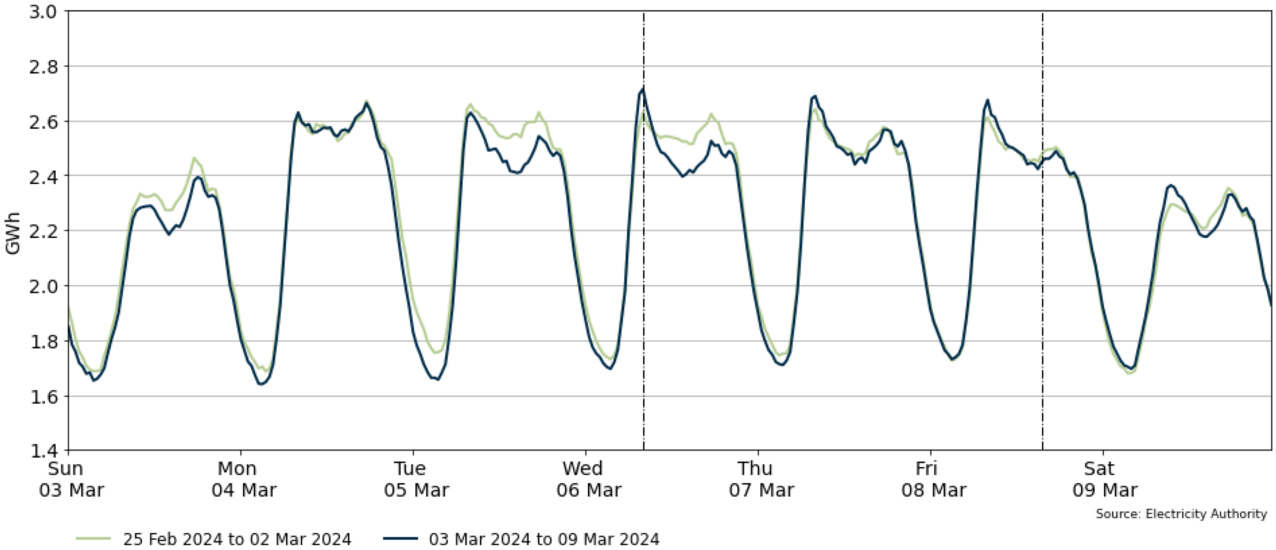
Figure 6: HVDC flow and capacity between 3-9 March



6. Demand

6.1. Figure 7 shows national demand between 3-9 March, compared to the previous week. Demand was lower this week on Sunday, Tuesday, and Wednesday afternoon, compared to the previous week. There was a peak in demand on Wednesday morning, which contributed to the spot price spike. The remaining days saw similar demand compared to the previous week.

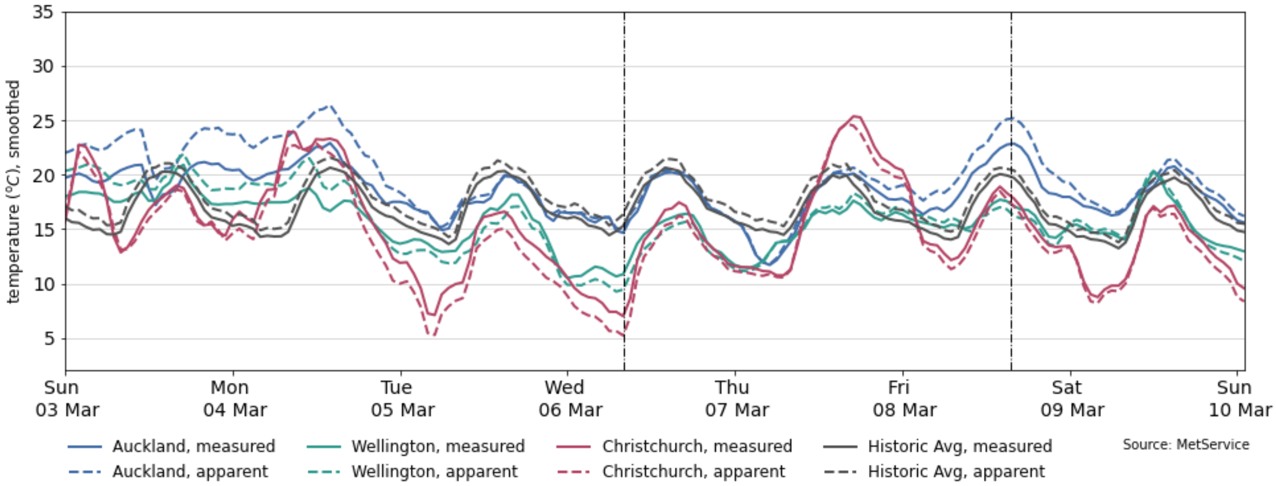
Figure 7: National demand between 3-9 March compared to the previous week



6.2. Figure 8 shows the hourly temperature at main population centres from 3-9 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 mainly fluctuated around the historical averages this week except between late Monday and Thursday when temperatures dropped, especially in Wellington and Christchurch. Christchurch saw larger temperature swings compared to the other cities. Temperatures in Auckland varied between 12ºC and 26ºC. Wellington temperatures fluctuated between 9ºC and 22ºC. Christchurch temperatures were between 5ºC and 25ºC. Low temperatures on Wednesday morning in Wellington and Christchurch likely contributed to the high morning peak demand.

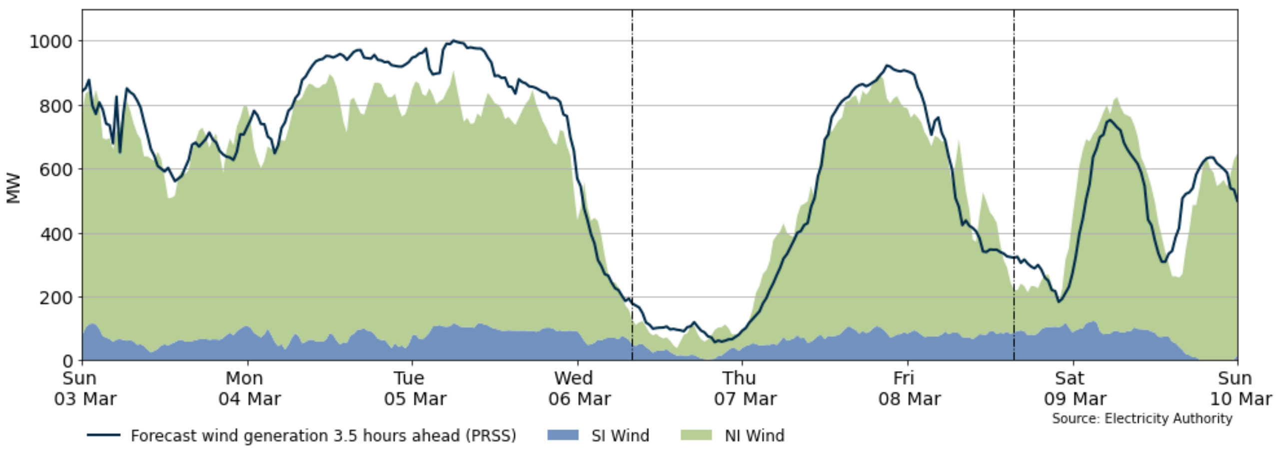
Figure 8: Temperatures across main centres between 3-9 March



7. Generation

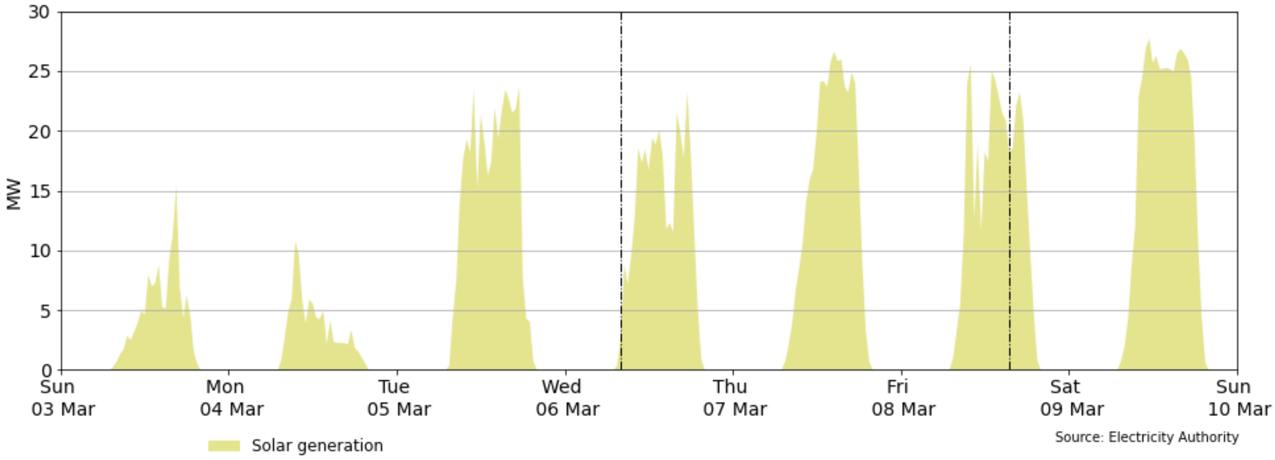
7.1. Figure 9 shows wind generation and forecast from 3-9 March. This week wind generation varied between 38MW and 908MW, with an average of 571MW. Wind generation was generating above 600MW until late Tuesday evening. Wind generation was low on Wednesday morning, during the price spike, and during a few hours on Friday afternoon, when North Island prices spiked. Around 100 MW of wind forecast inaccuracies on Friday afternoon also contributed to the high North Island prices.

Figure 9: Wind generation and forecast between 3-9 March



7.2. Figure 10 shows solar generation from 3-9 March. On Friday, Lodestone Edgecumbe solar farm began its commissioning process. The 32MW solar array is currently generating a maximum of 4MW. Solar generation this week was then mainly from the Kaitaia site, which saw several overcast days impacting its generation, as shown in Figure 10.

Figure 10: Solar generation between 3-9 March

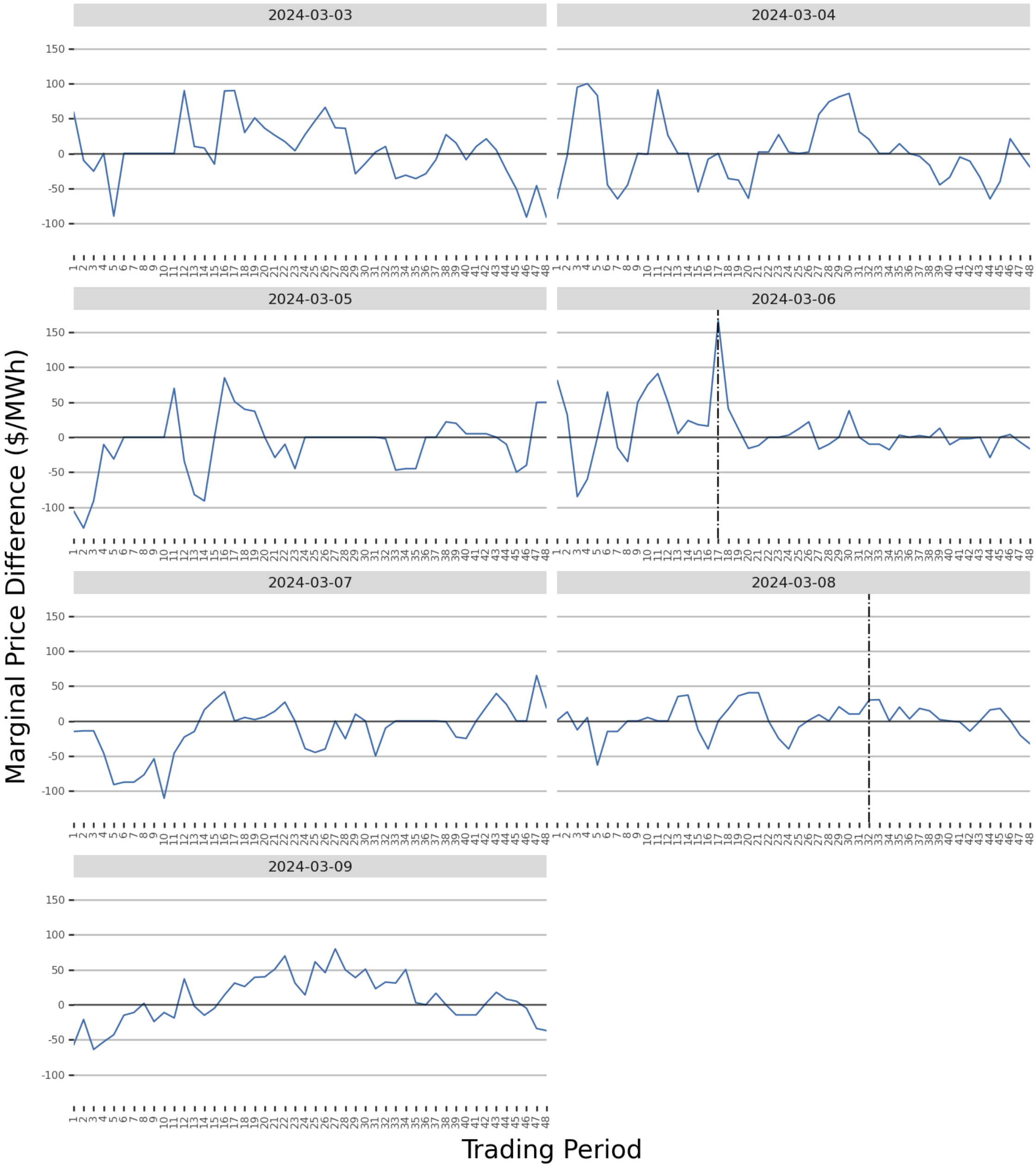


7.3. Figure 11 shows the difference between the real time dispatch (RTD) marginal price, and what the marginal price would have been based on the 1 hour ahead (PRSS) demand and wind forecasts at national level. This plot highlights when forecasting inaccuracies are causing large differences between pre-dispatch 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 largest difference between the RTD and PRSS prices happened during the Wednesday price spike, when the RTD prices were over $150/MWh higher than the 1-hour ahead PRSS prices at 8:00am. When examining the difference in RTD and PRSS prices at Ōtāhuhu only, the price spike on Friday afternoon was over $100/MWh more than the forecast price. During both price spikes, wind generation was over forecast, and demand was under forecast.

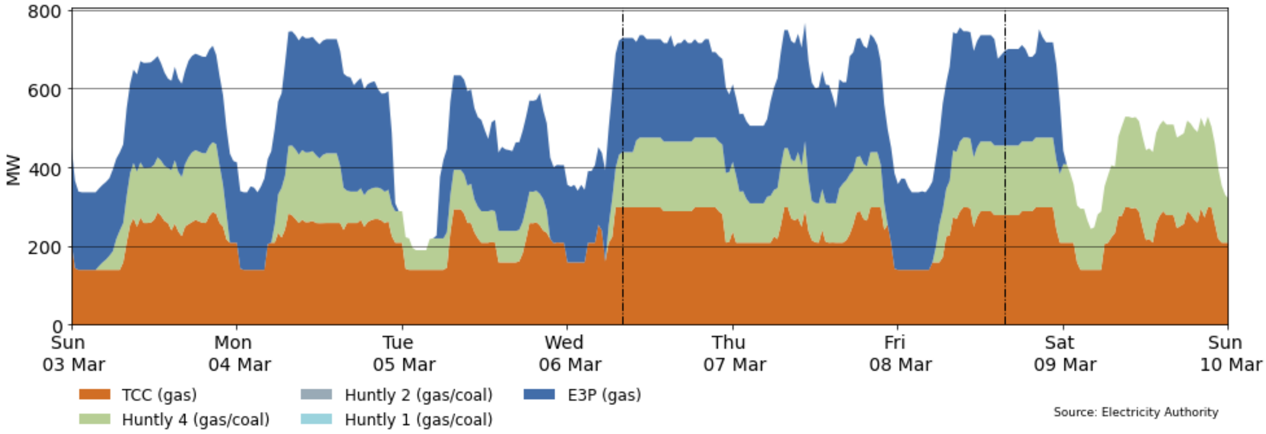
7.5. On the remaining days, the differences mostly stayed between positive and negative $100/MWh. This is an increase in RTD-PRSS differences when compared to the previous week, where differences were mostly between positive and negative $50/MWh, which indicates that price forecasting was less accurate this week.

Figure 11: Difference between national marginal RTD price and gate closure PRSS price, with the difference due to one-hour ahead wind and demand forecast inaccuracies between 3-9 March



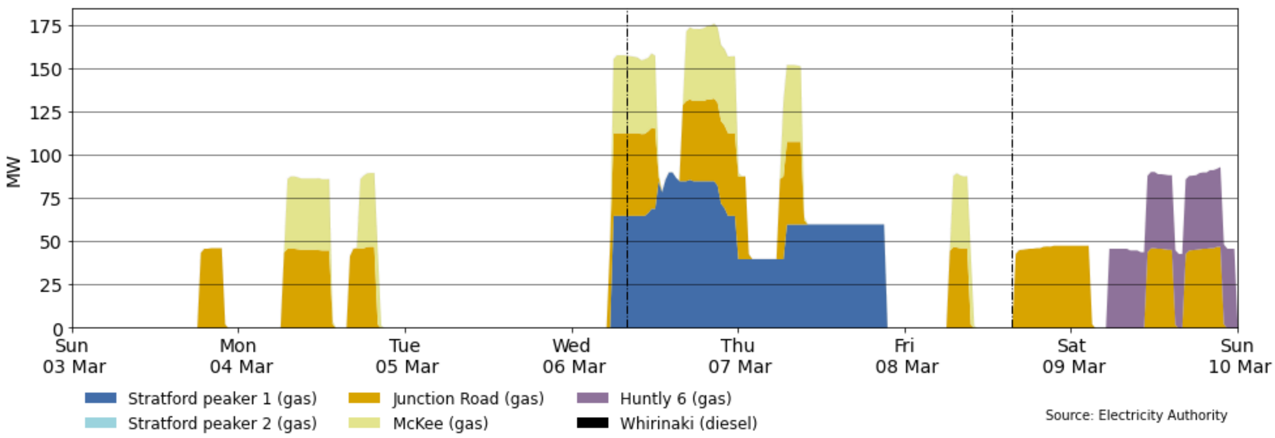
7.6. Figure 12 shows the generation of thermal baseload between 3-9 March. TCC provided baseload this week with Huntly 5 (E3P) also running from Sunday to late Monday and from Tuesday up to Saturday, when it was on outage. Huntly 4 also ran every day this week, although not continuously.

Figure 12: Thermal baseload generation between 3-9 March



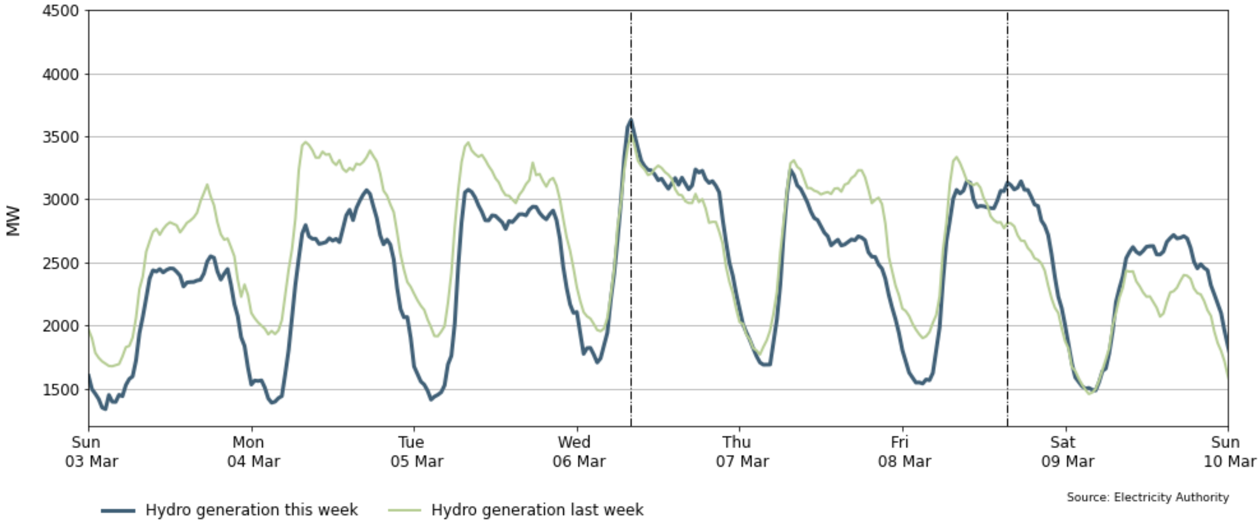
7.7. Figure 13 shows the generation of thermal peaker plants between 3-9 March. Peaker generation was required every day this week except for Tuesday. Low wind on Wednesday saw more peakers coming online. Junction Road ran for six days during peak and or shoulder periods. McKee ran during the weekdays on Monday, and from Wednesday to Friday. Stratford 1 ran continuously between Wednesday and Thursday. Finally, Huntly 6 ran on Saturday during the Huntly 5 outage.

Figure 13: Thermal peaker generation between 3-9 March



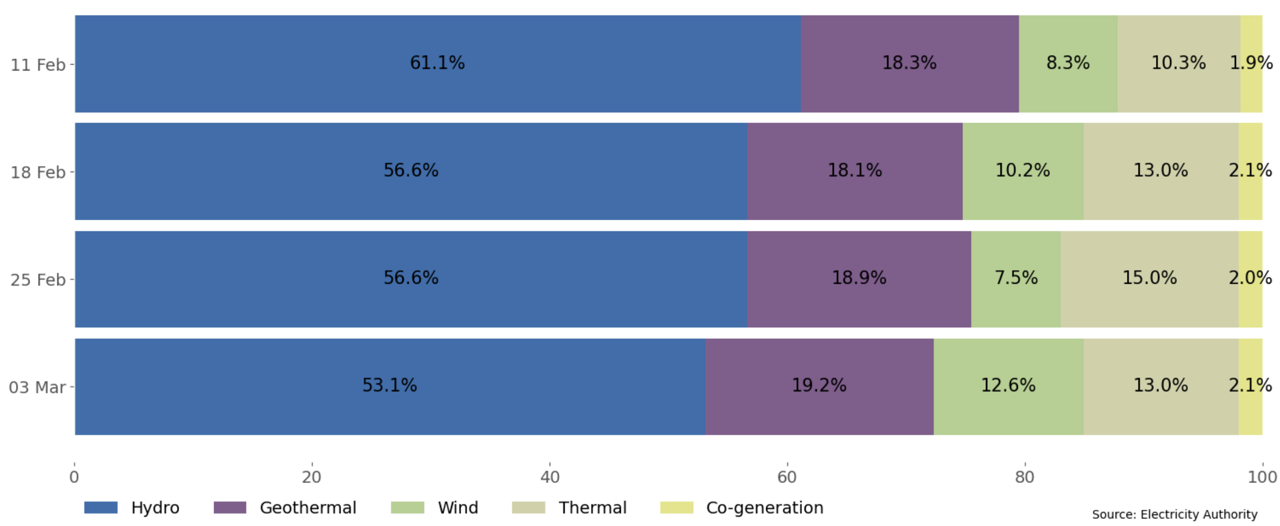
7.8. Figure 14 shows hydro generation between 3-9 March. Compared to the previous week, hydro generation was lower earlier this week, aligned with the periods of high wind generation. Hydro generation increased during the time when wind generation was low, on Wednesday and between Friday and Saturday.

Figure 14: Hydro generation between 3-9 March



7.9. As a percentage of total generation, between 3-9 March, total weekly hydro generation was 53.1%, geothermal 19.2%, wind 12.6%, thermal 13.0%, and co-generation 2.1%, as shown in Figure 15. The relative decrease in hydro generation is due to the relative increase in wind generation this week.

Figure 15: Total generation b type as a percentage each week between 11 February and 9 March



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 3-9 March ranged between ~1550MW and ~2350MW. 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) Stratford 1 was on outage on 3 and 8 March

(d) Huntly 6 was on outage on 6 and 7 March

(e) Huntly 5 was on outage on 9 March

(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 3-9 March

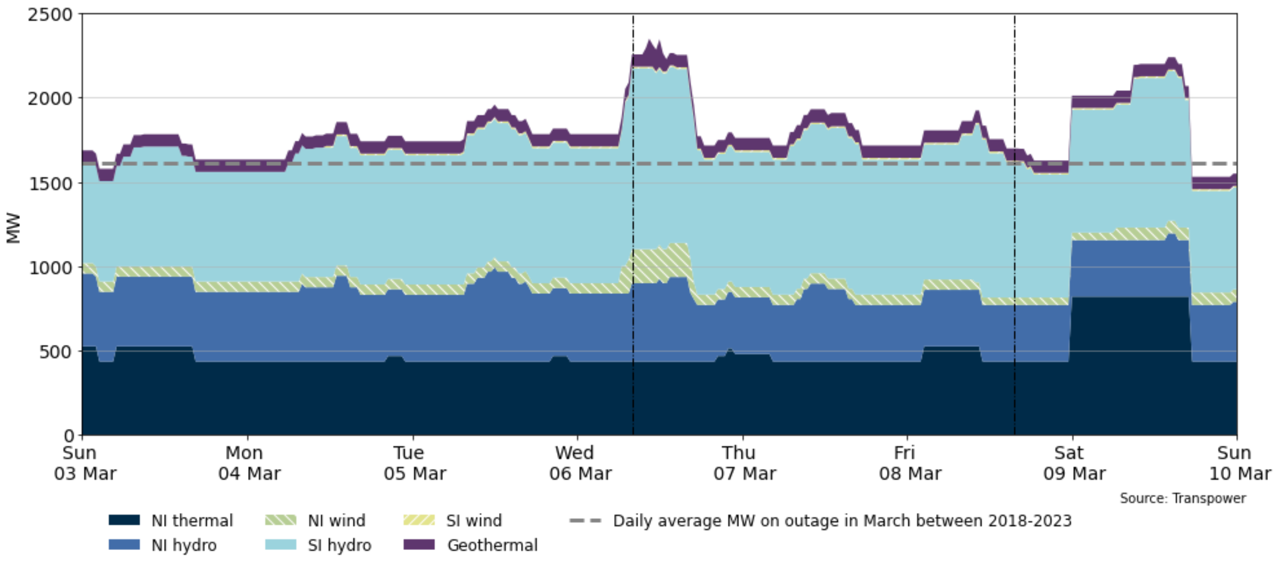
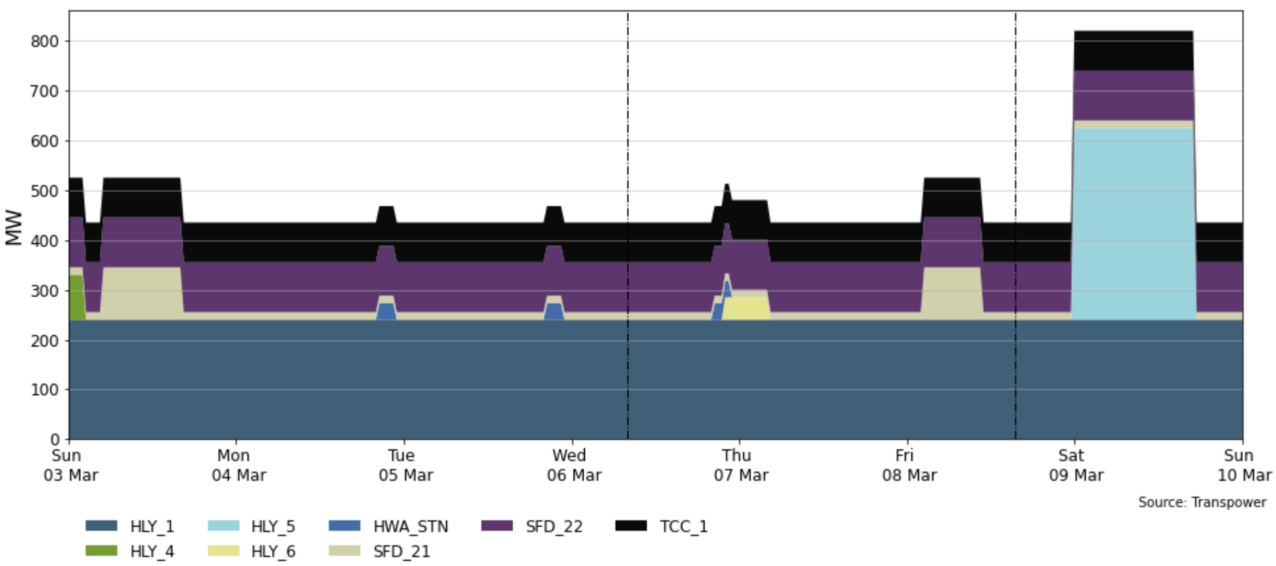


Figure 17: MW loss from thermal outages between 3-9 March

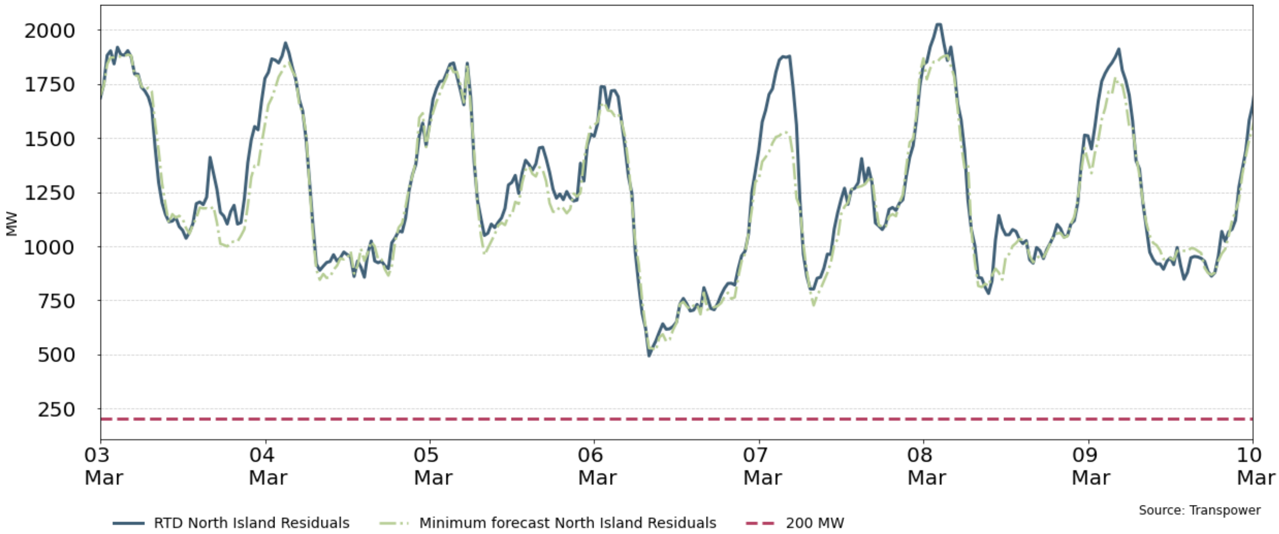


9. Generation balance residuals

9.1. Figure 18 shows the North Island generation balance residuals between 3-9 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 residual levels were healthy this week, reaching a minimum of ~630MW on Wednesday morning, during which demand was high due to lower temperatures. The minimum North Island generation residual levels reached a minimum of ~500MW, also on Wednesday morning, as shown in Figure 18.

Figure 18: North Island generation balance residuals 3-9 March



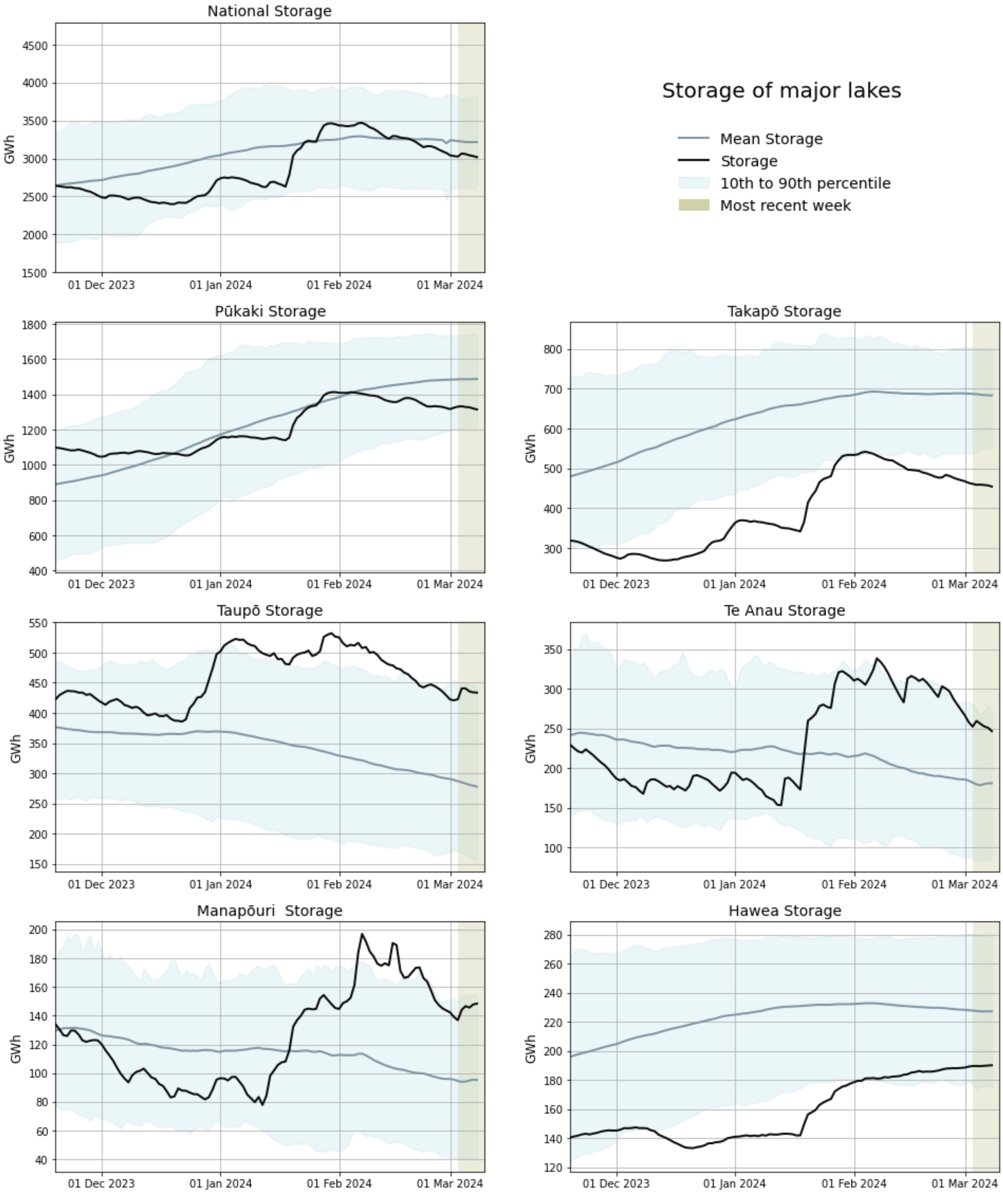
10. Storage/fuel supply

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 was approximately stable this week, still at 77% nominally full and ~95% of the historical average for this time of the year (as of 9 March).

10.3. Most lakes remained stable this week. Storage at lake Taupō is at its 90th percentile. Storage at lake Pūkaki remained steady, still sitting between its historical average and the 10th percentile. Lake Takapō remains below its 10th percentile, but its storage was also steady this week. Lake Manapōuri saw an increase in storage now sitting close to its 90th percentile while Lake Te Anau saw a decrease in its storage levels, now sitting below its 90th percentile. Hawea storage continued its increase, now distancing from its 10th percentile and moving towards its historical average.

Figure 19: Hydro storage



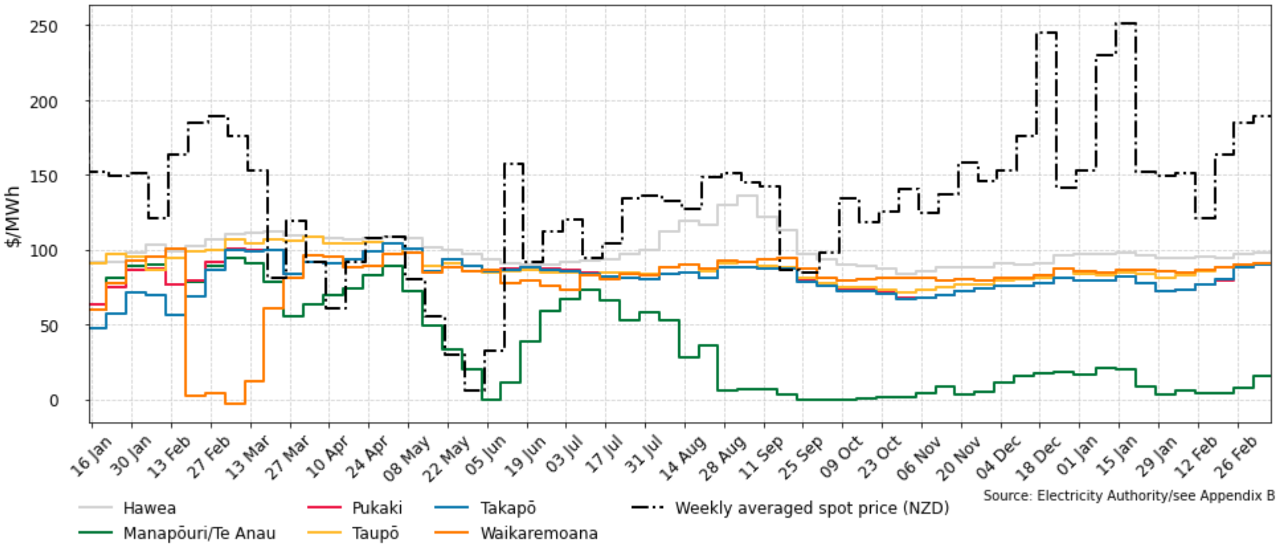
Source: Electricity Authority

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 9 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 marginal water values increased at all lakes. Water values at Manapōuri/Te Anau increased around ~$8/MWh while the increase from all other lakes was between ~$1-2/MWh.

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 9 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.

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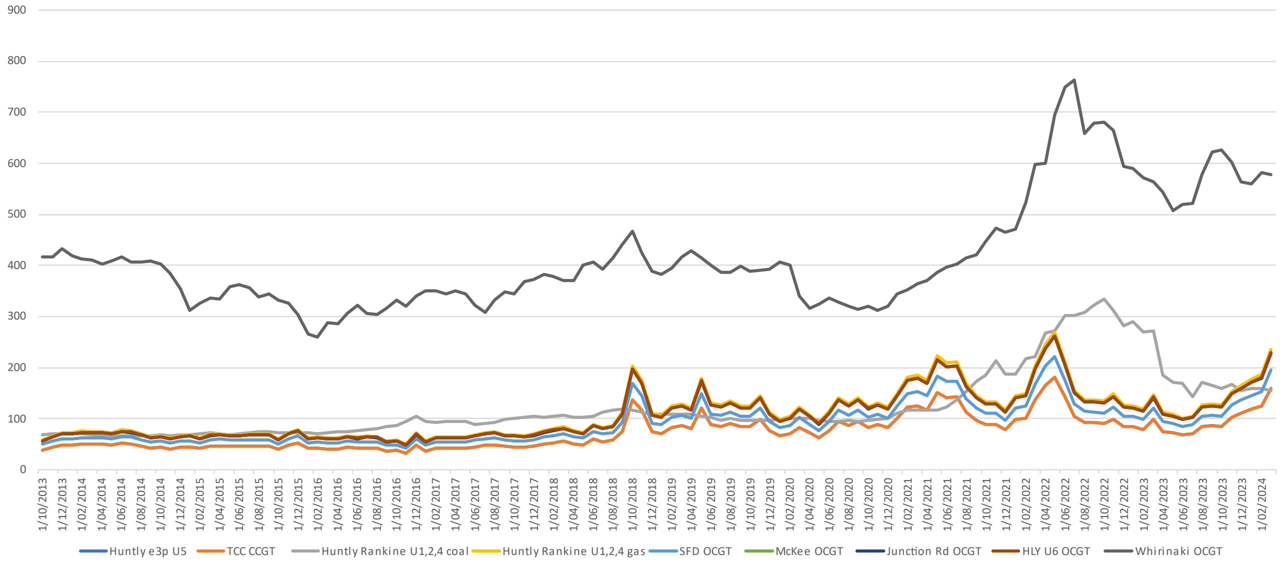
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

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

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

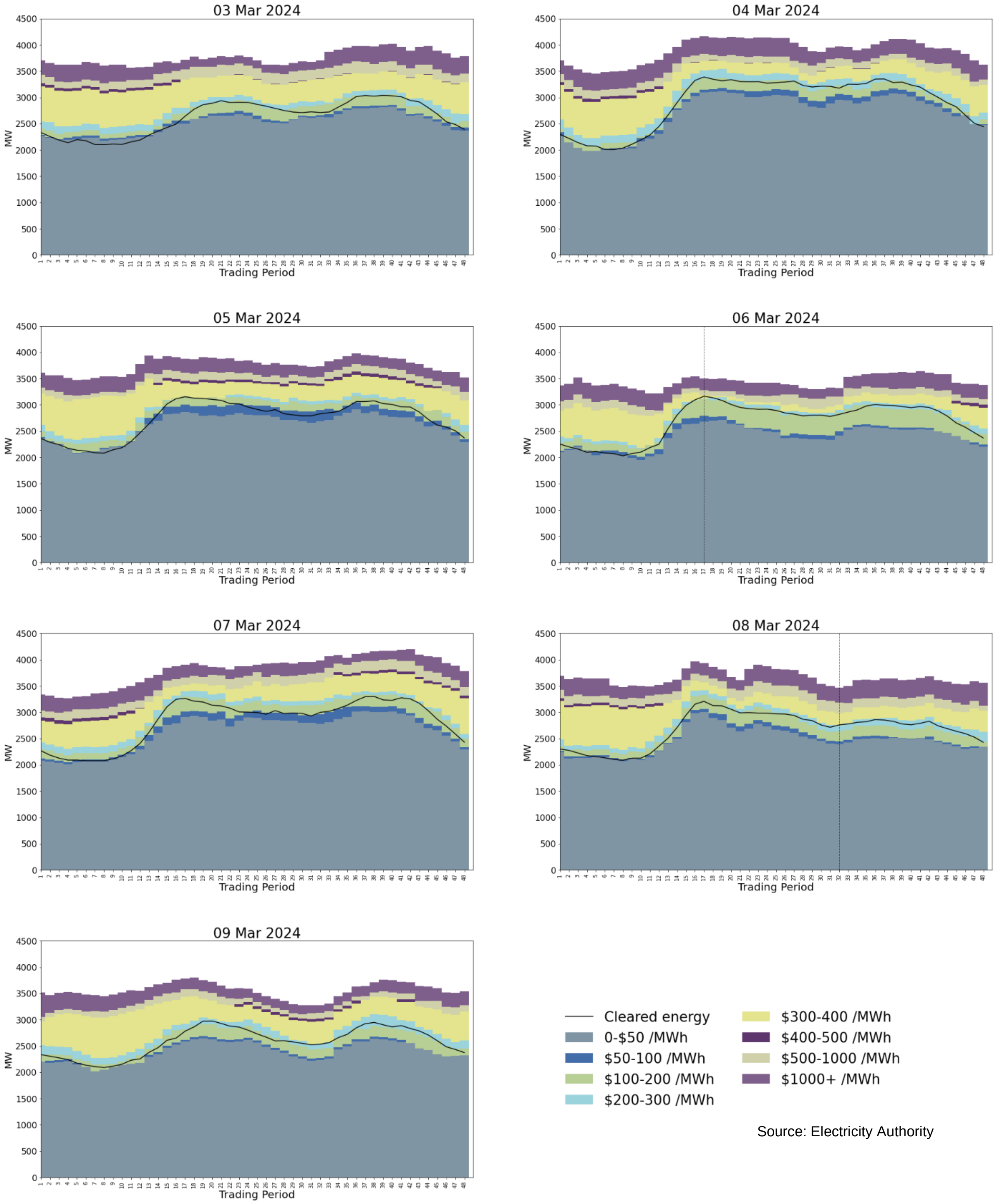
13. Offer behaviour

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 mostly cleared in the $100-$300/MWh region. During the price spikes offers were cleared in the $300-$400/MWh band.

13.3. In the South Island most of the offers were cleared within $100-$300/MWh across the week. Offers at the end of the week reached the $200-$300/MWh more often due to low wind generation on Friday and Saturday and Huntly 5 being on outage on Saturday.

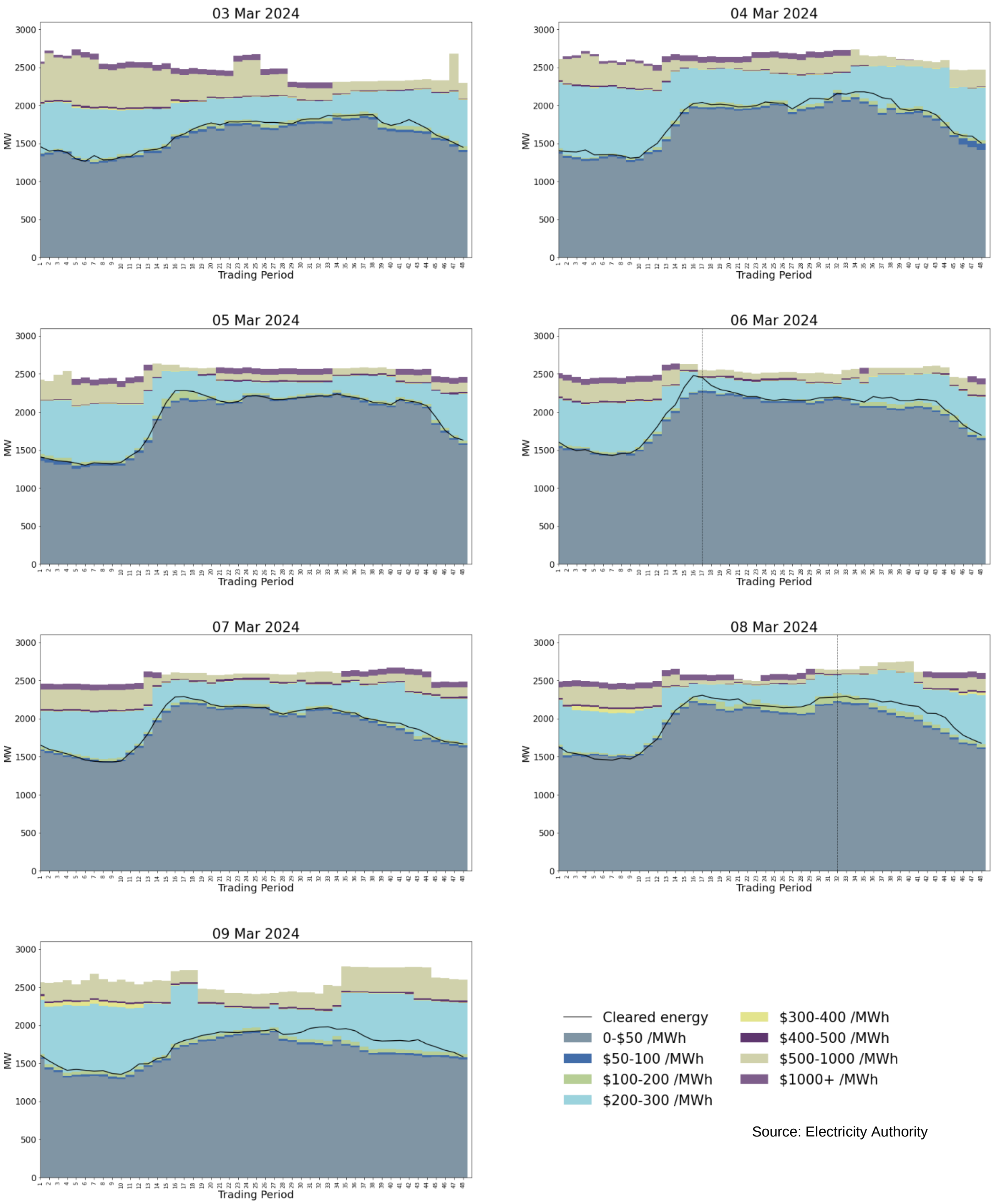
Figure 22: North Island daily offer stacks[3]



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. The market monitoring team will conduct further analysis on high North Island SIR prices between 5-6 March.

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.
22/02/2024	32	Further analysis	Genesis	Tokaanu	Offer prices
27/02/2024	1-2	Further analysis	Genesis	Huntly	Huntly start up
5/03/2024-6/03/2024	23,42,14	Further analysis	N/A	N/A	SIR prices