18 March 2024

# Trading conduct report

Market monitoring weekly report

# Trading conduct report

## 1. Overview for week of 10-16 March

1.1. Spot prices increased this week compared to the previous week, with prices mostly between \$200-\$250/MWh. Despite the higher prices, there were no price spikes this week. There were a few periods of price separation and reserve price spikes. Reserve price spikes were related to energy and reserves co-optimisation and the HVDC outage, which limited the reserve sharing capacity between the islands. TCC, Huntly 5, Huntly 4, and then Huntly 2 ran as baseload this week. Hydro storage decreased this week, now at ~92% of mean as of 16 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 10-16 March:

(a) The average wholesale spot price across all nodes was \$213/MWh.

(b) 95% of prices fell between \$25/MWh and \$293/MWh.

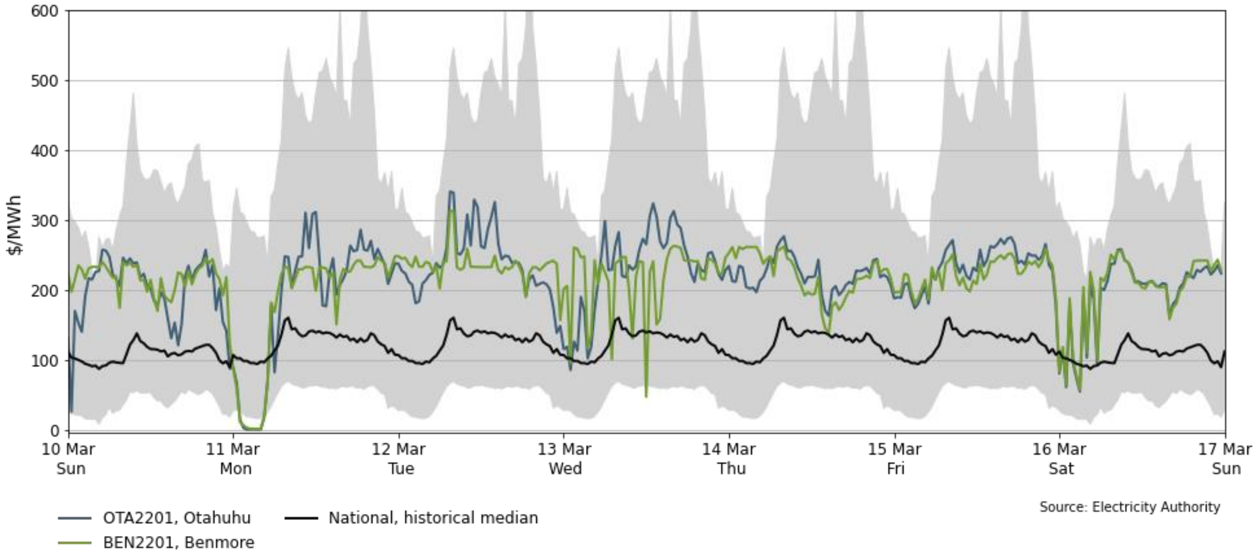
2.4. The spot prices this week were mainly above the national historical median, and mostly above \$200/MWh, influenced, in part, by the ongoing planned HVDC Pole 2 outage and declining hydro storage. The average spot price increased by \$44/MWh compared to the previous week. Tuesday morning saw the highest spot prices this week, \$340/MWh at Ōtāhuhu and \$314/MWh at Benmore.

2.5. Despite the increase in the average wholesale spot price, there were no price spikes this week and some periods of price separation. Price separation on Tuesday and Wednesday was related to a decrease in wind generation and the planned HVDC Pole 2 outage (which ended on Thursday).

2.6. This week even when wind generation was high, prices remained high since hydro marginal plants were offered in the more expensive price bands due to the decline in hydro storage.

[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day, and looking for prices that lie 1.5 times the interquartile range above the 75$^{th}$ percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where $Q_3$ is the 75$^{th}$ percentile (or third quartile value) and IQR is your inter-quartile range.

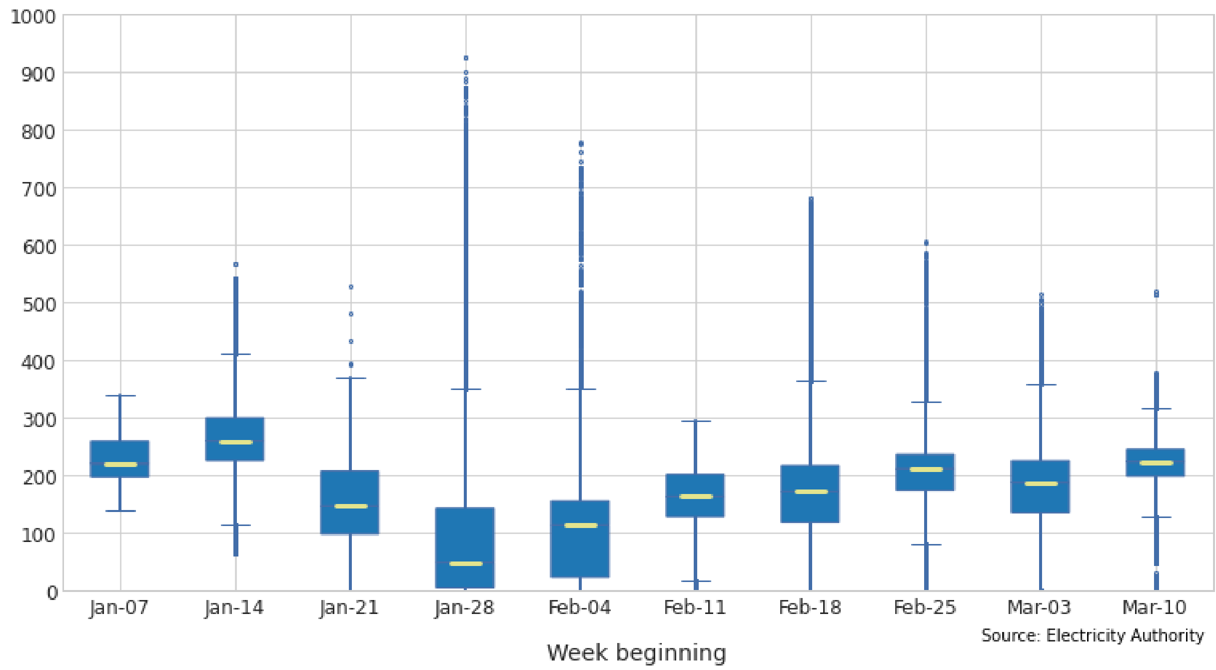
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 10-16 March**




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 higher compared to the previous week, with the median this week at $223/MWh, compared to $183/MWh in the previous week, a $40/MWh increase. The middle 50% of the prices were between $198-$245/MWh, also representing a more condensed price distribution compared to the previous week – with prices being less volatile.

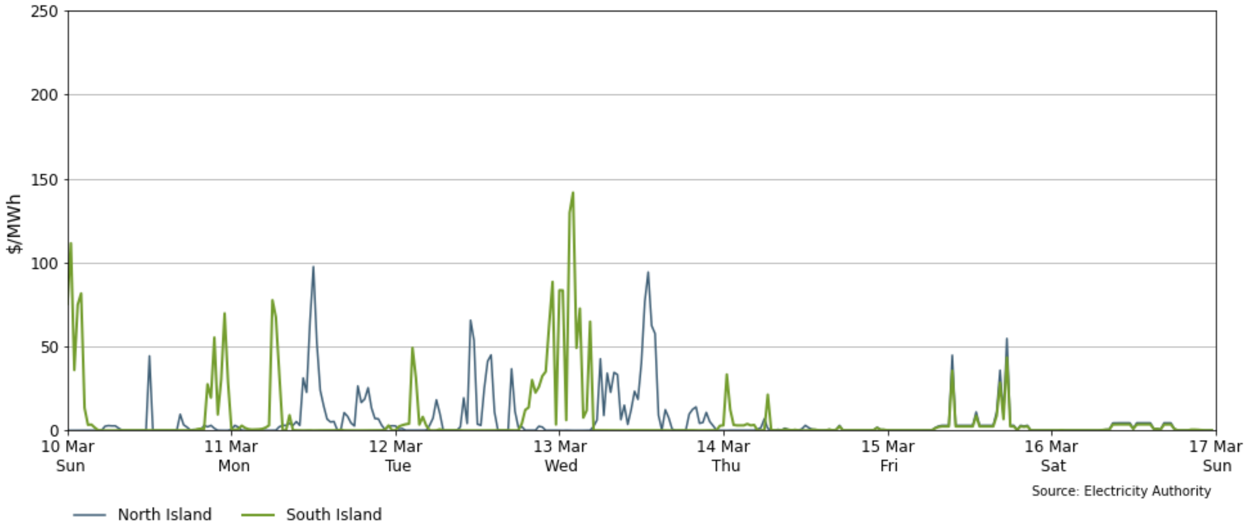
**Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks**



# 3. Reserve prices

3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR price spikes reflect, once again, 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. 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. High wind generation also might call for higher reserve requirements in the North Island when wind generators are setting the risk. Periods of low wind required higher northward flow of the HVDC, and hence more North Island reserves.

**Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 10-16 March**




3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly between $0-$10/MWh this week. A few SIR price spikes and price separation also happened this 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.

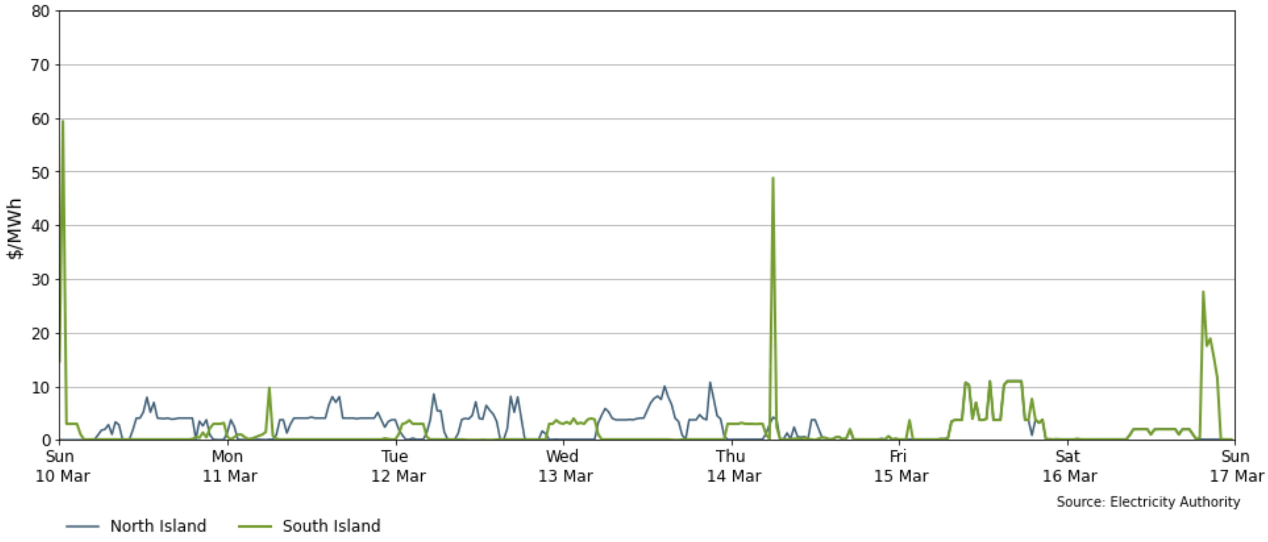
3.3. The South Island SIR spikes occurred:

(a) On Sunday when high southwards HVDC flows caused the HVDC to set the South Island risk.

(b) On Thursday when HVDC flow was reversing direction.

(c) On Sunday when there was limited South Island SIR offers. The monitoring team are conducting further analysis on these offers.

**Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 10-16 March**



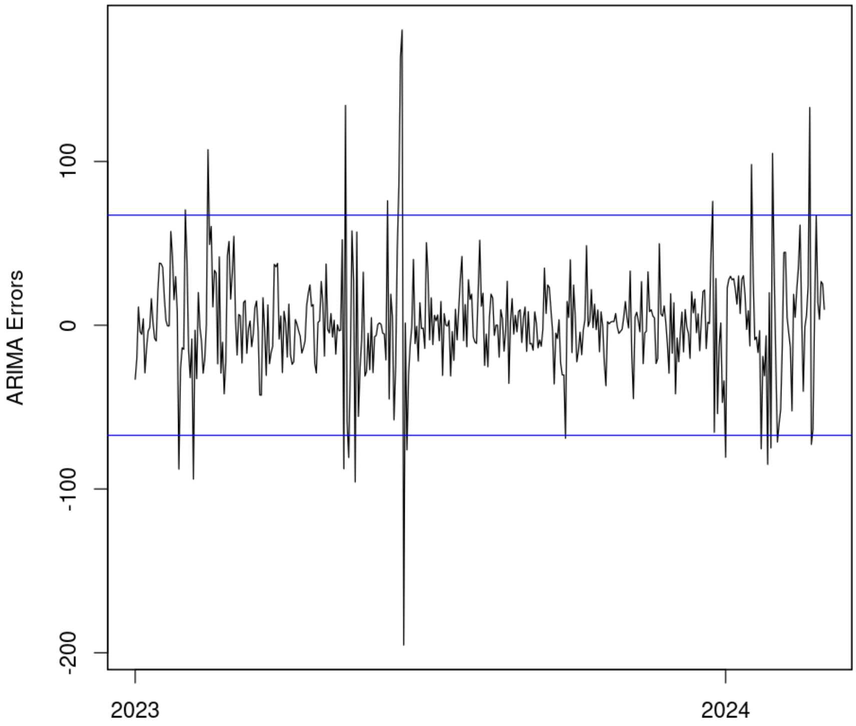

# 4. Regression residuals

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 2023-16 March 2024**

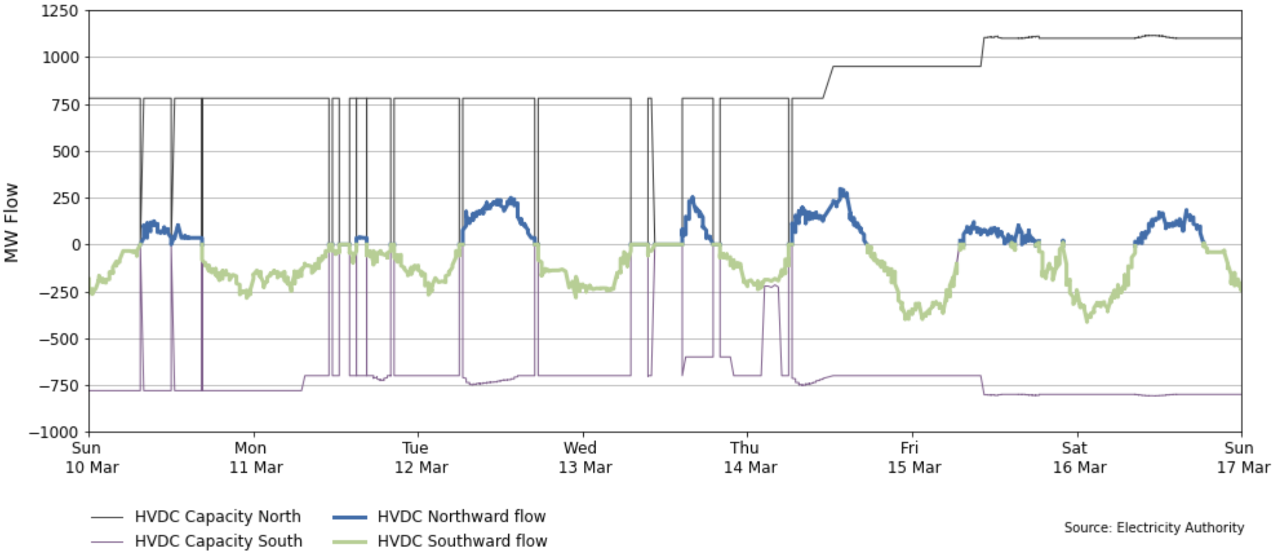



Source: Electricity Authority/see Appendix A

# 5. HVDC

5.1. Figure 6 shows HVDC flow between 10-16 March. HVDC flows this week were limited to 780MW until Thursday, due to the planned HVDC Pole 2 outage. During the period when Pole 2 was on outage, the flow remained limited by the reserve availability. The HVDC was flowing south for most of the time this week. Northwards flow happened mostly on weekdays during daytime, coinciding with times of increased demand and low wind generation (or high wind forecast inaccuracies). On Wednesday, the HVDC transfer limit was set to zero from 07:00 to 09:30 and from 10:30 to 14:30. In monopole operation the HVDC has a minimum transfer level of 35 MW in either direction. The HVDC was forecast to be running below this limit during this period and the direction was also uncertain. The transfer limit was set to zero during these periods to avoid the need to continually start and stop the pole and change its direction due to insufficient energy in the transfer schedules as North Island wind generation was low. This can occur when the HVDC is operating in monopole mode. This issue does not occur in bi-pole operation due to round power.

**Figure 6: HVDC flow and capacity between 10-16 March**

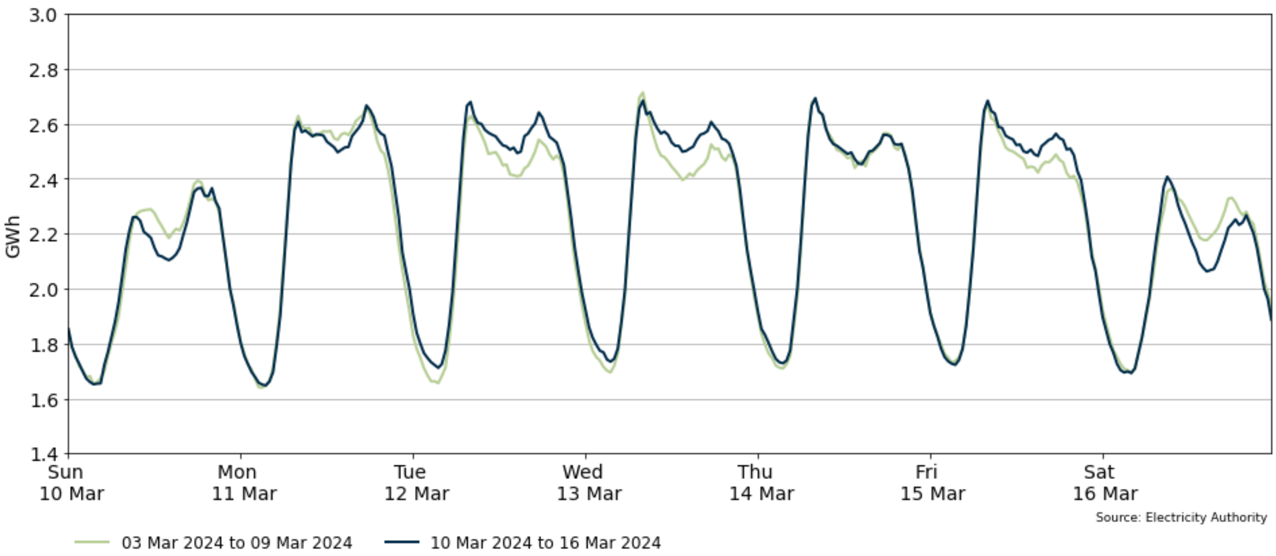



# 6. Demand

6.1. Figure 7 shows national demand between 10-16 March, compared to the previous week. Demand was mostly either comparable or higher than the previous week during weekdays, and lower over the weekend.

6.2. On Tuesday and Wednesday when demand was higher compared to the previous week, wind generation was also low or decreasing, which contributed to several trading periods of price separation during those days.

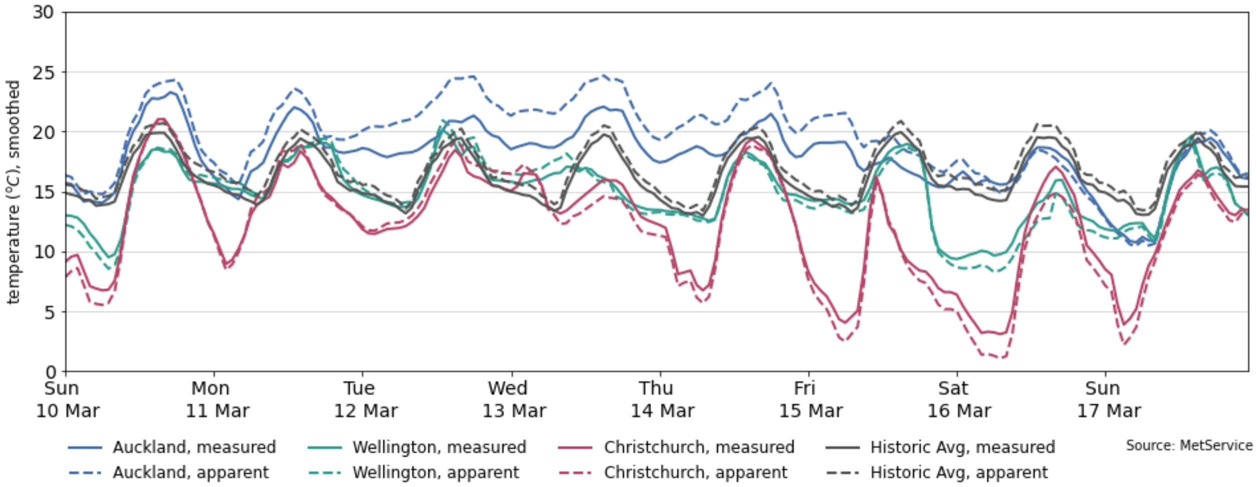
**Figure 7: National demand between 10-16 March compared to the previous week**




6.3. Figure 8 shows the hourly temperature at main population centres from 10-16 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.

6.4. Temperatures fluctuated around the historical average from Sunday to Wednesday this week, dropping from Thursday onwards across the country. Temperatures in Auckland varied between 11ºC and 25ºC. Wellington temperatures fluctuated between 8ºC and 21ºC. Christchurch temperatures were between 1ºC and 21ºC this week.

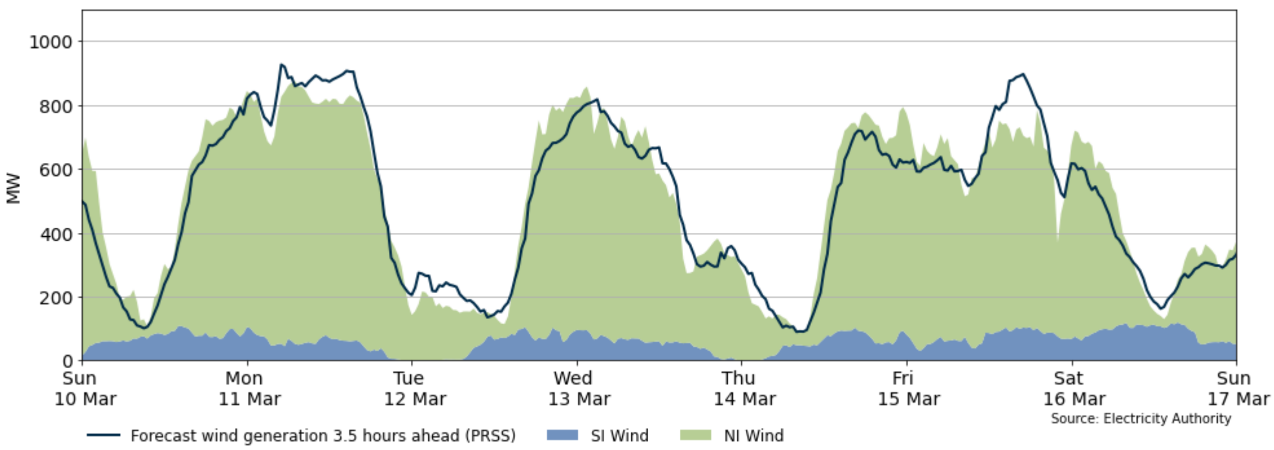
**Figure 8: Temperatures across main centres between 10-16 March**




# 7. Generation

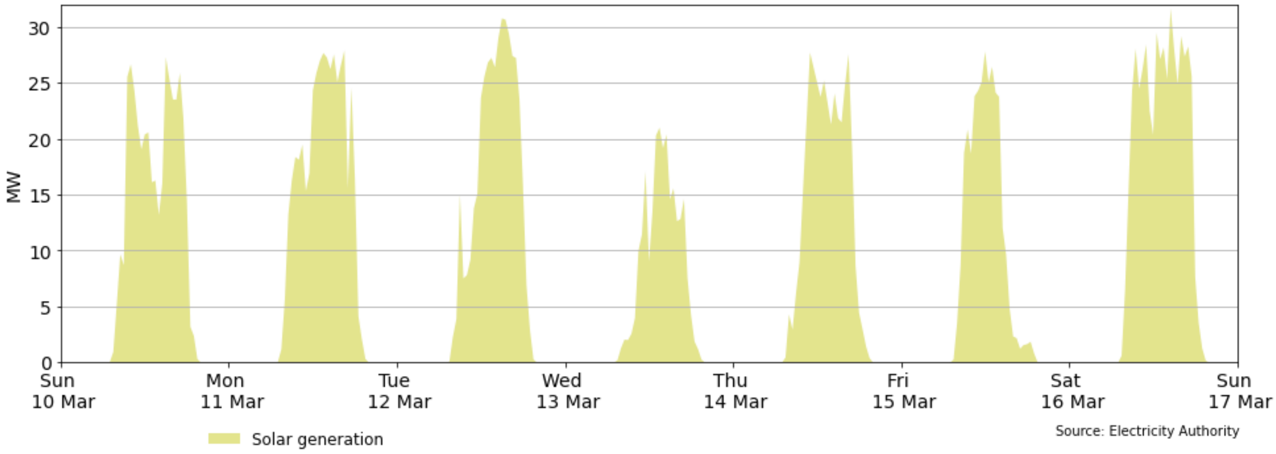
7.1. Figure 9 shows wind generation and forecast from 10-16 March. This week wind generation varied between 91MW and 875MW, and averaged 512MW. Compared to the previous week, wind generation was more variable. Wind generation was below 400MW for a several trading periods this week on different days, including Tuesday and Wednesday, which likely contributed to the price separation during those days. On Friday afternoon, several wind farms over forecast their generation, however, as wind generation was already high, this had little impact on final prices.

**Figure 9: Wind generation and forecast between 10-16 March**




7.2. Figure 10 shows solar generation from 10-16 March. The Lodestone Edgecumbe solar farm is still under commissioning process. The 32MW(DC)/24MW(AC) solar array is currently generating a maximum of 8MW. Solar generation this week saw few overcast days impacting its generation, mainly on Sunday and Wednesday, as shown in Figure 10.

**Figure 10: Solar generation between 10-16 March**

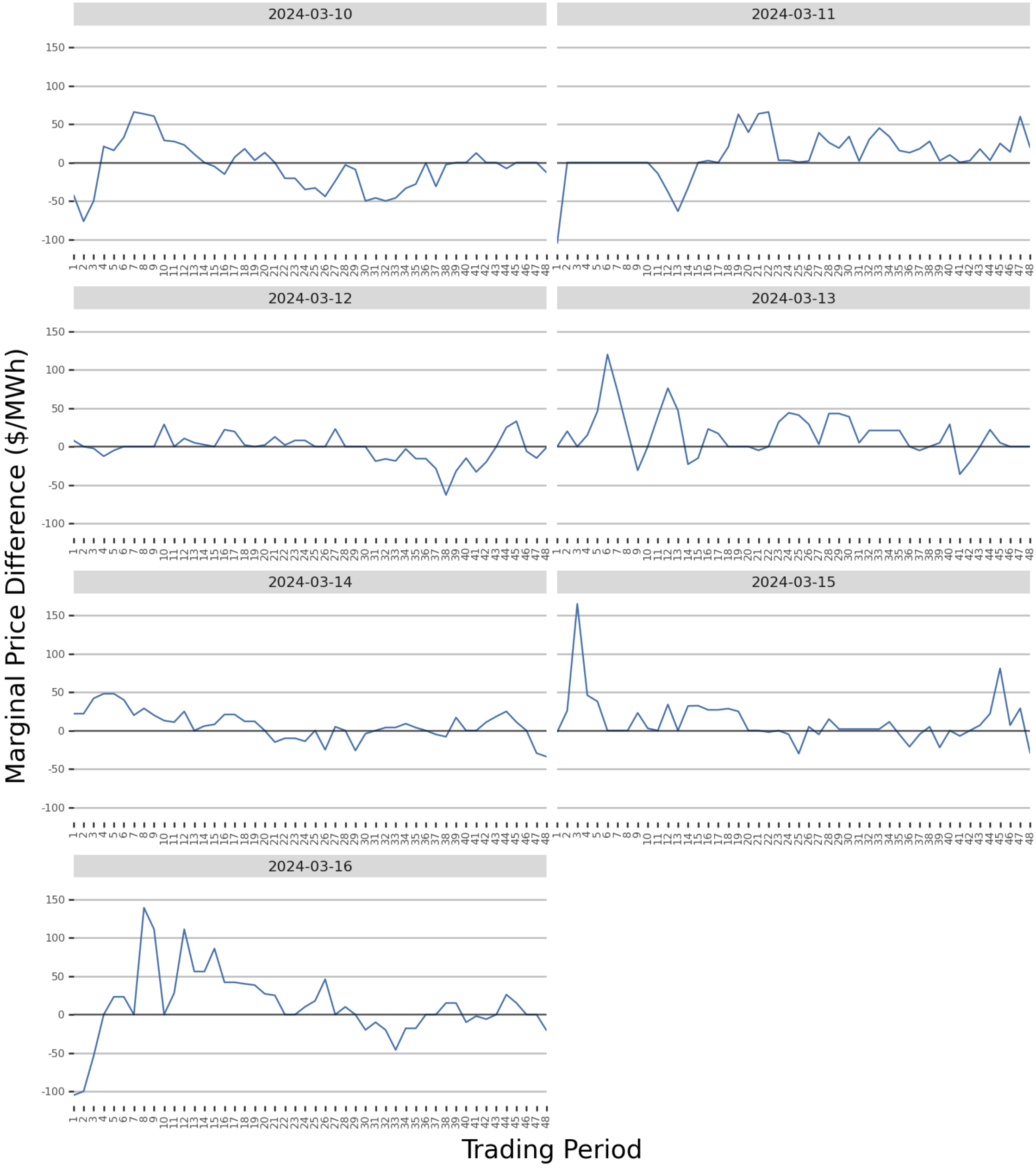



7.3. Figure 11 shows the difference between the real time dispatch (RTD) marginal price, and what the marginal price would have been based on the 1 hour ahead (PRSS) demand and wind forecasts at national level. This plot highlights when forecasting inaccuracies are causing large differences between pre-dispatch 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 on the early hours of Friday, when the RTD prices were over $150/MWh higher than the 1-hour ahead PRSS prices at 1:00am. However, since the largest difference happened so early in the morning, demand was low, and there was no spike in spot prices during that time.

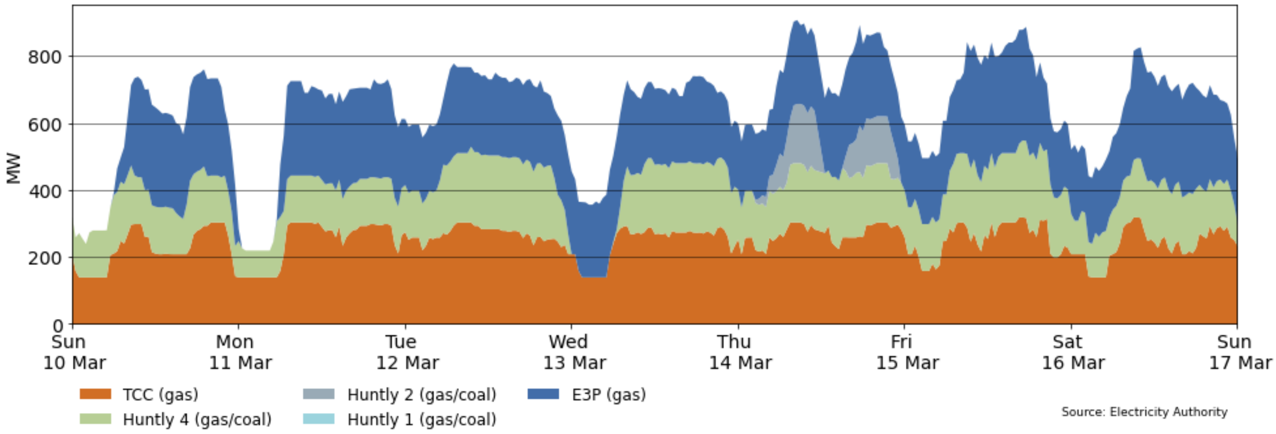
7.5. On the remaining days, the differences mostly stayed between positive and negative $50/MWh, with a few instances of differences reaching either the positive or negative $100/MWh mark. This is a decrease in RTD-PRSS differences when compared to the previous week, where differences reached the +/- $100/MWh more often, indicating that price forecasting was more accurate this week.

**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 10-16 March**



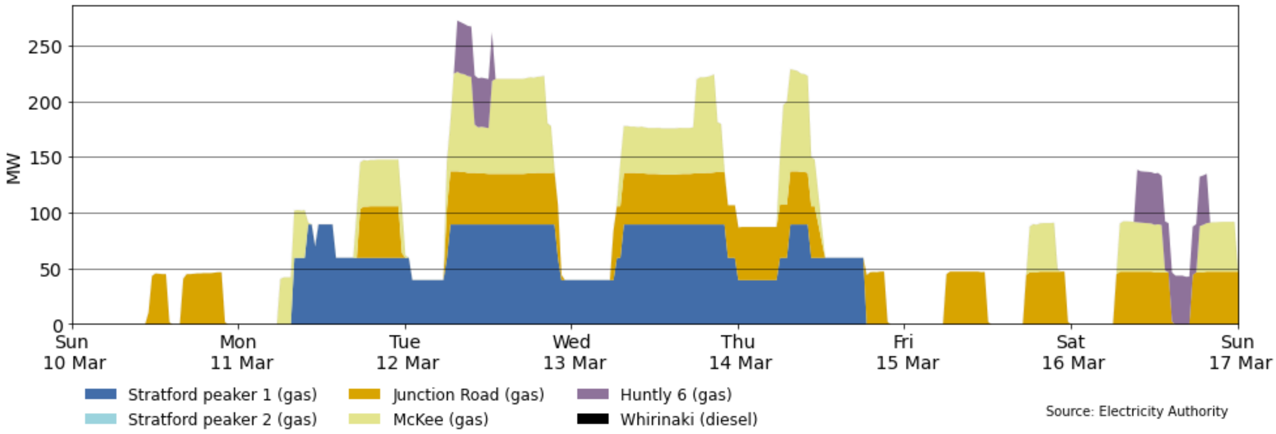

7.6. Figure 12 shows the generation of thermal baseload between 10-16 March. TCC provided baseload this week with Huntly 5 (E3P) also running for most of the day on Sunday and continuously from Monday onwards. Huntly 4 also ran continuously every day this week, except for a few hours on Wednesday. Huntly 2 ran for a few hours on Thursday.

**Figure 12: Thermal baseload generation between 10-16 March**



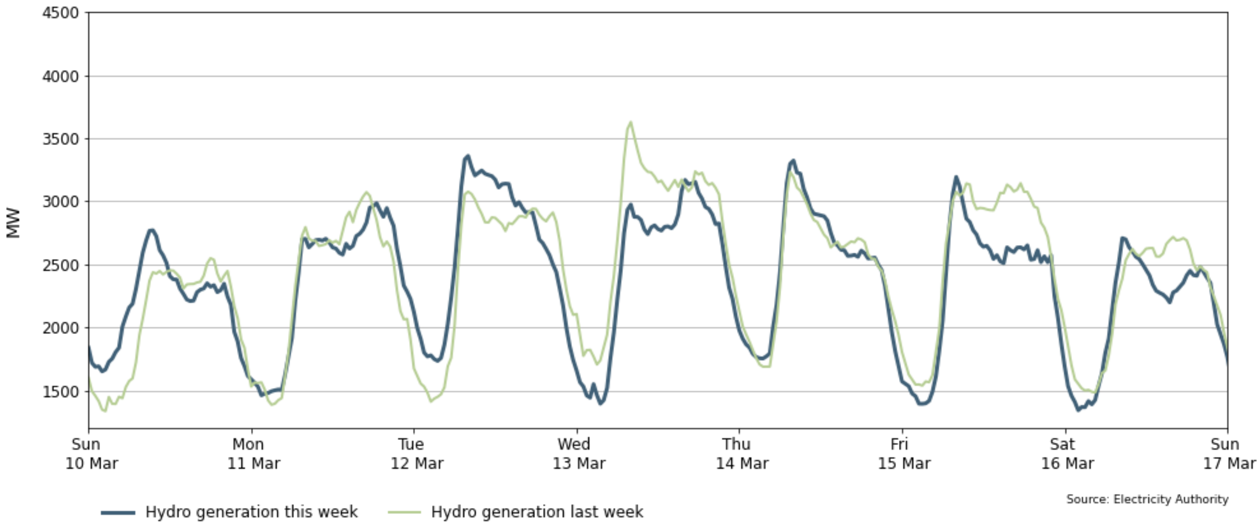

7.7. Figure 13 shows the generation of thermal peaker plants between 10-16 March. Peaker generation this week was required more between Monday and Thursday, especially during times with high demand and low wind generation. Junction Road ran every day this week – and ran more when wind was low on Tuesday and Wednesday. Stratford 1 ran continuously between Monday morning and Thursday afternoon. McKee and Huntly 6 also ran this week, the latter only on Tuesday and Saturday.

**Figure 13: Thermal peaker generation between 10-16 March**



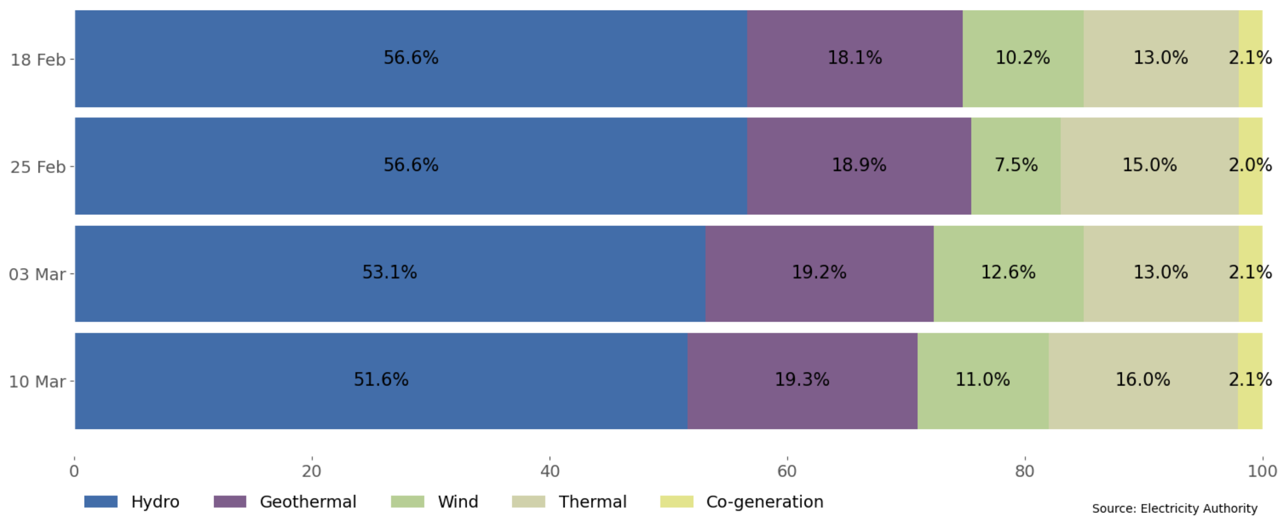

7.8. Figure 14 shows hydro generation between 10-16 March. Compared to the previous week, hydro generation was mostly either similar or lower this week. Hydro generation was high during periods of low wind generation, such as on Tuesday and Thursday. On Wednesday and Friday, when wind generation was high, hydro generation decreased.

**Figure 14: Hydro generation between 10-16 March**




7.9. As a percentage of total generation, between 10-16 March, total weekly hydro generation was 51.6%, geothermal 19.3%, wind 11.0%, thermal 16.0%, and co-generation 2.1%, as shown in Figure 15. The relative decrease in hydro generation was due to periods of high wind generation displacing hydro and increased thermal baseload generation, as hydro storage levels continue to decline.

**Figure 15: Total generation b type as a percentage each week between 18 February and 16 March**




# 8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 10-16 March ranged between ~1500MW and ~2300MW. 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 is on partial between 15-18 March

(d) Stratford 1 was on outage between 14-15 March

(e) TCC was on partial outage on 15 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 10-16 March**

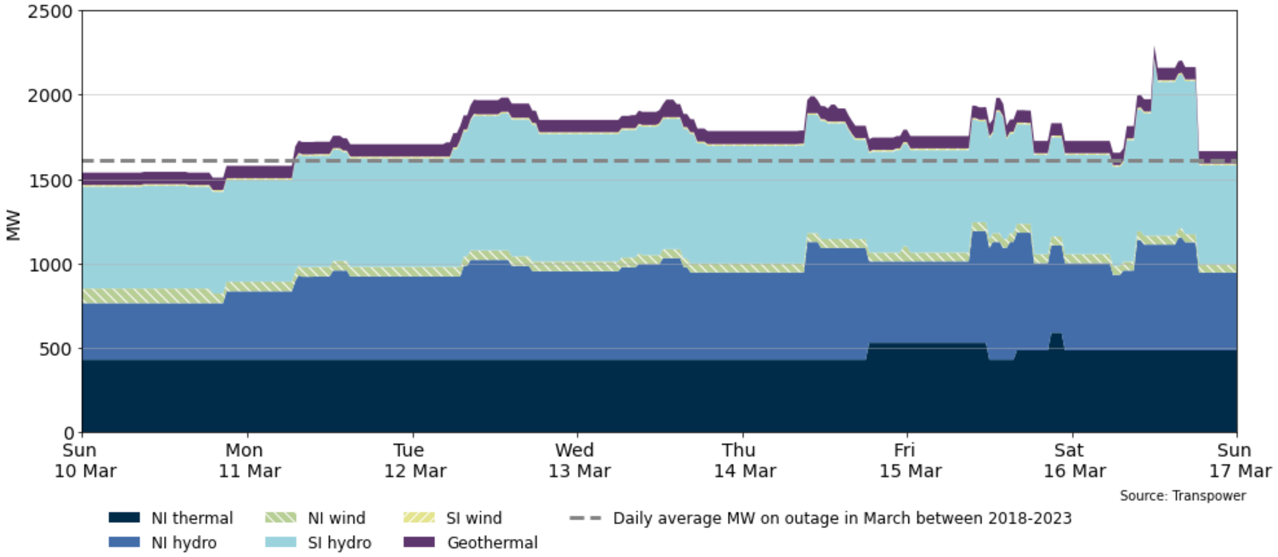
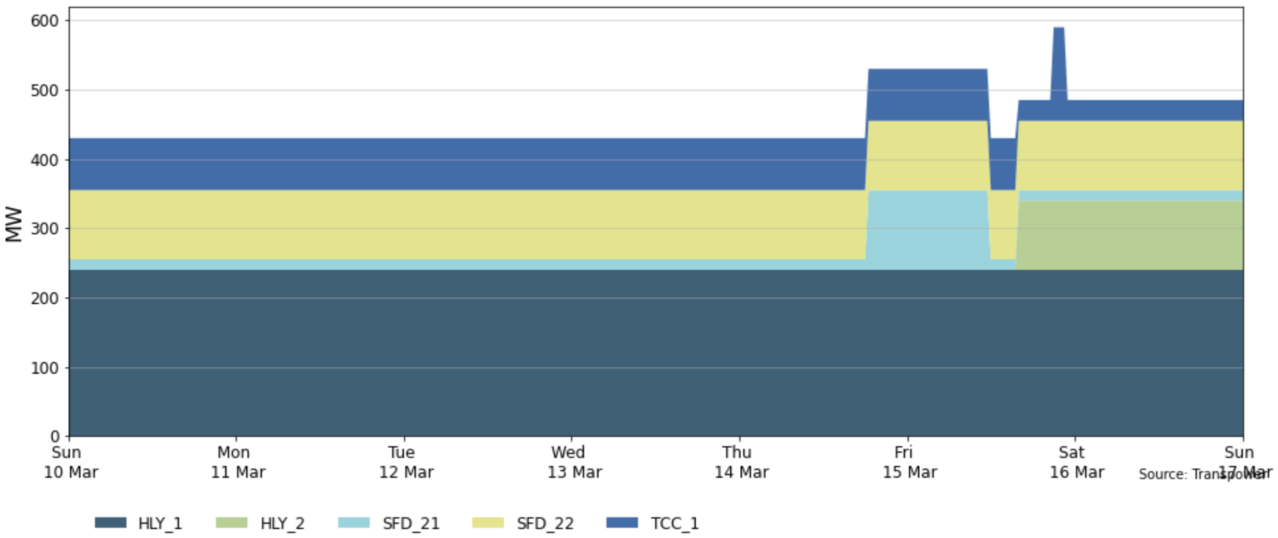



**Figure 17: MW loss from thermal outages between 10-16 March**

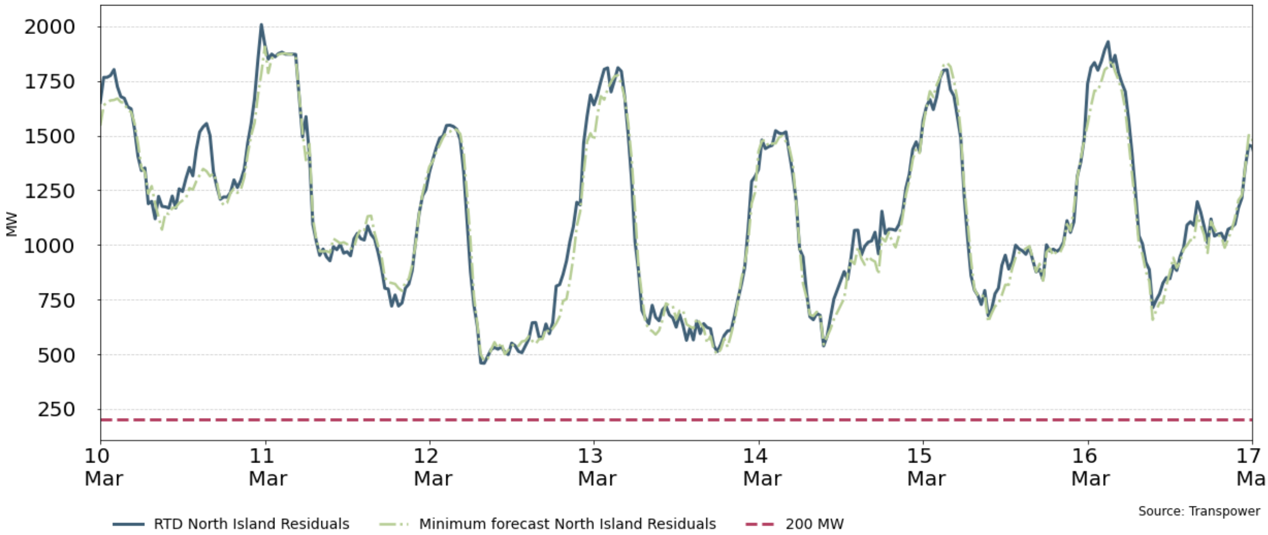



## 9. Generation balance residuals

9.1. Figure 18 shows the North Island generation balance residuals between 10-16 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 ~820MW on Tuesday morning, during which demand was high and wind generation was low. The minimum North Island generation residual levels reached a minimum of ~460MW, also on Tuesday morning, as shown in Figure 18.

**Figure 18: Generation balance residuals 10-16 March**



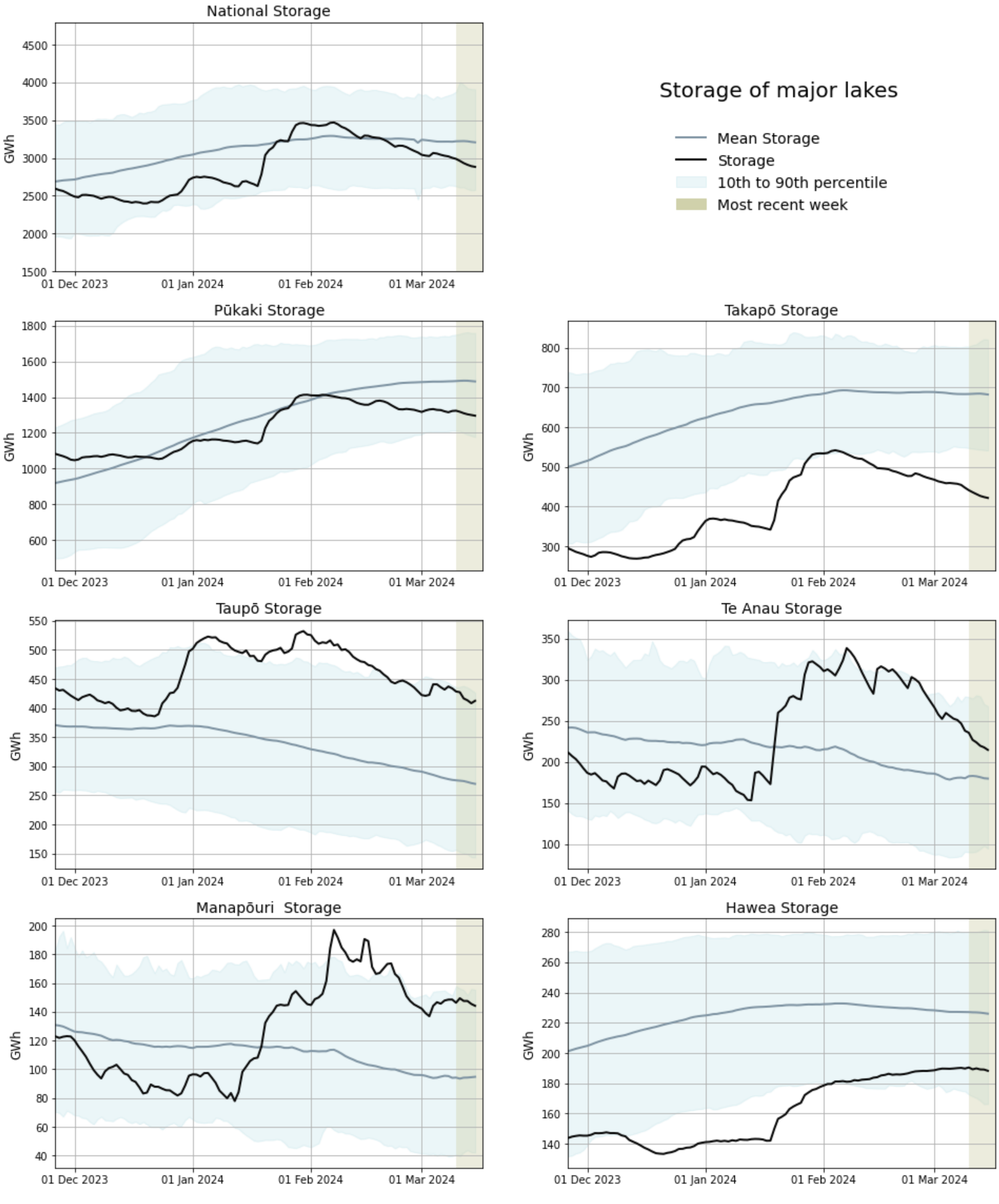

## 10. Storage/fuel supply

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 decreased this week, now sitting at 74% nominally full and ~92% of the historical average for this time of the year (as of 16 March).

10.3. Storage at most lakes decreased this week. Lake Taupō remains at its 90th percentile. Storage at lake Pūkaki decreased slightly, but it is still sitting between its historical average and the 10th percentile. Lake Takapō storage decreased this week, remaining below its 10th percentile. Lake Manapōuri and Te Anau both saw a decrease in storage. Hawea storage was stable this week.

**Figure 19: Hydro storage**



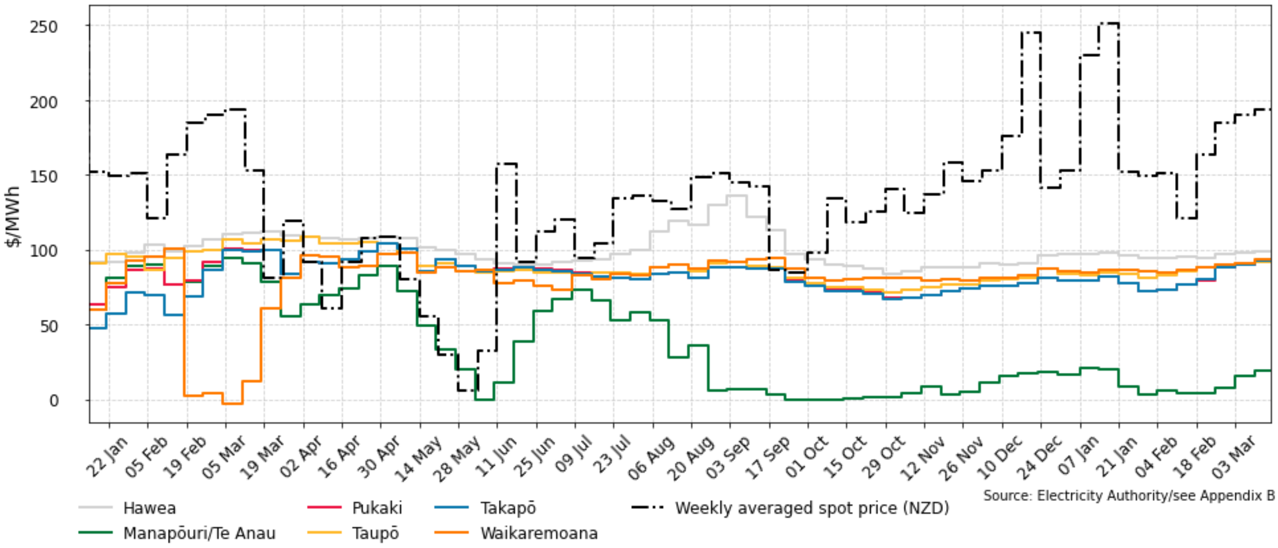

Source: Electricity Authority

# 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 16 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, all reservoirs saw an increase in price between ~$1/MWh (Taupō) and ~$4/MWh (Manapōuri/Te Anau), as storage continues to decline.

**Figure 20: JADE water values across various reservoirs between 8 January 2023 and 16 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.

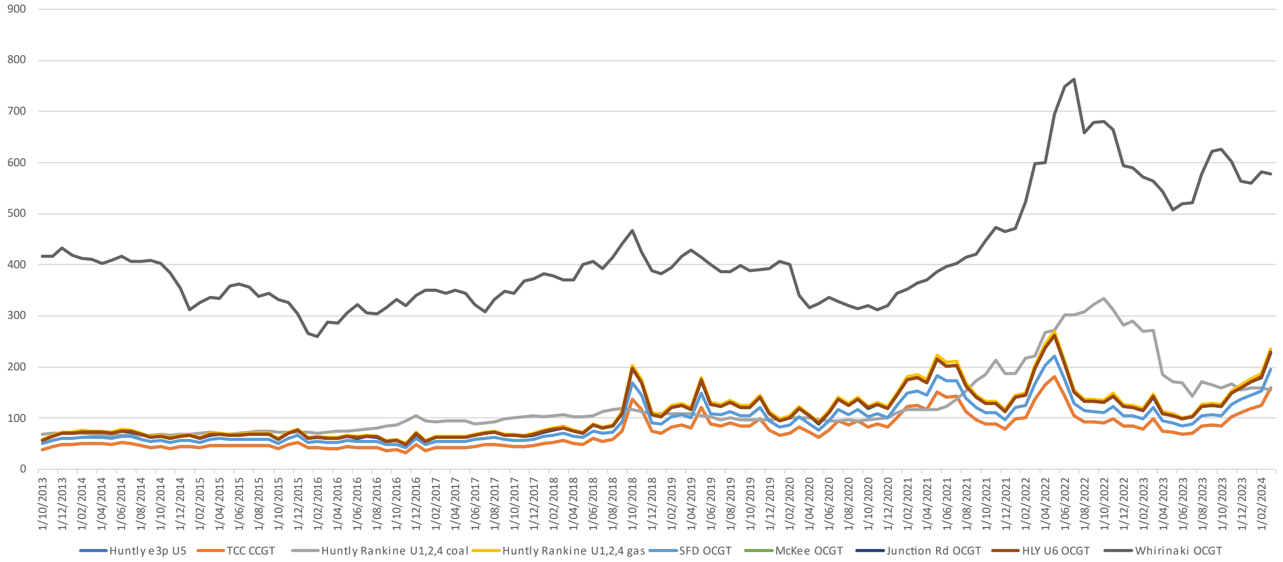
---

[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

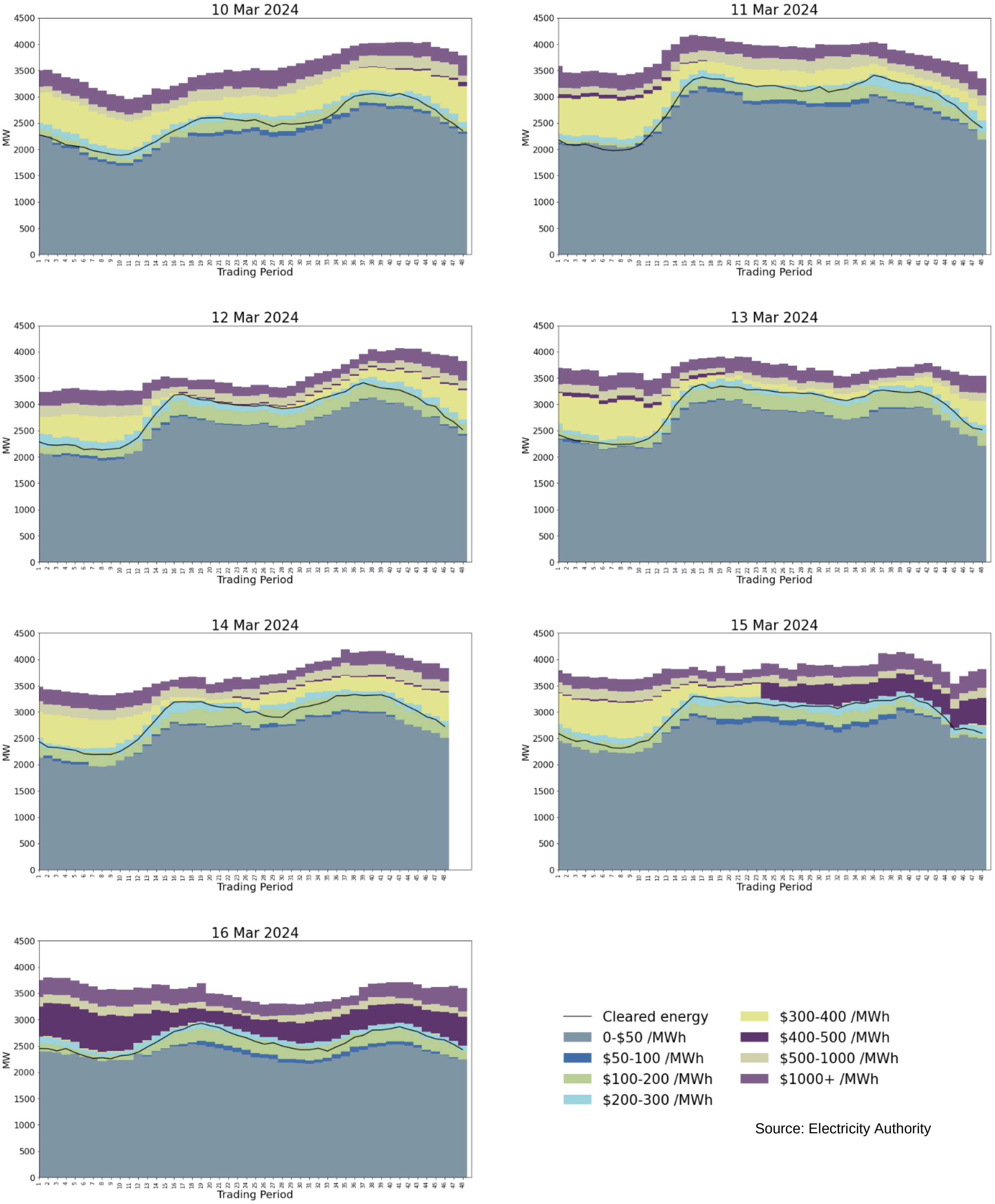
13.1. This week we split the national daily offer stacks between the two islands due to the planned HVDC outages. Figure 22 and Figure 23 show this week's offer stacks for the North and South Islands respectively. The black lines in the figures show cleared energy, indicating the range of the average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

13.2. In the North Island most of the offers during the week were cleared in the $100-$300/MWh region. On Friday and Saturday, Mercury changed its generation offers from the $300-$400/MWh band to the $400-$500/MWh band, as shown in Figure 22. The market monitoring team will conduct further analysis on Mercury's offer changes.

13.3. In the South Island most of the offers were also cleared within $100-$300/MWh across the week. The offers are consistent with the decrease in South Island hydro storage.

13.4. Finally, on 14 March, a scheduled Market System outage related to an inter-site switchover affected trading periods 24 and 25, which is why they are not shown in the figures.

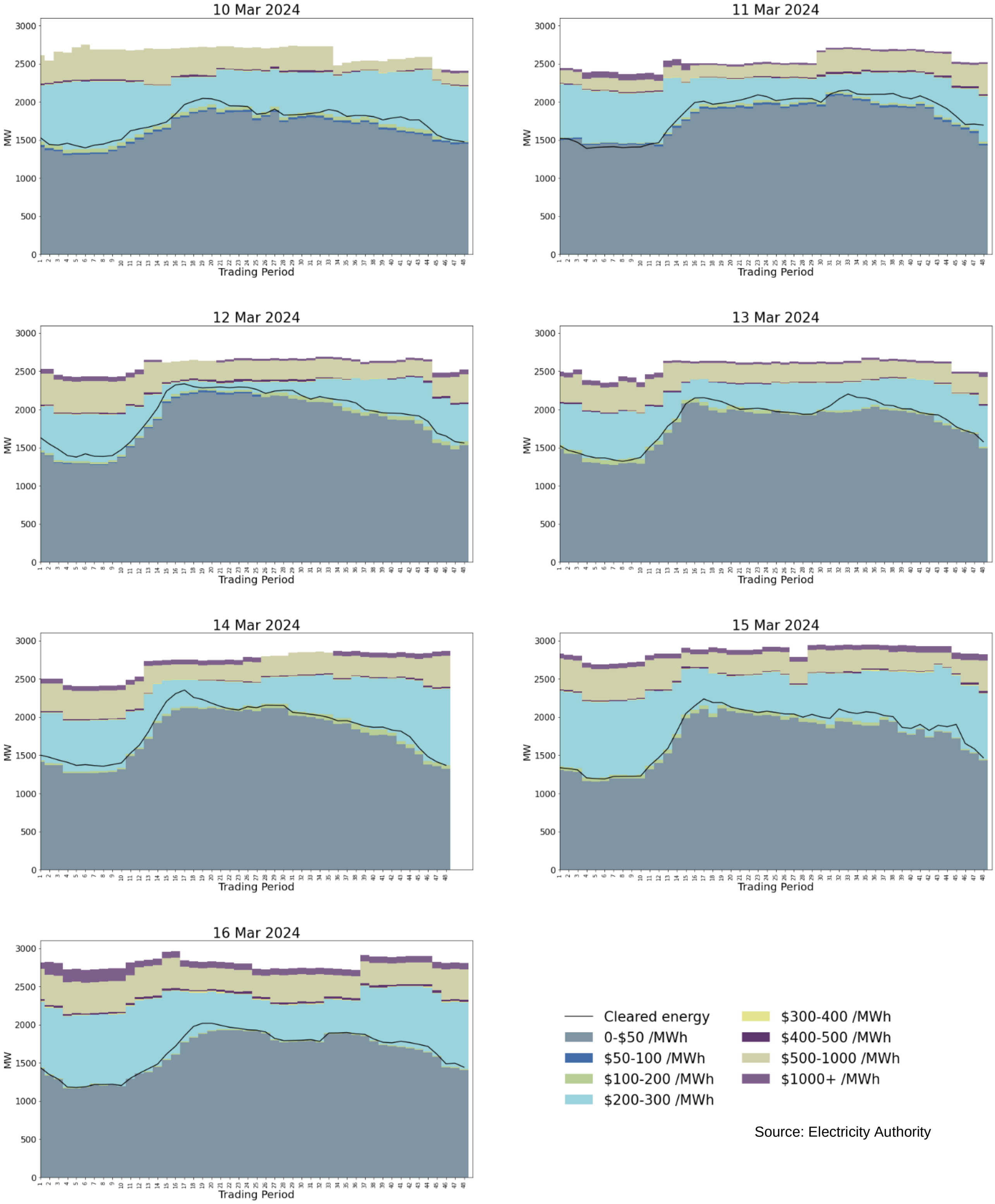
**Figure 22: North Island daily offer stacks[3]**




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 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 |
| **5/03/2024-6/03/2024** | 23,42,14 | Further analysis | N/A | N/A | SIR prices |
| **15/03/2024-16/03/2024** | Several | Further analysis | Mercury | Waikato hydro dams | Hydro offers |
| **16/03/2024** | 40-44 | Further analysis | Meridian | Multiple | Reserve offers |