7 April 2026

# Trading conduct report 29 March-4 April 2026

Market monitoring weekly report

# Trading conduct report 29 March-4 April 2026

## 1. Overview

1.1. This week the average spot price decreased by $25/MWh to $153/MWh. Lower prices this week are related to higher wind generation and low demand due to the Easter holiday weekend. National controlled storage increased slightly to 80% nominally full and 102% of the historical average for this time of the year.

## 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, it also singles 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. Between 29 March-4 April:

(a) The average spot price for the week was $153/MWh, a decrease of around $25/MWh compared to the previous week.

(b) 95% of prices fell between $57/MWh and $238/MWh.

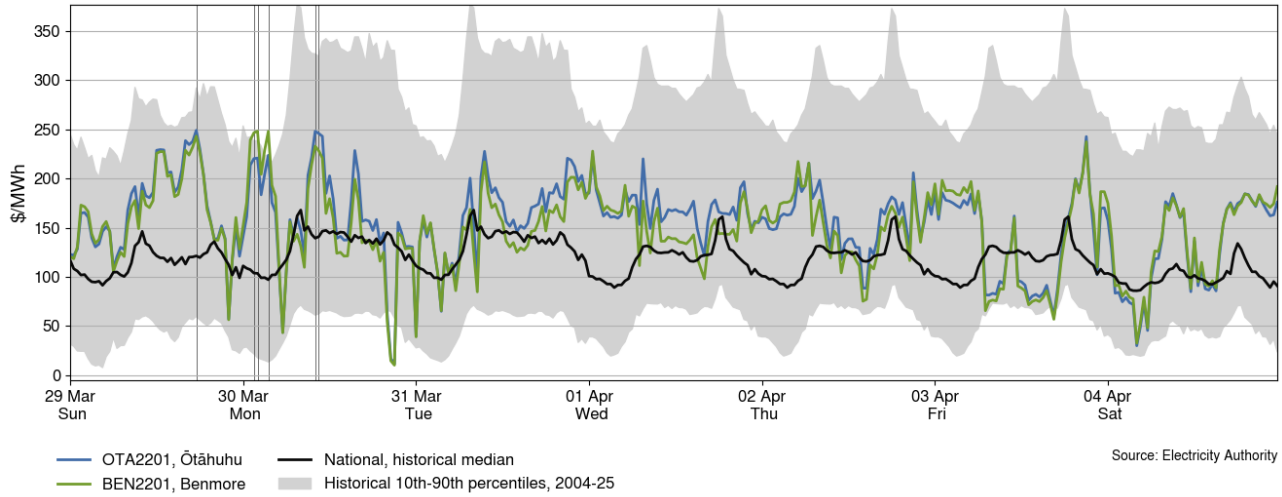
2.3. Higher wind generation and lower demand due to the Easter holiday weekend have contributed to lower prices this week.

2.4. The highest price at Ōtāhuhu this week was $249/MWh at 5.30pm on Sunday. During this time, demand was 84MW higher than forecast and intermittent generation was 95MW lower than forecast.

2.5. Several prices above $245/MWh also occurred at times on Monday, with intermittent generation between 22-143MW lower than forecast and demand between 76-133MW higher than forecast at these times.

2.6. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90$^{th}$ percentiles adjusted for inflation. Prices greater than quartile 3 (75$^{th}$ percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

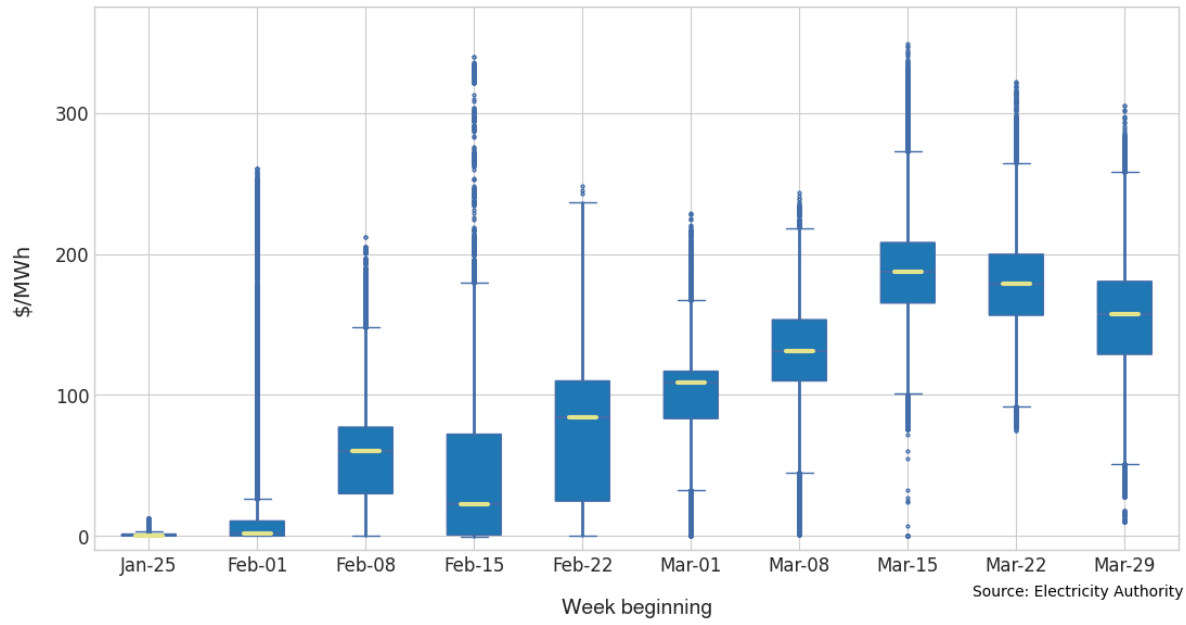
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 29 March-4 April**




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 blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.8. The distribution of spot prices this week was wider compared to the previous week. The median price was $157/MWh and most prices (middle 50%) fell between $129/MWh and $181/MWh.

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

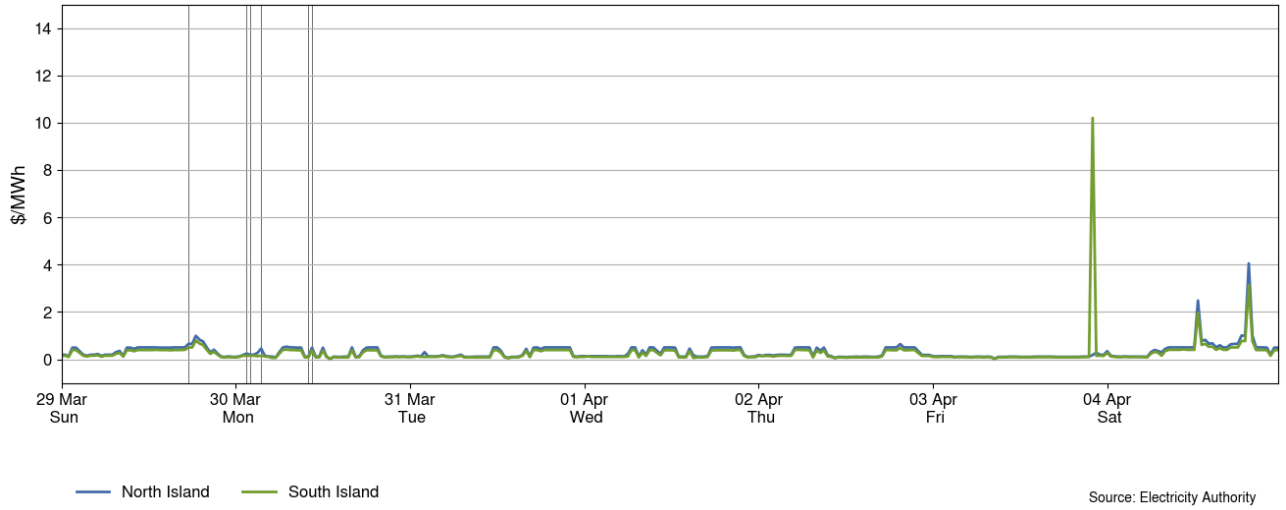



## 3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices across both the North and South Islands remained below $5/MWh this week, aside from one South Island price spike.

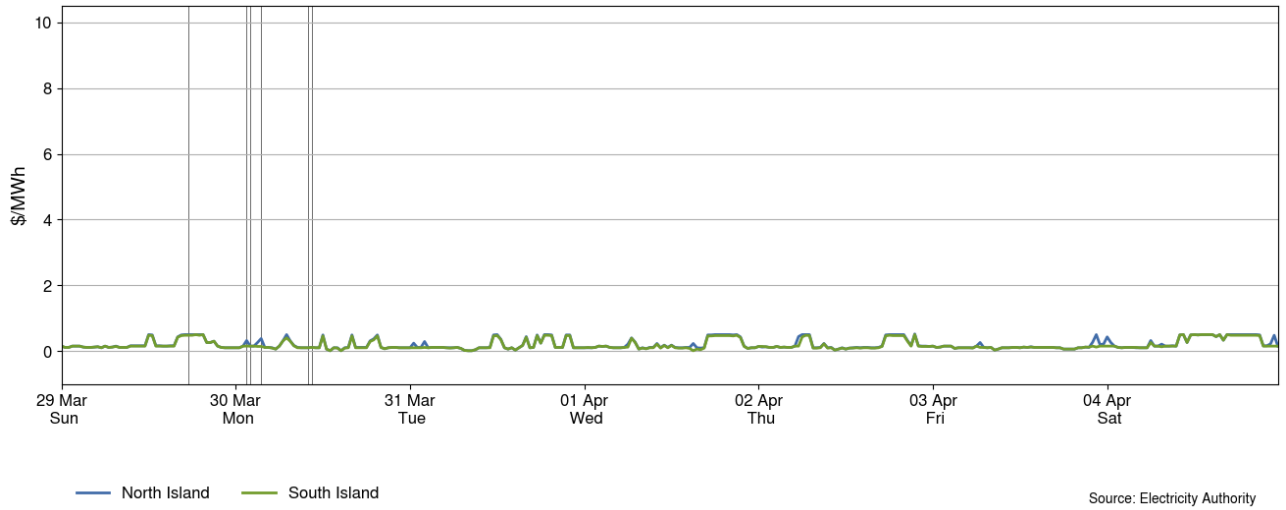
3.2. South Island FIR prices spiked to $10/MWh on Friday at 10.00pm during southward HVDC flow.

**Figure 3: Fast instantaneous reserve price by trading period and island, 29 March-4 April**




3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices across both the North and South Islands remained below $1/MWh this week.

**Figure 4: Sustained instantaneous reserve by trading period and island, 29 March-4 April**



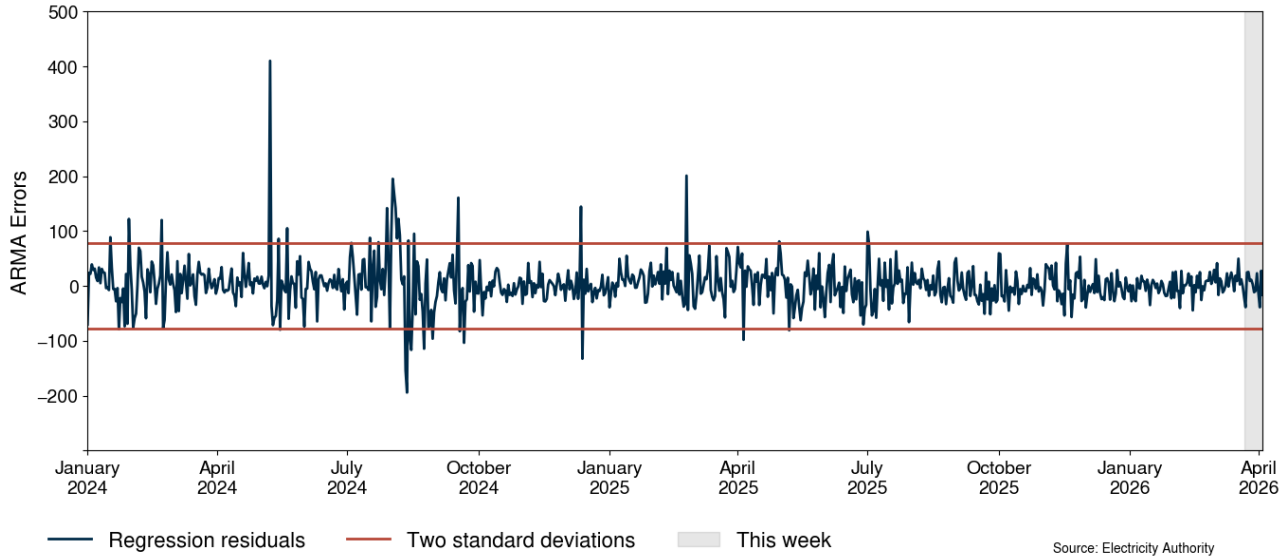

# 4. Regression residuals

4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot 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.

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 in the regression analysis.

4.3. This week, there were no residuals above or below two standard deviations, indicating that prices were similar to those predicted by the model.

**Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 4 April 2026**

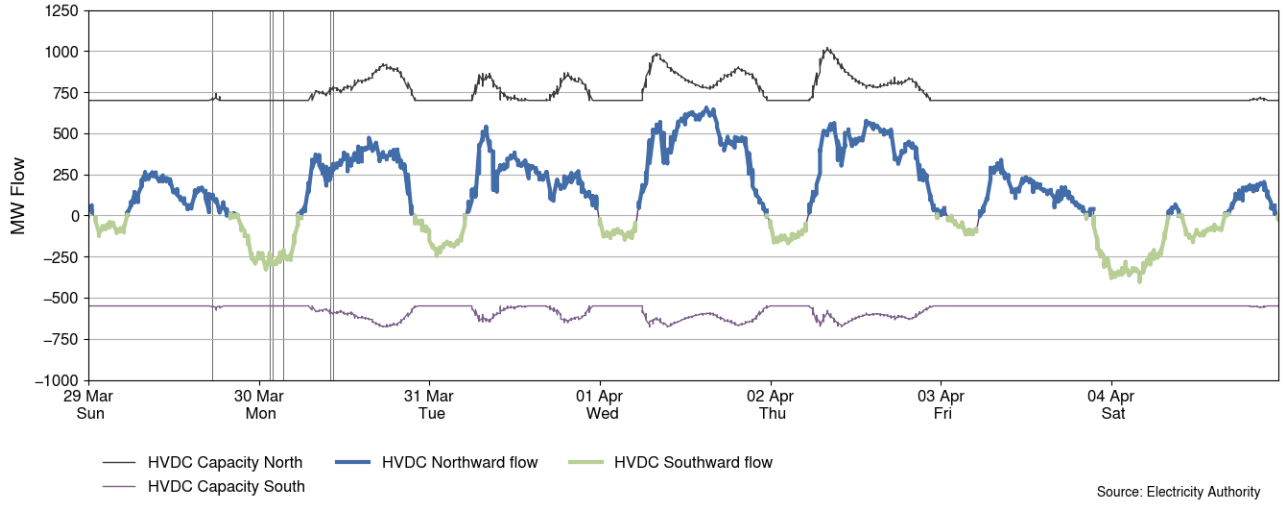



## 5. HVDC

5.1. Figure 6 shows the HVDC flow between 29 March-4 April. HVDC flows were mostly northward during the day and southward overnight, aside from a period of southward flow during the day on Saturday.

5.2. The highest northward HVDC flow of the week was 781MW on Wednesday at 3.00pm.

**Figure 6: HVDC flow and capacity, 29 March-4 April**




## 6. Demand

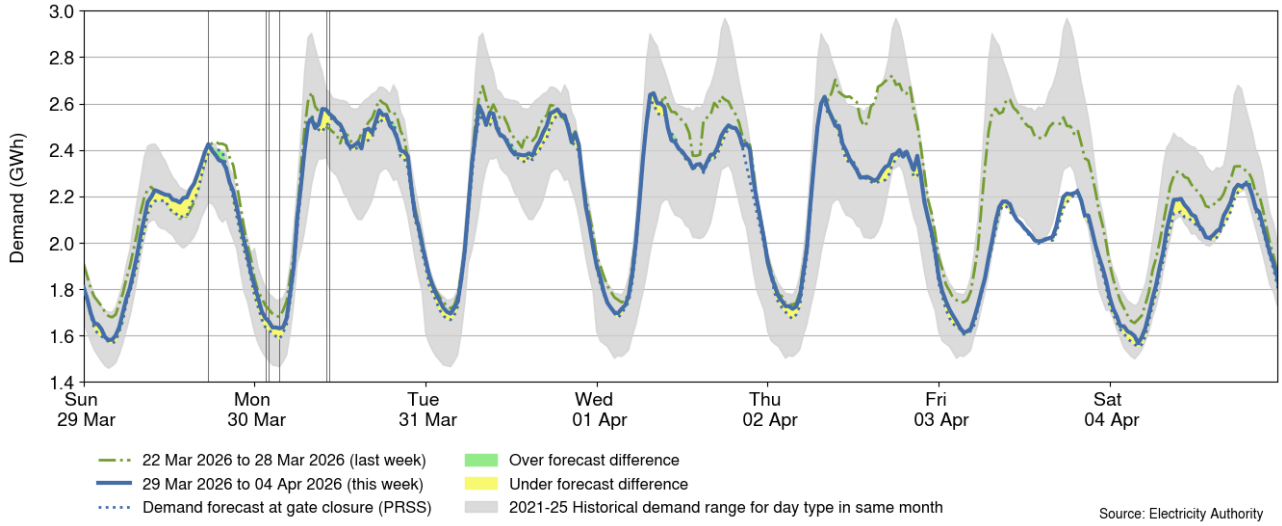
6.1. Figure 7 shows national demand between 29 March-4 April, compared to the historic range and the demand of the previous week.

6.2. Demand was mostly similar to the previous week between Sunday and Tuesday. On Wednesday and Thursday, demand was lower, aside from during the morning peaks.

Demand was also lower compared to the previous week from Friday onwards, with the Easter holiday weekend beginning.

6.3. The highest demand of the week was around 2.64GWh at 8.00am on Wednesday.

**Figure 7: National demand, 29 March-4 April compared to the previous week**

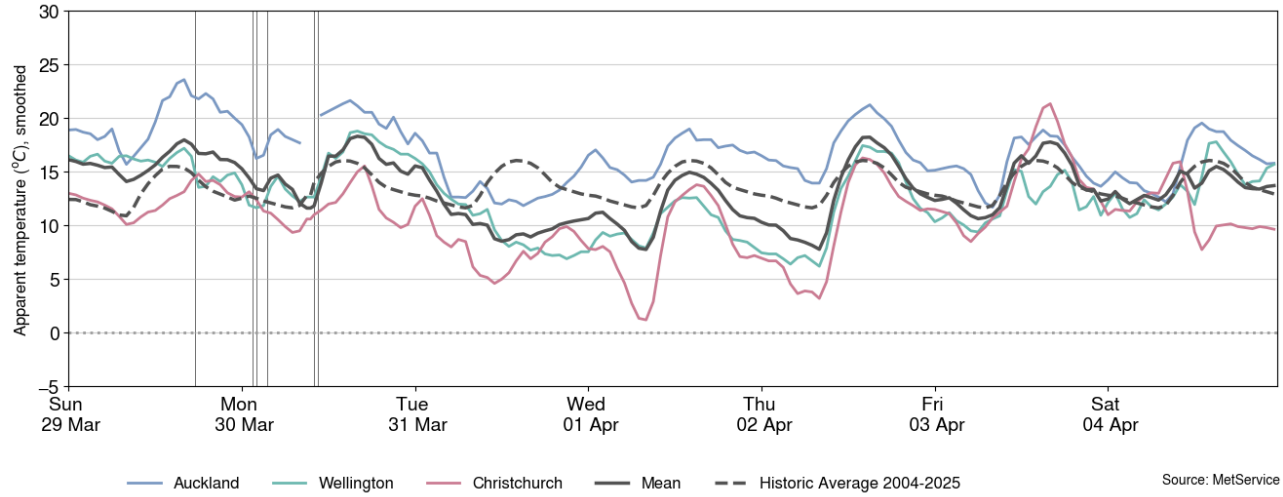



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 29 March-4 April. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.5. Apparent temperatures ranged from 12°C to 25°C in Auckland, 6°C to 19°C in Wellington, and 1°C to 22°C in Christchurch.

6.6. Note that data is missing for Auckland on Monday.

**Figure 8: Temperatures across main centres, 29 March-4 April**



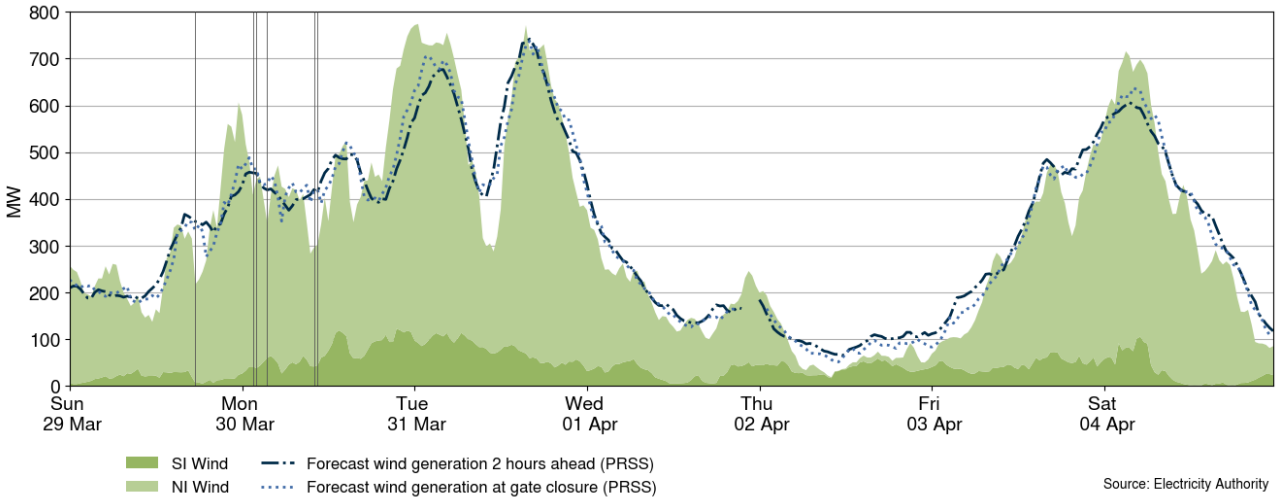
# 7. Generation

7.1. Figure 9 shows wind generation and forecast from 29 March-4 April. This week wind generation varied between 18MW and 774MW, with a weekly average of 325MW.

7.2. Wind generation increased from Sunday evening through to Tuesday, where wind dropped significantly before recovering shortly after. Following this, wind generation declined until Friday, increasing above 650MW by Saturday but declining again by Saturday evening.

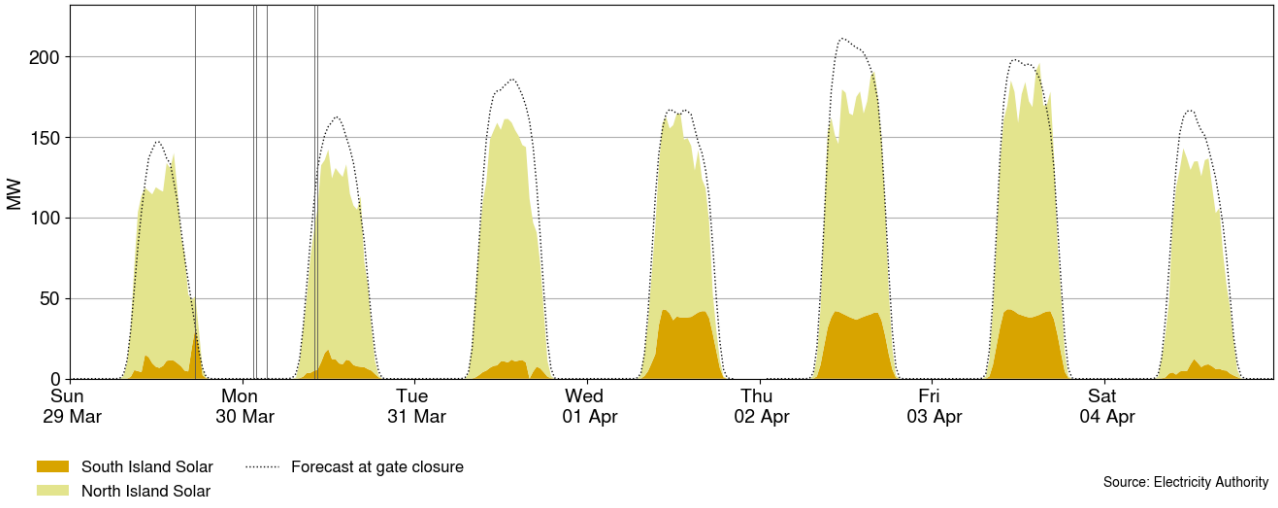
7.3. Note that forecast data is missing between trading periods 45 and 48 on Wednesday.

**Figure 9: Wind generation and forecast, 29 March-4 April**




7.4. Figure 10 shows grid connected solar generation from 29 March-4 April. Solar generation reached above 140MW each day this week, peaking at 3.00pm on Friday at 196MW.

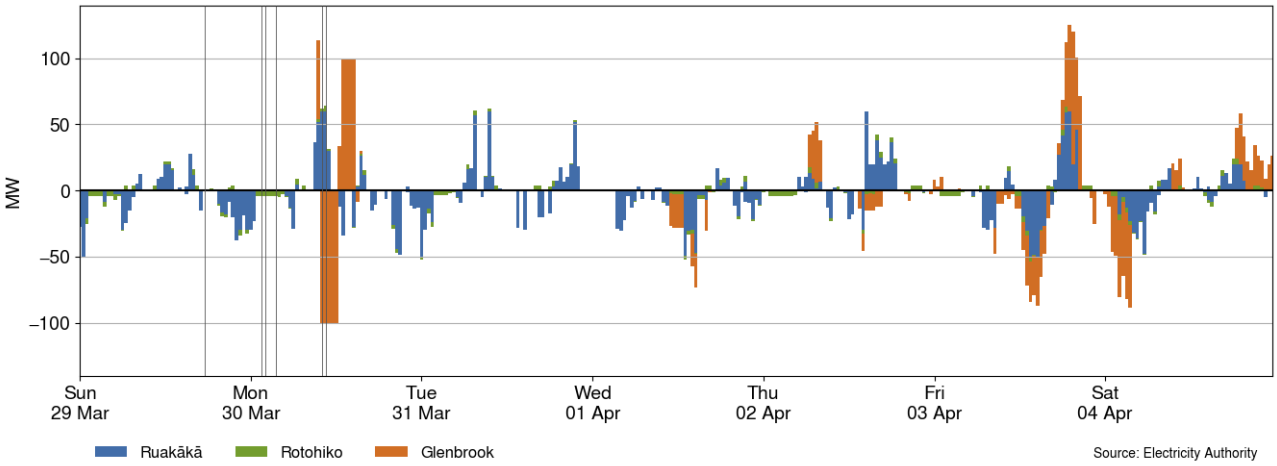
**Figure 10: Grid connected solar generation, 29 March-4 April**




7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.6. This week, the batteries mostly charged during times of relatively lower prices overnight or during the day. The batteries mostly discharged during higher prices during the day. The Glenbrook battery finished commissioning this week from Tuesday.

**Figure 11: Grid scale battery charge and discharge, 29 March-4 April**




7.7. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or intermittent generation is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and intermittent generation forecasting, the 1-hour ahead and the RTD intermittent generation and demand forecasts will rarely be the same. 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.

7.8. Several trading periods this week had marginal price differences greater than $50/MWh.

7.9. Sustained higher than forecast prices occurred on Sunday, Friday and Saturday during times when either wind and or demand varied from forecasts.

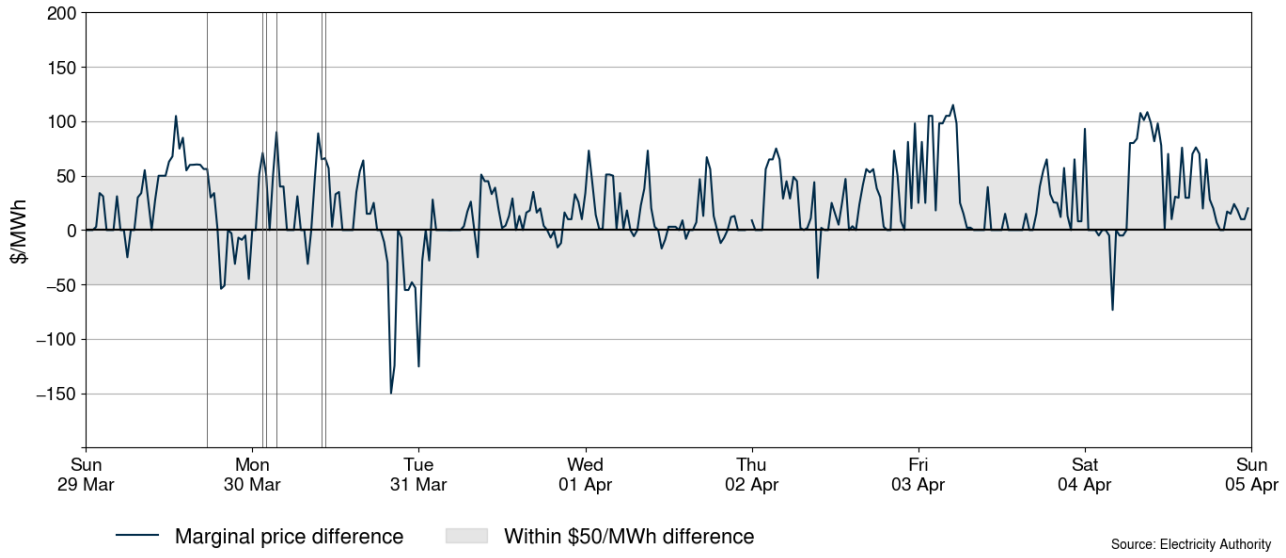
7.10. The maximum positive difference of $115/MWh occurred on Friday at 5.00am. At this time, demand was 60MW higher than forecast, and wind generation was 52MW lower than forecast.

7.11. The maximum negative difference of $150/MWh occurred on Monday at 8.00pm. At this time, demand was 17MW lower than forecast and wind generation was 86MW higher than forecast.

7.12. Note that data for trading period 48 is missing on Wednesday.

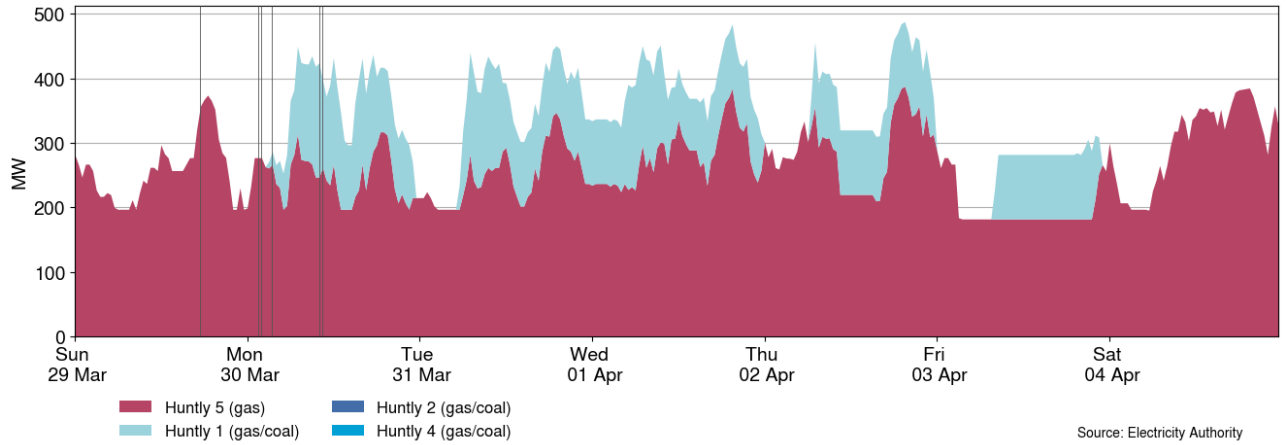
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

**Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead intermittent generation and demand forecast inaccuracies, 29 March-4 April**



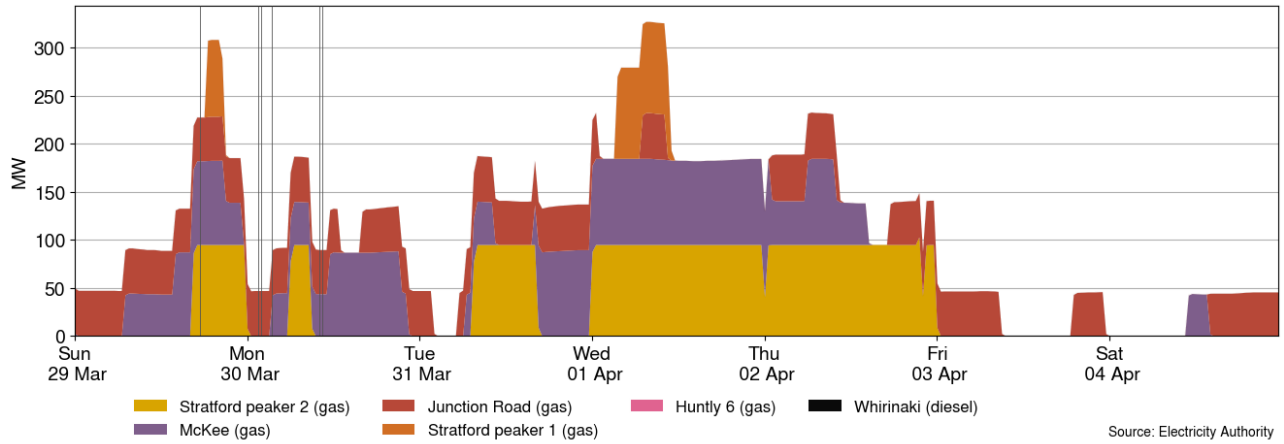

7.13. Figure 13 shows the generation of thermal baseload between 29 March-4 April. Huntly 5 ran continuously this week, with Huntly 1 running at times between Monday and Friday.

**Figure 13: Thermal baseload generation, 29 March-4 April**



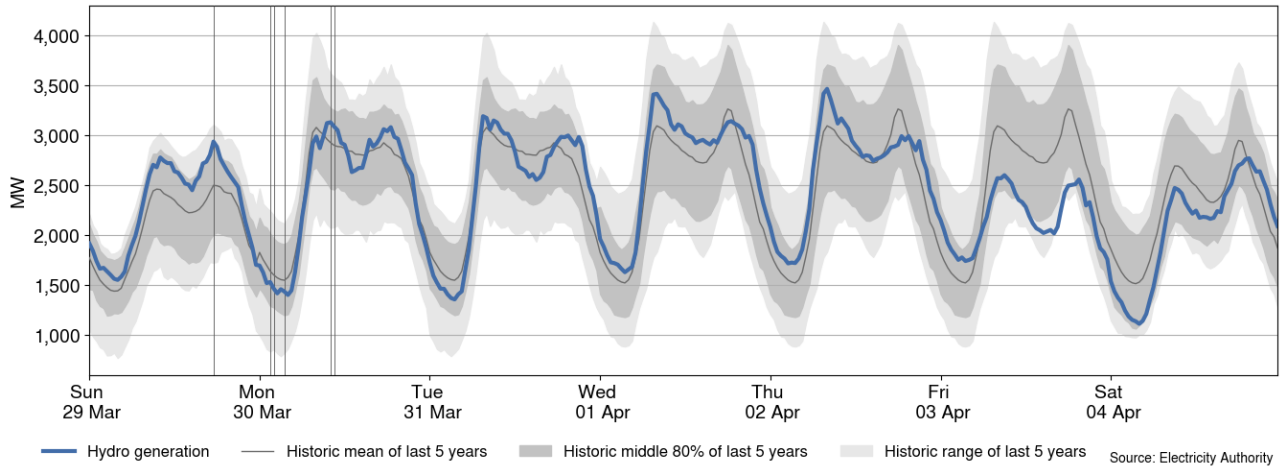

7.14. Figure 14 shows the generation of thermal peaker plants between 29 March-4 April. Junction Road ran at times each day this week, with McKee running at times each day aside from Friday. Stratford peaker 2 ran between Sunday and Thursday, while Stratford peaker 1 ran on Wednesday.

**Figure 14: Thermal peaker generation, 29 March-4 April**




7.15. Figure 15 shows hydro generation between 29 March-4 April. Hydro generation was often higher compared to the historic mean on Sunday. Between Monday and Thursday hydro generation was mostly similar to the historic mean, aside from during the Wednesday and Thursday morning peaks where generation was higher. Hydro generation was mostly below the historic mean on Friday and Saturday.

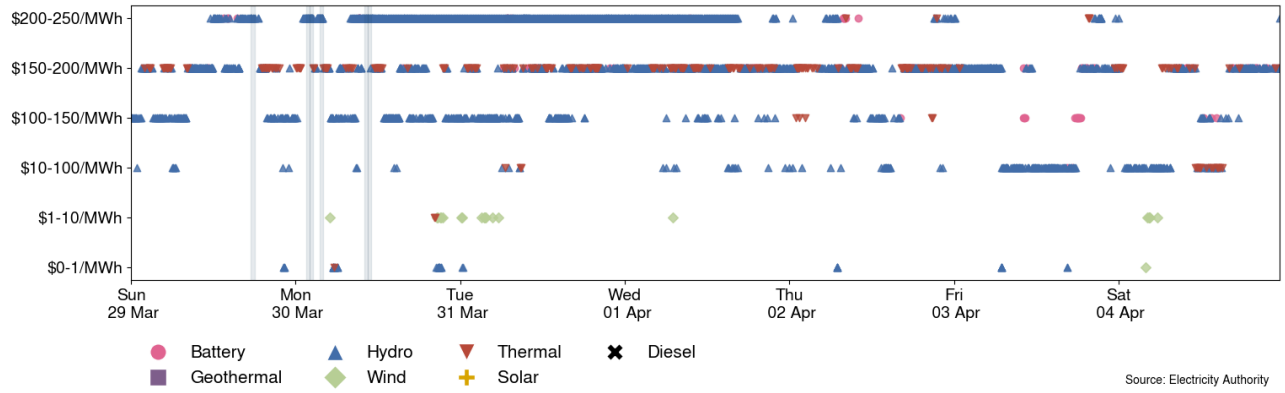
**Figure 15: Hydro generation, 29 March-4 April**




7.16. Figure 16 shows the distribution of marginal prices this week and what generation technology produced each marginal price. Note there can be multiple marginal plants for each 5-minute period.

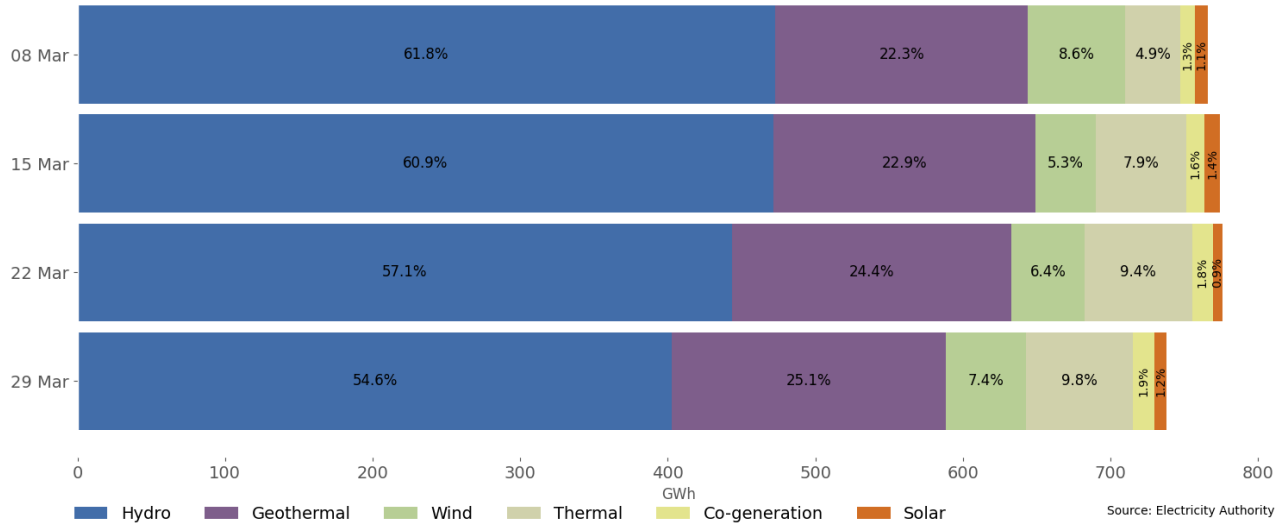
7.17. The highest prices were set by Contact hydro on Sunday. The most common technology setting prices this week was hydro generation, with thermal generation the second most common. Most marginal prices were between $150-200/MWh.

**Figure 16: Prices of marginal generation, 29 March-4 April**




7.18. As a percentage of total generation, between 29 March-4 April, total weekly hydro generation was 54.6%, geothermal 25.1%, wind 7.4%, thermal 9.8%, co-generation 1.9%, and solar (grid connected) 1.2%, as shown in Figure 17.

**Figure 17: Total generation by type as a percentage each week, between 8 March and 4 April**




# 8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 29 March-4 April ranged between ~1,065MW and ~2,213MW. Figure 19 shows the thermal generation capacity outages.

**Figure 18: Total MW loss from generation outages, 29 March-4 April**

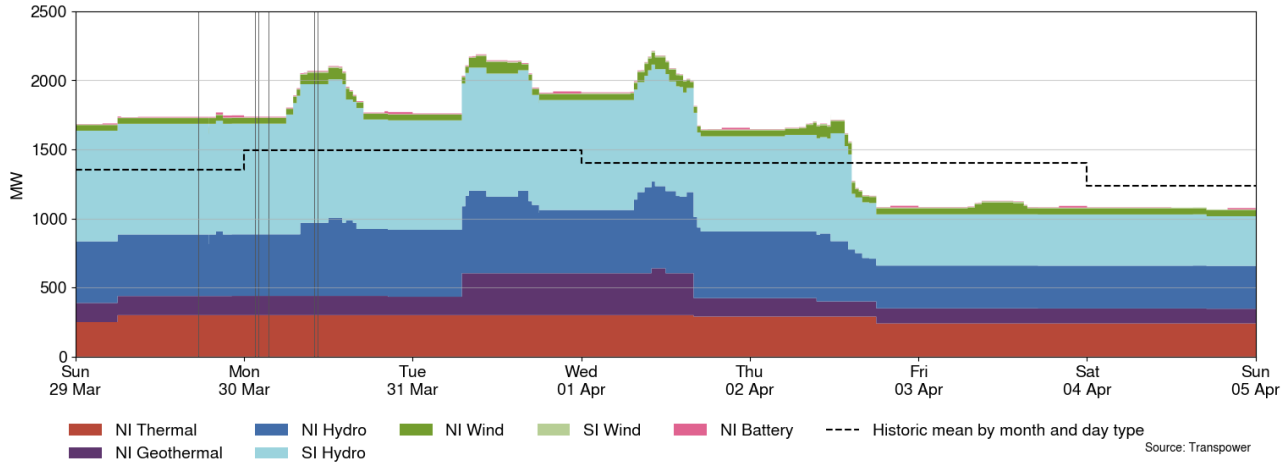
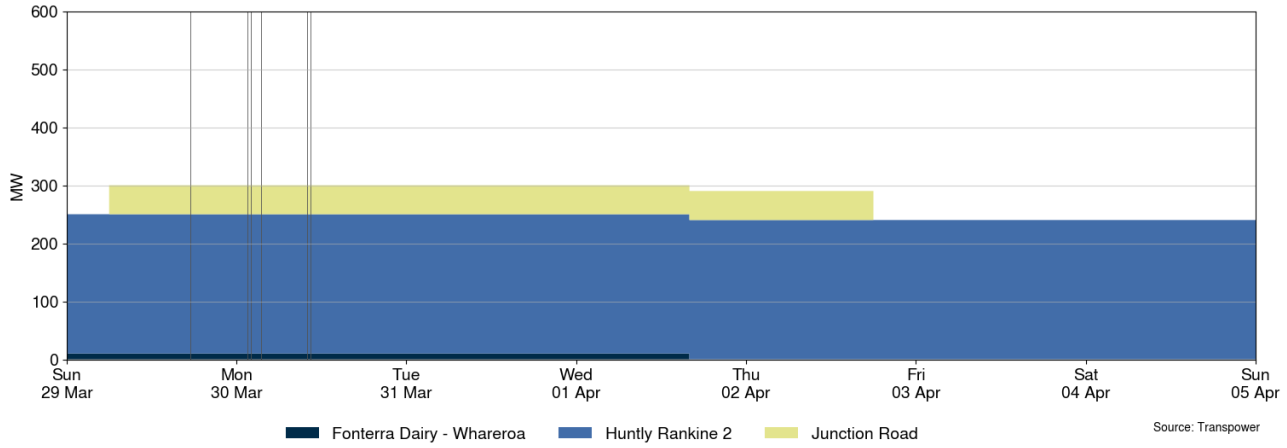



**Figure 19: Total MW loss from thermal outages, 29 March-4 April**




8.2. Notable outages include:

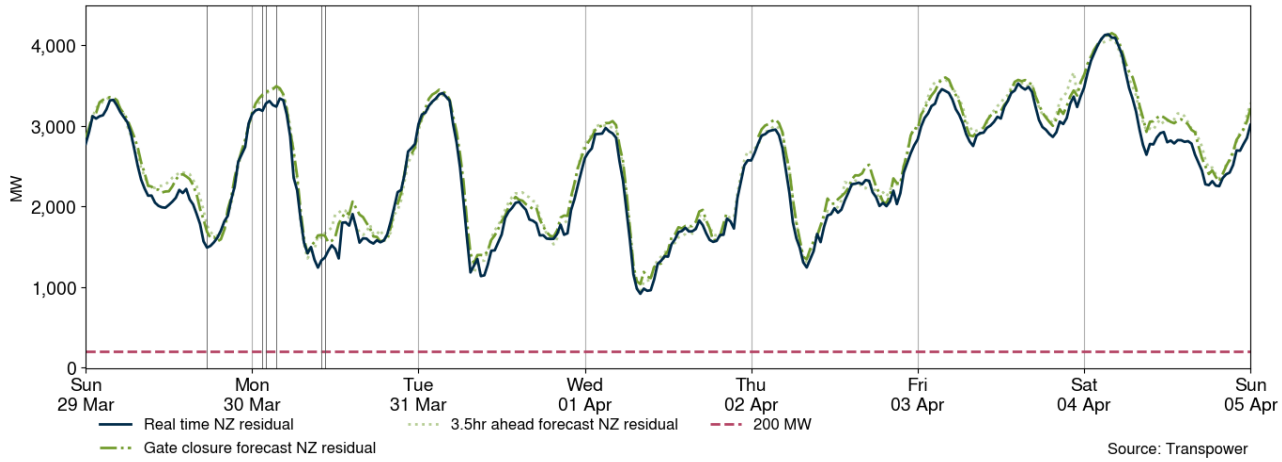
| Plant | Partial or Full | End Date |
|---|---|---|
| Manapōuri unit 5 | Full | 30 March 2026 |
| Tauhara | Full | 1 April 2026 |
| Benmore unit 5 | Full | 2 April 2026 |
| Huntly 2 | Full | 28 April 2026 |
| Rangipō unit 6 | Full | 28 April 2026 |
| Clyde unit 2 | Full | 1 May 2026 |
| Manapōuri unit 4 | Full | 30 June 2026 |
| Roxburgh unit 8 | Full | 2 September 2026 |

# 9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 29 March-4 April. 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 forecast low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.

9.2. Overall, national residuals were healthy this week. The lowest national residual was 918MW on Wednesday at 8.00am.

**Figure 20: National generation balance residuals, 29 March-4 April**




# 10. Storage/fuel supply

10.1. Figure 21 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. As of 4 April, national controlled storage was 80% nominally full and 102% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (83% full[2]) is close to its historic mean, while Lake Takapō (76% full) is below its historic mean.

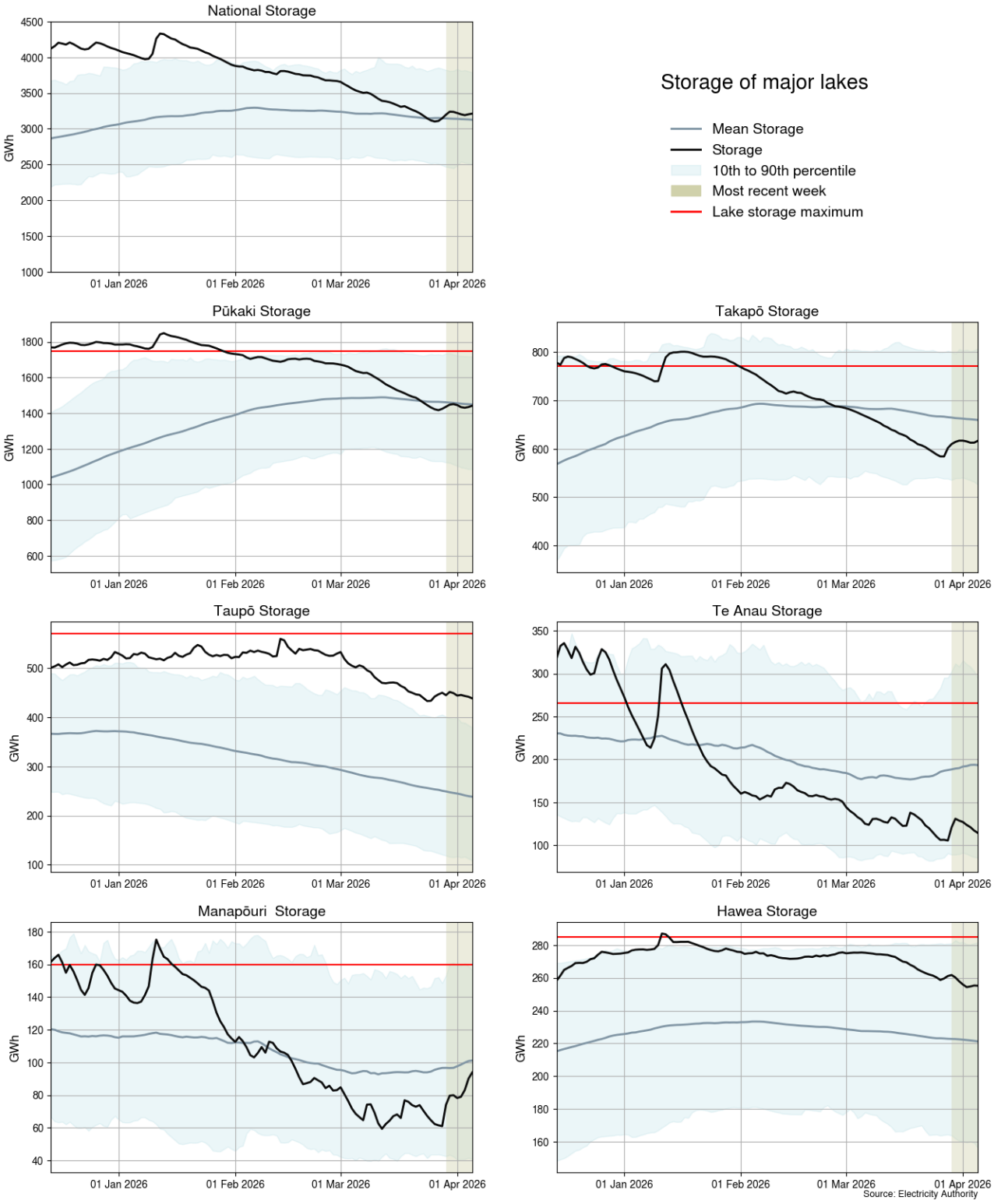
10.4. Storage at Lake Te Anau (42% full) is below its historic mean, with Lake Manapōuri (62% full) also below its historic mean.

10.5. Storage at Lake Taupō (76% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (89% full) is below its historic 90th percentile but remains above its historic mean.

[2] Percentage full values sourced from NZX Hydro.

**Figure 21: Hydro storage**




# 11. Prices versus estimated costs

11.1. 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).

11.2. 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.

11.3. Figure 22 shows an estimate of thermal SRMCs as a monthly average up to 1 March 2026. The SRMCs for all thermal-fuelled generation have increased, with the SRMC for diesel-fuelled generation increasing the most.

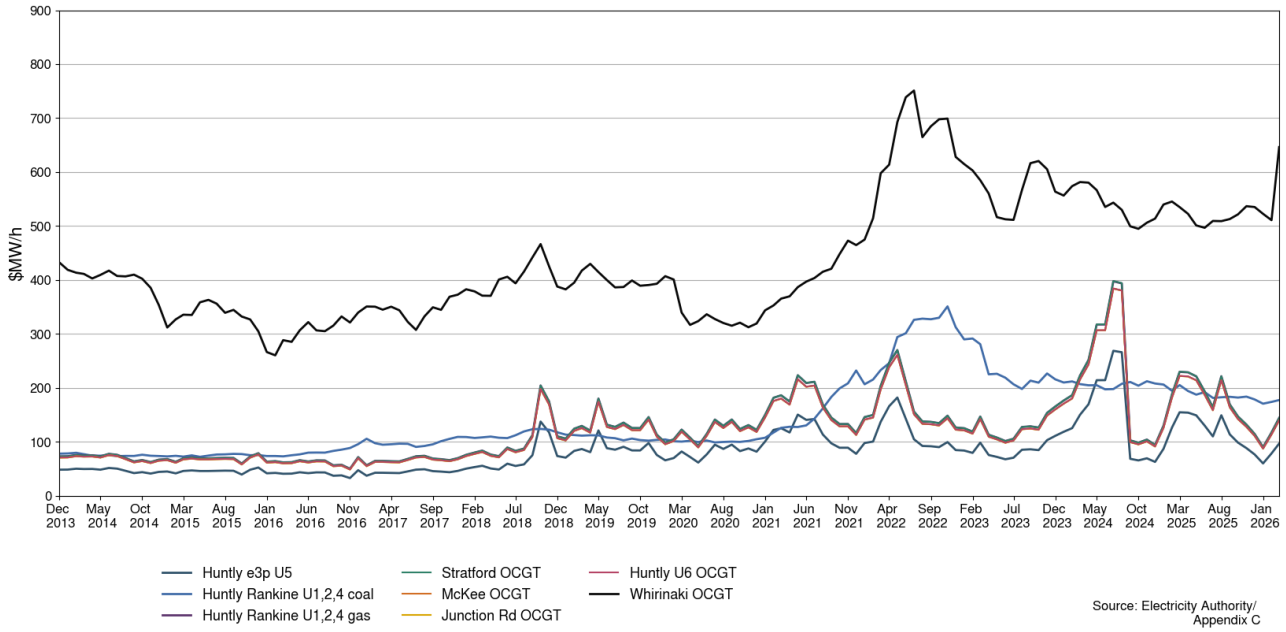
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$177/MWh. The cost of running the Rankines on gas is ~$144/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $97/MWh and $144/MWh.

11.6. The SRMC of Whirinaki has increased by $111/MWh to ~$646/MWh following ongoing international supply issues.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

**Figure 22: Estimated monthly SRMC for thermal fuels**



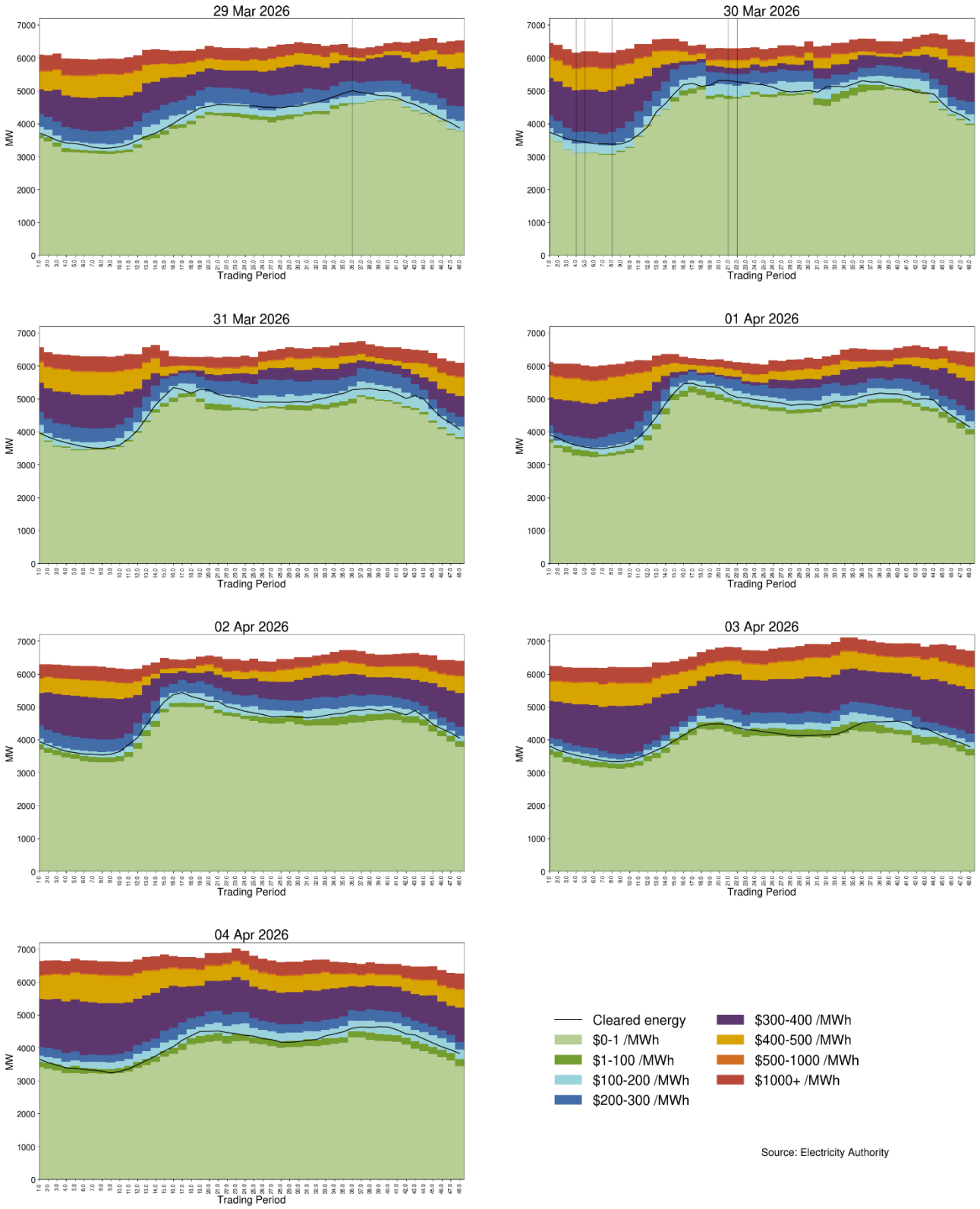

## 12. Offer behaviour

12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Most offers this week cleared below $300/MWh, with energy clearing below $200/MWh on Saturday.

12.3. Some high-priced Meridian hydro offers were priced up from the $300-400/MWh range into the $400-500/MWh range from Wednesday this week and Meridian hydro offers in the $300-400/MWh range also increased from Friday.

**Figure 23: Daily offer stacks**



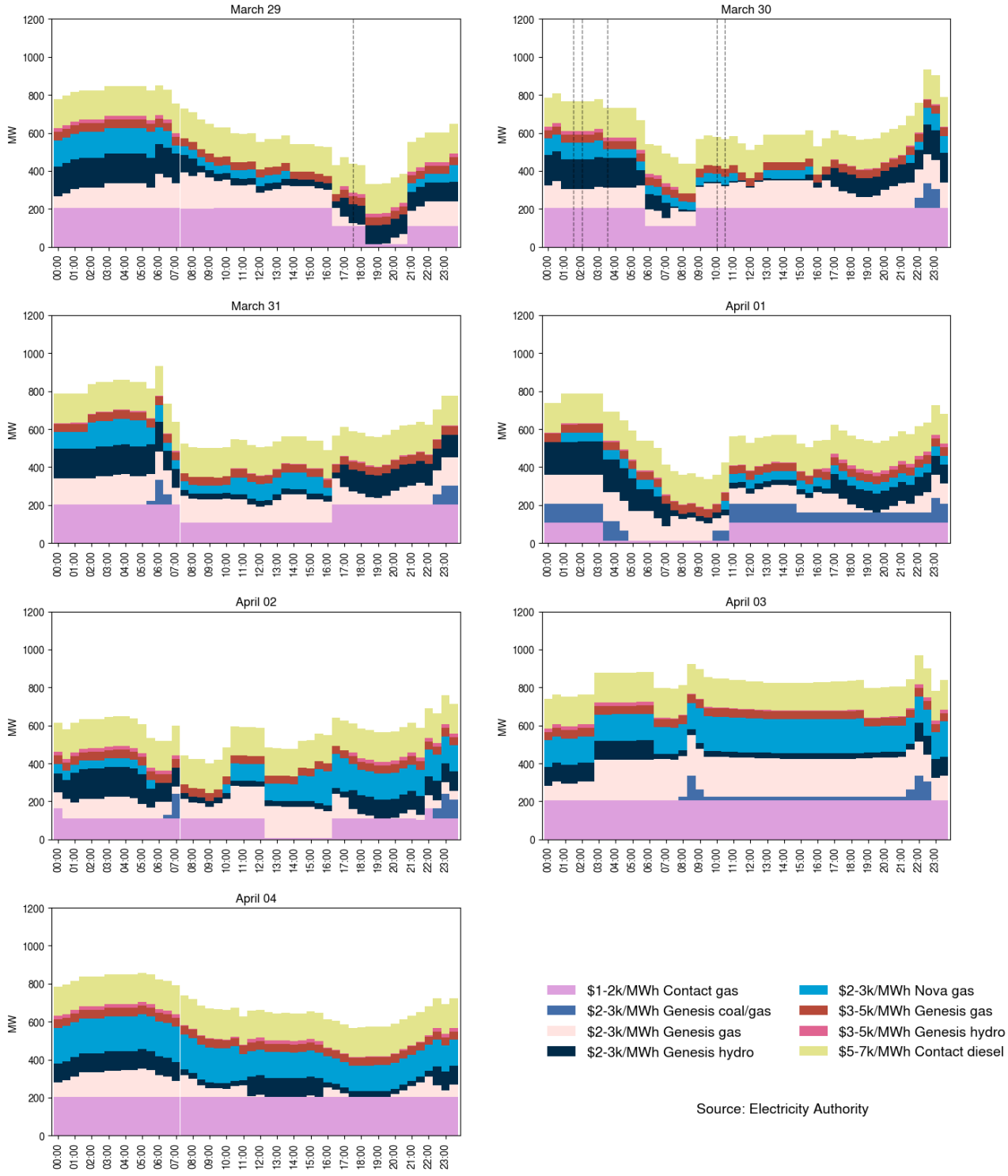

12.4. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.5. If forecast prices are lower than thermal operating costs, this signals some generators may not be needed in that half-hourly trading period. Thermal generators may then price their units high, as they aren't expecting to run. These high prices reflect increased operating

costs of running for only a short time. So, if demand is unexpectedly high, intermittent generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.6. On average 657MW per trading period was priced above $1,000/MWh this week, which is roughly 12% of the total energy available.

**Figure 24: High priced offers**



# 13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

**Table 1: Trading periods identified for further analysis**

| Date | Trading period | Status | Participant | Location | Enquiry topic |
|---|---|---|---|---|---|
| **8/12/2025-11/12/2025** | Several | Further analysis | Contact/Manawa | Coleridge, Cobb, and Matahina | Offers |
| **04/02/2026-05/02/2026** | Several | Further analysis | Contact/Manawa | Matahina | Offers |
| **03/03/2026-04/03/2026** | Several | Further analysis | Genesis | Waikaremoana | Offers |
| **13/03/2026** | 27-31 | Further analysis | Genesis | Huntly 1 and 4 | Offers |
| **13/03/2026** | 27-30 | Further analysis | Contact | Clyde | Offers |