20 April 2026

# Trading conduct report 12-18 April 2026

Market monitoring weekly report

# Trading conduct report 12-18 April 2026

## 1. Overview

1.1. This week the average spot price decreased by $48/MWh to $69/MWh. Lower prices this week are related to higher levels of wind generation, as well as higher hydro inflows. National controlled storage has increased to 83% nominally full and 109% of the historical average for this time of 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 12-18 April:

(a) The average spot price for the week was $69/MWh, a decrease of around $48/MWh compared to the previous week.

(b) 95% of prices fell between $0.52/MWh and $181/MWh.

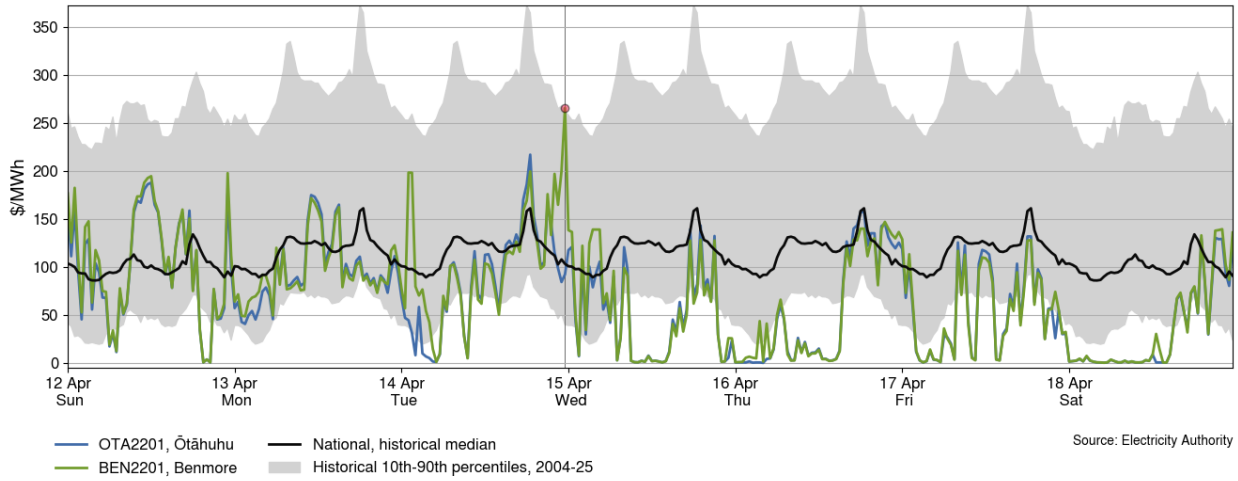
2.3. Prices have decreased this week due to high levels of wind generation and higher hydro inflows.

2.4. On Tuesday at 11.30pm, there was a price spike at Benmore to $266/MWh. At the same time, the price at Ōtāhuhu was $92/MWh. At this time, demand was 58MW higher than forecast, and intermittent generation was 145MW lower than forecast. North Island constraints prevented the HVDC from transferring more upper North Island generation.

2.5. Wednesday, Thursday and Saturday share a trend of low pricing in the morning and price spiking in the afternoon. The low prices are likely set by the high intermittent generation, and the price spikes are likely a result of large wind generation forecasting errors.

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.

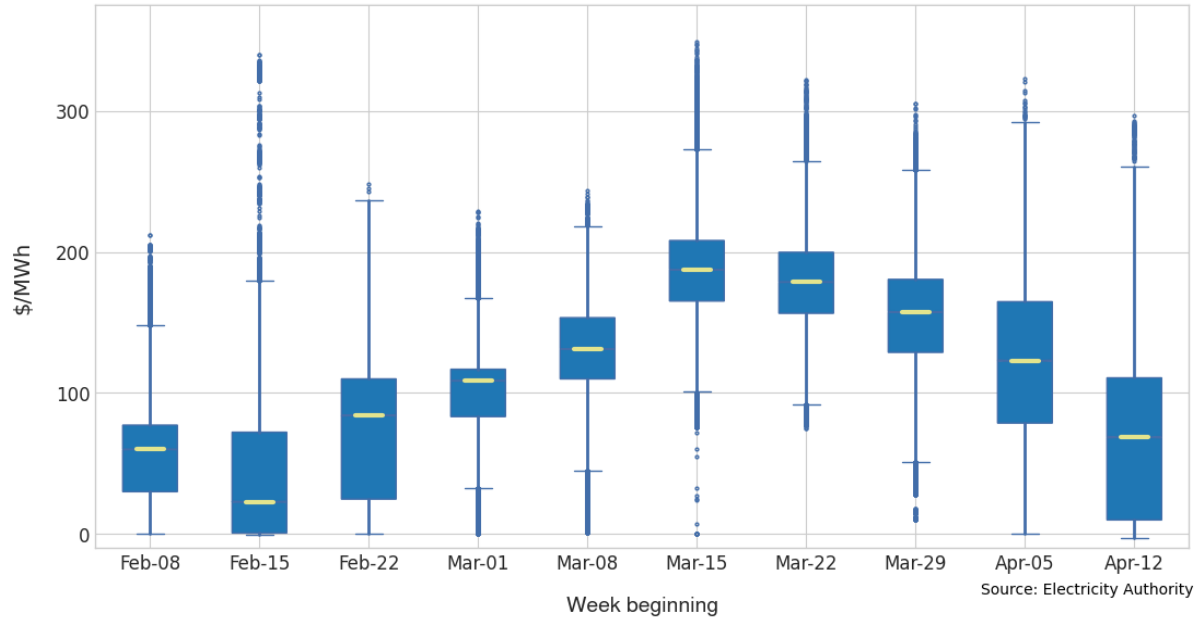
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 12-18 April**




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 lower than the previous week. The median price was $65/MWh and most prices (middle 50%) fell between $6/MWh and $109/MWh.

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




## 3. Reserve prices

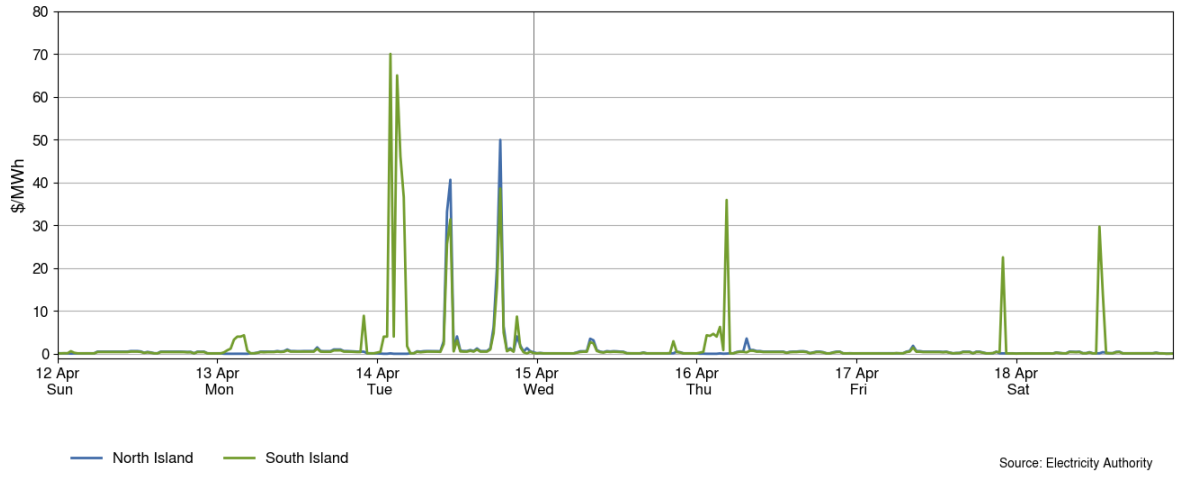
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in **Figure 3**. FIR prices remained mostly below $10/MWh, aside from several spikes throughout the week.

3.2. South Island FIR prices reached up to $70/MWh between 2.00am to 4.00am on Tuesday, with North Island FIR prices remaining around $0.10/MWh at the same time. During this time, the HVDC was flowing over 500MW southward and was setting the risk.

3.3. On Tuesday, North Island and South Island FIR prices also spiked above $26/MWh between 10.30am and 11.00am and at 6.30pm. During this time, Huntly 5 was the risk setter.

3.4. Other South Island FIR prices spikes occurred later in the week during periods of southward HVDC flow.

**Figure 3: Fast instantaneous reserve price by trading period and island, 12-18 April**

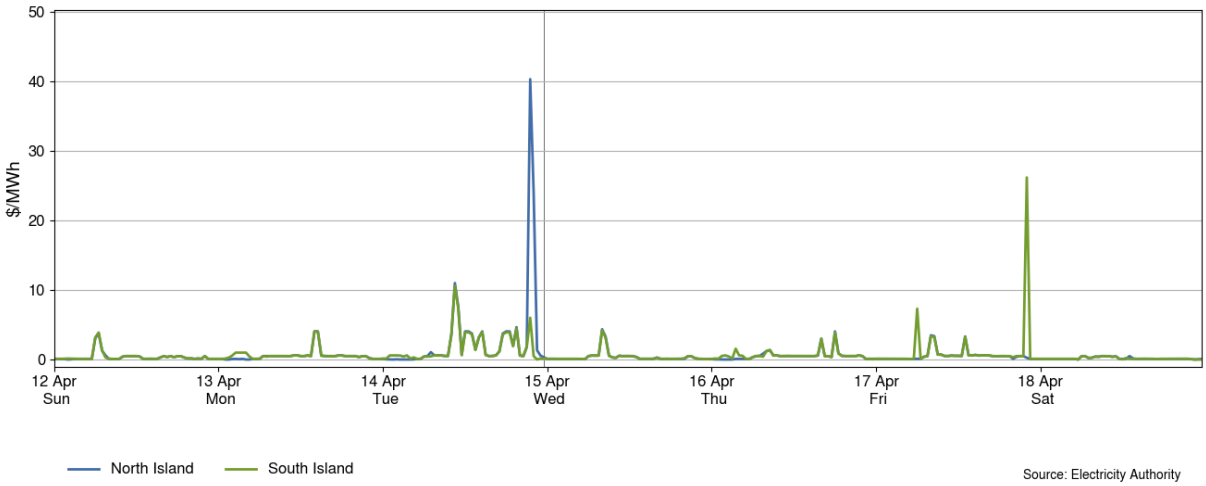



3.5. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices remained mostly below $15/MWh this week, aside from one North Island price spike on Tuesday and one South Island price spike on Friday.

3.6. North Island SIR prices reached $40/MWh at 9.30pm on Tuesday. The reserve required to cover the risk set by Huntly 5 increased during this time.

3.7. South Island SIR prices reached $26/MWh at 10.00pm on Friday during southward HVDC flow.

**Figure 4: Sustained instantaneous reserve by trading period and island, 12-18 April**



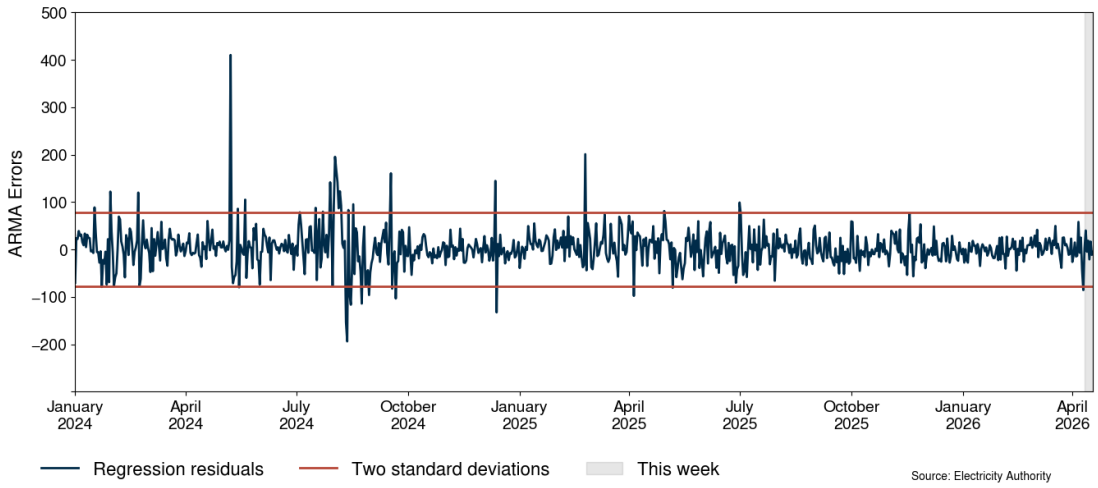
# 4. Regression residuals

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 - 18 April 2026**




# 5. HVDC

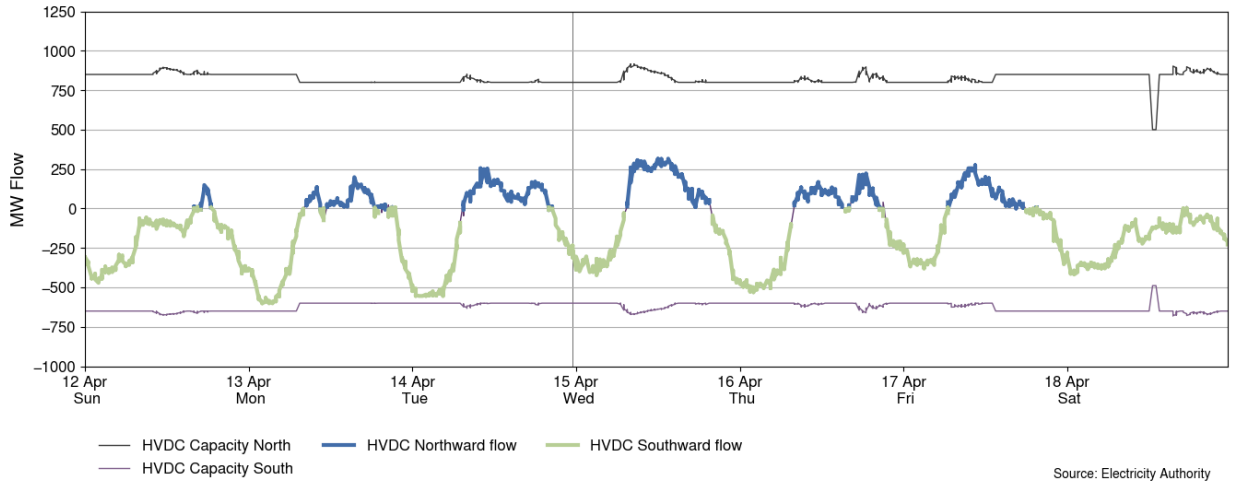
5.1. Figure 6 shows the HVDC flow between 12-18 April. Because of high levels of wind generation, HVDC flows were mostly southward through the week, with northward flow occurring during the day until Saturday.

5.2. The highest northward flow occurred on Wednesday at 12.00pm with a flow of around 316MW.

5.3. The highest southward flow occurred on Monday at 2.00am with a flow of around 601MW.

5.4. No northward flow occurred on Saturday 18th April due to high wind generation, and lower demand occurring on the weekend.

**Figure 6: HVDC flow and capacity, 12-18 April**



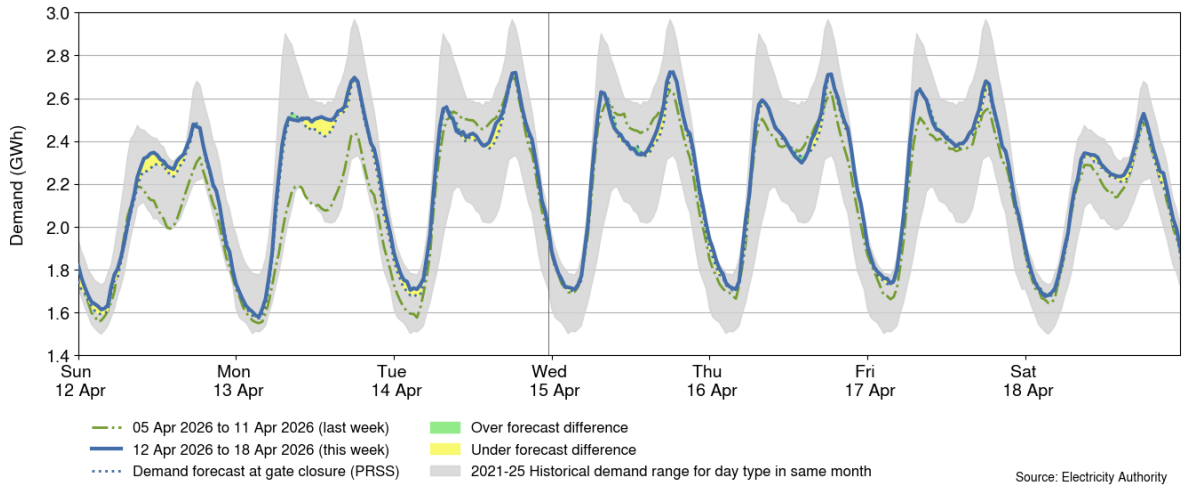

# 6. Demand

6.1. Figure 7 shows national demand between 12-18 April, compared to the historic range and the demand of the previous week.

6.2. On Sunday and Monday, demand was higher than the previous week due to the Easter holidays in the previous week. Demand was otherwise similar to the previous week.

6.3. On Sunday and Monday, demand was higher than forecast at times.

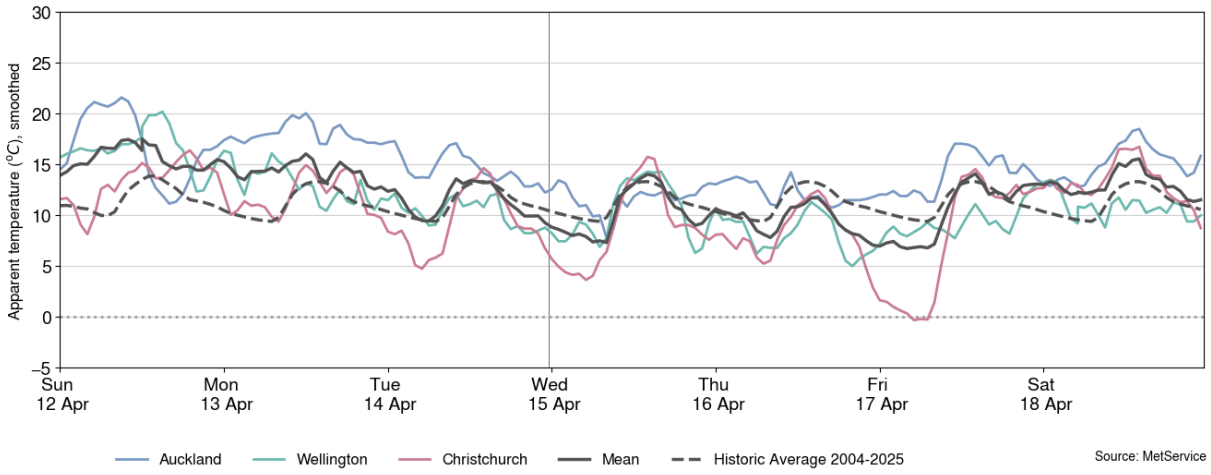
**Figure 7: National demand, 12-18 April compared to the previous week**




6.4. Figure 8 shows the hourly apparent temperature at main population centres from 12-18 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 5°C to 22°C in Auckland, 5°C to 20°C in Wellington, and 0°C to 17°C in Christchurch.

**Figure 8: Temperatures across main centres, 12-18 April**



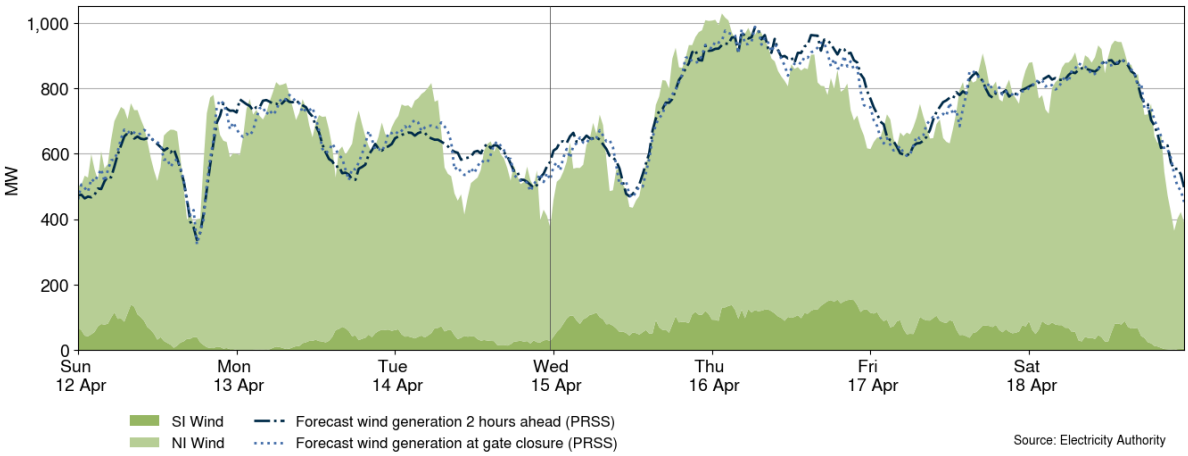

# 7. Generation

7.1. Figure 9 shows wind generation and forecast from 12-18 April. This week wind generation varied between 364MW and 1,028MW, with a weekly average of 708MW.

7.2. Wind generation was high overall with the daily average well above 350MW every day this week.

7.3. Wind generation forecasting errors occurred throughout the week. Wind forecasting errors were the result of an amalgamation of errors across multiple wind farms. Wind farms Harapaki and Waipipi were consistent contributors to larger over and under forecasting errors. Wind farms West Wind 1 and Te Āpiti contributed larger over and under forecasting errors on Sunday 12th of April.

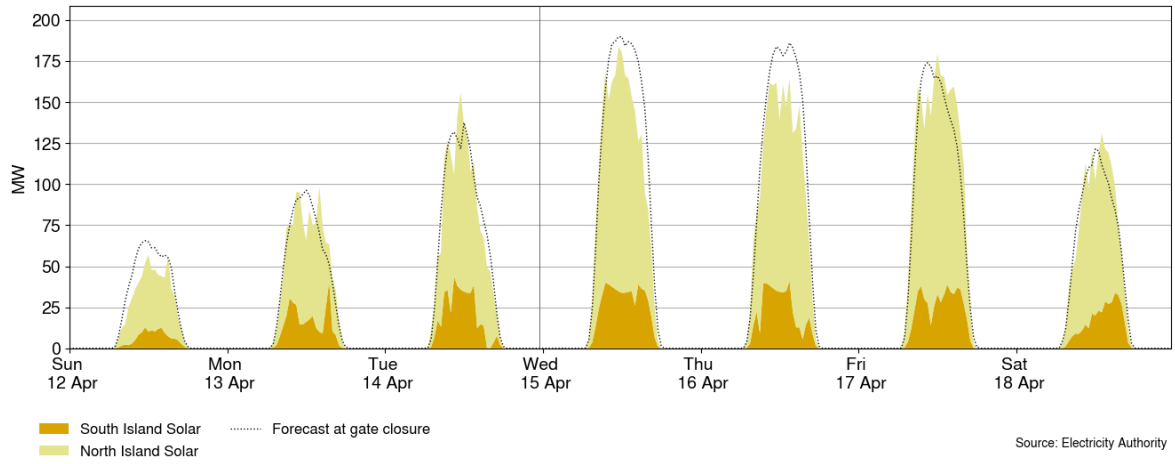
**Figure 9: Wind generation and forecast, 12-18 April**




7.4. Figure 10 shows grid connected solar generation from 12-18 April. Solar generation was low on Sunday (averaging 30MW) and Monday (averaging 53MW), and high on Wednesday, Thursday and Friday averaging at around 100MW. Solar generation averaged around 70MW on Tuesday and Saturday. Solar generation peaked at 138MW on Friday at 11.00am.

7.5. More noticeable solar generation over forecasting errors occurred on Wednesday and Thursday. Two large over forecasting errors, at around 50MW, occurred at 3.30 pm on Wednesday and 2.00 pm on Thursday.

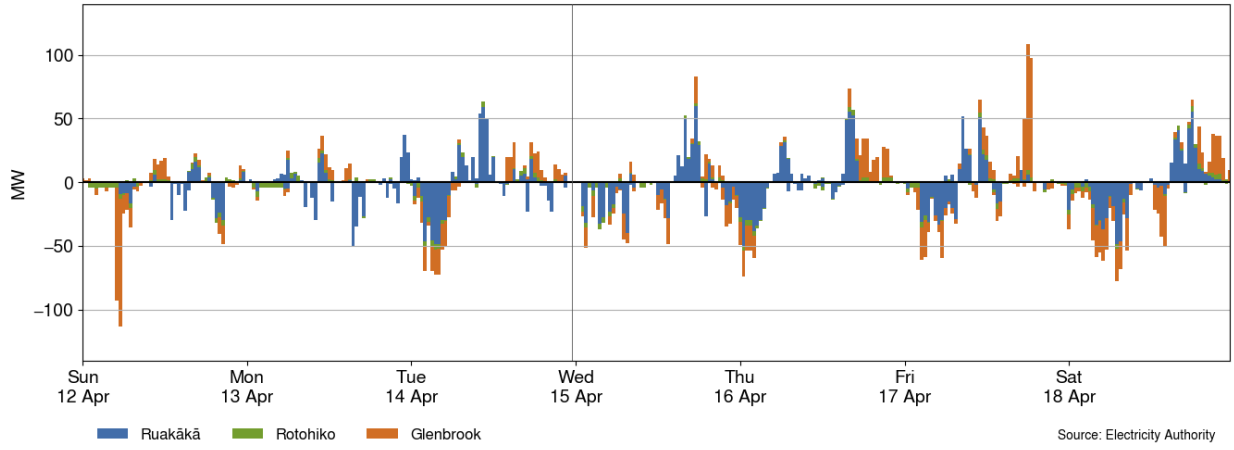
**Figure 10: Grid connected solar generation, 12-18 April**




7.6. 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.

7.7. 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. None of the batteries discharged during the price spike at 11.30pm on Tuesday.

**Figure 11: Grid scale battery charge and discharge, 12-18 April**




7.8. 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

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

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.

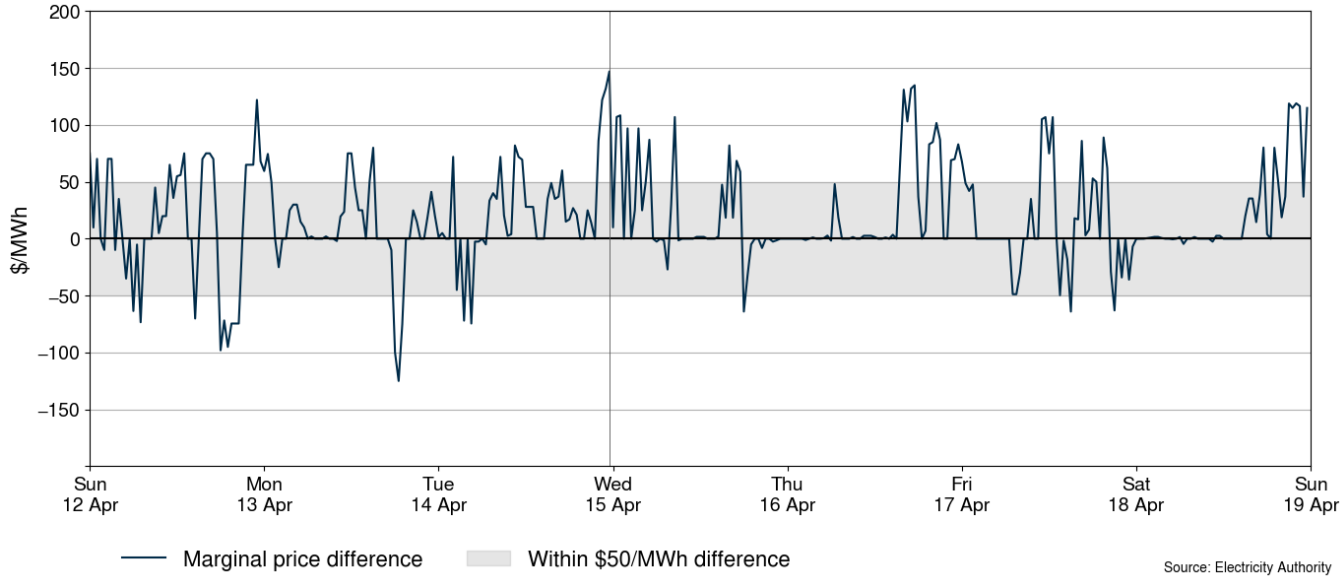
7.9. A number of trading periods this week had marginal price differences greater than $50/MWh.

7.10. Higher-than-forecast prices throughout this week generally occurred when wind generation was lower than forecast.

7.11. The maximum positive difference of $147/MWh occurred on Tuesday at 11.30pm. At this time, demand was 58MW higher than forecast, and wind generation was 145MW lower than forecast.

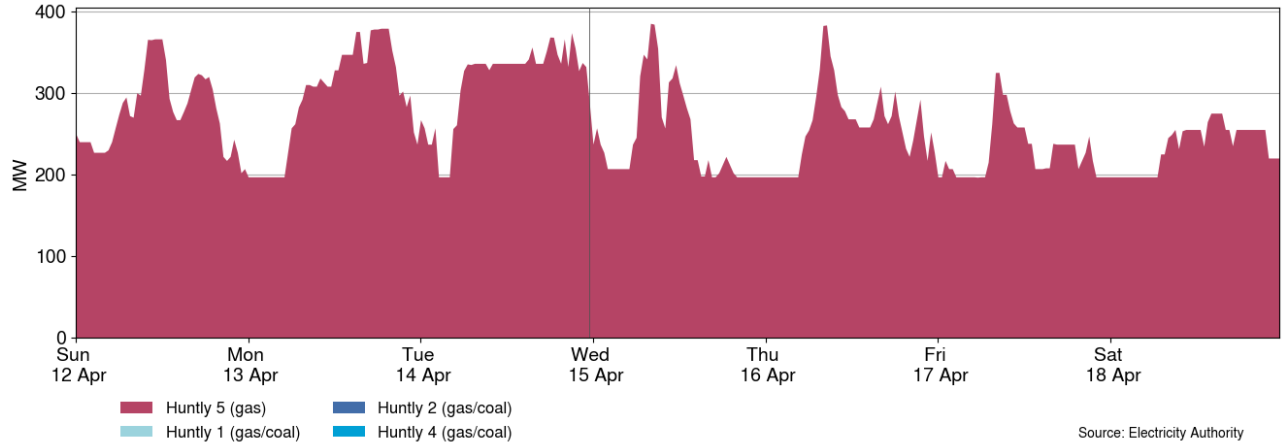
7.12. The maximum negative difference of $125/MWh occurred on Monday at 6.30pm. At this time, demand was 23MW higher than forecast and wind generation was 159MW higher than forecast.

**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, 12-18 April**



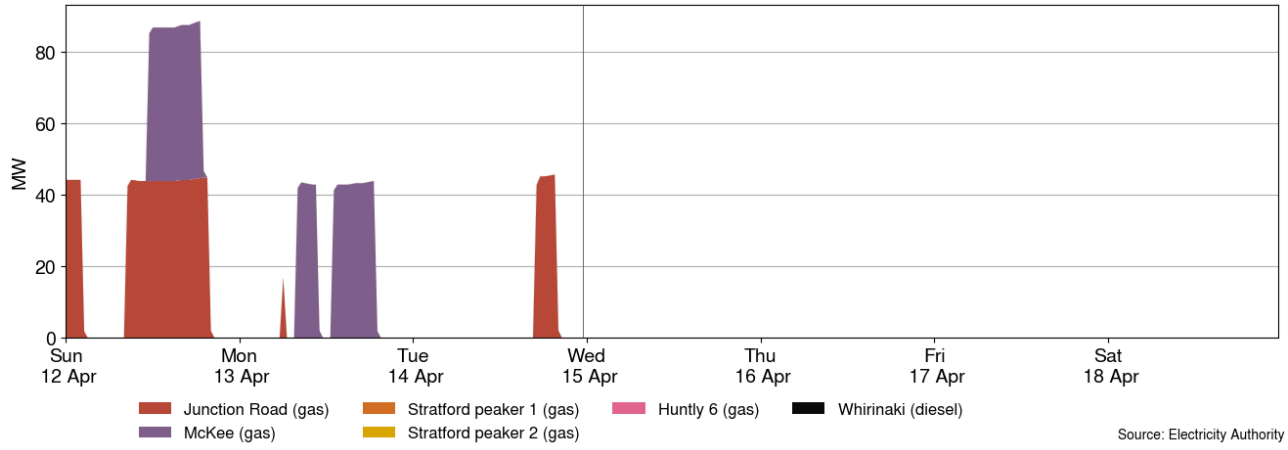

7.13. Figure 13 shows the generation of thermal baseload between 12-18 April. Just Huntly 5 ran continuously this week.

**Figure 13: Thermal baseload generation, 12-18 April**



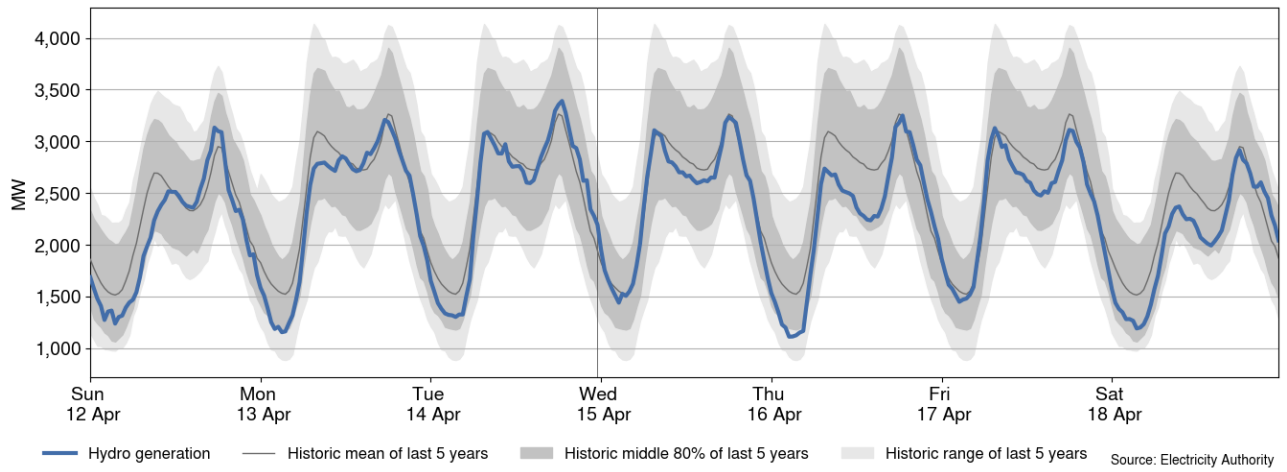

7.14. Figure 14 shows the generation of thermal peaker plants between 12-18 April. Junction Road ran at times from Sunday to Tuesday, and McKee ran at time on Sunday and Monday.

**Figure 14: Thermal peaker generation, 12-18 April**




7.15. Figure 15 shows hydro generation between 12-18 April. Hydro generation was mostly at its historic mean from Sunday to Wednesday, and below its historic mean from Thursday to Saturday. Overnight hydro generation was also below its historic mean.

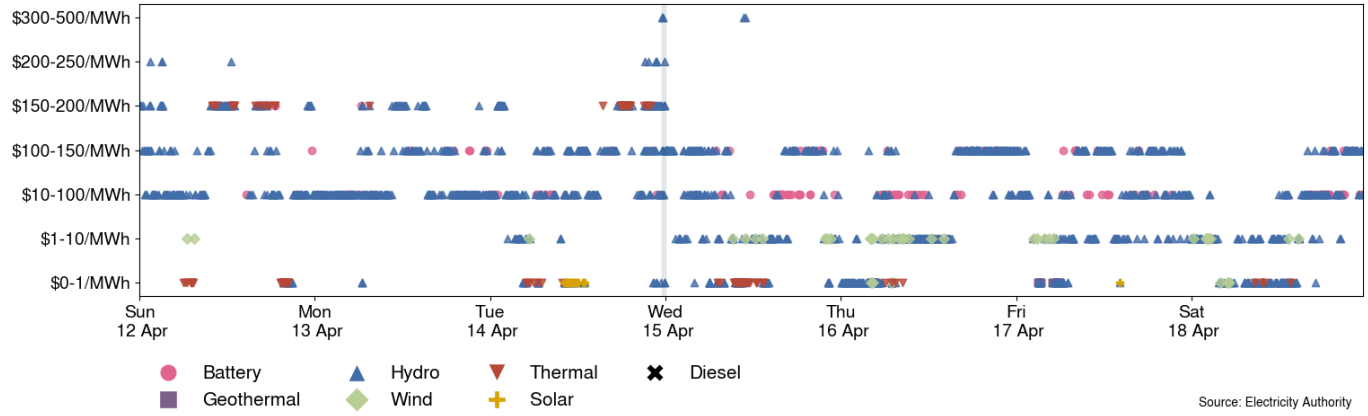
**Figure 15: Hydro generation, 12-18 April**



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.

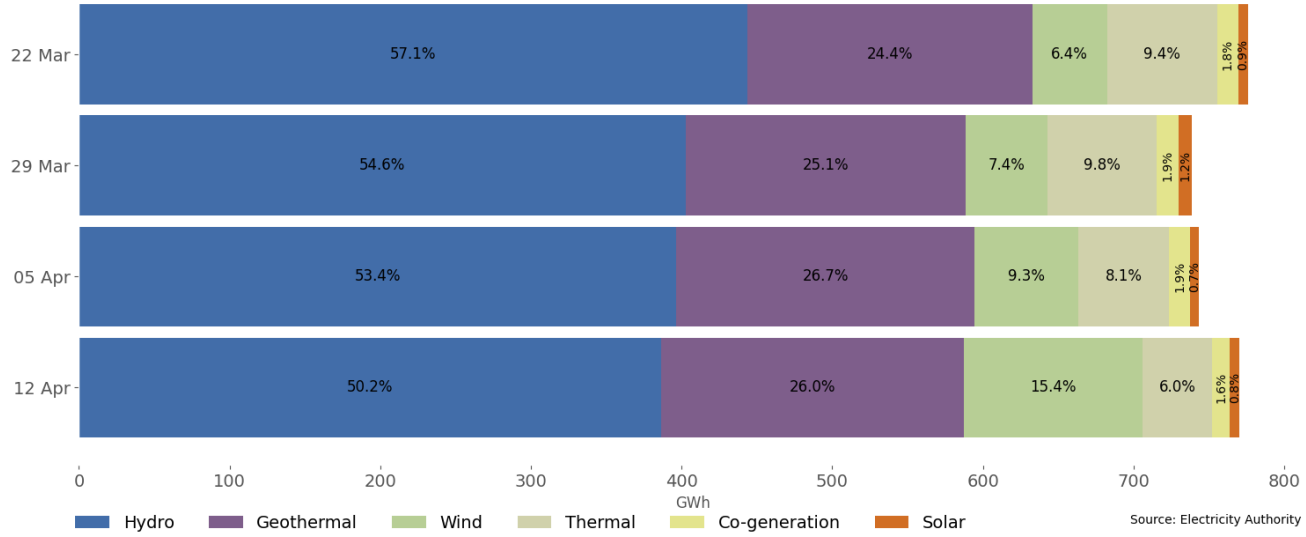
7.17. The highest prices were set by Manawa hydro on Wednesday. The most common technology setting prices was hydro generation, with battery the second most common. Most marginal prices were between $100-150/MWh.

**Figure 16: Prices of marginal generation, 12-18 April**




7.18. As a percentage of total generation, between 12-18 April, total weekly hydro generation was 50.2%, geothermal 26.0%, wind 15.4%, thermal 6.0%, co-generation 1.6%, and solar (grid connected) 0.8%, as shown in Figure 17.

**Figure 17: Total generation by type as a percentage each week, between 22 March and 18 April**




# 8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 12-18 April ranged between ~1,155MW and ~2,228MW. Figure 19 shows the thermal generation capacity outages.

**Figure 18: Total MW loss from generation outages, 12-18 April**

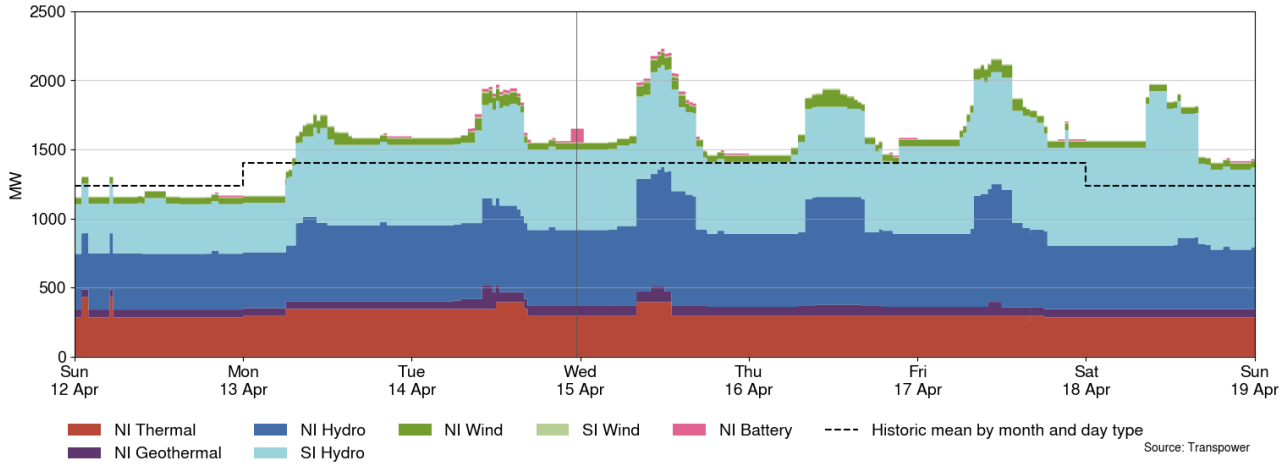
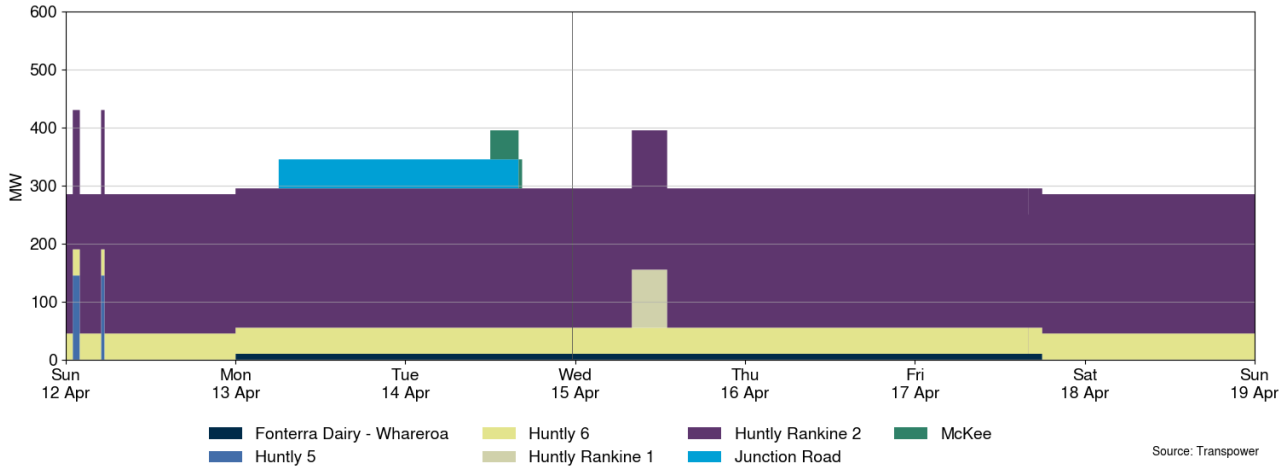



**Figure 19: Total MW loss from thermal outages, 12-18 April**




8.2. Notable outages include:

| Plant | Partial or Full | End Date |
|---|---|---|
| Manapōuri unit 7 | Full | 18 April 2026 |
| Huntly 6 | Full | 21 April 2026 |
| Manapōuri unit 3 | Full | 24 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

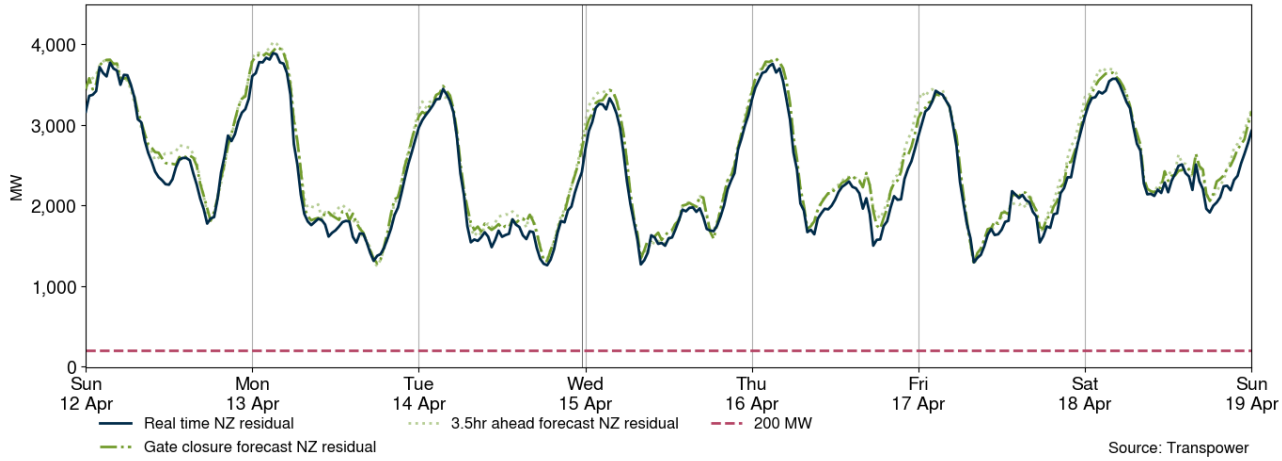
9.1. Overall, national residuals were healthy this week. The lowest national residual was 1,259MW on Tuesday at 6.30pm.

9.2. Figure 20 shows the national generation balance residuals between 12-18 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.

9.3. Overall, national residuals were healthy this week. The lowest national residual was 1,259MW on Tuesday at 6.30pm.

**Figure 20: National generation balance residuals, 12-18 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 18 April, national controlled storage was 83% nominally full and ~109% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (87% full[2]) is above its historic mean, while Lake Tekapō (78% full) is below its historic mean.

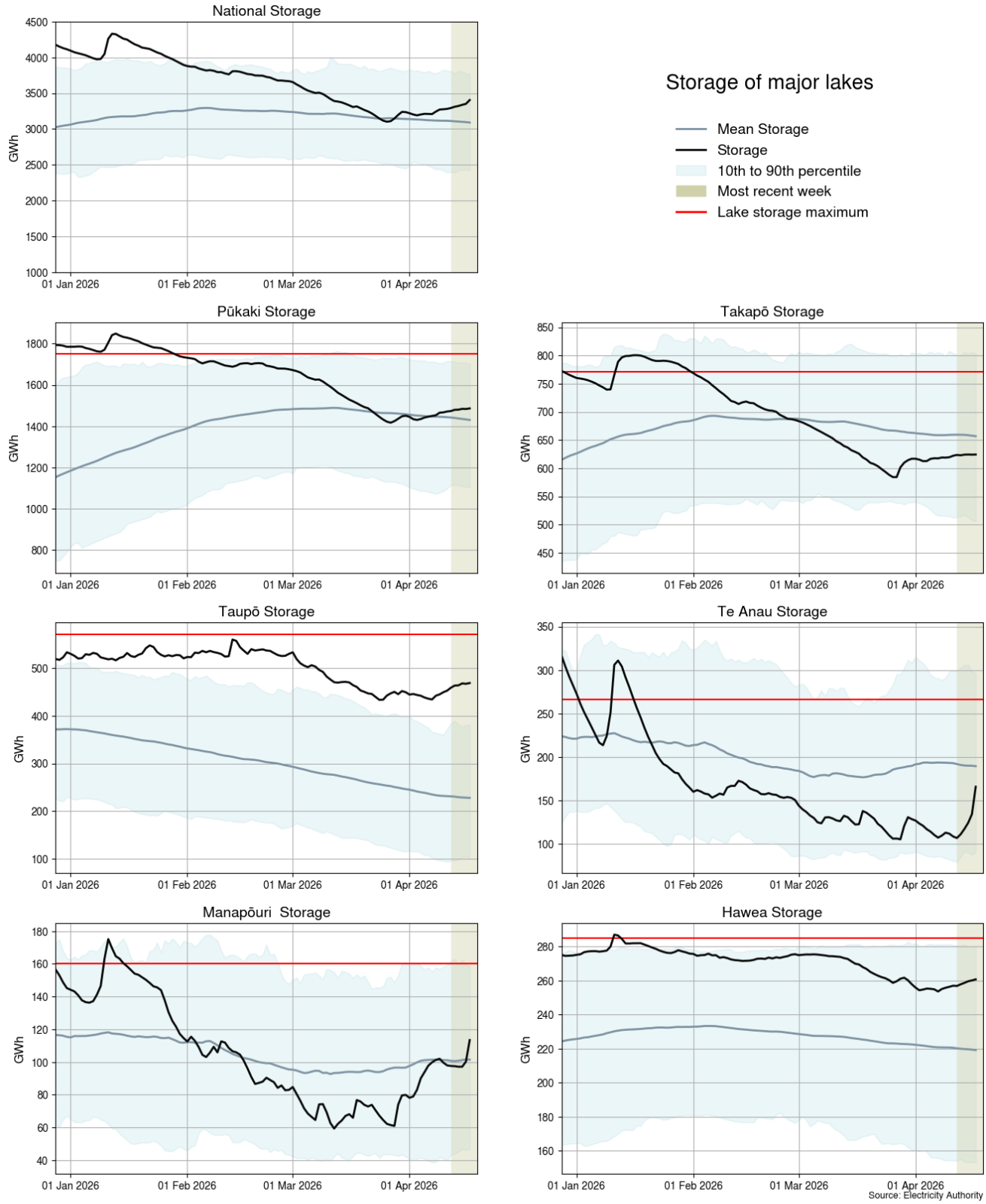
10.4. Storage at Lake Te Anau (74% full) is below its historic mean, with Lake Manapōuri (80% full) above its historic mean.

10.5. Storage at Lake Taupō (87% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (93% 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 April 2026. The SRMCs for all thermal-fuelled generation have increased, with the SRMC for diesel-fuelled generation increasing the most.

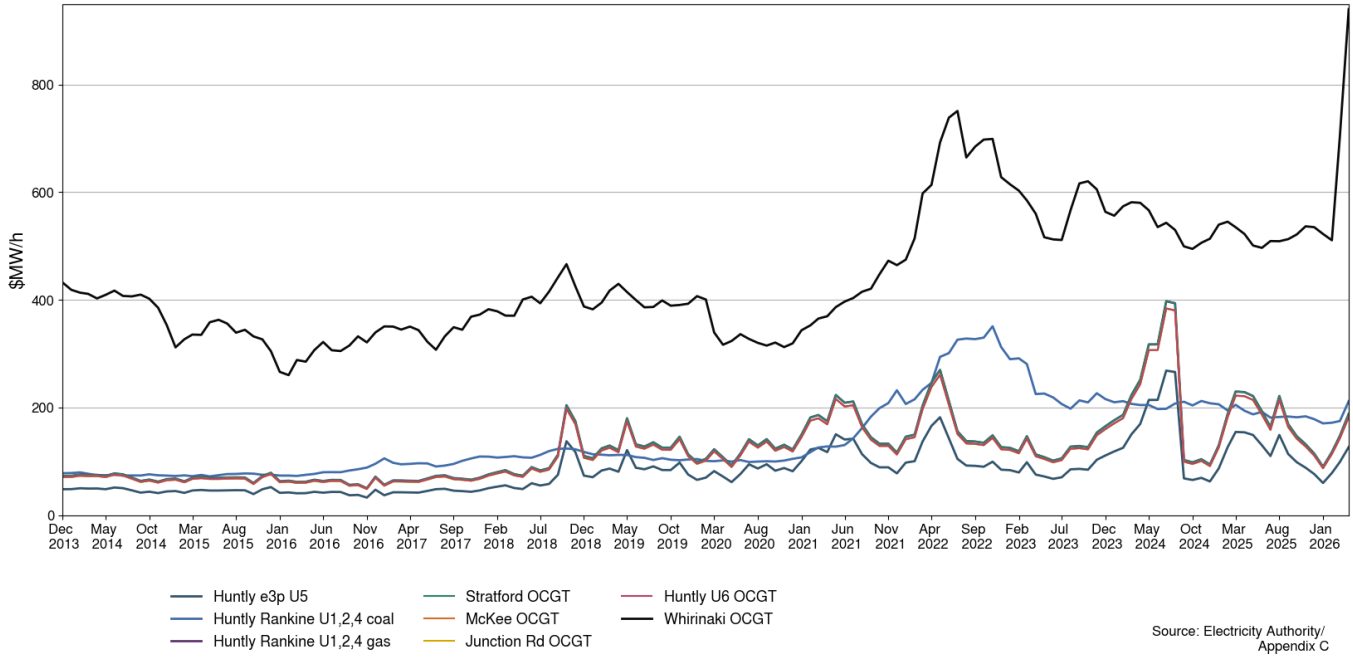
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$212/MWh. The cost of running the Rankines on gas at ~$188/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $126/MWh and $189/MWh.

11.6. The SRMC of Whirinaki, using diesel, has increased by ~$236/MWh to ~$940/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

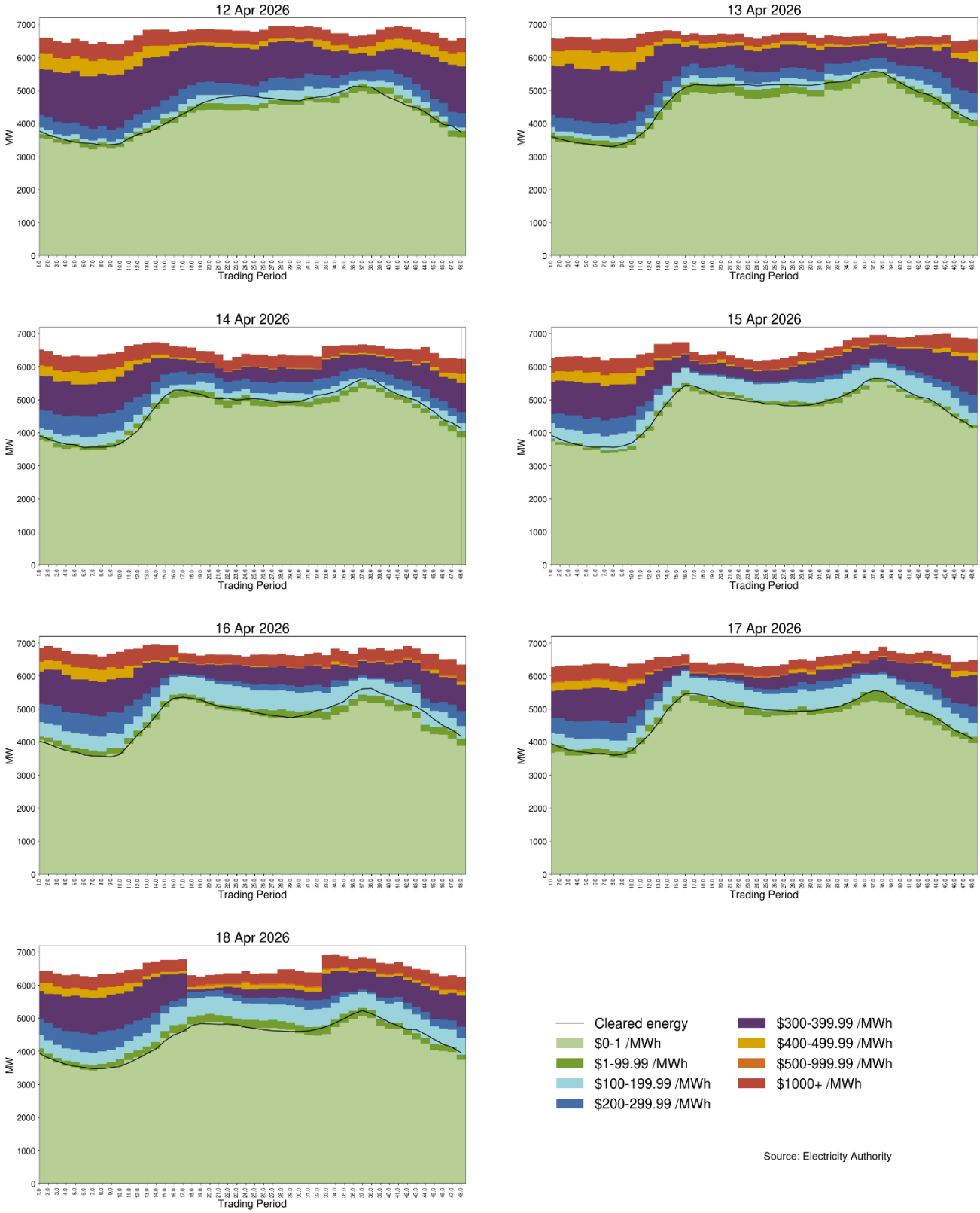
12.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. Most offers this week cleared below $200/MWh, although some energy did clear above $200/MWh at times on Tuesday.

12.3. Offers in the $300-400/MWh range reduced on Saturday during outages at Ōhau B and C.

12.4. From Monday, high priced Mercury hydro offers were priced down into the $200-300/MWh range from the $300-400/MWh range. From Wednesday, some Meridian hydro offers were priced down from the $200-300/MWh band into the $100-200/MWh band.

**Figure 23: Daily offer stacks**

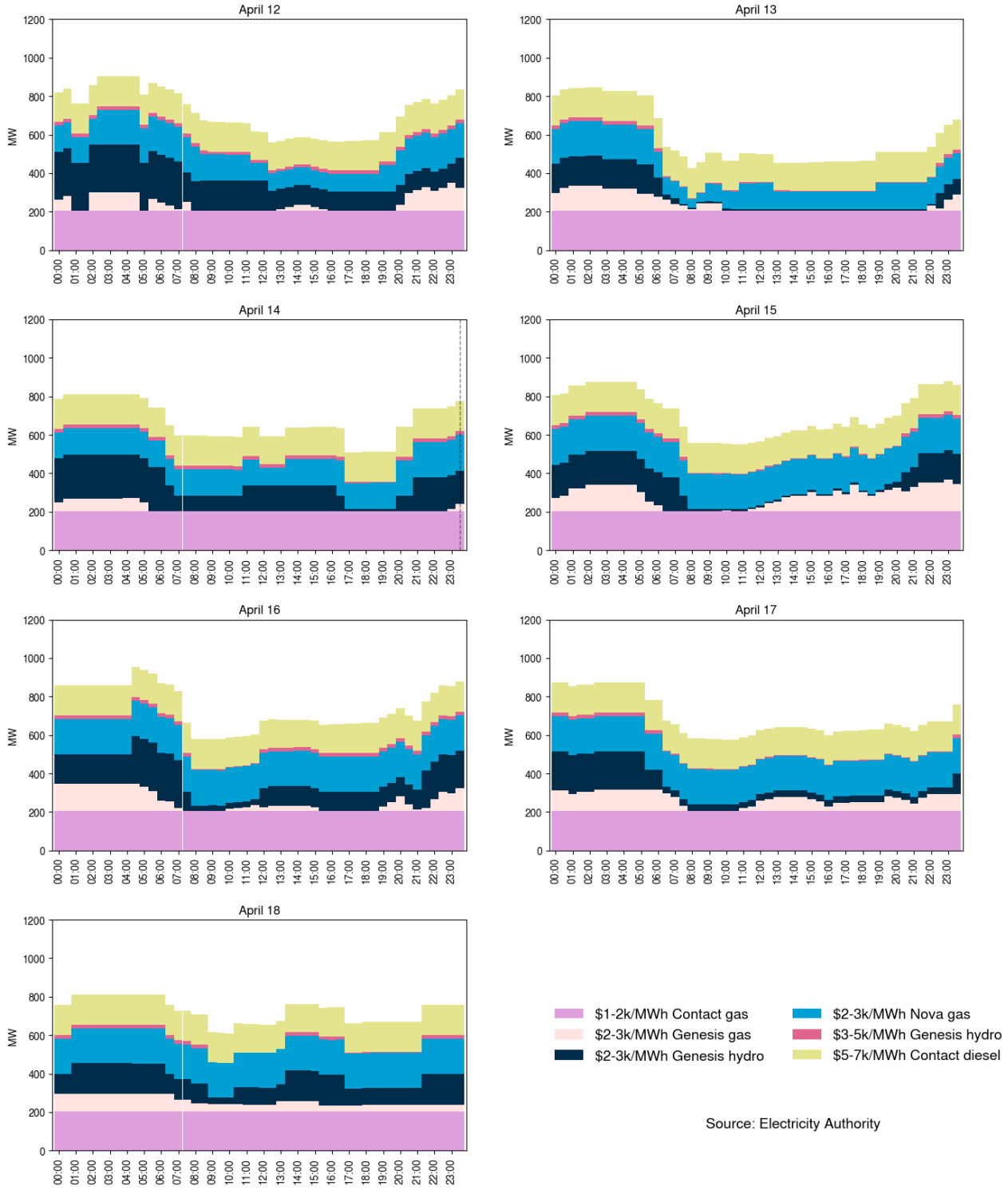


12.5. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.6. 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.

12.7. On average 691MW per trading period was priced above $1,000/MWh this week, which is roughly 14% 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 |