13 April 2026

Trading conduct report 5-11 April 2026

Market monitoring weekly report

Trading conduct report 5-11 April 2026

1. Overview

1.1. This week the average spot price decreased by $36/MWh to $117/MWh. Lower prices this week are related to higher wind generation and continued lower demand due to the Easter holidays. National controlled storage increased slightly to 81% nominally full and 104% 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 5-11 April:

(a) The average spot price for the week was $117/MWh, a decrease of around $36/MWh compared to the previous week.

(b) 95% of prices fell between $2/MWh and $231/MWh.

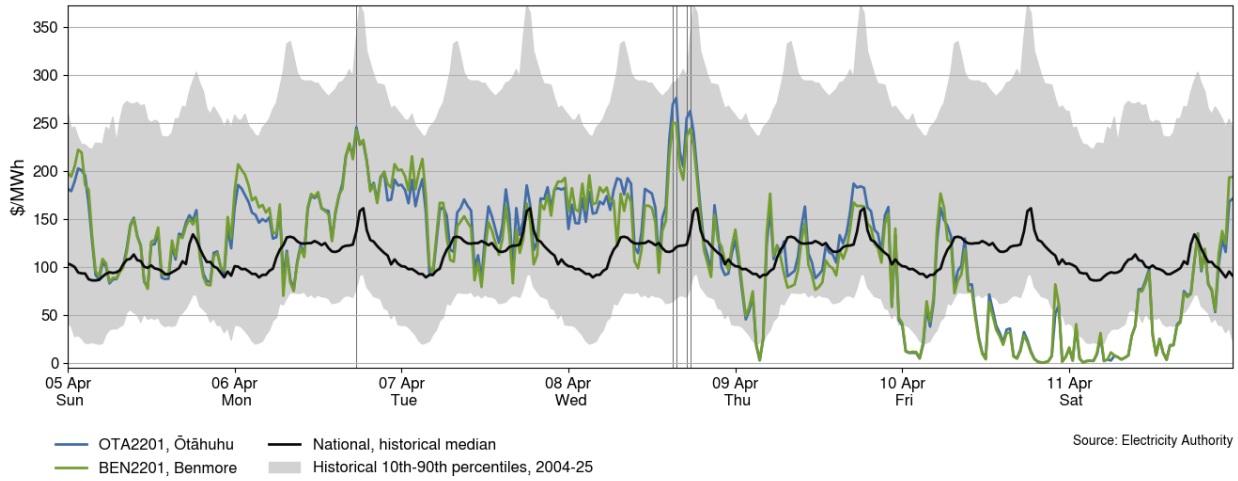
2.3. Higher wind generation and lower demand due to the Easter holiday weekend have contributed to lower prices this week.

2.4. Prices reached $245/MWh at Ōtāhuhu and $243/MWh at Benmore at 5.30pm on Monday. During this time, demand was 85MW higher than forecast, and intermittent generation was 116MW lower than forecast.

2.5. Prices spiked above $260/MWh on Wednesday, with a maximum Ōtāhuhu price of $276/MWh and a maximum Benmore price of $250/MWh both occurring at 3.30pm. During this time, demand was 158MW higher than forecast, and intermittent generation was 179MW lower than forecast.

2.6. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th 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.

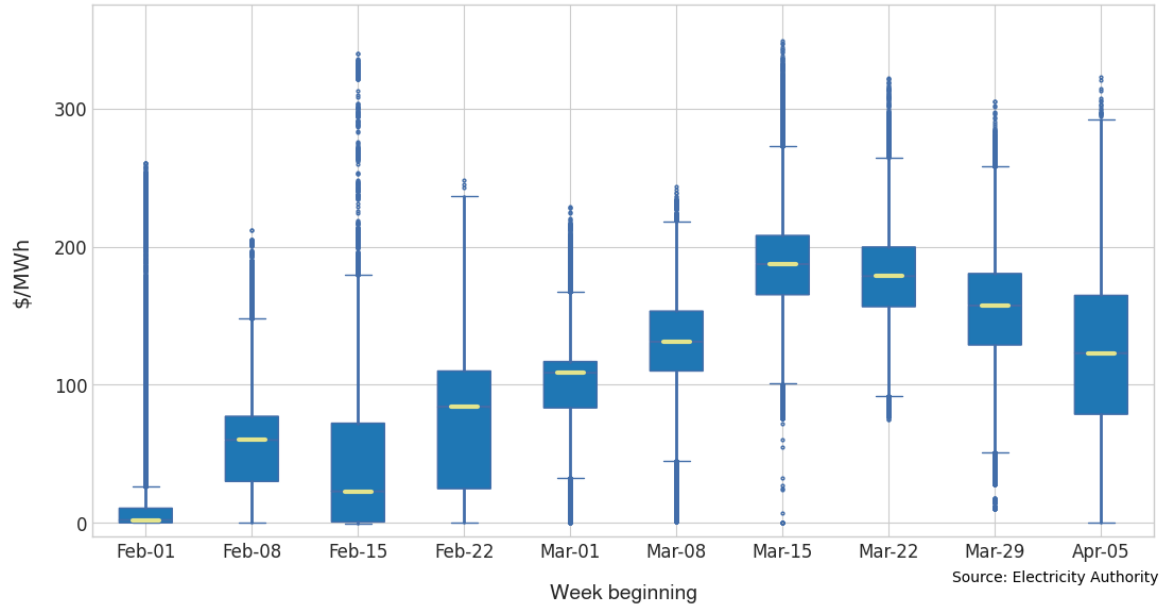
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 5-11 April



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 has shifted slightly lower than last week. The median price was $123/MWh and most prices (middle 50%) fell between $79/MWh and $165/MWh.

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

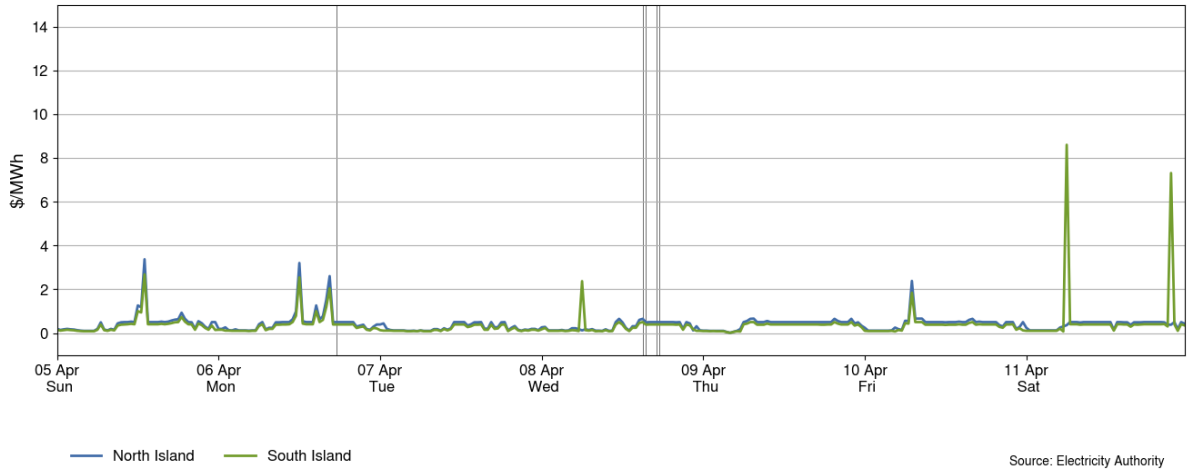


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices remained mostly below $1/MWh, aside from several spikes throughout the week.

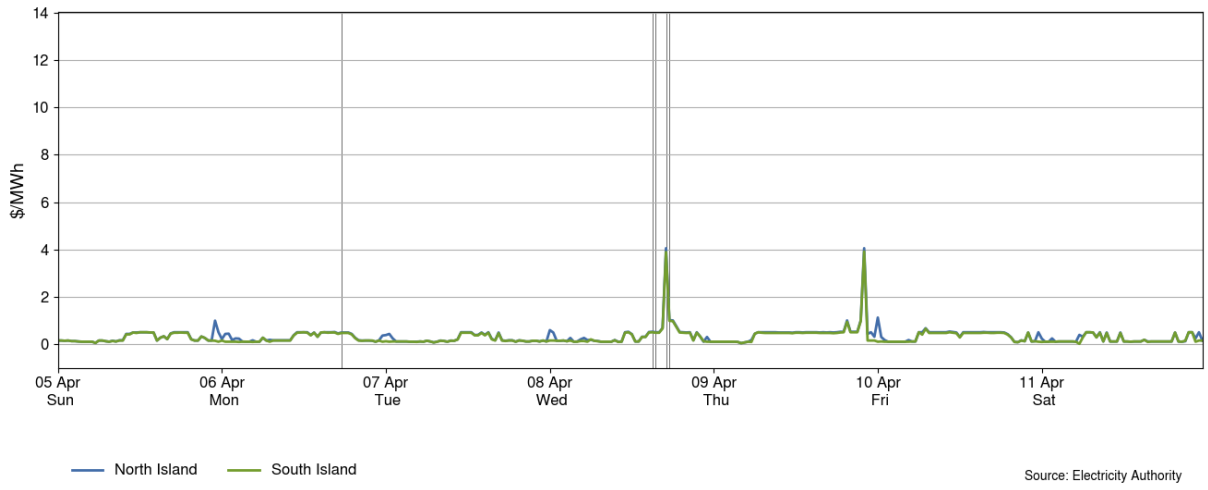
3.2. North Island FIR prices reached $3/MWh on Sunday 1.00pm, with South Island FIR prices reaching $3/MWh at the same time. South Island FIR prices reached $9/MWh on Saturday 6.00am, during southward HVDC flow.

Figure 3: Fast instantaneous reserve price by trading period and island, 5-11 April



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices remained below $5/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 5-11 April



4. Regression residuals

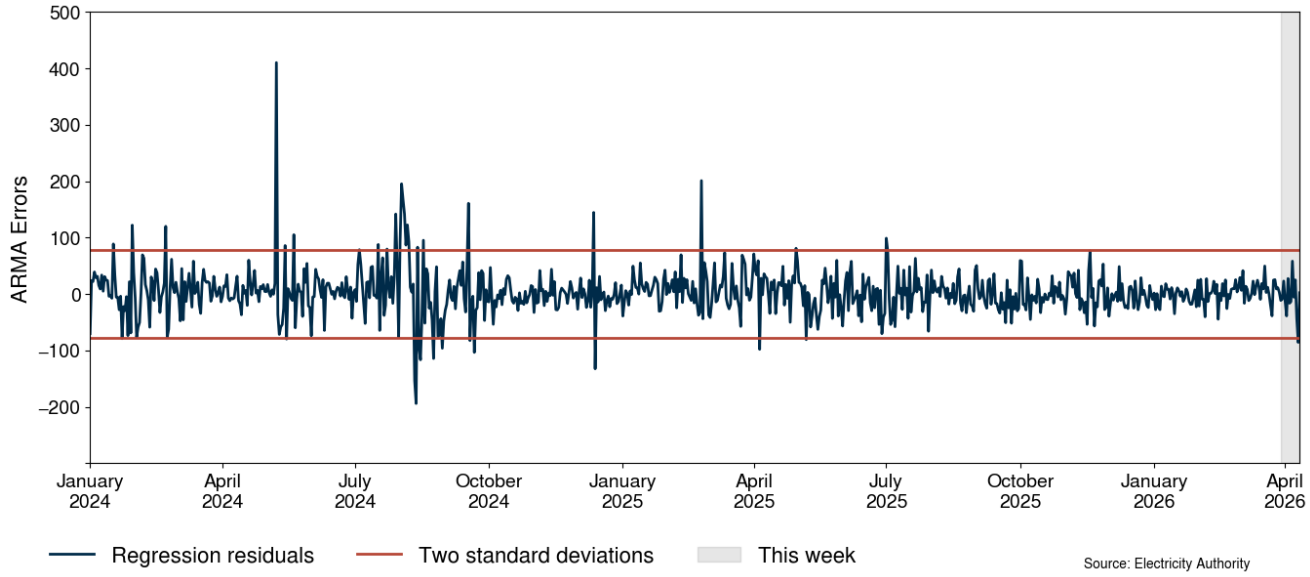
4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and 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 was a single residual below two standard deviations. This occurred on Friday 10th April, and indicates the modelled daily price was higher than the actual average daily price.

4.4. This is likely the model carrying over higher prices from the previous day, as prices dropped steeply on Friday due to a large increase in wind generation.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2024 - 11 April 2026

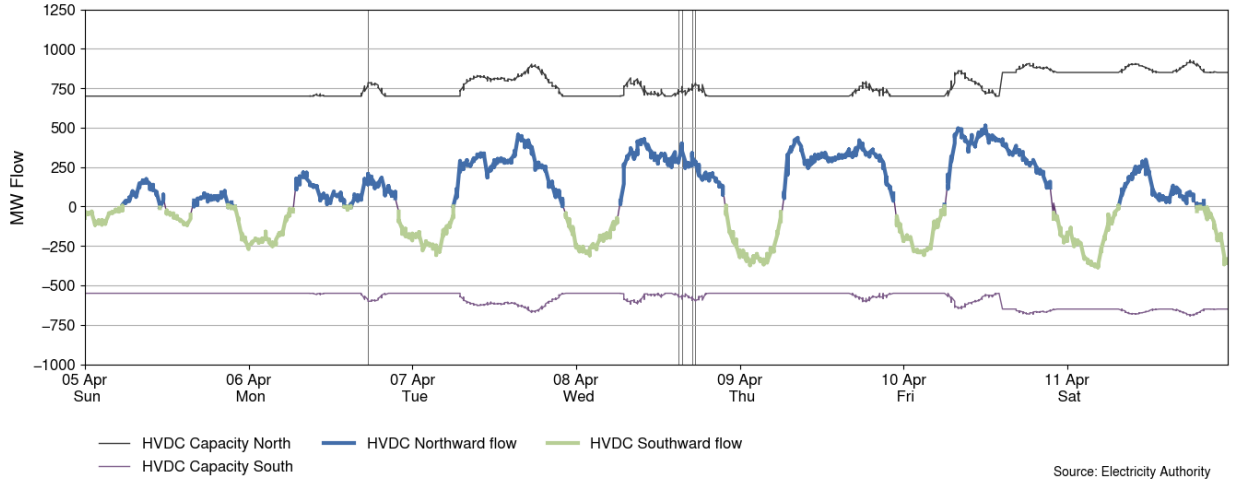


5. HVDC

5.1. Figure 6 shows the HVDC flow between 5-11 April. HVDC flows were mostly northward during the day, aside from a period on Sunday when wind generation was high. Southward HVDC flows occurred every night this week.

5.2. The highest northward flow occurred on Friday at 12.00pm with a flow of around 513MW.

Figure 6: HVDC flow and capacity, 5-11 April



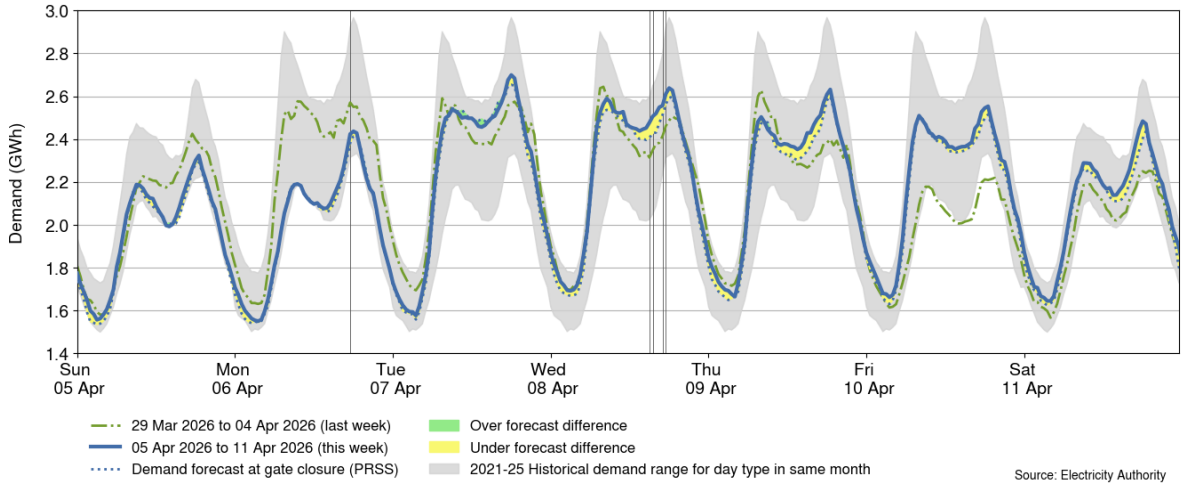
6. Demand

6.1. Figure 7 shows national demand between 5-11 April, compared to the historic range and the demand of the previous week.

6.2. On Sunday and Monday, demand was lower than the previous week, due to the Easter holidays. On Tuesday, Wednesday, and Thursday, demand was similar to the previous week, though the morning peaks were lower and the evening peaks were higher. Demand was also higher on Friday and Saturday, compared to the previous week, due to Easter holiday.

6.3. The highest demand of the week was around 2.7GWh at 6:00pm on Tuesday.

Figure 7: National demand, 5-11 April compared to the previous week

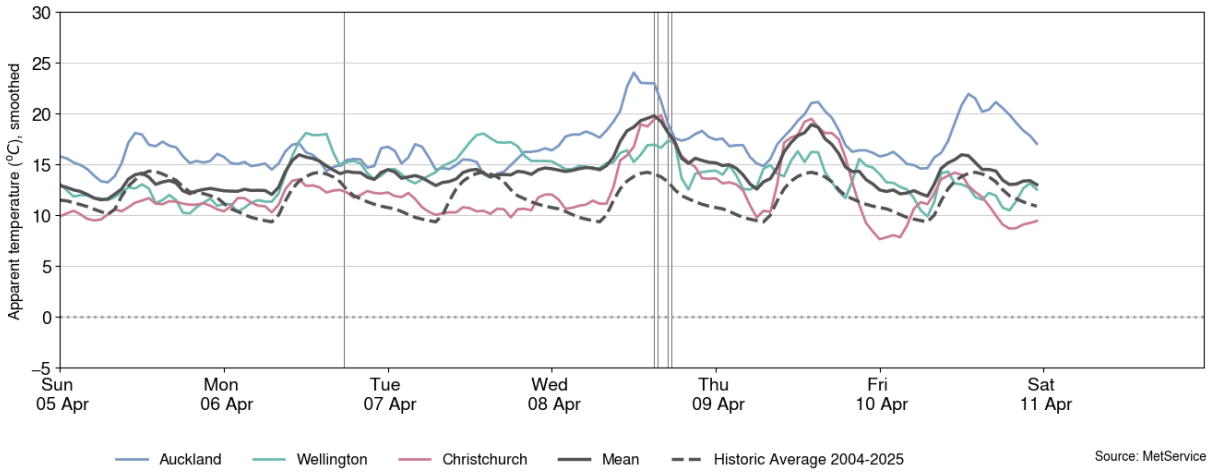


6.4. Figure 8 shows the hourly apparent temperature at main population centres from 5-11 April. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature 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 13°C to 24°C in Auckland, 10°C to 18°C in Wellington, and 7°C to 21°C in Christchurch.

6.6. Note that there is missing data on Saturday.

Figure 8: Temperatures across main centres, 5-11 April



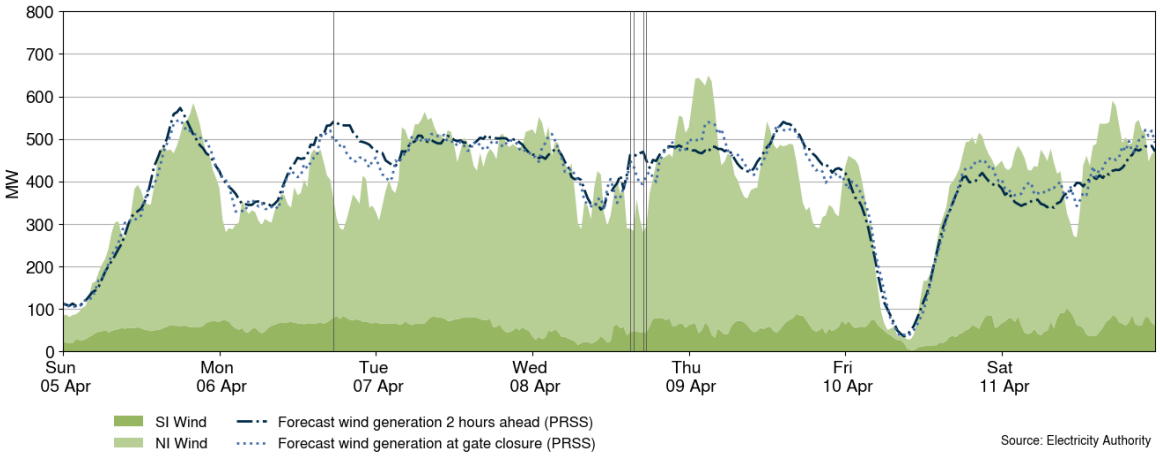
7. Generation

7.1. Figure 9 shows wind generation and forecast from 5-11 April. This week wind generation varied between 28MW and 674MW, with a weekly average of 410MW.

7.2. Wind generation was high overall, with the daily average above 350MW every day this week except for Friday (301MW) and Sunday (348MW). Wind generation showed a sudden drop on Friday and was also low in the early morning on Sunday.

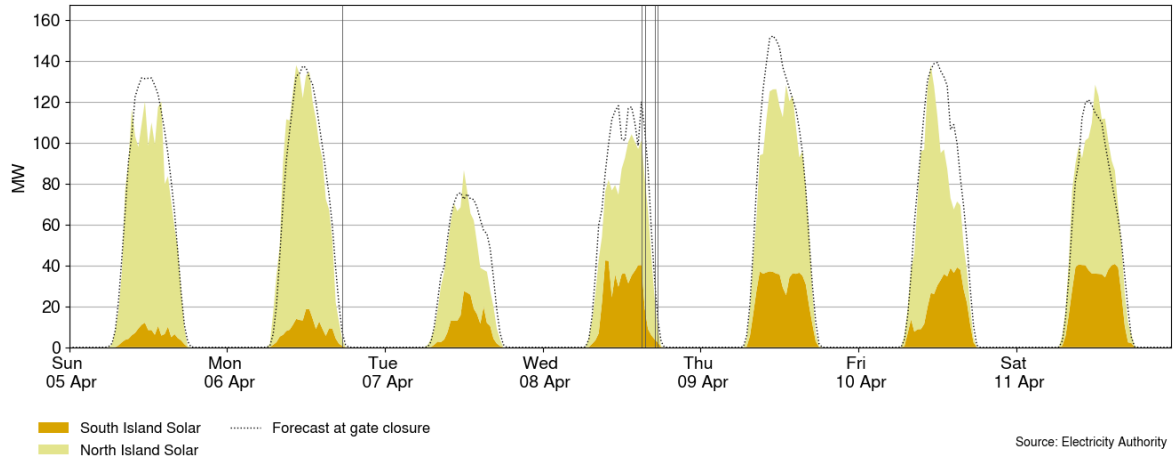
7.3. There was multiple large wind forecasting errors this week. Wind forecasting errors on Monday and Wednesday were the result of an amalgamation of errors across multiple wind farms.

Figure 9: Wind generation and forecast, 5-11 April



7.4. Figure 10 shows grid connected solar generation from 5-11 April. Solar generation generally reached between 120 to 140MW each day, apart from Tuesday, where it only reached around 80MW. Solar generation peaked at 138MW on Friday at 11.00am.

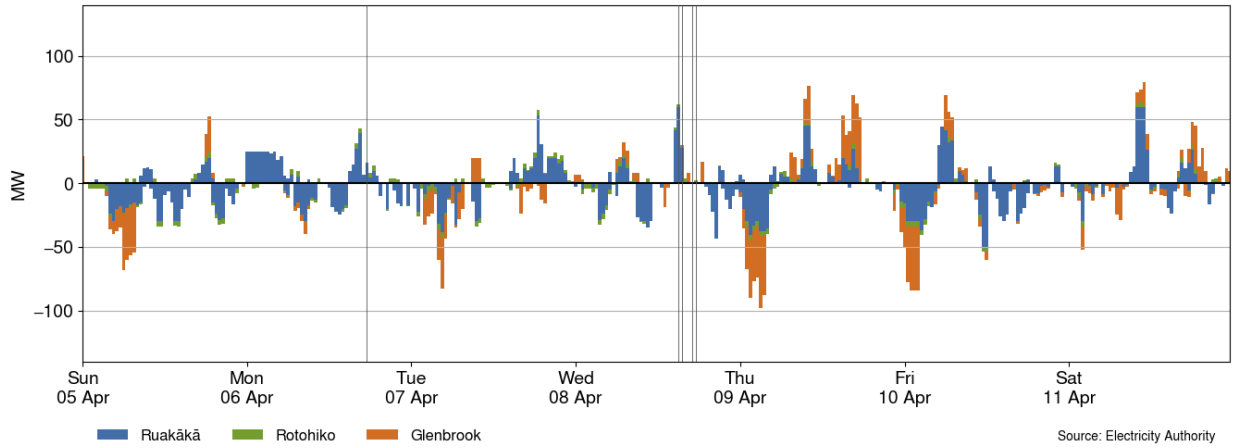
Figure 10: Grid connected solar generation, 5-11 April



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. Ruakākā discharged during some high prices on Wednesday afternoon.

Figure 11: Grid scale battery charge and discharge, 5-11 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.

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

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.

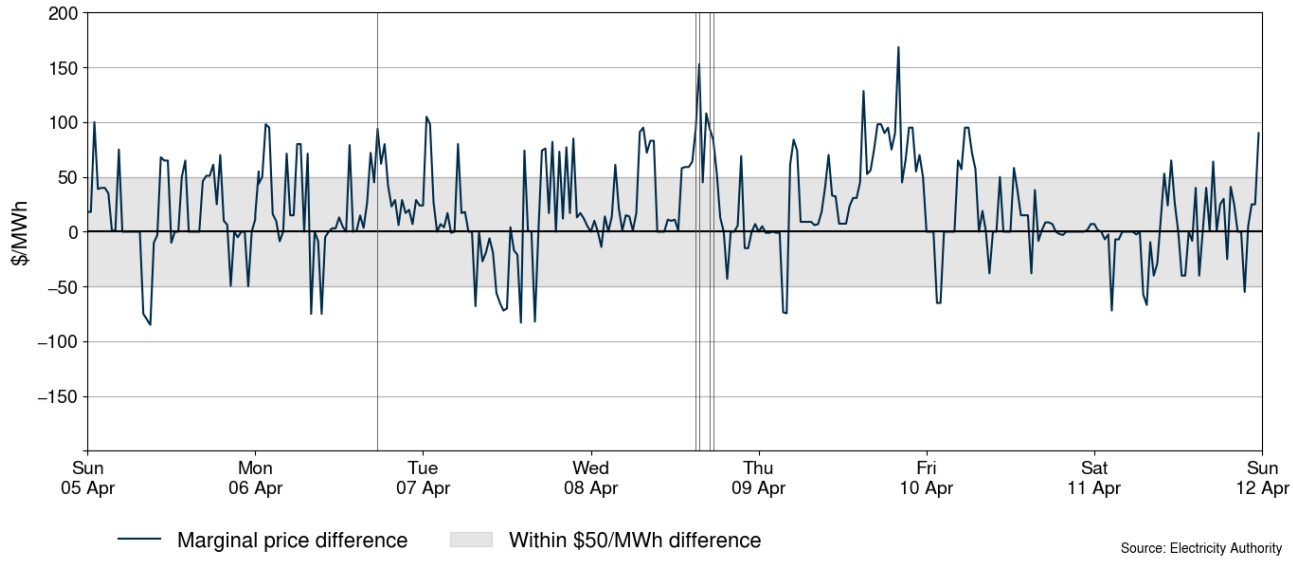
7.8. Many trading periods this week had marginal price differences greater than $50/MWh.

7.9. Several higher-than-forecast prices occurred between Sunday and Friday during times where either wind and/or demand varied from forecasts.

7.10. The maximum positive difference of $169/MWh occurred on Thursday at 8.00pm. At this time, demand was 12MW higher than forecast, and wind generation was 138MW lower than forecast.

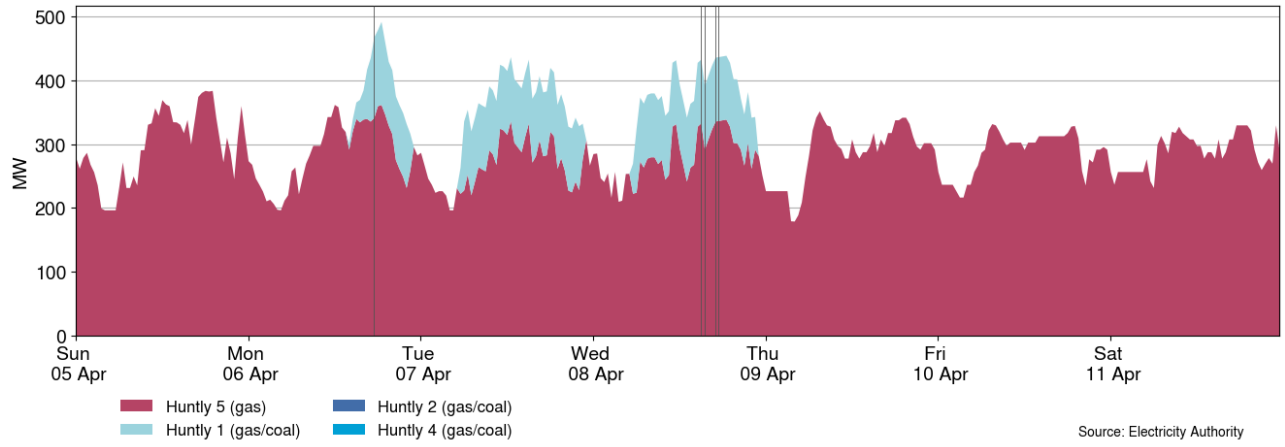
7.11. The maximum negative difference of $85/MWh occurred on Sunday at 9.00am. At this time, demand was 22MW higher than forecast and wind generation was 14MW higher than forecast.

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, 5-11 April



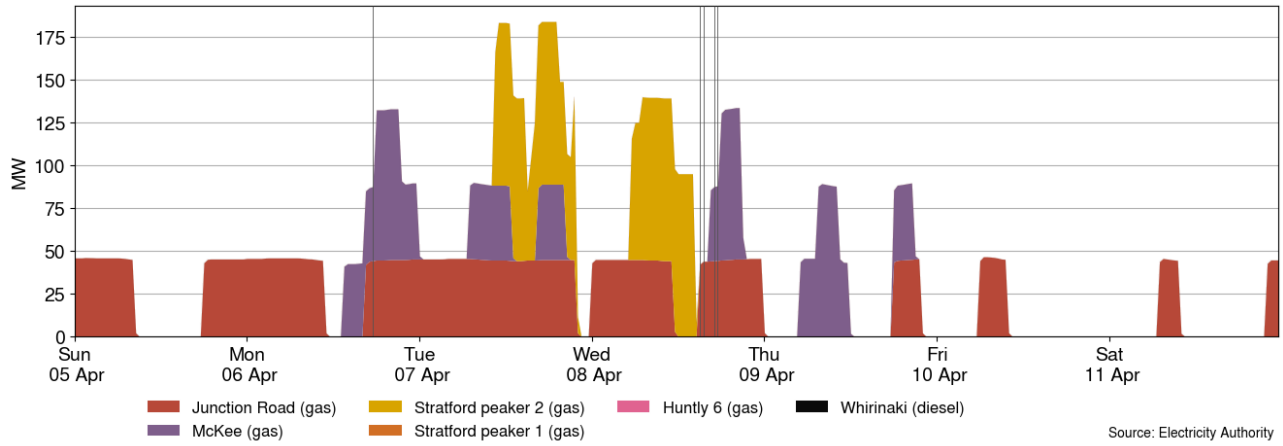
7.12. Figure 13 shows the generation of thermal baseload between 5-11 April. Huntly 5 ran continuously this week, and Huntly 1 ran at times from Monday to Wednesday.

Figure 13: Thermal baseload generation, 5-11 April



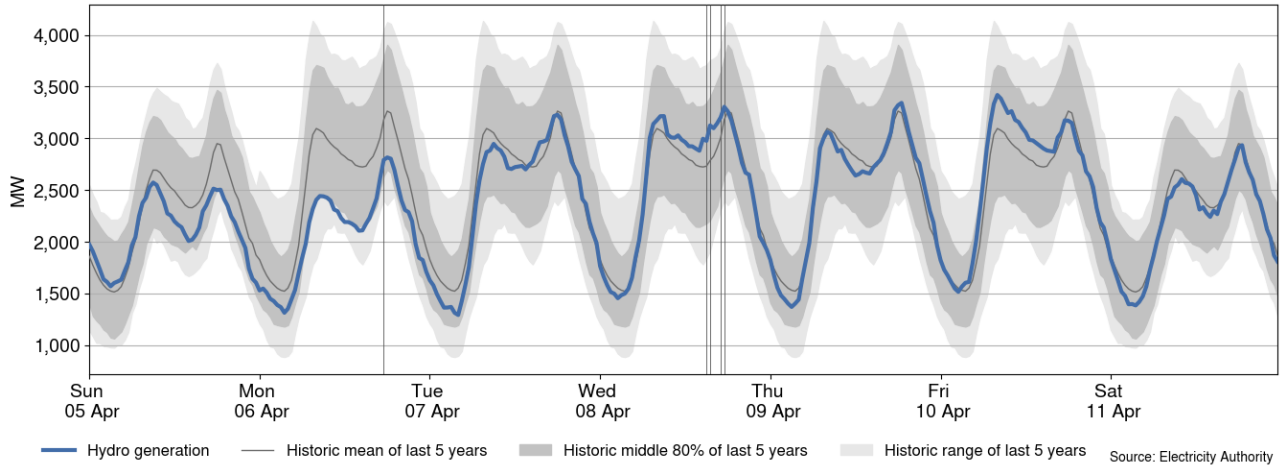
7.13. Figure 14 shows the generation of thermal peaker plants between 5-11 April. Junction road ran at times each day this week, McKee ran at times on each day between Monday and Thursday, and Stratford peaker 2 ran at times on Tuesday and Wednesday.

Figure 14: Thermal peaker generation, 5-11 April



7.14. Figure 15 shows hydro generation between 5-11 April. Hydro generation was mostly below the historic mean on Sunday and Monday. For the rest of the week hydro generation was mostly close to the historic mean, though it was higher on the Friday morning peak.

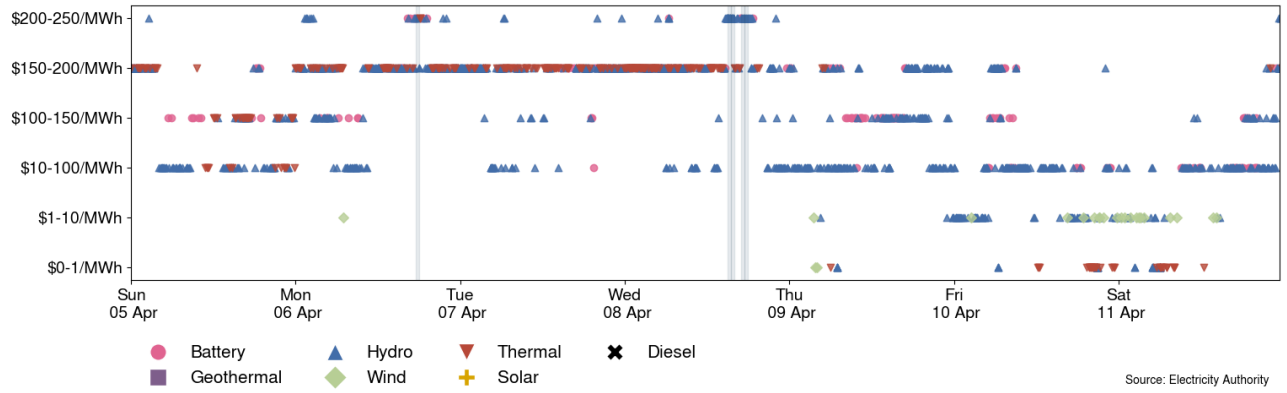
Figure 15: Hydro generation, 5-11 April



7.15. 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.

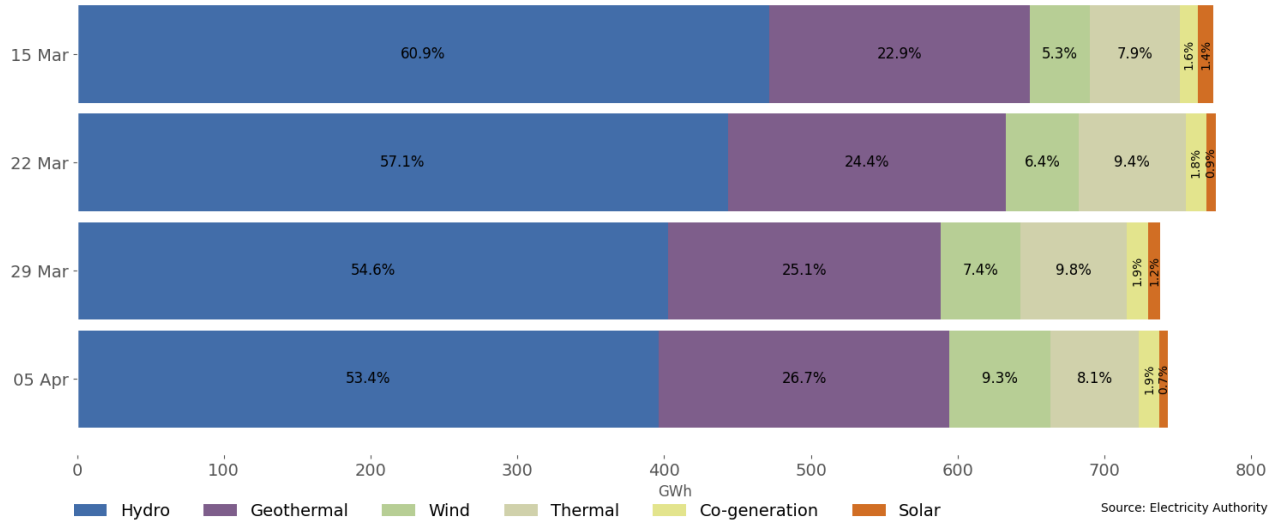
7.16. The highest prices were set by Meridian hydro on Wednesday. The most common technology setting prices this week was hydro generation, followed by thermal generation. Most marginal prices were between $150-200/MWh.

Figure 16: Prices of marginal generation, 5-11 April



7.17. As a percentage of total generation, between 5-11 April, total weekly hydro generation was 53.4%, geothermal 26.7%, wind 9.3%, thermal 8.1%, co-generation 1.9%, and solar (grid connected) 0.7%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 15 March and 11 April



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 5-11 April ranged between ~1,075MW and ~1,545MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 5-11 April

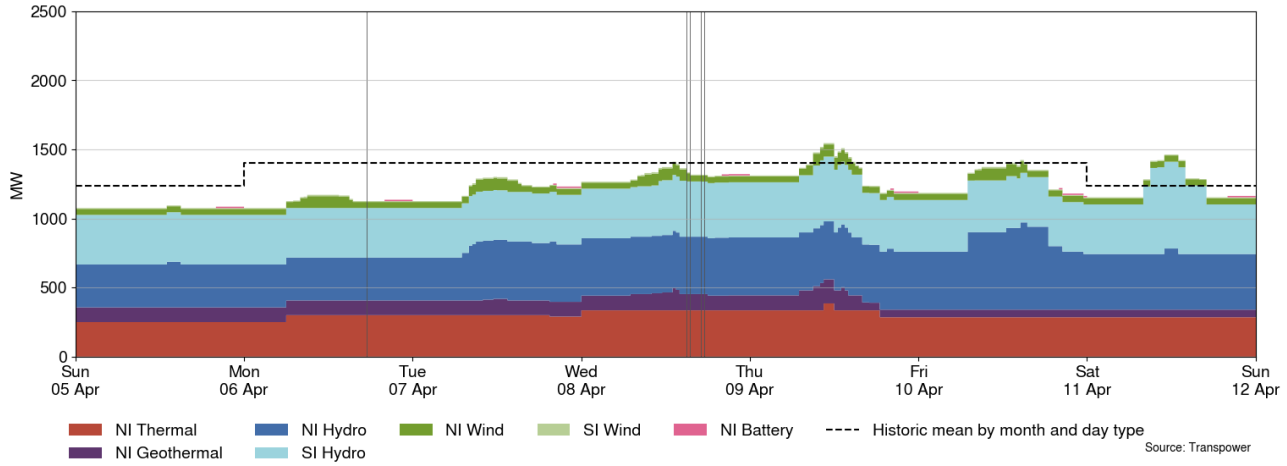
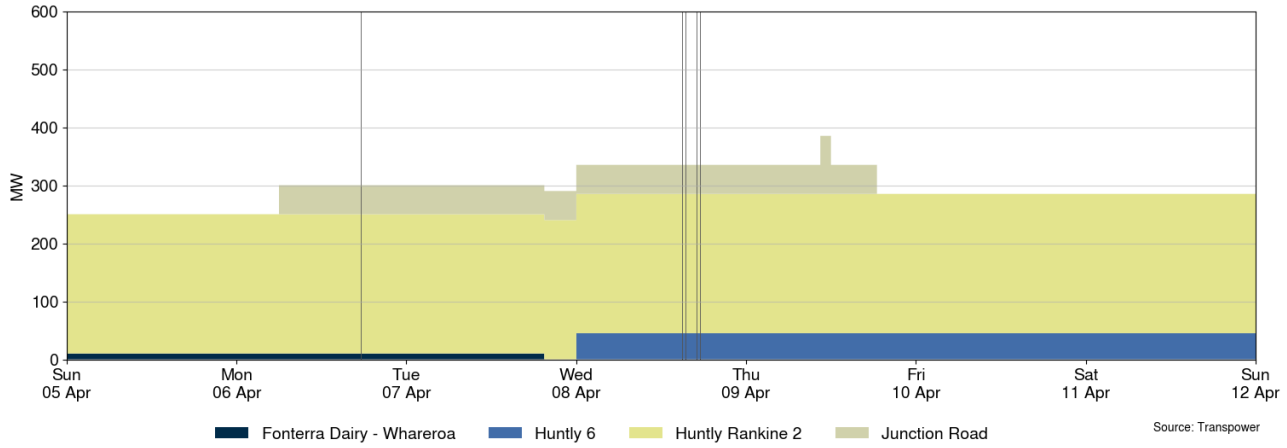


Figure 19: Total MW loss from thermal outages, 5-11 April



8.2. Notable outages include:

Plant	Partial or Full	End Date
Huntly 6	Full	17 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 4	Full	9 September 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

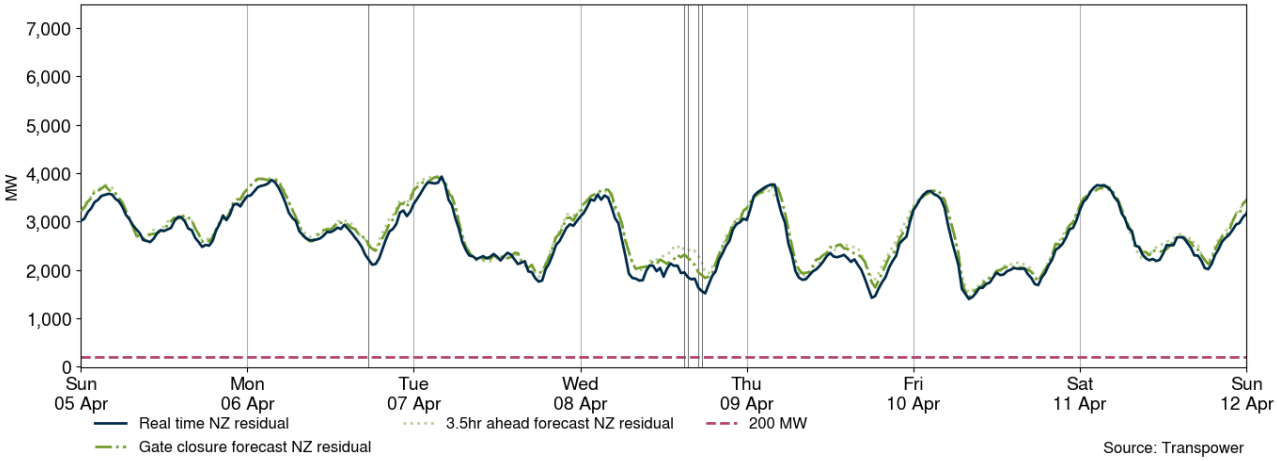
9.1. Overall, national residuals were healthy this week. The lowest national residual was 1,401MW on Friday at 8.00am.

9.2. Figure 20 shows the national generation balance residuals between 5-11 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 1,401MW on Friday at 8.00am.

Figure 20: National generation balance residuals, 5-11 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 11 April, national controlled storage was 81% nominally full and ~104% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (84% full[2]) is above its historic mean, while Lake Tekapō (76% full) is below its historic mean.

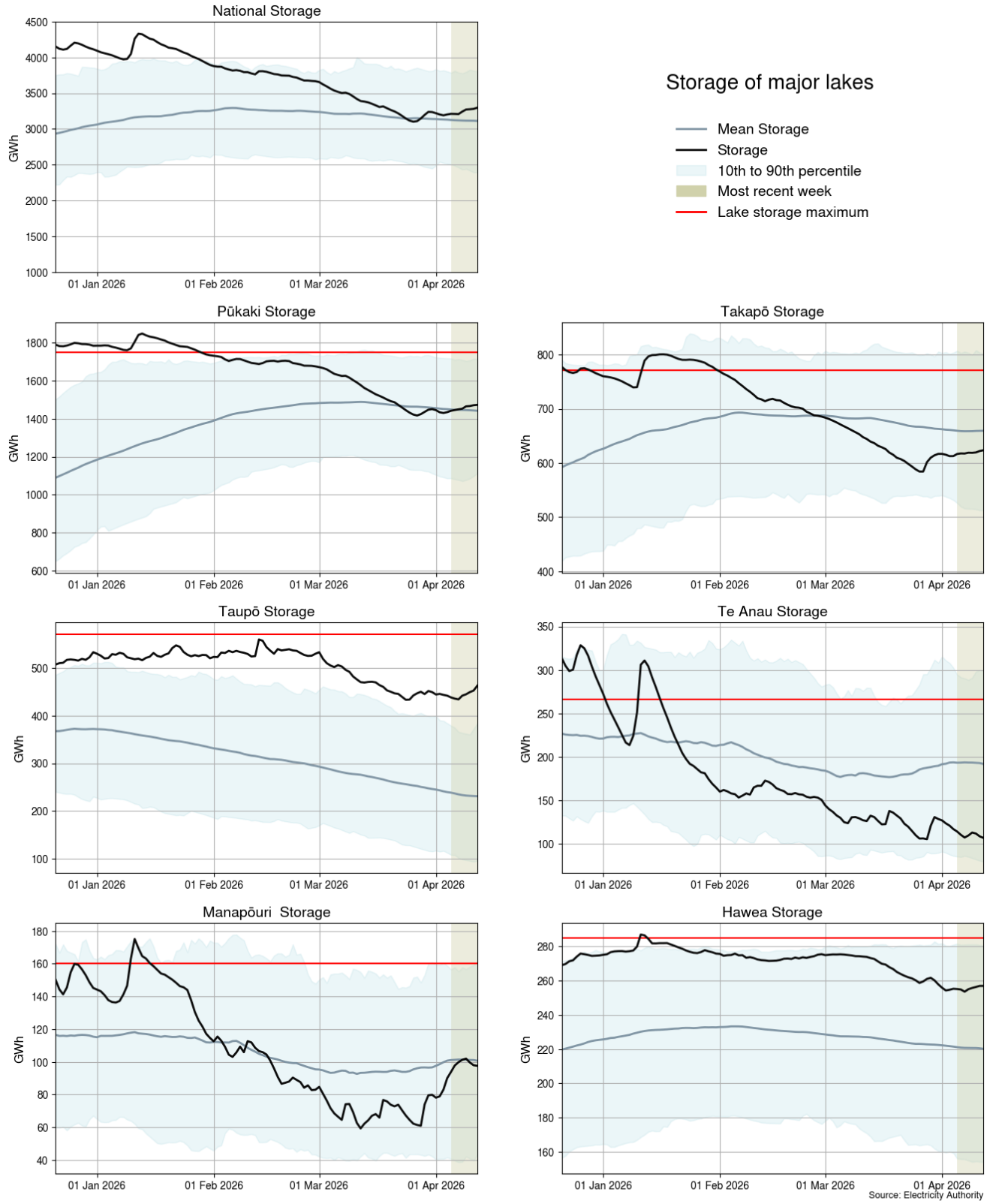
10.4. Storage at Lake Te Anau (40% full) is below its historic mean, with Lake Manapōuri (62% full) also below its historic mean.

10.5. Storage at Lake Taupō (81% full) is above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (90% 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.

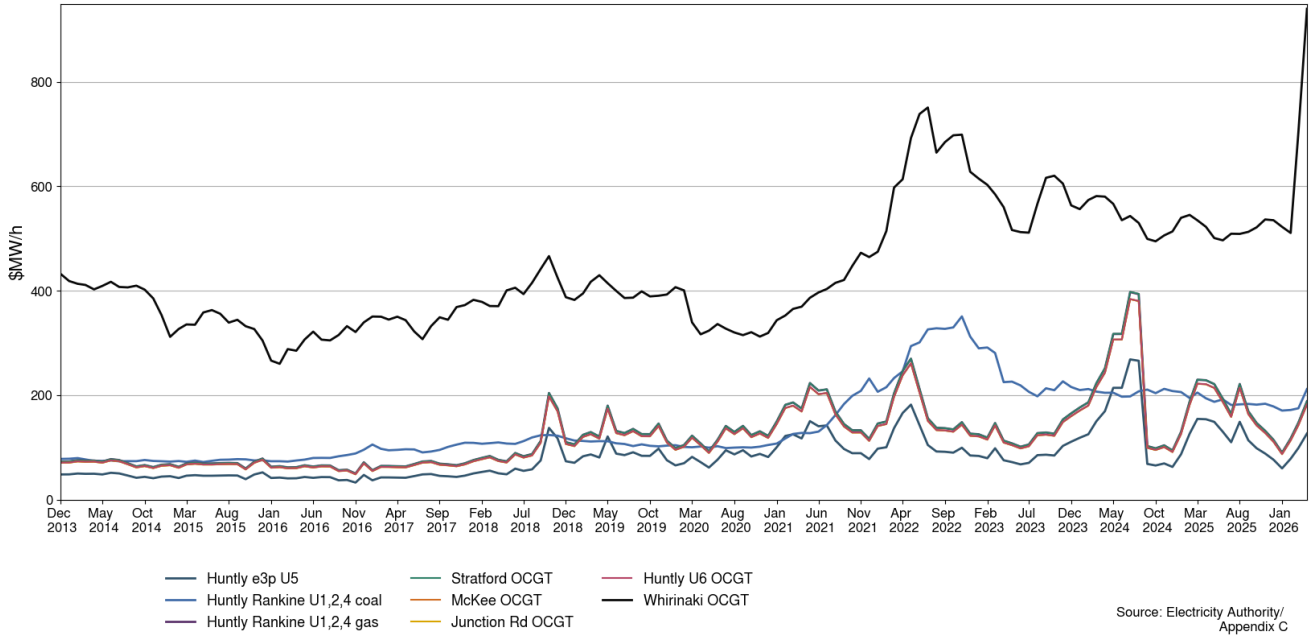
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$212/MWh. The cost of running the Rankines on gas at ~$188/MWh.

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

11.6. The SRMC of Whirinaki 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



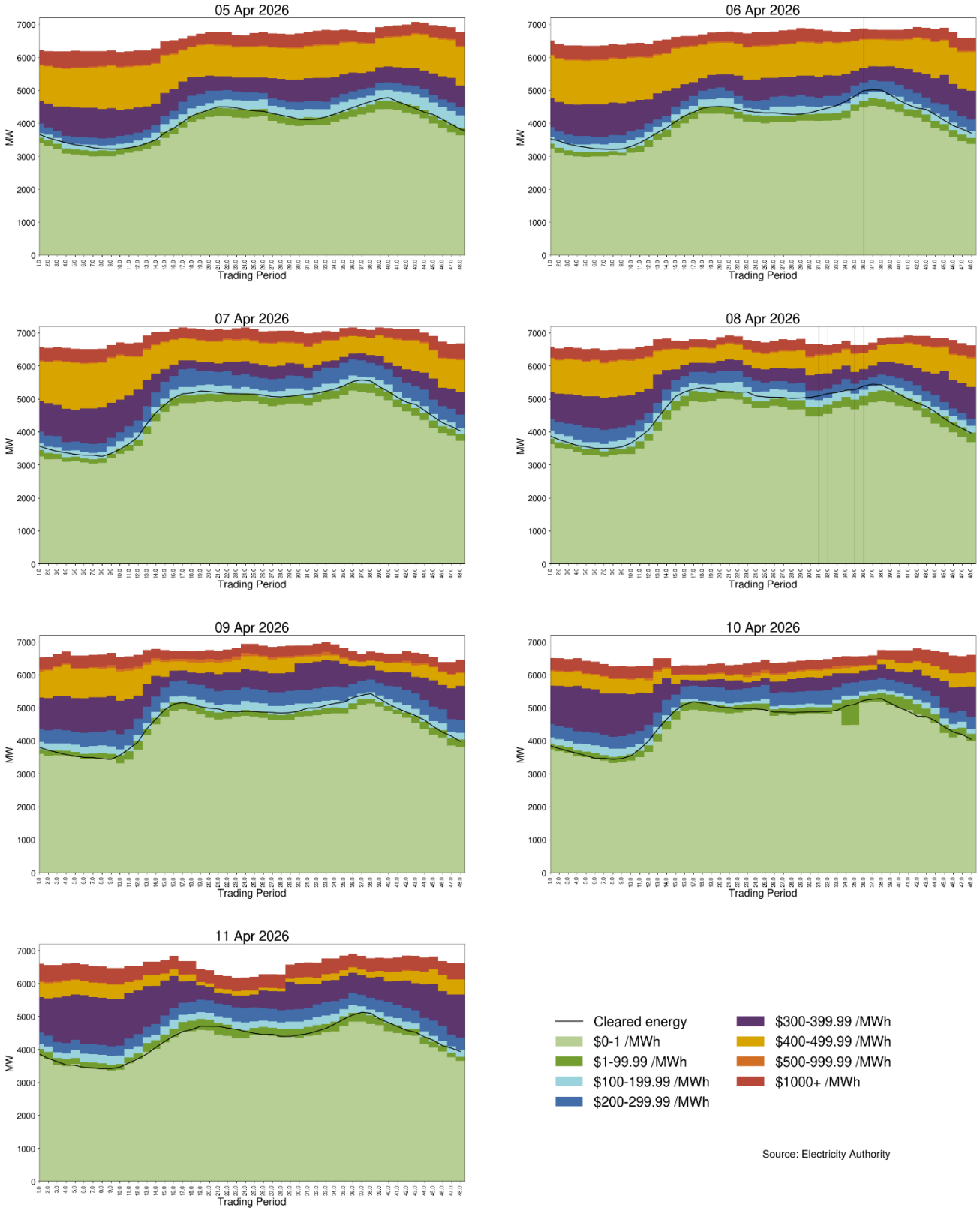
12. Offer behaviour

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, with energy clearing below $100/MWh on Friday evening and Saturday morning.

12.3. From Tuesday, offers in the $400-500/MWh range reduced as Mercury, Manawa and Meridian hydro offers decreased in either price or volume.

Figure 23: Daily offer stacks

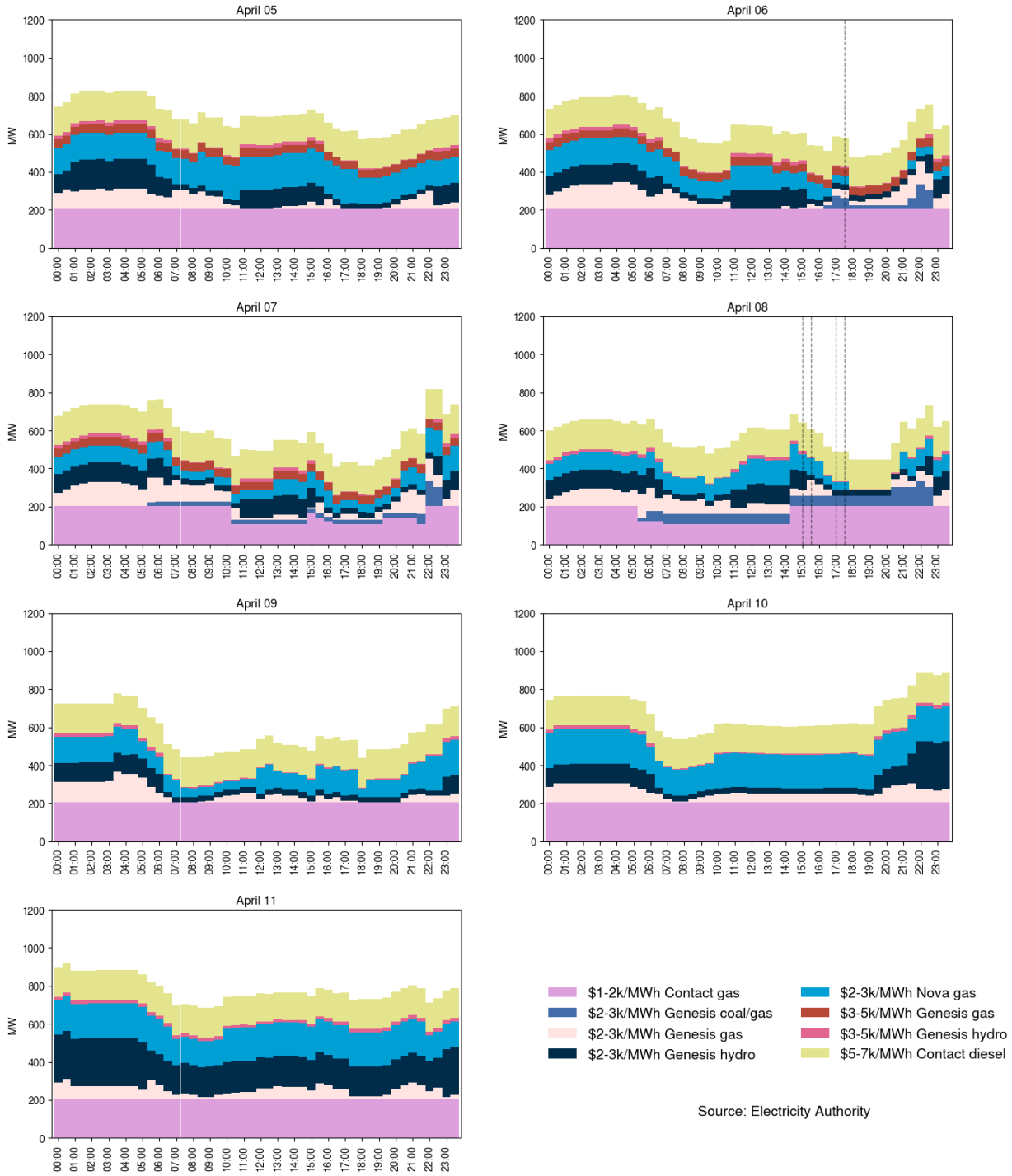


12.4. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 652MW 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