4 May 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 26 April-2 May 2026

Market monitoring weekly report

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1. Overview

1.1. This week the average spot price decreased by $3/MWh to $95/MWh. Lower prices this week are associated with lower demand and higher solar and wind generation. National controlled storage has decreased to 83% nominally full at 110% 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 26 April-2 May:

(a) The average spot price for the week was $95/MWh, a decrease of around $3/MWh compared to the previous week.

(b) 95% of prices fell between $1/MWh and $141/MWh.

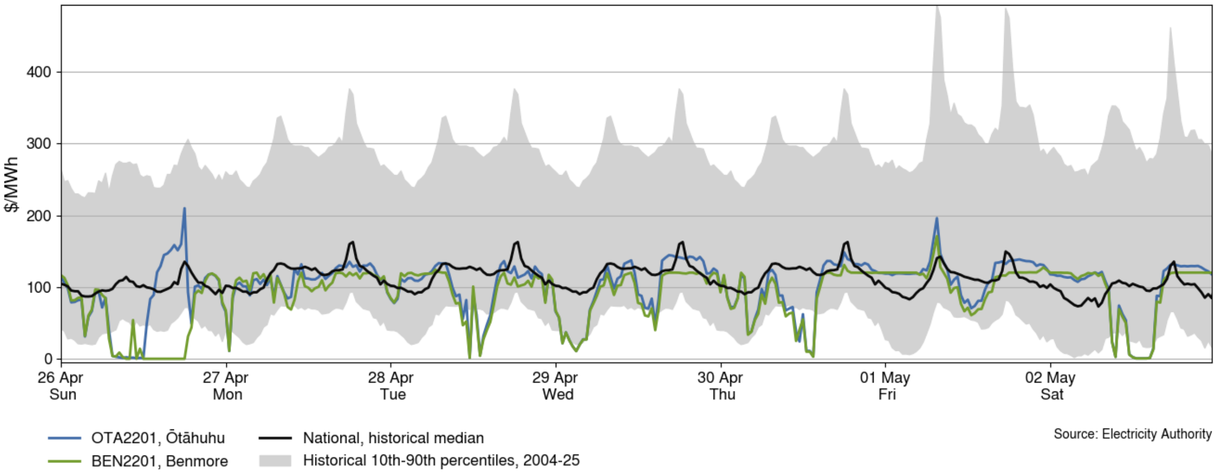
2.3. Prices are slightly lower this week compared to last week due to lower demand, and a small increase in solar and wind generation.

2.4. On Sunday from 1.00pm to 6.30pm there was a period of price separation, peaking at 6.00pm when the price at Ōtāhuhu was $210/MWh, and the price at Benmore was $0.01/MWh. The HVDC was on a full planned outage from 9.30am to 6.30pm on Sunday.

2.5. On Friday at 7.30am, prices at Benmore peaked at $170/MWh and prices at Ōtāhuhu reached $196/MWh. During this time, demand increase coincided with low temperatures for the week and low wind generation.

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.

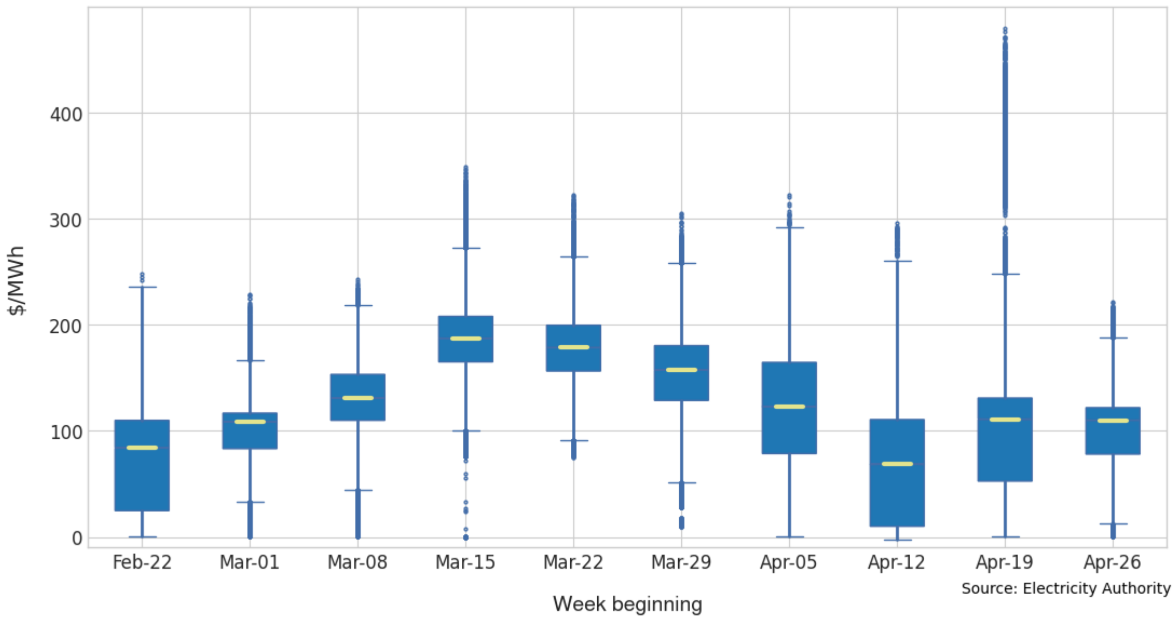
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 26 April-2 May



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 narrower compared to last week. The median price was $110/MWh and most prices (middle 50%) fell between $78/MWh and $122/MWh.

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



3. Reserve prices

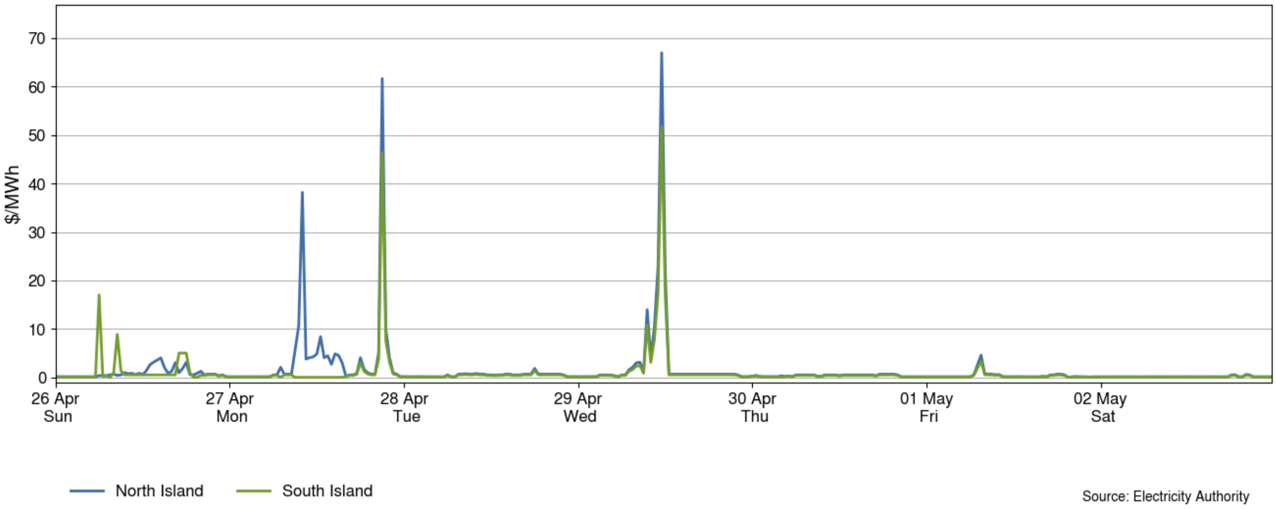
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices mostly remained below $1/MWh, with some spikes early in the week.

3.2. On Monday at 10.00am, North Island FIR prices spiked to $38/MWh, while South Island FIR prices were $0/MWh. During this time, the HVDC was the risk setter for the North Island, and the amount of FIR available was lower than adjacent trading periods.

3.3. On Monday at 9.00pm, FIR prices spiked to $62/MWh in the North Island and $46/MWh in the South Island. During this time, Huntly 5 was the risk setter. Generation at Huntly 5 increased, increasing the amount of reserve needed to cover this risk.

3.4. On Wednesday at 11.30am, FIR prices spiked to $67/MWh in the North Island and $52/MWh in the South Island. During this time, a group of geothermal generators in the North Island were setting the risk.

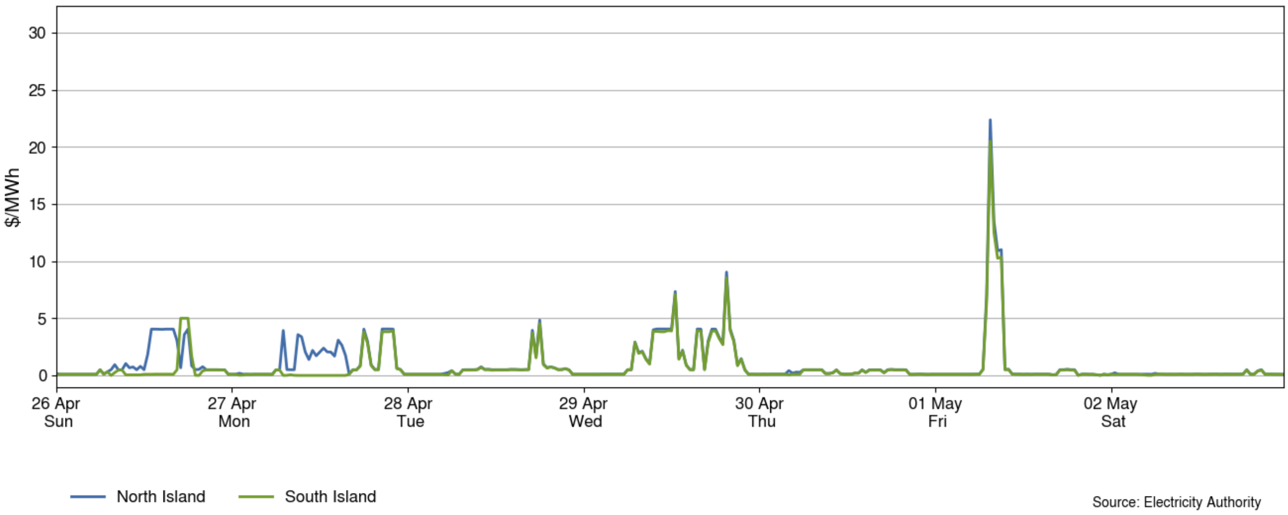
Figure 3: Fast instantaneous reserve price by trading period and island, 26 April-2 May



3.5. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices mostly remained below $1/MWh, with consistent spikes throughout the week.

3.6. On Friday at 7.30am, North Island SIR prices reached $22/MWh and South Island SIR prices reached $21/MWh. At this time, Huntly 5 was the risk setter. Generation at Huntly 5 increased, increasing the amount of reserve needed to cover this risk. This price spike coincided with a spot price spike at the same time.

Figure 4: Sustained instantaneous reserve by trading period and island, 26 April-2 May



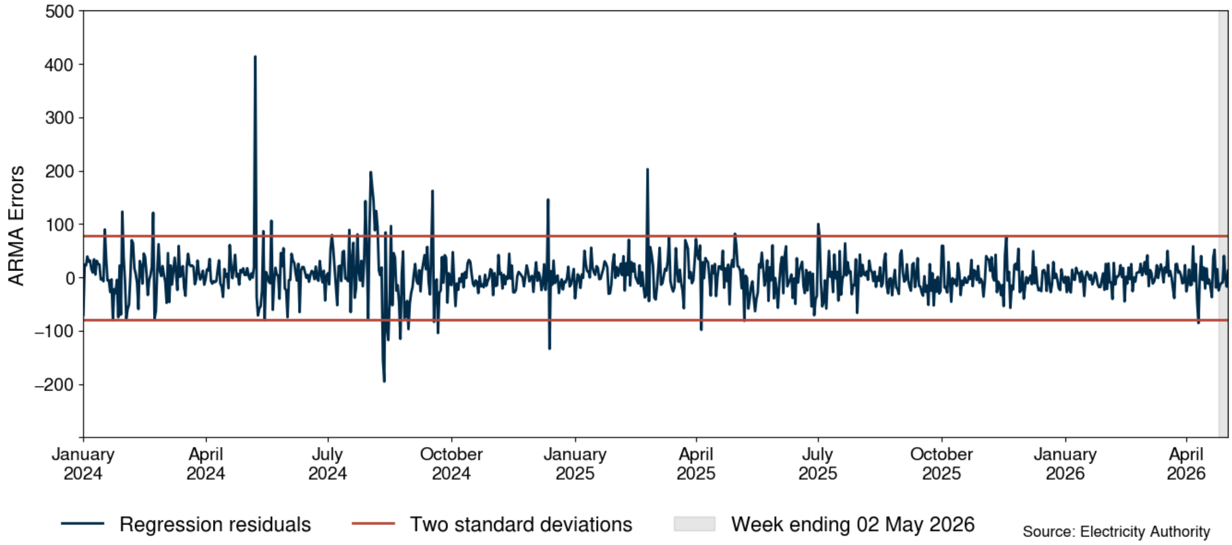
4. Regression residuals

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 - 2 MAY 2026



5. HVDC

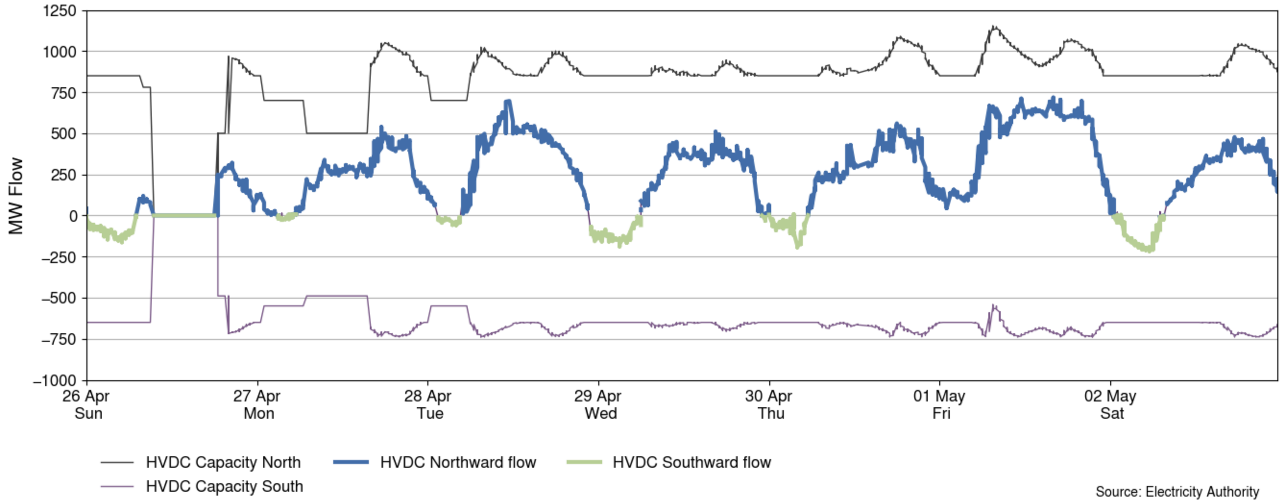
5.1. Figure 6 shows the HVDC flow between 26 April-2 May. HVDC flows were mainly northward this week due to relatively low levels of wind generation, with some southward flow occurring overnight when demand was low.

5.2. From 9.30am to 6.30pm on Sunday, the HVDC was on a planned outage to repair damage caused by recent weather events. The outage was originally planned to be just Pole 2 but was revised to include both Poles 2 and 3 at 9.30am on Sunday.

5.3. The highest northward flow occurred on Friday at 4.00pm, with around 717MW.

5.4. The highest southward flow occurred on Saturday at 5.30am, with around 217MW.

Figure 6: HVDC flow and capacity, 26 April-2 May

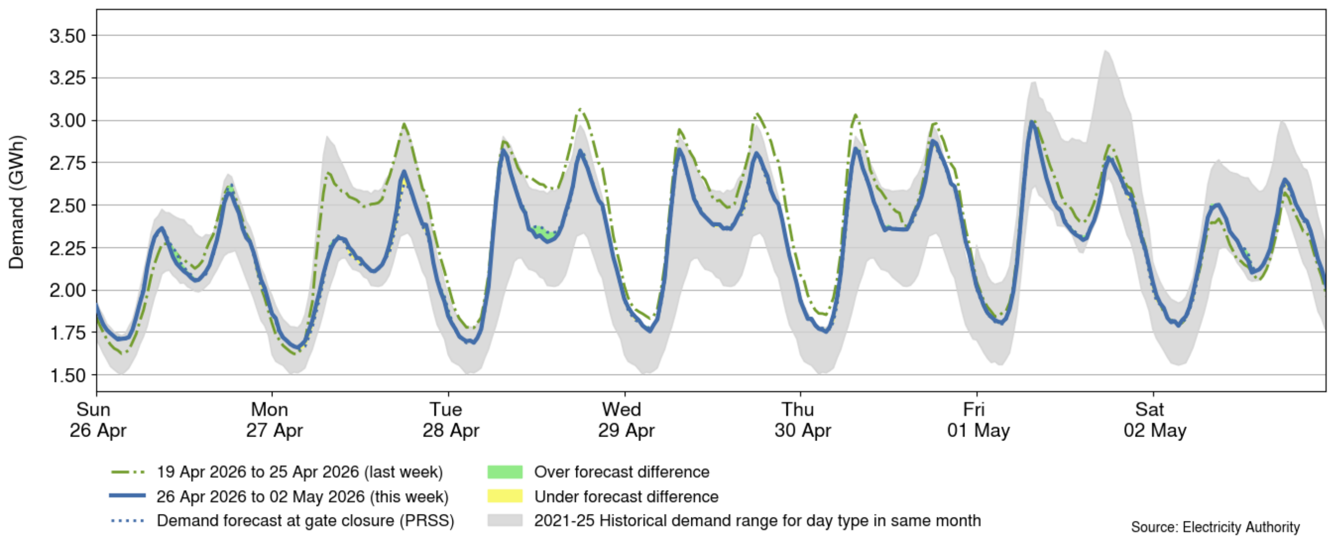


6. Demand

6.1. Figure 7 shows national demand between 26 April-2 May, compared to the historic range and the demand of the previous week.

6.2. Demand was generally lower than last week, due to warmer temperatures. Demand was lower on Monday due to ANZAC day. Demand was similar to last week on Friday and Saturday.

Figure 7: National demand, 26 April-2 May compared to the previous week

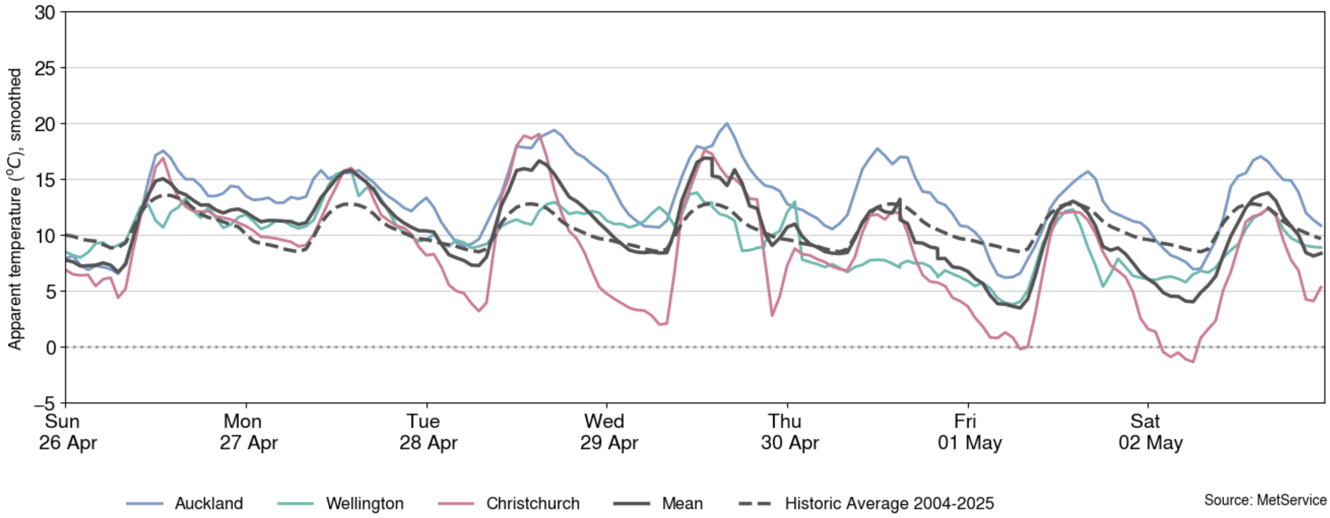


6.3. Figure 8 shows the hourly apparent temperature at main population centres from 26 April-2 May. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.4. Apparent temperatures ranged from 6°C to 20°C in Auckland, 4°C to 16°C in Wellington, and -2°C to 19°C in Christchurch.

6.5. Temperatures were mainly near the historic average but were below the historic average on Friday morning and evening.

Figure 8: Temperatures across main centres, 26 April-2 May

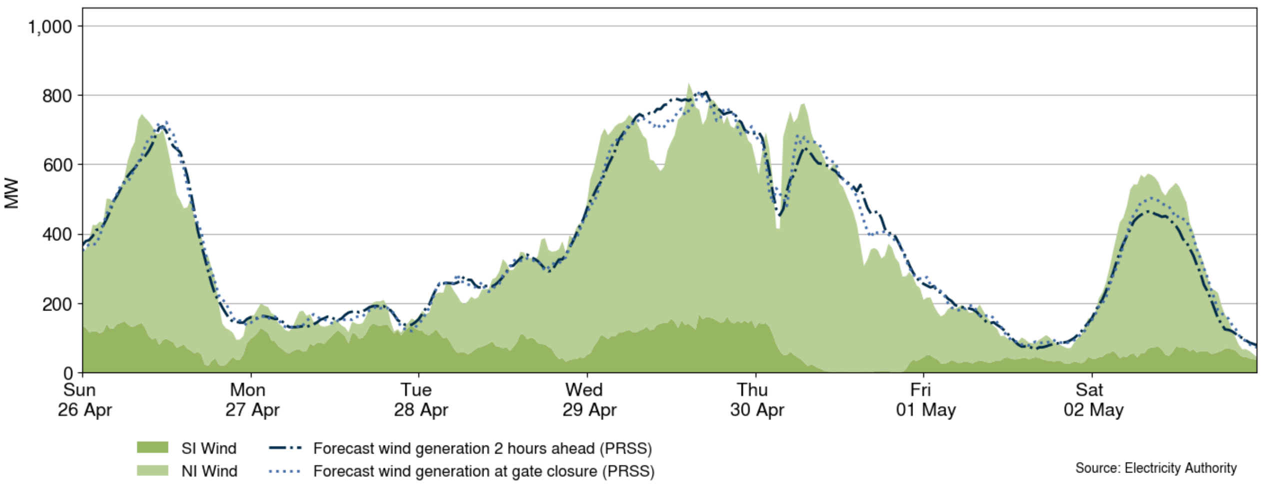


7. Generation

7.1. Figure 9 shows wind generation and forecast from 26 April-2 May. This week wind generation varied between 45MW and 835MW, with a weekly average of 366MW. Wind generation was low across Monday, Tuesday and Friday.

7.2. There were some larger forecasting errors on Sunday afternoon, Wednesday midday and Thursday afternoon, which were the result of an amalgamation of errors.

Figure 9: Wind generation and forecast, 26 April-2 May

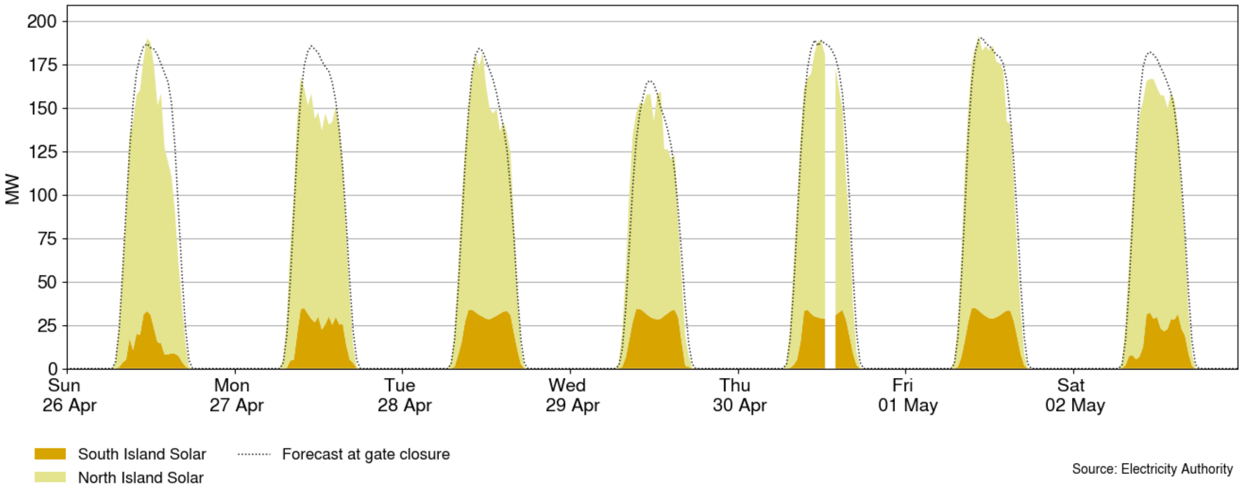


7.3. Figure 10 shows grid connected solar generation from 26 April-2 May. Solar generation was high this week, reaching 150MW every day and averaging around 100MW every day.

7.4. Solar generation reached 191MW on Thursday at 10.30am.

7.5. Note that data is missing for trading periods 27 and 28 on Thursday.

Figure 10: Grid connected solar generation, 26 April-2 May

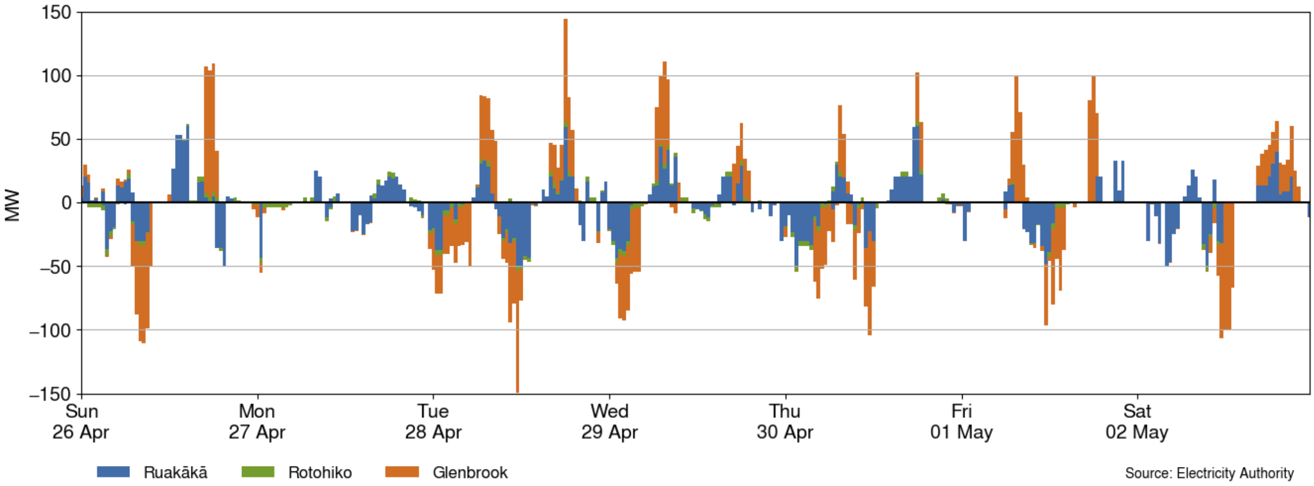


7.6. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh), Ruakākā (100MW/200MWh) and Glenbrook (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are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

7.7. This week, prices have been higher than usual overnight, and lower than usual during the midday peak. The batteries have been charging more during the day, and less overnight. As usual, the batteries have been discharging during peak periods.

7.8. On Sunday, the batteries charged in the morning when prices were lower, and discharged in the afternoon when North Island prices were higher.

Figure 11: Grid scale battery charge and discharge, 26 April-2 May



7.9. 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.

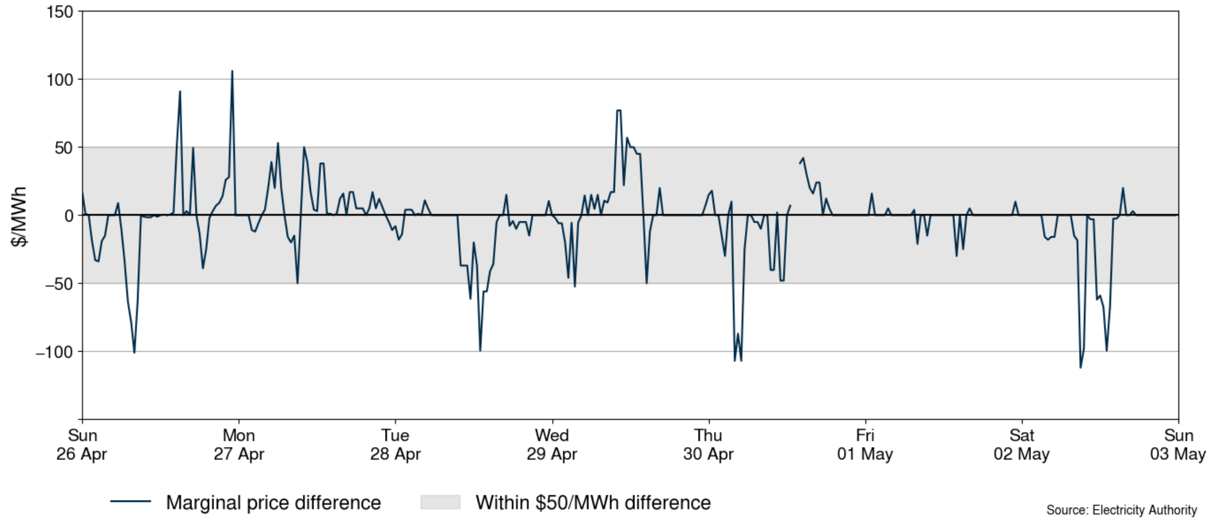
7.10. Some trading periods this week had a marginal price difference of more than $50/MWh.

7.11. The maximum positive difference of $106/MWh occurred on Sunday at 11.00pm. At this time, demand was 60MW higher than forecast, and wind generation was 39MW lower than forecast.

7.12. The maximum negative difference of $112/MWh occurred on Saturday at 9.00am. At this time, demand was 10MW lower than forecast, and wind generation was 64MW higher than forecast.

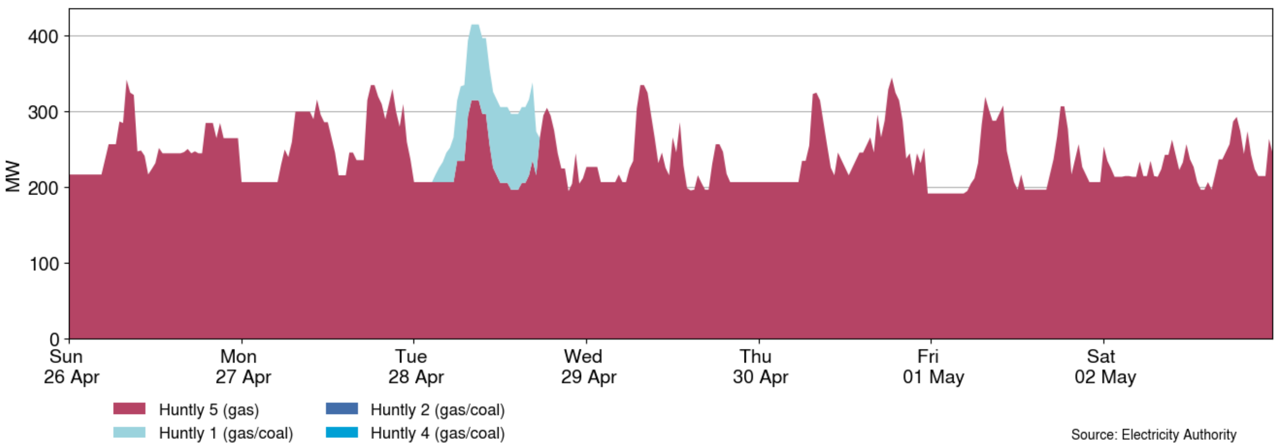
7.13. Note that data is missing for trading periods 27 and 28 on Thursday.

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, 26 April-2 May



7.14. Figure 13 shows the generation of thermal baseload between 26 April-2 May. Huntly 5 ran continuously throughout the week, and Huntly 1 ran on Tuesday.

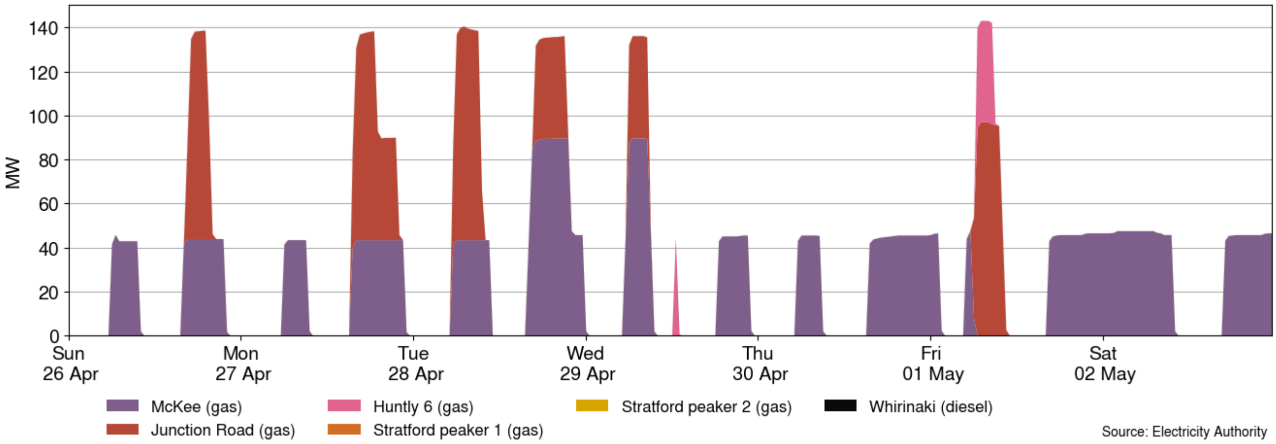
Figure 13: Thermal baseload generation, 26 April-2 May



7.15. Figure 14 shows the generation of thermal peaker plants between 26 April-2 May. McKee ran at times every day this week, Junction Road ran at times every day except Thursday and Saturday, and Huntly 6 ran at times on Wednesday and Friday.

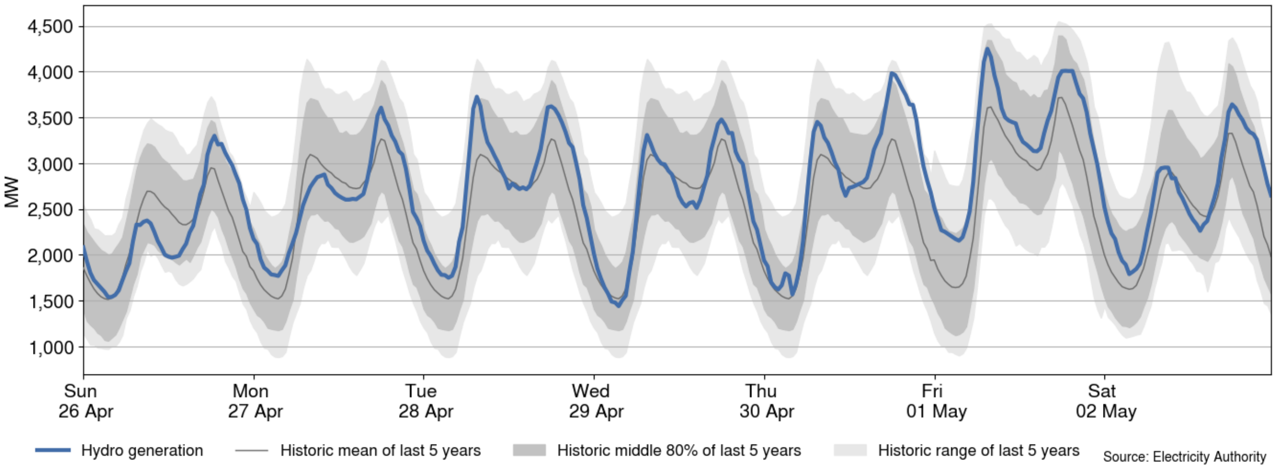
7.16. In the periods where Huntly 6 ran, it was offering all of its energy at less than $1/MWh, and it was offering all of its energy at over $1000/MWh at all other times.

Figure 14: Thermal peaker generation, 26 April-2 May



7.17. Figure 15 shows hydro generation between 26 April-2 May. Hydro generation was near the historic mean for most of the week but was above the historic mean on Thursday and Friday.

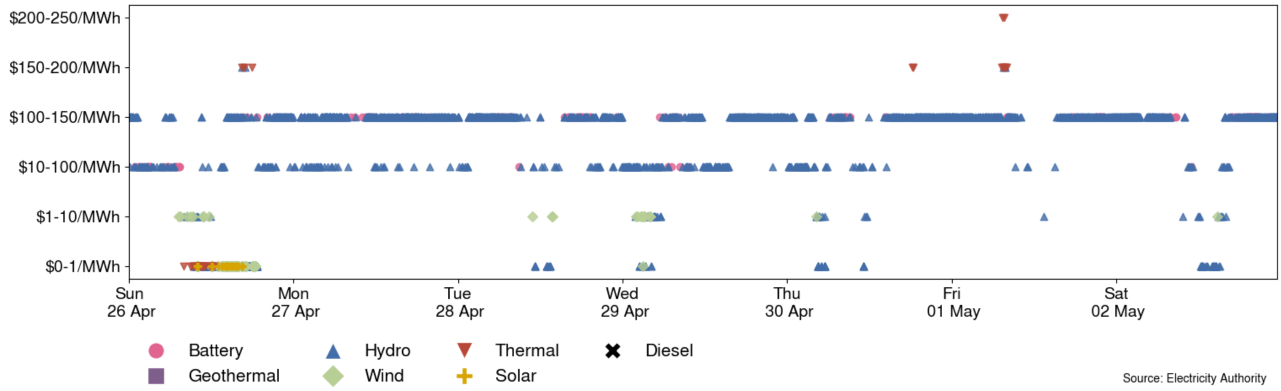
Figure 15: Hydro generation, 26 April-2 May



7.18. 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.

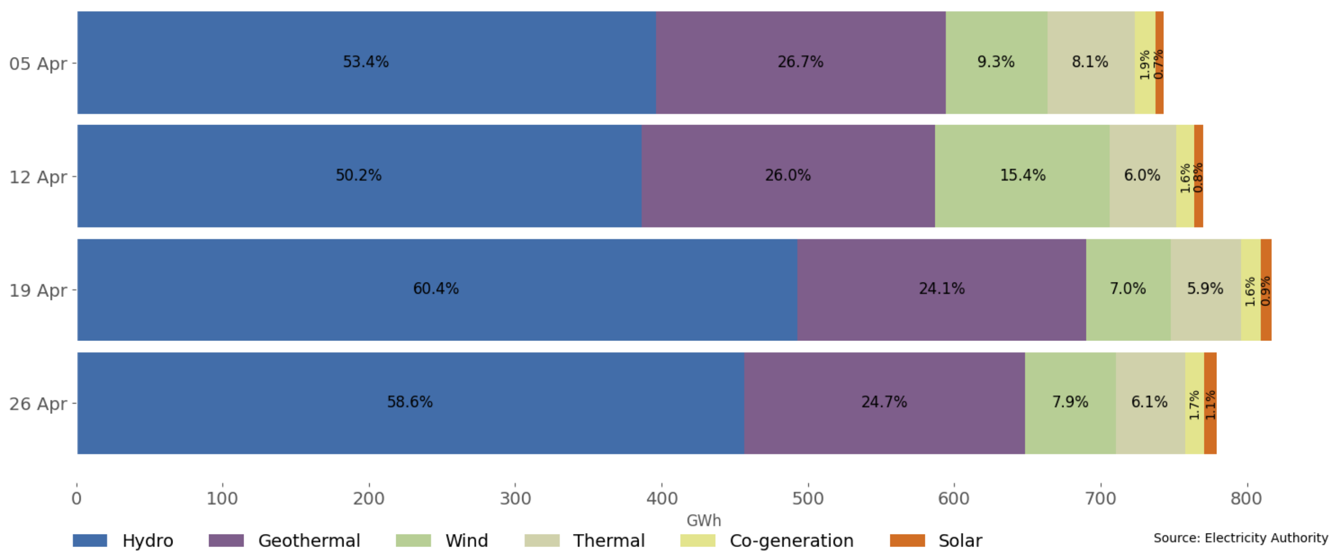
7.19. The highest prices were set by Genesis thermal on Friday. The most common technology setting prices was hydro generation, with batteries the second most common. Most marginal prices were between $100-150/MWh.

Figure 16: Prices of marginal generation, 26 April-2 May



7.20. As a percentage of total generation, between 5 April-2 May, total weekly hydro generation was 58.6%, geothermal 24.7%, wind 7.9%, thermal 6.1%, co-generation 1.7%, and solar (grid connected) 1.1%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 5 April and 2 May



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 26 April-2 May ranged between ~882MW and ~1,674MW. Figure 19 shows the thermal generation capacity outages.

8.2. The Glenbrook battery was on outage on Wednesday, and the Ruakākā battery was on outage on Monday and Friday.

Figure 18: Total MW loss from generation outages, 26 April-2 May

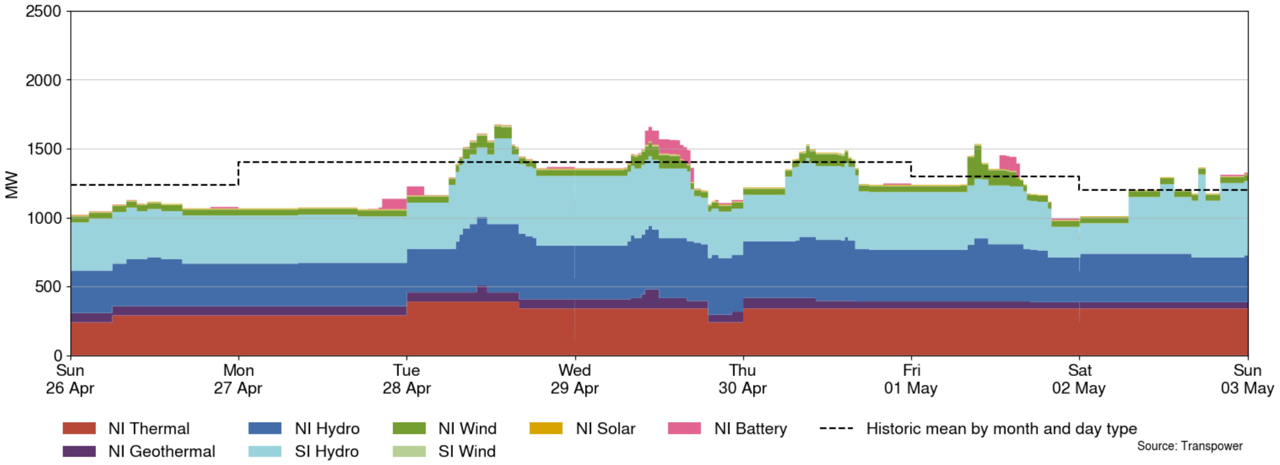
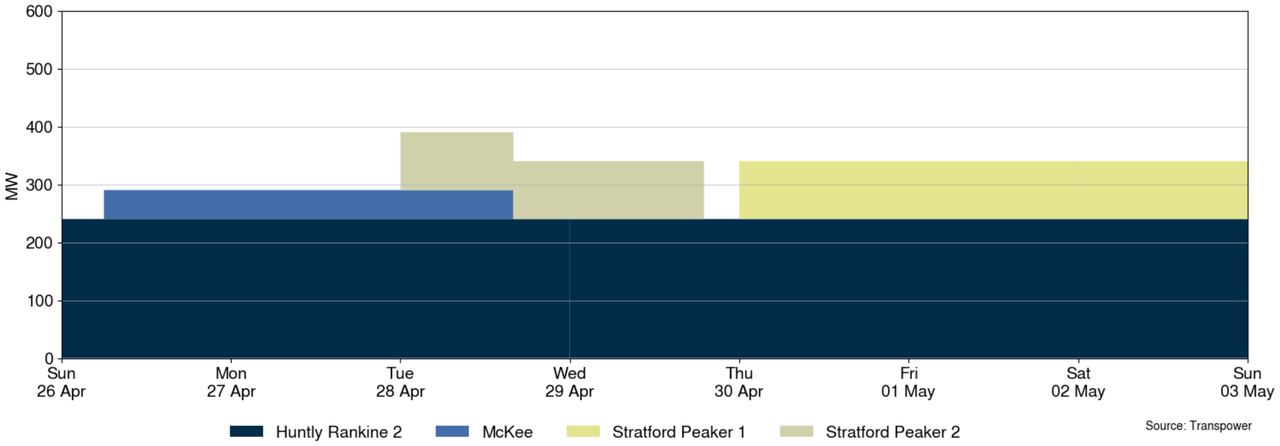


Figure 19: Total MW loss from thermal outages, 26 April-2 May



8.3. Notable outages include:

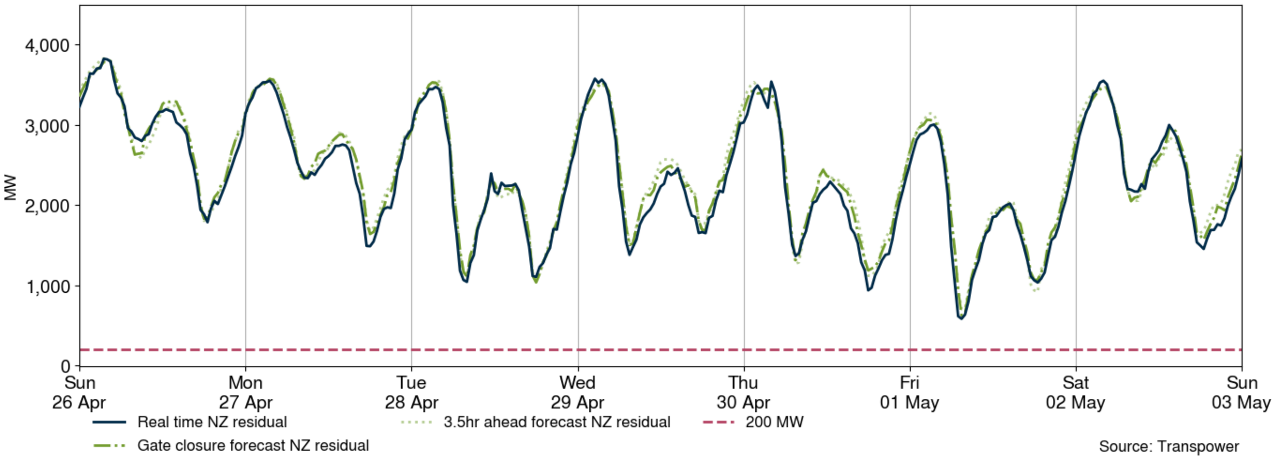
Plant	Partial or Full	End Date
Manapōuri unit 1	Full	29 April 2026
Clyde unit 2	Full	30 April 2026
Rangipō unit 5	Full	1 May 2026
Manapōuri unit 6	Full	4 May 2026
Rangipō unit 6	Full	9 May 2026
Stratford Peaker 1	Full	10 May 2026
Huntly 2	Full	20 May 2026
Manapōuri unit 4	Full	21 July 2026
Roxburgh unit 8	Full	2 September 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 26 April-2 May. 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 have been healthy this week. The lowest national residual was 584MW on Friday at 7.30am.

Figure 20: National generation balance residuals, 26 April-2 May



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 10^{th} to 90^{th} percentiles.

10.2. As of 2 May, national controlled storage was 83% nominally full and ~110% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (81% full[2]) is above its historic mean, while Lake Tekapō (70% full) is below its historic mean.

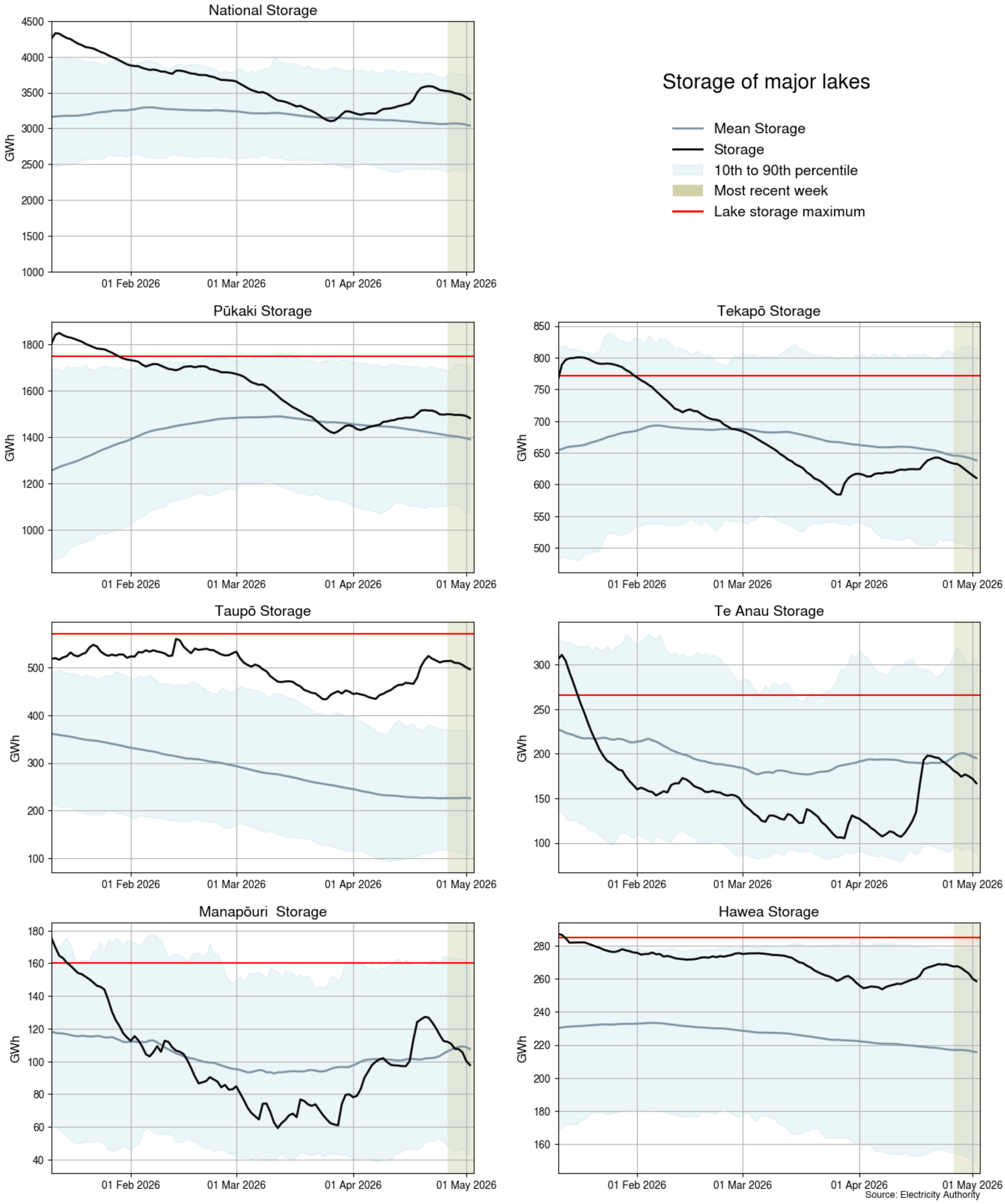
10.4. Storage at Lake Te Anau (61% full) is below its historic mean, with Lake Manapōuri (60% full) has dropped below its historic mean.

10.5. Storage at Lake Taupō (86% 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.

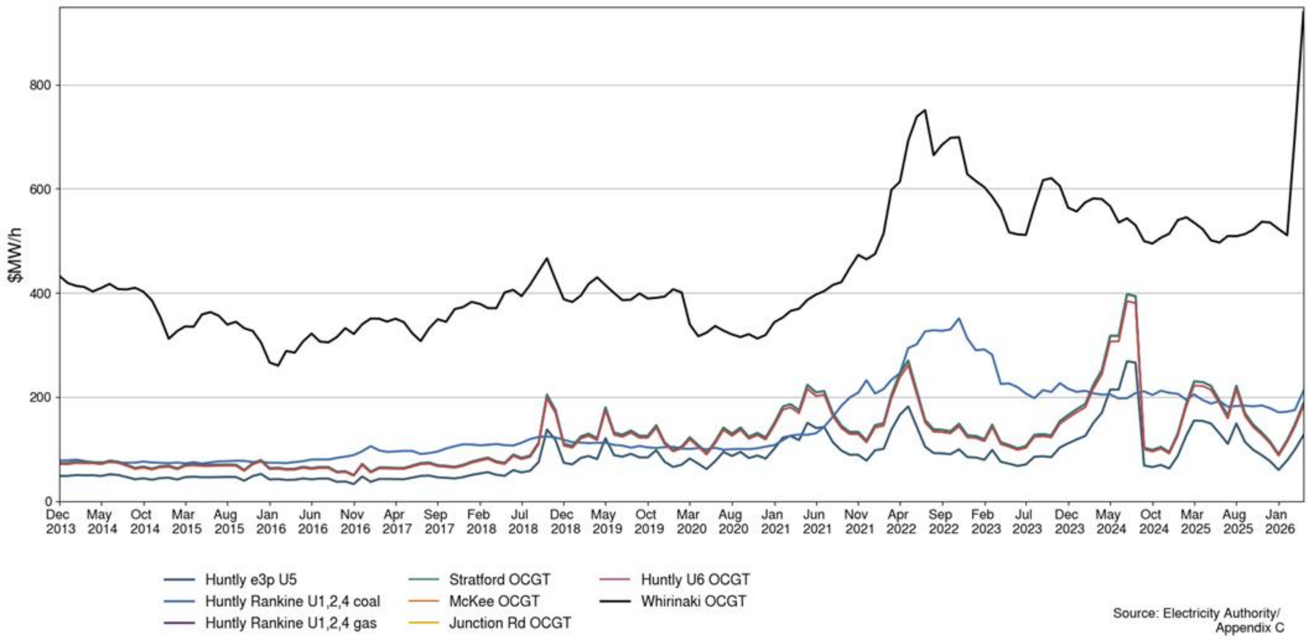
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$212/MWh. The cost of running the Rankines on gas is ~$188/MWh.

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



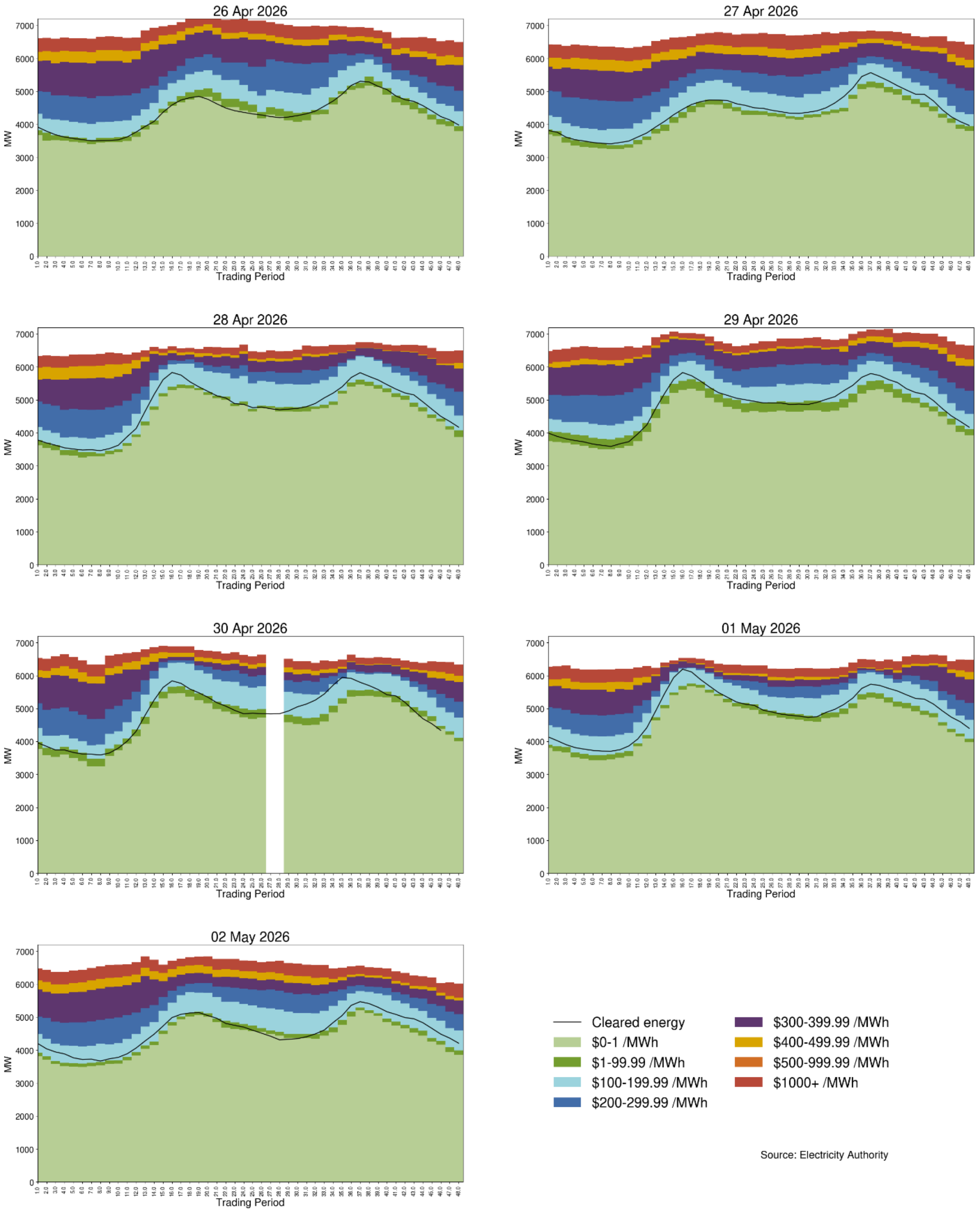
12. Offer behaviour

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 energy cleared below $200/MWh this week.

12.3. Note that offers data is missing for trading periods 27 and 28 on Thursday.

Figure 23: Daily offer stacks

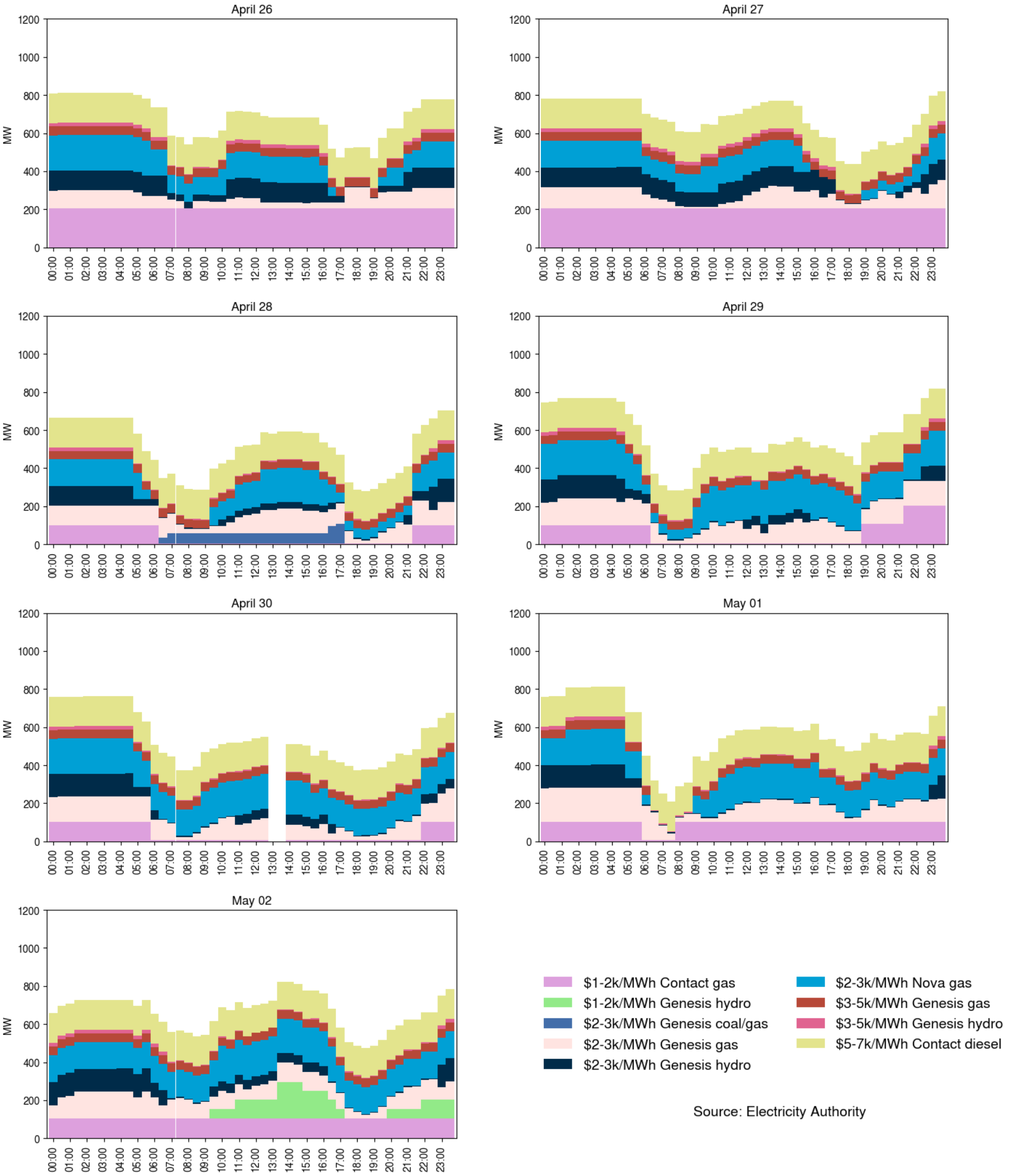


12.4. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 the 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 606MW per trading period was priced above $1,000/MWh this week, which is roughly 11% of the total energy available.

Figure 24: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions. The monitoring team is looking into Genesis and Contact hydro offers further this week.

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
22/04/2026-24/04/2026	Several	Further analysis	Genesis	Tokaanu	Offers
26/04/2026-02/05/2026	Several	Further analysis	Contact	Roxburgh	Offers
02/05/2026	Several	Further analysis	Genesis	Tokaanu	Offers