

2 February 2026

Trading conduct report 25-31 January 2026

Market monitoring weekly report

Trading conduct report 25-31 January 2026

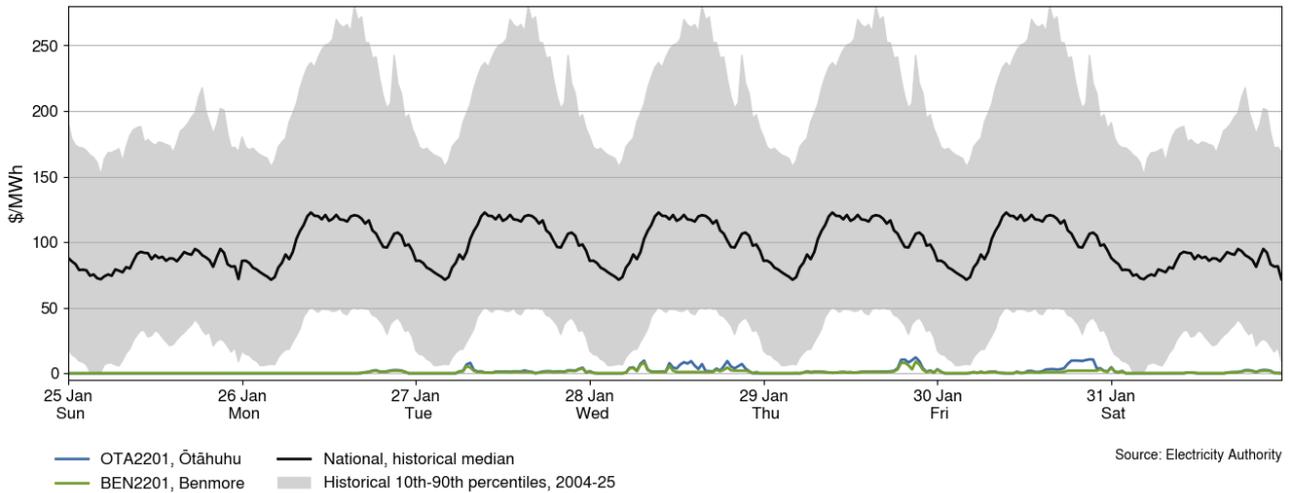
1. Overview

- 1.1. This week the average spot price decreased by \$1/MWh to \$1/MWh, with prices mostly remaining below \$9/MWh. Demand decreased slightly this week compared to last week. The proportion of hydro and geothermal generation increased this week, while wind and thermal generation fell. National hydro storage decreased but remains high at 95% nominally full and ~118% of the historical average for this time of the year.

2. Spot prices

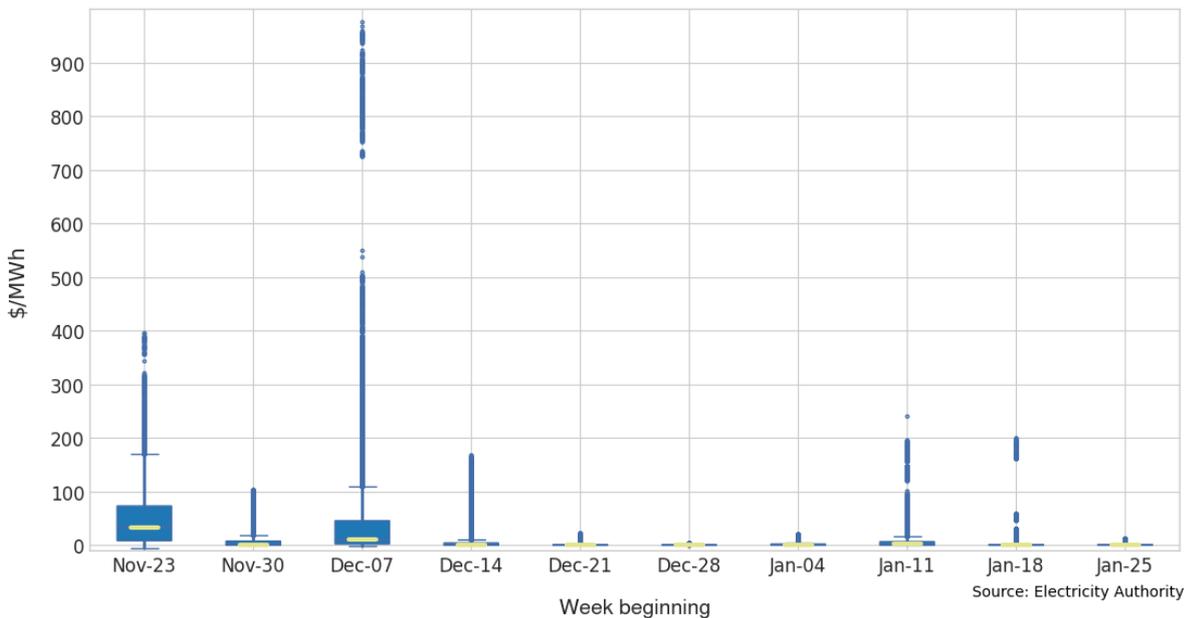
- 2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.
- 2.2. Between 25-31 January:
 - (a) The average spot price for the week was \$1/MWh, a decrease of around \$1/MWh compared to the previous week.
 - (b) 95% of prices fell between \$0.01/MWh and \$9/MWh.
- 2.3. Prices were very low overall this week. Lower demand and higher northward HVDC capacity this week contributed to lower prices this week than the previous week.
- 2.4. The highest Ōtāhuhu price of \$12/MWh occurred at 9.00pm on Thursday. Demand was 21MW higher than forecast at this time. There was also no thermal baseload running at this time.
- 2.5. Price separation between the two islands occurred at times on Wednesday and Friday when the HVDC was close to its northward capacity. Additionally, constraints in the Hawkes Bay region led to prices of \$0/MWh at times on Wednesday and Thursday.
- 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, 25-31 January



- 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 similar compared to last week. The median price was \$0.41/MWh and most prices (middle 50%) fell between \$0.01/MWh and \$1.4/MWh.

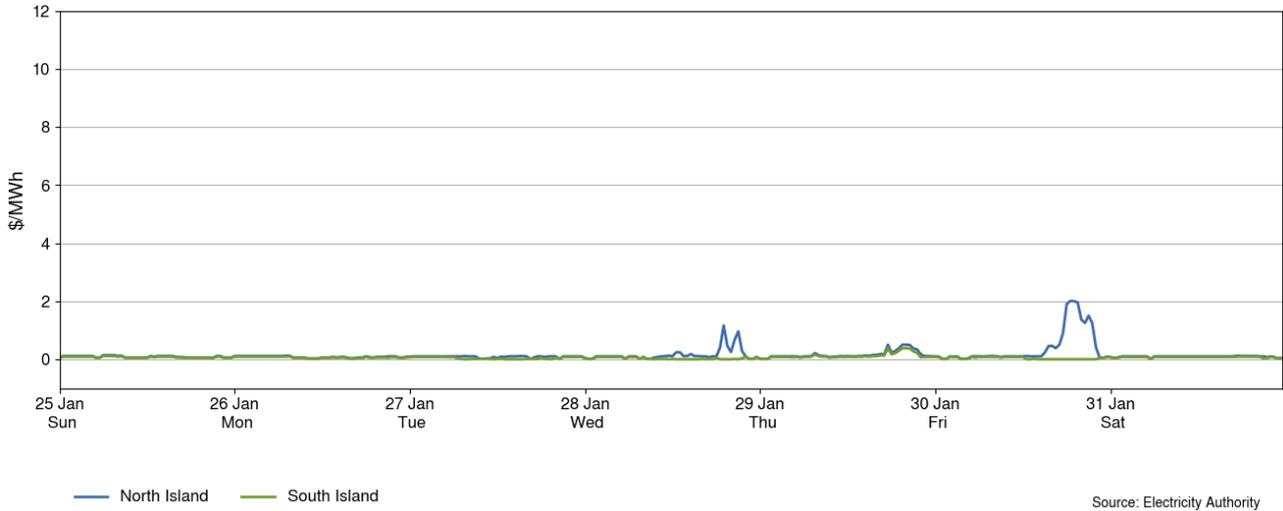
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

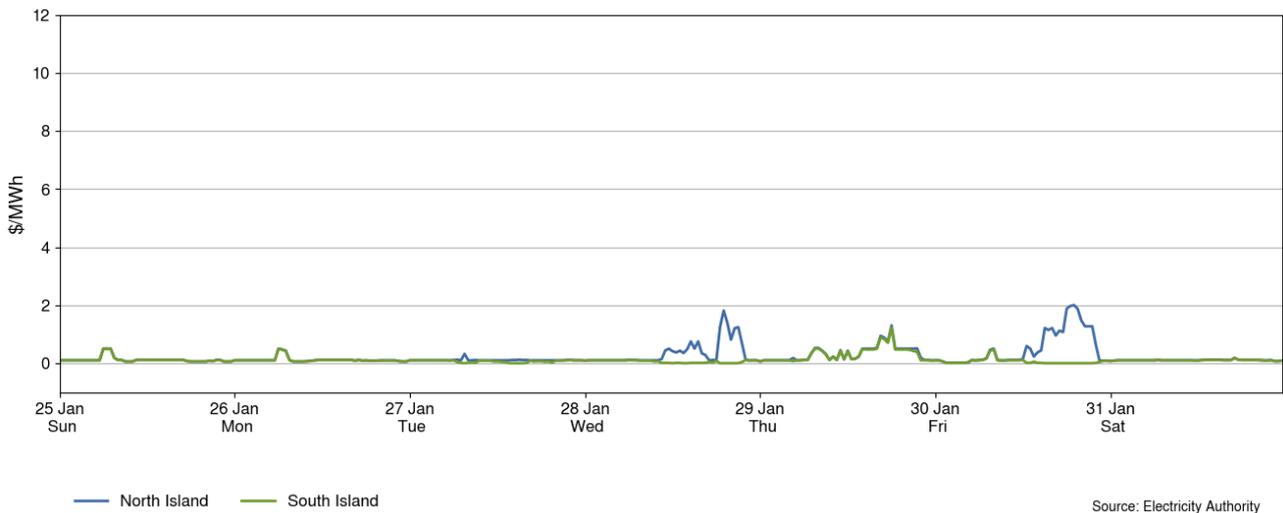
- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices across both the North and South Islands remained below \$3/MWh this week.

Figure 3: Fast instantaneous reserve price by trading period and island, 25-31 January



3.2. 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 \$3/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 25-31 January

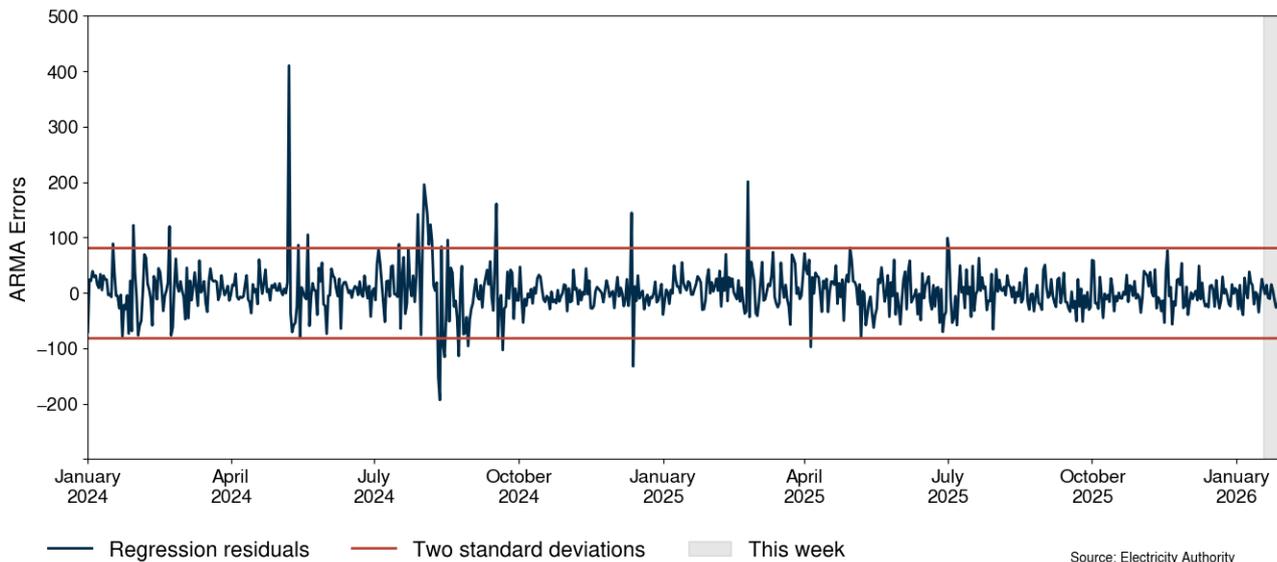


4. Regression residuals

- 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 2023 - 31 January 2026

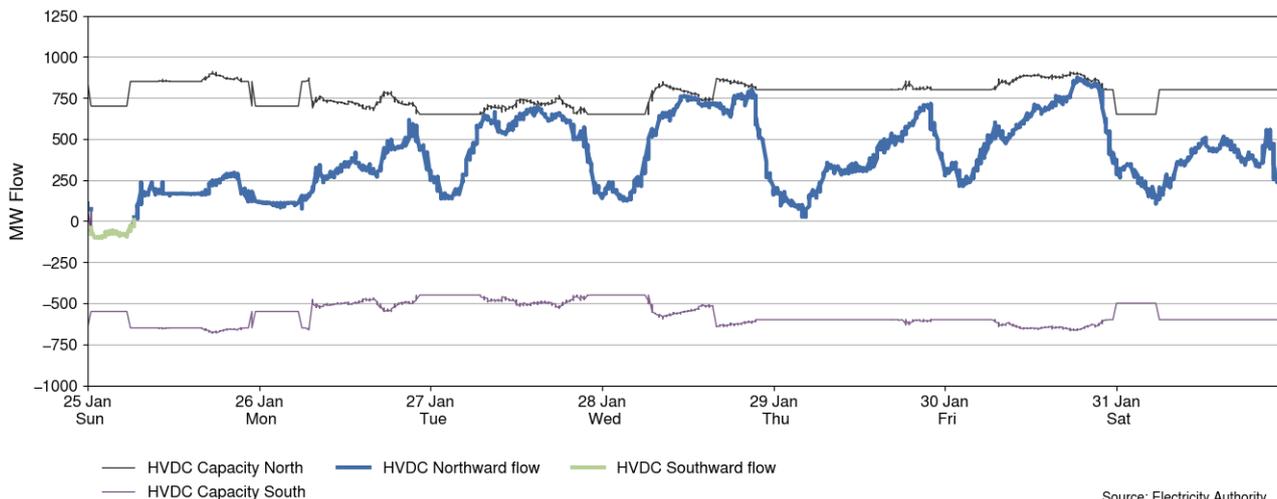


5. HVDC

5.1. Figure 6 shows the HVDC flow between 25-31 January. HVDC flows were mostly northward, with periods of southward flow overnight on Sunday.

5.2. The highest northward flow occurred at 6.30pm on Friday with a flow of around 873MW.

Figure 6: HVDC flow and capacity, 25-31 January



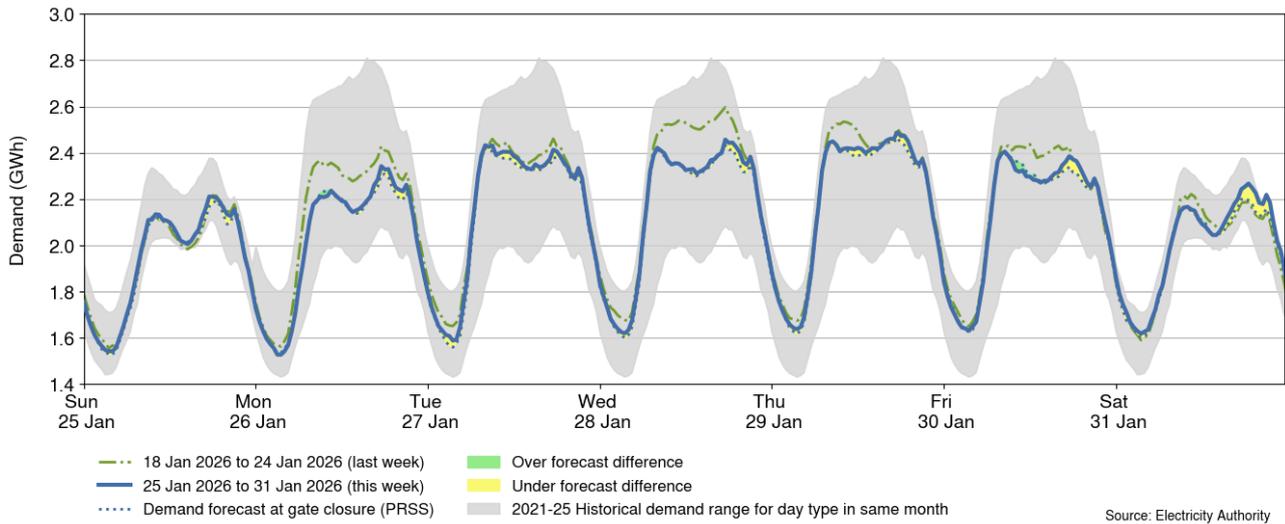
6. Demand

6.1. Figure 7 shows national demand between 25-31 January, compared to the historic range and the demand of the previous week.

6.2. Demand this week was close to or lower than the previous week, except on Saturday evening, where demand was higher than forecast and higher compared to the previous week.

6.3. The highest demand of the week was around 2.49GWh at 5.30pm on Thursday.

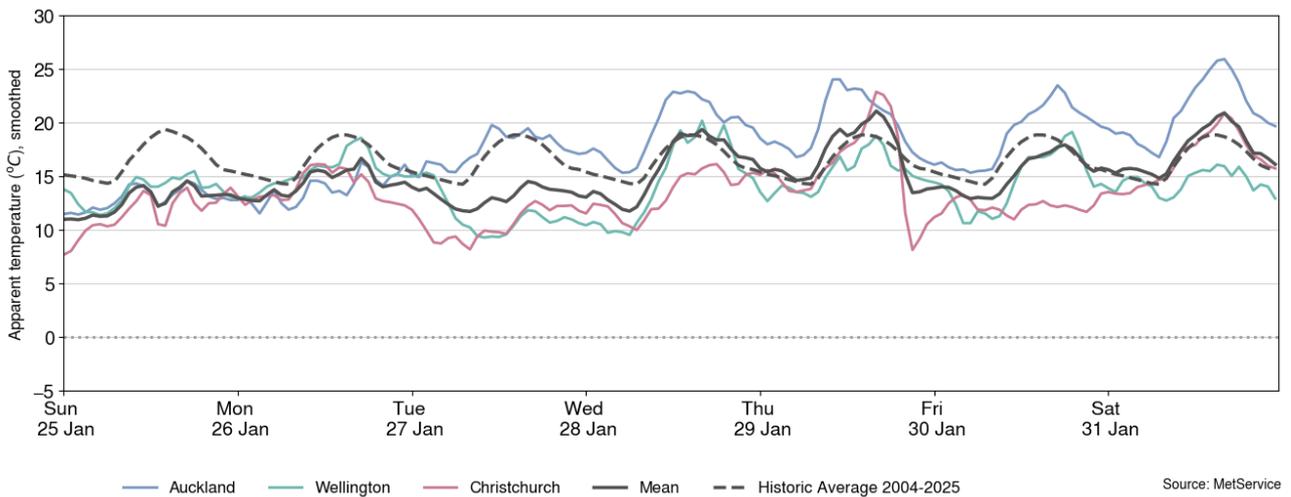
Figure 7: National demand, 25-31 January compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 25-31 January. 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 11°C to 26°C in Auckland, 9°C to 20°C in Wellington, and 8°C to 24°C in Christchurch.

Figure 8: Temperatures across main centres, 25-31 January



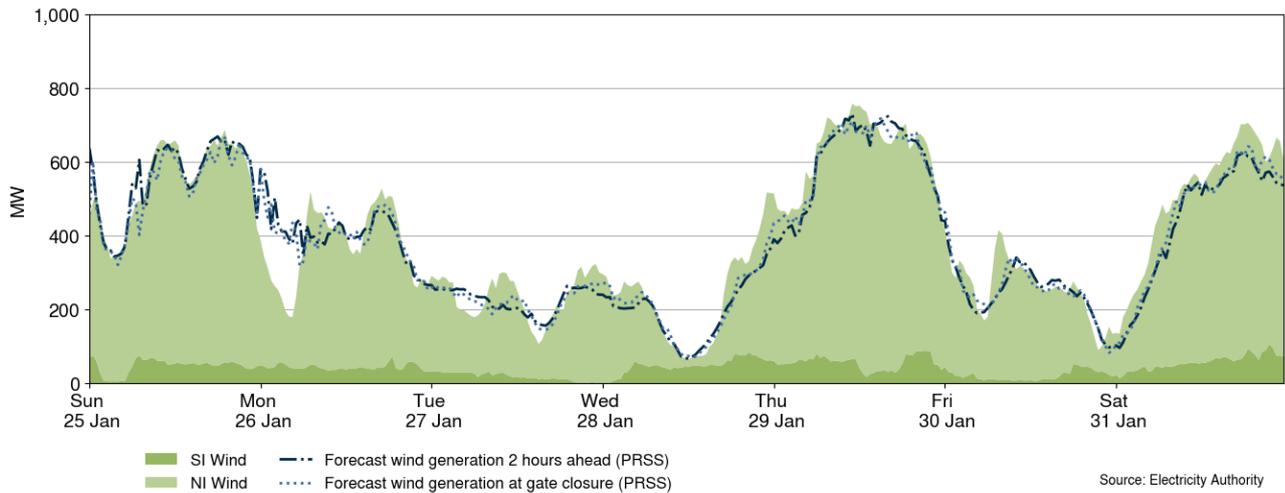
7. Generation

7.1. Figure 9 shows wind generation and forecast from 25-31 January. This week wind generation varied between 65MW and 759MW, with a weekly average of 398MW.

7.2. Wind generation was higher on Sunday, Thursday and Saturday, but was otherwise lower overall.

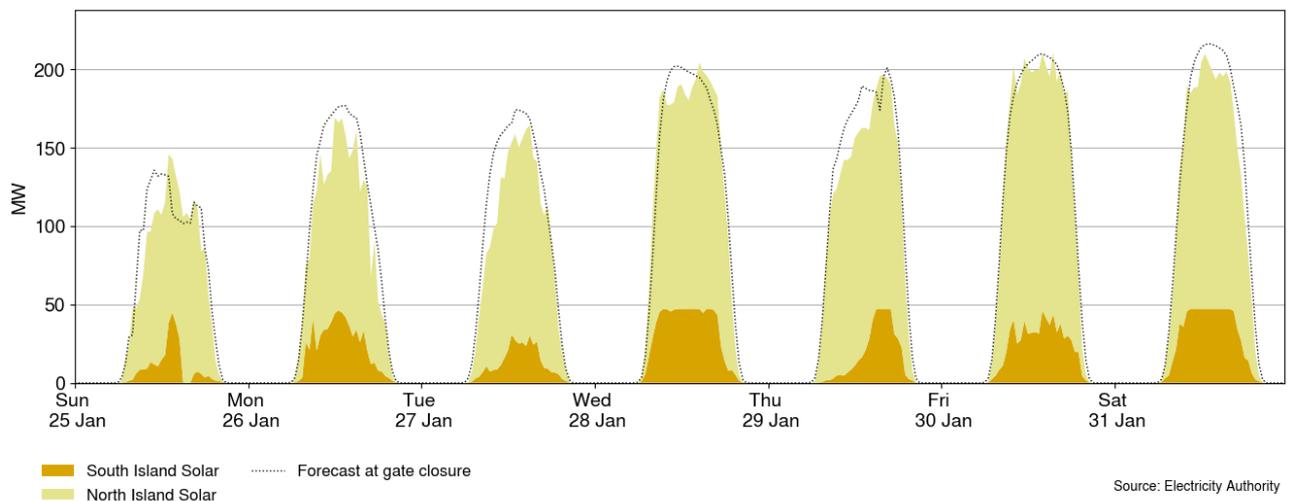
7.3. Wind forecasting errors on Monday morning were an amalgamation of errors across multiple wind farms. The monitoring team is looking further into forecasting errors at Turitea during this period.

Figure 9: Wind generation and forecast, 25-31 January



7.4. Figure 10 shows grid connected solar generation from 25-31 January. Solar generation reached above 145MW daily, peaking on Saturday at 3.30pm at around 211MW.

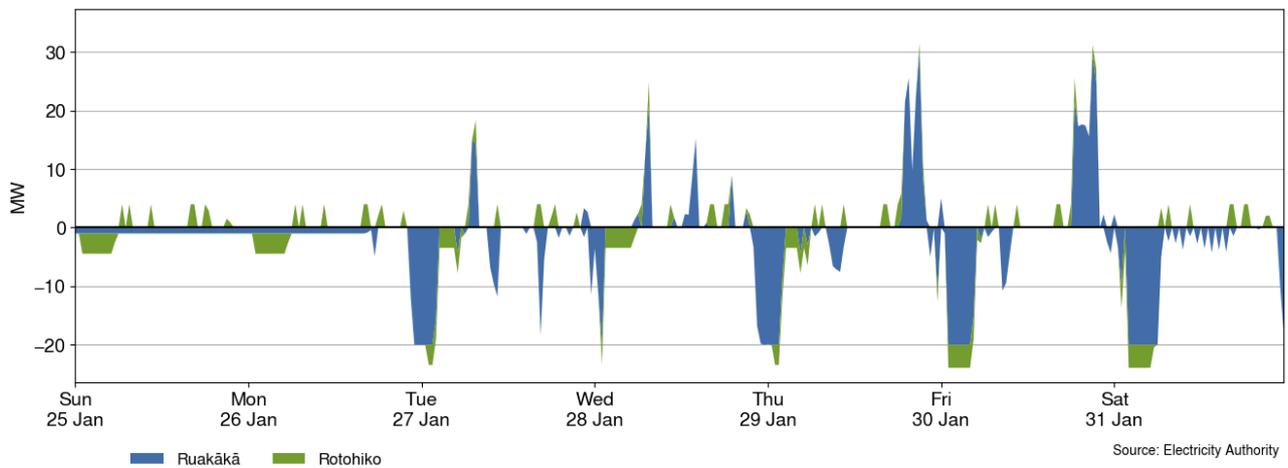
Figure 10: Grid connected solar generation, 25-31 January



7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh) and Ruakākā (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 discharged during the day when prices were higher. The batteries mostly charged overnight or during the day when prices were low. When daytime prices were lower on Sunday, Monday and Saturday, the batteries discharged less.

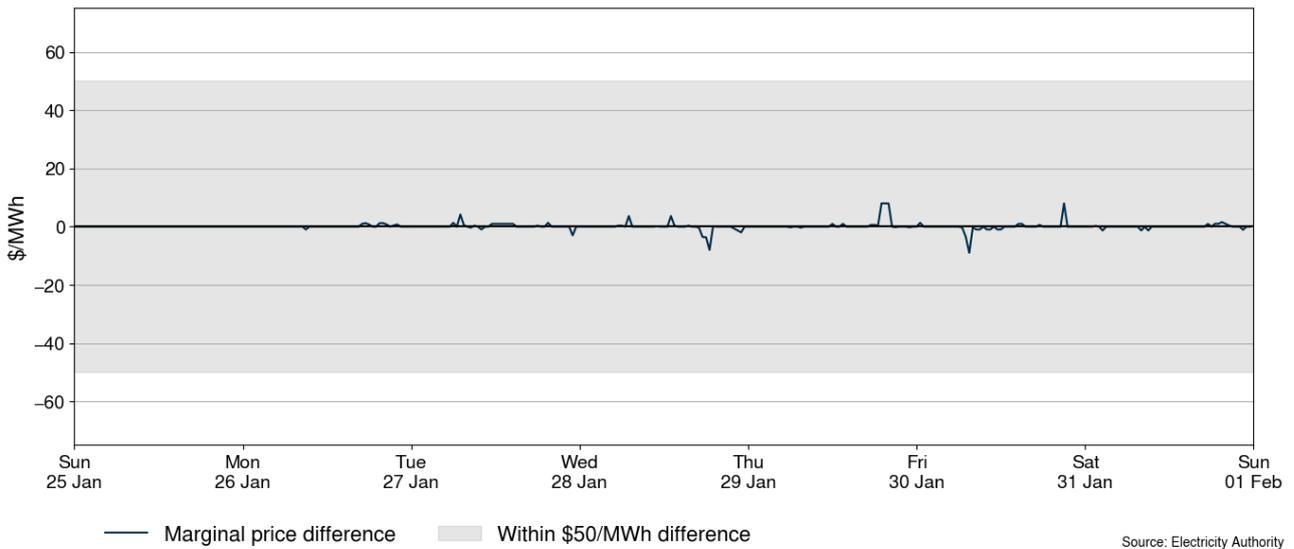
Figure 11: Grid scale battery charge and discharge, 25-31 January



- 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 (PRSS¹) 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. No trading periods this week had a marginal price difference above or below \$50/MWh.

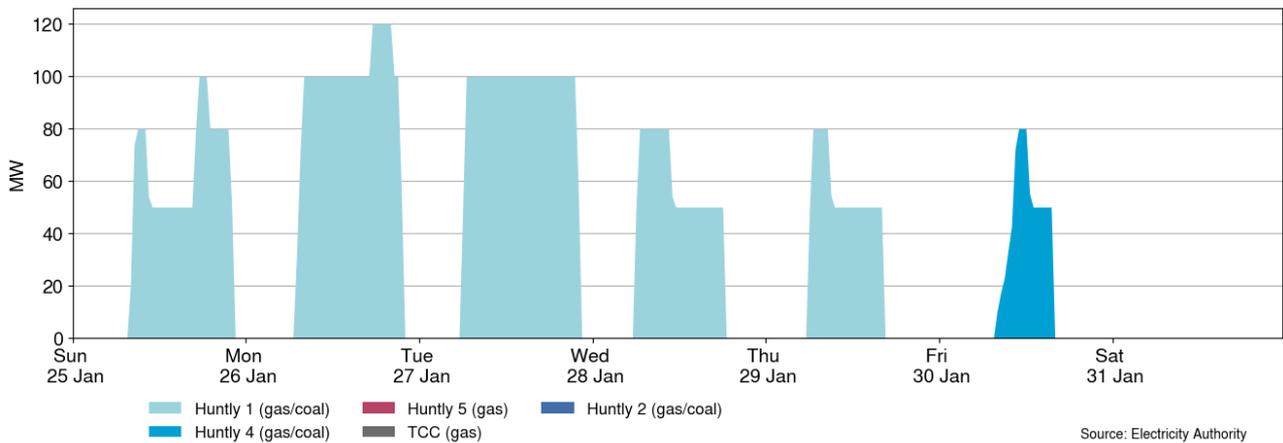
¹ Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 25-31 January



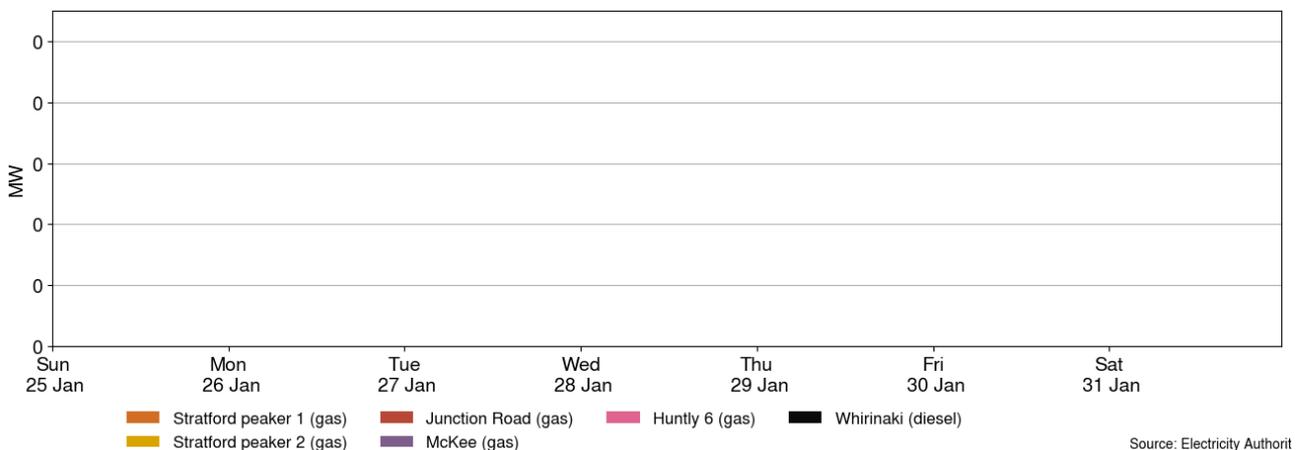
7.9. Figure 13 shows the generation of thermal baseload between 25-31 January. This week Huntly 1 ran each day between Sunday and Thursday, with Huntly 4 running on Friday.

Figure 13: Thermal baseload generation, 25-31 January



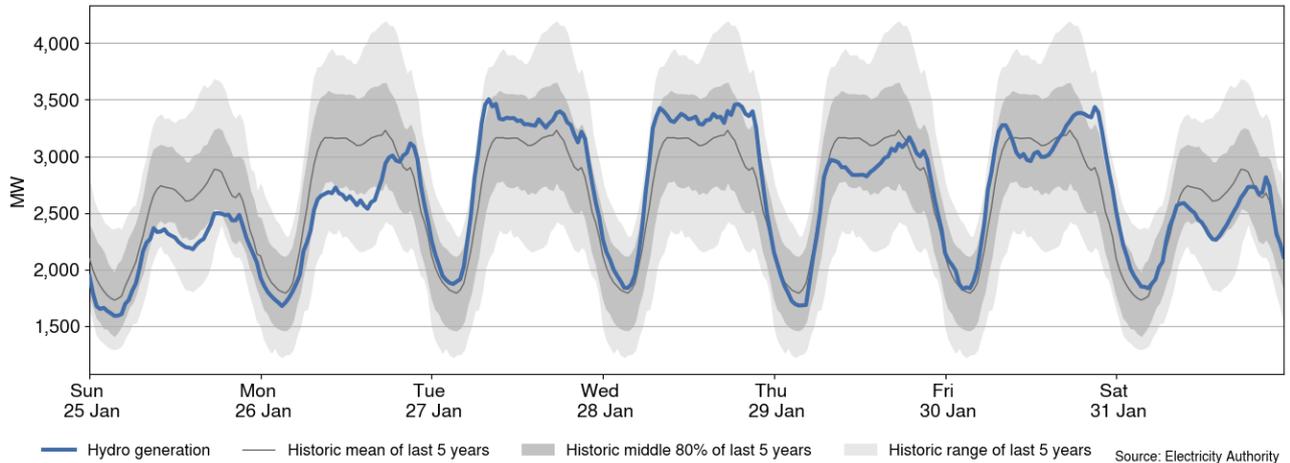
7.10. Figure 14 shows the generation of thermal peaker plants between 25-31 January. No thermal peaker plants ran this week.

Figure 14: Thermal peaker generation, 25-31 January



7.11. Figure 15 shows hydro generation between 25-31 January. Hydro generation was mostly lower than the historic mean on Sunday and Monday, and higher on Tuesday and Wednesday when wind generation was lower. For the rest of the week, hydro generation was mostly close to or below the historic mean, aside from on Friday where hydro generation increased during the evening peak.

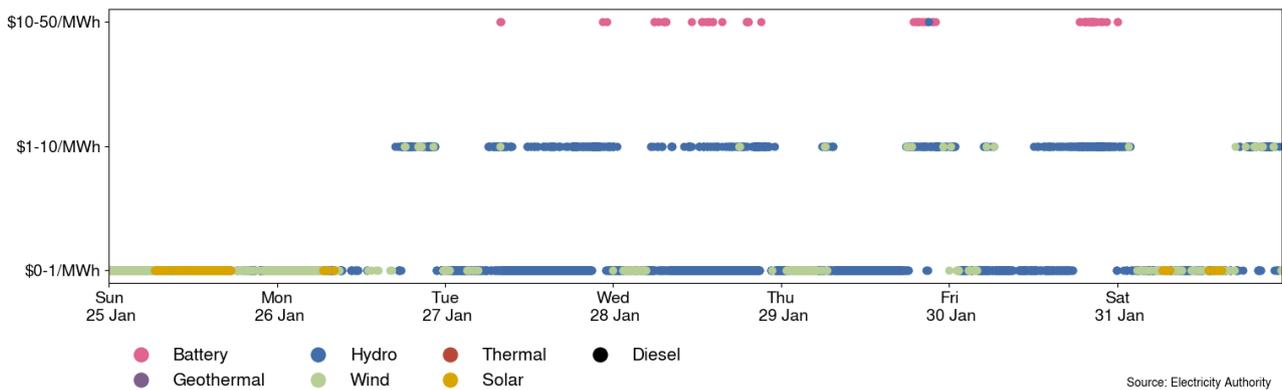
Figure 15: Hydro generation, 25-31 January



7.12. 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.

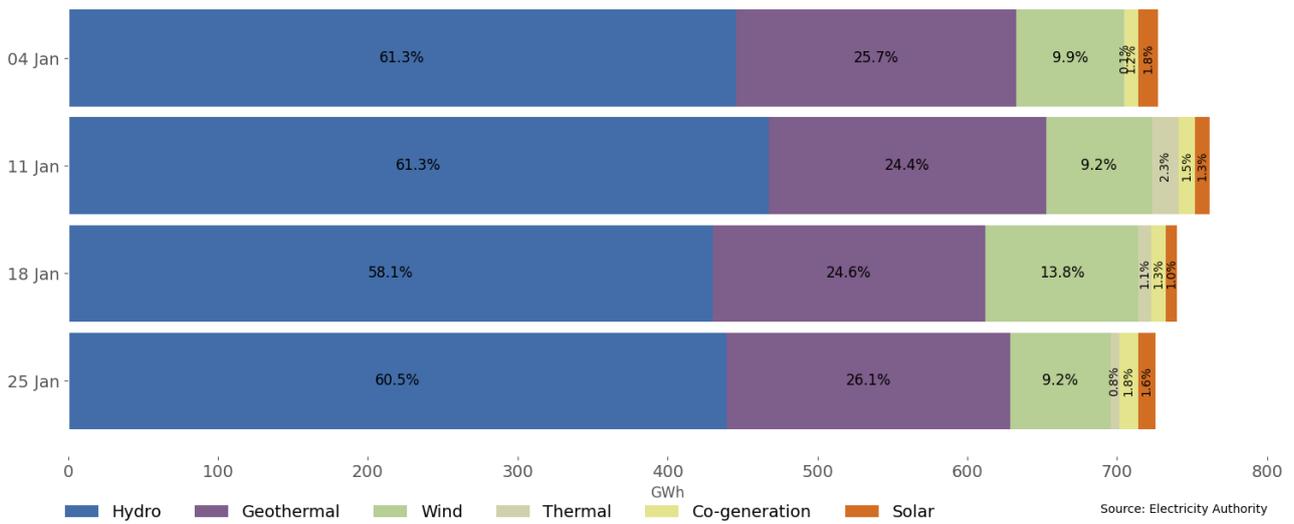
7.13. The highest prices this week were caused by the Ruakākā battery and Mercury hydro. The most common technology setting prices this week was hydro generation, with wind generation the second most common. Most marginal prices were between \$0-1/MWh.

Figure 16: Prices of marginal generation, 25-31 January



7.14. As a percentage of total generation, between 25-31 January, total weekly hydro generation was 60.5%, geothermal 26.1%, wind 9.2%, thermal 0.8%, co-generation 1.8%, and solar (grid connected) 1.6%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 4 January and 31 January



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 25-31 January ranged between ~1,395MW and ~1,988MW. Figure 19 shows the thermal generation capacity outages. TCC has been decommissioned and removed from outage reporting.

Figure 18: Total MW loss from generation outages, 25-31 January

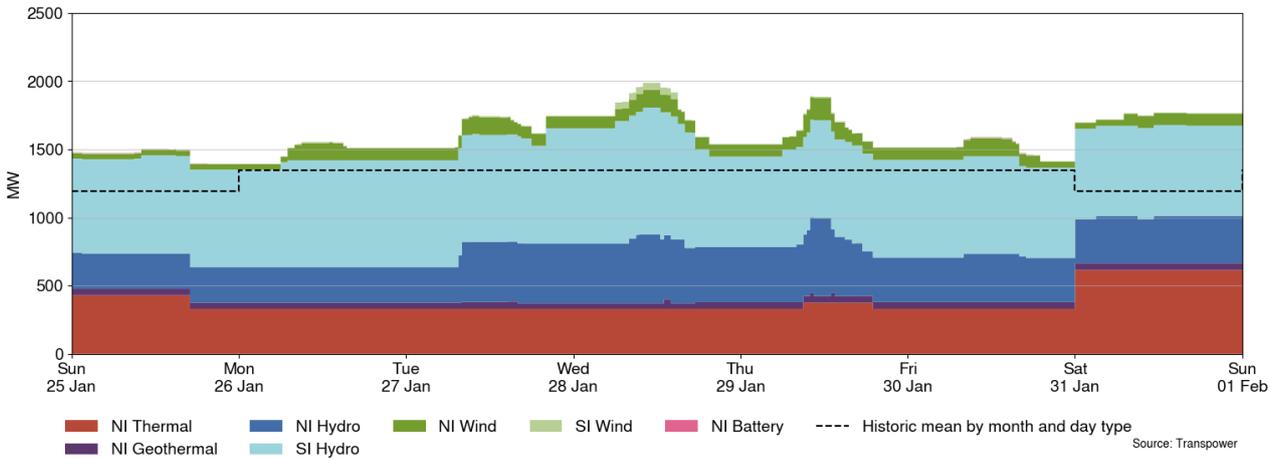
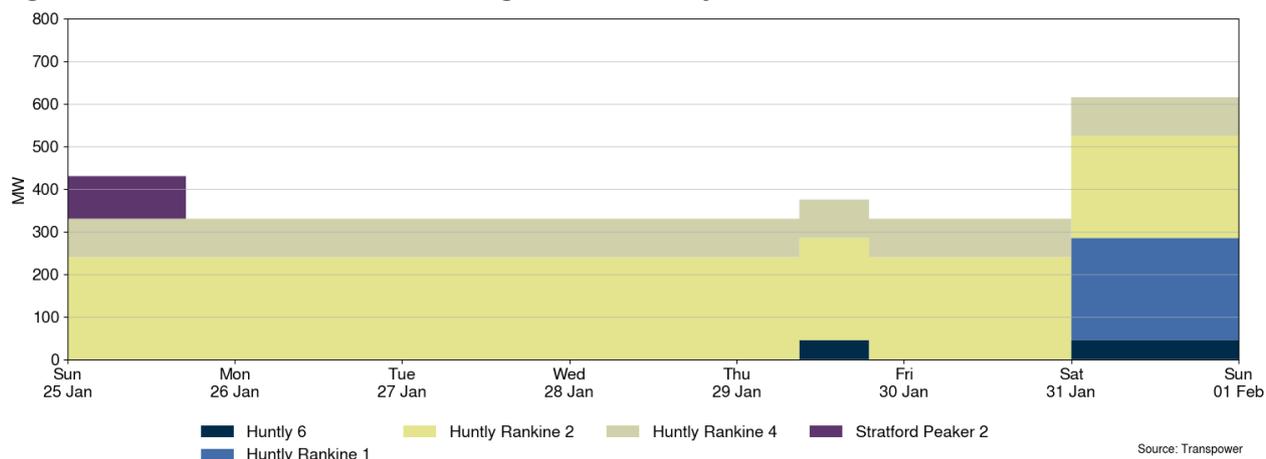


Figure 19: Total MW loss from thermal outages, 25-31 January



Source: Transpower

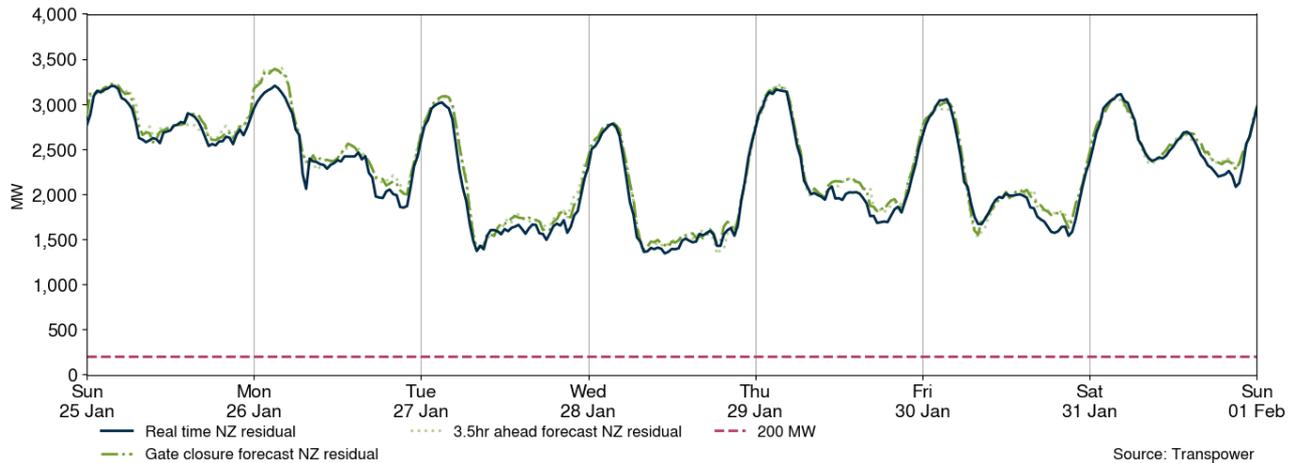
8.2. Notable outages include:

Plant	Partial or Full	End Date
Stratford peaker 2	Full	25 January 2026
Ōhau C	Partial	28 January 2026
Manapōuri unit 6	Full	28 January 2026
Huntly 1	Full	1 February 2026
Huntly 4	Partial	14 February 2026
Ōhau A	Partial	27 February 2026
Roxburgh unit 5	Full	11 March 2026
Rangipō unit 6	Full	29 March 2026
Huntly 2	Full	28 April 2026
Clyde unit 2	Full	1 May 2026
Manapōuri unit 4	Full	12 June 2026

9. Generation balance residuals

- 9.1. Figure 20 shows the national generation balance residuals between 25-31 January. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.
- 9.2. Overall, residuals were healthy this week. The lowest national residual was 1,343MW at 11.00am on Wednesday.

Figure 20: National generation balance residuals, 25-31 January

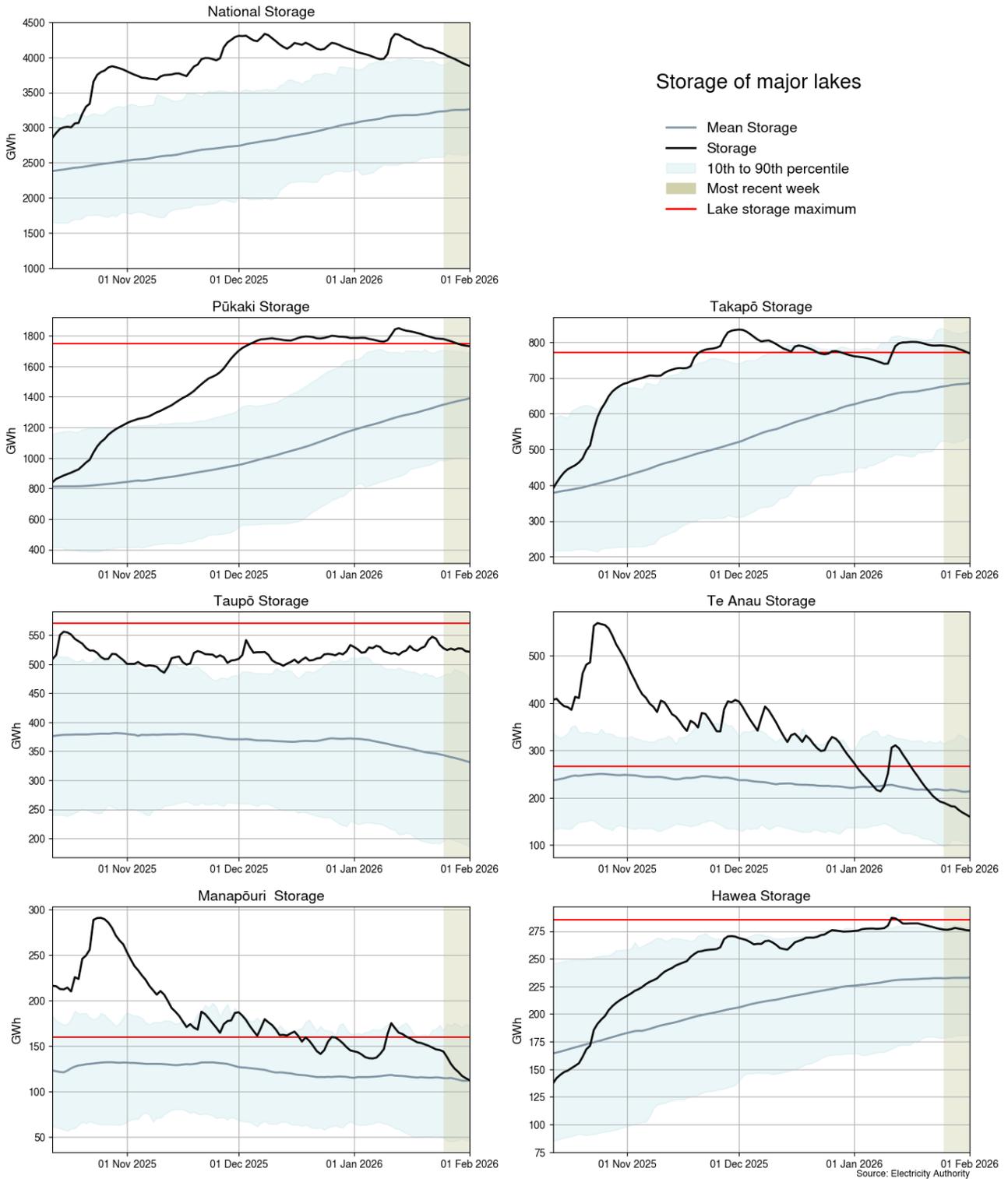


10. Storage/fuel supply

- 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 24 January, national controlled storage decreased to 95% nominally full and ~118% of the historical average for this time of the year.
- 10.3. Storage at Lake Pūkaki (99% full²) is above its historic 90th percentile, while Lake Takapō (99% full) is below its historic 90th percentile. Lake Pūkaki is spilling after exceeding its storage capacity.
- 10.4. Storage at Lake Te Anau (61% full) is below its historic mean, with Lake Manapōuri (72% full) now close to its historic mean.
- 10.5. Storage at Lake Taupō (91% full) is above its historic 90th percentile for this time of year.
- 10.6. Storage at Lake Hawea (97% full) is close to its historic 90th percentile.

² Percentage full values sourced from NZX Hydro.

Figure 21: Hydro storage

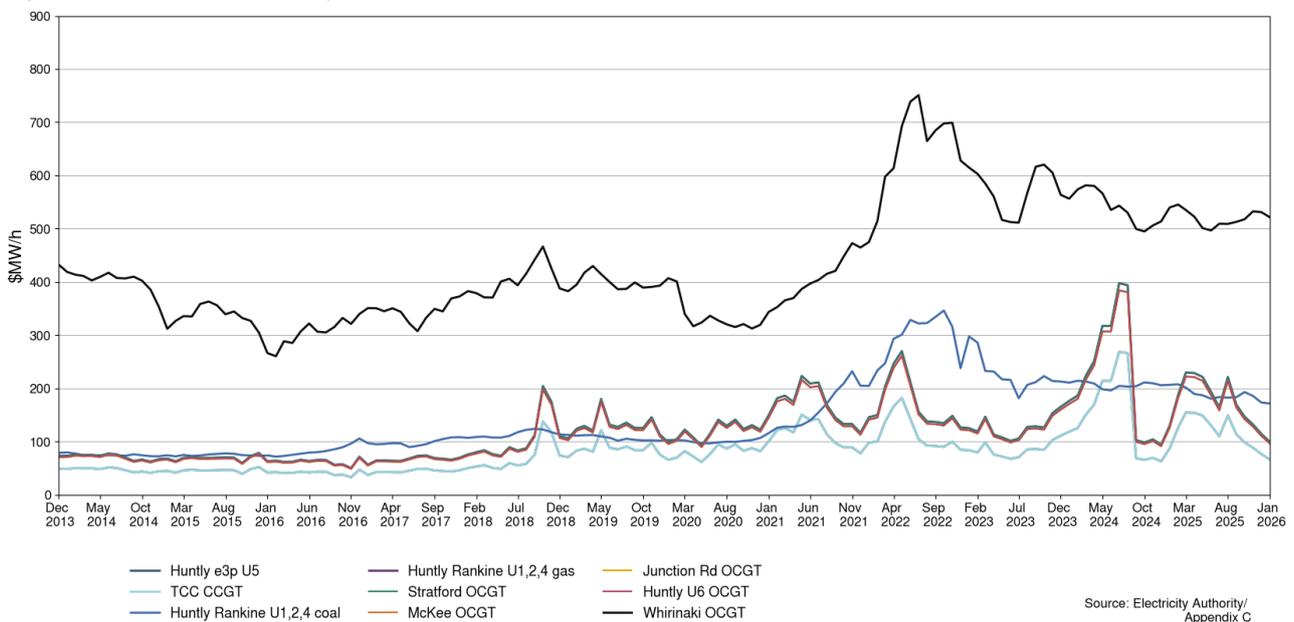


11. Prices versus estimated costs

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 January 2026. The SRMCs for gas- and diesel-powered generation have decreased, while the SRMCs for coal-fuelled generation has remained stable.
- 11.4. The latest SRMC of coal-fuelled Rankine generation is ~\$171/MWh. The cost of running the Rankines on gas is ~\$99/MWh.
- 11.5. The SRMC of gas fuelled thermal plants is currently between \$66/MWh and \$99/MWh.
- 11.6. The SRMC of Whirinaki is ~\$521/MWh.
- 11.7. More information on how the SRMC of thermal plants is calculated can be found in [Appendix C](#).

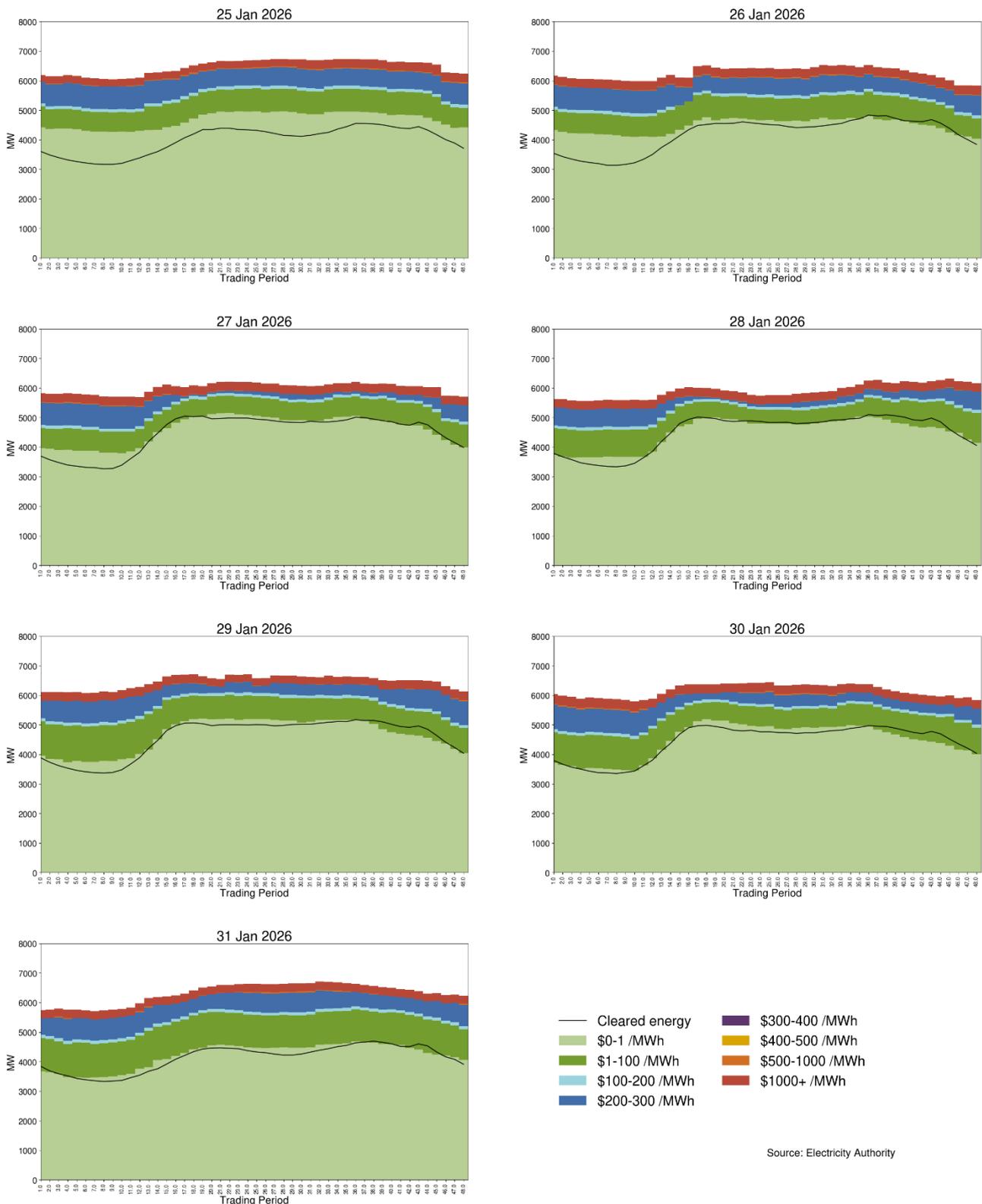
Figure 22: Estimated monthly SRMC for thermal fuels



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. This week, all offers cleared below \$100/MWh. At times on Tuesday and Wednesday, the amount of energy offered between \$200-300/MWh was reduced compared to other days with the outage of a unit at Maraetai contributing to this.

Figure 23: Daily offer stacks



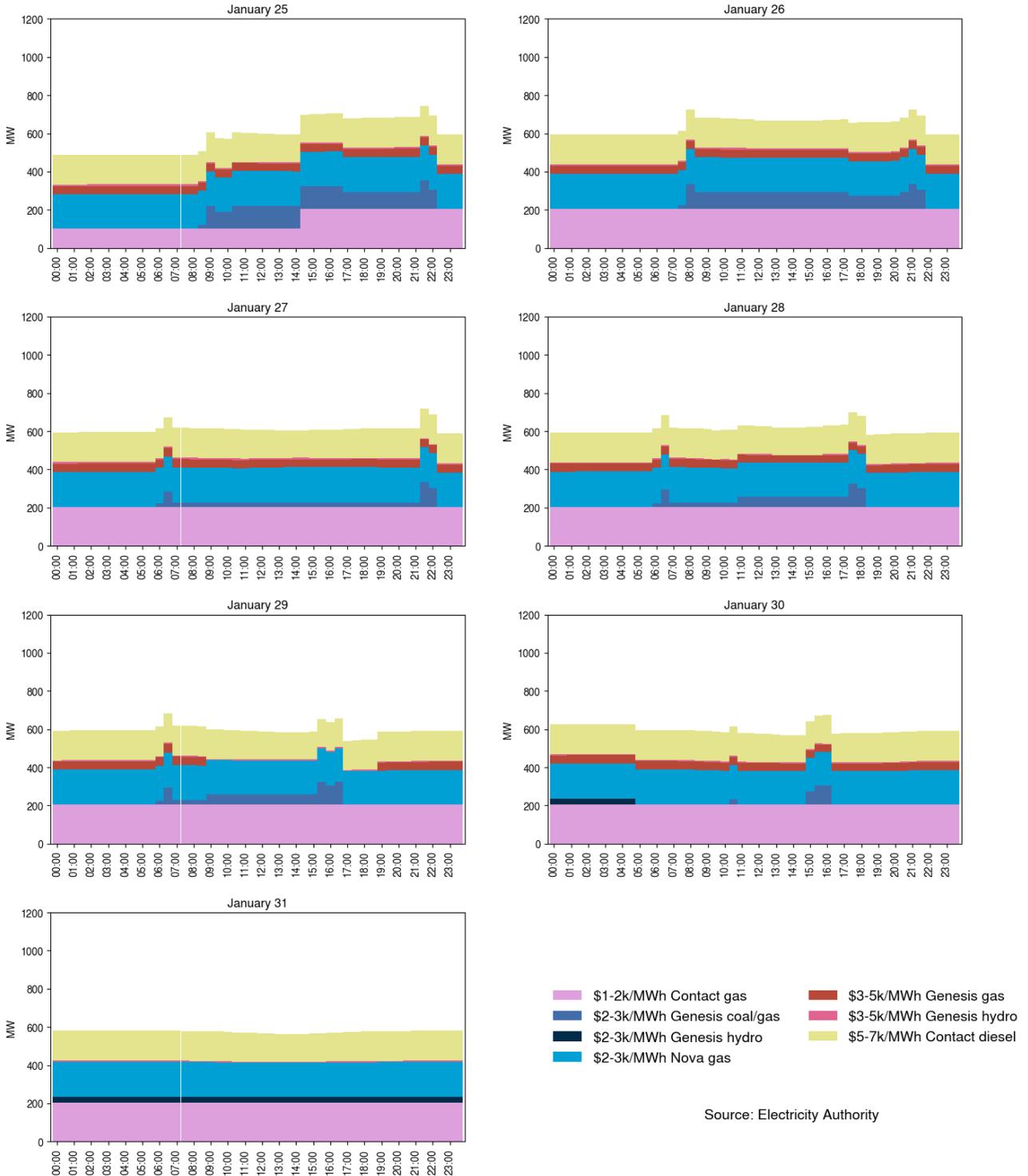
12.3. Figure 24 shows offers above \$1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

12.4. 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, wind generation dips, or other generation fails, these high-priced thermal generators may get dispatched, sometimes resulting in a high spot price.

12.5. On average 603MW 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. The monitoring team is looking further into Turitea forecasting errors.

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
12/01/2026-17/01/2026	Several	Further analysis	Mercury	Waikato	Offers
12/01/2026-17/01/2026	Several	Further analysis	Genesis	Huntly	Offers
21/01/2026-24/01/2026	Several	Further analysis	Genesis	Waikaremoana	Offers
29/01/2026	Several	Further analysis	Mercury	Turitea	Forecasting