16 February 2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 8-14 February 2026

Market monitoring weekly report

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1. Overview

1.1. This week the average spot price increased by $40/MWh to $55/MWh. Prices increased from Monday as wind declined, with higher demand and decreasing hydro storage also contributing to higher prices. The proportion of hydro and thermal generation increased this week, while wind and geothermal fell. National controlled storage continued to decrease and is at 93% nominally full and ~115% 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 8-14 February:

(a) The average spot price for the week was $55/MWh, an increase of around $40/MWh compared to the previous week.

(b) 95% of prices fell between $0.03/MWh and $124/MWh.

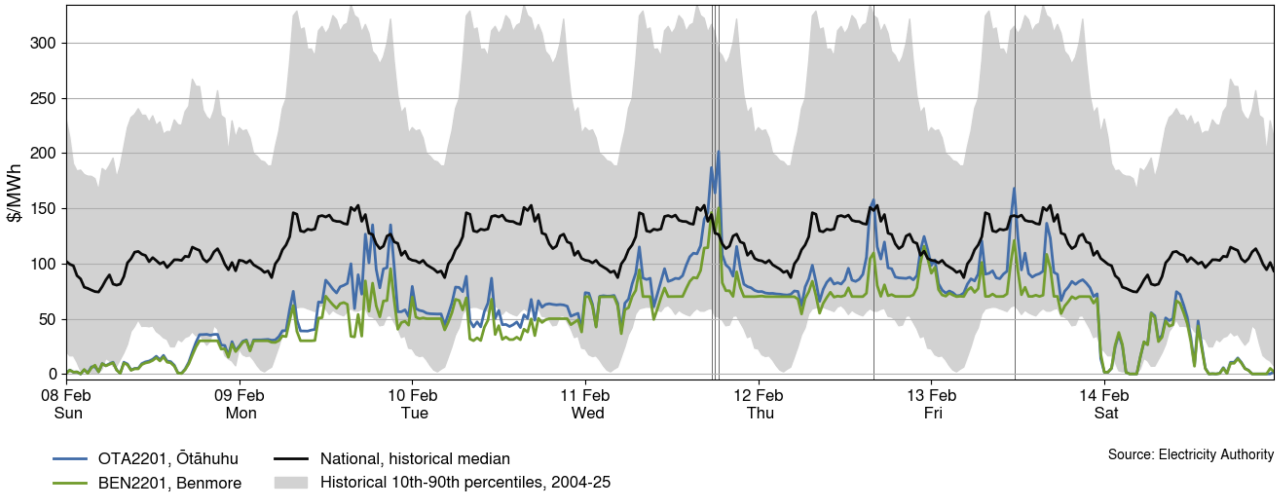
2.3. This week, prices increased with lower wind generation and higher demand. Additionally, continued hydro storage decline has seen most hydro schemes cease spilling and begin pricing up their offers, in particular at the Waitaki scheme.

2.4. On Wednesday, prices spiked above $160/MWh between 5.30pm-6.30pm, with the highest Ōtāhuhu price for the week of $201/MWh occurring at 6.30pm. During this period, demand was between 87-139MW higher than forecast and intermittent generation was between 28-43MW lower than forecast.

2.5. Prices also spiked above $150/MWh on Thursday at 4.00pm and on Friday at 11.30am, with demand and/or intermittent generation forecasting errors also contributing to higher prices at these times.

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.

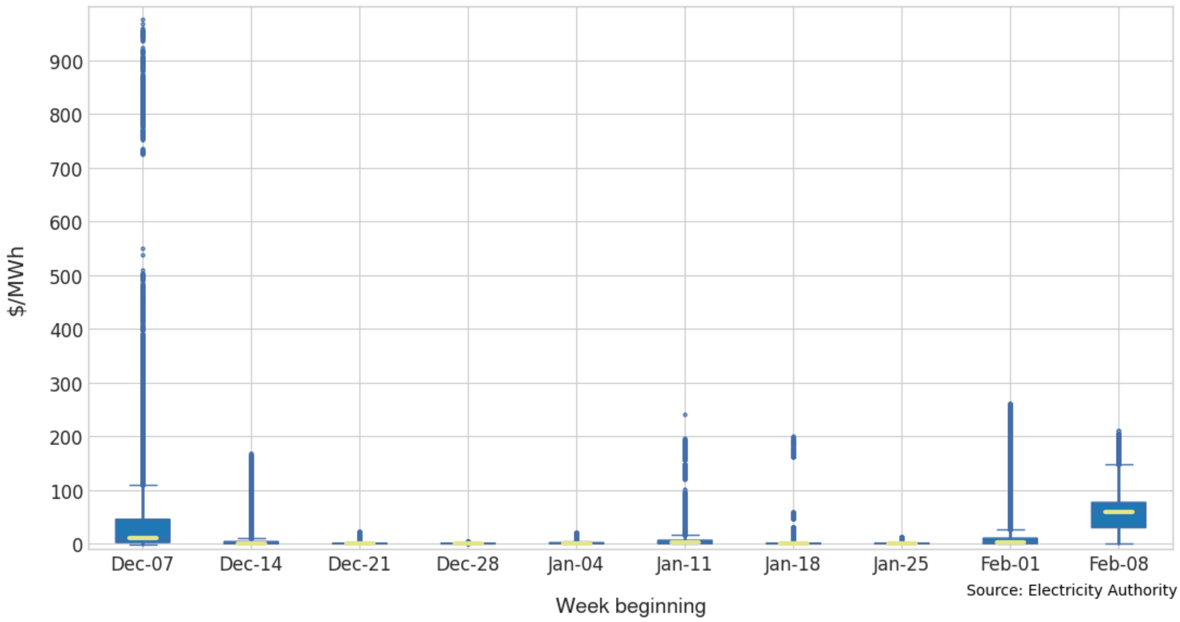
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 8-14 February



2.7. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.

2.8. The distribution of spot prices this week was wider compared to last week. The median price was $60/MWh and most prices (middle 50%) fell between $30/MWh and $77/MWh.

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

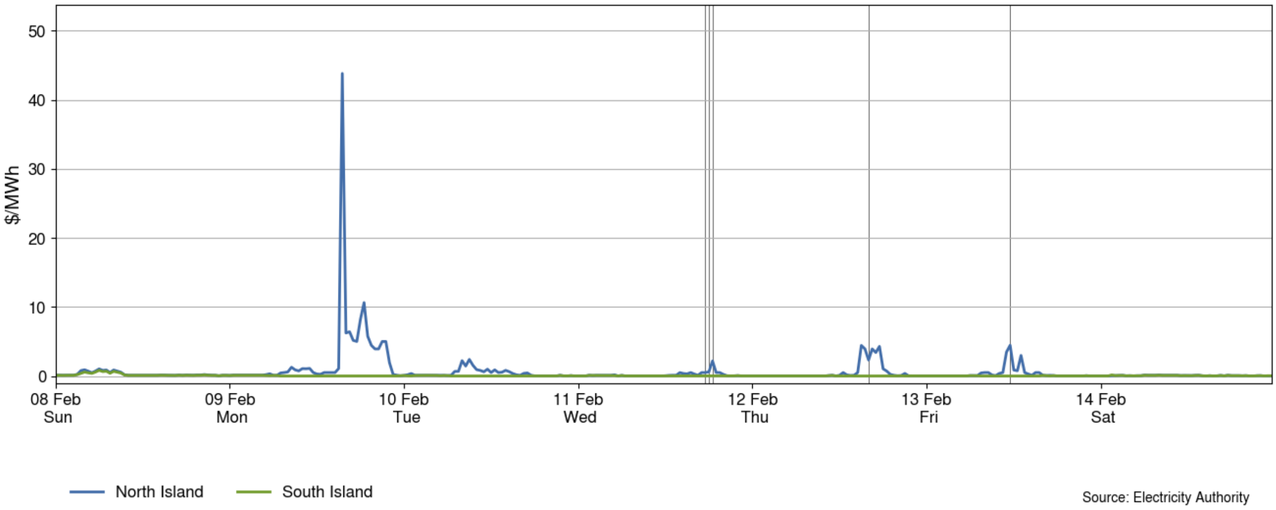


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices mostly remained below $10/MWh, aside from two North Island price spikes on Monday.

3.2. North Island FIR prices spiked to $44/MWh at 3.30pm on Monday. The HVDC was the risk setter at this time and the Ruakākā battery was not offering reserves during this trading period. North Island FIR prices again spiked above $10/MWh at 6.30pm during which time the HVDC's northward transfer increased.

Figure 3: Fast instantaneous reserve price by trading period and island, 8-14 February

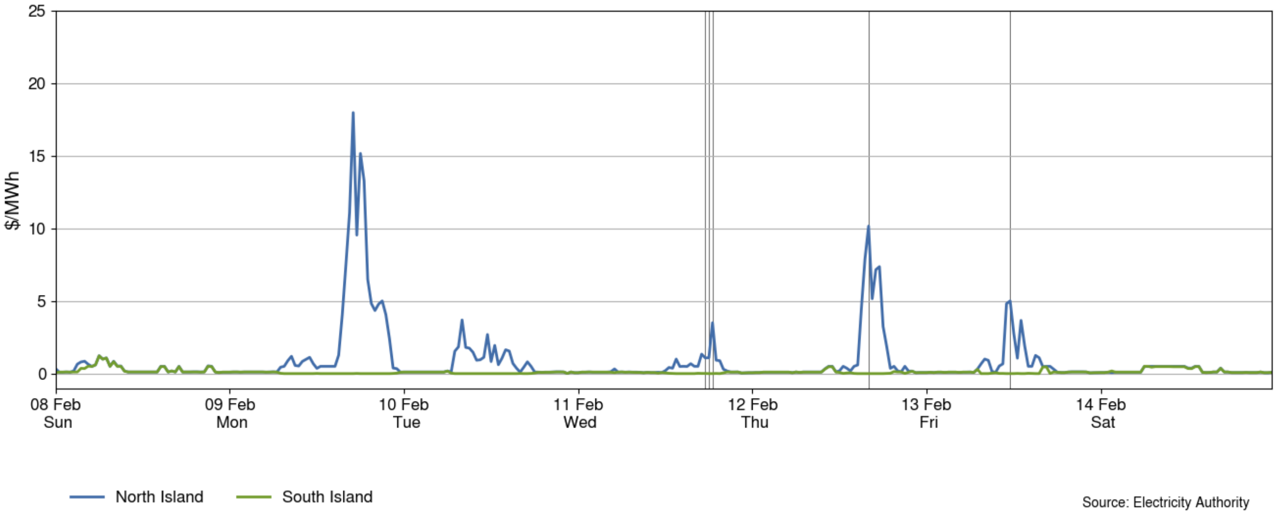


3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices mostly remained below $10/MWh, aside from a few North Island price spikes on Monday and one price spike on Thursday.

3.4. On Monday, North Island SIR prices spiked up to $18/MWh with the HVDC setting the North Island risk during this period.

3.5. North Island SIR prices also reached above $10/MWh on Thursday at 4.00pm. During this time, the HVDC was also the North Island risk setter.

Figure 4: Sustained instantaneous reserve by trading period and island, 8-14 February



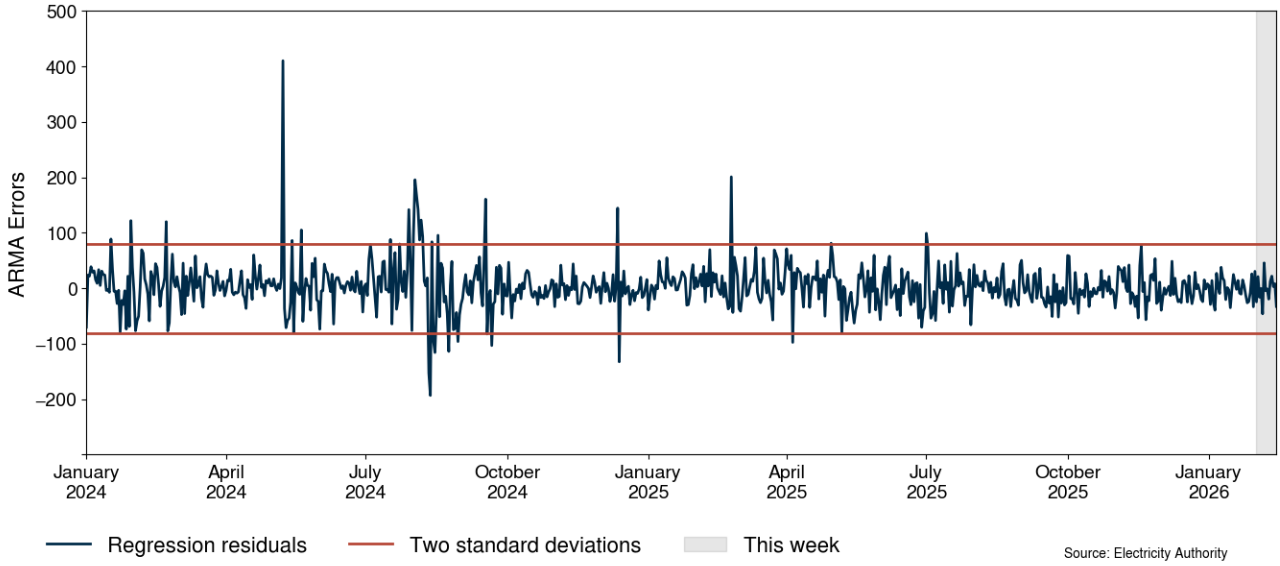
4. Regression residuals

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 - 14 February 2026

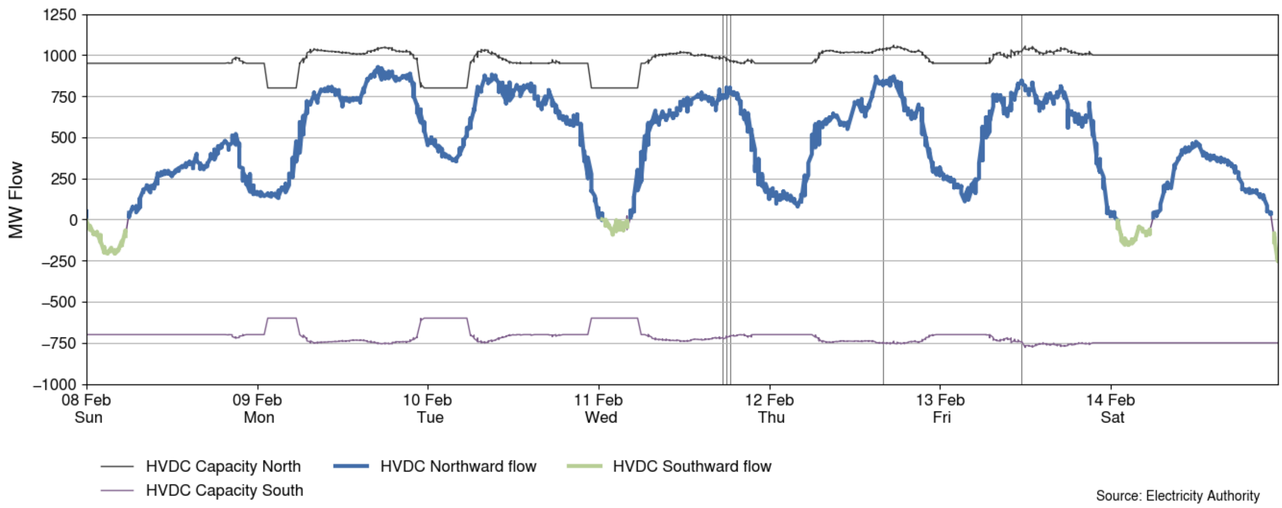


5. HVDC

5.1. Figure 6 shows the HVDC flow between 8-14 February. HVDC flows were mostly northward this week, with some southward flow overnight on Sunday, Wednesday and Saturday during times of higher wind generation.

5.2. The highest northward flow occurred at 5.00pm on Monday with a flow of 927MW.

Figure 6: HVDC flow and capacity, 8-14 February



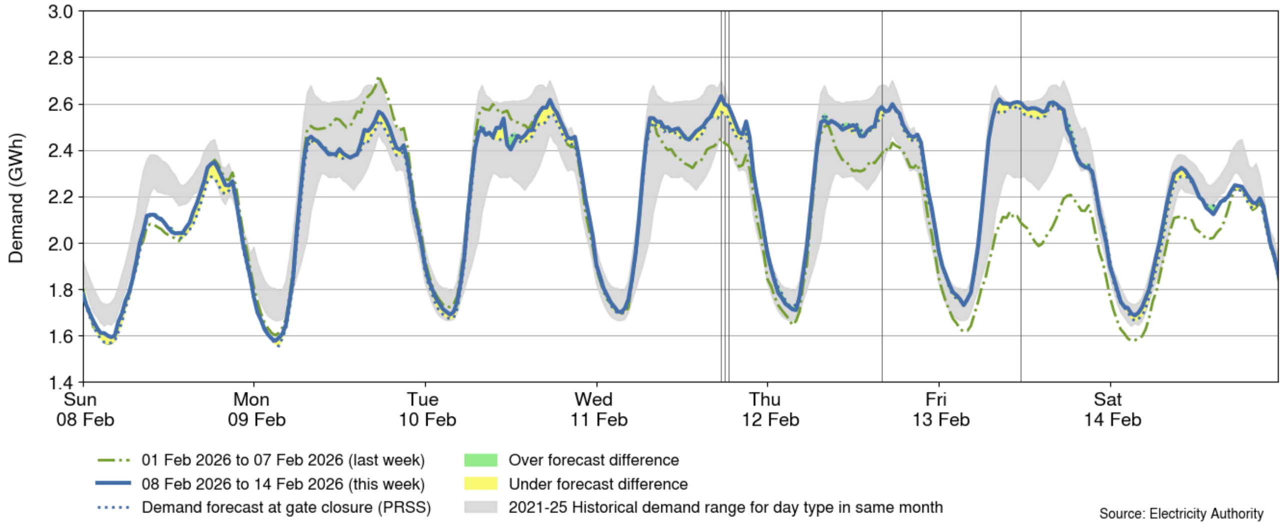
6. Demand

6.1. Figure 7 shows national demand between 8-14 February, compared to the historic range and the demand of the previous week.

6.2. Demand was close to or lower than the previous week, until Wednesday, where demand was mostly higher compared to the previous week until Saturday evening. Warmer temperatures and Waitangi Day last week have likely contributed to this.

6.3. The highest demand of the week was around 2.63GWh at 5.30pm on Wednesday.

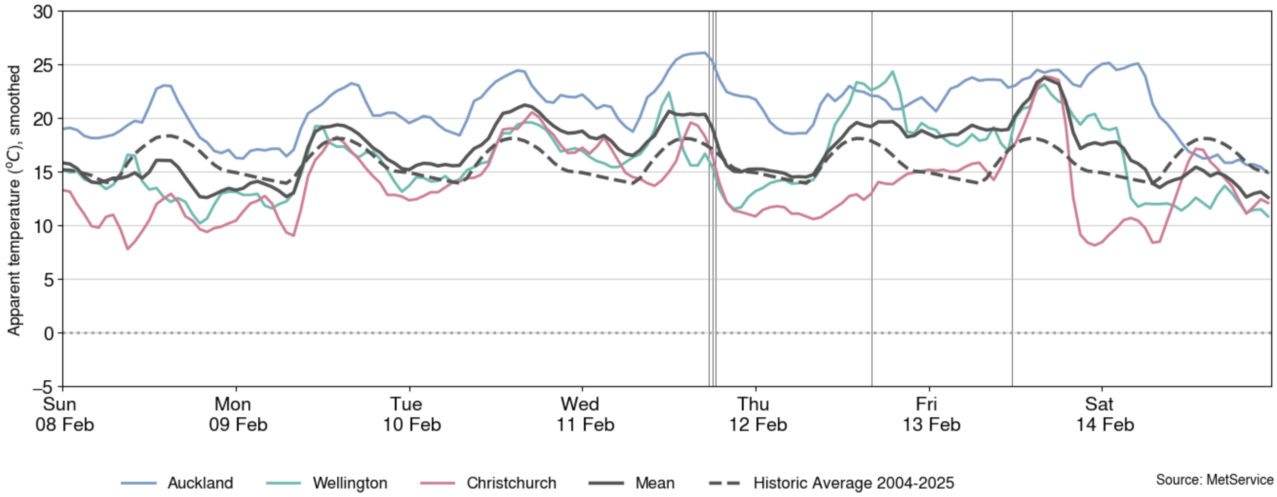
Figure 7: National demand, 8-14 February compared to the previous week



6.4. Figure 8 shows the hourly apparent temperature at main population centres from 8-14 February. 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 15°C to 26°C in Auckland, 10°C to 24°C in Wellington, and 8°C to 24°C in Christchurch

Figure 8: Temperatures across main centres, 8-14 February

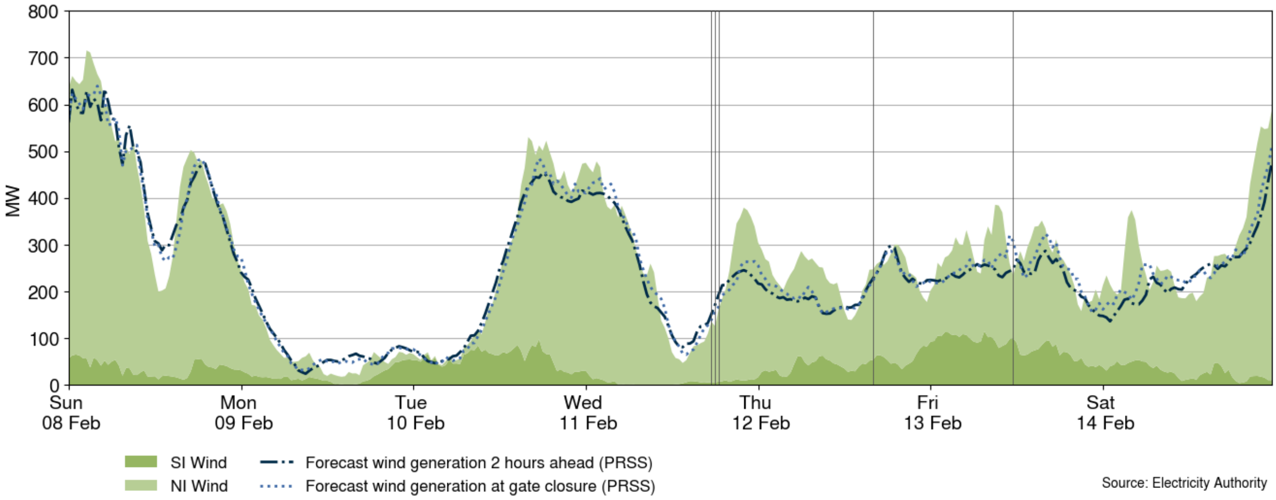


7. Generation

7.1. Figure 9 shows wind generation and forecast from 8-14 February. This week wind generation varied between 17MW and 715MW, with a weekly average of 263MW.

7.2. Wind generation decreased from Sunday, reaching below 100MW on Monday. Wind did increase on Tuesday, but declined again on Wednesday, remaining mostly below 300MW until Saturday evening.

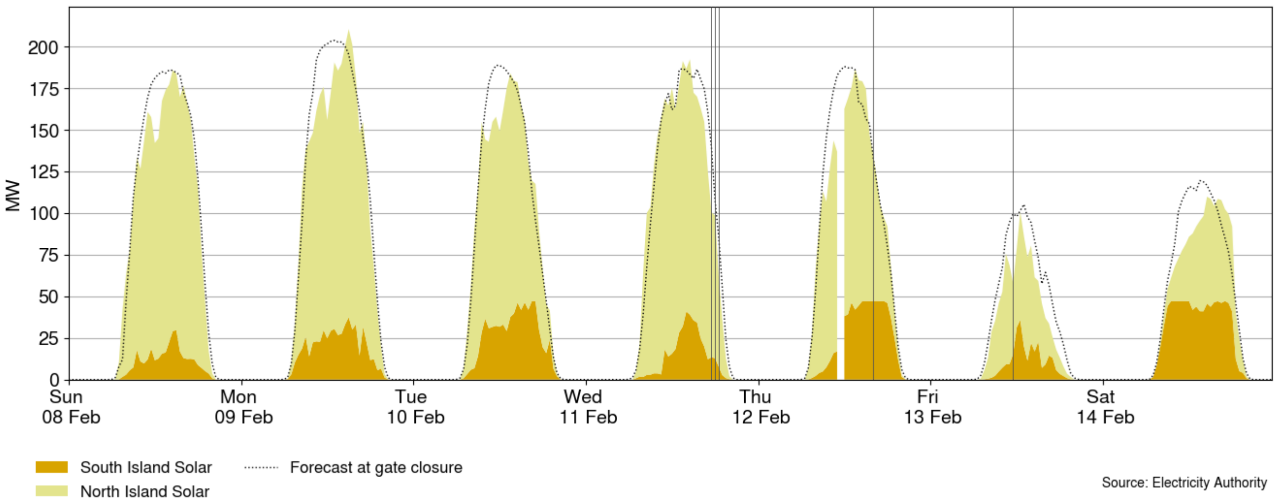
Figure 9: Wind generation and forecast, 8-14 February



7.3. Figure 10 shows grid connected solar generation from 8-14 February. Solar generation reached above 100MW daily, peaking on Monday at 3.00pm at around 211MW.

7.4. Note solar generation data is missing for trading period 24 on Thursday.

Figure 10: Grid connected solar generation, 8-14 February

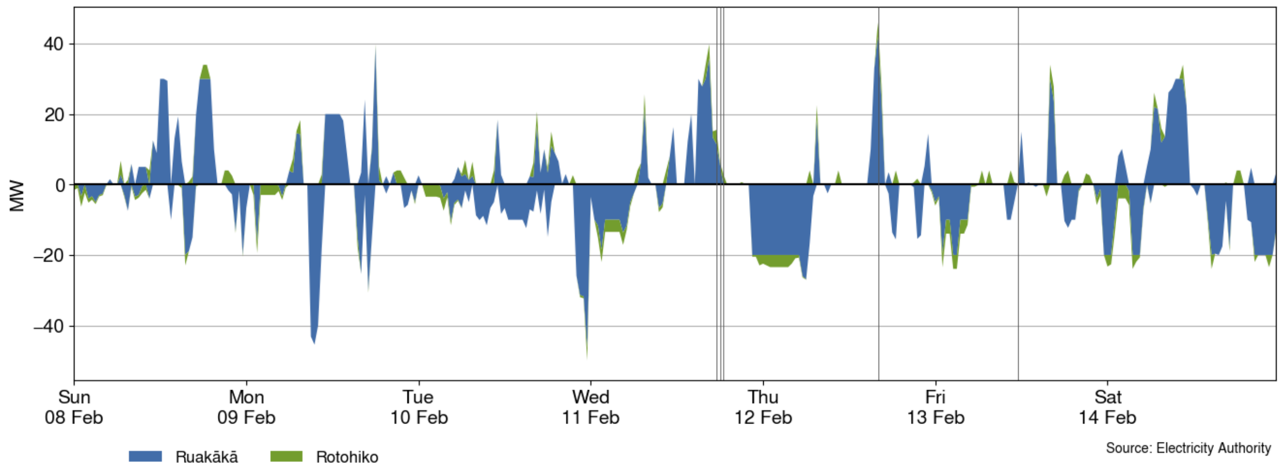


7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh) and Ruakākā (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

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 relatively lower. With higher prices this week, there were no days where the batteries discharged significantly less.

7.7. The highest prices on Wednesday occurred after the batteries had already depleted from discharge in the morning and early afternoon.

Figure 11: Grid scale battery charge and discharge, 8-14 February



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 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. Several trading periods this week has a positive marginal difference greater than $50/MWh.

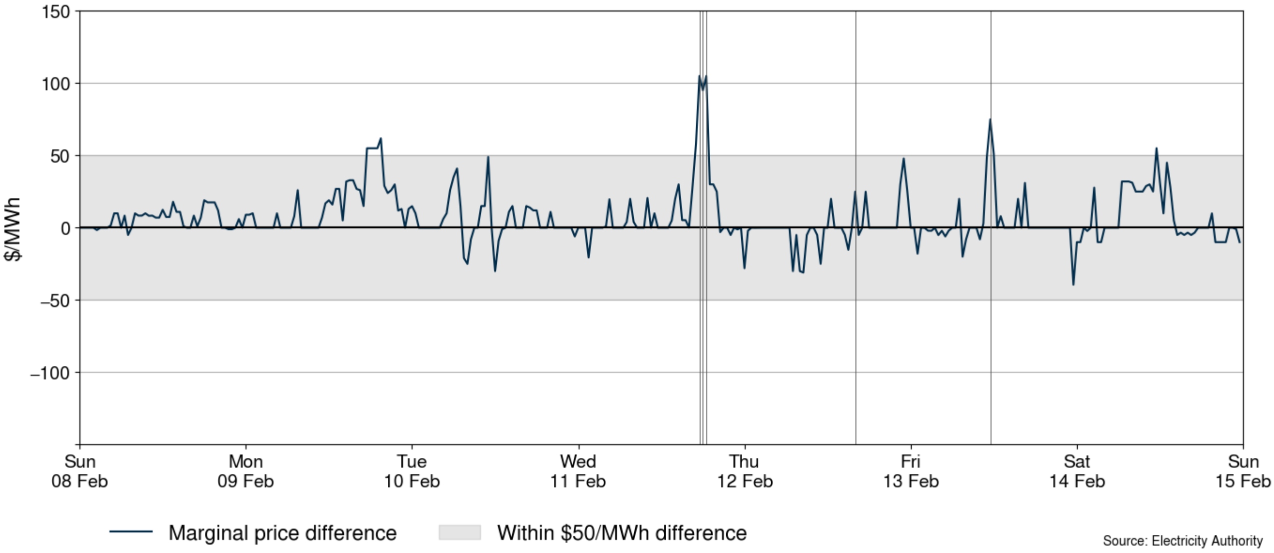
7.10. On Monday, positive differences of $55-62/MWh occurred between 5.30pm and 7.30pm. Demand was between 71-95MW higher than forecast during this time.

7.11. Wednesday saw positive differences of $58-105/MWh between 5.00pm-6.30pm. During this period, demand was between 87-139MW higher than forecast and intermittent generation was 28-54MW lower than forecast.

7.12. Additionally, positive price differences between $51-75/MWh occurred on Friday between 11.30am-12.00pm. Demand was between 56-65MW higher than forecast and intermittent generation was between 31-115MW lower than forecast.

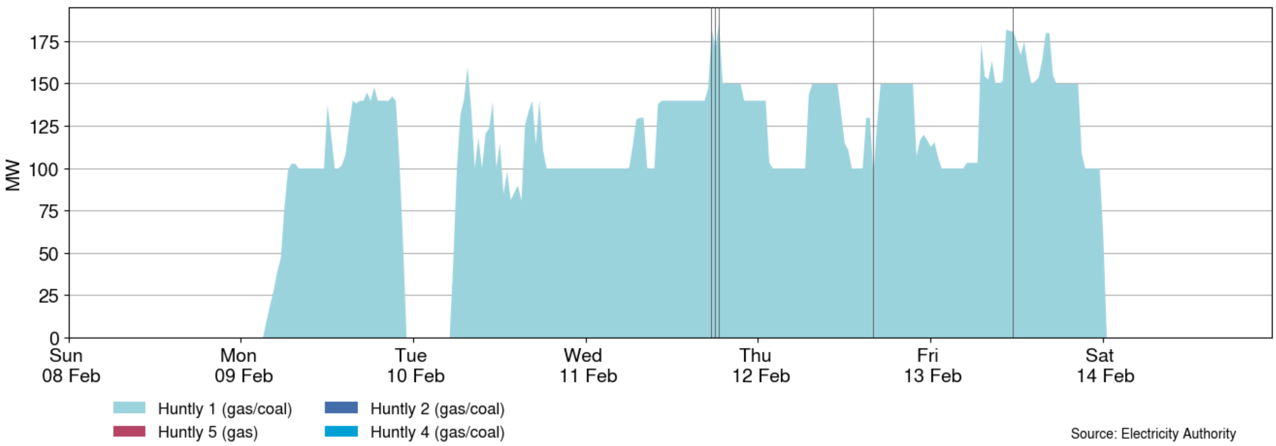
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 8-14 February



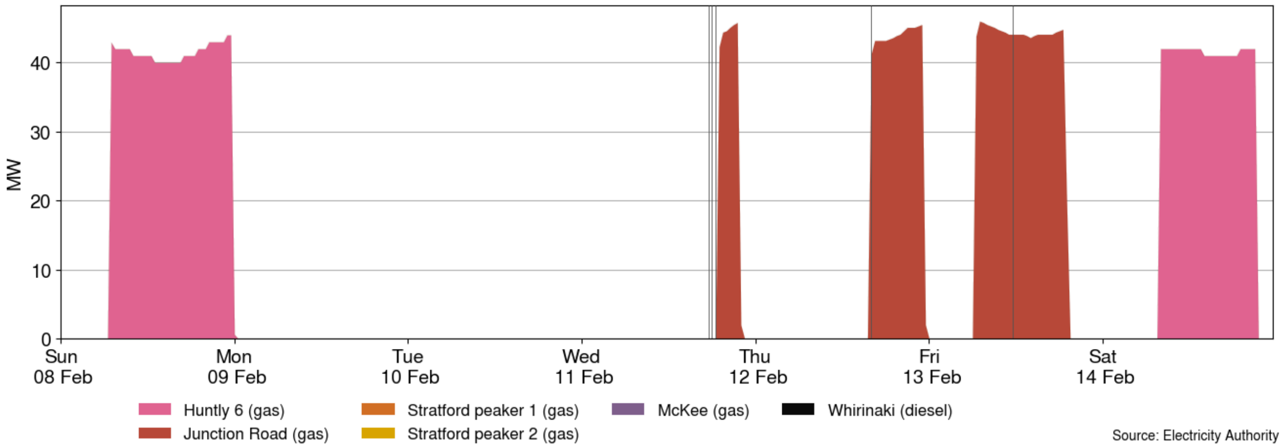
7.13. Figure 13 shows the generation of thermal baseload between 8-14 February. Huntly 1 ran on Monday and then ran continuously between Tuesday and Friday.

Figure 13: Thermal baseload generation, 8-14 February



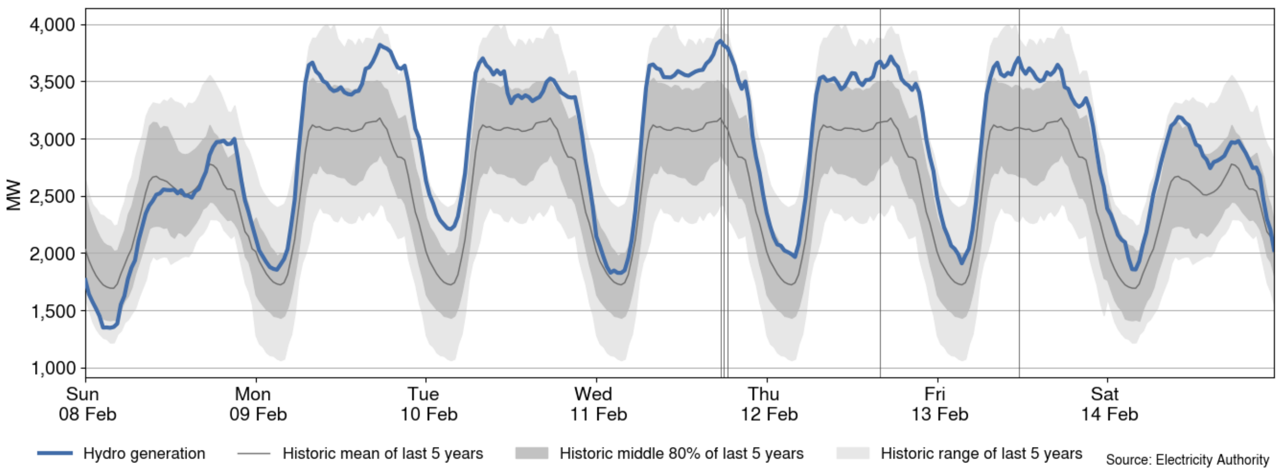
7.14. Figure 14 shows the generation of thermal peaker plants between 8-14 February. Huntly 6 ran on Sunday and Saturday this week, while Junction Road ran at times between Wednesday and Friday.

Figure 14: Thermal peaker generation, 8-14 February



7.15. Figure 15 shows hydro generation between 8-14 February. Hydro generation was higher than the historic mean for most of the week and often above the middle 80% of historic generation. Sunday morning saw lower hydro generation, likely due to higher wind generation.

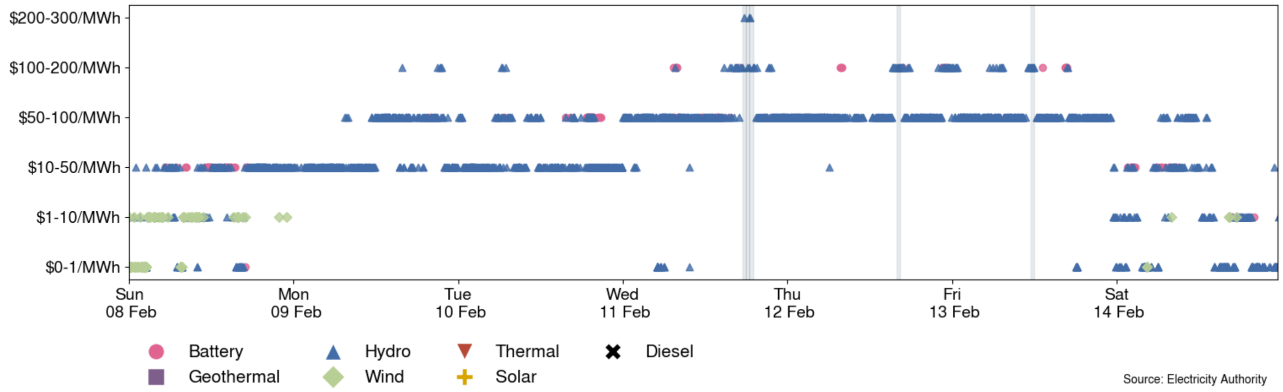
Figure 15: Hydro generation, 8-14 February



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.

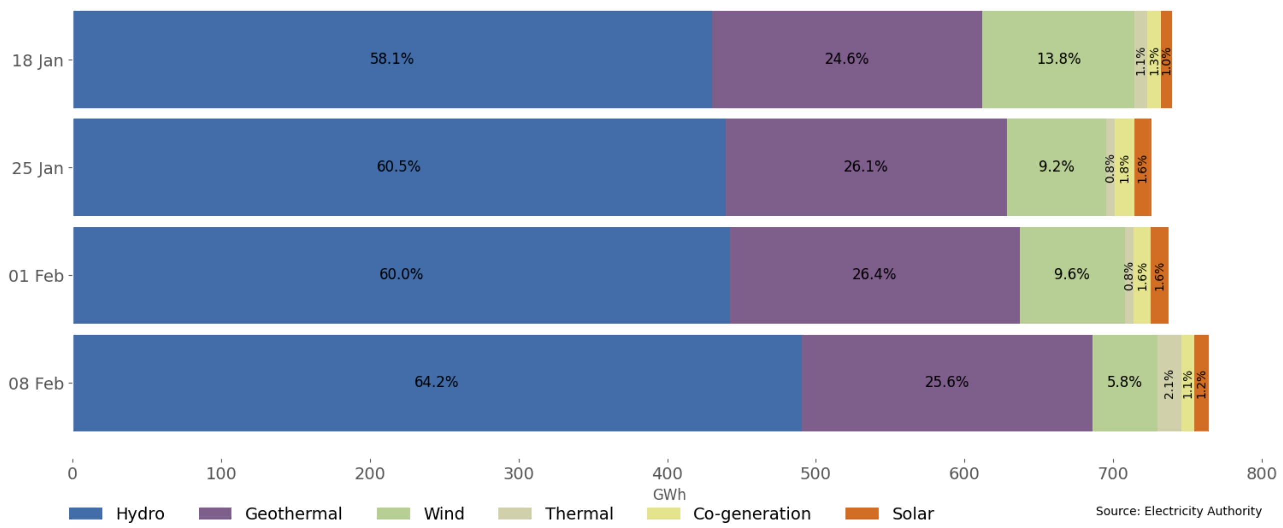
7.17. The highest prices this week were set by Mercury hydro. The most common technology setting prices this week was hydro generation, with wind generation the second most common. Most marginal prices were between $50-100/MWh.

Figure 16: Prices of marginal generation, 8-14 February



7.18. As a percentage of total generation, between 8-14 February, total weekly hydro generation was 64.2%, geothermal 25.6%, wind 5.8%, thermal 2.1%, co-generation 1.1%, and solar (grid connected) 1.2%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 18 January and 14 February



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 8-14 February ranged between ~1,392MW and ~2,065MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 8-14 February

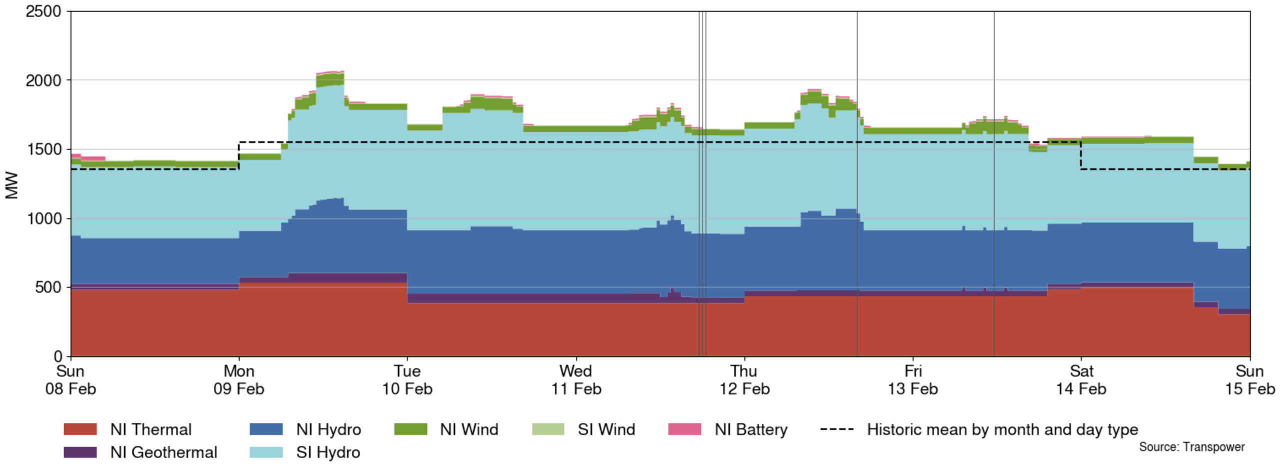
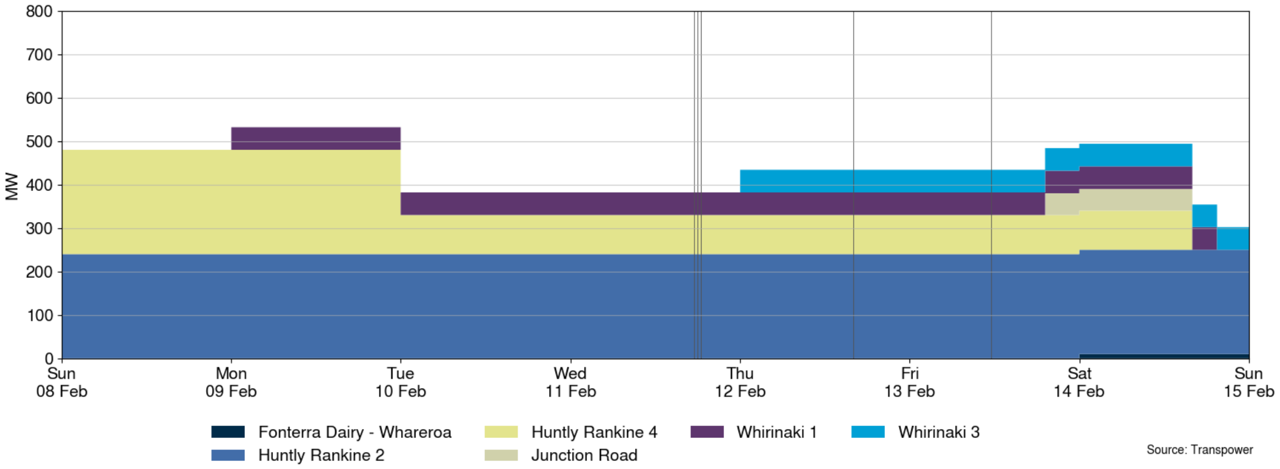


Figure 19: Total MW loss from thermal outages, 8-14 February



8.2. Notable outages include:

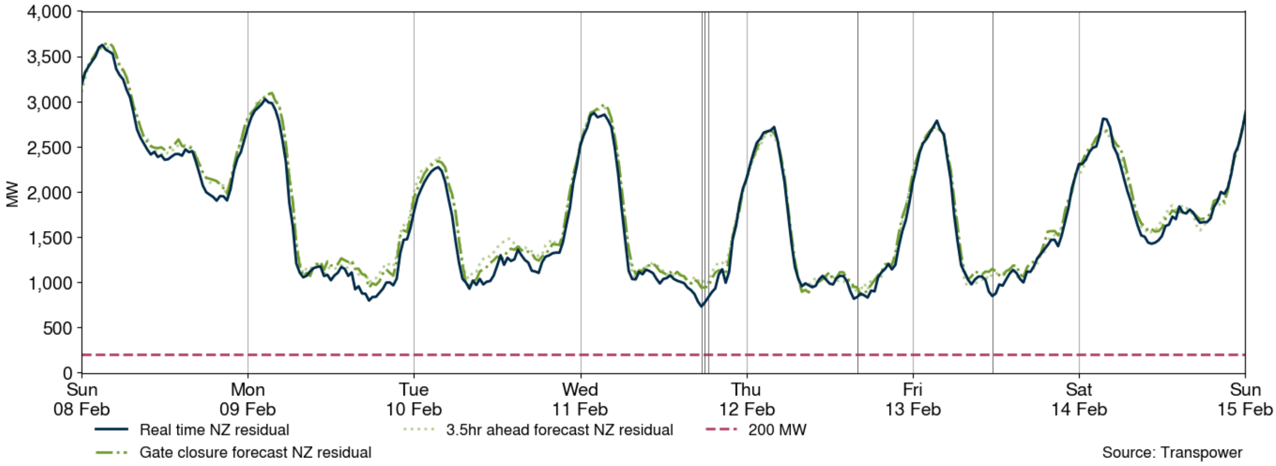
Plant	Partial or Full	End Date
Manapōuri unit 2	Full	13 February 2026
Huntly 4	Partial/Full	14 February 2026
Roxburgh unit 5	Full	26 February 2026
Ōhau A	Partial	6 March 2026
Rangipō unit 6	Full	29 March 2026
Huntly 2	Full	28 April 2026
Clyde unit 2	Full	1 May 2026
Manapōuri unit 4	Full	12 June 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 8-14 February. 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 730MW at 5.30pm on Wednesday.

Figure 20: National generation balance residuals, 8-14 February



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 14 February, national controlled storage decreased to 93% nominally full and ~115% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (98% full[2]) is close to its historic 90th percentile, while Lake Takapō (93% full) is below its historic 90th percentile but above its historic mean.

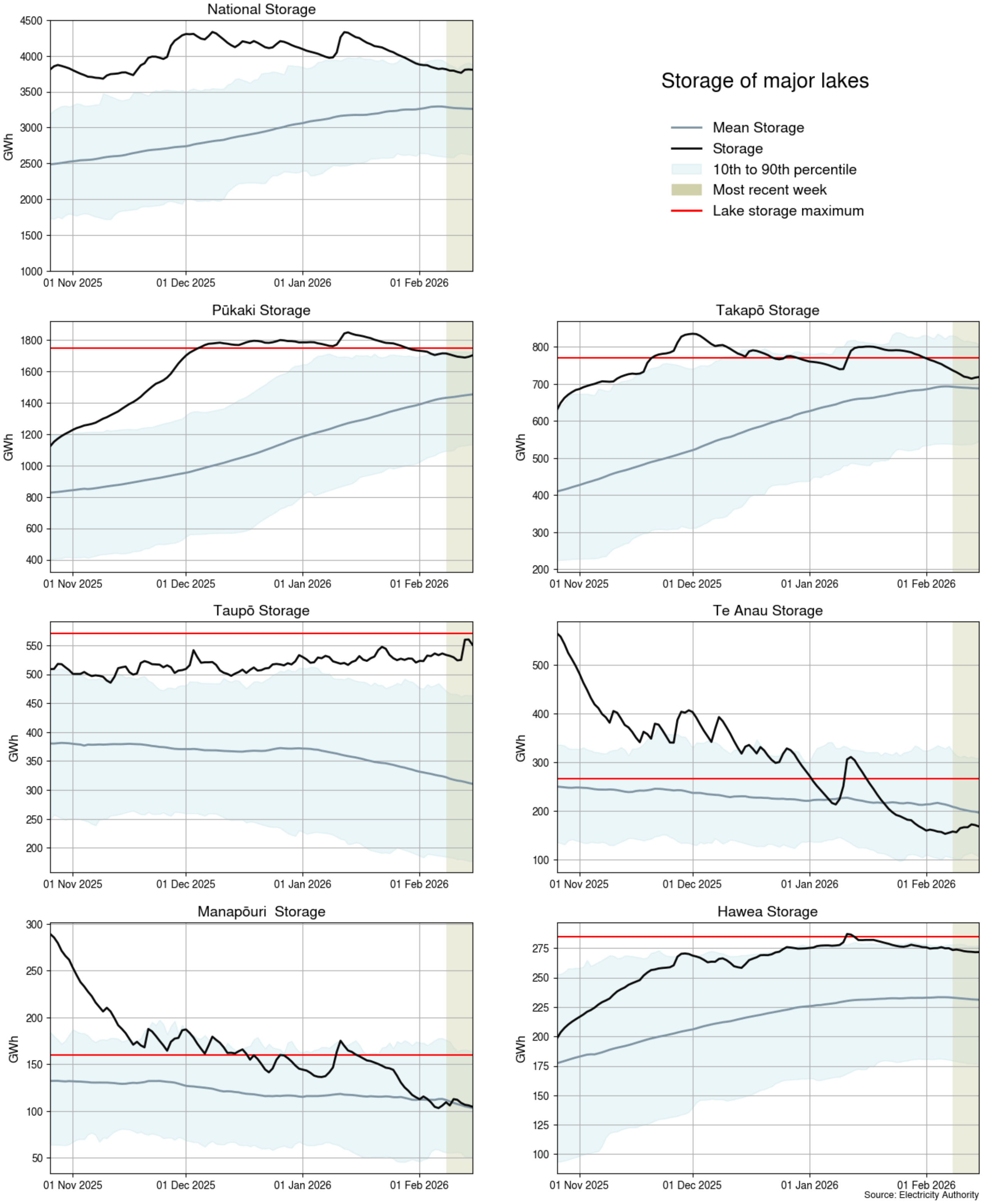
10.4. Storage at Lake Te Anau (64% full) is below its historic mean, with Lake Manapōuri (67% full) close to its historic mean.

10.5. Storage at Lake Taupō (96% full) remains above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (95% 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.

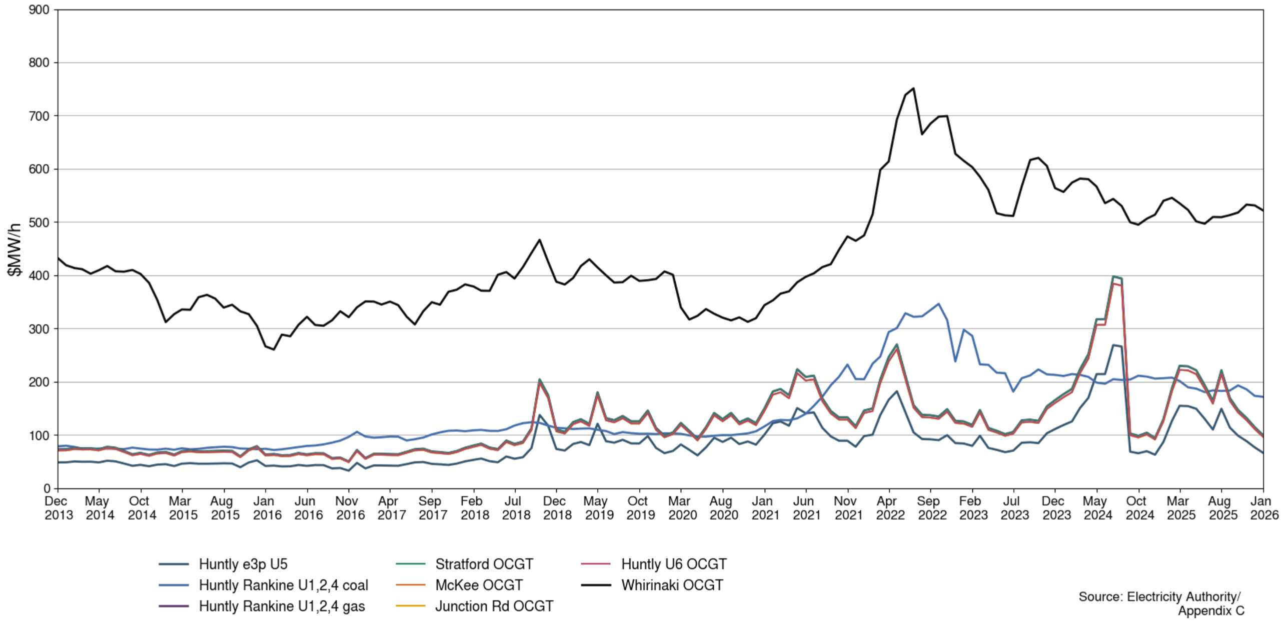
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$171/MWh. The cost of running the Rankines on gas is ~$99/MWh.

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



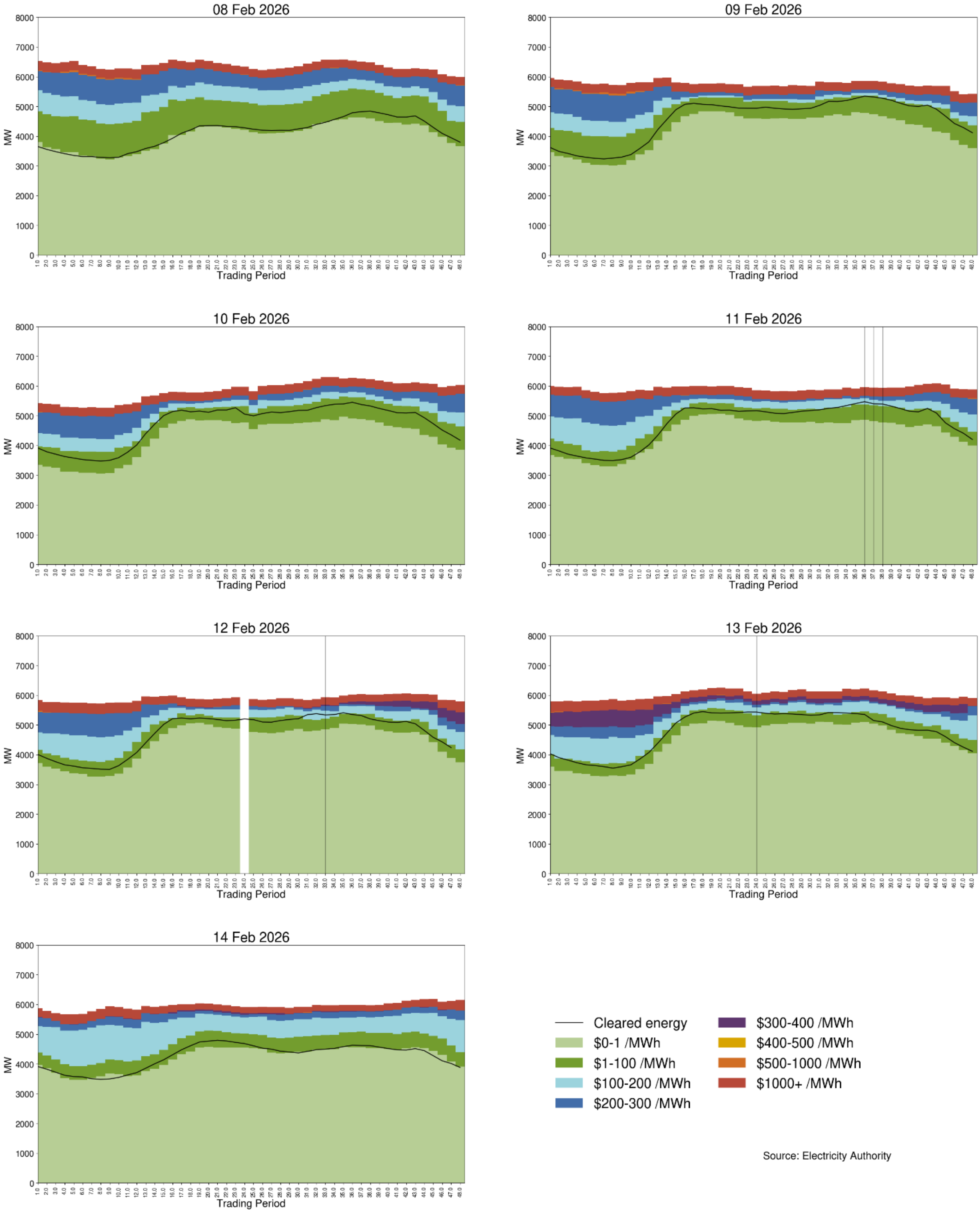
12. Offer behaviour

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. Most offers this week cleared below $100/MWh, except at times on Wednesday, Thursday and Friday, where some energy cleared between $100-$200/MWh. Energy offered between $300-$400/MWh increased between Thursday and Friday as Mercury hydro offers increased.

12.3. Note offer data is missing for trading period 24 on Thursday.

Figure 23: Daily offer stacks

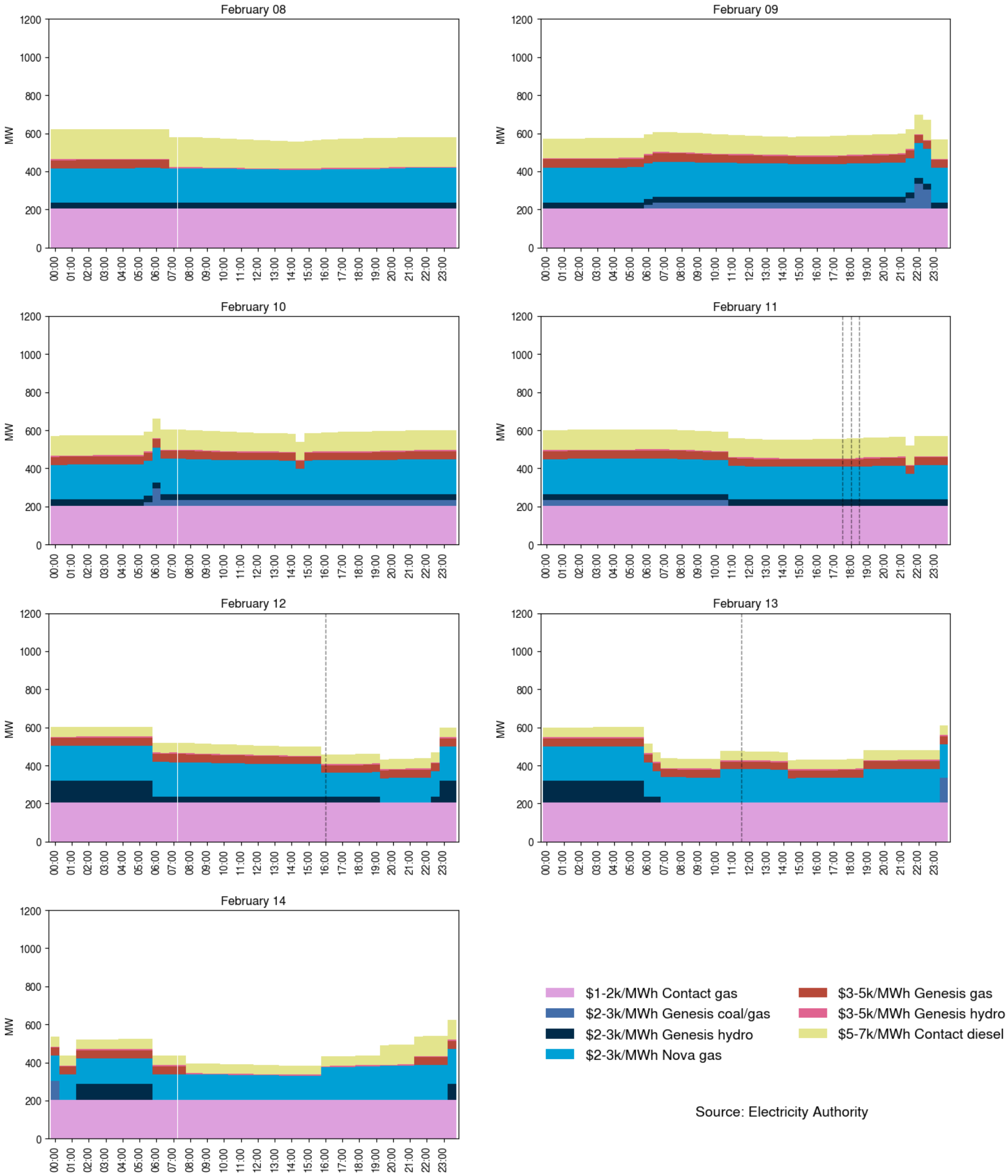


12.4. Figure 24 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 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.

12.6. On average 545MW 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.

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
21/01/2026-24/01/2026	Several	Further analysis	Genesis	Waikaremoana	Offers
02/02/2026	Several	Further analysis	Genesis	Huntly	Generation
04/02/2026-05/02/2026	Several	Further analysis	Contact/Manawa	Matahina	Offers