2 March 2026

Trading conduct report 22-28 February 2026

Market monitoring weekly report

Trading conduct report 22-28 February 2026

1. Overview

1.1. This week the average spot price increased by $33/MWh to $72/MWh, with higher thermal generation, lower wind generation, and the annual HVDC outages contributing to higher prices. National controlled hydro storage decreased this week to 91% nominally full and ~112% 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 22-28 February:

(a) The average spot price for the week was $72/MWh, an increase of around $33/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $147/MWh.

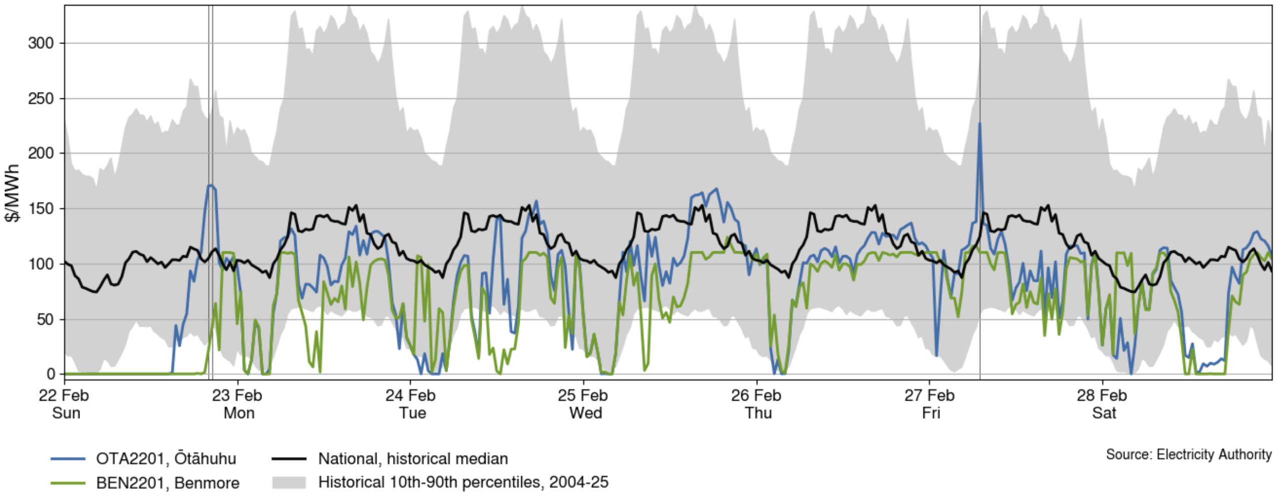
2.3. Prices are higher this week compared to last week due to higher thermal generation, lower wind generation and the annual planned HVDC outages continuing.

2.4. During the HVDC bi-pole outage on Sunday, prices remained around $0.01/MWh until 3.30pm, when prices began to increase as demand increased. Ōtāhuhu prices reached up to $171/MWh between 8.00pm and 8.30pm with demand between 80-112MW higher than forecast during this time. Prices at Benmore were $21/MWh and $42/MWh at these times.

2.5. Periods of price separation between the islands occurred throughout the week due to the planned Pole 2 outage and its impact on reserve sharing between the islands. The highest price at Ōtāhuhu this week was $227/MWh at 7.00am on Friday. North Island reserve price spikes contributed to this price with intermittent generation also 109MW lower than forecast at this time.

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.

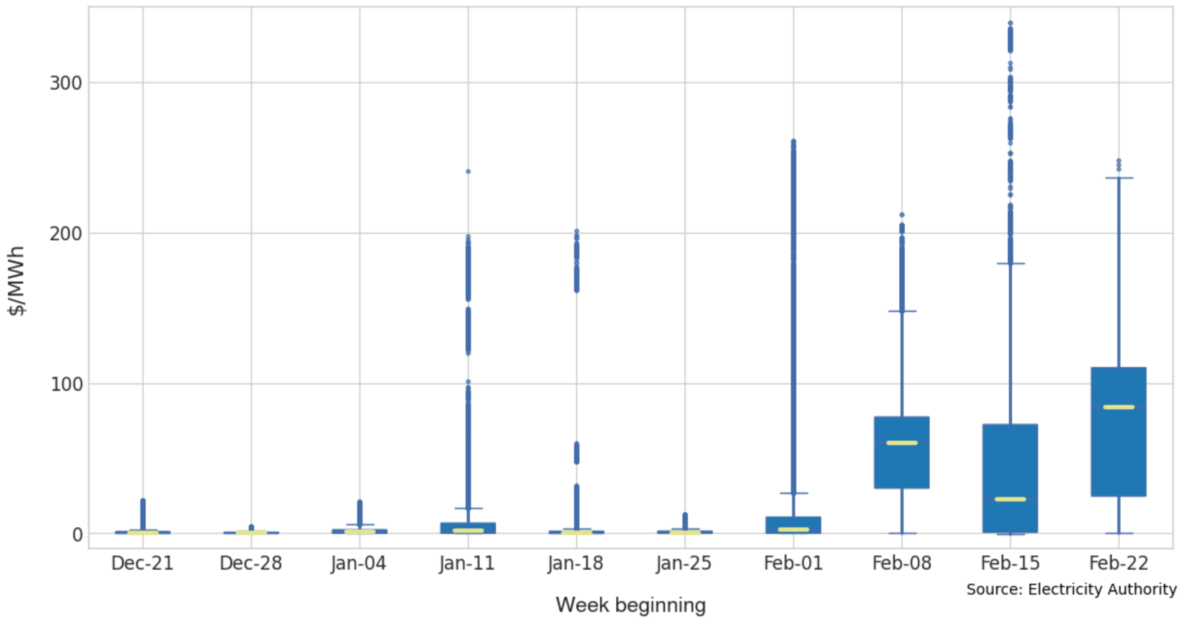
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 22-28 February



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 $84/MWh and most prices (middle 50%) fell between $25/MWh and $110/MWh.

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

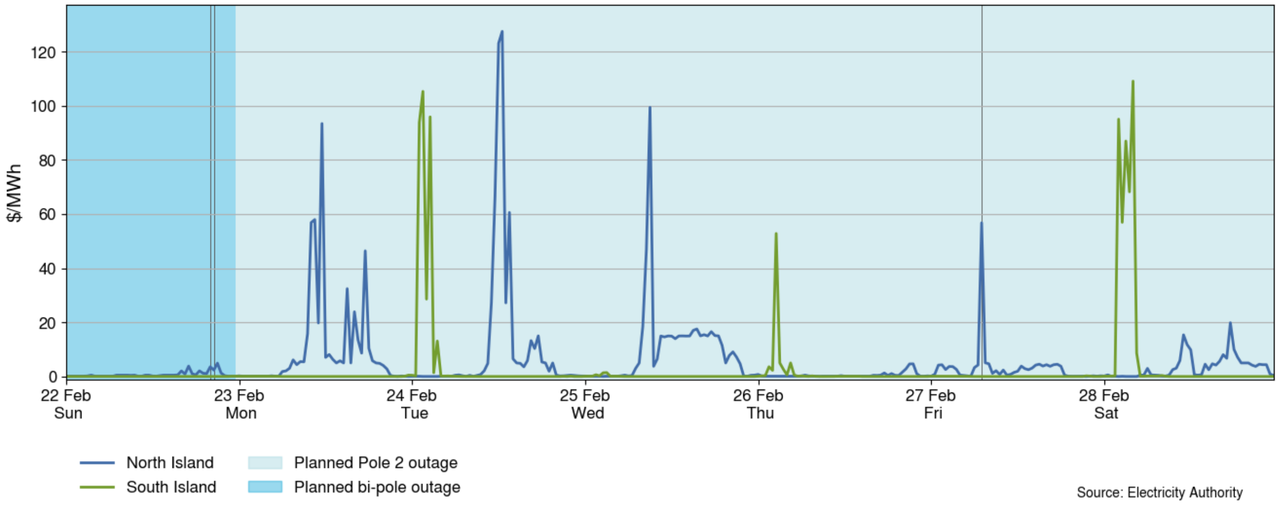


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $20/MWh this week, however, the planned HVDC Pole 2 outage contributed to several North and South Island price spikes throughout the week.

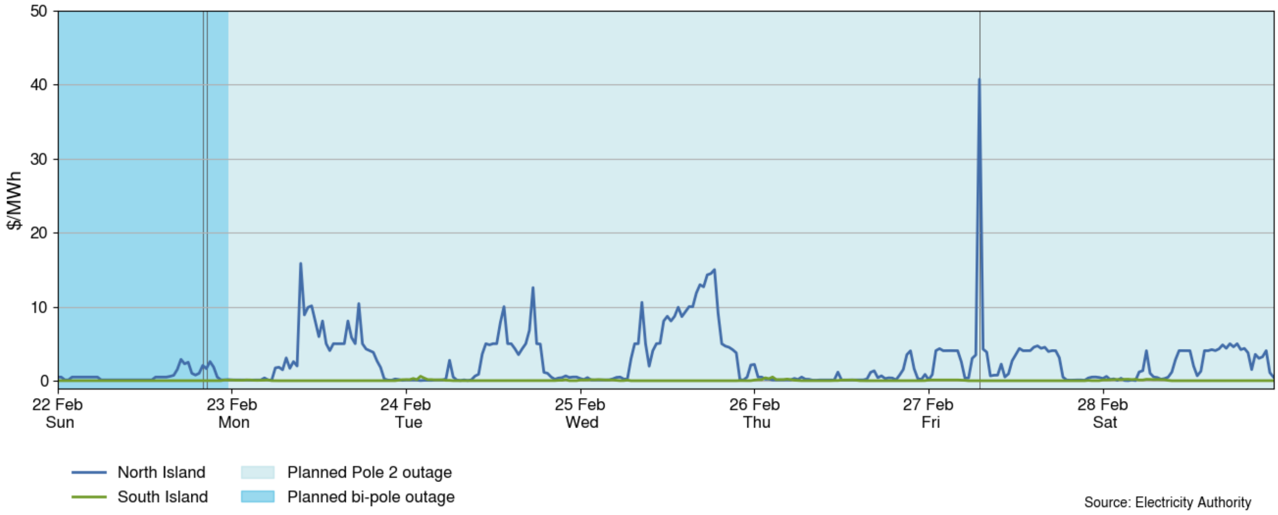
3.2. The highest North Island FIR price of $128/MWh occurred on Tuesday at 12.30pm. The highest South Island FIR price of $109/MWh occurred on Saturday at 4.00am when the HVDC was setting the South Island risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 22-28 February



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $20/MWh, except for 7.00am on Friday when the North Island SIR price was $41/MWh while the HVDC was setting the North Island risk.

Figure 4: Sustained instantaneous reserve by trading period and island, 22-28 February



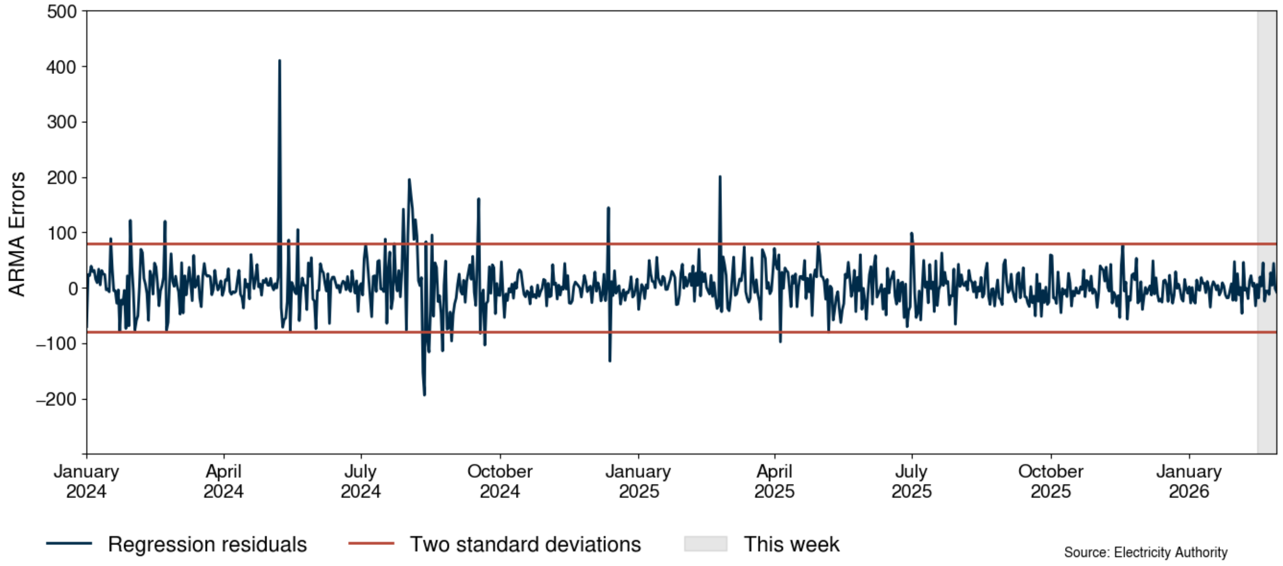
4. Regression residuals

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 - 28 February 2026



5. HVDC

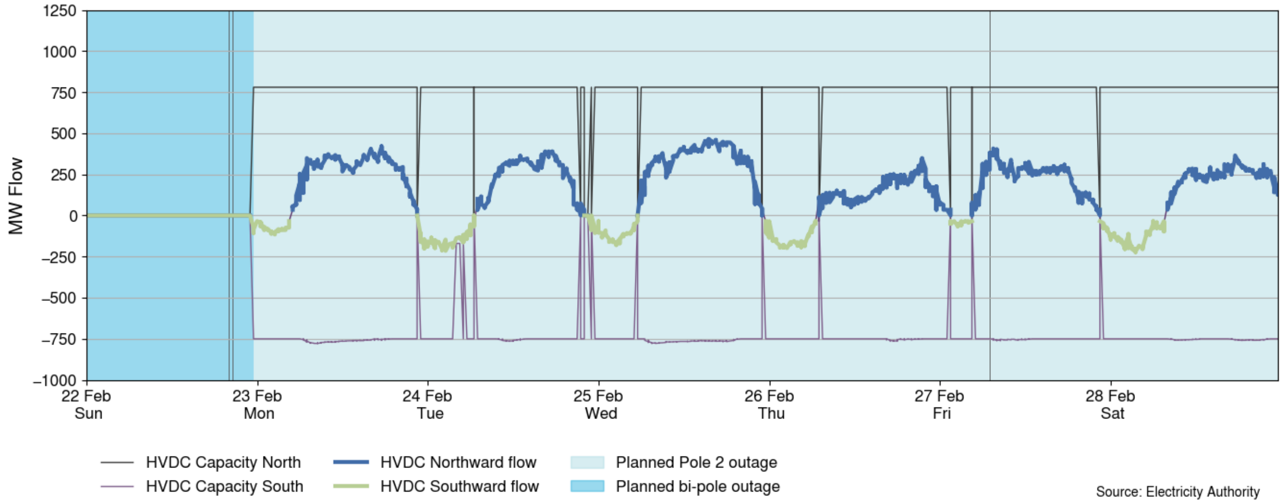
5.1. Figure 6 shows the HVDC flow between 22-28 February. HVDC flows were mostly northward during the day and southward overnight this week.

5.2. The bi-pole outage continued this week, ending on Sunday at 11.30pm. Following this, the outage of Pole 2 commenced, which is scheduled to end on 2 March.[1]

5.3. The highest northward flow occurred at 3.30pm on Wednesday with a flow of 466MW.

[1] CAN Planned Outage HVDC Pole 2, HVDC Pole 3 7187559573.pdf

Figure 6: HVDC flow and capacity, 22-28 February



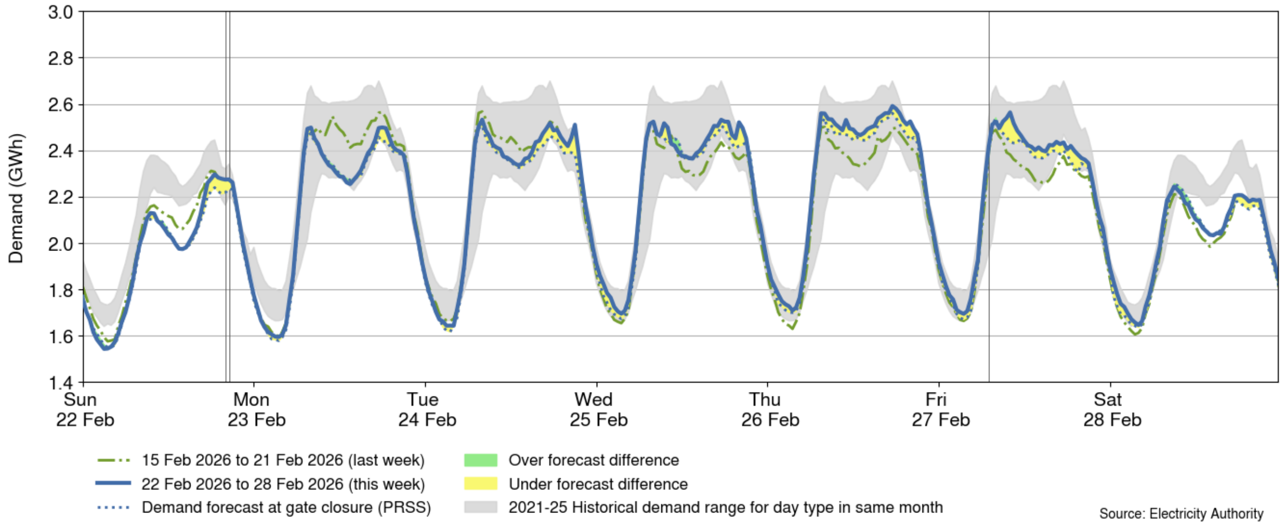
6. Demand

6.1. Figure 7 shows national demand between 22-28 February, compared to the historic range and the demand of the previous week. Demand was mostly similar compared to the previous week, with lower demand at times between Sunday and Tuesday and higher demand at times between Wednesday and Friday.

6.2. Demand was higher than forecast at times every day this week, with load control near Christchurch contributing to some of these errors.

6.3. The highest demand of the week was around 2.59GWh at 5.30pm on Thursday.

Figure 7: National demand, 22-28 February compared to the previous week

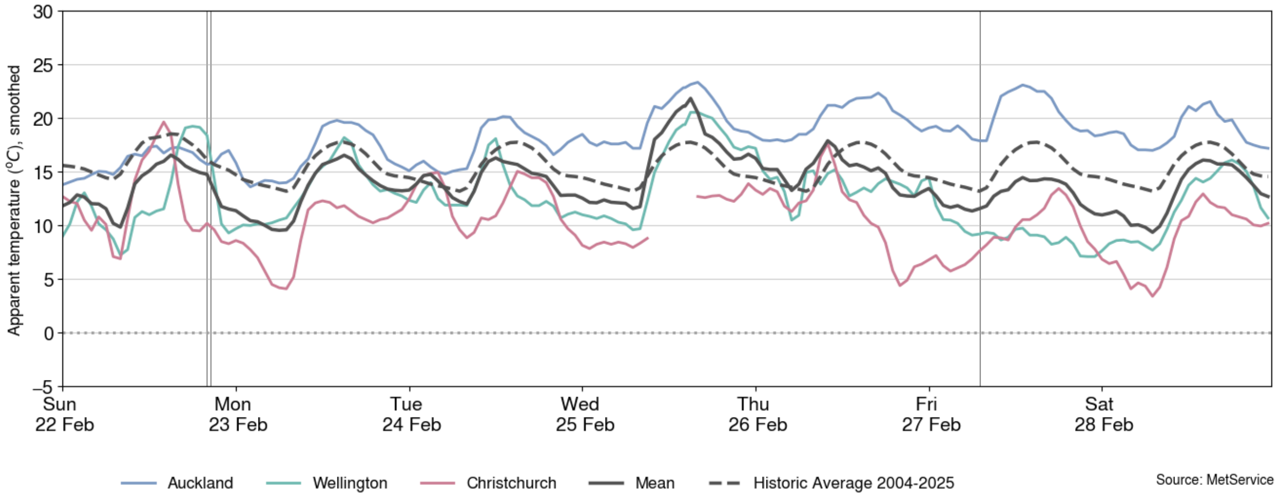


6.4. Figure 8 shows the hourly apparent temperature at main population centres from 22-28 February. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature 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 14°C to 23°C in Auckland, 6°C to 22°C in Wellington, and 3°C to 20°C in Christchurch.

6.6. Note that data is missing on Wednesday for Christchurch.

Figure 8: Temperatures across main centres, 22-28 February



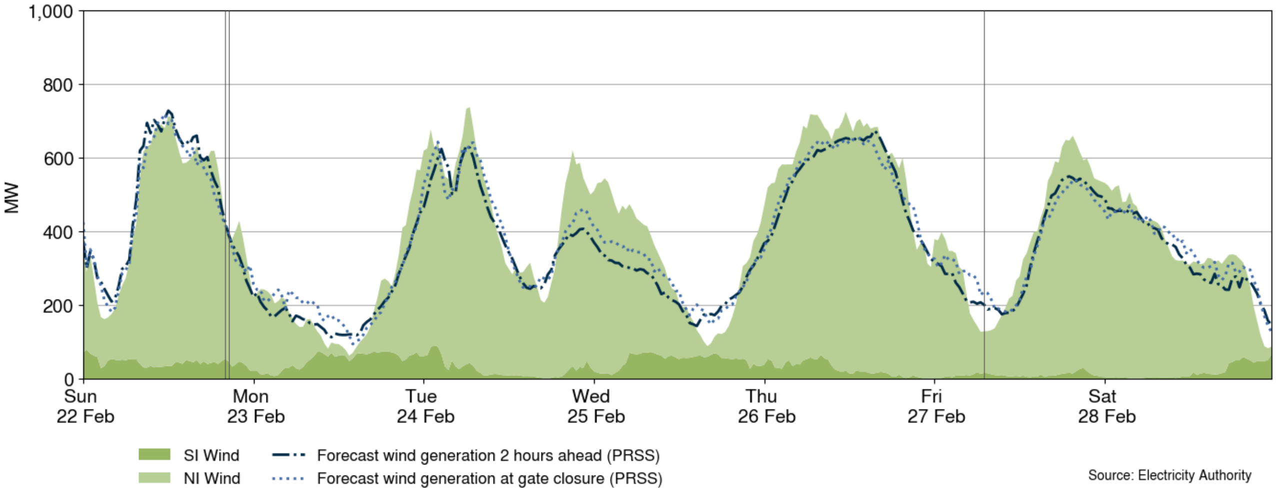
7. Generation

7.1. Figure 9 shows wind generation and forecast from 22-28 February. This week wind generation varied between 63MW and 738MW, with a weekly average of 399MW.

7.2. Wind generation varied greatly day-to-day this week. Tuesday and Thursday saw the highest average wind generation, while generation was lowest across Monday and Wednesday.

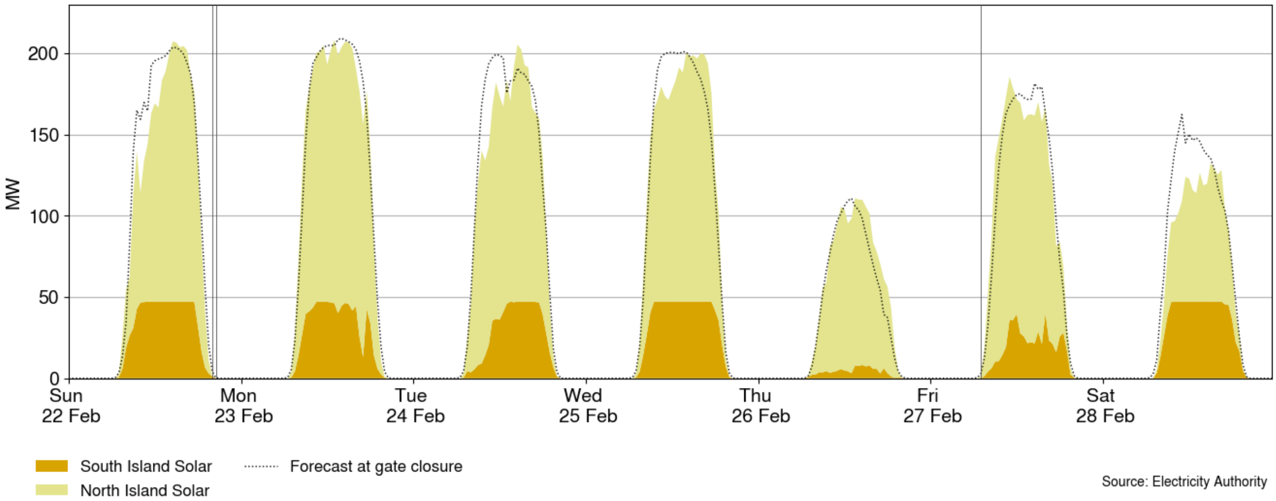
7.3. Wind forecasting errors on Wednesday were the result of an amalgamation of errors across multiple wind farms, while errors on Friday mostly came from Waipipi wind farm.

Figure 9: Wind generation and forecast, 22-28 February



7.4. Figure 10 shows grid connected solar generation from 22-28 February. Solar generation reached above 130MW daily, aside from on Thursday, where generation reached a maximum of only 111MW. Solar generation peaked on Monday at 1.00pm at around 208MW.

Figure 10: Grid connected solar generation, 22-28 February

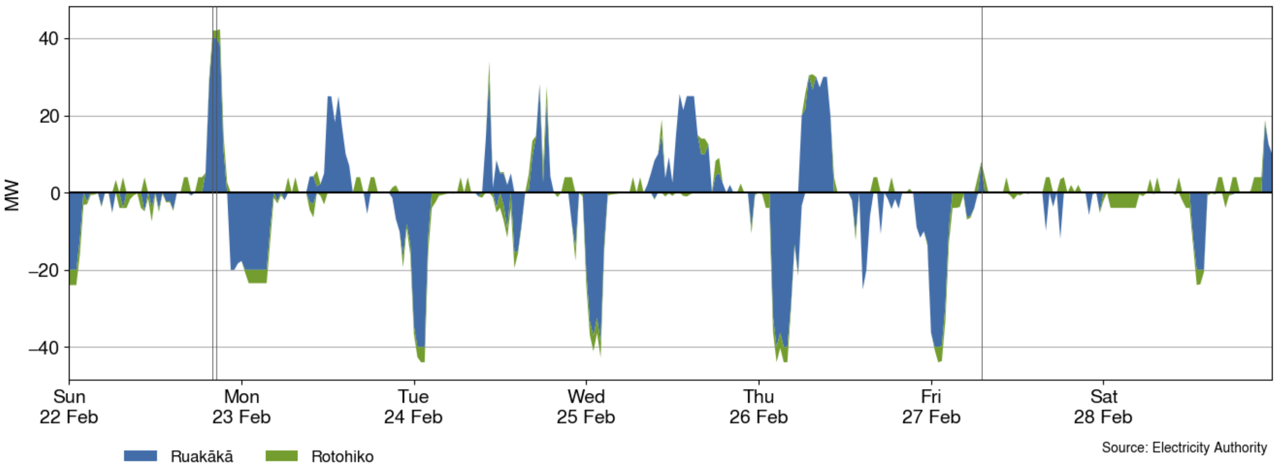


7.5. Figure 11 shows when the grid scale batteries Rotohiko (35MW/35MWh) and Ruakākā (100MW/200MWh) charged (negative values) and discharged (positive values). Typically, a grid scale battery charges when prices are low and discharges energy back into the grid when prices are higher.

7.6. This week the batteries mostly charged during the day or overnight when prices were relatively lower. The batteries mostly discharged when prices were higher during the day.

7.7. The Ruakākā battery did not discharge much during Friday's high price, likely due to being dispatched for reserves.

Figure 11: Grid scale battery charge and discharge, 22-28 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[2]) 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

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

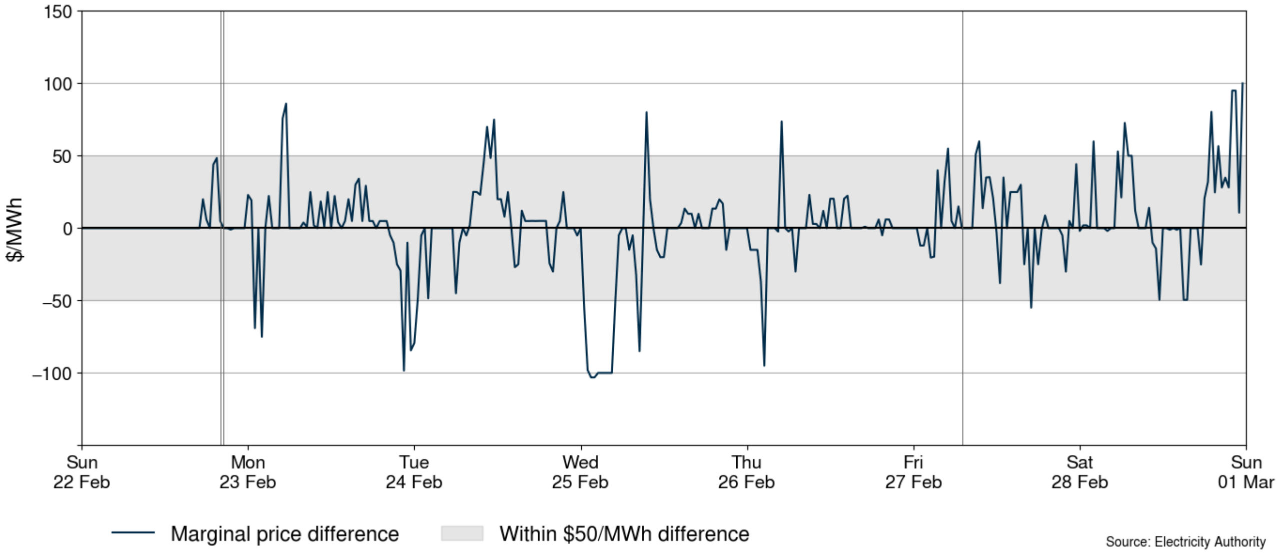
ahead and the RTD intermittent generation and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.9. Several trading periods this week had price differences of more than $50/MWh.

7.10. The maximum positive difference of $100/MWh occurred on Saturday at 11.30pm. During this time, demand was 53MW higher than forecast and wind generation was 40MW lower than forecast.

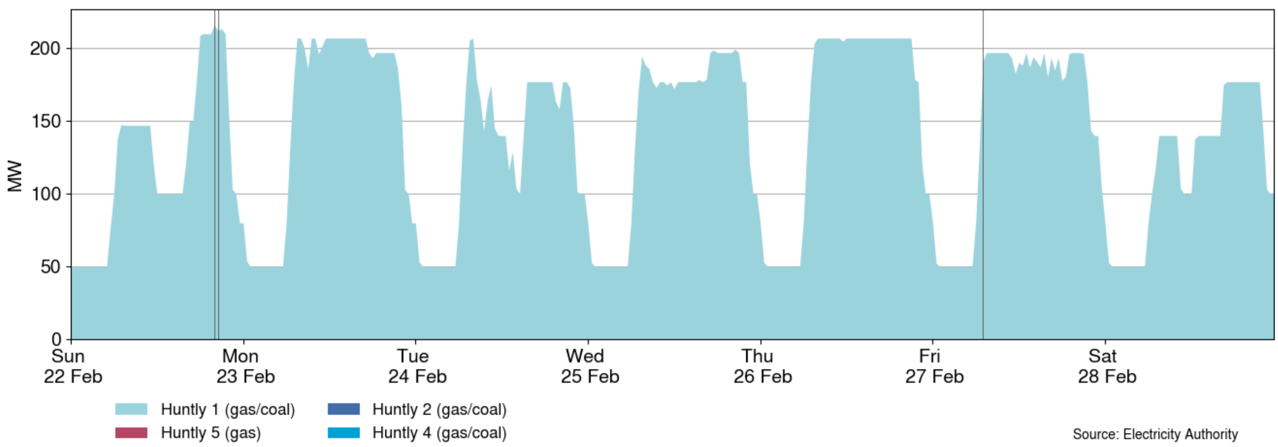
7.11. The maximum negative difference of $103/MWh occurred on Wednesday at 1.30am. During this time demand was 81MW higher than forecast, which would normally lead to a positive price difference. However, this demand error was outweighed by wind generation which was 174MW higher than forecast.

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, 22-28 February



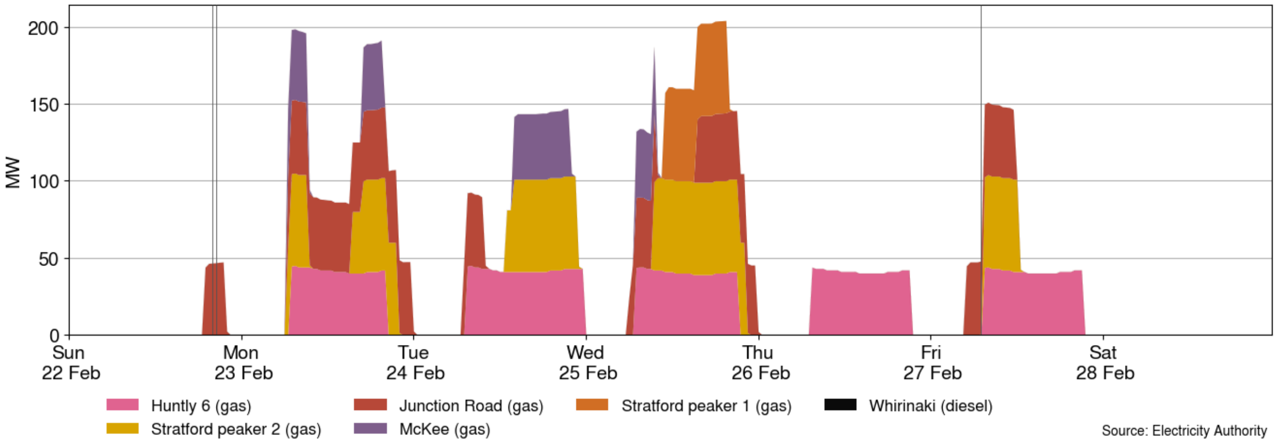
7.12. Figure 13 shows the generation of thermal baseload between 22-28 February. Huntly 1 ran continuously this week, generating more during the day and less overnight.

Figure 13: Thermal baseload generation, 22-28 February



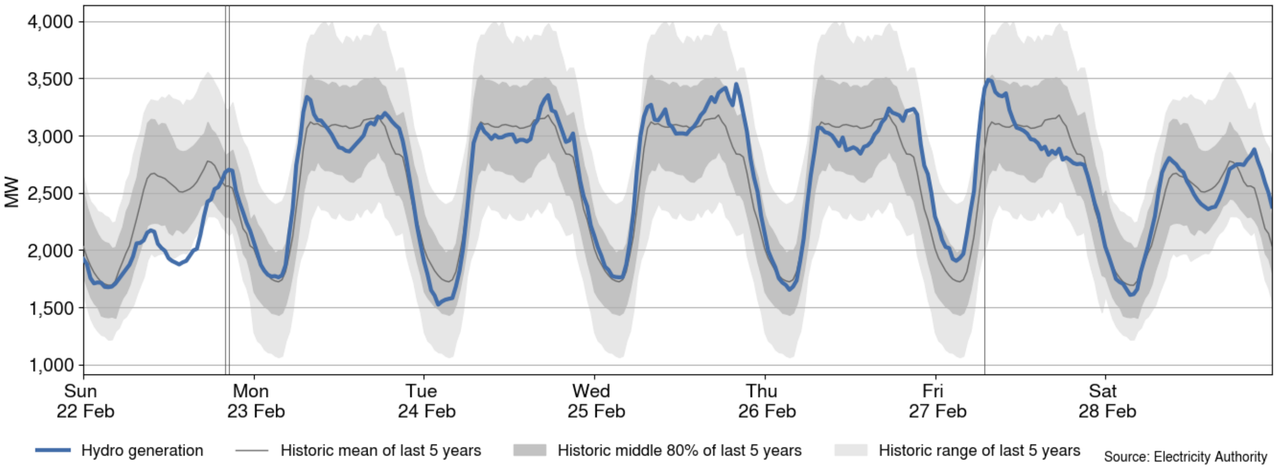
7.13. Figure 14 shows the generation of thermal peaker plants between 22-28 February. Huntly 6 ran each day between Monday and Friday. Junction Road, McKee and Stratford peaker 2 ran at various times between Sunday and Friday, with Stratford peaker 1 also running on Wednesday.

Figure 14: Thermal peaker generation, 22-28 February



7.14. Figure 15 shows hydro generation between 22-28 February. Hydro generation was mostly below the historic mean on Sunday, likely related to a combination of low demand, high wind and the bi-pole HVDC outage. For the rest of the week, hydro generation was mostly within the historic middle 80% of generation.

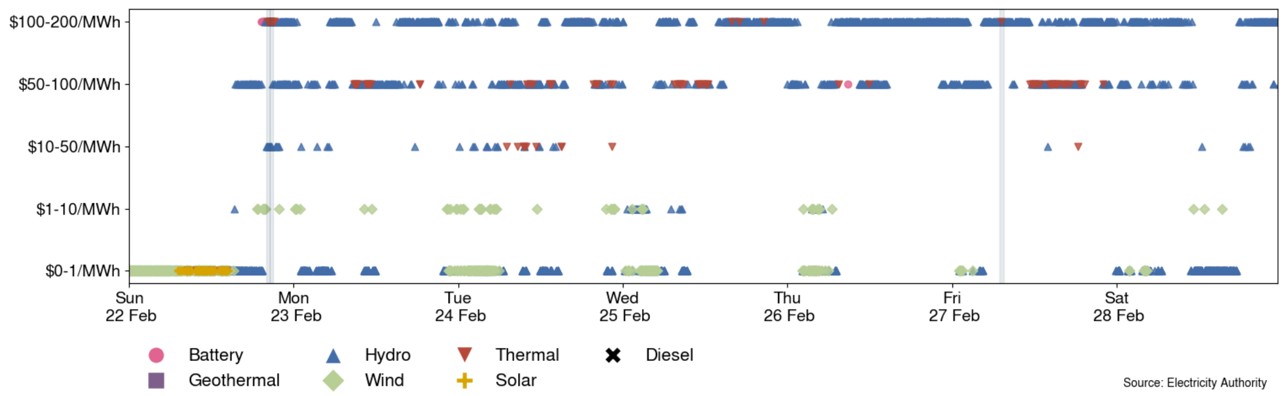
Figure 15: Hydro generation, 22-28 February



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.

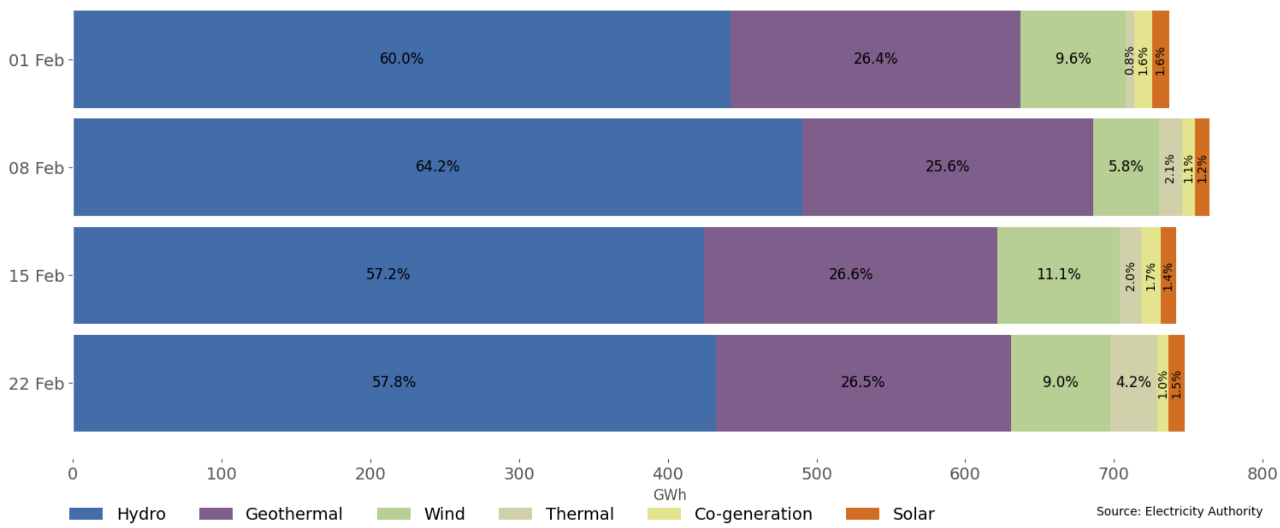
7.16. The highest prices were set by Genesis hydro on Friday. The most common technology setting prices this week was hydro generation, with wind generation the second most common. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 22-28 February



7.17. As a percentage of total generation, between 22-28 February, total weekly hydro generation was 57.8%, geothermal 26.5%, wind 9.0%, thermal 4.2%, co-generation 1.0%, and solar (grid connected) 1.5%, as shown in Figure 17. Thermal generation increased this week due to lower wind generation and planned HVDC outages limiting energy transfer between islands.

Figure 17: Total generation by type as a percentage each week, between 1 and 28 February



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 22-28 February ranged between ~1,290MW and ~1,937MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 22-28 February

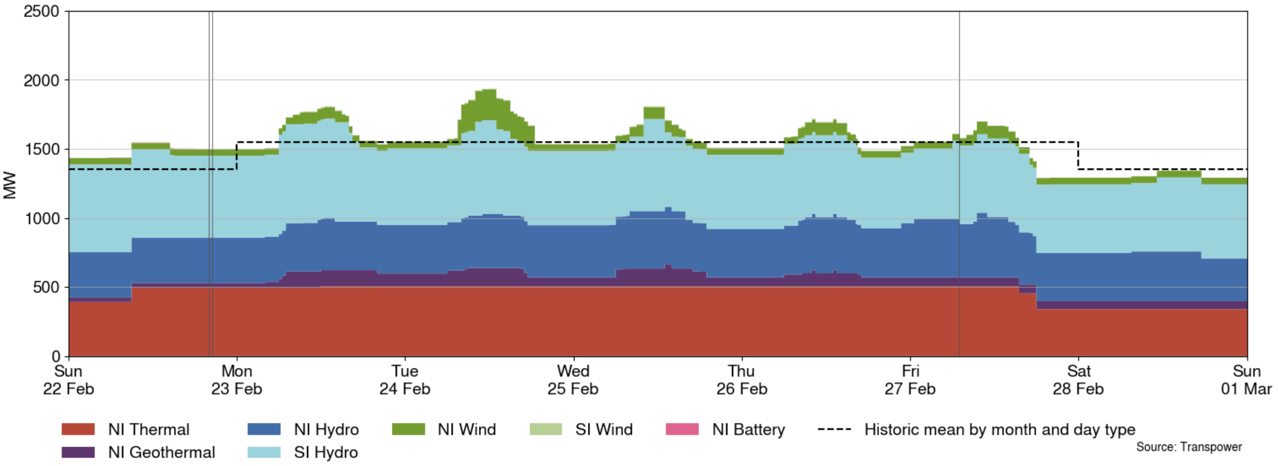
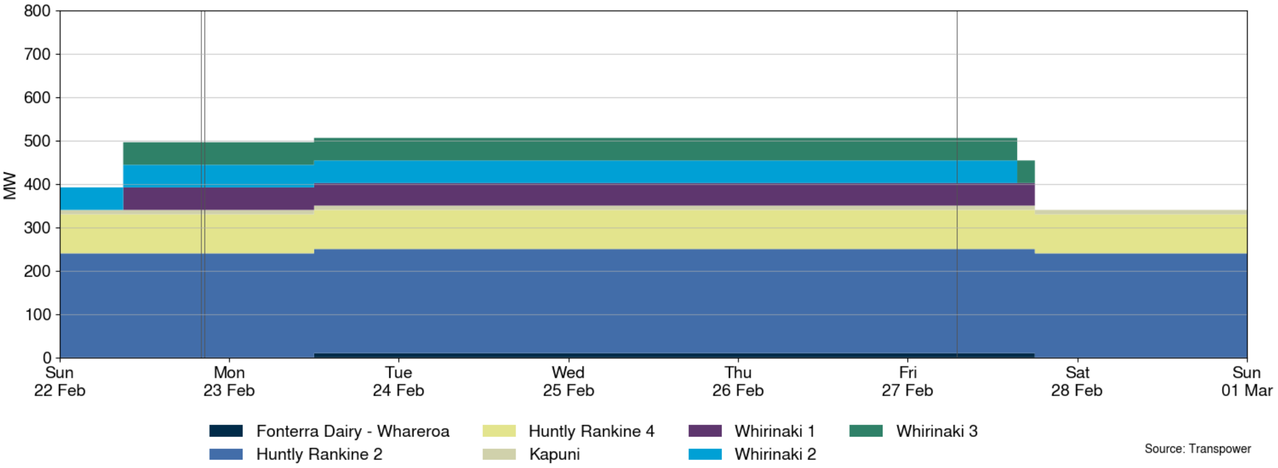


Figure 19: Total MW loss from thermal outages, 22-28 February



8.2. Notable outages include:

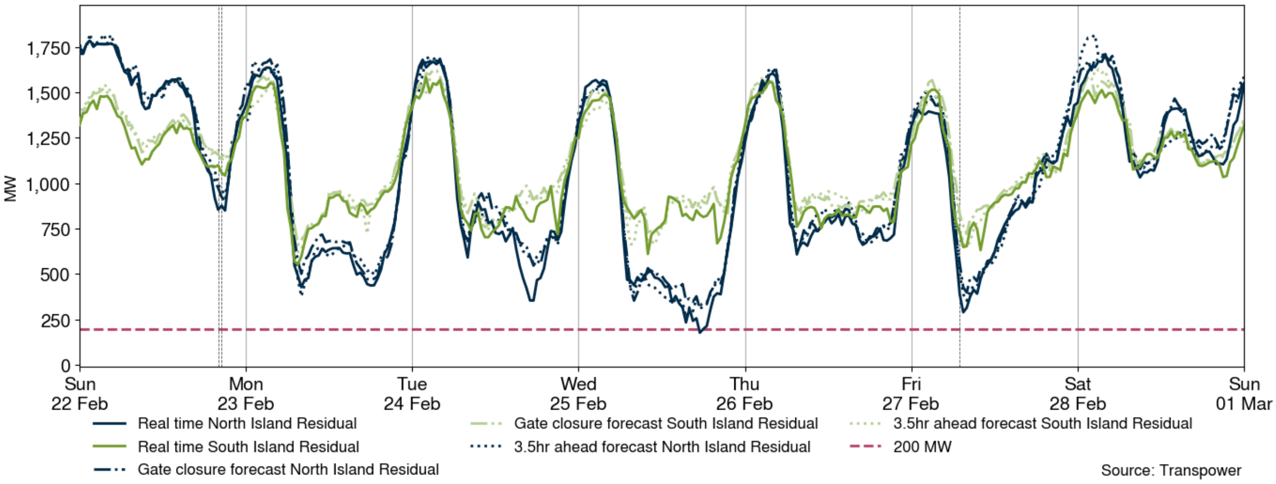
Plant	Partial or Full	End Date
Roxburgh unit 5	Full	22 February 2026
Waipipi wind farm	Full	24 February 2026
Whirinaki	Full	27 February 2026
Huntly 4	Partial	10 March 2026
Ōhau A	Partial	6 March 2026
Rangipō unit 6	Full	29 March 2026
Huntly 2	Full	28 April 2026
Clyde unit 2	Full	1 May 2026
Manapōuri unit 4	Full	12 June 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 22-28 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 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. The lowest North Island residual this week was 177MW on Wednesday at 5.30pm, which occurred during the highest North Island demand of the week. The lowest South Island residual this week was 554MW on Monday at 7.30am.

Figure 20: National generation balance residuals, 22-28 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 10th to 90th percentiles.

10.2. As of 28 February, national controlled storage decreased to 91% nominally full and ~112% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (96% full[3]) is below its historic 90th percentile but remains above mean, while Lake Takapō (85% full) is close to its historic mean.

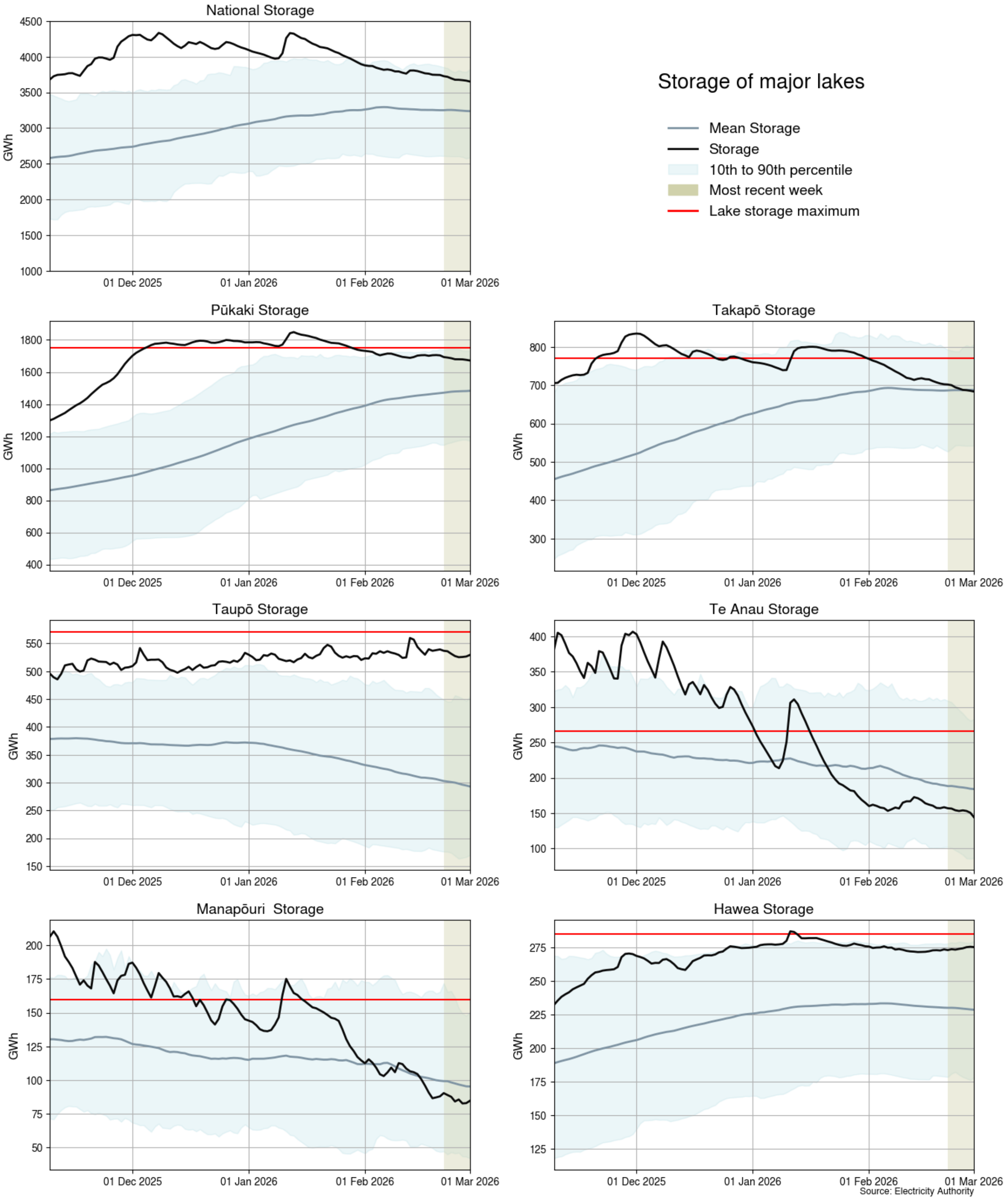
10.4. Storage at Lake Te Anau (54% full) is below its historic mean, with Lake Manapōuri (54% full) also below its historic mean.

10.5. Storage at Lake Taupō (92% full) remains above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (96% full) is close to its historic 90th percentile.

[3] 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 February 2026. The SRMCs for gas-powered generation have increased, while the SRMC for diesel-fuelled generation has decreased. The SRMC for coal-fuelled generation has remained stable.

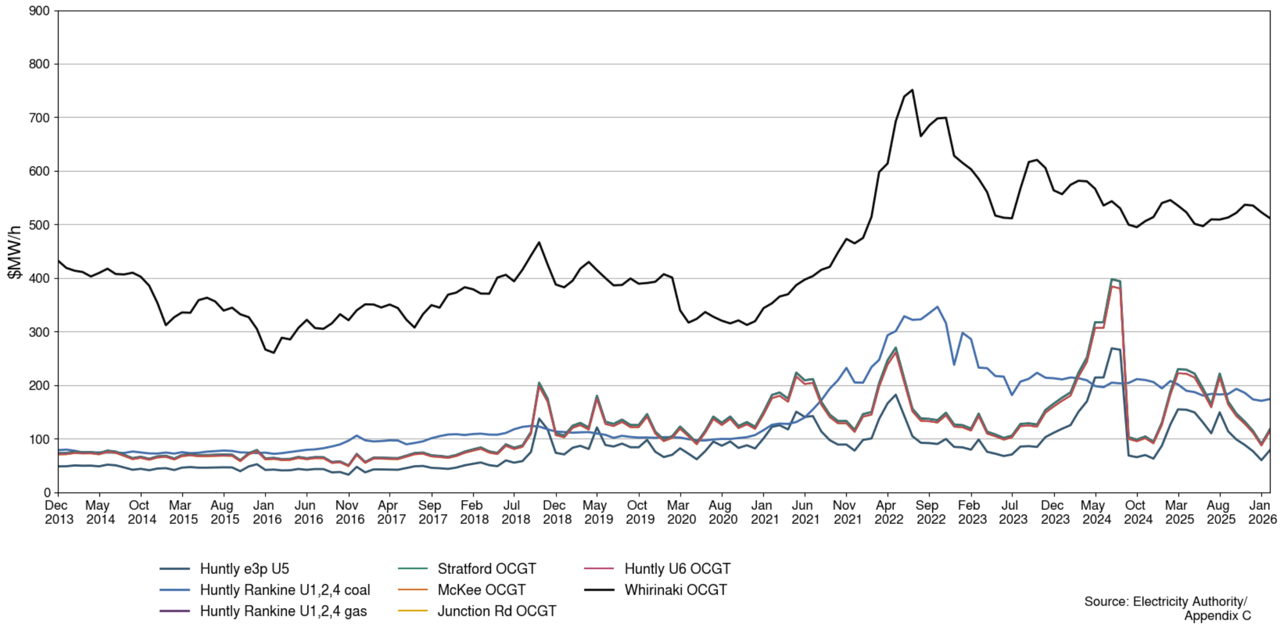
11.4. The latest SRMC of coal-fueled Rankine generation is ~$174/MWh. The cost of running the Rankines on gas is ~$117/MWh.

11.5. The SRMC of gas-fueled thermal plants is currently between $78/MWh and $117/MWh.

11.6. The SRMC of Whirinaki is ~$512/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



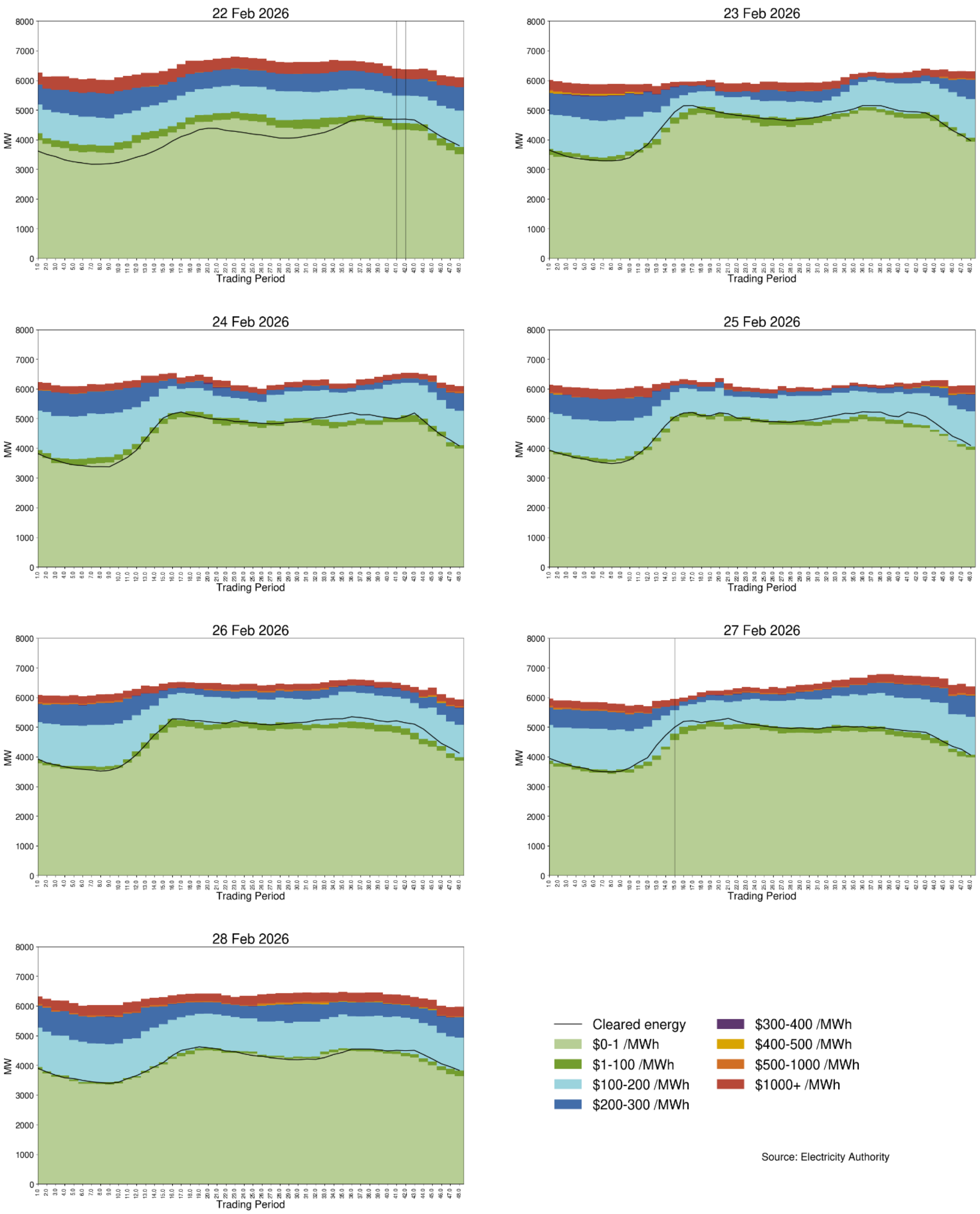
Source: Electricity Authority/ Appendix C

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 cleared in the $1-100/MWh or the $100-200/MWh range this week, although on Sunday, energy cleared below $1/MWh for much of the day.

Figure 23: Daily offer stacks



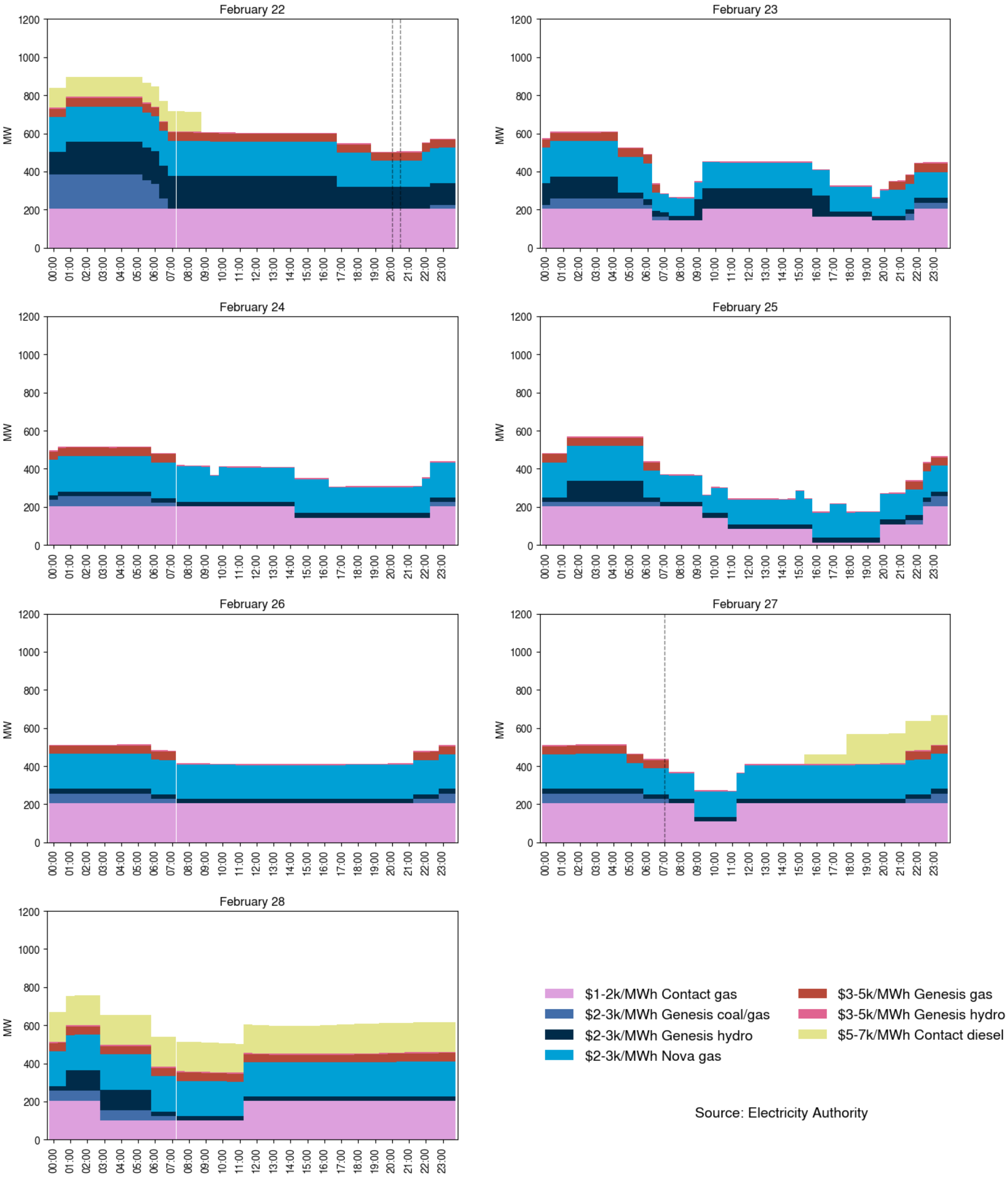
Source: Electricity Authority

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, intermittent 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 487MW per trading period was priced above $1,000/MWh this week, which is roughly 9% 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
04/02/2026-05/02/2026	Several	Further analysis	Contact/Manawa	Matahina	Offers