5 March 2025

Trading conduct report 23 February-1 March

Market monitoring weekly report

Trading conduct report 23 February-1 March

1. Overview

1.1. Spot prices were high this week due to hydro storage dropping to 67% nominally full, unexpected Huntly outages, planned HVDC outages and low wind. There were high energy and reserve prices in the North Island between 11.30am and 1pm.

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 23 February-1 March:

(a) The average spot price for the week was $318/MWh, an increase of around $79/MWh compared to the previous week.

(b) 95% of prices fell between $0.03/MWh and $519/MWh.

2.3. Prices increased this week due to:

(a) continued declining hydro storage

(b) continued low hydro inflows

(c) unplanned Huntly and geothermal outages

(d) the planned HVDC outages

(e) low wind generation

2.4. The highest price at Ōtāhuhu was $2,372/MWh at 12:30pm on Monday. Prices were above $600/MWh between 11am and 1pm that day. During this time:

(a) Huntly 1 unexpectedly stopped generating around 10.50am due to cooling issues[1].

(b) Tauhara geothermal also tripped and went on an unplanned outage from ~11.30am to 4pm.

These unexpected outages, paired with the planned HVDC Pole 2 outage led to high and energy pricing in the North Island from 11.30am to 1pm.[2]

2.5. The highest price of the week occurred at Wellsford and was $2,511/MWh during the highest price at Ōtāhuhu. This was due to transmission losses making the price higher than at Ōtāhuhu.

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[1] Cooling tower issue causes unplanned outage | Genesis NZ

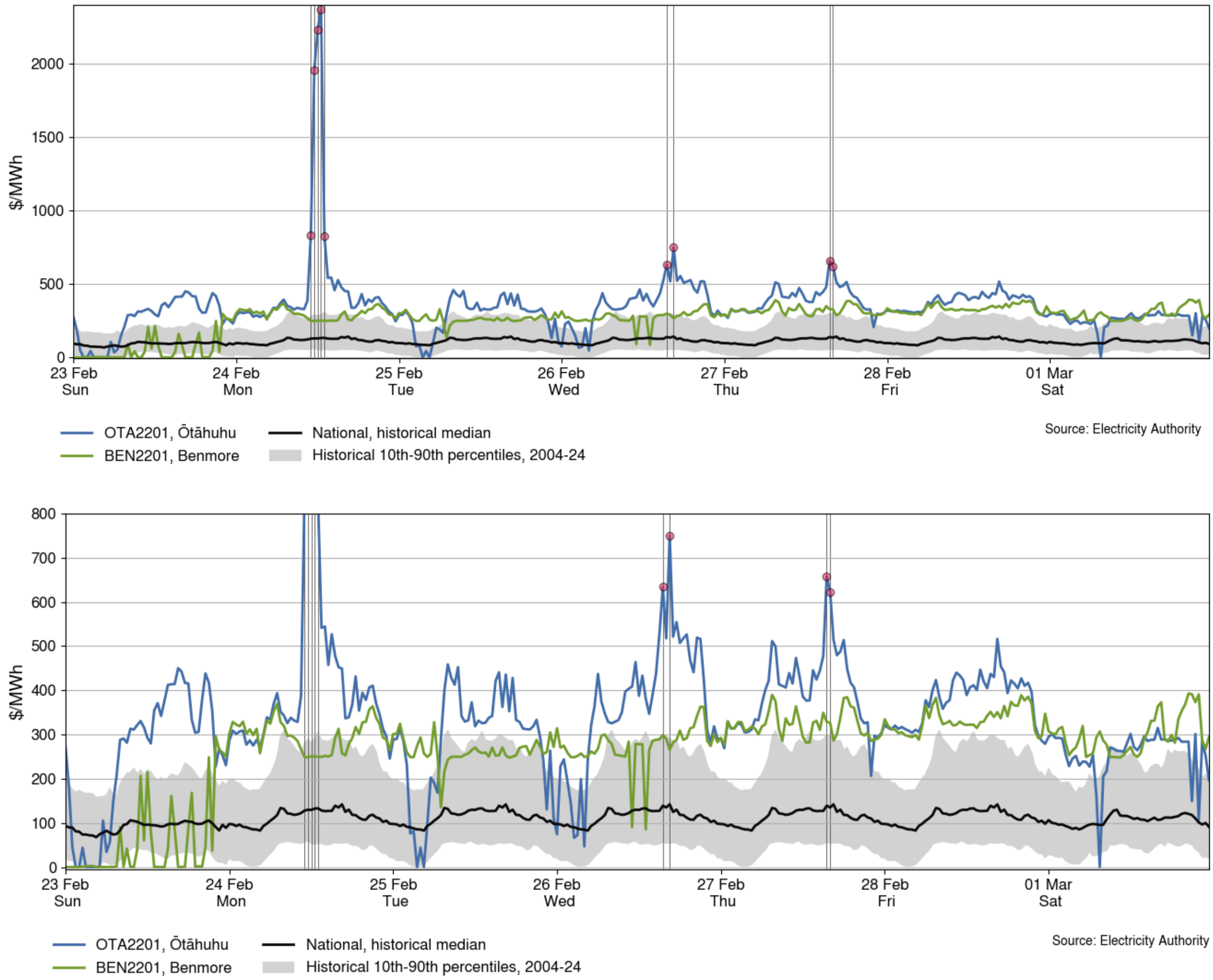
[2] HVDC outages limit energy or reserve that can be shared between islands. This often leads to spikes in reserve prices, an increase in North Island thermal generation increasing North Island spot prices, and a decrease in South Island hydro with very low South Island spot prices.

2.6. A CAN was issued at 1.21pm advising that North Island residuals were forecast at less than 200MW between 1.30pm and 5.30pm[3]. However, in real time residuals were above 200MW due to higher energy generation, some from higher than forecast wind. Increased wind generation may have prevented reserve scarcity during this period.

2.7. Huntly cooling issues and the planned HVDC outage persisted for the remainder of the week, limiting cheaper North Island energy and reserve. Other Ōtāhuhu price spikes such as those highlighted on Wednesday and Thursday were also related to high North Island FIR prices and low wind generation.

2.8. 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, 23 February-1 March



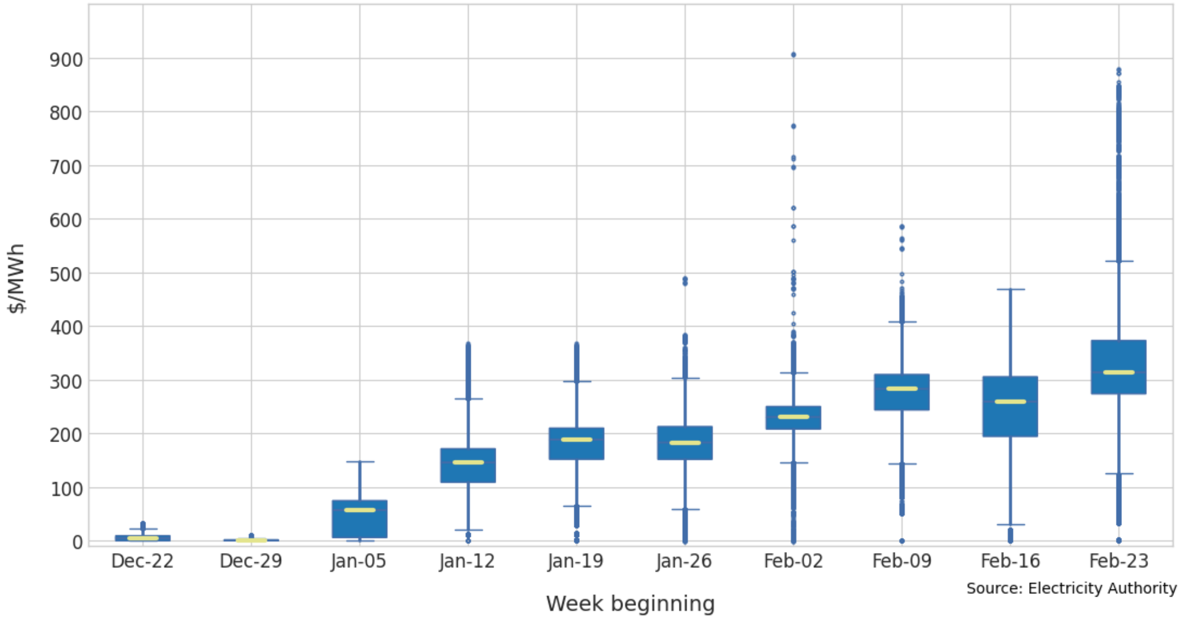
2.9. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to

[3] CAN Low Residual Situation 6033202536.pdf

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.

2.10. The distribution of spot prices this week was skewed higher than last week. The median price was $315/MWh and most prices (middle 50%) fell between $275/MWh and $373/MWh.

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

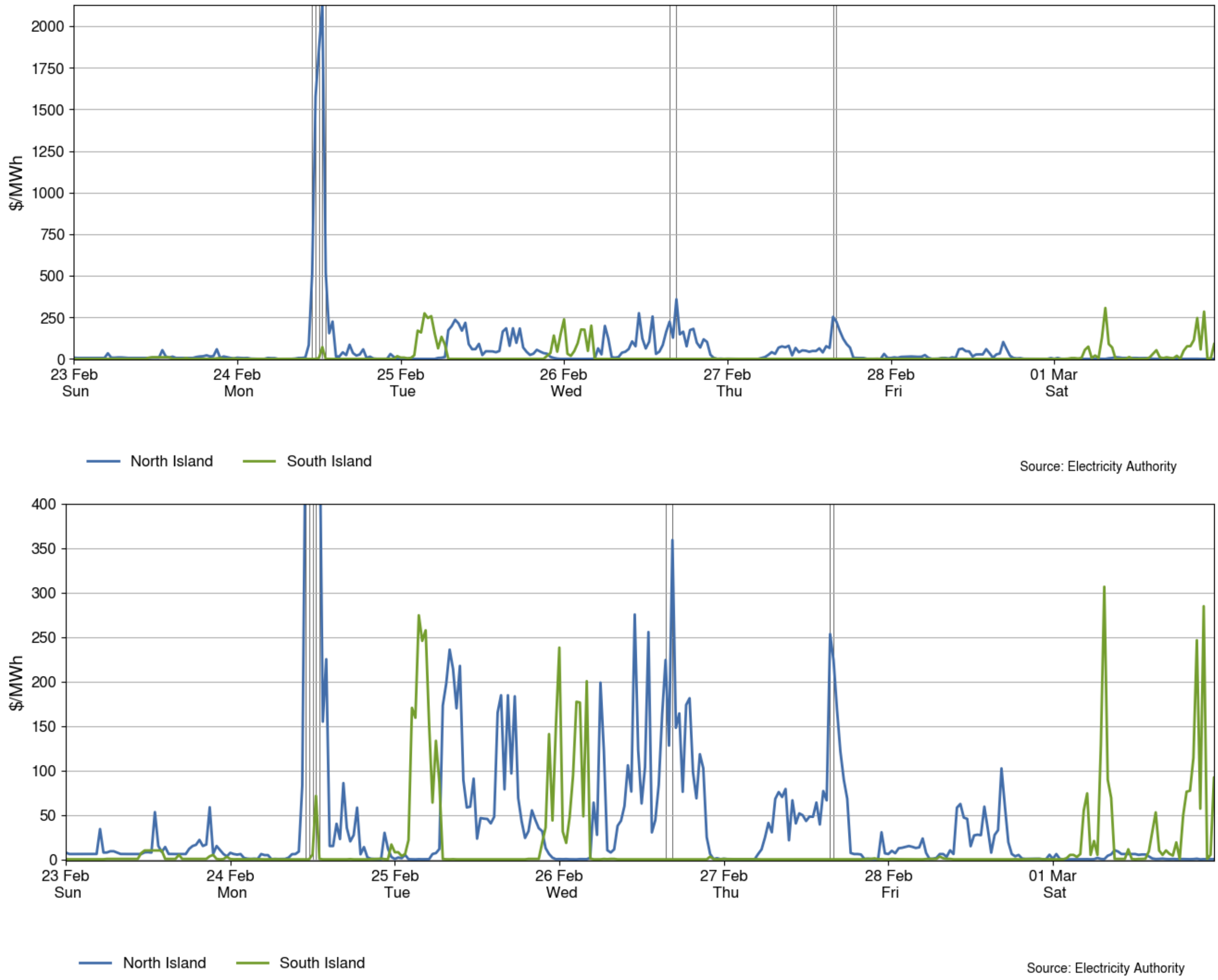


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $10/MWh but spiked high several times during the week.

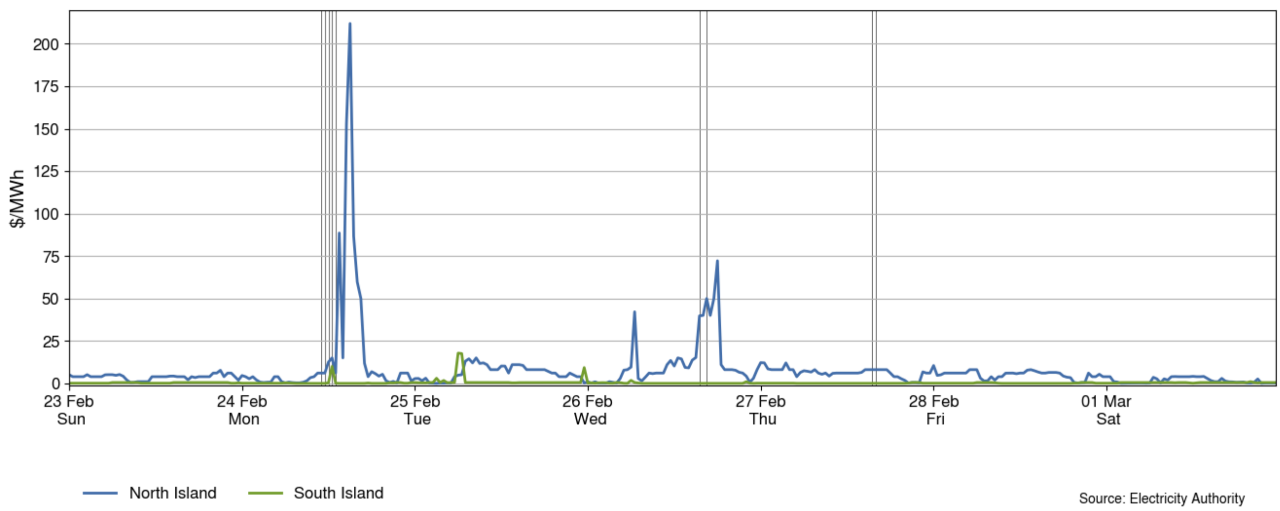
3.2. North Island FIR prices were high this week due to the planned HVDC outage, unplanned generation outages limiting reserve available and energy-reserve co-optimization during times of low wind generation. The highest FIR price was $2,127/MWh in the North Island at 12.30pm on Monday which occurred at the same time as the highest spot price this week. Some high South Island prices also occurred when the HVDC was flowing south and setting the South island risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 23 February-1 March



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $5/MWh. SIR prices spiked above $200/MWh on Monday afternoon in the North Island during the Low Residual Situation described in the customer advice notice (CAN) issued.

Figure 4: Sustained instantaneous reserve by trading period and island, 23 February-1 March



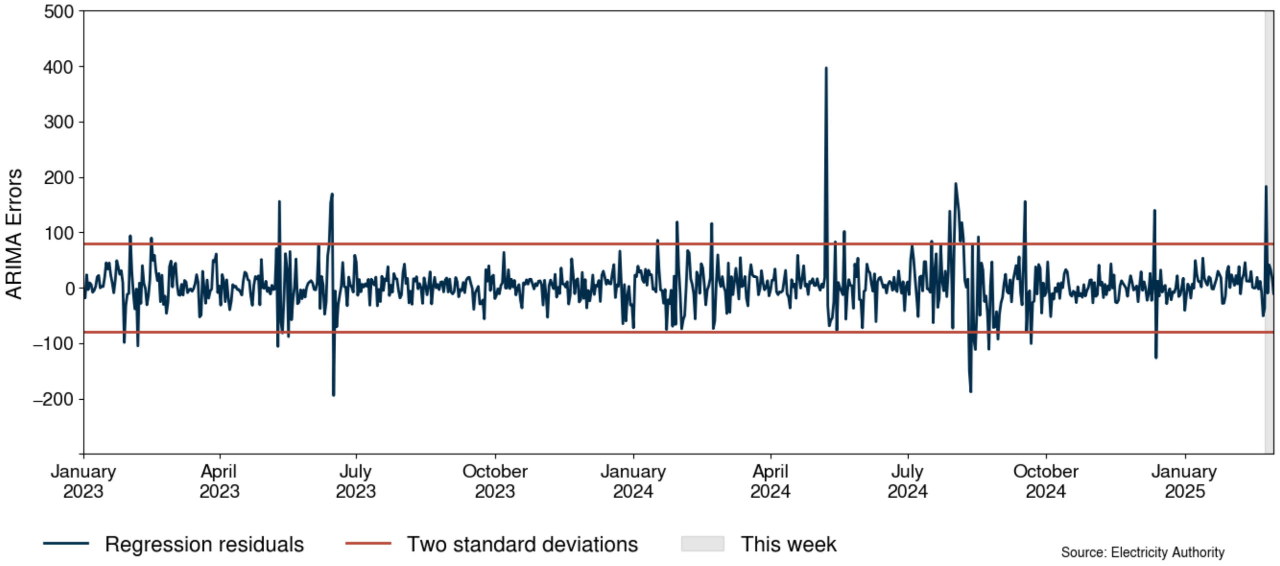
4. Regression residuals

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. Monday's regression residual was above two standard deviations. This was due to the high energy prices that day due to unexpected plant trips which aren't captured in the model .

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 1 March 2025

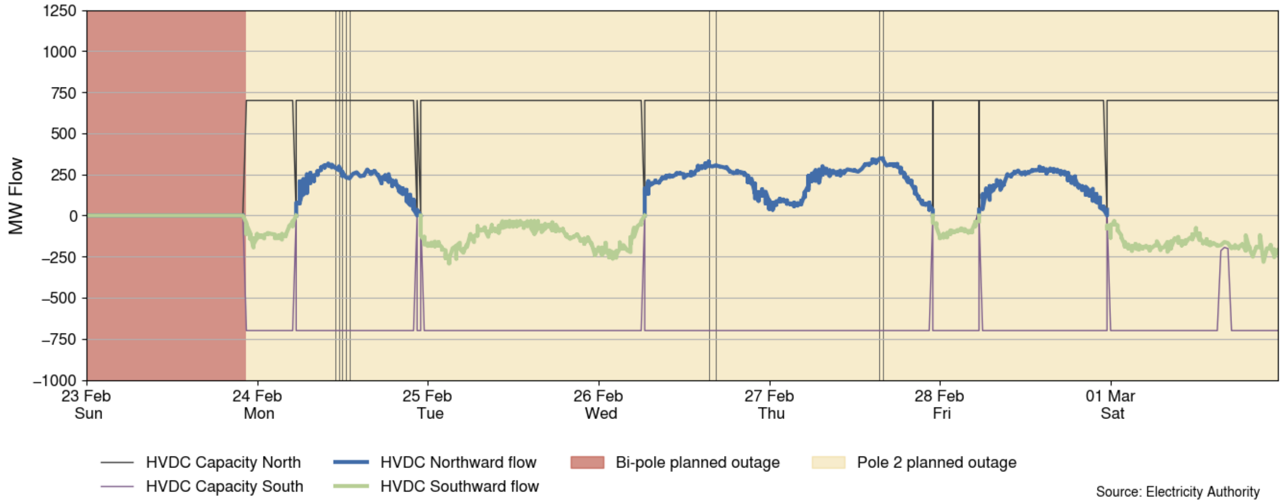


5. HVDC

5.1. Figure 6 shows the HVDC flow between 23 February-1 March. HVDC flows were lower this week due to planned HVDC outages.[4] Southward capacity on the HVDC dropped on Saturday. The monitoring team is analysing this further.

[4]Due to there only being one available pole at this time, capacity must drop to zero every time flows change direction.

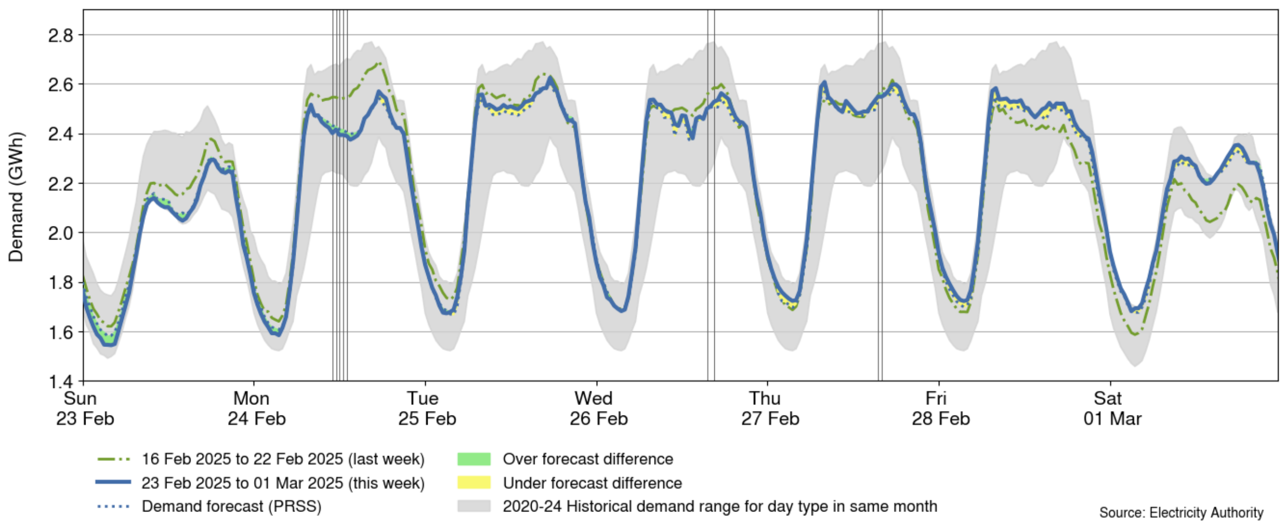
Figure 6: HVDC flow and capacity, 23 February-1 March



6. Demand

6.1. Figure 7 shows national demand between 23 February-1 March, compared to the historic range and the demand of the previous week. Demand was lower than last week on Monday and higher on Saturday. The maximum demand this week was around 2.62GWh at 5:30pm on Tuesday.

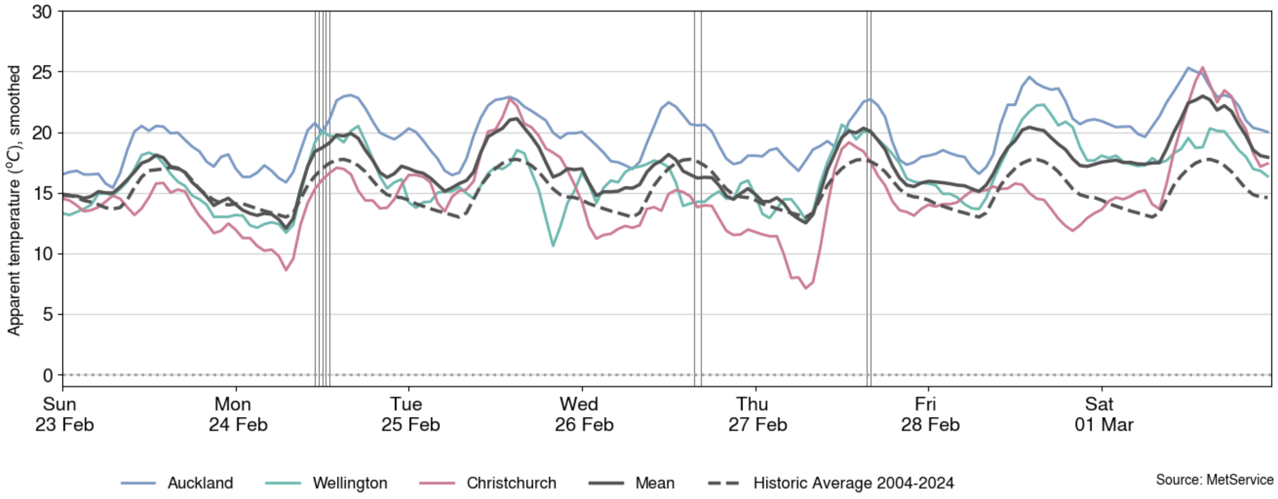
Figure 7: National demand, 23 February-1 March compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 23 February-1 March. 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.

6.3. Apparent temperatures ranged from 15°C to 26°C in Auckland, 11°C to 23°C in Wellington, and 6°C to 26°C in Christchurch. Apparent temperatures were above average most days this week, which may have increased cooling demand on certain days.

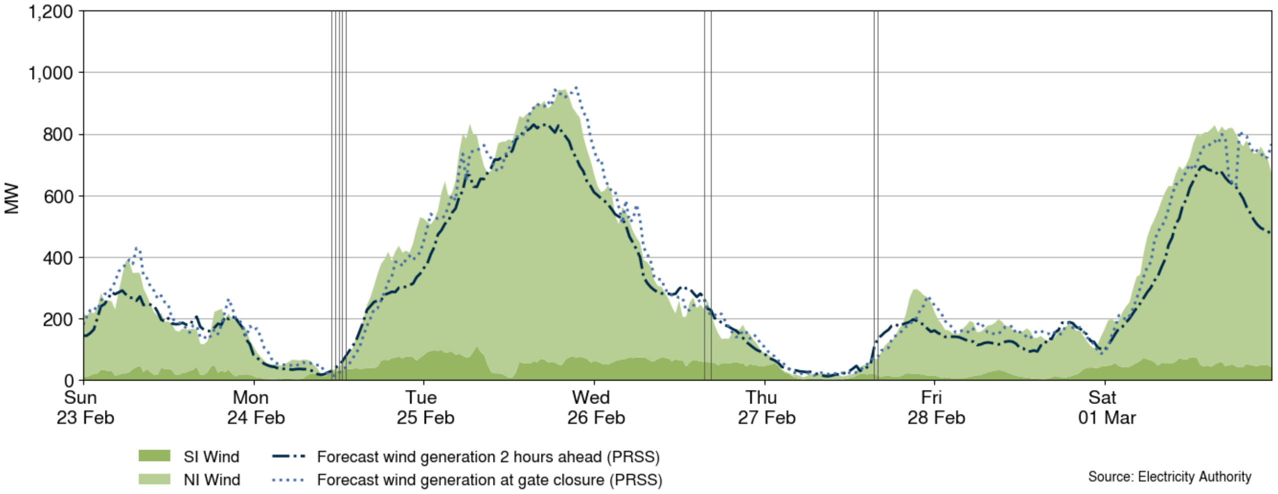
Figure 8: Temperatures across main centres, 23 February-1 March



7. Generation

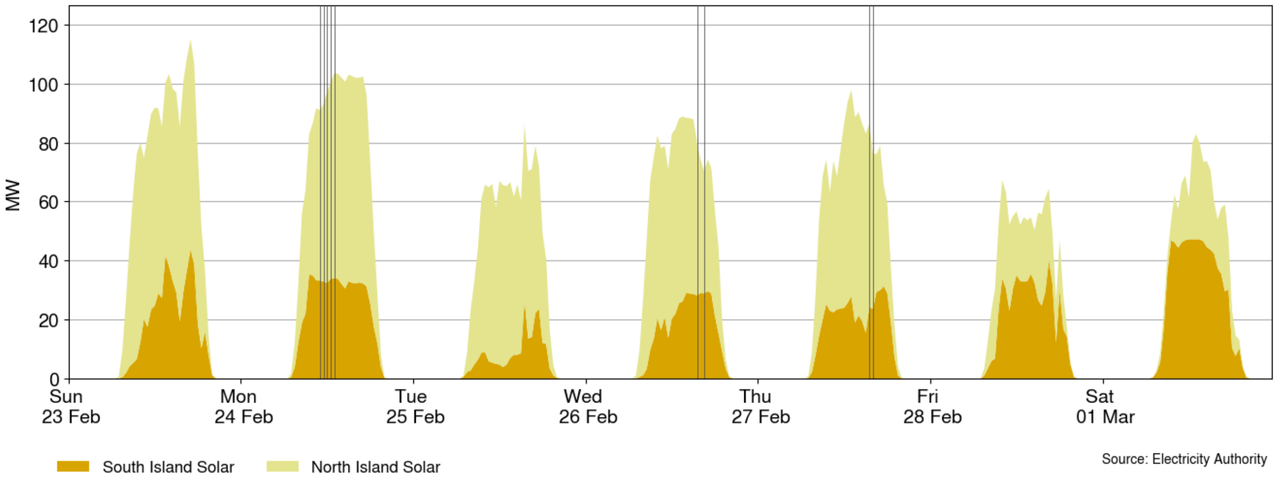
7.1. Figure 9 shows wind generation and forecast from 23 February-1 March. This week wind generation varied between 9MW and 945MW, with a weekly average of 335MW. Wind generation was low every day except Tuesday and Saturday.

Figure 9: Wind generation and forecast, 23 February-1 March



7.2. Figure 10 shows grid connected solar generation from 23 February-1 March. Solar generation reached above 100MW on Sunday and Monday. Maximum solar generation this week was 115MW at 5pm on Sunday.

Figure 10: Grid connected solar generation, 23 February-1 March



7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[5]) 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 wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind 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.

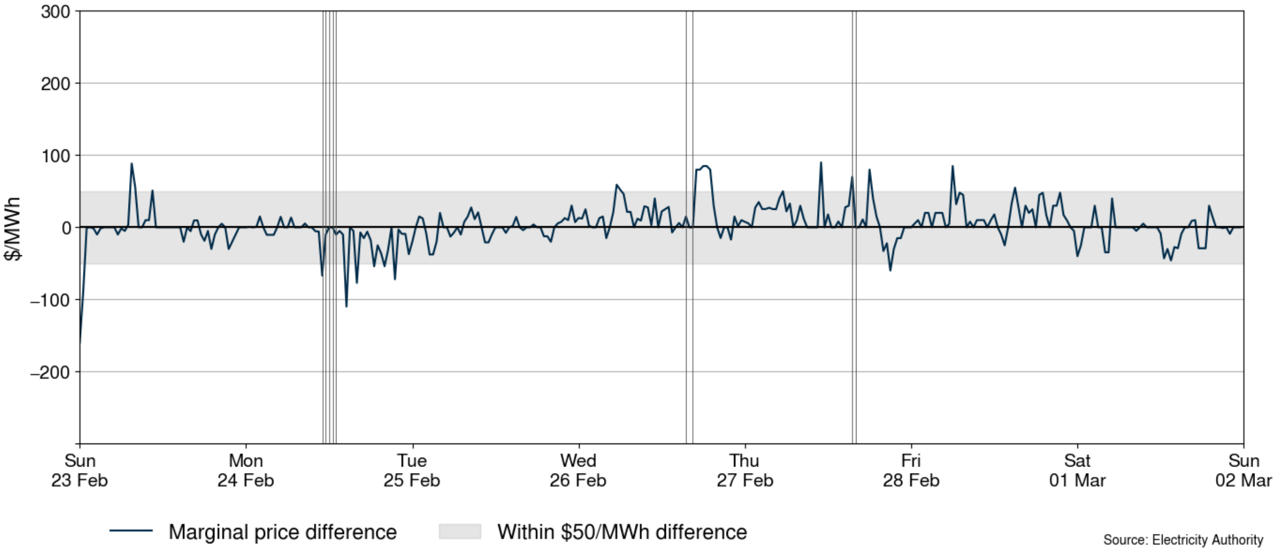
7.4. The largest positive marginal price difference was +$90/MWh at 11am on Thursday. Demand was 87MW higher than forecast at this time.

7.5. The largest negative marginal price difference was -$160 at midnight on Sunday. Demand was 66MW lower than forecast at this time.

7.6. Other marginal price differences larger than $50/MWh corresponded to wind or demand forecasting inaccuracies.

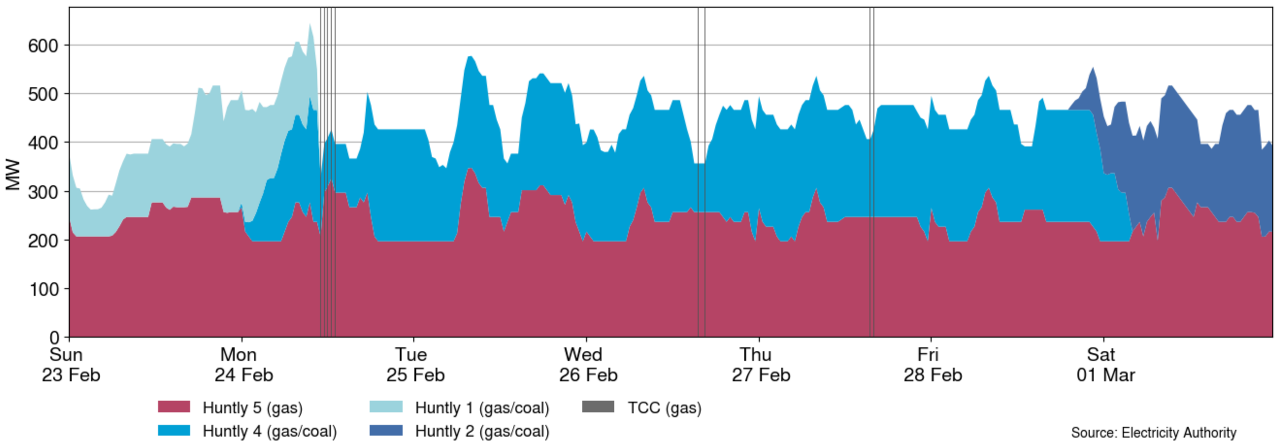
[5] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 23 February-1 March



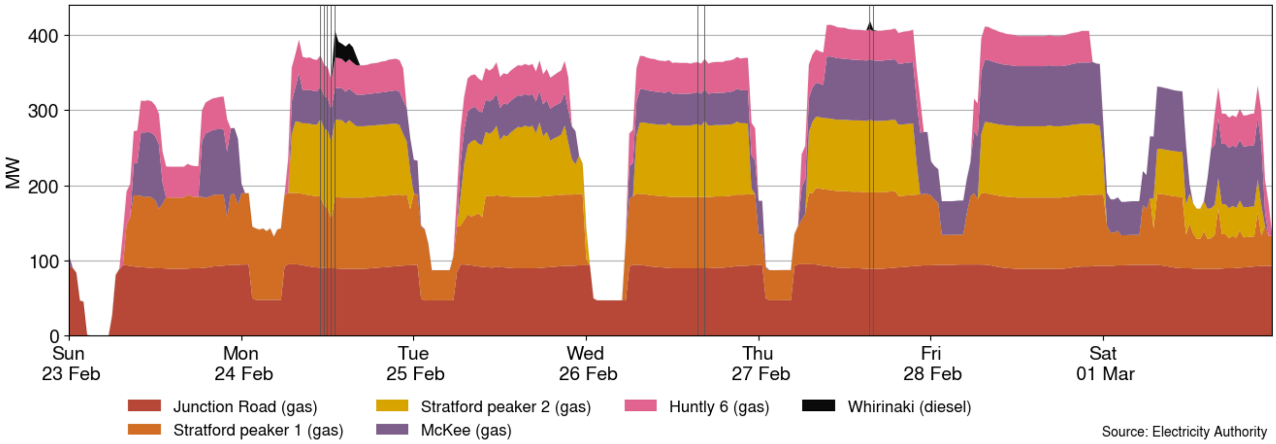
7.7. Figure 12 shows the generation of thermal baseload between 23 February-1 March. Huntly 5 generated baseload this week. Huntly 1 generated on Sunday but went on unplanned outage on Monday due to a cooling tower issue.[1] Huntly 4 generated Monday to Saturday. Huntly 2 came off its multiple month outage and began generating on Friday.

Figure 12: Thermal baseload generation, 23 February-1 March



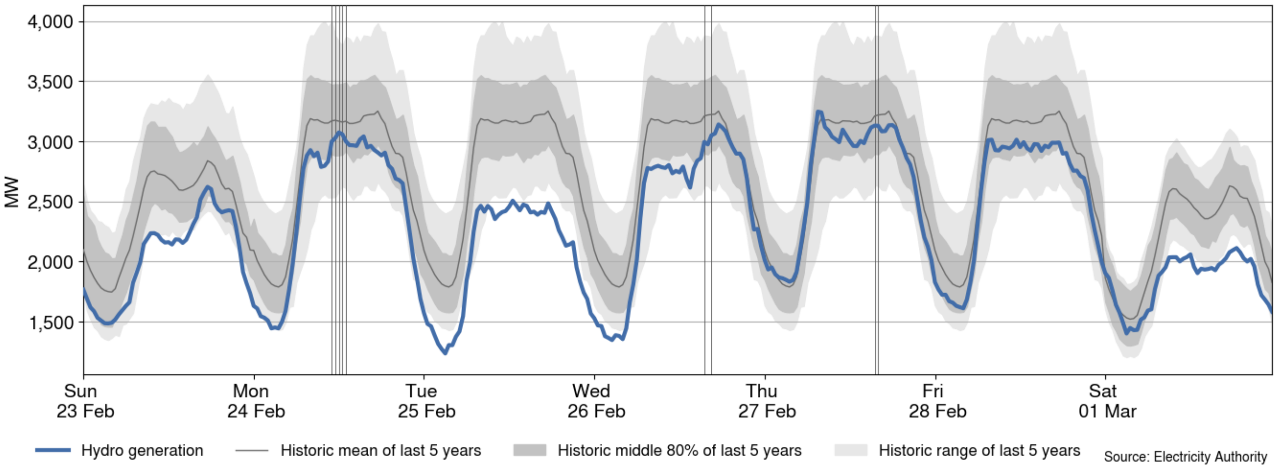
7.8. Figure 13 shows the generation of thermal peaker plants between 23 February-1 March. Junction Road, Stratford Peaker 1, McKee and Huntly 6 generated every day. Stratford Peaker 2 generated from Monday. Stratford Peaker 1 generated less during Monday's price spikes, and was dispatched as reserve instead, in response to the high reserve prices. Whirinaki generated on Monday and Thursday.

Figure 13: Thermal peaker generation, 23 February-1 March



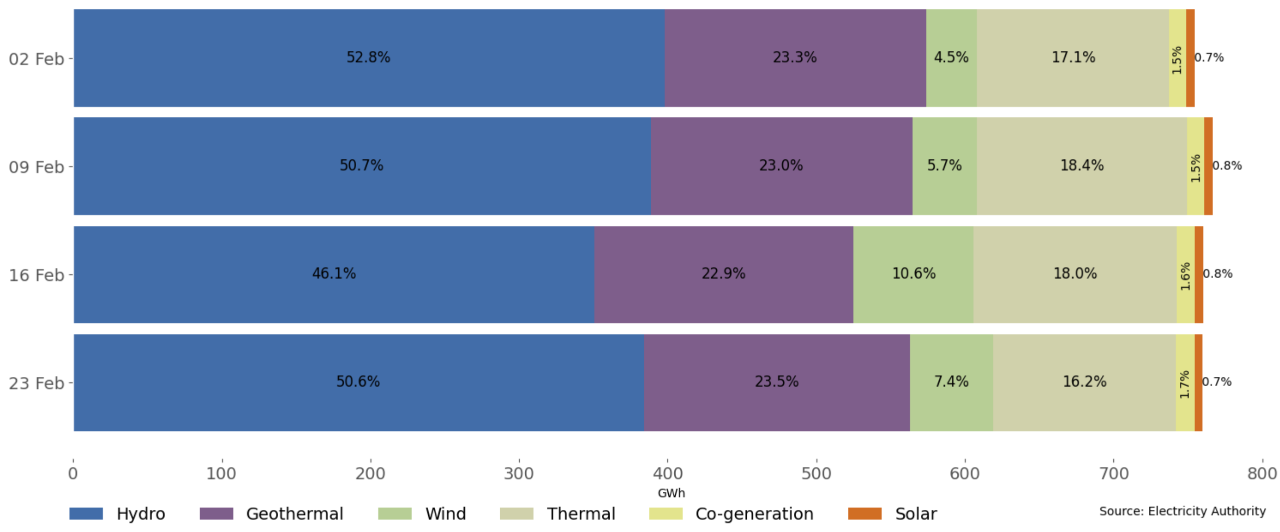
7.9. Figure 14 shows hydro generation between 23 February-1 March. Hydro generation was low on Tuesday and Saturday when wind was higher.

Figure 14: Hydro generation, 23 February-1 March



7.10. As a percentage of total generation, between 23 February-1 March, total weekly hydro generation was 50.6%, geothermal 23.5%, wind 7.4%, thermal 16.2%, co-generation 1.7%, and solar (grid connected) 0.7%, as shown in Figure 15. Hydro generation increased due to lower wind and Huntly outages decreasing thermal generation.

Figure 15: Total generation by type as a percentage each week, between 2 February and 1 March



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 23 February-1 March ranged between ~1,408MW and ~2,742MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC is on outage until 21 March (although it does not typically generate at this time of year regardless).

(b) Benmore was on partial outage 23 February.

(c) Huntly 2 was on a multiple month outage until 28 February.

(d) Huntly 1 and part of Huntly station went on several unplanned and short notice outages throughout the week due to cooling issues.

(e) Tauhara went on unplanned outage after tripping on 24 February.

(f) Manapōuri unit 4 is on outage until 12 December (extended from 18 September).

(g) Manapōuri unit 5 is on outage until 22 March (extended from 14 March).

(h) Clyde unit 1 is on outage until 23 May (brought forward from 25 June).

(i) Te Āpiti wind farm was on outage 25 and 26 February.

Figure 16: Total MW loss from generation outages, 23 February-1 March

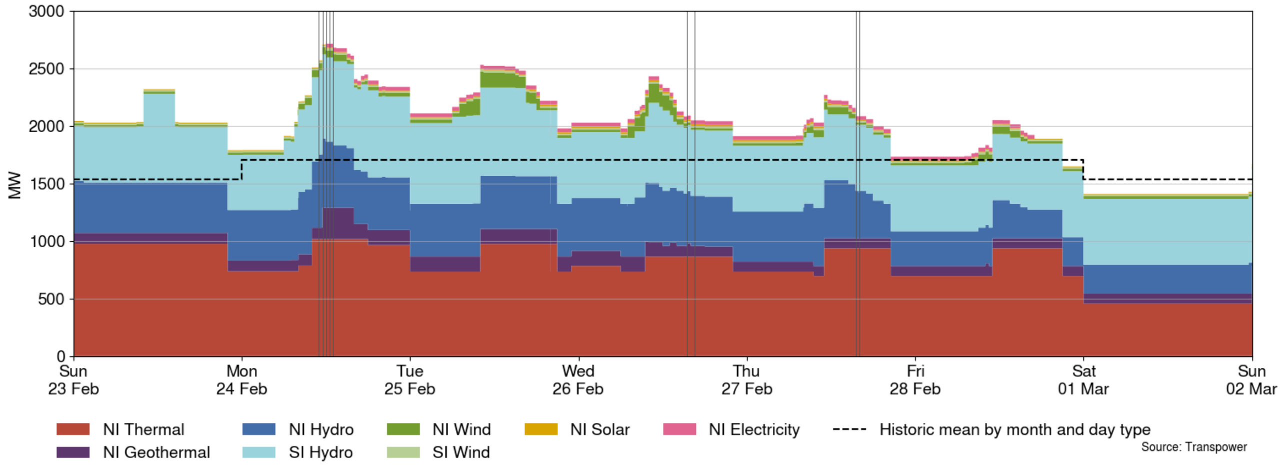
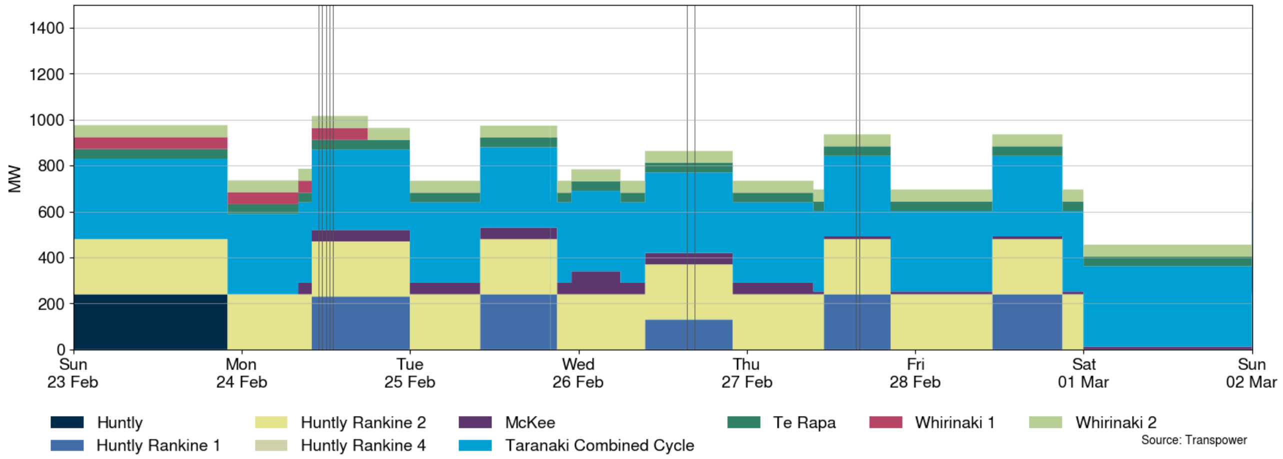


Figure 17: Total MW loss from thermal outages, 23 February-1 March

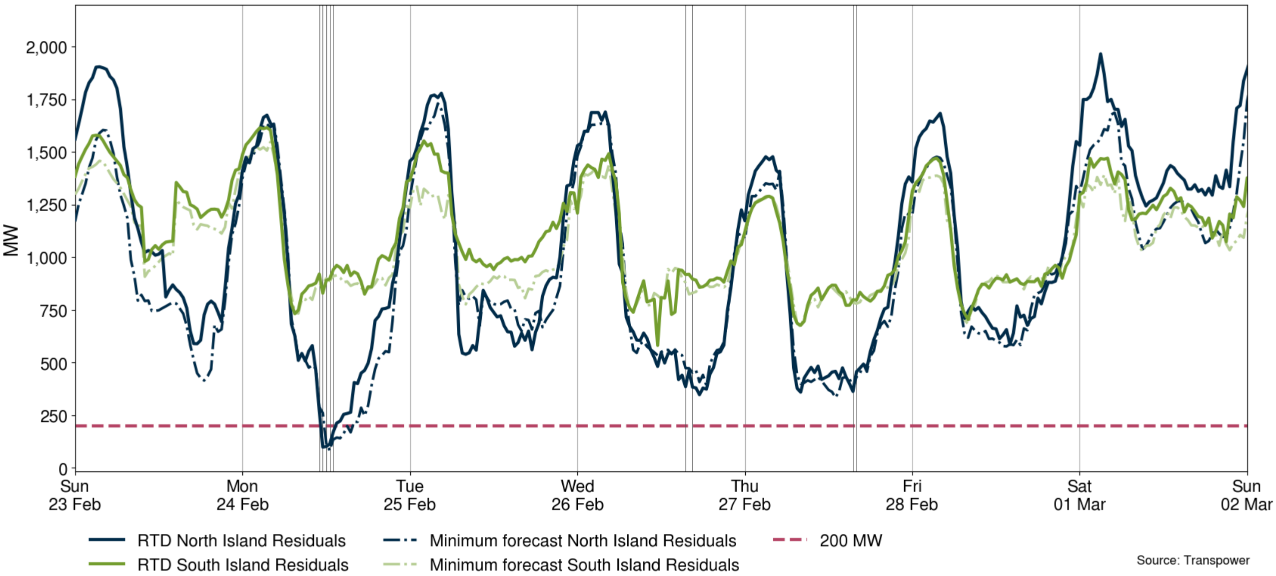


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 23 February-1 March. 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 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. North Island residuals dropped below 200MW on Monday, reaching a minimum of 99MW at 11.30am. North Island residuals also dropped below 500MW on Wednesday and Thursday.

Figure 18: North Island and South Island generation balance residuals, 23 February-1 March



10. Storage/fuel supply

10.1. Figure 19 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. National controlled hydro storage continued to decrease to 67% nominally full and ~83% of the historical average for this time of the year.

10.3. Lake Pūkaki (68% full) has decreased to below its historical 10th percentile.

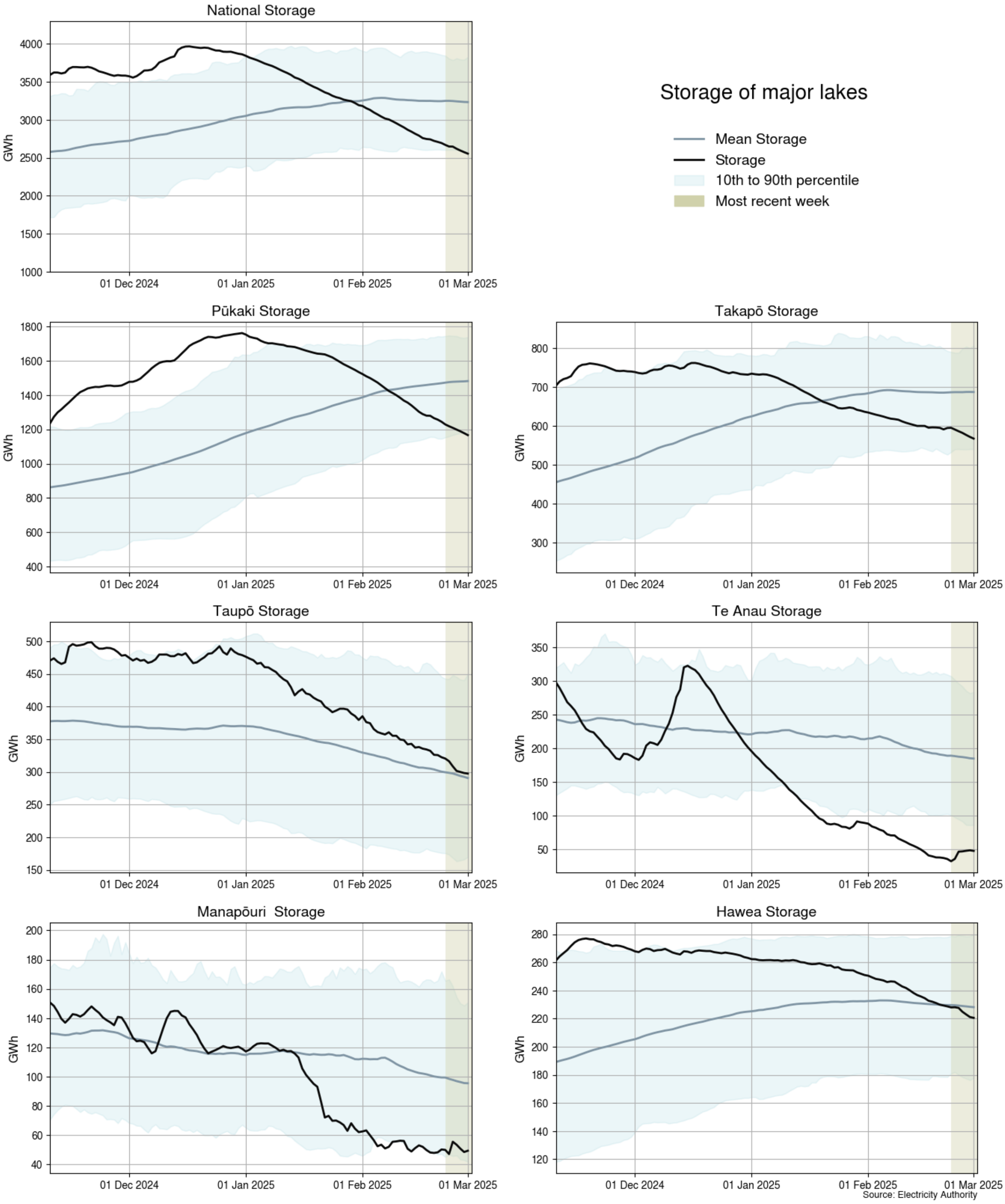
10.4. Lakes Takapō (71% full) and Hawea (77% full) have decreased and are still between their historical mean and 10th percentile.

10.5. Lake Taupō (52% full) decreased and is close to its historical mean.

10.6. Lake Te Anau has increased and is still below its historical 10th percentile.

10.7. Lake Manapōuri has fluctuated close to its historical 10th percentile.

Figure 19: 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 20 shows an estimate of thermal SRMCs as a monthly average up to 1 February. The SRMC for gas fuelled generation has increased compared to last month, the SRMC for coal remains similar and the SRMC for diesel fuelled generation has decreased.

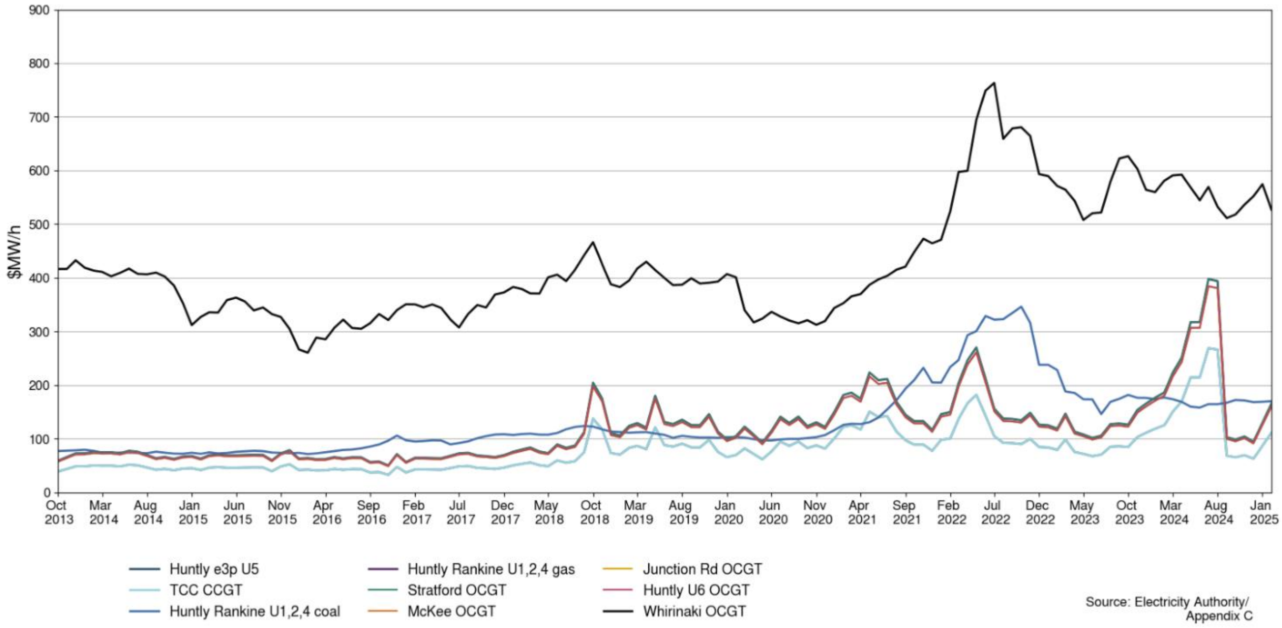
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$170/MWh, with the cost of running the Rankines on gas slightly lower at ~$165/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $111/MWh and $165/MWh.

11.6. The SRMC of Whirinaki is ~$527/MWh.

11.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

Figure 20: Estimated monthly SRMC for thermal fuels

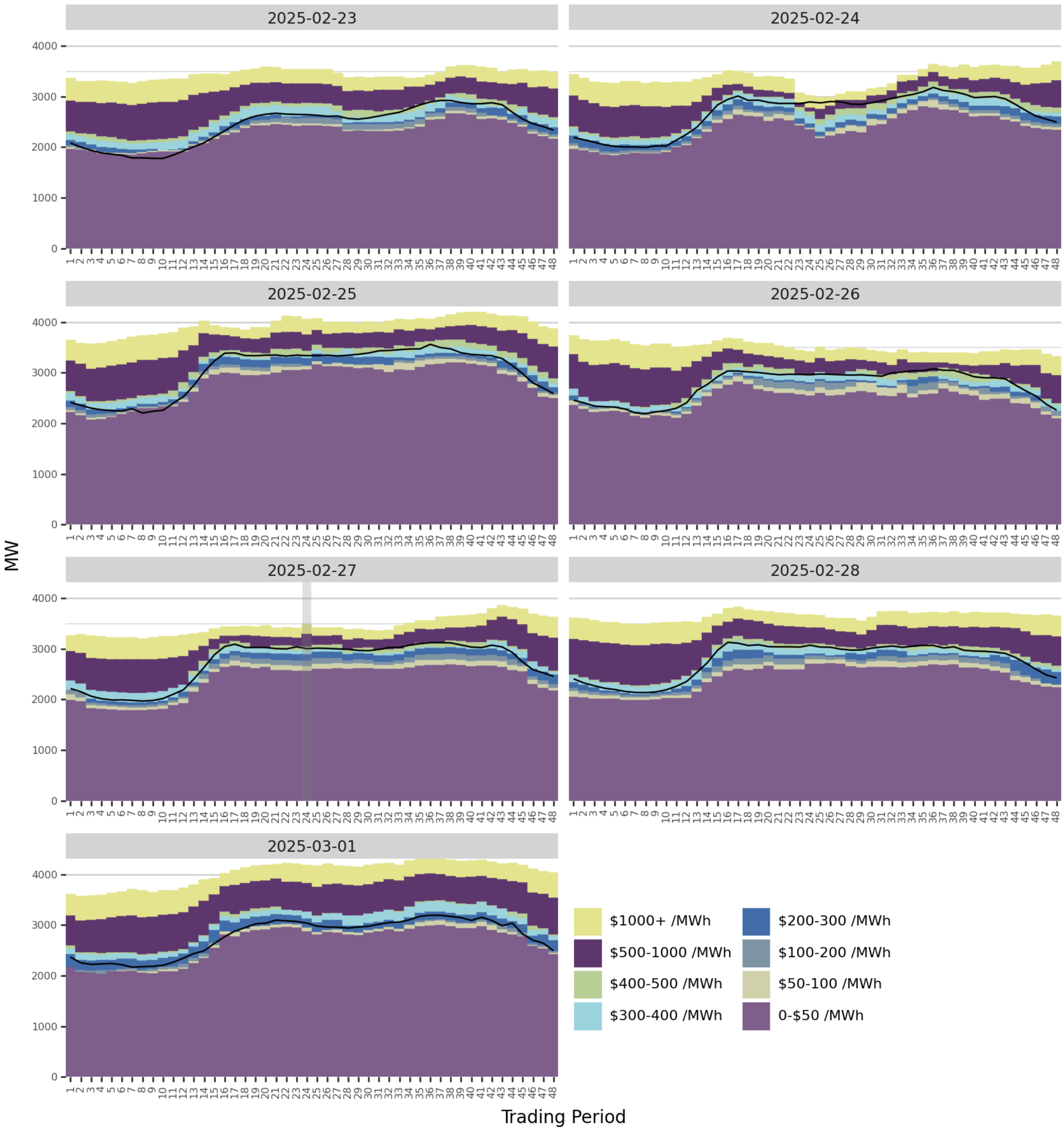


12. Offer behaviour

12.1. Figure 21 and Figure 22 show this week's national daily offer stacks in the North Island and South Island respectively. The black line shows cleared energy, indicating the range of the average final price.

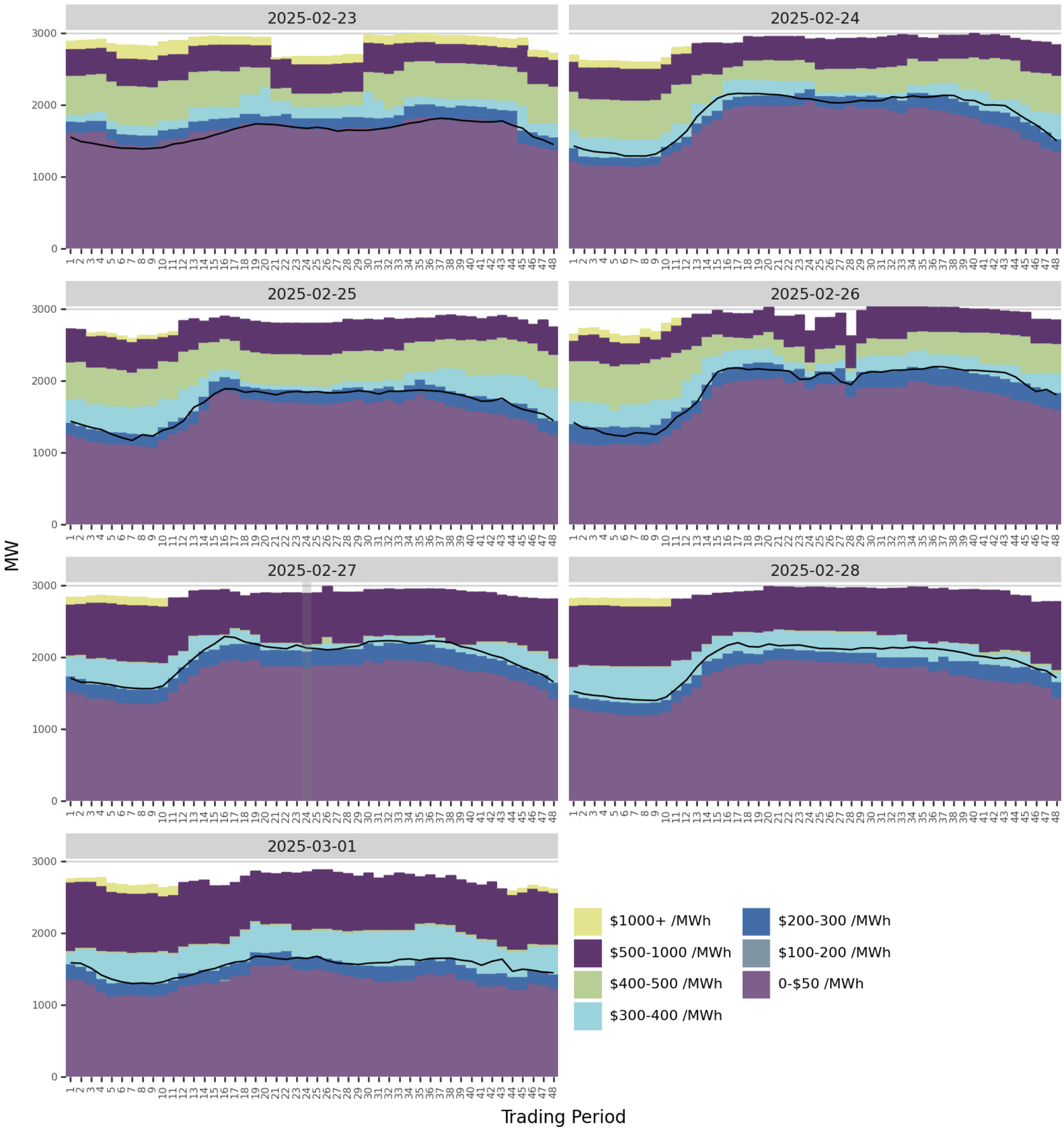
12.2. Most offers were clearing in the $300-500/MWh band in the North Island and $200-300/MWh band in the South Island this week.

Figure 21: Daily offer stacks in North Island[6]



[6] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

Figure 22: Daily offer stacks in South Island[6]

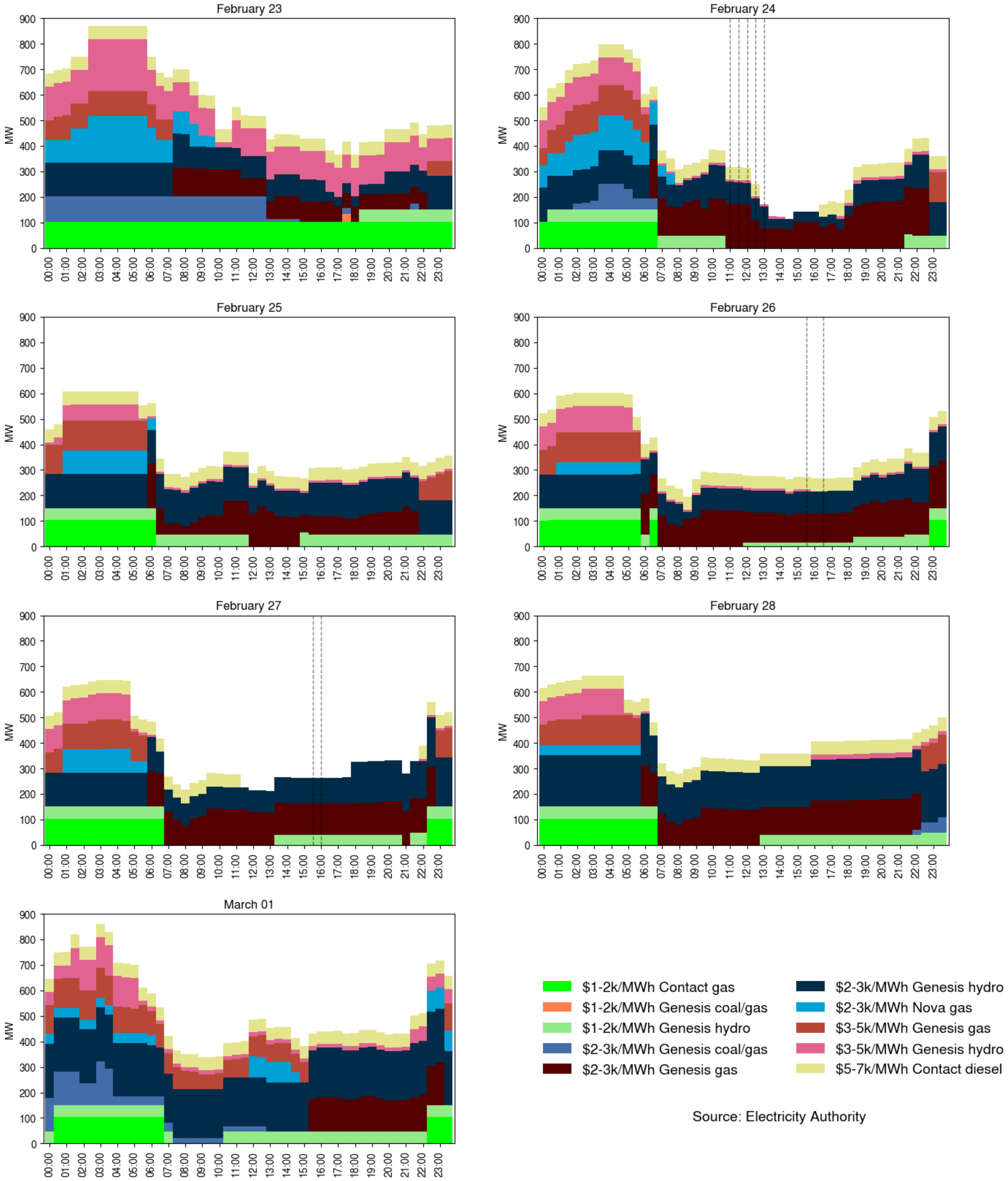


12.3. Figure 23 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

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 444MW per trading period was priced above $1,000/MWh this week, which is roughly 8.2% of the total energy available. This is a 2% increase from last week. We will be analysing hydro and thermal offers from Genesis and Stratford offers from Contact.

Figure 23: High priced offers[7]



Source: Electricity Authority

[7] RTD data for trading period 24 (11.30am) on Thursday 27 February is missing.

13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions, however, the monitoring team will be further analyzing some hydro and thermal offers from Genesis, and Stratford offers from Contact.

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
14/06/2023- 15/06/2023	15-17/ 15-19	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact	Clutha scheme	Hydro offers
21/02/2025	16	Further analysis	Contact	Stratford	Thermal offer
23/02/2025-1/03/2025	Several	Further analysis	Genesis	Huntly	Thermal offers
23/02/2025-1/03/2025	Several	Further analysis	Genesis	Tokaanu	Hydro offers
23/02/2025-1/03/2025	Several	Further analysis	Contact	Stratford	Stratford offers