21 January 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 12-18 January 2025

Market monitoring weekly report

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1. Overview

1.1. Spot prices increased this week to an average of $137/MWh due to low wind generation, increased thermal generation and a continuing low inflow sequence which has seen hydro storage drop from 90% to 86% nominally full in the last week.

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 12-18 January 2025:

(a) the average wholesale spot price across all nodes was $137/MWh.

(b) 95% of prices fell between $54/MWh and $220/MWh.

2.3. Overall, most spot prices were within $108-$171/MWh, meaning the weekly average price increased by around $88/MWh compared to the previous week. This increase in spot prices was contributed to by low wind, increasing thermal generation and decreasing hydro storage.

2.4. The highest spot price this week was 7.00am on Tuesday when the Ōtāhuhu price was $326/MWh and the Benmore price was $300/MWh. At this time, wind generation was low (~90MW), demand was increasing towards its morning peak and ~80MW higher than forecast. Spot prices dropped from 7.30am when more peaker generation was offered at <$1/MWh.

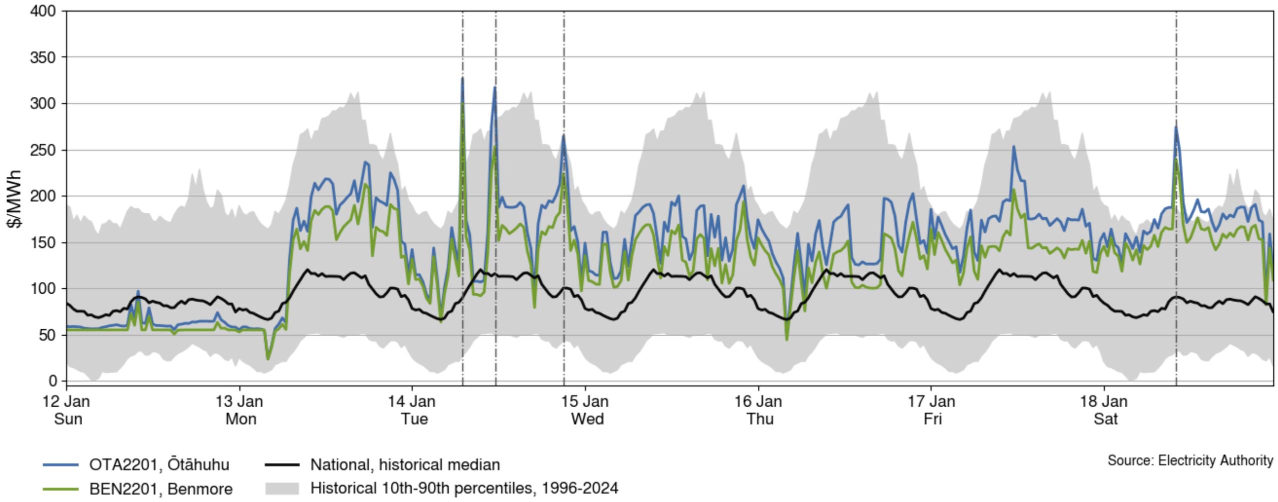
2.5. Spot prices also peaked at 11.30am on Tuesday at $317/MWh at Ōtāhuhu after Huntly 1 tripped at 10.39am and hydro generation ramped up, with some higher priced hydro being dispatched. Wind was low at the time and demand was ~60MW higher than forecast.

2.6. The sunset demand peak at 9pm on Tuesday also saw spot prices spike to $264/MWh at Ōtāhuhu and $224/MWh at Benmore. At this time, there was less thermal peaker generation than during the day, no solar generation and the Rankine units and higher priced hydro ramped up to meet demand.

2.7. Nga Awa Pūrua geothermal tripped just after 10am on Saturday, causing prices to spike to $274/MWh at Ōtāhuhu and $240/MWh at Benmore when higher priced hydro and thermal generation was dispatched.

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.

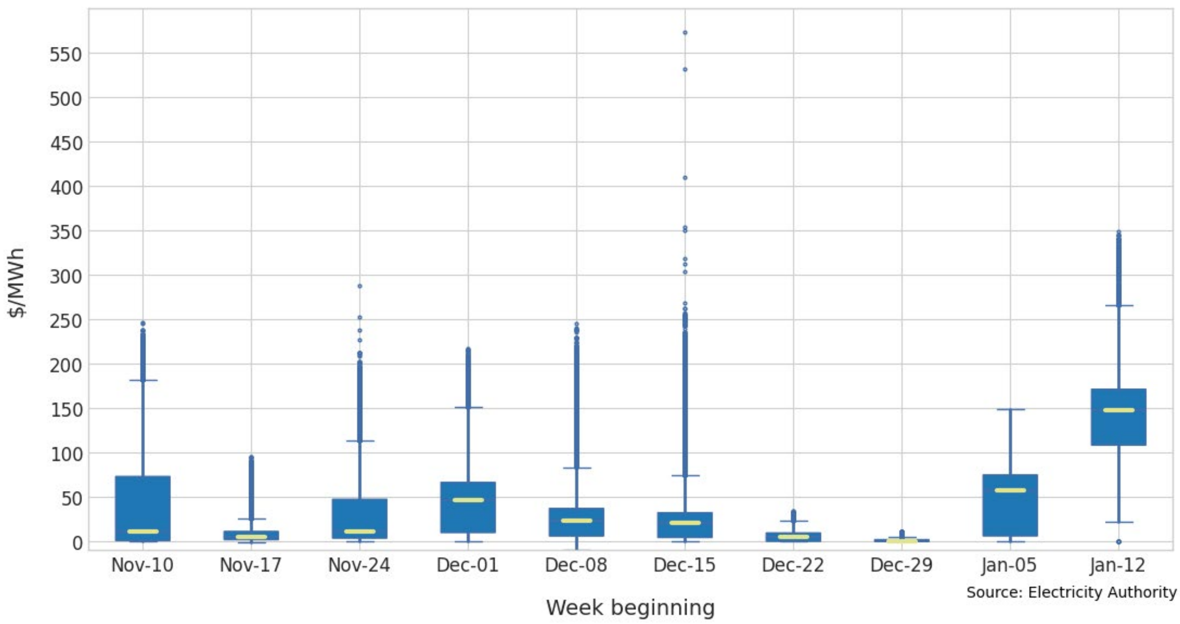
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 12-18 January 2025



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 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 spot price distribution increased this week to a median of $148/MWh with the middle 50% of prices between $108-$171/MWh.

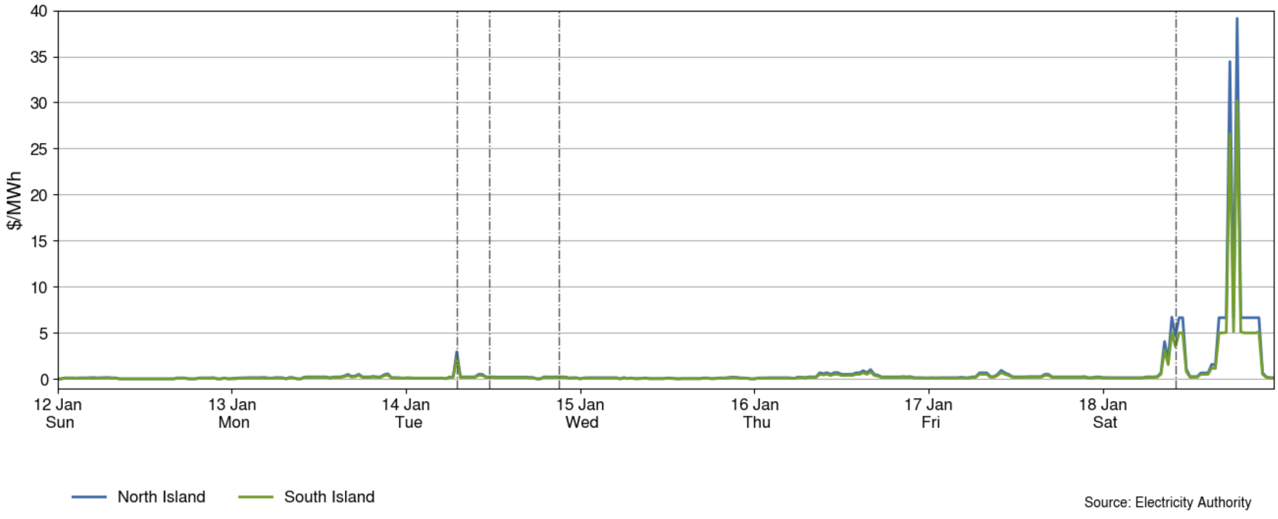
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

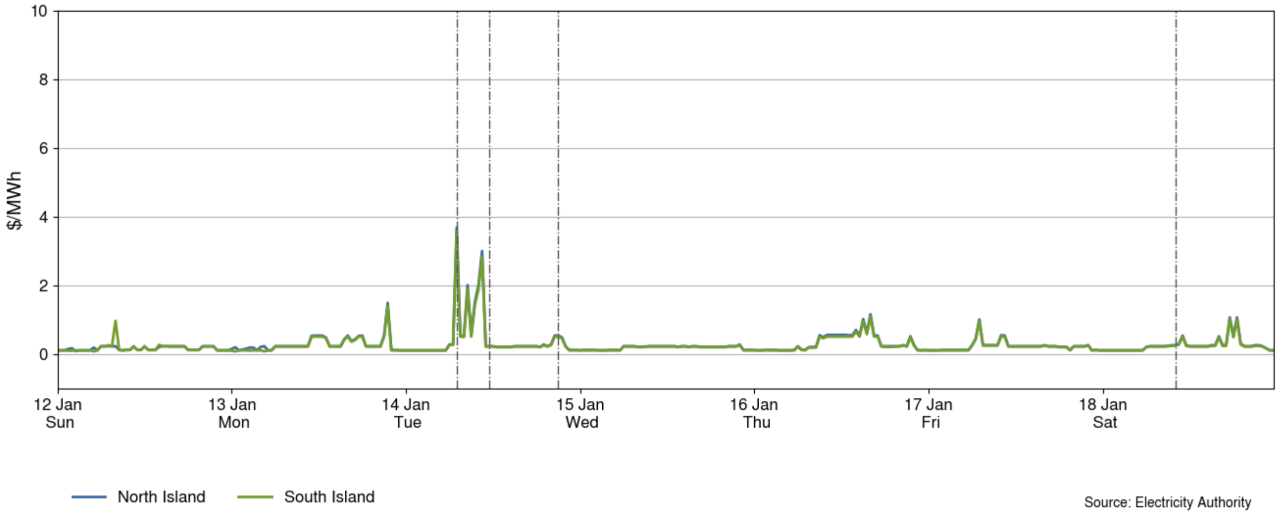
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week except for Saturday when FIR prices reached $39/MWh in the North Island and $30/MWh in the South Island at 6.30pm. These FIR prices spikes were because a higher amount of FIR was needed to cover the North Island risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 12-18 January 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh this week, reaching a maximum of $3.67/MWh at 7.00am.

Figure 4: Sustained instantaneous reserve by trading period and island, 12-18 January 2025



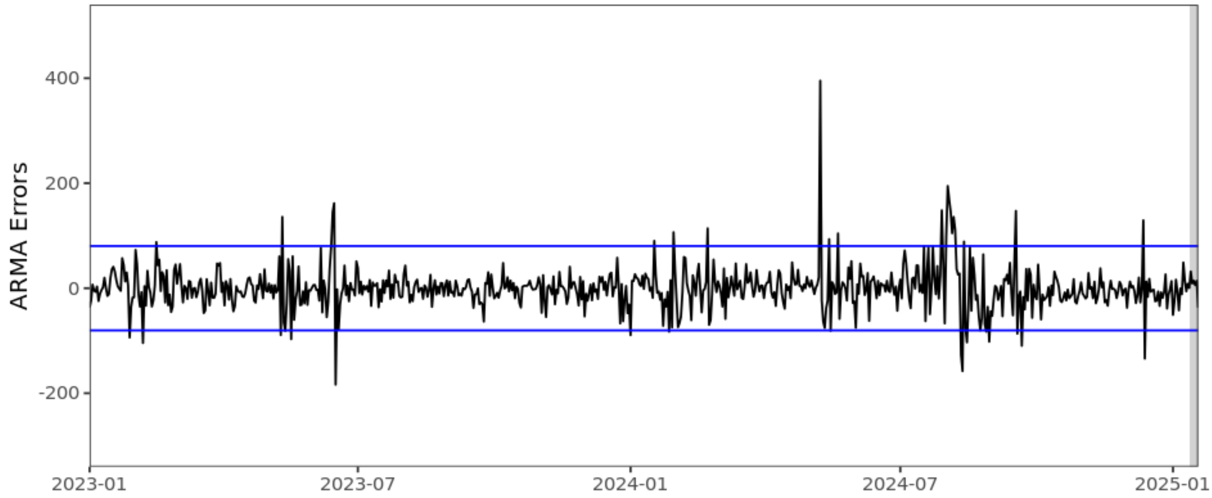
4. Regression residuals

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 the those predicted by the model.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 18 January 2025

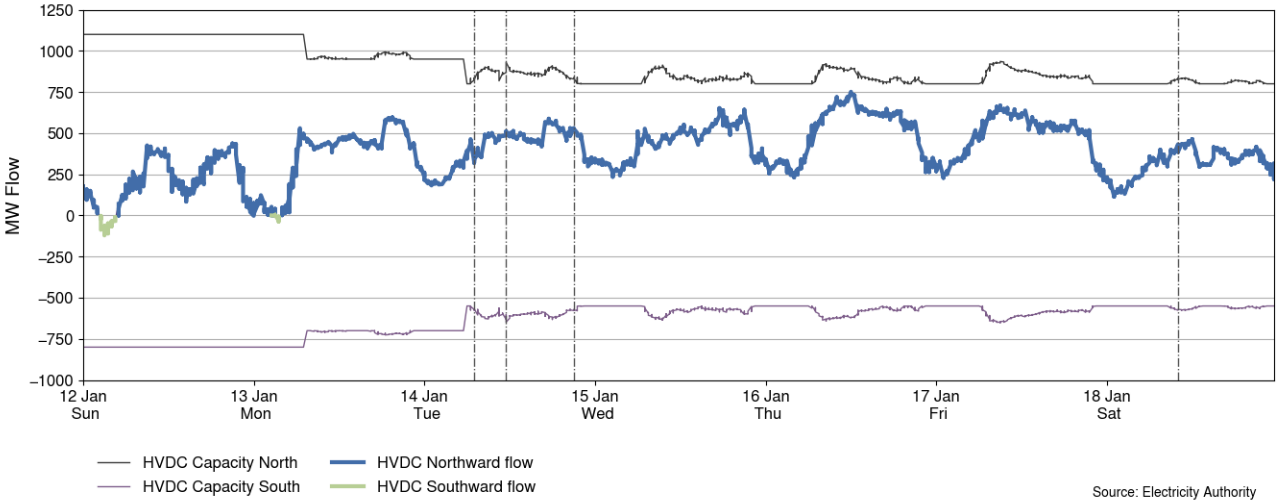


Source: Electricity Authority/Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 12-18 January 2025. HVDC flows were almost entirely northward this week, with two short periods of southward flow at the start of the week.

Figure 6: HVDC flow and capacity, 12-18 January 2025



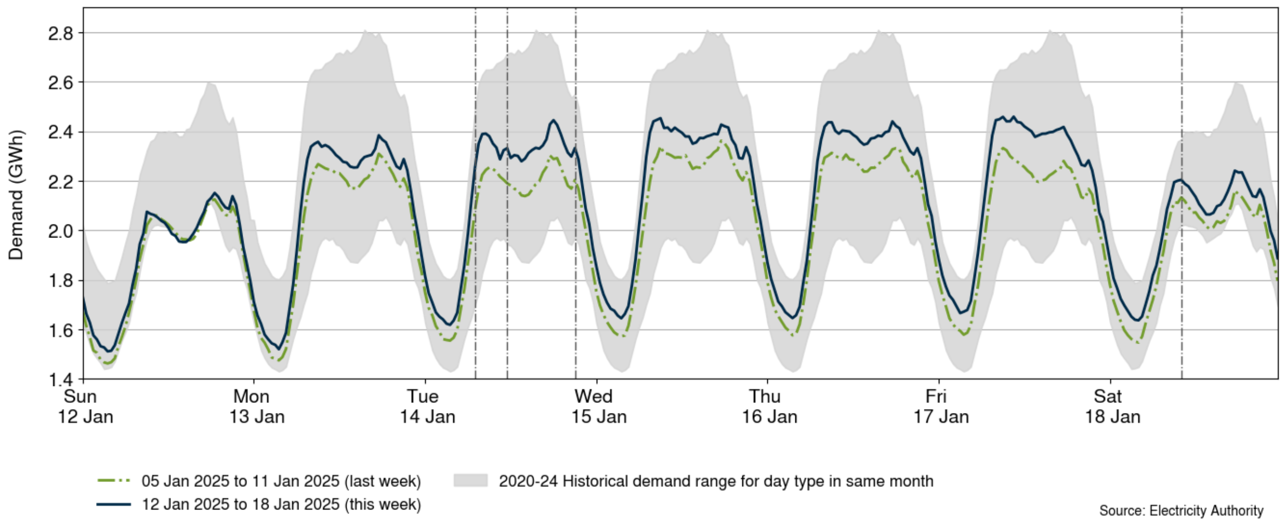
Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 12-18 January 2025, compared to the historic range and the demand of the previous week. Demand this week was within the historical range and higher than the previous week likely due to more people returning to work, and an increase in irrigation demand compared to last week.

6.2. The maximum demand this week was around 2.46GWh (4.92GW) at 10.30am on Friday.

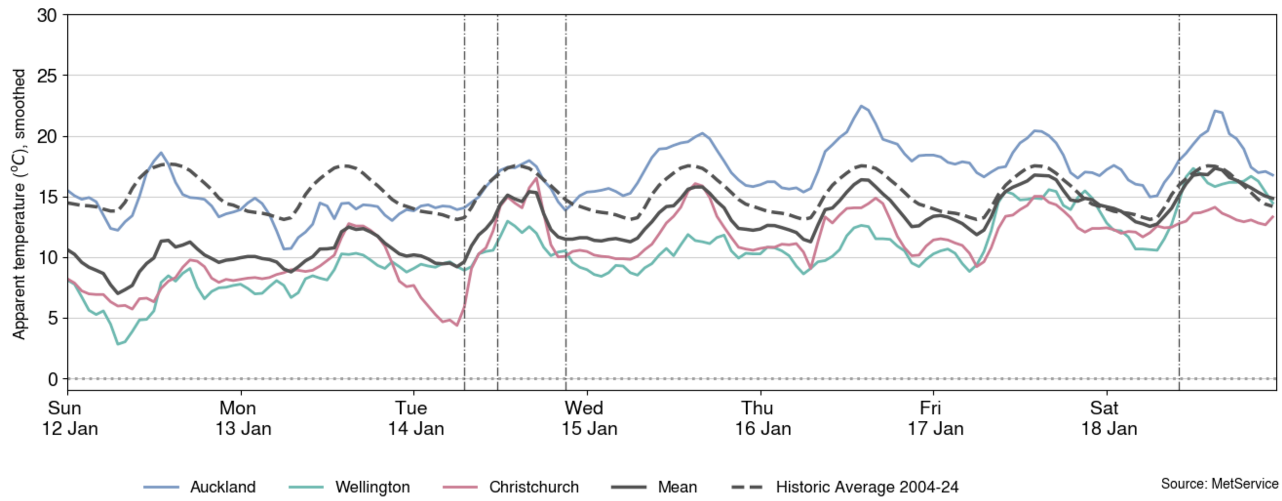
Figure 7: National demand, 12-18 January 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 12-18 January 2025. 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. Temperatures were below average this week and increased toward the historical average by Saturday. Apparent temperatures ranged from 10°C to 23°C in Auckland, 2°C to 18°C in Wellington, and 4°C to 18°C in Christchurch.

Figure 8: Temperatures across main centres, 12-18 January 2025

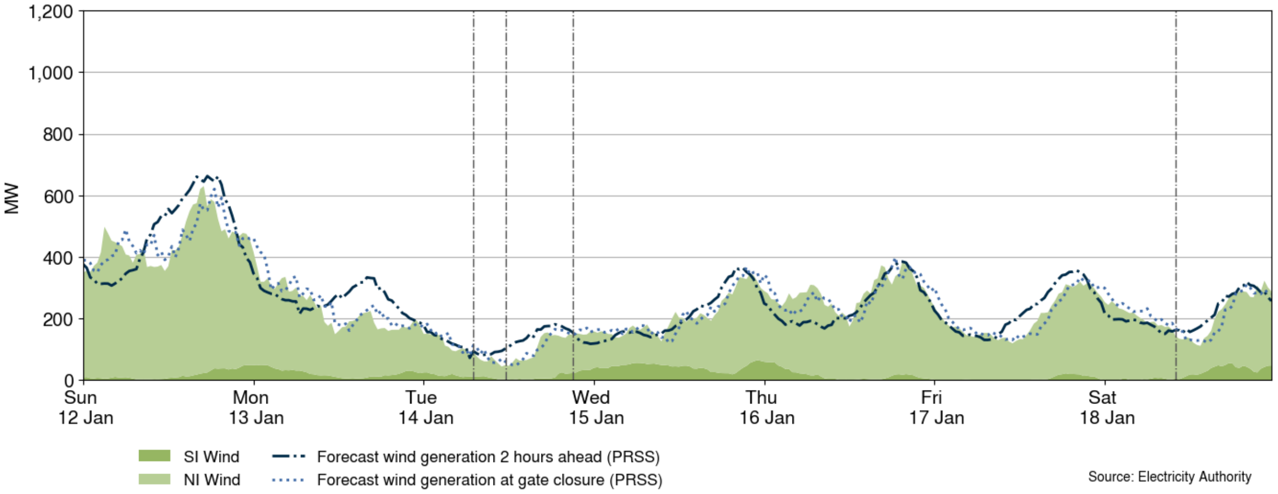


7. Generation

7.1. Figure 9 shows wind generation and forecast from 12-18 January 2025. This week wind generation varied between 44MW and 630MW, with a weekly average of 243MW. Wind generation was low this week, Sunday was the only day where the daily average wind generation was above 300MW.

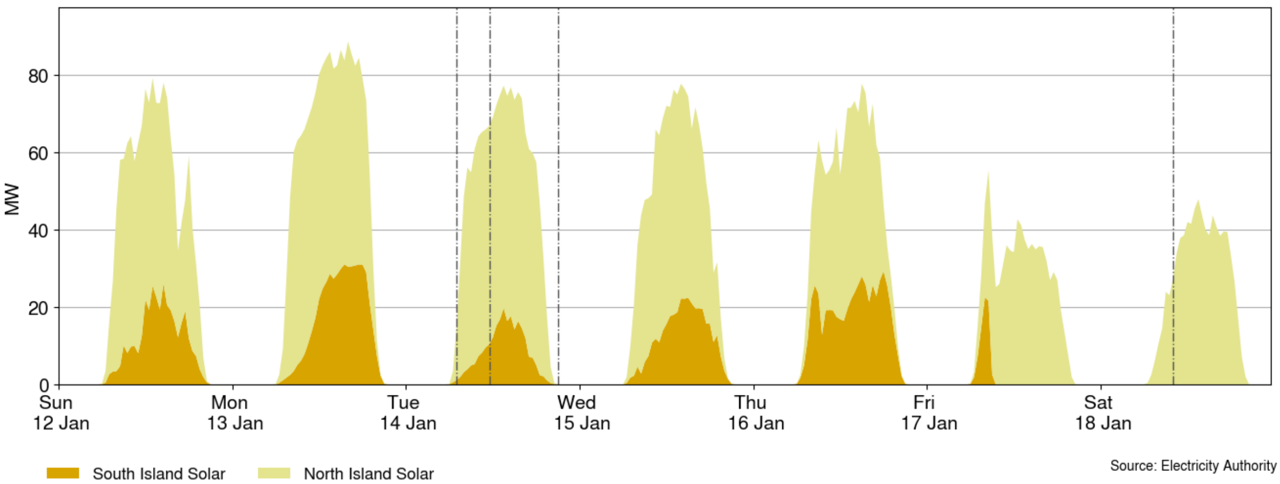
7.2. The largest negative wind forecast discrepancy was at 7.30pm on Sunday when wind generation was 108MW lower than forecast.

Figure 9: Wind generation and forecast, 12-18 January 2025



7.3. Figure 10 shows solar generation from 12-18 January 2025. Solar generation was highest on Monday, peaking above 80MW and was lowest on Friday and Saturday, peaking below 60MW.

Figure 10: Solar generation, 12-18 January 2025



7.4. 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[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 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

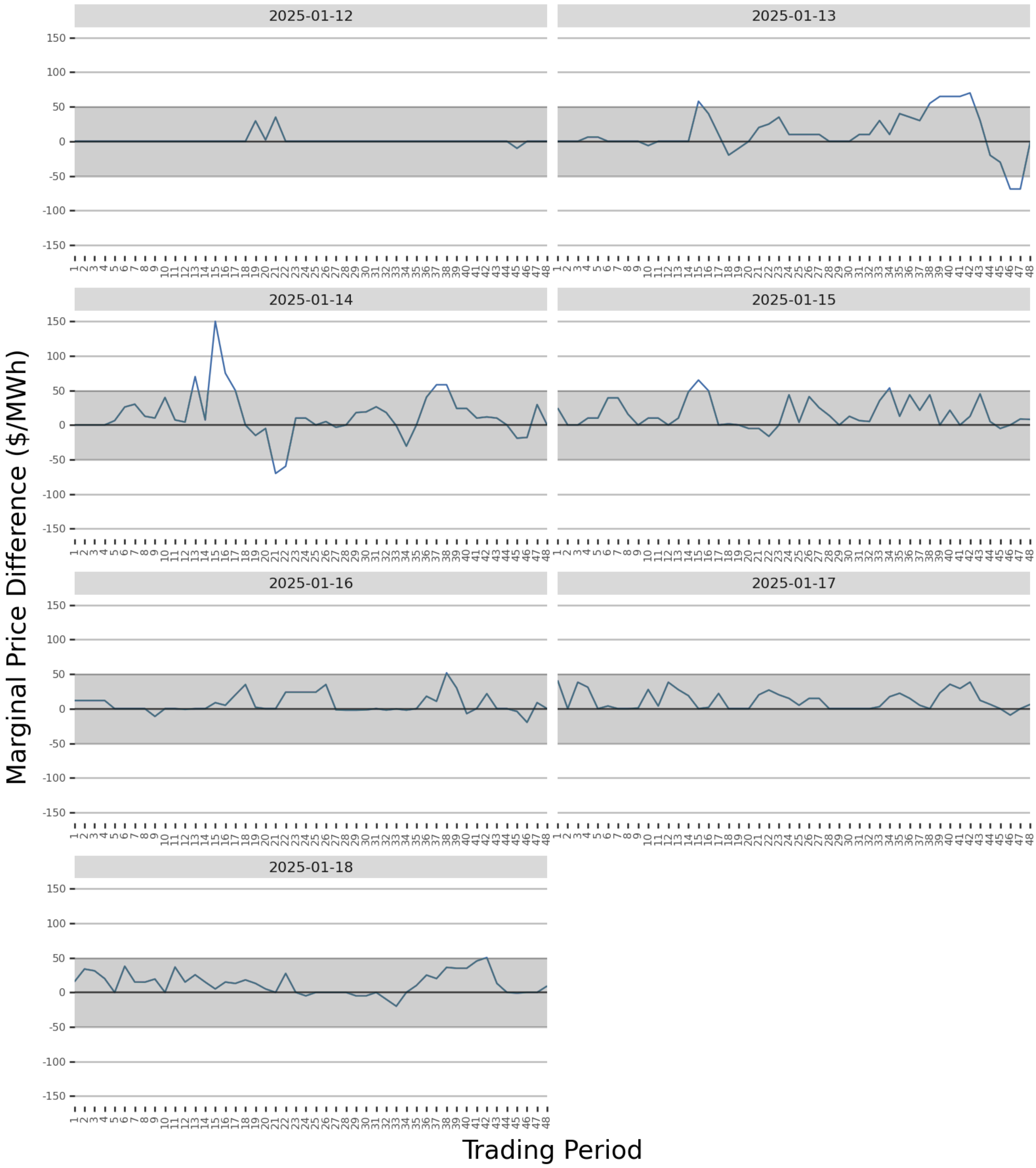
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.5. The greatest marginal price difference this week was at 7am on Tuesday 14 January at +$150/MWh when spot prices were at their maximum for the week and demand was ~80MW higher than forecast.

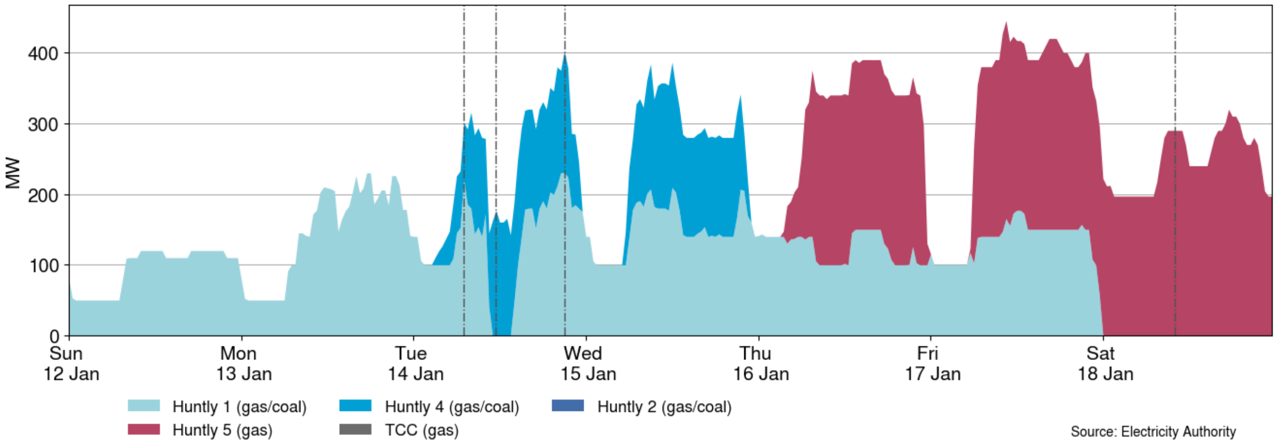
7.6. Other marginal price differences between $50-75/MWh occurred during the week due to wind and demand forecasting errors. The largest demand forecasting error was at 6pm on Tuesday when demand was 162MW higher than forecast.

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, 12-18 January 2025



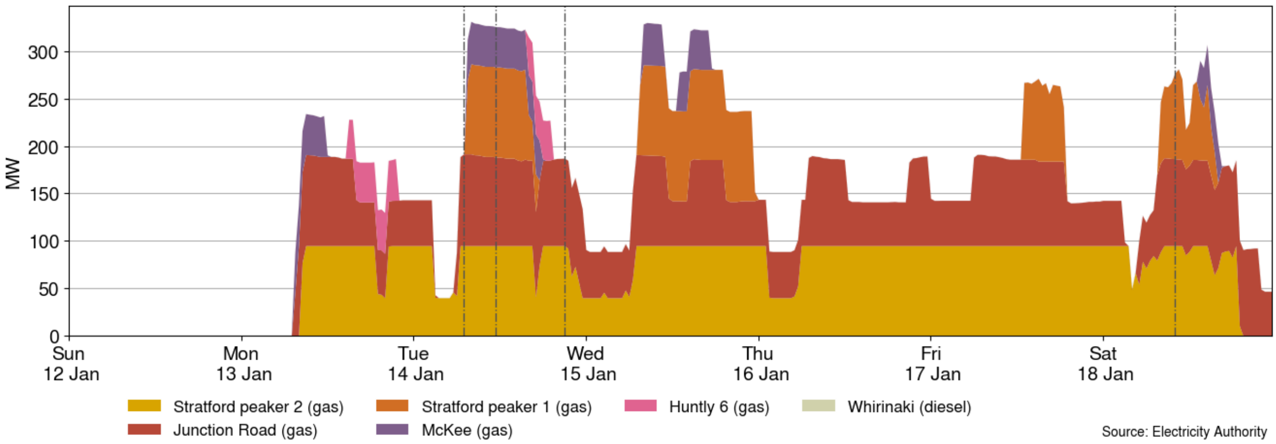
7.7. Figure 12 shows the generation of thermal baseload between 12-18 January 2025. Huntly 1 ran continuously until Friday night, except for a period on Tuesday when it tripped.[2] Huntly 4 ran during the day on Tuesday and Wednesday then Huntly 5 ran during the day on Thursday and continuously from Friday morning.

Figure 12: Thermal baseload generation, 12-18 January 2025



7.8. Figure 13 shows the generation of thermal peaker plants between 12-18 January 2025. Stratford 2 and Junction Road ran as baseload from Monday. Stratford 1 ran during the day on Tuesday, Wednesday, Friday and Saturday. McKee ran during the day from Monday to Wednesday and on Saturday. Huntly 6 ran on Monday and Tuesday.

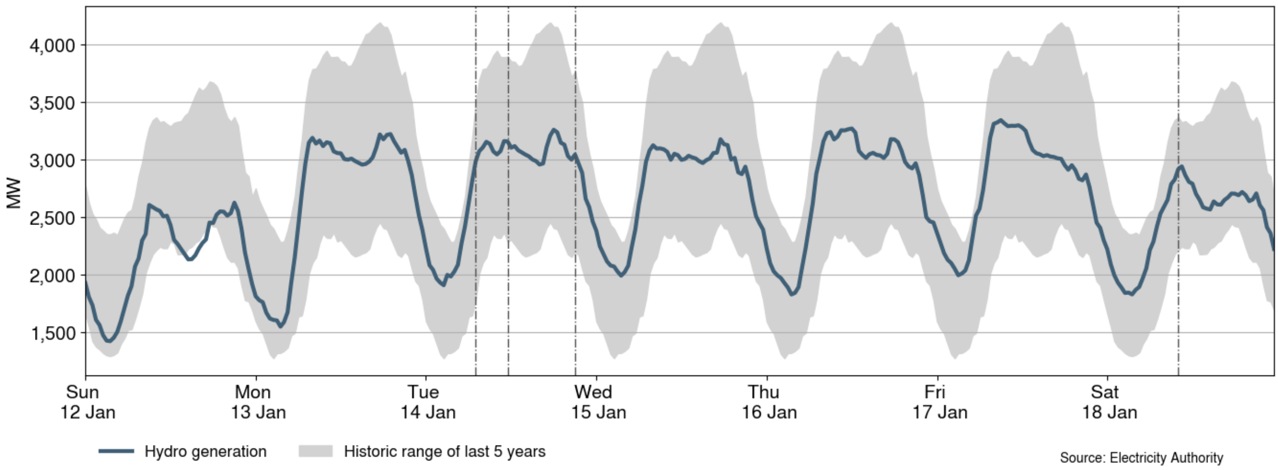
Figure 13: Thermal peaker generation, 12-18 January 2025



7.9. Figure 14 shows hydro generation between 12-18 January 2025. Hydro generation was within the historical range this week and was highest on Friday morning when demand peaked for the week.

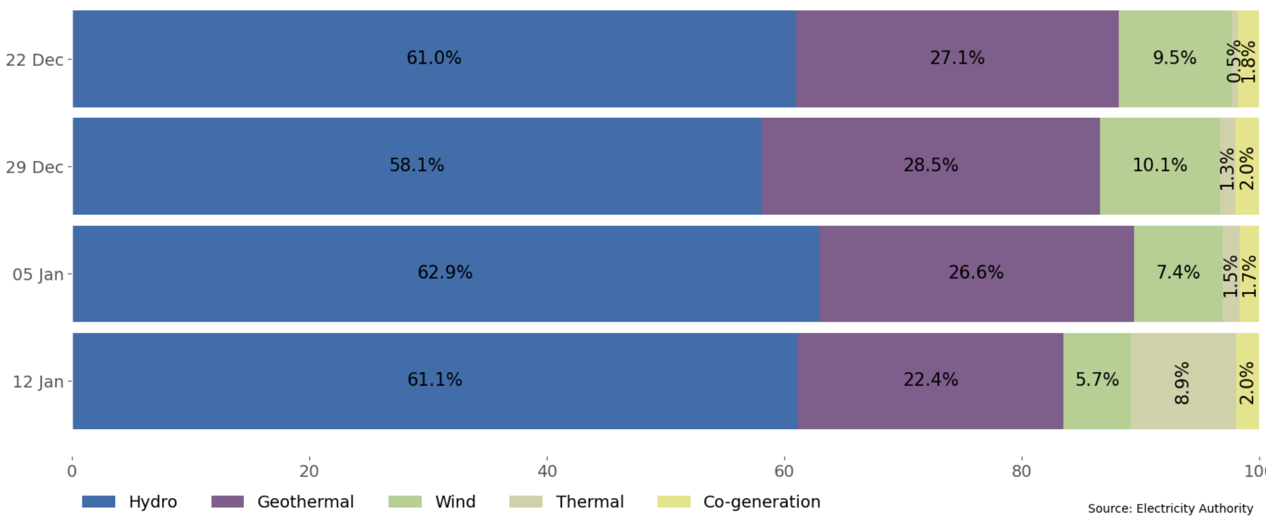
[2] EXN Frequency North Island Huntly Generation Tripped 5912100907.pdf | Transpower

Figure 14: Hydro generation, 12-18 January 2025



7.10. As a percentage of total generation, between 12-18 January 2025, total weekly hydro generation was 61.1%, geothermal 22.4%, wind 5.7%, thermal 8.9%, and co-generation 2.0%, as shown in Figure 15. Low wind, higher demand and geothermal/hydro outages this week saw the proportion of thermal generation increase significantly compared to previous weeks.

Figure 15: Total generation by type as a percentage each week, 22 December 2024 – 18 January 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 12-18 January 2025 ranged between ~1,160MW and ~2,240MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 is on outage until 14 March.

(b) Tauhara was on outage from 13-18 January.

(c) Manapōuri unit 4 is on outage until 18 September 2025.

(d) Clyde unit 1 is on outage until 25 June.

(e) Benmore unit 6 was on outage from 13-17 January.

(f) Nga Awa Pūrua was on outage on 18 January after it tripped just after 10am.[3]

Figure 16: Total MW loss from generation outages, 12-18 January 2025

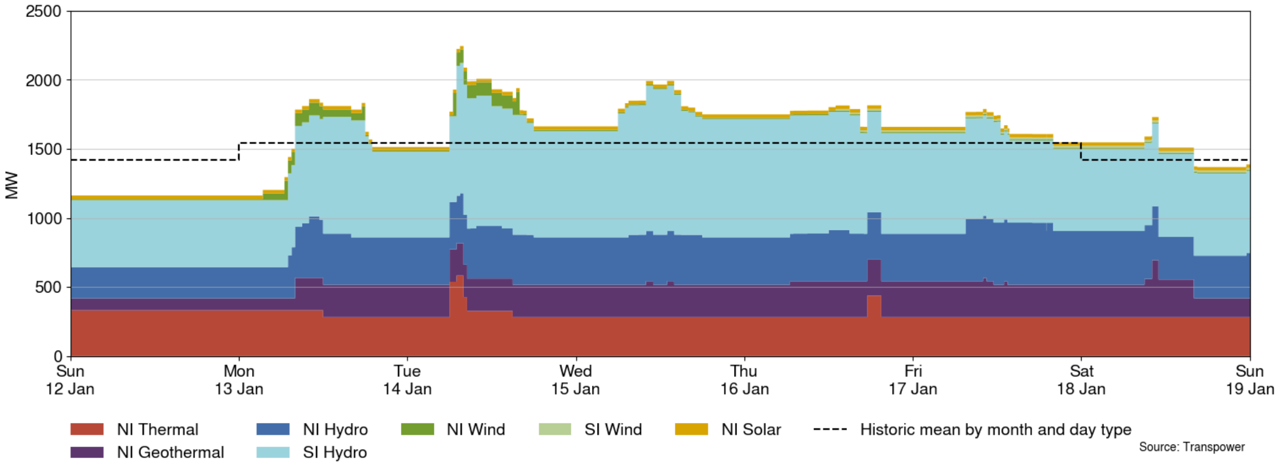
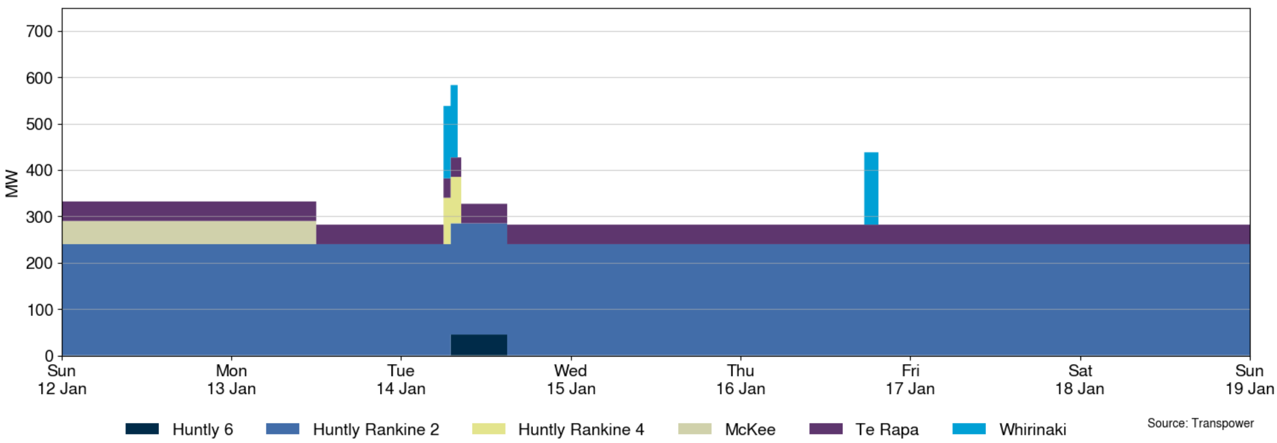


Figure 17: Total MW loss from thermal outages, 12-18 January 2025



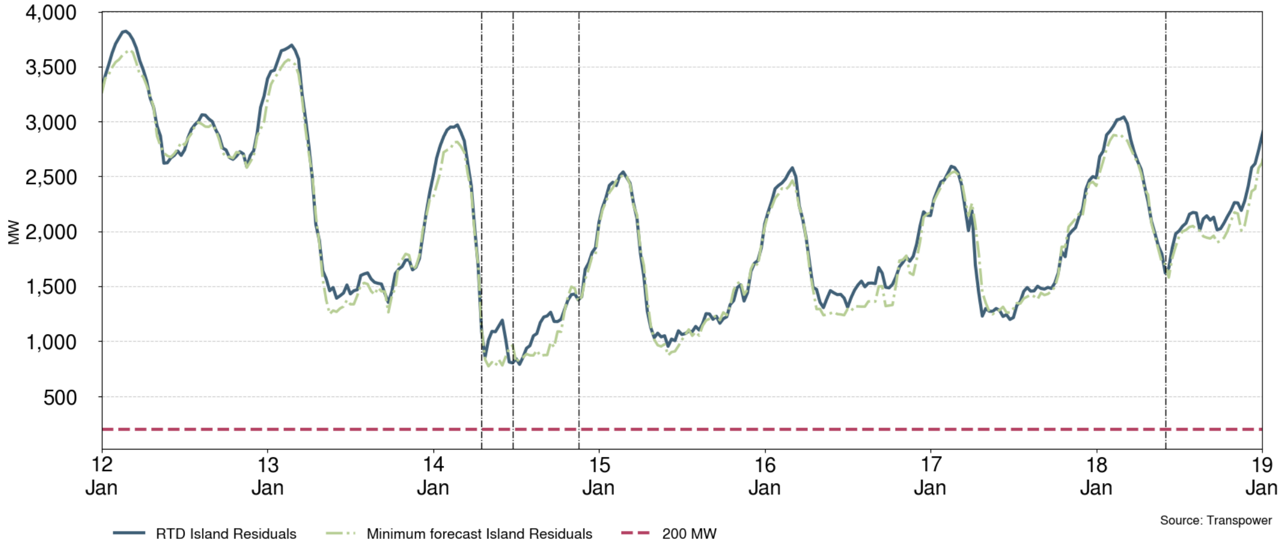
9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 12-18 January 2025. 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. The minimum North Island residual this week was ~410MW at 7.30am on Tuesday.

[3] EXN Frequency National Nga Awa Purua Generation Tripped 5923323022.pdf | Transpower

Figure 18: National generation balance residuals, 12-18 January 2025



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 storage has reduced this week. As of 19 January, national storage was 86% nominally full and ~109% of the historical average for this time of the year.

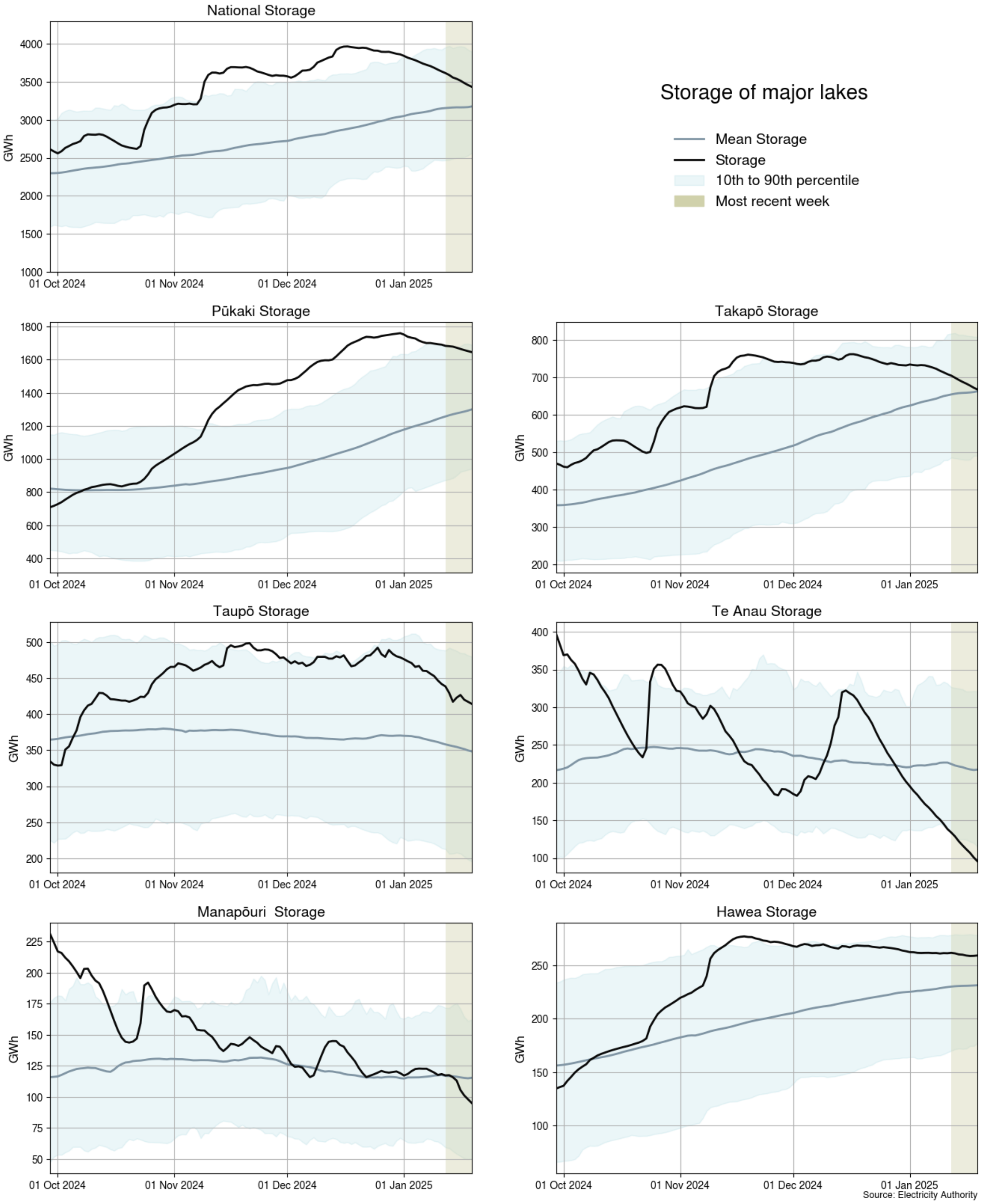
10.3. Lakes Pūkaki (94% full), Hawea (91% full) and Taupō (72% full) decreased this week and are now between their respective historical mean and 90th percentile.

10.4. Lake Takapō (86% full) reduced to its historical mean this week.[4]

10.5. Lake Manapōuri reduced to below its historical mean this week and Lake Te Anau has decreased below its historical 10th percentile.

[4] Percentage full values sourced from NZX Hydro.

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 January 2025. The SRMC for gas fuelled generation has increased compared to last month and the SRMC for coal and diesel fuelled generation remains similar to last month.

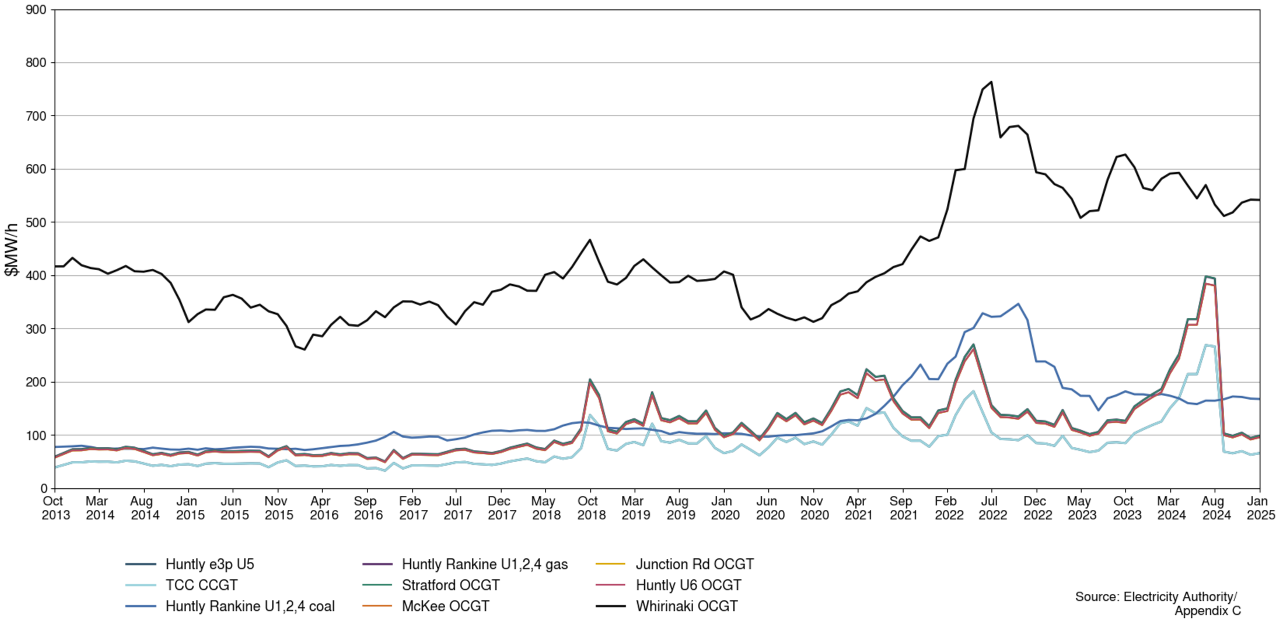
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$167/MWh, with the cost of running the Rankines on gas remaining lower at ~$98/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $66/MWh and $98/MWh.

11.6. The SRMC of Whirinaki is ~$541/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

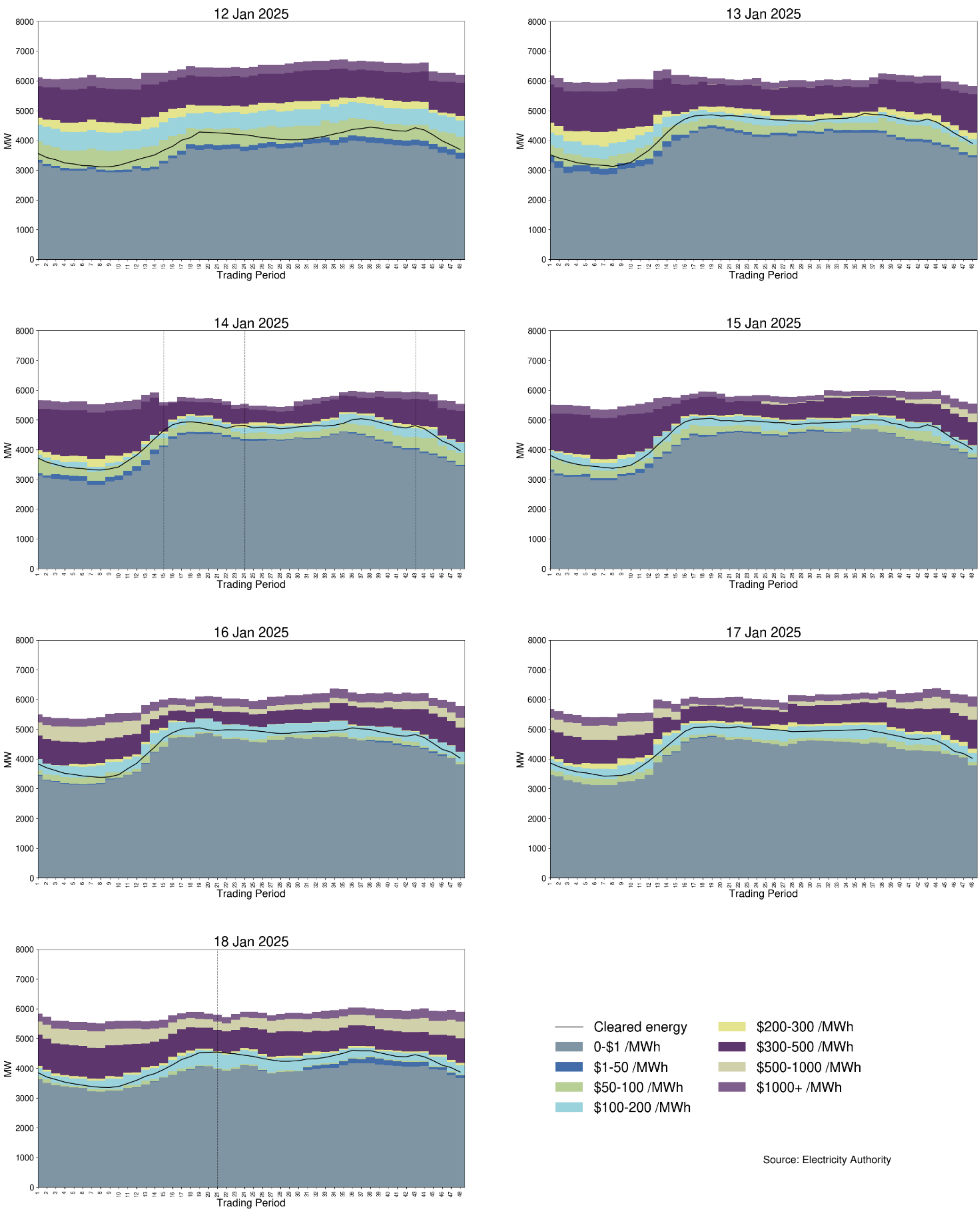


12. Offer behaviour

12.1. Figure 21 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 were clearing in the $100-$200/MWh band this week. From the 15 January, the $300-500/MWh band started to get smaller, and the $500-$1000/MWh band started to increase. The $50-$100/MWh offer band also got very small from 16 January.

Figure 21: Daily offer stacks



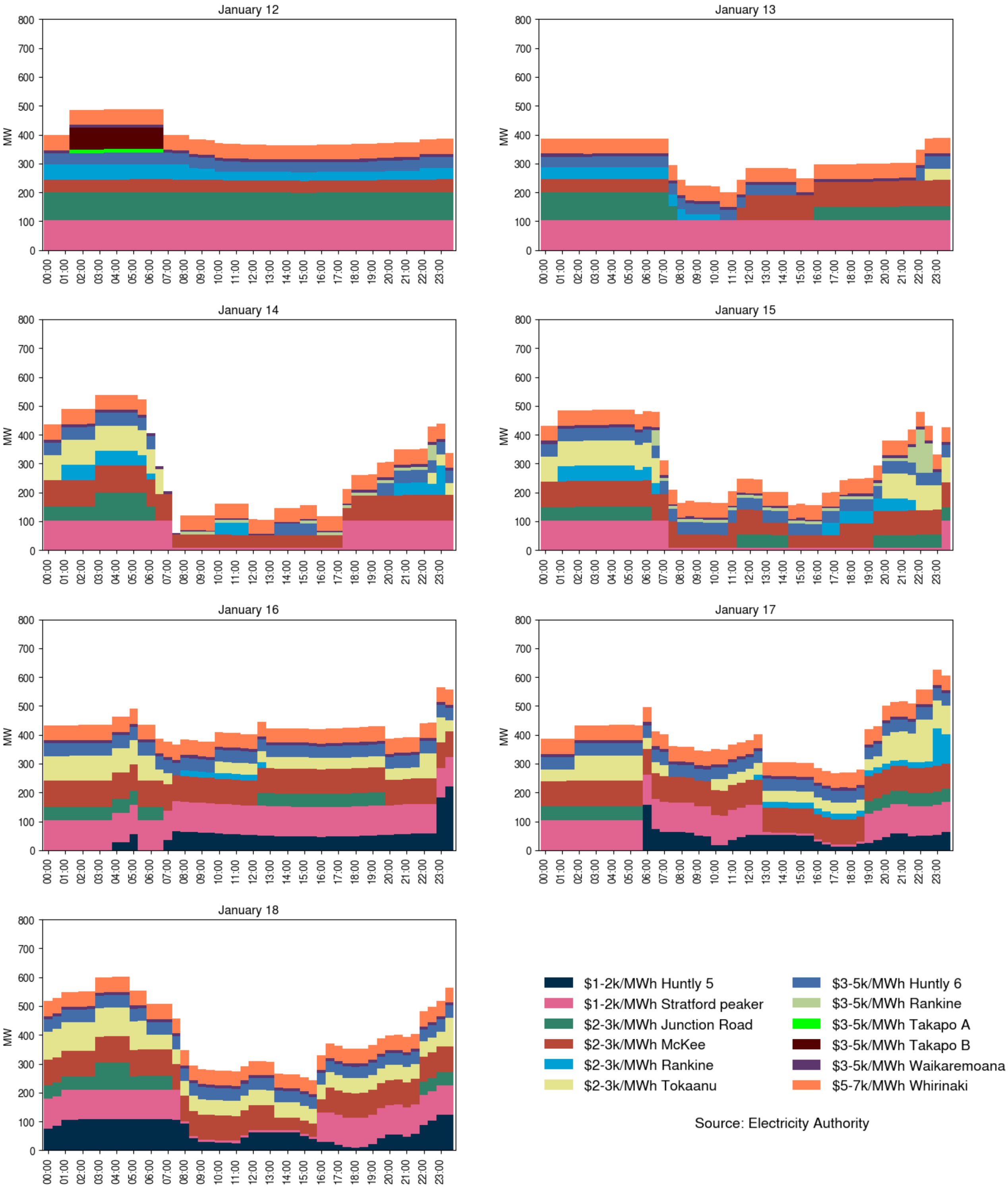
Source: Electricity Authority

12.3. Figure 22 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, 420MW per trading period was priced above $1,000/MWh this week, which is roughly 7% of the total energy available.

Figure 22: High priced offers



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. The monitoring team will be looking further into high priced offers at Tokaanu.

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	Passed to Compliance for advice	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance for advice	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact Energy	Clutha scheme	Hydro offers
8-14/12/2024	Several	Further analysis	Genesis	Waikaremoana	Hydro offers
12-18/12/2024	Several	Further analysis	Genesis	Tokaanu	Hydro offers