13 January 2025

Trading conduct report 5-11 January 2025

Market monitoring weekly report

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1. Overview

1.1. Spot prices increased this week to an average of $49/MWh after decreases in the amount of low-price generation in the offer stack, increased demand following the holiday period and low wind generation. National hydro storage reduced to 90% nominally full. HVDC flow was almost entirely northward and thermal generation remained low.

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 5-11 January 2025:

(a) the average wholesale spot price across all nodes was $49/MWh.

(b) 95% of prices fell between $0.12/MWh and $121/MWh.

2.3. Overall, most spot prices were within $4-$82/MWh and the weekly average price increased by around $47/MWh compared to the previous week.

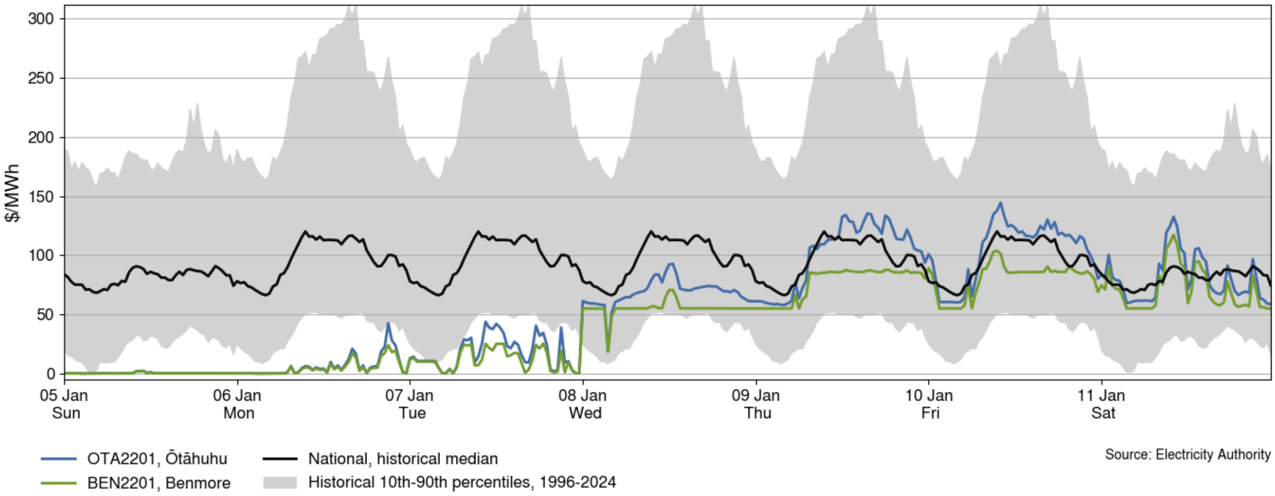
2.4. Sunday, Monday and Tuesday saw low spot prices below the historical 10th percentile. Spot prices increased from Wednesday following an increase in the amount of $50-$100/MWh offers and a decrease in the amount of low price offers in the offer stack.

2.5. Low wind generation and further increases in the offer stack saw spot prices increase to around the historical median from Thursday.

2.6. The highest spot price at Ōtāhuhu this week was $144/MWh at 10am on Friday when total wind generation was low at ~50MW. The Benmore price at the same time was $101/MWh.

2.7. 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.

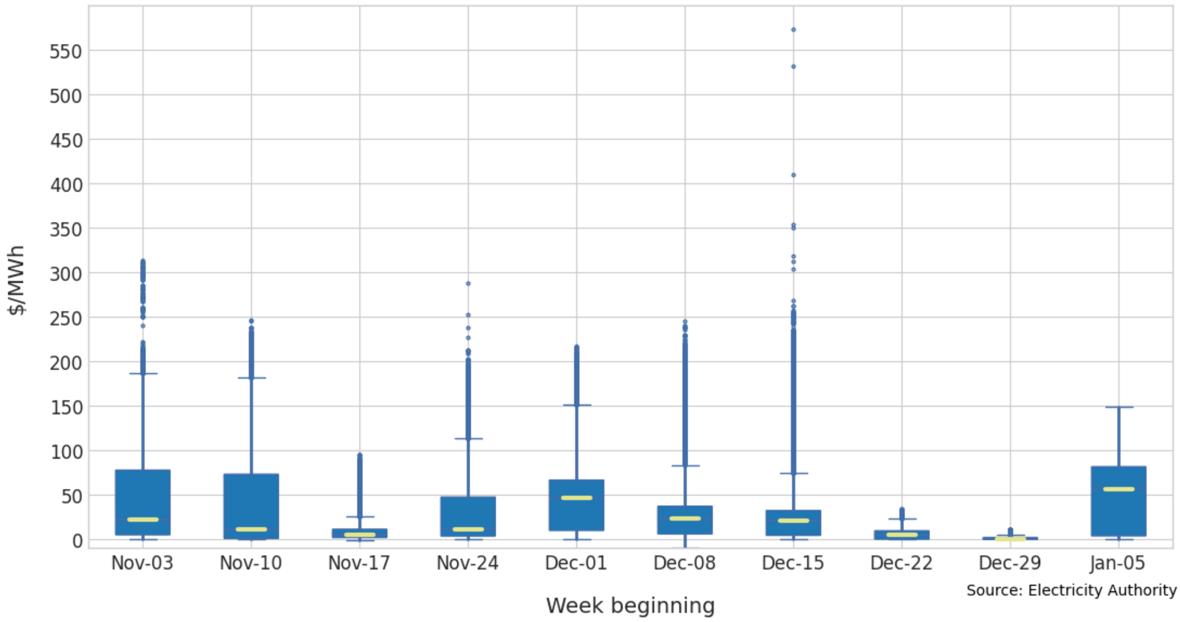
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 5-11 January 2025



2.8. 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.

2.9. The spot price distribution increased and widened this week with a median price of $57/MWh and the middle 50% of prices between $4-$82/MWh.

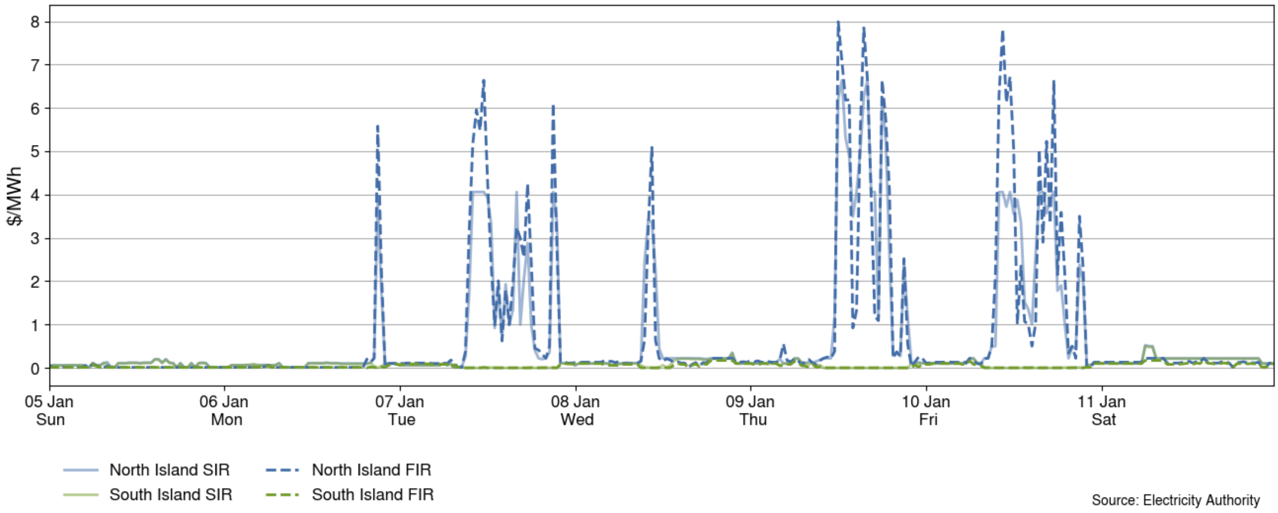
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

3.1. Fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) prices for the North and South Islands are shown below in Figure 3. South Island reserve prices were mostly below $0.10/MWh and North Island reserve prices spiked to a maximum of $8/MWh when the HVDC was setting the risk in the North Island.

Figure 3: Fast and sustained instantaneous reserve price by trading period and island, 5-11 January 2025



Source: Electricity Authority

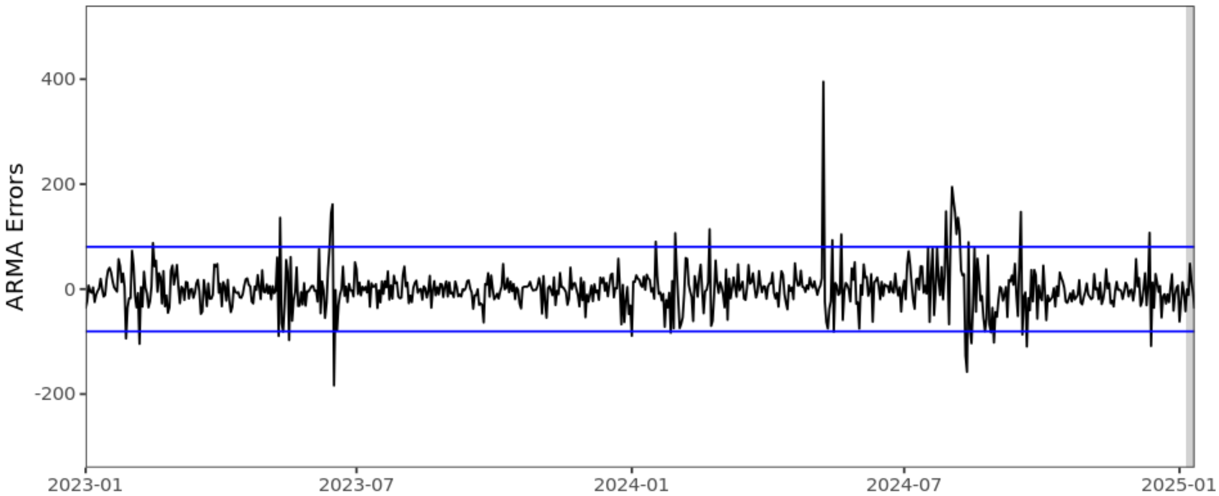
4. Regression residuals

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 4 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 4: Residual plot of estimated daily average spot prices, 1 January 2023 – 11 January 2025

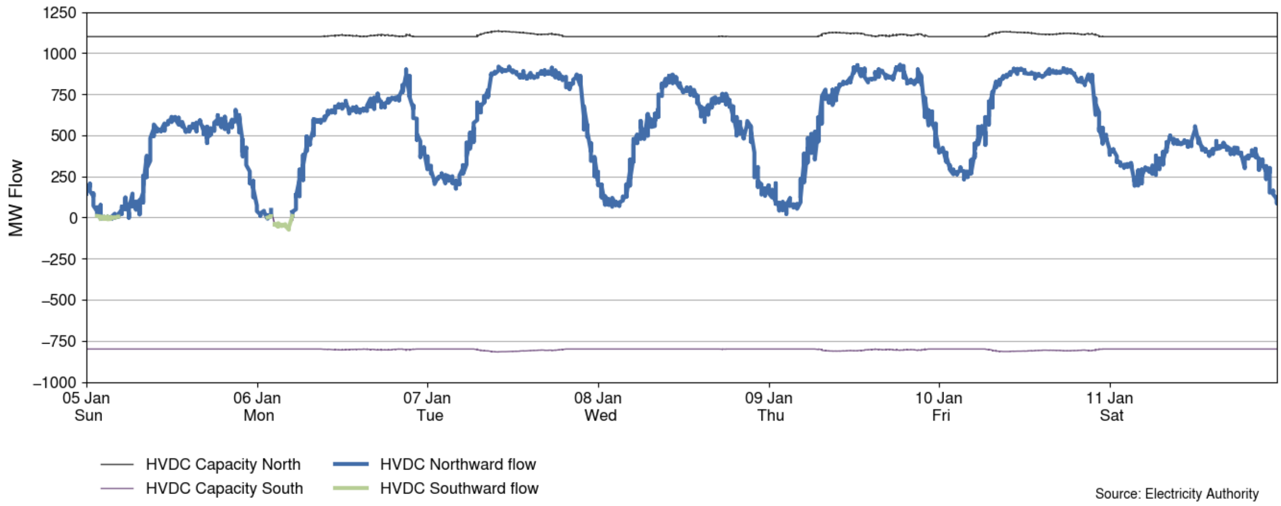


Source: Electricity Authority/Appendix A

5. HVDC

5.1. Figure 5 shows the HVDC flow between 5-11 January 2025. HVDC flows were almost entirely northward this week, with a small amount of southward flow overnight at the start of the week.

Figure 5: HVDC flow and capacity, 5-11 January 2025

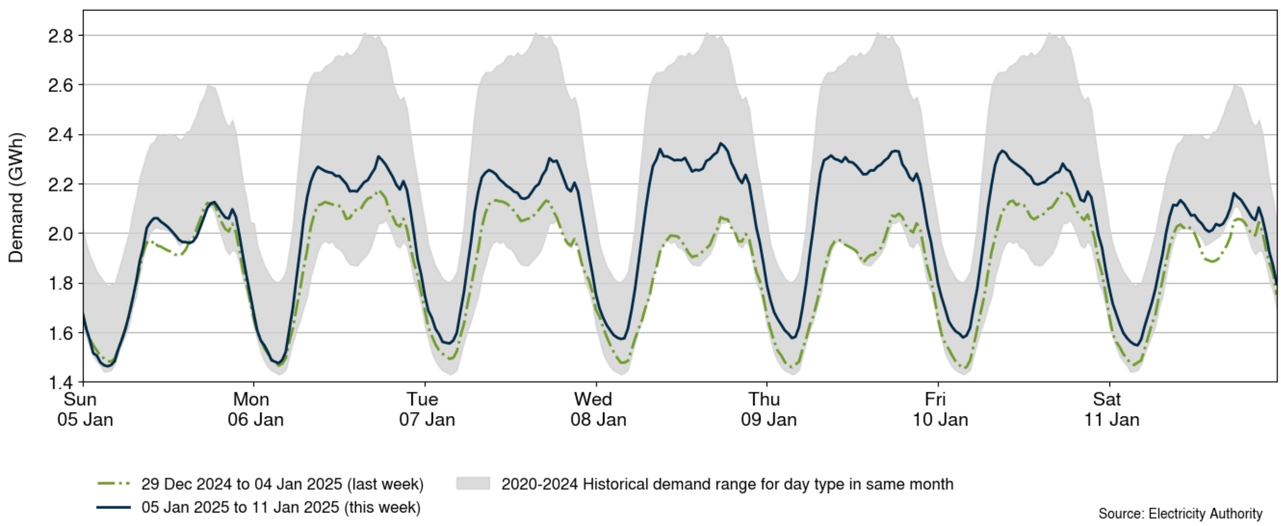


6. Demand

6.1. Figure 6 shows national demand between 5-11 January 2025, compared to the historic range and the demand of the previous week. With people returning to work and the holiday period ending, demand has increased from the previous week and was mostly within the historic range.

6.2. The maximum demand this week was around 2.36GWh (4.72GW) at 5.30pm on Wednesday.

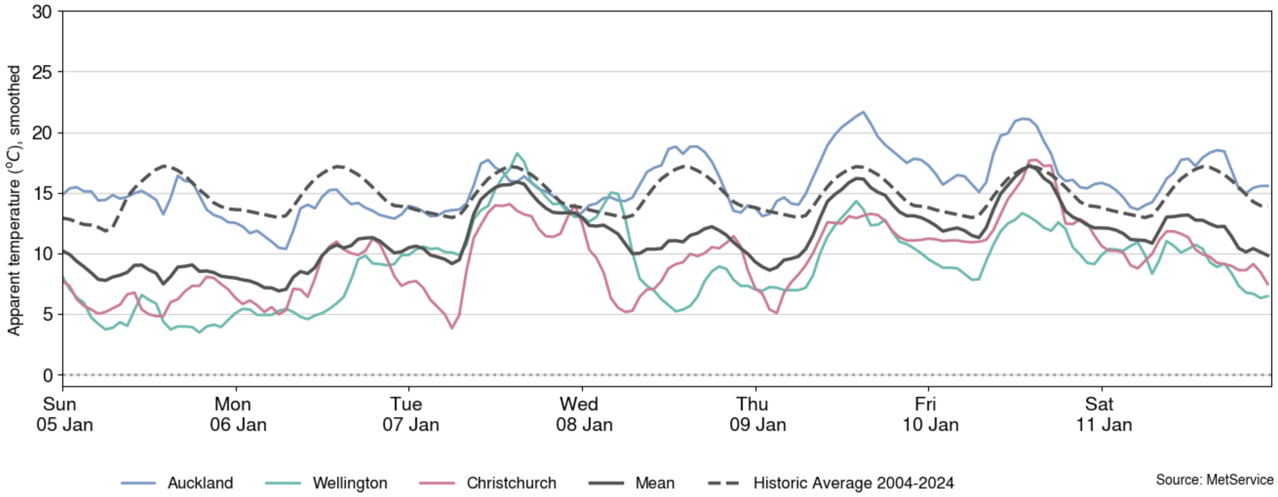
Figure 6: National demand, 5-11 January 2025 compared to the previous week



6.3. Figure 7 shows the hourly apparent temperature at main population centres from 5-11 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. Apparent temperatures were below average this week and ranged from 10°C to 22°C in Auckland, 3°C to 19°C in Wellington, and 3°C to 18°C in Christchurch.

Figure 7: Temperatures across main centres, 5-11 January 2025

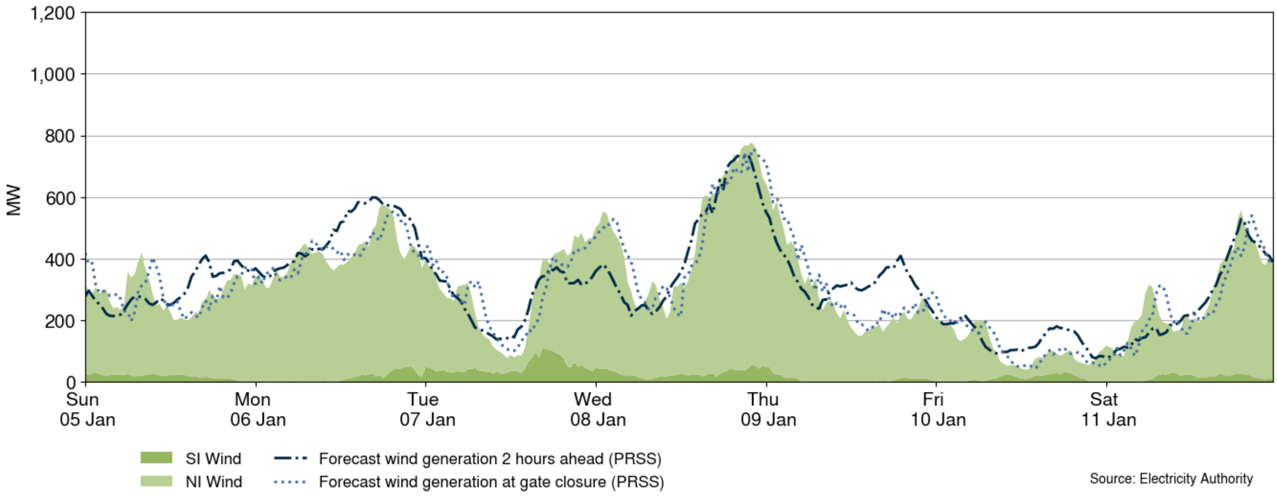


7. Generation

7.1. Figure 8 shows wind generation and forecast from 5-11 January 2025. This week wind generation varied between 40MW and 777MW, with a weekly average of 306MW. Wind generation was highest on Wednesday this week with a daily average of 483MW.

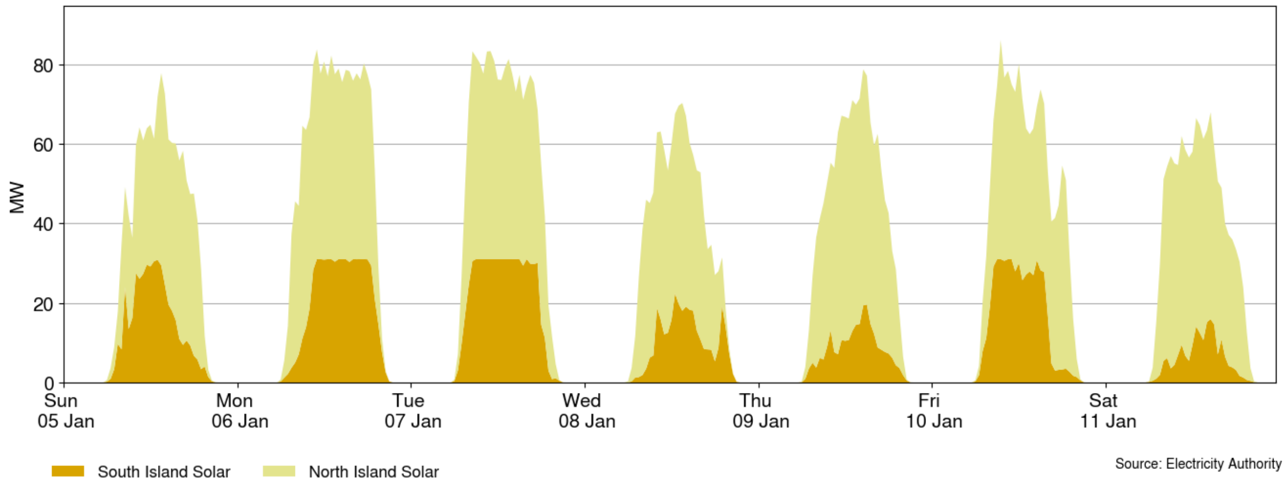
7.2. The greatest negative discrepancy between wind generation and the gate closure forecast was ~150MW at 7.30am on Tuesday.

Figure 8: Wind generation and forecast, 5-11 January 2025



7.3. Figure 9 shows solar generation from 5-11 January 2025. Solar generation peaked above 70MW every day this week except for Saturday.

Figure 9: Solar generation, 5-11 January 2025

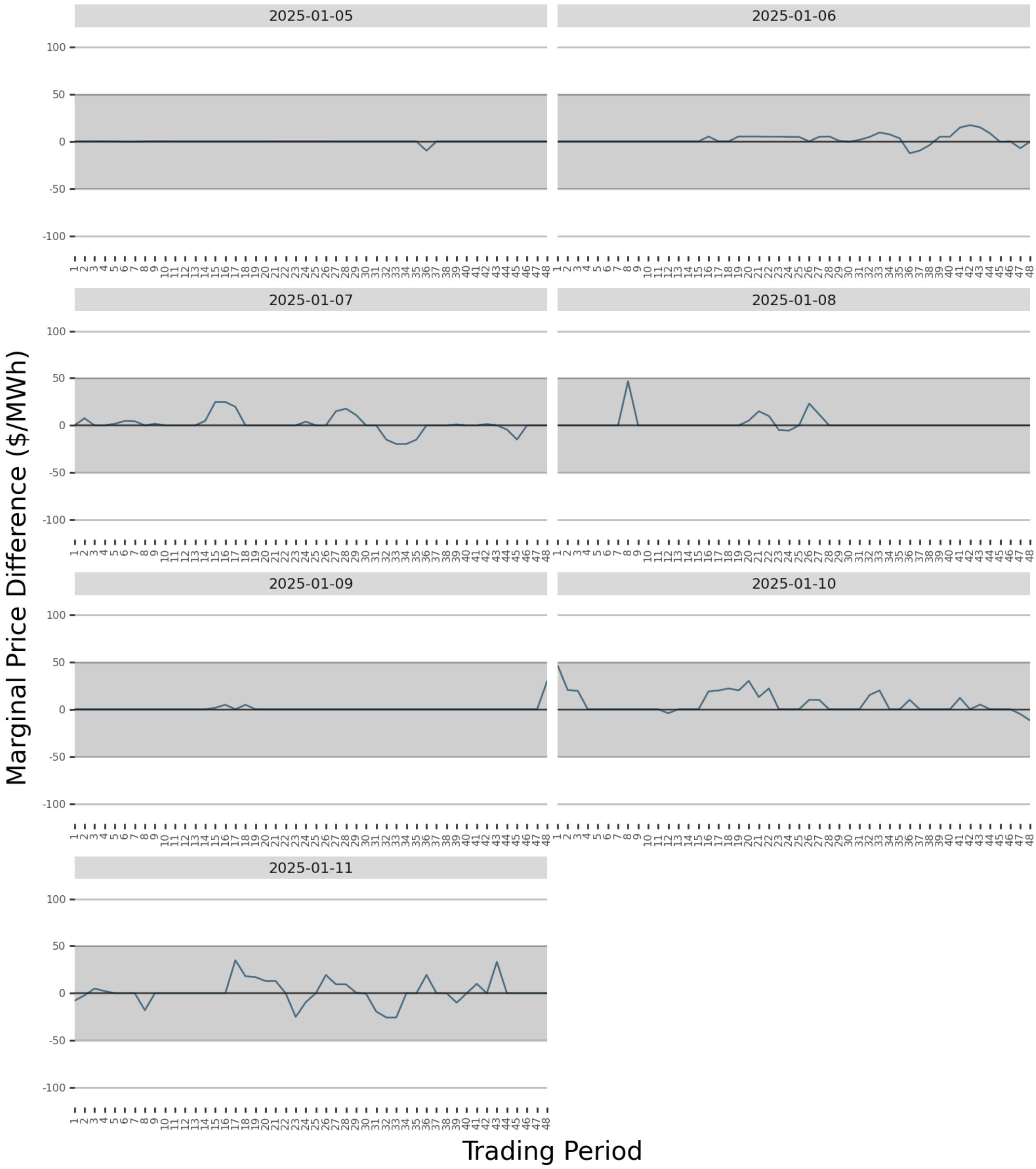


7.4. Figure 10 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 signal that forecasting inaccuracies had a large impact on the final price for that trading period.

7.5. Marginal price differences were less than $50/MWh every day this week.

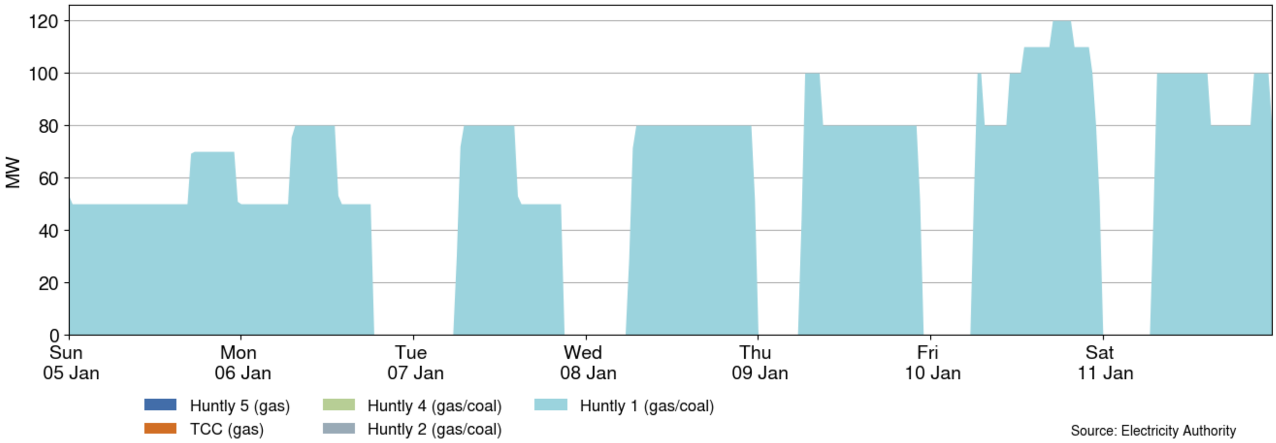
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 10: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 5-11 January 2025



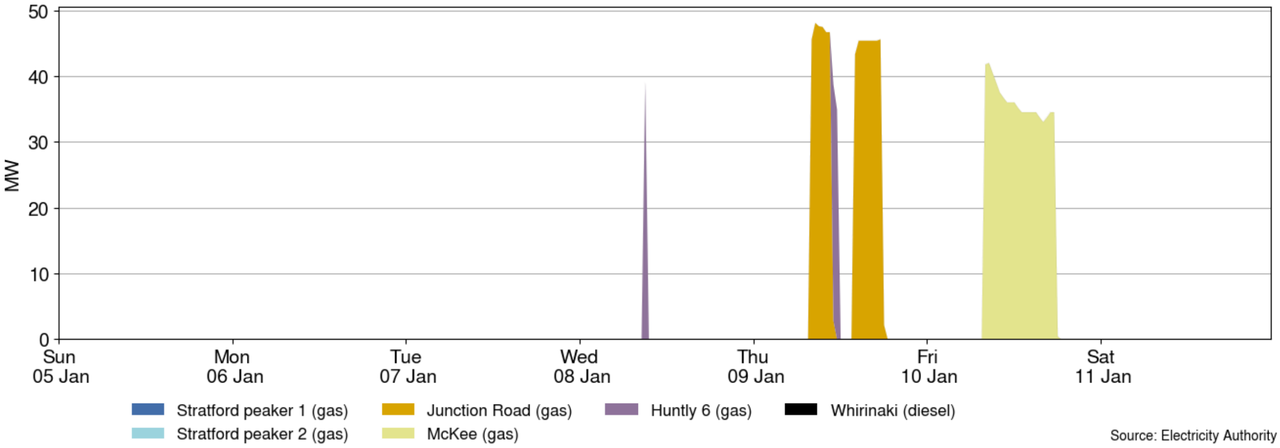
7.6. Figure 11 shows the generation of thermal baseload between 5-11 January 2025. Huntly 1 ran during the day every day this week, and also ran overnight on Sunday.

Figure 11: Thermal baseload generation, 5-11 January 2025



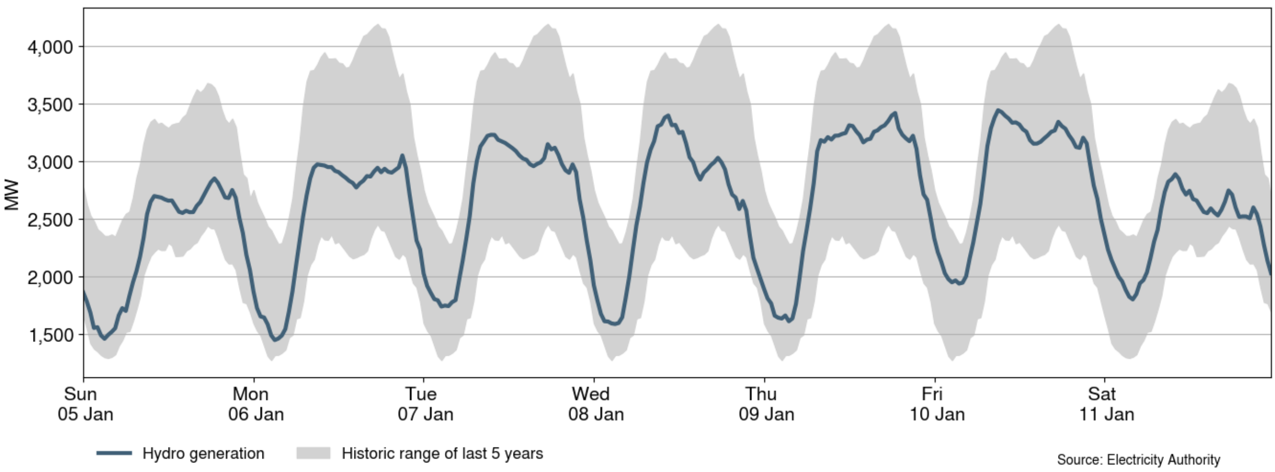
7.7. Figure 12 shows the generation of thermal peaker plants between 5-11 January 2025. Huntly 6 ran briefly on Wednesday and Thursday morning. Junction Road ran on Thursday morning and afternoon and McKee ran during the day on Friday.

Figure 12: Thermal peaker generation, 5-11 January 2025



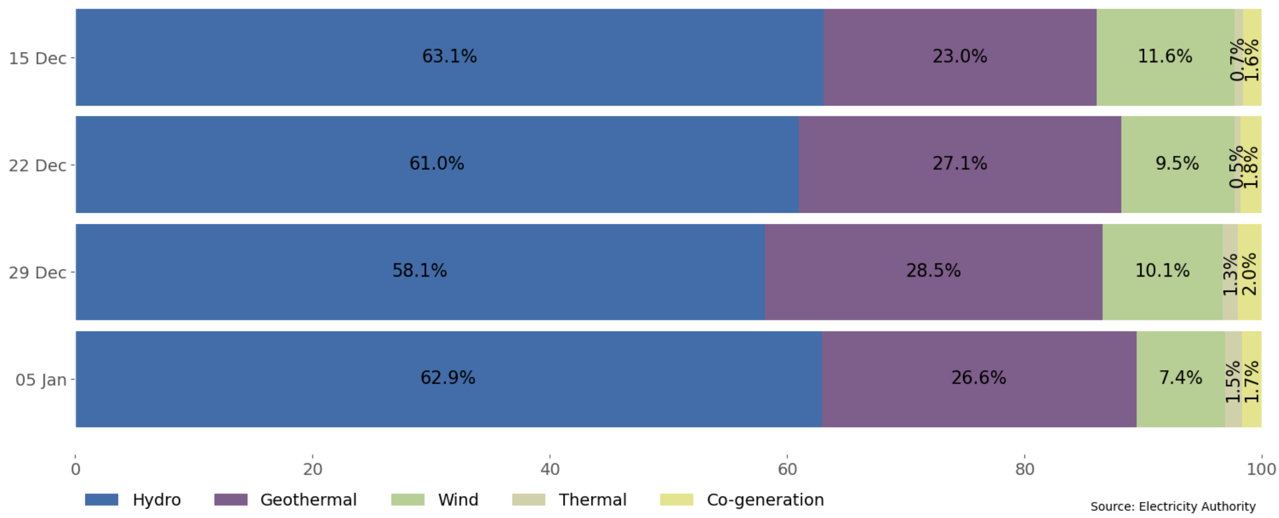
7.8. Figure 13 shows hydro generation between 5-11 January 2025. Hydro generation was in the middle of the historic range every day this week.

Figure 13: Hydro generation, 5-11 January 2025



7.9. As a percentage of total generation, between 5-11 January 2025, total weekly hydro generation was 62.9%, geothermal 26.6%, wind 7.4%, thermal 1.5%, and co-generation 1.7%, as shown in Figure 14. The proportion of hydro generation increased this week to make up for the lower proportion of wind generation compared to the previous week.

Figure 14: Total generation by type as a percentage each week, 15 December 2024 and 11 January 2025



8. Outages

8.1. Figure 15 shows generation capacity on outage. Total capacity on outage between 5-11 January 2025 ranged between ~1,140MW and ~1,580MW. Figure 16 shows the thermal generation capacity outages.

8.2. Notable outages include:

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

(b) Huntly 4 returned from outage on 10 January.

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

(d) Rangipō unit 6 is on outage until 11 April.

Figure 15: Total MW loss from generation outages, 5-11 January 2025

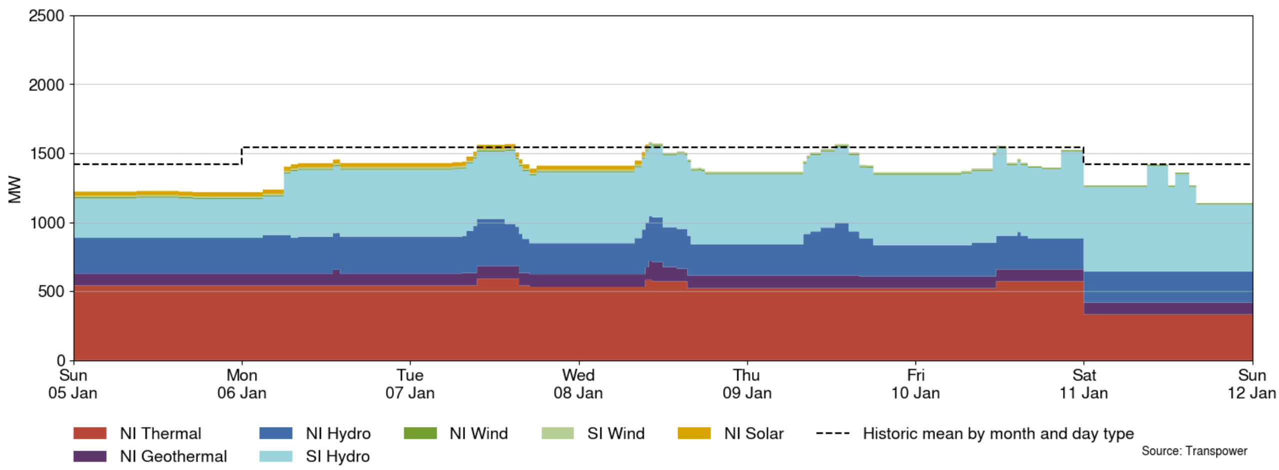
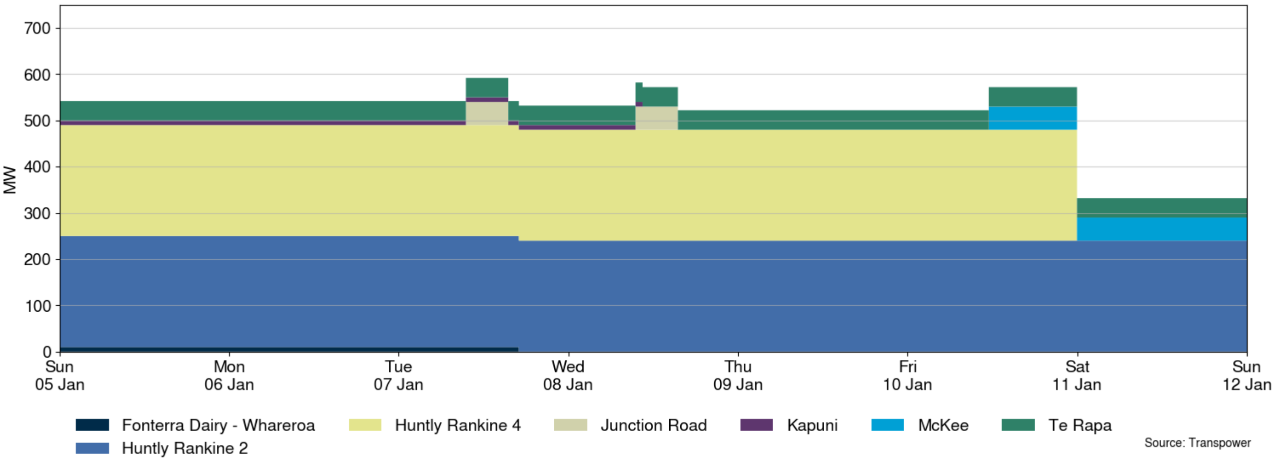


Figure 16: Total MW loss from thermal outages, 5-11 January 2025

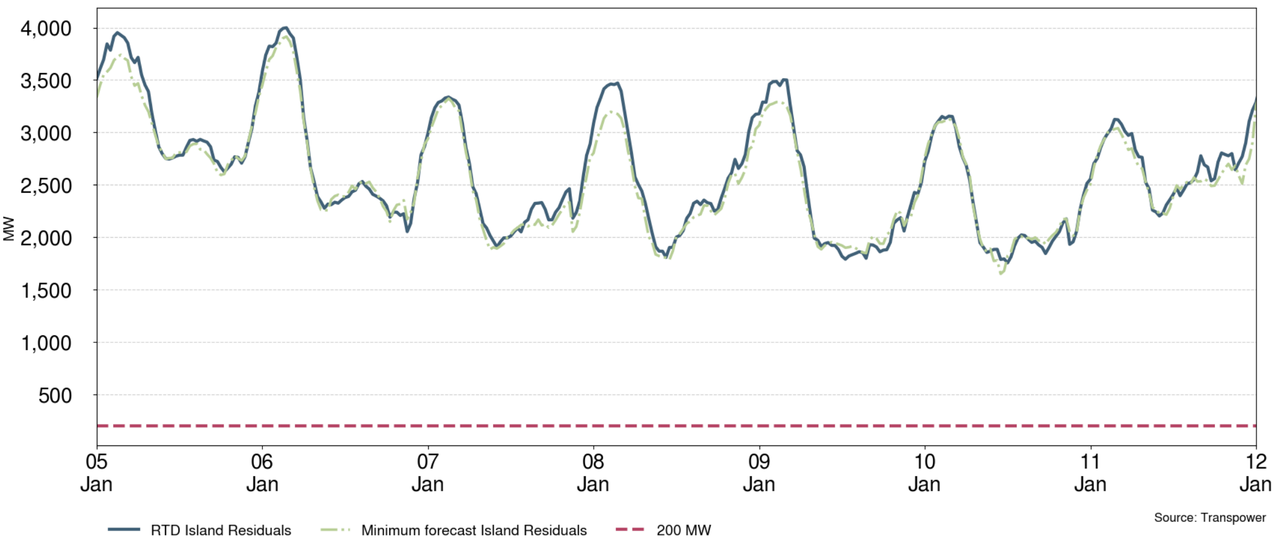


9. Generation balance residuals

9.1. Figure 17 shows the national generation balance residuals between 5-11 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 ~1,200MW at 10.30am on Wednesday.

Figure 17: National generation balance residuals, 5-11 January 2025



10. Storage/fuel supply

10.1. Figure 18 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 11 January, national storage was 90% nominally full and ~116% of the historical average for this time of the year.

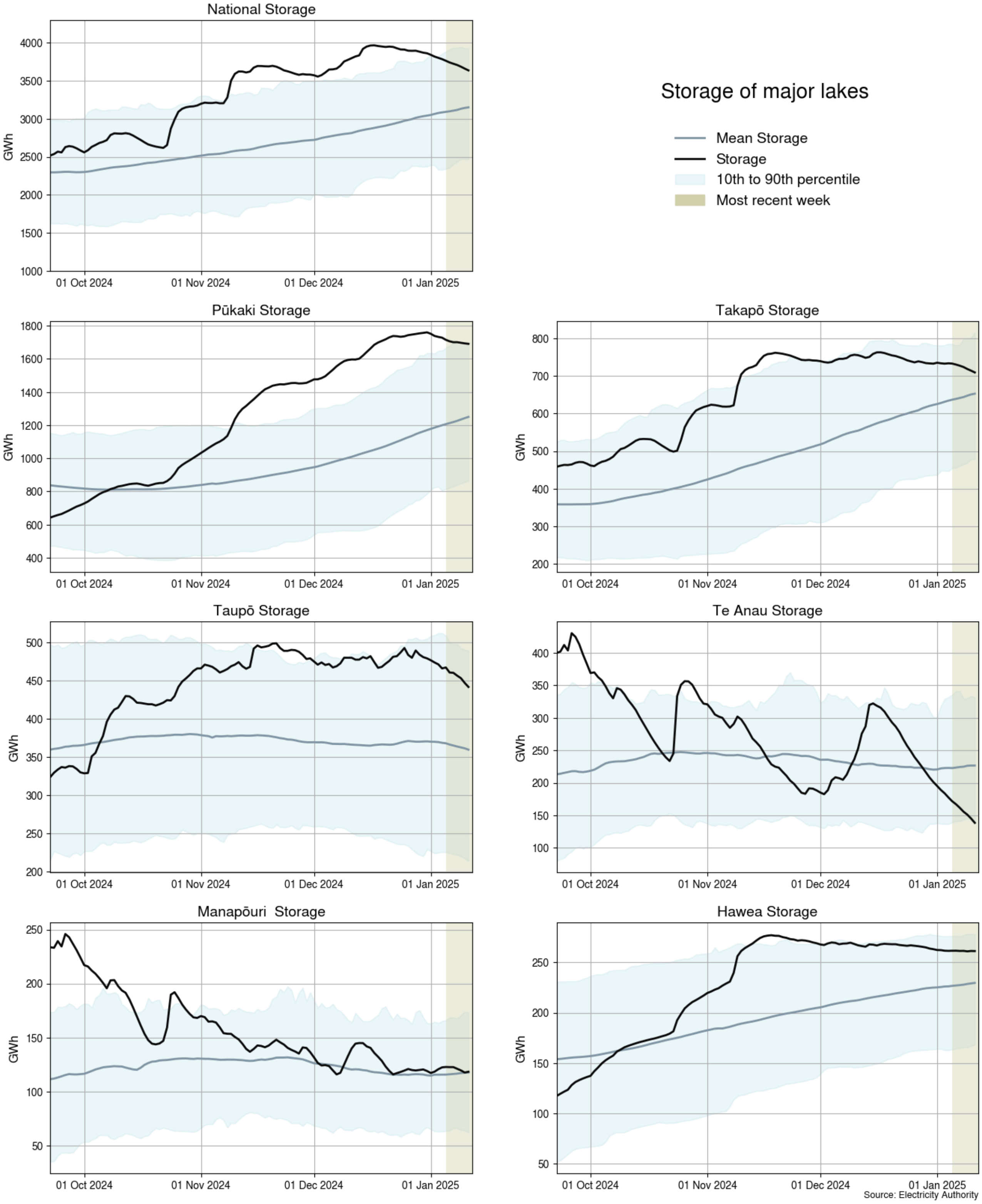
10.3. Storage at all major lakes except Lake Hawea reduced this week. Lake Pūkaki (97% full) has reduced to its historic 90th percentile. Lakes Takapō (91% full) and Taupō (77% full) started this week below their historic 90th percentiles and both continued to reduce towards their historic means.

10.4. Storage at Lake Hawea (92% full) held steady above mean but below its historic 90th percentile.[2]

10.5. Lake Te Anau dropped below its historic 10th percentile this week and Lake Manapōuri reduced slightly to its historic mean.

[2] Percentage full values sourced from NZX Hydro.

Figure 18: 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 19 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.

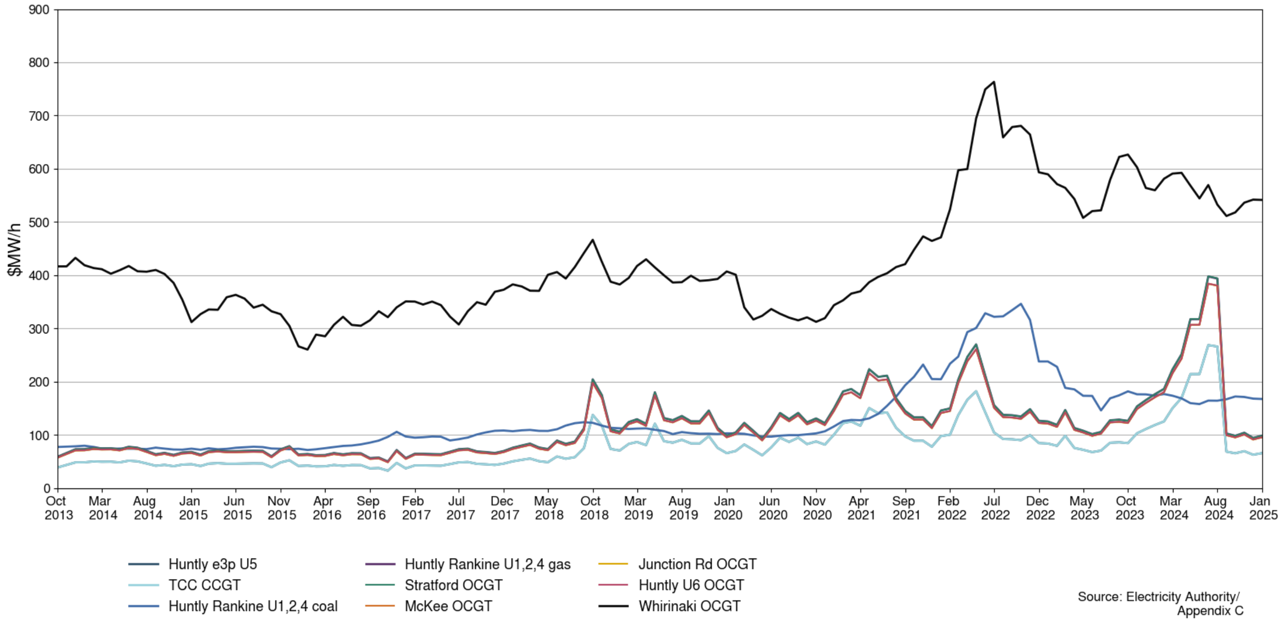
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$167/MWh, with the cost of running the Rankines on gas remaining lower at ~$98/MWh.

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 19: Estimated monthly SRMC for thermal fuels



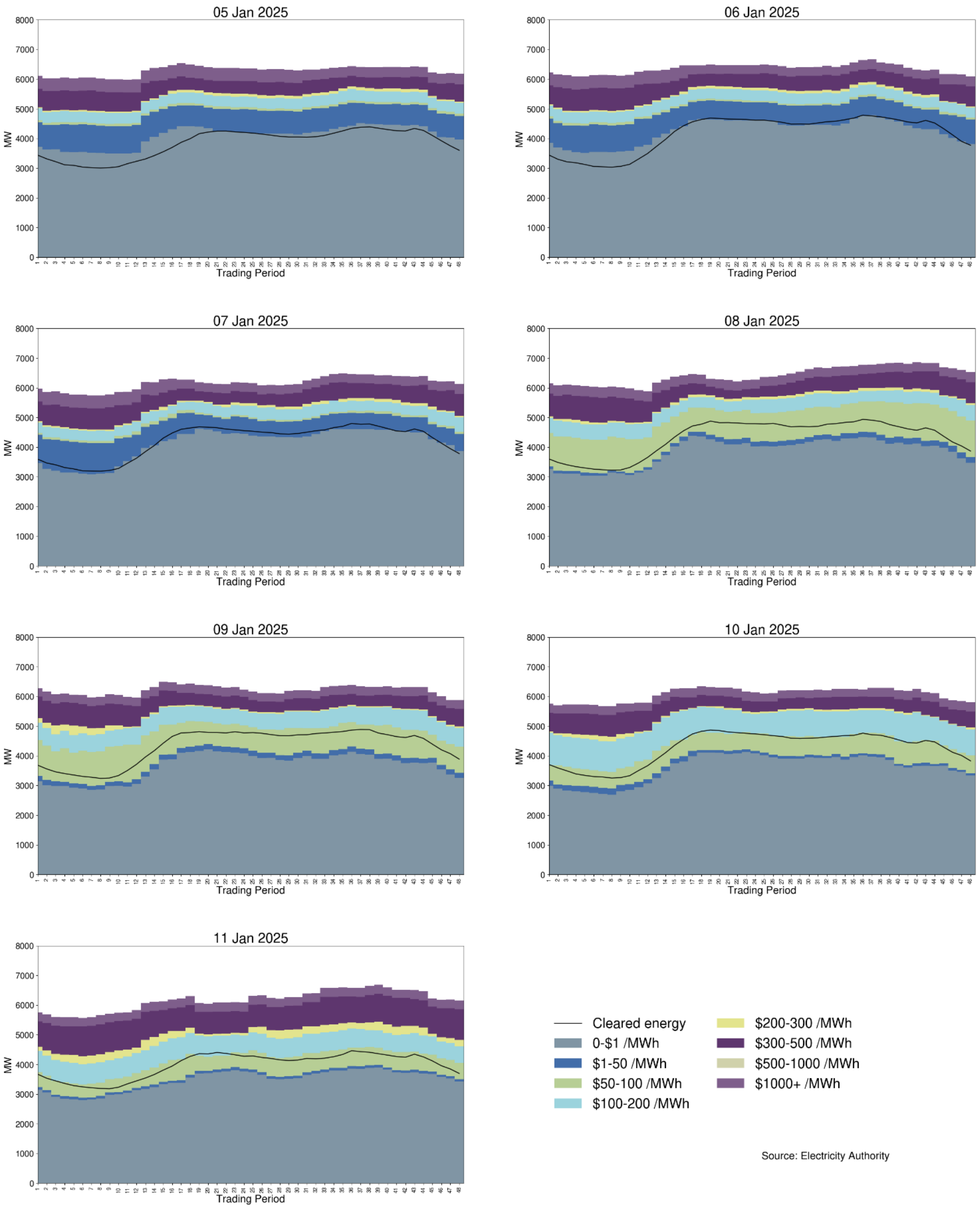
Source: Electricity Authority/ Appendix C

12. Offer behaviour

12.1. Figure 20 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

12.2. The $1-$50/MWh offer band reduced this week, with an increase to $50-$100/MWh offers from Wednesday, $100-$200/MWh offers from Thursday/Friday and $300-$500/MWh offers from Saturday.

Figure 20: Daily offer stacks

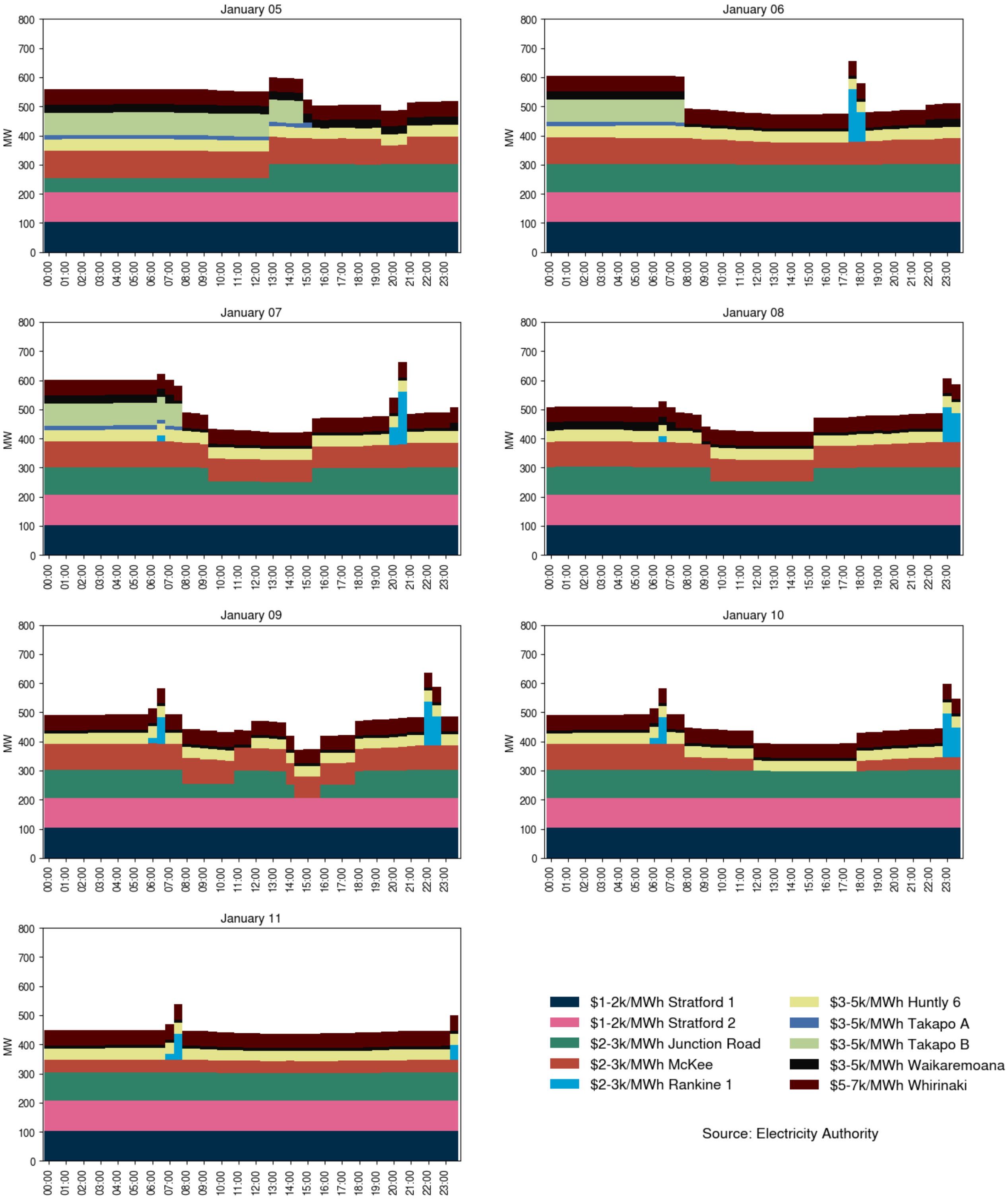


12.3. Figure 21 shows offers above $1,000/MWh in each trading period this week. The largest proportion these offers are fast start thermal operators.

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, 492MW per trading period was priced above $1,000/MWh this week, which is roughly 8% of the total energy available.

Figure 21: 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
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