22 December 2025

Trading conduct report 14-20 December 2025

Market monitoring weekly report

Trading conduct report 14-20 December 2025

1. Overview

1.1. This week the average spot price decreased by $32/MWh to $7/MWh. HVDC flows were mostly northward throughout the week and were at or near capacity at times. The proportion of wind and geothermal generation increased this week, while the proportion of thermal and hydro generation declined.

1.2. National hydro storage decreased slightly to 101% nominally full and ~139% of the historical average. However, this includes storage at Takapō, Pūkaki and Te Anau/ Manapōuri which is expected to spill.

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 14-20 December:

(a) The average spot price for the week was $7/MWh, a decrease of around $32/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $60/MWh.

2.3. This week, prices remained mostly below $75/MWh at Ōtāhuhu and below $25/MWh at Benmore. On Friday and Saturday prices were very low. Prices between the North and South Islands were separated at times between Monday and Thursday during periods of high northward HVDC flow.

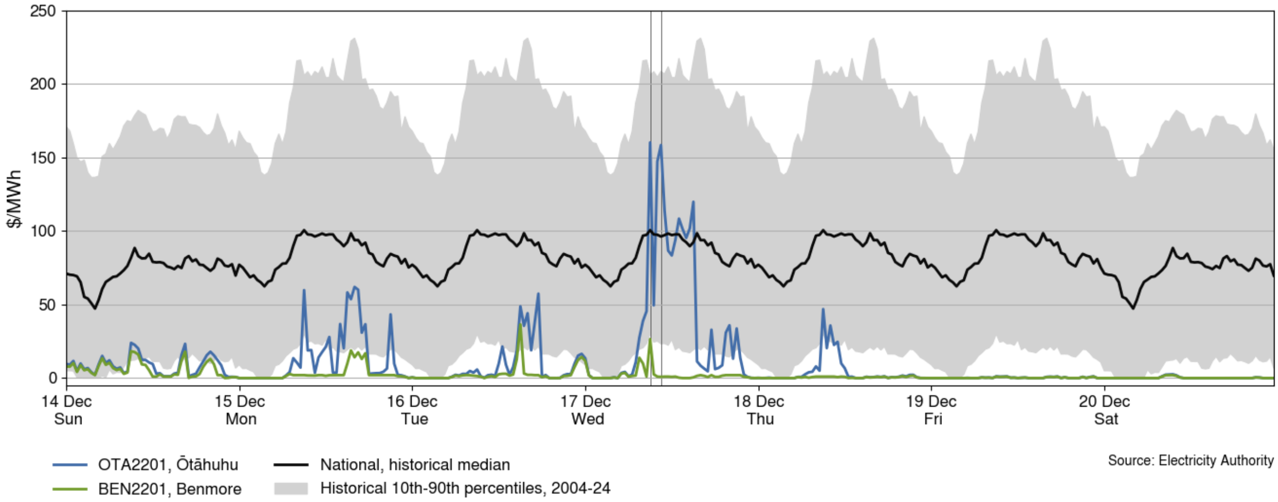
2.4. On Wednesday, North Island prices were mostly above $75/MWh between 9.00am and 3.00pm. During this time, wind was low and under forecast and the HVDC was close to its northward capacity. There were two price spikes above $150/MWh during this period, with Ōtāhuhu prices reaching $160/MWh and $159/MWh at 9.00am and 10.30am respectively.

(a) At 9.00am, North Island reserve prices spiked and intermittent generation was 171MW lower than forecast.

(b) At 10.30am, the HVDC northward capacity limit was reduced and intermittent generation was 146MW lower than forecast.

2.5. 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.

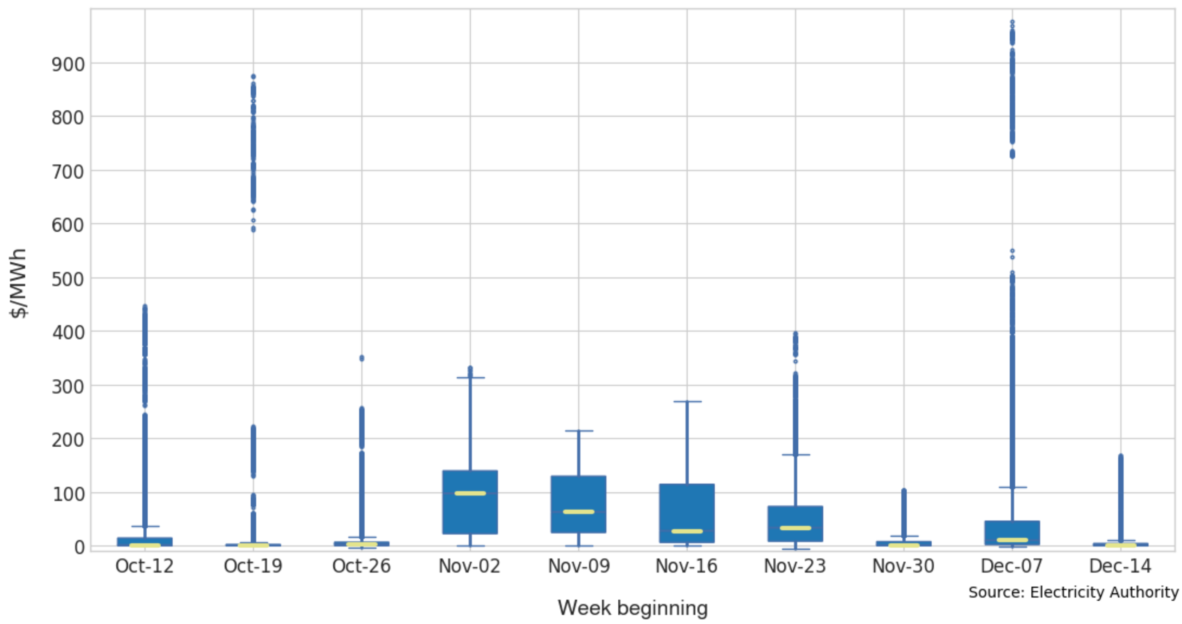
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 14-20 December



2.6. 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.

2.7. The distribution of spot prices this week was narrower compared to last week. The median price was $0.90/MWh and most prices (middle 50%) fell between $0.02/MWh and $4/MWh.

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

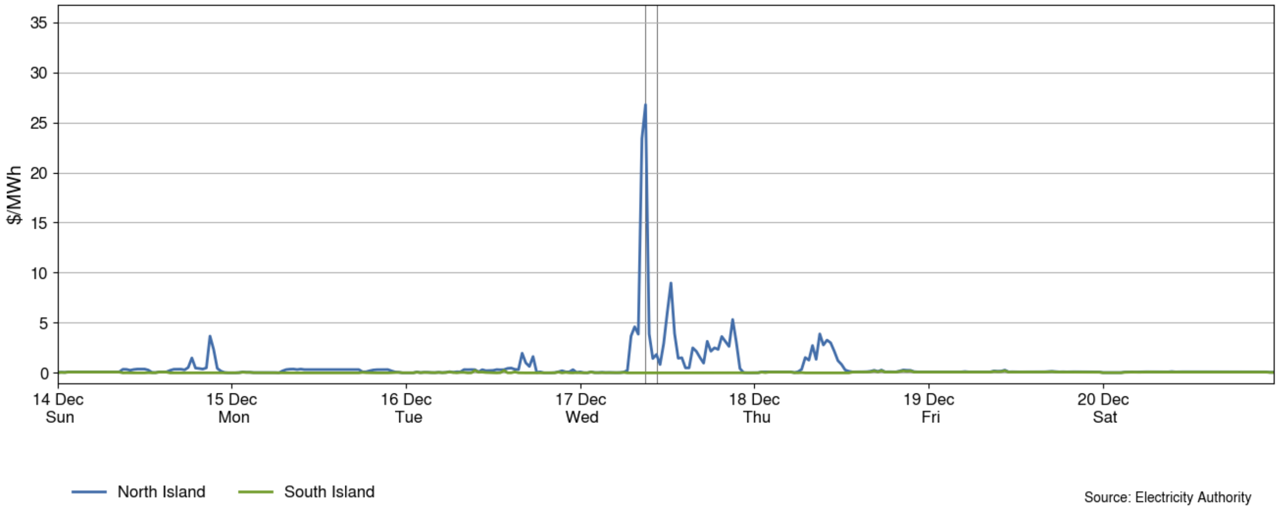


3. Reserve prices

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, aside from two price spikes on Wednesday.

3.2. On Wednesday, North Island FIR prices reached $23/MWh and $27/MWh at 8.30am and 9.00am respectively. During this time, the HVDC was the North Island risk setter.

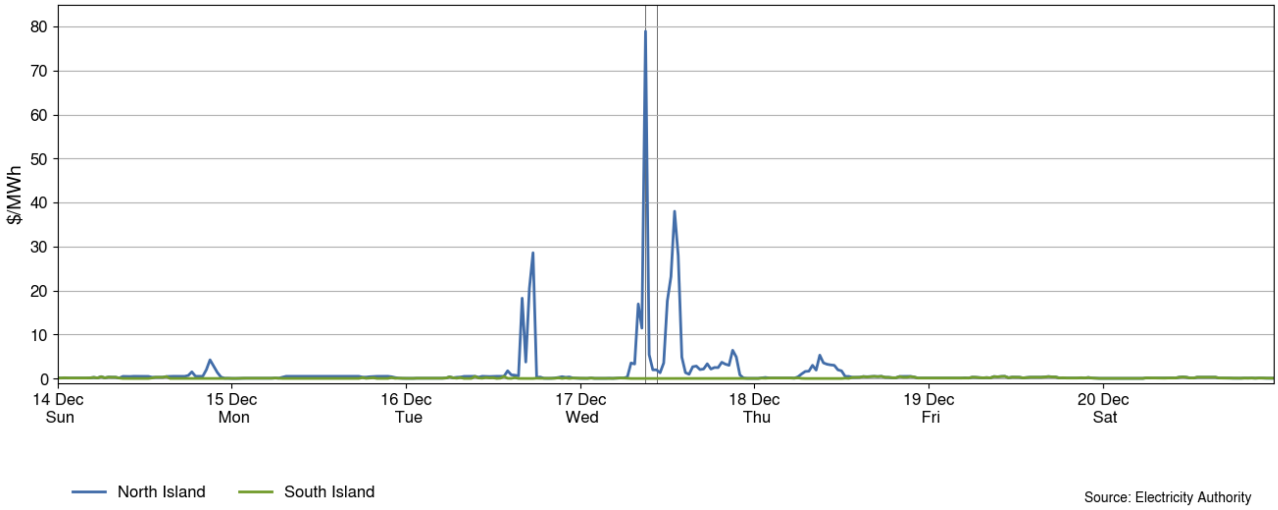
Figure 3: Fast instantaneous reserve price by trading period and island, 14-20 December



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $30/MWh, aside from two price spikes on Wednesday.

3.4. On Wednesday, North Island SIR prices reached $79/MWh and $38/MWh at 9.00am and 1.00pm respectively. The HVDC was the North Island risk setter at these times.

Figure 4: Sustained instantaneous reserve by trading period and island, 14-20 December



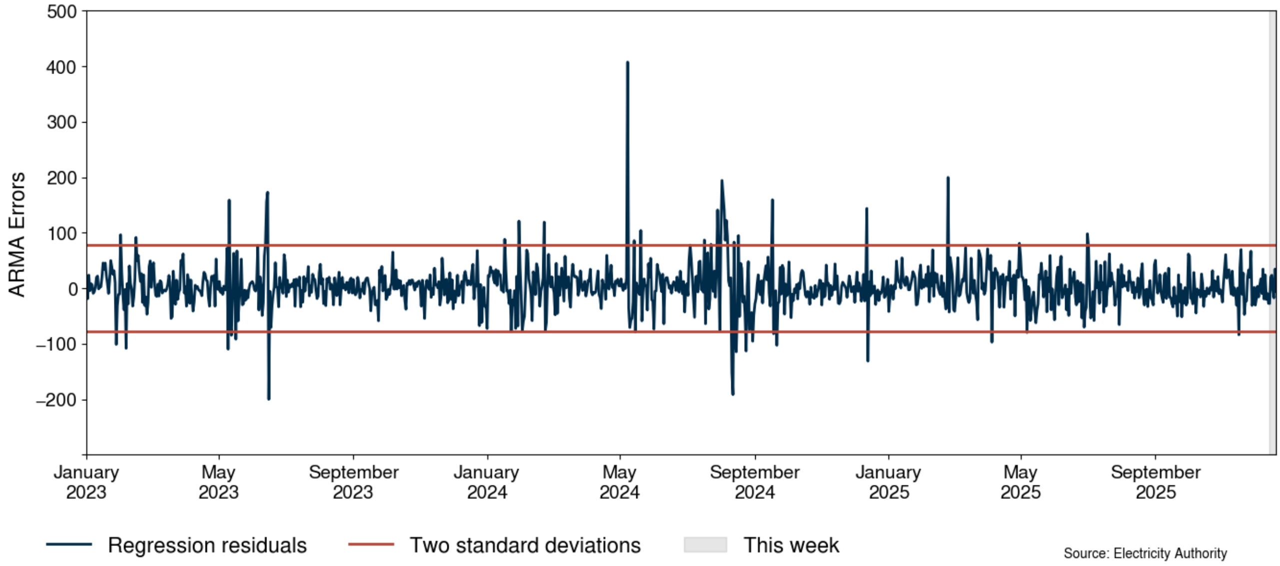
4. Regression residuals

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 2023 - 20 December 2025



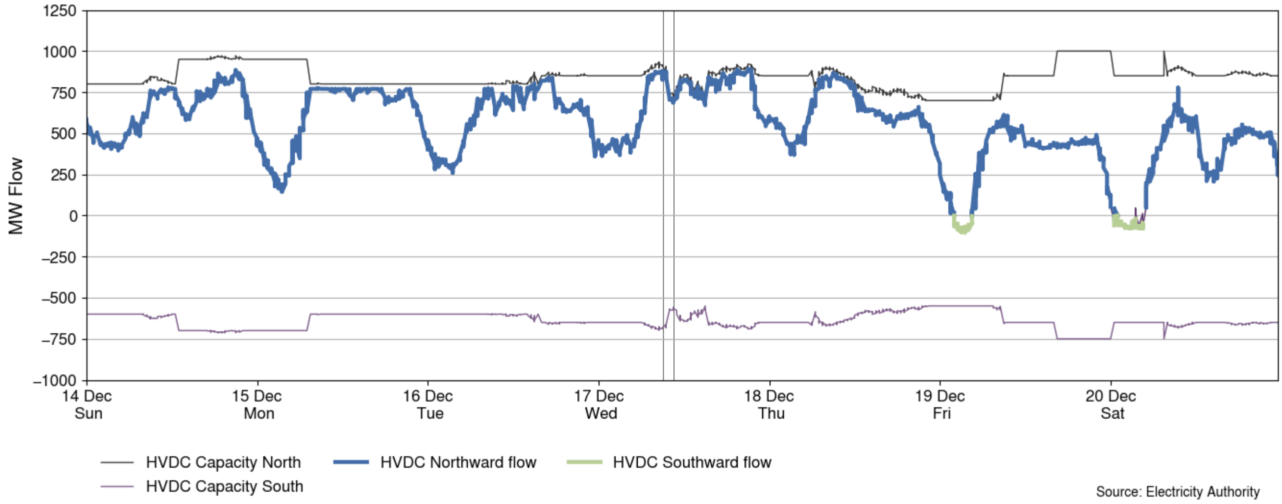
5. HVDC

5.1. Figure 6 shows the HVDC flow between 14-20 December. HVDC flows[1] were mostly northward this week, due to high hydro generation in the South Island. Some southward flow occurred overnight on Friday and Saturday, during periods of high wind and low demand.

5.2. The highest northward flow occurred at 9.00pm on Wednesday with a flow of around 891MW. HVDC northward flows were close to capacity limits at times between Monday and Thursday.

[1] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these being the one that determines the required quantity of instantaneous reserve. Reserve to cover generator risks can be shared between the North and South Islands. However, reserve to cover HVDC risks must be located in the receiving island. Because SPD (scheduling, pricing and dispatch) co-optimises energy and reserve, when an HVDC risk binds it can cause both energy and reserve price separation between the islands.

Figure 6: HVDC flow and capacity, 14-20 December

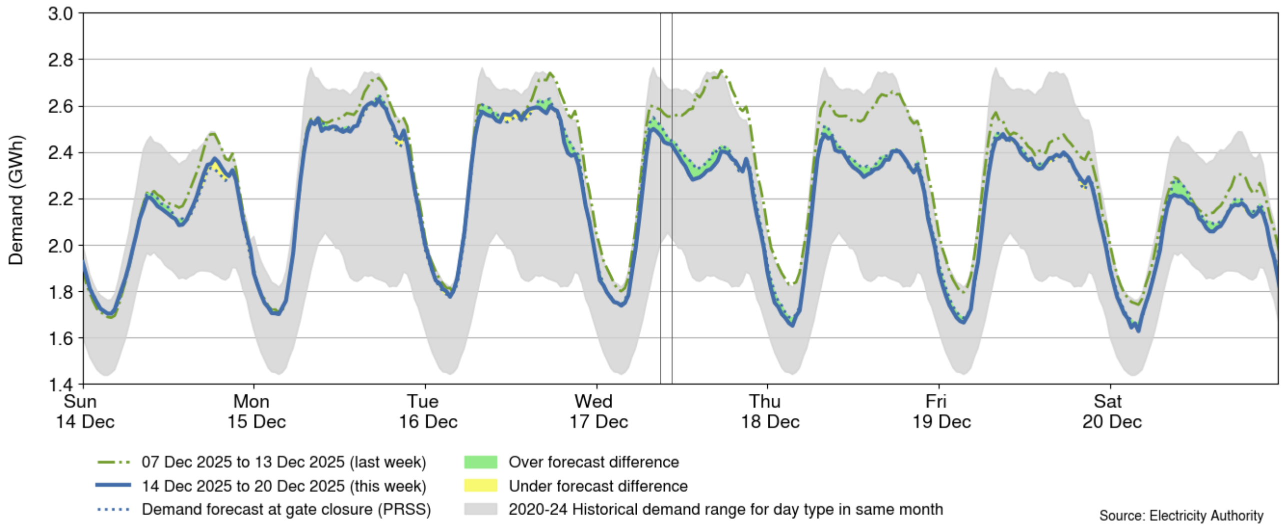


6. Demand

6.1. Figure 7 shows national demand between 14-20 December, compared to the historic range and the demand of the previous week.

6.2. Demand was lower overall compared to last week, especially on Wednesday and Thursday, likely due to cooler temperatures and the beginning of school holidays. The highest demand of the week was around 2.63GWh at 5.30pm on Monday. Demand was underforecast several times across the week, but especially on Wednesday.

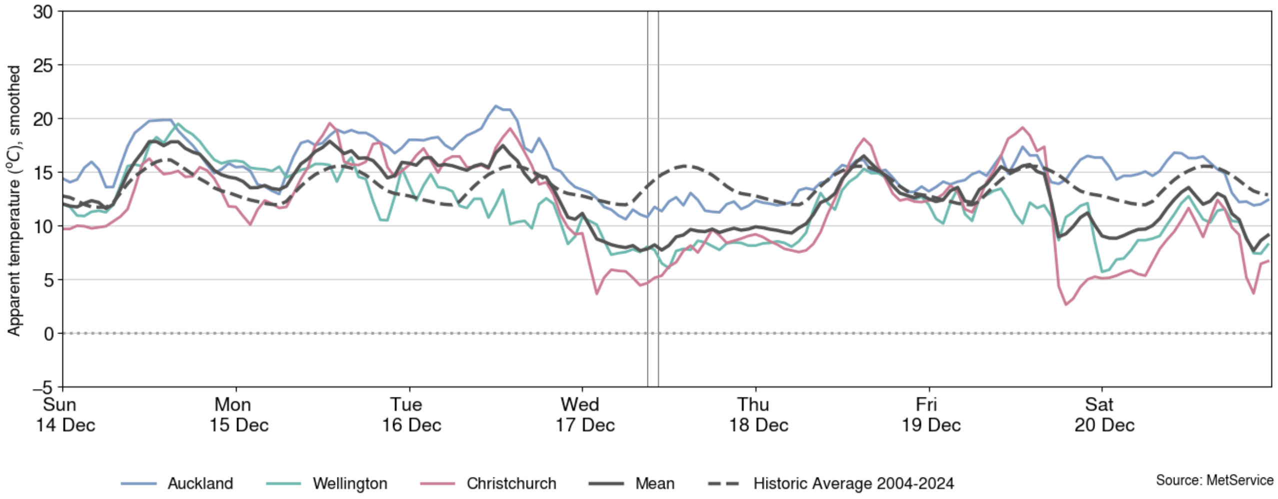
Figure 7: National demand, 14-20 December compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 14-20 December. 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 ranged from 10°C to 21°C in Auckland, 5°C to 20°C in Wellington, and 1°C to 21°C in Christchurch.

Figure 8: Temperatures across main centres, 14-20 December

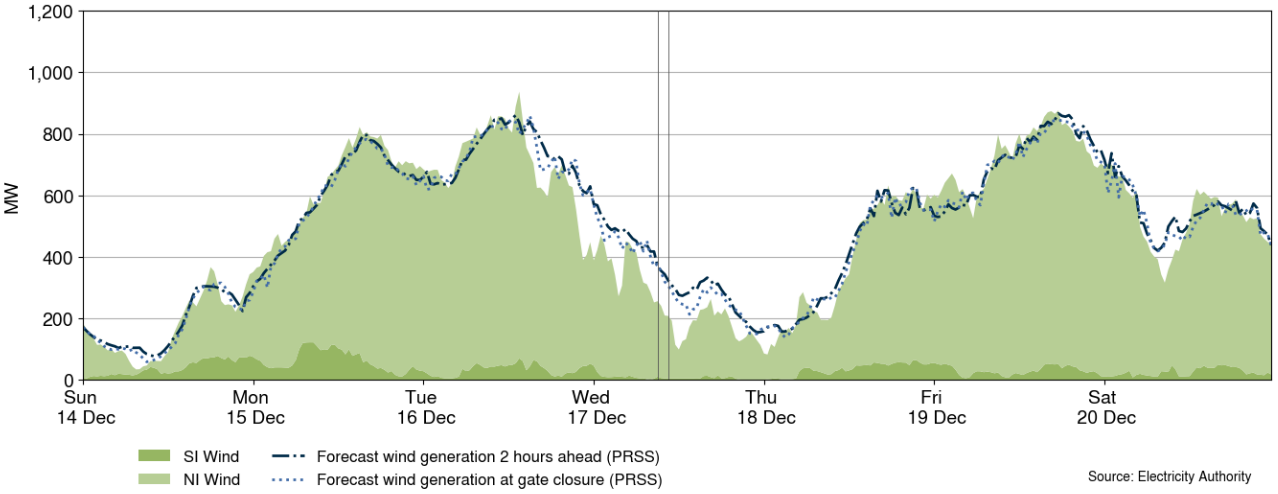


7. Generation

7.1. Figure 9 shows wind generation and forecast from 14-20 December. This week wind generation varied between 34MW and 937MW, with a weekly average of 484MW.

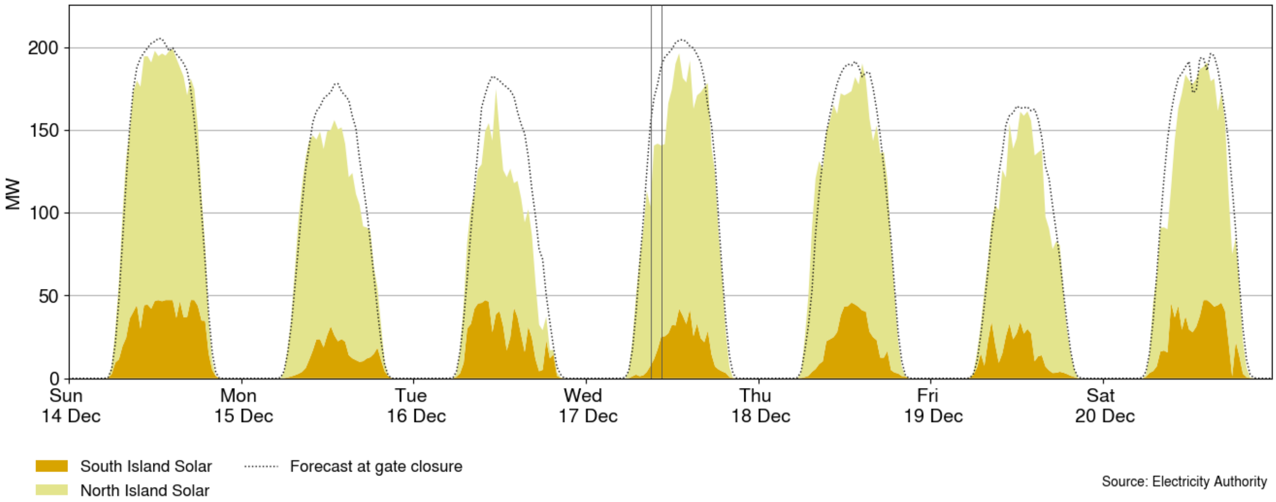
7.2. Wind generation was low on Sunday but increased to above 800MW at times on Monday and Tuesday. From Tuesday afternoon, wind generation fell again, remaining low until Thursday, where wind increased to above 500MW. Wind forecasting errors on Tuesday and Wednesday were an amalgamation of errors across multiple wind farms, with the largest error of 210MW occurring on Tuesday at 10.30pm.

Figure 9: Wind generation and forecast, 14-20 December



7.3. Figure 10 shows grid connected solar generation from 14-20 December. Solar generation reached above 155MW daily, peaking on Sunday at 2.30pm at around 199MW.

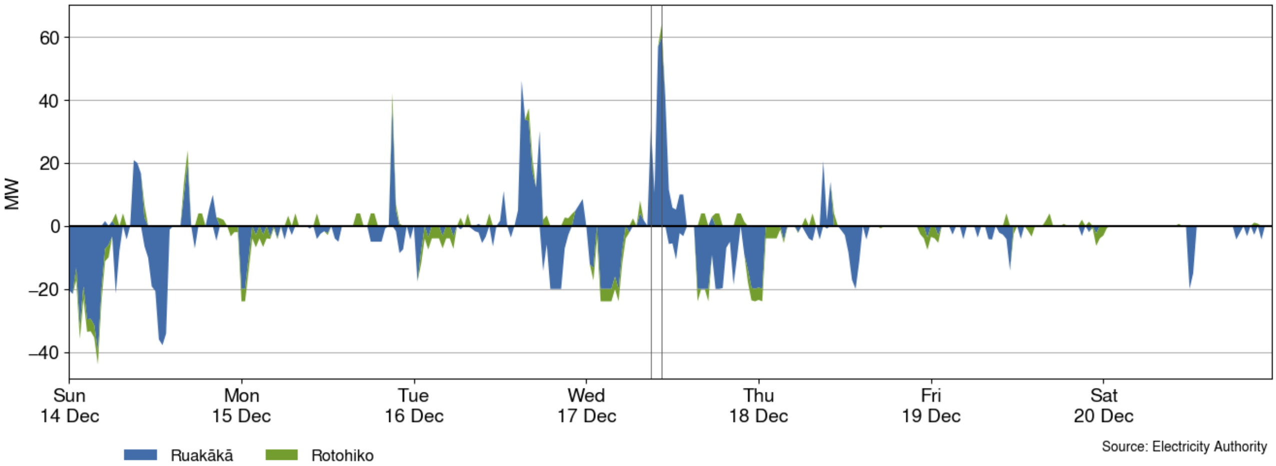
Figure 10: Grid connected solar generation, 14-20 December



7.4. 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.

7.5. This week, the batteries mostly charged overnight or during the day when prices were low. The batteries mostly discharged during either the morning or evening peaks. When daytime prices were low, such as on Friday and Saturday, the batteries discharged less.

Figure 11: Grid scale battery charge and discharge, 14-20 December



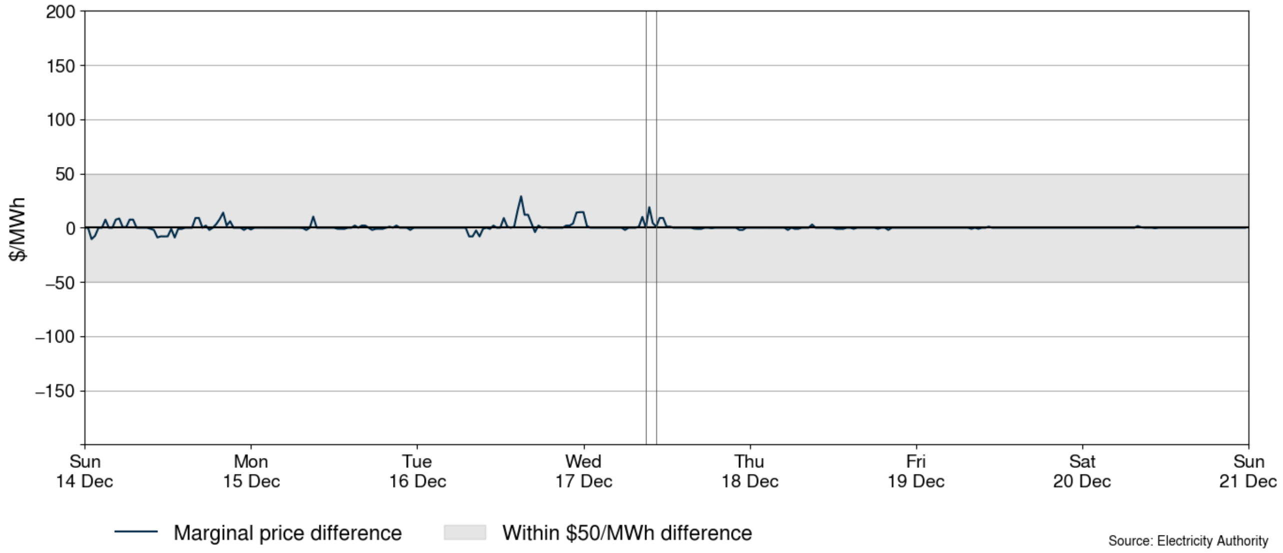
7.6. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time intermittent generation and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing 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 ahead and the RTD intermittent generation and demand forecasts will rarely be the same.

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

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.

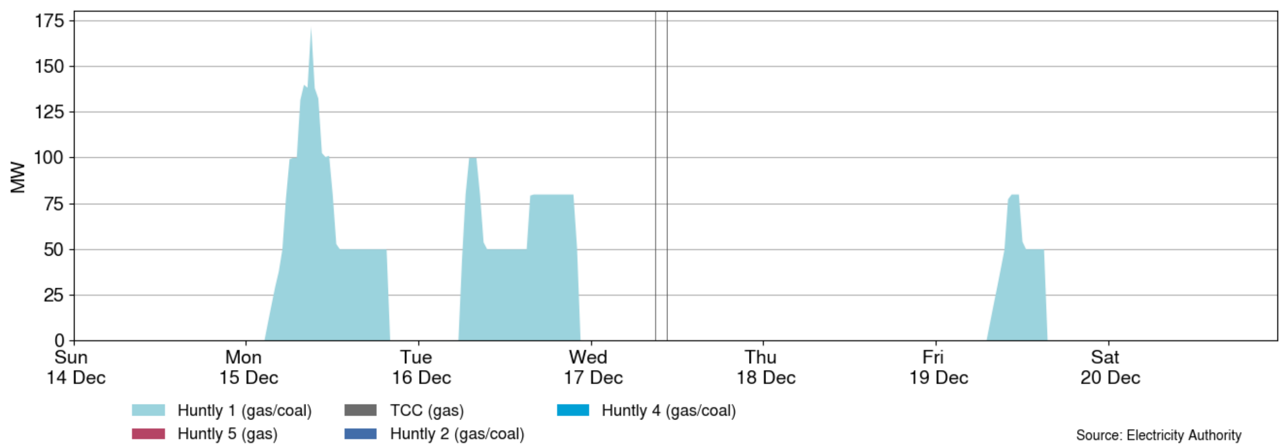
7.7. No trading periods this week had a marginal price difference above or below $50/MWh.

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, 14-20 December



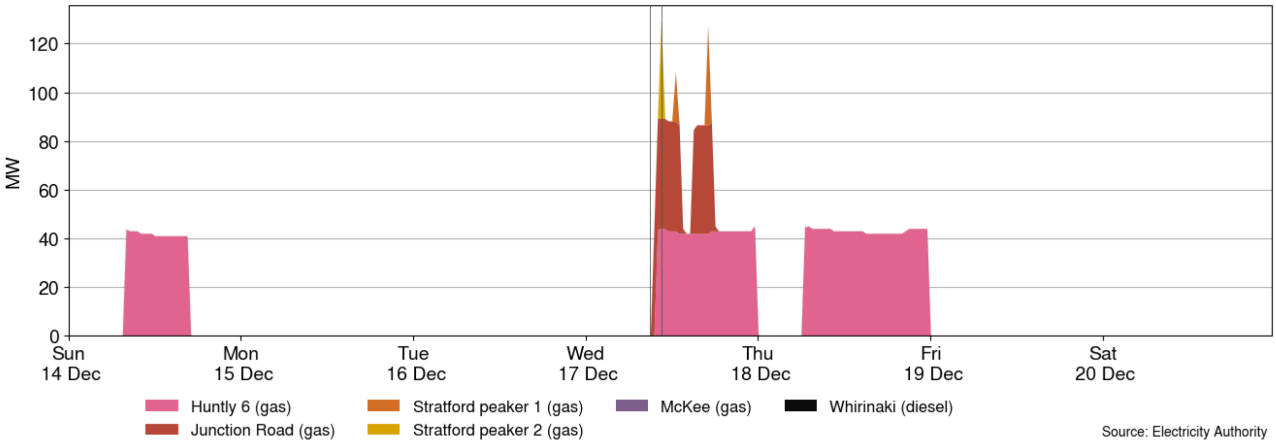
7.8. Figure 13 shows the generation of thermal baseload between 14-20 December. Huntly 1 ran on Monday, Tuesday, and Friday. On Wednesday morning, Huntly 1 was bona fide out at 7.35am and subsequently went on outage until 10.00am on Thursday.

Figure 13: Thermal baseload generation, 14-20 December



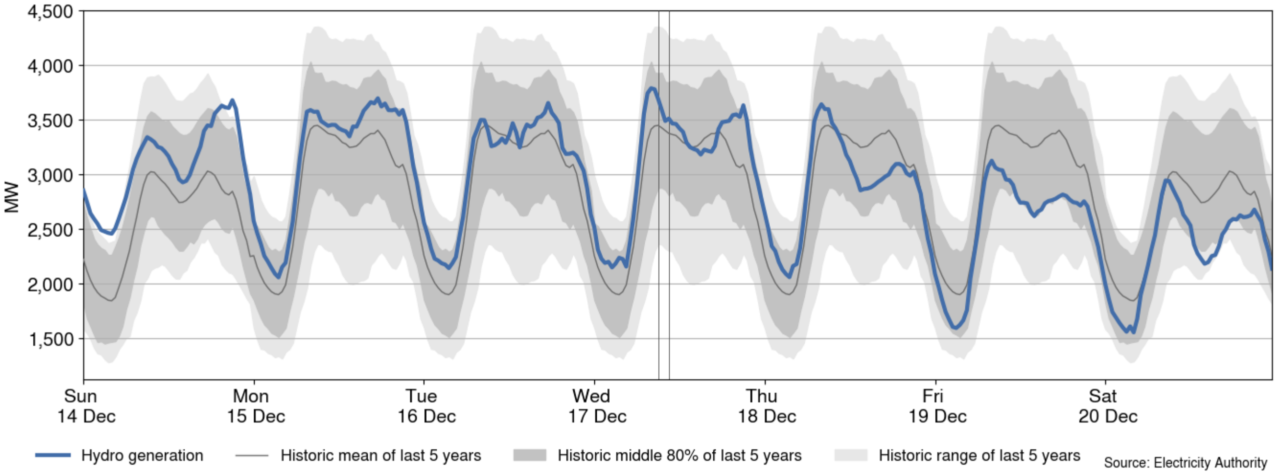
7.9. Figure 14 shows the generation of thermal peaker plants between 14-20 December. Huntly 6 ran on Sunday, Wednesday and Thursday. Junction Road as well as Stratford peakers 1 and 2 also ran on Wednesday, with Stratford peaker 1 running for one trading period either side of an outage between 12.30pm and 5.00pm.

Figure 14: Thermal peaker generation, 14-20 December



7.10. Figure 15 shows hydro generation between 14-20 December. Hydro generation was above the historic mean on Sunday, and above or close to the historic mean between Monday and Thursday morning. From Thursday afternoon onwards, hydro generation was often lower than the historic mean.

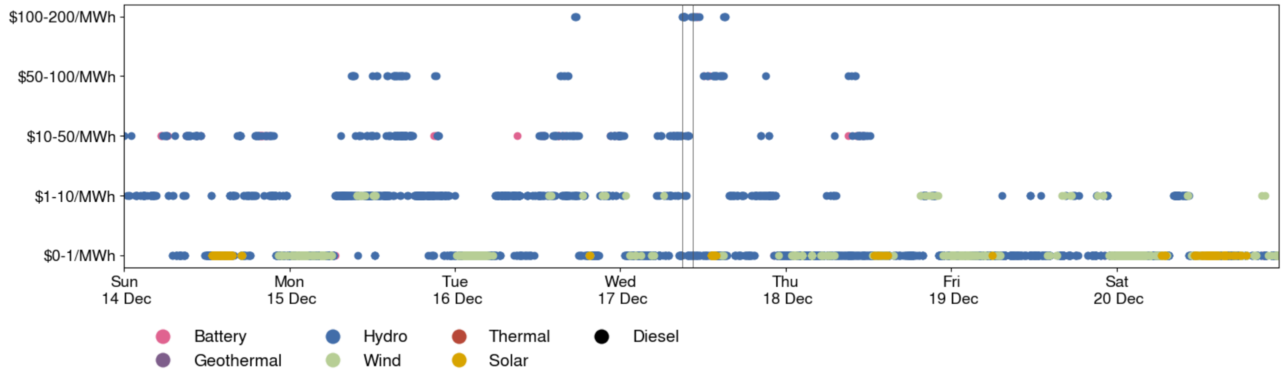
Figure 15: Hydro generation, 14-20 December



7.11. 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.

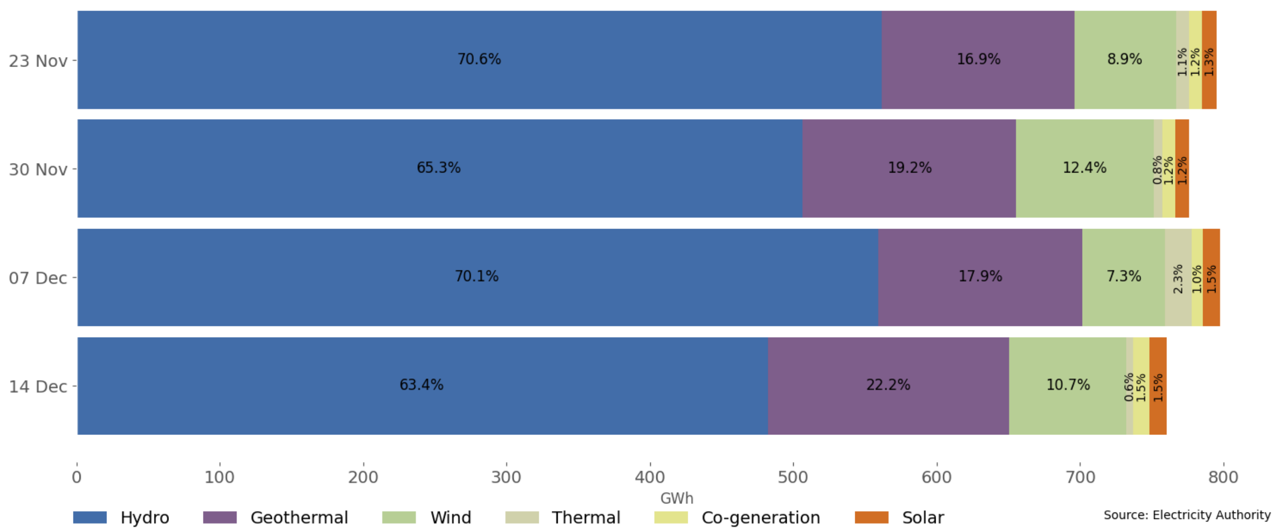
7.12. The highest prices this week were caused by Mercury hydro on Tuesday and Wednesday. The most common technology setting prices this week was hydro generation, with wind generation the second most common. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 14-20 December



7.13. As a percentage of total generation, between 14-20 December, total weekly hydro generation was 63.4%, geothermal 22.2%, wind 10.7%, thermal 0.6%, co-generation 1.5%, and solar (grid connected) 1.5%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 23 November and 20 December



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 14-20 December ranged between ~1,128MW and ~2,801MW. Figure 19 shows the thermal generation capacity outages. Generation outages decreased across the week as several geothermal outages ended.

Figure 18: Total MW loss from generation outages, 14-20 December

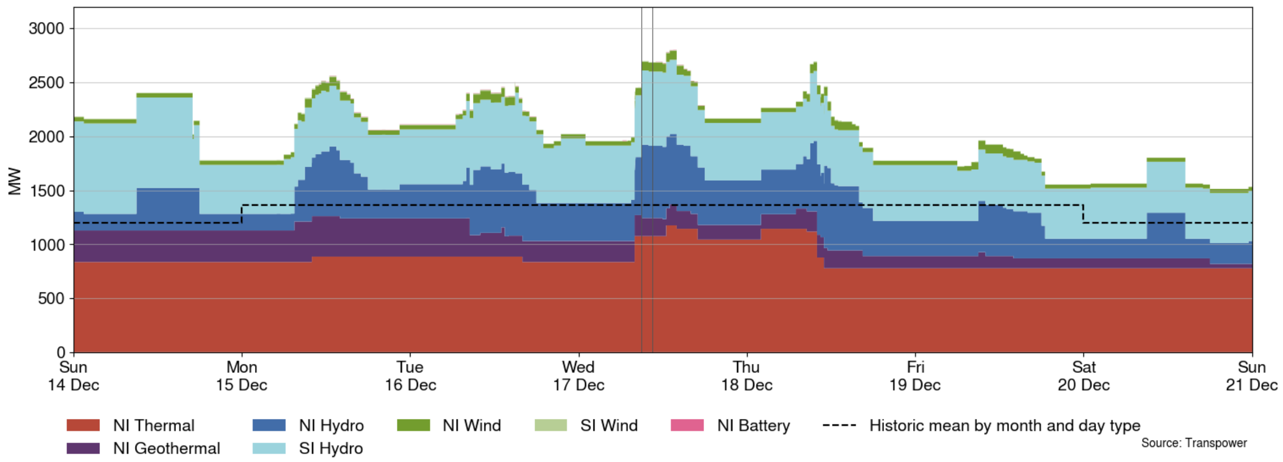
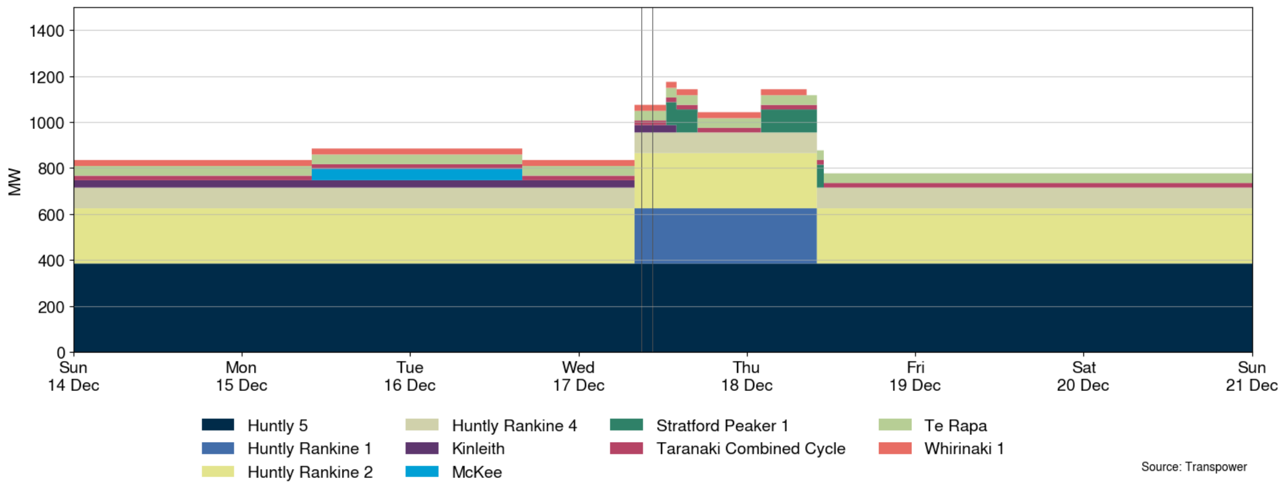


Figure 19: Total MW loss from thermal outages, 14-20 December



8.2. Notable outages include:

Plant	Partial or Full	End Date
Manapōuri unit 5	Full	14 December 2025
Manapōuri unit 7	Full	14 December 2025
Manapōuri unit 6	Full	14 December 2025
Tauhara geothermal	Full	16 December 2025
Huntly 1	Full	18 December 2025
Huntly 5	Full	21 December 2025
Ōhau C	Partial	16 January 2026
Huntly 4	Partial	31 January 2026
Ōhau A	Partial	18 February 2026
Roxburgh unit 5	Full	25 February 2026
Rangipo unit 6	Full	29 March 2026
Huntly 2	Full	28 April 2026

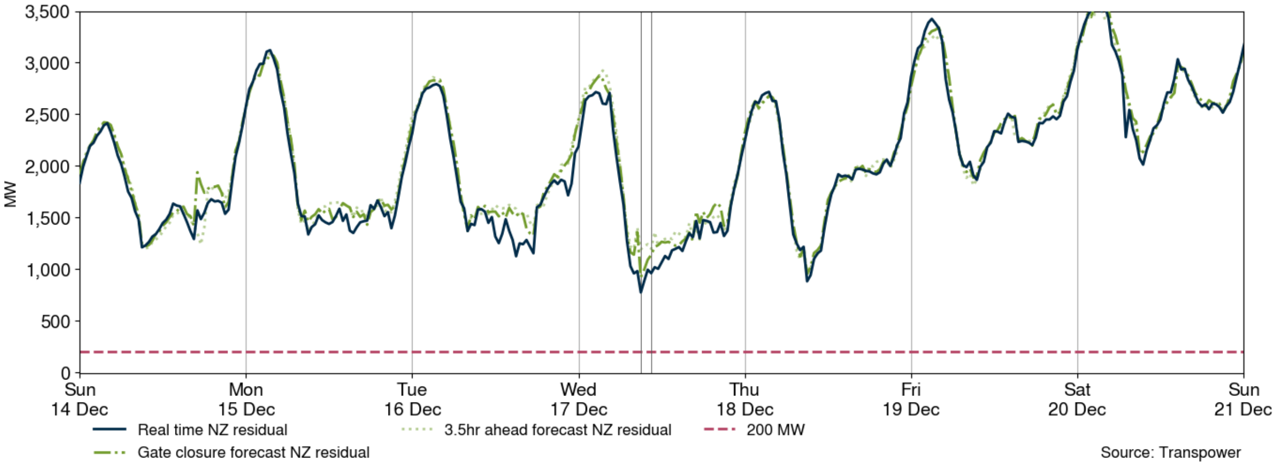
Manapōuri unit 4	Full	12 June 2026

9. Generation balance residuals

9.1. Figure 20 shows the national generation balance residuals between 14-20 December. 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 776MW on Wednesday at 9.00am.

Figure 20: National generation balance residuals, 14-20 December



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 21 December, national controlled storage increased slightly to 101% nominally full and ~139% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (102% full[3]) is above its historic 90th percentile, while Lake Takapō (101% full) is close to its historic 90th percentile. Both lakes have exceeded their storage capacities and are spilling.

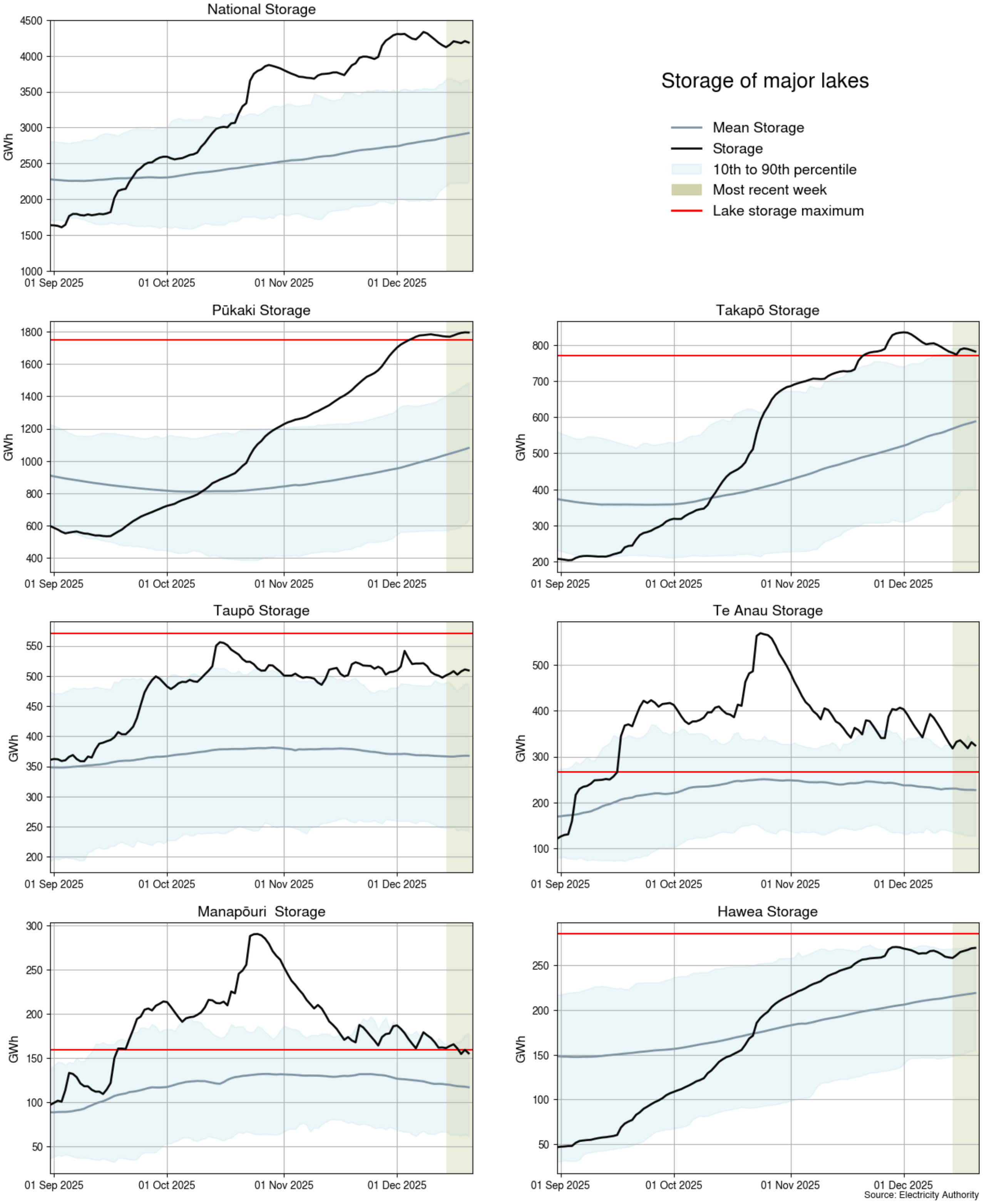
10.4. Storage at Lake Te Anau (118% full) is close to its historic 90th percentile, while Lake Manapōuri (96% full) is below its historic 90th percentile. Lake Te Anau has exceeded its storage capacity.

10.5. Storage at Lake Taupō (89% full) is just above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (94% 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 December 2025. The SRMCs for all thermal fuel types have decreased.

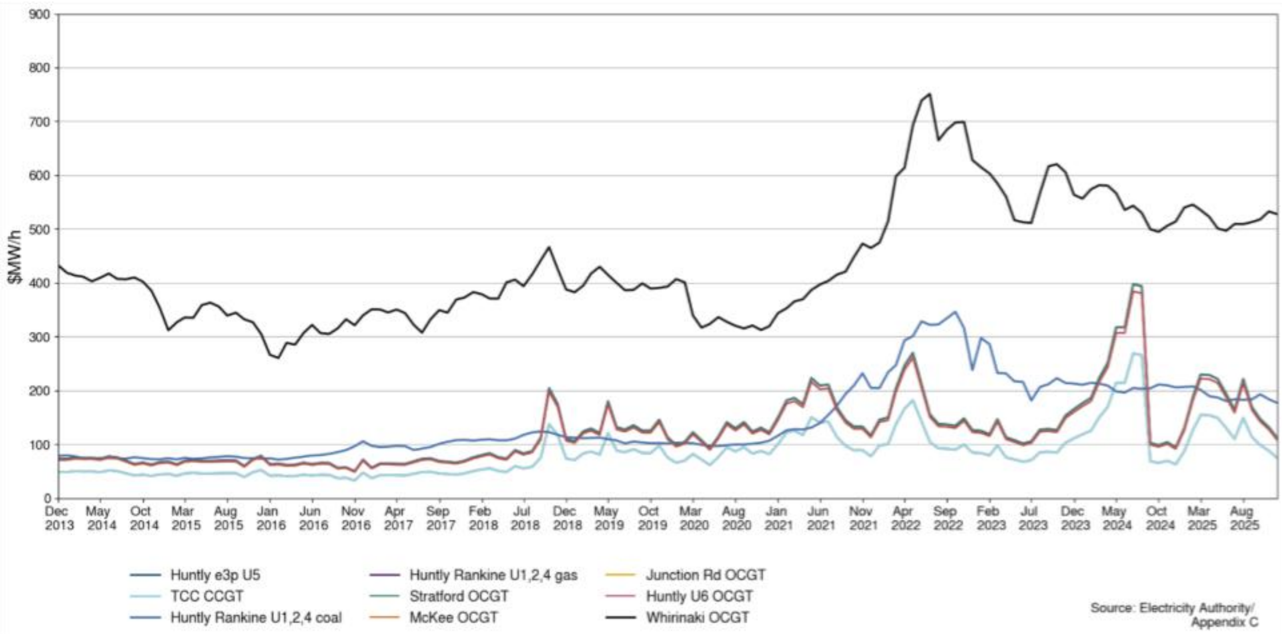
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$177/MWh. The cost of running the Rankines on gas is ~$111/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $74/MWh and $111/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 22: Estimated monthly SRMC for thermal fuels

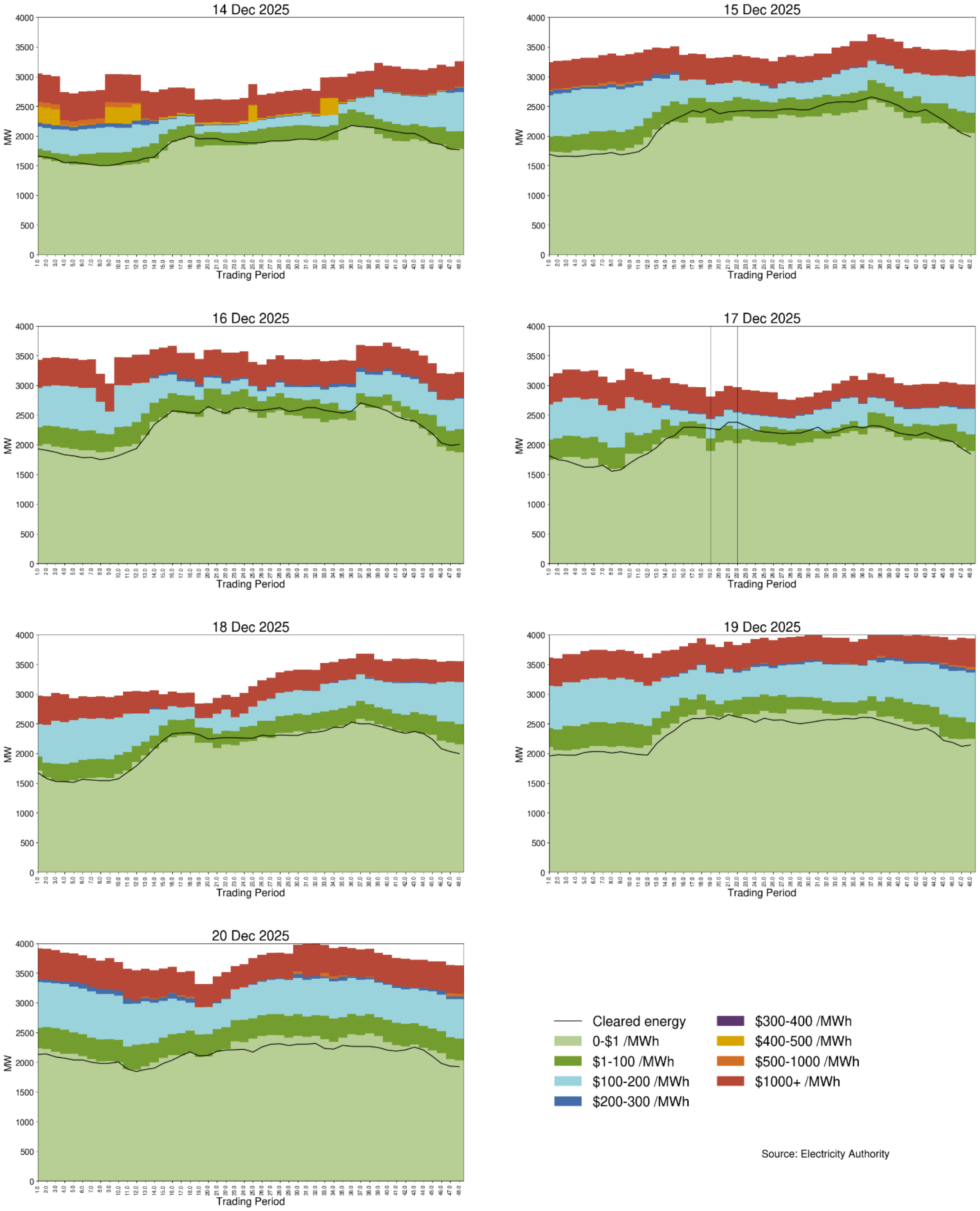


12. Offer behaviour

12.1. Figure 23 and Figure 24 show this week's national daily offer stacks split by the two islands. The black line shows cleared energy, indicating the range of the average final price.

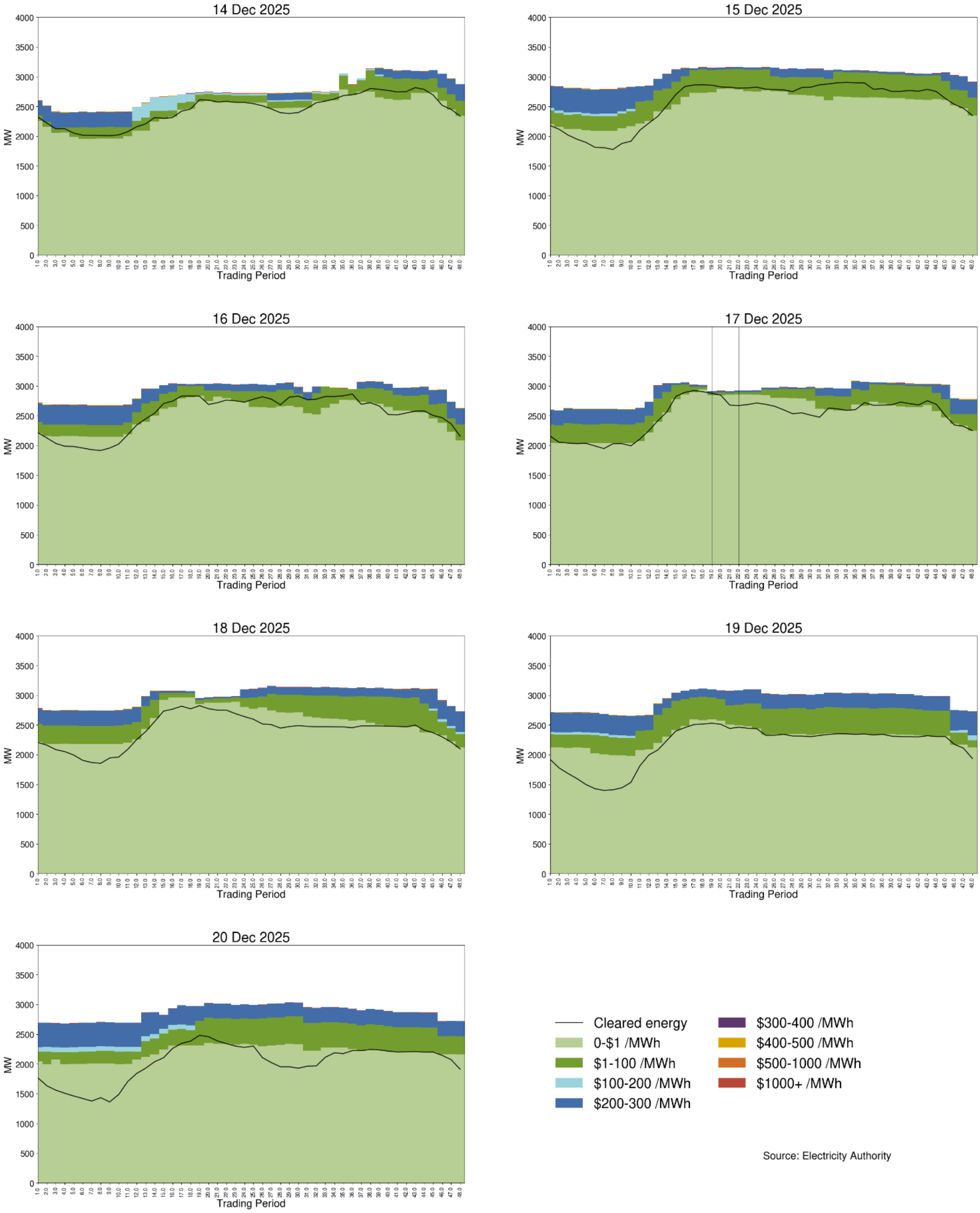
12.2. In the North Island, most offers cleared below $100/MWh every day except Wednesday. On Wednesday, some energy cleared in the higher band between $100-200/MWh at times. The monitoring team is looking further into changes to offers on Wednesday morning.

Figure 23: Daily North Island offer stacks



Source: Electricity Authority

Figure 24: Daily South Island offer stacks



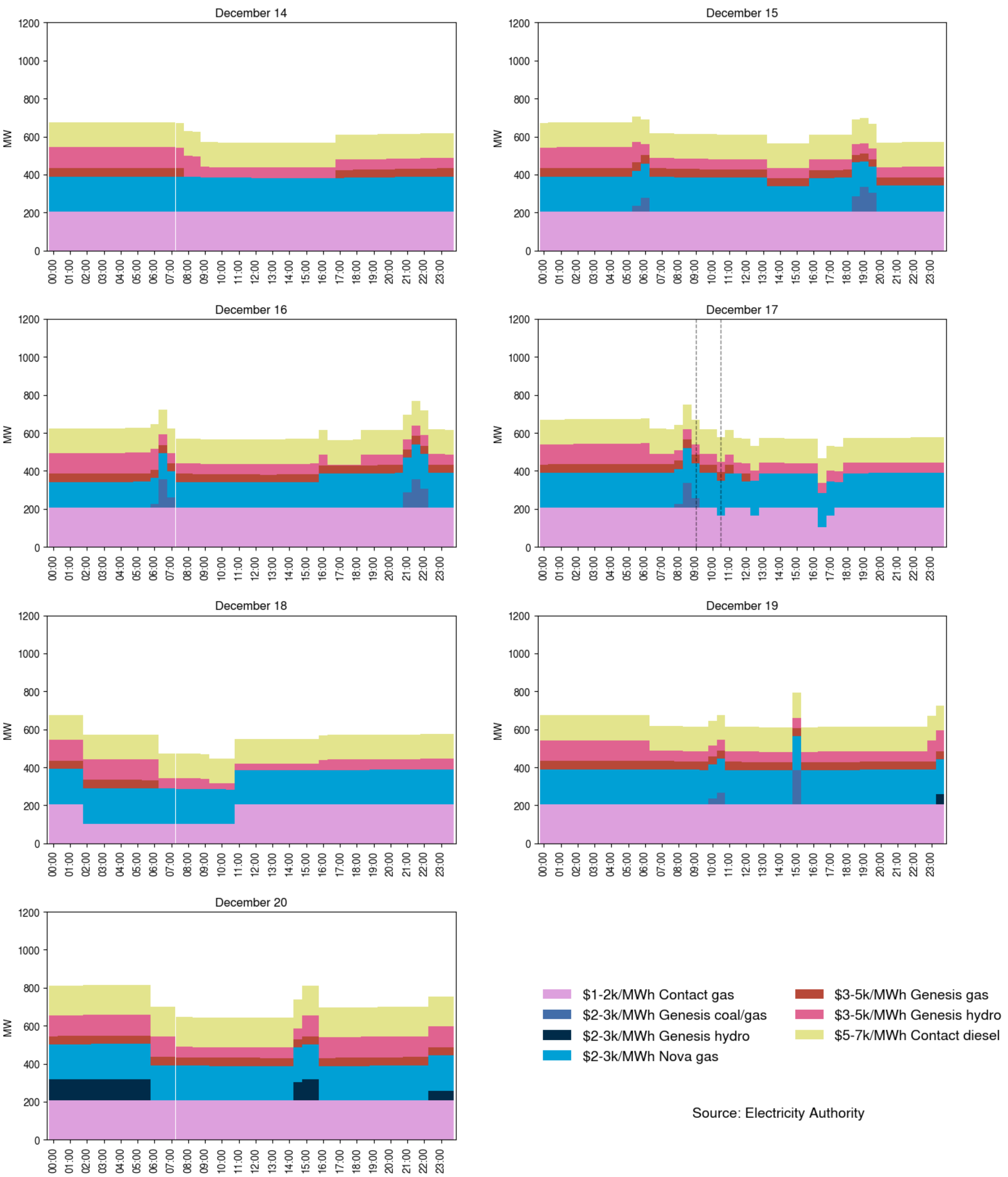
12.3. In the South Island, most offers cleared below $100/MWh. At times, such as trading period 19 on Wednesday, the amount of cleared energy was close to the amount of energy offered.

12.4. Figure 25 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 624MW per trading period was priced above $1,000/MWh this week, which is roughly 12% of the total energy available.

Figure 25: 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
27/11/2025	27	Further analysis	Contact	Roxburgh	Offers
8/12/2025-11/12/2025	Several	Further analysis	Contact/Manawa	Coleridge, Cobb, and Matahina	Offers
10/12/2025-20/12/2025	Several	Further analysis	Genesis	Tekapo	Offers
9/12/2025	36-48	Further analysis	Genesis	Huntly	Offers
17/12/2025	19	Further analysis	Mercury	Waikato	Offers