15 December 2025

Trading conduct report 7-13 December 2025

Market monitoring weekly report

Trading conduct report 7-13 December 2025

1. Overview

1.1. This week the average spot price increased by $32/MWh to $39/MWh. HVDC flows were entirely northward throughout the week and were at or near capacity at times. The proportion of hydro and thermal generation increased this week, while the proportion of wind and geothermal declined. National hydro storage decreased slightly to 99% nominally full and ~141% of the historical average. However, this includes storage at Manapōuri, Te Anau, Takapō and Pūkaki 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 7-13 December:

(a) The average spot price for the week was $39/MWh, an increase of around $32/MWh compared to the previous week.

(b) 95% of prices fell between $0.02/MWh and $226/MWh.

2.3. Spot prices spiked above $200/MWh several times throughout the week between Monday and Thursday. Prices on Friday, Saturday, and Sunday were very low.

2.4. On Monday, prices were above $200/MWh between 3.30pm and 6.30pm, reaching $942/MWh and $889/MWh at Ōtāhuhu at 4.30pm and 5.30pm respectively. During this time, the Benmore price remained below $3/MWh. Several factors contributed to high prices during this time:

(a) North Island reserve prices were high with the HVDC running northwards near its capacity.

(b) Demand was higher than forecast during this period, peaking at 110MW over forecast.

(c) Wind was falling during this period and up to 105MW lower than forecast at times.

(d) Some large station outages remained active including at Huntly 1 and 5, both Stratford peakers, and Tauhara geothermal.

(e) Wairakei ring transmission outages were constraining generation in the central North Island.

2.5. A number of other high prices occurred during the week, mostly due to wind and/or demand forecast errors. Additionally, wind was generally low and the HVDC close to northward capacity during these times.

(a) On Tuesday between 5.30pm and 7.30pm, Ōtāhuhu prices reached above $150/MWh and Benmore prices reached above $120/MWh.

(b) On Wednesday, price spikes occurred between 11.30am and 12.30pm and at 9.00pm where Ōtāhuhu prices reached above $200/MWh.

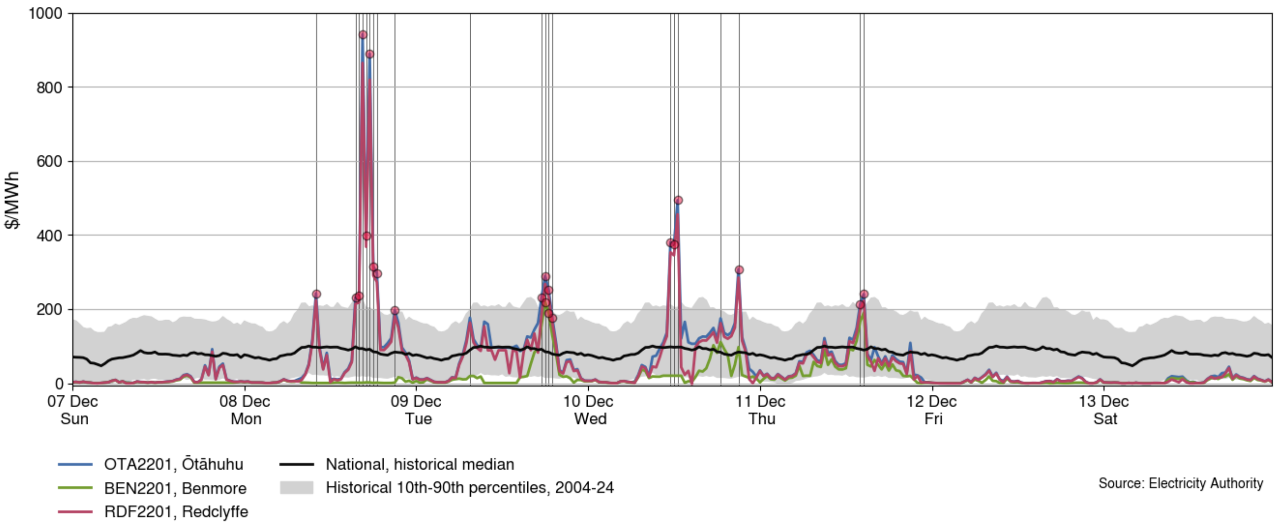
(c) On Thursday between 2.00pm-2.30pm prices reached above $200/MWh at Ōtāhuhu and above $150/MWh at Benmore.

2.6. Prices between the North and South Islands were separated at times between Monday and Wednesday. South Island prices did rise at times on Tuesday, Wednesday, and Thursday. The monitoring team is looking further into these prices.

2.7. Redclyffe and nearby nodes observed low prices and price separation at times on Tuesday and Wednesday due to constraints on Wairakei ring generation. Negative prices also occurred on Thursday at Atiamuri due to these constraints.

2.8. Figure 1 shows the wholesale spot prices at Benmore, Ōtāhuhu and Redclyffe 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.

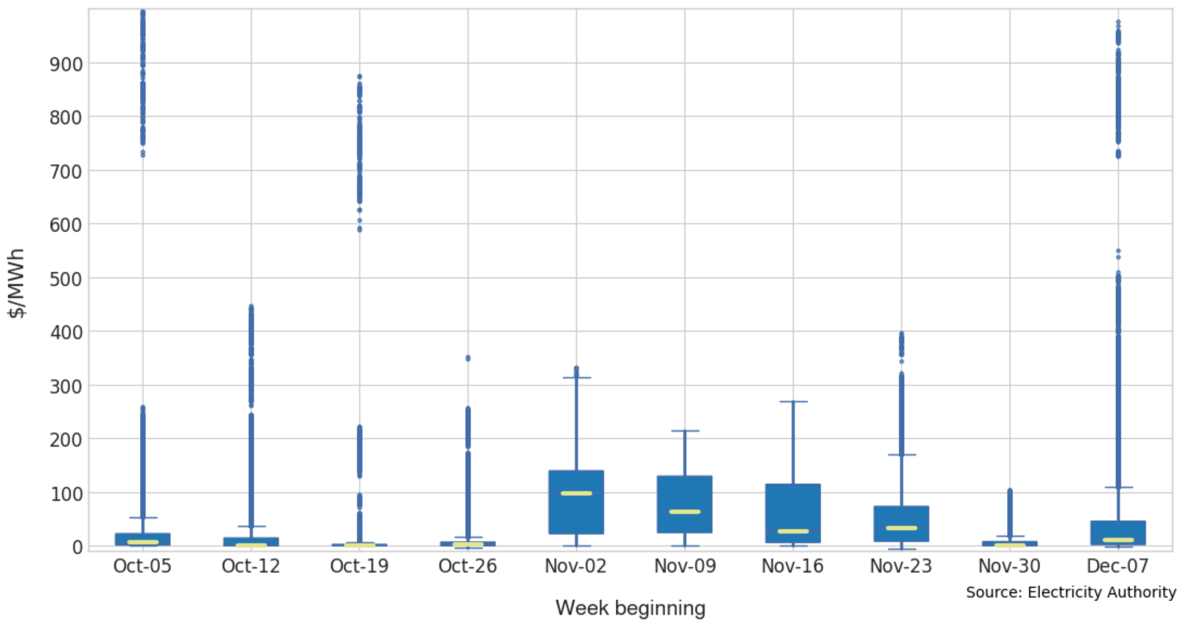
Figure 1: Wholesale spot prices at Benmore, Ōtāhuhu and Redclyffe, 7-13 December



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 distribution of spot prices this week was wider compared to last week. The median price was $10/MWh and most prices (middle 50%) fell between $2/MWh and $46/MWh.

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



3. Reserve prices

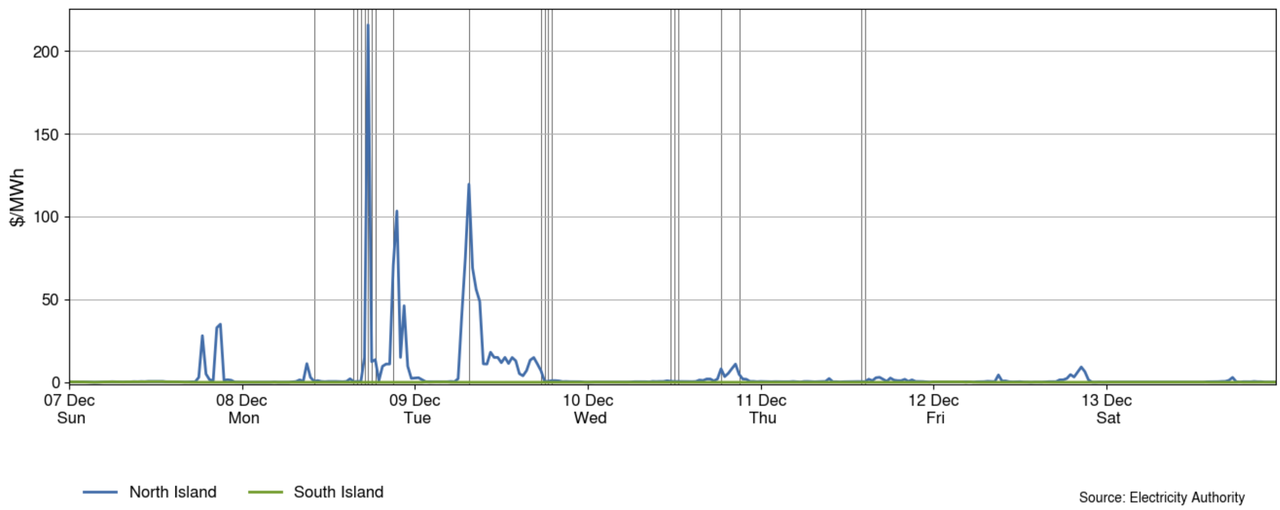
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $20/MWh with a few price spikes.

3.2. A significant North Island FIR price spike occurred on Monday at 5.30pm, with prices reaching around $216/MWh. North Island FIR prices also reached around $103/MWh at 9.30pm. The HVDC was the risk setter for the North Island during these high FIR price spikes.

3.3. Another North Island FIR price spike occurred on Tuesday at 7:30am, with prices reaching around $120/MWh. The HVDC was again the North Island risk setter at this time.

3.4. Additionally, Ruakākā was not offering any FIR from 5.00pm on Monday to 6.00pm on Tuesday.

Figure 3: Fast instantaneous reserve price by trading period and island, 7-13 December



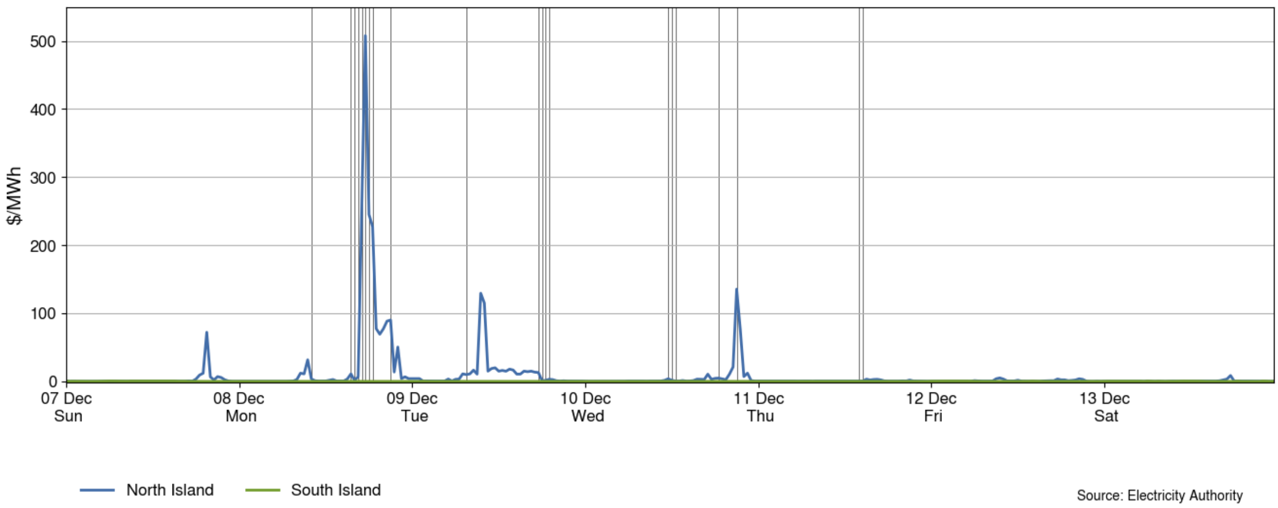
3.5. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $20/MWh with a few spikes.

3.6. On Monday, North Island SIR prices were over $200/MWh between 5.00pm and 6.30pm, peaking at 5.30pm at $508/MWh. The HVDC was the risk setter for the North Island during this period.

3.7. Additionally, North Island SIR prices spiked above $100/MWh on Tuesday between 9.30pm and 10.00pm and on Wednesday at 9.00pm. The HVDC was again the North Island risk setter at these times.

3.8. Ruakākā was also not offering any SIR from 5.00pm on Monday to 6.00pm on Tuesday.

Figure 4: Sustained instantaneous reserve by trading period and island, 7-13 December



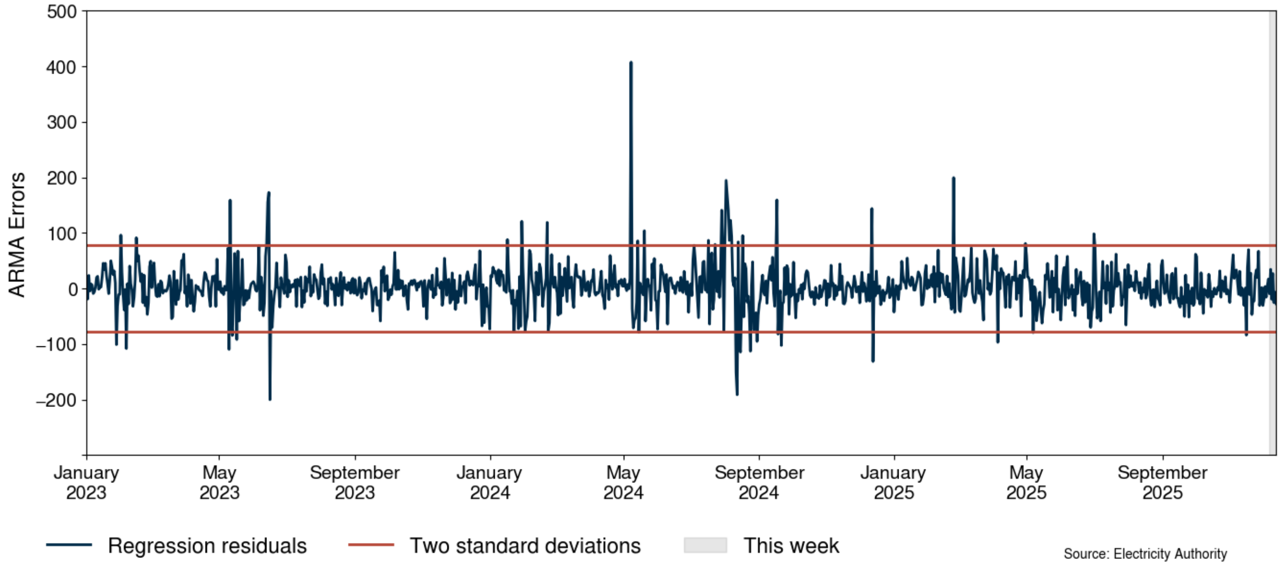
4. Regression residuals

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 - 13 December 2025

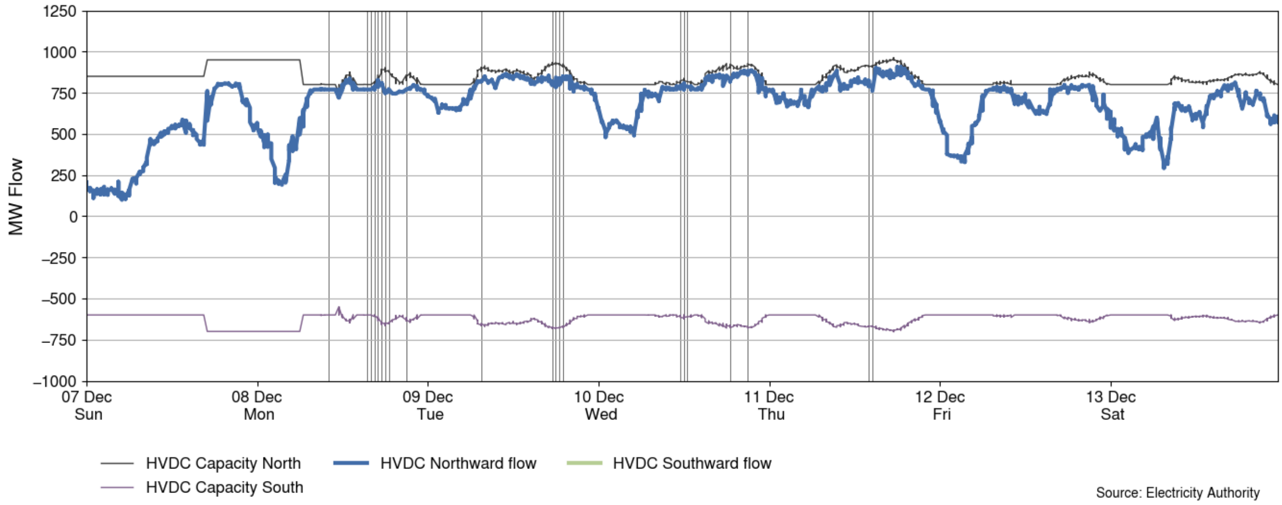


5. HVDC

5.1. Figure 6 shows the HVDC flow between 7-13 December. HVDC[1] flows were entirely northward this week due to high hydro generation in the South Island.

5.2. The highest northward flow occurred at 6.30pm on Thursday with a flow of around 909MW. HVDC northward flows were to their capacity limits at times on Monday through to Friday. The HVDC capacity is currently lower due to equipment outages.

Figure 6: HVDC flow and capacity, 7-13 December



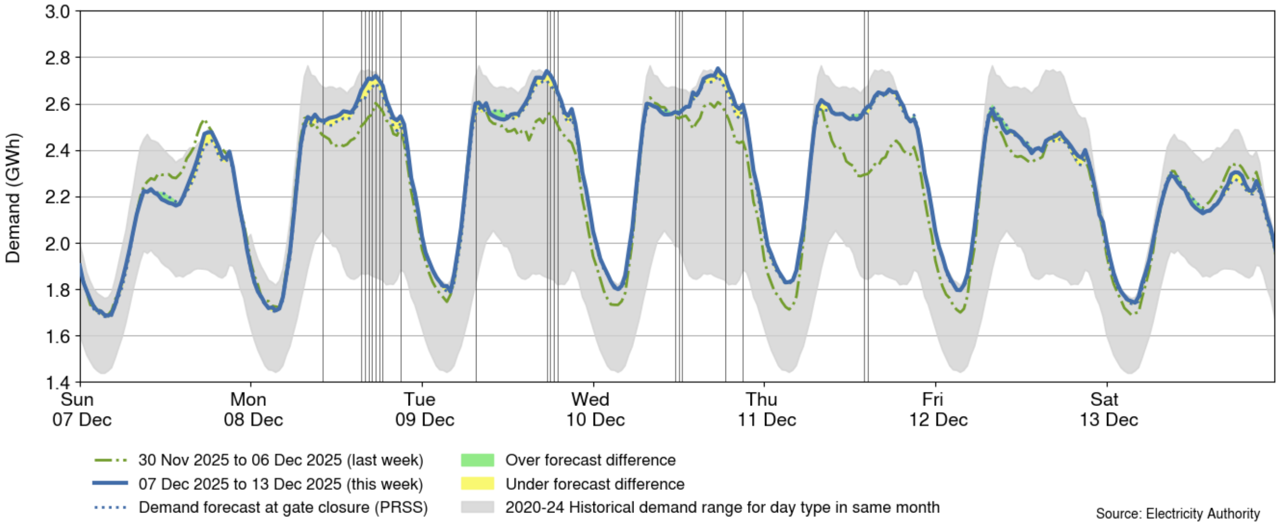
[1] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these being the one that determines the required quantity of instantaneous reserve. 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.

6. Demand

6.1. Figure 7 shows national demand between 7-13 December, compared to the historic range and the demand of the previous week.

6.2. Demand was higher compared to last week and often higher than forecast between Monday and Thursday, likely due to warm temperatures. Several evening peaks this week saw demand close to or higher than the historical demand range. The highest demand of the week was around 2.75GWh at 5.30pm on Wednesday.

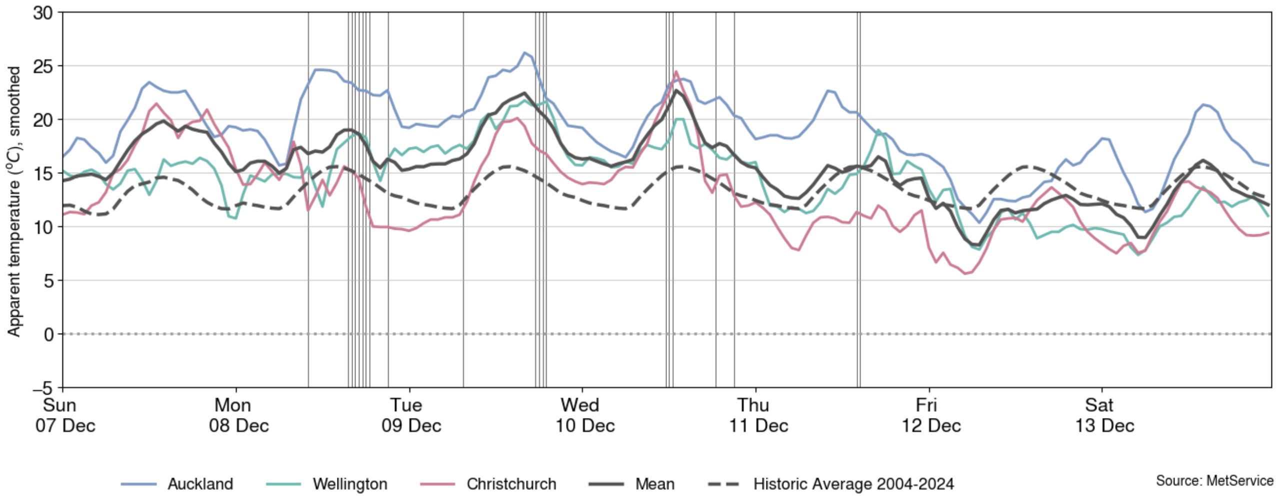
Figure 7: National demand, 7-13 December compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 7-13 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 26°C in Auckland, 7°C to 22°C in Wellington, and 4°C to 25°C in Christchurch. Auckland temperatures were highest on Monday and Tuesday.

Figure 8: Temperatures across main centres, 7-13 December

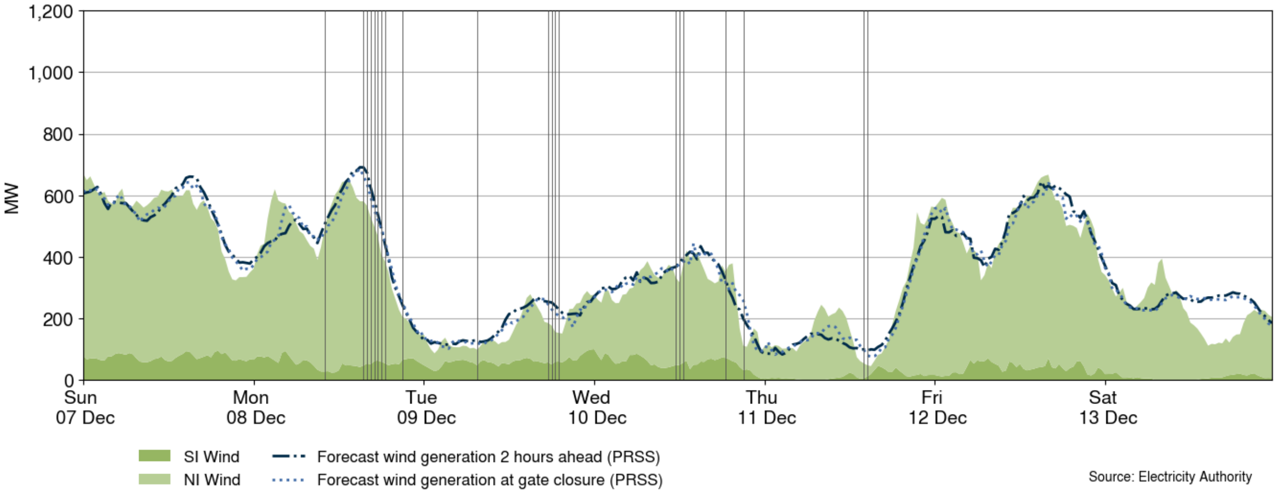


7. Generation

7.1. Figure 9 shows wind generation and forecast from 7-13 December. This week wind generation varied between 45MW and 670MW, with a weekly average of 344MW. Wind generation declined steeply on Monday evening to below 200MW and remained low until Friday.

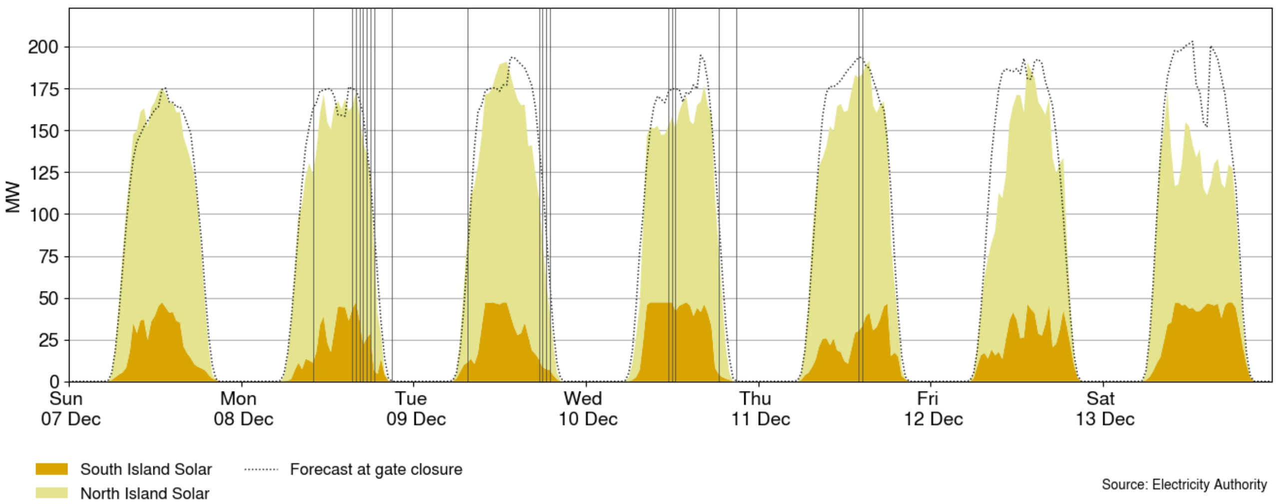
7.2. Saturday saw declining levels of wind return, however. The wind forecasting errors on Saturday were an amalgamation of errors across multiple wind farms.

Figure 9: Wind generation and forecast, 7-13 December



7.3. Figure 10 shows grid connected solar generation from 7-13 December. Solar generation reached above 170MW daily, peaking on Thursday at 3.30pm at around 192MW.

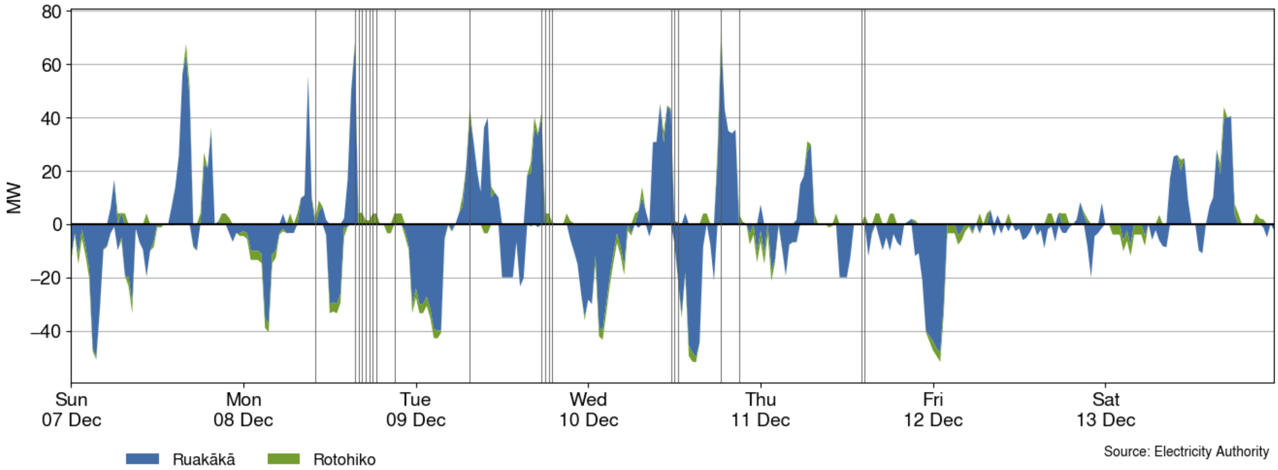
Figure 10: Grid connected solar generation, 7-13 December



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 when prices were low and also at times during the day after the morning peak. The batteries mostly discharged during the morning and evening peaks. When daytime prices were low, such as on Friday, the batteries discharged less.

Figure 11: Grid scale battery charge and discharge, 7-13 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 wind 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 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.

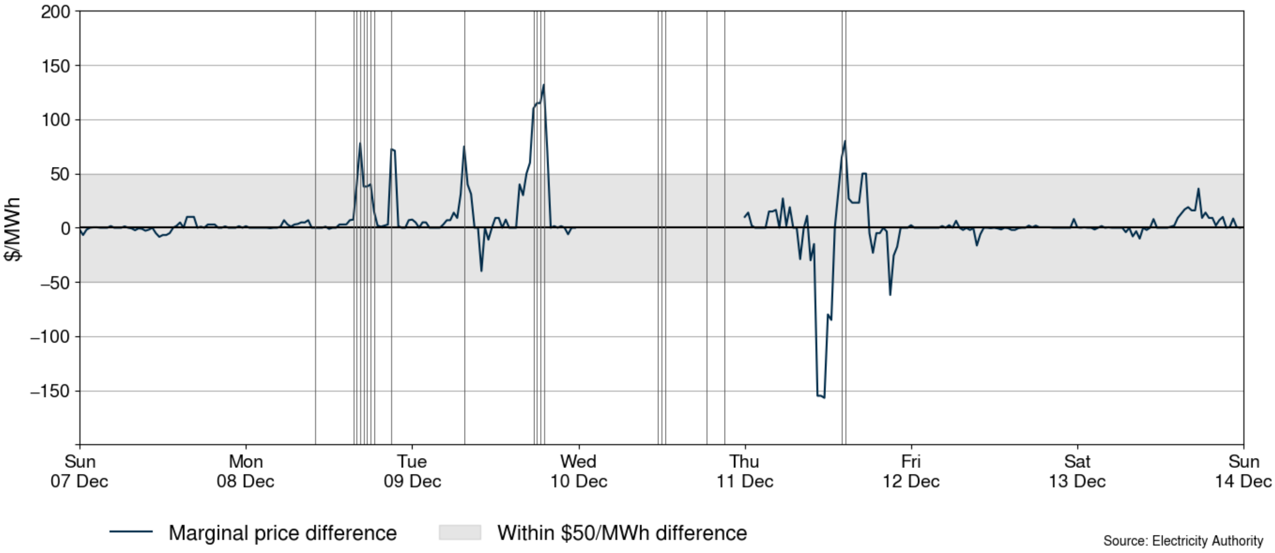
7.7. There were several trading periods with a positive marginal price difference above $50/MWh this week. The largest positive difference of $132/MWh occurred on Tuesday at 7.00pm. Demand was 13GWh higher than forecast, and wind was 57MW lower than forecast at this time.

7.8. The largest negative difference of $157/MWh occurred on Thursday at 11.30am. At this time, wind was 71MW higher than forecast.

7.9. Note that data is missing for Wednesday 10 December.

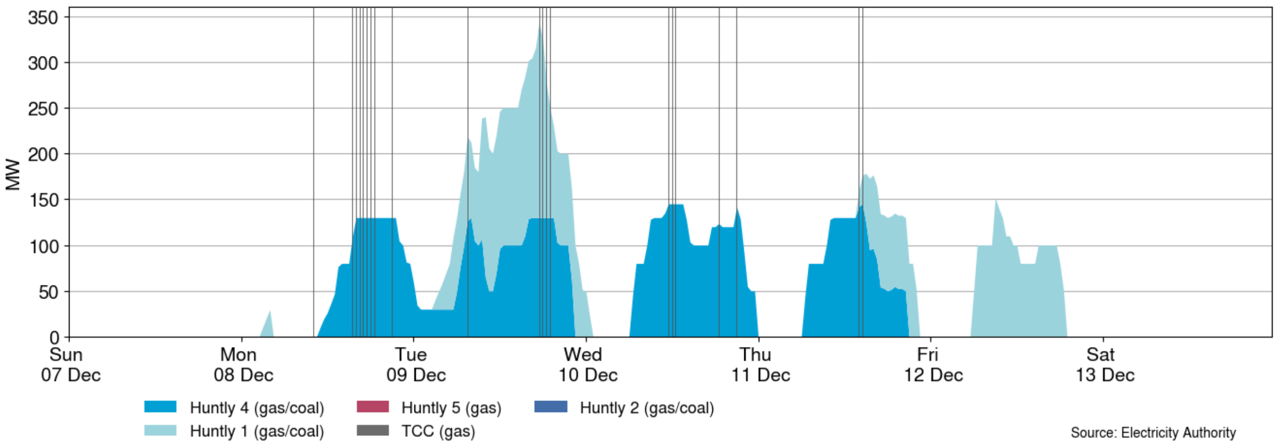
[2] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

Figure 12: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 7-13 December



7.10. Figure 13 shows the generation of thermal baseload between 7-13 December. Huntly 1 tripped off at 4.26am on Monday, before coming back online later in the week to run on Tuesday, Thursday and Friday. Huntly 4 ran between Monday and Thursday, and ran overnight between Monday and Tuesday.

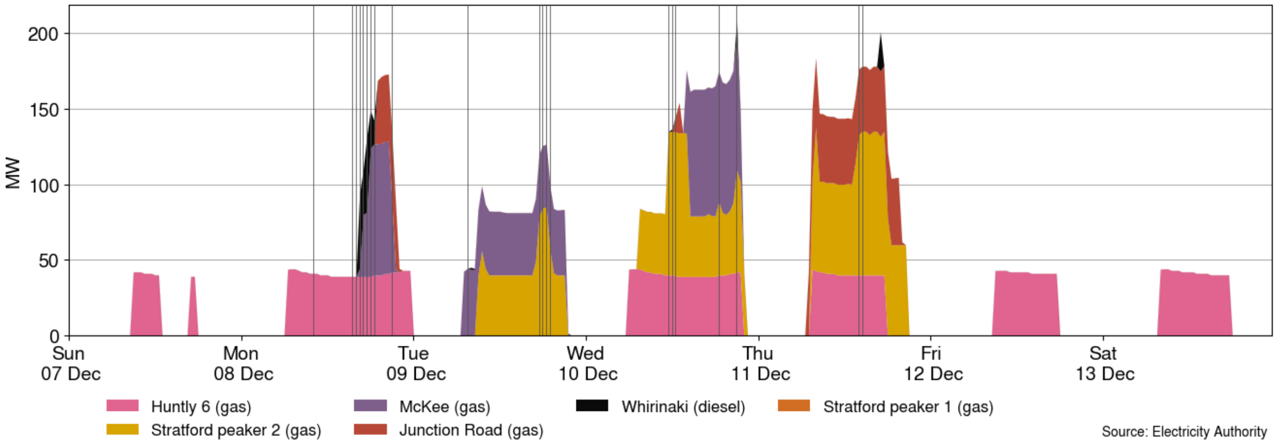
Figure 13: Thermal baseload generation, 7-13 December



7.11. Figure 14 shows the generation of thermal peaker plants between 7-13 December. Huntly 6 ran every day this week except for Tuesday, while Whirinaki ran at times between Monday and Thursday. On Tuesday, Whirinaki generated below 2MW during two Wednesday mid-morning trading periods.

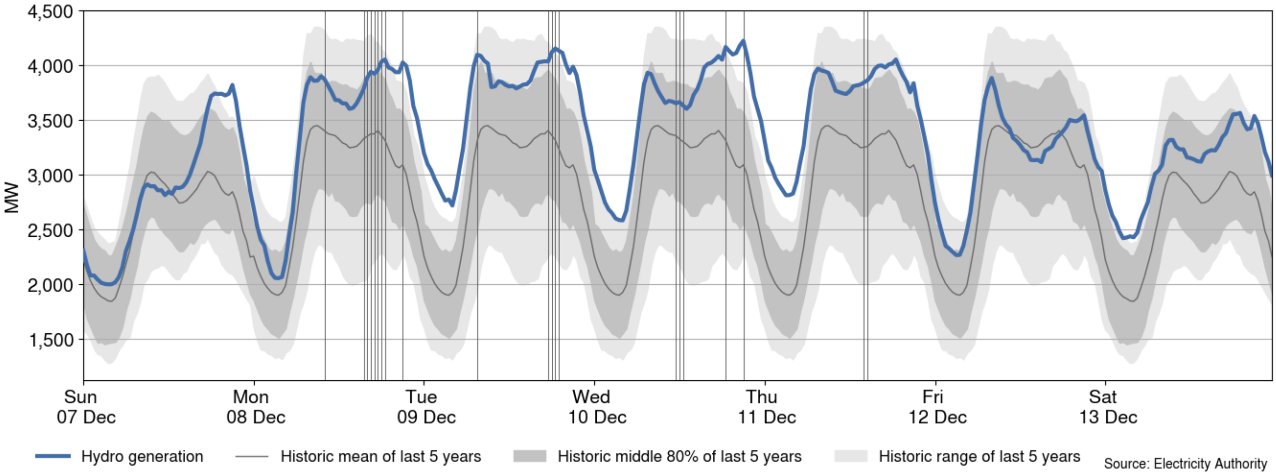
7.12. McKee ran between Monday and Wednesday and Junction Road ran on Monday, Thursday and Friday. Stratford peaker 2 also ran between Tuesday and Thursday.

Figure 14: Thermal peaker generation, 7-13 December



7.13. Figure 15 shows hydro generation between 7-13 December. Hydro generation was high overall this week, especially in the evenings between Sunday and Wednesday, where generation was higher than the historic range of the last 5 years.

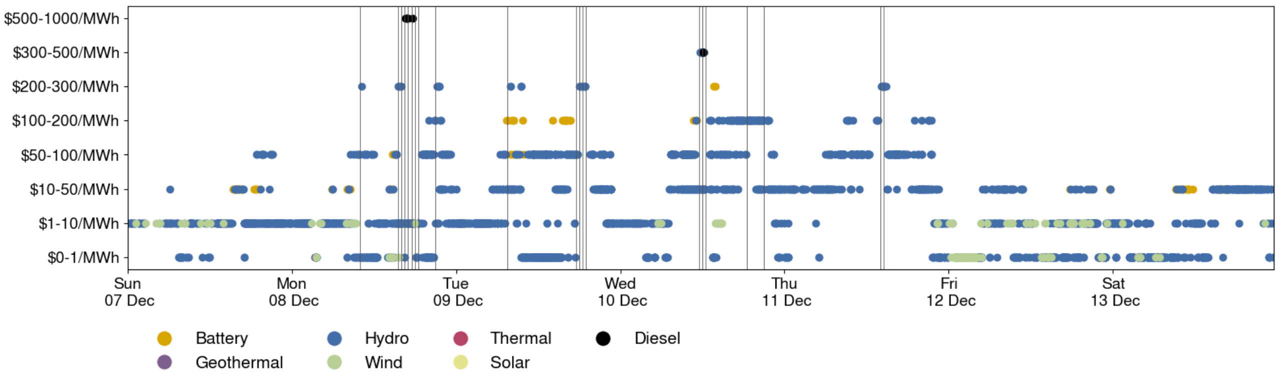
Figure 15: Hydro generation, 7-13 December



7.14. 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.

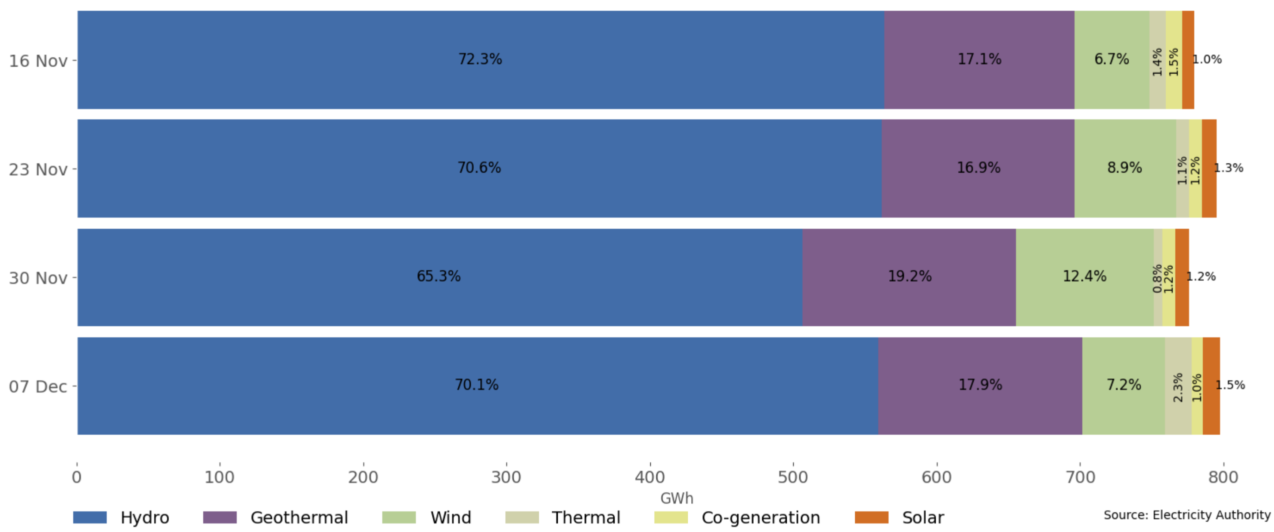
7.15. The highest prices this week were caused by Whirinaki on Monday. The most common technology setting prices this week was hydro generation, with wind generation the second most common. Most marginal prices were between $0-1/MWh.

Figure 16: Prices of marginal generation, 7-13 December



7.16. As a percentage of total generation, between 7-13 December, total weekly hydro generation was 70.1%, geothermal 17.9%, wind 7.2%, thermal 2.3%, co-generation 1.0%, and solar (grid connected) 1.5%, as shown in Figure 17.

Figure 17: Total generation by type as a percentage each week, between 16 November and 13 December



8. Outages

8.1. Figure 18 shows generation capacity on outage. Total capacity on outage between 7-13 December ranged between ~1,764 and ~3,051MW. Figure 19 shows the thermal generation capacity outages.

Figure 18: Total MW loss from generation outages, 7-13 December

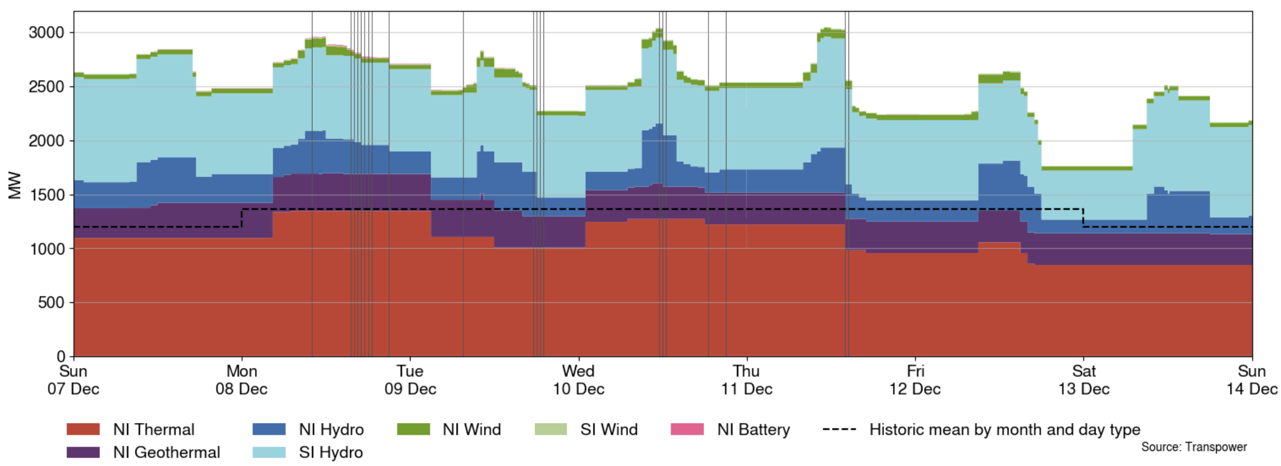
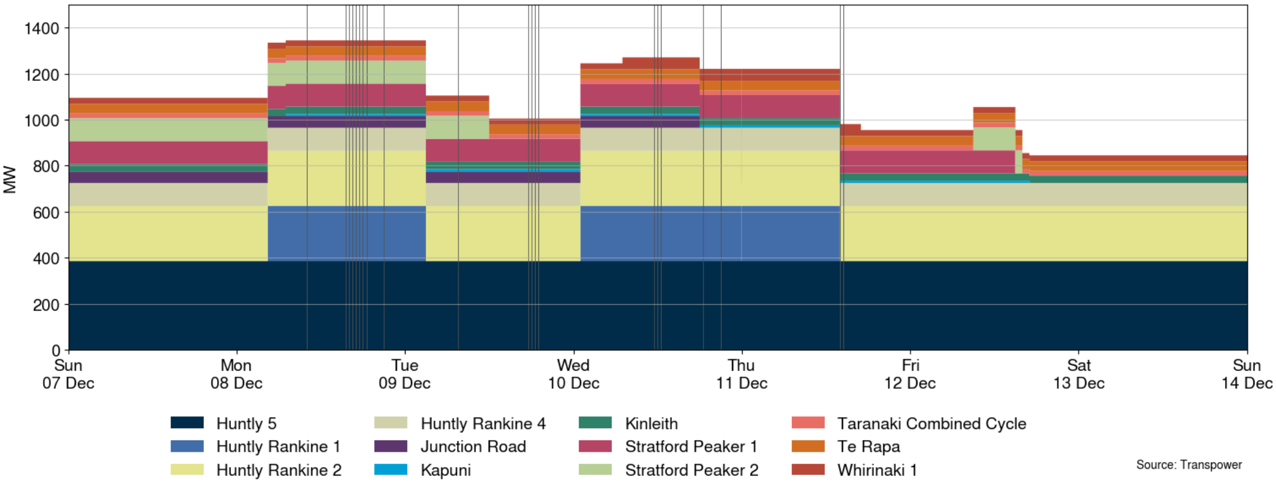


Figure 19: Total MW loss from thermal outages, 7-13 December



8.2. Notable outages include:

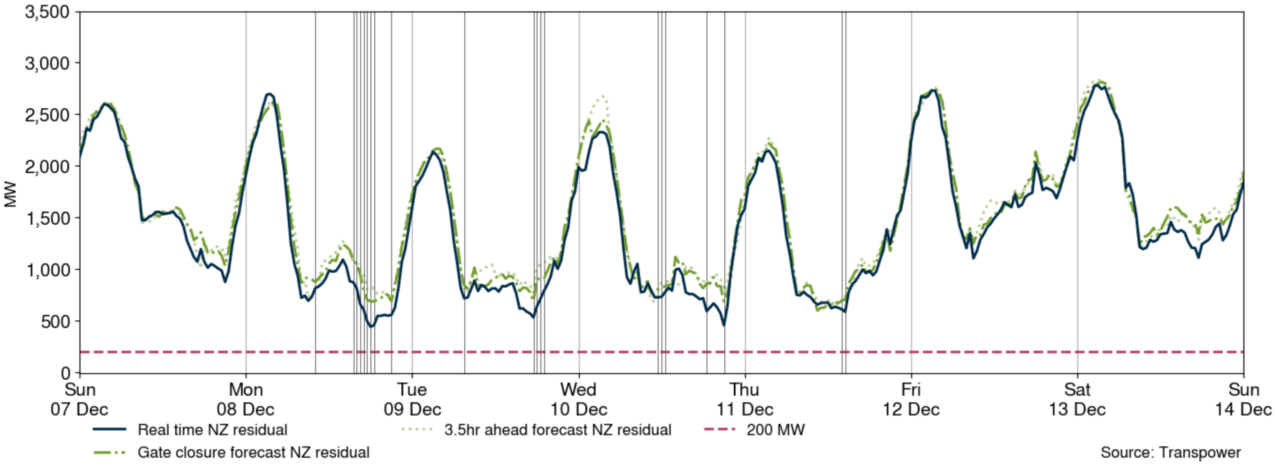
Plant	Partial or Full	End Date
Ōhau Station	Full	7 December 2025
Stratford Peaker 2	Full	9 December 2025
Huntly 1	Full	11 December 2025
Benmore unit 3	Full	12 December 2025
Stratford Peaker 1	Full	12 December 2025
Manapōuri unit 5	Full	14 December 2025
Manapōuri unit 7	Full	14 December 2025
Manapōuri unit 6	Full	14 December 2025
Tauhara geothermal	Full	16 December 2025
Huntly 4	Partial	17 December 2025
Huntly 5	Full	21 December 2025
Ōhau C	Partial	16 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 7-13 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 443MW on Monday at 6.00pm.

Figure 20: National generation balance residuals, 7-13 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 14 December, national controlled storage decreased slightly to 99% nominally full and ~141% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (101% 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.

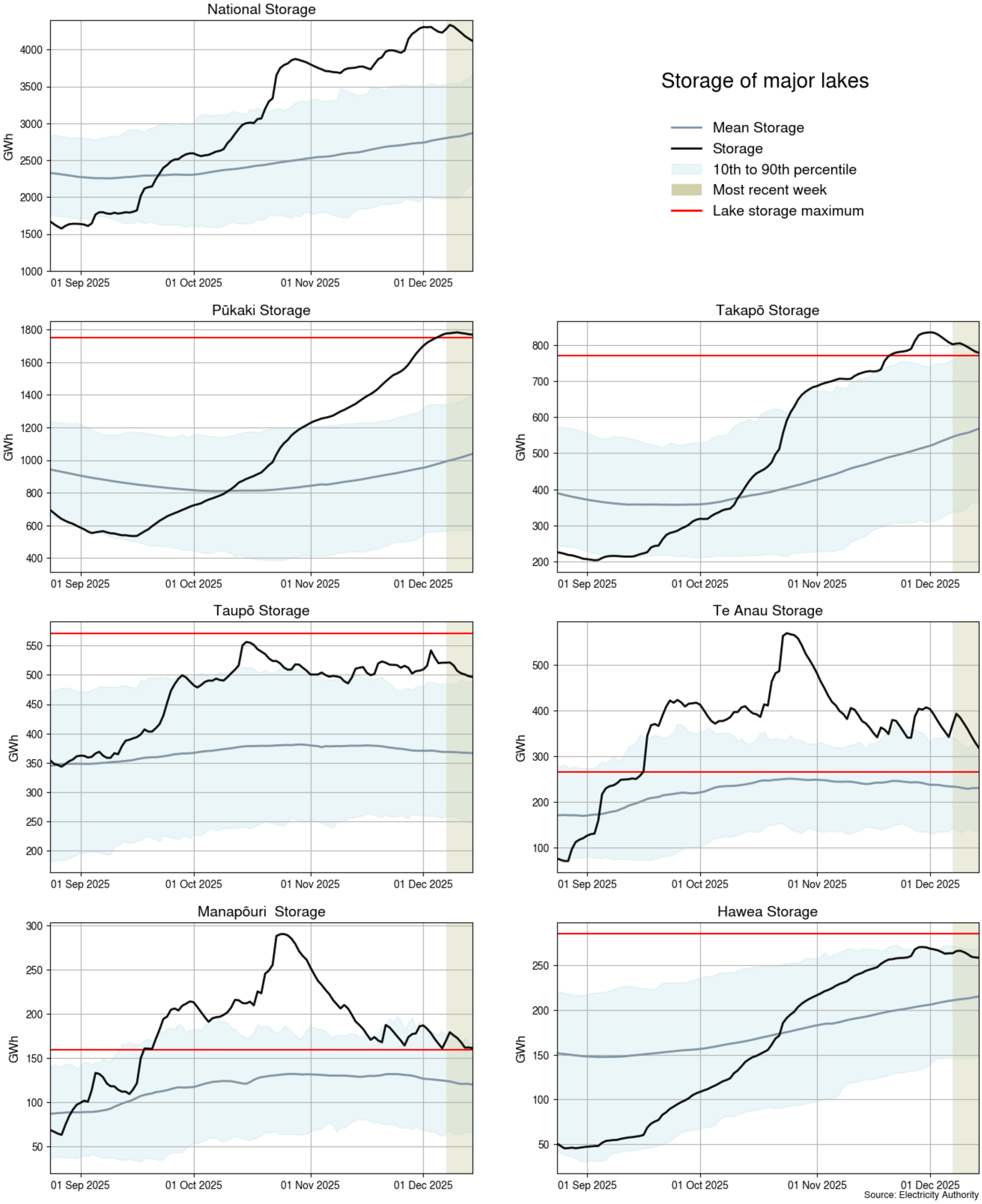
10.4. Storage at Lake Te Anau (120% full) is close to its historic 90th percentile, while Lake Manapōuri (103% full) is below its historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (87% full) is close to its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (91% full) is just below 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.

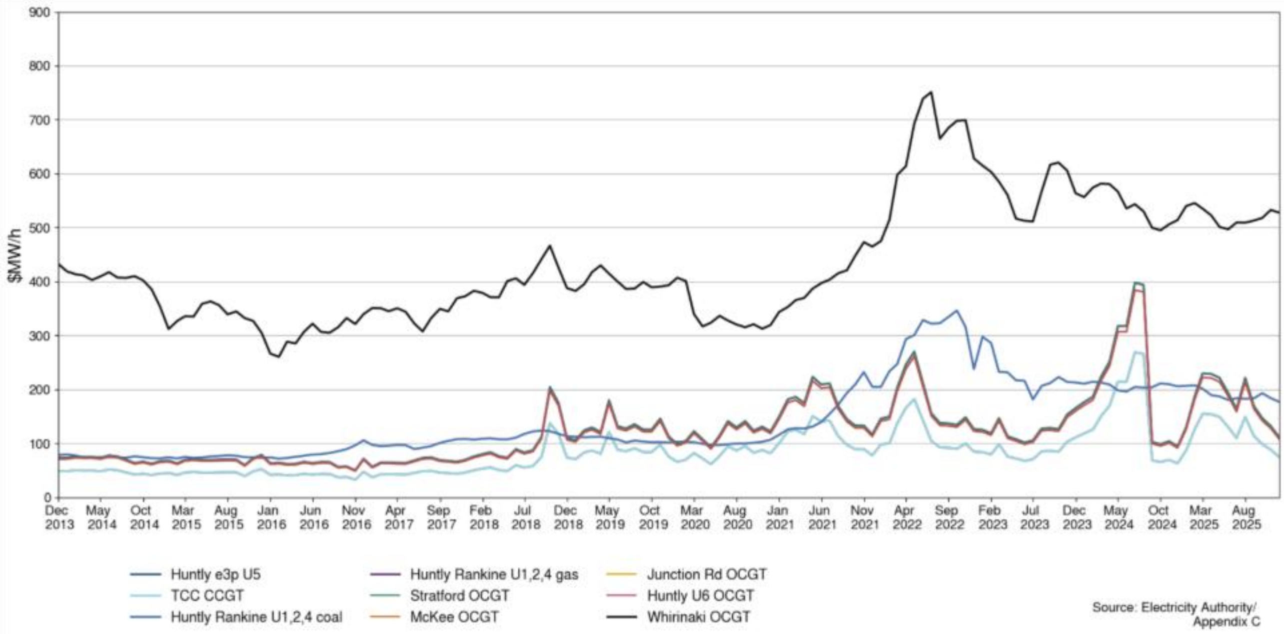
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$177/MWh. The cost of running the Rankines on gas is ~$111/MWh.

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

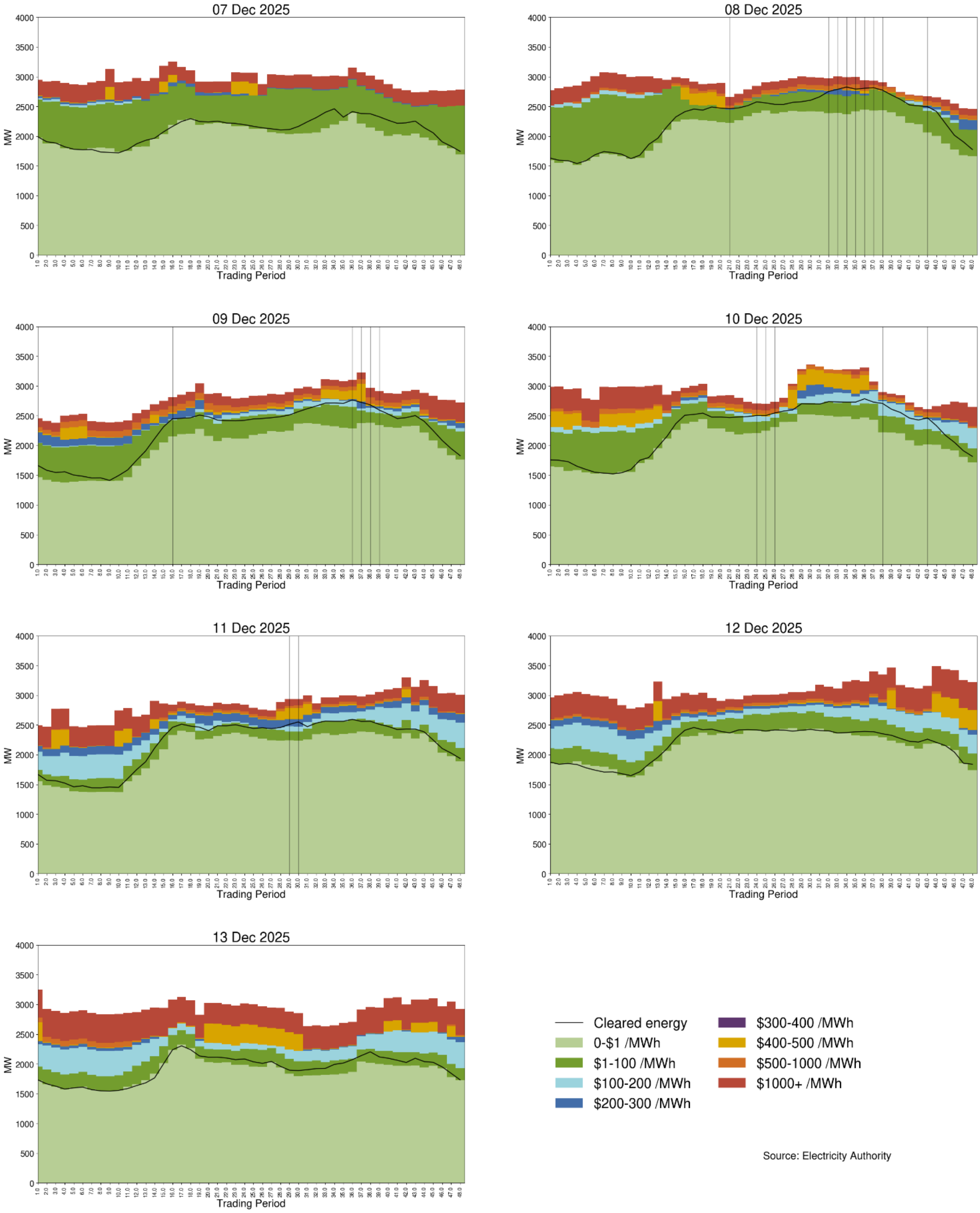


12. Offer behaviour

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.

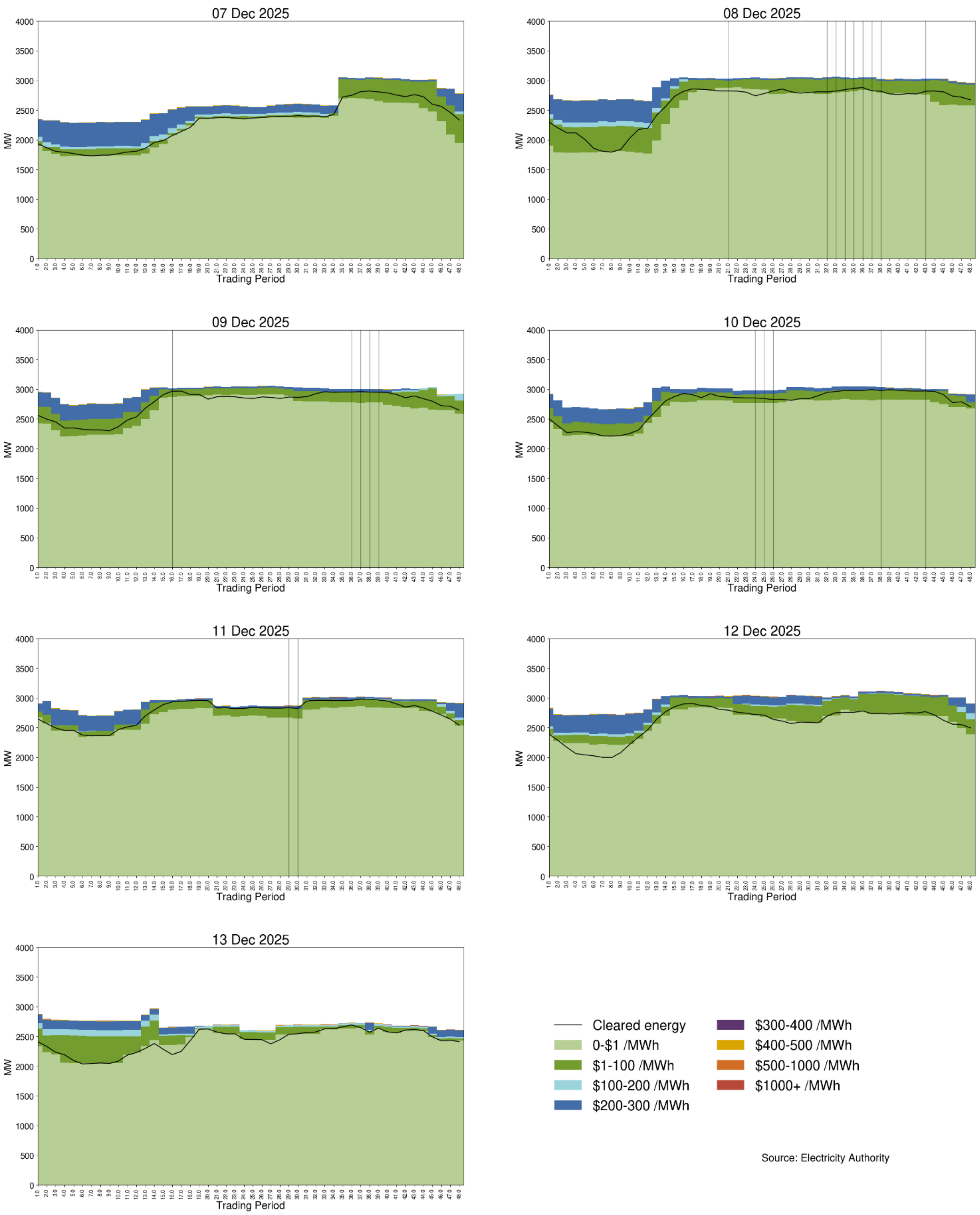
12.2. In the North Island, most offers cleared below $100/MWh on Sunday, Friday and Saturday, and within the $0/MWh-$200/MWh range on the remaining days. Between Monday and Thursday, wind and demand forecast errors pushed some offered energy into the higher bands at times.

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 between Sunday and Monday and between Friday and Saturday. Between Tuesday and Thursday, the amount of cleared energy was close to the amount of energy offered at times.

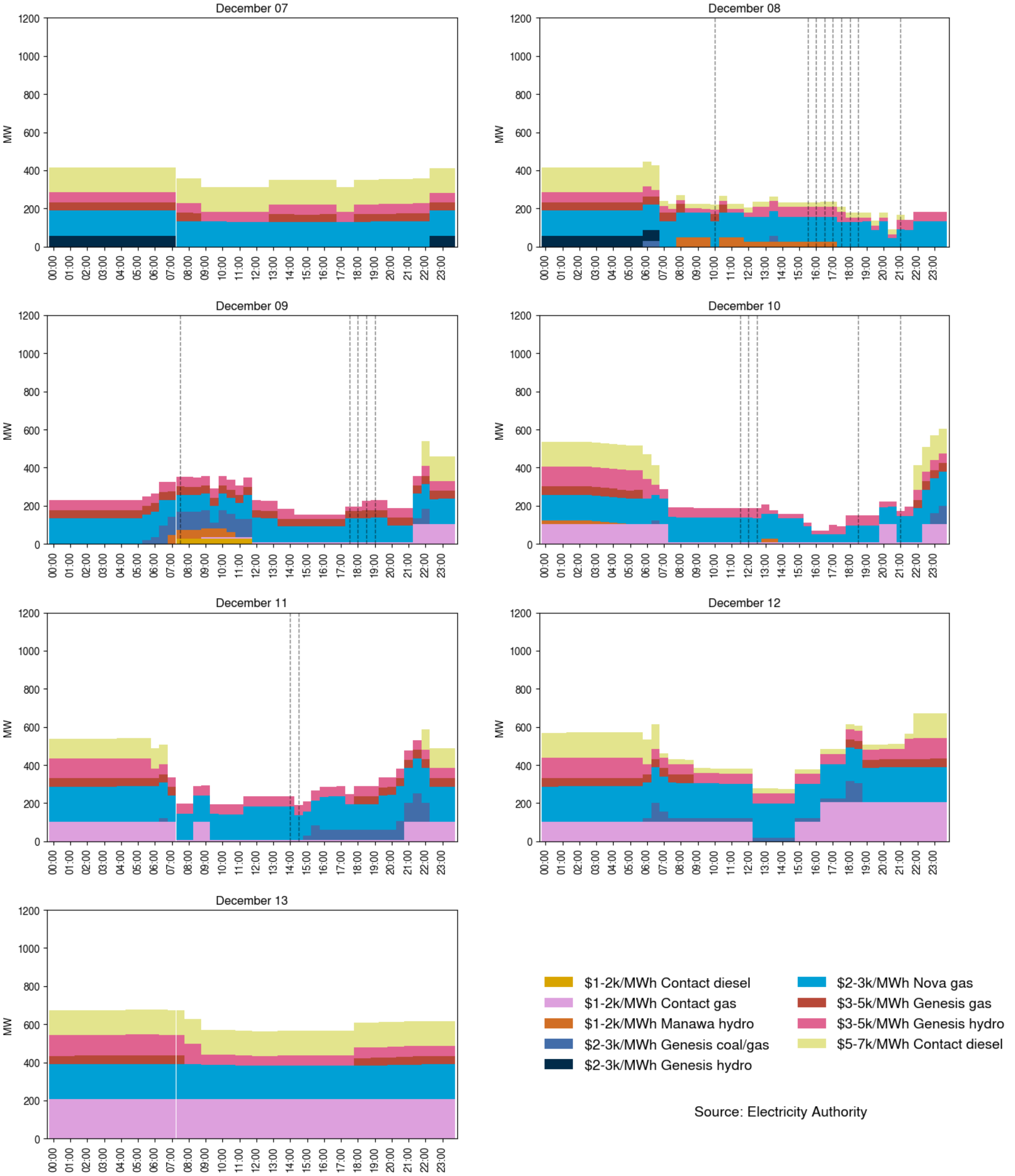
12.4. Figure 25 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 382MW per trading period was priced above $1,000/MWh this week, which is roughly 8% of the total energy available.

12.7. High hydro offers from Manawa/Contact between Monday and Wednesday are being analysed further by the monitoring team.

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. The monitoring team is looking further into Huntly, Ruakākā, Waikato, Coleridge, Cobb, and Matahina offers this week.

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
8/12/2025-12/12/2025	Several	Further analysis	Meridian	Ruakākā	Reserve offers
9/12/2025	37-48	Further analysis	Mercury	Waikato	Offers
9/12/2025	36-48	Further analysis	Genesis	Huntly	Offers