17 November 2025

Trading conduct report 9-15 November 2025

Market monitoring weekly report

Trading conduct report 9-15 November 2025

1. Overview

1.1. This week the average spot price decreased by $9/MWh to $75/MWh, and prices remained below $200/MWh. Hydro generation remained high, whereas geothermal generation was lower due to outages. HVDC flows were entirely northward throughout the week. National hydro storage slightly increased to 90% nominally full and around 138% of the historical average. However, this includes storage at Manapōuri and Te Anau, 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 9-15 November 2025:

(a) The average spot price for the week was $75/MWh, a decrease of around $9/MWh compared to the previous week.

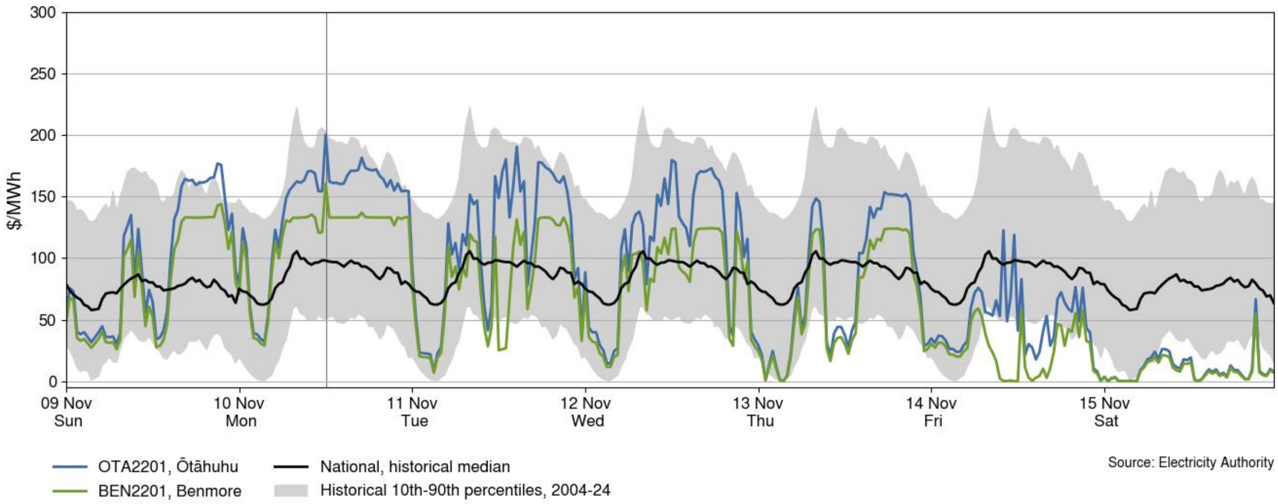
(b) 95% of prices fell between $0.04/MWh and $166/MWh.

2.3. This week, prices remained below $200/MWh, with notably low prices on Saturday due to low demand and high wind generation. Some price separation was observed on Tuesday and Friday during periods of high northward HVDC flow. Price separation averaged $20/MWh this week between the Ōtāhuhu and Benmore.

2.4. The highest price of the week occurred on Monday at 12.00pm, reaching $200/MWh at Ōtāhuhu and $161/MWh at Benmore. During that time, energy along the Waitaki scheme was constrained to manage a New Zealand's Aluminium Smelter (NZAS) reduction line off-load and restoration. The reduction in available South Island energy likely decreased Northward HVDC flows and resulted in increased dispatch of North Island generation.

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.

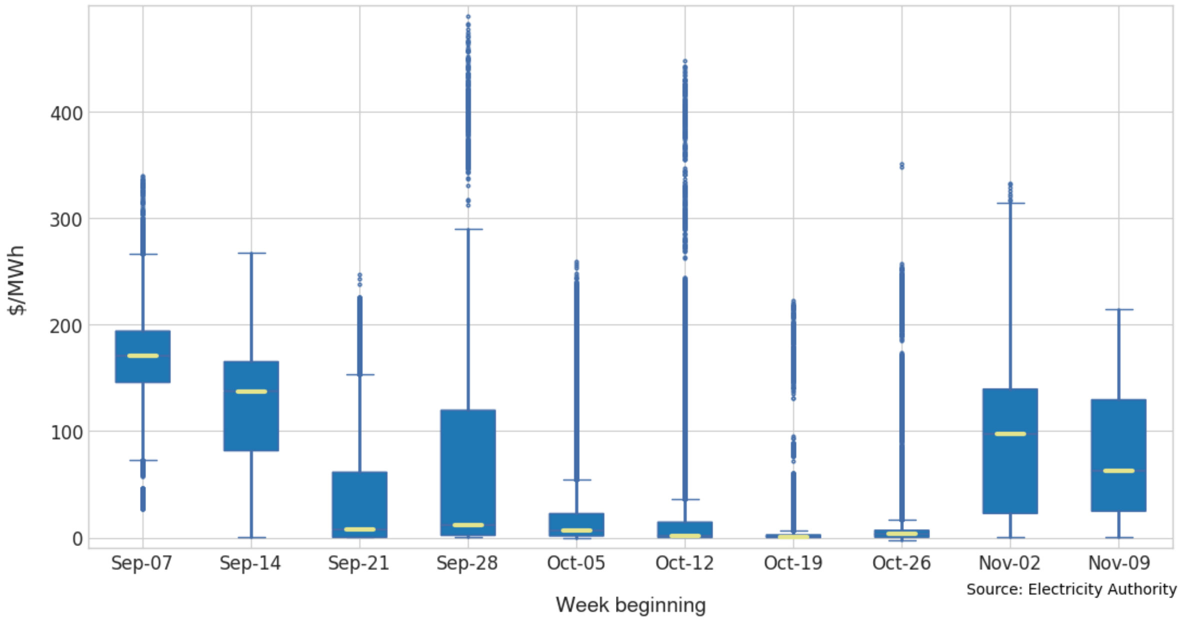
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 9-15 November 2025



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 narrow compared to last week, with no significant high price outliers. The median price was $63/MWh and most prices (middle 50%) fell between $25/MWh and $130/MWh.

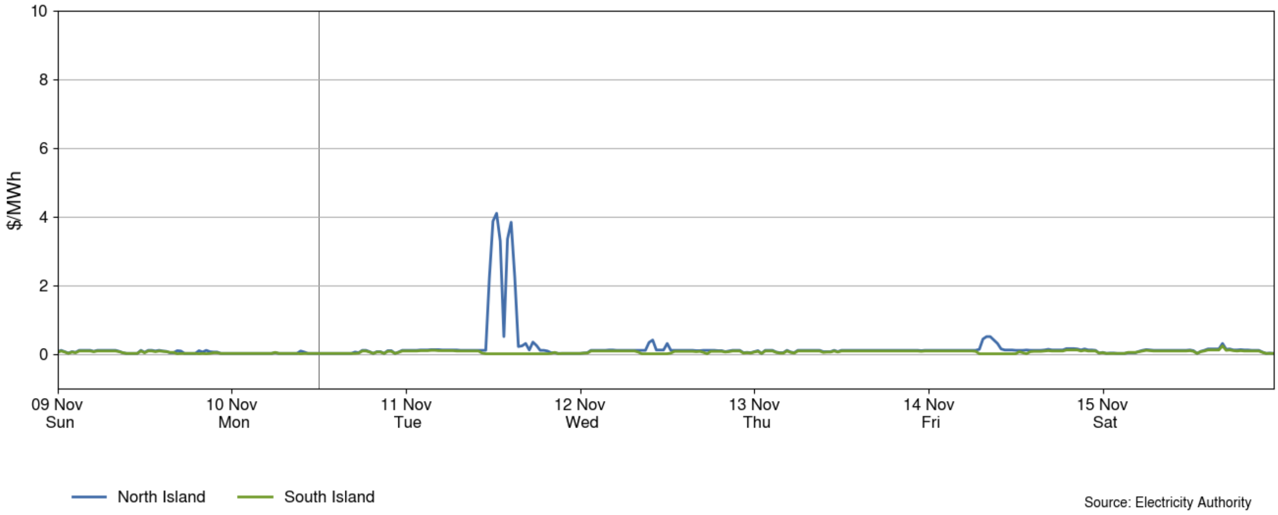
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

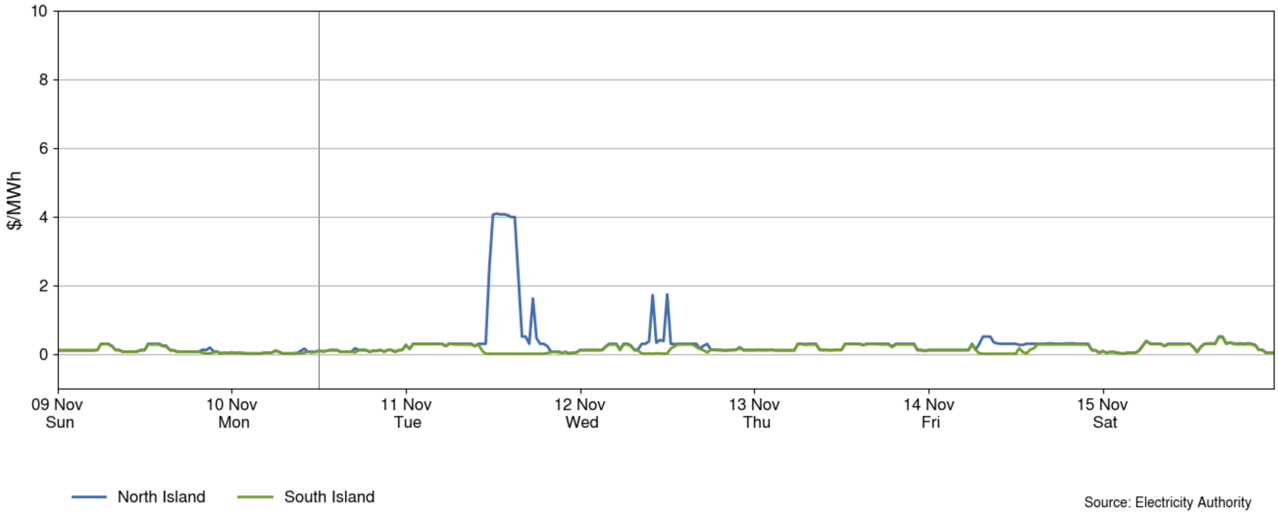
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week, FIR prices were below $5/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 9-15 November 2025



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were below $5/MWh throughout the week.

Figure 4: Sustained instantaneous reserve by trading period and island, 9-15 November 2025



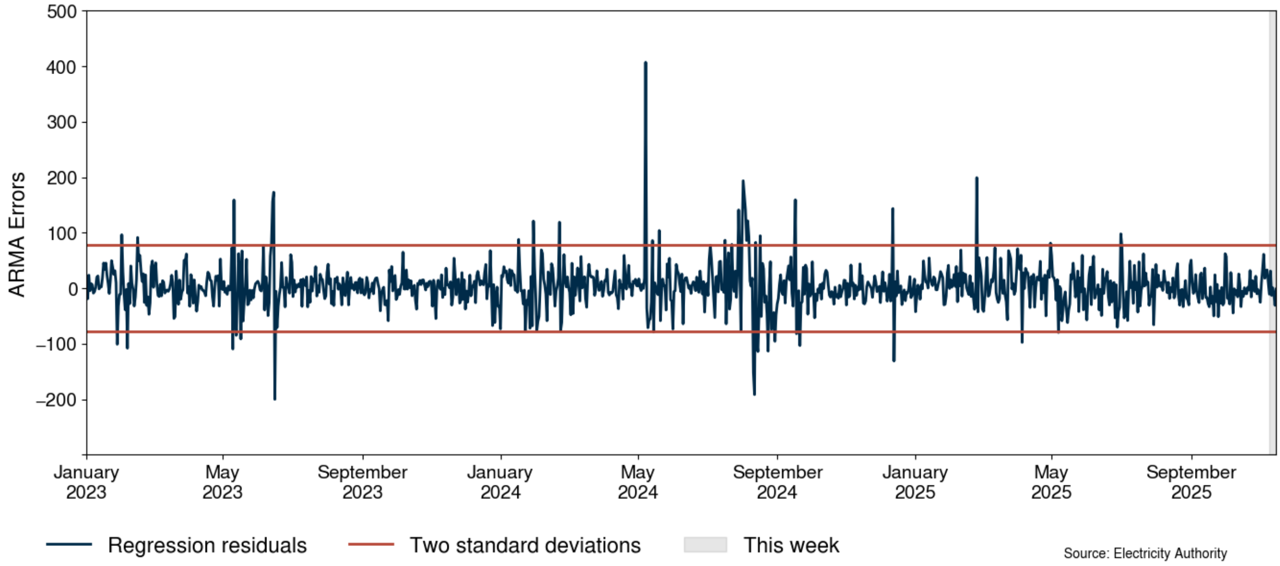
4. Regression residuals

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 those predicted by the model.

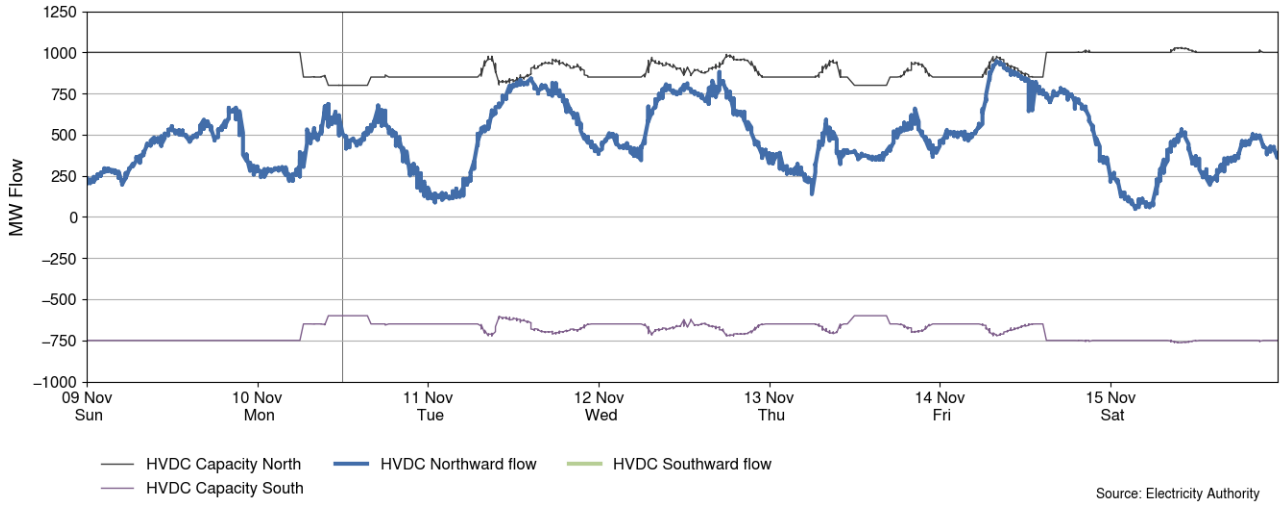
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 15 November 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 9-15 November 2025. HVDC flows were entirely northward this week due to high hydro generation in the South Island. The highest northward flow occurred at 8.00am on Friday with a flow of around 946MW, and the flows reached near the limited of the HVDC capacity.

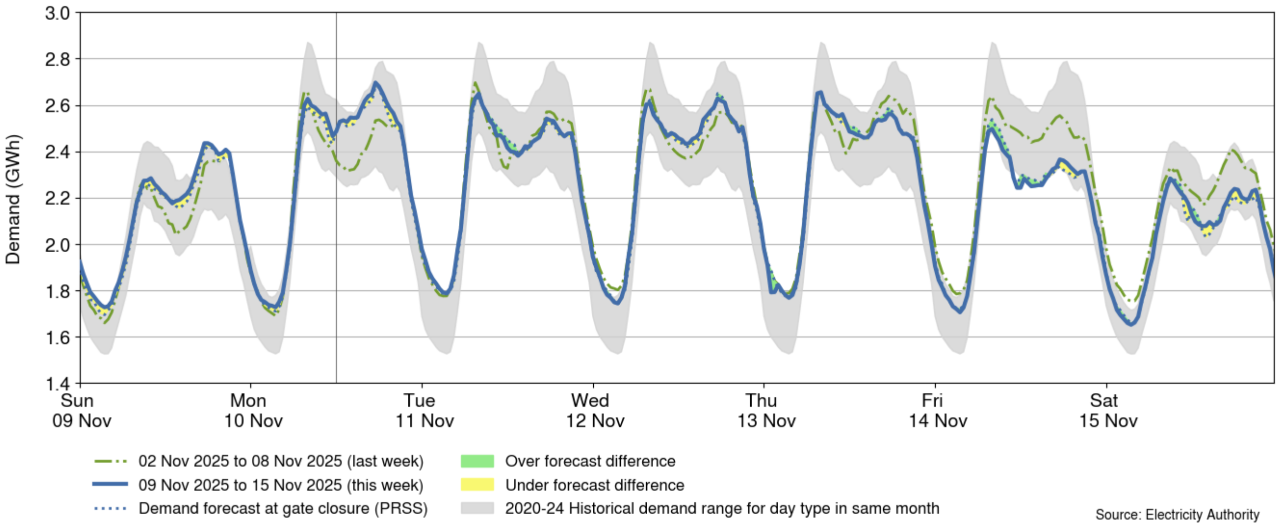
Figure 6: HVDC flow and capacity, 9-15 November 2025



6. Demand

6.1. Figure 7 shows national demand between 9-15 November 2025, compared to the historic range and the demand of the previous week. On Monday, demand was high compared to last week. However, on Friday demand was lower compared to last week. The highest demand of the week was around 2.70 GWh at 5.30pm on Monday.

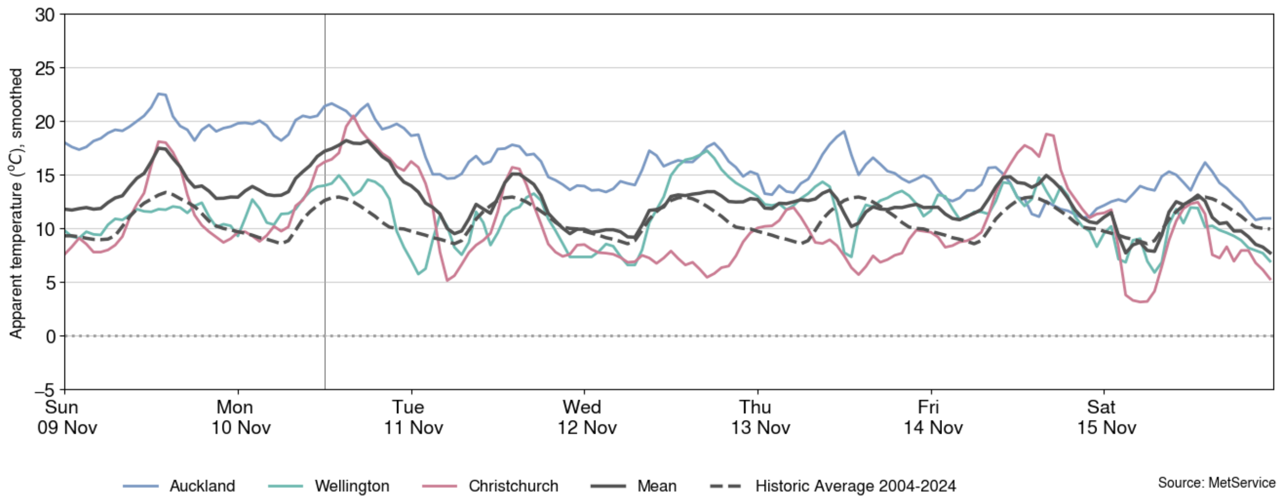
Figure 7: National demand, 9-15 November 2025 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 9-15 November. 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 10°C to 23°C in Auckland, 6°C to 17°C in Wellington, and 3°C to 22°C in Christchurch.

Figure 8: Temperatures across main centres, 9-15 November 2025

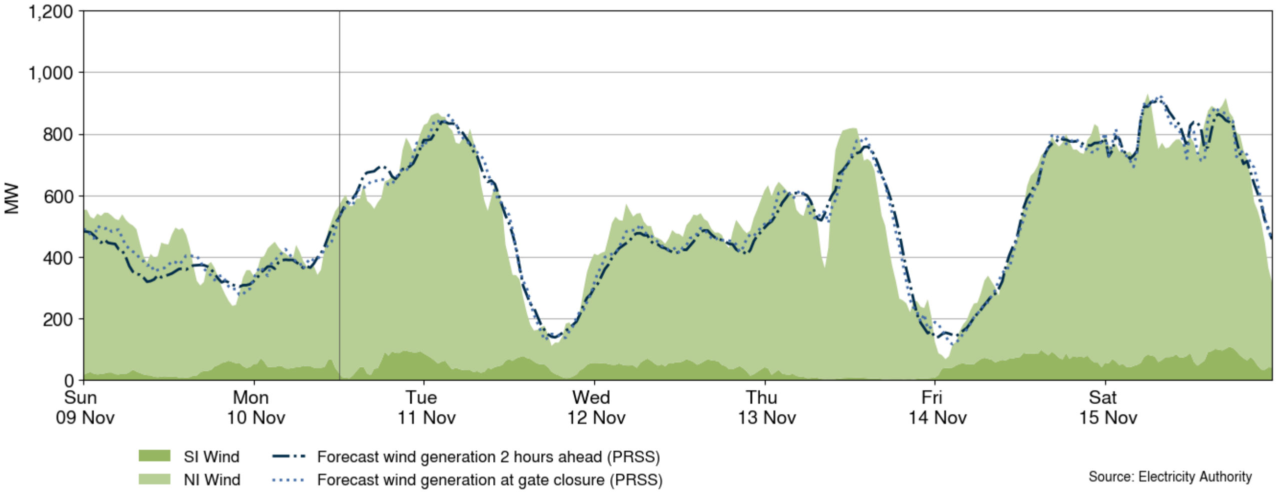


7. Generation

7.1. Figure 9 shows wind generation and forecast from 9-15 November 2025. This week wind generation varied between 68MW and 931MW, with a weekly average of 528MW.

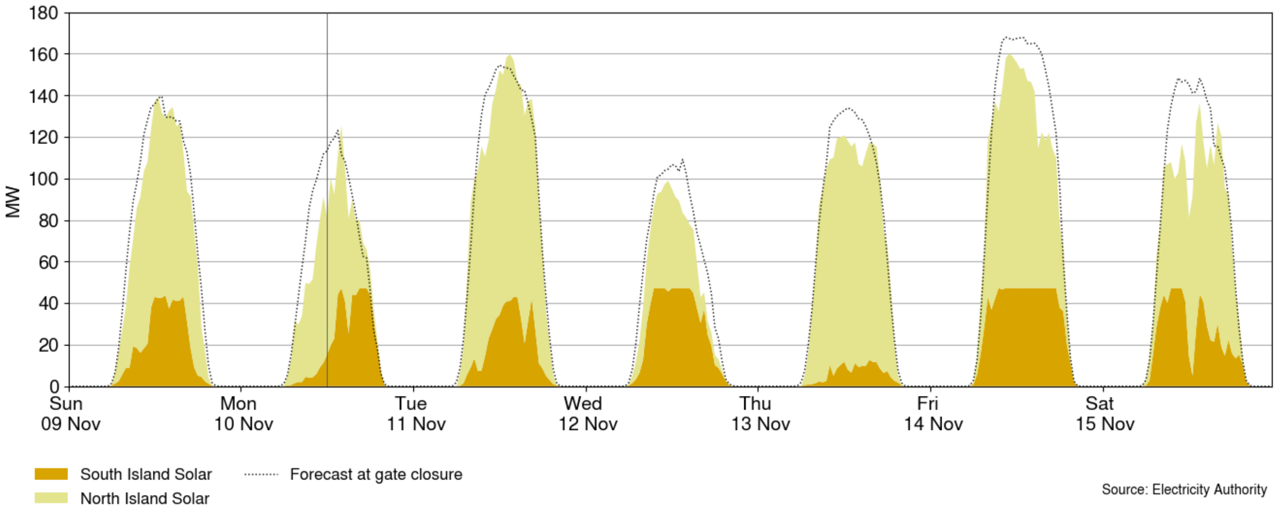
7.2. Wind generation remained stable at approximately 400MW on Sunday, before gradually increasing and exceeding 800MW on Tuesday. From Tuesday morning, wind began to decline to below 200MW, returning to around 400MW by Wednesday. A further decrease occurred on Thursday. However, between Friday evening and Saturday evening, wind generation was elevated, consistently remaining above 700MW.

Figure 9: Wind generation and forecast, 9-15 November 2025



7.3. Figure 10 shows grid connected solar generation from 9-15 November 2025. Solar generation peaked above 120MW daily, except on Wednesday, when it was below 100MW. Solar generation peaked at around 160MW on Friday at 11.00am.

Figure 10: Grid connected solar generation, 9-15 November 2025



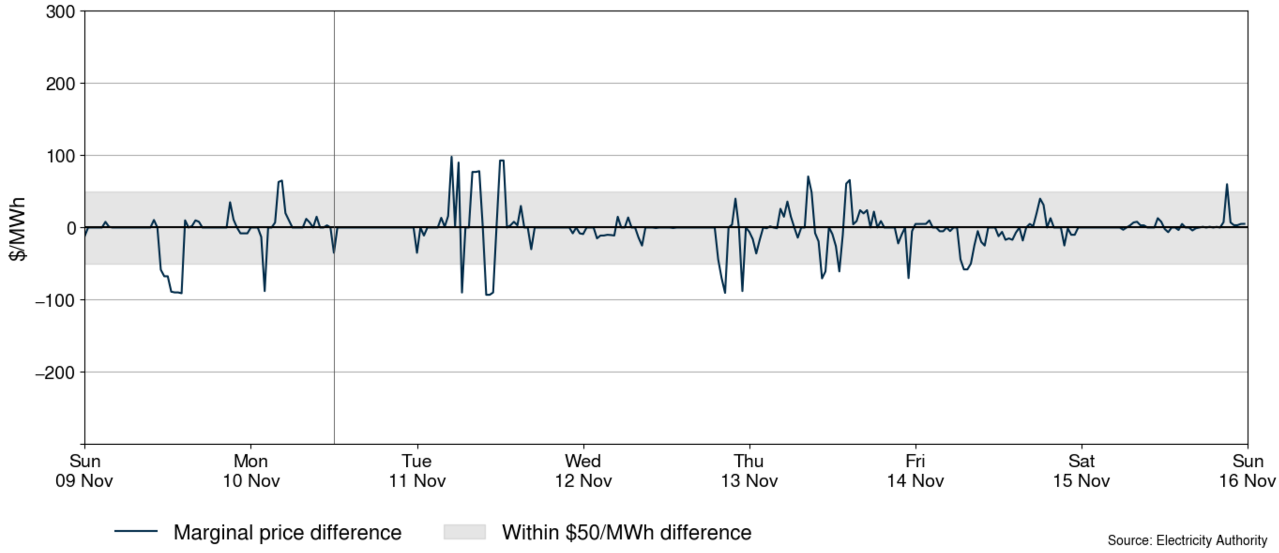
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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.

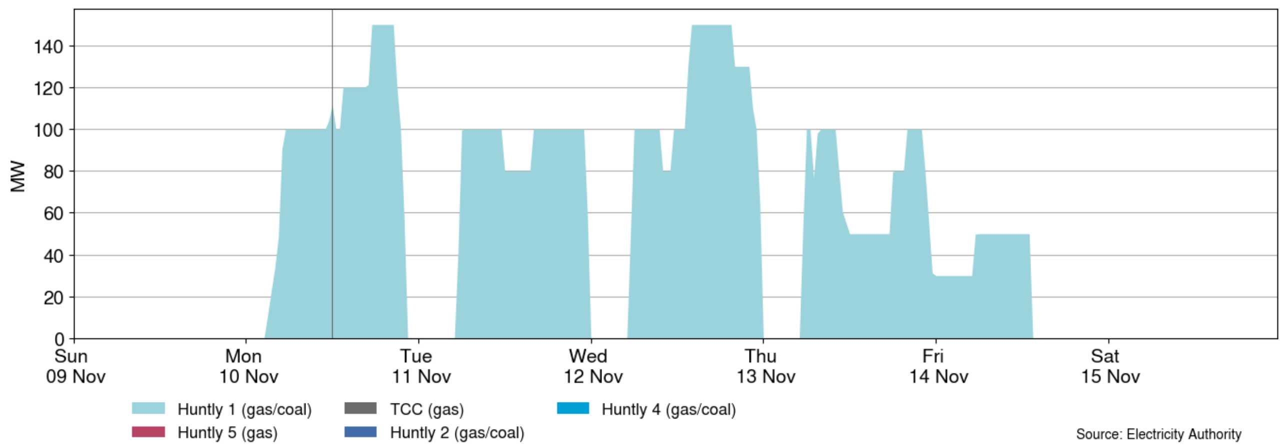
7.5. A few trading periods this week had positive marginal price differences above $50/MWh which were driven by wind and demand forecasting errors. The largest positive price difference of +$98/MWh occurred at 5.00am on Tuesday, when demand was 75MW higher than forecast and wind was 32MW lower than forecast.

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, 9-15 November 2025



7.6. Figure 12 shows the generation of thermal baseload between 9-15 November 2025. Huntly 1 ran from Monday to Friday afternoon, turning off overnight. Output from Huntly 1 increased during the price spike on Monday.

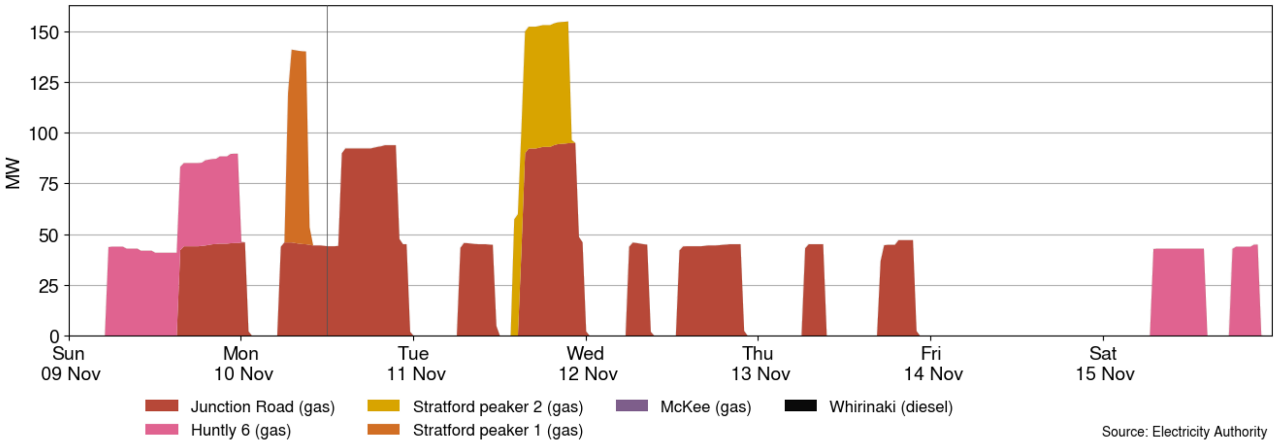
Figure 12: Thermal baseload generation, 9-15 November 2025



7.7. Figure 13 shows the generation of thermal peaker plants between 9-15 November 2025. Junction Road ran from Sunday to Thursday during both the morning and evening peaks. On Monday, it also ran continuously between the morning and evening peaks.

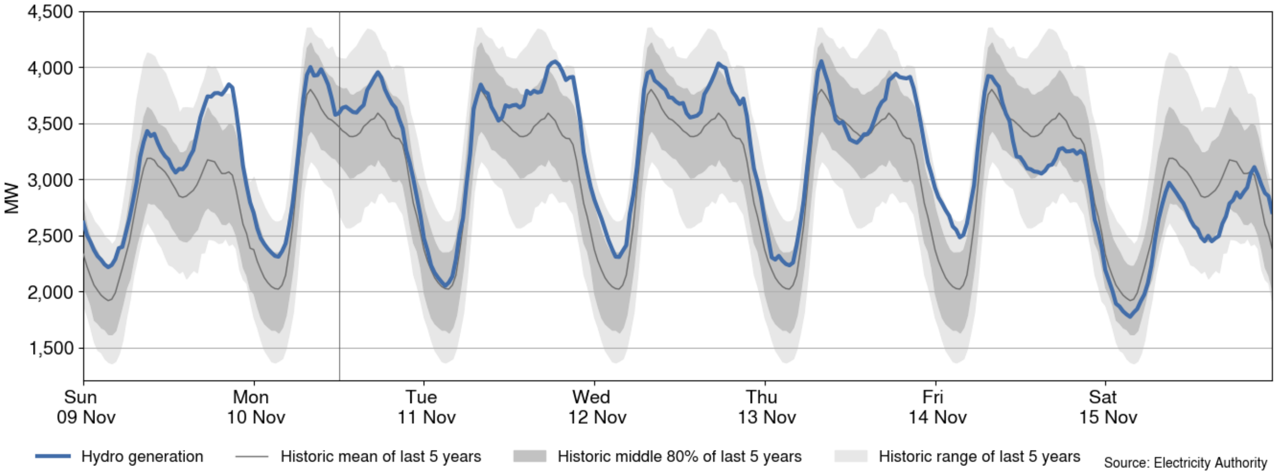
7.8. Huntly 6 ran on Sunday and Saturday. Stratford peaker 1 dispatched on Monday during the morning peak, while Stratford peaker 2 was dispatched on Tuesday evening to meet demand.

Figure 13: Thermal peaker generation, 9-15 November 2025



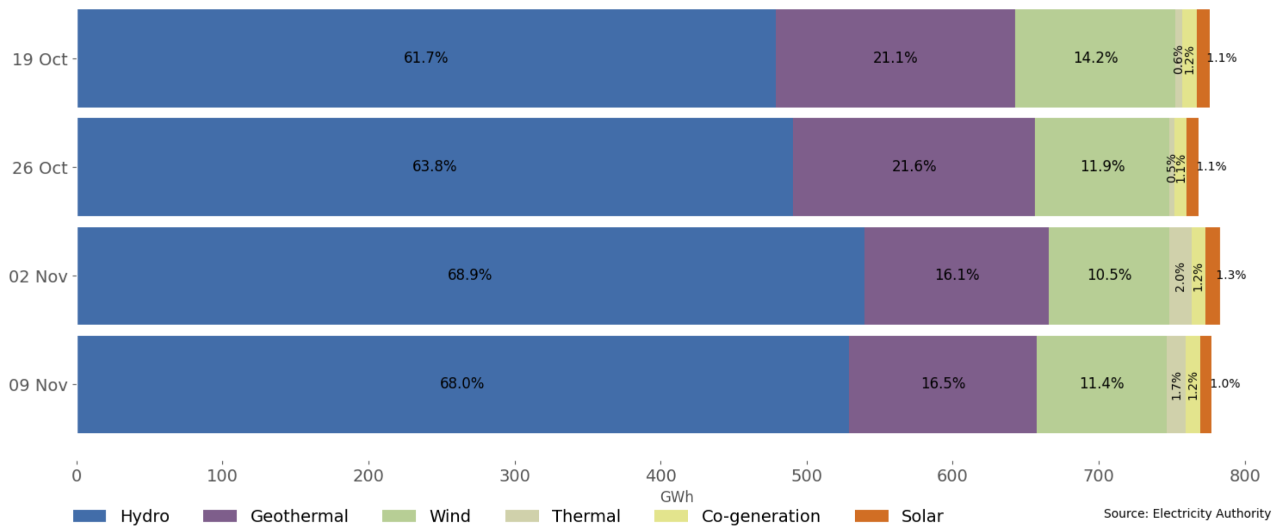
7.9. Figure 14 shows hydro generation between 9-15 November 2025. Hydro generation remained mostly within the middle 80% of historic generation. Hydro generation was high during the evening peaks. However, on Friday evening, hydro generation was relatively low, likely due to high wind generation.

Figure 14: Hydro generation, 9-15 November 2025



7.10. As a percentage of total generation, between 9-15 November 2025, total weekly hydro generation was 68.0%, geothermal 16.5%, wind 11.4%, thermal 1.7%, co-generation 1.2%, and solar (grid connected) 1.0%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 19 October and 15 November 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 9-15 November 2025 ranged between ~1,567MW and ~2,383MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 5 is on outage until 24 November 2025.

(b) Huntly 4 was on extended partial outage until 14 November 2025.

(c) Nga Awa Pūrua geothermal is on outage until 28 November 2025.

(d) Te Huka 3 geothermal was on outage until 12 November 2025.

(e) Tauhara geothermal is on outage until 22 December 2025, an extension from its previous end date of 29 November.

(f) Ruakākā battery was on partial outage between 9-15 November.

(g) Clyde unit 3 was on outage between 10-12 November, and unit 1 was on outage between 13-14 November 2025.

(h) Benmore unit 6 was on outage until 10 November 2025.

8.3. Some longer-term outages include:

(a) Ōhau A is on partial outage until 4 February 2026.

(b) Ōhau C is on partial outage until 16 January 2026.

(c) Roxburgh unit 5 is on outage until 25 February 2026.

(d) Rangipo unit 6 is on outage until 29 March 2026.

(e) Manapōuri unit 4 is on outage until 12 June 2026.

Figure 16: Total MW loss from generation outages, 9-15 November 2025

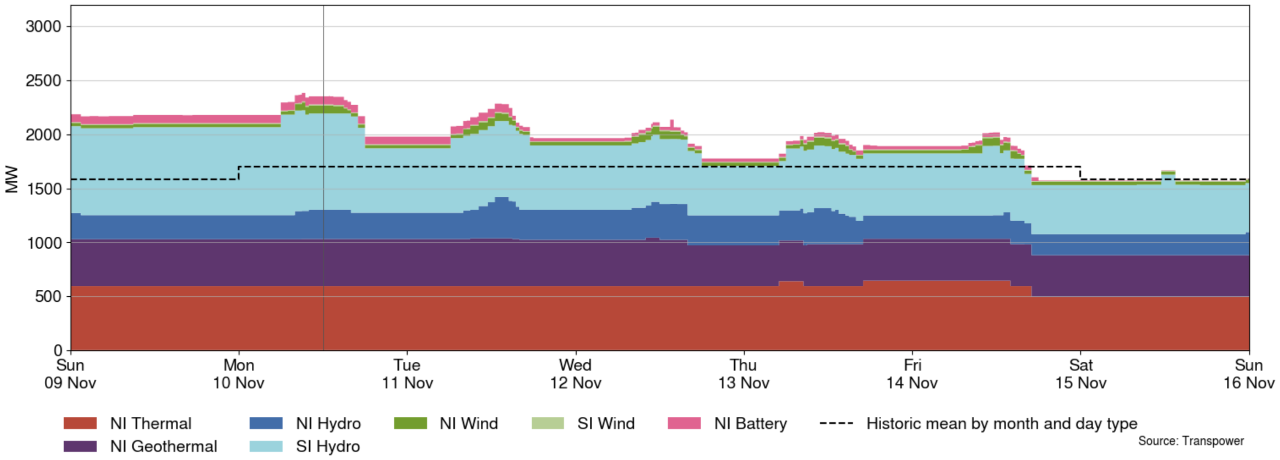
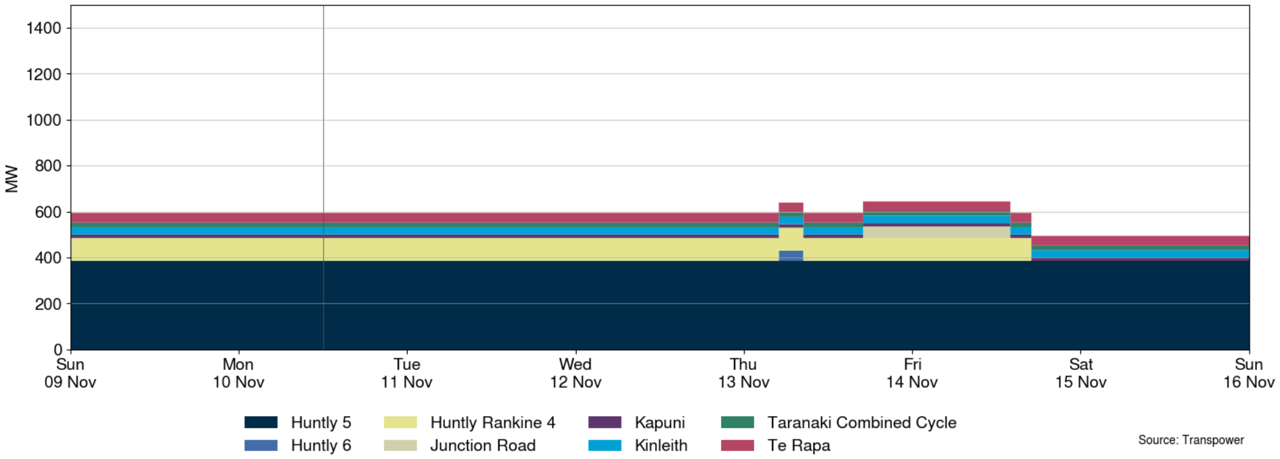


Figure 17: Total MW loss from thermal outages, 9-15 November 2025

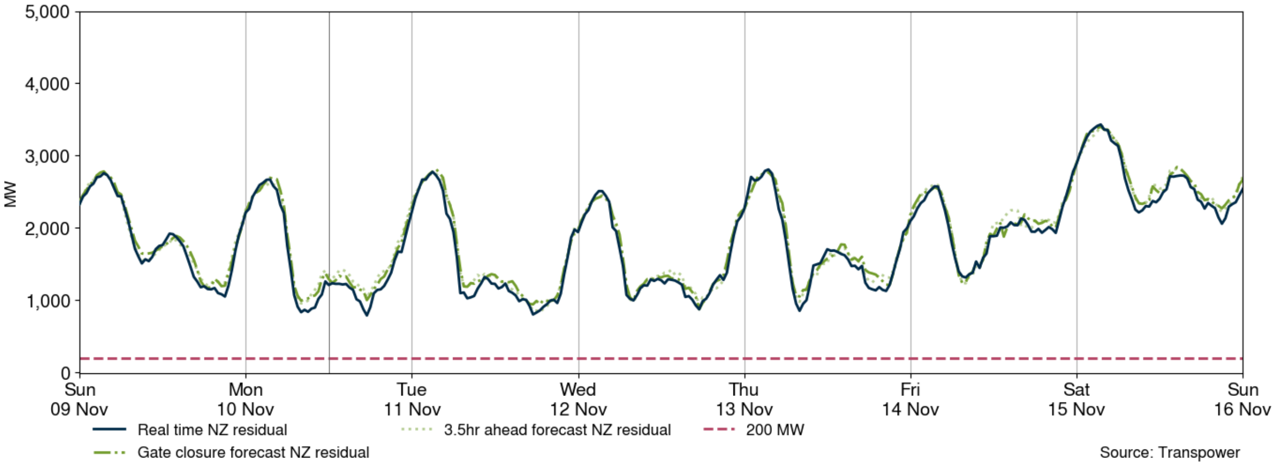


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 9-15 November 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. Overall, residuals were healthy this week. The lowest national residual was 790MW on Monday at 5.30pm.

Figure 18: National generation balance residuals, 9-15 November 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. As of 15 November 2025, national controlled hydro storage slightly increased to 91% of nominal full and ~138% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (80% full[2]) and Lake Takapō (94% full) are above their respective 90th percentile.

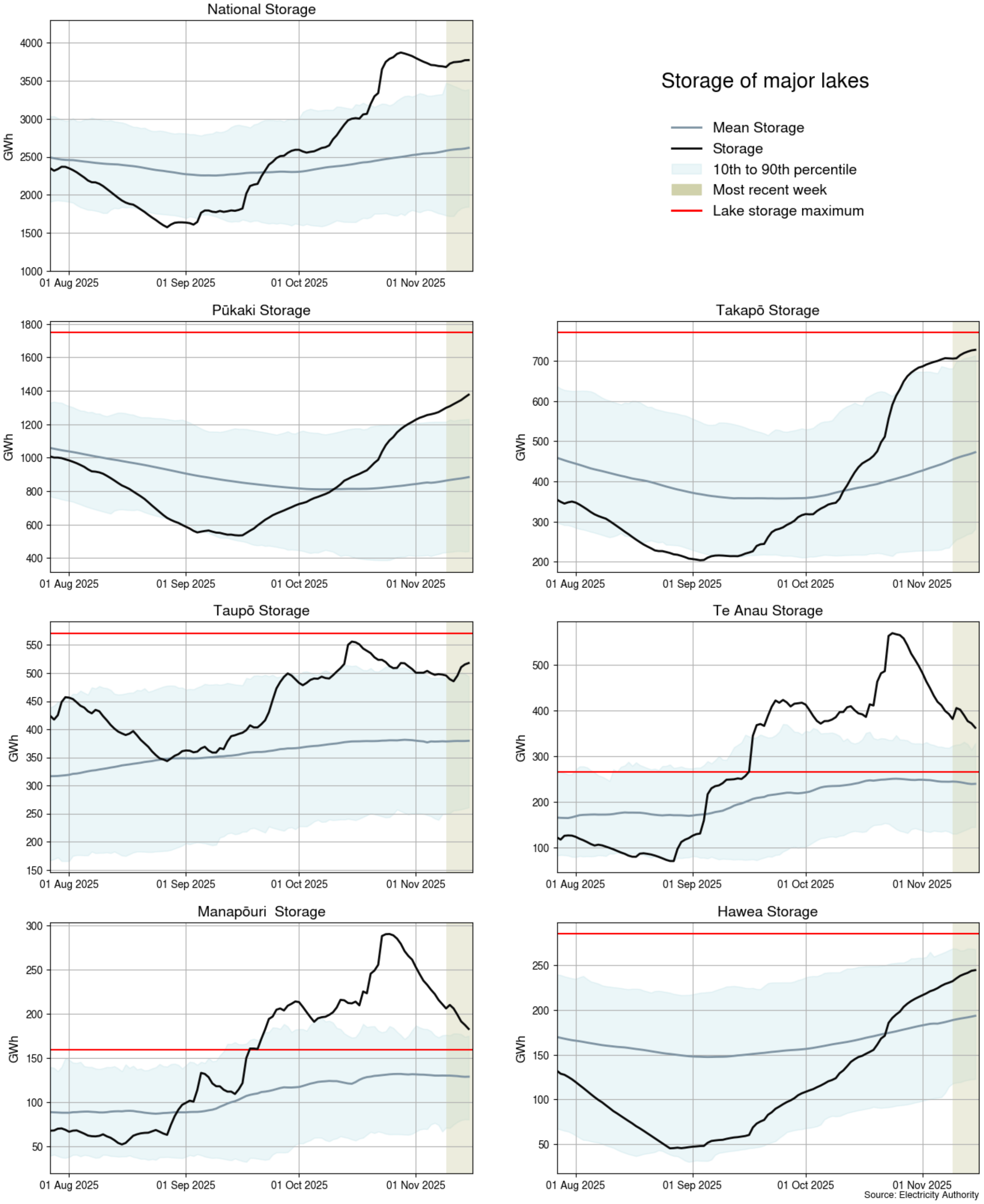
10.4. Storage at Lake Te Anau (132% full) and Lake Manapōuri (113% full) is above their respective historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (88% full) is slightly above its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (86% full) is above its historic mean.

[2] Percentage full values sourced from NZX hydrological summary 16 November 2025.

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 November 2025. Coal was last updated on 1 August, so the previous prices were carried forward. The SRMCs for gas-powered generation, and diesel-fuelled generation have remained stable.

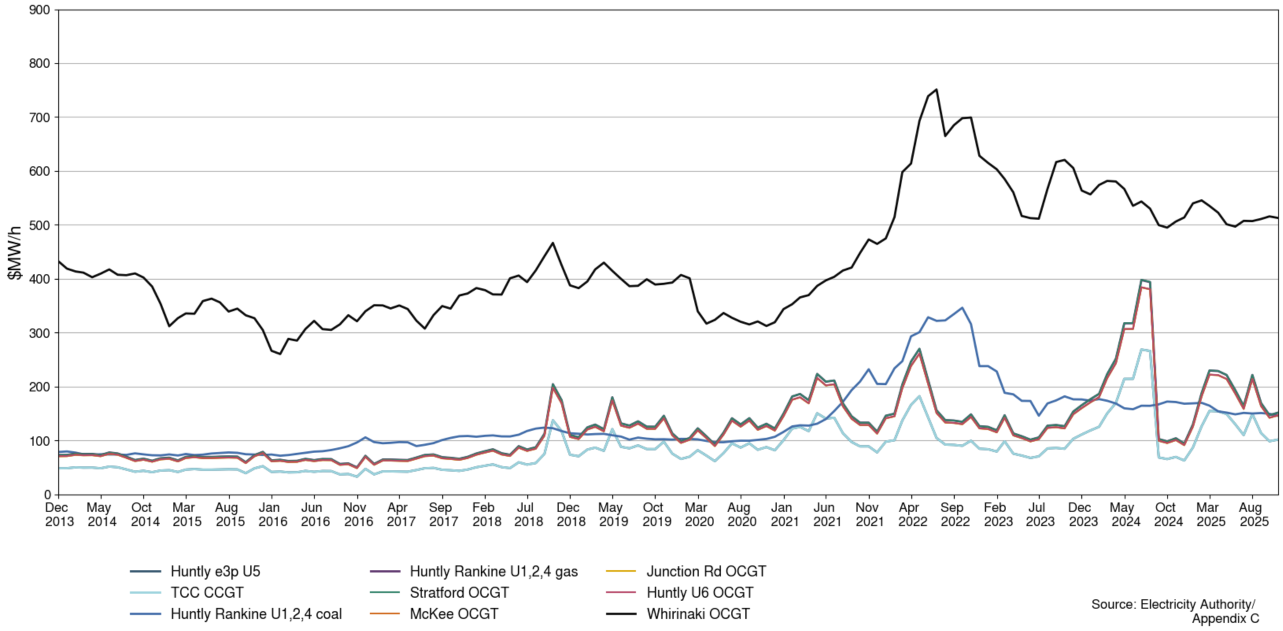
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$145/MWh. The cost of running the Rankines on gas is ~$151/MWh.

11.5. The SRMCs of gas fuelled thermal plants are currently between $101/MWh and $151/MWh.

11.6. The SRMC of Whirinaki is ~$513/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



Source: Electricity Authority/ Appendix C

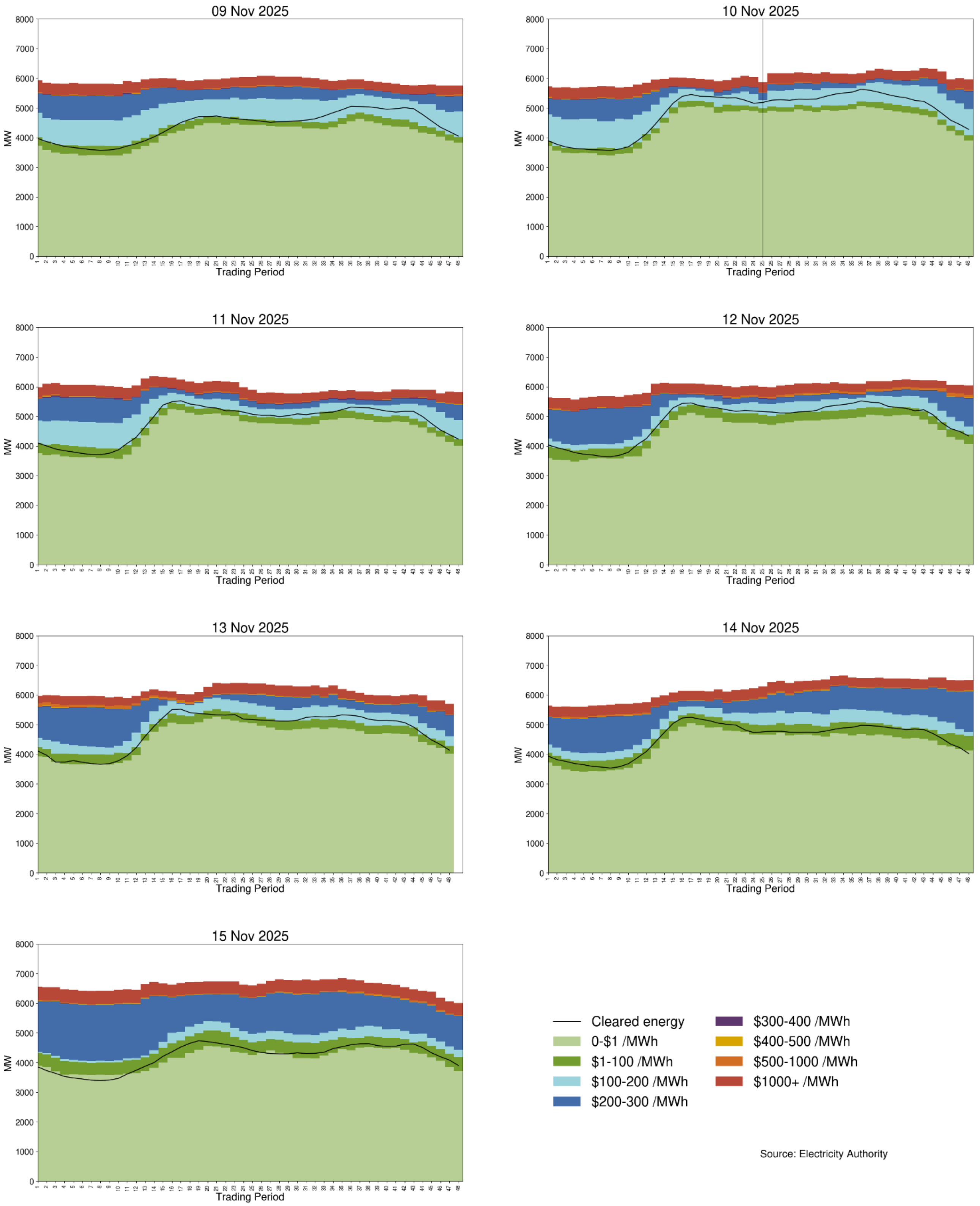
12. Offer behaviour

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. This week most offers cleared in the $0-$200/MWh range. However, on Saturday, energy cleared in the lower band.

12.3. On Monday (TP25), the drop in cleared energy (vertical black line) occurred because the Waitaki scheme was constrained to manage NZAS reduction line off-load and restoration.

Figure 21: Daily offer stacks[3]



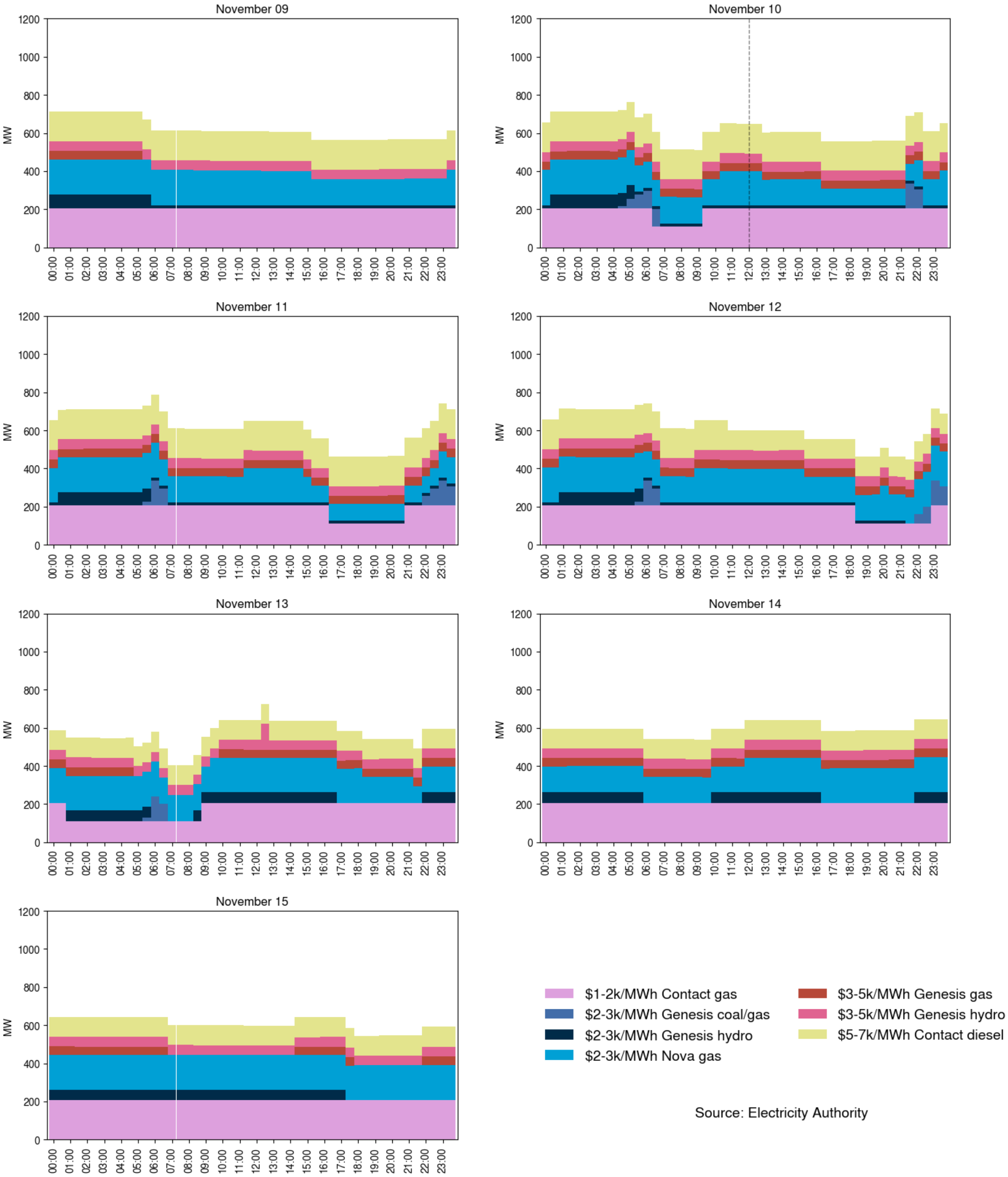
12.4. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

[3] Trading period 24 RTD data was missing on Thursday.

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 607MW per trading period was priced above $1,000/MWh this week, which is roughly 11.6% of the total energy available.

Figure 22: 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
8/05/2025-9/05/2025	Several	Further analysis	Genesis	Waikaremoana	Offers
21/10/2025-23/10/2025	Several	Further analysis	Meridian	West Wind	Offers
21/10/2025-1/11/2025	Several	Further analysis	Contact	Clyde	Offers
26/10/2025-1/11/2025	Several	Further analysis	Genesis	Takapō	Offers
5/11/2025	23-24	Further analysis	Contact	Stratford	Offers