10 November 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report
2-8 November 2025

Market monitoring weekly report

Trading conduct report 2-8 November 2025

1. Overview

1.1. This week the average spot price increased by $73/MWh to $84/MWh, although prices mostly remained below $200/MWh. Demand increased this week compared to the previous week. Hydro generation also increased, while geothermal generation decreased due to outages. National hydro storage slightly decreased to 89% 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 2-8 November 2025:

(a) The average spot price for the week was $84/MWh, an increase of around $73/MWh compared to the previous week.

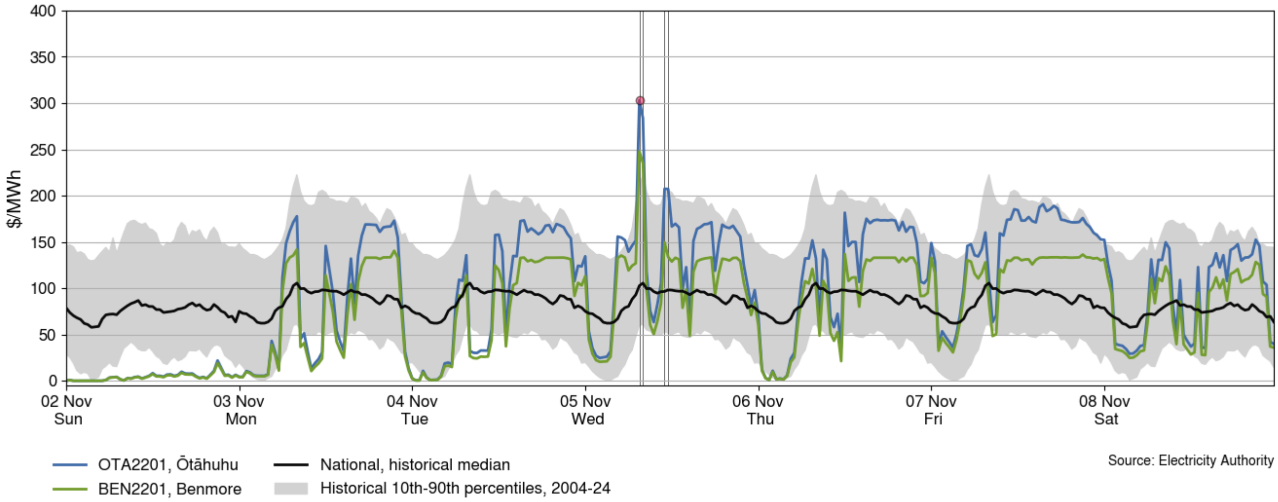
(b) 95% of prices fell between $0.04/MWh and $174/MWh.

2.3. This week, prices were mostly below $200/MWh with a few price spikes above that level on Wednesday. Prices were notably low on Sunday.

2.4. The highest price of the week occurred on Wednesday between 7.30am-8.00am during the morning peak, reaching up to $303/MWh at Ōtāhuhu and $248/MWh at Benmore. Wind generation during this period was low, ranging from 51MW to 56MW, which was 31MW-55MW below forecast. Another price spike was observed later on Wednesday between 11.00am-11.30am, with Ōtāhuhu prices of $207/MWh and Benmore prices between $134-149/MWh.

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.

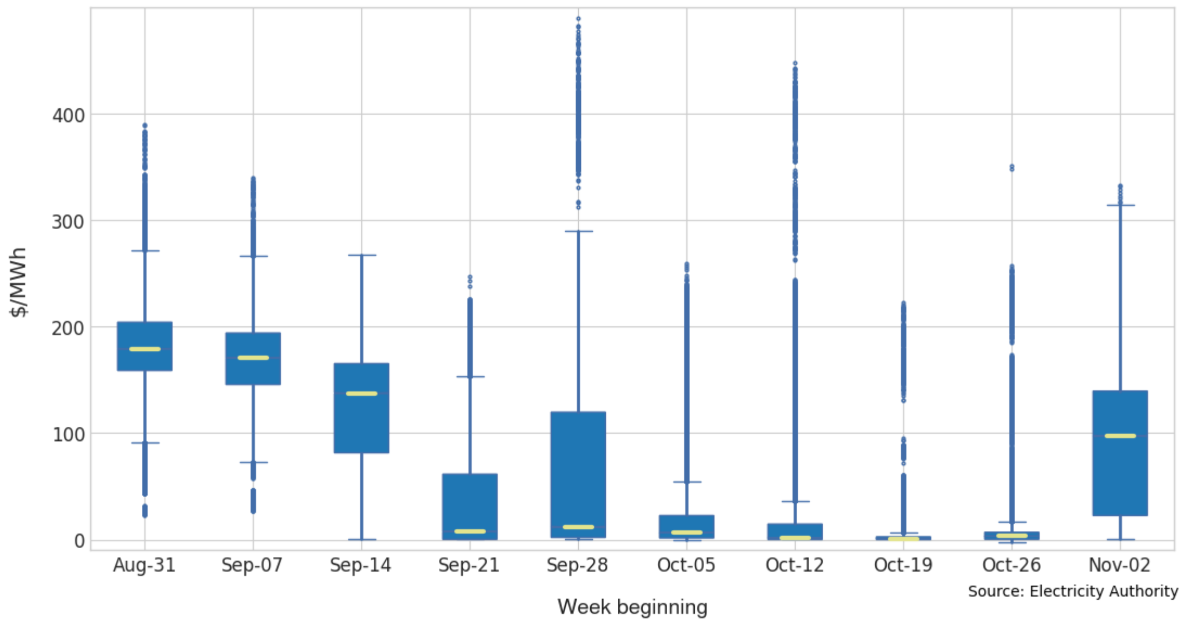
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 2-8 November 2025



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 wider compared to last week. The median price was $97/MWh and most prices (middle 50%) fell between $23/MWh and $140/MWh.

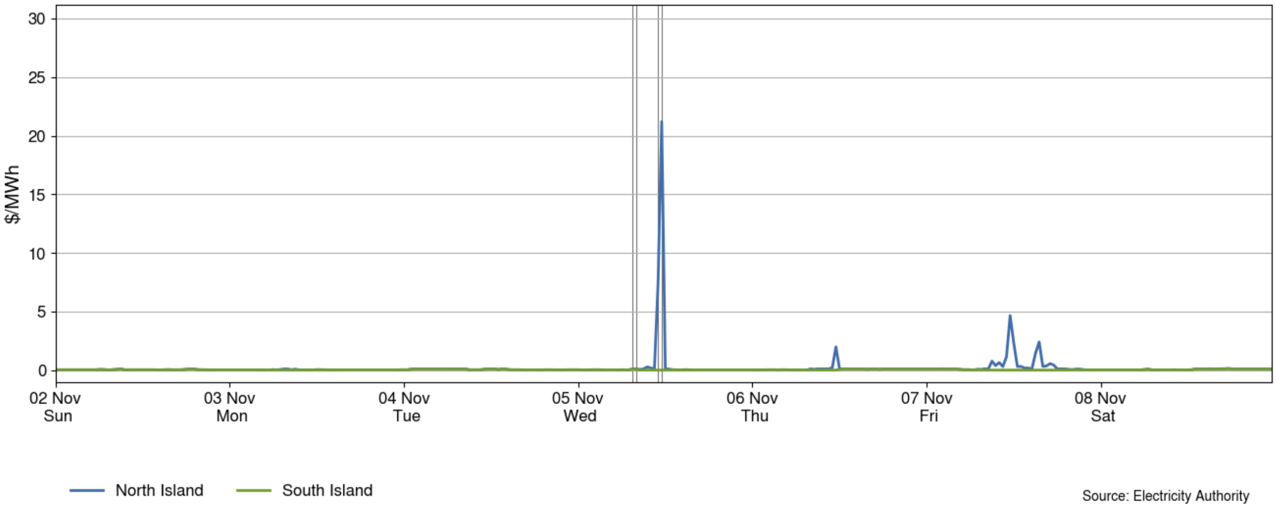
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

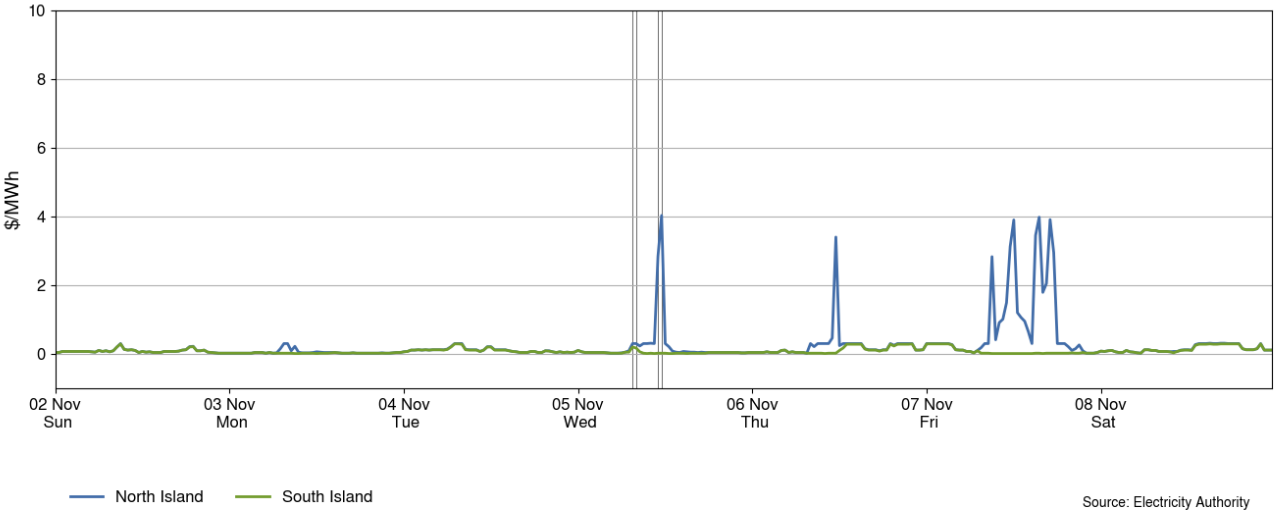
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. This week, FIR prices remained below $5/MWh, except for a spike on Wednesday at 11:30am when North Island FIR prices reached $21/MWh, while South Island prices stayed close to zero. At that time, HVDC was setting the risk for the North Island and transferring the week's maximum flow of around 830MW.

Figure 3: Fast instantaneous reserve price by trading period and island, 2-8 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, 2-8 November 2025



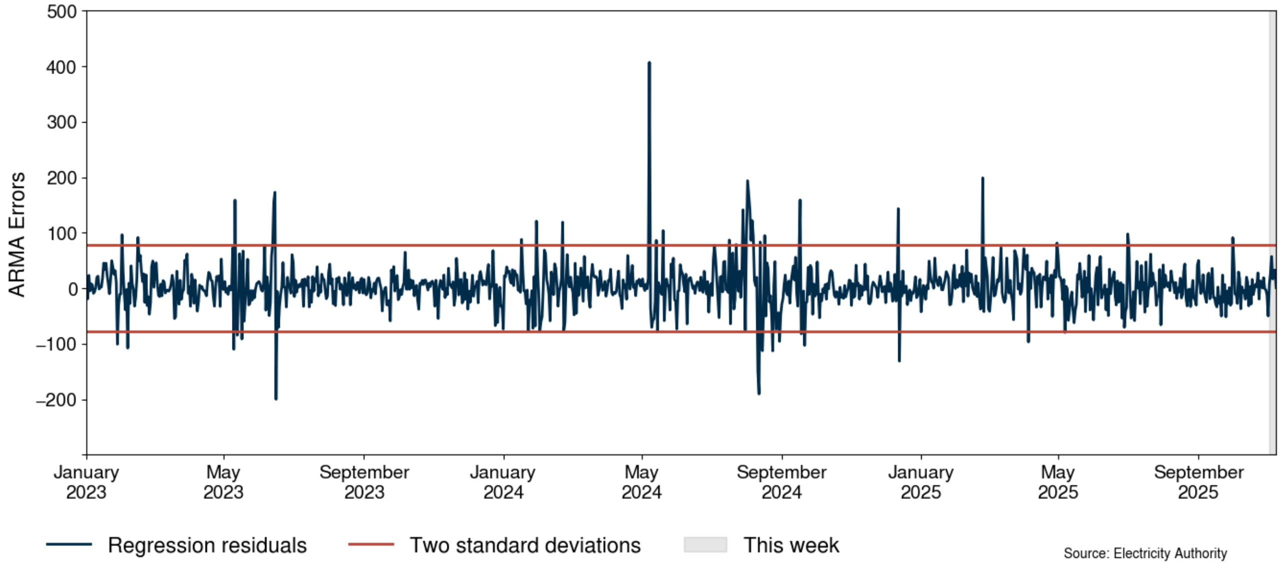
4. Regression residuals

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.

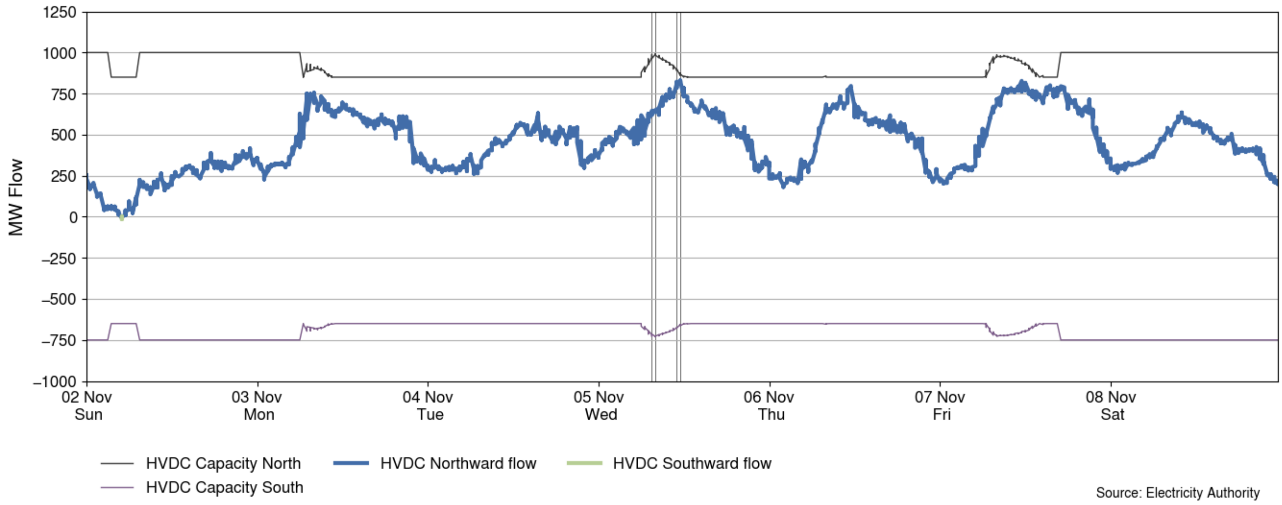
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 8 November 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 2-8 November 2025. HVDC flows were entirely northward this week due to high hydro generation in the South Island. The highest northward flow occurred at 11.30am on Wednesday with a flow of around 830MW.

Figure 6: HVDC flow and capacity, 2-8 November 2025

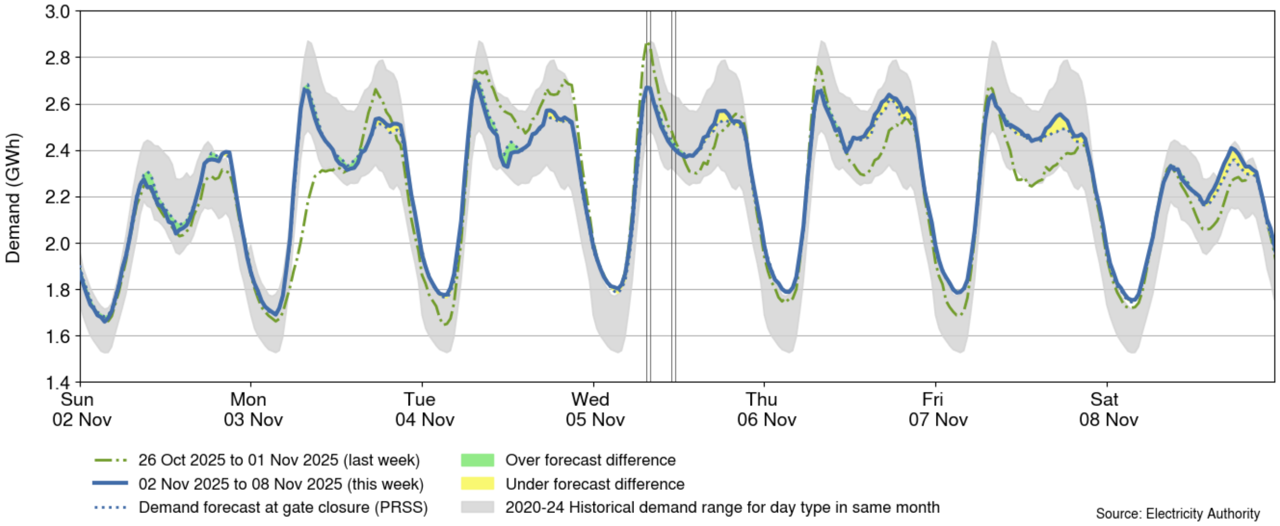


6. Demand

6.1. Figure 7 shows national demand between 2-8 November 2025, compared to the historic range and the demand of the previous week. Morning peak demand decreased compared to the previous week.

6.2. Last Monday's morning demand was low due to the public holiday, and this Tuesday's demand was lower than the previous week. From Wednesday afternoon onwards, demand was consistently higher compared to the previous week. The highest demand of the week was around 2.70 GWh at 7.30am on Tuesday during the morning peak.

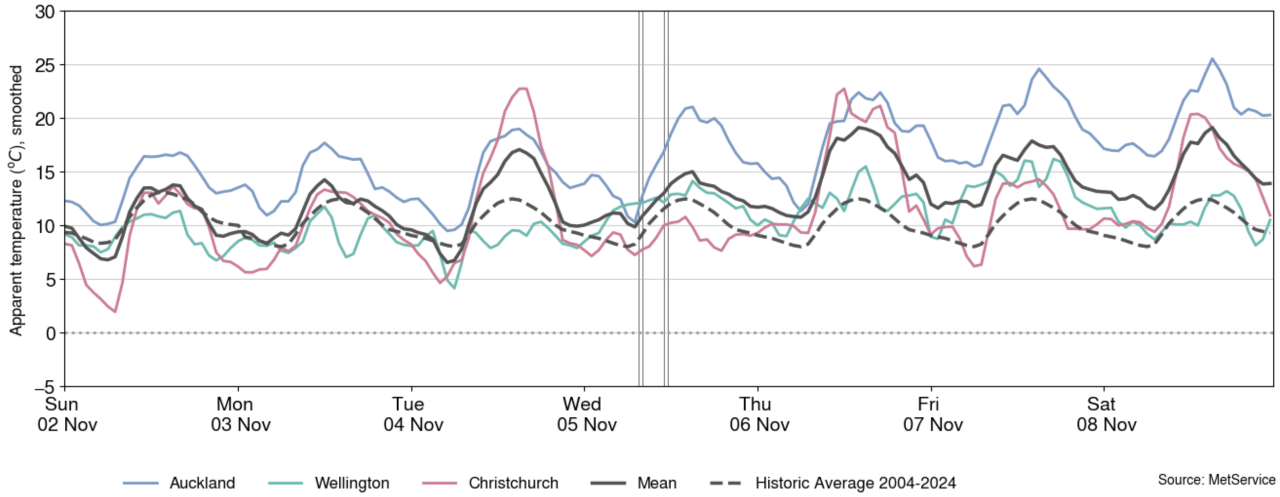
Figure 7: National demand, 2-8 November 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 2-8 November 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 ranged from 9°C to 26°C in Auckland, 4°C to 17°C in Wellington, and 2°C to 25°C in Christchurch.

Figure 8: Temperatures across main centres, 2-8 November 2025

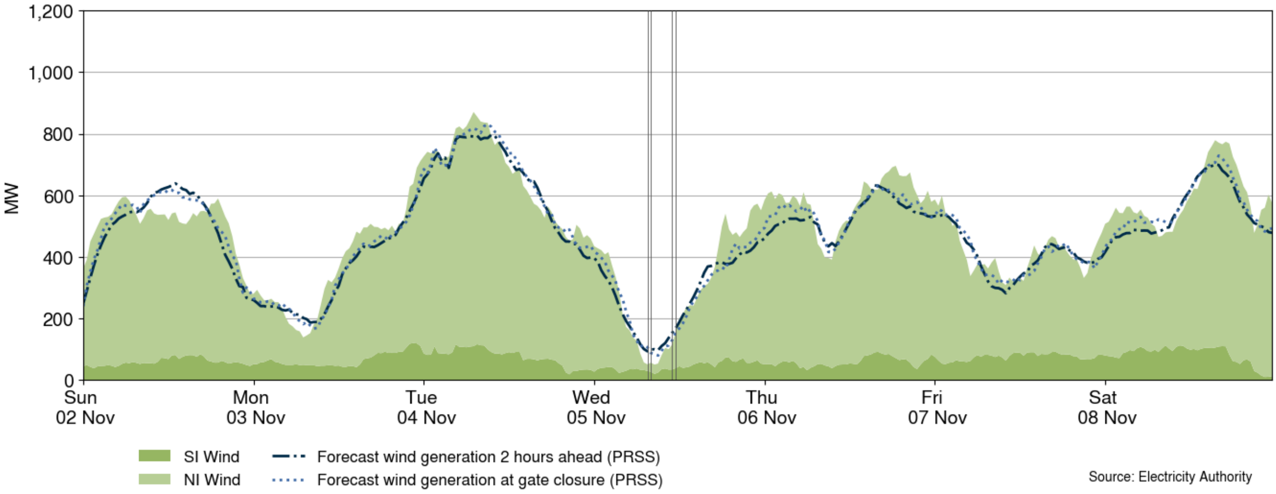


7. Generation

7.1. Figure 9 shows wind generation and forecast from 2-8 November 2025. This week wind generation varied between 50MW and 871MW, with a weekly average of 489MW.

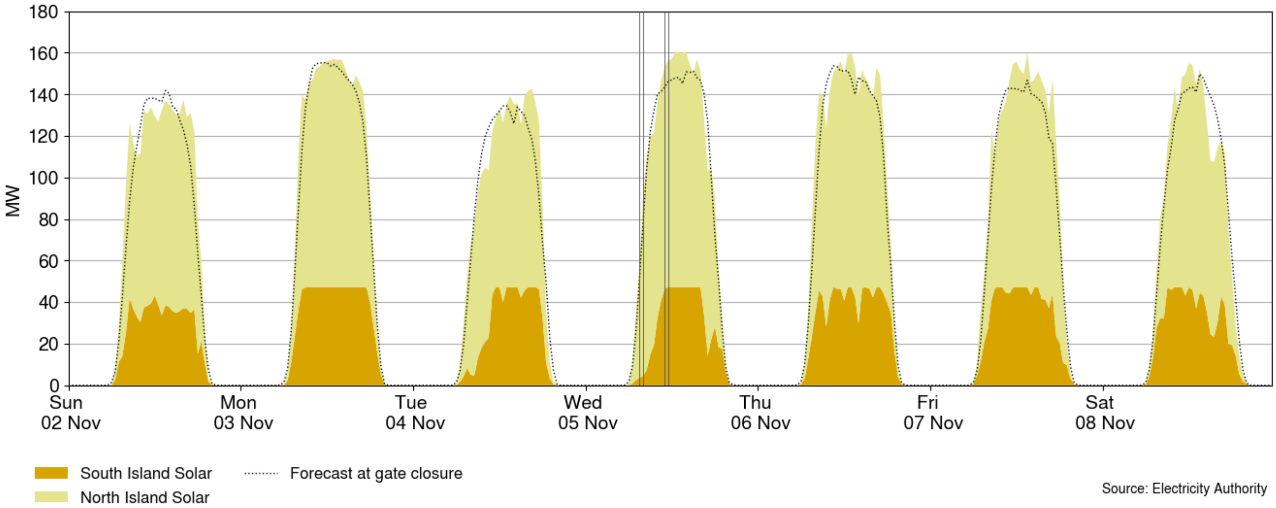
7.2. Wind generation remained mostly high on Sunday and began to gradually decline from Sunday night. It peaked on Tuesday, reaching a maximum of 871MW. The lowest wind generation of the week occurred on Wednesday during the price spikes. Between Thursday and Saturday, wind generation was mostly above 400MW.

Figure 9: Wind generation and forecast, 2-8 November 2025



7.3. Figure 10 shows grid connected solar generation from 2-8 November 2025. Solar generation peaked above 130MW daily, with a maximum of around 160MW on Wednesday at 2.00pm.

Figure 10: Grid connected solar generation, 2-8 November 2025

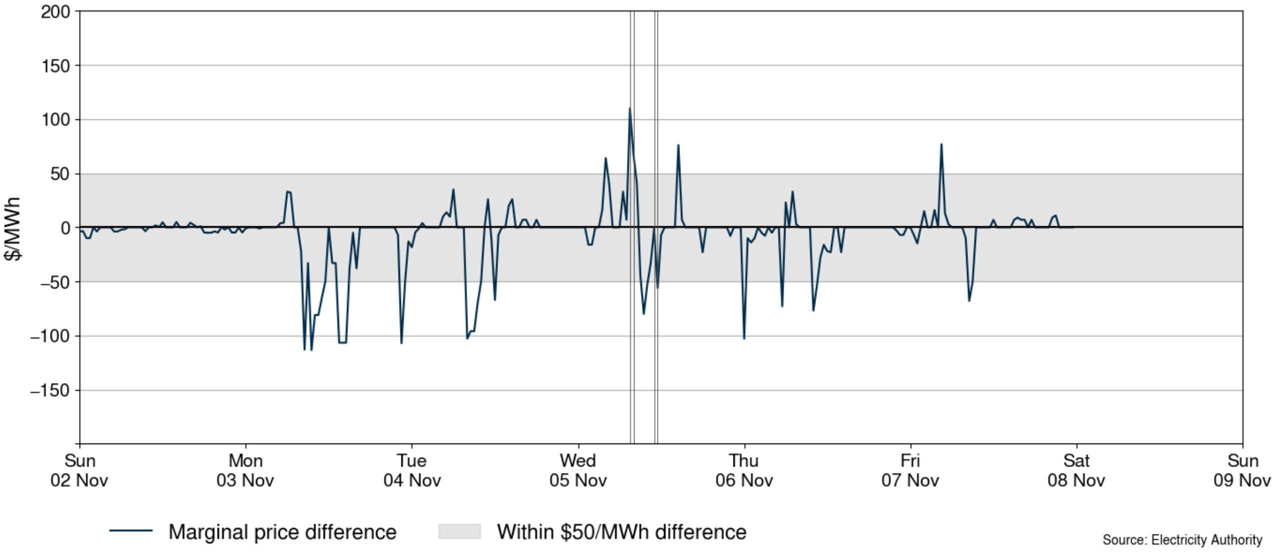


7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

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

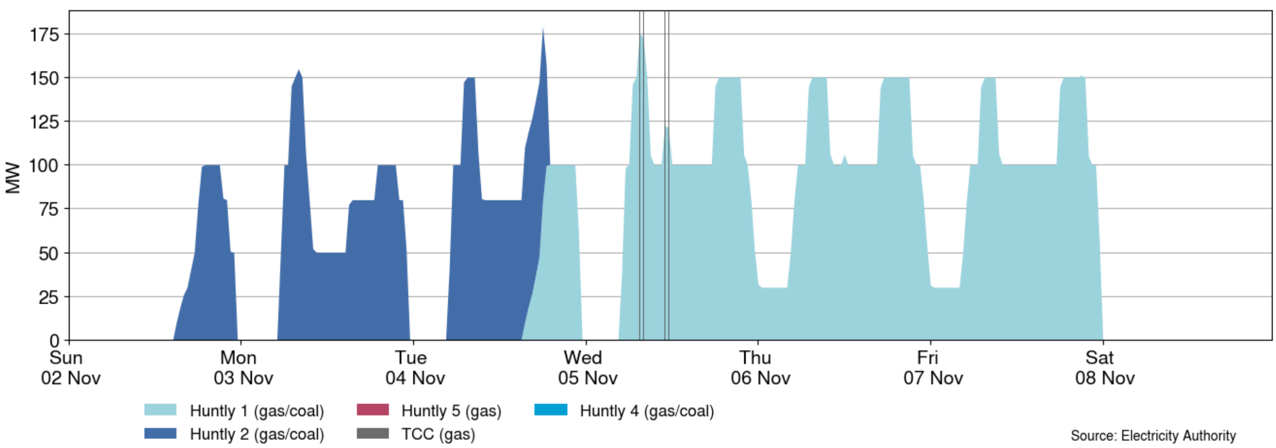
7.5. A few trading periods this week had positive marginal price differences above $50/MWh which were driven by wind and demand forecasting errors. The largest positive price difference of +$110/MWh occurred at 7.30am on Wednesday during the price spike, when demand was 5MW higher than forecast and wind was 55MW lower than forecast. During the price spikes later on Wednesday, prices were actually lower than simulated due to demand being slightly 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, 2-8 November 2025



7.6. Figure 12 shows the generation of thermal baseload between 2-8 November 2025. Huntly 2 ran from Sunday evening through to Tuesday evening. After returning from an outage, Huntly 1 resumed generation from Tuesday to Friday.

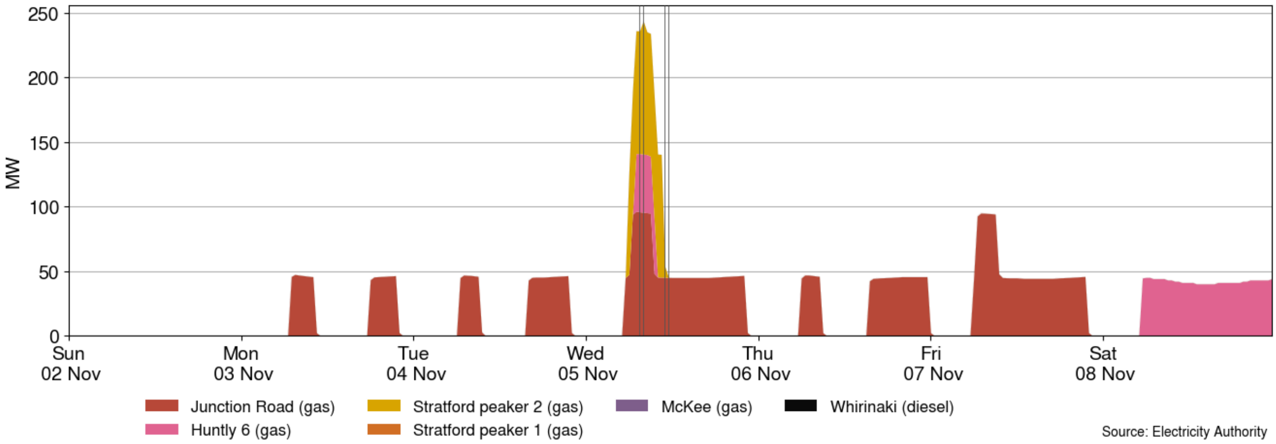
Figure 12: Thermal baseload generation, 2-8 November 2025



7.7. Figure 13 shows the generation of thermal peaker plants between 2-8 November 2025. Junction Road ran from Monday to Friday during both the morning and evening peaks. On Wednesday and Friday, it also ran continuously between the morning and evening peaks.

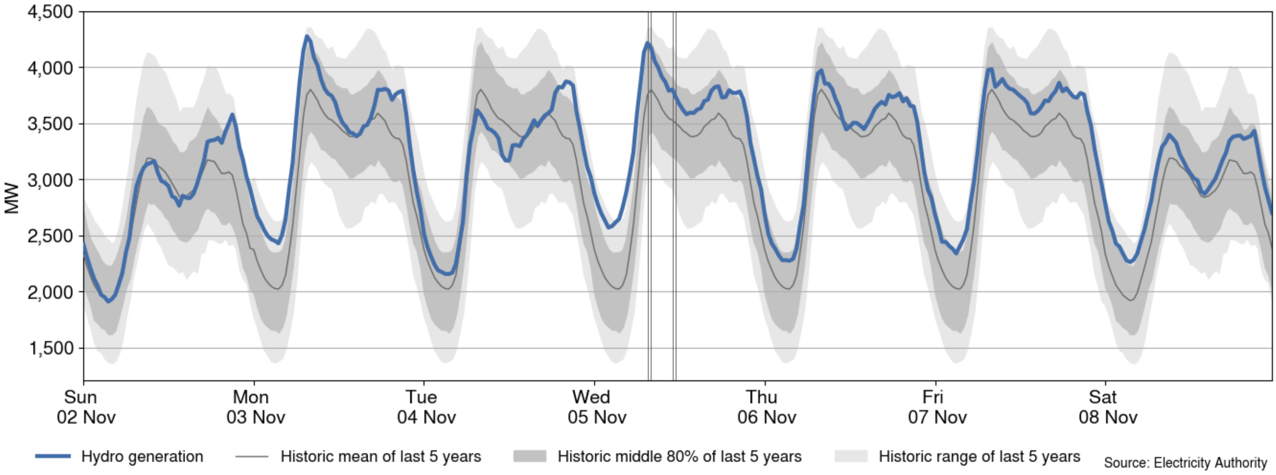
7.8. Huntly 6 ran during the Wednesday price spike and on Saturday. Stratford peaker 2 was also dispatched on Wednesday morning to meet demand.

Figure 13: Thermal peaker generation, 2-8 November 2025



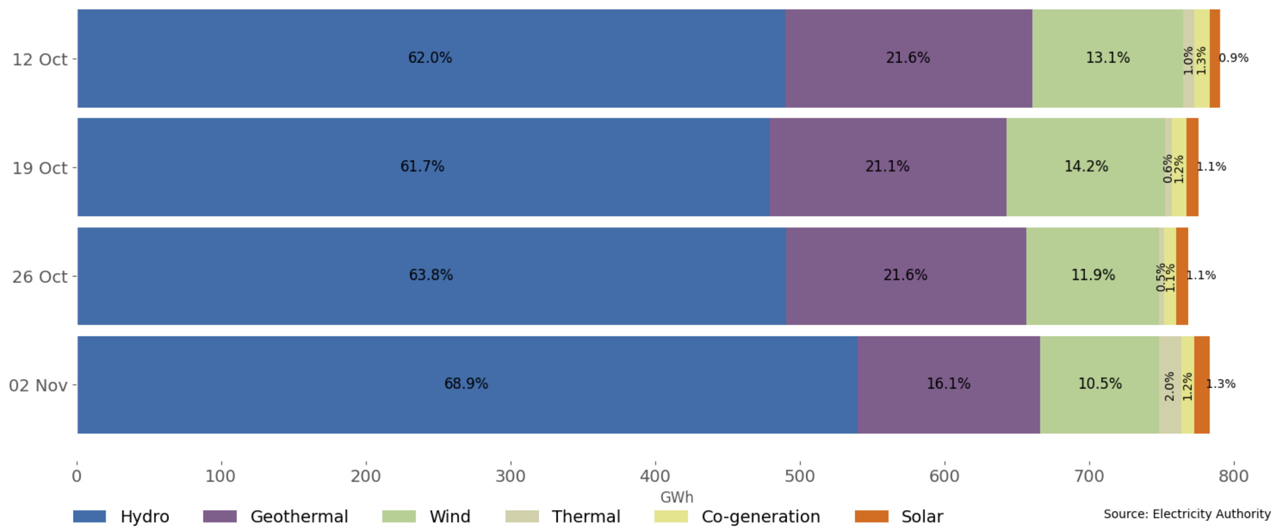
7.9. Figure 14 shows hydro generation between 2-8 November 2025. Hydro generation remained mostly within the middle 80% of historic generation. Hydro generation was elevated during the morning peaks on Monday and Wednesday. On Tuesday, hydro generation was relatively low, likely due to high wind generation.

Figure 14: Hydro generation, 2-8 November 2025



7.10. As a percentage of total generation, between 2-8 November 2025, total weekly hydro generation was 68.9%, geothermal 16.1%, wind 10.5%, thermal 2.0%, co-generation 1.2%, and solar (grid connected) 1.3%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 12 October and 8 November 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 2-8 November 2025 ranged between ~2,140MW and ~2,760MW. 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 1 was on outage until 4 November 2025.

(c) Huntly 4 is on extended partial outage until 14 November 2025.

(d) Stratford peaker 1 is on outage until 7 November 2025.

(e) Nga Awa Pūrua geothermal is on outage between 2-28 November 2025.

(f) Te Huka 3 geothermal is on outage until 12 November 2025.

(g) Tauhara geothermal is on outage between 2-29 November 2025.

(h) Ruakākā battery was on outage between 4-5 November (a few hours) and is on outage between 6-10 November 2025.

(i) Benmore unit 6 is on outage until 10 November 2025.

(j) Takapō B was on outage between 2-7 November 2025.

8.3. Some long-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, 2-8 November 2025

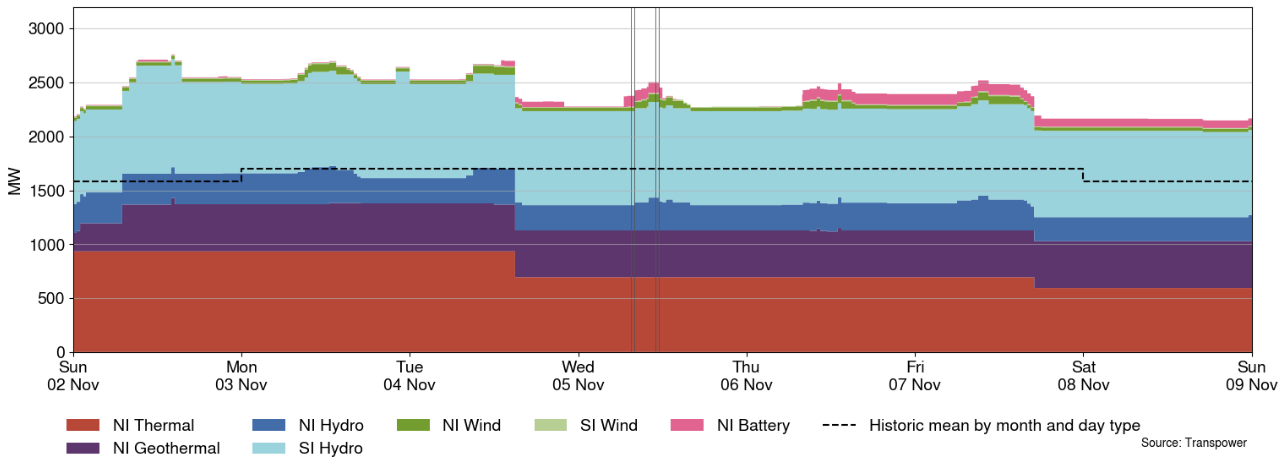
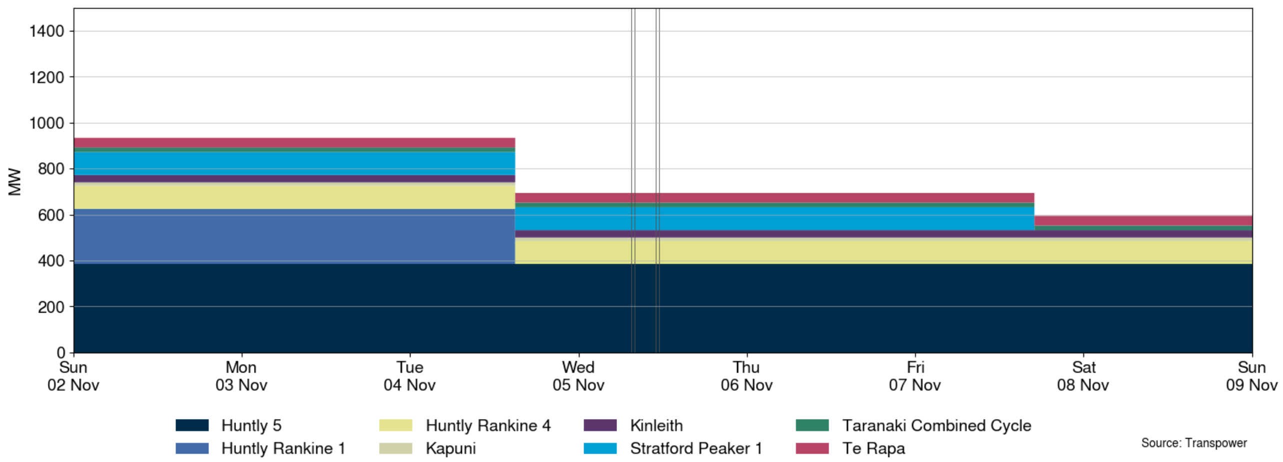


Figure 17: Total MW loss from thermal outages, 2-8 November 2025

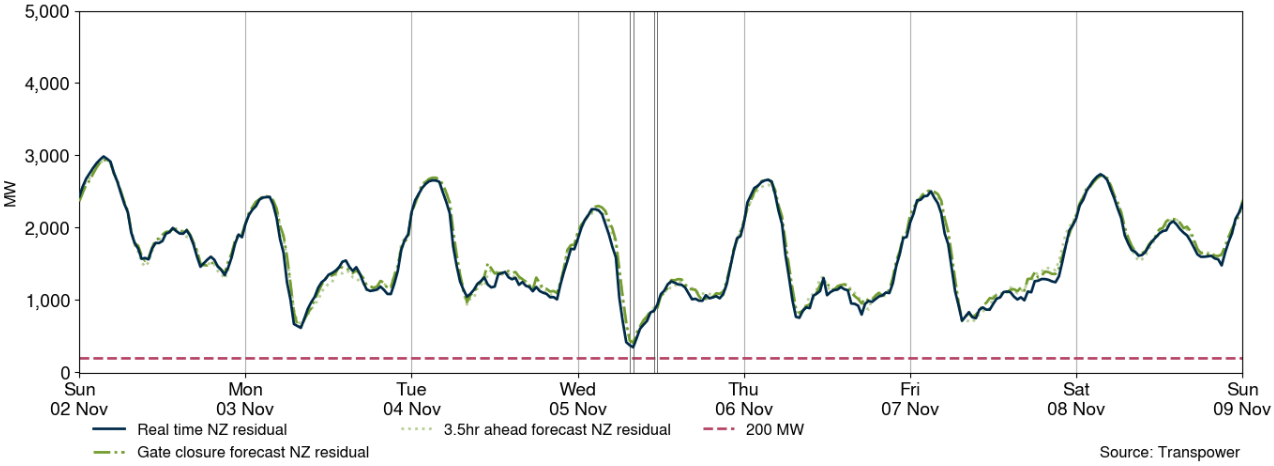


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 2-8 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 347MW on Wednesday at 8.00am.

Figure 18: National generation balance residuals, 2-8 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 7 November 2025, national controlled hydro storage slightly decreased to 89% of nominal full and ~138% of the historical average for this time of the year.

10.3. Storage at Lake Pūkaki (74% full[2]) and Lake Takapō (91% full) are slightly above their respective 90th percentile.

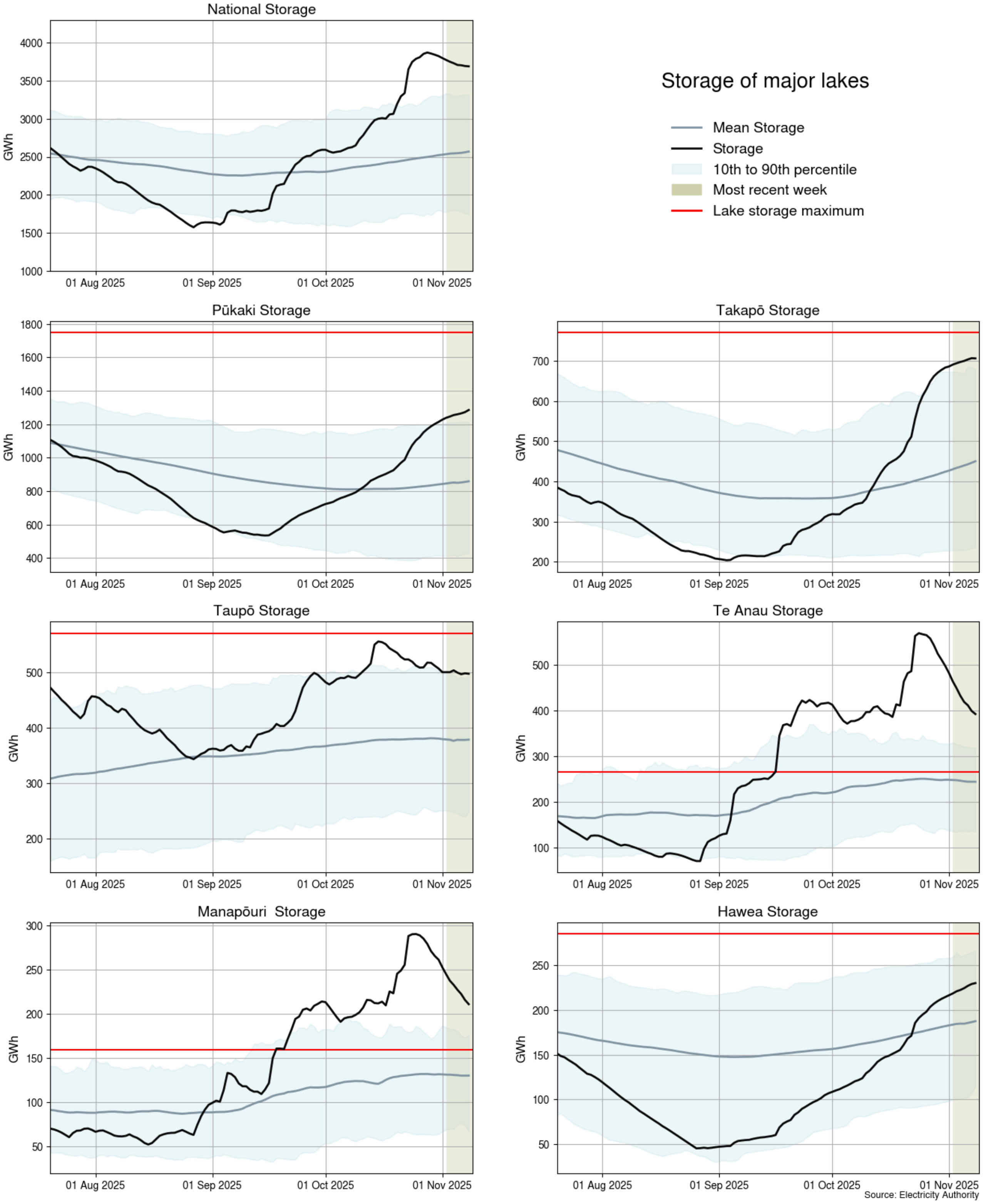
10.4. Storage at Lake Te Anau (143% full) and Lake Manapōuri (131% full) is above their respective historic 90th percentile. Both lakes have exceeded their respective storage capacities.

10.5. Storage at Lake Taupō (86% full) is touching its historic 90th percentile for this time of year.

10.6. Storage at Lake Hawea (81% full) is above its historic mean.

[2] Percentage full values sourced from NZX hydrological summary 9 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.

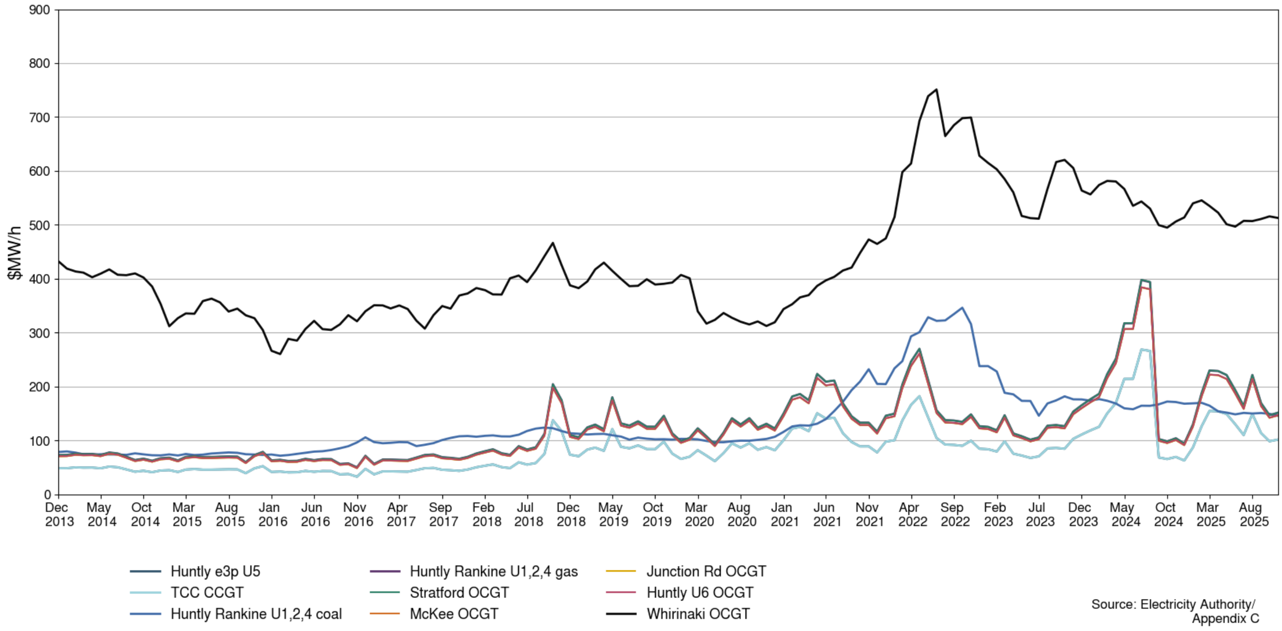
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$145/MWh. The cost of running the Rankines on gas is ~$151/MWh.

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



12. Offer behaviour

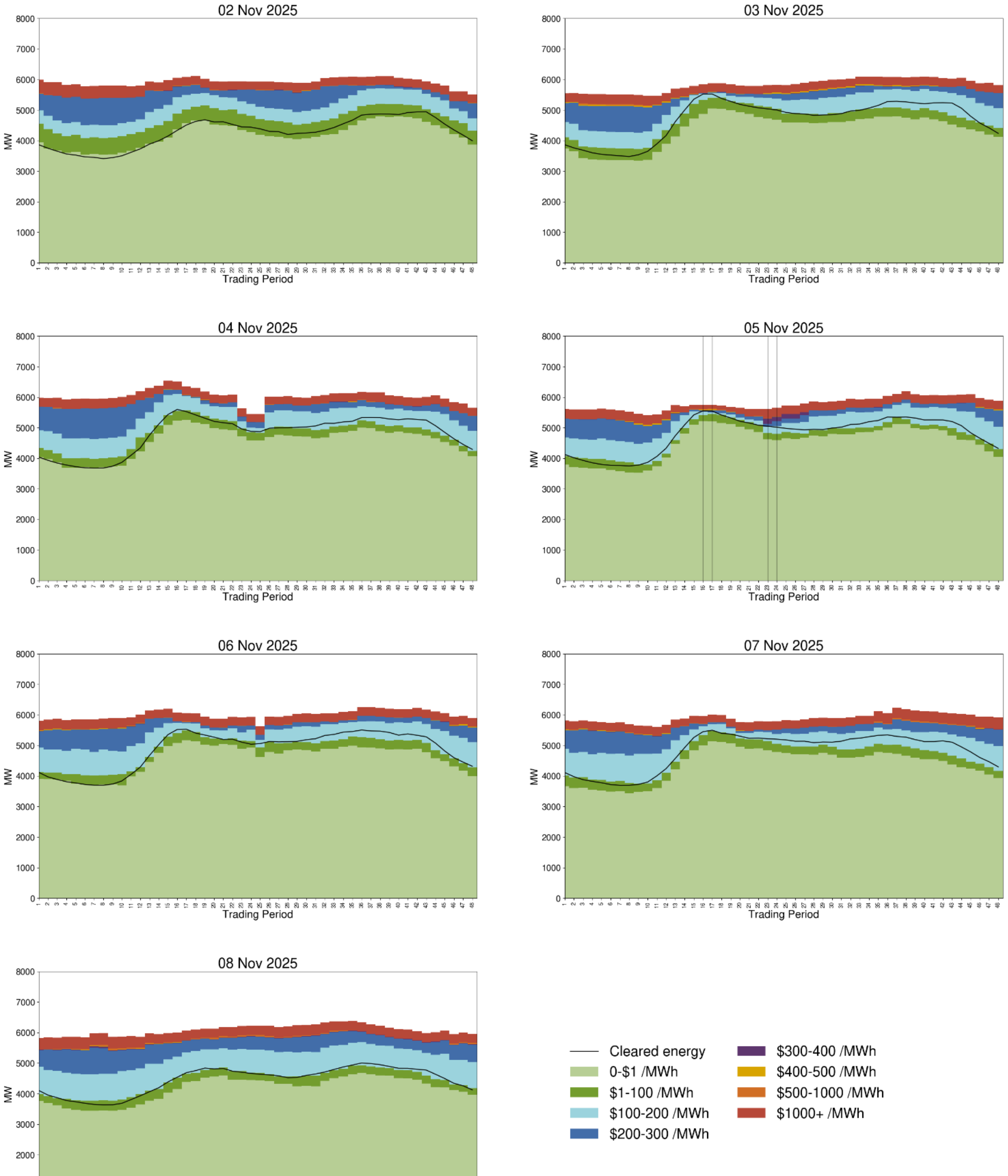
12.1. Figure 21 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

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

12.3. On Tuesday (11.00am-1.00pm) and Thursday (11.00am-12.00pm), energy along the Waitaki scheme was constrained to manage a NZAS reduction line off-load and restoration.

The reduction in low cost electricity on 5 November may have contributed to higher prices between 11am-11:30am.

Figure 21: Daily offer stacks



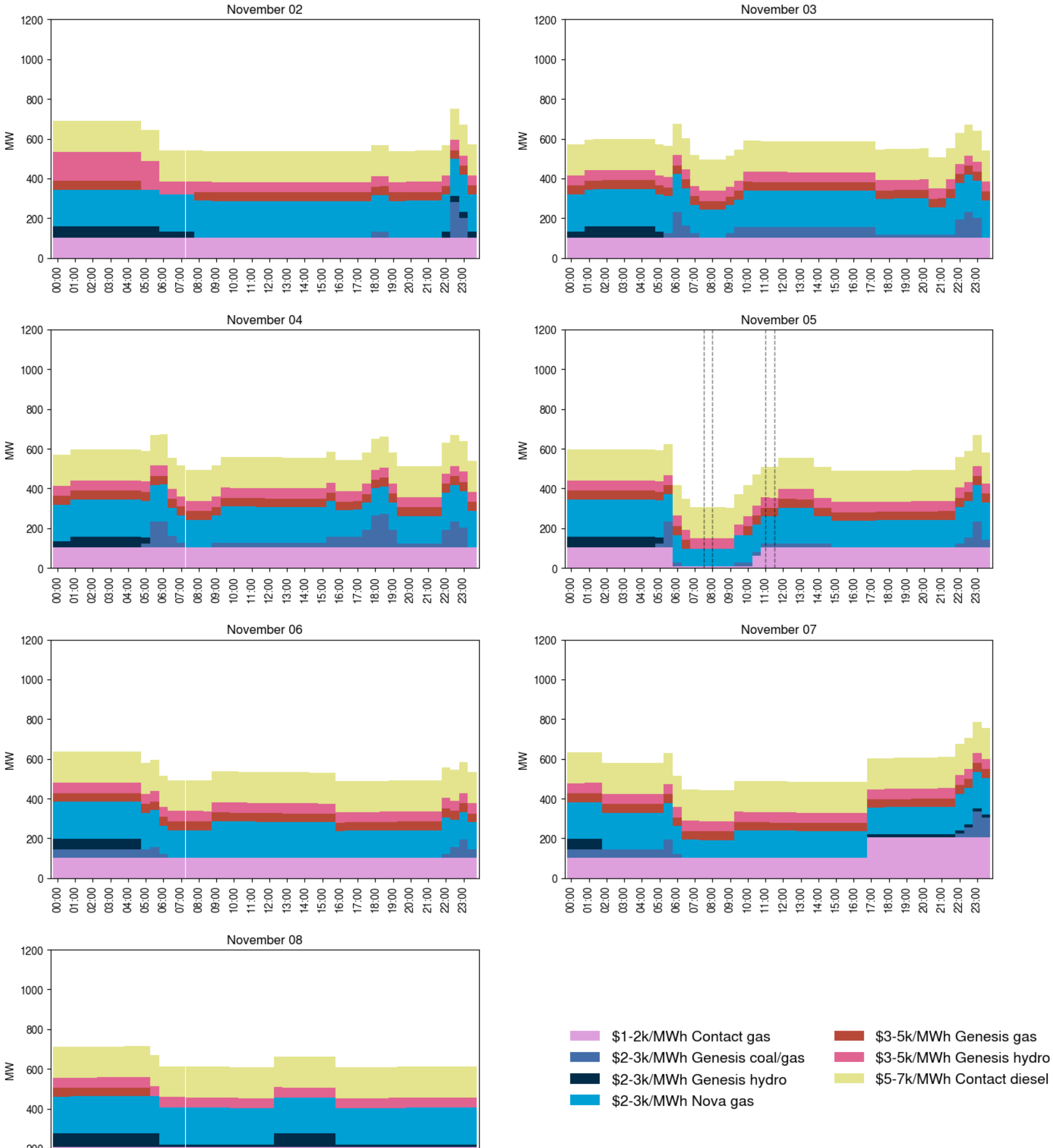
Source: Electricity Authority

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.

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 568MW per trading period was priced above $1,000/MWh this week, which is roughly 11.2% 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. The monitoring team is looking further into Waitaki and Starford 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
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	23-27	Further analysis	Mercury	Waikato	Hydro offers
5/11/2025	23-24	Further analysis	Contact	Stratford	Offers