27 May 2025

Trading conduct report 18-24 May 2025

Market monitoring weekly report

Trading conduct report 18-24 May 2025

1. Overview

1.1. The average price increased by $19/MWh this week to $160/MWh. National hydro storage remained stable at 67% nominally full and ~92% of the historical average, but hydro generation increased this week. Thermal generation was slightly lower. Cooler temperatures drove up demand, especially in the mornings.

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 18-24 May:

(a) The average spot price for the week was $160/MWh, an increase of around $19/MWh compared to the previous week.

(b) 95% of prices fell between $0.01/MWh and $279/MWh.

(c) Prices were slightly higher this week due to increased demand and slightly lower wind. Prices however remain lower than previous weeks due to continued sustained inflows, especially at Manapōuri, and the recent gas swap.

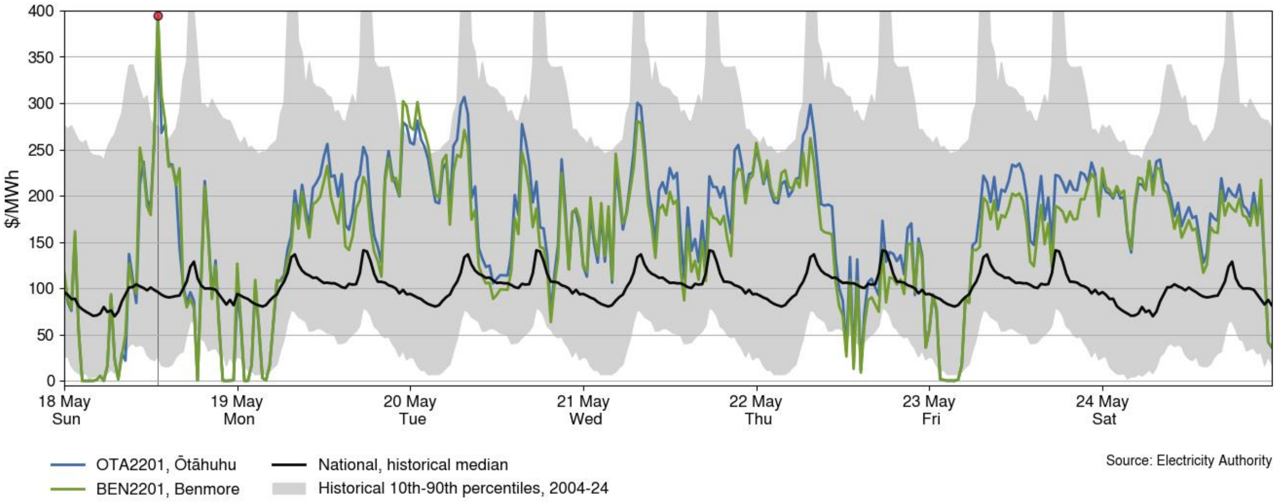
2.3. The highest price of the week occurred on Sunday at 1pm, with prices reaching $394/MWh at both Ōtāhuhu and Benmore. During this time wind was over forecast by 308MW. The following trading period also a wind error of 345MW. During these times additional hydro generation was dispatched which increased the spot price.

2.4. Other high prices which approached $300/MWh occurred on Monday at 11.00pm, Tuesday at 1am and 7.30am; and Wednesday at 7.30am. During these times wind generation was low and/or below forecast or demand was approaching its morning peak.

2.5. Higher wind on Thursday afternoon drove spot prices down.

2.6. 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.

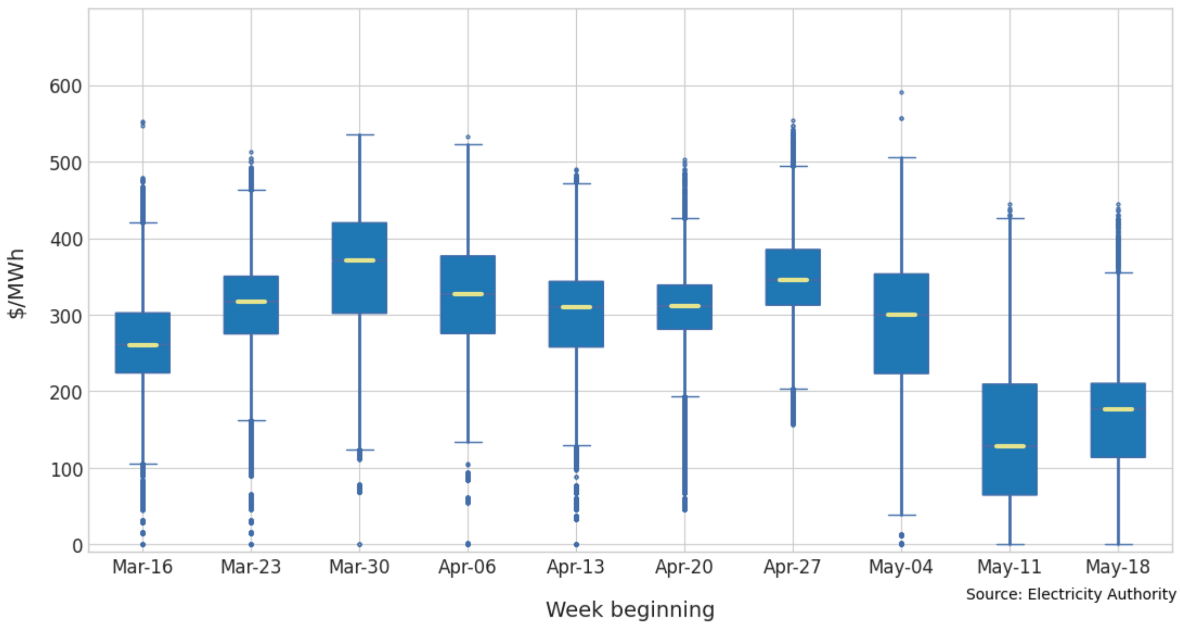
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 18-24 May



2.7. 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.

2.8. The distribution of spot prices this week was increased slightly compared to last week. The median price was $177/MWh and most prices (middle 50%) fell between $113/MWh and $210/MWh.

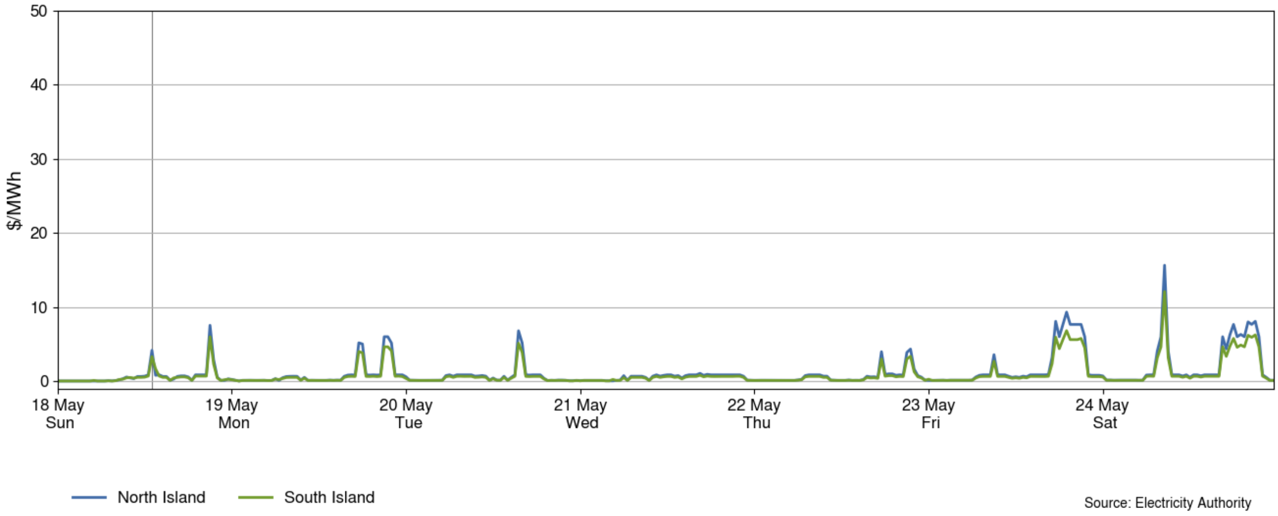
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

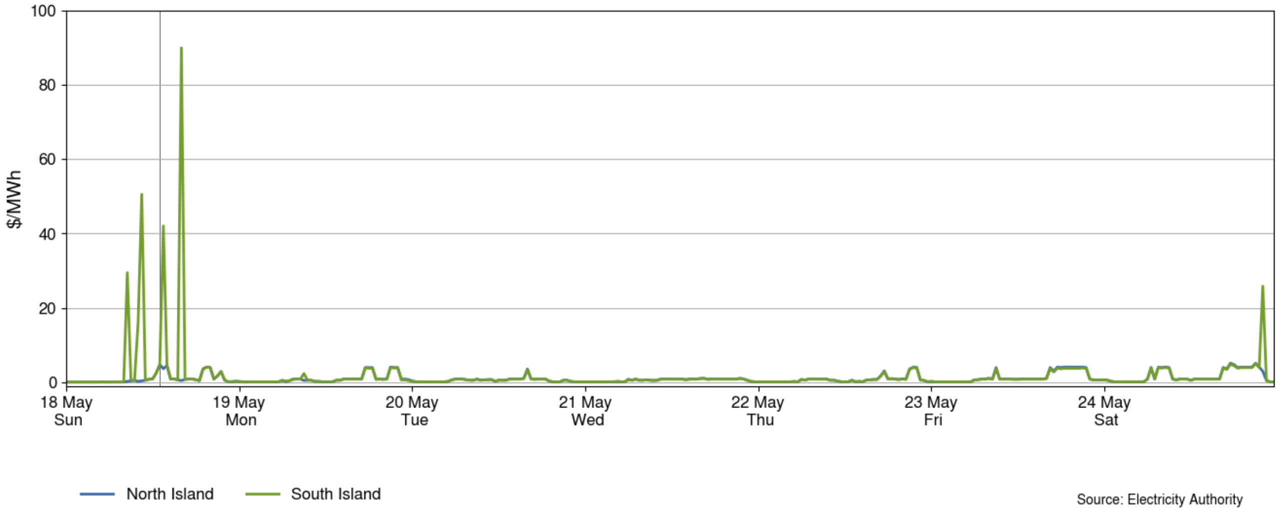
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. Most FIR prices were all below $10/MWh this week, with one spike on Saturday at 8.30am where North Island prices reached $16/MWh and South Island prices reached $12/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 18-24 May



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were all below $10/MWh this week apart from in the South Island on Sunday. During these periods the SIR that cleared in the South Island approached the limit of SIR available.

Figure 4: Sustained instantaneous reserve by trading period and island, 18-24 May



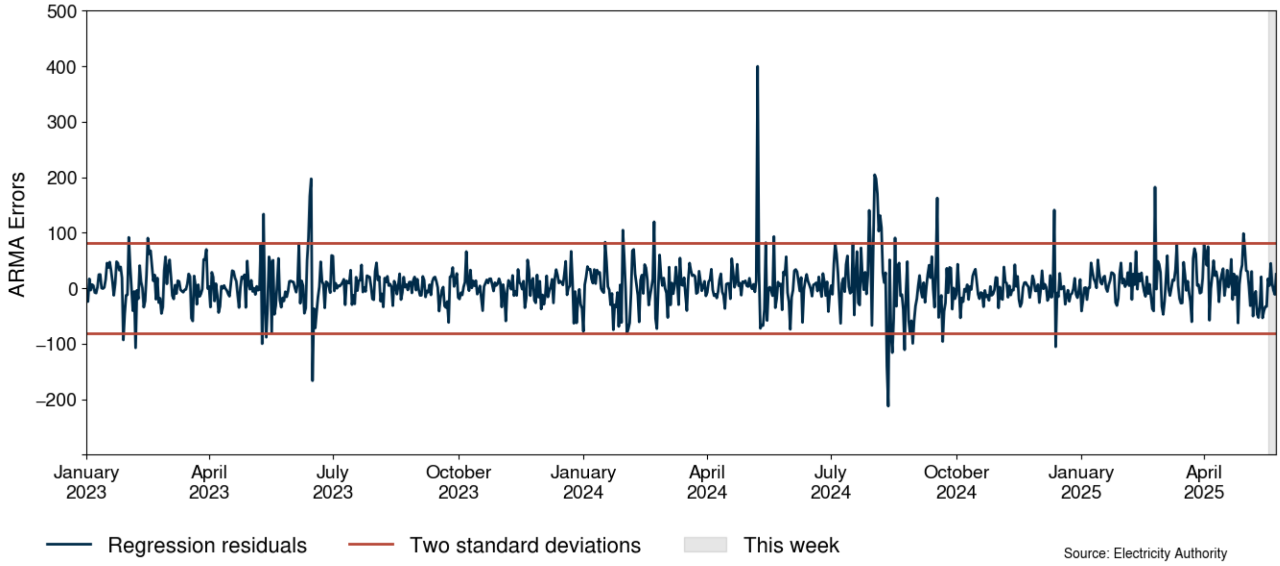
4. Regression residuals

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.

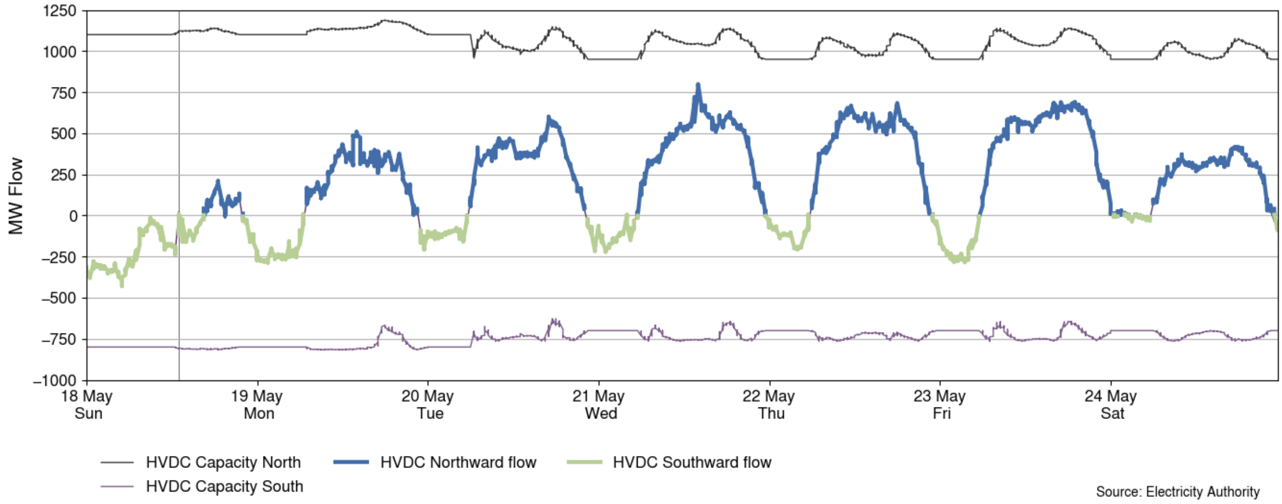
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 24 May 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 18-24 May. HVDC flows were mostly northward during the day and southward overnight. On Sunday during the price spike the HVDC ramped back on southward energy transfer during the period with the large wind forecasting inaccuracy. Northward flows reached over 750MW on Wednesday when wind generation was low.

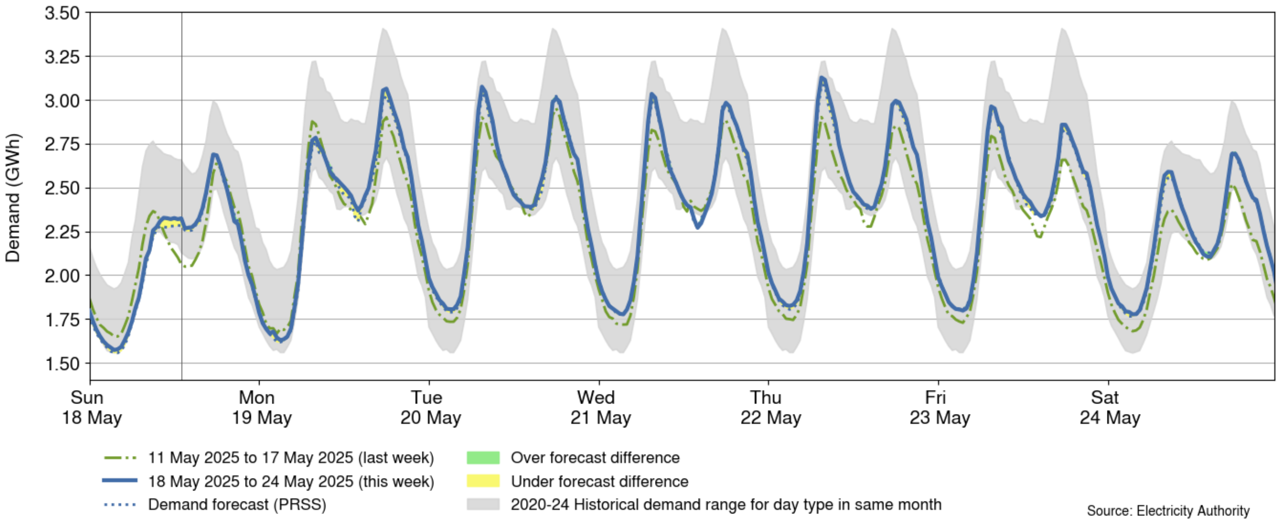
Figure 6: HVDC flow and capacity, 18-24 May



6. Demand

6.1. Figure 7 shows national demand between 18-24 May, compared to the historic range and the demand of the previous week. Demand was higher than the previous week with a continued larger difference between the peak and off peak. Demand was continuously higher than forecast on Sunday morning. The highest demand of the week was 3.13GWh at 7.30am on Thursday.

Figure 7: National demand, 18-24 May compared to the previous week

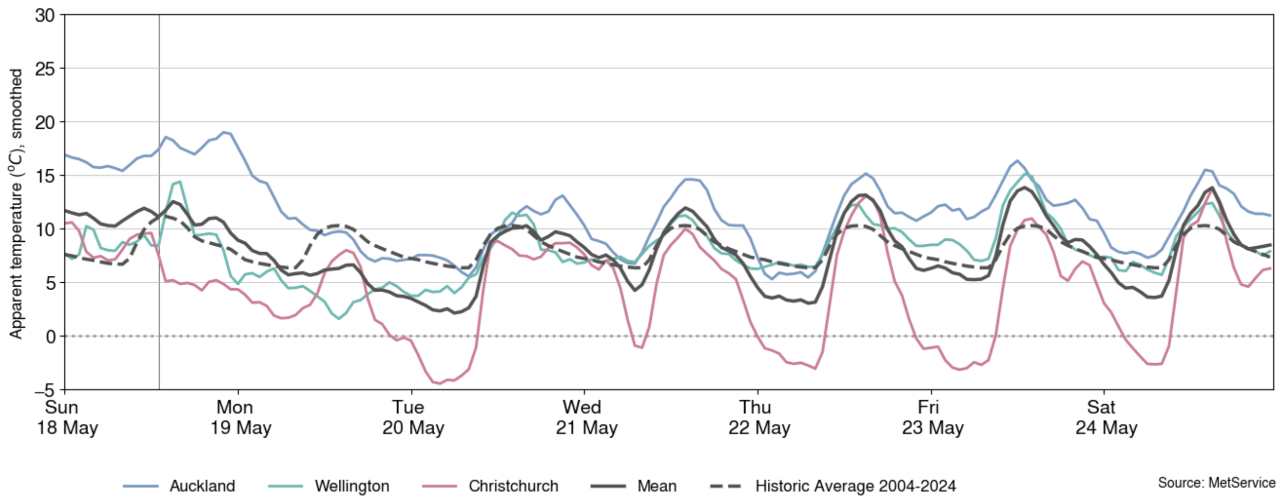


6.2. Figure 8 shows the hourly apparent temperature at main population centres from 18-24 May. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature 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. Temperatures were highest on Sunday and then declined through the week with Christchurch experiencing below freezing temperatures each morning.

6.4. Apparent temperatures ranged from 5°C to 20°C in Auckland, 2°C to 14°C in Wellington, and -5°C to 13°C in Christchurch.

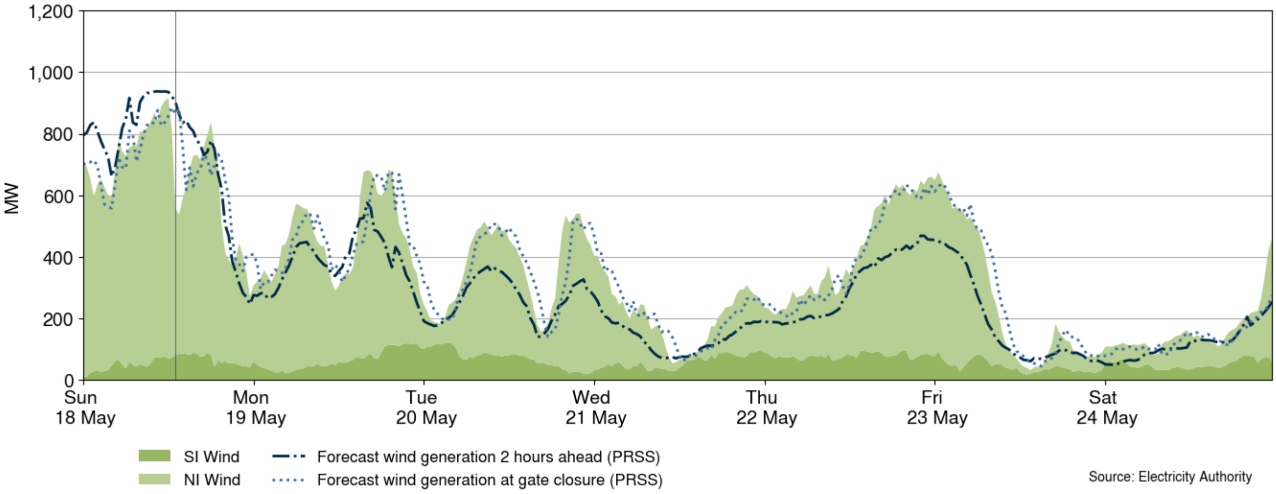
Figure 8: Temperatures across main centres, 18-24 May



7. Generation

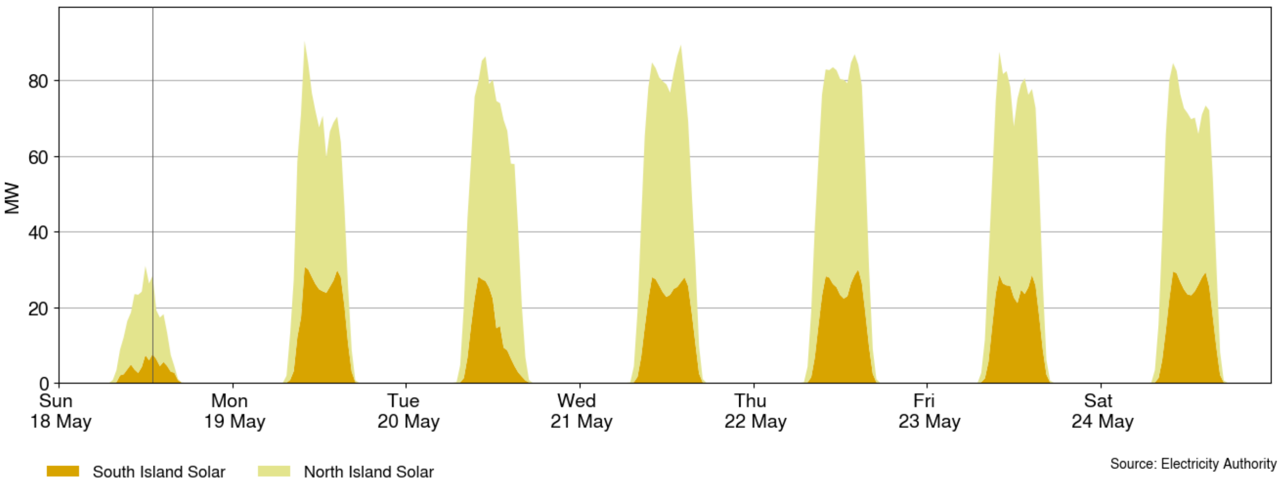
7.1. Figure 9 shows wind generation and forecast from 18-24 May. This week wind generation varied between 31MW and 916MW, with a weekly average of 361MW. Wind generation was lower than the previous week with over forecasting occurring on Sunday (when compared to the 2-hour ahead forecast) and higher than forecast during the week. Lower wind this week contributed to higher average spot prices. Lowest daily average wind was ~156MW on Saturday.

Figure 9: Wind generation and forecast, 18-24 May



7.2. Figure 10 shows grid connected solar generation from 18-24 May. Solar generation was low on Sunday, however, between Monday and Saturday generation averaged above 50MW.

Figure 10: Grid connected solar generation, 18-24 May



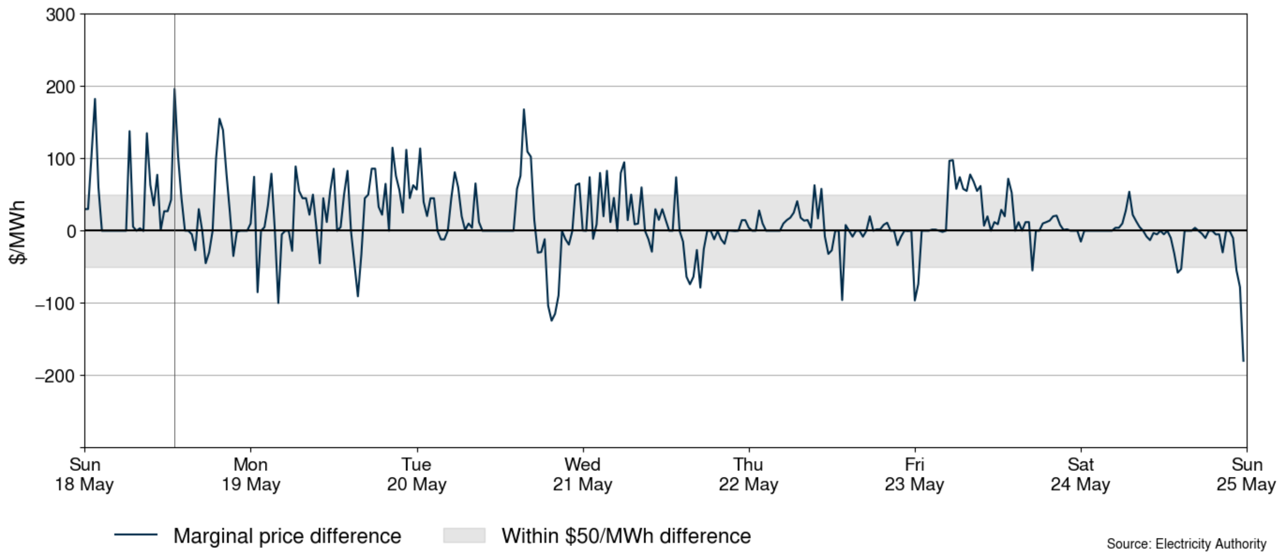
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

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

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.

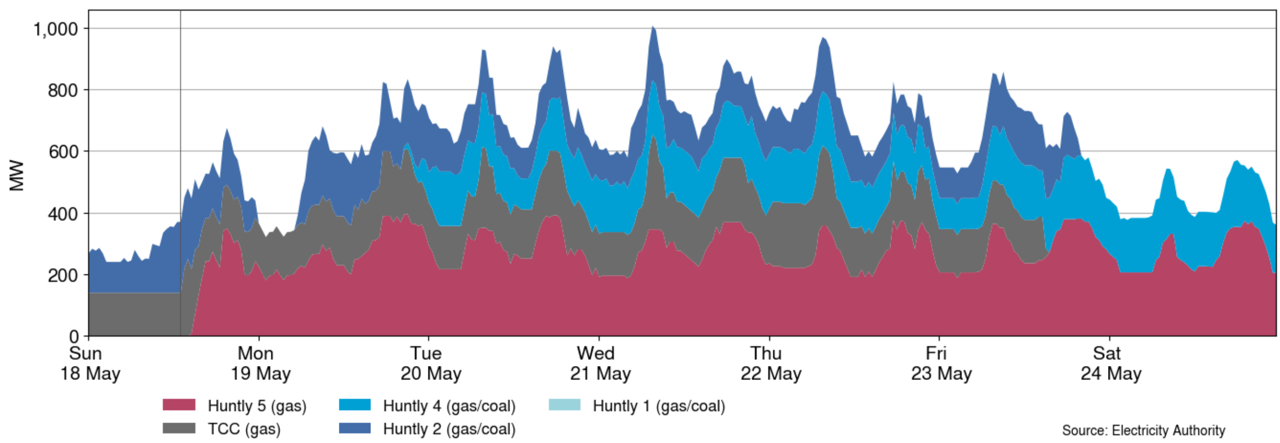
7.4. Several trading periods on Sunday had positive marginal price differences which were driven by the wind and demand forecasting errors. Another large positive price difference occurred on Tuesday when demand was over 100MW higher than expected and wind was 100MW lower than expected.

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, 18-24 May



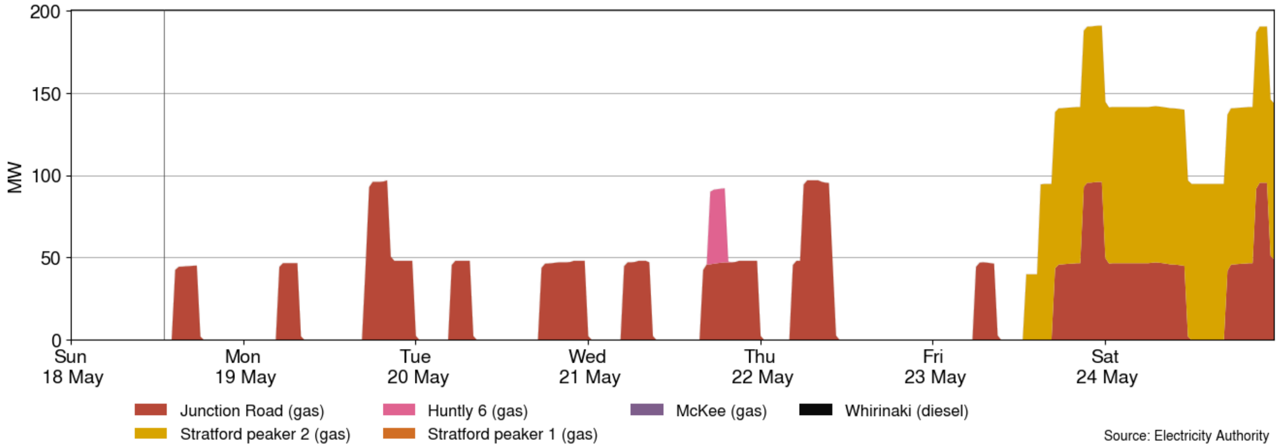
7.5. Figure 12 shows the generation of thermal baseload between 18-24 May. Huntly 5 ran this week from Sunday afternoon onwards. Huntly 2 briefly turned off in the early hours on Monday. From Monday afternoon Huntly 4 came online and together with TCC all units remained on contributing an average of 700MW to baseload.

Figure 12: Thermal baseload generation, 18-24 May



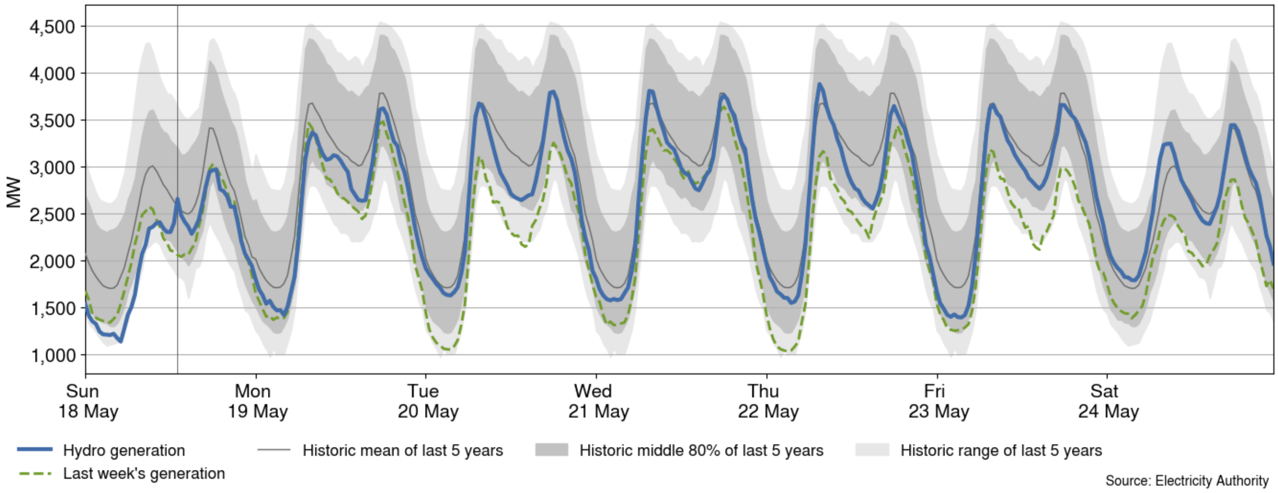
7.6. Figure 13 shows the generation of thermal peaker plants between 18-24 May. Junction Road ran this week, mostly to cover peak periods. Huntly 6 ran during Wednesday evening peak period. After TCC turned off, Stratford peaker 2 ran from Friday afternoon through Saturday.

Figure 13: Thermal peaker generation, 18-24 May



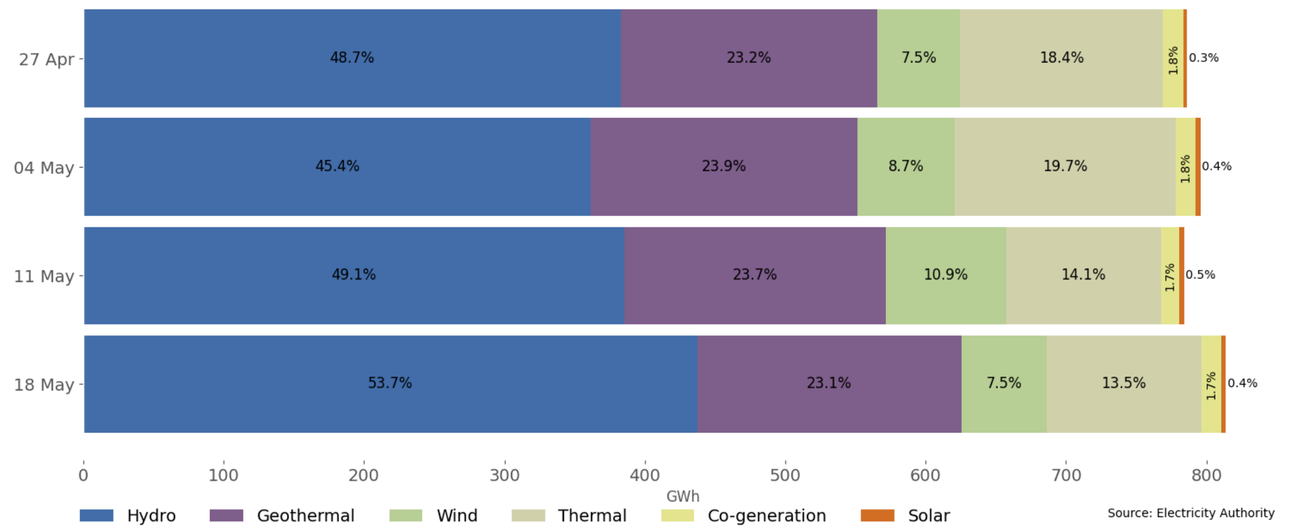
7.7. Figure 14 shows hydro generation between 18-24 May. Hydro generation this week was mostly higher than it was in the previous week, but still mostly at or below the historic mean. Hydro generation ramped up on Sunday during the price spike when wind generation dropped off.

Figure 14: Hydro generation, 18-24 May



7.8. As a percentage of total generation, between 18-24 May, total weekly hydro generation was 53.7%, geothermal 23.1%, wind 7.5%, thermal 13.5%, co-generation 1.7%, and solar (grid connected) 0.4%, as shown in Figure 15.

Figure 15: Total generation by type as a percentage each week, between 27 April to 24 May.



8. Outages

(a) Huntly 1 is on outage until 2 June.

(b) Huntly 2 was on outage until 26 May.

(c) Huntly 4 was on outage until 18 May.

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

(e) Clyde unit 1 was on outage until 22 May.

(f) Stratford peaker 1 is on outage until 30 June.

(g) Harapaki wind farm was on outage from 11.00am-7.00pm on 19 May.

(h) Waipipi wind farm was on outage 8.00am-6.00pm 21 May.

8.2. Figure 16 shows generation capacity on outage. Total capacity on outage between 18-24 May ranged between ~1020MW and ~1728MW. Figure 17 shows the thermal generation capacity outages.

8.3. Notable outages include:

(a) Huntly 1 is on outage until 2 June.

(b) Huntly 2 was on outage until 26 May.

(c) Huntly 4 was on outage until 18 May.

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

(e) Clyde unit 1 was on outage until 22 May.

(f) Stratford peaker 1 is on outage until 30 June.

(g) Harapaki wind farm was on outage from 11.00am-7.00pm on 19 May.

(h) Waipipi wind farm was on outage 8.00am-6.00pm 21 May.

Figure 16: Total MW loss from generation outages, 18-24 May

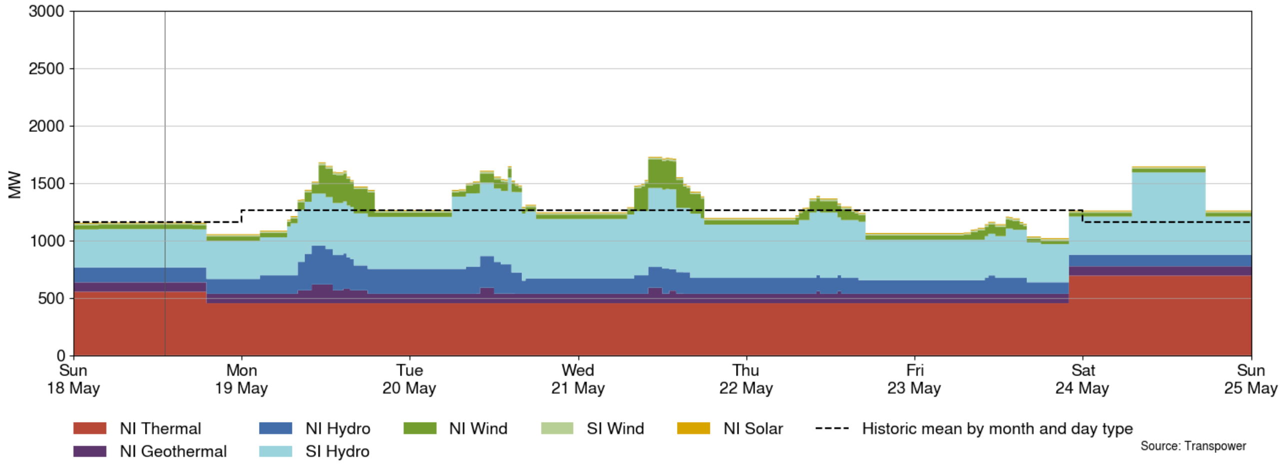
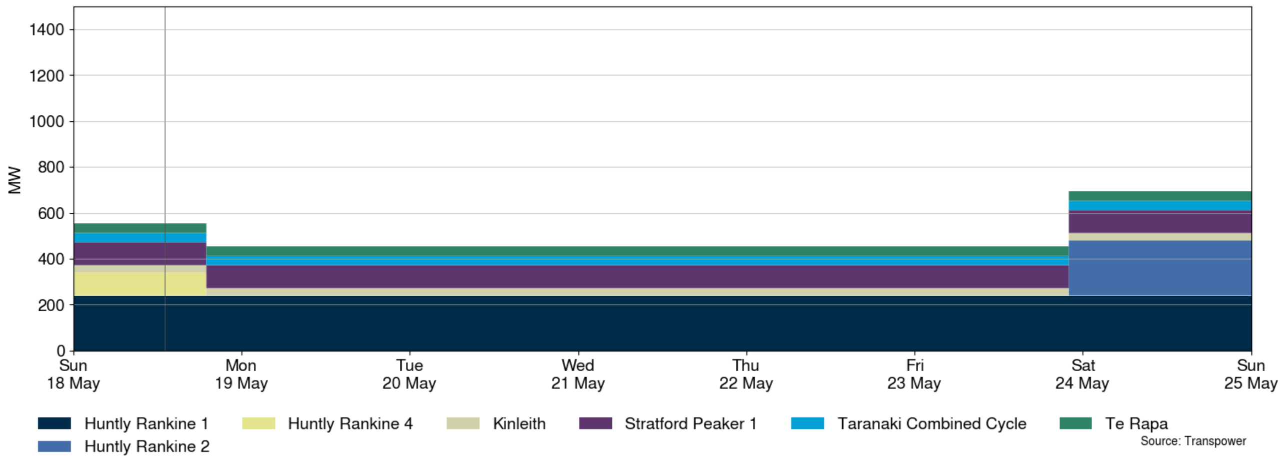


Figure 17: Total MW loss from thermal outages, 18-24 May



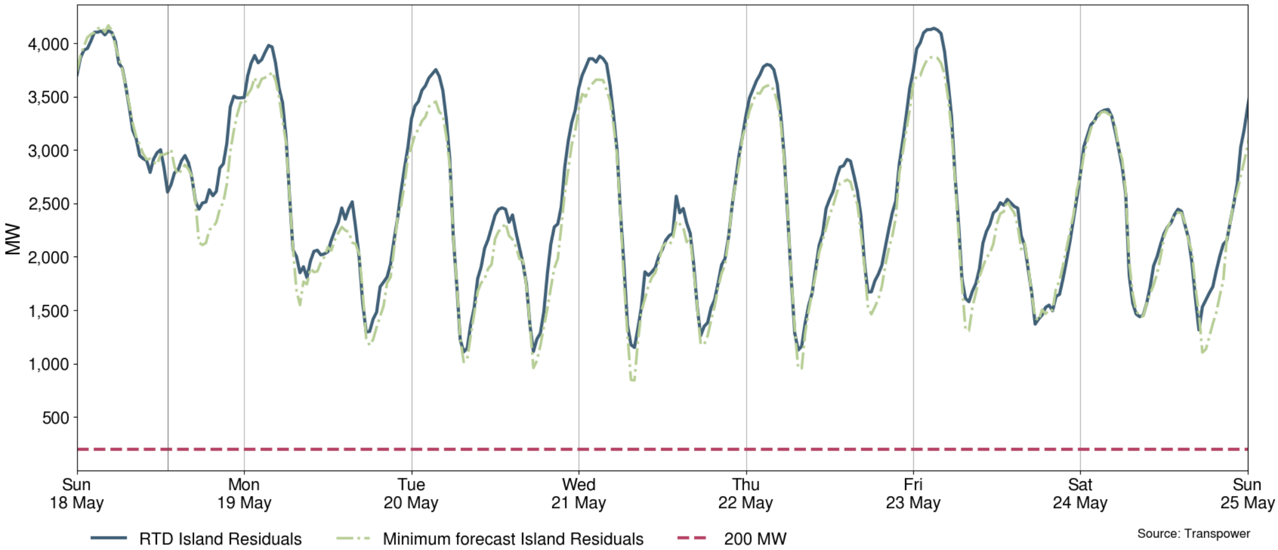
9. Generation balance residuals

9.1. Residuals were healthy this week. The lowest national residual was 1,109MW on Tuesday at 7.30am.

9.2. Figure 18 shows the national generation balance residuals between 18-24 May. 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.

9.3. Residuals were healthy this week. The lowest national residual was 1,109MW on Tuesday at 7.30am.

Figure 18: National generation balance residuals, 18-24 May



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 24 May, national controlled storage was 67% nominally full and ~92% of the historical average for this time of the year.

10.3. Storage at lakes Pūkaki (66% full)[2] and Takapō (54% full) are just above their historical 10th percentiles.

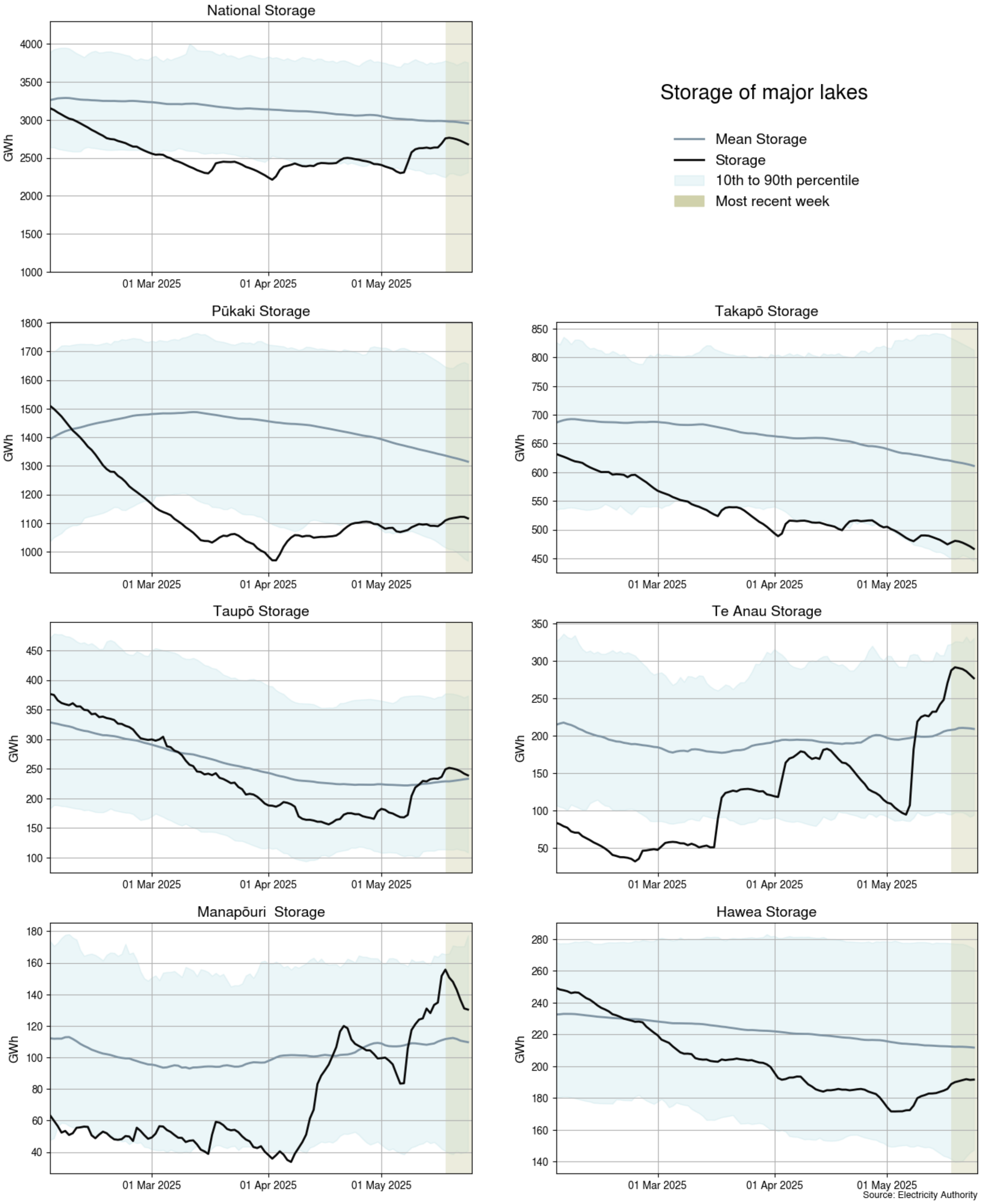
10.4. Lakes Te Anau and Manapōuri decreased during the week but are both still above their respective means.

10.5. Storage at Lake Taupō (42% full) is still around its historic mean.

10.6. Lake Hawea storage (68% full) increased and is still between its historical 10th percentile and mean.

[2] Percentage full values sourced from NZX Hydro (25 May 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 May 2025. The SRMCs for gas powered generation have increased slightly while coal and diesel fuelled generation decreased. As was the case last month, it is likely cheaper to run the Rankines on coal.

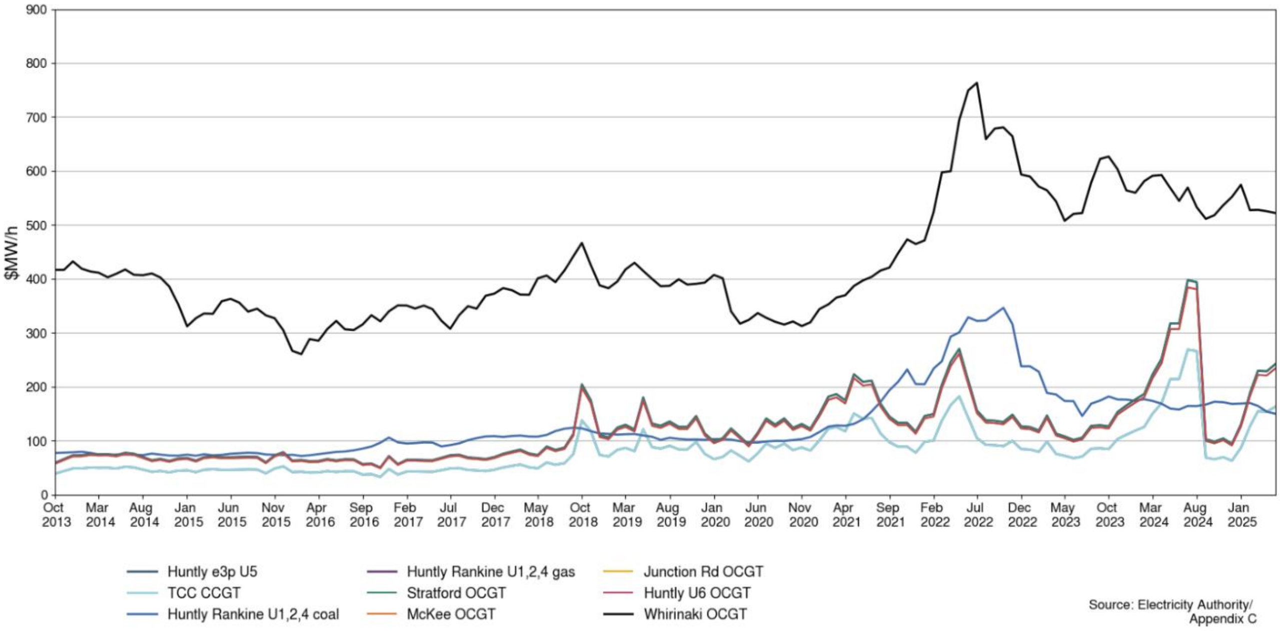
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$242/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $163/MWh and $242/MWh.

11.6. The SRMC of Whirinaki is ~$522/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



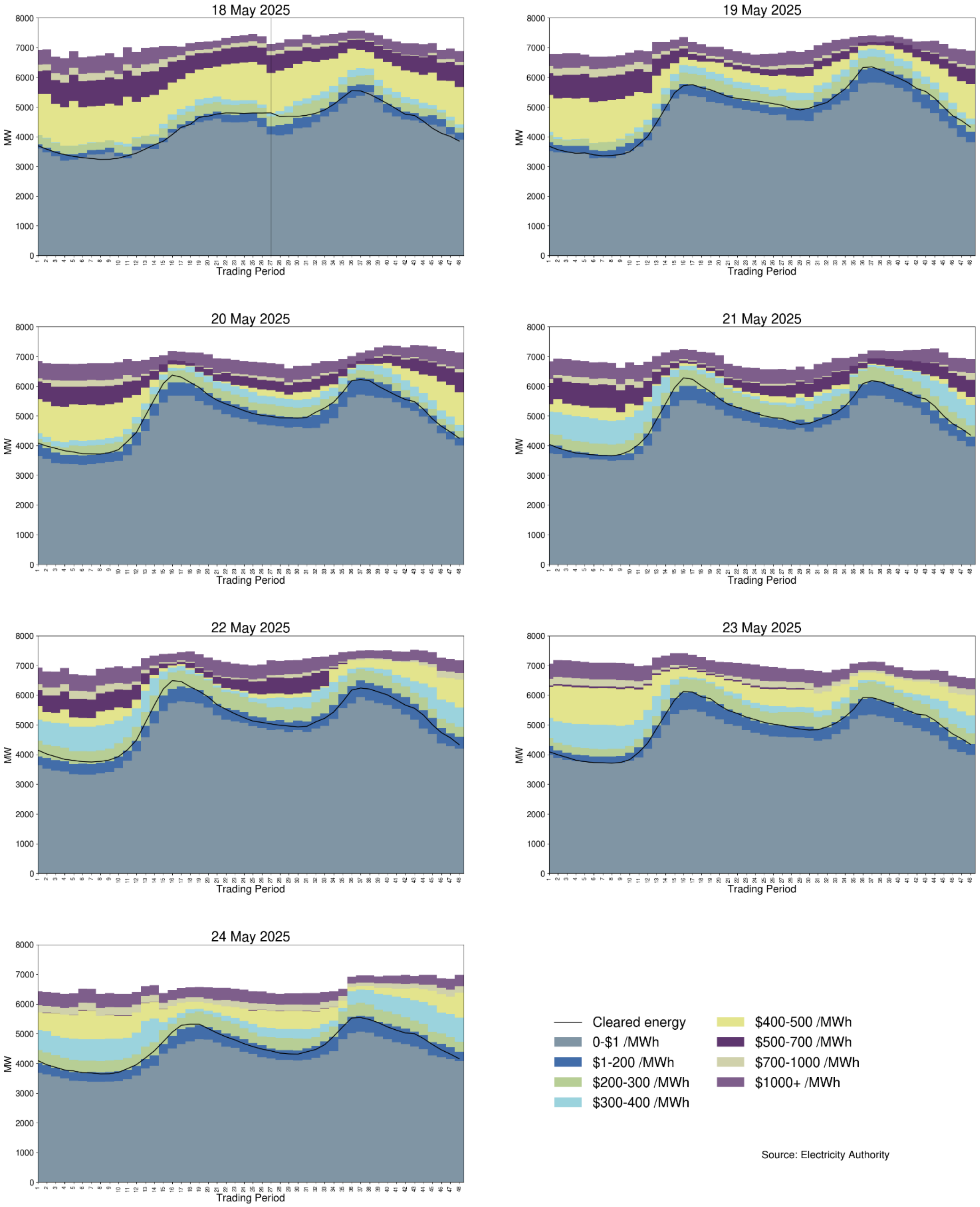
12. Offer behaviour

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 $1-$200/MWh or $200-$300/MWh bands. The wind forecasting errors on Sunday tipped the cleared energy into higher bands. Over the week most of the energy priced in the $400-$500/MWh band was priced down into the $300-

$400/MWh band. This was mostly Mercury hydro and reflects the decreased value of water as hydro storage increased to mean at Taupo.

Figure 21: Daily offer stacks



Source: Electricity Authority

12.3. 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.

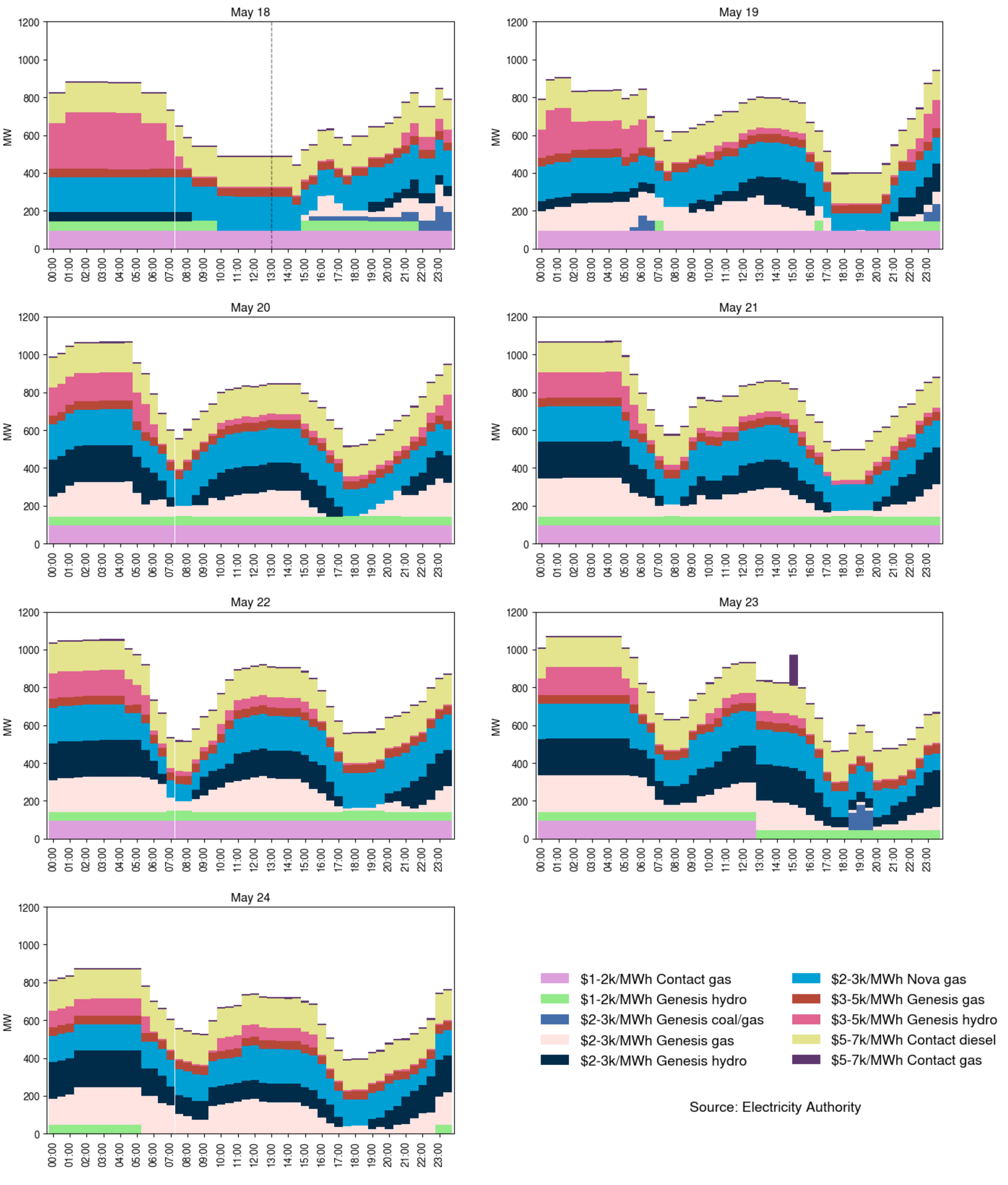
12.4. If forecast prices are lower than thermal operating costs, this signals some generators may not be needed in that half-hourly trading period. Thermal generators may then price their units high, as they aren’t expecting to run. These high prices reflect increased operating costs of running for only 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 748MW per trading period was priced above $1,000/MWh this week, which is roughly 12.4% of the total energy available.

12.6. The reduction in spot prices has driven some thermal generation offline, including this week TCC and McKee along with more limited running of Junction Road. When TCC is turned off it isn’t offered into the market due to its long start-up time but the fast start peakers continue to offer in at prices which cover their running costs for a short period.

12.7. The monitoring team will be doing further analysis of the high Contact gas offer on Friday.

Figure 22: High priced offers



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	Back with monitoring for analysis	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Back with monitoring for analysis	Contact	Multiple	High hydro offers
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact	Clutha scheme	Hydro offers
1/03/2025-26/04/2025	Several	Further analysis	Genesis	Takapō	Hydro offer pricing
15/05/2025	46-47	Further analysis	Genesis	Huntly	Rankine offers
23/05/2025	31	Further analysis	Contact	TCC	Offers