24 April 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 13-19 April 2025

Market monitoring weekly report

Trading conduct report 13-18 April 2025

1. Overview

1.1. The weekly average spot price decreased this week; however, prices are still mostly above $250/MWh. An increase in wind generation and completion of geothermal outages meant the proportion of generation from thermal decreased slightly. An unplanned HVDC outage on Thursday morning led to some large price separations during Thursday to Saturday, with Benmore prices higher than Ōtāhuhu at times. National controlled hydro storage remains below historic mean and around 63% nominally full.

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 13-19 April:

(a) The average spot price for the week was $297/MWh, a decrease of around $32/MWh compared to the previous week.

(b) 95% of prices fell between $157/MWh and $401/MWh.

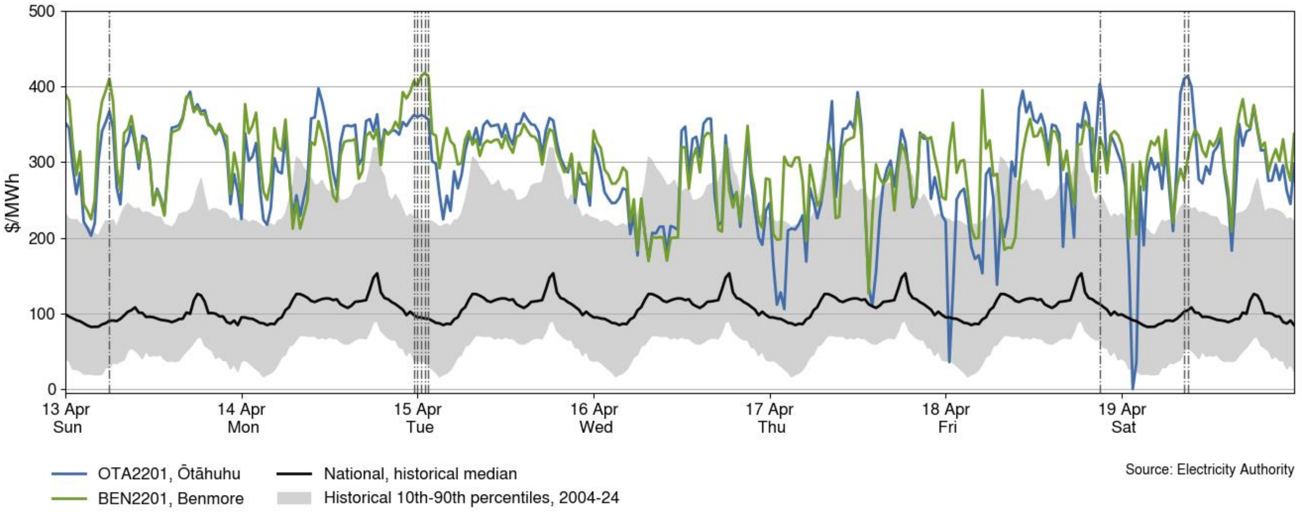
2.3. Although overall average prices decreased slightly this week, most prices are still above $250/MWh and sitting above the historic 90th percentile region.

2.4. There were a few instances where the Benmore price was higher than the Ōtāhuhu price. In the early hours of Tuesday morning Benmore prices were above $400/MWh. Ōtāhuhu prices were also high at around $350/MWh. There was a sharp decline in wind generation on Tuesday and demand was under forecast by ~30-66MW.

2.5. Later in the week at both 12.30am on Friday and between 1.30-2.00am on Saturday prices at Ōtāhuhu dropped to under $40/MWh whist remaining between $200-$300/MWh at Benmore. During these times North Island wind was high and southward export was limited by the HVDC outage.

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.

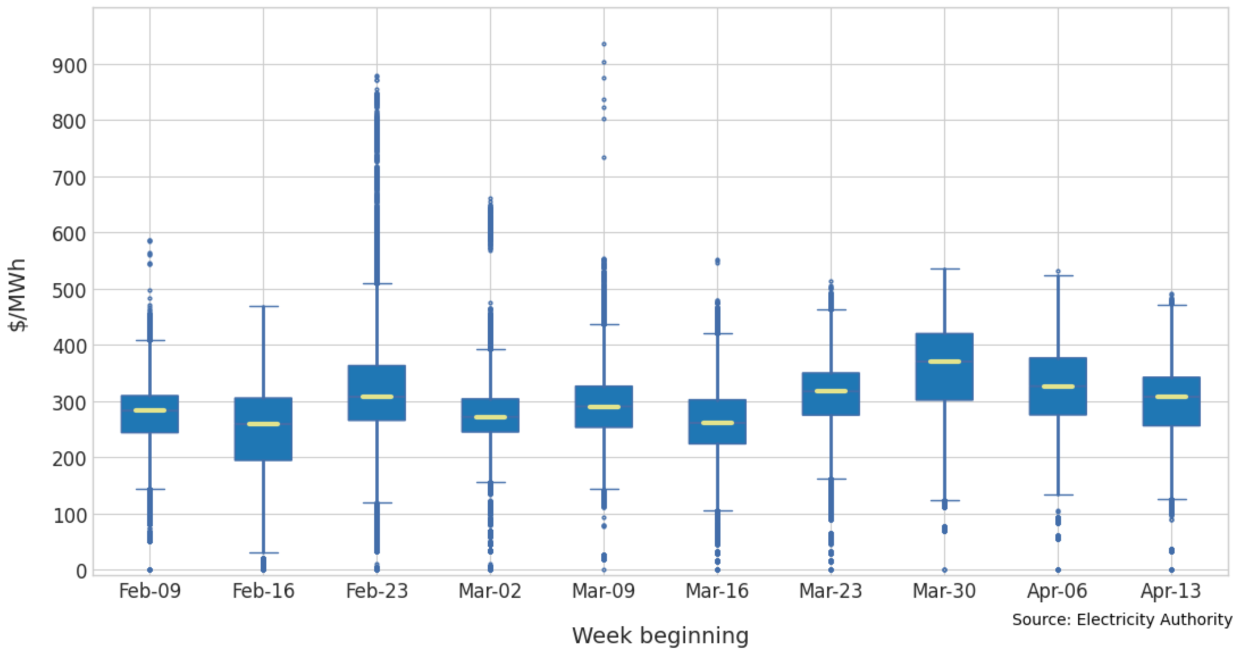
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 13-19 April



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 slightly lower than the previous week. The median price was $307/MWh, and most prices (middle 50%) fell between $256/MWh and $342/MWh.

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



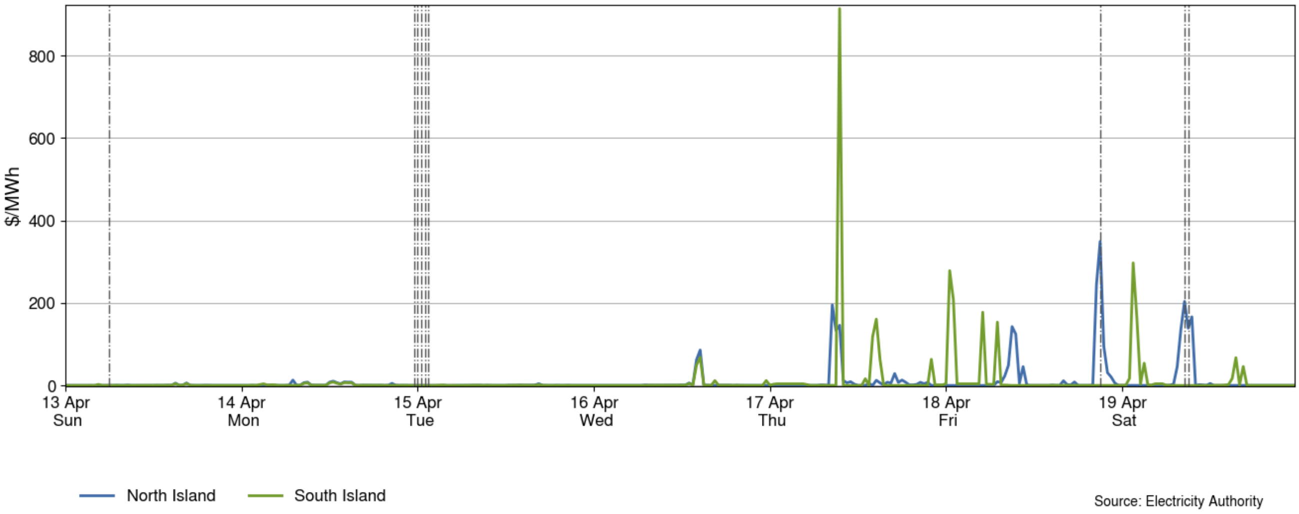
3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mainly under $10/MWh in the first half of the week. From Wednesday afternoon there was increased volatility in FIR prices with multiple instances of spikes and separations for both island reserves above $50/MWh.

3.2. The highest FIR price occurred on Thursday at 9.30am when there was reserve scarcity, with South Island FIR reaching $7000/MWh for one 5 min RTD during the 9.30am trading period. FIR averaged at $914/MWh for that trading period.

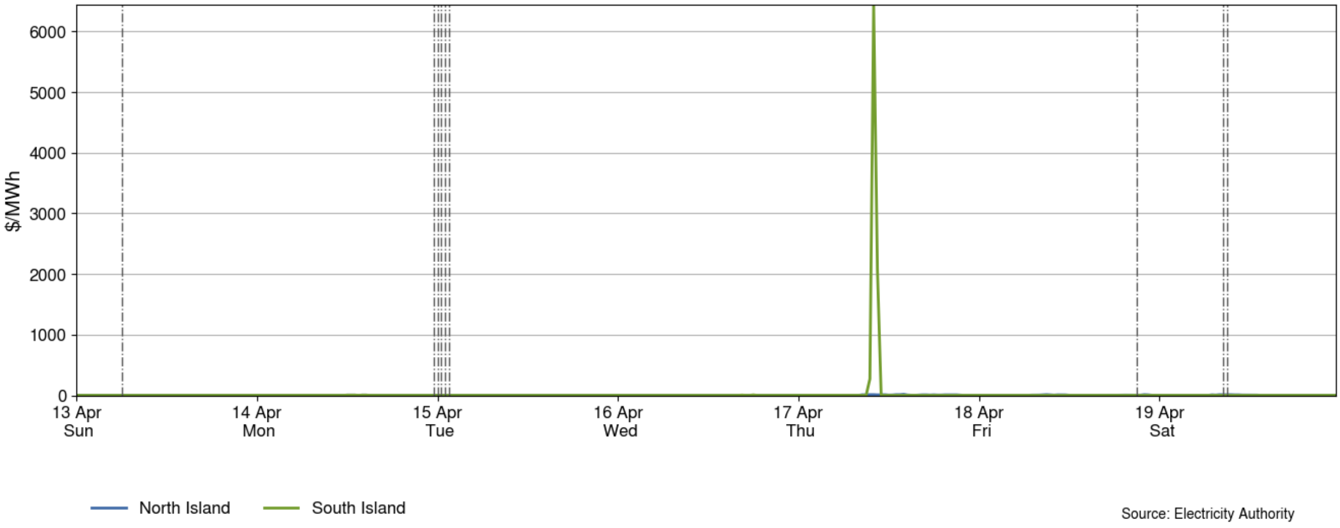
3.3. The spikes in reserve prices and instances of price separation between islands were due to reserve sharing limitations as a result of only one HVDC pole being in operation. Each island saw spikes at different times which corresponded to the direction of flow on the HVDC at the time, and where the risk was being set.

Figure 3: Fast instantaneous reserve price by trading period and island, 13-19 April



3.4. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh. Between the 10.00am and 10.30am trading periods on Thursday there was South Island SIR scarcity, South Island SIR averaged at ~$6450/MWh and $2,073/MWh respectively. The South Island SIR and FIR scarcity were related to reductions in HVDC risk offset and reserve sharing during the pole 2 outage.

Figure 4: Sustained instantaneous reserve by trading period and island, 13-19 April



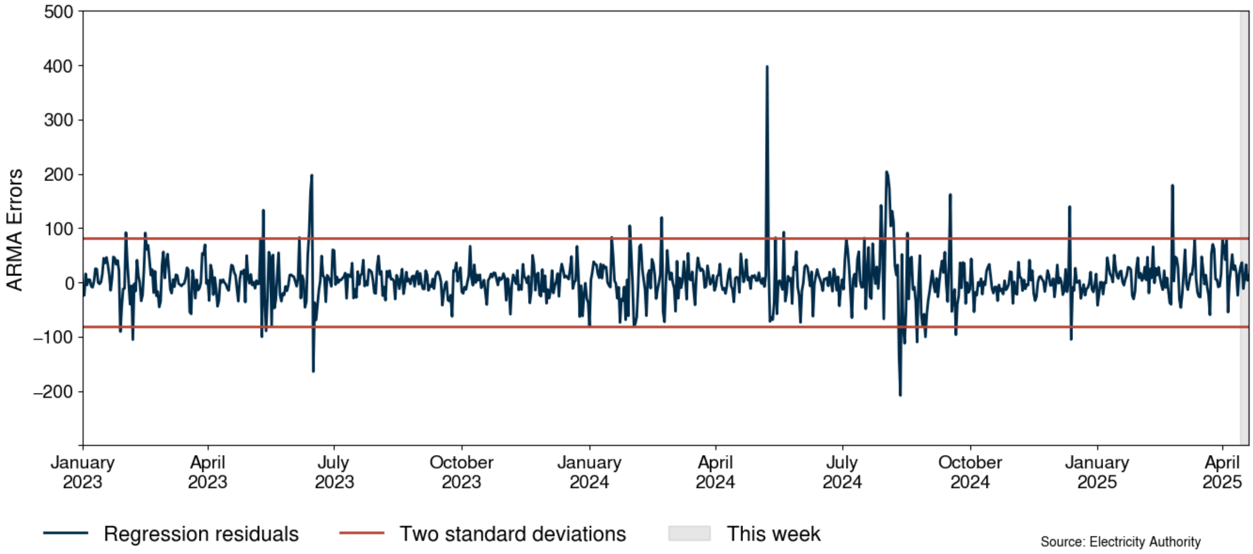
4. Regression residuals

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 - 19 April 2025

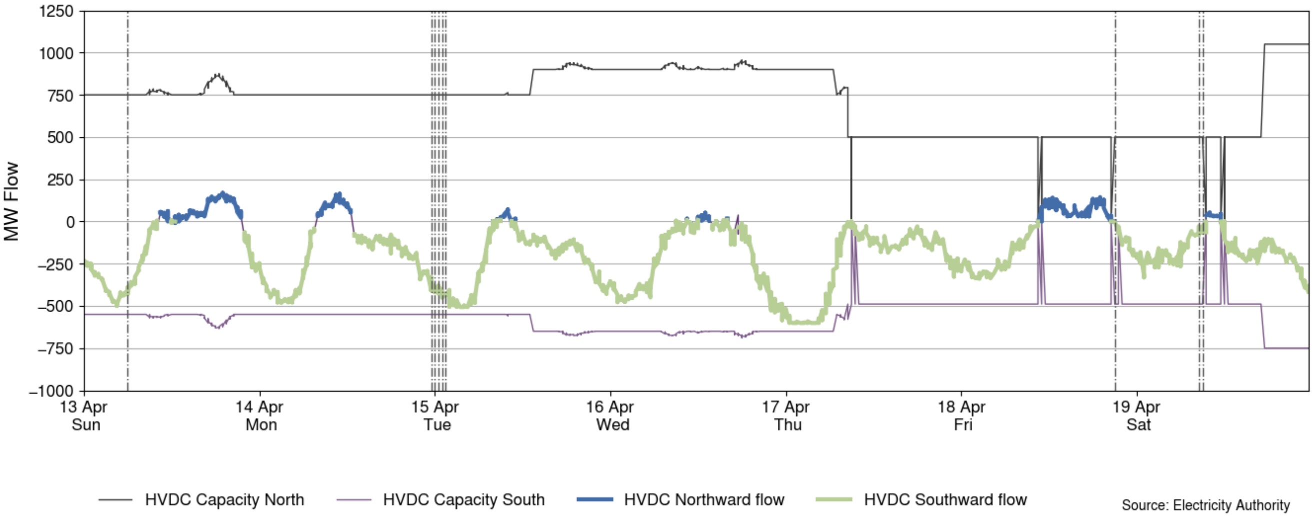


5. HVDC

5.1. Figure 6 shows the HVDC flow between 13-19 April. HVDC flow was mainly southward this week.

5.2. There was an unplanned HVDC outage[1] from around 8.30am on 17 April. This outage was initially due to come back at 6.00pm the same day but an update sent out in the afternoon indicated an extension to this outage until around 6.00pm on 19 April. As discussed above, when only one pole is operating, this limits the ability to reserve share across the islands resulting in the spikes seen in Figures 3 and 4.

Figure 6: HVDC flow and capacity, 13-19 April

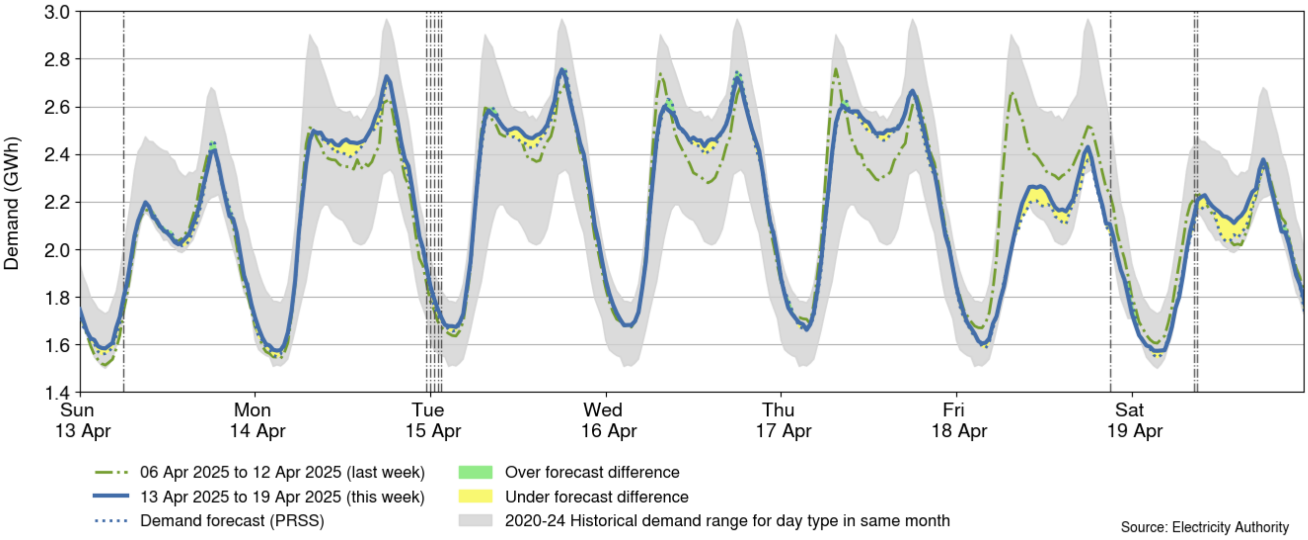


6. Demand

6.1. Figure 7 shows national demand between 13-19 April, compared to the historic range and the demand of the previous week. Demand was higher than forecast across the middle of the day from Monday to Wednesday and during parts of Friday and Saturday. Weekday evening demand was mostly above 2.6GWh with the maximum demand 2.75GWh at 6.00pm on Tuesday. The start of Easter weekend saw demand drop off from Friday.

[1] CAN Unplanned Outage HVDC Pole 3 6186543837.pdf

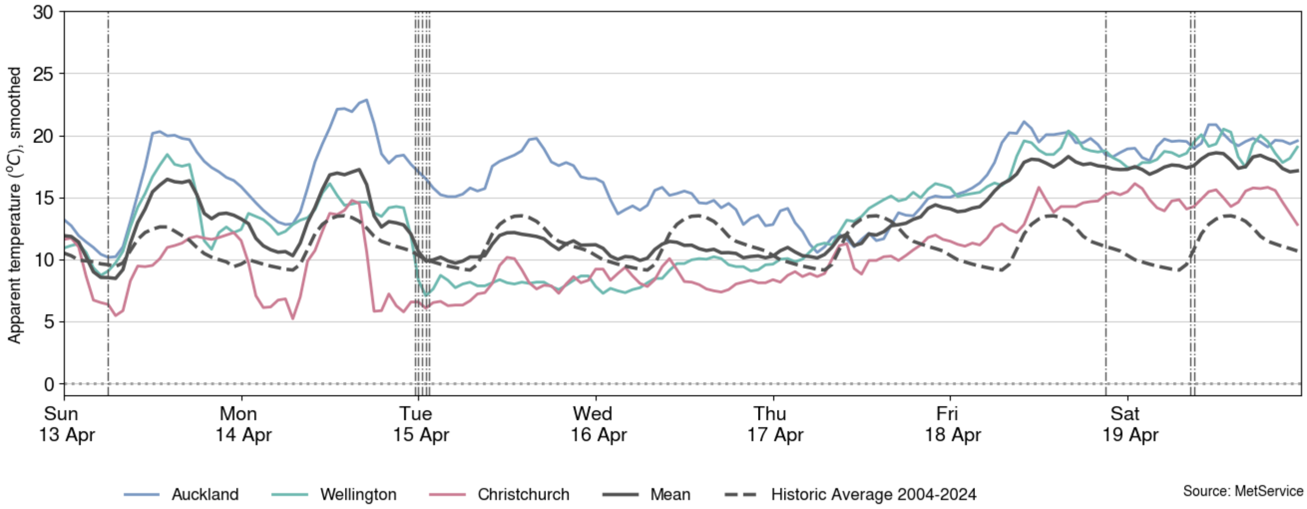
Figure 7: National demand, 13-19 April compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 13-19 April. 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 in Auckland were mostly above 15°C this week. Wellington temperatures were mainly above historic average except over Tuesday and Wednesday when temperatures fell to single digits. Christchurch saw the lowest temperatures dropping to as low as 4°C early in the week and a maximum of around16°C.

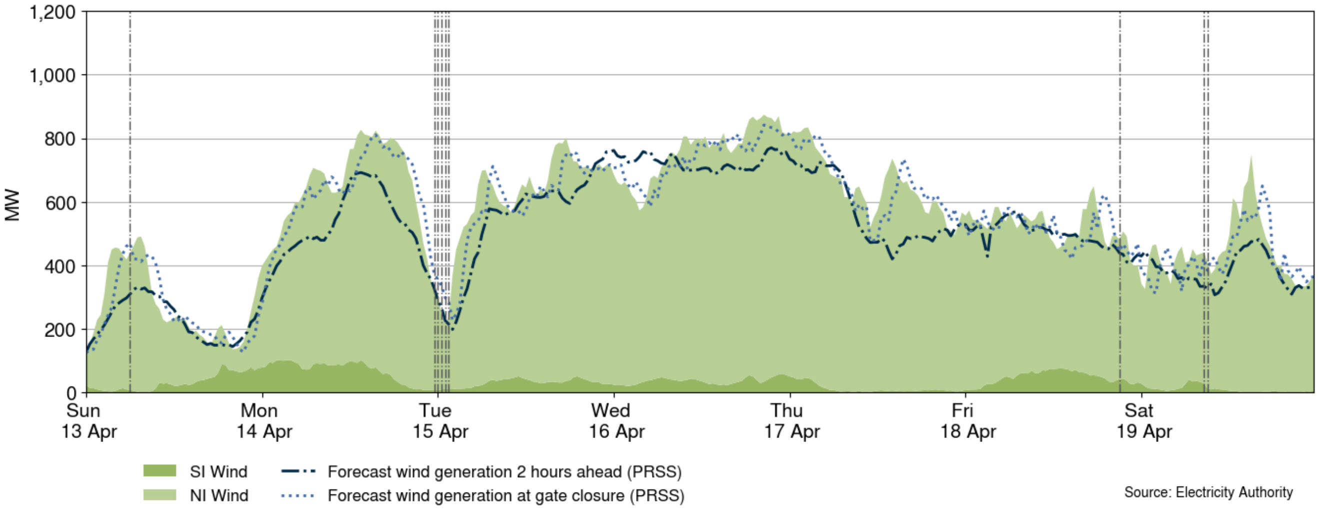
Figure 8: Temperatures across main centres, 13-19 April



7. Generation

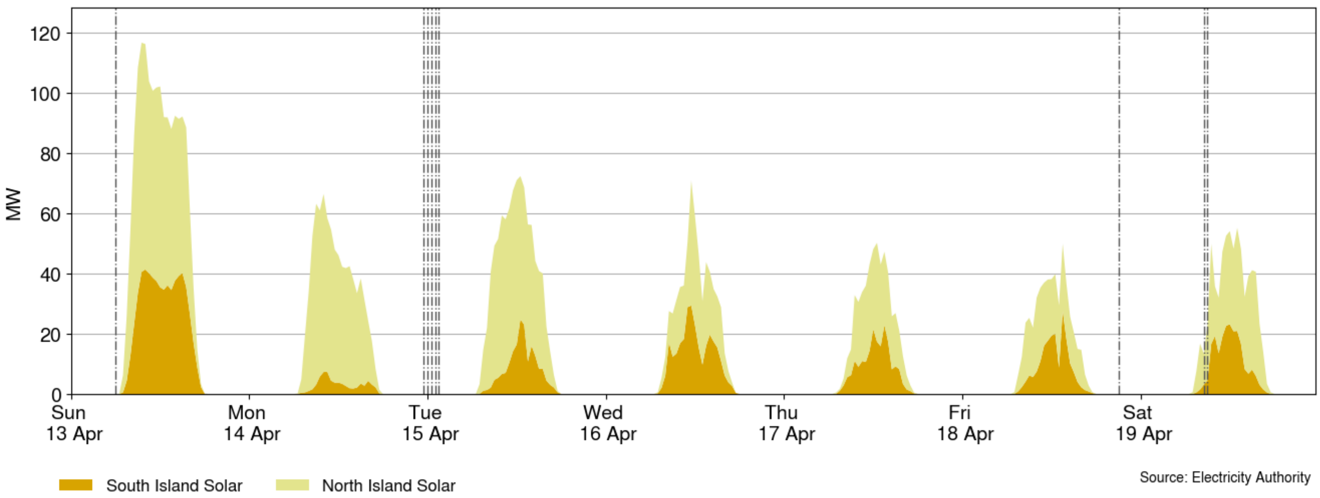
7.1. Figure 9 shows wind generation and forecast from 13-19 April. This week wind generation varied between 128MW and 874MW, with a weekly average of 559MW. Wind was reasonably consistent across the week with most days seeing periods of over 500MW of generation. Most of the over $400/MWh prices occurred on Tuesday morning when there was a significant drop in wind generation.

Figure 9: Wind generation and forecast, 13-19 April



7.2. Figure 10 shows grid connected solar generation from 13-19 April. Solar generation was mainly below 60MW this week, with the latter half of the week seeing less the 40MW at times due to unsettled weather particularly across the North Island.

Figure 10: Grid connected solar generation, 13-19 April



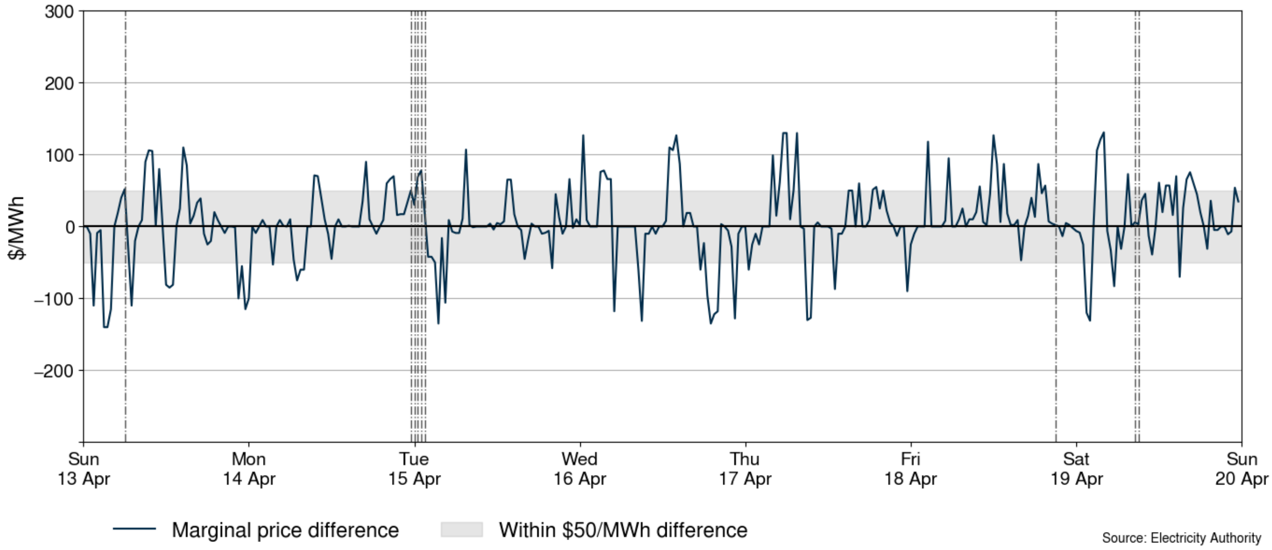
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being

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

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.

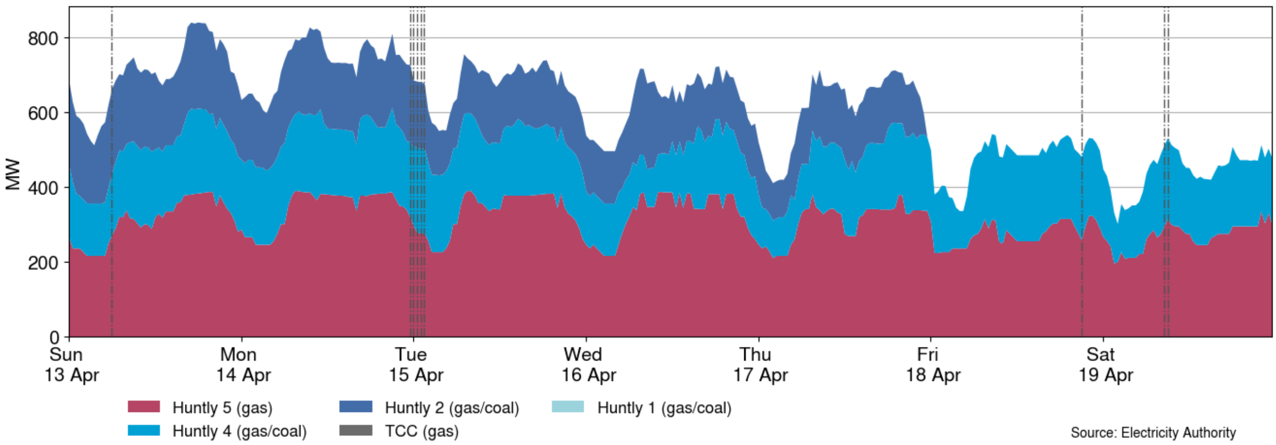
7.4. There were multiple marginal price differences above $50/MWh, all occurring where there were combinations of over forecast wind and under forecast demand. The highest marginal price difference was $131/MWh on 19 April at 4.00am. At this time wind was ~82MW lower than forecast and demand was 38MW higher 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, 13-19 April



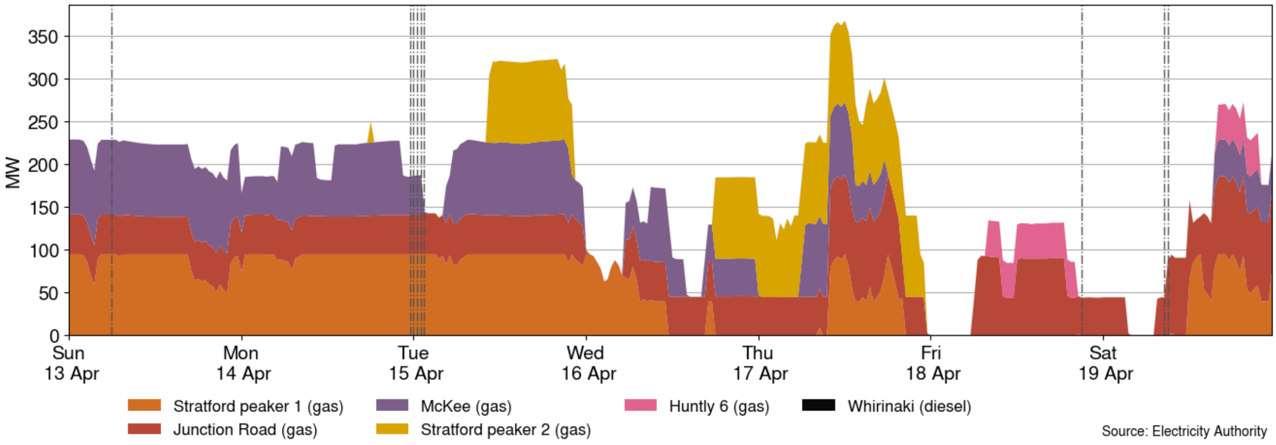
7.5. Figure 12 shows the generation of thermal baseload between 13-19 April. Huntly 5 and 2 Rankines provided baseload generation this week with all three generating until late Thursday evening. Huntly 2 stopped generating from Friday likely due to lower expected demand over Easter weekend.

Figure 12: Thermal baseload generation, 13-19 April



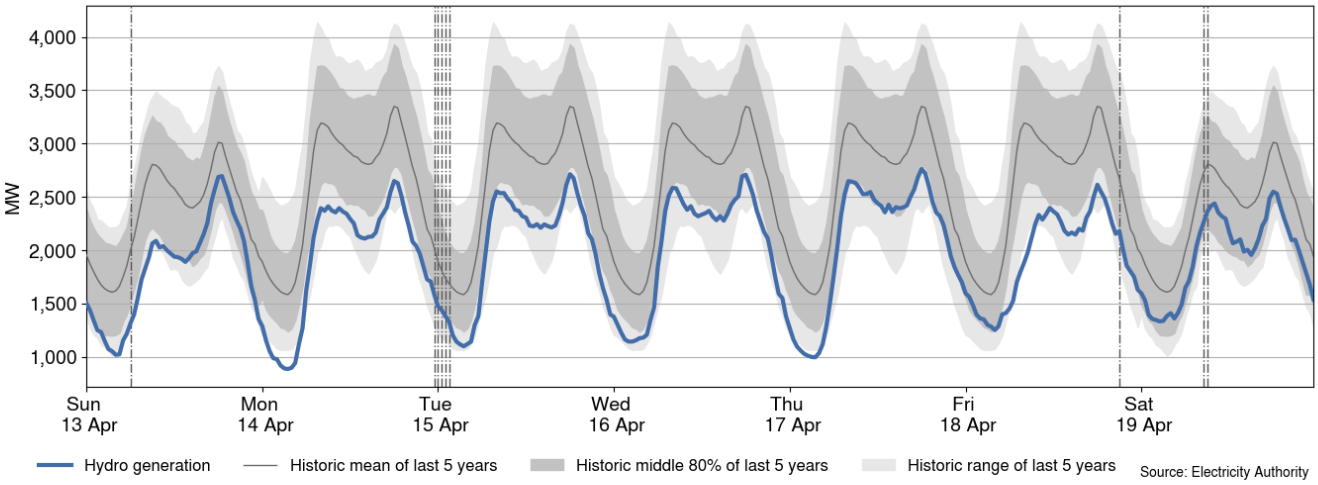
7.6. Figure 13 shows the generation of thermal peaker plants between 13-19 April. Stratford 1, Junction Road and McKee ran near continuously until Thursday this week. Stratford 2 ran on Tuesday form late morning to late evening before going back on a short outage. It then generated from Wednesday evening through to late Thursday evening. Huntly 6 ran during the day on Friday and then again on Saturday evening.

Figure 13: Thermal peaker generation, 13-19 April



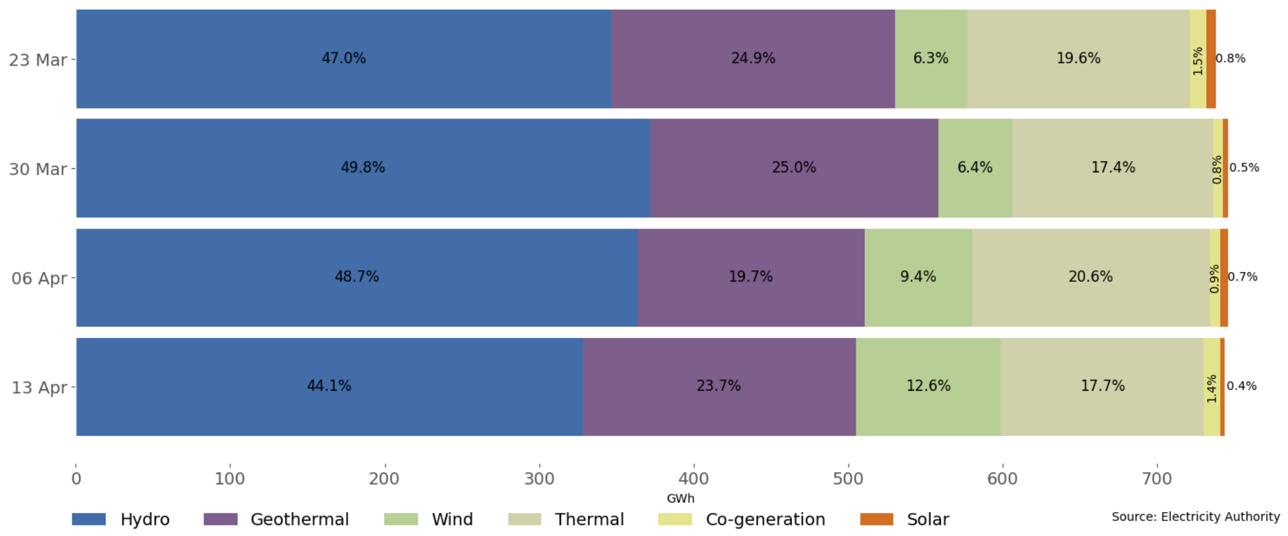
7.7. Figure 14 shows hydro generation between 13-19 April. Hydro generation was at the lower end of the historic range, with trading period average generation mostly below 2500MW apart from during peak periods.

Figure 14: Hydro generation, 13-19 April



7.8. As a percentage of total generation, between 13-19 April, total weekly hydro generation was 44.1%, geothermal 23.7%, wind 12.6%, thermal 17.7%, co-generation 1.4%, and solar (grid connected) 0.4%, as shown in Figure 15. With units returning from outage geothermal generation increased this week. This along with some higher wind generation saw a reduction in the proportion of thermal and hydro.

Figure 15: Total generation by type as a percentage each week, between 23 March and 19 April 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 13-19 April ranged between ~966MW and ~1983MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 1 is on outage until 2 June

(b) Tokaanu station was on outage during the morning on 13 April

(c) Tauhara was on outage until 14 April

(d) Manapōuri unit 4 is on outage until 12 June 2026, unit 2 returned from outage on 17 April

(e) Clyde has a unit on outage until 23 May

(f) Stratford 2 has two short outages on 14 and 16 April

Figure 16: Total MW loss from generation outages, 13-19 April

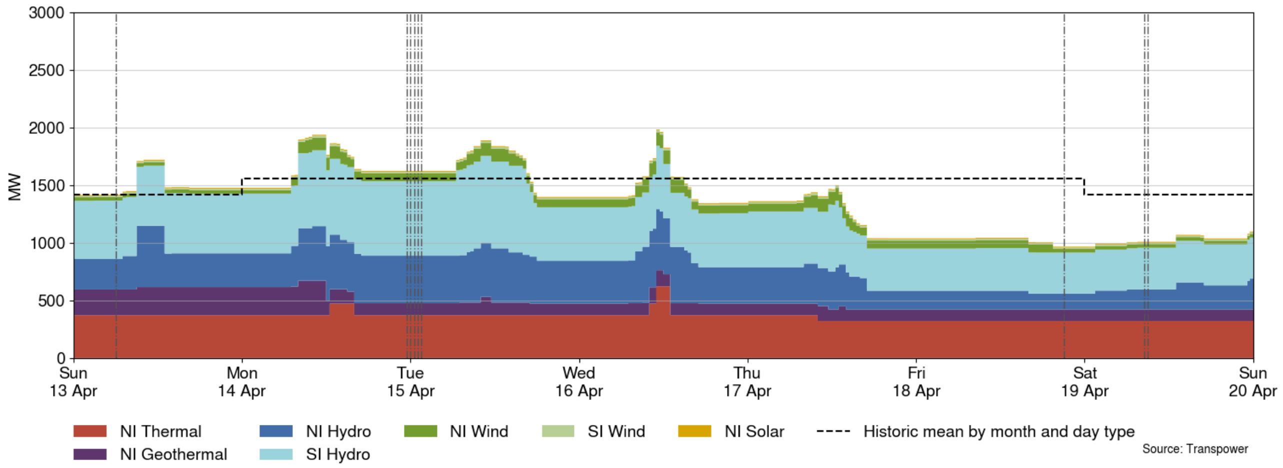
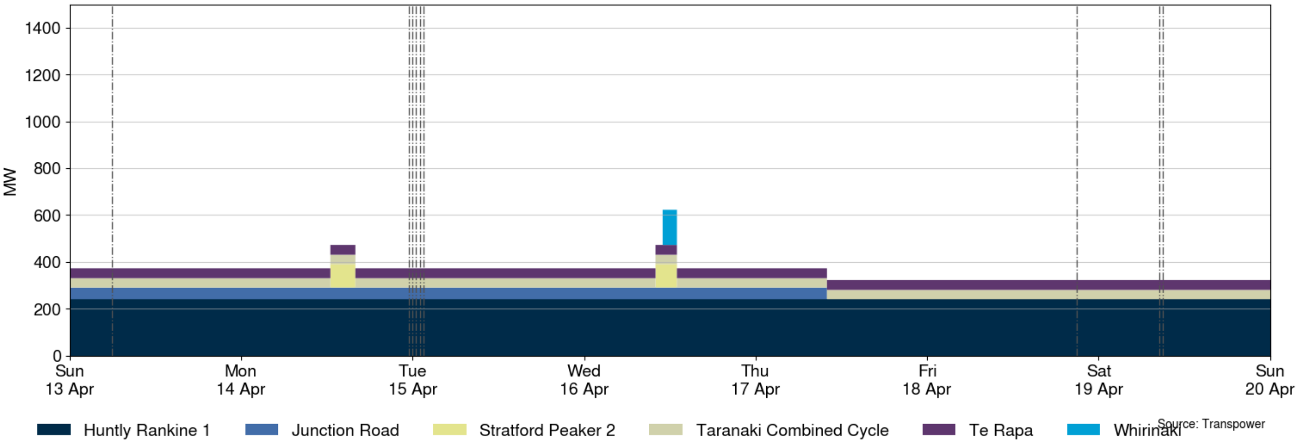


Figure 17: Total MW loss from thermal outages, 13-19 April

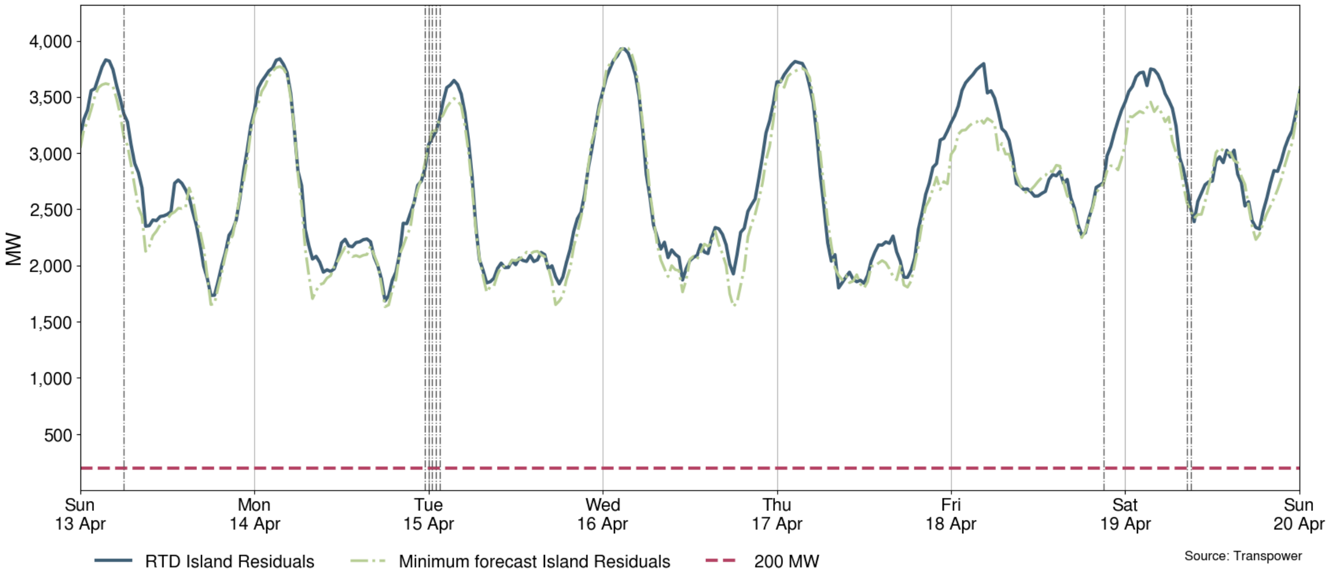


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 13-19 April. 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. Generation residuals continue to be healthy with the minimum North Island residuals this week of 777MW on Monday at 6.00pm.

Figure 18: National generation balance residuals, 13-19 April



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 10^{th} to 90^{th} percentiles.

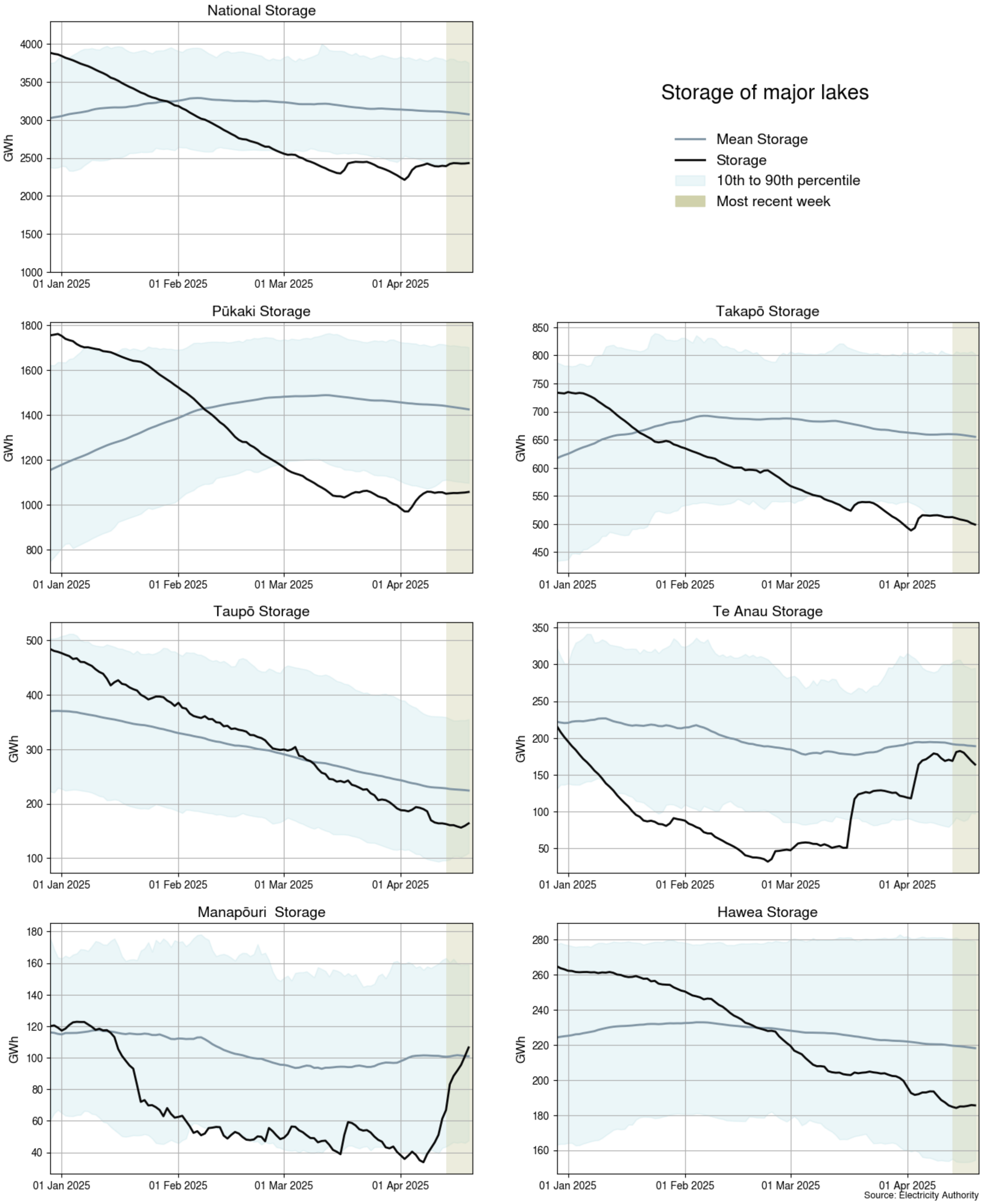
10.2. As of 19 April, national controlled storage was 63% nominally full and ~81% of the historical average for this time of the year.

10.3. Manapōuri was the only lake that had a noticeable increase in storage this week and is now sitting above its historic mean. Te Anau had a small increase at the beginning of the week before decreasing again, remaining just below its historic mean levels.

10.4. Pūkaki (64% full), Hawea (65% full) and Taupō (30% full)[3] all remained steady across the week and Takapō decreased slightly remaining close to its 10^{th} percentile region.

[3] Percentage full values are from NZX hydrological summary 21 April 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 April 2025. The SRMC for gas fueled generation has increased compared to last month. The SRMC for coal fueled generation has reduced slightly and the SRMC diesel fueled generation remains similar.

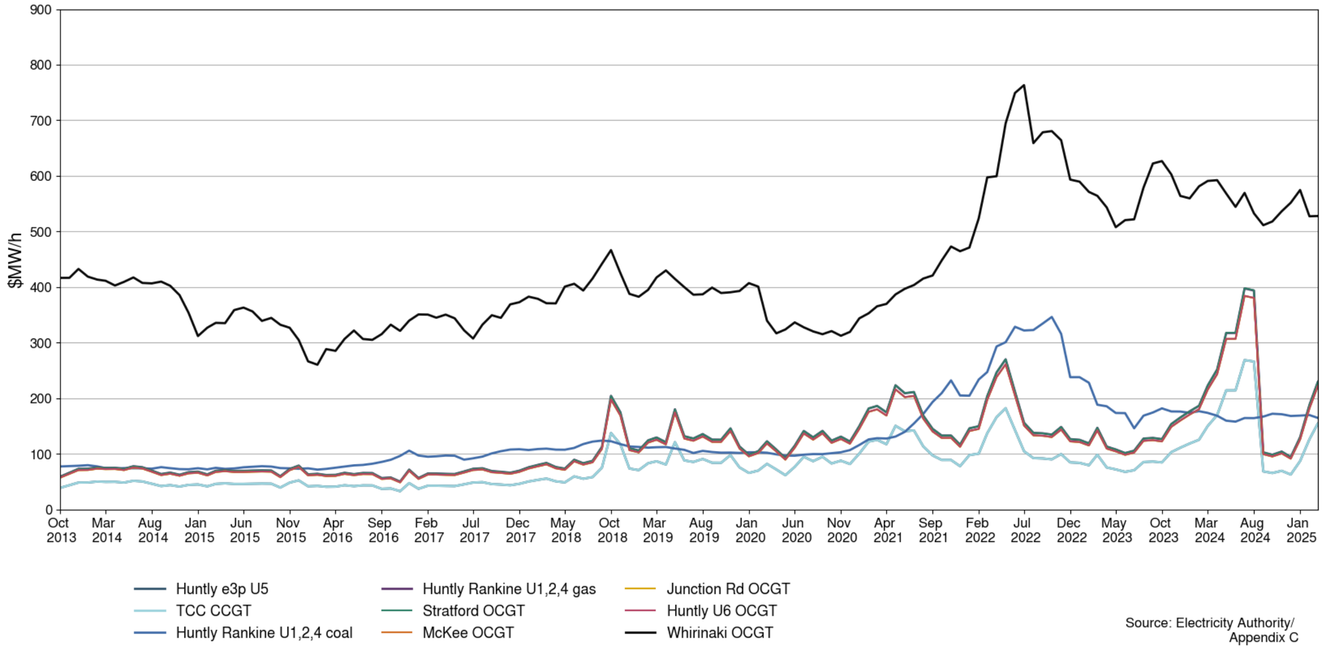
11.4. The latest SRMC of coal-fueled Rankine generation is ~$160/MWh, with the cost of running the Rankines on gas more expensive at ~$250/MWh.

11.5. The SRMC of gas fueled thermal plants is currently between $168/MWh and $250/MWh.

11.6. The SRMC of Whirinaki is still ~$528/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

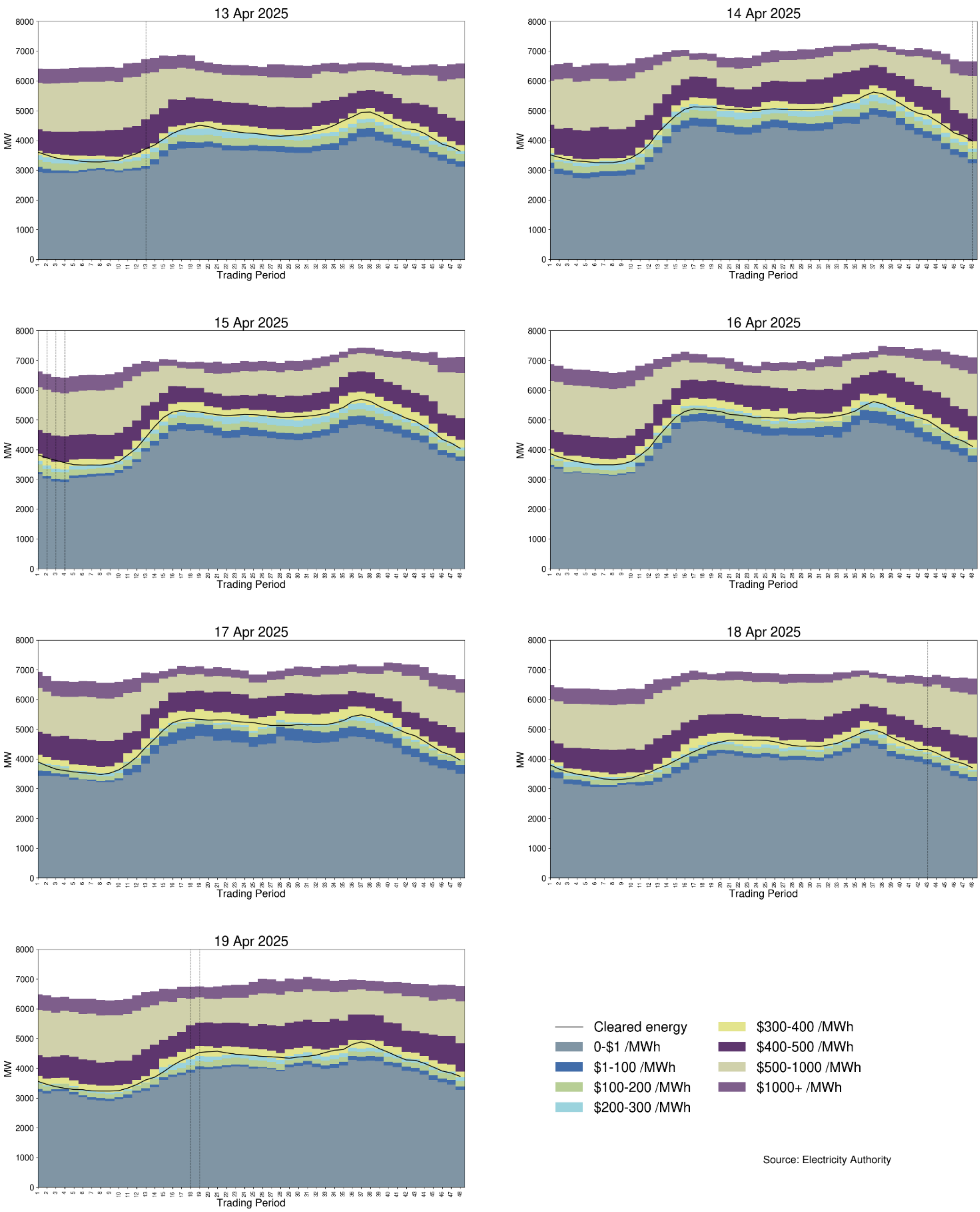


12. Offer behaviour

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. Offers were generally clearing in the $200-$500/MWh region this week. Offers within $50-$300/MWh range are generally low in volume with still quite a thick band of $300-$500/MWh offers. This is reflective of the high thermal commitment and still below average hydro storage.

Figure 21: Daily offer stacks



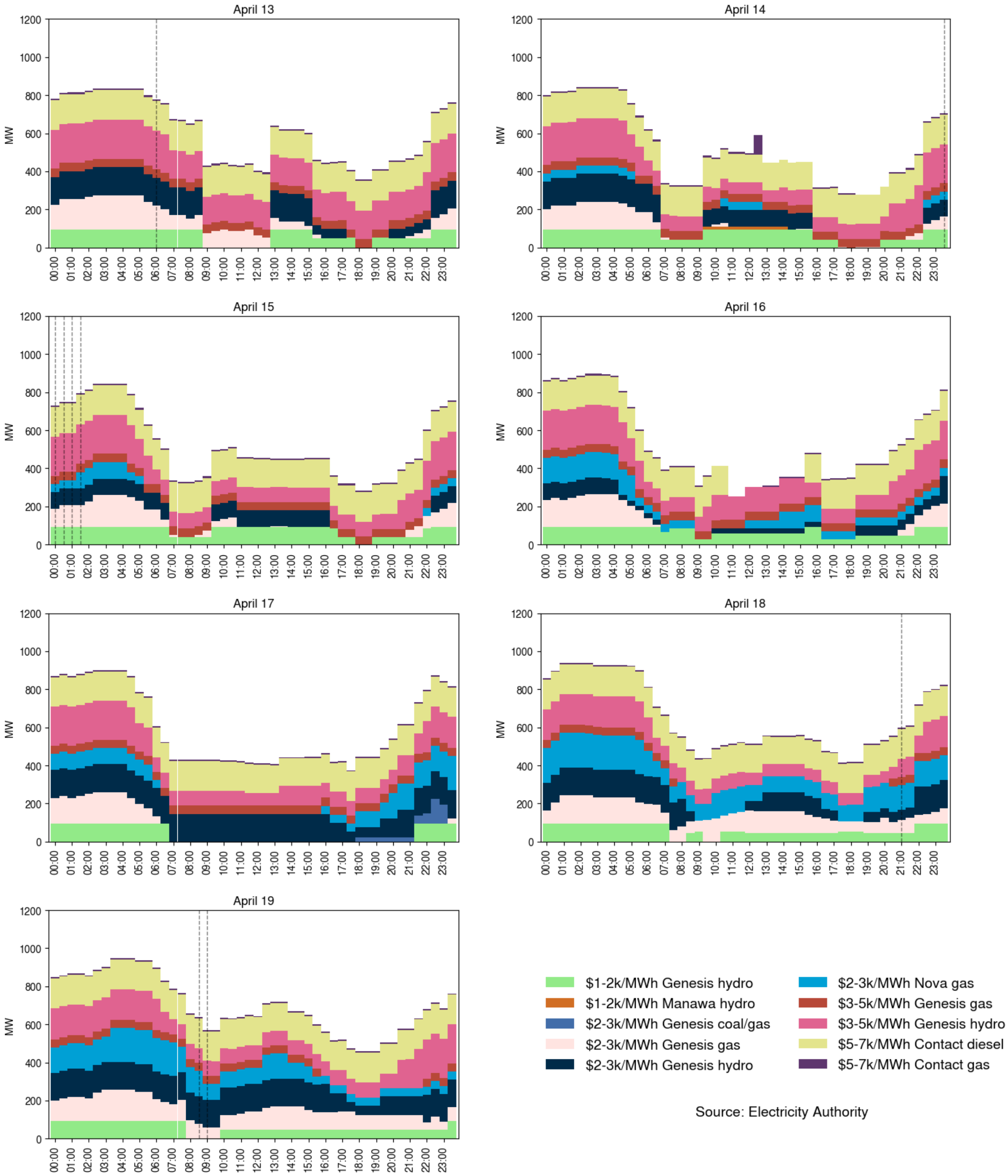
Source: Electricity Authority

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 are not 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 590MW per trading period was priced above $1,000/MWh this week, which is roughly 10% 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
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
18/03/2025	23-27	Further analysis	Genesis	Huntly	Unplanned outage
27/03/2025	20-28	Further analysis	Contact	Stratford peakers and TCC	Offers
4/04/2025	Several	Further analysis	Genesis	Huntly	Offers removed
2/04/2025- 4/04/2025	Several	Further analysis	Genesis	Takapō and Tokaanu	Offers