19 May 2025

Trading conduct report
11-17 May 2025

Market monitoring weekly report

Trading conduct report 11-17 May 2025

1. Overview

1.1. The average spot price decreased by $159/MWh this week to $141/MWh. National hydro storage has increased to ~68% nominally full and ~91% of the historical average for this time of year. Wind and hydro generation increased and thermal generation decreased.

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 11-17 May:

(a) The average spot price for the week was $141/MWh, a decrease of around $159/MWh compared to the previous week.

(b) 95% of prices fell between $0.02/MWh and $316/MWh.

2.3. Spot prices dropped below $250/MWh in the latter half of the week. This is likely due to:

(a) Higher wind

(b) Several generators starting to price portions of their hydro lower on Wednesday

(c) Increased hydro inflows

(d) Generators securing gas through deals with Methanex.[1]

2.4. The highest price at Ōtāhuhu was $356/MWh at 10.30am on Tuesday while the price at Benmore was $309/MWh. Prices were also similarly high at 10.00am. From 10.00am to 10.30am, demand was 143-187MW higher than forecast.

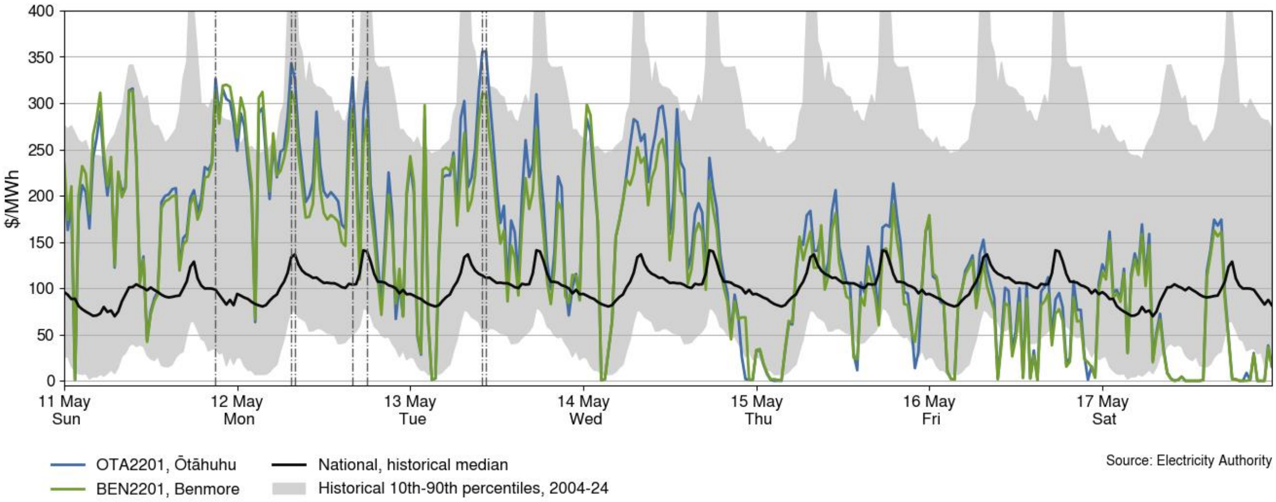
2.5. The price reached $326/MWh at Ōtāhuhu on Sunday at 9.00pm when demand was 56MW higher than forecast and wind was 66MW lower than forecast at gate closure, creating a collective forecast difference of 122MW.

2.6. The price reached $343/MWh at Ōtāhuhu on Monday at 7.30am when demand was 59MW higher than forecast and wind was low. There were two other prices above $300/MWh on Monday when wind was low.

2.7. 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.

[1] NZX, New Zealand's Exchange - Announcements, Contact Secures Gas From Methanex and Genesis to take flexible gas supply from Methanex | Genesis NZ

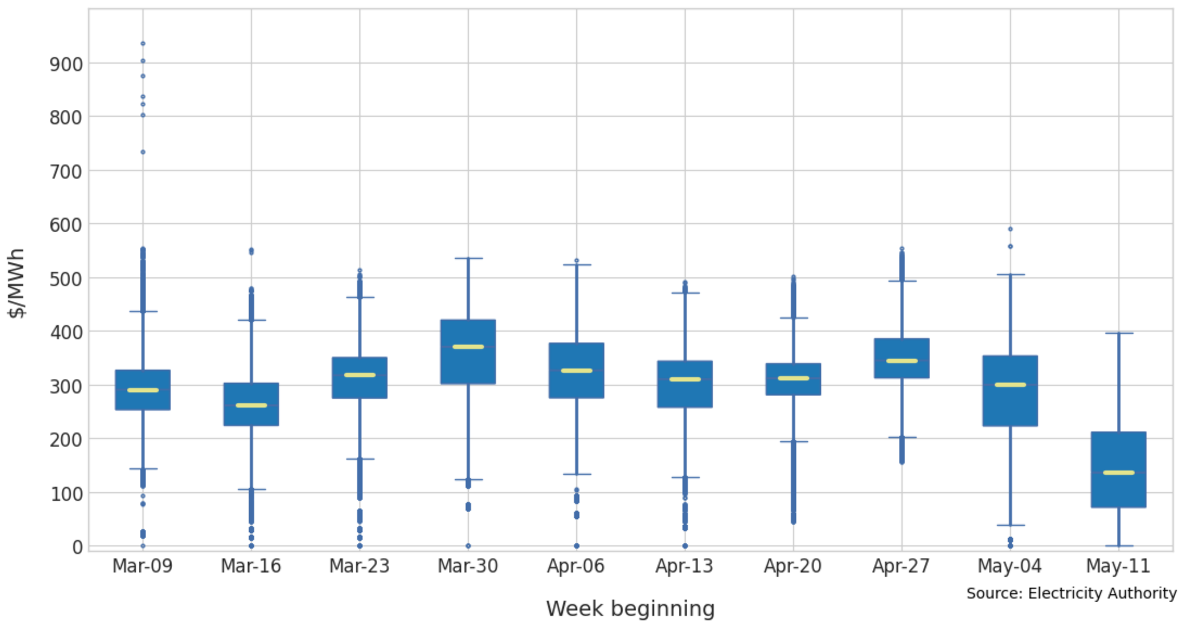
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 11-17 May



2.8. 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.

2.9. The distribution of spot prices this week was skewed lower. The median price was $137/MWh and most prices (middle 50%) fell between $72/MWh and $212/MWh.

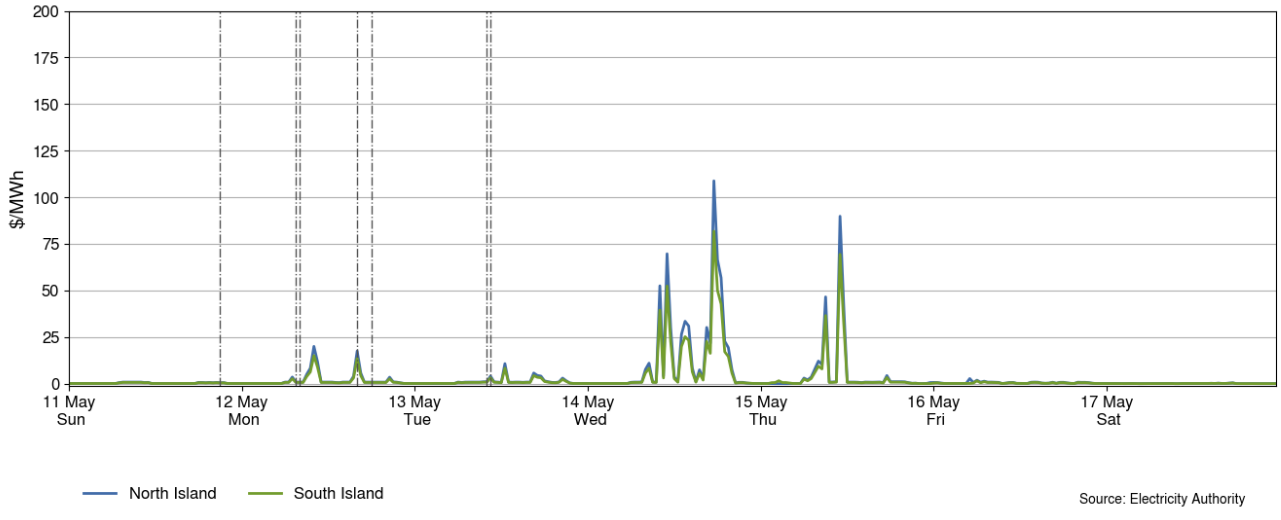
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

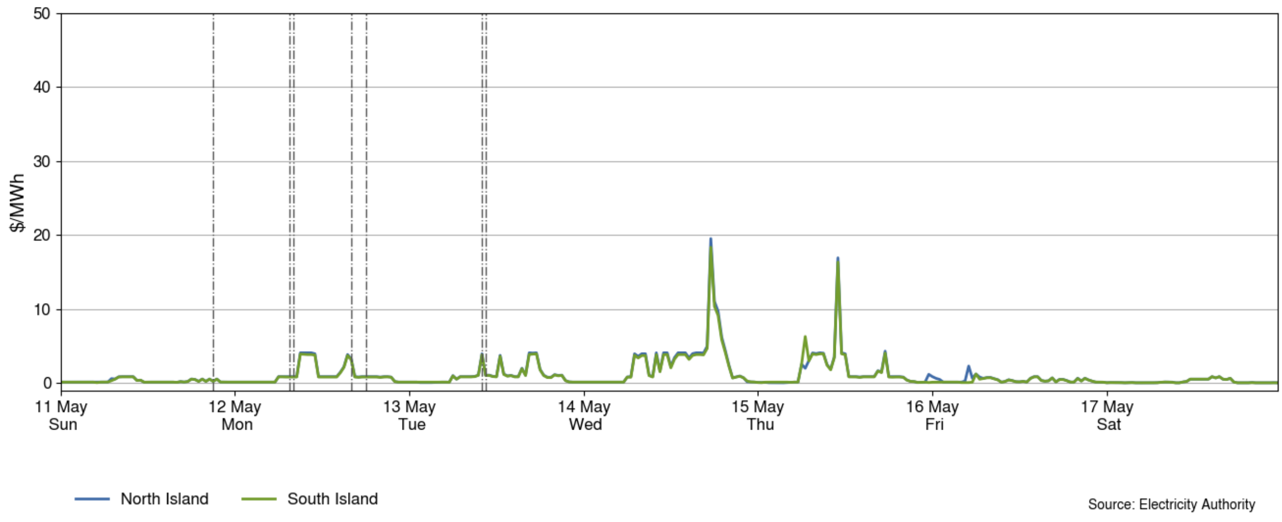
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh but spiked above $50/MWh several times on Wednesday and Thursday. Most of these spikes corresponded to an increase in the amount of FIR cleared or demand being higher than forecast by at least 60MW.

Figure 3: Fast instantaneous reserve price by trading period and island, 11-17 May



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh but spiked above $15/MWh in tandem with the higher FIR spikes.

Figure 4: Sustained instantaneous reserve by trading period and island, 11-17 May



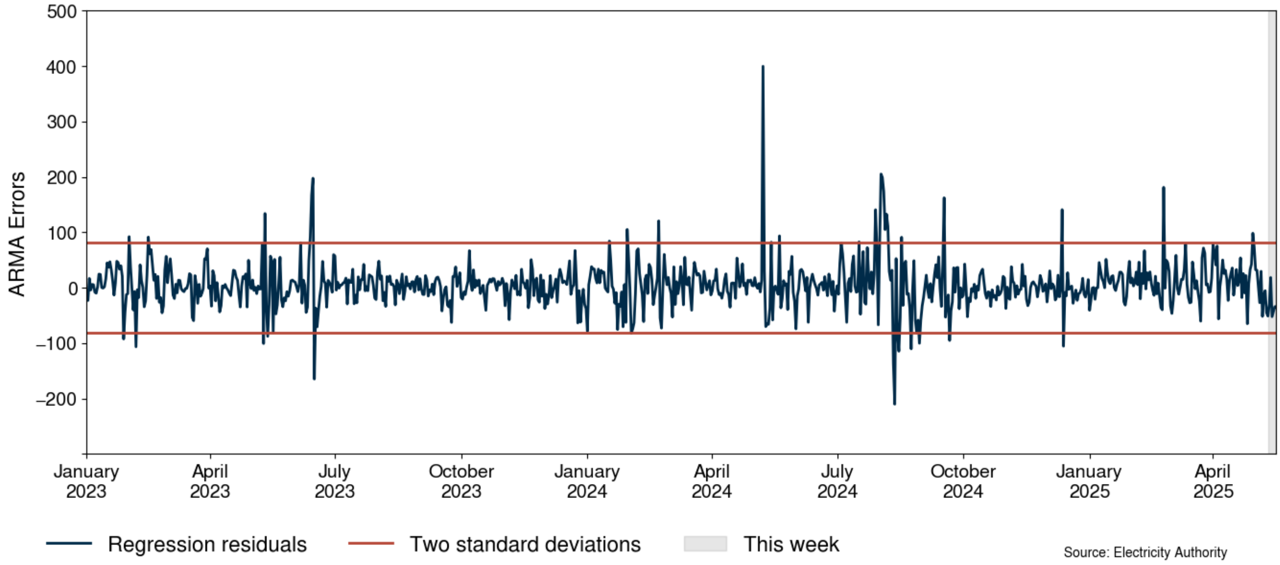
4. Regression residuals

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.

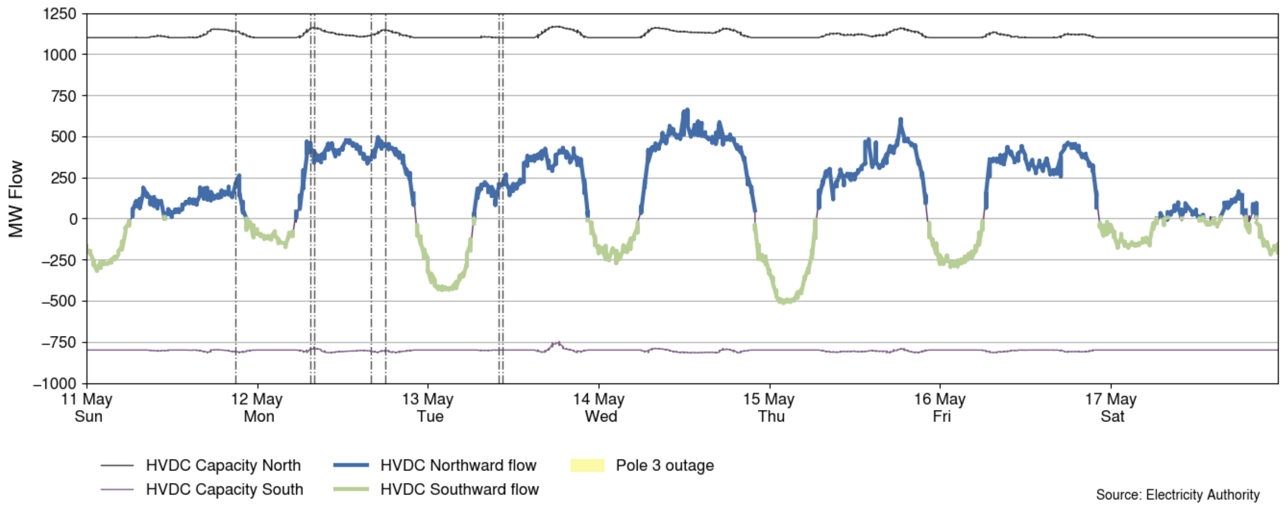
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 17 May 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 11-17 May. HVDC flows were mostly northward during the day and southward during the night.

Figure 6: HVDC flow and capacity, 11-17 May

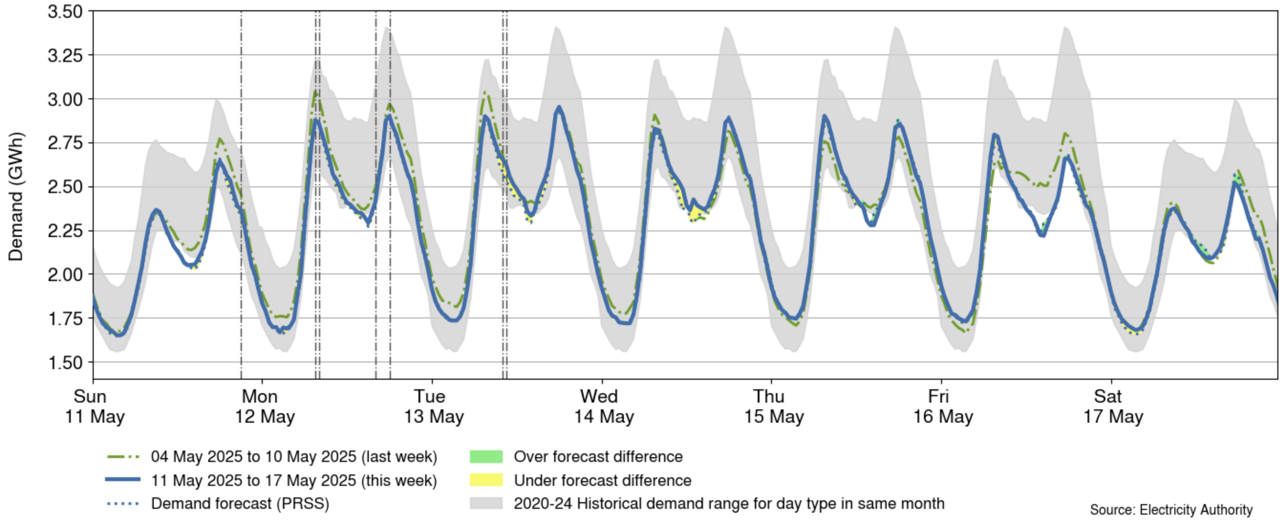


6. Demand

6.1. Figure 7 shows national demand between 11-17 May, compared to the historic range and the demand of the previous week. Demand was mostly close to last week's demand with a maximum of 2.95GWh on Tuesday at 6.00pm.

6.2. There were some large forecasting errors on Wednesday with the largest at 1.00pm when demand was 271MW higher than forecast. Around 160MW of this appears to be related to demand and bid discrepancies at Tiwai point likely due to potline changes.

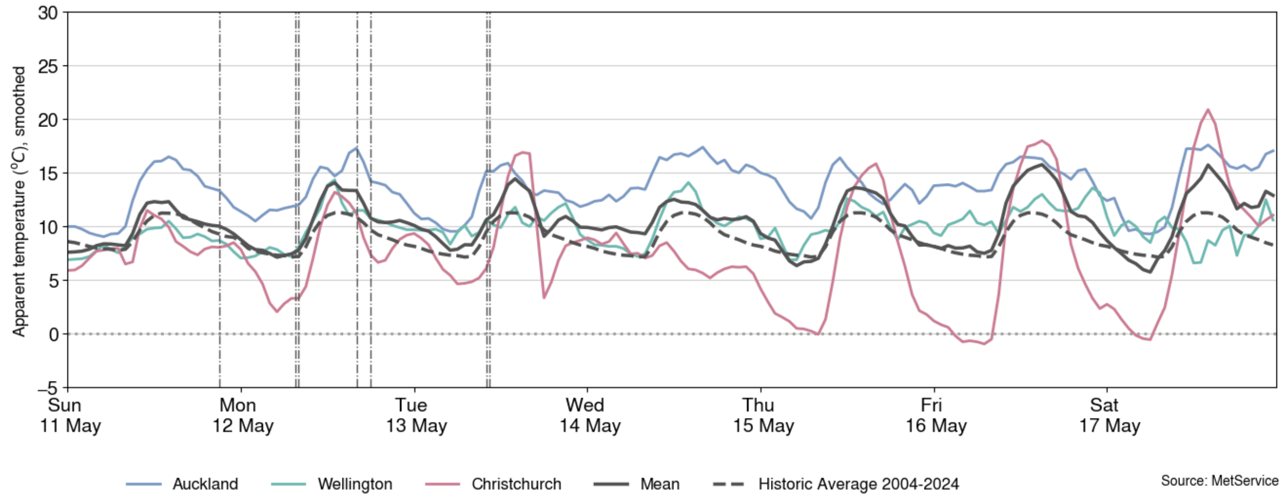
Figure 7: National demand, 11-17 May compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 11-17 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.

6.4. Apparent temperatures were close to average and ranged from 9°C to 18°C in Auckland, 6°C to 15°C in Wellington, and -1°C to 21°C in Christchurch.

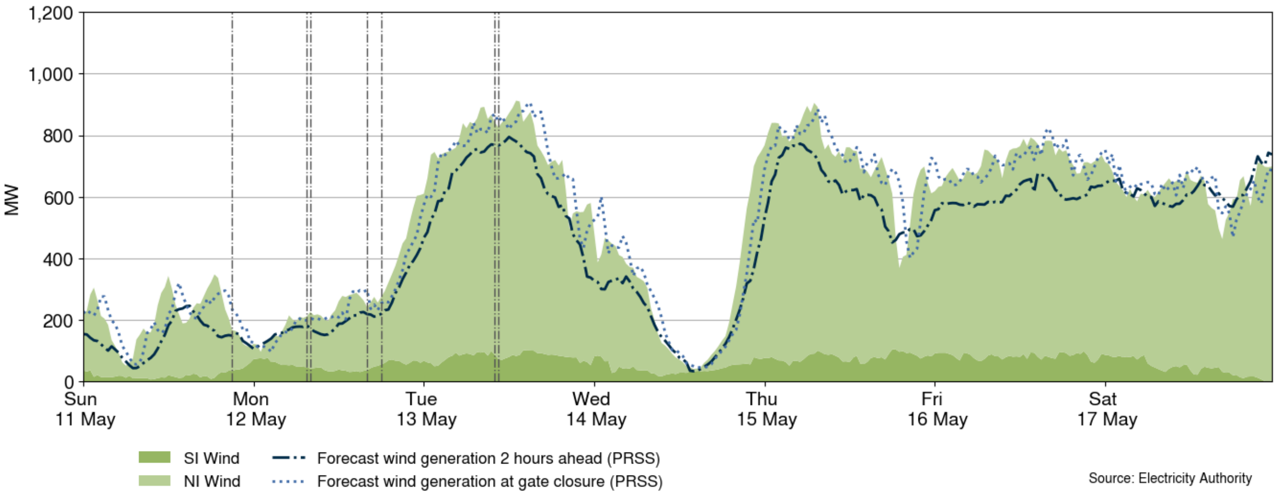
Figure 8: Temperatures across main centres, 11-17 May



7. Generation

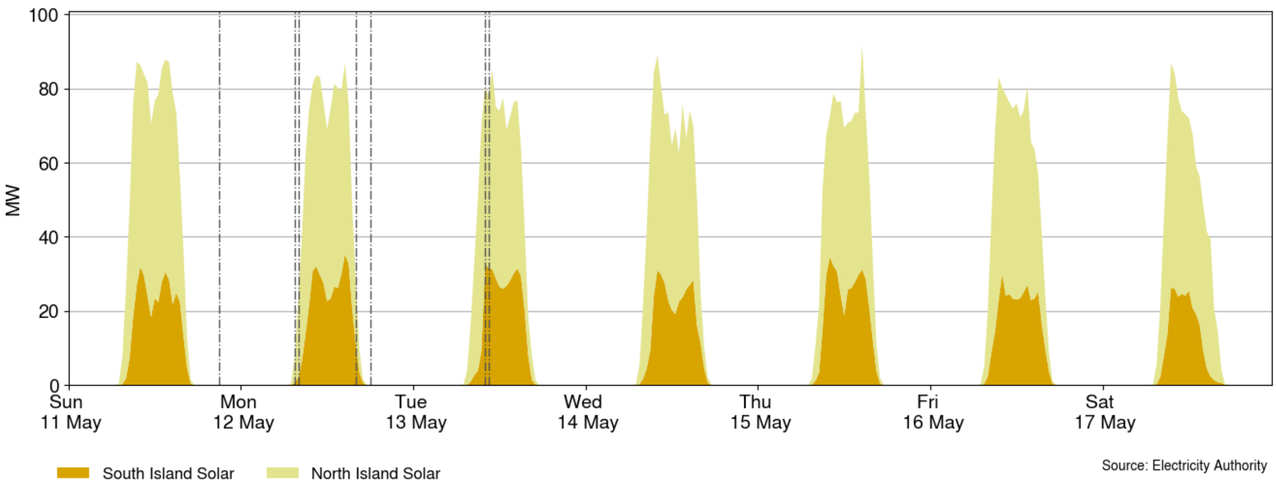
7.1. Figure 9 shows wind generation and forecast from 11-17 May. This week wind generation varied between 41MW and 912MW, with a weekly average of 511MW. Wind generation was low on Sunday, Monday and mid Wednesday, but high the rest of the week.

Figure 9: Wind generation and forecast, 11-17 May



7.2. Figure 10 shows grid connected solar generation from 11-17 May. Solar generation was mostly above 60MW this week.

Figure 10: Grid connected solar generation, 11-17 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[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.

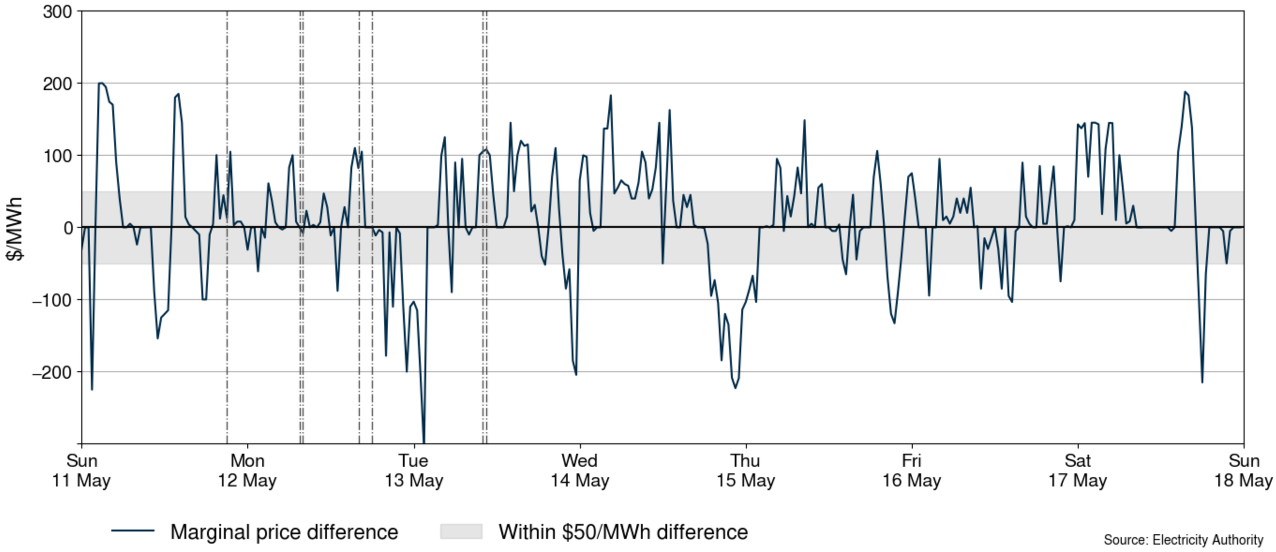
7.4. Marginal price differences were often outside the ±$50/MWh band this week due to frequent demand and wind forecasting inaccuracies.

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

7.5. The largest positive marginal price difference was +$200/MWh at 3.00am on Sunday. Demand was 30MW higher than forecast and wind was 72MW lower than forecast at gate closure, creating a collective 102MW difference.

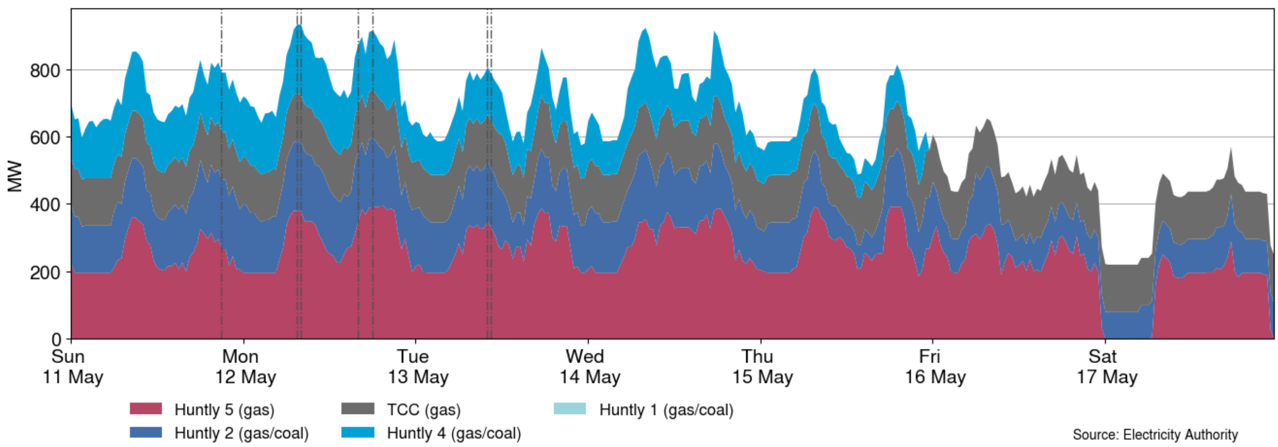
7.6. The largest negative marginal price difference was -$308/MWh at 1.30am on Tuesday. Wind was 201MW higher than forecast two hours ahead of gate closure and 125MW higher than forecast at gate closure.

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, 11-17 May



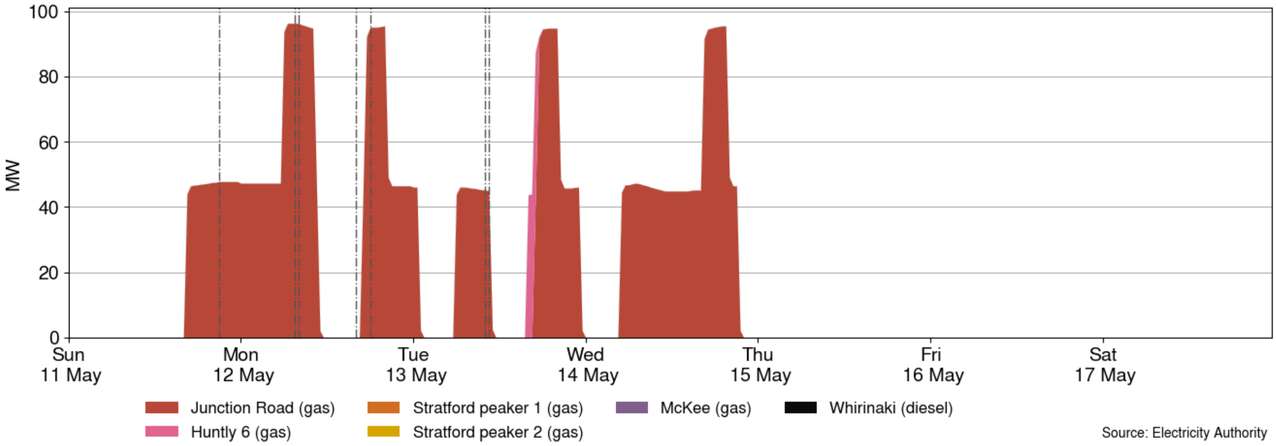
7.7. Figure 12 shows the generation of thermal baseload between 11-17 May. Huntly 2 and TCC generated baseload this week. Huntly 5 generated most of the week but was off Saturday morning. Huntly 4 generated before Friday.

Figure 12: Thermal baseload generation, 11-17 May



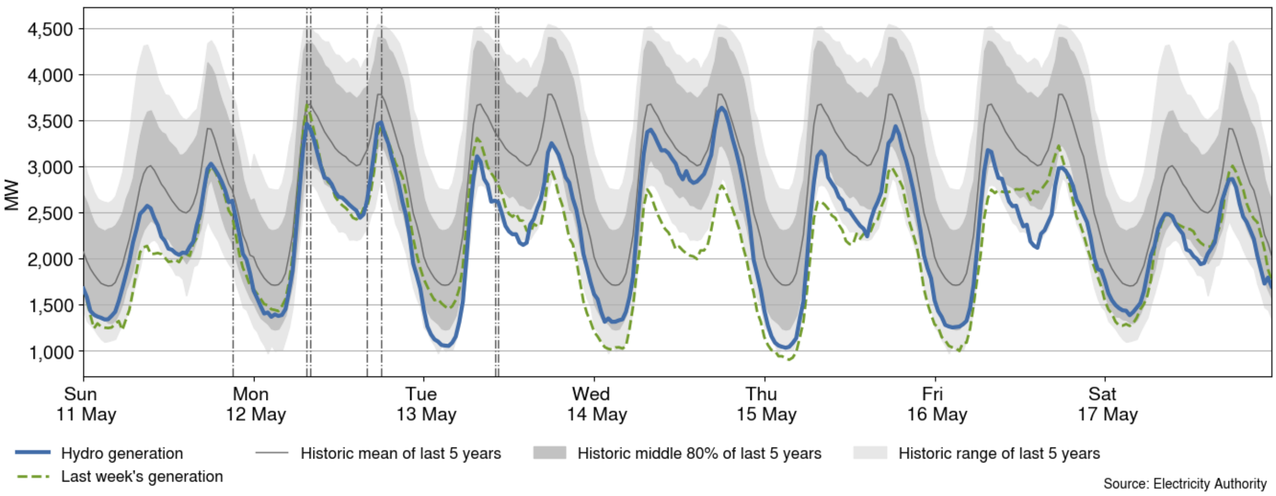
7.8. Figure 13 shows the generation of thermal peaker plants between 11-17 May. Junction Road generated Sunday to Wednesday. Huntly 6 generated briefly on Tuesday.

Figure 13: Thermal peaker generation, 11-17 May



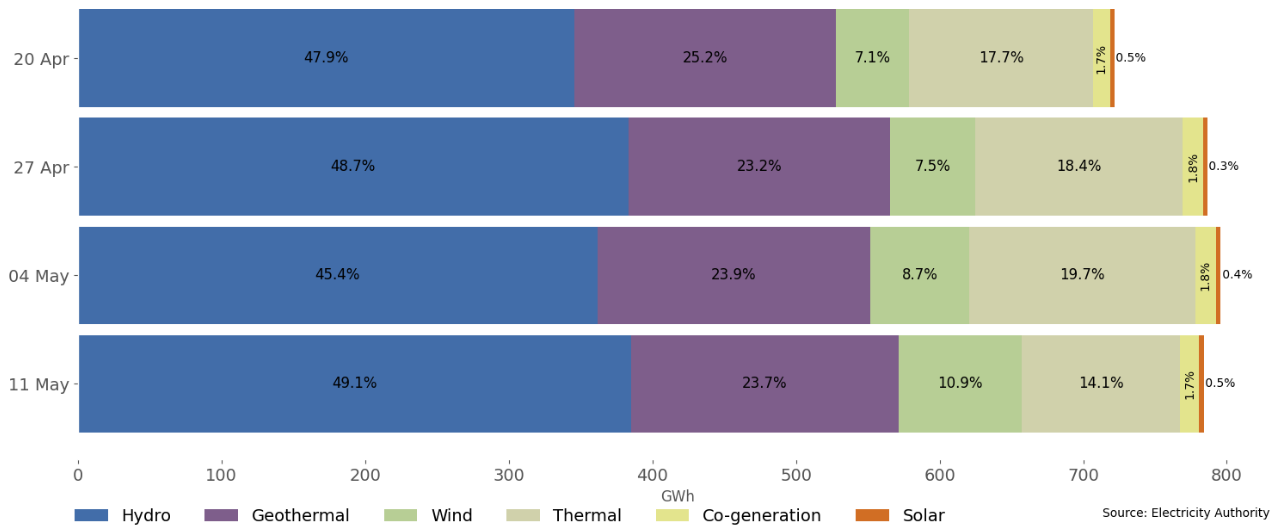
7.9. Figure 14 shows hydro generation between 11-17 May. Hydro generation was slightly higher this week compared to last week on most days.

Figure 14: Hydro generation, 11-17 May



7.10. As a percentage of total generation, between 11-17 May, total weekly hydro generation was 49.1%, geothermal 23.7%, wind 10.9%, thermal 14.1%, co-generation 1.7%, and solar (grid connected) 0.5%, as shown in Figure 15. Hydro and wind generation increased while thermal generation decreased.

Figure 15: Total generation by type as a percentage each week, between 20 April to 17 May 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 11-17 May ranged between ~1,048MW and ~1,742MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

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

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

(c) Manapōuri unit 0 was on outage 12 May.

(d) Manapōuri unit 6 was on outage 13-15 May.

(e) Clyde unit 1 is on outage until 23 May.

(f) Huntly 4 is on outage until 18 May.

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

Figure 16: Total MW loss from generation outages, 11-17 May

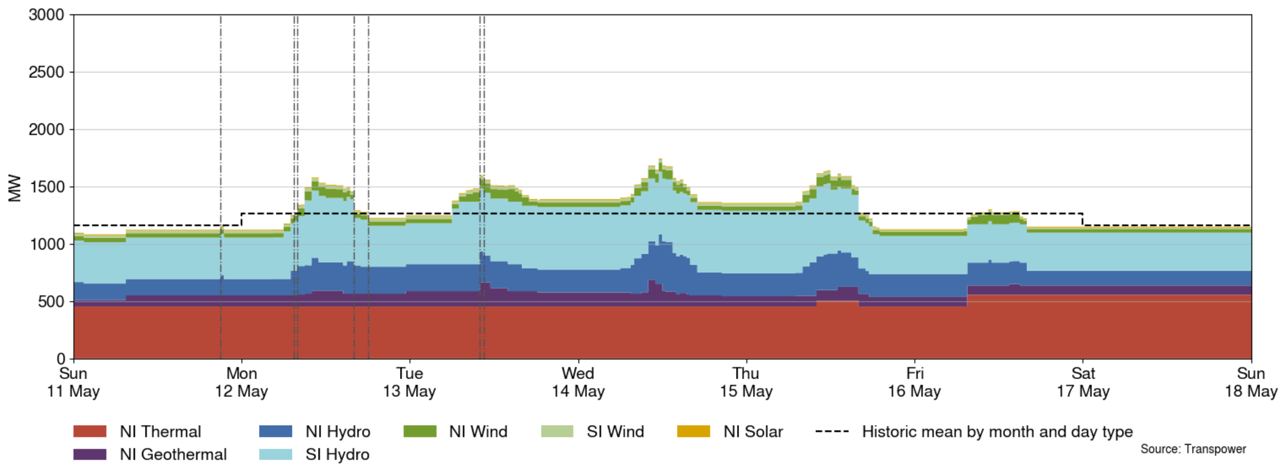
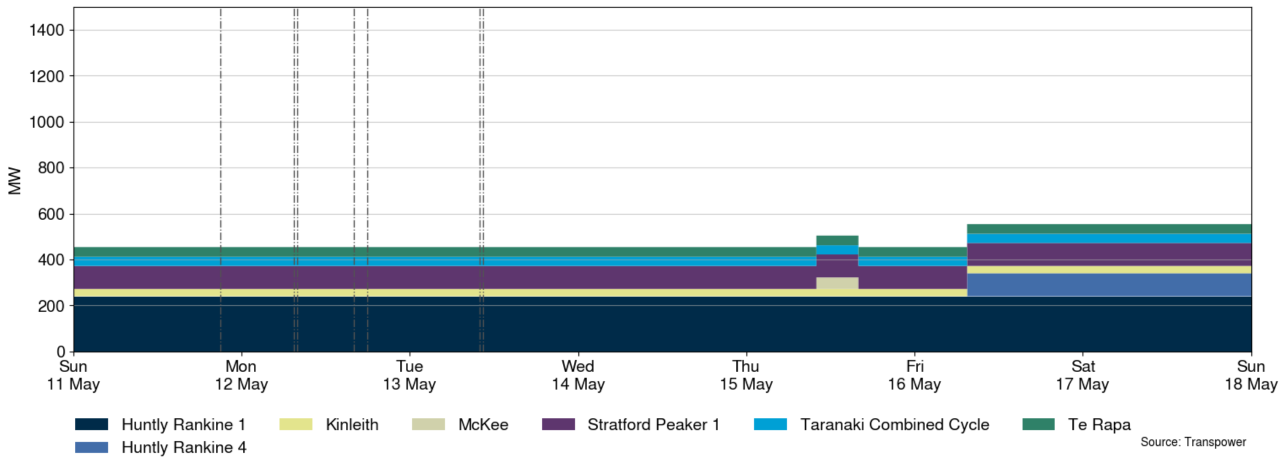


Figure 17: Total MW loss from thermal outages, 11-17 May

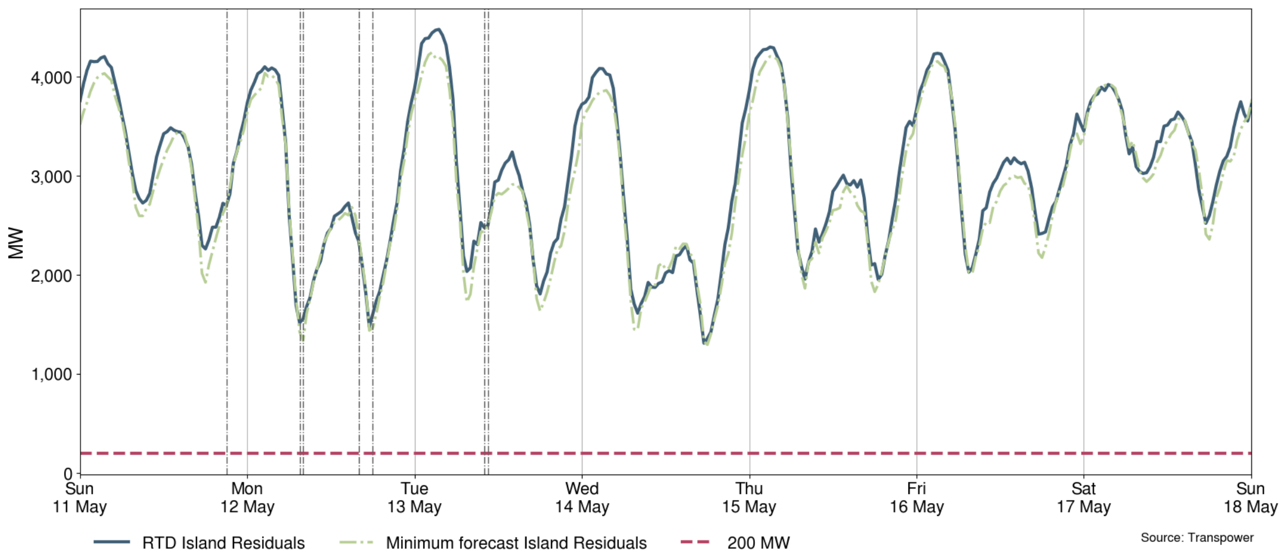


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 11-17 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.

9.2. Residuals looked healthy this week. The lowest island residual was 387MW at 6.00pm on Wednesday in the South Island.

Figure 18: National generation balance residuals, 11-17 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. National controlled storage increased and was 68% nominally full and ~91% of the historical average for this time of the year.

10.3. Storage at lakes Pūkaki (65% full)[3] and Takapō (56% full) are just above their historical 10th percentiles.

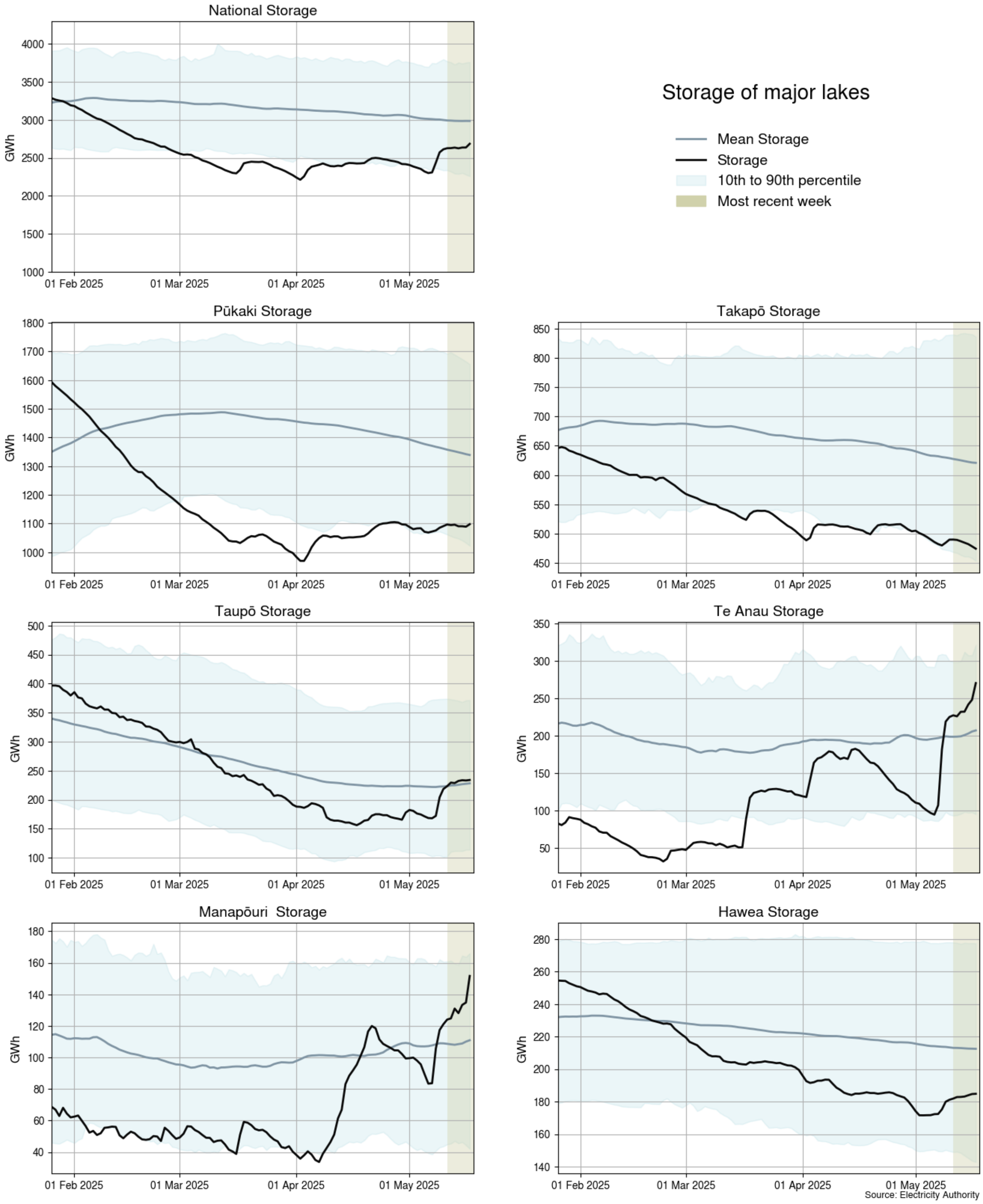
10.4. Lakes Te Anau and Manapōuri increased and are approaching their historic 90th percentiles.

10.5. Storage at Lake Taupō (43% full) is still around its historic mean.

10.6. Lake Hawea storage (66% full) increased and is still between its historical 10th percentile and mean.

[3] Percentage full values sourced from NZX Hydro.

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.

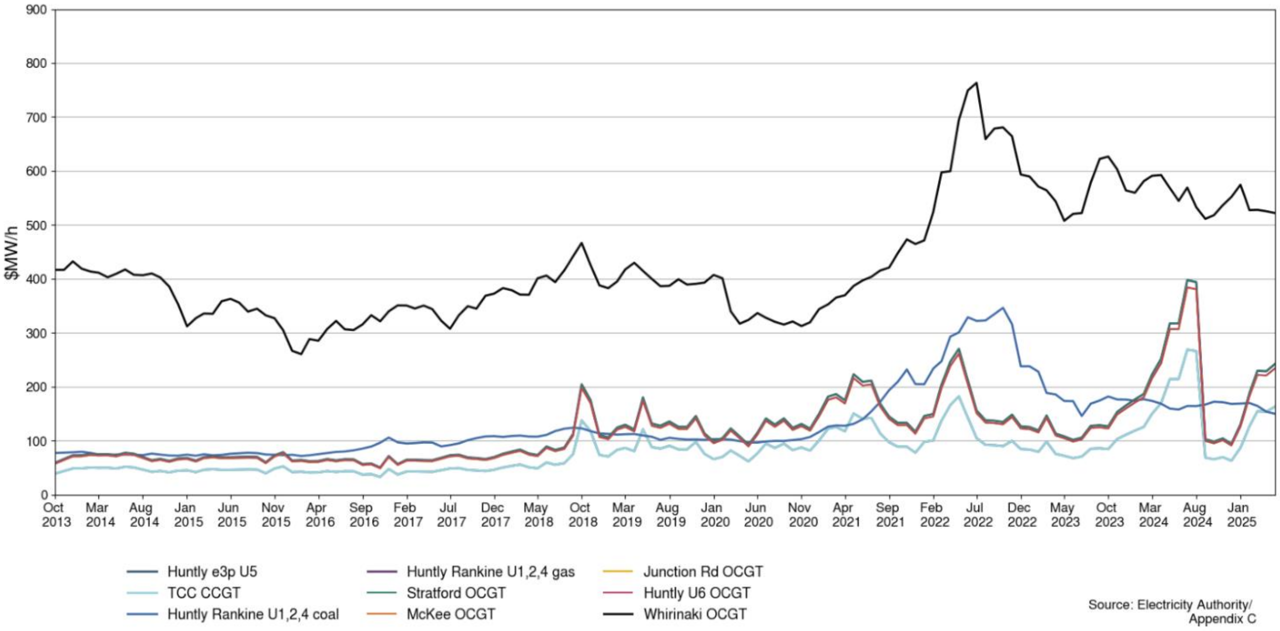
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$150/MWh. The cost of running the Rankines on gas is ~$242/MWh.

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

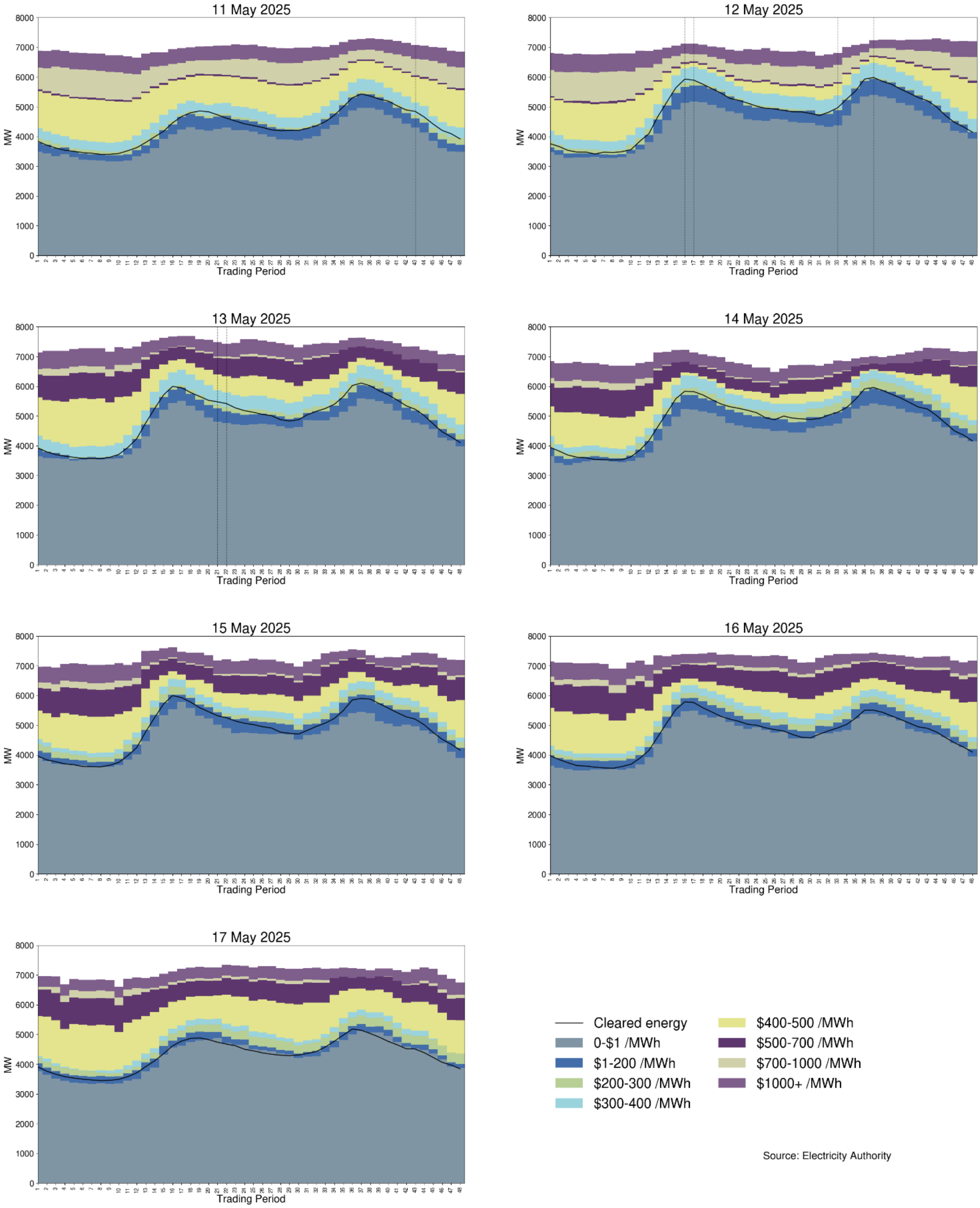


12. Offer behaviour

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. Offers were generally clearing in the $200-$500/MWh region at the beginning of the week and under $200/MWh at the end of the week.

Figure 21: Daily offer stacks



Source: Electricity Authority

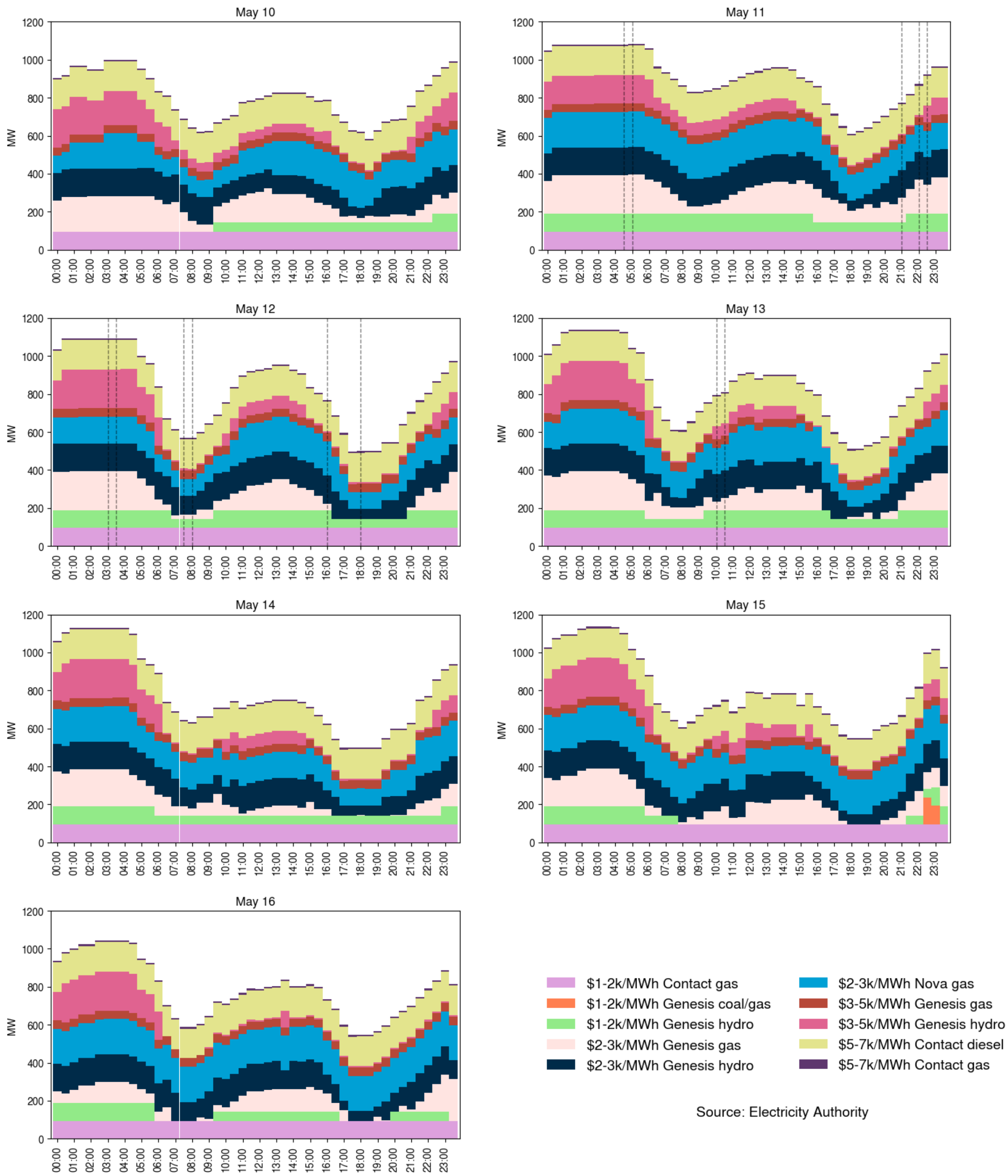
12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 824MW per trading period was priced above $1,000/MWh this week, which is roughly 13.2% of the total energy available. This is 1.3% higher than the previous week. Now that TCC is running the Stratford peakers and the McKee and Junction Road units are running less and being priced to reflect their running costs for a short period of time.

12.6. Genesis briefly priced a portion of the Rankine generation high on Friday evening.

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. We are looking further into offer changes at Huntly on 15 May.

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
27/04/2025- 3/05/2025	Several	Further analysis	Nova	McKee	Offer pricing
7/05/2025- 8/05/2025	Several	Further analysis	N/A	Fernhill	Wholesale price
15/05/2025	46-47	Further analysis	Genesis	Huntly	Rankine offers