7 May 2025

Trading conduct report 27 April-3 May 2025

Market monitoring weekly report

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1. Overview

1.1. The average spot price increased by $38/MWh this week to $345/MWh. Total demand was higher this week due to school holidays ending and severe weather. National hydro storage has decreased this week to ~62% nominally full and ~82% of the historical average for this time of year.

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 27 April-3 May:

(a) The average spot price for the week was $345/MWh, an increase of around $38/MWh compared to the previous week.

(b) 95% of prices fell between $240/MWh and $454/MWh.

2.3. Prices have been higher this week due to:

(a) Continued low hydro storage coming into winter.

(b) The school holidays ending, increasing demand compared to previous weeks.

(c) Weather patterns likely increasing demand and making demand forecasting less accurate.

2.4. The highest price at Ōtāhuhu this week was $467/MWh at 7.30am on Thursday. Prices at Ōtāhuhu were above $450/MWh from 7.30am to 9.00am that morning.

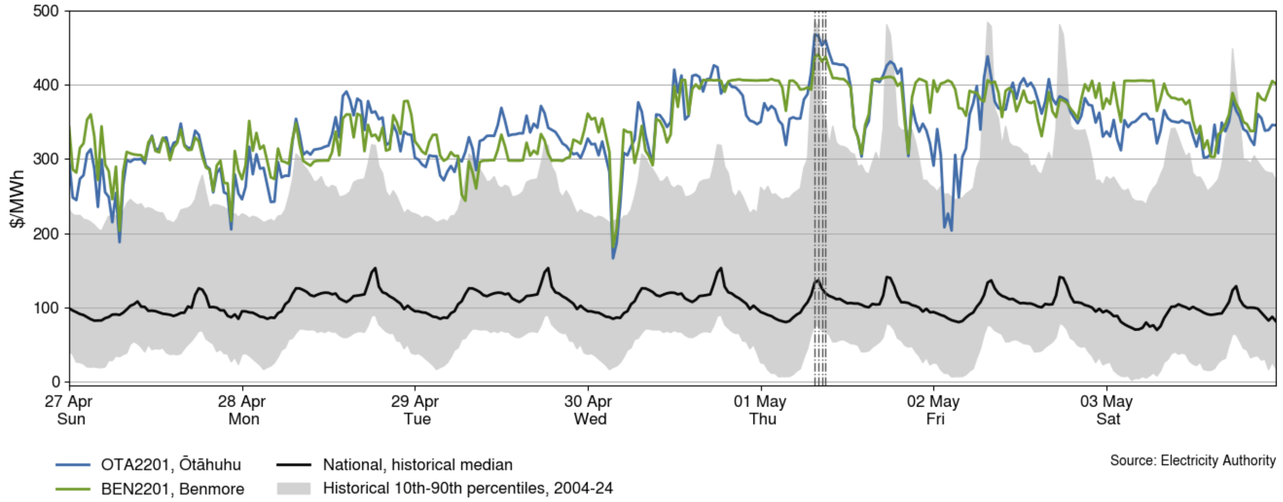
(a) Demand was more than 100MW higher than forecast for this time range. The highest demand forecasting inaccuracy within this time range was 142MW at 9.00am.

(b) At 7.30am wind was 93MW lower than forecast two hours ahead of gate closure. Wind forecasts two hours ahead of gate closure and at gate closure were between 98MW and 214MW from 8.00am to 9.00am.

2.5. There were also several instances overnight when Benmore prices where higher than those at Ōtāhuhu when the HVDC was flowing south.

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. Prices above $450/MWh are marked with black dashed lines.

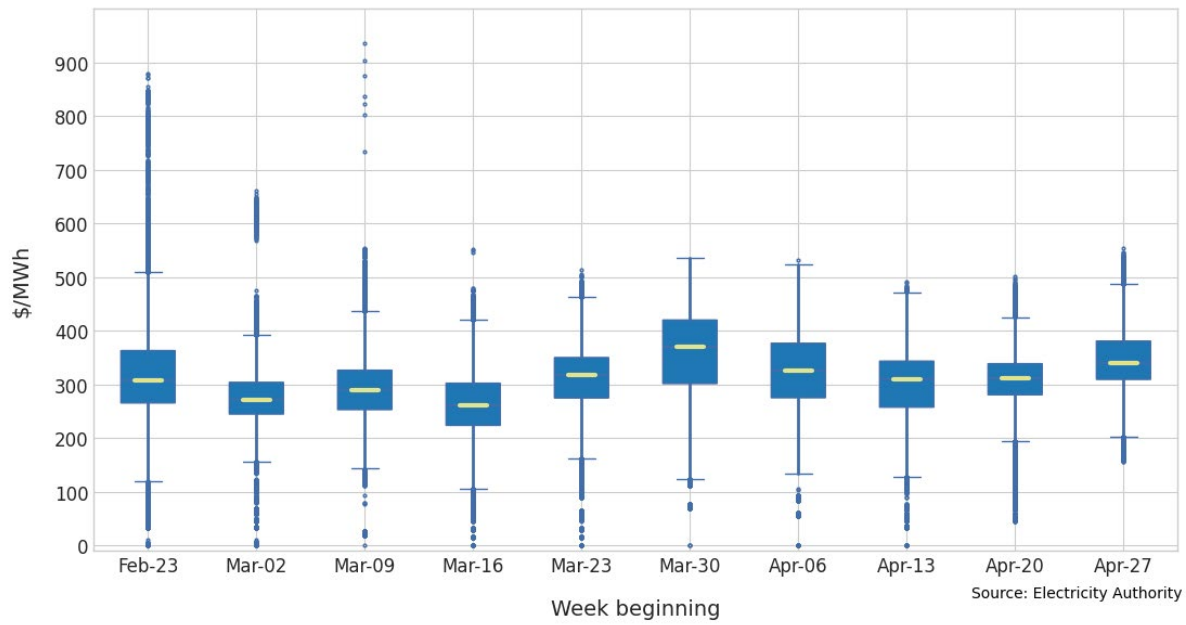
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 27 April-3 May



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 slightly higher and less volatile compared to last week. The median price was $340/MWh and most prices (middle 50%) fell between $310/MWh and $380/MWh.

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



3. Reserve prices

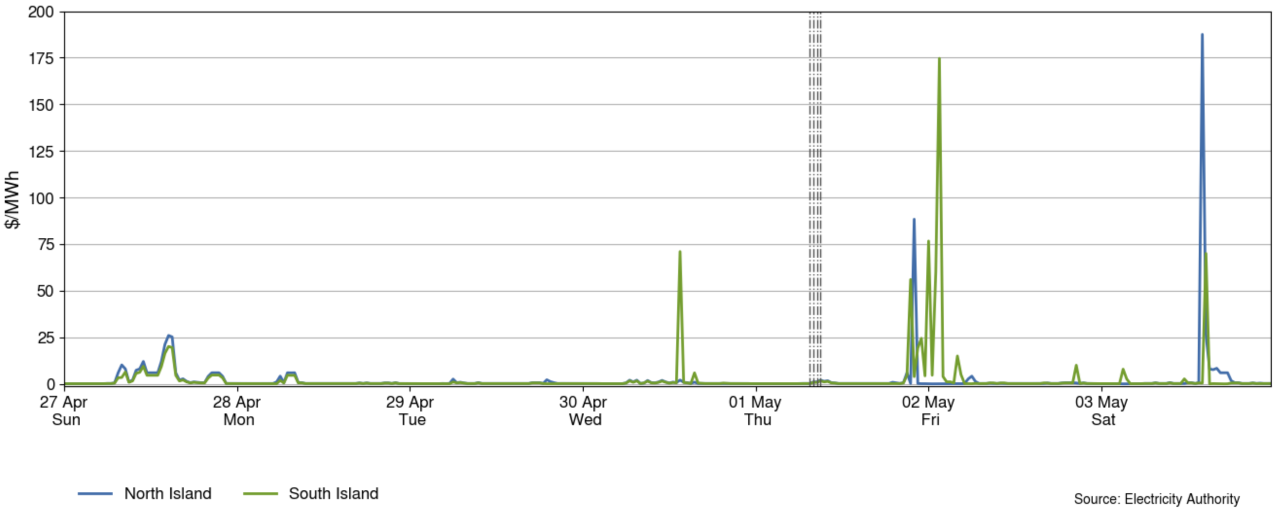
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh but spiked high several times.

3.2. FIR in the South Island spiked to $71/MWh at 1.30pm on Wednesday. Demand was 146MW higher than forecast at this time and the amount of FIR and SIR required increased.[1]

3.3. FIR also spiked from 9.30pm Thursday to 1.30am Friday. The 1.30am Friday spike was the highest for this period with the South Island FIR price reaching $175/MWh. HVDC pole 2 was on unplanned outage during this time[2], which likely contributed to the high FIR prices and FIR price separation.

3.4. FIR also spiked to $188/MWh in the North Island on Saturday at 2.00pm. HVDC Pole 2 went on a short notice outage that day from 2.00pm to 6.00pm.

Figure 3: Fast instantaneous reserve price by trading period and island, 27 April-3 May

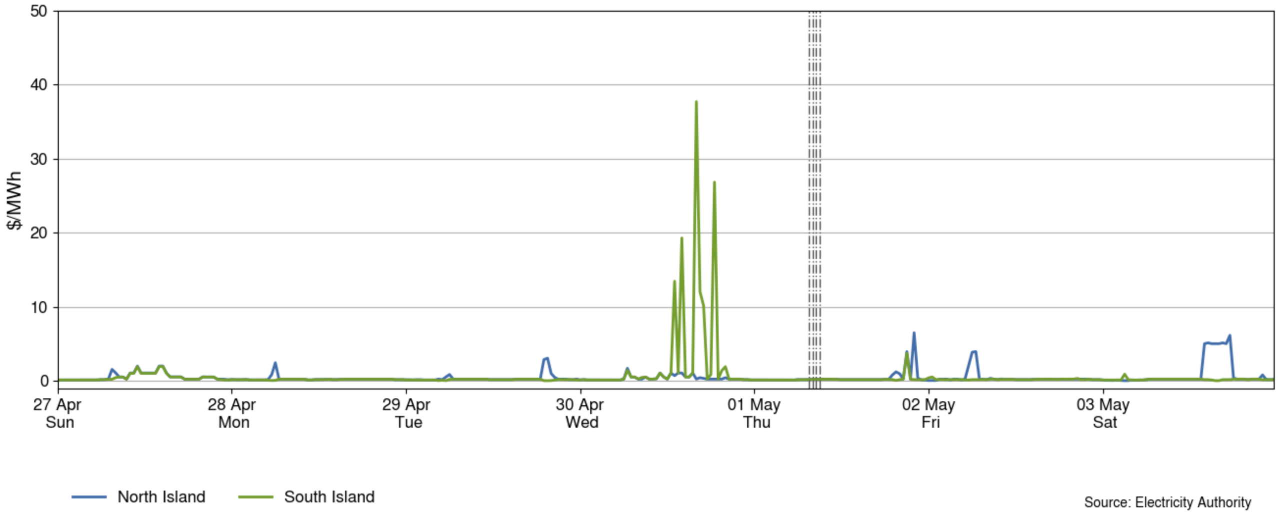


3.5. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $1/MWh but spiked above $10/MWh several times on Wednesday.

3.6. The highest SIR price was $38/MWh in the South Island at 4.00pm on Wednesday. Demand was more than 60MW higher than forecast for almost the entire day. The highest demand forecasting inaccuracy on Wednesday was 170MW at 2.00pm.

[1] Sometimes hydro generation is used to make up forecast differences when that generation would have otherwise been used to cover reserves.
[2] Customer Portal - POCP

Figure 4: Sustained instantaneous reserve by trading period and island, 27 April-3 May



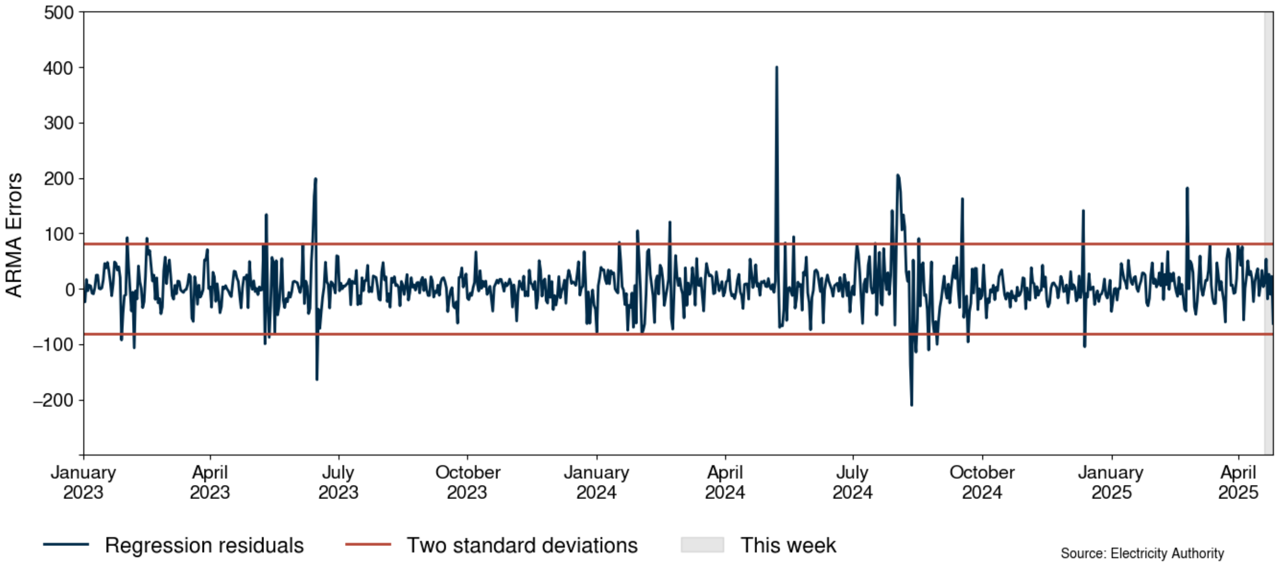
4. Regression residuals

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 – 3 May 2025



5. HVDC

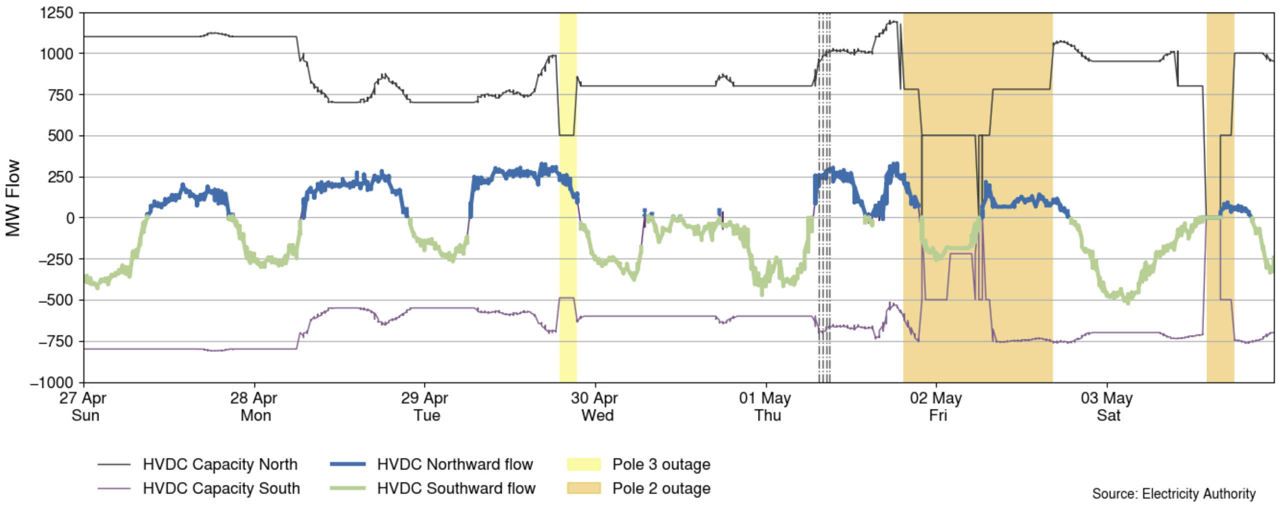
5.1. Figure 6 shows the HVDC flow between 27 April-3 May. HVDC flows were mostly Northward during the day except on Wednesday and Saturday morning when wind generation was higher. There were several unplanned and short notice HVDC outages this week.

(a) Pole 3 short notice outage from 7.00pm to 9.30pm on Tuesday[3].

(b) Pole 2 unplanned outage from 7.03pm Thursday to 6.00pm Friday[4].

(c) Pole 2 short notice outage from 2.00pm to 4.00pm on Saturday[5].

Figure 6: HVDC flow and capacity, 27 April-3 May

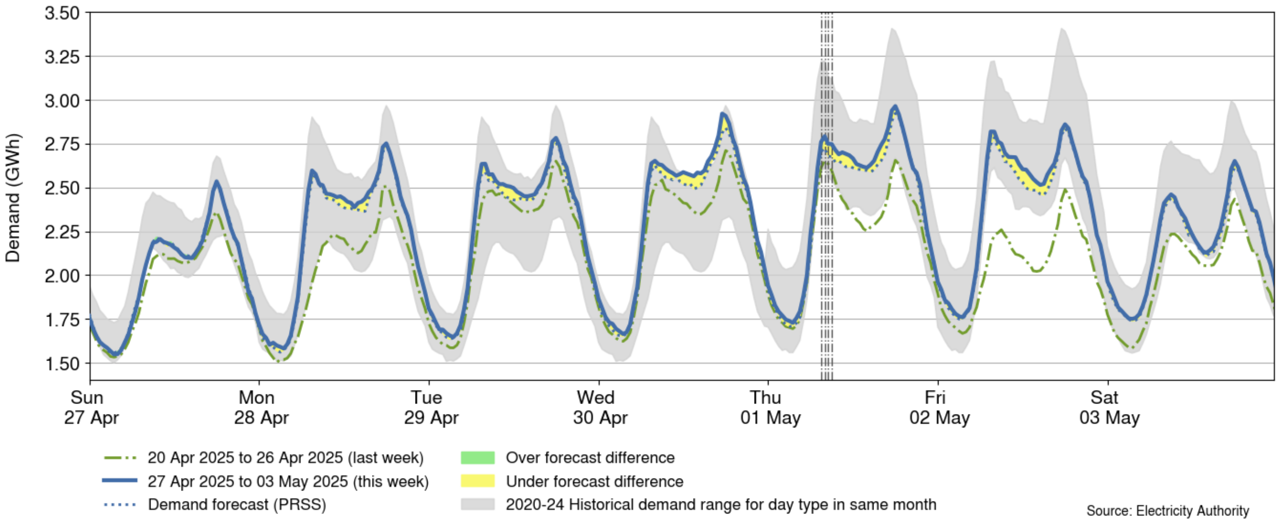


6. Demand

6.1. Figure 7 shows national demand between 27 April-3 May, compared to the historic range and the demand of the previous week. Demand was higher than last week due to the school holidays ending and below average temperatures from Wednesday. Demand was often over forecast this week.

[3] CAN Planned Outage HVDC Pole 3 6223520680.pdf
[4] CAN Unplanned Outage HVDC Pole 2 6232420901.pdf
[5] CAN Planned Outage HVDC Pole 2 6235113701.pdf

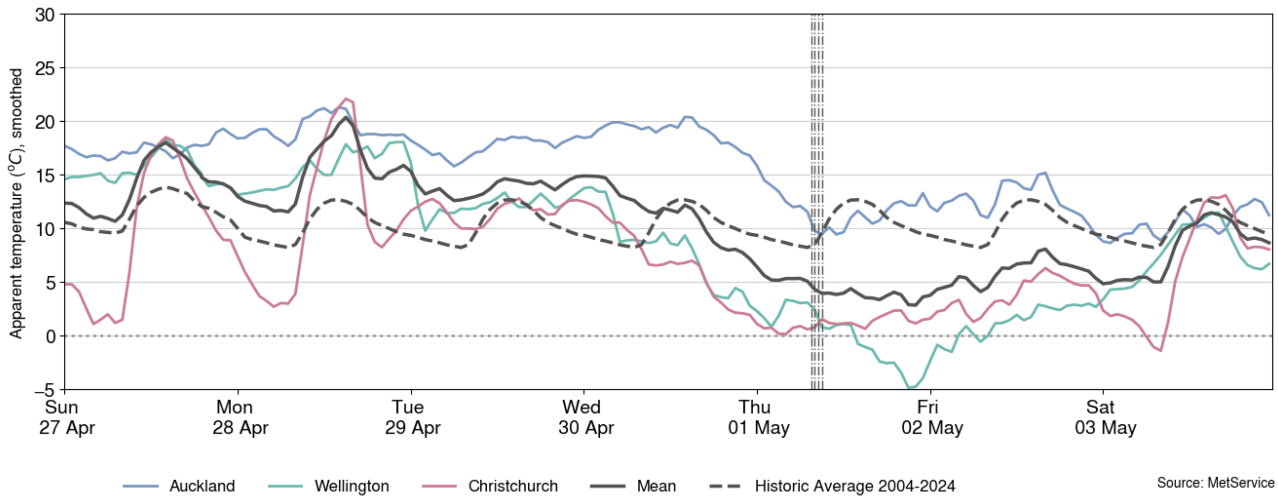
Figure 7: National demand, 27 April-3 May compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 27 April-3 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. Apparent temperatures were below average from Wednesday and ranged from 8°C to 22°C in Auckland, -5°C to 18°C in Wellington, and -2°C to 22°C in Christchurch.

Figure 8: Temperatures across main centres, 27 April-3 May

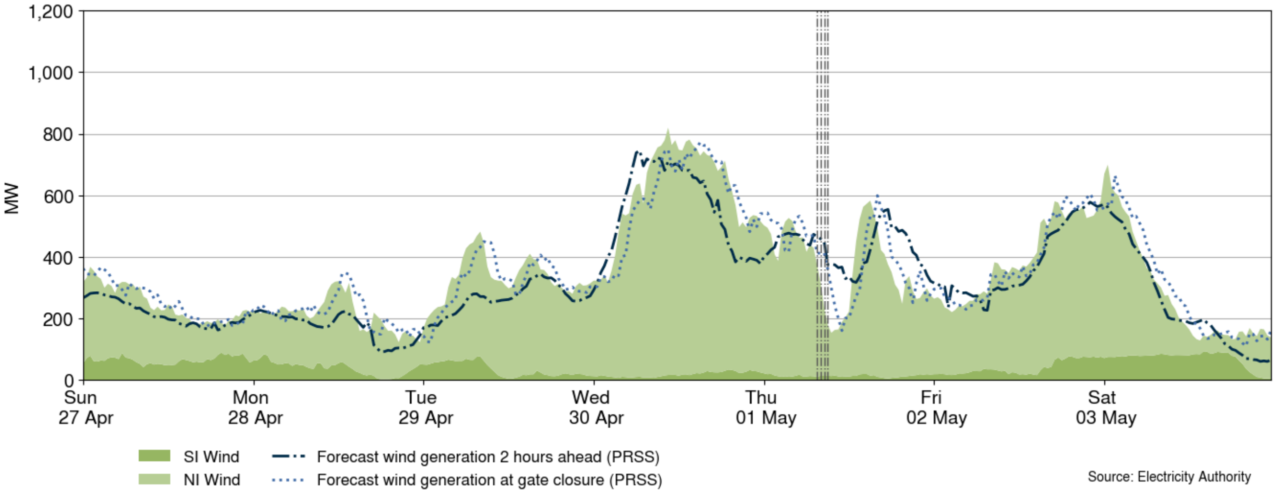


7. Generation

7.1. Figure 9 shows wind generation and forecast from 27 April-3 May. This week wind generation varied between 123MW and 820MW, with a weekly average of 351MW.

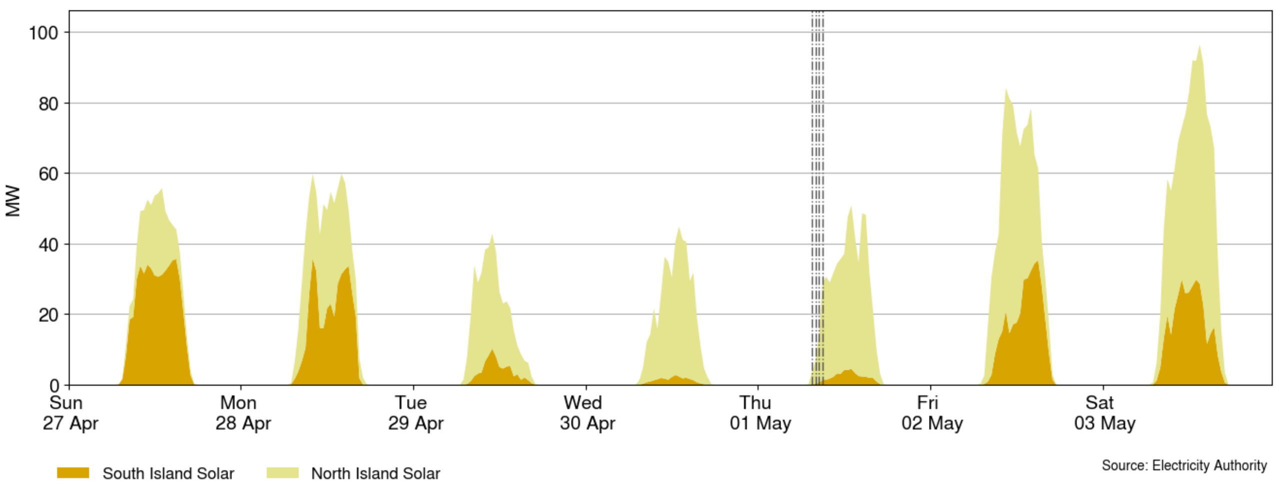
7.2. Wind generation was low from Sunday to Tuesday. Extreme wind on Thursday led to wind generation being low and lower than expected on Thursday due to windspeeds exceeding turbine operating ranges at multiple wind farms.

Figure 9: Wind generation and forecast, 27 April-3 May



7.3. Figure 10 shows grid connected solar generation from 27 April-3 May. Solar generation was low most days this week but reached 96MW on Saturday at 1.30pm.

Figure 10: Grid connected solar generation, 27 April-3 May



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[6]) 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.

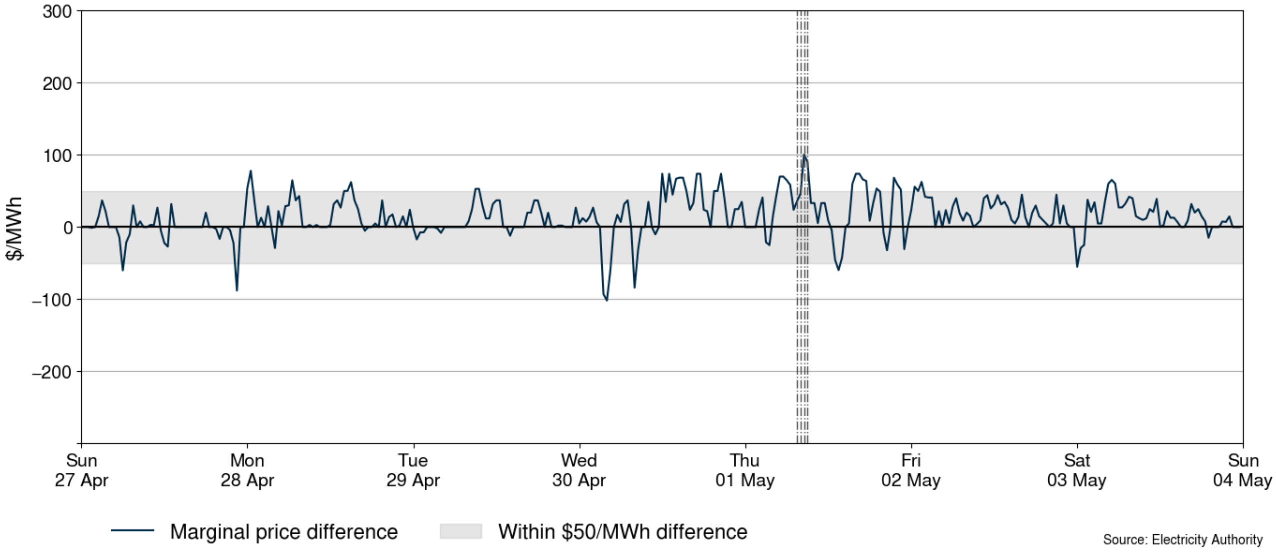
7.5. Marginal price differences were often outside the ±$50/MWh band this week due to frequent demand and wind forecasting inaccuracies.

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

7.6. The largest positive marginal price difference was +$100/MWh at 8.30am on Thursday. Demand was 140MW higher than forecast and wind was 214MW lower than forecast two hours ahead of gate closure and 178MW lower than forecast at gate closure.

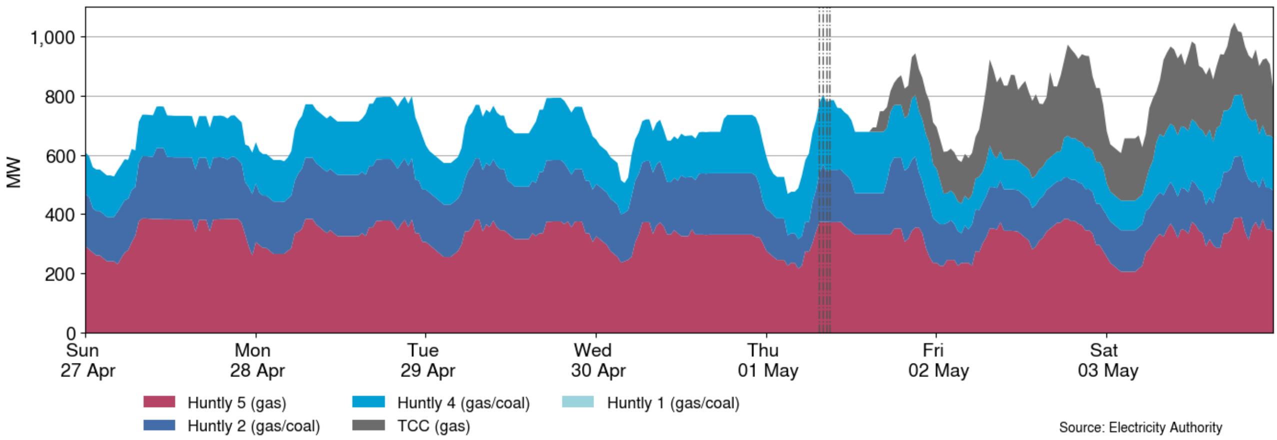
7.7. The largest negative marginal price difference was -$102/MWh at 4.00am on Wednesday. Wind was 140MW higher than forecasts at gate closure during this trading period.

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, 27 April-3 May



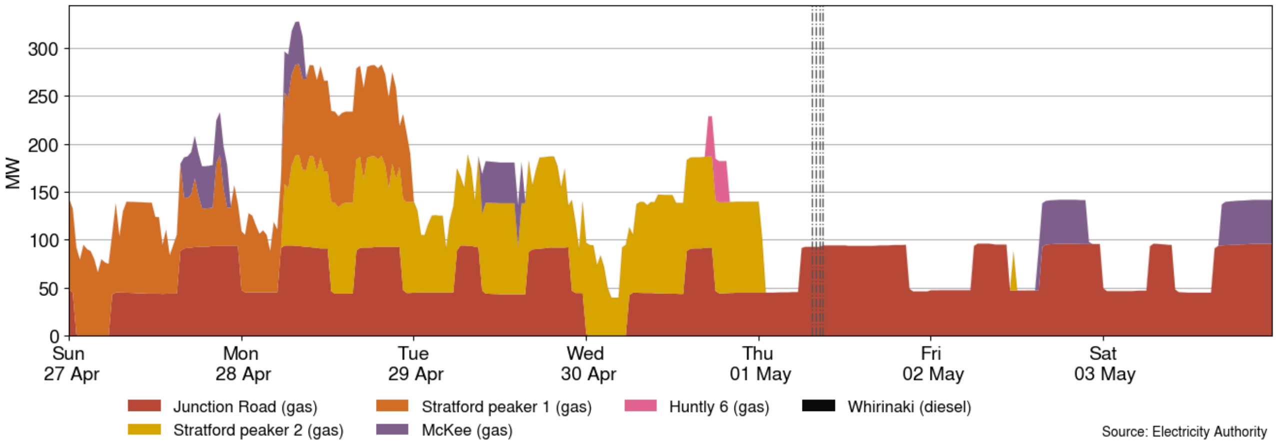
7.8. Figure 12 shows the generation of thermal baseload between 27 April-3 May. Huntly 5, 4 and 2 generated baseload this week. TCC started generating on Thursday.

Figure 12: Thermal baseload generation, 27 April-3 May



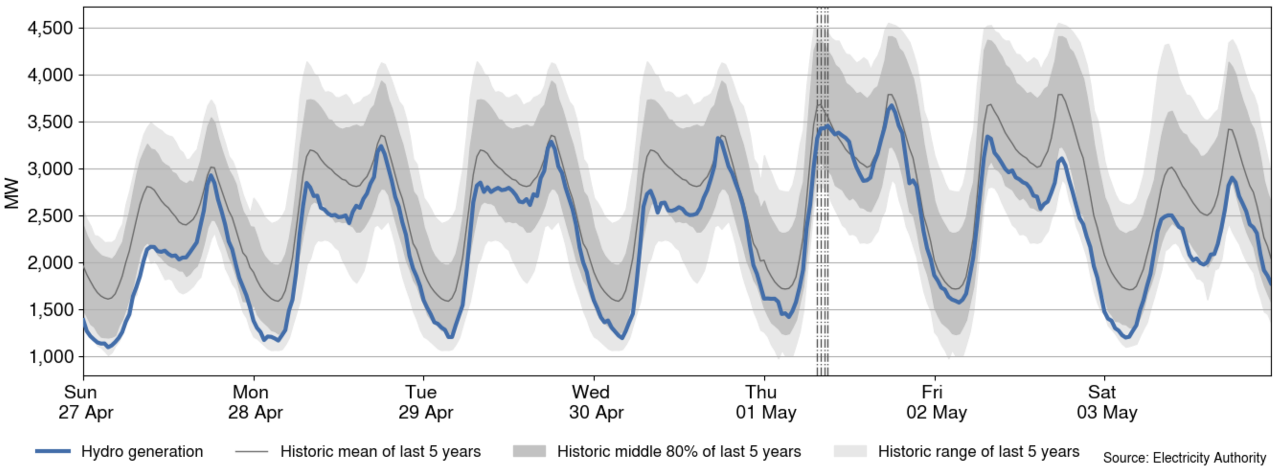
7.9. Figure 13 shows the generation of thermal peaker plants between 27 April-3 May. Junction Road generated every day. Stratford Peaker 1 generated Sunday and Monday then went on a month-long outage. Stratford Peaker 2 generated from Monday until it tripped at 12.42am on Thursday. McKee generated for short periods most days and Huntly 6 generated on Wednesday. Stratford Peaker 2 also generated for 1 trading period on Friday, which was likely a test after coming off its unplanned outage.

Figure 13: Thermal peaker generation, 27 April-3 May



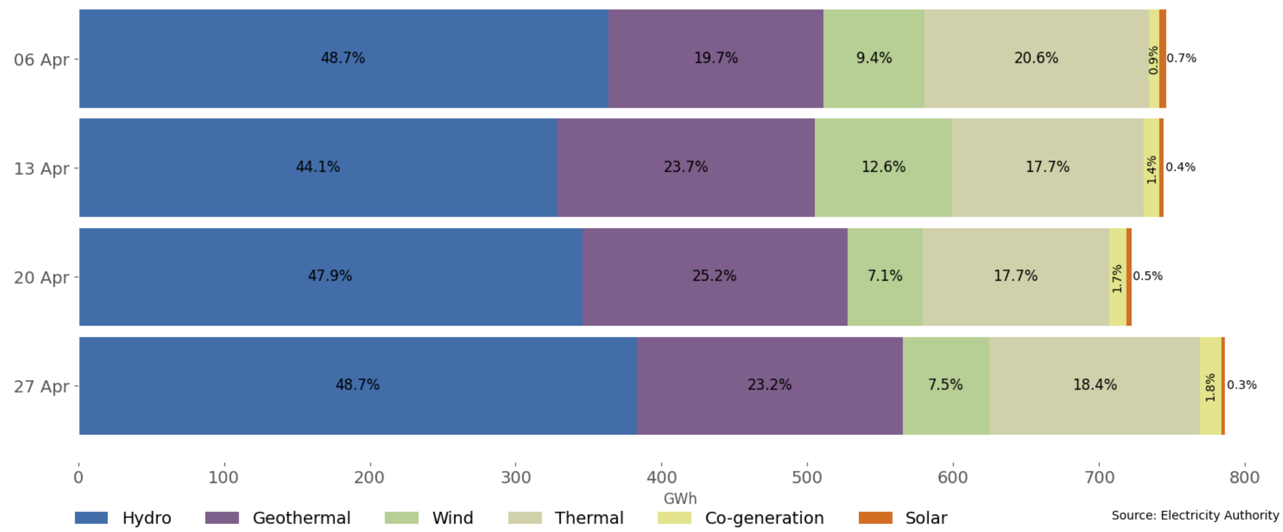
7.10. Figure 14 shows hydro generation between 27 April-3 May. Hydro generation was mostly between the historic 10th percentile and the historic mean.

Figure 14: Hydro generation, 27 April-3 May



7.11. As a percentage of total generation, between 27 April-3 May, total weekly hydro generation was 48.7%, geothermal 23.2%, wind 7.5%, thermal 18.4%, co-generation 1.8%, and solar (grid connected) 0.3%, as shown in Figure 15. This week, hydro and thermal generation increased due to higher demand.

Figure 15: Total generation by type as a percentage each week, between 6 April and 3 May 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 27 April-3 May ranged between ~993MW and ~2,037MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) TCC went on outage on 30 April but came back the next day.

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

(c) Ōhau A was on outage 3 May.

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

(e) Manapōuri unit 3 was on outage 30 April.

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

(g) Clyde unit 4 went on unplanned outage 30 April.

(h) Stratford peaker 2 went on unplanned outages 1 and 2 May.

Figure 16: Total MW loss from generation outages, 27 April-3 May

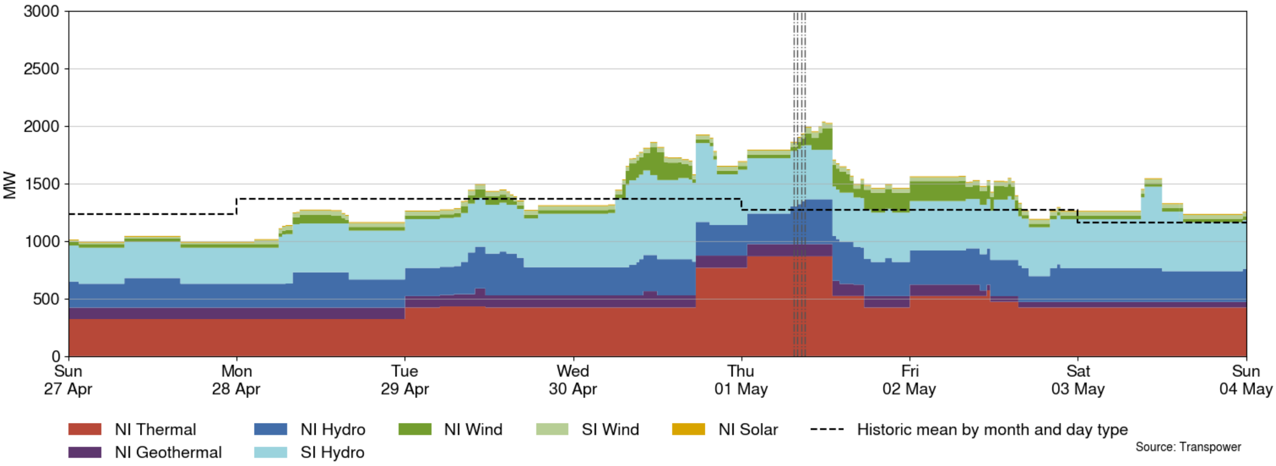
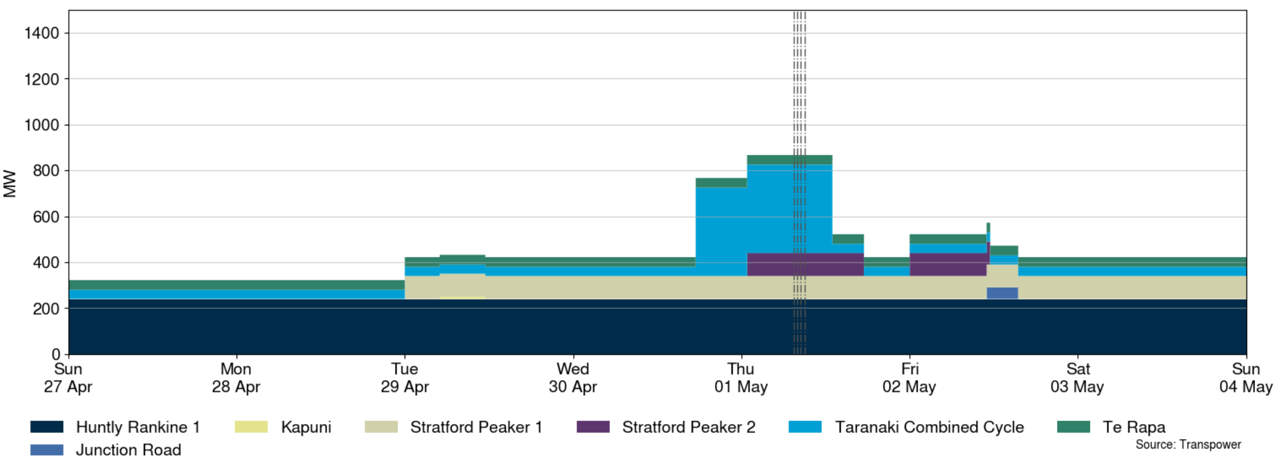


Figure 17: Total MW loss from thermal outages, 27 April-3 May

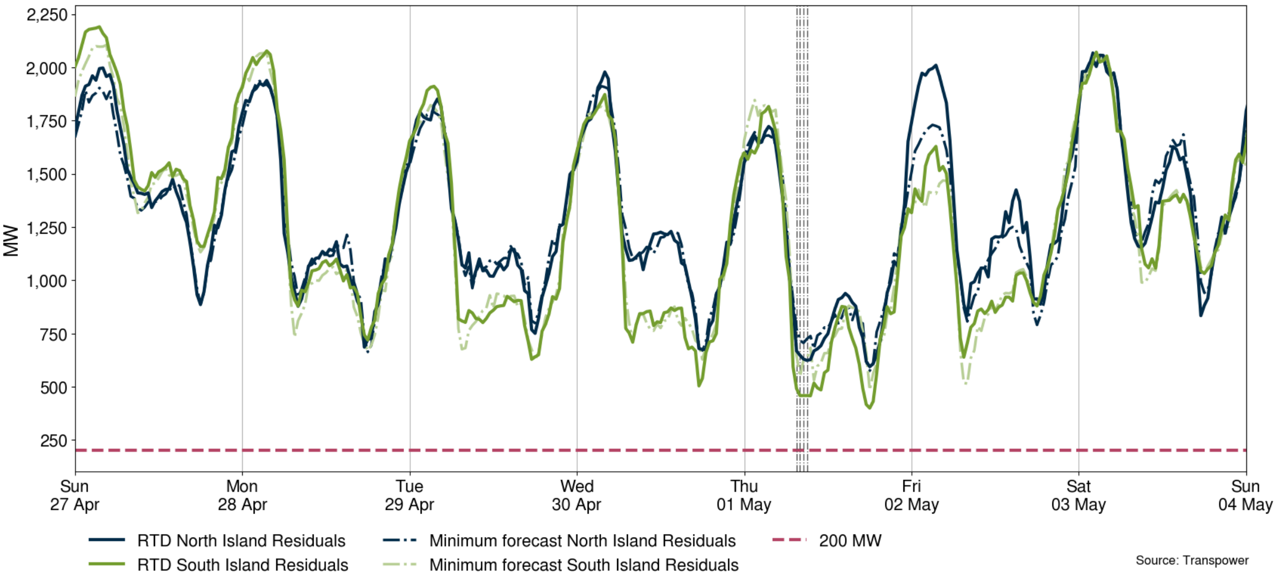


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 27 April-3 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. This week South Island residuals were frequently below North Island residuals but both were healthy. The minimum South Island residual was 400MW at 6.00pm on Thursday.

Figure 18: North Island and South Island generation balance residuals, 27 April-3 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.

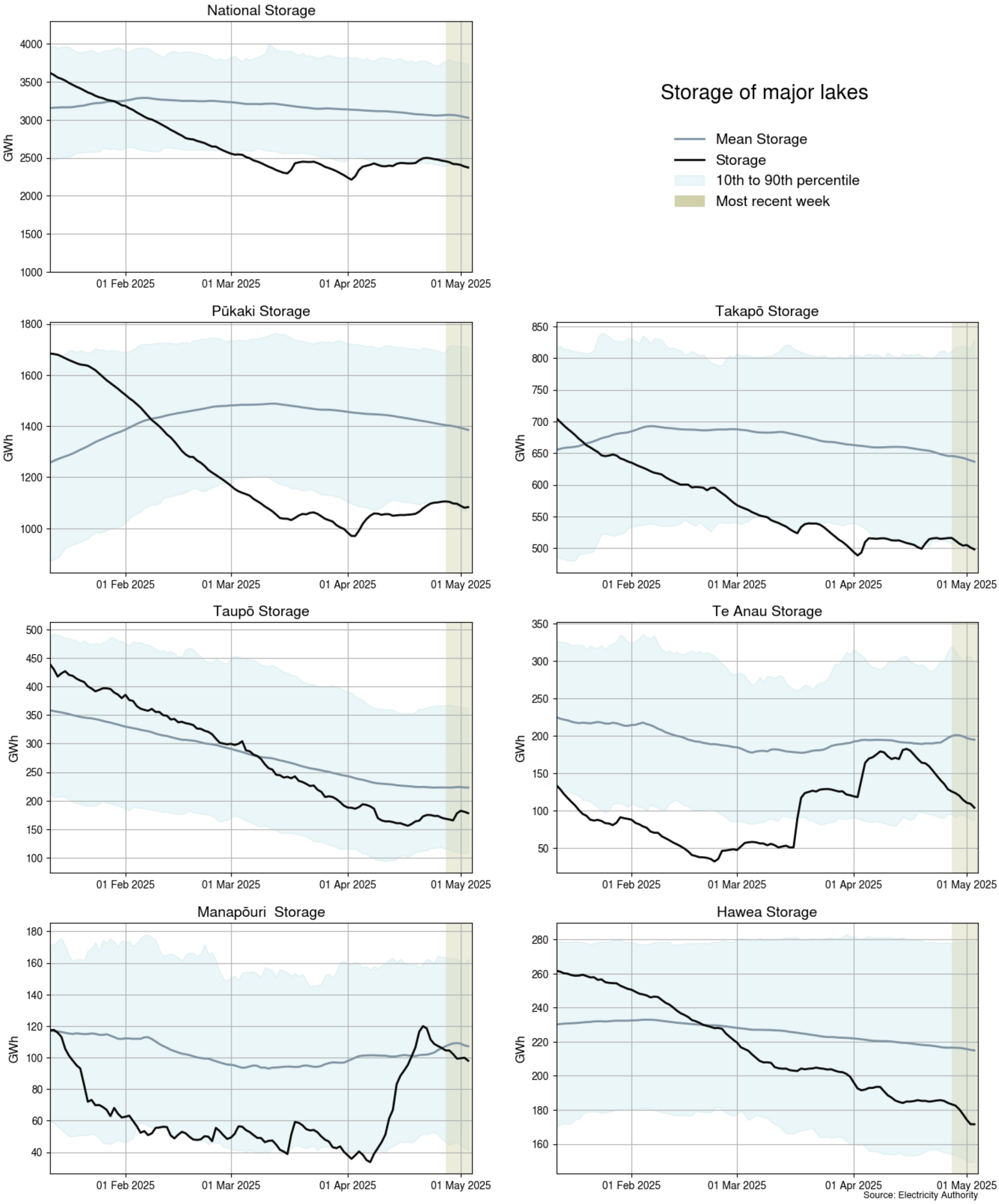
10.2. National controlled storage has decreased slightly. As of 3 May storage was 62% nominally full and ~82% of the historical average for this time of the year.

10.3. Storage at lakes Pūkaki (64% full)[7], Takapō (58% full) and Te Anau decreased in the last week and are now close to their historical 10th percentiles.

10.4. Storage at Lake Taupō (31% full) increased slightly while storage at lakes Hawea (61% full) and Manapōuri decreased. These lakes are between their respective historical 10th percentiles and means.

[7] 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 April 2025. The SRMC for gas fuelled generation has increased compared to last month. The SRMC for coal fuelled generation has reduced slightly and the SRMC diesel fuelled generation remains similar.

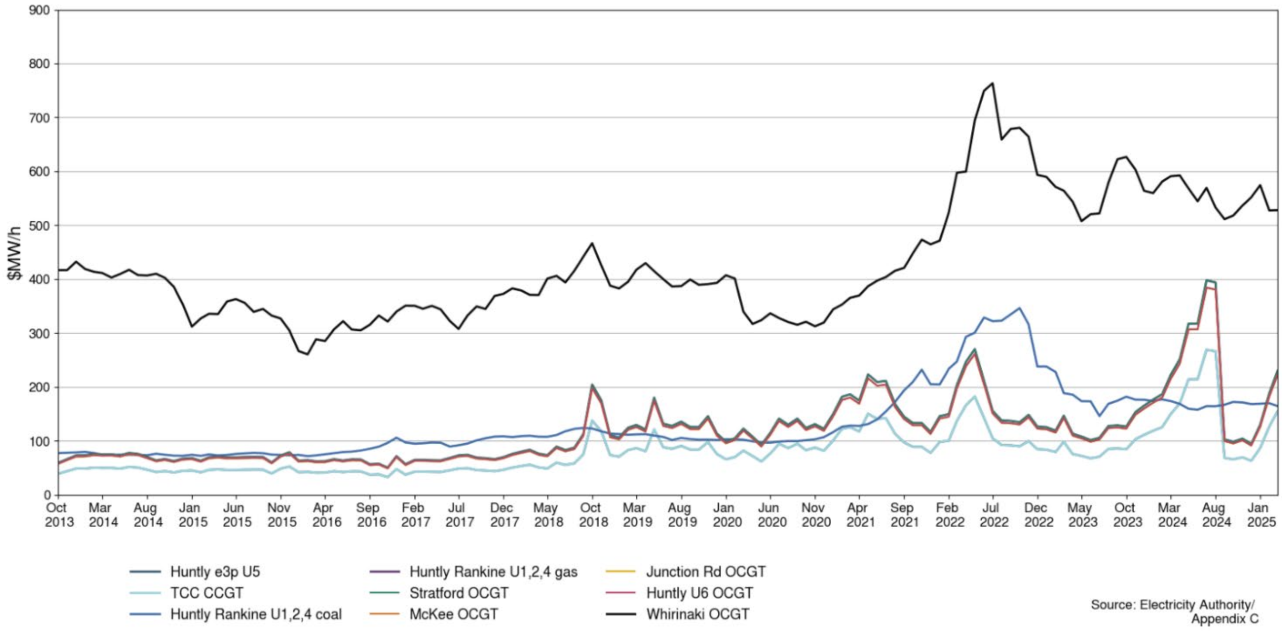
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$160/MWh, with the cost of running the Rankines on gas more expensive at ~$250/MWh.

11.5. The SRMC of gas fuelled 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

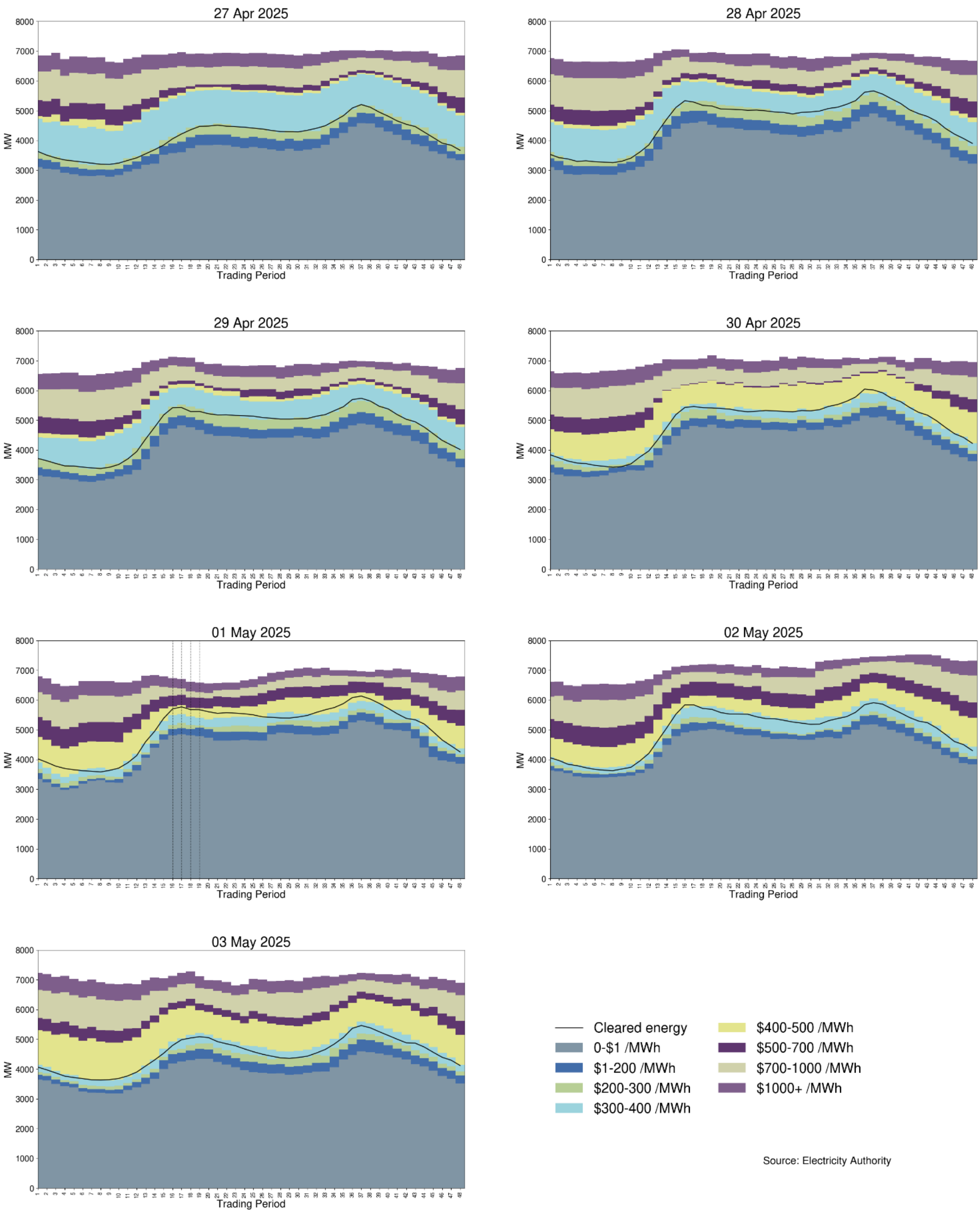


12. Offer behaviour

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. The increase in offer volume in the $400-500/MWh band from 30 April is Meridian pricing their hydro offers higher after they previously priced them lower from 24 April.

Figure 21: Daily offer stacks



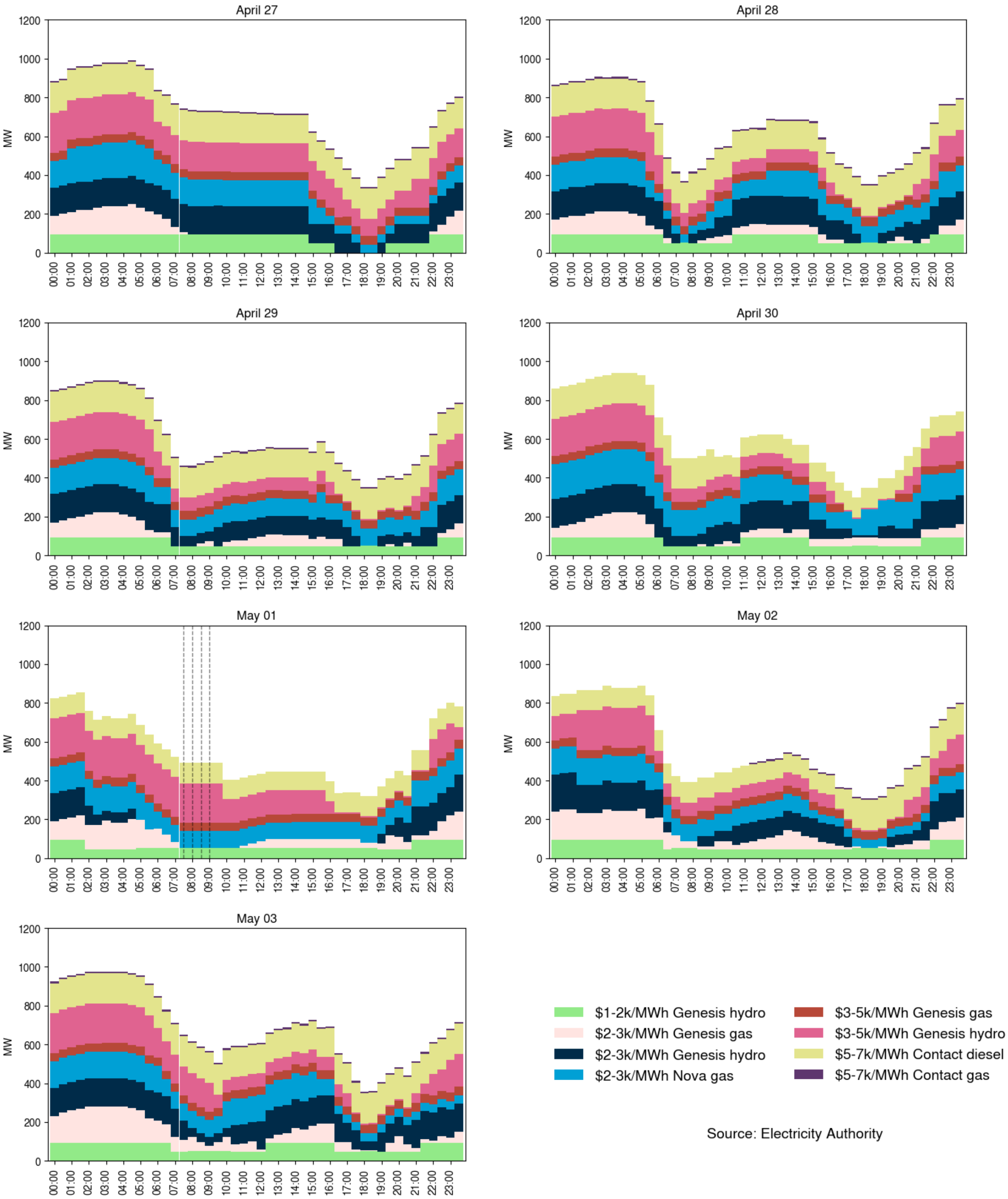
Source: Electricity Authority

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 629MW per trading period was priced above $1,000/MWh this week, which is roughly 10.5% of the total energy available and similar to last week.

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 will be further analyzing offers from McKee.

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
2/04/2025-11/04/2025	Several	Further analysis	Genesis	Takapō and Tokaanu	Offers
1/03/2025-26/04/2024	Several	Further analysis	Meridian	Waitaki	Hydro offer pricing
1/03/2025-26/04/2024	Several	Further analysis	Genesis	Takapō	Hydro offer pricing
1/03/2025-26/04/2024	Several	Further analysis	Mercury	Waikato	Hydro offer pricing
27/04/2025-3/05/2025	Several	Further analysis	Nova	McKee	Offer pricing