31 March 2025

Trading conduct report 23-29 March 2025

Market monitoring weekly report

Trading conduct report 23-29 March 2025

1. Overview

1.1. Spot prices increased this week to an average of \$308/MWh due to continued low hydro inflows (national storage has dropped to ~62% nominally full), low wind generation and unplanned thermal generation outages.

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 23-29 March 2025:

(a) The average spot price for the week was \$308/MWh, an increase of around \$35/MWh compared to the previous week.

(b) 95% of prices fell between \$120/MWh and \$432/MWh.

(c) Most spot prices were above the historical 90th percentile this week (except for Sunday), likely because of declining hydro storage, low wind generation and an unplanned outage of a Rankine unit.

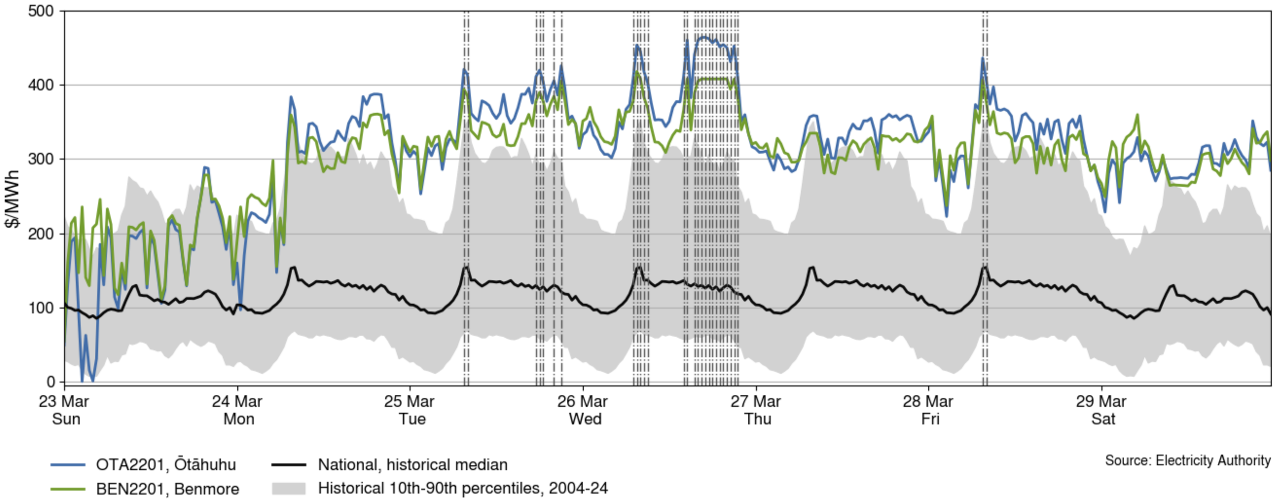
2.3. The maximum price at Ōtāhuhu (\$464/MWh) occurred at 5.00pm on Wednesday when wind generation was low, demand 37MW higher than forecast and increasing towards the evening peak. The Benmore spot price at the same time was \$408/MWh.

2.4. Other periods of spot prices greater than \$400/MWh this week typically coincided with peak demand periods, low wind generation and the periods of highest hydro generation.

2.5. The North Island and South Island prices separated early on Sunday morning during high wind generation and southward HVDC flow. At 2.30am, the Ōtāhuhu spot price was \$0.37/MWh and the Benmore spot price was \$236/MWh.

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 prices over \$400/MWh are marked with black dashed lines.

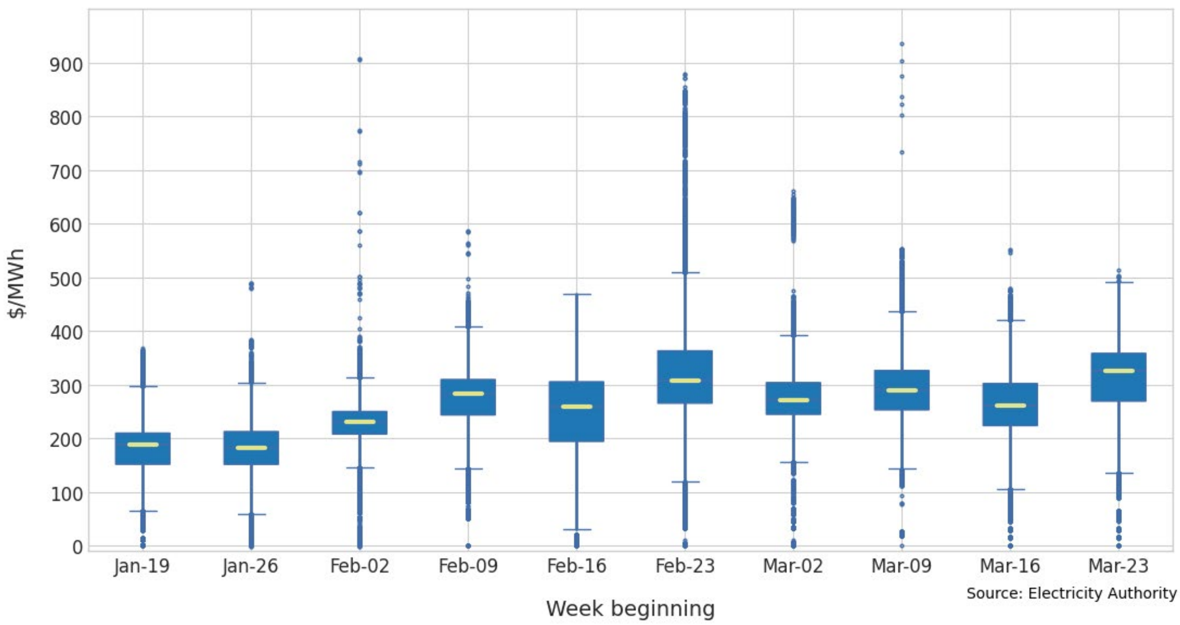
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 23-29 March 2025



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 skewed higher than last week. The median price was $326/MWh, and most prices (middle 50%) fell between $270/MWh and $359/MWh.

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

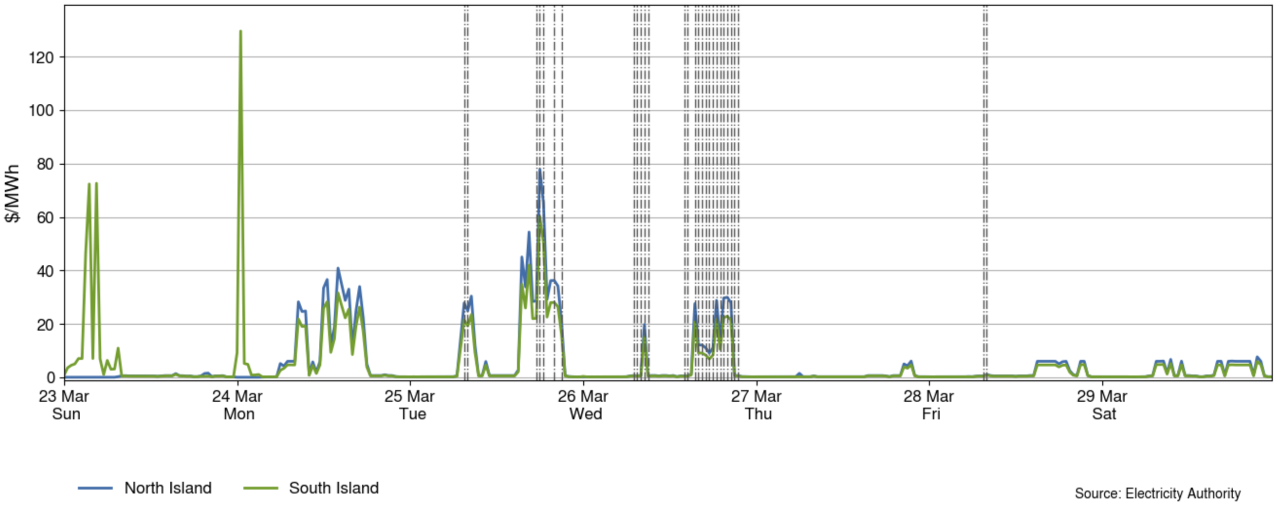


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. The maximum South Island FIR price was $130/MWh at 12.30am on Monday morning when southward HVDC flow was high and the HVDC was the risk setter. North Island FIR remained low throughout Sunday and early Monday morning.

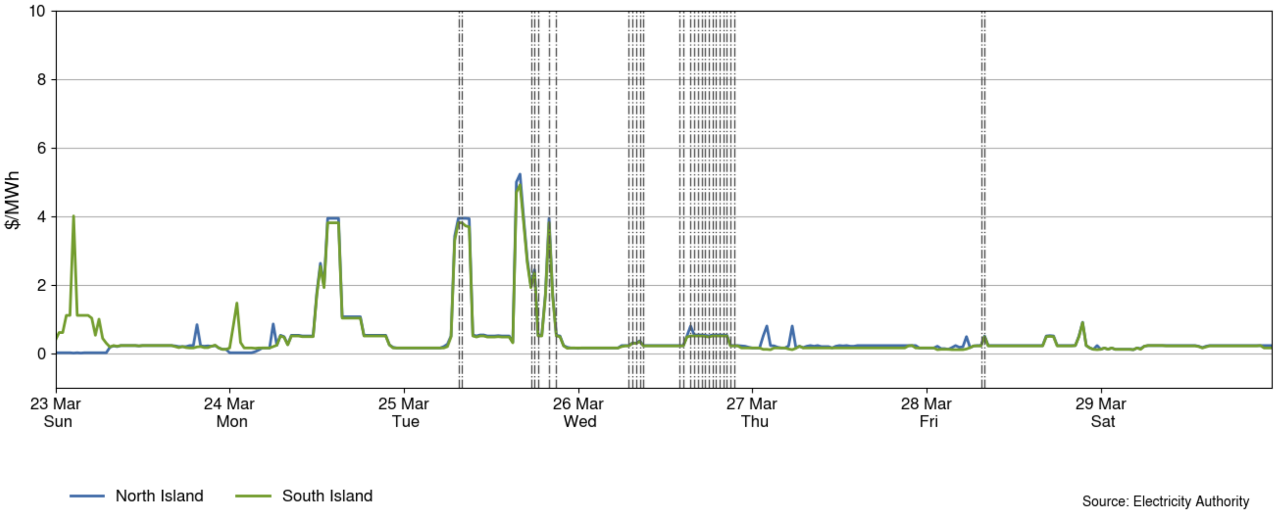
3.2. At 6.00pm on Tuesday, FIR prices increased to $60/MWh in the South Island and $78/MWh in the North Island. At this time, Huntly 5 was setting the risk and the amount of cleared FIR increased.

Figure 3: Fast instantaneous reserve price by trading period and island, 23-29 March 2025



3.3. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were all below $6/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 23-29 March 2025



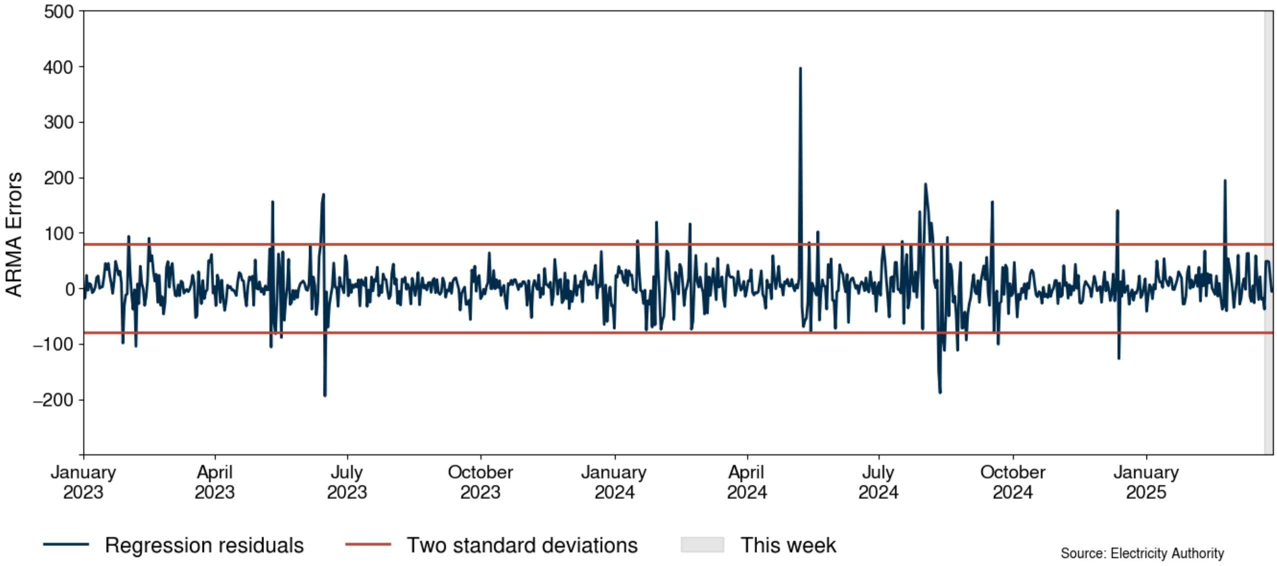
4. Regression residuals

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 – 29 March 2025

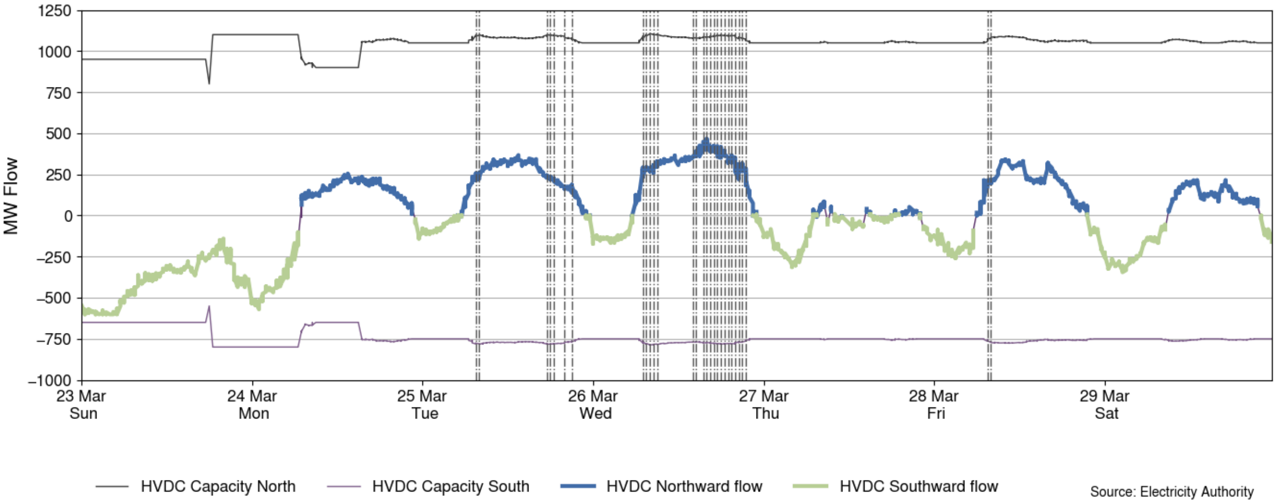


Source: Electricity Authority

5. HVDC

5.1. Figure 6 shows the HVDC flow between 23-29 March 2025. There was more northward flow on the HVDC than last week due to lower wind generation.

Figure 6: HVDC flow and capacity, 23-29 March 2025

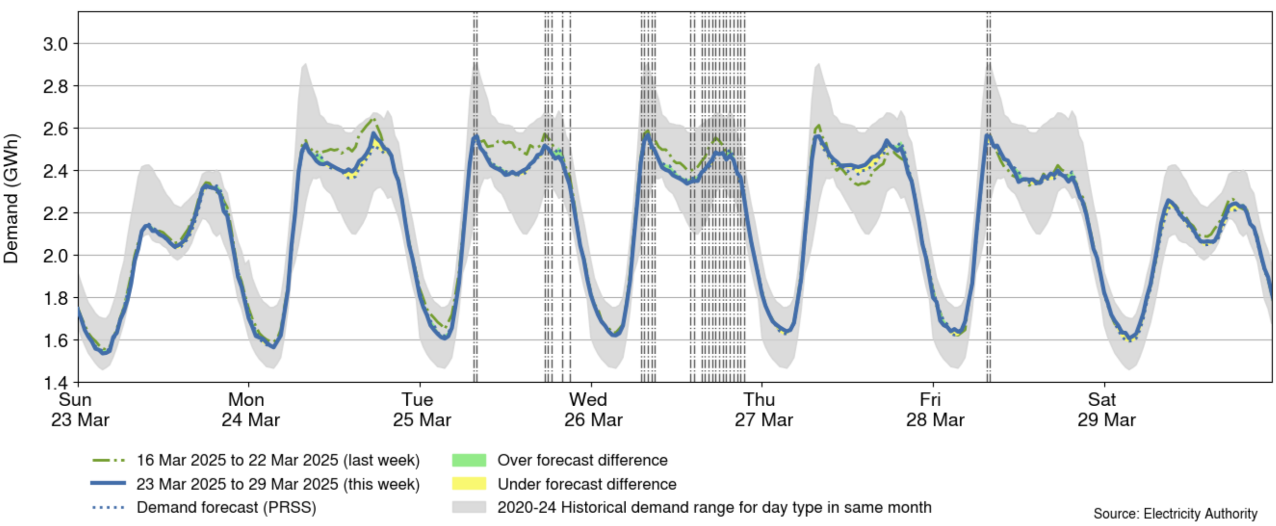


6. Demand

6.1. Figure 7 shows national demand between 23-29 March 2025, compared to the historic range and the demand of the previous week. Demand was mostly similar to or lower than last week, except for Thursday when demand was higher than last week during the day.

6.2. Peak demand this week was 2.58GWh at 5.30pm on Monday.

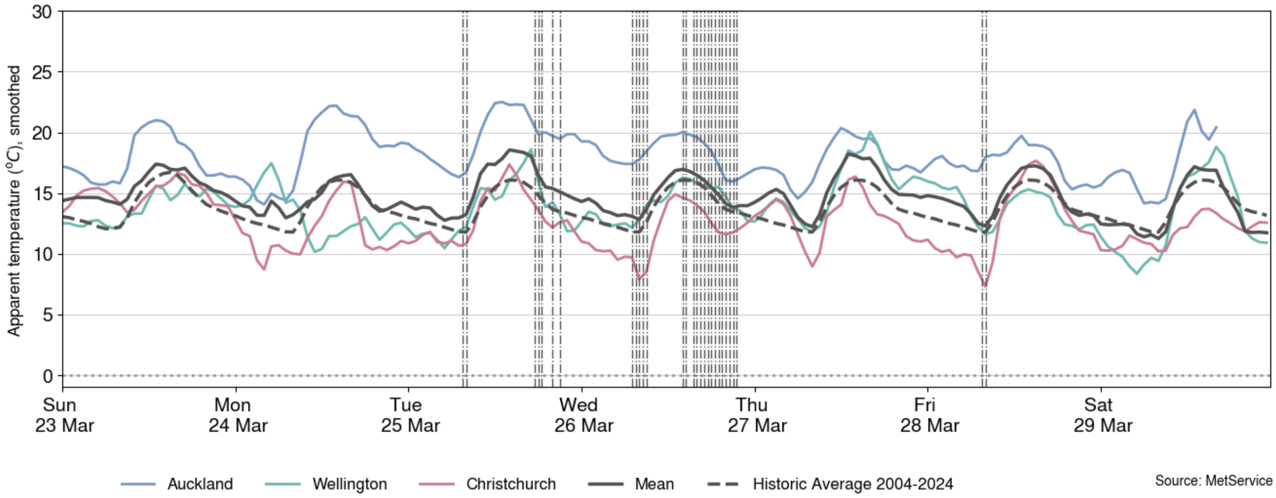
Figure 7: National demand, 23-29 March 2025 compared to the previous week



6.3. Figure 8 shows the hourly apparent temperature at main population centres from 23-29 March 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. National apparent temperatures were mostly around average this week, ranging from 13°C to 23°C in Auckland, 8°C to 20°C in Wellington, and 7°C to 18°C in Christchurch.

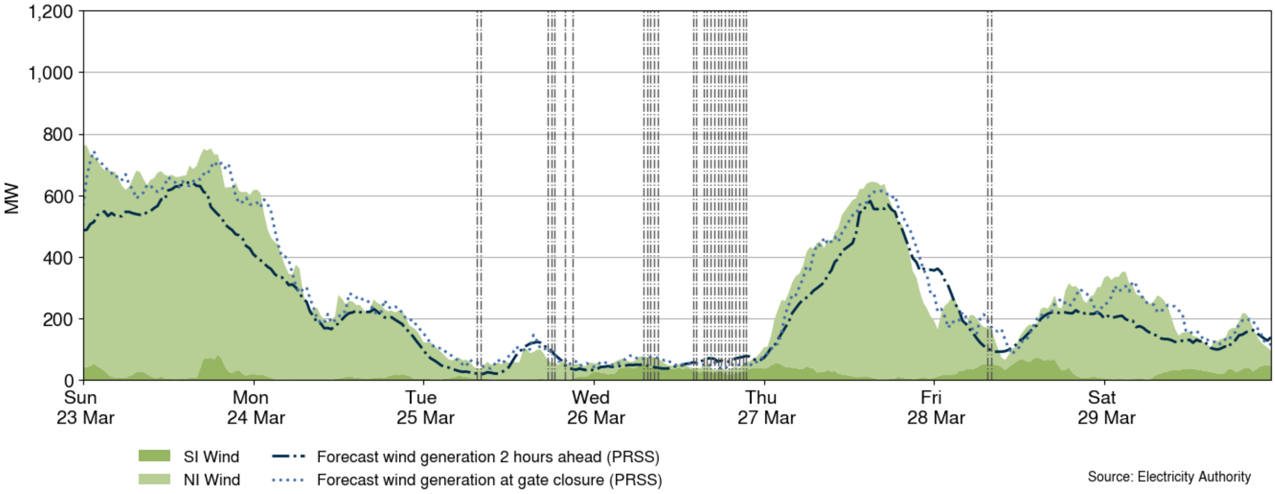
Figure 8: Temperatures across main centres, 23-29 March 2025



7. Generation

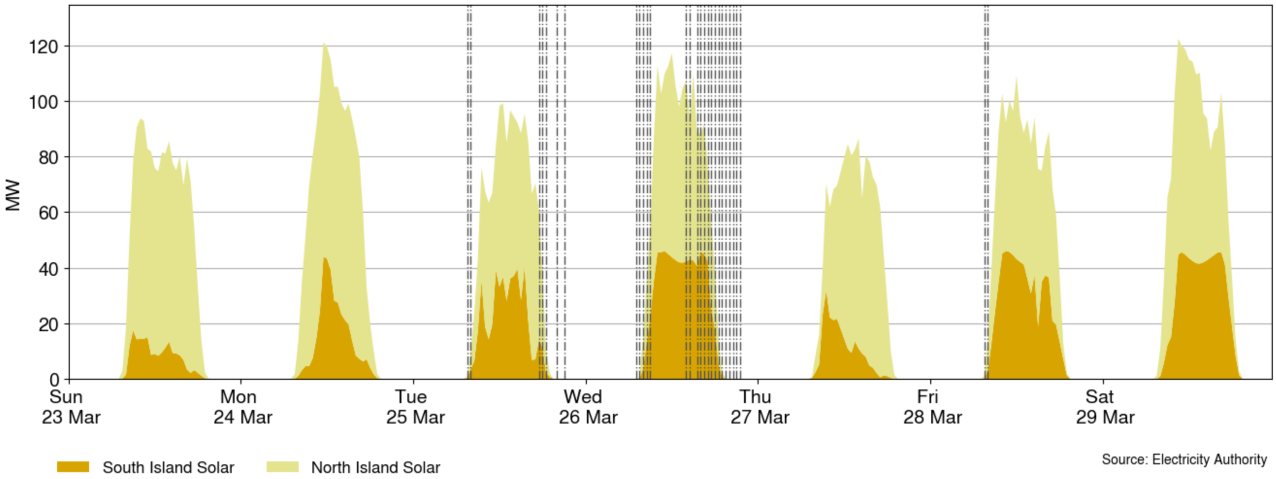
7.1. Figure 9 shows wind generation and forecast from 23-29 March 2025. This week wind generation varied between 30MW and 764MW, with a weekly average of 275MW. Wind generation was low every day this week except for Sunday and Thursday.

Figure 9: Wind generation and forecast, 23-29 March 2025



7.2. Figure 10 shows grid connected solar generation from 23-29 March 2025. Maximum solar generation of 122MW occurred at 10.30am on Saturday.

Figure 10: Grid connected solar generation, 23-29 March 2025

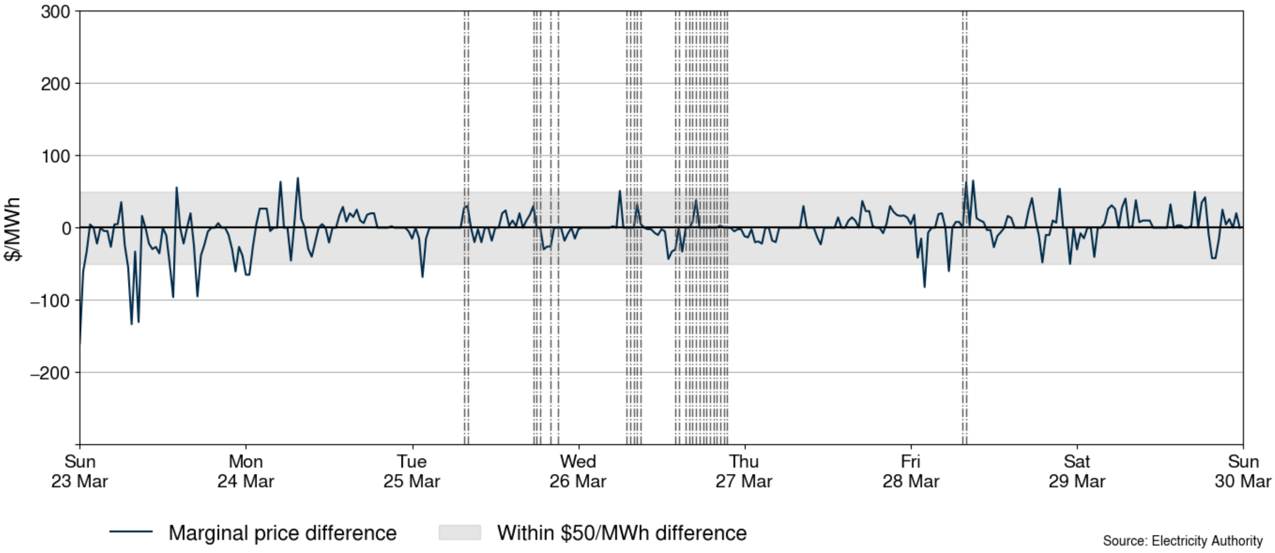


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 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. The largest marginal price difference was -$160/MWh at 12.00am on Sunday when wind generation was 198MW higher than forecast at gate closure. All other marginal price differences larger than $50/MWh were related to wind or demand forecasting errors.

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

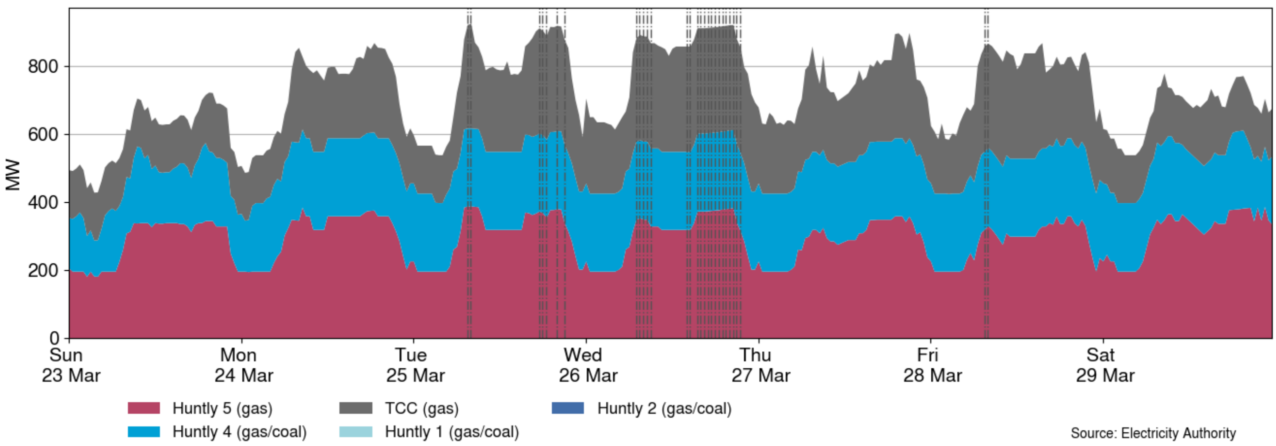
Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 23-29 March 2025



7.5. Figure 12 shows the generation of thermal baseload between 23-29 March 2025. Huntly 5, Huntly 4 and TCC ran as baseload generation this week.

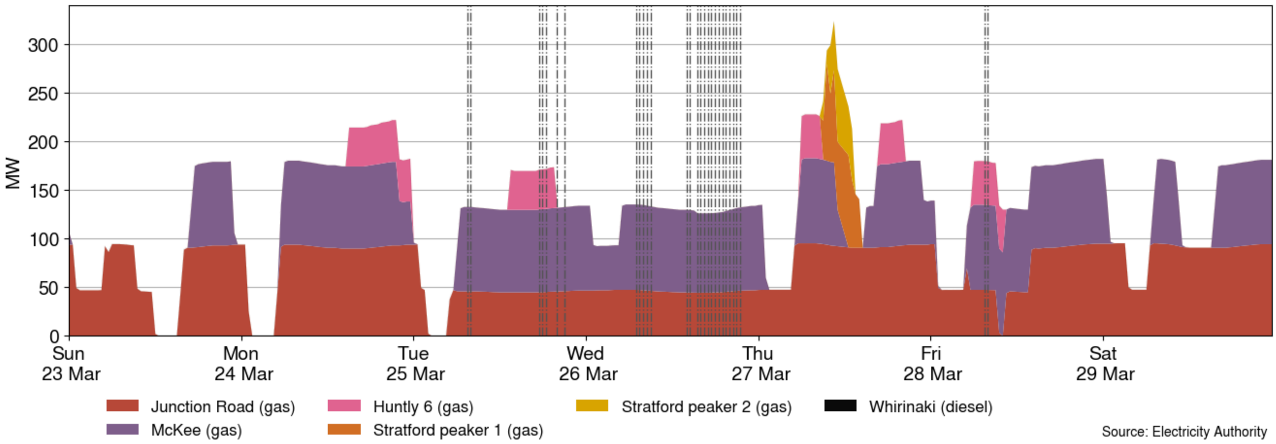
7.6. TCC offers were removed after gate closure when Stratford 2 tripped. The monitoring team will be further analysing these offer changes.

Figure 12: Thermal baseload generation, 23-29 March 2025



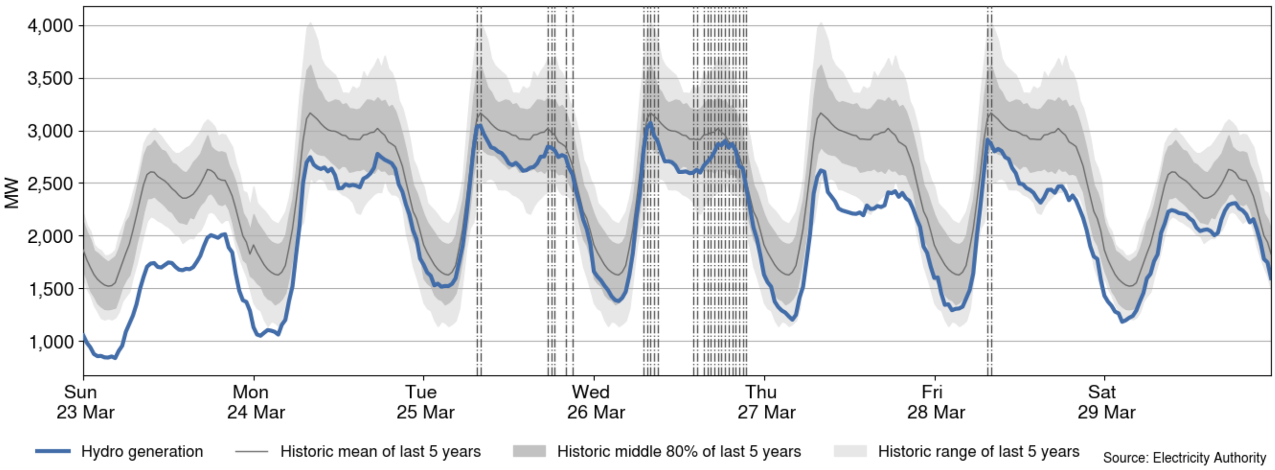
7.7. Figure 13 shows the generation of thermal peaker plants between 23-29 March 2025. Peaker generation came mostly from Junction Road and McKee this week, with Junction Road running near continuously for most of the week.

Figure 13: Thermal peaker generation, 23-29 March 2025



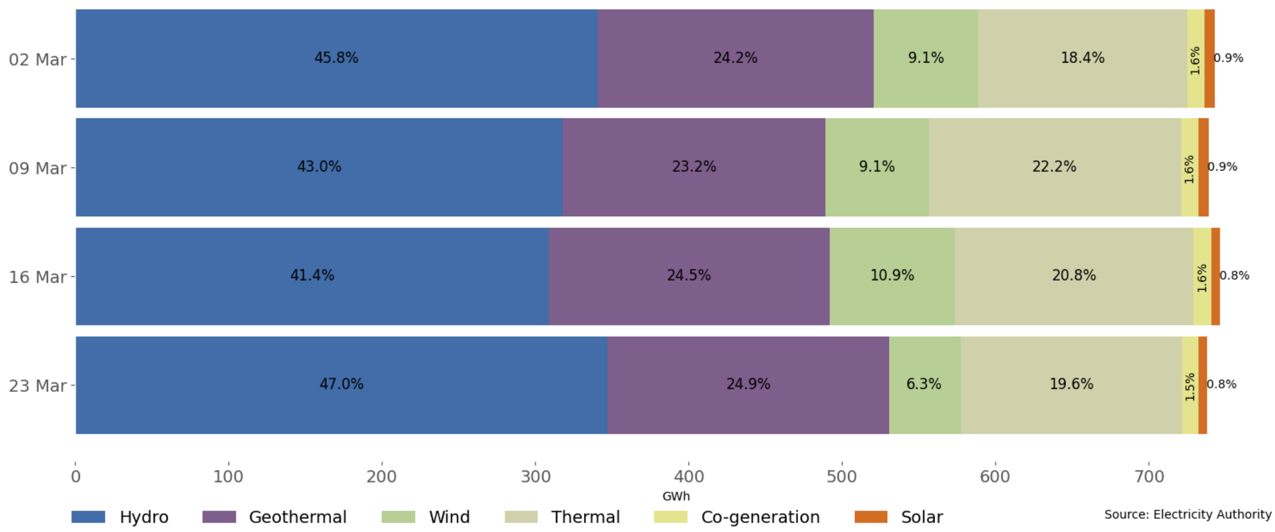
7.8. Figure 14 shows hydro generation between 23-29 March 2025. Hydro generation was mostly near the bottom of the historic range this week, but higher than it has been in previous weeks, and was highest on Tuesday and Wednesday when wind generation was lowest.

Figure 14: Hydro generation, 23-29 March 2025



7.9. As a percentage of total generation, between 23-29 March 2025, total weekly hydro generation was 47.0%, geothermal 24.9%, wind 6.3%, thermal 19.6%, co-generation 1.5%, and solar (grid connected) 0.8%, as shown in Figure 15. The proportion of wind generation dropped this week, and the amount of hydro generation increased.

Figure 15: Total generation by type as a percentage each week, between 2-29 March 2025.



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 23-29 March 2025 ranged between ~1,200MW and ~2,200MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

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

(b) Huntly 2 went on unplanned outage on 23 March and is expected to return from outage on 2 April.

(c) Maraetai was on outage from 25-28 March, excluding overnight on 26 March.

(d) Manapōuri unit 2 is on outage until 17 April.

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

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

(g) Stratford 2 returned from outage on 24 March.

Figure 16: Total MW loss from generation outages, 23-29 March 2025

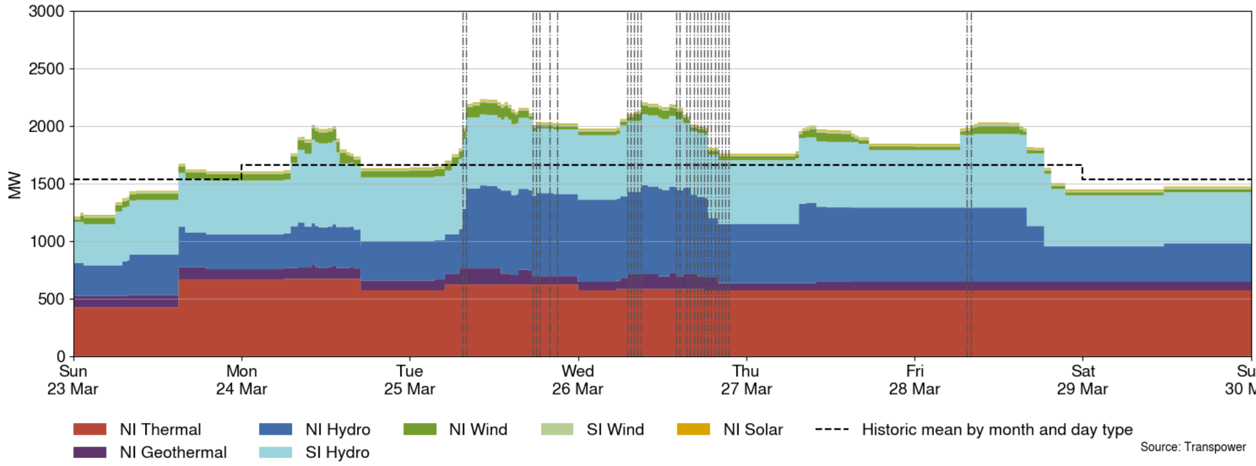
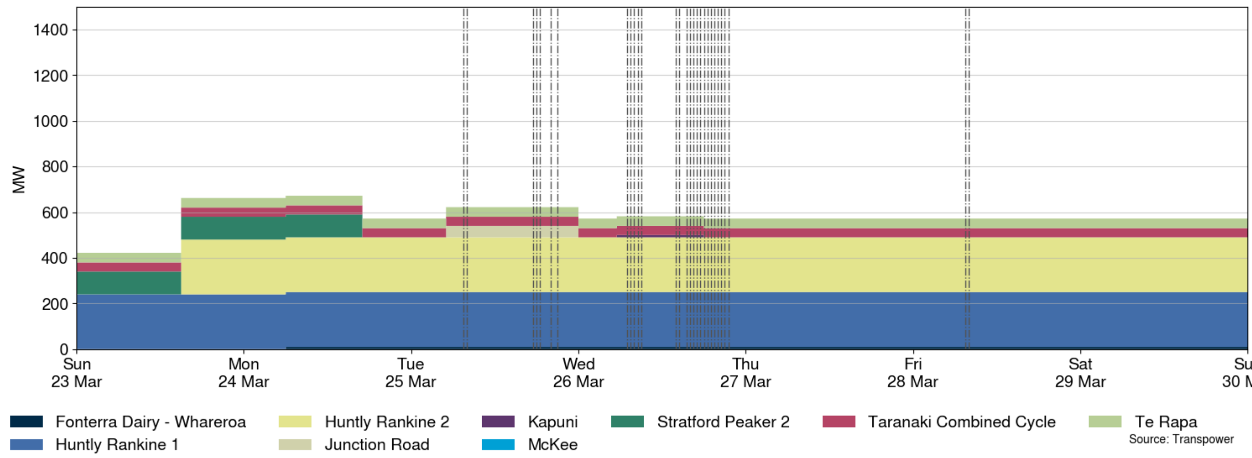


Figure 17: Total MW loss from thermal outages, 23-29 March 2025

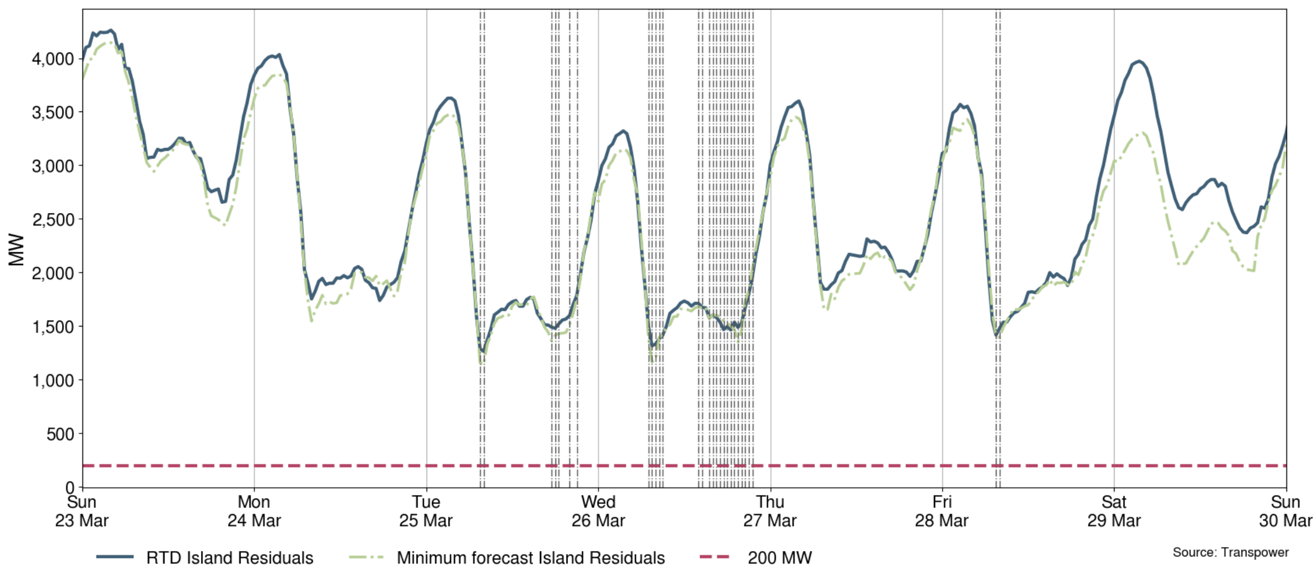


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 23-29 March 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. Generation balance residuals were healthy this week, with the minimum national residual balance of 1,264MW on 25 March at 8.00am. The minimum North Island residual was 690MW at 5.30pm on 25 March.

Figure 18: National generation balance residuals, 23-29 March 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. National controlled storage decreased this week to 62% nominally full and ~78% of the historical average for this time of the year.

10.3. Most lakes are showing a continued decline in storage with all lakes below their respective mean storage levels. Below highlights the current percentage full values as per the most recent NZX hydrological summary:

(a) Lake Taupō is 34% full[2]

(b) Lake Takapō 63% full and currently below its historic 10th percentile.

(c) Lake Pūkaki 58% full and currently below its historic 10th percentile.

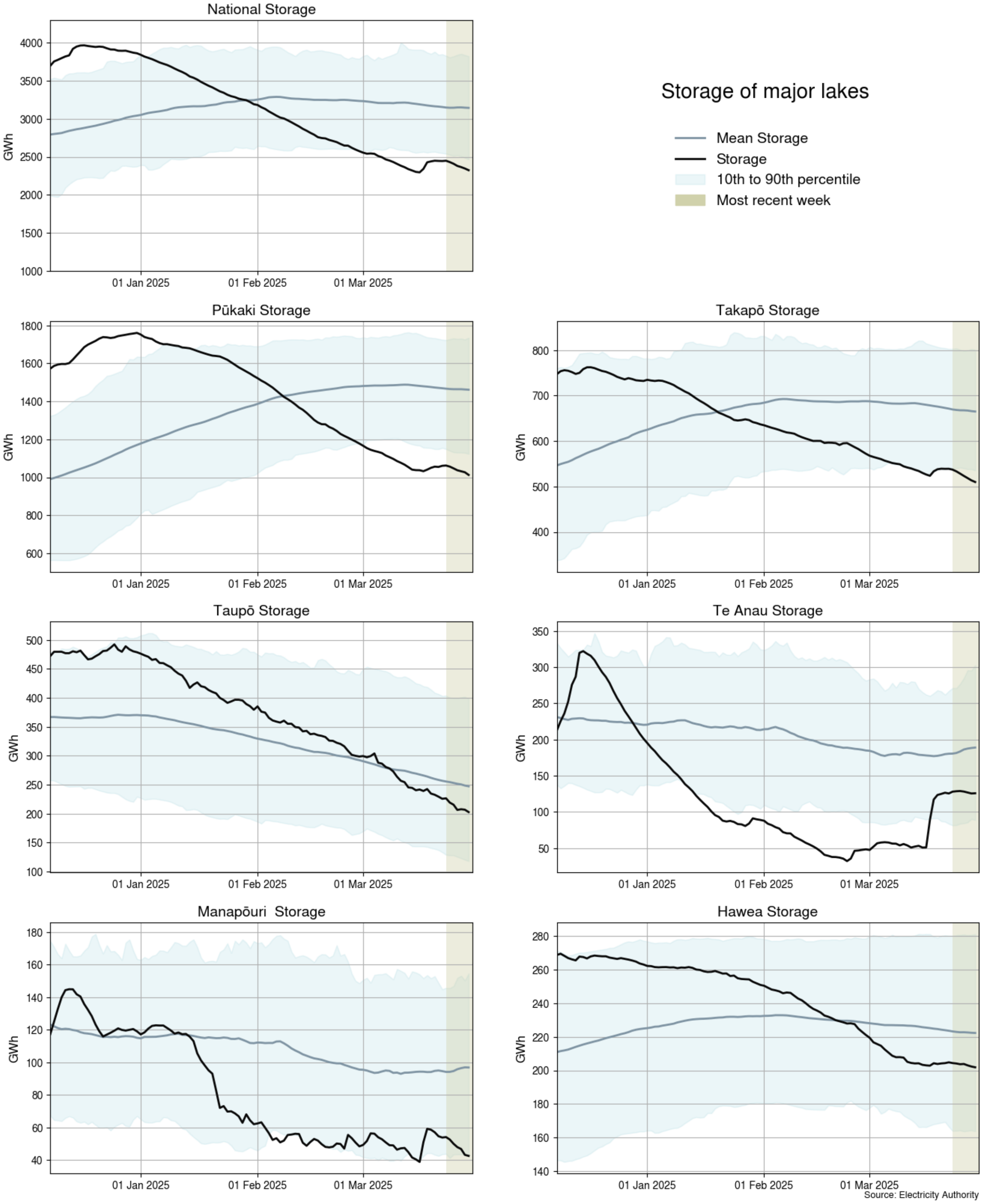
(d) Lake Hawea is 71% full.

(e) Te Anau is 46% full and still above its historic 10th percentile.

(f) Manapōuri is 28% full and near its historic 10th percentile.

[2] 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 March. The SRMC for gas fuelled generation has increased compared to last month. The SRMC for coal and diesel fuelled generation remains similar.

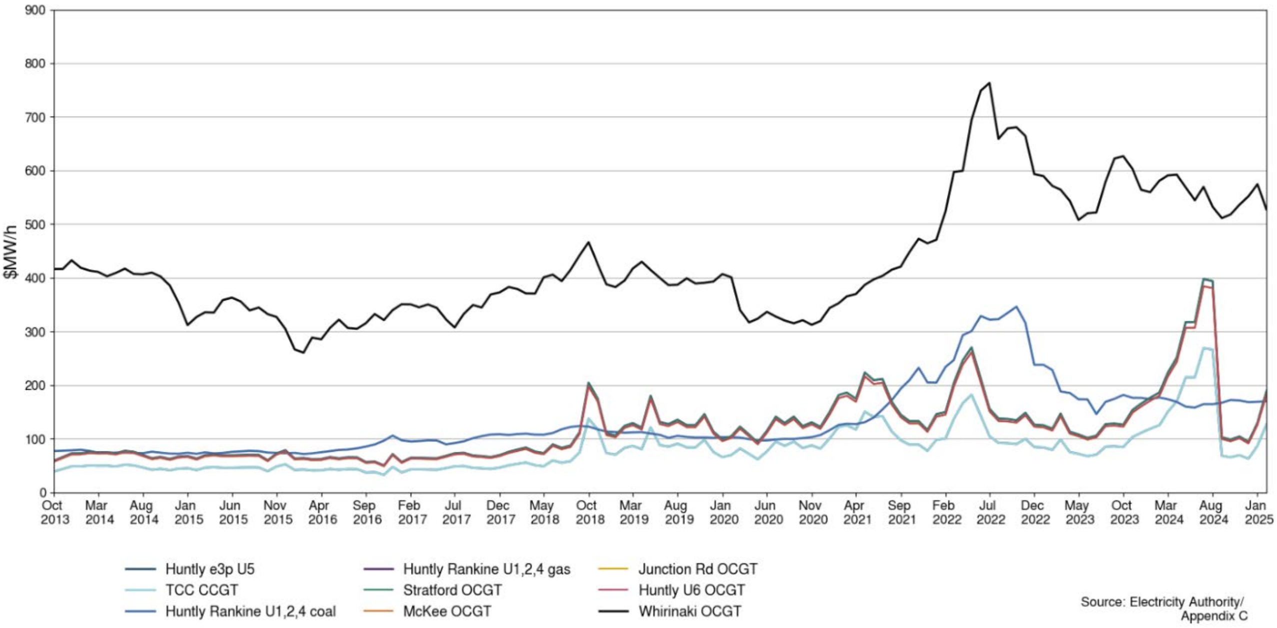
11.4. The latest SRMC of coal-fuelled Rankine generation is still ~$170/MWh, with the cost of running the Rankines on gas now more expensive at ~$224/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $150/MWh and $224/MWh.

11.6. The SRMC of Whirinaki is still ~$527/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

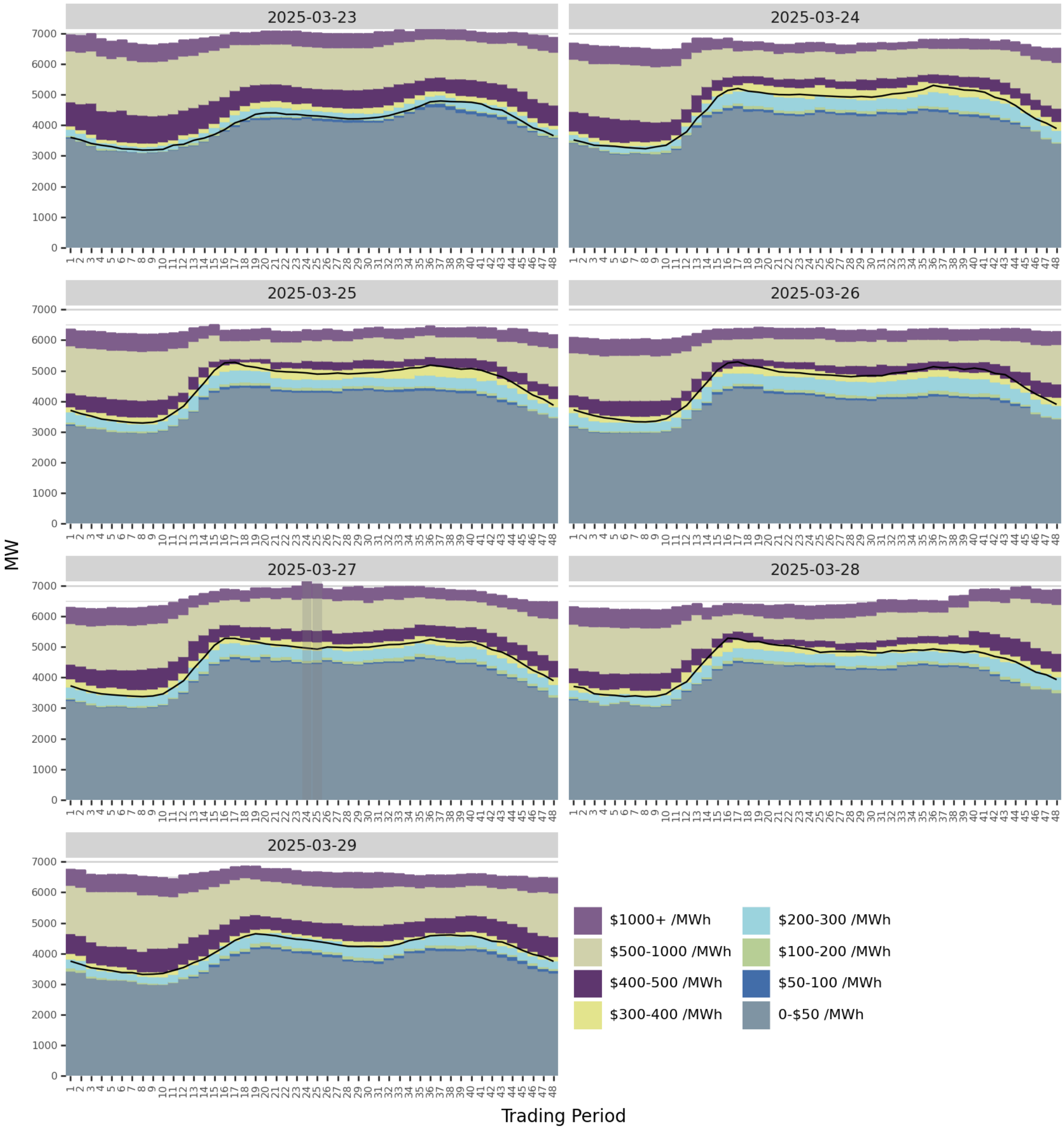


12. Offer behaviour

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 mostly clearing in the $300-$500/MWh region this week. There continues to be minimal offers in the $50-200/MWh price region with continued low hydro inflows.

Figure 21: Daily offer stacks[3]



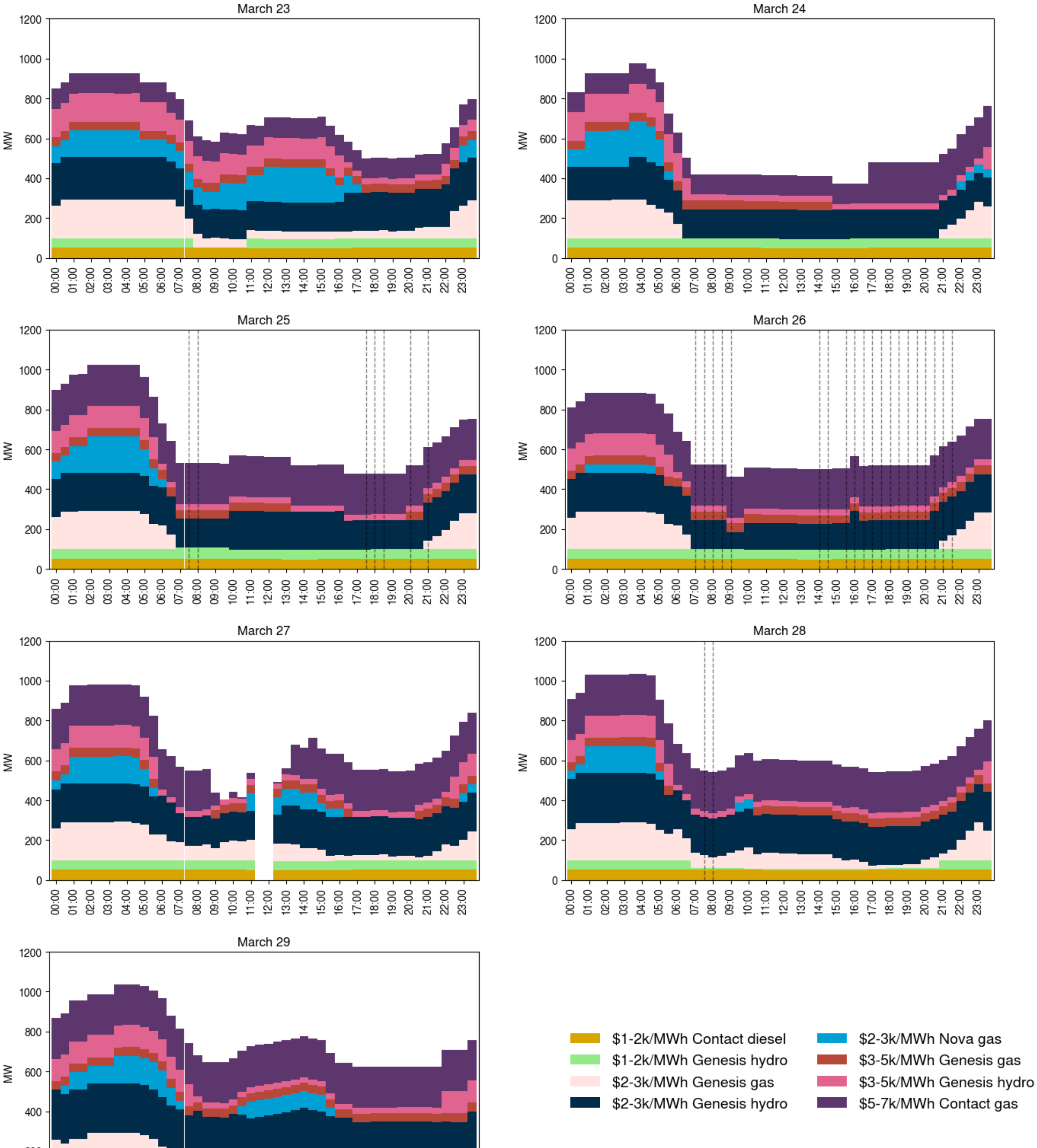
[3] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion 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, 675MW 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 [4]



Source: Electricity Authority

[4] The gap on the 27 March chart is due to unavailable RTD data for trading periods 24 and 25

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 offer changes at Stratford on 27 March.

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