26 March 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 16-22 March 2025

Market monitoring weekly report

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1. Overview

1.1. Spot prices were lower this week due to higher wind generation and a short increase to hydro inflows allowing hydro storage to remain at 64%. Prices were still mostly above $250/MWh due to low hydro storage, a high proportion of thermal generation and prices spiked during times with large forecasting inaccuracies.

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 16-22 March:

(a) The average spot price for the week was $273/MWh, an increase of around $24/MWh compared to the previous week.

(b) 95% of prices fell between $167/MWh and $385/MWh.

2.3. Spot prices have decreased slightly this week due to higher wind and a brief increase in hydro inflows that increased national hydro storage by 4%.

2.4. However, the average price is still above $250/MWh and prices frequently spiked above $400/MWh. This was due a combination of:

(a) low hydro storage

(b) high proportions of thermal generation running

(c) large wind forecast inaccuracies

(d) and large demand forecast inaccuracies.

2.5. The highest price at Ōtāhuhu was $446/MWh at 12:30pm on Tuesday. The price at Benmore was $405/MWh at this time. Prices were above $400/MWh at Ōtāhuhu between 11.30am and 12.30pm. Tuesday's high prices were due to a combination of factors:

(a) Huntly generation tripped at 11.30am, causing Huntly 2 generation to cut out. Huntly 2 didn't get back to its former generation until around 3.30pm.

(b) Demand was between 60-86MW higher than forecast during the period of higher prices.

(c) Wind was lower than forecast between 12-12.30pm. The largest discrepancy of 103MW lower than forecast two hours ahead of gate closure was at the time of the highest price.

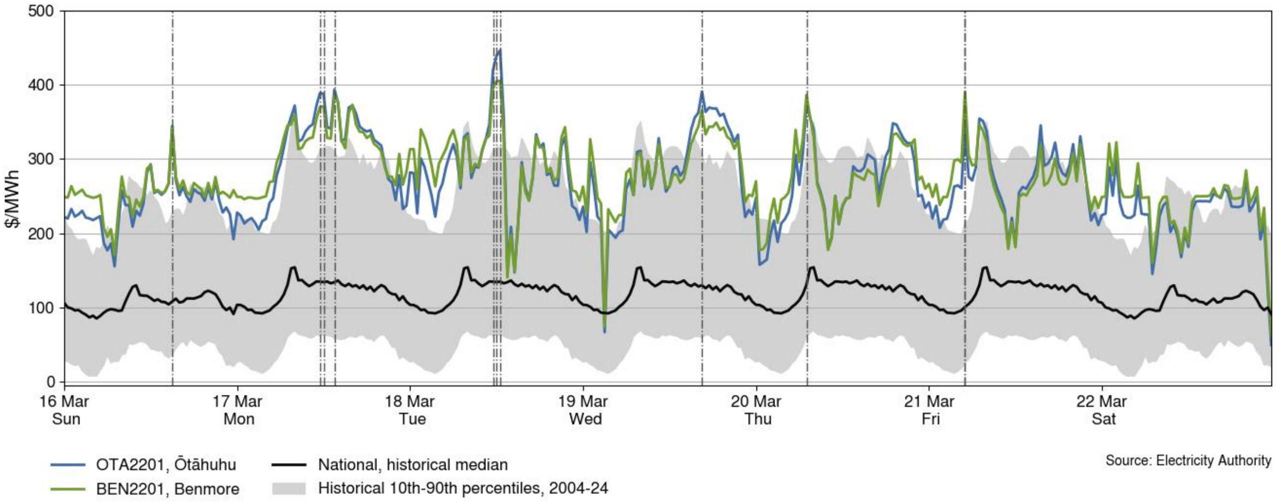
2.6. The higher prices on Monday to Friday also occurred at times when demand was higher than forecast and/or wind was lower than forecast by at least 100MW in total.

2.7. On Sunday, prices increased sharply to $345/MWh at Ōtāhuhu and $342/MWh at Benmore at 3pm. This was due to afternoon demand increasing slightly faster than generation offers increased.

2.8. The highest price of the week at any node was $1,992/MWh at 5.30pm on Monday at Tuai. This was due to line constraints in the area between 5-6pm. The highest national demand for the week also occurred at 5.30pm.

2.9. 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.

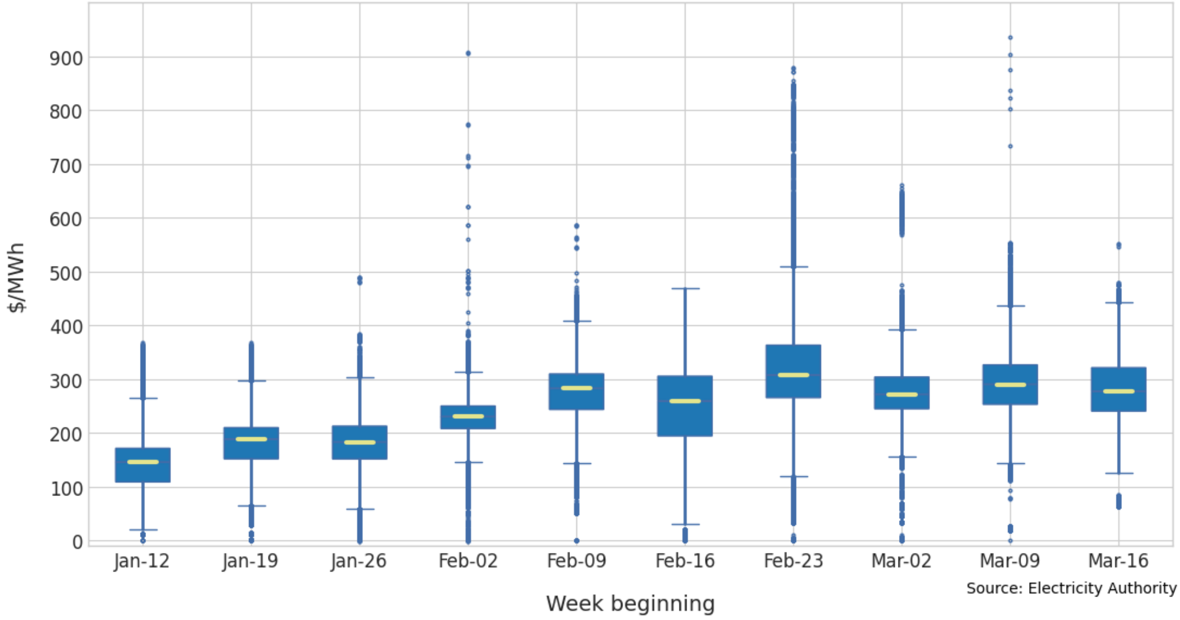
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 16-22 March



2.10. 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.

2.11. The distribution of spot prices this week was less volatile and skewed slightly lower compared to last week. The median price was $277/MWh and most prices (middle 50%) fell between $241/MWh and $321/MWh.

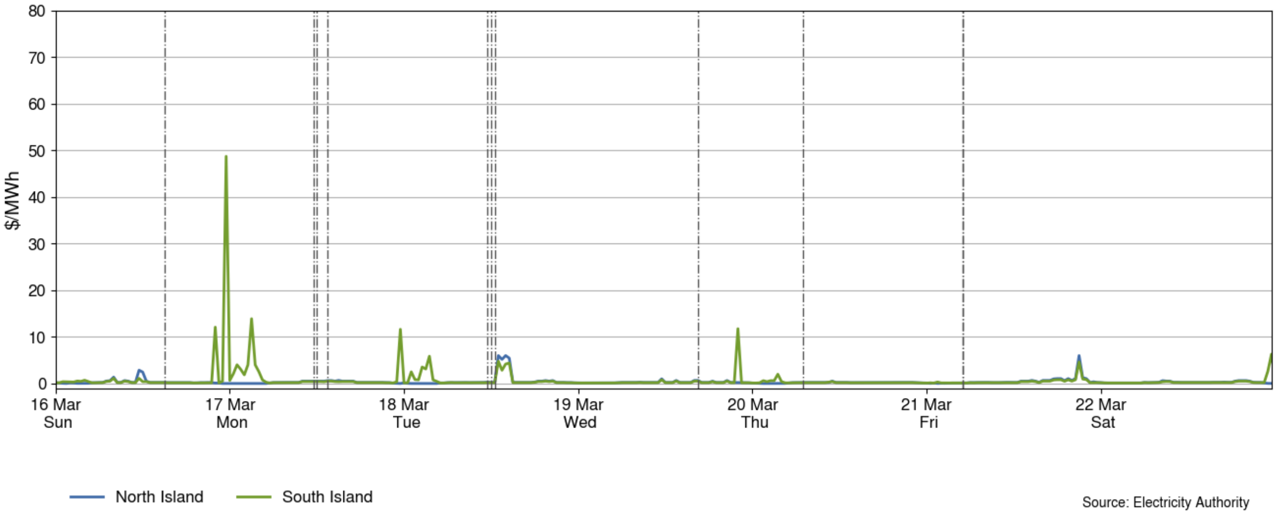
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

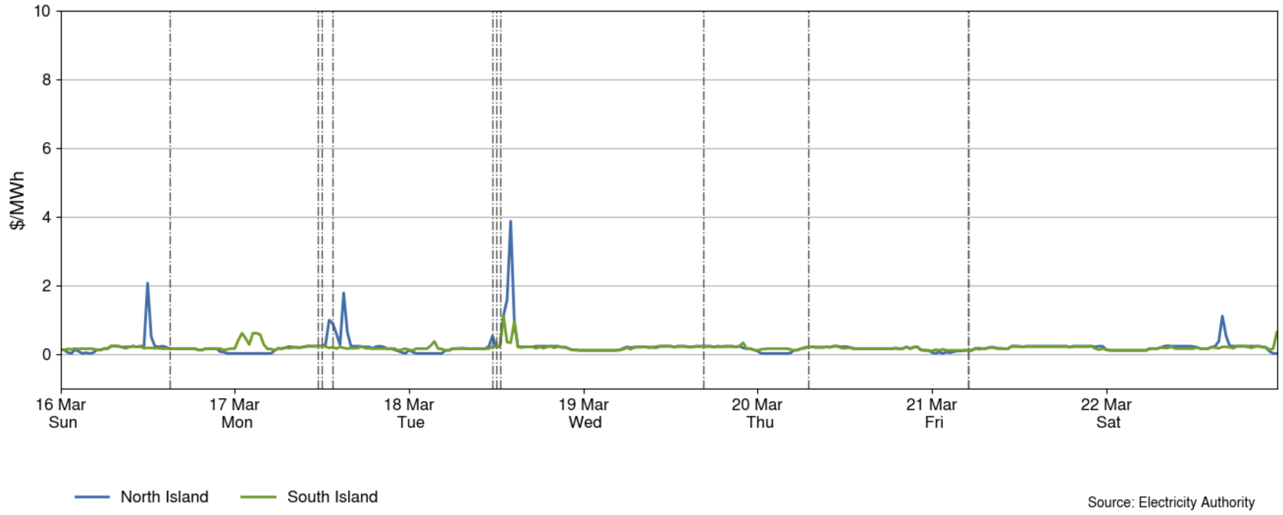
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh but spiked to $49/MWh in the South Island at 11.30pm on Sunday. This was due to a large increase in the amount of FIR required when the HVDC was flowing South.

Figure 3: Fast instantaneous reserve price by trading period and island, 16-22 March



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 and no higher than $4/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 16-22 March



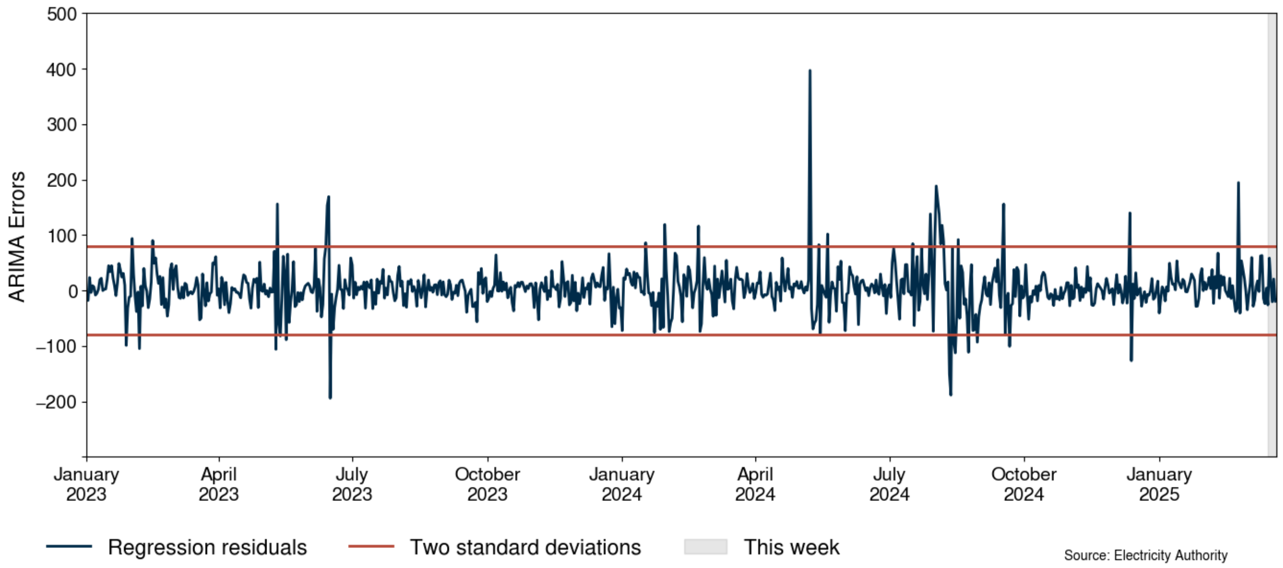
4. Regression residuals

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.

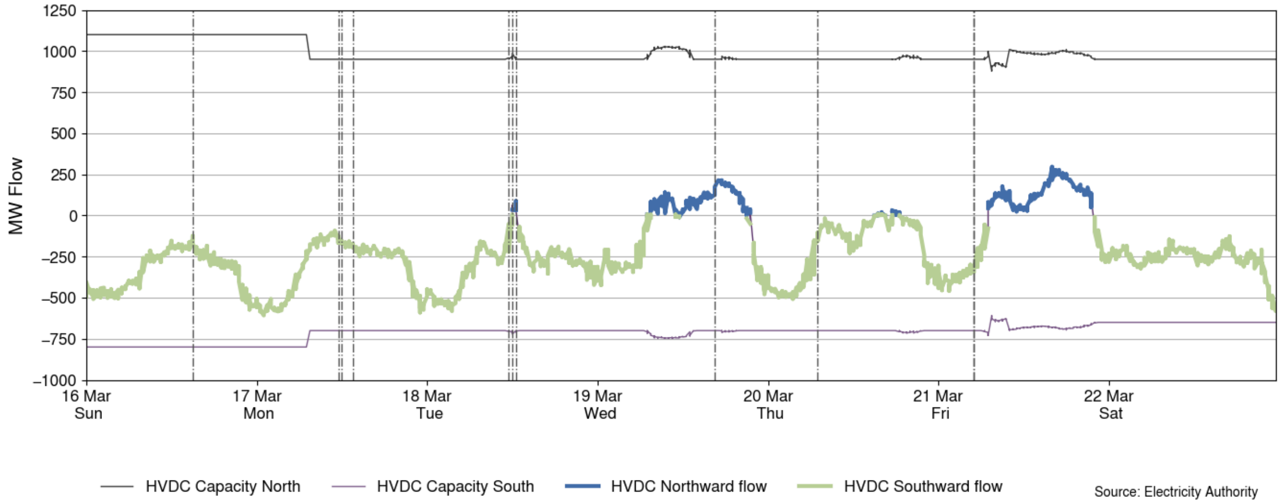
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 22 March 2025



5. HVDC

5.1. Figure 6 shows the HVDC flow between 16-22 March. HVDC flows were mostly southward due to low hydro storage, high North Island thermal generation and higher wind. Flows were mostly northward on Wednesday and Friday when wind was below 400MW.

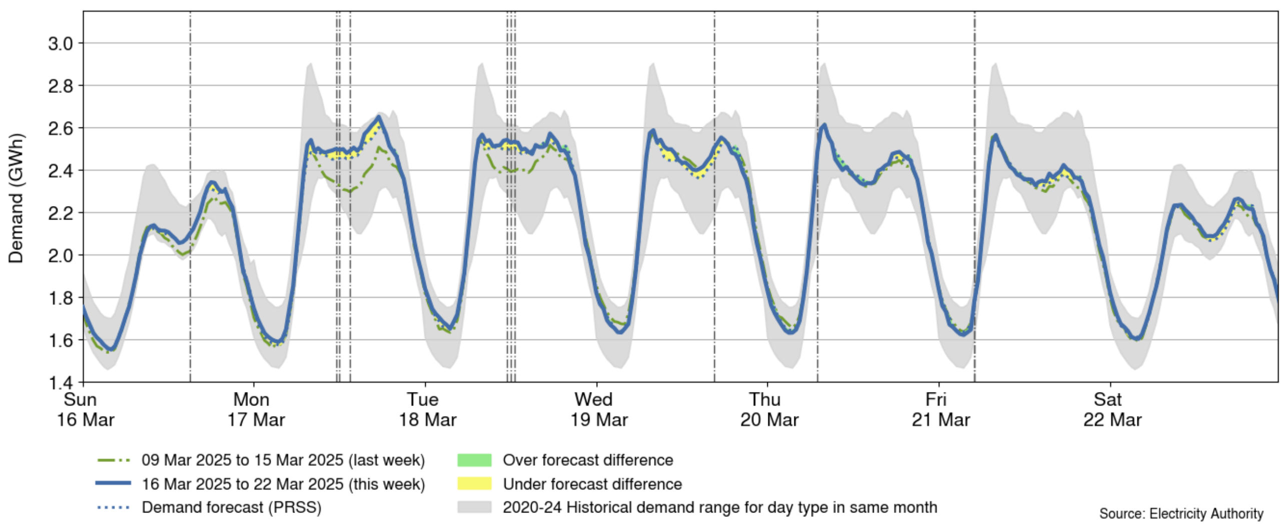
Figure 6: HVDC flow and capacity, 16-22 March



6. Demand

6.1. Figure 7 shows national demand between 16-22 March, compared to the historic range and the demand of the previous week. Demand was near the middle of the historic range for most of the week. Demand was higher than forecast frequently this week, especially Monday to Wednesday and during afternoons and evenings. Maximum demand was 2.65GWh at 5.30pm on Monday, reaching close to the historic maximum.

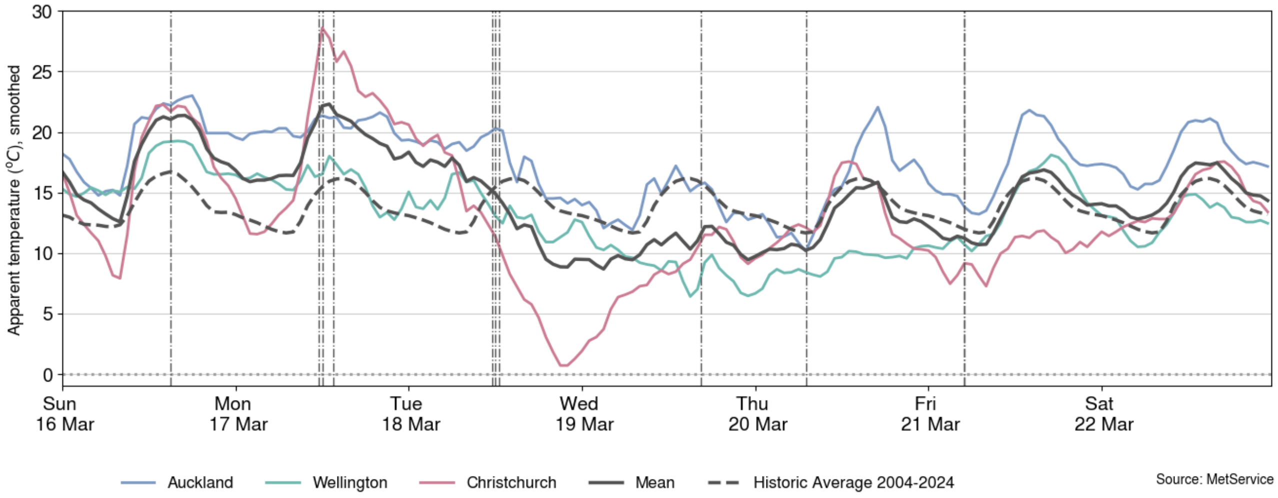
Figure 7: National demand, 16-22 March compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 16-22 March. 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 ranged from 10°C to 24°C in Auckland, 6°C to 19°C in Wellington, and 1°C to 31°C in Christchurch. There was a large temperature swing in Christchurch from Monday to Tuesday, which likely contributed to the demand forecasting errors on those days.

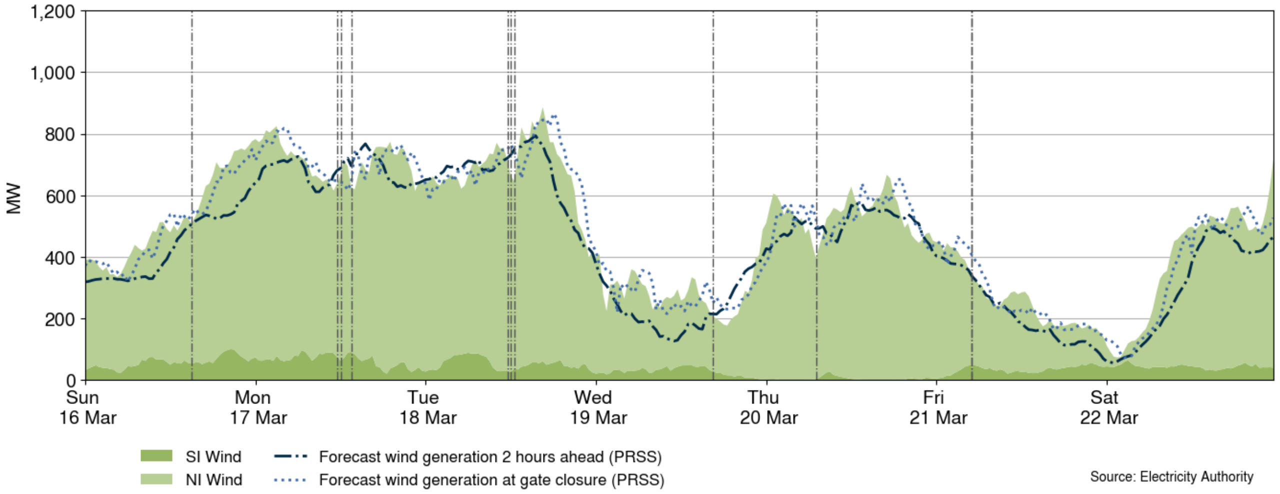
Figure 8: Temperatures across main centres, 16-22 March



7. Generation

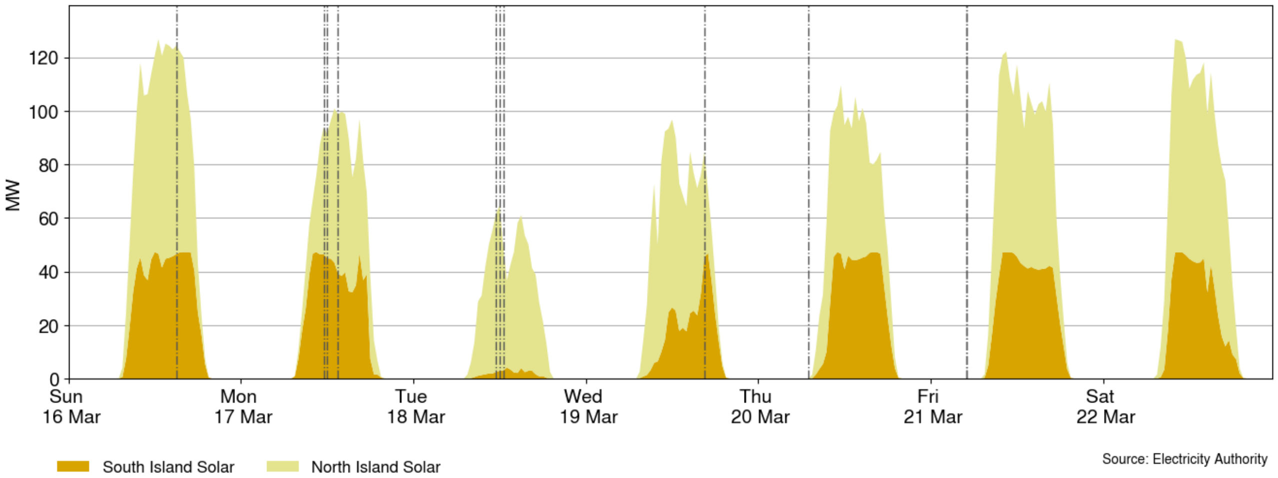
7.1. Figure 9 shows wind generation and forecast from 16-22 March. This week wind generation varied between 73MW and 886MW, with a weekly average of 485MW. Wind generation was high this week but lower on Wednesday and Friday. Most price spikes occurred when wind was overforecast.

Figure 9: Wind generation and forecast, 16-22 March



7.2. Figure 10 shows grid connected solar generation from 16-22 March. South Island solar generation was low on Tuesday. Sunday-Monday and Thursday-Saturday had daily generation mostly above 80MW. Maximum generation occurred at 12.30pm on Sunday and was 127MW.

Figure 10: Grid connected solar generation, 16-22 March



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.

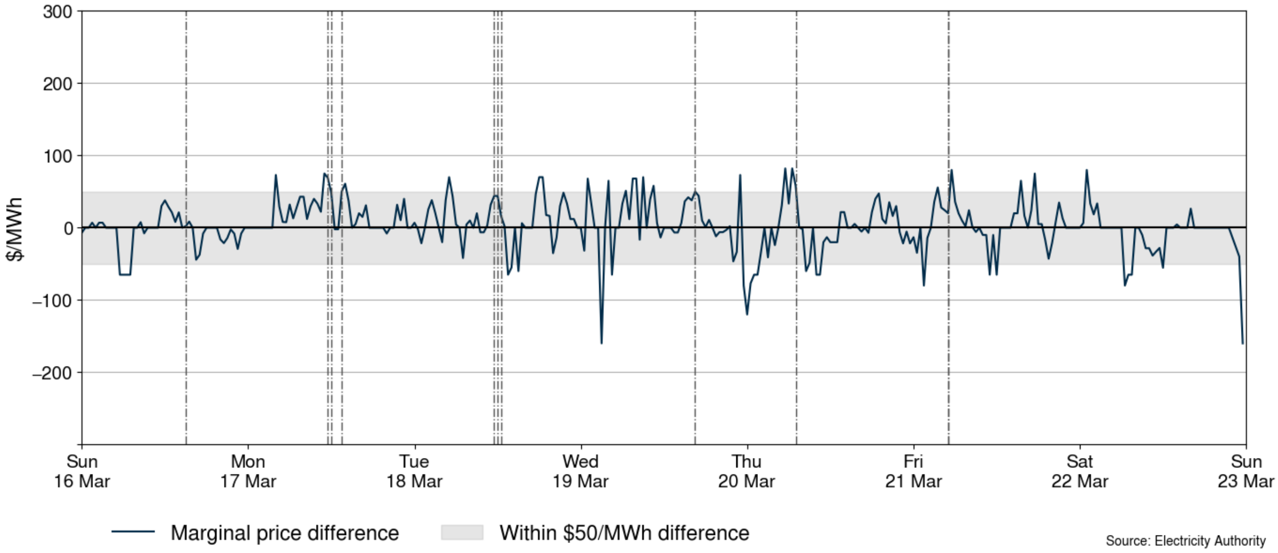
7.4. Demand and wind forecasting inaccuracies led to many marginal price differences lager than $50/MWh this week.

7.5. The largest positive marginal price difference of +$82/MWh occurred at 5.30am on Thursday. At this time, wind was 77MW lower than forecast at gate closure.

7.6. The largest negative price difference of -$160/MWh occurred at 3am on Wednesday. At this time, wind was 103MW higher than forecast at gate closure.

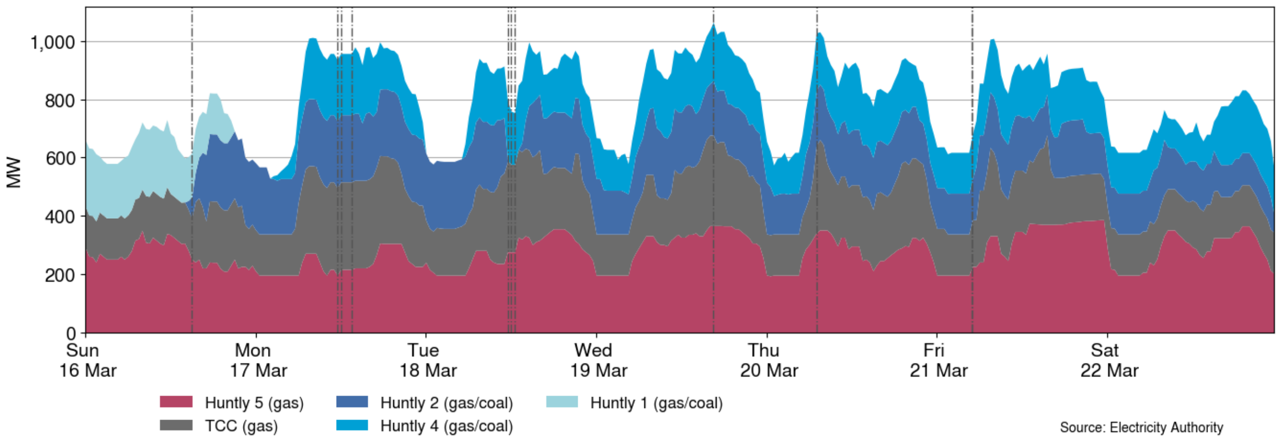
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 16-22 March



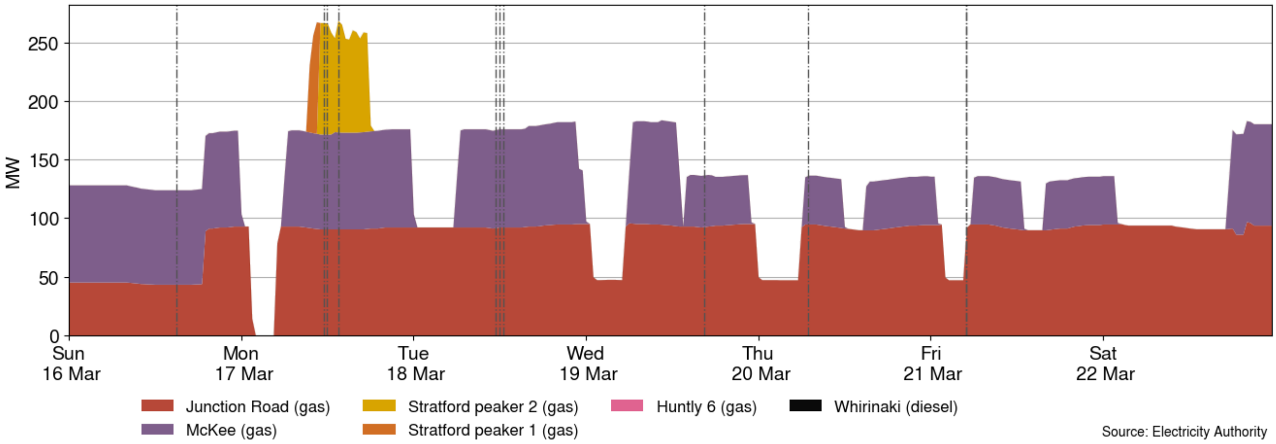
7.7. Figure 12 shows the generation of thermal baseload between 16-22 March. Huntly 5, TCC and the Rankines generated baseload this week. Huntly 1 only generated on Sunday then went on outage from Monday and Huntly 4 started generating on Monday after coming off outage. Huntly 2 cut out on Tuesday when Huntly generation tripped.

Figure 12: Thermal baseload generation, 16-22 March



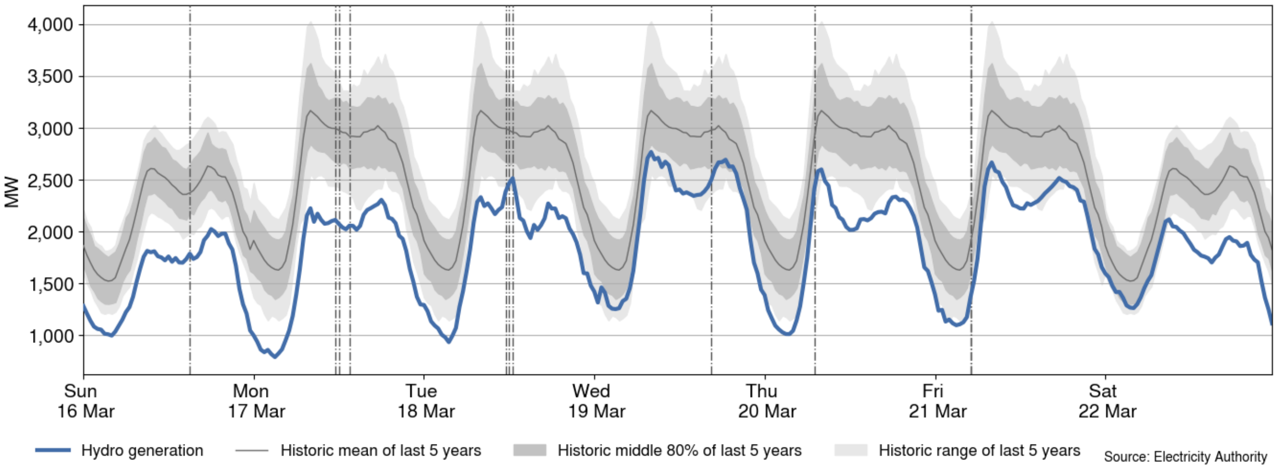
7.8. Figure 13 shows the generation of thermal peaker plants between 16-22 March. Junction Road and McKee generated every day this week. Stratford Peaker 2 generated on Monday. While Stratford Peaker 1 generation is logged, this was actually Stratford Peaker 2 covering Peaker 1 offers after Peaker 1 went on unplanned outage. McKee tripped at 1.26pm on Wednesday and went on an unplanned partial outage from 2pm until Friday.

Figure 13: Thermal peaker generation, 16-22 March



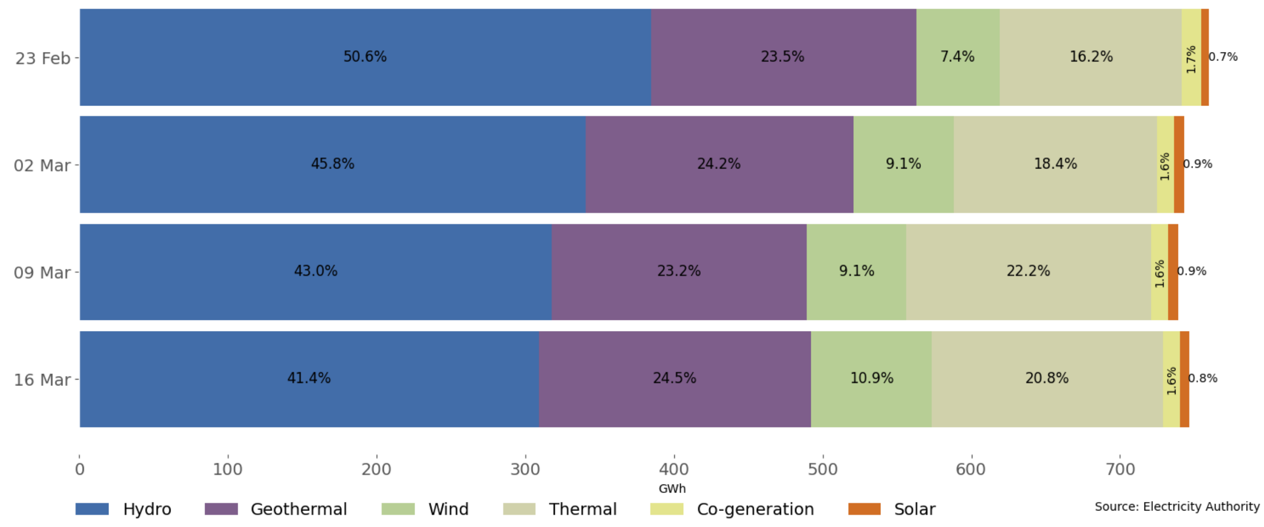
7.9. Figure 14 shows hydro generation between 16-22 March. Hydro generation was mostly below the historic range this week and higher on Wednesday and Friday when wind was low. Hydro generation ramped up on Tuesday during the Huntly 2 trip.

Figure 14: Hydro generation, 16-22 March



7.10. As a percentage of total generation, between 16-22 March, total weekly hydro generation was 41.4%, geothermal 24.5%, wind 10.9%, thermal 20.8%, co-generation 1.6%, and solar (grid connected) 0.8%, as shown in Figure 15. Hydro and thermal generation decreased slightly as geothermal and wind generation increased.

Figure 15: Total generation by type as a percentage each week, between 23 February and 22 March 2025



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 16-22 March was mostly below average and ranged between ~1,063MW and ~1,813MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 4 was on outage until 16 March.

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

(c) Ōhau A, B and C were on outage 22 March.

(d) Manapōuri unit 4 is on outage until 12 June 2026 (formerly 12 December 2025).

(e) Manapōuri unit 5 was on a month long outage until 18 March.

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

(g) Stratford Peaker 2 went on a short notice outage on 18 March and is due back 24 March.

(h) Stratford Peaker 1 went on a short notice outage on 17 March.

Figure 16: Total MW loss from generation outages, 16-22 March

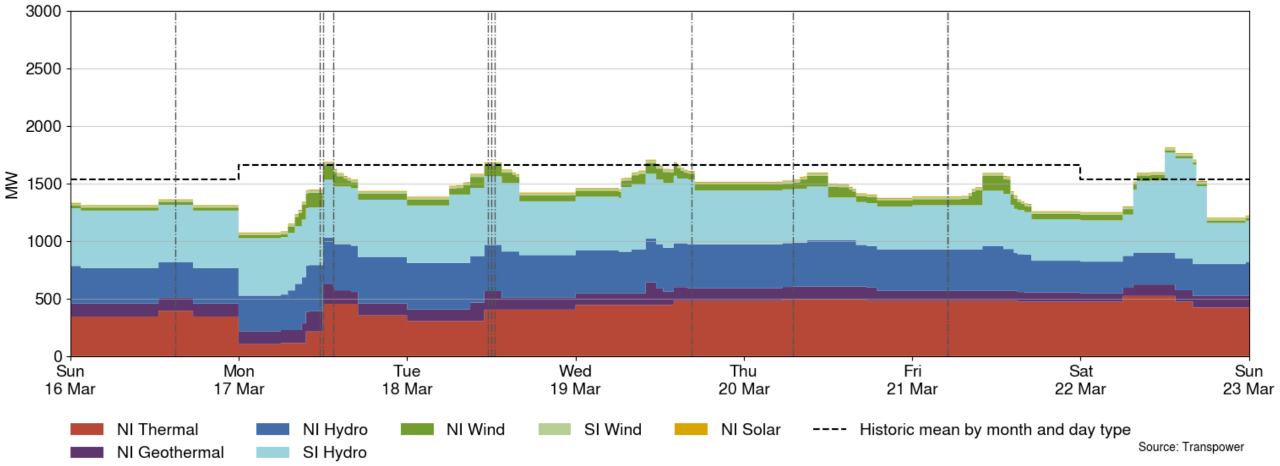
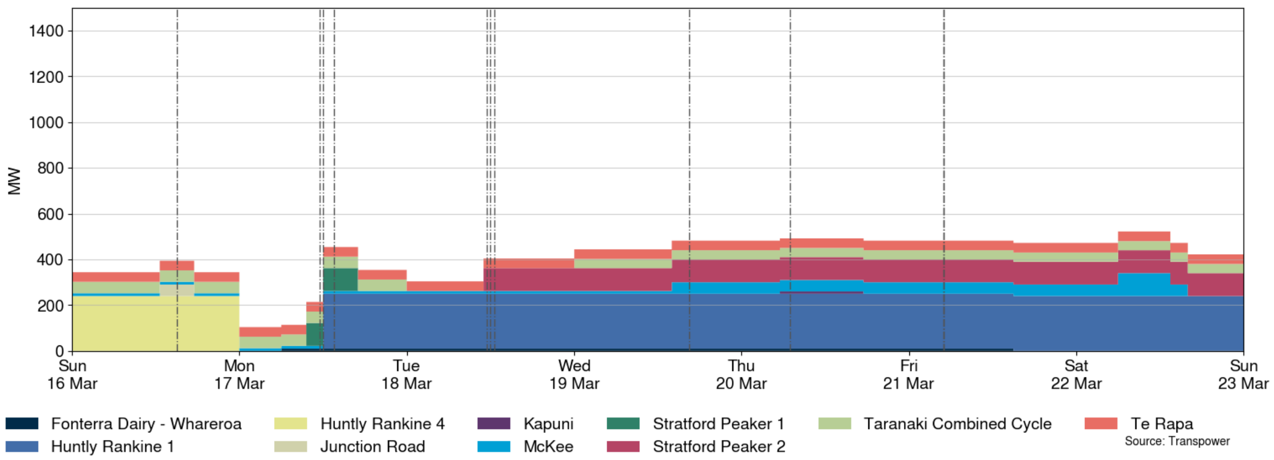


Figure 17: Total MW loss from thermal outages, 16-22 March

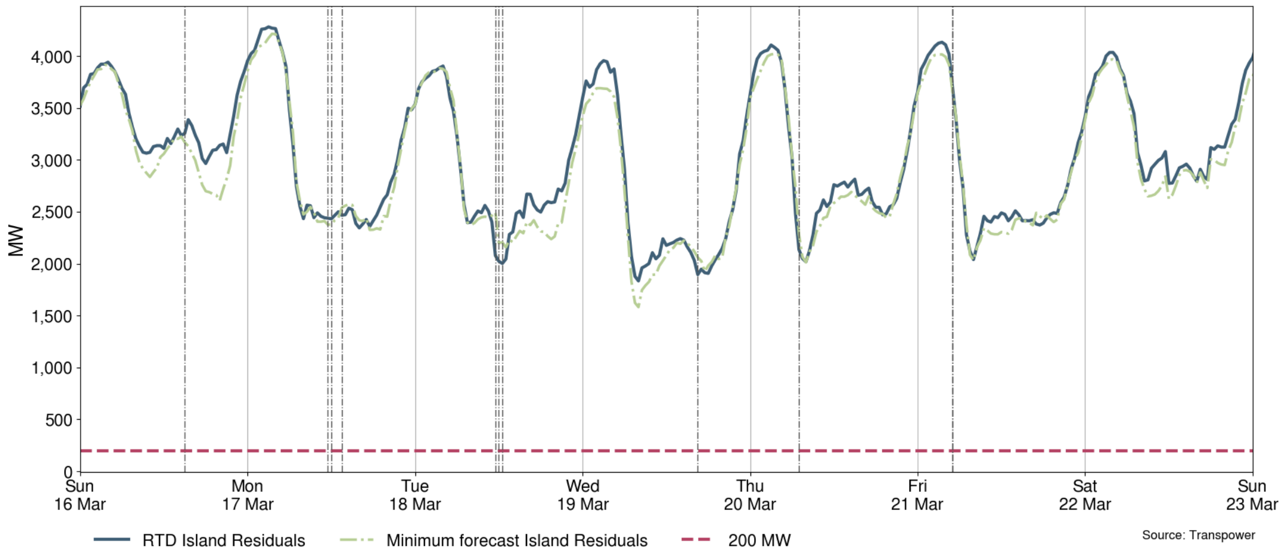


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 16-22 March. 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. North Island residuals reached a minimum of 935MW at 5.30pm on Wednesday.

Figure 18: National generation balance residuals, 16-22 March



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 slightly to 64% nominally full and ~80% of the historical average for this time of the year.

10.3. Lake Pūkaki (63% full[2]) has increased and is still below its historical 10th percentile.

10.4. Lake Takapō (67% full) has increased and is still around its historic 10th percentile.

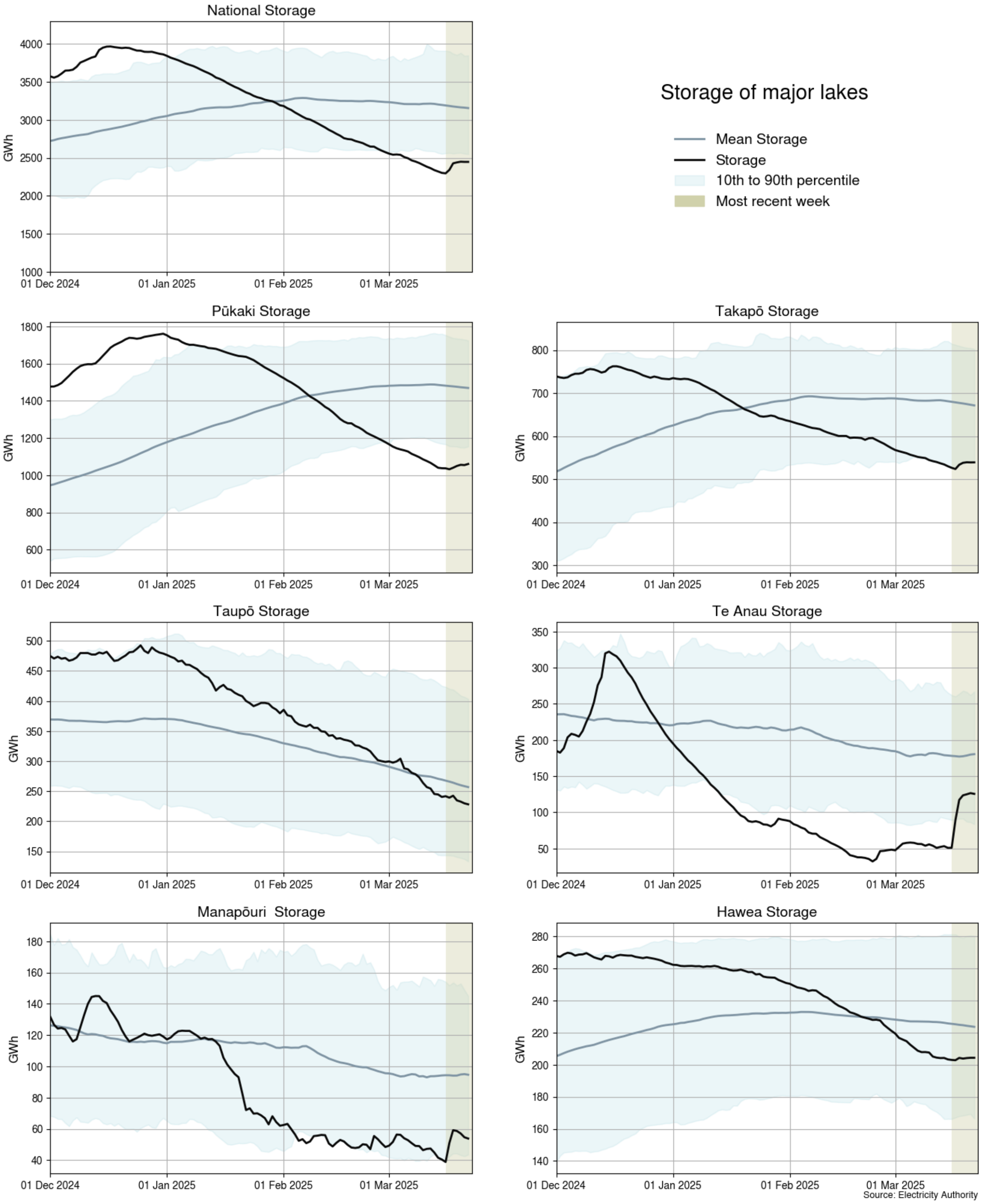
10.5. Lake Hawea (72% full) has increased and is still between its historical mean and 10th percentile.

10.6. Lake Taupō (40% full) has decreased and is still between its historical mean and 10th percentile.

10.7. Lakes Te Anau and Manapōuri have increased to above their respective historical 10th percentiles.

[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.

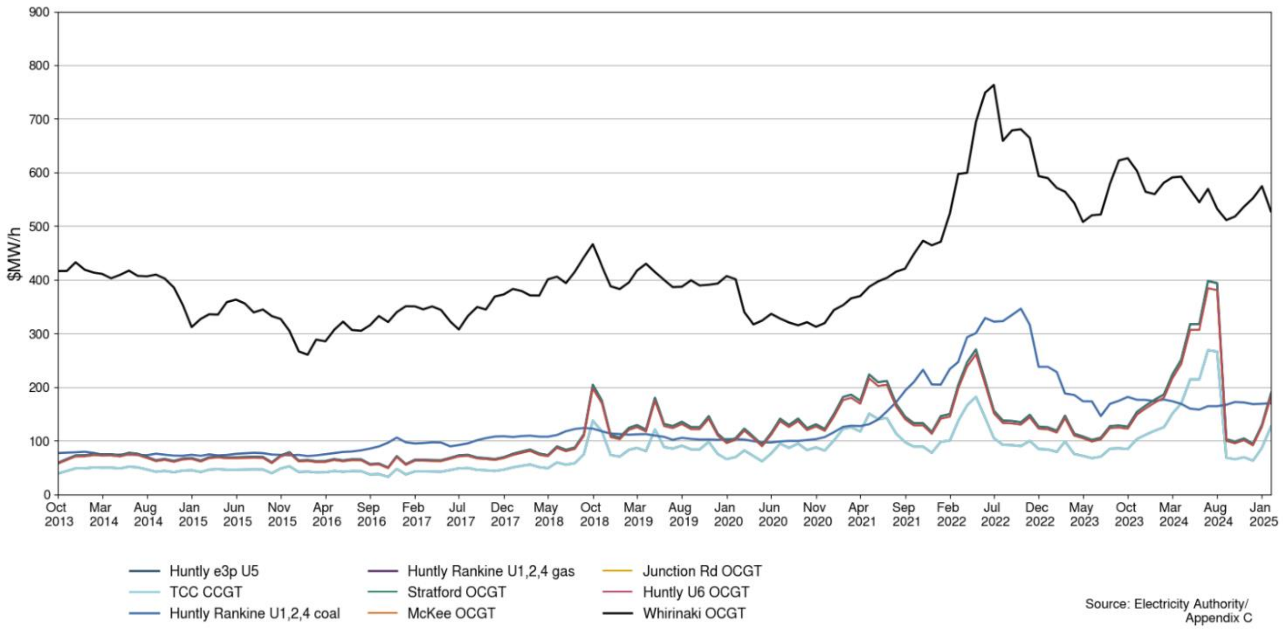
11.4. The latest SRMC of coal-fuelled Rankine generation is still ~$170/MWh, with the cost of running the Rankines on gas now more expensive at ~$224/MWh.

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

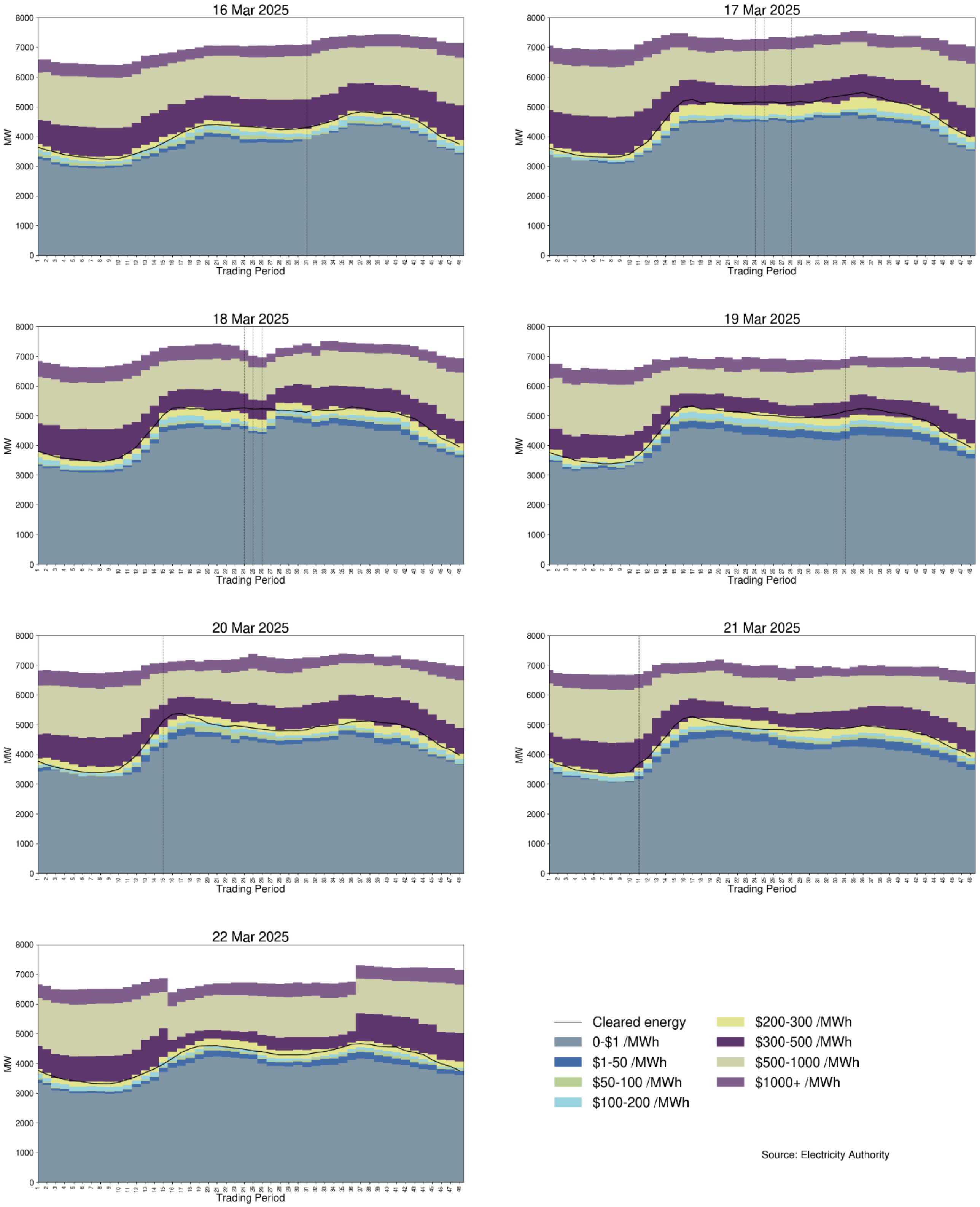


12. Offer behaviour

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. Most offers were clearing in the $200-300/MWh or $300-500/MWh bands this week. After hydro storage increased there was an increase in offers priced in the $1-50/MWh band. The trip at Huntly can be observed by the reduction in low priced offers on Tuesday, and the outage at Ohau is seen in the reduction in offers on Saturday.

Figure 21: Daily offer stacks

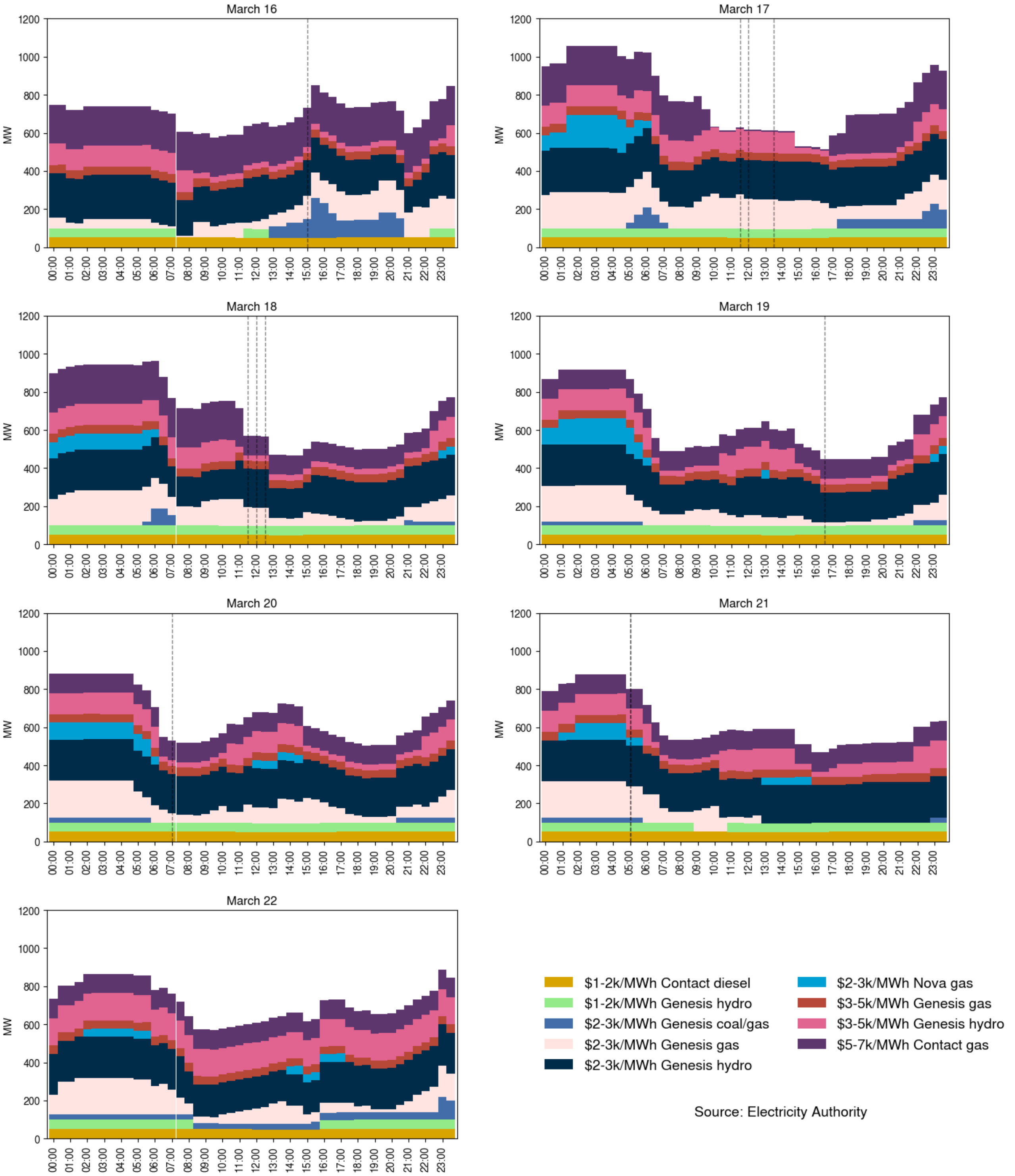


12.3. Figure 22 shows offers above $1,000/MWh in each trading period this week. The largest proportion of these offers are fast start thermal operators.

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 690MW per trading period was priced above $1,000/MWh this week, which is roughly 11.5% of the total energy available. This increase reflects the higher quantity of thermal currently online and very low hydro inflows, especially at schemes with only a small amount of storage.

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 team will in enquiring further with Genesis regarding the Huntly trip on Tuesday.

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
5/03/2025	23-32	Further analysis	Contact	Stratford	Stratford offers
9/03/2025-16/03/2025	Several	Further analysis	Contact	Multiple	Offers
18/03/2025	23-27	Further analysis	Genesis	Huntly	Unplanned outage