9 September 2024

Trading conduct report 1-7 September 2024

Market monitoring weekly report

Trading conduct report 1-7 September 2024

1. Overview

1.1. Prices decreased this week, compared to last week, due to a combination of hydro generation pricing decreasing due to increased storage, continued lower demand and high wind generation. Thermal generation decreased significantly this week. National controlled hydro storage increased to ~92% of historical average.

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. Suspected non-compliance situations may be passed onto the Authority's compliance team. In addition to general monitoring, this report 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 1-7 September:

(a) the average wholesale spot price across all nodes was $18/MWh.

(b) 95% of prices fell between $0.01/MWh and $130/MWh.

2.3. Overall, the majority of spot prices were within $0.01-$13/MWh, with the weekly average price decreasing by around $112/MWh compared to the previous week.

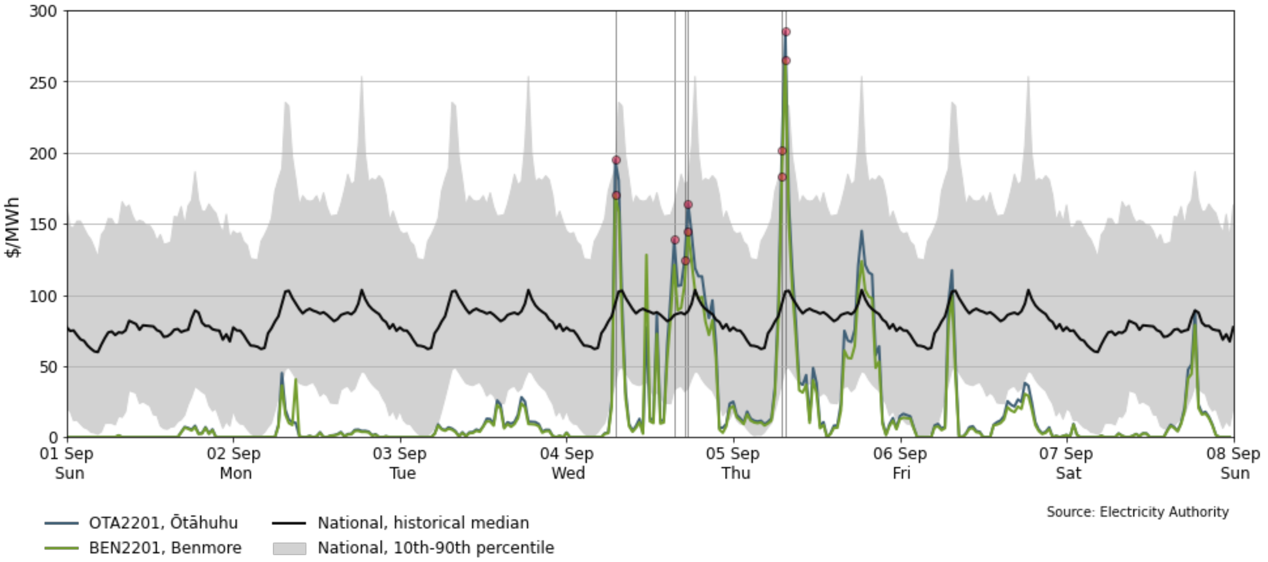
2.4. Prices were consistently below $50/MWh until Wednesday, while wind generation was high. More volatile prices occurred over the rest of the week, particularly on Wednesday and Thursday, when wind generation was low, but these prices were still mostly below the historical median.

2.5. The first of this week's highlighted prices occurred at 7:00am on Wednesday, when wind generation was over forecast by 134MW. Several more relatively high prices occurred between 3:30pm and 5:30pm, during times of combined wind and demand forecasting inaccuracies – which required higher-priced thermal and hydro generation to be dispatched.

2.6. The Ōtāhuhu spot price reached a weekly maximum of $285/MWh at 7:30am on Thursday, when high demand and low wind generation required more expensive thermal generation to be dispatched.

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.

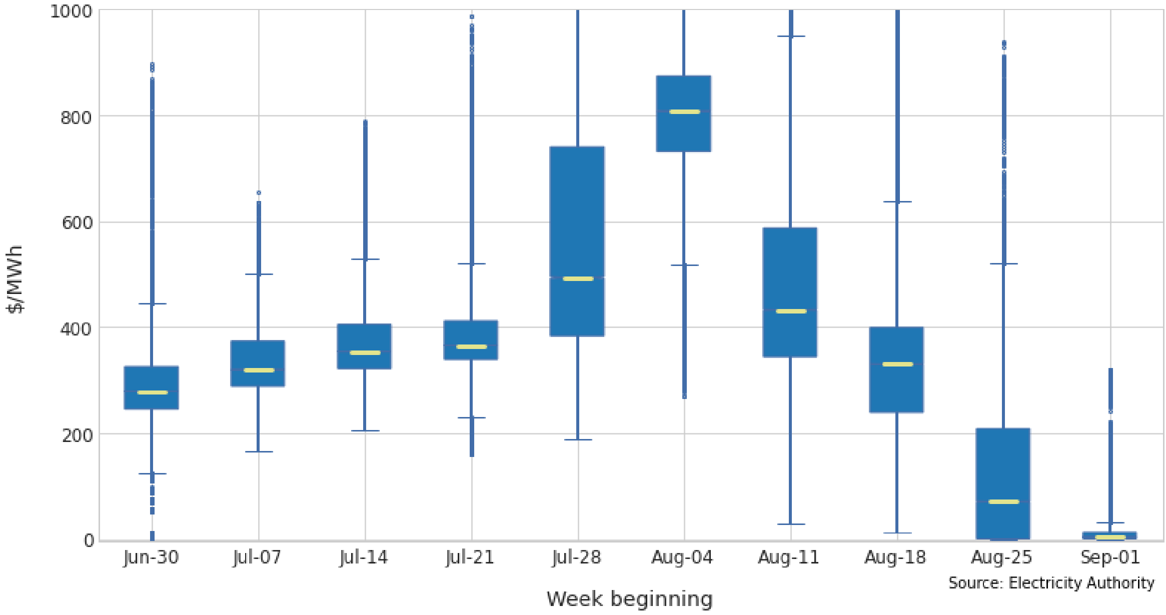
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 1-7 September



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. Compared to the previous week, the median price decreased by $66/MWh. The upper quartile and interquartile range also decreased, with more than 75% of this week's prices below the median price of any of the previous nine weeks.

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

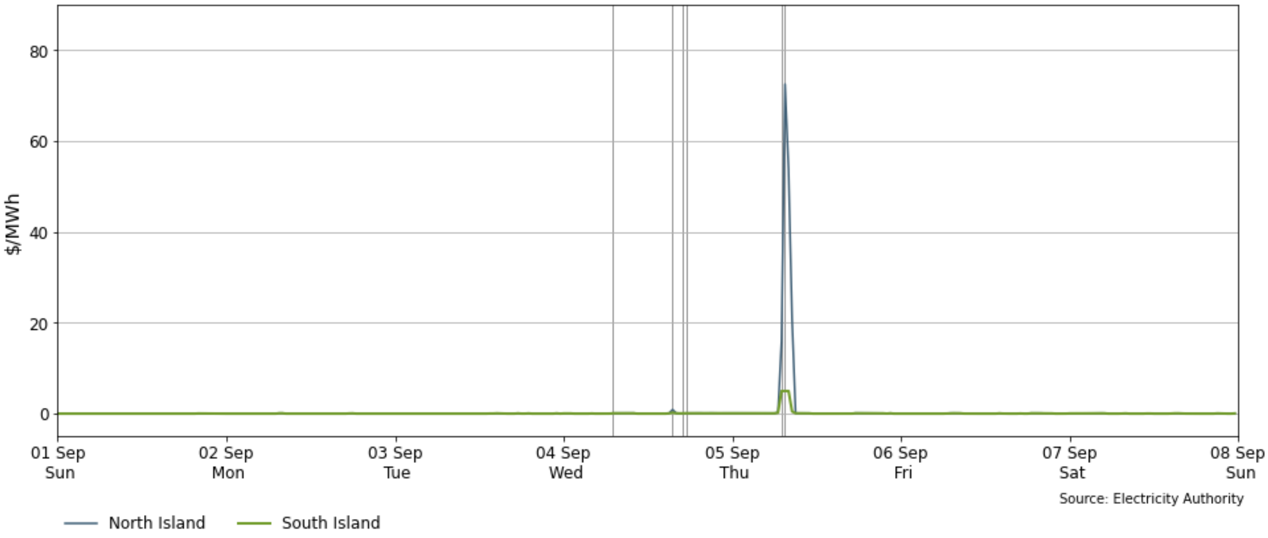


3. Reserve prices

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 this week, but reached $73/MWh in the North Island at 7:30am on Thursday, the same time as this week's highest spot price. The

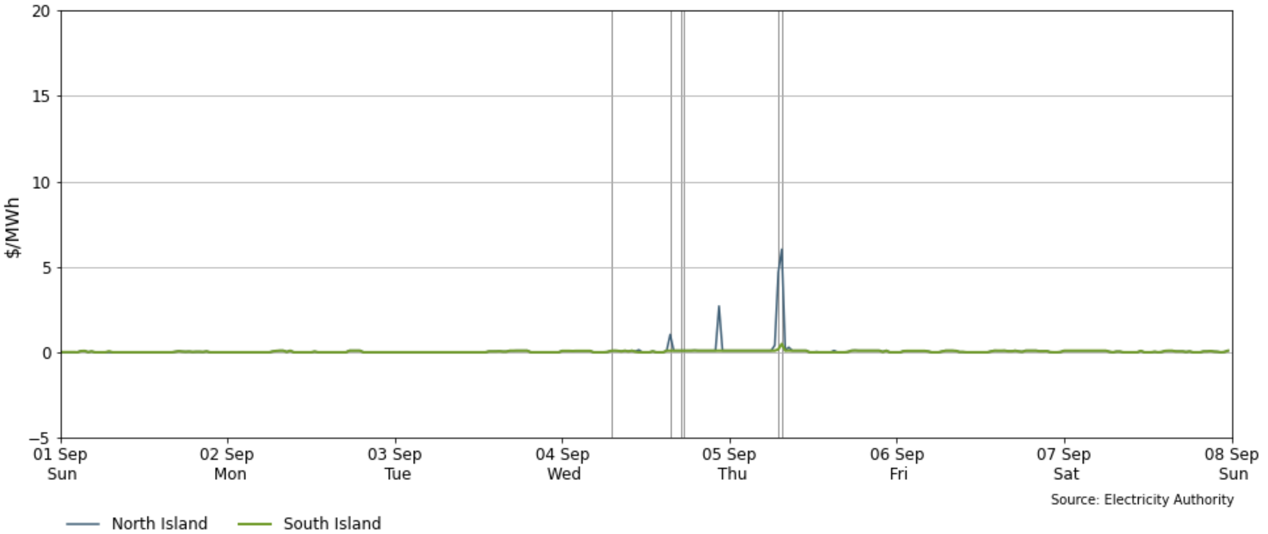
South Island FIR price at the same time was $5/MWh. This occurred as the FIR required to cover the North Island risk setter increased.

Figure 3: Fast instantaneous reserve price by trading period and island, 1-7 September



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 this week, reaching a maximum of $6/MWh in the North Island at 7:30am on Thursday.

Figure 4: Sustained instantaneous reserve by trading period and island, 1-7 September



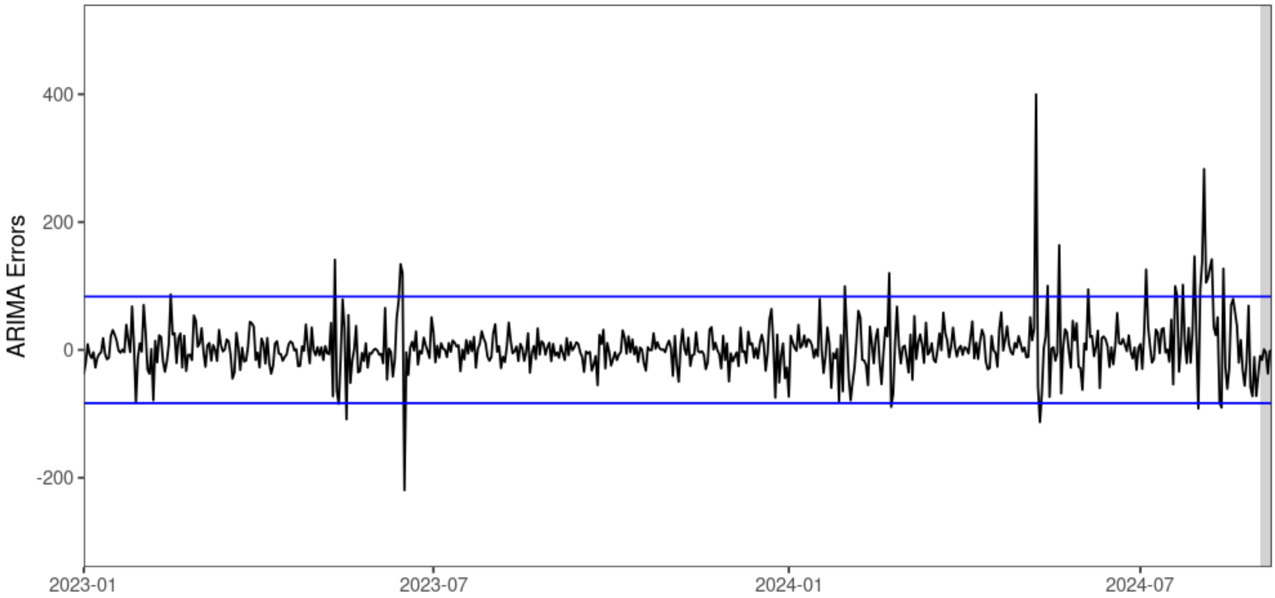
4. Regression residuals

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 of the data, indicating that prices were similar to what the model expected.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 7 September 2024

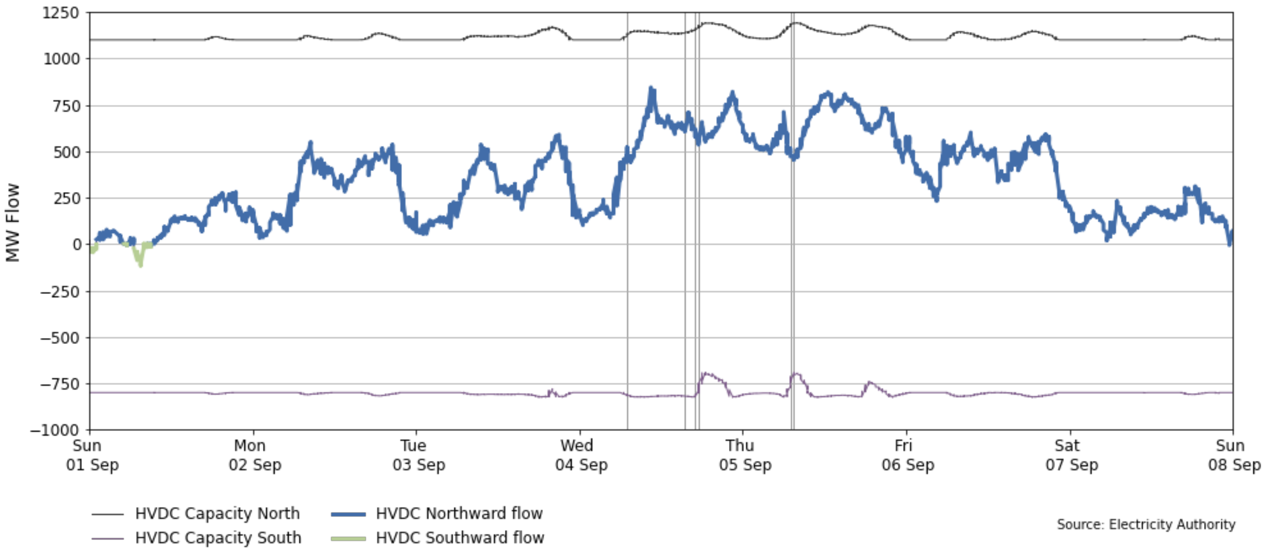


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 1-7 September. Due to increased hydro storage and generation, and lower South Island demand due to the Tiwai demand response, the HVDC flow was almost entirely Northward this week.

Figure 6: HVDC flow and capacity, 1-7 September

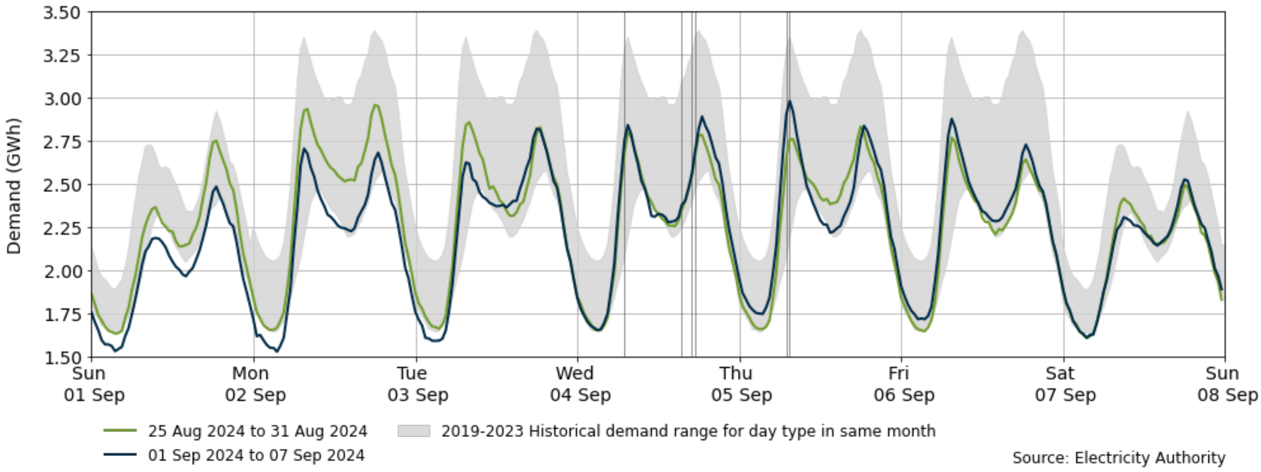


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 1-7 September, compared to the historic range and the demand of the previous week. Demand remained low this week, generally within or below the historical range for this time of year, due to above average temperatures and the reduction in demand from Tiwai. It was highest on Wednesday and Thursday when temperatures were relatively low, with the weekly maximum of 2.98GWh occurring at 7:30am on Thursday.

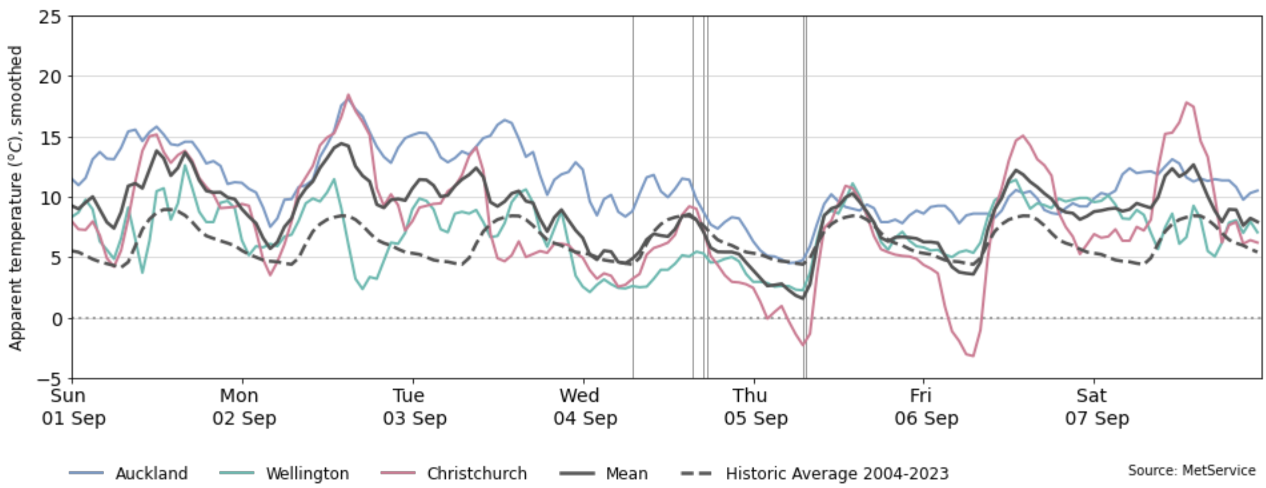
Figure 7: National demand, 1-7 September compared to historic range and previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 1-7 September 2024. The apparent temperate 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 ranged from 4°C to 19°C in Auckland, 1°C to 13°C in Wellington, and -3°C to 19°C in Christchurch. Temperatures were mostly above average this week, except for Wednesday and Thursday. Low temperatures on these days led to increased demand, likely contributing to higher prices on Wednesday and Thursday mornings.

Figure 8: Temperatures across main centres, 1-7 September

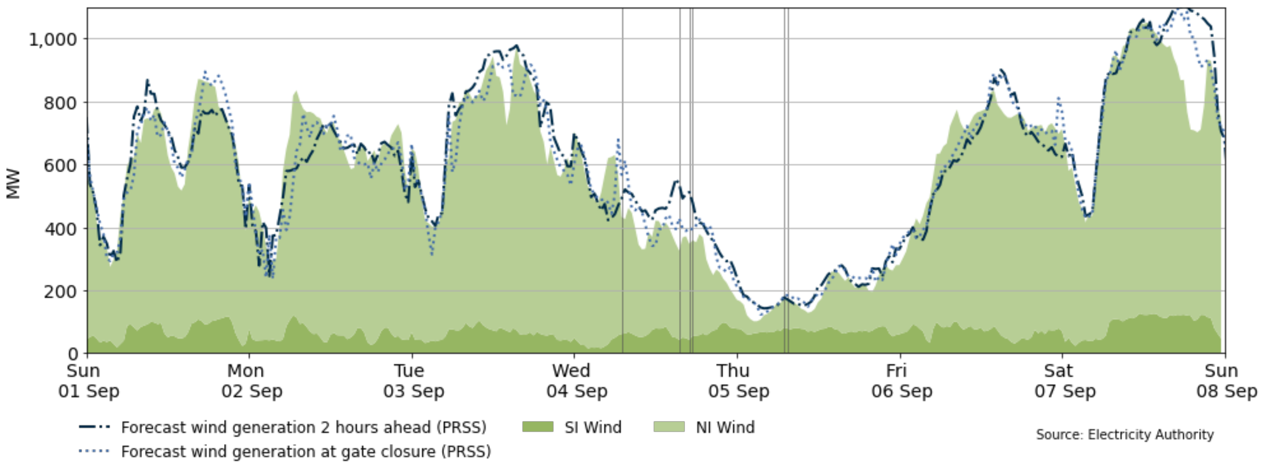


7. Generation

7.1. Figure 9 shows wind generation and forecast from 1-7 September. This week wind generation varied between 102MW and 1,056MW – setting the highest recorded average wind generation in a single trading period, for the second week in a row. The daily average was 578MW. High wind generation likely contributed to the decrease in prices this week. Wind generation was low and/or below forecast at the times this week's highlighted prices occurred, with average generation on Thursday only 186MW.

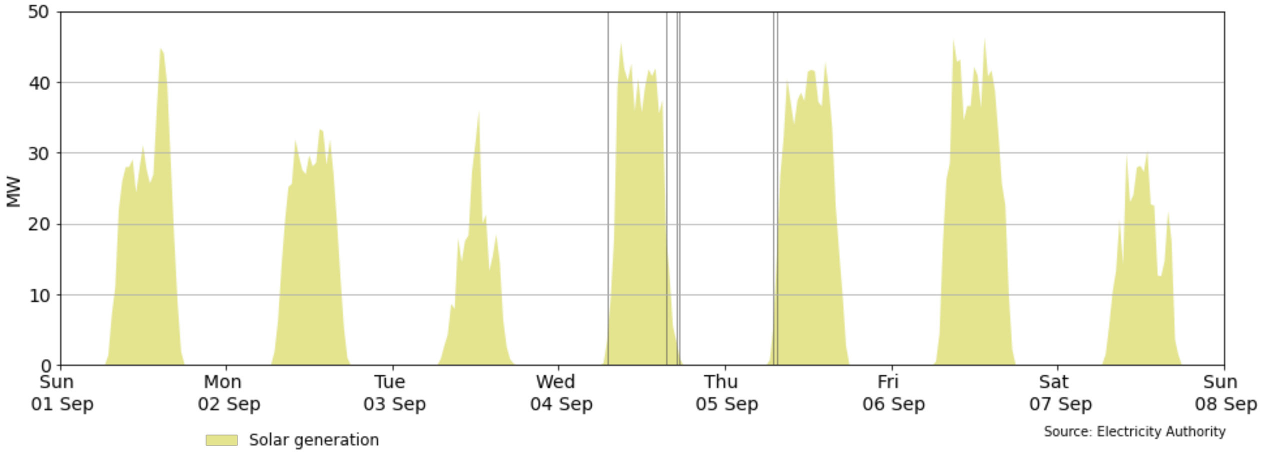
7.2. Wind generation was lower than forecast by ~180MW to ~320MW between 5.00pm to 8.30pm on Saturday. The monitoring team is looking further into this large forecasting discrepancy.

Figure 9: Wind generation and forecast, 1-7 September



7.3. Figure 10 shows solar generation from 1-7 September. Maximum daily solar generation was over 40MW each day except Monday, Tuesday and Saturday.

Figure 10: Solar generation, 1-7 September



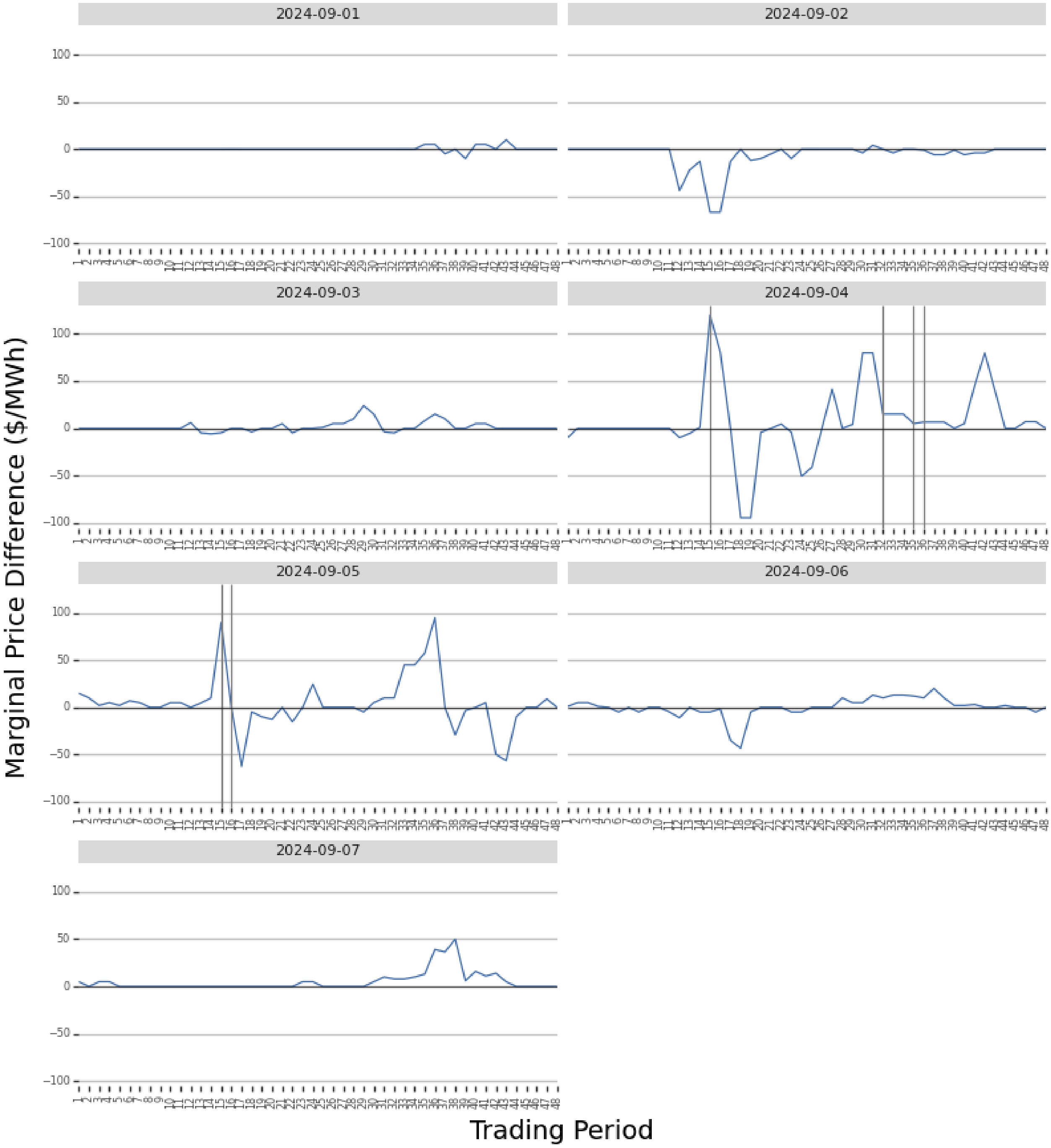
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

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

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.

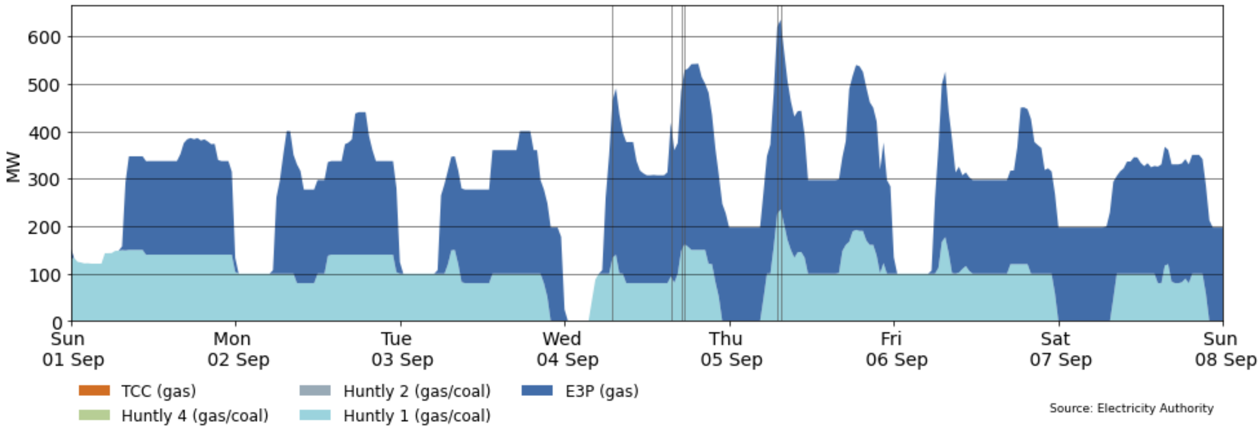
7.5. Prices were mostly similar to those simulated except on Wednesday and Thursday, which was when wind generation was mostly below 400MW –with large discrepancies between forecast and actual wind generation. The most notable positive (marginal prices higher than simulation) difference this week was $120 at 7:00am on Wednesday, when wind generation was 134MW lower than forecast. Throughout the rest of the week, prices were generally lower than or similar to those simulated.

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, 1-7 September



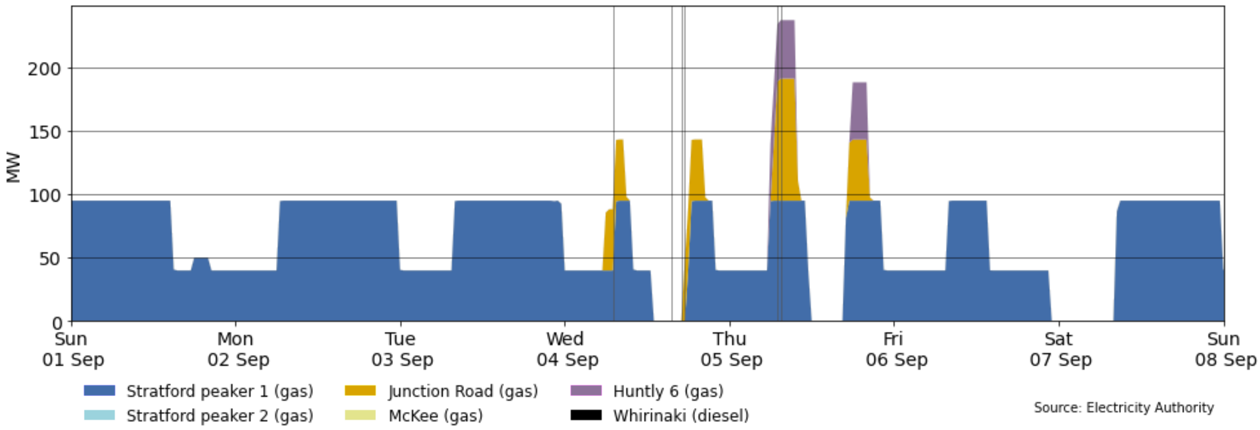
7.6. Figure 12 shows the generation of thermal baseload between 1-7 September. Huntly 1 and Huntly 5 (E3P) provided baseload generation this week. Both units ran every day, often turning off overnight, and ramping up when demand was high on Wednesday and Thursday. During the Thursday price spike, Huntly 5 ramped up to meet demand.

Figure 12: Thermal baseload generation, 1-7 September



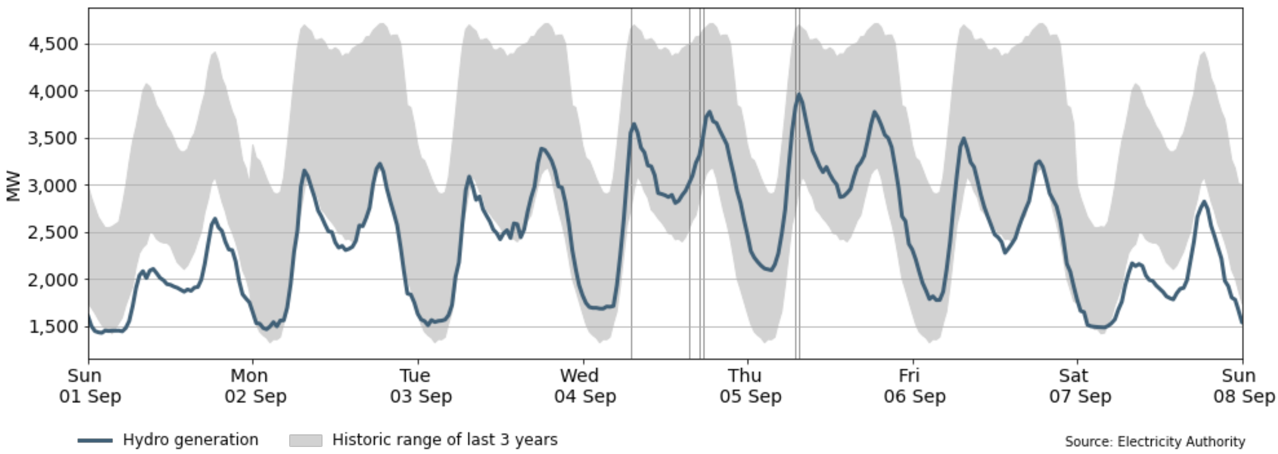
7.7. Figure 13 shows the generation of thermal peaker plants between 1-7 September. Stratford 1 ran every day this week as baseload support, turning off on Wednesday and Thursday afternoon and between Friday night and Saturday afternoon. Junction Road ran during peak periods on Wednesday and Thursday, joined by Huntly 6 on Thursday.

Figure 13: Thermal peaker generation, 1-7 September



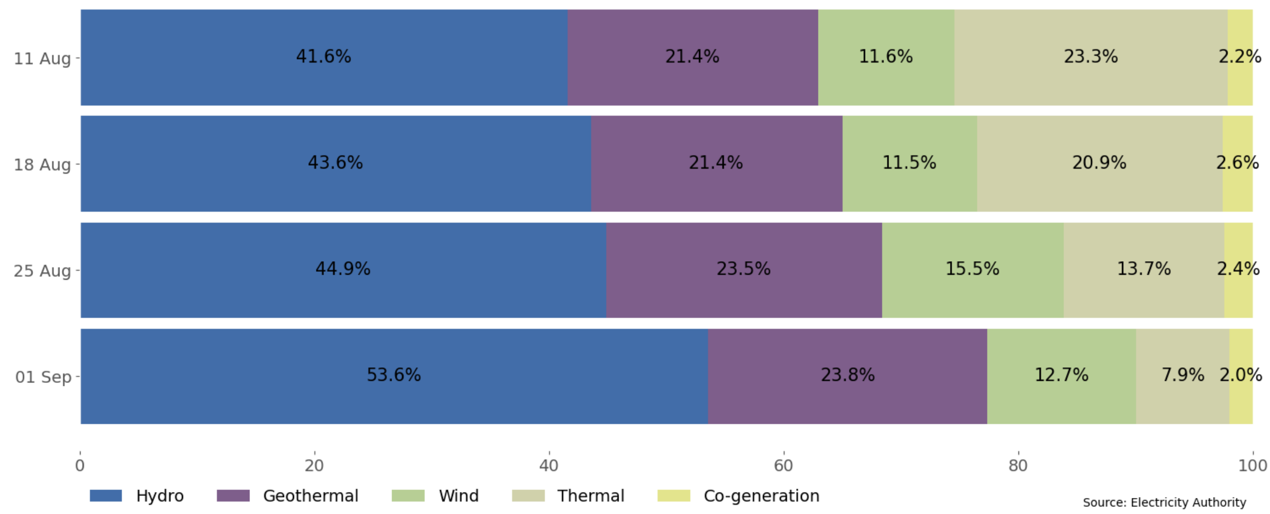
7.8. Figure 14 shows hydro generation between 1-7 September. Hydro generation remained low this week when compared to the historical range of the last five years. Hydro generation was highest on Wednesday and Thursday, when demand was high and wind generation was low and spot prices were the highest for the week.

Figure 14: Hydro generation, 1-7 September



7.9. As a percentage of total generation, between 1-7 September, total weekly hydro generation was 53.6%, geothermal 23.8%, wind 12.7%, thermal 7.9%, and co-generation 2.0%, as shown in Figure 15. Increased hydro generation allowed thermal generation to decrease significantly this week.

Figure 15: Total generation by type as a percentage each week, 11 August – 7 September 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 1-7 September ranged between ~1,050MW and ~1,600MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 4 is on outage until 8 September. This outage has been extended and was originally scheduled to end on 6 September.

(b) Stratford 2 is on outage until 27 September.

(c) Stratford 1 was on outage on 5 September.

(d) McKee had one unit on outage until 3 September and two units on outage on 7 September.

(e) Huntly 6 was on outage on 4 September.

(f) Glenbrook Steel’s co-generation unit was on outage on 2 September.

Figure 16: Total MW loss from generation outages, 1-7 September

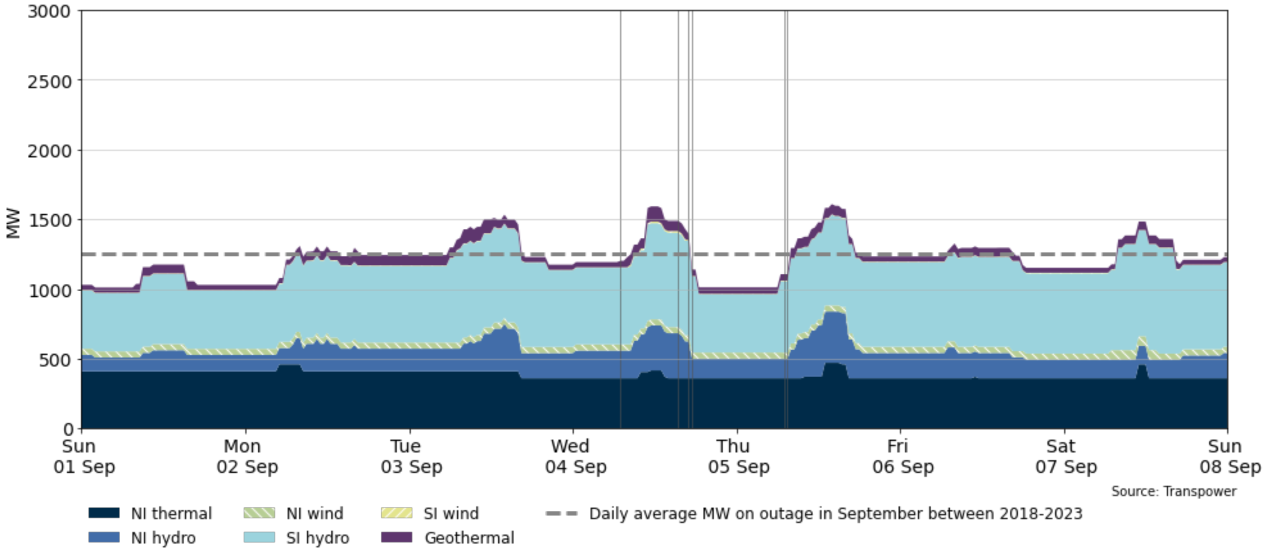
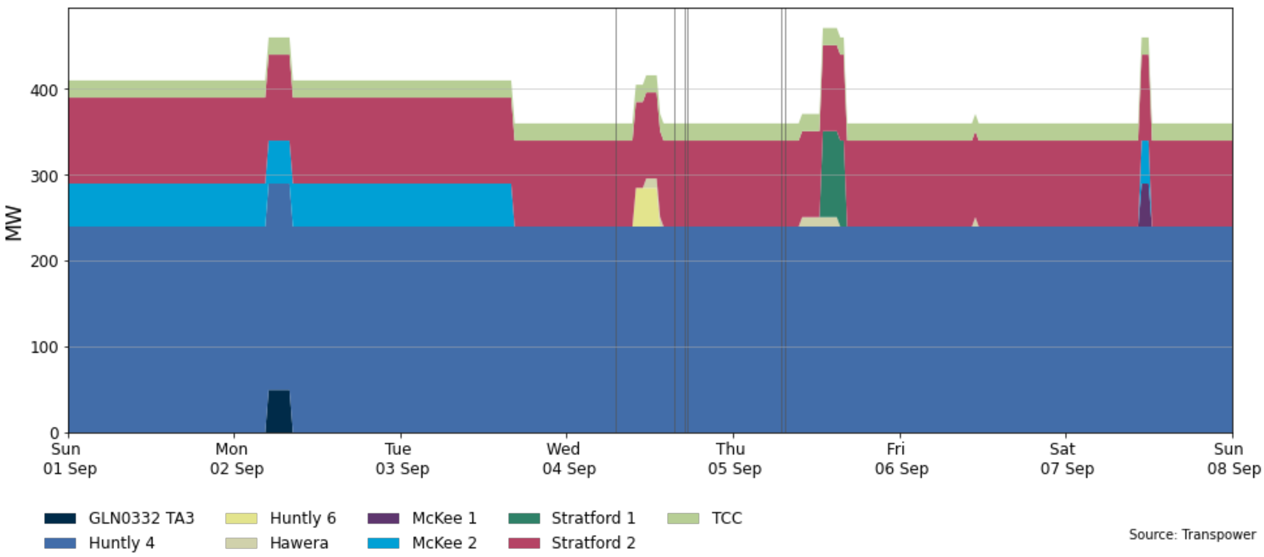


Figure 17: Total MW loss from thermal outages, 1-7 September

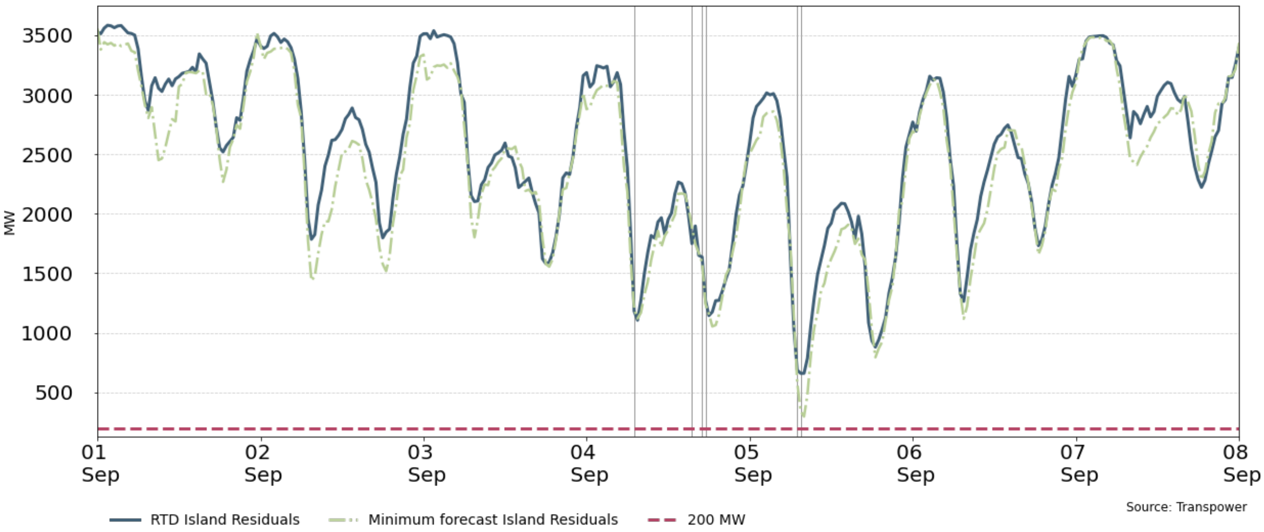


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 1-7 September. 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 balances were healthy this week. The minimum North Island residual was 254MW at 7:30am on Thursday, when wind generation was low and demand was high due to cold temperatures.

Figure 18: National generation balance residuals, 1-7 September



10. Storage/fuel supply

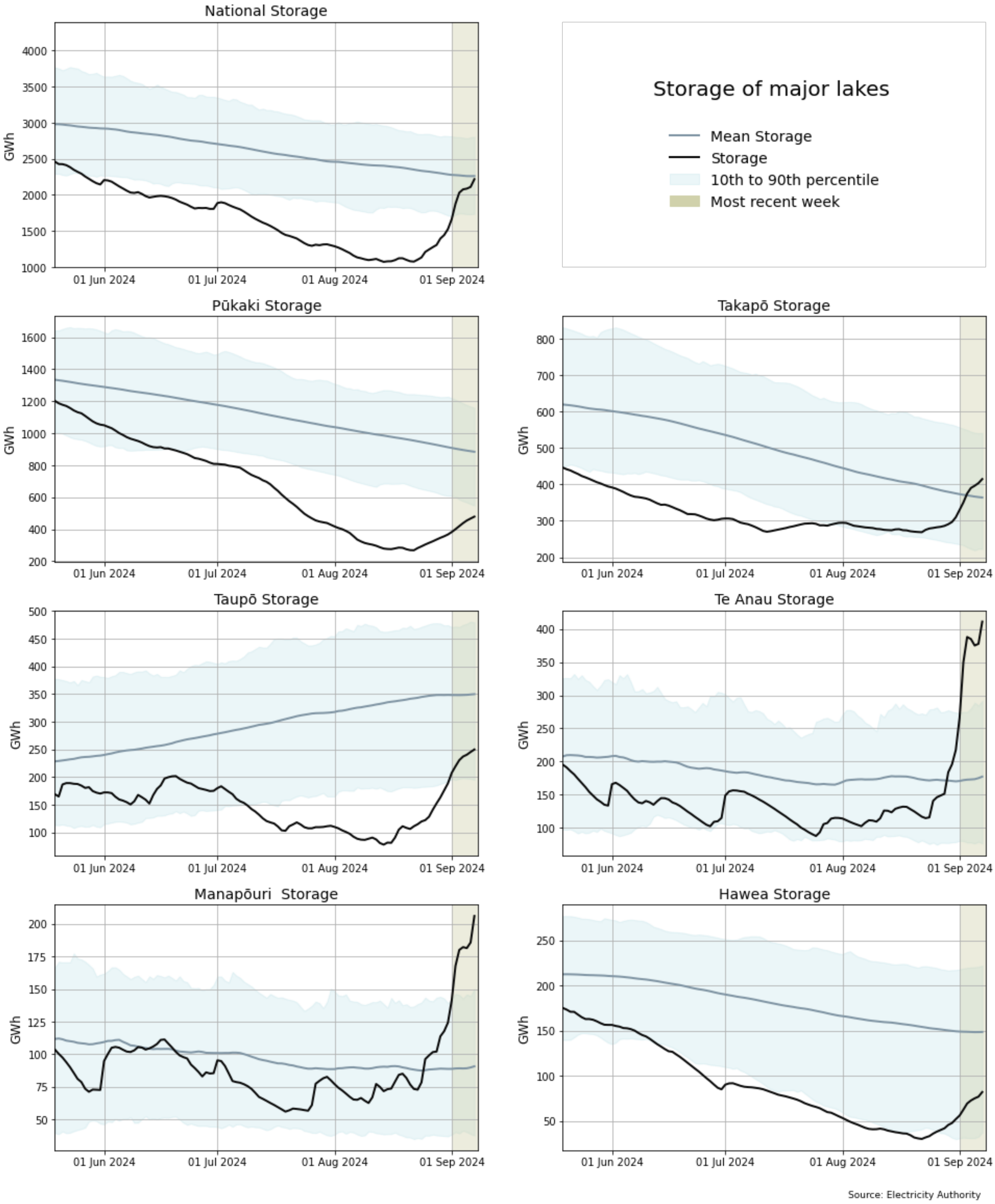
10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

10.2. National controlled storage increased this week and is ~54% nominally full and ~92% of the historical average for this time of the year as of 7 September.

10.3. Storage increased at all major lakes this week. Pūkaki remains below its 10th percentile, Taupō and Hawea are above their 10th percentiles but below mean, Takapō is above mean.

10.4. Heavy rainfall in the south west has seen both Te Anau and Manapōuri go above their historic 90th percentiles and high operating ranges. The Upper and Lower Waiau flows indicate spilling is occurring and may continue with more rain expected this week in the region. Manapōuri currently has two units on outage which are expected to return in March and September 2025 respectively.

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 September 2024. The SRMC for gas has decreased significantly from the previous month, while the coal SRMC and diesel SRMC have increased slightly. The drop in gas SRMCs is a result of Methanex temporarily closing their Motunui plant to resell gas to thermal generators, as well as less thermal generation being dispatched due to increased hydro storage.

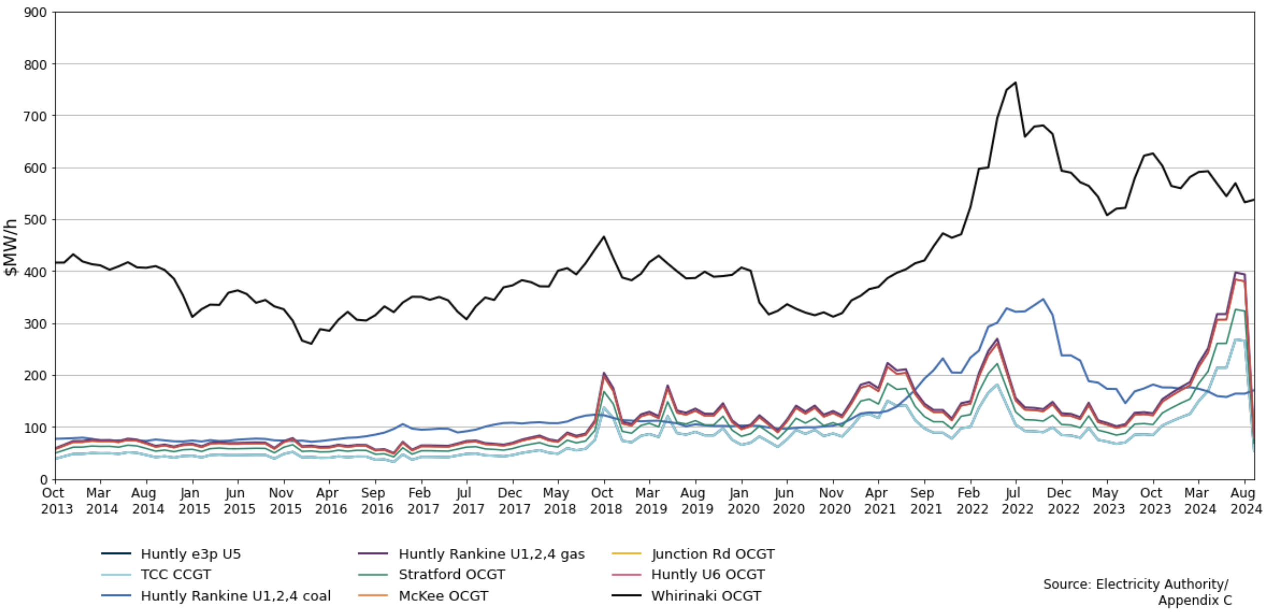
11.4. The latest SRMC of coal-fueled Rankine generation is ~$171/MWh. The cost of running the Rankines on gas is now less expensive at ~$82/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between ~$55/MWh and ~$82/MWh.

11.6. The SRMC of Whirinaki is ~$537/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

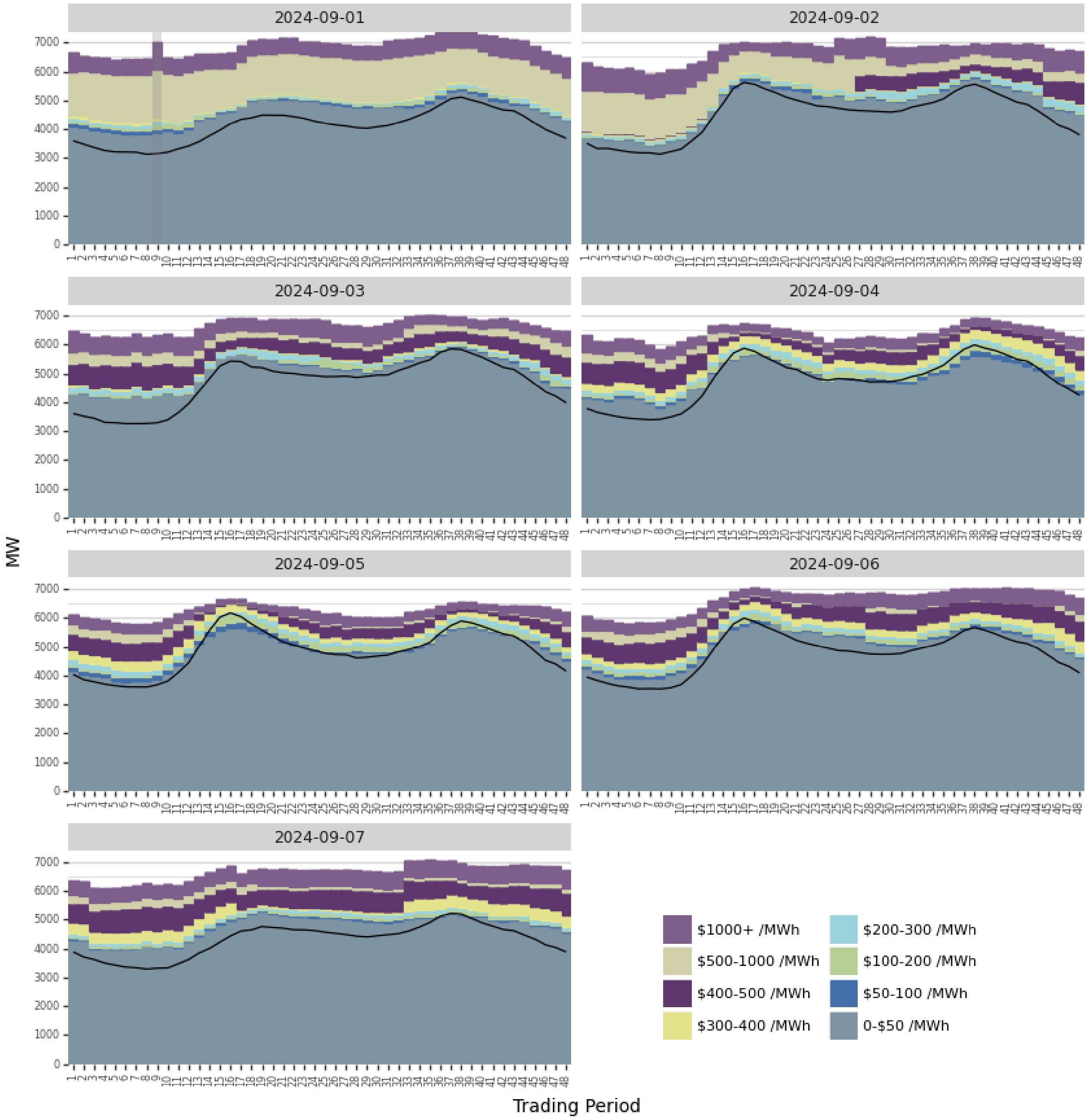


12. Offer behaviour

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 cleared in the $0-$100/MWh region this week. From Monday onwards the amount of offers in the $500-$1,000/MWh band decreased significantly, while the amount of offers in lower price bands increased. This was due to hydro generators changing their offers as storage increased.

Figure 21: Daily offer stacks[2]



13. Ongoing work in trading conduct

13.1. Prices generally appeared to be consistent with supply and demand conditions this week.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

[2] 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

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	Passed to Compliance for advice	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance for advice	Contact	Multiple	High hydro offers
1/07/2024-23/08/2024	Several	These trading periods are now part of a s16 review	N/A	N/A	High energy prices
07/09/2024	35-42	Further analysis	Meridian	Multiple	Wind forecasting