30 September 2024

Trading conduct report 22-28 September 2024

Market monitoring weekly report

Trading conduct report 22-28 September 2024

1. Overview

1.1. Prices decreased this week compared to last week, often dropping below $1/MWh overnight. Thermal generation remained low, with only Huntly 5 and one Rankine providing baseload generation for most of the week. National controlled hydro storage increased this week and is currently ~110% of mean.

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 22-28 September:

(a) the average wholesale spot price across all nodes was $73/MWh.

(b) 95% of prices fell between $0.01/MWh and $230/MWh.

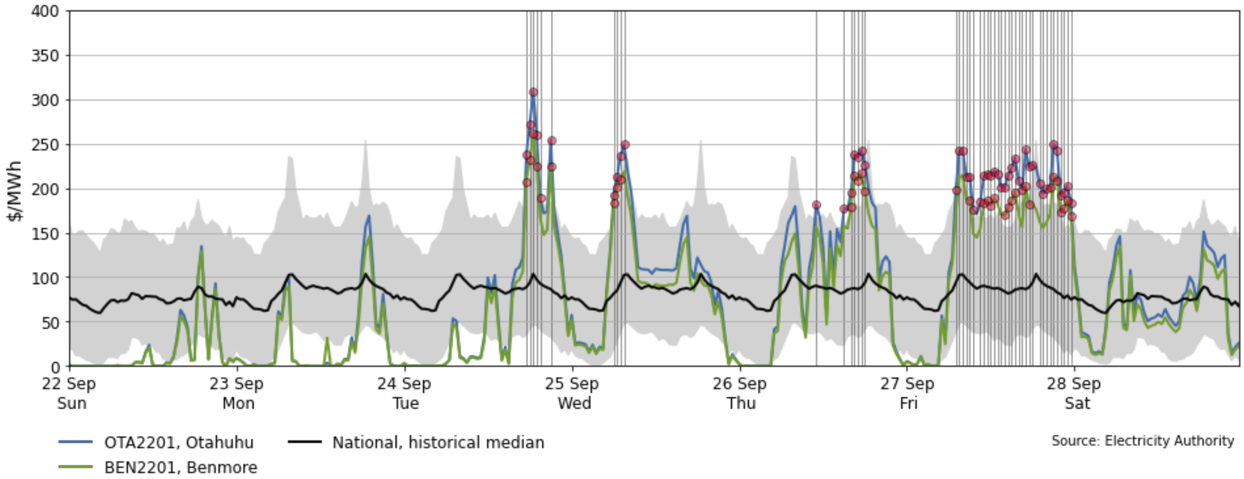
2.3. Overall, the majority of spot prices were within $3-$122/MWh, with the weekly average price decreasing by around $59/MWh compared to the previous week.

2.4. Prices were generally low overnight this week, often dropping below $1/MWh. However, they were mostly above the median during the day, especially from Tuesday onwards. Prices were consistently higher than mean on Friday, when wind was low. Several instances of inaccurate wind and demand forecasting, requiring higher-priced hydro and thermal generation to be dispatched, likely contributed to many of these prices above $200/MWh. Wind and demand forecasting discrepancies exceeded 100MW respectively on multiple occasions across the week where prices have been highlighted.

2.5. The Ōtāhuhu spot price reached a maximum of $309/MWh at 6.30pm on Tuesday. Demand was under forecast by 93MW and wind generation was over forecast by 365MW at the time, requiring high priced hydro generation to be dispatched.

2.6. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10th-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.

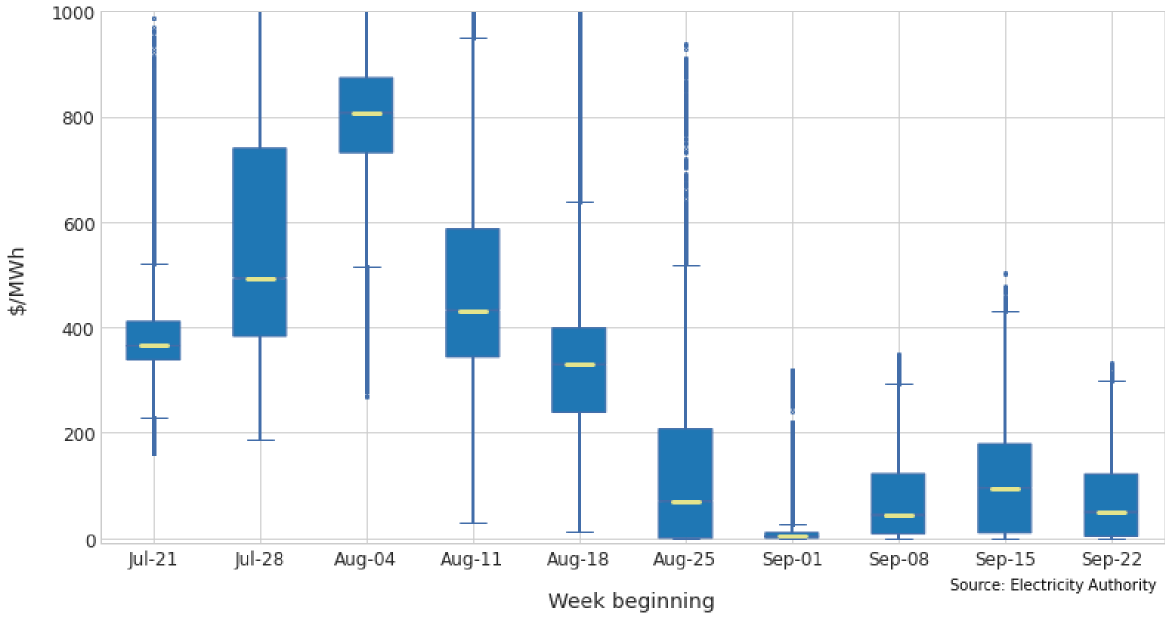
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 22-28 September



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. Compared to the previous week, the median price decreased by $46/MWh. The interquartile range and overall spread also decreased, indicating that prices were lower and less volatile this week.

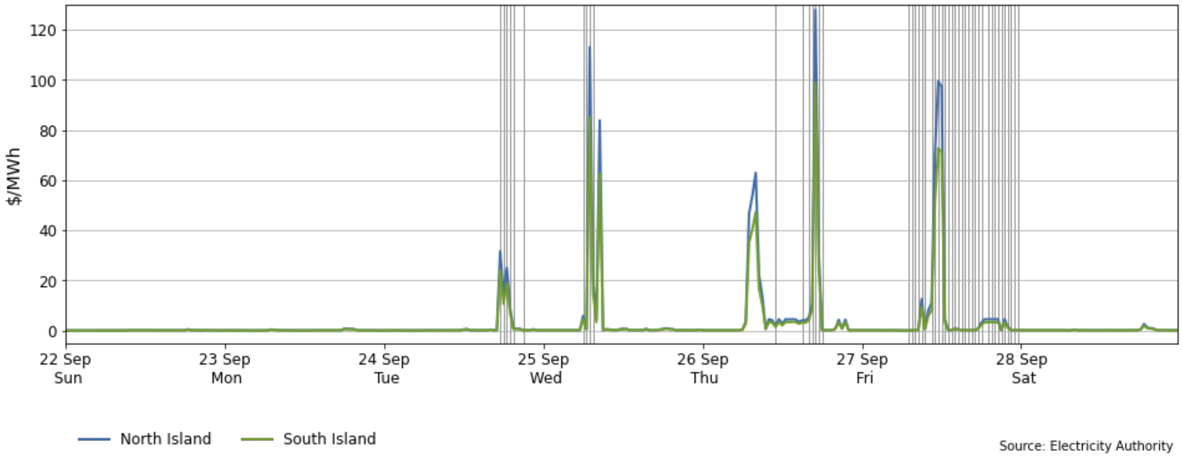
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

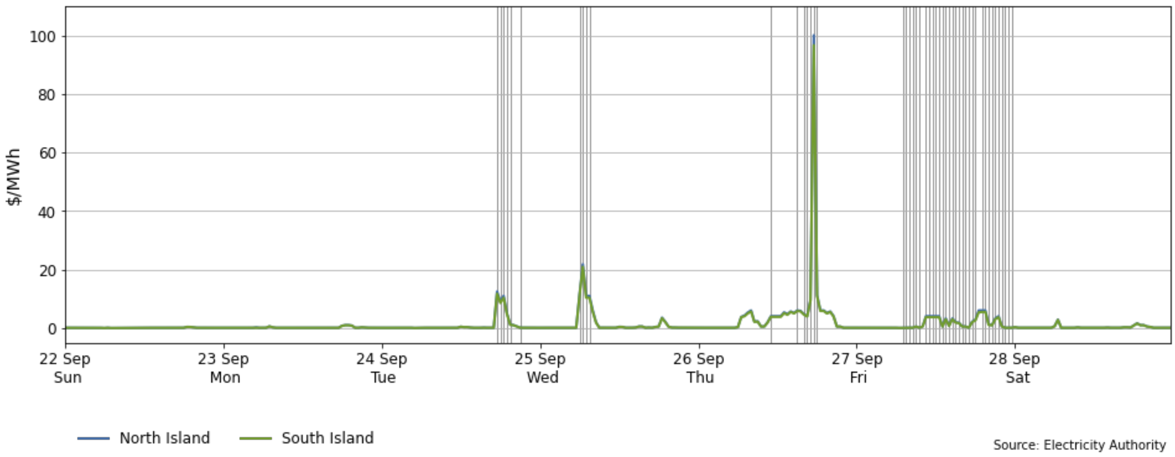
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week. However, they spiked above $90/MWh in the North Island during peak demand periods on Wednesday morning and Thursday evening, as well as at midday on Friday. This occurred as the FIR required to cover the risk setter increased at these times.

Figure 3: Fast instantaneous reserve price by trading period and island, 22-28 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 but reached a maximum of $100/MWh in the North Island at 5:30pm on Thursday, the same time as this week's maximum FIR price.

Figure 4: Sustained instantaneous reserve by trading period and island, 22-28 September



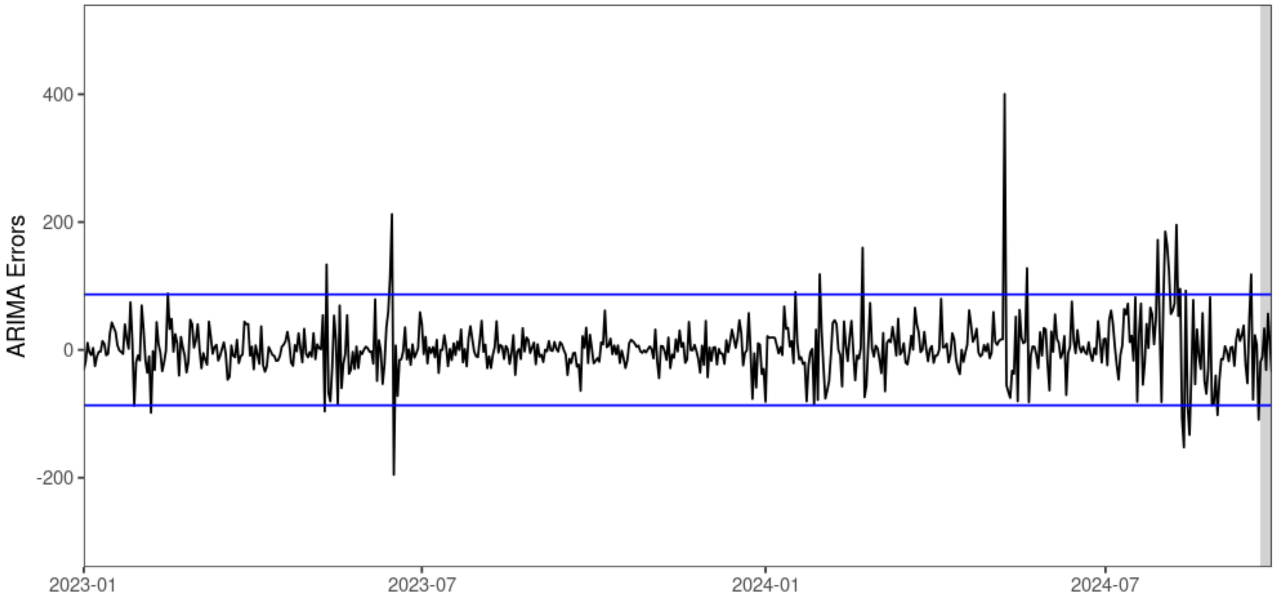
4. Regression residuals

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 two standard deviations of the data, indicating that prices were lower than or in line with what the model expected.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 28 September 2024

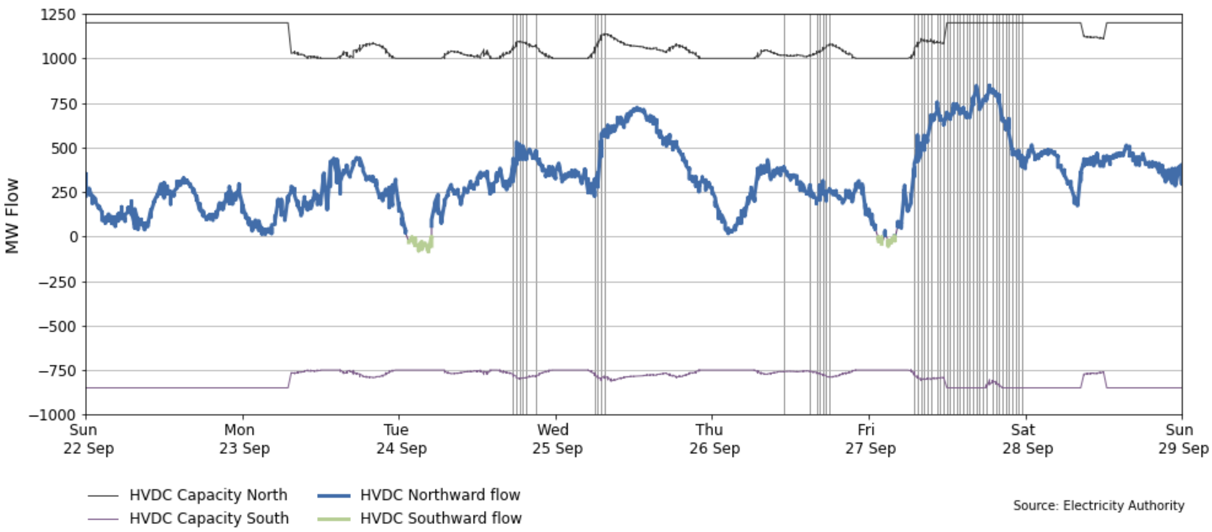


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 22-28 September. Due to increased hydro storage and generation, and lower South Island demand due to the Tiwai demand response, HVDC flow was almost entirely Northward this week. HVDC flow was highest on Friday when North Island wind generation was low and prices were high.

Figure 6: HVDC flow and capacity, 22-28 September

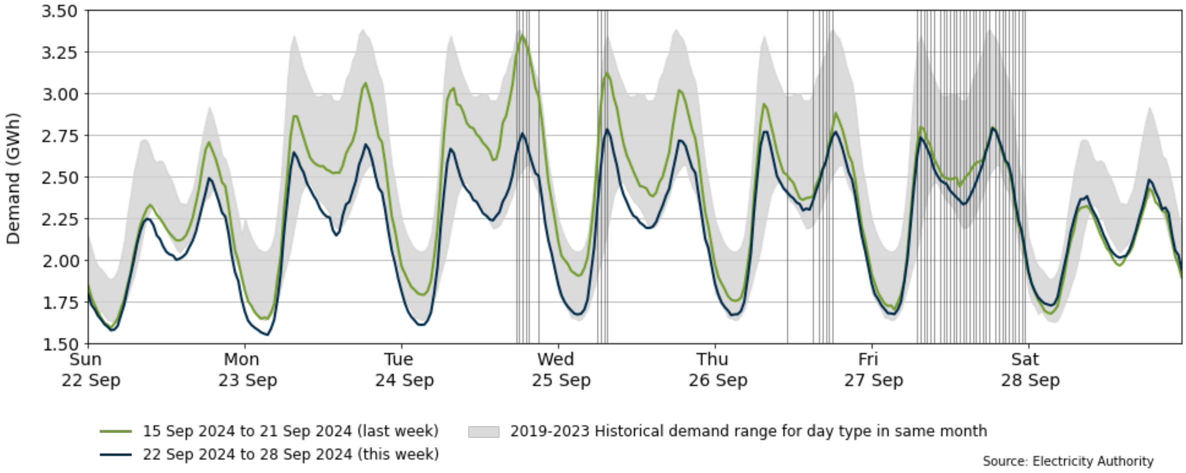


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 22-28 September, compared to the historic range and the demand of the previous week. Demand remained low this week, being within or below the historical range for this time of year, and much lower than the previous week. It was highest on Friday, when temperatures were low, with the weekly maximum demand of 2.79GWh occurred at 6.30pm. Tiwai began reducing their demand response this week.

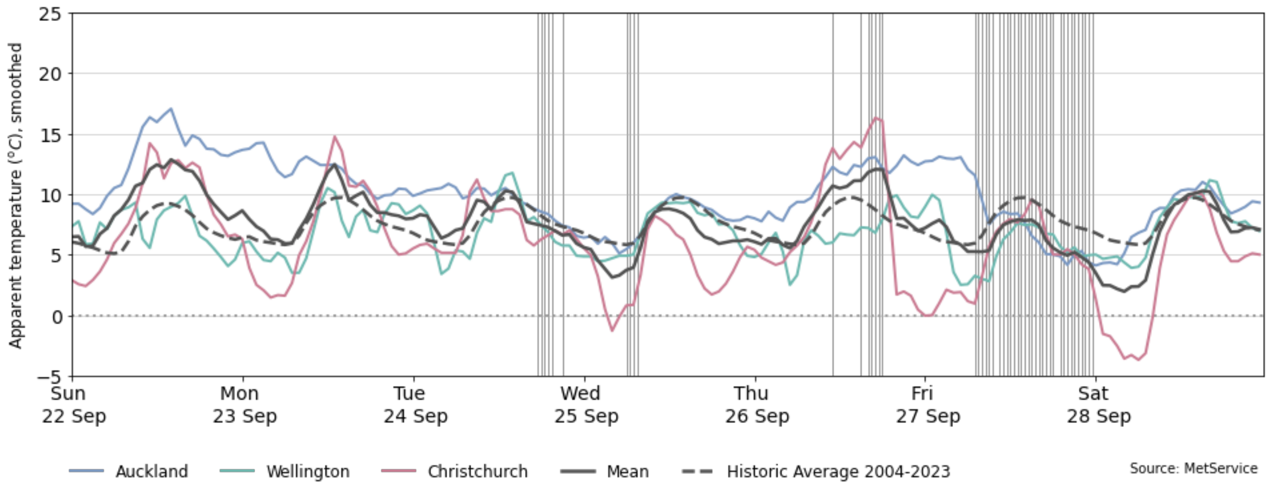
Figure 7: National demand, 22-28 September compared to historic range and previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 22-28 September 2024. 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. Temperatures ranged from 4°C to 17°C in Auckland, 1°C to 13°C in Wellington, and -4°C to 16°C in Christchurch. Temperatures were below average on Friday, leading to increased demand which likely contributed to higher prices.

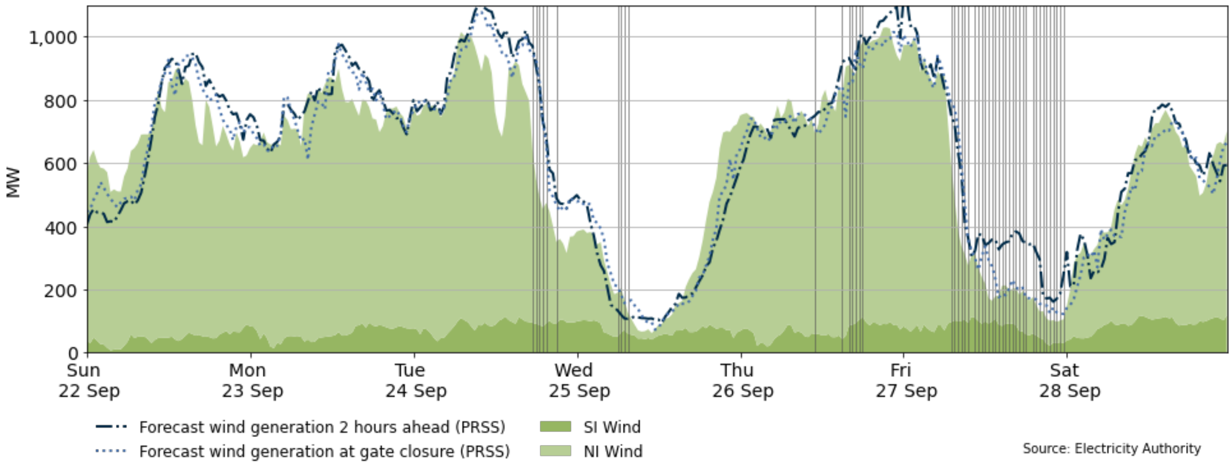
Figure 8: Temperatures across main centres, 22-28 September



7. Generation

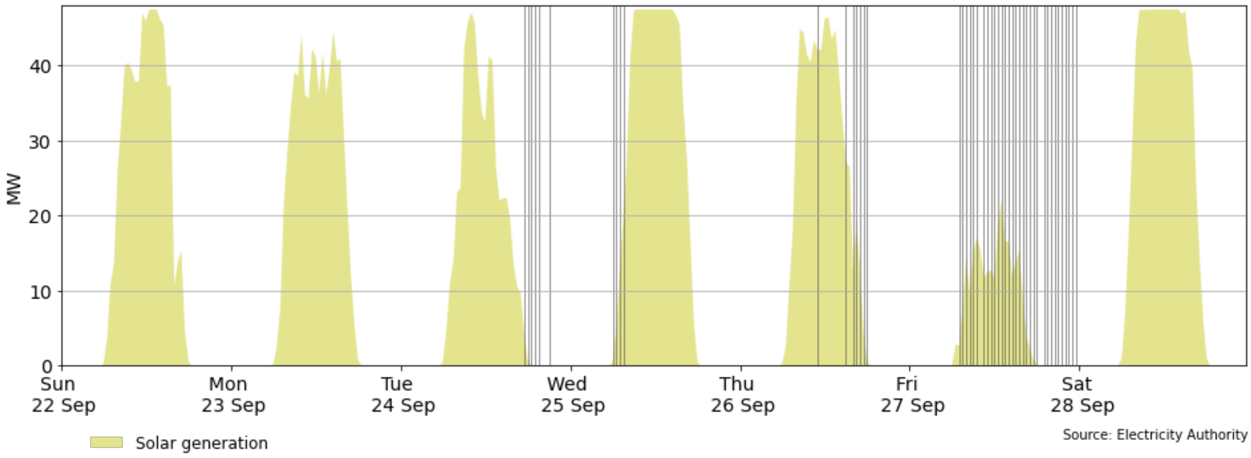
7.1. Figure 9 shows wind generation and forecast from 22-28 September. This week wind generation varied between 62MW and 1,029MW, with a weekly average of 608MW. Wind generation was low and/or below forecast at the times many of this week's highlighted prices occurred. On Tuesday, it was over forecast by as much as 380MW. During the period of high prices on Friday, wind generation was often below 200MW as well as being significantly over forecast.

Figure 9: Wind generation and forecast, 22-28 September



7.2. Figure 10 shows solar generation from 22-28 September. Solar generation peaked above 40MW every day this week except Friday, reaching a maximum of 47MW at 1.30pm on Wednesday. Solar generation was lowest on Friday due to overcast conditions.

Figure 10: Solar generation, 22-28 September



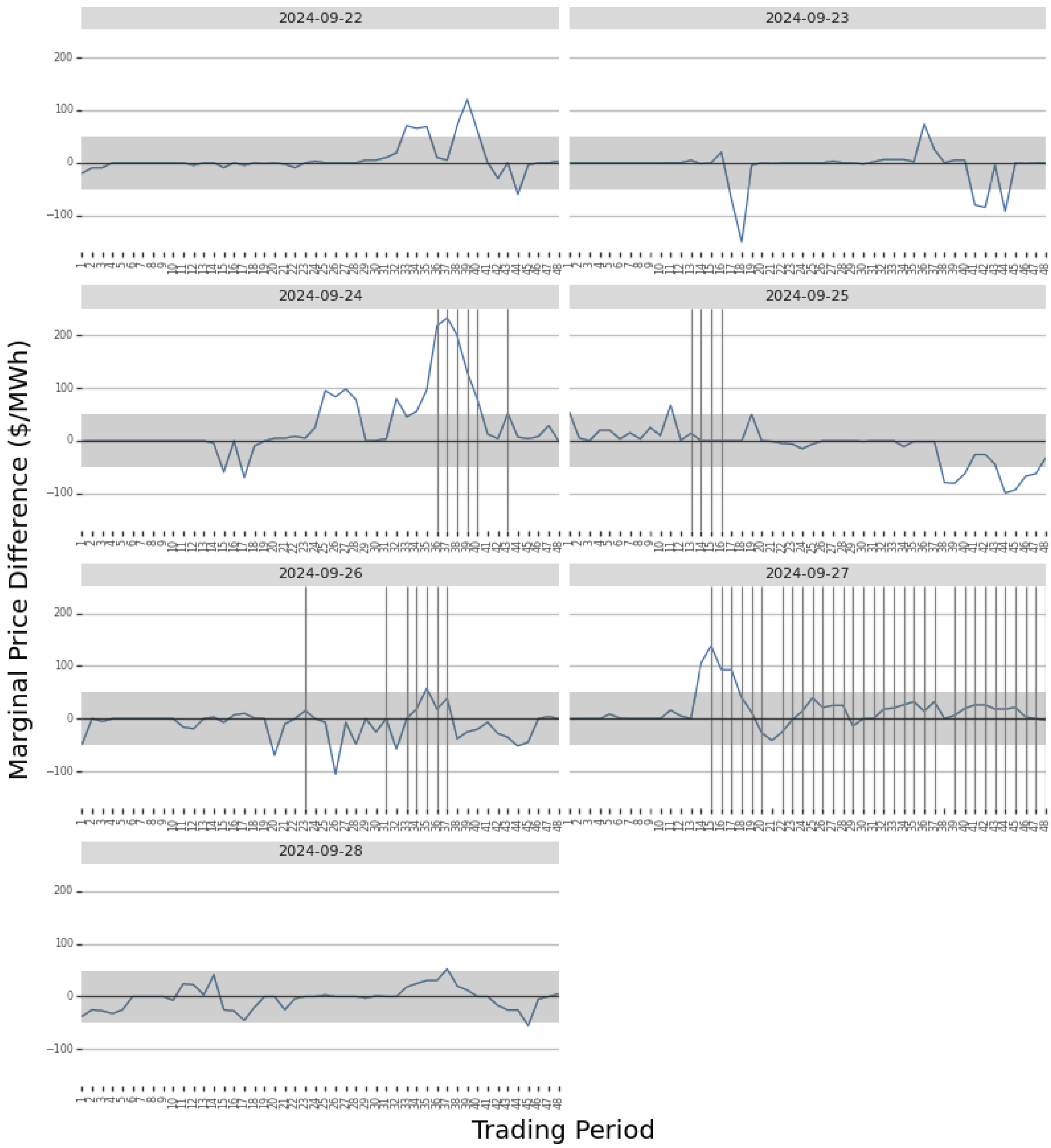
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 most notable positive (marginal prices higher than simulation) difference this week was $233/MWh at 6.00pm on Tuesday, when wind generation was 380MW lower than forecast

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

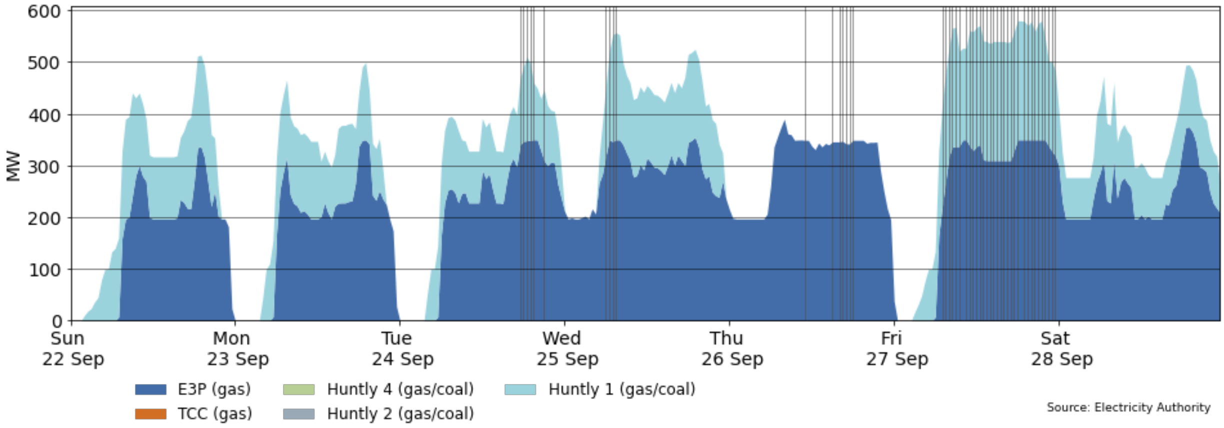
and demand was 59MW higher than forecast. Consistent positive differences greater than $100/MWh also occurred on Sunday and Friday. Throughout the rest of the week, prices were largely similar to or lower than those simulated.

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, 22-28 September



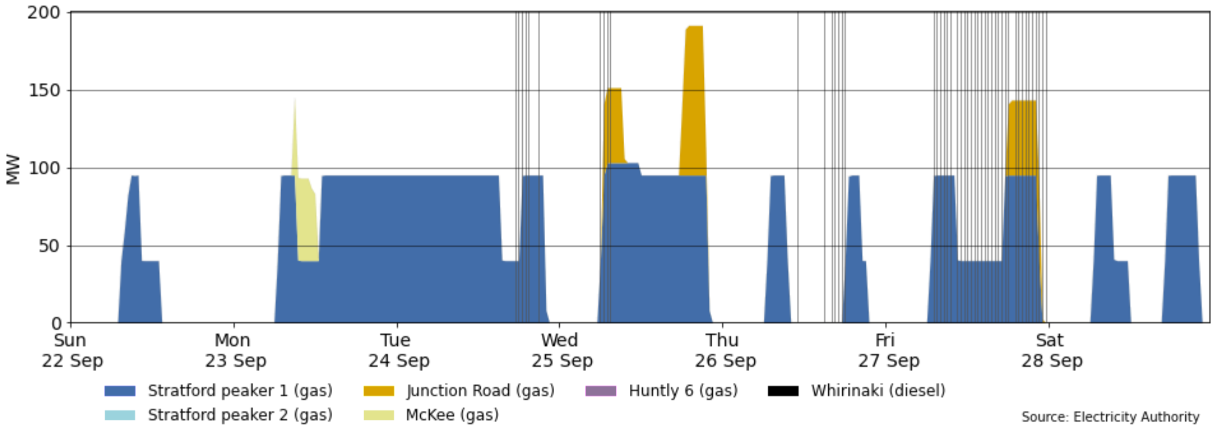
7.5. Figure 12 shows the generation of thermal baseload between 22-28 September. Huntly 1 and Huntly 5 (E3P) provided baseload generation this week. Huntly 5 ran from morning to midnight on Monday and Tuesday, then ran continuously for the rest of the week aside from early on Friday morning. Huntly 1 ran each day from Sunday to Wednesday, turning off overnight, then ran continuously from Friday morning. Thermal generation was highest on Friday when wind was low and spot prices were high.

Figure 12: Thermal baseload generation, 22-28 September



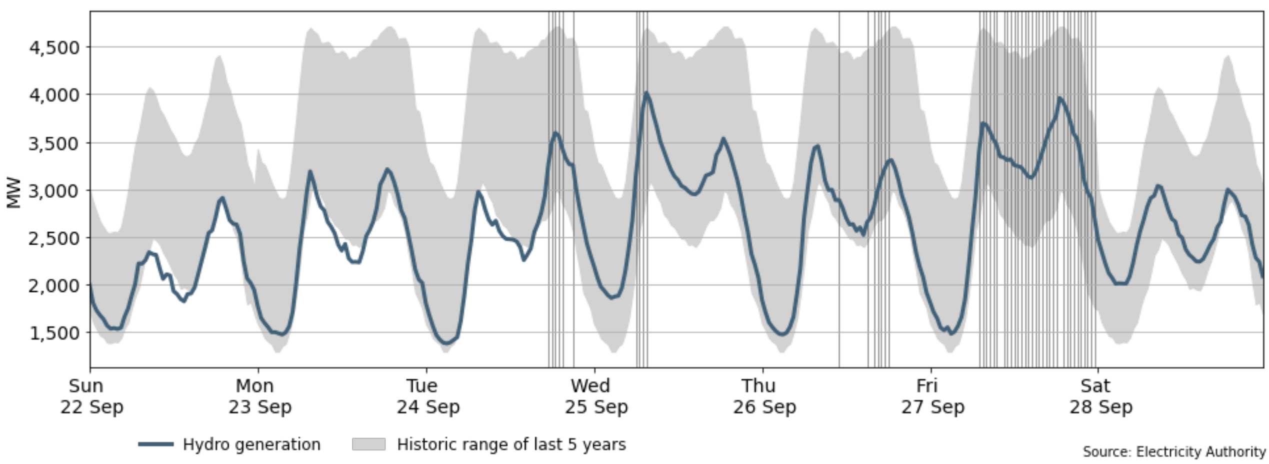
7.6. Figure 13 shows the generation of thermal peaker plants between 22-28 September. Stratford peaker 1 ran each day this week. McKee ran on Monday morning, and Junction Road ran during peak periods on Wednesday and Friday.

Figure 13: Thermal peaker generation, 22-28 September



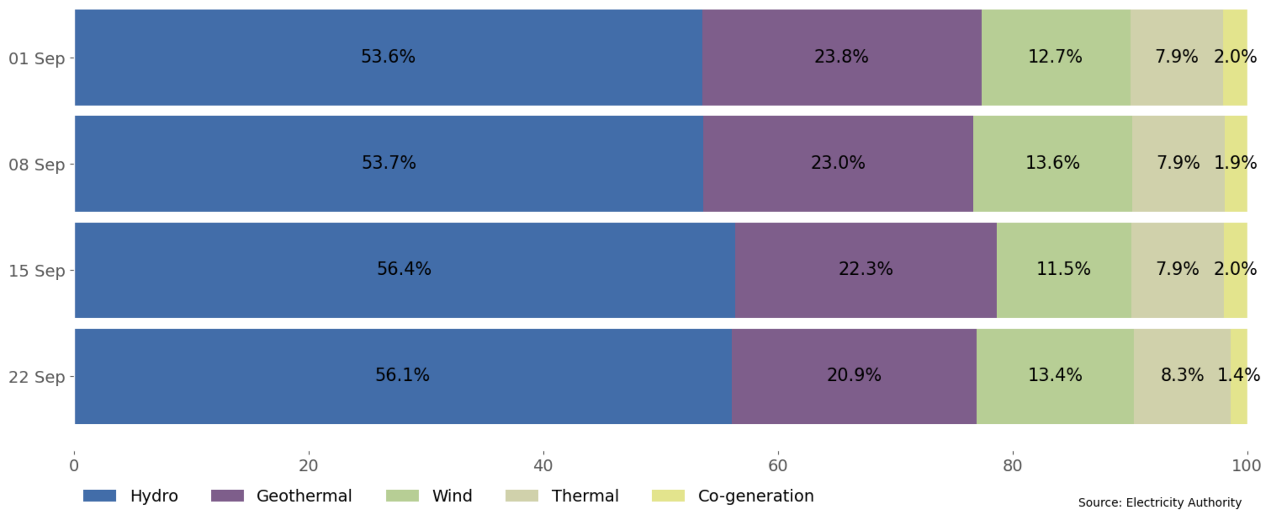
7.7. Figure 14 shows hydro generation between 22-28 September. Hydro generation remained low this week when compared to the historical range of the last five years. Hydro generation was highest on Wednesday evening and on Friday, when demand was high due to low temperatures and when wind generation was also low.

Figure 14: Hydro generation, 22-28 September



7.8. As a percentage of total generation, between 22-28 September, total weekly hydro generation was 56.1%, geothermal 20.9%, wind 13.4%, thermal 8.3%, and co-generation 1.4%, as shown in Figure 15. The proportion of wind generation increased slightly this week, leading to a decrease in the proportion of hydro generation. The proportion of geothermal generation also decreased due to outages at two large geothermal plants.

Figure 15: Total generation by type as a percentage each week, 1-28 September 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 22-28 September ranged between ~1,100MW and ~1,800MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 is on outage until 3 October.

(b) Huntly 6 is on outage until 2 October.

(c) Junction Road has one unit on outage on 28 September.

(d) The Stratford unit 2 outage has been extended again and is now scheduled to end on 23 October.

(e) Whirinaki unit 2 was on outage on until 23 September.

(f) Tauhara geothermal plant was on outage on 25 September.

(g) Kawerau geothermal plant was on outage on 28 September.

(h) Maraetai hydro was on outage on 27 September.

(i) Harapaki wind farm was on outage on 28 September.

(j) A number of South Island hydro units were also on outage this week, including units from Manapōuri, Benmore and Ōhau.

Figure 16: Total MW loss from generation outages, 22-28 September

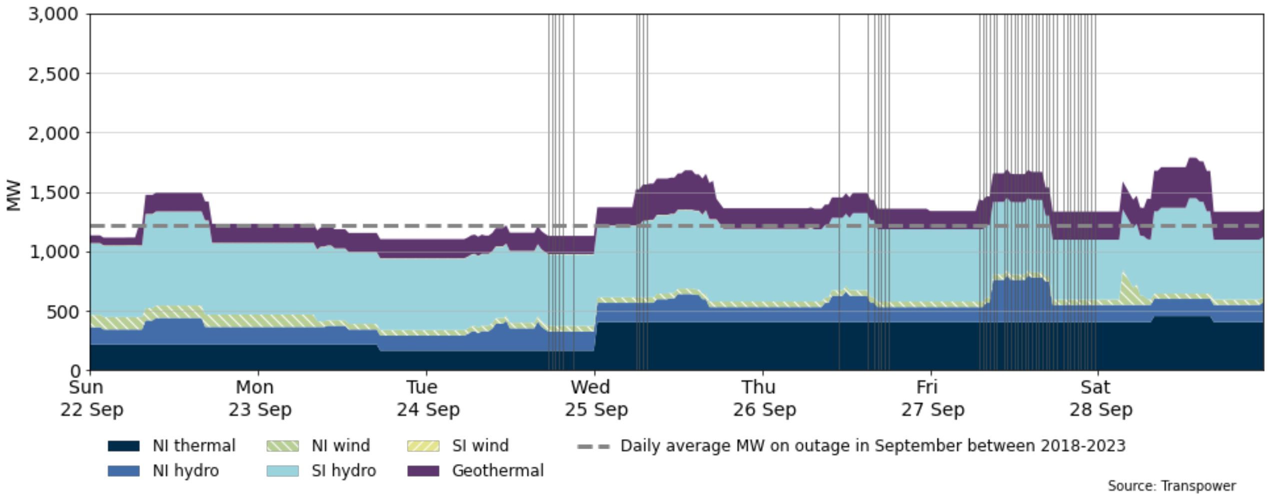
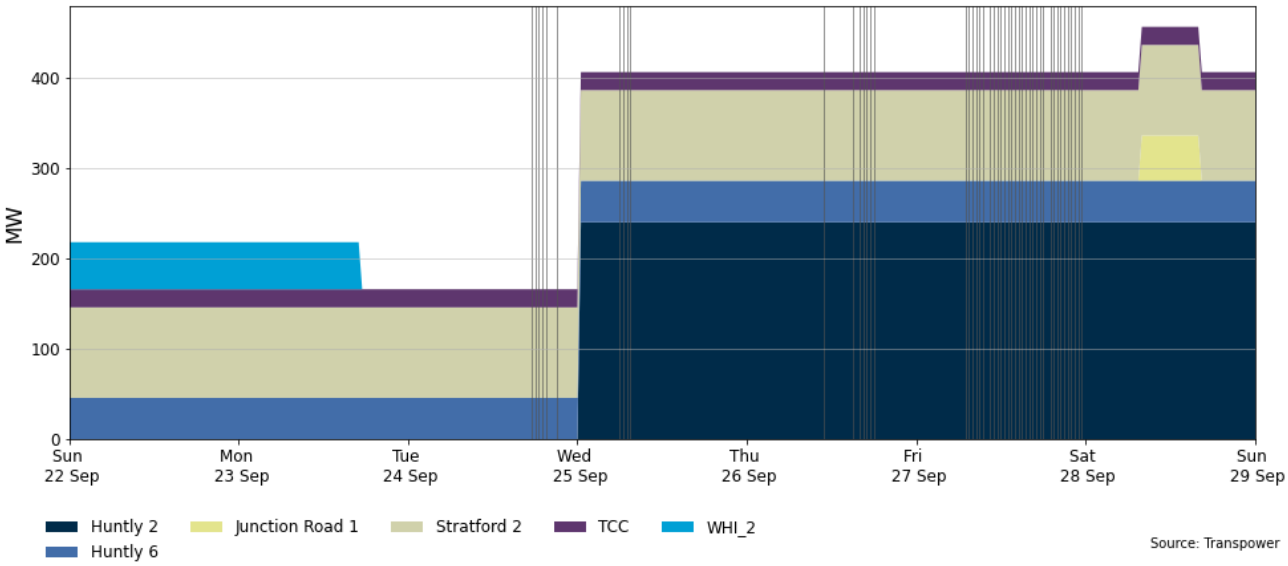


Figure 17: Total MW loss from thermal outages, 22-28 September

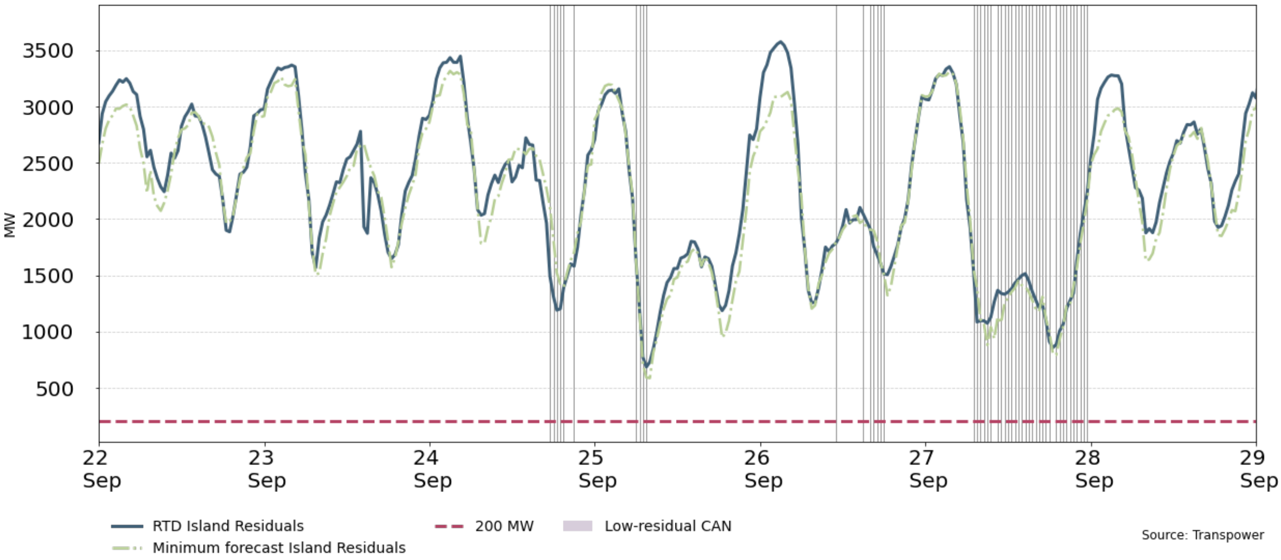


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 22-28 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 422MW at 8.00am on Wednesday.

Figure 18: National generation balance residuals, 22-28 September



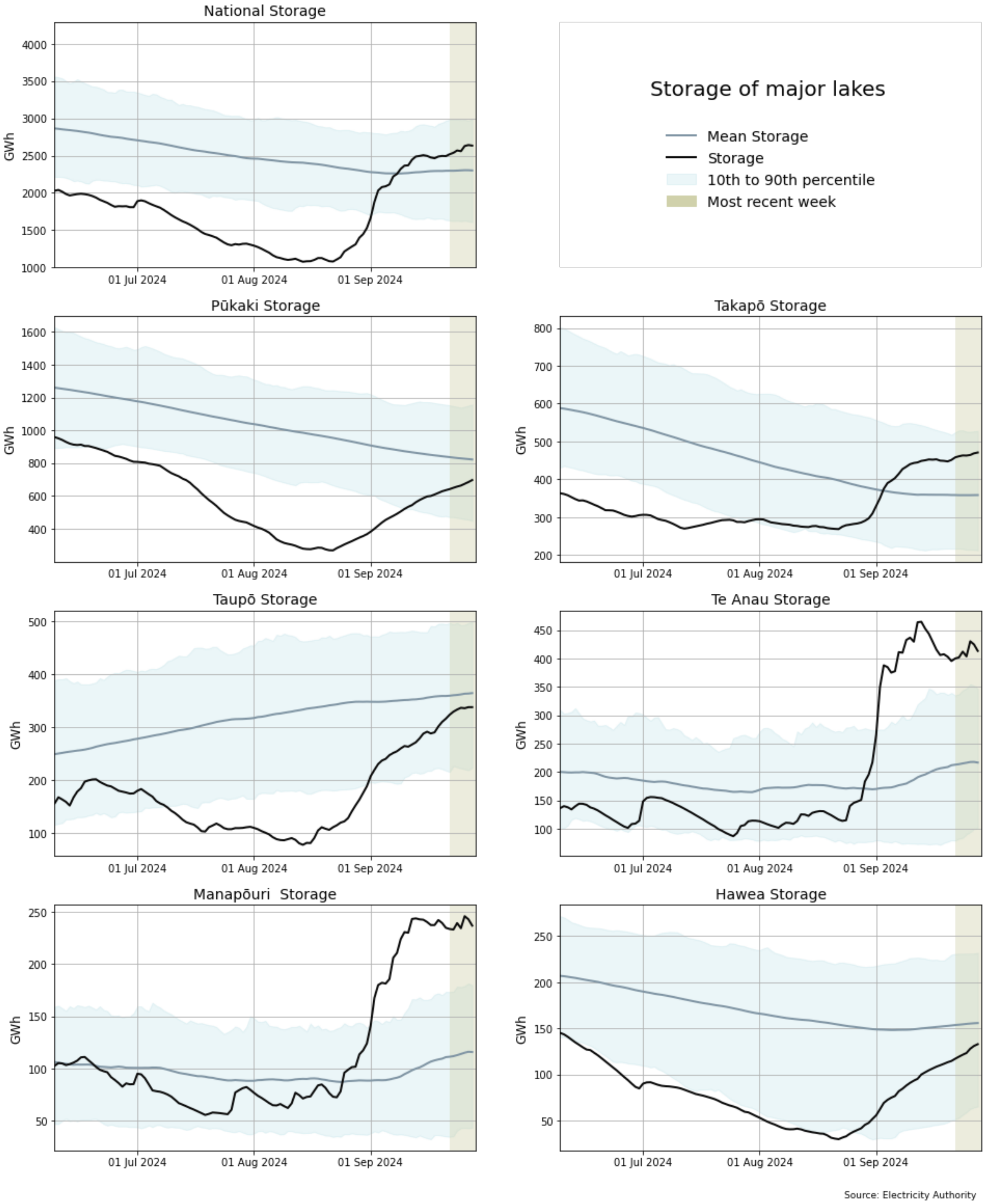
10. Storage/fuel supply

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 slightly this week. As of 28 September, storage was 64% nominally full and ~110% of the historical average for this time of the year.

10.3. Storage at all major lakes increased this week. Taupō, Pūkaki and Hawea are above their 10th percentiles but below their respective historic means. Takapō is above mean but below its 90th percentile. Levels at Te Anau and Manapōuri remain above their 90th percentiles and high operating ranges. Spilling is still occurring in the Upper and Lower Waiau catchment due to the recent high inflows in the area.

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.

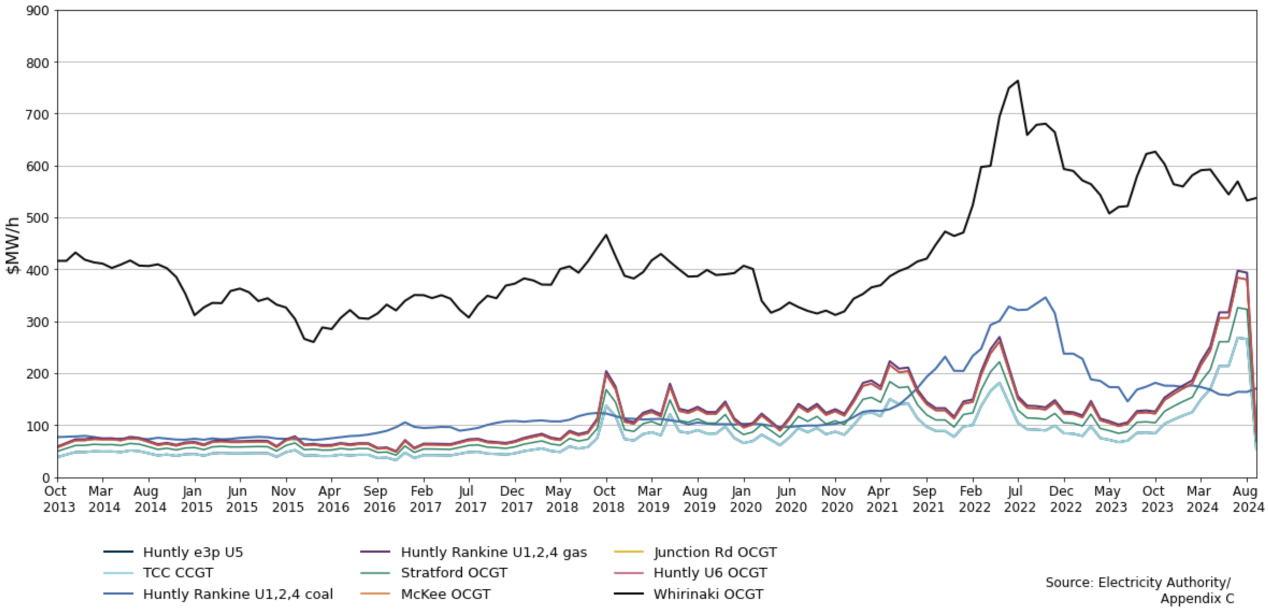
11.4. The latest SRMC of coal-fueled Rankine generation is ~$171/MWh. The cost of running the Rankines on gas is now less expensive at ~$82/MWh.

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



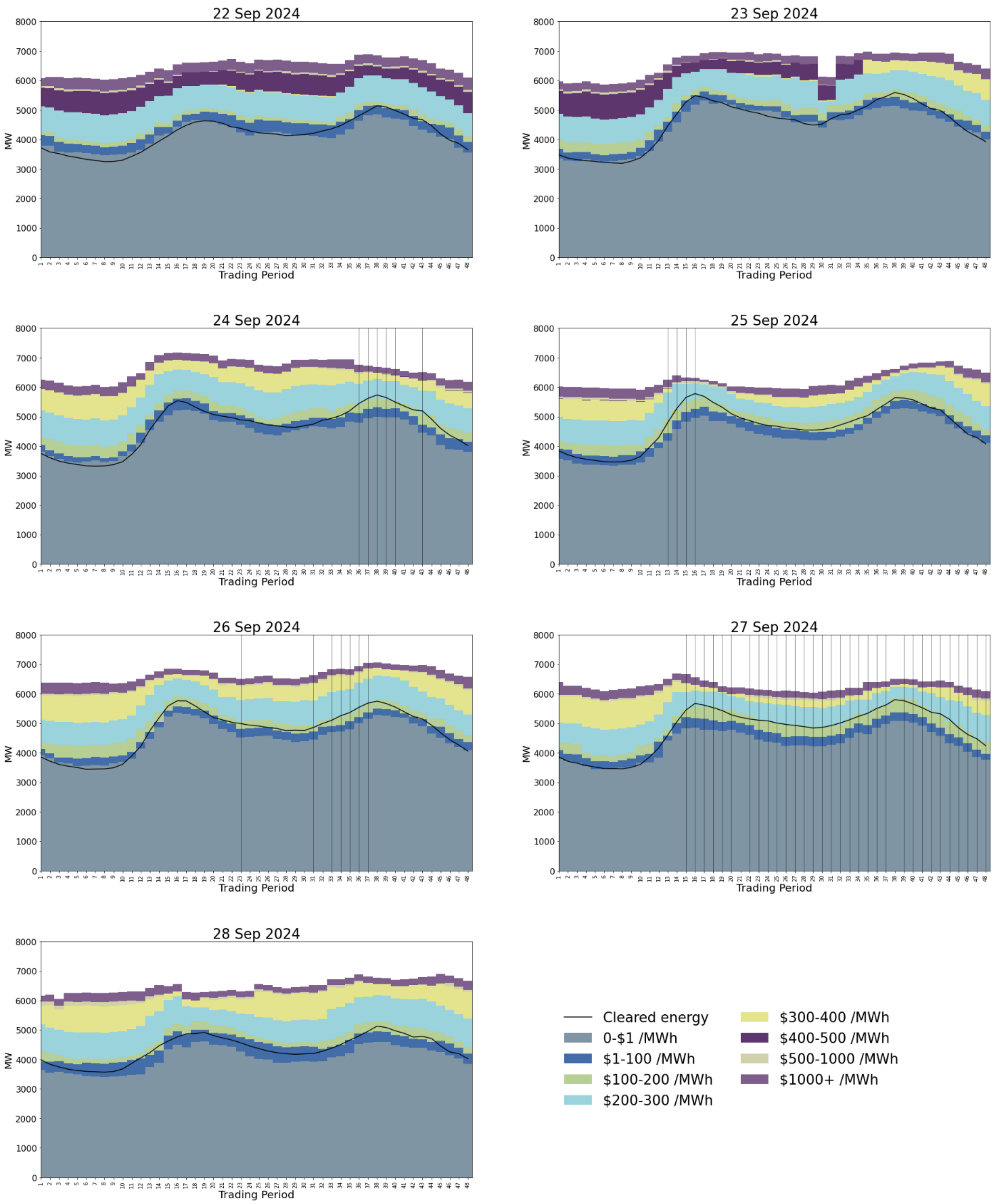
12. Offer behaviour

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 below $300/MWh this week. From Monday evening, the number of offers in the $400-$500/MWh band decreased and the number in the $300-$400/MWh band increased. This was due to hydro generators lowering the price of their offers as storage increased.

12.3. On Monday between trading periods 30-31, the number offers in the $200-$300/MWh band disappeared in real time – we are looking further into this.

Figure 21: Daily offer stacks



Source: Electricity Authority

13. Ongoing work in trading conduct

13.1. Prices generally appeared to be consistent with supply and demand conditions this week, however, some offers are being analysed further to ensure compliance with the trading conduct rule.

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	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
26/08/2024-26/08/2024	Several	Further analysis	Manawa	Tararua wind farms	Wind forecasting
17/09/2024	17	Further analysis	Nova	McKee	Thermal offers
23/09/2024	30-31	Further analysis	N/A	Waitaki scheme	Offers