19 August 2024

Trading conduct report 11-17 August 2024

Market monitoring weekly report

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1. Overview

1.1. Prices decreased this week, compared to last, due to high wind generation and improved gas availability for thermal generation. Low temperatures led to high demand on Wednesday morning, contributing to the Ōtāhuhu spot price reaching $1,100/MWh. TCC, Huntly 5 and three Rankines provided more baseload generation this week after gas availability increased. National controlled hydro storage decreased slightly, and remains around 54% 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. 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.

2.3. Between 11-17 August:

(a) the average wholesale spot price across all nodes was $481/MWh

(b) 95% of prices fell between $195/MWh and $859/MWh.

2.4. Overall, the majority of spot prices were within $345-$599/MWh, with the weekly average price decreasing by around $344/MWh compared to the previous week. The average Benmore spot price was $19/MWh higher than at Ōtāhuhu.

2.5. Prices were not as consistently high compared to the previous week, dropping below the mean and 90th percentile at times. The high prices seen over the last few weeks are primarily the result of low hydro storage, periods of low wind generation, and thermal generation costs rising due to limited gas supply. However, this week lower demand and increased wind generation, in addition to Methanex selling gas to thermal generators, likely contributed to the lower prices seen this week.

2.6. High wind generation while demand was low led to prices dropping below the historical median early on Monday morning.

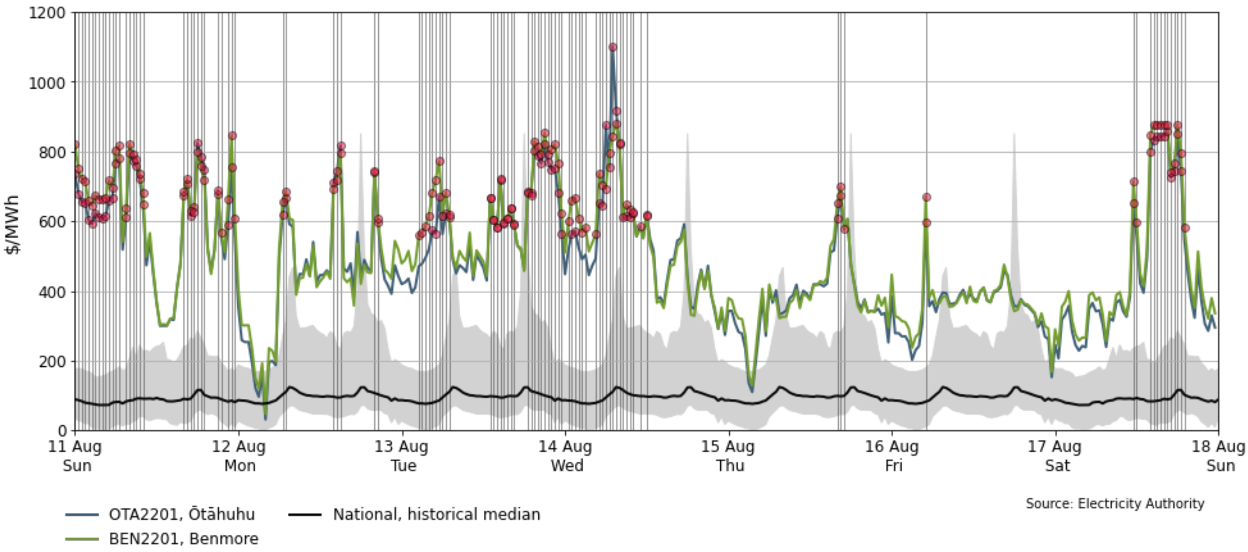
2.7. Prices spiked and separated between islands on Wednesday morning. At 7:00am, the Ōtāhuhu price reached a weekly maximum of $1,100/MWh, while the Benmore price at the same time was $882/MWh. Wind generation was relatively low at the time, and demand was high, requiring additional hydro generation to be dispatched.

2.8. Forecasting inaccuracies likely contributed to some high prices this week. Wind generation was more than 100MW below forecast at the times highlighted prices occurred on Monday, Friday and Saturday. Demand was more than 100MW higher than forecast when highlighted prices occurred on Monday, Wednesday and Saturday.

2.9. Additionally on Saturday, a decrease in available generation from 11am onwards, due to Manapōuri unit 3 tripping, likely contributed to higher prices as more expensive generation was then needed to be dispatched.

2.10. Due to continued instances of high prices this week, the monitoring team have added all trading periods for further analysis and additional information may be requested from generators.

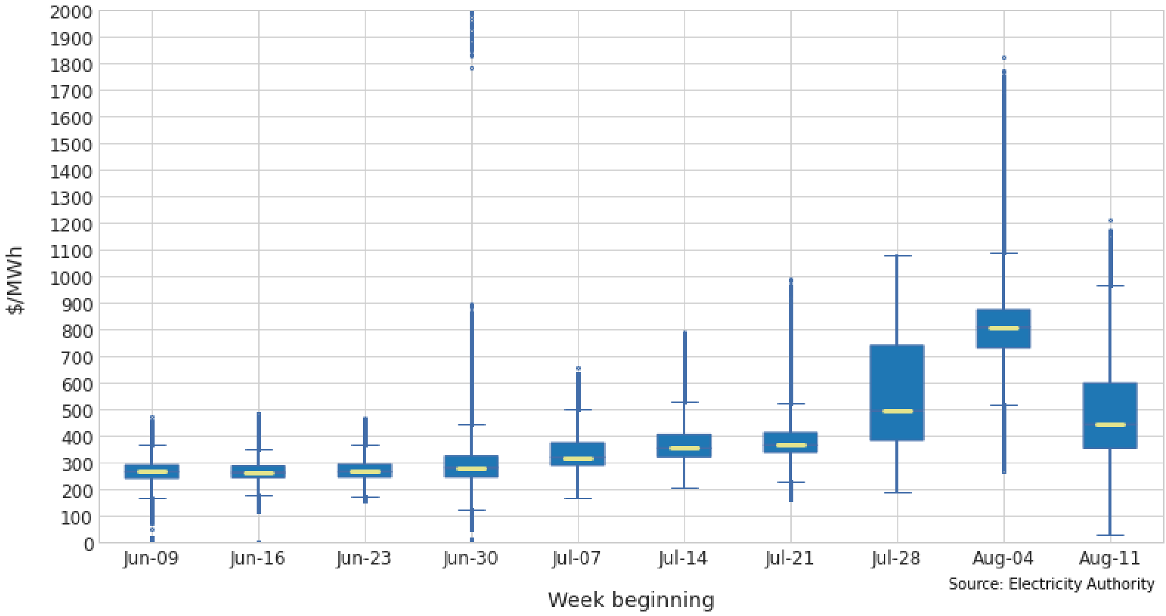
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 11-17 August



2.11. 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.

2.12. Compared to the previous week, the median price decreased by $364/MWh. The lower and upper quartiles also decreased, with the middle 50% of this week's prices entirely below the middle 50% of last week's prices. The interquartile range increased, but the number of outliers decreased.

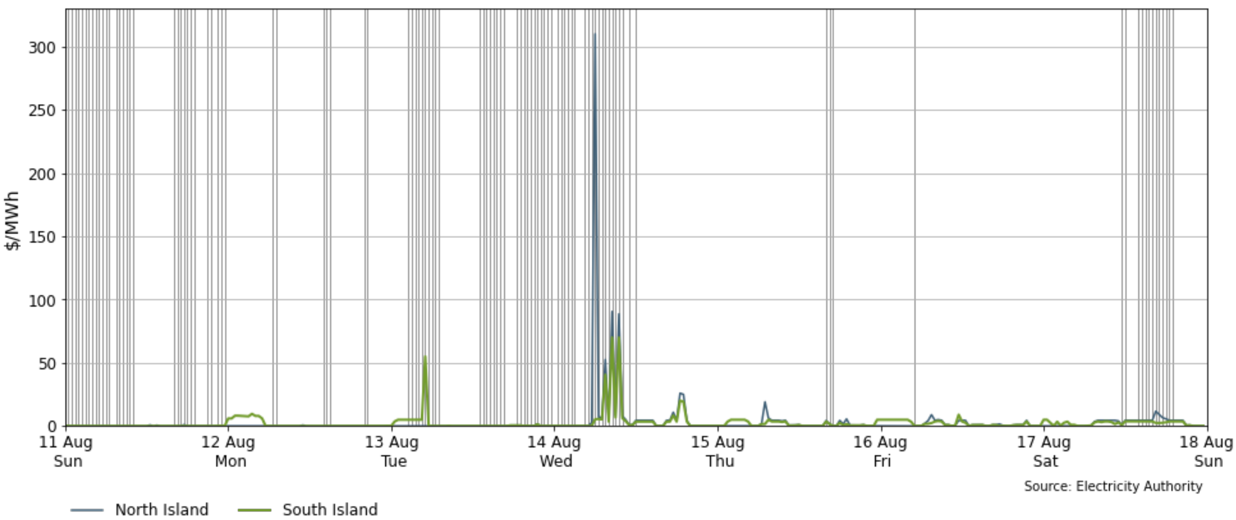
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



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 spiked on Wednesday morning, reaching $310/MWh at 6:00am in the North Island while remaining at $5/MWh in the South Island. During this time the HVDC was ramping down and changing direction, and during the final 5-minute period the HVDC was unable to provide reserves in the North Island[1], and hence more expensive North Island reserves were dispatched.

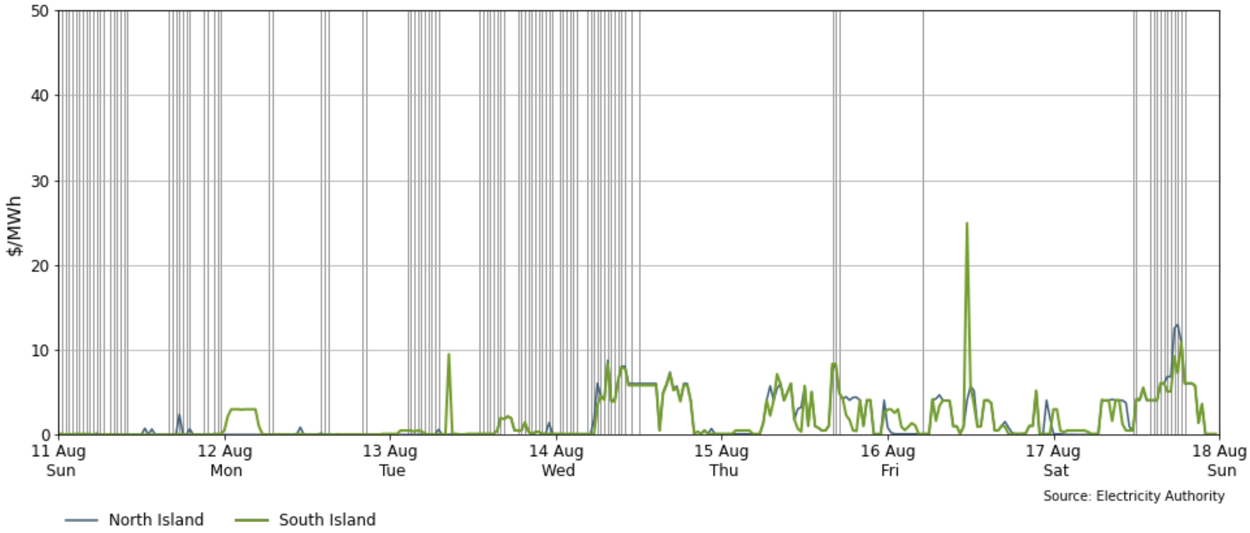
Figure 3: Fast instantaneous reserve price by trading period and island, 11-17 August



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly below $10/MWh this week, reaching a maximum of $25/MWh in the South Island at 11:30am on Friday.

[1] Price separation between islands when HVDC transfer is very low (ea.govt.nz)

Figure 4: Sustained instantaneous reserve by trading period and island, 11-17 August



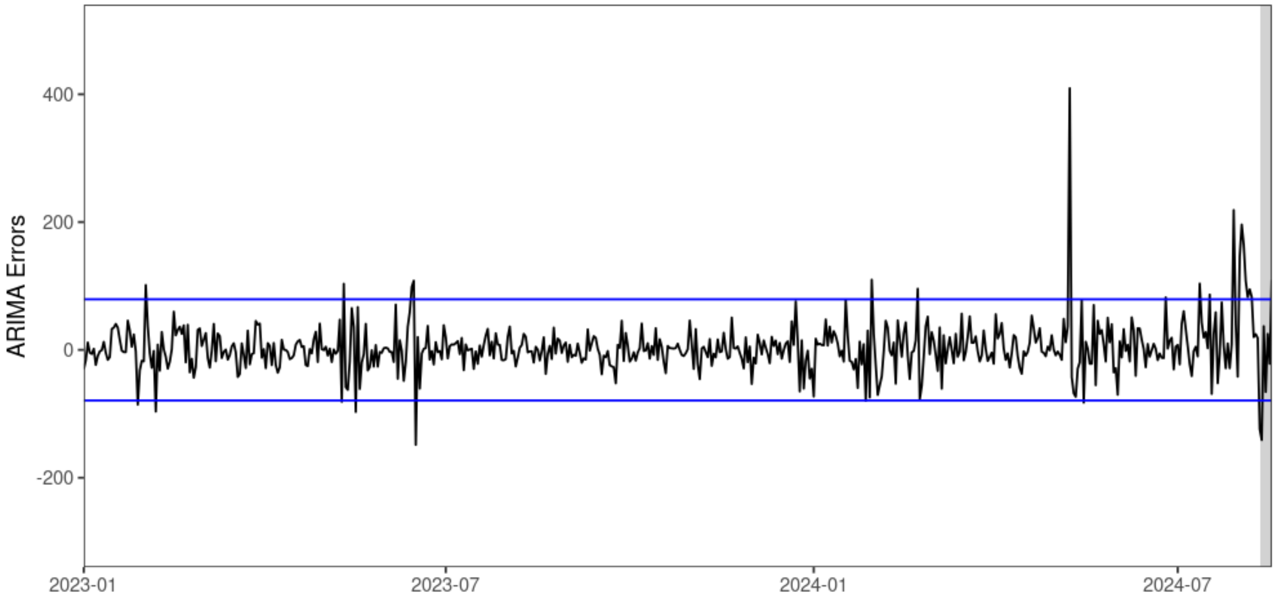
4. Regression residuals

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, the residual on Saturday was above two standard deviations of the data, indicating that prices on this day were higher than the model expected. This is likely due to demand and wind forecasting inaccuracies, as shown by our marginal price difference analysis.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 17 August 2024

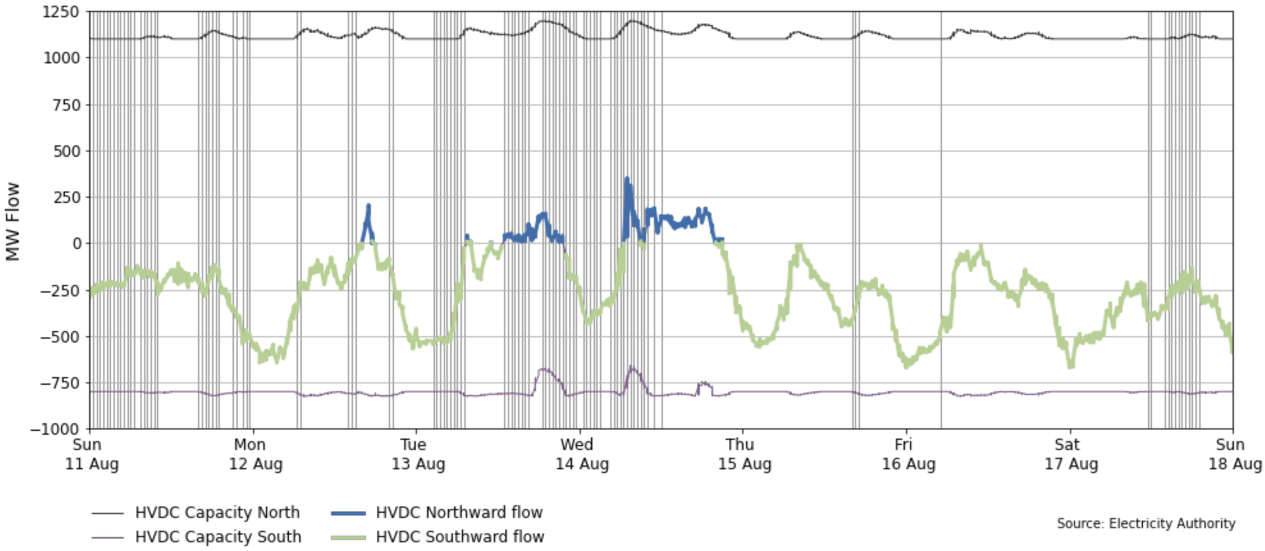


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 11-17 August. Due to low hydro generation in the South Island, HVDC flow was mostly southward this week. The flow was northward during the Wednesday morning price spike.

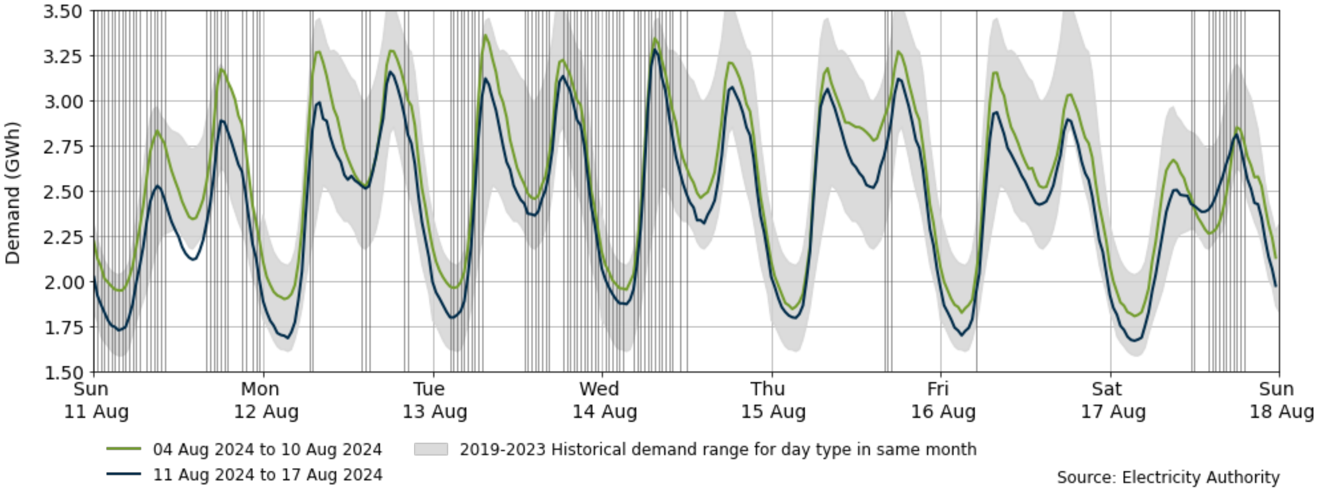
Figure 6: HVDC flow and capacity, 11-17 August



6. Demand

6.1. Figure 7 shows national demand between 11-17 August, compared to the historic range and the demand of the previous week. Demand was within or below the historical range for this time of year and was generally lower than the previous week. The maximum demand this week was 3.28GWh at 7:30am on Wednesday, when temperatures were low.

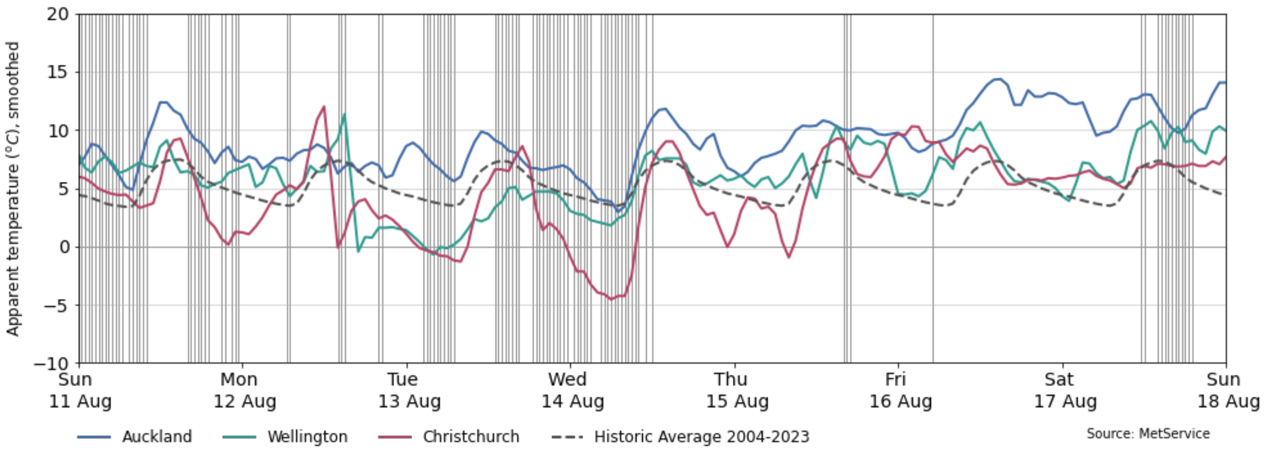
Figure 7: National demand, 11-17 August compared to historic range and previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 11-17 August 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 historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Temperatures ranged from 2°C to 15°C in Auckland, -2°C to 13°C in Wellington, and -5°C to 12°C in Christchurch. Temperatures were lowest between Monday and Wednesday, but increased and were mostly above average from Friday onwards. Temperatures were especially low on Wednesday morning when spot prices spiked.

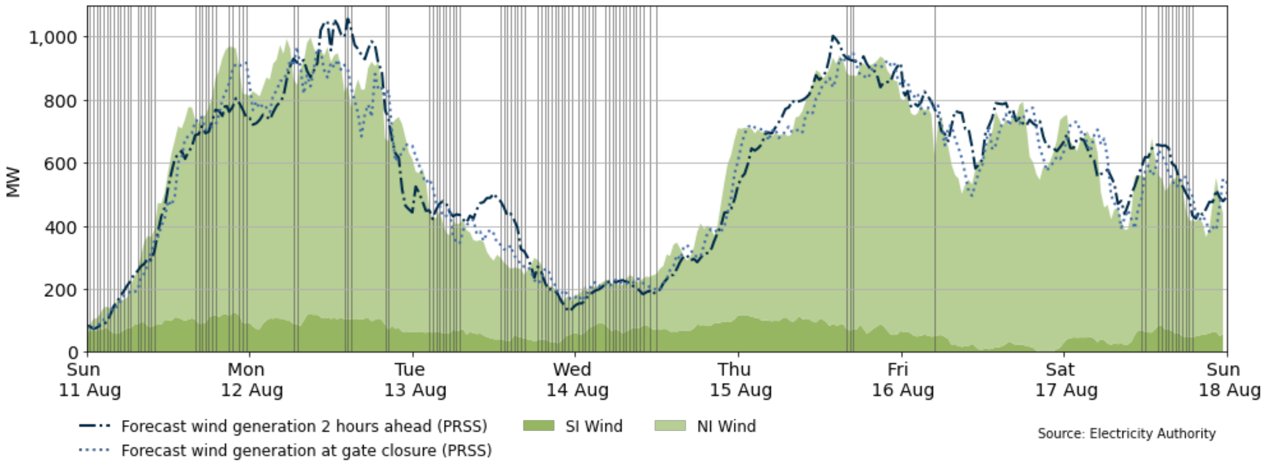
Figure 8: Temperatures across main centres, 11-17 August



7. Generation

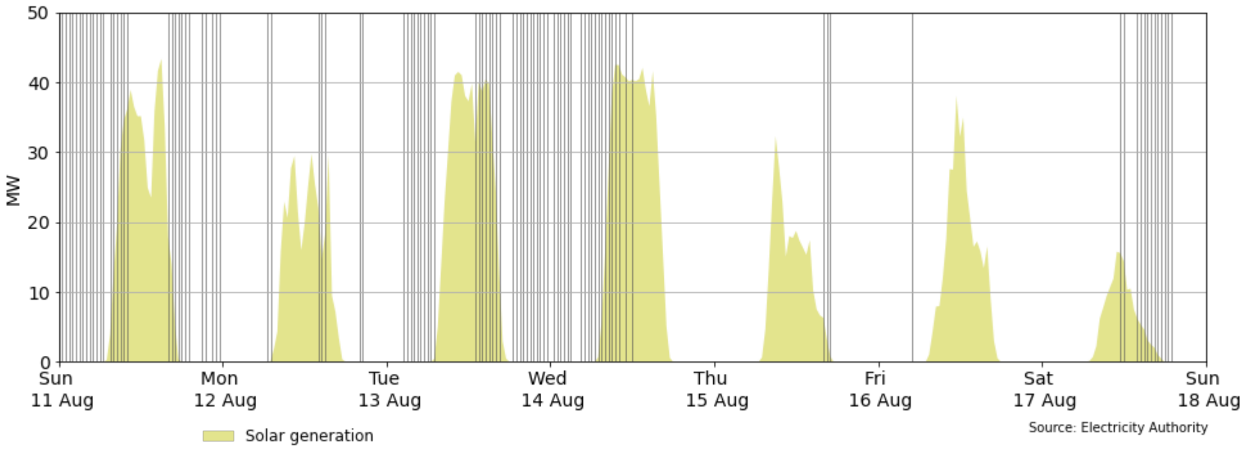
7.1. Figure 9 shows wind generation and forecast from 11-17 August. This week wind generation varied between 75MW and 998MW, with an average of 601MW. High wind generation likely contributed to the decrease in prices this week. Many of the week's highest prices occurred on Tuesday evening and Wednesday morning, when wind generation was at its lowest for the week.

Figure 9: Wind generation and forecast, 11-17 August



7.2. Figure 10 shows solar generation from 11-17 August. Maximum daily solar generation was over 30MW each day except Monday and Saturday this week. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource during winter.

Figure 10: Solar generation, 11-17 August



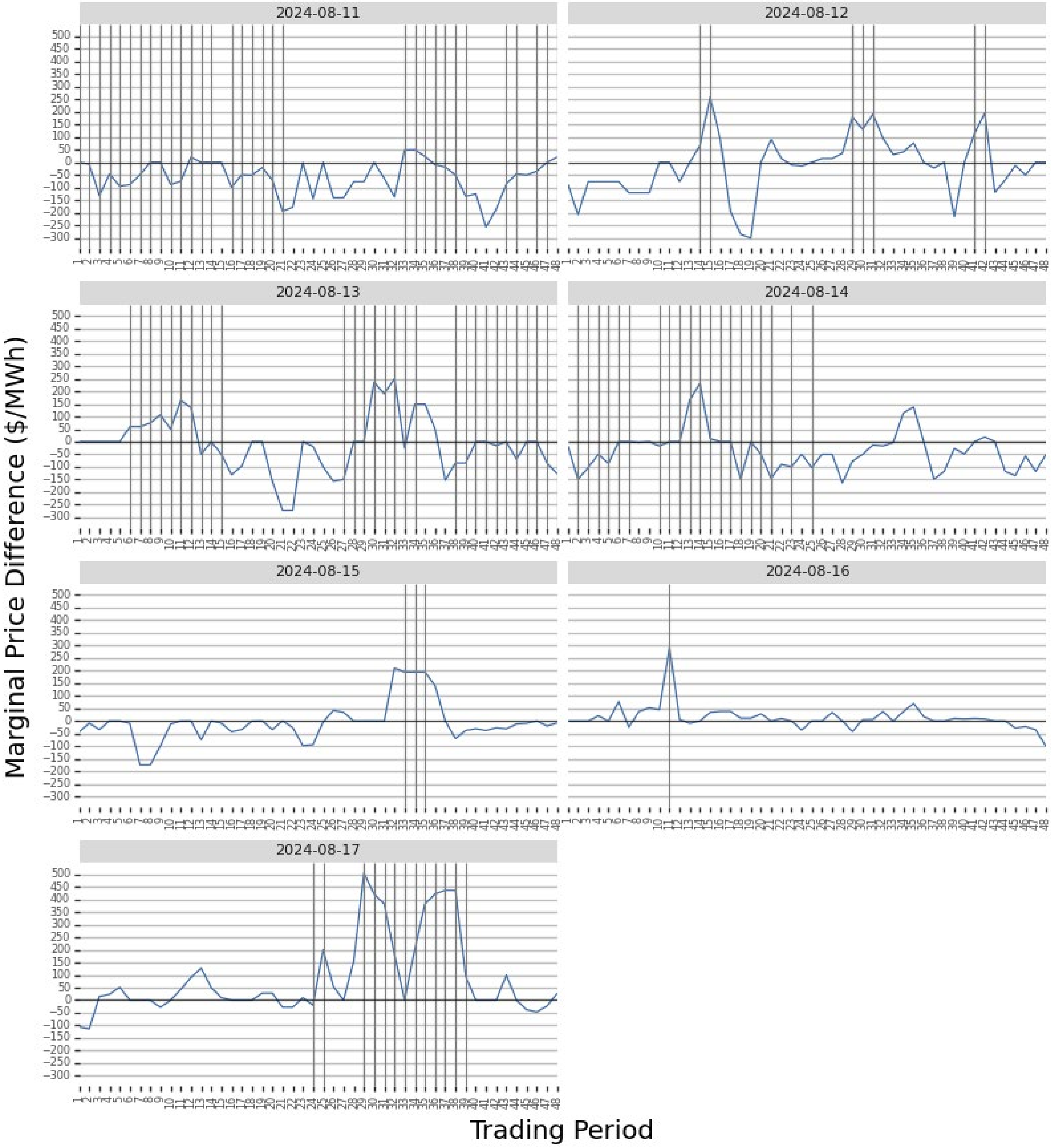
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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) differences this week occurred on Saturday afternoon, when demand was up to 190MW higher than forecast. Positive differences exceeding $250/MWh also occurred on Monday and Friday, when wind

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

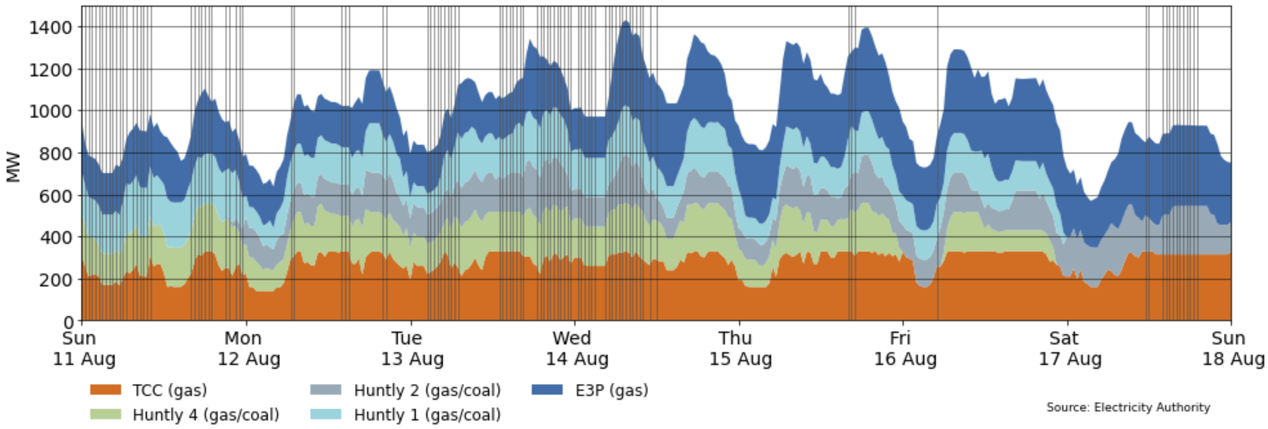
was more than 100MW below forecast. However, most often, prices were similar to or lower than those simulated.

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, 11-17 August



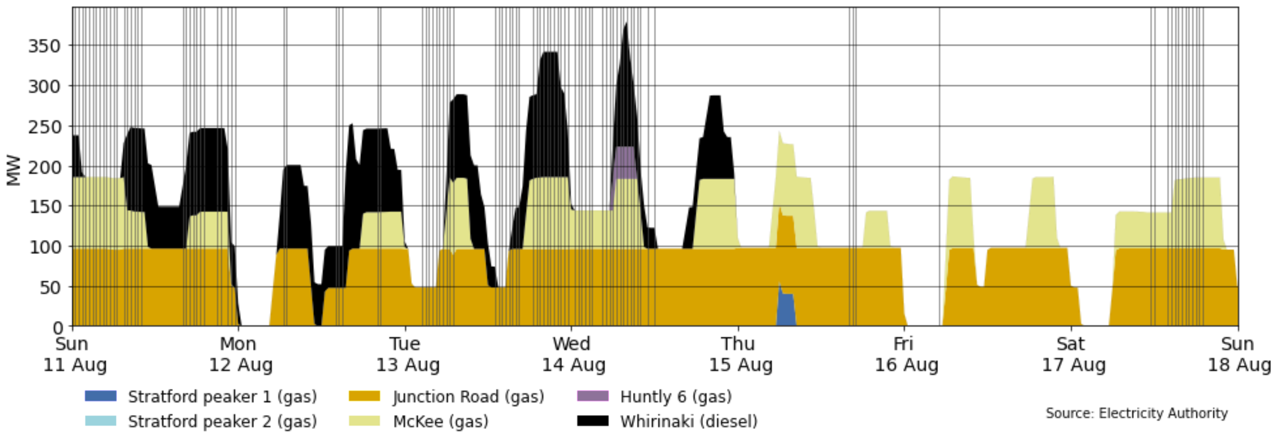
7.5. Figure 12 shows the generation of thermal baseload between 11-17 August. TCC, Huntly 4, Huntly 2, Huntly 1 and Huntly 5 (E3P) ran continuously to provide baseload generation this week. Huntly 2 began running on Sunday evening after returning from outage, and Huntly 1 and 4 turned off on Friday evening. All other units ran the entire week. Huntly 5 was often generating at close to its maximum capacity from Wednesday onwards, likely as a result of increased gas availability.

Figure 12: Thermal baseload generation, 11-17 August



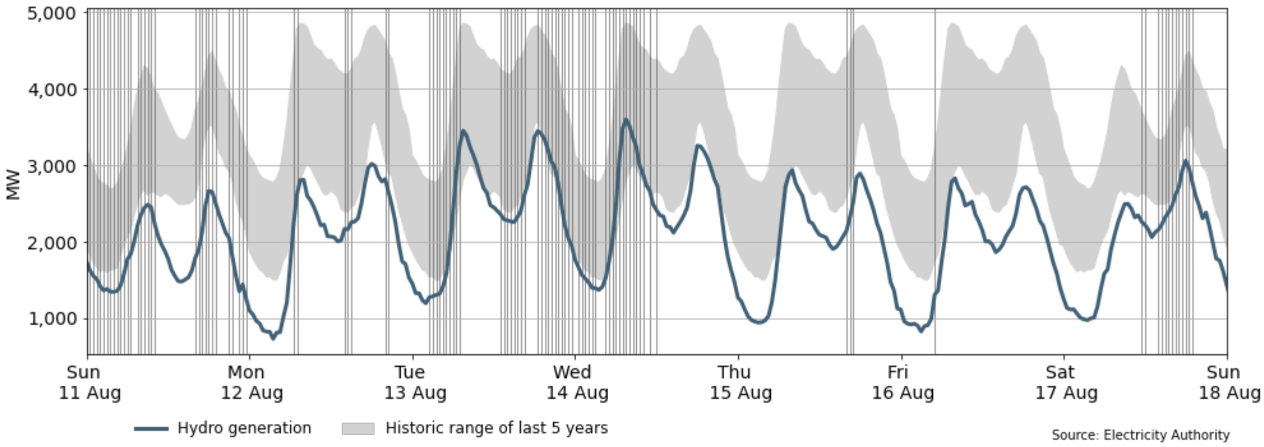
7.6. Figure 13 shows the generation of thermal peaker plants between 11-17 August. Junction Road ran every day, with McKee also running each day during peak and/or shoulder periods. Whirinaki ran during peak and shoulder periods between Sunday and Wednesday. Stratford 1 also ran briefly on Thursday morning, and Huntly 6 ran on Wednesday morning.

Figure 13: Thermal peaker generation, 11-17 August



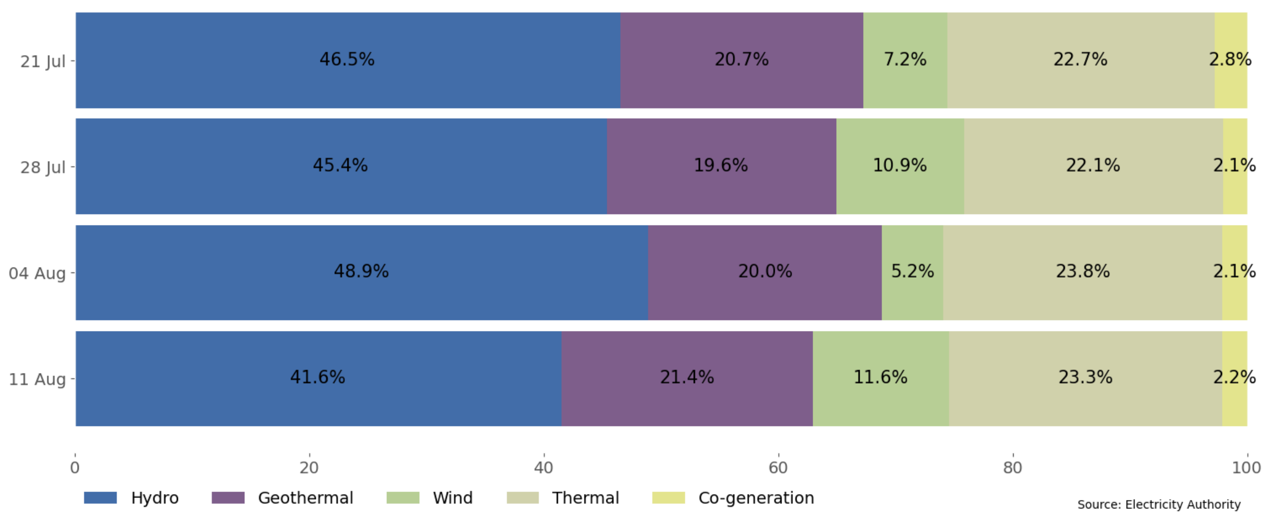
7.7. Figure 14 shows hydro generation between 11-17 August. Hydro generation was very low this week, mostly below the historical range of the last five years. This is due to low hydro storage, with a significant portion of hydro generation capacity priced highly to reduce likelihood that it will be dispatched and to conserve water. However, at times some of this capacity was needed. Hydro generation was highest on Wednesday morning this week due to high demand and lower wind generation, which may have contributed to the high prices at this time.

Figure 14: Hydro generation, 11-17 August



7.8. As a percentage of total generation, between 11-17 August, total weekly hydro generation was 41.6%, geothermal 21.4%, wind 11.6%, thermal 23.3%, and co-generation 2.2%, as shown in Figure 15. Wind generation increased this week, allowing hydro generation to back off further.

Figure 15: Total generation by type as a percentage each week, 21 July-17 August 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 11-17 August ranged between ~720MW and ~1,300MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 2 was on outage until 11 August.

(b) Huntly 4 is on outage from 16-19 August.

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

(d) McKee had one unit on outage on 11 August.

(e) Whirinaki Unit 2 was on outage on 13 August.

(f) Whirinaki Units 1 and 3 were on outage on 16 August.

(g) Harapaki wind farm was on outage on 14 August.

(h) West Wind wind farm was on outage on 16 August.

Figure 16: Total MW loss from generation outages, 11-17 August

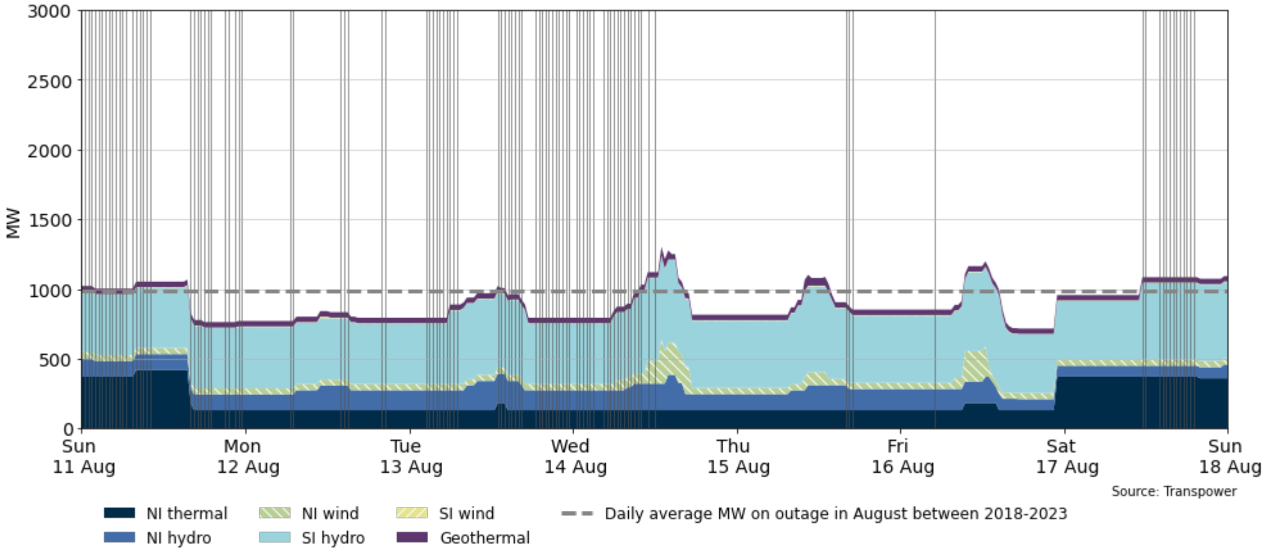
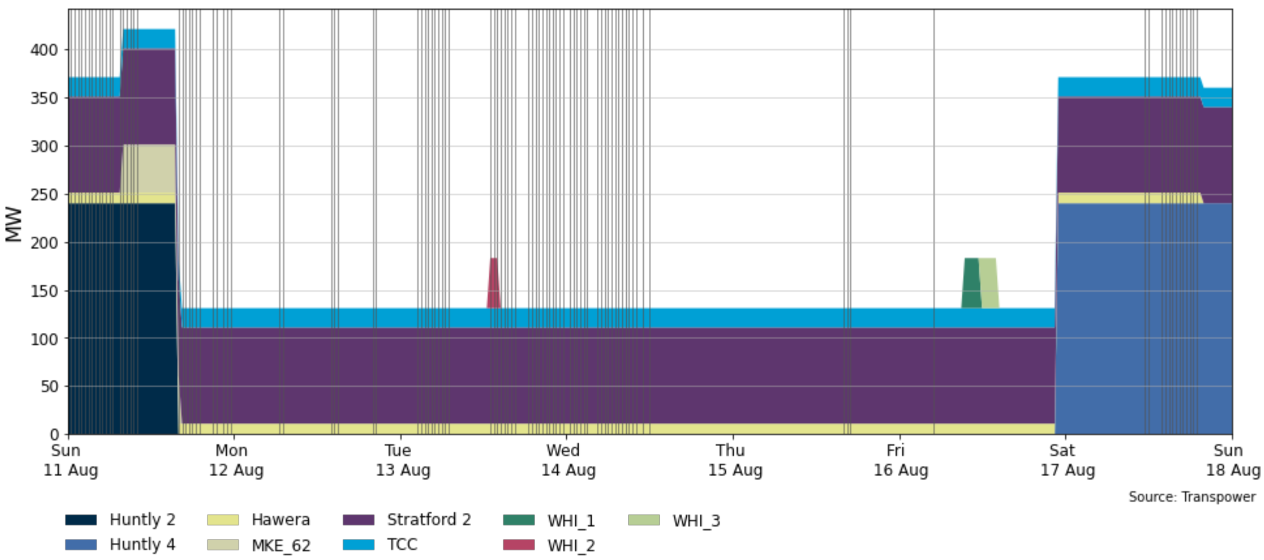


Figure 17: Total MW loss from thermal outages, 11-17 August

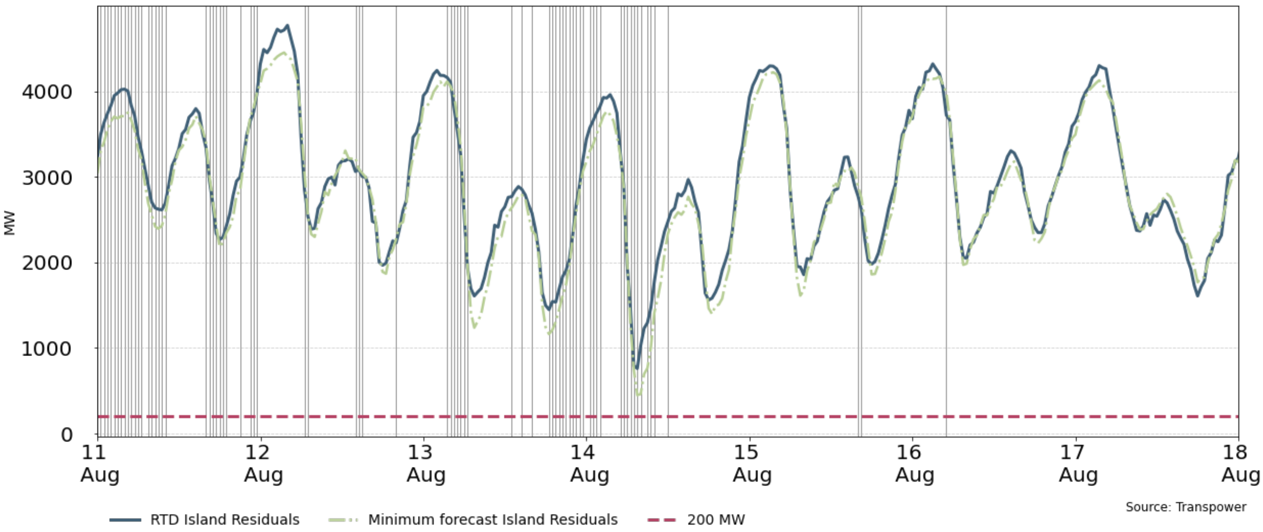


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 11-17 August. 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 257MW at 7:30pm on Wednesday.

Figure 18: National generation balance residuals, 11-17 August



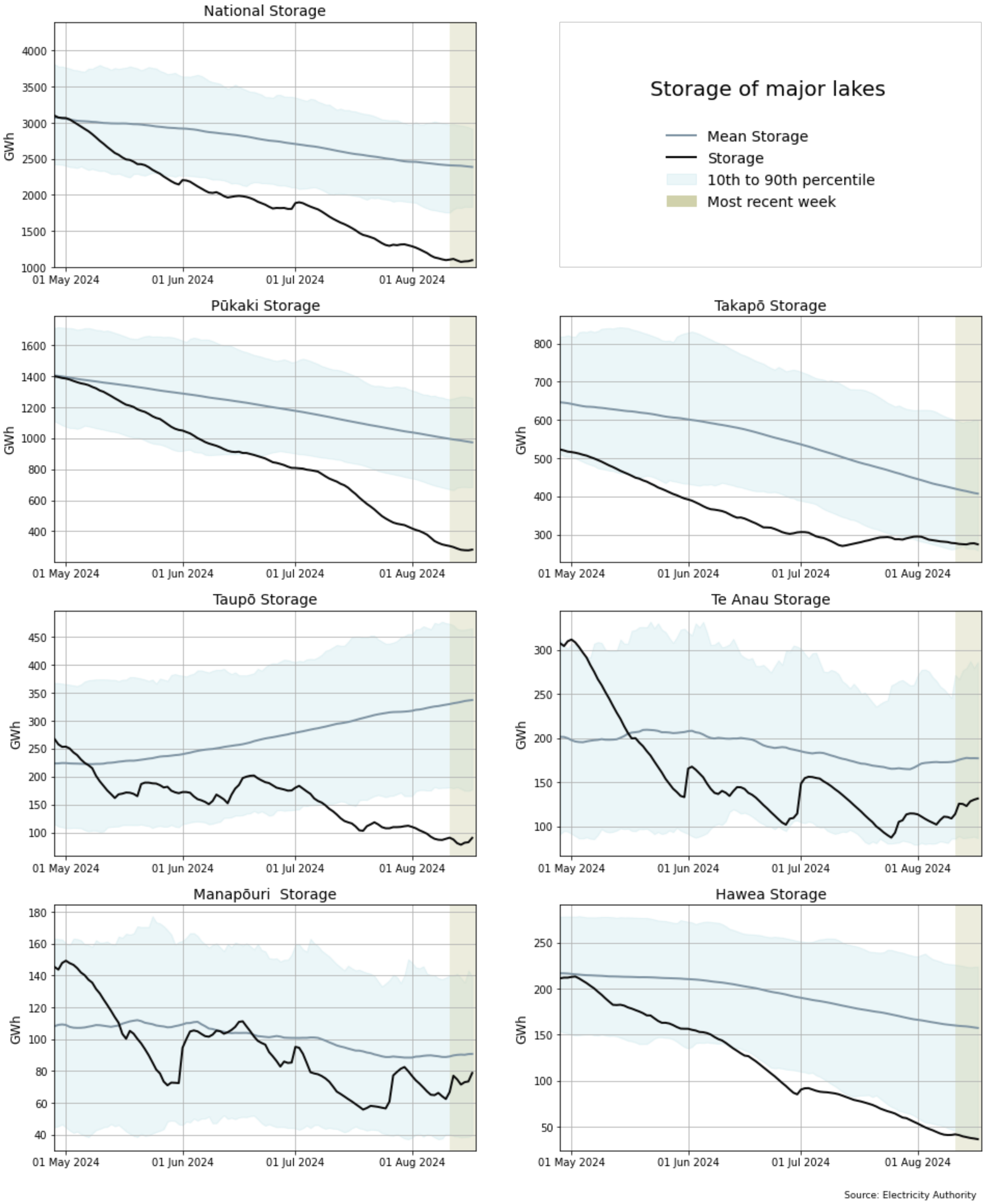
10. Storage/fuel supply

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 slightly this week and is ~33% nominally full and ~54% of the historical average for this time of the year as of 17 August.

10.3. Storage increased at Te Anau and Manapōuri this week, with both lakes still below mean but above their 10th percentiles. Storage at other lakes remained fairly stable or decreased, with Takapō and Hawea below mean and Pūkaki and Taupō below their 10th percentiles.

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 August 2024. The SRMC for gas has increased from the previous month, while the coal SRMC has remained stable and the diesel SRMC has decreased.

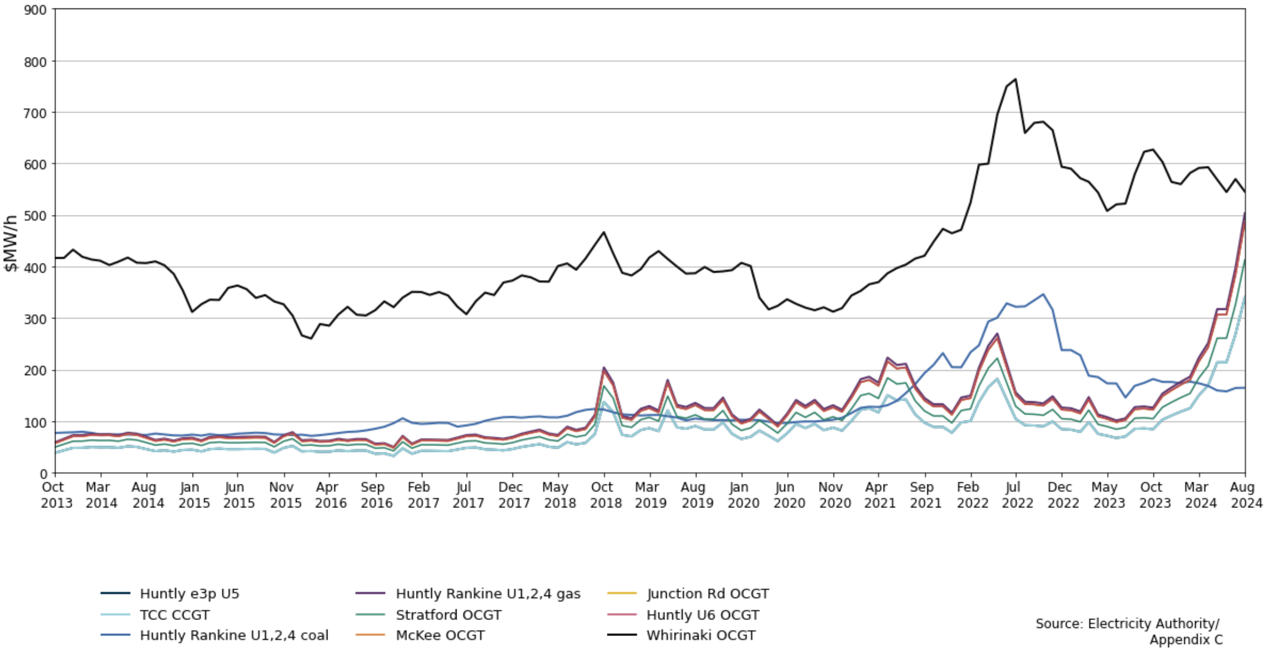
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$165/MWh. The cost of running the Rankines on gas remains more expensive at ~$503/MWh.

11.5. The SRMC of gas fuelled thermal plants continues to increase and is currently between ~$340/MWh and ~$503/MWh.

11.6. The SRMC of Whirinaki is ~$545/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

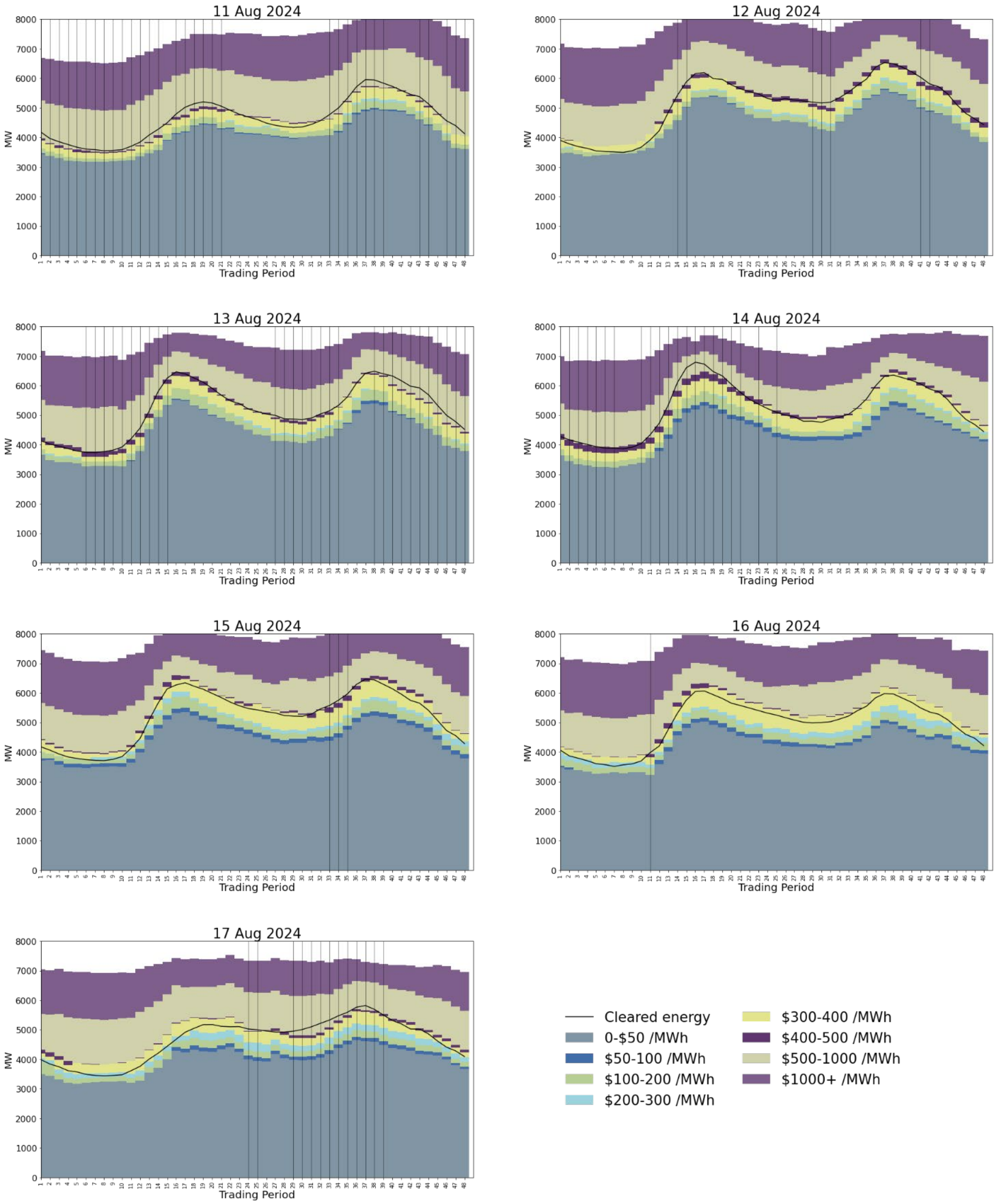


12. Offer behaviour

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 $300-$400/MWh and $1,000-$/MWh region this week. The number of offers in the $50-$100/MWh and $200-300/MWh bands has increased since last week, mostly due to more thermal generation being offered at a lower price due to increased gas availability.

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, but as prices remain high, we will be closely analysing offer behaviour to confirm this.

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
8/05/2024-10/05/2024	Several	Further analysis	Genesis	Multiple	Energy offers
1/07/2024-17/08/2024	Several	Further analysis	N/A	N/A	High energy prices