2 September 2024

Trading conduct report 25-31 August 2024

Market monitoring weekly report

Trading conduct report 25-31 August 2024

1. Overview

1.1. Prices decreased this week, compared to last week, likely due to high wind generation, lower demand, and hydro generation pricing decreasing due to increased storage. Thermal generation also decreased this week. National controlled hydro storage increased and is currently ~69% 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 25-31 August:

(a) the average wholesale spot price across all nodes was $130/MWh

(b) 95% of prices fell between $0.01/MWh and $391/MWh.

2.3. Overall, the majority of spot prices were within $0.01-$221/MWh, with the weekly average price decreasing by around $226/MWh compared to the previous week.

2.4. Prices were high, generally between $200-$400/MWh, from Sunday until Tuesday afternoon but dropped below $20/MWh overnight. Prices spiked during the morning and evening peak periods on Monday, respectively reaching $539/MWh and $608/MWh at Benmore. Demand was under forecast by over 100MW during the Monday evening peak, and wind generation was over forecast by as much as 232MW when some high prices occurred on Tuesday morning. These higher prices earlier in the week also occurred before the large storage increases seen at some lakes.

2.5. Prices were mostly below $200/MWh for the rest of the week and were often below the historical median, likely due to lower-priced hydro generation resulting from increased hydro storage. For most of Friday and Saturday, prices were below $1/MWh. However, there were occasional price spikes during this time:

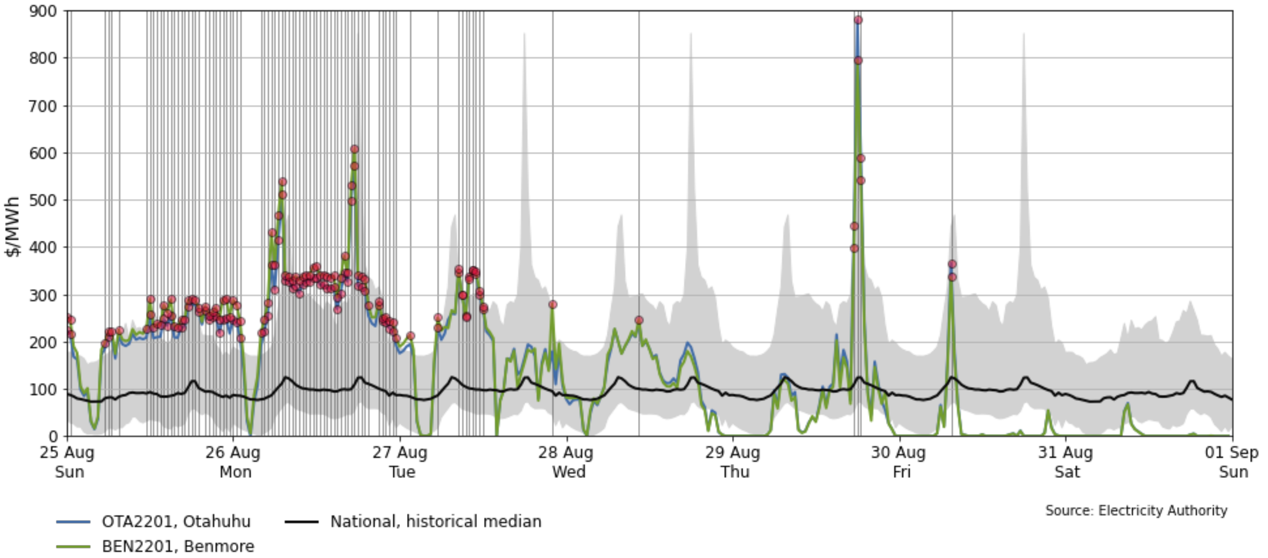
(a) At 10:00pm on Tuesday, the Benmore price reached $280/MWh while the Ōtāhuhu price remained at $179/MWh, possibly due to high wind generation in the North Island and low hydro generation in the South Island.

(b) Prices spiked in both islands on Thursday evening, with the Ōtāhuhu spot price reaching a weekly maximum of $880/MWh at 6:00pm. Wind was over forecast by more than 240MW at the time.

(c) Prices spiked again at 7:30am on Friday, exceeding $330/MWh at both Benmore and Ōtāhuhu. Wind generation was over forecast by 76MW and demand was under forecast by 42MW at time.

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 notable prices are marked with black dashed lines.

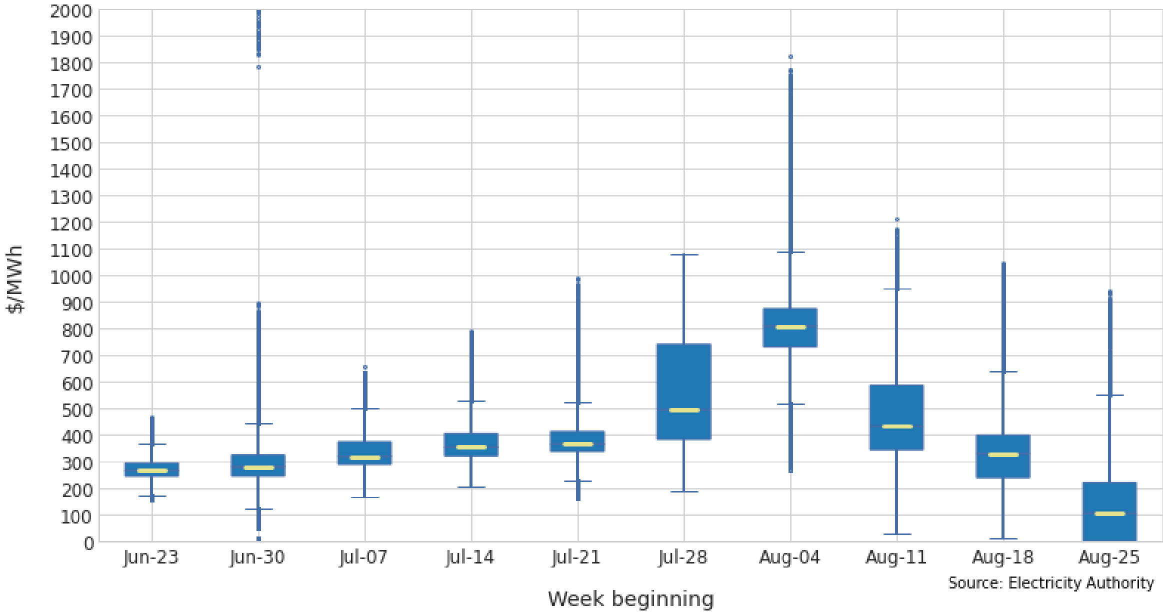
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 25-31 August



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 $225/MWh. The lower and upper quartiles also decreased, with the middle 50% of this week's prices entirely below the middle 50% of prices of any of the previous nine weeks.

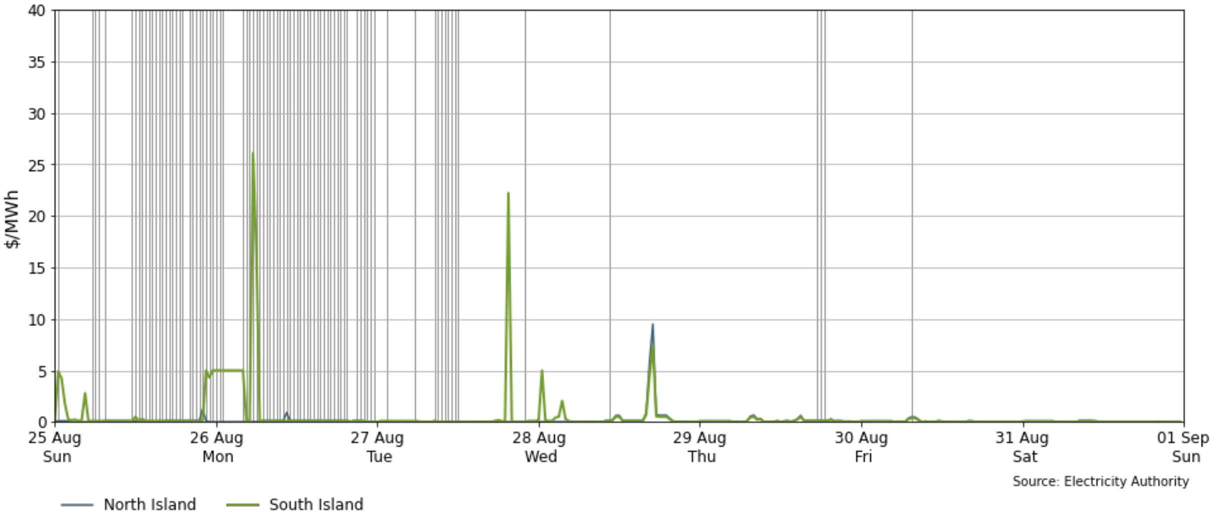
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

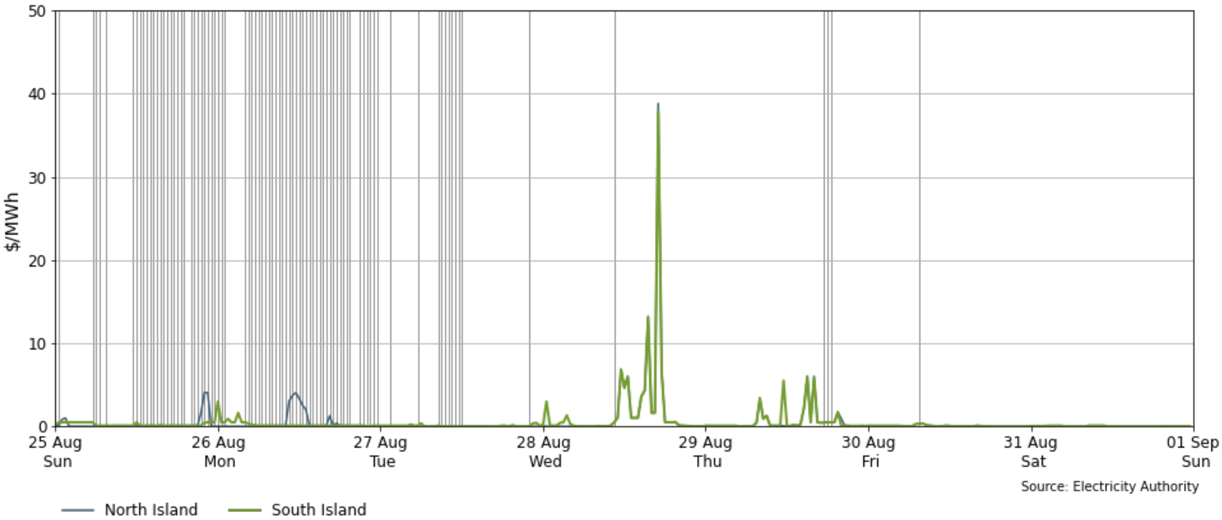
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week, but spiked above $20/MWh in the South Island at 5:30am on Monday and 7:30pm on Tuesday. High wind generation in the North Island, combined with low hydro generation in the South Island, saw high southward HVDC flow. The increased southward flow resulted in the HVDC becoming the binding risk and causing the separation in prices.

Figure 3: Fast instantaneous reserve price by trading period and island, 25-31 August



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 spiked above $37/MWh in both islands at 5:00pm on Wednesday. This occurred as the SIR required to cover the risk setter increased.

Figure 4: Sustained instantaneous reserve by trading period and island, 25-31 August



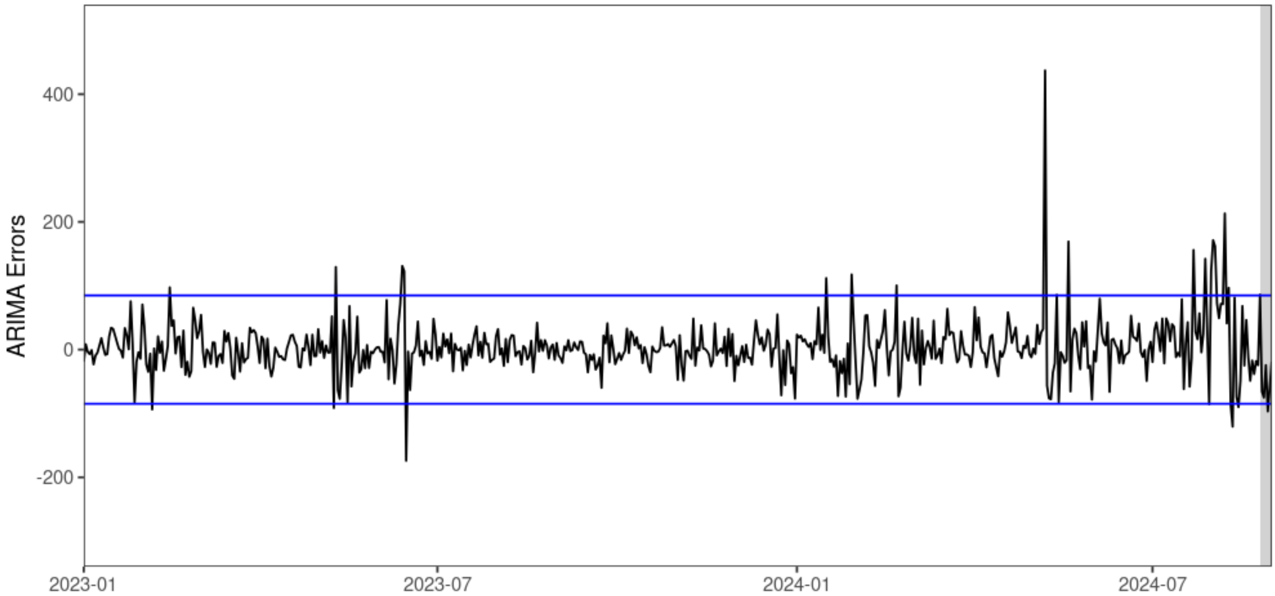
4. Regression residuals

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 Sunday was slightly above two standard deviations of the data, indicating that prices on this day were higher than the model expected.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 – 24 August 2024

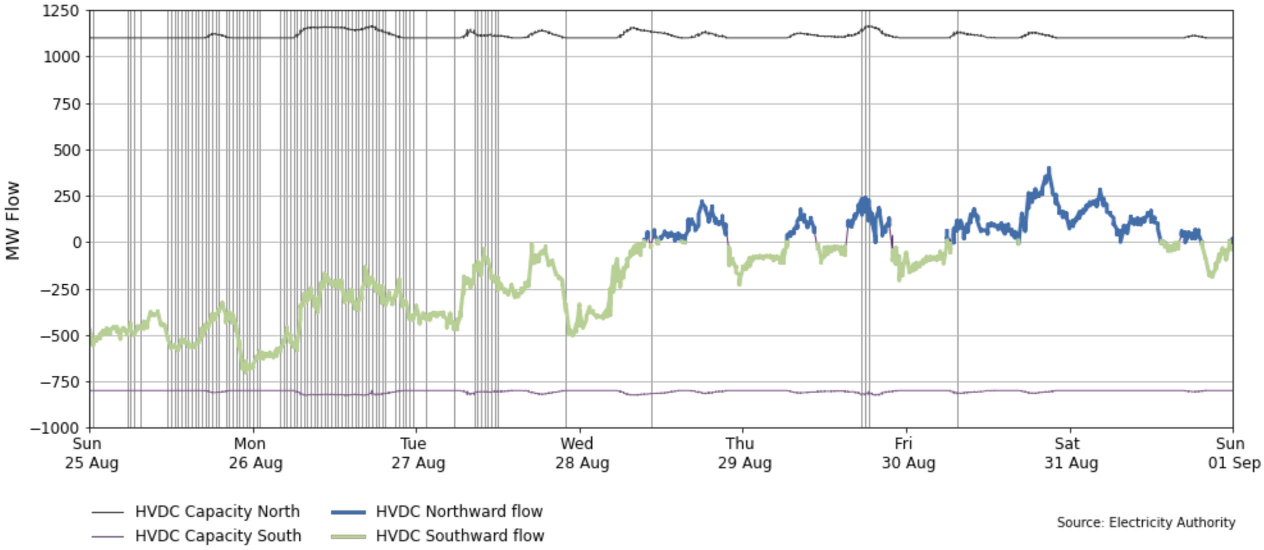


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 25-31 August. HVDC flow was entirely southward while prices were high at the start of the week. As hydro storage and generation increased, more Northward flow occurred.

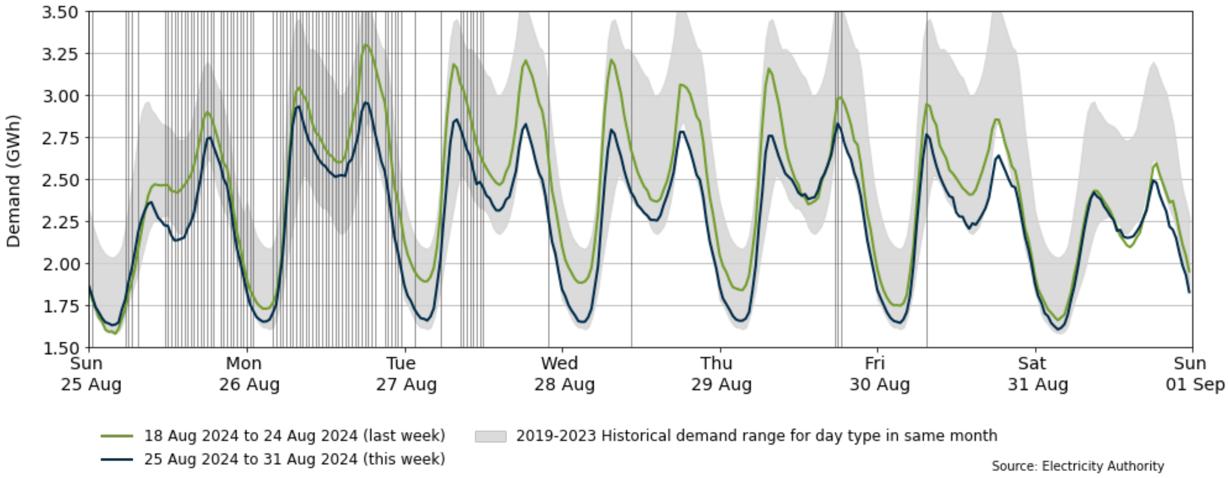
Figure 6: HVDC flow and capacity, 25-31 August



6. Demand

6.1. Figure 7 shows national demand between 25-31 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, likely due to above-average temperatures. The maximum demand this week was 2.96GWh at 6:00pm on Monday.

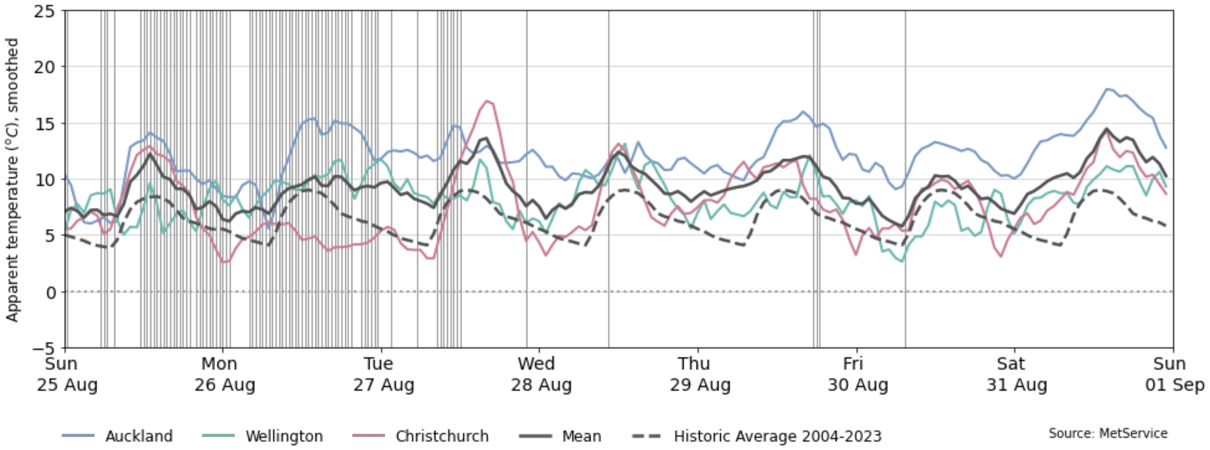
Figure 7: National demand, 25-31 August compared to historic range and previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 25-31 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 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 6°C to 18°C in Auckland, 2°C to 13°C in Wellington, and 2°C to 17°C in Christchurch. Temperatures were mostly above average this week.

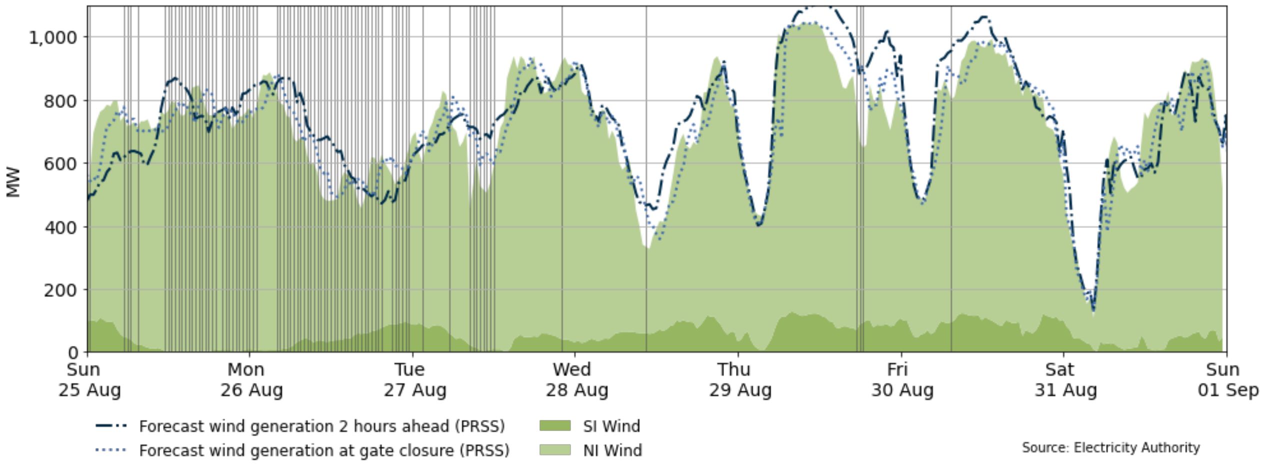
Figure 8: Temperatures across main centres, 25-31 August



7. Generation

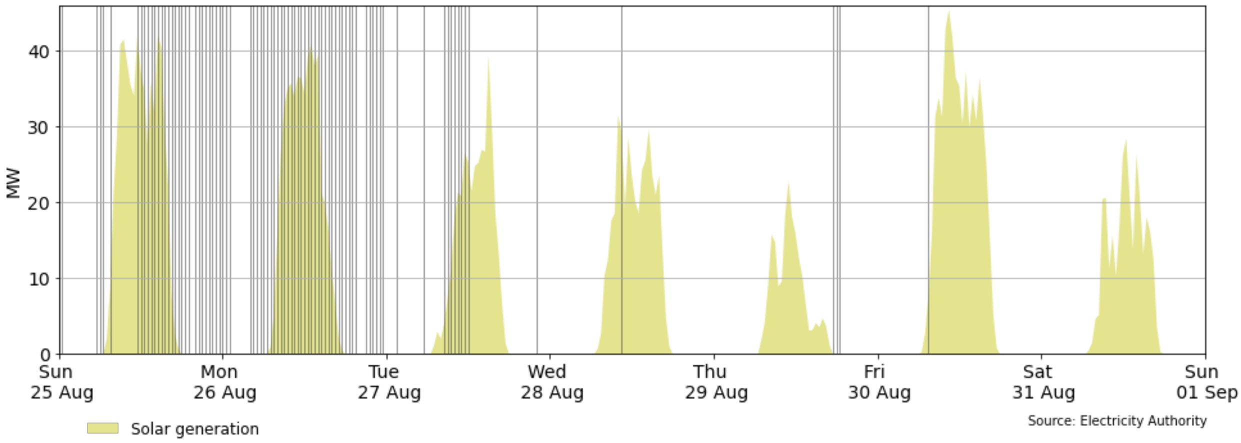
7.1. Figure 9 shows wind generation and forecast from 25-31 August. This week wind generation varied between 107MW and 1,049MW – the highest average wind generation in a single trading period on record. The daily average was 720MW. High wind generation likely contributed to the decrease in prices this week. The Thursday afternoon price spike had a difference of over 240MW between the wind forecast at gate closure and the real time generation. The monitoring team is looking further into some pre-dispatch wind offers this week.

Figure 9: Wind generation and forecast, 25-31 August



7.2. Figure 10 shows solar generation from 25-31 August. Maximum daily solar generation was over 40MW on Sunday, Monday and Friday. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource during winter.

Figure 10: Solar generation, 25-31 August

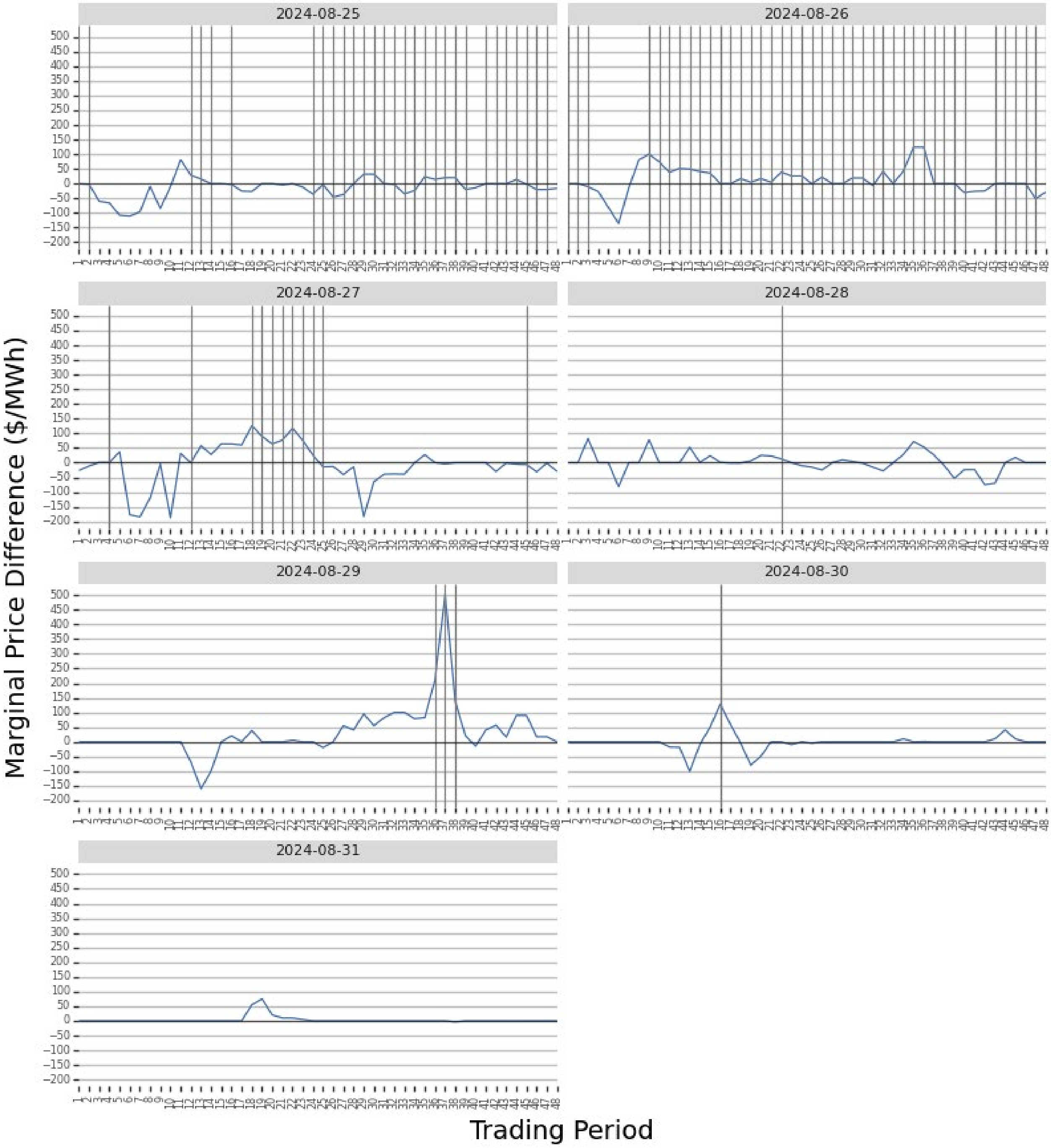


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 $503 at 6:00pm on Thursday, when demand was 92MW higher than forecast and wind generation was 243MW lower than forecast. Throughout the rest of the week, prices were generally lower than or similar to those simulated.

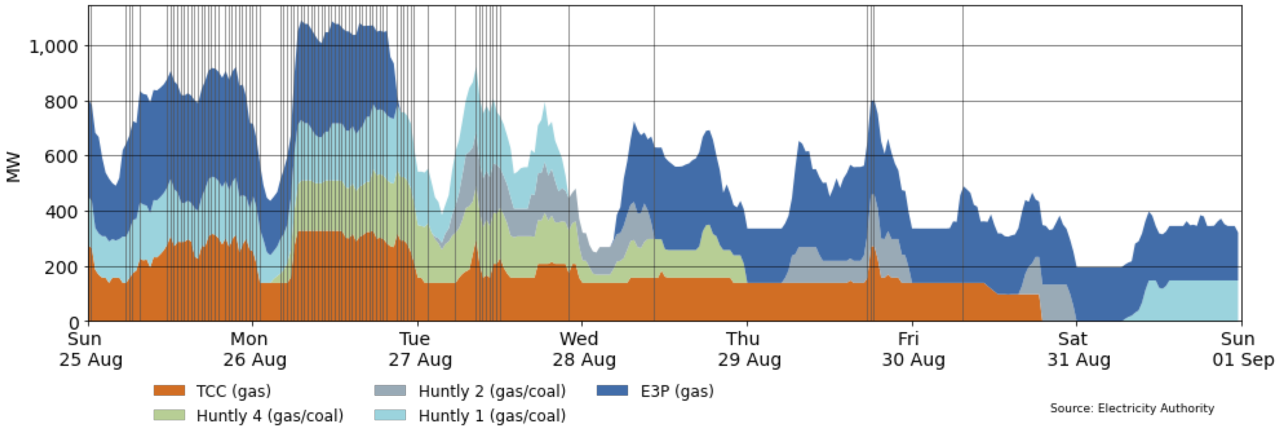
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 25-31 August



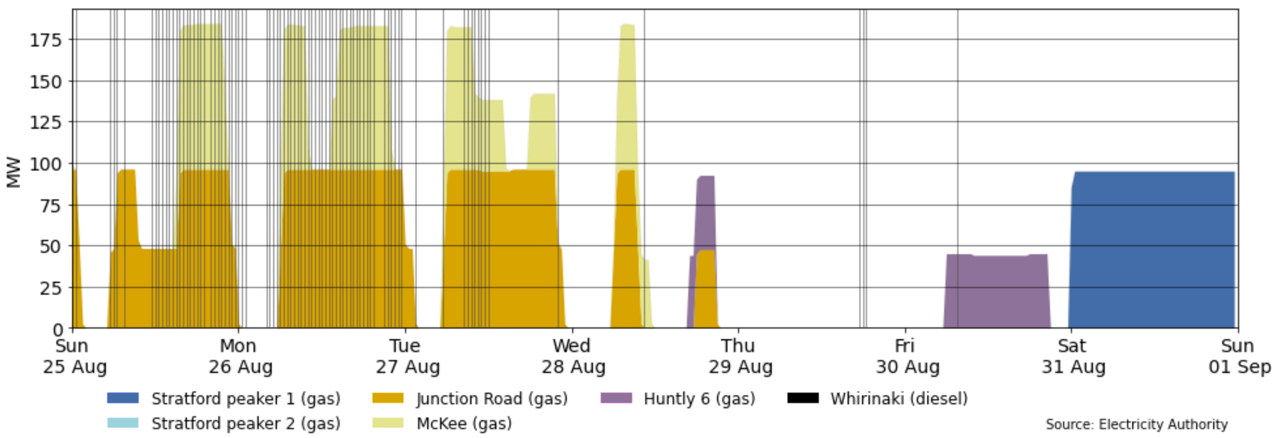
7.5. Figure 12 shows the generation of thermal baseload between 25-31 August. TCC ran continuously until Friday evening, and ramped up during the Thursday evening price spike. Huntly 1 ran from Sunday to Tuesday, and again on Saturday. Huntly 4 ran from Monday to Wednesday, after returning from outage. Huntly 2 ran on Tuesday, Wednesday, Thursday and Friday. E3P (Huntly 5) ran continuously for most of the week, but turned off on Monday night due to the Kupe gas field outage[2], then began running again on Wednesday morning.

Figure 12: Thermal baseload generation, 25-31 August



7.6. Figure 13 shows the generation of thermal peaker plants between 25-31 August. Junction Road ran during peak and shoulder periods, turning off around midnight, from Sunday to Tuesday, then during peak periods on Wednesday. McKee also ran during peak and shoulder periods from Sunday to Wednesday. Stratford 1 ran continuously on Saturday. Huntly 6 ran during the evening peak on Wednesday, and during peak and shoulder periods on Friday.

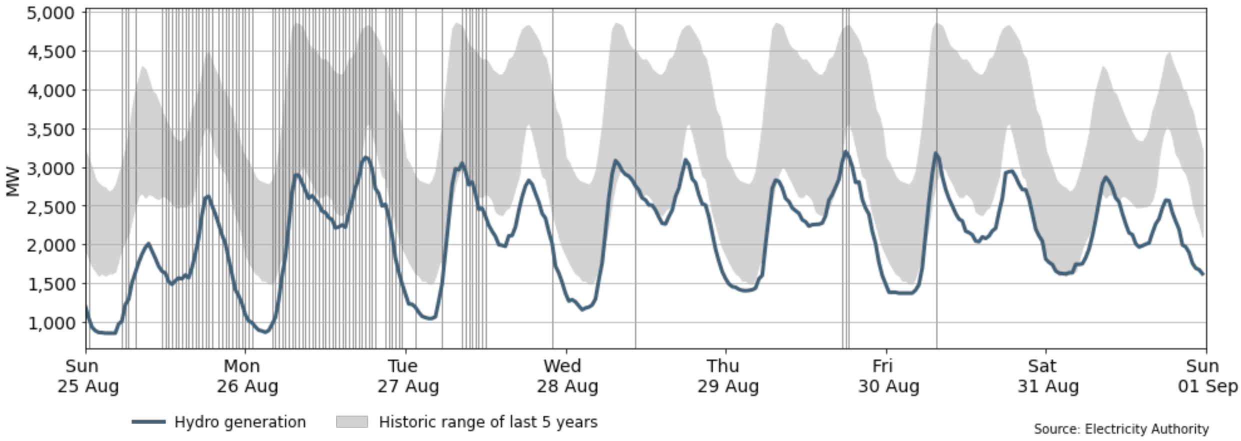
Figure 13: Thermal peaker generation, 25-31 August



7.7. Figure 14 shows hydro generation between 25-31 August. Hydro generation increased as storage did from Wednesday onwards, but remained low and was 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.

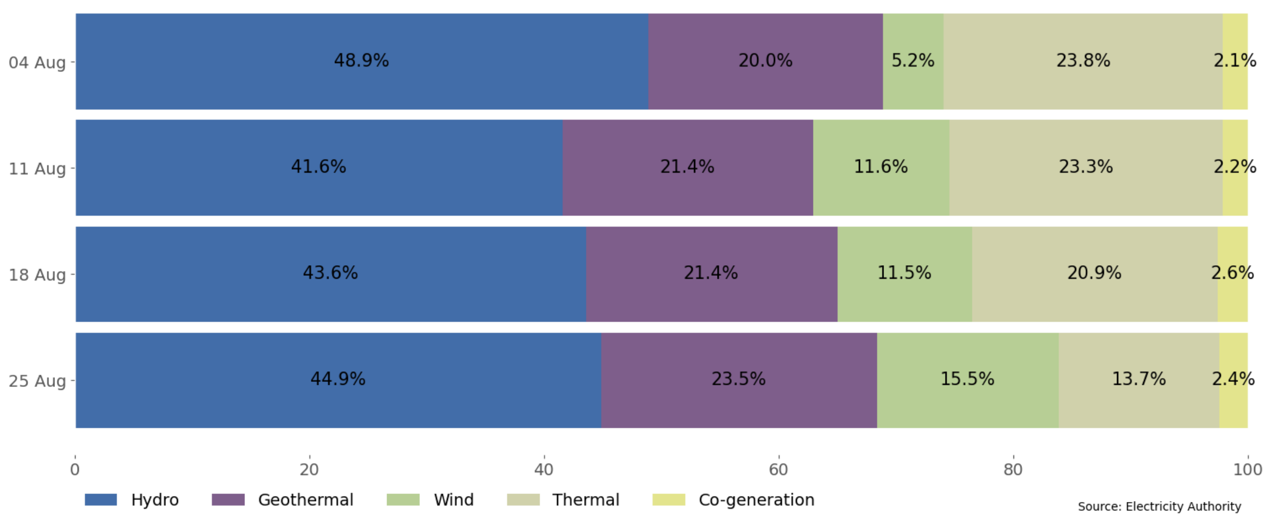
[2] https://outagedisclosure.gasindustry.co.nz/gasoutagplan-view/?id=a55dd43e-e963-ef11-a4e6-000d3ae05a8b&stepid=77ce9693-35ad-ed11-83fe-00224818a23d&sessionid=2250e0d0-db68-ef11-a670-000d3ad291d1

Figure 14: Hydro generation, 25-31 August



7.8. As a percentage of total generation, between 25-31 August, total weekly hydro generation was 44.9%, geothermal 23.5%, wind 15.5%, thermal 13.7%, and co-generation 2.4%, as shown in Figure 15. Lower demand, combined with the proportions of wind and geothermal generation increasing this week, allowed thermal generation to decrease significantly. Although the proportion of hydro generation increased this week, the amount of hydro generation dispatched this week actually decreased as total demand was lower than the previous week.

Figure 15: Total generation by type as a percentage each week, 4-31 August 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 25-31 August ranged between ~700MW and ~1,650MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 4 is on outage from 30 August to 6 September.

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

(c) Junction Road had on unit on outage on 30 August.

(d) McKee has one unit on outage from 29 August to 6 September.

Figure 16: Total MW loss from generation outages, 25-31 August

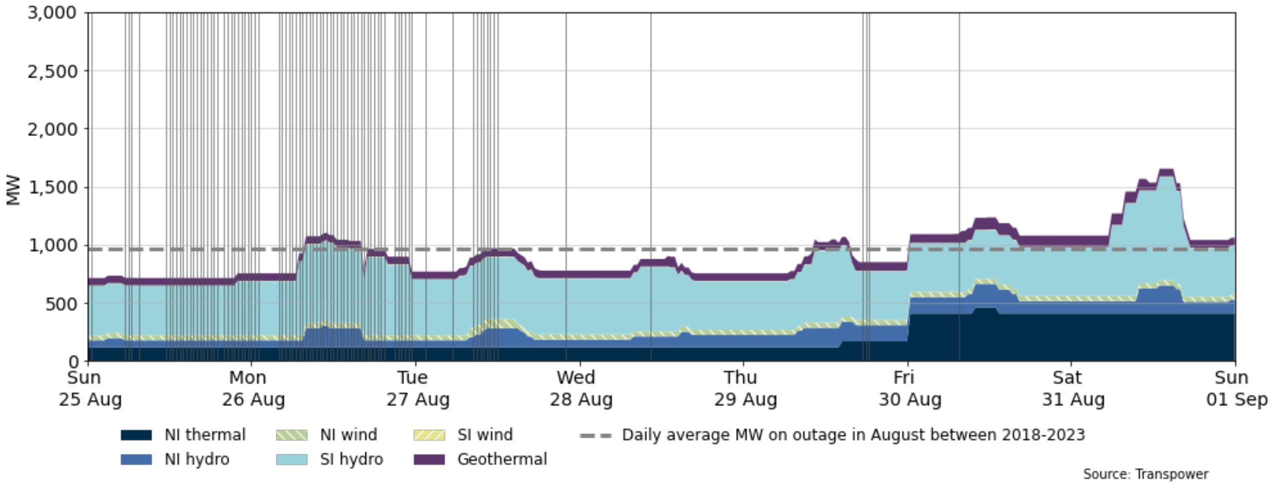
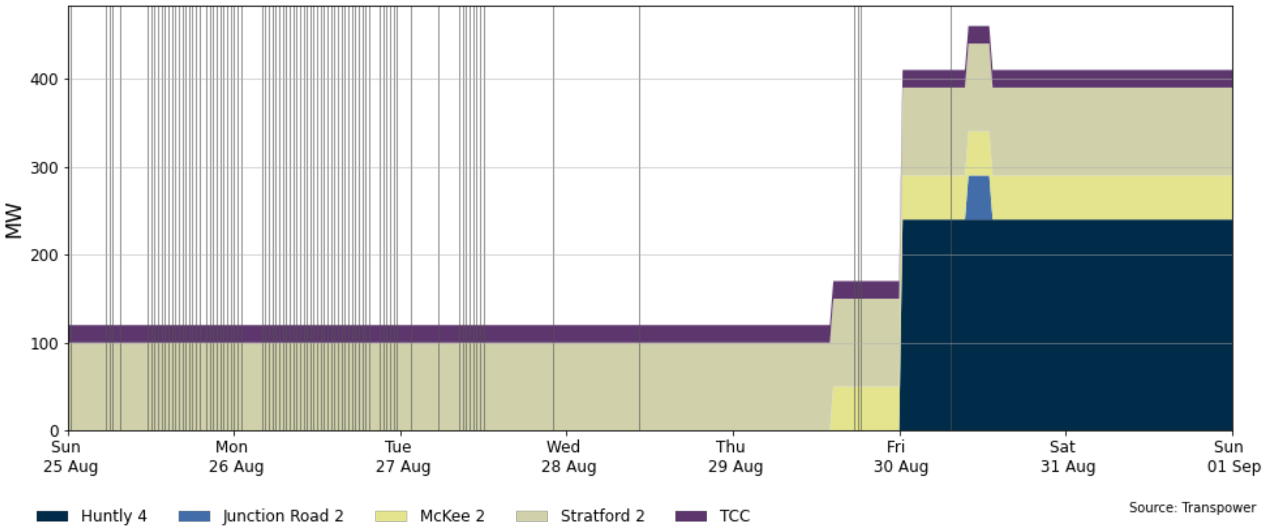


Figure 17: Total MW loss from thermal outages, 25-31 August

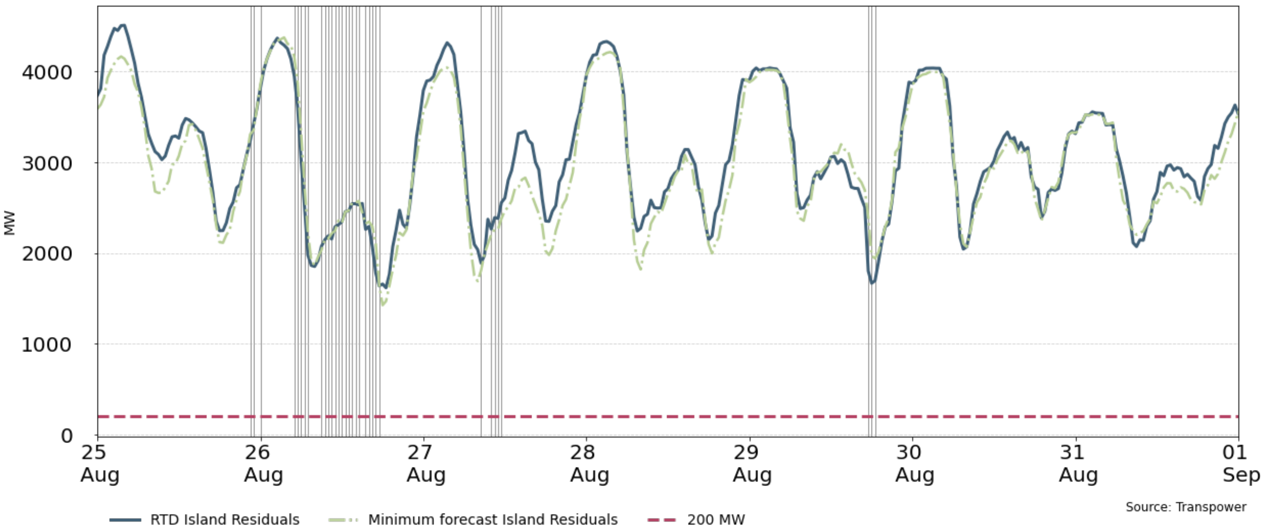


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 25-31 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 662MW at 6:30pm on Monday.

Figure 18: National generation balance residuals, 25-31 August



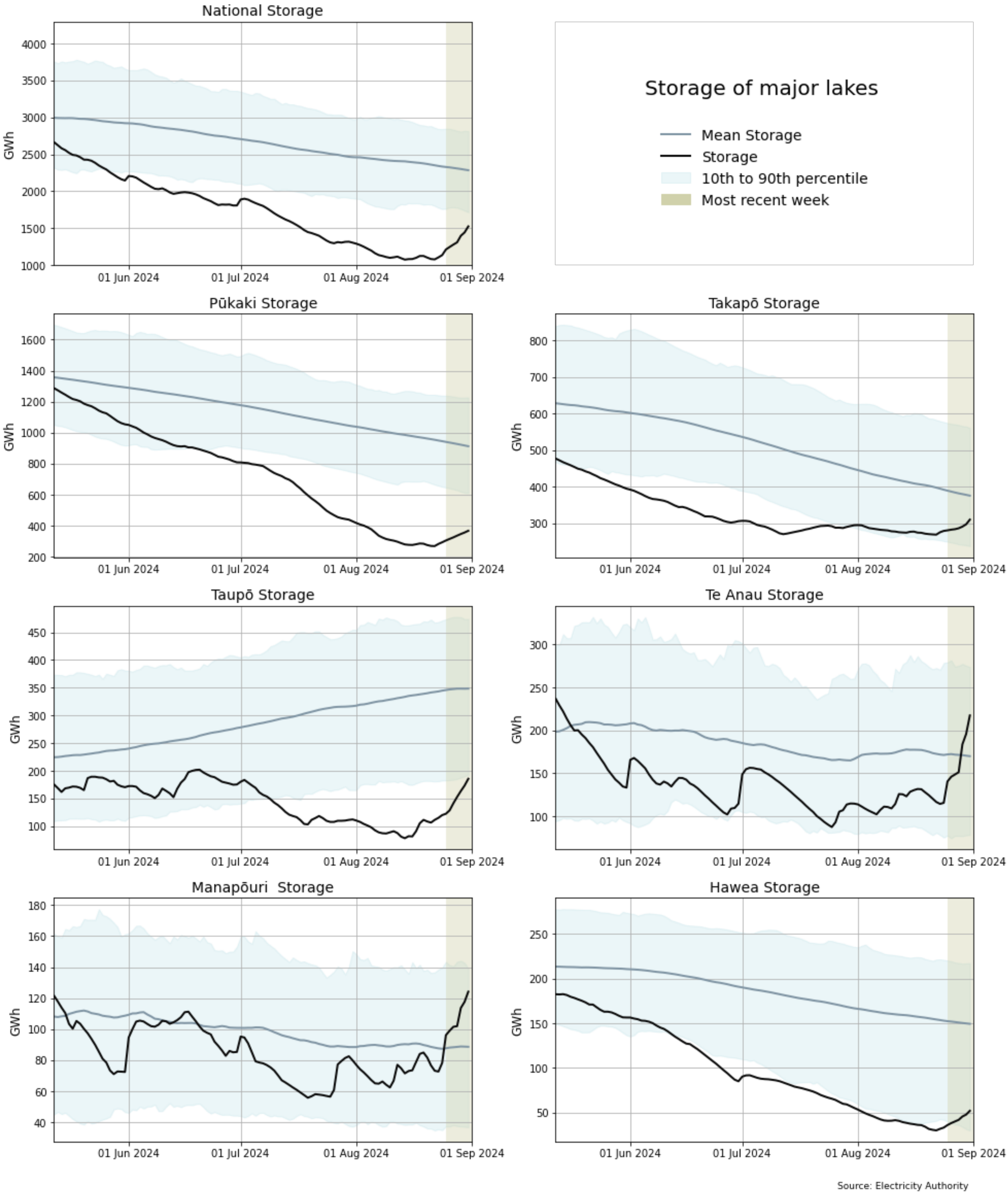
10. Storage/fuel supply

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 increased this week and is ~41% nominally full and ~69% of the historical average for this time of the year as of 31 August.

10.3. Storage increased at all major lakes this week. Pūkaki and Taupō remain below their 10th percentiles, Takapō and Hawea are above their 10th percentiles but below mean, and Te Anau and Manapōuri are now above their means.

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.

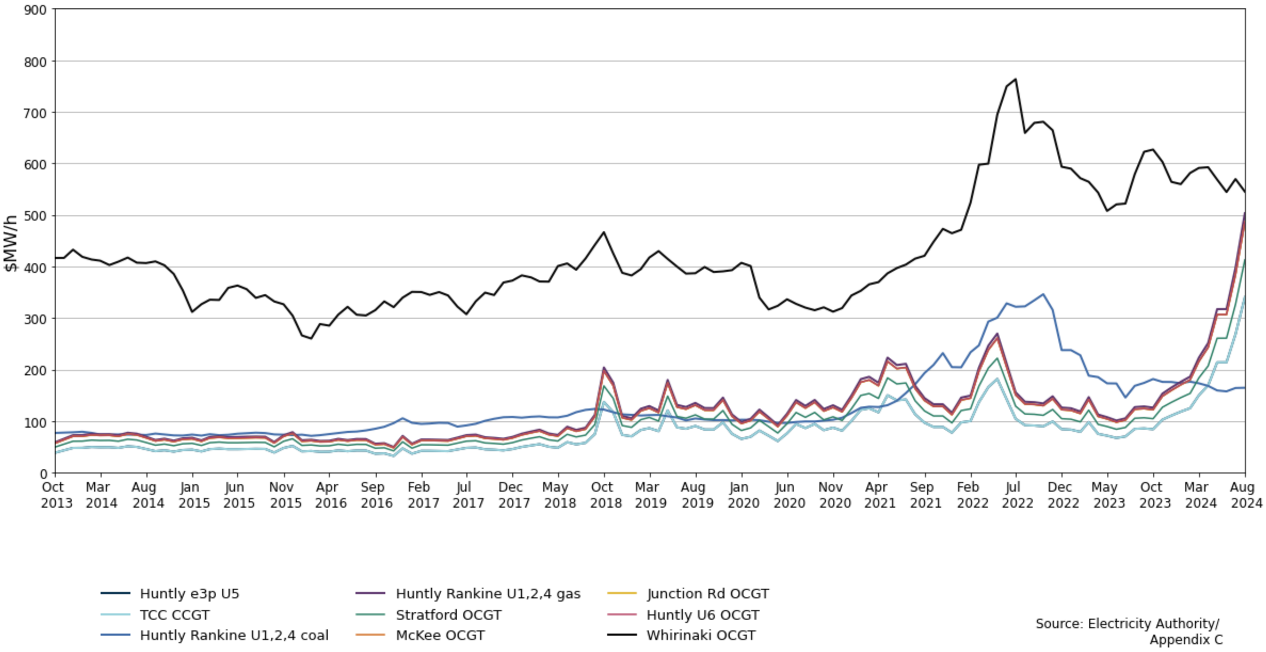
11.4. The latest SRMC of coal-fueled Rankine generation is ~$165/MWh. The cost of running the Rankines on gas remains more expensive at ~$503/MWh.

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



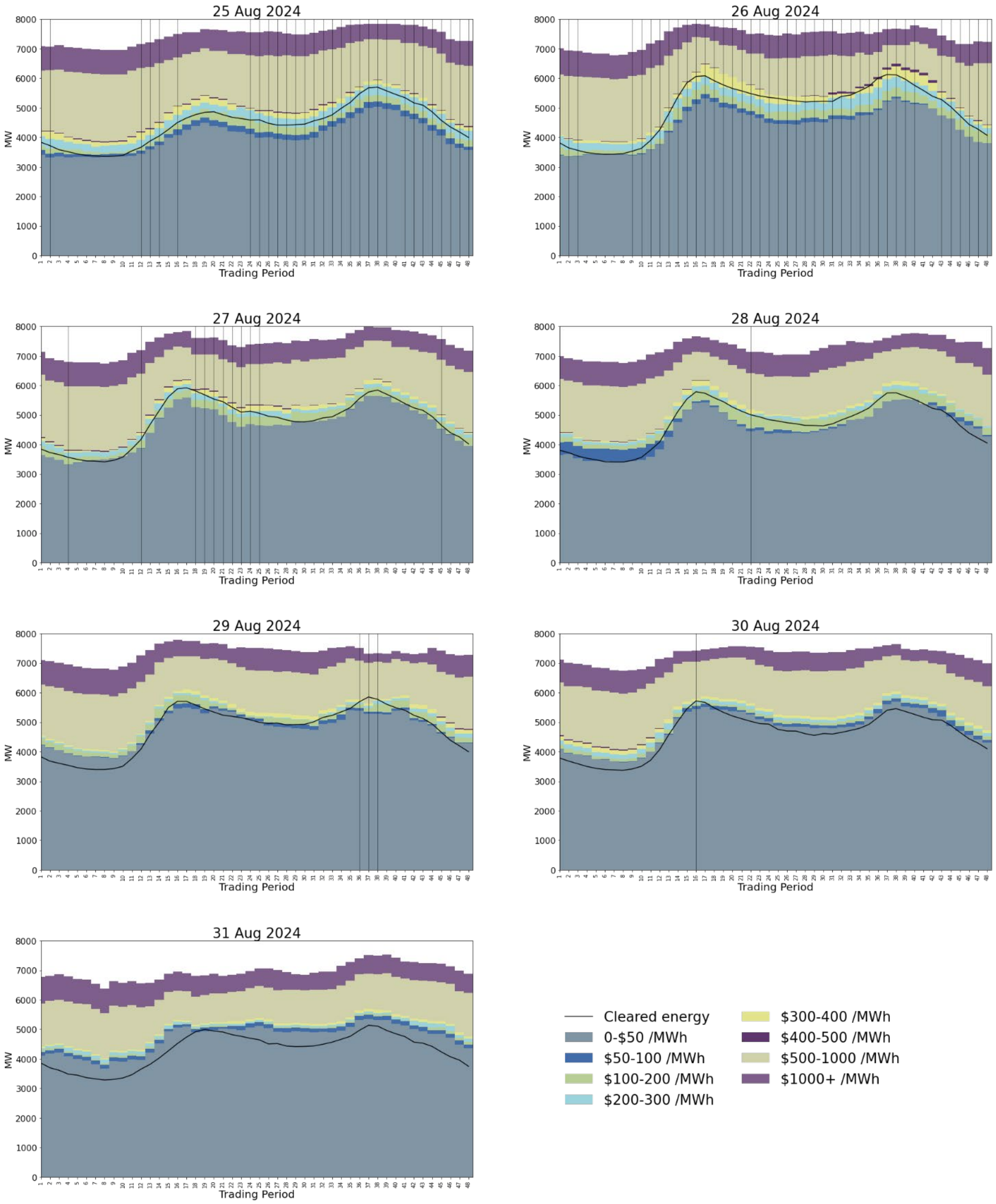
Source: Electricity Authority/ Appendix C

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. Between Sunday and Tuesday, most offers cleared in the $100-$400/MWh region. The thin offers bands in the $100-$500/MWh range led to price spikes when forecasting inaccuracies pushed prices up. From Wednesday onwards, the amount of offers in the $200-$400/MWh region decreased while the $0-$100/MWh region increased as hydro generators offers changed due to the increase in hydro storage.

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 we are further analysing wind offers from Mercury.

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	Further analysis	N/A	N/A	High energy prices
24/07/2024	18-20	Further analysis	Genesis	Huntly	Reserve offers
26/08/2024-31/08/2024	Several	Further analysis	Mercury	Tararua wind farms	Predispatch wind offers