15 July 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Trading conduct report 7-13 July 2024

Market monitoring weekly report

Trading conduct report

1. Overview

1.1. Low wind generation, very high gas prices and falling storage contributed to high spot prices this week, with prices at both Benmore and Ōtāhuhu frequently above the 90th percentile. TCC, Huntly 5 and three Rankines provided baseload generation this week. National controlled hydro storage decreased to around 67% 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. 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. Figures 1 and 2 show the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than the national historical 90th percentile are highlighted with a vertical black line. Other notable prices (≥$400/MWh) are marked with black dashed lines.

2.3. Between 7-13 July:

(a) the average wholesale spot price across all nodes was $332/MWh.

(b) 95% of prices fell between $234/MWh and $484/MWh.

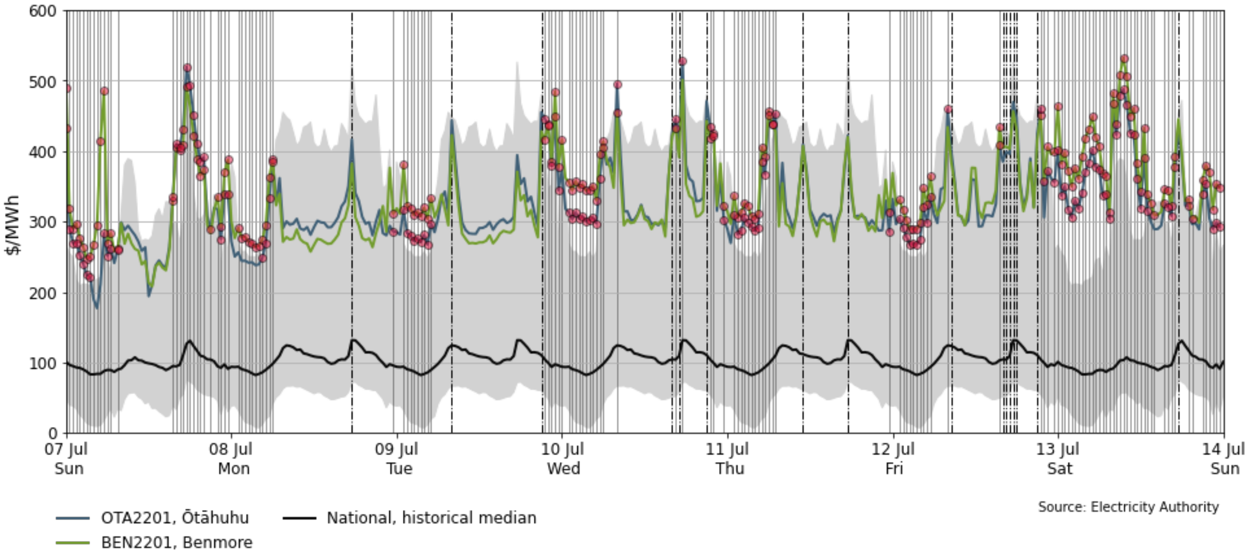
2.4. Overall, the majority of spot prices were within $287/MWh and $369/MWh, with the weekly average price increasing by $36/MWh compared to the previous week.

2.5. The majority of prices were above $300/MWh and often the 90th percentile this week. Most of the highlighted prices occurred outside of peak demand periods, usually overnight or early in the morning. There were some price spikes during weekday peak periods. These consistent high prices are primarily the result of low storage and thermal generation costs rising due to uncertain gas supply .

2.6. Benmore prices were high early on Sunday, reaching $486/MWh at 5:30am while the Ōtāhuhu price remained at $284/MWh. North Island wind generation was high and HVDC flow was entirely southward at the time. These conditions also led to FIR price separating and spiking in the South Island. From 3:30pm to midnight, prices were high at both nodes, between $275-$520/MWh. Wind generation had decreased by the time, requiring the use of higher-priced thermal generation.

2.7. Prices were particularly high on Saturday, mostly above the 90th percentile. Prices at Benmore were also higher than at Ōtāhuhu for most of the day, again due to high-priced hydro and thermal generation, in addition to significant wind forecasting inaccuracies. The Benmore price reached this week's maximum of $533/MWh at 9:30am.

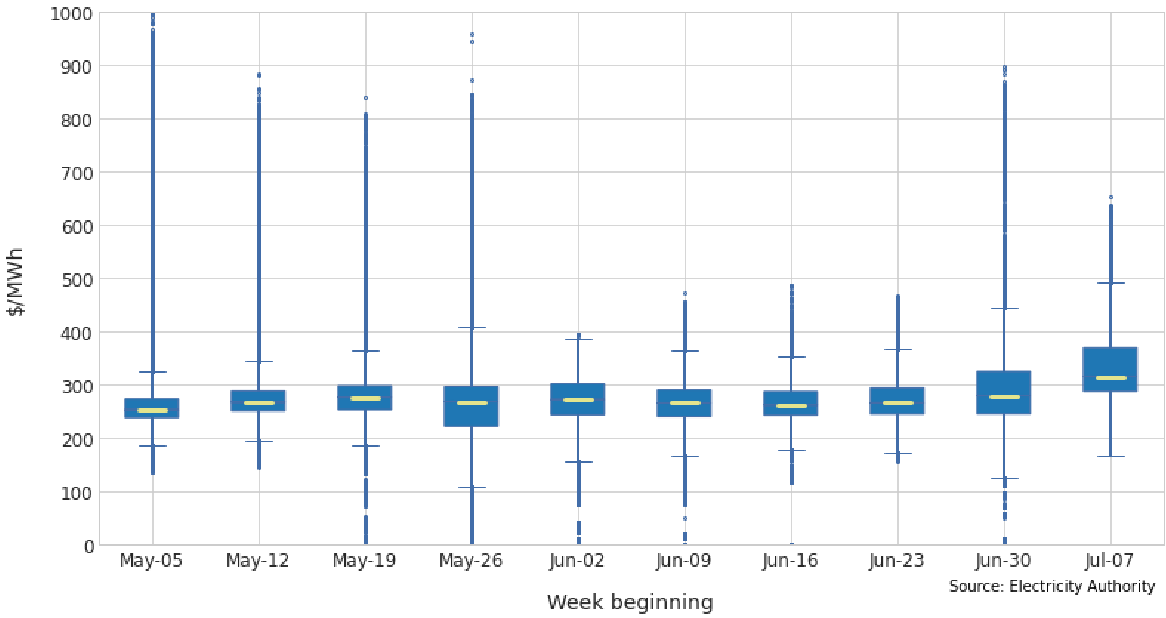
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 7-13 July



2.8. Figure 3 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 increased by $31/MWh. The spread of prices has shifted up, with 75% of this week's prices sitting above the median from the previous week. The overall range of prices decreased as there were less outliers. This indicates that prices were higher but less volatile than the previous week.

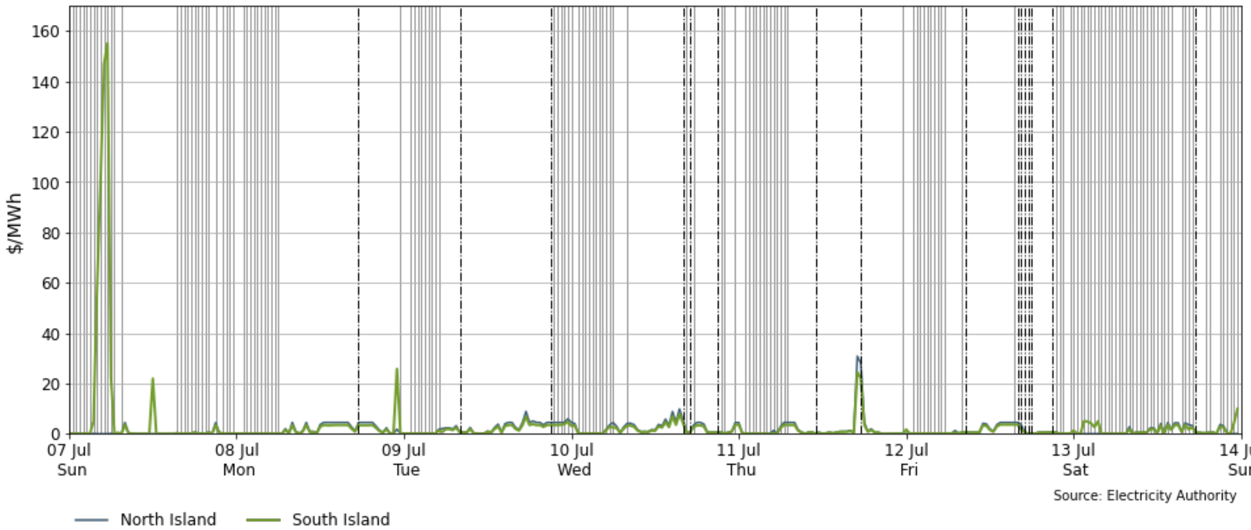
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

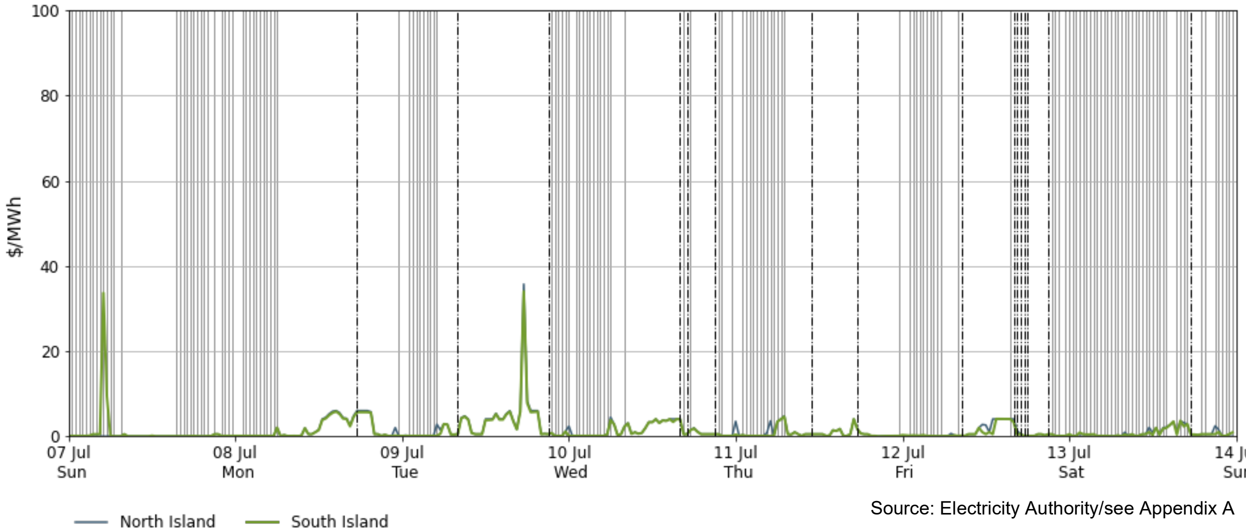
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were generally below $1/MWh, but spiked on Sunday morning, reaching $155/MWh at 5:30am in the South Island while remaining at $0/MWh in the North Island. High wind generation in the North Island saw southward HVDC flow increase. 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, 7-13 July 2024



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 5. SIR prices were generally below $1/MWh but spiked above $30/MWh in the South Island on Sunday morning (in line with the FIR spike above). The SIR price also spiked above $30/MWh in both islands on Tuesday evening.

Figure 4: Sustained instantaneous reserve by trading period and island, 7-13 July 2024



Source: Electricity Authority/see Appendix A

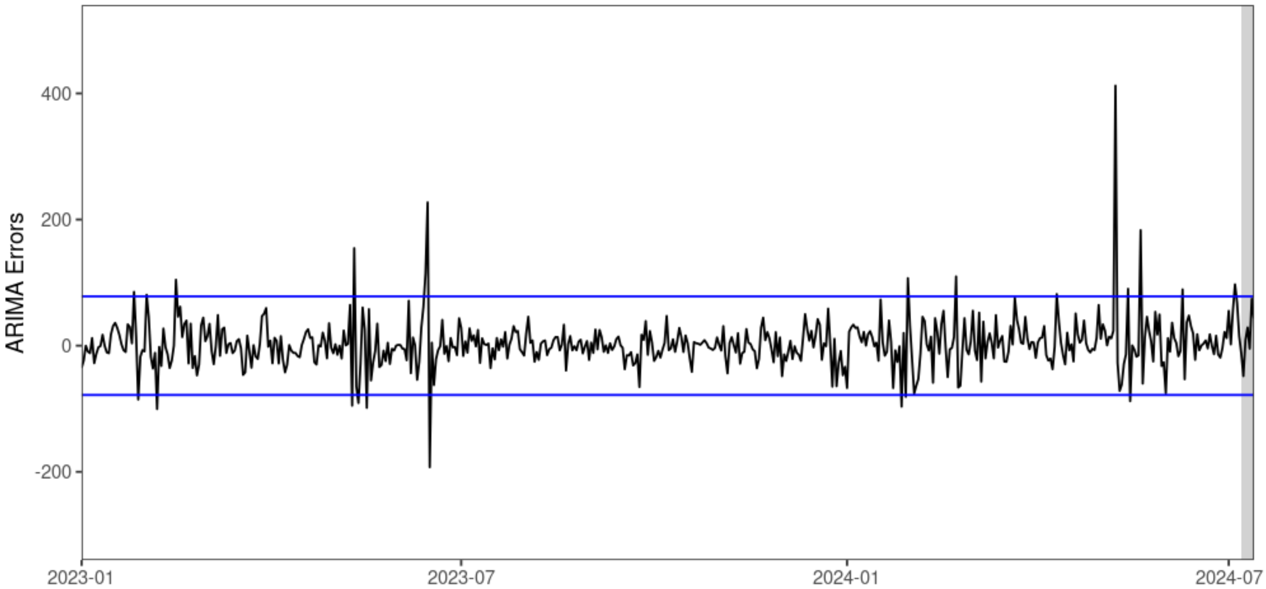
4. Regression residuals

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 6 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 the actual and modelled prices were similar.

Figure 5: Residual plot of estimated daily average spit prices, 1 January 2023 – 6 July 2024

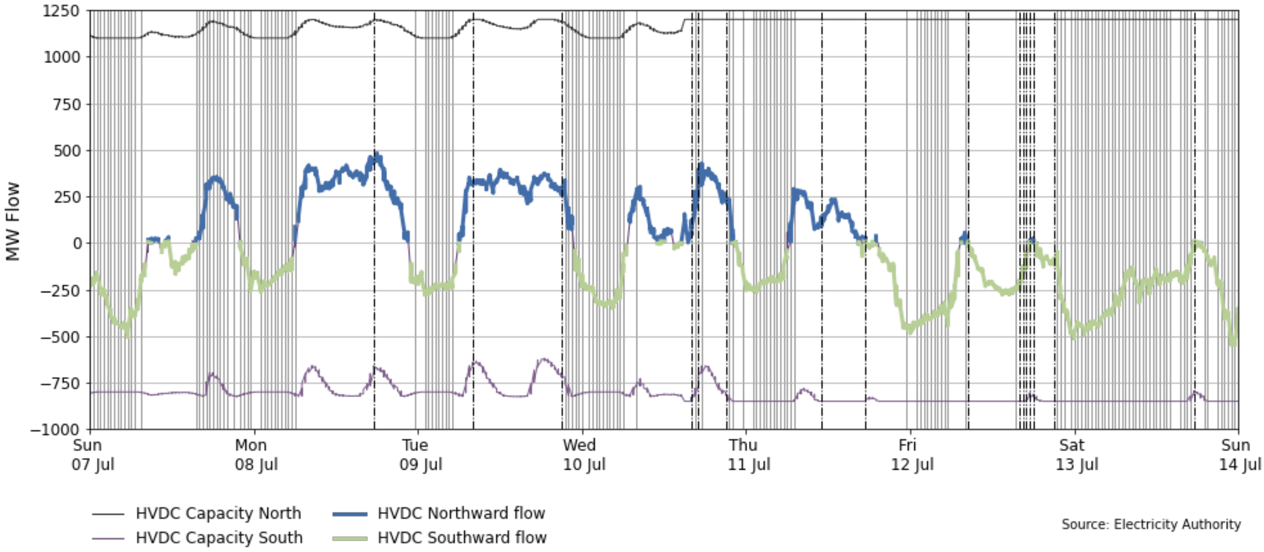


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 7 shows the HVDC flow between 7-13 July 2024. HVDC flows were mostly northward when wind generation was low at the start of the week. Flow was entirely southward on Saturday, when prices were particularly high, and was also southward when most other highlighted prices occurred and when North Island wind generation was higher.

Figure 6: HVDC flow and capacity, 7-13 July 2024

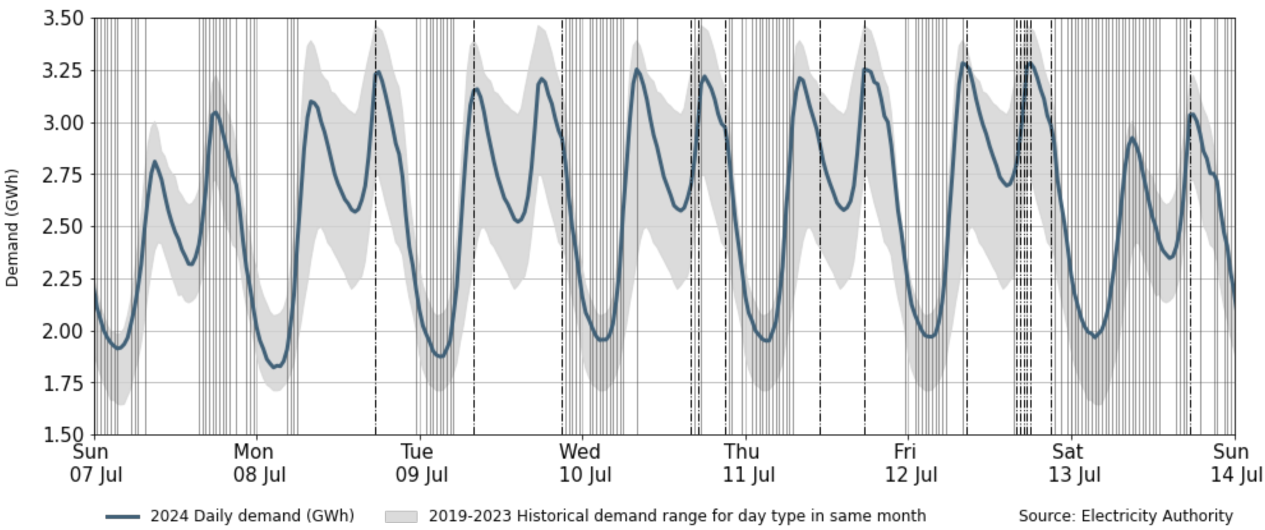


6. Demand

6.1. Figure 8 shows national demand between 7-13 July 2024, compared to the historic range. Demand was mostly within the historical range for July. Maximum demand for the week was 3.28GWh at 6:00pm Friday.

6.2. Demand on Saturday morning was close to the historical maximum demand for a weekend in July.

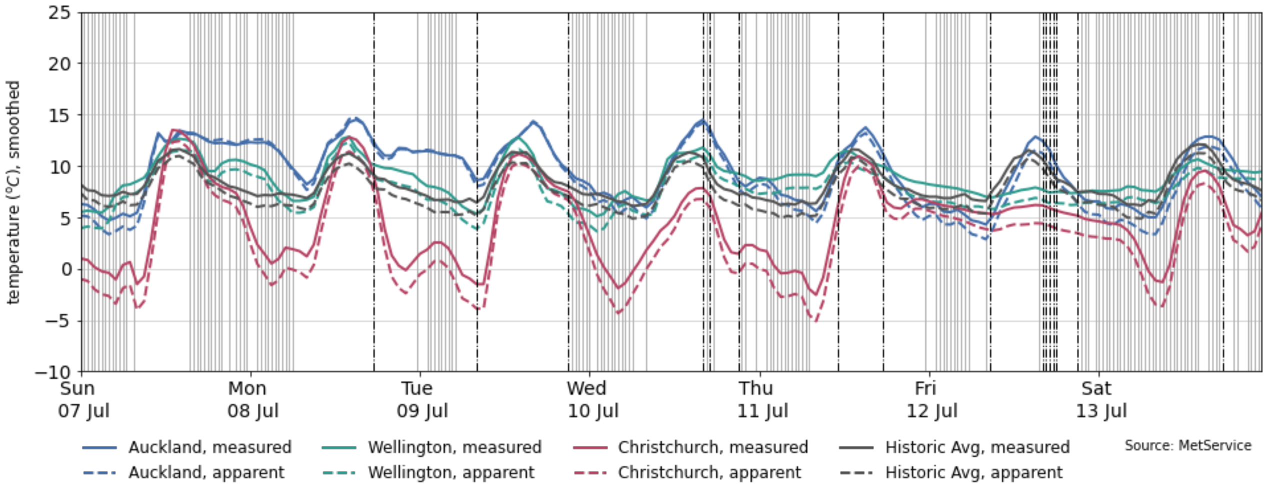
Figure 7: National demand, 7-13 July 2024 compared to historic range



6.3. Figure 9 shows the hourly temperature at main population centres from 7-13 July 2024. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres. Temperature data between Monday evening and Wednesday night was not available for Wellington and Christchurch.

6.4. Temperatures were generally close to or above average in Auckland, ranging from 3°C to 15°C. Wellington temperatures were close to average, between 4°C to 12°C. Temperatures in Christchurch were mostly below average, ranging from -5°C to 12°C.

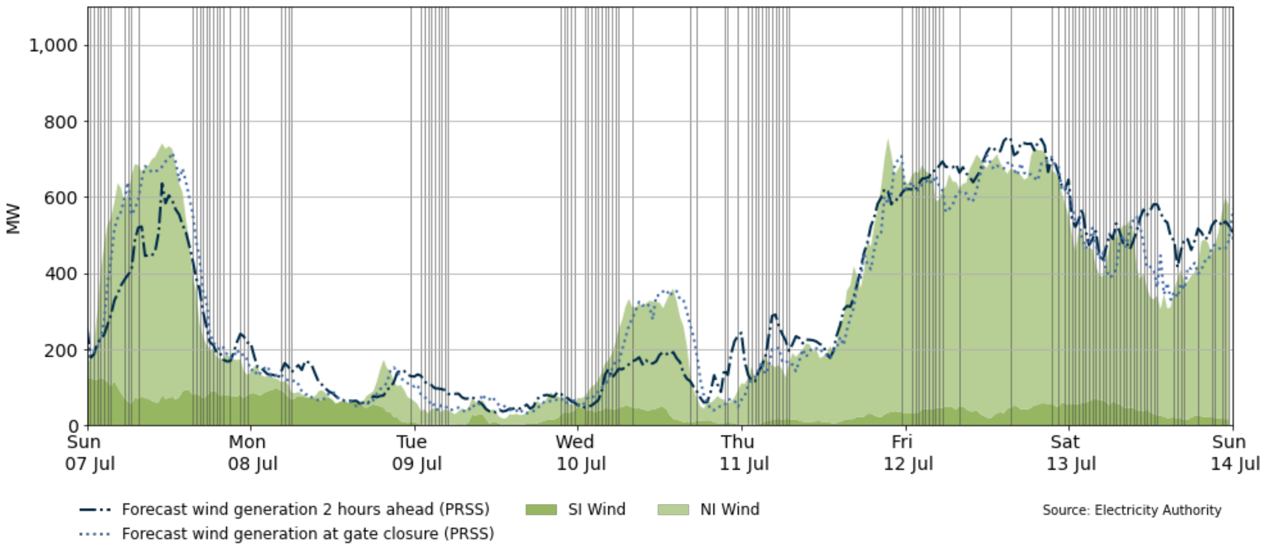
Figure 8: Temperatures across main centres, 7-13 July 2024



7. Generation

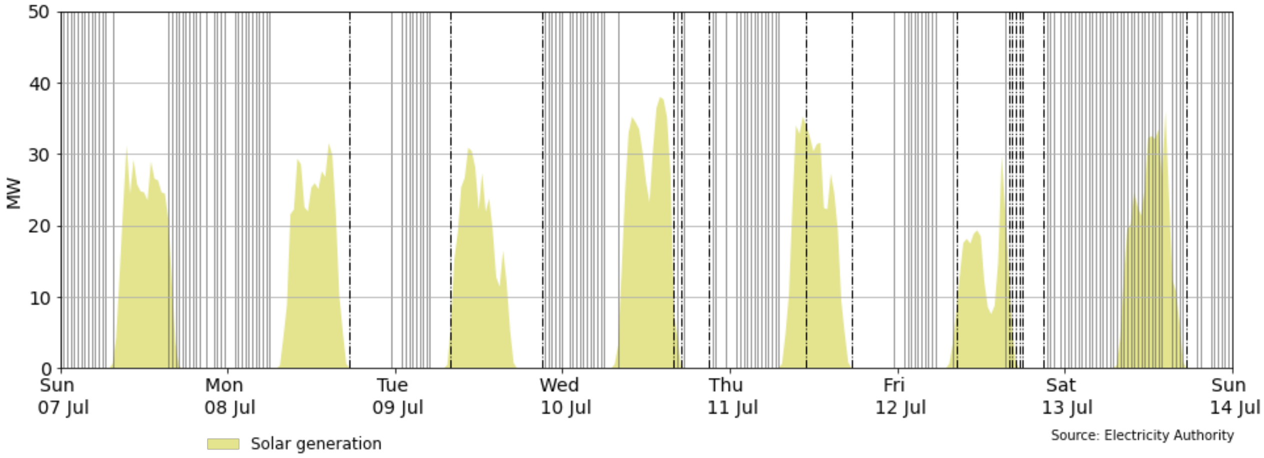
7.1. Figure 10 shows wind generation and forecast from 7-13 July 2024. This week wind generation varied between 18MW and 755MW, with a weekly average of 313MW. Wind generation was very low from Monday until Thursday and was often below forecast when many of the high prices occurred. Daily average wind generation was lowest on Tuesday at ~47MW. On Saturday, wind generation was over 200MW below forecast during multiple trading periods.

Figure 9: Wind generation and forecast, 7-13 July 2024



7.2. Figure 11 shows solar generation from 7-13 July 2024. Solar generation reached at least 30MW each day except Friday 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, 7-13 July 2024

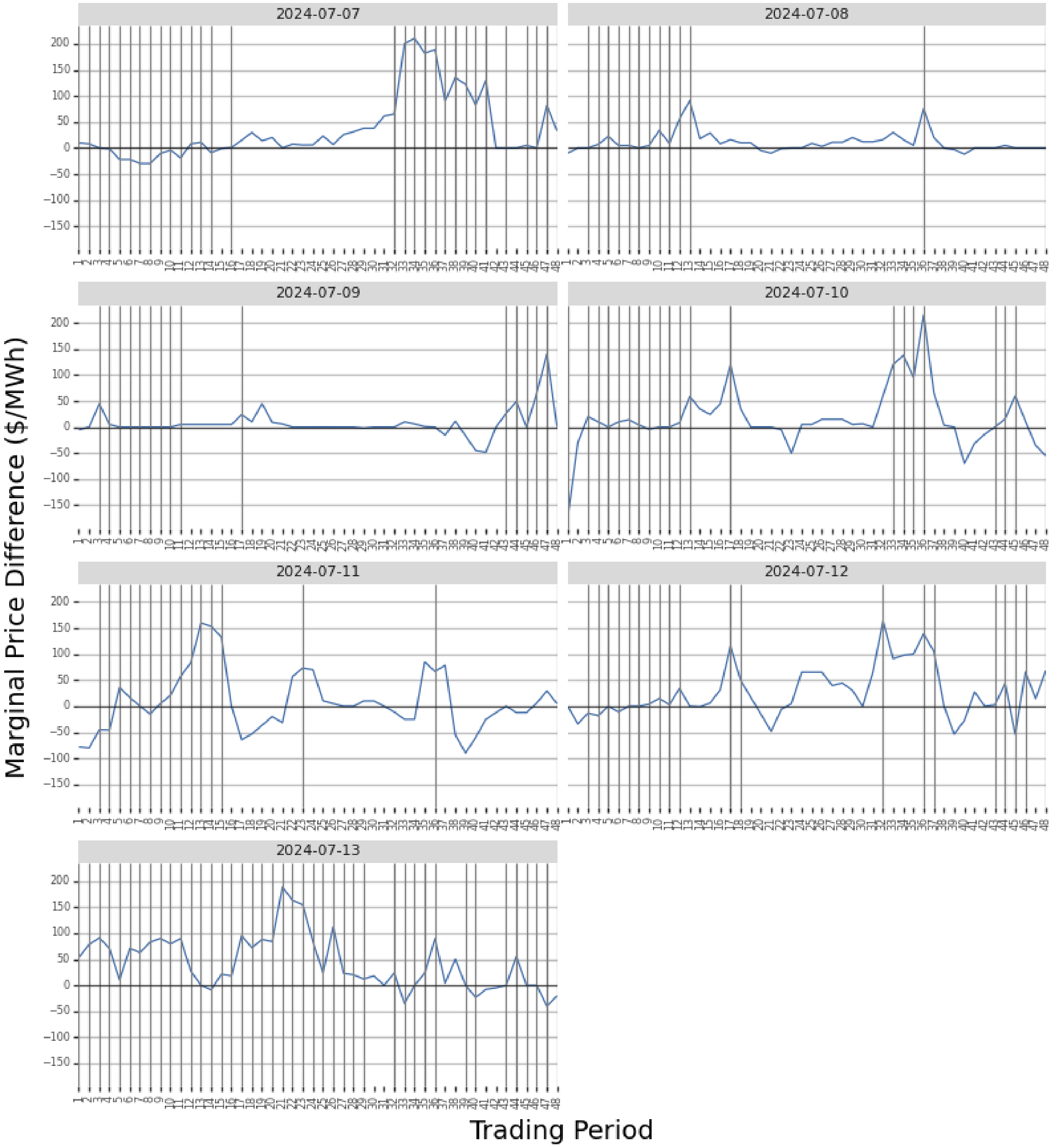


7.3. Figure 12 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 $215/MWh at 5:30pm on Wednesday. Prices were also frequently higher than the simulation between Thursday and Saturday.

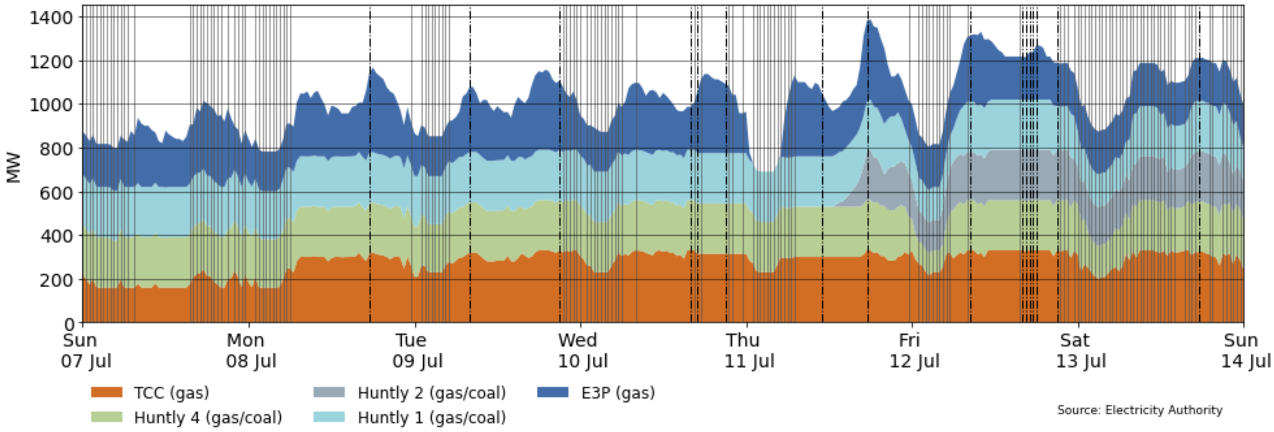
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 7-13 July 2024



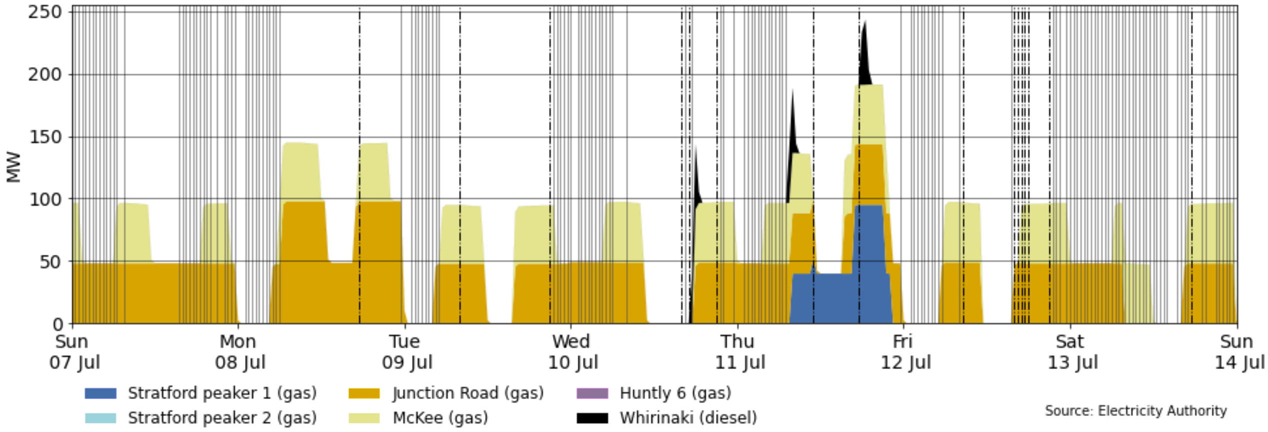
7.5. Figure 13 shows the generation of thermal baseload between 7-13 July 2024. TCC, Huntly 4, Huntly 1 and Huntly 5 (E3P) provided baseload generation this week, as did Huntly 2 after returning from outage on Thursday. All units ran continuously except Huntly 5, which turned off during the early hours of Thursday morning.

Figure 12: Thermal baseload generation, 7-13 July 2024



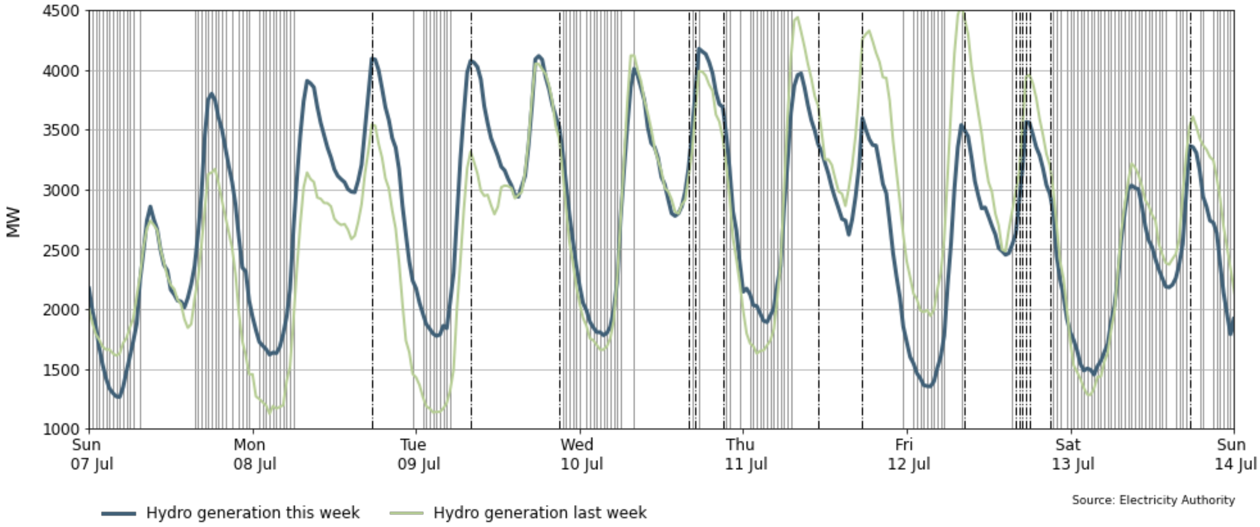
7.6. Figure 14 shows the generation of thermal peaker plants between 7-13 July 2024. Junction Road ran every day, mostly during peak and shoulder periods, as did McKee. Stratford 1 ran during the shoulder and evening peak period on Thursday, and Whirinaki ran during peak periods on Wednesday and Thursday.

Figure 13: Thermal peaker generation, 7-13 July 2024



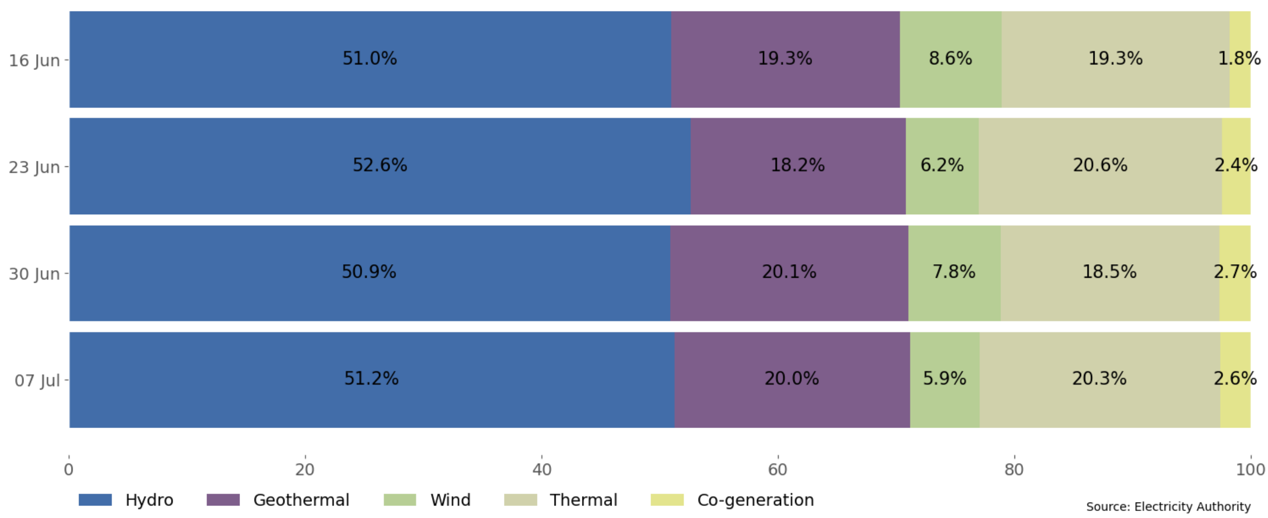
7.7. Figure 15 shows hydro generation between 7-13 July 2024. Overall, hydro generation was similar to the previous week, though it was higher at the start of the week when wind generation was low.

Figure 14: Hydro generation, 7-13 July 2024



7.8. As a percentage of total generation, between 7-13 July 2024, total weekly hydro generation was 51.2%, geothermal 20.0%, wind 5.9%, thermal 20.3%, and co-generation 2.7%, as shown in Figure 16. The proportion of thermal generation increased this week, compensating for the decrease in wind generation.

Figure 15: Total generation by type as a percentage each week, 9 June-6 July



8. Outages

8.1. Figure 17 shows generation capacity on outage. Total capacity on outage between 7-13 July 2024 ranged between ~760MW and ~1,400MW. Figure 18 shows the thermal generation capacity outages.

8.2. Notable outages include:

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

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

(c) White Hill wind farm is on outage from 11-15 July.

(d) Junction Road has one unit on outage on 25 July.

(e) McKee has one unit on outage until 29 July.

(f) Various North and South Island hydro units were on outage.

Figure 16: Total MW loss from generation outages, 7-13 July 2024

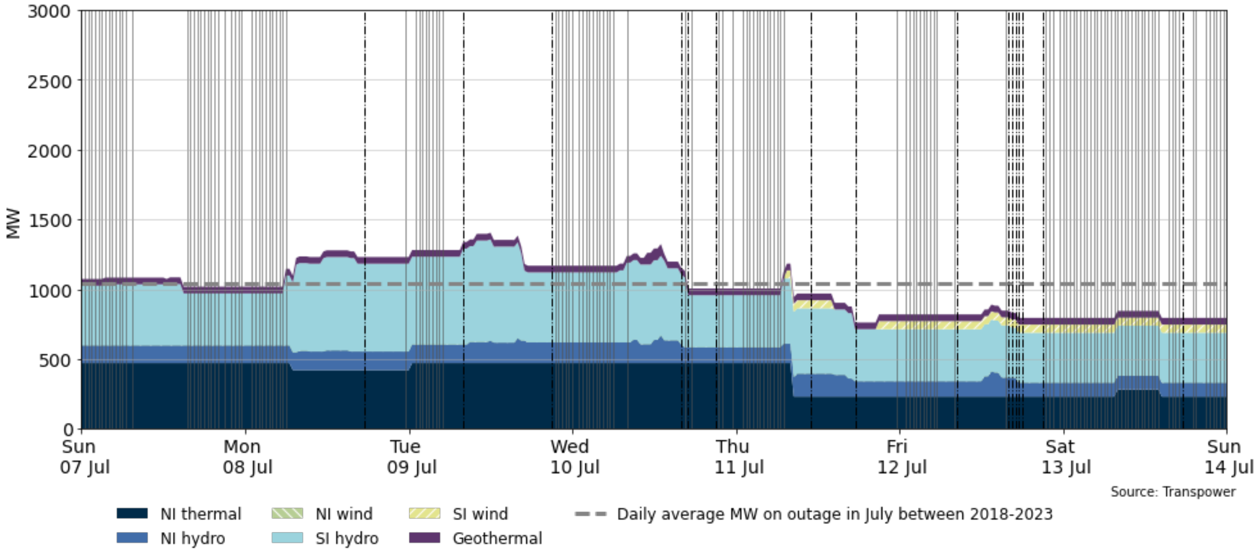
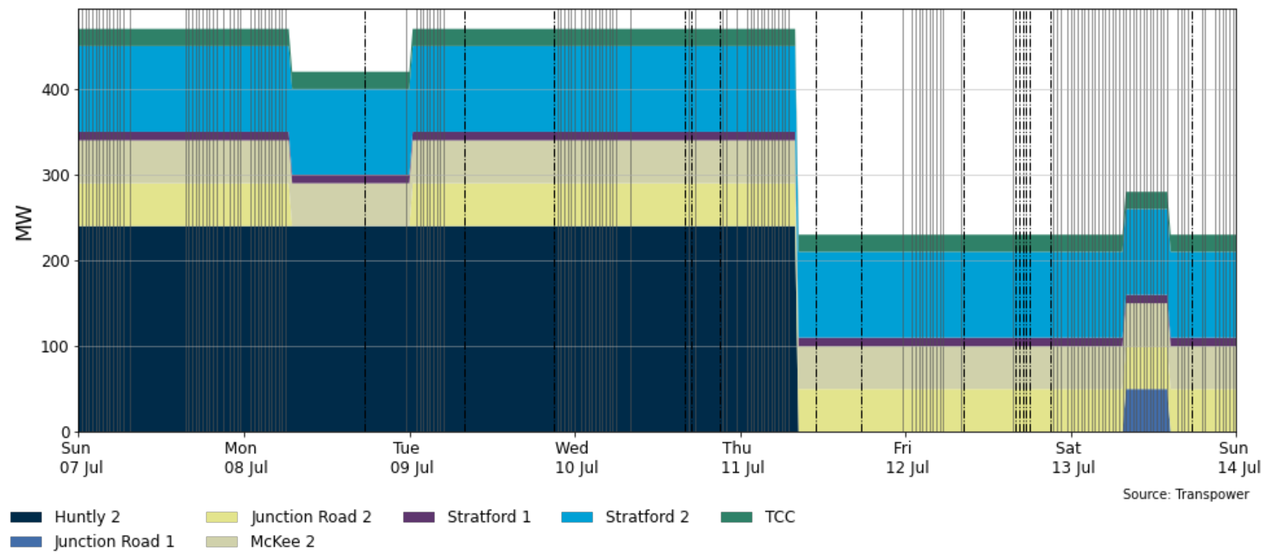


Figure 17: Total MW loss from thermal outages, 7-13 July 2024

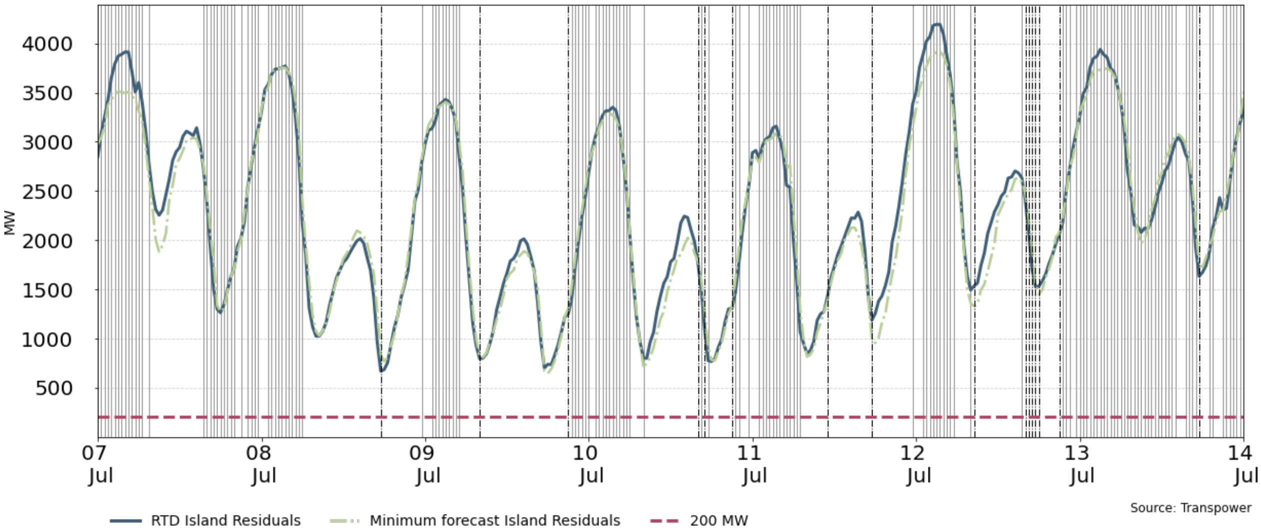


9. Generation balance residuals

9.1. Figure 19 shows the national generation balance residuals between 7-13 July 2024. 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 residuals were healthy this week. The minimum North Island residual was around 350MW at 5:30pm on Tuesday.

Figure 18: National generation balance residuals, 7-13 July 2024



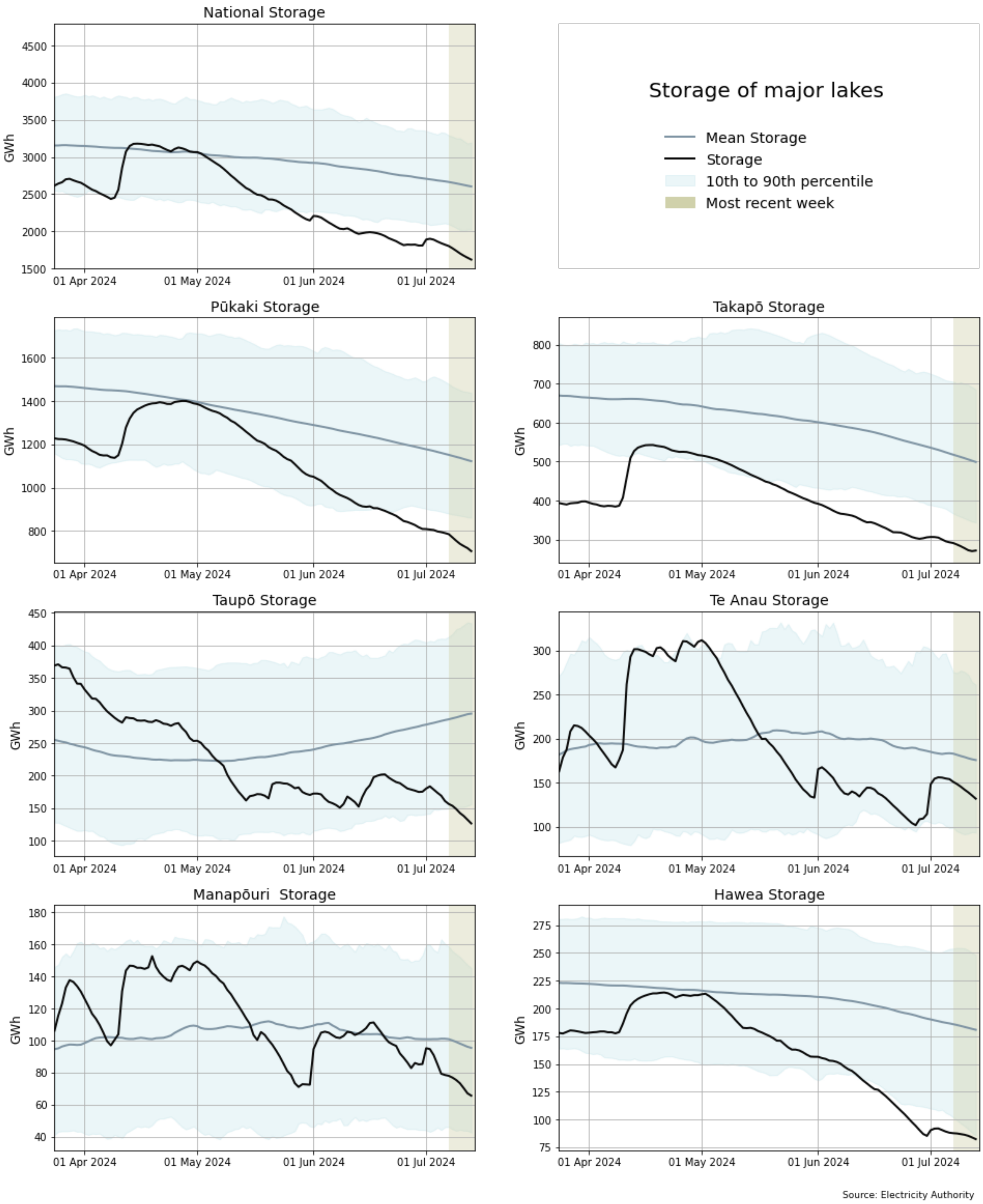
10. Storage/fuel supply

10.1. Figure 20 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 this week and was ~44% nominally full and ~67% of the historical average for this time of the year as of 13 July.

10.3. Storage decreased at all major lakes this week. Pūkaki, Takapō, Taupō and Hawea are below their 10th percentiles, while Te Anau and Manapōuri are below their historical means.

Figure 19: Hydro storage

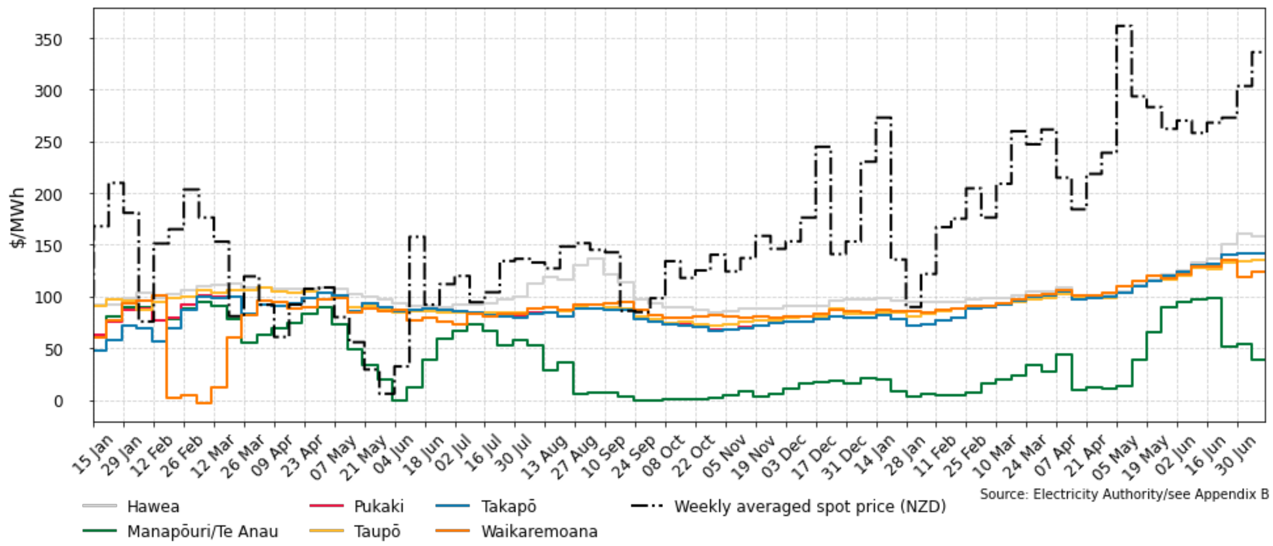


11. JADE water values

11.1. The JADE[2] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 21 shows the national water values between 1 July 2023 and 13 July 2024 obtained from JADE calculated at the start of the week. These values are used to estimate the marginal water value at the actual storage level. More details on how water values are calculated can be found in Appendix B.

11.2. Water values at most lakes remained similar to the previous week. Manapōuri/Te Anau saw the greatest decrease of $14.20/MWh, while Waikaremoana saw the greatest increase of $4.50/MWh.

Figure 20: JADE water values across various reservoirs, 8 January 2023 to 13 July 2024



12. Prices versus estimated costs

12.1. 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).

12.2. 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.

12.3. Figure 22 shows an estimate of thermal SRMCs as a monthly average up to 1 July 2024. The SRMCs for diesel and gas have both increased from the previous month, while the coal SRMC has remained stable.

12.4. The latest SRMC of coal-fuelled Rankine generation is ~$158/MWh. The cost of running the Rankines on gas remains more expensive at ~$377/MWh.

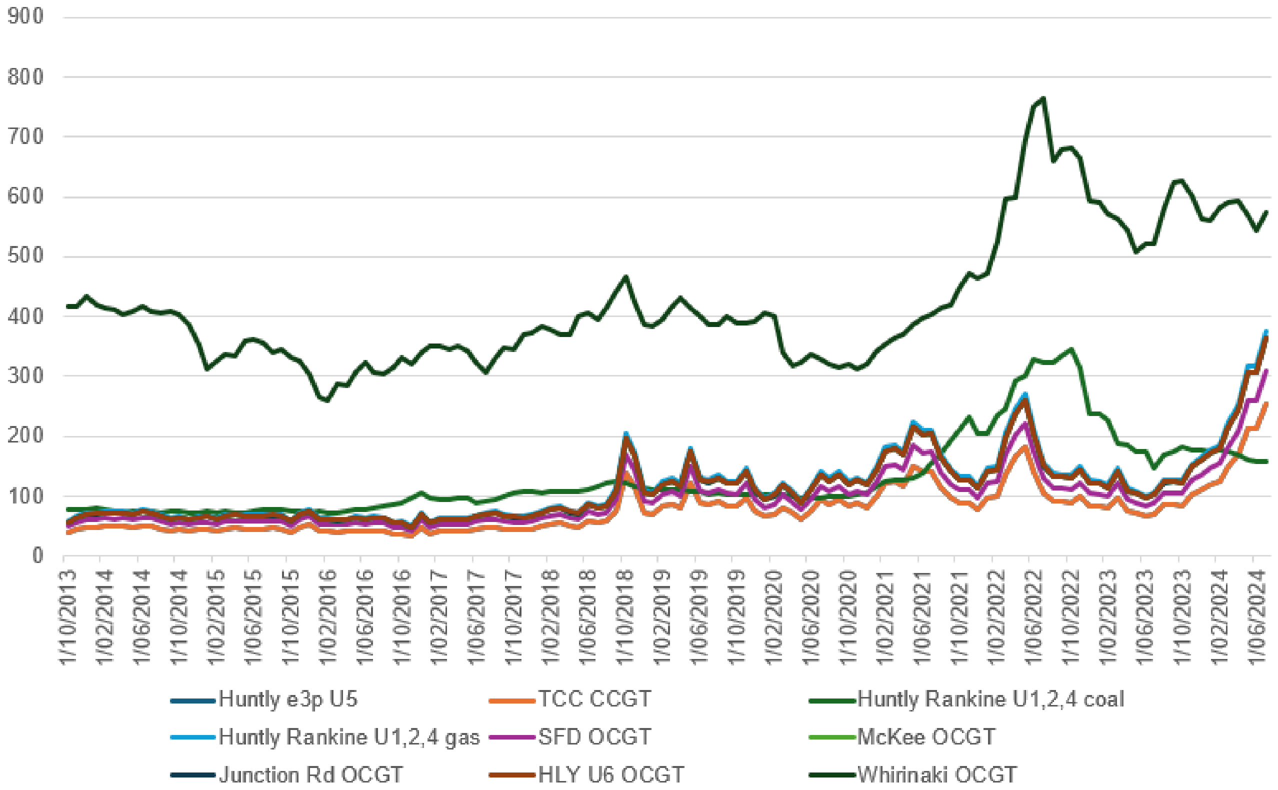
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

12.5. The SRMC of gas fuelled thermal plants is currently between ~$254/MWh and ~$377/MWh.

12.6. The SRMC of Whirinaki is ~$573/MWh.

12.7. More information on how the SRMC of thermal plants is calculated can be found in Appendix C.

Figure 21: Estimated monthly SRMC for thermal fuels

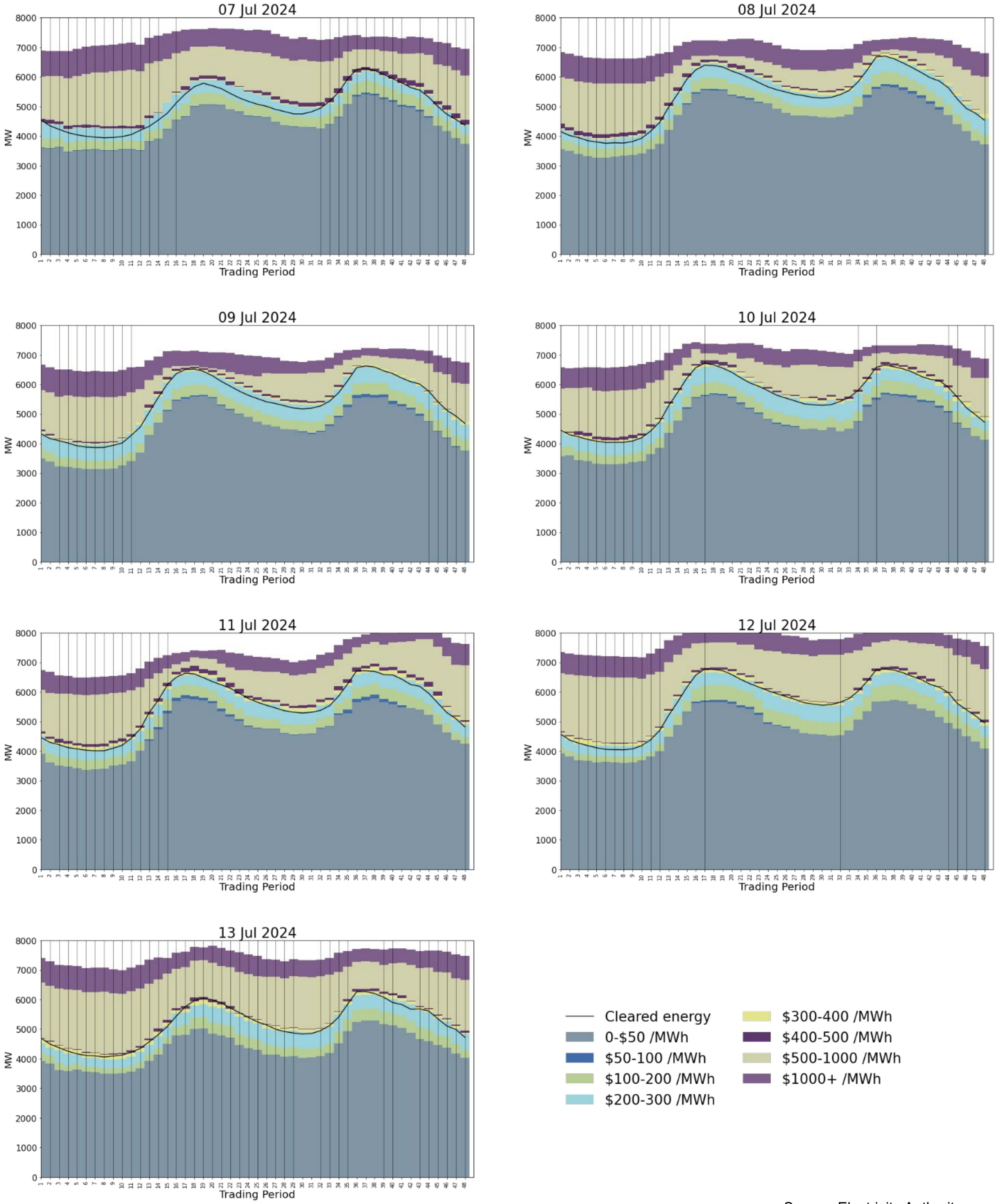


Source: Electricity Authority/see Appendix C

13. Offer behaviour

13.1. Figure 23 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price. Hydro generation pricing has increased as lake levels have declined, and the number of offers in the $500-$1,000 band has increased substantially as a result. Although most offers cleared in the $200-$400/MWh region, the number of offers in these bands has decreased.

Figure 22: Daily offer stacks



Source: Electricity Authority

14. Ongoing work in trading conduct

14.1. This week prices generally appeared to be consistent with supply and demand conditions, however, the high price on Friday morning and the high prices on Saturday afternoon will be further analysed by the market monitoring team.

14.2. 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	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance	Contact	Multiple	High hydro offers
8/05/2024-10/05/2024	Several	Further analysis	Genesis	Multiple	Energy offers
07/07/2024	11-13	Further analysis	Meridian	South Island	High energy and reserve prices
06/07/2024	41-48	Further analysis	N/A	N/A	Energy offers
13/07/2024	Several	Further analysis	N/A	N/A	High energy prices