29 July 2024

Trading conduct report 21-27 July 2024

Market monitoring weekly report

Trading conduct report 21-27 July 2024

1. Overview

1.1. Prices remained high this week due to low lake levels and high gas prices, and were frequently above the 90th percentile at both Benmore and Ōtāhuhu. Low hydro generation led to increased southward flow across the HVDC, causing South Island Fast Instantaneous Reserve prices to spike on Saturday. TCC, Huntly 5 and three Rankines provided baseload generation this week. National controlled hydro storage decreased to around 59% 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. 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 the 90th percentile of historic prices are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

2.3. Between 21-27 July:

(a) the average wholesale spot price across all nodes was $385/MWh

(b) 95% of prices fell between $242/MWh and $642/MWh.

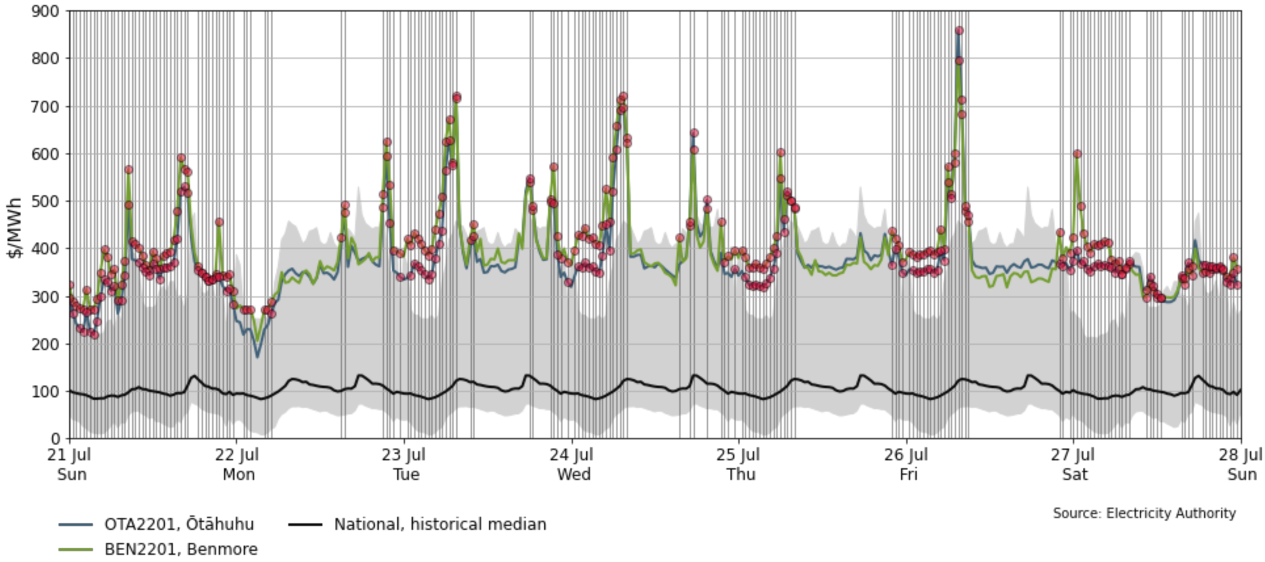
2.4. Overall, the majority of spot prices were within $339-$410/MWh, meaning the weekly average price increased by around $8/MWh compared to the previous week. The average Benmore spot price was $18/MWh higher than at Ōtāhuhu.

2.5. Prices were often above the 90th percentile this week. These consistent high prices are primarily the result of low hydro storage and thermal generation costs rising due to limited gas supply; the average price this week was similar to the marginal cost of gas fuelled thermal plants. Most of the highlighted prices occurred on weekends or outside of peak demand periods, with additional spikes occurring during peak periods.

2.6. The Ōtāhuhu spot price reached a maximum of $859/MWh at 7:30am on Friday. Demand was under forecast by more than 100MW at the time, requiring additional high-priced hydro generation to be dispatched. Shortly before the start of the trading period, an under-frequency event occurred due to Clyde tripping, which is also likely to have contributed to the high prices.

2.7. Forecasting inaccuracies likely contributed to this week's high prices. Demand was more than 100MW higher than forecast at times highlighted prices occurred on Sunday, Monday, Tuesday, Wednesday and Friday. Additionally, wind generation was more than 100MW below forecast when highlighted prices occurred on Sunday and Tuesday. Due to the low volume of offers priced between $400-$500/MWh, forecasting inaccuracies often pushed prices above $500/MWh and led to price spikes.

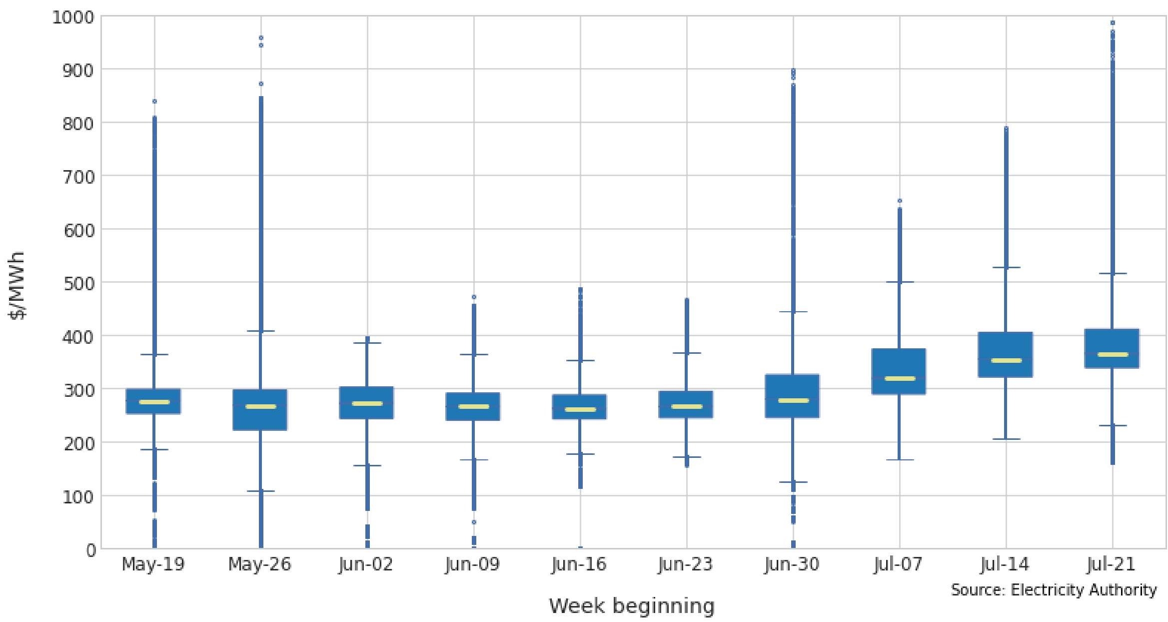
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 21-27 July



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 increased by $10/MWh. The overall spread of prices also increased as there were more outliers, indicating that prices have become more volatile.

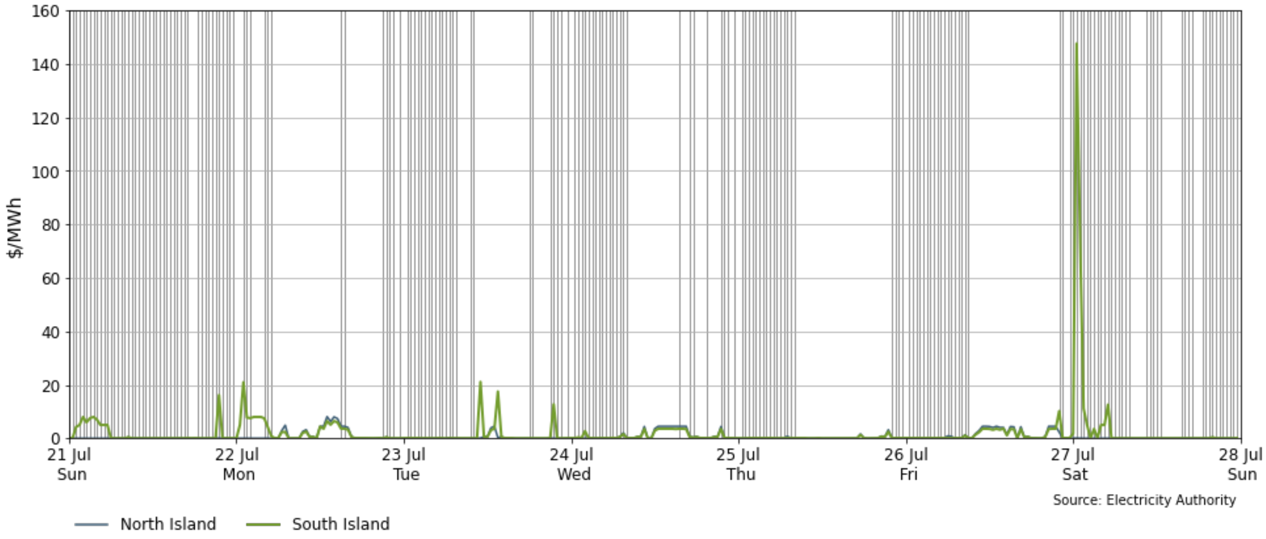
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

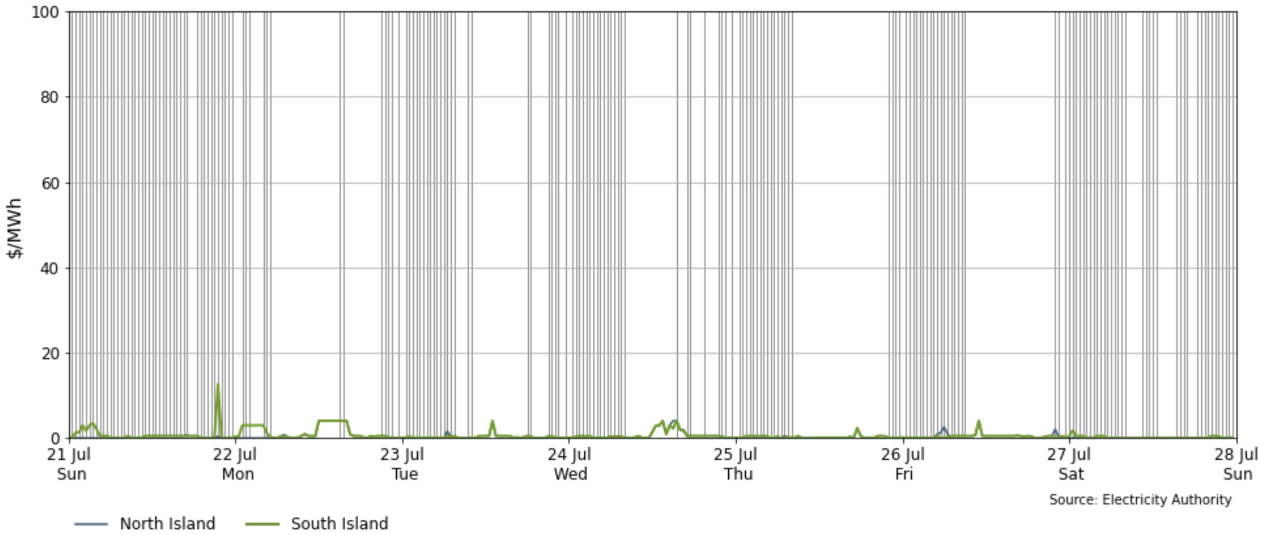
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week, but spiked at 12:30am on Saturday, reaching $148/MWh in the South Island while remaining at $0.08/MWh in the North Island. High wind and thermal generation in the North Island, combined with low hydro generation in the South 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, 21-27 July



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.

Figure 4: Sustained instantaneous reserve by trading period and island, 21-27 July



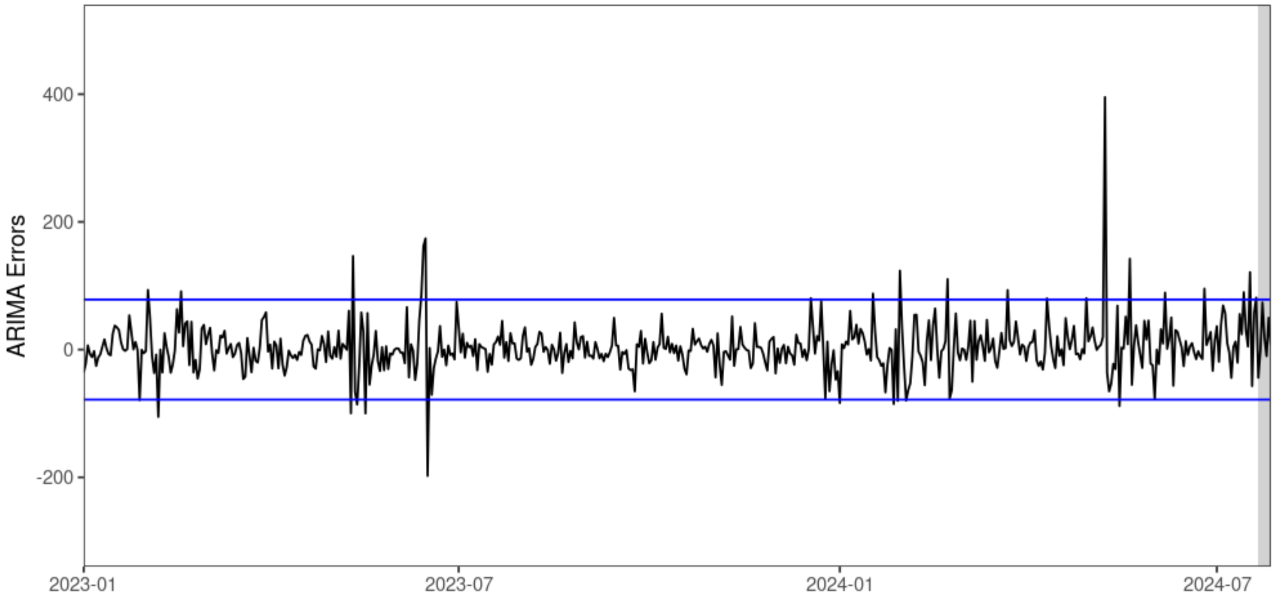
4. Regression residuals

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 the actual and modelled prices were similar.

Figure 5: Residual plot of estimated daily average spit prices, 1 January 2023 – 27 July 2024

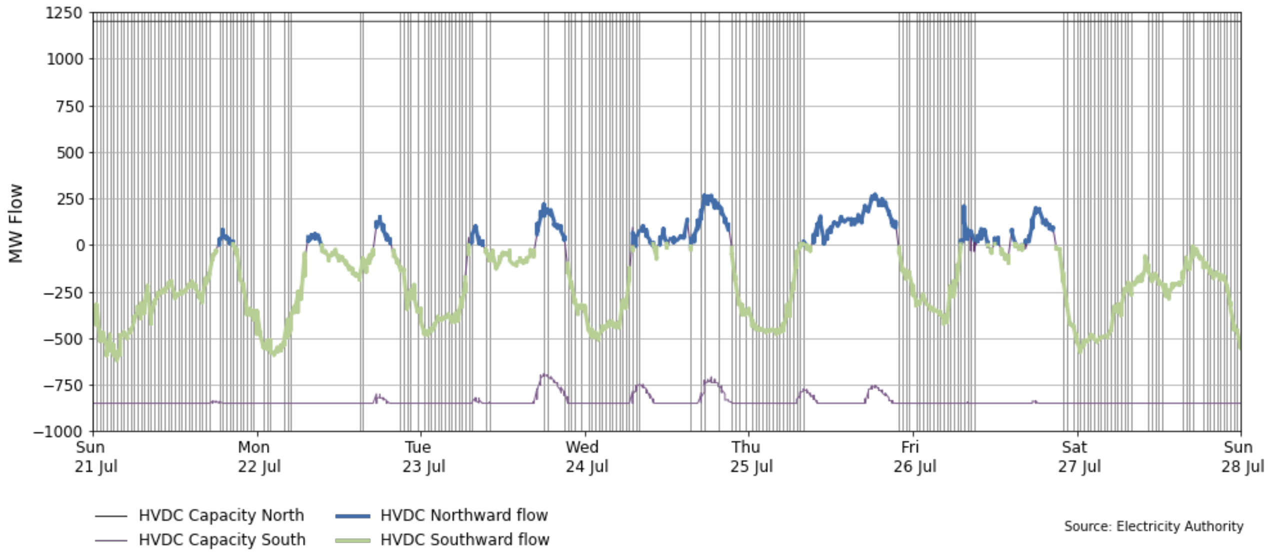


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 21-27 July. HVDC flow was mostly southward this week, particularly at the times most of the highlighted prices occurred.

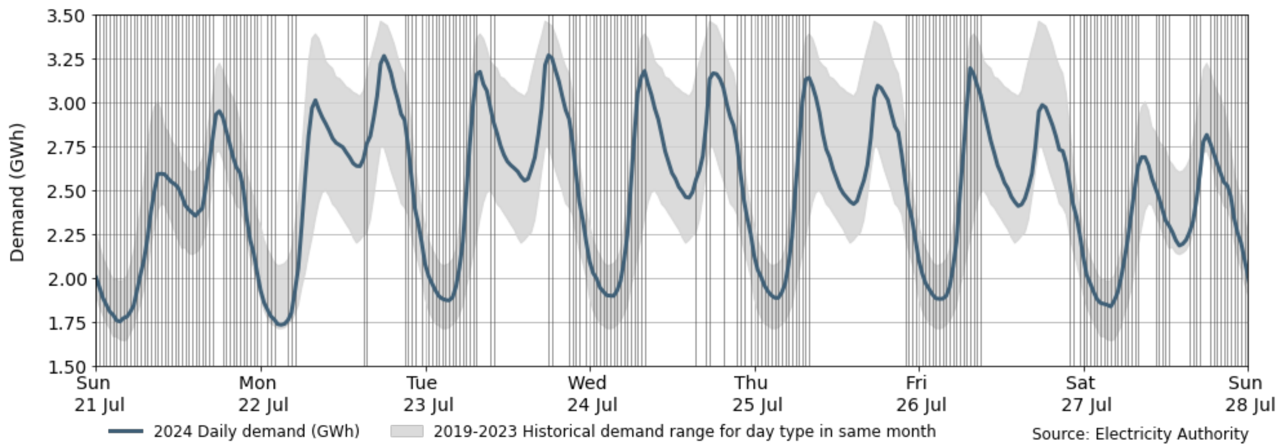
Figure 6: HVDC flow and capacity, 21-27 July



6. Demand

6.1. Figure 7 shows national demand between 21-27 July, compared to the historic range. This week, demand was within the historical range for this time of year. The maximum demand was 3.27GWh (6.54GW) at 6:00pm on Tuesday.

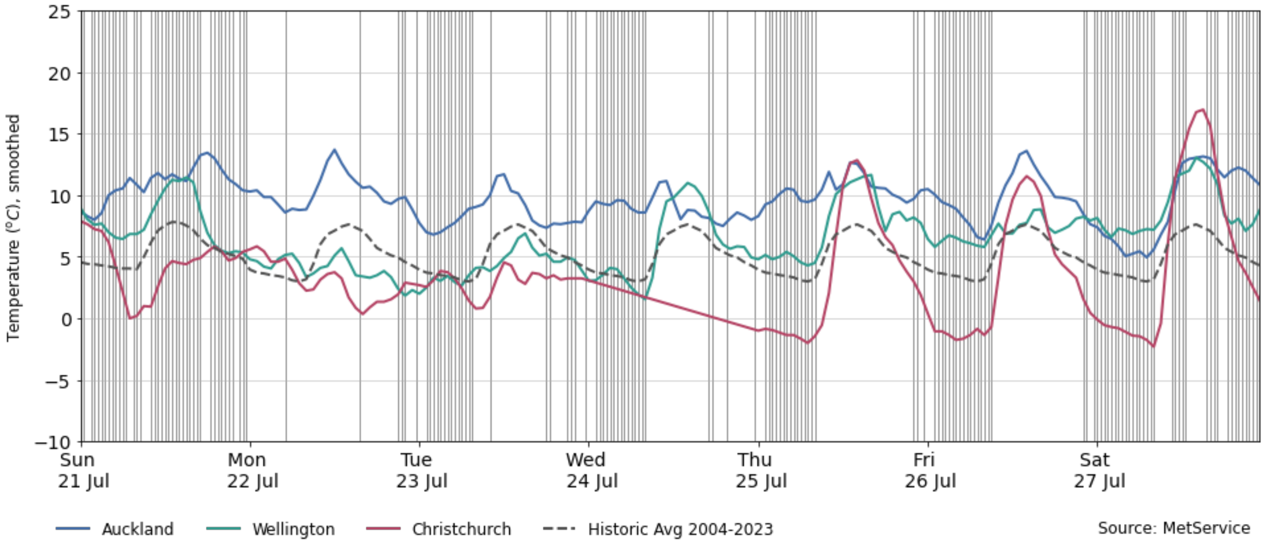
Figure 7: National demand, 21-27 July compared to historic range



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 21-27 July 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. Temperature data for Christchurch on Wednesday was not available.

6.3. Temperatures in Auckland were above the national average this week, between 5°C to 14°C. Wellington temperatures were generally close to or above average, between 2°C to 13°C. Temperatures in Christchurch were variable, ranging from -2°C to 17°C.

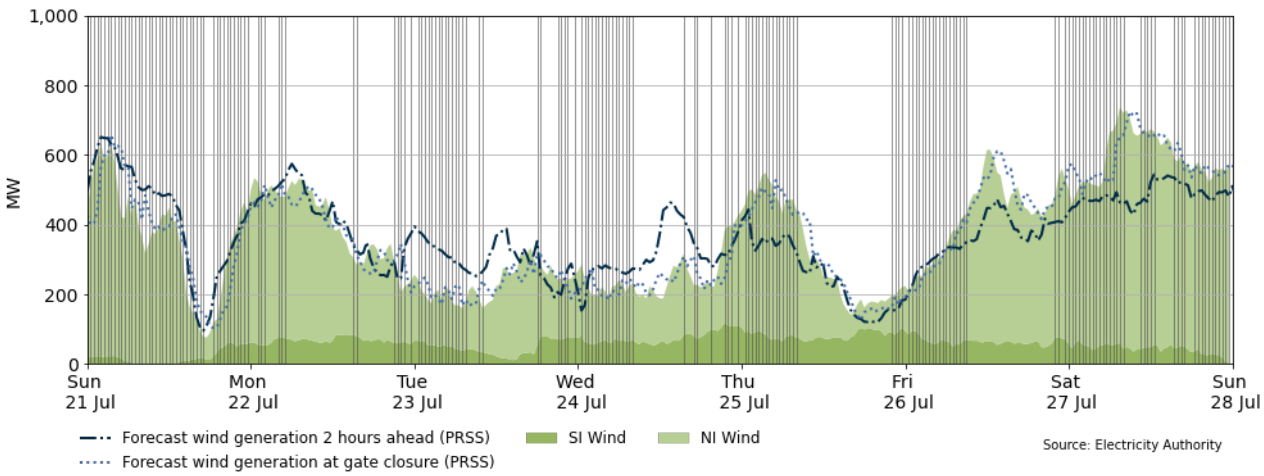
Figure 8: Temperatures across main centres, 21-27 July



7. Generation

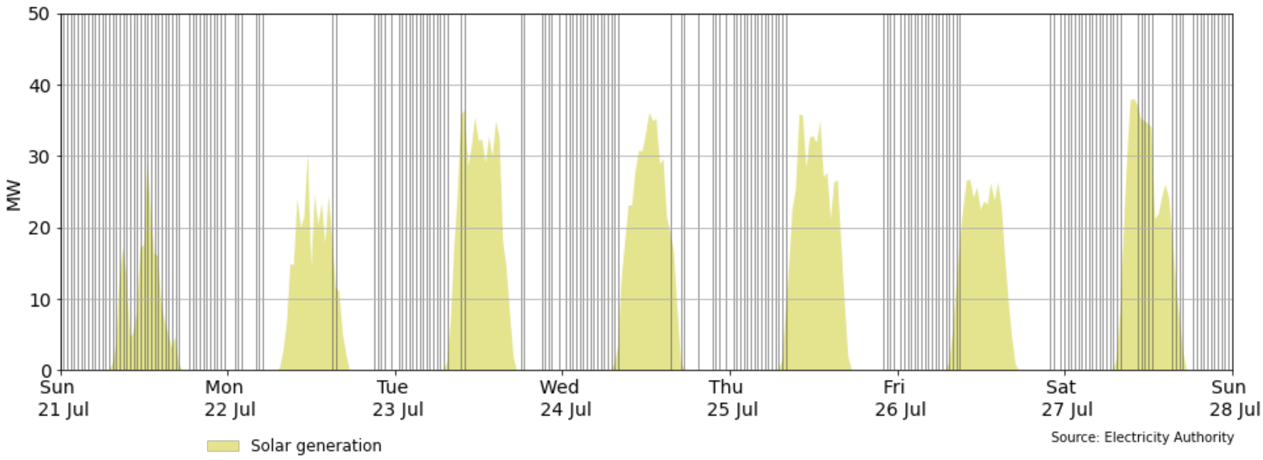
7.1. Figure 9 shows wind generation and forecast from 21-27 July. This week wind generation varied between 76MW and 736MW, with an average of 369MW. Forecasting inaccuracies may have contributed to high prices this week, with wind generation more than 100MW below forecast at the times highlighted prices occurred on Sunday and Tuesday.

Figure 9: Wind generation and forecast, 21-27 July



7.2. Figure 10 shows solar generation from 21-27 July. Solar generation reached 30MW every day except Monday and Fridy 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, 21-27 July

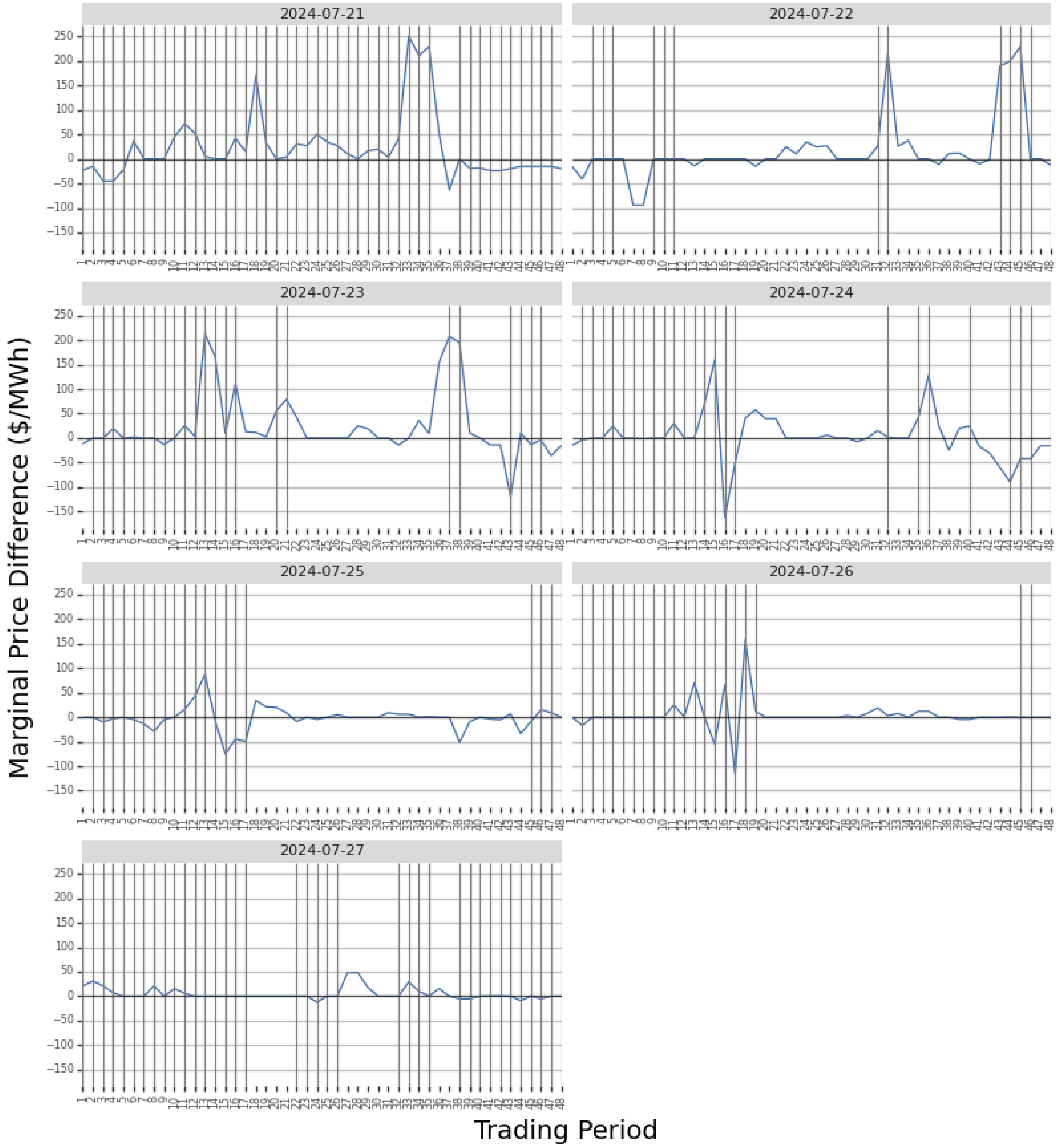


7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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 $251/MWh at 4:00pm on Sunday, when demand was 150MW higher than forecast and wind was 60MW below forecast. Positive differences exceeding $200/MWh also occurred on Monday and Tuesday.

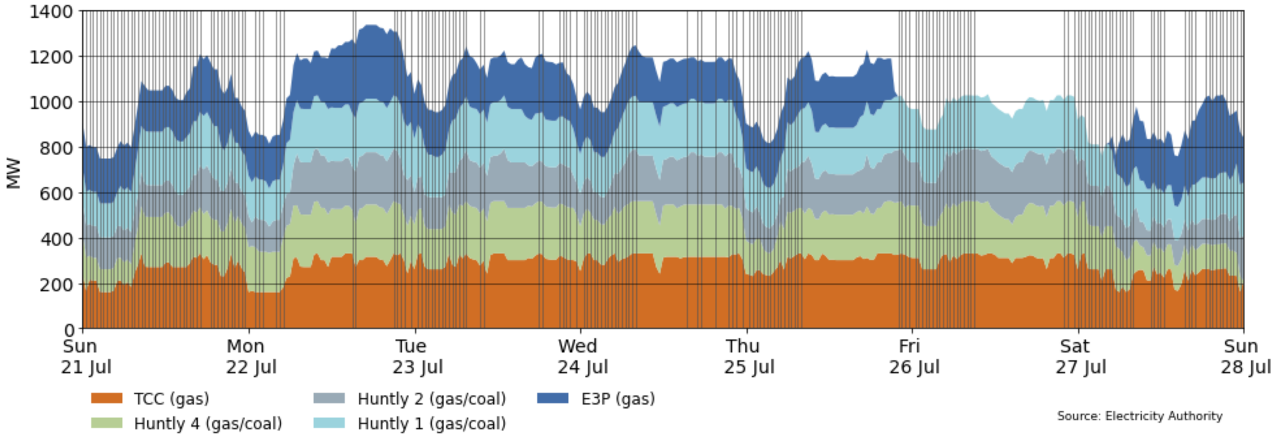
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 21-27 July



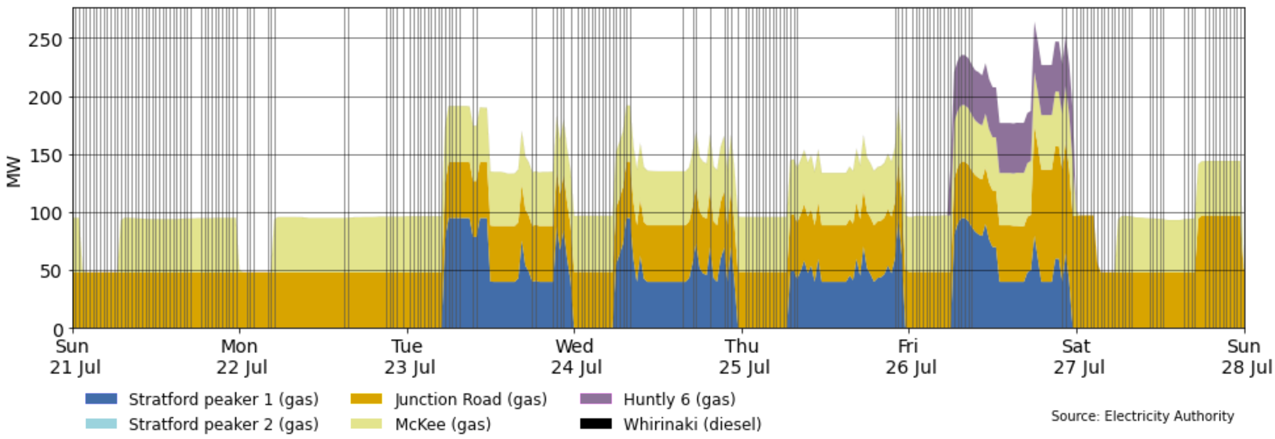
7.5. Figure 12 shows the generation of thermal baseload between 21-27 July. TCC, Huntly 4, Huntly 2, Huntly 1 and Huntly 5 (E3P) provided baseload generation this week. All units ran continuously apart from E3P, which was on outage from Thursday evening to Saturday morning.

Figure 12: Thermal baseload generation, 21-27 July



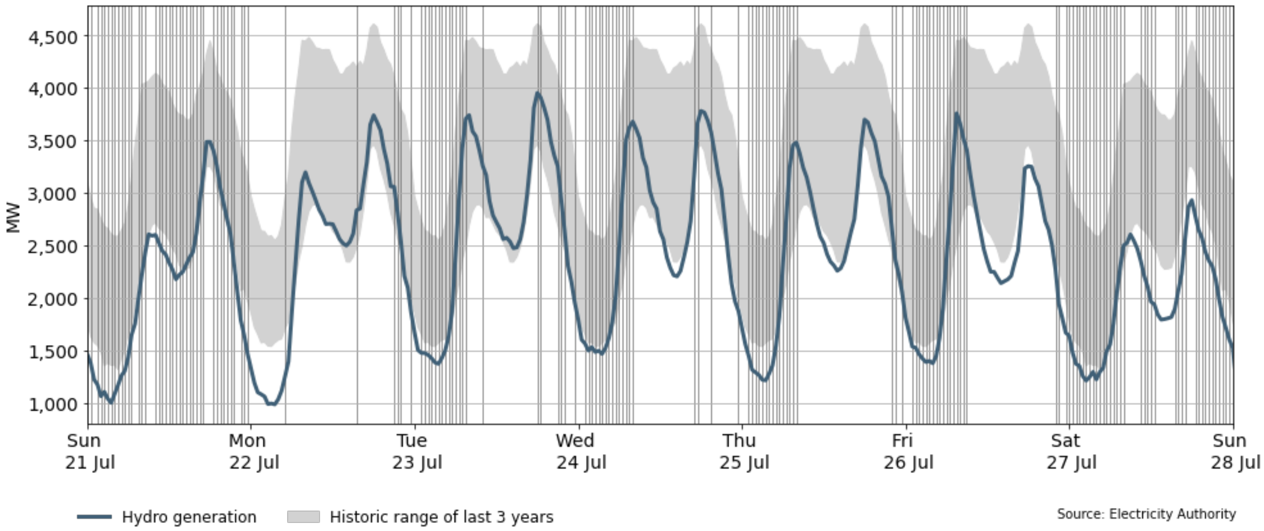
7.6. Figure 13 shows the generation of thermal peaker plants between 21-27 July. Junction Road ran continuously as baseload support the entire week. McKee ran near continuously, but turned off early in the morning on Sunday, Monday and Saturday, possibly to conserve gas. Stratford 1 ran from morning to midnight each day between Tuesday and Friday. Huntly 6 ran on Friday while E3P was on outage.

Figure 13: Thermal peaker generation, 21-27 July



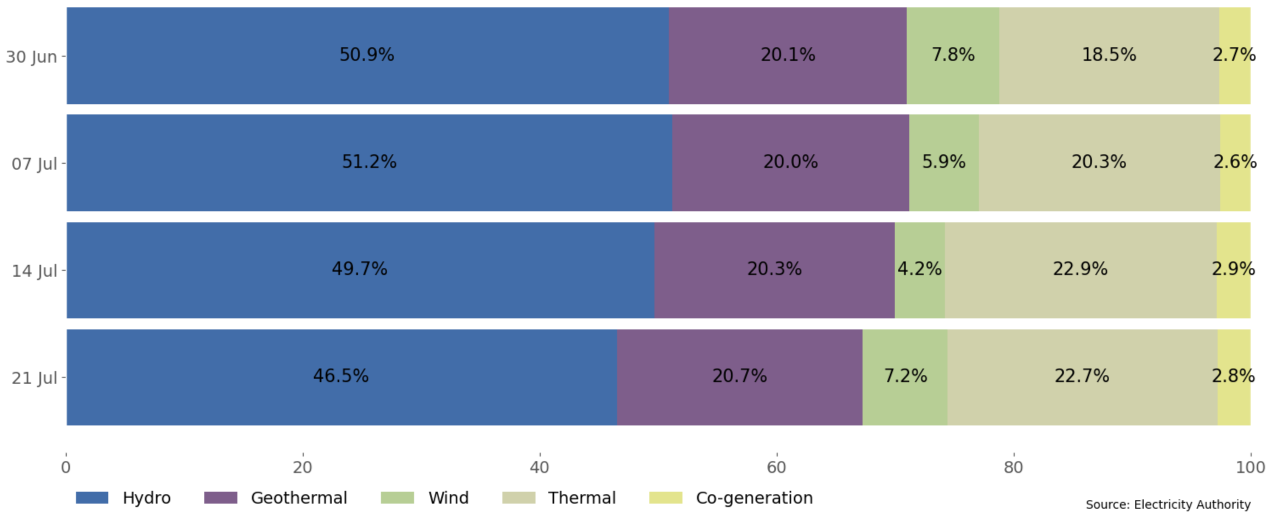
7.7. Figure 14 shows hydro generation between 21-27 July. Hydro generation was low this week, often close to the minimum of or below the historical range. This is due to low hydro storage, with a significant portion of hydro generation capacity priced highly to reduce likelihood that it will be dispatched and to conserve water. However, at times this capacity was needed, resulting in higher prices.

Figure 14: Hydro generation, 21-27 July



7.8. As a percentage of total generation, between 21-27 July, total weekly hydro generation was 46.5%, geothermal 20.7%, wind 7.2%, thermal 22.7%, and co-generation 2.8%, as shown in Figure 15. Wind generation increased this week, compensating for the decrease in hydro generation.

Figure 15: Total generation by type as a percentage each week, 30 June – 27 July 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 21-27 July ranged between ~880MW and ~1,400MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 5 (E3P) was on outage from 25-27 July.

(b) Stratford 2 is on outage until 23 September.

(c) McKee has one unit on outage until 2 August.

(d) Junction Road had one unit on outage until 26 July.

Figure 16: Total MW loss from generation outages, 21-27 July

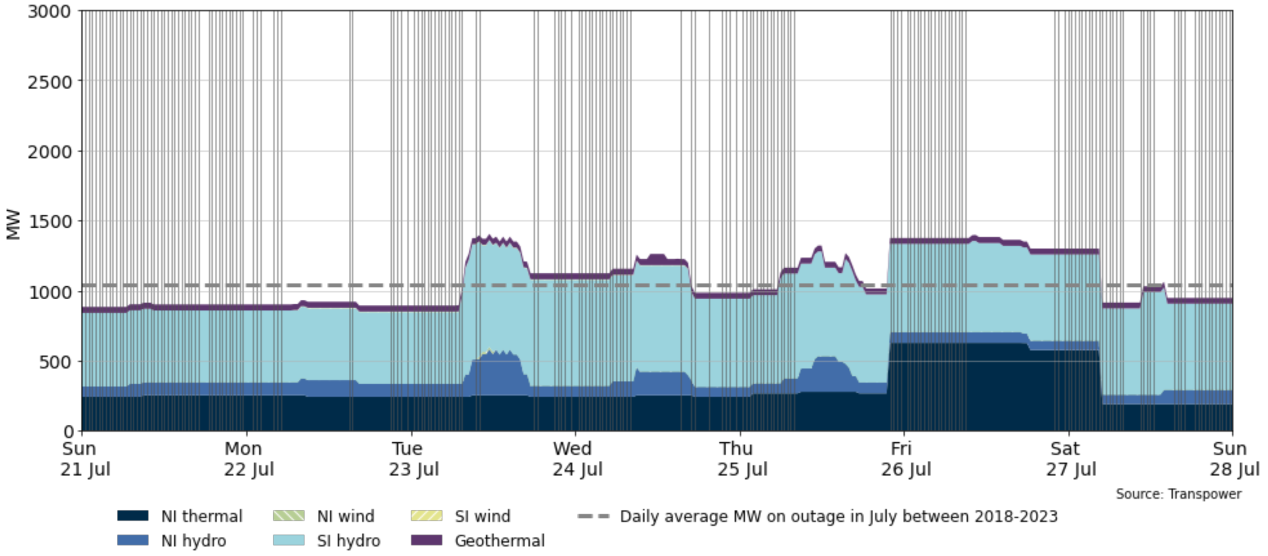
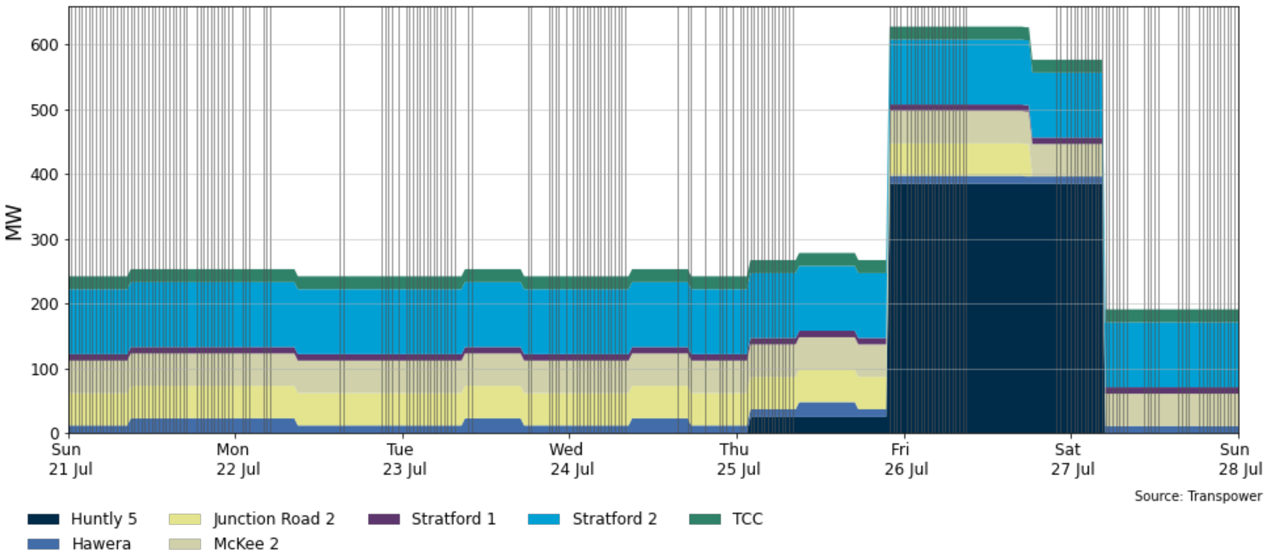


Figure 17: Total MW loss from thermal outages, 21-27 July

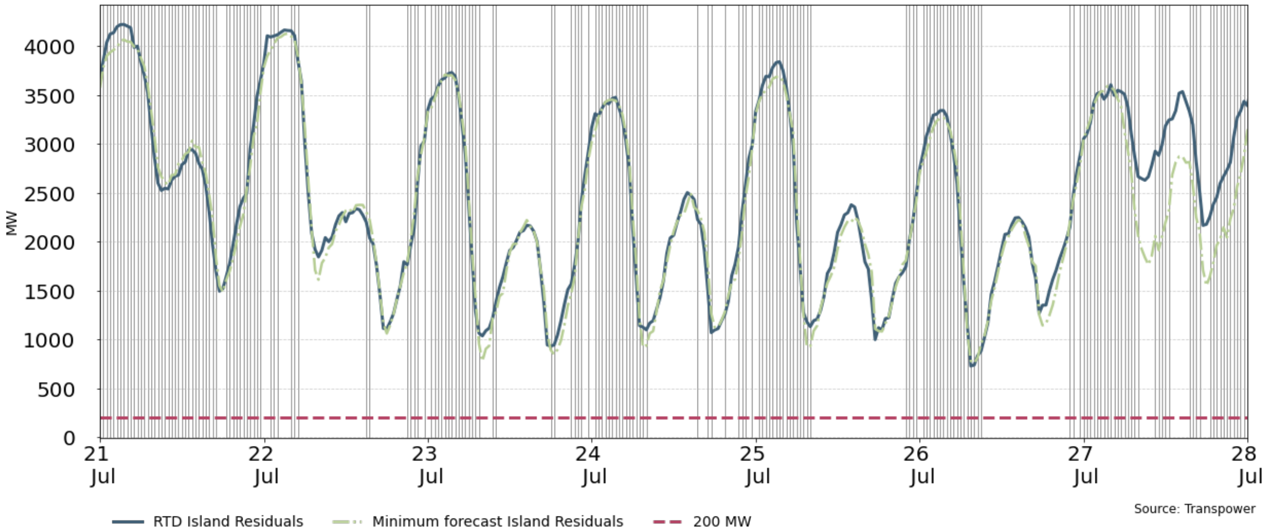


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 21-27 July. 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 312MW at 8:00am on Friday.

Figure 18: National generation balance residuals, 21-27 July



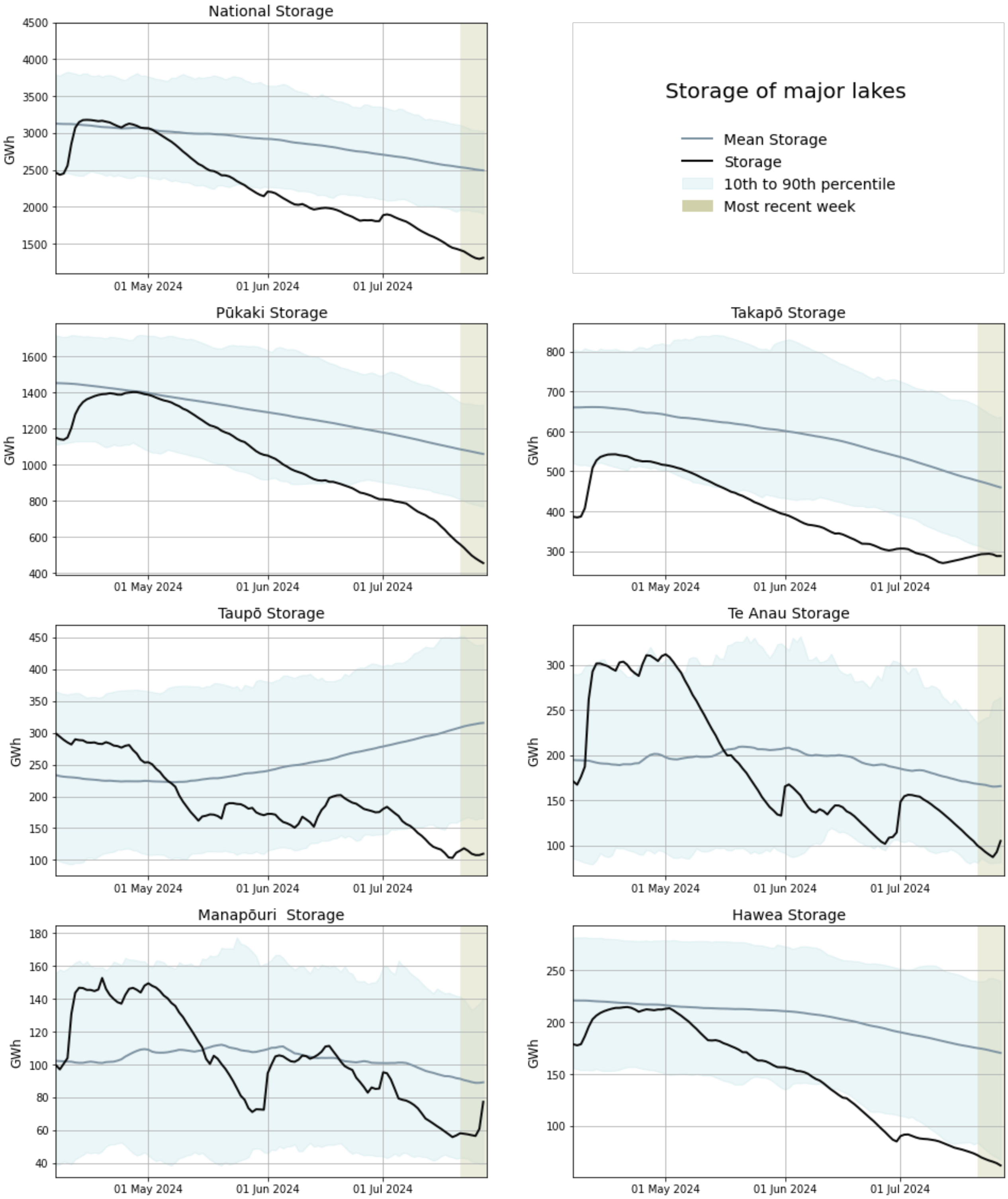
10. Storage/fuel supply

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 this week, with a slight increase towards the end of the week. As of 27 July, national controlled storage was ~37% nominally full and ~59% of the historical average for this time of the year.

10.3. Storage at Pūkaki continued to decrease, falling further below its 10th percentile. Storage at Takapō increased slightly, remaining just below its 10th percentile. Storage at Taupō fluctuated over the week, but decreased overall and remained below its 10th percentile. Storage at Te Anau and Manapōuri increased from the middle of the week, remaining below mean but above their respective 10th percentiles. Storage at Hawea continued to decrease and remained below its 10th percentile.

Figure 19: Hydro storage



Source: Electricity Authority

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 July 2024. The SRMC for diesel and gas have both increased from the previous month, while the coal SRMC has remained stable.

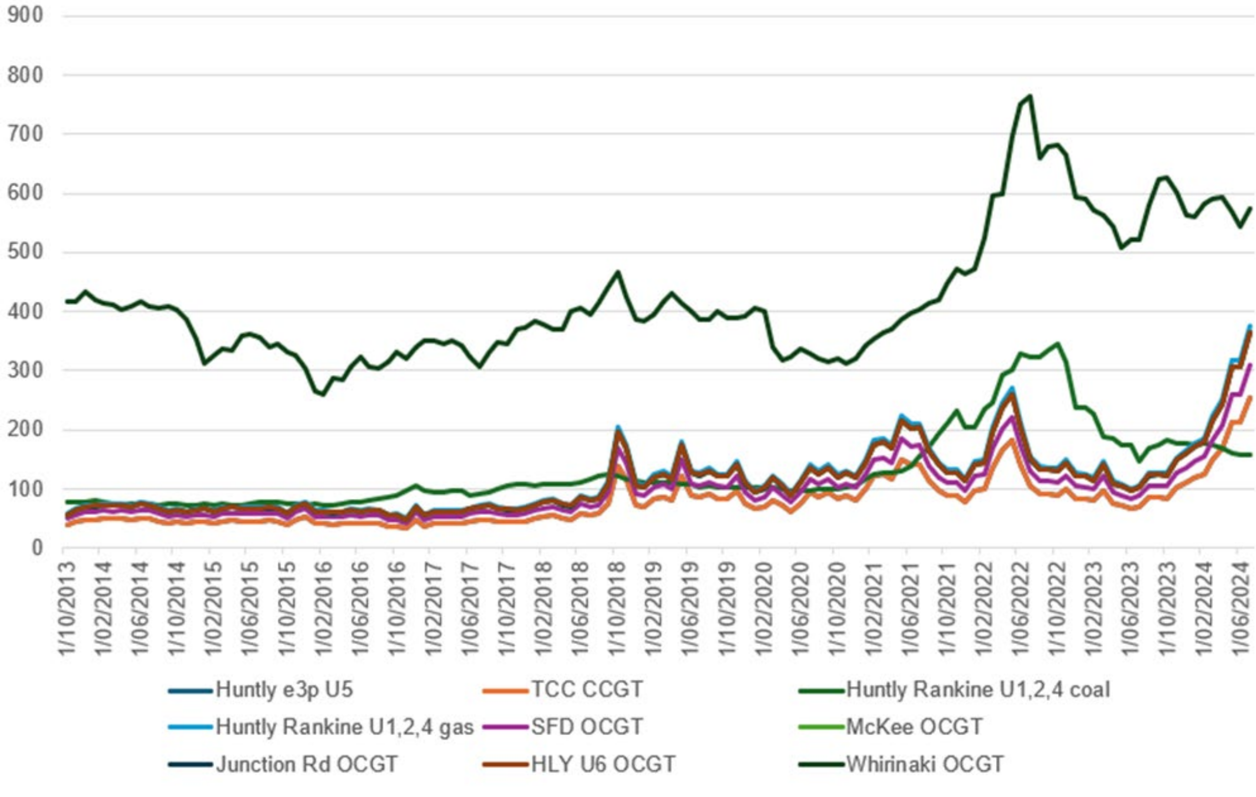
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$158/MWh. The cost of running the Rankines on gas remains more expensive at ~$377/MWh.

11.5. The SRMC of gas fuelled thermal plants continues to increase and is currently between ~$254/MWh and ~$377/MWh.

11.6. The SRMC of Whirinaki is ~$573/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



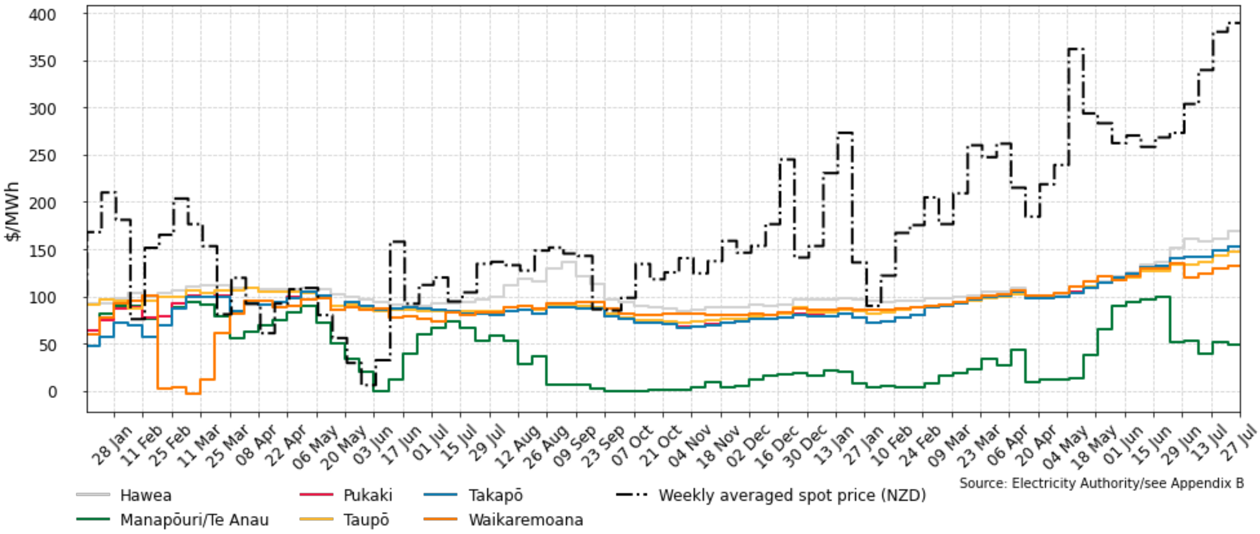
Source: Electricity Authority/see Appendix C

12. JADE water values

12.1. 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 8 January 2023 and 27 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.

12.2. Water values continued to increase by between $3.10/MWh (Waikaremoana) to $7.90/MWh (Hawea) this week at lakes except Manapouri, which decreased by $1.80/MWh. Overall, the model indicates a significant increase in water values over the last few months.

Figure 21: JADE water values across various reservoirs, 8 January 2023 and 27 July 2024



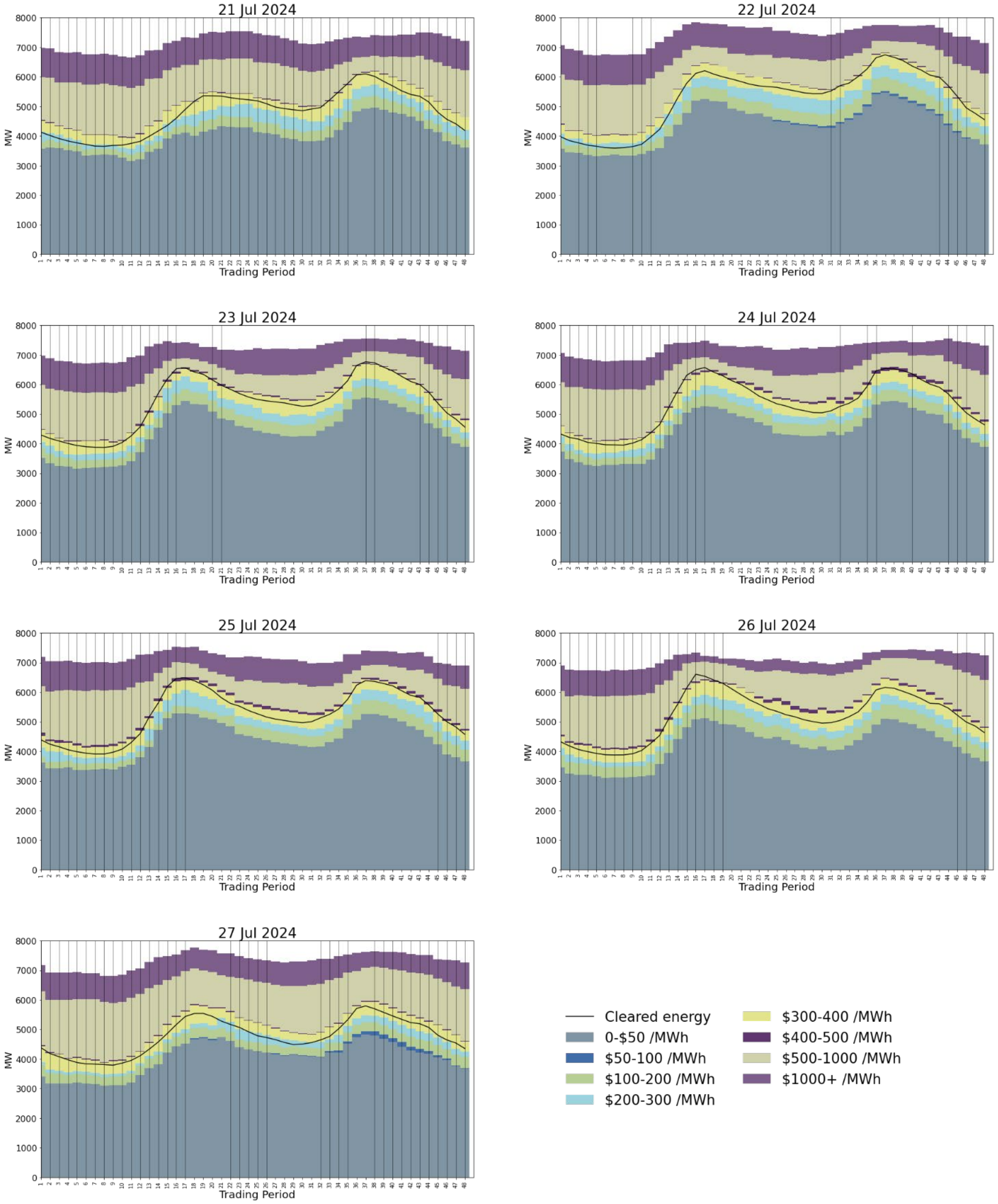
13. Offer behaviour

13.1. Figure 22 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.

13.2. Most offers cleared in the $300-$400/MWh band this week. The number of offers over $500/MWh remains high as a result of low lake levels increasing the price of hydro generation in order to conserve water. The thin $400-$500/MWh offer band led to a price spike exceeding $500/MWh at times each day this week, especially when there were forecast inaccuracies.

[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.

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.

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	Resolved	Meridian	South Island	High energy and reserve prices
06/07/2024	41-48	Resolved	N/A	N/A	Energy offers
13/07/2024	Several	Further analysis	N/A	N/A	High energy prices