29 April 2024

Trading conduct report

Market monitoring weekly report

Trading conduct report

1. Overview for the week of 21-27 April

1.1. Spot prices increased slightly this week, with most prices between $189-$248/MWh. This week there were no notable spot or reserve price separations or spikes. Demand generally increased this week, reaching the highest mark for the year on Monday. Hydro storage remained stable this week at ~102% of its historical average. The percentage contribution from hydro storage decreased this week due to several days of high wind generation.

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, we also single 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 21-27 April:

(a) The average wholesale spot price across all nodes was $214/MWh.

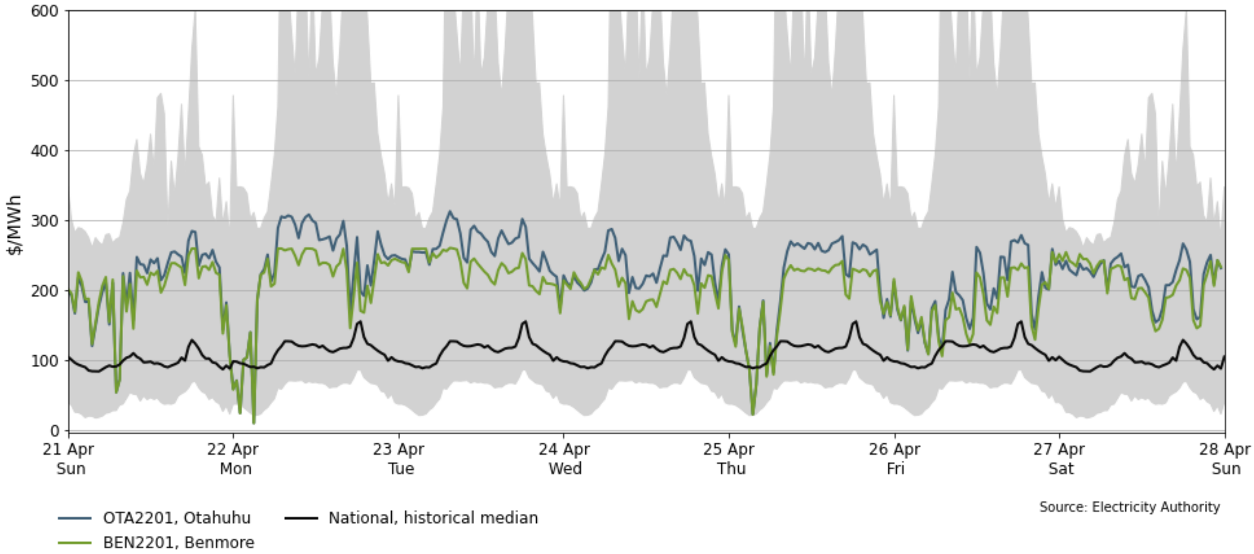
(b) 95% of prices fell between $77/MWh and $286/MWh.

2.3. This week, the majority of the spot prices were above the national historical median. Prices increased compared to the previous week with the average price increasing by around $37/MWh. There were no price spikes this week.

2.4. 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[1] of historic prices are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

[1] We are identifying any significantly high prices by using the historic distribution of prices depending on whether it is a weekday or weekend day and looking for prices that lie 1.5 times the interquartile range above the 75th percentile of the distribution. This is using the outlier calculation $Q_3+1.5\times IQR$, where Q_3 is the 75th percentile (or third quartile value) and IQR is your inter-quartile range.

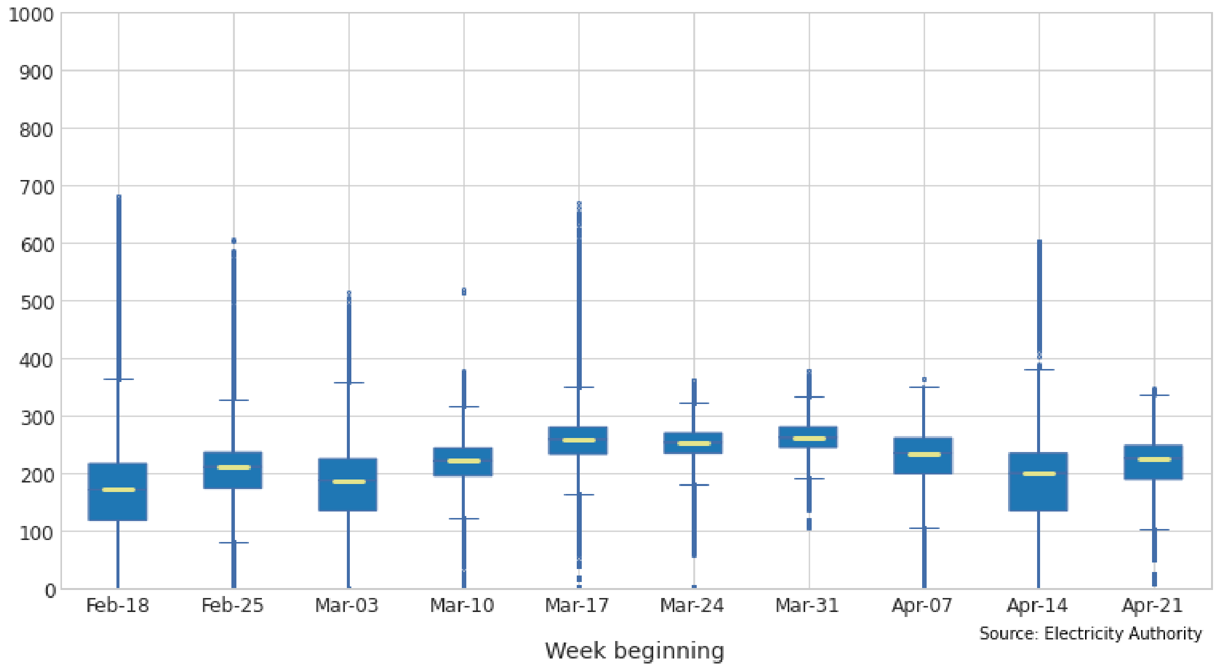
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu between 21-27 April



2.5. 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 box part shows the lower and upper quartiles (where 50% of prices fell). The "whiskers" extend to points that lie within 1.5 times the inter-quartile range (IQR) of the lower and upper quartile, and then observations that fall outside this range are displayed independently.

2.6. The spot price distribution was more condensed this week due to market conditions remaining relatively stable. This week's median price was $226/MWh, compared to $195/MWh in the previous week, a $31/MWh increase. The middle 50% of the prices were between $189-$248/MWh.

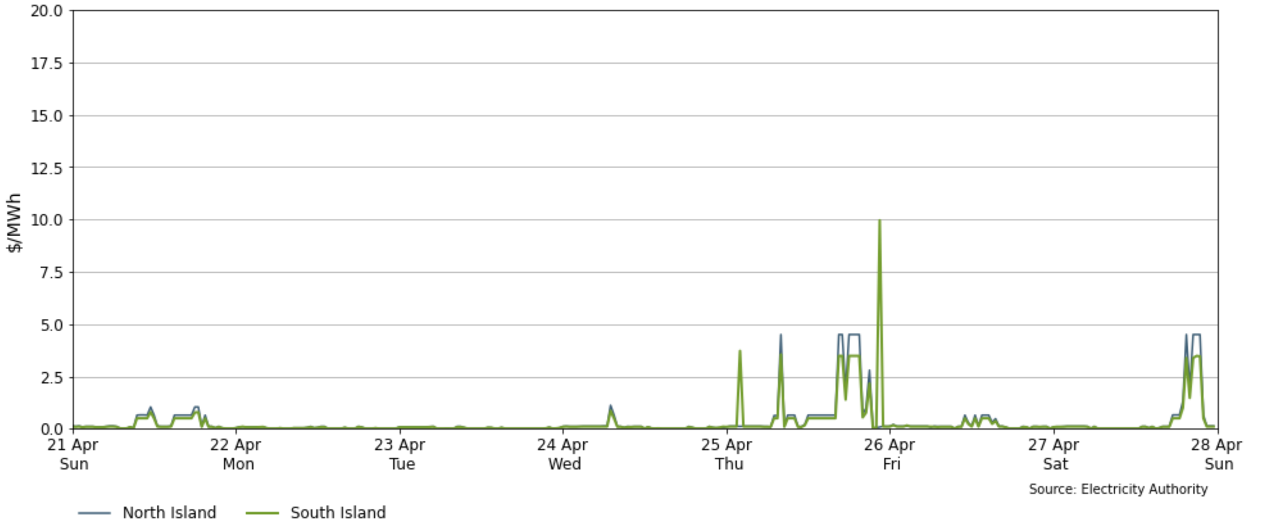
Figure 2: Boxplots showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

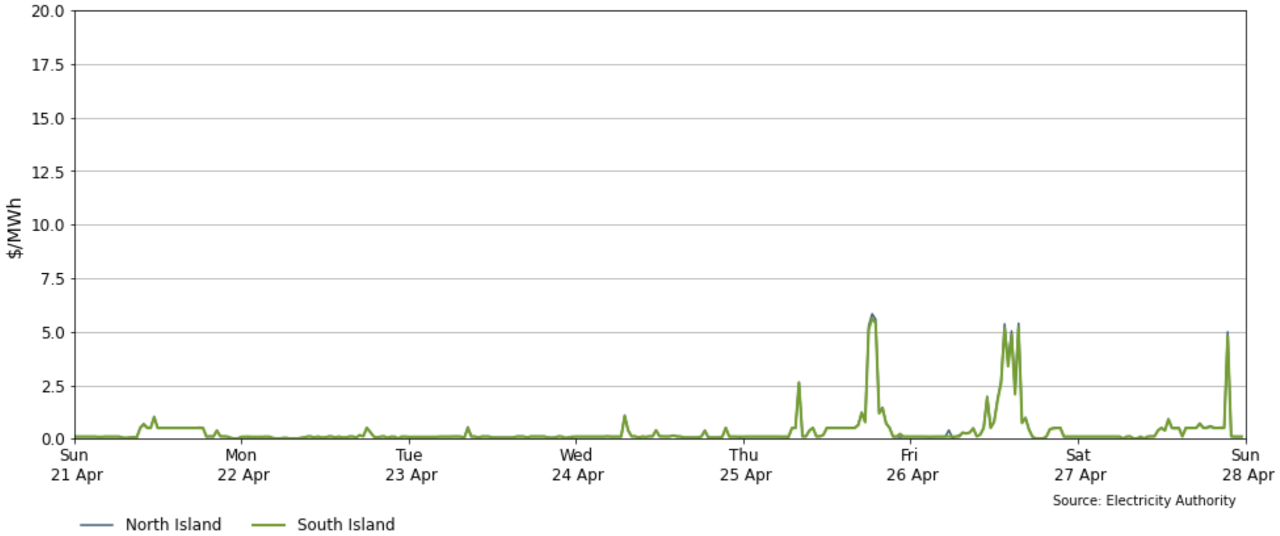
3.1. Fast Instantaneous Reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were all below $10/MWh this week. High HVDC southward flows on Thursday at 10:30pm during the trading period 46 caused a small spike in FIR prices.

Figure 3: Fast Instantaneous Reserve (FIR) price by trading period and island between 21-27 April



3.2. Sustained Instantaneous Reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mainly below $5/MWh this week, with a few prices on Thursday and Friday above that mark, but below $10/MWh.

Figure 4: Sustained Instantaneous Reserve (SIR) by trading period and island between 21-27 April



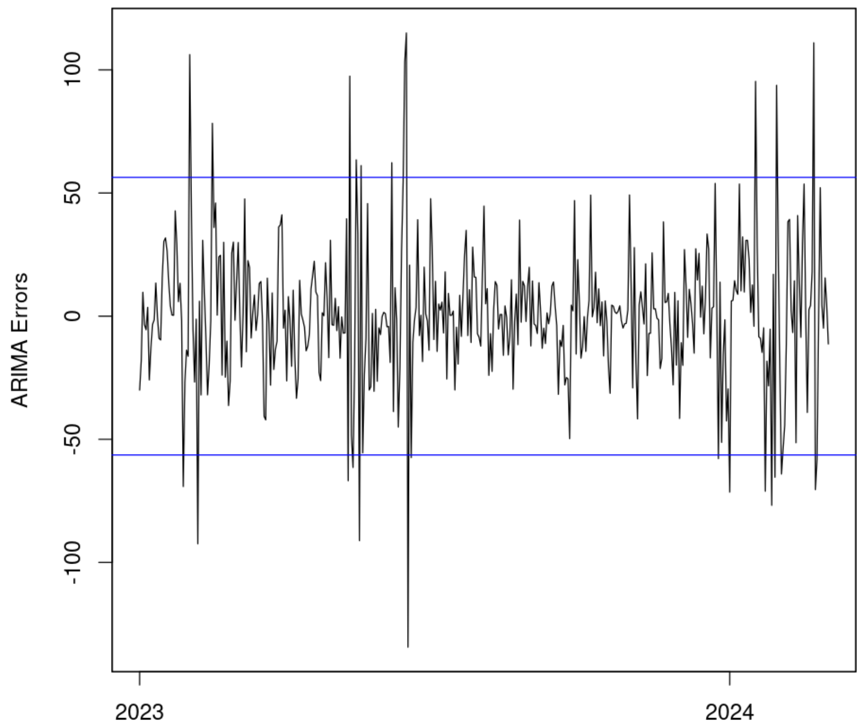
4. Regression residuals

4.1. The Authority's monitoring team uses a regression model to model spot price. The residuals show how close the predicted 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 on the trading conduct webpage.

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 for 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 from 1 January 2023 to 27 April 2024

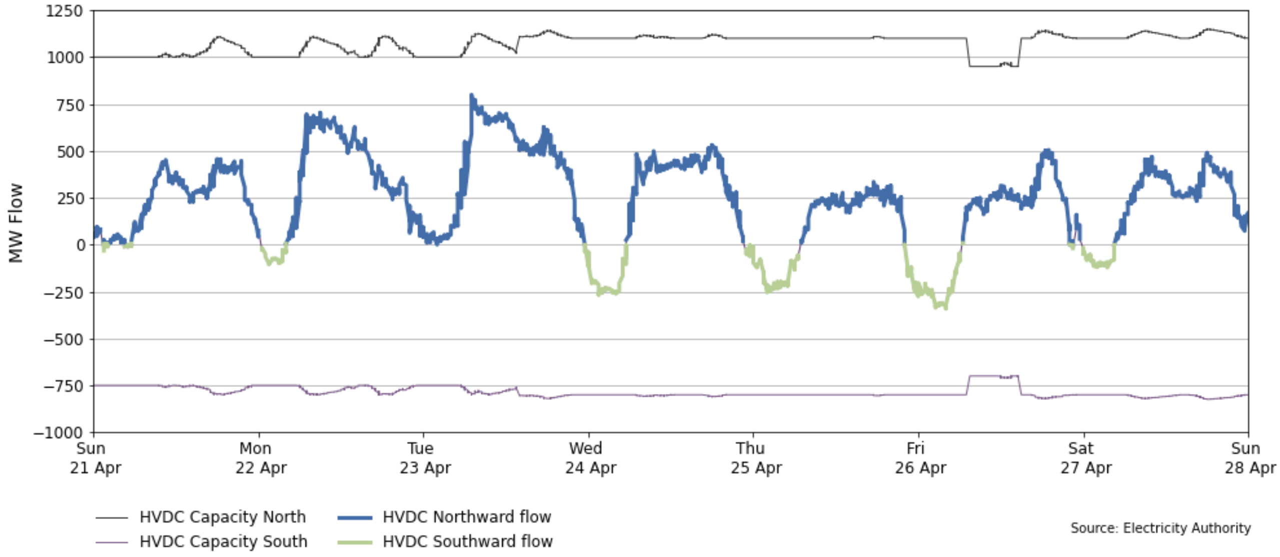


Source: Electricity Authority/see Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 21-27 April. HVDC was mostly flowing northward until Tuesday due to relatively low wind generation. From Tuesday onwards, higher southward overnight HVDC flows occurred due to high wind generation. Northward flows were also reduced on Wednesday and Friday due to high North Island wind generation. Flows were also lower on Thursday due to high wind generation and lower demand during the ANZAC day holiday.

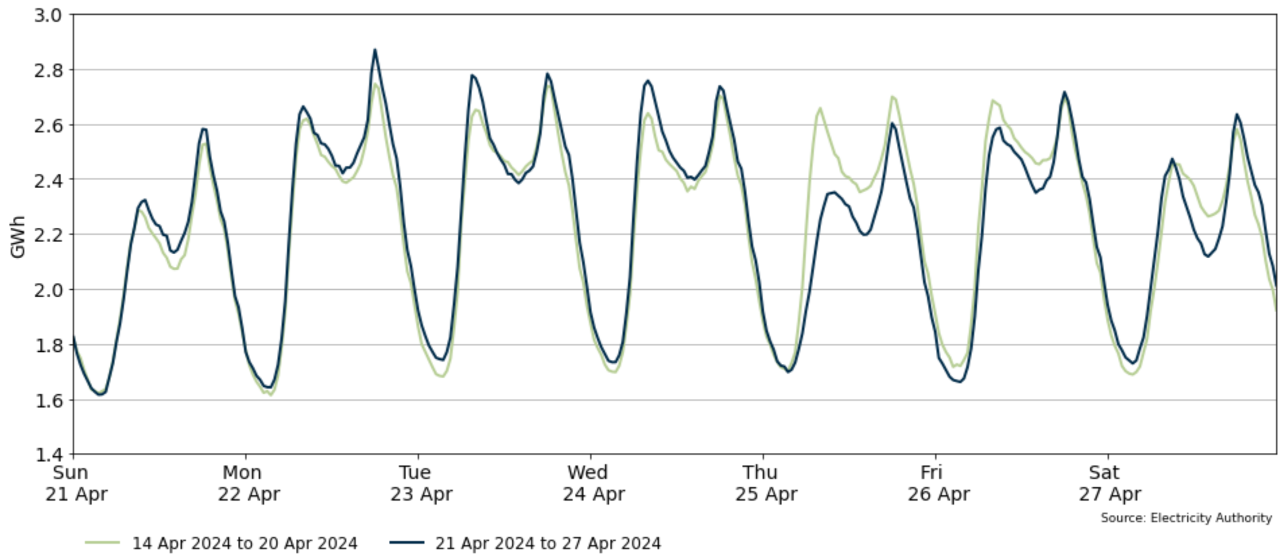
Figure 6: HVDC flow and capacity between 21-27 April



6. Demand

6.1. Figure 7 shows national demand between 21-27 April, compared to the previous week. Demand this week was slightly higher than the previous week except for Thursday due to the ANZAC day holiday. The Monday evening peak reached around 2.87GWh, the highest on record this year so far.

Figure 7: National demand between 21-27 April compared to the previous week

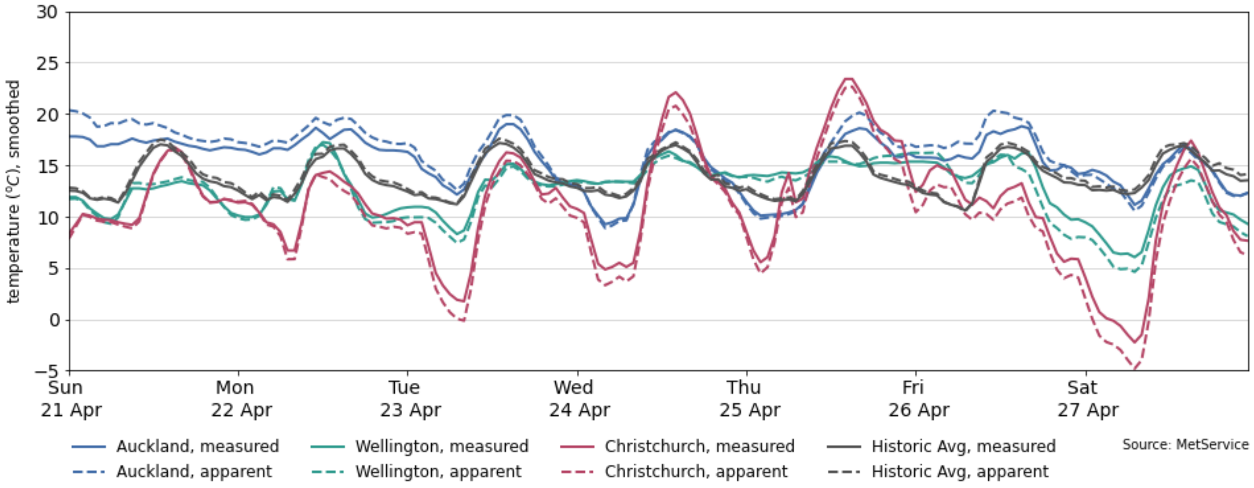


6.2. Figure 8 shows the hourly temperature at main population centres from 21-27 April. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature of similar weeks, from previous years, averaged across the three main population centres.

6.3. Apparent temperatures in Auckland were mostly at or above the historical averages this week, with temperatures varying between 9ºC and 20ºC. Temperatures in Wellington and Christchurch were often at or below the historical average this week, with

Christchurch showing larger temperature swings, between -5ºC and 23ºC. In Wellington, the apparent temperatures fluctuated between 5ºC and 17ºC.

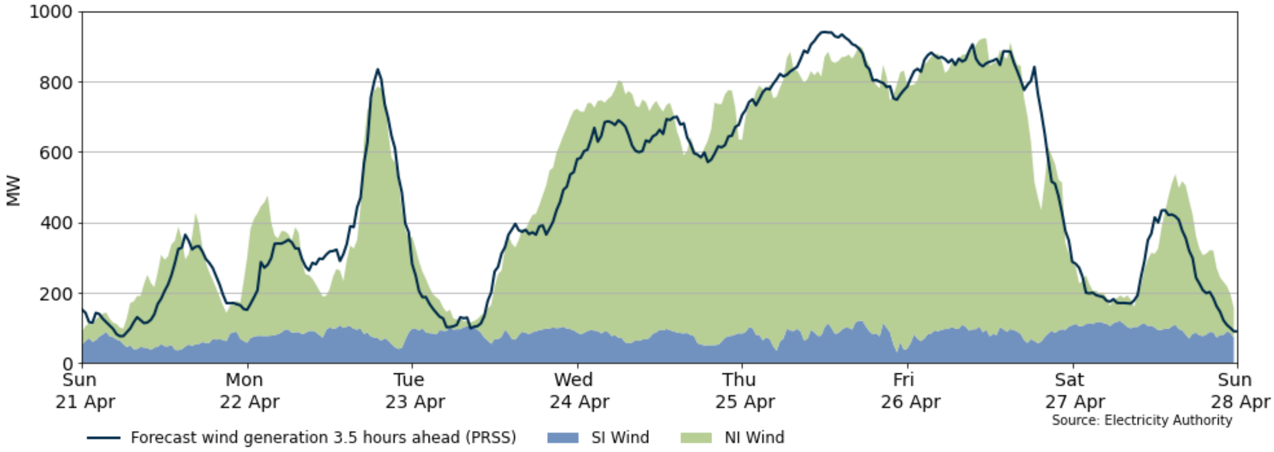
Figure 8: Temperatures across main centres between 21-27 April



7. Generation

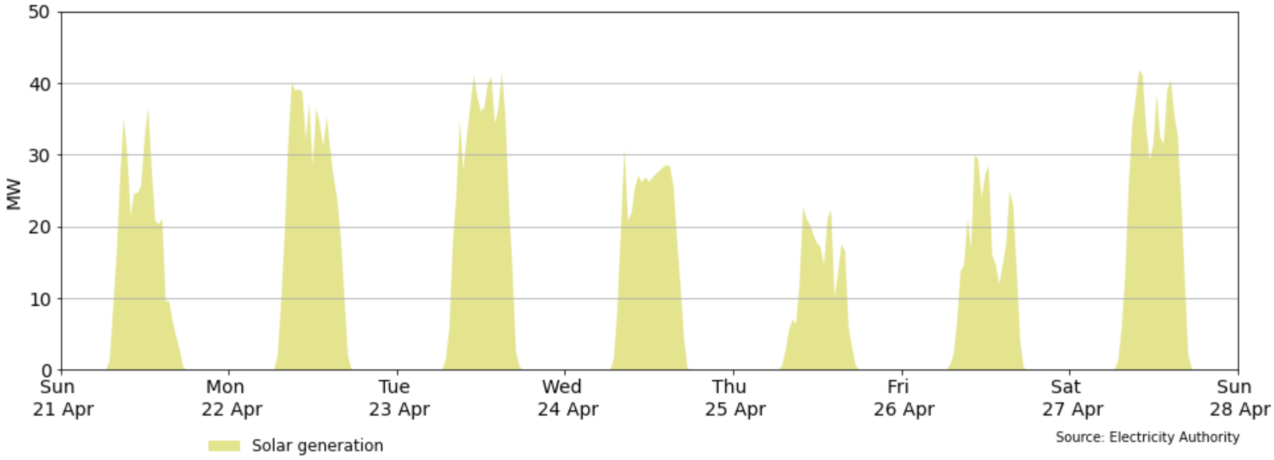
7.1. Figure 9 shows wind generation and forecast from 21-27 April. This week wind generation varied between 91MW and 922MW, with an average of 504MW. Wind generation was consistently high between Tuesday and Friday, at around 400MW-900MW. The remainder of the week saw wind generation mostly below 400MW, except for a few peaks, most notably on Monday evening, when generation reached almost 800MW for a short time.

Figure 9: Wind generation and forecast between 21-27 April



7.2. Figure 10 shows solar generation from 21-27 April. Solar generation was between 23MW-42MW this week, the minimum occurring on Thursday due to overcast conditions.

Figure 10: Solar generation between 21-27 April



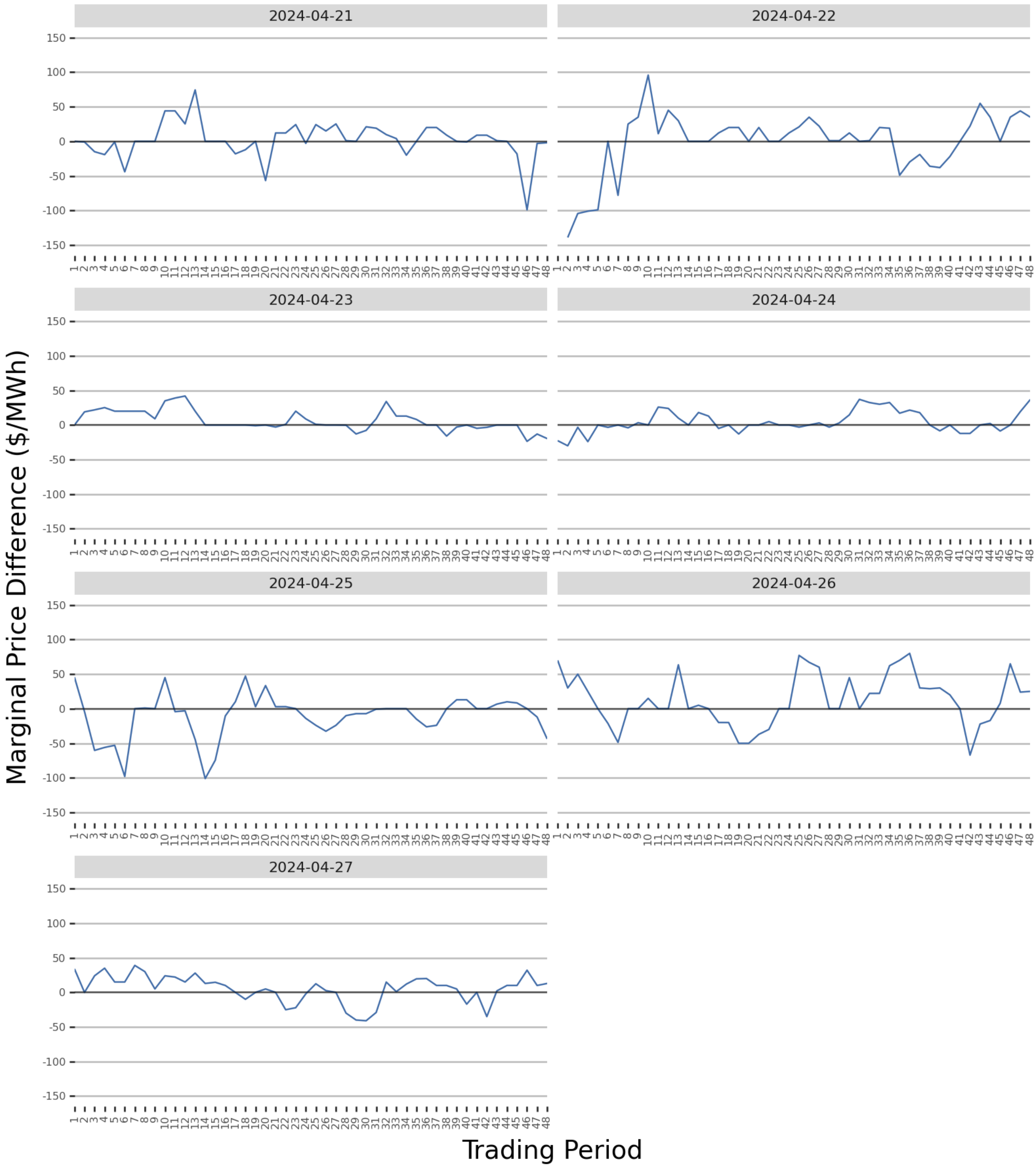
7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS) projections. The figure highlights when forecasting inaccuracies are causing large differences to 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, but 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. This week the most notable negative differences (prices lower than forecast) occurred between trading periods 1-3 (0:00am-1:30am) on Monday and during trading periods 6 and 14 (6:30am) on Thursday. The differences seen on Monday are related to wind generation being under-forecast sometimes by more than 200MW. On Thursday, wind generation was under-forecast while demand was over-forecast.

7.5. The largest positive price difference occurred on Monday when prices were around $100/MWh higher than the PRSS forecast during the trading period 10 at 4:30am when demand was under-forecast.

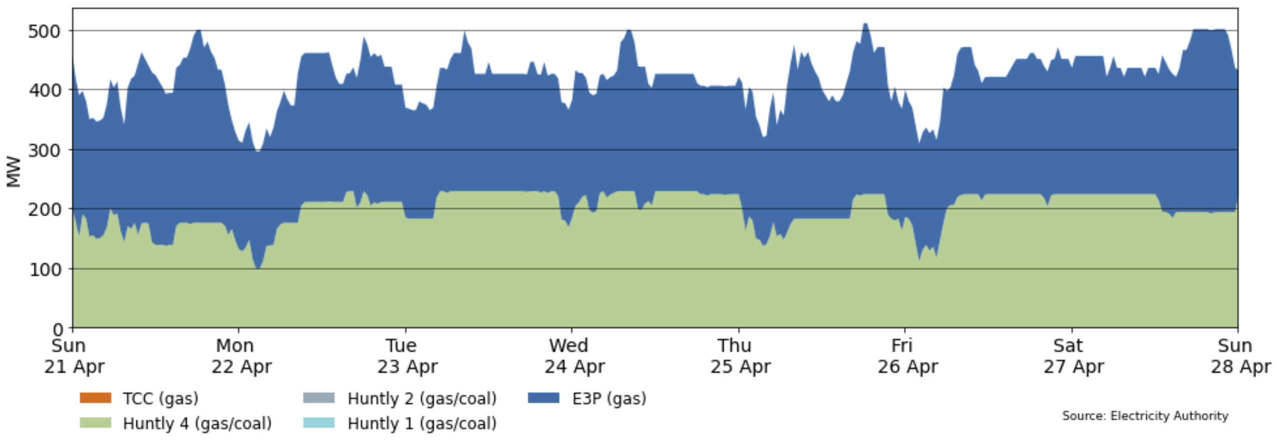
7.6. During most of the time this week, however, differences between actual and simulated RTD marginal prices were between +/-$100/MWh.

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 between 21-27 April



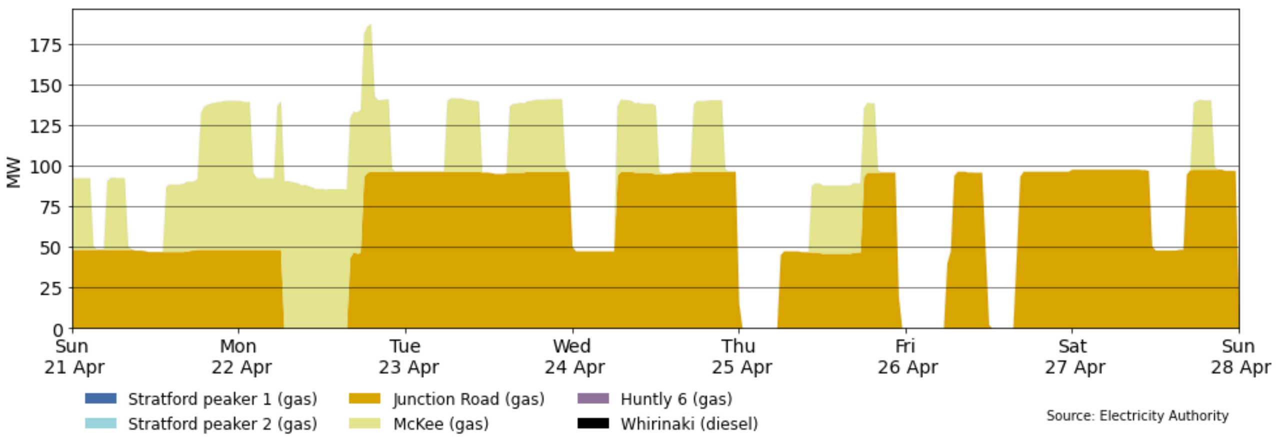
7.7. Figure 12 shows the generation of thermal baseload between 21-27 April. Huntly units 4 and 5 (E3P) ran continuously this week to support baseload, combined generating 300MW or more every day.

Figure 12: Thermal baseload generation between 21-27 April



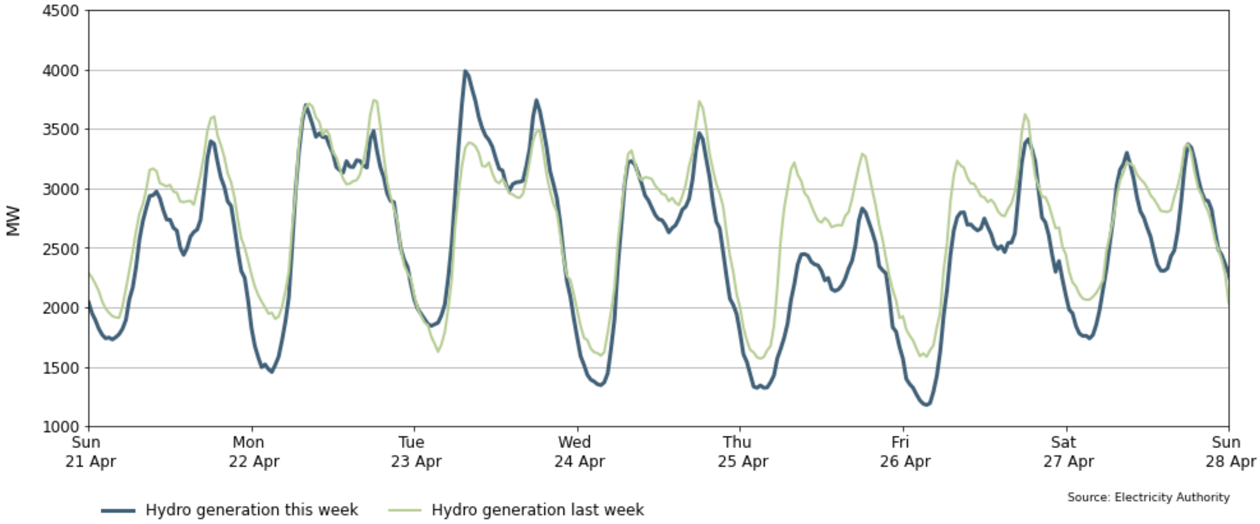
7.8. Figure 13 shows the generation of thermal peaker plants between 21-27 April. This week Junction Road and McKee were the only peaker plants running. Junction Road ran for most of the week, providing between ~50MW-~100MW. McKee ran more frequently during the first half of the week, and harder during the Monday evening demand peak.

Figure 13: Thermal peaker generation between 21-27 April



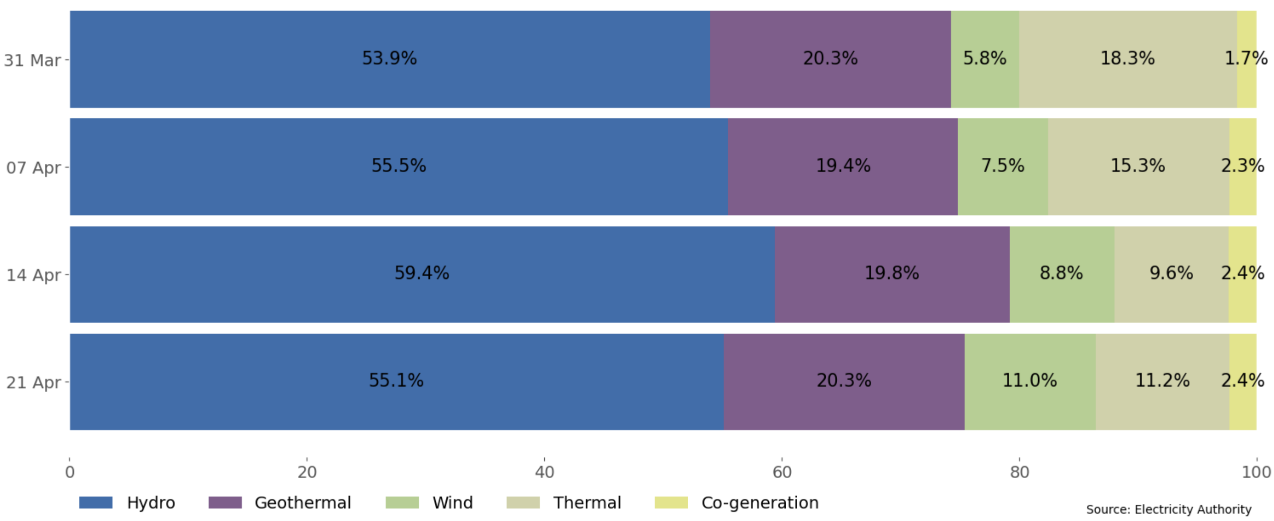
7.9. Figure 14 shows hydro generation between 21-27 April. Hydro generation this week was often similar or lower when compared to the previous week, except for Tuesday when wind generation was low.

Figure 14: Hydro generation between 21-27 April



7.10. As a percentage of total generation, between 21-27 April, total weekly hydro generation was 55.1%, geothermal 20.3%, wind 11%, thermal 11.2%, and co-generation 2.4%, as shown in Figure 15. The relative decrease in hydro generation this week can be related to the relative increase in wind generation, as hydro operators seek to conserve water for winter.

Figure 15: Total generation by type as a percentage each week between 17 March and 27 April



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 21-27 April ranged between ~1,150MW and ~1,800MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 1 is on outage until 29 April 2024

(b) Stratford 2 is on outage until 30 June 2024

(c) Junction Road was on partial outage between 21-22 April and on 25 April

(d) Stratford 1 was on outage between 22-24 April

(e) Several North and South Island hydro units were on outage this week.

Figure 16: Total MW loss due to generation outages between 21-27 April

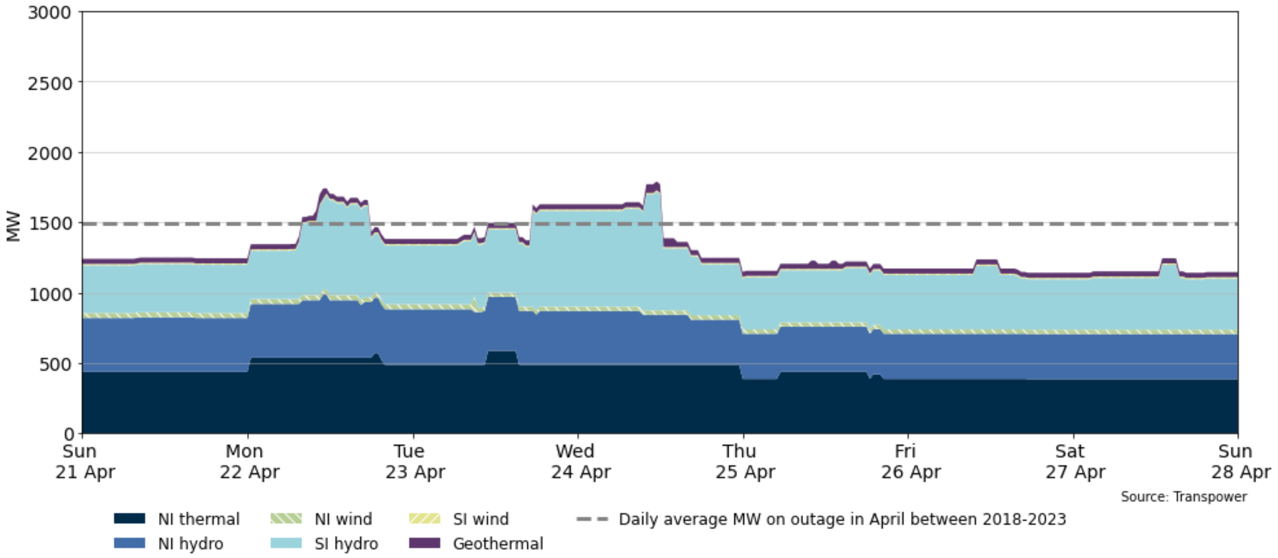
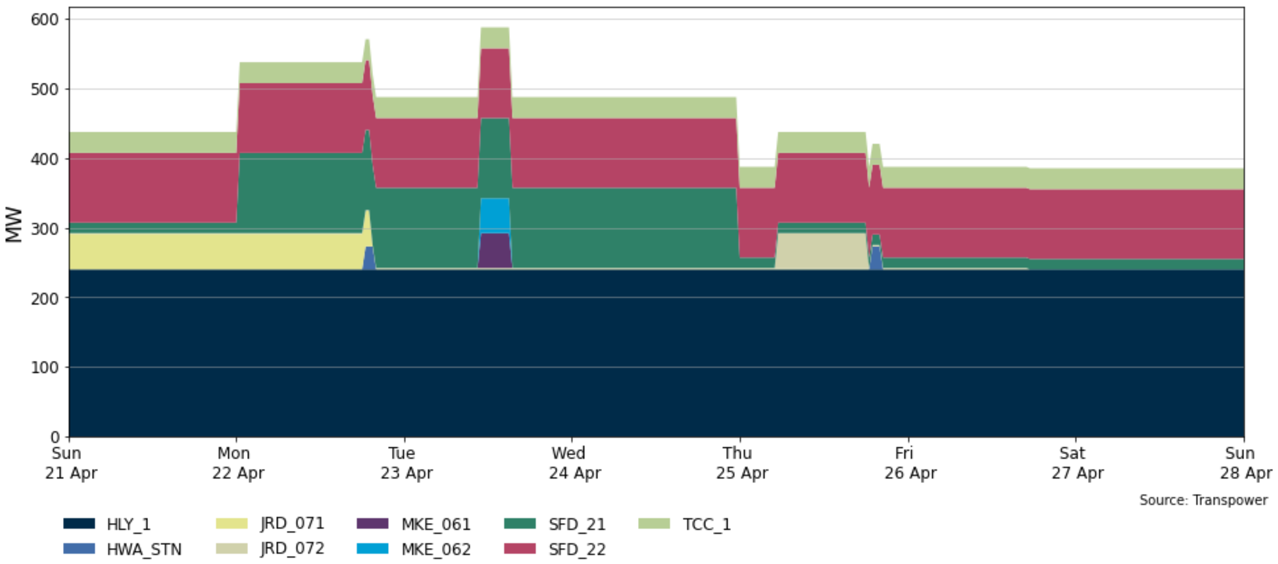


Figure 17: MW loss from thermal outages between 21-27 April



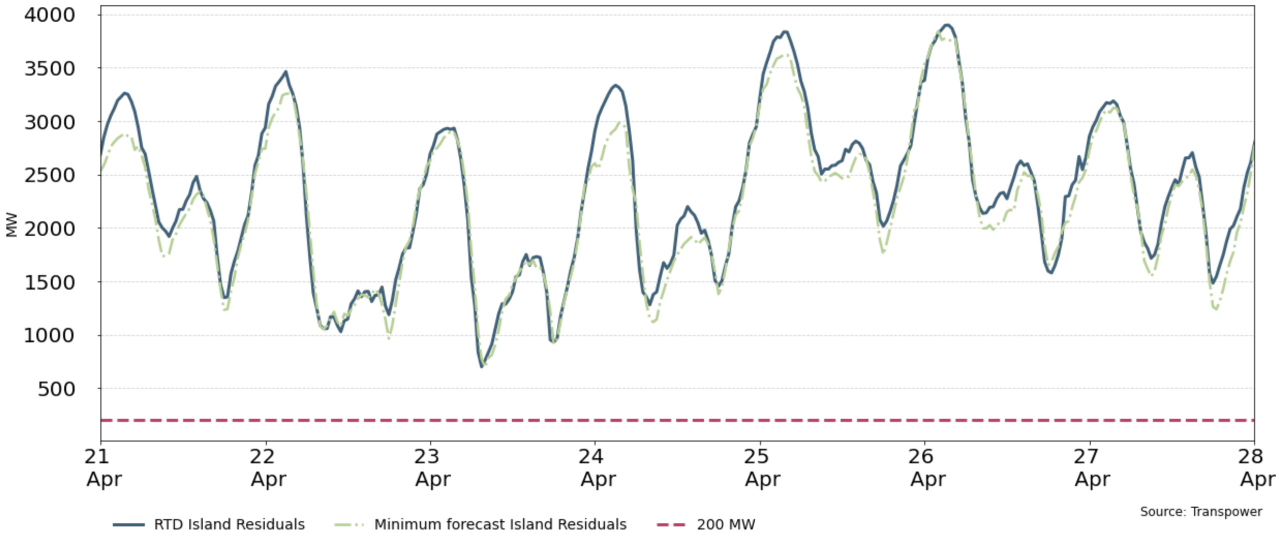
9. Generation balance residuals

9.1. Generation residuals were healthy this week, with the minimum national residual levels occurring on Tuesday at around 700MW and the minimum North Island residual levels at around 515MW when wind generation was low and demand was high.

9.2. Figure 18 shows the national generation balance residuals between 21-27 April. 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.

9.3. Generation residuals were healthy this week, with the minimum national residual levels occurring on Tuesday at around 700MW and the minimum North Island residual levels at around 515MW when wind generation was low and demand was high.

Figure 18: National generation balance residuals 21-27 April



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 remained stable this week, still sitting at 79% nominally full and ~102% of the historical average for this time of the year (as of 27 April).

(a) Lake Taupō is still sitting between its 90th percentile and its historical average after a slight decrease in storage this week.

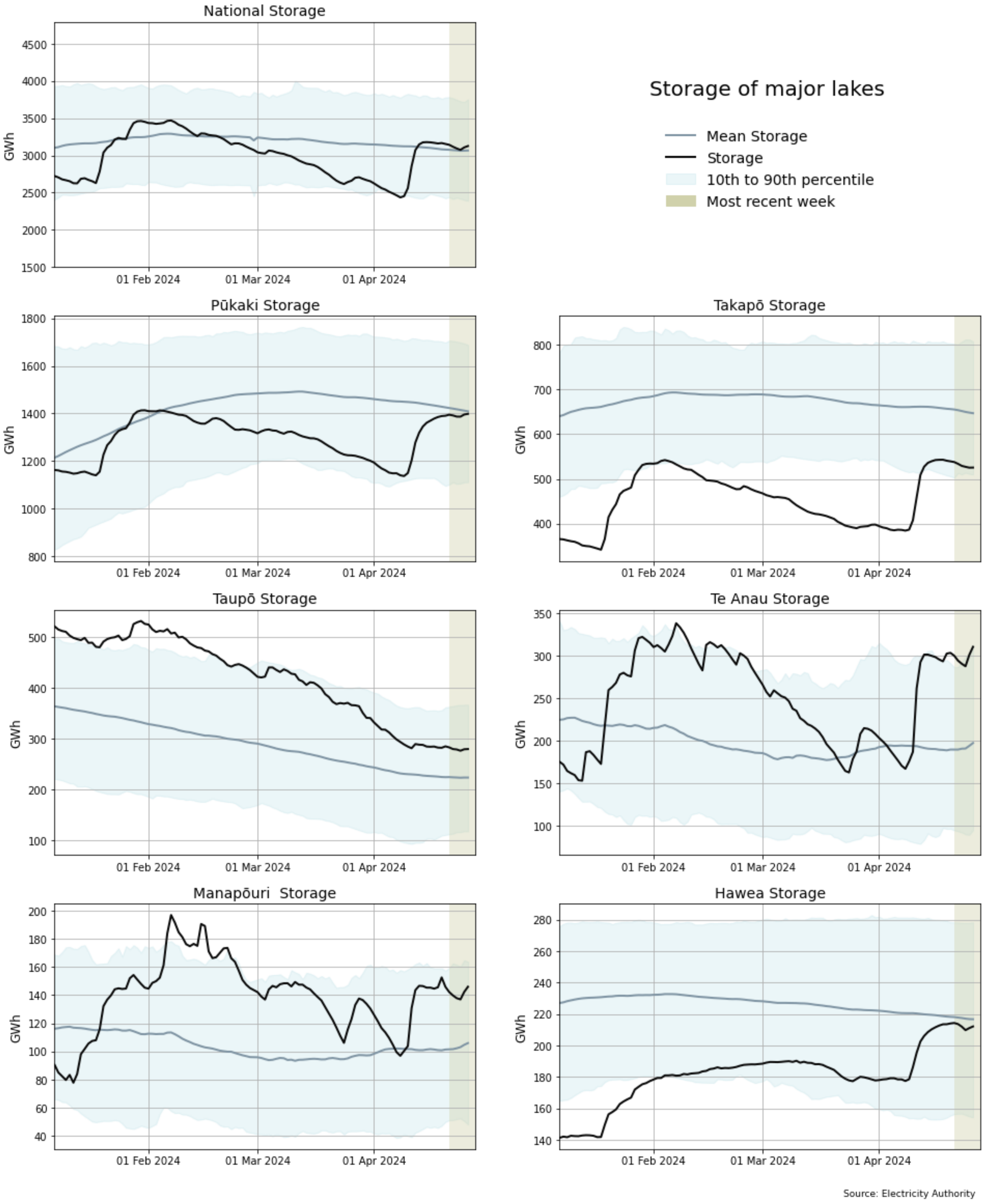
(b) Lake Pūkaki increased slightly this week, now sitting at its historical average.

(c) Lake Takapō storage decreased a little this week but remains above its 10th percentile.

(d) Lake Manapōuri and Te Anau saw an increase in storage. Lake Te Anau is close to its 90th percentile while Manapōuri is slightly below its 90th percentile.

(e) Lake Hawea's storage decreased a bit but is still sitting close to its historical average.

Figure 19: Hydro storage

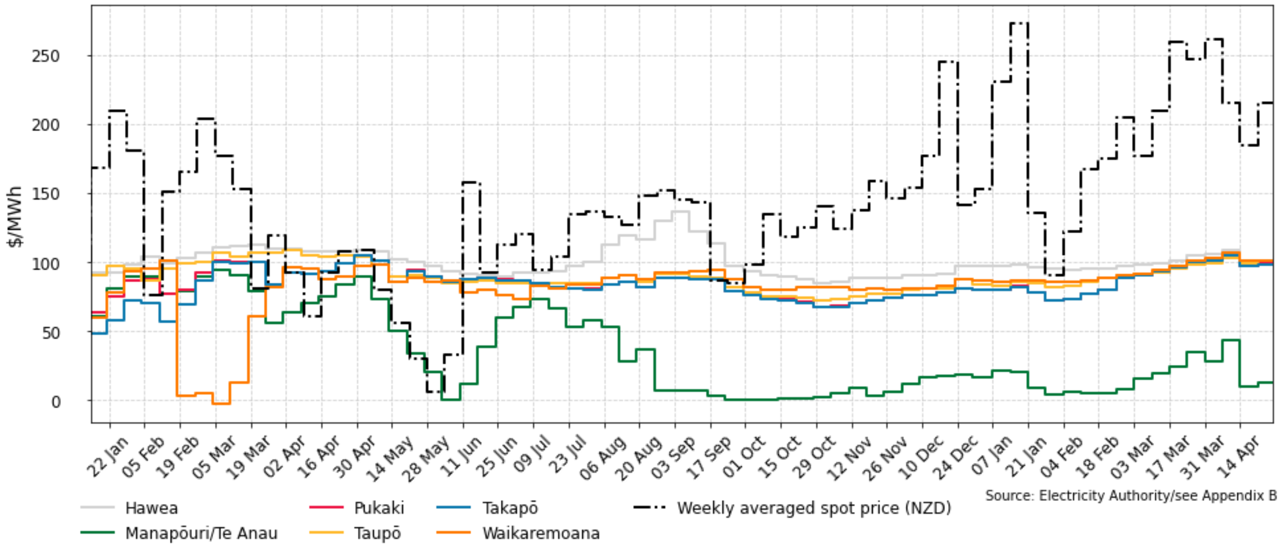


11. JADE water values

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 20 shows the national water values between 8 January 2023 and 27 April 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. Compared to the previous week, most lakes saw an increase in their water values between $0.50/MWh and $3/MWh. The exception was Lake Taupō, which saw a decrease of around $0.50/MWh.

Figure 20: JADE water values across various reservoirs between 8 January 2023 and 27 April 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 21 shows an estimate of thermal SRMCs as a monthly average up to 1 April 2024. The SRMCs for coal and diesel have seen small changes from the previous month. The coal SRMC decreased, while the diesel SRMC increased slightly. The gas SRMCs have increased this month, likely due to current gas availability and demand.

12.4. The latest SRMC of coal-fuelled Rankine generation is ~$164/MWh. The cost of running the Rankines on gas remains more expensive at ~$257/MWh.

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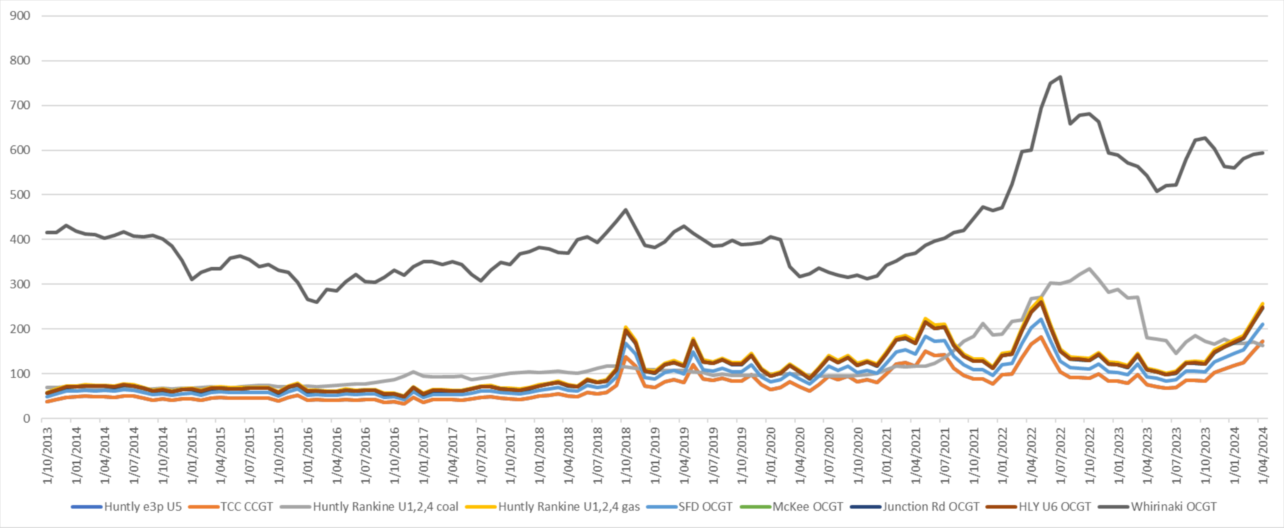
[2] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

12.5. The SRMC of gas-fuelled thermal plants is currently between ~$173/MWh and ~$257/MWh.

12.6. The SRMC of Whirinaki is ~$594/MWh.

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

Figure 21: Estimated monthly SRMC for thermal fuels



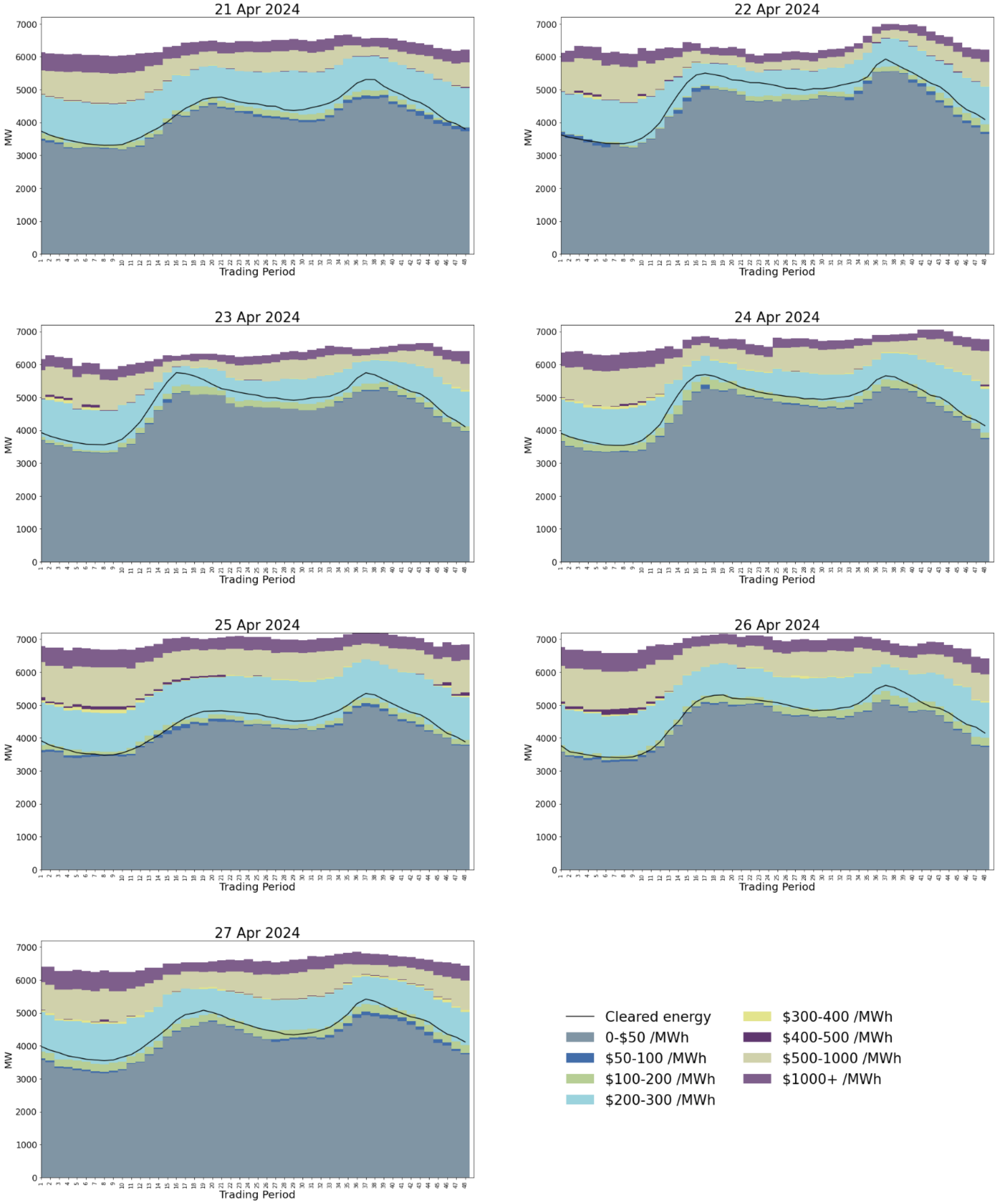
13. Offer behaviour

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. This week, similar to the previous week, the offer stacks between $50-$200/MWh were reasonably thin and most offers were cleared in the $200-$300/MWh region. A slight lowering in the position of the offers' clearing curve occurred after Tuesday, likely due to the increase in wind generation.

13.3. Overall, these offers reflect current gas prices and some lakes still being below average for this time of year, with many participants seeking to conserve water for winter.

Figure 22: Daily offer stacks[3]



Source: Electricity Authority

[3] PRSS data has been used for trading periods where RTD data was not available. These stacks will be highlighted within the offer stack and may be slightly higher than the adjusted offers.

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	TP	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	Further analysis	Contact	Multiple	High hydro offers
21/01/2024-27/01/2024	Several	Further analysis	Mercury	Waikato hydro dams	Hydro offers
15/03/2024-16/03/2024	Several	Further analysis	Mercury	Waikato hydro dams	Hydro offers