14 October 2024

Trading conduct report 6-12 October 2024

Market monitoring weekly report

Trading conduct report 6-12 October 2024

1. Overview

1.1. The majority of spot prices were low and below the historical 10th percentile region of prices this week. Thermal generation has remained low across the week reflective of lower demand and high amounts of renewable generation. Wind generation from Sunday to Wednesday was mostly between 600-1000MW and hydro storage has continued to increase. As of 12 October, national controlled storage was ~ 114% of historic mean.

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. Between 6-12 October:

(a) the average wholesale spot price across all nodes was $26/MWh

(b) 95% of prices fell between $0.02/MWh and $114/MWh.

2.3. Overall, the majority of spot prices were within $0.01-$50/MWh, with a lot below the historic 10th percentile of prices for this time of year. The weekly average price decreased by around $59/MWh compared to the previous week.

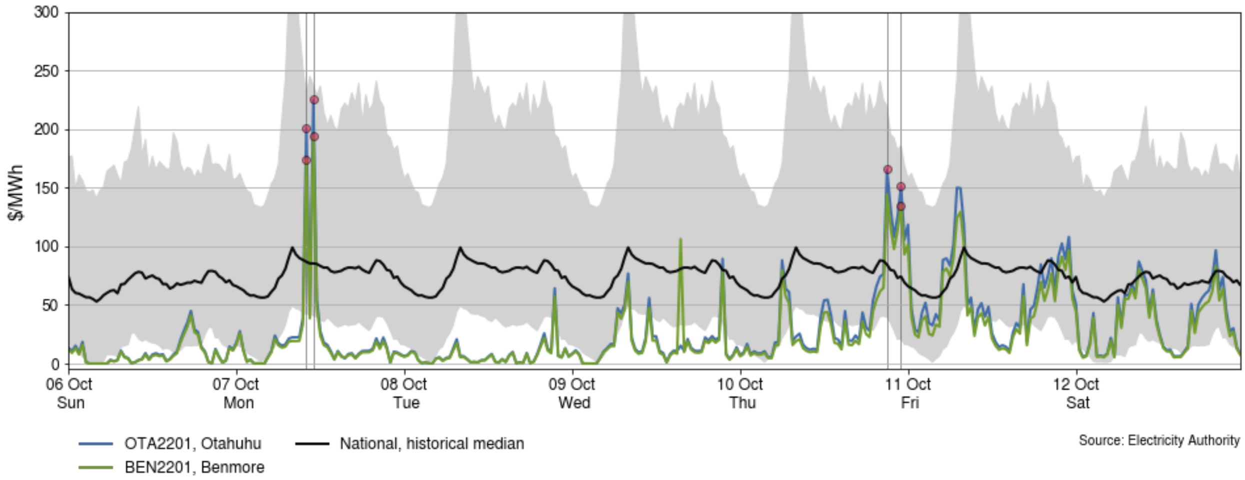
2.4. There were a few occasions where prices spiked above the median but remained within the historic 90th percentile region. The highest of those spikes was on Monday at 11.00am when the price at Ōtāhuhu reached $225/MWh and $194/MWh at Benmore. This was likely due to wind forecast inaccuracies as well as demand being higher than forecast, resulting in higher priced generation being dispatched.

2.5. There were also a few prices on Thursday evening that were between $100-$165/MWh. Wind generation was lower on Thursday and demand was higher than forecast, possibly due to a drop in temperatures that evening.

2.6. On Wednesday afternoon there was one instance of price separation where the Benmore price was ~$90/MWh higher than the Ōtāhuhu price. This was due to a sudden reduction in HVDC northward transfer that hit the HVDC ramp rate limit. This appears to have been caused by discretionary constraints applied to South Island generation by the system operator at this time.

2.7. 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.

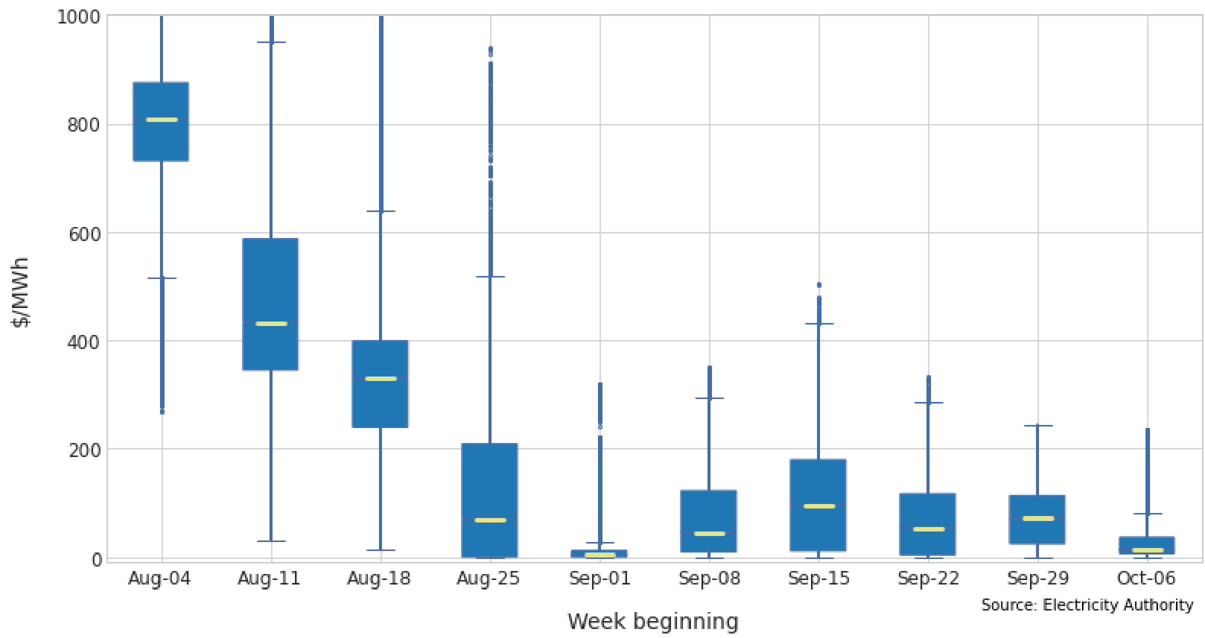
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 6-12 October



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. This week the overall distribution of prices was small with the middle 50% prices within $6-$36/MWh. There was also a shift in the distribution with more than 75% of this week's prices below last week's median.

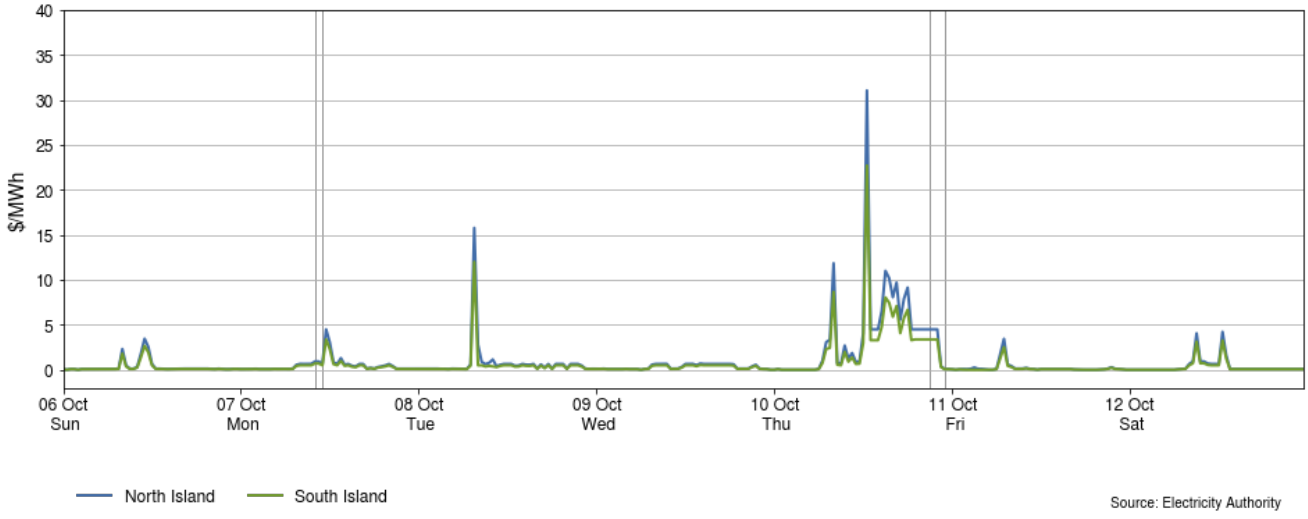
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

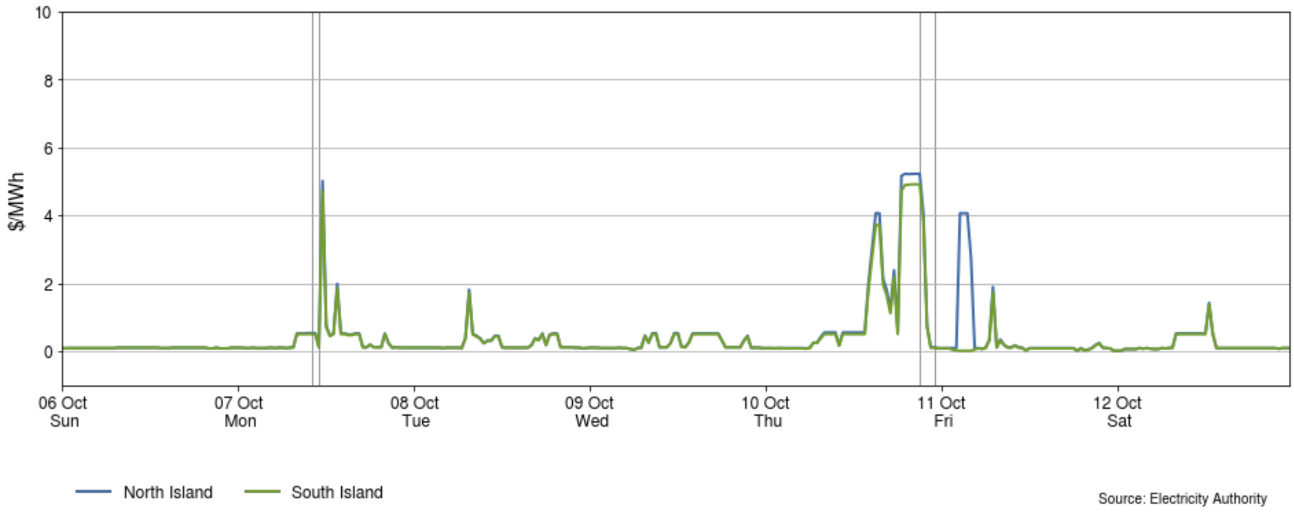
3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $5/MWh. There were some small spikes across the week, the highest of those at $31/MWh in the North Island and $22/MWh in the South Island.

Figure 3: Fast instantaneous reserve price by trading period and island, 6-12 October



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. All SIR prices were below $6/MWh this week.

Figure 4: Sustained instantaneous reserve by trading period and island, 6-12 October



4. Regression residuals

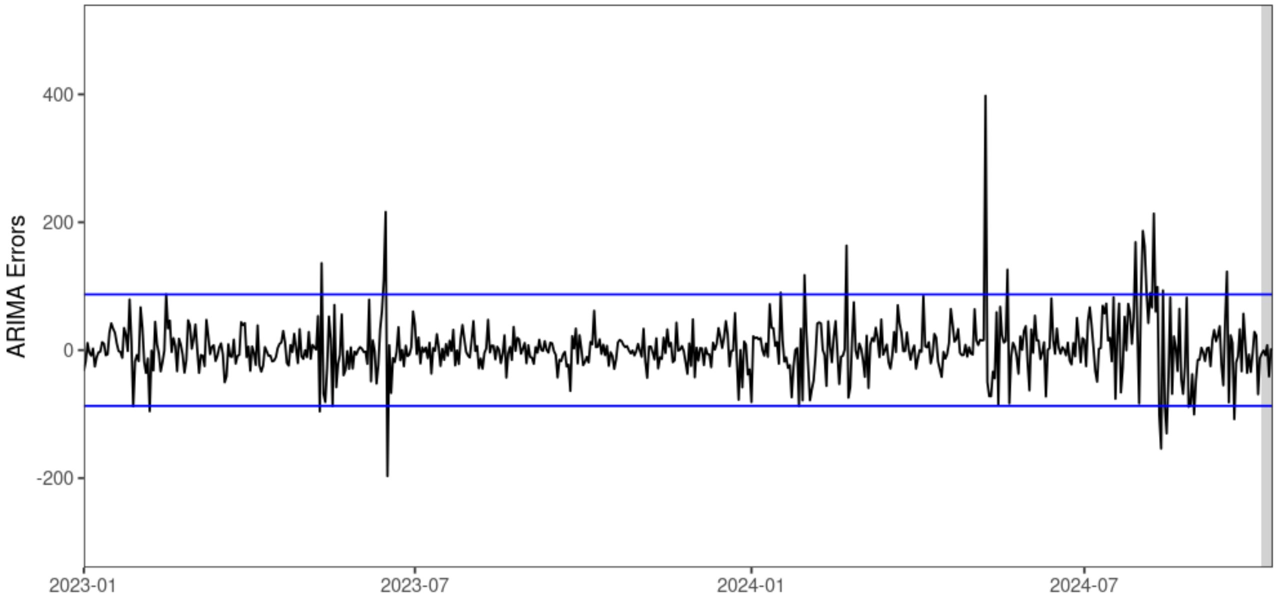
Source: Electricity Authority/see Appendix A

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 no residuals were above or below 2 standard deviations of the data meaning prices were in line with what the model expected.

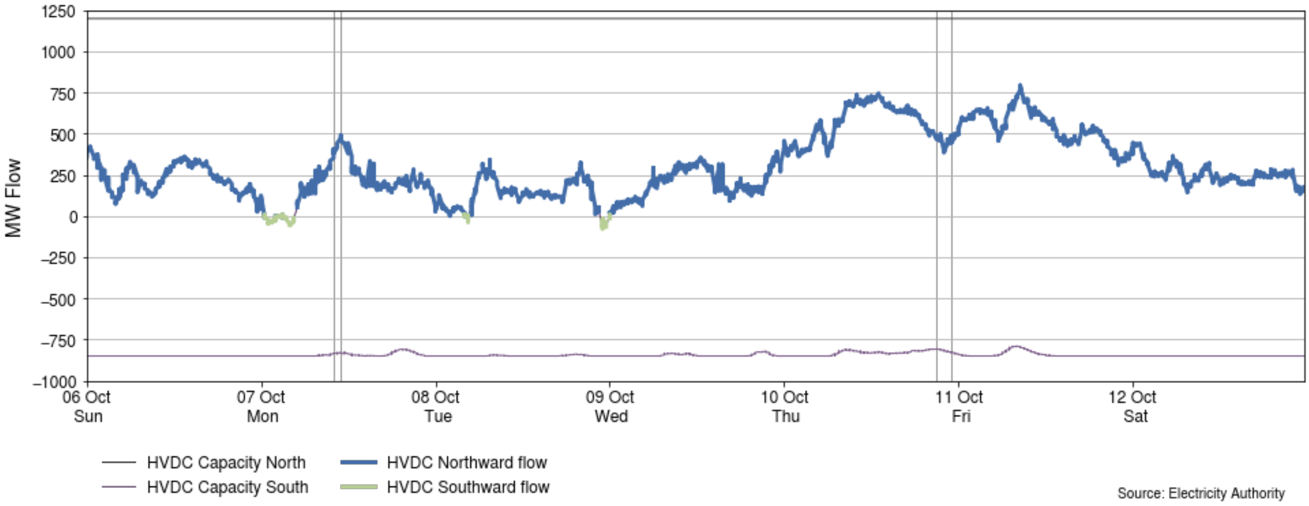
Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 12 October 2024



5. HVDC

5.1. Figure 6 shows the HVDC flow between 6-12 October. HVDC flows were mostly northwards this week due to more stable hydro conditions and lower demand across the country seeing less thermal generation required. Northward flows increased over Thursday when North Island wind generation was lower and hydro generation increased.

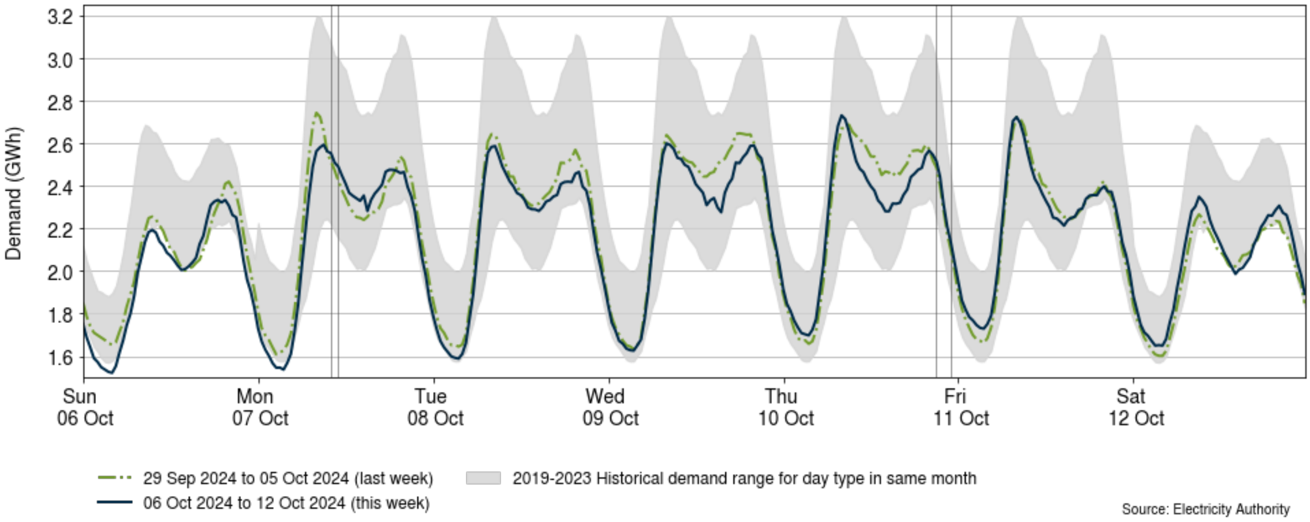
Figure 6: HVDC flow and capacity, 6-12 October



6. Demand

6.1. Figure 7 shows national demand between 6-12 October, compared to the historic range and the demand of the previous week. Demand peaks have been gradually decreasing as we move through spring with most peak periods this week seeing demand less than 2.6GWh.

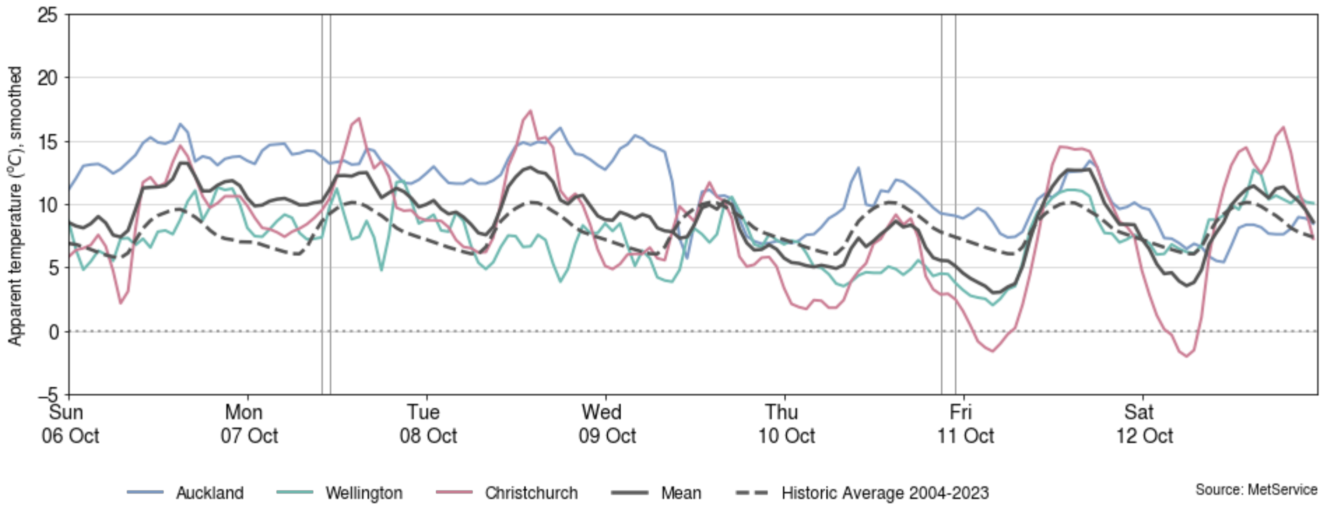
Figure 7: National demand, 6-12 October compared to the previous week and historical range



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 6-12 October. The apparent temperature 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. Changeable weather across the country has seen quite as bit of variation in temperatures across the week. Auckland was mainly above average with temperatures ranging between 5-18°C. Wellington temperatures ranged from 2-14°C. Christchurch saw some negative temperatures on Friday and Saturday morning but also saw temperatures above 15°C during the week.

Figure 8: Temperatures across main centres, 6-12 October

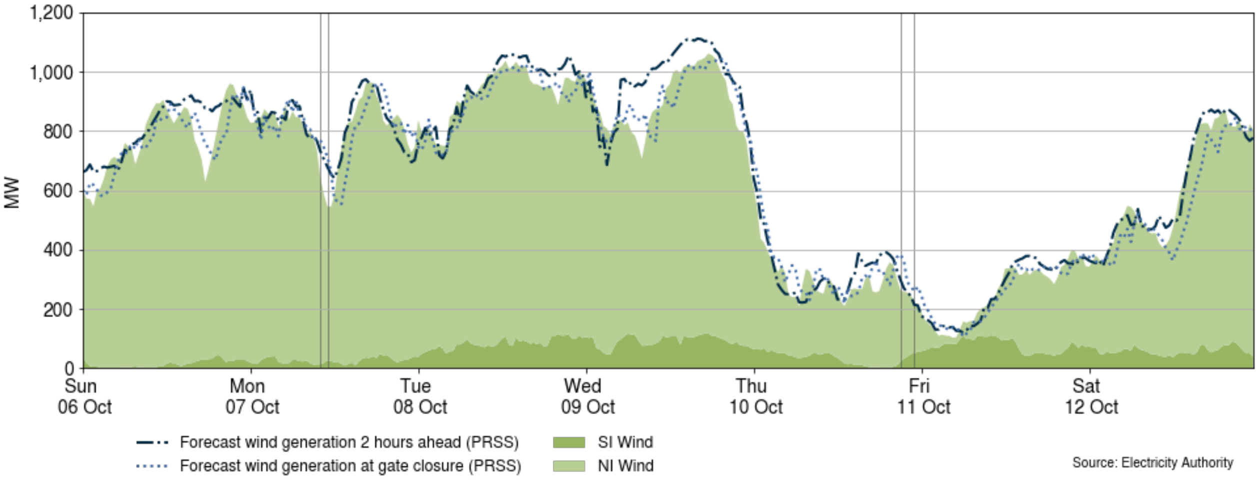


7. Generation

7.1. Figure 9 shows wind generation and forecast from 6-12 October. This week wind generation varied between 103MW and 1060MW, with a weekly average of 653MW. From Sunday to

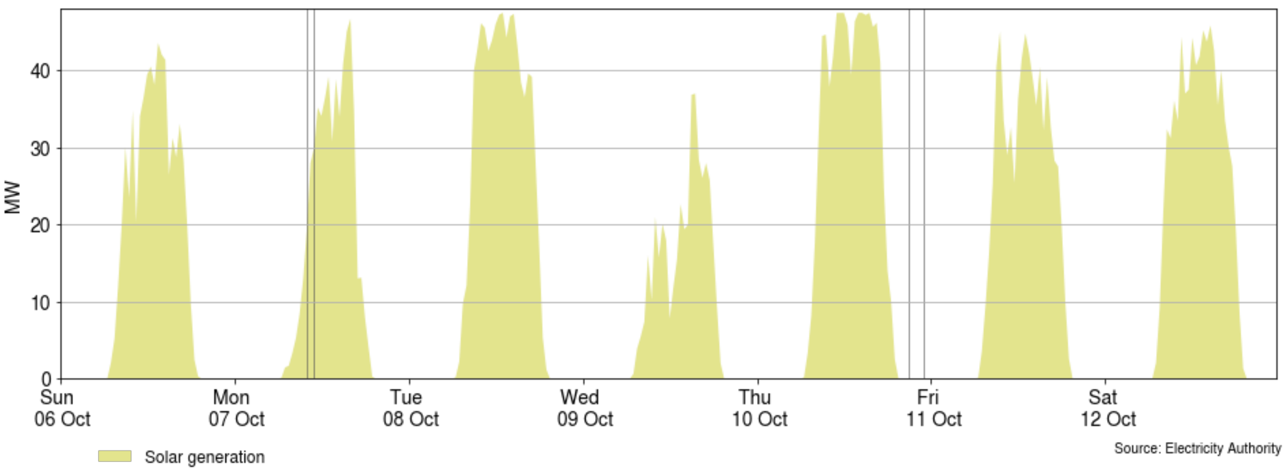
Wednesday there were multiple periods where wind generation was consistently above 800MW.

Figure 9: Wind generation and forecast, 6-12 October



7.2. Figure 10 shows solar generation from 6-12 October. Most trading periods saw above 30MW of solar generation this week with a maximum trading period average of ~47MW on both Tuesday and Thursday this week.

Figure 10: Solar generation, 6-12 October



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.

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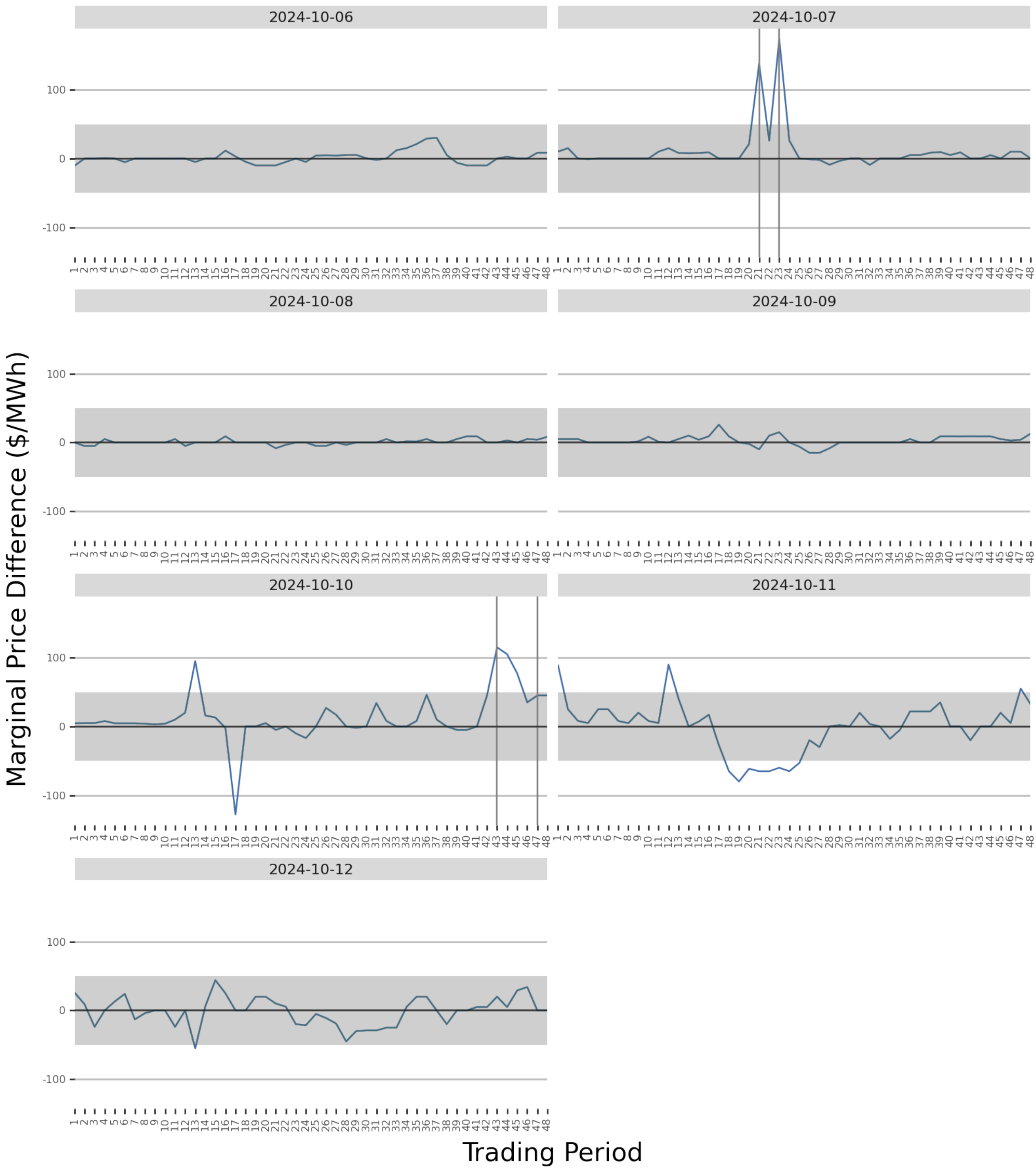
[1] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

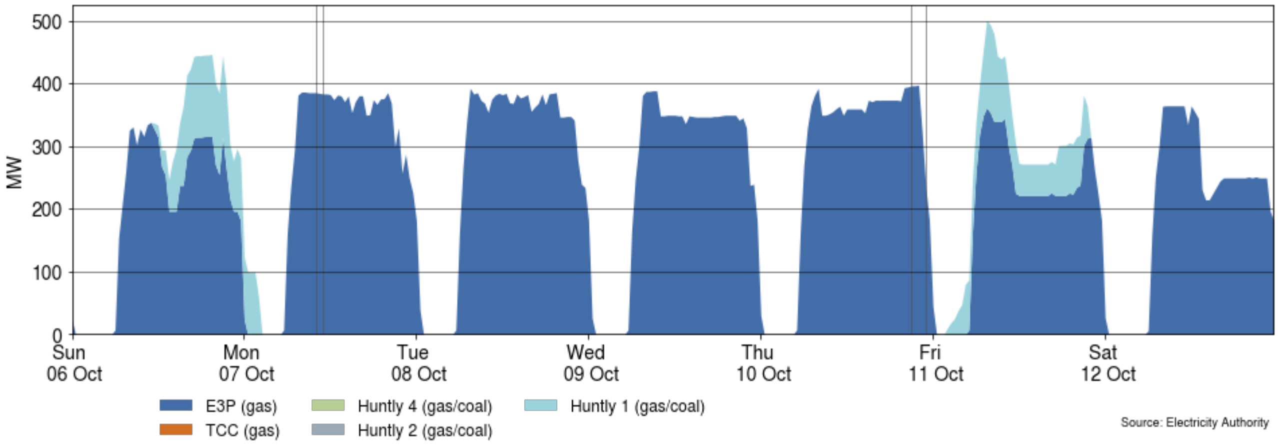
7.4. The first half of the week saw prices mostly similar to those simulated. The largest differences this week were around $115-174/MWh. These differences occurred where wind was below forecast by up to ~130MW, or demand was more than forecast by at least 60MW.

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, 6-12 October



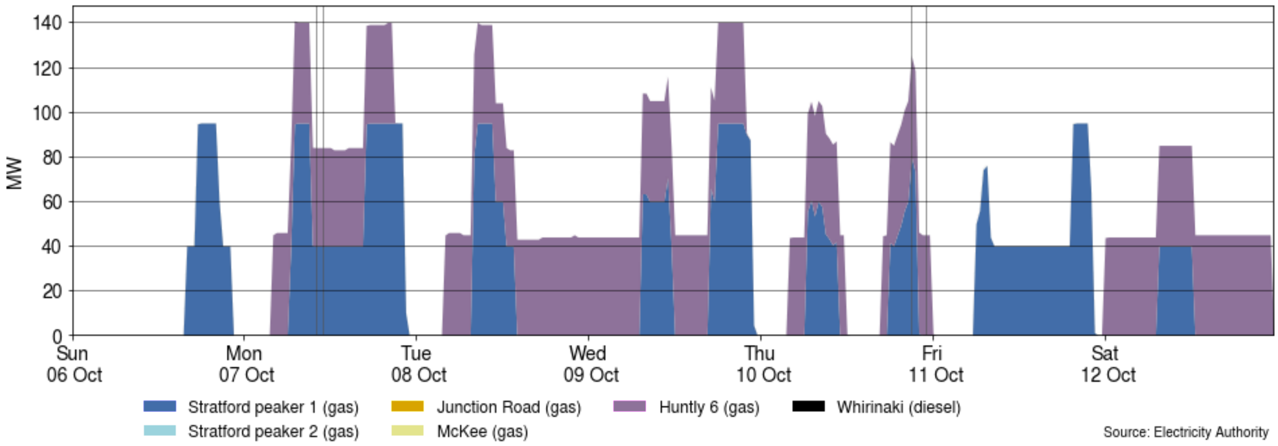
7.5. Figure 12 shows the generation of thermal baseload between 6-12 October. Huntly 5 was the main thermal baseload generation this week, running every day but turning off overnight. Huntly 1 ran from late morning Sunday to early hours on Monday morning as well as all day Friday.

Figure 12: Thermal baseload generation, 6-12 October



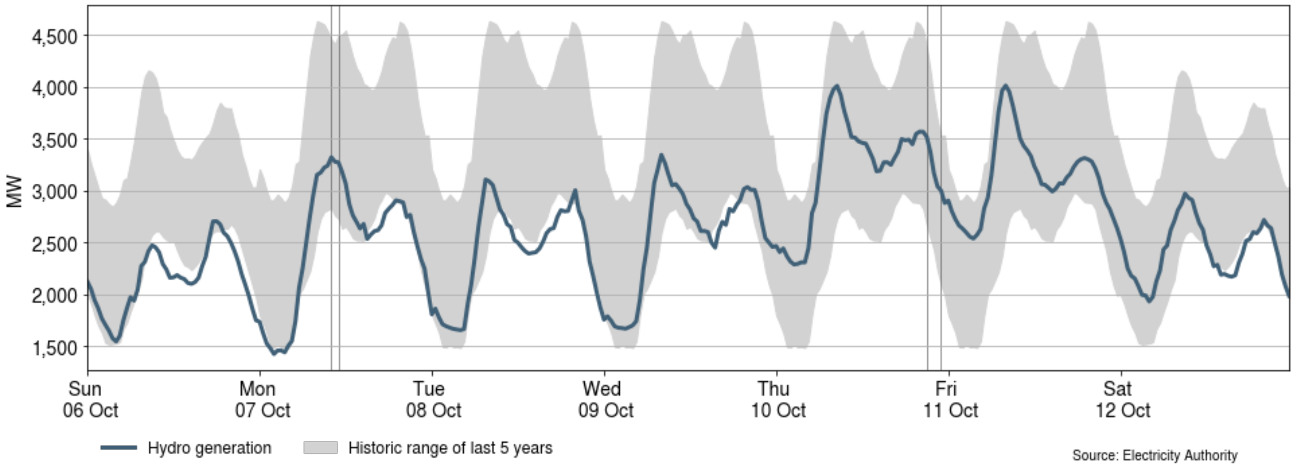
7.6. Figure 13 shows the generation of thermal peaker plants between 6-12 October. Peaker generation this week came from Stratford 1 and Huntly 6. Stratford 1 ran during most peak periods as well as the Monday and Friday shoulder periods. Huntly 6 ran from morning to evening on Monday and then continuously from Tuesday morning to Wednesday evening. Huntly 6 also generated during the Thursday peak periods and all-day Saturday.

Figure 13: Thermal peaker generation, 6-12 October



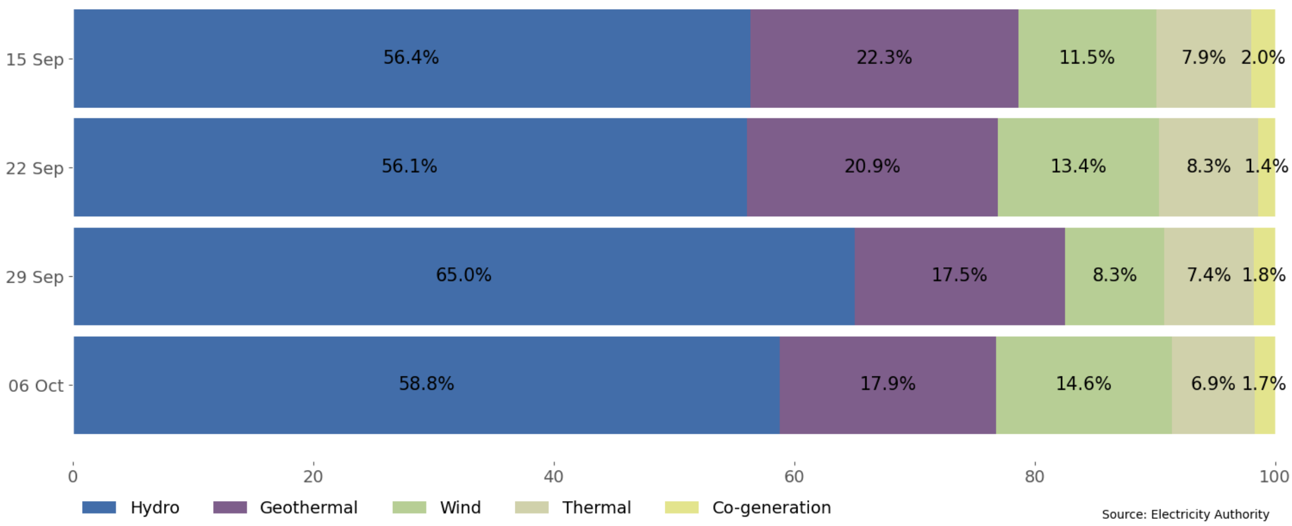
7.7. Figure 14 shows hydro generation between 6-12 October. Hydro generation was mostly at the lower end of the historic range of the last three years this week. There was an increase to hydro generation on Thursday and Friday due to lower wind generation.

Figure 14: Hydro generation, 6-12 October



7.8. As a percentage of total generation, between 6-12 October, total weekly hydro generation was 58.8%, geothermal 17.9%, wind 14.6%, thermal 6.9%, and co-generation 1.7%, as shown in Figure 15. An increase in the proportion of wind generation this week saw the proportion of hydro generation drop below 60% again this week.

Figure 15: Total generation by type as a percentage each week, 15 September and 12 October



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 6-12 October ranged between ~1,700MW and ~2,180MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Stratford 2 is on outage until 30 October.

(b) Stratford 1 was on outage 9 October.

(c) Huntly 4 was on outage until 13 October.

(d) Huntly 2 is on outage until 6 December.

(e) Two units at Te Mihi geothermal plant are on outage until 19 and 24 October, respectively.

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

Figure 16: Total MW loss from generation outages, 6-12 October

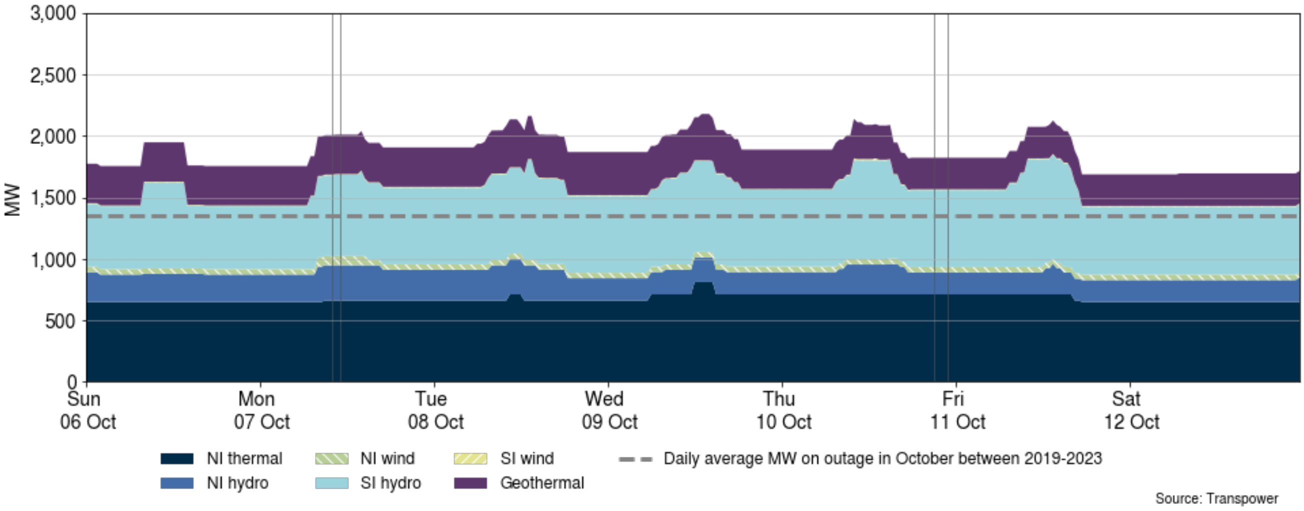
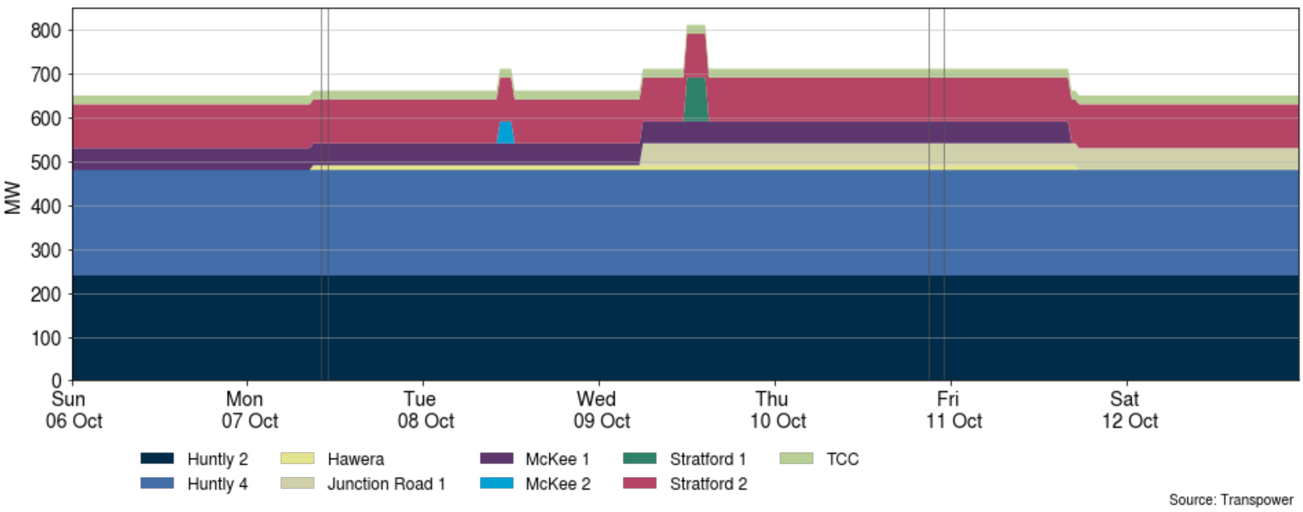


Figure 17: Total MW loss from thermal outages, 6-12 October

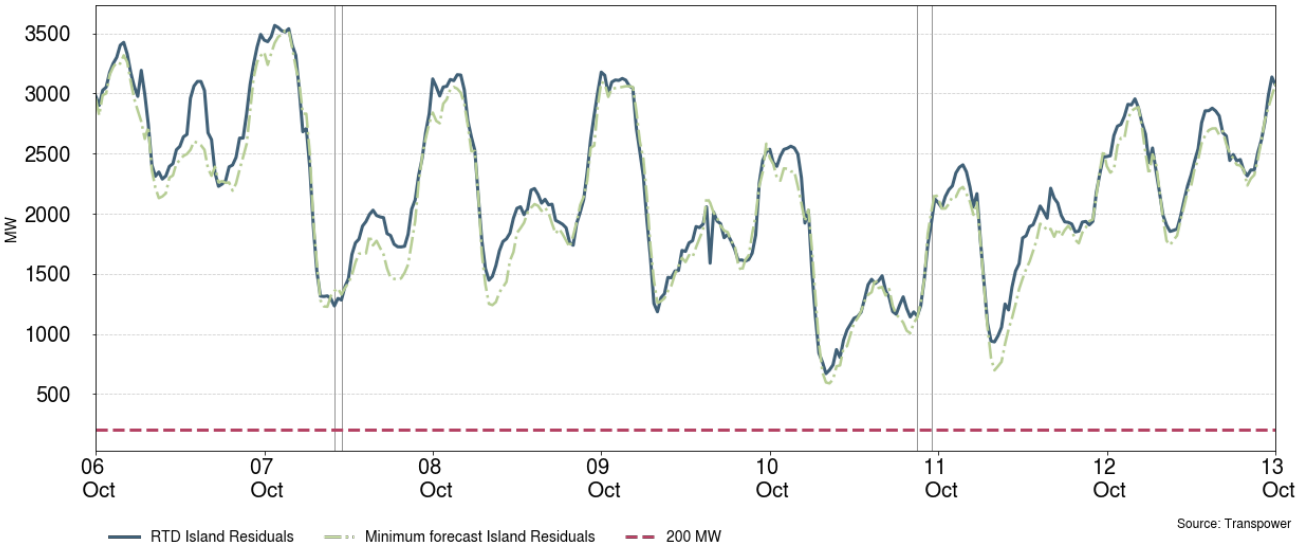


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 6-12 October. 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 with the minimum residual generation at ~670MW during the morning peak on Thursday.

Figure 18: National generation balance residuals, 6-12 October



10. Storage/fuel supply

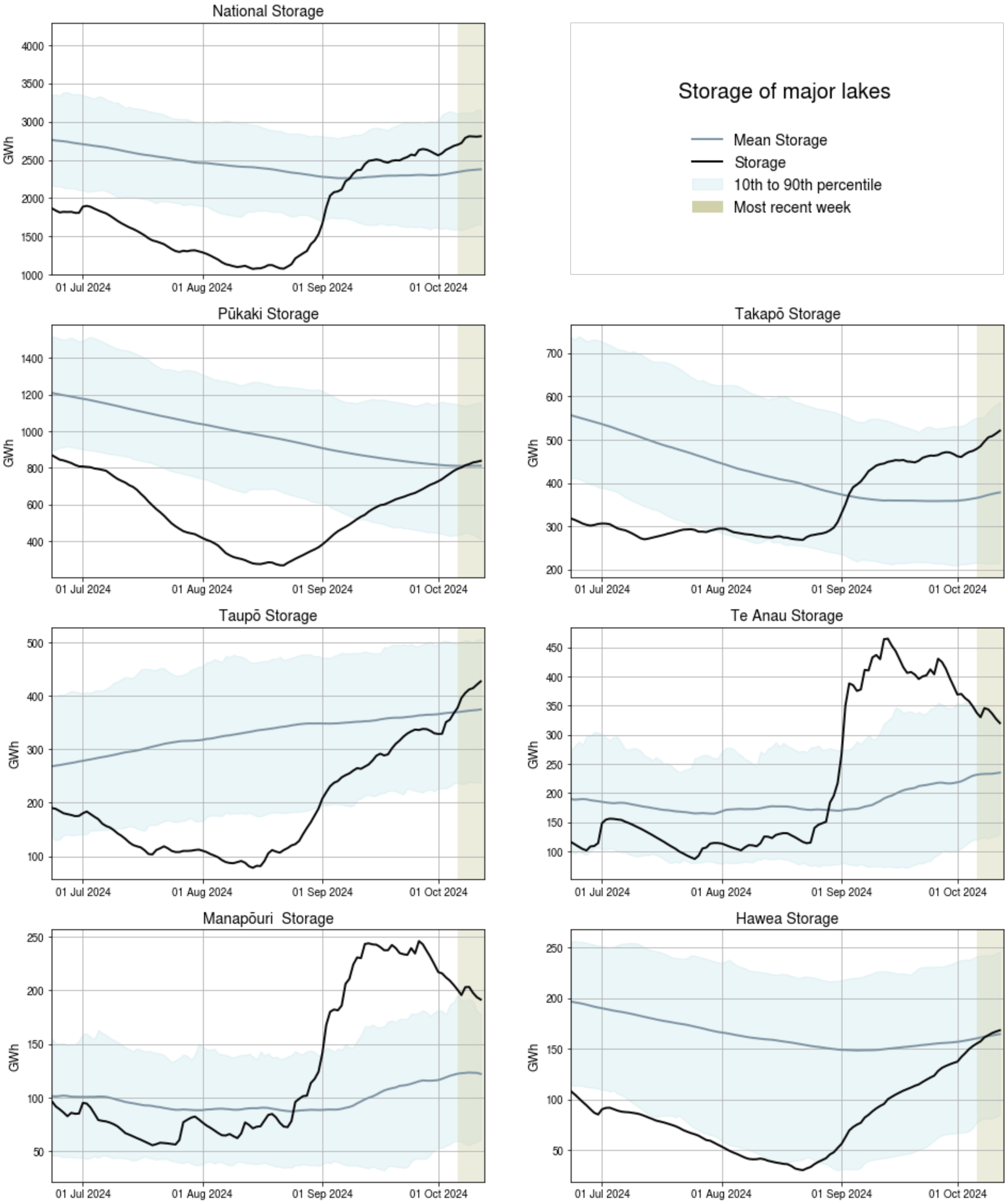
10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.

10.2. National controlled storage continued to increase this week. Controlled storage was ~69.7% nominally full and ~114% of the historical average as of 12 October.

10.3. All lakes saw some increase to storage during the week. Taupō storage is now above its historic mean with over 400GWh of storage. This is the highest storage at Taupō since March this year. Both Pūkaki and Hawea have increased and are now just above their respective mean values.

10.4. Manapōuri and Te Anau have both seen small increases to storage at the beginning of this week, decreasing from mid-week. Both lakes are still around their high operating ranges.

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

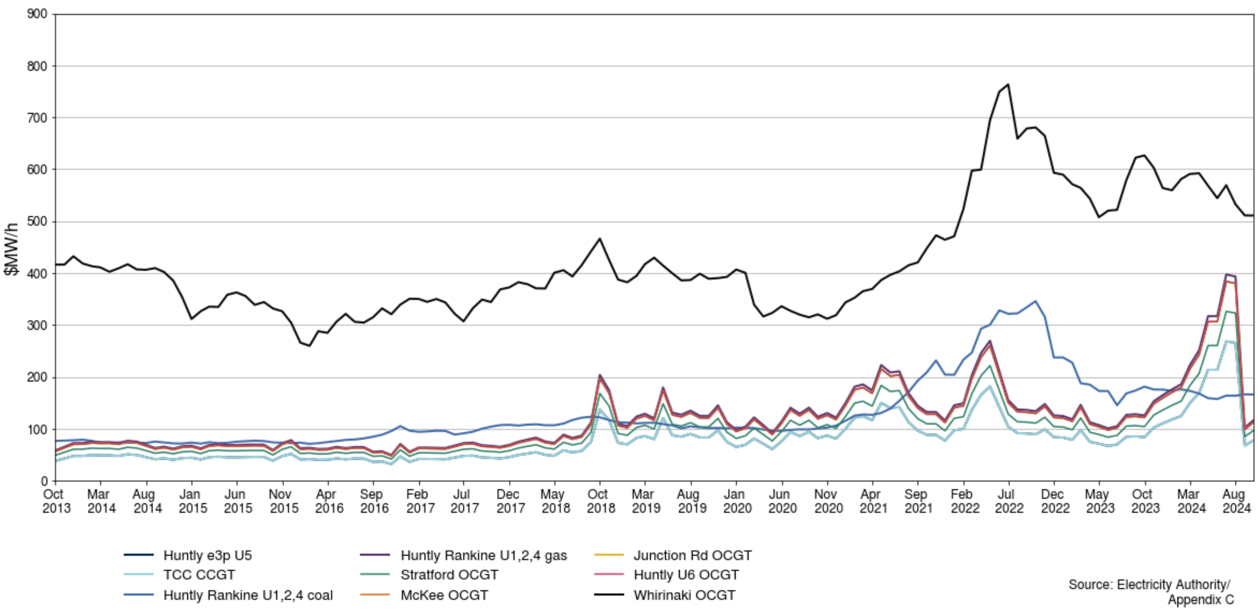
11.4. The latest SRMC of coal-fueled Rankine generation is ~$167/MWh. The cost of running the Rankines on gas remains less expensive at ~$117/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between ~$78/MWh and ~$117/MWh.

11.6. The SRMC of Whirinaki is ~$511/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



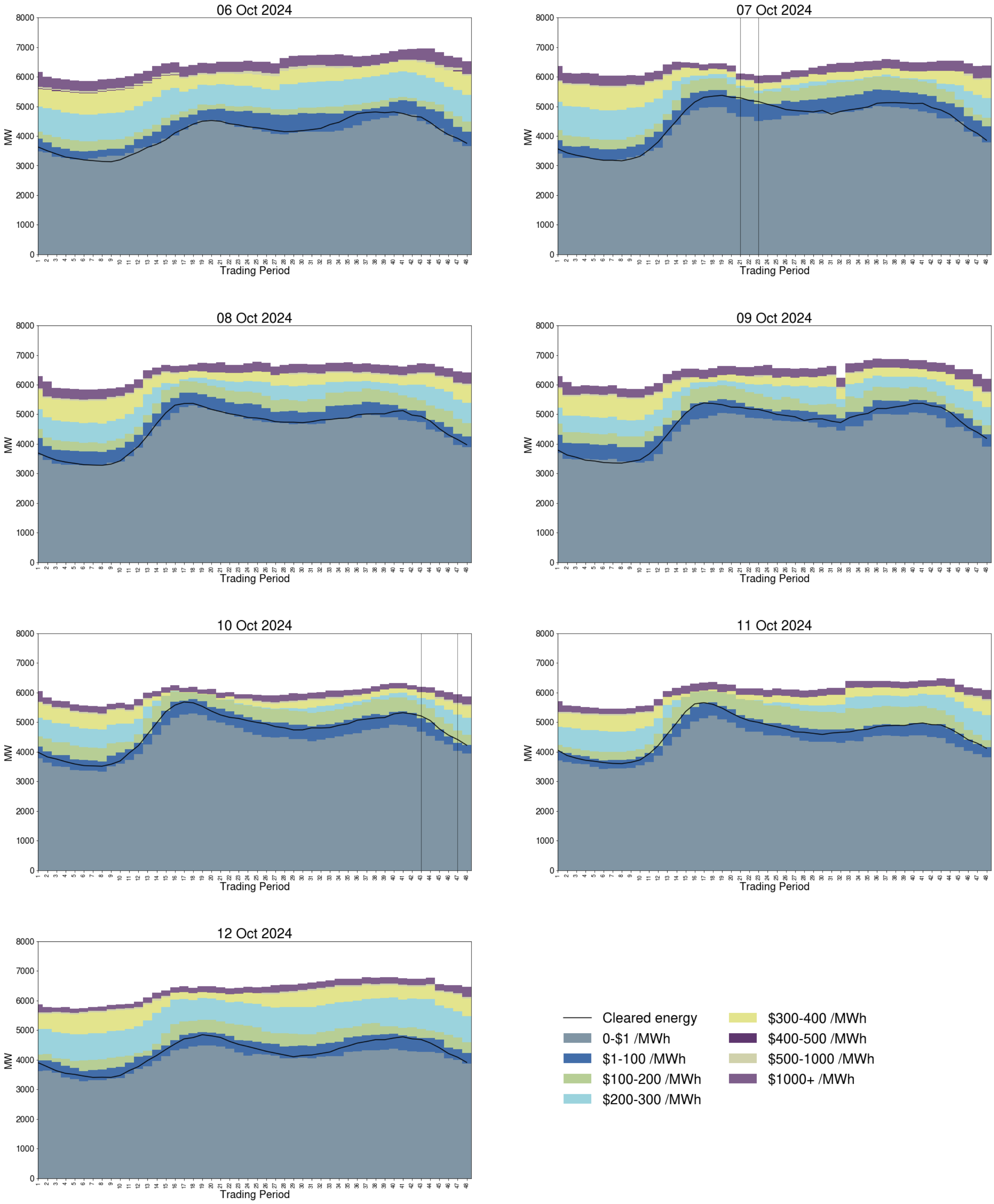
12. Offer behaviour

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

12.2. As hydro storage has continued to increase, we have seen an increase in offers within the $50-$100/MWh and $100-$200/MWh bands. In general, there has been a reduction in $200-$400/MWh offers across the week.

12.3. The dip in the offer stack on 9 October was due to discretionary constraints applied to South Island generation.

Figure 21: Daily offer stacks, 6-12 October



13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions.

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	These trading periods are now part of a s16 review	N/A	N/A	High energy prices
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact Energy	Clutha scheme	Hydro offers