4 November 2024

# Trading conduct report 27 October- 2 November 2024

Market monitoring weekly report

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## 1. Overview

1.1. Spot prices were low, with the majority under \$50/MWh and most below the historic 10th percentile this week. Lower springtime demand along with healthy hydro storage and increased wind generation this week likely influenced prices. Thermal baseload generation came from Huntly 5 and then Huntly 1 after Huntly 5 went on outage in the latter part of the week. Hydro storage increased again this week with controlled storage now ~123% of historic average for this time of year.

## 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 27 October- 2 November 2024:

(a) the average wholesale spot price across all nodes was \$9/MWh

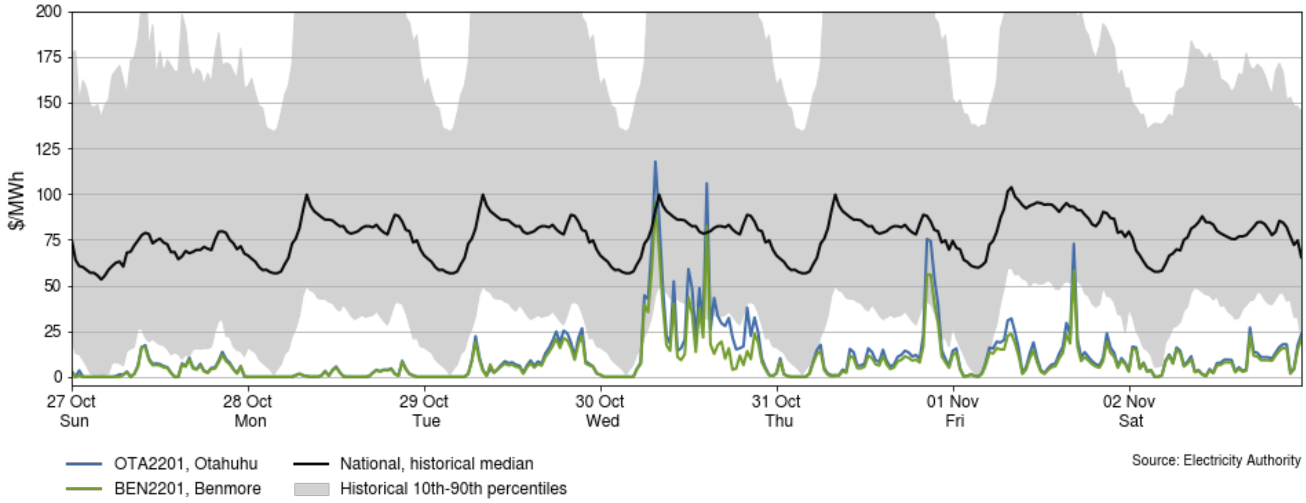
(b) 95% of prices fell between \$0.01/MWh and \$49/MWh.

2.3. Overall, spot prices were mostly below the historic 10th percentile region and under \$50/MWh this week. The weekly average price decreased by around \$39/MWh compared to the previous week.

2.4. There were a few small price spikes across the week with only two occasions when the Ōtāhuhu and Benmore prices were above the historic median. The first instance was where the price was \$118/MWh at Ōtāhuhu and \$95/MWh at Benmore, during the morning peak demand at 7.30am. The second was at 2.30pm where the prices were \$106/MWh and \$83/MWh respectively at each reference node. This increase to prices was likely related to forecasting inaccuracies.

2.5. 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.

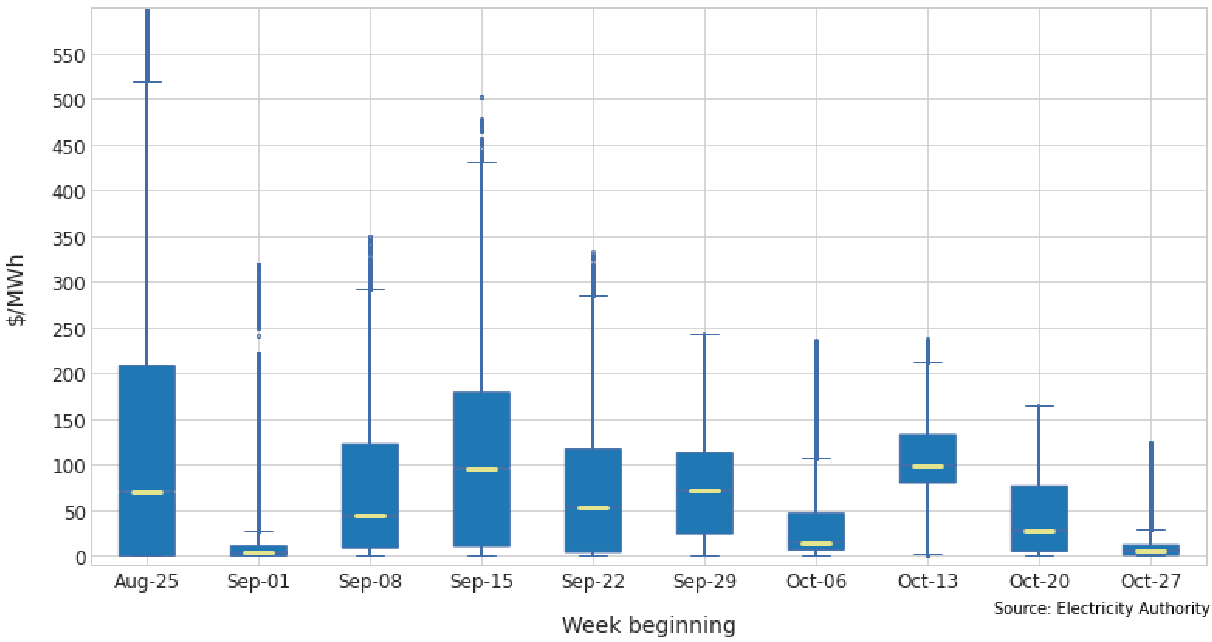
**Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 27 October- 2 November 2024**




2.6. 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.

2.7. The distribution of prices was condensed and lower than the previous week. The median price this week was $5.60/MWh, with the middle 50% of prices within $0.77/MWh-$12.32/MWh. Most prices were below last week's median of ~$28/MWh with ~75% of prices below $12/MWh this week.

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

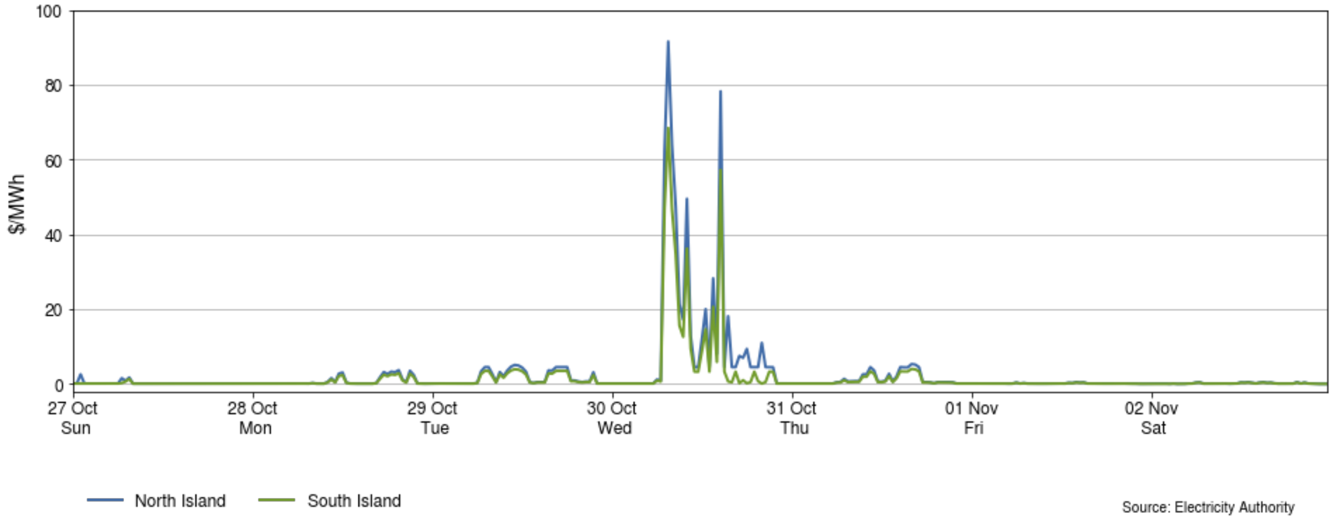



## 3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mainly below $5/MWh. There were some spikes on Wednesday in line with the increase to spot prices. The highest South Island FIR prices were between

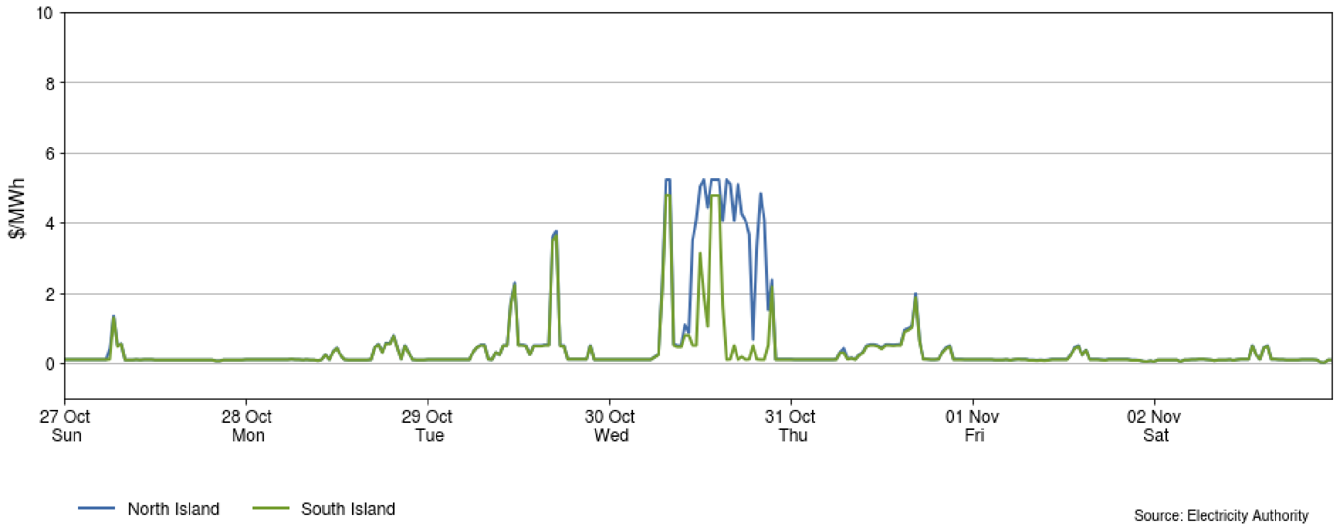
$35-$69/MWh and the highest North Island FIR prices were between $50-$92/MWh. These spikes were due to interactions in the spot and reserve market. It appears that SPD[1] reduced the binding generator risk to a level that could be covered by available cheap FIR offers rather than clearing expensive FIR offers.

**Figure 3: Fast instantaneous reserve price by trading period and island, 27 October- 2 November 2024**




3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were mostly under $5/MWh. There was some small price separation in both FIR and SIR from 3.00pm to 10.00pm due to HVDC constraints.

**Figure 4: Sustained instantaneous reserve by trading period and island, 27 October- 2 November 2024**




[1] SPD is the scheduling, pricing and dispatch tool the system operator uses to determine the optimal dispatch solution and calculate prices in the electricity market.

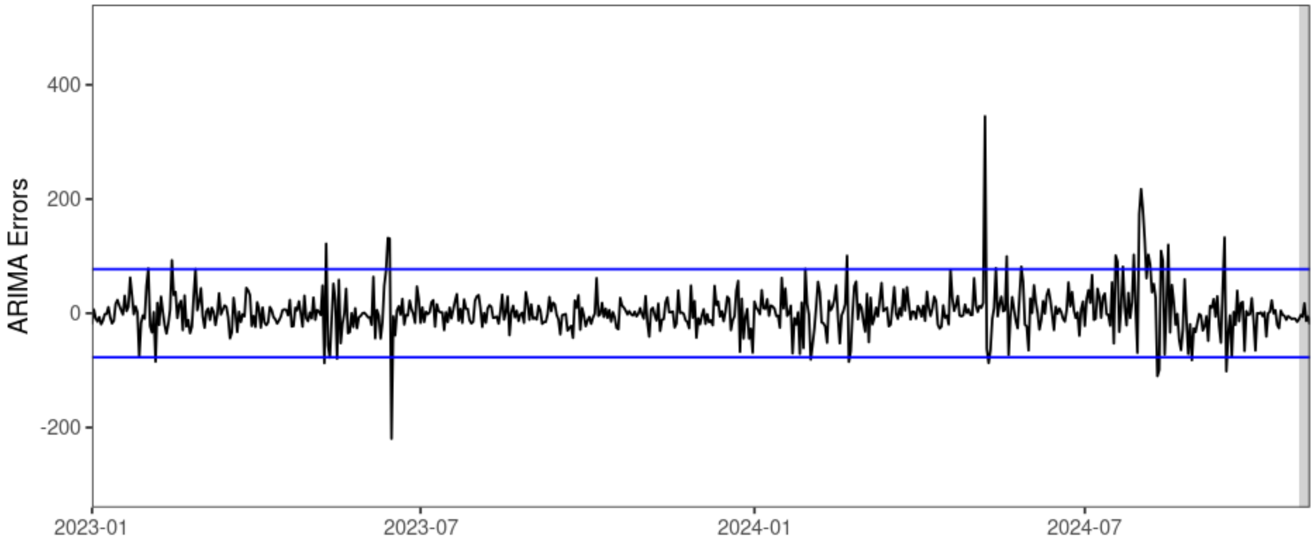
# 4. Regression residuals

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. All residuals were within two standard deviation of the data this week indicating prices were close to those expected by the model.

**Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 2 November 2024**

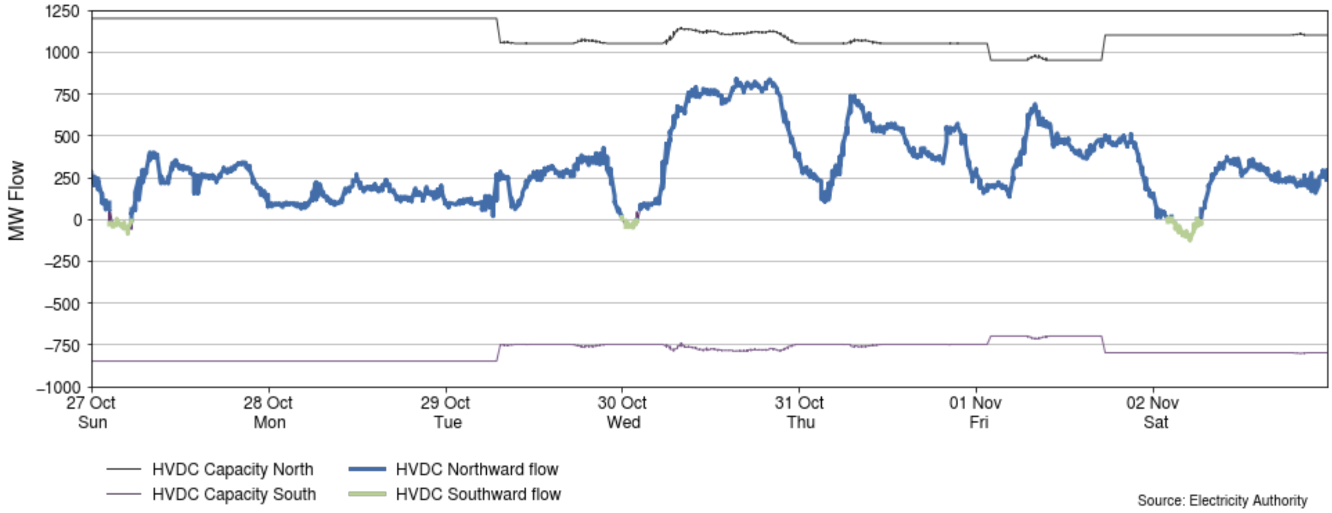



Source: Electricity Authority/Appendix A

## 5. HVDC

5.1. Figure 6 shows the HVDC flow between 27 October- 2 November 2024. HVDC flows mainly northwards this week. Flows were highest on Wednesday when North Island wind was lower.

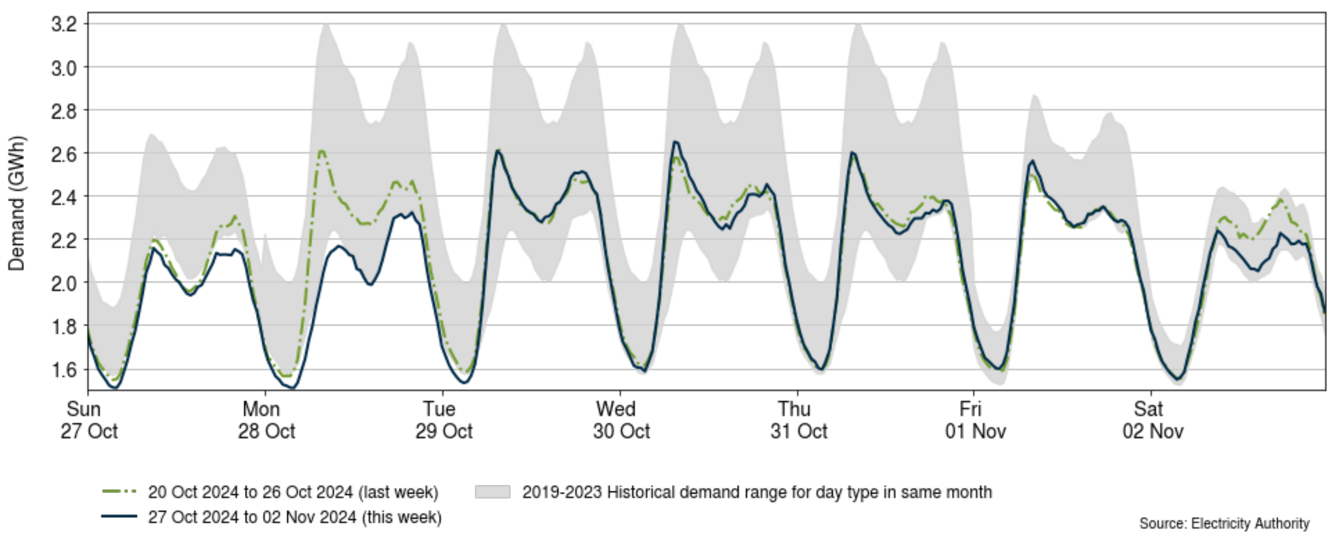
**Figure 6: HVDC flow and capacity, 27 October- 2 November 2024**




## 6. Demand

6.1. Figure 7 shows national demand between 27 October- 2 November 2024, compared to the historic range and the demand of the previous week. Demand was mainly at the lower end of the historic distribution with most weekday demand similar to the previous week. Lower demand on Monday was due to the public holiday for Labour Day. Weekday morning peak demand is still around 2.6GWh with the maximum demand this week on Wednesday of ~2.65GWh at 7.30am.

**Figure 7: National demand, 27 October- 2 November 2024 compared to the previous week**

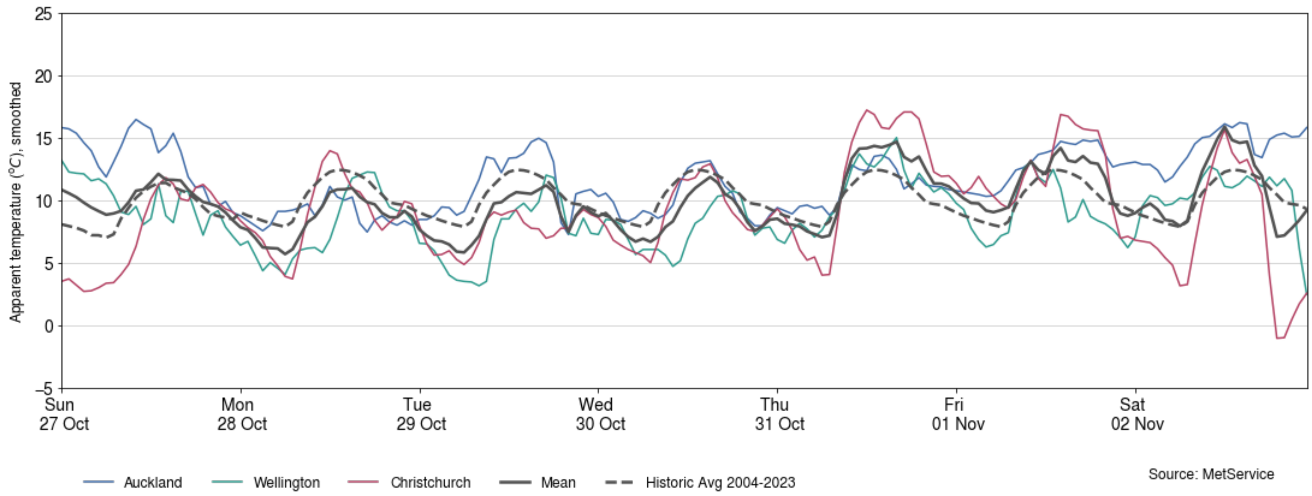


6.2. Temperatures varied from single digits to high teens across the week. Auckland apparent temperatures ranged from 4°C to 17°C, Wellington from ~2°C to 15°C and Christchurch from -1°C to 18°C.

6.3. Figure 8 shows the hourly apparent temperature at main population centres from 27 October- 2 November 2024. 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.

6.4. Temperatures varied from single digits to high teens across the week. Auckland apparent temperatures ranged from 4°C to 17°C, Wellington from ~2°C to 15°C and Christchurch from -1°C to 18°C.

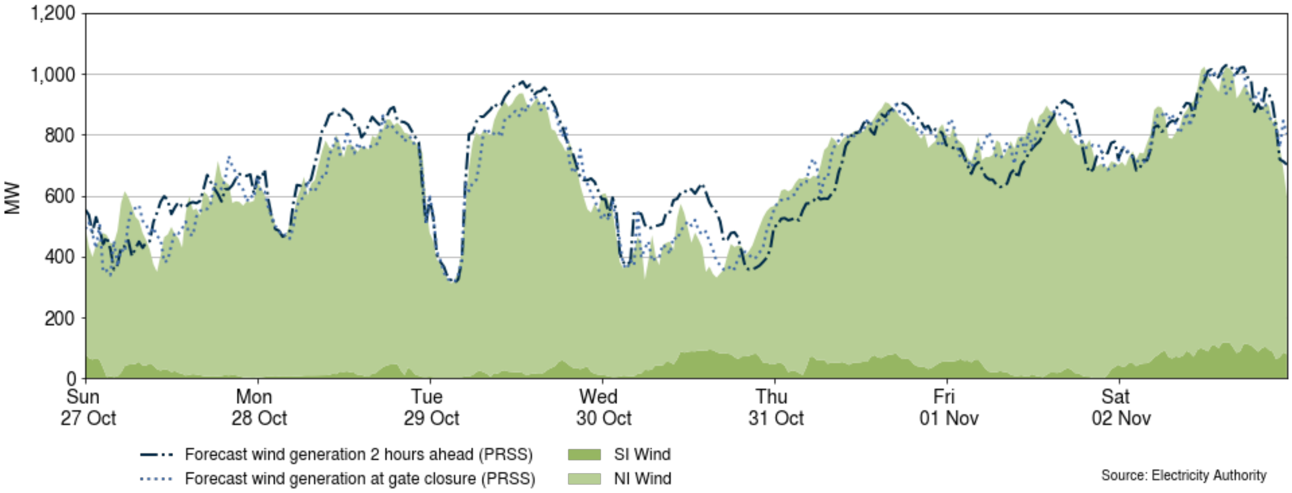
**Figure 8: Temperatures across main centres, 27 October- 2 November 2024**




## 7. Generation

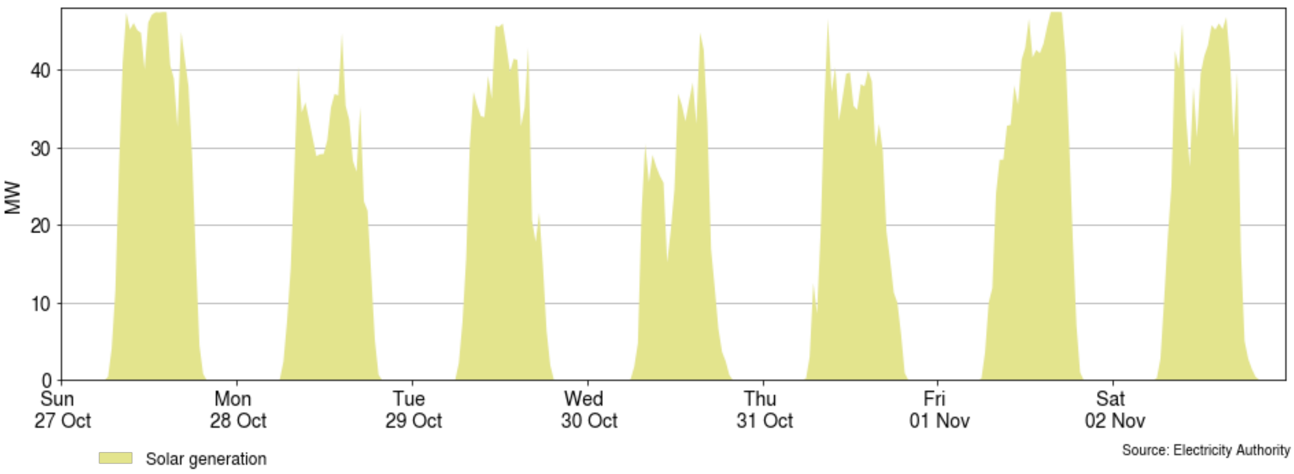
7.1. Figure 9 shows wind generation and forecast from 27 October- 2 November 2024. This week wind generation varied between 312MW and 1022MW, with a weekly average of 683MW. Wind generation was lowest on Wednesday, which was when spot prices were highest.

**Figure 9: Wind generation and forecast, 27 October- 2 November 2024**




7.2. Figure 10 shows solar generation from 27 October- 2 November 2024. Solar generation was mostly above 30MW this week. Each day reached a maximum trading period average of at least 45MW of generation.

**Figure 10: Solar generation, 27 October- 2 November 2024**

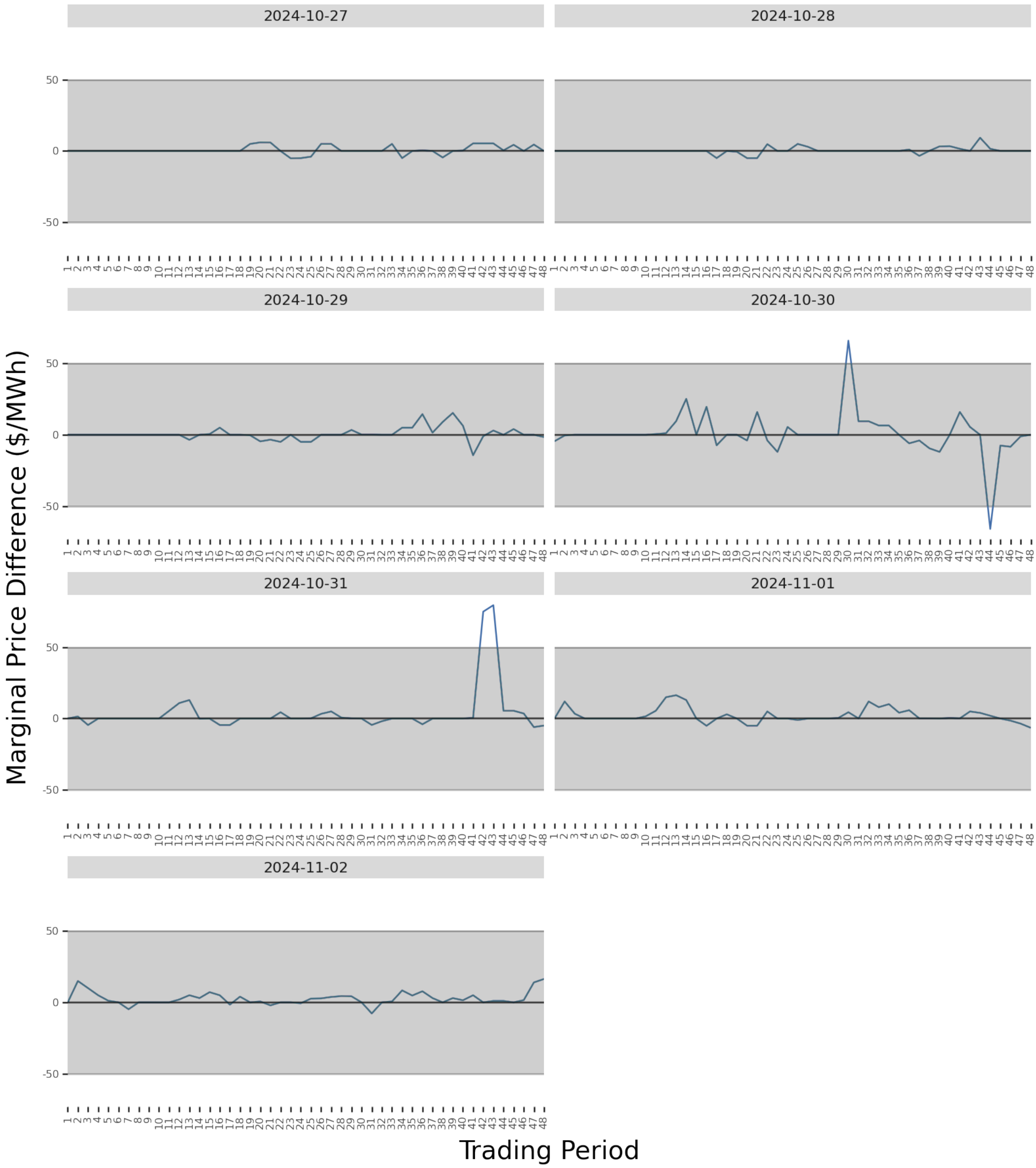



7.3. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences 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.

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

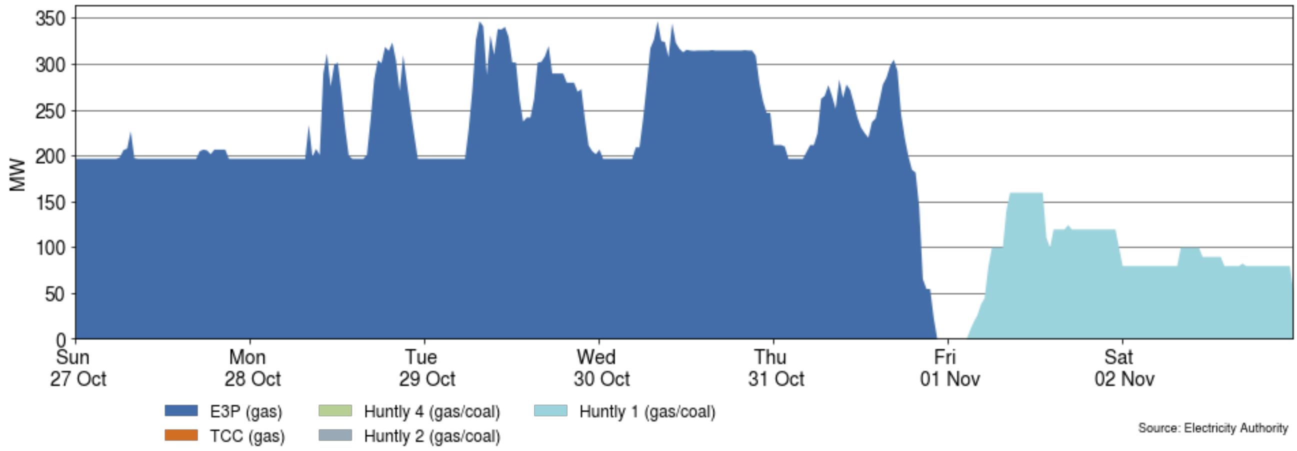
7.4. There were three occasions this week where the national marginal price was more than $50/MWh above the simulated price. Combinations of under forecast demand and over forecast wind of between ~80-170MW occurred during these trading periods.

**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, 27 October- 2 November 2024**



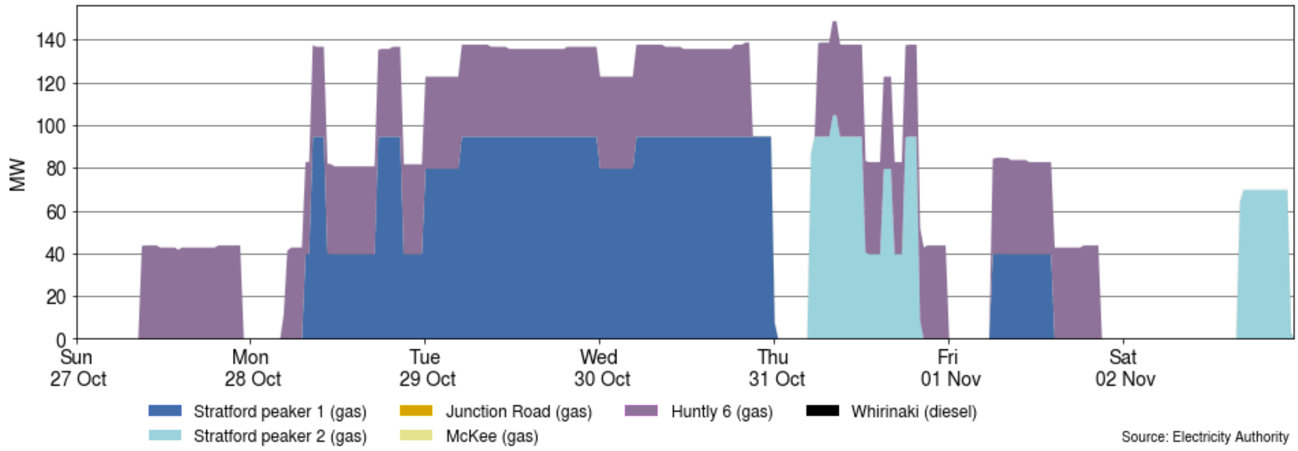
7.5. Figure 12 shows the generation of thermal baseload between 27 October- 2 November 2024. Huntly 5 ran continuously as baseload until the end of Thursday when it went on outage. Huntly 1 ran continuously from Friday morning.

**Figure 12: Thermal baseload generation, 27 October- 2 November 2024**



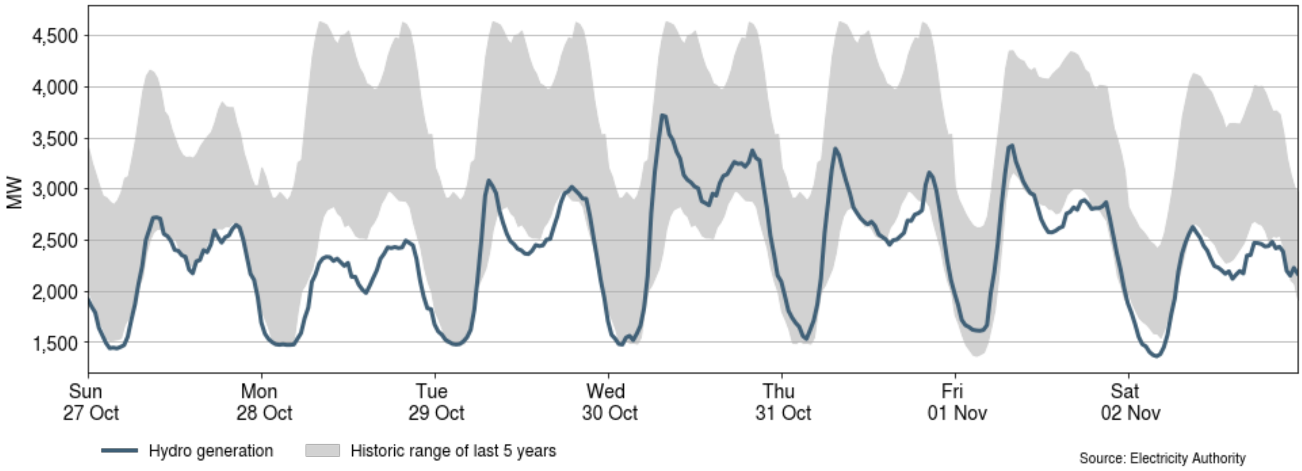

7.6. Figure 13 shows the generation of thermal peaker plants between 27 October- 2 November 2024. Peaker generation this week was from Huntly 6 and the Stratford units. Huntly 6 and Stratford 1 ran continuously from Monday to Wednesday. Stratford 2 joined Huntly 6 on Thursday running over peak and shoulder periods. Stratford 1 ran from Friday morning to early afternoon with Huntly 6 running over peak and shoulder periods that day. On return from a short outage Stratford 2 ran from late afternoon on Saturday until late evening.

**Figure 13: Thermal peaker generation, 27 October- 2 November 2024**



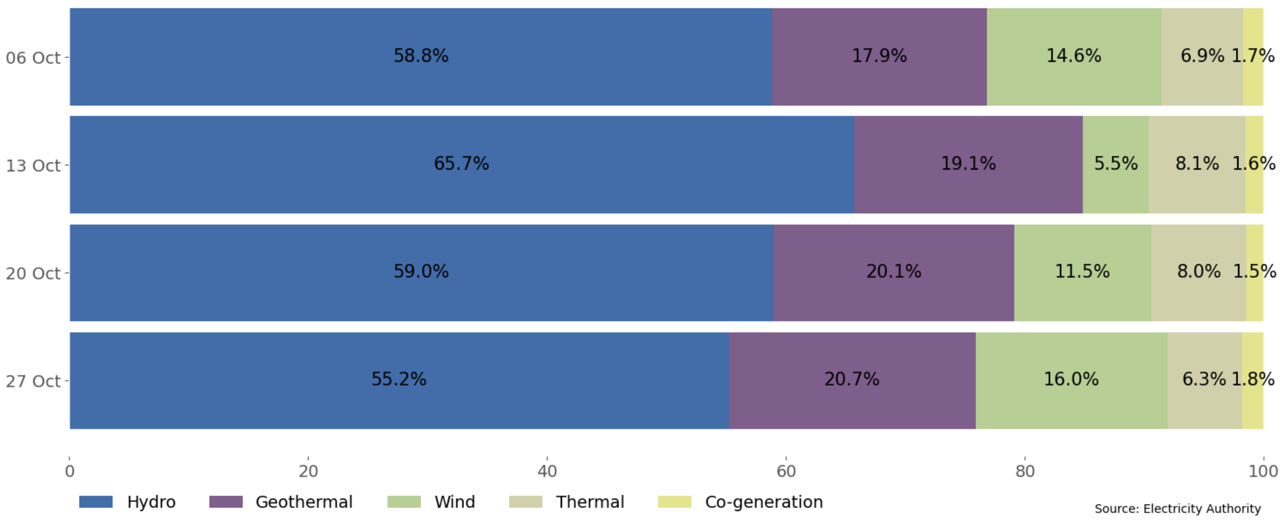

7.7. Figure 14 shows hydro generation between 27 October- 2 November 2024. Hydro generation was at the lower end of the historical average for this time of year. The highest generation from hydro was on Wednesday when wind generation was lower.

**Figure 14: Hydro generation, 27 October- 2 November 2024**




7.8. As a percentage of total generation, between 27 October- 2 November 2024, total weekly hydro generation was 55.2%, geothermal 20.7%, wind 16%, thermal 6.3%, and co-generation 1.8%, as shown in Figure 15.

**Figure 15: Total generation by type as a percentage each week, 6 October to 2 November**




# 8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 27 October- 2 November 2024 ranged between ~1,050MW and ~1,900MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 5 is on outage from 31 October-29 November

(b) Huntly 2 is on outage until 6 December

(c) Tauhara geothermal is on outage 30 October-11 November

(d) Stratford 2 had a short outage on 1 November

(e) Whirinaki has one unit on outage until 9 November

(f) One unit at Te Mihi was on outage until 31 October

(g) A number North and South Island hydro units are on outage.

**Figure 16: Total MW loss from generation outages, 27 October- 2 November 2024**

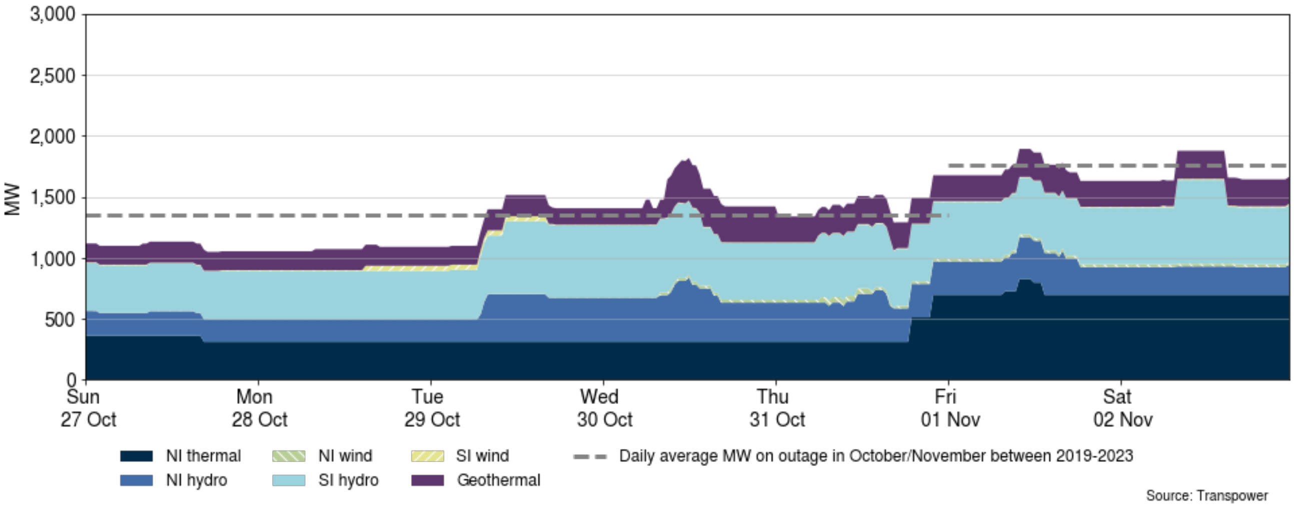
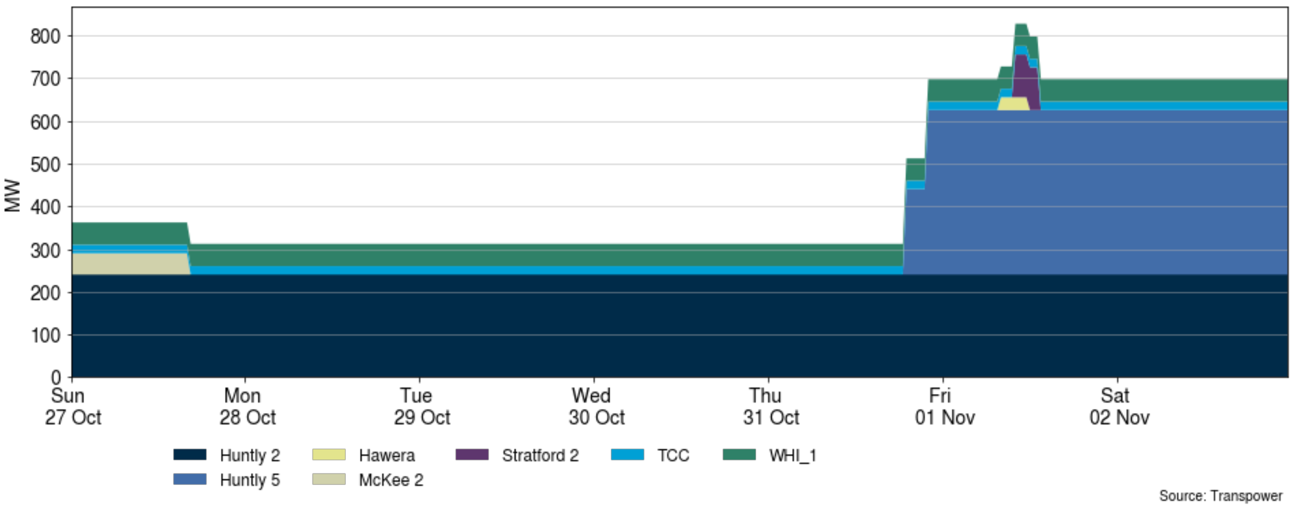



**Figure 17: Total MW loss from thermal outages, 27 October- 2 November 2024**

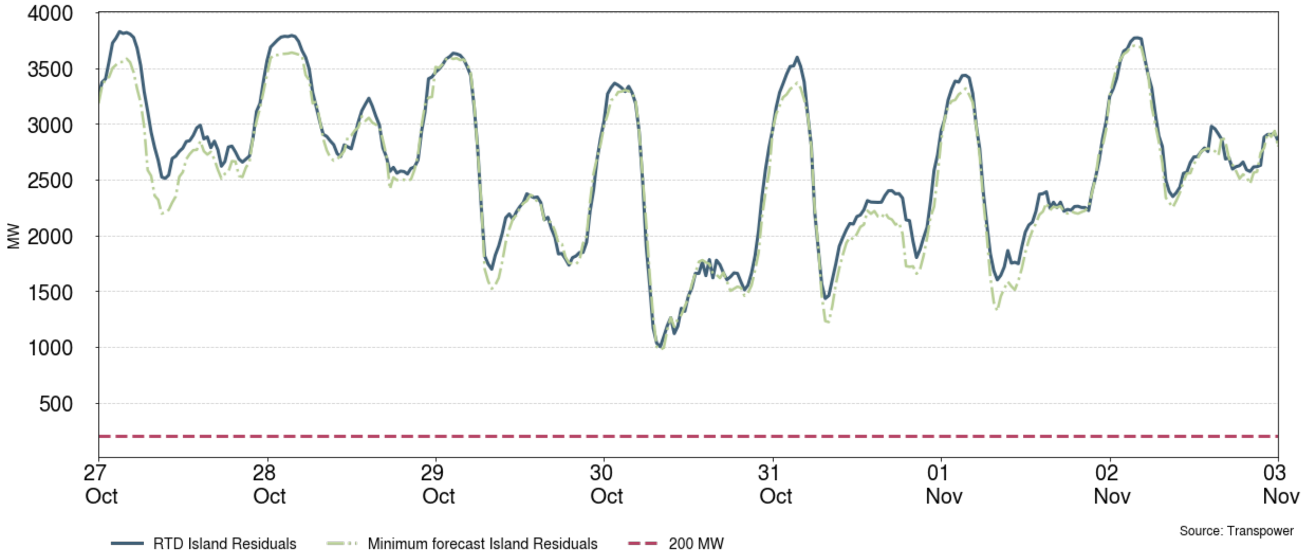



# 9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 27 October- 2 November 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. There were no residual generation balances below 1,000MW this week. The minimum of ~1,003MW was on Wednesday 8.00am. North Island residuals at this time were ~ 581MW.

**Figure 18: National generation balance residuals, 27 October- 2 November 2024**




## 10. Storage/fuel supply

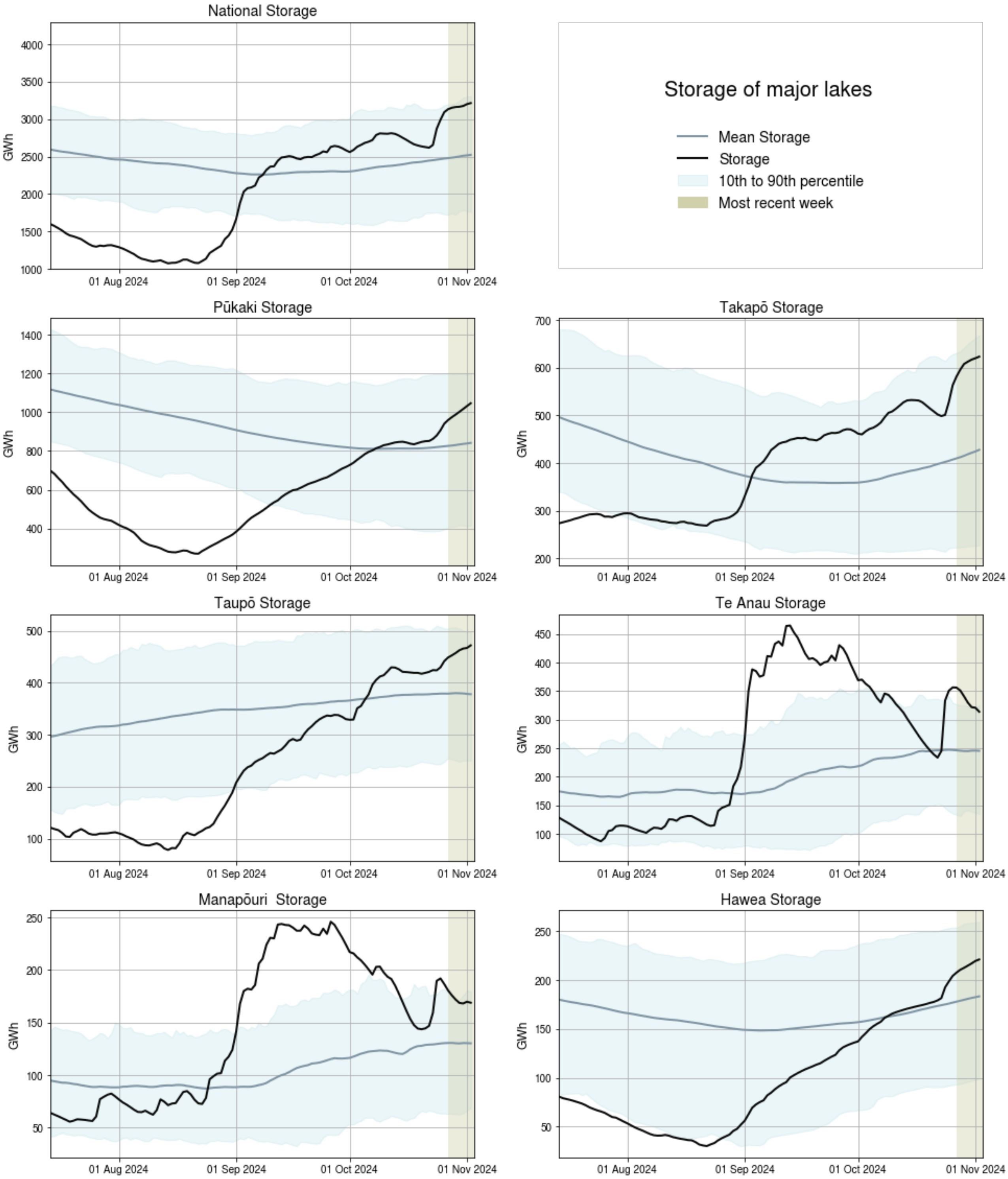
10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10$^{th}$ to 90$^{th}$ percentiles.

10.2. National controlled storage increased this week and was 78% nominally full and ~123% of the historical average as of 2 November.

10.3. Taupō storage has continued to increase and is now close to its 90$^{th}$ percentile region. Most South Island lakes saw an increase in storage with Pūkaki and Takapō now approaching their respective historic 90$^{th}$ percentile regions.

10.4. Manapōuri and Te Anau storage has decreased this week with both lakes close to their 90$^{th}$ percentile region and 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. 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-fuelled 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.

11.8. Figure 20 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.

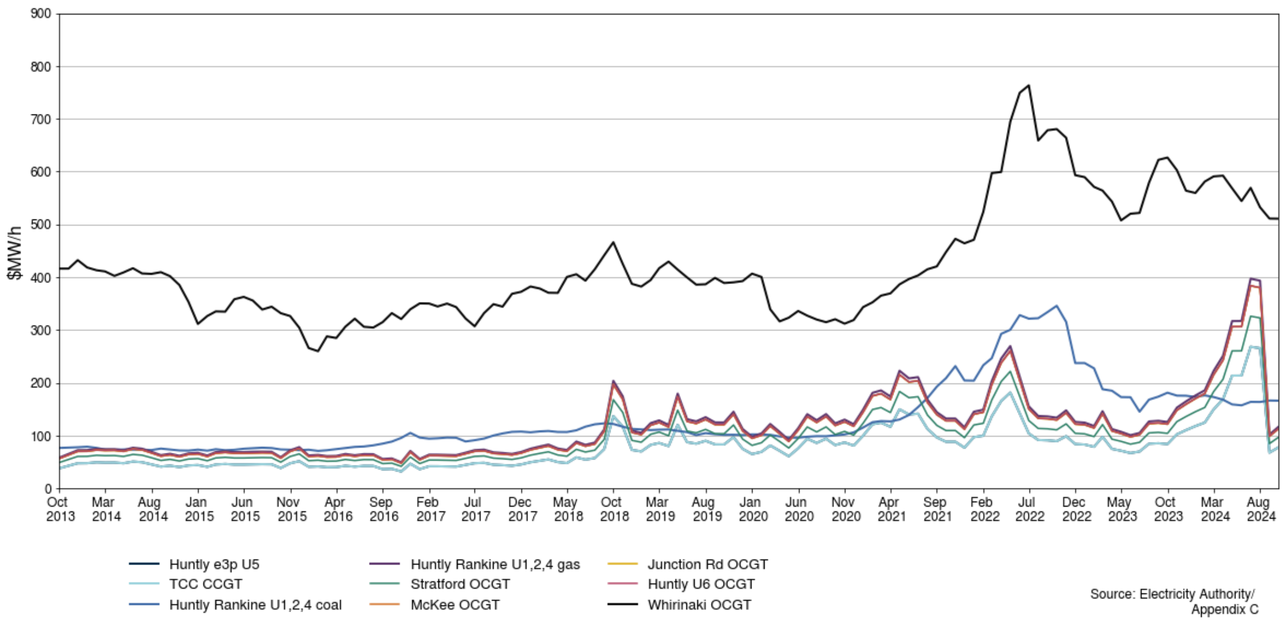
11.9. The latest SRMC of coal-fuelled Rankine generation is ~$167/MWh. The cost of running the Rankines on gas remains less expensive at ~$117/MWh.

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

11.11. The SRMC of Whirinaki is ~$511/MWh.

11.12. 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**

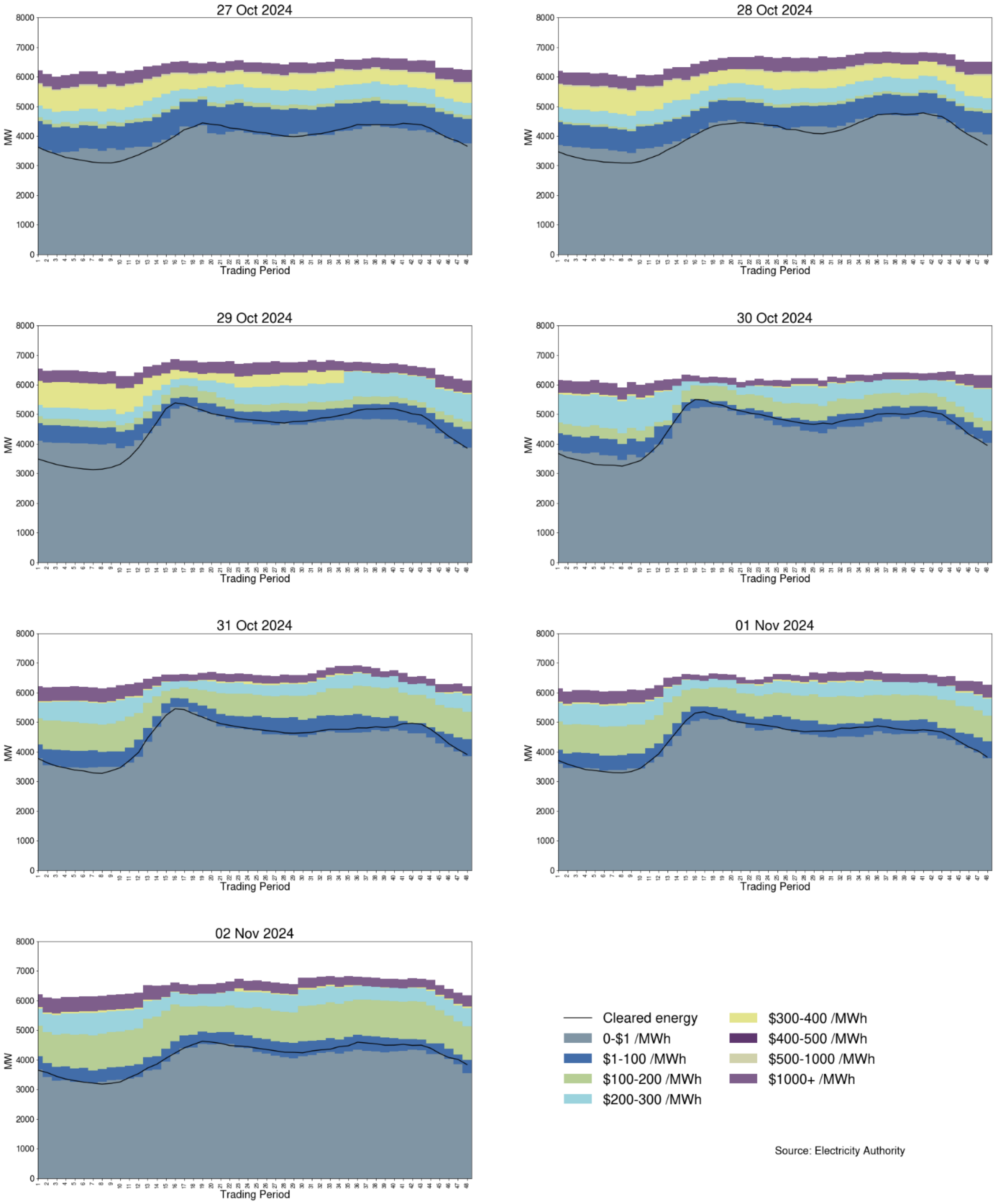


## 12. Offer behaviour

12.1. Figure 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. Most prices this week cleared under $100/MWh with some overnight prices clearing within the $0-$1/MWh band. This reflects lower demand coupled with sufficient hydro, and higher wind generation.

**Figure 21: Daily offer stacks**




Source: Electricity Authority

## 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 |