Trading conduct report 17-23 November 2024

Market monitoring weekly report

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1. Overview

1.1. Spot prices remained low this week and were consistently below the historic median. National hydro storage decreased slightly but remained high at 133% of mean, resulting in high hydro generation and high northward HVDC flow. Thermal generation was very low, with no baseload units running.

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 17-23 November 2024:

(a) the average wholesale spot price across all nodes was $11/MWh

(b) 95% of prices fell between $0.01/MWh and $61/MWh.

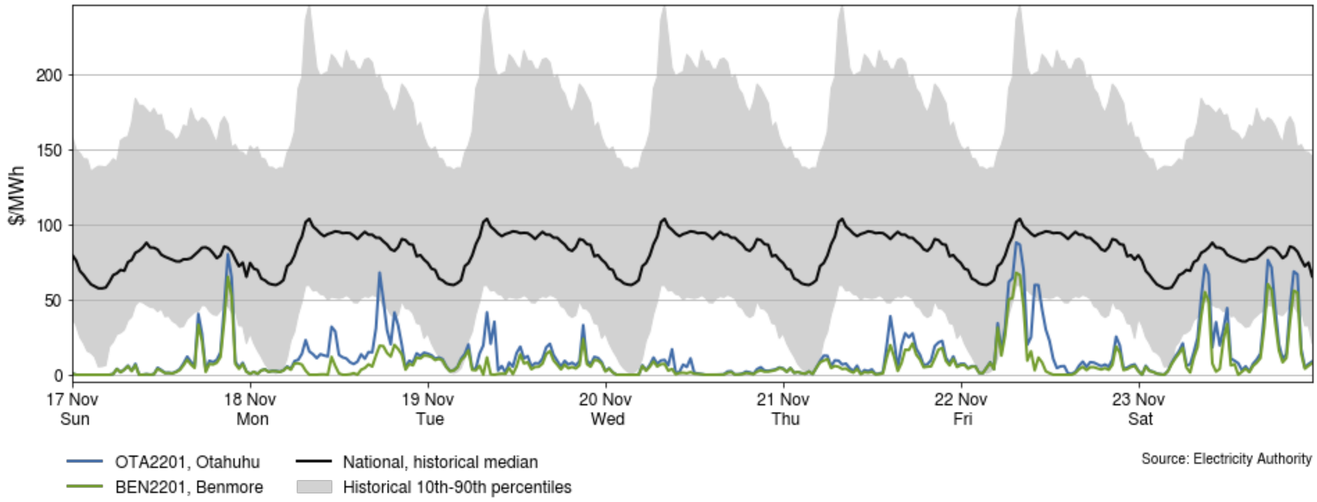
2.3. Overall, the majority of spot prices were within $2-$12/MWh and below the historic 10th percentile range. There were only a few of instances of prices above $50/MWh. The weekly average price decreased by around $31/MWh compared to the previous week.

2.4. There was some small price separation during the week. The highest was on Monday evening where the price at Ōtāhuhu was $68/MWh and at the same time the price at Benmore was $19/MWh. Price separation that occurred was small and likely due to transmission losses with high northward flows on the HVDC and lower wind generation in the North Island.

2.5. The Ōtāhuhu spot price reached a maximum of $88/MWh at 7.30am on Friday, when wind was significantly over-forecast.

2.6. 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.

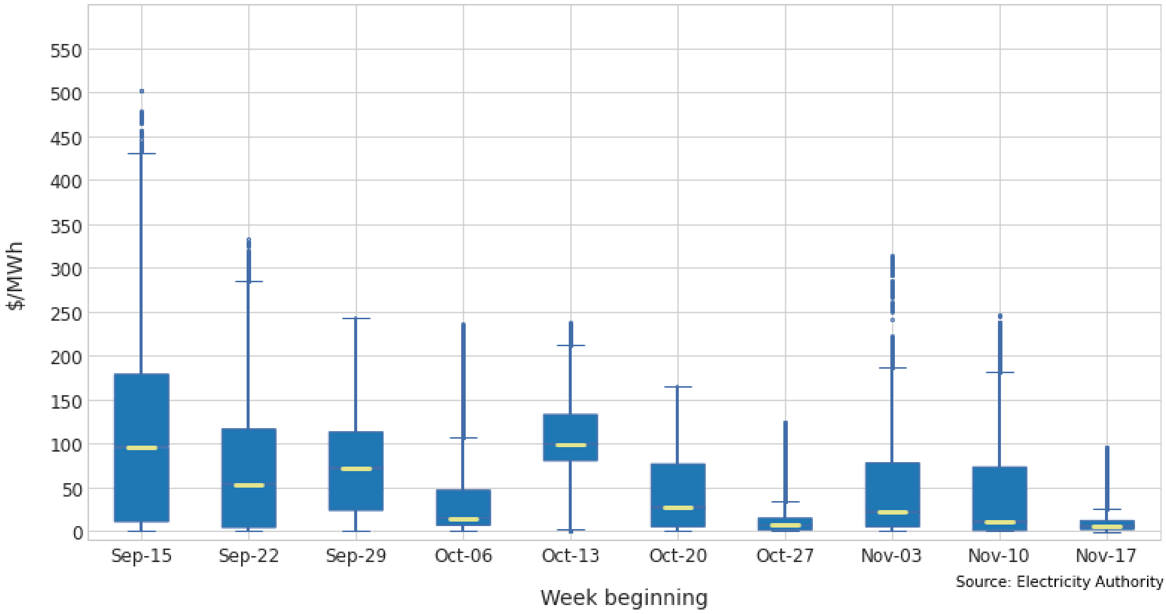
Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 17-23 November 2024



2.7. 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.

2.8. The median price decreased to $6/MWh this week. The overall range also decreased, with all of this week's prices below $100/MWh.

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. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4.

3.2. South Island reserve prices were consistently below $1/MWh this week.

3.3. The North Island FIR price exceeded $20/MWh on Monday evening and the mornings of Tuesday, Friday and Saturday, reaching a maximum of $41/MWh at 10.00am on Friday. These separations were due to high northward HVDC flow during low wind generation and the HVDC setting the risk. North Island SIR prices were below $7/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 17-23 November 2024

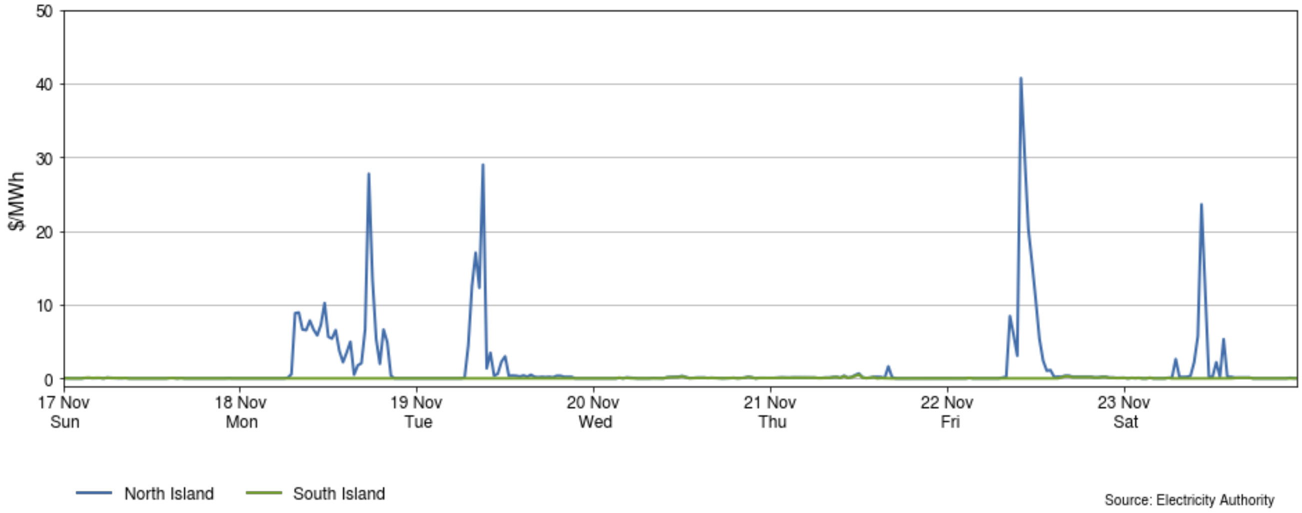
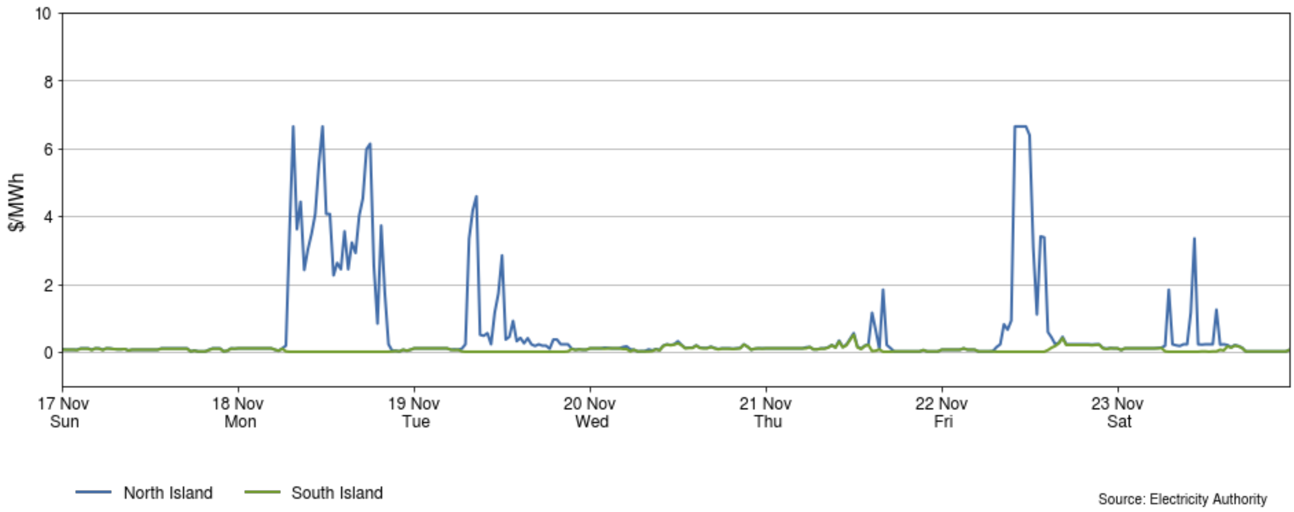


Figure 4: Sustained instantaneous reserve by trading period and island, 17-23 November 2024



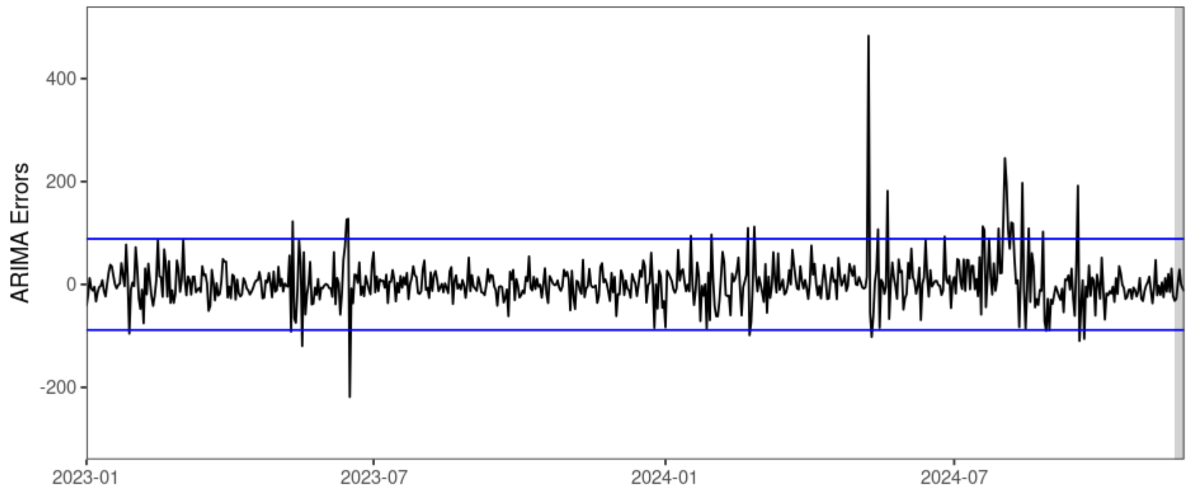
4. Regression residuals

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, indicating that prices were similar to those predicted by the model.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 23 November 2024

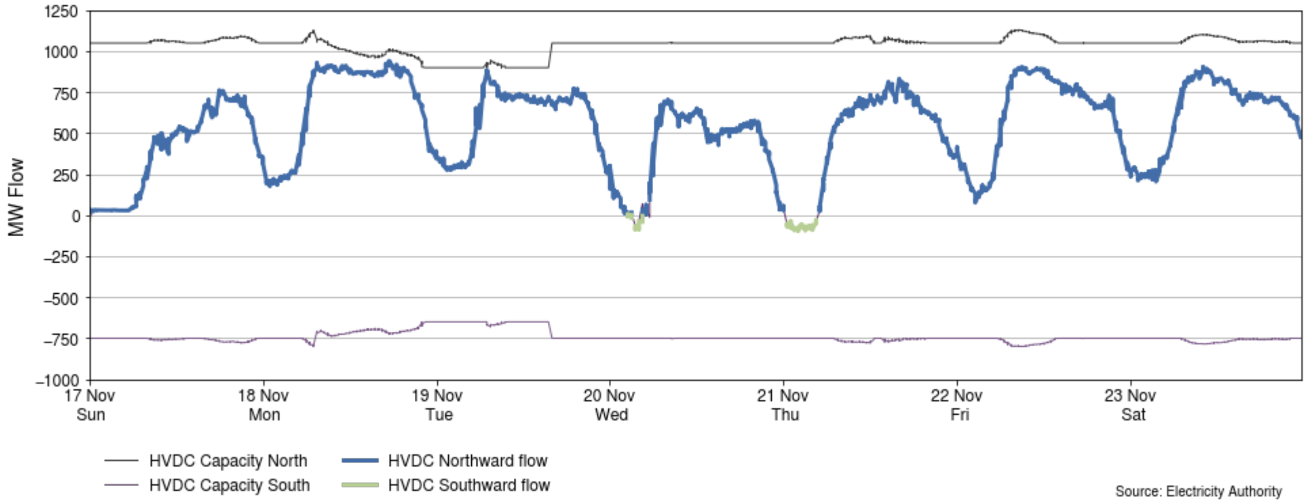


Source: Electricity Authority/Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 17-23 November 2024. HVDC flows were mainly northwards with near capacity northward flow on Monday and Tuesday. There were some small overnight southward flows on Wednesday and Thursday when wind generation was higher.

Figure 6: HVDC flow and capacity, 17-23 November 2024

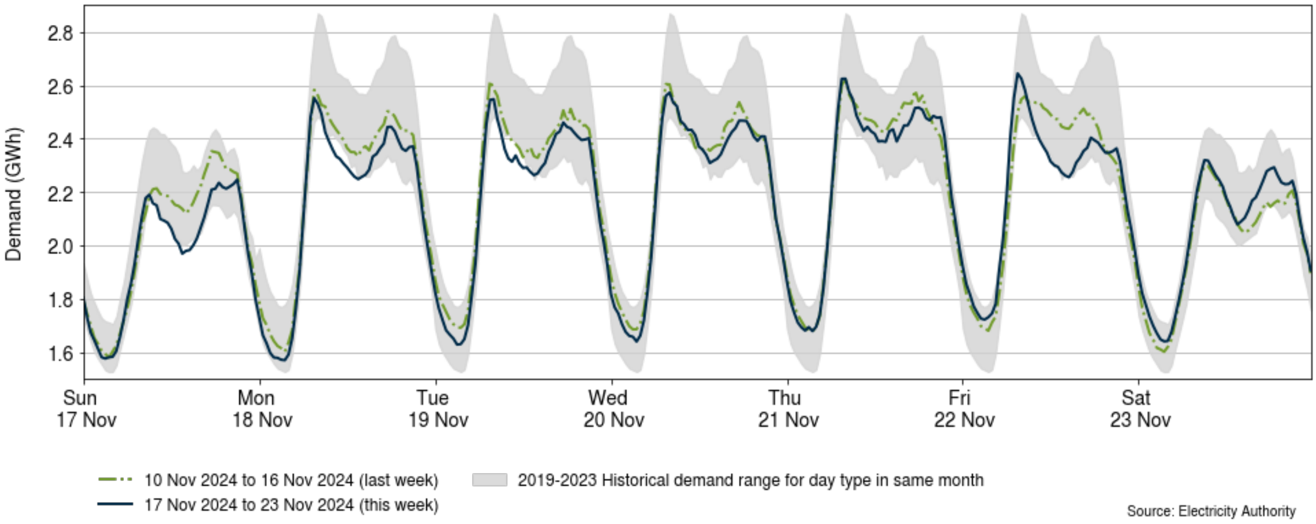


Source: Electricity Authority

6. Demand

6.1. Figure 7 shows national demand between 17-23 November 2024, compared to the historic range and the demand of the previous week. Demand mainly sat at the lower end of the historical range with the maximum demand this week at 2.64GWh during Friday morning's peak period and in line with a dip in temperatures.

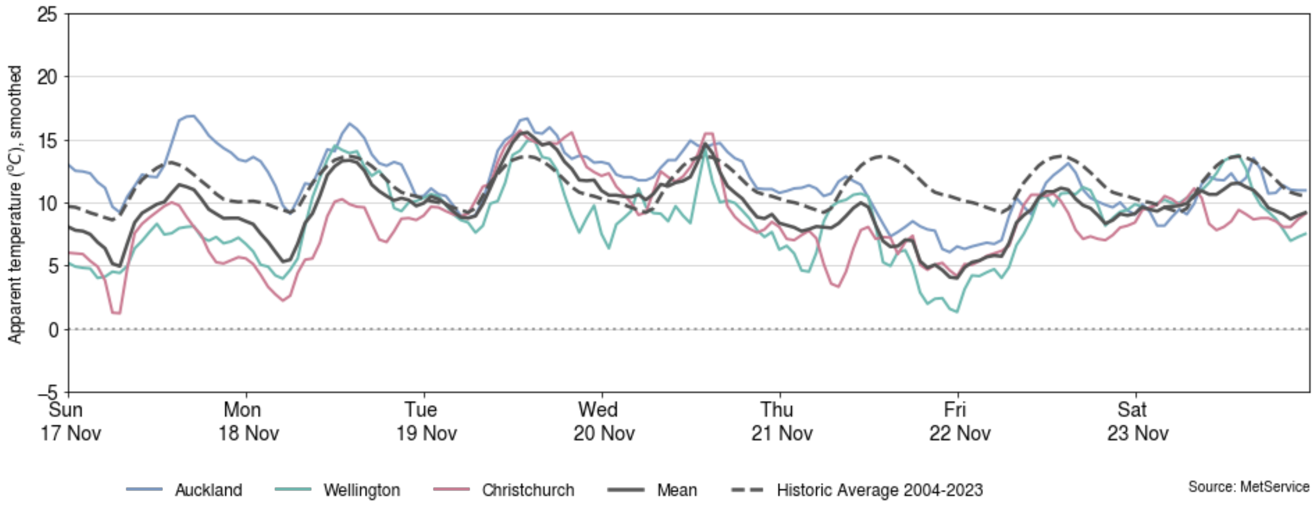
Figure 7: National demand, 17-23 November 2024 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 17-23 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.

6.3. Temperatures were generally close to or below average this week, ranging from 5°C to 17°C in Auckland, 0°C to 16°C in Wellington, and 0°C to 16°C in Christchurch. Temperatures were low on Friday morning, when demand and spot prices peaked.

Figure 8: Temperatures across main centres, 17-23 November 2024

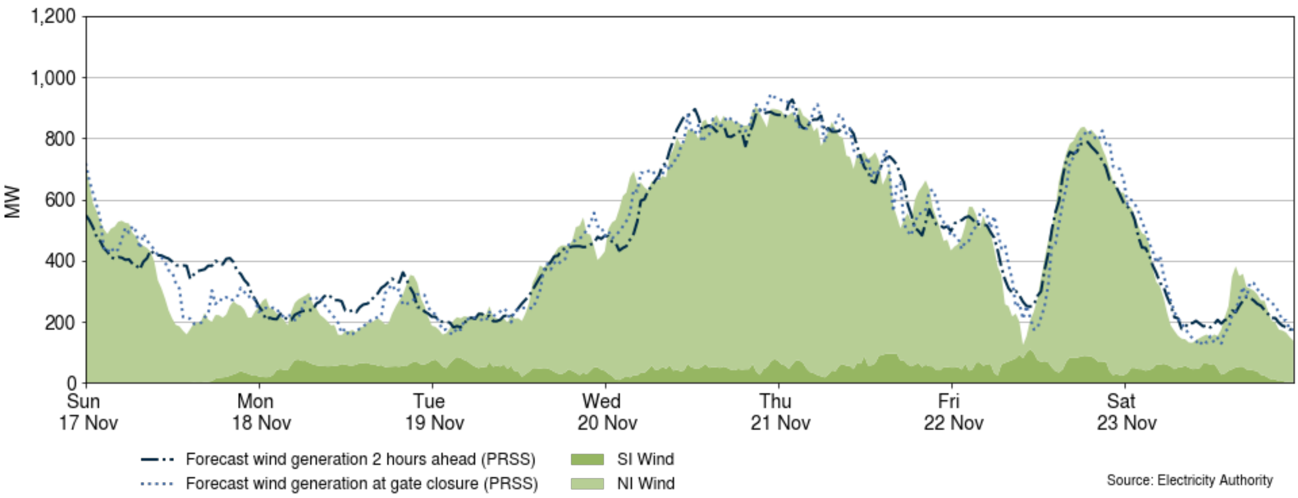


7. Generation

7.1. Figure 9 shows wind generation and forecast from 17-23 November 2024. This week wind generation varied between 124MW and 903MW, with a weekly average of 451MW. Wind generation was highest mid-week with daily average generation over 700MW on Wednesday and Thursday.

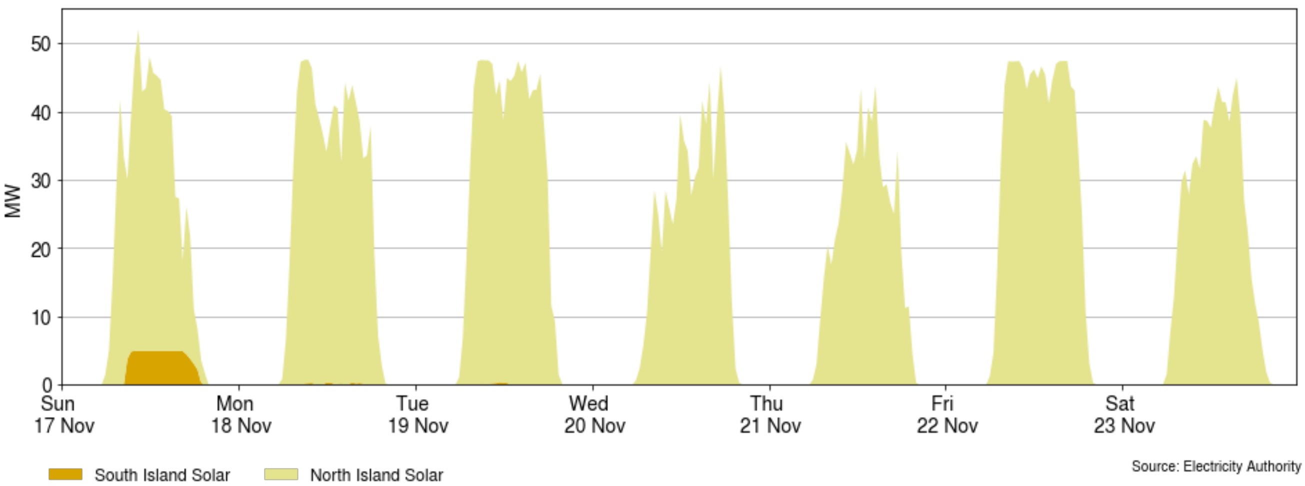
7.2. The largest gate closure forecast error was at 7.30am on Friday when wind generation was 194MW lower than forecast.

Figure 9: Wind generation and forecast, 17-23 November 2024



7.3. Figure 10 shows solar generation from 17-23 November 2024. The maximum trading period average solar generation was ~52MW this week. Overcast conditions on Wednesday and Thursday meant most trading periods saw less than 40MW of generation. There was less solar generation from the South Island this week with Lauriston solar farm still in its commissioning stages.

Figure 10: Solar generation, 17-23 November 2024



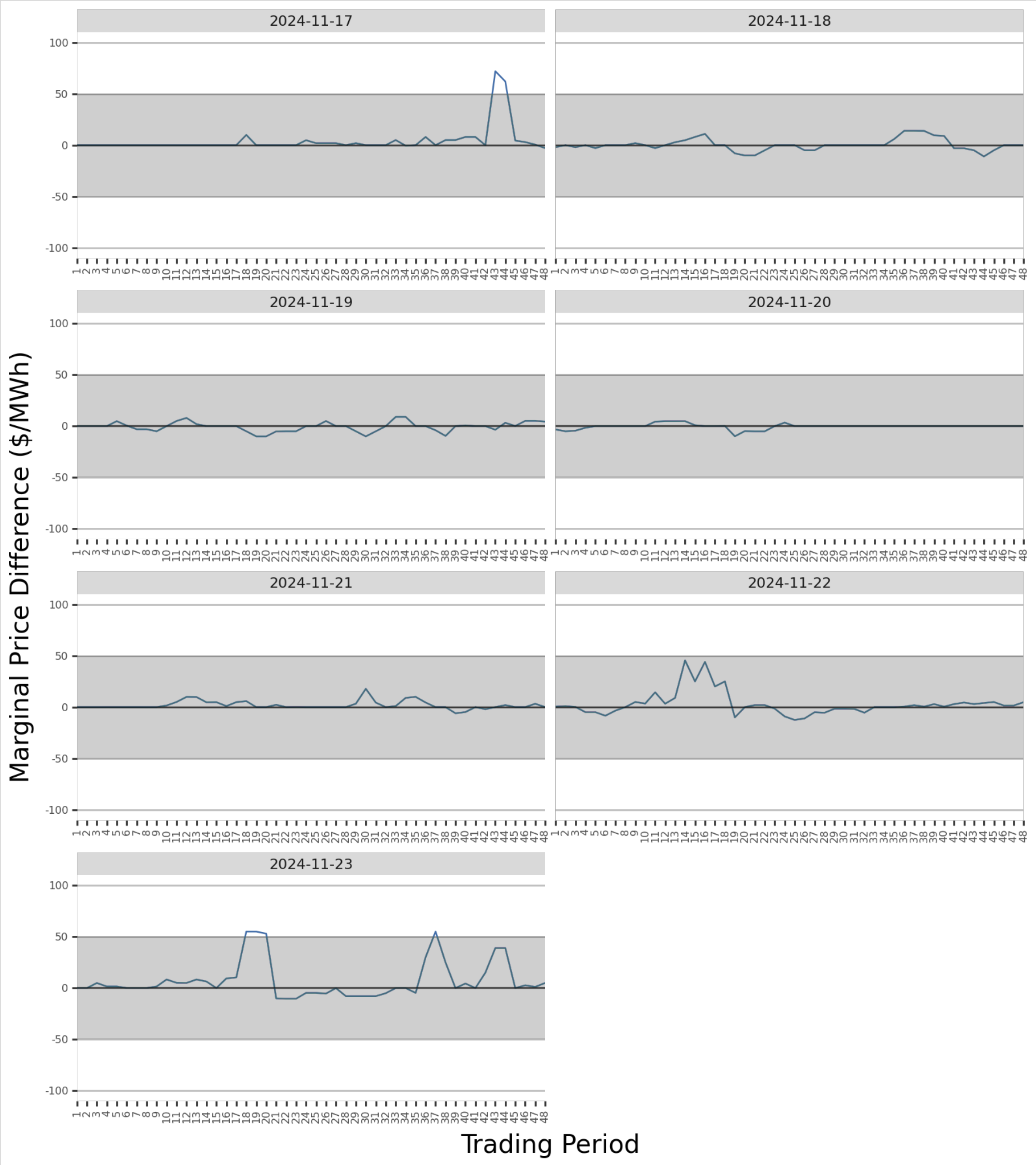
7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[1]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

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

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.

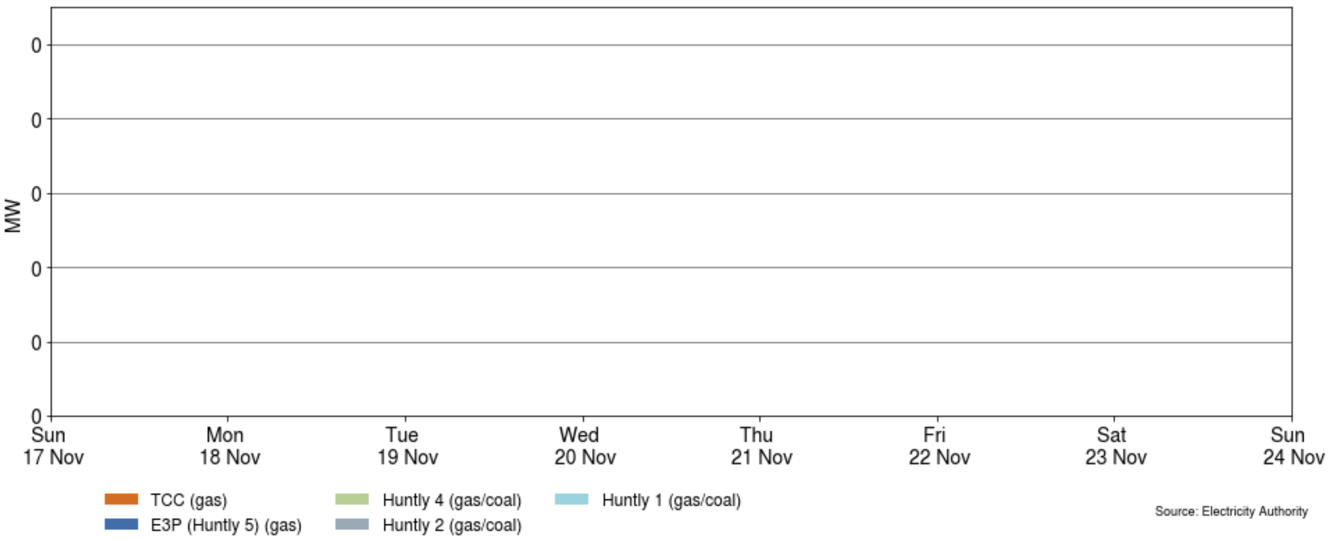
7.5. The most significant marginal price difference this week was $72/MWh at 9.00pm on Sunday, when wind generation was over-forecast. Prices were otherwise generally similar to those simulated.

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, 17-23 November 2024



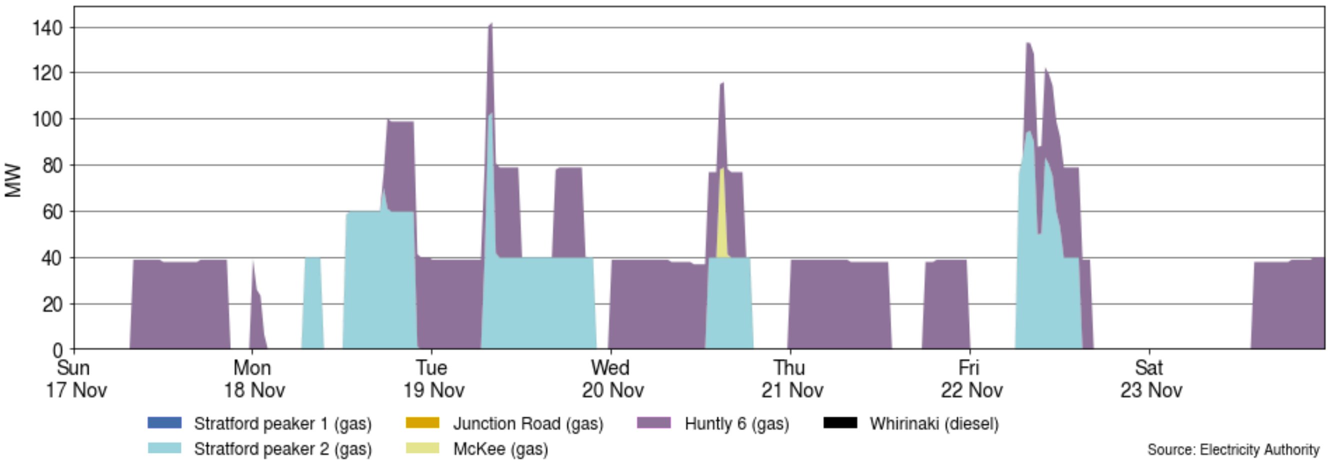
7.6. Figure 12 shows the generation of thermal baseload between 17-23 November 2024. There were no slow start thermal units running this week.

Figure 12: Thermal baseload generation, 17-23 November 2024



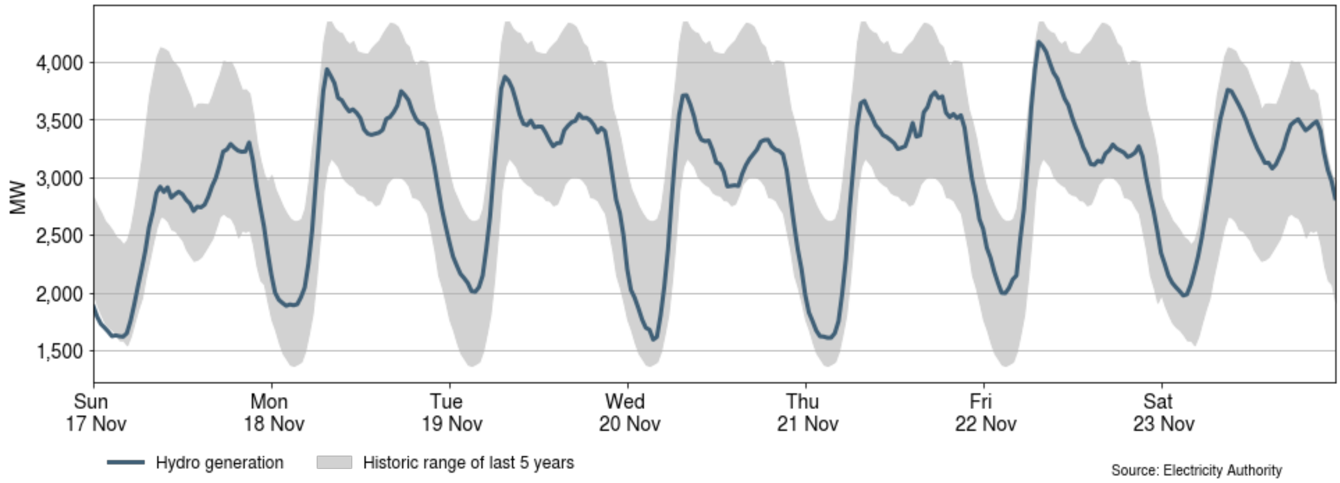
7.7. Figure 13 shows the generation of thermal peaker plants between 17-23 November 2024. Huntly 6 and Stratford 2 were the main peaker units running this week. Stratford 2 ran from Monday to Wednesday over peak and/or shoulder periods. Huntly 6 ran for longer periods, with midweek generation starting around midnight continuously through to late afternoon.

Figure 13: Thermal peaker generation, 17-23 November 2024



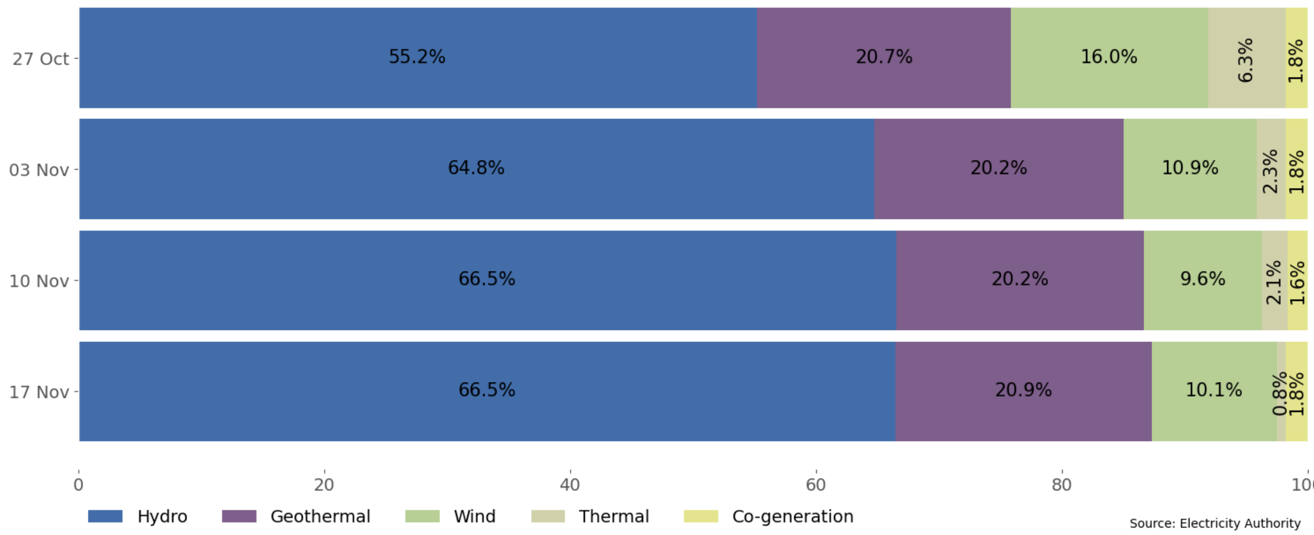
7.8. Figure 14 shows hydro generation between 17-23 November 2024. Hydro generation was around the middle of the historic range with some lower generation. This is in line with days of higher wind generation as well as some lower national demand.

Figure 14: Hydro generation, 17-23 November 2024



7.9. As a percentage of total generation, between 17-23 November 2024, total weekly hydro generation was 66.5%, geothermal 20.9%, wind 10.1%, thermal 0.8%, and co-generation 1.8%, as shown in Figure 15. The increase in wind generation this week, combined with hydro generation remaining high, allowed for thermal generation to drop below 1%.

Figure 15: Total generation by type as a percentage each week, 27 October to 23 November



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 17-23 November 2024 ranged between ~1,760MW and ~2,330MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 5 is on outage until 26 November.

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

(c) Huntly 1 is on outage from 23-29 November.

(d) Ngā Awa Pūrua geothermal plant is on outage from 20-30 November.

(e) Stratford peaker 2 was on outage on 18 November.

(f) Stratford peaker 1 is on outage until 1 December.

(g) Several large hydro units are on outage.

Figure 16: Total MW loss from generation outages, 17-23 November 2024

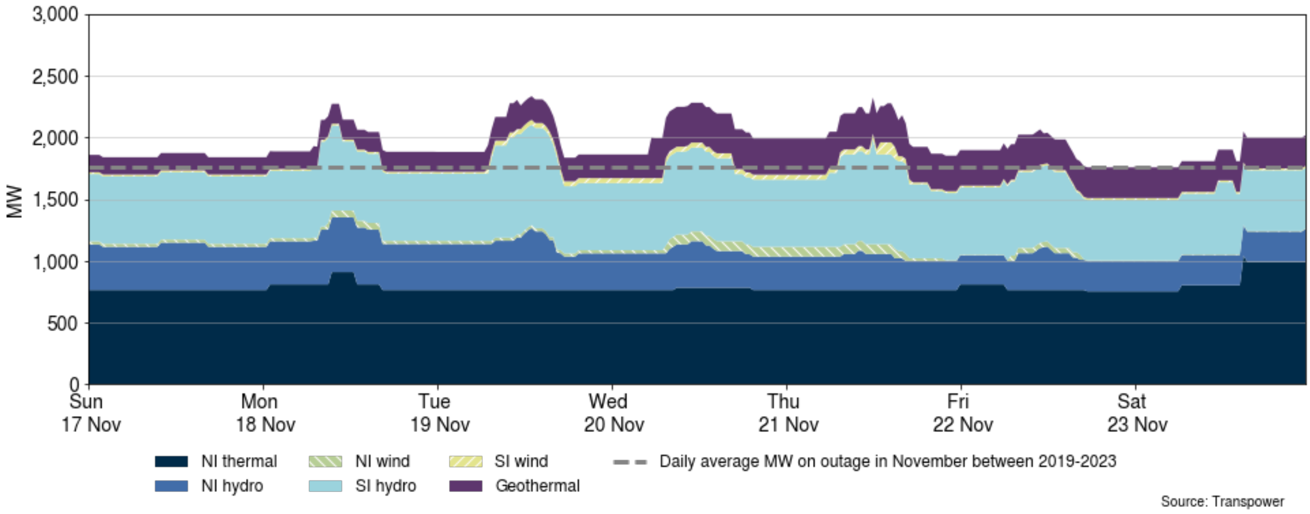
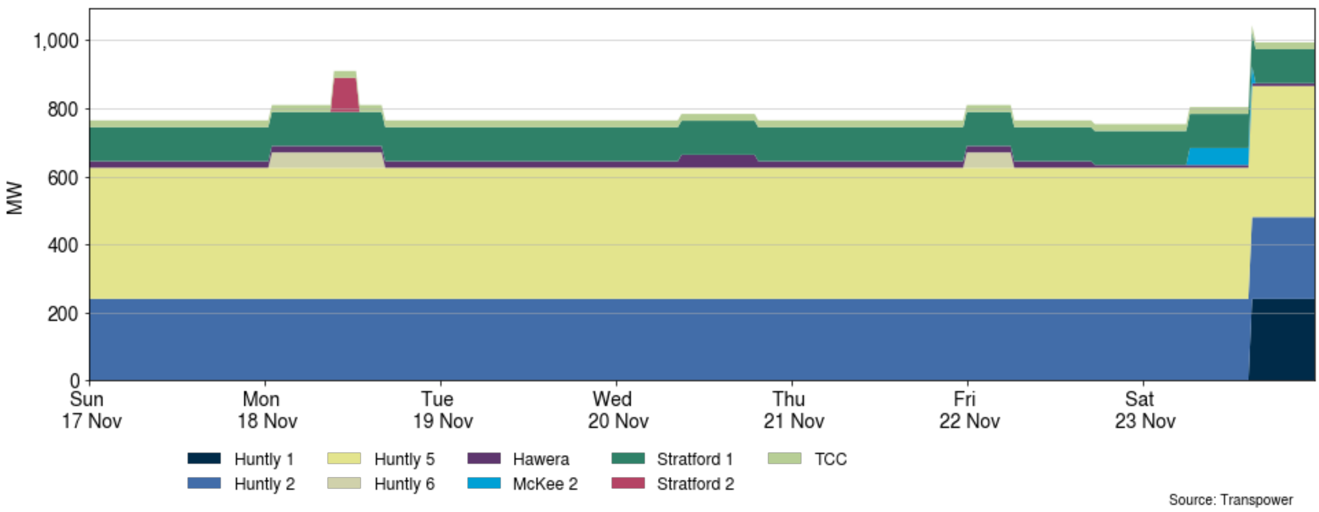


Figure 17: Total MW loss from thermal outages, 17-23 November 2024

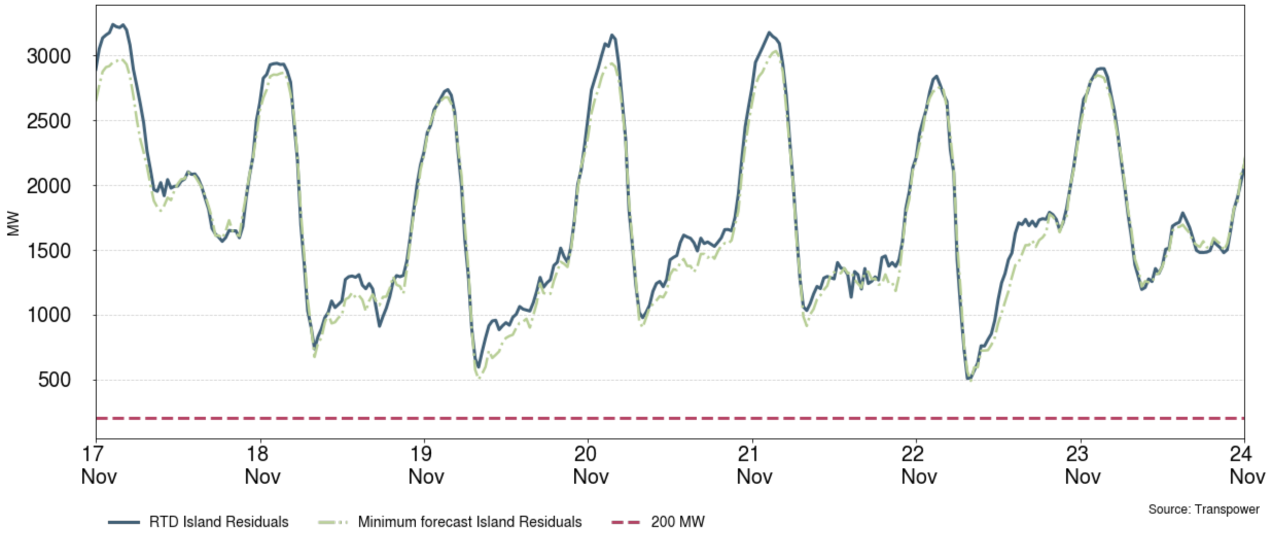


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 17-23 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. The minimum North Island residual this week was ~360MW at 7.30am on Friday.

Figure 18: National generation balance residuals, 17-23 November 2024



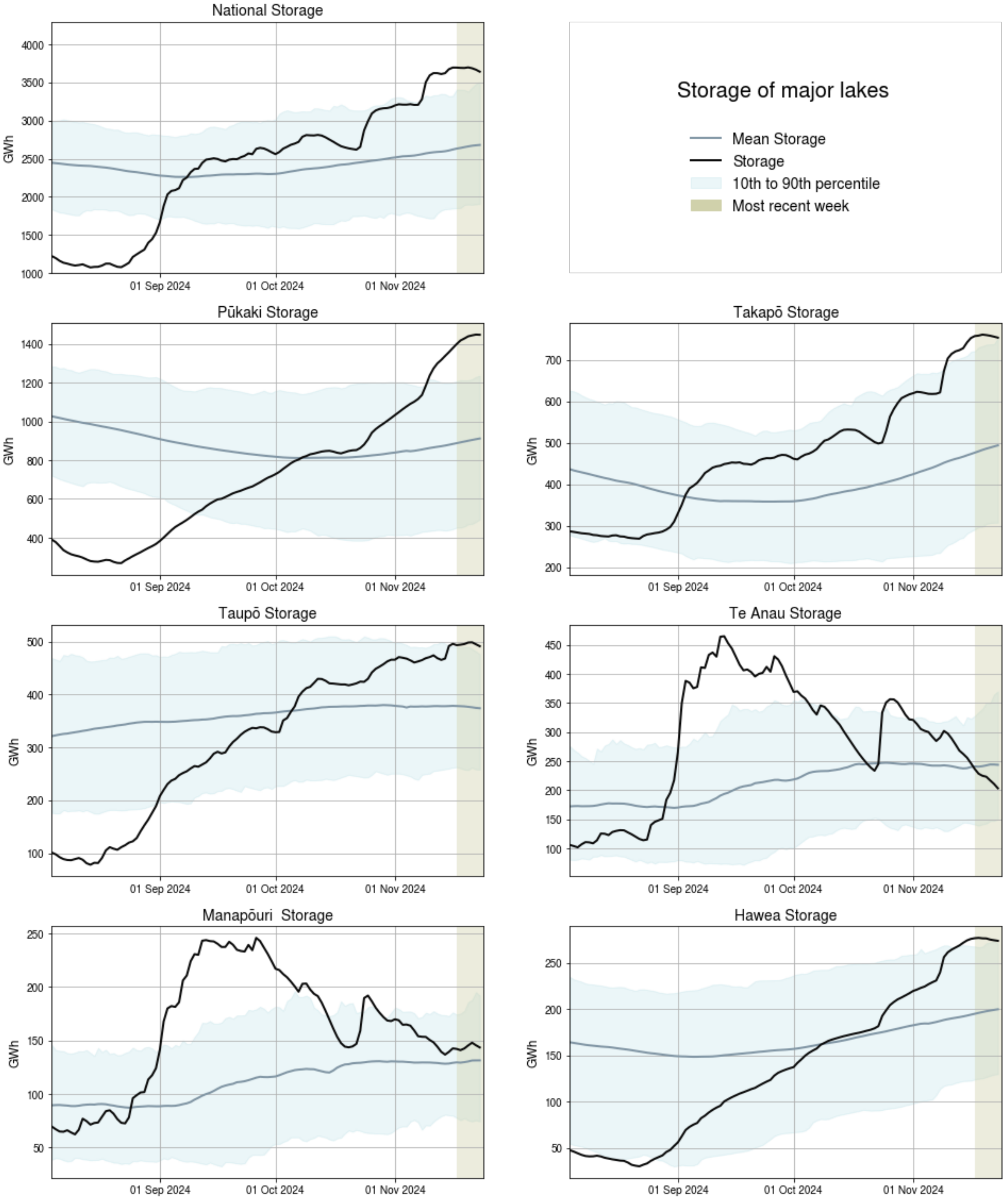
10. Storage/fuel supply

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 10th to 90th percentiles.

10.2. National controlled storage decreased slightly this week and was ~89% nominally full and ~133% of the historical average for this time of the year.

10.3. At the end of this week, storage was above the respective 90th percentiles of Pūkaki, Takapō, Taupō, and Hawea. Te Anau storage decreased below mean but remained above its 10th percentile. Manapōuri storage fluctuated but did not change significantly, remaining above mean but below its 90th 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 21 shows an estimate of thermal SRMCs as a monthly average up to 1 November. The SRMC for gas is similar to the previous month with only a small increase. Coal and diesel SRMC have also increased since the previous month.

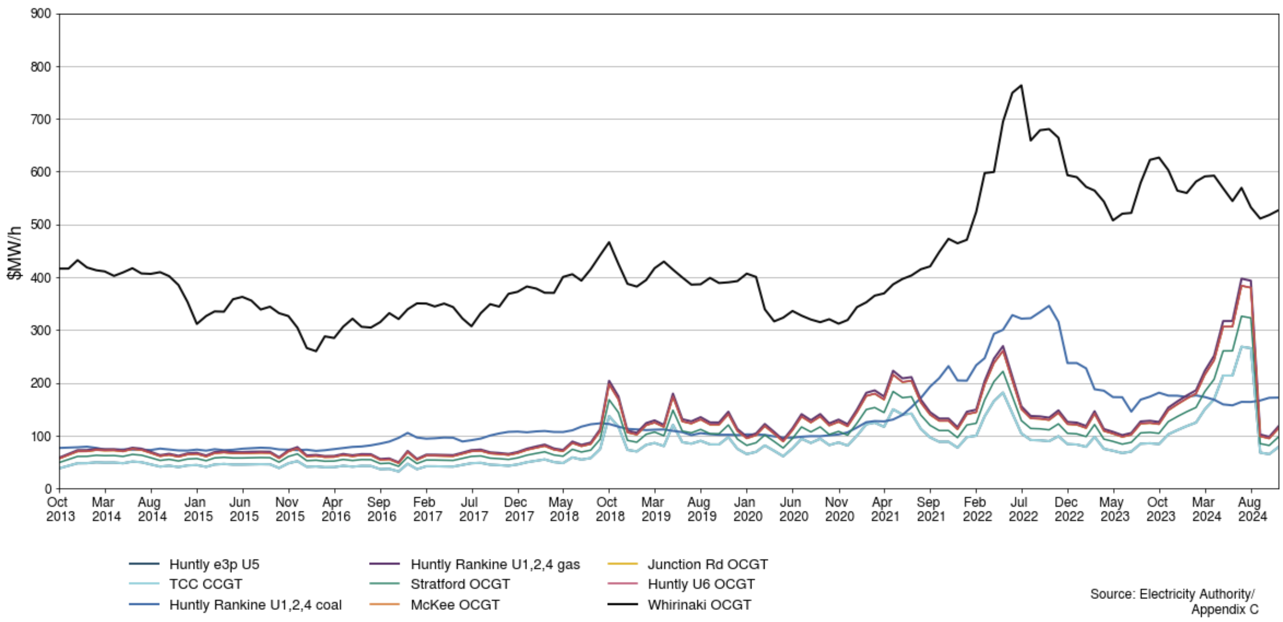
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$172/MWh with the cost of running the Rankines on gas remaining lower at ~$118/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $79/MWh and $118/MWh.

11.6. The SRMC of Whirinaki is ~$527/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

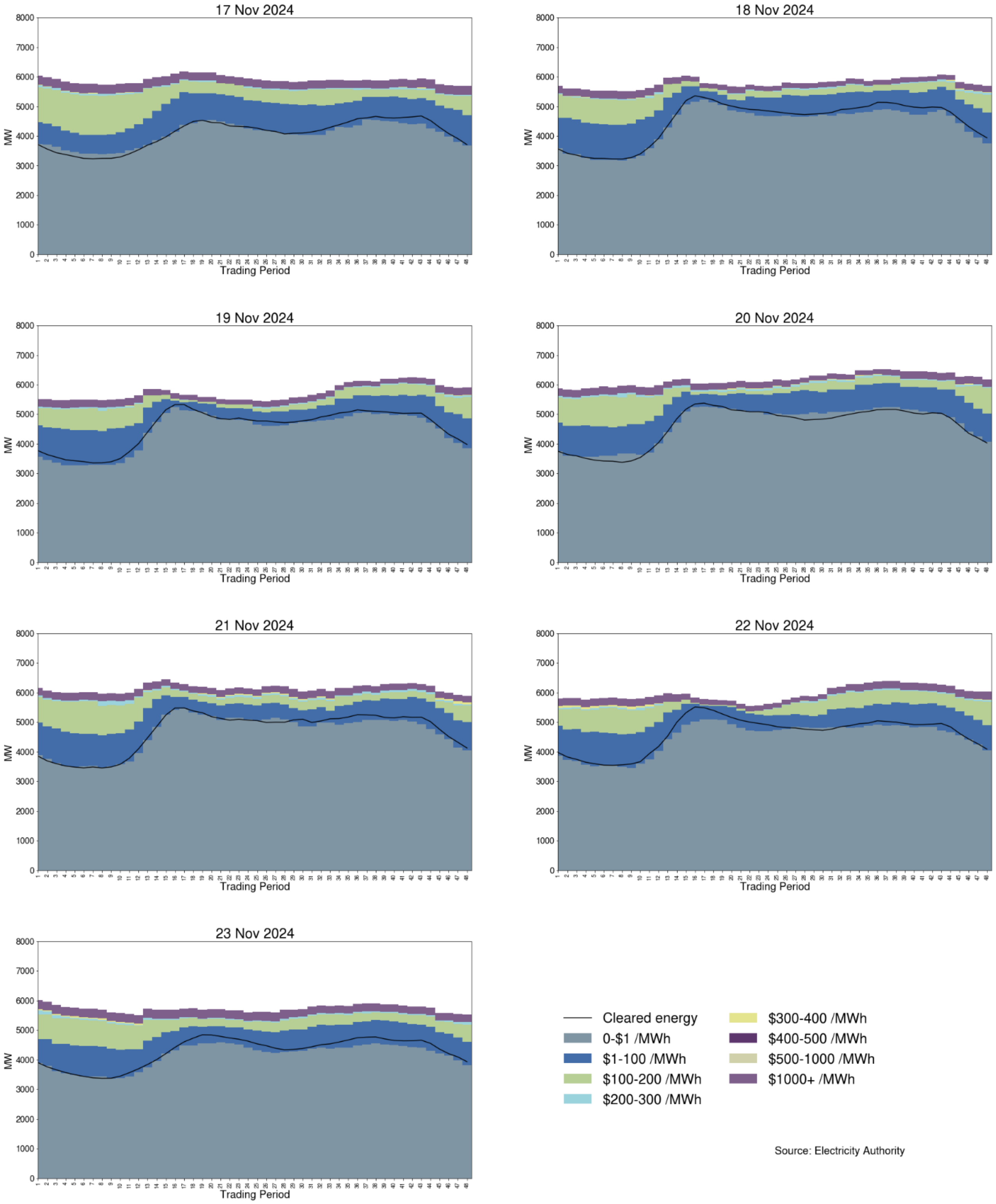


12. Offer behaviour

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. All prices cleared under $100/MWh this week with large number of prices clearing under $1/MWh. Healthy supply of hydro and other renewables along with lower demand and lower thermal commitment have kept the prices low this week.

Figure 21: Daily offer stacks



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
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact Energy	Clutha scheme	Hydro offers