9 December 2024

Trading conduct report 1-7 December 2024

Market monitoring weekly report

Trading conduct report 1-7 December 2024

1. Overview

1.1. Spot prices increased this week but were still mostly below the historical median. High northward HVDC flow and North Island transmission constraints led to price separation between islands and within the North Island at times. National hydro storage increased to ~90% nominally full. Thermal generation remains low.

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 1-7 December 2024:

(a) the average wholesale spot price across all nodes was $48/MWh.

(b) 95% of prices fell between $1/MWh and $123/MWh.

2.3. Overall, the majority of spot prices were within $16-$68/MWh and the weekly average price increased by around $22/MWh compared to the previous week.

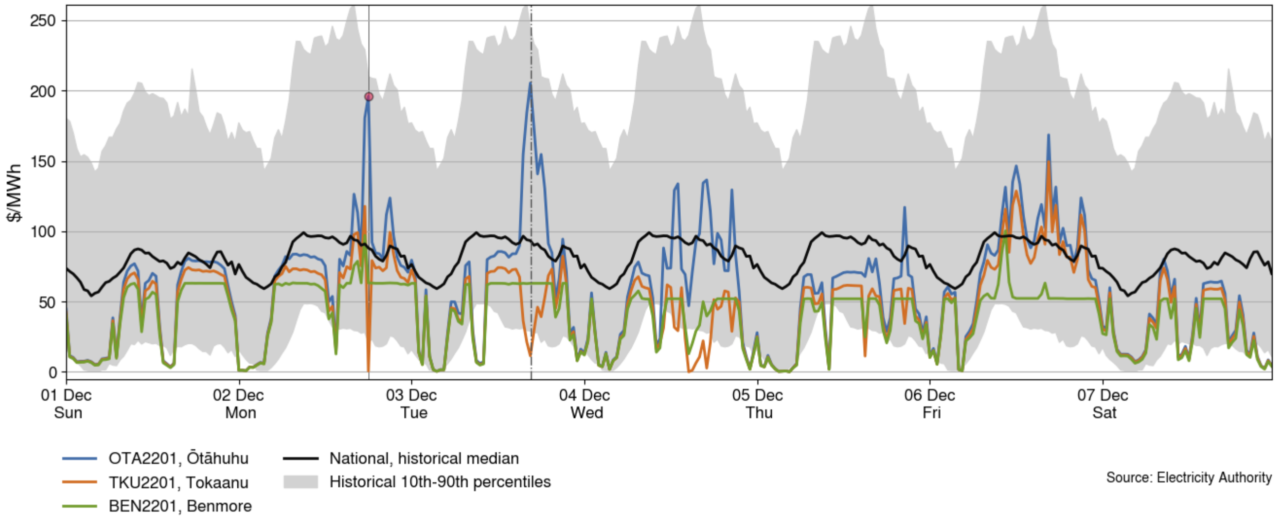
2.4. The highest spot price at Ōtāhuhu was $205/MWh at 4:30pm on Tuesday when demand was under forecast by ~120MW. North Island transmission constraints at the time lead to price separation and a spring washer effect which lead to a Tokaanu spot price of $11/MWh. At the same time, the Benmore spot price was $63/MWh.

2.5. Similar separations and spring washer effects also occurred at other times from Monday to Thursday. The most significant of these was at 6.00pm on Monday when the Ōtāhuhu spot price was $196/MWh, Tokaanu was $0.56/MWh and Benmore was $63/MWh. At the same time, demand was ~100MW higher than forecast.

2.6. HVDC northward flow was near its limit on Friday which saw price separation peaking at 4.30pm when the spot price at Ōtāhuhu was $169/MWh and the spot price at Benmore was $52/MWh.

2.7. Figure 1 shows the wholesale spot prices at Benmore, Ōtāhuhu and Tokaanu 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.

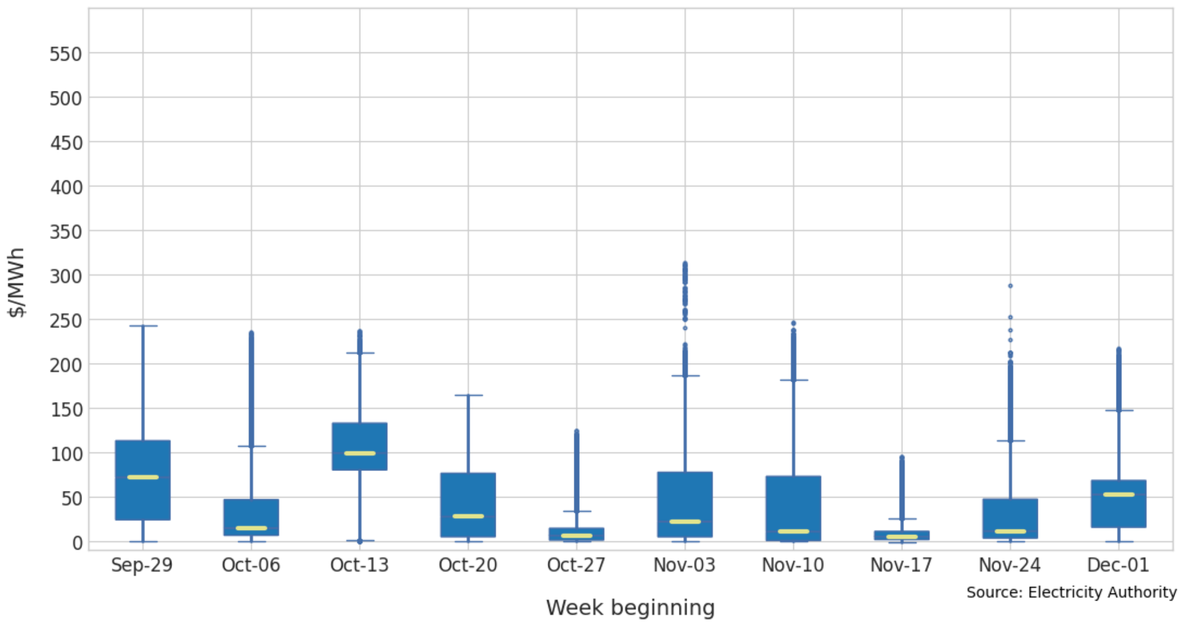
Figure 1: Wholesale spot prices at Benmore, Ōtāhuhu and Tokaanu, 1-7 December 2024



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. The median price increased to $52/MWh this week and the middle 50% of prices increased to between $16-68/MWh.

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

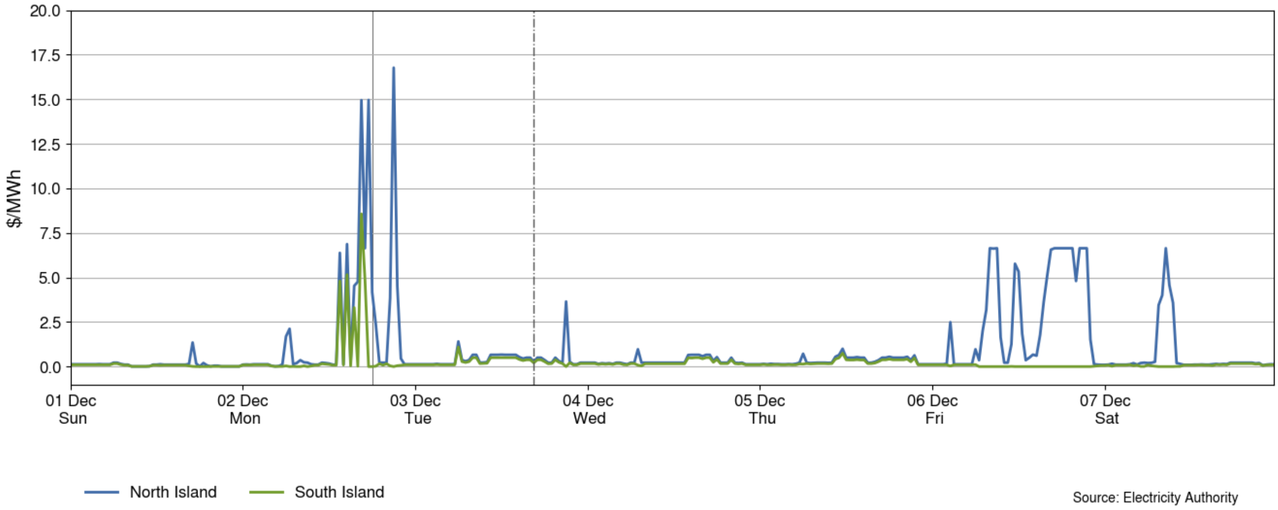


3. Reserve prices

3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below $1/MWh this week and peaked at ~$17/MWh in the North Island at 9.00pm on Monday. There was a small amount of separation between the

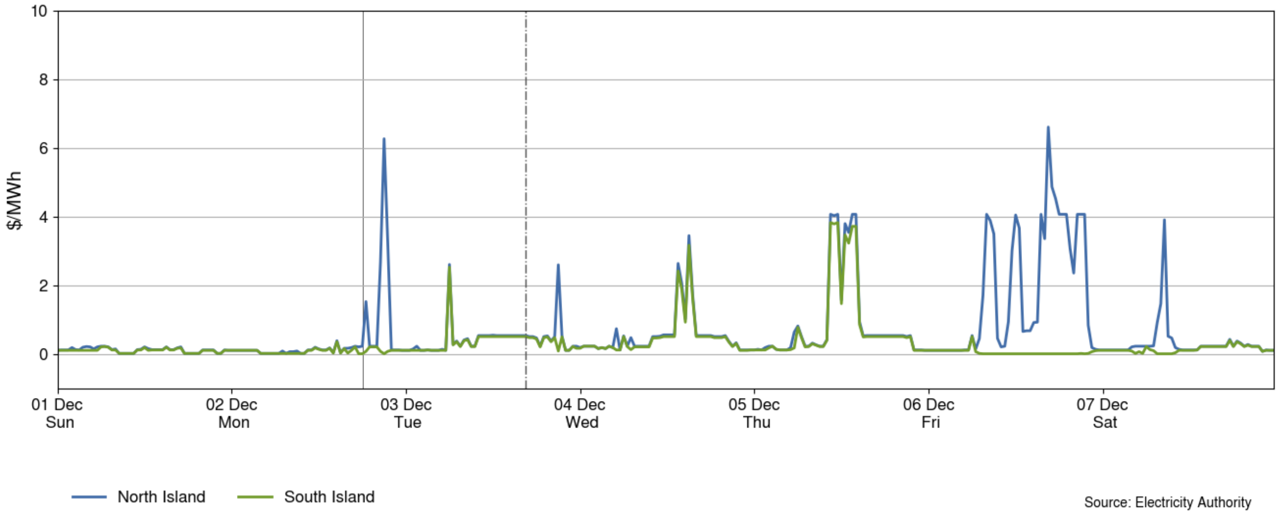
North Island and South Island FIR prices on Monday and Friday when the HVDC[1] was constrained and setting the risk.

Figure 3: Fast instantaneous reserve price by trading period and island, 1-7 December 2024



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 and peaked at ~$7/MWh in the North Island at 4.30pm on Friday.

Figure 4: Sustained instantaneous reserve by trading period and island, 1-7 December 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

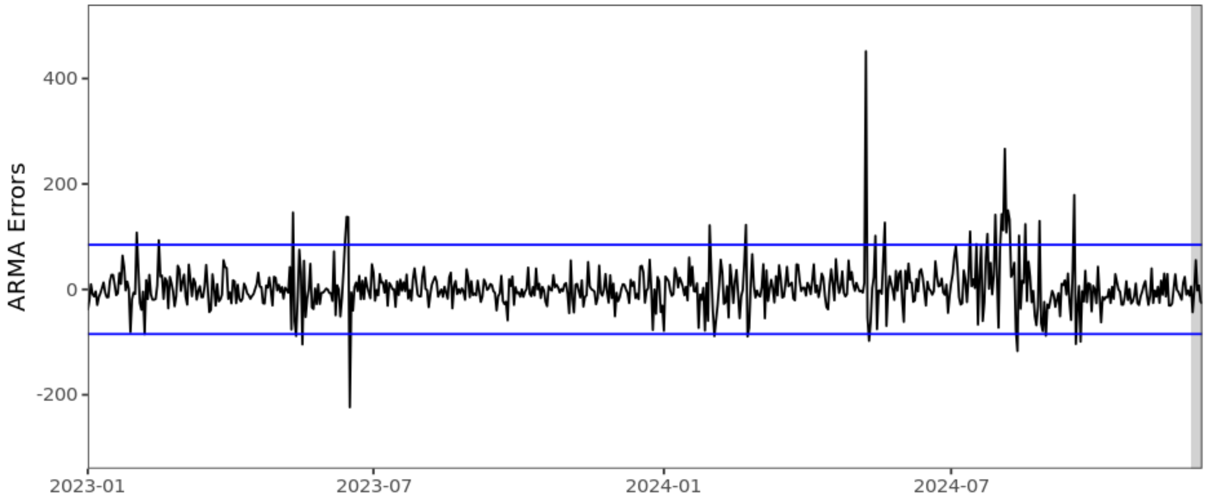
[1] Instantaneous reserve is procured to cover the potential loss of injection from a large generator or one or both poles of the HVDC link, called contingencies or risks. The binding risk is essentially the largest of these being the one that determines the required quantity of instantaneous reserve. Reserve to cover generator risks can be shared between the North and South Islands. However, reserve to cover HVDC risks must be located in the receiving island. Because SPD (scheduling, pricing and dispatch) co-optimises energy and reserve, when an HVDC risk binds it can cause both energy and reserve price separation between the islands.

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 – 7 December 2024

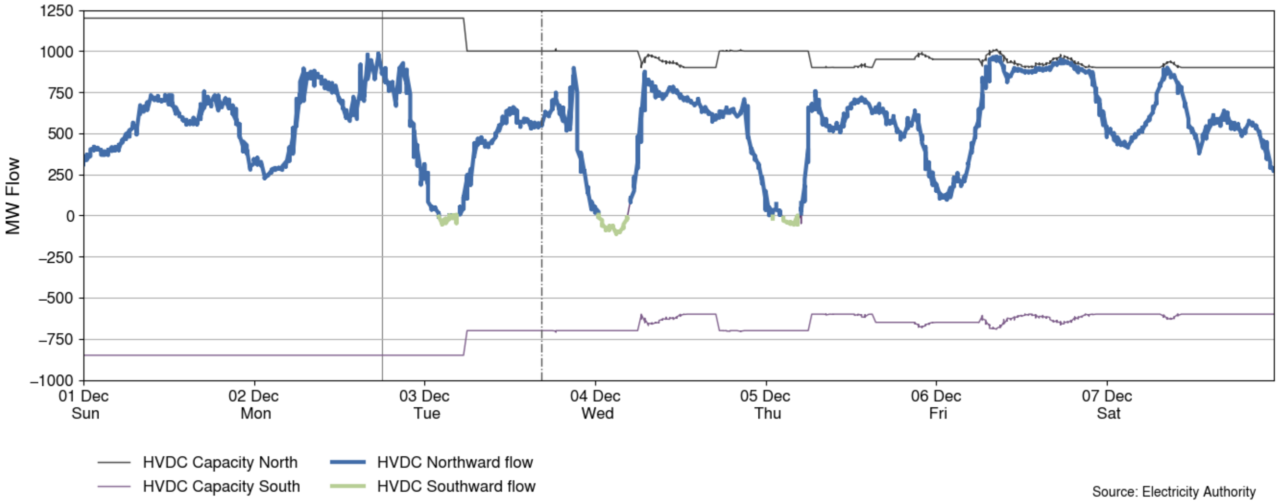


Source: Electricity Authority/Appendix A

5. HVDC

5.1. Figure 6 shows the HVDC flow between 1-7 December 2024. HVDC flow was mostly northward this week, with short periods of overnight southward flow from Tuesday to Thursday. The HVDC ramped up considerably on Tuesday evening at 9pm. During this time, wind generation was ~200MW overforecast and North Island demand was 42MW underforecast, leading to more energy being brought up from South Island.

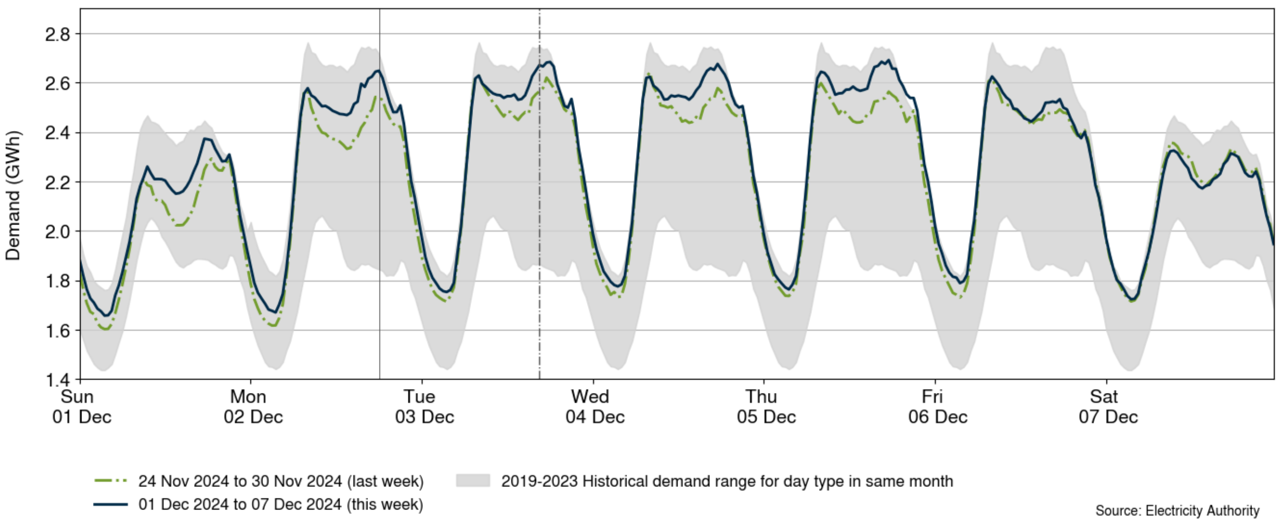
Figure 6: HVDC flow and capacity, 1-7 December 2024



6. Demand

6.1. Figure 7 shows national demand between 1-7 December 2024, compared to the historic range and the demand of the previous week. Demand was mostly higher than last week and at the upper end of the historic range for this time of year, this is likely due to increased industrial load at Tiwai, higher irrigation load and higher residential cooling load as temperatures warm. The maximum demand this week was around 2.69GWh (5.38GW) at 5:30pm on Thursday.

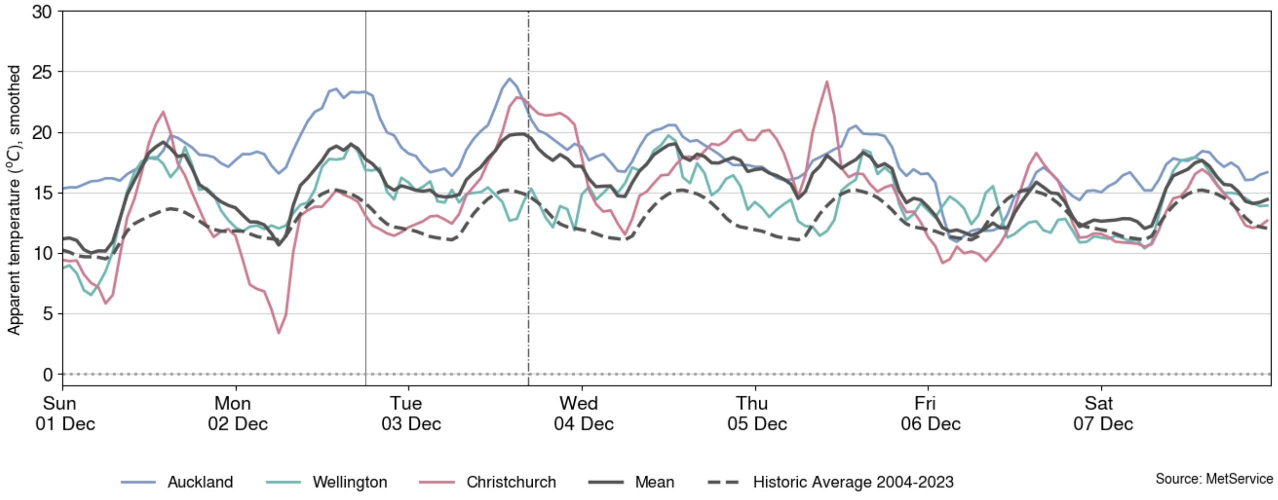
Figure 7: National demand, 1-7 December 2024 compared to the previous week



6.2. Figure 8 shows the hourly apparent temperature at main population centres from 1-7 December 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. Apparent temperatures were above average this week and ranged from 10°C to 25°C in Auckland, 6°C to 21°C in Wellington, and 3°C to 25°C in Christchurch.

Figure 8: Temperatures across main centres, 1-7 December 2024

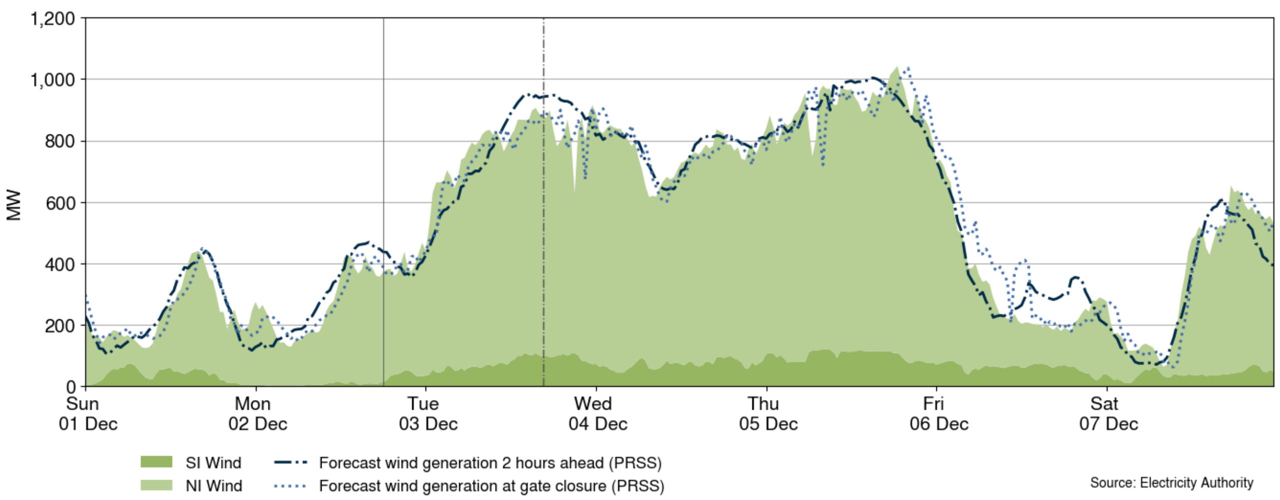


7. Generation

7.1. Figure 9 shows wind generation and forecast from 1-7 December 2024. This week wind generation varied between 63MW and 1,042MW, with a weekly average of 523MW. Wind generation was highest through the middle of the week and lowest on Saturday morning.

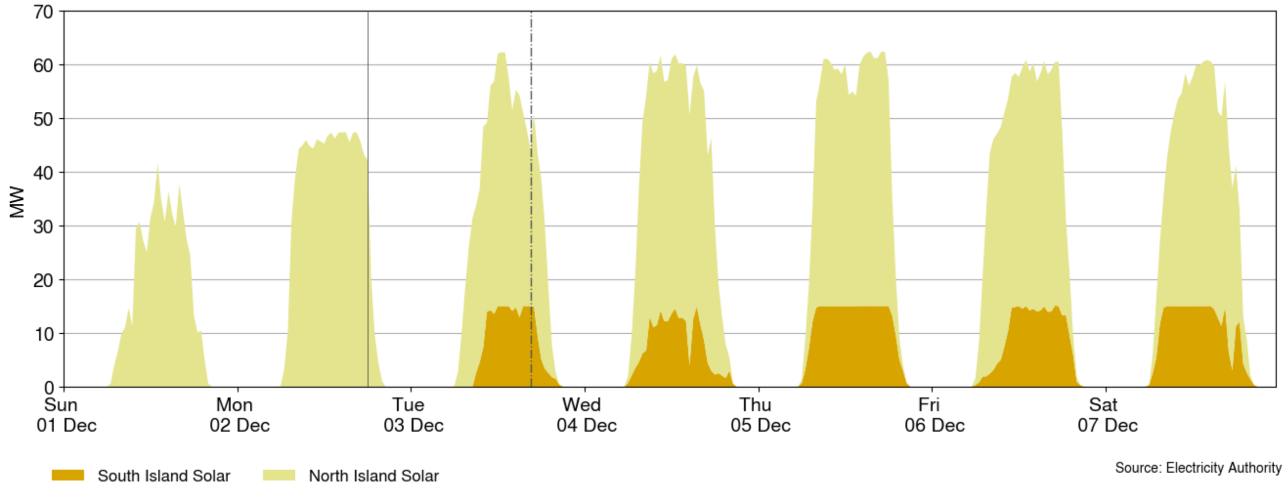
7.2. The largest negative gate closure forecast discrepancy was at 12.30pm on Friday when wind generation was ~200MW lower than forecast. Wind offering on Friday will be further analysed by the market monitoring team.

Figure 9: Wind generation and forecast, 1-7 December 2024



7.3. Figure 10 shows solar generation from 1-7 December 2024. Solar generation was lowest on Sunday and Monday and peaked at or above 60MW every other day this week. The Lauriston solar farm in the South Island generated up to 15MW each day from Tuesday.

Figure 10: Solar generation, 1-7 December 2024

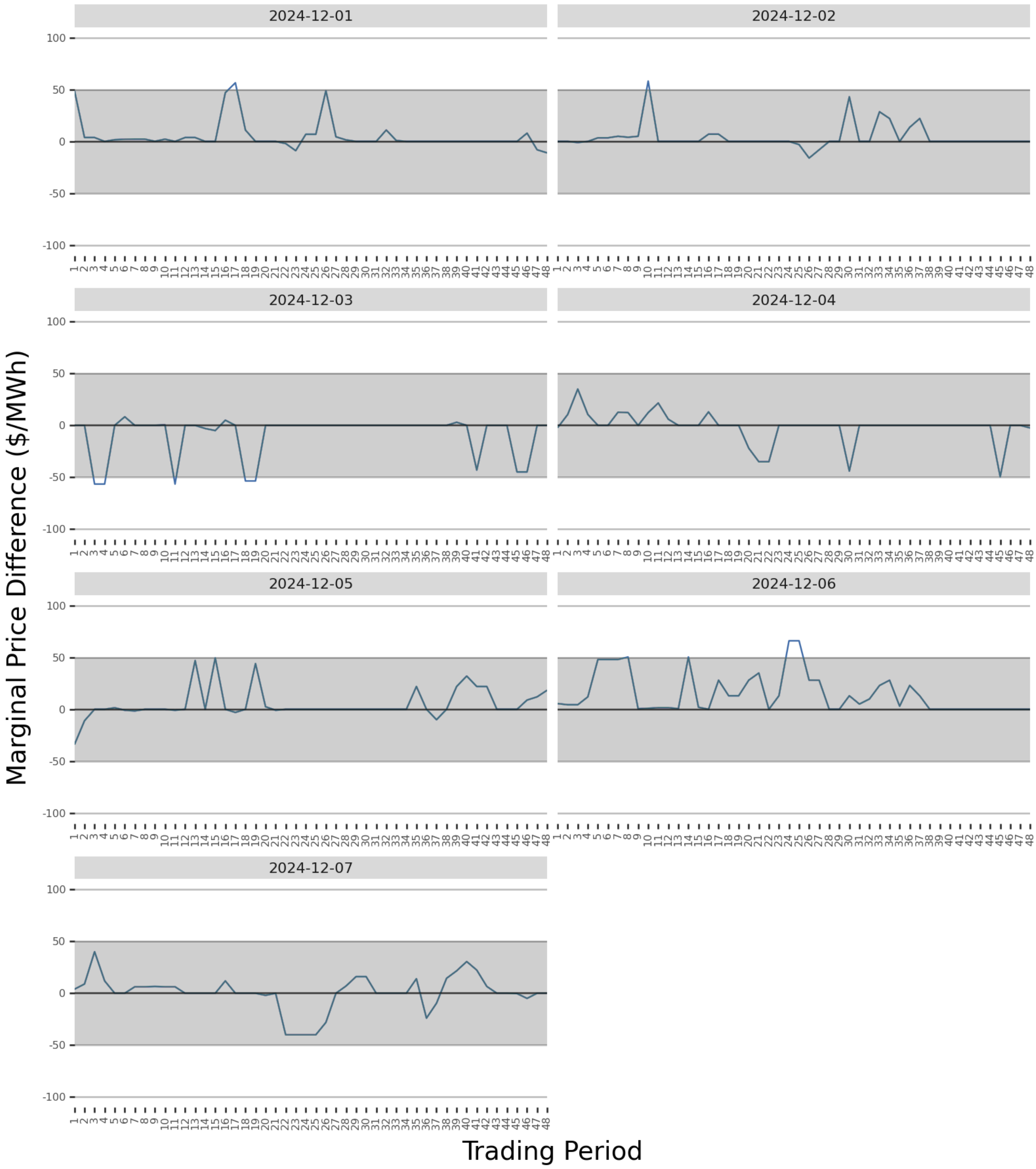


7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS[2]) projections. The figure highlights when forecasting inaccuracies are causing large differences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

7.5. The most significant marginal price difference this week was $66/MWh at 12.00pm on Friday. At this time, wind generation was ~200MW lower than the gate closure forecast and the HVDC was transferring at its northward capacity. Otherwise, prices were mostly within $50/MWh of simulated prices.

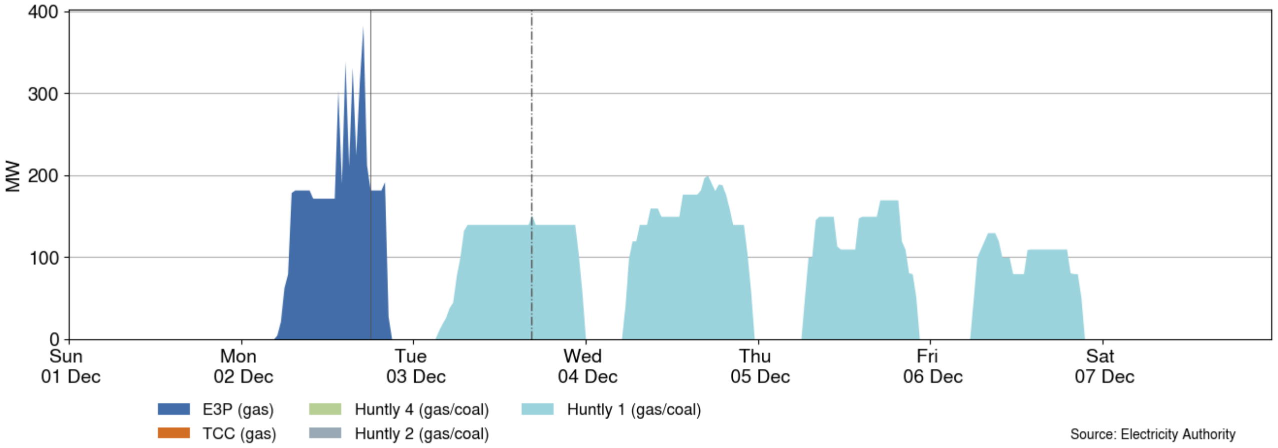
[2] Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

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, 1-7 December 2024



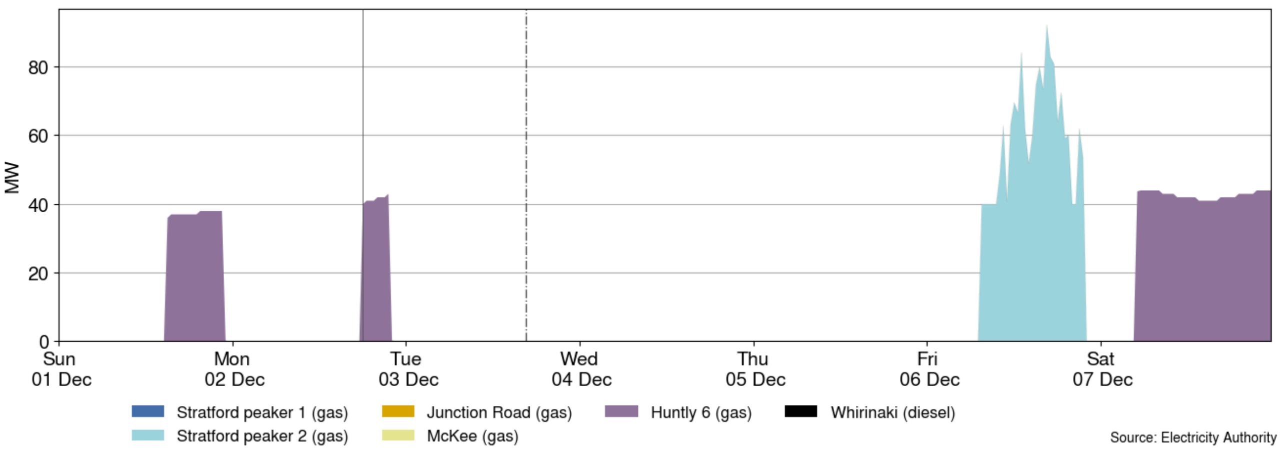
7.6. Figure 12 shows the generation of thermal baseload between 1-7 December 2024. Baseload generation was provided by Huntly 5 on Monday, which was recommissioning after being on outage (the large changes in output were related to this), and Huntly 1 from Tuesday to Friday.

Figure 12: Thermal baseload generation, 1-7 December 2024



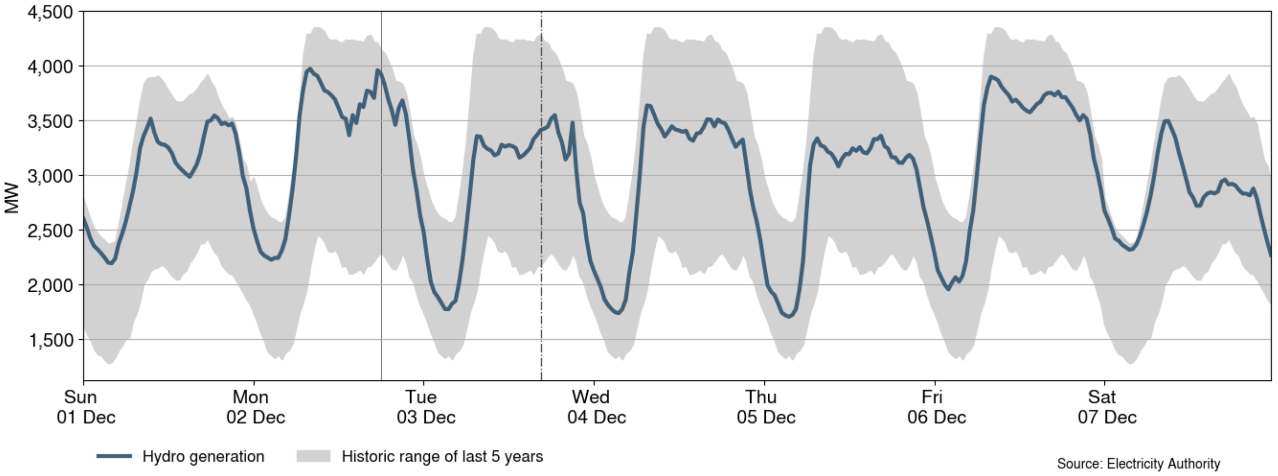
7.7. Figure 13 shows the generation of thermal peaker plants between 1-7 December 2024. Huntly 6 ran on Sunday and Monday evenings and all day on Saturday. Stratford 2 ran on Friday.

Figure 13: Thermal peaker generation, 1-7 December 2024



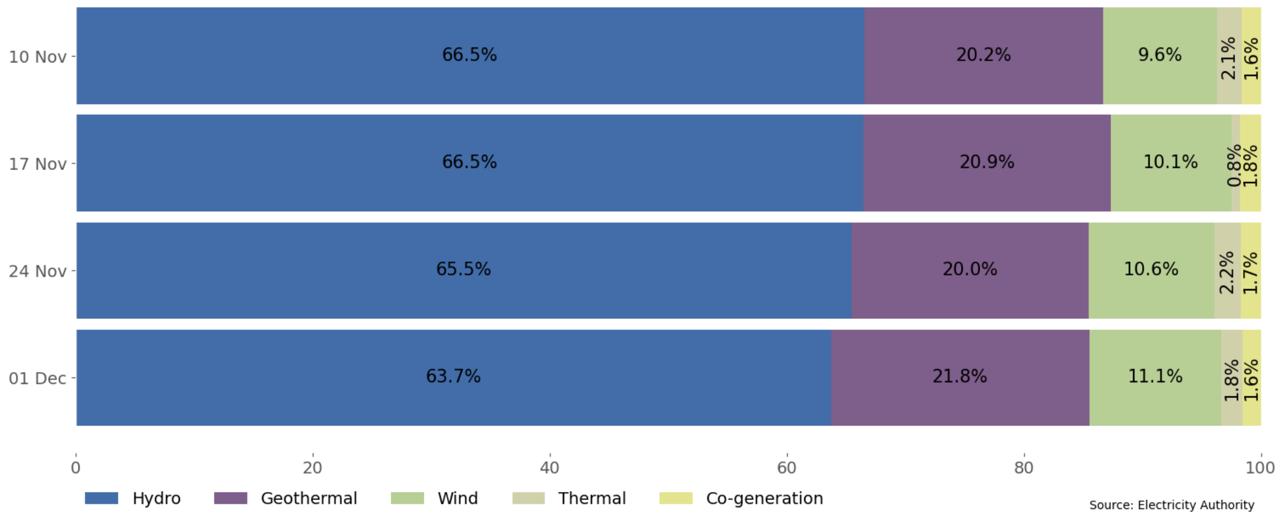
7.8. Figure 14 shows hydro generation between 1-7 December 2024. Hydro generation was highest on Monday and Friday when wind generation was low. Hydro generation increased on Tuesday evening to compensate for overforecast wind and underforecast demand.

Figure 14: Hydro generation, 1-7 December 2024



7.9. As a percentage of total generation, between 1-7 December 2024, total weekly hydro generation was 63.7%, geothermal 21.8%, wind 11.1%, thermal 1.8%, and co-generation 1.6%, as shown in Figure 15. The proportion of hydro generation reduced slightly this week and the proportion from geothermal increased slightly after Ngā Awa Purua returned from outage.

Figure 15: Total generation by type as a percentage each week, 10 November-7 December 2024



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 1-7 December 2024 ranged between ~1,100MW and ~2,100MW. Figure 17 shows the thermal generation capacity outages.

8.2. Notable outages include:

(a) Huntly 1 returned from outage on 2 December.

(b) Huntly 2 is on outage until 14 March 2025.

(c) Huntly 5 was on outage 30 November to 1 December.

(d) Stratford was on outage from 2 December to 4 December.

(e) Ngā Awa Purua returned from outage on 2 December.

(f) Stratford 1 returned from outage on 1 December.

(g) Several large hydro units are on outage.

Figure 16: Total MW loss from generation outages, 1-7 December 2024

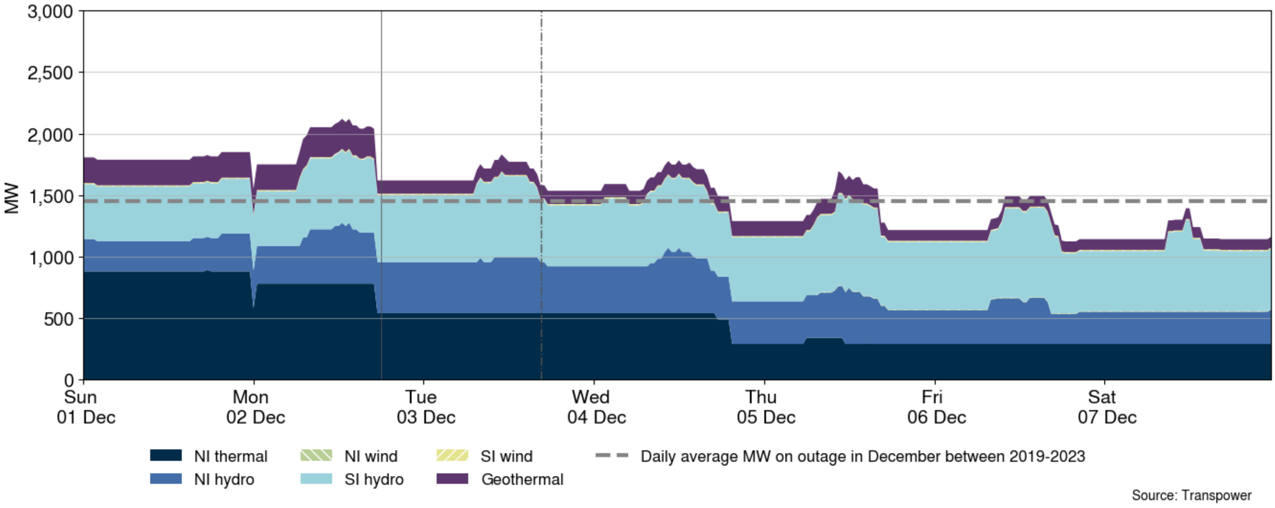
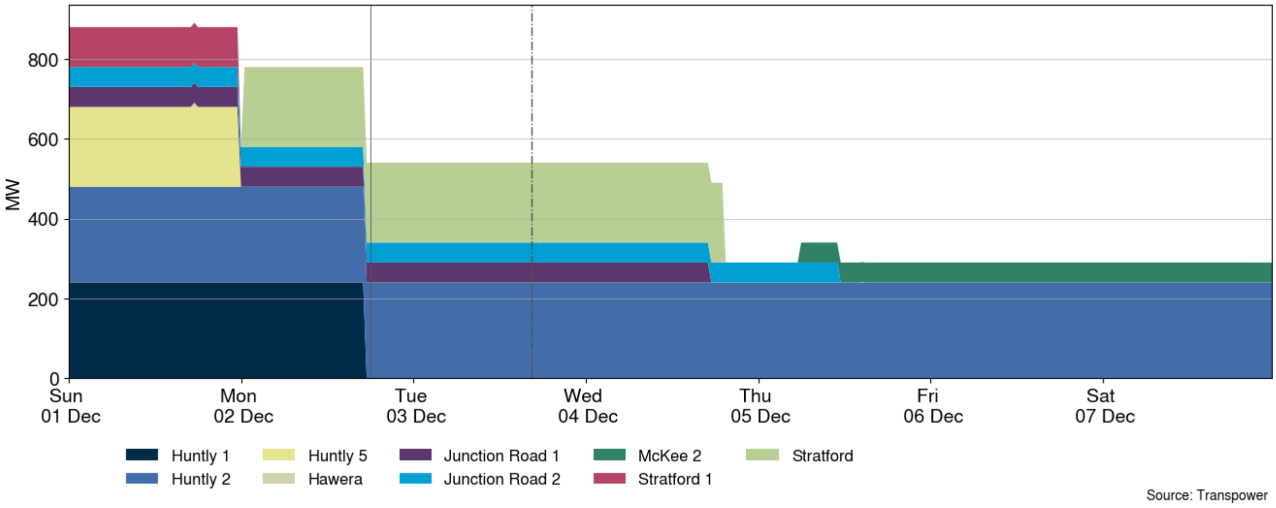


Figure 17: Total MW loss from thermal outages, 1-7 December 2024

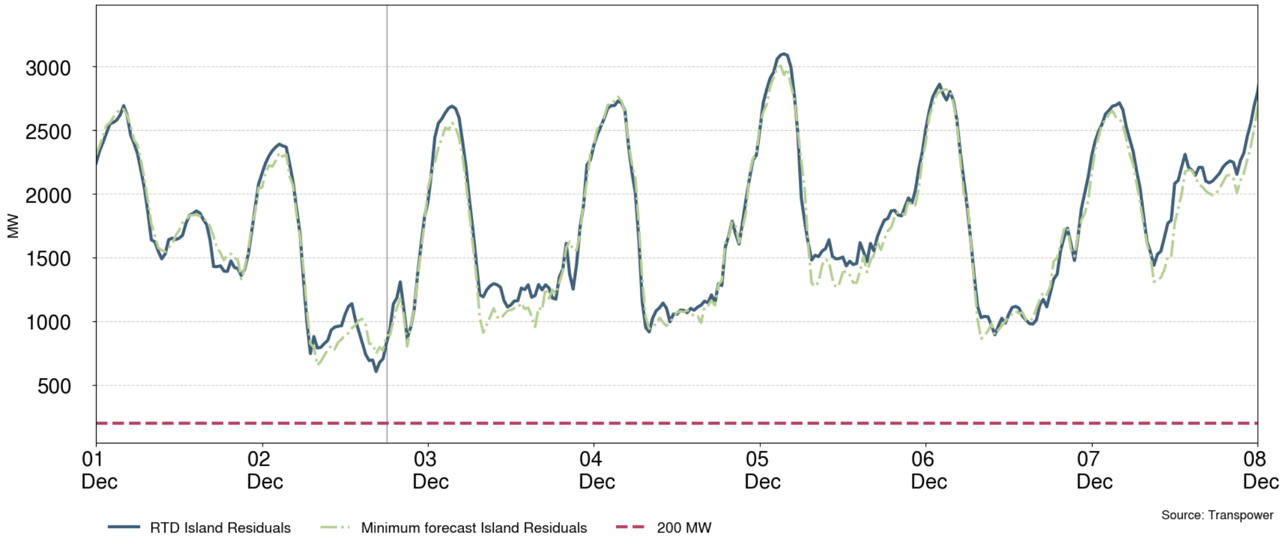


9. Generation balance residuals

9.1. Figure 18 shows the national generation balance residuals between 1-7 December 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 ~450MW at 2.30pm on Monday.

Figure 18: National generation balance residuals, 1-7 December 2024



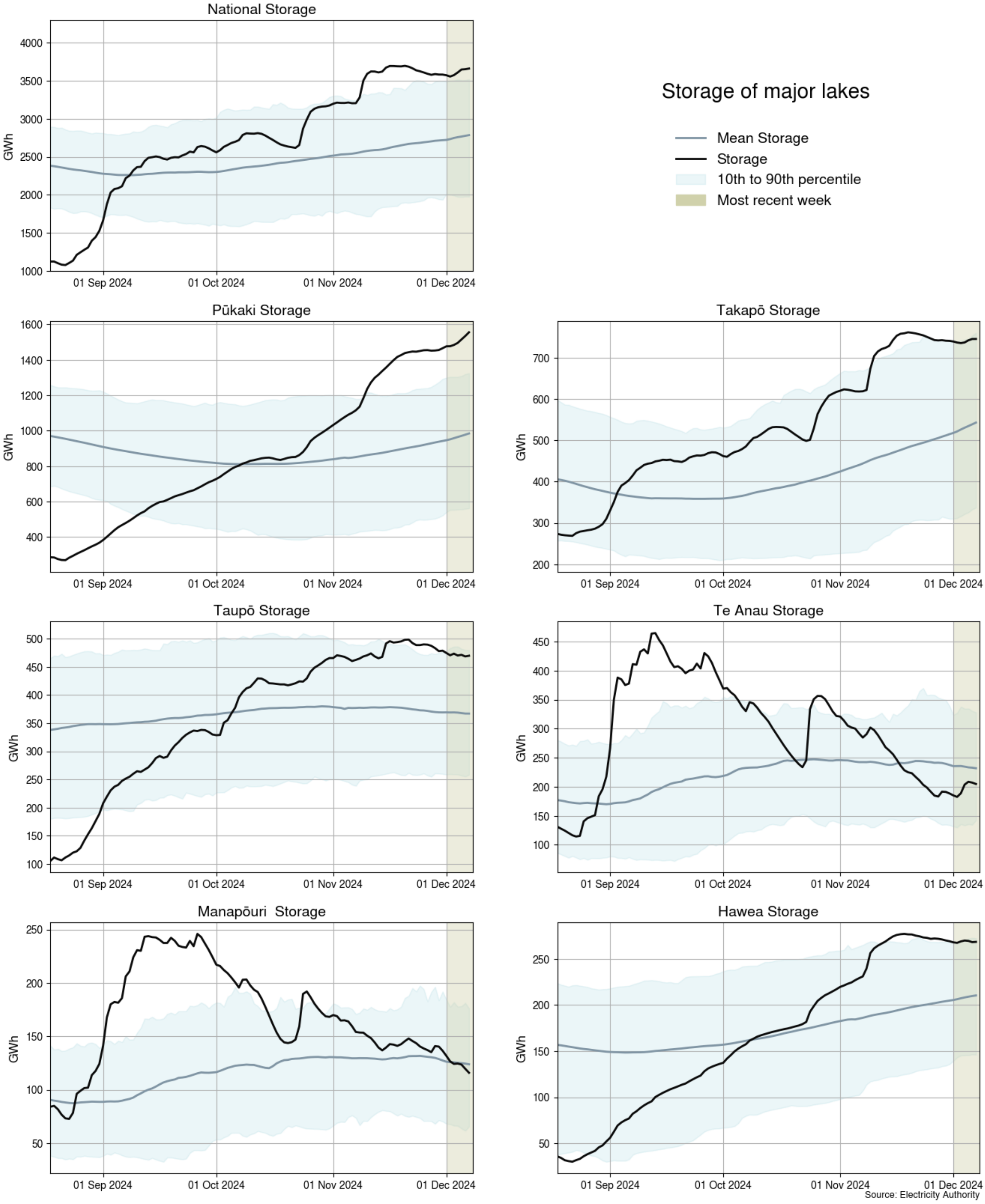
10. Storage/fuel supply

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 hydro storage increased this week. As of 7 Dec, national storage was ~90% nominally full and ~129% of the historical average for this time of the year.

10.3. Lake Pūkaki continued to increase above its historic 90th percentile to 91% full. Lakes Takapō (96% full), Taupō (82% full) and Hawea (94% full) remained steady near their historic 90th percentiles. Lakes Te Anau and Manapōuri ended the week below their historic means.

Figure 19: Hydro storage



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 December 2024. The SRMC for gas fuelled generation has decreased compared to last month and the SRMC for coal and diesel fuelled generation remains similar to last month.

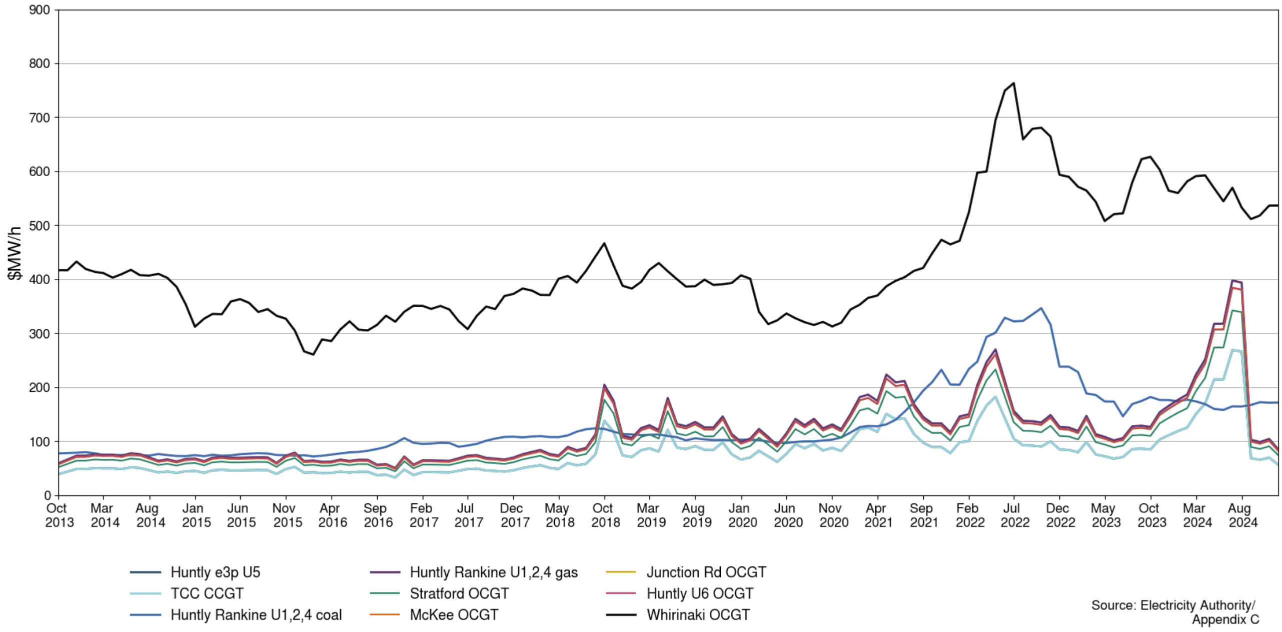
11.4. The latest SRMC of coal-fuelled Rankine generation is ~$171/MWh, with the cost of running the Rankines on gas remaining lower at ~$85/MWh.

11.5. The SRMC of gas fuelled thermal plants is currently between $56/MWh and $85/MWh.

11.6. The SRMC of Whirinaki is ~$536/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

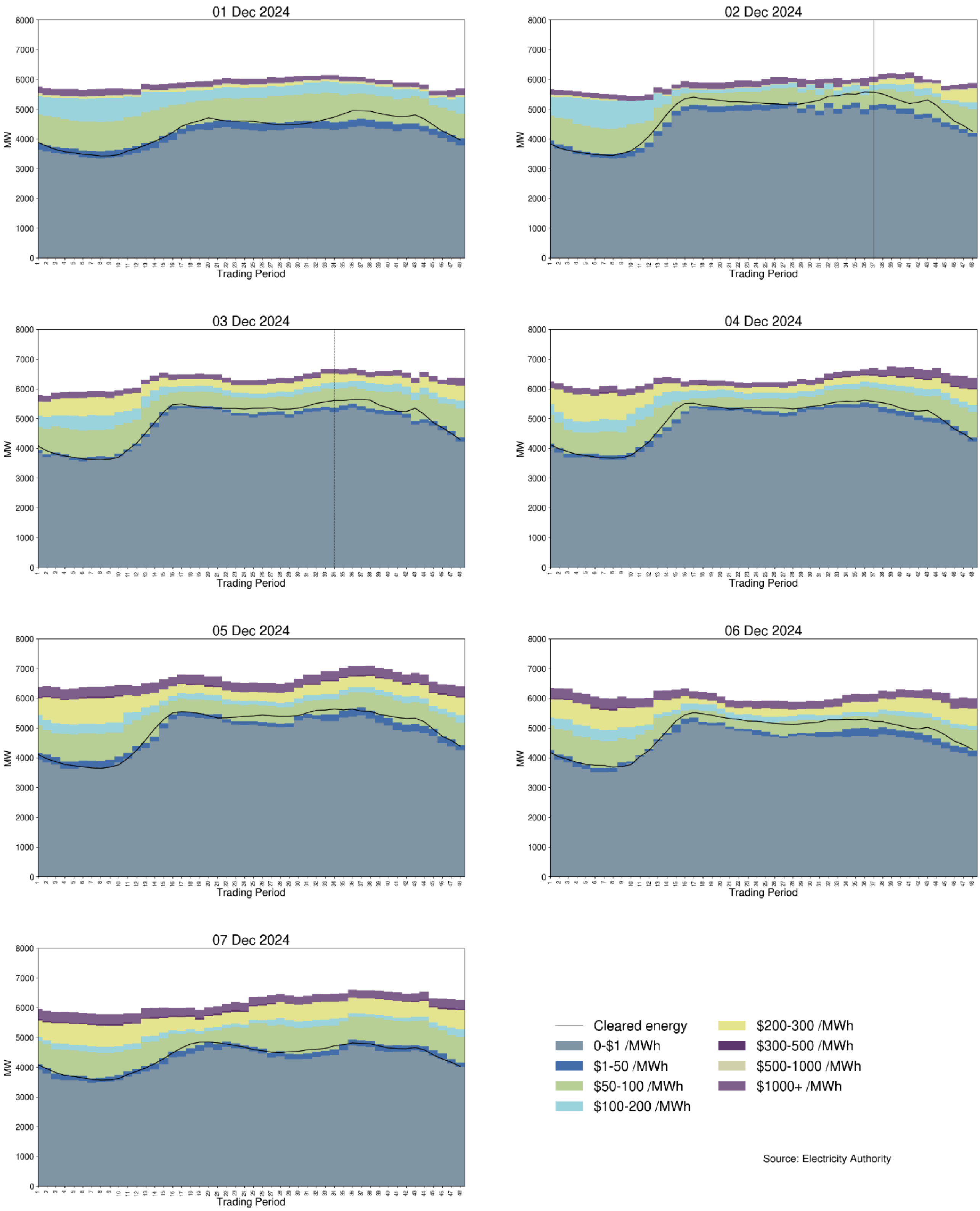


12. Offer behaviour

12.1. Figure 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 cleared under $100/MWh this week. The $200-300/MWh band increased from Monday afternoon, the monitoring team will be further analysing these offer changes.

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. Some trading periods and offer behavior is being further analysed by the market monitoring team.

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
2-7/12/2024	Several	Further analysis	Mercury	Waikato	Hydro offers
06/12/2024	Several	Further analysis	Manawa	Tararuas	Wind forecasting