Trading Conduct Report

Market Monitoring Weekly Report

12 October 2021

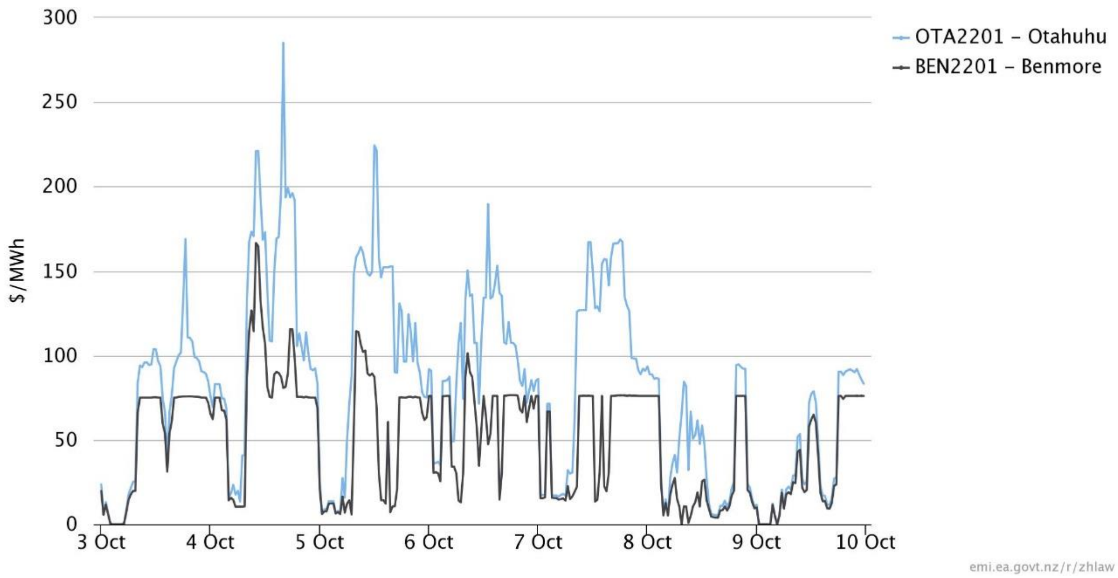
1 Overview for the week of 3 to 9 October

1.1 Prices this week appeared to be consistent with underlying supply and demand conditions.

2 Prices

Energy prices

Figure 1: Spot prices by trading period at Otahuhu and Benmore



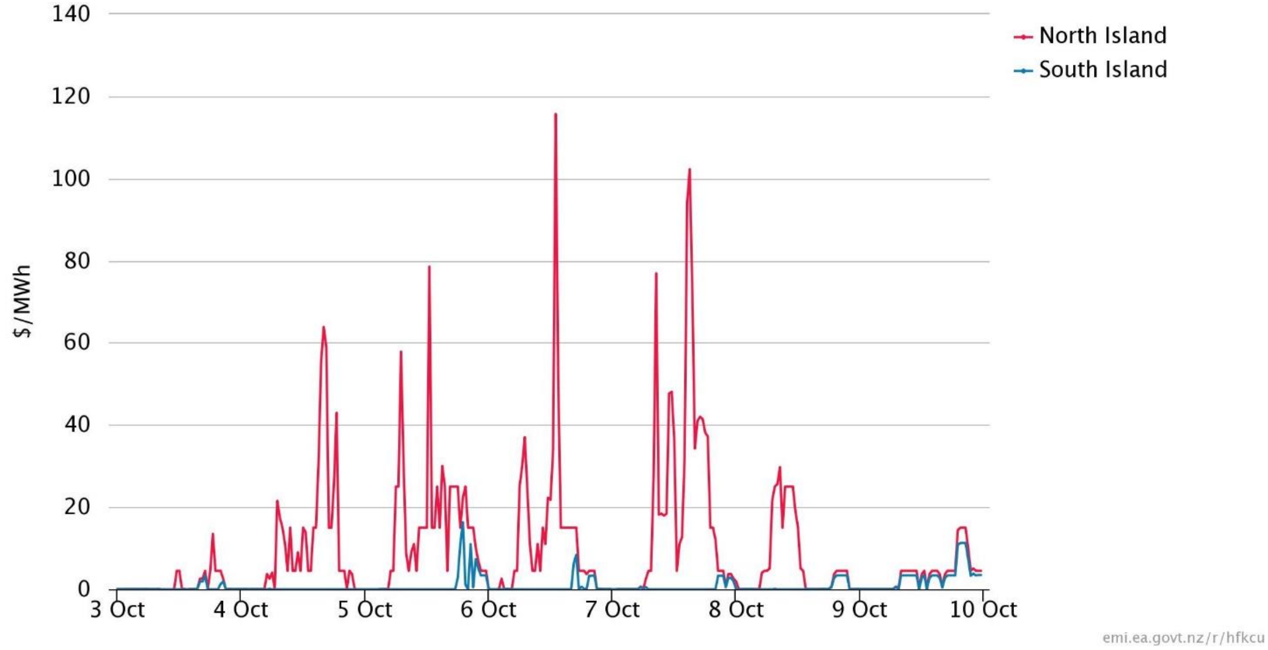
2.1 Average spot price this week was $67/MWh[1], down 16% from the previous week. There was frequent price separation between the North and South Island, with prices about $75/MWh at Benmore and over $100/MWh in the North Island (see Figure 1) due to HVDC transmission constraints. The highest price was $285/MWh at Otahuhu during TP 33 on 4 October.

[1] The simple average of the final price across all nodes, as shown in the trading conduct summary dashboard

Reserve Prices

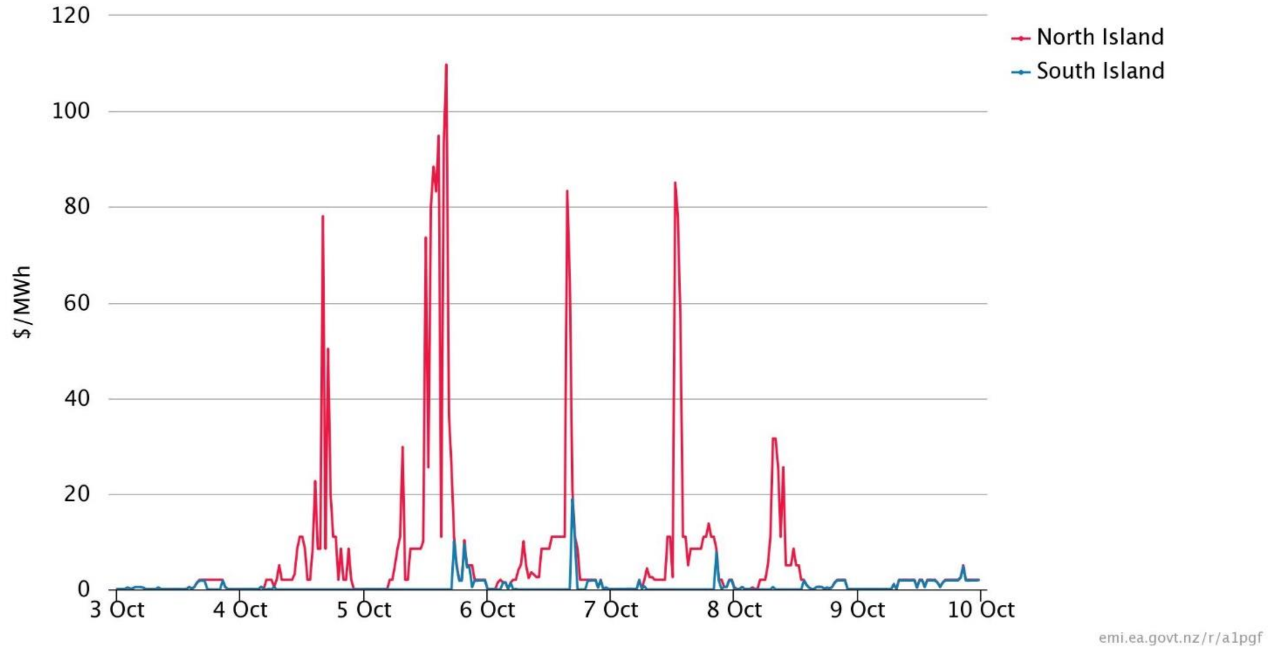
2.2 Fast instantaneous reserves (FIR) prices, shown in Figure 2, also had price separation between the North and South Island, with prices reaching to over $110/MWh (figure 3). This is due to high HVDC transmission which reduced reserve sharing and increased demand for North Island reserves.

Figure 2: FIR prices by trading period by Island



2.3 Sustained instantaneous reserves (SIR) prices, shown in Figure 3, also had price separation between North and South Island, though it was less frequent than FIR. This was also due to high HDVC transfer which limited reserve sharing between the islands and increased demand for North Island reserve.

Figure 3: SIR prices by trading period by Island

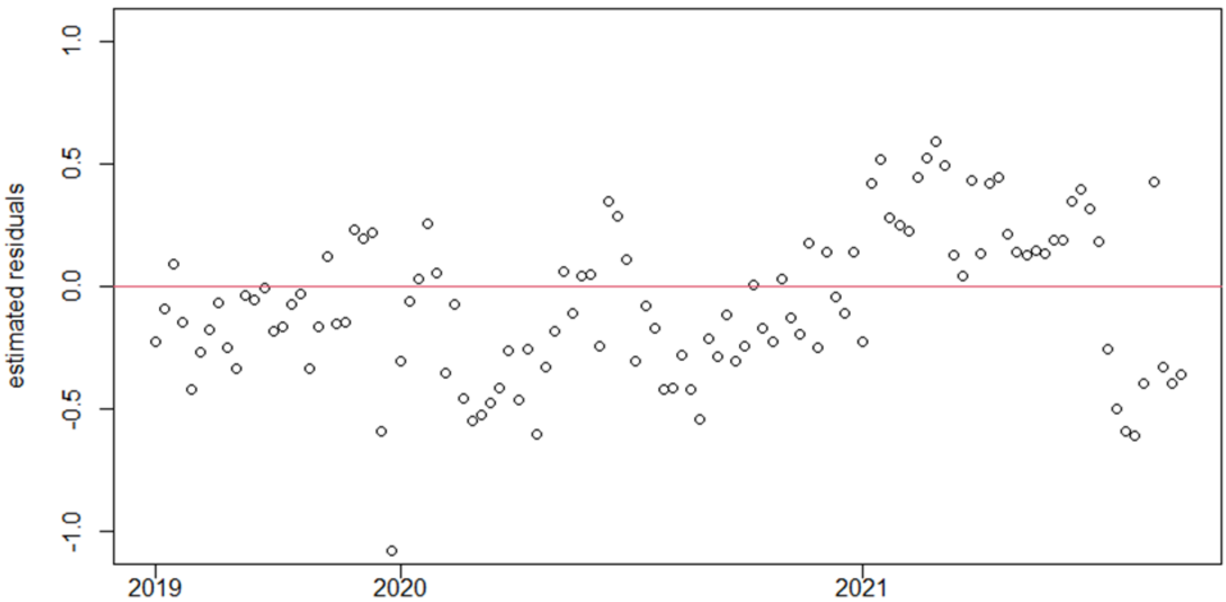


Residuals from regression models

2.4 The Authority's monitoring team has developed two regression models of the 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.

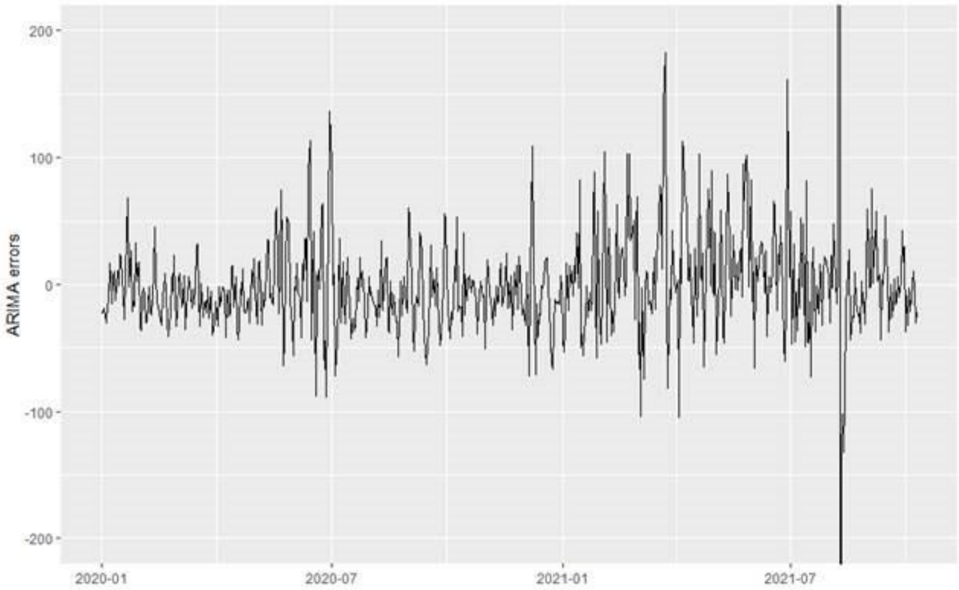
2.5 Figure 4 shows the residuals from the weekly model. During August 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 4: Residual plot of estimated weekly price from 2 July 2019 to 2 September 2021



2.6 Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were small, indicating prices were close to the model's prediction.

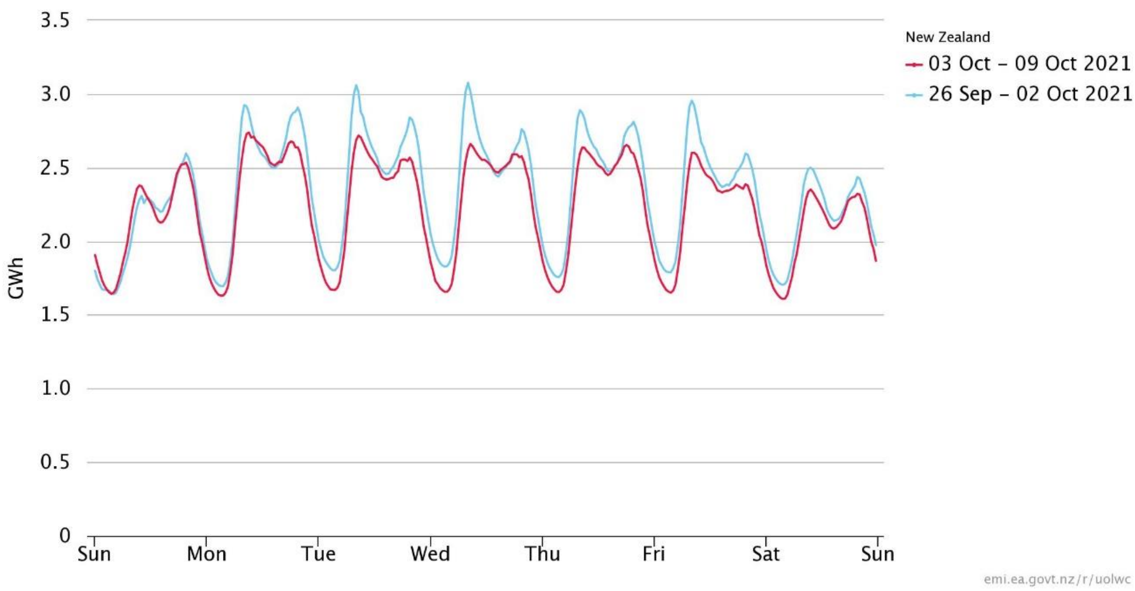
Figure 5: Residual plot of estimated daily average spot price from 1 July 2020 to 9 October 2021



3 Demand Conditions

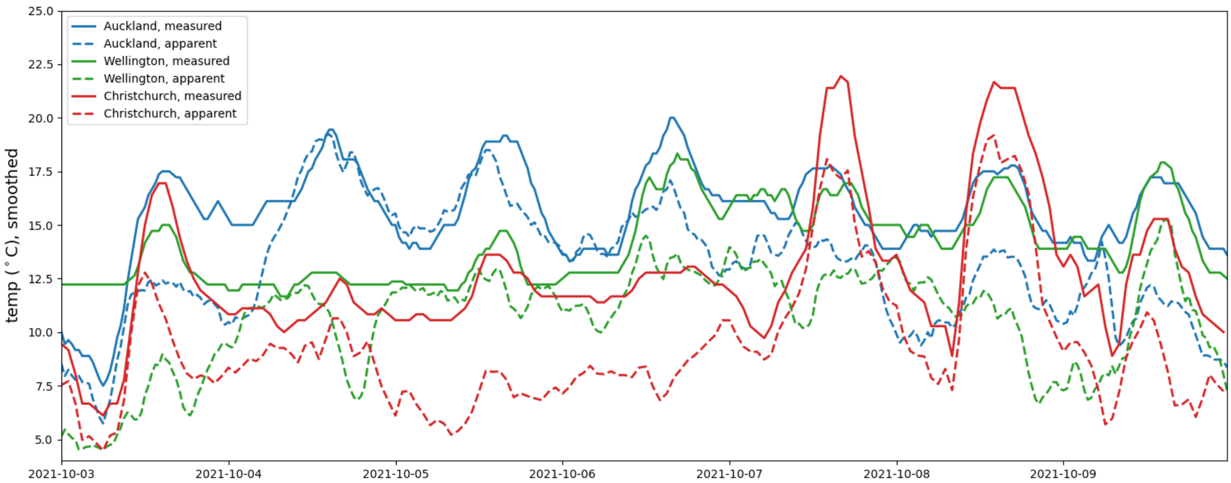
3.1 National demand was 4% lower than the previous week (see Figure 6) as weather conditions improve (see Figure 7). The morning and evening peaks were smaller due to less heating demand, while demand in the middle of the day was similar to last week.

Figure 6: National demand compared to previous week



3.2 Figure 7 shows hourly temperature data at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors, such as wind speed and humidity, to estimate how cold it feels. This week was warmer than the previous week, with actual temperatures above 10°C and apparent temperatures above 5°C for the whole week. In comparison, temperatures fell to 0°C in Christchurch last week.

Figure 7: Hourly temperature data at main population centres.

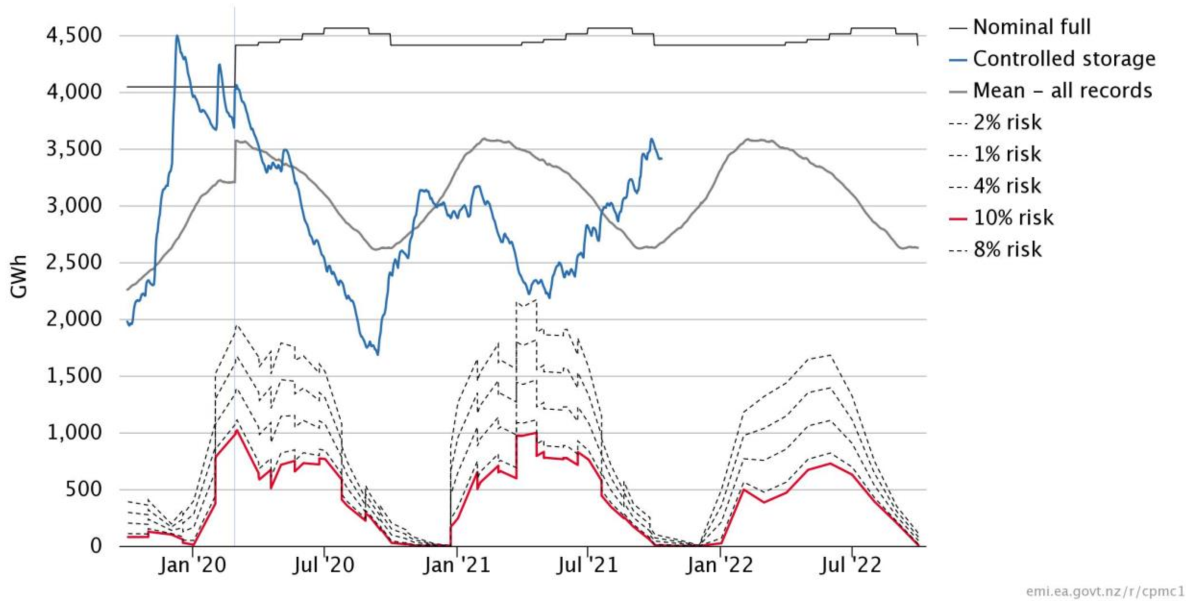


4 Supply Conditions

Hydro conditions

4.1 This week national hydro storage decreased this week, but is still high for this time of year, shown in Figure 8.

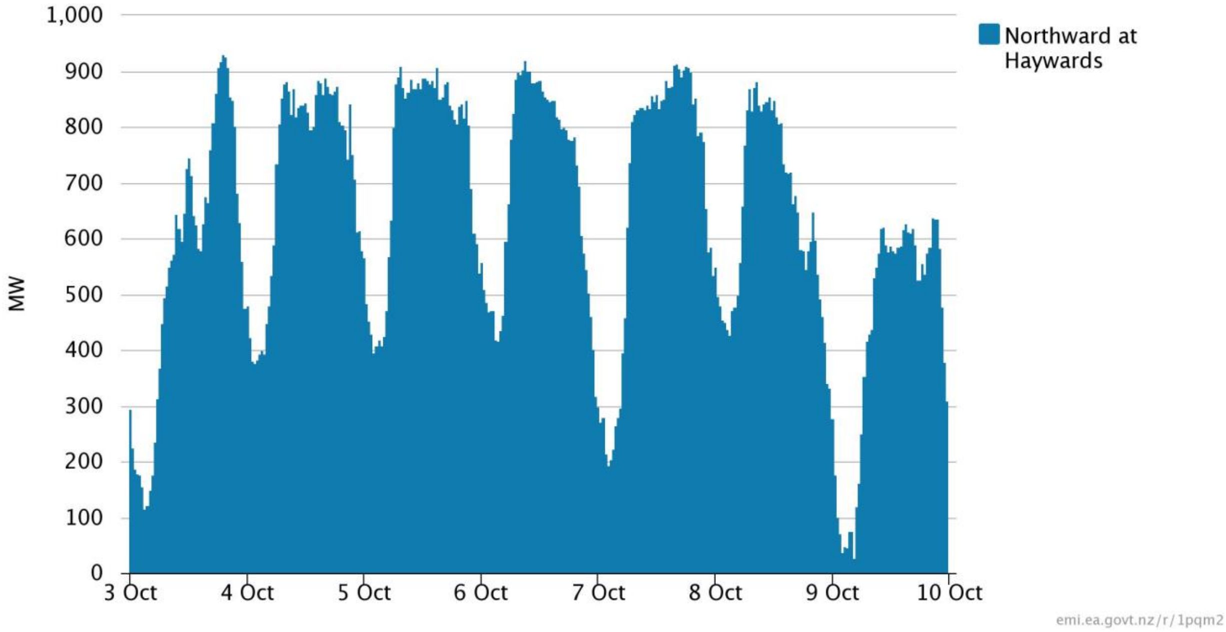
Figure 8: Electricity risk curves and current hydro supply



HVDC transfer

4.2 As a result of high lake levels in the South Island there was high Northwards transfer across the HVDC this week. This high transfer often caused the constraints to bind between Benmore and Haywards, which caused price separation. It also increased the reserve requirements in the North Island which increased reserve prices.

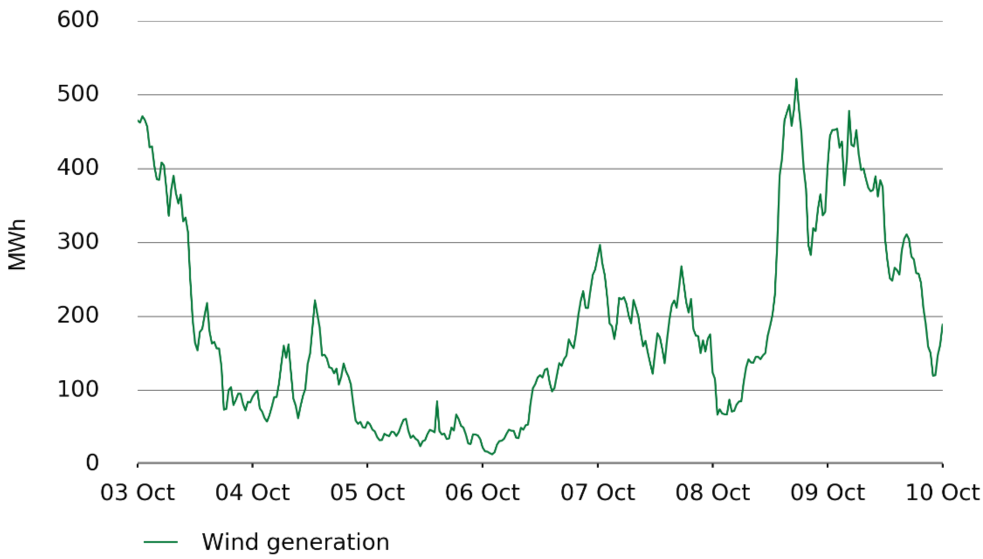
Figure 9: HVDC transfer for the week



Wind conditions

4.3 Total wind generation was 31GWh, down 46% from last week. Wind generation was quite low between 4 and 6 October (see Figure 10), and highest on 9 October. Low wind decreased available generation in the North Island and contributed to the price separation between the North and South Islands. Prices dropped for both islands on the 9 and 10 October when wind generation was high.

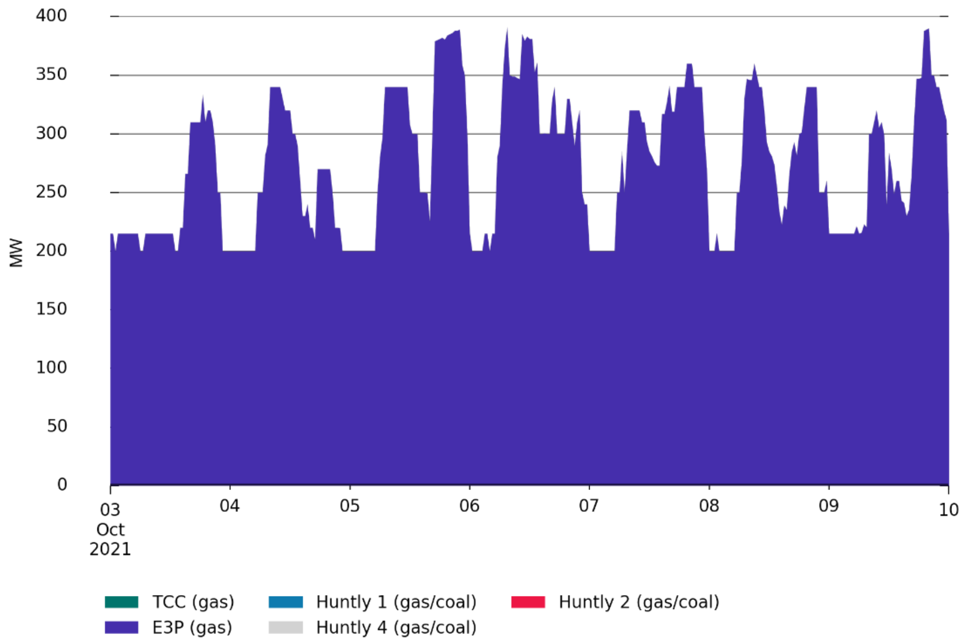
Figure 10: Wind generation for the week



Thermal conditions

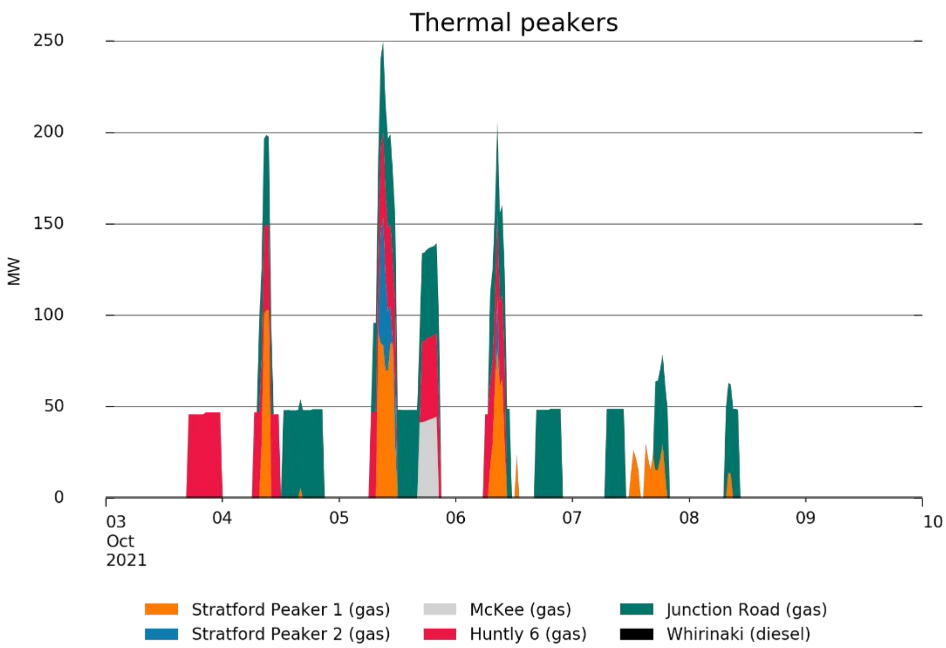
4.4 Baseload thermal generation remains low with only Huntly's E3P running as baseload, and no Rankine units running this week. It is likely no Rankine units were run this week due to low demand and high levels of hydro generation.

Figure 11: Generation from baseload thermal



4.5 Thermal peakers frequently ran this week, especially from 4 to 6 October when wind generation was low. The HVDC constraints binding and less thermal baseload would have also contributed to thermal peakers running more often this week to meet North Island demand.

Figure 12: Generation from thermal peakers



Significant outages

4.6 The following outages reduced available generation by at least 80MW:

(a) Clyde, 116MW (long term outage)

(b) Benmore, 90MW (5 July – 19 November)

(c) Manapouri, 125MW (19 July – 15 November)

(d) Huntly

(i) 240MW (24 September-3 October)

(ii) 240MW (4 October-19 December)

(e) Tekapo, 80MW (13 September – 16 January 2022)

4.7 Overall, there were fewer large outages compared to previous weeks, which increased available generation.

5 Price versus estimated costs

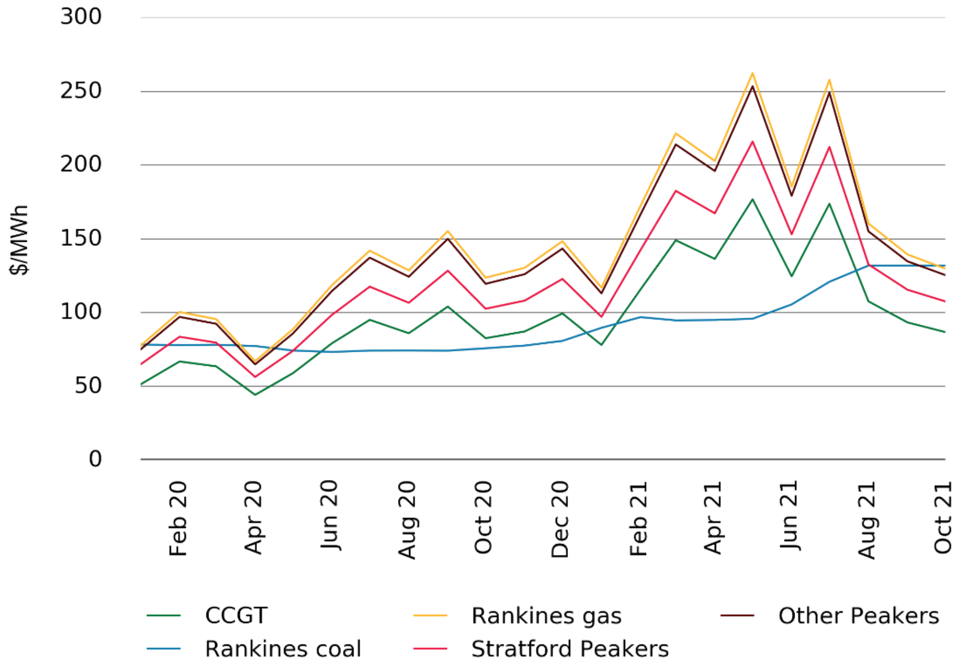
5.1 In a competitive market prices should be close to (but not necessarily at) the short run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).[2]

5.2 The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices[3] and the average heat rates for each thermal unit. Figure 13 shows estimates of thermal SRMCs as a monthly average. The thermal SRMC for gas fuelled generation continues to drop in October (to 11 October).

[2] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

[3] The SRMC for thermal fuels includes the carbon price. The gas price already includes the carbon price, but not the coal price, so the carbon price is added to the coal price before estimating the SRMC of coal.

Figure 13: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

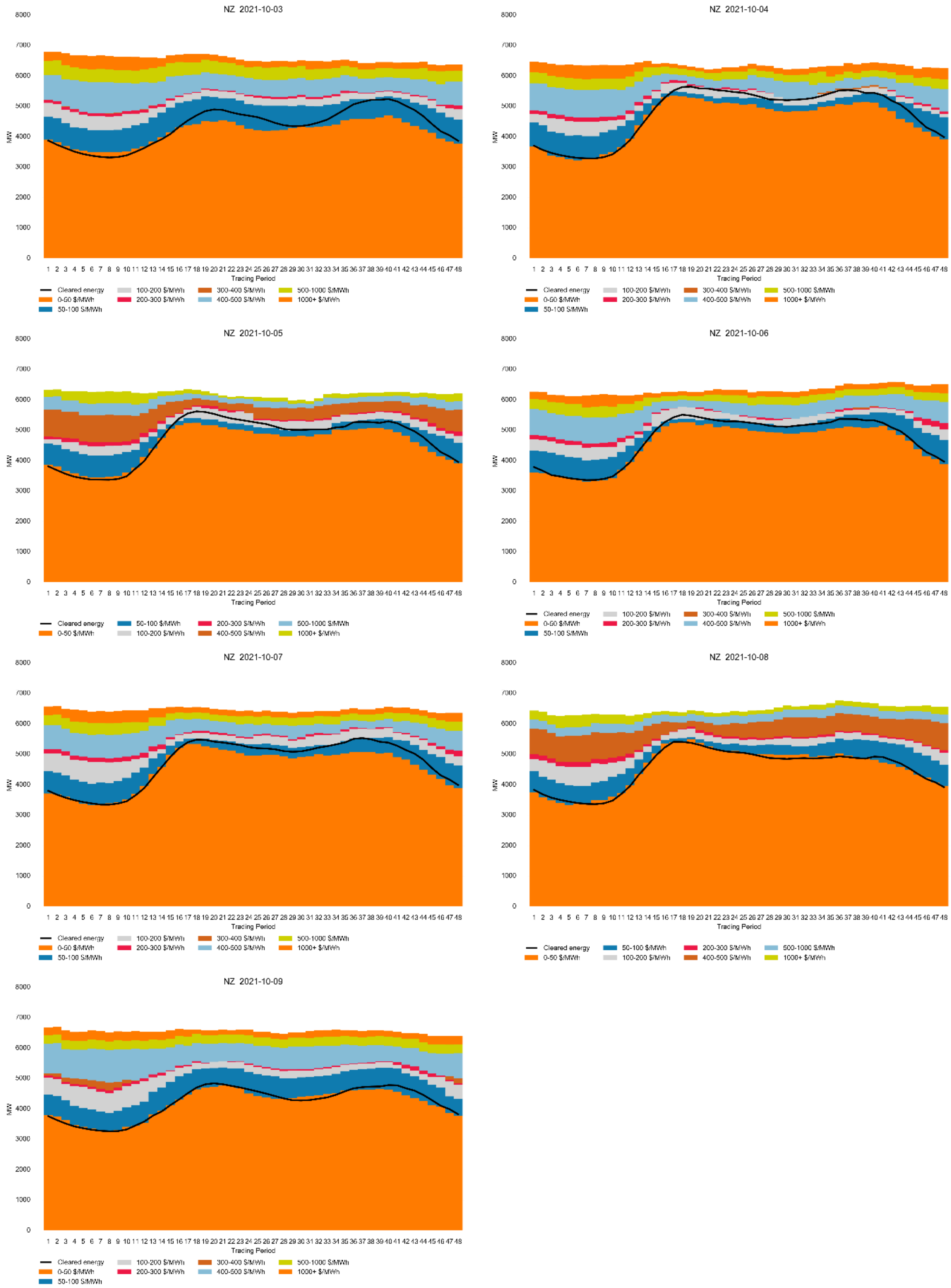
Final daily offer stacks

6.1 Figure 14 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[4] The black line shows the cleared energy, indicating the range of final prices, though this is less reliable for the period of the HVDC outage due to price separation.

6.2 Most offers continued to be below $200/MWh, with a thin offer stack at higher prices. Low wind generation reduced the quantity of offers below $100/MWh on 4 October compared to surrounding days, resulting in higher prices.

[4] The offer stacks show all offers bid into the market (where wind offers are truncated at their actual generation and excluding generation capacity cleared for reserves) in price bands and plots the cleared quantity against these.

Figure 14: Daily offer stack



Offers by trading period

6.3 The trading period (TP) with the highest price at Otahuhu was TP33 (4:00pm) on 4 October, shown by Figure 15. Figure 16 shows the same trading period the previous week. Each shows the offer stack, the generation weighted average price (GWAP) and cleared generation.

6.4 The offer curve continues to be quite steep above the $200/MWh offer mark. There was less thermal generation running this week as well as low wind on 4 October. This reduced available supply in the North Island. As the HVDC constraints were binding on 4 October not all available South Island generation could be dispatched to meet North Island demand, as a result generation offered above $200/MWh in the North Island was dispatched to meet North Island demand. One of the Stratford Peakers briefly ran to meet demand during trading period 33.

Figure 15: Offer Stack for trading period 33 on 4 October

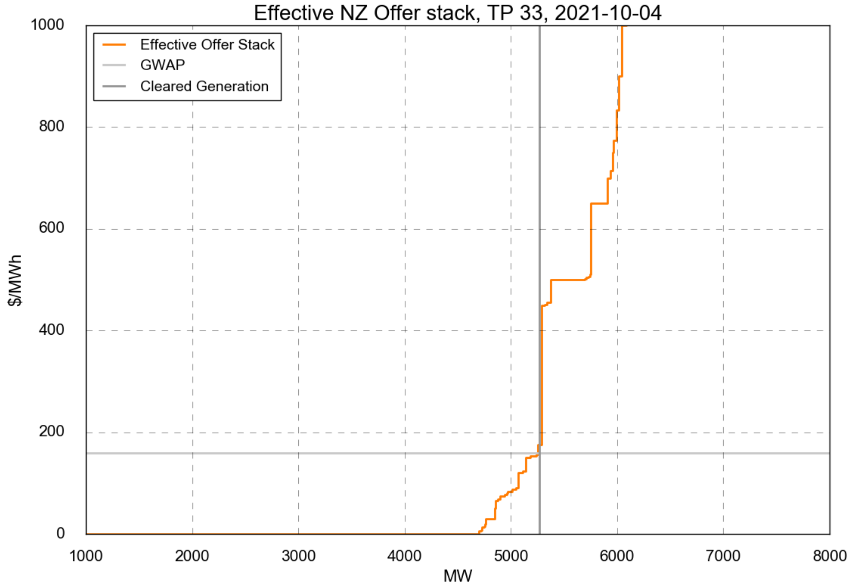
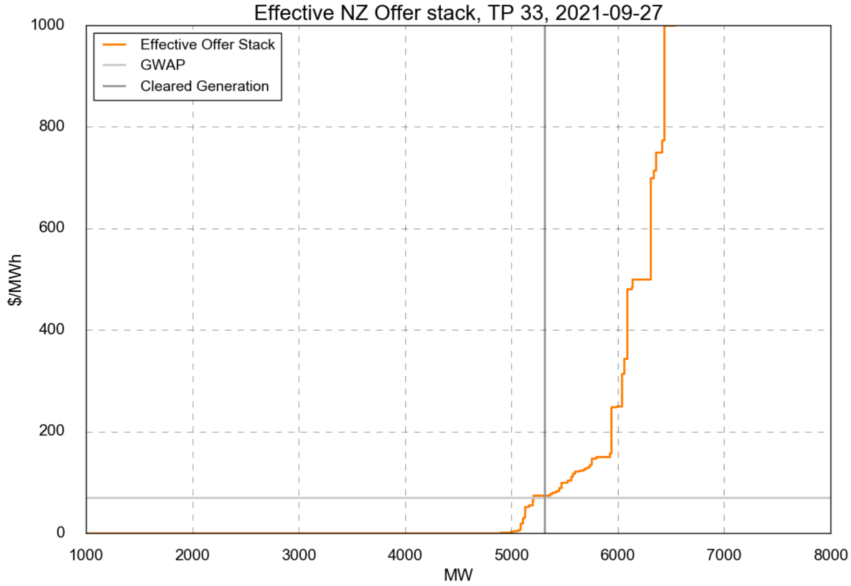


Figure 16: Offer Stack for trading period 33 on 21 September



Ongoing Work in Trading Conduct

6.5 No trading periods have been identified this week as needing further analysis.

6.6 Some of the trading periods identified for further analysis will be grouped in with ongoing work referred to compliance

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
30/06-20/08	Several	Compliance: review	High energy prices in shoulder periods
30/06-21/08	Several	Compliance: review	Withdrawn reserve offers

Appendix A Regression Analysis

A.1 The Authority's monitoring team has developed two regression price models. The purpose of these models is to understand the drivers of the wholesale spot price and if outcomes are indicative of effective competition.

Weekly Model

A.2 The weekly model is an updated version of the model published in https://www.ea.govt.nz/assets/dms-assets/27/27142Quarterly-Review-July-2020.pdf, Section 8, pg. 21-25

A.3 The regression equation is

$$\begin{aligned}\log(P_t - \theta_t) = \beta_0 &+ \beta_1(Storage_t - Seasonal.mean.storage_i)\\ &+ \beta_2(Demand_t - Ten.year.mean.demand_t) + \beta_3 Wind.generation_t\\ &+ \beta_4 \log(Gas.price_t) + \beta_5 Generation.HHI_t\\ &+ \beta_6 Ratio.of.adjusted.offer.to.generation_t + \beta_7 Dummy.gas.supply.risk_t\end{aligned}$$

where P_t is the PPI and trend adjusted weekly average spot prices; $t = week\ 1, \ldots, 52$ for each year; i= spring, summer, autumn and winter

Daily Model

A.4 The daily model estimates the daily average spot price based on daily storage, demand, gas price, wind generation, the HHI for generation (as a measure of competition in generation), the ratio of offers to generation (a measure of excess capacity in the market), a dummy variable for the period since the 2018 unplanned Pohokura outage started, and the weekly carbon price (mapped to daily). The units for the raw data are as following: storage and demand are GWh, spot price is $/MWh, gas price is $/PJ, and wind generation is MW, carbon price is in New Zealand Units traded under NZ ETS, $/tonne.

A.5 We used the Augmented Dicky-Fuller (ADF) to test all variables to see if they are stationary. If not, we tested the first difference and then the second difference using the ADF test until the variable was stationary. The first difference of a time series is the series of changes from one period to the next. For example, if the storage is not stationary, we use $storage_t - storage_{t-1}$.

A.6 We fitted the data using a dynamic regression model with Autoregressive with five lags (AR(5)). Dynamic regression is a method to transform ARIMAX (Autoregressive Integrated Moving Average with covariates model) and make the coefficients of covariates interpretable.

A.7 Once we dropped the insignificant variables; the ratio of offers to generation, the dummy variable for 2018 and carbon price, we got the following model[5], where *diff* is the first difference:

$$y_t = \beta_0 - \beta_1\left(storage_t - 20.year.mean.storage_{dayofyear}\right) + \beta_2 diff(demand_t) -$$
$$\beta_3\ wind.generation_t + \beta_4\ gas.price_t - \beta_5 diff(generation\ HHI_t) + \ \beta_6 dummy + \eta_t$$
$$\eta_t = \varphi_1\eta_1 - \varphi_2\eta_2 + \varphi_3\eta_3 + \varphi_4\eta_4 + \varphi_5\eta_5 + \varepsilon_t$$

A.8 ε_t, the residuals of ARMA errors (from AR(5)), should not significantly different from white noise. Ideally, we expect the ARIMA errors are purely random, and are not correlated with each other (show no systematic pattern). ARIMA errors equals y_t minus the estimate $\hat{y}$ with their five time lags.

[5] Updated, $diff(storage_t)$ has been replaced with $\left(storage_t - 20.year.mean.storage_{dayofyear}\right)$