Trading Conduct Report

Market Monitoring Weekly Report

21 September 2021

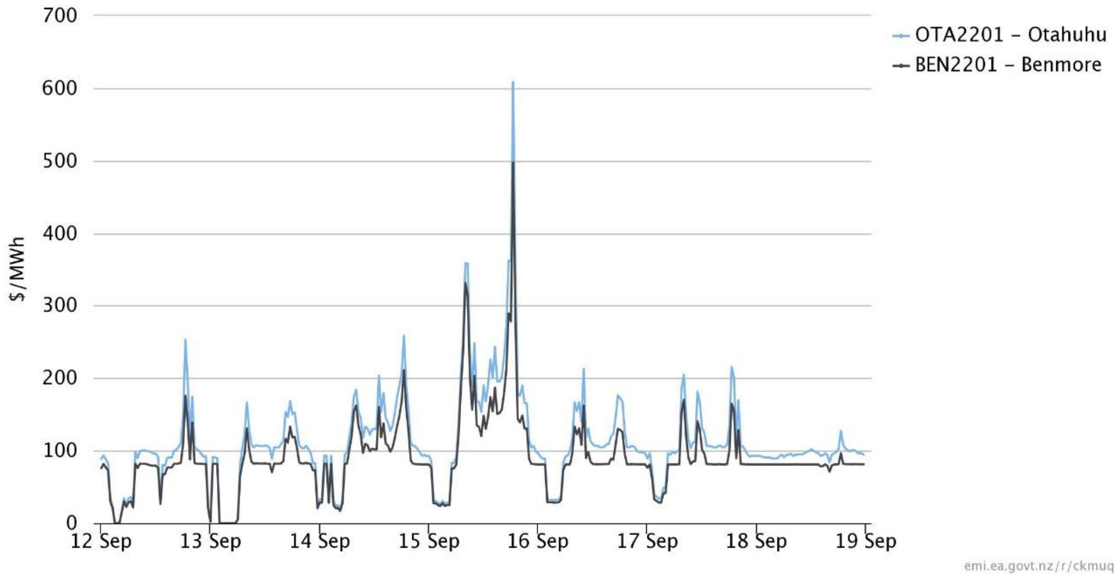
1 Overview for the week of 12 to 18 September

1.1 Prices this week appeared to be consistent with underlying supply and demand conditions. There was an increase in outages which caused tight supply during some peak periods resulting in high prices.

2 Prices

Energy prices

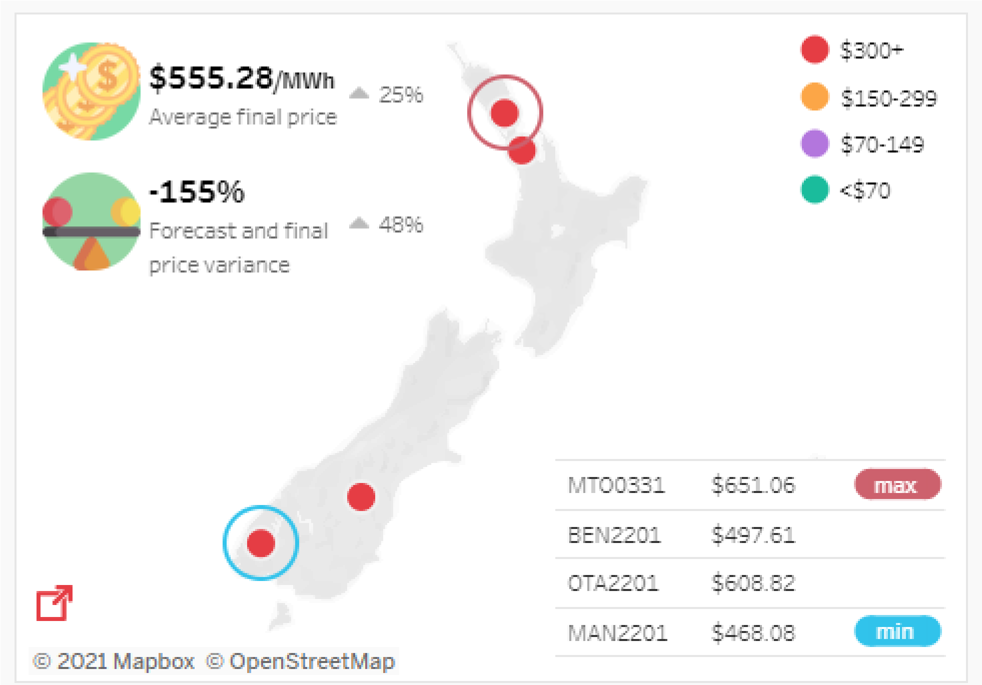
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.1 Average spot price this week was $100.77/MWh[1], about 5% higher than the previous week. There has been an increase in variation of prices recently with higher prices during the peaks and overnight prices falling as low as $0/MWh (see figure 1). Prices were highest on 15 September with the highest price occurring on TP 38 when prices reached $608.82/MWh at Otahuhu (see figure 2).

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

Figure 2: Spot prices for TP 38 on 15 September compared to previous week

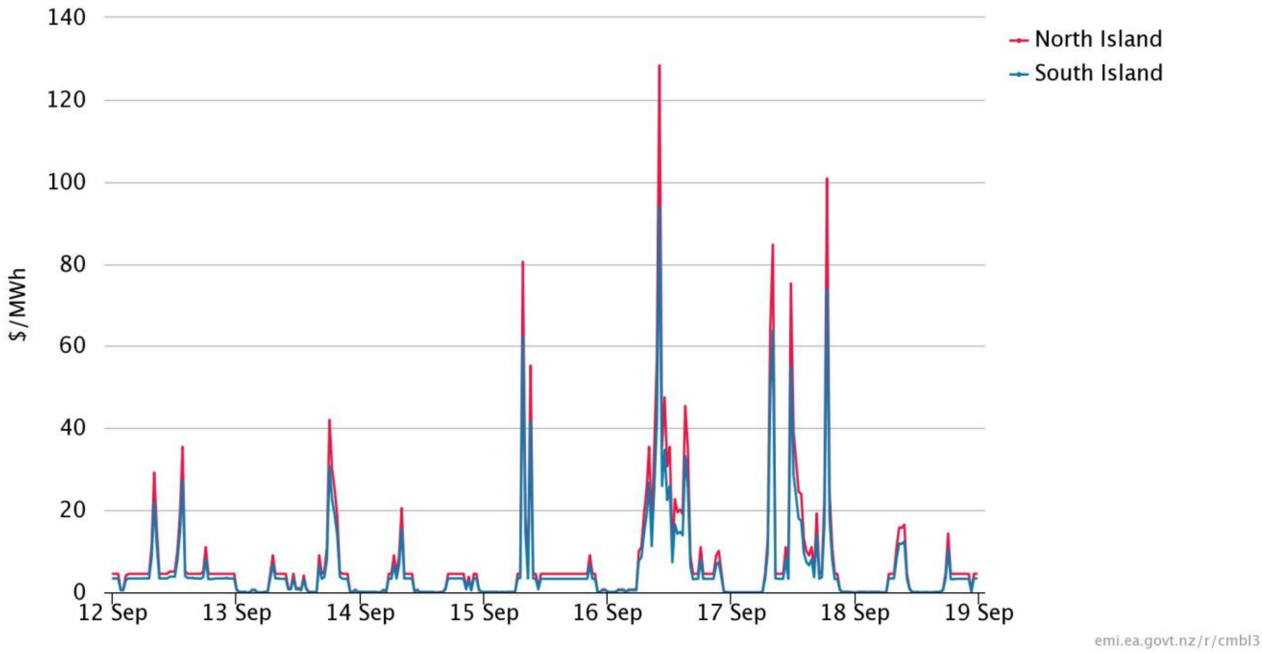


Reserve Prices

2.2 The prices for fast instantaneous reserves (FIR), shown in Figure 3, was also more variable this week. Most of the time prices were below $5/MWh, but there were several price spikes, with the highest reaching $128/MWh on 16 September TP21.

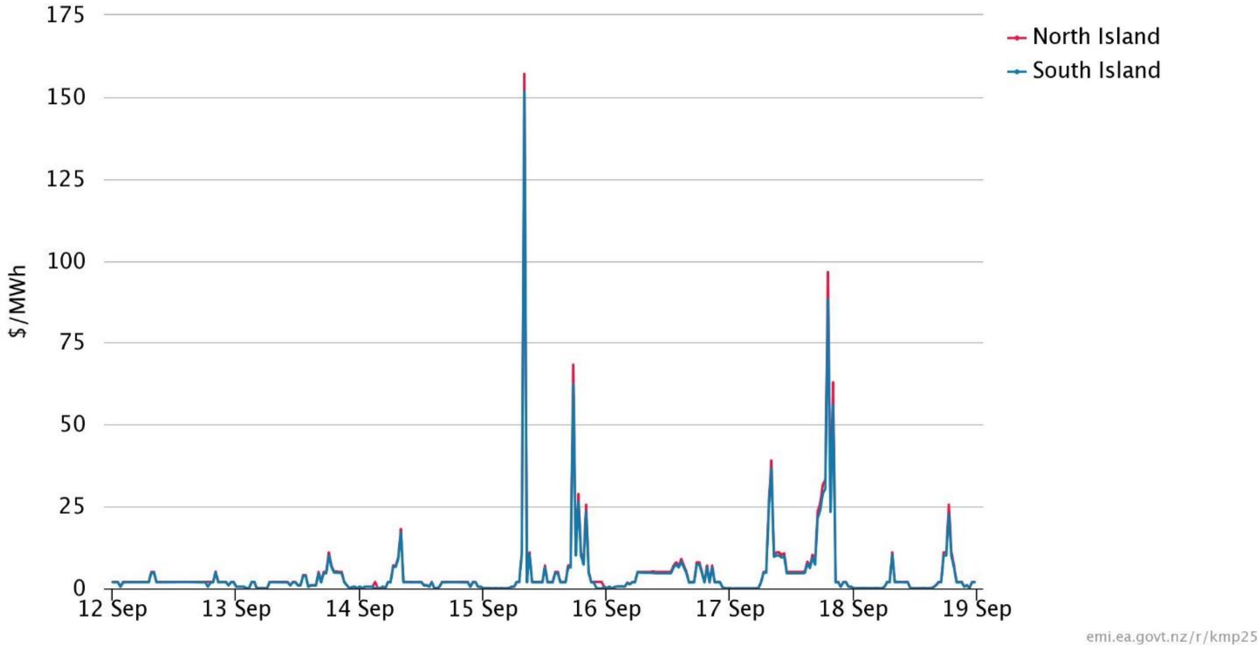
2.3 There were several outages this week (see 4.6) and as a result there was less reserve available and more of the available capacity was needed for energy generation. This resulted in higher FIR prices.

Figure 3: FIR prices by trading period by Island



2.4 The prices for sustained instantaneous reserves (SIR), shown in Figure 4, were below $25/MWh for most of the week. There were a couple of price spikes on the 15 September when energy prices were also high, and on 17 September. These occurred at times when overall supply was tight and prevented higher energy prices.

Figure 4: SIR prices by trading period by Island

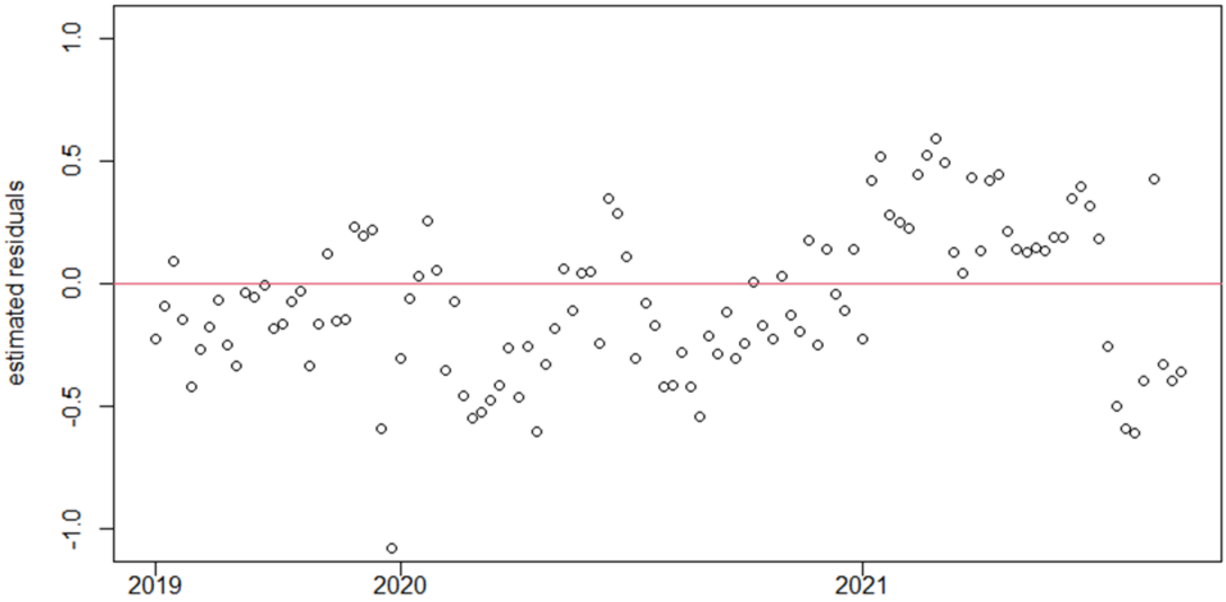


Residuals from regression models

2.5 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.

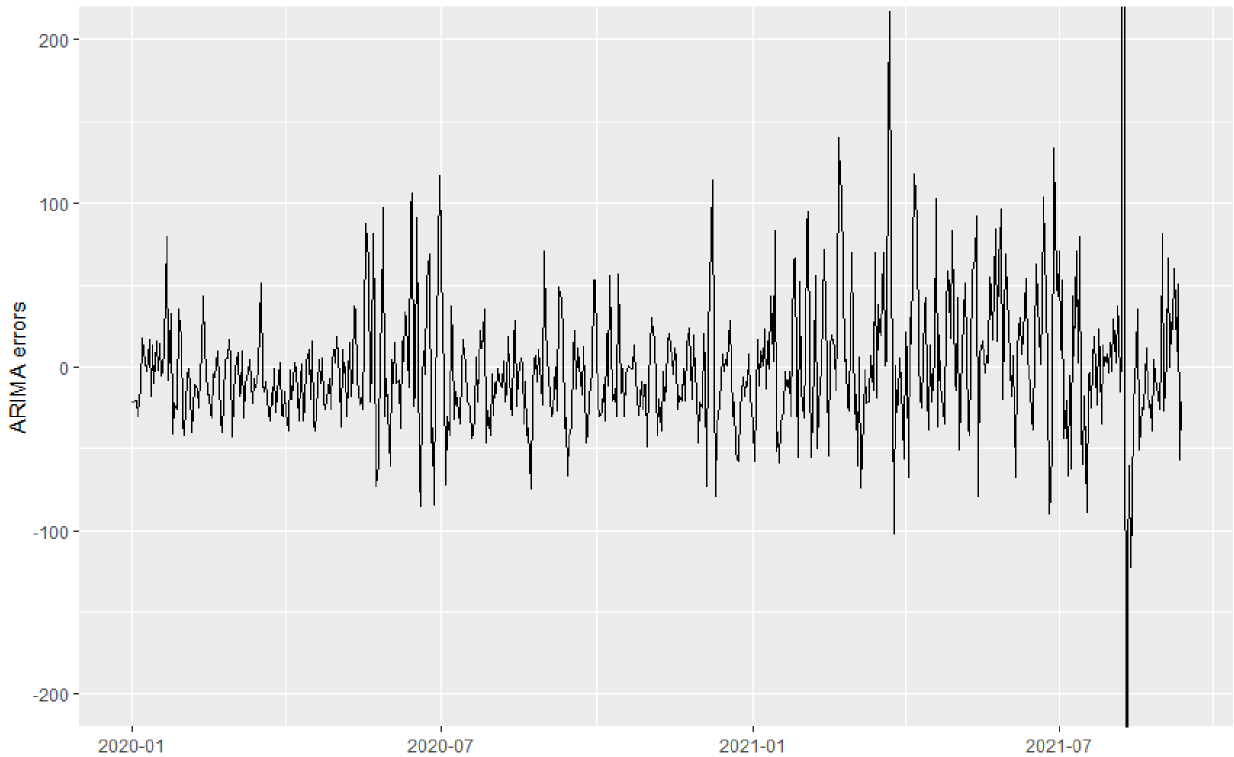
2.6 Figure 5 shows the residuals from the weekly model. During August 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 2 September 2021



2.7 Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were within the normal range.

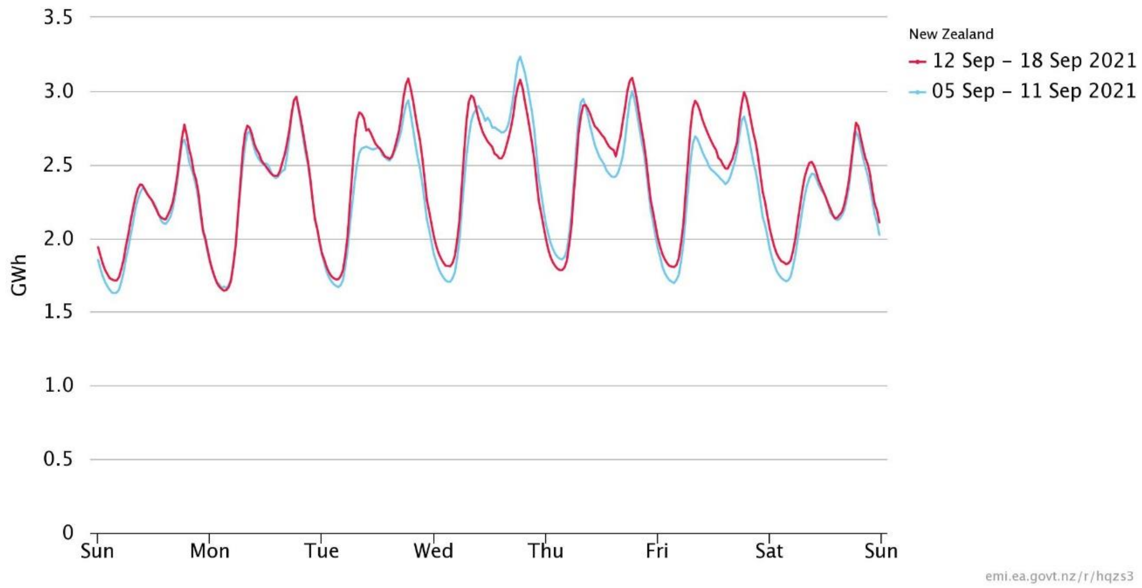
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 18 September 2021



3 Demand Conditions

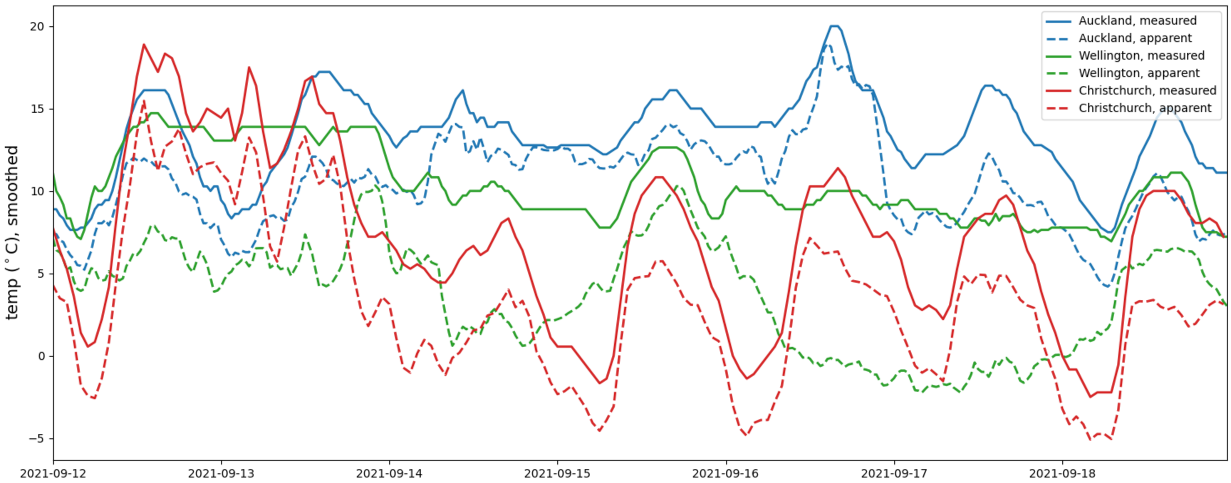
3.1 Demand was 3% higher than the previous week. Morning peak demand has increased since last Thursday when schools outside of Auckland reopened. Overall demand was highest in the middle of the week.

Figure 7: National demand compared to previous week



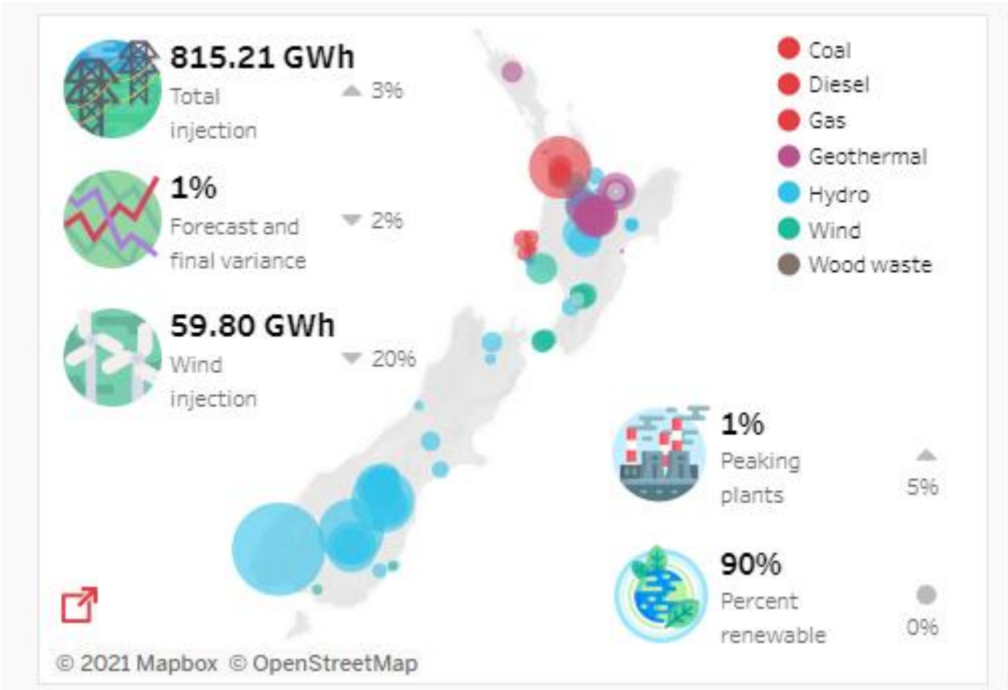
3.2 Figure 8 shows hourly temperature data at main population centres. The measure temperature is the recorded temperature, while the apparent temperature adjusts for factors, such as wind speed and humidity, to estimate how cold it feels. Temperatures were particularly cold in Christchurch overnight on the 15 and 16 September. There was less variation for measured temperatures in Wellington, but actual temperatures were colder on the 16 and 17 September due to strong winds.

Figure 8: Hourly temperature data at main population centres.



4 Supply Conditions

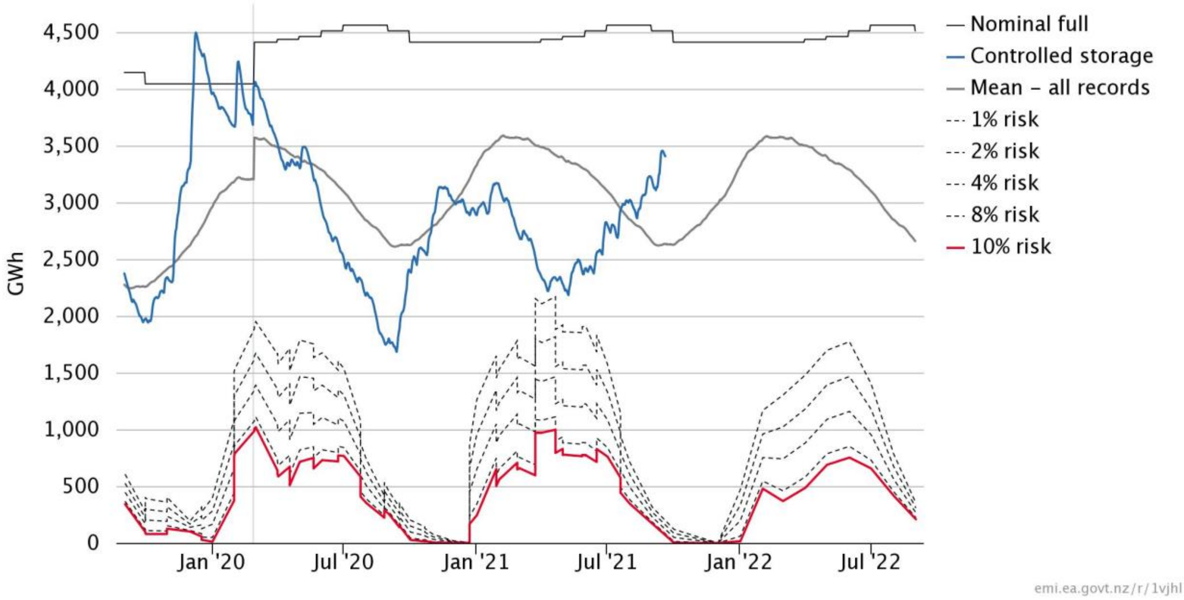
Figure 9: Generation in the last week compared previous week



Hydro conditions

4.1 This week national hydro storage continued to increase and is currently just below 3,500GWh. Since late-July all lakes except for Lake Taupo are above historical average levels for the time of the year.

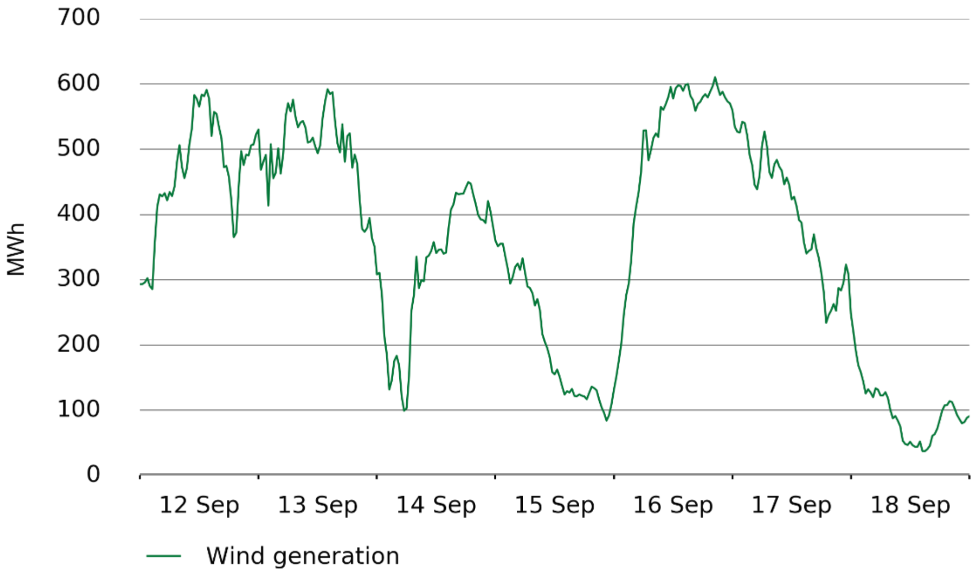
Figure 10: Electricity risk curves and current hydro supply



Wind conditions

4.2 Total wind generation was 59.8GWh, down 20% from last week. Wind was particularly low on 15 September and 18 September (see Figure 11). The fall in wind generation on 15 September contributed to the high prices.

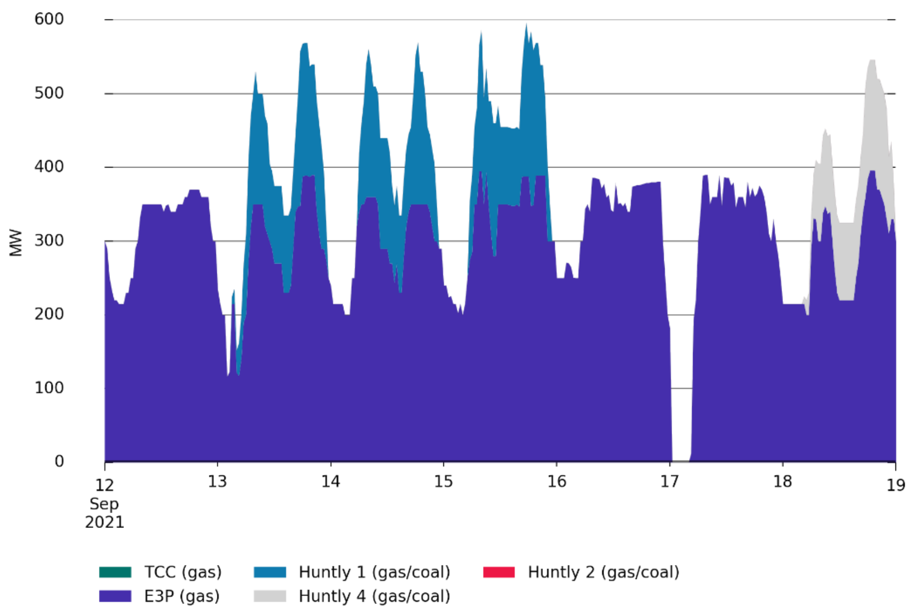
Figure 11: Wind generation for the week



Thermal conditions

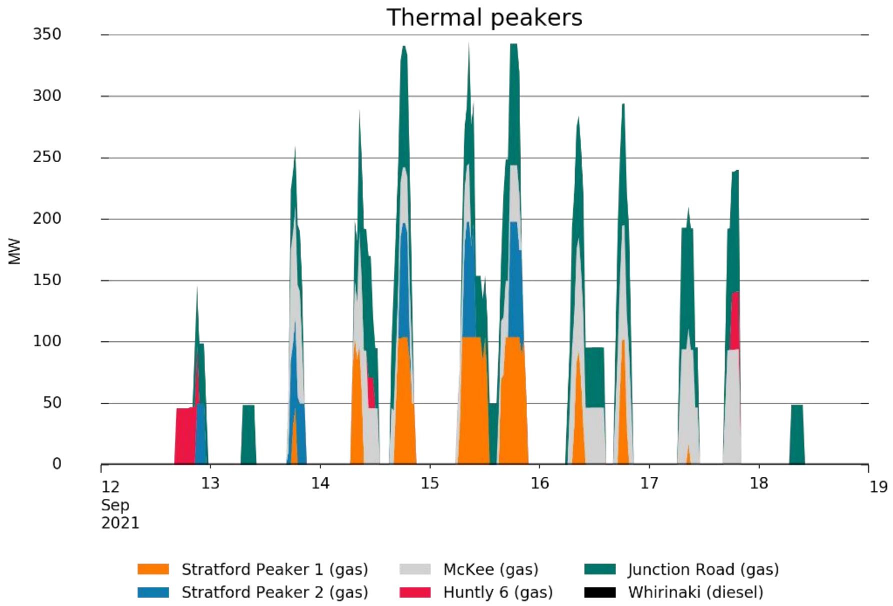
4.3 Baseload thermal generation remains low with only Huntly's E3P running as baseload most of the week. On some of the days one of the Rankine units was running. This reflects an overall decrease in demand for thermal generation as hydro storage increases and demand drops. Reserve prices were higher on the days when none of the Rankine units were dispatched.

Figure 12: Generation from baseload thermal



4.4 Thermal peakers continue to run primarily during the morning and evening peaks. Generation from thermal peakers reached 350MW on 14 and 15 September. This was all available peaker generation besides Whirinaki, as Huntly unit 6 had a planned outage and McKee had an unplanned outage

Figure 13: Generation from thermal peakers



Significant outages

4.5 There was an increase in outages this week, which is normal for this time of year. Te Mihi, a baseload geothermal generator, had an 83MW outage and there was a second 125MW outage at Manapouri, which combined effectively reduced baseload generation by 200MW as Manapouri has been generating at available capacity. There were also several outages at Tekapo and Ohau, with one Tekapo outage due to last until early next year.

4.6 The following outages reduced available generation by at least 50MW:

(a) Clyde,

(i) 116MW (long term outage)

(ii) 113MW (2pm-3pm, 13 September)

(b) Benmore,

(i) 90MW (5 July – 19 November)

(ii) 90MW (11am-2:30pm 17 September)

(c) Manapouri,

(i) 125MW (19 July – 29 October)

(ii) 125MW (13-16 September)

(d) Ohau,

(i) 55MW (2 August – 14 September)

(ii) 50MW (1 September – 14 September)

(iii) 50MW (6am-6pm 15 September)

(iv) 53MW (6am-4:30pm, 17 September)

(e) Huntly,

  (i) 240MW (27 August – 13 September)

  (ii) 240MW (15-22 September)

  (iii) 100MW (17-20 September)

  (iv) Peaker, 45MW (14-17 September)

(f) Tekapo,

  (i) 80MW (13 September – 16 January 2022)

  (ii) 30MW (13-15 September)

(g) Te Mihi, 83MW (13-17 September)

(h) Stratford peaker, 100MW (11am-2:30pm 14 September)

(i) McKee peaker, 50MW (14-15 September)

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 14 shows estimates of thermal SRMCs as a monthly average. High gas spot prices increased the thermal SRMC for July with prices dropping in August and so far in September (up to 18 September).

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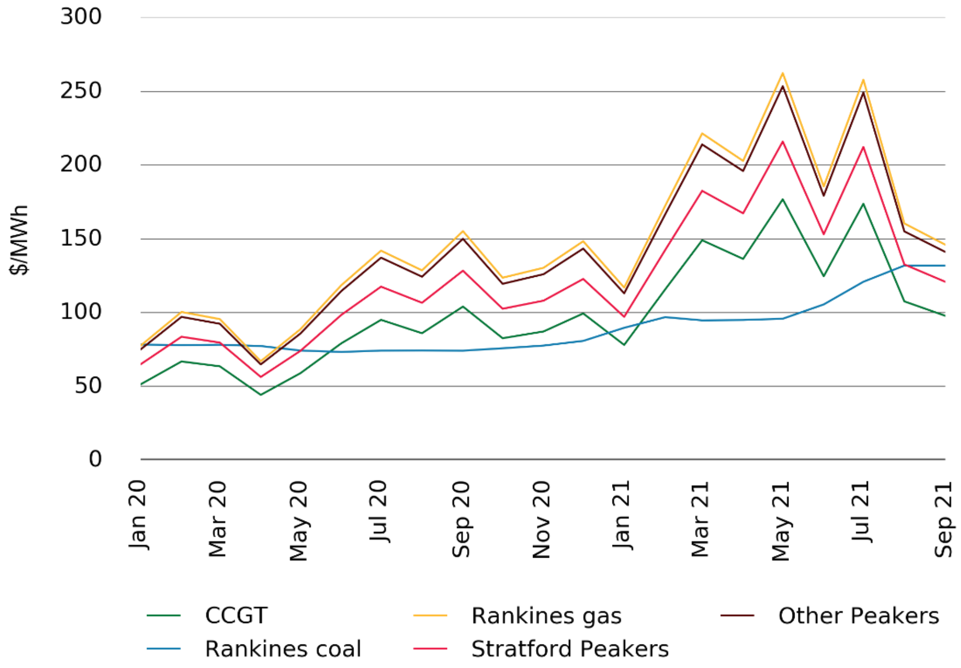
[2] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

[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 14: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

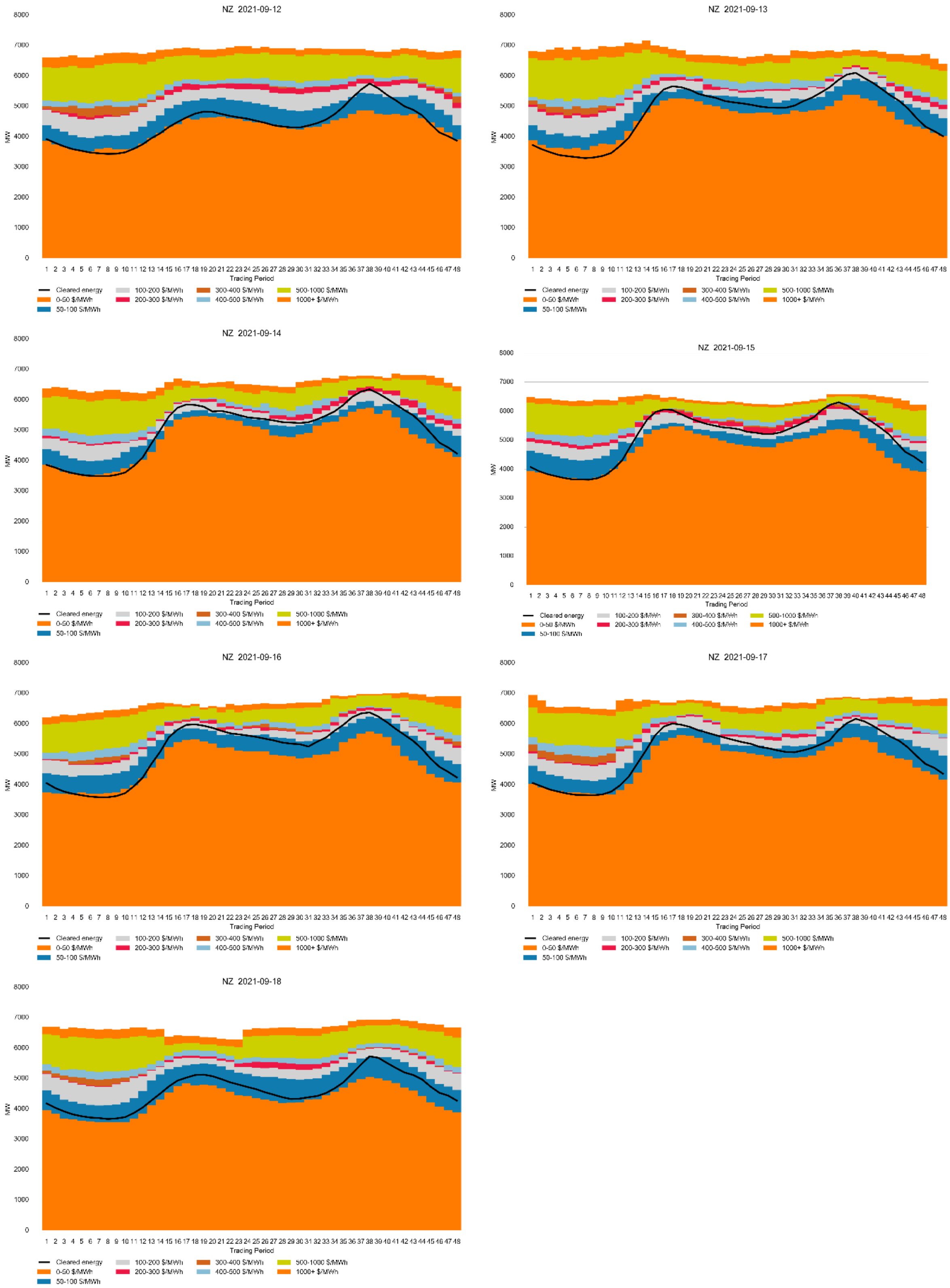
Final daily offer stacks

6.1 Figure 15 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 This week 17% of offers are over $350/MWh, 6% less comparing to previous week that the offers are over $350/MWh. Most offers continued to be below $200/MWh, with a thin offer stack at higher prices. This resulted in lower prices when demand was low, but high prices when demand was high and wind low, particularly on 15 September.

[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 15: Daily offer stack



Offers by trading period

6.3 The trading period (TP) with the highest price was TP38 (6:30pm) on 15 September. Figure 16 shows the offer stack, the generation weighted average price (GWAP) and cleared generation.

6.4 Cleared generation was about the same on the 15 September as it was at the same time the day before (figure 17). However, the offer stack on both days was quite steep at prices above $200/MWh. Wind generation on the 15 September was about 300MW lower than on 14 September, which shifted the offer stack left and had the impact of 300MW of additional demand, resulting in a much higher price on the 15 compared to 14 September.

Figure 16: Offer Stack for trading period 38 on 15 September

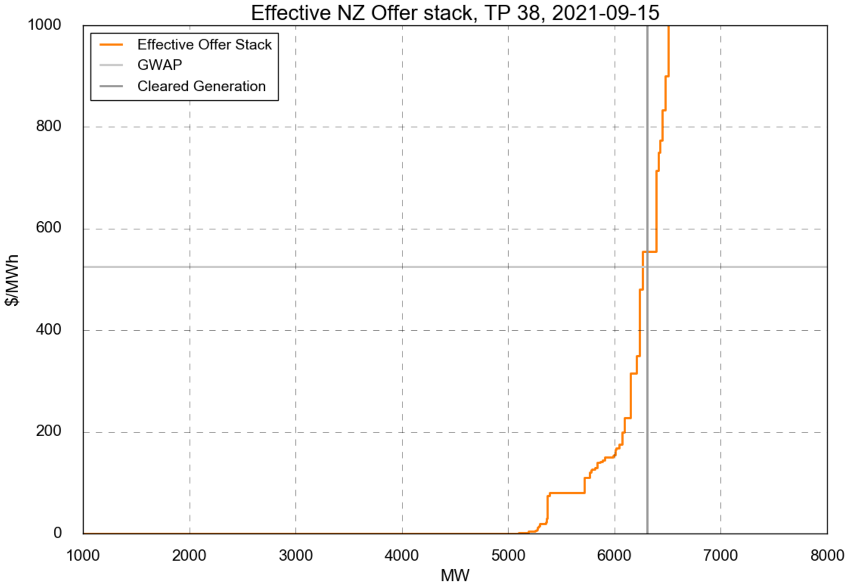
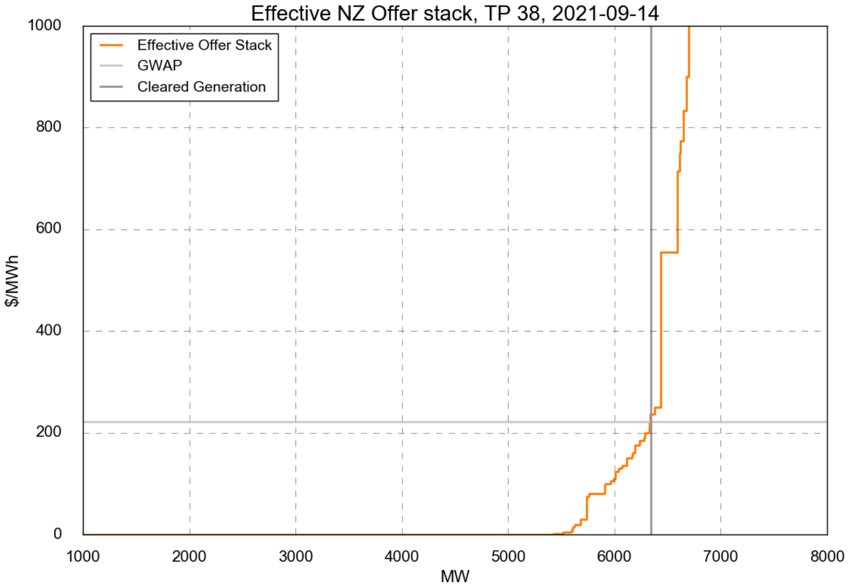


Figure 17: Offer Stack for trading period 38 on 14 September



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
21/08/2021	14	Grouped	High South Island SIR price, increase SIR required
30/06-20/08	Several	Compliance: review	High energy prices in shoulder periods
30/06-3/08	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 $\left(storage_t - 20.year.mean.storage_{dayofyear}\right)$