Trading Conduct Report

Market Monitoring Weekly Report

8 September 2021

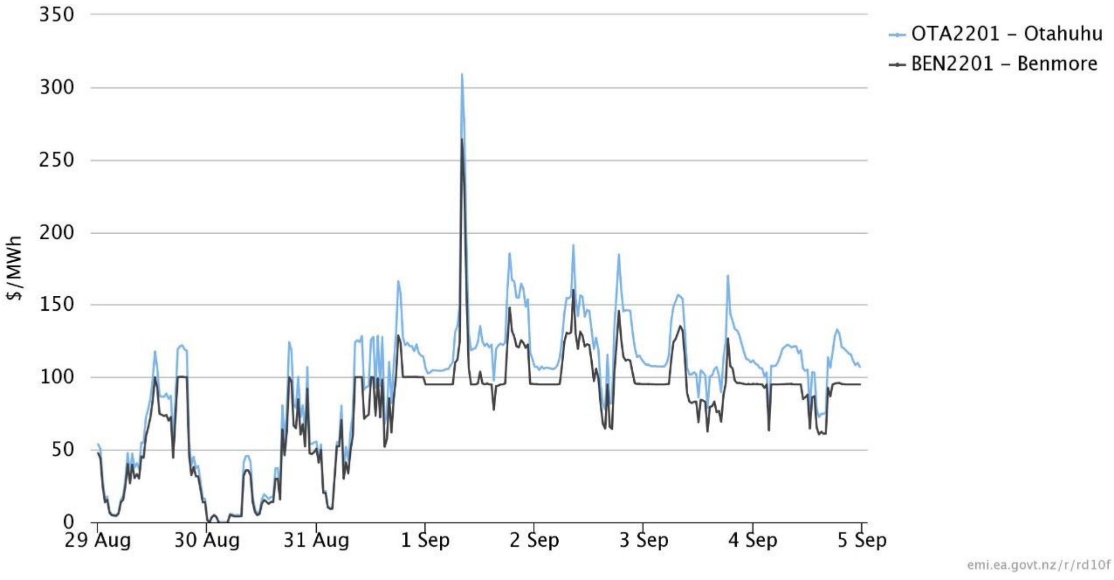
1 Overview for the week of 29 August to 4 September

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

2 Prices

Energy prices

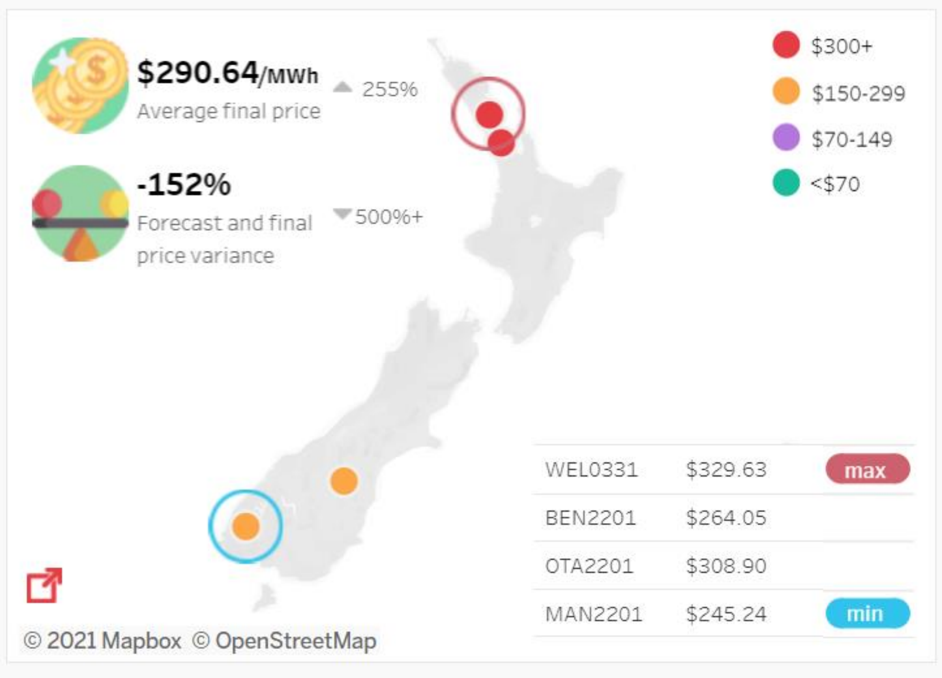
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.1 Average spot price this week was $88MWh[1], about 54% higher than the previous week. Prices were lowest earlier in the week when hydro storage was the highest and demand still low due to Covid19 alert level 4 (see figure 1). The highest price occurred on TP 17 1 September when prices reached $309/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

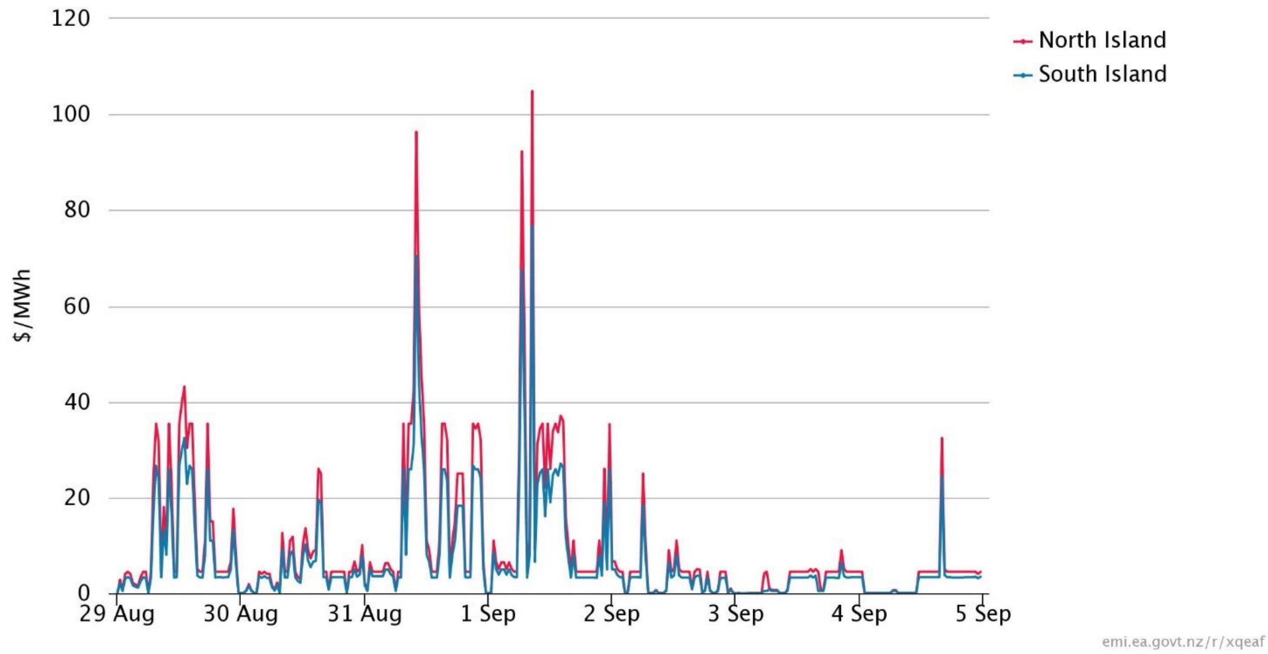
Figure 2: Spot prices for TP 32 on 17 August compared to previous week



Reserve Prices

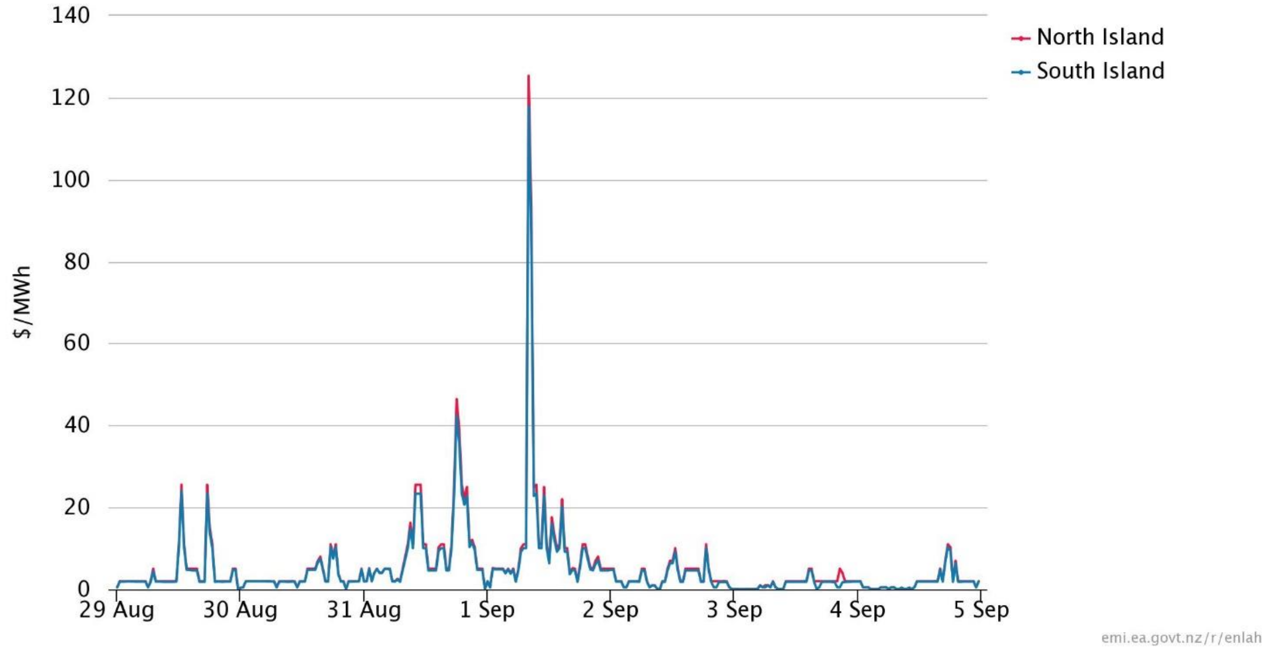
2.2 The prices for fast instantaneous reserves (FIR), shown in Figure 3, continued to frequently be high until 2 September when prices dropped to below $5/MWh the majority of the time. This is consistent with the increase in interruptible load (IL) available as most of the country moved out of alert level 4.

Figure 3: FIR prices by trading period by Island



2.3 The prices for sustained instantaneous reserves (SIR), shown in Figure 4 was highest on TP 17 on 1 September, coinciding with high energy prices. Otherwise SIR prices have been low, especially after 2 September.

Figure 4: SIR prices by trading period by Island

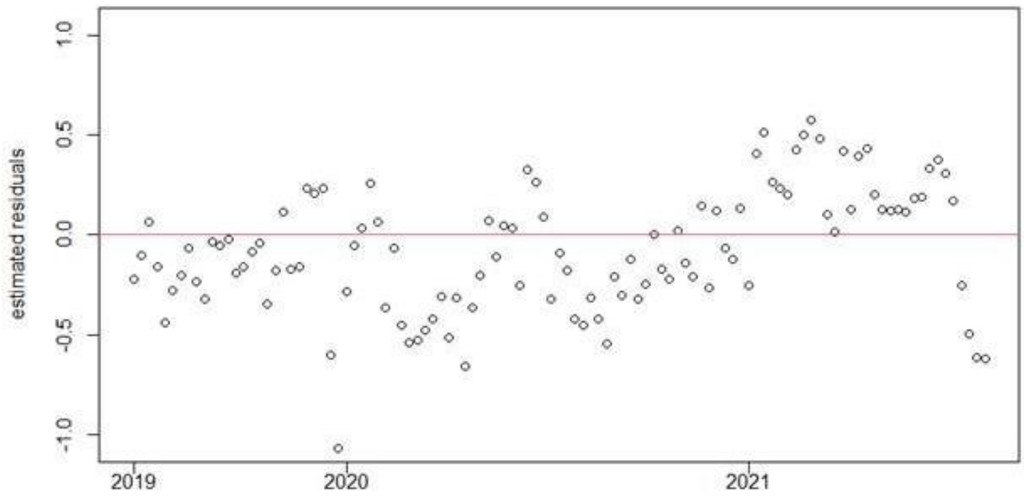


Residuals from regression models

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.

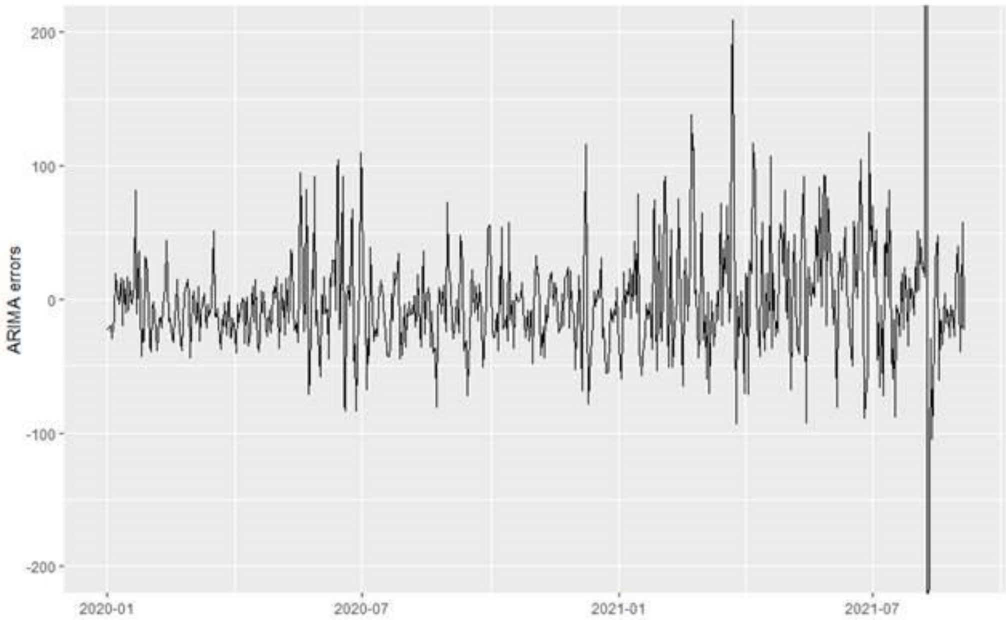
2.5 Figure 5 shows the residuals from the weekly model. During July 2021 the residuals were within the normal range, indicating that weekly prices were close to the model's predictions.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 29 July 2021



2.6 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.

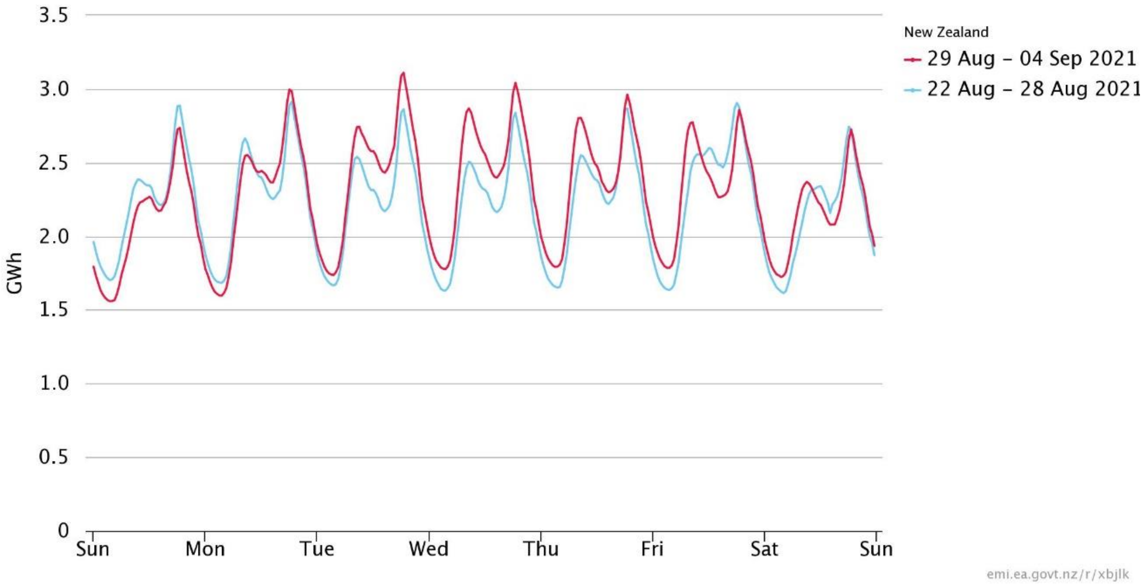
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 21 August 2021



3 Demand Conditions

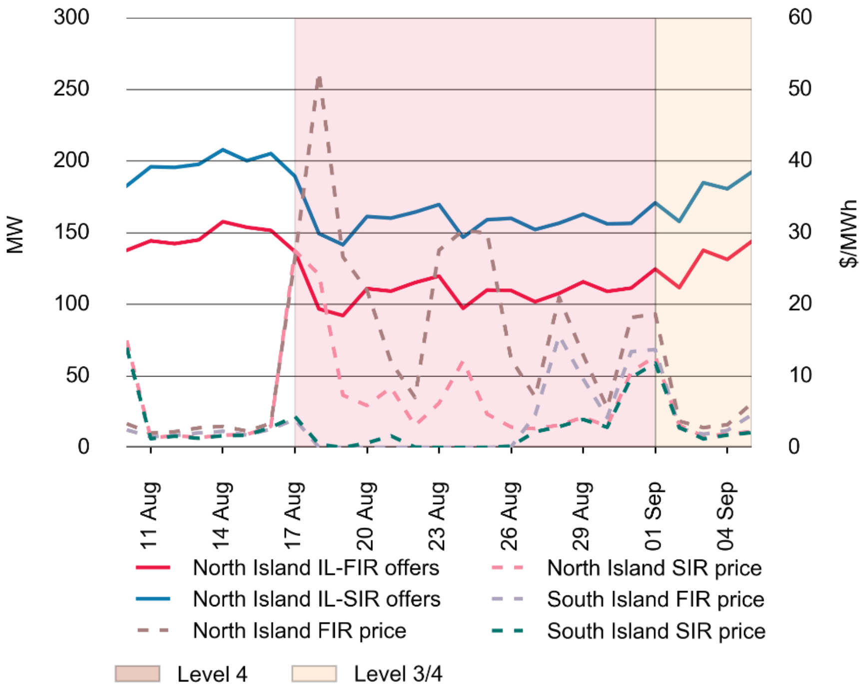
3.1 Demand was 3% higher this week as most of the country moved to Covid19 alert level 3 (except Auckland which stayed at alert level 4) from midnight Tuesday (see Figure 7). This was particularly noticeable for morning demand which was significantly higher on Wednesday morning than the week before.

Figure 7: National demand compared to previous week



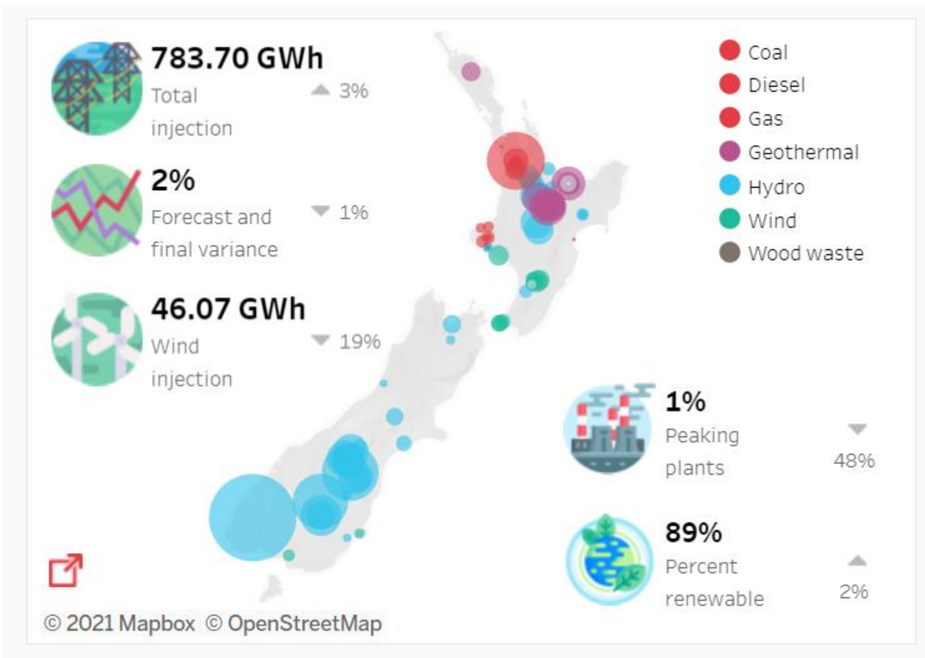
3.2 The drop in industrial load due to alert level 4 resulted in less interruptible load (IL) offered into the reserve market. This has contributed to the increase in reserve prices by reducing supply, particularly in the North Island. However, since most of the country moved to alert level 3 the amount of IL available has increased and reserve prices have dropped.

Figure 8: Interruptible load offers and reserve prices



4 Supply Conditions

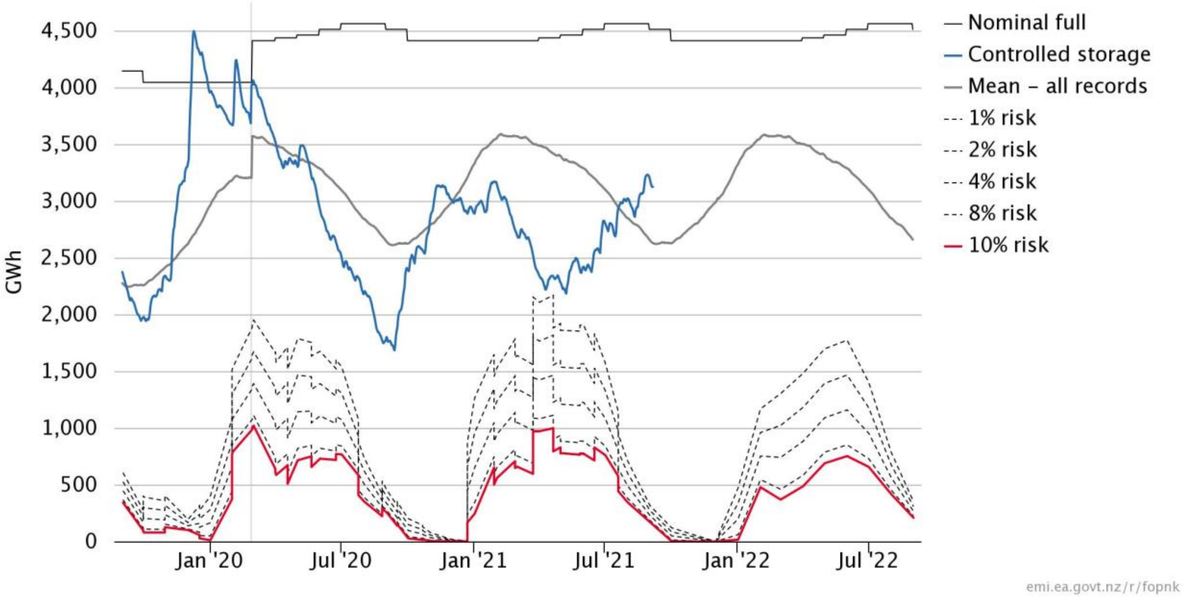
Figure 9: Generation in the last week compared previous week



Hydro conditions

4.1 This week national hydro storage was at 64% of total storage. Storage levels have dropped since 30 August but are still well above the mean level for this time of year.

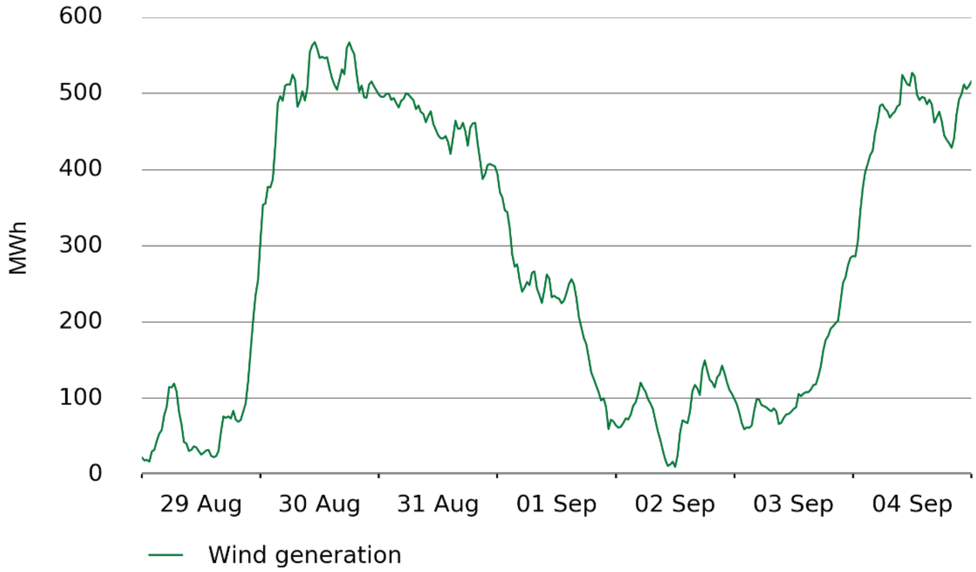
Figure 10: Electricity risk curves and current hydro supply



Wind conditions

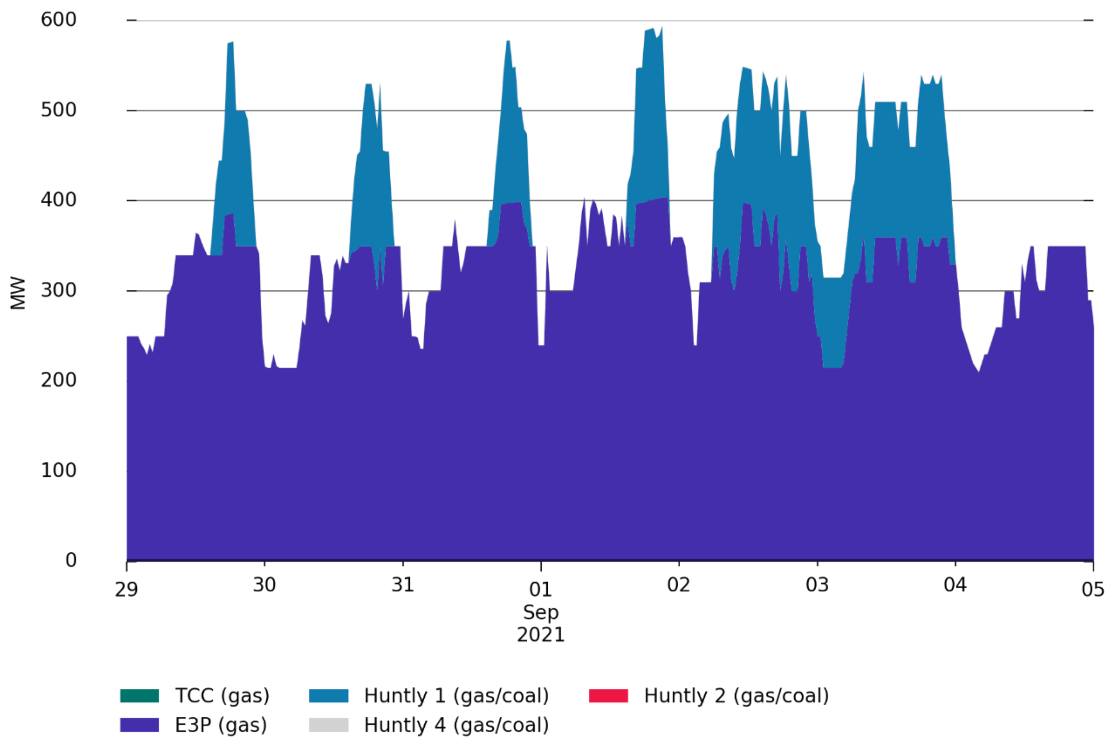
4.2 Total wind generation was 46GWh, about 19% lower than last week. Wind generation was above 400MWh on 30 and 31 August but dropped significantly on 1 September, remaining below 100MWh until 4 September when wind generation increased to above 400MWh again (see Figure 11).

Figure 11: Wind generation for the week



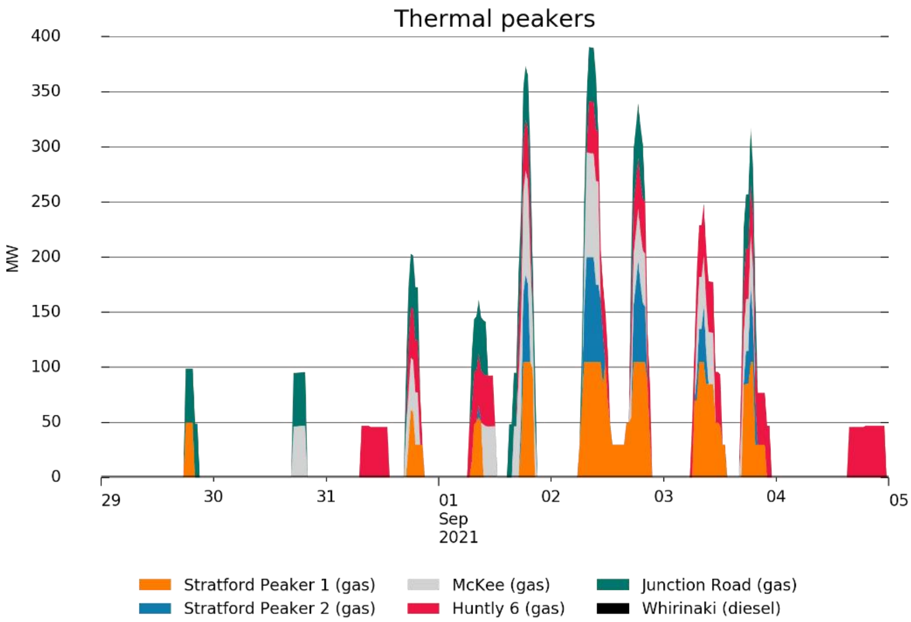
Thermal conditions

4.3 Thermal generation remains low, with only Huntly's E3P running as baseload the whole week. One of the Rankines, Huntly unit 1 was running only in the evenings when demand was higher, so was not running on Wednesday morning, when the highest price occurred. Likely in response to the demand increase on Wednesday, unit 1 was running on Thursday morning through to Friday evening.



4.4 Generation from thermal peakers continues to be low, with thermal peakers only needed during the peak trading periods. Stratford peaker 2 ran briefly on 1 September TP17, contributing just 11 MW. Needing the additional peaker to meet demand for a single trading period would have contributed to the high price.

Figure 12: Generation from thermal peakers



Significant outages

4.5 The following outages reduced available generation by at least 90MW:

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

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

(c) Manapouri, 125MW (19 July – 9 October)

(d) Huntly

(i) 240MW (27 August – 10 September)

(ii) 240MW (2 September 7am-1pm)

(iii) 240MW (4-5 September)

(e) Tekapo

(i) 93MW (30 August 1pm-3pm)

(ii) 80MW (3 September 8am-4pm)

(f) Stratford peaker, 100MW (4 September 6am-12:30pm)

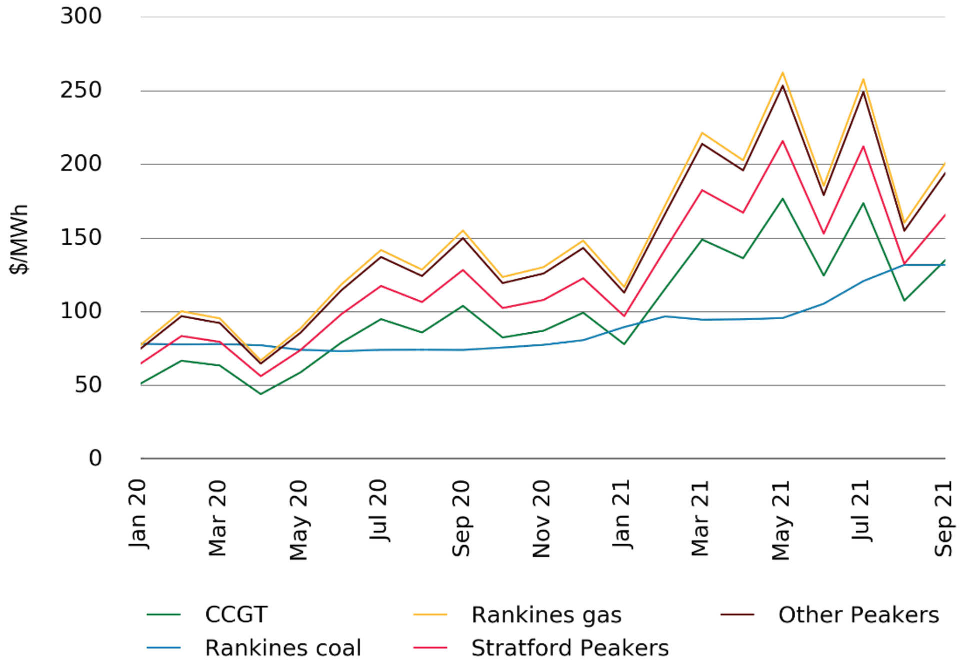
5 Price versus estimated costs

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]

[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/

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. High gas spot prices increased the thermal SRMC for July with prices dropping in August. Prices are higher so far in September (to 4 September), likely due to a planned outage at Pohokura and an unplanned outage at McKee. Coal is purchased by contract in advance and historically coal has been more expensive than gas but is currently on par with CCGT.

Figure 13: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

Final daily offer stacks

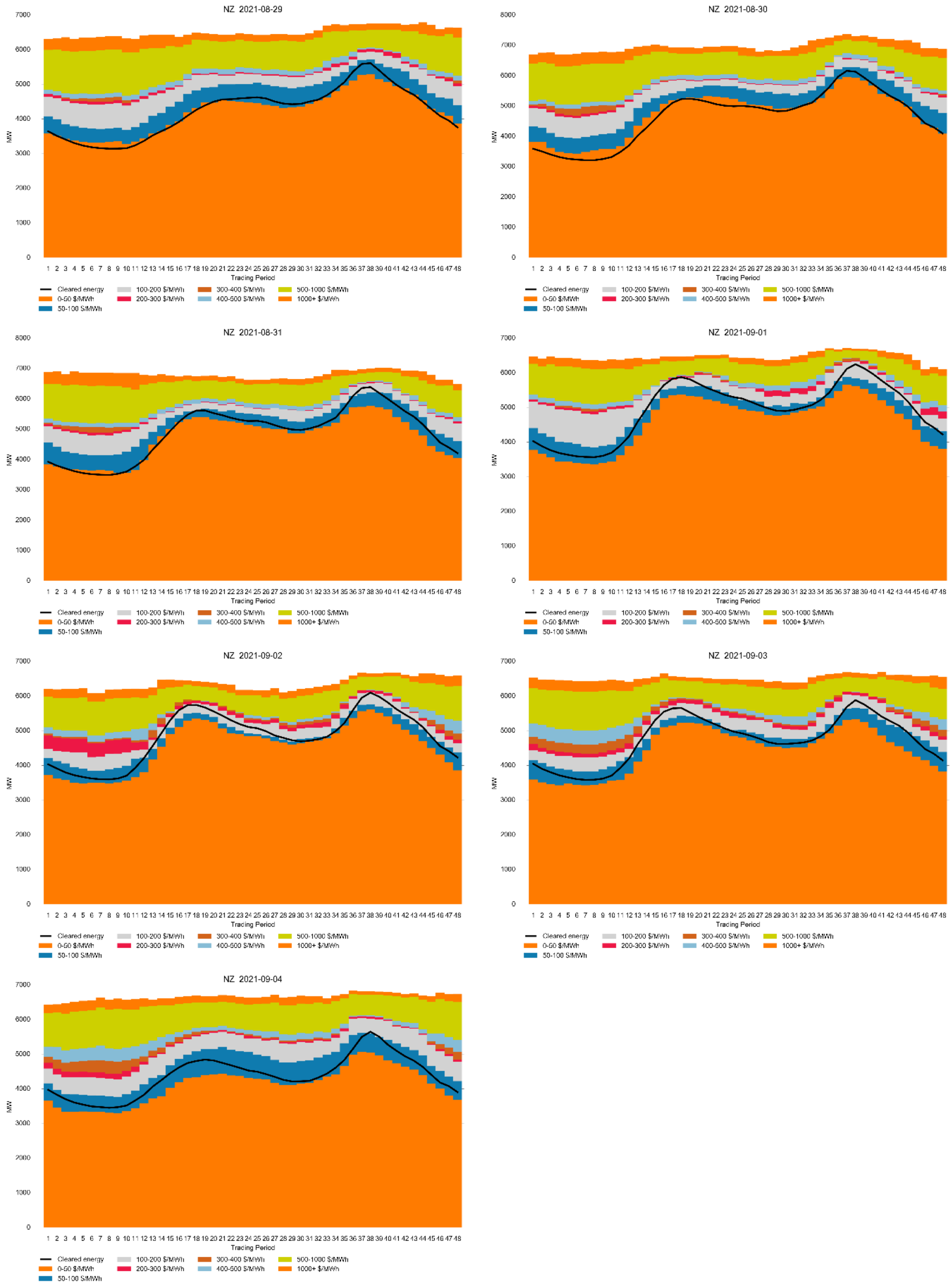
6.1 Figure 14 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[4] The black line shows the cleared energy, indicating the range of final prices, though this is less reliable for the period of the HVDC outage due to price separation.

6.2 This week there continued to be more offers in the $50-$100/MWh, with most offers clearing in this band, except during some peaks when prices cleared between $100-$200/MWh.

[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.

[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 was TP17 (8am) on 1 September. This was the first morning most of the country was at alert level 3 after two weeks at alert level 4. Anticipating demand under the changing alert levels is difficult and demand was 16% higher than the same trading period the previous week (Figure 16).

6.4 Prices were expected to be around $150/MWh at Otahuhu for trading period 17, indicating cleared generation was more than 100MW higher than expected. This caused prices to clear at quite a steep part of offer curve, where even a small increase in demand can cause a high increase in prices. This was seen with Stratford Peaker 2 dispatched for just 11MW during this trading period in order to meet demand.

Figure 15: Offer Stack for trading period 17 on 1 September

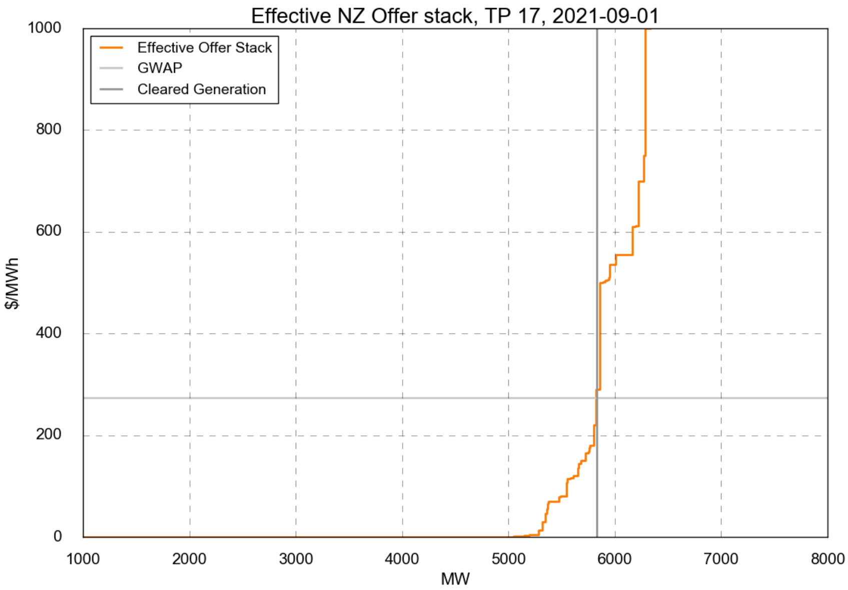
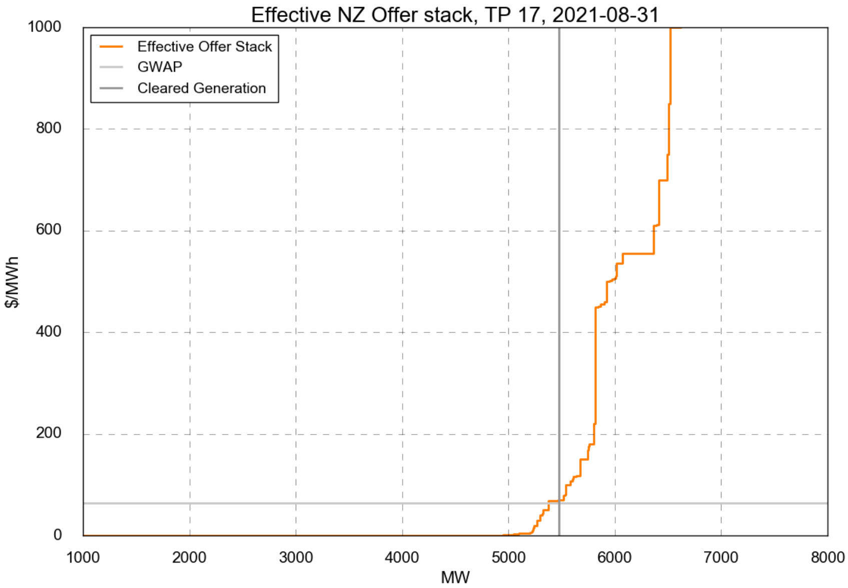


Figure 16: Offer Stack for trading period 17 on 31 August



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	Further Analysis	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 $\left(storage_t - 20.year.mean.storage_{dayofyear}\right)$