High Standard of Trading conduct

Market Monitoring Weekly Report

13 July 2021

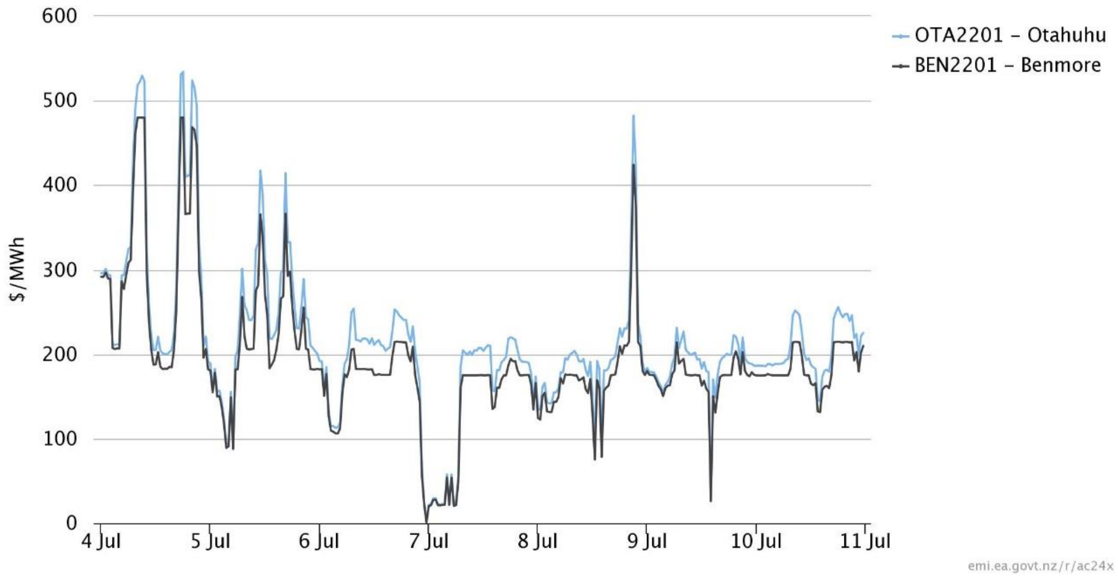
1 Overview for the week of 4 to 10 July 2021

1.1 High prices this week may be due to high demand and tight supply conditions but some trading periods warrant further analysis. The trading periods we will investigate further are listed at the end of this report.

2 Prices

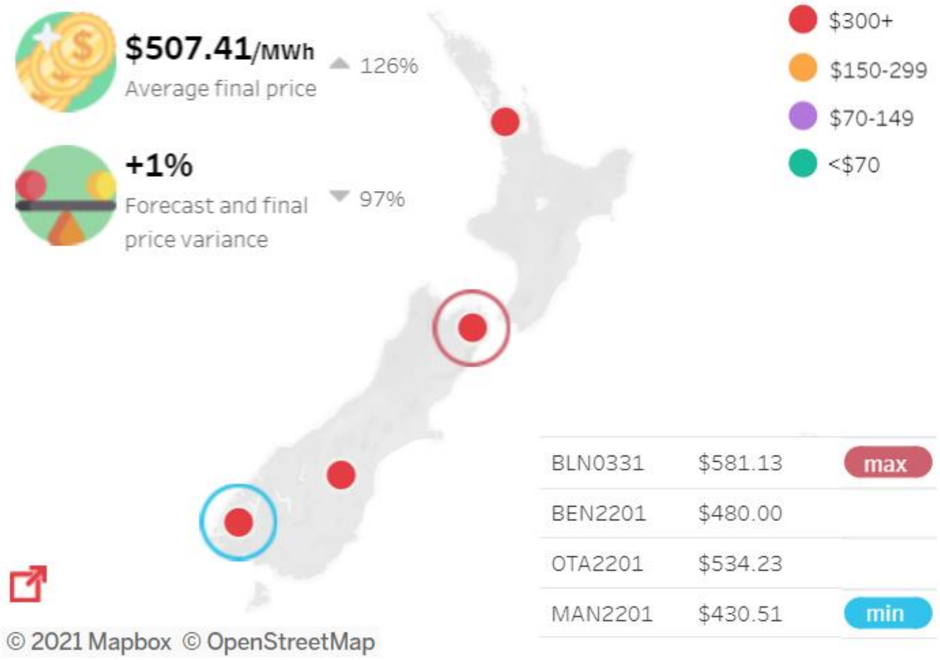
Energy prices

Figure 1: Spot prices by trading period at Otahuhu and Benmore, 4 to 10 July



2.1 Average spot prices this week were $203/MWh, down 20% from the previous week. The highest prices occurred during TP 37 on 4 July (see figure 2). Prices were highest on 4 and 5 July, following high prices last week. Prices from 6 July onwards stayed around $175/MWh at Benmore, with occasional fluctuations.

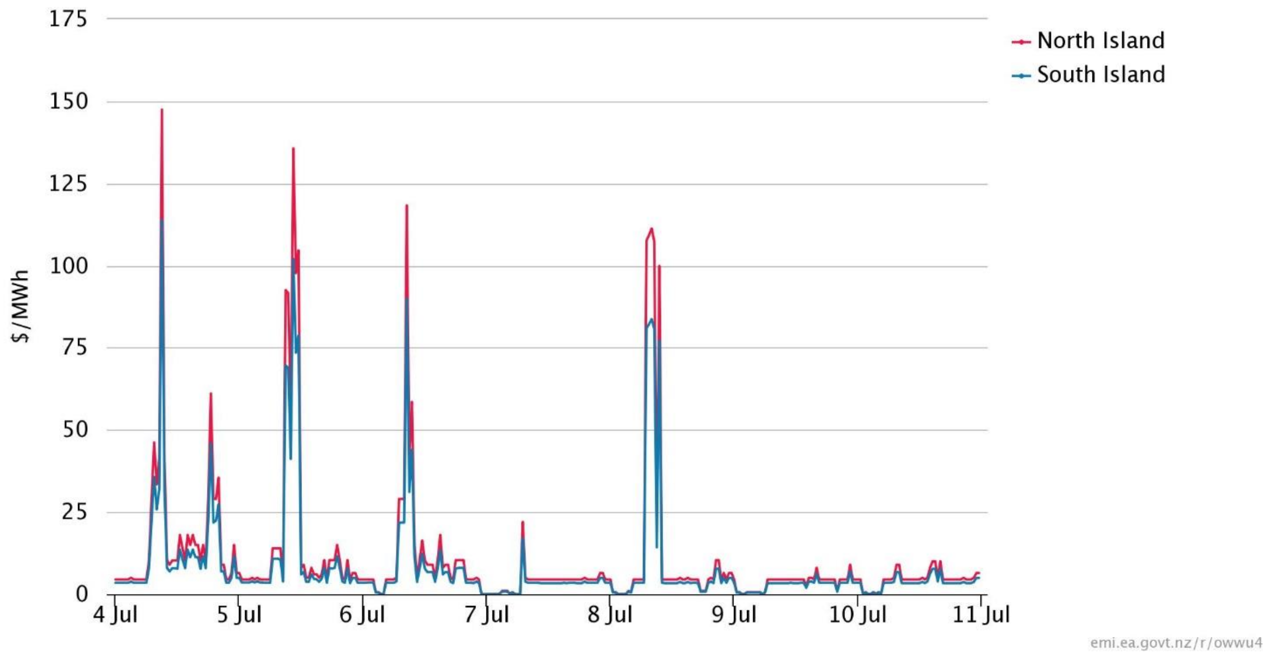
Figure 2: Spot prices for trading period 37 on 4 July compared to previous week



Reserve Prices

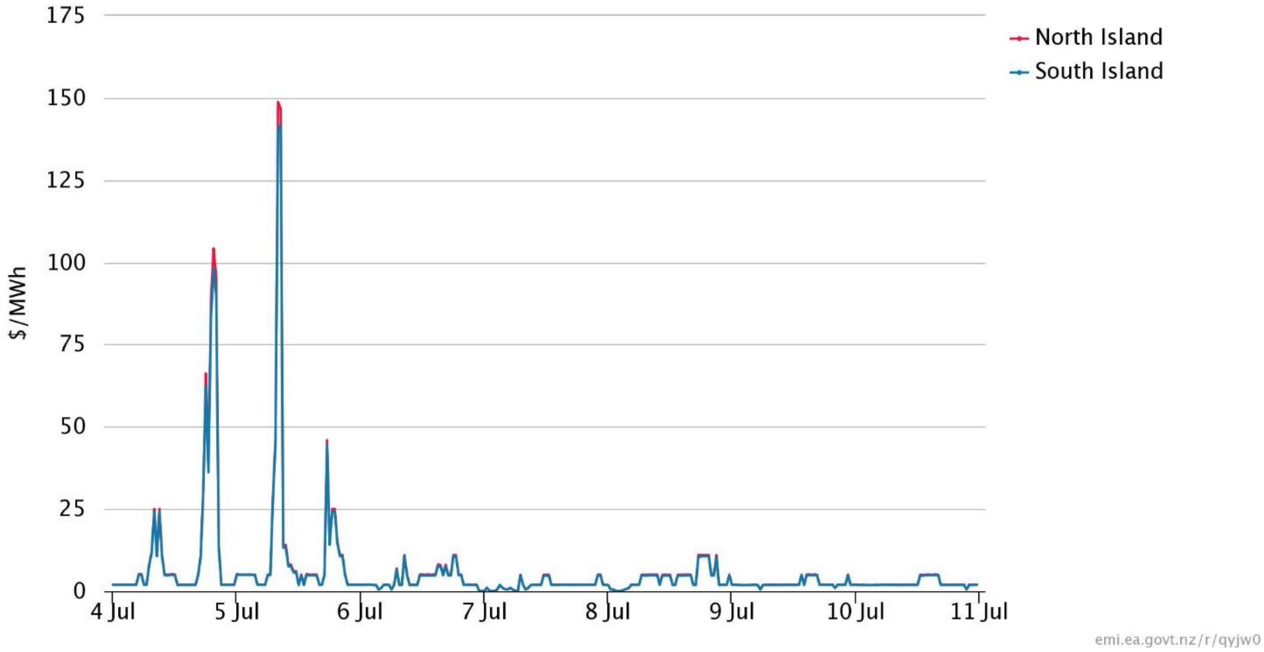
2.2 The prices for fast instantaneous reserves (FIR), shown in Figure 3 for this week, were usually below $5/MWh, but prices increased to over $100/MWh in the North Island six times this week.

Figure 3: FIR prices by trading period by Island, 4 to 10 July



2.3 The prices for sustained instantaneous reserves (SIR), shown in Figure 4 for this week, were usually below $5/MWh, with 2 instances of prices over $100/MWh early in the week.

Figure 4: SIR prices by trading period by Island, 4 to 10 July

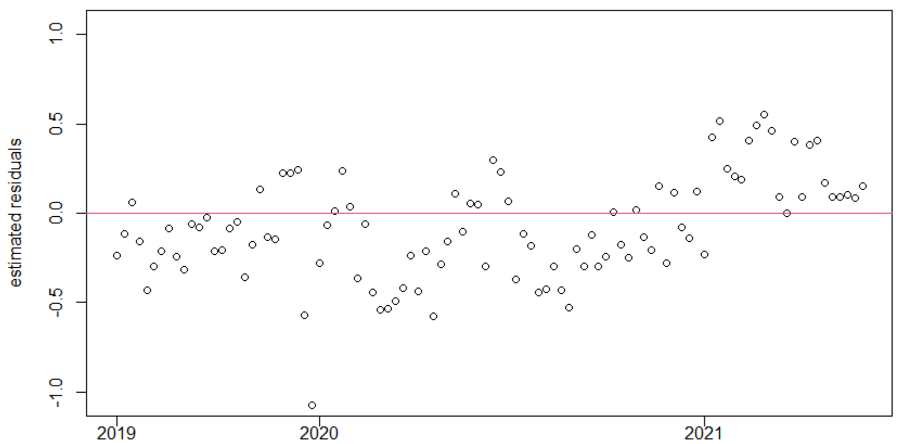


Residuals from regression models

2.4 The Authority's monitoring team has developed two regression models of the spot price. The residuals show how closely 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 May 2021 the residuals were close to zero, indicating that actual prices in May were close to the expected prices given market conditions.[1]

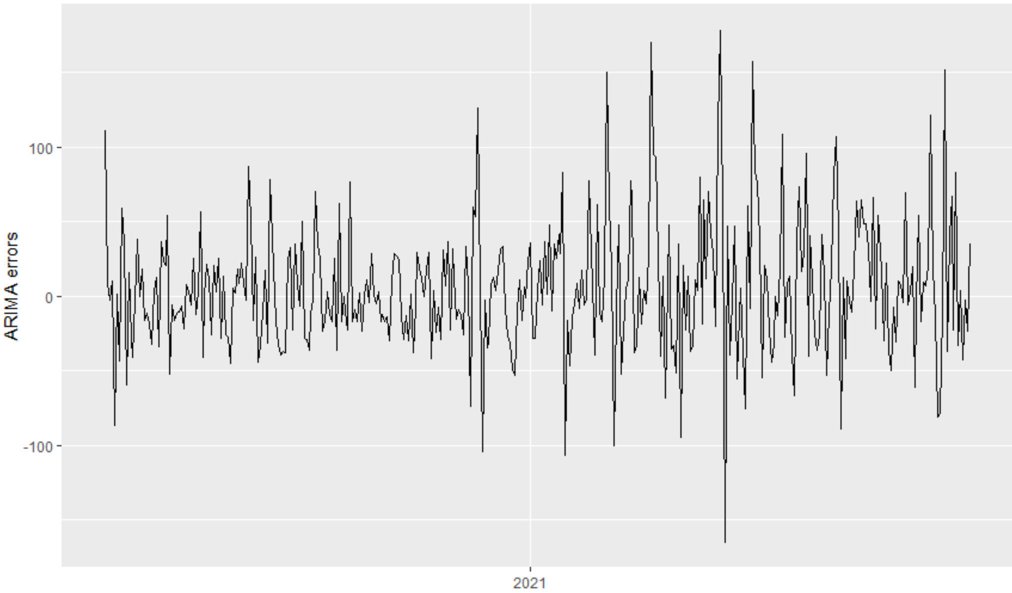
Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 27 May 2021



2.6 Figure 6 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. This week the daily residuals were much smaller than they were the previous week, indicating prices were closer to the expected price from the model.

[1] This model uses reconciled data and will be updated to end of June in mid-July.

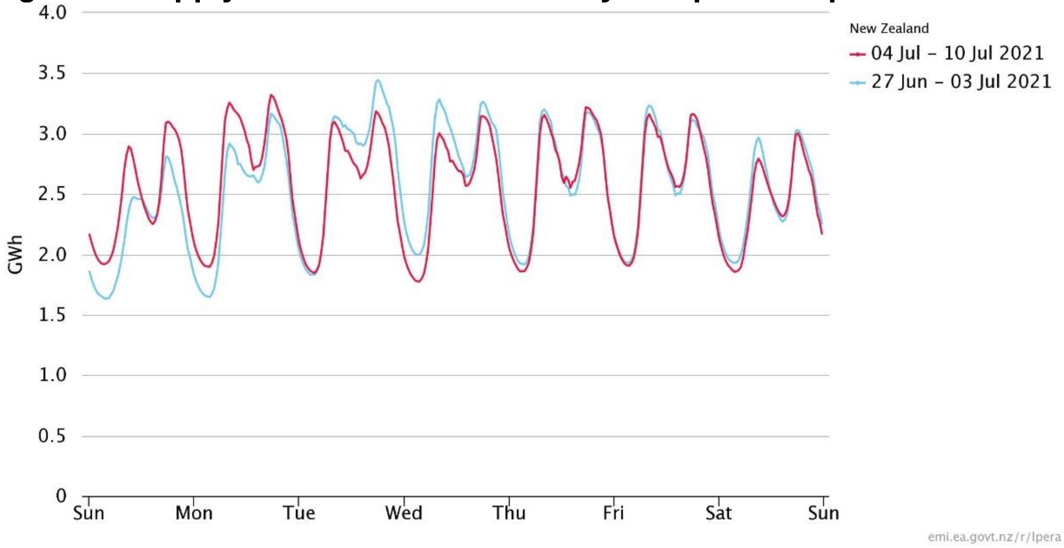
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 10 July 2021



3 Demand Conditions

3.1 Demand remained high on Sunday and Monday as cold weather continued, then was lower than last week on Tuesday and Wednesday.

Figure 7: Supply for the week 4 to 10 July compared to previous week

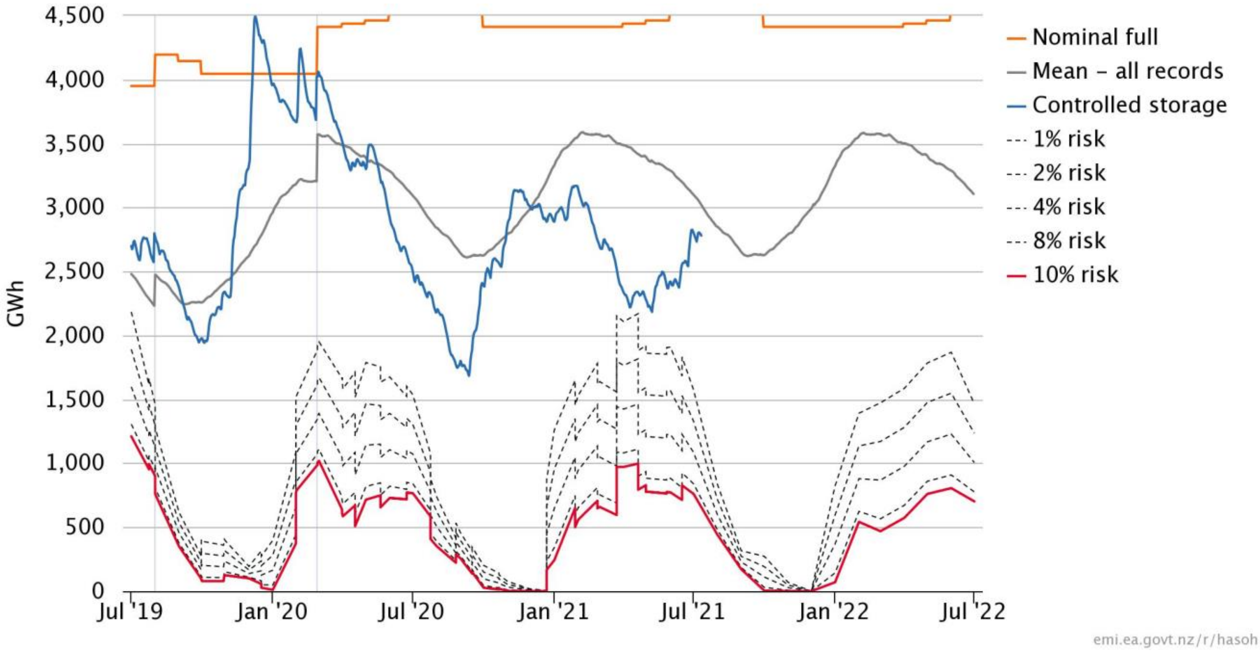


4 Supply Conditions

Hydro conditions

4.1 Total hydro supply is currently 54% of nominal full, down 1% from last week. Supply has been below the seasonal mean all year, but the gap has closed from over 1,000GWh to 200GWh.

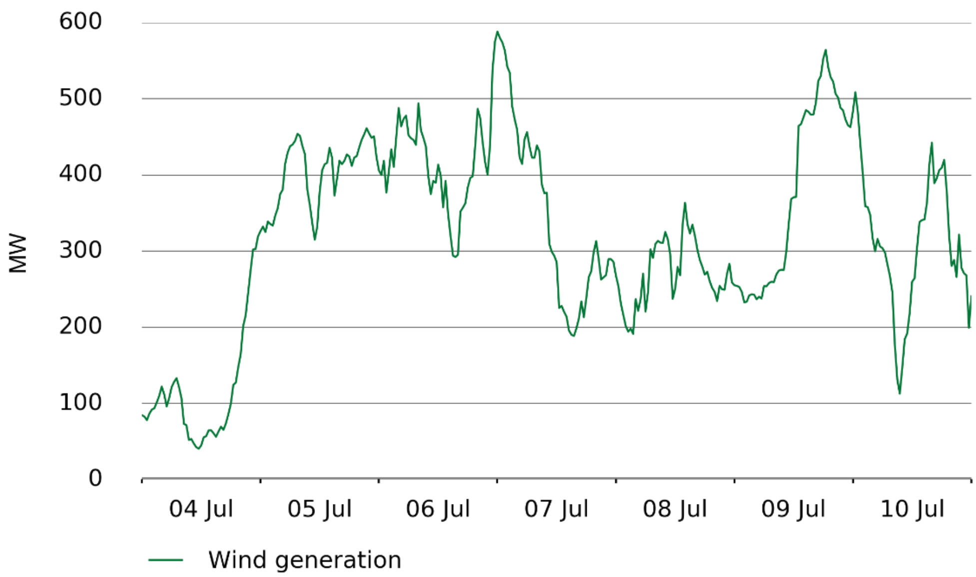
Figure 8: Electricity risk curves and current hydro supply



Wind conditions

4.2 Total wind generation was 54GWh this week, up 25% from last week. Wind conditions started low, around 100MW on 4 July but picked up that night, reaching 600MW on 6/7July. Wind was lower between 7 and 9 July then the rest of the week.

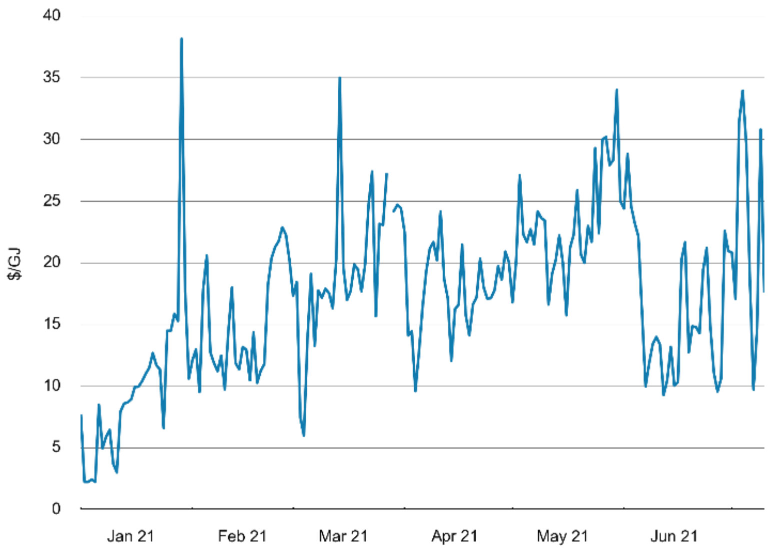
Figure 9: Wind generation for the week 4 to 10 July



Thermal fuel market conditions

4.3 Gas spot prices were volatile this week reaching $34/GJ on 4 July, down to $10/GJ on 7 July. The quantities of gas traded at spot prices is only a small part of the total gas market but does provide the opportunity cost of buying or selling an additional unit of gas.[2]

Figure 10: Spot gas, traded VWAP, daily, 1 January to 10 July 2021



Significant outages

4.4 The following outages reduced available generation by at least 100MW:

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

(b) Kawerau, 106MW (7 June to 19 July)

(c) Huntly 5, 145MW (7 July 1am-2:30am, 8 July 2am-3am)

(d) Huntly 4, 240MW (9 July-12 July)

(e) Manapouri, 125MW (6 July 7am-4:30pm, 7 July 7am-3pm, 8 July 9am-2pm)

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).[3]

5.2 The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices[4] and the average heat rates for each thermal unit. Figure 11 shows estimates of thermal SRMCs as a monthly average. High gas spot prices have

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[2] Opportunity cost for gas generators – when storage of gas is available - also includes the expected price of generating at a later date.

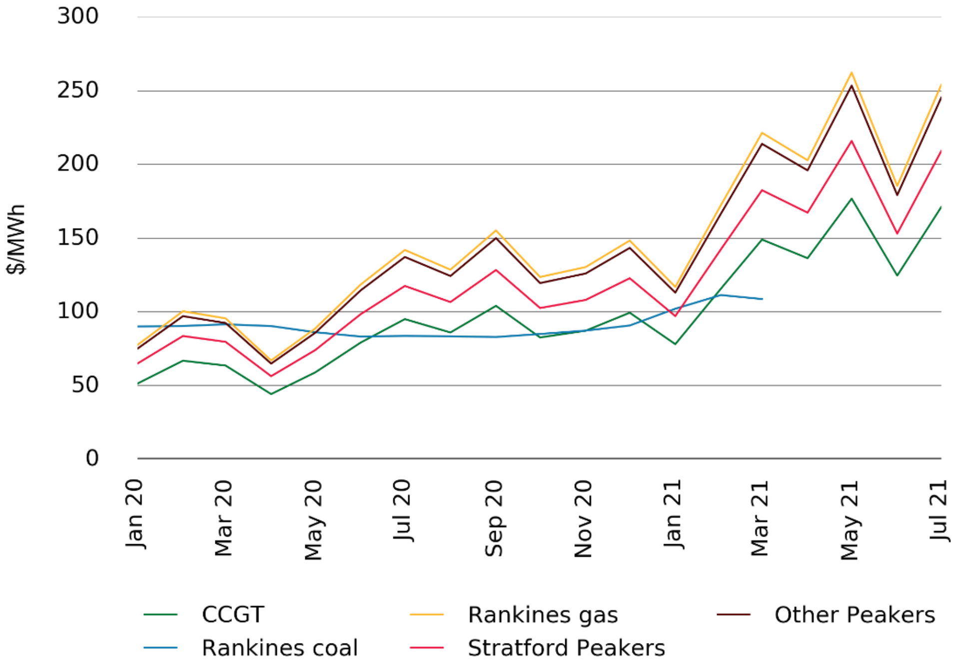
[3] For a discussion on these estimates, see our paper 'Approach to monitoring the trading conduct rule' at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-spot-market-trading-conduct-provisions/development/trading-conduct-review-decision-published/

[4] We have assumed that the gas price includes the cost of carbon. Adding the cost of carbon to the current gas prices would increase the gas SRMC by $15-20/MWh. The cost of carbon has been added to the coal price.

increased the thermal SRMC this month. Coal is purchased by contract in advance and the SRMC is based on coal prices up to March 2021. Historically coal has been more expensive than gas but is currently cheaper.

5.3 While this figure is monthly (the July value is for the month up to 10 July), gas prices do change daily which can impact the SRMC especially for peakers who buy gas off the spot market instead of by contract. This week the daily spot market gas price peaked at $34/GJ on 4 July. At this price the SRMC for gas peakers is likely between $310/MWh to $370/MWh.

Figure 11: Estimated monthly SRMC for thermal fuels



6 Offer Behaviour

Final daily offer stacks

6.1 Figure 12 shows this week's daily offer stacks, adjusted to take into account wind generation, reserves and frequency keeping.[5] The black line shows the cleared energy, indicating the range of final prices.

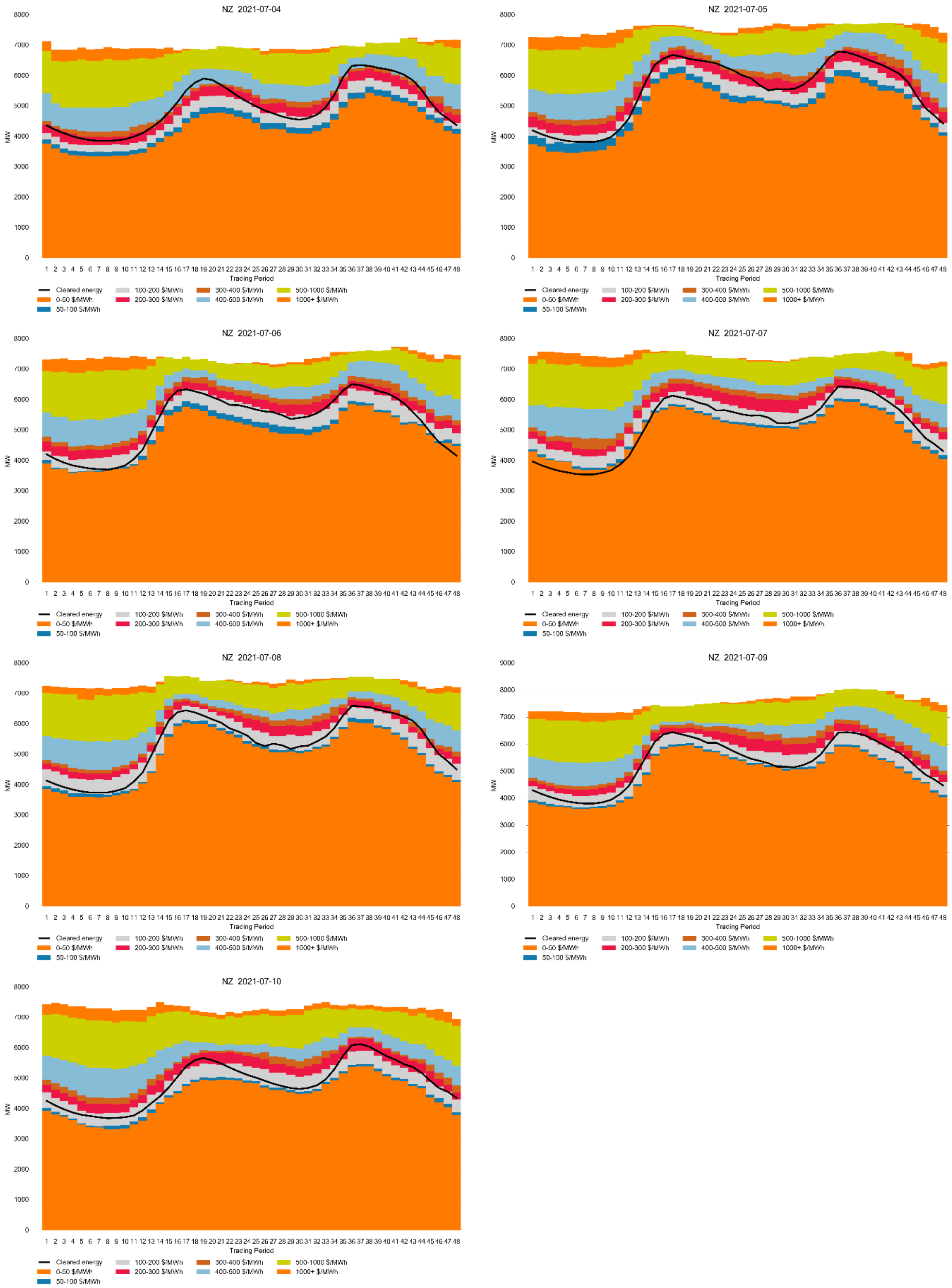
6.2 Generators appear to manage their offers to approximately follow the daily demand curve. This generally has the effect of making prices more level over the day. This could be efficient for energy constrained plants, such as hydro, seeking to apply limited fuel to the highest value periods. It could also be efficient for plants subject to non-convexities, such as thermal start-up costs and minimum unit outputs. However, if generators' demand forecasts turn out to be wrong, for example, if demand remains high later than expected on cold winter evenings or if wind suddenly dies away, this strategy can cause much higher-priced offer tranches to be cleared, resulting in much higher prices.[6]

[5] 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.

[6] Offers for each generating station or unit may contain up to 5 price tranches, with the first price tranche containing the lowest price offered, and each subsequent tranche having a higher price than the tranche preceding it.

Furthermore, these events frequently occur at times other than peak demand periods. Owing to the steepness of generators' offer curves, it may only take a small deviation in net demand to cause a significant price change. One such example occurred around 9 pm on 8 July—several hours after the evening demand peak. The Authority's monitoring team is considering whether prices during these trading periods are consistent with the new trading conduct provisions.

Figure 12: Daily offer stacks from 4 to 10 July



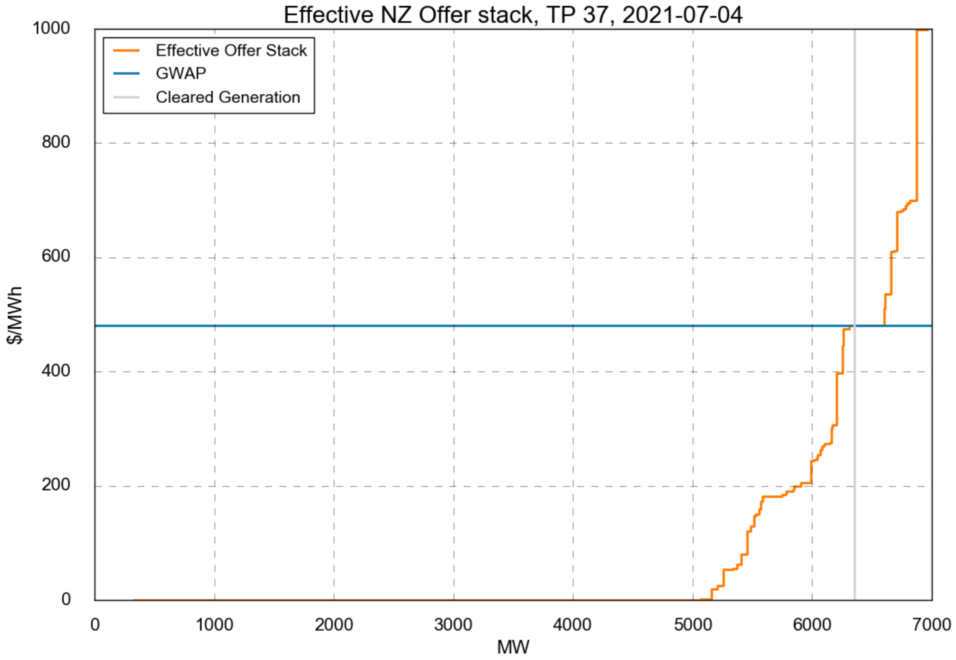
Offers by trading periods

6.3 The following section highlights a few of the trading periods that the Authority's monitoring team will be looking into further. The offer stacks are shown with the generation weighted average price (GWAP) and cleared generation.

6.4 The trading period (TP) with the highest price was TP37 (6pm) on 4 July. Wind generation was low, demand was 10% higher than the same time last week and the daily gas price was high at $34/GJ.

6.5 The offer stack (figure 12) shows that the offer curve was steep between $200 and $480/MWh (the price at Benmore).

Figure 13: Offer Stack for trading period 37 on 4 July



6.6 Another trading period with a high price was TP43 (9pm) on 8 July. Peak evening demand occurred during TP37 (6pm) with an average final price of $351/MWh. Despite lower demand, prices were more than $200/MWh higher during TP43.

6.7 Figure 14 shows TP43 and Figure 15 shows TP42, one trading period before. While demand decreased between these two trading periods it is unlikely supply conditions changed significantly between these trading periods. The shape of the offers is similar but there is less generation offered during TP43. Due to the steepness of the curve at the cleared price this has resulted in a large increase in prices.

Figure 14: Offer Stack for trading period 43 on 8 July

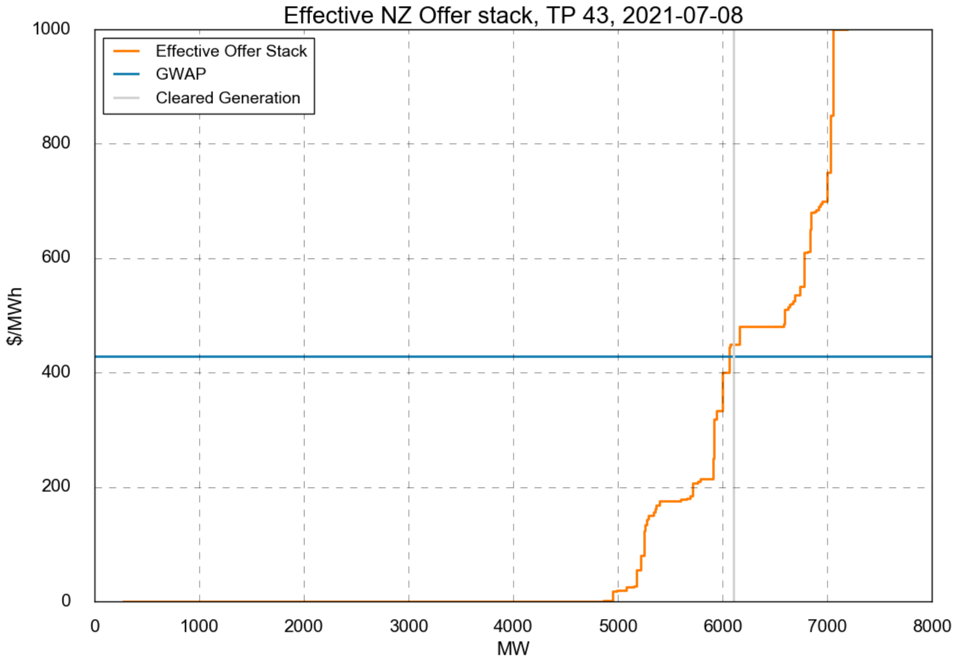
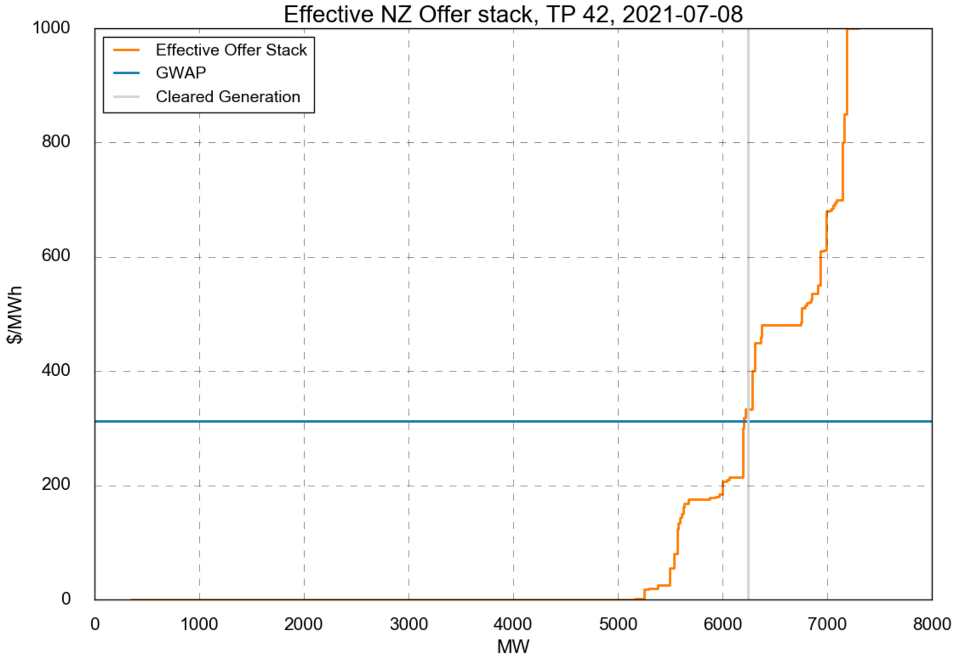


Figure 15: Offer Stack for trading period 42 on 8 July



7 Ongoing Work in Trading Conduct

7.1 We have identified the following trading periods as warranting further analysis by the market monitoring team.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
8/07/2021	43	Further Analysis	High price
8/07/2021	15-20	Further Analysis	High FIR prices
6/07/2021	18	Further Analysis	High FIR price
5/07/2021	34	Further Analysis	High price
5/07/2021	17-24	Further Analysis	High FIR/SIR prices, high prices
4/07/2021	36-43	Further Analysis	High prices, High SIR prices
4/07/2021	15-20	Further Analysis	High prices, High FIR price (19)
3/07/2021	16-20	Further Analysis	Highest prices, low wind
3/07/2021	26-30	Further Analysis	High FIR prices
3/07/2021	37	Further Analysis	Single price spike
2/07/2021	37-38	Further Analysis	High FIR and SIR price
1/07/2021	12-14	Further Analysis	Shoulder demand, low wind
1/07/2021	16-18	Further Analysis	High SIR price
30/06/2021	13-17	Further Analysis	Shoulder period to high demand period, FIR price also high
30/06/2021	42-44	Further Analysis	Shoulder period, prices higher than peak

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

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

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 $/PJ, and wind generation is MW, carbon price is the New Zealand Units traded under NZ ETS, NZ/$t.

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).

$$y_t = 109.64 - 0.35 \times\ diff(storage) + 0.79 \times diff(demand) - 7.32 \times\ wind.generation + 1.67 \times\ gas.price - 0.03 \times\ diff(generation\ HHI) +\ \eta_t$$

$$\eta_t = 0.74 \times \eta_1 - 0.05 \times \eta_2 + 0.14 \times \eta_3 + 0.02 \times \eta_4 + 0.09 \times \eta_5 + \varepsilon_t$$

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.