23 February 2022

Trading Conduct Report

Market Monitoring Weekly Report

1. Overview for the week of 13 to 19 February

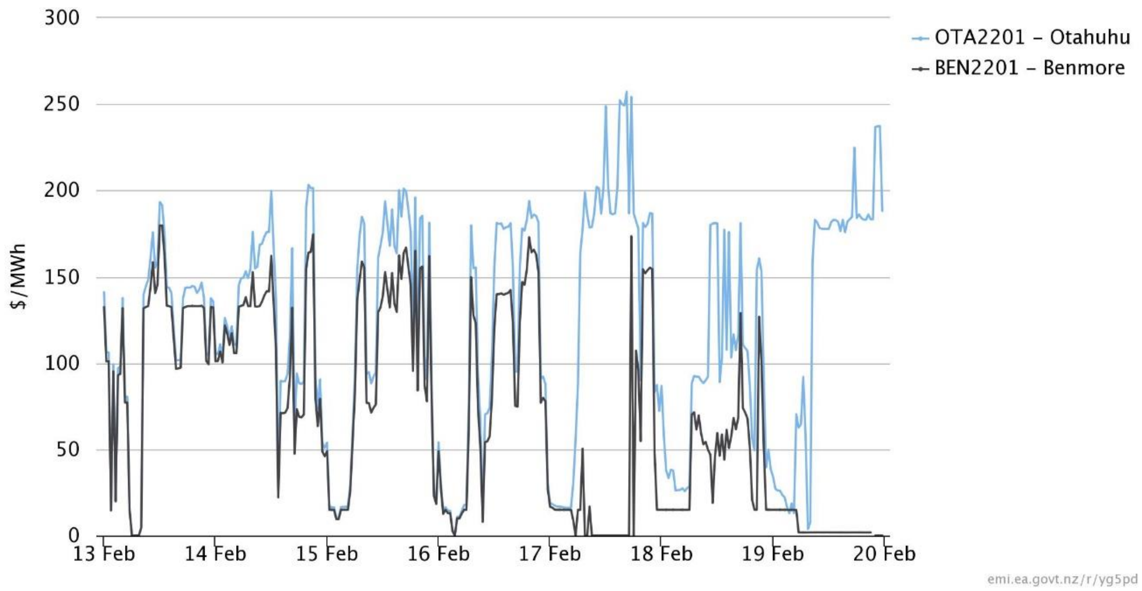
1.1. Energy prices this week were consistent with supply and demand conditions, including the impact of the HVDC outage which started on 17 February. However, some reserve prices and offer behaviour has been identified for further analysis.

2. Prices

Energy prices

2.1. The average spot price this week was $99MWh[1], 22% lower than last week. In the first half of the week prices at both Otahuhu and Benmore were usually between $100 and $200/MWh (see Figure 1), with some lower prices when demand was low and wind generation high. The HVDC outage which started on 17 February caused price separation between the North and South Island, with prices at Otahuhu reaching $254/MWh, with the highest price for TP 36 on 17 February (see Figure 2).

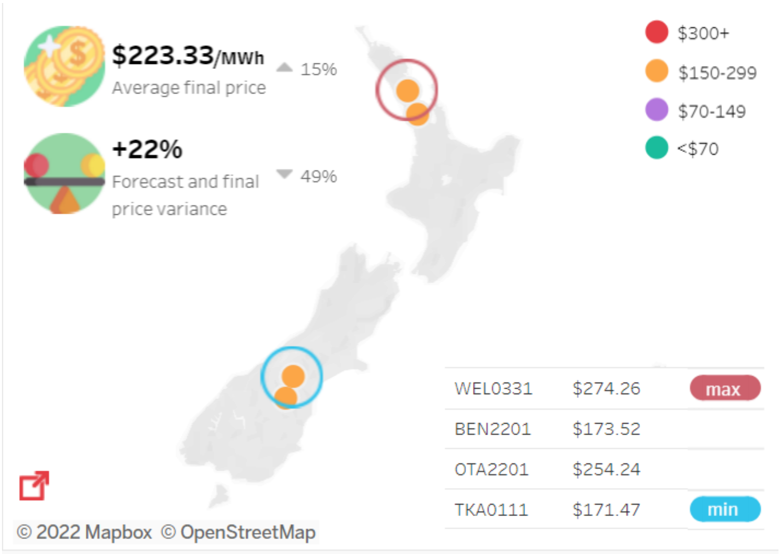
Figure 1: Spot prices by trading period at Otahuhu and Benmore



2.2. Prices were higher in the South Island during TP36, but there was still price separation between the North and South Island of about $80/MWh due to the HVDC outage.

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

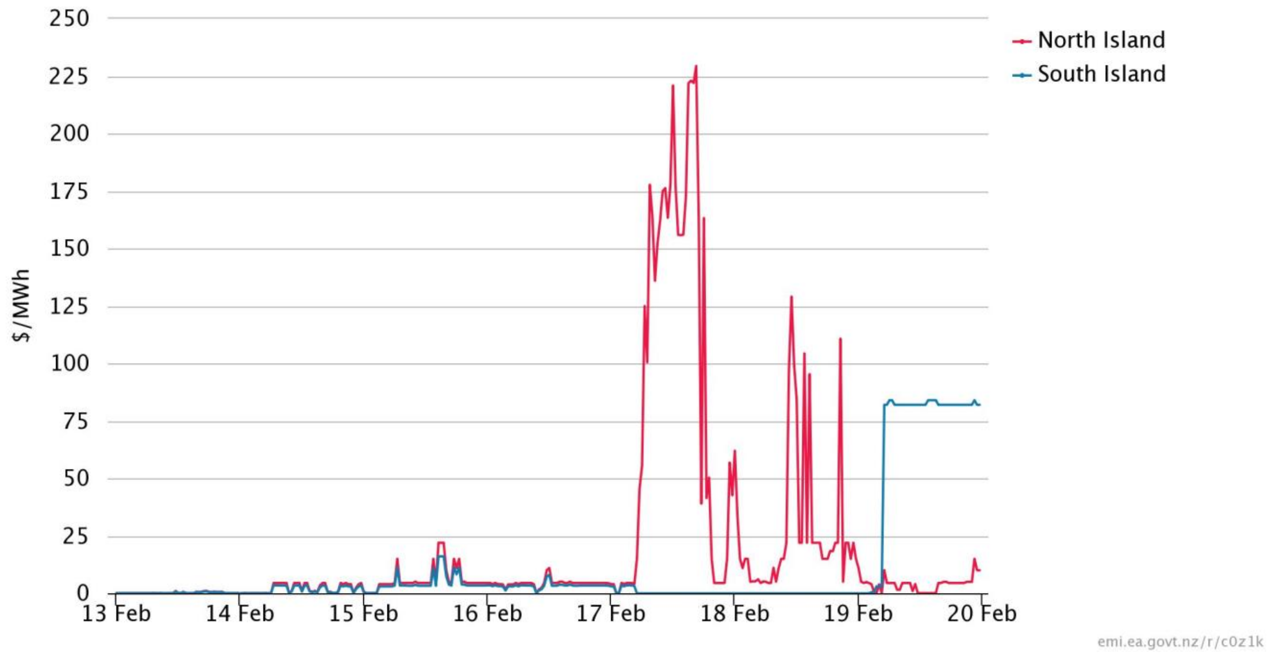
Figure 2: Spot prices for TP36 on 17 February compared to previous week



Reserve Prices

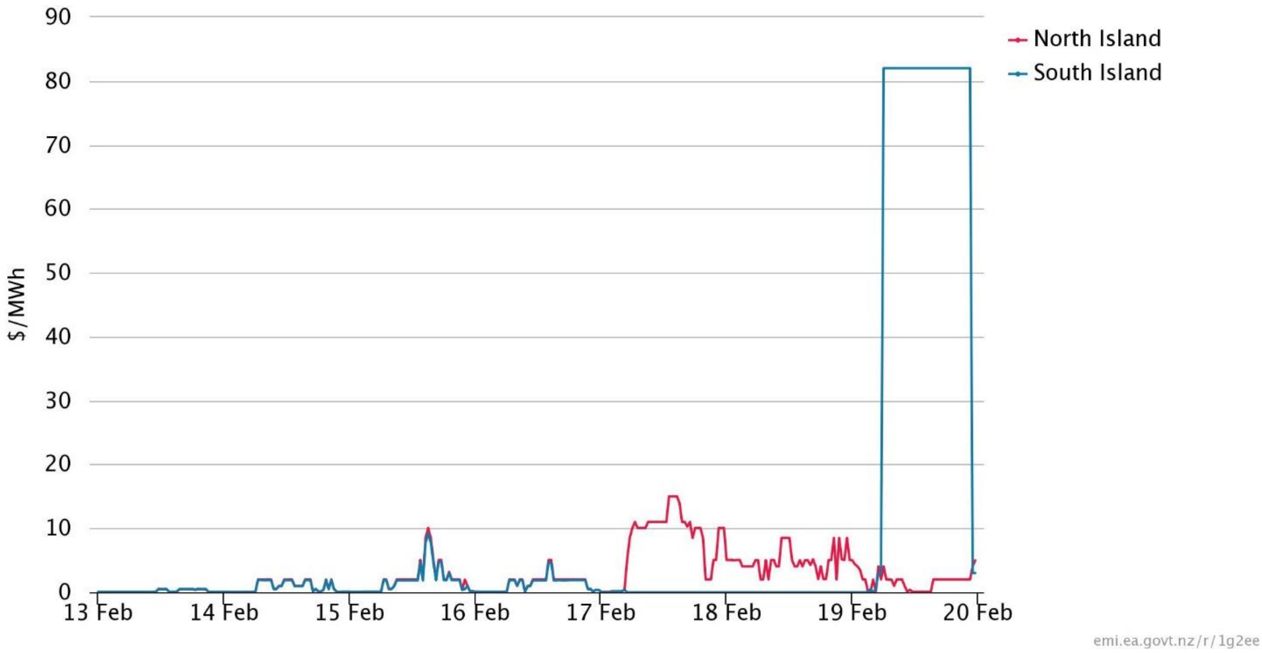
2.3. Fast instantaneous reserves (FIR) prices were usually below $25/MWh (see Figure 3). However, the HVDC outage caused price separation with higher North Island reserve prices on 17 and 18 February. The South Island FIR prices were around $80/MWh on 19 February.

Figure 3: FIR prices by trading period and Island



2.4. Sustained instantaneous reserves (SIR) prices were usually below $10/MWh (see Figure 4). The HVDC outage did cause price separation between North and South Island though North Island prices were not significantly high. South Island SIR prices were also around $80/MWh on 19 February.

Figure 4: SIR prices by trading period and Island



2.5. During the HVDC outage, North Island reserve requirement (FIR and SIR) increased by about 200MW compared to earlier in the week, due to limited reserve sharing with the South Island. This resulted in higher reserve prices especially on 17 February.

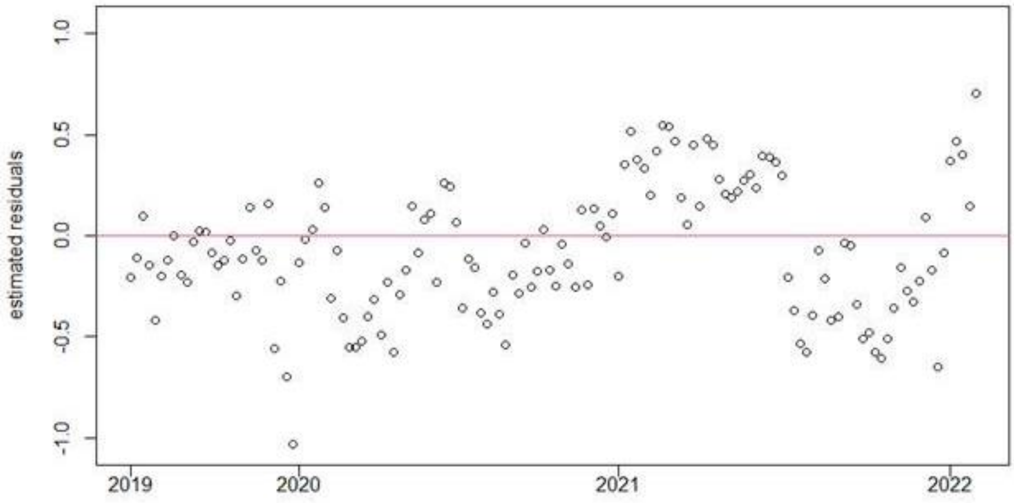
2.6. On 17 and 18 February, while only Pole 2 was on outage, South Island reserve requirement dropped as North Island reserves were available to cover a contingent event in South Island (by reducing transfer across Pole 3). This resulted in low reserve prices in the South Island. The bipole outage prevented reserve sharing so the South Island reserve requirement on 19 February was slightly higher than earlier in the week. This may be due to the high amount of hydro generation on outage. Further analysis will be done on offers to understand why South Island reserve prices were high on 19 February

Residuals from regression models

2.7. 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.

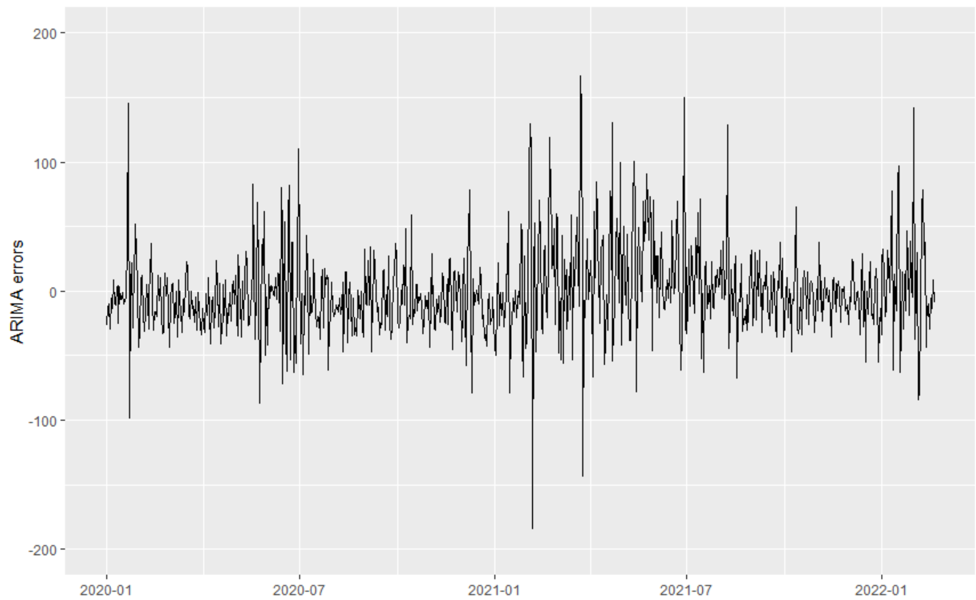
2.8. Figure 5 shows the residuals from the weekly model. During the first four weeks of January 2021 the residuals were within the normal range, indicating that weekly prices were close to the model’s predictions. However, the residual of the last week was high. This may be due to factors not captured by the model, such as Manapouri entering its low operating range. A report has been published on high January prices.

Figure 5: Residual plot of estimated weekly price from 2 July 2019 to 4 February 2022



2.9. 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.

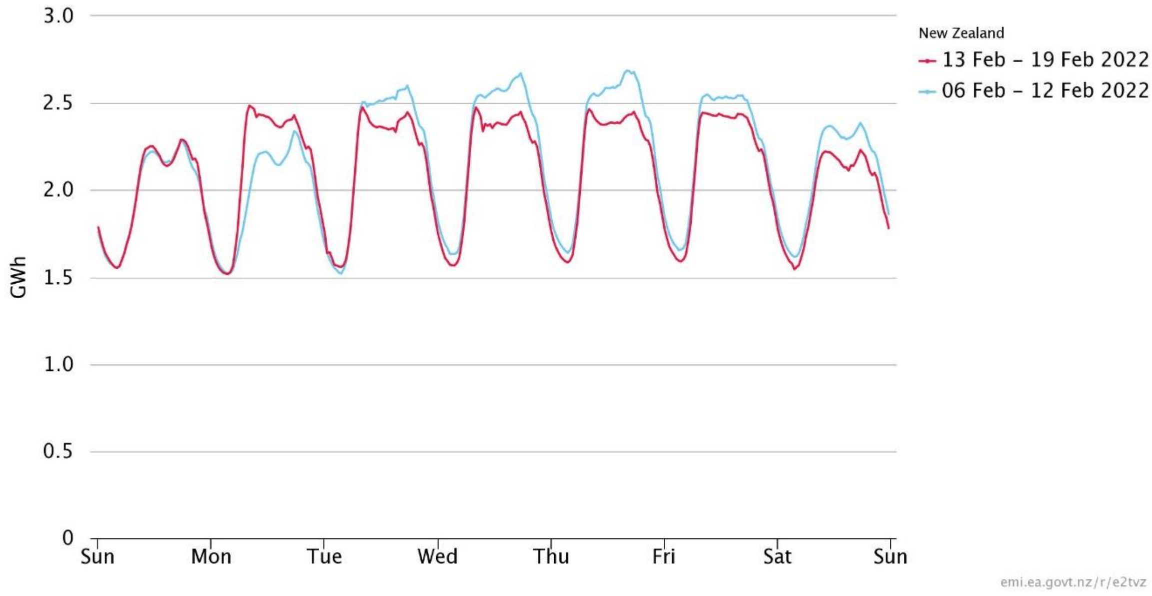
Figure 6: Residual plot of estimated daily average spot price from 1 July 2020 to 19 February 2022



3. Demand Conditions

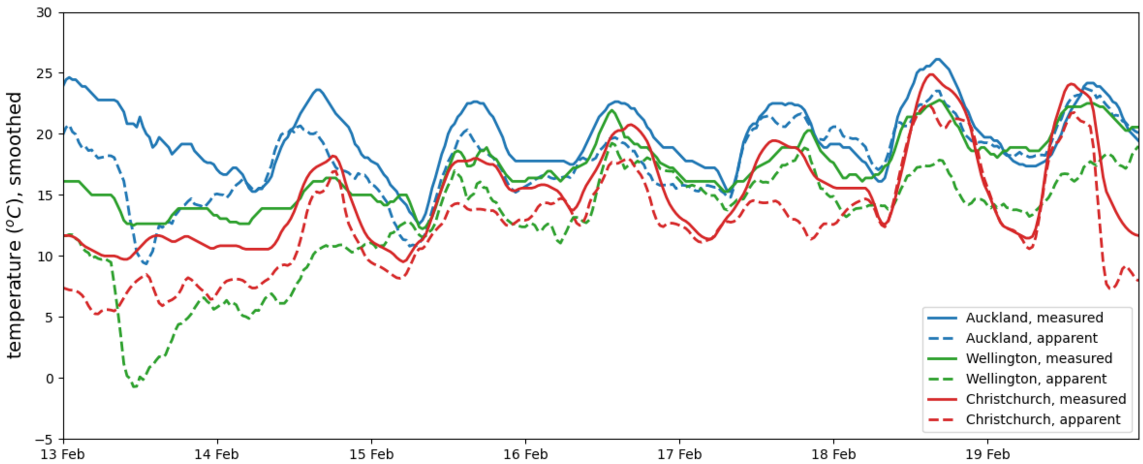
3.1. National demand was 3% lower than the previous week (see Figure 7). Demand was higher on Monday, as the previous Monday was Waitangi Day. Lower demand may be due to lower temperatures (see Figure 8).

Figure 7: National demand by trading period compared to the previous week



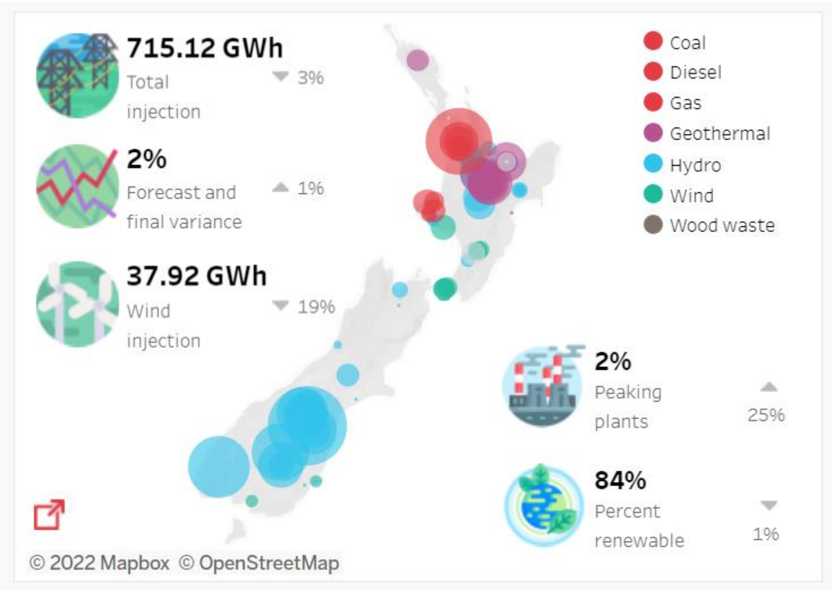
3.2. Figure 8 shows hourly temperature at main population centres. The measured temperature is the recorded temperature, while the apparent temperature adjusts for factors like wind speed and humidity to estimate how cold it feels. The week started cooler, with high wind contributing to low apparent temperatures on 13 February. While temperatures did increase later in the week apparent temperatures stayed below 25°C at all centres.

Figure 8: Hourly temperature data (actual and apparent) and humidity data at main population centres



4. Supply Conditions

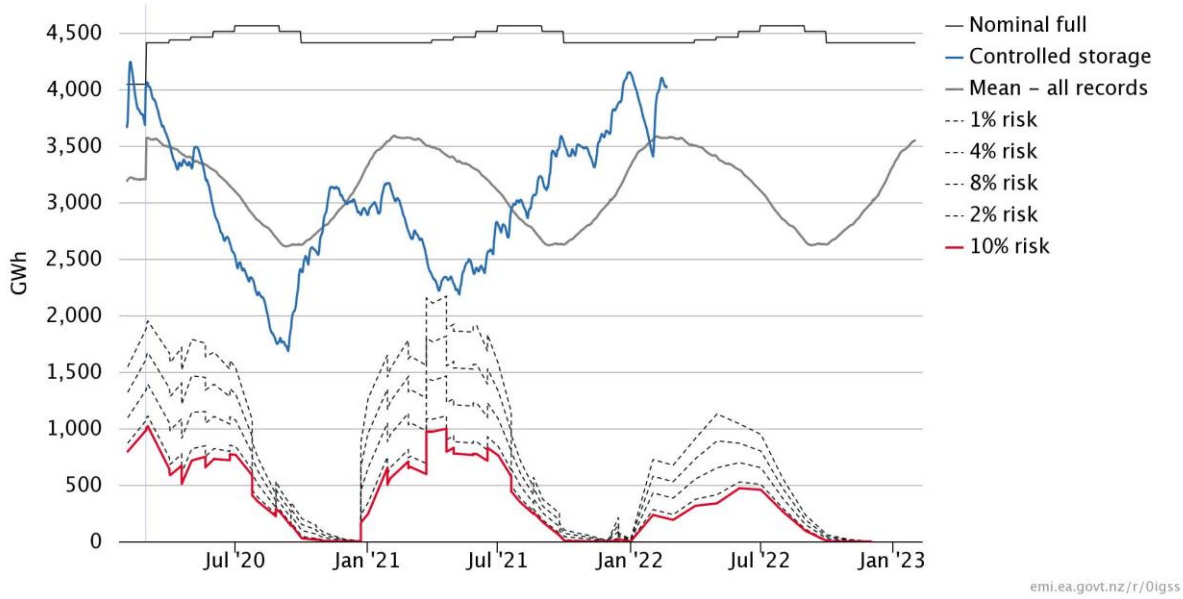
Figure 9: Generation in the last week compared to previous week



Hydro conditions

4.1. National hydro storage reached a high of 4,100 GWh on 13 February, and has since decreased to 4,029GWh on 19 February, shown in Figure 10. Inflows were above average in the North Island for most of the week.

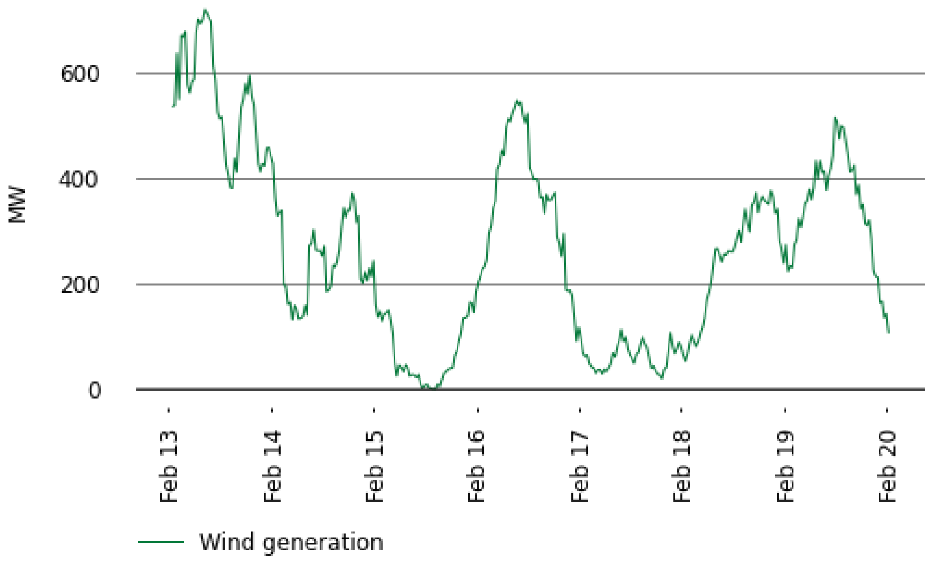
Figure 10: Electricity risk curves and hydro supply



Wind conditions

4.2. Total wind generation was 38GWh, down 19% from last week. Wind generation was variable throughout the week, with wind generation above 600MW on 13 February, and under 100MW on 15 and 17 February. Low wind generation on 17 February likely contributed to higher North Island energy and reserve prices, along with the HVDC outage.

Figure 11: Wind generation by trading period



Significant outages

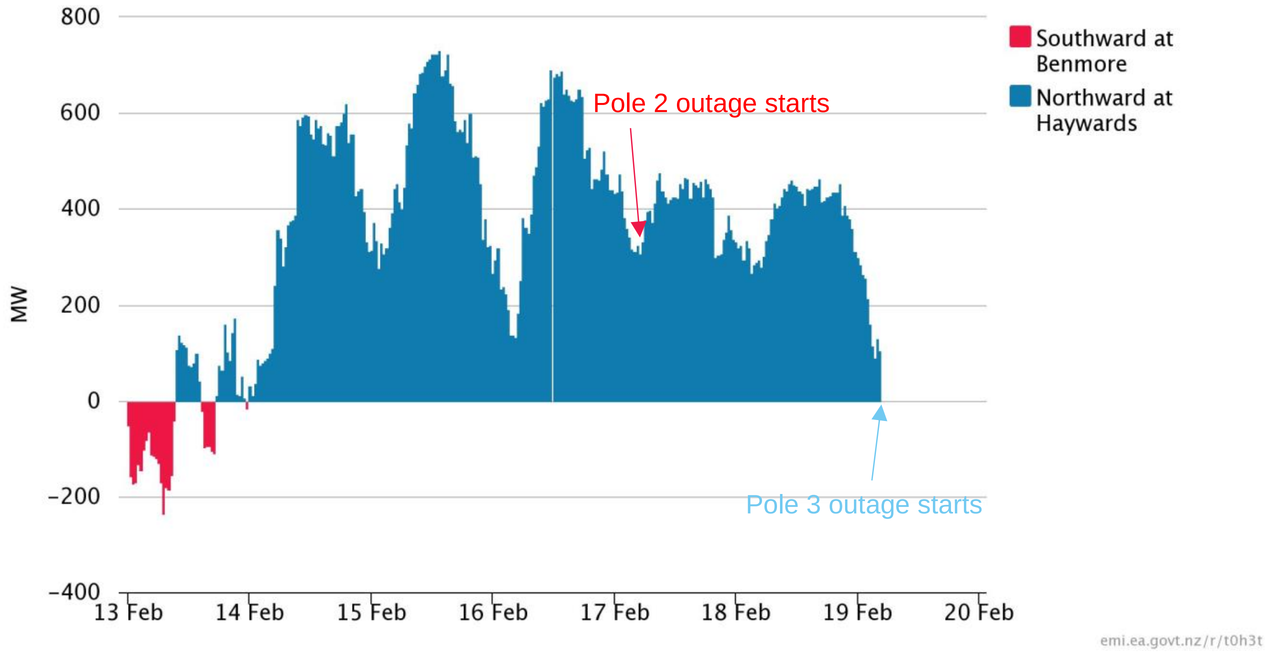
HVDC outage

4.3. There was a planned outage of the HVDC this week, which started on 17 February. Pole 2 was on outage from 17 February at 5am, expected back on 20 February[2] at 10pm, while pole 3 was on outage from 19 February at 5am, expected back on 22 February at 10pm.

4.4. Figure 12 shows that the HVDC transfer on 13 February was usually southward, due to low demand, high wind generation and high inflows in North Island. From 14 to 16 February HVDC transfer was between 500 and 700 MW northward during the day. On 17 and 18 February, with pole 2 on outage this dropped to 500MW, causing price separation between North and South Islands. On 19 February both poles were on outage (bipole outage) resulting in no transfer. During the bipole outage each island was a separate market. Excess supply caused low energy prices in the South Island while tight supply caused higher prices in the North Island.

[2] This outage was extended and instead pole 2 returned to service after 6:30pm on 21 February. This will be covered in more detail in next week's Trading Conduct Report.

Figure 12: HVDC transfer and HVDC outage

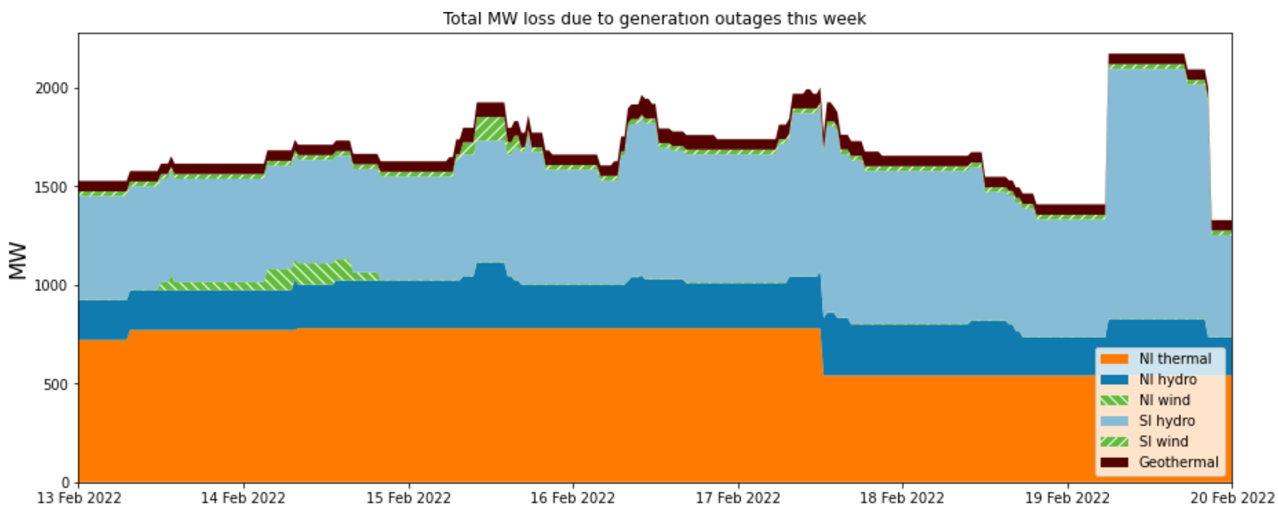


4.5. Overall, the HVDC outage has resulted in an increase in thermal and hydro generation in the North Island and a decrease in hydro generation in the South Island.

Generation outages

4.6. Over 1500MW of generation was on outage this week and reached over 2000MW on 19 February (see Figure 13). The amount of North Island thermal on outage dropped at midday on 17 February when Huntly unit 4 came back from outage. However, this did not make a big change to total MW on outage there was an increase in South Island hydro on outage, including 125MW at Manapouri. All the Ohau units were also on outage on 19 February likely to coincide with the full bipole outage.

Figure 13: Total MW loss due to generation outages



4.7. These are the more significant ongoing outages[3]: Note the ongoing outage at Clyde was extended to continue until 1 July.

(a) Clyde, 116MW (15 Feb 2021 – 1 July 2022)

(b) Berwick, 80MW (8 November 2021– 16 March 2022)

(c) Stratford peaker, 100MW, (31 October 2021 - 30 April 2022)

[3] Detailed outage information is available from https://pocp.redspider.co.nz/

(d) Manapouri, 125MW (23 January - 23 February)

(e) Tekapo, 80MW (17 January -19 February)

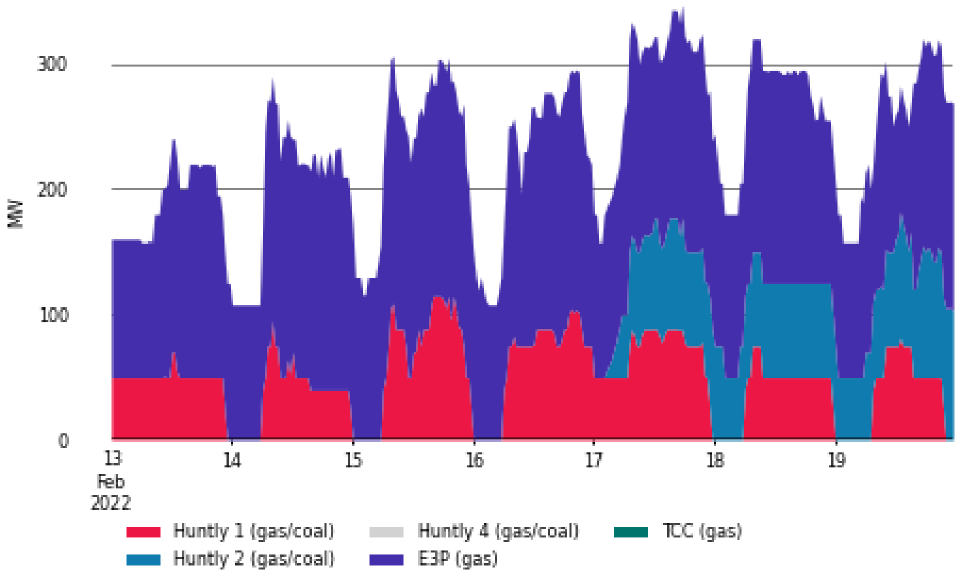
(f) TCC, 350MW, (22 January - 28 February)

(g) Huntly, Rankine 4, 240MW (5-17 February)

Thermal conditions

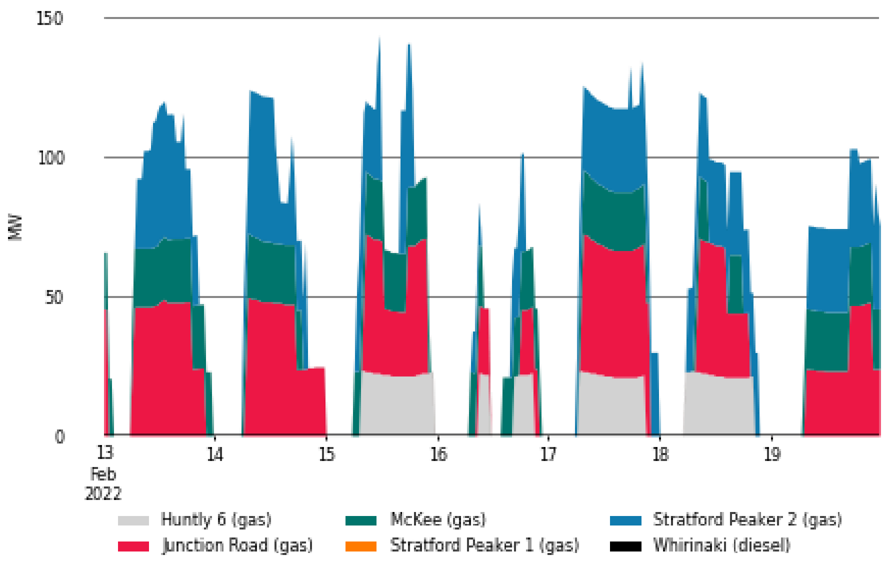
4.8. This week the E3P ran as baseload throughout this week, with lower output on 6 and 7 February when prices were down. One Rankine was running early in the week, but two units have been running since the HVDC outage started. The last Rankine unit has returned from outage but has not run due to high river temperatures.

Figure 14: Generation from baseload thermal by trading period



4.9. Generation from thermal peakers was high this week. High wind did reduce thermal generation on 16 February, while all available peakers besides Whirinaki ran most of the day on 17 February after HVDC outage begam.

Figure 15: Generation from thermal peakers by trading period



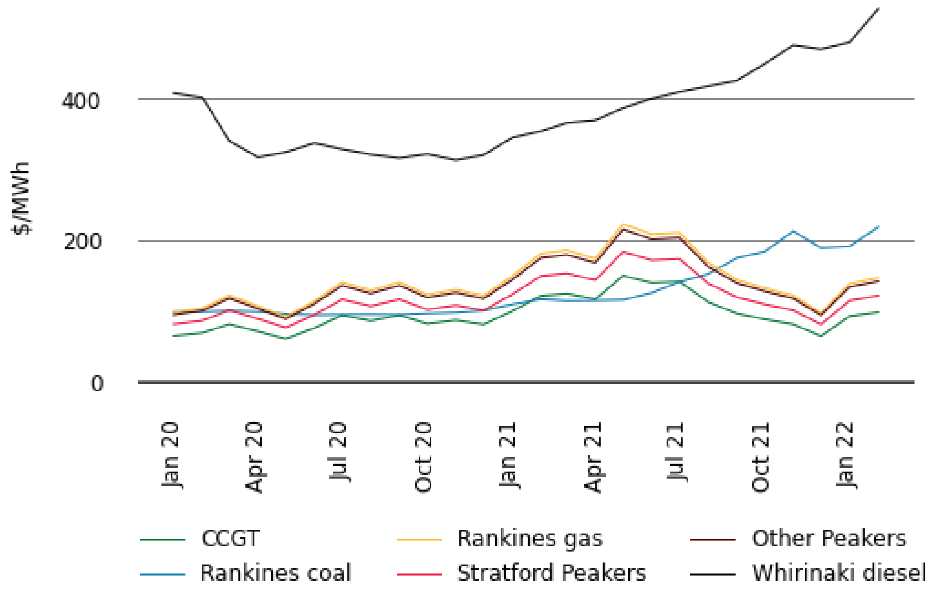
5. Price versus estimated costs

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).

Thermal Fuels

5.2. The SRMC (excluding opportunity cost of storage) for thermal fuels can be estimated using gas and coal prices, and the average heat rates for each thermal unit. Figure 16 shows an estimate of thermal SRMCs as a monthly average. The thermal SRMC of gas increased in January and February (to 20 February), likely due to the increase in gas consumption. The SRMC of coal and diesel both increased due to global supply and demand conditions and remain high. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal. The carbon price has continued to increase this year, recently reaching $85/tonne.

Figure 16: Estimated monthly SRMC for thermal fuels



JADE Water values

5.3. The JADE[4] model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 17 shows the national water values[5] to 20 February 2022 using values obtained from JADE. The outputs from JADE closest to actual storage levels are shown as the yellow water value range. These values are used to estimate marginal water value at the actual storage level, indicated by the blue line[6].

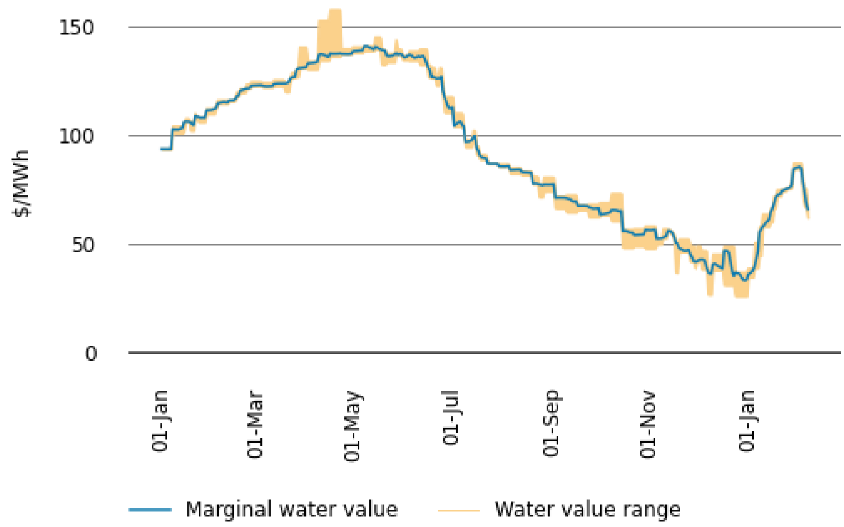
5.4. Figure 17 shows that the marginal water value declined from June to December as hydro storage levels increased and gas costs decreased. In January, the water values increased as hydro storage decreased and gas costs increased. While the increase in hydro storage did cause a decline in the water value it was still higher than the water values at the end of last year, likely due to being closer to winter when water values are usually highest.

[4] JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market. (More details in Appendix B)

[5] The national water values are estimated assuming all hydro storage reservoirs are equally full.

[6] See Appendix B, 3 for more details

Figure 17: JADE water values for January 2021 to February 2022



Monthly prices

5.5. Figure 18 shows the average price each month at Otahuhu and Benmore for 2021. It shows that prices have declined since June, similar to the trend for gas costs and water values. The high prices over winter were closer to the SRMC of thermal but as thermal generation decreased average prices have been closer to the marginal water value. Prices increased in January, as hydro storage declined, and thermal generation increased.

Figure 18: Average monthly prices at Otahuhu and Benmore last 12 months

6. Offer Behaviour

Daily Offer Stacks

6.1. Figure 19 shows this week's daily offer stacks, adjusted to take into account wind generation, transmission constraints, reserves and frequency keeping.[7] The black line shows the cleared energy, indicating the range of the average final price. Note that the black line does not indicate actual prices observed from 17 to 19 February due to the HVDC outage which caused price separation between the North and South Island.

6.2. This week demand was lower, which saw a decrease in generation offered at low prices. However, overall prices cleared at a lower price on average, with increased hydro storage in most reservoirs in both the North and South Island. Offers between $100-$200/MWh were particularly high on 13 February, with quantity in this tranche being dropped to lower prices later in the week.

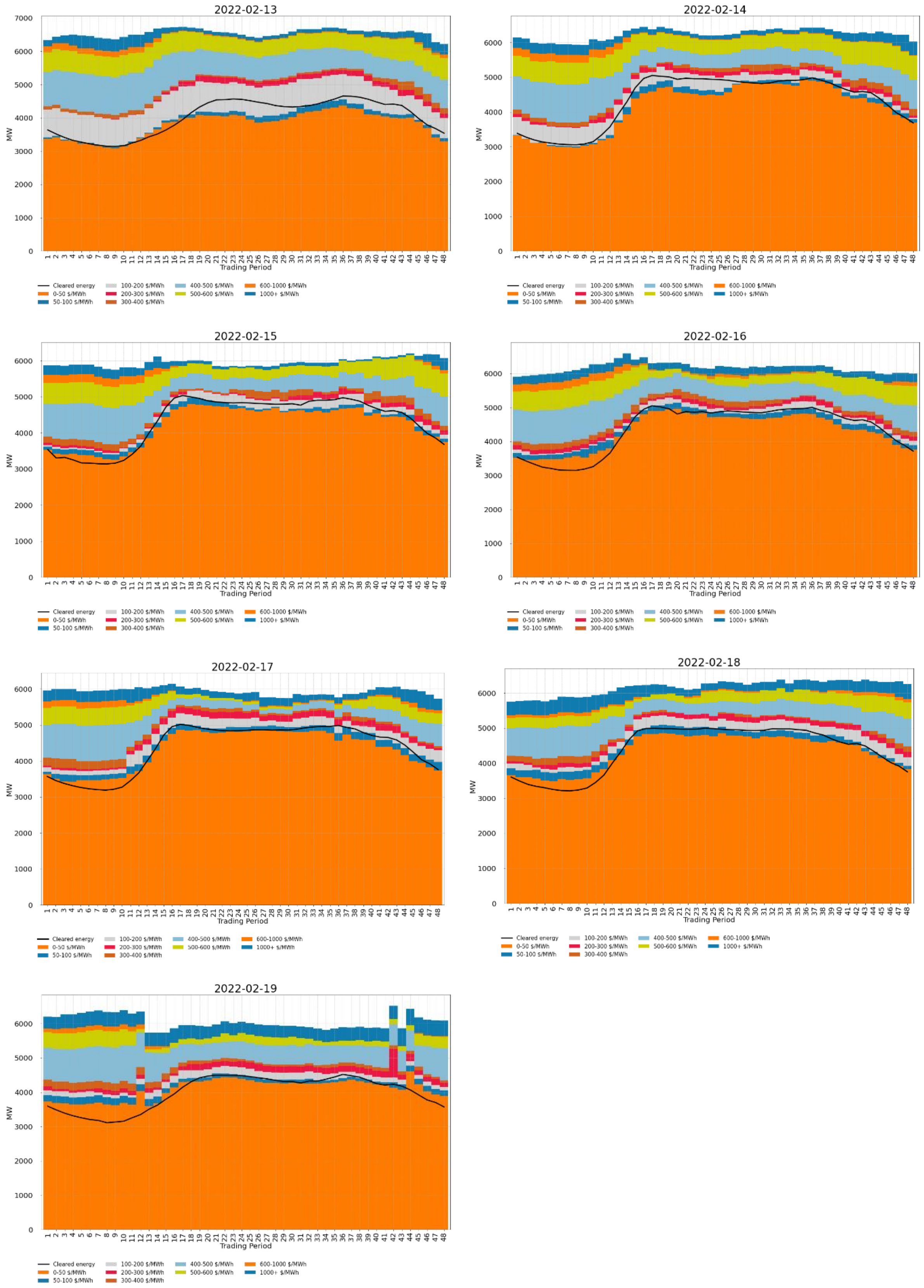
6.3. The Ohau outage impacted generation offers on 19 February. However, due to the HVDC outage this did not impact the North Island and energy prices remained low in South Island. Meridian changed offers at other stations in anticipation of the loss (and return) of Ohau, which is noticeable in trading periods at beginning and end of the outage.

6.4. There was a sudden decrease in generation offered during TP36 on 17 February, once wind generation and constraints are taken into account, however, this decrease is not observable in the raw offers. The indicates that the high prices at TP36 (particularly in South Island) were not due to any change in offers but that something else in the system constrained generation. At the time demand was at its peak and wind generation had dropped from the previous trading period.

6.5. Tekapo B unit 3 was returned from outage on 19 February at 5pm but was offered at prices above $1500/MWh despite high storage at Lake Tekapo. Prices in the South Island were only $0.03/MWh at the time, so this did not impact market outcomes. However, we have enquired with Genesis about why this unit was offered at such a high price.

[7] 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 19: Daily offer stack



Offers by trading period

6.6. The offer stacks of the trading periods (TP) with the highest prices are TP36 on 17 February is shown on Figure 20 along with the generation weighted average price (GWAP) and cleared generation. A similar trading period from an earlier week is shown in Figure 21. Note that the GWAP does not reflect observed prices as there was price separation due to the HVDC outage.

6.7. Cleared generation was lower on 17 February compared to the previous week, due to lower demand. However, the offer curve was steeper. This was due to an increase in South Island hydro on outage during the HVDC outage as well as low wind generation. The GWAP was similar on these two days, though actual prices were higher in the North Island on 17 February due to the HVDC outage.

Figure 20: Offer Stack for trading period 36 on 17 February

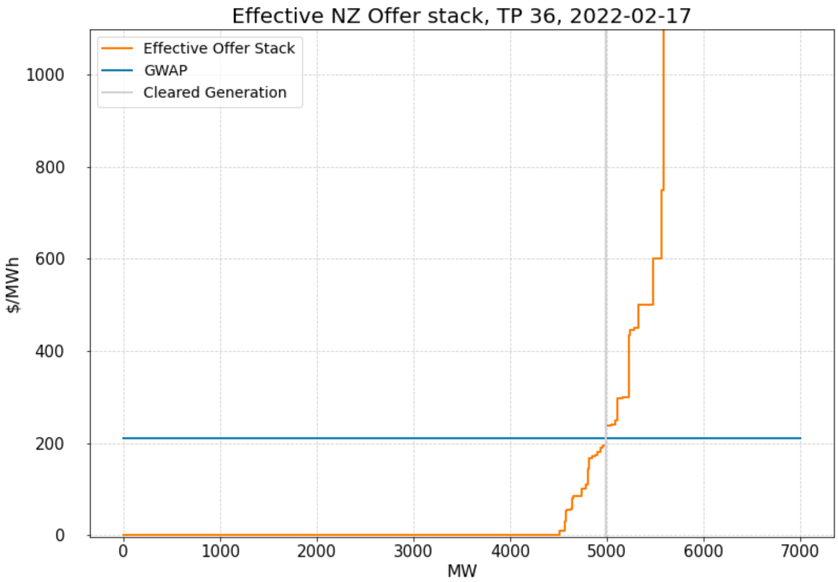
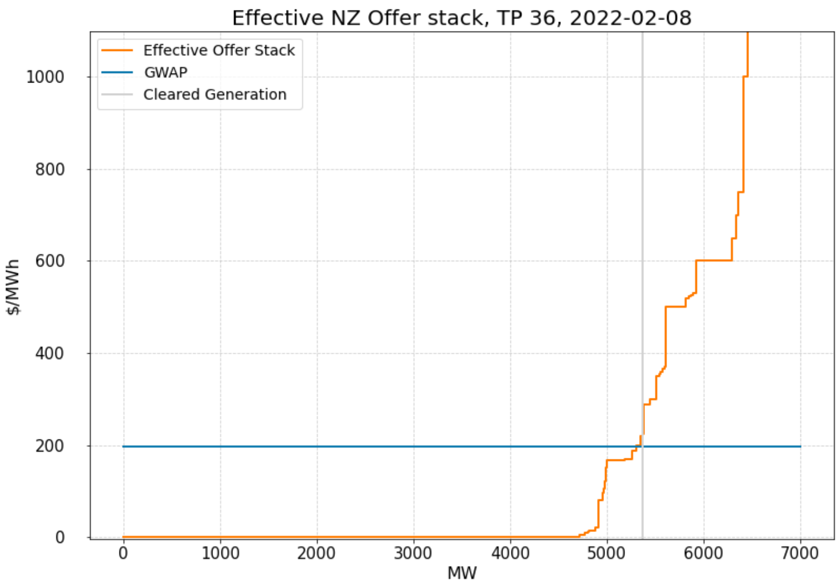


Figure 21: Offer Stack for trading period 36 on 8 February



Ongoing Work in Trading Conduct

6.8. Further analysis will be done of reserve prices in the South Island on 19 February.

6.9. The Authority has reached out to Genesis regarding offers from Tekapo B while Lake Tekapo was spilling.

6.10. The Authority's market monitoring team has received additional information regarding offers on 5 February. This was regarding offers and generation at Ohau A while Lake Ohau was spilling. Meridian has explained that the canal from Lake Ohau was at its maximum capacity (around 100MW worth of generation), and that increasing generation at Ohau A would have required additional flows from Lake Pukaki.

6.11. The Authority's compliance team has obtained information regarding withdrawn reserve offers and high energy prices. Further clarification and analysis is under way to consider compliance with the Code.

Table 1: Trading periods identified for further analysis

Date	TP	Status	Notes
19/02	35-48	Further Analysis	High priced offers at Tekapo-further information requested
19/02	13-47	Further Analysis	High South Island reserve prices
08/02-12/02	Several	Further Analysis	High inflows but continued high prices
08/02, 10/02	16-17, 19	Further Analysis	High FIR prices
05/02	Several	Resolved	Checking offers in Waitaki scheme after high inflows- additional information received
03/02	32	Further Analysis	High FIR price
19/01-20/01	Several	Further Analysis	High FIR prices
30/06-20/08	Several	Compliance enquiries in progress	High energy prices in shoulder periods
30/06-21/08	Several	Compliance enquiries in progress	Withdrawn reserve offers

Appendix A Regression Analysis

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

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

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,…,52 for each year; i = spring, summer, autumn, and winter

Daily Model

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.

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 $storage_t - storage_{t-1}$.

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.

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[8], where diff is the first difference:

$$y_t = \beta_0 - \beta_1(storage_t - 20.year.mean.storage_{dayofyear}) + \beta_2 diff(demand_t) - \beta_3\, wind.generation_t + \beta_4\, gas.price_t - \beta_5 diff(generation\ HHI_t) + \beta_6 dummy + \eta_t$$

$$\eta_t = \varphi_1\eta_1 - \varphi_2\eta_2 + \varphi_3\eta_3 + \varphi_4\eta_4 + \varphi_5\eta_5 + \varepsilon_t$$

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.

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

Appendix B JADE water value model

1. JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto.[9] JADE is identical to DOASA in terms of model inputs and outputs but is written using the Julia modelling language JuMP.

2. DOASA was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.[10] A version of DOASA has been used by EPOC for analysis of the New Zealand electricity market for many years, and SDDP is a well-known and widely accepted modelling tool for hydro-thermal optimisation in electricity systems. DOASA gives a consistent measure of the opportunity cost of water. The DOASA model seeks a policy of electricity generation that meets demand and minimises the expected fuel cost of thermal generation and value of lost load.

3. The JADE model outputs the marginal water value for a range of storage levels. The marginal water value, $y,$ at the actual storage level, $x,$ is estimated using the outputs closest to actual storage level (x_1, y_1) and (x_2, y_2) using the equation

$$y = y_1 + (\frac{x - x_1}{x_2 - x_1})(y_2 - y_1)$$

4. The following are some of the limitations of the assumptions in the JADE model:

   a. Load is based on forecasts for future periods and recent periods where reconciled data was not yet available.

   b. Forecast plant and HVDC outages based on current POCP data

   c. The estimated thermal fuel costs used in JADE may not accurately represent what hydro generators face, in terms of thermal generator offers. Hydro generators must manage their storage levels within the context of volatile thermal fuel prices and availability, and the thermal fuel cost estimates may not perfectly represent these.

   d. Non-dispatchable plant, such as wind, is modelled as having constant power output instead of stochastic power output

   e. Some hydro station head ponds and major reservoirs are governed by complex resource consent rules. The model limits used in JADE are necessarily somewhat simplified and may not accurately reflect the actual flexibility of these limits.

   f. Inflow probability distributions are based on past inflow sequences.

   g. JADE does not directly model stagewise dependence (i.e., from week to week) of inflows, e.g., if it was wet last week, it's more likely to be wetter this week as well. However, JADE approximates this effect by an approach called Dependent Inflow Adjustment (DIA), which artificially increases the variance of historical inflows when generating the cutting planes.[10]

5. We use the average water value over all of New Zealand from JADE rather than the water values for individual reservoirs because the individual reservoir water values are very volatile. This is due to the following.

   a. JADE does a forward solve (linear programming), so as long as the objective values are the same, it is likely to use all water from one reservoir first until it hits some constraint, before moving to the next reservoir. This leads to the likely extreme usage of small reservoirs (i.e., not using water proportional to total national storage by either holding back or letting it all go).

   b. Therefore, small (constrained) reservoirs in JADE are expectedly more likely to hit maximum or minimum levels or constraints, and this will be reflected in the water

[9] M V Pereira and L M Pinto, "Multi-stage stochastic optimization applied to energy planning," Mathematical Programming 52, (1991): 359–375.
[10] Electricity Authority, "Doasa overview," https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa.

values (high price if likely to hit minimum level and low price if likely to hit maximum level).

c. National water values are calculated based on absolute total national storage, not absolute individual reservoir storage, which tends to make the water values less volatile. That is, if we had two reservoirs with the same capacity and one had storage at 10 percent of capacity and the other at 90 percent, the national water value is based on total storage of 50 percent of total capacity