

Market Performance Quarterly Review Q2 2020

Information paper



Contents

1	Purpose of the report	4
2	Highlights over the last quarter	4
3	Demand	5
4	Retail market	8
	Switching	8
	Retail cost	9
5	Wholesale market	10
	Spot market commentary	10
	Low North Island inflows	11
	Generation	12
	Renewable generation	13
	Forward markets	14
6	Ancillary services	15
7	Special topic 1: Grid Events-November 2019	17
	Introduction	17
	20 November 2019 – a lightning strike caused no loss of supply at grid or distribution network level but shed 143 MW of consumer load	17
	27 November 2019 – bird streaming across an insulator triggered a region-wide unplanned outage while operating at N-security	19
8	Special Topic 2: Regression analysis of spot price drivers	21
	Data	21
	Results	22
	The effect of competition	23
	Interpretation	23
	Checking assumptions and diagnostic plots	24
	Testing for autocorrelated residuals	24
	Conclusions	25

Figures

Figure 1: Monthly demand in 2020 compared to mean demand 2010-2019	5
Figure 2: Difference in cumulative demand from the mean 2005-2020	5
Figure 3: Impact of alert level 4 on demand profile of work days ¹	6
Figure 4: Estimated Industrial load, excluding Tiwai	7
Figure 5: Trader and move-in switches 2015-2020	8
Figure 6: Per cent of switches which returned to their initial retailer within 90 days	9
Figure 7: Domestic Electricity Prices by component (QSDEP)	10
Figure 8: Average spot price and hydro storage	11
Figure 9: North Island inflows 2020	11
Figure 10: Lake Taupo Hydro storage	12
Figure 11: Generation by fuel source Jan-June 2015-2020	13
Figure 12: Renewable generation as a per cent of total 2019-2020	13
Figure 13: Forward Quarterly ASX prices at Otahuhu and Benmore	14
Figure 14: Monthly trading volumes for ASX baseload contracts	15
Figure 15: Monthly ancillary services costs	16
Figure 16: Available interruptible load and price of FIR and SIR	16

Figure 17: Approximate shape and duration of the voltage dip on each phase, as measured at Islington 220 kV bus	18
Figure 18: Northland grid, key locations	19
Figure 19: Diagnostic plots	24
Figure 20: Autocorrelation plot for residuals	25

1 Purpose of the report

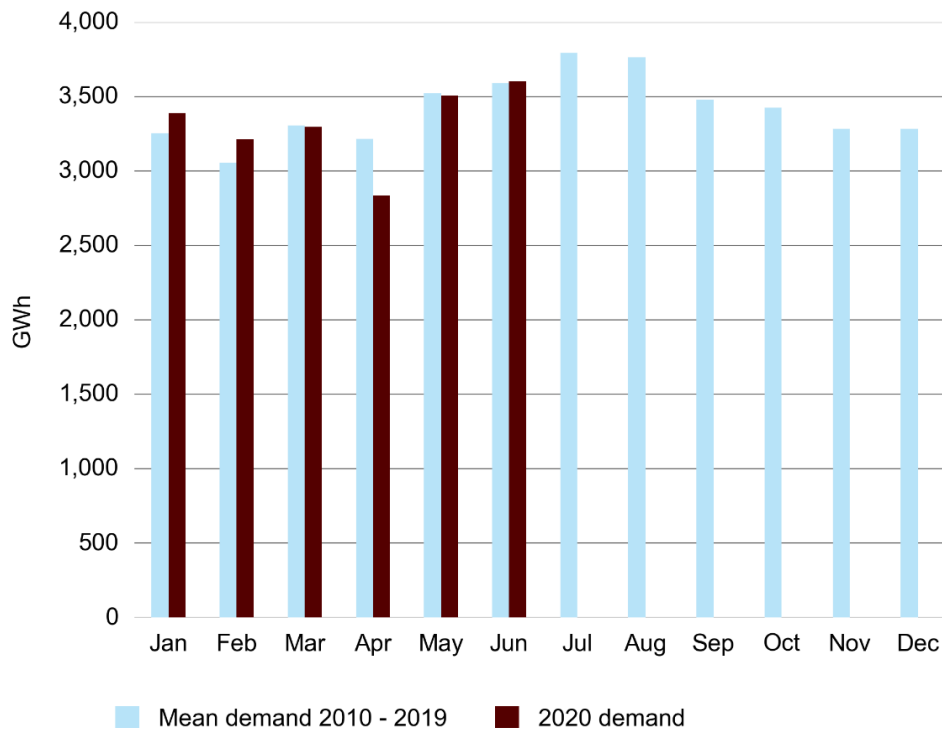
- 1.1 This document covers a broad range of topics in the electricity market. It is published quarterly to provide visibility of the regular monitoring undertaken by the Electricity Authority (Authority).
- 1.2 Quarter 2 of 2020 has been marked by the impact of Covid-19. While alert level 4 started at the end of quarter 1, most of the impact has been seen in this second quarter. This quarterly review will look at the impact seen on the electricity market at each alert level, as well as the current state of the market at alert level 1.
- 1.3 Many of these graphs are marked with the alert levels. The dates which follow are inclusive, with official changes of alert levels occurring at midnight
 - (a) Alert level 4, 26th March – 27th April
 - (b) Alert level 3, 28th April – 13th May
 - (c) Alert level 2, 14th May – 8th June
 - (d) Alert level 1, 9th June - current

2 Highlights over the last quarter

- 2.1 **Demand decreased especially during alert level 4.** Prior to the lockdown demand was close to 2019. Alert level 4 had a large impact on industrial demand and changed the daily profile of demand as most people stayed at home. As restrictions eased demand increased and is now back to the long-term average.
- 2.2 **Switching was down due to restrictions during alert levels.** There was a large drop in move-in switches during April. Trader switches were also lower than normal in both April and May.
- 2.3 **Low hydro inflows, especially in the North Island, are driving high prices.** The North Island has had the second lowest inflow sequence for the first six months of the year, since records began in 1926. Total hydro storage is well below the mean for this time of year. This has driven high prices since early May.
- 2.4 **Forward prices have dropped in response to the recent announcement that Tiwai smelter will close.** Forward prices for the rest of 2020 increased as restrictions lifted and demand increased, but all other forward prices have dropped, especially for Benmore from Q4 2021 onwards.

3 Demand

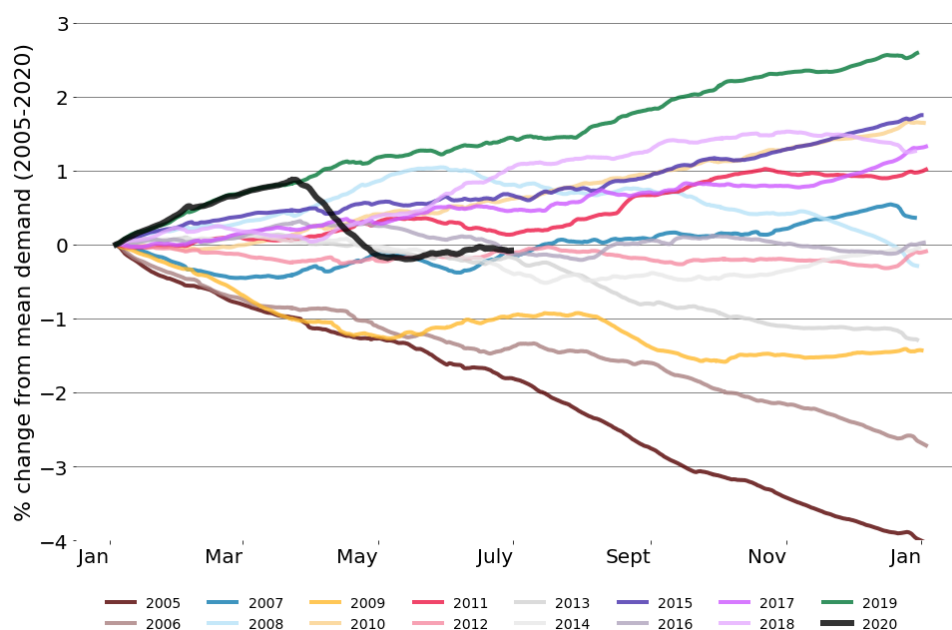
Figure 1: Monthly demand in 2020 compared to mean demand 2010-2019



Source: Electricity Authority

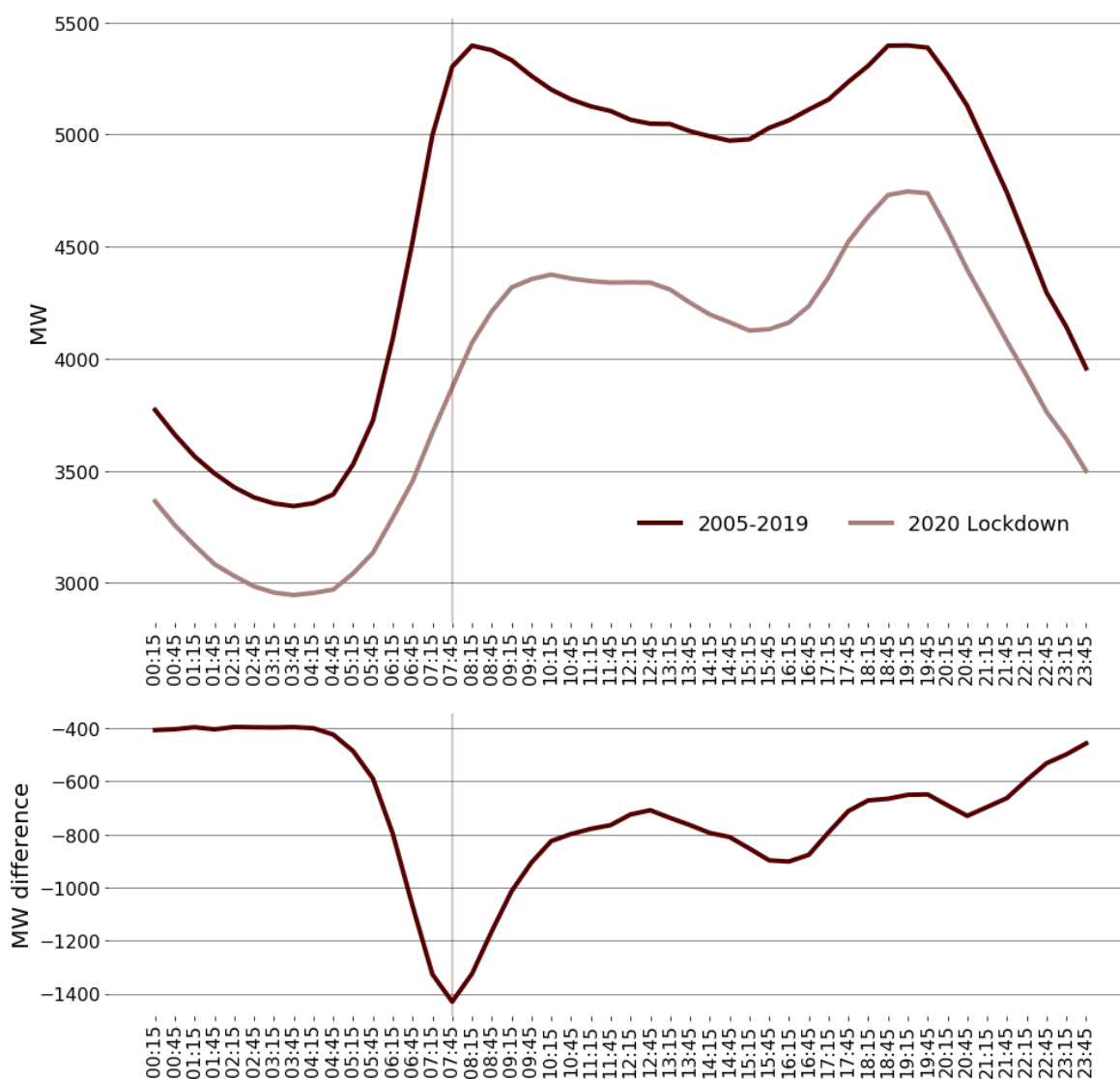
- 3.1 Reconciled demand (including Tiwai) was about 1 per cent higher than average (since 2010) in January and February (Figure 1). March started with the same trend, but the announcement of alert level 4 caused a dramatic drop in demand. The majority of April was spent at alert level 4, which is reflected in demand being 10 per cent lower than the average. May was split between alert level 3 and alert level 2, with schools reopening for all children on 18 May. NZ transitioned to alert level 1 early in June and there was not much noticeable difference to level 2, with demand just above the long-term average.

Figure 2: Difference in cumulative demand from the mean 2005-2020



- 3.2 Figure 2 shows the cumulative difference in demand compared to the mean since 2005. Until the change in alert levels at the end of March, demand for 2020 was tracking slightly higher than 2019. When alert level 4 started daily demand was much lower than the mean and cumulative demand dropped to below the long-term average at the start of May. Daily demand then returned to being closer to the long term mean and cumulative demand was at a similar level as 2012 or 2013 at the end of June.

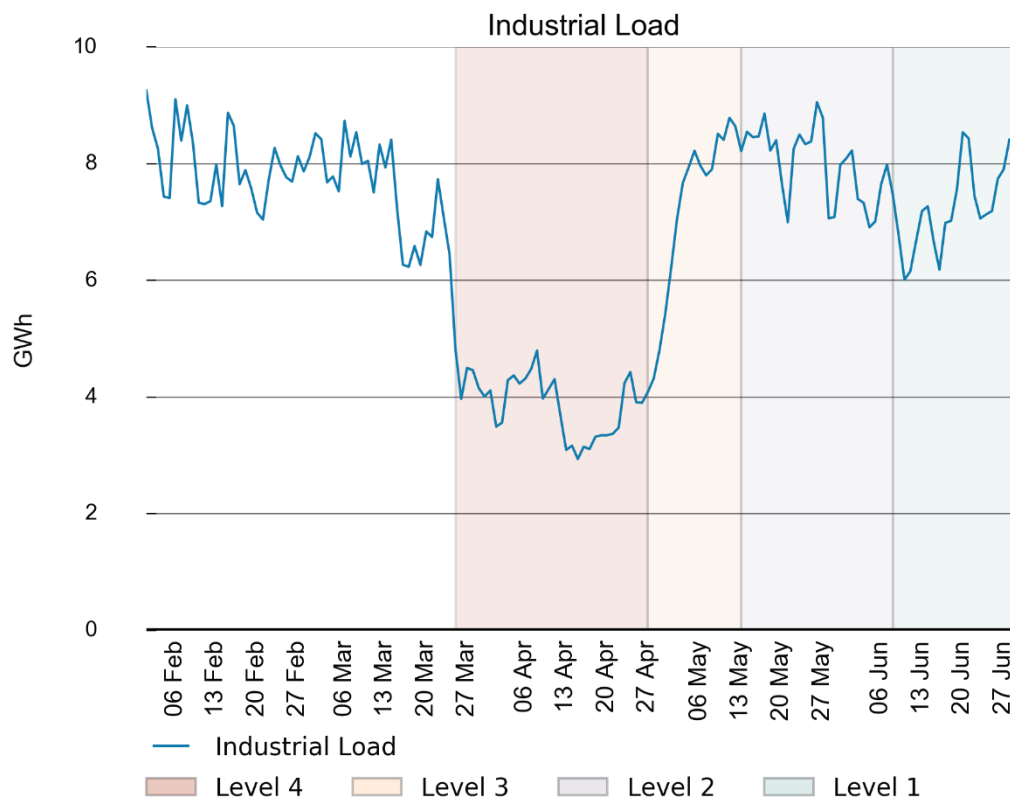
Figure 3: Impact of alert level 4 on demand profile of work days¹



- 3.1 Figure 3 shows the demand profile during alert level 4 on workdays compared to similar workdays in previous years¹. This shows that demand was between 400 to 1,400 MW lower than normal. The biggest difference was between 7.00am and 8:30am, the normal weekday morning peak. This was due to most people changing their routine as schools and non-essential workplaces were closed and many people were working from home. Morning peaks were flatter, and demand sometimes even peaked at midday, when people would be having lunch. The morning peak remained flattened until the 18th May, which was the day schools fully reopened to all students.

¹ This analysis is based on average demand profiles of Tuesdays to Thursdays, avoiding public holidays at this time of year, such as Easter.

Figure 4: Estimated Industrial load, excluding Tiwai



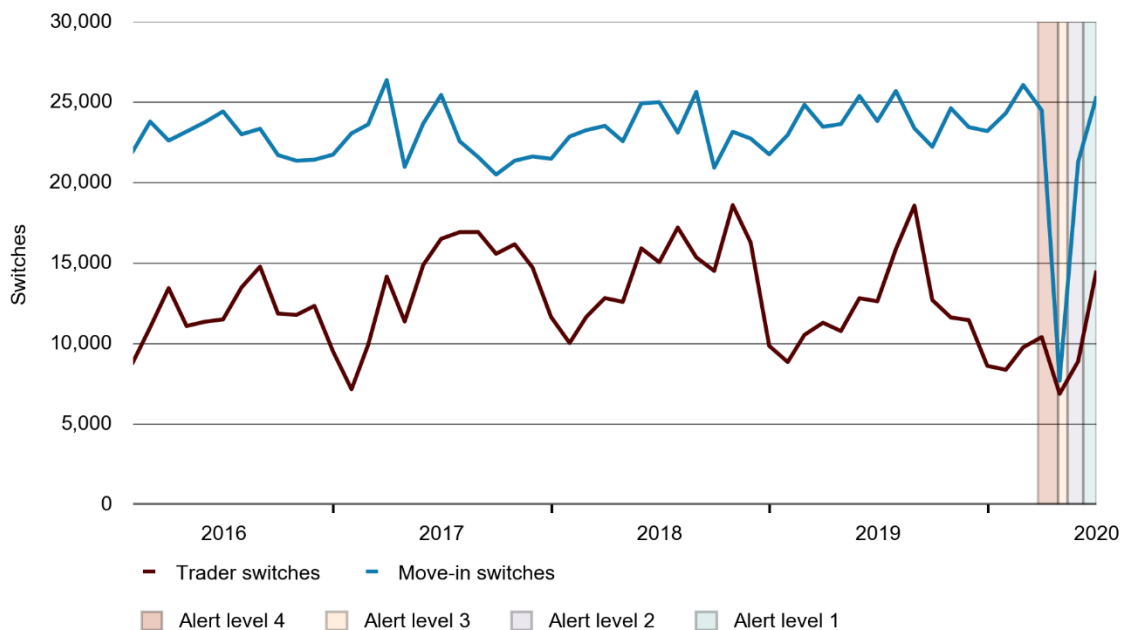
- 3.2 Figure 4 shows the daily demand of several GXP's which supply large industrial loads, excluding Tiwai. During alert level 4 almost all non-essential business shut down. Industrial load roughly halved between the level 4 announcement and the second day at level 4, as large industries shut down non-essential processes.
- 3.3 Industrial load began to increase again during level 3. It took about a week for production to ramp back up to normal levels seen before the lockdown. Industrial load dropped during the move to alert level 1 possibly due to high spot prices.
- 3.4 While Tiwai was given an exemption from the shutdown, it did close potline 4 in early April. Rio Tinto stated that this was to ensure the health and safety of its staff and to meet government directives. Potline 4 was not restarted as restrictions were lifted, and now that Rio Tinto has announced that Tiwai will be closing in August 2021, we assume it will remain shut down.
- 3.5 The restart of potline 4 in late 2018 was one of the main contributing factors to recent demand growth, so we can expect demand for the rest of 2020 to remain close to the long-term average. Other factors affecting demand are uncertain, but the global economic downturn due to the pandemic is likely to dampen economic growth—an important driver of electricity demand. Tiwai currently makes up around 13 per cent of demand and its closure will have a significant impact on demand growth.

4 Retail market

Switching

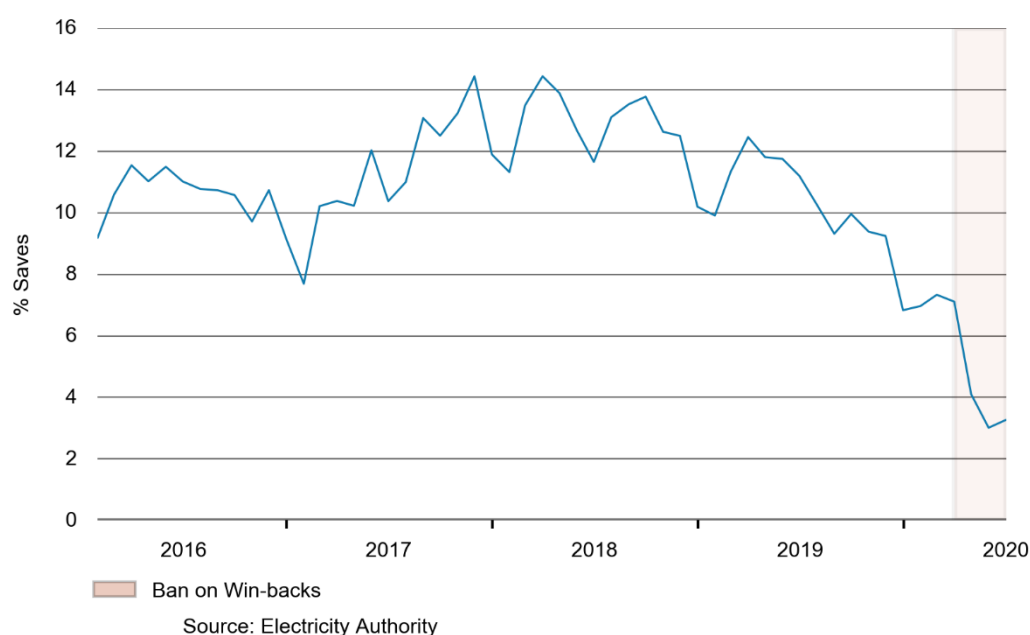
- 4.1 In the last quarter, the number of switches is down to 84,000 compared to over 100,000 switches in previous quarters. This was mostly due to restrictions on moving between properties during the alert level 4 with only 7,726 move-in switches recorded in April, as shown in Figure 5. Trader switches were also down in April and May, both with almost 4,000 fewer switches than the same months in 2019. The restrictions in place during the alert levels would have restricted some customer acquisition activity, such as door to door sales. In June, with almost all restrictions lifted, switching numbers had returned to normal.

Figure 5: Trader and move-in switches 2015-2020



- 4.2 In the last quarter, four of the large five retailers lost ICPs, with only Meridian growing by 4,525 ICPs. This was mostly through its brand Powershop which gained 3,448 ICPs. Mercury had the largest loss at 6,674 ICPs, Genesis lost 4,435 ICPs, Trustpower lost 2,478 ICPs and Contact lost 2,461 ICPs. Altogether these five retailers retain 85.3 per cent of the market.
- 4.3 Small and medium sized retailers continued to grow this last quarter with Nova Energy growing by 3,563 ICPs, Electric Kiwi by 3,674 ICPs, Vocus by 2,338 ICPs and Flick by 896 ICPs.

Figure 6: Per cent of switches which returned to their initial retailer within 90 days



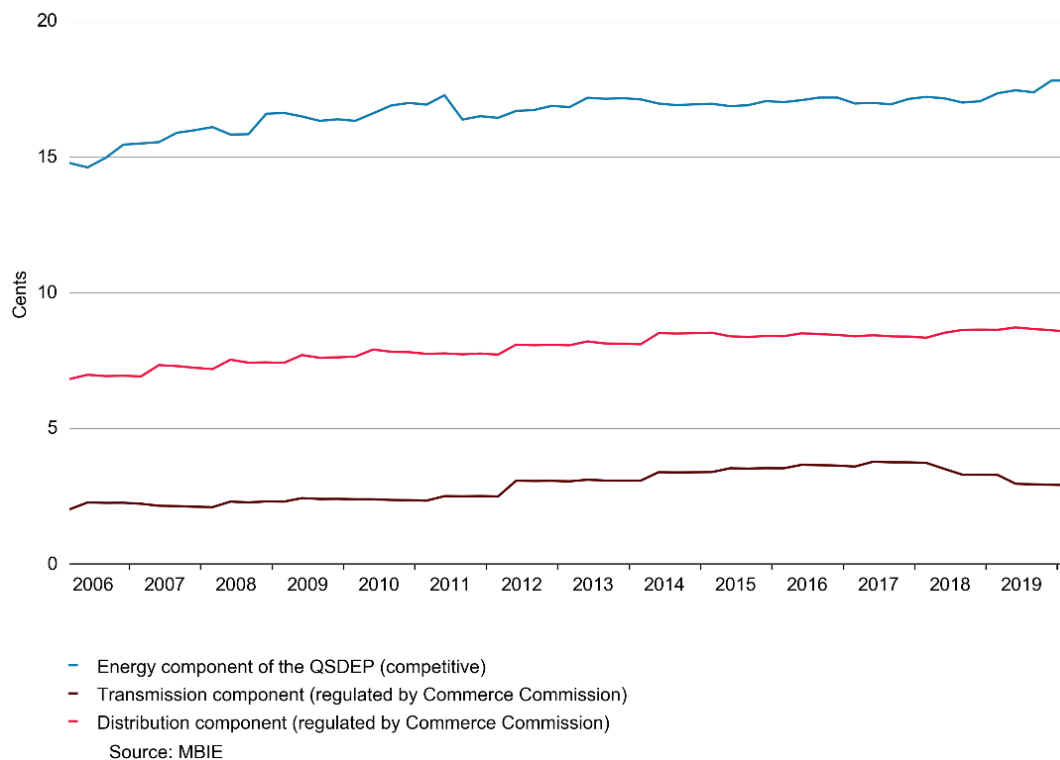
- 4.4 “Per cent Saves” in Figure 6 refers to the percentage of switching customers who returned to their initial retailer within 90 days of switching. These are potentially “win-backs” where the losing retailer contacts the consumer with a better deal to encourage them to stay. However, some of these customers will have switched back to their original retailer of their own accord.
- 4.5 In 2017 and 2018 between 10 and 14 per cent of switches returned to their initial retailer. In 2019 the Authority banned win-backs within a 180-day period of a switch, effective from 31 March 2020. During 2019 the per cent of switches saved was already declining, down to 7 per cent just before the ban. Since the ban on win-backs this has dropped down to about 3 per cent of switches.²

Retail cost

- 4.6 Figure 7 compares changes in the components that make up MBIE’s QSDEP- an indicator of residential retail prices, adjusted for inflation. The chart shows how the energy component of the QSDEP in real terms levelled off from May 2011. However, in 2019 and 2020 the energy component has increased. This is consistent with the increase in the average spot price. In contrast, the transmission component decreased in 2018 and 2019 after several years of increase.

² See [Win-back indicator monitoring trends](#) for more information on the impact of the win-back ban on switches

Figure 7: Domestic Electricity Prices by component (QSDEP)

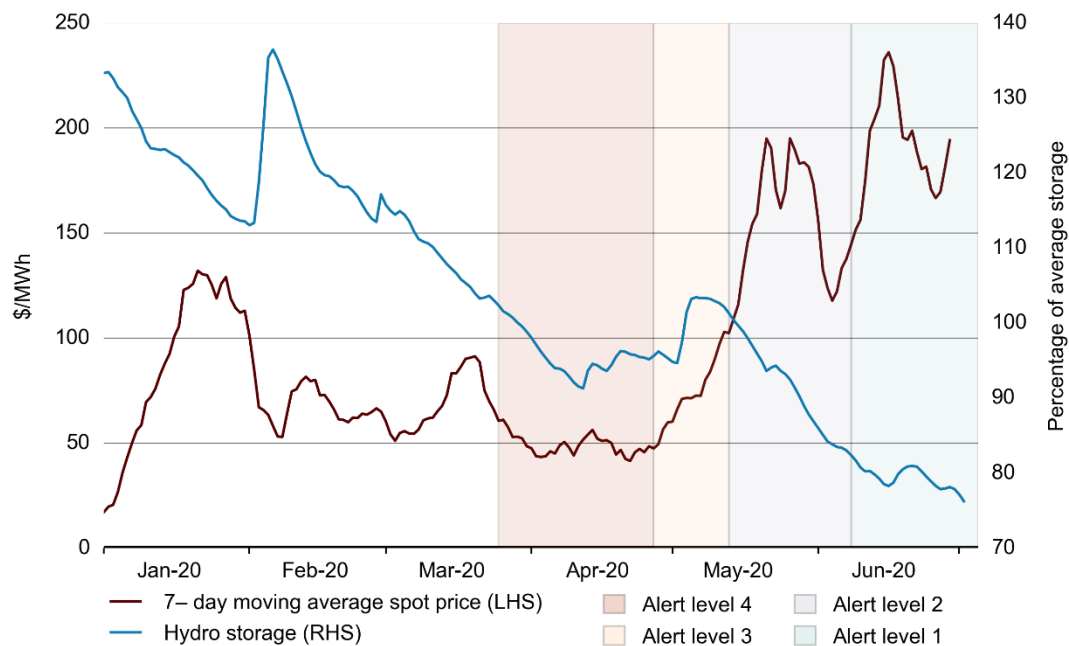


5 Wholesale market

Spot market commentary

- 5.1 The first half of the year has seen the spot market respond to a major outage, the pandemic and its associated demand fluctuations, and historically low North Island inflows.
- 5.2 The second quarter of 2020 started with low prices as the restrictions of alert level 4 reduced demand. Restrictions eased as temperatures started to get colder, and the net effect was increasing demand. At the same time the supply side of the market was getting tight. The HVDC outage and the restrictions during alert levels 3 and 4 saw outages for maintenance scheduled later than usual. Hydro storage also decreased, especially in Lake Taupo. The combined impact meant a sudden increase in spot prices.
- 5.3 On the 2 June, the TCC started running for the first time since February. This saw average prices drop to below \$150/MWh. However, hydro storage continued to drop below the mean and colder weather continued to increase demand, driving prices back up. June has overall been characterised by volatile prices due to a tight market.

Figure 8: Average spot price and hydro storage



Sources: Electricity Authority and NZX Hydro

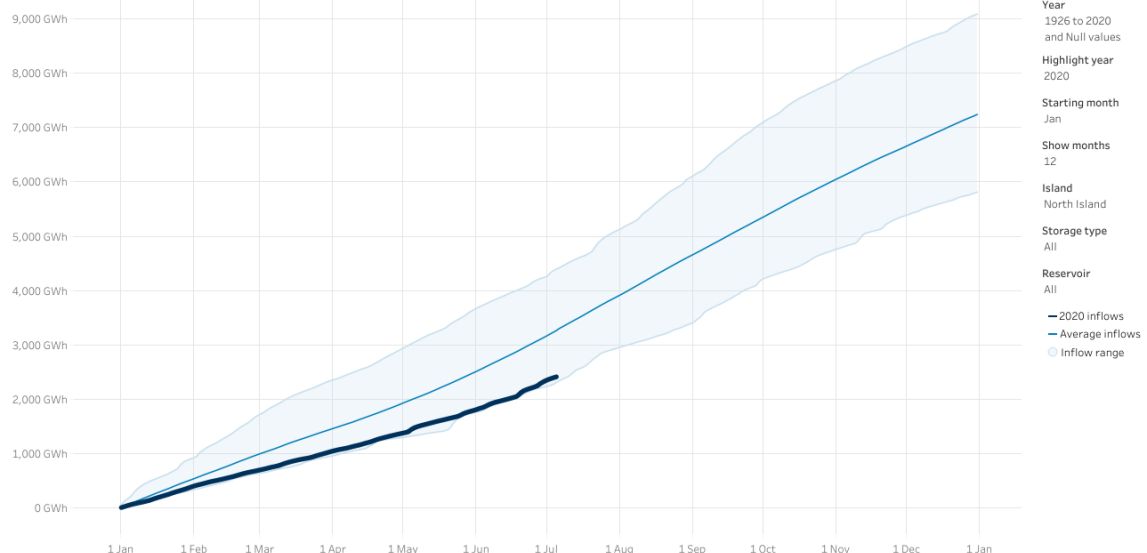
Low North Island inflows

- 5.4 Figure 9 shows the inflows in the North Island so far this year, as well as the range of inflows since 1926. At the end of June North Island inflows were the second lowest on record, with inflows only slightly higher than the driest year on record.

Figure 9: North Island inflows 2020

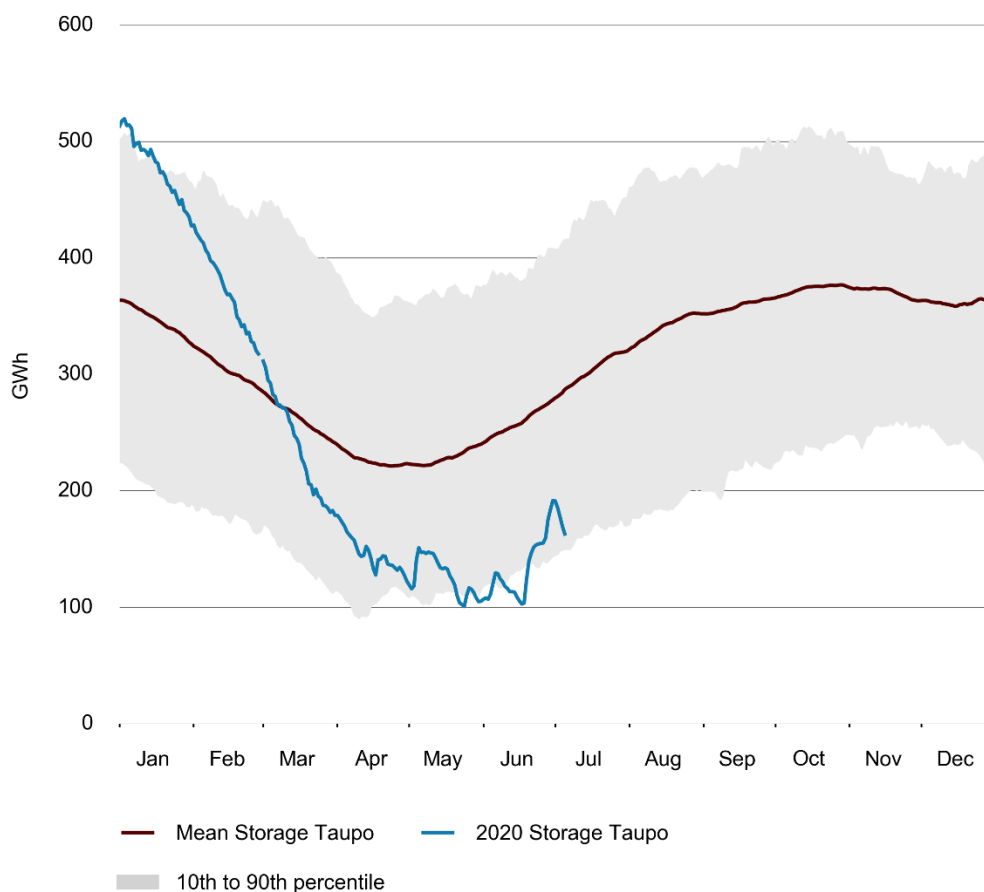
Hydro storage data from NZX hydro (data provided by NIWA) latest available data 5 Jul 2020

Cumulative inflows by day for 12 months Jan-Dec showing high-low range, 1926-2020 highlighting 2020



- 5.5 Figure 10 shows hydro storage in Lake Taupo, which holds most of the storage in the North Island. At the beginning of the year storage in Lake Taupo was relatively high, above the 90th percentile. However, due to the combined impact of low inflows and the HVDC outage, Taupo's lake level dropped substantially. At the end of May and for much of June storage was below the 10th percentile.

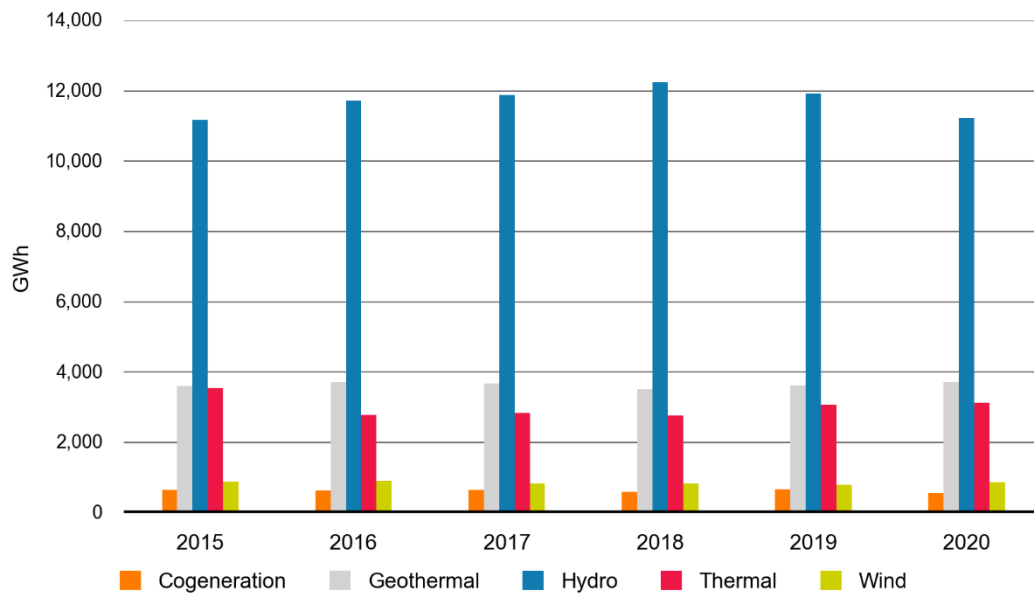
Figure 10: Lake Taupo Hydro storage



Generation

- 5.6 Figure 11 shows generation by fuel source for the first half of the year. Geothermal generation and wind generation were higher than most previous years due in part to new generation such as Te Ahi O Maui. Wind and geothermal were not impacted by the decrease in demand in April. Hydrogeneration was lower than the last few years, almost on par with 2015. Co-generation was more than 15 per cent lower than previous years, with co-generation a third of normal in April. Despite low utilisation in April, thermal generation was higher than the last few years, particularly during June when hydro storage was low.

Figure 11: Generation by fuel source Jan-June 2015-2020

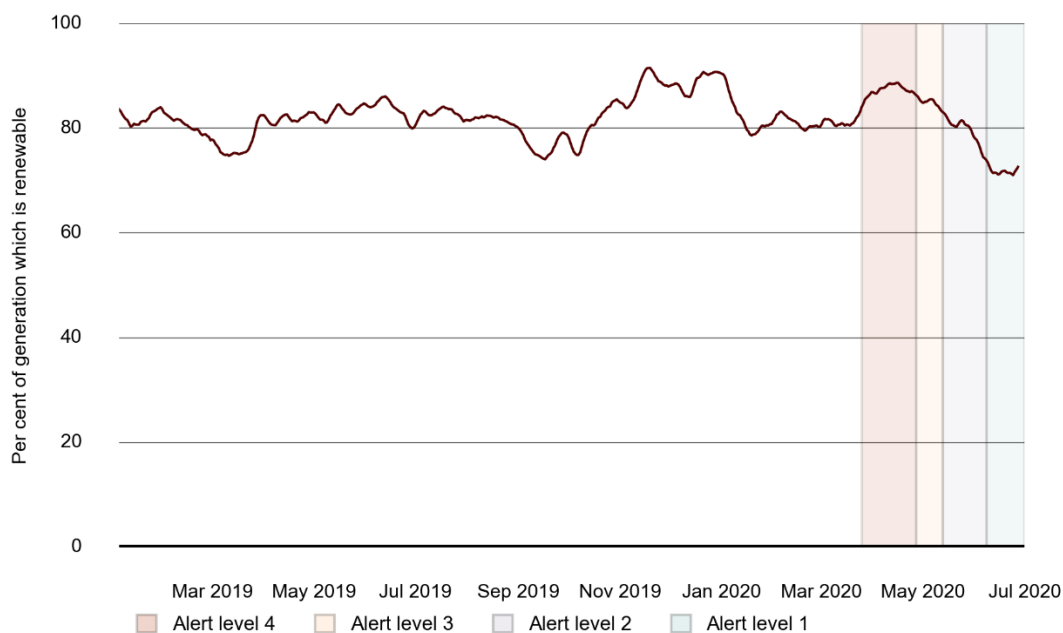


Source: Electricity Authority

Renewable generation

- 5.7 Figure 12 shows the percentage of generation which came from renewable sources. Generation from renewable sources is relatively high, usually between 75 and 85 per cent, with the majority from hydro generation. High inflows over summer 2019/20 increased renewable generation to 91 per cent of total at one point. This returned to 80 per cent until alert levels 4 and 3, when renewable generation increased to 85 per cent mostly due to the drop in demand. However, as restrictions eased and colder weather started, renewable generation dropped to a low of 71 per cent during June as more thermal generation was needed to meet demand.

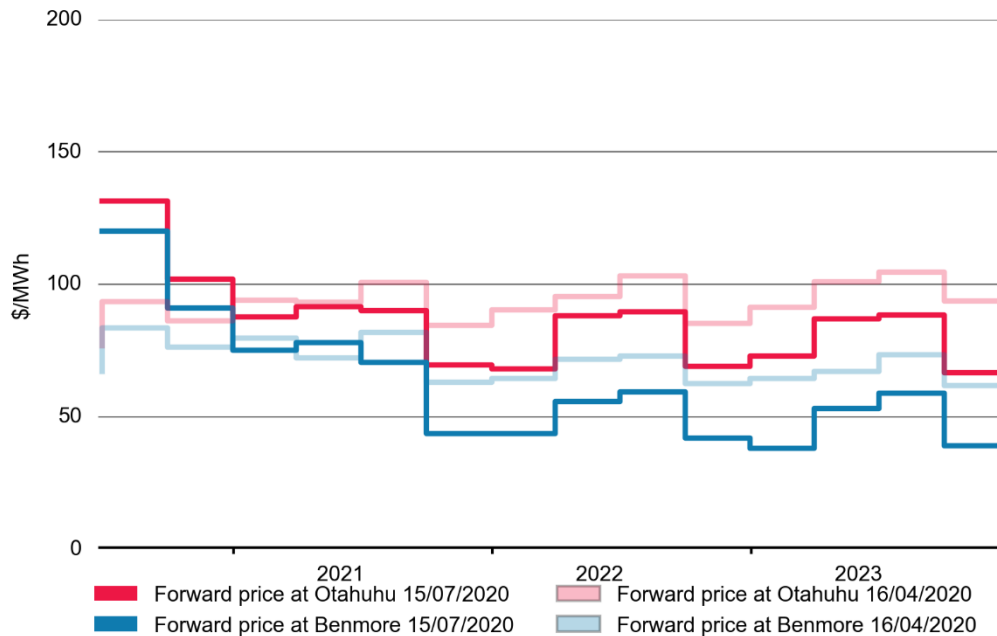
Figure 12: Renewable generation as a per cent of total 2019-2020



Forward markets

- 5.8 Figure 13 shows the forward price at Otahuhu (North Island) and Benmore (South Island) from mid-April and mid-July. Forward prices for Q3 and Q4 increased between April and July to \$131/MWh at Otahuhu.

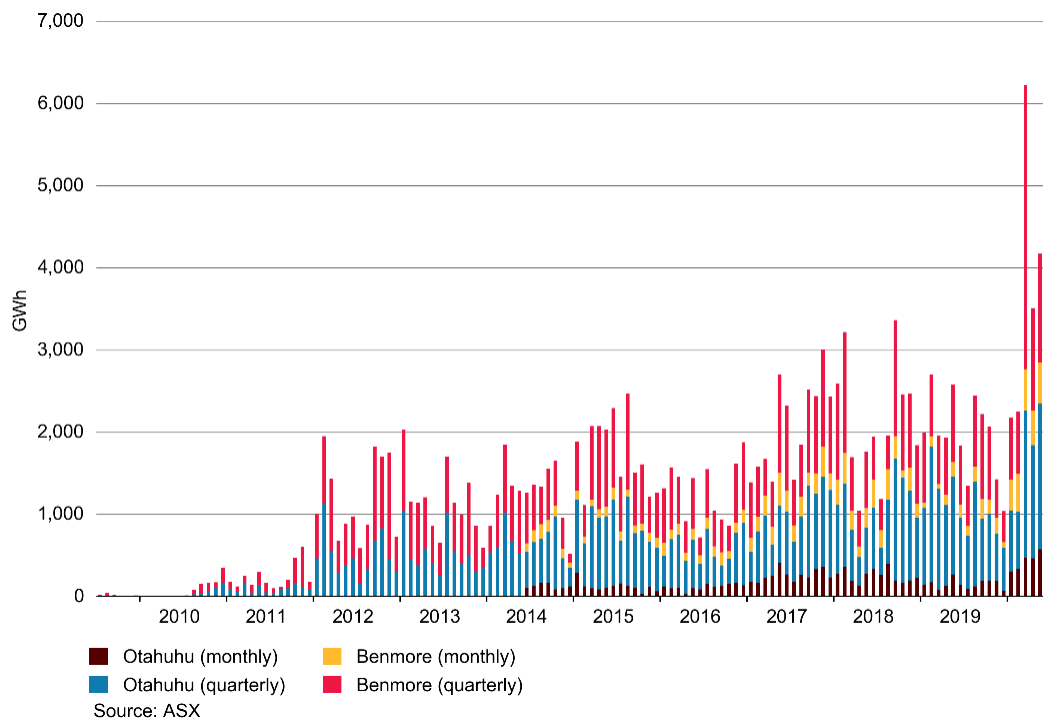
Figure 13: Forward Quarterly ASX prices at Otahuhu and Benmore



Source: ASX

- 5.9 Beyond 2020, forward prices have been impacted by the announcement Tiwai will close. The largest drop is for Q4 2021 from \$73/MWh to \$44/MWh showing the clear expectations that the Tiwai closure will result in significant price falls. There is also a wider gap between prices at Benmore and Otahuhu, indicating that traders expect transmission constraints to cause price separation. Transpower has announced plans to upgrade the Clutha Upper Waitaki lines at a cost of \$97 million to be finished in 2023.

Figure 14: Monthly trading volumes for ASX baseload contracts



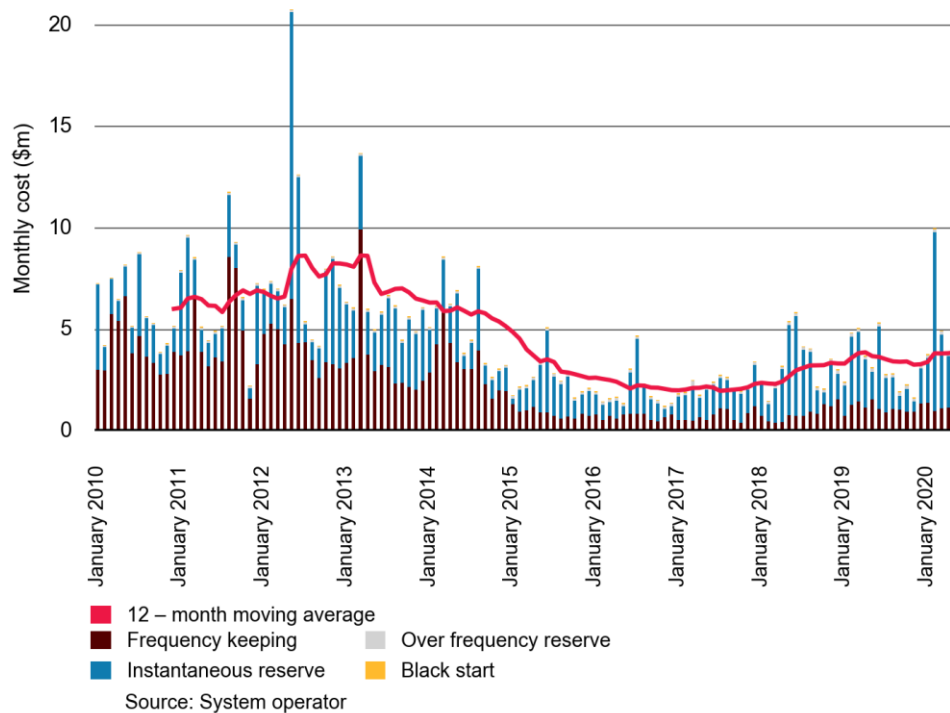
- 5.10 Figure 14 shows the volume of trades on the ASX futures market. From March onwards there has been a noticeable higher volume of trades with both March and June setting new records for trading volumes. New market making arrangements came into effect in February and this likely had an impact on the volumes traded.³ Increased trading activity may also have been due to participants reducing the risk of their positions in a quickly changing environment due to the pandemic, hydro storage and the gas market.

6 Ancillary services

- 6.1 Figure 15 shows ancillary services costs since the beginning of 2010. The moving average shows how costs fell between 2013 and 2018 mostly driven by decreases in frequency keeping costs. High spot prices since the end of 2018 have likely contributed to the slight rise in ancillary services costs.

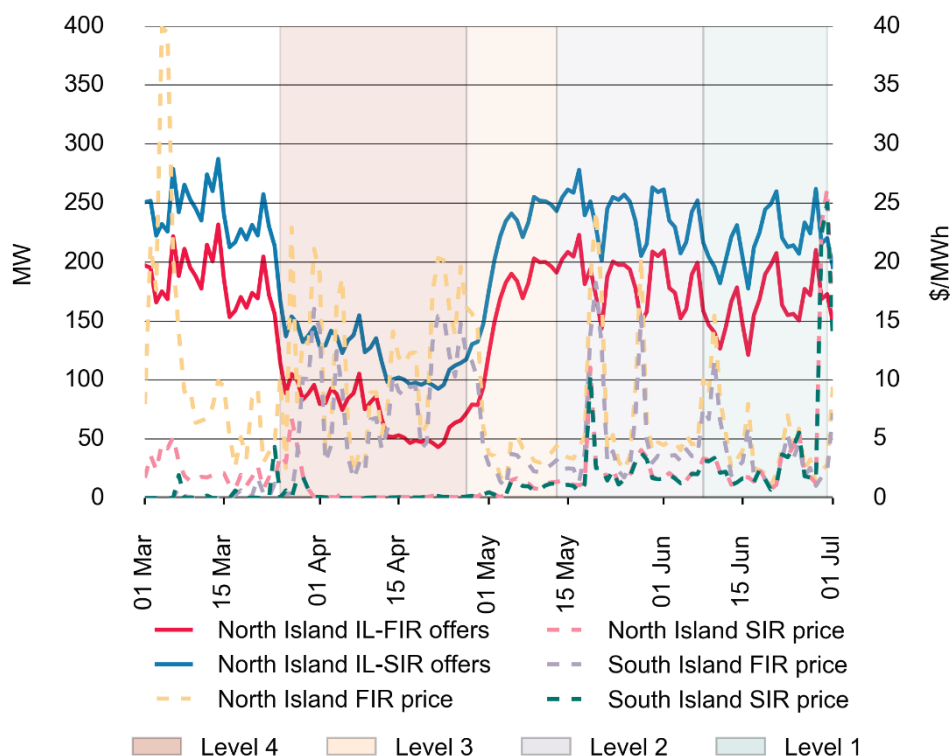
³ See [Update on futures market and market making](#) for more information on the impact of market making on volumes traded in March and June.

Figure 15: Monthly ancillary services costs



- 6.2 During alert levels 4 and 3, demand for instantaneous reserve dropped but not the overall cost. This was because the decrease in industrial load (Figure 4) meant less interruptible load (IL) was available. Figure 16 shows that the drop in IL resulted in an increase in the price of fast instantaneous reserves (FIR) in both islands. IL is suitable for FIR as it can respond within seconds while some generation takes time to ramp up. The price of sustained instantaneous reserves (SIR) dropped because more generation was available.

Figure 16: Available interruptible load and price of FIR and SIR



7 Special topic 1: Grid Events-November 2019

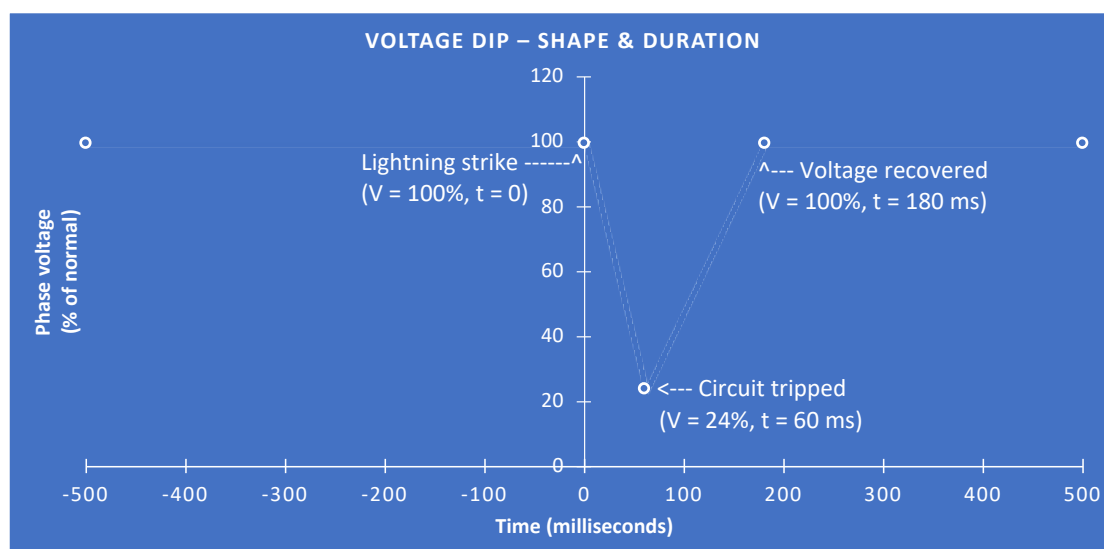
Introduction

- 7.1 In November 2019, the national grid experienced two notable – but separate – significant events that provided lessons around supply security, reliability and power quality.
- 7.2 While our more recent industry focus has been on understanding and responding to the Covid-19 pandemic, the Authority's Market Monitoring team looked into the November events. We initially approached Transpower with questions about the event triggers, the grid response and the impacts on consumers. Transpower's responses led us into discussions with some of the affected distributors.
- 7.3 In this section we'll briefly describe the events and discuss the lessons we think may be of interest to participants and consumers.

20 November 2019 – a lightning strike caused no loss of supply at grid or distribution network level but shed 143 MW of consumer load

- 7.4 Shortly after 2:30pm on 20 November 2019, the 220 kV Islington-Livingston circuit 1 tripped and auto-reclosed during a thunderstorm. Comparing before and after aggregate grid exit point (GXP) demand around the South Island indicates that 143 MW of consumer load tripped.
- 7.5 Lightning strikes to transmission lines are not uncommon and usually pass without incident – if a circuit trips as a result, auto-reclose protection will usually re-energise the circuit in a few seconds, once the energy in the strike has dissipated.
- 7.6 Islington-Livingston circuit 1 is one of four 220 kV circuits that interconnect Canterbury and the upper South Island to hydro generation in the Waitaki and Clutha Valleys. A line fault followed by an auto-reclose on one of those circuits normally causes no major issues.
- 7.7 For this event, the lightning strike short-circuited all three phase conductors (phases) to earth. Measured by a very sensitive event data recorder at Islington substation, the short circuits caused the voltage on each phase to drop to about 24 per cent of the normal voltage. The dip was of very short duration, lasting about 180 milliseconds (ie, 0.18 seconds) from event onset to the fault clearance, and then to the point of voltage recovery. Figure 17 shows a simplified timeline.
- 7.8 The voltage dip would have been most severe at the location of the lightning strike and would have diminished in magnitude as its effect radiated out across the South Island grid, through supply transformers and down into distribution networks. Of interest in this event is the effect of the voltage disturbance on consumer loads, particularly on loads that are particularly sensitive to voltage dips.

Figure 17: Approximate shape and duration of the voltage dip on each phase, as measured at Islington 220 kV bus



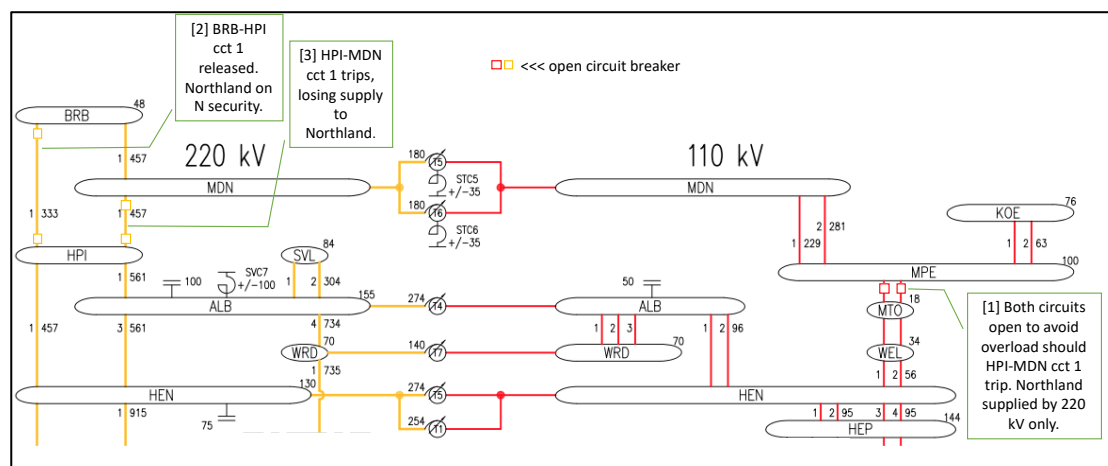
Source – Data provided by Transpower

- 7.9 Moving to distribution network level, the voltage dip transmitted through to electricity supplied at consumer supply voltages, usually 400 volts for consumers with three phase supplies and 230 volts for single phase consumers.
- 7.10 While the lowest voltage of the dip would not have been as severe as 24 per cent of normal voltage as measured at consumers' premises, it was nevertheless sufficiently low enough to cause a very large amount of consumer load to trip. Transpower continuously measures the aggregate amount of load supplied from the grid into distribution networks via GXPs. For this event, comparing load flow before and after the event revealed that 143 MW of consumer load tripped coincident with the lightning strike.
- 7.11 As for the grid level, no supply *connectivity* was lost to consumers from the distributors' perspective; it was just a voltage bump – what the Electricity (Safety) Regulations 2010 categorise as a "momentary fluctuation".
- 7.12 At consumer level, loads sensitive to severe but very short duration voltage dips tripped. From information provided by Transpower and distributors, we understand that irrigation pump motors are the main category of load that is vulnerable to voltage fluctuations; the regions where most load was lost align with the South Island's irrigation zones – ie, the East Coast from North Otago through to Nelson/Marlborough.
- 7.13 While irrigation water pumping is a load category that has expanded significantly in recent years, modern electronic motor loads in dairy factories and replacements of older equipment with more modern technology in recent years are other possible candidates.
- 7.14 A significant amount of non-rural load also tripped in this event, raising questions about what additional categories of load were affected, particularly in urban areas. Modern soft-start elevator motors and inverter heat pumps installed as part of the Christchurch rebuild are also likely to have contributed to the aggregate load that tripped.
- 7.15 The fault "ride-through" performance of modern electronic motor drives will be well understood by equipment suppliers—momentary voltage (and frequency) fluctuations are not a new phenomenon. Improvements of the ability of equipment sensitive to voltage fluctuations might exist via adjustments to motor protection and control settings. Distributors will likely have fielded queries of this nature and should be able to provide advice about where to seek further specialist support. The Authority will forward this report to distributors to draw their attention to this issue.

27 November 2019 – bird streaming across an insulator triggered a region-wide unplanned outage while operating at N-security

- 7.16 A double circuit 220 kV transmission line provides the primary supply to Northland from Whangarei to the Far North. Planned for the period 25 November to 6 December 2019, the 220 kV Bream Bay - Huapai circuit 1 was released from service to allow Transpower contractors to carry out work to maintain insulator attachment points.
- 7.17 This planned outage reduced supply security to Bream Bay, Kaikohe and Maungatapere substations from N-1 to N security, with supply continuity depending solely on the parallel 220 kV Huapai – Marsden circuit 1 remaining in service throughout the planned outage.
- 7.18 The two parallel 110 kV circuits that also supply the Northland GXP, that run from Henderson to Maungatapere, were switched out of service by opening their line circuit breakers at Maungatapere. This is a routine measure to avoid overloading these two small capacity 110 kV circuits (~56 MW capacity each) should the 220 kV Huapai - Marsden circuit 1 trip.

Figure 18: Northland grid, key locations



Substations: HUI – Huapai; BRB – Bream Bay; MDN – Marsden; MPE – Maungatapere; KOE – Kaikohe

Source: Transpower's NIPS-6 annotated

- 7.19 In line with routine practice for the outage configuration, Transpower disabled auto-reclose on Huapai - Marsden circuit 1; this measure prevents an out-of-synchronism auto-reclose onto distributed generation operating in the region. This most notably protects Top Energy's geothermal power station at Ngawha, which is electrically connected to the grid at Kaikohe.
- 7.20 At 9:34 am, during the planned outage, Huapai - Marsden circuit 1 tripped resulting in a loss of supply from the grid to Bream Bay, Maungatapere and Kaikohe substations. The cause of the trip was later determined to be bird streaming across an insulator on tower 234, causing a flashover and a single phase to earth fault. Figure 18 shows the layout of the grid circuits and the substations involved and the green boxes [1] – [3] show the sequence described above.
- 7.21 The Authority's market monitoring team looked into this event because it affected supply to a large region (180 MW across 72,000 consumers, including the oil refinery at Marsden Point) for in excess of an hour. Transpower successfully re-livened the faulted 220 kV circuit 1 hour after it tripped; staged re-livening of GXPs and then consumers by the local distributors.
- 7.22 Looking into this event, we were interested in communications between Transpower, distributors and large consumers about the outage, what role they played in outage planning and what they did to prepare. We engaged with Transpower and local distributors to understand the decision-making processes from outage planning through to restoration of supply.

- 7.23 Transpower has identified and implemented opportunities for improvement that should enhance supply reliability in Northland, with benefits that may flow to other parts of the grid. These include:
- (a) looking for areas along the Northland lines that might be attractive to large birds as perches and installing bird deterrent measures at high risk sites;
 - (b) reviewing how protection systems coordinate between Transpower and distributors to test existing assumptions about safely auto-reclosing a grid circuit following a fault while avoiding potential damage to downstream synchronous distributed generation. In the Northland case, while operating on a single 220 kV circuit in future, Transpower has changed its outage procedure to leave auto-reclose enabled but with a longer (10.5 second) time delay designed to allow time for Ngawha and other distributed generation to detect the loss of power from the grid and isolate itself. With this measure in place, a future intermittent fault under the same operating circumstances should reduce the impact to a 10.5 second outage;
 - (c) improved outage planning by coordinating an annual outage plan that more closely engages local distributors and large consumers – in this case the oil refinery and other large industrial consumers – to identify more optimal outage windows that better take account of large consumer maintenance periods where this is possible;
 - (d) working more closely with grid customers that may be subject to N security during planned outages regarding the customers' preferences for communications.
- 7.24 Since the outage in Northland in Nov 2019 Transpower has worked with both Northpower and TOP Energy to investigate longer term solutions for improving the security of supply during 220 kV circuit outages. Further investigation of system stability and dynamic response matters is required to confirm the suitability of a long-term development path. This work is currently being scoped.

8 Special Topic 2: Regression analysis of spot price drivers

- 8.1 This section presents some preliminary analysis of the drivers of the spot price. It builds on work the Authority published as part of its review of the Winter of 2017. That work looked at the relationship between the spot price and hydro storage. We build on this study to try to understand the effect of storage, demand, wind generation, gas price, and competition on the spot price.
- 8.2 We find that the spot price is determined by the balance of supply and demand in the market. These effects dominate any effects of changing competition. Note that effective competition is required for the balance of supply and demand to determine prices.
- 8.3 We estimated a regression equation that used the national average spot price as the response variable. New Zealand electricity demand, Waitaki hydro storage, wind generation, average marginal gas price, and the HHI for generation (as a measure of competition in generation) are the predictors.⁴ The reason we use Waitaki storage is to minimise any distortions due to the HVDC link between the South and North Islands.
- 8.4 We also included a dummy variable for the time from 28 September 2018 onwards. The reason for the dummy variable is because we believe that from around 28 September 2018, increased gas supply risk has been priced into the spot price.
- 8.5 Our research question is “what is the relationship between the spot price and storage, demand, wind generation, gas price, competition in generation, and gas price risk”.

Data

- 8.6 We use weekly average data from 1 January 2010 to 29 February 2020. Our gas price data is from the week of 1 October 2015, and we use offer data from the week of 13 December 2012. The transformation from the original daily data to weekly average data is based on a research paper by Thomson (2018).⁵ According to Thomson’s paper, weekly data is more conventional for seasonal analysis techniques, and it can enhance the systematic components of each time series, enabling a better understanding of any structural relationships between them.
- 8.7 Weekly averages are constructed from the original daily time series by forming successive weekly averages from the start of each year with 29 February included in the week of 28 February in leap years, and 31 December included in the week of 30 December. This yields 52 weeks for each year with the first week being the average of the first 7 days in January and the last week being the average of the last 8 days of December.
- 8.8 Price data is transformed based on Thomson’s (2018) PH model. This involves a logarithm transformation of the price to reduce the positive skewness in the price distributions for each period. This step makes the price more symmetric and Gaussian. We also use a shift to adjust for the seasonal effect on the prices. The shifted logarithm transformation for the price is $\log(P_t - \theta_t)$ where P_t is the weekly average electricity final price and θ_t is the threshold parameter satisfying $\theta_t = \theta_{t+52}$. θ_t is the lowest possible price for the week of the year correspond to week t . θ_t is estimated by local maximum likelihood.
- 8.9 We transformed the predictor variables from daily data to weekly average data using the same method we used to convert price.

⁴ The units for the raw data (non-transformed or non-adjusted data) are: storage and demand are GWh, spot price is \$/MWh, gas price is \$/PJ, and wind generation is MW.

⁵ Thomson, P.J. (2018). Updates of a regression model relating electricity spot price and hydro storage (PH Model) and a seasonal switching model for hydro storage (SH Model) using South Island data (2018). Report commissioned by the New Zealand Electricity Authority.

- 8.10 We also adjusted for seasonal effects on storage and demand. We have subtracted the seasonal mean from weekly storage. The season periods are defined in Thomson's paper: for each season, there are 13 weeks. Spring is from week 36 to week 48, summer is from week 49 to week 9 of next year, autumn is from week 10 to week 22 and winter is from week 23 to 35. This is to adjust for the seasonal impact on storage.
- 8.11 We adjusted demand by subtracting the ten-year weekly average from the weekly demand for each of the 52 weeks. This adjustment effectively means that seasonal effects—like the effect of temperature on the spot price—are removed from the data.
- 8.12 We adjusted offer and generation data in the same way as demand. Again, this method removes seasonal effects. We then take the ratio of offers to generation to get a measure of excess capacity in the market. The higher this ratio, the more competition at the margin and vice versa. Note we did not adjust wind generation.
- 8.13 We have taken a logarithm transformation for the gas spot price to reduce the skewness. For the dummy variable, a value of 0 is given for all time periods before the week of 28 September 2018, and a value of 1 is given for all weeks from 28 September 2018 onwards.
- 8.14 Our regression equation is:

$$\begin{aligned} \log(P_t - \theta_t) = & \beta_0 + \beta_1(\text{Storage}_t - \text{Seasonal.mean.storage}_i) \\ & + \beta_2(\text{Demand}_t - \text{ten.year.mean.demand}_t) + \beta_3\text{WindGen}_t \\ & + \beta_4 \log(\text{GasPrice})_t + \beta_5 \text{Generation.HHI}_t \\ & + \beta_6 \text{ratio.for.adjusted.offer.to.generation}_t \\ & + \beta_5 \text{DummyGasSupplyRisk}_t \end{aligned}$$

where $t = \text{week } 1, \dots, 52 \text{ for each year}; i = \text{spring, summer, autumn and winter}$

Results

- 8.15 The results are set out in Table 1. The coefficients for all of the predictor variables are statistically significant and most them have the expected signs, the R^2 is good, and the residual diagnostics are good (see below), so we have confidence in the results of this regression.

Table 1: Results from the regression

	Coefficients	Exp(coefficients)	P-values	significant?
Constant	5.884	359.34	0	Y
Adjusted storage	-0.0002996	0.9997	0.011248	Y
Adjusted demand	0.03501	1.0356	0.000154	Y
Wind generation	-0.02009	0.98	0.002072	Y
log(gas price)	0.3643	1.4395	0	Y
Generation HHI	-0.000996	0.999	0	Y
Ratio adjusted offer to generation	-0.00004454	0.9999555	0.061113	Y but weak
Dummy gas supply risk	0.3145	1.13695	0	Y
R^2	55.08%			

- 8.16 All estimated coefficients except generation HHI have the expected signs:
- when storage and wind generation increase, the spot price decreases.
 - when demand and the gas price increase, the spot price increases.
 - when the ratio of offers to generation increases, the spot price decreases.
 - The coefficient on the gas supply risk dummy suggests that gas supply risk has been priced into the spot price since September 2018.

The effect of competition

- 8.17 We expect a positive sign on the HHI as an increase in market concentration (increasing HHI) should suggest a reduction in competitive pressure and therefore higher prices. However, we have a negative sign.
- 8.18 HHI is the sum of the squared market shares. When storage falls, Meridian generates less, market shares become more even and the generation HHI falls. But under these circumstances the spot price will be high, as storage is low. This gives the negative sign in our regression suggesting a fall in concentration (increased competitive pressure) leads to higher prices. This negative sign in our regression results suggests that the storage effect dominates any market concentration effect.
- 8.19 The ratio of offers to generation is also a measure of competition. The higher this ratio the more competition there is at the margin, and the less likely it is that small changes in demand will lead to large price swings. The negative sign is expected—more competition means lower prices.
- 8.20 However, the marginal effect is small suggesting that underlying fuel supply, fuel cost, and demand are more important. Note that the fact that these factors affect price is itself an indicator of competition.
- 8.21 We have also tested for multicollinearity between the ratio of offers to generation, and the generation HHI. The correlation between them is very weak (-8 per cent). The Variance Inflation Factor (VIF) for the ratio and the generation HHI are 1.04 and 1.18 respectively. Both are small. The VIFs for the rest of the predictors are between 1 and 2.3, all less than 5. These small VIFs suggest that we don't have multicollinearity in the model. This means we are not 'hiding' the effect of either variable on the spot price by including both in the model and suggests again that the generation HHI is measuring more than just competition in the market.

Interpretation

- 8.22 Interpreting the results is not easy because we have transformed and adjusted the variables. The back-transformed interpretation for non-logarithm transformed estimated predictors is a one unit change in the estimated variables or adjusted estimated variables is associated with a percentage change in the weekly shifted price.

Adjusted storage: a unit increase in weekly adjusted storage causes on average a 0.03 per cent decrease in the weekly shifted spot price, holding other variables constant.

Adjusted demand: a unit increase in weekly adjusted demand causes on average a 3.6 per cent increase in the weekly shifted spot price, holding other variables constant.

Wind generation: a one MW increase in weekly wind generation causes on average a 2 per cent decrease in the weekly shifted spot price, holding other variables constant.

Gas price: a one percent increase in the weekly gas price causes on average a 44 per cent increase in the weekly shifted spot price, holding other variables constant.

Generation HHI: a one unit increase in weekly generation HHI causes on average a 0.1 per cent decrease in the weekly shifted spot price, holding other variables constant.

Ratio for adjusted offer to adjusted generation: a one unit increase in the weekly adjusted ratio of offers to generation causes on average a 0.005 per cent decrease in the weekly shifted spot price, holding other variables constant.

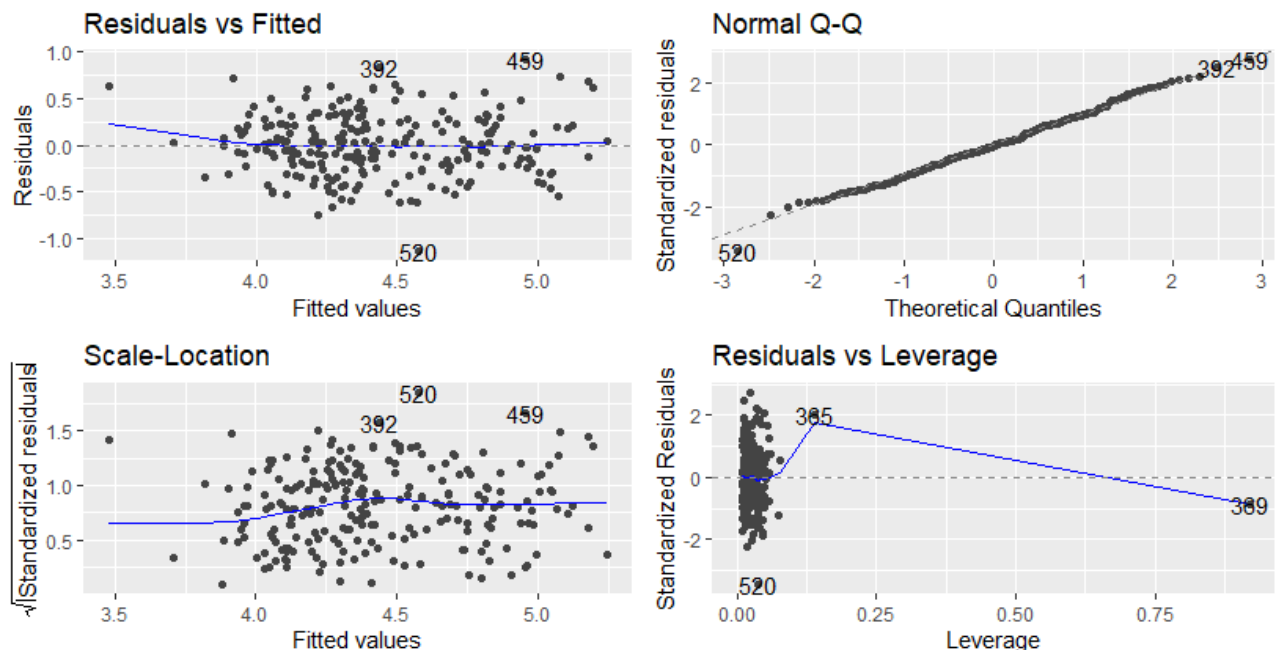
Dummy variable: For the time period from 28 September 2018 onwards, the weekly shifted spot price is 13.7 per cent higher on average than the weekly shifted price before the time period, holding other variables constant. This supports our hypothesis that gas supply risk is affecting the spot price.

R-squared: The R-squared suggests that 55.08 per cent of the variation in the shifted logarithm transformed weekly price can be explained by the predictors. This implies the model fits well.

Checking assumptions and diagnostic plots

- 8.23 A valid linear regression needs to satisfy linearity, normality, and homoscedasticity (constant variance). To check these assumptions, we use the diagnostic plots that are shown in Figure 19. The Residuals vs Fitted chart on the top left is for checking for linearity. The roughly horizontal line without a distinct pattern is consistent with linearity. The QQ-plot on the top right shows the points are roughly along a straight line with slightly heavy tails on both ends. This suggests that the residuals are normally distributed. The slightly heavy tails are likely due to holiday periods when there is a sharp drop in electricity usage. The scale-location plot on the bottom left shows a roughly horizontal line with roughly equally spread points. This is a good indication of homoscedasticity. The plot on the bottom right identifies influential points (outliers). For outliers, one solution is to take outliers out then re-run the regression. But spot price spikes are a feature of our energy only market, so we decided not to remove these outliers.

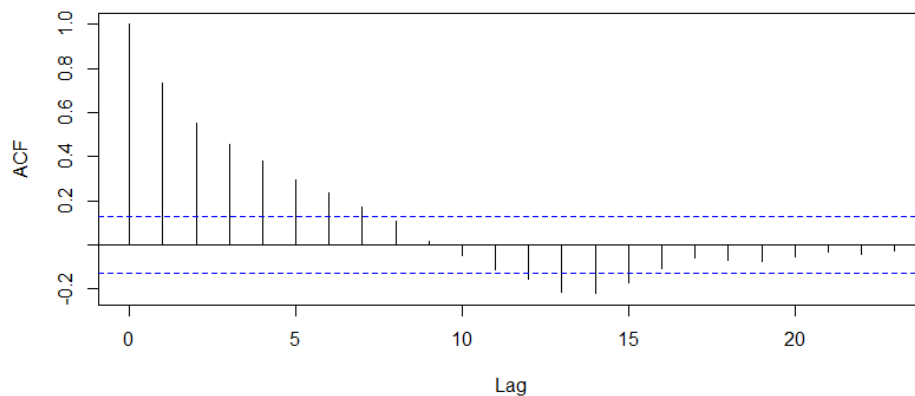
Figure 19: Diagnostic plots



Testing for autocorrelated residuals

- 8.24 Our data is time series data, so we check for autocorrelation in the residuals. Figure 20 shows at least the first seven lags of residuals are significant. The following results from the Breusch-Godfrey test confirms there is autocorrelation in the residuals. But autocorrelation does not invalidate our regression. When we use time series data for a linear regression, it is highly likely that this week's prices are similar to the previous week's prices, or even weeks before. Therefore, when fitting a regression model using time series data, it is common to find autocorrelation in the residuals, but this does not necessarily mean that the regression is unreliable.

Figure 20: Autocorrelation plot for residuals



Breusch-Godfrey test for serial correlation of order up to 10

data: Residuals

LM test = 131.26, df = 10, p-value < 2.2e-16

- 8.25 In addition, we used the Dicky-Fuller test to explore if the residuals are stationary⁶. A stationary time series definition has no systematic change in mean and variance and has no periodic fluctuations. The results from the test below show the test statistic is smaller than critical values at 1 per cent. So we can reject the null hypothesis and accept the alternative hypothesis that the residuals are stationary. Testing residuals for stationarity is not a formal test, but it can re-assure us that our regression is not spurious. We have confidence that our model is unbiased and reliable.

Value of test-statistic is: -5.7226

Critical values for test statistics:

	1pct	5pct	10pct
taul	-2.58	-1.95	-1.62

Conclusions

- 8.26 This model provides evidence to support the hypothesis that spot prices are determined by the balance of supply and demand and that these effects dominate any effects due to market concentration. Note that price being determined by underlying demand and supply indicates effective competition.
- 8.27 The model confirms what we qualitatively observe about the spot market: that high spot prices tend to coincide with low wind, low storage, high gas spot prices and other gas sector disruptions, and high demand.

⁶ Note: Strictly stationary assumptions are hardly achieved in applications. We use weak stationary (or wide-sense stationary) assumptions. Dicky-Fuller is a test for weak stationary.