DISCLAIMER

The purpose of the Evaluation Panels' consideration of the case studies is to analyze how the proposed Code amendment might be interpreted in a range of different scenarios. The analysis by the Evaluation Panels will assist MDAG in developing recommendations to the Authority's Board in relation to the proposed amendment. For the avoidance of doubt, please note:

- The case studies are either based on historical situations or are purely hypothetical, and the figures (such as prices) referred to in all of the case studies are fictional. MDAG has not included in the case studies any claims or specific issues that are currently under consideration by the Authority or the Rulings Panel. One should not assume that a case study is a reference to a specific industry participant or situation.
- Each case study is intentionally a relatively high-level summary of the situation (whether fictional or otherwise) and does not purport to contain all possibly relevant information. MDAG considers that a high-level summary is appropriate for the purpose of the Evaluation Panels.
- The case studies and the Evaluation Panels' consideration of the case studies do not purport to represent binding precedent on the interpretation of the current or proposed Code provisions.
- The case studies [and the Evaluation Panels' consideration of the case studies] do not constitute a reconsideration or re-opening of any previous decision by the Rulings Panel or the Authority.
- The case studies [and the Evaluation Panels' consideration of the case studies] do not represent the views of MDAG or the Authority.

INTRODUCTORY NOTE

The case studies detailed below represent a high-level summary of information relating to the hypothetical event in question. The case studies do not purport to contain all of the relevant information. Panel members may need to indicate what further information they require or, if that information is not available, what assumptions they need to make in relation to the facts in order to reach a view on whether a breach of the existing or proposed Code has occurred. Further, some of the information provided may not be directly relevant to answering the questions to be addressed by the panel.

GLOSSARY OF ABBREVIATIONS AND TERMS

FTR	Financial transmission rights are a hedge product designed to help parties manage the risk they face from large, unpredictable differences in wholesale electricity prices between different points on the transmission grid (usually between where electricity is generated and where it is purchased). This risk is referred to as 'basis risk' or 'locational price risk'. The FTR market helps to promote retail competition by encouraging retailers to compete for customers on a nationwide basis, as opposed to focusing primarily on regions close to where they own generation assets or have purchased electricity.
Gross Pivotal	A supplier is gross pivotal if, without at least some of the supplier's production, demand cannot be met. 'Gross pivotal' does not consider whether or not any of the supplier's volume is covered by hedge or retail contracts.
HVDC	High-Voltage Direct Current refers to an electric power transmission cable between the North and South Island that uses direct current for the bulk transmission of electrical power.
Instantaneous Reserves	Instantaneous reserve is generating capacity, or interruptible load, available to operate automatically in the event of a sudden failure of a large generating plant or the HVDC link. This service is required to stop the resulting fall in frequency, which is a critical power quality attribute, and allow the system frequency to recover promptly to 50 Hz.
Interruptible Load	Interruptible load is a form of instantaneous reserve whereby the consumer reduces its electricity demand by a fixed capacity and for a fixed time period upon request.
Long run marginal cost	Long-run marginal cost is the cost of changing output by one additional unit when capital is allowed to vary, and generally includes the recovery of capital costs with a suitable premium for risk.
MW	Megawatt is a unit of power equal to one million watts. It is generally used to denote the generation capacity of a power plant.
MWh	Megawatt hour is a unit of energy equal to the work done by a power of a million watts (MW) in one hour. It is generally used to denote the generation output of a power plant at a particular point in time (or trading period). Megawatt hours are the metering standard unit for the wholesale market.
N-1 Security	Is a grid reliability standard or a 'safety net' minimum reliability standard for contingencies (that is, events such as transmission or generation outages) on the core grid. N-1 security means that the system is planned such that, with all transmission facilities in service, the system is in a secure state, and for any one credible contingency event, the system moves to a satisfactory state. However, if more than one contingency event was to occur, load may have to be shed (ie. some consumers would lose power) to return to a satisfactory state.
Net Pivotal	Net pivotal is where a supplier is gross pivotal and some or all of the supply for which it is pivotal is not covered by hedge or retail contracts – that is, a supplier is net pivotal for the proportion of its pivotal generation volume that exceeds its hedging and retail commitments.
Short run marginal cost	Short-run marginal cost is the cost of changing output by an additional unit when capital is fixed and is generally made up of the fuel cost, operational costs, the opportunity cost of generating electricity or of providing instantaneous reserve, as applicable, and any scarcity rents.

EVALUATIONS PANEL

CASE STUDY #1

THE RELEVANT PARTIES

Generator A is a hydro generator that has a major share (~55%) of the market in the South Island. Its offer prices for its hydro plant are based on its (best) assessment of the operating cost of thermal generation (which is a proxy for the opportunity cost of stored water). The price at Generator A's closest point of connection averages around $150/MWh.

Generator B is a hydro generator that has a sizeable share (~15%) of the South Island market. It also proxies the cost of stored water with the operating cost of thermal generation.

Generator C is a diesel generator that has a total capacity of 100MW and it would normally offer capacity to meet peak demand in the South Island.

THE ALLEGED BREACH

On 30 June 2019, it was alleged that Generator A was in breach of the high standard of trading conduct provisions when it withdrew capacity for its 200MW offer tranche starting from trading period 37 (6pm). This capacity withdrawal continued until the next day. Subsequent investigations also determined that Generator A was in a gross[1] pivotal position during these periods.

In the breach allegation, it was claimed that Generator A's offer was inconsistent with previous trading behavior and the capacity withdrawal had contributed to a material increase in the final price. The breach allegation further claimed that Generator A would not have acted this way if it did not have significant market power.

CASE DESCRIPTION

It is a winter evening in June and demand is unusually high due to the cold weather. A storm is also moving across New Zealand. The forecasted prices for the evening are estimated to be around $100/MWh and the system is tight with most offered generation being scheduled for energy or reserves.

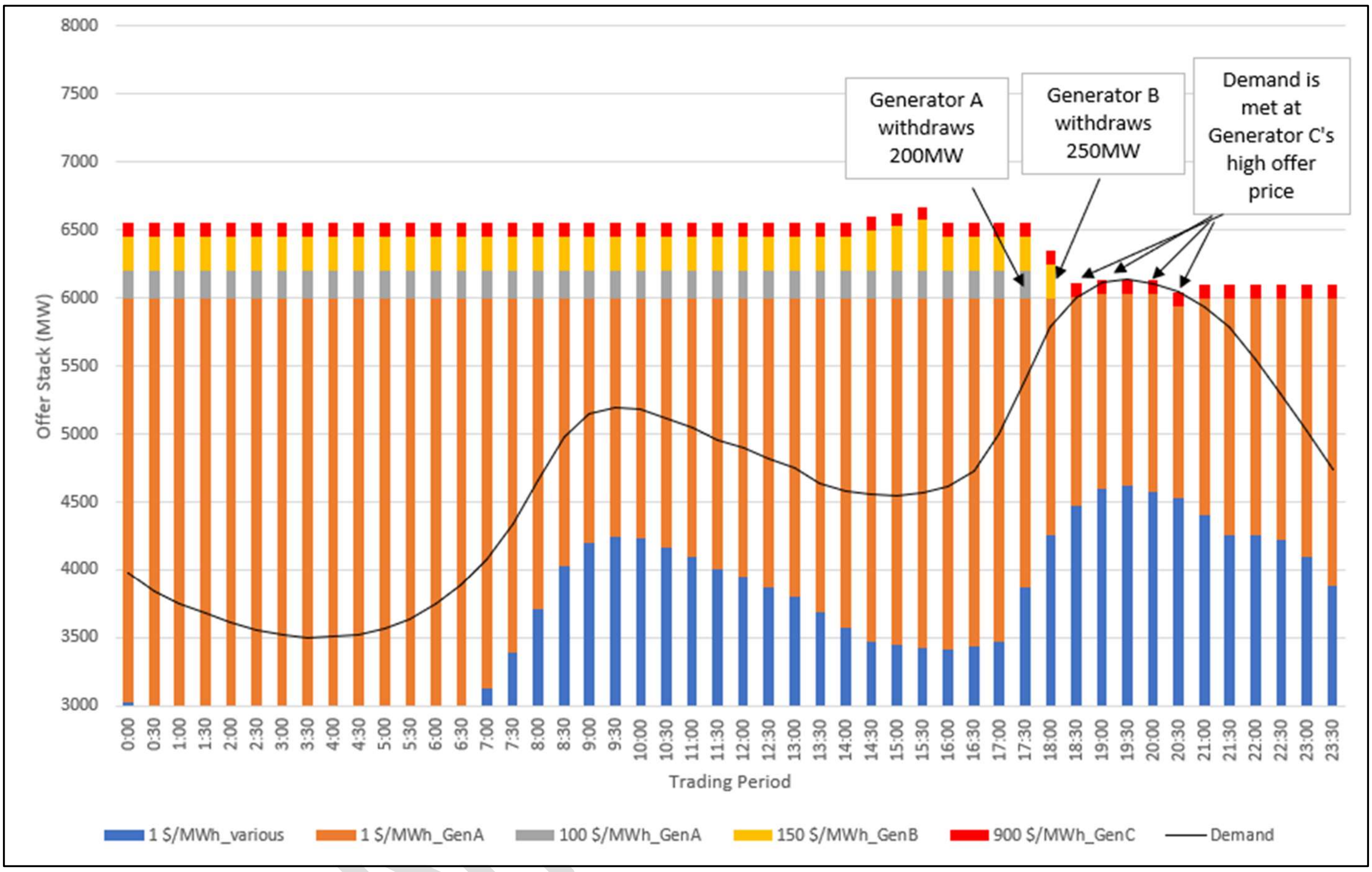
At 6pm, Generator A notified the system operator that it would be withdrawing a 200MW tranche of its hydro generation that it was offering at $100/MWh because of damage to its water intake structures caused by the storm. Generator A further notified that it was not expected to return to service until the following day.

At 6.30pm, Generator B informed the system operator that it is immediately shutting down 250MW of its hydro generation that it was offering at $150/MWh for the rest of the day because of a continuing connection transmission circuit outage that was also caused by the storm.

[1] See glossary for a detailed definition

Due to these unplanned outages, demand for trading periods 38 - 42 (6.30pm - 8.30pm) had to be met by the marginal source of supply, which is a 100MW diesel generator owned by Generator C. This generator has been offering consistently at $900/MWh for many years.

After trading period 42, the market price settled at $1/MWh offered by Generator A and remained at this price until the next day when the damage to the plants caused by the storm was repaired. The figure below illustrates the offer behaviour by these three parties and the electricity demand on that day.



THE PARTIES JUSTIFICATION

Generator A argued that its offers reflected supply constraints that occurred due to factors outside its control. It claimed that it had acted consistently when similar unplanned outages had occurred in the past and it was not exercising its significant market power or profiting from the pivotal position it was in at the time of the alleged breach.

Generator A further argued that during the trading periods in question, the market was operating in a competitive environment, and that it was the other generators' trading behaviour that ultimately set the higher final prices.

EVALUATIONS PANEL

CASE STUDY #2

THE RELEVANT PARTIES

Generator A operates a geothermal plant with a total capacity of 400MW. It would normally offers all its generation at $1/MWh and supplies around 5% of the market. The region is supplied by several generators and competition is high. As a result, Generator A has not been in a pivotal position in the past and it rarely sets the market price. Generator A's main strategy is to have its output fully dispatched at the ongoing market price of around $100/MWh.

Generator B is very similar in size to Generator A but operates a hydro plant in the same region. It has a total capacity of 200MW and normally offers at $1/MWh with the aim of being fully dispatched. Like Generator A, Generator B has not been pivotal in the past and it rarely sets the market price.

Generator C operates a gas-fired plant with a total generation capacity of 35MW. Its offers are frequently marginal and would often set the market price in the region of around $100/MWh.

THE ALLEGED BREACH

On 14 June 2019, it was alleged that Generator A and Generator B were both in breach of the high standard of trading conduct provisions when they raised their offer prices during trading periods 17 to 27 (8:00-13:00) when they were subsequently both found to be in a locally pivotal position after finding themselves upstream of an unplanned transmission constraint. As a result, the market price was set at a level that it would normally settle at (around $100/MWh) when there is no transmission constraint.

CASE DESCRIPTION

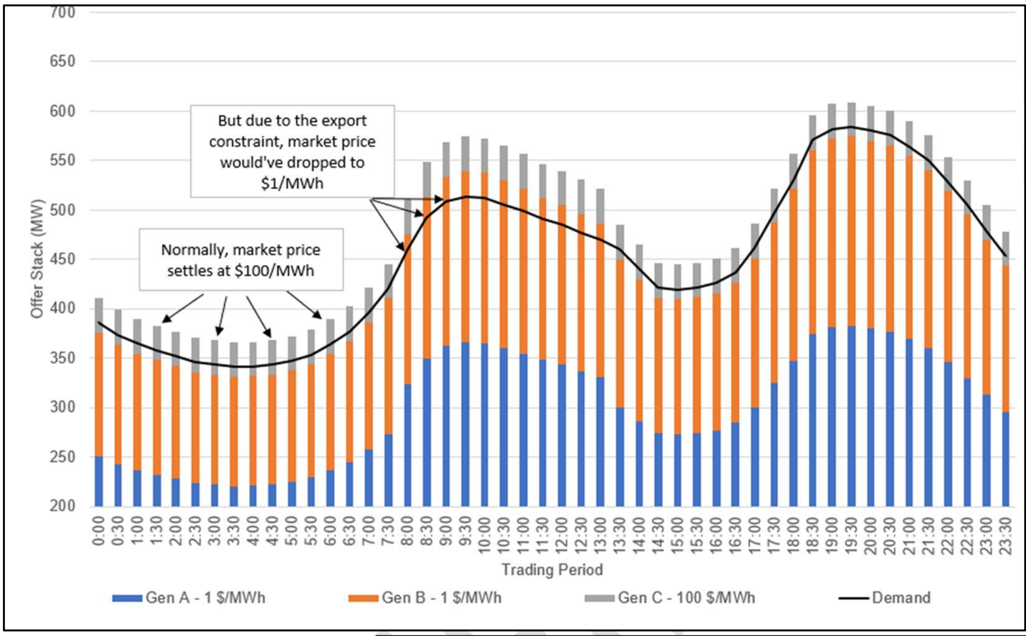
On the morning of 14 June 2019, the grid operator informed the market that it urgently needed to remove a transformer from service to carry out critical maintenance work. The outage would significantly reduce export transmission capacity from a major generation region. This situation required that generators support the load in the whole of that region until maintenance work is completed.

Three competing generators (Generators A, B and C) found themselves upstream of the constraint and the constraint rendered the larger two generators (Generator A and B) locally pivotal to meet demand until the repair work is completed.

Both Generator A and Generator B would normally offer all their generation capacity into the market at $1/MWh. The market price prior to the transformer being removed from service was $100/MWh and their offered capacity had been getting dispatched. The price at the generators' point of connection to the grid reflected the market price plus the cost of losses (i.e. it was not materially different from the national price). After the transformer was removed from service, export capacity became constrained and the price in the region fell to $1/MWh. This kick-started a change in offer behavior as follows:

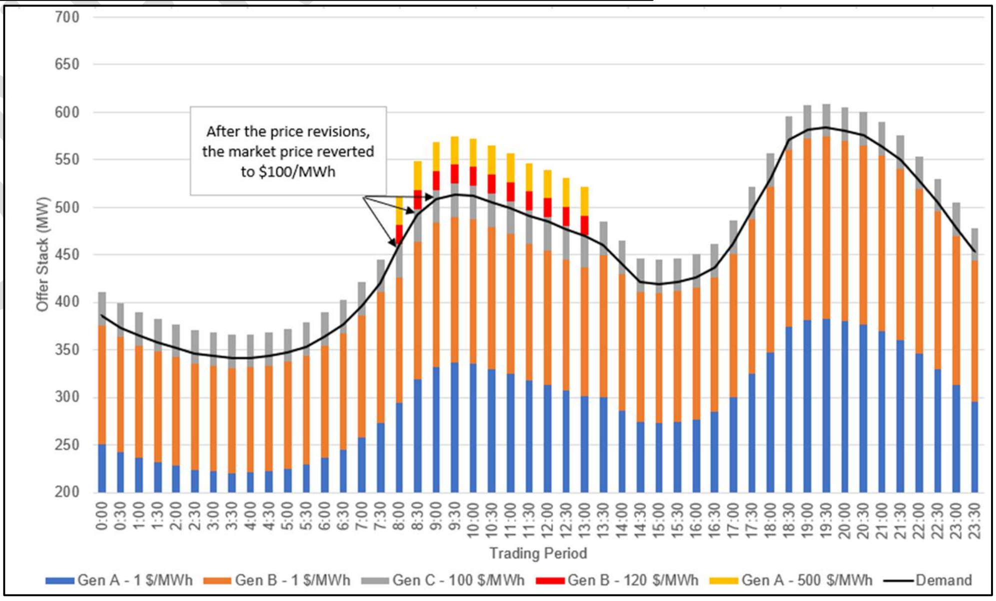
- Generator A (the geothermal plant operator) increased the offer price of its top 30MW tranche from $1/MWh to $500/MWh starting from trading period 17 (8am);
- Generator B (the hydro generator) lifted its top tranche offer of 20MW from $1/MWh to $120/MWh also from trading period 17 (8am);
- Generator C (the thermal operator) did not alter its offer of $100/MWh.

As a result of these offer price changes, Generator A and Generator B were dispatched down by the volume of their top tranche (30MW and 20MW, respectively). This relieved the constraint and the price in the region reverted back to its usual $100/MWh i.e. a price that would normally apply without the export constraint. The figure below illustrates the offers made by the three parties for demand downstream from the constraint in that region.



Before the offer price change

After the offer price change



THE PARTIES JUSTIFICATION

Generator A claimed that it wanted to avoid being marginally dispatched at such a low offer price. It considers this situation to be undesirable for a geothermal power station because being dispatched at $1/MWh is too low a price to recover its short run marginal cost[2] of $50/MWh. Generator A further claimed that the change in offer price is a sensible trading strategy given the unusual circumstances. Generator A explained that it was not aware of its pivotal position during trading periods 17 to 27 and its traders did not factor this circumstance in their day-to-day decisions.

Generator B argued that it was not willing to use its water resources for $1/MWh because it deemed that the value of stored water should be closer to the (usual) market price of $100/MWh. At this low price, it elected to store the water in the lake for use at a later time when prices are higher. Generator B also claimed that it was unaware that it was in a pivotal position during trading periods 17 to 27 and did not factor this circumstance in its day-to-day decisions.

[2] See glossary for a detailed definition

EVALUATIONS PANEL

CASE STUDY #3

THE RELEVANT PARTIES

Generator A has a total generation capacity of 2500MW from a portfolio of renewable assets with the bulk of its capacity being from hydro. It has a large share (~35%) of the market and is normally in a pivotal position for most trading periods. Its offer prices for its hydro plant are based on its (best) assessment of the operating cost of thermal generation (which is a proxy for the opportunity cost of stored water). The price at Generator A's closest point of connection averages around $150/MWh.

Generator B is a small, independent thermal generator with a total capacity of 80MW. With its current plant, Generator B can quickly ramp up or down its generation depending on the offer prices. Its offers are also partly informed by what its major competitors are offering in all trading periods. Generator B's plant flexibility and knowledge of its competitors' offer behavior would often place Generator B as a market price setter during peak hours.

THE ALLEGED BREACH

On 15 May 2019, it was alleged that Generator A was in breach of the high standard of trading conduct provisions when it revised its highest tranche of 150MW from $100/MWh to $200/MWh starting from trading period 13 and continuing throughout the following days. The market price would normally be set at $150/MWh during these periods.

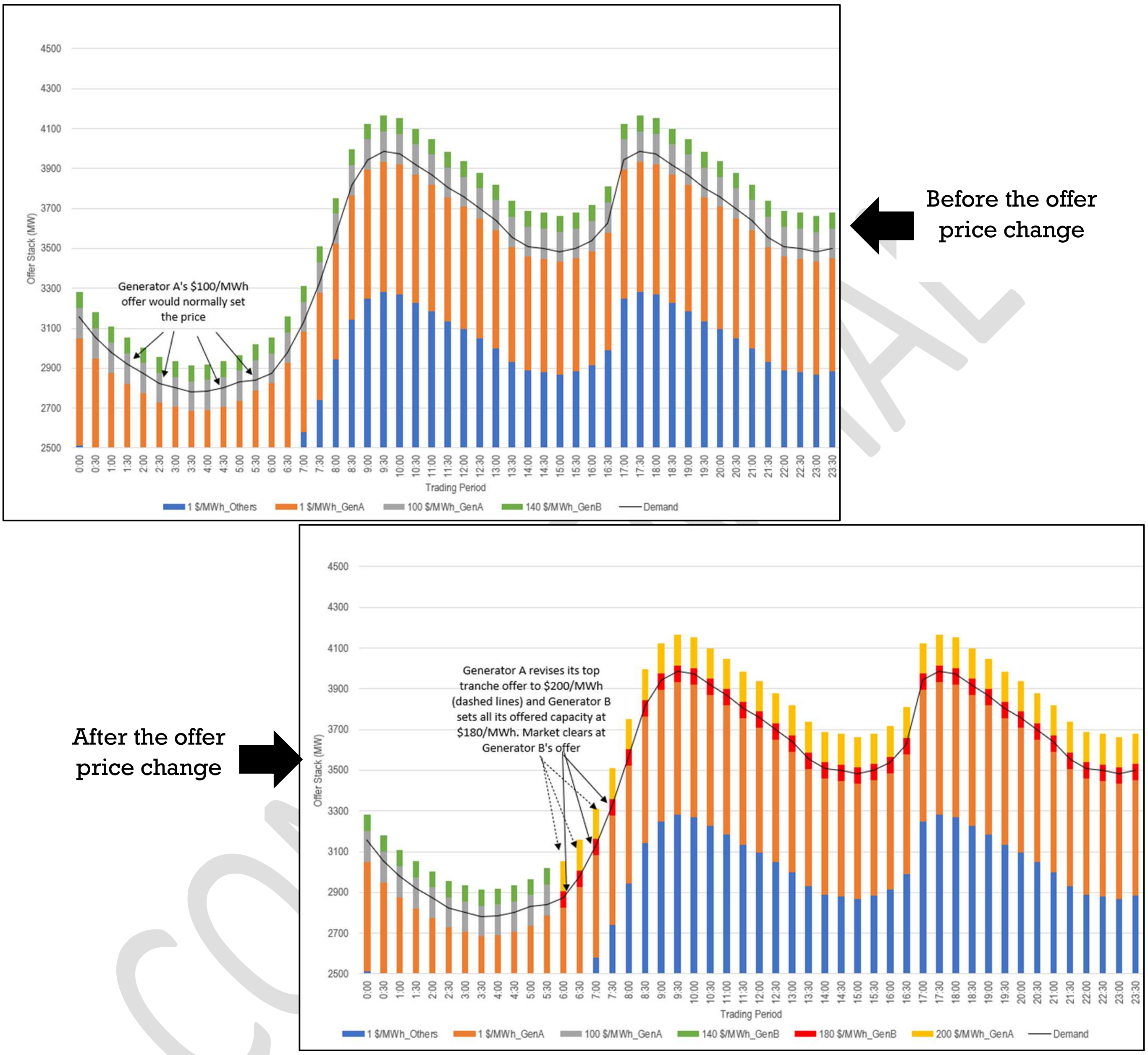
CASE DESCRIPTION

On the morning of 15 May 2019, Generator A reviewed newly-disclosed information by major gas suppliers that strongly indicated that the cost of thermal generation is likely to increase by 15% over the next couple of days due to unplanned maintenance work at a major gas field. Hydro storage levels at Generator's A location were at normal levels and no water shortages or dry weather were forecasted.

Based on this new information, Generator A elected to revise its highest tranche of 100MW from $100/MWh to $200/MWh starting from trading period 13 onwards to reflect the higher opportunity cost of stored water. During these trading periods, Generator A's supply was required to meet demand, making it the pivotal generator.

As stated above, Generator B's trading strategy is heavily guided by its competitors' behavior. Up to trading period 13, Generator B was offering all its capacity (80MW) at $140/MWh and was expected to set the market price. However, upon noticing Generator A's higher offer prices, Generator B reconsidered its offer strategy, and after having concluded that there were no offers between its own and Generator A's top tranche, Generator B elected to raise its offer price from $140/MWh to $180/MWh.

This is just below Generator A’s top tranche offer price (of $200/MWh) and resulted in a final price of $180/MWh. Generator B was not pivotal during this period. The figure below illustrates the dynamic of the offers of these two generators for the 15 May trading periods.



THE PARTIES JUSTIFICATION

Generator A claimed that its increase in offer prices was a purely operational decision that was taken after it had meticulously reviewed the cost of thermal generation. Generator A pointed out that it is long-standing industry practice to proxy the opportunity cost of stored water with the cost of thermal generation. If it doesn’t do so, then it would have lost out on the (higher) value of stored water. In which case, it would be more profitable to store water and generate electricity at a future date when thermal fuel prices are higher.

Generator A further claimed that during the trading periods were it was allegedly in breach of the Code provisions, it had offered all its generating capacity and had changed the offers as soon as it concluded its review of the information disclosed by the gas suppliers. Its trading conduct was consistent with previous behaviour when it had revised its offers based on new information including information on the cost of thermal generation.

Generator A pointed out that, even though the market price had materially increased, it was not directly through its change in offer price. Rather, it was Generator B who elected to raise its offers even after knowing that it was a market price-setter during the trading periods when the alleged breach took place. Hence, Generator A claimed that it should not be responsible for actions that were outside its direct control.

EVALUATIONS PANEL

CASE STUDY #4

THE RELEVANT PARTIES

Generator A is a vertically integrated company that operates in both the electricity generation and retail sectors. It has a portfolio of renewable assets, including hydro, wind and geothermal plants. It owns the majority (~55%) of the market share of generation in the South Island and is frequently the market price setter. Its total generation capacity is around 2000MW when all its power plants are running, including its wind installations. Generator A's retail arm supplies customers in both the North and South Islands. The price at Generator A's closest point of connection is normally around $100/MWh, reflecting offer prices from higher cost competing generators.

Generator B operates two gas-fired plants and one diesel plant in the North Island. It offers part of its generation capacity of its diesel plant to meet peak demand. Its total generation capacity is 500MW and it would normally offer at $200/MWh.

Generator C is a thermal generator in the North Island that would normally offer its total capacity of 200MW at an offer price of around $180/MWh.

THE ALLEGED BREACH

On 01 July 2019, it was alleged that Generator A and Generator B were both in breach of the high standard of trading conduct provisions when they raised their offer prices during trading periods 36 to 38 (5.30pm-6.30pm) to profit from a combination of high demand and scarce North Island generating capacity. Later investigations also concluded that Generator A was in a net pivotal position in the South Island during these trading periods.

CASE DESCRIPTION

On 01 July 2019, wind production was low due to cold, still weather. The cold weather also induced a sharp rise in national demand with most of this increase in demand being driven by North Island consumers. Demand in the South Island had also increased but this was easily met by Generator A who had ample hydro generation capacity at that time.

During this period, one of Generator B's large gas-fired plant, totalling 360 MW capacity, was not operating. This plant did not operate during the preceding month, although it was not recorded as being out for maintenance on the voluntary outage disclosure website https://pocp.redspider.co.nz/. In previous winters, Generator B had made it clear through various statements on its website that this plant may not be available to run, even if it is not out for maintenance.

On the morning of 01 July 2019, the system operator issued a warning notice that:
(a) notified participants there were potentially insufficient generation and reserve offers to meet demand and provide for *N-1* security[3] between 17.30pm and 19.00pm (trading periods 36 to 38) in the North Island;
(b) identified the cause as insufficient generation offers in the North Island;
(c) requested participants to increase the quantity of energy and reserve offers in the North Island.

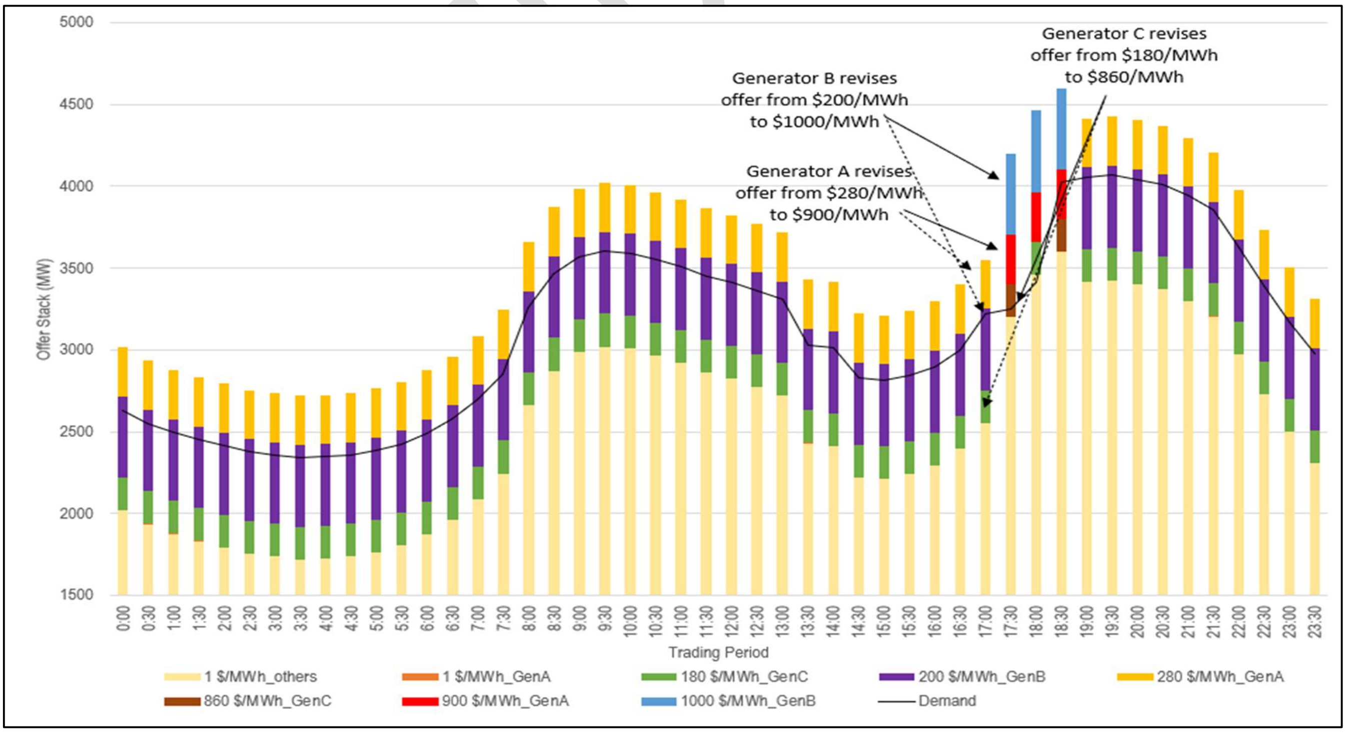
The combination of high demand and relatively scarce North Island generating capacity led to an increase in North Island prices and it was anticipated that there would be a wide price separation between the two Islands. If not mitigated, this situation would have exposed Generator A to substantial basis risk[4] (and to material revenue exposure to meet its retail market position).

In response to the anticipated price separation, Generator A revised its offer price for a 300MW top tranche from $280/MWh to $900/MWh for trading periods 36 to 38. This change in offer prices was made well before the actual gate closure. North Island generators could have met the increase in demand but at a much higher price than originally offered by Generator A (of $280/MWh) due to the scarce supply situation.

A few hours before trading periods 36 to 38, Generator B and Generator C also revised their offers as follows:

- Generator B, who chose not to operate one of its gas-fired plant, increased its offers for its diesel turbine generator from $200/MWh to $1000/MWh for trading periods 36 to 38;
- Generator C moved all its capacity (200MW) from $180/MWh to $860/MWh for trading period 36;
- Generator C made a similar offer change in trading period 38. Generator C did not change its offers for trading period 37 and this 200MW block (offered at $180/MWh) ultimately set the price for that period;
- Generator C's block offered at the higher price (of $860/MWh) set the price in trading period 36;
- Generator B's revised diesel turbine offer (of $1000/MWh) set the price in trading period 38.

The figure below illustrates the dynamic of the offers of these three generators during these trading periods.



[3] See glossary for a detailed definition
[4] the difference between the price where it supplied generation and where it had retail or hedge customers

The effect of this offer behaviour caused both energy and instantaneous reserve[5] prices to rise in the North Island. Electricity spot prices increased to $860/MWh during trading period 36 (5.30pm-6.00pm) and reached $1000/MWh during trading period 38 (6.30pm-7.00pm). The spot market normally trades at around $100 per MWh during these trading periods.

THE PARTIES JUSTIFICATION

Generator A argued that its offers were revised as soon as it could and in fact, had done so a few hours before gate closure. Generator A also pointed out that the high standard of trading conduct provisions are not well framed to deal with its particular circumstances i.e. when it is normally gross pivotal for a large proportion of the time but still needs to take market action in context of its overall market position.

Generator A also argued that its behaviour was the norm to cover basis risk and that basis risk management is a recognised trading strategy. Since Generator A is a vertically integrated generator-retailer, its primary instrument that it uses to manage basis risk is its physical generation portfolio and would typically run a close-to-neutral hedge position[6]. Therefore, Generator A did not consider that hedging instruments, such as FTRs[7], would have enabled it to manage the risk of material revenue exposure to meet its retail market position. Generator A considered FTRs to be a baseload product that is not suited to peak exposure issues, and that FTRs come with their own trading risks that can make them a relatively expensive risk management tool in some circumstances.

Generator A considered that the market outcome for the relevant trading periods is reflective of a competitive environment and pointed out that the offers made by other parties had set the final price for the trading periods 36 to 38.

Generator B argued that during the trading periods in question, it elected to raise its offer prices in response to Generator A's change in offer price (of $900/MWh). Generator B argued that this reflected normal competitive behaviour and the market price was driven by the scarcity situation in the North Island.

[5] See glossary for a detailed definition

[6] A neutral hedge position is a type of investment strategy were the combined position results in a yield that is dollar neutral regardless of the price change in the market

[7] See glossary for a detailed definition

EVALUATIONS PANEL

CASE STUDY #5

THE RELEVANT PARTIES

Generator A is a large hydro generator that has ~90% of the South Island market share and a total generation capacity of 3000MW. Due to its size, Generator A is normally in a net pivotal position[8] for most of the trading periods and would frequently set the price in the South Island. Generator A also has a large share of the instantaneous reserves market (~70%).

Generator A's energy offer prices are based on its assessment of the value of water available for generation. During periods of prolonged dry weather, and commensurate low hydro availability, Generator A would raise its offer prices to signal the market that water resources are on the decline. The nodal price at Generator A's closest connection is normally around $120/MWh, reflecting offers by more expensive remote generators.

Consumer X is the largest industrial consumer of electricity in the South Island and utilizes a large share (~15%) of the electricity supplied by Generator A. It offers interruptible load services[9] from having enough flexibility to shut down some of its production lines on demand. Rather than supplying these services directly to the market itself, it tenders these services to third parties, usually generators, to offer to the market on its behalf. During the period of the alleged breach, Generator A was the party offering this interruptible load to the market.

THE ALLEGED BREACH

On 01 May 2019, it was alleged that Generator A was in breach of the high standard of trading conduct provisions when it increased the offer price of instantaneous reserves between 12 May to 25 May from $1/MW to between $100/MW and $500/MWh when it had significant market power. The breach allegation stated that Generator A had the ability, with its own instantaneous reserve resources, to increase energy prices in the South Island. This was further enhanced by its acquisition of the offer rights for interruptible load by Consumer X. The acquisition of these offer rights made Generator A net pivotal in the South Island during this period when its instantaneous reserve offers and interruptible load agreement were used in conjunction with its energy offers.

CASE DESCRIPTION

During the period from November 2018 to May 2019, the South Island experienced record low hydro inflows due to prolonged dry weather conditions. This led to a commensurate increase in the value of water and induced Generator A to incrementally increase offer prices in the South Island over this period. The higher prices sent a signal to generators operating in the North Island to export generation to the South Island through

[8] See glossary for a detailed definition

[9] Interruptible load can be considered as a form of instantaneous reserves, with 1MW of interruptible load being approximately equivalent to 1.6MW of hydro-generated instantaneous reserve. See glossary for a detailed definition.

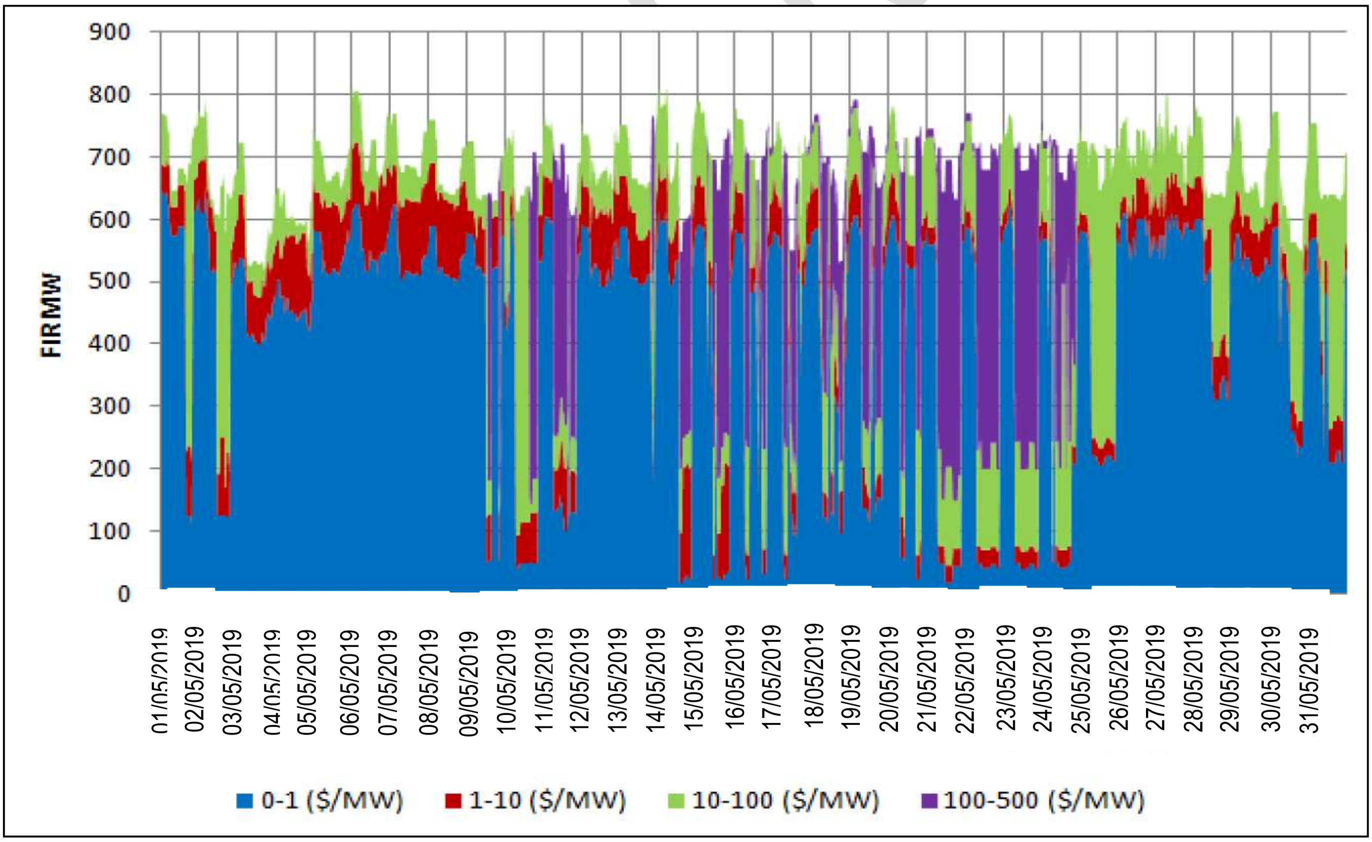
the HVDC[10]. This higher southbound transfer reduced the dependency on South Island generation and helped to conserve South Island hydro resources.

However, early in 2019, the grid operator informed the market that there were insufficient instantaneous reserves in the South Island to cover the HVDC contingent event risk. This was impeding additional HVDC southbound transfer and was increasing the reliance on declining South Island hydro resources.

Generator A responded by raising the price of instantaneous reserves supplied by its generation on offer in the South Island from $1/MW to between $100/MW-$500/MW in the period 01 May 2019 to 24 May 2019 for all trading periods.

Concurrently, Generator A acquired the offer rights for the interruptible load of Consumer X as part of an agreement to bring that interruptible load to the market and relieve the burden on its declining hydro generation resources.

The breach investigation subsequently determined that Generator A's significant quantity of reserve provided by its generation, and its control of Consumer X's interruptible load, led to Generator A being in a net pivotal position in the instantaneous reserve market. The effect of this trading strategy was an increase in the cost of covering the HVDC contingent event risk, leading to higher South Island energy and instantaneous reserve prices and wider locational price differences between the South Island and the North Island. After the 24 May, Generator A reverted its offers to those made when hydro resources are at normal levels. The figure below illustrates the instantaneous reserves offered in the South Island between 01 May 2019 to 24 May 2019.



10 See glossary for a detailed definition

THE PARTIES JUSTIFICATION

In its defence, Generator A argued that it had acted correctly when it raised the price of instantaneous reserves so that it sends a strong signal to the market that there was insufficient instantaneous reserves to cover the HVDC contingent event risk. In the period when it was allegedly in breach, Generator A stated that all its reserve capacity was being offered and it only raised its instantaneous reserves offer price as soon as the grid operator issued the warning that there was insufficient instantaneous reserves in the South Island. Generator A pointed out that raising instantaneous reserve prices when southbound transfers over the HVDC are high was consistent with its previous behaviour and market expectations.

Generator A also claimed that it entered into an interruptible load agreement with Consumer X because it feared that Consumer X would not make this interruptible load available if it was not offered a reasonable price. This agreement would ensure that this service is provided when needed. Generator A maintained that these two interventions ensured the continued southbound transfer of electricity and eased the pressure on declining South Island hydro resources. Generator A claimed that these interventions were not an abuse of its significant market power or its pivotal position, but it was a necessity driven by the record low hydro inflows.