The Authority's preliminary decision on claim of an undesirable trading situation

Claim submitted 12 December 2019 by Haast Energy Trading, Ecotricity, Electric Kiwi, Flick Electric, Oji Fibre, Pulse Energy Alliance, and Vocus

Preliminary decision released: 30 June 2020

Submissions close 5pm 11 August 2020

Executive summary

An undesirable trading situation (UTS) in the electricity market involves a situation that threatens, or may threaten, confidence in, or the integrity of, the wholesale market. The UTS provisions in the Code give the Authority powers to take corrective action if it considers a UTS has developed or is developing.

On 12 December 2019 the Authority received a claim from seven participants (the claimants) that a UTS had begun on 10 November 2019 and was continuing at the time of the claim. The claim alleged the UTS was caused by Meridian Energy (Meridian) and Contact Energy (Contact) spilling water from their hydro generation stations in the South Island, while simultaneously offering this generation into the spot market at prices above its short-run marginal cost (SRMC).

We investigated whether the issue threatens, or may threaten, confidence in, or the integrity of, the wholesale market. The UTS provisions require the Authority to undertake a broad analysis, considering not only direct impacts on the market, but also impacts on participants' confidence in the market. Factors that can influence participants' confidence include not only existing threats to the market but also potentially emerging situations that may threaten market confidence or integrity.

Our analysis and conclusions are set out in this preliminary decision document. In reaching our preliminary decision, we considered whether the evidence individually, in combination, or as a whole, supported a finding a UTS developed. Spilling occurred between 10 November 2019 and 16 January 2020 and, after considering each piece of analysis, our preliminary view is there was a UTS during the period 3 to 18 December 2019.

Framework for investigation

The UTS provisions promote, and are interpreted in light of, the Authority's statutory objective as set out in section 15 of the Electricity Industry Act 2010. The statutory objective requires the Authority to exercise its functions for the long-term benefit of electricity consumers. The UTS provisions in the Code are consistent with facilitating and encouraging competition and increasing the efficiency of the electricity industry.

Part of the complexity in investigating an alleged UTS is that it is not possible to directly observe confidence in or integrity of the wholesale market. We therefore look at indicators and other evidence to determine whether a UTS has occurred. We have looked specifically at the spot market and the forward market because between them they represent most of the value of the wholesale markets.

For the spot market we tested whether the outcomes we observed during the period of the spilling reflected supply and demand conditions. If participants observe prices and outcomes that are consistent with supply and demand conditions, it shows the spot market has integrity and participants can have confidence in it.

The Authority considers that if wholesale market outcomes reflect the supply and demand conditions, then there is no reason for confidence or integrity to be undermined. Conversely, if spot market outcomes vary widely from the underlying supply and demand conditions, then confidence or integrity may have been undermined and a UTS might have developed.

For the situation in question, fuel supply for hydro generators was abundant and all hydro generators in the South Island—for different periods during the investigation period—were spilling water because reservoirs were full. For a generator with storage water has value partly based on its opportunity cost because storage allows a generator to arbitrage across time.

Whether water is used to generate immediately, or stored for later use, part of its value is derived from the flexibility to choose between these two alternatives. For a hydro generator without storage, or with storage that is at or above capacity, water's value is derived only from its value from immediate generation—the opportunity cost is zero.

Participation is voluntary in the forward market and we use participation as an indicator of confidence or integrity. If confidence has been undermined, then participation will likely materially change – either falling as participants exit or rising due to lost confidence in the spot market leading to increased insurance against spot market exposure.

In conducting our investigation we:

a) investigated whether the **spot market** reflected underlying supply and demand conditions; and

b) analysed participation in the **futures market**, a material change in which could indicate a loss of confidence in the forward or spot markets (depending on the direction of change).

Our investigation framework is different from the approach laid out in the claim. The claimants alleged that Contact and Meridian's behaviour breached the high standard of trading conduct (HSOTC) provisions, and the nature and scale of this breach was so significant as to qualify it also as a UTS. The Authority's framework applies the UTS test directly rather than indirectly through an alleged breach of another Code provision. Finding a UTS does not also require or imply a breach of the HSOTC.

Separately from this UTS investigation, the Authority's Compliance team is considering the allegation that the HSOTC provisions were breached, following the processes required under the Electricity Industry (Enforcement) Regulations 2010. The test for a UTS is separate and a breach of the HSOTC provisions does not imply or require a UTS.

Investigation findings

Overall the outcomes in the spot market did not match our expectations of a power system with abundant cheap fuel. There were reasons for some of the things that we observed, such as consent conditions and limitations of generation plant. However, even allowing for these considerations, we consider there was significant unnecessary spill.

Context

The flood in December 2019 was a significant event. Historic data suggests that the only comparable events were in 2011 and 1995. Added to this was the HVDC outage scheduled for the first quarter of 2020 which meant North Island generators were trying to increase and conserve any storage they had.

Outcomes in the spot market did not match our expectations

- Offer prices fell at the Clutha stations and at Tekapo on the Waitaki in response to high inflows and spill. They also fell for a period at Meridian's Waitaki stations before increasing around 12 December. However, despite this short period when offer prices fell, offer prices at Meridian's Waitaki stations were much higher than at other stations in the South Island throughout the entire investigation period.
- Evidence shows Meridian was offering in such a way as to ensure the HVDC was not constrained. Managing the HVDC in this way benefits all South Island generators (and North Island net retailers) by preventing spot price separation between the North and South Islands.

- Spot prices did not react to widespread hydro spilling in a way we would expect. Electricity in New Zealand is priced by node and includes both generation costs and the cost of transmission losses and congestion. Large price differences, or price separation, indicate where transmission is constrained. These prices are important investment signals. When all South Island hydro stations are spilling, we would expect low South Island offer prices and price separation as transmission becomes constrained. This should lead to lower prices in the South Island than in the North Island, along with material intra-island and inter-island price separation.

- Spot prices eventually fell in late December due to reduced demand rather than offers changing because hydro stations were spilling. There is no evidence competitive pressure played a part in this price fall.

- Thermal generation ran in the North Island when South Island stations were spilling despite the HVDC seldom being close to its limits. In particular, the combined cycle plant at Stratford ran for a week while there was widespread spilling in the South Island. This is partly due to the lack of spot price response to the spilling.

- Transmission constraints did not bind often meaning there was less price separation than we would expect.

There were reasons for some of what we observed

- There were a range of issues associated with resource consents and generation equipment that affected how generators offered in the spot market. The effect of generators working within these limits is generation is withheld from the spot market by being offered at high prices. Our analysis distinguishes between this and other times when spot prices were still elevated.

Despite this we consider that there was a significant amount of unnecessary spill

- We simulated the spot market for December 2019 taking all the resource consent and equipment issues as given. We estimate there was excess spill equivalent to at least 55MW of generation capacity throughout December that could have been used for generation.
- We estimate the offer price needed to clear this generation is $6.35. If this generation had been dispatched, it would have resulted in North Island generation being displaced. If this North Island generation had storage, the North Island would have had more storage leading into the scheduled HVDC outage.
- We estimate about 17MW of the extra generation would have displaced North Island generation and resulted in increased North Island storage during December. It was known at the time there were planned HVDC and Pohokura outages during the first quarter of 2020. A large focus of the planning for that outage was security of supply, and North Island storage was critical to that. The foregone North Island storage likely meant the system was less resilient during the outage than it otherwise would have been, and that North Island prices were higher.

Cumulatively, these factors describe spot market outcomes that are far removed from our expectations[1]. From 3 to 18 December, generators spilled water in preference to lowering their offer prices and using the water to generate.

During the period of the alleged UTS, Meridian was pricing its offers to avoid the HVDC risk binding. We consider pricing offers to avoid the HVDC risk binding may contribute to

[1] We set out these expectations further at section 8.3.

threatening confidence in, and the integrity of, the wholesale market. We have previously advised Meridian that we do not agree with using offers to manage transmission constraints.

We observed no change in participation in the forward market. However, prices in the forward and financial transmission rights (FTR) markets are formed on expectations of the spot price. Spot prices that are inconsistent with underlying supply and demand conditions may have caused confidence or integrity of the forward market to be threatened over the long term. In particular, there is a risk that inefficiently high spot prices will flow through to futures prices, leading to withdrawal from the futures market over time. Inefficiently high prices in the South Island would also reduce pay outs on northwards (particularly inter-island) FTRs, which could affect confidence in that market.

This evidence and the impacts signal reduced efficiency of the electricity system. The spot price was higher than we would expect in the circumstances, which reduces demand and therefore reduces consumer welfare and allocative efficiency. The high prices also caused more expensive thermal generation to run in the North Island while there was excess spill in the South Island. This is a reduction in productive efficiency. The possible effects on the forward market prices noted above—which are used to signal investments—may affect dynamic efficiency. If these adverse outcomes in the spot market flow through to confidence in the forward and FTR markets, this would undermine efficient risk management and therefore competition, ultimately increasing prices for consumers.

Our preliminary view is there was a UTS during the investigation period

Our preliminary view is that confidence in or integrity of the spot market has been threatened—or may have been threatened—and there was an undesirable trading situation between 3 and 18 December 2019 because:

- Spot market outcomes differed markedly – for a sustained period – from what we expect given the underlying supply and demand conditions, and the scale of this difference is large.
- The confidence in, or integrity of, the forward market may have been threatened, due to its close link to the spot market.

If the Authority considers that there is indeed a situation which threatens, or may threaten, confidence in, or the integrity of, the wholesale market, it will then consider the second limb of the UTS test: whether the matter can satisfactorily be resolved by any other mechanism available under the Code (except clause 13.5A, which requires a high standard of trading conduct[2]). We are satisfied there is no other mechanism within the Code to resolve this situation other than via the UTS provisions.

The Authority has commenced a separate compliance process into the alleged breach of the trading conduct rules.

Next steps

This is a preliminary decision, and we welcome feedback.

We will consider all submissions before making our final decision.

2 See sub-clause (b) of the definition of 'undesirable trading situation', clause 1.1 of the Code. This means a UTS can also be a breach of the trading conduct provisions.

Where the Authority finds that a UTS is developing or has developed, it may take any action it considers necessary to correct the UTS. It is important to note that, as this is a preliminary decision, the Authority is yet to decide what action may be necessary. If the Authority reaches a decision that a UTS is developing or has developed, it will then separately consider what action is necessary. As required by the Code, the Authority will consult with affected participants unless it considers that it is impractical to do so, before taking any action.

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1 Introduction

1.1 A UTS is a situation that threatens, or may threaten, confidence in, or the integrity of, the wholesale market—and which cannot be resolved via other mechanisms under the Code. The Code provides the Authority powers to take corrective action if it considers a UTS has developed or is developing.

1.2 The Authority received a claim from seven participants on 12 December 2019 that a UTS had begun on 10 November 2019 and was continuing at the time of the claim. After considering the matter, we opened an investigation into the allegations made in that claim.

1.3 This document sets out our current analysis and preliminary decision, and the reasons for it, in relation to the situation described in the claim provided to us on 12 December 2019 ('the situation'). The views set out in this document remain subject to the Authority's review of all submissions received in relation to this matter.

1.4 In considering this claim, we have followed our guidelines for processing UTS claims.[3]

1.5 The structure of this paper is as follows:

(a) Section 2: the Authority's preliminary view

(b) Sections 3 – 5: background and introductory material

(c) Sections 6 – 9: preliminaries to and framework of investigation

(d) Sections 10 – 16: investigation and simulations into the spot market

(e) Section 17: investigation into the forward market

(f) Section 18: second limb of UTS test.

[3] The guidelines are on our website: https://www.ea.govt.nz/dmsdocument/8960-guidelines-for-participants-on-undesirable-trading-situations.

2 The Authority's preliminary view: the situation constitutes a UTS

2.1 The test described in Section 5 requires that, for a situation to constitute a UTS, confidence in, or integrity of, the wholesale market has been—or may have been—threatened. It is not possible to directly observe confidence in, or integrity of, the wholesale market. We therefore look at indicators and other evidence to determine whether a UTS has occurred. We have looked at the spot and forward markets as these markets constitute the majority of the value of the wholesale market.

2.2 Participation in the forward market is voluntary. We can use participation in the forward market as an indicator of whether confidence in, or integrity of, that market has been or may have been threatened. If confidence in, or integrity of, the forward market has been threatened, levels of participation in that market may change significantly. This analysis is set out in Section 17 below.

2.3 Participation in the spot market is not voluntary, so we would not observe a change in participation even if participants had lost confidence in the market or believed that its integrity had been threatened. For the spot market we examined whether the outcomes observed were consistent with supply and demand conditions. We set out what we would expect from an energy only spot market when the opportunity cost of water is zero. This counterfactual is set out in Section 8. We then tested what was observed in practice against this counterfactual and identified instances where what we saw differed from what we expected. The results of this analysis are set out in Section 16 and summarised in Table 1 below.

Table 1: Summarised results of analysis of the spot market

Spot market indicator	Expected behaviour in a competitive market against supply and demand conditions	Observed behaviour against supply and demand conditions
Offer behaviour	Offer prices fall when generators are spilling.	The Waitaki chain has higher offer prices compared to other stations, and these prices increased from 13 December onwards. Traders at other hydro stations lowered their offers in response to the full lakes and flood spill, from offer prices that were already at lower levels than Waitaki station offers. Meridian was offering to prevent transmission constraints – including the HVDC - from binding. This limited generation and resulted in unnecessary spill. Viewed in isolation the Authority's preliminary view is that the offering behaviour at Genesis' and Contact's South Island stations did not cause outcomes that were significant enough to constitute a UTS.

Spot prices	Prices fall when supply is abundant. Prices fall when demand falls.	Prices did not react to increased storage and the start of spilling. In late November to early December, the spot price increased despite rising hydro storage and stations spilling water. Storage was higher and demand lower in late November and early December compared to May and June, suggesting prices should be lower, but prices were similar. When spot prices did fall in mid-December, Meridian and Contact stated it was due to a fall in demand. There is no evidence that competitive pressure was forcing generators to reduce offer prices.
Price separation	Price separation occurs across transmission constraints when available generation supply exceeds transmission capacity	There were few trading periods when price separation occurred.
HVDC flows	Transfer across the HVDC as high as possible given other conditions	The northward flow on the HVDC did not increase in response to the increase in storage in December.
Transmission constraints	Transmission constraints bind when there is abundant, low priced supply in the South Island.	There were few trading periods during which constraints came close to binding.
Thermal generation	Thermal generation (with higher costs than hydro generation) falls when hydro storage increases.	The positive correlation between hydro storage and thermal generation during November and December 2019 indicates thermal generation remained high when hydro storage was high.
Spilling	Spilling minimised	Most of the total spill occurred between 2 – 11 December as a result of high inflows. Spill continued through most of December and stopped at different locations and times between 11 December and 16 January for most stations. Our simulations indicate that lower offer prices could have resulted in less spill.

2.4 We found no observable change in participation in the forward market.

2.5 Table 1 sets out how spot market outcomes were inconsistent with underlying supply and demand conditions in every aspect we looked at.

2.6 We simulated spot market outcomes under a counterfactual and estimated that the lower bound of additional spill caused by South Island hydro generators not changing their offers to reflect spilling was 55 MW throughout December, or 41 GWh. 55MW is about half the size of a generating unit at Benmore. This indicates the potential difference between the actual and expected outcomes is large. Our preliminary view is that even at the lowest end of the range, this level of waste is too large to be the result of ordinary market processes.

2.7 The South Island offer price required to clear the additional 55MW is about $6.35/MWh.

2.8 If 55MW of additional electricity had been generated it would have displaced North Island generation. To the extent that the displaced generation has storage associated with it, the North Island would have had more storage heading into the scheduled HVDC and Pohokura outages in the first quarter of 2020. We estimate about 17MW of the 55 MW would have displaced hydro generation on the Waikato River and resulted in an extra 12.6GWh of energy stored in Taupō ahead of the HVDC outage.

2.9 Our analysis and conclusions are set out in this preliminary decision document. After considering each piece of analysis individually and collectively, the Authority has reached a preliminary view that the events during the investigation period constitute a UTS because:

(a) Spot market outcomes differed markedly from what we would have expected given the underlying supply and demand conditions, and the scale of this difference is large, threatening the confidence and integrity of the spot market.

(b) The confidence or integrity of the forward market may have been threatened, due to its close link to the spot market.

(c) During the period of the alleged UTS, Meridian was offering to avoid the HVDC binding. We have previously advised Meridian that we do not agree with using offers to manage transmission constraints and wrote to Meridian about this in 2017 (regarding its conduct on 2 June 2016).

(d) While the Rulings Panel did not consider such conduct at the time (in 2017), and the Authority is considering the allegation that the HSOTC provisions were breached separately from this UTS investigation, we consider pricing offers so as to avoid the HVDC binding where it is contrary to market fundamentals may contribute to threatening confidence in, and the integrity of, the wholesale market. The inefficiently high offers during the periods of spill have the effect of economic withdrawal of the associated generation and avoidance of binding of relevant transmission constraints increasing prices for South Island consumers. These prices do not reflect the underlying supply and demand conditions.

The Authority has commenced a separate compliance process into a potential breach of trading conduct obligations

2.10 The claimants alleged that Meridian and Contact breached the high standard of trading conduct provisions of the Code.

2.11 This investigation was limited to considering whether there is a UTS. The Authority has commenced a separate compliance process into a potential breach of the trading conduct obligations in the Code in accordance with the Code breach process in the Electricity Industry (Enforcement) Regulations 2010.

3 This is a preliminary decision and we invite your feedback

3.1 The purpose of this paper is to set out the Authority's preliminary decision on the alleged 10 November 2019 UTS and give interested parties the opportunity to comment on that preliminary decision.

3.2 We will consider all submissions before making our final decision.

3.3 We are particularly interested in hearing from parties on the following topics:

(a) whether you agree with the framework for analysis

(b) whether you agree the appropriate factors have been considered

(c) whether you have been impacted by the situation.

How to make a submission

3.4 The Authority prefers to receive submissions in electronic format (Microsoft Word). Submissions in electronic form should be emailed to UTS@ea.govt.nz with *"Consultation on UTS preliminary decision"* in the subject line.

3.5 If you cannot send your submission electronically, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

Postal address	Physical address
Submissions	Submissions
Electricity Authority	Electricity Authority
PO Box 10041	Level 7, Harbour Tower
Wellington 6143	2 Hunter Street, Wellington

3.6 Please note the Authority wants to publish all submissions it receives. If you consider that we should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part

(c) provide a version of your submission that we can publish (if we agree not to publish your full submission).

3.7 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

3.8 However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act 1982 to withhold it. We would normally consult with you before releasing any material that you said should not be published.

When to make a submission

3.9 Please deliver your submissions by 5pm on Tuesday 11 August 2020.

3.10 We will acknowledge receipt of all submissions electronically. Please contact the Authority at UTS@ea.govt.nz or 04 460 8860 if you don't receive electronic acknowledgement of your submission within two business days.

4 Seven participants claimed a UTS started on 10 November 2019 and was ongoing at the time of the claim

4.1 On 12 December 2019 the Authority received a UTS claim by Haast Energy Trading, Ecotricity, Electric Kiwi, Flick Electric, Oji Fibre, Pulse Energy Alliance and Vocus. The claim is attached as Appendix A.

4.2 In summary, the claimants said:

(a) the relevant trading periods include trading periods from 11 November 2019 onwards

(b) Meridian and Contact have been spilling water

(c) the spilling of water means the ‘opportunity cost’ of value of water is zero, and the short-run marginal cost (SRMC) is near zero

(d) Meridian and Contact used their market power to offer in hydro generation at well above their SRMC

(e) Meridian and Contact’s trading behaviour during the relevant trading periods:

  (i) breached the High Standard of Trading Conduct (HSOTC) provisions (clause 13.5A) of the Code

  (ii) fell outside the safe harbour provisions of the Code (clause 13.5B)

  (iii) also qualifies as a UTS due to the nature and scale of the HSOTC breach

(f) the impact of the behaviour includes higher than otherwise wholesale electricity prices, unnecessary water spill, inefficient use of North Island hydro and thermal generation, and higher CO_2 emissions.

5 Undesirable trading situation is defined in the Code

5.1 Part 5 of the Code governs the Authority’s ability to act in respect of undesirable trading situations. Specifically, clause 5.1 of the Code provides that:

(1) If the **Authority** suspects or anticipates the development, or possible development, of an **undesirable trading situation**, the **Authority** may investigate the matter.

5.2 Undesirable trading situation is defined in clause 1.1 of the Code as:

any situation—

(a) that threatens, or may threaten, confidence in, or the integrity of, the **wholesale market**; and

(b) that, in the reasonable opinion of the **Authority**, cannot satisfactorily be resolved by any other mechanism available under this Code (but for the purposes of this paragraph a proceeding for a breach of clause 13.5A is not to be regarded as another mechanism for satisfactory resolution of a situation).

5.3 In determining whether there is a UTS, the Authority will therefore consider:

(a) whether the situation affects the wholesale market;

(b) whether the situation threatens, or may threaten, confidence in, or the integrity of, the wholesale market; and

(c) whether the situation may be resolved by any other mechanisms available under the Code (aside from the high standards of trading conduct provisions).

5.4 The wholesale market is defined in clause 1.1 of the Code as:

(a) the spot market for **electricity**, including the processes for setting—

(i) **real time prices**:

(ii) **forecast prices** and **forecast reserve prices**:

(iii) **provisional prices** and **provisional reserve prices**:

(iv) **interim prices** and **interim reserve prices**:

(v) **final prices** and **final reserve prices**:

(b) markets for **ancillary services**:

(c) the forward market for **electricity**, including the market for **FTRs**.

5.5 As to whether a situation threatens, or may threaten, confidence in, or the integrity of, the wholesale market, this provision requires the Authority to undertake a broad analysis, considering not only direct impacts on the market, but also impacts on participants’ confidence in the market and not only existing threats to the market, but also situations which “may threaten” market confidence or integrity.

5.6 To assist in identifying a potential UTS, clause 5.1(2) of the Code provides the following examples of what the Authority may consider to constitute a UTS:

(2) The following are examples of what the **Authority** may consider to constitute an **undesirable trading situation**:

(a) manipulative or attempted manipulative trading activity:

(b) conduct in relation to trading that is misleading or deceptive, or is likely to mislead or deceive:

(c) unwarranted speculation or an undesirable practice:

(d) material breach of any law:

(e) a situation that threatens orderly trading or proper settlement:

(f) any exceptional or unforeseen circumstance that is contrary to the public interest.

5.7 However, as is noted in clause 5.1(3) of the Code:

(3) To avoid doubt,—

(a) the list of examples in subclause (2) is not an exhaustive list, and does not prevent the **Authority** from finding that an **undesirable trading situation** is developing or has developed in other circumstances; and

(b) an example listed in subclause (2) does not constitute an **undesirable trading situation** unless the example comes within the definition of that term in Part 1.

5.8 Therefore, even if a situation does not appear on the list in clause 5.1(2), it may still be a UTS under the Code. Similarly, even where a situation does appear on the list in clause 5.1(2), the Authority will still need to establish that the definition of a UTS in Part 1 of the Code has been met.

5.9 For a situation to be categorised as a UTS it must meet the criteria set out in paragraphs (a) and (b) of the definition, as set out in paragraph 5.12. That is, it threatens, or may threaten, confidence in, or the integrity of, the wholesale market *and* it must not be able to be resolved by any other mechanism available under the Code. The definition also provides that a proceeding for a breach of the trading conduct provisions in clause 13.5A is not another mechanism for satisfactory resolution of a situation.

5.10 Read together with clause 5.5, which refers to the restoration of normal market operations after a UTS has occurred, a UTS will generally be a situation outside of the normal operation of the wholesale market.

5.11 A UTS may develop even if there is no Code breach, and a Code breach may occur without a UTS arising.

5.12 Where a UTS is found, clause 5.2 of the Code then provides that:

(1) If the **Authority** finds that an **undesirable trading situation** is developing or has developed, it may take any action that—

(a) the **Authority** considers necessary to correct the **undesirable trading situation**; and

(b) relates to an aspect of the **electricity** industry that the **Authority** could regulate in this Code under section 32 of the **Act**.

(2) The actions the **Authority** may take under subclause (1) include any 1 or more of the following:

(a) directing that an activity be suspended, limited, or stopped, either generally or for a specified period:

(b) directing that completion of trades be deferred for a specified period:

(c) directing that any trades be closed out or settled at a specified price:

(d) directing a **participant** to take any actions that will, in the **Authority's** opinion, correct or assist in overcoming the **undesirable trading situation**.

5.13 Clause 5.5 of the Code further provides that:

The **Authority** must attempt to correct every **undesirable trading situation** and, consistently with section 15 of the **Act**, restore the normal operation of the **wholesale market** as soon as possible.

6 We considered our statutory objective

6.1 The broad UTS provisions are consistent with:

(a) the economic rationale for UTS-type provisions. Such provisions are intended to achieve operationally efficient and competitive markets. In particular, they recognise that market providers cannot foresee all eventualities and that some practices may be difficult to identify and prevent in advance using other rules. As such, UTS provisions often give market providers broad discretion to address practices which might in some way threaten the market; and

(b) the Authority's statutory objective. The UTS provisions promote, and are interpreted in light of, the Authority's statutory objective as set out in section 15 of the Electricity Industry Act 2010, specifically:

> …to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

6.2 In considering the application of the UTS provisions, the Authority also considers its statutory objective. While the Code sets out the legal framework within which our consideration of a UTS must occur, our interpretation of our statutory objective provides an economic context.

6.3 We interpret our statutory objective as requiring us to exercise our functions—set out in section 16 of the Act—*for the long-term benefit of electricity consumers*:[4]

(a) facilitate or encourage increased competition in the markets for electricity and electricity-related services, taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in those markets

(b) encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst being robust to adverse events

(c) increase the efficiency of the electricity industry, taking into account the transaction costs of market arrangements and the administration and compliance costs of regulation, and taking into account Commerce Act 1986 implications for the non-competitive parts of the electricity industry, particularly in regard to preserving efficient incentives for investment and innovation.

What we will consider

6.4 In considering whether a situation threatens, or may threaten, confidence in, or the integrity of, the wholesale market, the Authority will look to gather evidence and conduct analysis. This might include, for example:

(a) evidence of participants' conduct during the alleged UTS;

(b) whether participants consider that confidence in the market has been threatened;

(c) historical evidence of what has happened in the market; and

(d) any other factors the Authority considers relevant.

6.5 The Authority may also conduct an economic analysis to determine whether what occurred in the market during the alleged UTS was consistent with what might be

[4] Our interpretation of our statutory objective is on our website: https://www.ea.govt.nz/about-us/strategic-planning-and-reporting/foundation-documents/.

expected to happen when the market is operating normally. Such an analysis may assist in identifying underlying issues in the market or unusual conduct by participants which might have caused, or been caused by, a UTS. It is also consistent with clause 5.5 of the Code, which, as noted above, suggests that a UTS may occur where the market is not operating normally and will be resolved when the market returns to normal operation.

Can the matter be addressed under any other provisions of the Code?

6.6 If the Authority considers that there is indeed a situation which threatens, or may threaten, confidence in, or the integrity of, the wholesale market, it will then consider the second limb of the UTS test, specifically whether the matter can be addressed under any other Code provisions. The high standard of trading conduct provisions, contained in clause 13.5A of the Code, are expressly excluded from this analysis, meaning a situation can be found to be a UTS and a breach of the trading conduct provisions.

6.7 In considering this limb of the test, the Authority does not consider the potential for future Code amendments. The High Court in *Bay of Plenty Energy v Electricity Authority* found that potential future Code amendments cannot be a "mechanism available under the Code" as required by the second limb of the UTS test.

7 Preliminaries: approach to investigation

7.1 The claimants alleged that Contact and Meridian's behaviour breached the HSOTC provisions, and the nature and scale of this breach was so significant as to qualify as a UTS.

The alleged breach of the HSOTC provisions is being investigated separately

7.2 The finding of a UTS does not also require a breach of the HSOTC provisions to have been found (or vice versa). While the Authority considers there may be some overlap between situations which amount to a UTS and situations where the HSOTC provisions have been breached, we have considered them as two separate tests.

7.3 Instead we have applied the UTS test directly. Our approach to test whether a UTS had developed or was developing over the investigation period was to consider whether confidence in, or integrity of, the wholesale market has been (or may have been) threatened and whether the issue could be addressed by other Code mechanisms.

7.4 The Authority's Compliance team is considering the alleged breach of the HSOTC provisions.

The wholesale market consists of several interrelated components

7.5 At the centre of the wholesale market is the spot market. The spot market selects the lowest-cost mix of available resources, in the form of generation or load reduction, to meet demand for each half hour—plus some reserve supply in case something goes wrong. The spot market determines the amount and location of generation needed to satisfy demand and in this way balances supply and demand.

7.6 The spot price is affected by a range of factors out of the control of both generators and consumers, such as rainfall in hydro catchments and the amount of wind at wind farms. These factors mean the spot price is volatile which in turn means consumers and generators need a means to insure themselves against price fluctuations.

7.7 The forward market provides this insurance using forward contracts that allow generators and purchasers to lock in spot prices in advance at an agreed node. These contracts mean both sides receive or pay a fixed price and avoid spot price volatility.

7.8 Similarly, prices can vary between nodes in the network for any particular half hour. Insurance is available in the form of a financial transmission right (FTR) that will pay the holder the price difference between two nodes. FTRs help generators and retailers manage the future price risk from transmitting electricity across different geographical points in the country.This matters for generators that are also retailers in cases where they generate at a node where the spot price is low, but purchase at a node where the spot price is high.

7.9 Other components of the wholesale market ensure the reliability and quality of electricity. The instantaneous reserves market provides idle generation that can start quickly if active generators are suddenly unable to generate because of a fault.

We analysed two key matters

7.10 To understand whether the situation in question threatens or, may threaten, confidence in, or the integrity of the wholesale market, we analysed two key matters:

(a) we investigated whether the spot market outcomes reflected changes in underlying supply and demand conditions

(b) we analysed participation in the futures market, a material change in which may, in some circumstances, indicate a loss of confidence in the forward market.

7.11 Participation is voluntary in the forward market, therefore may be an indicator of confidence or integrity. For example, any change in participation (ie, lower trading volumes on the Australian Securities Exchange) may indicate a loss in confidence or integrity. Increased participation may signal a loss of confidence in the spot market leading to a desire for less spot exposure. Reduced participation may indicate a loss of confidence in the forward market.

7.12 Participation in the spot market is not voluntary. There is no opportunity for participants to enter and exit the market in response to changing conditions if they wish to continue to supply or purchase electricity. This means participation in the spot market cannot be used to measure confidence or integrity The Authority has taken a different approach to analysing the spot market.

7.13 Our analysis of the spot market follows the logic that if wholesale market conduct or outcomes are not consistent with underlying supply and demand conditions, then there may be a risk that confidence or integrity may have been undermined.

7.14 This is similar to the approach taken for the 2018 UTS investigation.[5] In respect of the UTS alleged in 2018, we looked at how the wholesale market responded to a gas supply shock when gas became scarce. In this investigation we looked at a hydro inflow supply shock where hydro fuel became abundant.

7.15 In undertaking our assessment, we considered whether the evidence we found in our investigation, individually, in combination, or as a whole, was capable of supporting a finding that a UTS developed.

7.16 We note the approach of the investigation is focussed on outcomes and behaviour and does not attempt to find fault.

[5] Our decision on the Spring 2018 alleged UTS can be found on our website: https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/15-september-2018/

8 Preliminaries: our expectations are formed from a starting point of spilling generators having zero opportunity cost of water

8.1 We can look at spot prices and outcomes in the market and determine whether they are consistent with market conditions, including the underlying supply and demand conditions. If spot prices and outcomes are consistent with market conditions, it suggests the spot market has integrity, and that participants are likely to have confidence in it. Conversely, if the spot prices and outcomes differ from what we would expect, this may threaten the integrity of the market and the confidence participants have in it.

8.2 As set out below, the investigation period is defined by large increases in storage and spilling by South Island hydro generators. When a hydro generator is spilling, the opportunity cost of not storing water is zero. This is a case of abundant fuel.

8.3 All else being equal, when hydro generators in the lower South Island are spilling, we would expect to see:

(a) lower offer prices because the opportunity cost of water is zero for a spilling generator—this does not imply a zero offer price because of other costs of generating

(b) South Island spot prices to fall because of these lower offers

(c) South Island spot prices to separate from North Island spot prices if transmission limits are reached, or if not, low prices in both Islands

(d) More energy to flow over the HVDC because of lower South Island spot prices

(e) Spill to be minimised subject to consent conditions and the level of demand and HVDC capacity that prevailed at the time

8.4 These expectations follow logically from the reduction in the opportunity cost of water to zero when it cannot be stored. They are indicators of spot market efficiency. Efficiency in an economic sense is achieved when price equals cost in a competitive market. As part of its statutory objective, the Authority promotes competition for the long-term benefit of consumers. Increased competition[6] forces prices closer to cost as the industry competes for customers. As prices approach cost, electricity consumption increases benefitting consumers.

8.5 Efficiency in economics also refers to the use of the lowest cost technology to produce outputs. In the electricity industry this usually means using the lowest cost fuel source. As set out above, when a hydro station is spilling, the opportunity cost of the water is zero. The use of this abundant low-cost fuel is maximised when spill is minimised as set out in 8.3(e) above. Low cost South Island generation would then displace higher cost North Island generation as more energy flows over the HVDC. This means lower prices for consumers.

8.6 Efficiency in economics can also refer to efficient investment. This is particularly important for the electricity industry where investments in generation and transmission are large, indivisible, capital-intensive and long lived. There are two ways the list of expectations affects efficient investment. Firstly, the spot price—and expectations of the future spot price formed in the FTR and forward markets—are an important input into

[6] By competition we mean workable competition and the associated downward pressure on prices that this implies.

investment decisions. Secondly, the price differences that occur when prices separate signal the location and value of transmission investment. In these ways a market operating in accordance with our expectations at 8.3(b) and (c) above provides benefits to consumers in the form of efficient investment and lower long run prices.

9 Preliminaries: scope of investigation

We can look at what occurred in the wholesale market regardless of when it occurred

9.1 The Authority can initiate an investigation if it suspects or anticipates the development, or possible development of, a UTS. Clause 5.1A of the Code states:

> Despite clause 5.1(1), the **Authority** must not commence an investigation if more than 10 **business days** have passed since the situation, which the **Authority** suspects or anticipates may be an **undesirable trading situation**, occurred.

9.2 We consider that clause 5.1A places limits on when we can *begin* an investigation, but has no other effect.

9.3 Although some aspects of the alleged UTS occurred earlier than 10 business days before the claim was made, the claimants allege the UTS was continuing at the time the claim was made on 12 December 2019.

9.4 As we suspected that a UTS was ongoing at the time they made their claim, we were able to initiate our investigation on 13 December 2019, within the 10-business day period. Once the investigation started, clause 5.1A did not limit the scope of our investigation (that is, we could investigate events that took place earlier than 10 business days before the investigation started).

9.5 We also consider that we can take into account relevant matters that occurred before the start of the alleged UTS (that is, that occurred before 10 November 2019) for the same reasons.

We investigated the period from 10 November 2019 to 16 January 2020

9.6 As described in Section 4, the claimants said some generators were making large tranches of generation offers at higher than $50/MWh while they were spilling water, and as a result these stations were not dispatched as much as they would have been if their offers reflected the short run marginal cost (SRMC) of the water in these catchments.

9.7 We consider that the UTS claim relates to the specific offering behaviour and surrounding circumstances of water spilling. It is appropriate to base the investigation on the period in which those conditions existed and there is no need to expand the investigation further than the spilling period.

9.8 Data provided by the generators concerned clearly indicates the spilling sequence started on 10 November 2019 and ended on or before 16 January 2020.

9.9 The claimants have advised they have no objection to the investigation period ending on 16 January 2020.

We investigated two key aspects of the wholesale market

9.10 As described in paragraph 5.4, the wholesale market comprises the spot, forward, and ancillary services markets. We have looked at each of the spot and forward markets as these markets constitute most of the value of the wholesale market. We have looked at the market for reserves to the extent that it affected transfer over the HVDC. We have not investigated the other ancillary services or the FTR market. The latter trades so infrequently it would be difficult to discern anything from a small number of data points.

We included three parties in the investigation

9.11 The claimants said Meridian and Contact were making large tranches of generation offers at higher than $50 per MWh while they were spilling water. We decided to extend the investigation to include the activities of Genesis Energy Limited (Genesis) because it was also found to be spilling significantly from its South Island lakes during the period of investigation. We have also made reference to Mercury NZ Limited (Mercury) where relevant, but Mercury's activity was not a subject of the investigation.

We have sought information from relevant participants

9.12 In conducting this investigation, it has been necessary to seek information from relevant participants on several topics.

(a) When deciding the end date of the alleged UTS, we asked for the opinions of the claimants. They had no objection to our decision.

(b) As owners of the spilling South Island hydro generators, we asked Meridian, Contact and Genesis for data relevant to our investigation. For example, spilling and weather forecast data and any other information they considered relevant. Before the release of this preliminary decision we sent each of these parties content relevant to their respective data submissions, to check for errors of fact and any material that might be commercially sensitive. In the case of Meridian, we did two rounds of fact checking because of the complexity of the material involved.

10 Wholesale market conditions leading up to the investigation period

Key points

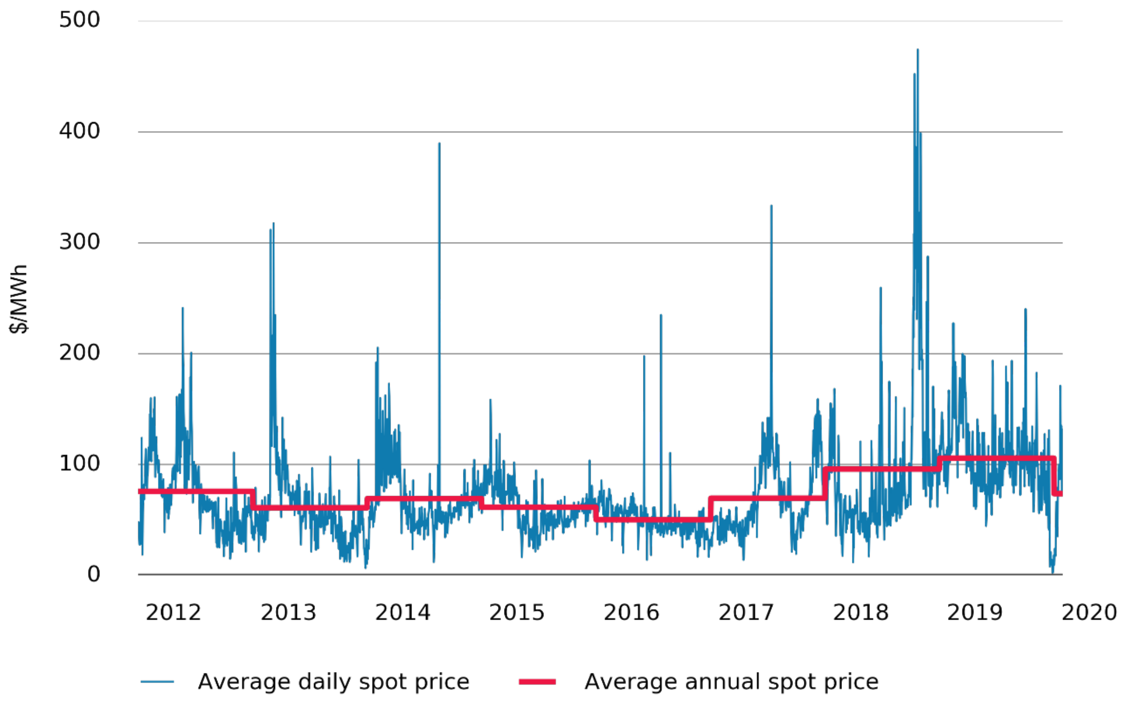
- We analysed the overall conditions in the wholesale market in the lead up to, and during, the period under investigation
- Spot prices were higher than previous years
- Hydro storage rose significantly towards the end of 2019

10.1 This section describes the conditions in the wholesale market in the lead up to, and during, the period under investigation. We focus on understanding what happened to electricity spot prices and hydro storage as these factors are at the centre of the claim.

Spot prices were higher than previous years

10.2 Figure 1 shows the average daily and average annual spot price from 2012 to 2020. Before 2018, the average annual spot price in New Zealand was about $80/MWh. However, this average does not capture significant yearly, monthly, weekly and half-hourly fluctuations that occur as supply and demand vary in real time.

Figure 1: Electricity simple average spot price for all of NZ

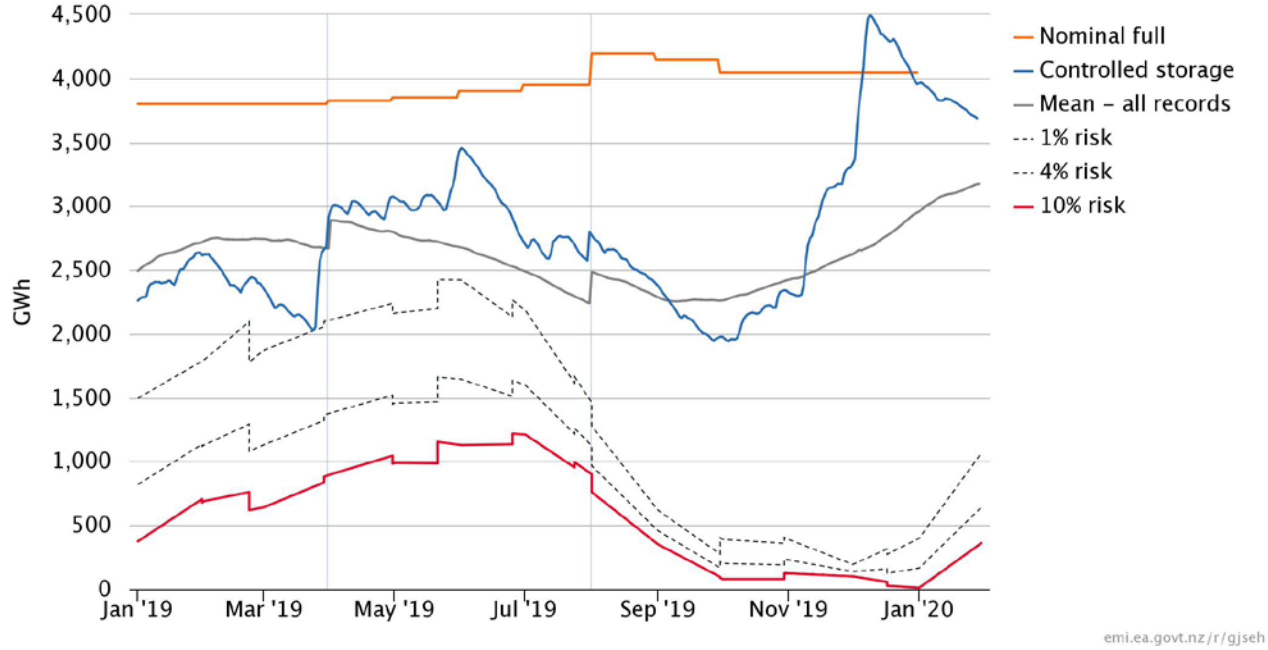


10.3 The average annual spot price in 2019 was $105.64/MWh. For most of the year, prices were higher than seen in previous years.

Hydro storage rose significantly towards the end of 2019

10.4 Figure 2 shows controlled hydro storage in 2019 and 2020. While dry weather at the beginning of the year caused storage to hit the 1 percent risk curve in March 2019, heavy rainfall at the end of March 2019 and in May 2019 kept the hydro lakes above the mean levels for most of winter. The levels did drop below the mean in September, until spring rain and snow melt led to strong inflows in November and December 2019. Note the sharp jumps in mean storage are due to changes to contingent storage at these times, not statistical anomalies.

Figure 2: 2019/20 hydro storage compared with Mean and HRC risk curves



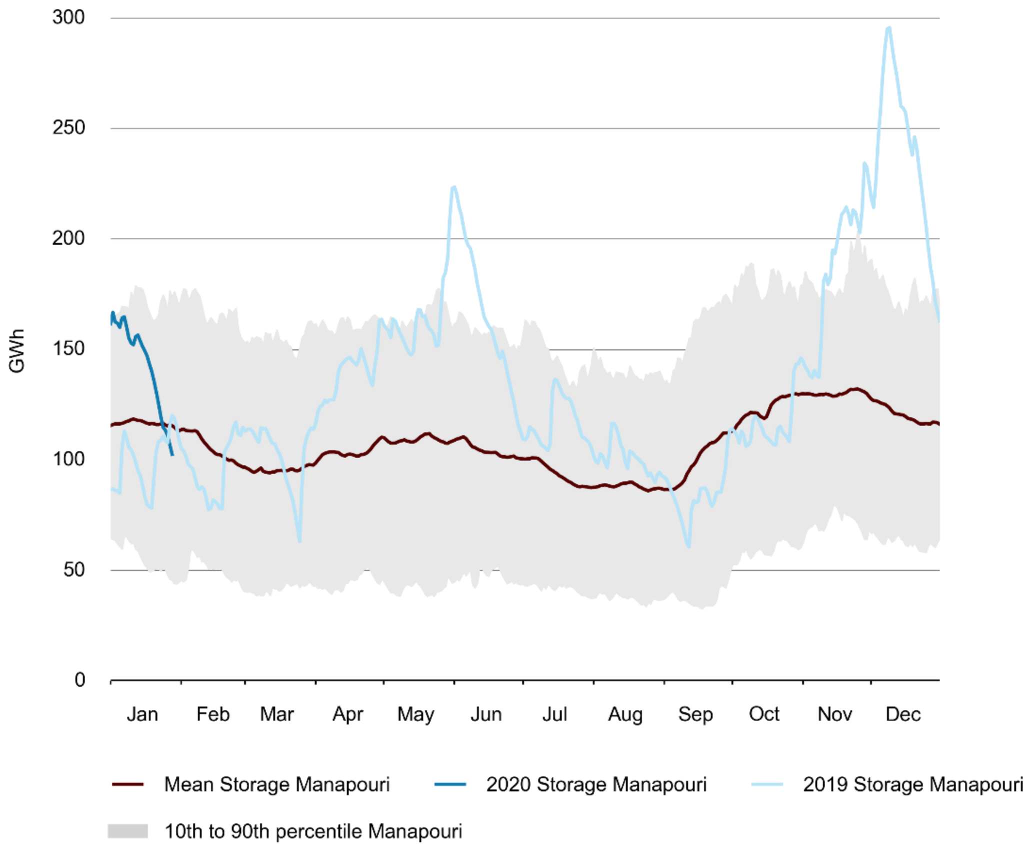
10.5 Heavy rainfall in December pushed hydro storage above the nominal full level, which resulted in spillage from all South Island hydro schemes. In January 2020, levels had dropped below the 'nominal full' amount but there was still spill from some generators until 16 January.

10.6 A hydro generator with a reservoir can arbitrage between time periods by storing inflows for later use. For example, a hydro generator may choose not to generate overnight in anticipation of higher prices during the following day. By using water to generate, the generator incurs an opportunity cost—the revenue the generator may have otherwise received if they used the water later. Conversely, by storing water, the generator incurs the opportunity cost of not using it to generate immediately. Whether a generator uses or stores water, the water's value is partly determined by the opportunity cost. When a hydro generator is spilling, because the reservoir is at maximum capacity, the opportunity cost of not storing water is zero.

10.7 The following graphs measure hydro storage for each of the large hydro lakes in GWh for 2019 and 2020. The values represent the possible electricity production from the current level of storage. The charts all show mean storage, and the shaded area shows the range from the 10th to the 90th percentile.

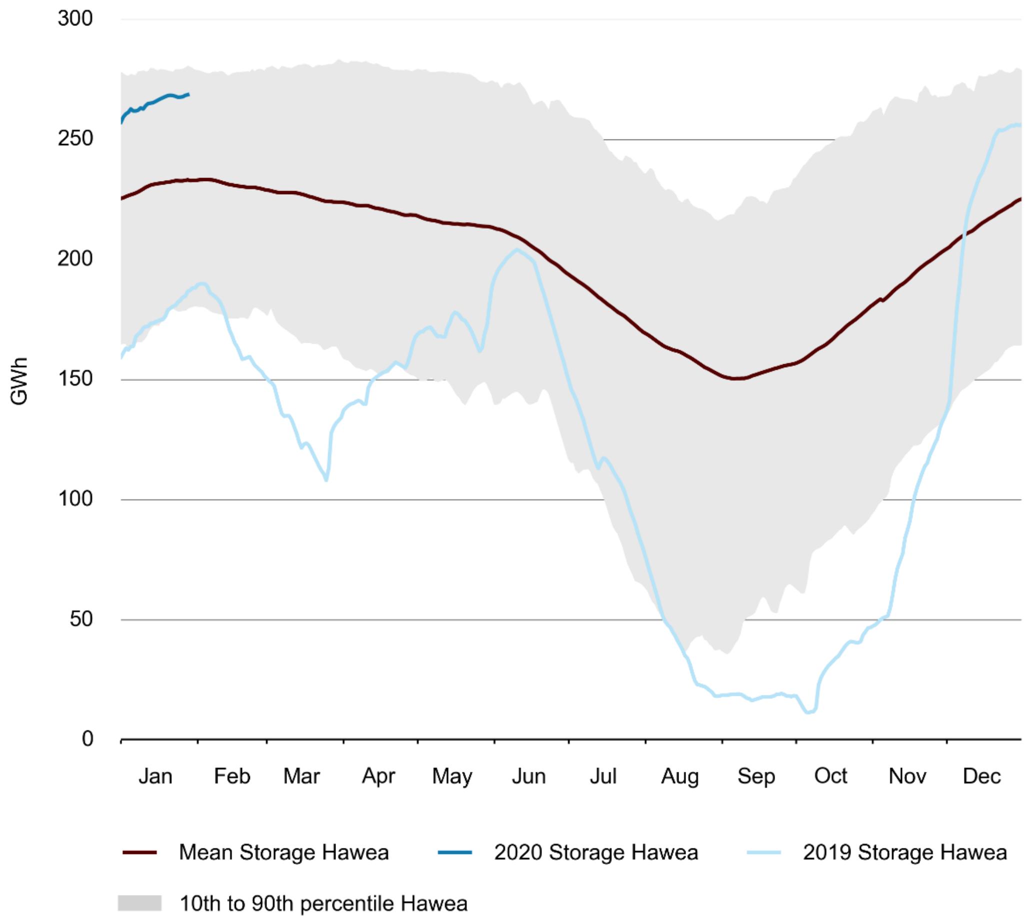
10.8 Figure 3 shows hydro storage in Lake Manapōuri. Manapōuri was above the 90th percentile in May and June 2019 after heavy inflows from 26 May. The lake was above the 90th percentile from 9 November due to a heavy rain event and stayed above this threshold, almost peaking at 300 GWh, until close to the end of 2019. At the beginning of 2020 the lake level continued to decline.

Figure 3: 2019/20 storage in Lake Manapōuri



10.9 Figure 4 shows hydro storage in Lake Hāwea in 2019. Lake Hāwea is the main storage for the Clutha hydro generators (Clyde and Roxburgh). At the end of 2019 and beginning of 2020 storage was above the mean but did not reach the 90th percentile.

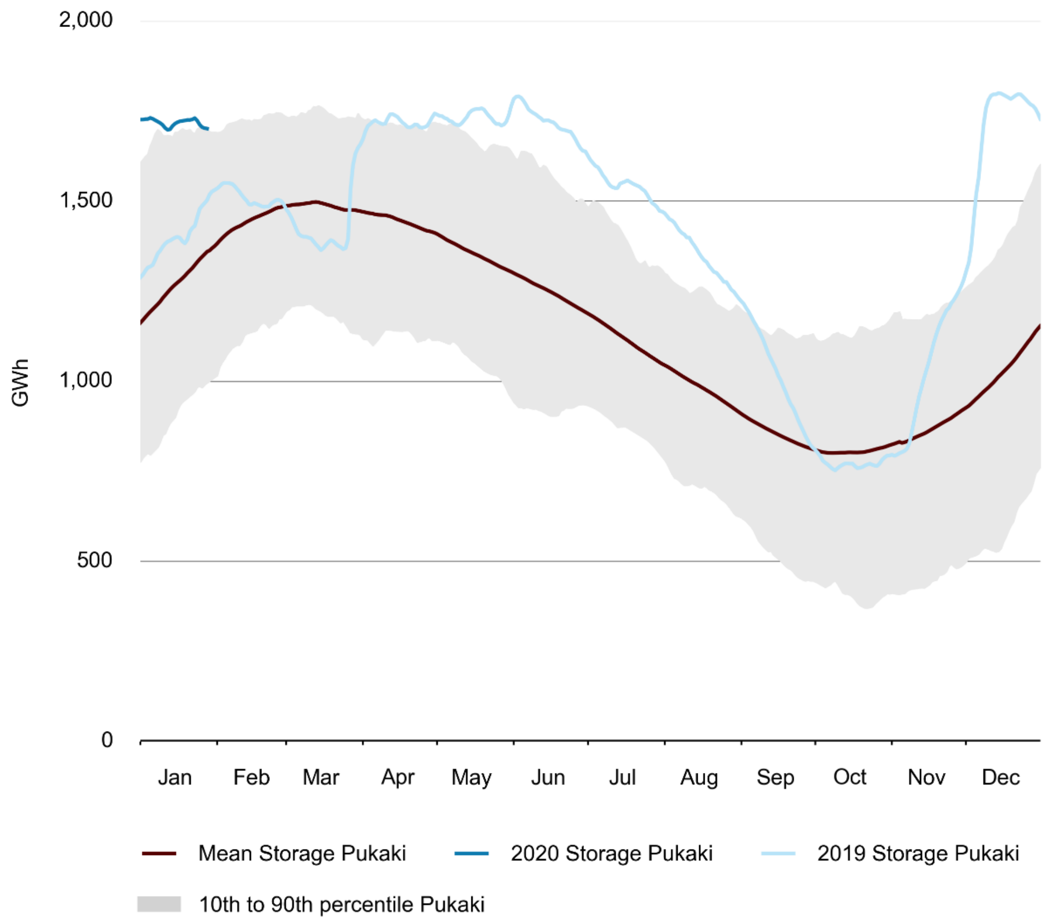
Figure 4: 2019/20 storage in Lake Hāwea



10.10 Figure 5 shows hydro storage in Lake Pukaki in 2019. Pukaki has a large consented operational range which means it provides the largest source of hydro storage in New Zealand (about half of New Zealand's hydro storage capability). Pukaki storage was above the 90th percentile for much of the winter before falling to below average in

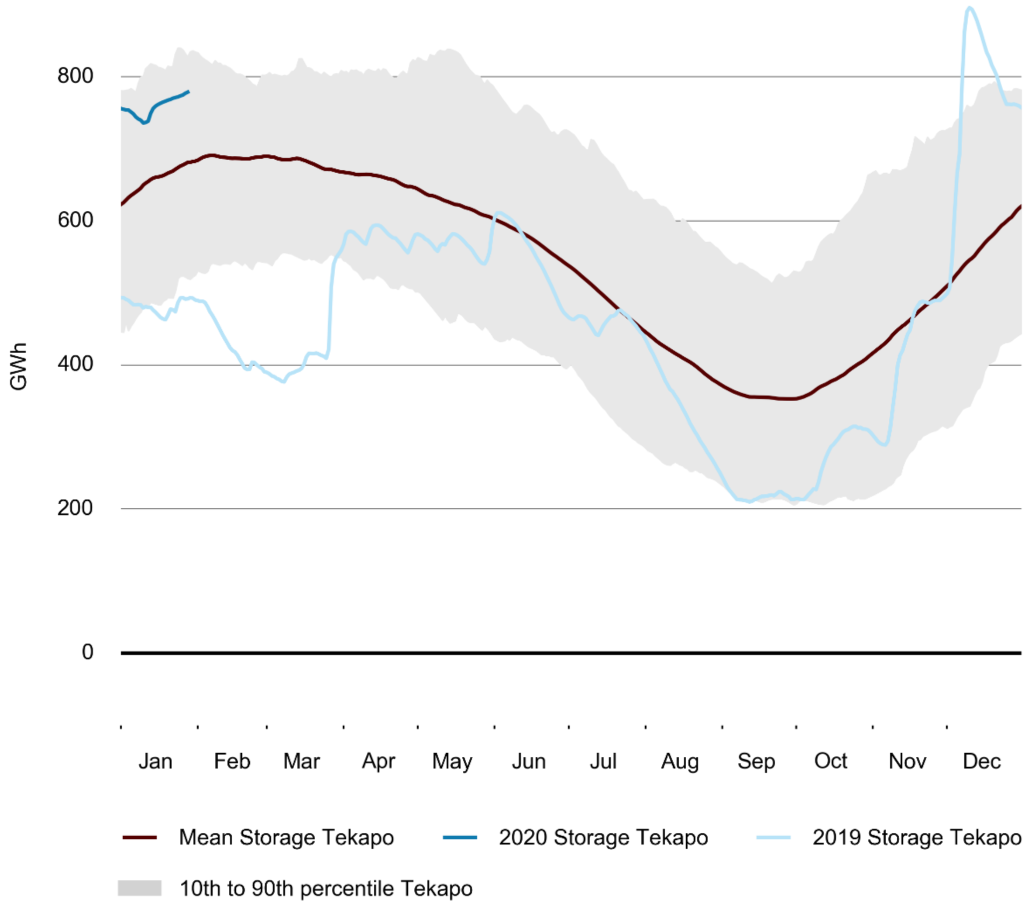
September, then climbing to high levels again over November and December 2019. The levels have remained above the 90th percentile at the end of the investigation period.

Figure 5: 2019/20 storage in Lake Pukaki



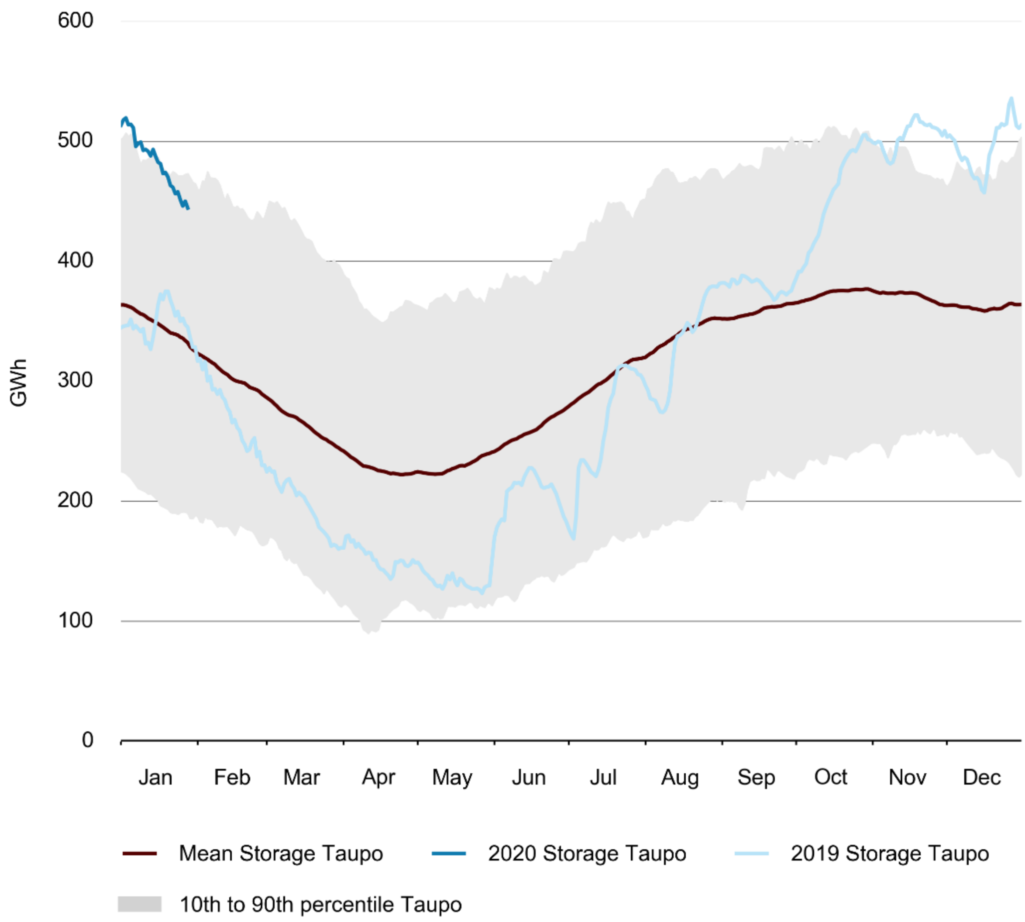
10.11 Figure 6 shows hydro storage in Lake Tekapo. Lake Tekapo was below mean storage for much of 2019 before strong spring inflows pushed storage above the 90th percentile late in the year.

Figure 6: 2019/20 storage in Lake Tekapo



10.12 Figure 7 shows hydro storage in Lake Taupō. Lake Taupō was below the mean for most of the first half of 2019 due to dry weather. Strong inflows meant Taupō crossed the 90th percentile in November and December 2019. Maintaining high storage in Taupō during November and December 2019 was important for system security given the planned HVDC outage in the first quarter of 2020. The outage restricted export capacity from the South to the North Island. During the outage it was reasonable to assume Taupo's level would reduce quickly due to the restricted transfer over the HVDC. This did happen as shown in Figure 7. Lake levels have been declining in 2020, but were still well above the mean levels at the end of the investigation period.

Figure 7: 2019/20 storage in Lake Taupo



11 We investigated indicators of confidence in and integrity of the spot market by checking whether outcomes matched expectations given underlying supply and demand conditions

Key points

- We analysed various spot market indicators and found they did not match our expectations during the investigation period
- Spot prices were high in the South Island during periods of spilling
- When spot prices fell it was due to a fall in demand rather than due to competitive pressure caused by abundant cheap fuel
- Price separation did not occur as much as expected
- HVDC flow did not increase
- Thermal generation increased when hydro storage increased

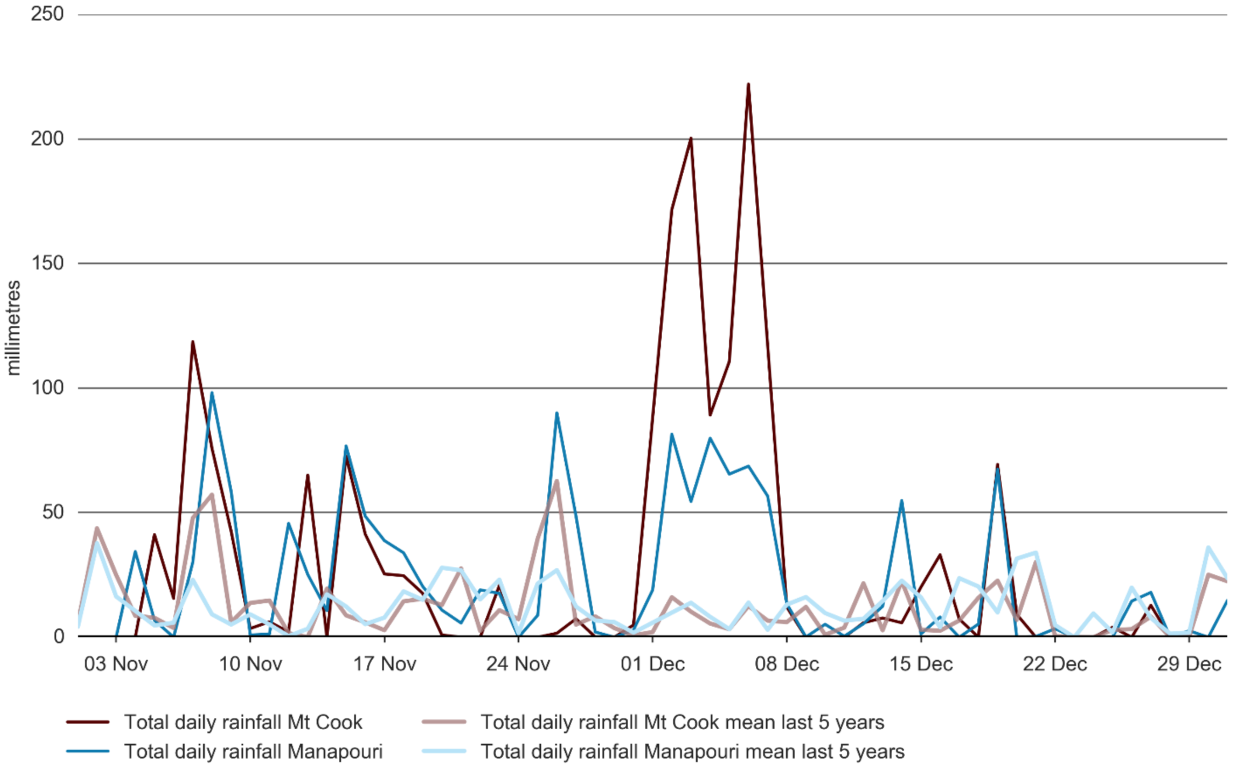
11.1 This section describes the outcomes that occurred in the spot market during the investigation period and compares them to our expectations. Factors analysed include hydro inflows, offer prices, spot prices, HVDC flows and transmission constraints, levels of spill, demand and thermal generation.

High inflows resulted in spill in the South Island

11.2 There was above average rainfall for the South Island in November and December 2019, including in many of the catchment areas for hydro generation. Total rainfall at Manapouri over November and December 2019 was 1390mm, compared to an average total (over November and December) for the last five years of 776mm. The figures for Mt Cook were 1776mm and 761mm respectively.

11.3 Figure 8 shows rainfall at two South Island locations. Rainfall was highest between 2 and 9 December 2019. The Rangitata River flooded on 8 December, damaging a number of pylons which resulted in the loss of the Islington to Livingston 220kV circuit. This led to more flow through the Waitaki lines—in particular the Aviemore-Benmore circuits—which meant these circuits were more likely to constrain.

Figure 8: Daily rainfall Mt Cook and Manapouri



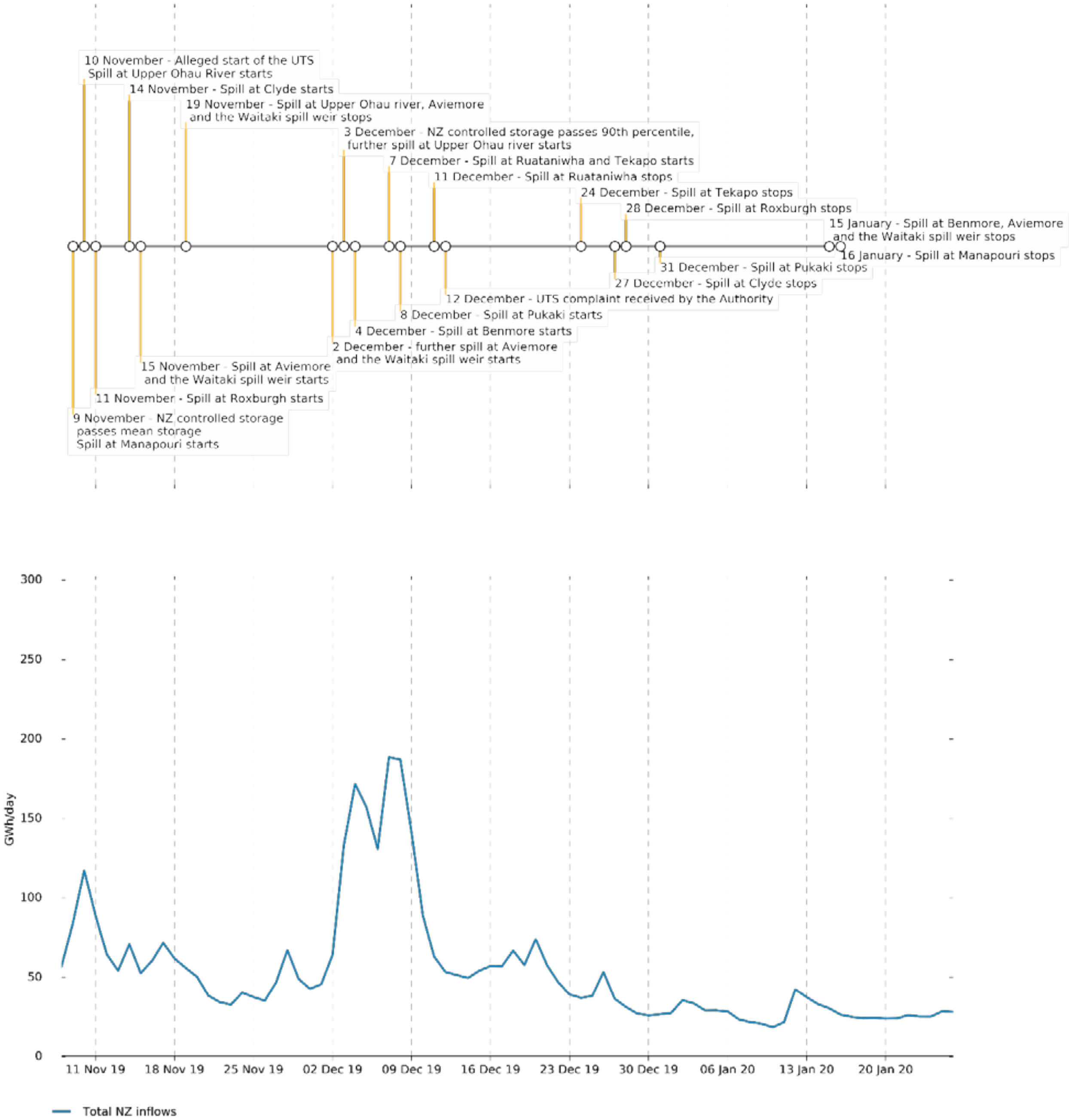
Source: NIWA

Figure 9: Lower SI showing hydro generation and transmission lines

11.4 Waterways and lakes used for hydro storage and generation usually have minimum and maximum allowable water levels and flows. These are determined by resource consents or by engineering constraints. The heavy rainfall in the catchment areas resulted in water levels above the maximum allowed in some lakes in the South Island. To get water levels back within the allowable range as quickly as possible, excess water was allowed to bypass the generation station and flow into waterways without being used to generate electricity. This is known as flood spill. There are other reasons why a hydro station may need to spill water without using it for generation, such as to meet resource consent minimum river flow requirements or to bypass turbines out for maintenance. But for the remainder of this report ‘spill’ refers to ‘flood spill’ which is over and above river flows needed for other resource consent issues.

11.5 Figure 10 shows the total controlled inflows in NZ from November 2019 – January 2020 as well as a timeline of when the South Island stations were spilling. Manapōuri was spilling the longest (9 November until 16 January). Most of the total spill occurred between 2 – 11 December. Spill continued through most of December and stopped between 24 December and 16 January depending on the station.

Figure 10: Timeline of spilling in the South Island and total inflows into NZ controlled storage lakes



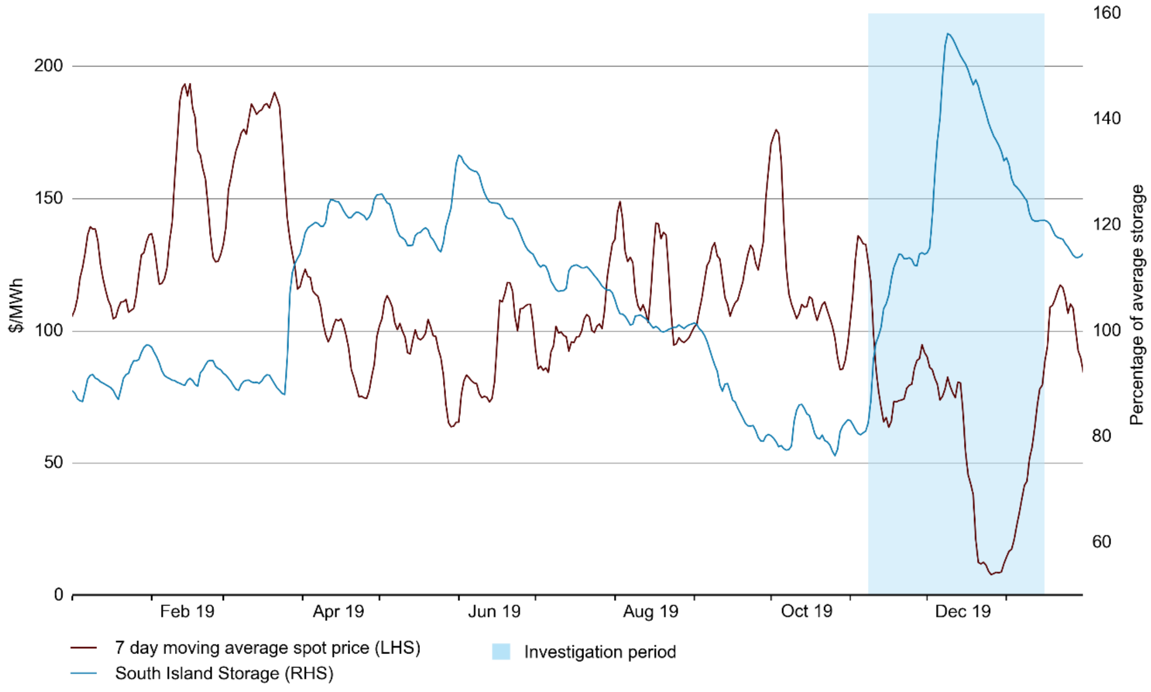
Spot prices did not initially react to increased hydro storage

11.6 We considered whether spot prices moved in a direction predicted by observed supply and demand conditions. Figure 11 shows the seven-day moving average spot price at Benmore, and hydro storage as a percentage of average. Over the long term, as hydro storage rises, the spot price falls. From 2015 to 9 November 2019, the correlation between hydro storage and the spot price (7 day moving average) was -0.49. A negative correlation indicates that when one increases, the other decreases and vice versa. When water is scarce, the opportunity cost of using water is higher and hydro offers increase. This makes more expensive thermal generation viable.

11.7 From mid-November the spot price was on average the lowest it had been in 2019. From 11 November (when the spot price shown in Figure 11 dropped below $100/MWh for the first time in November) until 16 January 2020, the average price was $56.50/MWh compared to an average of $117.95/MWh for the rest of 2019. Also as seen in Figure 11, the price dropped on 18 December down to a daily average of $10.70/MWh for the rest of December and remained around this price until 7 January when the HVDC outage started.

11.8 Despite an initial drop in price as storage rose, there was a period in late-November / early-December where the price levelled out and even rose slightly, as hydro storage continued to increase. When prices did eventually fall in late December, both Contact and Meridian claimed the reason was falling demand, rather than the abundant supply which can be seen clearly in the chart below. This suggests a lack of competitive pressure. We would normally expect any market faced with abundant cheap supply would see price fall as suppliers competed for market share. That this didn't happen during the UTS period suggests weak competition.

Figure 11: Spot price compared to hydro storage



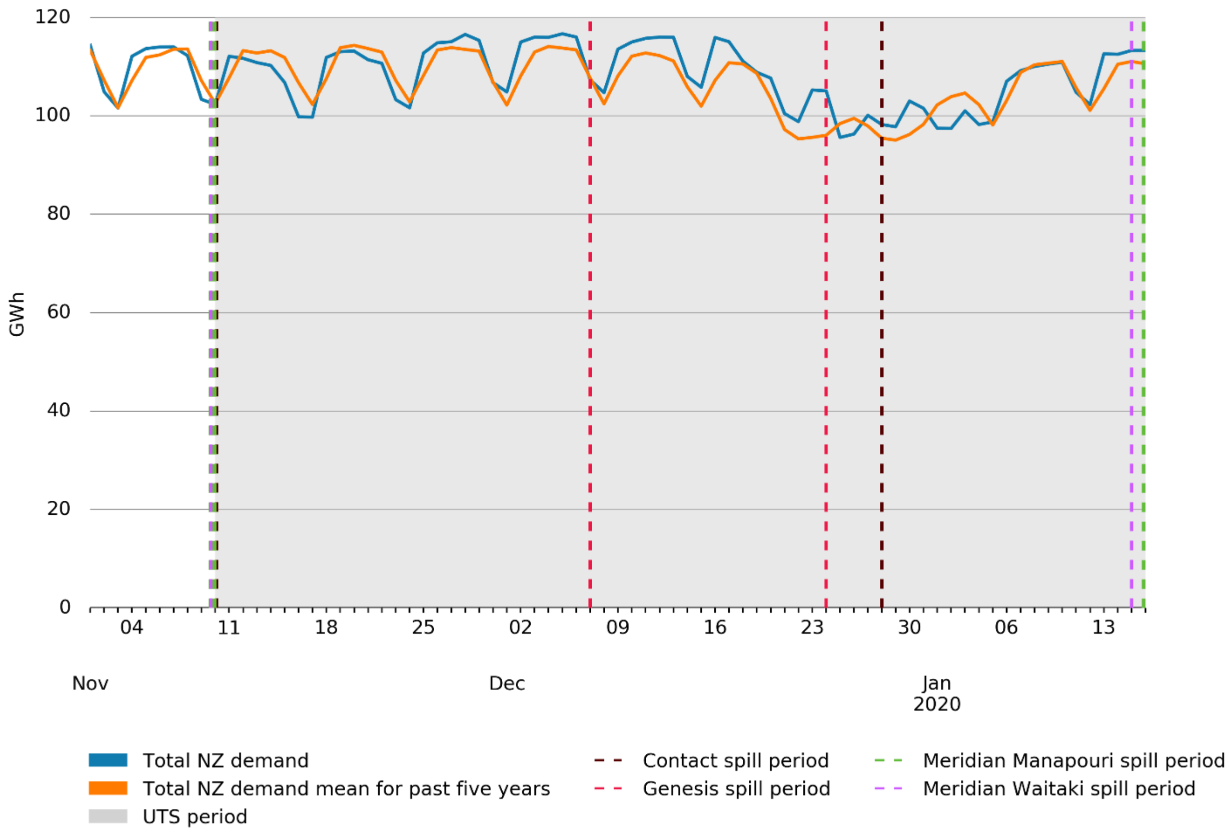
Spot prices decreased in late December due to a drop in demand

11.9 While annual demand was high in 2019 compared to previous years, demand is typically lower during summer, especially between 21 December and 5 January. Figure 12 shows total New Zealand demand and the fall in demand can be seen starting around 21 December.

11.10 Both Meridian and Contact made public statements saying the fall in price was due to a fall in demand. This suggests there was a lack of competitive pressure in the South Island at the time.

11.11 Prices increased as demand increased from 6 January.

Figure 12 Total New Zealand demand



11.12 Storage was higher and demand lower in early December compared to May and June when there was also spilling in the South Island. This suggests prices should have been lower, when in fact actual prices were similar to those in May and June.

Price separation did not occur very often

11.13 Electricity in New Zealand is priced by node, taking into account both generation costs and the cost of transmission losses and congestion. Large price differences, or price separation, indicates where transmission is constrained. These prices are in turn important investment signals.

11.14 As South Island generators had abundant cheap fuel while they were spilling, we would expect that offer prices would be low and for these stations to be dispatched accordingly. This would either lead to price separation between the North and South Islands if the HVDC bound, or low prices in both Islands as cheap South Island electricity displaced North Island generators. This latter case is what we saw after 18 December 2019.

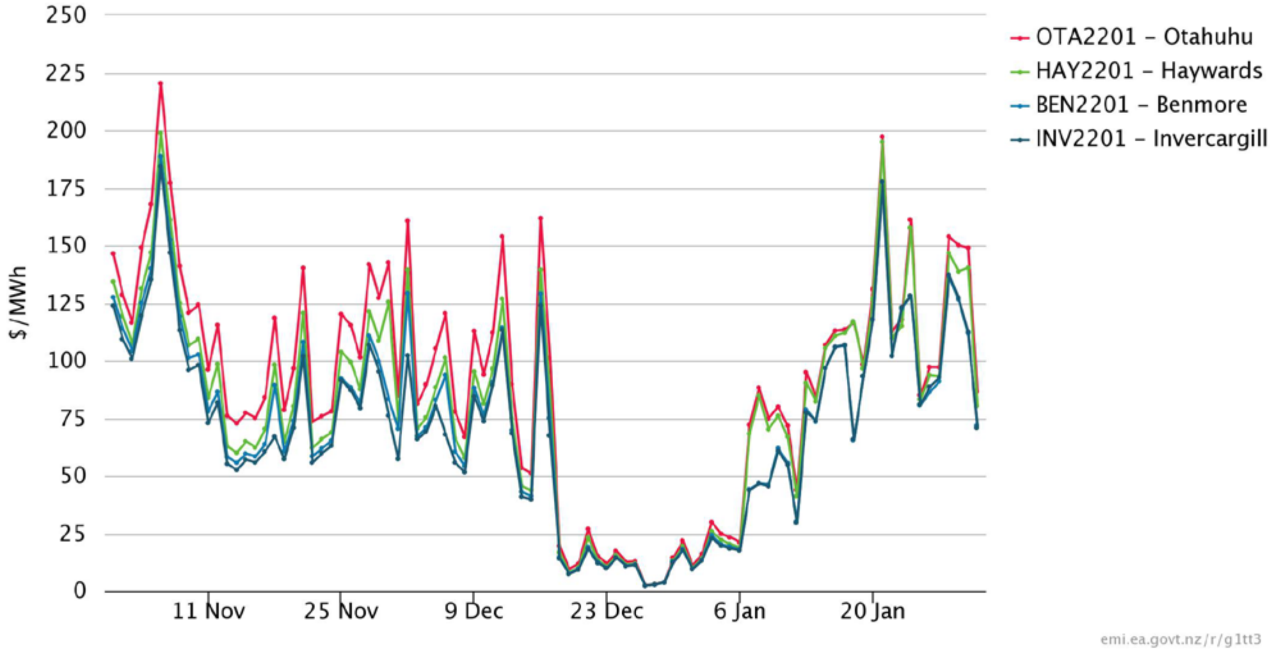
11.15 As set out above, we did not observe lower prices until 18 December. This section looks at price separation. Figure 13 shows the daily average price by key nodes. Over this period prices were lowest in Invercargill and highest in Otahuhu. This is consistent with northwards flows on the HVDC and associated transmission losses seen during the investigation period.

11.16 On some days there are signs of price separation. For example, on 7 January 2020, when the HVDC outage started, there was price separation between the South Island and the North Island. Contrary to our expectations, the chart suggests the abundance of hydro fuel in the South Island did not cause price separation.

11.17 There are very few days when there is any observable price separation between Invercargill and Benmore. If the prices were high because of constraints on the grid after the loss of the Islington-Livingstone circuit, then we would expect to see days where there is significant price separation between Invercargill and the rest of New Zealand. The loss of this circuit would have put more pressure on the Aviemore-Benmore circuits which were therefore more likely to constrain. This then limits transfer from the lower South Island to Benmore and the southern end of the HVDC.

11.18 The fact that this is not seen means either this constraint did not have an impact on price outcomes or generators structured their offers to prevent the constraints binding and the consequent price separation. Contact has told us this is the case, and Meridian's weekly Perform Reports contain direction to prevent transmission constraints.

Figure 13: Daily (generated weighted) average price by reference node



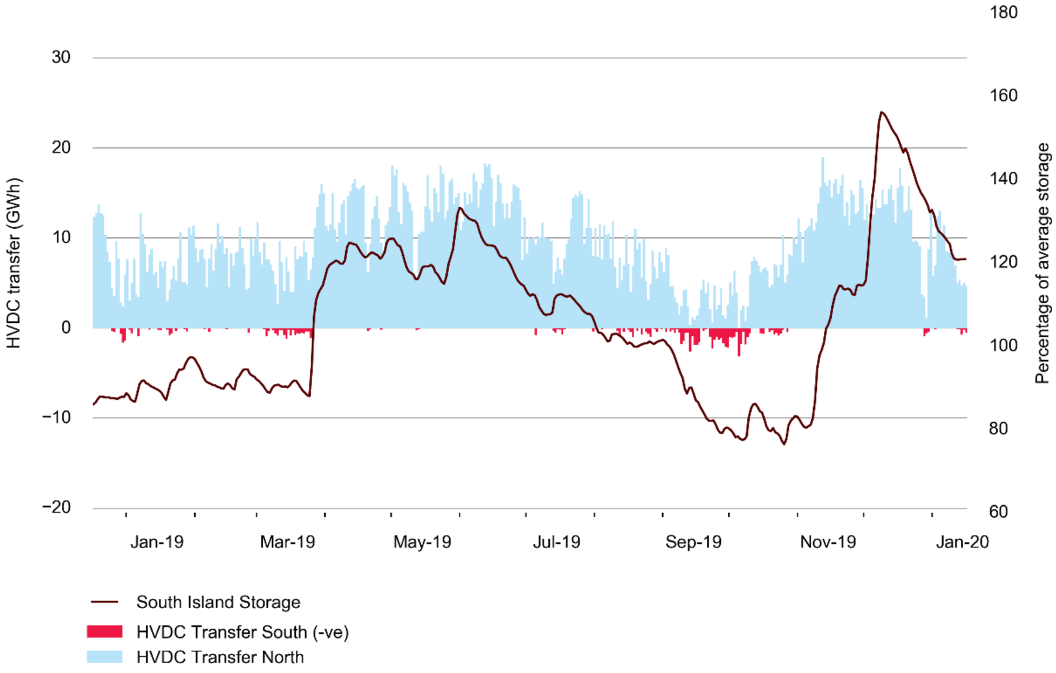
Northward HVDC flows did not increase

11.19 Figure 14 below shows average daily north and south flows over the HVDC and South Island hydro storage. In previous years, northward flow occurred most of the time. Southward flow occurred when South Island storage was low and North Island generation was needed to meet South Island demand. This pattern continued in 2019.

11.20 When water is abundant in the South Island, we would expect more northward flow over the HVDC on average as hydro operators lower their offer prices and are dispatched ahead of North Island generators. We note this is particularly true in late 2019 when the impending HVDC outage planned for the first quarter of 2020 meant North Island hydro operators would likely be wanting to store water for later use and therefore be raising their offer prices.

11.21 The northward flow on the HVDC did not increase in response to the increase in storage in December. Possible reasons why the flow north may have been restricted could include reserve requirements in the North Island, low demand in the North Island at that time of year, and 'must run' geothermal, hydro and wind. We show below that South Island Generation could have increased while accounting for these factors and the hydrological constraints that generators must manage.

Figure 14: HVDC flows and hydro storage

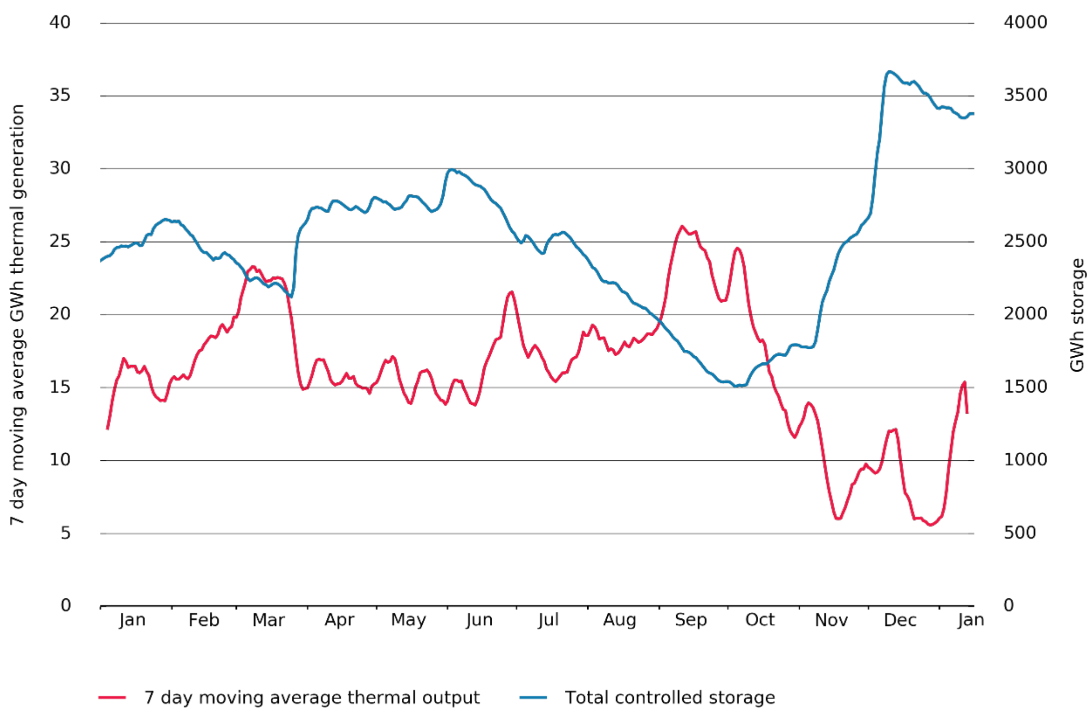


Sources: Electricity Authority and NZX Hydro

Thermal generation increased when hydro storage increased

11.22 When hydro storage is high, the opportunity cost of using water for generation is low. This means hydro generation is cheaper and so thermal generation, which has high fuel costs, usually decreases. This broadly inverse relationship is shown in Figure 15—when hydro storage increases, there is a strong tendency for thermal generation to fall and vice versa.

Figure 15: Thermal generation and New Zealand controlled hydro storage



11.23 This can also be shown by the negative correlation between thermal generation and hydro generation (rather than storage). A negative correlation indicates when one increases, the other decreases and vice versa. From 2013 to 2017 the correlation between thermal generation and hydro generation was -0.41 (calculated using daily data). In September and October 2018 when there was a lack of thermal fuel due to gas outages the correlation was -0.01. For the investigation period the correlation was 0.15. This is statistically different from the correlation from 2013 to 2017. This is the opposite of what we would expect as it implies that as hydro fuel becomes more abundant, the more thermal generation operates.

11.24 The negative correlation over the five years from 2013 to 2017 shows it is usual for thermal generation to decrease when hydro generation is higher. This makes sense as thermal generation would normally be higher cost than hydro generation when water is abundant. The correlation of approximately zero during September and October 2018 shows that in this case thermal was unable to replace hydro generation when hydro storage was low. As discussed in the decision paper for the 8 November 2018 UTS complaint, the most obvious explanation of this is a lack of thermal fuel due to gas outages.

11.25 The positive correlation during November and December 2019 indicates that thermal generation remained high when hydro generation was high, contrary to what we expect. For example, the Taranaki Combined Cycle (TCC) ran from the 9 to 13 December 2019 while some of the highest spill occurred on Contact's Clutha power stations.

11.26 Figure 16 and Figure 17 show the amount of thermal generation running during the UTS period. Figure 16 shows baseload thermal generation and Figure 17 shows peaking thermal generation.

Figure 16: Baseload thermal generation

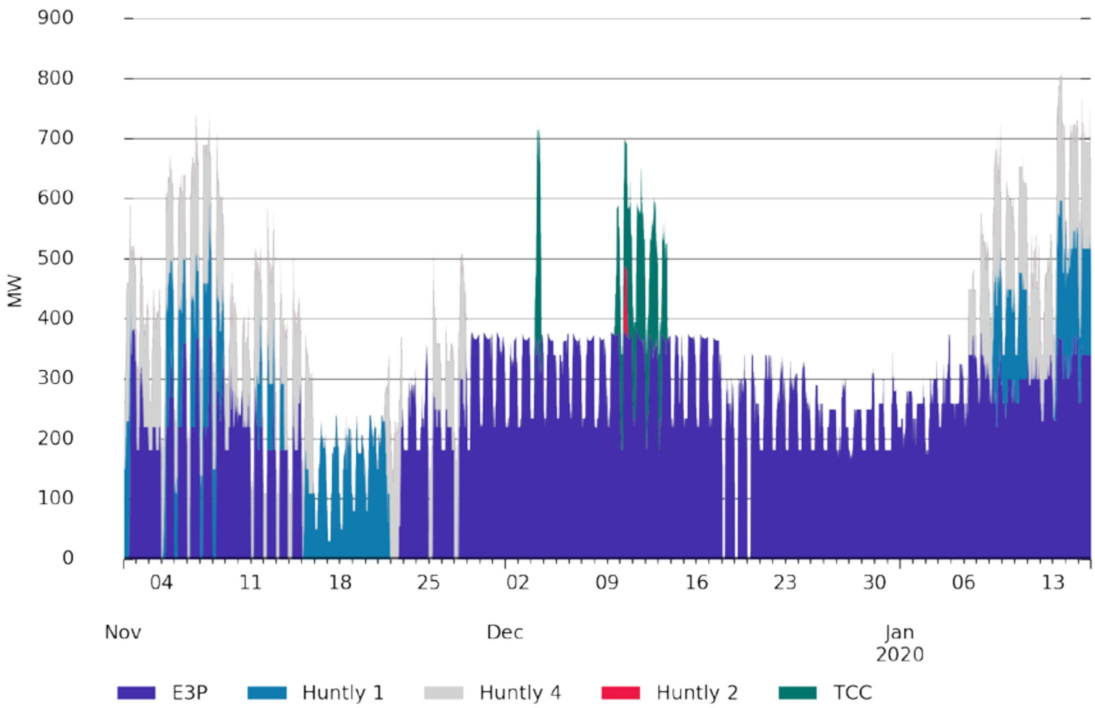
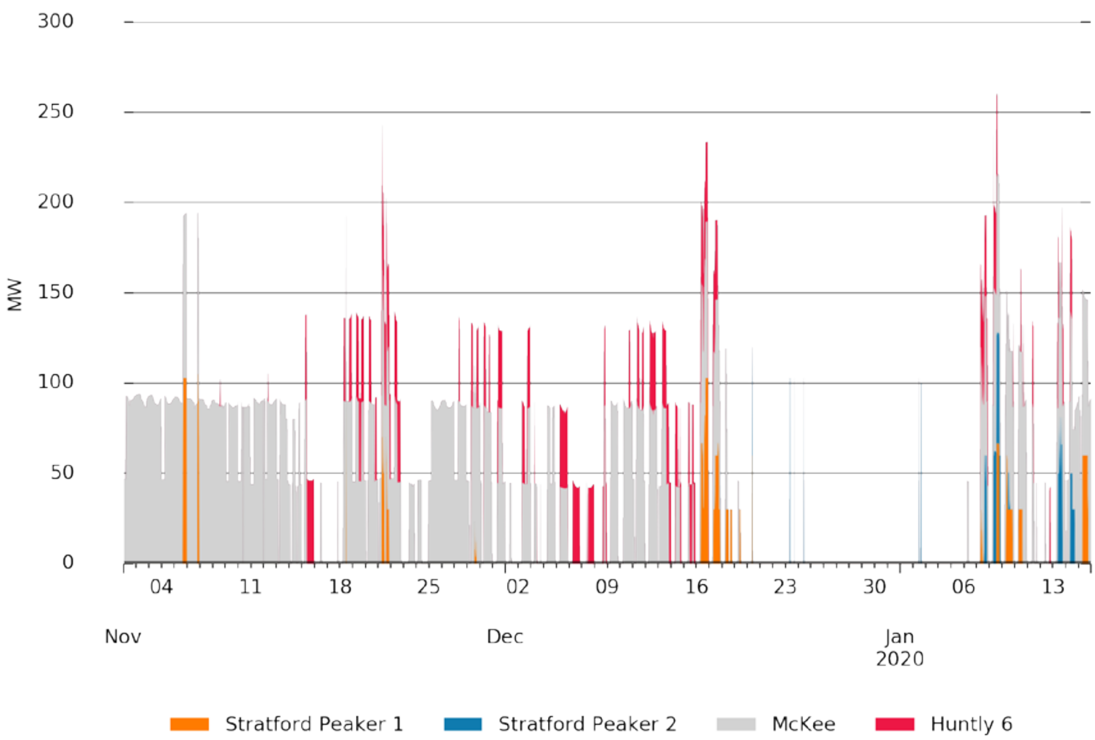


Figure 17: Peaking thermal generation



11.27 Contact has told us it ran TCC for portfolio reasons—generators wanting to generate at least as much as they purchase on the spot market. In this case a large tranche of thermal generation was offered into the market at a low price and consequently dispatched. This was during a week when output from Contact's Roxburgh station was reduced to comply with the conditions of the Clutha Flood Rules which are explained below.

Summary of spot market outcomes

11.28 None of the indicators we investigated showed the changes we would expect when hydro generators spill and the opportunity cost of water falls to zero. Specifically

(a) Prices remained high, and only fell due to a fall in demand rather than increased competitive pressure

(b) Prices did not separate

(c) Transmission constraints did not bind

(d) Transfer north over the HVDC did not increase

(e) Thermal generation increased.

12 Offer behaviour during the investigation period

12.1 To understand why spot market outcomes were not consistent with our expectations, we looked at the offer behaviour of the largest South Island generators.

Expectations and overview

12.2 The claimants allege that South Island generators were intentionally spilling water, rather than generating, and offered into the market at prices well above the SRMC of a spilling hydro generator. The Authority's view is this allegation may be tested by looking at how generators offered generation from the hydro lakes while they were spilling.

12.3 All else being equal, we would expect offer prices while spill was ongoing to be lower than at other times and reflect the zero opportunity-cost of water that cannot be stored. As described in Section 8, water usually has value derived from the ability to store it to use later. A spilling hydro generator does not have this option; hence the water has a zero opportunity-cost.

12.4 We would also expect offer prices to be low if a generator was anticipating that it would need to spill water soon. In this case, the benefit of storing an extra unit of water would be low as there is a high risk the generator would end up spilling that unit of water soon. The anticipated risk of spilling water would be based on how full the lake was already and expected inflows.

12.5 This section compares outcomes with the expectations set out in Section 8, including for each hydro generator or scheme:

(a) volume of spill compared to offer price (quantity weighted offer price – QWOP[7])

(b) volume of spill compared to offer bands

(c) volume offered compared to volume dispatched.

12.6 The generators analysed are the three largest South Island hydro generators:

(a) Manapōuri and Waitaki (operated by Meridian)

(b) Roxburgh and Clyde (operated by Contact)

(c) Tekapo (operated by Genesis).

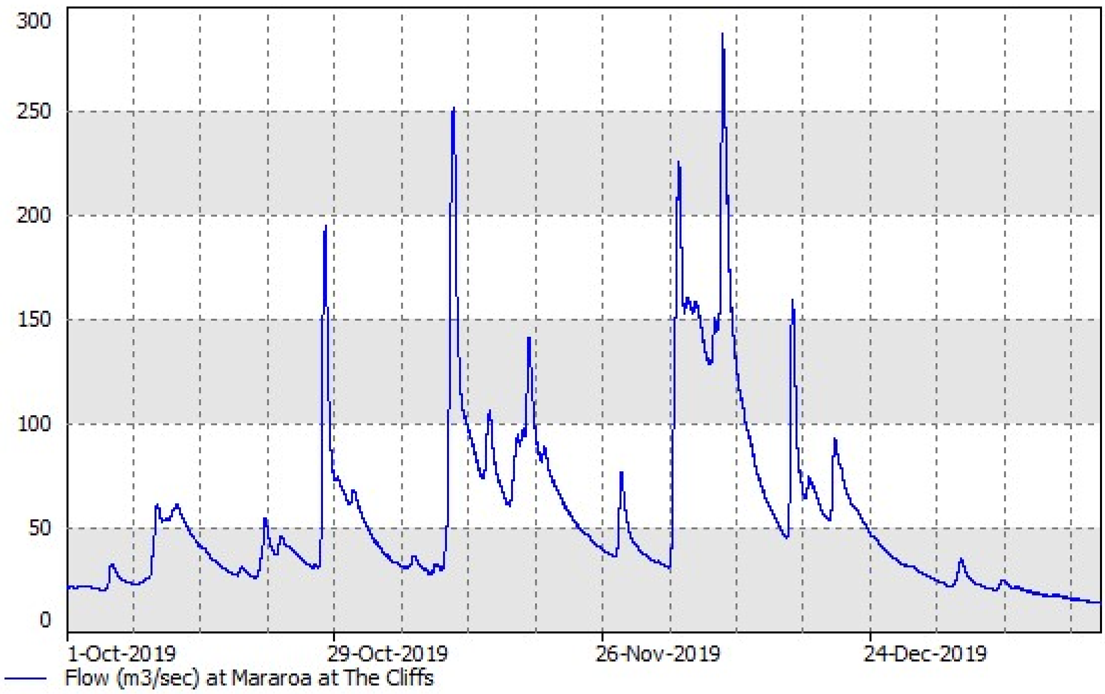
Manapōuri (Meridian)

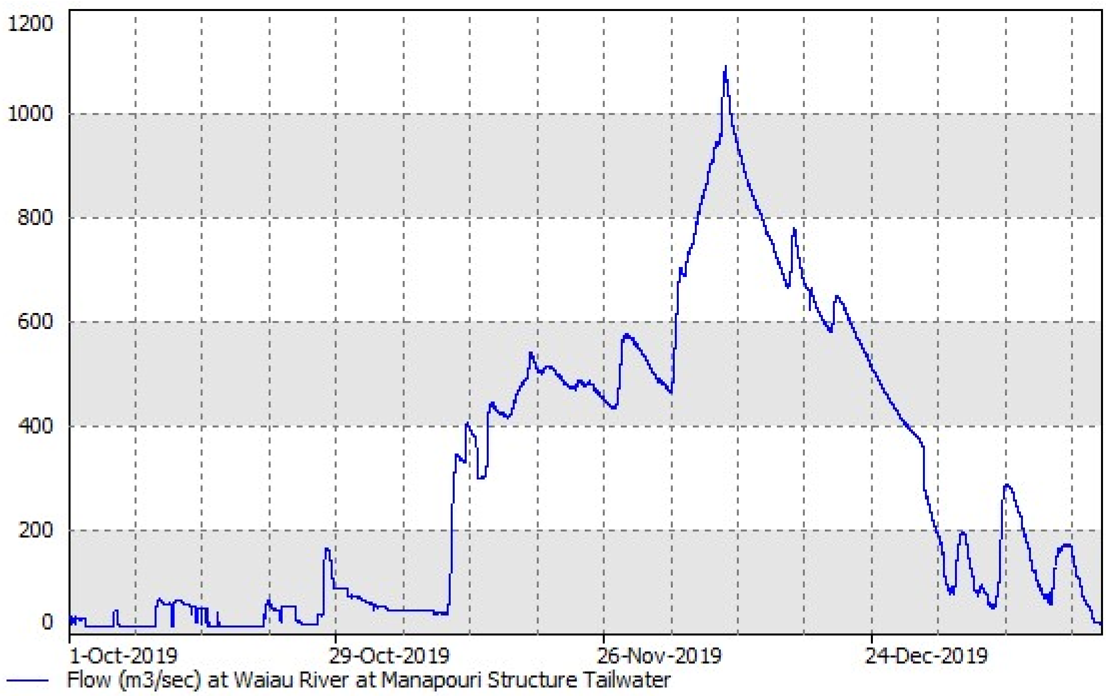
12.7 Manapōuri is the largest hydro power station in New Zealand and is in the Fiordland National Park, which has World Heritage status. Meridian has strict operating guidelines for Manapouri to ensure compliance with resource consents. During the investigation period, resource consents required Manapōuri to spill a minimum amount down the Waiau River, 16 cubic meters per second (cumecs) (minimum flows vary seasonally). When Mararoa River is turbid, spill is required to match the flow of the Mararoa River to prevent 'backflow' of the turbid water going into Lake Manapōuri. Meridian reported it is conservative with these guidelines and spills 16.7 cumecs to meet the minimum flow requirement and an additional 5 cumecs above the flow of the Mararoa River to meet turbidity requirements. These amounts have been subtracted from the spill data, so the

[7] QWOP is a weighted average price over up to 5 offer bands, each with a different price and quantity. The weights used are the quantities offered. This provides a useful summary which highlights the changes in offer behaviour. We also look at individual offer bands to further understand offer behaviour.

figures below are an estimate of flood spill over and above these resource management requirements.[8]

Figure 18: Mararoa and Waiau river flows

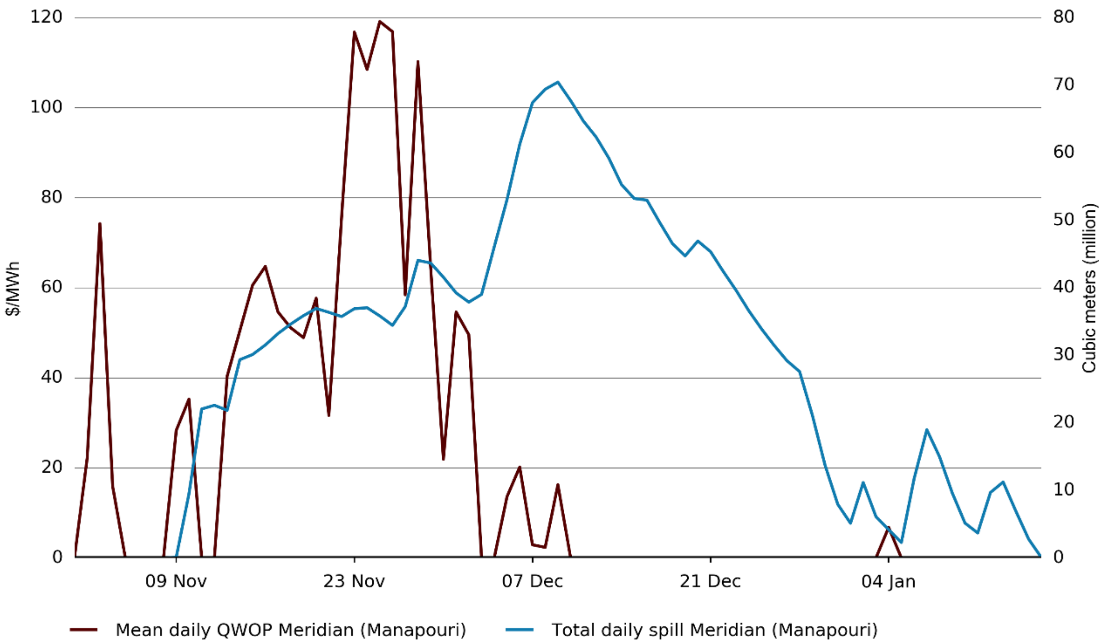




8 The Mararoa River flows into the Waiau River, the natural outlet of Lake Manapōuri, about 10 km southeast of the lake outlet. The Manapōuri spill control structure is located at the confluence of the Waiau and Mararoa Rivers. The hydro station is on the West Arm of the lake and discharges water into Deep Cove of Doubtful Sound.

12.8 Manapōuri was spilling for the longest period of all the stations. Spill started near the end of the day on 9 November 2019. During November offer prices remained high in some of the offer bands. Figure 19 shows the QWOP and flood spill for Manapōuri. It shows that the QWOP was up to $120/MWh during November and early December, then during December it dropped down to close to $0/MWh for most trading periods. Meridian told us spill at Manapouri is common because Lakes Manapouri and Te Anau have little storage compared to the inflows that they receive.

Figure 19: Manapōuri Quantity Weighted Offer Price and Estimated Flood Spill



12.9 Figure 20 shows Manapōuri's offer bands from October 2019 until flood spill ended in January 2020. It shows when it first started spilling there was no noticeable change to offers, with many offers still in the $10-$100/MWh range and higher. However, after the flooding event peaked in December most of its offers were $0.01/MWh or $0.02/MWh. This is consistent with the QWOP shown in Figure 19.

12.10 Meridian has stated that it sometimes prefers to generate from the Waitaki chain rather than Manapōuri. Meridian advised that before the flooding event in December it preferred to generate from the Waitaki chain to avoid spill from Lake Ōhau. We tested this with a simulation and found that fully dispatching Ōhau and Manapouri stations was not possible during November. Meridian therefore had a choice about where to spill and chose to spill at Manapouri rather than Ōhau because total generation output was constrained by demand and HVDC capacity.

12.11 After the flooding peaked in December, when it was harder to avoid spill on the Waitaki chain, Meridian said it chose to generate from Manapōuri. Again, this means Meridian was faced with a choice as to where to spill.

12.12 Figure 21 shows Meridian's offer bands for Manapōuri for 2019 and 2020. It shows that compared to the rest of 2019, Meridian's offer prices at Manapōuri were comparatively low during November and December when the Manapouri lake level was higher.

Figure 20: Manapōuri Offer Bands and Estimated Flood Spill

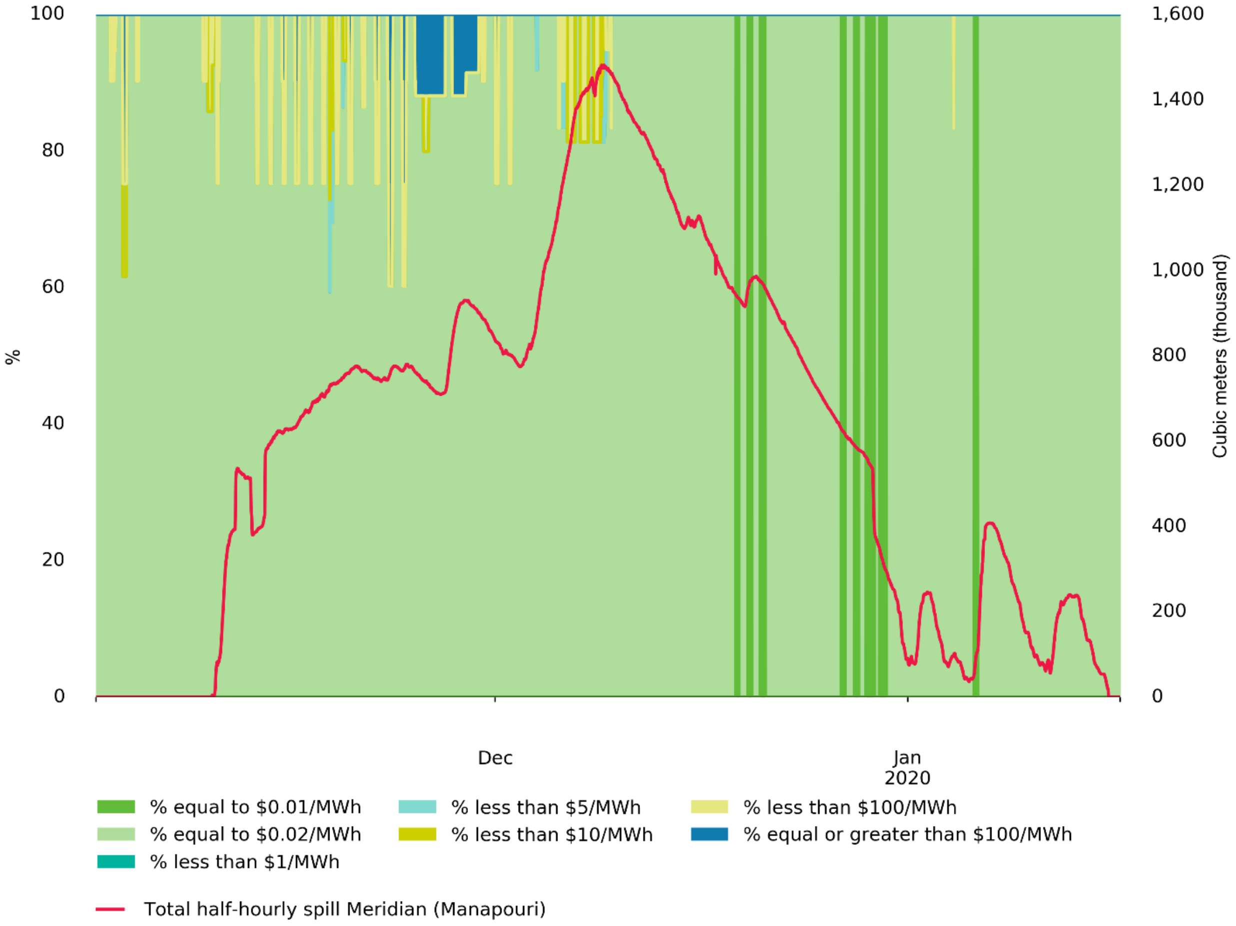
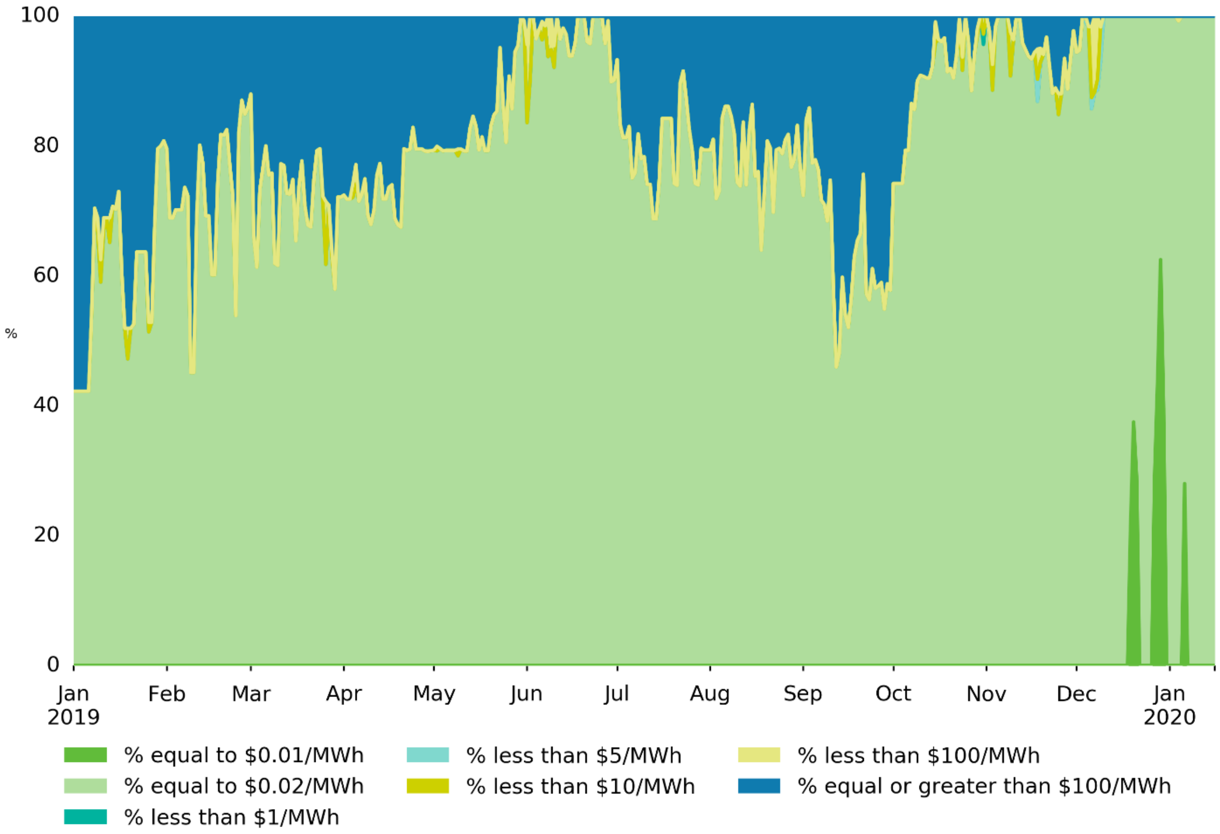


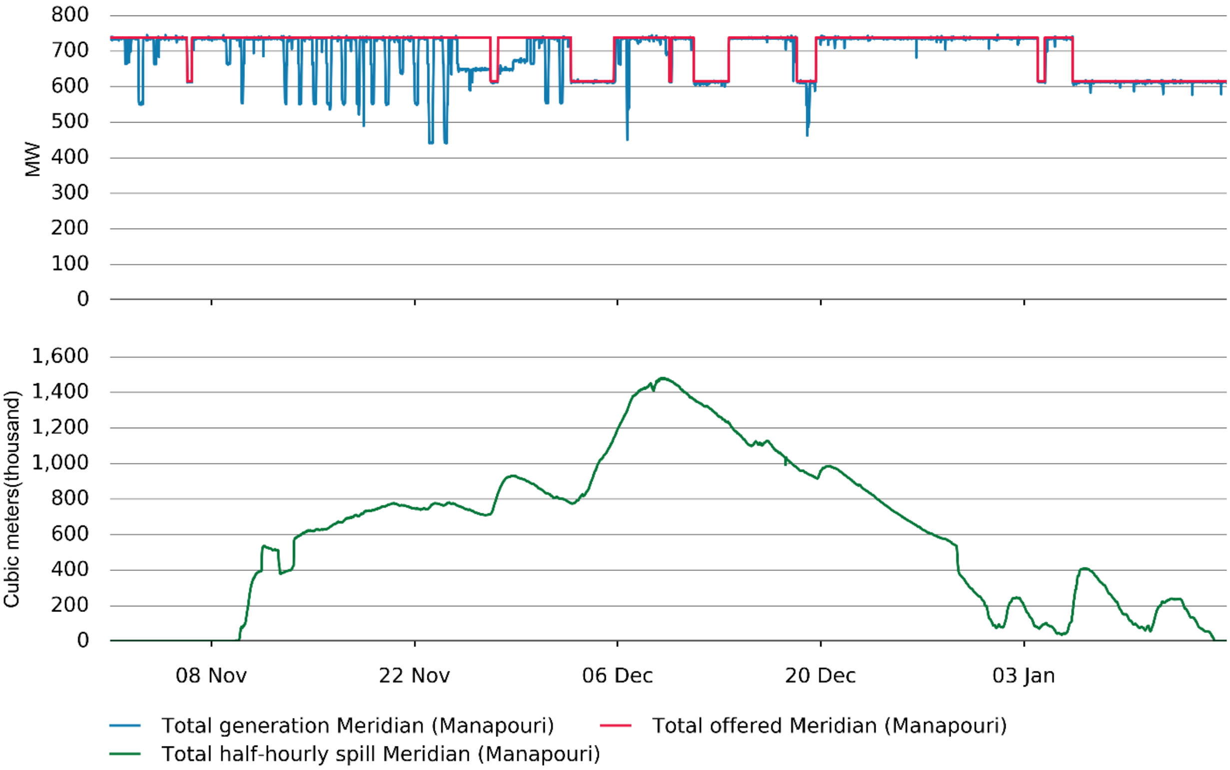
Figure 21: Manapōuri Offer Bands 2019/20



12.13 Figure 22 shows the quantity of generation offered at Manapōuri compared to the amount that was dispatched and used for generation during the investigation period. There are several periods where there are outages at Manapōuri and these can be seen as an approximately 100MW fall in offered quantities. In November, for most trading periods the total quantity offered was dispatched, but in many trading periods (usually overnight) not all the generation offered was dispatched.

12.14 As set out above, Meridian advised this was partly due to portfolio management—attempting to get Waitaki generation dispatched ahead of Manapōuri overnight, to avoid spill from Lake Ōhau. Lake Ōhau has less storage capacity than the other main lakes. In December until the end of spilling in January all the generation offered was dispatched in almost all trading periods (one exception being on 7 December when Manapōuri was constrained down by the System Operator due to electrical storms).

Figure 22 Manapōuri's MW Offered and generated by trading period



12.15 Overall, it appears that Manapōuri's offers after 4 December were generally consistent with maximising generation during a spill event. Manapōuri's offer behaviour is summarised in the table below.

Table 2 Summary of Manapōuri's offering behaviour

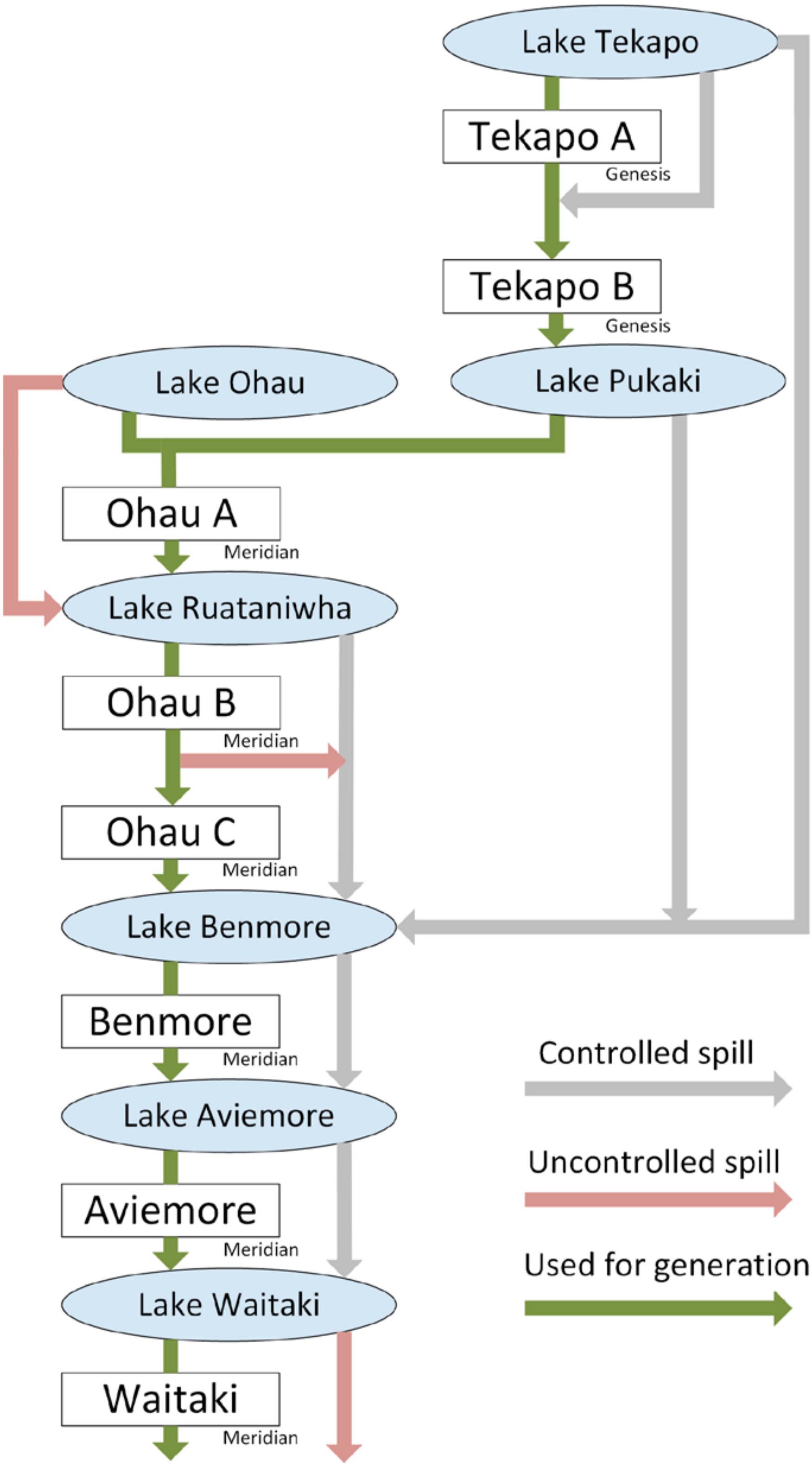
Volume of spill compared to offer price	Volume of spill compared to offer bands	Volume offered compared to volume dispatched
Spilling from 9 November 2019 – 16 January 2020. QWOP was up to $120/MWh during November and early December, then dropped down to close to $0 for most trading periods	No noticeable change to offers when spill started, with many offers still in the $10-$100/MWh range and higher. However, after the flooding event peaked in early December offers were $0.01/MWh or $0.02/MWh.	In November, for most trading periods the total quantity offered was dispatched, apart from many overnight trading periods. In December until end of spilling all the generation offered was dispatched in almost all trading periods.

Waitaki Hydro Scheme

12.16 This section covers the portion of the Waitaki hydro scheme which is owned and operated by Meridian. The Tekapo scheme, at the head of the Waitaki Valley, is owned and operated by Genesis and covered in a following section.

12.17 Figure 23 is a simplified version of the entire scheme (including stations owned by Meridian and Genesis) intended to show where water flows after it is either used for generation or spilled. This diagram does not show all the inflows into each lake nor the capacity of each lake or generator. It shows how spill from upstream stations can potentially be used by downstream generators.

Figure 23: Waitaki Hydro scheme (simplified version)



12.18 The Waitaki hydro scheme started spilling for a small period in November and then was spilling throughout December and into early January. The QWOP stayed high during the whole period —compared to other hydro stations—at $300-400/MWh and never dipping below $150/MWh. It fell slowly from early November and then started to increase from around 13 December. This is shown in Figure 24. Figure 25 shows Waitaki scheme spill by location.

12.19 The loss of the Islington to Livingston 220kV circuit occurred on 8 December. This decreased the capacity of flow from the lower South Island northward for the rest of the investigation period.

12.20 Meridian have advised that there are minimum discharge rates – from both generation and spill – at each Waitaki station once lake levels are high enough. This means that if there is spare capacity to generate, any spilt water is lost generation.

Figure 24: Waitaki Hydro Scheme Load Weighted Offer Price and Total Flood Spill

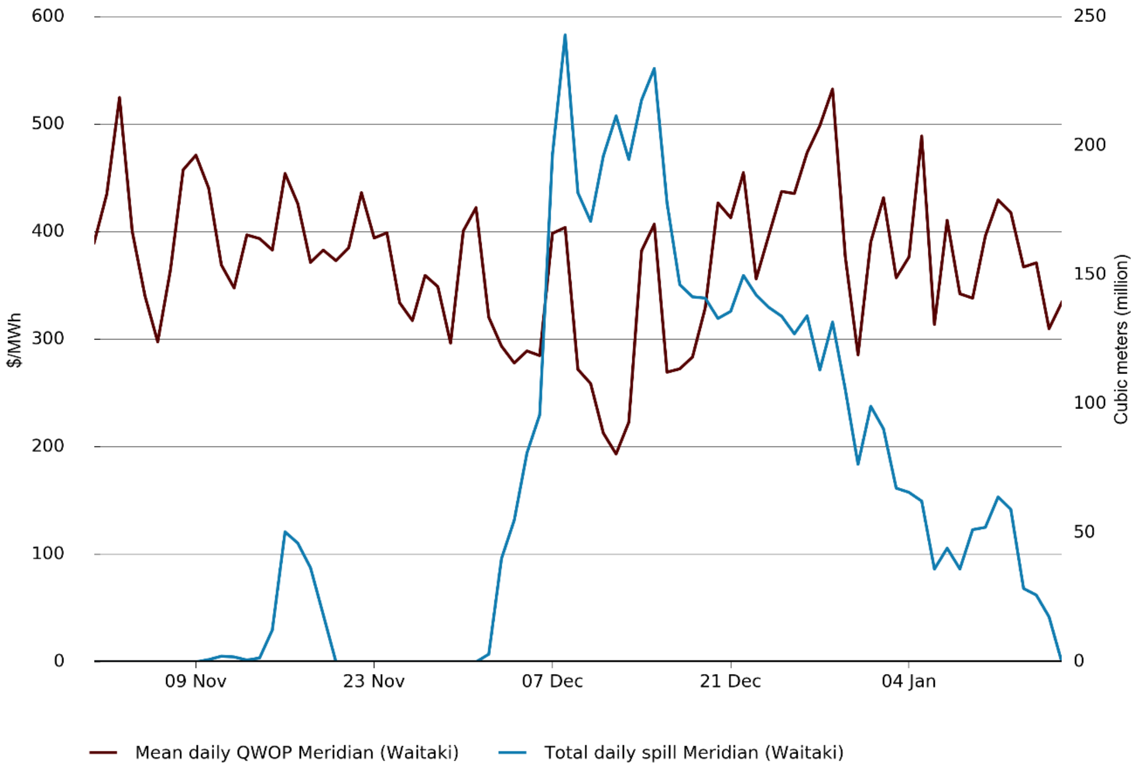
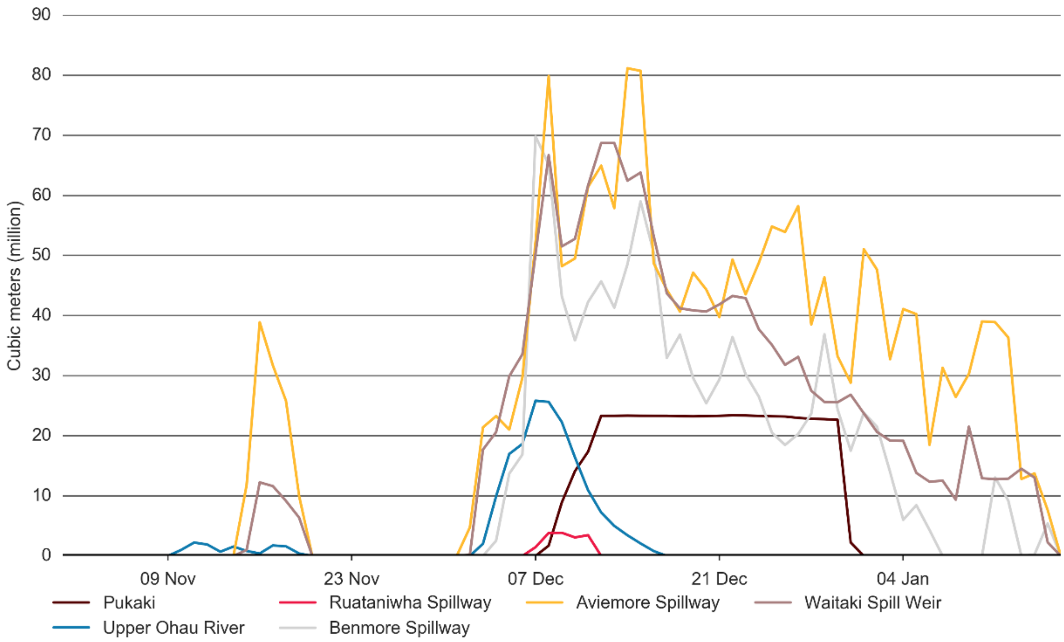
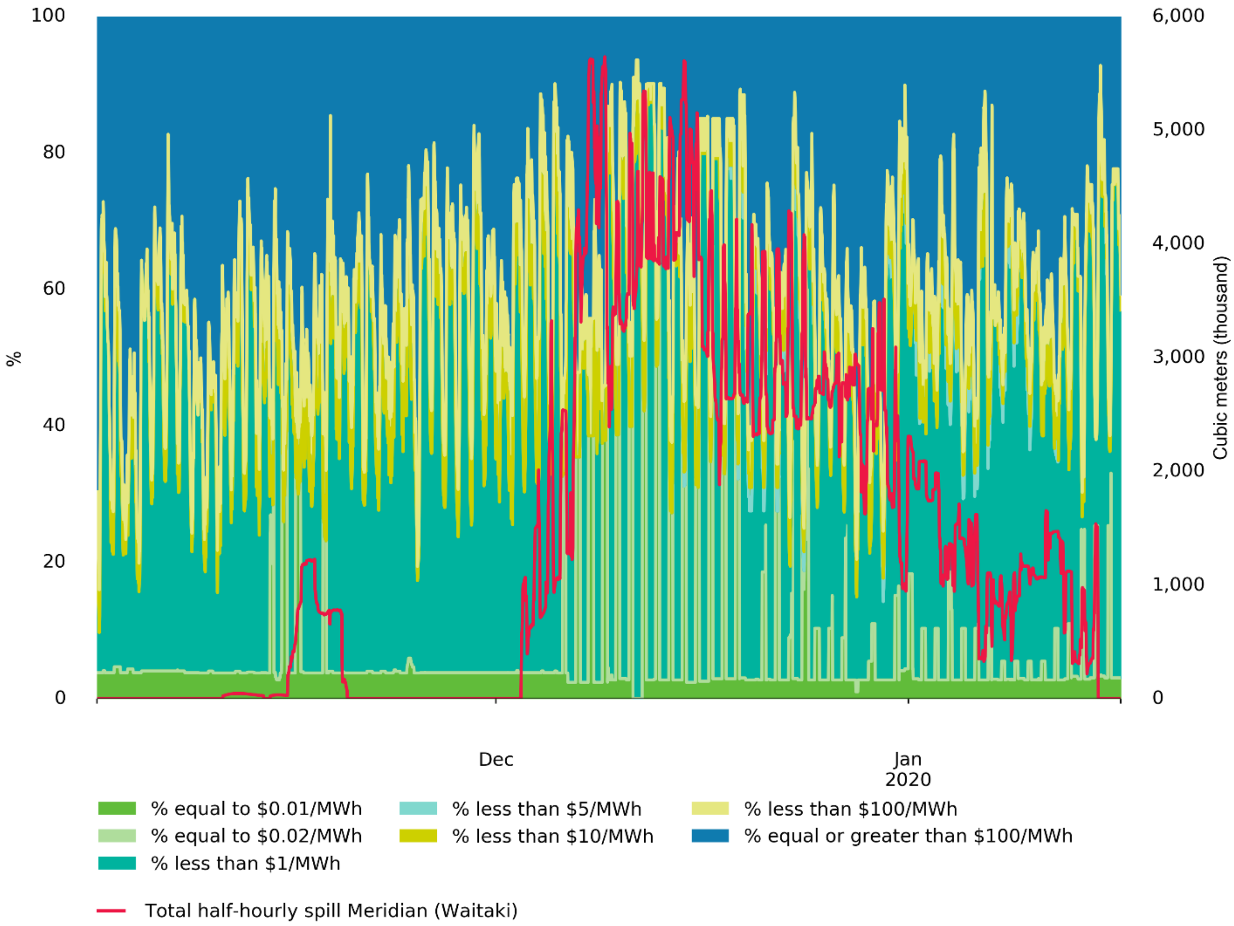


Figure 25: Waitaki scheme daily spill by location



12.21 Figure 26 shows the combined Waitaki hydro scheme's offer bands from October until spill ended in January. During spilling, there was an increase in offers less than $1/MWh. A significant amount was still being offered at over $100/MWh, especially overnight. The quantity of these high-priced offers increased during December. These offers are not consistent with what we expect from a hydro generator during spilling We do not expect to see high offer prices when the opportunity cost of the water is zero.

Figure 26: Waitaki Hydro Scheme Offer Bands and Flood Spill



12.22 Meridian explained its offers were consistent with transmission constraints, outages, low early summer demand and the need to manage flows consistent with resource consents.

12.23 The following extracts are from a 16 December Meridian internal report:

Generation stepped up again last week as we pushed as much water through the market while managing DC limits.

From a section entitled “trading tactics and hydraulic plan for last week”:

Strategy: Maximising sustainable generation while maintaining HVDC limits.

12.24 This later quote, or variations of it appeared in the same Meridian internal report from mid-December 2019 to late January 2020.

12.25 We conclude Meridian was actively managing the HVDC because of the combination of increased Waitaki offer prices, an absence of price separation over the HVDC despite the abundant inflows, and the articulation of a strategy of managing HVDC limits.

12.26 The Authority does not agree that Meridian should use offers to manage transmission constraints. This offer behaviour has a significant impact on the prices that end consumers pay and distorts prices as set out in Section 8.

We have previously stated participants should cover basis risk using available risk management products

12.27 The Authority conducted an enquiry into high market prices in 2013, which included a period when Meridian was spilling.[9] The enquiry stated:

> *We estimated the potential additional generation that could have been supplied from Manapōuri during these periods of high inflow spill, had lower priced energy offers been provided at Manapōuri. […] The simulations indicate that an additional 19GWh of energy could have been scheduled from Manapōuri during the 20 days of high inflow spill at Manapōuri, with the transmission security constraints in the region and South Island reserve requirements restricting further increases in its generation. […]*
>
> *While such a strategy may have been beneficial to Meridian, there is a net efficiency loss in the market when lower cost hydro energy is not dispatched and also not stored for later use. During these periods of spill at Manapōuri, the opportunity cost of water would have been zero or close to it, but was not used for generation. Instead, higher cost generation was dispatched resulting in a net increase in system dispatch costs.*

12.28 The Authority Board subsequently considered an alleged UTS in relation to Meridian’s trading behaviour on 2 June 2016. There are some parallels between Meridian’s behaviour then and in this investigation. In relation to the events of 2 June 2016, the Authority Board stated:[10]

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9 Refer: https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2013/enquiry-into-increased-market-prices-from-27-february-2013/

10 Refer: https://www.ea.govt.nz/dmsdocument/22116-8-may-2017-letter-from-chair-to-meridian-energy-re-trading-conduct-on-2-june-2016. Although the Authority Board expressed this view, as noted in the letter to Meridian, the Board decided against referring this matter to the Rulings Panel because this incident was the first such test of clauses 13.5A and 13.5B of the Code.

The Board was of the clear view that Meridian's trading conduct on 2 June 2016 was not of a high standard and breached clause 13.5A(1) of the Code. The Board was also of the view that the safe harbours in clause 13.5B(1) of the Code did not apply.

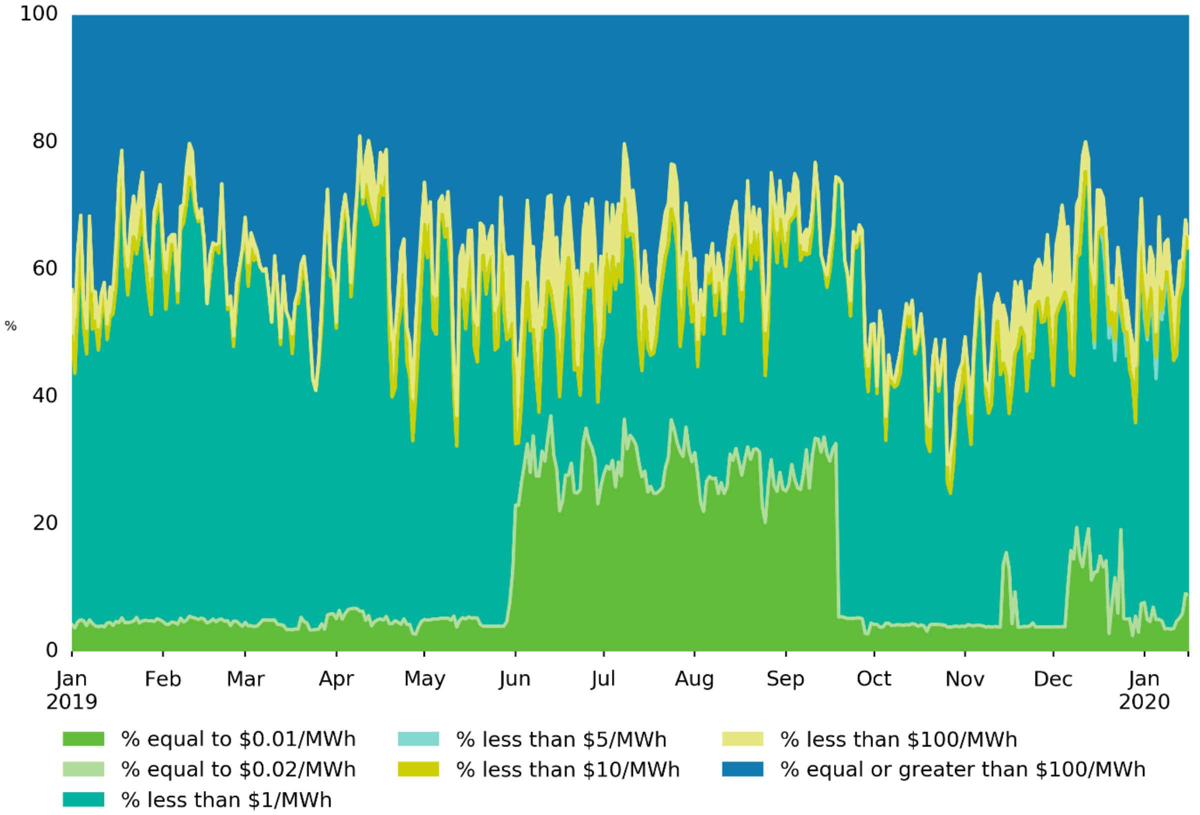
The Board's view is that Meridian used its pivotal position to cover its unhedged risk on 2 June 2016, which essentially resulted in the cost of the risk being met by other parties. The high standard of trading conduct provisions were introduced to improve the efficiency of prices in pivotal supplier situations and the Board would have expected Meridian to have adopted more responsible trading behaviour, either by covering its risk using other available risk management products or bearing the cost of the risk if it eventuates.

12.29 The 2019 alleged breach of the HSOTC provisions is being considered separately from this UTS investigation by the Authority's Compliance team. The compliance process is not a factor in reaching a preliminary decision on this alleged UTS.

Waitaki offers over the longer term

12.30 Figure 27 shows the offer bands for Waitaki hydro scheme for 2019 and January 2020. This shows the percentage of generation offered at $0.01/MWh and $0.02/MWh was much higher between June and mid-September than it was in December and January. Pukaki storage was above the 90th percentile at both these times. It also shows a consistently high amount of generation offered at over $100/MWh whether or not the scheme was spilling.

Figure 27: Waitaki Hydro Scheme Offer Bands 2019/20

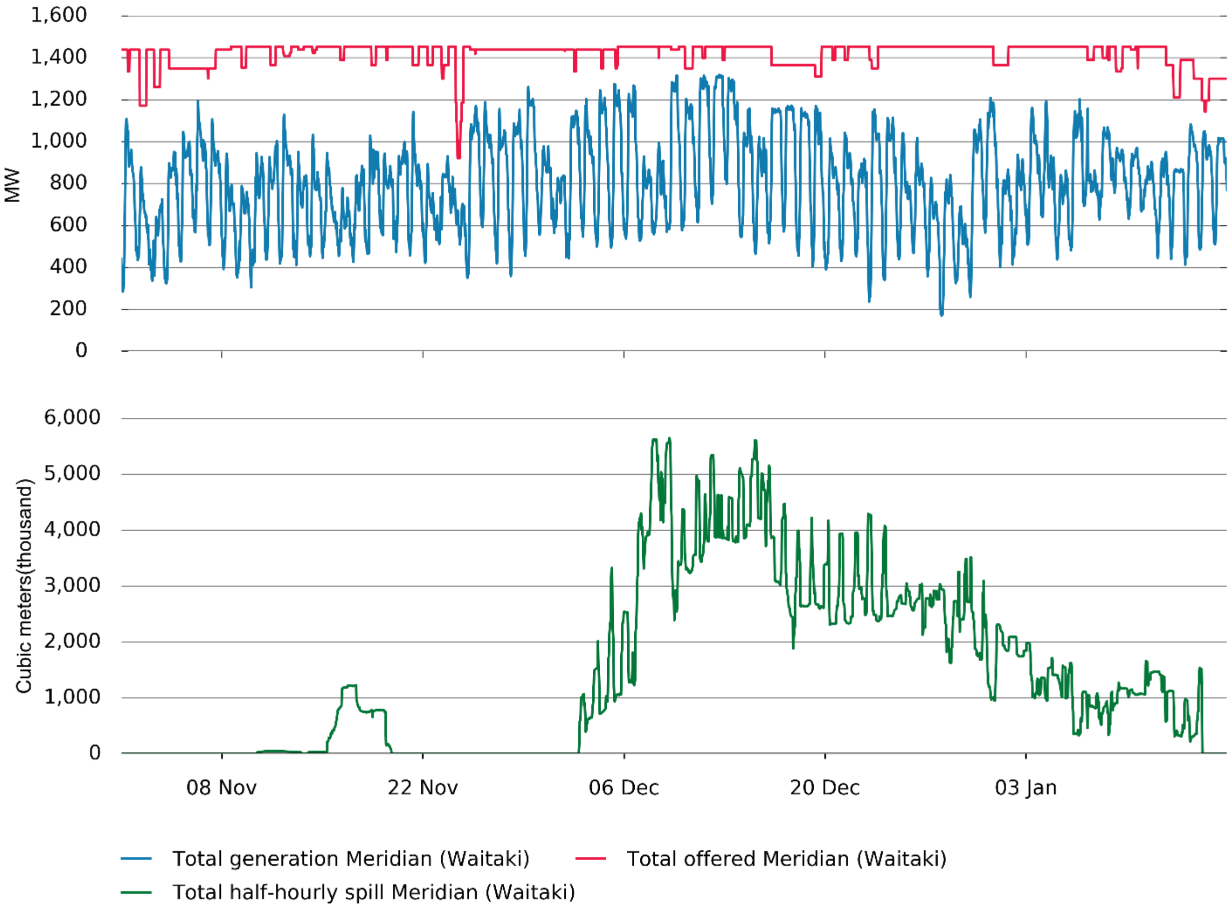


12.31 Figure 28 shows the amount the Waitaki scheme offered compared to the amount that was generated during the investigation period. Even when the Waitaki hydro scheme was spilling water, there was no trading period when all the offers were dispatched.

12.32 This is not a surprising outcome. It is unlikely that all Waitaki, Clutha and Manapōuri generation could be dispatched simultaneously due to early summer being a low demand time of year, North Island must run generation such as geothermal and wind, and transmission constraints.

12.33 However, while dispatch being less than offered generation is expected, the offer behaviour exhibited on the Waitaki while there is spilling is unexpected. We would expect offer prices to fall substantially as the opportunity cost of water fell to zero. In reality, offer prices increased from December 12 onwards.

Figure 28: Waitaki hydro scheme’s 's MW Offered and generated by trading period

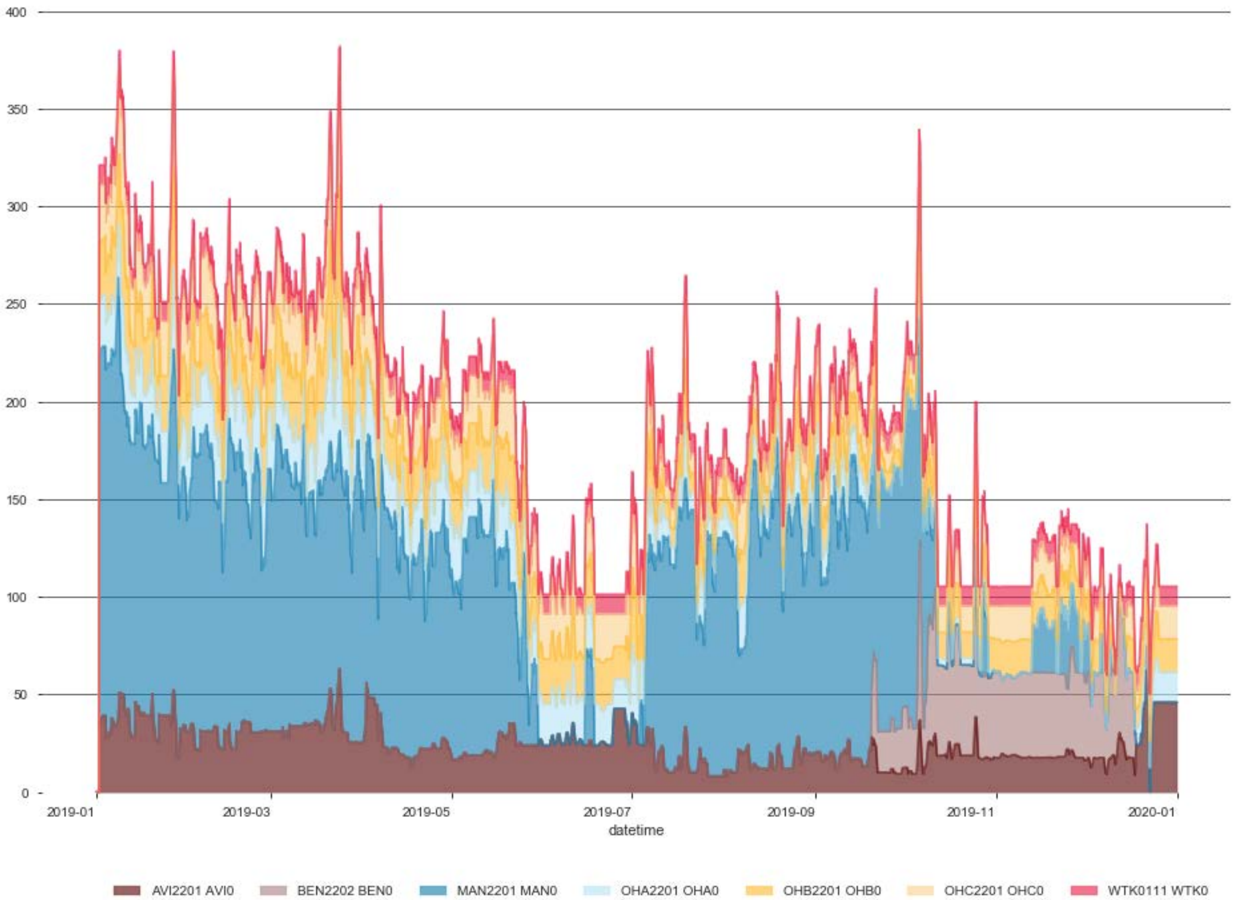


12.34 When looking at the hydro stations on the Waitaki scheme individually, we get a similar outcome, with only isolated trading periods where any station was fully dispatched.

12.35 Meridian also provides instantaneous reserves from its hydro generation. Meridian advised it usually offers reserves from Benmore, and so some of the quantity Benmore is capable of generating must be kept aside for reserves. However, Figure 29 shows in 2019 before October, Meridian was not offering any reserves from Benmore.

12.36 Reserve offers compete with energy offers in the system operator’s scheduling and dispatch model. This means that even if reserves are offered from Benmore, whether these reserves are dispatched or not (by dispatched this means keeping this offered quantity in reserve and not using it for generation) is dependent on the price at which Meridian offer these reserves, amongst other factors. So it is not necessarily true that Meridian need to keep any of Benmore's capacity available for reserves since SPD will efficiently allocate capacity between generation and reserve provided offers reflect marginal costs. Also, many other generators offer reserves into the market, so if Benmore offered no reserves there would typically not be a shortage of available reserves.

Figure 29: Offered reserves



Waitaki offer behaviour summary

12.37 Offer behaviour on the Waitaki scheme is summarised in the table below.

Table 3 Summary of offer behaviour on the Waitaki scheme

Volume of spill compared to offer price	Volume of spill compared to offer bands	Volume offered compared to volume dispatched
Waitaki hydro scheme was spilling for a small period in November and	During spilling, there was an increase in offers less than $1/MWh. However, a significant amount was still being offered at over	There was no trading period when all the offers were dispatched.

Volume of spill compared to offer price	Volume of spill compared to offer bands	Volume offered compared to volume dispatched
throughout December to 15 January. The QWOP stayed relatively high during the whole period despite the abundance of water.	$100/MWh, especially overnight.	QWOP increased from 12 December.

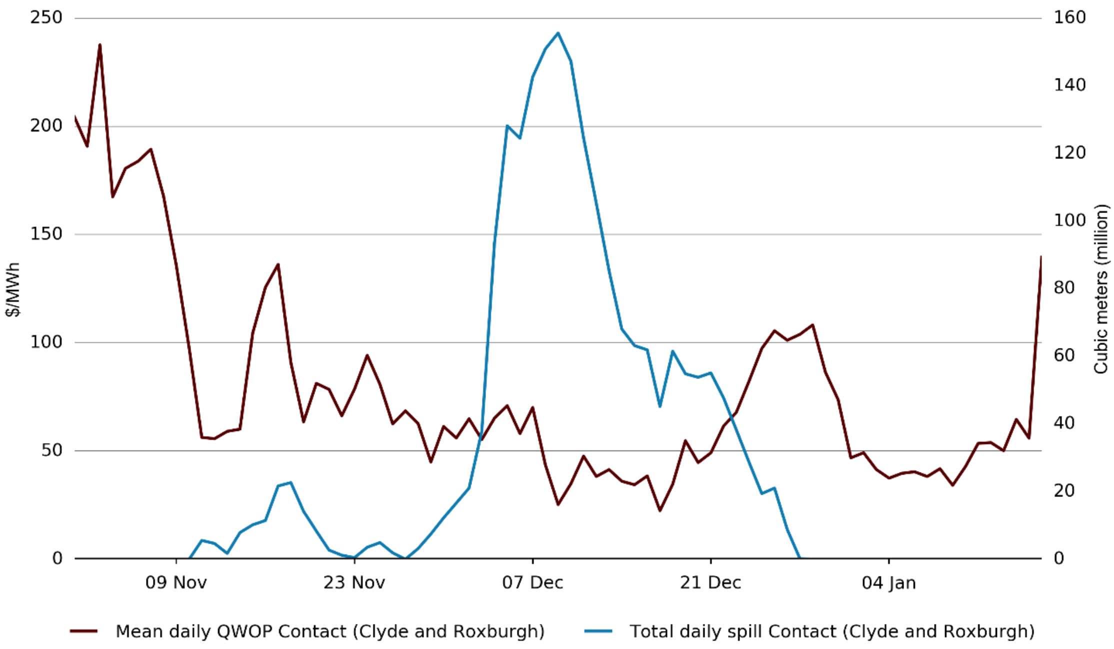
Clutha hydro scheme (Contact)

12.38 Contact owns and operates the Clutha hydro scheme, which comprises the Clyde and Roxburgh stations. Clyde and Roxburgh are essentially run-of-river—meaning outflows from generation and spill must match inflows. This is also a requirement of the Clutha Flood Rules that have been agreed by the Otago Regional Council under Contact's resource consents. Contact can control the flow from Lake Hāwea into the Clutha River, but Hāwea only accounts for about fifteen per cent of Clutha inflows. The inflows from Lake Wakatipu and Lake Wanaka are uncontrolled as are those from the other small tributaries that flow into the Clutha River.

12.39 Lake Hāwea did not flood during the investigation period, and flow out of Lake Hāwea was kept at the minimum allowed level of 10 cumecs. Contact was able to store about 200GWh of water in Lake Hāwea during the flood event. Clyde is upriver from Roxburgh, and the spill data in the charts below is the sum from both stations.

12.40 Figure 30 shows the mean daily QWOP for Clyde and Roxburgh and total daily spill. When Clyde and Roxburgh first started spilling in November the QWOP dropped from around $250/MWh to $50/MWh and generally stayed around this level through to January when the spill finished.

Figure 30: Clutha's (Roxburgh and Clyde) load weighted offer price and spill

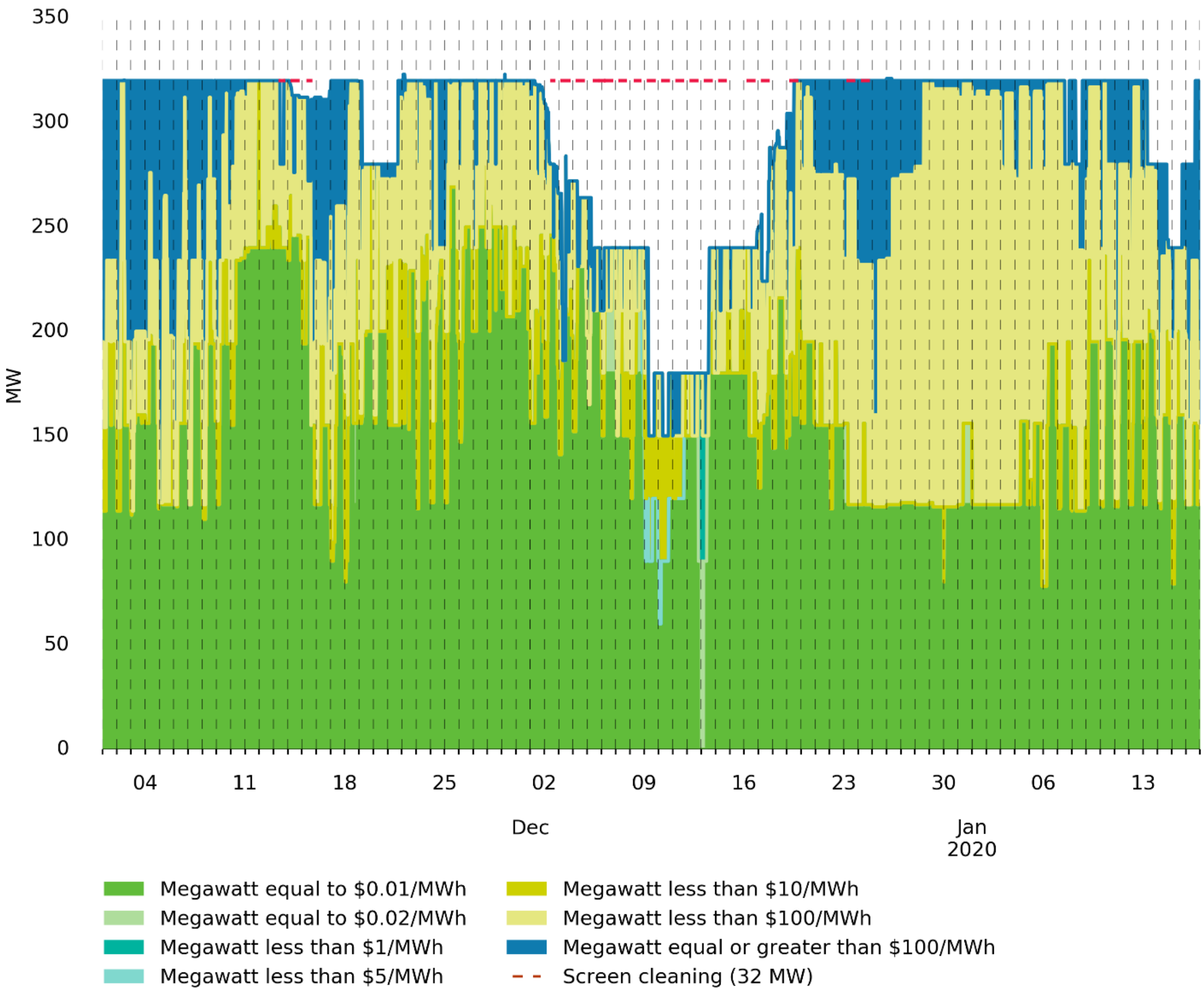


12.41 Contact's resource consents and the Clutha Flood Rules specify what Contact must do during a flood. During a flood, Clutha Flood Rules enable the level of Lake Roxburgh to be lowered to a specified level to allow for sediment flushing, and the inflows must match outflows from Roxburgh to keep the lake levels steady. Flushing the silt downstream reduces the risk of flooding to Alexandra which is important for the management of the scheme. When lowered to this point the pressure difference telemetry (measurement) Contact uses to detect blockages in the intake screens became inoperable. This meant intake screen blockages could not be easily detected.

12.42 During the December flood, Contact checked and cleaned away flood debris from the intake screens of each unit at Roxburgh station. Contact either offered the tranche for the unit being cleaned, about 32 MW, at a high price, or removed it completely`. Contact did this because the unit being cleaned could have been dispatched at short notice if the spot price was high enough. However, Contact wanted to avoid it being dispatched so the intake screens could be cleaned. This would have increased their QWOP during trading periods when screen cleaning was happening. This operation was carried out continuously while Lake Roxburgh was lowered to allow for sediment flushing.

12.43 Figure 31 shows Contact's offers and intake screen cleaning periods. It shows that during screen cleaning there was either a corresponding high-priced tranche, or some capacity simply not offered. The gradual reduction in offers from 2 December to 8 December is due to Lake Roxburgh being lowered and the Roxburgh generators becoming less efficient, lowering the amount of generation that can be offered. As the lake level was increased from 13 December, the reverse happens.

Figure 31: Screen cleaning and offer bands at Roxburgh station

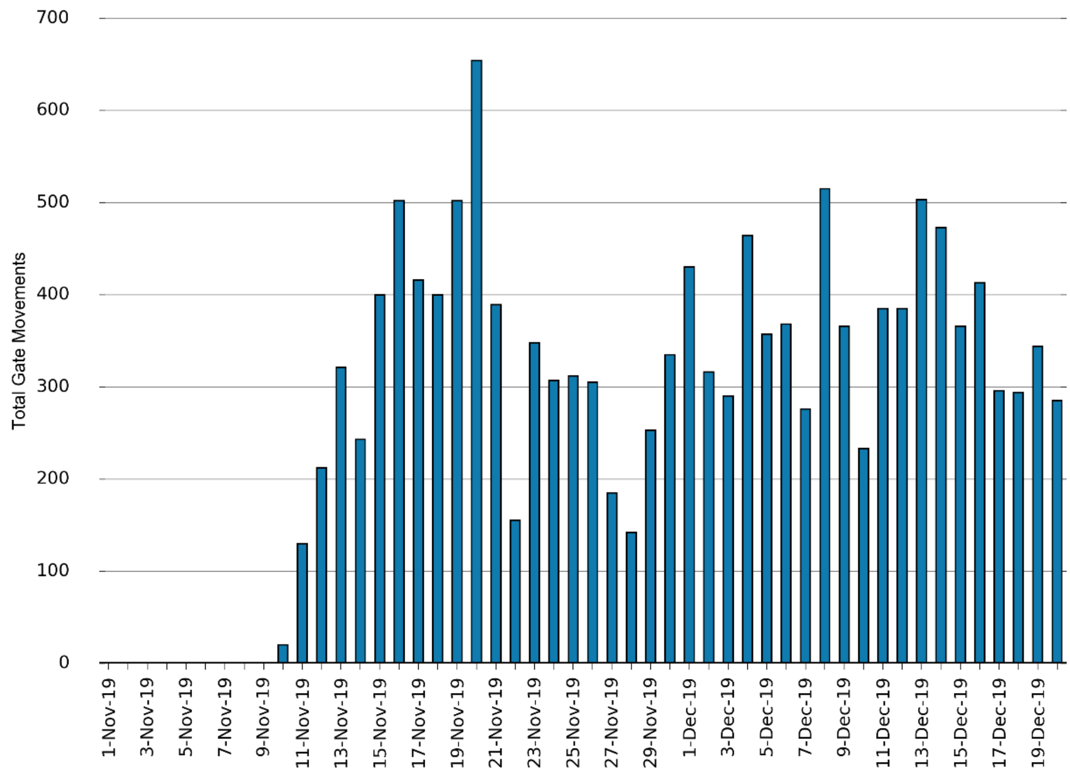


12.44 To meet the resource consent conditions and the Clutha Flood Rules, Clyde has a schedule that specifies the relationship between the lake level and total outflows from spillways, sluice gates and generators at Clyde. Contact is required to maintain what is called table discharge, so flows in equal flows out. This means that if its dispatch changes, spill must be altered to maintain table discharge.

12.45 To control the lake levels, Contact uses spill gates and sluice gates. The spill gates at Clyde have been recently automated–if the lake level changes (such as when Contact change the amount of water being used for generation) the spill gates adjust automatically to increase or decrease the flow of water through them.

12.46 The December flood was the first significant flood the automatic gates had been in place for. These gates operated more often than anticipated. The gate operations are shown in Figure 32. Contact tried to minimise these operations to avoid wear and tear. Part of this involved changing its offers to avoid being marginal and needing to change dispatch. This is because changes to dispatch (generation) would mean changes to how much it was spilling (ie, automatic spill gate changes), and cause wear and tear on the spill gates.

Figure 32: Spill gate operations at Clyde



12.47 Figure 33 shows the combined offer stacks for Clyde and Roxburgh along with the half hourly spill. The offer band data shows that Contact had fewer offers above $100/MWh when they were spilling. Figure 34 shows the same data over 2019/20 and shows that during December, Contact offered a lot of low-priced generation compared to the rest of the year.

12.48 It is still notable that some generation was being offered at over $100/MWh during flood conditions. In addition, during late December when the amount of spill fell, Contact started to offer fewer low-priced tranches. High priced tranches offered overnight seem to be independent of the screen cleaning and gate operations issue set out above.

Figure 33: Clyde and Roxburgh's offer bands and spill

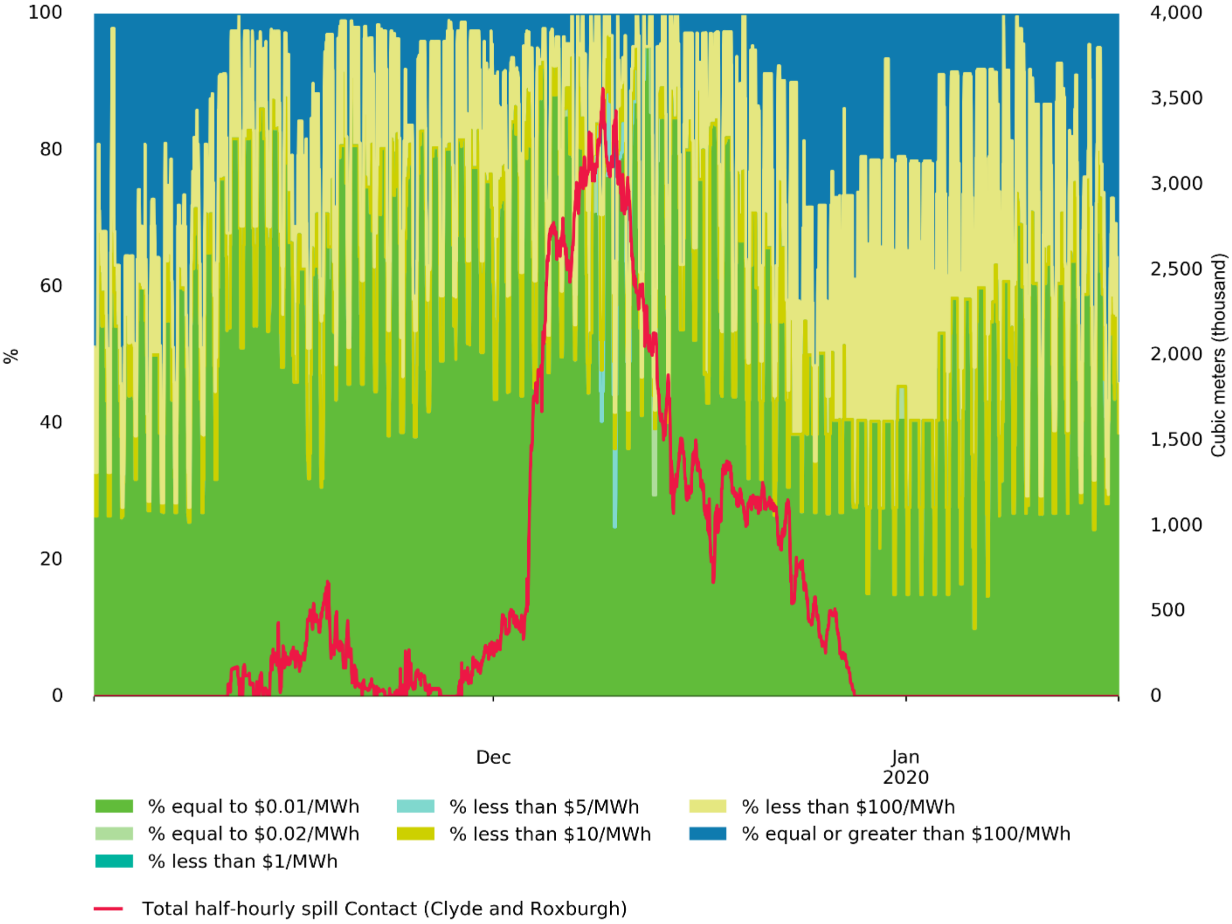
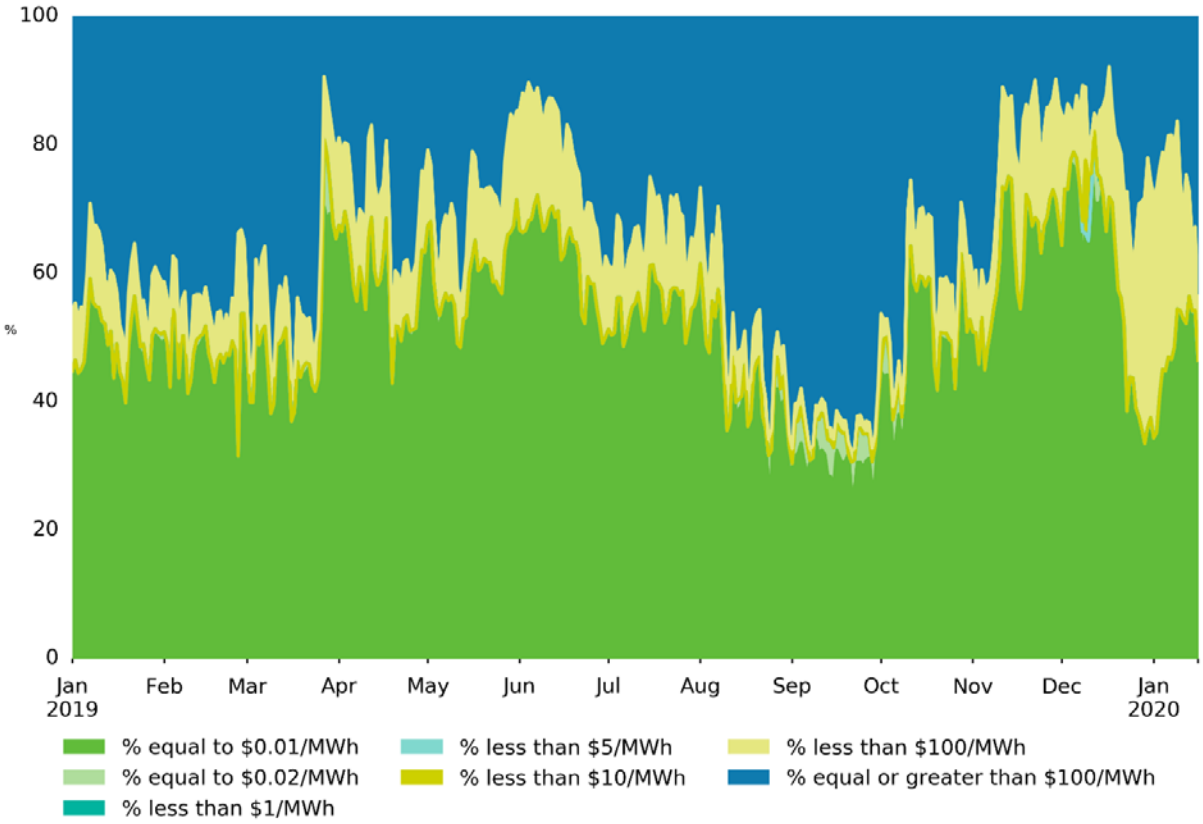


Figure 34 Contact Energy's Clutha River Offer Bands 2019/20



12.49 Figure 35 and Figure 36 show the amount offered and generated at Clyde and Roxburgh respectively. The amount offered at Clyde and Roxburgh changed due to flushing at both hydro schemes during the investigation period, and the reduction in efficiency due to Lake Roxburgh being lowered. There were trading periods where all generation offered was dispatched.

12.50 At Lake Roxburgh as part of requirements under the Otago Regional Council Flood Rules, Contact is required to remove sediment that builds up over time. Flushing the silt downstream during high flow events reduces the risk of flooding to Alexandra to ensure the safe and prudent management of the scheme. Contact said it also reduced the level of the head-pond lake of the Clyde Dam (Lake Dunstan) and as the lake levels reduced, the efficiency of the Clyde and Roxburgh units, and the power that could be physically generated, reduces.

12.51 At Roxburgh some of the trading periods where generation was below total offered were due to screen cleaning. At the end of December, generation was much lower than total offers as offer prices increased despite spill continuing.

12.52 At Clyde and Roxburgh offers were structured so that less generation was dispatched overnight. Because of the Clutha Flood Rules setting the total river flow, this means more spill was happening overnight. This action would have contributed to spot prices not falling to low levels overnight. This appears to be independent of the screen cleaning and gate operation issues set out above.

Figure 35: Clyde's MW Offered and generated by period

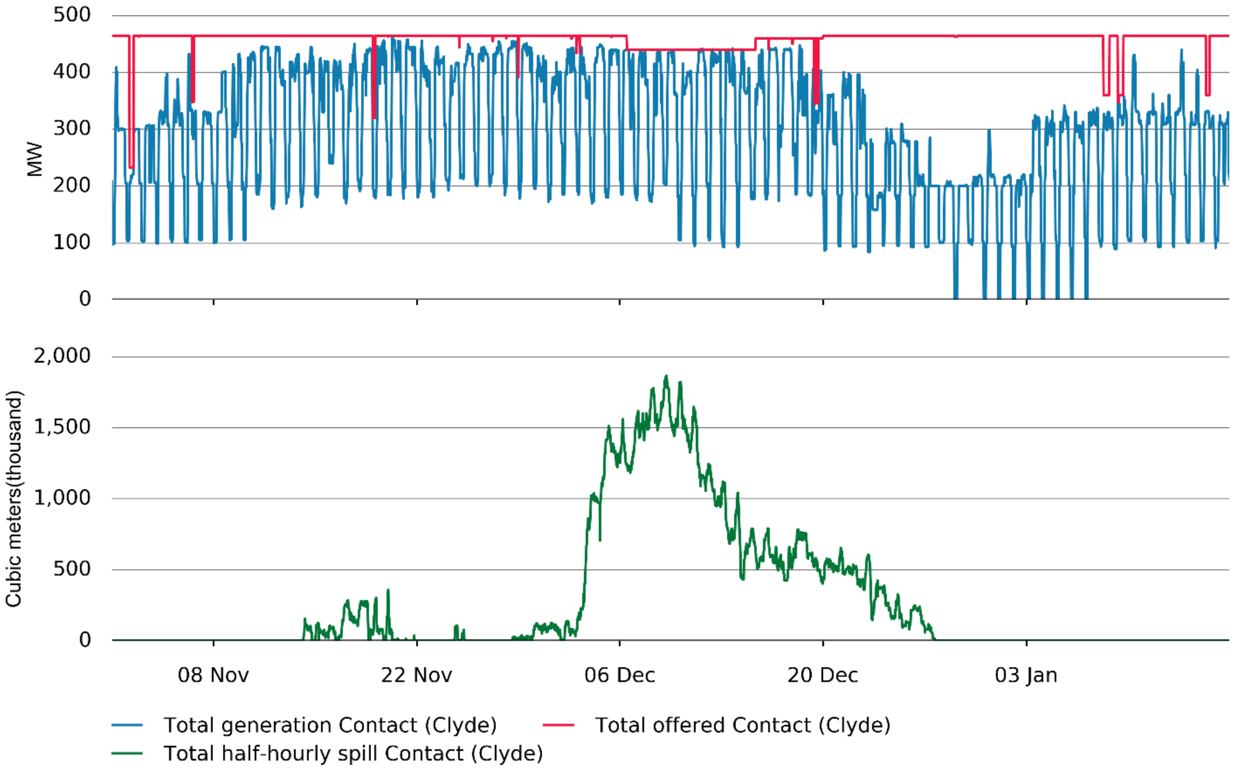
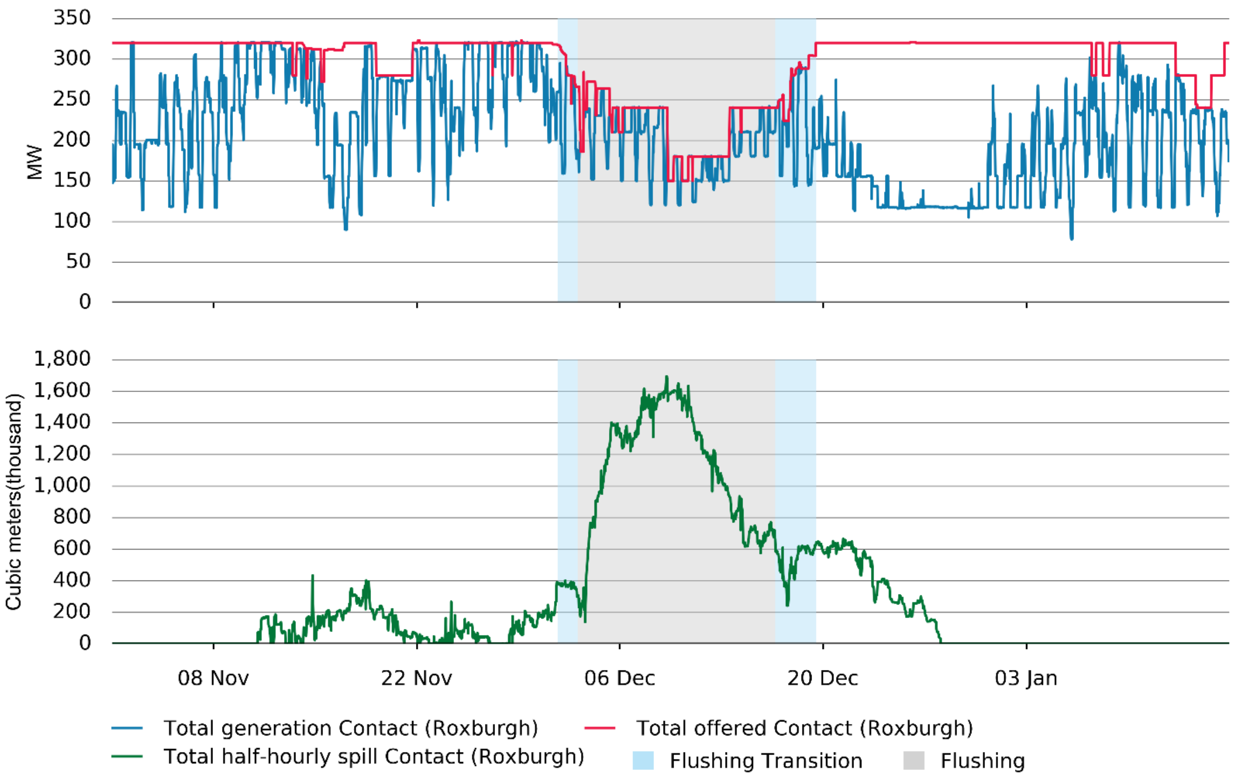


Figure 36: Roxburgh's MW Offered and generated by trading period



12.53 Clutha's offering behaviour is summarised in the table below.

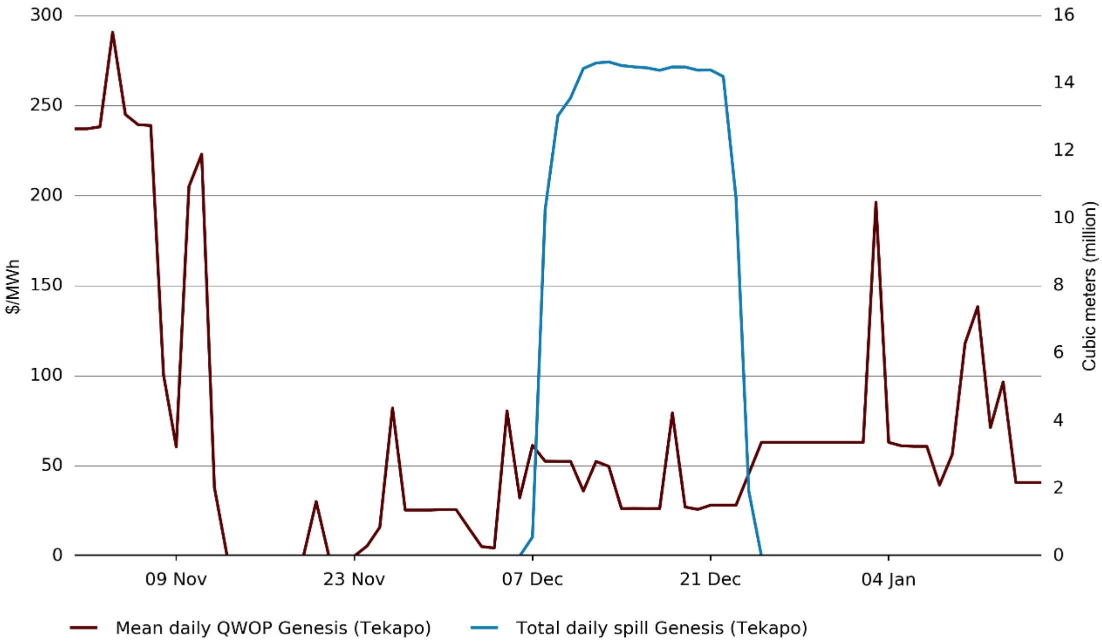
Table 4 Summary of Clutha's offering behaviour

Volume of spill compared to offer price	Volume of spill compared to offer bands	Volume offered compared to volume dispatched
When Clyde and Roxburgh first started spilling in November the QWOP dropped to $50/MWh and generally stayed between $25 and $100/MWh through to January when the spill finished.	Contact offered a lot of low priced generation compared to the rest of the year. Some generation was being offered at over $100/MWh during flood conditions.	The amount offered at Clyde and Roxburgh changed due to outages at both hydro schemes during the investigation period and, in Roxburgh's case, due to screen cleaning. Clyde and Roxburgh offers were structured so less generation was dispatched overnight and this meant that more spill occurred overnight. This action more than likely meant prices were higher overnight than they otherwise would have been.

Tekapo (Genesis)

12.54 Genesis reported flood spill at Tekapo in December. During most of the run up to and the time during the flood spill the QWOP was below $50/MWh.

Figure 37: Tekapo's load weighted offer price and spill



12.55 Figure 38 shows that in December 2019 Genesis had a large proportion of low-priced offers. Figure 38 shows an increase in higher priced offers (greater than $100/MWh) starting in late December. Figure 39 shows Tekapo's offer bands for 2019 and into 2020.

It shows that compared to the rest of 2019, Tekapo's offers were low during the period it was spilling.

Figure 38: Tekapo's offer bands and spill

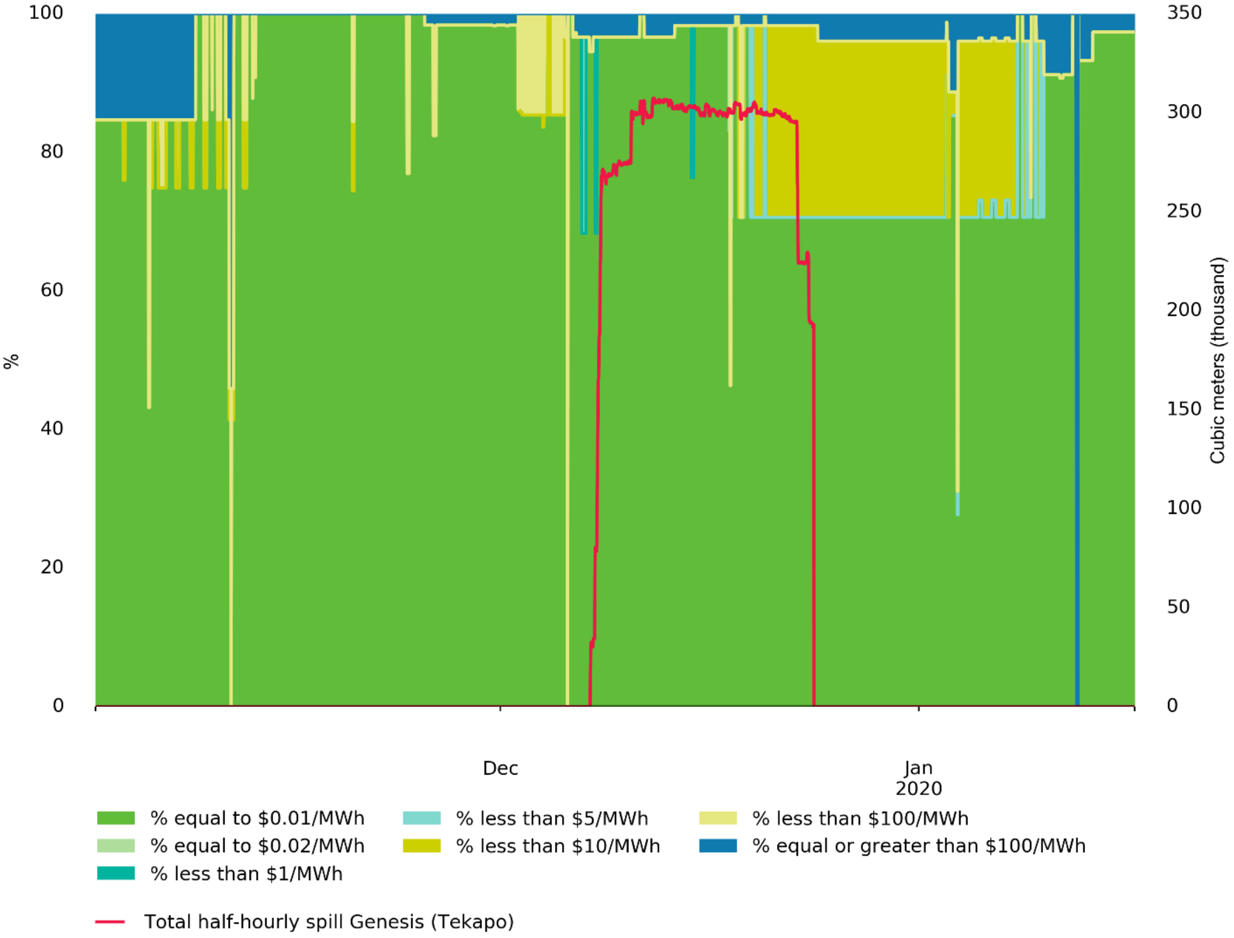
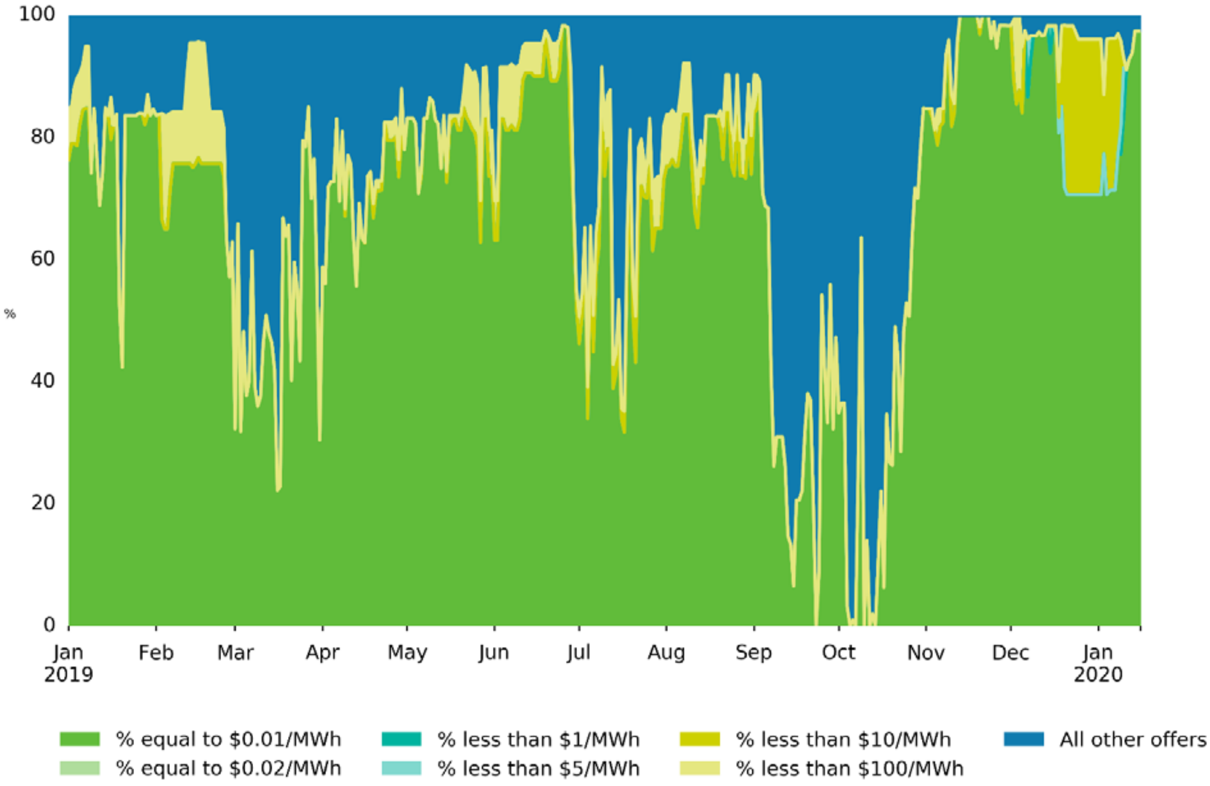
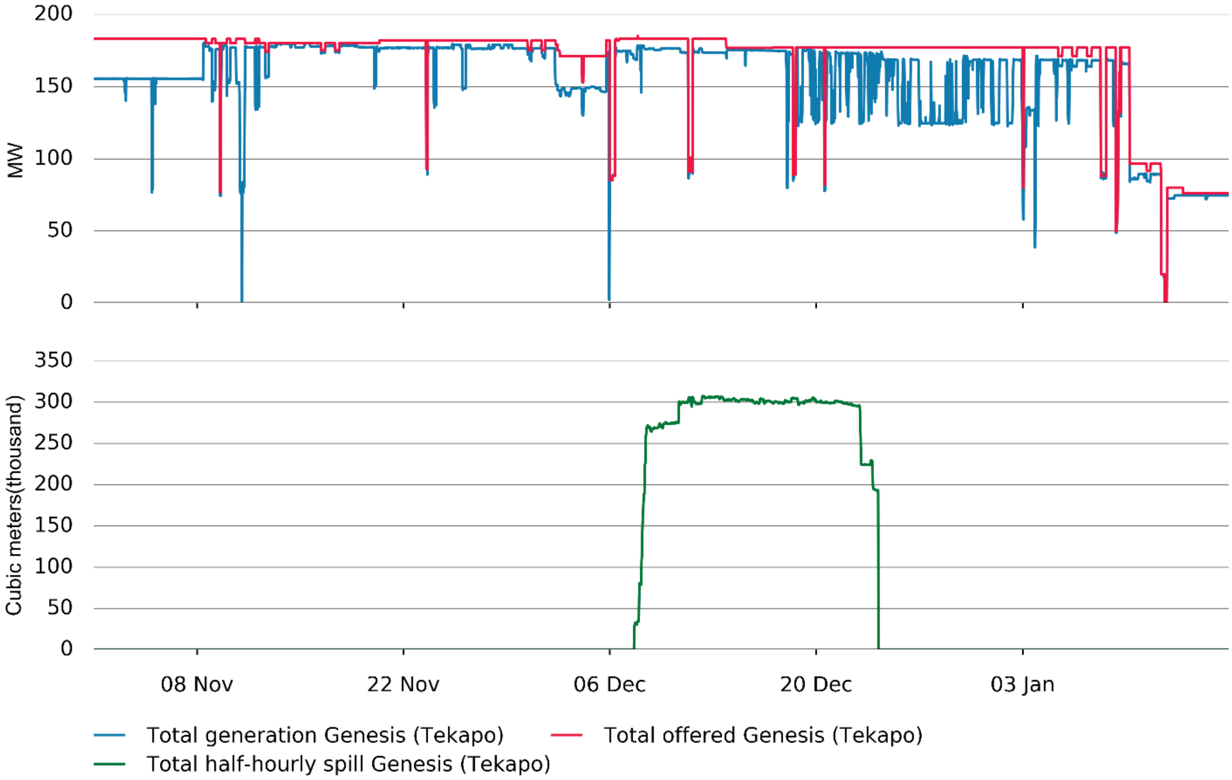


Figure 39: Tekapo's offer bands 2019



12.56 Figure 40 shows the amount offered and generated at Tekapo. During most of November and early December as Tekapo started spilling nearly all that was offered was used for generation. As with Contact's Clutha stations, Genesis was structuring Tekapo's offers so it could run less overnight. This happens late in the period during which Tekapo was spilling.

Figure 40: Tekapo's MW Offered and generated by trading period



12.57 Tekapo's offering behaviour is summarised in the table below.

Table 5 Summary of Tekapo's offering behaviour

Volume of spill compared to offer price	Volume of spill compared to offer bands	Volume offered compared to volume dispatched
During immediately before and during the flood spill the QWOP was below $50/MWh.	In December 2019 Genesis had a large proportion of low-priced offers during the first part of the spill period. Genesis then began to offer higher priced tranches overnight.	During most of November and early December as Tekapo started spilling nearly all that was offered was used for generation. In late December offers were structured so it would run less overnight.

Summary of offering behaviour

12.58 The table below summarises the offering behaviour by hydro scheme.

Table 6 Results of analysis of the spot market against our counterfactual

	Summary of offering behaviour
Manapōuri	Offers from 7 December were consistent with maximising generation during a spill event. But offers in November and early December were not consistent with what we would expect from a spilling hydro generator.
Waitaki	During spilling a significant volume was offered at over $100/MWh, especially overnight. This is inconsistent with what we would expect from a spilling hydro generator. The QWOP for the Waitaki was around $400 during the UTS period, regardless of whether there was spilling or not.
Clutha	QWOP dropped to $50/MWh in November when spilling started and generally stayed around $25-$100/MWh through to January. The direction of this fall is consistent with our expectations. Contact's offers reflected intake screen cleaning and the objective of trying to minimise its spill gate operations. Although QWOP fell, Contact offered high priced tranches throughout the flood. Contact's offers meant it was dispatched at lower levels overnight, meaning this is when most spill occurred. These higher priced offer tranches are not consistent with what we would expect from a spilling hydro generator, and the high overnight offers are inconsistent with the screen cleaning and gate operations set out above.
Tekapo	Immediately before and during the flood spill the QWOP was mostly below $50/MWh. Most of the time Tekapo was spilling, it was being fully, or almost fully dispatched. From about 19 December it started to be dispatched less overnight due to larger volumes being offered at higher prices. This is inconsistent with what we would expect from a spilling hydro generator.

13 RMA consent and other flood management issues that Meridian faced

13.1 At some points during the flood, offer behaviour was affected by the requirement to comply with the Resource Management Act (RMA) and to manage the flood responsibly in terms of the impacts downstream such as erosion, and safety of livestock and river users. Some of the offer behaviour described above was justifiable because it helped Meridian manage the very large inflows.

13.2 Contact faced similar issues, and these are dealt with in Section 12.

Manapouri

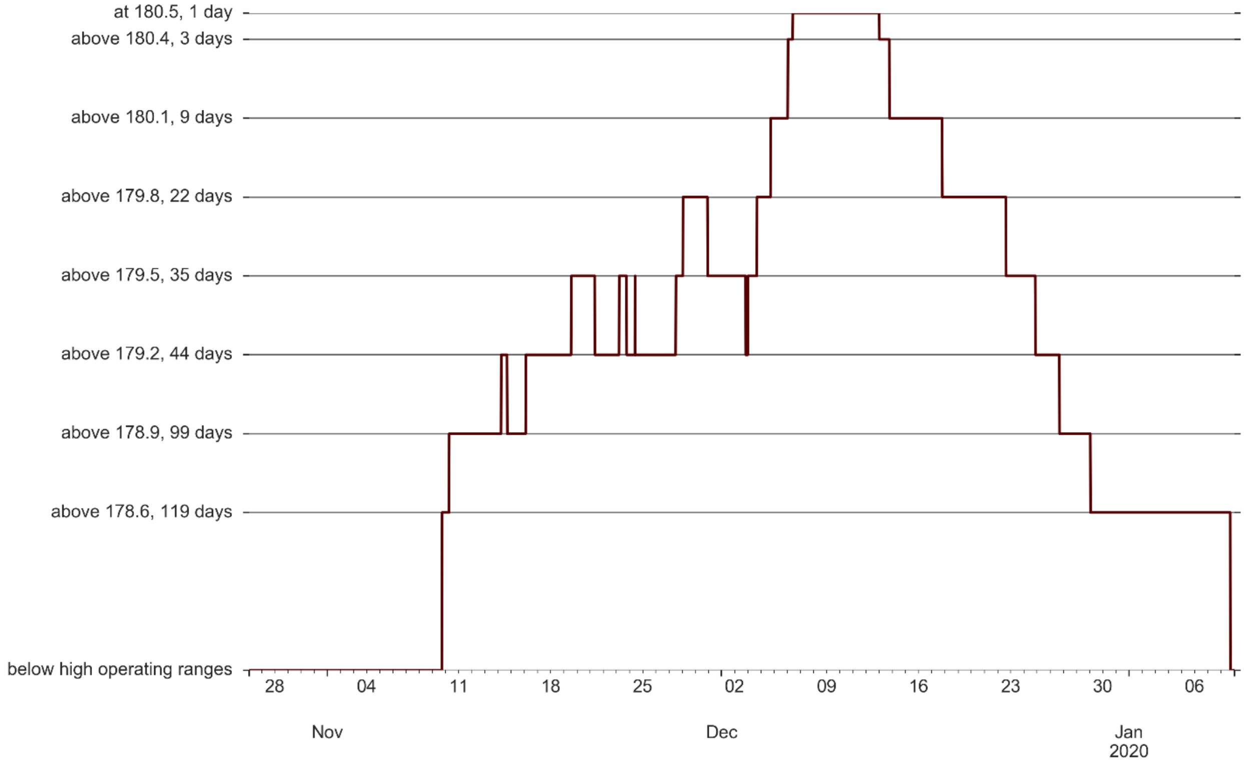
13.3 Manapouri's operating guidelines specify maximum durations above different lake levels. These durations and lake levels are shown in Figure 41. For example, the lake levels are only supposed to be above 180.5m for a duration of 1 day. From 19 November 2019, the lake level was such that Meridian had 35 days to reduce the level to 179.5m, and from 28 November it had 22 days to reduce the lake level to 179.8m.

13.4 These arrangements mean Meridian can store water—if for a limited duration—at the same time as spilling, if it is able to reduce the lake level within the specified number of days. However, there is also a specified interval between which they can have the lake at different levels. If they had another large inflow event soon afterwards they would need some of the specified duration remaining to be able to have the lake at those levels again.

13.5 Meridian has advised it was limiting generation overnight to avoid spilling from Lake Ohau and to help manage the level of the smaller storage lakes on the Waitaki scheme.

13.6 Meridian has said it needs to manage the levels of the smaller storage lakes carefully. Meridian advised these lakes (Ruataniwha, Benmore, Aviemore and Waitaki) are often left with too much or not enough stored water. Too much can result in the initiation of new spill; not enough can limit generation during the next day. Also, as shown in Figure 22, there was little generation capacity at Manapouri that was not dispatched.

Figure 41: Lake Manapouri lake levels and operating guidelines



Source: Meridian

13.7 The Authority simulated offering Manapouri and Ohau generation at $0.01/MWh to determine if—all things being equal—it was possible to fully dispatch Manapouri and Ohau during November. The results show that while the Ohau stations would have generated more, Manapouri would have generated less and spilled more. Consequently, the Authority does not believe that there was excess spill at Manapouri during November.

13.8 Note that any spilt water at Manapouri is lost forever – there are no other generating stations that can use this water further downstream. In contrast, if some water is spilt at some stations on the Waitaki scheme, it can still be used further down the chain at other stations (see Figure 23).

Waitaki River management issues

13.9 We asked Meridian about management of the Waitaki River during the flood event. It responded with details about how it was managing the river's flow. It was clear Meridian had many factors to consider when managing the flood on the Waitaki during December. These included the safety of people and plant, as well as operating within its resource consent conditions.

13.10 Once the Islington Livingston (ISL_LIV) 220kV circuit was lost on 8 December, transmission between Aviemore and Benmore was more prone to binding. If these circuits do bind then Meridian can no longer be block dispatched on the Waitaki—in other words Meridian would lose the ability to choose how much electricity is generated at each station over its full set of Waitaki stations[11].

[11] The System Operator will usually constrain affected stations out of the block for dispatch when there are transmission problems due to transmission outages. In their Customer Advice Notice of this outage on 8

13.11 This reduces the flexibility that Meridian has to manage the Waitaki River which matters during a large flood. It also causes the generation to vary—in particular at the Aviemore and Waitaki stations—which in turn causes variable river flows downstream, contrary to the resource consent conditions outlined below. Consequently, Meridian limited the generation from the Aviemore and Waitaki stations to prevent the Aviemore-Benmore (AVI_BEN) circuits from binding.

13.12 The Authority does not think offers should be used to manage transmission constraints. This undermines the rationale for nodal pricing by dampening locational price signals. This in turn effects efficiency as set out in section 8.

13.13 However, the Authority's view is that managing the circuit between Aviemore and Benmore in a conservative way was appropriate given the particular set of circumstances Meridian faced. In particular, the flood during December was a significant event that Meridian had to manage within its resource consent conditions. Block dispatch is an important part of this management.

13.14 In addition, there is no FTR between Benmore and Aviemore nodes, so there is no possibility for Meridian to use an FTR to hedge this locational risk.

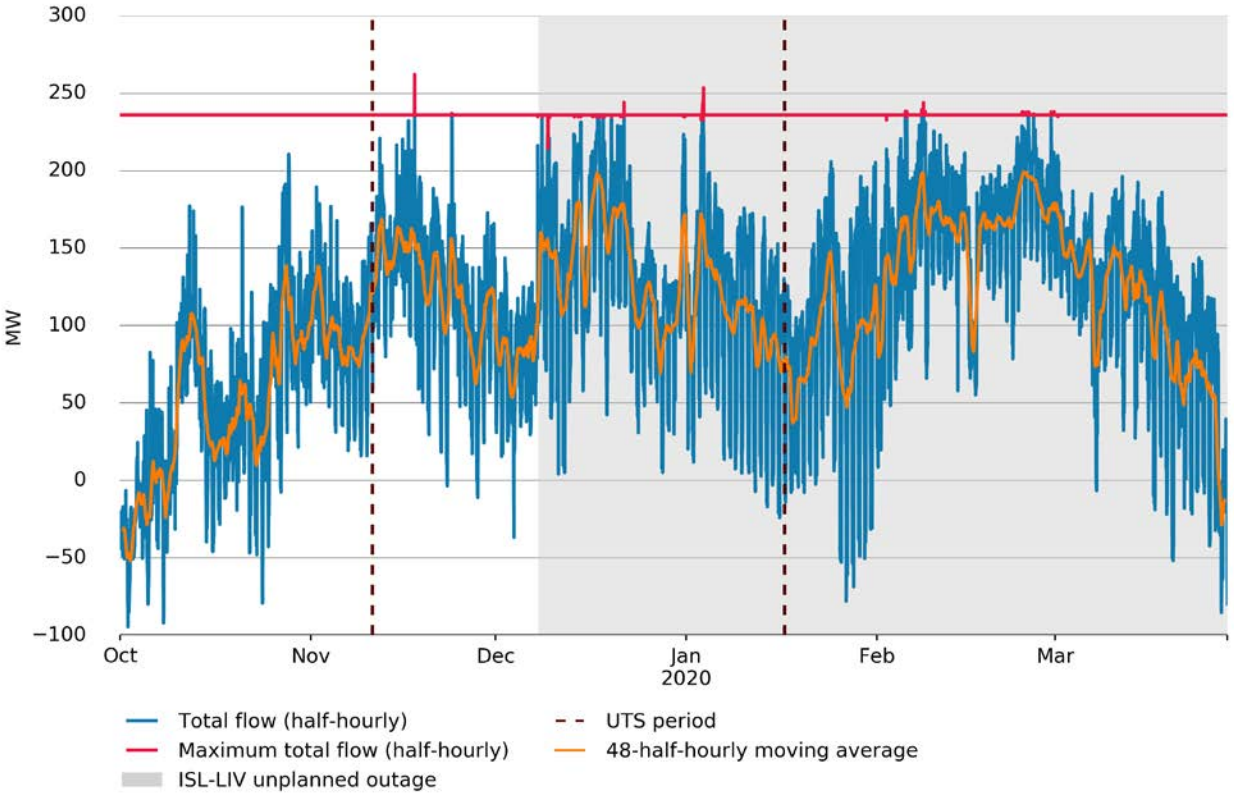
13.15 These factors, along with the possibility of factors outside Meridian's control affecting flow on that circuit lead the Authority to believe that managing AVI_BEN during December 2019 is acceptable.

13.16 Figure 42 below shows the flow on the AVI_BEN circuits. It shows that once the ISL_LIV circuit was lost, there was an immediate increase in flow on the AVI_BEN circuits. However, from then on, the general level of flows is not readily distinguishable from the period immediately before the loss of the circuit.

13.17 Meridian advised that many factors affect this circuit—the flow over the HVDC, upper South Island load, generation at other South Island plants. These are large factors compared to the capacity of the circuit. It is not surprising Meridian manages the risk of this circuit binding conservatively at times when block dispatch is critical.

December Transpower stated that 'The outage of this line may also impact generation dispatch due to subsequent constraints on Waitaki Valley 220kV circuits.' Additionally, Meridian told us that 'If the constraint were to bind then it would have resulted in sub block dispatch for Aviemore and Waitaki with Transpower requiring frequent changes in generation…'. Transpowers Customer Advice Notice is available here: https://www.transpower.co.nz/system-operator/operational-information/customer-advice-notices?year=2019#december

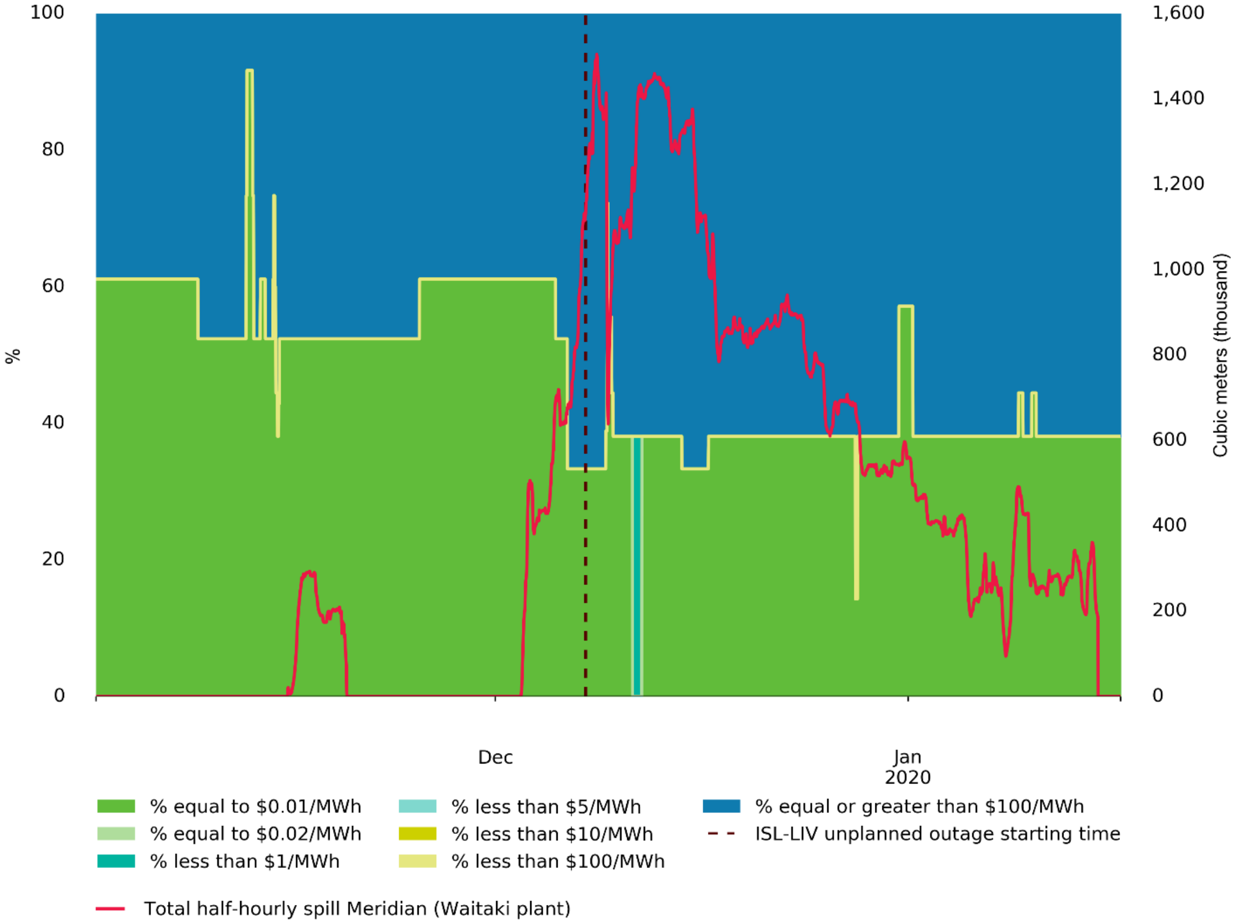
Figure 42: Flow and upper limit of the AVI_BEN circuits



13.18 Figure 43 and Figure 44 show offers and spill at Aviemore and Waitaki stations respectively. Figure 44 clearly shows Meridian increased the volume offered at high prices at Waitaki once the unplanned outage of the ISL-LIV circuit started. Figure 43 shows Meridian was changing the volumes it offered at different prices during December. Meridian was offering more lower priced volume during the day and then more higher-priced volume overnight. Figure 43 shows the relationship between the increased lower priced offers and less spill.

Figure 43 offers and spill at Aviemore

Figure 44 offers and spill at Waitaki station



13.19 Meridian has advised the spill gates at Aviemore are at risk of failure if they are adjusted often. Consequently, Meridian disabled its system at Aviemore that adjusts the spill gates in coordination with changes in generation, which keeps the river flow constant. This meant Meridian largely fixed Waitaki station generation at a constant level and minimised changes in generation at Aviemore.

13.20 Meridian has a resource consent obligation that in effect means the river flow below the Waitaki station should not change rapidly. The combination of this consent and the river management issues listed above meant during the event, Meridian was effectively managing the flow on the lower Waitaki at Benmore.

13.21 Benmore's spillway effectively has a "no-go" zone (to avoid damage to the base of the spillway)—Meridian can spill more than the upper bound of this zone, or less than the lower bound of this zone. If desired spill is within the no-go zone, the spillway must be set to alternate between the upper and lower bounds. In order to maintain relatively constant total Benmore flow, Meridian may have to change its generation up or down to compensate.

Limits of this analysis

13.22 The Authority acknowledges that Meridian had a very large inflow event to manage during the UTS period. We have designed our analysis below to simulate the power system without interfering in how Meridian was managing this flood. That analysis indicates that the market price that prevailed during the UTS period was not merely the result of resource management factors.

Summary of RMA consent issues

13.23 Meridian was faced with a large flood and was required to manage it within its consent conditions, and responsibly from the perspective of other river users. The Authority's view is that managing the circuit between Aviemore and Benmore in a conservative way was appropriate given the importance of maintaining block dispatch and the possibility of factors outside Meridian's control affecting flow on that circuit. These factors are taken into account in the following section where we estimate excess spill.

14 Estimating the amount of excess spill

Key points

- We estimate there was at least 55MW excess spill throughout December, or 41GWh of excess spill in total
- We estimate the price required to clear this generation is around $6.35/MWh
- We estimate about 12.6GWh of extra storage in the North Island could have been available for the HVDC outage in the first quarter of 2020
- Our method accepts all the RMA and river management issues outlined in the preceding section

Overview

14.1 We set out below a method and results for estimating how much more water could have been used to generate electricity. Our method is consistent with the electrical constraints that the power system operates under. In other words, for any extra generation to be useful, it must be able to be transmitted to where it can be used in a way that is consistent with any transmission constraints.

14.2 Our method is also consistent with the responsible management of the rivers and lakes that make up the South Island hydro generation fleet, which is set out in the preceding section. In other words, the analysis in this section takes as given all the consent conditions and generation equipment limitations set out above.

Introduction

14.3 Evidence presented in section 12 suggests capacity was withheld to prevent the HVDC from binding. Offer prices were increased to do this and the spot price was higher than it would have been had this capacity been used. This had the effect of reducing generation and therefore increasing spill. This section estimates the amount of excess spill that occurred.

14.4 Excess spill is spill that we estimate could have been used to generate electricity. For spill to be excess spill:

(a) the power station that it is bypassing needs to have sufficient spare capacity to generate

(b) using the water to generate rather than spilling it does not cause any resource consent issues or violate any plant operating constraints

(c) the extra generation must be able to be used in the power system.

14.5 The third condition is necessary as, for example, the extra generation cannot simply displace generation at other spilling hydro stations, thereby shifting spill to a different location. The same applies to wind and geothermal generation—if generation from these stations is displaced then spill is simply shifted to a different location and transformed into a different form.

14.6 In addition, any extra generation needs to be consistent with transmission constraints in the electricity system.

14.7 The claimants' analysis did not consider the possibility that spill would be simply shifted from one point in the power system to another. In addition the analysis did not include transmission constraints that would have been imposed on the dispatch model due to large perturbation modelled. Constraints are built by the System Operator's simultaneous feasibility test model in near real time, and large changes to input data may mean constraints are needed by absent from SPD. These factors are likely to mean that the claimants' analysis overestimated the value of excess spill.

14.8 We have no model that can integrate resource consent conditions with the different requirements of an efficient dispatch, so we have taken a two-step approach to estimating the excess spill:

(a) We used vSPD to estimate the maximum possible extra generation that could be exported over the HVDC. We did this by running a scenario where all large hydro in the South Island offered all capacity at $0.01 while spilling. Using $0.01 means that wind and geothermal in the North Island will not be displaced by the extra generation as this North Island generation is typically offered at $0.01 and losses ensure that it will be preferred in meeting North Island demand.

(b) We then set all generation to what was actually dispatched except for Benmore. We then calculated whether any part of the extra generation could have been generated at Benmore without changing the river flow downstream or breaching Meridian's resource consents. We chose Benmore because there are no constraints between Benmore and the HVDC, so any extra generation at Benmore can be exported.

14.9 The first step is to make sure that we include all the market constraints for any generation that might be produced by using excess spill. The second step constrains this generation to be consistent with Meridian's consent conditions at Benmore. And by assuming all other generation is as occurred during December, all other consent issues and equipment limitation issues are taken as given.

14.10 Extra generation at Benmore that does not breach resource consents is a measure of excess spill. We think that this measure of excess spill is conservative in the sense that other stations (including other Waitaki stations, Manapouri, Clyde and Roxburgh) could have generated more in instances when Benmore could not have produced all the extra generation that the power system could actually use.

14.11 In addition, this analysis assumes hard hydro limits when in fact Lake Benmore and the head ponds on both Aviemore and Waitaki all allow significant flexibility to avoid these limits. For example, assuming Benmore lake levels remain within resource consent requirements, the Benmore spillway could be operated at a different 'duty' or on/off cycle between the two no-go limits to maximise generation. Our analysis assumes that this flexibility is not used, again making the analysis conservative.

14.12 As the HVDC was flowing North during the UTS period, we have used HVDC export as a proxy for extra generation as this is where the extra generation would have to go. Other South Island generation was set at what it actually generated.

Excess spill: detailed methodology

14.13 The details of the specific steps we undertook to estimate the excess spill are as follows:

(a) All South Island generators except Benmore were modelled to generate the same as they did during the flood event – we use reconciliation (RM) data for this.

(b) Using vSPD we determined total South Island generation dispatched had all offers for spilling hydro stations been set to $0.01/MWh. This ensures all market constraints, including additional HVDC flow are satisfied, but ignores any spillway constraints at Benmore.

(c) The actual generation (RM data excluding Benmore) was subtracted from the total dispatch that the $0.01/MWh offer vSPD simulation predicts. This gave us a total potential Benmore generation series which is truncated at Benmore's generation capacity. This is the new potential Benmore generation ignoring the spillway constraint.

(d) The Benmore RM data (what was actually generated) was then subtracted from this new potential Benmore generation to get the additional potential Benmore generation.

(e) This was then converted to cumecs and subtracted from the spill data which is also in cumecs.

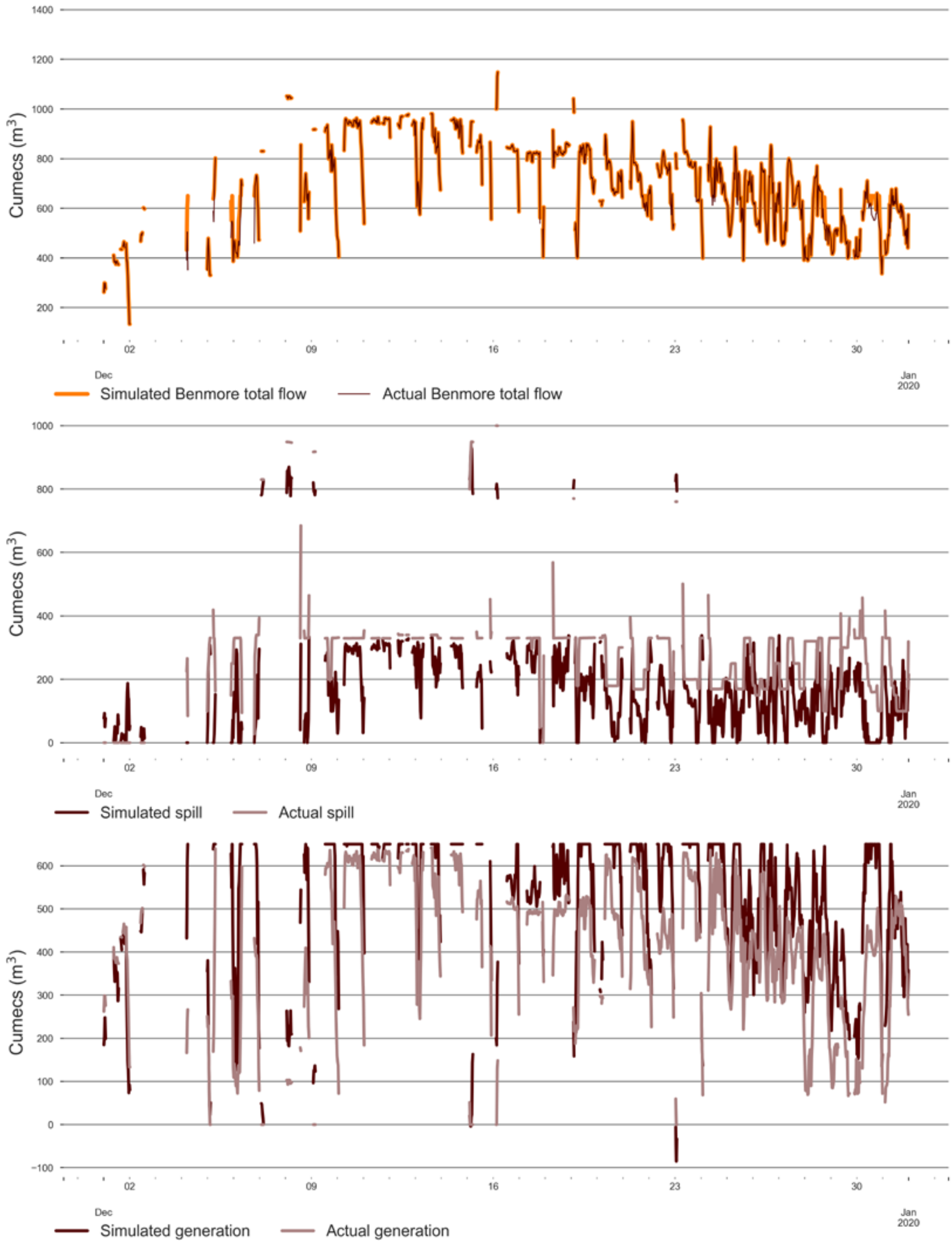
(f) If this resulted in spill within the no-go zone then the generation at Benmore in the trading period was discarded.

(g) For those trading periods that result in an increase in generation, this generation was converted to MW, summed, and converted to GWh.

Results

14.14 This analysis results in an estimate of average extra generation during December equivalent to 55MW of generation capacity—this is an estimate of generation from spilt water that could have been used for generation which would have satisfied both the market and hydro constraints. This would mean about 41 GWh of additional energy would have been produced during December. Benmore would have generated more than it did in reality during 76% of the trading periods in December.

Figure 45: Simulation results



14.15 Figure 45 shows the results of the estimation of excess spill. The top panel shows how the total flow from Benmore is unchanged by substituting spill for generation. The middle panel shows the simulated spill and the actual spill. The actual spill is the lighter line and much higher than the simulated spill in general. The difference between these lines is the excess spill. The bottom panel shows the simulated and actual generation. The difference in these lines shows how much more could have been generated at Benmore with water that was spilled. We have measured this in equivalent cumecs to be consistent with the other two panels.

Offer price needed for the South Island to generate the extra 55MW

14.16 This level of excess spill estimated for Benmore raises the question of what offers would need to be to clear this 55MW of extra generation. To estimate this, we used a single offer price in vSPD for all generation at Manapouri, the Clutha stations and all Waitaki stations while each was spilling. We varied this offer price until there was an extra 55MW of energy exported from the South Island during December. So instead of the $0.01/MWh used above to estimate the maximum potential extra generation that could have been generated by South Island generators, we estimate the price that would clear the extra 55MW of generation that we calculate to be consistent with the hydrological constraints in the South Island.

Results

14.17 Our modelling results in an estimated offer price is around $6.35/MWh. This means that to export the extra 55MW—regardless of where in the South Island it is generated—all spilling hydro would need to offer at this price.

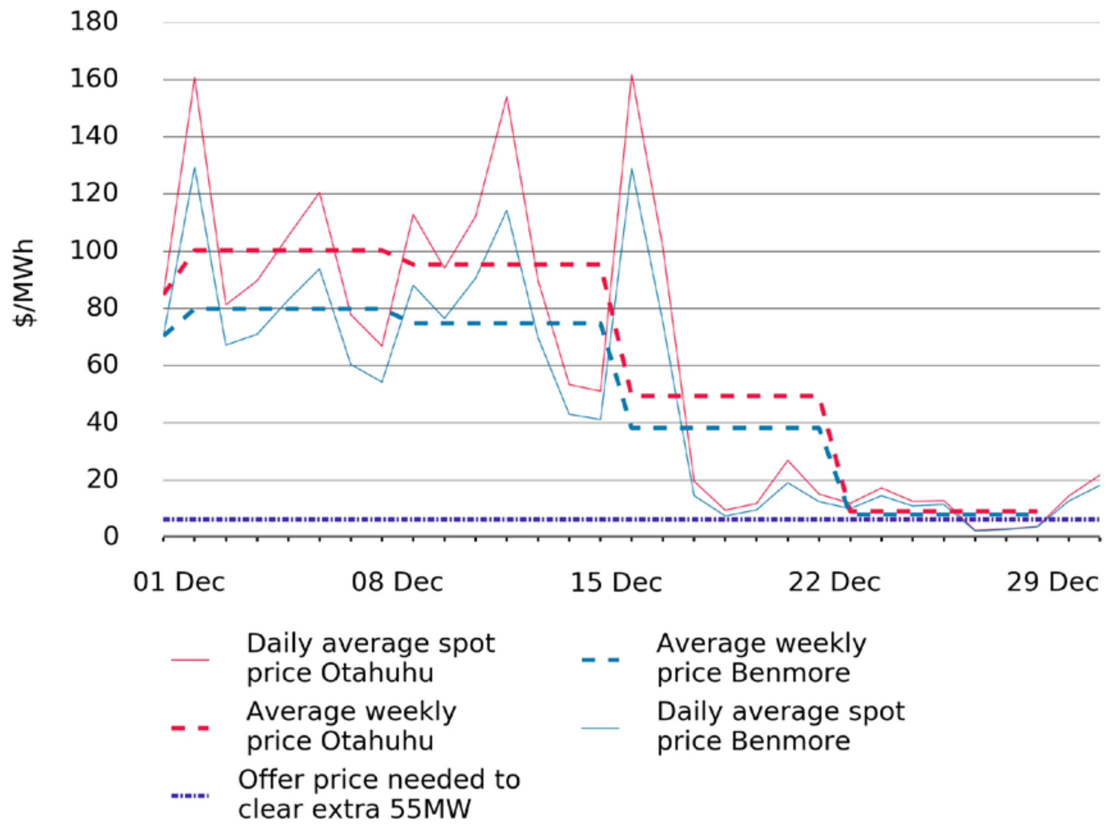
14.18 We believe it is a reasonable approach to estimating the price needed to clear an extra 55MW of generation. To estimate this price, we had to change South Island offers by a large amount. Had this happened we would have expected a competitive response from North Island generators. We do not have a model to estimate this response, so we caveat this estimate accordingly. We note however, that a competitive response from North Island generators would more than likely lower prices, benefitting North Island consumers. This simulation may also result in dispatches that are inconsistent with consent conditions, and change the timing of how water flowed down the Waitaki and Clutha systems.

14.19 Based on this modelling, our view is that offer prices and therefore spot prices would have had to have been materially lower for this excess spill to have been used for generation. In addition, an offer price of $6.35/MWh would still mean that North Island wind and geothermal would be dispatched as these generators are generally offered at $0.01/MWh. Any displaced North Island generation would be either thermal or hydro.

14.20 Figure 46 shows the daily average Benmore and Otahuhu spot prices for December 2019 along with the weekly averages. The $6.35/MWh estimated offer price is also shown. The large price difference we estimate would have been needed to clear this 55MW is shown as the distance between the Benmore line and the offer price line until late December—assuming the market would clear near this offer price.

14.21 Using this estimate for the offer price, for the period between 3 December and 18 December suggests there was an $80m impact on the spot market. However, the ultimate financial impact is currently not yet possible to determine because purchasers and generators are likely to be hedged.

Figure 46: Average and weekly average spot prices in December, and offer price needed to clear the extra 55MW



Security of supply impact

14.22 The UTS period preceded a planned HVDC outage which was scheduled to reduce the capacity of the HVDC from early January to early April—in the event, Transpower completed its work two weeks early. There was a concurrent planned Pohokura outage around the same time. It was reasonable for generators to expect there would be higher North Island prices during the outage because of the limited ability of the HVDC to transfer electricity North. These prices were obvious in the forward curve from about mid-2019 and signal the market's anticipated North Island scarcity during the outage.

14.23 Excess spill in the South Island prior to the HVDC and Pohokura outages could have left the power system in a less secure state—a lower level of storage in Lake Taupo—for the HVDC outage than would otherwise be the case. This is because the effect of the spill meant North Island generation was dispatched instead of the fuel being conserved so it was available for use during the HVDC outage. We therefore used the scenario set out above to determine how much Waikato hydro generation would have been displaced by the extra 55MW of South Island generation. We chose Taupo as it is the simplest to measure. The coal pile at Huntly, Ahuroa gas storage and the Waikaremoana hydro system can also store energy.

Results

14.24 Our modelling suggests that about 17MW of Waikato generation could have been displaced throughout December by extra South Island generation. This would mean an extra 12.6 GWh of energy stored in Lake Taupo leading into the HVDC outage in the first quarter of 2020. If this were the case, this would be energy that could have been used during the HVDC outage when capacity to import energy to the North Island was limited. This in turn would mean that North Island supply was more secure in that it would be more resilient to unplanned plant outages, but also it is likely to have meant lower prices during the outage due to a reduced need to run more expensive thermal generation.

15 Meridian advised that a period of spilling during April, May and June 2019 was similar

15.1 Meridian has suggested that there was a similar period of spill earlier in the year from April to June 2019, and that prices over the UTS investigation period were lower than over April to June. Our current view is that the UTS period and the April to June period are different because:

(a) Some market fundamentals were different:

(i) Demand was higher in April to June

(ii) Gas prices were higher

(b) Spilling and storage did not reach the levels seen during the UTS period (see Table 7 for a comparison of the level of spill between the two periods).

15.2 This means that we would expect higher prices over the April to June period than during the UTS period as a result of other – non-hydro fuel supply related – market fundamentals. It does not mean however that we have made a judgement about Meridian's offer behaviour during other periods of spill, as this would require more in-depth analysis. No UTS was alleged for the April to June period of spilling – or any other historic period of spilling – but this does not rule out the possibility that there may have been periods and behaviour similar to that currently under investigation.

Table 7: Total spill over the two periods

Catchment	UTS period (cubic meters, millions)	April-June 2019 (cubic meters, millions)
Meridian (Waitaki)	5213	1126
Meridian (Manapouri)	2637	877
Contact (Clyde and Roxburgh)	2108	417

15.3 Meridian's offer behavior was similar between the two periods, although their QWOP for Waitaki was higher over the UTS period (1 November 2019 to 16 January 2020) than for the April to June 2019 period (1 April 2019 to 30 June 2019), at \$372/MWh and \$304/MWh respectively. This was mainly due to a higher quantity being offered above \$899/MWh in the UTS period. The average megawatts being offered at over this price was 535MW over the UTS period and 413MW in April to June. Meridian also offered a lower amount in their lowest priced tranches during the UTS period compared to the April to June period (709MW and 758MW respectively, at average prices of \$0.02/MWh and \$0.06/MWh respectively).

15.4 We tested whether the increase in quantity in the higher offer bands for Aviemore and Waitaki may be due to the ISL-LIV transmission outage. Meridian told us that this outage effectively limited total generation from the Aviemore and Waitaki stations to around 200MW (compared to the nameplate capacity of 325MW for the two stations combined) to avoid the AVI-BEN circuit binding and therefore losing the flexibility of block dispatch. Instead of withdrawing this quantity in their offers, they moved more quantity to higher priced tranches.

15.5 Prior to the ISL-LIV outage, Meridian already offered an average of 128MW at prices higher than $899/MWh at Aviemore and Waitaki. It therefore was already effectively offering slightly *less* volume (325MW total capacity less 128 MW in high priced tranches is 197MW) at these two stations—in tranches that were more likely to be dispatched—than the 200MW capacity Meridian claimed that the two stations were effectively reduced to if Meridian were to retain the flexibility of block dispatch to manage the flood.

2011 and 2013 were more comparable in terms of storage

15.6 In late 2010/early 2011 and again in late 2012/early 2013, there were periods where storage in the South Island increased rapidly and rose above the nominal full level, reaching 3500GWh in 2011 and close to 4000GWh in 2013. In contrast, storage in the South Island in May/June of 2019 did not rise above the nominal full level, while during the UTS period storage rose substantially above this, reaching 4000GWh. The increase in storage in 2010/2011 and 2012/2013 also occurred at a similar time of the year (late December) as the UTS period under examination. We therefore also examined outcomes during these two periods. The three storage profiles are shown in Figure 47 - Figure 49 below. There have been other periods where spill has occurred at all South Island catchments, but here we concentrate on 2011 and 2013 for the reasons set out above.

Figure 47: SI storage in 2010-2011

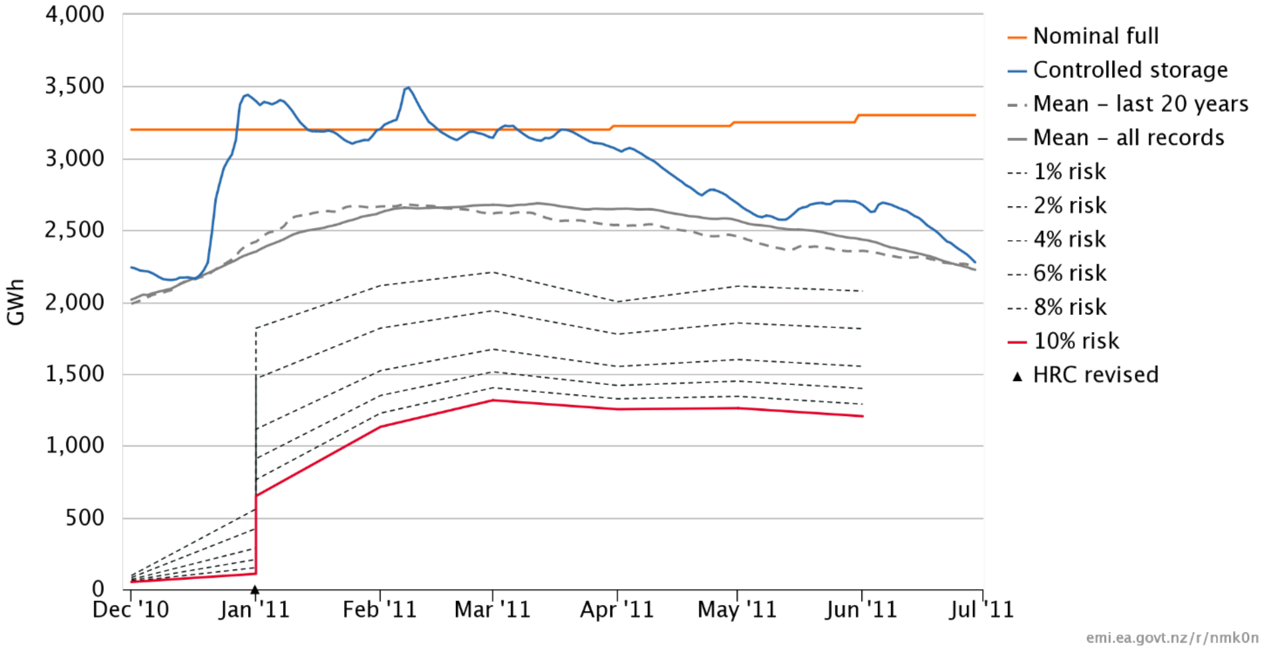


Figure 48: SI storage in 2012-2013

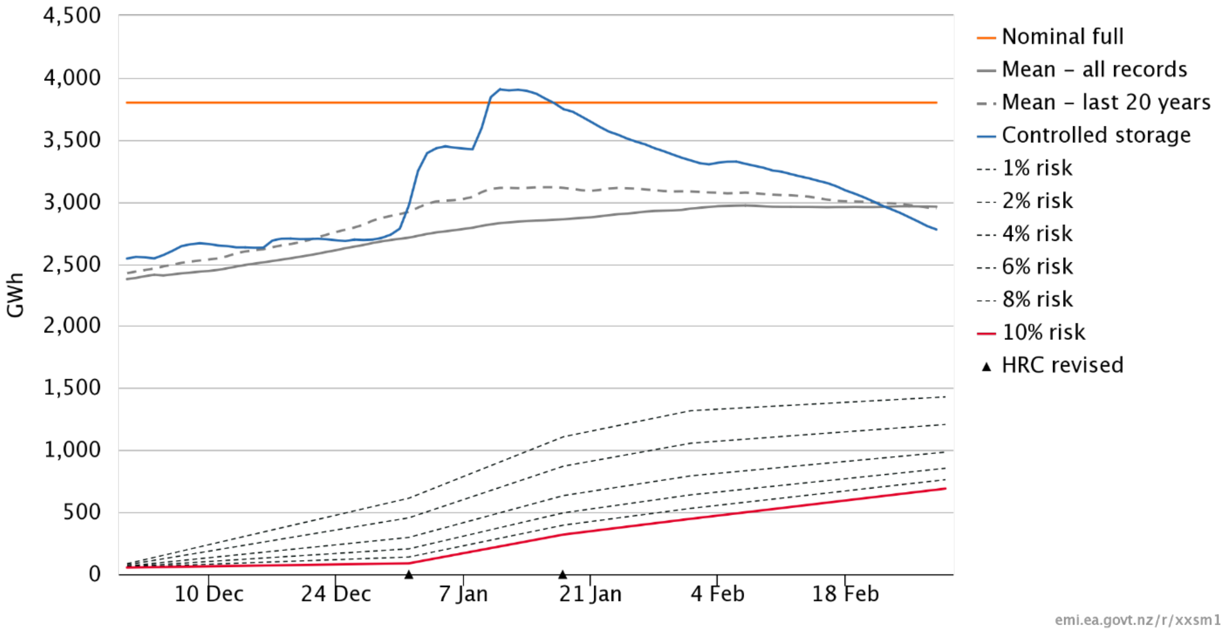
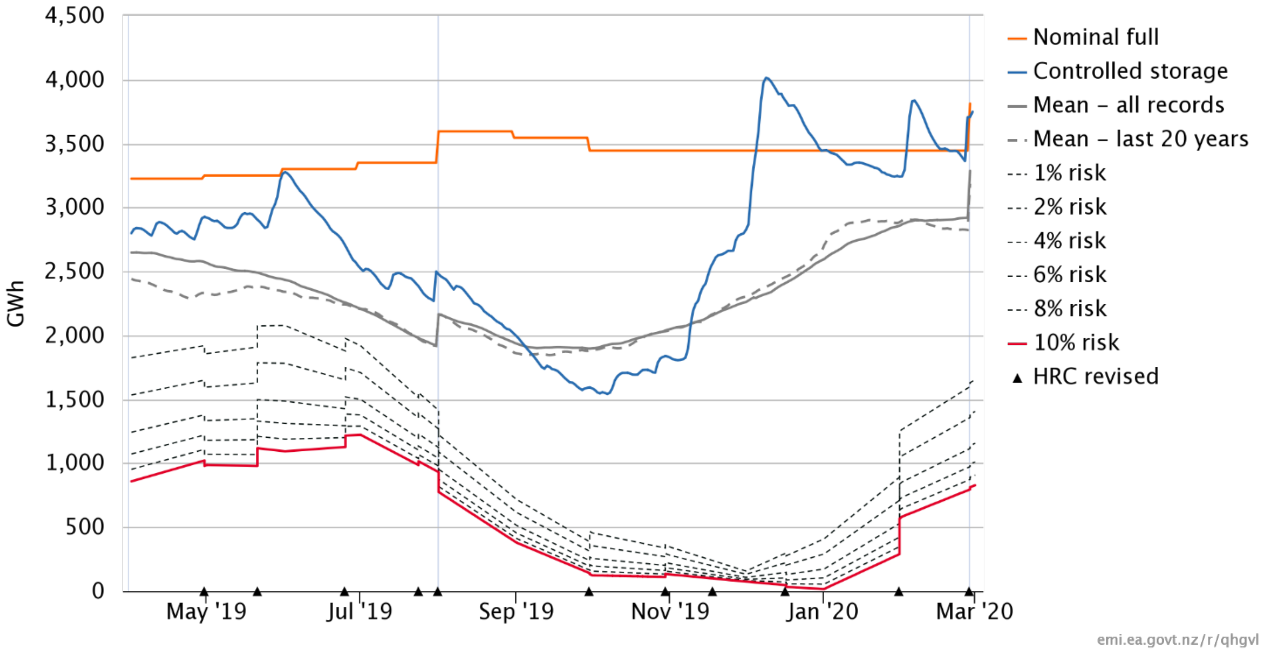


Figure 49: SI storage in 2019-2020



15.7 The average QWOP over the 2011 period (20 December 2010 to 20 March 2011) was $84/MWh, substantially lower than the QWOPs in the other periods examined.[12] Meridian advised us that this is driven by a change in the price of offers not expected to clear (ie, the highest priced tranches). Meridian lifted their top tranche prices following the 26 March 2011 high price event and UTS when prices were reset at $3,000/MWh. We therefore also examine the quantity offered above $99/MWh in 2011 and the UTS period. The average percent of total offers that were priced above $99/MWh in 2011 was 25%. This compares to 41% during the UTS period, 37% in April to June 2019, and 23%

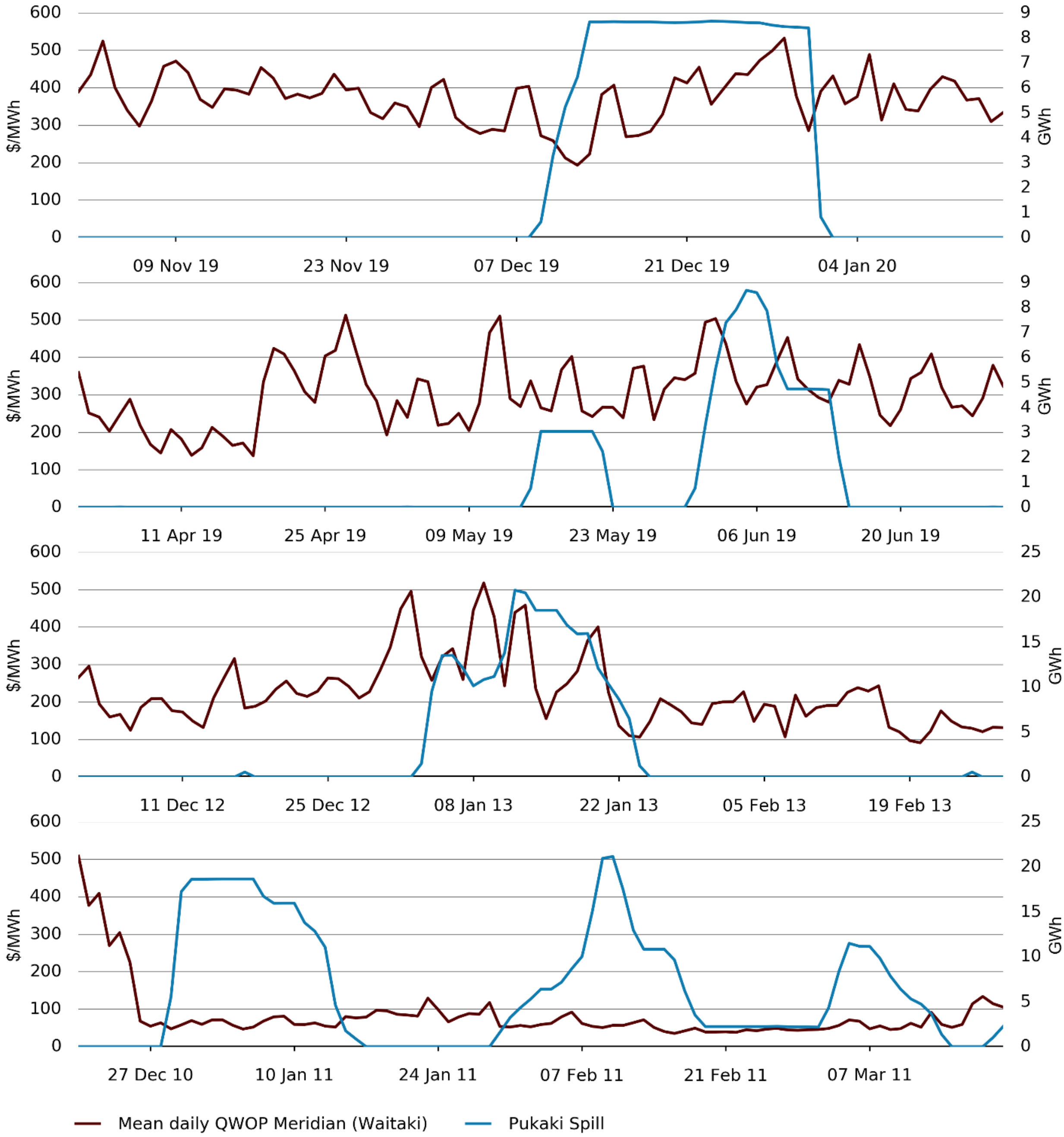
[12] While Meridian still operated Tekapo A and B during this period, we have ignored these stations in our analysis for 2010/2011 to keep consistency with the later time periods.

in 2013. From 2012 to the end of October 2019, during periods when Pukaki was spilling, the average percent of offers priced at over $99/MWh was 31%.

15.8 The average QWOP over the 2013 period (1 December 2012 to 28 February 2013) was $224/MWh, again lower than the two more recent periods of spill.

15.9 The contrast in offering behavior is shown in Figure 50 which shows offers and Pukaki spill for the UTS period, the mid-2019 period, the 2012/13 period, and the 2010/11 period. The fall in QWOP- without making any judgement on the absolute level - once storage increases as seen in the bottom panel is what we would expect from a hydro generator when the opportunity cost of water falls to zero. This is also what we broadly observed in 2019 at the Clutha stations and Tekapo.

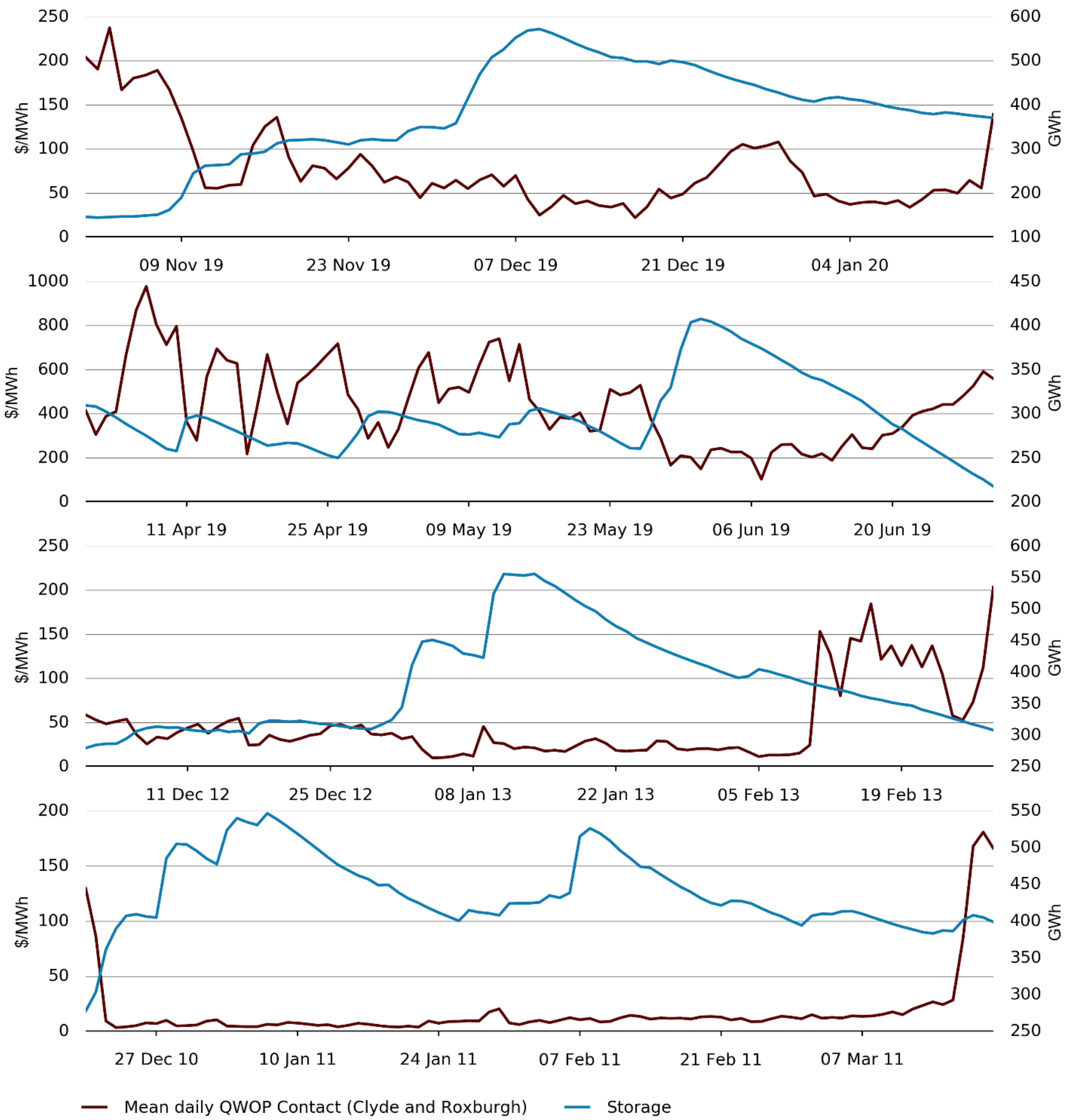
Figure 50: QWOP for Meridian's Waitaki stations and Pukaki spill



15.10 Figure 51 shows similar data for Contact's Clutha stations. In 2011 offer prices were very low once storage increased. 2013 offer prices were slightly higher but still lower than the two more recent periods. During mid-2019, offer prices started very high and fell once storage increased above 300GWh which is when the majority of the spill occurred.

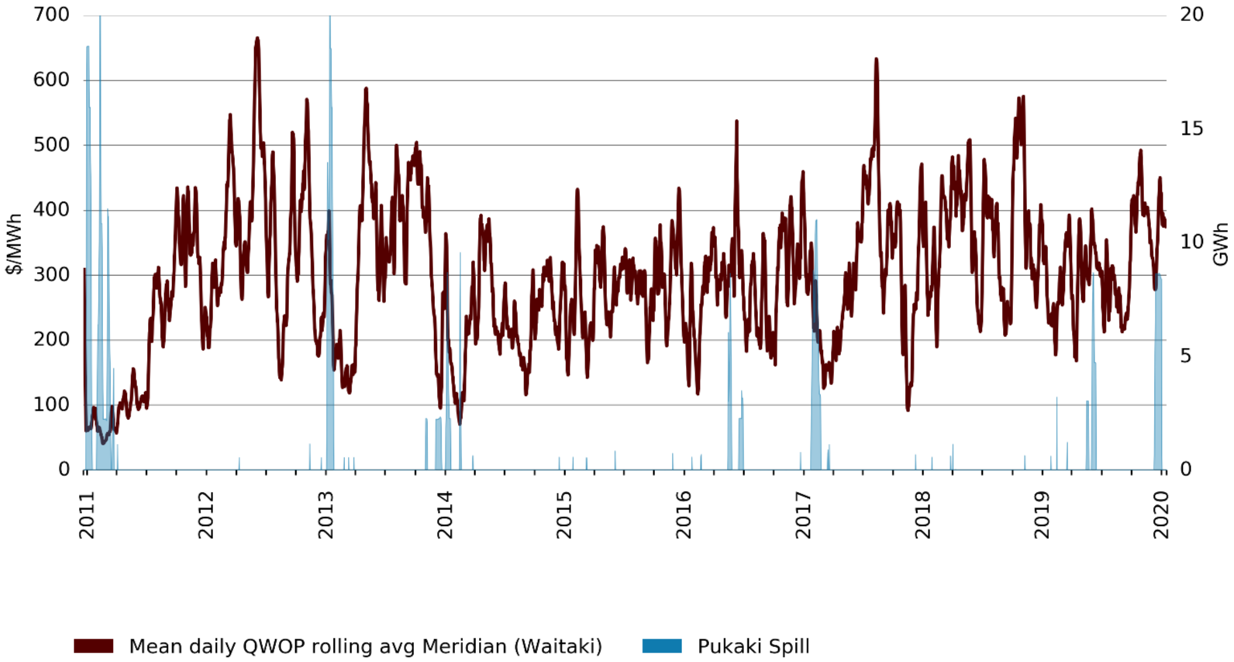
15.11 Both Figure 50 and Figure 51 show the stark contrast in how generators offered in 2010/11 and 2019.

Figure 51 QWOP for Contact's Clutha stations and storage in Wanaka, Wakatipu, Hawea



15.12 If we look at a longer time series of QWOP and storage shown in Figure 52, we see that prior to 2018, when there was spill at Pukaki during the summer months, the QWOP for the Waitaki stations decreased. The 2010/2011 period of high storage saw the lowest QWOPs, although in 2014 the QWOP also went below $100/MWh for a brief time. The average QWOP from 2012 to the end of October 2019 (so excluding the 2010/2011 period of low offer prices), during periods when Pukaki was spilling, was $267/MWh. During the UTS period this figure was $364/MWh. Using high Pukaki storage (greater than 1600GWh) instead of spill also gets similar QWOP averages. The UTS period stands out as a period of high storage with historically high QWOP.

Figure 52: QWOP rolling weekly mean and Pukaki spill from 2010



15.13 Pole 3 of the HVDC was commissioned in 2014. This increased the capacity of the HVDC making price separation less likely. This would suggest that during high inflow events generators would be more willing to cut offer prices. However the opposite appears to be true when 2010/11 and 2019 are compared.

16 Preliminary views on the spot market

16.1 The spot market indicators discussed in the preceding sections suggest that the market did not respond to high levels of hydro inflows as expected. Our analysis suggests that prices did not drop in response to the increase in hydro storage, even though all South Island generators were spilling water during the investigation period.

16.2 Meridian and Contact both stated that the fall in prices in late December was due to a fall in demand. This suggests that prior to the drop in demand there was a lack of competitive pressure on these generators to reduce their offers in response to high inflows and consequent spilling. This lack of competitive pressure allowed Meridian to manage the HVDC constraint, preventing price separation—to the benefit of all South Island generation.

16.3 Viewed in isolation, the Authority's preliminary view is that the combination of offering behaviour and RMA consent issues at Manapōuri, the Clutha stations and Tekapo are not significant enough to constitute a UTS. However, examining the offers of hydro generators indicates that Meridian's Waitaki chain, in particular, increased its QWOP from 13 December onwards after its QWOP was falling prior to the start of spilling. Meridian's Waitaki stations also offered at much higher prices than other South Island stations. Other stations simply decreased offers in response to the full lakes and flood spill. Manapōuri's offers did not drop until early December, despite spilling from early November. Contact's load weighted offer price at Clyde and Roxburgh, and Genesis's load weighted offer price at Tekapo fell once they started spilling. Clyde, Roxburgh and Tekapo all generated less overnight while spilling because offer prices increased overnight.

16.4 Our preliminary estimate of excess spill—spill that could have been used to generate electricity—is 55MW of generation on average throughout December. We believe that this is a conservative estimate.

16.5 Given Meridian was endeavouring to ensure that the HVDC did not bind and cause price separation, this is the lower bound of the capacity that was withheld to achieve this aim. We consider that the result of this was higher than necessary spot prices and a less secure power system heading into the HVDC outage schedule for the first quarter of 2020.

16.6 With reference to economic efficiency set out in section 8 above, there are three efficiency concerns with this behaviour. Firstly, the water was not used for generation despite not being storable and therefore having an opportunity cost of zero. This meant more expensive resource was used, including thermal generation. This is a productive efficiency cost.

16.7 Second, as the spot price would have had to have been lower for the excess spill to have been used for generation, there is an allocative efficiency cost as some efficient consumption may not have occurred.

16.8 Third, prices on the forward and FTR markets are determined by expectations of the spot price. The forward price in particular is used for making investment decisions. So any mis-pricing of forward contracts—caused by the market expecting Meridian to manage the HVDC and thereby withholding generation and spilling more—will likely affect investment decisions, ie dynamic efficiency.

16.9 These reductions in efficiency could have had second order effects on competition which could include discouraging entry into the retail and generation market simply because entrants cannot have confidence that prices are being determined competitively.

16.10 The Authority considers that these efficiency effects and the second order competition effects may all affect consumers in the long run. There was no immediate effect on consumers due to most consumers being on fixed price contracts. However, in the long run if retailers expect there to be high spot prices during times of abundant hydro storage, then retail prices will increase for consumers.

17 We investigated indicators of confidence in and integrity of the forward market

Key points

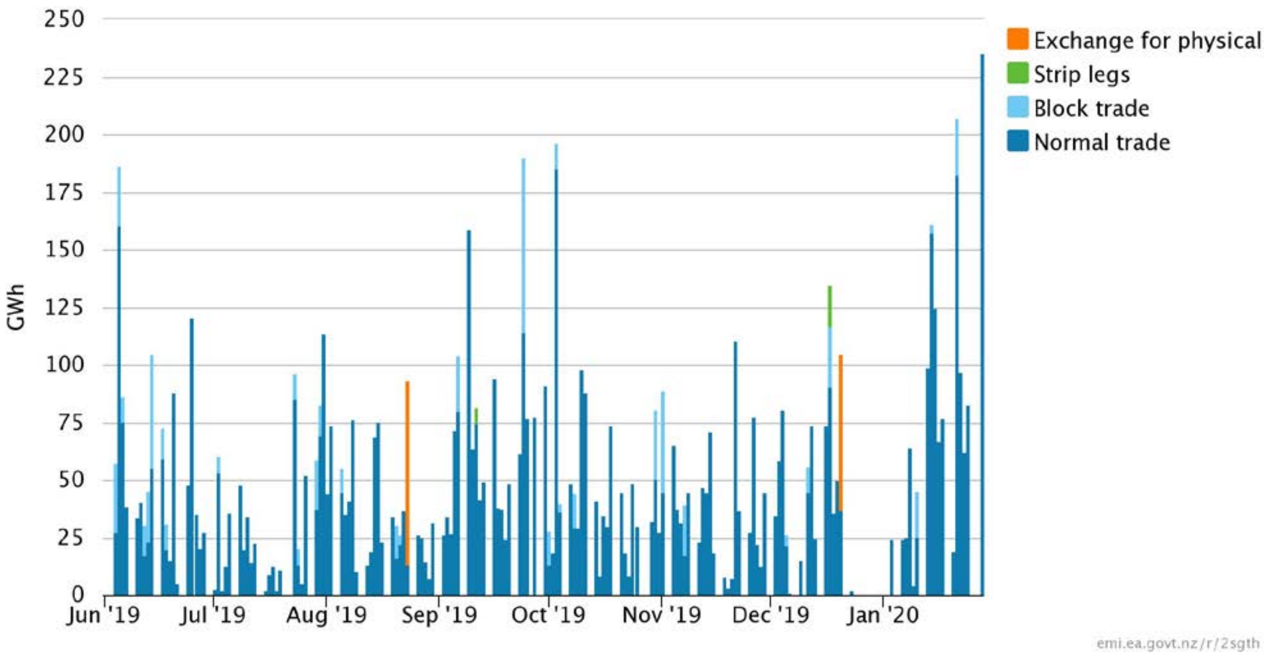
- We analysed participation in the futures market because a material change in this market may, in some circumstances, indicate a loss of confidence or integrity in the forward market
- We found no change in participation in the forward market over the investigation period
- Prices in the forward and FTR markets are formed on expectations of the spot price, so spot prices that are inconsistent with underlying supply and demand conditions may nonetheless still have caused confidence in or integrity of the forward market to be threatened over the long term

17.1 As described in Section 7, in order to assess whether confidence in, or integrity of, the wholesale market has been (or may have been) threatened, we analysed participation in the futures market; a material change in which may, in some circumstances, indicate a loss of confidence in the forward market. This may, in turn, be an indicator of concern about the integrity of either the forward market and/or the spot market. However, it is important to note that, even if there is a loss of confidence in the forward market, a prudent participant may nevertheless continue to utilise it in order to limit their exposure to the spot market. This may limit the extent to which participation in the forward market, at least in the short term, is a reliable indicator of confidence or integrity.

17.2 The following section analyses Australian Securities Exchange (ASX) futures trading volumes, market concentration for ASX products, unmatched open interest in ASX contracts and trading volumes for ASX and non-ASX forward contracts.

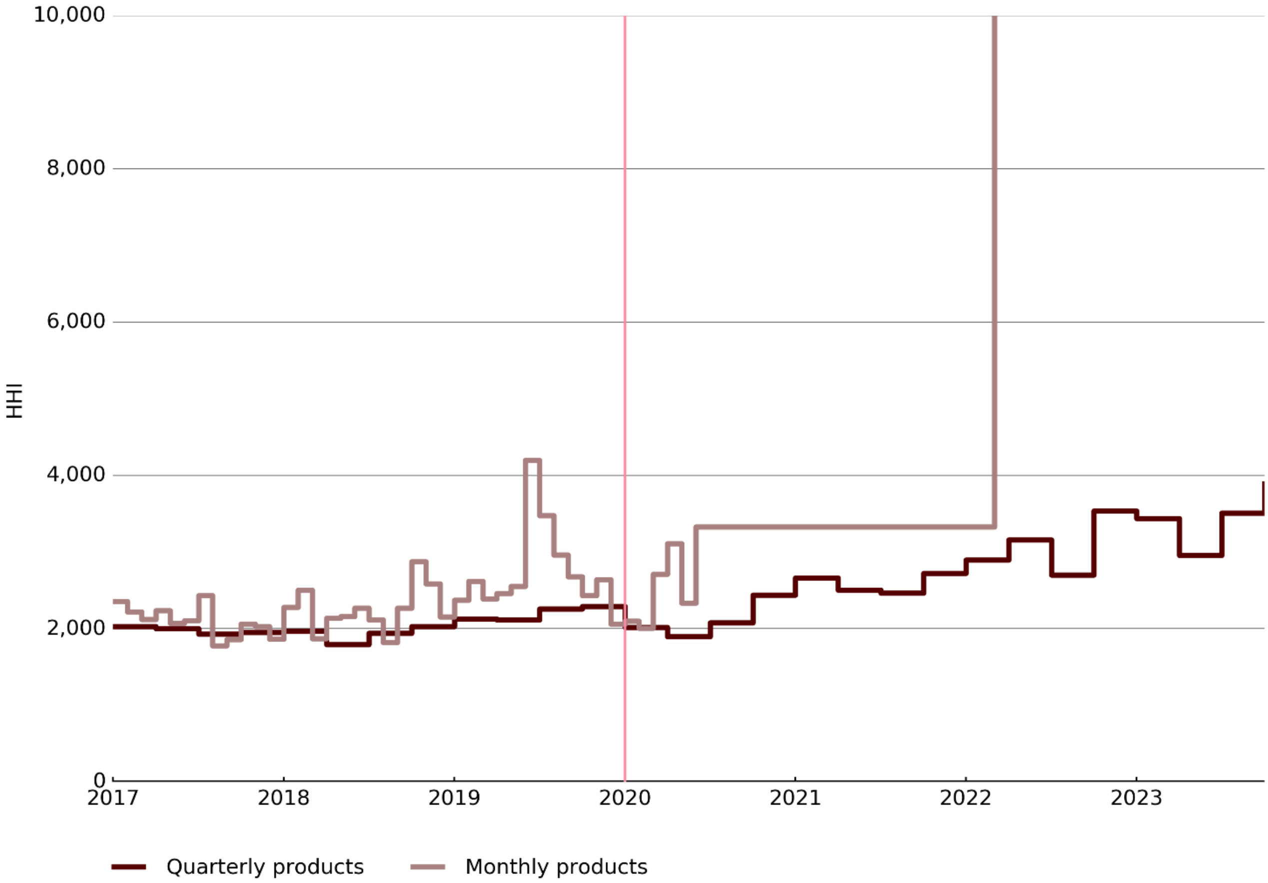
17.3 Figure 53 below shows that trading in short dated ASX futures contracts continued to be traded at a normal level during the investigation period, excluding the holiday period when the ASX was closed.

Figure 53: ASX short dated trading volumes



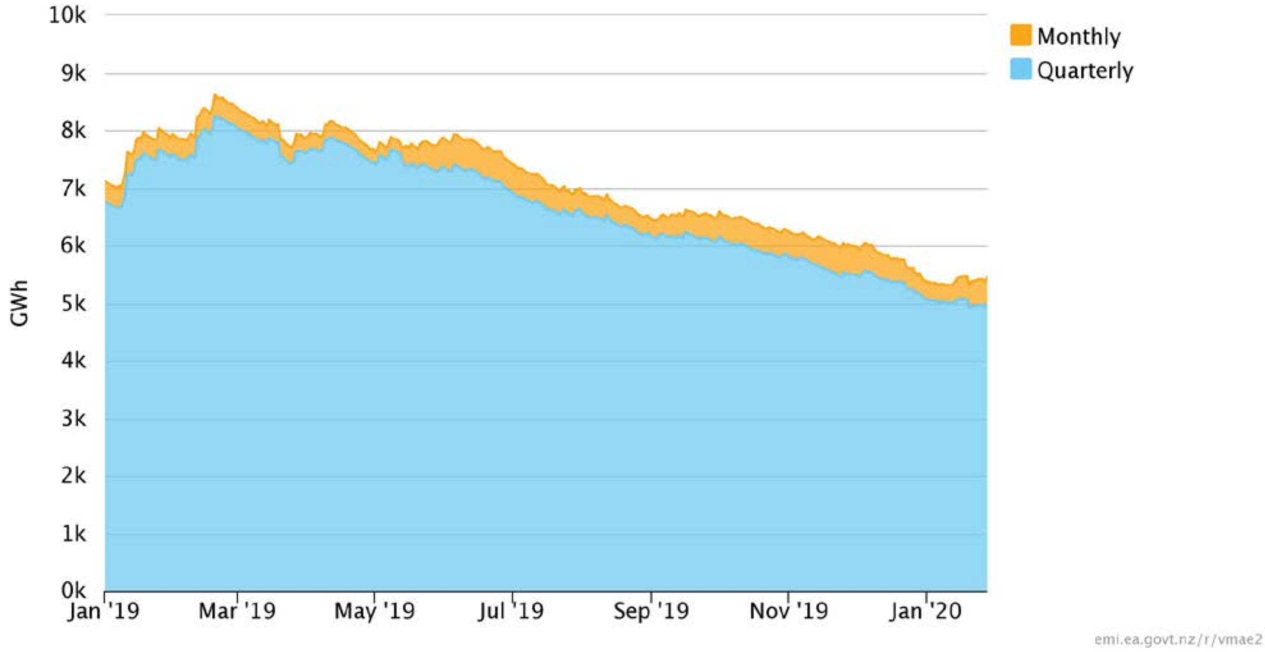
17.4 Figure 54 below shows Herfindahl-Hirschman Index (HHI) values for ASX products over time. HHI is a measure of market concentration. If participation by purchasers had reduced in the market for ASX contracts, we would expect the HHI to increase. However, the HHI values show that concentration levels have not materially changed. The spike in monthly HHI is due to longer dated contracts being thinly traded—this is a consistent observation in the ASX market. The high HHI will typically fall as the contract approaches maturity and it is progressively more heavily traded.

Figure 54: ASX buyer HHI



17.5 As shown in Figure 55 below, unmatched open interest (UOI) in ASX contracts decreased over 2019, with a similar rate of decrease in the investigation period as during other periods of 2019.

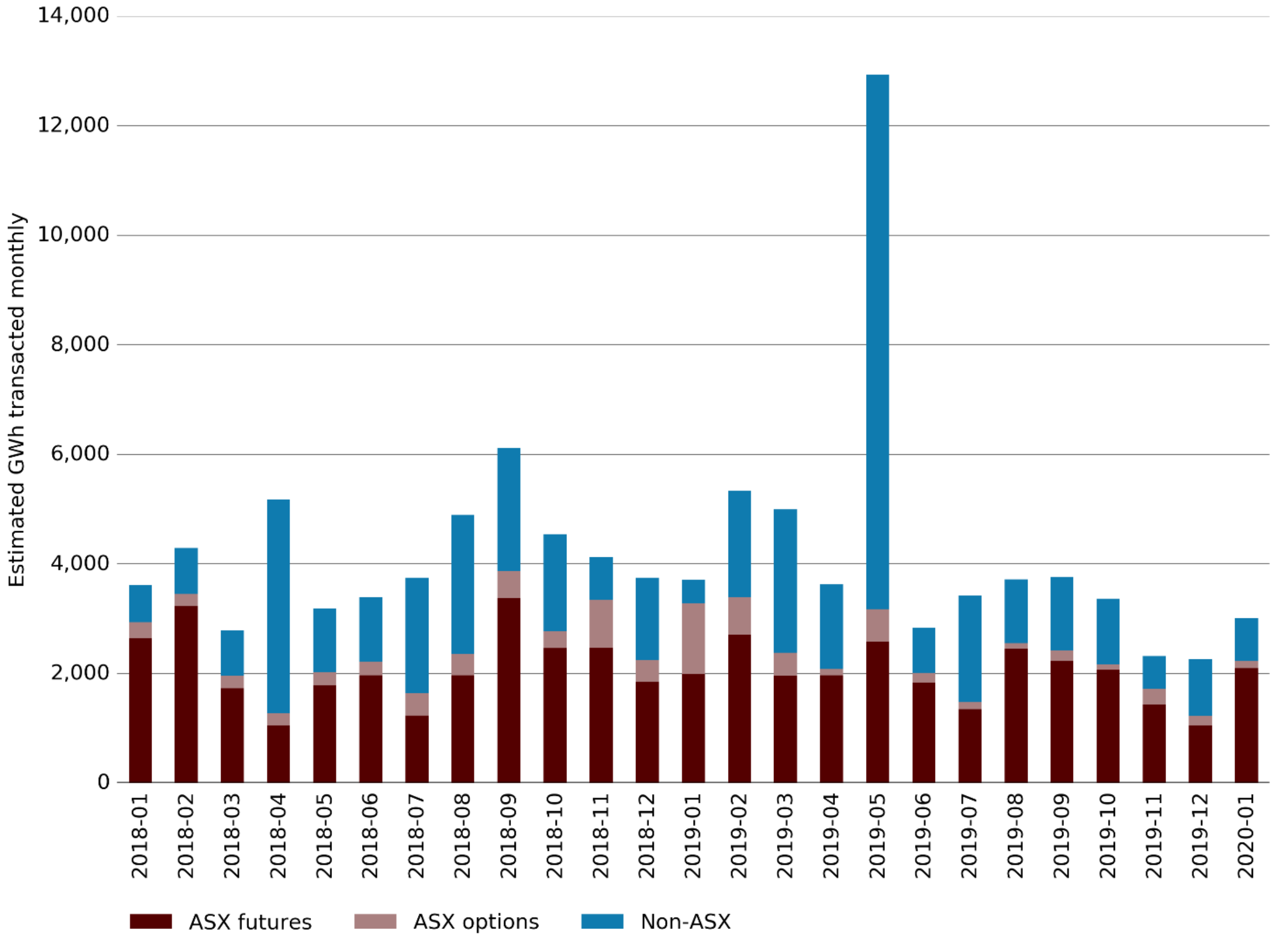
Figure 55: ASX unmatched open interest 2019



17.6 Figure 56 below shows trading volumes for ASX and non-ASX forward contracts. While the volume of trade is slightly lower in November and December 2019, it is not outside the range seen at other times during 2018 and 2019. The large increase in May 2019 was due to a large contract-for-difference associated with the new wind farm at Waverley.

17.7 The total volumes traded were lower in November and December 2019 compared to the rest of 2018 and 2019, but there was still over 2,000 GWh of trade transacted in each month.

Figure 56: ASX and non-ASX trading volumes



Preliminary views on the UTS with respect to the forward market

17.8 We can see no change in participation in the forward market over the investigation period that we can attribute to the observed spot market offer behaviour. This is consistent with the fact that hydrology is largely independent between years, so actions in one year are not able to affect subsequent years even if they have a large effect during a year. This may suggest that there was no threat to the confidence or integrity of the forward market.

17.9 Nonetheless, prices in the forward and FTR markets are formed on expectations of the spot price. Spot prices that are inconsistent with underlying supply and demand conditions may therefore cause changed expectations and therefore cause forward contracts and FTRs to be mis-priced.

17.10 It is therefore still possible that confidence or integrity of the forward market could be threatened over the longer term because the outcomes in the spot market were inconsistent with underlying supply and demand conditions, but that it is too early for this to manifest at a level we can measure.

18 The issue cannot be satisfactorily resolved by any other mechanism available under the Code

18.1 As described in paragraph 5.3, in determining whether there is a UTS, the Authority will consider:

(a) whether the situation affects the wholesale market;

(b) whether the situation threatens, or may threaten, confidence in, or the integrity of, the wholesale market; and

(c) whether the situation may be resolved by any other mechanisms available under the Code (aside from the high standards of trading conduct provisions).

18.2 Our preliminary conclusion is that the situation threatens, or may threaten, confidence in, or the integrity of, the wholesale market.

18.3 The situation is also (separately) being considered as a potential breach of the trading conduct provisions.

18.4 We reviewed the parts of the Code relevant to the claim and are satisfied there are no other means within the Code to resolve this situation other than via the UTS provisions. This is because the situation that is alleged to constitute a UTS relates to offering behaviour and, other than the trading conduct provisions (which are not to be regarded as mechanism for satisfactorily resolving a UTS), there are no other provisions in the Code that address this.

18.5 The Authority has only reached a preliminary view regarding this UTS claim. It is therefore too early to decide what mechanism (if any) might be necessary to correct this UTS. This will depend on the final decision of whether a UTS has occurred and, if a UTS is found, will be consulted upon in accordance with the Code requirements.

Appendix A 10 November 2019 UTS Claim

A.1 https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/10-november-2019/

Appendix B Peer Review

B.1 Given the significance of this preliminary decision we engaged an expert peer review of the decision framework and analysis in this preliminary decision paper. John Small, consultant for Covec, conducted the expert peer review attached.

Review of Electricity Authority Preliminary Decision on UTS Claim

John Small
June 2020

Introduction
Several electricity companies submitted information to the Electricity Authority (EA) in December 2019, claiming that an Undesirable Trading Situation (UTS) had occurred and was still occurring due to the actions of hydro generators in the South Island. The EA has investigated this claim and released its Preliminary Decision. This is an independent peer review of the Preliminary Decision.

I have no ongoing business or employment relationships with the EA or the claimants or the firms that are the subject of the UTS claim except as a consumer of electricity. I have worked as an independent consulting economist for almost thirty years and undertaken numerous assignments in electricity industries of New Zealand, Australia and the USA/Canada. I was a member of the Electricity Price Review which reported to the Minister of Energy in June 2019. This report contains my professional opinions on the analysis and conclusions reported in the Preliminary Decision.

My review contains two main sections below. I start by considering the substantive question of whether there was a UTS. Recognising the subjective nature of the definition of a UTS, this section includes an outline of my own interpretation of the UTS definition. The second section reviews the EA's analysis of the severity of the matters it has identified and assessed.

Was there a Problem?
In order to conclude that a UTS occurred, the EA must decide that a situation *"threatens, or may threaten, confidence in, or the integrity of, the wholesale market"*. This is a subjective test that invites the EA to stand in the shoes of particular market participants, such as the claimants who are largely retailers without a generation business.

Such parties have no right to expect the unrealistic textbook standard of perfect competition but should be able to expect workable competition between generators. Workable competition has precedent in our case law, where it includes the idea that markets have a tendency towards strong competition. In this review I use the term "competitive" as meaning "workably competitive" and assume that when buyers observe conduct that is inconsistent with workable competition, they will lose confidence in the integrity of the relevant market.

The wholesale market is multi-dimensional and includes the spot market (where participation is compulsory) and the (voluntary) forward market which itself includes both financial transmission rights and the futures contracts traded on the ASX.

In its analysis, the EA has focused on the spot market and the ASX-traded futures contract market for the reason that *"these markets constitute the majority of the value of the wholesale market"*. This seems a reasonable choice, especially since the spot market was a focus of the UTS claim and cannot be avoided by generators who wish to be dispatched. In the spot market, the EA examined whether generator offers and market outcomes were consistent with the physical conditions for supply and demand over the relevant period. In the futures market the focus was on the volume of trade for reasons explained in the Preliminary Decision (e.g. at ¶7.6). I agree with these analytical choices.

I also agree with the EA that there was no apparent change in participation in the futures market, the evidence for which is discussed in section 17 of the Preliminary Decision. In what follows, I therefore focus on spot market issues.

Opportunity Cost of Water and Competitive Market Expectations

A key element of the EA's reasoning is that the opportunity cost of using water in a hydro generator is zero when water is being spilled from that generator's storage facility. This follows from the fact that (excluding environmental requirements) spillage occurs when further storage of water is not possible. In this case spillage occurred because the storage facilities were full. Since generators did not have an opportunity to store extra water, there was no opportunity cost associated with using that water to generate electricity, so the EA is correct on this point.

The EA also correctly predicts (at ¶8.3) a range of observable consequences of widespread spilling across the Southern region that would occur if the spot market were competitive. Most of these consequences are in the form of *changes* that would be expected as spilling became widespread if the spot market were competitive. Setting aside (for now) questions about the strength of evidence available to test each prediction, and noting the *ceteris paribus* assumption, these predictions are valid and reasonable expectations for a competitive spot market.

The market conditions prevailing before spilling started are relevant context for testing the EA's predictions. They are documented in section 10 of the Preliminary Decision, which focuses on observed spot market clearing prices and levels of hydro storage. Compared to previous years, average spot prices were high throughout 2019. Total controlled hydro storage increased markedly in November and December of 2019 and most storage facilities (with the exception of Lake Hawea) were at least 90% full for some part of these two months.

Testing Spot Market Hypotheses

The predictions set out at ¶8.3 serve as hypotheses to be tested against observed data and information as a method for drawing inference about whether the spot market was behaving as a competitive market should. This testing process is reported in sections 11, 12 and 14 of the Preliminary Decision. There is not an exact correspondence between the predictions in ¶8.3 and the evidence presented. In what follows, I review the evidence presented on each hypothesis.

(a) Lower offer prices. As spilling begins, the opportunity cost of water falls to zero so competitive offer prices will tend to fall. I agree with the EA that such offers are unlikely to fall to zero, for example because of transmission costs. There is extensive detailed analysis of offer prices presented in section 12 of the Preliminary Decision, where three different indicators are applied to all of the southern hydro generators. Interdependent river systems (e.g. Waitaki, Clutha) are grouped together and due regard is given to other relevant physical and commercial factors such as transmission capacity and portfolio balancing. In each case the analysis is drawn together in a summary table. I consider those tables to accurately reflect the analysis. The final summary table (Table 6 at ¶12.58) is also accurate in my opinion. It presents an appropriately nuanced picture of offer behaviour, showing that in each case there was some aspect of offer behaviour at some point in the investigation period that was inconsistent with a competitive market, though this was not true of all measures at all generators at all times.

(b) Falling spot market prices. Over the long term there is a fairly strong negative correlation (-0.49) between hydro storage and spot market prices. Figure 11 shows that this feature was present in the first 10 months of 2019, with storage and spot prices generally moving in opposite directions. However, the same figure shows that this relationship broke down just after the start of the investigation period, when spot prices flattened and even increased as storage was rising. This is not surprising given the analysis of offer prices but it is inconsistent with a competitive spot market. Similarly, the eventual fall in spot prices on December 19th was attributed (by generators) as being a consequence of low demand as is common in the lead-up to Christmas. I agree with the EA that spot prices did not behave as would be expected in a competitive market with abundant hydro water.

(c) Price separation between North and South Islands. The evidence shows (Figure 13) very little inter-island price separation over the investigation period until 7 January when an outage began on the HVDC link. It does not establish that prices *should have* separated due to the abundance of water if the market were competitive. However, the fact that both Contact and Meridian were deliberately structuring their offers to avoid transmission constraints binding is consistent with that proposition. The Preliminary Decision indicates (at ¶12.26 and following) that the EA does not approve of this conduct and has twice previously expressed this view and the reasons for it. I agree with the EA's position, and consider that economic with-holding of capacity in this instance is inconsistent with normal competitive market conduct, particularly in an industry which has established a range of tools by which the risk of price separation can be managed. I note the EA considers that generators management of transmission constraints can be legitimate (¶13.21) so the context matters. Guidance could be useful on this point.

(d) Increased northward flow over HVDC. It is reasonable to expect that, other things being equal, a surplus of water in the southern hydro system would lead to increased northward flow over the HVDC link. Things that could limit this change are cited in the Preliminary Decision (at ¶11.20): the existence of must-run generation in the North Island, reserve requirements to maintain security in the North Island, and low demand which is normal around the Christmas period. The feasibility of extra northward flows is demonstrated in section 14 of the Preliminary Decision which concludes (at ¶14.23) that *"about 17MW of Waikato generation could have been displaced throughout December by extra South Island generation"*.

(e) Less generation from thermal sources. There are well established historical relationships between thermal generation output on the one hand and hydro storage and hydro generation on the other. At times when hydro storage is growing strongly, hydro generation tends to expand and thermal generation tends to contract. These historical patterns did not continue into the investigation period as shown in Figure 15 with respect to storage, and through a statistically significantly lower correlation in the case of hydro generation. Indeed, the historical correlation between thermal and hydro generation is -0.41 but this reverses sign to 0.15 during the investigation period.

The evidence discussed above shows that spot market outcome over the investigation period were not consistent with what I would expect from a competitive spot market under the relevant conditions. Buyers of electricity on the spot market know that prices can be volatile, even when the market is working well, because these prices signal relative scarcity (including between different locations) and abundance. It is important for the integrity of the market that spot market buyers can benefit appropriately from low generation costs when they occur. By contrast, if generators are not forced by competition to reduce offer prices when their costs are low, confidence in the integrity of the market will be lessened.

Scale of the Problem

It could be argued that any deviation by generators from competitive offer strategies threatens market confidence and integrity, however the Preliminary Decision goes further, seeking to estimate the scale of the resulting inefficiency in section 14. At a high level there are at least two ways this task could be approached: we could seek a price or dollar-based estimate or focus on resource flows. Either way, there is a need to establish a counterfactual scenario: to state reasonable expectations for what would have happened if the offer strategies of the relevant generators were instead designed to maximise output, as would have occurred if the market was competitive over this period. This is inevitably complex and therefore carries a risk of error.

The EA has chosen to focus on "excess spill" which is denominated in MWh and interpreted as the amount of electricity that could have been generated from southern hydro plants and which would have displaced more costly or valuable generation in the North Island.

In reviewing this aspect of the Preliminary Decision, I have focused on the following questions:

(a) Are the counterfactual assumptions reasonable? This includes questions of practical feasibility, such as respecting transmission constraints.
(b) Do the assumptions in aggregate tend to under-state or over-state the harm arising from the conduct at issue?
(c) Are there any errors of fact or logic?

Counterfactual assumptions

The principles used to define the counterfactual are described at ¶14.4 – 14.7. In my view they are reasonable. Nothing would have been gained by generating from the spilled water if that simply caused spillage of another renewable resource (e.g. wind, water) that also had zero opportunity cost somewhere else in the system. The analysis instead inquires whether resources with a non-zero value somewhere else in the system could have been *stored* instead of being used, had the southern generators behaved more competitively.

There are legal constraints on the way generators can affect the environment, which the Preliminary Decision discusses in section 13. These are particularly acute at Manapouri and they affect Meridian's portfolio choices between generating at Manapouri and on the Waitaki River system, where additional constraints also affect inter-river generation.

To avoid modelling the Manapouri environmental constraints and Meridian's portfolio choices between Manapouri and the Waitaki system, *the EA has estimated excess spill at Benmore only*. This is explained at ¶14.8 – 14.12 and the details of the methodology is at ¶14.13.

In my opinion these assumptions (including the detailed methodology) are reasonable. Provided the calculations have been accurately performed in compliance with this description (which I have not checked), the results can be reasonably interpreted as showing how much extra generation could have been supplied into the market from Benmore without displacing wind or geothermal generation in the North Island.

Under- or Over-Statement of Impact

In my view the modelling approach used in the Preliminary Decision is unambiguously conservative, in the sense of understating the amount of excess spill. I agree with the EA's reasoning at ¶14.10 and 14.11 on this point.

Errors of fact or logic

I have not identified any errors of fact or logic. This review has not included any detailed analysis of the data, coding used to estimate the scale of the effect, or the methods used to generate the graphs in the Preliminary Decision.

Appendix C Background to the Manapōuri and Waitaki hydro schemes

Resource consent conditions at Manapōuri

C.1 Under section 4A of the Manapōuri Te Anau Development Act 1963 the Minister of Energy and Resources promulgates operating guidelines based on recommendations from the statutory Guardians of Lakes Manapōuri and Te Anau. Meridian must comply with the operating guidelines except in exceptional natural circumstances. Departures from the operating guidelines are reported to the Minister of Energy and Resources and Minister of Conservation.

C.2 The current operating guidelines were gazetted in 2002 and set out three operating ranges of levels for each lake, within which Meridian may operate – Main, High, and Low operating ranges.

C.3 Meridian must endeavour to maintain continuous variation within the Main range of each lake and achieve annual mean levels within the Main operating ranges. The Main range for Lake Manapōuri is between 176.8m to 178.6 m, and Lake Te Anau's Main range is between 201.5m and 202.7m.

C.4 When Lake Manapōuri is in High Operating Ranges (above 178.6m for Manapōuri or above 202.7 for Lake Te Anau) Meridian must use its best endeavours to not exceed the maximum durations at given levels, and once below a given level to not again exceed that level until after a specified minimum interval for each level. For example, for Lake Manapōuri the maximum duration above 178.6m is 119 days with a 20 day minimum interval, but the maximum duration above 180.4m is 3 days with a 100 day minimum interval. It is accepted that guideline breaches may occur on rare occasions despite the best endeavours of the power station operator.

C.5 Likewise, Meridian has guidelines to follow when in Low operating ranges (below 176.8m for Manapōuri and 201.5m for Te Anau).

C.6 There are also guidelines to spill water at Lake Te Anau Control structure and at Lake Manapōuri Control structure. At Lake Manapōuri the procedures are designed, amongst other things, to reduce potentially dangerous increases to river flow downstream of the gates and to bypass flood flows from the Mararoa River in such a manner as to prevent dirty debris laden water from entering Lake Manapōuri.

C.7 Meridian also holds resource consents under the Resource Management Act 1991, namely Coastal Permits, Water Permits, and Discharge Permits, which include:

(a) minimum flow requirements;

(b) flushing flow requirements;

(c) requirements to manage turbid Mararoa river flows;

(d) requirements for changes in flow rates and the frequency of changes;

(e) fish and eel pass and transfer requirements;

(f) flood rules; and

(g) monitoring and reporting requirements.

C.8 Many of the resource consents also include a consent condition requiring compliance with the operating guidelines under the Manapōuri Te Anau Development Act – making non-compliance with the operating guidelines an offence under the Resource Management Act.

Resource consent conditions on the Waitaki

C.9 Meridian holds over 40 resource consents for its operations in the Waitaki scheme as well as over 70 ancillary consents. The conditions of the operating consents for the scheme also require compliance with extracts of the Waitaki Operating Rules of 9 November 1990 (as modified by the Electricity Industry Act 2010), in particular *Waitaki Power Stations, Appendix A*.

C.10 For each reservoir in the scheme resource consents stipulate a minimum and maximum lake level. When a lake is above the maximum control level then various discharge controls, including minimum discharges apply. Some of the lakes also have a design flood level, which is the maximum level the lake is designed to be able to deal with during a flood. For example, Lake Pukaki has a design flood level of 534.1m, a maximum control level of 532.5m, and a minimum control level of 518.2m (although when the system operator's contingent storage release boundary is crossed the consented minimum control level is 515m and during an Official Conservation Campaign the minimum control level permitted is 513m).

C.11 Each power station and spillway has a maximum use/discharge rate. Benmore and Aviemore power stations also have a maximum discharge rate that is a combination of all turbine and spill discharges. Resource consents also require minimum flow rates into the Upper Ōhau and Waitaki rivers.

C.12 When the level of Lake Ōhau is above maximum control level of 520.25m, mandatory Ōhau canal flows of 170 cumecs are required under the resource consents. When the level of Lake Ōhau is above the spill weir crest of 520.4m, mandatory canal flows increase to 200 cumecs and water will also begin to flow uncontrolled over the weir, into the Upper Ōhau River, and then into Lake Ruataniwha. Mandatory canal flows must pass through generating units at Ōhau A power station as there is no spillway for that station. Water in the Upper Ōhau River flows directly into Lake Ruataniwha. All water in Lake Ruataniwha must then be generated through both Ōhau B and Ōhau C stations or spilled from the Ruataniwha Spillway into Lake Benmore

Appendix D Glossary of abbreviations and terms

ASX	Australian Securities Exchange
Authority	Electricity Authority
AVI_BEN	Aviemore Benmore transmission circuit
The claimants	Haast Energy Trading, Ecotricity, Electric Kiwi, Flick Electric, Oji Fibre, Pulse Energy Alliance and Vocus
Code	Electricity Industry Participation Code 2010
Cumecs	Cubic meters per second
EMI	Electricity Market Information, a website maintained by the Authority
FTR	Financial Transmission Rights
GW	Gigawatt
GWh	Gigawatt hour
HHI	Herfindahl-Hirschman Index
HSOTC	High Standard of Trading Conduct Provisions
ISL_LIV	Islington Livingston transmission circuit
QWOP	Load weighted offer price
MW	Megawatt
MWh	Megawatt hour
RM	Reconciled generation data
RMA	Resource Management Act
The situation	The situation described in the claim provided to us on 12 December 2019
SRMC	Short run marginal cost
TCC	Taranaki Combined Cycle
UOI	Unmatched open interest
UTS	Undesirable trading situation

A detailed glossary is available at www.ea.govt.nz/glossary