Final Decision – Actions to Correct Undesirable Trading Situation December 2019

Decision

17 August 2021

Executive summary

Background

In December 2020, the Electricity Authority (Authority) decided that an undesirable trading situation (UTS) occurred between 3 and 27 December 2019 ('UTS period'). A UTS is a situation outside the normal operation of the electricity market that threatens, or may threaten, confidence in, or the integrity of, the wholesale market. The UTS provisions of the Code oblige the Authority to attempt to correct such situations and restore the normal operation of the market.

On 11 March 2021 the Authority published a consultation paper titled *Proposed Actions to Correct Undesirable Trading Situation 2019*, which proposed actions to correct the UTS and attempt to restore the normal operation of the market.

The Authority has now reached a final decision on the actions to correct the undesirable trading situation that occurred. The Authority has considered all information provided to it, including submissions and cross-submissions on the above consultation paper, and sets out its views below.

Implications for the spot electricity market

The Authority has decided to impose a cap of $13.70/MWh on the offer prices made by nine South Island generating stations from 3 to 27 December, inclusive. Offer prices made at or below the cap level will be retained, while offer prices above the cap will be revised to the level of the cap.

Informed by its analysis and submissions, the Authority considers that this calibration of the offer price cap accords with the abundance of water available for generation during the UTS period and the other constraints faced by generators. The Authority notes that this offer price cap results in electricity transfer within the operational capacity of the transmission system including the HVDC link. The calibration of the offer price cap is not unduly conservative as the MW transfer across the HVDC link is towards the maximum amounts transferred historically, as expected given the demand and supply, and hydrological conditions at the time.

The generating stations subject to the offer price cap are: Aviemore; Benmore; Clyde; Manapōuri; Ōhau A, B, and C; Roxburgh; and Waitaki. These generation stations will not be eligible for constrained on and off payments irrespective of their original offers.

The Authority has expanded the stations subject to the offer price cap by including Manapōuri in the group of generating stations with corrected offers. Offers from Manapōuri are managed in tandem with Meridian's other generating stations with corrected offers. Given these interdependencies the Authority has decided to treat the offers as an integrated whole, applying the offer cap to Manapōuri as well as other stations to restore the normal operation of the wholesale market. In reaching its UTS decision, the Authority considered that if market outcomes, including prices, became too far removed from underlying supply and demand conditions then confidence in the market may be threatened. Making Manapōuri subject to the offer price cap addresses concerns that Manapōuri's offers may have contributed to the threat to confidence in the wholesale market via high prices that were not in line with supply and demand conditions.

The quantity of dispatched electricity and accepted offer prices both contribute to confidence in the wholesale market. Offer prices from Manapōuri were predominantly at low levels but there were exceptions. As the claimants noted in their submission, Manapōuri made offers with prices above the offer price cap for 108 trading periods, and there were occasional spikes in quantity-weighted offer prices from Manapōuri for several hours at a time. Including Manapōuri in the correction decreases average South Island reference prices by about 10 cents and slightly increases MW flow over the HVDC link during the UTS period. The Authority considers these changes are consistent with the Authority's efforts to align market outcomes with the demand and supply conditions of the period. Several submissions supported making Manapōuri subject to the offer price cap.

Under the correction, generators subject to the offer price cap are not eligible for constrained on payments. Other generators that were dispatched during the UTS period will be eligible for constrained on payments if their original offers were above the revised final prices that arise from these actions to correct the UTS. This treatment of constrained on reflects normal market practice given Part 13 of the Code.

The revised offer prices for 3-27 December 2019 will result in new final spot prices for that period. The revisions to final prices will result in the spot market being resettled.

The Authority will work with the system operator, the pricing manager, the FTR manager and the clearing manager to implement this resettlement. Excess payments made by traders during the UTS period will be refunded to them once settlement is updated to reflect the revised nodal spot prices. Generators and reserves providers will likewise be required to refund the excess payments made to them, during the UTS period. The settlement amounts reflect actual generation, actual load, and reserves dispatched by the system operator, but at the revised final prices.

Implications for instantaneous reserves

The final prices for instantaneous reserves for the North and South Islands are also being revised to reflect the revisions to the energy offers from the relevant South Island hydro generators identified above. Prices for the instantaneous reserves market are co-optimised with prices in the spot market for electricity, and changes to offers in one market flow through to the other. Consistent with submissions, reserve offers have not been revised, because their amendment was not assessed as being necessary to correct the threat to confidence in the wholesale market.

Instantaneous reserve prices were also inflated by the confluence of events that caused the UTS. Dispatched providers of instantaneous reserves during the UTS will be eligible for constrained on payments if their instantaneous reserve offer prices were greater than the revised instantaneous reserve prices following the actions to correct the UTS. The revision to reserves settlement more closely approximates the market outcomes (ie the final prices) that would have occurred in the absence of the UTS.

Implications for derivatives

Derivatives are risk-management devices used to offset risks in the spot electricity market. By resetting final prices, the Authority has provided the necessary pre-conditions to enable derivatives to be resettled, given that derivatives are referenced to final prices. In the context of the 2019 UTS, the Authority's view is that private participants should determine whether their contractual obligations permit or indeed require resettlement of their derivative contracts given the revision to final prices. Contracting parties to derivatives that cover the UTS period should evaluate the terms and conditions of their contracts to ascertain whether the settlement of those contracts needs to be resettled. The Authority is not over-riding contractual terms that allocate risk in a particular way.

Given their terms and conditions, both the FTR market and hedges settled by the clearing manager through hedge settlement agreements (HSA) will be resettled.

The Authority notes that some derivatives contracts may not be re-settled because contracting parties consider that resettlement of derivatives is no longer desirable or permissible given other regulatory or contractual obligations. Notably, the Australian Stock Exchange (ASX) indicated in its submission that, "having regard to our regulatory obligations and the amount of time that has elapsed, our current assessment is that we would not change the settlement price of associated ASX derivatives".

The ASX is not a market operation service provider (MOSP) under the Electricity Industry Act (2010) (Act) and has no contractual arrangement with the Authority in relation to its provision of New Zealand electricity futures and options. Consequently, and noting also that the ASX operates in a separate legal jurisdiction, the Authority has no scope to direct the ASX to resettle ASX-traded futures and options.

The Authority considered, but ultimately decided against, an off-market correction of derivatives markets. This decision reflected jurisdictional challenges (associated with some derivatives counterparties being overseas and not participants, as defined in the Act), and practical difficulties associated with imperfect visibility of derivatives holdings. An off-market approach would not meet the Authority's obligation to correct the UTS as soon as possible and could only approximate market normality given that some entities that buy or sell derivatives are not regulated by the Authority. The Authority can only direct participants under Part 5 of the Code and cannot direct that settlement with overseas parties that are not participants be corrected to restore normal market operation. The Authority considers, given the challenges and additional time involved, an off-market correction in this case would not further assist in correcting the UTS and restoring confidence in the wholesale market.

The revision to final prices and FTR settlement also alters the residual LCE that can be returned to Transpower (which Transpower then allocates to distributors and direct grid connections). The Authority is directing the FTR manager and clearing manager to recalculate the loss and constraint excess and directs Transpower to revise the allocation of residual LCE. Following usual processes, the LCE payments will be treated as a credit (or potentially debit) in relation to grid charges.

The implementation of the actions to correct the UTS

Transpower and NZX submitted advice on the operational implementation of the actions to correct the UTS. The Authority has carefully considered this advice in determining its approach. Given that participants have had advance notice of the possible actions to correct the UTS, and noting that there is an operational process that needs to be implemented prior to settlement (meaning participants will have ample warning of resettlement), the Authority has decided to provide participants with 20 business days to meet their resettlement obligations once they have received notification from the clearing manager.

The invoices detailing resettlement amounts will be advised to traders via a special washup (not to be confused with the usual washup processes set out in the Code). The Authority is directing participants to make any payments required of them as specified in these invoices or to dispute the invoices following the processes set out in Part 14 of the Code.

The Authority is directing the clearing manager to disregard prudential security requirements for all amounts owing in relation to this UTS resettlement.

Further implementation details are discussed in section 4 of the decision paper.

Future UTSs and process matters

Several submitters expressed concern that the actions to correct might not sufficiently address the incentives for future behaviour of participants in similar circumstances. The Authority notes that the UTS provisions are concerned with correcting the UTS that occurred in December 2019 and are not about preventing future UTSs or ameliorating their consequences should they occur. However, the Authority has introduced new trading conduct rules in Part 13 of the Code, which came into force 30 June 2021, and these revised rules are expected to encourage better trading behaviour by participants, fostering trust and confidence in the wholesale market.

The Authority acknowledges that the investigation and decision process associated with the 2019 UTS has been lengthy and has required considerable effort by participants and other entities that have contributed their views. Suggestions have been made as to how the UTS process could be made faster and more transparent. The Authority will consider these suggestions when it assesses what may be learned from this UTS process.

Any questions about the implementation of the actions to correct over the remainder of 2021 can be directed to the Market Operations team at UTS2019@ea.govt.nz.

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1 Background

1.1 On 22 December 2020 the Electricity Authority determined that an undesirable trading situation took place between 3 and 27 December 2019 inclusive.[1] Under the Code, a UTS is a situation that threatens, or may threaten, confidence in, or the integrity of, the wholesale market and that cannot be satisfactorily resolved by any other mechanism of the Code.

1.2 The situation in December 2019 was exceptional. The South Island had extremely high rainfall, record inflows into South Island lakes and South Island hydro generators had to spill excess water to manage water levels and flows. Water was abundant, cheap, and available for generation. The Authority considered the abundance of fuel (water) should have increased competitive pressure but the analysis of the UTS period undertaken by the Authority shows it did not. Water was spilled that could have been used to generate electricity. Had this generation been dispatched, the Authority's analysis indicates that there would have been significantly lower electricity spot prices and North Island fuel (water) would have been conserved to deal with the impending HVDC and Pohokura gas outages. As well as adversely impacting the spot market, excess spill in the South Island increased security of supply risks in the North Island.

1.3 In short, the Authority found that a confluence of factors reduced normal competitive pressure in the wholesale market during the UTS period. The confluence of factors included extreme rainfall and high inflows; pending outages on the HVDC link and Pohokura gas field; Contact using new automated spill gates for the first time during a flood event; Meridian deciding to withhold generation to avoid the HVDC link binding; and Genesis operating as a price taker in the South Island. This confluence of factors resulted in unnecessary spill and prices remaining abnormally high when compared against supply and demand conditions. The situation was of significant scale and duration.

1.4 On 11 March 2021 the Authority published a consultation paper titled *Proposed Actions to Correct Undesirable Trading Situation 2019*, which outlined proposed actions to correct the UTS and attempt to restore the normal operation of the market as quickly as possible.[2] The Authority received sixteen submissions and eight cross-submissions on the proposed actions.

1.5 The wholesale market determines the spot electricity prices that retailers and purchasers must pay for electricity consumed and that generators receive for injected electricity. Offers impacted by a UTS propagate through to the prices that clear the market. The consultation paper proposed actions to correct the UTS by revising prices to levels that more closely approximate what would have occurred if the market had been operating normally, given the circumstances during the UTS period.

1.6 The Authority proposed to correct the UTS by capping offer prices of hydro generating stations on the Clutha and Waitaki river chains and recomputing the nodal prices that would have arisen given the revised offers. The revised final prices would then be used to re-compute the settlement payments due given the actual load and injected energy of the UTS period. Where necessary, constrained on payments would be made to

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1 See https://www.ea.govt.nz/assets/dms-assets/27/UTS-Final-Decision-Paper-22-December-2020.pdf.

2 See https://www.ea.govt.nz/assets/dms-assets/28/Consultation-paper-Proposed-Actions-to-Correct-Undesirable-Trading-Situation-2019.pdf.

generators that were dispatched (since for some generators their offer prices would be above the revised nodal prices) and to reserves providers. Generating stations with revised offers would not be eligible for constrained on payments.

1.7 In parallel to the UTS decision process, the offer behaviours of Meridian Energy Limited and Contact Energy Limited during the UTS period were investigated under clause 13.5A of the Code (as then applied). These investigations were discontinued in April 2021 because the offers of both parties were identified as being consistent with the 'safe harbours' provisions of clause 13.5B (again, as then applied). These clauses have since been revised with a view to encouraging more transparent and efficient trading conduct for the long-term benefit of consumers.[3]

2 The actions to correct the UTS are consistent with the objectives and obligations of Part 5 of the Code

2.1 A UTS, as defined in clause 1.1 of the Code, is a situation that threatens, or may threaten, confidence in, or the integrity of, the wholesale market, and is a situation that cannot be satisfactorily resolved by any other mechanism available under the Code (excepting clause 13.5A).

2.2 Under clause 5.2(1) of the Code, the Authority may take any action that it considers is necessary to correct the UTS, provided that such an action relates to an aspect of the electricity industry that it could regulate in the Code under section 32 of the Act. Clause 5.2(2A) of the Code notes that any directions to participants made as part of the actions to correct the UTS may be inconsistent with the Code but must not be inconsistent with the Act or any other law.

2.3 Under clause 5.5, the Authority must attempt to correct every undesirable trading situation and restore the normal operation of the wholesale electricity market as soon as possible. The Authority is not required, and is not able, to correct every immediate and forward-looking implication from the UTS. As previously noted, the Authority cannot perfectly resolve all consequences of the UTS that occurred in 2019 because of the irreversibility of some aspects – like the spill of water. The complexity of the market also makes it difficult to robustly identify all the effects that the UTS had on outcomes that subsequently eventuated. The corrective actions that the Authority has decided on are approximate solutions, reflecting the scope of the Authority's powers as provided for in the Code and limitations in the Authority's ability to identify and correct all aspects of the UTS.

2.4 Clause 5.2(1)(a) of the Code provides that the Authority may take any action necessary to correct the undesirable trading situation. Although not an exhaustive list, clause 5.2(2) of the Code provides four examples of actions that the Authority could take to correct the UTS. These examples include:

(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 specific period:

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

[3] See https://www.ea.govt.nz/assets/dms-assets/28/Trading-Conduct-Decision-paper-v2.pdf for the updated rules governing trading conduct.

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

2.5 The Authority is correcting the UTS by taking actions consistent with examples (c) and (d).

2.6 As noted in the consultation paper, clause 5.3 of the Code requires the Authority to consult with the system operator if an action to correct a UTS may have an effect on system security. The Authority engaged with the system operator on the proposed actions to correct though it does not consider that the actions would affect system security.

2.7 In accordance with clause 5.2(1) of the Code, the Authority considers that the proposed actions are necessary to correct the UTS, ie, the situation that arose in December 2019. The actions to correct the UTS are lawful and consistent with the Authority's obligations under Part 5 of the Code and the Electricity Industry Act 2010. The Authority has met its obligation to attempt to correct the UTS and restore the normal operation of the wholesale market as soon as possible, as per clause 5.5.

3 Summary of main submissions and cross-submissions on the actions to correct the UTS

3.1 Under clause 5.4 of the Code the Authority must consult with participants before taking actions to correct the UTS and must immediately advise registered participants of any actions taken. The Authority consulted via its March 2021 consultation paper and the subsequent submissions process.

3.2 The Authority received sixteen submissions and eight cross-submissions on the 11 March 2021 consultation paper. The submissions were carefully considered and changes were made to the actions to correct the UTS in light of this feedback. The submitters are identified in Table 1.[4] This decision paper advises registered participants of the Authority's findings and actions.

4 The submissions and cross-submissions can be found here: https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/10-november-2019/.

Table 1 Submitters and cross submitters

Submitter	Category	Submission (S) / Cross-submission (C)
ASX	Hedge market provider	S
'Claimants': Ecotricity, Electric Kiwi, Flick Electric, Haast Energy Trading (Haast), Oji Fibre Solutions, Vocus	Independent retailers, traders in electricity, and consumers	S, C
Contact	Integrated generator retailer	S, C
Enel X	Reserves aggregator	S
Fonterra	Trader in electricity	S
Genesis	Integrated generator retailer	S
Haast + Electric Kiwi	Trader in electricity & retailer	S
Mercury	Integrated generator retailer	S
Meridian Energy	Integrated generator retailer	S, C
MEUG	Industry representative for major consumers	C
Nova Energy	Integrated generator retailer	S, C
NZX	Market operations service provider	S
Pulse Energy Alliance	Retailer	S, C
Pioneer Energy	Generator	S, C
Transpower	Market operations service Provider	S
Trustpower	Integrated generator retailer	S, C
Walbran, Neil	Consultant	S

3.3 For the sake of brevity, in the following discussion and in tables we refer to Ecotricity, Electric Kiwi, Flick Electric, Haast Energy Trading, Oji Fibre Solutions and Vocus as the 'Claimants' because they alleged the breach of the UTS provisions in December 2019; Genesis Energy as Genesis; Meridian Energy as Meridian, Nova Energy as Nova; Pulse Energy Alliance as Pulse; Pioneer Energy as Pioneer, and we refer to Neil Walbran by his surname. Quotations from submissions and cross-submissions are generally followed by page numbers to identify the location of the statements being referenced.

3.4 A number of submitters proposed that Meridian and Contact should be held responsible for the UTS, that penalties should be applied, that parties that caused the UTS should not benefit from the correction, and that Meridian and Contact should make payments that indemnify other participants, keeping them financially whole. As required by Part 5 of the Code, the Authority must attempt to correct the 2019 UTS and restore normal market operation as quickly as possible. In the context of the December 2019 UTS, which reflected a confluence of factors, the actions to correct focus on the outcome in the market as a whole and are not designed to punish individual participants. The suggestions noted by these submitters in this regard are therefore not considered further in the design of the actions to correct the UTS.

3.5 Below, the Authority discusses the main issues that it considers to be pertinent to the design of the actions to correct the UTS. The references to submissions in that discussion necessarily summarise the views expressed. The Authority encourages readers to refer to the individual submissions to fully understand the perspective of individual submitters.

3.6 The main issues raised by submitters in relation to actions to correct the December 2019 UTS fell into nine broad categories.

(a) The overall design of the actions to correct the UTS

(b) The calibration of the cap on offer prices

(c) The specification of constrained on for peaking plants

(d) The resettlement of the instantaneous reserves market

(e) Implications for derivatives markets

(f) Incentives for future behaviour

(g) Process improvements to improve future UTS outcomes

(h) Other miscellaneous issues

(i) Operational processes to resolve the 2019 UTS

3.7 Each of these issues is discussed in turn below. In addition to discussing the themes in the body of the paper, the Authority has sought to capture respective views of submitters in summary tables at a high level. These tables do not replace the more detailed discussion in the body of the paper but are designed to provide a useful snapshot of the general position of submitters on the various themes.

The overall design of the actions to correct the UTS

What the Authority proposed

3.8 The Authority proposed to reset offer prices received by hydro generators on the Clutha and Waitaki river chains by placing a cap of $13.70/MWh on the offer prices. It was proposed that the aggregate volumes on offer would remain unchanged, because generators are incentivised to offer all available generation. The aggregate offer volumes embody any outages that affected the amount a generator could inject during the UTS period, relative to its nameplate capacity.

3.9 The proposal involved combining these ‘corrected’ offers with offers made from other generating stations together with actual load to determine nodal prices that would have prevailed in the absence of the UTS. The Authority proposed that these revised final prices would then be used to calibrate revised settlement payments between participants and the clearing manager. Participants would have to pay for their actual load over the

UTS period and generators would be remunerated for the actual energy that they injected.

3.10 The proposed approach approximates the outcome that would have occurred in the absence of the UTS because the pre-dispatch price discovery process cannot be replicated, and actual (historical) dispatch differs from what would have been optimally dispatched in the absence of the UTS.

Submitters' views

3.11 Submitters that explicitly considered the overall design of the actions to correct were generally in favour of recalibrating offer prices, final nodal prices, and settlement as proposed by the Authority, though contrasting views were provided about the calibration of the corrections. This latter issue is discussed separately below. The balance of submissions on the overall design is reported in Table 2.

Table 2 Overall design of the actions to correct

Generally for	Generally against	Not directly discussed
Contact, Haast+Electric Kiwi, Mercury, Meridian, Nova, NZX, Pulse, Transpower, Trustpower, Walbran	ASX, Claimants*, Enel X	Fonterra, Genesis, MEUG, Pioneer

* The Claimants' cross-submission revised their views about how to correct the UTS given the ASX submission.

3.12 The Authority also explicitly asked whether an off-market washup should be used instead of a correction of offers propagated to final prices via SPD. Submitters' views are summarised in the following table.

Table 3 Conduct an off-market wash-up?

For	Against	Not directly discussed	Undecided
ASX, Claimants*	Contact, Meridian, NZX, Pulse, Transpower, Walbran	Fonterra, Enel X, Genesis, Haast + Electric Kiwi, Mercury, MEUG, Pioneer, Trustpower	Nova**

* The Claimants' cross-submission revised their views about how to correct the UTS given the ASX submission.

** Nova submitted that 'it is difficult to say [answer] as the Authority has not provided details for the "off market" washup of settlement and what this might look like' (p. 4).

3.13 Neil Walbran provided a positive assessment of the actions to correct the UTS, noting '[t]he Authority is to be congratulated on its proposed approach to correcting the UTS in that it seems to have, mostly, achieved the delicate balance of ensuring benefits flow to end consumers while not overly undermining ability of generators to manage their locational risk by their offer strategy' (p1). Walbran also noted that '[t]he alternative "off-market" wash-up would be overly complex, and add little value' (p2).

3.14 Mercury's submission noted that it 'generally supports the approach being taken by the EA to remedy the UTS situation' (p.1). Trustpower indicated that it was '[b]roadly supportive' of the proposed remedy (p.1). Contact's submission (p. 5) indicated that it considered resetting prices in the electricity market for the UTS period was appropriate, though it also noted that the reset price will not be a perfect proxy of a market spot price in a dynamic market. Contact in its cross-submission indicated that the approach proposed was 'pragmatic' (p.1). In its cross-submission Meridian commented that the design approach was far superior to any off-market adjustment (p.3).

3.15 NZX strongly supported using the SPD model to reset final prices, noting that it is an established tool in the electricity market and produces results that are of high integrity and promote participant confidence in the final price setting process (pp 1-2). It also submitted that 'prices should not be reset directly' (p.3). NZX further submitted that an [offer] 'price cap is a straightforward and sensible approach to correcting the UTS' (p.3).

3.16 Transpower commented (p.4) that an 'in-market' resettlement would preserve the complex interactions within the market, improve traceability and record keeping, and would adjust historic prices in line with settlement.

3.17 The main dissenting submission was from the ASX, which proposed an off-market correction that left final spot prices unchanged (p.1). An off-market wash-up, by leaving final prices unchanged, would not lead to a resettlement of derivatives markets. Although the Claimants' original submission indicated qualified support for the proposed approach to correct the UTS, their cross-submission supported the ASX submission and proposed an off-market correction of the spot market, whilst leaving derivatives unchanged. Although primarily focussed on the implications for the instantaneous reserves (IR) market, Enel X submitted that the proposed revision was 'unlikely to approximate "normal" market operation' (p.2).

3.18 A relatively uncontentious proposal was to leave the aggregate amount offered by each generating station unchanged. This proposal respects any operational constraints that would prevent a generating station from generating at its nameplate capacity. Table 4 illustrates that most submitters agreed with this design feature or did not discuss it.

Table 4 Leave aggregate offers unchanged?

In favour of leaving aggregate offers unchanged	In favour of changing aggregate offers	Not directly discussed
Contacts, Claimants, Meridian, Nova, NZX, Pulse, Transpower, Walbran	[None]	ASX, Enel X, Fonterra, Genesis, Mercury, MEUG, Pioneer, Trustpower, Haast+Electric Kiwi

The Authority's decision

3.19 The Authority considers that the proposed actions – placing a cap on offer prices of certain South Island hydro generators and revising final prices and settlement – are necessary to correct the UTS and restore, to the extent possible, the normal operation of the market, in accordance with the requirements of the Code. The Authority notes that most submissions that discussed this issue supported the approach proposed in the consultation paper. The Authority has decided to leave aggregate offered volumes unchanged for all generating stations.

3.20 The approach taken replicates normal market processes as far as practicable in determining the actions to correct the UTS. An off-market settlement without adjustments to final prices would deviate further from the normal operation of the market. As NZX notes, the SPD model is an established tool in the electricity market to set final prices (p.1). The Authority also notes that SPD incorporates the physical properties and security constraints of the electricity system. An off-market settlement would not provide as much discipline on the determination of nodal pricing.

3.21 The Authority acknowledges that the proposed actions do not perfectly correct the 2019 UTS, in part because it is not possible to replicate the usual dynamics of price discovery. As a consequence, it is not possible to perfectly correct all participants' offer behaviour to ensure that it would have aligned with what would have occurred in the absence of the UTS. The actions to correct therefore reflect the Authority's best endeavours to correct the UTS but can only approximate normal operation of the wholesale market.

The calibration of the offer price cap

What the Authority proposed

3.22 One of the key elements calibrating the correction to the UTS is the magnitude of the cap on offer prices for the hydro generating stations in the lower South Island. The Authority proposed that there should be a cap on offer prices during the UTS period of $13.70/MWh.

Submitters' views

3.23 Submitters were split between those advocating for a higher offer price cap and those advocating for a lower offer price cap (see Table 5). Eight submitters did not address the calibration of the offer price cap directly.

Table 5 Submissions on offer price cap calibration

Favoured a lower offer price cap	Favoured an offer price cap of $13.70/MWh	Favoured a higher offer price cap	Not directly discussed
Claimants, Fonterra, Haast+Electric Kiwi, MEUG, Pulse	[None]	Contact*, Meridian, Nova, Walbran	ASX, Enel X, Genesis, Mercury, NZX, Pioneer, Transpower, Trustpower

* In its cross-submission.

3.24 Meridian advocated for a higher cap, submitting that a higher offer price cap was consistent with the excess Benmore spill analysis underpinning the preliminary and final decision papers on the UTS, and with the resultant feasible increase in generation. Walbran proposed a higher offer price to maintain incentives for increased renewables generation. (p1) Contact noted its support for Meridian's views on the offer price cap in its cross-submission. (p2)

3.25 Several submitters suggested that the calibration of the offer price cap was unduly conservative and raised concerns about the incentives for future behaviour. Fonterra for example, suggested that a conservative offer price 'leaves transgressing parties in a net positive position and reinforces the advantage of such conduct' (p.1); see also Haast+Electric Kiwi (p.2). Pulse submitted that '[t]he Authority should be guided by the actual offer prices at Manapōuri (and Tekapo A and B) in setting the cap' (p.2).

3.26 The Claimants in both their submission (e.g. at p.2) and cross-submission (e.g. at p.3) reiterated the view that the correction should involve setting an offer price at or below short run marginal cost (SRMC), which they consider to be a strategy that could have been implemented in real time to avoid unnecessary spill. MEUG proposed that the offer price cap should be $12/MWh, consistent with the historical outcomes of 18-27 December 2019, in the latter half of the UTS period (p.2).

3.27 Haast+Electric Kiwi submitted that '[t]he Authority should not adopt a "conservative" approach that favours suppliers at the expense of the long-term interests (benefit) of consumers' (p.3).

3.28 Several submitters (such as the Claimants, Pulse and Pioneer (in the context of incorporating spot market corrections into derivatives)) referenced workable competition in their submissions. Pulse for example submitted 'an offer cap of $13.70/MWh is well above the level that could be expected in a workably competitive market given the supply and demand conditions at that time' (p.2).

3.29 Contact's submission indicated concern that the offer price adjustment was theoretical and could not be obtained in real time (para. 5). Contact's subsequent cross-submission indicated that either an average offer price of $13.70/MWh should be used or, in agreement with Meridian's submission, that the offer price cap should be $19.98/MWh, consistent with one of the alternatives noted in the consultation paper (p.2).

3.30 The Claimants' cross-submission agreed with Contact's submission that the Authority's modelling did not adequately reflect imperfect information in real-time and that it was 'practically unachievable in real-time', but concluded that setting offers at or below SRMC would have been the safest and most reliable way for Contact and Meridian to ensure they did not needlessly spill water (p.3). The Claimants referenced figure 1 from Meridian's submission and noted that very low (eg 1 cent) offers reduce spill by the greatest amount. They concluded that '[t]his is consistent with a workably competitive market' (cross-submission, p. 3).

3.31 Contact raised concerns about the feasibility of the solution noting that the vSPD model run had Clyde frequently running at 464MW and therefore unable to provide FIR/SIR/frequency keeping and limiting the voltage control it can provide (p.2). Similar feasibility concerns were raised by Meridian.

The Authority's decision

3.32 Submissions were received indicating that the offer price cap should be both higher and lower than the Authority proposed. The Authority has decided to leave the offer price cap at $13.70/MWh as proposed in the consultation paper. The Authority is seeking to achieve market outcomes that are both feasible and consistent with the market circumstances of the period. Feasible outcomes are an important part of normal market outcomes.

3.33 Some submitters argued that the offer cap of $13.70/MWh was unduly conservative, and the cap should be calibrated at a lower level. As illustrated in figures 6 and 8 of the consultation paper, the Authority notes that the offer price cap results in lower prices and more South Island generation than the Authority's original analysis which identified the single flat offer required to clear the excess spill at Benmore. The offer price cap of $13.70/MWh results in prices that fall below the offer cap level when demand is low, whereas the flat offer price imposed a floor on prices close to $13.70/MWh.

3.34 The proposed offer cap results in low prices when load is low, but still results in higher prices when additional generation is required to meet load. As expected, final prices vary from trading period to trading period to clear the market.

3.35 The offer price cap results in a high amount of (notional) transfer across the HVDC link. As noted in table 6 of the consultation paper, the $13.70/MWh offer price cap results in notional average MW transfer across the HVDC link of 597.81 MW during the UTS period, whereas the flat offer price results in transfer of 587.64MW. These flows are notional in the sense that they would have occurred with revised optimal dispatch. Actual dispatch is unchanged in the correction. Only two calendar months in the last ten years would have resulted in more transfer north than the notional transfer that would have occurred during the UTS period.[5]

3.36 Relative to the actual HVDC transfer during the UTS, the proposed $13.70/MWh offer cap results in an average of 60 MW additional HVDC transfer. Decreasing the offer price cap to $7.42/MWh (consistent with the South Island Mean Injection charge) would increase transfer by less than 10MW more and raises questions about feasibility given other constraints.

3.37 The Authority has decided that it is not appropriate to lower the offer price cap further, as suggested by MEUG, given the information described above and the further points noted below. In response to MEUG's submission, the Authority notes that load within the latter half of the UTS period was low because of the Christmas holidays,[6] with accepted offers being relatively low in the offer stack. The Authority could have based the correction directly on the offers that were made in the latter half of the UTS, but ultimately concluded that the additional complexity would not improve the correction of the UTS.

3.38 As paragraph 6.9 of the consultation paper notes, the maximum transfer from the 13.70/MWh offer cap is just over 1000MW for a single trading period. Transfer at this level is at the upper end of what has occurred historically and, in the Authority's view, is consistent with the supply and demand conditions of the UTS period. HVDC transfer at this peak level is exceptional.[7] Only 14 trading periods since July 2009 have had HVDC transfer at such a peak. (Again, see footnote 5.)

3.39 The Authority agrees with Haast+Electric Kiwi that the correction of the UTS should be made in the long-term interest of consumers but reaches a different view as to how this long-run benefit should best be supported. The correction to the UTS seeks to reflect normal market operations, which by nature balance the welfare of consumers and generators to ensure that the latter continue to provide electricity to meet consumer needs.

3.40 Several submitters referenced workable competition in their submissions. Workable or effective competition is a situation in which entry and exit, and the threat thereof,

5 We note that Pole 3 of the HVDC link was completed within this period.

6 See www.emi.ea.govt.nz/r/wd3ll.

7 See www.emi.ea.govt.nz/r/2r4be.

disciplines the pricing of incumbents participating in the market. The courts have suggested that workably competitive markets have a tendency towards generating outcomes, such as normal rates of return, but also note that firms may earn higher-than-normal rates of return or even losses for extended periods.[8]

3.41 In the wholesale market, workable competition does not imply that pricing will be 'at' short-run marginal cost. In practice, offer prices are sometimes above and sometimes below short-run marginal cost. The Authority's correction enforces low pricing during the UTS period without forcing offer prices to exactly equal short-run marginal cost. The Authority considers that Pulse's suggestion that the Authority 'should be guided by the actual offer prices at Manapōuri (and Tekapo A and B) in setting the cap' (p.2) does not take into account the portfolio of offer prices normally provided by generators.

3.42 Some submitters argued that the offer price cap should be calibrated to SRMC. As noted in the original UTS decision paper, there is no requirement for generators to submit at SRMC. While a pre-dispatch process in the absence of the UTS may have resulted in offer prices different to those of $13.70/MWh, the Authority considers that offer prices at the specific calibrated level could have been achieved.

3.43 The Authority considers that forcing generators to offer according to SRMC would not be consistent with restoring market normality. A cap on offer prices at SRMC ignores all operational and hydrological constraints faced by the generators whose offers were adjusted, raising questions about its underlying feasibility.[9]

3.44 The Authority's $13.70/MWh offer cap aims to achieve feasible and normal outcomes whilst simultaneously restoring confidence in the wholesale market by ensuring that prices are commensurate with the hydrological conditions of the UTS period. No specific evidence was provided in submissions that demonstrated the $13.70/MWh offer price cap was generally infeasible.

3.45 Contact (submission, p. 2) noted that there was a reduction in generation on the Clutha, implying the correction was feasible for those stations. Meridian also noted (p.12, cross-submission) that, under the proposed correction, offer volumes at Ōhau A and Manapōuri would result in decreased generation and increased spill.

3.46 The Authority makes two observations in relation to these submissions. First, the Authority agrees with Meridian's cross-submission when it says:

> 'Displacement of hydro generation from different sources is inevitable in any modelled scenario with adjusted hydro offers. However, these individual station level outcomes are not particularly relevant to the Authority's methodology which is intended to estimate the amount of additional hydro generation that could feasibly be dispatched from the South Island as a whole and identify a price at which that might have occurred.'

3.47 Second, in ordinary circumstances some hydro stations are eligible for block dispatch, and so exactly how dispatch obligations are ordinarily met is also subject to a degree of flex.

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8 See *Wellington International Airport Ltd v. Commerce Commission* [2013] NZHC 3289.

9 As an aside, the Authority notes that SRMC for hydro generators depends on the level of storage (eg because of the opportunity cost of water) and hence the South Island Mean Injection rate (plus an operational and maintenance allowance) will not always be the SRMC of South Island hydro generation.

3.48 The Authority notes that the supply of instantaneous reserves is co-optimised with energy and Contact's observation that Clyde was not providing reserves under the $13.70/MWh offer price cap correction reflects that other generating stations' offers will have been accepted instead. Frequency keeping is a very small element in the context of the actions to correct. To reiterate, the correction approximates what would have occurred if the market had been operating normally.

3.49 Meridian proposed that a higher offer price was appropriate, either $19.98/MWh or a cap based on similar hydrological conditions (eg $29.59/MWh) to align with the analysis of the UTS decision paper. The Authority considers that the proposed correction provided an appropriate balance between feasibility and correcting offer prices to levels closer to the demand and supply conditions that prevailed during the UTS, given the likelihood of excess spill at other generation stations besides Benmore.

3.50 Meridian raised general concerns about the feasibility of the correction (see cross-submission pp 6-7), noting that it resulted in 30 percent more South Island hydro generation than was consistent with absorbing the excess spill at Benmore (being the approach the Authority took in its Decision Paper on the 2019 UTS), but did not demonstrate that the notional generation of the correction was infeasible given the other constraints faced by generators. The Authority notes that its objective for the actions to correct is not to achieve a given amount of generation but is to correct the UTS and restore normal market operation. Its goal is also to correct the UTS, rather than generally to gauge an estimate of its scale. The correction shifts the dial towards lower offer prices to account for excess spill at other stations besides Benmore, correcting the threat to confidence in the wholesale market posed by the UTS.

3.51 The cap on offer prices decided by the Authority corrects the UTS. The resultant prices could have been realised via normal price discovery processes. Contact and others submitted that the UTS correction reflected ex post analysis and the offer cap price could not have been identified in real time. The Authority agrees that the UTS correction is an ex post mechanism but considers that it provides a suitable approximation to the prices that would have been achieved by usual price discovery process if the confluence of factors that resulted in the UTS had not arisen. As noted previously, the correction to the UTS is necessarily an approximation to what would have occurred in real-time if the market had been operating normally.

The generating stations with revised offers

What the Authority proposed

3.52 The Authority proposed to cap offer prices during the UTS period for the following generating stations: Aviemore; Benmore; Clyde; Ōhau A, B, and C; Roxburgh; and Waitaki.

Submitters' views

3.53 Many submitters did not discuss which generating plants should be subject to an offer price cap. When discussed, submitters generally did not favour including North Island generating stations in the actions to correct. Meridian's submission indicated that all South Island generating stations should be subject to the offer price cap to be consistent with the methodology applied in the final decision paper (p.16) but that it would be reasonable for North Island offer prices to stay constant (p. 17). A number of submitters suggested that Manapōuri should also be included in the correction. In contrast, Meridian's cross-submission said there was no reason to apply the offer price cap to

Manapōuri (p.11). The Claimants suggested that Tekapo A and B's offers should also be subject to the offer price cap (see answer to Question 6, p. 14), though no explanation was given for this suggested inclusion.

3.54 Contact questioned whether its stations on the Clutha/Mata-Au River should be subject to the offer price cap, given that their offers reflected the operational and river management issues that they faced during the UTS period (p.6).

Table 6 Which generators should have corrected offers?

Favoured including Manapōuri	Favoured excluding Manapōuri	Favoured excluding North Island Generators?	Favoured excluding Clyde and Roxburgh?	Not directly discussed
Claimants, Haast+Electric Kiwi, Pulse	Meridian	Contact, Mercury, Meridian, Pulse, Walbran	Contact	ASX, Enel X, Fonterra, Genesis, NZX, Pioneer, Transpower, Trustpower, Walbran

* As discussed elsewhere, Nova submitted that offer prices for the McKee power plant should be adjusted to reflect the prices it received for generation produced during the UTS period, which could be interpreted as a reset of their offer prices to receive constrained on. Nova (p.1) supported the consultation proposal to cap offer prices from hydro generating stations on the Clutha/Mata-Au and Waitaki rivers.

The Authority's decision

3.55 The Authority has decided to include Manapōuri in the generating stations subject to an offer price cap. Therefore the stations to have their offer prices capped are: Aviemore; Benmore; Clyde; Manapōuri; Ōhau A, B, and C; Roxburgh; and Waitaki.[10] These stations have capped offer prices to assure market participants and the public that final prices are consistent with the abundance of water available to these generators during the UTS period and align with the normal operation of the market with normal competitive pressures. The decision paper noted that Tekapo A and B, run by Genesis, were acting as price takers during the UTS period, and so offer prices from these stations have not been corrected.

3.56 The Authority has extended the offer price cap to the Manapōuri generating station. Manapōuri is part of Meridian's portfolio of South Island hydro generation, and its offers are co-optimised with offers from other Meridian stations, reflecting in part transmission constraints that affect multiple stations. Given these interdependencies the Authority has decided to treat the offers as an integrated whole, applying the offer cap to Manapōuri as well as other stations to correct any threat to confidence in the wholesale market. Making Manapōuri subject to the offer price cap eliminates any concern that Manapōuri's offer

10 The stations inject electricity at the following points of connection: AVI2201 AVI0, BEN2202 BEN0, CYD2201 CYD0, MAN2201 MAN0, OHA2201 OHA0, OHB2201 OHB0, OHC2201 OHC0, ROX1101 ROX0, ROX2201 ROX0, and WTK0111 WTK0.

behaviour contributed to high prices that were inconsistent with the demand and supply conditions during the UTS period.

3.57 Several submissions suggested that Manapōuri should be subject to the offer price cap. The Claimants, for example (p. 14), noted that there were 108 trading periods in which some of the offers of the Manapōuri station were above the offer price cap and that 1.5 percent of Manapōuri's offered quantity (in terms of megawatts offered) was offered at prices above the cap.

3.58 Meridian cross-submitted that there was no reason to include Manapōuri, citing the consultation paper which indicated that Manapōuri offers were 'generally consistent' with maximising generation during a spill event and that offer prices were 'predominantly low'.[11] Meridian submitted that 'all the generation offered during the UTS period (bar the exception noted above [reflecting electrical storms]) was offered far below any of the proposed offer caps at $0.01 or $0.02/MWh.' (Meridian, cross-submission, p.11.) The Authority notes instead that <u>most</u> but <u>not all</u> Manapōuri offers were at low levels.[12] The Authority now considers that the offer bands made at high offer prices should be addressed to resolve potential threats to confidence in the wholesale market.

3.59 As Meridian has itself noted, the impact of bringing Manapōuri into the correction is not particularly substantial. The Authority nonetheless considers that the confidence effects warrant the inclusion.

3.60 Contact submitted, in both its submission and cross-submission, that the Clyde and Roxburgh stations should be excluded from the correction. The Authority disagrees with Contact's position. The Authority acknowledges that Contact faced flood management and operational difficulties during the UTS period that limited its ability to compete at the margins. However, the Authority considers that Contact's difficulties, together with the other elements in the confluence of factors, may have contributed to a reduction in competition for the duration of the UTS period, affecting pricing. Consequently, the Clutha/Mata-Au stations remain subject to the offer price cap in the actions to correct the UTS.

The specification of constrained on

What the Authority proposed

3.61 The Authority proposed that eligible generators that offered above the revised final price but were dispatched would be paid constrained on payments, representing the difference between the revised final price and their offer price. It was proposed that

11 Meridian's cross-submission suggested that a further consultation would be required if the Authority changed the mix of generation stations that are subject to the cap, ie, if Manapōuri was to have its offers corrected (p.13). The Authority notes that it explicitly consulted on which generating stations should be subject to an offer price cap and identified Manapōuri as one of those candidates (see question 6 of the consultation paper).

12 In subsequent correspondence with the Authority Meridian noted that some offer tranches were intended to mitigate transmission risks and the offer prices were intended to be just under market clearing prices at the time. Some band 5 offers were made as a non-clearing tranche because a unit returned from outage early and was technically available. Some volume was offered as a non-clearing band 5 offer overnight so that Waitaki offers with lower prices would clear first, to ensure compliance with minimum flow requirements on the Waitaki chain. On 9 December a small volume was offered in a non-clearing tranche because of the risk that the INV_NMA circuit would bind during an outage on the NMA_TWI_1 circuit. Following the tripping of unit seven at Manapōuri, the unit was initially returned as a non-clearing tranche to reflect that the unit was technically available. It was then reintegrated with Meridian's offer stack for subsequent trading periods.

generators subject to the offer price cap would not be eligible for constrained on payments.

3.62 In relation to peaking plants, reflecting Nova's earlier submission on the Preliminary Decision Paper, an alternative was also discussed (see para 5.49 of the consultation paper) in which peaking generators would be offered constrained on payments up to an estimate of their operating costs or marginal cost. In effect, this correction would be akin to revising the offers of peaking power plants to the level of their marginal cost.

Submitters' views

3.63 In general submitters supported the use of constrained on payments for dispatched generators whose offer prices exceeded revised final prices. Some submitters proposed that the details of constrained on payments should be amended.

3.64 Transpower (p.5) submitted that constrained on payments assist with dispatch compliance by ensuring that generators are compensated in line with their offers, maintaining incentives for generators to comply with dispatch instructions and supporting security of supply. The Claimants submitted that constrained on payments should be made (except in regard to Contact and Meridian) (p.3, 16) and Meridian's submission also noted that constrained on payments seemed like a reasonable approach (p.18).

Table 7 Make constrained on payments?

Favoured making constrained on payments	Against making constrained on payments	Not directly discussed
Claimants, Contact, Haast+Electric Kiwi, Meridian, MEUG, Nova, Pulse, Transpower, Walbran	[None]	ASX, Enel X, Genesis, Mercury, NZX, Pioneer, Trustpower, Fonterra

3.65 Nova's submission and cross-submission raised concerns that the proposed design of constrained on would result in operating losses at the McKee peaking plant given the magnitude of the revised final prices and the fact that McKee offer prices for periods when it was dispatched were towards the bottom of the offer stack.[13] Nova proposed that they should be remunerated at the original prices that prevailed during the UTS period. Contact raised similar concerns in its submission (p.2) in relation to its TCC power station.

3.66 MEUG agreed with Nova's submission (p.3) and submitted that only Meridian and Contact should bear the cost of resetting prices (p.2). Mercury had raised similar concerns about prices being reset below generators' short-run marginal costs in their earlier 15 September 2020 cross-submission (p.2) on the preliminary decision paper: 'the imposition of below short run marginal cost revenues on Nova ex-post… would not be an outcome expected under normal market conditions'.

13 Nova's submissions were made on behalf of itself and Todd Generation Taranaki Ltd (TGTL), which is a related company owned by Nova's ultimate parent. For simplicity, we do not distinguish between Nova and TGTL in this discussion.

3.67 Haast+Electric Kiwi noted the need for constrained on payments is a consequence of the UTS. They proposed that the Authority should adjust the cap on offer prices lower to offset constrained-on payments so that wholesale electricity purchasers and end-users with higher prices do not have to make payments that are higher than would have occurred in the absence of the UTS.

3.68 Haast+Electric Kiwi submitted that Contact and Meridian should not receive constrained on payments at all stations. They also submitted that the additional constrained on payments arising from sub-optimal dispatch during the UTS period should be funded by Contact and Meridian.

3.69 The Claimants submitted that Manapōuri should be subject to the offer price cap and therefore should not be eligible for constrained on.

The Authority's decision

3.70 Constrained on payments are typically required to meet demand and maintain security in exceptional circumstances. In the normal operation of the market, generators make offers and are eligible for constrained on payments if their stations are dispatched and their offers are greater than final prices at the relevant nodes. Generators do not receive constrained on payments if their offer prices for dispatched offers were below realised final prices (ie, if the offers were accepted 'in merit'.)

3.71 The Authority has decided that constrained on payments should be made in the usual way to all generators and reserves providers.

3.72 In response to Haast+Electric Kiwi's suggestion that Contact and Meridian should pay for constrained on payments, the Authority notes that, as set out above, there was a confluence of factors that resulted in the UTS. The Authority is aiming to approximate normal market outcomes and is not applying the actions to correct punitively.

3.73 The Authority has decided not to implement Haast+Electric Kiwi's proposal to lower the offer price cap to offset the constrained on payments arising from the UTS correction (in essence to keep purchasers whole). Lowering prices as suggested would allocate the constrained on costs to all generators. The Authority considers these constrained on payments to be part of the cost of delivering electricity during the UTS period, and that the end users of electricity should bear those costs in the normal way. With the actions to correct the Authority aims to restore normality, charging consumers for the electricity they consumed and remunerating generators for the electricity they have generated.

3.74 The Authority has decided not to make bespoke adjustments to offers from peaking plants.

3.75 A fundamental premise of the wholesale market is that generators submit offers at which they are willing to supply electricity. Peaking generators can of course submit offers above short-run marginal cost, taking into account the reduced operational efficiency that may arise from partial dispatch and any increased maintenance and operational costs, if they wish to do so.

3.76 As Nova explained,[14] it uses pre-dispatch information to identify periods when spot electricity prices are expected to be above its short-run marginal cost. For operational and design reasons, the McKee plant, which consists of two gas turbines, aims to generate electricity from the turbines at their most efficient level. Although the McKee

14 See Nova's answers to Q7 and Q13 on pp 5 and 7-8 of its submission.

generating units can operate below this efficient level, the efficiency of the turbines degrades, in part because the turbines were installed without variable inlet guide vanes.

3.77 Nova bids strategically at low levels near the bottom of the offer stack to ensure that it will continue to be dispatched at its efficient operational level for contiguous trading periods. Offering at the bottom of the offer stack ensures that the plant is dispatched at its efficient level for the desired trading periods. This offer behaviour enables it to avoid being the marginal plant and avoids being partially dispatched.

3.78 A consequence of this offer strategy is that other generators – such as hydro generators – will typically be at the margin, with some offer bands only partially dispatched. The general desire to avoid being at the margins contributed to the difficulties experienced by Contact with its spill gates, which it also sought to manage by strategically amending its offers on the Clutha river to avoid being marginal.

3.79 Offers made below SRMC result in risks that final prices may be at levels below marginal cost. In Nova's case, some of the days that it chose to generate during the UTS period – even absent the correction – resulted in operating losses, given that prices were below their estimated SRMC. These risks are ever present and occasionally are realised.

3.80 The Authority notes that prices at the McKee node, when the McKee peaking plant was generating, are estimated to be around $65/MWh under the UTS correction, much greater than the offer price cap being applied to the South Island hydro generators identified previously.

3.81 In earlier discussions with the Authority as part of the UTS investigation, Contact indicated that it dispatched its own peaking plants for portfolio reasons (to ensure that its load and generation was approximately balanced).[15] Given that Contact's motivation was not to supply peaking services, but rather reflected its own internal risk-management processes, the Authority again considers that the default treatment of constrained on for peaking plants remains appropriate.

3.82 Ultimately, the Authority considers that the design of constrained on as part of the actions to correct should not pose a risk to future security because UTSs are low probability events and even high-priced peaking offers could be dispatched if required for system security. Transpower has also indicated that it sees no risk to system security from the Authority's treatment of constrained on in the actions to correct (as detailed in the consultation paper).

The resettlement of the instantaneous reserves market

What the Authority proposed

3.83 The Authority proposed that instantaneous reserve offers would not be adjusted but that instantaneous reserve (IR) prices would be adjusted reflecting the revised energy only offers from hydro generators and the co-optimisation of spot and reserves markets.

Submitters' views

3.84 The settlement of the reserves market was not a key focus for many submitters. Nine submitters did not discuss the approach to the reserves market, and six submitted in favour of the Authority's proposal.

15 See para. 11.27 of *The Authority's preliminary decision on claim of an undesirable trading situation*, 30 June 2020.

3.85 Enel X, an aggregator of interruptible load, was the main dissenting submission. Enel X submitted that the reserves and energy markets are separate markets with distinct participants and conditions and submitted that IR participants should not be penalised ‘for the behaviour of others in a separate market’ (p.3). In its cross-submission, MEUG (p.2) supported Enel X’s submission and proposed that only Meridian and Contact should bear the costs of resetting prices. Enel X also submitted that ‘[t]he EA's approach does not take account how participants' behaviour might have changed had the market conditions been different’ (p.2).

Table 8 Submissions on the proposed approach to instantaneous reserves

In favour of Authority proposal	Against Authority proposal	Not directly discussed
Contact, Meridian, NZX, Pulse, Transpower, Walbran	Enel X, MEUG	ASX, Fonterra, Genesis, Haast+Electric Kiwi, Claimants, Mercury, Nova, Pioneer, Trustpower

The Authority’s decision

3.86 The Authority has decided to proceed with the proposed resettlement of the reserves market, taking into account the new energy only offers, but leaving instantaneous reserve offers unchanged. The Authority notes that the wholesale market consists of the spot market for electricity and the markets for ancillary services and includes processes for setting final reserves prices (as per Part 1 of the Code). The Authority also notes that the prices of spot and reserves are co-optimised in SPD. The Authority considers that settlement in both markets should be revised to reflect the updated energy offers. Reserves providers should not benefit from the original distortion of spot and reserves prices from the confluence of factors that led to the UTS. The UTS decision’s approach treats reserve providers symmetrically with generators, irrespective of whether they provide peak or base load.

3.87 The Authority agrees with Enel X that actions to correct the UTS do not account for how participants might have changed if market conditions had been different. The Authority considers that these behavioural changes cannot be perfectly accounted for in the actions to correct. The Authority notes that instantaneous reserves providers are eligible for constrained on payments if their offers are above the revised reserve prices.

3.88 Although not discussed in the submissions in any depth, the Authority also notes that it directs Transpower to revise settlement for frequency keeping.

Implications for derivatives markets

What the Authority proposed

3.89 The Authority proposed that energy offers at hydro generators should be revised and final prices should be recomputed using the SPD model. In general, the revision of final prices in the spot market, is expected to prompt resettlement of derivatives in accordance with the terms and conditions of those contracts, except where those terms and conditions provide otherwise.

3.90 The Authority proposed to allow the terms and conditions of derivatives contracts to determine whether the contracts are resettled and did not propose to over-ride contractual conditions. The consultation paper also proposed that the allocation of risk associated with a revision to final prices stemming from a correction to the UTS would be determined by the terms and conditions of the contracts and would not be over-ridden by the Authority.

3.91 The consultation paper also noted that futures and options traded on the ASX exchange might not be resettled given that the ASX had indicated to the Authority that it was of the view that a resettlement would likely be contrary with their fair, orderly, and transparent (FOT) obligations as an Australian Market Licence (AML) holder.

3.92 Lastly, the Authority suggested that it would not be possible to adjust trading in ASX futures and options through time, so proposed that any resettlement would pertain to holdings at the conclusion of the December 2019 month.

Submitters' views

3.93 On balance, submissions considered that derivatives markets should be resettled in tandem with any adjustment to spot electricity prices or agreed with the approach proposed by the Authority, though there were a couple of exceptions.

Table 9 Submissions on derivatives resettlement

Favoured derivatives being resettled	Favoured derivatives <u>not</u> being resettled	Generally agreed with Authority's proposed approach	Not directly discussed
Genesis, Mercury, Meridian, Pioneer, Pulse	ASX, the Claimants*, Trustpower**	Contact, Haast+Electric Kiwi, Nova, NZX, Transpower***, Walbran,	Enel X, Fonterra, MEUG

* The Claimants revised their view on derivatives in their cross-submission (pp.7-8). Cross-submission view represented in table.

** Based on Trustpower's cross-submission.

*** Transpower agreed with the proposed approach to the correction of FTRs and did not comment on resettlement of other derivatives (p.6).

3.94 As expected, the ASX submission (p.1) confirmed that they preferred an off-market correction to the spot market, noting that they considered that '[a] retrospective change to the spot electricity price is likely to have significant and lasting undesirable impacts on the hedging market.' Amongst other considerations the ASX indicated that there was a risk of decreased liquidity in hedging contracts and therefore increased costs for electricity users.

3.95 The cross-submission by the Claimants (including Haast) supported the ASX submission that resettlement of futures was not an appropriate option as it could undermine confidence in the ASX market (p.7).

3.96 In its submission on the consultation paper Haast + Electric Kiwi indicated that they 'agree[d] with how the Authority has treated pass through of spot prices to FTRs and derivatives markets' (p.3). They also noted that they had 'not identified any other sensible way to deal with FTRs and derivatives' (p.3). Walbran agreed 'with the Authority's proposed approach to let derivative markets adjust according to their terms and conditions. The alternative, of reaching into other markets, has high risks and little to gain' (p. 4). In their cross-submission, Trustpower submitted (p.1) that '[c]hanging the basis of arrangements that parties formally agreed to ex-post would introduce additional uncertainty for participants.'

3.97 Contact (p. 8) supported the Authority's view in the consultation paper that trade in derivatives undertaken through time would be impossible to unravel and that derivatives markets should be left to adjust according to their terms and conditions. Contact's cross-submission (p.1) acknowledged the practical and jurisdictional challenges of adjusting the hedge market.

3.98 Nova submitted (p.9) that it 'agrees that where the terms of derivative agreements provide for resettlement of prices, then that should be undertaken at the revised prices', but also '[i]deally, ASX futures contract settlement should also be redetermined, but Nova does not have any suggestions on how that might be resolved.'

3.99 A common theme from other submitters was that derivatives markets should generally be resettled in conjunction with any change in settlement in the spot market. Pioneer, for example, submitted that the Authority's proposal 'exclude[s] the derivatives market from its price reset – which Pioneer does not support' (p.1) and that 'it is not "arguable" that a return to normal or workably competitive wholesale market[s] requires derivatives to incorporate the proposed correction to spot prices – it is imperative' (p.2). Genesis (p.1) likewise submitted that ASX futures should be resettled against the reset prices, noting the risk that creating a split market would create winners and losers without justification.

3.100 The MOSPs provided submissions that generally supported the approach proposed for derivatives. NZX submitted that 'the appropriate approach here [for derivatives] is that each of these financial products should be treated within the bounds of the contractual merits of those products. Any direction contrary to these terms will be detrimental to the integrity of the product and wholesale market confidence' (p. 4). Transpower submitted that it supported the proposed approach in relation to FTR derivatives (p. 6).

The Authority's decision

3.101 The Authority has decided to reset <u>final</u> spot electricity prices. By resetting final prices, the Authority has provided the necessary pre-condition to enable derivatives to be resettled, given that derivatives are referenced to final prices.[16] In the context of the 2019 UTS, the Authority's view is that private participants should determine whether their contractual obligations permit or indeed require resettlement of their derivative contracts given the revision to final prices. The Authority notes that the approach taken here accords with the NZX submission. The Authority considers that derivatives should generally be resettled when there is scope to do so, and where such contracts do not have explicit provisions ruling out resettlement. The Authority also notes that hedges that are settled by the clearing manager through a hedge settlement agreement or the FTR allocation plan will be resettled by the clearing manager as a result of the Authority's decision.

3.102 As noted in Meridian's submission, ASX Operating Rule 3100 provides that ASX may take any action it considers necessary to ensure that a market for one or more products is fair, orderly and transparent. ASX has (amongst other powers) the ability to direct that 'Products be offered or settled at a price other than that provided for by the Rules, in

16 In contrast, an off-market settlement that did not reset final prices would create a disjuncture between the resettlement of the spot market resettlement and settlement of derivatives.

such manner and on such conditions as it may determine.'[17] Notwithstanding these powers, ASX has indicated that it will not resettle its futures and options given its interpretation of its Australian Market Licence and its obligation to provide a fair, orderly and transparent market. The Authority encouraged ASX to review their position in light of the submissions and cross-submissions made on the proposed actions to correct the UTS.

3.103 The Authority also notes that staff from the ASX's regulator, the Australian Securities and Investments Commission (ASIC), have also indicated to the Authority that they share ASX's interpretation of these obligations.

3.104 The Authority has no scope to direct the ASX to adjust derivatives settlement because ASX operates in a separate, overseas jurisdiction and had no contractual obligations with the Authority that relates to the provision of futures and options during the UTS period.

3.105 In response to Pulse and Pioneer's submissions, the Authority notes that 'practical impediments' – such as the Authority's inability to direct the ASX to resettle exchange-traded options and futures – do place constraints on the feasible actions the Authority can undertake to correct the UTS. These jurisdictional constraints were explicitly recognised by Trustpower and Contact in their submissions and cross-submissions.

3.106 Given the importance that some submitters attached to the resettlement of derivatives, and indirectly prompted by submissions, the Authority considered whether it would be feasible and desirable to conduct a separate off-market settlement of futures and options. Such an approach would implicitly over-ride the terms and conditions of private contracts.

3.107 The Authority's consideration of an off-market resolution raised additional issues, one being access to the data on derivatives holdings. The hedge market data in the Electricity Hedge Disclosure System[18] currently implies that not all derivatives contracts are being fully disclosed[19] and also raises the possibility that there would be some non-domestic participants that would have to pay in money given their derivative positions. The Authority considers it unlikely that all such entities would make such payments in an off-market settlement mechanism, implying that there would likely be a revenue shortfall for derivatives settlement.

3.108 Resolving a shortfall of derivatives revenue would not be feasible within a reasonable period of time and would not correct the UTS and restore normal market operations as soon as possible, as required by clause 5.5 of the Code. In light of these feasibility issues, the Authority considers that attempting an off-market resettlement of derivatives would not further assist in correcting the 2019 UTS and restoring confidence in the wholesale market.

3.109 As discussed in the consultation paper (para. 5.75), the revision to spot prices alters locational price spreads and has implications for settlement of financial transmission

17 See ASX Operating Rules, Rule 3100, available at: https://www2.asx.com.au/content/dam/asx/rulesguidance-notes-waivers/asx-operating-rules/rules/asx_or_section_03.pdf.

18 See https://www.electricitycontract.co.nz/.

19 For example, the amounts received from 'payers' from resettlement of futures should balance the amounts paid to 'recipients' from resettlement as this should be a zero sum rebalance. However, the hedge market data available to the Authority has more of the latter than the former.

rights (FTRs). The FTR market will be resettled given that clause 4 of the FTR participation agreement requires participants to comply with provisions of the FTR allocation plan, and clause 2.7 of the FTR allocation plan specifies that the FTR hedge value (provisional) relates to '[t]he final prices in $/MWh (published in accordance with Part 14 of the Code)'. Consequently, the correction of final nodal prices will result in resettlement of the FTR market for December 2019. To eliminate ambiguity, the Authority is directing the FTR manager to recalculate the loss and constraint excess (LCE) required to support the resettlement of the FTR market for the month of December 2019 and provide that information to the clearing manager.

Incentives for future participant behaviour

What the Authority proposed

3.110 The Authority proposed correcting the UTS that occurred in December 2019, consistent with its obligations under Part 5 of the Code. It did not seek to regulate future trading behaviour through this decision, and any changed incentives brought about by the actions to correct would be coincidental.

Submitters' views

3.111 Submitters raised concerns that future behaviour might not be appropriately moderated by the incentives associated with the actions to correct. Fonterra for example, suggested that a conservative offer price 'leaves transgressing parties in a net positive position and reinforces the advantage of such conduct.' (p.1) Fonterra also submitted (p. 1) that in financial markets 'when the penalties for market manipulation are no longer effective in deterring manipulative behaviour, the risk that participants choose to exercise market power increases.'

3.112 As noted earlier, Enel X submitted that restoring confidence would be 'better achieved by taking steps to ensure that the causers of the UTS do not repeat their actions, not by penalising market participants that had nothing to do with it' (p.2). The Claimants (submission p. 6) also raised concerns about the incentives for future behaviour if the actions to correct reward parties that contributed to the confluence of factors that led to the UTS.

3.113 Walbran provided a different perspective, noting that the Authority also needs to maintain incentives to invest in renewable generation (eg see answer to question 12), and submitted that the offer price cap should generally be higher as a consequence. MEUG (cross submission pp 2-3) agreed with Nova that it was important not to create perverse incentives to withdraw from providing services that support system security.

The Authority's decision

3.114 As the submissions discussed above indicate, the incentives for future behaviour can be interpreted in quite different ways. In relation to such incentive effects, the Authority considers that Part 5 of the Code requires it to correct the UTS that occurred. These incentives for future behaviour can be better addressed by amending the design of the Code and by ensuring that competition in the wholesale market is as strong as possible. In this regard, the Authority notes that it has already instituted changes to the trading rules, which came into force 30 June 2021. Given that UTSs are low probability events and the particular circumstances that led to the UTS were unusual, the incentive effects for usual market behaviour are comparatively small and are not a material consideration for the correction of the UTS.

Process improvements to improve future UTS outcomes

What the Authority proposed

3.115 The Authority proposed to correct the UTS of December 2019. Process improvements aimed at improving outcomes when UTSs occur in future are not addressed by this decision.

Submitters' views

3.116 Much of Trustpower's submission focused on suggesting process improvements that would improve the resolution of future UTSs. Here we briefly detail the three main elements discussed.

3.117 Trustpower focused on:

(a) resolving the UTS more quickly,

(b) improving the correction of derivatives markets in conjunction with corrections to the spot market, and

(c) changing the allocation of decision-making powers and processes.

3.118 In relation to (a), Trustpower suggested that a speedier identification of the facts would occur if parties were able to make submissions on the core issues at a hearing rather than sequentially responding to investigator questions via email (p.2).

3.119 In relation to (b), Trustpower submitted that the 2013 extension of the definition of a UTS to include hedge markets was problematic and that decoupled settlement of spot and derivatives markets could increase perceptions of risk associated with operating in the electricity market. Trustpower encouraged the Authority to issue guidelines as to when and how it might open hedge contracts or alternatively to reconsider introducing default hedge contract terms that would require resettling the contracts in designated circumstances. Trustpower submitted that 'requiring default contract terms would provide certainty regarding the outcomes of a UTS and not undermine the ASX' (p.3).

3.120 Trustpower submitted in relation to (c) that it was no longer clear that the Authority should be both the rule-maker and decision-maker in respect of UTS decisions. Trustpower submitted that when UTSs were first introduced, the view was that the rule-maker would be better positioned to respond in the necessary timeframe, and therefore also act as a decision-maker. Trustpower submitted that because a specific timeframe no longer applies, the Authority's role should be as an investigator-prosecutor only, with decision-making made by an independent Rulings Panel. Trustpower also questioned whether separate processes were really required under the trading conduct and UTS provisions.

3.121 The Authority notes that other participants also raised concerns about the length of time taken to resolve the UTS, including Contact, Fonterra, Mercury, and Meridian. Meridian, for example, suggested that the Authority should review and streamline the process for future UTS investigations. Meridian also submitted that decoupling of spot and derivative markets might not arise if prices during the UTS period are not finalised.

The Authority's decision

3.122 The Authority appreciates the feedback on the investigation and decision process for the UTS and will consider what steps should be undertaken to improve transparency, certainty, and timeliness in resolving future UTSs, separate to the current decision. In particular, the Authority may consider what steps need to be taken to ensure greater coherence between the spot and derivatives markets if any resettlement is undertaken in future.

Other miscellaneous issues

3.123 This sub-section briefly describes several miscellaneous issues raised by submitters and provides some brief responses from the Authority.

3.124 Fonterra submitted that some of the additional consequences of the UTS, such as the cost of emissions from additional thermal dispatch and the reduced security of supply in the North Island, should be taken into consideration in the design of the actions to correct.

3.125 In response, the Authority notes that the UTS provisions seek to correct the situation that has arisen in the wholesale market and that extending the actions to correct to the additional consequences would be outside of this scope. Identifying the consequences of the UTS, and disentangling those consequences from other considerations, would also be problematic and would prolong the resolution of the UTS.

3.126 Several submitters noted that there may have been a 'competitive response' from other generators to different offer behaviour by the South Island hydro generators, eg if the offer cap had been imposed in real time. Nova, for example, makes this observation in relation to its peaking generation station McKee. Meridian (cross-submission, pp 9-10) raised the issue of competitive response in relation to excess spill, submitting that other integrated retailers might have lowered their offer prices to ensure that they are dispatched to cover their retail contracts. Meridian submitted that competitive response might result in lower reductions in excess spill than expected. (Although the hydro spill consequences arising from such competitive responses are ambiguous, greater supply would be expected to result in lower spot prices.)

3.127 The Authority agrees with submitters that competitive response from other generating stations may have occurred if the UTS offer cap had been applied in real-time. However, the Authority considers that such competitive response cannot be perfectly replicated in the actions to correct the UTS. The actions are, in this respect, an approximation to the outcomes that would have occurred if more usual competitive pressures had arisen during the UTS period.

Operational processes to resolve the 2019 UTS

What the Authority proposed

3.128 The Authority proposed the following process to revise offers, final prices and final reserve prices, and settlement:

(a) the Authority would determine revisions to offer prices and offer volumes for the 48 trading periods of each of the relevant days in the UTS period for the relevant generating stations;

(b) reset offers would be provided to the pricing manager who would then use their interface to the system operator's SPD software to calculate revised final prices and final reserve prices;[20]

[20] Transmission constraints would be taken as given from the original UTS period.

(c) the wholesale information and trading system (WITS) would be used to publish the final prices and final reserve prices;

(d) the reconciliation manager would provide data on the electricity generated and consumed by traders, as recorded in December 2019;

(e) the Authority would direct the FTR manager to recalculate rentals and provide that information to the clearing manager to enable the clearing manager to resettle FTR contracts for the period;

(f) the revised final prices and final reserve prices and original reconciliation data would be passed to the clearing manager to identify the payments that need to be made and received, adjusting for the payments originally made or received; the clearing manager would invoice traders for these amounts, and would make payments to traders who were owed money;

(g) the clearing manager would be directed to scale revised settlement payments by a suitable interest rate to account for the delay;

(h) the Authority would provide information to the clearing manager about which generators are eligible for constrained on compensation and that compensation would also be resettled;

(i) the Authority would direct Transpower, as grid owner, to revise distributions of residual loss and constraint excess in relation to the UTS period to transmission customers (distributors, large consumers directly connected the grid, and generators);

(j) the Authority consulted on the possibility of instructing retailers to reimburse consumers that were on variable price terms for any over-payment during the UTS period.

3.129 The Authority also consulted on the following five questions (Q18-Q22) related to the implementation of the UTS correction, repeated here verbatim.

Q18: How should the Authority use its powers under Part 5 in relation to LCE payments?

Q19: Should the Authority use its powers under Part 5 of the Code to direct retailers to reimburse consumers that had contracts on variable price terms? What, if any, action should the Authority take in relation to variable price contracts?

Q20: How should any resettlement arising from the actions to correct the UTS be implemented?

Q21: If there is a resettlement, what window of time after invoicing should be allowed for traders to meet their obligations?

Q22: Please provide feedback on the operational implementation of the proposed actions to correct the UTS, including the interest rate that should be used to scale payments.

3.130 This sub-section outlines feedback on these operational details and questions and provides some responses. The Authority's decision and its outline of the mechanisms used to implement the correction are contained in section 4. NZX and the System Operator provided submissions about the operational implementation of the UTS and their views are incorporated in the following section.

Submitters' views

3.131 Q18, regarding the proposal to resettle LCE payments, was uncontroversial and, where directly discussed, was generally supported by submitters that responded to this question (ie, Neil Walbran, Transpower, Claimants, Meridian, Pulse.)

3.132 The views on Q19, regarding whether the Authority should use its powers to direct retailers to reimburse consumers on contracts with variable price terms, were roughly evenly split. Walbran and Meridian submitted that the Authority should direct retailers to reimburse consumers on variable price terms while Contact and Nova submitted that the Authority should not specifically direct retailers to reimburse customers that had contracts on variable (spot) price terms.

3.133 Walbran suggested it was important for consumers to receive a benefit from the UTS price recalculation. Meridian noted that in principle all parts of the market should be directed to resettle based on the recalculated final prices to restore the normal operation of the market. Contact submitted that it expected reimbursement to occur for consumer contracts with variable price terms and considered direction unnecessary. Nova submitted that the Authority should not override existing contracts, as there are mechanisms for resolving disputes either directly with the retailer or via Utilities Disputes Limited. Nova noted that reimbursement becomes complex when taking into account customer switches and any other disputes or credit issues. Nova also noted that retailers may be incentivised to reimburse customers given the [likely] media attention on the UTS.

3.134 Q20, regarding how any resettlement should be implemented, was addressed in seven submissions. Walbran submitted that the approach seemed reasonable (p.4) and submitted that it should be implemented as simply and quickly as reasonably practical to restore market confidence (p.2). Transpower submitted that the correction process should run out of sync with codified business-as-usual (BAU) processes until the pricing outputs from the correction process are known and can be incorporated into BAU washup processes (p.6). NZX submitted that the resettlement ought to take place within two calendar years of December 2019 and be resettled as an additional washup as per subpart 6 of Part 14 of the Code (p.4). Enel X did not explicitly submit on the operational implementation, other than to note that the reserves market should not be resettled. Contact agreed that implementing resettlement might take several months and suggested traders be provided sufficient time to allow for any liquidity implications (p.9). Nova suggested that resettlement should be implemented via a separate invoice/credit note (p.10). Meridian submitted that it was comfortable with the Authority and clearing manager immediately implementing any resettlement that results from the actions to correct the UTS (p.20).

3.135 Q21, regarding the window of time after invoicing which should be allowed for traders to meet their obligations, was also discussed in a small number of submissions. Walbran submitted the settlement period should be kept as short as is practical (suggesting a three-month window would be reasonable) (p.4). As noted above, NZX considered resettlement should follow standard washup procedures (p.4). Contact suggested that affected parties 'should be provided an extended settlement period of two months' (p.9). Nova suggested a shorter 30-day period from the date of invoice to settlement (p10). Meridian submitted that a window of time is unnecessary because resettlement has been signalled for a long time and proposed that usual processes be followed as for any other invoice (p.10). Pulse submitted sufficient time should be allowed for the one-off adjustment and suggested that the reconciliation wash-up process might provide a guide as to an appropriate timeframe (p.7).

3.136 Q22, seeking feedback on the operational implementation of the proposed actions to correct, elicited a few suggestions from submitters, as reported in the paragraphs below.

3.137 NZX noted that it would likely take at least 2 months to perform all of the required actions including development, unit and system testing, audit, documentation, reporting and deployment (p.4). Transpower provided specific comments on the resettlement of LCE payments, and additional comments in the body of its submission about steps that would need to be implemented.

3.138 Nova suggested that the clearing manager might need to confirm with parties that the terms of a hedge settlement agreement (HSA) provided for the redetermination of the settlement amount (and suggested that it might require a certificate signed by both parties) (p.10).

3.139 Meridian suggested that the implementation steps appear reasonable but suggested that additional steps should be added to direct the resettlement of derivatives contracts based on revised nodal prices (p.20). Meridian suggested that the interest used to scale payments should be the bank bill rate calculated daily from the original payment due date until the date of resettlement, less any withholding tax and compounded at the end of each calendar month (p.21). Pulse suggested that the interest rate used in default distributor agreements between distributors and retailers could be used to scale payments (p.7). Mercury acknowledged, and was supportive of, a suitable interest rate being applied, but did not specify how it should be determined.

The Authority's decision

3.140 The Authority's responses to the suggestions on the implementation of the actions to correct is largely implicit in the decisions outlined in the following section. For clarity, the Authority briefly addresses each of the questions in turn.

3.141 Regarding LCE (Q18), and in accordance with submissions, the Authority has decided to resettle LCE and residual LCE flows as proposed. LCE results from settlement prices and, in resettling those prices, the Authority considers it appropriate to account for the corresponding impact on LCE.

3.142 Regarding reimbursement of consumers (Q19), the Authority considers that retailers should meet their contractual obligations to consumers with variable tariff agreements but has decided, in agreement with Nova and Contact's submissions, that the contracting parties should determine whether these agreements need to be resettled. The Authority notes that final prices will be revised as part of the actions to correct the UTS. This approach is consistent with that taken for derivatives. As per the UTS provisions, the Authority has focused on correcting outcomes in the wholesale market and considers that participants and contracting parties should determine for themselves how these corrections flow through to other contractual obligations.

3.143 As for the implementation of resettlement (Q20), the Authority has decided to follow processes similar to washups, as outlined in Part 14 of the Code. (See further discussion in section 4.)

3.144 Regarding the window of time for payment (Q21), the Authority notes that clause 14.18(2) of the Code requires the clearing manager to advise participants on the 9th business day of the month following the billing period of each amount owing/payable, and clause 14.31 requires payment by the 20th day of the month (or the next business day), implying fewer than 11 calendar days between notification and payment deadline. In light of submissions, the Authority has decided to allow 20 business days between invoice notification and payment deadline, balancing implementation concerns about resettlement payments against the need to restore the normal operation of the market as soon as possible. The payment deadline is not expected to coincide with the usual billing cycle. (Table 11 details the intended timeline from here.)

3.145 In terms of the operational implementation of the actions to correct (Q22), the Authority has decided that interest payments should be based on the default interest rate as defined in the Code. (See further discussion in section 4.)

3.146 One additional comment is made in relation to Nova's comment about the implementation of HSAs. Schedule 14.4 refers to final prices in relation to the specification of the floating price used to compute settlement. Consequently, HSAs would resettle once the final prices are revised as part of the actions to correct the UTS.

4 Actions to correct the December 2019 UTS

The actions to correct

4.1 The Executive Summary summarised the actions to correct the UTS and facets of the actions were discussed in section 3. This section collates in one place the actions to correct the UTS and turns to the directions required to implement those actions.

4.2 As discussed in the consultation paper, the Authority considers that there is no scope to un-spill the excess spill that occurred during the UTS period, and the Authority is therefore not taking any actions to address excess spill. The Authority also cannot identify and restore the sequence of financial trades that would have occurred if the market had been operating normally during the UTS period. The Authority's actions to correct do not address environmental issues associated with increased thermal generation during the UTS period because this would be outside of the scope of an action to correct the threat to confidence in the wholesale market.

4.3 The Authority has decided that the actions to correct the December 2019 UTS are most properly directed towards the immediate outcomes in the wholesale market during that period. The core action to correct the UTS is to revise settlement of the wholesale market for the 3-27 December 2019 UTS period.

4.4 The calibration of the re-settlement is determined by placing a cap on the offer prices of 9 South Island hydro generating stations, constraining offer prices to be no more than $13.70/MWh for all trading periods in the UTS period. These offers are then fed into the SPD model to approximate the final prices and final reserve prices that would have eventuated in the absence of the UTS.

4.5 The volumes offered and consumed are maintained at their original levels to compute the revised prices.

4.6 The South Island hydro generating stations with capped offers are: Aviemore; Benmore; Clyde; Manapōuri; Ōhau A, B, C; Roxburgh; and Waitaki.

4.7 Offers from North Island generators are <u>not</u> being revised.

4.8 The instantaneous reserves market is being resettled, reflecting the fact that reserve and energy offers are co-optimised in the SPD model.

4.9 Instantaneous reserve offers are not being revised.

4.10 Revising prices should result in derivatives contracts being resettled, except where otherwise provided. The Authority's view is that the terms and conditions of those contracts should determine their revision or otherwise. The Authority notes that derivatives contracts not subject to New Zealand law and contracts that explicitly rule out resettlement are unlikely to be resettled as discussed elsewhere in this decision paper. The Authority has noted the jurisdictional and other difficulties inherent in resettling some (eg ASX-traded) derivatives contracts.

4.11 The resettlement of the wholesale market for the UTS period will proceed using washup processes similar to that outlined in subpart 6 of Part 14 of the Code. Other aspects of the actions to correct are specified in the remainder of this section.

Directions relating to implementation of the actions to correct the UTS

4.12 Under clause 5.2 of the Code, the Authority **directs** NZX, Energy Market Services (EMS), and Transpower, in their roles as participants, to collaborate to implement the correction of the UTS.

4.13 The Authority invites NZX, EMS, and Transpower to submit change requests or Statements of Work (as outlined in the non-functional specifications of their service provider agreements) to the Authority in relation to the costs of implementing the actions to correction the UTS.

4.14 The Authority **directs** participants to make any payments required of them as specified in invoices sent by the clearing manager or to dispute the invoices following the processes set out in Part 14 of the Code (noting the direction in paragraphs 4.27-4.28 below regarding the scope of allowable disputes).

4.15 The Authority **directs** the pricing manager to retrieve the daily case files for the UTS period from its archives or similar, and update the offers with the offer price cap outlined in this decision paper for the 9 South Island hydro generating stations with points of connection in Table 10.

Table 10 Hydro generating stations' points of connection subject to the offer price cap

AVI2201 AVI0	BEN2202 BEN0	CYD2201 CYD0
MAN2201 MAN0	OHA2201 OHA0	OHB2201 OHB0
OHC2201 OHC0	ROX1101 ROX0	ROX2201 ROX0
WTK0111 WTK0		

* Note that Roxburgh generating station makes offers at two points of connection.

4.16 The Authority **directs** the system operator and pricing manager to correct any errors, infeasibilities, or high spring washer pricing situations and use the revised offers as an input in the SPD model to compute revised final prices and final reserve prices for the period starting 0000 hours on 3 December 2019 and ending 2400 hours on 27 December 2019.

4.17 The Authority **directs** the pricing manager to follow usual processes, to the extent possible, and provide the revised final prices and final reserve prices to the WITS, FTR and clearing managers, the system operator, and the Authority.

4.18 The Authority **directs** the WITS manager to publish the final prices and final reserve prices to all participants that would usually receive such pricing information.

4.19 The Authority **directs** the clearing manager to make constrained on payments to the generating stations and reserves providers that were dispatched when their offer prices were above the revised final prices, except for the hydro generating stations identified in paragraph 4.15.

4.20 The Authority **directs** the FTR manager to compute the amount of loss and constraint excess that must be applied to the settlement of FTRs for the December 2019 month, given the revised final prices, and provide that information to the clearing manager as per usual processes.

4.21 The Authority **directs** the FTR manager to recalculate residual loss and constraint excess for the December 2019 month and to inform the clearing manager as per usual processes.

4.22 The Authority **directs** the system operator to recalculate the ancillary serves settlement amounts for the month of December 2019, and provide that information to the clearing manager as per usual processes.

4.23 The Authority **directs** the system operator to incorporate revised constrained on/off amounts into monthly settlement information sent to the clearing manager.

4.24 The Authority **directs** the clearing manager to resettle all relevant amounts owing (see paragraph 4.39), including amounts for hedge settlement agreements, ancillary services, FTR settlements and residual loss and constraint excess paid to Transpower for the UTS period and for each revision of the UTS period.

4.25 As per clause 14.25 of the Code, participants have up to two years from the invoice date to dispute the amounts (dollars) notified to them by the clearing manager.

4.26 The Authority **directs** the clearing manager to following usual resolution processes if an amount is disputed, though noting additional directions in paragraphs 4.27-4.28.

4.27 The Authority **directs** the clearing manager to disregard disputes relating to the resettlement of the wholesale market for the UTS period unless processing or data errors are the source of the dispute. Disputes about the level of the offer price cap applied to hydro generators or the generators subject to the offer price cap are not to be considered.

4.28 The Authority also **directs** the clearing manager that no further volume-related revisions are to be undertaken for the UTS re-settlement invoices, noting the 14-month timeframe for revisions to volumes during the UTS period has ended.

4.29 The Authority **directs** the clearing manager to resettle each revision, using the revised final prices and final reserve prices. Resettlement amounts will accrue interest dating back to the payment dates for the revision invoices in accordance with clause 14.38(2) of the Code.

4.30 The Authority **directs** Transpower to recompute the allocation of residual loss and constraint excess due to distributors and direct consumers, using the usual LCE payment methodology, and to credit or debit grid charges accordingly, in line with usual processes and as soon as practicable.

4.31 The Authority will provide letters to NZX, Energy Market Services, and Transpower outlining its directions and expectations about the implementation of the UTS correction (in the form attached as Appendix A, Appendix B, and Appendix C).

4.32 The Authority **directs** NZX, Transpower and the FTR manager to make any process, system or software changes required to implement the actions to correct the UTS within the timeframe outlined in the letters in the appendices. If there are impediments to this timeline the Authority **directs** that it is to be advised as early as possible and may provide an extension to the timeframe if warranted.

4.33 Table 11 outlines the expected timeframe for the implementation of the actions to correct the UTS.

Table 11 Expected timeline

Date	Milestone
17 August 2021	Authority announces actions to correct
August-November	NZX/Transpower/FTR Manager develop and apply processes and systems to enable resettlement
24 November 2021 (UTS invoice date)	Clearing manager notifies participants of their obligations
20 December 2021 (UTS resettlement date)	Invoices to be settled – amounts owed to the clearing manager to be received by the clearing manager in cleared funds by 1:00pm and amounts to be paid by the clearing manager to be paid by 4:00pm
First feasible grid invoice date after 24 November 2021	Resettlement of residual LCE will be undertaken at the next available transmission/grid invoice date

4.34 The Authority will arrange for an independent audit of the processes and software used to implement the actions to correct the UTS.

4.35 The Authority **directs** MOSPs to provide the auditors with all assistance required to enable them to fulfil their obligations to the Authority.

4.36 The Authority **directs** MOSPs to disregard usual audit obligations under clauses 3.16-3.18 of the Code in relation to any software changes required by the UTS implementation.

4.37 The Authority **directs** the clearing manager that the resettlement prompted by the actions to correct the UTS should be invoiced separately and conducted separately relative to business-as-usual processes, as submitted by Transpower (p.2).

4.38 The Authority **directs** the clearing to manager to separately itemise the resettlement amounts for each revision invoice but collate them into a single invoice payable for the UTS period.

4.39 As submitted by NZX, the UTS correction is to be implemented as an additional washup in line with the processes outlined in Subpart 6 of Part 14 of the Code.

4.40 The Authority **directs** the clearing manager to determine the amounts owing and payable in accordance with clauses 14.19 and 14.20 of the Code and advise participants by 12 November 2021, unless otherwise agreed with the Authority. These washup settlement amounts are for:

(a) electricity

(b) instantaneous reserves

(c) constrained off compensation

(d) constrained on compensation

(e) ancillary services in relation to frequency keeping

(f) hedge settlement agreements

(g) FTRs

(h) loss and constraint excess, and

(i) residual loss and constraint excess.

4.41 For the avoidance of doubt, the Authority **directs** the clearing manager <u>not</u> to revise must-run dispatch auction revenue, black start, over frequency reserve, extended reserve, and voltage support settlements.

4.42 The Authority **directs** the clearing manager that the generating stations identified in Table 10 are <u>not</u> eligible for constrained on or off payments for energy or reserves or frequency keeping.

4.43 The Authority **directs** the clearing manager to settle amounts owing in accordance with clause 14.31 of the Code.

4.44 As per clause 14.38(2), washup amounts accrue daily interest (less any deduction for resident withholding tax) based on the bank bill bid rate from the date payments were made for the UTS period (ie, the dates payment was made for the original settlement and each revision invoice).

4.45 The Authority **directs** that any non-payment of washup amounts will be resolved via the default process outlined in clause 14.41. For the avoidance of doubt, any amounts owing as a result of these actions to correct are amounts owing to the clearing manager under Part 14 of the Code. Failure to pay is an event of default under Subpart 7 of Part 14 of the Code and the clearing manager has all the remedies available to it under Subpart 7.

4.46 Participants may dispute amounts owing or payable as per clause 14.25 (noting the direction in paragraphs 4.27-4.28 above regarding the scope of allowable disputes).

4.47 The Authority **directs** the clearing manager to use original reconciliation volumes in conjunction with revised final prices and final reserve prices to effect the resettlement.

4.48 Given that an amount owing based on the volume information was previously advised under Part 14, the Authority **directs** that participants may not commence disputes relating to volume information, given clause 15.29.

4.49 As noted in the executive summary, the Authority **directs** the clearing manager to disregard prudential security requirements for all amounts owing as a result of this UTS resettlement between the UTS invoice data and the UTS resettlement date.

4.50 The Authority **directs** the clearing manager to disregard the impact of the UTS correction on final prices in relation to FTR initial margin requirements.[21] The Authority notes that the influence of the December 2019 month on initial margin requirements will be of limited duration.

4.51 Table 12 outlines the responsibilities of the system operator, the pricing and clearing manager, and the FTR manager and the steps that will need to be undertaken to implement the actions to correction the UTS. The cells of each row can be implemented simultaneously, but each row is generally dependent on (at least some) preceding cells from previous rows.

Table 12 Implementation of the actions to correct – simplified process map

System Operator (SO) Grid Owner (Transpower)	Pricing / clearing / reconciliation / WITS / reconciliation manager (NZX)	FTR Manager (EMS)	Electricity Authority
SO and Transpower as grid owner make any necessary process and system changes required to implement the actions to correct the December 2019 UTS	Pricing / clearing / reconciliation/ WITS managers make any necessary process and system changes required to implement the actions to correct the December 2019 UTS	FTR manager makes any necessary process and system changes required to implement the actions to correct the December 2019 UTS	Authority contracts with independent party to audit software changes, methodology and processes and outputs of pricing, clearing and FTR managers and system operator

21 See the FTR policy on prudential requirements and the clearing manager's FTR prudential security assessment methodology, https://www.ftr.co.nz/documents/10179/66236/3.1.4+FTR+Policy+-+Prudential+Requirements+-+24112014+-+Final.pdf/e18dc46e-e96d-4754-8f3a-4915b9aa5066 and https://www.nzx.com/rails/active_storage/blobs/eyJfcmFpbHMiOnsibWVzc2FnZSI6IkJBaHBBbHNQIiwiZXhwIjpudWxsLCJwdXIiOiJibG9iX2lkIn19--49d2d2659f74aa1b5548326be57f99ceec8600a6/FTR_Prudential_Methodology__November_2020_.pdf.

System Operator (SO) Grid Owner (Transpower)	Pricing / clearing / reconciliation / WITS / reconciliation manager (NZX)	FTR Manager (EMS)	Electricity Authority
	Pricing manager retrieves offer case files for the UTS period from its own archives.		Authority provides pricing manager with: 1) magnitude of offer price cap and 2) generating stations subject to offer price cap. Authority makes available its own vSPD analysis on final prices from corrected energy offers.
SO supports pricing manager with final price calculation (as/if needed)	Pricing manager updates the (energy) offer information for the UTS period and re-computes final prices using SPD Pricing manager uses vSPD offers as a cross-check on pricing computations.		
	Pricing manager sends final prices (for energy and reserves) for the UTS period to Transpower, EMS, the Authority, and the WITS manager		
SO re-runs ancillary services settlement for reserves (reflecting dispatched reserves and revised IR prices)	WITS manager disseminates final prices to clearing manager, FTR manager, system operator, and industry participants more generally		Authority independently verifies final prices using inputs and vSPD. Any discrepancies to be resolved by Authority and Pricing Manager

System Operator (SO) Grid Owner (Transpower)	Pricing / clearing / reconciliation / WITS / reconciliation manager (NZX)	FTR Manager (EMS)	Electricity Authority
SO provides revised reserve settlement values to clearing manager		FTR manager calculates retained loss and constraint excess for FTR settlement as per clause 14.16 and schedule 14.3, and provides LCE and residual LCE data to clearing manager (requires small software change)	
SO incorporates revised constrained on/off amounts into monthly settlement information sent to clearing manager	Clearing manager computes constrained on payments for all stations except those subject to the offer price cap.		Authority reviews independent audit findings and resolves any issues with the pricing, clearing and FTR managers and system operator
Transpower determines residual LCE payments to be allocated to distributors and direct consumers using its usual LCE payment methodology. Transpower, as per usual, will provide a credit/debit against grid charges once residual LCE has been received.	Clearing manager invoices and makes payments to resettle energy, instantaneous reserves, constrained off; constrained on; ancillary services; HSAs; FTRs, LCE and residual LCE; and other payment flows for the UTS period.		

4.52 The process concludes with participants meeting any resettlement obligations as notified by the clearing manager and invoking any default procedures as required.

5 Conclusion

5.1 The Authority acknowledges that the undesirable trading situation of December 2019 was complex and that it took the Authority a lengthy period to investigate and reach a decision. The Authority thanks participants and submitters for their participation in the process to resolve the December 2019 UTS. Any questions about the implementation of the actions to correct over the remainder of 2021 can be directed to uts2019@ea.govt.nz.

Appendix A Letter to NZX

17 August 2021

Pricing and Clearing Managers
NZX
11 Cable Street
Wellington 6011

Attention: Shane Dinnan

Dear Shane

This letter outlines the Electricity Authority's directions to NZX, as the pricing, reconciliation and clearing managers, to resolve the 3-27 December 2019 undesirable trading situation (UTS). These directions are issued based on the Authority's powers to direct participants under Part 5 of the Code.

As published in our 17 August 2021 decision paper on the actions to correct the UTS, the Authority is directing NZX, Transpower, and Energy Market Services to collaborate to implement the actions to correct the UTS. The Authority is also directing Transpower and Energy Market Services to provide the pricing and clearing manager with every assistance required to achieve the timeframes noted in the decision paper.

The Authority is directing the clearing manager to invoice participants for the resettlement of the UTS by 24 November 2021 and to receive or credit monies by 20 December 2021, unless otherwise agreed with the Authority. Any deviation from the timeframe must be communicated to the Authority as early as practicable.

The Authority is directing NZX to follow the implementation guidelines outlined in the 17 August 2021 decision paper on the actions to correct the UTS. See especially section 4 and the tasks outlined in Table 12 of the paper.

The Authority will appoint auditors to review and audit the methodology, process and system changes required to implement the UTS. The Authority is directing NZX to provide them with all assistance required to fulfil their obligations.

The Authority invites NZX to submit a change request or statement of work in relation to these directions, as outlined in the non-functional specifications of your service provider agreement.

If NZX has any concerns or requires clarification in relation to these directions, then the first point of contact are the staff of the Market Operations team at the Authority. These staff can be reached by email at uts2019@ea.govt.nz.

Thank you for your assistance in expediting the implementation of these actions to correct the UTS.

Best regards

Sarah Gillies
General Manager Legal, Monitoring and Compliance

Level 7, Harbour Tower, 2 Hunter Street, PO Box 10041, Wellington 6143, New Zealand TEL + 64 4 460 8860 FAX + 64 4 460 8860 WEB www.ea.govt.nz

Appendix B Letter to Transpower

17 August 2021

System Operator
Transpower
22 Boulcott Street
Wellington 6011

Attention: Stephen Jay

Dear Stephen

This letter outlines the Electricity Authority's directions to Transpower as the system operator (and the grid owner that receives residual loss and constraint excess from the clearing manager) to resolve the 3-27 December 2019 undesirable trading situation (UTS). These directions are issued based on the Authority's powers to direct participants under Part 5 of the Code.

As outlined in our 17 August 2021 decision paper on the actions to correct the UTS, the Authority is directing Transpower, NZX, and Energy Market Services to collaborate to implement the actions to correct the UTS.

The Authority is directing the system operator to provide every assistance required to enable the clearing manager to invoice participants for the resettlement of the UTS by 24 November 2021 and to receive or credit monies by 20 December 2021, unless otherwise agreed with the Authority.

The Authority is directing Transpower to follow the implementation directions outlined in the 17 August 2021 decision paper on the actions to correct the UTS. See especially section 4 and the tasks outlined in Table 12 of the paper.

The Authority will appoint auditors to review and audit the methodology, process and system changes required to implement the UTS. The Authority is directing Transpower to provide them with all assistance required to fulfil their obligations.

The Authority invites Transpower to submit a change request or statement of work in relation to these directions, as outlined in the non-functional specifications of your service provider agreement.

If Transpower has any concerns or requires clarification in relation to these directions, then the first point of contact are the staff of the Market Operations team at the Authority. These staff can be reached by email at uts2019@ea.govt.nz.

Thank you for your assistance in expediting the implementation of these actions to correct the UTS.

Best regards

Sarah Gillies
General Manager Legal, Monitoring and Compliance

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Appendix C Letter to Energy Market Services

17 August 2021

FTR Manager
Energy Market Services
Waikoukou
22 Boulcott Street
Wellington 6011

Attention: Richard Rowell

Dear Richard

This letter outlines the Electricity Authority's directions to Energy Market Services (EMS) as the FTR manager to resolve the 3-27 December 2019 undesirable trading situation (UTS). These directions are issued based on the Authority's powers to direct participants under Part 5 of the Code.

As outlined in our 17 August 2021 decision paper on the actions to correct the UTS, the Authority is directing EMS, Transpower, and NZX to collaborate together to implement the actions to correct the UTS.

The Authority is directing the FTR manager to provide every assistance required to enable the clearing manager to invoice participants for the resettlement of the UTS by 24 November 2021 and to receive or credit monies by 20 December 2021.

The Authority is directing EMS to follow the implementation guidelines outlined in the 17 August 2021 decision paper on the actions to correct the UTS. See especially section 4 and the tasks outlined in Table 12 of the paper.

The Authority will appoint auditors to review and audit the methodology, process and system changes required to implement the UTS. The Authority is directing EMS to provide them with all assistance required to fulfil their obligations.

The Authority invites EMS to submit a change request or statement of work in relation to these directions, if required, as outlined in the non-functional specifications of your service provider agreement.

If EMS has any concerns or requires clarification in relation to these directions, then the first point of contact are the staff of the Market Operations team at the Authority. These staff can be reached by email at uts2019@ea.govt.nz.

Thank you for your assistance in expediting the implementation of these actions to correct the UTS.

Best regards

Sarah Gillies
General Manager Legal, Monitoring and Compliance

Level 7, Harbour Tower, 2 Hunter Street, PO Box 10041, Wellington 6143, New Zealand TEL + 64 4 460 8860 FAX + 64 4 460 8860 WEB www.ea.govt.nz