Meridian submission
Proposed actions to correct 2019 UTS

27 April 2021

This submission by Meridian Energy Limited (**Meridian**) responds to the Electricity Authority (**Authority**) consultation paper on its proposed actions to correct the undesirable trading situation (**UTS**) that occurred between 3 and 27 December 2019.

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Nothing in this submission is confidential.

Executive Summary

The Authority has decided that a confluence of factors constituted a UTS between 3 and 27 December 2019. This submission does not seek to relitigate the Authority's final UTS decision.

Meridian agrees with the Authority that if spot market outcomes between 3 and 27 December 2019 are to be retrospectively adjusted, the best way to do that would be:

- to cap offers from South Island hydro generators (capping only Waitaki and Clutha offers is reasonable given the offers from other hydro schemes);
- use the market scheduling, pricing and dispatch tool (vSPD) to re-solve each trading period with the offer caps in place;
- revise and replace the final prices already published with final prices calculated via the re-solve; and
- use the revised final prices and original reconciliation data to resettle the market and adjust payments made and received by participants.

The Authority proposes a $13.70 / MWh offer cap. The rationale for the $13.70 / MWh offer cap is that it is the level necessary to achieve the hydrological outcome sought by the Authority – elimination of the 28 GWh of "excess spill" the Authority found took place over the UTS period by notionally generating an additional 28 GWh from South Island hydro stations over the UTS period. There is no other basis for an offer cap at that level. However, the $13.70 / MWh offer cap, according to the Authority's analysis, in fact reduces spill by 36.1 GWh over the UTS period. This would result in around 30 percent more hydro generation than the Authority calculated was physically and legally feasible while ensuring the relevant hydro stations could continue to comply with the Resource Management Act and with other hydrological, operational, and market constraints. An action to correct that delivered this outcome would be a departure from the Authority's final UTS decision and the analysis that supported that decision.

Meridian agrees in principle with the concept of an offer cap as a means of correcting a UTS. The cap needs to be at a level that:

- is consistent with the Authority's analysis to date;
- would have resulted in a feasible outcome in the real world; and
- corrects the UTS identified by the Authority and restores the normal operation of the market.

It would be consistent with these principles for the Authority to construct an offer cap based on the actual offers made during similar hydrological conditions in the past when a UTS was not found to have occurred. This would best represent the restoration of normal market operations and would therefore be most closely aligned with Part 5 of the Code.

However, the Authority prefers instead an offer cap that delivers a specific hydrological outcome – elimination of 28 GWh of spill. According to the Authority's analysis the offer cap that delivers this outcome is $19.98 / MWh. Meridian submits that this should be the offer cap applied by the Authority and not the $13.70 / MWh indicated.

The spot market is only one part of the wholesale market. To the extent possible, the Authority should ensure that the revised final prices also flow into the settlement of derivatives. Meridian agrees with the Authority's view that "hedge markets should be allowed to fully carry out their role of managing risk."[1] To achieve this outcome the Authority should direct the resettlement of derivatives to the extent possible under its powers. Where the spot market and derivative contracts settle based on different final prices, the proposed action to correct will not restore the normal operation of the market and this difference may lessen rather than restore confidence in the wholesale market. Such differences in the basis for wholesale market settlement should be minimised by the Authority to the extent possible.

[1] Proposed actions to correct, page iv

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Full wholesale market resettlement should be the goal

Adjusting offers and using vSPD to recalculate final prices is the best option

Meridian agrees with the Authority that the preferred option should be to correct the UTS by adjusting offers and recalculating final prices in the electricity market (Option O). This is far preferable to a direct reset of prices themselves (Option P) or an ‘off-market’ wash-up of spot electricity payments to and from the clearing manager (Option S).

Adjusting offers and using the vSPD tool to recalculate final prices would produce the outcome most closely aligned with the normal operation of the market and would properly account for nodal prices and the complexity of losses and constraints. Other options would involve more arbitrary judgements by the Authority to determine the level of nodal prices or the extent of wash-ups and would not reflect the normal operation of the electricity market.

Under the normal operation of the market, everything settles based on final prices

We agree with the Authority that any proposed actions to correct the UTS must aim to restore the normal operation of the wholesale market.

Under normal market operation, final spot prices are published and spot market settlement occurs based on those final prices. However, the spot market is only one part of the wholesale market. Derivative contracts also settle based on published final spot prices. Participants have confidence in this process. To restore normal market operations, any proposed action to correct must therefore clearly result in recalculated *final* prices. That way, to the extent possible, the entirety of the wholesale market will resettle as it would normally. Any action to correct that results in some parts of the wholesale market resettling but not others (for example resettlement of the spot market but not derivatives) will not represent the normal operation of the market. Indeed, such a situation would be unprecedented and would *never* occur in the normal operation of the market.

In the normal operation of the market, hedge settlements balance or net out against spot settlements, that is their purpose. Therefore, a fully hedged participant would be ambivalent to the level of spot prices. However, if derivatives do not resettle with the spot market then some unjustifiable wealth transfers will occur between the counterparties to contracts.

Consider the example of a contract for difference (CfD) of 1 MW between a generator as a seller and a retailer as a buyer. For this example, assume a strike price for the CfD of $80 / MWh. Now also assume an original final spot price of $50 / MWh, which is subsequently revised and replaced by a new final spot price of $40 / MWh. If the spot price is below the strike price, the retailer would pay the generator the difference between the spot and strike prices. The result is that the parties will settle at $80, regardless of the spot price and the parties are fully hedged for that 1 MW. However, as can be seen in the partial resettlement example below, if the CfD and spot market settle at different prices there is a windfall gain to one party that was never intended.

Original settlement at $50 / MWh

Retailer		Generator	
Spot revenue (1MW)	CfD revenue (1MW)	Spot revenue (1MW)	CfD revenue (1MW)
-$50	-$30	$50	$30
TOTAL -$80		TOTAL $80	

Full resettlement at $40 / MWh

Retailer		Generator	
Spot revenue (1MW)	CfD revenue (1MW)	Spot revenue (1MW)	CfD revenue (1MW)
-$40	-$40	$40	$40
TOTAL - $80		TOTAL $80	

Net revenues unchanged, parties are hedged at $80 / MWh regardless of spot price changes

Resettlement of spot to $40 / MWh but CfD does not resettle

Retailer		Generator	
Spot revenue (1MW)	CfD revenue (1MW)	Spot revenue (1MW)	CfD revenue (1MW)
-$40	-$30	$40	$30
TOTAL - $70		TOTAL $70	

Windfall benefit of $10 and unintended outcome (hedge at $80 / MWh does not result)

The wealth transfers that would result from settlement of spot and derivatives at different prices cannot be justified in principle. Ideally, the entirety of the wholesale market should resettle based on the same shared understanding of final prices. Meridian agrees with the Authority's view that "hedge markets should be allowed to fully carry out their role of managing risk."[2] Therefore, to restore normal market operations, any proposed action to correct must result in recalculated *final* prices that, to the greatest extent possible, flow through to derivative contracts.

[2] Proposed actions to correct, page iv

The Authority should direct resettlement of derivatives contracts where possible

Ideally, the Authority would go further and direct resettlement of derivative contracts based on the recalculated final prices. To that end, the Authority should:

- Be clear in its final decision to direct that the final prices already published for 3 to 27 December 2019 become null and void and are replaced by the final prices calculated and published by the pricing manager and based on the Authority's offer caps.
- Direct that derivative contracts between electricity industry participants resettle based on the new final prices.
- Encourage other derivative contracts to be resettled on the same basis.

The Authority states that "the allocation of risk implicit in derivatives contracts should be determined by the voluntary agreements of contracting parties".[3] The Authority has also said that it "sees no reason to void the allocation of risk voluntarily agreed by parties".[4] This characterisation - that directing resettlement of derivatives would "void" voluntary agreements - is inaccurate. Meridian considers a direction in respect of derivatives would affirm the intent of the hedges agreed between participants rather than leave open the possibility of wealth transfers between the parties that would never have occurred under the normal operation of the market. The reluctance to make directions in respect of derivatives also contradicts statements made by the Authority that "ideally, the settlement of derivative contracts should reflect the prices that would have prevailed if the UTS had not occurred."[5] Furthermore, it seems that the Authority does intend to direct the FTR manager so that resettlement of FTRs can occur. The Authority should not pick and choose which parts of the wholesale market to resettle, it should apply a consistently principled approach that seeks to resettle as much of the wholesale market as it can based on the same recalculated final spot prices.

At paragraph 5.61 of the proposed actions to correct paper the Authority states that:

> "A revision to final spot prices would prompt some derivative contracts to resettle, though not necessarily all. Some derivatives contracts expressly allocate the risk of

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[3] Proposed actions to correct, page iv. In previous decisions, the Authority has been comfortable overriding the voluntary arrangements of contracting parties, for example through the recent Default Distribution Agreement, mandatory market making, prohibition on save and win-backs, and indeed any Code change to compel participants to act other than how they would do so voluntarily.
[4] Proposed actions to correct, paragraph 5.62
[5] Proposed actions to correct, paragraph 5.63

> price resettlement between the parties to the contract. In other cases, the allocation of risk is not explicitly specified and must be inferred. In yet other cases the allocation of risk is opaque and would be subject to negotiation between the contracting parties."

Meridian does not consider it reasonable for the Authority to implement an action to correct that would result in such uncertainty in the market. The Authority should not knowingly create a situation that could lead to costly negotiation, and in a worst case scenario, arbitration or litigation to resolve any contractual uncertainty. The costs of this could outweigh any benefits of the regulatory intervention and it could lessen confidence in the market rather than restore confidence. The reasons given by the Authority for not making directions in respect of derivatives relate largely to exchange traded instruments (i.e. ASX contracts) that can be traded over time and for which the timing of a resettlement would be challenging. The same cannot be said of OTC contracts.

According to the Authority:[6]

> "If the wholesale electricity market were operating normally, markets for financial derivatives, including bilateral 'over the counter' (OTC) forwards, financial transmission rights, and futures and options would adjust to reflect final prices in the spot electricity market. These financial derivatives are used by participants to manage their risk positions. Ideally, the settlement of derivative contracts should reflect the prices that would have prevailed if the UTS had not occurred."

Meridian agrees this is what should ideally occur, and for the most part, the Authority has the ability to ensure that this happens. Clause 5.2(2)(c) of the Code empowers the Authority to take any action that the Authority considers is necessary to correct the undesirable trading situation including direct that trades be closed out or settled at a specified price.

[6] Proposed actions to correct, paragraph 5.63

Actions to correct must restore normal market operations

Any offer cap must be consistent with the Authority's assessment of hydrology in its earlier decision paper

The proposed actions to correct paper states that "the methodology used to establish this offer price cap follows the approach used in the December 2020 UTS Final Decision Paper". However, that is not correct – there are fundamental differences in the methodology.

Throughout the Authority's preliminary decision paper and final decision paper, the Authority applied a methodology[7] to calculate "excess spill". The methodology respected Resource Management Act requirements, operational and hydrological constraints, and market constraints (such as transmission constraints and the level of generation the market could absorb). Following this methodology, the Authority estimated 28 GWh of "excess spill" for the period 3 to 27 December 2019.[8]

The Authority next used vSPD to estimate the offer level that would result in the dispatch of an additional 28 GWh of hydro generation in the South Island. The preliminary decision paper referred to the vSPD reset as a "single offer price", while the final decision paper referred to this as an "average" offer of $13.70 / MWh for South Island hydro stations from 3 to 27 December 2019.[9]

Instead of resetting offers at a single price point or to deliver an average price of $13.70 / MWh, the Authority now proposes to apply a price *cap* to hydro generation offers from Waitaki and Clutha stations. The effect of an offer *cap* is significant. Many offers were made below the proposed cap meaning that a cap at $13.70 / MWh would have resulted in a lower average offer price or single offer price equivalent over the period of the UTS and, in the

[7] Described in detail in section 14 of the preliminary decision paper.
[8] See paragraph 7.64(b) of the final decision paper. To put this 28 GWh of "excess spill" in context, during December 2019 the scale of the inflow events meant that Meridian spilled around 1300 GWh from its hydro dams in order to safely manage the hydrology of the catchment, consistent with resource consent requirements. During the same period Meridian also generated 1150 GWh from its hydro stations. This was the most hydro generation for the month of December in Meridian's history (even more than Meridian ever generated back in the years when Meridian also operated the two Tekapo stations). The Authority's decision that 28 GWh more could have been generated needs to be seen in this context.
[9] See paragraph 14.16 of the preliminary decision paper and paragraph 7.67 of the final decision paper.

real world, has not been proven to be feasible as it would have resulted in the dispatch of more than the additional 28 GWh of hydro generation that the Authority has calculated was possible while respecting Resource Management Act and other constraints. In fact, as recreated in Figure 1 below, the Authority's analysis shows the $13.70 / MWh price cap would have resulted in the dispatch of 36.1 GWh of additional hydro generation. Therefore, the Authority is proposing an action to correct that would dispatch around 30 percent more South Island hydro generation than it previously calculated was feasible, and is proposing to do so from fewer generating stations.[10]

The Authority's only rationale for the $13.70 / MWh figure is to achieve a hydrological outcome – 28 GWh of additional South Island hydro generation (and equivalently less spill). The figure only achieves that outcome if it is applied as a reset of all offers. Using that figure as a price *cap* rather than a *reset* price for all offers does not achieve the hydrological outcome sought by the Authority. As achieving that hydrological outome is the only reason for using the $13.70 / MWh figure, the Authority's proposal to use it in a novel way that does not achieve that outcome is inappropriate.

To achieve the hydrological outcome sought, either all offers need to be reset at $13.70 / MWh or a cap should be applied that delivers an average offer price of $13.70 / MWh. This seems to be the effect of the $19.98 / MWh offer cap included in the proposed actions to correct paper and referenced throughout Appendix A. The $19.98 / MWh offer cap would result in the dispatch of the 28 GWh of additional hydro generation sought and it is not clear to Meridian why the Authority has not selected this as the preferred option, consistent with its earlier decision.

Infeasible market outcomes should not be the result of any action to correct

Meridian accepts that 28 GWh is a reasonable estimate of the additional generation that might have been dispatched over the period of the UTS with perfect hindsight and oversight of the entire market in real time. However, it is not clear that it would have been possible to generate an additional 36.1 GWh from the Waitaki and Clutha schemes while still observing the constraints of Resource Management Act requirements, operational and hydrological constraints, and market constraints (such as transmission constraints and the level of generation the market could absorb).

[10] In the final UTS decision offers were adjusted for all South Island hydro generation operated by Meridian, Contact, and Genesis. However, in the proposed actions to correct the Authority only proposes to adjust offers for the Waitaki and Clutha schemes.

The Authority has previously acknowledged the importance of resource management and operational constraints. At paragraph 7.71 of the final decision paper the Authority states:

> "Throughout our investigation into the alleged UTS we have endeavoured not to second guess generators' real time management of the flooding. As pointed out in submissions, safety of people, plant, and environments was the paramount concern of hydro generators during the flooding. Our estimate of excess spill relies on a substitution of controlled spill for generation at Benmore while all other South Island plant is held constant. We agree with a number of submitters that it is not realistic or reasonable to expect generators to behave perfectly with respect to their offers in these circumstances, given their priorities."

And at paragraph 5.43 of the proposed actions to correct paper, in discussing the potential for offer price rests below $13.70 / MWh, the Authority states that:

> "Whether even lower prices would have been feasible, given resource management and operational constraints, is difficult to determine robustly. In contrast, the $13.70/MWh price was feasible in the context of the resource management obligations that were being managed on the Waitaki River."

Here the Authority acknowledges the need for feasible outcomes and the feasibility of a $13.70 / MWh price level or reset. The leap of logic is in assuming an offer *cap* at $13.70 / MWh results in the same feasible outcome as a *reset of all offers at a single price level*. In the Authority's own words, the feasibility of an offer price cap that results in 36.1 GWh of additional generation from the Waitaki and Clutha is at best "difficult to determine robustly".

Any action to correct must be designed to correct a UTS by restoring the normal operation of the market. A scenario in which the market delivers outcomes that have not been shown to be legally or physically possible, does not represent the normal operation of the market and would not restore confidence in the market. Any infeasible action to correct will do the opposite, undermining confidence in the market and in the market regulator.

Claims that the Authority's assessment of hydrology was conservative are not well founded and do not mean hydrology can be ignored

At paragraph 7.18 of the final decision paper, the Authority acknowledges that its estimate of "excess spill" does not factor in competitive response – the analysis effectively assumes a static offer from all participants and that any adjustment of hydro offers to undercut others would not be met by subsequent offer changes, for example by North Island generators with take or pay gas contracts, or those wanting to maintain their own generation to cover their retail contracts. The model used was only ever intended to give a static market solve and is not designed to represent outcomes in a dynamic market. This significant limitation means the estimate of “excess spill” is approximate and, in Meridian’s opinion, in no way conservative.

There are further issues with the Authority’s calculation of “excess spill” that suggest it is not in fact conservative. For example, in many trading periods the Authority’s modelling of “excess spill” allows unrealistically high generation output from Benmore station (above the highest offered generation of 532 MW). This appears to be because the Authority’s model ignores transformer losses and local service usage. The unrealistically high volumes modelled from Benmore could not be sustained in the real world while maintaining frequency response at 50Hz. By Meridian’s calculation, once these factors are appropriately accounted for, the estimate of “excess spill” should be 26.5 GWh. In this respect, the Authority’s 28 GWh is an overestimate and not at all conservative.

In short, the Authority should not now impose an action to correct that is inconsistent with its prior analysis and that would deliver an outcome that is unsupported by evidence as to its feasibility in the real world. It would also not be reasonable for the Authority to dismiss this analytical flaw by simply saying the estimate of “excess spill” is conservative. If the Authority has a better way to estimate “excess spill” it should have used that method in its substantive decision and made the case for an offer cap to deliver that outcome.

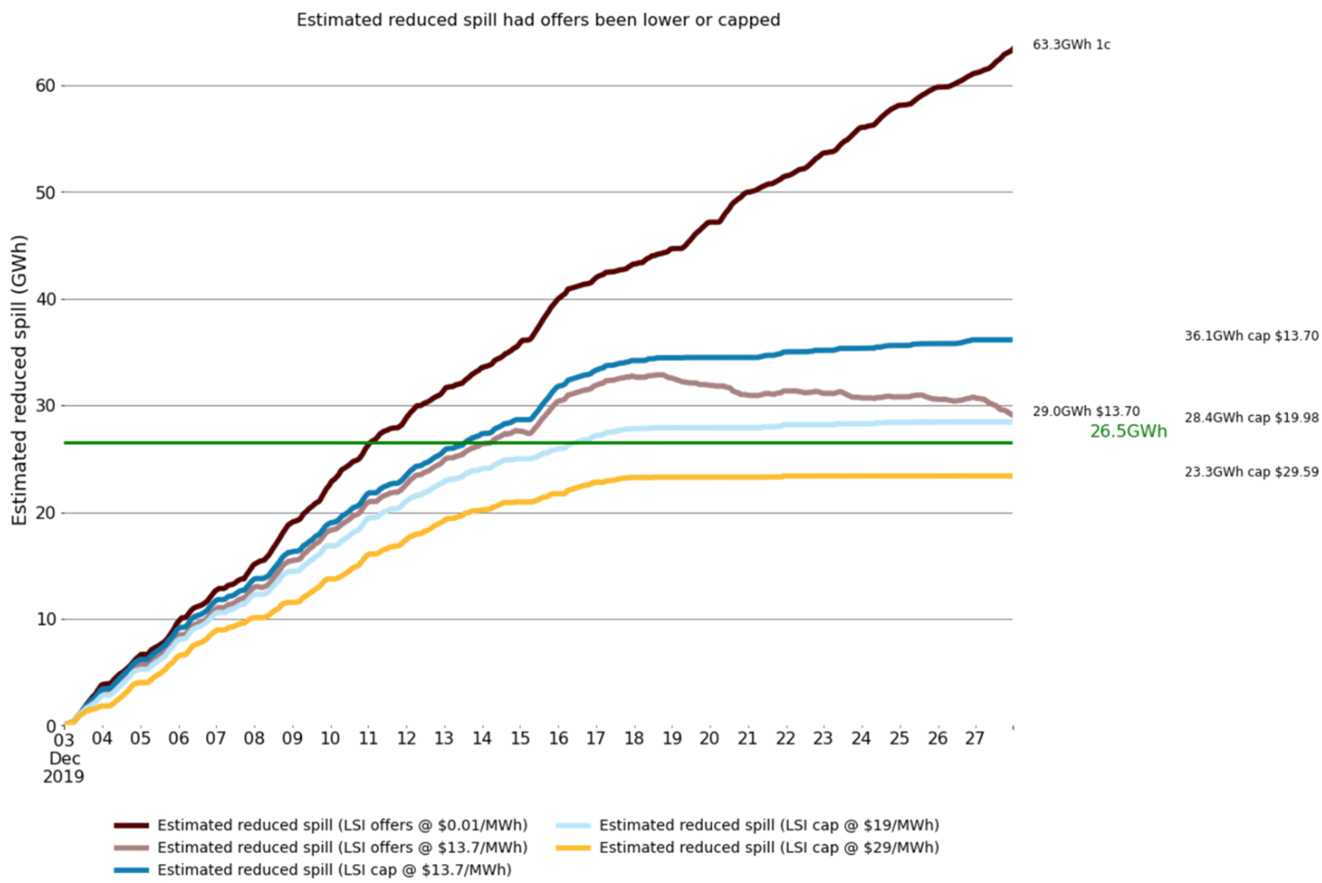
Alternatively, offers could be adjusted to reflect offers under similar hydrology

The Authority’s analysis shows that a $19.98 / MWh offer cap would deliver an average offer price of $13.70 / MWh and would result in the dispatch 28 GWh of additional hydro generation. To the extent the Authority wants to correct for this physical outcome, Meridian accepts that a $19.98 / MWh offer cap would achieve that result.

However, rather than back solving the offer cap or level which would achieve the 28 GWh of additional South Island hydro generation, it would be preferable to adjust offers based on the offers made during similar hydrological conditions. According to the Authority, the median historical daily price in the lower South Island when South Island hydro storage is above the 99th percentile is $29.59 / MWh. Rather than connecting an offer price to an estimate of “excess spill” and seeking to achieve a more efficient physical outcome in hindsight, an offer reset based on the prices (or ideally offers) in the lower South Island when storage was above the 99th percentile would seek to directly connect offers with normal market outcomes experienced in the past. This action to correct would therefore be more closely aligned with the legal tests in Part 5 of the Code.

Figure 1 below is the output from the Authority’s own vSPD runs showing the amount of additional South Island hydro generation at different offer resets and offer caps. As can be seen the $19 / MWh offer price cap (light blue) is equivalent to the $13.70 / MWh offer reset used in the UTS decision paper (light brown), while the dark blue $13.70 / MWh offer cap results in additional generation in excess of 28 GWh. For completeness we have also added a 26.5 GWh line to Figure 1, which is the amount of additional hydro generation that would be feasible if the Authority’s methodology appropriately accounted for frequency keeping at Benmore. As shown, the appropriate offer would have to be somewhere between $19.98 / MWh and $29. 59 / MWh to notionally generate 26.5 GWh of additional South Island hydro generation over the UTS period.

Figure 1: Volume of additional hydro generation with different offer adjustments



Meridian also notes that despite the confluence of events and supposed lack of competitive pressure between 19 and 27 December 2019, there was minimal incremental reduced spill after 18 December 2019. This is unsurprising given the daily average South Island prices between 19 and 27 December 2019 ranged from $2.33 up to $19.78 / MWh. This may suggest that there is little if any case for actions to correct the UTS identified after 18 December 2019 as the outcomes in the market very closely reflect the normal operation of the market.

Attachments

Appendix 1: Responses to consultation questions

	Question	Response
1	What, if any, actions should the Authority undertake to address excess spill, system security, and any other consequent effects? How would such actions address the objectives of Part 5 of the Code?	It is impossible to adjust what physically happened in December 2019. The Authority is right to focus on the prices in the spot market that occurred during the UTS period – these can be adjusted.
2.	Do you agree that the Authority should seek to correct the UTS period by resetting the payments made/received by spot market purchasers and generators? (If not, please explain your reasoning.)	This is a reasonable approach.
3.	Do you agree that the Authority should attempt to correct settlement during the UTS period by resetting prices in the electricity market?	Notionally adjusting offers and using these to reset final prices is a reasonable approach.
4.	Do you agree that injection and off-take volumes should remain unchanged in any resettlement?	Yes. Electricity generated and consumed cannot be un-generated or un-consumed.
5.	Do you agree that the Authority should attempt to correct the UTS by revising final prices in the electricity market, rather than by an 'off-market' wash-up of spot electricity payments to and from the clearing manager?	Meridian agrees with the Authority that the preferred option should be to correct the UTS by adjusting offers and recalculating final prices in the electricity market (Option O). This is far preferable to a direct reset of prices themselves (Option P) or an 'off-market' wash-up of spot electricity payments to and from the clearing manager (Option S).
6.	If offer prices and offer volumes are reset, which hydro generating stations should have offers reset? (Please answer yes/no, with any additional supporting commentary.)	To be consistent with the methodology applied in the final decision paper, all South Island hydro offers should be reset.
7.	If offer prices and volumes are reset, do you agree that North Island offer prices and offer volumes should remain the same as	As we have noted in previous submissions, a static offer and complete lack of competitive response from North Island generators is not realistic. This calls into question the Authority's calculations of "excess spill" and conserved North

	originally submitted? (If not, please identify any alternative actions.)	Island storage. However, given vSPD is only designed to give a static market solve in a given trading period, for the purposes of the proposed actions to correct, holding North Island offers constant seems a reasonable approach. Anything else would require broad assumptions to be made about what North Island generators might have done under different market conditions. This would be an inherently subjective assessment and difficult to ground in evidence.
8.	Do you agree that resetting offer prices and volumes by imposing a cap is the preferred action to correct the UTS? If not, please identify preferred alternatives.	An offer cap appears to be a sensible option, provided it is at the right level.
9.	If revisions to offer prices are to vary through time or across generating stations, how should the offer prices be determined?	This would likely be too complex, and the judgements required would be too difficult to justify.
10.	Do you consider that final prices should be reset directly? If so, how should they be calibrated?	No.
11.	Do you agree that the aggregate offer volumes of each generating station should equal the aggregate amount offered by that station during the UTS period? Please describe any preferred alternatives.	This seems reasonable. As the Authority notes, generators tend to offer their full capacity and manage volumes by attempting to match offer volumes with offer prices that they do not expect to clear. The Authority is wrong to suggest that this is done for profitability reasons. High priced tranches are generally used to manage storage prudently and to ensure compliance with resource consents, and operational, hydrological and market constraints. As the Authority notes, the 'lost' generation during the UTS period "primarily reflected bands of offered generation at high offer prices that did not clear". This highlights the risk for the Authority that in lowering the offer price of these high priced bands it must be confident that the offers still comply with resource consents, and operational, hydrological and market constraints. The Authority has shown this is possible for 28 GWh of additional hydro generation but no more.

12.	Which of these mechanisms in paragraph 5.41(a) – (e), if any, should be used to calibrate 'corrected' electricity offer prices? (Please identify any other preferred alternatives.)	Meridian prefers mechanism (c) or an offer cap of $19.98 / MWh.[11] It is not clear why the Authority prefers an offer price cap that would deliver a specific hydrological outcome (28 GWh of additional South Island hydro generation). As detailed in the body of this submission, a price cap based on the offers made during similar hydrological conditions would be preferable and would be more closely connected with normal market outcomes experienced in the past and more closely aligned with the legal test in Part 5 of the Code. If the Authority does persist with an offer price cap to deliver a hydrological outcome, the basis for the level of the price cap must be clear. The $13.70 / MWh price cap proposed is baseless because it does not in fact deliver the desired outcome (28 GWh of additional South Island hydro generation). As detailed in the body of this submission, the $13.70 / MWh price cap would dispatch around 30 percent more hydro generation than what the Authority previously identified was feasible while complying with resource consent, operational, hydrological and market constraints. An offer price cap at $19.98 / MWh (with average offer prices of $13.70 / MWh across the UTS period) would deliver the hydrological outcome sought by the Authority and Meridian would consider this to be a logical option.
13.	Do you agree that generators, other than those with 'reset offers', that were dispatched to generate electricity at offer prices above the reset final prices should be treated as constrained on? (If not, please identify preferred alternatives.)	This seems like a reasonable approach.

[11] We understand the offer price cap of $19.98 / MWh results in an average offer price of $13.70 / MWh across the UTS period and that this option may therefore be equivalent to the single offer price of $13.70 / MWh in option (a). However, the actions to correct paper is not clear on this point. The tables in Appendix A of the actions to correct paper all refer to the $19.98 / MWh offer cap rather than any single offer price option. Meridian considers this to be the better approach and we are unsure why the $19.98 / MWh offer cap option is not presented in paragraph 5.41 of the actions to correct paper.

14.	Do you agree with the Authority's proposal not to revise constrained off payments, associated with frequency keeping? (If not, please explain and identify any preferred alternatives.)	This seems like a reasonable approach.
15.	Should offers to the instantaneous reserves market during the UTS period be corrected? If so, how should instantaneous reserve offers be corrected?	No. We agree with the Authority's assessment that reserve offers do not need to be adjusted to restore confidence in the wholesale market.
16.	Do you agree with the proposed approach to treatment of derivatives for the purposes of correcting the UTS? Please explain your answer.	No. Derivatives are just as much a part of the wholesale market as the spot market. As the Authority says, "ideally, the settlement of derivative contracts should reflect the prices that would have prevailed if the UTS had not occurred." The Authority should therefore do everything it can to resettle the entire wholesale market on the same basis. The Authority should not pick and choose which derivatives it will make directions in respect of (the only directions that seem to be proposed are in respect of the FTR market). The Authority should apply a consistently principled approach that seeks to resettle as much of the wholesale market as it can based on the recalculated offers and resulting spot prices. We accept that the Authority may not be able to direct non-participants to resettle.
17.	Are there any additional, feasible and lawful actions that the Authority should or could undertake in relation to derivatives markets?	Yes, see above. The Authority should therefore do everything it can to resettle the entire wholesale market on the same basis. At a minimum this includes directing: • that FTRs resettle; and • that derivative contracts between participants resettle.
18.	How should the Authority use its powers under Part 5 in relation to LCE payments?	Like derivatives, we would expect LCE payments to be recalculated to the extent possible including if that means clawbacks and reallocation or wash-ups of residual LCE payments by Transpower.

19.	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?	In principle, all parts of the market that settle based on final spot price inputs should be directed to resettle based on the recalculated final prices. This includes retail contracts that pass through spot energy costs to consumers. This would best restore the normal operation of the market.
20	How should any resettlement arising from the actions to correct the UTS be implemented?	Meridian would be comfortable with the Authority and clearing manager immediately implementing any resettlement that results from the actions to correct.
21.	If there is a resettlement, what window of time after invoicing should be allowed for traders to meet their obligations?	We see no need for a window of time for participants to meet their obligations stemming from the actions to correct the UTS, after they have been invoiced. The potential for this resettlement has been signalled for a long time and should not be unexpected. Under the functional specifications of the market operation service provider agreement between the Authority and the clearing manager, the clearing manager calculates the amounts payable and receivable for each invoice period, and for each wash-up. The amounts payable and receivable as a result of any resettlement should be treated in the same way as any other invoice – where each participant is required to pay their amount payable in cleared funds into the clearing manager's operating account by 1300 hours on the 20th calendar day (or the next business day if this is not a business day).
22.	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.	The implementation steps appear reasonable. However, additional steps should be added to direct the resettlement of derivative contracts between participants based on the revised nodal prices calculated by the pricing manager and published on WITS. It seems unusual that the Authority includes a step to direct FTR outcomes and contemplates directing outcomes for retail contracts but not wholesale contracts. A principled decision would direct resettlement of all

		aspects of the market to the greatest extent possible within the Authroity's jurisdiction. Resettlement of every part of the market (or as much as possible) would best restore the normal operation of the market. The interest rate used to scale payments should, if anything, be the bank bill bid rate calculated daily from the original payment due date until the date of resettlement, less any deductions for resident withholding tax, compounded at the end of each calendar month. This would be consistent with the business requirements for wash-ups in the functional specifications of the market operation service provider agreement between the Authority and the clearing manager.