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Submissions
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Review of IR Event Charge and Cost Allocation – WAG Discussion Paper

Meridian appreciates the opportunity to provide feedback on the above paper. Our feedback comprises Meridian's responses to specific consultation questions provided in Appendix A and comments from this covering letter.

The need for thorough assessment and consideration of changes to current arrangements

Averaging $38 million annually for the period 2008-2015, procurement costs of Instantaneous Reserves (IR) are material. The potential for IR cost allocation methods to create wider energy market distortions and reduce the benefits obtained from a national reserves market is real. Meridian fully supports continuing the use of the current, well-established island-based allocation method while the WAG and ultimately the EA undertakes thorough and detailed assessment of potential changes.

We appreciate the WAG's engagement with industry and detailed work in support of the review so far. However, as the WAG's paper acknowledges, the WAG is at an early stage of its considerations. It will be important that industry has the opportunity to provide input into the next iteration of the WAG's and / or the EA's proposals. As we mention in our detailed feedback attached, Meridian would be happy to present to the WAG on our views of the options from this consultation.

Like the WAG, Meridian considers there are two principles that should be followed in allocating IR costs:

1. Costs would be allocated to parties causing (or exacerbating) the need for IR; and
2. The cost allocation would send a marginal signal.

Meridian agrees this should drive the most efficient outcomes. As discussed below Meridian proposes a third principle or test of the outcomes produced by the application of these first two principles namely that "Cost allocation arrangements need to be non-distortionary and promote efficient market outcomes." This additional test / objective needs to be applied broadly – within the reserves and energy markets and also to confirm utilisation of greater HVDC capacity is appropriately incentivised.

Unit-based allocation is a critical flaw of existing arrangements

The WAG in its paper focuses on three potential problems with the existing method of general cost allocation:

1. dulling of price signals for causers of IR costs from use of the general IR pro-rata cost allocation approach;
2. dulling / distortion of price signals from use of the Transmission Pricing Methodology (TPM) to pass through HVDC IR costs; and
3. inconsistencies in the allocation of IR costs to assets presenting secondary event risks.

Of fundamental importance in defining the problems here is ensuring that cost allocations do not stand in the way of realising expected benefits from a national IR market – i.e. more efficient reserve procurement and cost allocation overall – or encourage distortions in reserve / energy markets.

Seen in this context there is, in Meridian's view, a fourth significant problem with the existing method of general cost allocation, namely unit-based charging. As noted by the WAG, the application of unit-based charging escalates charges for multi-unit stations like Manapouri and Benmore to levels well in excess of the level dictated by the risk amount for those stations that is used for procurement purposes (i.e. 7 times the 120 MW risk amount or reserve requirement in the case of Manapouri – which exceeds, by some considerable margin, the allocation for stations with a unit creating a 400 MW reserve requirement). The WAG paper considers this problem is a consequence of the pro-rata approach (see page 30) and accepts it is a departure from the 'causers pay' principle. While Meridian agrees it is a clear departure from that principle we do not see it as a necessary consequence of the pro-rata approach. A better, more 'causers pay' application of the pro rata approach would allocate costs to a station in accordance with the risk amount or reserve requirement actually driven by that stations. This is more consistent with and reflective of the level of reserve costs actually driven by a particular station (i.e. a 7 unit station with 7 x 120MW units actually only drives a reserve requirement of 120MW, the same level of reserve cost as a station with a single 120MW unit). In Meridian's view this problem is arguably the most significant of all the potential problems with the current cost allocation methodology and, if there is to be any change, it needs to be addressed as a first priority.

Current island-based allocations mask unit-based allocation impacts and remain a valid choice

Meridian agrees with the WAG's assessment that maintaining the current island-based allocation methodology is unlikely to impact negatively on incentives within the energy or reserve markets. Experience to date with the operation of the NIRM has proved this assessment to be correct.

As the WAG recognises, due to the current technical and physical limitations of the HVDC, the NIRM does not and will not operate as a fully "national" market. There is therefore no "automatic" requirement for cost allocation to be on a national basis and no reason why an island-based method cannot be retained, whether on an interim or longer-term basis at least until there is some confidence that a better alternative has been clearly identified. As stated above Meridian considers that there is a strong case for the WAG to recommend amendments to the current unit-based method of allocating costs. In terms of other proposed changes we consider further analysis is required and that in the meantime maintaining the current island-based approach remains a legitimate choice. As recognised by the WAG, the current island-based allocation also has the 'happy coincidence' that it masks the problems with unit-based allocation because the profile of risk setters in each island currently happens to be the same – see page 30 of the WAG's paper.

A modified 'Cost-to-island-causer' approach is the most appealing of the WAG's other options

The current island-based allocation methodology is Option 1 of 5 cost allocation options identified by the WAG. Of the other four, Meridian considers that a modified version of Option 4 'Cost-to-island-causers' may promote the best outcomes. Meridian's proposed modification would involve allocating costs to each island (including to the HVDC in the receiving island) in accordance with the relative marginal offers in each island. This is discussed further below. Without this modification this approach may introduce distortions into participants' reserve offers and the full potential benefits of the NIRM may not be achieved.

Option 5 'Cost-to-HVDC-then-to-AC-island-causers' – as it is currently proposed by the WAG – is complex, and gives preference to assigning high proportions of cost to one of the least controllable risks – the HVDC. In addition, we consider:

- The proposed approach does not adequately satisfy the principle of 'causer-pays', in certain situations allocating higher costs to the HVDC than to NI AC plants despite both presenting the same (400 MW) level of risk.
- The suggestion that the HVDC is 'unique' that is used in justifying this approach is incorrect. The Scheduling Pricing and Dispatch (SPD) process is just as able to generate efficient solutions in dispatching the HVDC as it is when dispatching generating plant.
- This option would be inappropriate while the current TPM remains in place. The current TPM sits at the lowest rung of the EA's hierarchy of preferred approaches to cost allocation. It is not even a 'beneficiaries pay' approach (like the EA's currently proposed new TPM) let alone an 'exacerbators approach'.

IR cost allocation options – summary of Meridian views

Meridian's views in respect of the WAG's different IR cost allocation options are set out in the table below. Regardless of which option is chosen Meridian considers the first priority should be replacing the current unit-based reserve cost allocation methodology with a methodology that allocates costs at the station level in accordance with the risk amount or reserve requirement actually driven by that station i.e. in the case of a multi-unit station like Manapouri this would be based on the 120MW reserve costs it actually drives (as adjusted to reflect any de minimis) and not 7 x 120MW that it currently pays. This change can be combined with any of the options in the WAG's paper.

Option	Comments	Meridian ranking
Retaining the current island-based method (WAG option 1)	Island-based allocation is a valid and acceptable approach to sustain until a clearly better option is identified	1
'Cost-to-island-causers' (WAG option 4)	Subject to the modification we have suggested (cost allocation to islands in accordance with relative marginal reserve offers), is likely to promote the best outcomes of all the WAG's 4 alternative options	2
'Cost-to-HVDC-then-to-AC-island-causers' (WAG option 5)	A complex approach that poorly targets exacerbators and exacerbates recognised inefficiencies of the current TPM	3
National allocation – with or without sharing adjustments (WAG options 2 and 3)	At least under a unit-based cost allocation, is ineffective in targeting exacerbators and carries high risk of perverse outcomes. Not supported by Meridian.	N/A

Meridian also considers that, in the context of a 'causers pay' approach, allocation of costs to the HVDC and recovery of those costs through the TPM is problematic. All of the options in the WAG paper involve significant allocation of costs to the HVDC and recovery of those costs from the parties who meet the costs of the HVDC under the TPM. The current TPM sits at the lowest rung of the EA's hierarchy of preferred cost allocation approaches. Even if the EA's currently proposed reforms are adopted (1 April 2019 at the earliest) the TPM will be a 'beneficiaries pay' methodology not a 'causers pay' methodology. Having such a methodology sit at the heart of 'causers pay' approach to IR cost allocation is a fundamental inconsistency. We suggest that other cost allocation options should be considered that have the potential to resolve this inconsistency (e.g. by allocating costs that would have been allocated to the HVDC nationally amongst all generators).

Other issues

Commissioning plant 'causers' of secondary event risks have potential to create high IR costs and should be charged using a cost effective method of allocation. In terms of the other categories of secondary risk causers identified by the WAG, we agree with the principle that IR costs should be recovered from causers where it is cost effective to do so. We share the WAG's view that this criteria is unlikely to be met for smaller plant (< 30 MW), requiring alternative approaches to be considered.

The event charge is more in keeping with a causer-pays approach and should be retained, with the level at which the charge is set to be reviewed. Meridian does not support re-allocating the event charge to IL providers under existing, non-event based, procurement arrangements.

Further details on points raised above are provided in Appendix A detailing our responses to specific consultation questions.

Please contact us if you have any questions relating to this submission.

Yours sincerely,

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Appendix A – Responses to Consultation Questions

	Question	Response
1	Do you agree with our identification of the problems with current arrangements?	As noted above we consider that the WAG has failed to recognise that the current unit-based allocation methodology is a significant problem that needs to be addressed as a first priority. If 'causer pays' is the key principle to be observed (and Meridian agrees it is) a methodology that so clearly fails to accurately align and reflect costs back to their causers is unsatisfactory. In particular, a station with seven units of 120MW drives the same level of reserve cost as a station with a single unit 120MW station and far less reserve cost than a station with a 400 MW unit. Allocating 7 x 120MW of reserve costs to the first station giving it a cost allocation which exceeds the costs allocated to the 400MW station, represents a fundamental flaw in the current methodology. Otherwise, subject to the points noted below, we broadly agree with the WAG's identification of problems. Also while not a focus of the WAG's assessment, interactions with revenue arrangements are also an important consideration. These interactions are not a 'problem' under the current cost allocation methodology but potentially will be if another methodology is chosen. In particular, care needs to be taken with cost allocations that disrupt the alignment of charges with prices as they carry with them the possibility of higher prices overall, compromising in the process the benefits intended to be achieved (i.e. lower cost reserves overall). The five specific problems with the current IR cost allocation arrangements identified by the WAG are: 1. A likely 'dulling' of price signals for causers of IR (such as large unit plant) from the current pro-rata general cost allocation method which, in the view of the WAG, may result in long-term inefficiencies in plant investment. 2. HVDC related distortions in price signals from the continuation of an island-based cost allocation approach, with potential resulting short-term operational and / or long-term investment inefficiencies. 3. HVDC related potential dulling of price signals from using the Transmission Pricing Methodology (TPM) to pass through HVDC IR costs which may cause long-term inefficiencies in plant investment. 4. Inconsistencies in the allocation of IR costs to assets presenting secondary event risks (e.g. commissioning and AOPO non-compliant plant) which may result in long-term investment inefficiencies and some operational inefficiencies. 5. Event charges provide limited impact on incentives for reliability and do not allow reimbursement for actual interruption costs in the way originally intended. In respect of (2), it seems from a review of the WAG's paper that the WAG considers that this potential problem is more theoretical than real – see the discussion in Meridian's response to Q6 below. Meridian agrees. In addition, as already

	Question	Response
1	Do you agree with our identification of the problems with current arrangements? (cont).	mentioned rather than just considering distortion of price signals from cost allocation alone, what should be the focus is the overall effect of cost allocation as it interacts with revenue arrangements i.e. also considering how island-based pricing can act to subdue prices irrespective of whether receiving island prices are higher. As our Q9, and Q13-Q17 responses discuss in more detail, Meridian's initial comments on the other problems identified are that: • The allocation of IR charges to the HVDC and subsequent pass through using the TPM does not create any meaningful incentives for reliability and does not achieve causer pays. It may well be that there are no better alternatives, but the issue should be considered further. Regardless, it is not until 1 April 2019 at the earliest that the TPM could move from the lowest rung of the EA's hierarchy of cost allocation approaches and become a 'beneficiaries pay' approach. Before that time Meridian does not consider that the WAG's Option 5 'Cost-to-HVDC-then-to-island-causers' to be a credible alternative to the current arrangements. • Commissioning plant 'causers' of secondary event risks have potential to create high IR costs and should be charged using a cost effective method of allocation. In terms of the other categories of secondary risk causers identified by the WAG, we agree with the principle that IR costs should be recovered from causers where it is cost effective to do so. We agree with the WAG's view that this criteria is unlikely to be met for smaller plant (< 30 MW), and support more extensive adoption of AOPO standards instead being pursued in the first instance. The event charge is more in keeping with a causer-pays approach and should be retained, with the level at which the charge is set to be reviewed. Meridian does not support re-allocating the event charge to IL providers under existing procurement arrangements.
2	Do you agree with these basic principles for allocating IR costs?	Meridian agrees with the WAG's suggested principles, namely causer-pays based charging and signalling of marginal costs, to ensure plant and system costs are correctly signalled and internalised. Achieving this will require cost allocations that reflect the risks posed to the system by the generating units to which the relevant costs are allocated. As the WAG notes it is also important to take account of potential limitations set by the practical realities of the sector. A third, additional principle or test of the outcomes produced by applying the first two principles should also be considered: • Principle 3 – Cost allocation arrangements need to be non-distortionary and promote efficient market outcomes. This objective / test needs to be applied broadly – specifically in relation to ensuring appropriate energy and reserves market incentives are maintained and in respect of ensuring that appropriate utilisation of increased HVDC capacity is not inhibited.

	Question	Response
3	Do you agree that continuing with island-based cost allocation after the introduction of the NMIR is unlikely to create perverse incentives on parties to inefficiently withhold energy or IR capacity?	Yes. Maintaining island-based cost allocations post the introduction of the NMIR carries considerably lower risk from an incentives perspective than the method of national cost allocation originally contemplated by the Authority (national allocations at all times the HVDC is operational, with no adjustment to reflect the level of IR sharing). The originally contemplated approach would have exposed participants to high costs they are prevented from managing using additional reserves (owing to reserve sharing capacity constraints). This had the potential for wider flow-on energy market implications such as the inefficient withholding of capacity.[1] Meridian's view that continuing with island-based allocations is unlikely to create perverse incentives has been borne out by our monitoring to date of use of island-based cost allocations for the NMIR. Continuing with the current island-based cost allocation approach remains an acceptable and valid approach pending the identification of a clearly "better" alternative.

[1] Meridian's '*Proposal to alter the way IR availability costs are allocated*' *26 April 2016 submission provides further details* (*http://www.ea.govt.nz/dmsdocument/20699*)

	Question	Response
4	What are your views on the merits of moving to a runway methodology (or its sub-options)?	Meridian considers that the choice between a runway methodology and a pro rata allocation method is a secondary issue to the fundamental problem with general cost allocation namely the current unit-based approach, as opposed to allocating charges to a station in accordance with the actual risk amount or reserve requirement driven by that station. That said, when it comes to choosing between pro rata and runway we accept the potential benefits of a runway methodology are uncertain, but also consider the potential benefits are understated by the WAG's analysis. In particular: • If the fundamental problem of unit-based allocation is not addressed, then as the WAG recognises in the paper, the runway methodology will potentially ameliorate the perverse result produced by national cost allocation whereby a medium-sized unit owner could end up paying significantly more in reserve costs than the large unit owner whose investment decisions have driven most of those reserves costs. These costs could be of a scale significant enough to encourage inefficient operational decisions – whether in terms of withholding capacity or operating at reduced capacity. • The assessment of investment efficiency impacts is premised on current and future investment projects alike being constructed with small generation unit sizes. This is in contrast to some of the more recent investments that have been made – in particular the recent 700 MW HVDC investment and CE risk. • While not a focus of the WAG's assessment, removal of the event charge will further lessen the degree of marginal cost signalling from a pro rata approach. There needs to be further consideration of this impact if event charge removal (which Meridian does not support) is to be progressed. A runway methodology will potentially provide an important corrective measure to the perverse outcomes a national cost allocation may otherwise create (that is, charges that are highly disproportionate to the level of risks created). As an aside, Meridian does not agree with the view of some WAG members (page 28) that the supposed impact on 'regulatory certainty' of moving to a runway approach is a valid consideration. At base this is a form of 'status quo bias'. Meridian's view is that: • As the Electricity Authority has recognised elsewhere, 'regulatory certainty' is not promoted by retaining regulatory settings that are clearly inefficient and therefore inconsistent with Authority's statutory objective. Instead, where a better alternative is available "…the Authority consistently and transparently pursuing its statutory objective is the best way for it to promote regulatory certainty and the right climate for investment in the capital intensive electricity industry over the long-term." In Meridian's view the WAG should frame its recommendations accordingly. • If there is sufficient certainty that material efficiency gains are available then regulatory settings should be adjusted to capture those gains.

	Question	Response
5	Do you agree that a de minimis should continue and, if so, at what level?	Meridian, like the WAG, considers there could be merit in the SO reviewing whether the 60 MW de minimis threshold remains appropriate. This threshold has been in place for almost 20 years without adjustment and was decided on with only minimal analysis at that time.
6	Are there other cost allocation options you think should be considered?	Yes. As already indicated Meridian believes the first priority in any IR cost allocation review should be to change the current unit-based allocation arrangements and instead allocate costs to a station in accordance with the risk amount or reserve requirement actually driven by that station.[2] This is a fundamental problem with the current methodology which is not addressed by any of the options discussed in the WAG paper. Our comments below on the WAG options should be seen in that light. Meridian also considers that, in the context of a 'causers pay' approach allocation of costs to the HVDC and recovery of those costs through the TPM is problematic. All of the options in the WAG paper involve significant allocation of costs to the HVDC and recovery of those costs from the parties who meet the costs of the HVDC under the TPM. The current TPM sits at the lowest rung of the EA's hierarchy of preferred cost allocation approaches. Even if the EA's currently proposed reforms are made (1 April 2019 at the earliest) the TPM will be a 'beneficiaries pay' methodology not a 'causers pay' methodology. Having such a methodology sit at the heart of 'causers pay' approach to IR cost allocation is a fundamental inconsistency. We suggest that other cost allocation options should be considered that have the potential to resolve this inconsistency (e.g. by allocating costs that would have been allocated to the HVDC nationally amongst all generators). **Comments regarding the WAG's options** The WAG paper records that in deciding to defer making changes to IR cost allocation until the WAG had completed its review the Authority Board considered that "continuing with an island approach to cost allocation was unlikely to be the best long-term solution" (page 35). The reasoning of the Authority's Board is not set out in the WAG's paper. However they seem to have reached this view on the basis that if, for example, North Island generators face only the costs of IR procured in the North Island in circumstances where, in order to meet a North Island risk, an equivalent amount of IR also has to be procured in the South Island

[2] With Manapouri, for instance, its current allocation based on 420 MW of IR costs (7 units *60 MW) = 420 MW) would fall under this approach to an allocation based on the actual reserve costs driven by the station of 60 MW.

	Question	Response
6	Are there other cost allocation options you think should be considered? (cont.)	(with those costs met by South Island generators) this could: • Affect long term investment and retirement decisions; and • Alter participants' energy and IR offers in a negative manner. The second of these concerns appears to have been dismissed by the Authority Board itself in deciding to persist with island-based cost allocation pending the outcome of the WAG review (and the WAG itself agrees and takes the view that any operational inefficiencies of persisting with the current island-based cost allocation method are largely prevented by the SPD tool – see page 25). Meridian agrees. Experience to date with the NIRM suggests the Authority Board, the WAG and Meridian are correct. In relation to the first concern relating to long term investment and retirement decisions the WAG paper suggests that although in theory the current cost allocation method: • May drive investment in plant of a larger size than is efficient, the WAG are sceptical that this will happen in practice because all the likely (geothermal and wind) new plant that will be built in New Zealand is much smaller than the CCGTs) – see page 26 of the WAG's paper; • May prevent the efficient early retirement of existing plant, in practice this is highly uncertain due to a range of factors – see page 27 and Appendix B. It is therefore not clear why the Authority Board considered that an island approach is "unlikely" to be the best long-term solution. It may be that the Authority Board considers the potential for investment in larger plant (than is efficient) is more significant than the WAG. Alternatively, perhaps the Board considered that the so-called national IR market "automatically" or "by definition" is likely to require a national method of cost allocation. Meridian considers this view is not correct. The analysis to date does not seem to have produced any clear cut reason why an island-based method of allocation and national IR market cannot co-exist, whether on an interim or longer-term basis. As the WAG's paper acknowledges, constraints of the HVDC and technical rules of procurement mean that the IR market cannot function as a national market at all times. In particular, as noted on pages 37 and 38 of the WAG paper: • "…the physical limitations of the HVDC to transfer IR mean that the new NMIR will never be completely 'national' i.e. there will almost always be situations where some relatively expensive reserve needs to be procured in a particular island (generally the North Island because that is where the large thermal units are located) because there are technical limitations on the amount of IR the HVDC is capable of transferring from one island to the other."

	Question	Response
6	Are there other cost allocation options you think should be considered? (cont.)	• "A DC CE risk can only be met by IR procured in the receiving island. This has significant implications for the NMIR because at high levels of energy transfer across the HVDC, IR must be procured in the receiving island, irrespective of whether it is cheaper in the other island. At this stage Meridian believes that there is no reason why an island-based method cannot be retained, whether on an interim or longer-term basis at least until there is some confidence that a better alternative has been clearly identified. In the meantime maintaining the current island-based approach remains a legitimate choice and, as recognised by the WAG, it has the "happy coincidence" that it masks the problems with unit-based allocation because the profile of risk setters in each island currently happens to be the same – see WAG paper at page 30. In respect of options 2 and 3 in the WAG paper Meridian agrees (at least under the current unit-based cost allocation) agrees with the WAG's assessment that: • Option 2 - a fully nationalised approach to cost allocation (i.e. allocating all costs across risk setters across both islands, with no adjustment for reserve sharing capability) will be ineffective in targeting exacerbators. As we've previously submitted, it is also an unprincipled method with the potential to create wider energy market distortions. • Option 3 - modifying the fully nationalised method of allocation to account for reserve sharing limits (the "factored by HVDC reserve sharing limits" option) will still mean costs will be imperfectly signalled and causers are not charged in proportion to the level of risk they create. Also, as far as we can tell, this option seems to allocate costs as if the full 220MW sharing limit is achieved at all times when that will clearly not be the case. In respect of Option 4 in the WAG paper Meridian supports most elements of the 'Cost-to-island-causers' approach (Option 4 in the WAG's paper) although we suggest that if this option was to be implemented then rather than allocate shared IR costs to risk setters in each island at the same price, shared IR costs should be allocated to risk setters in each island <u>in proportion to the marginal reserve offer price in each island</u> (this is not necessarily the same as the marginal reserve price in each island). This assigns cost to risk in each island in line with the cost they impose on the system (i.e. a risk in a low-priced island should not have to pay the price of the high-priced island if cheap reserve were available in that island – the cost of that risk to the system is comparatively low). This gives a strong incentive to offer in reserves at lowest-cost in both islands. In contrast, as currently formulated Option 4 (and indeed the other allocation methodologies in the WAG's paper) may promote 'pricing up' of reserve offers, particularly for the low-price island to match the higher priced island.

	Question	Response
6	Are there other cost allocation options you think should be considered? (cont.)	In the example of Option 4 with 120MW of shared IR (100SI, 20NI), and with the SI price at $1 and NI price at $10, then SI risks pick up cost in accordance with their pro rata or runway share of 1/11 x $300 = $27. NI risks and the HVDC pick up costs in accordance with their pro rata or runway share of 10/11 x $300 = $273. This reflects the relatively low cost of risk in the lower-priced island, while reflecting the greater value of shared reserves to the higher-priced island. As an aside, we note the WAG paper seems to contain an error in discussing this option: on page 42 it provides that of the total 400MW of reserve purchased in the situation where the HVDC is transferring 800MW energy, 302MW is solely allocated to NI risk setters and 22MW + 98MW (a total of 120MW) would be allocated nationally i.e. 420MW in total or 20MW more than is required. It seems from the description of this option on page 42 that what is meant is that only 280MW of the reserve purchased in the NI would be allocated solely to NI risk setters. In respect of Option 5 in the WAG paper, 'Cost-to-HVDC-then-to-AC-island-causers' we consider the method of charging is complex, and gives preference to assigning significant proportions of costs to one of the least controllable risks (the HVDC) that in reality are also shareable. It is also an option that in effect exacerbates the underlying inefficiencies of the TPM, making it an unacceptable option until the TPM has been reformed. In addition: • The logic behind this option is difficult to follow. Meridian is unsure why it is accepted in the paper that the co-optimising Scheduling Pricing Dispatch tool (SPD) generates efficient market solutions in its treatment of offers from larger generating plant (see page 25 "SPD determines the least-cost combination of plant to meet demand, and automatically chooses the optimal output of generation and IR procurement simultaneously, based on energy and reserve offer prices") but a different view is taken of the HVDC. Instead, rather than treat the HVDC as an enabler of a (partial) national reserves market, this option seems to posit a full national reserves market and then to treat the HVDC as an 'exacerbator' of IR costs to the extent the current physical limitations of the HVDC mean it does not deliver on that market. However, somewhat illogically, it only does this for one of the current physical limitations of the HVDC (i.e. its inability to transfer reserves to cover a DC CE risk) whereas for the other physical limitation of the HVDC (i.e. its inability to transfer more than 220MW of reserve) it takes this as a 'given'. In the example discussed in the WAG's paper this means that in the situation of 800MW HVDC energy transfer, the HVDC is considered to have 'prevented the procurement of 122MW of cheaper South Island IR' because in that situation the HVDC's inability to transfer reserves to cover the NI DC CE risk of 302MW means that 302MW of NI IR has to be purchased instead of the 180MW of NI IR that has to be purchased when HVDC energy transfer is at 680MW or less i.e. an 'additional' 122MW. It's not clear why the same principle does not require that the full 302MW of '

	Question	Response
6	Are there other cost allocation options you think should be considered? (cont.)	‘more expensive’ NI IR costs be allocated to the HVDC on the basis that it’s other physical limitation (the inability to transfer more than 220MW of IR) is similarly preventing the procurement of cheaper South Island IR. • This method does not adequately satisfy the principle of causer-pays, with the WAG’s analysis on page 44 for example establishing a far greater HVDC allocation of costs for a 900 MW transfer level than to NI AC plants (220MW of NI reserve vs 180 MW of NI reserve) – even though each create the same level of risk (400MW of NI reserve). As the WAG recognise in the paper, increased use of the TPM to allocate HVDC-related costs will exacerbate the inefficiencies the Authority has recognised in the current TPM through the long running TPM reform process to date. With any final TPM reforms not due to take effect until 1 April 2019 at the earliest, we do not consider that increasing in the meantime the level of cost allocation via the TPM would be consistent with the Authority’s statutory objective unless other alternatives were shown to clearly be even more inefficient. Meridian therefore considers his option would be inappropriate while the current TPM remains in place. We also note the current TPM sits at the lowest rung of the EA’s hierarchy of preferred approaches to cost allocation. It is not even a ‘beneficiaries pay’ approach (like the EA’s currently proposed new TPM) let alone an ‘exacerbators approach’. **Other comments** Meridian notes this consultation question appears on page 45 of the WAG’s discussion paper, part way through section 6.2 “HVDC-related issues”. In the pages preceding this consultation question, the WAG’s discussion paper asserts at page 34, “Transpower [in its role as grid owner] faces strong regulatory incentives to make existing HVDC capacity available. In particular it is obligated under part 12 of the Code to make the full capacity of the HVDC available to the market”. No reference within part 12 is given and Meridian has been unable to find a passage in part 12 of the Code that places such an obligation on Transpower in its role as Grid Owner. It would be useful if the WAG could provide a cross-reference for its assertion. Related to this Meridian also notes that WAG’s discussion paper asserts, again at page 34, that “Transpower is incentivised under the Part 4 framework to make any new investments that would pass a public net benefit test. Thus, to the extent that the costs of a fourth cable were less than the projected economic benefits, in terms of altered energy and capacity outcomes taking account of any IR impacts, then the regulatory framework would incentivise Transpower to undertake that investment.” Meridian has checked this assertion by reviewing the background documents on GIT/modelling for Pole 3 approval. In summary: • Transpower’s modelled benefits of a 700MW Pole 3 were $191m. • This was derived from a weighted scenario approach using GEM and SDDP to model costs and benefits over 30 years.

	Question	Response
6	Are there other cost allocation options you think should be considered? (cont.)	• The modelling appears to assume the HVDC operates unconstrained and, under the 700MW Pole 3 option ultimately approved seems to allow up to 1400MW of DC flows overall. • This may in part be due to the purpose of the GIT, which is to identify the highest NPV option and demonstrate the NPV is positive i.e. it may not require a highly sophisticated modelling approach. However it does seem the GEM/SDDP modelling did not incorporate any modelling of reserves and that the original Pole 3 investment case was on the basis of unconstrained use of the nameplate capacity of the HVDC which hasn't been achieved in practice. Further even if Transpower in its role as Grid Owner has the correct incentives, Meridian notes there is no discussion in the WAG's paper of whether Transpower, in its role as System Operator has the correct incentives, particularly in terms of how it models the HVDC for the purposes of calculating reserve requirements. At footnote 20 the paper indicates this is because "…considerations of system operator incentives are not relevant to the cost allocation considerations." On the contrary, Meridian's view is that the HVDC limitations modelled by the System Operator have such a significant impact on reserve costs that it is critical to consider the System Operator's incentives in determining the level of these costs when setting a cost allocation framework.
7	Which option do you think sends price signals to underlying causers of the need for, and location of, IR to be procured in a manner which best meets the cost allocation principles of section 5?	Meridian considers the fundamental issue of unit vs station-based allocation needs to be addressed in order for any cost allocation option to meet the cost allocation principles of section 5. Of the options considered by the WAG then either Option 1 or Option 4: "Cost-to-island-causers" in our view best satisfies criteria regarding efficient price signals. Of these two Meridian suggests Option 1 should remain in place until further analysis is completed. However, subject to that analysis, and with the adjustment specified in our Q6 response, Option 4 should in addition ensure non-distortionary charges that encourage lower costs overall (Meridian's suggested third principle). The WAG's paper states the main drawback with Option 4 is that "it doesn't send a marginal signal to the HVDC that indicates the IR cost implications of high HVDC energy transfers." This criticism would have some force if allocation of costs to the HVDC was more consistent with the underlying 'exacerbators pay' cost allocation principle that the WAG considers should, so far as practically possible, be implemented here. HVDC costs are, however, passed through by Transpower to third parties and are therefore not internalised by Transpower in their decision making relating to the HVDC. Further, neither the current TPM nor the Authority's proposed new TPM allocate HVDC costs using an exacerbators pay methodology. For this reason Meridian believes this criticism misses the mark as it fails to recognise the limitations that are already inherent in using the TPM to allocate IR costs.

	Question	Response
8	Do you think the choice of general cost allocation approach (i.e. pro-rata versus runway) has a bearing on which option for cost allocation under the NMIR would be most appropriate?	No.
9	To what extent do you think the choice of best option is affected by the effectiveness of how costs allocated to the HVDC are passed-on to ‘underlying causers’ of the level of energy transfer across the HVDC?	For reasons already discussed (i.e. the TPM is not an ‘exacerbators pay’ approach) Meridian considers that IR costs allocated to the HVDC are not currently passed-on to ‘underlying causers’ of the level of energy transfer across the HVDC. Within any one trading period the level of energy transfer across the HVDC is the product of a complex series of interactions that are optimised via SPD into a least cost solution. In this context it does not make a lot of sense to speak of ‘causers’ of a certain level of energy transfer across the HVDC. As also discussed above, the HVDC component of the current TPM is recognised by the Authority to involve significant inefficiencies. Until the TPM is reformed, increased allocation of reserve costs to the HVDC will exacerbate the inefficiencies recognised by the Authority. Meridian requests there is further consideration by the Authority of alternatives to the TPM for allocating HVDC reserve costs. Option 5 – the ‘Cost-to-HVDC-then-to-AC-island-causers’ approach – creates a high level of exposure to the recognised deficiencies of the current TPM and in Meridian’s view is not a credible alternative at this point.

	Question	Response
10	Do you believe that some IR cost allocation options could materially impact on participants' incentives to offer energy and IR to a degree that could have material outcomes on these markets?	Yes. Refer our Q6 and Q11 response.
11	If yes, which options are likely to give rise to such outcomes, and could you provide worked examples demonstrating such effects?	Options 2, 3 and 5 - 'national allocation', 'factored by HVDC reserve sharing limits', and 'Cost-to-HVDC-then-to-AC-island-causers' - all have the potential to create charges that are highly disproportionate to the level of risks / costs created. The scale of the impact will at times be significant, and provide participants with little choice than to consider all options available for managing those costs - whether reserves or energy offers, or even operational decisions (reduced volumes or capacity). As we detail in our Q6 response, modifications to the 'Cost-to-island-causer' option (option 4) are required to counteract the potential for perverse impacts on reserve pricing. Meridian would be happy to present to the WAG on impacts of the various proposed approaches.

	Question	Response
12	Do you agree that HVDC-related IR costs should continue to be allocated to the HVDC owner and passed-on to market participants via the TPM, and do you have any observations about the interim allocation of IR costs under the NMIR?	See our response to Q8.

	Question	Response
13	Do you think cost-allocation for commissioning plant should: a) continue as is; b) change to be quantity-and-price-runway-based without application of a de minimis; or c) change to be quantity-runway-based without application of a de minimis?	Meridian considers that commissioning plant should be changed to be quantity-and-price-runway-based or quantity-runway-based, depending on which is the more cost effective option to administer. See also our Q1 response for further comments.

	Question	Response
14	Do you think a change to allocating costs to commissioning plant on a runway basis should only occur if general cost allocation were to move to a runway basis?	No. To the extent it is cost effective to do so, the runway method of charging should be utilised for commissioning plant, irrespective of the general cost allocation approach used.
15	What cost-allocation approach do you think should apply for plant with under-frequency and voltage-fault-ride-through dispensations?	Meridian agrees with the WAG's view – that is, where IR costs are created, these should be recovered from causers in a way that is cost-effective. For plant with dispensations from under frequency (8.19) AOPO obligations, it is unclear how aspects of the SO's recently determined interim approach will operate (in particular whether "the greater of the two island costs" is to be derived from aggregated quantities at the higher price, or the relevant quantity in each island at each island's price). This requires clarification. In any event, Meridian's view is that the principle of causer-pays dictates that these amounts should instead be charged at the sum of the two amounts, that is the summed value of the relevant island quantity at the relevant island price within each island. For Meridian's White Hill wind farm in particular, the manual processes that need to be followed by the SO in assigning allocations may also create a need for further potential adjustment. With new voltage-fault-ride-through standards, it is important that asset owners are provided with clarity and consulted as soon as practical on the specific methodologies that may be used for IR cost allocation so they can make informed decisions on investing or seeking dispensations.

	Question	Response
16	What measures do you think should be implemented to address small generation plant that are currently excluded from the need to comply with frequency related AOPOs?	The secondary CE risks from smaller plant (< 30 MW) may create high system costs and need to be addressed. In terms of the specific measures that should be implemented, Meridian agrees with the WAG's assessment that there are alternative courses of action (in particular more extensive adoption of AOPO standards) that should be pursued ahead of changes to IR cost allocation to target the risks small generation plant can present.
17	Do you think the event charge should be retained, and if so, on what basis?	Yes. The event charge as a construct is more in keeping with causer pays, although it is not clear the extent to which this is achieved in practice due to: a) The practice of re-allocating the event charge back to event causers providing payment for reserves. b) The $1,250 per MW lost charge which has remained unchanged for some time and may no longer reflect an appropriate assignment of costs. Further assessment of the legitimacy of the specific event charge level and provision of rebates to event causers is therefore required. Levying event charges for the HVDC also needs to be revisited. The direct pass through of costs using the TPM means that HVDC event charges are of no material consequence for incentives for reliability and do not target actual causers. Re-assigning event charges to IL providers under current IL procurement methods is not a justifiable approach and is not supported by Meridian. Allocating event charges to IL providers should be revisited if a new event-based procurement approach was able to be demonstrated to be of benefit. Meridian considers, however, the case for introducing event-based procurement has yet to be made.