

Submitter	Comments
Q1: Do submitters agree with the list of identified concerns? If not, why not?	
EnerNOC	Yes, the list covers most of the relevant concerns. In particular, we agree that it is important that extended reserves requirements (or the expiry of exemptions therefrom) do not cause IL to be withdrawn from the IR market, as this would be likely to increase costs considerably. EnerNOC would add that the interruption of feeders is rather a blunt instrument. It is inconsistent with consumers' expectations from a modern industry with a "smart grid" and smart meters. These expectations are reasonable: with the continuing increases teleworking, and medical dependence on uninterrupted power, both the direct costs and the extended consequences of feeder-level interruption will continue to rise. The extended reserves framework provides an opportunity to align grid resilience with future customer needs, maximising the economic benefits.
Contact	Yes.
ENA	No. While we acknowledge that some of the issues identified in s2.4 of the Paper are real (e.g. "Participants' abilities to interrupt a fixed percentage of their load differ") we believe that the focus on remedying concerns via a market-based solution is not justified by the issues discussed in the paper. Also, while we recognise the requirement for the Authority to focus on delivery of outcomes that meet its statutory objective (s 3.1.1 of the Paper) we consider that the relevant part of that objective in the provision of AUFLS is to <i>promote reliable supply by</i> – rather than <i>competition in</i> – the electricity industry for the long-term benefit of consumers.
Genesis	Yes. However, we also consider that the current arrangements do not optimise the allocation of AUFLS in a more targeted way that: - protects essential users of electricity from being disconnected during an under-frequency event. For example, we are aware that, in some parts of the network, police stations and hospitals face the risk of disconnection during an under frequency event. These consumers place a high value on continuous supply and would prefer not to have their consumption interrupted. - allows individual consumers to opt in or out according to interruption cost. As noted in our cover letter, we consider that developments in advanced metering technology could provide a way to address these concerns in the future.
Meridian	Meridian agrees the Authority has set out an accurate list of potential concerns, although we note it is difficult to gauge the extent of any potential barriers to the uptake of equivalence arrangements on the basis of the information provided. Meridian supports the suggested design criterion set out by the Authority regarding the need for any arrangements for procuring extended reserves to promote lowest cost load to be offered into the IR market where it is economic to do so. We assume this will ensure arrangements are designed in a way that addresses measures that impede the ability of distributors to offer reserves into the

	IR market.
MEUG	Yes subject to the following two comments. First, we agree “equivalence” in paragraph 2.4.1(b) is a concern but not for the reasons explained in that paragraph. For MEUG the problem with the current equivalence provisions in Part 8 is that they do not facilitate re-allocation of obligations to deliver the lowest cost mix of needed extended reserves. The reasons for this are probably because: • Uncertainty to participants around the decision making process by the system operator to have an equivalence arrangement granted. There are no precedents for AUFLS equivalence arrangements and the first party to make an application will incur high transaction costs; • There is the significant risk of being gouged by distributors exercising market power. Second, the current regime, that is in effect a mandated administrative approach, fails to link the cost of providing reserves with exacerbators that cause the need for AUFLS. Extended reserve events are caused by unforeseen transmission and or generator asset or production failures. Those parties should bear the cost of AUFLS rather than load disconnected.
Northpower	Subject to the introductory comment above¹, we agree with the concerns identified on clause 2.4.1 of the consultation paper. However, Northpower suggests that there are additional concerns that are not listed, including: • The requirement for each distributor to provide a minimum of 16%+16% of load for AUFLS at all times leads to a significant over-provision of AUFLS in some time periods which the System Operator has identified could result in a complete collapse of the North Island system if both blocks of AUFLS were shed at those times; and • There was lack of clarity in the Rules, and now in the Code, regarding the requirement to not offer IL from load dedicated to AUFLS. We interpret it as not “double counting” but it can also be interpreted as having to disable IL on all feeders controlled by AUFLS relays.
NZ Steel	We generally agree with the issues mentioned in section 2.4 of the paper, but a further concern of ours is the “..at all times..” phrase in section7(6), Schedule 8.3, Technical Code B. This phrase greatly restricts our ability to offer 4 x 8% blocks of our own demand.
Pacific Aluminium	Yes, the Authority has identified the major concerns.
Powerco	No, for the following reasons: (a) Flexibility: Powerco does not agree with the Authority’s assumption that smaller distributors have difficulty sub-dividing their loads. AUFLS control is generally applied at the individual 11kV feeder level, and even distributors with as few as eight 11kV feeders

¹ In its opening remarks, Northpower considered that comments in the paper regarding its exemption from AUFLS obligations could be misinterpreted and clarified that its exemption relates to one GXP only.

	are able to provide the required blocks without difficulty. (b) Equivalence and (c) Dispensations: The equivalence and dispensation provisions in Part 8 of the Code provide the System Operator with a degree of flexibility which could potentially help to reduce compliance costs. However, in practice, as the consultation paper notes, there has been no need to use these provisions. This would seem to support Powerco's view that there is no particular problem with the current approach to the allocation of AUFLS obligations and, hence, no need for a fundamental re-assessment of that approach. (d) Interruptible Load: Powerco offers some of its interruptible load into the IR market. This load is kept separate from and discounted from the AUFLS block requirements. Hence, for us, the satisfaction of the AUFLS requirements has no direct effect on the IR market, or indirect effect on the energy market. (e) Exemptions: This paragraph appears to apply mainly to direct connects. The current arrangements which exempt direct connects appear to have caused no problems, given the extreme rarity of actual AUFLS events. Also, most direct connects are high value industrial loads which would be costly to include in any AUFLS scheme and would therefore be very likely to be excluded if market-based arrangements applied. Again, Powerco does not see how the current arrangements give rise to any concerns or lead to the conclusion that a fundamental re-assessment is required.
Transpower	We agree that the paper captures a number of efficiency concerns which are then reflected through the range of option designs. Our primary concern is that system security is met and we support the aim of achieving this efficiently.
Vector ²	n/a
WEL	Yes, we agree with the list.

Q2: What level of targeting do distributors consider is achieved in practice?	
EnerNOC	Of our distribution-connected FIR-providing industrial customers, we have only found one that was on an AUFLS feeder. This was worked around using "internal equivalence" arrangements with the network company. The disturbing aspects are that (a) the company did not know that they were on an AUFLS feeder, and hence liable to interruption without compensation, and (b) the network company initially considered that the fact that they had chosen to put that customer on an AUFLS feeder should disqualify the customer from participating in the IR market. Sourcing FIR from smaller distribution-connected customers is important, because it greatly increases diversity, compared to the traditional centralised generation and direct connect industrial sources. This diversity provides greater predictability and reliability. It is

² Vector's submission was not provided in the suggested format. Their responses have been fitted under the questions they approximately relate to, but there may be some overlap in some places.

	hence essential that distributors' choices in fulfilling extended reserves obligations do not impede the participation of their customers in the IR markets.
Contact	N/A.
ENA	Targeting can be expected to become more precise as smart network technologies are deployed. It would appear more productive to concentrate on the removal of impediments to smart network deployment (such as those identified in ENA's July 2012 discussion document ³) in order to improve the industry's capability to target lowest cost customers and activities.
Genesis	We understand that distributors can allocate AUFLS provision unevenly across grid exit points to reflect differing network sizes and configurations. However, distributors are unlikely to have the necessary information to be able to effectively target the allocation of AUFLS in a way that reflects the true cost to consumers of this service.
Meridian	Meridian considers this question is best answered by distributors. We note, however, that rolling outage planning processes will provide distributors with an understanding of relative interruption costs to inform their choices.
MEUG	No comment.
Northpower	Most distribution feeders that supply primarily residential loads (which, according to Table 1 of the consultation paper, have the lowest interruption cost) also supply small and medium non-residential load (including suburban shopping centres, supermarkets and medical centres) to which Table 1 assigns the highest interruption cost. So, while distributors would seek to target load with low interruption costs, it is inevitable that load with higher interruption costs will be included on the same feeders. It is also the residential load that contains the load most suitable for IL (namely hotwater load), adding to the IL/AUFLS dilemma. However, the major problem is that the "16%+16% minimum at all times" requirement means that distributors have to include higher value load in the AUFLS mix to ensure the requirement is met at the most challenging times, which Figure 8 in the consultation paper appropriately identifies is from midnight to 6am.
NZ Steel	As this question is aimed at distributors, we offer no view.
Pacific Aluminium	No comment.
Powerco	Powerco considers that it appropriately targets lower cost loads for inclusion in AUFLS. Essential services, such as airports and hospitals, are excluded – these would suffer high costs if shed. A problem with the Authority's approach is that it assumes customers know ahead of time what their interruption costs would be in a high impact, low probability event. This is unlikely to be the case, given

³ *Smart Network opportunities and the current regulatory environment.* A report prepared by the ENA's Smart Network Working Group. July 2012

	the rarity of such events and their uncertain duration.
Transpower	Not applicable.
Vector ⁴	n/a
WEL	Varies in practice from GXP to GXP and is mostly driven by the ultimate objective to comply all the time trying to minimise over-compensation as much as possible (for both technical and customer service/financial reasons). More smaller blocks will complicate the issue, worsening the level of targeting and making the event more likely to occur for the part of participants.

Q3: Do you agree with the Authority's conclusions regarding relatively low cost measures? If not, why not?	
EnerNOC	We agree that it makes sense for distributors to focus on residential feeders for the most-called blocks. We would suggest that distributors should take care to rotate the blocks after an extended reserves event, so that the same customers are not always the first to be interrupted. This is analogous to how some distributors rotate their ripple zones.
Contact	Contact supports the Electricity Authority's initiative to more efficiently assign non IL load to AUFLS.
ENA	In general no: • Weighing the benefits of protecting against a low-incidence/ high impact event against the costs of that protection is a notoriously difficult exercise. The costs of providing AUFLS via existing arrangements are not readily identifiable in the Paper but the overall cost vs the potential costs of a major system failure would appear low. • AUFLS provide protection against cascading system failures that could have prolonged and very costly implications. Here we are conscious that the value of reliable electricity to consumers includes factors such as long-term impacts on NZ's international marketing image that are hard to quantify. Accordingly, we consider that the relative cost of providing AUFLS seems reasonable. • It would be useful to see the final outcome of the EA's current VoLL investigation before forming a view on the cost of load loss to different customers.
Genesis	Any costs should be commensurate with the benefits. As noted in our cover letter there: • are significant efficiency benefits to be gained from more targeted provision of AUFLS at the consumer premise level; and,

⁴ Vector's submission was not provided in the suggested format. Their responses have been fitted under the questions they approximately relate to, but there may be some overlap in some places.

	• may be potential for advanced meters to provide this service in the future. Therefore, we suggest that the Authority investigate how advanced metering technology would need to develop to make it a cost-effective solution that is technically compliant with the System Operator's requirements.
Meridian	Meridian agrees it is essential that any measures to improve the allocation of loads to AUFLS are relatively low cost, having noted the reasonably modest scale of potential benefits and potential scale of costs from displacing load in the IR market suggested by the Authority's analysis. We also note that calculations supporting the Authority's estimates of potential benefits assume AUFLS-prompted interruptions take place far more frequently than typically experienced in the past (its usage on 15 December 2011, for instance, representing its first use for 15 years). We also agree with the Authority's conclusion that differences in load structures and the likely frequency of extended reserve events in the South suggests the scale of potential benefits from improvements in the allocation of load is likely to be more limited than in the North.
MEUG	This question refers to paragraph 4.1.18 (b) that states "Relatively low cost measures to improve the allocation of other loads to AUFLS could be beneficial, especially in respect of the first block." MEUG agrees and notes it may also be feasible to allocate the first three blocks of a four x 8% regime to households based on the results graphed in figure 3: Estimated North Island residential load vs total island GXP load. MEUG notes that table 1 reports the average unit cost for a 2 hour interruption for residential customers of \$5,000/MWh is half that of the next highest load category of large non-residential customers.
Northpower	With due respect, it is not clear to us as to what the Authority's conclusions in clauses 4.1.14 to 4.1.18 of the consultation paper actually are. However, we agree with clause 4.1.17 that it would be impractical to allow smaller consumers to opt in or out, but there would be additional benefits if large consumers within distributor networks were able to be considered separately or avoided altogether in relation to any obligations for AUFLS. Figure 4 in the consultation paper shows dramatically how the load attributable to the "Five largest consumers" is a significantly higher proportion of the total load on the Northpower network in comparison to most other North Island distributors and therefore why the simple "one-size fits all" rule of "16%+16% minimum at all times" simply does not work for the Northpower network.
NZ Steel	We generally agree.
Pacific Aluminium	We agree that it is most efficient for load to choose the reserves market where it has the highest value. Mandated regulatory approaches do not achieve this. We agree with the Authority that the withdrawal of low cost load from the IR market to provide AUFLS would have a significant adverse economic impact. The current approach, when applied to directly-connected industrial consumers, is likely to have this

	effect. This is one reason why the current approach is manifestly inadequate.
Powerco	There may be some opportunity to improve the allocation of loads to AUFLS, but this could be achieved administratively as effectively as by any other means. As noted in response to the previous question, the rarity of high impact low probability events means that it is unlikely that customers would know ahead of time what their interruption costs would be during such an event. Hence, it is difficult to see how a market approach could target higher cost consumers more effectively than an administrative approach.
Transpower	We do not consider the Authority has adequately described what the low cost measures are that will improve the allocation of load to AUFLS.
Vector ⁵	n/a
WEL	It is not only about the cost literally. IR/IL is just a load shifting for the distribution (h/w), AUFLS on the contrary are the lights out for real.

**Q4: Do you agree that distributors and direct connects should be responsible for providing extended reserves in both islands?
If not, why not?**

EnerNOC	Yes. It makes sense to use the same approach on both islands. Involving retailers would only add to the cost. With regards to the involvement of direct connects, it is particularly important to ensure that these obligations do not lead to them withdrawing FIR capacity, as the use of capacity for FIR provides greater economic benefits than its use for extended reserves. EnerNOC suggest that a clean way to achieve this would be for any FIR offered from a direct connect site to be counted towards the fulfilment of its extended reserves obligations. The system operator already has a record, from initial compliance tests, of the amount of FIR that each site is able to provide. All that is required in addition to this is confirmation, from the direct connect customer and/or aggregator, that the load is still being actively offered in the FIR market.
Contact	Yes, this is the most pragmatic and economic solution.
ENA	We consider that the continued exclusion of direct connect customers would remove some of the potentially lower cost customers from the AUFLS regime. At the very least we would recommend that the EA consider options for ensuring that direct connects meet 'user pays' costs

⁵ Vector's submission was not provided in the suggested format. Their responses have been fitted under the questions they approximately relate to, but there may be some overlap in some places.

	associated with the AUFLS protection they enjoy.
Genesis	We consider that, over time, development of advanced metering services will enable retailers to be able to offer this service into the extended reserves market. Transpower is also an alternative to the current extended reserve providers, as demonstrated by current South Island arrangements. We suggest Transpower should therefore be evaluated on a like-for-like basis.
Meridian	Yes.
MEUG	In the context of the discussion in paragraph 5.2.3 to 5.2.6 we assume this question could be restated “do you agree distributors and direct connects rather than retailers should be responsible for implementing an appropriate extended reserves regime in both islands?” In that case our answer is yes though as market mechanisms are introduced there should be no barriers to retailers and aggregators entering those markets.
Northpower	Yes, distributors and direct connects have knowledge of the nature of the load connected to their feeders. However, we suggest that the Electricity Authority must guard against other participants (who do not have an obligation in relation to AUFLS) eroding the pool of load available for IL and AUFLS in an uncoordinated manner. For example, third-party load aggregators have a valid role in the IL market but they do not have any obligations to provide AUFLS.
NZ Steel	We agree that it would not be economically feasible for individual residential consumers and SMEs within distributor networks to decide whether or not their loads will provide extended reserves. Therefore, we feel that both distributors and direct connects should be involved in the provision of extended reserves in the North Island (as this is where NZ Steel is located).
Pacific Aluminium	This is the wrong question and suggests that regulatory compulsion, as we have now, is an appropriate approach. It is not. The real issue is how the procurement of extended reserves should be organised in order to facilitate the greatest participation from distributors and direct connects or other parties such as retailers. Clearly, a market-based approach is most likely to achieve this where distributors, direct connects and other providers are free to participate as they choose, as occurs now in the instantaneous reserves (IR) market. There is no fundamental reason why this cannot be applied to the procurement of extended reserves as well. Regulatory compulsion only leads to inefficiencies and higher overall costs. This is unlikely to be for the long-term benefit of consumers.
Powerco	Yes, we agree that distributors and direct connects should be responsible for physically providing “extended reserves” in the form of AUFLS relays. However, if the procurement of load to satisfy AUFLS requirements were to be treated as an ancillary service subject to tender, or some other market-based approach were to be introduced, the responsibility for ensuring that sufficient “extended reserves” were procured and retained at any time should rest with the System Operator.
Transpower	The current policy (whether currently intended or just the consequence of past regulatory decisions) is that only North Island Distributors and the Grid Owner make their assets AUFLS compliant. Transpower (as asset owner) is a provider for the South Island

	because historically it was proving difficult for Distributors to meet the obligation. We would like more reasoning on what has changed in the current environment to make it now more likely that direct connects and all distributors would be able to meet any new responsibility under an obligation. Under a market provision the responsibility would be on the contracted party.
Vector ⁶	Who is best placed to identify high and low-value load? The Authority also takes the view that distributors are better placed than the Authority to identify higher or lower value load. While distributors will know their customers better than the Authority, they are not able to identify the hierarchy of value that different consumers place on their load and could only attempt a relatively high-level, broad-brush allocation approach. It is not at all clear that the Authority would be materially less effective at this and if the Authority was to undertake the identification of high and low-value load there would at least be a nationally consistent approach. Vector recommends the Authority establish principles for identifying high and low value load at a national level. This could be a simple matter of confirming the criteria developed by the Electricity Commission for setting priorities for maintaining supply to particular customer groups. These criteria are set out in section 10.4 of the Arrangements for Rolling Outages consultation paper, 14 November 2008. Exemptions for direct connect customers Vector strongly supports the removal of the exemptions for direct connect customers. The exemptions for the direct connect customers have lasted too long and their justification is too weak, especially if parties are able to trade their obligations. Direct connect customers are free riding on the system security delivered by distributors who accept and take steps to meet their AUFLS responsibilities. Vector accepts that requiring direct connect customers to provide standard AUFLS blocks in the same manner as distributors may be impractical due to the nature of their obligations. Therefore, Vector recommends that direct connect customers be subject to AUFLS obligations but continue to be provided with the ability to transfer this obligation to other parties, subject to agreeing suitable commercial arrangements. This could be achieved under options C or D in the consultation paper. Vector notes the Authority's concern that requiring direct connects to provide AUFLS would reduce the amount of interruptible load (IL) being offered into the interruptible reserves market. Vector does not accept that this is a valid reason to retain the exemptions. Some direct connects are able to make IL bids. The fact that they can physically do so indicates that they are able to contribute to meeting their own AUFLS obligations - the fact that they would prefer to make such load available as IL for a fee does not change their ability to make it available for AUFLS. If direct connects wished to continue providing IL, they could do so subject to contracting with a distributor to provide AUFLS on their behalf.

⁶ Vector's submission was not provided in the suggested format. Their responses have been fitted under the questions they approximately relate to, but there may be some overlap in some places.

WEL	WEL agrees with equal obligations on both islands.
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Q5: Do you agree that there are no real impediments to distributors exchanging obligations? If not, why not?	
EnerNOC	Yes.
Contact	Yes.
ENA	We strongly disagree: - Presumably any such exchanges would be driven by normal market incentives. At present, most distributor-managed load is subject to price and quality control by the Commerce Commission. Before most electricity distribution networks (as parties with a strong established position as AUFLS providers) could participate effectively in an exchange of obligations it would be necessary to remove dis-incentives for this, and to provide appropriate incentives. The Part 4 regime would need to be adjusted to allow efficient pricing incentives to flow through to networks, and not be netted off from total allowed returns. It may be that the long-awaited 'section 54Q' arrangements that the Commission appears to be prepared to introduce in 2015 will open the door for electricity networks to participate in an AUFLS market. However, at least until the s54Q regime is defined it is premature to consider participation in such a market. - Bidding for or acquiring another network's AUFLS provision role is a difficult concept to understand. Does the Authority envisage (mainly domestic) customers in one area being connected to AUFLS in order to protect a range of customers in another area, with implications of cross-subsidies or other distortions (such as doubling up of AUFLS cover due to broad targeting)? Here the additional exposures to Consumer Guarantees Act claims embodied in the Consumer Law Reform Bill are a potential mine-field.
Genesis	We agree that the main impediment is likely to be distributor's willingness to participate in exchanging obligations. We consider that taking a market-based approach to the allocation of extended reserves will address this by increasing the commercial incentives for distributors.
Meridian	Meridian agrees there do not appear to be any real impediments that would prevent distributors exchanging obligations. As the paper correctly highlights, there will be choices available as to how this could be incentivised through policy design.
MEUG	It does appear there are no impediments to distributors currently exchanging obligations without any financial transactions. The fact no such arrangements have been implemented is either due to distributors not understanding that option, or a lack of financial incentives, or at the minimum an ability to recover transaction costs. The solution therefore is to introduce some financial incentives subject to:

	• The scale of any market approach being commensurate with the need and proven benefits over an administrative approach for each block. For example see MEUG response to Q3 on the possibility of using mandated obligations on residential customers for first tier blocks. • Careful consideration of market power concerns will be needed⁷. • Ensuring procurement costs are assigned to Transpower and generators as exacerbators consistent with the approach used for Instantaneous Reserves.
Northpower	As long as it is clear that provision of AUFLS across each island is mandatory and Distributors are not exposed in any way to claims for losses if AUFLS load is shed.
NZ Steel	We agree re exchanging obligations, but if a party is interested in purchasing a block / some blocks from another party, then we have a concern regarding the possible exercising of market power by the seller as the market will be thin.
Pacific Aluminium	Yes, we agree. Further consideration needs to be made in a market-based context and in light of the System Operator's revised requirements for extended reserves. In this regard, a zonal approach is likely to yield the greatest benefits, rather than the current cumbersome and inefficient GXP basis. We also agree that participants should be able to make efficient trade-offs between participating in the IR and/or extended reserves markets.
Powerco	Yes.
Transpower	Any trading of obligations would need the overview of the System Operator to ensure that a different provider would still meet the required security objectives. Depending on the design of the option, a likely impediment is distributor location.
Vector ⁸	Real incentives are needed to make the proposals work While the consultation paper does not properly address the issue, it is important to recognise that distributors do not have incentives to participate in an AUFLS trading regime. Direct connect customers may have an incentive to participate as they may find it cheaper to pay another participant to meet their AUFLS obligations than to meet them themselves but, for the reasons discussed below, this does not apply to distributors. Conceptually, distributors could enter into the following type of arrangement:

⁷ Paragraph 5.3.3 of the consultation paper recognises limited distributor incentives and market power concerns need to be considered.

⁸ Vector's submission was not provided in the suggested format. Their responses have been fitted under the questions they approximately relate to, but there may be some overlap in some places.

	• Distributor A: has a network configuration that requires them to place higher value load onto an AUFLS block. • Distributor B: has a network configuration that enables them to meet their AUFLS obligations from low-value load only and has additional low-value load “spare”. • Distributor A pays Distributor B to provide AUFLS on their behalf. However, in reality the high and low value load is not high or low value to Distributor A or B, but to their customers. So while customers would benefit from the distributors trading the load, it is unclear why any distributor in the position of Distributor A would devote time and effort to participate. Further, Distributor B may be reluctant to participate due to increased regulatory risk (through taking on further compliance obligations) unless the value is sufficient to justify the additional risk. It is not clear that such value will be available in trading the obligations for events that happen once per decade, on average. If the above scenario were changed so that A was a direct connect customer, trading would more likely occur as there would be a strong incentive for A (holding high value load) to trade with B. As direct connect A values its load highly, it would pay Distributor B to provide AUFLS on their behalf. Failing a ‘direct connect – distributor’ arrangement, incentives for a ‘distributor – distributor’ trade could exist if the distributors in Distributor A’s position were paid part of the estimated consumer benefit of any trading arrangement they enter into. The settings of such an arrangement would need to ensure that any increased revenue did not simply offset other revenue permitted under a price cap set by the Commerce Commission. If the Authority considers that a trading regime is likely to deliver net benefits nationally, it is unclear why it would not consider payments to distributors to incentivise trading agreements. Based on the Authority’s analysis, such incentives must be capable of delivering net benefits overall. Instead, the Authority’s preferred option contains a punitive incentive whereby distributors would need to take part or pay a penalty. Such an arrangement is unlikely to build support for the proposal. Furthermore, although distributors can deliver the proposed AUFLS regime more cost-effectively, it is the entire market that benefits (generators as well as load suppliers). Hence, distributors should be provided with positive incentives and ought not to bear all the costs themselves. Vector recommends the Authority provide meaningful positive incentives for distributors to participate in any trading regime. Additionally, paragraph 5.9.3 proposes setting procurement costs to participants as a proportion of their load. This is the intended “negative incentive” that will push parties to participate. However, if these costs are treated as recoverable costs under the input methodologies, distributor incentives to participate will be much reduced. Vector recommends the Authority consider the way in which payments would be treated under the Input Methodologies, as this will have a significant impact on the power of the incentives.
WEL	Agree. It is definitely worth exploring.

Q6: Do you agree that options A to D are the most plausible range of options? If not, what alternatives are plausible?

EnerNOC	Yes.
Contact	Yes, however option D (Ancillary Services Procurement) could also be prohibited by cost.
ENA	We agree that options E and F are not plausible. If further consideration is given to reviewing the AUFLS regime then we agree that this should be limited to options A to D.
Genesis	As consistent with our cover letter, we consider that, advanced meters could make option F a plausible, cost effective option, in the future.
Meridian	Meridian agrees the Authority has correctly identified the plausible set of policy options. We support the Authority's assessment that establishing a half-hourly, IR type market ("Option E") or centralised market to facilitate participation by individual consumers ("Option F") is likely to involve costs in excess of any potential benefits and should not be pursued at this point.
MEUG	For completeness the status quo could be added to the far left hand side in figure 7. Figure 7 treats each option as being discrete. MEUG suggests it may be least cost to apply different options to each extended reserve block. This may change over time as improved market mechanisms are developed.
Northpower	Yes
NZ Steel	We agree that the options mentioned are the plausible range. However, for completeness, the status quo could be added.
Pacific Aluminium	Options A to D are plausible, but so are market-based approaches similar to the process for procuring IR. We recognise that the Authority does not want to consider such an approach at this time due to the complexity, but that does not mean it should be dismissed. We see option D as being on the path to better market-based arrangements that leverage off technological innovation such as advanced metering infrastructure and smart grids. A tender-based approach is not the end-point, despite the Authority's assertion at paragraph 5.5.5 that an IR style market would be prohibitively costly to develop relative to the potential benefits. This needs further analysis.
Powerco	No. Only option A is a plausible alternative to the current approach. Options B to D require either the regulator, the System Operator or market participants themselves to be able to accurately value the expected average interruption costs of high impact low probability events. In our view, the rarity of such events means this is not possible in practice.
Transpower	Agreed

Vector ⁹	Options A – D Vector considers that the Authority has identified the full range of options that are open to it. However, the consultation paper discusses the options at a high level only. While the options seem workable, the lack of detail provided prevents Vector from fully understanding or considering the implications and potential risks and issues under each option. Therefore we are unable to provide a fully informed opinion on which option is most preferable in this submission. The key element that is lacking from the analysis is consideration of the likely ability and willingness of parties to participate in any of the proposed options. In particular, Vector is concerned that the Authority is ready to go forward with a market based solution without establishing the level of demand (e.g. whether direct connects and distributors are willing to pay for AUFLS services) and supply (e.g. whether distributors are prepared to offer more AUFS in return for payment). It is not clear that the Authority has attempted to discover whether shifting to a market based AUFLS regime would encourage those currently exempt (or dispensed) to trade and/or offer their load. The Authority appears to have assumed that if a higher cost for non-compliance is imposed, supply will follow. This has not been demonstrated (at least not in the consultation paper). Vector recommends that the Authority assess the likely supply and demand for a market-based AUFLS trading scheme before progressing this project further. From Vector's perspective, we would be concerned if we were to take on AUFLS responsibilities of other parties as we would also be taking on increased regulatory risk to our business. Therefore, the monetary value of the transaction would need to be considerable to incentivise Vector to participate in such a market. It is important to consider not just the current exemptions (six direct connects are exempt) but also the existing dispensations for generators (there are currently numerous dispensations for wind farms and thermal plants). These dispensations are available to those unable to comply, or excluded from complying, with the current requirements relating to contributions to frequency support in under-frequency events – and are being made available for free to the generators. Vector recommends that any market-based regime for extended reserves should include generators. Generators should be required to pay if they cannot meet their requirements to provide frequency support under clause 8.19 of the Code. In regards to the Authority's preferred approach (Option D), Vector recommends that the 'exacerbator pays' approach be applied to the tender-based option, as this would ensure that the generators and the grid owner have incentives with regard to the efficient provision of measures necessary to ensure system security. Options E and F are infeasible Vector agrees that the option of individual consumers making decisions as to whether they offer extended reserves is infeasible, with prohibitive transaction costs. This is an obvious conclusion.
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	Vector recommends options E and F are not considered any further.
WEL	Agree with that range.

Q7: Do you agree with the Authority's preliminary conclusions? If not, why not?	
EnerNOC	Yes. We agree that the tender-based process (Option D) seems to be the best long-term solution. The use of a market mechanism allows for flexibility and innovation. Tendering on a gross basis ensures broad participation. Together, this should ensure that resilience is achieved at lowest total cost. Option C2 is second-best, but we consider the gross approach of Option D to be greatly preferable.
Contact	In principle we support the tender process and recommend a trial is established. However, we note that applying the exacerbator pays example¹⁰ of instantaneous reserves under frequency event charges, does not provide any further incentive to Contact Energy than the current portfolio drivers. As the value drivers can be distorted we support this approach not being used. In our view the beneficiary pays approach¹¹ to allocate procurement costs to participants (network companies) in proportion to their load share is a better methodology as it allows participants to make their own value judgments on extended reserves and instantaneous reserves (IL).
ENA	In general we disagree. As events in financial and property markets have demonstrated, market approaches can incentivise unwarranted risk-taking and illicit behaviours. Network security is of fundamental importance, and it is not hard to envisage it becoming compromised over time if the 'markets first' philosophy is extended into activities that will deliver relatively modest returns while holding in reserve potentially very valuable assets (e.g. leading to 'borrowing' from AUFLS commitments in order to cover positions taken in energy or IR markets).
Genesis	Yes, subject to the comments in our cover letter.
Meridian	While we agree a tender-based system offers certain attractions at a conceptual level, we consider it would involve significant changes in funding arrangements and currently also have some concerns as to whether it will prove to be optimal from an efficiency perspective. Central to these concerns is that, relative to IL, actual use of extended reserves products to-date has been far more

¹⁰ Section 5.9.6

¹¹ Section 5.9.3

	limited. We are concerned potential benefits will be substantially lessened because of this and consider it is critical the system can be demonstrated to have low implementation and running costs to be considered a viable option. We also consider this suggests there are merits in continuing to explore “low cost ways” to facilitate trading of obligations, like the Authority has proposed. For these reasons, Meridian considers robust cost benefit analysis is strongly needed. We also note we would welcome fuller information on the compliance arrangements that would apply under a tender-based approach and how the different funding approaches identified by the Authority would work in practice under a tender-based system.
MEUG	Only partly. We agree further investigation of tender-based options should be considered. This should not be considered the best long term solution. The Authority should maintain a watch on more sophisticated market mechanisms as technology improves. We do not think an obligation and trade basis using equal percentage obligations on all grid connected parties is much different from the status quo because it fails to link exacerbators with the cost of providing extended reserves. An evolutionary approach to introducing market mechanisms should be considered. As noted in response to questions 3 and 5 it may be that for the first few blocks an administrative approach mandating obligations on residential, customers may be lowest cost. For the last or last few blocks a tender-based approach could be considered.
Northpower	We agree that the two options listed in clause 6.1.7 of the consultation paper are worthy of further investigation and evaluation. That is not to say that either of them should necessarily be the final solution(s) but the evaluation process should be such that the “pros and cons” are defined to facilitate further discussion. Northpower also believes that some form of the “overs and unders” exchange (rather than an auction contemplated by clauses 5.8.5 to 5.8.8 of the consultation paper) could be beneficial. For instance, without a partial exemption Northpower would not be able to meet the strict 16%+16% requirements during the early hours of the morning but, at certain other times of the day, we have in excess of 16%+16% connected to AUFLS relays. If this could be exchanged with another participant who had a complementary profile, then that would be a Win-Win outcome. Northpower is of the opinion that some of the fundamental issues need to be resolved prior to, or in conjunction with, developing the proposals further. For completeness, we list some of these in the following: Northpower would like to remind the Authority that there are issues raised in previous submissions that, from Northpower’s perspective, do not appear to have been addressed in the consultation paper or, where they have been mentioned, they are not covered in the conclusions. From Northpower’s perspective, the most fundamental issue is that certain types of load are strategically important on a national basis (not just to the consumer directly affected) and these should be excluded from the pool of load from which AUFLS is drawn.

	Much of the load that is presently covered by exemptions is excluded on the basis that it is more valuable as IL and the consumers involved gain financial benefit from offering IL. However, some of the load that is exempted is on the basis that it is not practical due to size, and nationally strategically not desirable, to contemplate shedding any significant portion of the load, even in a rare event that results in AUFLS being triggered. (The issue of sheer size is similar to that highlighted for the smelter in clause 4.1.19 in the consultation paper.) Another issue relates to provision of AUFLS and IL on the same feeder. One interpretation of the rule is that, if a feeder is connected to an AUFLS relay, then any IL on that feeder must not be offered to the market (or even that it should be disabled). Another interpretation is that any load offered for IL must be excluded from the assessment of the 16%+16% for AUFLS so, for example, if a load of 100MW includes 10MW of hot-water load suitable for IL on feeders assigned to AUFLS, then there would need to be 42MW of load on the AUFLS feeders (32MW for AUFLS + 10MW for IL). This needs to be clarified so that the expectations are clear for distributors and other participants. Northpower suggests that the second interpretation (allowing IL and AUFLS on the same feeders but not double-counting the load) is the most practical in terms of maximising use of load suitable for IL on distribution networks.
NZ Steel	We generally agree with the Authority's preliminary conclusions and also support MEUG's suggestion that an evolutionary approach to introducing market mechanisms should be considered.
Pacific Aluminium	We agree with many of the Authority's conclusions, but not all. In particular we agree that the Authority should further develop option D as a tender-based approach for the procurement of AUFLS is most likely, out of all the options considered, to improve procurement efficiency. However, we only consider this a stepping stone to a more efficient procurement methodology that is similar to the way IR is currently procured. Therefore, the Authority should not consider successful implementation of a tender-based approach to be the end point. As discussed, we disagree with the Authority's assertion in paragraph 5.5.5. The section 5.9 discussion around cost allocation associated with option D is a little confusing. Paragraphs 5.9.5 and 5.9.6 seem to conflate allocating the cost of procuring extended reserves with the event charge should an extended contingent event occur. These are separate issues. As noted by the Authority in the paper, extended under-frequency contingent events are caused by failures at grid-connected generating stations and/or the transmission grid. Applying the exacerbator-pays approach would mean allocating the cost of procuring extended reserves to mitigate the impact of such extended contingent events to grid connected generators and Transpower. The transaction costs of doing this would also likely be less than allocating the costs to load as there are fewer parties to transact with. It is our view that allocating the cost of procuring extended reserves for extended under-frequency contingent events to grid-connected generators and Transpower (as exacerbators) is more consistent with Authority's statutory objective.
Powerco	No. The Authority's analysis assumes that it is possible to accurately value the expected average interruption costs of high impact low probability events ahead of time. In our view, the rarity of these events makes this impossible in practice. Consequently, our conclusion is that there is no reason to believe that a market-based approach to procuring load to satisfy AUFLS requirements would necessarily result in a more efficient outcome than the current administered approach. Hence, given the transaction costs associated

	with market-based procurement methods, the current administered approach is likely to be a more efficient means of identifying low cost load to satisfy AUFLS requirements and the only alternatives that should be considered are other administrative methods, such as option A.
Transpower	We do not think the cost benefit analysis is sufficiently robust to be able to agree that the tender process is the preferred solution. However we support further analysis of the preferred options as proposed by the Authority.
Vector ¹²	Vector is, however, concerned with the practicality of the EA's proposal. Particularly in relation to whether there is sufficient value involved to justify the costs of establishing and operating a more market-based system of trading AUFLS obligations. Overall, Vector considers that the Authority's analysis and proposals are weighted towards an economically idealistic outcome without fully considering the practical implications. The purpose of the AUFLS system is to act as a last-resort emergency measure to prevent cascade failure across either the North or South Island. Given the severe economic and social consequences of a cascade failure, a mandated regime is not unreasonable. The rarity of AUFLS events means that it is unlikely that an accurate estimate of the costs of interruptions can be made before they occur. Thus a market-based approach may not be able to successfully drive efficiencies in the provision of AUFLS, and may be less efficient overall. Vector recommends that these issues be considered in a cost-benefit analysis of the Authority's proposal. It is notable that overseas provision of emergency reserves is achieved through mandatory obligations rather than market arrangements. This implies that what the Authority has proposed is unusual and has not been considered the optimal solution by regulators overseas, who are also concerned with ensuring that their industry is capable of responding to an emergency under-frequency event and protecting consumers as much as possible from the severe economic consequences of cascade failure.
WEL	Agree. It is definitely worth of exploring further and seeking the opinions on smaller number of options, but developed in greater and more practical details.

Supplementary comments	
EnerNOC	n/a
Contact	Contact Energy (Contact) supports the Electricity Authority (Authority) in its initiative of more efficient assignment of non- interruptible load (IL) to Automatic under-frequency load shedding (AUFLS). Contact agrees that an interruptible reserve (IR) style market and an individual consumer choice option are prohibitive due to cost,

¹² Vector's submission was not provided in the suggested format. Their responses have been fitted under the questions they approximately relate to, but there may be some overlap in some places.

	and for this reason they should not be pursued further. Contact supports the system operator (SO) expressing requirements by zone rather than by GXP. Our rationale is that this will better provide distributors with the flexibility to reallocate requirements and enable participants to exchange obligations within each zone.
ENA	n/a
Genesis	Support market-based approach Genesis Energy supports the Authority's preference for a market-based approach to improve the procurement of extended reserves. We agree with the Authority's decision to further investigate the establishment of a tender-based procurement process (Option D) and a bulletin board trading platform (Option C). Advanced metering may enable more sophisticated market options We consider future technological changes, in particular in the advanced metering area, will enable the development of a sophisticated extended reserves market.¹ Advanced meters have the potential to enable residential customers and small-medium enterprises to directly participate in a future market for extended reserves. The Authority's analysis in this paper identifies the significant efficiency benefits that could be achieved from this type of targeted provision of extended reserves. We encourage the Authority to consider these potential benefits in the development of the extended reserves market. In particular, we suggest that the Authority must be careful not to rule out the potential for advanced meters to provide extended reserves in the future. To explore this potential further, we suggest that the Authority document the requirements that advanced meters would need to meet to act as under-frequency relays in a way that is consistent with the System Operator's own technical requirements. This type of analysis will assist in identifying opportunities for future innovation in the metering market. In addition, we consider this information should be used as part of the System Operator's current review of AUFLS requirements. This will ensure that any further investment in AUFLS infrastructure does not limit the potential use of advanced meters in this space (for example, we understand that the System Operator is currently considering a shift to a df/dt AUFLS System).
Meridian	Meridian would first like to indicate our support for the Authority's suggestion to adopt the phrase "extended reserves" in favour of AUFLS, on the basis that this could assist in promoting the emergence of broader types of products to support system security. Regarding the Authority's next steps, Meridian considers detailed cost benefit analysis is needed on its "first preferred" tender-based procurement mechanism that also considers lower cost options to facilitate trading of obligations. We request this analysis covers in detail the compliance and funding arrangements for a tender-based system.
MEUG	n/a
Northpower	Introductory comment In our opinion, the statement in clause 2.4.1(e) of the consultation paper is open for misinterpretation.

	“For various reasons, all direct connects and one distributor have been exempt from the obligation to provide (AUFLS)” could be interpreted as the one distributor (identified in footnote 8 as Northpower) having a total exemption. Northpower’s exemption relates only to the provision of AUFLS at one out of the five GXP’s to which the Northpower network is connected. Note that the references to “North Power” throughout the consultation paper should be “Northpower”, please. Fundamental issues not yet resolved Northpower would like to remind the Authority that there are issues raised in previous submissions that, from Northpower’s perspective, do not appear to have been addressed in the consultation paper or, where they have been mentioned, they are not covered in the conclusions. From Northpower’s perspective, the most fundamental issue is that certain types of load are strategically important on a national basis (not just to the consumer directly affected) and these should be excluded from the pool of load from which AUFLS is drawn. Much of the load that is presently covered by exemptions is excluded on the basis that it is more valuable as IL and the consumers involved gain financial benefit from offering IL. However, some of the load that is exempted is on the basis that it is not practical due to size, and nationally strategically not desirable, to contemplate shedding any significant portion of the load, even in a rare event that results in AUFLS being triggered. (The issue of sheer size is similar to that highlighted for the smelter in clause 4.1.19 in the consultation paper.) Another issue relates to provision of AUFLS and IL on the same feeder. One interpretation of the rule is that, if a feeder is connected to an AUFLS relay, then any IL on that feeder must not be offered to the market (or even that it should be disabled). Another interpretation is that any load offered for IL must be excluded from the assessment of the 16%+16% for AUFLS so, for example, if a load of 100MW includes 10MW of hot-water load suitable for IL on feeders assigned to AUFLS, then there would need to be 42MW of load on the AUFLS feeders (32MW for AUFLS + 10MW for IL). This needs to be clarified so that the expectations are clear for distributors and other participants. Northpower suggests that the second interpretation (allowing IL and AUFLS on the same feeders but not double-counting the load) is the most practical in terms of maximising use of load suitable for IL on distribution networks.
NZ Steel	n/a
Pacific Aluminium	We agree with the Authority’s preliminary view that a tender-based process for procuring extended reserves is a useful first step in improving the efficiency with which extended reserves are procured. However, should such a scheme be implemented, we do not consider it to be the end point. Instead, the Authority should continue to work on better market-based approaches that enable extended reserves to be procured in much the same way as instantaneous reserves (IR) for contingent events are procured. We support the Authority continuing to develop a tender-based approach to procuring extended reserves. The procurement cost

	should be recovered from grid connected generators and Transpower as it is the failure of their assets that causes the need for extended reserves. We do not yet consider that a tender-based procurement mechanism should be the end point of developments in this area and consider further analysis is warranted.
Powerco	General comment As a general comment, we wish to flag our concern that much of the consultation document is based on the assumption that AUFLS is a form of reserves, used to restore system frequency when extended contingent events occur. As noted by the System Operator in its November 2009 submission on <i>AUFLS Exemptions – Issues and Options</i>, AUFLS blocks are relied on by the System Operator to avoid cascade failure for events beyond the magnitude of an extended contingent event. The current consultation paper assumes that AUFLS is only required to manage an extended contingent event. The commentary and conclusions throughout the paper rely on the accuracy of this assumption. In Powerco's view this assumption is incorrect. AUFLS is relied upon as the last resort – the last control available to avoid system blackout. This last resort mechanism should remain simple and certain. Administered versus market-based approaches to AUFLS Market-based solutions are powerful when the market is informed by good information. However, that is not the case with respect to the procurement of load to satisfy AUFLS requirements. The Authority's analysis assumes that it is possible to accurately value the expected average interruption costs of high impact low probability events ahead of time. In our view, the rarity of these events makes this impossible in practice. Consequently, our conclusion is that there is no reason to believe that a market-based approach to procuring load to satisfy AUFLS requirements would necessarily result in a more efficient outcome than the current administered approach. Hence, given the transaction costs associated with market-based procurement methods, the current administered approach is likely to be a more efficient means of identifying low cost load to satisfy AUFLS requirements and the only alternatives that should be considered are other administrative methods, such as option A. Supplementary comment With respect to flexibility and future proofing, the System Operator is currently reviewing the operational flexibility of the existing AUFLS requirements, with a view to making improvements. In our view, this is the correct approach to enhancing the flexibility of the AUFLS system and future proofing it. The information in section 5 and Appendix D on arrangements elsewhere shows that AUFLS is a mandatory non-market system in nearly all other jurisdictions. The exception is PJM, in the eastern USA, where distributors may opt out and pay other distributors to provide the service. There would therefore appear to be no international precedent for an ancillary service tender or other market-based approach to the procurement of load to satisfy AUFLS requirements.
Transpower	System security is paramount

	We strongly agree with the Authority that any new arrangement must ensure that the required amount of load is available at all times to protect the system against large and rare events. We are currently reviewing (with the Authority) the AUFLS framework and anticipate reaching a conclusion shortly. In this paper the Authority has assumed for its options analysis a four block scheme (4 blocks at 8% load cover). This analysis may need to be revisited in light of our conclusions from the AUFLS framework review. A market for AUFLS provision is worth further investigation We support the principle that load control is a valuable service. In the long run enabling parties to be compensated for providing controllable load for system security will create incentives for the market to develop capability to deliver this service. Although we support the Authority undertaking further analysis of options D and B (the tender option and the obligation and trade option) we cannot agree that the Authority's analysis at this stage enables us to conclude that these are the preferred solutions. We consider that, consistent with the Code Amendment Principles (specifically #3), cost benefit analysis should be the main tool for differentiating between options. The paper does not adequately attempt to quantify the costs and benefits (the disadvantages and advantages) for each option and we think too much reliance has been placed on using the lower-order amendment principles as the decision tool. We look forward to further engagement with the Authority to surface some of the costs and benefits of its preferred options. For example we consider that there will be greater administrative costs for the SO under all options, as well as increased transaction costs for industry participants as they engage with any new procurement process. It is also unlikely that a tender process could immediately deliver 100% coverage, given current limitations in accessing all parties that would be willing to be compensated for controllable load and the commercial incentives across the industry to participate. A transition mechanism from obligations to market provision would be necessary.
Vector	Cost-benefit analysis required Vector has previously raised concerns that the Authority appears willing to regulate to deliver theoretical improvements which deliver minimal and uncertain net present value to the industry.¹³ It is notable that the Authority's paper does not contain a cost-benefit analysis. Such an analysis would need to weigh the economic benefits of the proposal in terms of more efficient provision of AUFLS once every 10-15 years (assuming no increase in the frequency of such events) against the costs of implementing a tender process. It is Vector's expectation that the low frequency of AUFLS events will mean that the value placed upon the trading ability by participants is likely to be too low to justify the costs of option D. Vector recommends that the Authority develop a robust cost-benefit analysis of its proposed options, including an assessment of any increased risk of failure to deliver AUFLS as required. Rolling outage requirements need to be considered

¹³ Vector Limited, *Submission to Electricity Authority on Standardisation: Model Use-of-System Agreements and Proposed Code Amendments*, 8 September 2011, pages 14-15.

	The consultation paper as a whole appears to overlook the requirement for distributors to drop load as part of a rolling outage regime. We consider this to be an important issue in terms of allocating load to its most appropriate uses and it is insufficient to consider the value of load for AUFLS and IL purposes only. For example, paragraph 4.1.14 of the consultation paper appears to consider that the allocation of non-residential load to AUFLS would be undesirable. However, if it is accepted that (a) residential load has the lowest VoLL and (b) AUFLS events occur less frequently than supply shortages, then it should follow that residential feeders should be allocated to be dropped during rolling outages following a supply shortage declaration under Part 9 of the Code, while higher value load should be allocated to AUFLS as it is likely to be interrupted less frequently. If this point is accepted then the Authority will need to reconsider its analysis of where relatively high- and low-value load should be allocated. Further, if a regime of trading AUFLS obligations is efficient and workable, it is not clear why a similar trading regime should not be established to meet the supply shortage rolling outage requirements. Vector recommends the Authority includes the rolling outage Code requirements in its analysis of the options.
WEL	n/a