

Efficient procurement of extended reserves

Consultation Paper

Submissions close: 5pm, 14 November 2012

2 October 2012



Executive summary

The Electricity Industry Participation Code 2010 (Code) currently places obligations on participants to automatically disconnect blocks of load at specified frequency and time settings during large under-frequency events. This obligation to provide automatic under-frequency load shedding (AUFLS) rests with distributors and direct connects in the North Island and with Transpower in the South Island. Each block of AUFLS represents a fixed proportion of the participant's load.

Disconnecting a portion of load for one to three hours during a large rare system under-frequency disruption provides protection against a complete electricity system collapse, after which it could take more than a day to restart and fully restore the system. The system operator is currently reviewing the technical requirements for AUFLS and is expected to make recommendations later this year.

In parallel with the system operator's review, the Electricity Authority (Authority) is considering options to improve the way in which AUFLS are procured. The Authority is mindful that the term *AUFLS* refers to a specific mechanism to provide reserves, just as interruptible load is a particular mechanism to provide instantaneous reserves. The Authority has therefore decided to adopt the term *extended reserves* to allow for the possibility that mechanisms other than AUFLS could be available in the future to deal with events currently covered by AUFLS.

The Authority considers that procurement of extended reserves could be more efficient, as the current approach imposes mandatory obligations on participants to provide AUFLS. For historical reasons, direct connects and one distributor have been exempt from the Code obligation to provide AUFLS in the North Island. It is possible that some of the exempt load would be less costly to interrupt than other loads already supplying the service within distribution networks. On the other hand, withdrawing these exemptions could lead some participants to withdraw interruptible load (IL) from the instantaneous reserves (IR) market to meet their AUFLS obligations. That could have significant adverse economic impacts on consumers generally, potentially costing a few million dollars per year.

More broadly, in its review of the level of extended reserves cover needed, the system operator has identified concerns about over-provision of the service at times and the need for improved monitoring. The Authority also considers that incentives and scope for innovation could be improved as the service is currently secured via mandatory obligations in the Code rather than via contractual arrangements.

Given the potential value at stake, one focus of the Authority's review of procurement options is to ensure IL is withdrawn from the IR market only when that is the efficient outcome. Beyond those considerations the focus is on allocating extended reserves obligations to the parties with the lowest interruption costs and in a way that encourages innovation. As extended reserves interruptions occur very rarely, however, potential savings in expected

interruption costs are likely to be of the order of a few hundred thousand dollars a year, and moderately uncertain.

The Authority considers that a plausible range of options includes:

- a) setting targeted obligations;
- b) providing for participants to pay an administered price to opt out of obligations;
- c) supporting the exchange of obligations through trading on a bulletin board;
- d) a formalised market for trading around obligations; and
- e) procuring all extended reserves through a tender process.

Allowing participants to make trade-offs regarding their participation in the extended reserves service based on their particular circumstances is likely to lead to more efficient outcomes than administered targeting or pricing regimes. In this regard, the Authority considers that the more market oriented an option is the more consistent it is likely to be with the Authority's statutory objective.

The Authority's preliminary view is therefore that:

- a) if a practical tender-based procurement process could be implemented relatively cheaply that would be the preferred option, being the most market oriented option;
- b) if not, given a preference for small scale trial and error options, the next best option would be to focus on low cost ways to facilitate trading around extended reserves obligations (for example, by developing standard agreements/ protocols and establishing a bulletin board).

Subject to submitter feedback, the Authority intends to investigate the design of the tender-based and bulletin board options in more detail and to consult on a preferred option.

The purpose of this paper is to seek stakeholder feedback on the Authority's preliminary views.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
Minister	Minister of Energy and Resources
AUFLS	Automatic under-frequency load shedding
df/dt	Trigger mechanism using rate of change of frequency settings
Direct connect	A consumer with a point of connection to the grid
f-t	Trigger mechanism using fixed frequency-time settings
IL	Interruptible load
IR	Instantaneous Reserves
RoCoF	Rate of change of frequency (Hz per second)
SOROP	System operator rolling outage plan

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1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 The Authority is considering options to improve the way in which extended reserves are procured. This paper uses the term *extended reserves*, rather than the traditional *AUFLS* term, to move the terminology away from the specific mechanism used to provide reserves. As a matter of good market design, the Authority wishes to allow for the possibility that mechanisms other than AUFLS could be available in the future to deal with events currently covered by AUFLS.

1.1.2 The term extended reserves has been adopted because it complements the term instantaneous reserves. Instantaneous reserves are used to restore frequency to acceptable levels when contingent events occur (e.g. the failure of the largest source of generation on the grid), whereas extended reserves are used to restore frequency when extended contingent events occur (e.g. the simultaneous failure of multiple sources of generation, as occurred on 13 December 2011).

1.1.3 This paper sets out the Authority's initial evaluation of options for improving the way in which extended reserves are procured. This work is being undertaken alongside work by the system operator to determine physical requirements for AUFLS.

1.2 Purpose of this paper

1.2.1 The purpose of this paper is to consult with participants and persons that the Authority thinks are representative of the interests of persons likely to be substantially affected by the way in which extended reserves for under-frequency management are provided.

1.3 Submissions

The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with Consultation Paper—Efficient procurement of extended reserves in the subject line.

If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

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- 1.3.1 Submissions should be received by 5pm on 14 November 2012. Please note that late submissions are unlikely to be considered.
- 1.3.2 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.
- 1.3.3 If possible, submissions should be provided in the format shown in Appendix A. Your submission is likely to be made available to the general public on the Authority's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

2. Background

2.1 Role of extended reserves

- 2.1.1 Supply and demand on the transmission system must be kept in balance to maintain system frequency within acceptable levels, to avoid system collapse and indiscriminate loss of supply to consumers. *Under-frequency events* are situations where frequency falls below acceptable levels, due to the sudden loss of supply.
- 2.1.2 Protection against under-frequency events due to the failure of a single transmission element or generating unit is provided by a combination of generator spinning reserves and interruptible load (IL). These reserves are procured through the half hourly instantaneous reserves (IR) market. Requirements are typically set so that if the largest single contingency on the system at the time occurs, the system frequency will not fall below 48 Hz¹. Events of this size typically occur several times a year with smaller events occurring a few times a month. The smaller events are also covered through the reserves market².
- 2.1.3 Protection against larger and much rarer under-frequency events is currently provided by measures that are mandated under the Code, including asset performance capabilities and extended reserves in the form of automatic under-frequency load shedding (AUFLS). Unlike IR, there is no organised market for procuring extended reserves.

2.2 Technical requirements

- 2.2.1 AUFLS facilities were introduced in the North Island in the 1960s³ and in the South Island in 2003. They automatically disconnect blocks of load from distribution feeders at the GXP level or at zone substations within distribution networks in order to arrest the fall in system frequency and maintain it within acceptable limits⁴.
- 2.2.2 There are two blocks per island, each nominally representing 16% of GXP demand, which trip at frequency-time (f-t) settings specified in the Code.

¹ Additional IR is procured if a bi-pole HVDC failure would otherwise cause the system frequency to fall below the minimum level taking account of AUFLS.

² Although IL is only triggered during events for which the system frequency falls below 49.2 Hz.

³ When the original HVDC link was commissioned.

⁴ The frequency range and the limits and times within which the grid and connected assets must be capable of operating are specified in part 8 of the Code.

However, the system operator is reviewing the level of AUFLS required⁵ and is likely to recommend significant changes to North Island arrangements⁶. As that work is still in progress, it is unclear what the system operator will recommend. An illustrative example of the sort of options the system operator is considering is summarised in Appendix B. The system operator is due to make recommendations regarding AUFLS technical requirements later this year. In the meantime, for the purpose of analysis in this paper a four block scheme along the lines of that in Appendix B is assumed.

2.2.3 Although the operation of extended reserves is tightly coordinated within the overall under-frequency management, including with respect to IL, each block of AUFLS can be considered as a separate extended reserves product.

2.3 Responsibility for providing AUFLS

2.3.1 Under the Code, the obligation to provide AUFLS rests with the grid owner in the South Island and distributors and consumers connected directly to the grid (direct connects) in the North Island. However, direct connects have never provided AUFLS and have been granted exemptions since the Electricity Governance Rules (which preceded the Code) came into effect.

2.3.2 Subject to system operator agreement, the Code provides flexibility for an AUFLS provider to:

- (a) Redistribute obligations across its GXPs.
- (b) Put in place equivalence arrangements to achieve the required technical outcomes.
- (c) Seek dispensations from full compliance, subject to payment of costs resulting from the non-compliance.

2.4 Issues with existing allocation

2.4.1 A number of aspects of the existing arrangements, when considered collectively, give rise to potential efficiency concerns. In particular:

- (a) **Flexibility:** Participants' abilities to interrupt a fixed percentage of their GXP load differ. For example, a small distributor with a high proportion of large loads or a direct connect will have more difficulty sub-dividing its load

⁵ <http://www.systemoperator.co.nz/n5573.html>.

⁶ This could include levels of cover which vary with time of day and year and which could be expressed as a band to avoid over-provision and loss of supply due to system over-frequency events following an under-frequency event.

into the required block sizes than a large distributor with multiple GXPs and a diverse range of loads.

- (b) **Equivalence:** The general equivalence provisions in part 8 of the Code provide some flexibility for participants to avoid excessive compliance costs. No such arrangements have been entered into, although the granting of exemptions has probably reduced the need. If participants were required to comply with extended reserves obligations because equivalence arrangements were not available, or did not reflect associated interruption costs, overall interruption costs could be higher.
- (c) **Dispensations:** The general dispensation provisions in part 8 of the Code in principle provide some flexibility for participants to avoid excessive compliance costs due to extended reserves interruptions and/or having to withdraw IL from the IR market to comply with extended reserves requirements. The system operator can grant a dispensation if it is satisfied that it can meet its principal performance obligations (PPOs), subject to the participant paying any costs that result from the dispensation. No dispensations from extended reserves have been granted and in order to do so a basis for the system operator to determine and allocate costs resulting from a dispensation would need to be agreed⁷. However, without compensating measures (such as increasing obligations on others or procuring more IR), granting dispensations would reduce the amount of extended reserves available, potentially reducing system resilience to major events.
- (d) **Interruptible Load (IL):** AUFLS obligations are in addition to any IL that has been cleared in the IR market being provided at the GXP at the time of an AUFLS event. This requirement increases AUFLS compliance costs for participants offering a significant portion of their load as IL. As discussed in 4.1.5, limiting the availability of IL would have significant flow-on impacts on the IR and, indirectly, energy markets.
- (e) **Exemptions:** For various reasons, all direct connects and one distributor have been exempt from the obligation to provide⁸. The Authority

⁷ The Electricity Commission consulted on a methodology in 2005 (<http://www.ea.govt.nz/our-work/consultations/pso-cq/clarification-of-rules-relating-to-dispensations-and-exemptions-from-aufls-requirements/>).

⁸ Direct connects were first required to provide AUFLS when the Electricity Governance Regulations (EGRS) were introduced in 2003. The EGRs allowed for the possibility of specific exemptions from AUFLS requirements where the cost of complying with AUFLS would be excessive. However, the Electricity Commission found the AUFLS exemption criteria to be unworkable and, pending resolution, granted exemptions under its general exemption provisions to North Island direct connects and North Power. Alternative provisions were designed and consulted on in 2005 and, following refinements, in 2009. The 2005 proposals were not able to be progressed until Transpower's MSP project was completed. The 2009 proposal was not advanced to allow time for the system operator to undertake a fundamental review of AUFLS arrangements, among other reasons.

acknowledges that these exemptions have been necessary. However, consideration of exemptions and IL/AUFLS interactions has highlighted the need for a more fundamental assessment of how extended reserves obligations should be allocated.

Question: Do submitters agree with the list of identified concerns? If not why not?

2.4.2 Given these issues, the Authority is considering options for allocating extended reserves requirements more efficiently, including the role that might be filled by market-based mechanisms.

3. Economic Framework

3.1.1 Any changes to the existing arrangements must support the Authority's statutory objective to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. All three arms of the Authority's statutory objective are potentially relevant to this paper:

- (a) **Reliability:** the primary purpose of extended reserves is to ensure that the electricity system is resilient to large scale rare under-frequency events⁹. Any changes to the way in which extended reserves are allocated must not compromise this.
- (b) **Efficient operation:** subject to the above requirement, a key focus of this paper is on efficient allocation of loads to meet IR and extended reserves requirements.
- (c) **Competition:** competition in the IR market should be preserved, or enhanced, and it may be feasible to introduce competition for the supply of extended reserves (subject to benefits exceeding costs).

3.1.2 The Authority's Code Amendment Principles¹⁰ ensure that any proposal to amend the Code is consistent with the statutory objective. It is appropriate that they be applied in this paper as it is a high level assessment of potential options, which could ultimately lead to a Code amendment proposal. In this regard, analysis in section 4 indicates that there is a case for change¹¹ but that the choice of options will be limited to those with relatively low cost. Where it is difficult to differentiate between options, there should be a preference for:

- (a) Small-scale 'trial and error' options (Code Amendment Principle 4).
- (b) Greater competition (Principle 5).
- (c) Market solutions (Principle 6).
- (d) Flexibility to allow innovation (Principle 6).
- (e) Non-prescriptive (Principle 7).

3.1.3 In light of the above and concerns about the current approach to allocating extended reserves requirements, as highlighted in the preceding section, the following design criteria have been adopted in this paper:

⁹ The system operator is reviewing AUFLS requirements to ensure that the electricity system is resilient to large and rare failures,

¹⁰ <http://www.ea.govt.nz/document/5133/download/about-us/documents-publications/foundation-documents/>

¹¹ The paper is consistent with Code Amendment Principles 2 (Clearly Identified Efficiency Gain or Market or Regulatory Failure) and 3 (Quantitative Assessment).

- (a) Any arrangement must ensure that the required amount of extended reserves is available at any time to protect the system against large and rare events.
- (b) In an ideal world:
 - (i) loads with the lowest interruption cost would be offered as IL into the IR market where it is economic to do so;
 - (ii) other loads would be selected for extended reserves so as to minimise expected interruption costs;
 - (iii) decisions about the allocation of load for IL and extended reserves purposes would be made by the consumers concerned;
 - (iv) consumers that are interrupted would be compensated by those who avoid being interrupted¹²;
 - (v) arrangements would be flexible and future proof – i.e. able to adapt to changing requirements and technologies.
- (c) The objective of any proposal should be to facilitate these ideals subject to the benefits exceeding the costs.

3.1.4 With this in mind, the remainder of this paper is structured as follows:

- (a) Section 4 assesses the potential impacts of improving the way in which loads are allocated to extended reserves requirements taking account of potential IR market impacts.
- (b) Section 5 develops and compares a plausible range of high level options that might achieve net benefits.
- (c) Section 6 sets out the Authority's preliminary views on the way forward.
- (d) Section 7 sets out next steps.

¹² The rationale for this is developed in section 5.9.3 and 5.9.5.

4. Potential for improved allocation

- 4.1.1 The role and primary benefit of extended reserves are to maintain system frequency within the limits at which equipment can safely operate, thus preventing cascade failure and blackout due to rare and large-scale events. Automatically disconnecting a portion of load in a controlled manner for one to three hours is clearly preferable to a complete system failure requiring a prolonged black-start of the grid, potentially taking a few days to complete full restoration. The focus of the system operator's current technical review is to avoid complete system failure by determining the overall level of AUFLS cover required in each island, including appropriate block sizes, trip settings and coordination.
- 4.1.2 The Authority's focus in this paper is on options for efficient procurement of the necessary level of extended reserves consistent with technical requirements.
- 4.1.3 In an ideal world:
- (a) loads with the lowest interruption cost would be offered as IL in the IR market, where it is economic to do so;
 - (b) the next lowest cost tranches would be available for extended reserves duty; and
 - (c) load with high interruption costs would not be offered for IR or extended reserves duty.
- 4.1.4 Misallocation of load between these categories will have adverse economic impacts. Misallocation of low cost load out of the IR market could occur if participants were to meet their extended reserves obligations using load that would otherwise provide IL. Whether IL would be withdrawn is a commercial consideration for the participant depending on its expected interruption costs, including its ability to divide load into the required block sizes, expected IL revenues and its ability to obtain a cost-effective equivalence arrangement.
- 4.1.5 Analysis presented in Appendix C indicates that replacing the IL that is provided by direct connects in the North Island IR market could cost of the order of \$4.5m per annum and potentially up to \$13m per annum in the long run. However, it also suggests that it is unlikely that all IL would be withdrawn and a more realistic estimate, absent acceptable equivalence arrangements, could be of the order of \$1.3m to \$4m per annum (a present value of approximately \$8m to \$24m¹³). That is a significant concern.
- 4.1.6 With respect to loads other than IL, the scenario in Table 1 has been modelled to gain some insights into the potential economic impact of misallocation of loads

¹³ 10% discount rate over 10 years.

into/ out of AUFLS. The analysis assumes that residential load is on average less costly to interrupt for 2 hours or so than other load categories¹⁴ (excluding IL).

Table 1: Average North Island AUFLS interruption costs scenario

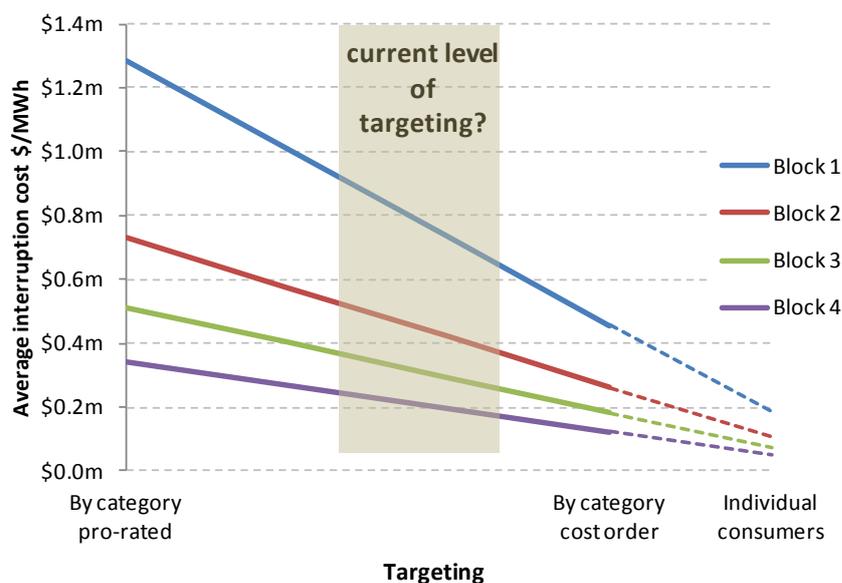
Load category	2 hour interruption cost	Expected cost \$/MW/hour			
		4 Years	7 Years	10 Years	15 years
Residential	\$5,000 /MWh	\$0.29	\$0.16	\$0.11	\$0.08
Small non residential	\$35,000 /MWh	\$2.00	\$1.14	\$0.80	\$0.53
Med non residential	\$20,000 /MWh	\$1.14	\$0.65	\$0.46	\$0.30
Large non residential	\$10,000 /MWh	\$0.57	\$0.33	\$0.23	\$0.15
Non grid industrial	\$15,000 /MWh	\$0.86	\$0.49	\$0.34	\$0.23
Grid industrial	\$12,000 /MWh	\$0.68	\$0.39	\$0.27	\$0.18

- 4.1.7 Reading from left to right, each row of the table shows, for a particular consumer category:
- (a) the average cost per MWh of a 2 hour interruption; and
 - (b) the expected cost per MW in any hour of an interruption assuming an event occurs once every 4 years (if in block 1), 7 years (block 2), 10 years (block 3) and 15 years (block 4).
- 4.1.8 For the above scenario, Figure 1 illustrates how expected annual interruption costs could vary in the North Island depending on how load categories were allocated to 4 AUFLS blocks¹⁵.

¹⁴ For example, AEMO uses values of customer reliability (VCR) for industrial and commercial consumer categories which are around three and eight times higher than for residential consumers (Value of Customer Reliability Issues Paper, AEMO, 30 June 2011). Studies commissioned by the Authority are still in progress but preliminary indications are that the scenario assumptions are reasonable estimates of the likely range of average interruption costs for each category of consumers. The studies reflect the cost of interrupting different types of loads completely which for AUFLS purposes is appropriate for consumers within distribution networks but not for direct connects. For the purpose of this paper, average interruption costs for North Island non-IL direct connect load for AUFLS purposes is assumed to be in the range \$12k per MWh.

¹⁵ Assuming two-hour interruptions occur once every four years for block 1, seven years for block 2, ten years for block 3 and 15 years for block 4 (more frequent than historical events). Modelled using 2011 GXP data.

Figure 1: Scenario expected interruption costs per annum

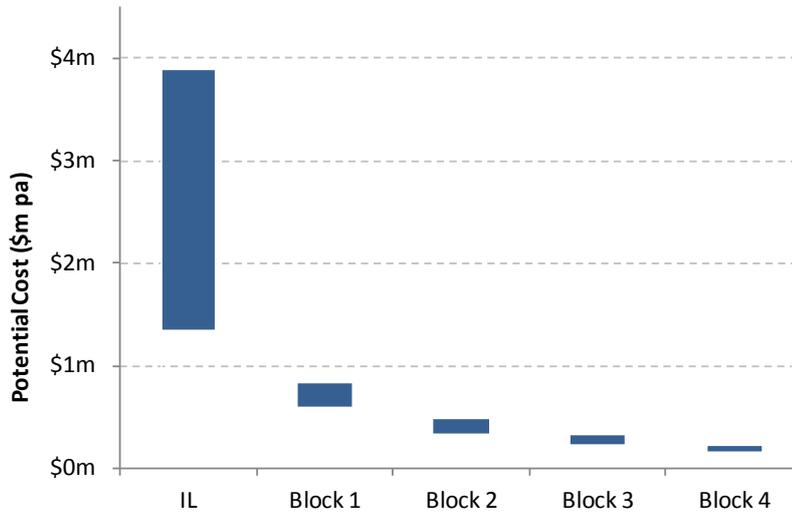


4.1.9 At the left of the chart, ‘by category prorated’ assumes that each category of load is assigned to AUFLS in proportion to its share of island GXP demand. ‘By category cost order’ assumes that load categories are interrupted in order of their cost of interruption (assuming that were possible at the GXP feeder/ zone substation level). The stylised dotted lines illustrate how expected AUFLS interruption costs could be reduced further if it were possible for individual consumers to opt in or out according to interruption cost. The shaded area on the chart highlights that the current level of targeting is probably better than prorated but, with AUFLS facilities installed at the GXP or zone substation level, it is impractical to target a particular category of consumers without interrupting other types of consumers. These issues are discussed further below.

4.1.10 For the assumed scenario, expected block 1 interruption costs would fall from around \$1.13m pa, with prorated targeting, to around \$0.46m pa, with perfect targeting of consumer categories in cost order – a theoretical reduction in expected interruption costs of \$0.68m pa. Given less frequent operation, the corresponding differences for lower blocks decrease. Potential differences will also vary depending on assumptions about interruption costs.

4.1.11 For example, Figure 2 shows the theoretical maximum difference in expected annual costs for each block assuming a range of direct connect interruption costs between \$6k and \$30k per MWh. For comparison, the range of potential IL impacts noted previously is also shown.

Figure 2: Perfect targeting of consumer categories vs prorated allocations



4.1.12 In practice, as noted previously, the potential impact of improving the allocation of load to AUFLS feeders is likely to lie between the pro-rated and theoretical targeting of load categories in cost order.

4.1.13 Firstly, to the extent that distributors are able to target feeders supplying largely residential load and avoid feeders with more sensitive loads,¹⁶ the actual level of targeting will be better than the pro-rated level. Estimating the extent, though, would require detailed knowledge of the approach taken within each network and the proportions of residential and non-residential consumers on selected feeders.

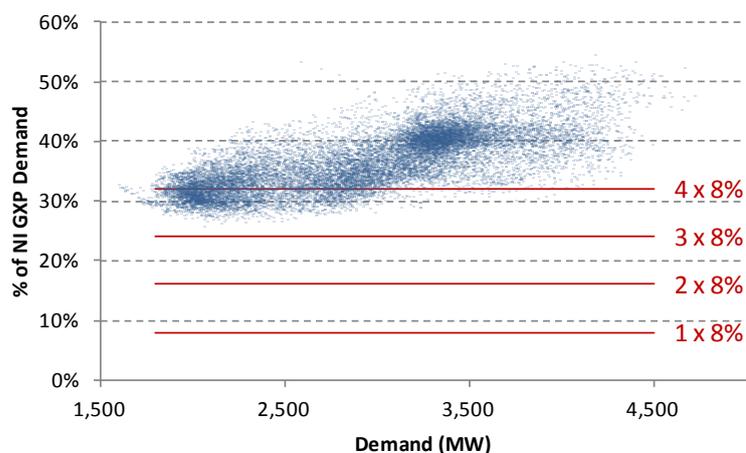
Question: What level of targeting do distributors consider is achieved in practice?

4.1.14 Secondly, residential load in the North Island could in theory provide four x 8% load blocks¹⁷ for most of the time as illustrated in Figure 3. In practice though, even if residential load were targeted, assigning load to AUFLS at the GXP or zone substation feeder level would inevitably result in some non-residential load being interrupted.

¹⁶ For example, some distributors note in their Participant Rolling Outage Plans that they apply the priorities in the rolling outage guidelines when selecting AUFLS feeders.

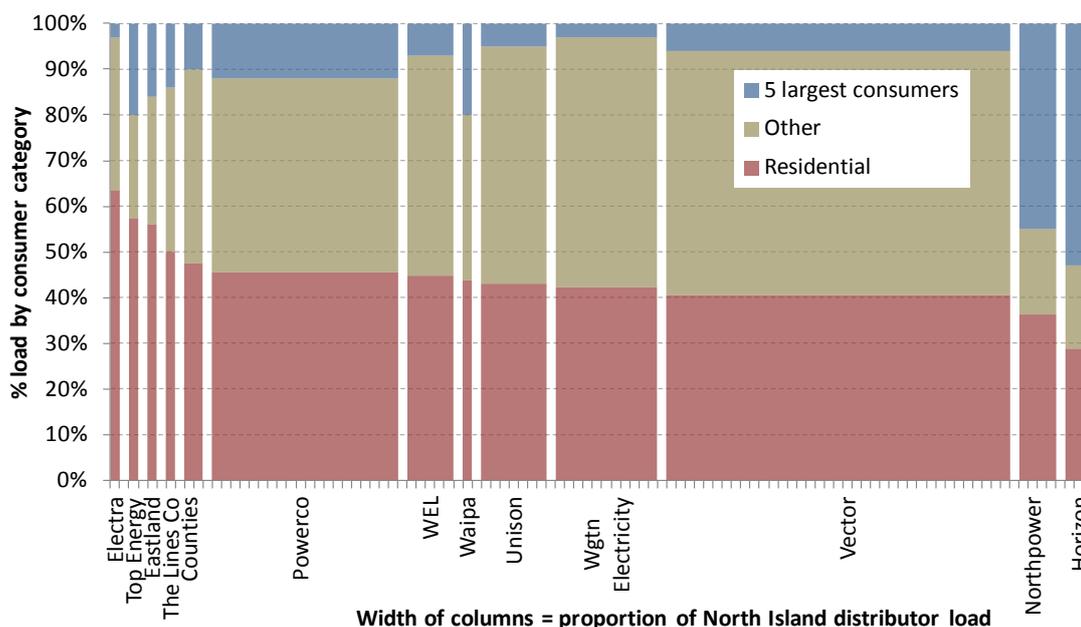
¹⁷ As profiled AUFLS requirements are likely to be adopted, given a lower proportion of demand is needed at times of higher demand, residential load is likely to be well above AUFLS requirements at times of high demand.

Figure 3: Estimated North Island residential load vs total island GXP load¹⁸



4.1.15 This will also vary by distributor given differing network topography and, as illustrated in Figure 4, varying proportions of load types (although it can also be seen that a few networks account for the majority of distributor load).

Figure 4: North Island network loads¹⁹

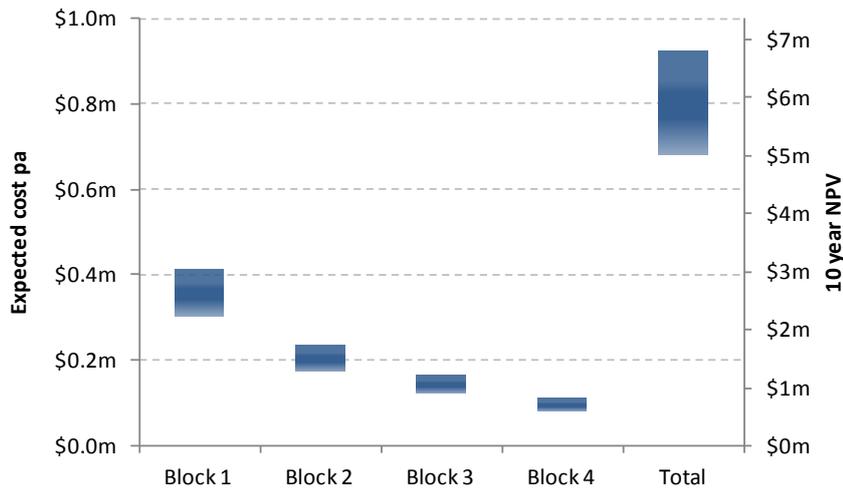


¹⁸ Estimated from 2011 half-hourly North Island demand data and a synthesised residential series derived from GXP demand at Wilton substation scaled up to represent estimated residential demand. The latter assumes 75% of residential ICPs are in the North Island (in proportion to population) and an average household consumption of 7,800 kWh pa.

¹⁹ Derived from information disclosure statistics and, for residential load estimates, an assumption that 85% of ICPs are households with an average consumption of 7,800 kWh pa.

4.1.16 It is impractical to estimate accurately the potential benefits of more efficient assignment of non-IL loads to AUFLS but up to half of the potential range in Figure 2 could be a plausible estimate. This is illustrated in Figure 5 below which also shows a ten year NPV band (read off the right axis).

Figure 5: Indicative potential benefits from improved allocation of non-IL load



4.1.17 Some of the potential benefits depend on how distributors allocate load to AUFLS, noting that approximately 90% of North Island load is within their networks. Potentially, significantly greater benefits might be achievable if individual consumers were able to be targeted. It would be very costly to establish and administer arrangements to enable individual consumers to opt in or out and to locate facilities at the consumer level²⁰ but some additional benefits could be achievable if large consumers within distributor networks were able to be more directly targeted or avoided.

4.1.18 The above analysis highlights that:

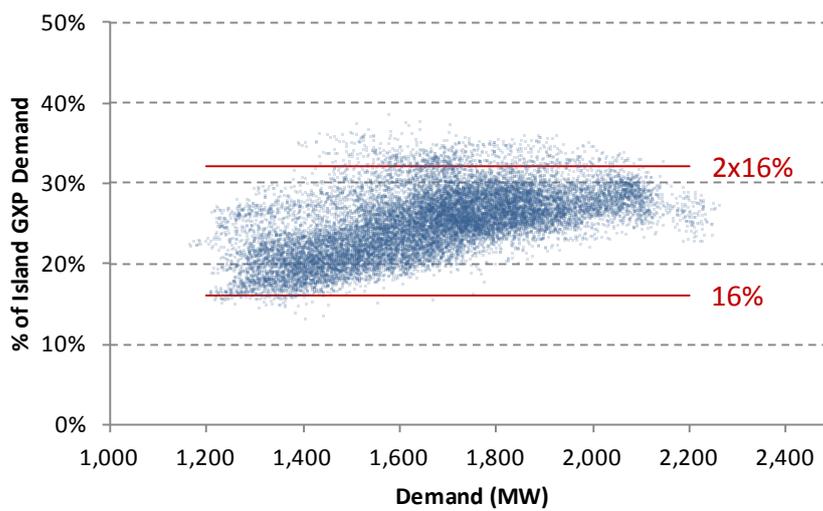
- (a) If lowest value load was to be withdrawn from the IR market to provide AUFLS there would be significant adverse economic impacts, even if only a portion was to be withdrawn.
- (b) Relatively low cost measures to improve the allocation of other loads to AUFLS could be beneficial, especially in respect of the first block.

²⁰ Currently 460 AUFLS relays are configured in the North Island to trip load at 32 GXP feeders and 223 zone substations within distribution networks. The system operator has estimated it will cost around \$6m to upgrade these facilities to a 4 block scheme. It would be significantly more costly to install and administer AUFLS facilities closer to individual consumers to achieve greater discrimination between loads.

Question: Do you agree with the Authority’s conclusions regarding relatively low cost measures? If not why not?

4.1.19 The South Island is somewhat different with Rio Tinto being the only direct connect and, given the smelter’s size, a much lower proportion of load is residential as illustrated in Figure 6.

Figure 6: South Island residential load as a proportion of island GXP demand



4.1.20 It is also likely that extended reserves events in the South Island will occur less frequently. The potential for benefits through improving the allocation of load to AUFLS are therefore likely to be less than in the North Island. Measures to improve the allocation of loads to AUFLS in the North Island may not necessarily be applicable to the South Island although the incremental costs could make it worthwhile.

5. Options

5.1 Arrangements elsewhere

5.1.1 Automatic load shedding schemes are a common feature of power systems around the world. As summarised in Appendix C for a number of jurisdictions:

- (a) Requirements are typically achieved through mandatory obligations on grid owners or connected parties.
- (b) Some countries allow IL to be counted towards extended reserves obligations, although in many jurisdictions the amount IL is proportionately lower and the amount of load under extended reserves schemes is disproportionately higher. For example, the Australian NEM has a much larger portion of load assigned to AUFLS (6 x 10% blocks) and a proportionately lower amount of IL.
- (c) While there is sometimes scope to avoid the obligation, it is often unclear how allocations are administered in practice.
- (d) PJM appears to be an exception in that distributors can avoid their obligation by paying an administered fee reflecting the carrying cost of an open cycle gas turbine. Some implications of this approach are discussed later.

5.2 Responsibility for providing extended reserves

5.2.1 Analysis in the previous section confirms that viable options for improving the allocation of load to extended reserves will be limited to relatively low cost arrangements. Hence the ideal of residential consumers and small-medium enterprises (within distributor networks) deciding whether their loads will provide extended reserves is currently infeasible, i.e. the transaction costs would be excessive with current technologies. The objective of any option should thus be to mimic the ideal outcome to the extent that is practical and economic.

5.2.2 Assigning blocks of load to extended reserves at the GXP feeder or distributor zone substation level is traditionally seen as a relatively low cost mechanism consistent with managing rare events. In this regard, arrangements in New Zealand are similar to those in other jurisdictions, although different in each island. i.e. Transpower is responsible in the South Island and connected parties (distributors and direct connects) are responsible in the North Island.

5.2.3 In principle, the obligation could be assigned to retailers. However, they would need to establish AUFLS facilities at individual customer premises (which would

be prohibitively costly²¹) and/ or collaborate with other retailers and the relevant distributor to trip blocks of load within a network²². Any such arrangement would also need to accommodate customers switching between retailers. Coordination of arrangements by the system operator would be more complex. Thus it is not considered economically or technically viable to place the obligation on retailers.

5.2.4 Both Transpower and distributors have the technical means to implement extended reserves schemes like AUFLS. Close cooperation between Transpower and distributors and direct connects could achieve similar outcomes. It is probably also easier for Transpower to coordinate requirements with the system operator.

5.2.5 However, distributors have the technical ability to discriminate within the network, better knowledge of loads within their networks, and commercial relationships with retailers and in some instances with end consumers.

5.2.6 *It is therefore preferable that the responsibility for providing extended reserves be with distributors and direct connects in both islands.*

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

5.3 Nature of obligation or service

5.3.1 How the extended reserves service or obligation is defined is an important consideration for procurement options. At present, requirements are procured by requiring identical percentages of the load at each GXP to be assigned to extended reserves (on top of any IL). In the context of this paper, this raises a number of issues.

5.3.2 **Equal vs targeted obligations:** The current approach of setting identical percentage obligations is simple. However, it may not necessarily be efficient unless participants were able to trade in and out of their obligations depending on relative interruption costs. On the other hand, setting targeted obligations requires value judgements about interruption costs with risks of getting it wrong, resulting in less efficient outcomes than may be possible with other mechanisms.

²¹ The system operator has estimated that it will cost around \$6m²¹ to upgrade the existing 460 North Island AUFLS facilities to a 4 block scheme. That would be a small fraction of the cost to install relays at consumer sites.

²² In the Australian NEM, retailers with a peak load of 10 MW or more at a point of connection are obliged to make up to 60% of the load they supply available for automatic load shedding. In practice that is an enabling provision and load shedding is generally implemented at the feeder level by network providers according to priorities within each state that are set by a Jurisdictional Coordinator.

Such risks will increase if the decisions are not able to be influenced directly or indirectly by the loads concerned.

- 5.3.3 *Moving away from equal percentage obligations should only be considered if there were impediments to efficient trading of obligations, such as limited distributor incentives or market power concerns.*
- 5.3.4 **Net vs gross obligations:** Obligations are currently allocated on a net basis (at the GXP level). As load shedding protects the entire power system, it could be argued that a participant's obligations should be linked to total load rather than GXP load. However, this could complicate monitoring and coordination and some on-site generation could trip if on-site load were to be tripped (for example cogeneration).
- 5.3.5 *There is no compelling reason to move away from requirements set on a net (GXP) basis.*
- 5.3.6 **Zonal vs GXP based obligations:** Obligations are currently set at the individual GXP level. A participant has some ability, subject to system operator agreement, to re-allocate its overall requirement across GXPs (if it has more than one). It appears that this ability (a form of internal equivalence) is apparently not widely understood. Re-allocation also requires the system operator's approval. Expressing requirements by zones²³ rather than by GXP would confirm flexibility for distributors to reallocate requirements and for participants to exchange obligations within each zone²⁴. Subject to system operator agreement, distributors could still reallocate from one zone to another and participants could exchange obligations between zones.
- 5.3.7 *It would be preferable to set obligations on a zonal basis, the zones being pre-defined by the system operator.*
- 5.3.8 **Accounting for IL:** Any procurement option will need to ensure that IL is not inefficiently withdrawn from the IR market. Allowing participants to reduce their obligation by the amount of IL they provide, as in some other countries, would reduce overall availability of extended reserves. The impact could be limited by restricting this flexibility to direct connects and procuring replacement extended reserves from elsewhere. However, that could still result in lower cost load (i.e. above a direct connect's IL load) not being available for extended reserves. In that respect, completely exempting participants that provide any IL could be worse.

²³ For example, taking account of system islanding requirements in certain regions it may be appropriate to establish a small number of zones within each island, similar to zones used by the system operator for other purposes (e.g. voltage).

²⁴ In principle distributors can reallocate obligations between GXPs now but this option (a form of internal equivalence) is apparently not widely understood. Re-allocation also requires the system operator's approval.

5.3.9 *The objective should be to ensure that participants only withdraw IL from the IR market where that is the efficient outcome.*

5.3.10 *It would be preferable if participants were able to make efficient trade-offs between IL, and extended reserves requirements and alternatives (such as equivalence style options).*

5.4 Distributor willingness to participate

5.4.1 Distributors account for approximately 90% of North Island load. If they were unwilling to vary from their base obligations, that could limit the effectiveness of procurement options involving voluntary mechanisms such as equivalence or trading. For example, some distributors may be concerned about being seen to receive payment for interrupting consumers, although this could presumably be mitigated by distributors forwarding their payments onto the relevant customers. In this regard, some procurement options are likely to provide better incentives for distributors to participate and, indeed to engage with at least larger consumers or retailers, than others.

5.4.2 There appear to be no regulatory impediments and distributors currently participate in the IR market. The use of water heating load for IL probably goes largely unnoticed but extended reserves interruptions occur very rarely – years apart – and consumers within distribution networks get interrupted 2 to 3 times a year on average.

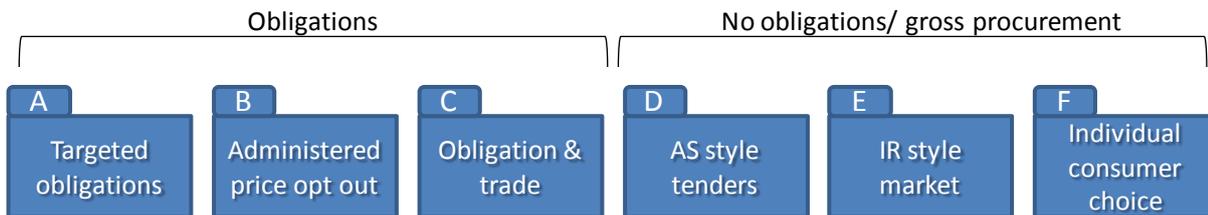
5.4.3 *There would appear to be no real impediments to distributors exchanging obligations but options which provide incentives to do so should be explored.*

Question: Do you agree that there are no real impediments to distributors exchanging obligations? If not why not?

5.5 Range of procurement options

5.5.1 In principle, a range of high level options could be considered along the lines illustrated in Figure 7. Note that 'AS style tenders' in option D refers to the tendering arrangements used to procure ancillary services such as over-frequency arming and black start.

Figure 7: Range of options for procuring extended reserves



5.5.2 With reference to option C (obligation and trade) in Figure 7:

- (a) The existing AUFLS regime is technically an ‘obligation and trade’ mechanism as the possibility to opt out/ opt in via bilaterally agreed equivalence arrangements exists under the current regime.
- (b) It may be possible to enhance these arrangements to facilitate the trading of obligations, for example through standardised equivalence contracts and a bulletin board (Option C1) or establishing a centrally administered periodic ‘overs and unders’ auction (Option C2).

5.5.3 Moving to the left of option C in Figure 7:

- (a) Under option B participants could be allowed to opt out of their obligations for a fee, perhaps subject to certain criteria to ensure overall extended reserves requirements are assured.
- (b) Under option A targeted obligations for participants could be set using prescribed criteria to reduce reliance on equivalence arrangements and avoid the risk of costly misallocation of loads.

5.5.4 Moving to the right of option C in Figure 7, extended reserves could be procured on a voluntary basis:

- (a) Under option D a tender process could be established along the lines employed annually for over-frequency reserves or black start services.
- (b) Under option E an IR style market could be established where participants could bid on a half-hourly basis to supply requirements.
- (c) Option F would involve a mechanism where individual consumers could opt in or out through a centralised market.

5.5.5 The Authority considers options E and F in Figure 7 would be prohibitively costly (relative to potential benefits) to develop, administer and participate in and would be inconsistent with the economic framework in section 3. The remaining options are discussed below. The discussion is intended to enable a high level assessment of the likely design issues in order to compare the options rather than to develop design details.

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

5.6 Option A - Targeted obligations

5.6.1 This would involve establishing criteria in the Code which the system operator would use to allocate overall requirements for each block of extended reserves to individual distributors and direct connects.

5.6.2 For example, given the amount of residential load relative to overall AUFLS requirements:

- (a) Direct connects could be excluded from the first (South Island) or the first two (North Island) blocks on the assumption that distributors will endeavour to minimise the amount of industrial and commercial load they assign to those blocks. If there were still concerns about the risk of IL being withdrawn, the option for direct connects to count IL as part of their AUFLS contribution, as in the NEM, could also be considered.
- (b) The overall distributor share of requirements in each island could be prorated to individual distributors based on the proportion of their load that is residential (along the lines shown in Figure 3: Estimated North Island residential load vs total island GXP load).
- (c) Distributor guidelines for assigning loads to AUFLS could be established along similar lines to the SOROP²⁵ guidelines for distributor rolling outage plans. (If direct connects were excluded from lower blocks, distributors would be deciding which loads to assign to approximately 95% of North Island AUFLS requirements and approximately 80% of South Island requirements).
- (d) The system operator could specify zones within which distributors obligations must be met, rather than by GXP²⁶.

5.6.3 Potential advantages of such an approach include:

- (a) Avoiding uncertainties and difficulties associated with exemptions and participants' abilities/ willingness to obtain/ offer equivalence arrangements.
- (b) Reducing the risk of direct connects withdrawing IL from the IR market.

²⁵ Part 9 of the Code requires the system operator to prepare and maintain the "System Operator Rolling Outage Plan" (SOROP) for managing supply shortages.

²⁶ In principle the current approach of specifying the obligations as percentages of load at each GXP and providing for distributors to reallocate their overall obligation between GXPs subject to system operator agreement should achieve the same outcome. However, it may be better to provide the flexibility up front to encourage the flexibility to be used and/ or avoid the reluctance/ transaction costs of seeking approvals.

- (c) Mitigating the potential impact of higher value load being tripped given a significantly smaller probability of the lower blocks tripping.
- (d) Low implementation and administration costs.
- (e) No financial costs to allocate as any additional administration costs would be small and could be absorbed within the current cost allocations under the Electricity Authority levy.

5.6.4 Potential disadvantages include:

- (a) Additional administrative complexity in moving away from equal percentage obligations.
- (b) The risk of getting administered targets wrong. For example, direct connects being unable to subdivide their load and/ or misestimating interruption costs.
- (c) Unless excluded altogether, direct connects may still have to trip load in excess of the required block sizes or to withdraw IL from the IR market.
- (d) Continued, but reduced, reliance on equivalence arrangements to avoid excessive compliance costs.
- (e) Some loads would enjoy the benefit of higher security at the expense of others (although all loads benefit from the avoidance of system collapse/ black start).

5.7 Option B - Administered price opt-out

5.7.1 This would involve establishing an administered price which parties would pay to opt out of their obligations. For example:

- (a) An opt-out fee would be set based on estimates of expected interruption costs²⁷.
- (b) The ability to opt out would be limited to direct connects (and possibly to small distributors that meet specified criteria. e.g. their non-residential load and/ or IL exceeds specified proportions of their load).
- (c) The system operator would set the same nominal percentage of load obligations for all distributors and direct connects, including an allowance

²⁷ For example, a fee of \$0.43 /MW/hour would equate to an expected interruption costs for blocks 1 and 4 of around \$7.5k per MWh and \$28k per MWh assuming 2 hour interruptions at 4 and 15 year intervals. A fee based on the cost of peaking capacity (as in PJM) would be easier to verify but would be considerably higher than expected AUFLS interruption costs, risking reallocation of IL to AUFLS duty. At \$145/kW pa (open cycle gas turbine capacity) an equivalent opt-out fee would be \$16.5/MW/hour considerably higher than IL revenues (of the order of \$4 to \$5 /MW/hour for fast and sustained IL combined). Such a fee would also be inconsistent with the concept of AUFLS covering severe events for which it is considered uneconomic to carry surplus generation capacity.

for some parties opting out. Alternatively, or as well, the system operator could procure more IR at times when insufficient extended reserves is available and allocate the additional cost to parties that have opted out²⁸.

- (d) An eligible party that wished to avoid all or part of its obligation would pay the opt-out fee multiplied by its average MW of non-compliance. For simplicity, the average MW figure could be based on an annual estimate (for example, from the previous year's load data).
- (e) The system operator would confirm the opt-out subject to payment of the fees and overall extended reserves provision still meeting minimum requirements (or rely on procuring additional IR if extended reserves is insufficient and allocating the costs to opt-out parties).
- (f) Fees collected in the island would be paid out to all fully compliant parties in proportion to their obligation to provide extended reserves (as they would effectively be compensating for parties that have opted out).

5.7.2 Potential advantages of such an approach include:

- (a) Reducing reliance on the availability of bilateral equivalence arrangements (negotiating equivalence arrangements may be difficult given lack of market price visibility, load disparities between parties and unclear incentives for distributors).
- (b) The ability for parties to weigh up their own circumstances and opt-in or out (noting the difficulties and ambiguity associated with the EGR exemption provisions). Such circumstances include the practicalities of splitting load into requisite block sizes, interruption costs, and foregone IL revenue.
- (c) Parties covering those which opt out receiving a payment for doing so.
- (d) Relatively low implementation and administration costs.

5.7.3 Potential disadvantages include:

- (a) Opt-out costs would need to be allocated.
- (b) Inherent difficulties involved in establishing opt out fees and associated risks of inefficient outcomes.
- (c) The possibility of over or under-provision if assumptions made about opting-out when setting nominal obligations do not play out (unless general obligations are adjusted to compensate, or some risk of insufficient extended reserves would be tolerable if the system operator is able to procure additional IR at the time).

²⁸ This possibility has been considered in the past. For example see footnote 7.

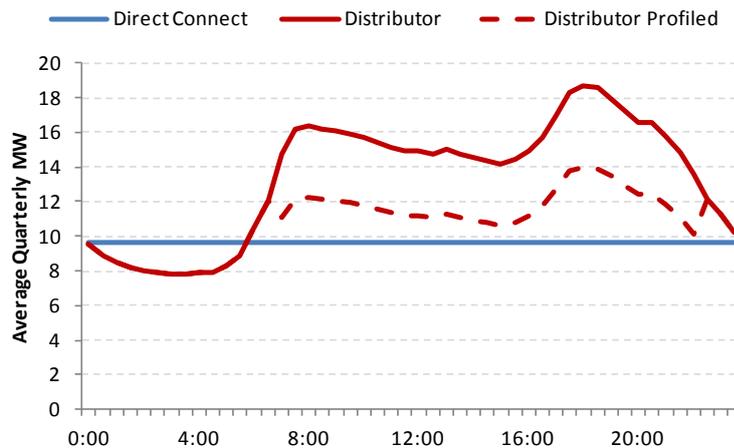
5.8 Option C – Obligation and trade

5.8.1 This would involve establishing a platform to assist parties to trade out of their (equal percentage) obligations. This could involve facilitating equivalence arrangements through an electronic bulletin board (Option C1) or alternatively an organised ‘overs and unders’ market for trading around obligations (Option C2).

5.8.2 Option C1 – Bulletin board approach:

- (a) An electronic bulletin board could be set up for parties to anonymously post bids/ offers for equivalence arrangements.
- (b) Bids and offers would be for a standard term (say 1 or 3 years) and format e.g. average MW, type of load (flat or profiled), price per MW and the first block for which it would be considered.
- (c) It may be practical to establish a basis for trading flat and profiled obligations. As illustrated below, setting profiled obligations could make it easier to trade obligations for flat and profiled loads²⁹.

Figure 8: Percentage obligations for flat and peaky loads³⁰



- (d) Interested parties could make contact with each other, anonymously initially, to discuss/ negotiate potential equivalence arrangements.
- (e) Optional standardised equivalence contracts could be developed to simplify transactions.

²⁹ If the system operator proposes that obligations be expressed as percentage bands (minimum and maximum requirements) that may provide some flexibility to agree equivalence arrangements.

³⁰ Illustrative only. Solid lines represent 8% fixed obligations. The dashed line represents 8% off-peak and 6% peak. How requirements will be expressed has yet to be determined by the system operator.

- (f) Equivalence arrangements would need to be registered with the system operator who would confirm that technical requirements are met. Allowing obligations to be met on a zonal rather than GXP basis could enable automatic approval of equivalence within a zone.
- (g) The system operator would adjust the obligations of the respective parties to reflect any equivalence arrangements.

5.8.3 Potential advantages of such an approach include:

- (a) It may be possible for larger loads within networks that are not on AUFLS feeders to participate (provided they have certainty about not being assigned to AUFLS by the distributor).
- (b) Interested parties that identify each other would have the flexibility to negotiate a workable arrangement and the system operator could exercise discretion as to what is an acceptable arrangement. For example, from a system perspective, it may be technically equivalent for a party with a particular load shape to trip less load at certain times (or maybe at a higher frequency) than the obligated party is required to shed.
- (c) Relatively low implementation and administration costs.
- (d) Minimal financial costs to allocate (other than for establishing and operating the bulletin board). These costs could be absorbed within the current cost allocations under the Electricity Authority levy.

5.8.4 Potential disadvantages include:

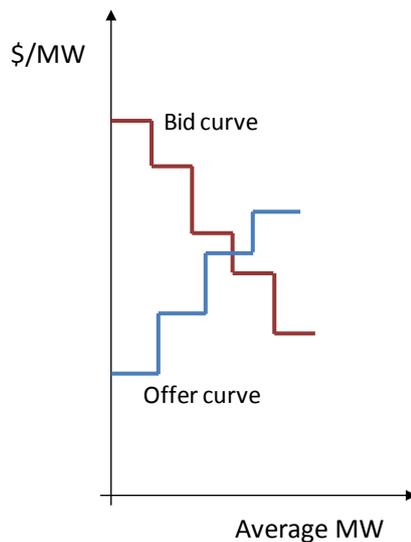
- (a) Distributors may not be willing to participate.
- (b) It is difficult for distributors to know consumer interruption costs (although offers would provide some pricing visibility).

5.8.5 **Option C2 – Organised ‘overs and unders’ trading:**

5.8.6 An alternative would be to support the obligation and trade option with an organised ‘overs and unders’ market. For example:

- (a) Parties could submit multi tranche offers/ bids to exceed/ reduce their obligations to a central clearing/ auction process (operated periodically, say annually).
- (b) The form of offers (bids) would need to be determined. e.g. annual fees for providing percentage increments (decrements) of load consistent with the way obligations are currently expressed (but which in future could include different peak and off-peak obligations with minimum and maximum levels) or average MW reductions (perhaps peak and off-peak).

- (c) If bids and offers were to be percentage-based, it may be difficult for direct connects to conform to a fixed percentage³¹ of their load so they could be permitted to submit non-conforming MW-based bids and offers.
- (d) Offers and bids would indicate the applicable zone and the first block for which they are to be considered.
- (e) Bids and offers would be stacked in decreasing (increasing) \$/MW values to create respective decremental demand and incremental supply curves (if in percentage terms, offers/ bids would need to first be converted into average MW and \$/MW values).
- (f) Bids and offers for the island would nominally be matched as illustrated below.



- (g) A clearing procedure would need to be developed to ensure that system operator zonal constraints are not violated (and possibly, if bids or offers cannot be partially cleared, which to accept, or not, and what the clearing price should be).
- (h) The auction process would clear blocks in order with any uncleared offers from previous blocks included (uncleared bids from previous blocks would remain as obligations). It may be necessary to enable participants to tag offers to specific blocks if relays are unable to meet all requirements³².
- (i) The system operator would adjust and register the obligations of participants in accordance with the auction outcome. i.e. the basis for participant compliance would be their revised obligations.

³¹ Because the MW reduction relates to a particular piece of equipment

³² For example, if the participant only has f-t relays then offers for blocks 1 or 2 would not be eligible for blocks 3 and 4 require df/dt.

- (j) Affected parties would receive/ make monthly payments for incremental/ decremental adjustments to their original obligations (based on the annual \$/MW clearing price converted into monthly fees for the cleared amounts).

5.8.7 Potential advantages of this approach include:

- (a) System operator confidence about the overall availability of extended reserves.
- (b) A transparent price discovery process.
- (c) Depending on the level of participation, distributors may have greater ability/ incentives regarding the loads to interrupt (or not).

5.8.8 Potential disadvantages include:

- (a) Additional costs to implement and administer the auction and settle cleared bids/ offers.
- (b) Distributors may be reluctant to participate or their offers and bids may not reflect underlying interruption costs (although multiple bids and offers and greater transparency could help to mitigate that risk).
- (c) Less flexibility than if equivalence could be agreed bilaterally. i.e. overs/unders trading requires standardised products whereas with bilateral arrangements, somewhat disparate capabilities could be acceptable to the system operator (e.g. one party tripping a smaller amount at a higher frequency than another party's obligation requires, accommodating different load shapes etc).

5.9 Option D – Ancillary service style tender

5.9.1 Another option is to procure extended reserves through a tender process. Individual participant's commitments would then be formed contractually rather than specified in the Code. The selection process could include flexibility regarding the mix of loads accepted with respect to profiles (potentially avoiding some of the issues noted above in trading around obligations) and any zonal restrictions.

5.9.2 Under this option, extended reserves would be procured on a gross basis through a tendering process, which could be conducted annually or perhaps tri-annually. For example:

- (a) The system operator would specify the overall requirements to be procured for each block of extended reserves. e.g. as a percentage band of island load, or profiled percentage bands depending on time of day/ year as in the system operator's preliminary proposal.

- (b) Distributors could tender multiple tranches for specified percentages of their non-IL load indicating the first block to which each tranche may be assigned and the zone it would be delivered in. The tenders could specify an annual \$ fee for each tranche. For reasons noted previously, tendering average MW reductions (and \$/MW prices), maybe for peak and off-peak periods, would be preferable if practical.
- (c) Direct connects would tender on the same basis or could submit non-conforming flat MW and \$/MW per year tenders (given lack of diversity and potential difficulty in complying with a fixed percentage of load. i.e. the MW amount would relate to specified plant items).
- (d) Tendered tranches for the first block would be converted into MW profiles (using historical data or an otherwise defined process) and \$/average annual MW prices and stacked up in ascending \$/MW price order.
- (e) The system operator would select sufficient tranches from the stack (subject to any zonal constraints within the island) to satisfy the overall island requirements for the first block. Some system operator discretion as to the overall requirement to procure may be needed depending on the mix of conforming and non-conforming tranches and any zonal constraints (although the cost recovery mechanism discussed later is likely to minimise that).
- (f) The highest priced tranches selected would set respective peak and off peak \$/MW per year prices (this could include a different price in a constrained zone or some means of allocating additional procurement costs within that zone)³³.
- (g) Any tranches not selected for block one would be transferred into the second block selection process (and so on, subject to technical suitability as declared in the tender) and the above process repeated (it is understood that the technical AUFLS arrangements proposed by the system operator would enable distributors to physically reassign load between blocks)³⁴.
- (h) Repeat tender rounds could be held, enabling participants to respond to indicative outcomes and converge on practical results.
- (i) The system operator would register each party's obligation, if any, with respect to each block.

³³ In addition to being more efficient, setting a uniform price has the advantage that participants can bid a zero price rather than having to second guess where the market might clear.

³⁴ To minimise the risk of inadvertent outcomes, it could be desirable to have more than one iteration (like a pre-scheduling process) with participants being able to increase quantities and/ or reduce prices in response to the initial outcome.

- (j) Each provider, subject to compliance, would be paid monthly (or annually) for the quantity of extended reserves they have been cleared to provide. The fee would be calculated from the cleared price and the cleared amount.
- (k) Procurement costs would need to be recovered. As discussed below this is an important consideration.

5.9.3 One option is to allocate procurement costs to participants in proportion to their share of load. Any revenue they earned from providing extended reserves would offset their share of procurement costs. A participant that did not offer, or offered a very high price and was not cleared, would face the market clearing price for its share of extended reserves. For example, if the clearing price was equivalent to \$0.5/MW/hour, a distributor with an average load of 400 MW would face a cost of \$560k pa³⁵. If it had been cleared for 32% of its load no costs would be allocated to it (irrespective of the clearing price).

5.9.4 Allocating procurement costs according to load shares would approximate a 'beneficiaries pay' approach, reduce value impacts on participants (depending on their level of participation) and tend to mitigate market power concerns.

5.9.5 Another option is to allocate procurement costs to exacerbators – that is, to parties that could (1) take action to reduce the risk of extended reserve events occurring or (2) avoid taking action that increase the risk of such events.

5.9.6 The 'exacerbators pay' approach is currently used for IR-level under-frequency events. Applying it to extended reserves involves determining the expected cost of extended reserve events (to set the charge rate) and applying that charge to the party or parties causing the event. This approach could have significant value impacts and it wouldn't mitigate potential market power issues.

5.9.7 Potential advantages of a tender-based approach include:

- (a) Transparency / price visibility.
- (b) All parties would have incentives to participate given financial obligations (via cost allocation).
- (c) Avoiding the problem of possible mismatches between offers and bids under the obligation and trade options. i.e. the system operator could procure whole tendered tranches (adjusting overall requirement slightly).
- (d) Distributors could offer extended reserves on behalf of large users on their network and pass on payments or recover costs.
- (e) Participants would have flexibility as to the quantities they tender.

³⁵ For 32% of the load assuming a uniform clearing price for all extended reserves.

- (f) The system operator would have flexibility procuring the appropriate mix of extended reserves (and the ability to vary procurement needs).
- (g) Procurement through a contractual framework, as for ancillary services, may improve system operator and participant incentives with respect to innovation, monitoring and compliance.

5.9.8 Potential disadvantages of such an approach include:

- (a) All parties interested in supplying extended reserves would have to submit offers with associated effort (although a default offer equivalent to the nominal block sizes would require minimal effort).
- (b) Relative to potential benefits, it could be relatively costly to implement, administer and participate in (depending on timeframes and how often tenders were run).
- (c) There may be concerns about market power, although with greater transparency (parties tendering prices on gross quantities) and allocating costs according to net load these concerns should be no more or less than under the obligation and trade options.

5.10 Comparison of options

5.10.1 The options under consideration represent the plausible range given likely costs relative to potential benefits. It would be uneconomic or impractical, at least with current technologies, to develop arrangements that would achieve the ideal outcomes described in the economic framework in section 3. Instead the question is which of the plausible options can be expected to yield outcomes most closely approximating those expected under the ideal approach. That, and consistency with the Authority's statutory objective and Code Amendment Principles, is the intent of the comparison of options set out in Table 2.

5.10.2 Note that the following elements have not been included in the table because they are common to all options:

- (a) All options meet the reliability arm of the Authority's statutory objective (provided any reduction in extended reserves under the administered price opt-out option is acceptable or able to be offset by procuring additional extended reserves).
- (b) *Code Amendment Principle 1: Lawfulness:* Only lawful options have been considered.
- (c) *Code Amendment Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure:* The options in this paper are under consideration because the Authority has identified efficiency concerns with the existing

Code obligations regarding extended reserves procurement (in the form of AUFLS).

- (d) *Code Amendment Principle 3: Quantitative Assessment:* Key assumptions are set out in this paper along with an assessment of the potential efficiency gains with respect to the provision of extended reserves requirements and preservation of IL benefits.

Table 2: Comparison of options		Option A Targeted obligations	Option B Administered price & opt-out	Option C1 Bulletin board	Option C2 Organised over/ under trading	Option D Gross tender based	
Efficient operation	Avoid inefficient IL withdrawal	✓✓	✓✓	✓✓	✓✓	✓✓	
	Minimise interruption costs	Avoid excessive interruption costs	✓?	✓✓	✓	✓	✓✓
		Participant flexibility	✓	✓✓	✓	✓	✓✓
		Efficient targeting by distributors	?		?	✓?	✓✓?
	Transaction costs	Administration cost	Low	Low ³⁶	Low	Moderate	Moderate ³⁷
		Participant cost	Low	Modest	Modest	Modest	Moderate
	Consumer compensation		?	✓ ³⁸	✓ ³⁸	✓? ³⁹	
	Price visibility		✓	✓	✓✓	✓✓	
	Future proof/ flexibility to evolve			✓	✓	✓✓	
Other Code Amendment Principles	4) Small scale trial/error		✓	✓✓			
	5) Greater competition			✓	✓	✓✓	
	6) Market solutions			✓	✓	✓✓	
	7) Allow innovation			✓		✓✓	
	8) Non-prescriptive			✓✓		✓✓	

³⁶ Including the administration cost of allocating charges to parties opting out of obligations.

³⁷ Including the administration cost of making payments and allocating charges for extended reserves.

³⁸ Indirect for consumers within distribution networks depending on any pass-through (possibly for larger consumers if part of equivalence or trading of obligations).

³⁹ Potentially stronger incentives for pass through given greater transparency.

6. Preliminary preference

- 6.1.1 The Authority is inclined to the view that if a practical tender-based process could be implemented cheaply that would be a preferable option. It would enable participants to make their own judgements about the provision of extended reserves and IR. With financial obligations rather than physical obligations, participants would have incentives to participate and costs could be allocated to reflect proportionate benefits. They would also have flexibility as to how much load they could physically contribute, especially where load is not easily sub-dividable. The system operator would have flexibility to achieve overall requirements and to adjust requirements over time through the procurement plan process rather than locking all requirements in the Code. Such an approach would also appear to fit well with the system operator's preliminary proposal to upgrade North Island AUFLS facilities. That would take some time to implement but once in place would improve procurement flexibility.
- 6.1.2 Key risks with the tender-based option are that it could become costly and that potential benefits are uncertain. It also represents a significant change from current practice.
- 6.1.3 At the other end of the spectrum of options, setting administered targets (note exemptions are a form of targeting) would be a low-cost way of ensuring that IL is not withdrawn from the IR market but the efficiency costs depend on the regulator making the right exemption decisions. With 90% of North Island load within distributor networks, and distributors deciding which feeders are assigned to extended reserves, the current arrangements are effectively an administered regime anyway. Assuming distributors target residential feeders to the extent practical, placing direct connect loads into blocks 3 and/or 4 may be consistent with the treatment of higher value loads by distributors. However, while that would preserve IL, it may not be efficient – load that is less costly to interrupt may not be available (or assigned to lower blocks) and distributors will have varying degrees of difficulty in meeting their obligation and avoiding sensitive loads.
- 6.1.4 This highlights the inherent problem with an administered targeting regime - value judgments which are difficult for the regulator to make and which can have unintended consequences. Participants are better placed to evaluate trade-offs regarding the provision of IL and extended reserves based on their own particular circumstances. While distributors may not know consumer interruption costs, they will be aware of the load mix within their networks and particularly in relation to sensitive load and large loads. Options to enable participants to make the trade-offs are therefore preferred and also consistent with the preference for market-based solutions where practical.
- 6.1.5 The administered pricing option could enable participants to make their own assessments, and avoid the need for equivalence arrangements, but carries the

risks of getting the price wrong and having insufficient extended reserves available (or having to increase obligations on others).

6.1.6 Noting the preference for small scale trial and error options, focusing on ways to facilitate trading around obligations appears to have merit. Developing standard agreements/ protocols and establishing a bulletin board fits with the preference for market-based solutions and could be extended to the South Island. It could also provide some price transparency, potentially enable large consumers within distributor networks to participate and be less restrictive than trading standard products through an organised 'overs and unders' market. i.e. there would be scope for innovation regarding technical equivalence (subject to system operator agreement). For example, a smaller block of load tripping at a higher frequency and having the same impact on the system as a larger block tripping at a lower frequency may be technically acceptable to the system operator but it would likely be impractical to facilitate such a trade in an organised overs/unders market.

6.1.7 On balance the Authority's preliminary view is that:

- (a) Subject to practicality and cost, the tender-based option is the preferred solution and should be evaluated in more detail; and
- (b) In the meantime, low cost options to facilitate equivalence arrangements, such as the bulletin board approach, should also be investigated further.

Question: Do you agree with the Authority's preliminary conclusions? If not why not?

7. Next steps

- 7.1.1 Following submissions on this paper, the Authority intends to review its preliminary findings in light of submissions and develop and consult on a preferred proposal, including Code amendment requirements. This work will need to be coordinated with and take into account the system operator's technical proposals regarding AUFLS requirements which are due later this year.

Appendix A Format for submissions

Question No.	General comments in regards to the:	Response
1	Do submitters agree with the list of identified concerns? If not why not?	
2	What level of targeting do distributors consider is achieved in practice?	
3	Do you agree with the Authority's conclusions regarding relatively low cost measures? If not why not?	
4	Do you agree that distributors and direct connects should be responsible for providing extended reserves in both islands? If not why not?	
5	Do you agree that there are no real impediments to distributors exchanging obligations? If not why not?	
6	Do you agree that options A to D are the plausible range of options? If not what alternatives are plausible?	
7	Do you agree with the Authority's preliminary conclusions? If not why not?	

Appendix B Illustrative example of a revised North Island AUFLS regime

- B.1.1 There are currently two AUFLS blocks in each island, each nominally representing 16% of the island’s GXP demand. The blocks are configured to trip progressively at frequency-time (f-t) settings specified in the Code.
- B.1.2 The system operator is reviewing the level of extended reserves cover and associated technical delivery mechanisms and is likely to recommend significant changes to North Island requirements⁴⁰. That work is still in progress and it is not yet clear what the system operator will propose. However, one of the examples from earlier analysis undertaken by the system operator in 2011 illustrates the nature of changes being considered⁴¹. Under that four block arrangement, each block would be triggered at specified f-t settings with accelerated tripping of the third and fourth blocks during more extreme events using rate of change of frequency (RoCoF or df/dt) technology. It is also possible that block sizes will be specified as a band with some degree of time-based profiling rather than a constant percentage of GXP load⁴².

Table 3: Illustrative example of a 4 block scheme in the North Island

	Accelerated element			Under frequency 1		Under frequency 2		% GXP load
	df/dt	Guard frequency	time	frequency	time	frequency	time	
Block 1	N/A	N/A	N/A	47.8Hz	0.3s	N/A	N/A	8%
Block 2	N/A	N/A	N/A	47.5Hz	0.3s	47.8Hz	15s	8%
Block 3	-0.8Hz/s	48.5Hz	0.4s	47.3Hz	0.3s	47.5Hz	15s	8%
Block 4	-1.5Hz/s	48.8Hz	0.4s	47.3Hz	0.3s	47.5Hz	15s	8%

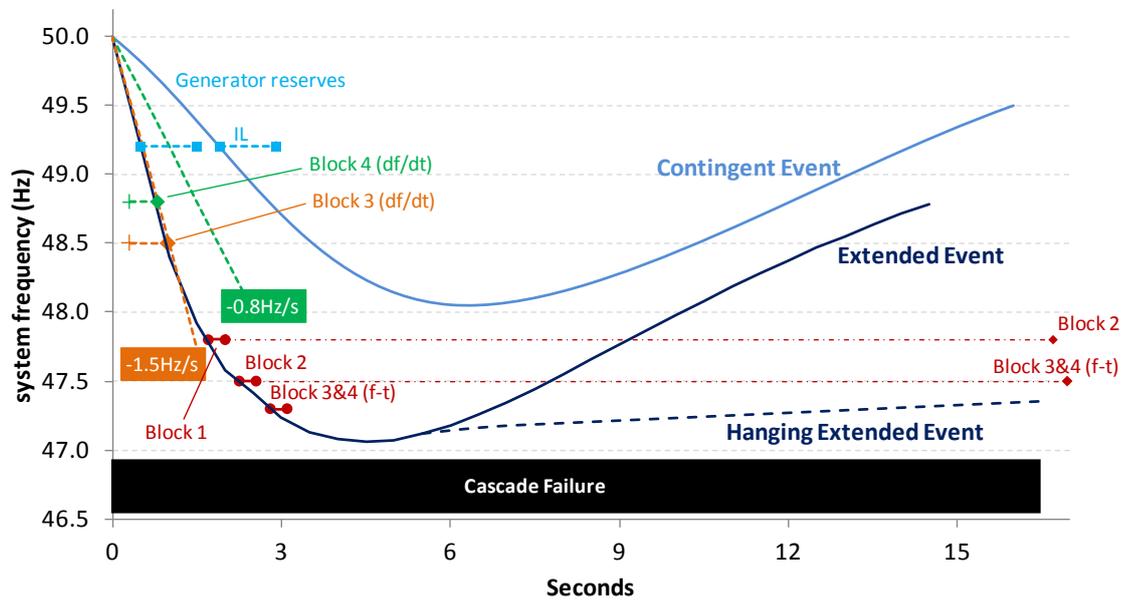
- B.1.3 Figure 9 shows a stylised depiction of how the above 4 block scheme would operate within the overall under-frequency management regime.

⁴⁰ To avoid over-provision and loss of supply due to system over-frequency events following an under-frequency event.

⁴¹ http://www.systemoperator.co.nz/f5573,67412593/AUFLS_Presentation_Slides_Published_Aug_2011.pdf

⁴² To mitigate post event over-frequency risks. During peak demand periods a lower percentage of GXP load is required under AUFLS.

Figure 9: Illustrative operation of a 4 block scheme in the North Island



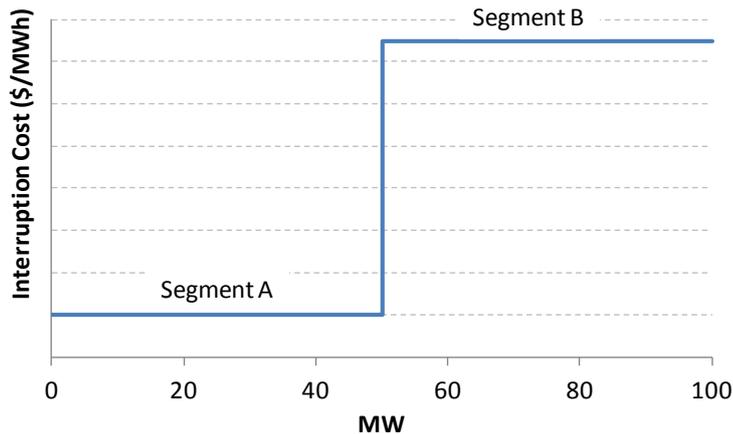
B.1.4 The system operator is due to make recommendations regarding AUFLS technical requirements later this year⁴³.

⁴³ <http://www.systemoperator.co.nz/n5573.html>

Appendix C Potential IL withdrawal economic impacts

C.1.1 By way of example, consider a notional 100 MW direct connect load with a mixture of low and high interruption costs as illustrated in Figure 10.

Figure 10: Notional direct connect load



C.1.2 The participant could either:

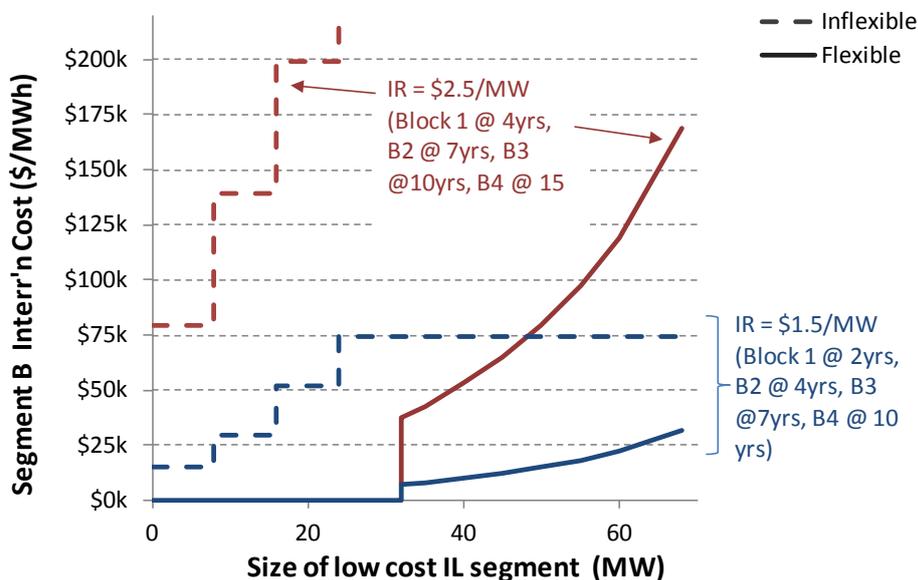
- (a) Use the low cost load segment A for IL and provide extended reserves from the high cost segment B; or
- (b) Forego IL revenue and use the low cost load segment to provide extended reserves.

C.1.3 Figure 11 illustrates how the trade-offs involved depend on the cost of interrupting the high cost load segment for extended reserves⁴⁴, whether there is flexibility to trip part of each segment and the size of IL segment A. It is assumed that the low cost load could earn revenue from both the fast and sustained IR markets.

C.1.4 The lines on the chart indicate the interruption cost of load segment B above which, for certain assumptions, the participant could be better off providing extended reserves (instead of IL) from the low cost load segment.

⁴⁴ Assuming an average of 8 IL events per year of 15 minutes duration at a cost of \$2,000 per MWh.

Figure 11: IL and extended reserves trade-offs



C.1.5 The dashed lines represent idealised fully ‘flexible’ scenarios where any desired portion of either load segment is able to be tripped. The solid lines represent worse case ‘inflexible’ scenarios where each load segment can only be tripped in its entirety. In each case, the lower (blue) lines represent pessimistic scenarios with relatively frequent 3 hour extended reserves events and a low average IR price⁴⁵.

C.1.6 By way of example, the lower solid (blue) line indicates that if the IL segment is half of the load (50 MW), the break-even interruption cost of the extended reserves segment (the other half of the load) would be approximately \$15k/MWh. Because the high and low cost segments can only be tripped in their entirety, if the IL segment is less than 32 MW (equivalent to 4 AUFLS blocks), the participant would need to trip the full high cost segment⁴⁶ and there would be no point in withdrawing IL and foregoing IR revenues. In contrast, the lower dashed line indicates that if the participant was able to provide 4 separate 8 MW AUFLS blocks from the high cost load segment, the breakeven interruption cost would be substantially higher.

C.1.7 To estimate what direct connects would do in practice would require an understanding of their ability to subdivide their load and of their interruption costs. Direct connects currently provide around 150 MW of IL⁴⁷ in the North Island. To

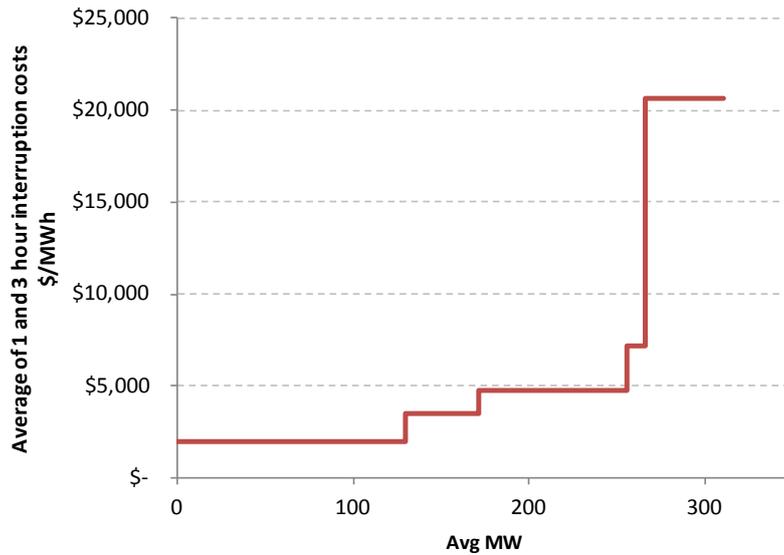
⁴⁵ The IR price is the average of fast and sustained IR prices and each MW of IL earns twice the assumed average IR price.

⁴⁶ Similarly, IL above 68 MW is not shown as IL would have to withdrawn to provide AUFLS anyway.

⁴⁷ Average of sustained and fast IL for year ending 31 March 2012.

replace that contribution could cost in the order of \$4.5m per annum⁴⁸ and potentially up to \$13m per annum in the long run⁴⁹. However, it seems unlikely that all IL would be withdrawn given the likely range of interruption costs. For example, Figure 12 gives an estimate of the interruption costs for non-IL load at a number of direct connects sites⁵⁰.

Figure 12: Possible interruption costs



C.1.8 Accepting a number of uncertainties, including participants’ risk perspectives, a more realistic estimate of the amount of IL that might be withdrawn, absent acceptable equivalence arrangements, could be in the order of 30%, costing in the order of \$1.3m to \$4m per annum.

⁴⁸ Based on market data for year ending 31 March 2012 and assuming a cost of \$2,000 per MWh for eight 15 minute events per annum.

⁴⁹ If the contribution at peak/ high priced times of around 90 MW had to be replaced ultimately by peaking generation capacity at around \$145/kW pa.

⁵⁰ Derived from VoLL study data published by the Authority in January 2012 (<http://www.ea.govt.nz/our-work/programmes/transmission-work/investigation-of-the-lost-load/>) and in one instance, where study data could not be matched to a site, an assumption of \$20k/MWh (the highest tranche in Figure 12. As the VoLL study estimates relate to full site interruptions, the values have been scaled up to give a weighted average value assuming an IL quantity (historical average) with an interruption cost of around \$2,000 per MWh. The lowest cost tranche in Figure 12 seems implausibly low – at a level more consistent with load that is suitable for IL although it does not appear to be utilised as such.

Appendix D Extended reserves arrangements elsewhere

D.1 The following is a summary of relevant aspects of automatic under-frequency load shedding arrangements in other jurisdictions. It has not been practical to establish some aspects clearly in a number of instances, as reflected in the table.

Responsibility for providing	
UK	Network Operators (i.e. distributors) and grid connected customers
Ireland	The Distribution System Operator (DSO) and grid connected customers.
Australia (NEM)	<p>Load shedding capability (automatic or manual, aka UFLS) is required at any connection points where the maximum load is greater than 10MW.</p> <p>UFLS has to be provided by grid connected customers and Network Service Providers. For grid connected customers it has to be automatic (i.e. as for AUFLS). AEMO is responsible for making sure there is sufficient load-shedding capability available.</p> <p>Arrangements for load shedding are agreed between Transmission Network Service Providers and connected Distribution Network Service Providers and may include the opening of circuits in either a transmission or distribution network.</p>
Midwest Reliability Organisation	Technically the obligation is on the transmission system operators, but they pass it off onto their customers, which essentially means that the burden is on distributors and grid connected customers.
Singapore	The Power System Operator (PSO i.e. the EMA) is responsible for facilitating extended reserves arrangements, but can alternatively delegate this function to the transmission system operator.
PJM	Distributors

How much is required	
UK	The number and size of blocks for Network Operators and grid connected customers are determined by NGET (National Grid – the transmission owner), and depend on the transmission area that a Network Operator is connected to.

How much is required																																																		
	<table border="1"> <thead> <tr> <th rowspan="2">Frequency Hz</th> <th colspan="3">%Demand disconnection for each Network Operator in Transmission Area</th> </tr> <tr> <th>NGET</th> <th>SPT</th> <th>SHETL</th> </tr> </thead> <tbody> <tr> <td>48.8</td> <td>5</td> <td></td> <td></td> </tr> <tr> <td>48.75</td> <td>5</td> <td></td> <td></td> </tr> <tr> <td>48.7</td> <td>10</td> <td></td> <td></td> </tr> <tr> <td>48.6</td> <td>7.5</td> <td></td> <td>10</td> </tr> <tr> <td>48.5</td> <td>7.5</td> <td>10</td> <td></td> </tr> <tr> <td>48.4</td> <td>7.5</td> <td>10</td> <td>10</td> </tr> <tr> <td>48.2</td> <td>7.5</td> <td>10</td> <td>10</td> </tr> <tr> <td>48.0</td> <td>5</td> <td>10</td> <td>10</td> </tr> <tr> <td>47.8</td> <td>5</td> <td></td> <td></td> </tr> <tr> <td>Total % Demand</td> <td>60</td> <td>40</td> <td>40</td> </tr> </tbody> </table>	Frequency Hz	%Demand disconnection for each Network Operator in Transmission Area			NGET	SPT	SHETL	48.8	5			48.75	5			48.7	10			48.6	7.5		10	48.5	7.5	10		48.4	7.5	10	10	48.2	7.5	10	10	48.0	5	10	10	47.8	5			Total % Demand	60	40	40		
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Ireland	<p>Unsure. An amount, split into discrete MW blocks, the number, location, size and frequency of which is specified by the TSO in discussion with the DSO. They are supposed to give a reasonably uniform disconnection across all Grid Supply Points.</p>																																																	
Australia (NEM)	<p>Grid connected customers must provide their AUFLS load in manageable blocks spread over a number of steps within under-frequency bands from 49.0 Hz down to 47.0 Hz as nominated by AEMO.</p> <p>Network Service Providers have to be able to withstand contingent events affecting up to 60% of total system load, but it's not clear how much of that has to be controlled automatically.</p> <p>Some old guidelines suggest that all 60% would be under AUFLS, but the new rules are less specific. Those guidelines also suggest that as far as reasonably practicable, it should be shared among the NEM regions in proportion to the average region demands (in the absence of separation of regions).</p>																																																	
Midwest Reliability Organisation	<p>The MRO region has three coordinated AUFLS programs:</p> <table border="1"> <thead> <tr> <th>MRO-Canada: SaskPower</th> <th>MRO-Canada: Manitoba Hydro</th> </tr> </thead> <tbody> <tr> <td>Step 1: 59.3 Hz, 6% Load</td> <td>Step 1: 59.3 Hz, 20.6% Load</td> </tr> <tr> <td>Step 2: 59.0 Hz, 9% Load</td> <td>Step 2: 59.0 Hz, 12.2% Load</td> </tr> <tr> <td>Step 3: 58.7 Hz, 7% Load</td> <td>Step 3: 58.7 Hz, 16.6% Load</td> </tr> <tr> <td>Step 4: 58.5 Hz, 7% Load</td> <td>Step 4: 58.5 Hz, 7.2% Load</td> </tr> <tr> <td>Step 5: 58.3 Hz, 5% Load</td> <td>Step 5: 58.3 Hz, 7.5% Load</td> </tr> <tr> <td></td> <td>Step 6: 58.0 Hz, 8.9% Load</td> </tr> </tbody> </table> <table border="1"> <thead> <tr> <th>MRO-US</th> </tr> </thead> <tbody> <tr> <td>Step 1: 59.3 Hz, 10% Load</td> </tr> <tr> <td>Step 2: 59.0 Hz, 10% Load</td> </tr> <tr> <td>Step 3: 58.7 Hz, 10% Load</td> </tr> </tbody> </table> <p>The first three frequency set points are the same for the entire region so that all entities would participate during a region-wide or multi-region islanding condition. However, the Canadian provinces have additional load-shedding</p>			MRO-Canada: SaskPower	MRO-Canada: Manitoba Hydro	Step 1: 59.3 Hz, 6% Load	Step 1: 59.3 Hz, 20.6% Load	Step 2: 59.0 Hz, 9% Load	Step 2: 59.0 Hz, 12.2% Load	Step 3: 58.7 Hz, 7% Load	Step 3: 58.7 Hz, 16.6% Load	Step 4: 58.5 Hz, 7% Load	Step 4: 58.5 Hz, 7.2% Load	Step 5: 58.3 Hz, 5% Load	Step 5: 58.3 Hz, 7.5% Load		Step 6: 58.0 Hz, 8.9% Load	MRO-US	Step 1: 59.3 Hz, 10% Load	Step 2: 59.0 Hz, 10% Load	Step 3: 58.7 Hz, 10% Load																													
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How much is required	
	steps since they are at a higher risk of islanding on their own.
Singapore	Unclear, but as with other countries, the obligation is split into blocks, with the number, size, location and frequency setting specified by the PSO.
PJM	Different for different regions, but broadly along the lines of: AUFLS relays that will interrupt at least 30 percent of peak load with 10 percent of the load interrupted at each of three frequency levels: 59.3 Hz, 58.9 Hz and 58.5 Hz.

Who decides which customers are included	
UK	The Network Operators, but the distribution of the blocks is required to give a reasonably uniform disconnection across all Grid Supply Points.
Ireland	The TSO sets requirements for the DSOs and grid connected customers to meet. Residential customers are targeted first and the DSO tries its best to avoid targeting Industrial Customers.
Australia (NEM)	Each state has a “Jurisdictional System Security Coordinator” (JC) who provides AEMO with a schedule setting out the order in which loads in the region are to be shed. If AEMO is the JC then the Minister provides the schedule. Beyond that, it is assumed to be done by the Transmission Network Service Provider with direction from AEMO, if the AUFLS service is indeed implemented at that level.
Midwest Reliability Organisation	The distributors, though some coordination between distributors and/or grid connected customers will be subject to the approval of the TSO.
Singapore	The PSO or transmission system operator if delegated.
PJM	Distributors presumably

Is it possible to get out of an obligation to provide AUFLS	
UK	The intention is that the distribution of the blocks will be such as to give a reasonably uniform application throughout the Network Operator’s distribution system, but may take into account any operational requirements

Is it possible to get out of an obligation to provide AUFLS	
	and the essential nature of certain demand.
Ireland	<p>Customers can be classified as exempted or priority customers, which would be expected to include hospitals, emergency services, communication facilities, essential generation house supplies, and large industrial customers which have processes of a nature that result in particular hardship in the event of loss of supply. Customers other than exempted or priority customers, are treated equally in the event of load shedding, subject to technical feasibility.</p> <p>Demand of generators which is required to enable start-up of those generators are not to be subject to AUFLS obligations.</p>
Australia (NEM)	<p>Yes, sort of. The JC provides AEMO with a list of sensitive loads. AEMO's load-shedding procedures must include a requirement that sensitive loads aren't disconnected automatically until they reach a certain frequency specified in those procedures. If that load would have normally been interrupted at a higher frequency band then it has to be replaced with an equivalent load.</p> <p>For example, the "Gladstone Power Station Agreement Act" specifies that the Boyne Island aluminium smelter will be included in the list of sensitive loads by the JC, and won't be cut off until the frequency drops below 47Hz.</p> <p>NSW also appears to allow for registered participants to negotiate an AUFLS agreement with AEMO, or the Minister if it can't agree within 6 months. Presumably this means that grid connected customers could negotiate some form of dispensation or equivalence arrangement if agreeable with AEMO/the Minister.</p>
Midwest Reliability Organisation	<p>In the US region, load shed within an individual company (LSE) does not necessarily need to total 10% per step since it may make electrical sense for a neighbouring utility to take on a portion of their load-shed obligation. One transmission system operator specifically allows customers with multiple connected loads to spread the obligation across its load however it wants, subject to approval.</p> <p>Currently the obligations aren't mandatory (the regulations are still being sorted out), and this may change once regulations are put in place.</p>
Singapore	The PSO develops a policy detailing the basis for exclusions to load management activities that are undertaken for the purpose of shedding load during under-frequency conditions.
PJM	If a distributor is determined to not have the required under-frequency relays,

Is it possible to get out of an obligation to provide AUFLS	
	<p>it pays an under-frequency relay charge of:</p> <p>Charge = D x R x 365</p> <p>where</p> <p>D = the amount, in megawatts, the Electric Distributor is deficient; and</p> <p>R = the daily rate per megawatt, which is based on the annual carrying charges for a new combustion turbine generator, installed and connected to the transmission system. This is currently set at \$58.400/per kilowatt-year or \$160 per megawatt-day.</p>

Are parties paid to provide AUFLS	
UK	No
Ireland	No
Australia (NEM)	No
Midwest Reliability Organisation	No. Although presumably if LSEs were to share obligations then that could come at a cost to one party.
Singapore	No
PJM	Sort of. They are charged for not meeting the requirements, and the proceeds are shared amongst those that do, in proportion to their contribution to peak demand.

How is interruptible load treated	
UK	Load provided as an ancillary service is excluded from providing AUFLS. However, they have to provide the balance of any load, up to their AUFLS levels, as AUFLS if it is not otherwise committed (i.e. it counts towards their AUFLS obligation)
Ireland	It is not necessary for a grid connected customer to provide AUFLS if it is providing low-frequency disconnection at a higher level of frequency as an Ancillary Service.
Australia (NEM)	Any load shedding capability that is the subject of an ancillary services agreement or enabled as a market ancillary service can be counted as AUFLS.

How is interruptible load treated	
	Hydro pumps, and other loads that have a low likelihood of being available for tripping, should be treated as available for frequency control ancillary services only, and excluded from analysis of under-frequency load shedding
Midwest Reliability Organisation	Unclear. But a 10% manual load shed obligation exists on top of that already provided for AUFLS.
Singapore	Unclear.
PJM	Unclear. But there are also manual load shed obligations and these do appear to overlap with AUFLS to some degree.