Automatic Under-Frequency Load Shedding (AUFLS)

Scheme Options Economic and Provision Review

System Operator

4/08/2011

SYSTEM OPERATOR

Keeping the energy flowing

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	Position	Date
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1 Executive Summary

Automatic Under-Frequency Load Shedding (AUFLS) is a vital part of the New Zealand power system's under-frequency management tools used to manage security and is the system's last-resort safety net to prevent power system collapse and blackout following large, rare system events.

New Zealand's AUFLS scheme is made up of a minimum of two 16% blocks in each island. This means that a minimum of 32% of customer demand can be automatically disconnected in two stages to seek to restore stability to the power system. The current AUFLS arrangements are largely based on historical practice. In 2009, the System Operator determined that a technical review of these arrangements was required. This technical review was completed in 2010[1].

The results of the technical review concluded that there is sufficient reserve generation, interruptible load and AUFLS available to prevent system collapse from large defined risks, such as the sudden disconnection of HVDC bi-pole, at all times. This is likely to require the transfer on the HVDC link to be limited to below its maximum capability under certain system conditions to ensure power system security.

However the results of the technical review demonstrated that the overall design of the AUFLS scheme provides the System Operator with insufficient confidence that the current AUFLS scheme will be effective to prevent the system from collapsing from large risks that are not currently identified. Furthermore there is concern that the current AUFLS scheme could result in over-frequency and potentially system collapse from defined risks.

To address the issues identified in the technical review, the System Operator worked through a process of identifying technical options and undertaking cost-benefit analyses of those options. In addition, after several participants raised concerns regarding inefficiencies in the current AUFLS provision method (which can result in limiting participation in the instantaneous reserves market), the System Operator also investigated opportunities to improve AUFLS provision efficiency.

This report presents the findings and conclusions on those investigations.

The System Operator has concluded there are two AUFLS scheme options which are technically feasible for the North Island. Both options require the number of AUFLS blocks to be increased to four blocks. However, the options differ in their tripping mechanism. The two options are:

- use of rate of change of frequency relays (also known as df/dt); and
- use of fixed frequency and time relays and raising the contingent event (CE) frequency target.

In addition, there are two feasible variations of each of the above options (which essentially allows a "fine tuning" of each of the options).

Both of the options (and their variations) were analysed from a benefit perspective. This analysis demonstrated the option to raise the CE frequency target, while technically feasible, is not economically feasible, producing a net benefit range of -$50 million to $12 million over 15 years. The option of using df/dt relays results in a net benefit range of $16 million to $89 million over 15 years.

[1] The technical report can be found at http://www.systemoperator.co.nz/n3210,521.html

Compared with the current scheme the technical benefits arising from the use of df/dt relays, the System Operator's preliminary finding is that either variation of the df/dt relay options would be appropriate as an AUFLS scheme for the North Island.

The System Operator has considered the implementation requirements (including timing requirements) of any change to the AUFLS scheme options. Its findings are summarised in this report. In particular, it is noted that any changes to the AUFLS arrangements which require investment will need to recognise the regulatory investment cycle, which is approximately two years. Implementation requirements may differ across North Island GXPs and therefore the System Operator seeks participant's feedback in this regard.

For the South Island the System Operator believes it is prudent to hold off proposing new AUFLS schemes until there is further clarity of the future of AUFLS provision at the Tiwai grid exit point. In the interim, the System Operator has identified that increasing the trip setting of the second AUFLS block to 46 Hz will offer considerable improvement of the current South Island AUFLS scheme.

During the review (in April 2011), the System Operator undertook an industry discussion of AUFLS provision options, including a dynamic procurement option to address some participants' desire for an AUFLS market. From that discussion there did not appear to be any widespread desire for dynamic market arrangements nor firm proposals as to how such market arrangements would ensure the provision of AUFLS load.

The continued use of a mandated AUFLS scheme will be required in the foreseeable future. Industry feedback following the technical review highlighted the challenge to provide the current 16% blocks, which often results in over-provision of AUFLS load. The System Operator has outlined options available within the current code that may assist with limiting the over-provision associated with a mandated AUFLS scheme and increase the efficiency of providing AUFLS load.

The technical options, and associated benefit analysis, will be presented and discussed with industry at System Operator workshops commencing on 8th August 2011. Following the workshops, the System Operator will consider industry feedback before making recommendations to the Electricity Authority regarding the future AUFLS arrangements in both islands.

2 Glossary

Term	Acronym	Description
Alternating Current	AC	An electric current that reverses directions at regular intervals. In New Zealand's electricity system this occurs 50 times a second. See frequency
Automatic Under-Frequency Load Shedding	AUFLS	Automatic shedding of electrical load when the frequency falls below preset frequency levels as specified in the Code.
Automatic Voltage Regulator	AVR	A device that continuously monitors the voltage at a voltage regulating point on the system (generator, condenser, transformer etc.) and automatically initiates corrective action to maintain that voltage within pre-set limits.
Bi-pole		Both poles of the HVDC link are commonly referred to as the bi-pole. See *HVDC*.
Blackstart		In the event of a blackout the first generating station required to initiate the system restoration process must do so without relying on the external energy sources which would normally be available from the system. Self-starting without external energy sources is known as a 'blackstart'
Busbar		A busbar, or bus, is a common electrical connection between multiple electrical devices.
Combined Cycle Gas Turbine	CCGT	A type of generation where a gas turbine generator generates electricity and the waste heat is used to make steam to generate additional electricity via a steam turbine. Examples of CCGT plant on the New Zealand power system include Otahuhu B, Stratford Power Ltd, and Huntly unit 5
Contingent Event	CE	Events that could happen relatively frequently or cause a severe enough impact on the power system and the estimated cost and benefit of mitigation justify incorporating pre-event measures into the scheduling and dispatch processes. Examples of such measures are instantaneous reserves or security constraints.
Electricity Industry Participation Code 2010	Code	Electricity Industry Participation Code 2010
Direct Current	DC	An electric current that does not reverse and flows in only one direction. See *HVDC*.
Extended Contingent Event	ECE	Events that may have a severe impact on the power system but the likelihood of them occurring is too low to justify implementing any mitigating measures in planning time. In such cases, reliance may be placed on demand shedding (AUFLS) to avoid power system collapse.
Electricity Governance Rules and Regulations	EGRs	The Electricity Governance Rules and Regulations 2003.
Frequency		The frequency at which alternating current is transmitted from a power plant to the end user. Frequency is measured in Hertz (Hz). In most parts of the world, including New Zealand, the frequency is 50 Hz. In the Americas it is typically 60 Hz.
Grid Exit Point	GXP	A point of connection where electricity may flow out of the grid.

Fast Instantaneous Reserve	FIR	Fast or six second reserve is the additional capacity provided six seconds after the event to stop sudden fall of the frequency and maintain provision for at least sixty seconds. Fast acting reserve providers that can start delivering extra energy very quickly are used in the very short term. This is done through partially loaded spinning reserve (PLSR) or tail water depressed (TWD) which provide extra output within six seconds. Fast reserve can also come from providers which disconnects load within a second of the frequency hitting the 49.2 Hz. This is known as Interruptible load (IL).
High Voltage Direct Current	HVDC	A high-voltage direct current (HVDC) link connects the power systems of New Zealand's North and South Islands. These cables are commonly referred to as the Cook Strait Cable or the HVDC. The HVDC is made up of two poles known as Pole 1 and Pole 2. Transpower is carrying out a project to replace Pole 1 with a new pole (to be known as Pole 3) by 2012
Hertz	Hz	See frequency
Interruptible Load	IL	Demand which, by commercial arrangement between the System Operator and a provider, may be disconnected automatically for the purposes of maintaining grid security. IL is a type of instantaneous reserve.
Instantaneous Reserves	IR	Additional generation and interruptible load which are able to counter a contingent event, the response being fast enough to limit the fall in frequency to within the limits set out in the code. Instantaneous reserve comes in the form of interruptible load, partly loaded spinning reserve and tail water depressed reserve. ***Note:*** *There are two classes of instantaneous reserve:* 1. Fast instantaneous reserve, being fast enough to limit the fall in frequency; and 2. Sustained instantaneous reserve, being able to replace the lost supply to assist in the recovery of frequency to 50 Hz.
Load		Another term for electricity demand (consumption of electrical energy).
Megavolt-ampere reactive	Mvar	Reactive power is measured in volt-amperes reactive (var). A megavolt-ampere reactive (Mvar, pronounced megavar) is equal to one million var.
Megawatt	MW	A watt is a unit for measuring electric energy. One megawatt is equal to one million watts.
Partly Loaded Spinning Reserve	PLSR	This is a form of instantaneous reserve. PLSR is spare capacity held in reserve on a generating unit, but not operating at full output, which is able to provide instantaneous reserve following a drop in system frequency.
Pole		See *HVDC*
Reserve Management Tool	RMT	Models the power system performance to optimise the amount of reserves required to keep the frequency inside the targeted frequency range should a contingent or extended contingent event occur.
Scheduling, Pricing, and Dispatch Mode	SPD	This is a linear programming model used to produce schedules of the optimal dispatch quantities and nodal prices for the electricity wholesale market. The primary objective of SPD is to achieve the most economic dispatch of reserves and generation to meet system demand.
Sustained	SIR	Sustained or 60 second reserve is the additional capacity that

Instantaneous Reserve		can be provided between zero and sixty seconds to stabilise the frequency. The total output at sixty seconds has to be sustained for up to 15 minutes after the event.
Special Protection Scheme	SPS	Equipment provided for detecting equipment overloads or abnormal conditions in power systems and initiating remedial action.
Static Var Compensator	SVC	An electrical device for providing fast-acting reactive power on high-voltage electricity transmission networks. It regulates voltage and stabilises the system.
Trip		In this report *trip* is used in reference to: System events - the sudden disconnection of a large amount of generation e.g. tripping of multiple generation units or tripping of the HVDC. AUFLS – the operation of the AUFLS scheme. Interruptible load – the operation of the IL scheme
Tail Water Depressed Reserve	TWDR	This is a form of instantaneous reserve provided by hydro generators. TWDR is generating capacity on a motoring hydro generation unit with no water flowing through the turbine that is available to provide instantaneous reserve following a drop in system frequency.
Voltage		The flow of electrical charge is known as electrical current. The force that is applied to the electrons to make them flow is known as voltage. As an analogy, consider water flowing through a pipe: the current is the rate of water flow, and the voltage is equivalent to the pressure that is applied to make the water flow through the pipe. Voltage is measured in volts (V) or kilovolts (kV). One kilovolt is equal to one thousand volts.
Value of Lost Load	VoLL	This is the value of unserved energy which is a result of outages of primary transmission equipment that disconnect customers from the supply of electricity. Currently VoLL is valued at $20,000/MWh. This means that for each hour that a MW of electricity demand cannot be supplied it is counted as having a cost of $20,000. It represents the estimated economic value of the energy to the customer.
The vectorised SPD	vSPD	The vSPD model was developed to replicate the schedules, prices and dispatches produced by the SPD market clearing engine used in the New Zealand Electricity Market.

3 Introduction

3.1 Background and Purpose

AUFLS is the acronym for Automatic Under-Frequency Load Shedding and describes the set of relays in New Zealand which automatically trip blocks of load following a severe under-frequency event to seek to restore the system frequency.

These relays are relied upon by the System Operator as a last resort to attempt to prevent the collapse of the system from under-frequency following an extended contingent event or other undefined events which have the potential to cause a system blackout.

The AUFLS obligations are set out in Part 8 Schedule 8.3 Technical Code B of the Electricity Industry Participation Code ("the Code"). Distributors[2] in the North Island and grid owners in the South Island are required to provide a minimum of 2 x 16% blocks of AUFLS as described in Table 3-1 and Table 3-2 below:

Table 3-1 Required AUFLS settings for North Island

	Block 1 – North Island	Block 2 – North Island
Trip Frequency (Hz)	47.8	47.8
Time Delay (sec)	0.4	15
2nd Trip Frequency (Hz)	-	47.5
Time Delay (sec)	-	0.4

Table 3-2 Required AUFLS settings for North Island

	Block 1 – South Island	Block 2 – South Island
Trip Frequency (Hz)	47.5	47.5
Time Delay (sec)	0.4	15
2nd Trip Frequency (Hz)	-	45.5
Time Delay (sec)	-	0.4

The current Code arrangements are based on historical practice and it is our understanding that no real cost-benefit analysis was undertaken when the obligations were included into the Electricity Governance Rules (EGRs).

Following the commencement of the EGRs in 2004, several participants were granted exemptions from the AUFLS obligations. Responding to questions from the Electricity Commission in 2009 regarding the effect of granting extensions to such exemptions, the System Operator raised concerns about whether the current AUFLS scheme was capable of adequately covering an extended contingent event given the number of changes to the power system since AUFLS arrangements were first introduced. In light of these concerns, the System Operator conducted a technical review of the existing AUFLS scheme in 2010 to better understand the ability of current AUFLS arrangements to cover large system events[3].

[2] For the purpose of Part C obligations this includes consumers connected directly to the grid, also known as 'direct connects'

[3] The technical report can be found at http://www.systemoperator.co.nz/n3210,521.html.

The technical review concluded the current AUFLS arrangements are sufficient to recover the system from credible events. However, AUFLS are unlikely to be effective at recovering the system from a number of other large events. It was noted that some of the current reserve products do not respond fast enough to interact well with AUFLS.

The technical review concluded that different AUFLS arrangements would be required to improve AUFLS response to large system events.

The System Operator presented the findings to industry participants through a series of workshops. Industry participants informed the System Operator of different factors that limit the efficiency of AUFLS provision, contribute to over provision of AUFLS load, and unnecessarily limit participation into the instantaneous reserves market.

Following the AUFLS technical review the System Operator and the Electricity Authority initiated an Under-Frequency Management (UFM) review.

The purpose of the UFM review was to determine strategies and measures that offer the most reliable, secure, and cost effective under-frequency management model to provide greater certainty of system integrity during major under frequency events and to operate an efficient market.

The UFM review was undertaken in three work streams:

1. Instantaneous Reserves review
2. AUFLS Scheme Options Economic and Provision review
3. Asset Owner Performance Obligations (AOPOs) and Principal Performance Obligations (PPOs) review

The UFM three work streams were pursued concurrently, acknowledging the areas of interconnection. The AUFLS work stream aimed to make recommendations where possible before the completion of the UFM review, and the remaining UFM work streams will be carried out in light of the AUFLS recommendations.

The AUFLS Scheme Options Economic and Provision review aimed to:

1. Determine the technically feasible alternative options for an AUFLS scheme and undertake a cost benefit analysis on these options.
2. Understand the implementation requirements of each technically feasible option.
3. Understand AUFLS provision limitations and inefficiencies and determine options for addressing such limitations and inefficiencies.

The purpose of this report to set out the System Operator's findings on each of the above and to seek industry and stakeholder views on such findings. Once the System Operator has considered any comments received in respect of this report's findings, it expects to make recommendations to the Electricity Authority.

This report assumes a reasonable level of understanding of reserve management concepts. For those requiring additional background information a high level overview of reserve management concepts can be found in Appendix A.

The System Operator wishes to acknowledge and express appreciation to Simon Coates and Robert Derks for their significant input to the cost benefit analysis material included in this report.

3.1.1 Providing comments to the System Operator

The System Operator request comments on this report's findings by Friday 16 September 2011 so that it can continue the next phase of work. We will also take account of any feedback received at our upcoming workshops on the 8, 10, or 12th of August 2011.

The System Operator's preference is to receive submissions in electronic form. The electronic version should be emailed with the phrase "Submissions on AUFLS scheme options" in the subject header to justin.blass@transpower.co.nz. Hard copies can be posted to the following address:

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The System Operator will acknowledge receipt of all submissions electronically.

The System Operator values openness and transparency and therefore comments will be published on the System Operator's website. Those providing comments should discuss with the System Operator any intended provision of confidential information, prior to sending the information.

4 Investigation of AUFLS Scheme Options

The 2010 technical review demonstrated the current AUFLS scheme is insufficient to protect the system from large low probability risks. In addition, the current AUFLS scheme, while sufficient to arrest the frequency falling following an extended contingent event, may result in over-frequency which could result in system collapse. The objective of this review was to develop an AUFLS scheme that is technically, economically and operationally effective.

Following from the technical options presented in the technical review, the System Operator undertook work to refine the options and complete an economic analysis of them. To begin the process the System Operator identified the desired objectives. It then considered the options available to meet the desired objectives.

4.1 Development of AUFLS Scheme Options

4.1.1 What is the objective of an AUFLS scheme?

The primary objective of an AUFLS scheme is to perform load reduction to match a significant loss of supply in order to maintain the frequency within safe operating ranges and prevent system wide collapse from occurring.

4.1.2 What scheme options were developed?

In the technical review the System Operator identified four AUFLS scheme options. Table 4-1 outlines the schemes studied in the technical review for both the North and South Islands.

Table 4-1 AUFLS Schemes studied in the Technical Report

Scheme No	*North Island*	*South Island*
1	Existing scheme 2 x 16 %	Existing scheme 2 x 16 %
2	2 x 25 %	2 x 16 % with df/dt
3	4 x 10 %	4 x 8 %
4	4 x 8 % with df/dt	4 x 12 %
5	4 x 10 % with CE target of 48.5 Hz	

Further information on the settings for each scheme can be found in Section 5.3 of the technical review report. The technical review report included an analysis of the ability of the existing and alternative AUFLS schemes to cover for rare large risks. The result of the analysis allowed the System Operator to create a short list of technically feasible options it believes were improvements over the existing scheme to be assessed as part of the economic review.

4.1.3 What makes a scheme technically feasible?

To ensure the design of the scheme provides the system with an effective safety net, the System Operator tested the schemes against a range of scenarios. The main indicators of AUFLS scheme performance are the size of the load shed and the speed of operation.

Analysing the size of load shed is important to consider because excessive load shedding can cause the frequency response to overshoot. This is of special concern for the North Island system as there are significant amounts of thermal generation which will trip on over-frequency protection when operating above 52 Hz. If this occurs while the thermal units are generating, there will a second dip in

system frequency which may not be recoverable since there may not be enough AUFLS left to balance this subsequent loss of generation.

Having more and smaller blocks allows better “matching” of load shedding to the initial contingency loss reducing the potential for over-frequency and over-voltage from excessive load shedding.

Over shedding can also be reduced by increasing the distance between AUFLS block trip settings. The current North Island AUFLS blocks are set .03 Hz apart. When the frequency decay is very fast this can result in both blocks tripping when only one is required, as the second block is triggered before the first block operates. Increasing the distance between trip settings will provide additional space to prevent this kind of unnecessary tripping. This discrimination between blocks increases the effectiveness of AUFLS by limiting excessive load shedding.

The System Operator acknowledges there are a wide range of system conditions. The condition of the system at any point in time determines the risks and the rate of frequency fall associated with the loss of the risk. As no AUFLS system can be infinitely large or fast, its design is a compromise between practical performance and flexibility of system operation.

Building from these factors, the System Operator developed criteria for considering the validity of the options proposed in the technical review. The criteria includes that the scheme must:

- be proven against a range of scenarios identified in the technical review;
- have sufficient discrimination between blocks to efficiently trip load;
- trip sufficient amount of AUFLS load to avoid over shedding and frequency overshoot; and
- improve system response from current scheme.

A performance summary table, chart of frequency traces and detailed discussion is provided for each scheme and scenario in Section 6 of the technical review report. Table 4-2 (below) includes an overview of the results and outlines the feasibility assessment of the schemes assessed in the technical review report.

4.1.4 Technical Review Results of the North Island Scheme Options

Table 4-2 Summary table for results of the North Island studies

Scheme Studied	Summary of North Island Results	Proven against Scenarios	Separation between blocks	Minimal excess shedding	Improvement from Status Quo	Scheme Evaluation
Existing scheme 2 x 16%	Five out of six scenarios collapse. AUFLS is insufficient in either quantity, speed of response, or both for the scenarios studied.	×	×	×	-	Infeasible
2 x 25%	This scheme studied the effect of increasing the total quantity of AUFLS. One out of six scenarios collapse but three result in significant over-frequency due to over-shedding. Over-shedding is inefficient and can lead to risk of system collapse if the magnitude of the over-shedding is significant.	×	×	×	×	Infeasible
4 x 10%	This scheme studied the effect of increasing the number of blocks and decreasing the block size in order to reduce the potential for over-shedding. Five out of six scenarios collapse. Adding more blocks alone does not reduce the risk of over-shedding if the blocks are set to trip too close together. The speed of the AUFLS response is too slow to prevent collapse in most of the scenarios studied.	×	×	×	×	Infeasible
4 x 8% with df/dt elements	This scheme studied the effect of increasing the speed of the AUFLS response by triggering AUFLS on the rate of change in frequency. Two out of six scenarios collapse. Using df/dt triggers allows AUFLS to operate before 48 Hz and gives generator turbines and AVRs time to respond and help recover the system. This scheme demonstrates that the system response can be improved without increasing the total quantity of AUFLS. Df/dt schemes need more investigation in terms of capability of relays and optimisation of settings.	-	✓	✓	✓	Feasible

Scheme Studied	Summary of North Island Results	Proven against Scenarios	Separation between blocks	Minimal excess shedding	Improvement from Status Quo	Scheme Evaluation
4 x 10% with CE target of 48.5 Hz	This scheme studied the effect of increasing the speed of the AUFLS response by triggering AUFLS at a higher frequency (using the existing trigger mechanism). One out of six scenarios collapse. The higher trip settings allow generator turbines and AVRs time to respond to help recover the system. This scheme produces the best results of the schemes studied as it accounts for the total quantity of the AUFLS response, the number and size of blocks and the speed of the response.	✓	✓	✓	✓	Feasible

4.1.5 *Conclusions on North Island AUFLS Scheme Options*

Based on the above analysis, the System Operator has determined there are two feasible AUFLS scheme options that meet the objective. These are:

- 4 x 8 % df/dt
- 4 x 10 % with CE target of 48.5 Hz

The System Operator then created variations of the feasible schemes. The variations are technically feasible solutions that also allow the option of fine tuning the schemes. Table 4-3 outlines the variations created.

Table 4-3 AUFLS Variation Schemes Created for Economic Analysis

	Proposed Scheme	**Variation Scheme**
	Existing scheme 2 x 16 %	
Option A	4 x 8 % with 4 blocks df/dt	4 x 8 % with 2 blocks df/dt
Option B		4 x 8 % with 3 blocks df/dt
Option C	4 x 10 % with CE target of 48.5 Hz	4 x 8 % with CE target of 48.5 Hz and IL tripping at 49.5 Hz
Option D		4 x 10 % with CE target of 48.5 Hz and IL tripping at 49.5 Hz

4.1.6 Technical Review Results of the South Island Scheme Options

Table 4-4 Summary table for results of the South Island studies

Scheme Studied	Summary of South Island Results	Proven against Scenarios	Separation between blocks	Minimal excess shedding	Improvement from Status Quo	Scheme Evaluation
Existing scheme 2 x 16%	3 out of 6 scenarios collapse or are very close to collapse. AUFLS is insufficient in size for the collapsed (bi-pole tripping) scenarios. Over-shedding results in high frequency for one scenario studied, although the frequency is within the code limits. Including an AUFLS response at Tiwai results in better (higher) minimum frequencies for the scenarios that do not collapse.	✓	✓	×	-	Feasible with changes
2 x 16% with df/dt	2 out of 6 scenarios collapse 3 of the scenarios studied do not trigger on df/dt (i.e. they trigger on the existing settings). This scheme does not provide significantly different or better results than the existing scheme except when an AUFLS response is included at the Tiwai GXP. Increasing the speed of the AUFLS response without modifying other variables (such as total size or number of blocks) does not improve the performance of the existing scheme.	✓	✓	×	×	Improvement deemed insignificant
4 x 8%	2 out of 6 scenarios collapse The results of this scheme are mixed in comparison with the existing scheme. 2 scenarios studied perform worse under this scheme, but the problem of over-shedding is avoided for one scenario. This scheme illustrates that the total quantity of AUFLS is a key issue for the South Island. Increasing the number of blocks does not improve the performance of the existing scheme if the total quantity of AUFLS remains the same.	✓	✓	✓	×	Minor benefits over current scheme
4 x 12%	2 out of 6 scenarios collapse. These scenarios collapse as the disturbance to the system is greater than 70%. With an AUFLS response included at Tiwai, no scenarios collapse although the code minimum frequency limit of 45 Hz is breached for 2	✓	✓	✓	✓	Benefit in increasing the total quantity of

Scheme Studied	Summary of South Island Results	Proven against Scenarios	Separation between blocks	Minimal excess shedding	Improvement from Status Quo	Scheme Evaluation
	scenarios. This is the best performing scheme as more load is available to be shed by AUFLS (48%) and smaller blocks reduce the potential for over-shedding. Extra reserve is still required under this scheme to keep the frequency within the EGR limits for 2 of the scenarios, but far less is required than any of the other schemes studied.					AUFLS load.

4.1.7 Summary of South Island AUFLS Options

Only one option met all of the feasibility criteria for an AUFLS scheme option in the South Island.

There are a number of factors which make South Island AUFLS scheme requirements different then the North Island schemes. These factors include the relative size of the ECE risk, the AUFLS frequency band of operation and the issue of non-compliance in the South Island.

When the HVDC is transferring south, the loss of the bipole can cause a much larger disturbance relative to the total size of South Island load. The South Island AUFLS range is currently 48 Hz to 45 Hz, which allows for a greater margin between AUFLS block trip settings which enables discrimination. In addition, there is currently no AUFLS response at the South Island's largest source of demand, the Tiwai grid exit point.

Accordingly, increasing the number of AUFLS blocks allows for better control of load shedding and reduction in the potential for over-shedding in the South Island. However, there is no real benefit to be gained by increasing the number of blocks in the South Island if the total quantity of AUFLS (32%) remains the same. As found in the technical review, increasing the total quantity of AUFLS in the South Island would likely provide the most benefit, by reducing the amount of reserve procured during high HVDC South transfer.

Whilst the System Operator has undertaken significant work to determine technically feasible AUFLS scheme options for the South Island, the System Operator believes it is prudent to refrain from further analysing AUFLS scheme options until there is further clarity of the future of AUFLS provision at the Tiwai GXP. The inclusion of an AUFLS response at Tiwai will decrease the amount of reserve required to cover high HVDC south and improve the South Island AUFLS safety net.

In the interim, the System Operator has identified that increasing the trip setting of the second AUFLS block to 46Hz will improve the current South Island AUFLS scheme as the second AUFLS block is currently set to trip very close to 45 Hz. An increase in the trip setting would raise the minimum frequency reached following most of the AUFLS events studied. Further information can be found in the technical review report.

Once the future of AUFLS at the Tiwai GXP has been determined the System Operator will undertake the benefit analysis of the South Island AUFLS scheme options.

5 Cost Benefit Analysis of the North Island AUFLS Scheme Options

The aim of this section is to report on the investigation of which AUFLS scheme option provides the North Island with an operable and cost effective safety-net. The economic assessment analyses the benefits and costs of each scheme option in three areas of how each scheme:

- affects the procurement of instantaneous reserves (IR).
- affects the amount of load loss from an AUFLS event or blackout.
- could be implemented and the costs of different implementation methods.

5.1 Instantaneous Reserve Procurement

The existence of the AUFLS scheme is a key factor in determining the appropriate procurement of IR to ensure a secure system following contingent and extended contingent events. Consequently, a change to the AUFLS scheme would have an impact on the amount of IR required to be procured. A full explanation of the interaction between AUFLS and reserve procurement is set out in Appendix A of this report.

To determine the impact of AUFLS scheme options on reserve procurement, the System Operator's Reserve Management Tool (RMT) is used to calculate the Net Free Reserve (NFR) values resulting from each scheme option. The NFR values are then used by SPD to procure the required reserves to secure the system. Appendix A includes a high level explanation of how RMT calculates NFR values.

The following section sets out the scenarios used to produce the NFR values and the NFR results for each scheme option.

5.1.1 North Island Scenarios

Table 5-1 North Island scenarios studied

System Load (MW)	HVDC North Flow (MW)	HVDC Risk Subtractor (MW)	HVDC CE Risk (MW)	HVDC ECE Risk (MW)	HLY5 Generation (MW)	AC CE Risk (MW)	AC ECE Risk (MW)
Heavy Load (4600)	900 (sent)	650	197 (received)	847 (received)	390 (Max)	HLY 5 (390)	N/A
	1200 (sent)		456 (received)	1106 (received)			
Medium Load (3600)	1400 (sent)		622 (received)	1272 (received)		HLY 1 (240)	HLY Station (960)
Light Load (2000)	No HVDC Flow	0	0	0	390/250 (Max/Min)		

30 cases were constructed based on the load and generation scenarios set out in Table 5-1. Each scheme option was run for all 30 cases in RMT. RMT calculated the NFR values for each case and scheme option.

5.1.2 NFR results

Table 5-2 FIR ECE Net Free Reserve availability

Case #	4 x 8% with 2 blocks df/dt	4 x 8% with 3 blocks df/dt	4 x 8% with increased CE limit & IL setting	4 x 10% with increased CE limit & IL setting
1	847.32	847.32	847.32	847.32
2	960.00	960.00	960.00	960.00
3	1106.35	1106.35	1106.35	1106.35
4	1106.35	1106.35	1106.35	1106.35
5	1178.68	1195.61	1195.61	1272.53
6	1179.97	1195.61	1194.32	1272.53
7	0.00	0.00	0.00	0.00
8	960.00	960.00	960.00	960.00
9	0.00	0.00	0.00	0.00
10	960.00	960.00	960.00	960.00
11	845.33	845.35	845.34	847.32
12	958.00	958.00	958.00	960.00
13	894.68	908.97	906.92	1104.35
14	914.84	923.52	923.52	1104.35
15	842.08	852.15	852.15	1116.45
16	846.38	857.91	857.91	1138.61
17	0.00	0.00	0.00	0.00
18	942.20	956.01	956.01	960.00
19	0.00	0.00	0.00	0.00
20	914.04	928.07	926.16	960.00
21	425.20	438.79	438.79	568.63
22	411.38	415.74	415.74	562.97
23	383.93	396.93	396.93	507.14
24	348.82	363.50	348.82	485.06
25	344.15	360.43	344.84	457.70
26	311.65	311.65	311.65	437.35
27	0.00	0.00	0.00	0.00
28	362.48	380.23	374.37	503.99
29	0.00	0.00	0.00	0.00
30	368.46	380.23	380.23	503.99

Table 5-2 displays the FIR NFR values resulting from each of the 30 cases for the proposed scheme options for the ECE risk. Details of the cases and results can be found in Appendix B.

5.1.3 Instantaneous Reserve Benefit Analysis and Results

To understand the implications for the New Zealand energy market the NFR values were used in three different assessments to:

- determine the fixed carrying cost of holding capacity available to provide IR over and above the amount of capacity required to meet energy requirements
- determine the short run marginal cost estimation utilising average increased or decrease in reserves.
- capture the total market cost of both energy and reserve, by replicating the SPD model (utilising the Electricity Authory's vSPD software).

The results of each of the assessments are set out in the following section, considered from the perspective of benefits gained. Any costs will be seen as negative benefits.

The benefit analysis was undertaken to quantify the benefits of the following North Island scheme options (as set out in section 4.1.4 of this report):

- Scheme Option A: 4 x 8% with 2 blocks df/dt
- Scheme Option B: 4 x 8% with 3 blocks df/dt
- Scheme Option C: 4 x 8% with CE target of 48.5 Hz and IL tripping at 49.5 Hz
- Scheme Option D: 4 x 10% with CE target of 48.5 Hz and IL tripping at 49.5 Hz

Fixed Carrying Cost Methodology

Reserves and energy are similar products but used for different purposes and offered at different prices. Reserves can be seen as dedicated capacity, or energy on standby, available precisely when the System Operator requires it. Many generators can offer capability as either energy or reserve, or a combination of the two.

During outages of significant generating plant or times of extremely high demand it can become challenging to meet the energy and reserve requirements with the capacity available; this is known as scarcity. During times of scarcity the cost of meeting energy and reserve requirements can be very high. Although there are only a few periods of capacity scarcity they can have the largest impact on instantaneous reserve cost.[4]

The cost of holding a generator's capacity available to provide instantaneous reserves is known as a fixed carrying cost. The objective of examining the fixed carrying cost is to analyse what affect the proposed AUFLS arrangements have on the overall requirement for capacity to be held on system to supply reserves during times of scarcity.

The cases of high demand will be analysed to forecast the scheme's affect during times of scarcity. The value used to price the carrying cost is estimated as the carrying cost of an open cycle gas turbine, as this is the most likely marginal source of generation.[5]

It was also assumed the value of IL should not be regarded as the marginal source of capacity because at times of shortage the price of electricity will justify using the interruptible load to avoid peak demand cost. Further detail of the methodology and assumptions is in Appendix D.

[4] See Appendix C for more detail on this assumption
[5] The carrying cost of OCGT is estimated at $145/kWh

Fixed Carrying Cost Results

The objective of examining the fixed carrying cost was to analyse what affect the proposed AUFLS scheme options have on the overall requirement for capacity to be held on the system during times of scarcity. As scarcity generally results from extremely high demand only high demand cases were investigated.

This section outlines the results of the North Island studies against the high demand cases described in Appendix B.

For each scheme the RMT results will be analysed and then compared against the resulting values from economic values.

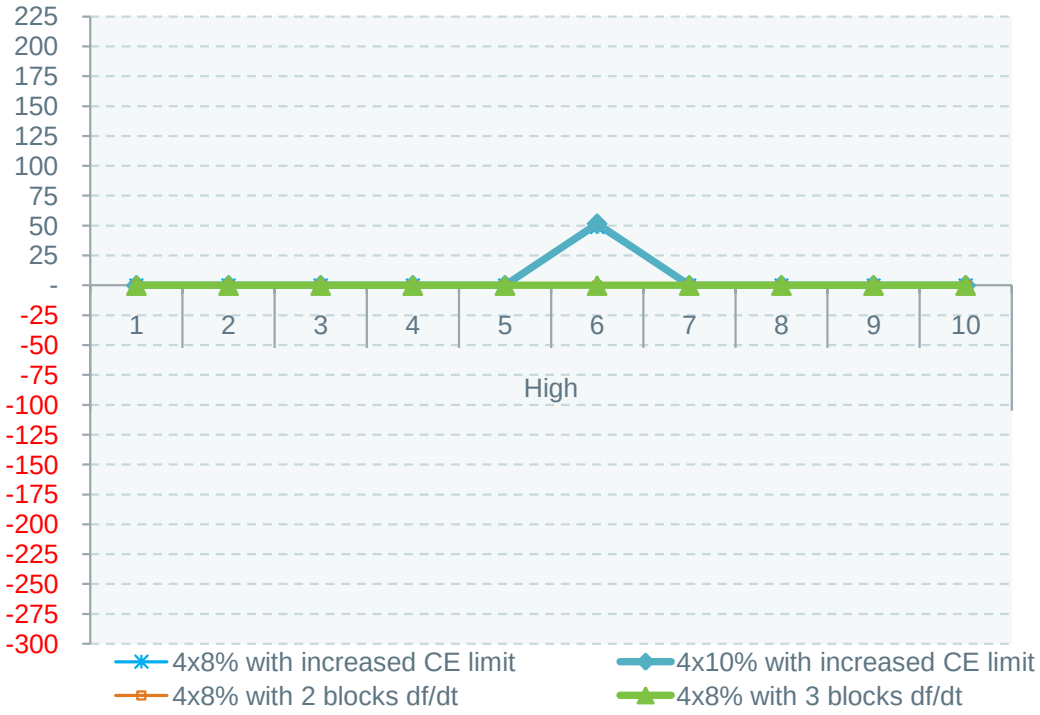

Figure 5-1 Altered IR results for the proposed schemes relative to the current AUFLS scheme

The effect of Options A & B: df/dt schemes

For the high demand cases studied both df/dt schemes result in no increase or decrease in the required amount of reserves and therefore no change to the carrying cost during times of scarcity.

The effect of Option C: 4x8% with an increased CE limit

Unlike the df/dt schemes, the 4x8% scheme requires the CE limit to be increased to 48.5 Hz. RMT will now be required to procure enough reserves to prevent the frequency from falling below 48.5 Hz.

Increasing the CE limit alone increases the IR requirements during high demand to an average of 117 MW. Increasing the IL operation frequency to 49.5 improves the performance of the scheme but still requires on average an additional 49 MW of reserves.

To observe the impact on carrying capacity the 49 MW of additional reserve is then multiplied by the cost of carrying additional peaking capacity ($145/kW/yr or $0.145/MW/yr) which results in an estimated benefit of -$7.1m to the market each year. The increase of the CE limit requires more IR to be available and therefore increases the capacity required to be able to cover for contingent events.

Table 5-3 Summary table for Option C carrying cost results

	4 x 8% with increased CE limit	4 x 8% with increased CE limit & IL setting
Max increased IR requirement during high demand (MW)	117	49
Benefit @ $.145/MW/yr carrying cost ($m/yr)	-$17.0m	-$7.1m

The effect of Option D: 4 x 10% with an increased CE limit

The 4 x 10 % scheme also requires an increase of the CE limits to 48.5 Hz. Similar to the results discussed for the previous scheme; the 4 x 10% scheme requires more reserve to be able to keep the system secure.

Increasing the CE limit alone increases the amount of IR required by an average of 120 MW. Increasing the IL operation frequency to 49.5 improves the performance of the scheme but still requires on average an additional 51 MW of FIR.

To observe the impact on carrying capacity the 51 MW of additional reserve is then multiplied by the cost of carrying additional peaking capacity ($145/kW/yr or $.145/MW/yr) which results in an estimated benefit of -$7.5m to the market each year. The increase of the CE limit requires more IR to be available and therefore increases the capacity required to be able to cover for contingent events during times of scarcity.[6]

[6] As CE limit is binding should theoretically result in the same values for both the 4x8% and the 4x10% schemes. But variations in the calculation by RMT results in slight changes to the amount of NFR values.

Table 5-4 Summary table for Option D carrying cost results

	4 x 10% with increased CE limit	4 x 10% with increased CE limit & IL setting
Max increased IR requirement during high demand (MW)	120	51
Benefit @ $145/kW/yr carrying cost ($m/yr)	-$17.0m	-$7.5m

Summary of Fixed Carrying Cost Results

There was no reduction in capacity carrying cost observed for any of the AUFLS scheme options based on investigations using high demand cases. At times of high demand the amount of AUFLS load is also high which results in sufficient coverage of the ECE risk.

Increasing the CE limit (as required for scheme options C and D) has a significant impact on the total amount of reserves required on the system. The increase in the amount of reserves results in an increased cost of carrying the capacity during times of scarcity. The carrying cost of raising the CE limit has near-present value of $106.5 million dollars.

Table 5-5 Summary of fixed carrying cost results

	4 x 8% with 2 blocks df/dt	4 x 8% with 3 blocks df/dt	4 x 8% with increased CE limit & IL setting	4 x 10% with increased CE limit & IL setting
Max increased IR requirement during high demand (MW)	0	0	49	51
Benefit @ $145/kW/yr benefit carrying capacity ($m/yr)	0	0	-$7.1m	-$7.5m

5.1.4 SPD estimation Methodology and Results

The purpose of the SPD estimation methodology is to determine the total market cost (energy and reserves) resulting from the AUFLS scheme options. To estimate the total market cost, it is necessary to simulate the interaction between RMT and SPD.

To estimate total market cost the function of SPD needs to be taken into consideration. The objective function of the SPD model is to optimise both energy and reserves. SPD co-optimises energy and reserve requirements because these two products are closely related.

As previously stated, many generators can offer their capability as either energy or reserve, or a combination of the two. In addition, the reserves a generator can deliver are often dependent on the amount of energy the generator has been dispatched to provide, making the production of energy and reserves highly interactive. SPD utilises this interaction to co-optimize energy and reserves.

The market normally iterates between RMT, which produces NFRs and ramp rates for SPD, and SPD, which produces dispatches for RMT. The iterations allow SPD to co-optimize the cost of reserves and energy.

The iterations would be too detailed for this project so a linear interpolation method was developed. The NFR values calculated from RMT were used to create a linearly interpolated function of island NFRs based on HVDC transfer, island total load and (for the north island only) maximum unit generation. This allows for SPD to co-optimise the NFR values with the dispatch through linear interpolation.

The method is accurate to the extent that NFR for each risk type and island can be written as a piecewise linear function of HVDC transfer, island load and maximum unit generation.

Representative and extreme days were chosen to be simulated through vSPD, utilising the NFR interpolation function for each AUFLS option to observe the effects of each scheme on the total market cost. The results for each scheme were then compared against the current scheme to arrive a difference in market cost per trading period. A detailed description of the SPD estimation methodology can be found in Appendix B.

The effect of Option A & B: df/dt schemes

The results for the df/dt schemes were inconclusive. No clear cost or reduction from the proposed AUFLS schemes could be attributed to the vSPD results.

The effect of Option C & D: increasing the CE limit

Increasing the CE limit requires more FIR available on the system when the CE risk is binding and results in a greater market cost. A clear average value was hard to discern from the results. However the representative and extreme days showed an estimated average increase of around $240/trading period and $145/trading period respectively. As a guide, $100/trading period approximately equates to a market cost of $1.75 million a year and $25 million NPV.

5.1.5 *Short Run Reserve Cost Methodology and Results*

This methodology requires the total IR requirements for each scheme options (maximum of FIR and SIR) to be compared to the current scheme. Any differences are averaged to provide an estimated average quantity of additional or reduced spinning reserve operating throughout the year.[7]

Short Run Reserve Cost Results

The effect of Option A: 4x8% with 2 blocks with df/dt elements

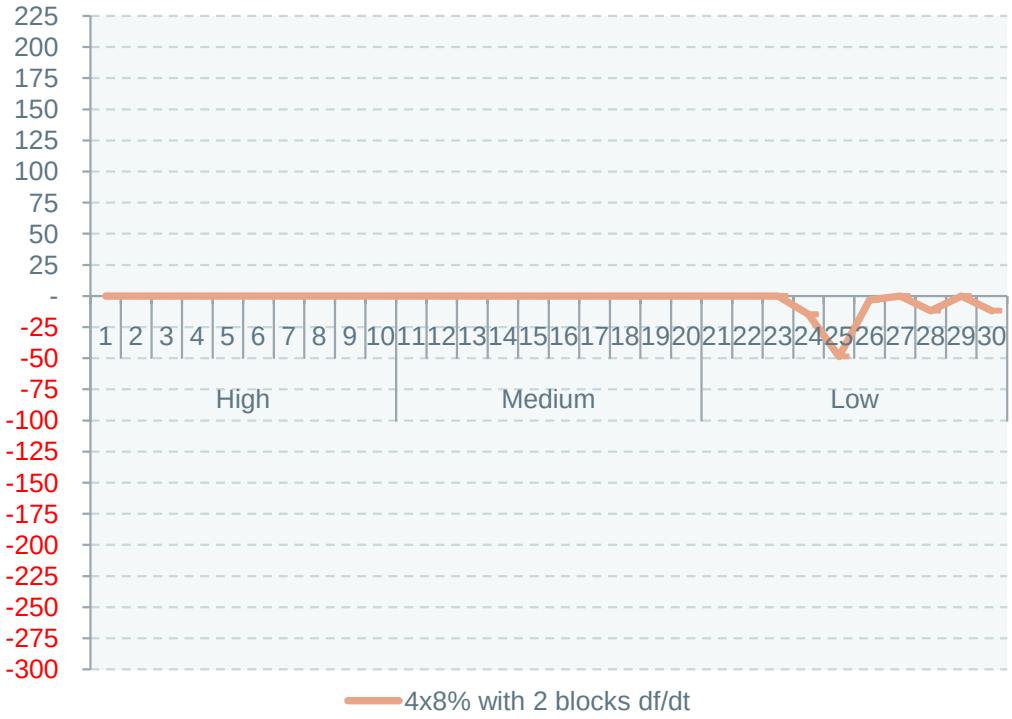

Figure 5-2 Altered overall IR requirement relative to the current scheme for the 4x8% with 2 blocks df/dt

Figure 5-2 sets out the 4 x 8% with 2 blocks of df/dt scheme results. With regard to overall quantity of reserves needed on the system (maximum FIR and SIR), the scheme offers little improvement over the current scheme.

The average reduction of IR requirement across all cases is -3 MW, which results in a reduction of -26 MWh of reserves required over a twelve month period. This results in a market impact of less than $100,000 per annum (assuming the cost of spinning reserve is $1/kWh). The reduction is minimal and it is concluded no material benefit can be gained.

Table 5-6 Summary table for Option A short run cost results

	4 x 8% with 2 blocks df/dt
Average increased/reduced IR requirement (GWh)	-26
Benefit @ $1/kWh SRMC ($m/yr)	$0.0m

[7] The averaged values are then estimated using the assumed short-run marginal cost of $1 MWh.

The effect of Option B: 4x8% with 3 blocks with df/dt elements

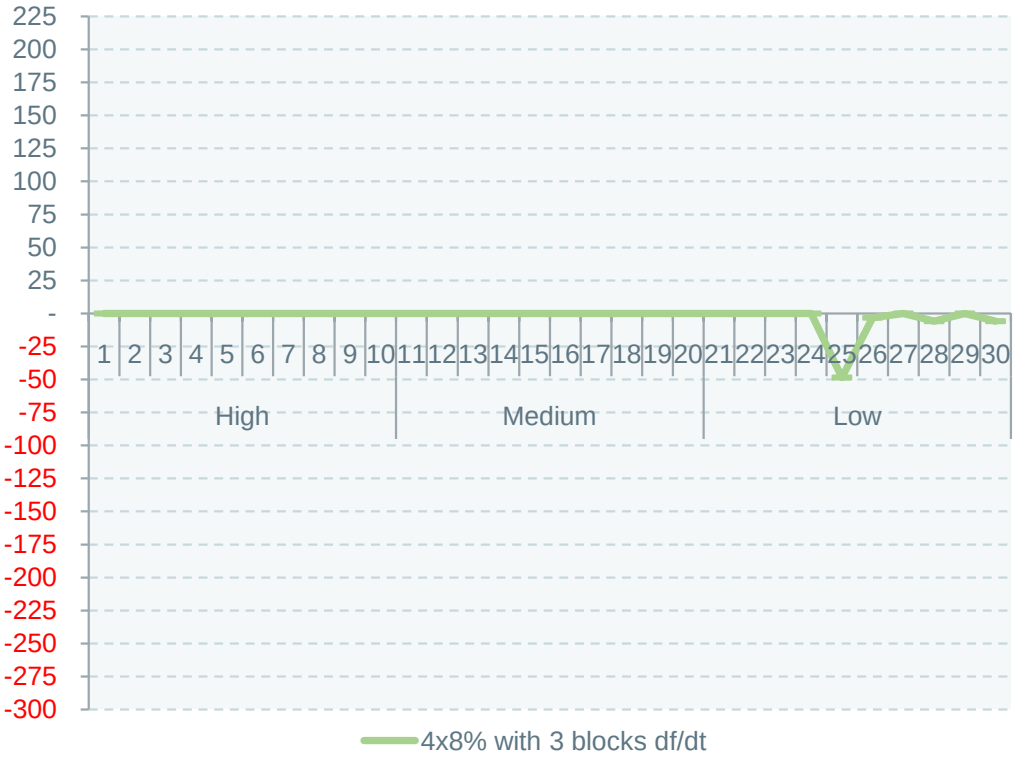

Figure 5-3 Altered overall IR requirement relative to the current scheme for the 4x8% with 3 blocks df/dt

Figure 5-3 sets out the 4 x 8% with 3 blocks of df/dt scheme results. Similar to the previous scheme (with regard to overall quantity of reserves needed on the system) this scheme option offers little improvement over the current scheme.

The average reduction of IR requirement across all cases is -2 MW, which results in a reduction of -19 MWh of reserves required over the course of the year.[8]

The reduction is minimal and it is concluded that no material benefit can be gained.

Table 5-7 Summary table for Option B short run results

	4 x 8% with 3 blocks df/dt
Average increased/reduced IR requirement (GWh)	-19
Benefit @ $1/MWh SRMC ($m/yr)	$0.0m

[8] Updated RMT values were included in report however we not updated in Appendix D.

The effect of Option C: 4x8% with an increased CE limit

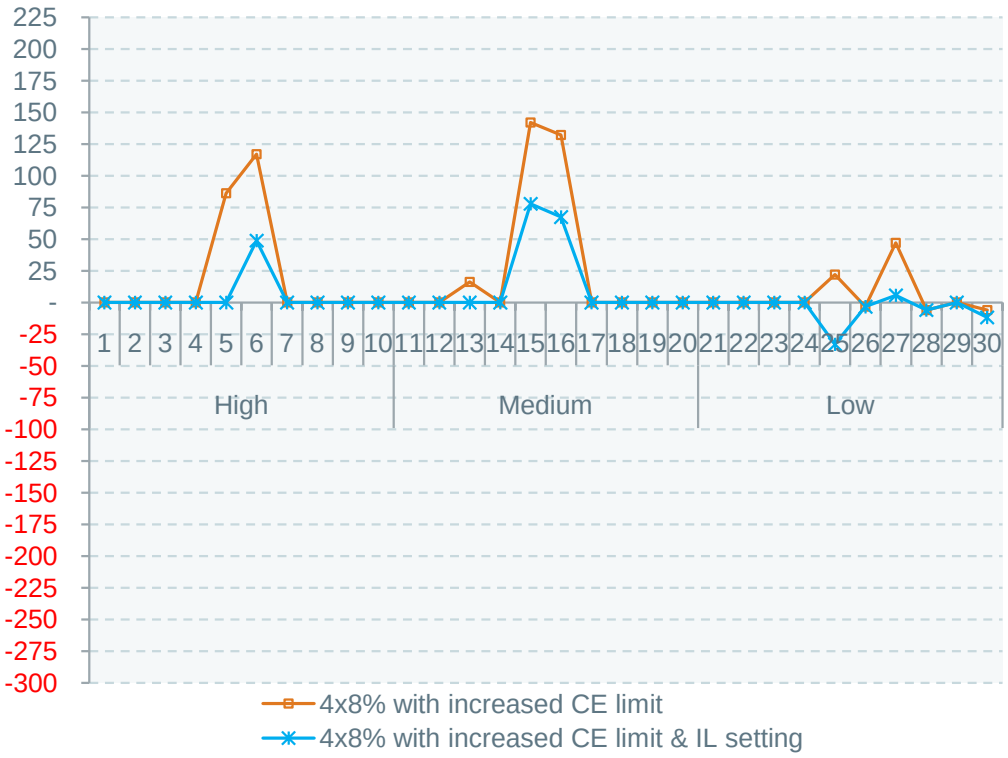

Figure 5-4 Altered overall IR requirement relative to the current scheme for the 4x8% with increased CE limit

Figure 5-4 sets out the 4 x 8% with increased CE limit scheme results with and without the increased IL trip limit settings. The scheme option offers little improvement over the current scheme and, at several times, requires additional reserves to be procured. Increasing the IL settings does reduce the amount reserves required on the system, though it is not enough to create any significant benefit from the scheme.

The average addition of IR requirement across all cases is 5 MW and results in an additional 43 MWh of reserves required over ta twelve month period. This results in a market impact of less than $100,000 per annum (assuming the cost of spinning reserve is $1/kWh). The additional cost is minimal and therefore it is concluded that no material benefit can be gained.

Table 5-8 Summary table for Option C short run results

	4 x 8% with increased CE limit	4 x 8% with increased CE limit & IL setting
Average reduced IR requirement (GWh)	-160	-43
Benefit @ $1/MWh SRMC ($m/yr)	-$0.2m	-$0.0

The effect of Option D: 4 x 10% with an increased CE limit

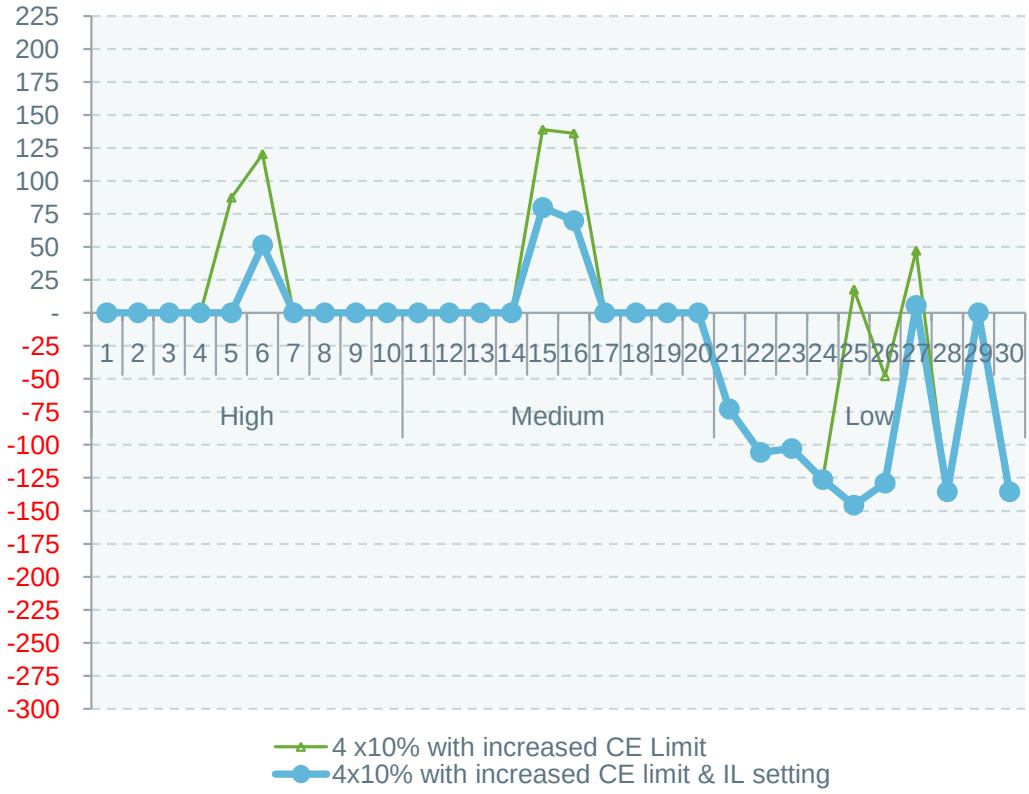

Figure 5-5 Altered overall IR requirement relative to the current scheme for 4x10% with increased CE Limit

Figure 5-5 sets out the 4 x 10% with increased CE limit scheme results with and without the increased IL trip limit. The figure demonstrates that impact of the AUFLS scheme when the ECE is bindings (cases 21-26, 28, 30). When the ECE is binding the scheme presents significant improvements over the current AUFLS scheme. However, for the cases when the CE is the binding risk, the scheme either makes no improvement or requires additional reserves to be procured.

The average reduction of IR requirement across all cases is -25 MW, which results in a reduction 218 MWh of reserves required over a twelve month period. This results in a market impact of less than $200,000 per annum (assuming the cost of spinning reserve is $1/kWh).

Table 5-9 Summary table for Option D short run results

	4 x 10% with increased CE limit	4 x 10% with increased CE limit & IL setting
Average reduced IR requirement (GWh)	52	218
Benefit @ $1/MWh SRMC ($m/yr)	$0.1m	$0.2m

Summary of Short Run Benefit Results

Table 5-10 Summary of short run results

	4 x 8% with 2 blocks df/dt	4 x 8% with 3 blocks df/dt	4 x 8% with increased CE limit & IL setting	4 x 10% with increased CE limit & IL setting
Average reduced IR requirement (GWh)	26	19	-43	218
Benefit @ $1/MWh SRMC ($m/yr)	$0.0m	$0.0m	$0.0m	$0.2m

Table 5-10 demonstrates that the overall impact of short run cost is marginal. The value of the altered short-run costs of IR provision is very low for all scheme options. This is due to:

- the change in the average overall amount of IR required is very small for most scenarios
- the cost of hydro generators operating in spinning reserve mode is very low.

In conclusion, it is unlikely that any short run cost or benefit will influence the overall benefit of an AUFLS scheme option.

5.1.6 *Conclusion of North Island Instantaneous Reserve Procurement Results*

Table 5-8 Summary of IR Procurement Results

	4 x 8% with 2 blocks df/dt	4 x 8% with 3 blocks df/dt	4 x 8% with increased CE limit & IL setting	4 x 10% with increased CE limit & IL setting
Fixed carrying benefit ($m/yr)	$0.0m	$0.0m	-$7.1m	-$7.5m
SPD Estimated Total Market benefit ($m/yr)[9]	$0.0m	$0.0m	-$1.75m	-$1.75m
Short Run benefit ($m/yr)	$0.0m	$0.0m	$0.0m	$0.2m
Net benefit ($m) – Per year	$0.0m	$0.0m	-$8.85m	-$9.05m
Present Value (PV) ($m) @ 8% discount	$0.0m	$0.0m	-$75.75m	-$77.46m

The Present Value row is the discounted present value of the annual expected value over 15 years, using an 8% discount rate. In summary, the investigation into the effect of each AUFLS scheme option on the procurement of IR concluded the following:

- none of the AUFLS scheme options reduce the required IR capacity carrying
- scheme options C and D, being those that raise the CE limit, are likely to result in increased IR carrying capacity costs of approximately $7m per annum
- none of the AUFLS scheme options reduce the total market cost
- scheme options C and D are likely to increase total market cost by $1.75m per annum
- there is negligible benefit attributable to any of the AUFLS scheme options in terms of reduced variable costs of reserve operation.

[9] The fixed carrying cost method and the vSPD method are parallel methods. The vSPD method will be used as sanity check to verify the results of the fixed carrying cost method; however will not be included in the scheme total cost, as this cost has already been accounted for.

5.2 Un-served Energy Benefit Analysis and Results

The previous section outlined that the different AUFLS scheme options are unlikely to substantially reduce instantaneous reserve cost and some even increase them. The next significant source of benefits relates to the altered amount of load shed following an AUFLS event due to an AUFLS scheme option.

The following section investigates the possible benefits gained from AUFLS scheme options that result in less demand disconnected from supply. Two areas were investigated in which AUFLS schemes have the potential to benefit New Zealand by reducing the amount and time load is disconnected from supply. These are:

- reduced quantities of AUFLS load shed in an AUFLS event
- reduced likeliness of system collapse.

5.2.1 Reduced quantities of AUFLS load shed in an AUFLS event

If an AUFLS scheme option which, by comparison with the current scheme, reduces the amount of AUFLS load shed to recover from an AUFLS event there is a benefit for New Zealand. A reduction in shed load will occur from events that result in partial operation of AUFLS, being events that do not require all AUFLS blocks to recover the system frequency. Partial AUFLS events can be caused by a:

- CE occurring when insufficient IR has been procured
- CE occurring when the system is not as secure as expected.

An AUFLS scheme option that, following a major event, trips only three blocks to recover the system frequency would provide a reduction in shed load by comparison with the current scheme which would trip all AUFLS blocks.

Quantifying the Benefits

The benefit of reduced load shed is equal to the quantity of shed AUFLS load avoided, multiplied by the value of the shed load, multiplied by the average number of hours to restore the load.

For this analysis a simple value of lost load (VoLL)[10] number of $20,000/MWh was used for both the value of avoided AUFLS load being dropped and the value of avoided system collapse. This value was chosen as being used historically to value the benefit of avoided un-served energy when valuing transmission investments.

It is acknowledged there is considerable uncertainty about the scale of un-served energy benefits. However, the uncertainty does not impact on the relative merits of the AUFLS scheme options, only on the absolute magnitude of such benefit.

Details around the assumptions used to calculate and quantify the benefits are in Appendix D.

[10] VoLL represents the estimated economic value of the energy to the customer.

Table 5-9 – Benefit of reducing the amount of AUFLS load shed due to decreased block size

	Average MW load	Quantity of AUFLS load reduced (% of total system load)	Total Outage time (hrs)11	Value ($m) using VoLL $20k/MWh
Partial AUFLS events				
North Island	3,196	10%[12]	3	$19m
South Island	1,370	10%	2.5	$7m
Major AUFLS events				
North Island	3,196	5%[13]	4.5	$14m
South Island	1,370	5%	3.75	$7m

Table 5-9 shows the estimated value of not shedding an AUFLS block following a partial AUFLS event. Table 5-10 indicates that there could be substantial value in reducing the amount of AUFLS load shed following an AUFLS event. However, the rate of recurrence of the event will determine the scale of the benefit. If the event were only to occur once every ten years the expected annual value would need to be divided by ten.

Probability-weighted values of avoided AUFLS load shed

It was also necessary to consider the likelihood of such AUFLS events occurring. A detailed description of the how the probabilities were derived is in Appendix D and the results summarised in Table 5-10.

Table 5-10 – Likelihood of partial AUFLS events occurring

	Likelihood in given TP	Likelihood in year	Return period (yrs)
Probability of a CE occurring when insufficient IR has been procured	0.00008%	1.37%	73
Probability of a CE occurring when system not as secure as expected	0.00015%	2.55%	39
Probability of a CE and a sympathetic trip occurring		12.00%	8.3

Probability of having CE when there is insufficient IR

Under normal conditions the System Operator procures sufficient reserves to cover both the CE and ECE (with the level of reserves purchased being set by whichever event was 'binding'). However, at times of capacity scarcity there may be insufficient capacity on the system to meet both energy and reserve requirements. At such times, the System Operator may chose to operate the system with lower reserves cover and/or pre-emptively shed load to free up supply capacity to provide reserves.

It is assumed that there will be 20 hours in the year where insufficient reserves will be available such that the occurrence of a CE will result in AUFLS being triggered. Combined with the probability of a CE occurring, this gives a per half-hour

[11] As AUFLS load will be restored throughout the restoration process, an average value of restoration has been used

[12] The percent load was valued above 8% on average to include the likely amount of over-provision.

[13] There is a smaller savings following major events as many will drop all four blocks of the AUFLS scheme options which would result in no savings over the current scheme.

probability of such an occurrence of 0.00008%. Expressed another way, this equates to a return period of once every 73 years.

Probability of a CE occurring when the system is in an unexpectedly insecure state

Another potential cause of an AUFLS event is if the system is in an unexpectedly insecure state due to the 'actual' system state turning out to be less secure than was assumed at the start of the 5 minute period when the requirement for IR was calculated.

A conservative estimate has been made that system security is unexpectedly insecure to a degree that would result in AUFLS being triggered in a CE event 0.5% of the time. However, it should be noted this number is subject to considerable uncertainty.

This percentage needs to be further factored by consideration of whether the CE is likely to be binding at such times. It is assumed the CE will be the binding risk approximately 85% of the time.

This 85% probability must be multiplied by the 0.5% value estimated above to give a combined probability that system security is unexpectedly insecure to a degree that would result in AUFLS being triggered in a CE event of 0.43%.

When multiplied with the probability of a CE occurring, this gives a per half-hour probability of such an outcome of 0.00015%, which corresponds to a return period of once every 39 years.

Probability of having a CE plus a sympathetic trip

It is possible an event greater than a CE, but less than an ECE could occur. This has been termed a 'Major' AUFLS event and could result in both 16% blocks being triggered under the current AUFLS scheme, but may only result in three of the four blocks being triggered for those schemes which have four blocks.

Such an outcome is considered possible if another significant asset were to trip 'sympathetically' in response to the frequency disturbance caused by a contingent event. Based on the simple analysis outlined in Appendix C, a conservative value of 2% has been used

Summary of Reduced Quantities of AUFLS Load Shed Results

Table 5-11 Estimate of PV benefit of reduced AUFLS load shed in North Island due to smaller block sizes

	Likelihood in year	Return period (yrs)	Expected benefit ($m/yr)	PV over 15 years @ 8.0% ($m)
CE occurs when insufficient IR has been procured	1.37%	73	$.13m	$1.1m
CE occurs when system not as secure as expected	2.55%	39	$.24m	$2.1m
CE and a sympathetic trip occurs	12.00%	8.3	$1.29m	$11.1m
Net benefit ($m)	-	-	$1.67m	$14.3m

Table 5-11 overviews the benefits gained from reducing the amount of AUFLS load shed following an AUFLS event. The expected benefit is the value of a shed AUFLS block, set out in Table 5-11, divided by the return period. The Present Value (PV) column is the discounted present value of such an annual expected value over 15 years, using an 8% discount rate.

Given the assumptions, the greatest benefit accrues from avoiding AUFLS load shed in events which feature a secondary event, due to the assumed greater probability of such events.

It should be noted this value only adds to those schemes which consist of smaller sized blocks. No such value accrues to those schemes which continue with the 2 x 16% configuration. The benefit of those schemes which have a 4 x 10% configuration is assumed to be factored downwards by 8/10.

5.2.2 Reduced likeliness of system collapse

The other main potential un-served energy benefit of the AUFLS schemes options is the ability of the schemes to be more resilient to events that the current AUFLS scheme can probably not survive and prevent system collapse.

In this respect, the following categories of potential benefit have been considered:

- reducing the risk that the triggering of AUFLS may cause an over-frequency event which results in system collapse
- saving the system in situations where an event that is larger than the ECE occurs.

Quantifying the benefits

Using the same framework as quantifying the reduction of AUFLS load shed, the estimate value of avoiding a single system collapse event is set out in Table 5-12.

Table 5-12 Estimated value of avoiding a system collapse event

	Average MW load	Average Outage time (hrs)14	Value ($b) using VoLL $20k/MWh
North Island	3,196	24	$1.5b
South Island	1,370	18	$.5b
New Zealand	4,566	-	$2.0b

The benefit of reducing the amount of AUFLS load shed in an event (as set out in Table 5-9 earlier) is measured in the millions of dollars; the cost of avoiding a black-out is measured in the billions. There is considerable uncertainty regarding estimating the cost of a black-out. However, the values displayed Table 5-12 will be used to provide a high level estimate of potential benefit gained from avoiding system collapse.

Probability-weighted values of avoided system collapse

The System Operator considers any event which triggers the current AUFLS scheme has the *potential* to cause an over-frequency event. In situations when the frequency rises above 52 Hz it is likely a number of generators would trip off (particularly geothermal generation, gas turbines and wind farms) which may cause the frequency to fall down again, in which event there would be no safety net to arrest such fall. System collapse may occur.

In light of the potential for the current scheme to cause system collapse following an AUFLS event the next review step was to identify the likelihood of an AUFLS event occurring. Table 5-13 below illustrates the range of potential likelihoods of the system suffering an AUFLS event based on variations in assumptions regarding the likelihood of suffering:

- a secondary (or 'sympathetic') trip in response to a contingent event trip
- an extended contingent event.

Table 5-13 Estimated probability of having an AUFLS event in a year

CE Risk:		Low			Central			High		
Second Risk:		Low	Cen	High	Low	Cen	High	Low	Cen.	High
ECE Risk	Low	12%	16%	25%	13%	22%	40%	15%	28%	55%
	Cen	22%	26%	35%	23%	32%	50%	25%	38%	65%
	High	35%	39%	48%	36%	45%	63%	38%	51%	78%

The probability of a secondary tripping has major implications for the probability of having an AUFLS event in a year, as can be seen in Table 5-13. While Table 5-13 indicates there is a substantial chance of the system having an AUFLS event in a given year, no information is available to enable an estimation of how many of the events would result in an over-frequency event of a scale which in turn would result in system collapse (under the current AUFLS arrangements).

An assumption is made that 0.1%, 0.5%, and 2% represent the range of likelihood an AUFLS events would result in over-frequency to such an extent to cause system

[14] As load will be restored throughout the total outage time, an average value of the total restoration time has been used for calculation.

collapse. It should be appreciated that there is no evidence to justify such a number, although the technical review did indicate that for some of the schemes and cases considered, over-frequency was a significant problem.

Further, it is also necessary to consider how many of these events would not result in system collapse if smaller AUFLS blocks were implemented. In this respect, some of the benefit could be achieved from the proposals to encourage use equivalence arrangements for AUFLS. Thus, an assumption was made that only 50% of the AUFLS events which would cause blackout under current AUFLS arrangement would be avoided solely due to implementing smaller AUFLS blocks.

The results of the estimation of benefit gained by more efficient shedding are outlined in Table 5-14 for the range of assumptions.

Table 5-14 Estimation of the scale of potential benefit of smaller AUFLS blocks avoiding over-frequency system collapse

		Combined likelihood of Current AUFLS over-freq Blackout			Avoided cost of NI blackout due to smaller blocks ($m/yr)			PV over 15 years @ 8.0% ($m)		
Current AUFLS Risk of Over-Freq Blackout		**Low**	**Cen**	**High**	**Low**	**Cen**	**High**	**Low**	**Cen.**	**High**
CE, Secondary, ECE Risk	**Low**	0.0%	0.1%	0.2%	$0.2m	$0.9m	$3.5m	$2m	$8m	$30m
	Cen	0.0%	0.2%	0.6%	$0.5m	$2.5m	$9.8m	$4m	$21m	$84m
	High	0.1%	0.4%	1.6%	$1.2m	$6.0m	$24m	$10m	$51m	$206m

Probability an event larger than an ECE will occur

In theory, if an event greater than an ECE occurs there may be insufficient reserve to preserve the system and black-out will occur. However, it is possible some events which are marginally larger than the ECE will not result in system collapse for some AUFLS schemes, as discussed in Appendix A.

It is inherently hard to estimate how many rare events may occur which would be saved by the 4 x 8% df/dt scheme but not by the current 2 x 16% scheme. To give a feel for the scale of potential value, the following table simply shows how the value would change for differing event return periods, and differing black-out costs.

Table 5-15 Summary of benefit of avoided blackout for AUFLS scheme options compared to return period of the causing event

Black-out cost ($b)	Avoided cost of black-out ($m/yr)				PV over 15 years @ 8.0% ($m)			
Return period (yrs):	**50**	**100**	**250**	**500**	**50**	**100**	**250**	**500**
$0.8b	$15.3m	$7.7m	$3.1m	$1.5m	$131m	$66m	$26m	$13m
$1.5b	$30.7m	$15.3m	$6.1m	$3.1m	$263m	$131m	$53m	$26m
$3.1b	$61.4m	$30.7m	$12.3	$6.1m	$525m	$263m	$105m	$53m

As can be seen in Table 5-15, even if a new AUFLS scheme only saved one black-out event every 500 years, and the cost of black out was 'only' $800m, this would still represent a 15 year PV benefit of $13m. In other words, it would be worth spending up to $13m to capture such a benefit.

It is not known what the actual return period of such events would be, but once every 500 years seems very conservative. Accordingly, this review assumed a 500 year return period as the Low scenario, with once every 250 years being used as the Central scenario.

5.2.3 Summary of Un-served Energy Benefit Results

The investigation into the benefits gained from reducing the demand disconnected from supply resulted in a range of potential benefits for the AUFLS scheme options. The values used to represent the likelihood of events in the section are subject to considerable uncertainty and so the magnitude of the benefit is taken into consideration. The assumptions give a range of benefits that outline the merits of the AUFLS scheme options. The benefits gained from reducing the un-served energy cost will apply to all AUFLS scheme options considered and are outlined as follows:

- there is an estimated PV benefit of $14.3m for AUFLS scheme options that reduce the amount of AUFLS load shed following an AUFLS event.[15]
- there is an estimated range of PV benefit between $2m-$8m for AUFLS scheme options that avoiding excess tripping that results in over-frequency and system collapse
- there is an estimated range of PV benefit between $13m-$26m for AUFLS scheme options that improve the system resilience against events larger than the ECE risk.

5.3 Implementation Costs

One of the costs to be considered in any cost benefit analysis of the AUFLS scheme options is the cost of implementing the scheme itself. The following section reports on the cost and time associated with implementation of the proposed scheme. A high level analysis of implementation can be found in section 6 of this report.

The cost benefit analysis of the options relies on having 'solid' cost estimates for each of the scheme options. For physical implementation the scheme options fall into two broad categories:

- df/dt schemes (scheme options A and B)
- Fixed frequency and time schemes (scheme options C and D).

The approximate costs of each are set out below.

5.3.1 Df/Dt Schemes

Most of the relays that presently provide AUFLS protection in the North Island do not have a df/dt feature. Therefore both df/dt alternatives will require new relay hardware. Preliminary discussions with Transpower's asset owner secondary systems group (i.e. the group responsible for providing power system protection for the grid) have indicated that if df/dt AUFLS protection were required, there is a technical preference for centralised AUFLS schemes. Centralised in this respect means a single AUFLS relay providing trip signals to AUFLS enabled circuit breakers at each GXP or zone substation (see section 6 for more detail).

The concept design for the df/dt schemes is based on the use of a single SEL751 feeder protection relay per substation dedicated to providing AUFLS protection. This relay was selected as SEL relays are already widely used in the industry (hence is it known technology) and the 751 has the required features, namely up to four df/dt elements, up to six fixed f and t set points, capability to provide the required number of output contacts and an IEC61850 communications interface.[16]

Currently there are approximately 300 substations in New Zealand that have AUFLS functionality. This number includes both Transpower and distribution

[15] The benefit of the scheme with a 4x10% configuration is assumed to be factored downwards by 8/10.
[16] Information on the SEL751 relay in provided in Appendix D.

company-owned substations. Of these approximately 200 already employ centralised 'stand-alone' AUFLS schemes. The balance employ distributed integrated schemes.

The sites that use stand-alone schemes may be converted to df/dt AUFLS by replacing the frequency sensing relay already there (usually ABB type 81 relay), with an SEL751. Much existing wiring could be reused and the overall impact on the substation largely limited to replacing the relay, testing and commissioning the modified installation.

Sites using integrated schemes will require a new AUFLS panel. The panel will contain the SEL751 relay and be connected to the trip coils of all feeder circuit breakers at each site, to allow for flexibility in selecting how to allocate AUFLS. Each relay will be connected via SCADA to allow for remote enable / disabling of AUFLS feeders. A test switch and test socket will be provided in each AUFLS panel.

Transfield in Dunedin were asked to estimate the cost of building and installing the approximate 100 new 'stand-alone' AUFLS panels that would be required to provide df/dt protection at the sites that presently employ integrated AUFLS schemes.

Two variants of the panel were priced, namely floor and wall mounted versions. It is assumed Transpower will employ floor mounted versions and distribution companies will use wall mounted versions (there is generally less available free floor space in zone substations).

Of the 300 substations in New Zealand that have AUFLS functionality, 265 of them are located in the North Island. Approximately 195 already employ centralised 'stand-alone' AUFLS schemes and the balance employ distributed integrated schemes.

The estimated cost of implementing either of the df/dt AUFLS alternatives in the North Island on the above basis is $5,593,500. This is an 'industry' cost that would be shared across AUFLS owners in the North Island, namely the individual distribution companies. Refer to Appendices E for details of the cost estimate.

5.3.2 Fixed Frequency and Time Schemes

Fixed frequency and time schemes support the concept of providing more AUFLS tripping blocks (i.e. four blocks in total instead of two) with different frequency and time delays. This type of scheme can be accommodated by some of the numerical relays presently used by both Transpower and some distribution companies. However, there are a considerable number of AUFLS relays that cannot accommodate four frequency and time set points. New hardware will be required for these sites. This includes Transpower sites that use the Multilin SR760 feeder protection relay, as that relay can only accommodate two under frequency set points.

There are approximately 460 relays that provide AUFLS functionality at present in the North Island. This number includes relays used in 'stand-alone' and integrated schemes. Of these 180 can accommodate four fixed frequency and time set points, though the remaining 280 cannot and would have to be replaced.

SEL751 numerical relays have been selected for approximately 280 existing AUFLS relays that cannot accommodate additional fixed frequency and time set points. The work required to change these relays would largely be limited to replacing the existing relay and testing and commissioning the modified installation. It is expected that most of the existing wiring could be reused.

The estimated cost of implementing either of the fixed frequency and time AUFLS alternatives across New Zealand is estimated at $2,652,000[17]. This cost would be shared between the individual distribution companies. Refer to appendix E for details of this cost estimate.

5.3.3 *Implementation Coordination Cost*

The process of installing the relays will require comprehensive project management. Prudent project management will ensure:

- during implementation New Zealand will still have an effective AUFLS system; and
- there is central oversight to ensure the installed relays meet any new code requirements.

The assumed cost of coordinating the installation is $500,000.

5.3.4 *Implementation Costs Conclusion*

The estimated costs of implementing the two options are:

Scheme	Relay Cost	Implementation Coordination	Total Implementation Cost
df/dt schemes (scheme options A and B)[18]	$5,593,500	$500,000	$6,093,500
Fixed frequency and time schemes (scheme options C and D)	$2,652,000	$500,000	$3,152,000

[17] The costs for North Island and the whole of NZ are estimated to be about the same as the total number of relays to be changed are very similar (280 vs. 300)

[18] The cost based on the capability of the SEL 751 relays which can manage 4 df/dt settings.

5.4 Summary of North Island Cost-Benefit Results

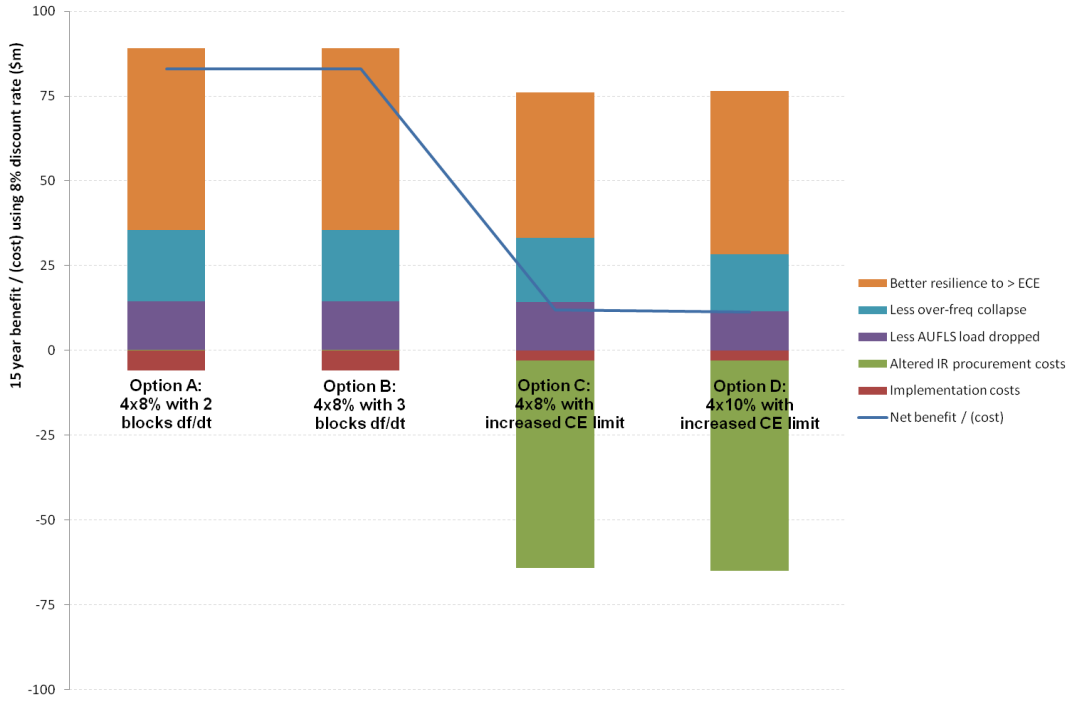

Figure 5-5: 'Central' estimate of costs and benefits of AUFLS scheme relative to current scheme

Figure 5-5 provides an overview of the cost benefit analysis of the proposed AUFLS scheme options. The central estimate includes the middle of the range benefits expected from the un-served energy analysis.

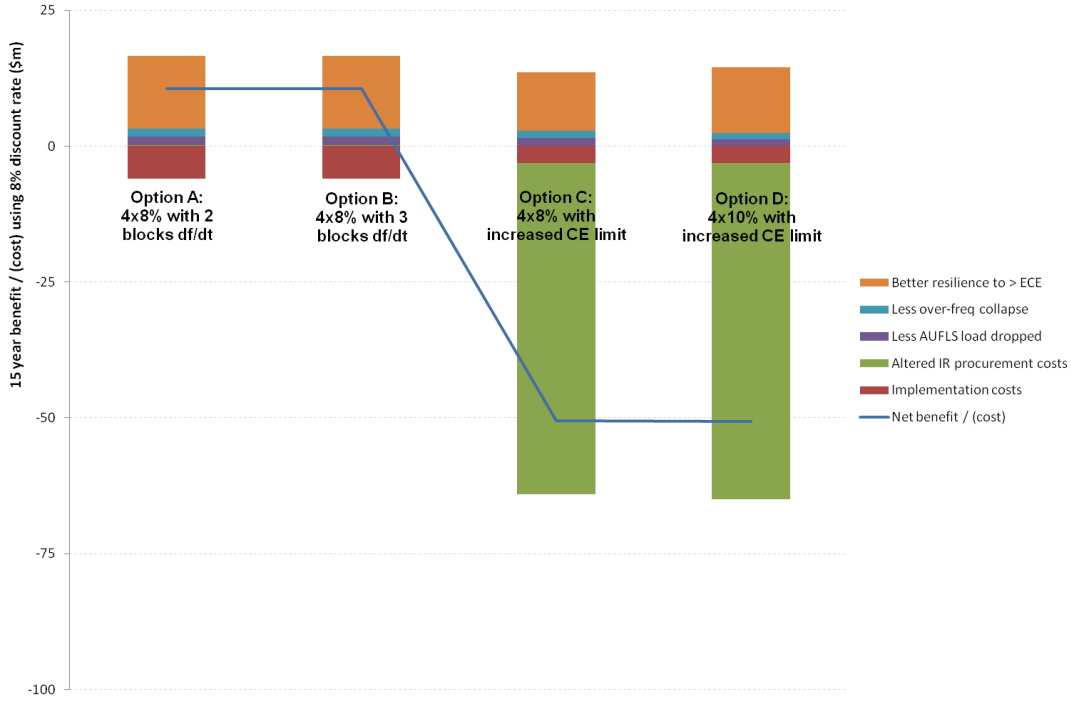

Figure 5-6: 'Low' estimate of cost and benefits of AUFLS scheme relative to the current scheme

Figure 5-6 provides an overview of the cost benefit analysis of the proposed AUFLS scheme options including the low benefit estimate from the un-served energy analysis.

5.5 Conclusions from Benefit Analysis

On the basis of the benefit analysis, the System Operator has concluded that while scheme Options C and D are technically feasible they are not economically feasible compared with scheme options A and B. The net benefits of Options C and D can approach -$50million/15 years, as seen in Figure 5-6.

Given the technical benefits arising from options A and B compared to the current scheme, the System Operator's preliminary findings, based on the technical review and this review's benefit analysis, is that either option A or option B would be appropriate as an AUFLS scheme for the North Island.

Table 5-16 Summary of North Island AUFLS scheme option analysis

Proposed Scheme	Benefit from technical review	Benefit to Instantaneous Reserves Procurement	Un-served Energy benefit	Implementation cost	Review of Results
Option A: 4 x 8% with 2 blocks df/dt	No required increase in total required AUFLS load. More blocks enables better load matching and reduces likeliness of over frequency. Accelerated AUFLS operation enables generator response to assist system recovery. Largely maintains discrimination between blocks.	No observable benefit or cost.	Potential range of benefit of $16m - $89m	Estimated at $5.6m.	Net benefit range of $10m to $83m.
Option B: 4 x 8% with 3 blocks df/dt	No required increase in total required AUFLS load. More blocks enables better load matching and reduces likeliness of over frequency. Accelerated AUFLS operation enables generator response to assist system recovery. Largely maintains discrimination between blocks.	No observable benefit or cost.	Potential range of benefit of $16m - $89m	Estimated at $5.6m.	Net benefit range of $10m to $83m.
Option C: 4 x 8 % with CE target of 48.5 Hz	No required increase in total required AUFLS load. More blocks enables better load matching and reduces likeliness of over frequency. Higher trip settings enables generator response to assist system recovery. Maintains discrimination between blocks.	Significant increase in cost to the Market estimated at $61m	Potential range of benefit of $13m - $76m	Estimated at $2.7m	Net benefit range of -$50m to $12m.
Option D: 4 x 10 % with CE target of 48.5 Hz	More blocks enables better load matching and reduces likeliness of over frequency. Higher trip settings enables generator response to assist system recovery. Maintains discrimination between blocks which reduces the likeliness of over frequency. Increased amount of AUFLS load results greater cover against large risk.	Significant increase in cost to Market estimated at $62m	Potential range of benefit of $13m - $76m	Estimated at $2.7m	Net benefit range of -$50m to $12m.

6 Implementation Considerations

Any significant change to the New Zealand AUFLS arrangements will need to be effected through Code changes. If a Code change requires assets to perform differently than under the previous codes, affected asset owners may be required to invest in new assets to meet the changed Code requirements. As set out in the discussion on implementation costs in section 5.3 of this report, any of the AUFLS scheme options would require a large number of new relays to be installed.

The following section sets out some of the implementation considerations (other than cost) if one of the AUFLS scheme options identified in section 4.1 were to be included into the Code.

6.1 Overview of the existing AUFLS system

The first AUFLS system in New Zealand was installed in the 1960's at selected North Island grid exit points. This system was set-up to trip in-feeds to distribution companies during an under frequency event.

Ownership of the North Island scheme was transferred from Transpower (i.e. GXPs) to the distribution companies (i.e. zone substations) in the early 1990's because the amount of load controlled was considered to be too coarse. It was also determined that finer control of AUFLS load would be achieved if it were enabled at the zone substation level. Transpower undertook a programme of assisting distribution companies during the ownership change by providing under frequency relays[19] to those who asked for them.

AUFLS relays at GXPs were kept in service following the change of ownership but it was anticipated that these relays would gradually be phased out as the individual distribution companies installed their own AUFLS systems. Some distribution companies have moved all AUFLS functionality from GXPs to zone substations. Some have moved none, while most have a combination of AUFLS at GXPs and zone substations.

South Island AUFLS were introduced in 2003. These schemes are owned by Transpower and were installed at the GXP and point of supply level in close consultation with the South Island distribution companies who advised which GXP feeders to trip in an AUFLS event.

6.1.1 Types of Implemented AUFLS Schemes

There are two types of AUFLS schemes in service at present:

- stand-alone schemes (also known as centralised schemes)
- integrated schemes (also known as distributed schemes)

[19] Transpower provided the ABB type 81 relay.

Stand-Alone Schemes

This type of scheme comprises of a separate 'stand-alone' AUFLS panel that usually includes a relay which senses system frequency and produces trip signals in an under frequency event. Stand-alone AUFLS panels normally include selector switches that allow for individual circuit breakers to be connected to the scheme. Stand-alone AUFLS schemes may also be described as 'centralised' schemes because there is one frequency sensing relay that trips all of the AUFLS enabled circuit breakers at each site.

Stand-alone AUFLS systems are usually used when the feeder protection relays at the substation are not capable of providing under frequency protection. They are found mainly at zone substations, but Transpower still has a few at some of its GXPs.

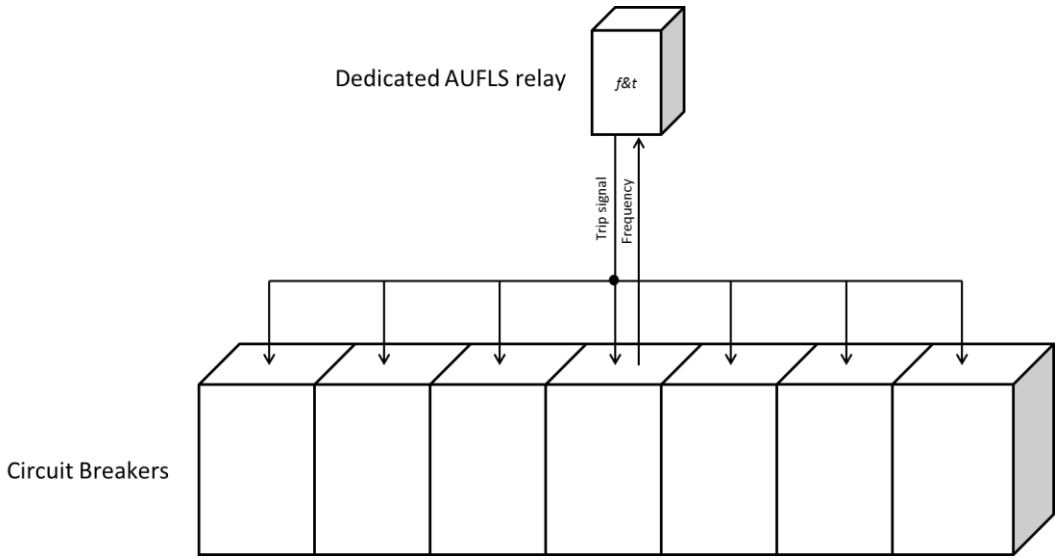

Figure 6-1 Diagrammatic representation of a 'stand-alone' or 'centralised' AUFLS scheme

Integrated Schemes

Many of the modern feeder protection relays used by Transpower and distribution companies are of the numerical multifunction type. Many of these relays include an under frequency element that can be 'set' for those feeders that require AUFLS functionality. Therefore, AUFLS at sites that have numerical relays is often 'integrated' with feeder protection. Integrated AUFLS schemes can also be described as 'distributed' schemes because each individual circuit breaker has its own frequency sensing and tripping function.

The types of feeder protection relays Transpower installs at its GXPs are either SEL351 or GE Multilin SR760 multifunctional numerical relays. Both of these types of relays have under frequency elements that are used to provide AUFLS protection. Some distribution companies also use multifunction numerical relays that include under frequency elements which are used for AUFLS.

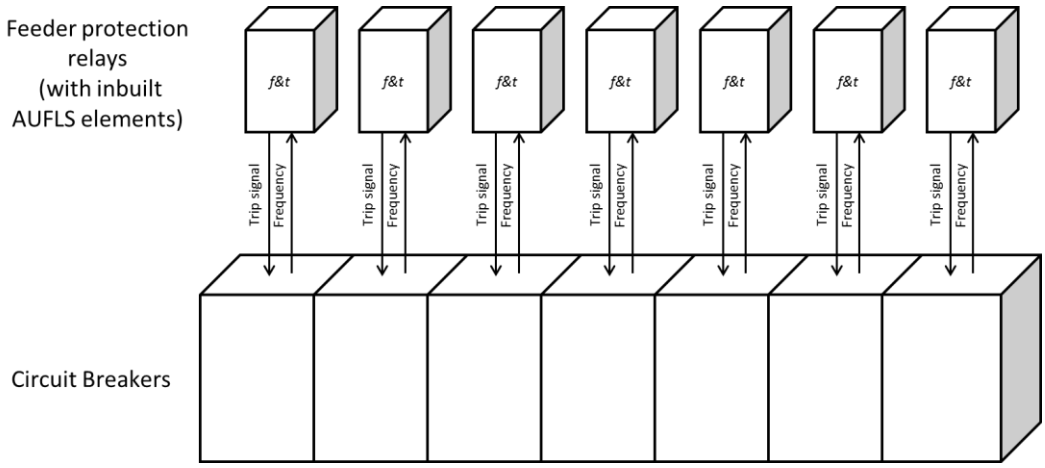

Figure 6-2 Diagrammatic representation of an 'integrated' or 'distributed' AUFLS scheme

6.2 Addressing the use of df/dt schemes

The technical review report highlighted the importance of the speed of AUFLS response in preventing system collapse in the North Island. The existing AUFLS scheme uses under-frequency elements to trigger the AUFLS blocks. This means AUFLS will trip once the frequency has dropped below a set frequency.

Another way to trigger AUFLS is to use rate of change of frequency elements. Also known as df/dt elements, this means AUFLS will trip if the rate of frequency decay reaches a certain speed. A benefit of a df/dt scheme is it allows AUFLS to be triggered at frequencies higher than the 48 Hz CE target frequency; it anticipates an AUFLS event and responds. Operating AUFLS earlier slows down the rate of change of frequency so that the time to minimum frequency is longer; this gives more time for generator governors to act.

While the df/dt schemes were proven against the scenarios studied in the technical review report, it was highlighted that further investigation is required to understand the capability of the relays and optimisation of settings. As there are various system events outside of AUFLS events that can cause the frequency to fall at a fast rate it is important to ensure that the use of df/dt elements does not result in unwarranted trippings[20] or operation for CE events.

Various scenarios were developed to derive the optimal settings for df/dt elements to provide protection against unwarranted trippings. Iterative testing resulted in the proposed settings outlined in Table 6-1. The detailed investigation is set out in Appendix C.

Table 6-1 Proposed NI AUFLS df/dt settings

	Accelerated element			Under frequency element 1		Under frequency element 2		Block Size
	Df/dt_{set}	f_{guard}	T_{d3}	f_{set1}	T_{d1}	f_{set2}	T_{d2}	
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%

[20] Sharp decay in frequency can be caused by different reasons. One example is the local loss of supply causing nearby df/dt elements to operate.

Only two of the four blocks in the proposed settings utilise rate-of-change-of-frequency elements. A guard frequency has been used to prevent unwarranted trippings and prevent AUFLS operating for a CE event. The guard frequency will not allow operation of the relay before the frequency falls below a set limit. The end result is the frequency must fall at the rate equal to or greater than the set speed (Df/dt_{set}) and the frequency must be below the guard frequency (f_{gaurd}) before the relay will trip the AUFLS block.

Each of the four blocks has two under frequency elements, one operating in a fast time period (T_{d1}) while the other requires considerably longer operating time (T_{d2}). The purpose of the fast operating under frequency elements are to serve either as backups to the rate-of-change-frequency elements (block 3 and 4) or the main tripping element when rate-of-change-of-frequency acceleration is not used (block 1 and 2).

The longer operating under frequency element's main function is to restore the system frequency should it stay low for a prolonged period of time. As low system frequencies are harmful for some generators (particularly the gas turbines) and can reduce machine efficiency, extended period of grid operation at low frequency should be minimised.

The studies give the System Operator confidence the df/dt settings are ready to undergo testing on the system. However the System Operator is aware settings for the df/dt elements will need to be monitored periodically to ensure the appropriate settings are in use. This process should follow a similar cycle and process to the Credible Events review.

6.3 Technical Feasibility

Each of the AUFLS scheme options identified in section 4.1 of this report may affect the way the power system responds to frequency variations. In this regard, preliminary discussions with Transpower grid owner indicate further consideration is needed to understand, and provide feedback on, the technical requirements to implement the different scheme options including any limitations in how such schemes would operate on the system.

For example, a rigorous testing process would be required before a df/dt AUFLS scheme is implemented on the grid. This would involve building a prototype AUFLS panel and running it on the grid (though not attached to any circuit breakers) for a period of time to determine its response to frequency changes. This would be required because of concerns about the risk of falsely tripping feeders as the result of normal frequency movements on the grid.

6.4 Investment Changes to the AUFLS System

The following section sets out the System Operator's understanding of how any investment required as a result of a change to the AUFLS arrangements might be recovered by Transpower and distribution companies.

6.4.1 Transpower

Transpower grid owner has recently had its three year 'minor capital expenditure budget approved by the Commerce Commission. By this approval, Transpower is allowed to spend (i.e. recover) up to a maximum preapproved total amount over the three year period on capital projects classified as 'minor'. This generally includes projects under a certain threshold (i.e. $5 million until 2015, then rising to $20m). It is up to the Transpower to decide which projects to carry out and to balance the need for investment against available funds. Projects that are required to comply with Code generally will be approved, however this may mean that other non-compliance projects may be affected (i.e. delayed or cancelled).

It appears that Transpower's capital expenditure on a project such as modifications to the AUFLS scheme may be accommodated in the present three year budget, even though this work was not included in the original plan. The next regulatory reset will be for a five year period and this will be submitted in December 2013.

6.4.2 Distribution Companies

Distribution companies are regulated by the Commerce Commission under a 'price – quality' arrangement where the distribution company is allowed to recover up to a predetermined amount per year from its customers provided they comply with certain quality requirements. New projects, including those required to meet compliance with the Code, may affect the capital spend plan and the list of projects the company carries out for the coming year.

Public disclosure of the capital spend plan is required in each distribution companies' annual Asset Management Plan but this is generally for information only and changes can be made to the plan if required. However, we understand that capital spend plans for the coming financial year are generally required to be approved by the relevant distribution company's Board of Directors approximately six months before the financial year starts. Any changes to the plan after this would therefore require board approval. In order to meet these timeframes, any new projects (such as those required by the AUFLS review) are usually planned about two years ahead of when they are required.

6.5 Conclusion on Implementation Requirements

To fully understand the implementation requirements (including timing requirements) of a change to the AUFLS arrangements (particularly if this necessitates a change to the AUFLS technology used) the System Operator needs Transpower grid owner's and distributors' feedback on any potential issues that may arise from implementing the different scheme options.

Any changes to the AUFLS arrangements which require investment will need to recognise the regulatory investment cycle requirements. As set out in this report, such investment cycle is approximately two years. Consideration needs to be given to any opportunities for concurrently enhancing the existing system during the investment process.

As set out in section 5.3 of this report, the process of installing any new AUFLS relays would require a coordinated project management approach to ensure New Zealand maintained an effective AUFLS system throughout implementation, as well as centralised project management to ensure the installed relays meet any new code requirements.

7 The Implications of Exemptions on the Effectiveness of AUFLS

7.1 Background

There are currently six connected parties (distributors and direct connects) that are exempt from meeting AUFLS code requirements. These are:

- Norske Skog Tasman Ltd
- Northpower Ltd
- Winstone International Pulp and Paper
- Toll NZ Ltd
- Pan Pac Forest Products, and
- New Zealand Steel.

These exemptions, and extensions to these exemptions, were granted by the Electricity Commission on the basis the rules pertaining to the test for granting exemptions needed further clarification. The Electricity Commission consulted industry on options to clarify the exemption test criteria but decided not to progress any changes until a wider review of the AUFLS requirements had been completed by the System Operator. Approximately 400-500 MW of load is currently exempted from AUFLS.

The direct financial impact test, formerly in Rule 6.6 of Technical Code B of Schedule C3 of Part C of the Rules, has not been included in the Code and any future exemptions granted by the Electricity Authority will be granted under the Electricity Act exemption process.

A number of concerns have been raised regarding the granting of these exemptions. There are potential inequities, for example, in exemptions being granted as all end-users benefit from the provision of AUFLS, including those participants who are exempt from providing it. Inequities are also introduced through other means such as participants being included in an AUFLS block but being excluded from providing IL. On the other hand, those who are not included in an AUFLS block can participate freely in the IL market. Differences in the size and make up of distributor networks can also mean some end-users may or may not be exempt from AUFLS, simply by virtue of which network they are connected to.

There is also the potential for the total AUFLS base to erode over time with the granting of exemptions. In practice, AUFLS exemptions are made up for by procuring more IR when the ECE is binding. However, this relies on sufficient IR being offered to cover such a scenario.

The following section considers the implications for system security and market impacts from granting exemptions for AUFLS provision. The intention is to inform the exemption process, rather than propose or recommend a position as to whether or not exemptions should be granted.

7.2 Implications of Exemptions

Utilising the methodology employed to measure the benefits of the proposed AUFLS schemes, the System Operator created a scheme with the exemptions removed to observe the impact of exemptions on the amount of reserves procured by RMT.

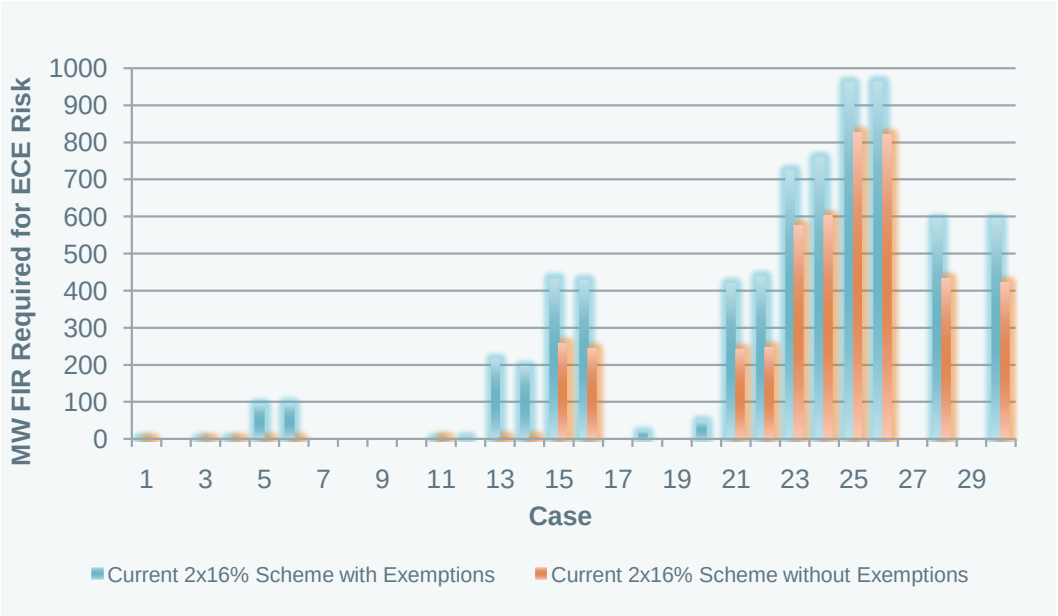

Figure 7-1 Effect of Exemption of FIR Requirement

Figure 7-1 displays a comparison of the amount of FIR required by the current scheme with and without exemptions. Note that RMT does not calculate an NFR value greater than the risk; as a result the required amount of reserve goes to zero. At times when more NFR exist than the risk, the additional amount is hidden and so the additional benefit of the scheme will also be hidden. This can cause the difference between schemes to appear to be zero when in reality it would not be. For purposes of creating an average comparison the results were excluded when both schemes NFR values were equal to the size of the risk.

For the cases studied the removal of exemptions reduced on average the amount of FIR reserves required to cover for extended contingent events by 127 MW. During cases which the extended contingent event was the binding risk the removal of exemptions resulted in an average reduction of 160 MW.

The vSPD analysis calculated the removal of exemptions resulted in a market benefit of $5-$10 per hour or approximately $170,000 per year or about $1-$2.5 million net present value.

In addition to the impact on procurement of reserves it should be noted that when designing the schemes, as outline in Appendix A, exemptions were not taken into consideration as their future existence is unknown. Any exemptions granted are a deviation from the design of the scheme and a degradation of its performance.

7.3 Conclusions on Effect of Exemptions from AUFLS' Obligations

The System Operator considers the following factors should be considered by the Electricity Authority when assessing an application for an exemption from AUFLS' obligations:

- any exemption from AUFLS provision degrades the safety net and additional load is needed in order to restore AUFLS to the design specification. This could require non-exempt parties to increase their AUFLS provision to cover the exempt load
- any exemption will require additional reserves to be procured during certain conditions which will be borne by the wider market as cost in both energy and reserves.

If neither of the above actions are taken it must be accepted that safety net has been degraded, leaving the system more exposed to events.

8 AUFLS Provision and Market Options

8.1 Background

A number of industry workshops were held in August 2010 to discuss and seek feedback on the AUFLS technical review findings. In these workshops, a number of participants advised the AUFLS' review should consider potential market arrangements for AUFLS provision.

In light of industry response at this workshop the System Operator and the Electricity Authority initiated the next stage of the AUFLS review in early 2011 to investigate the economic and technical effectiveness of potential AUFLS arrangements, consider the factors limiting efficiency of AUFLS provision and explore the potential for market arrangements.

An AUFLS market options workshop was held on Thursday 14 April 2011 to better understand various industry participants' perspectives on AUFLS market development options and ultimately find a way to progress towards an optimal AUFLS arrangement for New Zealand.

The following section provides a brief overview of the industry perspectives shared at the workshop, key findings of the workshop, and suggested next steps.

8.2 AUFLS Provision and Market Options

The current AUFLS scheme is a mandated code requirement which requires distributors in the North Island and the grid owner in the South Island to provide 2 blocks of demand (a block being a minimum of 16% total pre-event demand) at all times from each grid exit point.[21]

Three different AUFLS provision options were presented to industry at the workshop on 14 April 2011 and details of these options can be found in Appendix E. The first provision option was a simple allocation method based on a stated obligation required to be met by the obligated parties. This is the mechanism currently used for AUFLS provision.

The second provision option maintained the obligations of the simple allocation method but also provided a mechanism for parties to seek out equivalent provision of their obligations with other (lower cost) providers.

The third option was a more dynamic and market orientated approach for the provision of AUFLS, based on a market mechanism where AUFLS is procured in a similar way to energy and market based ancillary services (e.g. reserves and frequency).

The general views of the industry participants are summarised below (Note: that this in no way should attribute such views to any specific participant or enable such groups to have different views from that stated below).

During the workshop the distribution companies generally appeared in support of a mandated obligation to provide AUFLS. This differed from some major users and the aggregators who generally believed there should be the ability to institute a property right around provision of AUFLS (with associated payment) and to prepare for a future dynamic market.

The movement from an unpaid (but not costless) obligation to the establishment of a property right to load requiring payment whether delivered as IL or AUFLs did not appear to be supported by distribution companies. One distribution company believed it had little to no interest in seeking commercial incentives for AUFLS provision.

[21] See Technical Code B of Schedule 8.3 Part 7

Whether or not AUFLS provision should remain a mandated scheme or move to a voluntary, dynamic market is open for discussion and investigation. If there is a strong desire for such dynamic market arrangements industry participants will need to put forward firm proposals as to how such market arrangements would be effected. The use of a mandated scheme will be required in the foreseeable future.

Based on the assumption of continuing use of a mandated scheme, the following challenges remain to be addressed:

1. the dynamic nature of demand;
2. the differing sizes and configurations of networks.

8.2.1 The Dynamic Nature of Demand

Load patterns vary throughout the day and year. As load varies the quantity of AUFLS load will likely vary accordingly. Distributors in the North Island and the grid owner in the South Island are required to provide a level of AUFLS that is greater than minimum level at all times. Distributors have reported that they over-arm demand to meet the minimum requirement of 2x16% at all times.

The System Operator sought out studies to confirm over-provision of AUFLS load, the details of which can be found in Appendix G. In the North Island, the average provision of AUFLS block 1 and Block 2 are observed to be in the range of 18% - 22% during weekdays for both summer and winter. During the weekends, the average provision of AUFLS Block 2 ranges from 20%-25 while Block 1 percentage ranges from 19% - 23%.

Over-provision can result in over-frequency following an AUFLS tripping which in turn could result in cascade failure. It is important to minimize the amount of overprovision where possible. To ensure there are options available to limit over-provision and provide distributors with the ability to more efficiency provide load, two options have been highlighted:

- AUFLS & IL Feeder Sharing
- Use of timers on AUFLS relays.

AUFLS & IL Feeder Sharing

The Code prohibits AUFLS blocks from including any interruptible load (IL) procured by the System Operator in order to maintain certainty of AUFLS provision.[22]

However, the Code is unclear as to the definition of 'AUFLS blocks' (i.e. do blocks constitute the entire load supplied from a feeder connected an AUFLS relay?) It has been previously thought by participants, including the System Operator, that AUFLS blocks constituted all load connected behind an AUFLS relay. However, recently alternative views of the Code requirements have emerged.

The System Operator has a concern if load is able to be double counted as both IL and AUFLS. Doing so may, in our view, degrade the AUFLS safety net. However any load provided over and above the required block level would seem to be available to be provided as interruptible load. The Code appears to provide room for distributors to offer load surplus to their obligation as IL, provided they still meet their AUFLS obligation.

Where AUFLS and IL are offered from the same feeders there seems to be a clear responsibility on the offering party to maintain their AUFLS obligation (i.e.

[22] See Technical Code B of Schedule 8.3 Part 7 subclause 7

ensure the configuration of relays results in the required amount of IL and AUFLS tripping at their respective frequencies).

Distribution companies appear to be in support of the ability to offer IL from behind an AUFLS feeder. It becomes important, however, that IL and AUFLS feeder sharing is properly managed when an aggregator or a retailer has rights to the load for IL purposes. Distributors will need to be aware of any load in their network being offered as IL, as it potentially might already be required to meet the AUFLS obligations. This would most likely require an IL provider to agree to a maximum quantity with the distribution company and provide time based data of how much IL was offered on the feeder.

The aggregators note that Smart Grid developments will likely require all classes of electricity consumers to have property rights over load (including for AUFLS). The thinking is the granularity of control (more parties able to be subject to AUFLS through the use of new technology) will enable consumers to have choice about whether they want to be included in AUFLS.

To date there have been no firm proposals how such market arrangements would ensure the required provision of AUFLS. Therefore the use of a mandated scheme will be required for the foreseeable future.

Use of timers on AUFLS relays

From the workshop feedback, it appears some distribution companies have to over provide during the day in order to maintain their AUFLS obligation overnight. In light of this challenge, a distribution company suggested the use of a scheme which would switch relays off during times of the day while ensuring their obligations are still met.

Some distribution companies see the provision of AUFLS as a purely static activity and the use of timers would require additional development and monitoring to ensure the scheme is effective.

The System Operator would accept a scheme that switched relays off to prevent over provision as long as the following provisions are met:

- the scheme is protection grade in all aspects; and
- the network company still provides their obligations under the code.

8.2.2 The differing sizes and configurations of networks

Distribution companies across New Zealand face unique challenges brought about from the size and configuration of their networks. For network companies with low network diversity it is challenging to separate critical and non-critical customers and still meet their AUFLS obligations. In some cases critical load such as hospitals and emergency services end up in AUFLS blocks.

One distribution company advised the arrangement of their network required them to have an AUFLS relay connected to all of their feeders, excluding supply to a dairy factory, to meet the current obligations.

The System Operator recommends that an audit of AUFLS load be carried out to understand how many points of critical supply are connected to AUFLS across the country.

Direct connect participants may be challenged by the size and configuration of their demand to provide the required AUFLS blocks, if exemptions are no longer available. The System Operator believes two existing Code provisions need to be understood by participants, providing potential avenues to address the foregoing issues:

- redistribution between GXPs and networks

- use of Equivalence Arrangement

Redistribution between GXPs

The Code allows for redistribution of AUFLS quantities between grid exit points, provided the overall AUFLS obligations are still met.[23] This enables distribution companies with the flexibility to optimise their AUFLS provision between GXPs in their network or to arrange for an equivalence arrangement with another distribution company or direct connect. A redistribution of AUFLS load must be approved by the System Operator.

In considering an approval request the System Operator would take into consideration the effect of moving load into specific regions to understand any adverse effects. For example, if all AUFLS load ends up in one place it could lead to post event over-voltage and system collapse.

One caution to the redistribution of load is the impact redistribution can have on electrical islanding. In various places circuit trippings during planned outages or double circuit trippings can disconnect (island) regions of the grid. In order for the electrical island to form, there has to be a balance of load and generation in the region. The previous technical report highlighted that AUFLS provision in these regions can assist in the ability to create a successful electrical island following an unplanned system split. This secondary benefit of AUFLS should be considered for any change.

Redistribution between GXPs provides a potential avenue for distribution companies to utilise more of their own network to avoid arming critical load for AUFLS. However if there insufficient network diversity available, the distribution company would need to seek out an equivalence arrangement whereby another AUFLS provider met the code obligations on behalf of the distribution company (see below).

Use of Equivalence Arrangements

A distribution company may apply to the System Operator for approval of an equivalence arrangement which would enable parties with AUFLS obligations to make arrangements with other parties to meet their AUFLS obligations. The System Operator can only approve such arrangement if it fully offsets the obligations it seeks to replace. Whilst an equivalence arrangement may be granted on the basis another party will provide the obligated requirement, the code requirements (or the agreed equivalence arrangements) remain at all times with the distribution company to ensure the required amount of AUFLS is provided.

The use of an equivalence arrangement is a mechanism available to ensure the required quantity of AUFLS is met while providing the ability for those with low network diversity or unique load configurations with the opportunity to seek better arrangements with less overprovision or cost of interruption.

Feedback from the market options workshop indicated some distribution companies considered this as a viable potential option as a means to ensure supply to critical loads.

Whilst the ability to apply for an equivalence arrangement is available in the current code, no equivalence arrangements for AUFLS provisions have been applied for. The System Operator's view is that this is likely to be because either distributors are unaware that such mechanism exists or, alternatively, there is

[23] See Technical Code B of Schedule 8.3 Part 7 subclause 8

insufficient detail around the types of AUFLS equivalences that would be acceptable to the System Operator.

8.3 AUFLS Provision and Market Options Conclusion

Currently there appears to be insufficient desire for dynamic market arrangements and a lack of firm proposals as to how such market arrangements would ensure the provision of AUFLS load.

The continued use of a mandated scheme will be required for the foreseeable future until a better feasible provision arrangement option emerges

To limit the over-provision associated with a mandated scheme and increase the efficiency of providing AUFLS load, distributors are recommended to investigate the use of the following options:

- timers on relays
- offering surplus IL provision from behind an armed AUFLS feeder
- redistribution of AUFLS provision between GXP.
- equivalence arrangements to avoid the arming of critical load and compensate for unique load configurations.

9 Next Steps

The System Operator will be engaging with industry participants to ensure the findings from this economic paper are well understood and that industry feedback has been thoroughly considered. The System Operator will discuss the options presented in this report at seminars starting on 8th August 2011.

Once the System Operator has analysed feedback, it will finalise recommendations and present them to the Electricity Authority. In parallel the System Operator will be conducting further work in the following areas:

- an audit of critical load connected to AUFLS feeders around the country
- testing of df/dt relays and further technical analysis of df/dt implementation requirements
- discussion with North Island distributors to further understand of the implementation processes and requirements
- continue to work with Transpower to address the provision of AUFLS load at the Tiwai GXP.

10 Summary of Questions for Consideration

The System Operator would appreciate industry feedback on the following questions:

- Does industry support the cost benefit analysis methodology used in this review?
- Were there other factors you believe should have been considered by the cost benefit analysis?
- Are there other factors that need consideration for implementation?
- What needs to be considered with the investment cycle for the implementation of a new AUFLS scheme?
- Are there any suggestions to improving the process of seeking equivalence arrangements for AUFLS?
- Are you interested in participating in equivalence arrangements?
- Would you seek out to optimise your provision of AUFLS by utilising other providers?
- Are there any suggestions or concerns from the market options and provision section?