Common Quality Development Plan

Evaluation of Options

461407-2

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Introduction and Purpose

1. This document, prepared for the Electricity Commission (Commission) Board (Board), provides an overview of the work undertaken under the strategic arm of the common quality development planning process to evaluate potential developments. It summarises:

   a. The framework used to develop and evaluate potential strategic common quality development initiatives.

   b. The strategic initiatives and options considered.

   c. The evaluation and ranking of possible development options.

   d. A suggested set of development projects and indicative next steps.

Background and Guide to this Paper

2. Preparation of a longer-term development plan for common quality is a key task in the Commission's work programme.

3. The first stages of the strategic development work stream are set out in Table 1 below.

Table 1: Progressing Strategic Development

Task	
1	Understand and describe how the current arrangements work
2	Identify alternative arrangements or strategic improvements
3	Evaluate initiatives identified in the previous task
4	Recommend, to the Electricity Commission Board (Board), a short list of strategic options for detailed scoping and costing

4. This paper is concerned with tasks 2 to 4 in Table 1. In relation to task 1 in Table 1, the reader is referred to the companion paper "Common Quality Development Plan - Current Arrangements for Frequency, Voltage, Reliability and Security".

5. The next section of this paper summarises the synthesis and categorisation of potential development options presented in this paper. Subsequent sections cover:

   a. The overall approach to identifying and evaluating potential development options;

b. Frequency development;

c. Voltage development;

d. Reliability and security development;

e. Overall evaluation of options; and

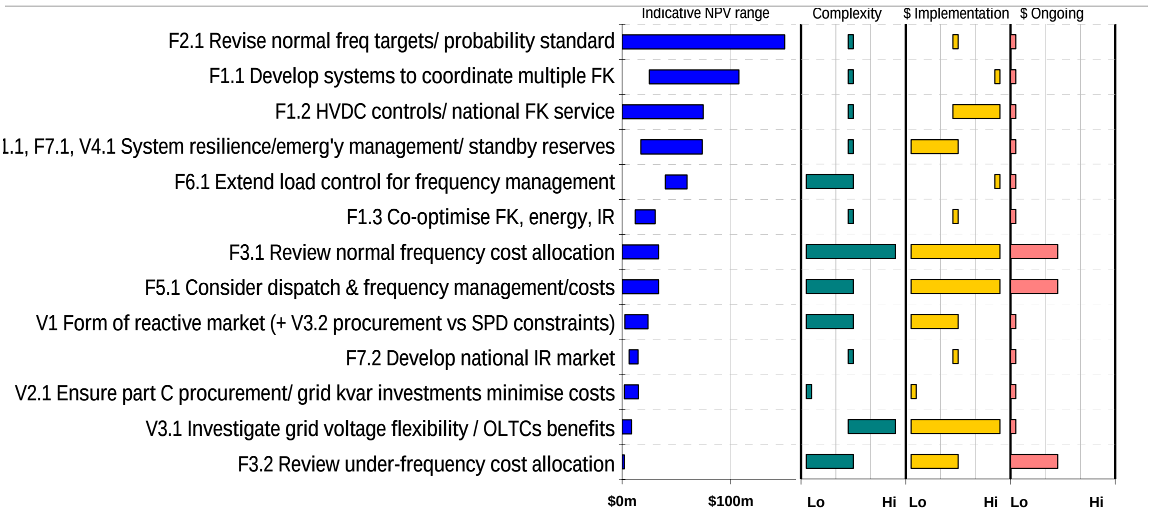
f. Indicative project outlines.

Summary

6. In conjunction with the Common Quality Advisory Group (CQAG), a large number of potential common quality development options relating to frequency, voltage and reliability and security were identified. This process international research, reviews of earlier working group papers, consideration of current arrangements and CQAG development workshops.

7. From that work, development options with potential to address key common quality issues were identified. These options, described individually later in this document, were then assessed using the evaluation framework described in the next section. Where practical, these assessments included quantitative analysis, as illustrated in Figure 1. Other options were assessed through more qualitative means.

Figure 1: Summary of Indicative Assessments



Note: Bar widths indicate assessment uncertainty

8. As a result of the overall evaluation process, taking into account supporting or dependent relationships, potential common quality development options have been grouped and categorised as follows.

Category A: Potential to deliver highest benefits (even if challenging and/or costly)	
A1: Initial review of normal frequency targets & dynamic procurement	This would involve reviewing the normal frequency band and immediately adjacent frequency bands and the corresponding approach to specifying frequency keeping procurement needs with a view to reducing overall costs (direct and indirect). It would seek input from the Commission's wind project and involve system trials. A full review of how normal frequency targets are specified to minimise long term overall costs would not be considered until other normal frequency initiatives have been implemented.

A2: Develop systems to co-ordinate multiple frequency keepers	This would involve developing a system for coordinating multiple frequency keepers, along the lines an AGC system but tailored to NZ requirements (e.g. block dispatch), and changing the market arrangements to co-optimise frequency keeping with energy and instantaneous reserves to ensure lowest overall cost. The first stage would investigate technical and commercial design requirements to enable costs and benefits to be confirmed and an implementation plan/ budget submitted to the Board. In the interim, changes to the frequency keeper selection method (to take account of potential constrained-on and constrained off costs) are being investigated with a view to reducing procurement costs.
A3: Investigate technical options for HVDC frequency control	Transpower has recently indicated, in response to a Commission request, that this capability will not be practical without upgrading HVDC control systems. These issues should be explored fully with Transpower because of the potential benefits involved and because of possible implications for future HVDC investment. Implications need to be understood with regard to A-2 above (e.g. should its scope be limited to the North Island initially or for each island independently, or can the HVDC receive an AFC system dispatch signal along the same lines as a generating unit MW set point controller or block dispatch system would receive).
A4: Optimise emergency management arrangements	This would involve a review of emergency management, including under-frequency and voltage management and the need for a standby reserves scheme to ensure least overall cost over time. This would include investigating how to extend the use of load control for frequency management (in particular through frequency sensitive hot water control relays and adding more and / or smaller AUFLs blocks); assessing the system's resilience major events and reviewing minimum frequency envelopes and how/ when mandated and ancillary services are utilised.

Category B (Potential for significant benefits, or easy wins, and fairly independent)	
B1: Progress towards appropriate form of reactive market	This would involve a staged approach to enhancing reactive market arrangements. Initial steps would include (1) ensuring zones target problem areas and setting kvar prices as originally intended; (2) reviewing technical reactive standards and dispensation/ cost allocation arrangements to ensure they are efficient (seeking input from the Commission's wind project) and (3) investigating whether further enhancements would be beneficial.

B2: National instantaneous reserves market/ reserve sharing between islands	The Commission is in discussion with Transpower regarding this project to investigate implementation requirements. Transpower has developed and presented a prototype proposal. This project can proceed in parallel with other projects subject to system operator availability and any Schedule Pricing and Dispatch (SPD) changes.

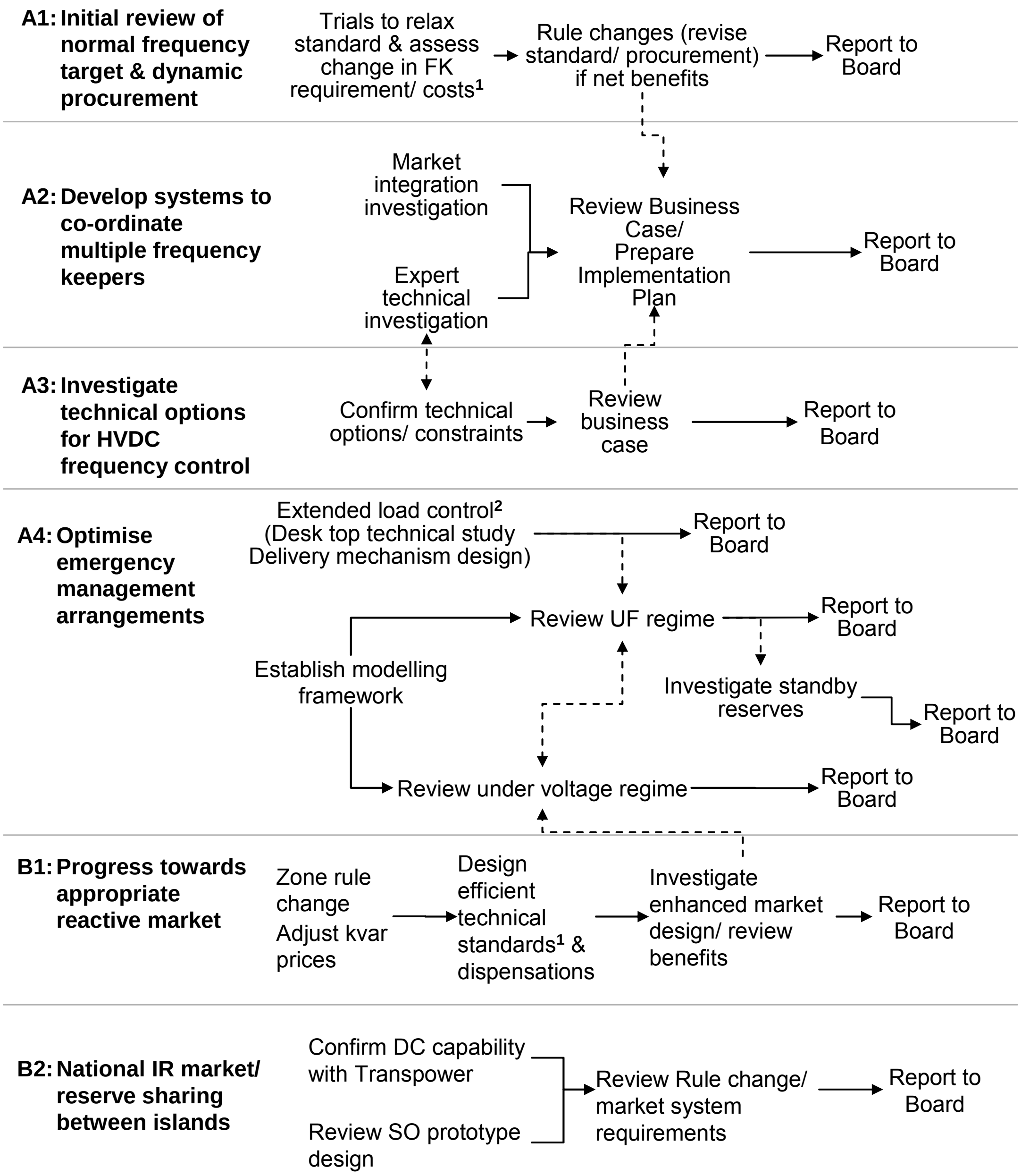
Category C (Lower potential benefits &/ or other projects will weaken benefits)	
C1:Review normal frequency cost allocation	This should be re-considered following other measures to reduce normal frequency costs. However, input from the Commission's wind project should be sought to assess whether it would be appropriate to extend the current allocation of procurement costs to intermittent wind generation).
C2:Review current dispatch systems and performance	This project, which would consider dispatch changes to enhance frequency management and reduce costs, should be re-considered once the outcome of other measures to reduce frequency related costs have been established.
C3:Review under-frequency cost allocation	This should be re-considered following the outcome of other projects A4 and B2.

Category D (Potential benefits from proactive common quality input to other areas)	
D1: Minimise overall cost of part C procurement & part F kvar investments	With efficient part F/ part C co-ordination, it should be possible to ensure that, without compromising security, part F arrangements do not prevent part C procurement options competing as alternatives to grid kvar investments. Ongoing common quality perspectives on this issue should be provided as input to relevant aspects of the Commission's transmission's work program.
D2:Assess possibility of increase grid operating voltage flexibility	There may be potential benefits (security and cost) from increasing average grid voltages, within nominal ranges, and investing in transformer on load tap changers in some grid locations to increase grid voltage flexibility. Transpower, through the part F investment process and in its capacity as system operator, is best placed to assess the likely benefits of this option. The Commission could ask Transpower to advise whether it considers there are likely to be significant benefits and / or what would be required to identify these.

D3: Active input into part F developments	Ongoing active monitoring and input to transmission work-streams would have common quality benefits. Areas of particular interest are: consistency between operational reliability and security standards and grid planning requirements; ability to vary system operation from N-1; and defining service levels at grid off-takes.

9. Figure 2 provides an indicative outline of how category A and B projects could be progressed under the Common Quality Development Plan.

Figure 2: Indicative activities to progress category A and B projects

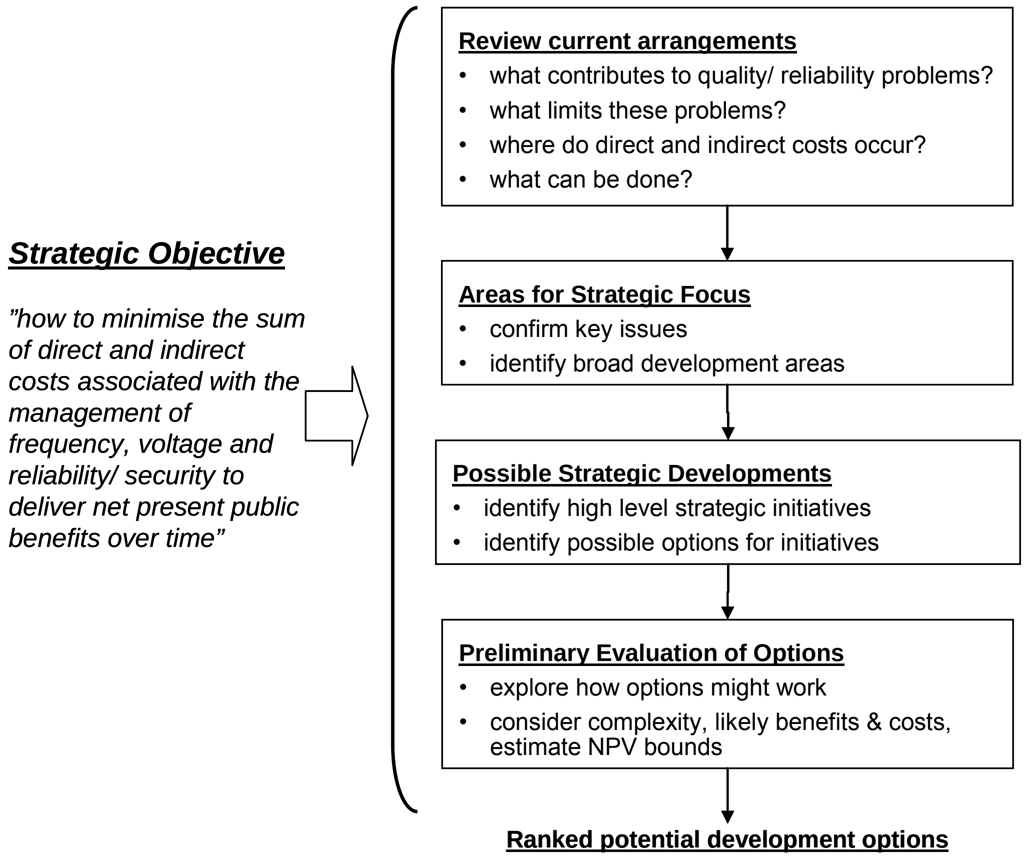


Notes: 1) Seeking input from Commission's wind project
2) With input to/ assistance from Commission's load management project

Overall Approach

10. Figure 3 illustrates the overall framework used for developing and evaluating development options.

Figure 3: Framework for Identifying and Evaluating Potential Development Options



11. Note that in practice, frequency and voltage development initiatives were largely considered separately in the first instance. A number of reliability and security issues were also covered in considering frequency and voltage, particularly in relation to emergency management. The structure of this document largely reflects this, by considering frequency, then voltage and finally reliability and security.

12. For each potential development option, to the extent practical, the preliminary evaluation process highlighted in Figure 3 involved the following:

   a. Considering the nature of benefits offered and issues that would need to be taken into account;

   b. Estimating the possible quantum of net public benefits:

      – estimates of upper and lower net present value (NPV) bounds were attempted to recognise uncertainty; and

- standalone assessments were undertaken (actual benefits may not be cumulative in practice but the objective is only to establish relative rankings of options, not detailed business cases for particular developments).

c. Considering other criteria, summarised in Table 2, that could influence priorities (e.g. an option that is simple to implement may be worth pursuing immediately even if the potential public benefits are less).

Table 2: Other assessment criteria

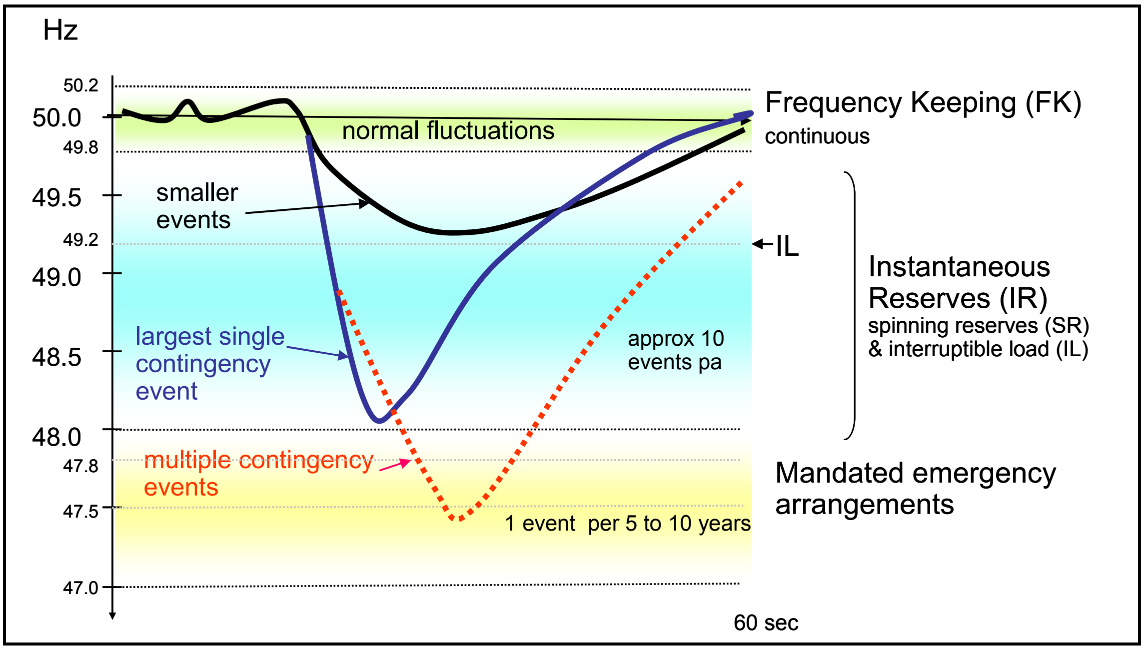
Criteria	***Basis for assessments***		
Costs	Low	Moderate	High
Implementation	< $1m	$1m to $5m	> $5m
Ongoing	< $0.2m pa	$0.2m to $1m pa	> $1m pa
Complexity	Technical & Administrative (Low, Moderate or High)		
Dependencies	Does the option require or support other options?		

Frequency Development

Overview of current arrangements

13. Section 2 of the Current Arrangements paper describes current frequency management arrangements. These can be summarised very broadly as illustrated in Figure 4.

Figure 4: Overview of Current Frequency Management



14. Generation must be closely matched to demand, which varies continuously, or the system will become unstable. Under normal circumstances, the System Operator is therefore expected to maintain frequency within +/- 0.2 Hz of 50 Hz (the "normal frequency band"). To meet this objective, it relies on a combination of:

    a. The dispatch process (to adjust supply to meet nominal demand);

    b. Mandated generator free governor action (which automatically increases/ decreases supply when the frequency falls below/ rises above 50Hz); and

    c. Frequency keeping services it procures from generators (to quickly restore frequency to 50Hz[1] and maintain generators close to their nominal dispatch set points).

15. Momentary fluctuations outside the normal frequency band are permitted during system events (for example, when generation or transmission trips or a large load is switched on). The System Operator is expected to manage frequency so that the rate and size of fluctuations is maintained within specified limits. The frequency must remain within extreme high or low limits

1 And manage system time error.

to avoid cascade failure of assets and loss of supply. The size of generating units and the HVDC in the NZ power system means that under-frequency management is particularly important. (Over-frequency event management is also very important but is less problematic).

16. To manage under-frequency fluctuations, the System Operator relies on a combination of:

    a. Mandated generator free governor action;

    b. Procuring instantaneous reserves (generation and interruptible load);

    c. Emergency load shedding (AUFLS[2]).; and

    d. Mandated asset owner performance obligations, in particular requirements for generating units and the HVDC to support frequency and remain connected over a specified frequency range.

17. The System Operator's ability to manage frequency fluctuations within specified limits is obviously dependent on sufficient assets being made available to it.

18. Sufficient instantaneous reserves are procured to ensure that:

    a. The frequency will not fall below 48Hz, and will recover within 60 seconds, if the largest single contingency event occurs. i.e. loss of the largest generating unit or a pole of the HVDC, whichever is the larger risk at the time.

    b. The frequency will not fall below 47Hz in the North Island/ 45Hz in the South Island, and will recover within 60 seconds, if both poles of the HVDC trip. The instantaneous reserves assessment assumes AUFLS will have operated.

19. Around 90% of the time, additional instantaneous reserves are not required to satisfy (b) above.

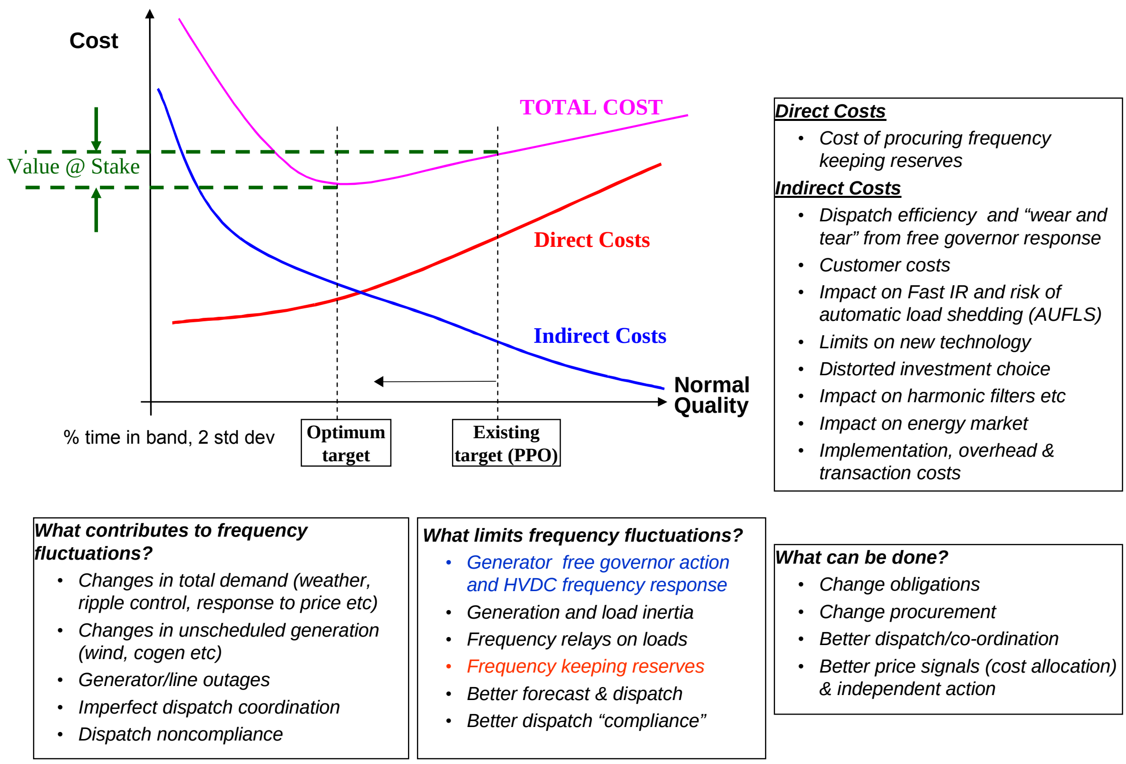
Direct and indirect costs of normal frequency management

20. The chart within Figure 5 is a stylised illustration of the way in which direct and indirect costs associated with managing normal frequency vary with the target level of normal frequency quality. For example, if the quality target is relaxed (larger fluctuations permitted) the level of direct procurement costs should fall. However, indirect costs will tend to increase. For example, greater free governor action may increase generator wear and tear (due to continual cycling of equipment) and efficiency losses (by forcing generators away from

[2] Automatic Under Frequency Load Shedding facilities in each island disconnect two 16% blocks of demand if low frequency settings are reached. Although more relevant to emergency voltage management, if necessary, the system operator will instruct distributors (or as a backstop measure, the grid owner) to disconnect demand.

optimal loading). The optimum normal frequency quality target will be the point where the sum of direct and indirect costs is minimised.

Figure 5: Minimising Direct and Indirect Costs of Normal Frequency Management



21. In practice, an accurate assessment of these curves will be very difficult to make. However, it is helpful to consider, as highlighted in the boxes in Figure 5, the various factors that contribute to or mitigate normal frequency fluctuations, the nature of direct and indirect costs and what levers can be used to optimise overall costs.

22. In this regard, in relation to the current arrangements for managing normal frequency described in detail in section 2 of the Current Arrangements paper, the following observations can be made:

   a. Direct costs for frequency keeping for the year ending August 2006 were approximately $60m, and have risen by more than 400% over the last five years.

   b. There are concerns that significant levels of additional intermittent generation (in particular wind) will increase frequency keeping requirements and procurements costs.

   c. Few generators meet specified technical performance requirements for providing the frequency keeping service (e.g. MW ramping rate and MW range requirements).

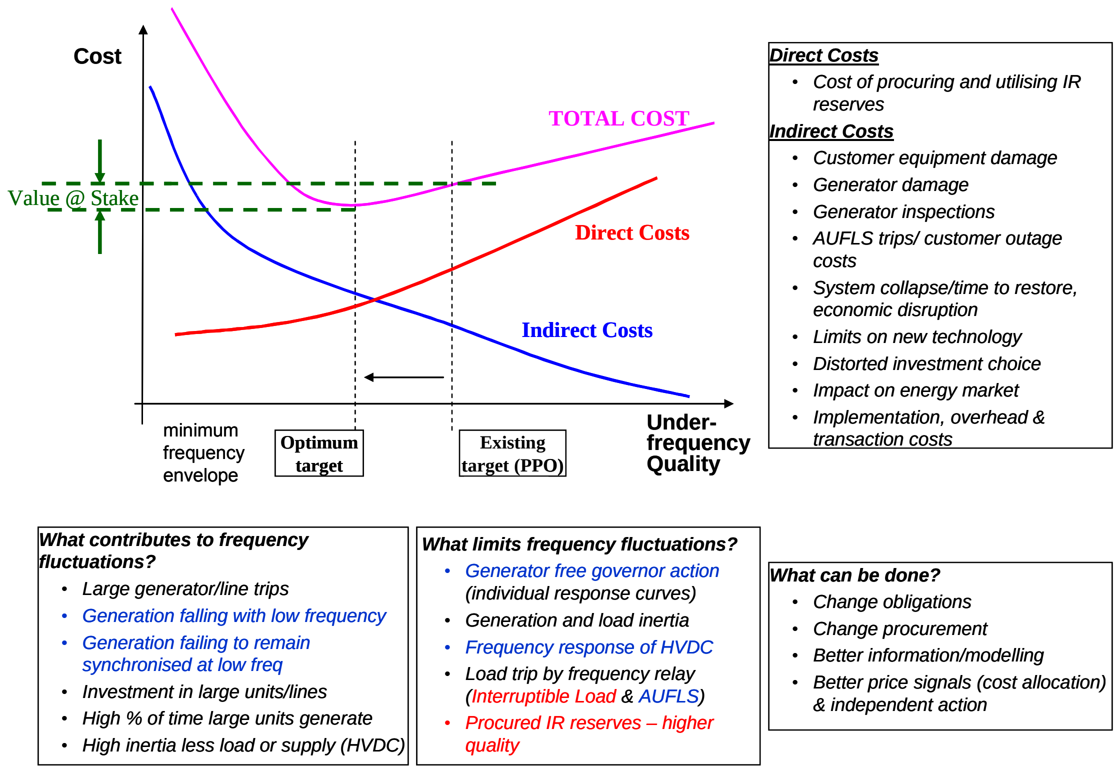
   d. There may be barriers to alternative frequency keeping providers, including the possibility of load management options.

e. Indirect costs are difficult to quantify but a previous survey[3] suggests that if the normal frequency band were to be widened, most customers would probably be indifferent but some generators are likely to incur extra costs (due to mechanical wear and tear and efficiency penalties because of free governor action).

Direct and indirect costs of under-frequency management

23. Following the same approach as above, Figure 6 summarises factors that contribute to or limit under-frequency fluctuations, direct and indirect cost components and the levers that are available to minimise overall costs.

Figure 6: Minimising Direct and Indirect Costs of Under-Frequency Management



24. As for normal frequency management, it is difficult to assess the set of quality targets and associated arrangements that would optimise the overall level of direct and indirect costs associated with under-frequency management. However, in this regard, in relation to the current under-frequency arrangements described in detail in section 2 of the Current Arrangements paper, the following observations can be made:

a. Direct costs for under frequency management vary from month to month and year to year depending on market conditions. For calendar years 2000 to 2005, annual instantaneous reserves costs varied between approximately $13m and $25m. On a rolling 12 months basis between

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[3] Frequency Quality Survey, GSC Secretariat, September 2003.

August 2000 and August 2006, annual instantaneous reserves costs varied between approximately $5m and $32m, and averaged approximately $17m.

b. The number of instantaneous reserves providers, both from generators and interruptible load sources, is significant but there may be barriers to low cost alternatives including demand management options.

c. There are concerns[4] that arrangements for managing under-frequency events may be sub-optimal in terms of under-frequency limits, events covered, the mix/ level of mandated versus procured services and so-called free reserves.

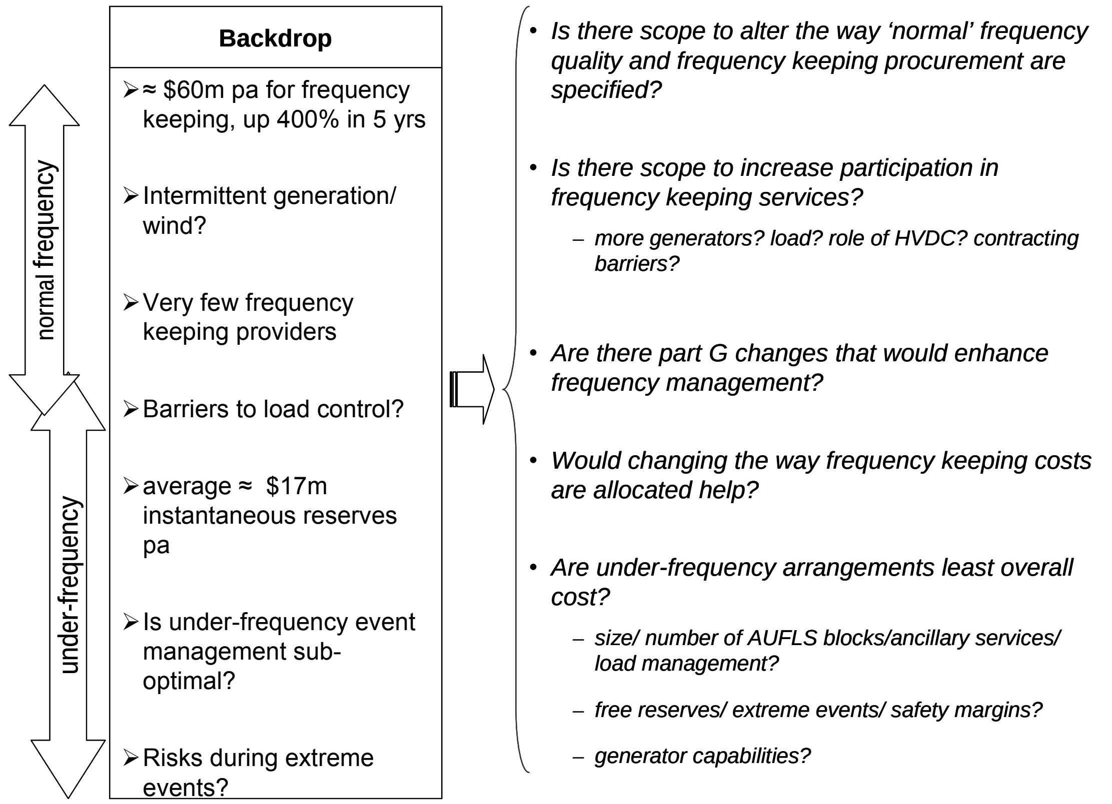
d. Although North Island frequency limits were tightened in 2001 to better reflect the capabilities of modern thermal generators, there are residual concerns about modern thermal generator capabilities during extreme under-frequency events, given the potential consequences for grid security. Thermal generator investments in the South Island limits would be unable to comply with the current minimum frequency obligation there of 45Hz.

Areas for Strategic Focus

25. In the context of possible strategic directions for frequency management, Figure 7 summarises questions that emerged from the above issues.

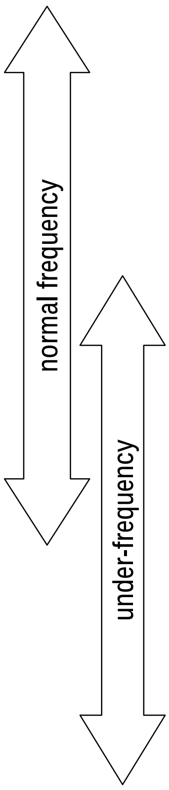
[4] e.g. see the GSC's Frequency Standards Working Group (FSWG) and Frequency Development Working Group (FDWG) reports.

Figure 7: Framing Frequency Management Questions



26. The above processes lead to identification of the following areas of strategic focus to guide consideration of possible frequency development options. i.e. areas of focus in relation to the overall objective of "minimising the sum of direct and indirect cost associated with frequency management to deliver net present public benefits over time".

Figure 8: Strategic Focus For Frequency Developments



1. Reduce barriers to entry and increase supply of frequency keeping services?
2. Specification of normal frequency management targets/ procurement?
3. Can efficiency be improved through better signals to the causers of normal and under-frequency deviations?
4. Are there barriers to new forms of normal and under-frequency ancillary services?
5. Are there part G (dispatch) changes that would enhance frequency management?
6. Extend use of load control to manage frequency?
7. Review under-frequency arrangements to confirm least *overall* cost?

27. These focus areas form the basis of the series of broad normal and under-frequency management strategic initiatives described in the following.

Possible Strategic Frequency Initiatives and Options

28. The strategic focus areas shown in Figure 8 were used to filter out potential frequency developments from the large range of possible alternatives identified in conjunction with the Common Quality Advisory Group (CQAG)[5].

29. The potential frequency development options identified are set out in Table 3:

[5] The process carried out in conjunction with the CQAG included development workshops to explore issues with the current arrangements and possible opportunities to address them as well as research relating to arrangements and developments in other countries and earlier reports from various GSC working groups.

Table 3: Possible Frequency Development Initiatives and Options

Initiative		*Options*	
F1	Reduce barriers and increase supply of frequency keeping services	F1.1	Develop systems to coordinate multiple frequency keepers.
		F1.2	Alter HVDC control system and procurement arrangements to allow national frequency keeping service.
		F1.3	Co-optimise frequency keeping, energy & instantaneous reserves (integrate offers and dispatch) to reduce barriers to participating in all three markets.
F2	Specification of normal frequency management targets/ procurement	F2.1	Revise normal frequency targets and determine an appropriate probability standard.
F3	Better signals to the causers of normal and under-frequency deviations	F3.1	Review normal frequency cost allocation arrangements.
		F3.2	Review under-frequency cost allocation arrangements.
F4	Inefficient barriers to forms of normal and under-frequency services	F4.1	Consider whether there are barriers to some forms of frequency reserves.
F5	Part G changes to enhance frequency management	F5.1	Consider dispatch changes to enhance frequency management/ reduce costs[*].
F6	Extend use of load control to manage frequency	F6.1	Consider how to extend the use of load control for normal and under-frequency management.
F7	Review under-frequency arrangements to confirm least overall cost	F7.1	Review under-frequency arrangements to ensure they are optimal for NZ.
		F7.2	Develop a national instantaneous reserves market.

Evaluation of Frequency Development Options

30. In this section, each of the potential frequency development options is discussed and evaluated. In each case, the format followed is to briefly:

    a. Describe the option.

[*] Note that other frequency development initiatives, for example aspects of option 1.1 above, would also involve Part G. However, the focus here is on dispatch.

b. Consider the nature of benefits it offers.

c. Identify issues that would need to be addressed if the option were to be progressed.

d. Assess potential net public benefits (where practical) and other supporting criteria (as described in paragraph 12 above).

31. For the purpose of assessing potential benefits, the following baseline cost assumptions have been made.

Table 4: Baseline cost assumptions for evaluation of potential frequency benefits

Service	***Baseline Cost pa***	***Comment***
Frequency Keeping	$45m	For the year ending August 2006, the cost of procurement was approximately $60m. However, it is assumed there will be some reduction in costs when the frequency keeper selection method is changed to take account of estimated constrained-on/ -off costs.
Instantaneous Reserves	$17m	Procurement costs are volatile but have averaged approximately $17m pa since 2001.

32. Note that NPV net benefits have been estimated simply as follows:

$$NPV = (\$B_{PA} - \$C_{PA}) \times 7.5 - \$C_{SU}$$

Where: $\$B_{PA}$ = estimated annual benefits (savings)

$\$C_{PA}$ = estimated annual costs

7.5 = multiplier equivalent to approximately 10% pre-tax real discount rate over 15 years

$\$C_{SU}$ = estimated development/ implementation costs

33. This simplified approach is appropriate given the purpose of making NPV estimates on a standalone basis (ranking), and the level of uncertainties involved. A consistent term of 15 years has been used for all assessments.

F1.1 Develop systems to coordinate multiple frequency keepers

Outline

34. A number of possibilities exist including:

a. <u>Extending frequency keeping co-ordination across companies.</u> For example, it may be practical for Mighty River Power and Genesis Energy (the two current North Island providers) to simultaneously maintain frequency. Genesis has coordinated the frequency keeping service across its Huntly and Tongariro stations although extending this to multiple companies is likely to be technically and commercially difficult. Of itself, this would not increase competition for the service and it is uncertain whether or not it would significantly lower costs.

b. More comprehensive central coordination using automatic frequency control systems. Distributed frequency control using AGC[6] is relatively common overseas, with and without market arrangements:

- a traditional AGC system models the power system and generating unit technical characteristics in detail;
- it continuously monitors system frequency error, issues adjustments to generating unit load set points to manage frequency (e.g. every 5 or 6 seconds via SCADA) and monitors actual generation; and
- technically AGC systems can simultaneously perform both the dispatch and frequency regulation functions.

c. Enhanced coordination through pricing mechanisms and dispatch incentives. It may be possible to provide financial incentives / penalties to reward / incentivise generator frequency response[7]. However, without some form of central co-ordination this is unlikely to be a practical option. Some jurisdictions have introduced payments for participating in AGC based frequency control regimes. e.g. PJM in the US and the NEM in Australia.

35. A number of other countries have legacy AGC systems that predate electricity markets. As NZ has no legacy arrangements, the infrastructure and requirements for a fully fledged AGC system could be significant. For example, to implement a full traditional AGC system for unit dispatch purposes is likely to require SCADA systems upgrades. On the other hand there is an opportunity to consider a less extensive automatic frequency control (AFC) regime that takes account of modern technology and NZ specific circumstances. For example, a NZ AFC system would need to be consistent with electricity market and dispatch technical arrangements, including block dispatch efficiency objectives.

36. In the following, a possible high level approach for NZ is developed for evaluation purposes.

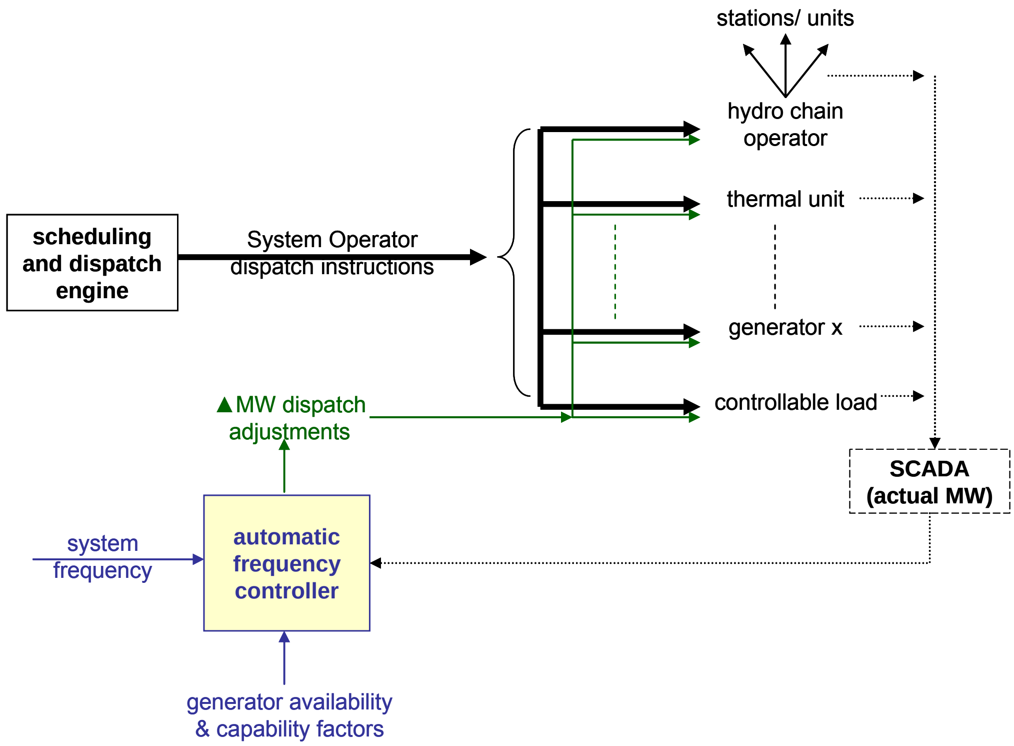
Possible NZ approach

37. A possible technical approach to AFC implementation that would appear to suit NZ circumstances is illustrated in Figure 9.

6 Automatic Generation Control.

7 For example, it has been suggested that the nominal energy price could be adjusted regularly within each half hour according to the level of frequency error. (A similar approach has been used in India to improve dispatch).

Figure 9: Outline of Possible NZ Arrangement



38. Under the existing market arrangements, the System Operator uses the market SPD model to formulate dispatch instructions to generators according to their energy and instantaneous reserve offers to simultaneously satisfy demand and system security requirements. The market also accommodates block dispatch of hydro chains to provide flexibility to optimise river chain efficiency. Generators implement dispatch instructions issued by the System Operator.

39. A full traditional AGC system that simultaneously dispatched individual generating units and maintained frequency, although technically feasible, could compromise the benefits of block dispatch. It would also be relatively costly given the need to install high grade SCADA systems to meet on-line control reliability and performance requirements for continuous dispatch of the system[8].

40. A less costly alternative would be to augment the current dispatch arrangements (illustrated by the bold lines in Figure 9) with an AFC system to issue "MW dispatch adjustments" to generators via existing SCADA systems. i.e. generators would continue to adjust unit load set points to implement dispatch instructions as happens now and a simplified form of AGC would measure frequency error and issue signals to generators that could be used to adjust dispatch to correct frequency. The adjustments could be issued to individual units, stations or hydro blocks and would need to take account of generator capabilities (MW range, rate of change etc).

[8] Transpower has indicated that protection grade SCADA would be required and that existing SCADA communications are for monitoring purposes rather than full control.

41. The description above is overly simplistic and detailed technical investigations would be needed to decide on the most appropriate form of AFC given NZ conditions and likely costs and benefits. Investigation would need to focus on the potential benefits and issues summarised in the following.

Nature of benefits (Systems to coordinate multiple frequency keepers)	
Increased competition	Opportunities for more providers to participate. Greater discipline on providers. More competition between providers.
Better performance	Providers could offer smaller quantities at faster rates. The system operator could adjust quantities / quality more readily.
Lower costs	Requirements could be selected from the cheapest offered tranches. Procurement costs could be lowered.
Future proofing	Potential to adjust frequency keeping quantities/frequency targets in future (e.g. if wind penetration increases overall frequency keeping requirements).

Nature of Issues (Systems to coordinate multiple frequency keepers)	
Overall NZ requirements	It is probably better to think in of terms of an automatic frequency control (AFC) system for NZ rather than a full traditional AGC system dispatching individual generation units continuously. Could existing SCADA be used to simultaneously issue ‘adjust load’ instructions to multiple providers? ▪ The use of SCADA for frequency keeping across two generating sites/ companies could perhaps be trialled? Could block dispatch flexibility be preserved? Should a scheme be voluntary with offers/ payments or should technical requirements be mandated on all generators? NEMMCO experience suggests there may be significant benefits from distributing frequency keeping service across multiple providers and paying for service (see later). ▪ Is NEMMCO experience transferable? (bigger market, legacy AGC system etc)

Nature of Issues (Systems to coordinate multiple frequency keepers)	
Technical issues	Calculating overall requirements for frequency keeping. Establishing individual generator's capabilities and treatment of block dispatch groups. Holding spare capacity in reserve for both frequency keeping and instantaneous reserves. Calculating the rate and size of raise and lower MW instructions to participants to correct real time frequency deviations and system time error. Selecting and sharing frequency keeping duty between providers, given disparate MW response ranges and rates and block dispatch requirement, to adjust providers up and down using SCADA to achieve least cost. Allowing for co-existence of central coordination with free governor action. Deciding whether an open loop regime for issuing/ monitoring instructions would be adequate or whether a closed loop system would be necessary.
Administration issues	Deciding whether payments should be based on monitored or assumed (instructed) responses and how to deal with non performance. Deciding contractual and technical requirements to participate. Compliance/ monitoring arrangements. Migrating commercially and technically from existing arrangements.
Inter-dependencies	Could be further enhanced by option F1.3 (co-optimising frequency keeping with instantaneous reserves and energy) and option F1.2 (national frequency keeping). Benefits could influence/ be influenced by option F5.1 (measures to enhance dispatch). Variants of option F3.1 (normal frequency cost allocation) could be alternative or supporting mechanisms.

Australian experience

42. It is helpful to consider the NEMMCO regime to gain some insights into the potential benefits an AFC arrangement in NZ might offer. The Australian National Electricity Market (NEM) has one of the most sophisticated market oriented approaches to procuring frequency control ancillary services (FCAS). While a similar level of sophistication is likely to be difficult to justify in New Zealand, the following aspects are worthy of note:

    a. The NEM has a full AGC regime.

    b. The NEM is a bigger system than NZ's.

c. The NEM standard is that 'normal frequency' should be within ±0.15 Hz of 50HZ for 99% of the time (in NZ the requirement is +/- 0.2Hz).

d. Procurement of reserves needed to meet the standard is reviewed regularly:

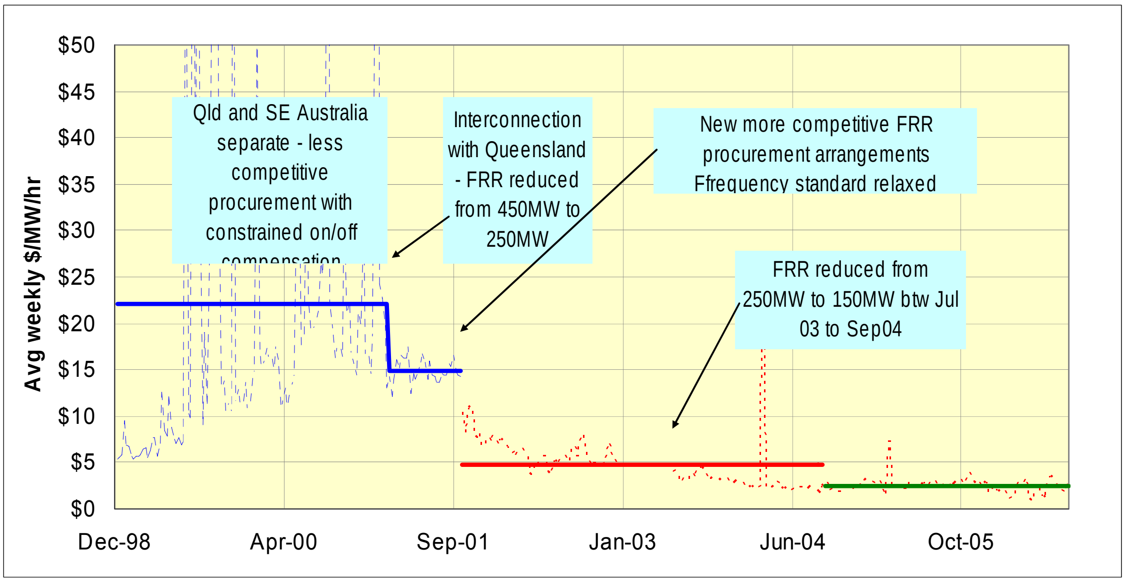
- E.g. on 30 September 2001, the standard was relaxed from ±0.1Hz to +/-0.15Hz for 99% of the time and a longer recovery time provided for.
- This reduced procurement needs and lowered costs.

e. The NEM procures 8 separate frequency control ancillary services (FCAS) through competitive market arrangements. This includes raise and lower frequency keeping services that are co-optimised with energy and dispatched every 5 min.

f. The costs of regulation FCAS raise and lower services are allocated to generators and off-take customers on the basis of causer-pays factors.

43. Figure 10 shows how the average procurement cost of regulating reserves changed in the NEM between December 1998 and August 2006.

Figure 10: Changes in the cost of frequency regulation in the Australian NEM



44. Key points to note are that:

a. The average direct cost of frequency keeping services has reduced significantly from around $22 per MWh to around $2.50 per MWh. The comparable costs in New Zealand are of the order of $50 per MWh at present in the North Island and $19 per MWh in the South Island[9].

9 i.e. approximately $43m pa to procure a 100 MW band (+/-50MW) for North island frequency keeping requirements and approximately $17.5m in the South Island (based on procurement costs for the 12 months ended August 2006).

b. Interconnection with Queensland in March 2001 reduced the quantity of frequency regulating reserve required in the NEM from 450MW to 150MW. The average procurement cost (per MWh) fell by around one third to approximately $15 per MWh.

c. When more competitive procurement arrangements were introduced on 30 September 2001, the average cost of frequency keeping reserves immediately fell by approximately one third to around $10 per MWh. Over the following 18 months, the average procurement cost continued to fall to around $5 per MWh, an overall reduction from September 2001 of around 65%.

d. The amount of frequency keeping reserves was reduced from 250MW to 150MW between July 2003 and September 2004. Average procurement costs fell have subsequently fallen to around $2.50 per MWh.

45. Care needs to be taken in considering how the NEM arrangements might indicate the potential benefits that could accrue if some form of AFC were to be introduced in New Zealand. For example:

a. A legacy AGC system was in place over the full period covered in Figure 10. The benefits observed above relate to a mixture of factors. Even with the legacy AGC system, average procurement costs were originally more comparable to New Zealand's current costs.

b. Interconnection with Queensland has helped to lower procurement requirements and costs. (A possible parallel in New Zealand is the possibility of using the HVDC link to share frequency keeping between islands. However, the grid owner has indicated that this is not technically feasible until the pole 2 control system and pole are replaced).

c. Procurement arrangements have changed. For example, relaxing the normal frequency standard reduced overall procurement needs.

d. Market prices for frequency keeping procurement may not reflect actual costs, although it appears that increased competition (not just reduced procurement quantities) has contributed to significant cost reductions.

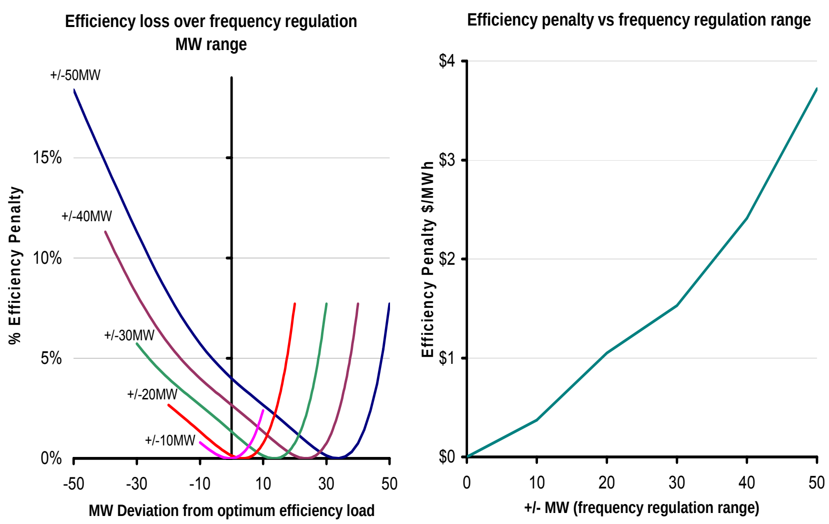
e. The potential costs of market complexity need to be accounted for, noting that New Zealand is a smaller market and does not have a legacy AGC system.

Indicative assessment

46. It is clearly very difficult to assess the potential benefits of introducing centralised frequency coordination arrangements along the lines proposed previously (paragraph 35 onwards) from a national resource cost perspective, especially without more detailed technical investigation and design work. The following preliminary assessment therefore explores that range of economic benefits that might be achievable. i.e. plausible upper and lower NPV bounds.

Upper NPV bound (Systems to coordinate multiple frequency keepers)	
Background	The Australian NEM achieved a reduction in overall regulation costs of more than 75%, but this is not easily applied to NZ: ▪ NEM is a larger market, with mainly thermal generation and a legacy AGC system. ▪ Procurement needs have fallen. ▪ Frequency keeping is co-optimised with other FCAS. But the NEM average price (less than $5/MWh) indicates potential benefits of enabling more providers and offering more flexibility to providers (e.g. smaller quantities, different participation factors).
Estimate of costs/ benefits	Benefits: ▪ Assuming that interim measures will be able to reduce annual frequency keeping procurement costs to around $45m, as suggested in Table 4, around $32m of that would be in the North Island (or $37 per MWh equivalent). ▪ If system to coordinate multiple frequency keepers could reduce North Island costs alone by a further 50%, to an average frequency keeping cost of around $18/MWh, direct costs would fall by approximately $18m pa (the current NEM price of around $2.50 per MWh equivalent). Costs: ▪ Only a rough estimate is possible at this stage but assume $5m to implement a basic scheme and $1m pa to operate and administer.
Indicative upper NPV	The above benefits and costs would represent an upper bound standalone NPV of approximately $108m[10]. ▪ Could be higher if future wind supply levels increase frequency keeping requirements.

10 Calculated as described in paragraph 32

Lower NPV bound (Systems to coordinate multiple frequency keepers)	
Background	Underlying frequency keeping costs fall with quantity and rate of change requirements. ▪ e.g. as illustrated in Figure 10, hydro station efficiency losses fall (rise) as the frequency regulating range required of a provider reduces (increases). **Figure 11: Efficiency implications of regulation requirement**  Note: Analysis ignores any constraints imposed on upstream and downstream river chain optimisation ▪ River chain efficiency/ replacement generation costs can also be affected. ▪ A thermal station also faces efficiency penalties and, unless it is the marginal station at the time, the market also incurs replacement generation costs. ▪ Frequency keeping provider O&M costs (wear & tear) will also be affected by the extent of regular cycling needed to maintain frequency. ▪ Indirect costs are also likely to be incurred by other generators due to free governor action inducing wear and tear and efficiency losses.
Estimate of costs/ benefits	Benefits: ▪ A conservative estimate of efficiency savings (along the above lines) of around $3/MWh represents approximately $2.5m pa per Island. Costs: ▪ $5m to implement basic scheme and $1m pa to operate/ administer.

Lower NPV bound (Systems to coordinate multiple frequency keepers)	
Indicative upper NPV	The above benefits and costs would represent a standalone lower NPV bound of approximately $25m.

Other evaluation criteria (Systems to coordinate multiple frequency keepers)	
Complexity	Done elsewhere but tailoring to NZ situation would be necessary (e.g. block dispatch, no legacy AGC system).
Implementation Costs	Could be relatively high although scope to use some existing SCADA and to avoid full blown AGC.
Ongoing Costs	More contracts and administration; compliance/ monitoring etc?
Dependencies	Could be further enhanced by option F1.3 (co-optimising frequency keeping with instantaneous reserves and energy) and option F1.2 (national frequency keeping service). Benefits could influence/ be influenced by option F5.1 (measures to enhance dispatch). Variants of option 3.1 (normal frequency cost allocation) could be alternative or supporting mechanisms.

Overall assessment (coordinate multiple frequency keepers)				
Indicative NPV[11]	Complexity	Costs		Dependencies
		Implement	Ongoing	
$25 to $107m	Moderate	High	Low	F1.3, F1.2, F3.1, F5.1

F1.2 National frequency keeping service

Outline

47. This option would involve using the HVDC to share frequency keeping duties between the two islands. Ideally, changes would be made to HVDC controls to enable a national frequency keeper, and possibly extended to enable HVDC loading (MW) to be adjusted/ dispatched along AGC/ AFC lines.

[11] As noted earlier, a standalone estimate is made for ranking purposes only - the estimated benefits of options will not be cumulative.

Nature of benefits (National frequency keeping service)	
Lower requirement	It may be possible to reduce the quantity of frequency keeping required nationally from +/- 50MW in each island because og greater national supply and demand diversity.
Competition	Four frequency keepers could compete nationally (instead of two per island). Four separate companies would compete to provide the service.
Costs	Requirements could be selected nationally from the cheapest offers. North Island would have access to lower cost South Island frequency keeping services. Lower procurement costs (less quantity required and/ or more competition?)

Nature of issues (National frequency keeping service)	
Feasibility	Is it technically possible/ safe to change the existing control system? ▪ Initial indications from Transpower are that the existing HVDC control systems would need to be upgraded. Alternatively, could the HVDC be "dispatched" at regular intervals (say 6 seconds) along similar lines to way generating units would be dispatched via an AFC system?
Potential limitations	Would the capability for multiple frequency keepers/ AFC be required? ▪ For example, if one provider cannot meet the national requirement. ▪ Especially if the need for frequency keeping increases due to increasing wind generation. Limited use at times of high and low HVDC transfers? ▪ Potentially costly to back off the HVDC at times. ▪ Reversal of flows impractical when operating at low transfers may be problematic.
System performance	Technical system stability issues would need to be assessed.

Indicative Assessment

Potential upper NPV bound (National frequency keeping service)	
Background	If the HDVC can be used to share frequency keeping between islands, this should: ▪ Create more frequency keeping options (4 companies nationally instead of two per island). ▪ Provide North Island access to potentially cheaper South Island services. ▪ South Island frequency quality is typically better suggesting some capacity to contribute to North Island requirements. ▪ Diversity between islands may also help to reduce quantity required. ▪ If national frequency keeping requirement could be reduced from +/-50MW in each island to +/-75MW nationally, then one national provider might be practical.
Estimate of costs/ benefits	Benefits: ▪ +/-75MW from a single frequency keeper @ $14.5/MWh (consistent with South island share of annual procurement cost in Table 4) instead of the annual cost of a provider in each island (consistent with annual procurement costs in Table 4) would represent a potential upper bound of around $30m pa savings (Meridian offers +/-75MW at times in the South Island). ▪ Realistic upper bound savings might be of the order of $10m pa to take account of factors such as high and low load HVDC constraints (limiting effectiveness) and additional costs per MWh of extending the frequency keeping requirement for one provider from the current requirement of +/-50MW to +/-75MW. Costs: ▪ Assume relatively inexpensive to implement for upper bound estimate (e.g. HVDC dispatch option with cost of around $.2m).
Indicative upper NPV	If low cost to implement, standalone upper NPV bound could be of the order of $75m.

Potential lower NPV bound (National frequency keeping service)	
Background	It may not be practical to meet national frequency keeping requirements from a single provider. HVDC dispatch option may be infeasible and it may be costly (or infeasible) to upgrade HVDC control systems to automatically balance frequency between islands.

Potential lower NPV bound (National frequency keeping service)	
Estimate of costs/ benefits	Benefits: ▪ Without AFC or some form of multiple frequency keeper provider coordination, there may be no significant benefits. Costs: ▪ Control system upgrade costs could be several $m.
Indicative upper NPV	This indicates a lower bound of zero (or less).

Other evaluation criteria (National frequency keeping service)	
Complexity	Control system upgrades might be required although technically feasible. Technical system stability issues may need to be assessed.
Implementation Costs	Could be high if HDVC control system upgrade is required. ▪ In its HVDC investment proposal to the Commission[12], Transpower estimated that the cost of upgrading pole 2 control systems to be around $10m (in 2005 dollars).
Ongoing Costs	Probably minimal – potentially lower transaction costs if one frequency keeping provider nationally would be sufficient. There may be some additional HVDC O&M costs.
Dependencies	Co-ordination of multiple providers (option F1.1) may be needed if more than one frequency keeping provider is required to keep frequency in both islands simultaneously.

Overall assessment (National frequency keeping service)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$0 to $74m	Moderate	Mod-High?	Low	option F1.1

12 http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/gup/Vol3/HVDC-summary.pdf#search=%22HVDC%20control%20system%20upgrade%2C%20NZ%22

F1.3 Co-optimise frequency keeping with energy & IR

Outline

48. This option would enable the same MW of capacity to be offered for frequency keeping, energy and instantaneous reserves. i.e. as for energy and instantaneous reserves at present. The market would then be able to accept offers for all three products and simultaneously schedule, dispatch and price them to co-optimise the use of these resources.

Nature of benefits (Co-optimise frequency keeping with energy & IR)	
Efficiency	In principle, it should lower barriers to participation (though more effective if it is also possible to coordinate multiple frequency keepers simultaneously). Should increase overall efficiency for offering /dispatching all three products. Could increase competition between generators.
Procurement costs	Would allow availability and constrained on/off costs to be accounted for directly in selecting frequency keeping providers.
Competition	In principle, the above efficiencies may enable greater competition between suppliers, though the extent to which this might occur is partly dependent on the ability for multiple generators to keep frequency simultaneously.

Nature of issues (Co-optimise frequency keeping with energy & IR)	
Technical	Need to specify frequency keeping offers and re-formulate SPD. Changes to SPD are complex and timing might be tied to SPD replacement, but there are examples to draw on (e.g. Australia, Singapore). Additional complexity in market, part G changes.
Dependencies	Would need to have a mechanism for coordinating multiple frequency keepers (e.g. option F1.1).

Indicative Assessment

Potential upper NPV bound (Co-optimise frequency keeping with energy & IR)	
Background	Design of FK offers and integration within SPD may be reasonably standard and readily accommodated. There may be significant increases in competition between generators if multiple generators can keep frequency simultaneously.

Potential upper NPV bound (Co-optimise frequency keeping with energy & IR)	
Estimate of costs/ benefits	Benefits: ▪ Procurement costs in the NEM fell by approximately 30% following introduction of similar regime in 2001. ▪ However, the NZ market is less competitive so assume an upper bound for cost savings of 10%. ▪ Therefore, standalone savings might have an upper bound of $4.5m pa (assuming procurement costs of $45m pa). Costs: ▪ Implementation costs could be $1m (incremental) as a potential lower bound, while ongoing costs could be $0.3m/yr.
Indicative upper NPV	These assumptions indicate an NPV (upper bound) for this option of $30m.

Potential lower NPV bound (Co-optimise frequency keeping with energy & IR)	
Background	Design of FK offers and integration within SPD might be hard to agree and complicated to implement. There may not be much increase in competition between generators as a standalone project.
Estimate of costs/ benefits	Benefits: ▪ Assume savings of only 5% as lower bound ($2.3m pa). Costs: ▪ Implementation costs could be as high as $3m (incremental) if agreement on FK offer design and implementation is complicated. ▪ Assume nominal ongoing costs of $0.3m pa.
Indicative lower NPV	These assumptions indicate an NPV (lower bound) of $12m.

Other evaluation criteria (Co-optimise frequency keeping with energy & IR)	
Complexity	Specification of FK offers is crucial to determine complexity of changes required in SPD (and associated implementation costs). However, there are several examples elsewhere to draw upon (eg Singapore and NEM). There may be some additional administrative complexity as a result of the extra bidding and prices.
Implementation Costs	Could be relatively low if market system upgrade project provides for it.

Other evaluation criteria (Co-optimise frequency keeping with energy & IR)	
Ongoing Costs	Only moderate ongoing costs of pricing/settlements/scheduling etc are expected.
Dependencies	This initiative provides the most benefits if multiple generators can keep frequency simultaneously, therefore it is best implemented in conjunction with option F1.1.

Overall assessment (Co-optimise frequency keeping with energy & IR))				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$12m-$30m	Moderate	Moderate	Moderate	Option F1.1

F2.1 Review normal frequency targets & determine probability standard

49. This option would review the ±0.2Hz normal frequency band (i.e. 49.8 Hz to 50.2 Hz) and complete the set of momentary frequency fluctuation rate limits prescribed in the Rules[13]. Prescribing these limits would enable the system operator to adjust periodically the quantity of frequency keeping services (up or down) to meet the target at minimum cost.

50. Reviewing the size of the normal frequency band has the potential to lower the costs of normal frequency management. Widening the normal frequency band reduces the ramp rate required of frequency keeping units, which is a barrier to entry into the frequency keeping market. Reducing the ramping requirement could therefore increase competition and lower the direct costs associated with procurement of the frequency keeping ancillary service.

51. However, increasing the number and extent of momentary frequency fluctuations increases the potential for frequency to fall or rise as a result of a sudden and unexpected loss of a generation unit or transmission asset and the cost of measures used to mitigate such events.

52. Such a change also increases the amount of ramping by generators fitted with speed governors automatically varying output to correct frequency deviations. This increases indirect costs associated with wear and tear and uncertainties in predicting hydro output and storage levels.

[13] Rule 2.2.3 in section II of part C requires the system operator to act as a reasonable and prudent system operator with the objective of ensuring that the aggregated rate of occurrence of momentary fluctuations in frequency in the North and South Islands does not exceed prescribed levels. However, the list provides limits for frequency bands below 49.5 Hz and above 50.5 Hz but does not provide limits for bands between these levels.

Nature of benefits (Review normal frequency targets, probability standard)	
Costs	Optimally sizing the normal frequency band has the potential to lower the costs of normal frequency management (both indirect and direct costs). Linking the frequency fluctuation limits to frequency keeping procurement has the potential to decrease costs. If the number of momentary frequency fluctuations is well within the limits prescribed then the system operator can relax the requirements for frequency keeping performance which could reduce the cost of procurement.

Nature of issues (Review normal frequency targets, probability standard)	
Cost/quality trade-off estimation	It is difficult to calculate indirect costs (wear-and-tear, dispatch inefficiency, customer costs, higher IR costs, technology restrictions etc). It is difficult to quantify the impact of changes in quality on the quantity of frequency keeping required and the associated cost.
Policy	It may be beneficial to split the momentary frequency fluctuation limits between islands.

Indicative Assessment

Potential upper NPV bound (Review normal frequency targets, probability standard)	
Background	Work by the FDWG in 2003 suggested moderate benefits ($2-3m pa) from widening the normal frequency band. Direct costs have risen sharply since that time so there could be much larger benefits from relaxing the normal frequency band and the momentary frequency fluctuation limits if the indirect.
Estimate of costs/ benefits	Benefits: ▪ In 2003, the FDWG estimated the indirect costs of widening the normal band to ±0.3Hz to be approximately $20m p.a. If that would avoid having to procure any frequency keeping, the net saving would be over $20m p.a.[14] Costs: ▪ Assume a nominal cost of $0.3m for review and rule change.
Indicative upper NPV	If FDWG estimates of the indirect cost curve made in 2003 still hold, and no frequency keeping services are procured, then the NPV (upper bound) could be just short of $150m. This estimate is very sensitive to assumptions about the level of direct procurement costs and any measures to reduce direct costs.

14 Direct cost savings of $45m/yr minus $20m/yr indirect costs of lowering the standard.

Potential lower NPV bound (Review normal frequency targets, probability standard)	
Background	It is possible that indirect costs are higher than estimated in 2003 and that relaxing the current standard may not significantly alter the technical requirements for frequency keeping.
Estimate of costs/ benefits	Benefits: ▪ No benefits would accrue. Costs: ▪ A nominal cost of $0.3m has been assumed to cover a review and rule change.
Indicative lower NPV	The NPV could be zero or negative under the lower bound assumptions.

Other evaluation criteria (Review normal frequency targets, probability standard)	
Complexity	Difficult to accurately assess direct and indirect cost curves, but relatively simple to implement and operate to a new standard.
Implementation Costs	The costs associated with the review and the consequential rule change.
Ongoing Costs	Increased indirect costs, which are more than offset by reduced direct costs.
Dependencies	Benefit from lowering standard is reduced if direct costs can be lowered through other initiatives affecting costs.

Overall assessment (Review normal frequency targets, probability standard)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$0 to $150m	Moderate	Low	Low	F1.1, F1.2, F1.3

F3.1 Review normal frequency cost allocation arrangements

Outline

53. This option would review the method for allocating frequency keeping costs to send stronger signals to generators and purchasers causing or correcting normal frequency deviations.

54. Frequency keeping costs are currently allocated to loads based on MWh purchased. This allocation mechanism:

a. Does not correspond with a party's contribution to the problem.

b. Does not recognise that other parties (e.g. intermittent generation) could also cause frequency deviations.

c. Is carried out on a national basis even though the service is procured separately for each island.

55. Possible alternatives to the current method could include:

a. Allocating frequency keeping costs by island.

b. Allocating c/kWh share of frequency keeping costs to generators that hold a dispensation from correcting frequency.

c. Establishing 2 or 3 classes of load with corresponding factors for sharing frequency keeping costs.

d. More sophisticated options involving frequency deviation metrics along the lines of the NEMMCO regime.

Nature of benefits (Review normal frequency cost allocation arrangements)	
Dynamic efficiency	New generation investment projects would compete on a level playing field if the causers of frequency deviations (e.g. wind) were to pay an appropriate share of costs.
Cost reductions	If behaviours (design and operation) were to change as a result of more targeted cost allocation (reflecting the contributions of causers), that would lower overall costs.

Nature of issues (Review normal frequency cost allocation arrangements)	
Design trade-offs	Trade-off between the amount of effort (and cost) expended in calculating "contribution" factors that accurately reflect the contribution (cause or correction) each load or generator provides. Would need to preserve opportunities for non-compliant generators and loads to mitigate effects through equivalence arrangements. Questions regarding ex-ante (static) or ex-post (average or dynamic) determination of contribution factors (e.g. generic contribution/ cause factors reassessed annually versus using SCADA to measure / assess actual performance).

Indicative Assessment

Potential upper NPV bound (Review normal frequency cost allocation arrangements)	
Background	If the new allocation enhances investment decision making and changes existing participants' behaviour then benefits could be substantial.
Estimate of costs/ benefits	Benefits: ▪ If an extra 100-200 MW of wind increased frequency keeping costs by 10% and this could be avoided by alternative firm generation at the same cost (e.g. geothermal), the benefit of signaling the extra costs could be \$4.5m pa. ▪ Both wind and geothermal generation options are being actively investigated and developed and so this issue has a high probability of being relevant over the next 15 years. Costs: ▪ Investigation and recommendation of an alternative allocation mechanism and the rule change could be undertaken relatively cheaply (assume \$0.2m).
Indicative upper NPV	Based on these assumptions an NPV (upper bound) could be around \$34m, but uncertain and difficult to assess.

Potential lower NPV bound (Review normal frequency cost allocation arrangements)	
Background	Reallocating costs may not change existing or investment behaviours significantly.
Estimate of costs/ benefits	Benefits: ▪ Minimal. Costs: ▪ Could equal or exceed benefits if the alternative mechanism was complicated to implement and maintain.
Indicative lower NPV	The NPV could be zero or negative under the lower bound assumptions.

Other evaluation criteria (Review normal frequency cost allocation arrangements)	
Complexity	Investigating and deciding on an alternative is expected to be moderately complex.
Implementation Costs	Implementing an alternative allocation mechanism could range from low (e.g. setting static factors for sharing costs) to high (e.g. complex metrics involving 6-second SCADA data), although the Australian experience could be drawn upon as a guide.

Other evaluation criteria (Review normal frequency cost allocation arrangements)	
Ongoing Costs	Again, calculating the cost allocation each month could be relatively similar to existing costs or it could be much more expensive, depending on the design.
Dependencies	None.

Overall assessment (Review normal frequency cost allocation arrangements)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
\$-ve to \$34m Highly uncertain	Low -High	Low – High	Mid – High	None

F3.2 Review under-frequency cost allocation arrangements

Outline

56. This option would review the current instantaneous reserves cost allocation methodology to determine whether external cost impacts of asset owner investment and maintenance/ operating decisions could be more accurately signalled to asset owners and whether this would have overall efficiency benefits. Possibilities include simplifying the current regime, such as adjusting or removing the 60MW deminimus and/or the administered event charge, or adopting a new regime, for example the runway methodology and/ or the introduction of market-based event charges.

Nature of benefits (Review under-frequency cost allocation arrangements)	
Efficiency	If cost allocation signalled under-frequency costs that asset owners impose on the system, then this could be factored into their decisions about: ▪ The size and reliability of assets they invest in. ▪ Maintaining and making available their assets to the market.

Nature of issues (Review under-frequency cost allocation arrangements)	
Uncertain effectiveness	Is the current allocation method creating investment distortions? Would improved signalling of under-frequency cost impacts lead to more efficient investment and maintenance/operational decisions? ▪ Other factors may cause perverse outcomes. ▪ E.g. Transpower's apparent lack of commercial incentives under current investment and price cap arrangements.

Nature of issues (Review under-frequency cost allocation arrangements)	
Cost/ complexity vs efficiency trade-offs	Would the cost/ complexity of improving the accuracy of signals be justified: ▪ Runway methodology may more accurately signal costs if significantly larger single contingency risks (>400MW) are expected in the future. ▪ Market based event charges may more accurately signal costs of increased frequency of load interruption caused by less reliable assets. Could the cost allocation method be simplified without causing inefficient investment / maintenance: ▪ E.g. removal of the administered event charge and 60MW deminimus.
Policy	How would equivalence and dispensations be handled under changed cost allocation? Should the impact of double contingency risks (e.g. bi-pole failure) be accounted for in the cost allocation?

Indicative Assessment

Potential upper NPV bound (Review under-frequency cost allocation arrangements)	
Background	It is very difficult to quantify potential benefits without detailed analysis. The current methodology approximately signals to asset owners the costs that investment in large generating units and transmission lines imposes and the external costs due to load shedding caused by less reliable assets. An optimistic view might be that there could be incremental benefits from improving the accuracy of cost signals, particularly if large unit sizes (e.g. 600MW) are likely to be considered in the NZ market.
Estimate of costs/ benefits	Benefits: ▪ Building say a 500MW unit might increase average instantaneous reserves requirements by roughly 150MW, perhaps costing around $7m pa. ▪ Under the current cost allocation regime, the 500MW unit investor is likely to face approximately 20-25% of total IR costs[15], say around $5-6m-pa, whereas under the runway methodology it is likely to face the full $7m incremental cost. ▪ The national benefit of signaling the full incremental cost could thus be $1-2m/yr if, as a result the investor built 2 smaller units instead. ▪ However, no one is currently investigating building units greater than 400MW and hence the likelihood of this issue becoming significant is relatively low, say 20%. ▪ An upper bound estimate of potential benefits might thus be of the order of $0.3m pa (20% of $1-2m pa) or around $2.3m in NPV terms. Costs: ▪ Changes to Rules and settlement systems might cost around $0.3m. ▪ Note that if an event based market were to be developed that would involve extra design/ implementation and ongoing costs (perhaps $0.5m and $0.1m respectively).
Indicative upper NPV	The upper bound NPV benefit of signalling costs more accurately could be around $2m.

15 The share of IR availability costs allocated to a 500MW unit would be in proportion to its capacity above the 60MW deminimus relative to the combined capacity of all thermal units above 60MW plus the HVDC risk less 60MW. In addition the 500MW unit will pick up some additional share of the costs via trips/ event charges. Taken together these might represent 20-25% of the total costs ($17m +7m = $24m/yr). This is approximately $5-6m/yr.

Potential lower NPV bound (Review under-frequency cost allocation arrangements)	
Background	Reallocating costs may not change the behaviour of participants significantly and/or alternative arrangements may be complex and implementation and extra on-going costs may erode/negate potential benefits.
Estimate of costs/ benefits	Benefits: ▪ It is possible that little or negative benefits may accrue. ▪ For example, if the deminimus were to be removed, cost signals to investors in larger unit size assets would be less rather than more accurate and cost savings from a simpler methodology are likely be minimal. Costs: ▪ Changes to Rules and settlement systems might cost between \$0.1m and \$0.3m, depending on option. ▪ If an event based market were to be developed that would involve extra design/ implementation and ongoing costs (perhaps \$0.5m and \$0.1m respectively).
Indicative lower NPV	The NPV could be very low or negative under the lower bound assumptions.

Other evaluation criteria (Review under-frequency cost allocation arrangements)	
Complexity	Depends on chosen design, but options are generally expected to be of low to moderate complexity.
Implementation Costs	Depends on chosen design, but some options would require settlement software changes. Designing and developing an event based marker could involve significant cost.
Ongoing Costs	Calculating settlements each month could be similar to or more costly than now depending on the chosen design. Administering an event market could involve significant costs.
Dependencies	If very fast load control is predominantly from water heaters (Option F 6.1) and this can be shown to have a negligible interruption cost, the administered event charge could be lowered or eliminated.

Overall assessment (Review under-frequency cost allocation arrangements)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
\$0m to \$2m	Low - Mod	Low-Mod	Low to Mod	Option F6.1

F4.1 Consider barriers to some forms of frequency reserves

Outline

57. This option would involve investigating whether there are barriers to contracting for new or existing forms of reserves, in particular:

    a. Are there inefficient barriers to long term investment/ contracting options? e.g. a pumped storage scheme.

    b. Are there disincentives to make products available? e.g. transmission peak demand charges deterring generators offering tail water depressed services (TWD).

Nature of benefits (Barriers to some forms of frequency reserves)	
Competition	If inefficient market or contracting barriers for some forms of frequency reserves can be lowered, enhanced competition might result, lowering overall procurement costs.

Nature of issues (Barriers to some forms of frequency reserves)	
Procurement framework	In principle, investors could offer long term contract options now. However, the current contracting framework is relatively short term (half hourly reserves market, annual frequency keeping). An framework would need to be developed to compare short term and long term procurement options.
Long term risks	In the short to medium term, there appears to be considerable scope for other lower cost frequency development options to strand long term investment options (conversely, contracting for long term investments at this time may deter less costly/ more beneficial options).
Conflicting incentives	Incentives to make services available may be weakened by other commercial drivers (e.g. peak transmission demand charges may deter generator TWD offers; multiple applications of interruptible load).
Certainty vs compliance costs	Seeking greater certainty about the availability and performance of ancillary services can impose/ reduce compliance costs on providers, reducing services offered/ increasing costs. The converse can also occur.

Multiple applications	It may be difficult for some capacity to compete efficiently – e.g. for interruptible load (network management, AUFLS, instantaneous reserves, peak demand management, energy price response) and generation capacity (frequency keeping not co-optimised with energy and instantaneous reserves).

Indicative assessment

58. It is considered unwise at this stage to attempt estimating the potential benefits of long term contracting options on a standalone basis because of the considerable potential for other lower cost development options to undermine any benefits. Consideration of longer term contracting options and the development of a framework for evaluating long and short term procurement options should therefore be deferred until other lower cost development options have been implemented. For example, if the average cost of frequency keeping services could be lowered to even three times that in the NEM, the long run cost purpose built capacity, such as a pumped storage scheme, would need to be less than $7.50 per MWh to just break even[16].

59. In relation to possible disincentives to making frequency services available:

    a. The potential for peak transmission demand charges deterring TWD offers is to be considered under the Commission's transmission workstream.

    b. Potential enhancements to the co-optimisation of frequency keeping with energy and instantaneous reserves would be considered under option F1.3.

    c. The issue of multiple uses of load control is to be considered within Commission's load management and metering project which is currently developing information on the existing capability of the current load control systems.

    d. The issue of potential trade-offs between certainty/ provider compliance costs and implications for system security/ overall cost has been discussed at various times in reviewing the procurement plan. This is the purpose of the procurement planning process but any trade-offs will depend on the outcome of other development options. For example, increasing the number and/ or size of AUFLS blocks may make it more acceptable from a security perspective to relax compliance requirements for some services in order to reduce overall costs.

60. Accordingly, option F4.1 has not been evaluated further at this stage given its dependence on lower cost development options that could reduce the cost of frequency management, in particular F1.1, F1.2, F1.3, F2.1, F5.1, F6.1, F7.1, F7.2. The issue of compliance cost trade-offs should continue to be reviewed regularly within the procurement planning process.

[16] To make a commercial return at that price, the capital cost would need to be less than $250 per KW assuming depreciation over 30 years, operating and maintenance costs of around $20 kW pa, and a post tax real discount rate of 8%.

F5.1 Dispatch enhancements for managing frequency/ reducing costs

Outline

61. This would involve considering mechanisms and/ or incentives to improve dispatch efficiency and dispatch compliance. Options include any or all of the following:

    a. Improving demand/ wind forecasts.

    b. Requirements to notify the system operator of significant short term changes in demand and generation.

    c. Technical limits/ ramp rates for demand and intermittent generation.

    d. Penalties/ payments for dispatch compliance.

    e. Improving systems to better coordinate generator responses to dispatch instructions (including considering benefits of using an AGC-style system for both dispatch and frequency).

Nature of benefits (Dispatch enhancements for managing frequency/ reducing costs)	
Reduce costs	Smaller frequency keeping requirements and therefore lower procurement costs.

Nature of issues (Dispatch enhancements for managing frequency/ reducing costs)	
Evaluation	How to establish relative merits of better forecasting, shorter dispatch intervals, reducing times for issuing and implementing dispatch instructions and overall compliance with dispatch instructions? How much do random outages, small trips, start ups/ shutdowns (and in future intermittent wind) contribute to frequency keeping requirements? What could readily be done now to improve overall dispatch effectiveness within current arrangements? To what extent would an integrated AGC system for dispatch and frequency keeping assist? Would improved frequency keeping (e.g. options F1.1 to F1.3) be enough?
Compliance issues	Need to ensure that any incentives for dispatch compliance do not interfere with need for generators to automatically support frequency.

Indicative Assessment

Potential upper NPV bound (Dispatch enhancements for managing frequency/ reducing costs)	
Background	Improved forecasting, dispatching more frequently and better compliance with dispatch instructions might reduce frequency keeping requirements. However, some frequency keeping would still be required to meet unpredictable demand/ wind changes, random events as above etc.
Estimate of costs/ benefits	Benefits: According to a small data sample collected from the system operator[17], the standard deviation for NI demand is ≈ 65MW and NI generation dispatch deviations ≈ 35 MW (it is not possible to apportion dispatch deviations between free governor action and dispatch compliance). ▪ The combined standard deviation is 74 MW. ▪ If dispatch deviations could be reduced by up to 50% (17.5MW), this would reduce the combined standard deviation by 10%. ▪ If frequency keeping costs could be reduced by 10%, this would result in savings of around $4.5m pa. Costs: ▪ These could be low if limited to changes to the Rules (assume $0.2m).
Indicative upper NPV	Based on these assumptions the NPV (upper bound) is about $34m.

Potential lower NPV bound (Dispatch enhancements for managing frequency/ reducing costs)	
Background	If dispatch deviations are significantly less than short term demand/ wind variations and they are unavoidable because of continual random events (e.g. line/ small generator/ load trips/ start ups/ shut downs etc) there may be no benefits.
Estimate of costs/ benefits	Benefits: ▪ Zero Costs: ▪ These could be very high if extensive system changes are required (eg for an AGC-style dispatch and frequency management system).
Indicative lower NPV	Based on these assumptions the NPV (lower bound) could be zero or negative.

17 Used in preparing the "Current Arrangements" paper in Appendix 1.

Other evaluation criteria (Dispatch enhancements for managing frequency/ reducing costs)	
Complexity	Deciding: Moderate (need to analyse scope for improvements in current process or improving forecasting, reducing dispatch intervals, improving dispatch compliance). Implementing: Low (if minimal change) to Mod (if rule/ process changes).
Implementation Costs	Low (if simple rule or other changes can be made which improve the current process) to high (if extensive system/ process/ rule changes are required).
Ongoing Costs	Low to moderate, depending on nature and extent of compliance costs.
Dependencies	Implementing an AFC system (option F1.1) and/or co-optimising frequency keeping with energy and instantaneous reserves (option F1.3) would improve dispatch compliance. If reallocating frequency keeping costs (option F3.1) would change behaviours, this would reduce benefits.

Overall assessment (Dispatch enhancements for managing frequency/ reducing costs)				
Indicative NPV (standalone)	Complexity	Costs		***Dependencies***
		Implement	Ongoing	
$0-$34m	Low-Mod	Low-High	Low-Mod	Options F1.1, F1.3, F3.1

F6.1 Consider extending use of load control for frequency management

Outline

62. This option would investigate distributed staggered frequency-based control of thermal loads (water heaters, air conditioners etc) to help manage frequency and to reduce quantities of instantaneous reserves (and possibly frequency regulating reserves) procured by the system operator. For example, it is understood that around 250,000 existing domestic water heating control relays are able to be triggered at adjustable frequency settings.

Nature of benefits (Extending use of load control for frequency management)	
Technical performance	Could enable water heating (and potentially other) load to be tripped earlier (in a graduated manner) as the frequency drops. Could increase the total load response (IL & AUFLS) to under frequency events. May be feasible to reduce frequency keeping requirements if relays fitted can respond to both low and high frequencies.
Costs	Could replace some direct instantaneous reserve procurement at AUFLS (indirect) cost. May also be possible to reduce frequency keeping procurement if feasible for frequency control purposes.

Nature of issues (Extending use of load control for frequency management)	
Technical	Evaluating/ monitoring how much controllable load can be relied upon: • At different times of the day and under different supply and demand scenarios (e.g. high spot prices). • Competing uses (e.g. interactions with ripple peak load management and AUFLS). • How much can frequency keeping and instantaneous reserves quantities be reduced as a result? There is an opportunity to provide input to the Commission's Load Management Project on these issues[18]. Is load control as described a technically feasible option for keeping normal frequency (including trip/ restore settings to avoid system "hunting"/ instability).
Design	Should mandated or commercial procurement options be considered ($/relay, $/relay/yr)? Mechanisms for mandating/ setting relays/ compliance?

18 In particular the Existing Capabilities Working Panel and Value/Price Working Panel

Indicative Assessment

Potential upper NPV bound (Extending use of load control for frequency management)	
Background	It may be possible to increase frequency controllable load by several hundred MW (e.g. replacing old relays, fitting relays to air conditioning, refrigeration loads).
Estimate of costs/ benefits	Benefits: ▪ It might be possible to substantially reduce instantaneous reserves procurement except when the extended contingent event (ECE) binds.[19] e.g. if the ECE is not binding for 85% of the time it may be possible to reduce instantaneous reserves costs by around $13.5m annually[20]. ▪ Might also be additional benefits from reduced frequency keeping if additional frequency control capability exists but this has been excluded because of the uncertain nature of the extra costs and benefits. ▪ The above would represent NPV (upper bound) benefits of around $74m (based on using existing relays now and phasing in additional relays over 10 years). Costs: ▪ Assume $5/ relay reprogramming cost for existing 250k relays with frequency trip capability, and $40 incremental cost to add frequency trip capability when 500k other relays are replaced. ▪ Approximately $1.3m upfront plus NPV $13.8m over time as remaining units are replaced. ▪ Ignore ongoing compliance costs.
Indicative upper NPV	Overall NPV benefit (upper bound) of around $60m.

19 (Earlier) frequency based tripping of hot water load that is currently part of AUFLS would reduce instantaneous reserves procurement for single contingency cover but would increase the proportion of time the ECE binds.

20 Roughly based on saving 80% of average instantaneous reserves procurement costs ($17m pa) for 85% of the time.

Potential lower NPV bound (Extending use of load control for frequency management)	
Background	Around 250,000 existing hot water control relays have frequency trip capability, which could provide >100MW of additional controllable load at peak times (possibly more off-peak).
Estimate of costs/ benefits	Benefits: ▪ Might reduce instantaneous reserves procurement by 30% when the ECE is not binding ($5m pa savings). Costs: ▪ Assume average reprogramming cost of $1.3m (250k existing relays at around $5 per relay).
Indicative lower NPV	Overall NPV benefit (lower bound) of around $40m.

Other evaluation criteria (Extending use of load control for frequency management)	
Complexity	Technically feasible to install and set relays. Technical difficulties estimating total controllable load that can be relied on. Commercial and/or compliance issues given service distributed over large number of loads.
Implementation Costs	Requires reprogramming relays with existing capability, installing frequency relays when existing ripple relays need to be replaced, installing new relays for larger thermal loads.
Ongoing Costs	Low ongoing costs to users. System operator would need to be able to monitor level and performance of controlled load.
Dependencies	May require extra safety margin and/or extra AUFLS to avoid increasing risk of system collapse (option F7.1).

Overall preliminary (Extending use of load control for frequency management)

Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$40m - $60m	Low - Mod	High	Low	Option F7.1

F7.1 Review under-frequency arrangements to ensure optimal for NZ

Outline

63. This option would involve a detailed review of under-frequency arrangements, including picking up on earlier FSWG recommendations. For example:

    a. Reviewing the under frequency limits in both the North and South Islands.

    b. Reviewing the minimum frequency envelope (including the minimum time generating units must remain connected and maintain pre-event output).

    c. Reviewing the size and/ or number of AUFLS blocks.

    d. Accounting for off-grid generation.

    e. Reviewing the under-frequency contingency events specifically covered by mitigation measures such as instantaneous reserves and AUFLS.

    f. Assessing the optimality of the current 48Hz limit for single contingency events, relay settings for interruptible load and units in tail-water depressed mode, AUFLS settings etc.

Nature of benefits (Review under-frequency arrangements to ensure optimal for NZ)	
Certainty/ reliability	Greater certainty about system integrity during major under-frequency events and which events are covered. More AUFLS would lessen concern about accounting for free reserve and unexpected multiple contingency events.
Costs	Potential to reduce overall under-frequency management costs (e.g. optimising instantaneous reserve/AUFLS arrangements). More AUFLS would lessen concern about accounting for free reserve and reduce instantaneous reserve costs (including option F7.2). Smaller blocks of AUFLS would reduce the quantity and cost of load tripped following an event.
Dynamic efficiency	Providing greater certainty about technical requirements for new generation investments should enhance dynamic efficiency (e.g. low frequency limits and thermal investment in South Island; wind farm capabilities/ potential cost implications for system).

Nature of issues (Review under-frequency arrangements to ensure optimal for NZ)	
Design	If more emergency load shedding capability is required, would need to consider the relative merits of commercial procurement or mandated obligations and how to target lower value loads for higher (more frequently triggered) blocks. Rule/ regulatory changes, including AUFLS and other system policy/ procurement changes, dispensations etc will need to be addressed.
Economic trade-offs	Framework needed to decide which events should be covered by what measures/ instruments including how to value mandated measures, loss of load probability etc.
Technical	Uncertain whether current under frequency limits, including 45Hz minimum frequency, are limiting thermal investment in the South Island. Consideration of under-frequency limits and performance obligations in general should take wind technologies into account.
Complexity	Potentially complex analysis may be necessary. e.g. will the single contingency under-frequency limit (currently 48Hz) need to be reset to accommodate extra AUFLS blocks/ achieve discrimination (this could be considered alongside option F6.1 – extended load control).

Indicative Assessment

Potential upper NPV bound (Review under-frequency arrangements to ensure optimal for NZ)	
Background	Without undertaking the review it is very difficult to assess the potential benefits. Benefits would generally relate to improved security (e.g. greater cover for multiple contingency/ rare events, lower thermal generator risks, smaller AUFLS interruptions) and lower overall cost (for interruptions, dynamic efficiency re new investment).
Estimate of costs/ benefits	Benefits: ▪ Assume an extra 400MW of AUFLS could avoid the risk of system collapse due to under-frequency events: – assume a cost of $360m for system collapse ($40/kWh and average loss of 3,000 MW for 3 hours[21]); – additional AUFLS cost per event would be around $16m (based on $20 per kWh for 400MW for 2 hours); – if the current risk of system collapse[22] due to large scale under-frequency events is 1:100 years, and this could be avoided, that would provide an 'expected' benefit of $3.4m pa[23]; and – that is around $25m in NPV terms. ▪ If 200MW of extra instantaneous reserves necessary to cover the ECE binding 10% of time could be avoided, this would save around $0.9m pa (assuming roughly $5 per MWh consistent with annual procurement costs assumed in Table 4 for approximately 400MW average procurement) – that would represent an expected net benefit of approximately $6.5m in NPV terms. ▪ If with greater reliance on free reserves, instantaneous reserves procurement could be reduced by 20%, that would achieve savings of around $3.4m pa – that would represent an expected net benefit of approximately $25m in NPV terms. ▪ It is very difficult without undertaking the proposed review to assess expected additional benefits but some allowance should be made: – e.g. additional benefits could relate to more/smaller AUFLS blocks (greater discrimination and lower cost of interruptions) and new investment (e.g. lower thermal generator risks, lower SI thermal investment costs, economics of wind technologies); and – an indicative range could be $0 to $20m NPV (*although highly uncertain*).

21 The FSWG assumed a cost of $40 per kWh for system collapse.

22 The actual risk is difficult to quantify but these assumptions are considered representative.

Potential upper NPV bound (Review under-frequency arrangements to ensure optimal for NZ)	
	Costs: ▪ Assume it could cost up to $4m depending on requirements (e.g. number of additional AUFLS blocks and resetting existing blocks).
Indicative upper NPV	Overall NPV benefit (upper bound) of around $75m.

Potential lower NPV bound (Review under-frequency arrangements to ensure optimal for NZ)	
Background	A lower bound assessment would be similar to the above but using more conservative assumptions about likely benefits.
Estimate of costs/ benefits	Benefits: ▪ If the current risk of system collapse due to under-frequency events is significantly less, say around 1 in 500 years, and this option could eliminate that risk, the expected benefit would be around $0.7m pa[24] – that would represent an 'expected' net benefit of around $5m in NPV terms. ▪ Assume only 50% of the upper bound benefits relating to ECE cover and use of free reserves – that would represent an expected net benefit for these aspects combined of approximately $16m in NPV terms. ▪ Ignore any additional benefits. Costs: ▪ Assume it could cost up to $4m depending on requirements (e.g. number of additional AUFLS blocks and resetting existing blocks).
Indicative lower NPV	Overall NPV benefit (lower bound) of around $17m.

Other evaluation criteria (Review under-frequency arrangements to ensure optimal for NZ)	
Complexity	Would require technical & system studies, including new investment scenarios. AUFLS would be reasonably straightforward technically, but there would be some administrative complexity in assigning load to blocks.

23 ($360m - $16m)/ 100 years

24 Assuming an event cost of $360m and cost of additional AUFLS of $16m as before but with a probability of 1:500 years.

Other evaluation criteria (Review under-frequency arrangements to ensure optimal for NZ)	
Implementation Costs	If additional AUFLS blocks are required and existing AUFLS facilities need to be adjusted, could be a few $m. Any Rule changes likely to be non trivial, especially if involving commercial procurement arrangements.
Ongoing Costs	Ongoing net compliance costs should be relatively low (the benefits of administering any new commercial procurement arrangements vs mandated AUFLS would need to exceed compliance costs).
Dependencies	Technology issues relevant to wind study? May be benefits from combining with Option F6.1 (extend load control). May support Option F7.2 (national reserves market) - bipole & free reserves issues.

Overall assessment (Review under-frequency arrangements to ensure optimal for NZ)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$17m - $75m	Mod	Low-Mod	Low	Wind, Options F6.1, F7.1

F7.2 Develop a national instantaneous reserves market

Outline

64. This option would explicitly account for the export of instantaneous reserves from one island to the other via the HVDC. e.g. it would enable South Island reserves to compete commercially to contribute to North Island instantaneous reserves requirements. Changes to SPD and RMT models would be needed.

Nature of benefits (Develop a national instantaneous reserves market)	
Competition	There would be increased competition to supply North Island instantaneous reserves requirements.
Procurement needs	Accounting explicitly for so called free reserves via the HVDC should reduce North Island instantaneous reserves requirements. At times the same reserves could cover the risk requirements.

Nature of benefits (Develop a national instantaneous reserves market)	
Lower costs	While the value of South Island reserves would increase, North Island and overall instantaneous reserves procurement costs would potentially reduce.

Nature of issues (Develop a national instantaneous reserves market)	
Technical	Need to incorporate into SPD, although the system operator has presented a possible prototype design[25]. Need to account for risk of HVDC bipole trip in procuring instantaneous reserves requirements.
Reducing security buffer	RMT currently assumes only 25 MW of free reserves via the HVDC whereas in practice free reserves can be around 250MW. System frequency therefore tends to remain well above the 48Hz limit when the largest single contingency event occurs. The implications for system security of removing this buffer would need to be considered given other uncertainties (e.g. thermal generator low frequency issues, actual AUFLS amounts etc).

25 Refer http://www.esc.auckland.ac.nz/Epoc/workshop2006.html (presentation by Vladimir Krichtal, Transpower)

Indicative Assessment

Potential upper NPV bound (Develop a national instantaneous reserves market)	
Background	It is very difficult to assess the potential benefits. An upper bound estimate could be based on cost savings from South Island instantaneous reserves replacing North Island instantaneous reserves.
Estimate of costs/ benefits	Benefits: ▪ Assume 200MW of South Island reserves (similar to the average level of free reserves) could replace North Island reserves for 60% of the time. ▪ Assume South Island reserves would be up to $2 per MWh cheaper than displaced North Island reserves. ▪ This could generate savings of around $2m per year, or NPV benefits of around $16m. ▪ Transpower estimated net economic benefits of around $0.68m over 4 months of 2004 market data[26]. ▪ Assuming annual benefits of three times that amount (around $2m) this aligns with the above estimates. Costs: ▪ Assume $1m for upgrading systems (RMT, SPD etc) and negligible additional ongoing costs.
Indicative upper NPV	These assumptions suggest an upper bound NPV estimate of around $15m.

Potential lower NPV bound (Develop a national instantaneous reserves market)	
Background	It is possible that savings may be less due to interactions between South and North Island reserve markets leading to new market equilibriums.
Estimate of costs/ benefits	Benefits: ▪ Assume only half of the upper bound benefits are realised, around $1m pa or NPV of approximately $7.5m. Costs: ▪ Assume $1m for upgrading systems (RMT, SPD etc) and negligible additional ongoing costs.
Indicative lower NPV	These assumptions suggest a lower bound NPV estimate of around $6m.

26 http://www.esc.auckland.ac.nz/Epoc/workshop2006.html

Other evaluation criteria (Develop a national instantaneous reserves market)	
Complexity	Modelling changes are likely to be relatively complex although Transpower has previously presented a prototype design (refer footnote 25).
Implementation Costs	Could be significant, perhaps of the order of $1m, although it is possible that prototype work presented by Transpower and the system operator's market systems project may help. Some changes to pricing and settlement systems may be required.
Ongoing Costs	Low – no significant ongoing changes have been identified.
Dependencies	In addressing issues such as free reserves, Option F7.1 (review under-frequency arrangements) would support this option. It is possibly a pre-requisite.

Overall preliminary assessment (Develop a national instantaneous reserves market)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$6m - $15m	Moderate	Moderate	Low	Option F7.1

Voltage Development

Overview of current arrangements

65. Unlike frequency, for which there is a specific system operator primary performance obligation (PPO), nominal and actual voltage levels vary across the grid. However, both voltage and frequency management are critical inputs to the system operator's other PPO - to avoid cascade failure of assets leading to loss of supply. In this regard, grid voltages must be managed so that:

    a. Assets are operated within their safe voltage range to avoid tripping, or damage, and loss of supply.

    b. Voltage collapse does not occur following a contingent event leading to uncontrolled loss of supply.

66. Many factors influence voltage levels over time, by location and dynamically. For example, the level and nature (real and reactive components) of loads, generation and grid flows, transmission asset characteristics etc.

67. In addition to its importance in maintaining security of supply, voltage management can also reduce reactive power flows around the grid. This can reduce losses and potentially alleviate transmission constraints.

68. Current arrangements relating to voltage management are based on the system operator:

    a. Operating the system within mandated asset voltage ranges for grid, distributors & generators.

        – Subject to dispensations, distributor and directly connected consumer and generator equipment must be capable of operating when specified grid voltages are within mandated ranges.

    b. Dispatching generation and transmission assets made available to it, including:

        – use of mandated generator reactive support capabilities;

        – use of grid owner equipment (tap changers, capacitors, synchronous condensers, SVCs etc); and

        – constraining energy dispatch if necessary.

    c. Procuring voltage support services if necessary (approx $3-4m pa):

        – contracts in the Auckland region for several years (1 – 3 years); and

        – contract in upper South Island for 2005/6 summer (3- 6 month).

d. As a last resort, relying on emergency management provisions:

- it issues warning notices or grid emergency notices including actions relevant participants can take to assist;
- it instructs disconnection of load if necessary to avoid voltage collapse, regional loss of load; and
- if extreme limits reached, asset owners are to take independent automatic action to support and restore voltage.

69. The costs of voltage support services procured by the system operator within a procurement zone are recovered from distributors and direct connect consumers that zone:

a. The Rules currently specify four zones[27]:

Zone	***1***	***2***	***3***	***4***
Approximate region	North of Huntly	Rest of North Island	North of Christchurch	Rest of South Island

b. Within a procurement zone, distributors, and consumers connected directly to the grid, nominate peak kvar demand at grid off-takes. They pay peak kvar charges (and a penalty rate if they exceed the nominated peak kvar).

c. Residual procurement costs (over/ under-recovery) are reallocated to distributors according to kWh. This is intended to reward better peak demand power factor.

70. Indirect procurement of voltage support also occurs in the form of:

a. Mandated generator reactive performance requirements and grid owner kvar investments (capacitors etc).

b. Any peak power factor improvements that result in zones where the peak kvar pricing regime is active.

c. Any demand response that results from higher local energy prices as a result of voltage security constraints applied to SPD binding.

71. Finally, where an asset owner cannot comply with technical obligations relating to voltage, it can apply to the system operator for a dispensation or approval of an equivalence arrangement. In relation to a dispensation from reactive obligations, a generator is required to pay the kvar charge if procurement is required in its zone.

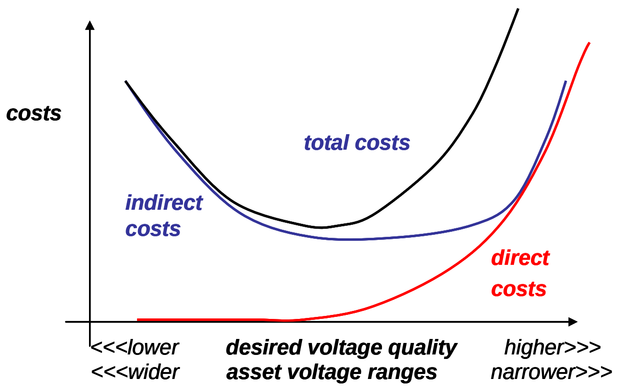
27 The procurement and cost allocation regime is only active in zone 3 (for summer 2005/6) and zone 1.

72. More detailed discussion of current voltage management arrangements can be found in section 3 of the Current Arrangements paper.

Voltage management issues

73. Following a similar approach as described previously for frequency, Figure 12 summarises factors that contribute to or limit voltage problems, direct and indirect cost components and the levers that are available to minimise overall costs.

Figure 12: Minimising Direct and Indirect Costs of Voltage Management



Direct Costs

- *cost of procuring voltage support ancillary services*

Indirect Costs

- *customer costs*
- *losses*
- *emergency demand reductions*
- *asset owner compliance costs*
- *new grid owner equipment costs*
- *limits on new technology*
- *distorted investment choice*
- *impact on energy market*
- *implementation, overhead & transaction costs*

What contributes to voltage problems?

- *reactive power flows on the grid:*
  - *off-take reactive flows/ p.f.*
  - *grid equipment reactance*
  - *loads a long way from generation*
- *asset owner non-compliance*
- *generator/ line/ load outages*
- *local voltage constraints on grid operation*

What limits voltage problems?

- *generator excitation/ tap changers/ MW dispatch*
- *grid owner tap changers, var compensating equipment*
- *off-take power factor (note poor PF at low load can avoid over voltage)*
- *voltage support ancillary services*
- *demand management*
- *new investment in generation and transmission*

What can be done?

- *change obligations*
- *change procurement*
- *better coordination systems*
- *better price signals (cost allocation)*
- *better independent action (e.g. automated systems)*

74. The chart in Figure 12 is a stylised illustration of the manner in which direct and indirect costs will vary as voltage quality requirements are tightened or relaxed. If voltage range and quality requirements are made very tight, additional direct costs (for voltage management) and indirect costs (for greater investment in grid assets) will be incurred. If requirements are relaxed too much, direct procurement costs will fall but indirect costs will rise, ultimately excessively.

75. In practice, while it is difficult to assess the arrangements that would optimise the overall level of direct and indirect costs associated with voltage management, the above framework is a useful means of considering the nature and potential level of impacts. In this regard, and taking into account the current voltage management arrangements described in detail in section 3 of the Current Arrangements paper, the following issues relating to voltage management have been identified.

Investment & procurement accountabilities & timeframes

76. At present, if additional reactive support capability is needed in a region, this could be procured through part F (transmission investment) or part C (ancillary services) arrangements as depicted in Table 5.

Table 5: Part F and C procurement/ cost recovery

Element	*Part F*	*Part C*
Procurement	Transpower (as grid owner) can install reactive support equipment (capacitors, SVCs etc).	The system operator procures 6 month to 3 year ancillary support contracts within the annual procurement process.
Recovery of costs	For investments approved by the Commission, Transpower can recover costs from connected parties through transmission charges.	System operator procurement costs are recovered from distributors and directly connected consumers in the relevant zone through the kvar charging regime.

77. If the system operator procurement were to include long term contracts (e.g. for 5 to 10 years+):

   a. Would participants invest in reactive/voltage support capability to provide services to the system operator?

   b. Could all forms of reactive support, including grid owner, compete in procurement/tendering process?

78. But unclear how to ensure:

   a. Competition between potential providers?

   b. Choices between grid investment & voltage support service procurement?

Short term procurement trade-offs

79. The system operator in principle has a number of options available for short-term voltage support procurement as summarised in Table 6:

Table 6: Short Term procurement Trade-offs

Element	*Approach*	*Costs*	*Cost allocation*
Contracts	System operator procures voltage support contracts ▪ eg upper South Island generation, upper North Island synchronous compensation.	Certainty about availability and costs.	Costs recovered through zonal kvar pricing regime.
System Operator constrained-on	System operator constrains-on offered generation for voltage support/ security reasons.	Energy prices unaffected, no direct demand signal.	Costs “attributable to system operator” (part G of Rules). System operator has had difficulty recovering these costs (without contracts).
Market constrained on	Security constraints applied to SPD. SPD dispatches offered generation.	Local energy price rise, strong demand signal.	Costs met through energy prices (no SO constrained-on costs).
Emergency Measures	System operator *warning & emergency notices.* ▪ Request participant actions. ▪ Instruct demand reduction. Independent participant emergency actions.	Energy prices may be high (depending on cause) but fall due to emergency measures.	Costs lie where they fall.

80. The trade-offs implied in each case are different and raise some potentially complex questions. For example:

a. How should these trade-offs be made in practice?

b. What are the demand side implications?

c. Is there a role for commercial contracting for demand response[28]?

Pricing arrangements

81. Currently, the system operator sets peak kvar prices in zone 1 and, recently, in zone 3. It sets a $ per kvar rate in each procurement zone which is designed to recover its projected voltage support procurement costs within the zone. Distributors and any direct connect consumers in the relevant zone pay this rate for peak kvar demand at each grid off-take connection. They pay a penalty rate for kavr in excess of their nominated peak kvar demand at each grid off-take connection.

82. Whereas peak kvar rates are currently set so as to recover estimated voltage procurement costs:

    a. The original intent was that peak kvar prices within a zone would reflect the marginal cost of system operator procurement. i.e. the price of the most expensive contract in the zone procured through the system operator's tender process.

    b. This would enable connected parties to directly trade-off the cost of central procurement against the actions they can take to improve power factor.

    c. This results in over- or under-recovery of actual voltage support procurement costs within a zone. Residual over/ under costs are therefore reallocated to off-takes within zone on a per kWh basis. This rewards good power factor.

83. Potential issues arising from current arrangements include:

    a. Should zonal kvar prices be set at the marginal cost of procuring static capacitors when there are voltage problems to ensure that local power factor correction measures can compete with (and reduce/ avoid the need for) central procurement of reactive support services? i.e. rather than being set (lower) so as to recover estimated procurement costs.

    b. Should zonal kvar prices be set to zero – or a low nominal level – in zones where there are no voltage problems?

    c. Should kvar prices ramp up in a zone in anticipation of voltage problems emerging? Or step change?

    d. Should zonal kvar prices be replaced by, or supplemented with, mandated power factor requirements?

Products

84. There are two generic forms of voltage support – static and dynamic:

[28] Vector has suggested that voltage procurement options should include demand-side participation

a. Static reactive support (e.g. using capacitor banks) is an important aspect of managing steady state reactive power flows and voltage levels. Poor peak demand power factor can increase static support requirements. In this regard, local power factor improvement measures are also a form of reactive support.

b. Dynamic reactive support provides insurance against voltage collapse during contingent events. i.e. fast acting reactive reserves can cover loss of transmission or generation capacity that could lead to voltage collapse and loss of supply. Dynamic reactive support "capability" can be provided by SVCs, generators, synchronous compensation and load management.

85. There may be scope to reduce overall voltage support costs by improving the way these services are delineated in terms of how they are specified, contracted and priced.

Definition of kvar pricing zones

86. The kvar pricing regime is intended to signal when and where procurement of voltage support services is required. It is intended to:

a. Encourage power factor improvements and generator compliance with reactive obligations.

b. Reduce requirements for central procurement of voltage support services.

87. At present, kvar procurement zones can only be altered or created through the formal rule change process. If zones are poorly defined, they will not efficiently target kvar problems:

a. For example, as currently defined, zone 3 is much larger than the upper and top of South Island problem areas. This dilutes kvar signals in these regions (understating the cost of poor power factor).

b. Combined with weak kvar prices, discussed previously, the kvar pricing regime will therefore be of limited effect.

c. It has been suggested that mandating power factor requirements may be a better approach. However, that would risk problems and would also need to be well targeted. For example, it could result in additional distributor (consumer) costs to achieve compliance for no gain. In some instances, poor power factor at times of low demand can actually assist voltage management.

88. How and where to define zones to effectively target power factor improvement and minimise overall costs, including for reactive procurement, warrants consideration.

Consistency in mandating standards

89. Mandating technical performance obligations can be a low cost means of obtaining voltage support services. For example, the capability to export or import reactive power is a standard feature of synchronous generators. However, not all generators are identical and different standards imply different costs. How reactive standards and applied to other participants, or not, can also have cost/ efficiency implications. In this regard, some interesting aspects of the current arrangements are highlighted in Table 7:

Table 7: Current approach to off-takes and injection

Element	*Generators*	*Distributors/ Direct Consumers*
Mandated kvar standards	Required to comply with part C reactive obligations.	No power factor obligations in part C of the Rules.
		But may be included in transmission connection codes being developed accordance with part F of the Rules?
Non compliance	May apply to system operator for a dispensation or equivalence arrangement if unable to comply.	Not applicable in relation to part C; unclear how/ if connection contracts would enforce compliance?
Incentives	May face kvar price for reactive non compliance (if procurement required in zone). No direct part C incentive to invest in or make available more than mandated reactive capability.	Pay peak kvar price if voltage support needs to be procured in the zone, and penalty kvar price for any kvar in excess of nominated peak.

90. These differences and potential inconsistencies raise a number of questions including:

    a. Should market arrangements for power factor and reactive requirements be extended?

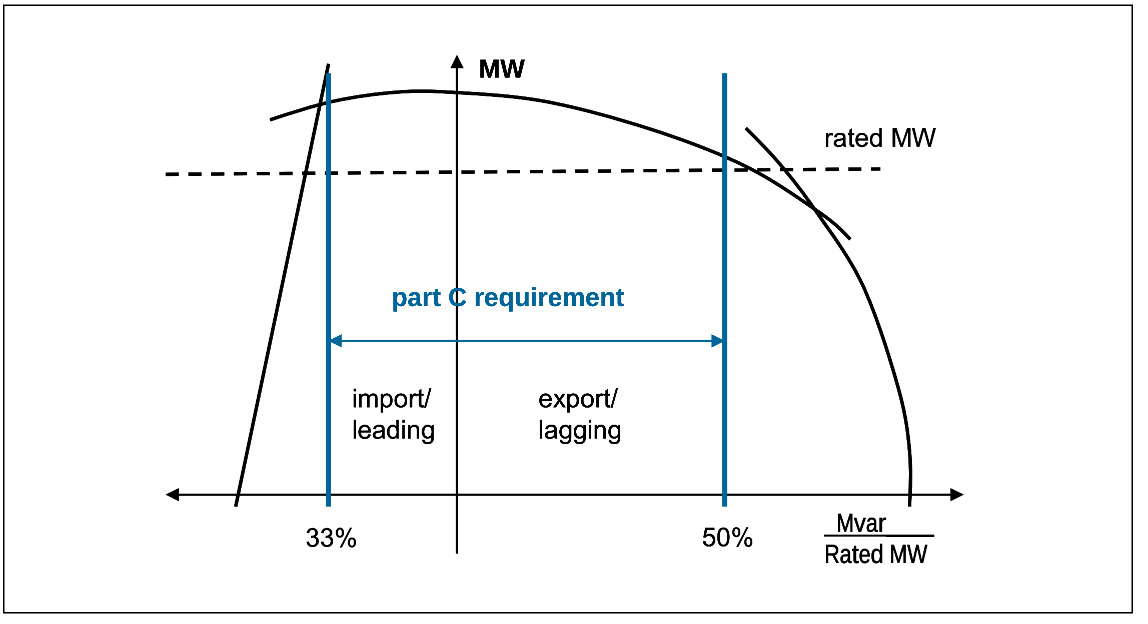
    b. Should generation and off-take power factor / reactive requirements be mandated?

    c. What are the efficiency/ cost implications of applying different approaches in connection code (under part F) and part C requirements?

Mandated generator standards

91. By design, synchronise generators provide reactive support regulation capability and are a low cost source of kvar. However, not all generators are identical. As illustrated in Figure 13, generator kvar requirements are specified in simplified form, at generator terminals, in part C of the Rules.

Figure 13: Part C generator reactive capability obligations



92. Two implications of this approach to specifying requirements are that:

    a. Non-compliant generators may have to pay for kvar shortfalls (through dispensation or equivalence arrangements in zones where voltage support procurement is required).

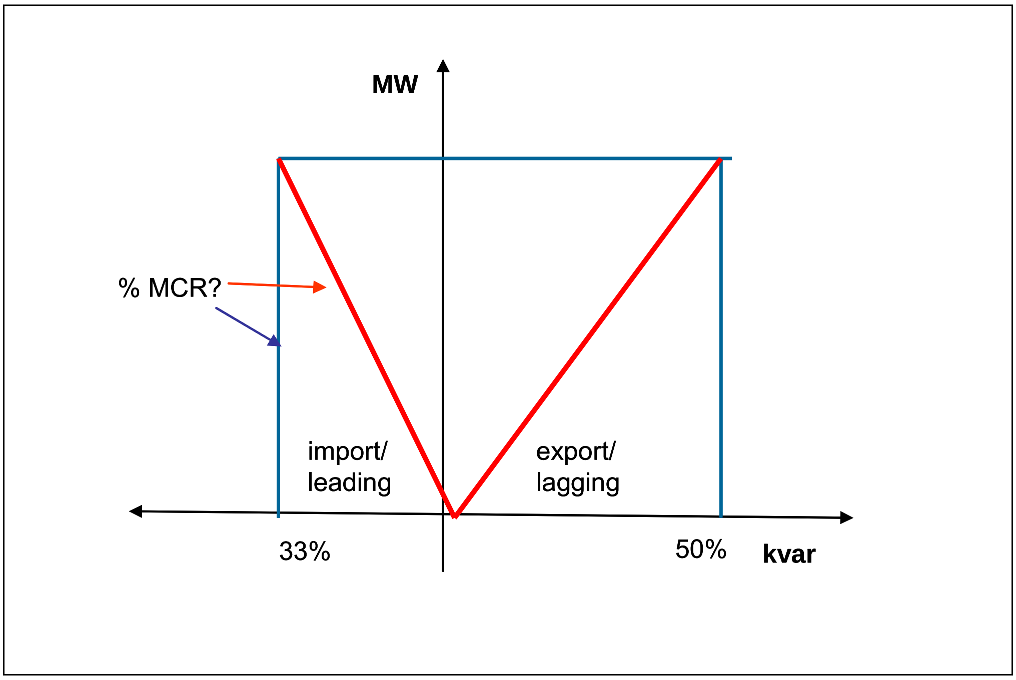
    b. There are no direct incentives to make extra kvar capability available to the system operator.

93. Compliance cost for some generation technologies can be significant:

    a. The equivalence and dispensation regimes are intended to allow generators to make investment/ design trade-offs.

    b. Alternative interpretations of part C generator reactive requirements have been debated with regard to wind as in Figure 14.

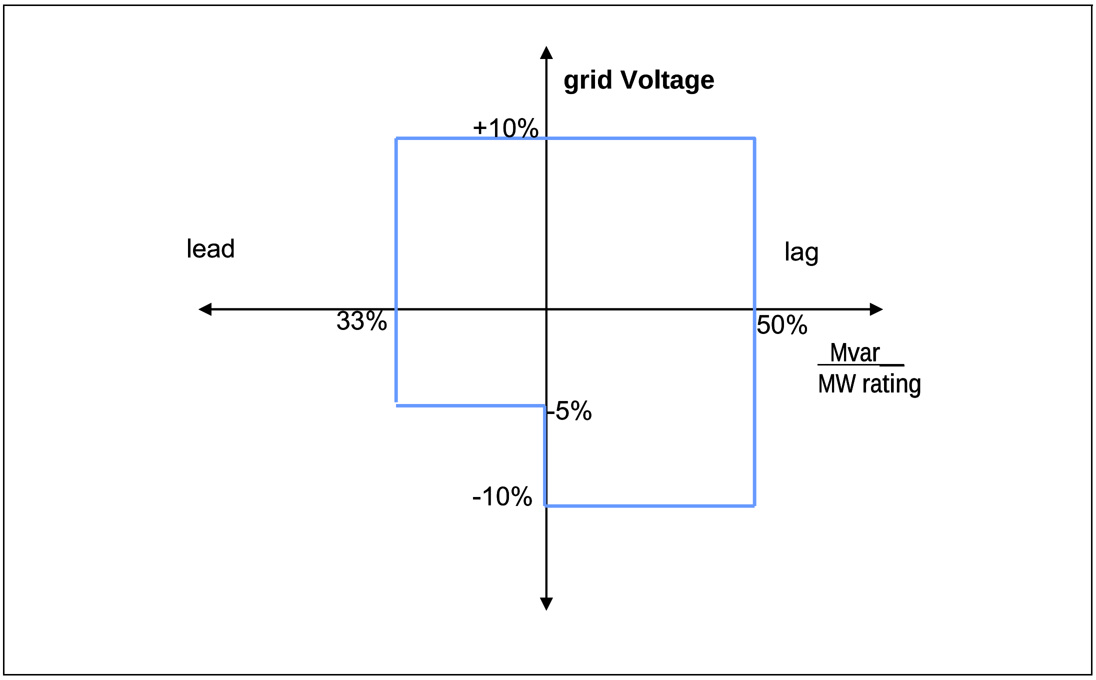
Figure 14: Alternative interpretation of MCR for wind generation kvar requirement



c. There are potential adverse economic efficiency implications for competion between new investments if costs are not signalled properly.

94. There is also a significant level of generator non-compliance with the reactive support voltage range indicated in Figure 15 (especially where OLTCs[29] do not exist).

Figure 15: Part C generator reactive support voltage range requirement



29 On line (or on load) tap changer.

95. These issues raise questions about whether:

a. Generator reactive/ voltage obligations can be revised to reduce overall voltage support costs (including transaction costs).

b. Signals to investors and plant owners can be enhanced (through improved standards and/or pricing arrangements).

Voltage and dispatch

96. Reactive power flows on the grid affect overall current levels. Higher levels of reactive power flow, and corresonding current flows, result in greater transmission losses, reduces constraint margins and impacts on voltage profiles across the grid, influencing the risk of grid voltage collapse. From a system operation perspective:

a. These interactions can be complex to evaluate and manage.

b. SPD, the market dispatch and pricing engine, uses a simplified dc representation of the power system. SPD cannot explicitly account for voltage profiles in scheduling and dispatching energy. The risk of voltage collapse can be accounted for indirectly via the application of generic security constraints to SPD.

97. There may be opportunities to operate and dispatch the system to enhance voltage management. For example:

a. Can grid elements be operated at slightly higher voltage to reduce reactive power flows (losses and possibly alleviate voltage constraints)?

b. Are there dispatch tools/ systems that would assist the system operator to optimise voltage profiles for security purposes while minimising losses and alleviating constraints? For example, would there be benefits in making constrained off payments to access extra generator reactive capacity?

Voltage range constraints on system operation

98. Dating back to development of the current part C arrangements, there are suggestions that lack of on-line tap changers (OLTCs) on transformers in some locations around the grid constrains system operation. e.g. the voltage range over which the system operator is able to manage the core grid may be constrained due to historical voltage range requirements at some grid connections. If this is correct, then installing OLTCs (which in practice probably means replacing existing transformers) in some critical locations would provide more operating voltage flexibility on the core grid. This is a relatively complex issue and a number of aspects would need to be worked through:

a. Are there in fact potential net benefits (for example due to reduced losses and/ or better voltage profiles for security management) from upgrading certain transformers? Would these benefits justify the cost of upgrading transformers?

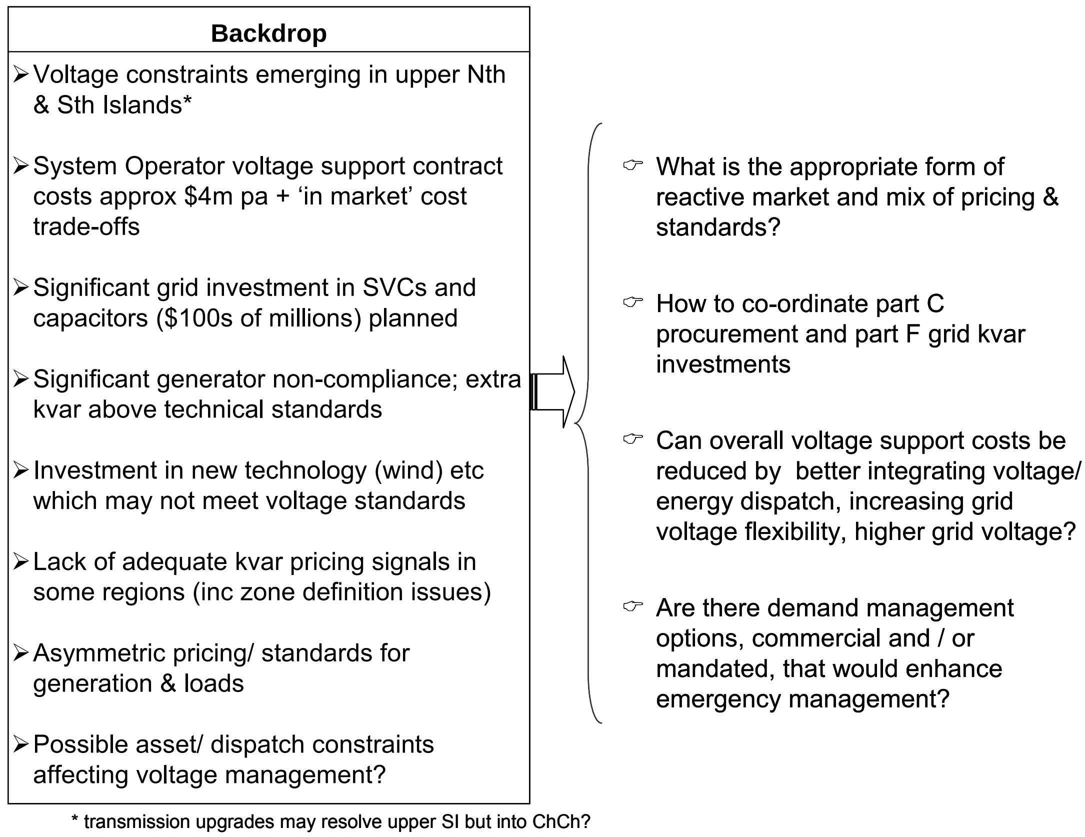
b. Who should pay? To the extent there would be benefits, these would be collective, extending beyond parties connected at the specific grid connection points involved.

99. This issue has relevance to part C/ system operation. However, it is more properly characterised as a part F (grid investment) issue with system operation/ part C implications.

Voltage Development - Areas for Strategic Focus

100. Consideration of the above issues, in conjunction with current arrangements described in Appendix 1, as illustrated in Figure 16, suggests four broad areas for voltage development options. i.e. areas of focus in relation to the overall objective of “minimising the sum of direct and indirect cost associated with voltage management to deliver net present public benefits over time”.

Figure 16: Broad areas for voltage development



Possible Strategic Voltage Initiatives and Options

101. The strategic focus areas outlined in Figure 16 were used to consider potential voltage development options from the range of possibilities identified in conjunction with the CQAG. (As for frequency development, that exercise included common quality development workshops, research relating to arrangements and developments in other countries and reports from various GSC working groups).

102. In relation to voltage development, the areas of strategic focus map relatively neatly into the development initiatives set out in Table 8.

Table 8: Possible Voltage Development Initiatives and Options

Initiative	*Option*
V1 Appropriate form of reactive market.	V1.1 Design efficient technical standards. V1.2 Enhance kvar pricing. V1.3 Improve targeting of problem areas. V1.4 Enhance kvar procurement/ contracting arrangements.
V2 Co-ordination of part C procurement & part F grid kvar investments.	V2.1 Ensure that part C procurement and grid kvar investments can compete to minimise voltage support costs over time.
V3 Voltage flexibility & integration with dispatch.	V3.1 Investigate potential benefits of increasing average grid voltages (within nominal ranges) and OLTC investments to increase grid voltage flexibility. V3.2 Investigate how to trade-off kvar procurement options versus SPD security constraints.
V4 Enhance load control/ emergency response.	V4.1 Review emergency arrangements relating to voltage management, including the role of load management.

Evaluation of Voltage Options

Initiative V1: Appropriate form of reactive market

103. Because options V1.1 to V1.4 are closely inter-related, and elements of each already exist, they are collectively considered in the following as initiative V1.

Outline

104. This initiative would involve considering the mix and form of technical standards, pricing, zones and procurement arrangements that are appropriate for a reactive power market in the NZ context:

   a. Option V1.1: Design efficient technical standards: designing appropriate reactive power and power factor standards for generators and grid off-take connections.

   b. Option V1.2: Enhance kvar pricing**:** defining a default kvar pricing methodology to incentivise power factor improvement and generator kvar contributions to reduce central voltage support procurement needs.

   c. Option V1.3: Improve targeting of problem areas: defining kvar zones so that problem regions of the grid can be accurately targeted.

   d. Option V1.4: Enhance kvar procurement and contracting arrangements: developing a framework for contracting voltage support enhanced services (e.g. reactive reserves, load management).

Nature of benefits (Appropriate form of reactive market)	
Efficient investment	Appropriately designed technical standards should ensure investment in low cost reactive support and low cost peak power factor improvement options (e.g. generator kvar capability, capacitors on motors etc). Generation investors would have incentives to invest in extra reactive capability / and to avoid investing in technology which can't meet the standard in regions with voltage problems. Where there are system benefits, investors in technologies with better reactive capability would be rewarded.
Competing options	Power factor improvement and generator reactive capability should compete directly with central procurement options.
Minimising overall costs	Collectively these measures should minimise the overall costs of voltage support, including central procurement requirements, over time.

Technical standards issues

105. Mandating technical standards (performance obligations) is a means of ensuring low cost reactive/ voltage support services are available:

    a. kvar regulation is a standard capability for synchronous generators and is generally available at low cost.

    b. Improving poor power factor will often be a low cost alternative to central procurement (e.g. at end user level).

106. Setting nominal kvar requirement for all generators would:

    a. Signal to designers/ suppliers the need for kvar capability (& support international trends).

    b. Ensure investors would compare the long run cost of alternative developments on the same basis.

    c. Enable investors to trade-off non-compliance vs system costs through dispensations regime.

107. Setting a nominal peak power factor requirement would:

    a. Signal that poor peak off-take power factor can be detrimental to voltage management.

    b. Signal good practice to loads (compliance should generally be low cost and, as for base generator kvar capability, provides additional system benefits by reducing reactive flows/ losses).

    c. Enable distributors and directly connected consumers to trade-off the cost of non-compliance with system costs through dispensations and/ or market kvar pricing.

108. However, mandating *one size fits all* technical requirements can impose costs without benefits. It is therefore important that generators and loads can trade-off the cost of compliance with mandated technical standards against any extra system costs due to non-compliance. Options to achieve this include:

    a. The dispensations regime, with payments for any extra procurement due to a dispensation.

    b. Through a kvar market. For example, charges for *unders* (non-compliance) and payments for *overs* (capability above mandated requirements).

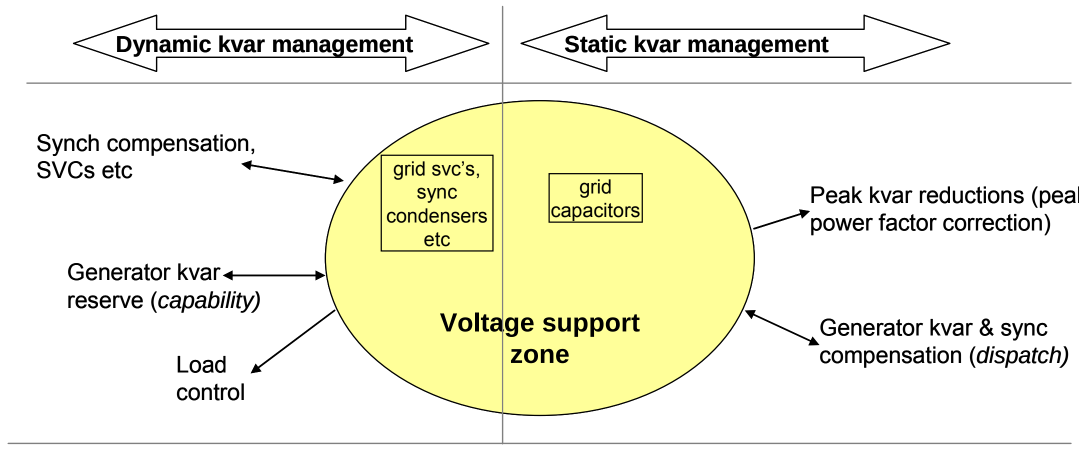
    c. Regional kvar pricing - zero (or low) in regions with no voltage problems.

109. In relation to kvar pricing, a number of issues would need to be considered as discussed in the following.

kvar pricing issues

110. Figure 17 illustrates the key components that contribute directly to physical kvar management on the grid[30]As illustrated, voltage management measures tend to be of a regional nature – hence the diagram is based around the concept of a voltage support zone. Static kvar management relates to steady state voltage management (for example, dispatch of generator reactive capability or switching of capacitor banks to maintain normal voltage levels). Dynamic kvar management relates to fast acting kvar 'capability' – analogous to instantaneous reserves. i.e. it is used to cover contingent events that would otherwise threaten voltage collapse.

Figure 17: kvar management arrangements



111. A kvar pricing regime would ideally reflect separately for dynamic and static sources the value (or cost) of contributions to kvar management within a zone, and be applied consistently across each form of kvar support. In this regard, a issues that would need to be considered include:

   a. Whether generator payments should be based on actual kvar (utilisation) or kvar availability (capability)?

   b. Whether off-takes and generators should pay/ be paid be for all kvar or overs/ unders relative to mandated requirements?

   c. Whether generator kvar prices should be based on estimated variable costs or cost of alternatives (capacitors etc)?

      – prices based on the costs of alternatives would clearly signal the value of kvar support in a problem zone;

      – at other times, when there is not a voltage problem, should the price fall to zero or a nominal operating cost?

   d. How to price normal (static) and fast reserves (dynamic) reactive support?

[30] Dispatch and grid characteristics etc affect kvar flows but the intent here is to illustrate specific kvar management measures to manage grid voltage / security levels given these other factors.

e. Should load be contracted as a form of dynamic support?

f. What to do about residual over or under cost recovery? As residual sums could be large, marginal incentives could be distorted/ diluted significantly if the reallocation of any residual amounts is inappropriate.

g. How to value reactive contributions from one zone to another?

Default generator standards

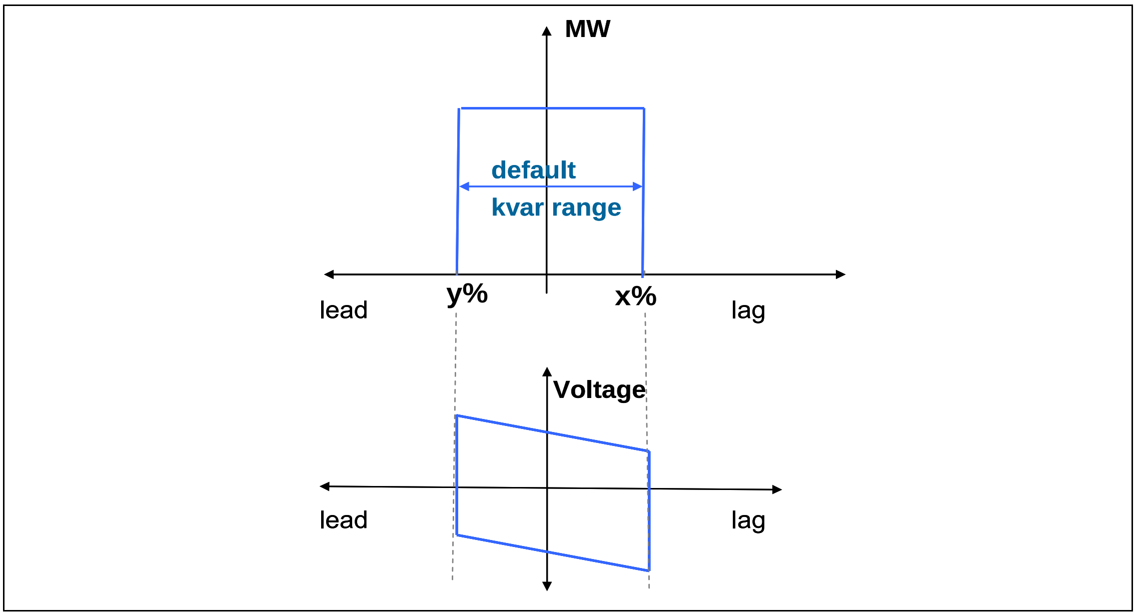
112. *Default* generator reactive standards should be designed to ensure low cost reactive support:

a. The current generator standards are difficult to comply with, yet significant kvar capability exists beyond the standard.

b. A simple but realistic default capability standard with kvar over/ under payments and more achievable voltage range requirements could avoid unnecessary transaction and compliance costs and provide greater certainty for asset owners and the system operator.

113. For example, a default generator standard (hypothetical) could be along the lines illustrated in Figure 18.

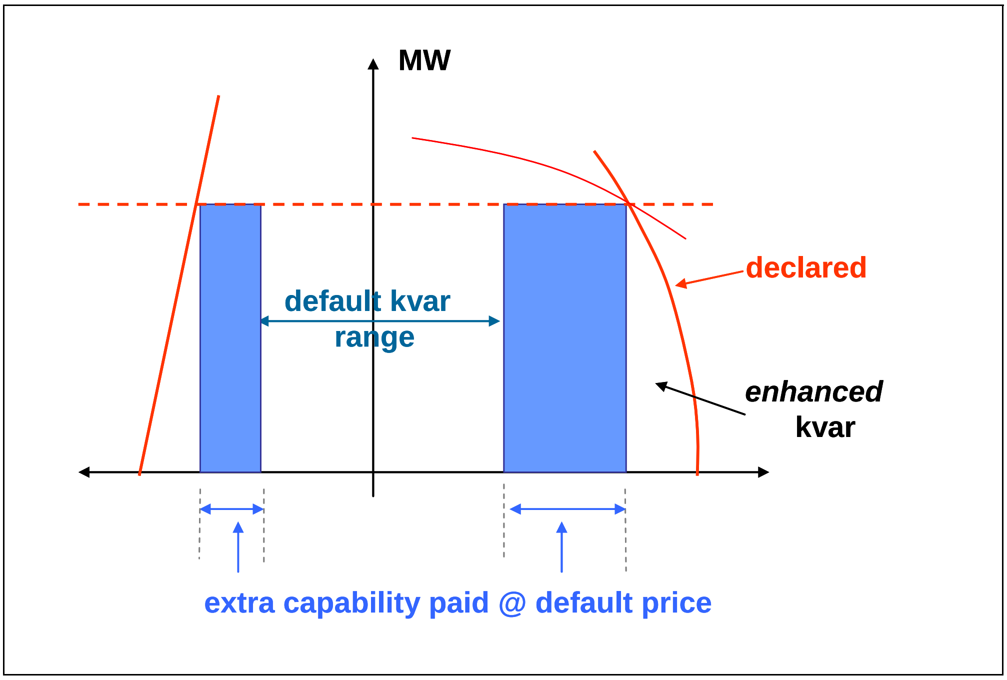
Figure 18: Simplified default generator standard (stylised)



114. A generator would declare its detailed kvar and voltage range capability to the system operator. In principle, an overs/ unders pricing regime could then operate along the following lines:

a. Generator kvar capability above the default standard (as indicated in Figure 19) could be paid the default kvar price for the zone. A shortfall in generator kvar capability would require a dispensation with the shortfall charged at the default kvar price for the zone. The default price for the zone would be zero (or low) if there are no voltage problems/ kvar procurement requirements.

Figure 19: Possible approach to generator kvar pricing



b. Additional kvar capability could be offered to the system operator in the procurement tendering process. For example, extra kvar at low MW (as highlighted in Figure 19) could be offered as an enhanced service in problem zone. This could include the right for the system operator to constrain generation off to obtain the extra kvar.

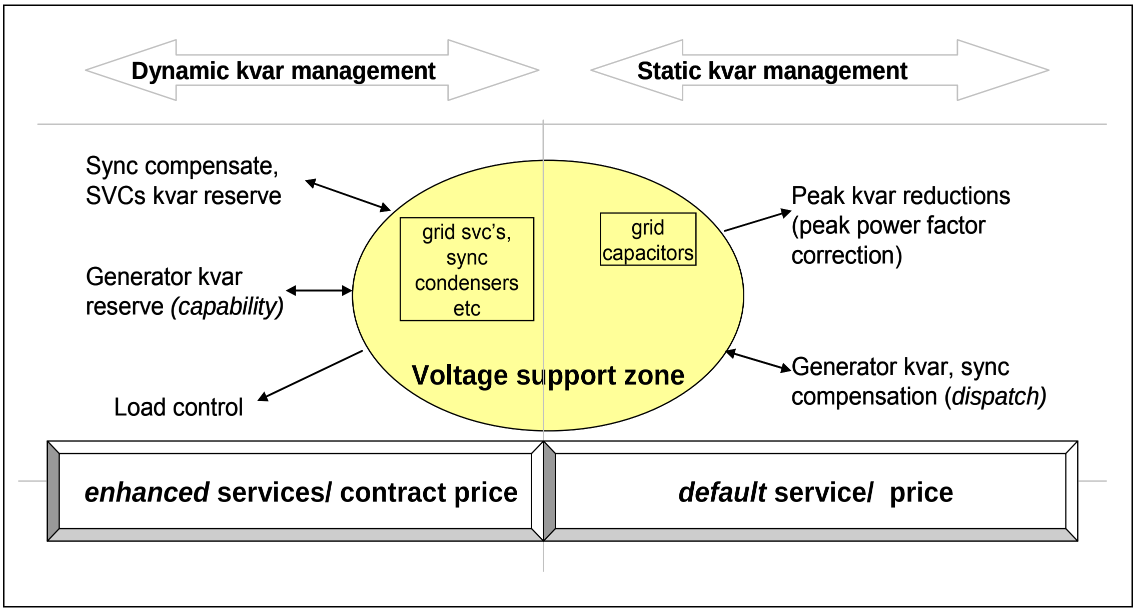
115. A number of practical issues would need to be worked through in order to implement such a regime, including how to assess compliance given kvar and voltage range interactions (which may need to be simplified around location specific voltage range requirements) and how to set default kvar prices in problem zones.

116. Setting default generator kvar standards would need to take account of and support the Commission's strategic wind project.

Possible conceptual reactive market design

117. Given the issues and concepts discussed in the preceding sections, a possible kvar market regime could be designed along the lines illustrated in Figure 20.

Figure 20: Conceptual reactive market design



118. Key aspects of the arrangement are summarised in Table 9.

Table 9: Overview of possible reactive market arrangements

Element	*Default arrangements*	*Enhanced services*
Procurement Mechanism	Default off-take power factor & generator reactive standards + payments for overs / unders: ▪ Mandatory participation at default kvar prices; ▪ marginal incentives same as paying/ charging for all kvar; ▪ but signals good practice (plus $rewards not just $penalties).	System operator tenders for fast kvar capability: ▪ Voluntary contracts regime; ▪ fast acting generator kvar (outside envelope for overs/ unders in default regime); ▪ include load options.
Pricing Arrangements	In active zones, default over/ under kvar price equivalent to long run capacitor cost.	Tender price cap would be set at the long run cost of SVC capacity.

Element	*Default arrangements*	*Enhanced services*
Payments	Off-takes charged/ paid default kvar price for power factor below/ above mandated (e.g. 0.97) ▪ use actual instead of “nominated” peak off-take kvar; ▪ charges/ payments based on +/- kvar relative to power factor standard. Generators charged/ paid default price for under/ over “capability” ▪ avoid complexity of paying for actual kvar utilisation); ▪ incentives to declare capability to system operator. Generators paid constrained on/ off costs if necessary.	Contracted parties would be paid for fast kvar “capability” (or equivalent in load terms) ▪ system operator would have rights to enable the service; ▪ contract penalties for non performance?
Cost Recovery	Reallocate/ recover residual costs as widely as practical to avoid distorting marginal signals.	

Defining kvar zones

119. Fixing kvar prices at the long run cost of alternatives will at least send the correct signal to off-takes and generators in a problem area of the grid. However, If reactive/ voltage support zones are poorly defined, as at present:

   a. Problem areas will not be targeted effectively, imposing costs on some participants for no particular system benefit.

   b. Reactive contributions from power factor improvement measures and generators outside of the specific problem area will be overvalued (assuming some form of reactive market arrangements along the lines indicated above).

120. It should be practical to improve targeting of problem areas. For example:

   a. A larger number of zones could be defined in the Rules. Whereas four zones are pre-defined at present, the system operator uses 11 or 14 regions for other purposes. Either of these might form a useful basis for defining zones.

b. Alternatively, it may be preferable to provide for a mechanism in the Rules for defining zones as and when required. For example, criteria could be included in the Rules for the system to propose zones for Commission agreement as part of the procurement planning process.

121. Signalling the relative value of kvar contributions between zones should also assist. Analysis of inter-zonal effects could be used to establish inter-zone "location factors" and set default kvar prices in other zones which recognise the relative contribution of direct kvar support within a zone and support from outside the zone.

Indicative Assessment

Potential upper NPV bound (Appropriate form of reactive market)	
Background	Potential benefits could accrue from lowering reactive flows on the grid through power factor improvements, better utilisation of existing generator reactive capability and incentives to invest in additional capability. In principle, this could defer or reduce the cost of central voltage support procurement, improve security in problem zones and reduce grid losses. However, it is very difficult to assess the potential benefits of this proposal.
Estimate of costs/ benefits	Benefits: ▪ Transpower has indicated approximately $100m of investment in grid SVCs & capacitors will be needed out to 2030 in the Upper North Island plan it submitted to the Commission. A 3 year deferral of this program would represent approximately $10m NPV. An NPV of $15m might be possible across all regions of the grid. ▪ Power factor improvement could reduce reactive flows/ grid losses although again the quantum is highly uncertain. If, for example, average losses could be reduced from 5% to 4.95%, this would save approximately 20 GWh of supply pa with an NPV of around $9m (assuming $60 per MWh). ▪ Assume no change in underlying system security risks. Costs: ▪ Implementation and ongoing costs should be relatively low with possible savings in compliance costs.
Indicative upper NPV	Based on these assumptions the NPV (upper bound) could be of the order of $24m.

Potential lower NPV bound (Appropriate form of reactive market)	
Background	As noted above, it is very difficult to assess the potential benefits that might accrue.

Potential lower NPV bound (Appropriate form of reactive market)	
Estimate of costs/ benefits	Benefits: ▪ Assume only half of the potential value of deferring grid reactive/ voltage support investments for 1 year and no other benefits (approximately $2.5m NPV). Costs: ▪ Implementation and ongoing costs should be relatively low with possible savings in compliance costs.
Indicative lower NPV	Based on these assumptions the NPV (lower bound) could be of the order of $2.5m.

Other evaluation criteria (Appropriate form of reactive market)	
Complexity	Design: Relatively low to moderate - some ability to draw on previous work and overseas procurement arrangements (e.g. UK, FERC). Implementation: Relatively low to moderate – Rule changes and new processes to develop.
Implementation Costs	Low to moderate. Mainly cost of design, rule change process and enhanced procurement arrangements. Systems costs should be relatively low.
Ongoing Costs	Low, possibly negative if compliance costs are reduced.
Dependencies	Part F procurement coordination (option V2.1) and integration of contracted kvar vs SPD constrained-on trade-offs (option V3.2).

Overall assessment (Appropriate form of reactive market)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$2.5m-$24m	Low - Mod	Low - Mod	Low	V2.1 and V3.2

V2.1 Ensure part C procurement & part F kvar investments compete

Outline

122. Procurement of voltage support services under part C (default and contracted) are potential alternatives to investment in grid kvar equipment under part F. The objective of minimising overall voltage support costs over time would be fostered if participant incentives to improve power factor, offer additional kvar capability (from existing capability or investment) are not undermined by

investments in grid capacitors and SVCs. e.g. if Transpower were to invest in grid kvar equipment as a backstop to part C procurement options in regions where there are voltage problems.

Nature of benefits (Ensure part C procurement & part F kvar investments compete)	
Efficient investment	Longer term system operator contracts for enhanced services and default reactive market arrangements should incentivise generation investments in problem regions (all other things being equal).
Minimising overall costs	A default kvar price (set at static capacitor cost) would encourage off-take power factor improvement and availability of extra generator kvar capability as potential alternatives to grid investments in capacitors. System operator tendering for enhanced services contracts (up to the SVC price cap) could delay or avoid grid SVC investments.

Nature of issues (Ensure part C procurement & part F kvar investments compete)	
Risks	The effectiveness of reactive market arrangements under part C could be undermined if not appropriately coordinated with part F developments.
Governance	Ensuring effective coordination between part C central procurement and part F investment arrangements is a broader issue than the common quality development plan.

Indicative Assessment

Potential upper NPV bound (Ensure part C procurement & part F kvar investments compete)	
Background	Some of the potential benefits of Initiative V1 (reactive market arrangements) depend on the way in which grid kvar investments are managed. $15m (45%) of the upper bound NPV assessment of potential benefits of Initiative V1 derives from part C procurement (default and enhanced contracting) delaying grid kvar equipment investments.
Estimate of costs/ benefits	Benefits: ▪ NPV benefits of $15m might be possible across all regions of the grid (see upper bound assessment for reactive market initiative). ▪ Assume no change in underlying system security risks. Costs: ▪ Implementation and ongoing costs should be relatively low with possible savings in compliance costs.
Indicative upper NPV	Based on these assumptions the NPV (upper bound) could be of the order of $15m.

Potential lower NPV bound (Ensure part C procurement & part F kvar investments compete)	
Background	As above. All of the lower bound NPV assessment of potential benefits of Initiative V1 derive from part C procurement (default and enhanced contracting) delaying grid kvar equipment investments.
Estimate of costs/ benefits	Benefits: ▪ NPV benefits of $2.5m might be possible across all regions of the grid (see lower bound assessment for reactive market initiative). ▪ Assume no change in underlying system security risks. Costs: ▪ Implementation and ongoing costs should be relatively low with possible savings in compliance costs.
Indicative lower NPV	Based on these assumptions the NPV (lower bound) could be of the order of $2m.

Other evaluation criteria (Ensure part C procurement & part F kvar investments compete)	
Complexity	Low, governance issues to resolve.
Implementation Costs	Low.
Ongoing Costs	Low.
Dependencies	Would enhance Initiative V1.

Overall assessment (Ensure part C procurement & part F kvar investments compete)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$2-$15m	Low	Low	Low	Initiative V1

123. The nature of this initiative is more akin to a part F proposal to enable common quality benefits than a common quality proposal per se. i.e. the Commission would need to ensure that, without compromising security, part F arrangements do not prevent part C procurement options competing as alternatives to grid kvar investments.

V3.1 Investigate potential benefits of increasing grid voltage flexibility

Outline

124. This option would involve investigating:

   a. The feasibility and potential net benefits of increasing average grid voltage levels (within nominal ranges) to reduce losses/ voltage support costs and/ or improve system security.

   b. The potential net benefits of increasing system operator flexibility to manage grid voltage levels by investing in OLTCs in strategic grid locations.

Nature of benefits (Investigate potential benefits of increasing grid voltage flexibility)	
Minimising costs	If operational grid voltage levels could be raised within nominal voltage ranges, this could reduce losses/ voltage support costs and possibly improve security.
System flexibility	Increased grid operating flexibility (with lower costs and/ or enhanced system security) may be possible if OLTCs are installed in some locations on the grid.

Nature of issues (Investigate potential benefits of increasing grid voltage flexibility)	
Uncertainty	While in principle there is the possibility of some benefits, these are highly uncertain without undertaking relatively complex analysis.
Inter-dependency	It is unclear whether raised operating voltages can be considered independently of OLTC questions.
Cost recovery	The costs of investing in OLTCs (or other location specific investments) are likely to exceed the benefits accruing at a particular grid connection point.

Indicative Assessment

Upper NPV bound (Investigate potential benefits of increasing grid voltage flexibility)	
Background	There is likely to be a close relationship between the possibility of higher voltage levels and any OLTC flexibility constraints. Without undertaking the required analysis, it is very difficult to assess potential benefits.

Upper NPV bound (Investigate potential benefits of increasing grid voltage flexibility)	
Estimate of costs/ benefits	Benefits: ▪ If average grid voltage levels could be raised, even a very small reduction in average losses would yield significant benefits. ▪ E.g. if average losses could be reduced from say 5% to 4.95%, this would save supply of approximately 20GWh pa. ▪ At say $60/MWh, this would represent savings of around provide an NPV of around $9m. Costs: ▪ Investigations of the order of $0.3m may be necessary. ▪ Assume an upper bound scenario where benefits could be achieved without any investment.
Indicative upper NPV	The above assumptions, which are highly uncertain, would suggest an upper bound NPV of the order of $8.5m.

Lower NPV bound (Investigate potential benefits of increasing grid voltage flexibility)	
Background	As above.
Estimate of costs/ benefits	Benefits: ▪ Assume similar benefits as above (i.e. marginal reduction in losses saving approximately $9m NPV). Costs: ▪ Investments may be required to achieve these benefits (e.g. replacing some transformers with ones fitted with OLTCs). ▪ The costs could be several million.
Indicative lower NPV	Based on these assumptions the NPV (lower bound) could be negligible.

Other evaluation criteria (Investigate potential benefits of increasing grid voltage flexibility)	
Complexity	Moderate, possibly high, in terms of analytical requirements.
Implementation Costs	Highly uncertain: potentially spanning low to high.
Ongoing Costs	Low.
Dependencies	Possible part F cost recovery issues.

Overall assessment (Investigate potential benefits of increasing grid voltage flexibility)				
Indicative NPV (standalone)	Complexity	Costs		Dependencies
		Implement	Ongoing	
$0-$9m	Mod - High	Low - High	Low	Part F

Approach to developing this option

125. Transpower is clearly best placed to assess the potential benefits and costs of this option:

   a. Transpower has in the past raised the possibility that not having transformers with OLTCs in some locations constrains system operation. Under the part F regime, it can propose grid investments to the Commission for approval.

   b. The system operator is able to operate grid assets within their mandated voltage ranges (subject to local voltage quality constraints of the form noted above or any dispensations from compliance).

126. Transpower is best placed to assess the extent of any benefits associated with increased voltage flexibility on the grid and/ or reduced losses. The Commission could invite Transpower/ the system operator to consider the potential benefits of these initiatives and what practical measures, and costs, would be involved.

V3.2 How to trade-off kvar procurement options vs SPD constraints

Outline

127. This option would involve investigating the possibility of integrating voltage management more closely with energy dispatch to minimise overall costs. For example:

   a. Developing tools or policies regarding trade-offs between the direct cost of procuring kvar contracts (to commit more generating units or contracting with load) and the indirect costs of applying voltage/ security constraints to SPD.

   b. Tools and systems to assist the management of voltage profiles across the grid.

Nature of benefits (How to trade-off kvar procurement options vs SPD constraints)	
Minimising overall costs	In situations where it is cheaper to procure contracts for voltage support (direct or constrained-on), regional energy market (price) impacts would be reduced.
Enhancing system security	There may be scope to improve active management of grid voltage profiles (e.g. by more tightly integrating voltage with dispatch) and enhance security.

Nature of issues (How to trade-off kvar procurement options vs SPD constraints)	
Cost allocation	Constrained-on costs can be difficult for the system operator to recover.
Policy questions	Is it better to signal regional voltage problems in market prices, to evoke demand response, or rely on constrained on generation/ demand response contracts? Tight zones might help?
Technical complexity	On-line integration of voltage management and dispatch is unlikely to be a viable option in the foreseeable future, and/or would be costly.

Approach to developing this option

128. The discussion above suggests that:

a. Any consideration of how to make trade-offs between direct procurement options and the use SPD voltage/ security constraints should be undertaken within the context of reactive market arrangements, in particular option V1.4 (procurement of enhanced voltage support services).

b. Enhanced dispatch and voltage integration is probably best left to the system operator to assess within its overall work program??

129. Accordingly, option V3.2 has not been evaluated further and it should be incorporated into option V1.4 as suggested above.

V4.1 Review emergency management, including load management role

Outline

130. This option would involve reviewing emergency arrangements relating to voltage management (along similar lines to the review of emergency arrangements relating to under-frequency management – option F7.1). The review would consider possible load management options that could assist voltage management including mandated requirements, such as automatic under-voltage load shedding (AUVLS), and commercial contracting options.

Nature of benefits (Review emergency management, including load management role)	
System security	More certainty regarding emergency management.
Competition	Commercial load management options could compete as enhanced services with other fast acting kvar reserves.
Minimising costs	More options available to SO to lower overall cost of voltage management.

Nature of issues (Review emergency management, including load management role)	
Inter-dependency	Any arrangements would need to be consistent with the Electricity Commission's load management work program. There is a degree of commonality between emergency arrangements (including load response measures) and operating procedures relating to voltage and frequency management. The use of commercial load management options is closely related to the possibility of procurement of enhanced voltage support services (option V1.4) under the reactive market initiative V1.

Approach to developing this option

131. The discussion above suggests that:

a. Any consideration of commercial load management options should be undertaken within the context of reactive market arrangements, and in particular option V1.4 (procurement of enhanced voltage support services).

b. Any review of emergency management arrangements and procedures relating voltage management should be undertaken alongside consideration of emergency arrangements relating to under-frequency (option F7.1) and extending the use of load control (option F6.1).

132. Accordingly, option V4.1 has not been evaluated further and its key elements should be added to other initiatives as suggested above. This is discussed further in relation to reliability and security in the following section.

Reliability & Security Development

Background

133. In practice, from a system operation perspective the concepts of reliability and security with key aspects of frequency and voltage management. For example, the 'avoid cascade failure PPO' and emergency arrangements in relation to under-frequency and voltage event management. However, as described in section 4 of the Current Arrangements paper, the concepts of reliability and security encompass system operation and part C arrangements more generally, extending beyond specific frequency and voltage management arrangements.

134. Further, part C and related system operating policies tend to focus on specific technical performance requirements of asset owners, contingency events to be covered, and event management procedures. While these arrangements are reasonably well documented, the actual underlying levels of system reliability and security are unclear. For example, what is the system's resilience to events not specifically covered and the likelihood of occurrence?

135. Reliability and security are also important elements of grid investment planning. While the latter is beyond the scope of the common quality development plan, consistency and clarity between system operation (parts C and G of the Rules) and grid planning (part F) with respect to reliability and security requirements is important. Part F arrangements in particular are still evolving and how this occurs may have implications for system operation and vice versa.

Possible Reliability & Security Development Initiatives/ Options

136. In light of the above, and in conjunction with the CQAG, the following reliability and security development initiatives and options were identified. As discussed in the following section, some of these are closely related to frequency and voltage development initiatives.

Table 10: Possible reliability and security development options

Initiative		***Option***	
R1	Clarify reliability and security objectives	R1.1	Review events covered and assess system resilience to events not specifically covered in the policy statement.
		R1.2	Review consistency between operational reliability and security standards and grid planning requirements.
		R1.3	Ability to vary system operation from N-1.
		R1.4	Define service levels at grid off-takes.

Initiative	Option
R2 Operational enhancements	R2.1 Operational reporting of standby reserves. R2.2 Investigate standby reserves schemes.

Evaluation of Reliability & Security Options

R1.1 Review events covered/ assess system resilience to other events

137. In simplistic terms, the current arrangements involve:

a. Operating the system given the assets made available so that there is sufficient capacity (including mandated and procured reserves) to cover single contingency events (including loss an HVDC pole) without having to rely on forced load shedding.

b. Ensuring that the risk of a HVDC bipole trip is covered by AUFLS and, if necessary, additional reserves.

c. For all other events larger than a single contingency, relying on reserves procured under (a) or (b) above and automatic or manual load shedding to avoid cascade failure leading to uncontrolled loss of load.

138. This option would review the contingency events currently covered under part C arrangements, and assess the system's resilience to larger events not specifically covered.

Assessment

139. There are strong synergies between this option and emergency management aspects of under-frequency and voltage development options, in particular:

Option F7.1	Review under-frequency arrangements to ensure they are optimal for NZ.
Option V4.1	Review emergency arrangements relating to voltage management, including the role of load management.

140. For example, each of these options would consider which contingency events are covered as would option R1.1. It is therefore considered appropriate to merge these options and broaden the scope of option R1.1 to "clarify reliability objectives and optimise emergency management arrangements".

R1.2 Consistency between operational/ grid planning standards

Outline

141. This option would consider how the new arrangements in part F for grid reliability, grid investment and transmission contracting are likely to impact on security and reliability from a system operation perspective.

Assessment

142. Some aspects of the part F arrangements are not yet fully developed and implemented. Accordingly the nature of the implications is evolving with progressive implementation of (and experience with) part F constructs such as the Grid Reliability Standards, the Grid Reliability Report and Benchmark Agreements. Their development is beyond the scope of common quality developments, although consistency, incentives and interface issues will be directly relevant.

143. It is therefore proposed that a watching brief be maintained on part F development, with proactive input regarding any potential system operation reliability and security implications.

R1.3 Ability to vary system operation from N-1

Outline

144. This option would consider a process for getting the agreement of affected parties to allow for a certain part of the system to be operated at less than N-1 security, either on a temporary or permanent basis. This might involve, for instance, agreeing that the System Operator will not invoke pre-event load-shedding for a particular regional situation, but instead accepting that there could be significant emergency loss of load in the event of a contingency. Other arrangements might include the use of inter-trip schemes.

145. It is worth noting that part C already allows for parties to contract with the System Operator for higher levels of security, and to pay the associated incremental costs.

Assessment

146. If sufficient assets are not made available to the system operator, without agreements of the sort envisaged above, it is faced with having to make trade-offs between the level of security delivered to different groups of grid users and consumers.

147. The Benchmark Agreements in part F act as a default transmission agreement in the event that Transpower and the contract counter-party fail to enter a bilateral agreement. It is likely that Benchmark Agreements will set out asset-based service measures for capacity. Relevant counterparties (likely to be

distributors and generators) would be able to enter negotiations with Transpower for a different capacity service measure. The parties would then offer the relevant assets into the scheduling and dispatch process in accordance with the provisions of part C and part G.

148. This would provide a means for parties to enter into “local quality arrangements” such as varying from an “N-1” operational reliability level.

149. It is therefore proposed that this option be added to the watching brief for Option R1.2 above, with proactive input to ensure that the transmission contracting framework enables the establishment of local quality agreements, and that such agreements are not inconsistent with orderly and efficient operation of part C.

R1.4 Define service levels at grid off-takes

Outline

150. This option involves defining service levels at each grid off-take point, thereby establishing clear expectations regarding the service delivery for the customers at that off-take point.

Assessment

151. As for Option R1.3, on reflection grid off-take service level definition would appear to be more of an asset owner to asset owner issue. Accordingly, it is proposed that this option be added to the watching brief for Option R1.2 and R1.3 above, with proactive input to ensure that the transmission contracting framework enables the establishment of local quality agreements, and that such agreements are not inconsistent with orderly and efficient operation of part C.

R2.1 Operational reporting of standby reserves

Outline

152. This option involves routine publishing by the system operator of standby reserve margins[31] for each half hour of market schedules. This would provide more regular information to participants about system capacity margins to enable them to make better assessment of system security and plan accordingly. e.g. increase offers, reduce demand.

[31] The level of spare capacity offered in excess of that required to meet demand and reserves requirements.

Assessment

153. The system operator is currently developing a standby reserves reporting system along the lines above following a Commission request in 2005.

R2.2 Investigate standby reserves schemes

Outline

154. This option would consider possible mechanisms to ensure that sufficient standby reserves are available to cover a second contingent event until normal instantaneous reserves can be restored. A number of possibilities exist ranging from mandating that available thermal plant be offered through to market arrangements such as setting a higher instantaneous reserves requirement at times or introducing a new standby reserves product.

Assessment

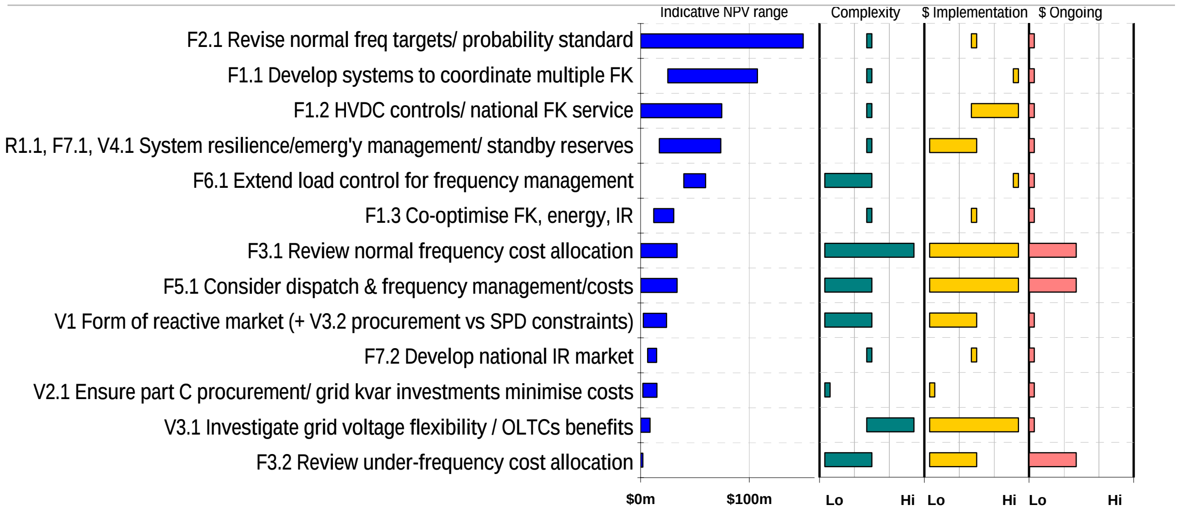
155. An implication of adopting this option is that load management options are always likely to be less economic than carrying spare supply capacity sufficient to cover two contingent events. It is difficult to make an assessment of this option without first clarifying the overall objective for reliability and security (option R1.1). Accordingly, this option should be considered in conjunction with option R1.1.

Overall Evaluation of Development Options

Summary of assessments

156. Figure 21 summarises the overall assessments of options (excluding interdependencies in general which are discussed later).

Figure 21: Summary of Indicative Assessments



Note: Bar widths indicate assessment uncertainty

157. In relation to Figure 21, note that:

a. Some options have been combined as discussed previously. These are identified in the chart.

b. As the system operator is currently progressing option R2.1 (operational reporting of standby reserves), this has been excluded from the chart.

c. Three part C/ part F coordination options have also been omitted from the chart because, as discussed previously, the issues involved deserve ongoing monitoring and proactive input with regard to part F developments rather than being considered as specific common quality development options. These options are:

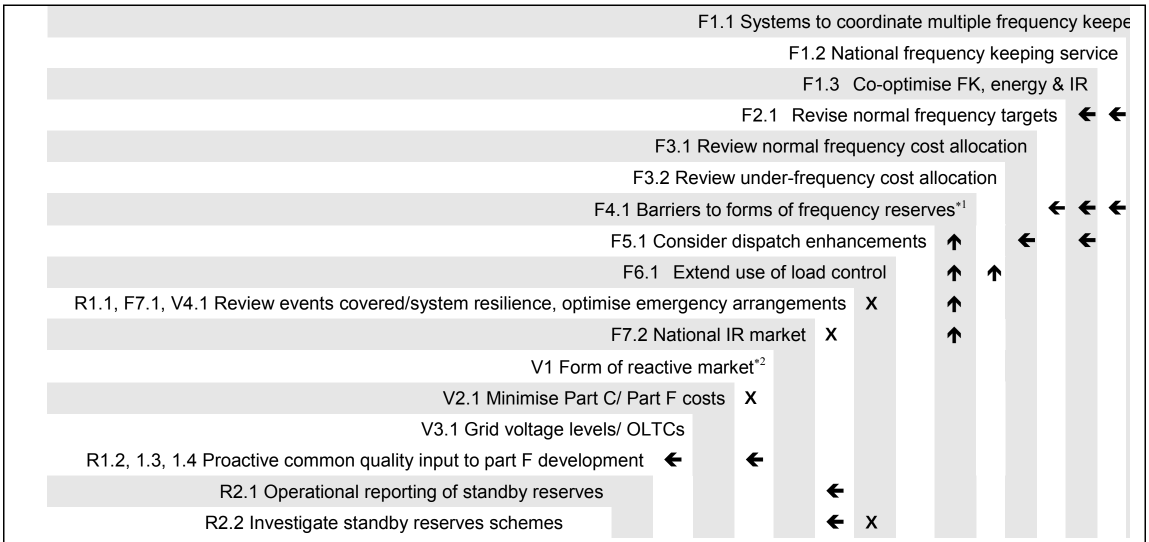
- Option R1.2 - review consistency between operational reliability and security standards and grid planning requirements.
- Option R1.3 - ability to vary system operation from n-1.
- Option R1.4 - define service levels at grid off-takes.

d. The NPV assessment for the combined Option R1.1 is based on the assessment for Option F7.1 (optimize under-frequency management) rather than attempting to evaluate the three options collectively. The overall benefits are therefore likely to be higher than indicated.

e. The widths of the bars in the left hand chart in Figure 21 indicate the range of NPV estimate uncertainty for each option. For example, as noted previously, HVDC frequency sharing offers potentially large NPV benefits but it is uncertain whether the HVDC can do this or whether control systems would need to be upgraded first. In contrast, the “multiple frequency keeping” and “extending load control” options have more certain minimum benefits.

f. In general, standalone assessments were undertaken for ranking purposes only. NPV estimates cannot be added together to estimate likely overall benefits. In particular, implementing one option could significantly affect the potential benefits that could result from another. In this regard, Figure 22 summarises interdependencies identified in evaluating the frequency, voltage and reliability options. It indicates, for example, that the potential benefits of relaxing the normal frequency targets could be influenced significantly by the multiple frequency keeping development option.

Figure 22: Development option inter-dependencies



*Notes: (1) **X** indicates that one option supports or influences the other. (2) ↑ or ← indicates one directional support or influence.*

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*1 This option has been included in the table to highlight its dependence on other options (noting that it was dropped off the list of options for that reason).

*2 Including V3.2 (kvar procurement versus the use of SPD constraints)

Categorisation of developments

158. Based on the overall assessment of options, taking into account interdependencies and indicative NPVs and uncertainties, potential developments have been regrouped and sorted within the following categories:

a. Category A: development projects with the potential to deliver the highest benefits, even if technically challenging and/or costly to achieve.

b. Category B: development projects with the potential to deliver significant benefits, or where relatively easy wins could be achieved, and which could be progressed relatively independently.

c. Category C: developments with lower potential benefits and/ or where other higher value projects are likely to significantly weaken benefits.

d. Category D: developments elsewhere where proactive input from a common quality perspective is likely to yield overall benefits.

159. Potential developments have been grouped and categorised accordingly as follows.

Category A projects

A1 Initial review of normal frequency target & dynamic procurement

160. This would involve reviewing the normal frequency band and immediately adjacent frequency bands[32] and the corresponding approach to specifying frequency keeping procurement needs with a view to reducing overall costs (direct and indirect). Input from the Commission's wind project should be sought.

161. Physical system trials would be needed to evaluate the extent to which relaxing the standard would affect procurement quantities and to enable feedback from participants as to indirect cost impacts. A test plan would need to be prepared in conjunction with the system operator. Stakeholder consultation would also be necessary regarding any implications for frequency quality and any potential inconsistencies with existing Rule requirements.

162. This project would represent the first stage of option F2.1 (set normal frequency targets). i.e. a full review of how normal frequency targets are specified would not be considered until other initiatives have been implemented, given the likely complexity, uncertainty about indirect costs and high level of dependence on other options that could reduce direct procurement costs and alter total cost versus frequency quality curves.

A2 Develop systems to co-ordinate multiple frequency keepers

163. This would combine options F1.1 (multiple frequency keepers) and F1.3 (co-optimisation of frequency keeping with energy and instantaneous reserves). There are strong interdependencies between these options, and also the market systems/ SPD upgrade being undertaken by the system operator.

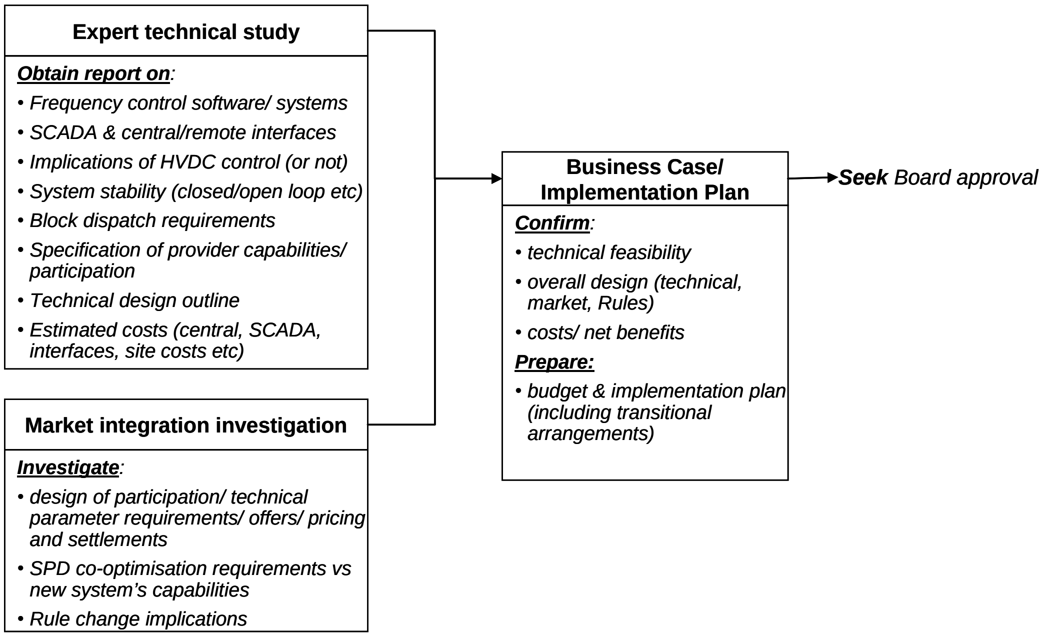
164. The first stage of this project would be progressed along the lines shown in Figure 23. An independent technical expert would need to be engaged to assess the technical feasibility of and requirements for an AFC system that

32 Momentary fluctuation rates have yet to be specified for each of the frequency bands immediately above and below of the normal band.

meets NZ's requirements. System operator and generator technical input to that work would be necessary.

165. The market integration aspects would require system operator input noting implications for, and from, its market systems development project.

Figure 23: Project A2 - Developing systems to co-ordinate multiple frequency keepers



166. This project would be a major undertaking, requiring a detailed technical investigation phase required to confirm technical feasibility, key design aspects and overall benefits prior to implementation. In the meantime, interim changes to the method for selecting a frequency keeper in each island are being investigated. The aim is to lower overall procurement costs by factoring potential constrained-on and constrained off costs into the frequency keeper selection methodology. It is also possible that an initial review of the normal frequency standard and procurement requirements may help.

A3 Investigate technical options for HVDC frequency control

167. The Commission has asked Transpower to investigate HVDC frequency sharing capability (option F1.2) as an immediate common quality development initiative. Transpower has recently indicated that this capability will not be practical without upgrading HVDC control systems. These issues should be explored fully with Transpower because of the potential benefits involved (national reserves market/single frequency keeper and AFC) and because of possible implications for future HVDC investment.

168. There may also be significant implications for project A-2 (developing systems for multiple frequency keepers). For example, decisions would need to be made regarding the scope of an AFC system. i.e. limited to the North Island initially or developed for each island independently? Or is it possible (or even preferable) that the HVDC could receive an AFC system dispatch signal along

the same lines as a generating unit MW set point controller or block dispatch system would receive?

A4 Optimise emergency management arrangements

169. This would involve a combination of:

    a. Investigating how to extend the use of load control for frequency management, in particular through frequency sensitive hot water control relays (option F6.1) and if desirable adding more and / or smaller AUFLs blocks.

    b. Reviewing events covered & assessing the system's resilience to other events not specifically covered (option R1.1).

    c. Reviewing under-frequency management arrangements to ensure they are least overall cost over time (option F7.1).

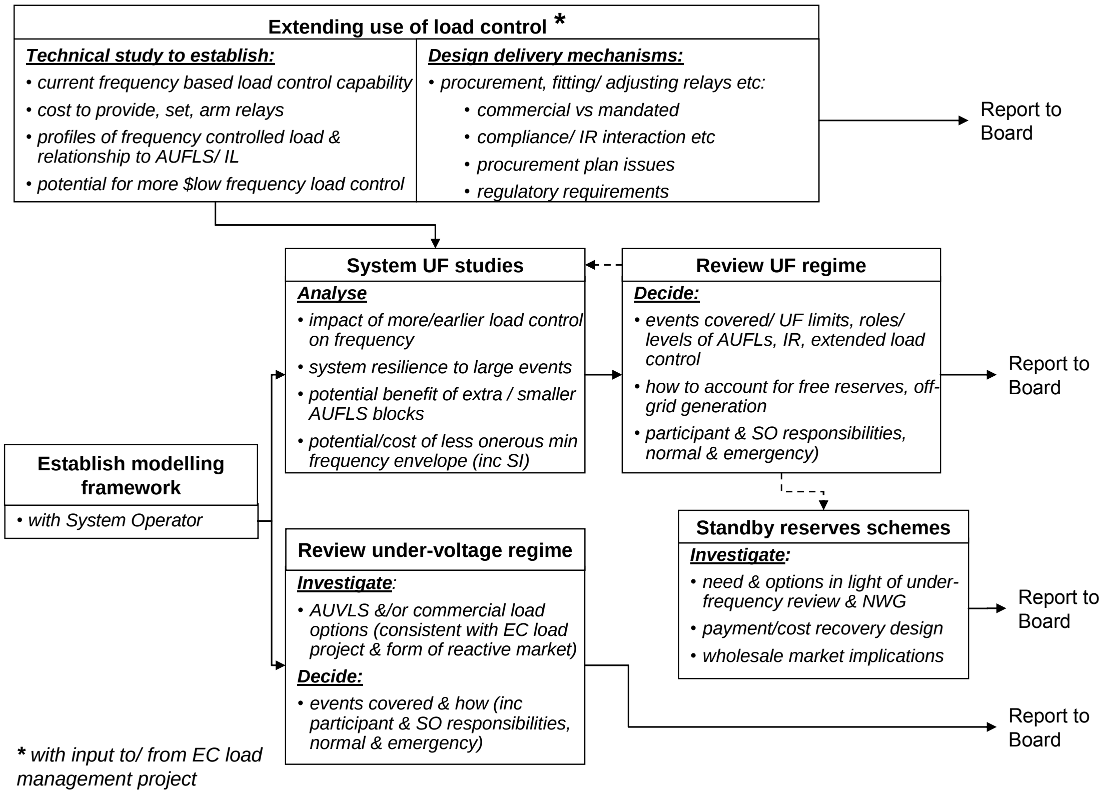
    d. Reviewing emergency voltage management arrangements, including load control options (option V4.1).

    e. Investigating standby reserves schemes (option R2.2).

170. Note that option R2.1 (operational reporting of standby reserves) is already underway as an immediate development initiative.

171. This project would be progressed along the lines shown in Figure 24. The sequencing of tasks in this option is important. In particular, if the use of load control for under-frequency management can be extended to provide more system reserves, or more effective system reserves, at lower overall cost, this would have a substantive bearing on subsequent tasks above.

Figure 24: Project A4 -Optimise emergency management arrangements



Category B projects

B1 Progress towards appropriate form of reactive market

172. This option would investigate a staged approach to developing initiative V1 (form of reactive market), incorporating option V3.2 (kvar procurement vs SPD constraint tradeoffs).

173. This option has been included in the B category because, while its overall benefits are likely to be less than for category A projects, it is largely independent of other initiatives and some aspects should be relatively straightforward to implement to achieve quick wins. In particular:

    a. Define zones to improve targeting of problem areas and implement enhanced kvar pricing as originally intended.

    b. Design efficient kvar technical standards and dispensation/ cost allocation arrangements, seeking input from the Commission's wind project.

174. The potential benefits of progressing further towards the reactive market outlined in this document would then be assessed relative to other Commission priorities. This project may have implications for emergency voltage management arrangements, in particular the possibility of commercial load management options as alternative forms of kvar procurement.

B2 National IR market/ reserve sharing between islands

175. This project would involve option 7.2 (develop a national instantaneous reserves market). This was previously identified as an immediate development initiative. The Commission is in discussion with Transpower regarding this project to investigate implementation requirements. It has developed and presented a prototype proposal. This project can proceed in parallel with other projects subject to system operator availability and any SPD changes.

Category C developments

C1 Review normal frequency cost allocation

176. Option F3.1 (review normal frequency cost allocation) should be considered following other measures to reduce normal frequency costs. However, depending on recommendations from the Commission's wind project, it may be appropriate to consider extending the current allocation of procurement costs to intermittent wind generation.

C2 Review current dispatch systems and performance

177. This would involve option F5.1 (consider dispatch changes to enhance frequency management/ reduce costs). This project should be re-considered once the outcome of other measures to reduce frequency related costs are clearer (in particular projects A1, A2 and A3).

C3 Review under-frequency cost allocation

178. This would involve option 3.2 (review under-frequency cost allocation). This should be considered following the outcome of projects A4 and B2.

Category D developments

D1 Minimise overall cost of part C procurement & part F kvar investments

179. This would involve option V2.1 (ensure that part C procurement and grid kvar investments can compete to minimise voltage support costs over time).

180. With efficient part F/ part C co-ordination, it should be possible to ensure that, without compromising security, part F arrangements do not prevent part C procurement options competing as alternatives to grid kvar investments. In this regard, common quality perspectives on this issue should be provided as input to relevant aspects of the Commission's transmission's work program.

D2 Assess possibility of increase grid operating voltage flexibility

181. This would involve option V3.1 (investigate potential benefits of increasing average grid voltages, within nominal ranges, and OLTC investments to increase grid voltage flexibility).

182. Transpower, through the part F investment process and in its capacity as system operator, is best placed to assess the likely benefits of this option. The Commission could ask Transpower to advise whether it considers there are likely to be significant benefits and / or what would be required to identify these.

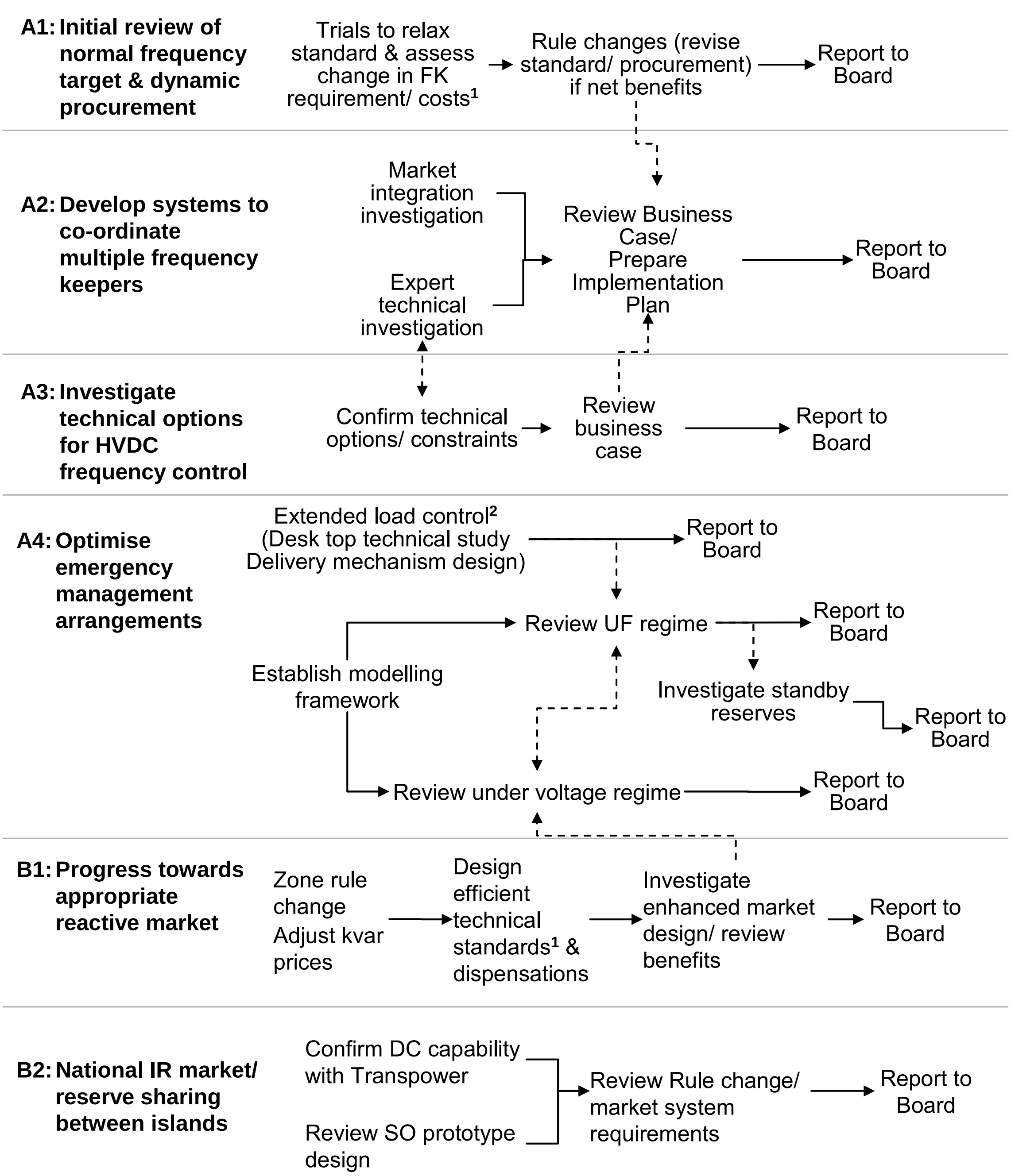
D3 Active input into part F developments

183. This involves ongoing active monitoring and common quality input into options R1.2 (review consistency between operational reliability and security standards and grid planning requirements), R1.3 (system operator ability to vary from n-1) and R1.4 (define service levels at grid off-takes).

Indicative Project Outlines

184. Figure 25 sets out a possible development program, leading to Board recommendations for implementation, reflecting the above categorisation and outline of projects.

Figure 25: Proposed development strategy



Notes: 1) Seeking input from Commission's wind project
2) With input to/ assistance from Commission's wind project