ANCILLARY SERVICES IN NEW ZEALAND: RECOMMENDATIONS FOR CHANGE

A Report Commissioned By Industry Participants

December 1999

Compilation Of Papers

Foreword to the NERA report - Ancillary Services: Next steps

An introduction and summary of the NERA report from the project sponsors and an indication of the next steps required.

Ancillary Services In New Zealand: Recommendations For Change - Executive Summary

The Executive Summary of the NERA Report that outlines the method of analysis used and the recommendations made.

Ancillary Services In New Zealand: Recommendations For Change - Final Report

The full report by NERA.

Ancillary Services: Key Issues and Questions

The paper submitted to NERA describing the key ancillary service issues that require resolution. The issues are presented as a series of questions accompanied by a short discussion.

Addendum to 'Ancillary Services: Key Issues and Questions'

A background to ancillary services in New Zealand, including a description of each service and the costs and issues involved.

Submissions To The Paper 'Ancillary Services: Key Issues And Questions'

A summary of the submissions received on the Key Issues and Questions Paper, and how the points raised in each submission are handled in the NERA report.

Foreword to the NERA report

Ancillary Services: Next steps

Introduction

In early October, the Chief Executives of lines and energy companies representing a major cross-section of the industry initiated a project to surface and discuss key issues in relation to ancillary services. A paper outlining issues identified was circulated widely within the industry and referred to National Economic Research Associates (NERA), an international consulting firm, to recommend solutions.

Attached is a copy of the NERA report.

General approach

In considering who should pay for ancillary services, NERA emphasises the dynamic effects of allocating ancillary service costs. In particular, NERA argue that costs should be allocated to provide participants with incentives to undertake an alternative action when that alternative would lower costs overall. Consistent with this objective, NERA recommends that ancillary service costs be recovered as follows.

Ancillary Services Cost Recovery

Service	Level of Costs (1998/99)	Current Allocation	Proposed Cost Recovery
Frequency Control	$14.1m	Lines companies	CQC recover costs from retailers via c/kWh uplift on reconciled energy purchases. Costs of constraining on generators for frequency control should be recovered on same basis.
Instantaneous Reserves	$5.5m	Generators and HVDC	No change: CQC recover costs from generators and HVDC link (in line with Stage 1 Belgrave Committee recommendations).
Over-Frequency Arming	$0.2m	SI generators	Transpower (grid owner) via transmission use of system charges.
Black Start	$0.04m	Generators and lines companies	Transpower (grid owner) via transmission use of system charges.
Voltage Support	$5.7m	Lines companies and transmission use-of-system	Transpower (grid owner) via transmission use of system charges, capped to reflect least cost supply options Agreed kVAr offtake between lines businesses and Transpower (grid owner)

Subject to implementing incentive contracts described below, there is considerable support amongst the Chief Executives that these cost allocations will provide the best available prospects for minimising ancillary service costs, although there is inevitable variance on particular issues.

NERA recommends that two incentive contracts be established. These contracts should motivate the central agencies involved in purchasing and coordinating ancillary services to conduct activities in a way that minimises the costs of maintaining the Grid Security Policy. Specifically:

- The deed between the GSC and the CQC should include profit incentives for the CQC to make efficient decisions regarding the trade-off between using ancillary services and alternative actions, such as refinements to dispatch. These incentives would be subject to maintaining system quality and security objectives.

- A contract defining the ancillary services purchase function should be let separately. This contract would include profit incentives for the purchaser to innovate to reduce the costs of purchasing ancillary services.

The next steps

In order to achieve early gains, it is considered the following steps would enable new arrangements to be in place by 1 April 2000.

a) The GSC include financial incentives in the deed being negotiated with the CQC. This might be achieved by allowing the CQC to retain an agreed portion of any cost saving arising from a reduction in the quantum of ancillary services required to maintain agreed quality standards.

b) The GSC specify and let the terms for the ancillary services purchase function separately from the coordination function of the CQC. Potential suppliers of the service (including the incumbent) should have an opportunity to propose innovative ways to conduct the purchase function, undertake settlement, and share risk.

c) To facilitate entry into the provision of ancillary services, the CQC define and publish its requirements for each ancillary service (ie. the service purchased) in a manner that is not biased unjustifiably between different technologies or types of providers.

d) To ensure that the allocation of ancillary service costs (as set out in the table above) is comprehensive and neutral between alternative market trading arrangements:

    - The reconciliation agreements, MARIA and NZEM, require members to hold contracts with the CQC covering the allocation of ancillary service costs.[1]

e) To support compliance with any technical and performance standards necessary to maintain the common elements of quality as specified in MACQS:

[1] NZEM members, if they desire, could include within the rules of NZEM a generic contract applying to all members to avoid the transaction costs of completing bilateral contracts with the CQC.

- The reconciliation agreements, MARIA and NZEM, require members to hold contracts with the CQC.

- Transpower, as grid owner, include in its connection contract a requirement that all entities connecting to the grid hold a contract with the CQC.

f) To provide transparency in its relationship with the grid owner, the CQC put in place an explicit and transparent agreement between itself and the grid owner.

g) Transpower (as grid owner) agree in its connection contracts a kVAr offtake limit with each distribution network. Transpower would charge lines businesses for exceeding this offtake.

h) Transpower confirm that:

- Investment in voltage support equipment will be treated in the same manner as any other new investment to maintain capacity. It is expected that new investment will proceed only where agreement has been reached with customers (those who pay for transmission).

- Charges for voltage support will be capped for no less than an annual period, and be set at a level to reflect the expected lowest long-term cost supply options.

These steps should ensure the implementation of the Grid Security Policy is not hindered by ancillary service issues, and that the costs of these services are minimised through time.

Project Sponsors of this report were:

CentralPower Ltd
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ANCILLARY SERVICES IN NEW ZEALAND: RECOMMENDATIONS FOR CHANGE

EXECUTIVE SUMMARY

Final Report for the CEO's Forum

Prepared by NERA

November 1999
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EXECUTIVE SUMMARY

1. BACKGROUND

NERA has been commissioned by the CEO's Forum[1] to provide recommendations on key issues in relation to the arrangements for ancillary services in New Zealand.

Purchase costs for ancillary services currently amount to around $26m per annum, compared with a total value of electricity traded through the New Zealand Electricity Market (NZEM) of $1.6bn. Frequency control accounts for close to half of the total ancillary service cost, followed by voltage support and instantaneous reserves. The cost of both over-frequency arming and black start, the two remaining ancillary services, are both very low. Given these current cost levels for the different ancillary services, the greatest scope for cost reduction appears to be in the areas of frequency control and voltage support.

NERA has been asked to make recommendations to cover both pragmatic solutions which can be implemented in the short-term and any additional improvements desirable for the medium term.

2. NERA'S FRAMEWORK FOR ASSESSMENT

2.1. Arrangements should maximise the incentives for efficient behaviour

Discussions of who should pay for ancillary service are often framed in the context of who 'causes' the need for the service or who 'benefits' from having a stable electricity system. In contrast, the framework we have used to assess current arrangements and to recommend changes is to look at 'who can make a difference', ie, who can act to reduce the cost of ancillary services required.

In order to improve overall efficiency in meeting system operation targets, the contractual arrangements in the ancillary services market should provide market participants with an *incentive* to undertake an alternative action, when that alternative is lower cost relative to the purchase of ancillary services.

In some cases, the party who can make a difference may be the same as the party causing the need for the service, or the party that benefits from the service. It may, however, be a different party entirely.

1 This forum consists of the Chief Executives of a number of lines and energy companies, representing a cross section of the New Zealand electricity industry.

2.2. Implications for cost allocation

In order for market participants[2] to make a trade-off between the purchase of ancillary services or undertaking an alternative action which is efficient from a system perspective, the party (or parties) making the trade-off must face all of the costs and benefits associated with their decision.

In a system with a large number of potential trade-offs and where the costs and benefits (in terms of the avoided costs of ancillary services) are decentralised, this implies that incentives for efficient behaviour rely on the ability of parties to form a coalition. There are significant transaction costs associated with coalitions, which rise as the number of participants increases. There are also competition policy concerns when members of those coalitions are in competitive market sectors.

Assessing the current arrangements in terms of the incentives they provide for efficient behaviour has implications for the current allocation of the costs of ancillary services, and these are brought out in our recommendations.

The current mechanisms for cost recovery and the current governance arrangements in New Zealand provide only weak incentives on parties to take decisions on the basis of minimising costs. There is therefore a need to ensure a high degree of transparency in relation to the costs incurred in achieving system operation targets. Effective contractual arrangements also need to be put in place, to enable these costs to be monitored effectively by those market participants from whom they are ultimately recovered. In addition, the contractual arrangements governing cost recovery should themselves provide the party taking the decision on the appropriate trade-off between the purchase of ancillary services and alternative actions with an incentive to try to minimise the costs it incurs.

NERA's recommendations focus on how cost transparency and effective monitoring can be achieved in practice, and also set out an appropriate form of incentivising arrangement.

2.3. Improving the efficiency with which ancillary services are purchased

In addition to improving the efficiency of the trade-off between the purchase of ancillary services and alternative actions, there is also potential to improve the efficiency with which ancillary services are purchased. For example, it may be possible to reduce the administration costs associated with purchasing ancillary services. Costs can also potentially be reduced through introducing innovations in the purchase arrangements, such as changes in tender procedures which allow a greater number of parties to offer to provide the required service.

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2 For the purposes of this report, the term 'market participants' is used to refer to generators, retailers, lines businesses and Transpower.

Such improvements in the efficiency of the purchase function would result in a further source of ancillary service cost reduction.

In our analysis we have considered:

i. the extent to which participation in the process of developing appropriate contractual arrangements for the procurement of ancillary services can be broadened, in order to promote innovation; and

ii. means by which the process of actually conducting tenders or other means of ancillary service procurement can be driven by a body independent of the party which is deciding on the appropriate trade-off between purchasing ancillary services and alternative actions.

Our recommendations with respect to improving the efficiency of the purchase function are set out below.

3. RECOMMENDATIONS

We have presented our recommendations in the context of the ten issues raised in the Industry Report. Key points of the recommendations are highlighted in Table 1.

Given the limited time in which this report has been prepared, we have only been able to make a broad assessment of the costs associated with alternative arrangements. Our recommendations therefore reflect a degree of judgement, based on our experience of what has worked in other systems, rather than an exhaustive analysis of the costs of alternatives in the New Zealand context.

It is important to recognise that there is no ‘perfect solution’ to the issues raised below. Rather, we have concentrated on pragmatic measures which may be expected to improve incentives for efficient behaviour, and hence reduce the costs associated with the provision of ancillary services from their current level. Our recommendations are aimed at establishing a transparent and workable framework within which all parties can operate.

Table 1: Summary of Key Recommendations

Service	Level of Costs (1998/99)	Cost Allocation (initial)	Cost Recovery
Frequency Control	$14.1m	CQC (currently Transpower); Costs of constraining on generators for frequency control also to be allocated to CQC	Retailers: c/kWh uplift on reconciled energy purchases
Instantaneous Reserves	$5.5m	No change: generators and HVDC link (in line with Stage 1 Belgrave Committee recommendations)	Generators' energy prices
Over-Frequency Arming	$0.2m	Transpower (grid owner)	Transmission use of system charges
Black Start	$0.04m	Transpower (grid owner)	Transmission use of system charges
Voltage Support	$5.7m	Transpower (grid owner) Agreed kVAr offtake between lines businesses and Transpower (grid owner)	Transmission use of system charges

3.1. General Issues

How should contracts between the industry and the system operator (Transpower) be structured so as to ensure that decisions on the mix of objectives achieve desired outcomes at least overall cost?

i. Contractual arrangements for ancillary services should be structured to provide market participants with an *incentive* to undertake an alternative action, when the total costs of that alternative are lower than the cost of ancillary services.

ii. The implications of the above principle for the current cost allocation arrangements are detailed in Table 1. Transpower (as grid owner) should bear the costs of voltage support, black start and over-frequency arming, in the first instance. CQC (currently Transpower) should bear the costs of frequency control, in the first instance. The costs of instantaneous reserves should continue to be charged to generators, in line with the Stage 1 Belgrave Committee recommendations.

iii. The GSC (or some other industry body) should agree with Transpower how, for frequency control, instantaneous reserves and voltage support, the audited cost of both:

- purchases under ancillary service contracts; and
- alternative actions which substitute for the purchase of that ancillary service (eg, network investment, out of merit order dispatch)

will be brought together as one account for each service.

iv. The GSC (or some other industry body) should agree with Transpower how the total cost for achieving each of the three system operation targets, as reflected in the above accounts, are to be recovered from other market participants. The basic form of such cost recovery should be an incentivising contract, under which a target cost associated with each system operation objective is agreed, together with the extent of any cost overrun Transpower has to bear and the percentage of any cost reduction it is permitted to keep.[3]

Such an arrangement would provide Transpower with an incentive to make efficient decisions regarding the trade-off between using ancillary service contracts and alternative actions (eg, dispatch, network investment). The parameters which determine this incentive arrangement should be subject to regular review by the GSC and Transpower (eg, annually).

[3] The key features of such an incentive contract are described in detail in section 4 of the main report

v. Relations between Transpower and the market participants from whom Transpower ultimately recovers its costs should be governed by an overall contract, which sets out the principles and methods of cost allocation. This contract should be negotiated between Transpower and the market participants via the GSC (or some other industry body), and may incorporate specific criteria covering the grounds on which Transpower is required to make its trade-off decision. Market participants can refuse to accept costs if there are strong grounds for arguing that Transpower has not complied with the principles and cost allocation methods in the contract.

vi. The GSC (or some other industry body) should continually monitor Transpower's decisions on the trade-off it makes and the costs incurred, and seek explanation where appropriate.

vii. In the medium term, institutional reforms may be necessary to strengthen market participants' expectation of long term cost recovery (eg, through some form of explicit contracting). Such reforms would remove the potential for bias in decisions in favour of incurring short run rather than long run costs.

How should the purchase function for ancillary services be structured so as to ensure ancillary services are purchased at least cost over time and the financial exposure of the industry is managed appropriately?

viii. There is an important distinction between the role of designing and agreeing contracts for ancillary service procurement and the role of deciding whether to purchase ancillary services under contract or to undertake some alternative action (eg, network investment or out-of-merit-order dispatch). Reducing the cost of ancillary services requires improvements in efficiency in <u>both</u> of these roles.

ix. We have interpreted the term "purchase function" as the role of designing and agreeing contracts for ancillary service procurement. (Our recommendations with respect to the role of deciding whether to purchase ancillary services under contract or to undertake some alternative action have been discussed in (i) to (vii) above.)

x. The system operator (CQC) should set down technical standards for the provision of frequency control, instantaneous reserves and voltage support, in consultation with the industry via the GSC (or some other industry group). These technical standards should be consistent with the system security standards defined in MACQS.

xi. The GSC should appoint an Ancillary Service Procurement Agent (ASPA). The role of the ASPA will be:

- to set down contractual requirements for provision of each of these ancillary services and determine procurement arrangements, in accordance with CQC's technical standards. Such a process will enable innovation in the sources of ancillary service that may be offered by market participants, in contract design and in procurement arrangements. CQC should be consulted as part of this process to ensure that the contractual requirements do comply with the technical standards. These contractual provisions and procurement arrangements should be reviewed by the ASPA on a regular basis (eg, annually), to provide an on-going process for introducing innovation into the procurement arrangements; and

- to organise and run, on a regular basis, a tender (or other procurement arrangement) for each of the three services, on the basis of the above contractual requirements. The ASPA tendering procedure will select providers of these ancillary services, on the basis of prices received, and issue these providers with contracts. The other party to these contracts will be CQC, for frequency control and instantaneous reserves, and Transpower (as asset owner) for voltage support.

xii. The GSC should explore ways of providing the ASPA with a performance incentive, eg, the fee that the ASPA is paid by the industry for performing the procurement service, as defined above, may be dependent on achieving a pre-defined outcome, such as a reduction in the average tender price.

What is the best contractual means of binding the relevant parties to the arrangements?

xiii. Currently the GSC contract structure envisages two means of requiring parties to arrange contracts with CQC. Firstly, entities currently connected to the grid will be required to enter into contracts with the CQC, as a condition of Transpower's use of system agreement. Secondly, entities not connected to the grid will also be required to to contract with the CQC. A potential option for enforcing the second arrangement is through requiring parties to NZEM and/or MARIA to also hold a contract with the CQC.

xiv. We would envisage that similar means could be employed to require parties to enter into contracts with CQC in relation to cost recovery for ancillary services. Such contracts should be of the form recommended in (v) above.

3.2. Frequency Related Services

To the extent that costs of frequency related ancillary services are allocated to 'off-take' or 'load', should that mean energy market participants (retailers), or lines businesses?

xv. Allocating the cost of frequency control to retailers rather than lines businesses would increase incentives for efficient behaviour. However, incentives would be increased further by allocating the costs to CQC in the first instance (see below).

xvi. Any agreement on the allocation of the costs of frequency control to retailers should occur through an existing industry forum, such as the GSC or the NZEM, to avoid competition policy concerns.

Are there good reasons for believing that moving to some basis other than 'cause' for allocating costs would achieve significant gains such as outweigh the costs of making a change?

xvii. Costs should be allocated on the basis of providing incentives for efficient behaviour (rather than on the basis of 'cause').

xviii. This principle implies the following:

- the costs of instantaneous reserves should remain allocated to generators, as presently;[4]
- CQC and generators should negotiate explicit contracts covering this cost allocation arrangement (in line with the recommendations under section 3.1 above). Such contracts should explicitly provide an incentive for CQC to lower its costs, through allowing it to retain a proportion of any cost saving, or bear a proportion of any cost increase;
- the costs associated with the purchase of frequency control and the costs of "constraining on" generation[5] should be allocated to CQC (currently Transpower), in the first instance;
- CQC's costs associated with frequency control should ultimately be recovered from retailers, via a c/kWh uplift on (reconciled) energy purchases. CQC and the retailers should negotiate an explicit contract (via the GSC) covering this cost allocation arrangement. This contract should provide CQC with an incentive to minimise the costs of achieving system frequency targets (in line with the recommendations under section 3.1 above).

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4 In line with Stage 1 of the Belgrave Committee's recommendations.

5 These costs arise as a result of managing frequency through dispatch. Currently, these costs are borne by energy market purchasers.

Should over frequency arming be allocated on the same basis: ie, the causor of the need for the service (in this case the owner of the HVDC link)?

xix. The costs of purchasing over- frequency arming should be reallocated to Transpower (as asset owner), to improve incentives for efficient behaviour.

3.3. Grid Related Services

Would incorporating black start costs into transmission charges along with a requirement for Transpower to publish each year the total cost of black start for the previous year (including any change in contingent liability) strike an appropriate balance between minimising administration costs and ensuring accountability?

xx. Black start costs should be reallocated to Transpower (as grid owner), in the first instance. Transpower should recover these costs through its TUOS charges.[6] Reallocating the costs of black-start in this way would not weaken incentives for efficient behaviour.

xxi. Transpower should publish its total black start costs each year, including the implied contingent liability, in order to ensure accountability.

To the extent that voltage support costs are allocated to 'off-take' or 'load' should that mean energy market participants (retailers), or lines businesses?

xxii. We recommend that the costs of voltage support be reallocated to Transpower (as grid owner). Such a reallocation would bring together all of the costs associated with the various alternatives for providing voltage support, to be faced by the same party.

xxiii. Transpower (as grid owner) would ultimately recover the costs of voltage support through its TUOS charges. However it would bear the risks associated with cost over-runs and the associated cost volatility in the first place.

xxiv. The costs Transpower recovers through its TUOS charges should be audited, and explicit criteria agreed between Transpower and the GSC (or some other industry body) to enable the reasonableness of the costs incurred to be monitored and to provide Transpower with an incentive to minimise costs (in line with the recommendations in section 3.1 above).

xxv. We recommend that a kVAr offtake limit (and associated power factor) be agreed for all distribution networks, and reflected in contracts between Transpower and each lines business. Lines businesses would be charged by Transpower for exceeding this offtake. Lines businesses and Transpower should be free to negotiate (transparent) variations to this required power factor, where that would lower overall system costs of meeting voltage support requirements.

[6] Transmission Use of System charges.

What are the appropriate instruments under which off-take would purchase MVArs and providers receive payment for MVArs?

Would the advantages of utilising an AC power-flow model for the purposes of scheduling, dispatch and pricing outweigh the disadvantages?

xxvi. There are currently no electricity markets internationally which price reactive power. There is therefore no information on which to assess the costs of an AC model against its benefits.

xxvii. From a practical standpoint, the introduction of a spot market for reactive power would not appear to be a viable alternative to the purchase of voltage support services, at least in the short- to medium- term.

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1. INTRODUCTION

NERA has been commissioned by the CEO's Forum[1] to provide recommendations on key issues in relation to the arrangements for ancillary services in New Zealand. Specifically, the CEO's Forum has identified ten key questions in its paper 'Ancillary Services: Key Issues and Questions'[2] (the "Industry Report"). These are the issues they feel need to be resolved in order to ensure efficient and effective contracting for ancillary services. NERA has been asked to make recommendations to cover both pragmatic solutions which can be implemented in the short-term and any additional improvements desirable for the medium term.

The structure of this report is as follows:

Section 2 sets out the framework we have used both to assess the current ancillary services arrangements in New Zealand and to assist in identifying potential improvements. We have used this framework as a means of considering the extent to which the incentives faced by market participants under the current arrangements encourage them to make choices which are consistent with improved system efficiency, and what changes would improve these incentives.

Section 3 presents our analysis of the application of the framework to each of the five ancillary services discussed in the Industry Report. Section 4 then outlines practical steps to achieve the recommendations which emerge. It also discusses measures to improve the efficiency with which ancillary services are purchased.

Section 5 brings together the conclusions and recommendations from sections 3 and 4 in a manner which directly responds to the ten questions posed in the Industry Report.

Given the limited time in which this report has been prepared, we have only been able to make a broad assessment of the costs associated with alternative arrangements. Our recommendations therefore reflect a degree of judgement, based on our experience of what has worked in other systems, rather than an exhaustive analysis of the costs of alternatives in the New Zealand context.

It is also important to recognise that there is no 'perfect solution' to the issues raised in the Industry Report. Rather, we have concentrated on pragmatic measures which may be expected to improve incentives for efficient behaviour, and hence reduce the costs associated with the provision of ancillary services.

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1 This forum consists of the Chief Executives of a number of lines and energy companies, representing a cross section of the New Zealand electricity industry.

2 *Ancillary Services: Key Issues and Questions*, 5 October 1999. We have also had regard to the Addendum on the *Status of Ancillary Service Arrangements*, which accompanied this paper.

2. FRAMEWORK FOR ASSESSMENT

Before we turn to look at each of the key questions raised in the Industry Report, it is worth setting out the framework we have used both to assess the current ancillary services arrangements in New Zealand, and to assist in identifying potential improvements.

2.1. Scope of Assessment

A key concern raised in the Industry Report is how to ensure that decisions on the mix of instruments used to achieve system operation targets achieve the desired outcomes at lowest overall cost. Responding to this concern has implications for the appropriate allocation of ancillary costs between market participants, which is itself a further issue raised in the Industry Report.

The Industry Report expresses the view that the quantity of ancillary services currently purchased, and the balance between some of these services, may not be efficient, given the relative costs of individual ancillary services and the cost of alternative measures which would reduce the level of ancillary services required.

There are two trade-off decisions which are made under the current regime:[3]

i. Transpower decides whether to purchase ancillary services or to achieve system operation targets through alternative means (eg, through investing in the grid); and

ii. other market participants decide whether or not to undertake actions (eg, investment in the distribution system, load management) which reduce the need for (and therefore the costs associated with) the purchase of ancillary services.

We have used the framework set out in this section as a means of considering the extent to which the incentives faced by market participants under the *current* arrangements encourage them to make choices which are consistent with improved system efficiency. We have also assessed what *changes* would improve these incentives. That is, what changes can be made (both short and long term) to improve incentives for market participants to behave in a way which lowers the overall system cost of achieving system operation targets.

In addition to improving the efficiency of the trade-off between the purchase of ancillary services and alternative actions, there is also potential to improve the efficiency with which ancillary services are purchased. Such improvements in the efficiency of the purchase function would result in a further source of ancillary service cost reduction. We consider this further in section 4.2.

[3] The questions of (1) the appropriate level of system operation targets (which determines the quantities of either ancillary services or alternative actions required), and (2) of the balance between services which are to be provided as a condition of connection to the grid and those which are purchased separately, are beyond the scope of the current report.

2.2. Identifying Appropriate Incentives

In general, in order to improve overall efficiency in meeting system operation targets, the contractual arrangements in the ancillary services market should provide market participants with an *incentive* to undertake an alternative action, when that alternative is lower cost relative to the purchase of ancillary services. [4]

The following five questions provide a framework for assessing the appropriateness of incentives under alternative arrangements for ancillary services.

- **What are the alternatives to purchasing each of the ancillary services?**

First, we have considered what alternative actions would replace or reduce the need to purchase each of the ancillary services discussed in the Industry Report. These alternatives will obviously differ for each of the services being considered.[5]

For example, in order to maintain system frequencies within the required band, the alternatives available to purchasing frequency control services include managing frequency through dispatch or through varying the flow of power over the HVDC link.[6] Similarly, voltage levels can be maintained within specified limits through the purchase of voltage support services (either static or dynamic), or through investment in voltage support equipment.

In theory, the alternatives identified in response to the above question could be carried out by a number of parties, including end-use consumers, retailers, generators, distribution lines businesses, Transpower (in its role as transmission asset owner or as system operator) or even a party outside of the electricity industry. The remaining questions in the framework are designed to assist in identifying, (1) who currently has an incentive to undertake one of the alternative actions identified, when that represents an efficient outcome from a system perspective, and (2) whether there are other parties who would have a stronger incentive if the current arrangements for ancillary services were changed.

- **Under the current ancillary service arrangements, who bears the costs associated with purchasing ancillary services? Who would benefit, by avoiding the current cost associated with purchasing ancillary services, if one of the above alternatives to purchasing ancillary services was undertaken?**

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[4] For the purposes of this report, the term 'market participants' is used to refer to generators, retailers, lines businesses and Transpower.

[5] The alternatives we have identified in response to this first question reflect either those alternatives which are currently available or which can currently be anticipated. Our analysis is therefore largely static. Other, currently unknown, alternatives may well emerge in the future. Moreover, the commercial incentives market participants face may themselves encourage the development of new alternatives. However, the focus of our brief is to develop *pragmatic* recommendations, and we have therefore restricted the analysis to known alternatives. The potential for new alternatives to emerge highlights the importance of keeping the arrangements for ancillary services under review, in order to ensure that conclusions reached now remain applicable in future periods.

The incentives for any party to undertake (or to fund another party to undertake) one of the alternative actions identified in the previous question will depend on the extent to which they can capture the benefits of such actions, defined in terms of the expected reduction in the ancillary service costs they face.

Market participants will have an incentive to undertake an alternative measure if the cost of doing so is less than the amount by which they will benefit (in terms of the ancillary service costs they avoid through undertaking the alternative measure). Where the costs market participants face reflect all of the system costs of both the alternatives and the ancillary services, then decisions to proceed with lower cost alternatives will represent an efficient system outcome.

The benefits realised by market participants (and therefore the incentives they face) in turn depend on:

i. the allocation of the costs of ancillary services (*ie, who benefits from a reduction in these costs as the result of pursuing an alternative?*); and

ii. the extent of any positive network externalities (*ie, is it only the party incurring the cost of undertaking the alternative action that benefits?*).

In order to identify who would benefit from undertaking an alternative, it is first necessary to identify who currently bears the cost associated with each ancillary service. The Industry Report has already identified which market participants bear the cost of each ancillary service under the current arrangements.

The second point relating to positive externalities deserves further clarification. The existence of a positive externality means that one party may incur the cost of an alternative, but the benefits (in terms of the ancillary service costs avoided) will also accrue to other parties, rather than solely to the individual undertaking the action. If this is the case, there may then be a range over which the cost of pursuing an alternative is greater, for that one individual, than the benefits they will obtain, although less than the benefit that accrues to all parties. The greater the extent of the externality, the larger will be this range. From a system point of view, undertaking the alternative would be efficient, since it reduces overall system costs. However, no individual party will have an incentive to undertake the alternative, since they cannot capture the full system benefit.

Positive externalities are a common feature of networks. A solution often requires a coalition of beneficiaries to be formed, in order to internalise the costs and benefits. However, there will be coordination costs associated with forming a coalition, which can be expected to rise along with the number of parties involved. For example, one would expect the cost associated with coordinating a large number of end-users to be greater than that associated with coordinating a smaller number of lines businesses or generators. This transaction cost needs to be considered in assessing the cost of pursuing an alternative.

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[6] The High Voltage DC (HVDC) link connects the transmission networks in the North and South Islands.

For the purposes of this paper, we have designed a transparent index of such transaction costs. This index is intended to be illustrative only, but provides a useful means of comparing the likely scale of transaction costs associated with the formation of coalitions by different groups of market participants.[7]

It is also important to note that competition policy may prove to be a factor limiting the extent to which it is permissible to form a coalition of market participants, particularly in the retail and generation sectors where there is currently competition.

In order to answer the second question in our framework fully, we therefore need to consider not only who currently bears the cost associated with each ancillary service, in the first instance, but also the extent to which those parties are able to capture the benefits of undertaking an alternative and the extent to which the benefit also accrues to others.

- **Are there other parties who would be able to capture more of the benefits associated with pursuing alternatives, assuming that the costs of pursuing such alternatives were assigned to them instead of to the party or parties who currently bear the cost of purchasing ancillary services? What implications does this have for the optimal allocation of the costs of ancillary services or alternatives?**

We have already noted that the alternatives identified in answer to the first question could in theory be carried out by a number of parties. Improving overall system efficiency implies that contracts need to be designed so as to place the incentive to undertake alternative actions with that party (or those parties) that face the lowest cost in doing so, and are best able to capture the benefits.

The cost of undertaking the alternative includes *transaction* costs, associated with any need to form a coalition of beneficiaries. It also includes the *information* costs parties face in pursing alternatives. We would expect the size of these information costs to increase, the lower the degree of overlap of the alternatives with the market participant's current business activities. That is, where the alternative is very different to the market participant's current business, there will be very few, if any, economies of scope associated with that market participant undertaking the alternative. Conversely, where the alternative does overlap with the market participant's current areas of

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7 Our index has been derived on the basis of the following assumptions:

(i) the cost associated with negotiating and agreeing a contract between two parties is NZ$50,000 (ie, three weeks of time at average consultant rates); and

(ii) the cost of negotiating and agreeing a contract within a coalition will rise in relation to the number of bilateral relations there are within that coalition.

As a result of (ii), the transaction costs associated with a coalition will rise exponentially with the number of participants. The number of bilateral relationships in a coalition of n participants is (n-1)+(n-2)+(n-3)…+1.

For example, there are five main generating companies within New Zealand. There are ten possible bilateral discussions within this group of five generators. The transaction costs of forming a coalition of these five generators is therefore estimated at $50,000*10, ie, $500,000.

Such an estimate is of course a simplification of the actual costs that would be associated with forming such a coalition in practice, but, applied consistently across different groups of market participants, it provides a useful illustration for the purposes of this paper.

business, there will be economies of scope and, hence, lower information costs associated with the alternative.[8]

Where information costs become significant, parties will in practice appoint an agent, ie, a party with better information, to undertake the alternative on their behalf. However, although this avoids the information costs, the parties appointing the agent will incur further transaction costs in negotiating an appropriate contract with the agent, to incentivise the agent to act in a way consistent with the aims of the appointing parties and to ensure a sufficient degree of transparency, so that the agent's behaviour can be monitored.

We have therefore considered whether there are other parties who would be better placed to undertake an alternative, in terms of their ability to capture more of the benefit associated with the alternative and to incur lower costs in its implementation,[9] than those parties currently bearing the cost of ancillary services. The response to this question will have direct implications for the allocation of the costs of ancillary services or alternative actions.

- **How do the current mechanisms for cost recovery and current governance arrangements affect the incentives discussed above?**

The preceding discussion of the incentives on market participants to behave in a way which maximises system efficiency has focused on the incentives arising as a result of who bears the costs associated with each ancillary service, in the first instance. In particular, we have assumed that market participants will take decisions on the basis of minimising costs. However there are two other important factors which should be taken into account:

i. what are the arrangements for market participants to recover costs?

ii. will market participants take decisions on the basis of minimising the costs they face?

Ultimately, market participants will seek to recover both the costs of ancillary services and the costs of undertaking alternatives from other market participants and, eventually, end-use consumers. Such mechanisms for eventual cost-recovery include network charges (both transmission and distribution) and the prices charged by both generators and retailers for energy.

The arrangements surrounding these mechanisms may also have an impact on incentives. This is because market participants' incentives will be determined not just by the relative costs of alternative options, which they bear in the first instance, but also by a desire to minimise the probability of non-recovery of those costs. Crucially, in the absence of an explicit contract which provides a high degree of assurance that investment costs will be allowed to be incorporated within

[8] For example, in the case of investment in the distribution network, lines businesses will have access to their own engineers and already have information about the past performance of the network. They therefore face greater economies of scope in undertaking investment in the distribution network than would a coalition of generators, who would need to find ways of acquiring that information.

[9] Including information costs and the transaction costs associated with appointing an agent.

future charges, participants may perceive a greater likelihood of cost recovery in the short-term rather than the long-term.

Inefficient outcomes (from a system perspective) may arise if there is any difference in a market participant's expectation of its ability to recover any (or part) of the costs it incurs in relation to ancillary services compared with alternative measures. For example, a market participant may perceive an alternative action to be lower cost than the reduction in ancillary service charges it will achieve. From a system point of view, undertaking the alternative would be efficient, since it would reduce overall costs. However, the market participant may perceive that the mechanisms in place for it to recover its costs are more robust in the case of ancillary service charges, than they are for the alternative. Such differences may arise as a result in differences in the cost-recovery mechanisms themselves, or from differences in the nature of the costs incurred (ie, whether they are short or long term). The lower expectation of cost recovery will therefore weaken the incentive for the market participant to pursue the lower cost alternative. In some instances, therefore, market participants may not have strong enough incentives to pursue alternatives, even though those alternatives represent a more efficient outcome from a system point of view.

In addition, our discussion of the incentives on market participants to behave in a way which maximises system efficiency has assumed that such participants will take decisions on the basis of minimising costs. In New Zealand, a large number of the companies operating in the electricity sector are either state owned corporations (Transpower, some generators) or are owned by community trusts (lines businesses, some generators). The extent to which current governance arrangements affect the objectives of market participants therefore needs to be taken into account.

- **What changes would improve incentives for efficient behaviour?**

Working through the answers to the above four questions will highlight the extent to which the current arrangements for purchasing each ancillary service provide sufficient incentives for market participants to pursue alternatives which reduce the need for ancillary services, when these alternatives represent a lower cost outcome for the system as a whole.

As a result, the framework provides a means for assessing the extent to which changes to the current arrangements would improve the incentives for efficiency under the current arrangements. It also provides insight into what would need to be achieved in order to implement a more robust, longer-term solution.

3. APPLYING THE FRAMEWORK

The previous section outlines the general framework we have used in assessing the current arrangements for ancillary services in New Zealand and in evaluating potential alternatives. This section of the report applies this framework to each of the ancillary services identified in the Industry Report in turn, namely:

i frequency control;

ii instantaneous reserves;

iii over-frequency arming;

iv black start; and

v voltage support.

Several implications emerge in relation to the key issues highlighted in the Industry Report. These are brought out explicitly in section 5of this report.

3.1. Frequency Control

3.1.1. What are the alternatives to purchasing frequency control services?

Maintaining system frequency within the desired range is identified in the Industry Report as one of the system operation targets for which a range of alternative instruments can be used.

Frequency control services have historically been purchased by Transpower (as system operator) from generators. Alternative means of maintaining system frequency, which would reduce the need to purchase frequency keeping services, include:

- varying dispatch in closer intervals;
- investment to enhance the capability of the HVDC link to 'fine-tune' injections of power into the North Island; and
- load management systems, which can allow load to be tripped in response to frequency changes.[10]

[10] We understand from discussions with Transpower that instantaneous reserves and frequency control are <u>not</u> substitutable products. Specifically, instantaneous reserves are required to maintain frequency in response to a significant outage of generation or a significant change in load: frequency control services would not be able to be substituted for the use of reserves in such instances. To the extent that future developments do result in these services becoming considered as substitutes, then the conclusions reached in this report regarding the allocation of costs would need to be revisited. In particular, contracting and purchase arrangements should unite the costs associated with both frequency control and instantaneous reserves, and the alternatives to both, so that they are borne by the same party, in order to provide incentives for a trade-off between all the relevant options which minimises overall system costs.

In order to maintain frequency by varying dispatch, it may be necessary to invest in more sophisticated IT systems for system operation. The costs of managing frequency through dispatch will also include the costs of "constraining on" generators.

The frequency of the system can also be maintained by varying load, rather than generation, as currently. In particular, the Industry Report notes that it is potentially possible to install devices which trip customer load in response to frequency changes. Such an option could be an alternative to the purchase of ancillary services from generators.[11]

Currently the cost of purchasing frequency control services is around $14m.

3.1.2. Under the current ancillary service arrangements, who bears the costs associated with purchasing frequency control? Who would benefit, by avoiding the current cost associated with purchasing frequency control, if one of the above alternatives was undertaken?

Currently the costs of purchasing frequency control are allocated, in the first instance, to the lines businesses. The extent to which this cost allocation provides the lines businesses with an incentive to pursue actions to reduce the need to purchase ancillary services (when such actions are lower cost) depends on their ability to capture the benefits, in terms of the avoided costs of ancillary services.

The extent to which lines businesses incur all of the system costs associated with the alternative will also determine whether the incentives they face to undertake alternative options will lead to behaviour which improves system efficiency. The costs associated with investment in IT systems or in the capability of the HVDC link or those of installing and operating load tripping mechanisms would be borne directly by the lines businesses. The costs associated with "constraining on" generation (as a result of managing frequency through dispatch) are currently borne by purchasers in the energy market (ie, retailers and large consumers), through higher uplift charges.[12]

If any individual lines business undertook one of the alternative options identified, it would result in a reduction in frequency control charges to that lines business, and also to all of the other lines businesses. That is, the benefits of undertaking any of the alternative options would accrue to all of the lines businesses (through reducing the charges they face for ancillary services); no one individual lines business is able to capture all of the system benefit. This means that, for some alternatives, the cost to any individual business may be greater than the benefits that business would accrue, although below the benefit to the system as a whole. An individual business will not have an

[11] In addition, it may represent an alternative source of providing frequency control. The difference relates to whether load management is being undertaken to reduce the *demand* for frequency control (as it is if considered as an alternative to the purchase of ancillary services), or to increase the *supply* of frequency control services (as it is if considered as a source of frequency control). The difference between load management as a factor affecting the demand for or the supply of frequency control will be reflected in the institutional arrangements for procurement and cost recovery.

[12] If generators are "constrained on" to provide frequency support, through the purchase of frequency control, then these payments are met by Transpower, who passes them through to lines businesses, in the first instance. However, if Transpower manages frequency through dispatch of the energy market (rather than through the purchase of frequency control), then the costs of "constraining on" generators is added to the 'uplift' component of energy prices.

incentive to undertake that alternative action, even though it would improve overall system efficiency.

There are 29 lines businesses in New Zealand, all of whom would benefit from lower ancillary service charges following the implementation of an alternative to the purchase of frequency control. In order to capture all of the system benefits it would therefore be necessary for these businesses to form a coalition. The transaction costs associated with coordinating such a coalition and agreeing on the appropriate action to undertake are likely to be fairly significant, given the number of companies involved. On the basis of our index, we would assign a value of $20.3m to these transaction costs.[13]

In addition, although such a coalition would internalise the benefits associated with pursuing an alternative, it would not internalise all of the costs in the case of managing frequency through dispatch, since the costs associated with "constraining on" generation are currently borne by retailers (as well as consumers purchasing direct from the energy market).[14] As a result, a situation could arise in which a coalition of lines businesses may have an incentive to manage frequency by dispatch as the result of the direct cost to them being less than the benefit they receive in terms of reduced frequency control charges, even though the total system cost (ie, including the cost borne by retailers in the form of higher uplift charges) associated with managing dispatch is above the cost of purchasing frequency control.

In addition, lines businesses would face significant *information* costs in undertaking the alternatives identified. Costs would be incurred both in identifying and undertaking *investment* in any systems upgrade necessary to enhance the capability to manage frequency through dispatch, or in improving the capability to vary the capacity of the HVDC link. There would also be significant information costs associated with the actual *operation* by the lines businesses of the dispatch process to achieve frequency control (including the operation of the HVDC link). In our view, these costs are likely to be prohibitive and would lead the lines businesses to appointing an agent with better information to manage both investment and system dispatch on their behalf. However, there are *transaction* costs associated with designing a suitable contract to incentivise such an agent to act in a way consistent with the lines businesses' cost minimising objectives.

The lines businesses would also face information costs relating to actions to manage load, although we would expect these costs to be lower than in the case of the other two alternatives, as lines businesses have more direct experience of the pattern of load flows in the system and therefore would have some economies of scope in undertaking load management.

3.1.3. Are there other parties that would be better placed to capture the benefits?

The above discussion implies that the current allocation of the costs of frequency control to the lines businesses may not be efficient, in terms of providing an incentive for the businesses to pursue

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[13] Within a coalition of 29 participants there are 406 possible bilateral discussions. Assigning a cost of $50,000 to each discussion gives a total of $20.3m

[14] In the rest of this report, we use the word "retailer" to refer to both retail companies and direct-use consumers.

alternatives to the purchase of frequency control (when these alternatives are cheaper from a system perspective).

The alternative actions identified in section 3.1.1 can in theory be undertaken by number of parties, including end-use consumers, retailers, generators or Transpower (either in its role as transmission asset owner or as system operator).

3.1.3.1. End-use consumers

There are 1.6m end-users in New Zealand. The large number of end-use consumers and the existence of positive network externalities means that action by any one individual end-user would only capture a very small fraction of the benefit. However, the number of participants necessary to form a coalition would need to be much greater than in the case of the lines businesses, since the benefits are shared among a greater number of parties. Again, we would expect that the transaction costs associated with establishing a coalition and agreeing on an action are likely to rise with the number of participants. The number of end-users is such that we would expect such costs to be prohibitive. Certainly, the extent of such transaction costs will be several orders of magnitude greater in the case of end-users than in the case of lines businesses.

3.1.3.2. Retailers

One of the questions raised in the Industry Report is whether the costs of frequency related ancillary services should be allocated to retailers rather than to lines businesses, as is the case currently. Allocating the costs to retailers would provide them with an incentive to avoid these costs by undertaking alternative measures to reduce the need to purchase frequency control.[15] However, again, the extent of this incentive for any one retailer will depend on their ability to capture the benefit (in terms of avoided costs) associated with the alternative. The existence of positive externalities means that any one retailer will not be able to capture all of the benefits associated with undertaking an alternative.

There are currently around ten retail companies operating in New Zealand.[16] On the basis of our index, this would imply transaction costs of around $2.25m, ie, *below* that associated with the lines businesses.[17] However, there are two further factors which should be borne in mind.

The first is that retailers may be anticipated to both enter and leave the market over time. Any coalition of retailers would also therefore need to be able to deal with the addition of new members and the exit of old ones. We would expect that this would directly complicate the formation of a coalition, potentially increasing the associated costs above those shown in our index.

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15 Given that the cost of "constraining on" generators in the energy market is currently borne by energy purchasers, retailers (as a group) also incur all of the costs associated with the alternative actions.

16 Plus a small number of direct-use customers.

17 There are 45 possible bilateral relationships within a coalition of 10 retailers. At an average cost per relationship of $50,000 this gives a total transaction cost of $2.25m.

Secondly, there are likely to be restrictions placed by competition policy on the extent to which a coalition of retailers is acceptable, given that retailers operate in a competitive market.

3.1.3.3. Generators

The costs of frequency support could also be allocated to generators. Any action by an individual generator would result in a benefit (in terms of a reduction in ancillary service costs) across all generators. Again, in order to capture all of the benefits of an alternative, generators would need form a coalition. There are five main generators operating in New Zealand.[18] Our index of transaction costs suggests that the transaction costs associated with such coalitions may be in the order of $0.5m, ie, below the costs of both retailers and lines businesses. However, a coalition of generators would not internalise all of the costs of frequency control, if the cost of "constrained on" generators continues to be passed through to energy purchasers via uplift.

In addition, there are again likely to be competition policy concerns associated with a coalition of generators who are operating in a competitive environment.

3.1.3.4. NZEM, MARIA and MACQS

On the basis of relative transaction costs, generators and retailers appear to be potentially better placed than lines businesses to capture the benefits of undertaking alternatives to frequency control, as a result of the smaller number of participants necessary for a coalition. However, we have noted that there are likely to be restrictions placed by competition policy on the extent to which coalitions of generators or retailers are acceptable, given that each operates in a competitive market.

There are some existing coalitions in the New Zealand market which it is worth considering further in the context of frequency control, namely the NZEM, MARIA[19] and the multilateral agreement, MACQS.[20] All three of these coalitions have received Commerce Commission approval.

The NZEM is comprised of both generators and energy consumers. The NZEM Rules Committee is the body which was previously responsible for negotiating with Transpower (as system operator) over the delivery specifications of the IT systems necessary to run the market, and the payment Transpower received. To a large extent, therefore, this represents an existing coalition, which has a proven track record in negotiating, both among coalition members and with Transpower. If the costs of frequency control were allocated across retailers through NZEM (rather than lines businesses as at present) then this grouping has the potential to internalise all of the costs and benefits associated with each of the alternatives. Since this grouping already exists, the transaction costs of bringing generators and retailers together in this way is likely to be lower, although there will still be negotiation costs in relation to the actual decisions taken.

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18 We understand that there are a number of small IPP hydro generators, in addition to the five main generating companies.

19 Metering and Reconciliation Information Agreement (MARIA).

20 The Multilateral Agreement on Common Quality Standards (MACQS) is intended as a forum for industry bodies to come together to determine common elements of system security and quality and decide arrangements for ancillary services and cost allocation (among other things).

MACQS is a multilateral agreement between industry participants which is currently in the process of being established, as the outcome of the Grid Security Policy review. We understand that to date 70 per cent of generators and 80 per cent of retailers have joined MACQS but that no lines businesses have yet agreed to join. The ultimate composition of the MACQS coalition is yet to be established. The effectiveness of the Grid Security Council (GSC), as the representative body for MACQS, in acting as a negotiating party is also as yet untested. It is therefore difficult at this stage to draw conclusions about the extent to which GSC is an appropriate body to determine the trade-off between the purchase of frequency control and investment in alternative actions. However, it is clear that it has significant potential to act in the role of a coalition.

3.1.3.5. Information costs faced by each of the above market partipants

In addition to the costs associated with forming a coalition, each of the market participants discussed above (including the NZEM, MARIA and the GSC) would also face significant information costs associated with pursuing each of the alternatives identified; the exception being retailers in the case of load management. These information costs would in practice be likely to lead the market participants to appoint an agent (who would be a party with superior information) to undertake the action on their behalf.

Transpower (in its role of system operator) is the most obvious agent in the case of investment in IT systems for dispatch and actual system operation, since it is the party which would have the lowest information costs (ie, greatest economies of scope) in undertaking this role. In addition, since Transpower is also the current asset owner of the HVDC link, it would have superior information to the lines businesses relating to any investment in the HVDC link, and so may also be an appropriate agent in this case too.[21]

Under such an agency relationship there is a need to either design appropriate contractual relationships which correctly incentivise the agent to behave in a way which corresponds to the objectives of the appointing coalition, or to ensure that there is a sufficient degree of transparency to allow the agent’s behaviour to be monitored.

3.1.3.6. Transpower

The other party which we have yet to consider in relation to who could bear the costs of frequency control is Transpower. If Transpower were allocated the costs of frequency control and if it were to manage frequency either through dispatch, through the operation of the HVDC link or through load management, it would receive the entire benefit of doing so, through a reduction in the ancillary services charges it faced. There would be no need for Transpower to form a coalition to internalise these benefits: in relation to our index it would have zero transaction costs.

Under the current institutional arrangements, Transpower would not bear all of the system costs associated with management of frequency through dispatch, since the cost of “constraining on”

[21] In the case of load management, Transpower (in either of its roles) would face greater information costs than would either the lines businesses or retailers.

generation is borne by purchasers in the energy market, via uplift. Since it does not bear the full costs associated with alternatives, its incentives may not lead to a trade-off which is the most efficient (ie, least cost) from a system point of view.

In order to internalise all of the system costs to Transpower, the costs of "constraining on" generators in the energy market would therefore also need to be allocated to Transpower directly, in the first instance. This would result in Transpower facing a trade-off between its own costs and benefits consistent with the overall system costs and benefits.[22] This would be consistent with practice in the UK, where NGC acts as principal (rather than agent) in relation to the trade-off between frequency control and managing frequency via dispatch, and as a result bears a proportion of the costs associated with out of merit dispatch.[23]

Transpower would ultimately recover its costs associated with frequency control via an uplift on energy purchases charged to retailers (ie, a c/kWh charge). A c/kWh uplift charge represents a lower barrier to entry to new retailers than would a fixed monthly charge or annual charge, given that retailers may be expected to be both entering and leaving the market. In order to minimising the scope for parties to avoid the uplift charge, it should be applied through direct contractual relationship between CQC and retailers, based on the reconciled volumes settled through MARIA.

3.1.4. How do the current mechanisms for cost recovery and current governance arrangements affect the incentives discussed above?

The above discussion implies that assigning the costs of frequency control and the costs of generators being "constrained on" to Transpower, as system operator (CQC), would improve incentives for efficient behaviour. However, we also need to consider whether there are any aspects of the current institutional arrangements in New Zealand which would affect these incentives.

Assigning the costs of frequency control directly to Transpower (as system operator) in the first instance, implies a significant departure from its current role as an agent in purchasing ancillary services on behalf of other parties. It would transform Transpower into a principal (as opposed to an agent) in relation to frequency control services. As a consequence, Transpower would directly bear the risks associated with fluctuations in the level of frequency control costs.

In the UK, NGC has acted as principal in relation to frequency control since 1994/95. The costs of ancillary services fell by over 30% in real terms following the change in arrangements.[24]

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22 It has been suggested that in managing frequency through dispatch Transpower may impose costs on other parties, in particular generators (through increased wear and tear) and energy users, through a reduction in service quality. With respect to the latter, we recommend that service quality objectives are specified contractually as part of the MACQS agreement.

23 In the UK these out of merit dispatch costs are called "operational outturn" costs. The limit to NGC's exposure to operational outturn costs (which in turn limits the risk NGC faces as principal) was negotiated with the England & Wales Pool, as part of the arrangements for NGC accepting the role of principal in relation to frequency control services.

24 NGC's operating costs for ancillary services fell 33% between 1993/94 and 1994/95. Real costs rose 18% in 1995/96, but have continued to decline in real terms since then. The total (real) reduction in costs between 1993/94 and 1999/98 has been 37%. A cost breakdown relating solely to frequency control is not available.

We recognise that the degree to which the industry (including Transpower) is prepared to accept Transpower acting in the role of principal (rather than agent) in relation to the purchase of frequency control will determine whether such a change is acceptable and the timeframe within which such a change could be achieved.

Moreover, we would expect Transpower's ability to bear both the risk associated with a role as principal, and the cashflow volatility, to depend to some extent on the continued amalgamation of its system operator role (CQC) and grid ownership. If the CQC function were to be separated from grid ownership, the extent to which CQC (as an independent entity) is able to act as principal would need to be reassessed.[25]

A further caveat is that Transpower may not take decisions on the appropriate trade-off between the purchase of ancillary services on the basis of minimising the costs it faces, as a result of it being a state owned company subject to influences other than profit maximisation.

3.1.5. What changes would improve incentives for efficient behaviour?

The above discussion indicates that, since the costs and benefits associated with alternatives to purchasing frequency control currently accrue to a wide range of parties, the current arrangements of allocating the costs of purchasing frequency control to lines businesses do not provide strong incentives for efficient behaviour. There are likely to be significant transaction costs associated with the lines businesses undertaking any of the potential alternatives to the purchase of frequency control services. Moreover, lines businesses do not bear all of the system costs associated with managing frequency through dispatch.

From the discussion in 3.1.3, it appears that Transpower (CQC) would be better placed to capture the benefits of alternatives to frequency control. It would ultimately recover these costs through a c/kWh uplift charge on reconciled energy purchases.

We note that the current governance arrangements in New Zealand may not provide Transpower with a strong incentive to make decisions on the basis of minimising costs. This implies the need for both a high degree of transparency regarding the costs that Transpower incurs in relation to frequency control and for an explicit contractual agreement between Transpower and retailers covering the costs that can be passed through to them. This cost allocation agreement should be of a form which provides Transpower with a direct incentive to minimise the cost of achieving system frequency targets.

Section 4.1 discusses how such transparency can be achieved in practice and sets out an appropriate form of incentivising contract for Transpower.

[25] The GSC and Transpower will jointly review within two years whether the CQC function should become contestable.

3.2. Instantaneous Reserves

3.2.1. What are the alternatives to purchasing instantaneous reserves?

Instantaneous reserves are purchased by Transpower to maintain system frequency. In particular, the purchase of instantaneous reserves allows system frequency to be maintained in response to large jagged changes in generation or load. (The purchase of frequency control services, discussed in the previous section, allows frequency to be maintained in response to much smaller and smoother changes in generation and load).

The main alternative to purchasing instantaneous reserves would be investment to improve the frequency keeping tolerance of generation or the HVDC link.[26]

The cost of purchasing instantaneous reserves was close to $11m in 1996/7. However, this cost has fallen to $5.5m in 1998/99, following the derating of the HVDC link and an increase in the volume of interruptible load offered into the market.

3.2.2. Under the current ancillary service arrangements, who bears the costs associated with purchasing instantaneous reserves? Who would benefit, by avoiding the current cost associated with purchasing instantaneous reserves, if the above alternative was undertaken?

Generators and Transpower (as owner of the HVDC link) currently bear the costs associated with purchasing instantaneous reserves.

Charges for instantaneous reserve are levied in two parts. Availability charges are levied across all generators and on Transpower (as owner of the HVDC link) and, in the first instance, are set at a level designed to recover the expected costs of instantaneous reserve over the year. Event based charges are then levied on the owners of failing plant, as a flat fee related to MW interrupted[27], and are passed through as a rebate on the availability charge to other generators, or the grid.

The costs incurred by each generator and Transpower (as owner of the grid) are therefore directly linked to the non-availability of their individual plant. If a generator invests in order to improve the frequency keeping tolerance of its plant, it will lower its expected event charges it faces, but not the event charges faced by other generators or the HVDC link. There are no positive externalities associated with investment by any one individual; individual generators are able to capture all of the benefit of undertaking the alternative. Under the current cost allocation mechanism, therefore, generators and Transpower (as owner of the HVDC link) do face incentives which encourage efficient behaviour.

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26 We understand that it may also be possible to reduce the demand for frequency keeping services through innovations in dispatch, eg shortening the dispatch period, or calling non-offer generation.

27 Either MW of injection from generation interrupted, or MW of the HVDC link or AC grid transfer unavailable.

3.2.3. Are there other parties that would be better placed to capture the benefits?

The alternatives identified in section 3.2.1 relate to investment in generation and the grid. End-use consumers, retailers and lines businesses would all face information costs above those of the generators and Transpower (as asset owner), in identifying and undertaking these alternatives, since they would be able to exploit fewer economies of scope with their current business activities. Moreover, there would be positive externalities associated with investment undertaken by any one member of any of these groups, since it would not be possible to link event charges with actions by any one individual retailer, lines business or end-use consumer. This in turn implies the need to form a coalition of beneficiaries in order to align incentives with actions that would be efficient from a system perspective, with the associated transaction costs.

It does not therefore appear that another party is better placed to capture the benefits of undertaking alternatives to the purchase of instantaneous reserves.

3.2.4. How do the current mechanisms for cost recovery and current governance arrangements affect the incentives discussed above?

Generators currently recover both the cost of instantaneous reserve charges and the costs associated with investment through their energy charges. There is nothing in the cost recovery mechanism that would lead them to prefer the purchase of ancillary services over investment.

3.2.5. What changes would improve incentives for efficient behaviour?

Given the analysis in section 3.2.2 and section 3.2.3 above, the current allocation of the costs of instantaneous reserves appears to provide the best incentives for behaviour with regard to the trade-off between the purchase of instantaneous reserves or alternative investment consistent with achieving system frequency targets at the lowest cost to the system as a whole. We would not therefore suggest any change to the current cost allocation arrangements.

We recommend that Transpower (CQC) continues to act as the central purchaser for instantaneous reserves, on behalf of the generators. There are two potential options for improving the performance of CQC in this agency role. The first is to increase the transparency associated with CQC's purchasing function (see section 4.1). Since CQC currently pays the market clearing price for instantaneous reserves, the costs incurred by CQC can be made reasonably transparent.

It may also be desirable for the generators to negotiate a performance related contract with CQC, to provide it with a direct incentive to minimise purchase costs. An appropriate form of such a contract is set out in the annex.[28]

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[28] We would view the potential for efficiency improvement in the purchasing arrangements for instantaneous reserves to be lower than in the case of frequency control, as a result of the market for reserves having already been opened up to parties other than generators. As a result, we would view the need to put in place such incentivising contracts on CQC as a lower priority than in the case of frequency control. However, this conclusion is based on a degree of judgement and therefore we recognise that there may be alternative views.

3.3. Over-Frequency Arming

3.3.1. What are the alternatives to purchasing over-frequency arming?

Over-frequency arming services are purchased by Transpower in order to protect against a sudden and substantial rise in system frequency in the South Island in the event that the HVDC link were to trip at a time when a substantial quantity of energy was being sent to the North Island.

An alternative action which would reduce the need to purchase over-frequency arming services would be to undertake investment in the HVDC link to lower the probability of it tripping.

The current purchase cost of over-frequency arming services is less than $0.2m.

3.3.2. Under the current ancillary service arrangements, who bears the costs associated with purchasing over-frequency arming? Who would benefit, by avoiding the current cost associated purchasing over-frequency arming, if the above alternative was undertaken?

The cost of over-frequency arming is currently charged to the two generating stations in the South Island. It is these generators who would benefit from investment in the HVDC link which reduced the need to purchase over-frequency arming, in terms of avoiding the current cost of purchasing over-frequency arming.

If investment in the HVDC link was undertaken by either of the two generators individually, then, as well as reducing the ancillary service charges borne by that generator, it would also reduce the charges borne by the other generator in the South Island. Either of the generators is therefore limited in respect to its ability to capture the entire reduction in ancillary service costs. The extent of this externality is likely to be limited, since the benefits (in terms of lower over-frequency arming costs) only accrue to two parties. Each party would therefore be able to capture a substantial proportion of the cost reduction. This may still provide them with a sufficient incentive to undertake investment in the HVDC link. However, the degree of investment will be less than if an individual generator were able to capture the entire reduction in over-frequency arming costs achieved.

By forming a coalition in order to jointly fund investment in the HVDC link, the South Island generators would be able to internalise all of the costs and benefits (in terms of lower over-frequency arming charges) associated with that investment. There would be transaction costs associated with forming this coalition and agreeing on the level and method of investment. However, given that there are only two players involved (and therefore only one bilateral relationship), we would anticipate that such transaction costs would be fairly modest: on the basis of our index these costs are $50,000.[29]

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[29] This discussion may suggest that reallocating the costs of over- frequency arming to just one of the South Island generators (rather than to both) may improve incentives for efficient behaviour, as it would not require a coalition to be formed. However, we would expect the costs of agreeing such a reallocation to be significant (since the generator being assigned the

There would also be information costs associated with any direct investment by generators in the HVDC link, relating to determining the most appropriate investment to undertake and the direct costs associated with that investment.

3.3.3. Are there other parties that would be better placed to capture the benefits?

In the case of end-users, retailers, lines businesses or generators in New Zealand as a whole,[30] the greater number of market participants in each of these categories means that the share of the reduction in over-frequency arming costs that would be captured by any one participant acting alone is a small proportion of the total reduction in system costs, reducing the incentive on any one individual to undertake investment in the HVDC link. This implies that it would be necessary for a greater number of players to get together and form a coalition to internalise any cost reduction achieved by the investment, compared with the current case of the two South Island generators. Since we would expect the transaction costs associated with forming these coalitions to rise as the number of participants increases, we would therefore expect transaction costs to be higher if the investment were to be undertaken by any of these groups market participants rather than by South Island generators. Our index suggests costs of $20.3m, $2.5m, and $0.5m for lines businesses, retailers or all generators, respectively. In addition, significant information costs would be incurred by each of these groups of market participants, in determining the most appropriate investment to make.

The above analysis suggests that South Island generators are better placed to capture any reduction in over-frequency arming costs arising from investment in the HVDC link as an alternative to the purchase of over-frequency arming services, than are either end-users, retailers, lines businesses or generators in New Zealand as a whole.

The other party which we have not yet considered in relation to its ability to capture the benefit of investment in the HVDC link is Transpower, in its role as the current asset owner of the HVDC link. If Transpower (as asset owner) were to be charged the cost of purchasing over-frequency arming, then it would be able to capture the entire benefit of reducing those charges through investment in the HVDC link. That is, there would be no externalities associated with Transpower's investment in the link, in terms of over-frequency arming reductions also accruing to other parties. There would therefore be no need to form a coalition to align total system costs and benefits and, hence, none of the associated coordination costs. Moreover, as a result of being the current owner of the HVDC link, Transpower would also have lower information costs than would the South Island generators. Both of these factors imply that Transpower (in its role of asset owner of the HVDC link) would face stronger incentives to behave in a way which improved system efficiency, if it faced the cost of over-frequency arming, than do the South Island generators under the current arrangements.

The next step in our framework is to assess the extent to which the current institutional arrangements may affect the incentives identified in our analysis above.

entire cost would be likely to strongly resist such a change). There would also be competition policy concerns relating to discrimination.

3.3.4. How do the current mechanisms for cost recovery and current governance arrangements affect the incentives discussed above?

If Transpower (as asset owner) was allocated the cost of over-frequency arming, the current mechanism through which it would recover this cost is its TUOS charges. Costs associated with investment in improving the reliability of the HVDC link would also be recovered through TUOS charges.

In the absence of an explicit contractual commitment covering long term investments, Transpower may face a greater expectation of the recovery of short run costs, versus long run costs. This may influence Transpower's decision over whether to incur the cost of investment in the HVDC link or to bear the cost of purchasing over-frequency arming. In particular, it may lead Transpower to prefer the latter, even when the costs of investment in the link are below those of purchasing over-frequency arming. The probability that costs, especially long-term investment costs, may not be recovered, could therefore undermine Transpower's incentives for efficient behaviour.

In addition, since Transpower is a state owned enterprise it may be subject to influences which result in it having incentives other than profit maximisation. This again would weaken the incentives identified above.

The current institutional framework may therefore undermine some of the strength of the incentives faced by Transpower (as asset owner) to behave in a way which enhances overall system, if it bore the costs of over-frequency arming, in the first instance.

3.3.5. What changes would improve incentives for efficient behaviour?

Our analysis indicates that the efficiency of providing system protection in relation to a tripping of the HVDC link may be enhanced by allocating the costs of purchasing over-frequency arming to Transpower (as asset owner) rather than the South Island generators, as at present. [31]

However, there are several institutional reforms which underpin this conclusion. These include measures that would increase Transpower's certainty of cost-recovery for long term investments, and ensure that Transpower takes decisions on the basis of cost minimisation.

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30 Rather than generators in the South Island alone.

31 The distinction between allocating the costs to Transpower as asset owner and Transpower as system operator would become important if the two roles were to be separated in future. We have therefore aimed to be clear in our discussion which of Transpower's current roles is being referred to.

3.4. Black Start

3.4.1. What are the alternatives to purchasing black-start services?

Black start capability enables the power system to recover from a total shut down.

Investment and maintenance of the grid can lower the probability of a black start event occurring. Such actions can therefore be considered to be an 'alternative' to event based black start payments or, more accurately, to the contingent liability associated with the probability of event based payments. They are not, however, an alternative to black start availability payments, since such actions can never completely remove the possibility of a total shut down.

Moreover, it is important to recognise that the incentives to maintain the grid to avoid a total shut down are not materially affected by the desire to avoid black start payments, but by a desire to avoid VOLL,[32] given the considerable difference between the size of black start payments (small) in comparison to VOLL (large). The issue of maximising the incentives to undertake alternatives to avoid ancillary service costs is therefore, arguably less relevant in the context of black start, since the relevant trade-off is not between black start payments or grid investment, but between incurring VOLL or grid investment.

Notwithstanding the above, we have considered it worthwhile to analyse black start within our framework, in order to insure that any decision in relation to black start taken on pragmatic grounds does not have unforseen implications for incentives.

3.4.2. Under the current ancillary service arrangements, who bears the costs associated with purchasing black start? Who would benefit, by avoiding the current cost associated with purchasing black start, if the above alternative was undertaken?

Generators and lines businesses currently jointly bear the costs associated with black start services. Any increase in investment in or maintenance of the grid which reduced the probability of a total shut down would therefore benefit both generators and lines businesses by reducing the probability of their exposure to black start event based charges.

If any one generator or lines business were to undertake investment or maintenance in the grid, then they would not be able to capture the full benefit of that action, since the reduction in the contingent liability associated with black start payments would, under the current cost allocation arrangements, accrue to all generators and lines businesses. Again, in order to internalise all of the costs and benefits of the alternative action it would be necessary for the generators and lines businesses to form a coalition. There would be 34 parties in such a coalition: our index suggests that the coordination cost would be in the order of $28m.[33]

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32 Value of Lost Load (VOLL)., ie, value of energy that is not supplied following a power system shutdown.

33 There are 561 possible bilateral relationships between a coalition of 34 members. At an average cost of $50,000 a relationship, this gives a total cost of $28m.

In addition, any coalition of lines business and generators would face considerable information costs in identifying what types of actions will successfully reduce the likelihood of a complete system shutdown, and in assessing the cost of those actions, since there are no economies of scope with their other business activities. Given the likely size of these information costs, generators and lines businesses would be likely in practice to appoint an agent, who has better information than them regarding alternative options, to undertake the actions on their behalf. However, this implies that further transaction costs would need to be incurred in order to develop and agree an appropriate contract to cover this agency relationship.

The above analysis suggests that incentives for efficient behaviour under the current cost allocation arrangements for black start services are not strong. However, this conclusion needs to be tempered by recognition that it is not the desire to avoid black start payments which is driving investment in grid security.

3.4.3. Are there other parties that would be better placed to capture the benefits?

The preceding analysis highlighted the significant positive externalities associated with action by any individual lines business or generation business to reduce the probability of a complete grid shut down. This in turn implies significant transaction costs in forming a coalition among that number of market participants in order to internalise the benefits. Generators and lines businesses would also face significant information costs in identifying and undertaking alternatives which relate to the transmission grid.

The analysis of the transaction and information costs faced by generators and lines businesses will also hold true for end-users and retailers. End-users and retailers will also face substantial information costs.

The party with the lowest information costs in relation to maintenance and operation of the grid is Transpower, as asset owner. This suggests that, at the very least, it is Transpower who would be appointed as agent by any coalition of market participants to undertake alternatives to reduce the contingency costs associated with grid failure (assuming that an appropriate contract could be put in place to give Transpower an incentive to operate in lines with the coalition's interests). However, if Transpower (as asset owner) itself in the first instance bore the costs and the contingent liability associated with black start services, then it would be able to capture the entire benefits (in terms of reducing the costs and liabilities it faces) of undertaking investment and maintenance in the grid. Since there would be no beneficiaries, the benefit realised by Transpower would reflect total system benefits and it will face an incentive to make an efficient trade-off between purchasing black start services and investment and maintenance in the grid.

Once again, the incentives discussed above will be affected by institutional arrangements. We consider these below.

3.4.4. How do the current mechanisms for cost recovery and current governance arrangements affect the incentives discussed above?

If the costs of black start services were allocated to Transpower (as grid asset owner), then it would recover the cost of those service through its TUOS charges. It would also recover any costs associated with investment and maintenance in the grid through its TUOS charges.

As previously discussed, inefficiencies may arise if Transpower considers that it has more certainty of recovering its costs in the short term, rather than in the long term, leading to it having a preference for the purchase of ancillary services over investment.

Transpower may also make decisions on the appropriate trade-off based on considerations other than cost minimisation, as a result of it being a state owned enterprise.

However, as we have stressed, the incentives on Transpower to invest in and maintain the grid in order to minimise the likelihood of a complete shut down come from factors other than the desire to avoid black start payments. We would not therefore expect either of the above factors to have a material impact on Transpower’s decisions in relation to grid investment. Indeed, we would expect that much of the ‘non-profit’ objectives on Transpower relate to ensuring the security of the grid.

3.4.5. What changes would improve incentives for efficient behaviour?

Given that the alternative to black start payments (ie, investment and maintenance of the grid) is motivated by factors other than a desire to minimise black start costs, our framework is less relevant to the case of black start than it is to the other ancillary services. The relevant trade-off is not between black start payments or grid investment, but between incurring VOLL or grid investment.

However, notwithstanding the above, any reallocation of the costs of black start to Transpower (who would then recover those costs through its TUOS charges) would not appear to provide any adverse incentives.

This conclusion would tend to lend support for the argument in the Industry Report for reallocating the cost of black start to Transpower, on pragmatic grounds relating to the cost of administering the current black start cost recovery regime. However, in the absence of firm information about the size of the administration costs, it is not possible for us to draw a firm conclusion.

3.5. Voltage Support

3.5.1. What are the alternatives to purchasing voltage support services?

There are several alternatives to the purchase of voltage support services.

Currently, Transpower make a trade-off between:

- investment in voltage support equipment; and
- purchase of voltage support as an ancillary service:
  - via contracts with generators and owners of synchronous condensers and static var compensators (ie, dynamic voltage support);
  - via contracts which fund investment in capacitor banks (ie, static voltage support); and
  - through “constraining on” generation.

The need for voltage support services can also be reduced through:

- installing capacitor banks or other equipment in the distribution networks, to reduce the distribution network requirements for reactive power;
- managing the load attached to the distribution network, to reduce the use of reactive-power intensive equipment (ie, those driven by electric motors); and
- the introduction of an explicit pricing mechanism for reactive power.[34]

System efficiency requires that decisions as to the appropriate mix of the above alternatives are made on the basis of relative cost. In general, the long run cost of providing voltage support through either capacitor banks or static var compensators (SVCs) is below that of “constraining on” generation to provide reactive power. This is particularly the case where the thinness of the market for voltage support means that generators can largely foresee when they will be “constrained on”.[35] However, the demand for voltage support will fluctuate, and there may be ‘transitory’ conditions for which the cost of investing in voltage support equipment is above that of “constraining on” generation whenever the transitory conditions arise.

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[34] The introduction of explicit prices for reactive power is discussed further in section 3.5.6.

[35] The demand for reactive power is locational, meaning that there are a limited number of generators in an area which can meet this demand.

3.5.2. Under the current ancillary service arrangements, who bears the costs associated with purchasing voltage support? Who would benefit, by avoiding the current cost associated with purchasing voltage support, if one of the above alternatives were undertaken?

The bulk of the costs of voltage support are currently allocated to the 6 lines businesses in Zone 1. Specifically, the lines businesses in Zone 1 bear the majority of the fixed costs of voltage support, associated with the long term contracts Transpower has with the owners of voltage support equipment. Transpower also attempts to charge the Zone 1 lines businesses the variable costs associated with “constraining on” generation; the allocation of these latter costs is currently disputed by the lines businesses.

There is a (smaller) charge for voltage support levied on the 23 remaining lines businesses, who are outside of Zone 1. This charge is levied to cover various administration costs associated with voltage support services.

Since it is the lines businesses that currently face the costs of voltage support, it is the lines businesses who would therefore benefit through avoiding these charges if one (or more) of the alternatives identified above were to be pursued. Given the differences in the charging regimes between lines businesses in Zone 1 and those outside of Zone 1, the extent to which any one lines business benefits needs to be assessed in relation to how much of the costs it currently bears. The extent of the incentive for efficient behaviour implied by the current allocation of voltage support costs will depend on the lines businesses ability to capture the benefits associated with undertaking alternative options.

If any of the lines businesses were to undertake one of the alternatives to the purchase of voltage support identified in section 3.5.1, it would reduce the overall requirements to purchase voltage support, ie, the benefit of reduced voltage support costs will accrue to the other lines businesses, as well as the business undertaking the action.

In order to internalise all of the costs and benefits associated with the alternatives, the lines businesses would need to form a coalition. Our index of the transaction costs associated with forming such a coalition and negotiating and agreeing courses of action suggests that for all 29 of the lines businesses to join together in this way would have a cost of around $20.3m.

However, given the current charging regime for voltage support, the majority of the benefits of alternative actions would accrue to the 6 lines businesses in Zone 1. The costs of forming a coalition of these 6 businesses may be expected to be much lower: at around $0.75m. Such a coalition would capture most of the benefits of undertaking an alternative.

In terms of the alternatives discussed in section 3.5.1, the lines businesses are likely to have the greatest economies of scope (and therefore the lowest costs) in undertaking investments in capacitor banks in their own distribution networks, compared to the other alternatives. They would face higher information costs in relation to load management or investment in voltage support equipment in the transmission grid.

3.5.3. Are there other parties that would be better placed to capture the benefits?

The small number of lines businesses in Zone 1 means both that individual companies are able to capture a significant proportion of the benefits associated with their actions, and that the costs of forming a coalition between these businesses is lower than it would be for a coalition with more than 6 members. In addition, economies of scope suggest that the information costs associated with investment in the distribution networks in Zone 1 will be lower for the Zone 1 businesses than for other market participants. The zone 1 businesses would face higher costs in relation to investment in the distribution networks outside of Zone 1.

Assigning the costs of voltage support to either end-users, retailers or generators would imply both greater transaction costs, in terms of forming a coalition to capture the benefits of investment in the distribution network, and greater information costs (in the case of investment in the distribution network), than under the current arrangements.

It therefore appears that the lines businesses are the best placed to capture the benefits of investment in the distribution network to reduce reactive power requirements. However, investment in the distribution network cannot completely substitute for either grid investment or the purchase of voltage support services to meet grid requirements. We therefore still need to consider whether the lines businesses are the best placed to capture the benefits of investment in the grid or load management, or whether the costs would be more appropriately allocated to other market participants.

As the current transmission asset owner, Transpower would have the lowest information costs associated with investing in the voltage support equipment for the transmission system as an alternative to the purchase of voltage support. If the costs of voltage support[36] were allocated directly to Transpower (in its role as grid owner), then it would be able to capture the entire benefit of undertaking alternatives. There would be no need for it to form a coalition of interests, and, hence, no associated transaction costs. Transpower would ultimately recover these costs through its TUOS charges, but it would bear the risks associated with cost over-runs and the associated cost volatility in the first instance.

A further alternative to the purchase of voltage support identified in section 3.5.1 is a reduction in the use of reactive-power intensive equipment, or the fitting of equipment to reduce the amount of reactive power such equipment demands. End-users and retailers are likely to have greater economies of scope in undertaking such initiatives than other market participants.

Action by individual consumers to reduce their use of reactive-power intensive appliances would (a) be unlikely to be sufficient to reduce the need for voltage support unless adopted by a large number of consumers; and (b) would result in positive externalities for other end-use customers, which would not be captured by those undertaking the investment. Our index of coalition costs suggests

[36] ie, both the fixed costs of purchasing voltage support through long term contracts and the variable costs associated with "constraining on" generators.

that the costs of forming a coalition of end-users to undertake load management (or another of the alternatives identified above) is likely to be prohibitive.

Retailers would be in a position to adopt load management schemes designed to reduce the need for reactive power. Action by any one retailer would benefit other retailers, suggesting that a coalition would need to be formed to internalise the benefits. Our index suggests that such transaction costs for a coalition of the 10 retailers currently operating in New Zealand would be $2.5m. There would also be competition policy concerns with the establishment of a coalition of retailers in Zone 1.

Given the above, it appears unlikely that changing the allocation of voltage support costs from lines businesses to retailers would improve incentives for efficient behaviour, and, indeed, is more likely to lessen them. The allocation of the costs to Transpower, as grid asset owner, does appear to provide the potential to improve incentives for efficiency with respect to investment in voltage support equipment for the grid. However, there are institutional factors which may impact on its incentives to take decisions on the basis of cost minimisation (see below).

3.5.4. How do the current mechanisms for cost recovery and current governance arrangements affect the incentives discussed above?

It has been raised in discussions with us that the current governance arrangements applying to Transpower may not provide it with an incentive to take decisions on the basis of minimising costs. To the extent that there is no monitoring of Transpower's TUOS charges by an independent party, this may also provide it with the ability to pass through all of the costs it incurs. However, these concerns regarding the strength of incentives to minimise costs and the ability to pass through costs are also applicable to the lines businesses, who currently bear the costs of voltage support. In particular, a large number of these businesses are owned by trusts, which may not be profit maximising, and there is no independent oversight of the costs that are incorporated in the lines businesses DUOS charges.

As discussed previously, differences in the expectation of cost recovery may arise as a result of the short term payments for voltage support versus the longer term over which the cost of investment (either in the grid or in the distribution network) are recovered. In the absence of a credible commitment to allowing the cost of investment to be passed through into DUOS or TUOS charges, the lines businesses and/or Transpower may have a preference for short-term rather than long-term expenditure.

3.5.5. What changes would improve incentives for efficient behaviour?

Under the current cost allocation regime, the lines businesses (and in particular the 6 lines businesses in Zone 1) currently have an incentive to undertake alternatives to the purchase of voltage support, when the cost of such investment is lower than the cost of purchasing voltage support. Lines businesses have lower information costs than other market participants in relation to investment in the distribution network. However, they will face higher information costs than other market participants in relation to investment in the transmission network, or load management.

From the above discussion, there would appear to be two areas in which the incentives for efficient behaviour could be improved:

i. an agreement between Transpower (as asset owner) and each lines business on the reactive power offtake for each distribution network; and

ii. a reallocation of the costs of voltage support, in the first instance, to Transpower (as asset owner).

To the extent that the level of investment in the distribution network can affect the overall reactive power requirements for the grid, there is a need to establish property rights at the transmission-distribution boundary, in order to facilitate the trade-off between reactive power requirements of the distribution and transmission networks. Such property rights are applicable to all of the boundaries with the different distribution networks (not just the Zone 1 networks), since there is a potential trade-off for each of the distribution networks.

The introduction of these property rights could be achieved by agreeing a kVAr off-take (and associated power factor) between Transpower and each of the lines businesses: the current kVAr off-take nomination for the Zone 1 businesses and the 0.95 power factor would appear to represent a standard which could be explicitly incorporated into contracts between all of the lines businesses and Transpower.[37] Lines businesses would pay a penalty to Transpower if they failed to meet the agreed standards, under a similar mechanism to that operating currently in Zone 1 (ie, explicit payments per kVAr offtake above the agreed level). Lines businesses and Transpower should also be free to negotiate deviations from the required kVar offtake, eg, lines businesses may agree to achieve a kVAr reduction (higher power factor) in return for an explicit payment for the reduction achieved.

The second area in which changes would have the potential to increase overall system efficiency is in allocating the costs of voltage support directly to Transpower (as asset owner) in the first instance. Such an allocation would mean that the same entity faced all of the costs associated with the trade-off between (i) investing in voltage support equipment in the grid, (ii) purchasing voltage support under contract; and (iii) "constraining on" generators to provide reactive power.

In the UK, NGC faces all of the above costs and makes its decision as to whether to invest in new voltage support equipment or to purchase its reactive power requirements from generation on the basis of an economic assessment of the costs of each option.[38] That is, NGC assesses the investment and operation costs associated with voltage support equipment against the expected cost of "constraining on" generation, over a two to three year time horizon. Since the market is aware that NGC makes this explicit type of cost comparison, it acts as a limiting factor in the prices generators bid into the market when they expect to be "constrained on" to provide voltage support.

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37 We note that it has been suggested that a power factor of less than 0.95 may be applicable for some distribution network, and that it is the nominated kVAr offtake that determines the network's reactive power requirement.

38 In the UK, tenders are held to provide voltage support equipment, with NGC then purchasing the assets and recovering the cost through its TUOS charges.

We noted in 3.5.4 above that there are concerns regarding both Transpower's incentive to make the above trade-off on the basis of minimising costs, and its ability to pass through all of the costs it incurs through its TUOS charges.

These concerns should be addressed by negotiating explicit criteria between Transpower and the GSC (or another industry body) regarding the costs Transpower can recover through its TUOS charges. These criteria could include requirements to make a trade-off between alternatives on an expected cost basis, similar to that made by NGC. The agreement should also provide Transpower with an incentive to minimise costs, by allowing it to keep a proportion of any cost reduction below a target level, and to bear the cost of any cost overrun. The industry will need to monitor Trnaspower's compliance with the agreed criteria. The contractual mechanism via which such arrangements could be introduced is set out in section 4.1.

The industry's scrutiny of Transpower's role will in effect be akin to explicit regulation. Whilst it is unlikely to be an easy task, especially initially, the main requirement for a successful outcome will be to set up an effective body that is able to negotiate on the industry's behalf, according to clear-cut objectives and procedures. In the current New Zealand context, the GSC and the associated MACQS forum would appear to be key contenders for this role as a monitoring and negotiating body.

3.5.6. Introducing a market for reactive power

We noted in section 3.5.1 above that introducing an explicit market for reactive power, or MVArs, would directly address the need to provide voltage support by other means.

The debate internationally over whether to explicitly account for reactive power as part of the energy market has focused on the use of AC power flow models. These models can be used in two ways. One alternative is to internalise the cost of reactive power into prices for active power. Under such an arrangement, there would still be a single market price, but it would encompass the cost of reactive power.

The alternative would be to introduce a parallel spot market for reactive power. Producers could then offer MVArs and load purchase MVArs directly through the market, alongside sales and purchases of (active) energy. We understand that it is this latter arrangement of a separate spot market for MVArs which has been the focus of most debate in New Zealand.

One of the recommendations in the recent review of the ancillary service arrangements in Australia by NEMMCO[39] was for:

> "a competitive two-way spot market [for reactive power] integrated with the energy spot market and dispatched by NEMMCO. [..] In its final implementation this envisages a full nodal active/reactive power dispatch optimisation [..]." [40]

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[39] NEMMCO is the system operator in the Australian National Electricity Market.

[40] *Ancillary Service Review – Recommendations*, NEMMCO Consultation Document, 10 August 1999, p15.

However, this recommendation is very much a long-term recommendation, rather than something which NEMMCO feels is achievable in the short- or medium- term. Indeed, the NEMMCO report makes the following observations:

> " At this stage, commercial software to do this optimisation is unavailable and is unlikely to be available for another 5 years. [..] The recommendation to use nodal pricing for reactive power is far reaching and has not been implemented elsewhere within a market structure, to NEMMCO's knowledge."[41]

NERA is also unaware of any electricity markets internationally which price reactive power. One of the difficulties with such arrangements is again the need for market participants to form coalitions before they will have sufficient incentive to undertake investment in response to differences in the market price of reactive power between regions.[42] It is the facilitation of such investment that would result in the greatest scope for improved market efficiency, rather than solely the adaptation of consumers demand patterns in response to reactive power price signals.

From a practical standpoint, therefore, the introduction of a spot market for reactive power would not appear to be a viable alternative to the purchase of voltage support services, at least in the short- to medium- term.

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41 Op cit, p15.

42 The difficulties are analogous to those relating to entrepreneurial investment in transmission links in a system with modal spot pricing for active power.

4. LOWERING THE COST OF ANCILLARY SERVICES

The discussion in the previous section has looked at ways to improve the incentive for market participants to undertake alternatives to the purchase of ancillary services, when these alternatives are lower cost. In particular, we have recommended that the costs of frequency control and voltage support be allocated to Transpower,[43] and that Transpower (as system operator) continue to operate as central purchaser for instantaneous reserves on behalf of the generators.

We noted, however, that the current mechanisms for cost recovery and the current governance arrangements in New Zealand provide only weak incentives on Transpower to take decisions on the basis of minimising costs and may enable it to pass the costs it incurs straight through to other market participants.

In order for such cost reallocation to be successful in improving incentives for efficient behaviour, it will therefore be necessary:

i. to increase the transparency regarding the trade-offs made by Transpower and the costs it incurs in meeting system operation targets;

ii. to provide Transpower with an incentive to make such a trade-off on the basis of lowering costs; and

iii. to assign an explicit monitoring role to the industry.

Section 4.1 sets out practical steps to achieve each of the above.

In addition to improving the efficiency of the trade-off between the purchase of ancillary services and alternative actions, there is also potential to improve the efficiency with which ancillary services are purchased. For example, it may be possible to reduce the administration costs associated with purchasing ancillary services. Costs can also potentially be reduced through introducing innovations in the procurement arrangements, such as changes in tender procedures which allow a greater number of parties to offer to provide the required service.

Such improvements in the efficiency of the purchase function would result in a further source of ancillary service cost reduction. We consider this further in section 4.2.

4.1. Achieving an Efficient Trade-off

4.1.1. Transparency

GSC (or some other industry body) should agree with Transpower how, for each ancillary service, the audited cost of both:

43 In the case of frequency control, we have recommended that Transpower in its role as CQC bear the costs, in the first instance. For voltage support, we have recommended that Transpower, in its role as grid owner, bear the costs in the first instance.

i. purchases under ancillary service contracts; and

ii. alternative actions which substitute for the purchase of that ancillary service (eg, network investment, out of merit order dispatch),

will be brought together as one account for each service.

This will result in increased transparency regarding the costs Transpower incurs in relation to achieving each system operation target.

4.1.2. Providing an incentive for cost minimisation

The GSC should agree with Transpower how the total cost for achieving each of the three system operation targets, as reflected in the accounts described above, are to be recovered from other market participants.

The basic form of such cost recovery should be an incentivising contract, under which a target cost associated with each system operation objective is agreed, together with the extent of any cost overrun Transpower has to bear and the percentage of any cost reduction it is permitted to keep.

Such an arrangement would provide Transpower with an incentive to make efficient decisions regarding the trade-off between using ancillary service contracts and alternative actions (eg, dispatch, network investment). Annex 1 contains a detailed description of the key features of such an incentive arrangement.

The parameters which determine this incentive arrangement should be subject to regular review by the GSC and Transpower (eg, annually).

4.1.3. Requirement for industry monitoring

Relations between Transpower and the market participants from whom Transpower ultimately recovers its costs should be governed by an overall contract, which sets out the principles and methods of cost allocation. This contract should be negotiated between Transpower and the market participants via the GSC (or some other industry body), and may incorporate specific criteria covering the grounds on which Transpower is required to make its trade-off decision.

Market participants can refuse to accept costs if there are strong grounds for arguing that Transpower has not complied with the principles and cost allocation methods in the contract.

The industry (and in particular those market participants ultimately bearing the cost of the service) should continually monitor Transpower’s decisions on the trade-off between the purchase of ancillary services and alternative actions, and seek explanation where appropriate. Market participants can refuse to accept costs if there are strong grounds for arguing that Transpower has not complied with agreed principles and cost allocation methods.

The monitoring by market participants of the reasonableness of the costs being incurred (and passed through) by Transpower fulfils a similar function to that of explicit regulation in other systems. Whilst it is unlikely to be an easy task, especially initially, the main requirement for a successful outcome will be to set up an effective body that is able to negotiate on the industry's behalf, according to clear-cut objectives and procedures. In the current New Zealand context, the GSC would appear to be a key contender for this role as a monitoring and negotiating body.

4.2. Allowing for Innovation in Procurement Arrangements

In addition to improving the efficiency of the trade-off between the purchase of ancillary services and alternative actions, there is also potential to improve the efficiency with which ancillary services are purchased. Improvements in the efficiency of the purchase function would result in a further source of ancillary service cost reduction.

Costs can potentially be reduced through introducing innovations in procurement arrangements, such as changes in tender procedures which allow a greater number of parties to offer to provide the required service. There would appear to be particular scope for cost reduction in the case of the purchase of frequency control services. Currently only generators provide bids to Transpower (as the purchaser of ancillary services) for frequency control services. We understand that it may be possible to extend the market to load, through the introduction of load management systems which allow load to be tripped in response to frequency changes.[44]

Broadening participation in the process of developing appropriate procurement arrangements and in the conducting of tenders for the purchase of ancillary services, is one way to promote such innovation. This could be achieved in the following manner.

Firstly, the system operator (CQC) should set down technical standards for the provision of frequency control, instantaneous reserves and voltage support, in consultation with the industry via the GSC (or some other industry group). These technical standards should be consistent with the system security standards defined in MACQS.

Secondly, the GSC should appoint an Ancillary Service Procurement Agent (ASPA). The role of the ASPA will be:

- to set down contractual requirements for provision of each of these ancillary services and determine procurement arrangements, in accordance with CQC's technical standards; and
- to organise and run, on a regular basis, a tender (or other procurement arrangement) for each of the three services, on the basis of the above contractual requirements.

Appointing the ASPA to set down contractual requirements will facilitate innovation in the sources of ancillary service that may be offered by market participants, in contract design and in procurement arrangements. CQC should be consulted as part of this process to ensure that the

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44 Such an expansion of the market would appear to be consistent with current recommendations in Australia, which envisage that "various competing service providers" would offer frequency control services to NEMMCO via a spot market arrangement, and receive a common market clearing price. (NEMMCO, Ancillary Service Review – Recommendations, 10 August 1999).

contractual requirements do comply with the technical standards. These contractual provisions and procurement arrangements should be reviewed by the ASPA on a regular basis (eg, annually), to provide an on-going process for introducing innovation into the procurement arrangements.

The ASPA tendering procedure will select providers of ancillary services, on the basis of prices received, and issue these providers with contracts. The other party to these contracts will be CQC, for frequency control and instantaneous reserves, and Transpower (as asset owner) for voltage support.

The GSC should explore ways of providing the ASPA with a performance incentive. For example, the fee that the ASPA is paid by the industry for performing the procurement service, as defined above, may be dependent on achieving a pre-defined outcome, such as a reduction in the average tender price.

5. RECOMMENDATIONS

The Industry Report raises a number of key issues and questions in relation to ancillary services. The preceding sections have provided a consistent framework within which to appraise the current arrangements and to assess alternatives. In these sections we have also touched on many of the key issues raised in the Industry Report.

In this section we bring together the conclusions from the preceding analysis, in order to provide concise responses to each of the key issues raised in the Industry Report.

It is important to recognise that there is no 'perfect solution' to the issues raised below. Rather, we have concentrated on pragmatic measures which may be expected to improve incentives for efficient behaviour, and hence reduce the costs associated with the provision of ancillary services from their current level. Our recommendations are aimed at establishing a transparent and workable framework within which all parties can operate.

5.1. General Issues

How should contracts between the industry and the system operator (Transpower) be structured so as to ensure that decisions on the mix of objectives achieve desired outcomes at least overall cost?

i. Contractual arrangements for ancillary services should be structured to provide market participants with an *incentive* to undertake an alternative action, when the total costs of that alternative are lower than the cost of ancillary services.

ii. The implications of the above principle for the current cost allocation arrangements are detailed in Table 1. Transpower (as grid owner) should bear the costs of voltage support, black start and over-frequency arming, in the first instance. CQC (currently Transpower) should bear the costs of frequency control, in the first instance. The costs of instantaneous reserves should continue to be charged to generators, in line with the Stage 1 Belgrave Committee recommendations.

iii. The GSC (or some other industry body) should agree with Transpower how, for frequency control, instantaneous reserves and voltage support, the audited cost of both:

- purchases under ancillary service contracts; and
- alternative actions which substitute for the purchase of that ancillary service (eg, network investment, out of merit order dispatch)

will be brought together as one account for each service.

iv. The GSC (or some other industry body) should agree with Transpower how the total cost for achieving each of the three system operation targets, as reflected in the above accounts, are to be recovered from other market participants. The basic form of such cost recovery should be an incentivising contract, under which a target cost associated with each system operation objective is agreed, together with the extent of any cost overrun Transpower has to bear and the percentage of any cost reduction it is permitted to keep.[45]

Such an arrangement would provide Transpower with an incentive to make efficient decisions regarding the trade-off between using ancillary service contracts and alternative actions (eg, dispatch, network investment). The parameters which determine this incentive arrangement should be subject to regular review by the GSC and Transpower (eg, annually).

v. Relations between Transpower and the market participants from whom Transpower ultimately recovers its costs should be governed by an overall contract, which sets out the principles and methods of cost allocation. This contract should be negotiated between Transpower and the market participants via the GSC (or some other industry body), and may incorporate specific criteria covering the grounds on which Transpower is required to make its trade-off decision. Market participants can refuse to accept costs if there are strong grounds for arguing that Transpower has not complied with the principles and cost allocation methods in the contract.

vi. The GSC (or some other industry body) should continually monitor Transpower’s decisions on the trade-off it makes and the costs incurred, and seek explanation where appropriate.

vii. In the medium term, institutional reforms may be necessary to strengthen market participants’ expectation of long term cost recovery (eg, through some form of explicit contracting). Such reforms would remove the potential for bias in decisions in favour of incurring short run rather than long run costs.

How should the purchase function for ancillary services be structured so as to ensure ancillary services are purchased at least cost over time and the financial exposure of the industry is managed appropriately?

viii. There is an important distinction between the role of designing and agreeing contracts for ancillary service procurement and the role of deciding whether to purchase ancillary services under contract or to undertake some alternative action (eg, network investment or out-of-merit-order dispatch). Reducing the cost of ancillary services requires improvements in efficiency in <u>both</u> of these roles.

ix. We have interpreted the term “purchase function” as the role of designing and agreeing contracts for ancillary service procurement. (Our recommendations with respect to the role of deciding whether to purchase ancillary services under contract or to undertake some alternative action have been discussed in (i) to (vii) above.)

[45] The key features of such an incentive contract are described in detail in section 4 of the main report

x. The system operator (CQC) should set down technical standards for the provision of frequency control, instantaneous reserves and voltage support, in consultation with the industry via the GSC (or some other industry group). These technical standards should be consistent with the system security standards defined in MACQS.

xi. The GSC should appoint an Ancillary Service Procurement Agent (ASPA). The role of the ASPA will be:

- to set down contractual requirements for provision of each of these ancillary services and determine procurement arrangements, in accordance with CQC's technical standards. Such a process will enable innovation in the sources of ancillary service that may be offered by market participants, in contract design and in procurement arrangements. CQC should be consulted as part of this process to ensure that the contractual requirements do comply with the technical standards. These contractual provisions and procurement arrangements should be reviewed by the ASPA on a regular basis (eg, annually), to provide an on-going process for introducing innovation into the procurement arrangements; and

- to organise and run, on a regular basis, a tender (or other procurement arrangement) for each of the three services, on the basis of the above contractual requirements. The ASPA tendering procedure will select providers of these ancillary services, on the basis of prices received, and issue these providers with contracts. The other party to these contracts will be CQC, for frequency control and instantaneous reserves, and Transpower (as asset owner) for voltage support.

xii. The GSC should explore ways of providing the ASPA with a performance incentive, eg, the fee that the ASPA is paid by the industry for performing the procurement service, as defined above, may be dependent on achieving a pre-defined outcome, such as a reduction in the average tender price.

What is the best contractual means of binding the relevant parties to the arrangements?

xiv. Currently the GSC contract structure envisages two means of requiring parties to arrange contracts with CQC. Firstly, entities currently connected to the grid will be required to enter into contracts with the CQC, as a condition of Transpower's use of system agreement. Secondly, entities not connected to the grid will also be required to to contract with the CQC. A potential option for enforcing the second arrangement is through requiring parties to NZEM and / or MARIA to also hold a contract with the CQC.

xv. We would envisage that similar means could be employed to require parties to enter into contracts with CQC in relation to cost recovery for ancillary services. Such contracts should be of the form recommended in (v) above.

5.2. Frequency Related Services

To the extent that costs of frequency related ancillary services are allocated to 'off-take' or 'load', should that mean energy market participants (retailers), or lines businesses?

xi. Allocating the cost of frequency control to retailers rather than lines businesses would increase incentives for efficient behaviour. However, incentives would be increased further by allocating the costs to CQC in the first instance (see below).

xii. Any agreement on the allocation of the costs of frequency control to retailers should occur through an existing industry forum, such as the GSC or the NZEM, to avoid competition policy concerns.

Are there good reasons for believing that moving to some basis other than 'cause' for allocating costs would achieve significant gains such as outweigh the costs of making a change?

xiii. Costs should be allocated on the basis of providing incentives for efficient behaviour (rather than on the basis of 'cause').

xiv. This principle implies the following:

- the costs of instantaneous reserves should remain allocated to generators, as presently;[46]
- CQC and generators should negotiate explicit contracts covering this cost allocation arrangement (in line with the recommendations under section 5.1 above). Such contracts should explicitly provide an incentive for CQC to lower its costs, through allowing it to retain a proportion of any cost saving, or bear a proportion of any cost increase;
- the costs associated with the purchase of frequency control and the costs of "constraining on" generation[47] should be allocated to CQC (currently Transpower), in the first instance;
- CQC's costs associated with frequency control should ultimately be recovered from retailers, via a c/kWh uplift on (reconciled) energy purchases. CQC and the retailers should negotiate an explicit contract (via the GSC) covering this cost allocation arrangement. This contract should provide CQC with an incentive to minimise the costs of achieving system frequency targets (in line with the recommendations under section 5.1 above).

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[46] In line with Stage 1 of the Belgrave Committee's recommendations.

[47] These costs arise as a result of managing frequency through dispatch. Currently, these costs are borne by energy market purchasers.

Should over frequency arming be allocated on the same basis: ie, the causor of the need for the service (in this case the owner of the HVDC link)?

xv. The costs of purchasing over- frequency arming should be reallocated to Transpower (as asset owner), to improve incentives for efficient behaviour.

5.3. Grid Related Services

Would incorporating black start costs into transmission charges along with a requirement for Transpower to publish each year the total cost of black start for the previous year (including any change in contingent liability) strike an appropriate balance between minimising administration costs and ensuring accountability?

xvii. Black start costs should be reallocated to Transpower (as grid owner), in the first instance. Transpower should recover these costs through its TUOS charges.[48] Reallocating the costs of black-start in this way would not weaken incentives for efficient behaviour.

xviii. Transpower should publish its total black start costs each year, including the implied contingent liability, in order to ensure accountability.

To the extent that voltage support costs are allocated to 'off-take' or 'load' should that mean energy market participants (retailers), or lines businesses?

xix. We recommend that the costs of voltage support be reallocated to Transpower (as grid owner). Such a reallocation would bring together all of the costs associated with the various alternatives for providing voltage support, to be faced by the same party.

xx. Transpower (as grid owner) would ultimately recover the costs of voltage support through its TUOS charges. However it would bear the risks associated with cost over-runs and the associated cost volatility in the first place.

xxi. The costs Transpower recovers through its TUOS charges should be audited, and explicit criteria agreed between Transpower and the GSC (or some other industry body) to enable the reasonableness of the costs incurred to be monitored and to provide Transpower with an incentive to minimise costs (in line with the recommendations in section 5.1 above).

xxii. We recommend that a kVAr offtake limit (and associated power factor) be agreed for all distribution networks, and reflected in contracts between Transpower and each lines business. Lines businesses would be charged by Transpower for exceeding this offtake. Lines businesses and Transpower should be free to negotiate (transparent) variations to this required power factor, where that would lower overall system costs of meeting voltage support requirements.

[48] Transmission Use of System charges.

What are the appropriate instruments under which off-take would purchase MVArs and providers receive payment for MVArs?

Would the advantages of utilising an AC power-flow model for the purposes of scheduling, dispatch and pricing outweigh the disadvantages?

xxii. There are currently no electricity markets internationally which price reactive power. There is therefore no information on which to assess the costs of an AC model against its benefits.

xxiii. From a practical standpoint, the introduction of a spot market for reactive power would not appear to be a viable alternative to the purchase of voltage support services, at least in the short- to medium- term.

ANNEX 1: OUTLINE OF INCENTIVISING ARRANGEMENT FOR TRANSPOWER

In section 4.1 we highlighted the potential scope to improve the incentives faced by Transpower in achieving system operation targets through an agreed cost sharing arrangement. This annex sets out a potential incentivising scheme for Transpower, along the lines of the schemes which currently operate for NGC in the UK.

Key Features of an Incentive Scheme

Under such an incentivising scheme, a target value for the costs of each system operation target (ie, frequency, voltage support, instantaneous reserves) would be set in advance, through negotiation between the market participants who bear the cost of the service (via the GSC) and Transpower.

If Transpower manages to 'out perform' this cost target, by achieving the system operating target at a lower cost, then it gets to keep a proportion of the cost savings achieved.

Conversely, if the costs incurred by the Transpower *exceed* the cost target, then Transpower would only be able to pass through a proportion of the difference between the target and the actual cost to those market participants who bear the cost of the relevant ancillary service, rather than the entire cost. This results in Transpower itself bearing a proportion of the cost overrun.

The extent of the cost savings kept by Transpower and the amount of any cost overrun it has to bear are both capped in absolute dollar amounts. This limits the degree of financial risk Transpower is exposed to. (However, it also limits the incentives it faces).

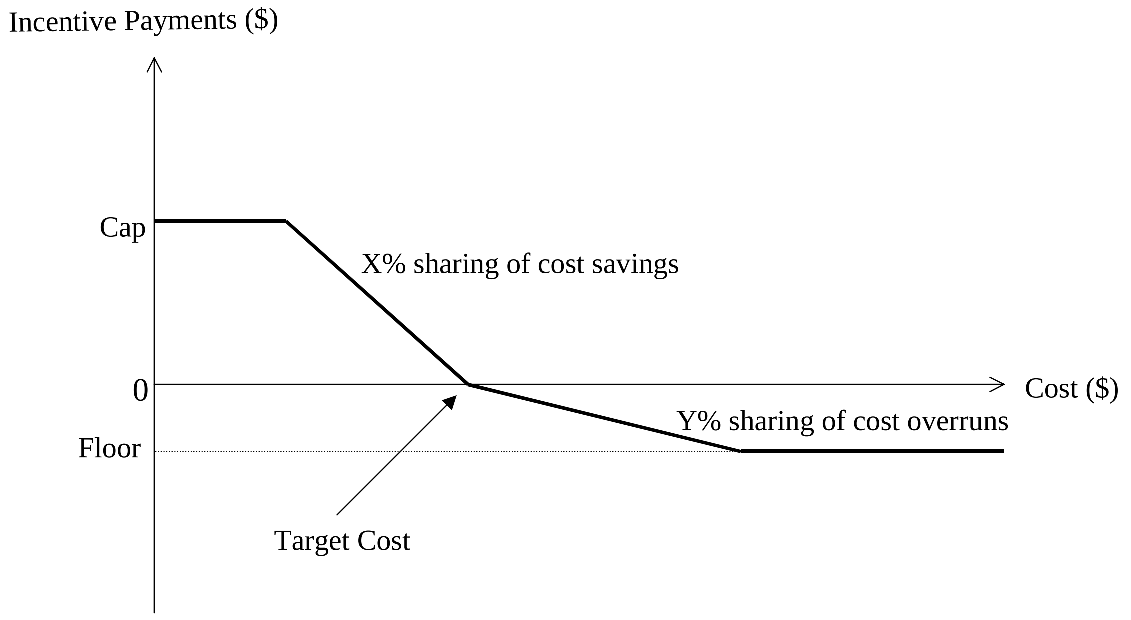
The key parameters under such an incentive scheme are therefore:

- the target cost for each system operation objective (in $);
- the proportion of any cost reduction kept by Transpower (defined in percentage terms, ie, X%);
- an absolute cap on the revenue that can be earned by Transpower from achieving cost reductions (in $);
- the proportion of any cost overrun which Transpower is not able to pass through to market participants (defined in percentage terms, ie, Y%); and
- an absolute floor on the losses that Transpower bears as the result of any cost overrun (in $).

These parameters are illustrated in Figure 1.

The extent of the sharing of any cost savings between Transpower and the market participants does not have to be the same as the sharing of any cost overruns (ie, X and Y do not have to be equal percentages). However, overall the scheme needs to offer a reasonable prospect of cost recovery, if Transpower achieves a normal level of efficiency.

Figure 1: Form of Cost Sharing Incentive Scheme



The parameter values chosen may differ, along with the target costs, for each ancillary service being purchased under such a scheme. To the extent that there is considered to be greater scope to achieve cost reductions for some system operation objectives rather than others (eg, frequency control and voltage support), the size of the incentive faced by Transpower may be greater,[49] or the cost target may be set at a lower value.

GSC would appear to provide an appropriate forum for the negotiation between market participants and Transpower regarding appropriate parameter values.

In addition, it may be necessary to define certain events over which Transpower is deemed to have no control, and which have a material affect on its costs.[50] The operation of the incentive scheme would then disregard changes in costs arising as a result of these pre-defined events.

Appropriate contractual arrangements between market participants and Transpower would need to be put in place to support the introduction of any incentive scheme.

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49 The size of the financial incentive in relation to the motivation is provides for Transpower depends on the extent to which other costs must be incurred by Transpower in order to reduce purchase costs, eg, 'effort' or long term investment (which may not be renumerated).

50 In the UK such events are known as Income Adjusting Events and are tightly specified.

Ancillary Services: Key Issues and Questions

An industry-funded report to promote discussion and comment

5 October 1999

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Introduction and scope of paper

Introduction

Various ancillary services are necessary for the smooth and secure operation of the New Zealand electricity system. For the purposes of this paper, these are frequency keeping, instantaneous reserve, over-frequency arming, voltage support, and black start. Transpower has historically purchased these services under arrangements it, for the most part, determines. Purchase costs incurred by Transpower are allocated (recovered) separately from transmission charges.

There has been a high level of disputes around payment for these services, leaving Transpower exposed financially. This situation, the move foreshadowed in Transpower's Statement of Corporate Intent (SCI) to make services more contestable, changes to decision making which would arise from the adoption of the Grid Security Policy (GSP), and the recent separation of lines and energy companies, all suggest a need to achieve an industry consensus as to how these services are to be managed going forward. To that end, the Chief Executives of lines and energy companies representing an extensive cross-section of the industry initiated a project to recommend improved arrangements for ancillary services, with this paper being the first step.

The aim of this paper is to identify the key issues that need to be resolved to ensure effective and efficient contracting for ancillary services. The issues identified form a brief to an international consulting firm, National Economic Research Associates (NERA), which has been commissioned to recommend solutions. NERA's recommendations are to cover pragmatic improvements that can be implemented in the short-term, and any additional improvements desirable for the medium-term. This paper is being circulated to industry participants for comment, and comments received by 15 October will be forwarded to NERA.

It is hoped that the resulting recommendations will form the basis for consensus as to how ancillary services are to be managed and provide a sound basis from which GSP can build.[1] The paper does not address broader issues associated with system operation, common quality levels, or connection requirements.

[1] Contact Energy feels that the objective of achieving consensus for change may be at risk by inclusion in the scope of this review and recommendations any material changes to current cost allocation, and that the main focus should therefore be on identifying pragmatic solutions to improve efficiency and transparency in current arrangements for the benefit of those paying for the services.

Structure of paper

The balance of the paper:

- Outlines the process for industry comment and the NERA review.
- Overviews current arrangements.
- Lists the key issues to be addressed.

The addendum covers, in detail:

- Current governance arrangements.
- Role and purchase arrangements for ancillary services.
- Dollar costs and trends.
- Current cost allocation methods.

Process and timetable

This paper:

- Is being forwarded to NERA to recommend solutions to the issues identified. NERA are to draw on both their own expertise and international precedents and provide a final report by the end of October.

- Is being circulated to interested parties within the industry with an invitation to comment. All comments received by 15 October will be forwarded to NERA.

NERA's final report will be distributed to all interested parties.

Background

Summary of current arrangements

Existing governance structures for ancillary services are largely internal to Transpower. Currently Transpower decides the services to be purchased, how the services are purchased, the purpose to which they are applied, and how costs are allocated. Transpower also owns and manages assets which can affect the demand for and cost of ancillary services. Conflicts of interest inherent in these roles are not managed systematically. This structure gives rise to several general issues relating to decision-making and contract arrangements for the purchase of ancillary services

Services purchased as ancillary services can be split into two categories: frequency related services and grid related services. Frequency control, instantaneous reserves, and over-frequency arming are all purchased to assist in maintaining **frequency** at targeted levels. Voltage support and black start are purchased to ensure **grid capacity** can be maintained.

Annual costs of purchasing ancillary services currently amount to about $26 million per annum. Aggregate costs, however, mask diverging trends. Where purchase arrangements have been opened to new providers, such as for instantaneous reserves, costs have fallen significantly (from around $11 million per annum in 1996 to about $5.5 million in 1999). Where they have remained focused on historical supply arrangements, costs have risen. For instance, frequency keeping costs have risen from $11 million in 1996 to around $14 million in 1999.

Purchase costs of ancillary services are allocated (recovered) through different approaches. Some fall to generators, some to lines companies. Some are recovered from particular companies or regions deemed to 'cause' the need for the service, while others are recovered by a universal charge.

Ongoing disputes over ancillary services suggest considerable room for improvement. As competition intensifies in the industry, robust commercial arrangements should lower ancillary service costs overall. Conversely, inflexible or poorly conceived arrangements are likely to be exploited. The above issues are discussed in more detail in the addendum.

General contracting and purchase issues

General issues

This section sets out the general questions to be addressed in order to achieve an efficient and effective contract structure for ancillary services. The following sections address issues specific to frequency related services and grid related services.

Achieving an efficient mix of services

A mix of instruments is utilised to achieve system operation targets, especially for frequency. These instruments include purchased ancillary services, dispatch, market prices, and conditions for connection. Some are substitutes for others, at least to a limited degree (for instance frequency control and dispatch). Time profiles of costs may also vary considerably with some solutions having low short-term but high long-term costs and vice versa – there can be trade-offs between investment and short-term costs.

Existing arrangements for system operation (real time co-ordination of the system) provide no mechanism for making these trade-offs transparent or for managing conflicts of interest. Nor is it evident that incentives are aligned to ensure the least cost solution overall. Achieving efficient use of ancillary services will therefore require the following question to be addressed:

1. **How should contracts between the industry and the system operator (Transpower) be structured so as to ensure that decisions on the mix of instruments used to achieve system operator objectives achieve desired outcomes at least overall cost?**

Structure of central purchase function

A purchase/contracting function is likely to be required for at least some ancillary services for the foreseeable future. Recent experience has shown that innovations in contracting can reduce considerably the cost of ancillary services, as well as reduce the need for central agencies. Conversely, we have also seen rises in prices where an open, competitive market has not been achieved. This raises issues of whether the purchase function should remain integrated with the system operator function and whether benefits of shared information from integration outweigh the benefits of transparency and accountability from separation. Volatility in supply and demand and ongoing structural changes in the industry also give rise to financial risks that need to be managed. A key question to address is:

2. **How should the purchase function for ancillary services be structured so as to ensure ancillary services are purchased at least cost over time and the financial exposure of the industry is managed appropriately?**

Binding contracts

In the absence of further regulatory intervention, the solutions to the issues raised in this paper will be implemented by contract. Reliance on contractual solutions gives rise the following questions:

3. **What is the best contractual means of binding the relevant parties to the arrangements?**

Frequency related services

Questions to be answered

This section identifies the questions to be answered with regard to frequency related questions.

Implication of split of lines and energy

Following the legislative separation of lines and energy businesses, Transpower opted to continue charging lines businesses for ancillary services. Robust commercial arrangements will require the following question to be answered:

4. **To the extent that costs of frequency related ancillary services are allocated to 'off-take' or 'load', should that mean energy market participants (retailers), or lines businesses?[2]**

The answer to this question should assume that the objective is to achieve the most economically efficient allocation. If other important objectives emerge, then changes to achieve these objectives should be identified explicitly.

Costs allocated to causor of service

Current allocation methods for the major categories of frequency related ancillary services (frequency keeping and instantaneous reserves) would appear to allocate the costs to the entity or category of entities that are the primary cause of the need for the service. Instantaneous reserve is allocated to generators and transmission owners, and frequency keeping is allocated to 'loads' as defined in (4) above. The differences in approach give rise to the following questions:

5. **Are there good reasons for believing that moving to some basis other than 'cause' for allocating costs would achieve significant gains such as to outweigh the costs of making a change?**

6. **Should over frequency arming be allocated on the same basis; i.e; the causor of the need for the service (in this case the owner of the HVDC link)?**

[2] For Retailers or Lines Companies, read 'direct supply customers' where a major end-user is in that role.

Grid related services

Voltage and black start

This section identifies the questions to be addressed in relation to grid related ancillary services.

Black start

Transpower sells a transmission service that relies on an energised grid. Black start is purchased to ensure the grid can be re-energised in event of a major failure. The amount of money involved is relatively small. Transpower has managed to reduce the cash payments associated with black start significantly, in part through event based contracts. Event based contracts create a contingent liability, the details of which are not known publicly. The cost of maintaining a separate allocation regime for black start would not seem justified. The following question should be addressed:

7. **Would incorporating black start costs into transmission charges along with a requirement for Transpower to publish each year the total cost of black start for the previous year (including any change in contingent liability) strike an appropriate balance between minimising administration costs and ensuring accountability?**

Voltage support

Where Transpower elects to contract for static voltage support rather than invest, the costs are allocated to 'off-take' customers (lines companies currently). Costs incurred by Transpower in contracting for dynamic voltage support, generation constrained on to provide voltage, and for voltage reserves are allocated to these customers, although this is an area of considerable dispute. Where Transpower invests in voltage support equipment, the costs are included in its transmission charges. The following questions need to be addressed:

8. **To the extent voltage support costs are allocated to 'off-take' or 'load', should that mean energy market participants (retailers), or lines businesses?**

9. **What are the appropriate instruments under which off-take would purchase MVArs and providers receive payment for MVArs?**

10. **Would the advantages of utilising an AC power-flow model for the purposes of scheduling, dispatch and pricing outweigh the disadvantages?**

Addendum to ‘Ancillary Services: Key Issues and Questions’

Status of Ancillary Service Arrangements

5 October 1999

Introduction

Content

This addendum overviews current arrangements for products purchased as 'ancillary services' in New Zealand. It sketches existing governance structures, and describes the relevant services and functions they perform. Current purchase arrangements, cost trends, and cost allocation (recovery) methods for each service are outlined.

Current Governance

Governance internal to Transpower

Existing governance structures for ancillary services are primarily internal to Transpower, which currently:

1. Determines the performance objectives (for example frequency targets) for the national electricity system, and hence the demand for ancillary services.

2. Determines the ancillary service requirements necessary to achieve the performance targets (for example the contingency covered by reserves).

3. Selects the mix of instruments to be used to achieve the target (for example frequency keeping versus dispatch).

4. Decides whether the ancillary services will be required as a condition of connection, purchased under commercial contract, or provided by Transpower.

5. Dispatches ancillary services (whether mandated, purchased, or provided by Transpower) to achieve the performance objectives.

6. Monitors and enforces compliance with any mandatory ancillary service related requirements.

7. Determines the purchase arrangements for any contracted ancillary services and negotiates contracts with ancillary service providers.

8. Decides who should meet the costs of purchasing ancillary services and in what proportion, and sets the prudential standards.

9. Bears, in the first instance, the risk of any difference between the cost of purchasing ancillary services and the amount raised through the cost allocation methodology.

Changes to governance initiated

In September 1997, the Government announced revised objectives for Transpower as set out in its SCI. Transpower's SCI now requires it to:

- Make services contestable wherever possible.
- Provide services at a quality and quantity agreed by customers and produce them at least cost.
- Allow customers to make the trade-offs between price and service level.
- Enable an appropriate majority of customers to make the trade-off where services are common.

Transpower initiated the GSP process as a means of achieving these objectives.

Role and purchase arrangements for ancillary services

Outline

This section provides brief descriptions of the products purchased as 'ancillary services' in New Zealand and their purpose.

Services encompassed by the term ancillary services (at least for the purposes of this paper) are frequency keeping, instantaneous reserve, over-frequency arming, voltage support, and black start. Each is discussed in turn.

Frequency keeping

Role of frequency keeping

If variations in demand (electricity usage) across an electricity network are not matched by corresponding changes in generation, frequency will vary. Changes in frequency in either the North Island or South Island AC networks potentially affect all grid users connected to the relevant network.[1] All users connected to an AC network are affected by a change in frequency because all alternating current machines connected to the network rotate at the same speed. The New Zealand system is operated to maintain frequency within a band of +/- 0.2 Hz of 50 Hz.

Limitations in dispatch, equipment control systems, and market pricing, mean that these mechanisms are generally not sufficient to manage system frequency within the target band. Frequency control reserves are therefore purchased to assist in maintaining the frequency standards set by the Grid Security Standard in each AC network, and to ensure frequency time error equals zero over any 24 hour period.[2]

[1] The HVDC link means that frequency variations are contained within either network.
[2] To avoid compounding errors, a reduction in frequency in one period is offset in a subsequent period so that over any 24 hour period the error is zero. This is a different product to maintaining the frequency within the target band and different sources are often used to supply these two services.

Sources of frequency keeping services

Frequency control has historically been provided by one or more generators operating in a partly-loaded mode. The generator continually varies output, as necessary, to maintain frequency within the band. This balances out the net effect of a large number of *small and relatively smooth* changes in load (or generation output). Larger changes in load over time are covered by dispatch.

Energy consumers (demand side) can provide frequency control through devices that trip load in response to changes in frequency, although this option is not currently utilised in New Zealand. Transpower has also tried limiting the requirement for specific frequency keeping services in the South Island by relying on dispatch at closer intervals (5 versus 30 minutes).

Purchase of frequency control

Transpower invites offers from generators, on a week ahead basis, to provide frequency-keeping services for each half-hour. The frequency-keeping station is selected on the basis of these offers (security or dispatch requirements may lead to adjustments). Generators are paid the tender price for maintaining frequency, and receive the spot price for any energy generated. This process does not explicitly balance the costs of managing frequency by dispatch with other options, nor allow easy entry for non-traditional suppliers.

Two major generating companies compete to provide frequency control services for the South Island and three in the North Island. A proposed change in the wholesale market to move to five minute dispatch and pricing may allow small generating companies to provide frequency control services (because the MW band requirements for frequency control would be smaller). The MW band is set by the quantity of load expected to be switched on or off the system over a given time period.

Instantaneous reserve

Role of instantaneous reserve

Like frequency keeping, instantaneous reserve is purchased to maintain frequency. In contrast to frequency keeping, instantaneous reserve offsets *large jagged* changes in generation (or load) that reduce frequency on the grid (generators providing frequency control would be insufficient in themselves). Instantaneous reserve consists of generation capacity or equivalent load reduction available within a few seconds of a sudden failure of a generating or transmission facility.

Classes of instantaneous reserve

There are two classes of instantaneous reserve in New Zealand:

- *fast reserve*, defined as the additional capacity (in MW) that can be provided within 6 seconds of system frequency declining to 48 Hz due to a sudden failure of a generating plant or transmission facility.

- *sustained reserve*, defined as the additional capacity (in MW) that can be provided to restore the system frequency to 49.25Hz within 60 seconds of a failure of generating plant or transmission facility. Sustained reserve may be contracted to operate for periods up to 15 minutes until merit order generation is dispatched to replace the capacity shortfall created by the failure of generation or transmission equipment.

Purchase of instantaneous reserves

Potential providers of instantaneous reserves must first register with Transpower. If Transpower concludes that an entity has the capability to provide reserves, Transpower contracts to pay the provider of instantaneous reserves an availability payment determined by the New Zealand Electricity Market (NZEM) clearing price for reserve. Generators scheduled for reserve and called to run are also paid the spot price for energy generated.

Over frequency arming

Role and purchase of over frequency arming

If the HVDC link were to trip when substantial energy was being sent to the North Island, frequency in the South Island would rise very quickly before over-speed protection of generators could respond. To prevent this, some generators are equipped with relays to trip the generator before excessive frequencies are reached. The two major generating companies located in the South Island are contracted to provide over-frequency arming services.

Voltage support

Role of voltage support

Voltage levels on the national grid - and within the connected distribution networks run by lines companies - are maintained within specified limits by injecting or absorbing *reactive power* at certain nodes. Maintaining voltage levels within specified limits is important for maintaining transmission capacity, protecting equipment, and minimising transmission losses. Reactive power requirements are location sensitive.

Reactive power is an abstract representation of one component of the current flowing in an AC circuit. Measurement is in VArs or MVArs. The amount of reactive power varies with changes in voltage and current flow, with the amount of variation depending on the circuit components. Consequently, transmission and distribution networks and the generation and demand connected to them affect the derived measure of reactive power and in this sense, each appears to either consume or generate quantities of reactive power. In reality, reactive power is an abstraction in that it is the currents and voltages that have changed. Reactive power is provided and consumed by transmission and distribution networks, generators, capacitor banks, static VAr compensators (SVC's) and synchronous condensors.

Voltage support can be considered as two products; dynamic support that responds to the loss of generation or transmission plant and static support that solves transmission capacity problems. The dynamic support is typically sourced from equipment that will respond during transient conditions, such as generators and SVC's. The static support is typically provided through grid investment, usually in capacitor banks.

Classes of voltage support

Voltage support requirements can be grouped into:

- Reactive power required for distribution network conveyance (including load requirements).
- Reactive power required for grid conveyance.
- Reactive reserves required to respond to system events.

Each is discussed briefly.

Distribution network requirements

Under current terms of interconnection with Transpower, local distribution networks are required to maintain a power factor of 0.95. This means that for every 10MW of real power drawn into a local network, 3.2MVAr of reactive power may also be drawn (consumed). Networks with higher reactive power consumption need to manage load or invest in capacitor banks or other equipment to maintain the power factor target (in practice, many networks do not achieve the power factor standards specified in the Grid Connection Contracts, and in effect become consumers of reactive power from the grid).

Grid requirements

Most requirements for voltage support for the grid are provided either by Transpower voltage support equipment, such as capacitors or Static VAr Compensators (SVC's), or by generators through the injection of real power. Generators are required to meet certain reactive power capabilities as a term of connection to the grid. Transpower also recently tendered for static voltage support from capacitors and dynamic voltage support from SVC or synchronous condensors in the Auckland area to supplement its own.

Generators offered into the market may also be 'constrained on' (dispatched out of merit order) to provide voltage support. By constraining on generation to provide peak MVAr requirements over a relatively small number of hours each year, fixed investment in capacitors or SVCs is avoided[3].

Reactive reserves

Reactive reserves provide a role similar to instantaneous reserves, except the reserve provided is MVAr not MW. Reactive reserve is provided by equipment that is able to respond automatically to system events. Relevant equipment includes generators, synchronous condensors, SVCs, and loads.

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[3] However, constraining on generation can be a very expensive option where generators can predict the requirement and, due to their monopoly position in a geographical area, significantly inflate their prices.

Purchase of voltage support

As noted, Transpower has several long-term supply contracts with owners of generators and synchronous condensors that allow it to request specific voltage support, as well as contracts for static voltage support from capacitors.

Generators constrained on to provide voltage support are paid a 'constrained on payment' by Transpower. This payment is calculated as the difference between the generator offer price and the market clearing price multiplied by volume of energy generated. The generator is also paid the market clearing price for energy generated through the spot market. The costs of constrained on payments for voltage support are charged in the first instance to Transpower, which must then seek to recover it.

It should be noted that the need to consider MVArs explicitly derives from the approximation of using an approximate DC power-flow model for dispatch and pricing. Moving to an AC power-flow model would result in MVAr requirements being reflected in energy prices. However, the underlying problems still need to be well understood and the AC power-flow model will not address the issue of investment in static support plant.

Blackstart

Role and purchase of black start

Black start capability enables the power system to recover from a total shut down. Some power stations can self-start and energise the nearby grid. Progressively, the entire grid would be energised so that, ultimately, full supply is restored.

Transpower seeks competitive tenders to provide black start. At least five generating companies have plant with black start capability. Transpower purchases black start through a mix of event and availability charges.

Dollar costs and trends

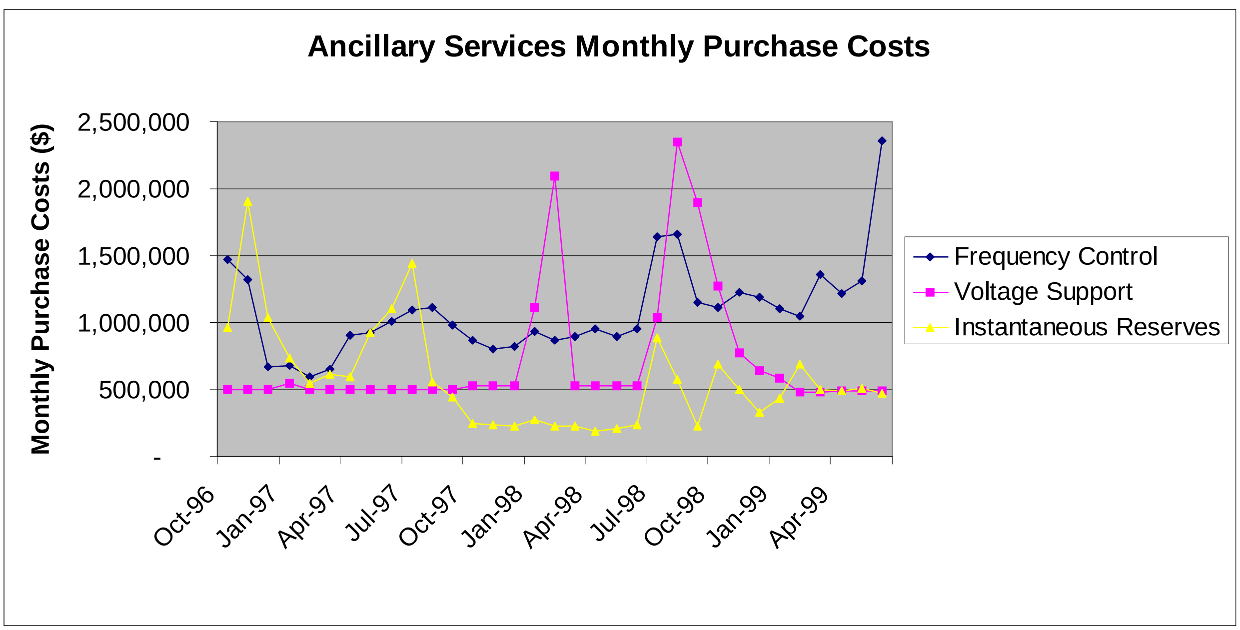
Current annual costs

Purchase costs for ancillary service currently amount to around $26 million per annum. The table below compares annual costs of ancillary services over the first three years of the NZEM market. All amounts are calendar years to September.[4]

Service	1996/97	1997/98	1998/99
	$ million	**$ million**	**$ million**
Frequency Control	$11.5	$12.4	$14.1
Voltage Support	$ 6.1	$12.2	$ 5.7
Instantaneous Reserve	$10.9	$ 3.8	$ 5.5
Over-Frequency Arming	$ 0.19	$ 0.19	$ 0.17
Black Start	$ 0.4	$ 0.25	$ 0.04
Total	**$29.0**	**$28.0**	**$25.5**

Trends in purchase costs

Trends in monthly purchase costs for the three main categories of ancillary services are shown in the chart below.



[4] The table does not include the investments made by several of the Zone 1 line companies in static compensators within their networks. This capital response was as a direct result of the increasing costs.

Explanation of trends

Explanations for major trends in purchase costs experienced since October 1996 include:

Voltage Support – The costs of fixed voltage support contracts remained static given the medium term nature of these contracts. However, these costs are now expected to decline due to the decommissioning of Marsden and the recent lines company and Transpower capacitor investment in Auckland. The 1998 peaks in the purchase costs reflect the cost of constraining on Huntly.

Instantaneous Reserves – Quantities of reserves purchased to cover the largest system contingent risk have changed since 1996. Derating of the HVDC link in 1997 reduced purchase quantities as the HVDC or Huntly previously set the contingent risk. The commissioning of the 350 MW Stratford Power Plant has had the effect of increasing the contingent risk and the associated quantity of reserves purchased. Contact Energy's Otahuhu B plant will also have an effect on the balance of reserves.

On the supply side, the advent of NZEM provided generators and purchasers (demand side, through interruptible load) with a mechanism to offer reserve into the spot market. Allowing interruptible load to compete with generation through a clearing price for reserve has had a significant impact on the clearing price and on associated payments for instantaneous reserve. The volume of interruptible load offered into the market has increased from approximately 150 MW in 1996 to about 570 MW in 1999, and interruptible load now accounts for about 70% of scheduled reserve.

Frequency Keeping – Costs of South Island frequency keeping services increased significantly in June 1999 due to increased offer prices from the two generator suppliers. Transpower is now attempting to manage frequency in the South Island through dispatch of the marginal South Island generator, rather than purchase frequency keeping services.

Existing cost allocation methods

Current cost allocation methods

This section describes the current methods adopted by Transpower for allocating (recovering) the purchase costs of ancillary services (including the costs of the purchasing function carried out by Transpower).

Frequency keeping

Transpower currently charges ‘off-take loads’ frequency keeping services on a c/kWh basis determined annually. Transpower defines ‘off-take loads’ to mean lines businesses and direct supply customers (major consumers directly connected to the grid).

Instantaneous reserves

Transpower has implemented stage 1 of the cost allocation method for instantaneous reserves agreed by the Instantaneous Reserves Steering Committee (the Belgrave Committee). Allocation is in two parts:

- Availability charges, reflecting the “stand by” cost of some reserves.
- Event charges, reflecting the cost incurred following any event causing a frequency disturbance.

Other details are as follows:

- Event charges are charged to the owner of failing plant as a flat amount per MW of injection or HVDC or AC grid transfer interrupted. The flat charge is set to recover around 50 percent of the expected cost of procuring net instantaneous reserves over the course of a year.
- Availability charges for net instantaneous reserves are allocated to generators and the HVDC link on a per MWh basis.
- In applying the event and availability allocation methods, the risk quantities are adjusted for a 60 MW deminimus generation unit size and the risk imposed by the HVDC. Full costs of instantaneous reserves are allocated as availability charges, with a rebate made when event charges are paid.

Stage 2 of the Belgrave Committee recommendations would involve all reserves being both purchased and allocated on an event basis.

Voltage support Voltage support cost allocations are divided into fixed and variable components. Fixed costs are for long-term reactive power contracts for capacitors and synchronous condensors. Variable costs are incurred by constraining on generation plant when required to meet security guidelines.

Historically, Transpower has recovered fixed voltage support costs on a c/kWh basis, which was set annually according to expected usage and costs. These charges amounted to about 0.07 c/kWh for 'off take' loads classified by Transpower as "Zone 1" (approximately off take loads located north of Huntly), and about 0.01 c/kWh for all other off take loads[5]. As with frequency, Transpower defines 'off-take loads' to mean lines businesses and direct supply customers.

Transpower has recently agreed with its zone 1 customers to introduce a new allocation methodology for them as follows:

- An annual rate of $4.42 per unit of nominated kVAr demand (as nominated by the customer).
- A monthly penalty rate of $1 per unit of peak kVAr *above* the nominated amount.
- The remaining cost to be recovered on a kWh basis using estimates of likely demand.

Transpower attempts to charge the variable voltage costs to its Zone 1 customers on per kWh basis. The lines companies dispute this charge.

All other zones continue to be charged at 0.01 c/kWh.

Over frequency arming Transpower allocates the costs of purchasing over frequency arming to South Island generators.

Black start Black start costs are allocated to generators and off-take on a kW basis. As with other ancillary services, Transpower defines off-take to mean lines businesses and direct supply customers.

[5] The perception within much of the industry is that this approach to charging does not provide correct signals.

Submissions To The Paper
'Ancillary Services: Key Issues And Questions'

Four submissions were received to the paper 'Ancillary Services: Key Issues And Questions'. These were from:

Counties Power – 12 October, 1999

Interim Grid Security Committee - 12 October, 1999

Transpower - 14 October, 1999

Major Electricity Users Group - 15 October, 1999

Counties Power Submission

The key point of the Counties Power submission was that, apart from MVAr off-take to correct for a line company's power factor, lines companies cause none of the Ancillary Services and so should not be charged for them.

The framework used by NERA focuses on ensuring that those parties that can act to reduce the cost of ancillary services face incentives to do so. This approach may result in those that do not "cause" these services to nevertheless bear some of the costs.

Interim Grid Security Committee Submission

This submission was largely a background paper that summarised the self-regulating structure being implemented through the Grid Security Policy. It provided a useful input into the report but did not require a direct response.

Transpower Submission

This submission contained four issues that have arisen as a result of a detailed analysis of the GSP design. These related to the following areas.

Issue 1 The mismatch between timeframes of purchase and sale of ancillary services and the risks associated with this.

The distribution of risks was considered by NERA as part of the incentives on the CQC to minimise cost. For the CQC to have effective incentives to minimise the costs, it is recommended that it carry some of the downside risk and have the opportunity to profit from reducing costs below expected levels.

Issue 2 The possibility of a fixed budget cap on the CQC for ancillary services

The NERA report recommends who should bear the costs of ancillary services and the contractual arrangements to bind the parties involved. It also discusses possible incentive based contracts that include budget caps.

Issue 3 The focus of incentives to create innovative purchase strategies as a solution to drive least cost purchase of ancillary services

The NERA report and recommendations focus around placing incentives to minimise costs with those entities that are capable of taking appropriate actions.

Issue 4 The methods of contractually binding all parties

The NERA report recommends using existing institutional arrangements where possible to contractually bind relevant parties to the proposed arrangements.

Major Electricity Users Group Submission

This submission contained a number of comments on the paper that aimed to clarify the issues and proposed several points for NERA to consider in their analysis. These included the following issues.

Issue 1 The inclusion of Extended Load Shedding in the list of ancillary services

Extended Load Shedding has not been included in the project as the list of ancillary services has been limited, for practical reasons, to those for which there is an explicit charge.

Issue 2 The role of MACQS and potential conflicts of interest between service providers

The NERA report addresses who should bear the costs of ancillary services and the contractual relationships required. The report focuses on ensuring there are appropriate incentives within the overall system to reduce costs. Parties bearing those costs can be expected to ensure the appropriate price discovery mechanisms are in place.

Issue 3 The definition of economically efficient allocation

The NERA report adopts the approach that an economically efficient allocation occurs when overall system costs are minimised.

Issue 4 The need for comprehensive cost-benefit analysis and greater transparency in the purchase of ancillary services.

NERA has been able to make only a broad assessment of the costs and benefits, and no well-defined cost-benefit analyses have been conducted. NERA has supported its recommendations with experience from other jurisdictions, wherever possible.

The NERA report recommends greater transparency in the relationship between the CQC and Grid Owner roles, in the setting of charges, and with respect to trade-offs between substitutable ancillary services.