COMMERCE COMMISSION

Gas Control Inquiry

Final Report

Public Version

29 November 2004

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EXECUTIVE SUMMARY

Background

Introduction

1 The Commerce Commission (Commission) is undertaking the Natural Gas (gas) Control Inquiry (Inquiry) in response to a request from the Minister of Energy (Minister) dated 30 April 2003. The Minister has requested the Commission to report by 29 November 2004.

2 The letter of request and subsequent correspondence with the Minister (terms of reference) require the Commission to report on whether goods and services supplied by persons in markets directly related to either a gas transmission system or a gas distribution system or both (gas services) should be controlled.

3 This report presents the Commission's final recommendations.

Suppliers

4 The suppliers of gas services can be grouped under two headings: transmission and distribution service suppliers.

Table 1: Transmission and Distribution Service Providers

Transmission Business	**Transmission Pipeline Systems**
NGC Transmission (NGCT)	South, North, Kapuni to Rotowaro, Bay of Plenty, Morrinsville, LTS, Frankley Road
Maui Development Limited (Shell, Todd, OMV)	Oaonui to Huntly (Maui pipeline)
Todd Petroleum and Shell	Kapuni to Hawera
Todd Taranaki	McKee Production Station to Faull Road
Swift Energy	Rimu to NGC South and Waihapa to New Plymouth and TCC power stations (the TAW pipeline)
Westech Energy	Surrey Road to NGC LTS
Distribution Business	**Distribution Pipeline Systems**
NGC Distribution (NGCD)	Northland, Whangaparoa, South Auckland, Waikato, Bay of Plenty, Rotorua, Taupo, Gisborne, Kapiti Coast
Powerco	Napier and Hastings area, Southern Hawke's Bay, Taranaki, Manawatu, Levin and Foxton, Hutt/Mana and Wellington
Vector	Greater Auckland, Tuakau and Ramarama
Wanganui Gas	Wanganui/Rangitikei
Nova Gas	Wellington, Porirua, Hutt Valley, Hastings, Hawera, Papakura and Manukau City

5 NGCT is currently the only transmission business that provides third party access to its transmission system. However, Maui Development Limited

(MDL) is currently working through a proposal to offer a service to transport third party gas on the Maui pipeline.

Inquiry Process

6 The Commission has previously released the Draft Framework Paper and Draft Report.[1] Conferences have been held and submissions taken on both of these reports. The Commission's Inquiry process is detailed in Table 2.

Table 2: Inquiry Process

Item	Date
Proposed process released by Commission	30 May 2003
Written submissions on proposed process	16 June 2003
Draft Framework Paper released by Commission	16 July 2003
Process published in *Gazette* notice pursuant to s 57(2) of the Commerce Act	25 July 2003
Written submissions on Draft Framework Paper	20 August 2003
Conference on Draft Framework Paper	1–4 September 2003
Cross submissions following conference	19 September 2003
Draft Report released by Commission	21 May 2004
Revised process published in *Gazette* notice pursuant to s 57(2) of the Commerce Act	3 June 2004
Written submissions on Draft Report	2 July 2004
Conference on Draft Report	22–28 July 2004
Cross submissions following conference	13 August 2004
Tax Treatment Draft Paper released by Commission	8 September 2004
Written submissions on Tax Treatment Draft Paper	23 September 2004
Draft cost benefit model numbers released by Commission	2 November 2004
Written submissions on draft cost benefit model numbers	5 November 2004
Final Report provided to Minister of Energy	29 November 2004

7 Background issues are discussed in more detail in Chapter 1 (Background).

Legal Framework

8 The terms of reference and statutory framework for the Inquiry are discussed in Chapter 2 (Legal Framework).

Ministerial Request

9 The Minister requires the Commission to report to the Minister as to whether an Order in Council under s 53 of the Commerce Act may and should be made in relation to gas services (Commerce Act 1986 s 52 and s 56).

[1] Commerce Commission, Gas Control Inquiry Draft Framework Paper, July 2003. Commerce Commission, Gas Control Inquiry Draft Report, 21 May 2004.

Imposition of Control

10 Section 52 of the Commerce Act requires the Commission to consider two key issues in relation to whether or not control under Part V may be imposed. Goods or services may be controlled under s 52 if:

- competition is limited or is likely to be lessened in a relevant market; and
- control is necessary or desirable in the interests of persons who acquire or supply the goods or services in the affected market or markets.

11 In considering whether competition is limited or is likely to be lessened, the Commission assesses both structural and behavioural considerations in the markets in which gas services are or will be supplied.

12 In considering whether control is necessary or desirable in the interests of acquirers, the focus is on the benefits of control for the acquirers of gas services (both direct and indirect acquirers). This has involved an analysis of what would happen if a form of control were not imposed (the counterfactual), contrasted with the potential benefits and detriments to acquirers if control were to be imposed (the factual).

13 Having determined whether control 'may' be introduced under s 52, the Commission has conducted further analysis to determine whether an Order in Council imposing control 'should' be made (s 56(1)). The matters considered in relation to whether control may be imposed remain relevant. In addition, the Commission has considered the efficiency costs of achieving reductions in excess returns, the magnitude of the benefit to acquirers, the impact of a recommendation not to control and other qualitative considerations.

The Form of Control

14 The Inquiry is limited to assessing whether control under Part V may and should be imposed and not the form of that control. To advise the Minister on how the Commission would administer control, prior to any declaration of control, would risk predetermining the processes associated with administering control under Part V.

15 However, in order to assess the likely costs and benefits of control the Commission must select a hypothetical form of control. Consequently, the Commission has assumed a form of price cap regulation under Part V. The form of control assumed for this purpose is preliminary and will not pre-empt any decision the Commission may be required to make in the future regarding control under Part V.

Request for Additional Advice

16 The Minister also requested the Commission's advice on 'the methodology that the Commission considers appropriate for valuation of pipeline assets', 'the net benefits to the public of control' and 'any other matter that the Commission may think relevant to a decision on whether control should be introduced'.

17 Finally, if the Commission recommends that gas services should be controlled, the Minister asked for the Commission's advice on the technical provisions relating to declaration of control as set out in s 57A of the Commerce Act.

18 The Commission's responses to these requests are provided in Chapter 20 (Recommendations).

Competition Analysis

19 Competition issues are discussed in Chapter 3 (Competition Issues).

Market Definitions

20 In defining markets, the Commission has given careful consideration to previous decisions of the Courts and of the Commission in energy related cases. In addition, it has given particular attention to determining how markets may be defined to best assist it to address the questions of relevance to the Inquiry.

21 The markets adopted by the Commission are:

- the market for the provision of gas transmission services between North Taranaki and Huntly;
- the market for the provision of gas transmission services for the rest of the North Island;
- the separate markets for the provision of gas distribution services in the area encompassed by each incumbent gas network; and
- the market for the provision of gas distribution services to commercial and industrial consumers in the vicinity of bypass networks.

22 Metering has been incorporated as an element of the gas services market where the provider of gas services also provides a metering service.

Generic Competition Issues

23 Transmission systems have natural monopoly characteristics. New competitive entry may be possible where there are capacity constraints, but at present there is surplus capacity in most parts of the transmission system.

24 Head-to-head competition between transmission systems is possible between North Taranaki and Huntly (where NGCT and MDL have parallel pipelines) and in Taranaki (where there are several small transmission pipelines in the same area).

25 Distribution systems also have natural monopoly characteristics, with limited potential for new entry. Entry where it has occurred has been in the form of bypass pipelines. Bypass opportunities tend to be limited to areas where there is a concentration of medium to large customers who are close to a transmission pipeline, or to an existing bypass network which can expand, or where there is an alternative source of gas (such as landfill gas).

26 Where there is a bypass network, the Commission considers that there is strong evidence of vigorous competition, which has had a major impact on distribution prices. However, outside the very limited bypass areas there is little potential for pipeline-on-pipeline competition in the distribution markets.

27 The Commission considers that the constraint provided by the energy users to switch energy forms provides a constraint on energy suppliers, but this falls short of the constraint which suppliers face in competitive markets.

28 Long-term contracts and the regulatory regime provide some limited constraint on gas service providers, particularly for large users.

29 The analysis of generic competition issues has led the Commission to conclude that while, in general, there is workable or effective competition in bypass markets, competition is limited elsewhere.

Assessment Overview

30 An overview of the Commission's assessment approach is provided in Chapter 4 (Assessment Approach).

31 The Commission, having determined that the goods or services are supplied in a market in which competition is limited (s 52(a)), considers s 52(b) which provides that goods or services may be controlled if control is necessary or desirable in the interests of acquirers. The Commission terms this the net acquirers benefit test (NAB test).

32 In applying the NAB test the Commission assesses the net benefit to acquirers of control (the factual) relative to the situation with no control (the counterfactual).

33 The NAB of control is estimated using the following approach:

- identifying the potential benefits of control;
- identifying the potential costs of control; and
- balancing one against the other.

34 The benefits to acquirers of control broadly emerge from reducing any excess returns or inefficiencies associated with the counterfactual (i.e. in the absence of control) less any costs of control. An analysis of company performance in the counterfactual compared to an efficiently operating market is used to measure the potential benefits of control.

35 The costs of control emerge in terms of compliance and administration costs for the business and the regulator (direct costs) and the control mechanism's effects on efficiency incentives (indirect costs).

36 If the Commission finds that there are net benefits to acquirers from control, then it *may* recommend control.

37 In recommending to the Minister whether control *should* be imposed, the Commission may have regard to all matters it considers necessary or desirable.

The Commission considers the following additional matters relevant in deciding whether it should recommend control:

- the net efficiency cost to the economy of reducing excess returns;
- the size of NAB assessed in terms of the returns earned by the business and the impact of control on prices to consumers;
- the impact of recommending no control; and
- other qualitative considerations.

38 The Commission notes also that the Minister has a wider discretion than the Commission to consider other matters including alternative forms of regulation distinct from control under Part V.

39 In reaching its decisions on whether control may and should be imposed, the Commission has relied on quantitative analysis, using a model developed for this purpose, and qualitative analysis in developing the model and choosing relevant parameters. The model provides support to the Commission's deliberations. However, it does not substitute for the Commission's exercise of judgment in which it ensures that it has taken account of the cumulative effect of all relevant considerations.

Assessment Principles for Efficient Prices

40 Chapter 5 (Assessment Principles for Efficient Prices) details the Commission's pricing principles which provide the basis of its building blocks assessment of the net benefits to acquirers.

41 The Commission considers the following generic pricing principles are suitable for determining efficient prices and normal returns:

- allocatively efficient prices should be set and normal returns should be earned over time;
- productive efficiency should be maintained over time. This requires the adoption of least cost production practices. The Commission engaged Meyrick and Associates to provide advice on the productive efficiency of the gas pipeline businesses; and
- dynamic efficiency should be maintained over time. This requires that over- or under-investment be avoided. The Commission's view is that there are no significant dynamic inefficiencies in the gas pipeline businesses.

Normal Returns

42 The Commission considers that over the life of an asset the returns discounted by an appropriate WACC should equal the initial investment amount. This is referred to as the Net Present Value (NPV) = 0 principle, and is adopted by the Commission in this Inquiry.

43 Normal returns need to be assessed over a period of time, so that singular events do not bias the results and thereby unduly influence the Commission's recommendations. The analysis period for most businesses under investigation

covers the period 1997 – 2008, with the exception of Vector whose assessment covered the period 2000 – 2008.

44 Returns must be calculated using an appropriately determined asset base. The Commission has used ODV valuations in this Inquiry and a nominal WACC. The NPV = 0 principle requires any revaluation gains/losses on the assets to be treated as income.

Assessment Approach

45 The Commission's approach to assessing NAB is described in Chapter 5 (Assessment Approach) and involves:

- identifying the potential benefits of control;
- identifying the potential costs of control. It is assumed in the main that such costs ultimately fall on consumers;
- balancing benefits against the costs; and
- taking account of the asymmetric risks associated with a decision to impose control.

Benefits of Control

46 The Commission considers the potential benefits of control separately from the potential costs. This approach has been adopted for clarity of exposition. The sources of potential benefits of control include:

- excess returns being reduced by control, with a transfer of wealth from suppliers to acquirers (being a net benefit to acquirers);
- allocative inefficiency being reduced by control. Inefficient levels of service quality for the price charged could also be addressed through control;
- productive inefficiency being reduced by control; and
- dynamic inefficiency being reduced by control, because of continued/improved availability of services.

Allocative Inefficiencies

47 The Commission has adopted a long-run model using an average cost pricing approach so allocative inefficiencies (which are measured by the deadweight loss of consumer surplus) are driven largely by the degree to which prices diverge from average costs (which include a normal return), and the price elasticity of demand for pipeline services. The Commission assumes an elasticity of -0.3 for the gas distribution services and -0.1 for transmission services.

Excess Returns

48 Any excess returns are measured as the difference between what the gas pipeline business is currently earning and what the Commission considers is a normal return for such a business. The calculation can be expressed mathematically as:

Excess returns ($) = Net Earnings ($) – (Asset base x WACC).

49 Net earnings equal the earnings before interest of the gas pipeline businesses less tax, depreciation and operating expenses plus any revaluation gains/losses and capital contributions from customers.

50 Where revaluations are only done periodically (e.g., every three years), the revaluation gains/losses calculated are spread back over the period to which they relate, and the asset base is also smoothed.

Productive Inefficiency

51 The Commission asked Meyrick & Associates to examine the productivity of the New Zealand gas pipeline businesses and the growth in productivity of NGCT. It was unable to draw conclusions from this analysis. However, the Commission considers that regulation could achieve productivity improvement in addition to the trend rate of 0.83% of total costs for all the gas businesses.

Dynamic Inefficiency

52 The Commission could not identify (absent control) any significant dynamic inefficiency with regard to gas pipeline businesses. Thus, benefits from control cannot be achieved.

Costs of Control

53 The costs of control can be broken down into two types: direct and indirect costs.

Direct Costs

54 The direct costs of control include those that fall on the gas pipeline businesses (compliance costs), and those borne by the regulator (regulator's costs).

55 The direct costs of control are those that would be additional to the costs of the existing regulatory regime. The Commission has used figures provided by the gas pipeline businesses to estimate their compliance costs, while it has used the costs of this Inquiry as the primary basis for determining the regulator's costs of control.

Indirect Costs

56 The Commission has modelled five indirect costs of control, in terms of:

- unrecoverable excess returns;
- unachievable allocative efficiencies;
- productive inefficiencies created by control;
- reductions in service quality; and
- deterred new investment.

57 Control would move towards but would not exactly replicate the competitive price. As a result, only a proportion of the potential allocative efficiency gains would be secured under the control scenario, the rest would be unrecoverable.

The Commission has adopted a factor of 20% to discount the potential excess returns benefits of control (i.e., only 80% of excess returns would be recoverable). Allocative efficiency benefits are discounted by 36%.

58 The Commission considers that control could impose productive inefficiency in the order of 0 to 0.66% of total costs, to reflect the potential costs of control. The mid-point of 0.33% is used for the purposes of the modelling base case.

59 The Commission considers that dynamic inefficiency may be created by control. Control may cause under-investment that might result in reduced service quality for existing customers, or to a delay in supplying new customers by extension of the network (missing market).

Taking Account of the Asymmetric Risks of Imposing Control

60 The Commission recognises that the risks associated with imposing control are asymmetric: that is the costs of imposing control when it is not justified are higher than the cost of not imposing control when it is justified. Further, in assessing whether control is justified, the Commission needs to ensure consistency with its likely approach if control were declared.

61 The Commission is of the view that a WACC should be chosen from the upper end of the distribution in determining whether to impose control on the gas businesses but that the implicit margin on WACC provided by the costs of control needs to be taken into account. The implicit margins provided by the costs of control for each of the businesses are shown in Table 3.

Table 3: Implicit Margins Provided by the Costs of Control

	Direct costs margin	Indirect costs margin	Total implicit margin[II]
Wanganui Gas	2.1%	0.8%	**2.8%**
NGCD	0.5%	0.8%	**1.3%**
NGCT	0.2%	0.4%	**0.6%**
Powerco	0.5%	1.3%	**1.8%**
Vector	0.3%	1.4%	**1.6%**

Modelling Issues and Sensitivity Tests

62 Data limitations can affect the results of any model. The Commission has taken every effort to minimise the risks associated with data limitations. It has required gas pipeline businesses to complete a data template, has sought further clarification of the data provided, and in some cases adjusted the information provided.

63 The Commission was particularly concerned about common cost allocations by the businesses, and has adjusted the common costs of Powerco and Vector in the base case analysis. The Commission also has reservations as to the forecast information provided and revisions to historical figures made in some cases.

[II] Note there may be rounding differences when adding the direct and indirect cost margins to get the total margin.

64 No model can be expected to reflect all real world scenarios. Nonetheless, the Commission considers that a building blocks model, by linking prices and returns to the costs incurred by gas pipeline businesses does provide a reasonable method for the evaluation of business behaviour in markets of limited competition.

65 Sensitivity tests were run on numerous variables in the modelling including:

- asset base – only possible for Wanganui Gas given data limitations;
- WACC;
- common costs;
- self-insurance (Powerco, Vector, Wanganui Gas);
- growth forecasts;
- excess returns unrecoverable;
- dynamic inefficiency costs of control; and
- tax (Powerco and Vector).

66 The range of sensitivities presented for each variable above was a matter of Commission judgment. An overview of the approach is discussed in Chapter 7 (Modelling Issues and Sensitivity Tests) and results are presented in the company chapters.

Asset Valuation

67 Chapter 8 (Asset Valuation) discusses asset valuation issues. The valuation of assets is a key variable in the assessment of normal returns, since capital costs are a significant proportion of the total costs.

68 The Commission's preference is to use opportunity cost to value non-sunk assets, and a cost-based approach (either historic cost or ODRC/ODV) to value sunk assets. The Commission notes that either the depreciated historic cost (DHC) or ODV approach may be used to assess excess returns under an NPV = 0 approach.

69 The Commission has based its advice on the ODV valuations. This is largely based on the greater availability of relatively robust and comparable data for this methodology compared to historic cost data. Non system assets were valued at historic cost as were easements.

Weighted Average Cost of Capital (WACC)

70 WACC is the weighted average cost of debt and equity capital raised at the margin. Like the asset base, it is relevant both for determining prices and for assessing performance. The Commission has determined what it considers to be an appropriate WACC for gas pipeline businesses within New Zealand.[III] A

[III] In formulating the views expressed on WACC in this Report, the Commission obtained advice from Dr Martin Lally. A copy of his report to the Commission is contained on the Commission's website under 'Regulatory Control Inquiry on Gas Pipelines'.

discussion of WACC issues is contained in Chapter 9 (Weighted Average Cost of Capital).

71 Key determinants of WACC are the risk-free rate, leverage, debt premium, market risk premium, asset beta and leverage.

- *risk-free rate*: the Commission has adopted a three-year term for the risk-free rate for gas pipeline businesses on the basis that this most closely proxies the likely time horizon of price setting in the gas pipeline industry. The three-year risk-free rate averaged over July 2003 was 0.050.
- *market risk premium*: the Commission's conclusion is that the appropriate mid-point estimate for the TAMRP is 0.07.
- *beta*: the Commission has adopted a mid-point asset beta for the gas businesses of 0.5. Although the characteristics of gas transmission and distribution differ in some respects, there is insufficient information available to justify applying different betas.
- leverage: the Commission has adopted an optimal leverage of 40% based on analysis of comparable businesses. It used this leverage weight in determining the debt premium and in determining WACC.
- *debt premium*: In determining the debt premium, the Commission has considered the actual premiums that the businesses pay above the risk-free rate, as well as costs to businesses with similar credit risk. The Commission is of the view that a debt margin of 0.012 would be appropriate for the gas businesses assuming 40% leverage.

WACC Estimates

72 A WACC estimate can be derived drawing on the estimates for the various parameters discussed above. These parameter values translate into a cost of equity of 0.092 and a point estimate of WACC of 0.072.

73 The point estimate on WACC reflects five parameters over which there is significant uncertainty i.e., the market risk premium and four components of the asset beta. Such parameter uncertainty results in uncertainty over WACC and this can be formalised in a probability distribution for WACC. In translating the uncertainty over parameter values into a distribution for WACC, it has been assumed that the parameters are independent.

74 Assuming 'normality' in the WACC distribution, the percentiles of the WACC distribution are derived as shown for 2003 in Table 4 below:

Table 4: Percentiles of the WACC Distribution

Percentile	25th	50th	60th	70th	80th	90th
WACC	.064	.072	.075	.078	.082	.087

75 The Commission has used the WACC at the 50th percentile in its base case analysis ('mid-point WACC').

Tax

76 To ensure that returns are assessed in a way that is consistent with the NPV = 0 principle, the Commission calculates tax payable from taxable net profits rather than the prima facie tax based on profits in the regulatory accounts.

77 In calculating excess earnings, the Commission follows standard practice in incorporating the interest tax deduction in the WACC. The tax payable appearing in the calculation of excess earnings is the tax payable in the absence of debt. If the levered tax payable is positive, the unlevered tax payable is simply the levered tax payable plus the interest tax shield. If the gas business is in a tax loss position, the treatment is more complex. The options for treating tax in these circumstances, and other issues, such as the treatment of asset sales are discussed in detail in Chapter 10 (Treatment of Tax in Cost Benefit Analysis).

Comparative Benchmarking

78 The Commission engaged Meyrick & Associates (Meyrick) to undertake a comparative benchmarking study of New Zealand and selected Australian gas pipeline businesses. A copy of the Meyrick report to the Commission is available on the Commission's website.[IV] During consultation, Pacific Economics Group (PEG), on behalf Vector and NGC, provided a benchmarking study that compared Vector and NGC to forty US gas distributors.[V]

79 Taken at face value, the results of the Meyrick and PEG analyses provide conflicting evidence on the efficiency of the New Zealand distribution businesses. As a result of the conflicting evidence and the unresolved factors associated with the two analyses, the Commission draws no definitive quantitative conclusions from the benchmarking analyses undertaken to date. Overall the Commission considers that the benchmarking analysis undertaken by Meyrick and PEG reinforces its prior reservations, and those expressed in submissions by interested parties on the Draft Framework Paper, about the ability in such studies to make like for like comparisons given the data currently available.

80 Chapter 11 (Benchmarking) describes in more detail the Meyrick and PEG analyses.

NGCT

81 Chapter 12 (NGC Holdings Ltd – Transmission (NGCT)) discusses in detail the competition and cost benefit analysis undertaken for NGCT, and the Commission's recommendations on whether control may and should be imposed on NGCT.

[IV] Meyrick and Associates, *Comparative Benchmarking of Gas Networks in Australia and New Zealand*, Report prepared for the Commerce Commission, May 2004.
[V] Pacific Economics Group, *New Zealand Gas Distribution Cost Performance: Results from International Benchmarking*, June 2004.

Competition

82 In respect of the transmission market, the Commission has considered the competitive impact of interfuel competition, head-to-head competition with MDL, long-term supply contracts and the regulatory regime and concludes that the constraint they provide on transmission service providers is limited. Accordingly, the Commission considers that the competition faced by NGCT in the transmission markets in which it operates is limited.

Net Acquirers Benefit (NAB)

83 In determining whether control may be imposed, the Commission assesses the NAB of imposing control. The results of the Commission's base case and sensitivities of the NAB test over the period 1997 – 2008 are presented below.

Table 5: NGCT

Scenario	**NAB Annuity ($000)**
Base case	2,364
High and low WACC (75^{th} and 25^{th} percentile)	-263 to 4,913
Higher growth in forecast period [ ]	3,505
High and low unrecoverable excess return (25% and 10%)	2,090 to 2912
Common cost reductions (10-30%)	2,738 to 3,486
Low and high missing market elasticity	2,115 to 2,488
High and low missing market output effect	2,115 to 2,613

84 Overall, sensitivity testing on NGCT's NAB indicates that net benefit to acquirers would remain for all but one of the sensitivities tested (75^{th} percentile of WACC).

85 The Commission's view is that both requirements in s 52 of the Commerce Act are met for NGCT, and that gas services supplied by NGCT may be controlled.

Should Control be Introduced

86 The Commission considers the following additional matters in assessing whether control 'should' be introduced: the net efficiency cost to the economy of reducing excess returns; the size of the benefits; and the impact of a recommendation not to control.

87 The net efficiency costs to the economy of reducing excess returns for NGCT were $1.096 million in annuity terms in the analysis period. The recoverable excess returns were $3.629 million, giving a transfer cost ratio of 30% (i.e., the cost of transferring each $1 of recoverable excess returns to consumers involves a net cost to the economy of $0.30).

88 NGCT earned an average return of approximately 9.1% over the analysis period. The NAB of NGCT suggests that transmission prices could be reduced by as much as 3.5% which would result in a reduction in delivered energy prices to retail customers (assuming transmission constitutes 10% of final price) in the order of 0.35%. Alternatively, the reduction in transmission charges would save the average direct customer $213,000. Such savings would likely be passed on to end consumers.

89 The Commission considers that if control were not imposed, the threat of control might be weakened which could result in future increases in prices from current levels.

90 The Commission concludes that control should not be imposed on NGCT.

Overall Recommendation for NGCT

91 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by NGCT may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on NGCT under Part V of the Commerce should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

92 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on NGCT should be strengthened and requests the Minister consider applying to NGCT a regime comparable to the targeted control regime applicable to electricity lines businesses under Part 4A.

93 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

94 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

95 In addition, the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the

businesses to disclose consistent and robust information and therefore, requests that the Minister consider strengthening the gas pipeline information disclosure regime.

Other Matters for the Minister to Consider

96 The Commission has not considered the implications of Vector's proposed acquisition of NGC. The Minister may need to consider the implications of that acquisition should the acquisition proceed.

NGCD

97 Chapter 13 (NGC Holdings Ltd – Distribution (NGCD)) discusses in detail the competition and cost benefit analysis undertaken for NGCD, and the Commission's recommendations on whether control may and should be imposed on NGCD.

Competition

98 In respect of competition faced by NGCD, the Commission has considered the competitive constraints arising from interfuel competition, the threat of by-pass, long-term supply contracts and the regulatory regime and concludes that the constraint they provide on NGCD is limited. Accordingly, the Commission considers that the competition faced by NCGD in the markets it operates in is limited.

Net Acquirers Benefit (NAB)

99 In determining whether control may be imposed, the Commission assesses the NAB of imposing control. The results of the Commission's base case and sensitivities for the NAB test over the period 1997 – 2008 are presented below.

Table 6: NGCD

Scenario	**NAB Annuity ($000)**
Base case	1,600
High and low WACC (75th and 25th percentile)	783 to 2,390
Higher growth in forecast period (3.5%)	2,380
High and low unrecoverable excess return (25% and 10%)	1,440 to 1,921
Common cost reductions (10-30%)	1,788 to 2,165
Low and high missing market elasticity	1,448 to 1,676
High and low missing market output effect	1,448 to 1,752

100 Overall, sensitivity testing on NGCD's NAB indicates that net benefits to acquirers would remain for all sensitivities tested.

101 The Commission's view is that the requirements of s 52 of the Commerce Act are met for NGCD, and that gas services supplied by NGCD may be controlled.

Should Control be Introduced

102 The Commission considers the following additional matters in assessing whether control 'should' be introduced: the net efficiency cost to the economy of reducing excess returns; the size of the benefits; and the impact of a recommendation not to control.

103 The net efficiency costs to the economy of reducing excess returns for NGCD were $0.913 million in annuity terms in the analysis period. The recoverable excess returns were $2.455 million, giving a transfer cost ratio of 37% (i.e., the cost of transferring each $1 of recoverable excess returns to consumers involves a net cost to the economy of $0.37).

104 NGCD earned an average return of approximately 10.5% over the analysis period. The NAB of NGCD suggests that its distribution prices could be reduced by as much as 5.6% which would result in a reduction in delivered energy prices (assuming distribution constitutes 40% of final price) to retail customers in the order of 2.2%. Alternatively, the reduction in distribution charges would save the average direct customer $29 or a 5.6% reduction in their annual line charges.

105 The Commission considers that if control were not imposed, the threat of control might be weakened, which could result in future increases in prices from current levels.

106 The Commission concludes that control should not be imposed on NGCD.

Overall Recommendation for NGCD

107 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by NGCD may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on NGCD under Part V of the Commerce should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

108 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on NGCD should be strengthened and requests the Minister consider applying to NGCD, a regime comparable to the targeted control regime applicable to electricity lines businesses under Part 4A.

109 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and

operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

110 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

111 In addition, the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests that the Minister consider strengthening the gas pipeline information disclosure regime.

Other Matters for the Minister to Consider

112 The Commission has not considered the implications of Vector's proposed acquisition of NGC. The Minister may need to consider the implications of that acquisition should the acquisition proceed.

Powerco

113 Chapter 14 (Powerco Limited (Powerco)) discusses in detail the competition and cost benefit analysis undertaken for Powerco, and the Commission's recommendations on whether control may and should be imposed on Powerco.

Competition

114 In relation to competition faced by Powerco, the Commission has considered the competitive constraints arising from interfuel competition, the threat of by-pass, long-term supply contracts and the regulatory regime and concludes that the constraint they provide on Powerco is limited. Accordingly, the Commission considers that the competition faced by Powerco in the markets it operates in is limited.

Net Acquirers Benefit (NAB)

115 In determining whether control may be imposed, the Commission assesses the NAB of imposing control. The results of the Commission's base case and sensitivities for the NAB test over the period 1997 – 2008 are presented below.

Table 7: Powerco

Scenario	NAB Annuity ($000)
Base case	3,719
High and low WACC (75th and 25th percentile)	2,925 to 4,542
Higher growth in forecast period (3.5%)	5,020
High and low unrecoverable excess return (25% and 10%)	3,421 to 4,318
Common cost reductions (10-30%)	3,978 to 4,497
Low and high missing market elasticity	3,625 to 3,766
High and low missing market output effect	3,625 to 3,813
High and low tax clawback	3,355 to 3,595
Self insurance	3,181

116 Overall, sensitivity testing on Powerco's NAB indicates that net benefit to acquirers would remain for all sensitivities tested.

117 The Commission's view is that the requirements of s 52 of the Commerce Act are met for Powerco, and that gas services supplied by Powerco may be controlled.

Should Control be Introduced

118 The Commission considers the following additional matters in assessing whether control 'should' be introduced: the net efficiency cost to the economy of reducing excess returns; the magnitude of the benefits; and the impact of a recommendation not to control

119 The net efficiency costs to the economy of reducing excess returns for Powerco were $0.732 million in annuity terms in the analysis period. The recoverable excess returns were $4.395 million, giving a transfer cost ratio of 17% (i.e., the cost of transferring each $1 of recoverable excess returns to consumers involves a net cost to the economy of $0.17).

120 Powerco earned an average return of approximately 12.7% over the analysis period. The NAB of Powerco suggests that its distribution prices could be reduced by as much as 12.2% which would result in a reduction in delivered energy prices (assuming distribution constitutes 40% of final price) to retail customers in the order of 4.9%. Alternatively, the reduction in distribution charges would save the average direct customer $51 or a 12.2% reduction in their annual line charges.

121 The Commission considers that if control were not imposed, the threat of control might be weakened, which could result in future increases in prices from current levels.

122 The Commission concludes that control should be imposed on Powerco.

Overall Recommendation for Powerco

123 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Powerco may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Powerco under Part V of the Commerce should be made.

Advice on Relevant Matters

124 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. If the Minister were to introduce alternative mechanisms for NGCT, NGCD and Wanganui Gas (such as a regime comparable to the targeted control regime applicable to electricity lines businesses under Part 4A), there may be benefits in having all businesses, including, Powerco, under the same regime.

125 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

126 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

127 In addition, the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

Vector

128 Chapter 14 (Vector Limited (Vector)) discusses in detail the competition and cost benefit analysis undertaken for Vector, and the Commission's recommendations on whether control may and should be imposed on Vector.

Competition

129 In relation to competition faced by Vector, the Commission has considered the competitive constraints arising from interfuel competition, the threat of by-

pass, long-term supply contracts and the regulatory regime and concludes that the constraint they provide on Vector is limited. Accordingly, the Commission considers that the competition faced by Vector in the markets it operates in is limited.

Net Acquirers Benefit (NAB)

130 In determining whether control may be imposed, the Commission assesses the NAB of imposing control. The results of the Commission's base case and sensitivities for the NAB test over the period 2000 – 2008 are presented below.

Table 8: Vector

Scenario	NAB Annuity ($000)
Base case	6,921
High and low WACC (75th and 25th percentile)	5,692 to 8,215
Higher growth in forecast period (3.5%)	6,612
High and low unrecoverable excess return (25% and 10%)	6,422 to 7,926
Common cost reductions (10-30%)	7,522 to 8,730
Low and high missing market elasticity	6,763 to 7,000
High and low missing market output effect	6,763 to 7,079
High and low tax clawback	6,024 to 6,626
Self insurance	6,557

131 Overall, sensitivity testing on Vector's NAB indicates that net benefits to acquirers would remain for all sensitivities tested.

132 The Commission's view is that the requirements of s 52 of the Commerce Act are met for Vector, and that gas services supplied by Vector may be controlled.

Should Control be Introduced

133 The Commission considers the following additional matters in assessing whether control 'should' be introduced: the net efficiency cost to the economy of reducing excess returns; the size of the benefits; and the impact of a recommendation not to control

134 The net efficiency costs to the economy of reducing excess returns for Vector were $0.702 million in annuity terms in the analysis period. The recoverable excess returns were $7.489 million, giving a transfer cost ratio of 9% (i.e., the cost of transferring each $1 of recoverable excess returns to consumers involves a net cost to the economy of $0.09).

135 Vector earned an average return of approximately 13.5% over the analysis period. The NAB of Vector suggests that its distribution prices could be reduced by as much as 18.5% which would result in a reduction in delivered

energy prices (assuming distribution constitutes 40% of final price) to retail customers in the order of 7.4%. Alternatively, the reduction in distribution charges would save the average direct customer $114 or a 18.5% reduction in their annual line charges.

136 The Commission considers that if control were not imposed, the threat of control might be weakened which could result in future increases in prices from current levels.

137 The Commission concludes that control should be imposed on Vector.

Overall Recommendation

138 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Vector may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Vector under Part V of the Commerce should be made.

Advice on Relevant Matters

139 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. If the Minister were to introduce alternative mechanisms for NGCT, NGCD and Wanganui Gas (such as a regime comparable to the targeted control regime applicable to electricity lines businesses under Part 4A), there may be benefits in having all businesses, including, Vector, under the same regime.

140 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

141 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

142 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests that the Minister consider strengthening the gas pipeline information disclosure regime.

Wanganui Gas

143 Chapter 15 (Wanganui Gas Limited) discusses in detail the competition and cost benefit analysis undertaken for Wanganui Gas, and the Commission's recommendations on whether control may and should be imposed on Wanganui Gas.

Competition

144 In relation to competition faced by Wanganui Gas, the Commission has considered the competitive constraints arising from interfuel competition, the threat of by-pass, long-term supply contracts and the regulatory regime and concludes that the constraint they provide on Wanganui Gas is limited. Accordingly, the Commission considers that the competition faced by Wanganui Gas in the markets it operates in is limited.

Net Acquirers Benefit (NAB)

145 In determining whether control may be imposed, the Commission assesses the NAB of imposing control. The results of the Commission's base case and sensitivities for the NAB test over the period 1997 – 2008 are presented below.

Table 9: Wanganui Gas

Scenario	NAB Annuity ($000)
Base case	155
High and low WACC (75th and 25th percentile)	47 to 264
Higher growth in forecast period (0.5%)	174
High and low unrecoverable excess return (25% and 10%)	120 to 224
Common cost reductions (10-30%)	174 to 211
Low and high missing market elasticity	152 to 156
High and low missing market output effect	152 to 158
Historic cost asset base	24
Self insurance	121

146 Overall, sensitivity testing on Wanganui Gas's NAB indicates that net benefit to acquirers would remain for all sensitivities tested.

147 The Commission's view is that the requirements of s 52 of the Commerce Act are met for Wanganui Gas, and that gas services supplied by Wanganui Gas may be controlled.

Should Control be Introduced

148 The Commission considers the following additional matters in assessing whether control 'should' be introduced: the net efficiency cost to the economy

of reducing excess returns; the size of the benefits; and the impact of a recommendation not to control

149 The net efficiency costs to the economy of reducing excess returns for Wanganui Gas were $0.374 million in annuity terms in the analysis period. The recoverable excess returns were $0.527 million, giving a transfer cost ratio of 71% (i.e. the cost of transferring each $1 of recoverable excess returns to consumers involves a net cost to the economy of $0.71).

150 Wanganui Gas earned an average return of approximately 11.8% over the analysis period. The NAB of Wanganui Gas suggests that its distribution prices could be reduced by as much as 0.2% which would result in a reduction in delivered energy prices (assuming distribution constitutes 40% of final price) to retail customers in the order of 0.1%. Alternatively, the reduction in distribution charges would save the average direct customer $1 or a 0.2% reduction in their annual line charges.

151 The Commission considers that if control were not imposed, the threat of control might be weakened which could result in future increases in prices from current levels.

152 The Commission concludes that control should not be imposed on Wanganui Gas.

Overall Recommendation

153 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Wanganui Gas may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Wanganui Gas under Part V of the Commerce should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

154 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on Wanganui Gas should be strengthened and requests that the Minister consider applying to Wanganui Gas, a regime comparable to the targeted control regime applicable to electricity lines businesses under Part 4A.

155 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime

has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

156 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

157 In addition, the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests that the Minister consider strengthening the gas pipeline information disclosure regime.

Maui Development Limited

158 Chapter 17 (Maui Development Limited (MDL)) discusses in detail the competition and cost benefit analysis undertaken for MDL, and the Commission's recommendations on whether control may and should be imposed on MDL.

Competition Analysis

159 In respect of the transmission market, the Commission has considered the competitive impact of interfuel competition, head-to-head competition with NGCT, long-term supply contracts and the regulatory regime and concludes that the constraint they provide on MDL's transmission services is limited. Accordingly, the Commission considers that the competition faced by MDL in the transmission markets in which it operates is limited.

Net Acquirers Benefit

160 The Maui Gas Contract restricts the Maui pipeline to Maui gas alone. However the parties to the Contract have now reached an agreement to vary the Contract to allow for the carriage of non-Contract gas on the Maui pipeline, although priority will still be given to the carriage of Maui Gas which is subject to the Contract. MDL was not able to provide the Commission with revenue and expense data for cost benefit modelling. In the absence of detailed information, the Commission has focussed its analysis on the open access proposal, associated information, and the comparability of MDL with NGCT.

161 The access regime for non-Contract gas is still being negotiated and is currently in draft form. The Commission has given careful consideration to the draft open access regime for the Maui pipeline and possible prices for access. However, due to its draft status, it is not sufficiently certain to be used as a basis for assessing MDL's future pricing behaviour.

162 The Commission considers that the other significant transmitter of gas, NGCT, faces similar competitive constraints, and has underlying market power which reasonably approximates that of MDL. In the absence of reliable information from MDL which can be used to assess its future behaviour, the Commission has looked to NGCT as a guide.

163 The Commission's analysis has concluded that NGCT is earning excess returns and that there would be NAB from control. The Commission infers that there would also be NAB from controlling MDL. The Commission notes that it has calculated that control on NGCT may result in a reduction in its prices by around 3.5%, and concludes that a similar benefit might be achieved through control of MDL.

164 The Commission's view is that the requirements of s 52 of the Commerce Act are met for MDL, and that gas services supplied by MDL may be controlled.

Should Control be Introduced

165 The Commission considers the following additional matters in assessing whether control 'should' be introduced: the net efficiency cost to the economy of reducing excess returns; the size of the benefits; and the impact of a recommendation not to control

166 The net efficiency costs to the economy of reducing excess returns for MDL are assumed to be the same order of magnitude as NGCT's i.e., around 30%. Thus, the cost of transferring each $1 of recoverable excess returns to consumers is likely to result in efficiency costs to the economy of around $0.30.

167 As noted above, the Commission assumes that control could reduce MDL's transmission prices by around 3.5%.

168 The Commission considers that if control were not imposed, the threat of control might be weakened which could result in future increases in prices from current levels.

169 The Commission concludes that control should not be imposed on MDL.

Overall Recommendation

170 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by MDL may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on MDL under Part V of the Commerce should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

171 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on MDL should be strengthened and requests the Minister consider applying to MDL, a regime comparable to the targeted control regime applicable to electricity lines businesses under Part 4A.

172 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

173 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

174 The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests that the Minister consider strengthening the gas pipeline information disclosure regime and bringing MDL into that regime.

Nova Gas

175 Chapter 18 (Nova Gas Limited (Nova Gas)) discusses in more detail the competition analysis undertaken for Nova Gas.

Competition Analysis

176 Nova Gas operates in the bypass market. Nova Gas faces direct competition from incumbent gas pipelines in the bypass market. The level of competition for customers is vigorous. Nova Gas also faces constraints from interfuel competition and from the regulatory regime.

177 With respect to s 52(a) of the Commerce Act, the Commission's assessment is that Nova Gas faces workable or effective competition in the market where it provides gas services. That is, competition is not limited in this market.

178 The Commission advises that the gas services supplied by Nova Gas Limited may not be controlled.

Taranaki Pipelines

179 In addition to the 'principal' transmission pipelines discussed above there are a number of pipelines of smaller length, all situated in Taranaki.

180 The LTS pipeline owned by NGC and the Surrey Road pipeline owned by Westech Energy are considered to fall outside the definition of 'transmission system' in the terms of reference and are therefore outside the ambit of the Inquiry.

181 The Frankley Road pipeline owned by NGC is included in the analysis of NGCT.

182 With respect to the McKee Production Station to Faull Road pipeline (Todd Taranaki) and the Rimu to NGC South pipeline (Swift) the Commission's assessment is that competition to these pipelines is not limited. The

Commission advises that the gas services provided by these pipelines may not be controlled.

183 With respect to the Kapuni to Hawera pipeline (Todd Petroleum and Shell), and the TAW pipeline (Swift Energy) the Commission's assessment is that competition is limited but that there is unlikely to be net benefit to acquirers from control. The Commission does not consider that it is necessary or desirable in the interests of acquirers for control to be imposed. The Commission reports that the gas services provided by these pipelines may not be controlled.

184 These pipelines are discussed in more detail in Chapter 19 (Taranaki Pipelines).

Comparative Business Information

Net Acquirers Benefit

185 The benefits, costs and net acquirers benefit assessed at the 25th percentile, mid and 75th percentile points of WACC for NGCT, NGCD, Vector, Powerco and Wanganui Gas are set out in Table 10.

Table 10: Net Acquirers Benefit

	Annuity ($000)		
	25th WACC	**Mid WACC**	**75th WACC**
NGCT			
Total benefits	8,278	5,170	2,062
Total costs	3,365	2,806	2,325
NAB	**4,913**	**2,364**	**-263**
NGCD			
Total benefits	4,376	3,375	2,386
Total costs	1,986	1,775	1,603
NAB	**2,390**	**1,600**	**783**
Powerco			
Total benefits	6,927	5,892	4,896
Total costs	2,386	2,173	1,972
NAB	**4,542**	**3,719**	**2,925**
Vector			
Total benefits	11,721	10,047	8,457
Total costs	3,507	3,126	2,766
NAB	**8,215**	**6,921**	**5,692**
Wanganui Gas			
Total benefits	844	706	570
Total costs	580	551	523
NAB	**264**	**155**	**47**

Net Efficiency Costs to the Economy of Reducing Excess Returns

186 The Commission has found NAB for all businesses investigated. The positive NAB has been driven by excess returns as the net efficiency effect of control is

always found to be negative. Table 11 highlights the trade off between the net efficiency effects and recoverable excess returns for each business.

Table 11: Net Efficiency and Recoverable Excess Returns Trade-off[VI]

	NGCT	NGCD	Powerco	Vector	WGL
Recoverable excess returns ($000)	3,629	2,455	4,395	7,489	527
Net efficiency effect ($000)	-1,096	-913	-732	-702	-374
Net cost of $1 transfer to acquirers	$0.30	$0.37	$0.17	$0.09	$0.71
Times recoverable excess returns exceed efficiency effect	3.3	2.7	6.0	10.7	1.4

Size of the Benefits

187 Table 12 shows the average returns earned by the businesses over the analysis period. The mid-point of WACC was 8% on average over the same period.

Table 12: Average Returns of the Businesses

Company	Average Returns on Capital
WGL	11.8%
NGCD	10.5%
NGCT	9.1%
Powerco	12.7%
Vector	13.5%

188 Table 13 shows the change in transmission and distribution prices to reduce the positive NAB for each business back to zero.

Table 13: Effect on Transmission/Distribution Prices

Company	Price Effect
NGCT	-3.5%
NGCD	-5.6%
Vector	-18.5%
Powerco	-12.2%
WGL	-0.2%

189 Table 14 shows the impact in dollar terms of reducing prices to the point where NAB = 0 relative to the average annual consumption per connection.

Table 14: Reduced Annual Charges per Connection

	Average annual gain per acquirer	Average annual charge per acquirer
WGL	$1	$323
NGCD	$29	$518
NGCT	[ ]	[ ]
Powerco	$51	$415
Vector	$114	$617

[VI] Recoverable excess returns are calculated as the total excess returns less 20% thereof, as this proportion is considered unrecoverable. The efficiency costs include costs that fall on producers and acquirers.

190 Table 15 shows the potential change in the delivered gas price to retail customers if both distribution and transmission prices were reduced to a point where NAB=0 in the Commission's model. This calculation assumes that transmission's share in the delivered gas price is 10%, while distribution's share is 40%.

Table 15: Effect on Final Delivered Gas Price

(Transmission and Distribution Combined)

Company	Price Effect
NGCD	-2.6%
Vector	-7.8%
Powerco	-5.2%
WGL	-0.4%

191 It should be noted that the calculations in this sub-section are made on the basis of bringing NAB back to zero, not to where the efficient level of price would be if the costs of control were ignored.

Other Requests from the Minister

Appropriate Valuation Methodology for this Inquiry

192 The Commission investigated the use of both historic cost and replacement cost valuation approaches for this Inquiry. The historic cost information was found to be generally unavailable. ODV/ODRC valuations were readily available and relatively robust compared to the historic cost information. Therefore, the Commission considers that the appropriate valuation methodology for this Inquiry to be ODV/ODRC.

Net Benefits to the Public of Control

193 The Minister requested the Commission to advise him on the net public benefits of control. The net public benefits assessment measures only efficiency effects. The efficiency effects under the net public benefits assessment are largely the efficiency effects within the NAB test.[VII]

194 The benefits, costs and net public benefits assessed at the mid-point of WACC for NGCT, NGCD, Vector, Powerco and Wanganui Gas are set out in Table 16.

[VII] The Commission notes that two additional benefits and costs of control affect producers only, and are included in the net public benefits analysis. These two additional matters are explained at the end of Chapter 4 (Overview of the Assessment Approach). They have proved generally immaterial in the present Inquiry.

Table 16: Net Public Benefits

Company	Mid WACC (Annuity $000)
NGCT	
Total efficiency benefits	644
Total efficiency costs	1,740
Net Public Benefits	**-1,096**
NGCD	
Total efficiency benefits	306
Total efficiency costs	1,219
Net Public Benefits	**-913**
Powerco	
Total efficiency benefits	401
Total efficiency costs	1,134
Net Public Benefits	**-732**
Vector	
Total efficiency benefits	685
Total efficiency costs	1,388
Net Public Benefits	**-702**
Wanganui Gas	
Total efficiency benefits	47
Total efficiency costs	421
Net Public Benefits	**-374**

Technical Provisions Relating to Section 57A of the Commerce Act

Description of Services

195 The Order made under s 53 of the Commerce Act may identify the services to which it relates:

- by a description of the services; or
- by a description of the kind or class to which the services belong.

196 The Order may apply to services:

- supplied in or for delivery within specified regions, areas, or localities in New Zealand;
- supplied in different quantities, qualities, grades or classes;
- supplied by or to or for the use of different persons or classes of persons.

197 The Commission would identify the services in the Order by the suppliers of the gas services. Accordingly the Order would refer to the services supplied by some or all of NGC Holdings Limited (Transmission), NGC Holdings Limited (Distribution), Powerco Limited, Vector Limited, Wanganui Gas Limited and Maui Development Limited in markets directly related to either a natural gas transmission system or a natural gas distribution system or both.

198 Where 'transmission system' is defined as:

> Transmission system means that part of a system that conveys gas from the point where the gas leaves a gas processing facility to the boundary of the gasworks or gate station outlet flange supplying gas-
>
> (a) for distribution; or
>
> (b) to a gas customer, where the gas does not enter a distribution system.

199 Where 'distribution system' is defined as

> Distribution system means all fittings, whether above or below ground, under the control of a gas distributor and used to distribute gas from-
>
> (a) The boundary of the gasworks or gate station outlet flange supplying gas for distribution; or
>
> (b) The outlet of the container in which gas for distribution is stored-
>
> to the outlet of the gas measurement system of the place at which the gas is supplied to a consumer or gas refueller (or, where no such gas measurement system is provided, to the custody transfer point of the place at which the gas is supplied to a consumer or gas refueller); and, for the purposes of any regulations made under section 54 of this Act relating to odorisation or the measurement of calorific value, includes a gas transmission system.

200 In addition, the Commission considers that gas meters should be separately identified in any Order.

Date of Expiry

201 The Order made under s 53 of the Commerce Act must specify the date on which it expires (s 57A(4)).

202 The Commission acknowledges that it can be problematic to set a period of control without determining the form of control. It considers, however, that the appropriate period for expiry of an Order declaring control would be 11 years.

203 If a shorter period was adopted then another inquiry would have to be undertaken if control were to be extended. The Commission has the ability itself to vary authorisations and the form of control under Part V and also has the ability under s 56 of the Commerce Act to recommend amendment or revocation of the Order that declares control, should a shorter period of control become desirable.

Other Matters for the Minster to Consider

204 The Commission has not considered the implications of Vector's proposed acquisition of NGC. The Minister may need to consider the implications of that acquisition should the acquisition proceed.

1 BACKGROUND

Introduction

1.1 The Commerce Commission (Commission) has undertaken the Gas Control Inquiry (Inquiry) in response to a request from the Minister of Energy (Minister) dated 30 April 2003. The initial request and subsequent correspondence with the Minister (the terms of reference) required the Commission to report on whether goods and services supplied by persons in markets directly related to either a natural gas transmission system or a natural gas distribution system or both (gas services) should be controlled. The initial request required the Commission to respond to the Minister by 1 November 2004. In September 2004 the Commission requested, and was granted, an extension from 1 November 2004 to 29 November 2004.

1.2 In response to the initial request from the Minister, the Commission proposed a process for the Inquiry on 30 May 2003 and invited interested parties to make submissions on that process.

1.3 The Commission proposed a two stage consultative process. The first stage defined the Commission's framework for investigating the performance of the relevant sectors while the second stage focused on the application of the framework and interpretation of the associated findings.

1.4 As part of the first consultative stage, the Commission released the draft framework paper on 16 July 2003 (Draft Framework Paper). The Draft Framework Paper set out the Inquiry background and presented the proposed legal and analytical frameworks to be used and sought comment on those frameworks. The Commission received submissions, held a conference and received post conference cross submissions on the Draft Framework Paper during August and September 2003.

1.5 As part of the second consultative stage, the Commission released the draft report on 21 May 2004 (Draft Report). The Draft Report set out the Commission's initial view on whether any of the gas services should be controlled. The Commission received submissions, held a conference and received post conference cross submissions on the Draft Report during June and July 2004.

1.6 Subsequent to the conference on the Draft Report, the Commission released a paper entitled 'Tax Treatment in the Commerce Commission's Cost Benefit Analysis' (Tax Paper). The Tax Paper described the Commission's proposed approach to the treatment of tax in the Inquiry. The Commission accepted submissions on the Tax Paper up to 23 September 2004.

1.7 The Commission has carefully considered all of the submissions it received on the Draft Framework Paper, Draft Report and Tax Paper in preparing this report (Final Report). The Final Report sets out the Commission's final recommendation to the Minister on whether any of the gas services should be controlled.

1.8 The Final Report is structured as follows:

Table 1.1: Final Report Structure

Chapter	Content
Background	• Key parties to the Inquiry • Inquiry process • Current Regulatory Environment • Industry Background
Legal Framework	• The terms of reference for the Inquiry • Commission's interpretation of the relevant parts of the Commerce Act 1986 (Commerce Act) • The Commission's Counterfactual
Competition Analysis	• Competition analysis principles • Industry competition analysis
Overview of Assessment Approach	• May control be imposed • Should control be imposed
Assessment Principles for Efficient Pricing	• Principles for determining efficient prices and normal returns
Assessment Approach	• Approach to assessing benefits of control • Approach to assessing costs of control • Implicit margin provided by costs of control
Modelling Issues and Sensitivity Tests	• Modelling practicalities • Key sensitivities
Asset Valuation	• Asset valuation concepts • Historic versus replacement cost approaches • Application to gas pipeline businesses
Weighted Average Cost of Capital (WACC)	• Commission's methodology for calculating WACC for gas pipeline businesses
Treatment of Tax in the Cost Benefit Analysis	• Commission's principles • Issues • Approach used in modelling
Comparative Benchmarking	• Review of the benchmarking analysis and role it plays in the decision process
Company Specific Chapters	• Operational details • Competition analysis specific to each company • Benefits and costs of control analysis for each company including whether control would be in the interests of acquirers and the public
Conclusion	• Commission's recommendations, advice and additional information requested by the Minister

1.9 The Final Report refers to various sections of the Commerce Act. It does not, however, seek to set out in detail every provision of the statutory regime under

Parts IV and V of the Commerce Act. The actual wording in the Commerce Act prevails over any potential inconsistencies contained, or any omissions from summarising the Commerce Act provisions, in the Final Report.

Key Parties to the Inquiry

Suppliers

1.10 Gas pipelines consist of high pressure transmission pipelines and the lower pressure distribution pipelines. The suppliers of the gas services associated with transmission and distribution pipelines are presented below.

Transmission

1.11 The gas transmission system transports gas at high pressures[1] from the outlets of gas field processing plants to large industrial and commercial consumers in the gas wholesale market, NGC Holdings Limited transmission (NGCT) network and local gas distribution systems.

1.12 The transmission pipelines that the Commission is aware of are identified in the table below.

Table 1.2: Transmission Pipelines

Company	Pipeline Systems
NGCT	South, North, Kapuni to Rotowaro, Bay of Plenty, Morrinsville, LTS, Frankley Road
Maui Development Limited (Shell, Todd, OMV)	Oaonui to Huntly (Maui pipeline)
Todd Energy	Kapuni to Hawera
Swift Energy	Rimu to NGC South, Waihapa to New Plymouth and TCC power stations
Westech Energy	Surrey Road to NGC LTS

1.13 The Commission is aware that NGCT is currently the only transmission business that provides third party access to its transmission system. However, Maui Development Limited (MDL) is currently working through a proposal to offer a service to transport third party gas on the Maui pipeline. As the LTS and Surrey Road pipelines do not transport gas to a gas consumer or a gas distributor the Commission considers they fall outside the ambit of this Inquiry. The Commission considers that all other pipelines identified above are subject to the Inquiry.

Distribution

1.14 Gas distribution systems transport and distribute natural gas from transmission pipeline gate stations (used for isolation, pressure reducing and metering) to the meters of end consumers. There are five gas distribution businesses operating

[1] Transmission systems generally operate at pressures over 2000 kPa.

within the North Island, which the Commission considers to be covered by the Inquiry. The table below shows the regions where each company owns distribution systems.

Table 1.3: Distribution Systems

Company	Region
NGC Distribution (NGCD)	Northland, Whangaparoa, South Auckland, Waikato, Bay of Plenty, Rotorua, Taupo, Gisborne, Kapiti Coast
Powerco	Napier and Hastings area, Southern Hawke's Bay, Taranaki, Manawatu, Levin and Foxton, Hutt/Mana and Wellington
Vector	Greater Auckland, Tuakau and Ramarama
Wanganui Gas (WGL)	Wanganui/Rangitikei
Nova Gas (Nova)	Wellington, Porirua, Hutt Valley, Hastings, Hawera, Papakura and Manukau City

1.15 The Commission considers that the distribution businesses (systems) identified above are subject to the Inquiry.

Acquirers

1.16 The Commission considers the key acquirers (direct and indirect) of the relevant gas services to be:

- Contact Energy;
- Genesis Energy;
- Ballance Agri-Nutrients;
- e-Gas Ltd;
- Carter Holt Harvey;
- BHP;
- Fletcher Building;
- Fonterra Dairy Co-op Group;
- other business consumers; and
- residential consumers.

Other Interested Parties

- Petroleum Exploration Association of New Zealand (PEANZ); and
- Major Electricity Users Group (MEUG).

1.17 A number of suppliers are also classed as acquirers due to their involvement in gas retailing.

Inquiry Process

1.18 In response to the request from the Minister, the Commission released a proposed process for the Inquiry on 30 May 2003 and invited interested parties to make submissions on that process. After careful consideration of the submissions received, the Commission adopted the process detailed in the following table. The dates in the table have been updated to reflect the latest information.

Table 1.4: Inquiry Process

Item	Date
Proposed process released by Commission	30 May 2003
Written submissions on proposed process	16 June 2003
Draft Framework Paper released by Commission	16 July 2003
Process published in *Gazette* notice pursuant to s57(2) of the Commerce Act	25 July 2003
Written submissions on Draft Framework Paper	20 August 2003
Conference on Draft Framework Paper	1–4 September 2003
Cross submissions following conference	19 September 2003
Draft Report released by Commission	21 May 2004
Revised process published in *Gazette* notice pursuant to s 57(2) of the Commerce Act	3 June 2004
Written submissions on Draft Report	2 July 2004
Conference on Draft Report	22–28 July 2004
Cross submissions following conference	13 August 2004
Tax Treatment Draft Paper released by Commission	8 September 2004
Written submissions on Tax Treatment Draft Paper	23 September 2004
Draft cost benefit model numbers released by Commission	2 November 2004
Written submissions on draft cost benefit model numbers	5 November 2004
Final Report provided to Minister of Energy	29 November 2004

Gazette Notice

1.19 Section 57(2)(a) of the Commerce Act provides that, before making any report under s 56 of the Commerce Act, the Commission must publish its intention to do so in the *Gazette* and in any other manner (if any) that the Commission considers appropriate.

1.20 In accordance with s 57(2)(a) the Commission published its initial process in the *Gazette* on 25 July 2003 and an updated process in the *Gazette* on 3 June 2004.

Commission Reports and Consultation

Draft Framework Paper

1.21 As part of the first consultative stage, the Commission released the Draft Framework Paper on 16 July 2003, accepted submissions on the paper up to 20 August 2003 and held a conference on the paper in the first week of September 2003.

1.22 The Commission received fourteen written submissions prior to the conference and six written cross submissions following the conference.

1.23 During the conference seven interested parties presented their views on the Draft Framework Paper and answered Commission questions.

Draft Report

1.24 As part of the second consultative stage, the Commission released the Draft Report, the Commission's cost benefit model and a number of consultants' reports (see table 1.5 for the list) on 21 May 2004. The Commission accepted submissions up to 2 July 2004 and held a conference on the Draft Report between 22 and 28 July 2004.

1.25 The Commission received eighteen written submissions prior to the conference and twelve written cross submissions following the conference.

1.26 During the conference nine interested parties presented their views on the Draft Report and answered Commission questions.

1.27 During consultation on the Draft Report, parties indicated that some of the tax numbers provided by the gas pipeline businesses subject to the Inquiry did not correctly incorporate the interest tax shield. In a notice released on 22 June 2004, the Commission acknowledged the potential error in the tax figures provided by the gas pipeline businesses, and sought additional information from the businesses to enable the correct modelling of tax. The Commission Chair stated at the commencement of the Draft Report gas conference that the Commission's updated tax modelling would be released to interested parties, who would have an opportunity to provide written comments on it.

Tax Treatment Draft Paper

1.28 In response to comments on tax matters the Commission released the Tax Paper on 8 September 2004. The Tax Paper described the Commission's proposed approach to the treatment of tax in the cost benefit modelling, and indicated the impact of the approach using updated figures provided by the gas businesses. The Commission accepted submissions on the Tax Paper up to 23 September 2004. The Commission received four written submissions on the Tax Paper.

Draft Cost Benefit Model Numbers

1.29 The Commission released the draft cost benefit model numbers (Draft Model) to the businesses on 2 October 2004. The Draft Model was provided to allow the businesses to check whether it was consistent with the data provided by the businesses or the changes made from the Draft Report. The Commission accepted submissions on the Draft Model up to 5 October 2004. The Commission received four written submissions on the Draft Model.

Commission Consultant Reports

1.30 As part of this Inquiry the Commission engaged consultants to prepare and provide reports relating to specific packages of work. The consultants reports prepared and the Commission report with which each was released are listed in the table below.

Table 1.5: Consultants Reports

Consultant	Report Title	Commission Report
Dr Martin Lally	'The Weighted Average Cost of Capital for Gas Pipeline Businesses', 24 November 2004	Final Report
Dr Martin Lally	'Review of Submissions on Tax Treatment in the Commerce Commission's Cost Benefit Analysis', 24 November 2004	Final Report
Meyrick & Associates	'Note on Gas Common Cost Allocations', 12 October 2004	Final Report
Meyrick & Associates	'Review of the Pacific Economics Group Gas Inquiry Papers', 19 November 2004	Final Report
Meyrick & Associates	'Note on Monte Carlo Analysis', 30 September 2004	Final Report
Dr Martin Lally	'The Treatment of Gains on the Sale of Assets', 2 September 2004	Tax Paper
Dr Martin Lally	'The Interest Tax Deduction and the Calculation of Excess Earnings', 6 September 2004	Tax Paper
Dr Martin Lally	'The Weighted Average Cost of Capital for Gas Pipeline Businesses', 14 May 2004	Draft Report
Meyrick & Associates	'Comparative Benchmarking of Gas Networks in Australia and New Zealand', 14 May 2004	Draft Report
Meyrick & Associates	'Productivity Growth in New Zealand Gas Distribution Networks', 14 May 2004	Draft Report
Energy Market Consulting Associates	'Gas Control Inquiry: Consistency Review of ODV Network Asset Valuations', 17 May 2004	Draft Report
Energy Market Consulting Associates	'Gas Control Inquiry: Matters to be Addressed if Undertaking an Economic Value Assessment of the MDL Pipeline', 17 May 2004	Confidential version only, not released
Cranleigh Strategic	'Gas Control Inquiry: Asset Valuation – The Historic Cost Approach', 29 April 2004	Confidential version only, not released

Final Report

1.31 The Commission has now completed this Final Report setting out its final report to the Minister on whether any of the gas services should be controlled. The Commission has carefully considered all of the submissions it received on the Draft Framework Paper, Draft Report, Tax Paper and the Draft Model. Where appropriate or relevant, the Commission has addressed certain individual submissions within this Final Report.

1.32 All submissions, cross submissions, conference presentations, conference transcripts, Commission reports and public versions (where available) of the consultants' reports are available on the Commission's website under 'Regulatory Control Inquiry on Gas Pipelines'.

Confidentiality

1.33 A number of the Commission reports, the Commission cost benefit models, consultants' reports and submissions received from interested parties contain confidential information. Where possible public and confidential versions of the reports, models and submissions have been prepared. The Commission made an order under s 100 of the Commerce Act (s 100 Order) in relation to the Inquiry to prohibit the disclosure of any information provided to or prepared by the Commission during the course of the Inquiry and identified by any party or the Commission as being confidential.

1.34 The s 100 Order will expire after the conclusion of the Inquiry. The Official Information Act 1982 will apply from that time.

Current Regulatory Environment

1.35 The operation of the gas pipeline sector and the supply of gas services in New Zealand are governed by a combination of legislation, regulations, standards and arrangements.

Current Legislation

1.36 The current legislation, regulations and standards related to gas services are set out in the table below.

Table 1.6: Gas Industry Legislation, Regulations and Standards

Category	Current Arrangements
Gas specific regulations and legislation	The Gas Act 1992 The Gas Regulations 1993 Gas (Information Disclosure) Regulations 1997
General legislation applying to the Gas Industry	Plumbers Gasfitters and Drainlayers Act 1976 Health Safety and Employment (HSE) Act 1992 Hazardous Substances and New Organisms Act 1996
Other related legislation	Commerce Act 1986 Fair Trading Act 1986 Building Act 1991

	Building Regulations 1992 Consumer Guarantees Act 1995
Codes and Standards applicable to the Gas Industry	New Zealand Building Code 1993 New Zealand Gas Pipeline Access Code 1998 NZS 5442: 1990 Specification for reticulated natural gas

1.37 The regulatory framework and other arrangements currently employed to promote efficiency in the supply of gas services is set out in the following table.[2]

Table 1.7: Regulatory Environment

Category of Regulation	Current Arrangements
Competition legislation, governing certain kinds of anti competitive conduct, as well as mergers or takeovers that are likely to substantially lessen competition.	Commerce Act 1986
Regulation providing for non-discriminatory access to certain "bottleneck assets".	The New Zealand Gas Pipeline Access Code NGCT Transmission Information Memorandum Reconciliation Agreements Transmission Service Agreements The current access arrangements have been developed on a voluntary basis in response to the provisions of the Commerce Act which prevents a dominant firm restricting supply of a product or service which cannot be viably duplicated. The amendments to the Commerce Act in 2001 replace this concept of dominance with clauses that prevent a firm that has "a substantial degree of power in a market" taking advantage of that power for the purpose of restricting entry, preventing competition or eliminating a person from that or any other market.
Price regulation, to avoid monopoly pricing.	Gas (Information Disclosure) Regulations 1992. Part IV of the Commerce Act (threat of implementation and any such inquiries and subsequent control).
Regulation of safety and technical standards.	Legislation, regulations and technical standards as set out in table 1.6.

Gas Government Policy Statement

1.38 The Commission is required to have regard to relevant Government statements of economic policy, pursuant to s 26 of the Commerce Act in making its recommendation. It must give such statements genuine attention and thought, and such weight as the Commission considers appropriate.

[2] Adapted from ACIL Consulting, *Review of the New Zealand Gas Sector, A Report to the Ministry of Economic Development*, October 2001.

1.39 Pursuant to s 26 of the Commerce Act, the Commission received (20 October 2004), from the Minister of Commerce, a Government Policy Statement entitled 'Government Policy Statement on Gas Governance' (GPS). The GPS sets out the Government's gas industry objectives, and desired objectives for governance and rules relating to wholesaling, processing, transmission, distribution and retailing of gas. The GPS replaces the 'Government Policy Statement: Development of New Zealand's Gas Industry' of 27 March 2003.

1.40 The content of the GPS is discussed in detail below.

1.41 The GPS identifies the Government's overall policy objective for gas as being:[3]

> To ensure that gas is delivered to existing and new customers in a safe, efficient, fair, reliable, and environmentally sustainable manner.

1.42 The GPS states the Government is seeking the following specific outcomes:[4]

- 'The facilitation and promotion of the ongoing supply of gas to meet New Zealand's energy needs, by providing access to essential infrastructure and competitive market arrangements;
- Energy and other resources are used efficiently;
- Barriers to competition in the gas industry are minimised to the long-term benefit of end-users;
- Incentives for investment in gas processing facilities, transmission and distribution, energy efficiency and demand-side management are maintained or enhanced;
- The full costs of producing and transporting gas are signalled to consumers;
- Delivered gas costs and prices are subject to sustained downward pressure;
- The quality of gas services and in particular trade-offs between quality and price, as far as possible, reflect customers' preferences;
- Risks relating to security of supply, including transport arrangements, are properly and efficiently managed by all parties;
- Consistency with the Government's gas safety regime is maintained; and
- The gas sector contributes to achieving the Government's climate change objectives by minimising gas losses and promoting demand-side management and energy efficiency.

1.43 Within the GPS the Government invites the industry to establish an industry body in a co-regulatory governance setting.

1.44 Principles guiding the development of the industry body are detailed in the GPS.

1.45 The Government expects the industry body to develop, and submit to the Minister for approval, proposed regulations and rules providing for effective industry arrangements in the following areas:

[3] Government Policy Statement on Gas Governance, 20 October 2004.
[4] Government Policy Statement on Gas Governance, 20 October 2004.

- production and wholesale markets – development of wholesale gas trading, secondary market for trading, capacity trading arrangements and protocols for fair and reasonable access to essential processing infrastructure;
- transmission and distribution – establishment of an open access regime across transmission pipelines to provide access on reasonable terms and conditions; establishment of consistent standards and protocols across distribution pipelines to provide access on reasonable terms and conditions; establishment of gas flow measurement arrangements for the effective control and management of gas; and
- retail markets - protocols so that barriers to customer switching are minimised, development of arrangements for handling consumer complaints, development of model consumer contracts that are fair to consumers and retailers.

1.46 The Government plans to monitor the progress of the industry body in developing the arrangements outlined in the GPS and has set dates for the industry body to submit proposed rules and regulations for specific arrangements. The Government expects all arrangements to be in place by December 2005.

1.47 The Government states that if an industry body is not established or if the industry body does not deliver the expected industry outcomes, the Government will establish a Crown regulatory authority.

1.48 The Commission is required in terms of s26 of the Act, to have regard to the relevant GPS in reaching its decisions. During its consideration of the issues connected with the Inquiry the Commission has given careful consideration to, and had regard to, the two statements transmitted by the Government. Due to the arrival of the GPS after the period for consultation had ended, the Commission has not consulted with interested parties on the revised GPS but did so in respect to the March GPS.

Current Regulatory Monitoring

1.49 The economic regulation of gas pipeline businesses is currently addressed through the Gas (Information Disclosure) Regulations 1997 (the Regulations), the general competition requirements of the Commerce Act and Fair Trading Act, and the threat of further regulation, including control. The Regulations require six categories of information to be disclosed. These are:

- line charges;
- contracts (agreements);
- pipeline capacity information;
- line charge (pricing) methodologies;
- financial statements and performance measures; and
- methodologies for allocation of costs, revenues, etc.

Gas Amendment Act

1.50 On 17 October 2004 the Gas Amendment Act 2004 received the Vice-Regal assent.[5] This Act amended the Gas Act 1992 (Gas Act) to establish an industry governance structure to achieve the Government's policy objectives for the gas industry as set out in the GPS.

1.51 As amended, the Gas Act gives the Minister of Energy regulation-making powers. In particular, the amended Gas Act provides a process by which the Minister of Energy may recommend the establishment of an Energy Commission, by expanding the structure of the Electricity Commission. The purpose of such a Commission would be to govern the gas industry if members of the industry do not form an industry body or the industry body does not deliver the Government's objectives for the gas sector through self-regulation.

1.52 Regulations may be made in relation to the operation of the gas wholesale market, processing facilities and the transmission and distribution of gas (including a provision for prescribing reasonable terms and conditions for access to gas transmission and distribution pipelines), and a range of consumer protection issues.

1.53 The Gas Act also confers on the industry body or Energy Commission regulation making powers in relation to:

- terms and conditions of access to the Maui pipeline;
- retail and consumer issues;
- wholesale market;
- gas processing facilities; and
- transmission and distribution of gas (other than on terms and conditions of access to Maui pipeline).

<u>Gas Co-Regulatory Governing Body</u>

1.54 The Gas Act, as amended by the Electricity and Gas Industries Act, enables co-regulation by the Government and industry body. The Gas Act sets out :

- the process for approval and revocation of an industry body;
- objectives of an industry body in relation to recommendations for gas governance regulations;
- the discretion of the Minister to set objectives and outcomes to be pursued by the industry body;
- mechanisms to ensure the industry body is accountable to the Minister including the industry body strategic plan and annual report; and
- provisions relating to levying industry participants and the costs of the industry body that may be met by the levy fund.

[5] During the bill stage the Gas Amendment Act 2004 was part of the Electricity and Gas Industries Bill.

1.55 Upon approval the industry body has the authority to recommend to the Minister that regulations be made and, once they are in force, to ensure that the regulations and rules are complied with.

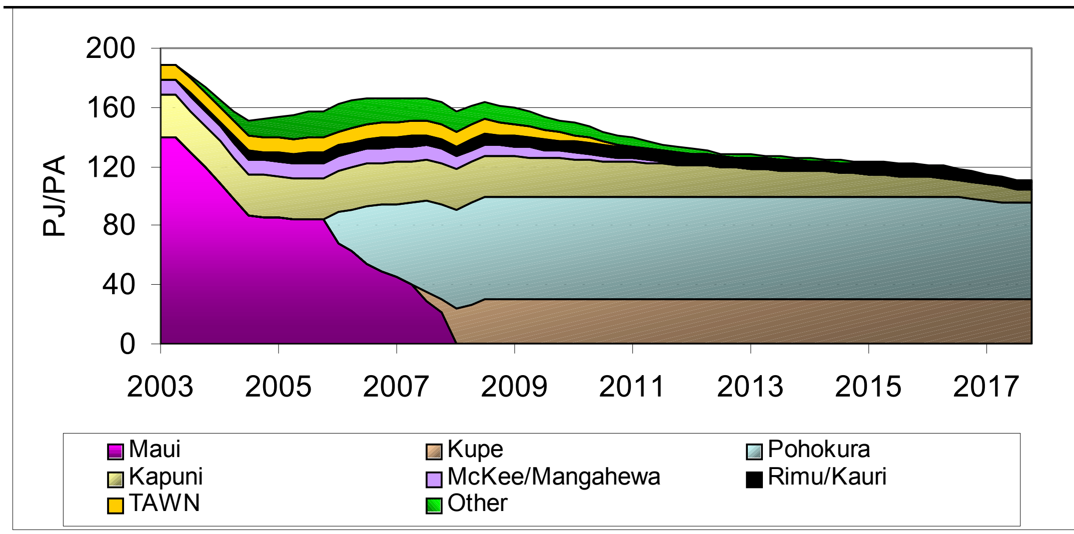
Industry Background

1.56 Natural gas became a significant contributor to the energy sector with the development of the Kapuni field which commenced production in 1970, followed by the Maui field in 1979. Other fields have been developed in the Taranaki region since that time although Maui and Kapuni remain the predominant sources of gas supply.

1.57 Gas accounted for around 24% of total primary energy supply in New Zealand in 2003. In 2003 a total of 170 PJ was produced (excluding gas flared, gas reinjected and LPG extracted) a reduction of 26% from 2002. The anticipated decline in production from the Maui field, in particular, is likely to result in reduced production in future years, notwithstanding the likelihood of production from the new Pohokura and Kupe fields in the next two or three years.

1.58 Determining future production levels is extremely difficult. At the Framework Conference NGC provided a chart showing its projections through to 2017, and these seemed broadly in line with other projections seen by the Commission. This diagram is reproduced below.

Figure 1.1: Market Supply Forecast (NGC 2003 estimate)



1.59 The demand for gas over the last thirty years has been largely driven by the plentiful and relatively inexpensive gas available from the Maui field. The change in demand for gas between March 1974 and 2004 is shown in the following table.[6]

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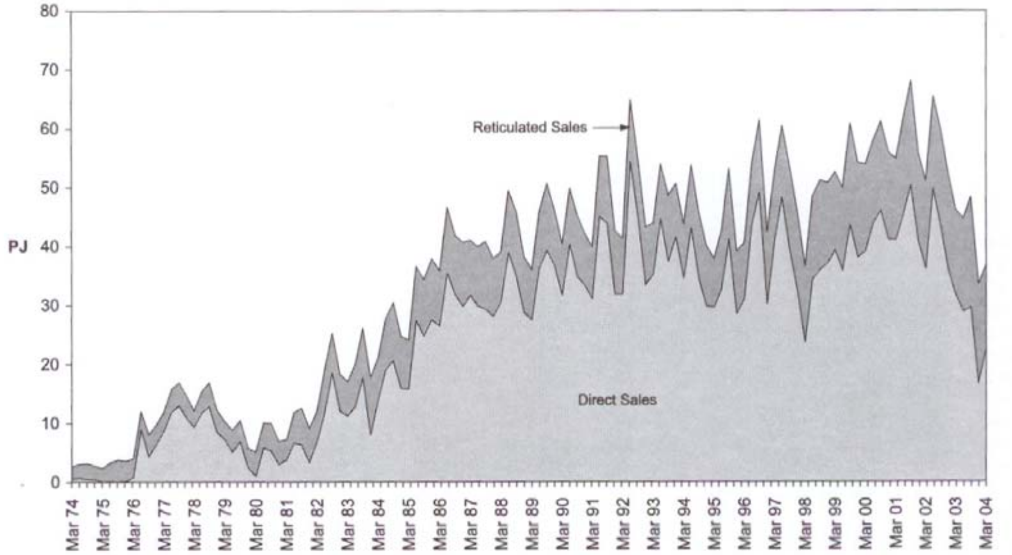
[6] Ministry of Economic Development, *New Zealand Energy Data File*, July 2004.

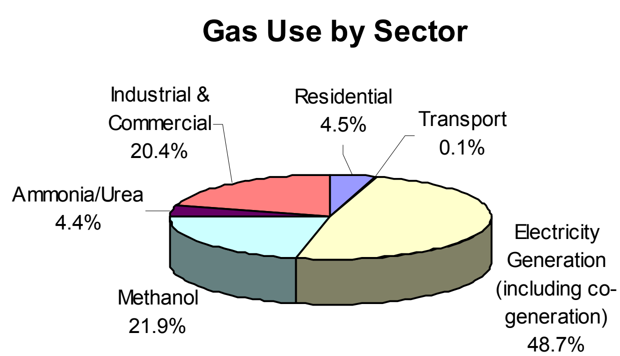
Figure 1.2: Demand for Gas



1.60 The three main users of gas in New Zealand are petrochemicals (methanol and ammonia/urea), electricity generation and direct reticulated users. Methanol has been produced by the Motuni and Waitara valley methanol plants owned by Methanex. The depletion of the Maui gas field has resulted in Methanex producing substantially less than the plants' capacity of 2.4 million tonnes of methanol per year. In a June 2004 media release Methanex stated that it had obtained enough gas to produce approximately 1 million tonnes of methanol in 2004 and had the flexibility to produce up to 500,000 tonnes of methanol in 2005.

1.61 Gas users by sector are illustrated in the figure below.[7]

Figure 1.3: Gas Use by Sector (March 2004 Year)



1.62 Between March 2003 and March 2004 approximately 40.9 petajoules (25 per cent) of New Zealand's gas was transported throughout the North Island via the high pressure transmission system. This gas was transported directly to major users and to gas utilities for distribution to the other industrial users and to the

[7] Ministry of Economic Development (2004).

commercial and residential sectors. The amount of transported gas used by the specific sectors is set out in the table below.[8]

Table 1.8: Transported Gas Use By Sector (March 2004 Year)

Sector	Gas Used (PJ)	Percentage of Reticulated Gas
Industrial	20.6	50.3
Commercial	12.8	31.3
Residential	7.3	18.0
Domestic Transport	0.2	0.4
Total	40.9	100

1.63 The transportation of gas to gas users is divided into transmission and distribution. As noted above, the transmission component is the transport of gas at high pressures from the outlets of gas field processing plants to local gas distribution systems and also direct to large industrial consumers. The principal transmitters are MDL and NGCT.

Table 1.9: Gas Transmitters (2003)

Gas Transmitter	Length (km)	Gas Conveyed (PJ p.a.)
MDL (Maui Pipeline)	313	125.0
NGCT	2,187	93.3

1.64 Shell/Todd, Swift Energy and Westech Energy also operate some limited transmission pipelines.

1.65 The distribution function involves the transportation of gas at lower pressure from a gate station on a transmission pipeline to the end consumers. Many parts of the distribution networks date back to the days before natural gas was produced when the networks were used to deliver coal gas.

1.66 There are currently five distributors of natural gas – NGCD, Powerco, Vector, WGL and Nova. The system lengths and gas conveyed by these businesses are contained in the table below.

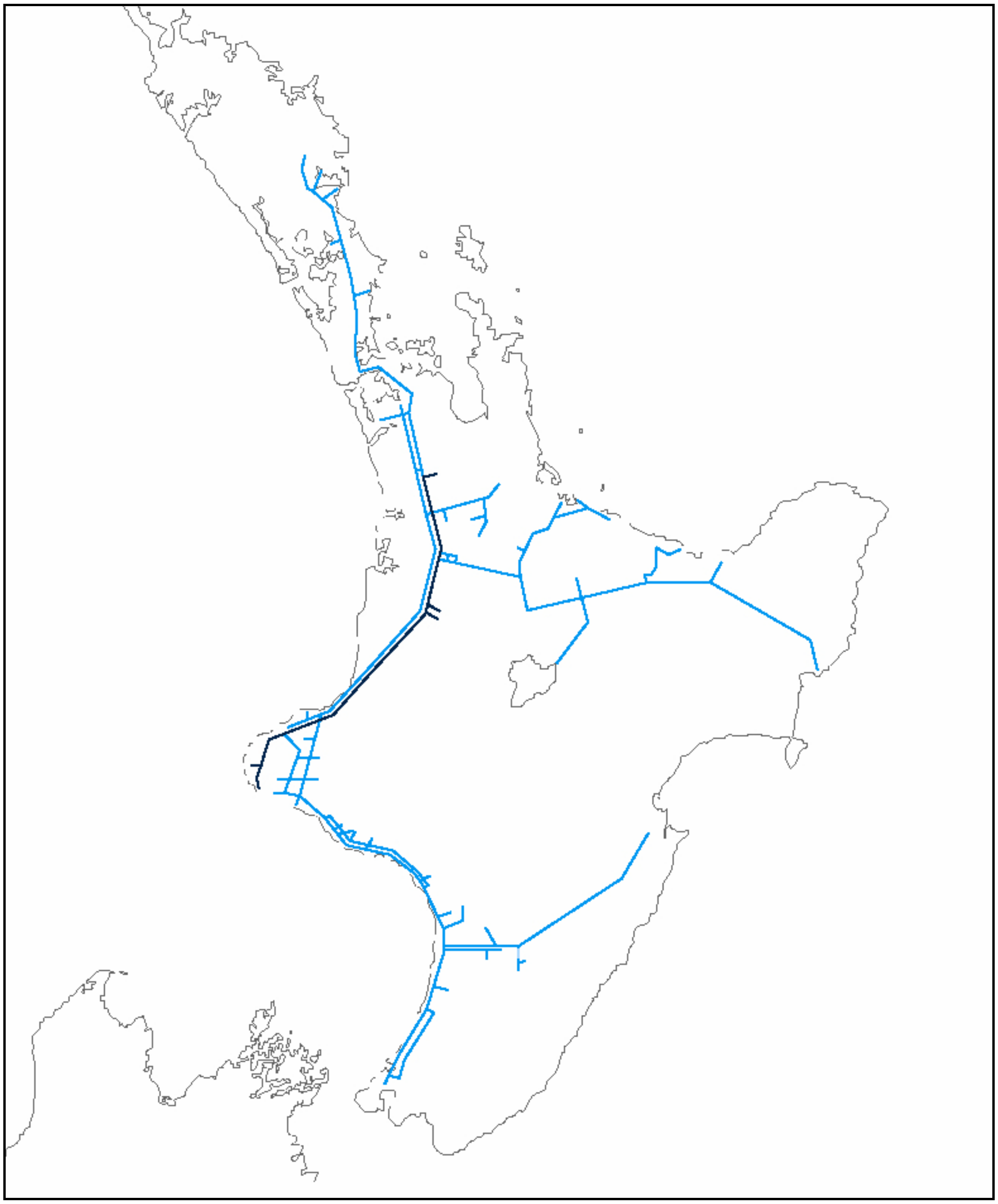
Table 1.10: Gas Distributors (2003/2004)

Gas Distributor	Length (km)	Gas Conveyed (PJ p.a.)
NGCD (to June 2004)	2,807	11.1
Powerco (to March 2004)	5,368	10.0
Vector (to December 2003)	5,008	11.5
WGL (to June 2004)	356	1.1
Nova (2003)	100	[ ]

1.67 The following map indicates the location of the transmission pipelines.

[8] Ministry of Economic Development (2004).

Figure 1.4: High Pressure Transmission Pipelines



2 LEGAL FRAMEWORK

Introduction

2.1 This chapter sets out the terms of reference and the statutory framework for the Inquiry.

Process for Declaration of Control

Enabling Provisions

2.2 Section 53 of the Commerce Act allows the Governor-General, by Order in Council, on the recommendation of the Minister of Commerce, to declare that specified goods or services be controlled. The Minister of Commerce must not make a recommendation unless he or she is satisfied that the goods or services may be controlled under s 52.

2.3 Under s 54, the Minister of Commerce may require the Commission to advise on quantitative or qualitative thresholds that would assist in assessing whether goods or services should be controlled. Section 56 allows the Commission to report to the Minister of Commerce on whether or not an Order under s 53 should be made, amended or revoked. In so doing, the Commission may have regard to all matters it considers necessary or desirable. The Commission may report on its own initiative or following a request from the Minister of Commerce.

2.4 For the purposes of the Inquiry, the Minister of Energy can, pursuant to s 13 of the Ministry of Energy (Abolition) Act 1989[9], exercise and perform the powers and duties conferred on the Minister of Commerce under ss 53, 54 and 56 of the Commerce Act with respect to the prices of specified classes of goods and services. An Order in Council was made under s 13 of the Ministry of Energy (Abolition) Act providing that gas services are services to which s 13 applies.[10] According to that Order in Council, ‘gas services’ includes services in connection with either or both gas transmission or gas distribution services or both of them.

Announcement of Inquiry

2.5 On 6 November 2002, the Minister stated that he would request that the Commission report on whether increased regulatory control should be introduced for gas services. Specifically the Minister noted:[11]

> There has been significant debate over whether gas pipeline prices are excessive. Some commentators believe that there is evidence that monopoly rents have been received by at least the main pipeline owners. However the issues are not straightforward, and there is room for debate.

[9] The Electricity and Gas Industries Bill amends the Ministry of Energy (Abolition) Act. Within the heading of s 13 the word 'prices' has been omitted and substituted with the words 'goods or services'. S 13(1) is amended by omitting the words 'the prices of'.

[10] Energy Services (Gas) Order 2003. Appendix 1 comprises a copy of this order.

[11] Hon. Pete Hodgson, *Gas pipeline monopolies under investigation,* www.beehive.govt.nz, 6 November 2002.

> A formal inquiry by the Commerce Commission under section 56 of the Commerce Act offers the best way of dealing with the various monopoly issues, including appropriate asset valuation. The Government will be asking for an inquiry covering all gas transmission and distribution pipelines, including the Maui pipeline. Such an inquiry is expected to take 18 to 24 months.

2.6 The announcement by the Minister was followed by an official request to the Commission on 30 April 2003.

Ministerial Request and Subsequent Communication

2.7 The Commission has undertaken the Inquiry in response to a letter of request from the Minister on 30 April 2003.[12] The letter provides as follows:

> The purpose of this letter is to request the Commission to report to me no later than 1 November 2004 on whether or not an Order in Council under section 53 of the Act should be made in relation to the goods and services connected with either gas transmission or gas distribution or both (gas services). For the avoidance of doubt, 'bypass' pipelines and pipelines owned by Maui Development Limited are to be included…
>
> In reaching its view on whether control should be introduced, I ask for the Commission's specific advice on:
>
> - whether gas pipeline services may be controlled in terms of section 52 of the Act;
> - the methodology that the Commission considers appropriate for valuation of pipeline assets for the purpose of its advice on the matters covered in this letter;
> - the net benefits to the public of control; and
> - any other matter that the Commission may think relevant to a decision on whether control should be introduced.
>
> If the Commission recommends pipeline services should be controlled, I also request the Commission's specific advice on the technical provisions relating to declaration of control as set out in section 57A of the Act.

2.8 The Commission wrote to the Minister on 20 June 2003 to confirm its interpretation of certain terms referred to in his letter of 30 April 2003.

2.9 The Minister responded on 9 July 2003 agreeing with the Commission's interpretation of his letter of 30 April 2003. In particular, the Minister stated that for the purpose of the request the Commission is to apply the following interpretations:

- the references to 'gas pipeline services' and 'pipeline services' mean 'gas services' as explicitly defined;
- 'Gas' means natural gas, and only that gas. Liquefied petroleum gas (LPG) is not intended to be covered by the Inquiry;
- 'Connected with' means 'supplied by persons in markets directly related to'. Goods or services physically connected with gas transmission and distribution pipelines that may include goods and services not owned or

[12] A copy of this letter and the other correspondence between the Minister and the Commission in relation to the terms of reference of the Inquiry can be found on the Commission's website under 'Regulatory Control Inquiry on Gas Pipelines'.

operated by owners of gas pipelines are not intended to be covered by the review;

- ‘Gas transmission or gas distribution’ means ‘a gas transmission system or a gas distribution system’ where ‘transmission system’ and ‘distribution system’ are defined in the Gas (Information Disclosure) Regulations 1997 and the Gas Act 1992 respectively. Small-scale pipelines such as those in commercial buildings were not intended to be covered by the review; and
- ‘Pipelines owned by Maui Development Limited’ means only those pipelines owned by MDL that form a gas transmission or distribution system (or part thereof). Other pipelines owned by MDL that are not part of a transmission system or distribution system are not intended to be covered by the inquiry.’

2.10 The terms of reference for the Inquiry consist of the original letter of request dated 30 April 2003, the Commission’s letter seeking clarification dated 20 June 2003 and the Minister’s reply dated 9 July 2003.

2.11 On 28 September 2004 the Commission wrote to the Minister requesting an extension of the due date for delivery of the final report, to 29 November 2004. The Commission submitted that the extension was required in order for it to complete its analysis of new issues, in particular the treatment of tax that had arisen during consultation on the draft report dated 21 May 2004. The Commission’s request was granted by the Minister on 5 October 2004.

Goods and Services Covered by the Terms of Reference

2.12 With respect to the goods and services to be covered by the Inquiry, the terms of reference state:

> …whether an Order in Council under section 53 of the Act should be made in relation to the goods and services supplied by persons in markets directly related to either a natural gas transmission system or a natural gas distribution system or both (gas services).

2.13 As stated above, ‘transmission system’ and ‘distribution system’ are defined in the Gas (Information Disclosure) Regulations 1997 and the Gas Act 1992 respectively. The Gas (Information Disclosure) Regulations 1997 defines ‘transmission system’ as:

> Transmission system means that part of a system that conveys gas from the point where the gas leaves a gas processing facility to the boundary of the gasworks or gate station outlet flange supplying gas-
>
> (a) For distribution; or
>
> (b) To a gas customer, where the gas does not enter a distribution system.

2.14 The Gas Act 1992 defines ‘distribution system’ as:

> ‘Distribution system’ means all fittings, whether above or below ground, under the control of a gas distributor and used to distribute gas from-
>
> (a)The boundary of the gasworks or gate station outlet flange supplying gas for distribution; or
>
> (b)The outlet of the container in which gas for distribution is stored-

> to the outlet of the gas measurement system of the place at which the gas is supplied to a consumer or gas refueller (or, where no such gas measurement system is provided, to the custody transfer point of the place at which the gas is supplied to a consumer or gas refueller); and, for the purposes of any regulations made under section 54 of this Act relating to odorisation or the measurement of calorific value, includes a gas transmission system.

2.15 In conducting this Inquiry, the Commission considers that the Minister's request relates to two key functions, being connection to a gas distribution system or gas transmission system, and transport of gas over that system.

2.16 The Commission considered whether meters should be included within the scope of this Inquiry. NGC in particular, argued that it had never been the intention of the Minister to include consumer gas metering within the Inquiry and submitted that consumer gas metering was a specific 'carve out' from the scope of the Inquiry. They based this argument on an extract from the Minister's letter of 9 July 2003 that '…pipelines that may include goods or services not owned or operated by owners of gas pipelines were not intended to be covered by the Inquiry'.

2.17 The Commission is not persuaded by this submission. The clarification was provided so that the Commission did not need to consult with owners of a range of goods and services not owned or operated by owners of gas pipelines on whether goods or services physically connected with gas transmission and distribution pipelines should be covered by the Inquiry. The Commission considers that meters are not excluded.

2.18 The Commission considers, in light of the terms of reference, the Inquiry's purpose and the generally regional nature of the relevant markets, that where gas metering on a distribution or transmission system is:

- owned by the same person who owns the relevant gas distribution or transmission system, those meters are included within the scope of the Inquiry;
- not owned by the same person who owns the relevant gas distribution or transmission system, those meters are outside the scope of this Inquiry.

2.19 It is open to the Commission to conclude that control is warranted in respect of some, but not all, of the goods and services within the scope of the Inquiry. Should an Order for control be made, s57A enables goods or services to be identified in such a way that any part or element of them 'can be dealt with separately'. Meters (or any other kind or class of good or service) may therefore be separately identified in the Order. This treatment of meters is covered in more detail in the competition and company specific chapters.

Section 52 – May Control be Imposed?

2.20 The Minister's letter of 30 April 2003 requests that the Commission report to him on '…whether gas pipeline services may be controlled in terms of 52 of the Act.' Section 52 of the Commerce Act provides:

> Goods or services may be controlled if—

(a) the goods or services are, or will be, supplied or acquired in a market in which competition is limited or is likely to be lessened; and

(b) it is necessary or desirable for those goods or services to be controlled either—

(i) in the interests of persons acquiring the goods or services (whether directly or indirectly), if the goods or services are acquired from a person who faces limited or lessened competition for the supply of those goods or services; or

(ii) in the interests of suppliers, if the goods or services are supplied to a person who faces limited or lessened competition for the acquisition of those goods or services.

2.21 In reporting to the Minister as to whether control may be imposed, the Commission needs to be satisfied that the requirements of s 52 are met. The Commission notes that goods or services may not be controlled (and the Minister must not recommend that an Order for control be made) unless both limbs of the s 52 test are met (i.e. competition is limited or is likely to be lessened in the relevant market and control is necessary or desirable in the interests of persons who acquire or supply the goods or services in affected markets) (ss 52 and 53). Under s 56(1), the Commission '…may report to the Minister on whether or not an Order in Council under s 53 should be made, amended or revoked.'

2.22 The purpose of the Commerce Act is 'to promote competition in markets *for the long-term benefit of consumers* within New Zealand'. The Commerce Act contains provision in Part 4 for imposition of controls on goods and services, because markets, for whatever reasons, do not always operate efficiently or deliver competitive outcomes. For example, a market may be composed of only one supplier which may be able to exploit that position by raising prices above the competitive level, or by allowing costs to rise, or by being slow to innovate, without suffering any adverse consequences from competitors.

2.23 Provision therefore exists for goods and services to be placed under control where (in terms of s 52) there is limited competition or competition in a market is lessened and it is necessary or desirable for goods or services to be controlled in the interests of acquirers or suppliers. The Commission has to find positively on both aspects in order to satisfy itself that control of goods or services may be imposed.

2.24 The control of goods or services may be seen as appropriate only where it is likely to achieve a better outcome for acquirers than the uncontrolled and uncompetitive market is capable of producing. Account must be taken of the costs that control itself will cause to be incurred. Control imposes several costs; for instance, the costs of the regulator, the compliance costs of the regulated entities, and possible market distortions flowing from imperfectly executed control.

2.25 In order to recommend control of goods or services, the Commission must satisfy itself that acquirers would benefit from control, compared to the counterfactual. The costs created by control (that acquirers bear) need to be outweighed by the benefits achieved by control (that flow to acquirers). If the weighing of the benefits and costs demonstrates that an improvement in the economic welfare of acquirers would result, then control would be demonstrated to be necessary or desirable in the interests of acquirers.

2.26 In responding to the Commission's Draft Report, Vector submitted that the s 52 test was only one component of the advice being sought from the Commission by the Minister and that the Minister was asking the Commission to advise on the basis of a broad range of factors, not just the s 52 test. Vector noted that the Minister's letter of 30 April 2003 specifically requested advice on '…any other matter that the Commission may think relevant to a decision on whether control should be introduced.' While acknowledging the importance of the statutory test, Vector's submission was that the Commission was being asked to advise on whether control should (as distinct from may) be imposed.

2.27 The remainder of this section describes the Commission's approach in applying s 52 in accordance with the Minister's request. The following section describes the Commission's approach to the Minister's request for the Commission's specific advice on the matters enumerated in his letter of 30 April 2003, including the Commission's approach to advice on whether control should be imposed.

Is Competition Limited or Likely to be Lessened?

2.28 Under s 52 the Commission must address whether competition is 'limited or is likely to be lessened' in the market for the supply of gas services.

<u>Competition</u>

2.29 'Competition' is defined in s 3(1) of the Commerce Act to mean 'workable or effective competition'. The High Court in *ARA v Mutual Rental Cars (Auckland Airport) Ltd*[13] and *Fisher and Paykel Ltd v Commerce Commission*[14] approved the formulation of workable competition as meaning:

> …a market framework in which the pressures of other participants (or the existence of potential new entrants) *is sufficient to ensure that each participant is constrained to act efficiently* and in its planning to take account of those other participants or likely entrants as unknown quantities. To that end there must be an opportunity for each participant or new entrant to achieve an equal footing with the efficient participants in the market by having equivalent access to the means of entry, sources of supply, outlets for product, information, expertise and finance. This is not to say that particular instances of the items on that list must be available to all. That would be impossible. For example, a particular customer is not at any one time freely available to all suppliers. Workable competition exists when there is an opportunity for sufficient influences to exist in any one market which must be taken into account by each participant and which constrain its behaviour. (Emphasis added)

2.30 As to the particular elements and principles that underlie workable or effective competition, the courts in New Zealand have generally approved the Australian Trade Practices Tribunal's discussion in *Re Queensland Co-operative Milling*

[13] (1987) 2 TCLR 141 166.
[14] (1990) 2 NZLR 731 757.

Association Ltd: Re Defiance Holdings Ltd[15] (*Re QCMA*). In that case the Australian Trade Practices Tribunal cited the United States Attorney-General's observation that 'the basic characteristic of effective competition in the economic sense is that no one seller, and no group of sellers acting in concert, has the power to choose its level of profits by giving less and charging more' and that 'the antithesis of competition is undue market power in the sense of the power to raise price and exclude entry'.[16] The Tribunal stated that '…competition expresses itself as rivalrous market behaviour' and that:

> …effective competition requires both that prices should be flexible reflecting the forces of demand and supply and that there should be independent rivalry in all dimensions of the price-product-service packages offered to consumers and customers.'

2.31 The Tribunal stressed five elements of market structure as being material to whether firms compete:

> '(1) the number and size distribution of independent sellers, especially the degree of market concentration; (2) the height of barriers to entry, that is the ease with which new firms may enter and secure a viable market; (3) the extent to which the products of the industry are characterised by extreme product differentiation and sales promotion; (4) the character of 'vertical relationships' with customers and with suppliers and the extent of vertical integration; and (5) the nature of any formal, stable and fundamental arrangements between firms which restrict their ability to function as independent entities.[17]

2.32 In *Telecom Corporation of New Zealand Limited v Commerce Commission*[18] the Court of Appeal confirmed the need to give weight to both structure and behaviour when examining a market environment, and confirmed that the weighting must vary according to the particular facts. Richardson J (as he then was) stated '…structures only function through people and at the end of the day it is how participants in the market behave that counts'.[19]

2.33 The Court of Appeal endorsed the approach of the Commission of the European Community in *re Continental Can Co Ltd*[20] and said:

> The approach reflects the concern for how firms behave and eschews a total preoccupation with structure.[21]

2.34 The five market structure elements referred to by the Trade Practices Tribunal in *Re QCMA* were used by counsel as the basis for analysing competition in the relevant market both before the High Court and the Court of Appeal in *Tru Tone Ltd v Festival Records Retail Marketing Ltd.* Counsel also referred to a sixth element – 'behaviour in the market'. Both courts accepted this basis of

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[15] (1976) 8 ALR 481, *Tru Tone Ltd v Festival Records Retail Marketing Ltd* (1988) 2 NZLR 352, and *Fisher and Paykel Ltd v CC* (1990) 2 NZLR 731, 759.
[16] Ibid at 514-517, *Report of the National Committee to Study the Anti-Trust Laws* (1955).

[17](1991) 4 TLR 473.
[18] (1992) 3 NZLR 429.
[19] Ibid at 444.
[20] (1972) CMLR D11.
[21] *Telecom Corporation of New Zealand Limited v Commerce Commission*, (1992) 3 NZLR 429, 444.

analysis.[22] In discussing this analysis the Court of Appeal stated: '…behaviour in the market, reflects the reality that constraints on the operation of firms are a key indicator of market power'.[23]

2.35 In assessing the state of competition in the relevant markets the Commission will consider both the structural elements of the market and the behaviour of market participants.

2.36 The Commission's approach to competition analysis is set out in the Commission's Merger and Acquisition Guidelines.[24] The Commission considers: existing competition, potential competition and other competition factors.

Limited or Likely to be Lessened

2.37 The Commission must determine whether competition in the relevant markets for gas services is 'limited or is likely to be lessened'. The Commission focuses on the higher test of 'limited', and considers it need only look at whether competition is 'likely to be lessened' in circumstances where competition is not found to be limited.

2.38 The Commission interprets the phrase 'likely to be lessened' as describing the situation where a future event or occurrence or set of circumstances is anticipated to have an effect on competition in a market in which workable or effective competition may or may not currently be 'limited'. The test is forward looking.

2.39 The ordinary meaning of 'limited' applies as the term is not defined in the Commerce Act. Competition will be 'limited' where it is restricted. Consequently, the Commission views limited competition as denoting a restriction or impairment to workable or effective competition. The Commission assesses the consequences of any limited competition in the relevant markets. The consequences of a lack of workable or effective competition can manifest themselves in various ways, including allocative, productive and dynamic inefficiencies and excessive returns.[25]

2.40 In applying the test of limited competition, the Commission considers the purpose of the Commerce Act, which is to promote competition in markets for the long-term benefit of consumers within New Zealand. The control provisions of the Commerce Act are interpreted in light of the objective of

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[22] High Court *Tru Tone Ltd v Festival Records Retail Marketing Ltd* (1988) 2 TCLR 525, Court of Appeal *Tru Tone Ltd v Festival Records Retail Marketing Ltd* (1988) 2 NZLR 352. The first five are the elements of market structure emphasised in the assessment of the competition process in *Re Queensland Co-operative Milling Association Ltd* (1976) 25 FLR 169, 189 and in such New Zealand cases as *Re Application by Visionhire Holdings Ltd* (1984) 4 NZAR 288. The sixth, behaviour in the market, reflects the reality that constraints on the operation of firms are a key indicator of market power. (1976) 8 ALR 48.
[23] Court of Appeal *Tru Tone Ltd v Festival Records Retail Marketing Ltd* (1988) 2 NZLR 352.
[24] A copy of the Merger and Acquisition Guidelines can be found on the Commission's website under 'Adjudication'.
[25] Allocative, productive and dynamic efficiency concepts are explained in the Chapter 5 (Assessment Principles for Efficient Pricing).

maintaining competitive and efficient markets and also having regard to the meaning of competition in the Commerce Act as being workable or effective, but not necessarily perfect, competition.

2.41 The Commission's view is that a nominal or de minimis restriction or impairment of competition in a market is not sufficient to satisfy the limited competition requirement. There needs to be *more than* a nominal or de minimis restriction or impairment of competition.

2.42 In determining whether workable or effective competition is limited in the relevant markets for gas services, the Commission considers both structural and behavioural elements. This involves taking into account all of the relevant factors, including: the number and relative sizes of competitors in the market; the nature of entry and of any barriers to entry that may exist; the behaviour of incumbents and the competitive constraint that one gas pipeline business may have upon another; the existence of countervailing power of the acquirers of gas pipeline services; and the regulatory environment within which market participants operate.

Necessary or Desirable in the Interests of Acquirers

2.43 The Commission considers that the second limb of the test for control under s 52 requires that the necessity or desirability of control must be considered in relation to the interests of acquirers or suppliers of the goods or services in question. The Commission must determine whether there is evidence to show that control of gas services is 'necessary or desirable' in the interests of either the persons directly or indirectly acquiring, or supplying, the specified services. The Commission concludes that the relevant interests to be examined within the Inquiry are those of acquirers (whether directly or indirectly) of gas services.

2.44 The phrase 'necessary or desirable' was considered by the Court of Appeal in *New Zealand Employers Federation v National Union of Public Employees*[26] In the context of s 52, the expression ' necessary or desirable' has a wider scope than would 'necessary' by itself, enabling the condition to be met on either ground provided there is sufficient relevant evidence in support of the conclusion reached.

2.45 The Commission considers the reference in s 52 to direct or indirect acquisition requires an examination of the interests of direct acquirers such as gas retail businesses and large gas consumers, as well as the interests of indirect acquirers such as the end users who purchase gas from gas retail businesses.

2.46 In Chapter 1 (Background) the Commission stated that acquirers of gas services include not only direct acquirers (gas retailers), but also indirect acquirers (end use consumers). Section 52 provides no grounds for

[26] (2001) NZCA 315. In the Court of Appeal, Keith J interpreting the *Interpretation Act 1999* s 11 stated at Para 64: '…while substitution of the word 'desirable' in subs (2) for 'expedient' may have no significant effect (a matter on which I express no view), its inclusion in subs (3) in addition to 'necessary' does widen the scope of that provision.'

distinguishing between New Zealand and overseas acquirers, (in contrast to the public benefit test in s 67 of the Commerce Act, where 'public' is interpreted as the public of New Zealand).

2.47 The Commission does not consider it necessary, for the purposes of s 52, to determine the relative shares of any net benefits received by direct acquirers and indirect acquirers.

2.48 The term 'interests' is not defined in the Commerce Act and, therefore, the ordinary meaning of the word applies. Control is 'in the interests of' acquirers (s 52) where it is to their advantage or benefit. Consequently, the Commission must determine whether the imposition of control would be beneficial to the direct and indirect acquirers of gas services.

2.49 The Commission approaches the question as to whether control is 'necessary or desirable...in the interests of' acquirers by measuring the likely benefits of control that would accrue to acquirers of gas services, balancing against those the likely costs of such control that would be borne directly or indirectly by acquirers. Only then can it be determined whether the interests of acquirers would be met by control. The Commission considers that if the weighing of these benefits and costs demonstrates that an improvement in the economic welfare of acquirers would result, then control would be demonstrated to be necessary or desirable in the interests of acquirers.

Counterfactual

2.50 The benefits and costs to acquirers that would be likely to flow from control of gas services in the future are assessed against a counterfactual of what might otherwise happen in the future in the absence of control. Thus, a comparison is made between two hypothetical future situations, one with control and one without. The differences between these two scenarios are then attributed to the impact of control.

2.51 In framing a suitable counterfactual, the Commission bases its view on a pragmatic and commercial assessment of what is likely to occur in the absence of control.[27] As with many business acquisitions, the most likely counterfactual may be a continuation of the status quo, with the gas pipeline businesses operating under the present form of regulation, which includes information disclosure and the possibility of control being imposed at some point in the future.

2.52 The Commission has considered the likely impact if control were not imposed. Specifically, the Commission anticipates that the effectiveness of the Part 4 regime as a means of control could (at least for a time) be reduced. This might allow the gas pipeline businesses somewhat greater latitude in behaviour, leading to an increase in inefficiencies or excess pricing. Alternatively, that outcome could have the effect of providing a benchmark over which gas pipeline businesses would not wish to pass, in anticipation that control might be imposed.

[27] See the discussion in Commerce Commission, *Decision No.277: New Zealand Electricity Market*, 30 January 1996, especially p 16.

2.53 The Commission notes, however, that there is always the possibility that a further inquiry may occur in the future, if the behaviour of any of the gas pipeline businesses were to warrant this. This is reinforced by the observation that the Commission's framework for Part 4 assessment is now well settled and the familiarity the Commission has gained with the industry.

2.54 The Commission also considers that, where possible, both the factual and the counterfactual should reflect the initiatives flowing from the GPS. As described in Chapter 1 (Background), the objective of the GPS is to ensure that gas is delivered to existing and new customers in a safe, efficient, fair, reliable, and environmentally sustainable manner.

2.55 Regarding industry-led solutions, the Government expects the industry to develop arrangements which include:

- the establishment of an open access regime across all high pressure transmission pipelines to provide access on reasonable terms and conditions;
- the establishment of consistent standards and protocols across all distribution pipelines to provide access on reasonable terms and conditions; and
- arrangements for the effective control and management of gas.

2.56 An issue raised in submissions was the extent to which the counterfactual and the factual should recognise possible changes to the regulatory environment outlined in the GPS.[28] The Commission also considered the impact of amendments to the Gas Act 1992.

2.57 The Commission has taken account of the impact of the GPS and the recent changes to the Gas Act and their effect on competition in the counterfactual and factual in the subsequent chapters of this Report. The current regulatory environment and in particular the GPS and the amendments to the Gas Act are discussed in more detail in the Background chapter (Chapter 1).

Should Control be Introduced?

2.58 The Minister's request asked the Commission to report on whether an Order in Council under s 53 should be made.

2.59 An Order in Council cannot be made unless the requirements of s 52 are met. Notwithstanding that the s 52 requirements may be met, the Commission may report to the Minister on whether an Order in Council imposing control should be made, amended or revoked (s 56(1)). In so doing, the Commission is authorised to have regard to all matters it considers necessary or desirable (s 56(2)).

2.60 Having determined that control may be imposed, the Commission conducted further analysis to determine whether an Order in Council 'should' be made.

[28] See for example NGC Holdings Limited; *Submission in respect of the Draft Framework Paper*; 20 August 2003.

The matters considered in determining whether control 'may' be imposed remain relevant. There are also additional matters the Commission considers relevant in determining whether control should be introduced. These include:

- the cost to the economy of reducing excess returns;
- the size of the benefits; and
- the impact of a recommendation not to control.

2.61 In Chapter 4 (Overview of Assessment Approach), the Commission considers each of these issues in detail and then weighs them in order to decide whether to recommend to the Minister whether an Order in Council imposing control should be made.

2.62 The Commission's analysis as to whether an Order in Council imposing control should be made are set out in each of the company-specific chapters (Chapter's 12 – 19) and its recommendations are set out in Chapter 20 (Conclusion).

Control Provisions

2.63 The control provisions, as detailed in Part 4 of the Commerce Act, provide for the imposition of control over the supply of goods and services by Order in Council. These provisions must be read with the purpose of the Commerce Act; 'to promote competition in markets for the long-term benefit of consumers within New Zealand.'

2.64 The Commission may, of its own initiative, or following a request from the Minister (s 56(3)) must, report to the Minister on whether it considers that goods or services should be controlled (s 56(1)). In considering such a report, the Commission may have regard to all matters it considers necessary or desirable (s 56(2)).

2.65 The Governor-General may make an Order in Council controlling the supply of goods or services on the recommendation of the Minister (s 53(2)). The Minister must not make such a recommendation unless satisfied that the requirements of s 52 are met (s 53(3)).

2.66 Goods or services subject to control may be identified by a description of the goods and services, or by a description of the kind or class to which the goods or services belong (s 57A(1)). The control may apply to goods or services supplied in or for delivery within specified regions, areas, or localities in New Zealand; supplied in different quantities, qualities, grades, or classes; or supplied by or to or for the use of different persons or classes of persons (s 57A(2)). The Order in Council must specify the date on which it expires (s 57A(4)).

2.67 In carrying out the Inquiry the Commission has accordingly conducted its analysis and is reporting to the Minister on a company-specific basis. Section 57A(2)(c) provides that a declaration of control may relate to goods or services 'supplied by … different persons or classes of persons'. This approach also recognises that an Order in Council may apply to goods or services supplied in or for delivery within specified regions, areas, or localities in New Zealand.

2.68 Once an Order in Council has been made, controlled goods or services cannot be supplied unless an authorisation (or an undertaking) has come into effect in respect of the supply of those goods and services, and the supply is in compliance with the authorisation (or undertaking) (s 55). The Commission is responsible for making such authorisations (ss 70 and 71), or accepting such undertakings (s 72).

Technical Provisions Relating to the Declaration of Control

2.69 In the event that the Commission recommends that pipeline services should be controlled, the Minister asked for the Commission's specific advice on the technical provisions relating to declaration of control as set out in s 57A of the Act.

2.70 Section 57A(3) allows for separate treatment of any part or element of goods or services and it is open to the Commission to recommend control in respect of some, but not all of the goods and services within the scope of the Inquiry.

2.71 Upon the making of an Order in Council, s 57A enables goods or services to be identified in such a way that any part or element of them 'can be dealt with separately'. Any other kind or class of good or service (e.g. meters) may therefore be separately identified in the Order.

2.72 Once an Order in Council has been made, s 70(1) empowers the Commission to make an authorisation in respect of all or any component of the prices, revenues, or quality standards relating to the supply of the controlled goods or services, using whatever approach it considers appropriate. And s 70(3) contemplates the possibility of different authorisations in respect of prices, revenues, or quality standards to meet different circumstances relating to the supply of controlled goods or services.

2.73 In Paragraphs 2.12 to 2.19 the Commission describes the 'gas services' which are subject to the Inquiry. The Commission considers that meters (as described in paragraphs 2.16 - 2.18) should be separately identified in any Order.

2.74 The Commission considers that an Order in Council may apply to gas services supplied by particular specified persons.

Expiry of the Order

2.75 Section 57A(4) of the Commerce Act requires that the Order in Council imposing control made under s 53 must specify the date on which it expires.

2.76 With regard to electricity lines businesses, s 57L of the Commerce Act sets a maximum term of 5 years for a declaration of control, but allows the Commission to make a further declaration of control after considering the purpose of subpart 1 of Part 4A of that Act. Price cap control periods are commonly set for five years.

2.77 Ultimately the issue of when any such Order in Council will cease for the gas pipeline businesses is closely related to the incentives created by the control mechanism contemplated during the period of the Order and when the cessation of control altogether is in prospect. These two issues are clearly intertwined.

2.78 It may take up to one year to fully implement a Part V control regime, once any such Order in Council for control has been made.

2.79 Options for when such an Order in Council may expire include:

- declaring control initially for six years, with the understanding that one year would be devoted to implementation and five years to the operation of, for example, a price cap. A second five-year price cap would then be contemplated after a review; or
- declaring control for 11 years, with the understanding that one year would be devoted to implementation and 10 years to the operation, for example, of two, five-year regulatory cycles of a price cap regime.

2.80 A practical issue arises under s 57A. The Commission cannot pre-empt any decision regarding the form of control at this stage, as an Order declaring control must be made before the Commission can determine the form of control. However, under s 57A(4), the Order declaring control must specify the date on which it expires. The period of control then must be determined without reference to the eventual form of control to be determined under Part V of the Commerce Act.

2.81 The Commission acknowledges that it can be problematic to set a period of control without determining the form of control. It considers, however, that the appropriate period for expiry of an Order in Council declaring control would be 11 years.

2.82 If a shorter period were adopted then another inquiry would have to be undertaken. The Commission has the ability itself to vary authorisations and the form of control under Part V and also has the ability under s 56 to recommend amendment or revocation of the Order in Council that declares control, should a shorter period of control become desirable.

The Form of Control

2.83 Following any Order in Council, Part V of the Commerce Act provides for the administration of control. Section 70(1) empowers the Commission to make an authorisation of all or any component of the prices, revenues, or quality standards relating to the supply of the controlled goods or services, using whatever approach it considers appropriate.

2.84 The approach adopted by the Commission may include the use of formulae or other methods from which prices or revenues may be determined (s 70(2)).

2.85 In exercising its powers under s 70(1), the Commission must have regard to (s 70A):

- the extent to which competition is limited or is likely to be lessened in respect of the controlled goods or services;
- the necessity or desirability of safeguarding the interests of persons who acquire (whether directly or indirectly) or supply the controlled goods or services; and
- the promotion of efficiency in the production and supply or acquisition of the controlled goods or services.

2.86 Section 70B requires the Commission to follow a particular procedure in reaching a decision as to the nature and form of any control. As part of that process, acquirers and suppliers have a right to be heard and the Commission must have regard to any submissions they make. This process must logically take place at some point after control has been declared, as the Commission's power to authorise applies only to controlled goods or services, and goods and services are only controlled when an Order in Council declares them to be so.

2.87 Section 71 provides for the transitional period immediately following a declaration of control, by allowing the Commission to make provisional authorisations pending the making of a final determination under section 70.

2.88 There are sanctions in relation to supply otherwise than in compliance with an authorisation. Section 55 provides that no person may supply any controlled goods and services unless authorised (ss 70 or 71) or under an undertaking (s 72). Failure to comply with s 55 renders a natural person liable to a fine not exceeding $50,000 and a body corporate liable to a fine not exceeding $500,000 (s 86(1)).

2.89 The Commission's view is that it should not advise the Minister on how it would administer control, prior to any declaration of control. To do so would risk predetermining the processes associated with administering control under Part V. This Inquiry is therefore limited to assessing whether control under Part V may and should be imposed and not the form of that control.

2.90 However, in order to calculate the likely costs of control, and therefore assess the likely costs and benefits of control, the Commission must select a form of control to be used for that purpose. Therefore, the Commission does consider one form of control on the basis that, and only to the extent that, consideration of one form of control that might possibly be imposed is necessary for the Commission to have regard to the net benefits to acquirers and the net benefits to the public. The Commission considers that it can only test the net benefits of control by assessing the likely costs of control.

2.91 Any hypothetical form of control considered for the purposes of the Inquiry will accordingly be preliminary and will not pre-empt any decision the Commission may be required to make in the future regarding control, should that be necessary under Part V.

2.92 The Commission notes that it would be possible to implement alternative forms of control to price cap regulation under Part V. Section 70(1) authorises the Commission to make an authorisation in respect of prices, revenues or quality standards 'using whatever approach it considers appropriate'. Under s 72, the Commission may "obtain or accept a written undertaking from the supplier" of the controlled goods or services, instead of making an authorisation.

2.93 Other forms of regulation, distinct from Part V control, could also be introduced following legislative intervention. For example, a form of targeted control, similar in effect to that applicable to large electricity lines businesses under Part 4A of the Act, could be introduced.

Request for Additional Advice

2.94 The Minister has requested[29] the Commission's specific advice on 'the methodology that the Commission considers appropriate for valuation of pipeline assets, 'the net benefits to the public of control' and 'any other matter that the Commission may think relevant to a decision on whether control should be introduced'.

Valuation Methodology

2.95 The Commission describes the asset valuation methodology it considers appropriate in Chapter 8 (Asset Valuation).

Net Benefits to the Public of Control

2.96 In undertaking this analysis, the Commission has adopted an approach generally consistent with that used in the past when considering whether restrictive trade practices or business acquisitions should be authorised in terms of ss 58 or 67 of the Commerce Act. Under this approach, the Commission has regard to economic efficiency (allocative, productive, and dynamic efficiencies) only and assesses the potential net efficiency gains for the public as a whole.

2.97 This approach follows the Court's views in *Telecom Corporation of New Zealand Ltd v Commerce Commission*[30] (AMPS- A decision) the court stated.

2.98 An issue arises as to whether any excess returns obtained by foreign investors in firms that are the subject of the Inquiry should be treated as a detriment to New Zealand under the efficiency assessment[31]. The High Court in the AMPS-A decision rejected the view:

> …that profits earned by overseas investment in this country are necessarily to be regarded as a drain on New Zealand. New Zealand seeks to be a member of a liberal multilateral trading and investment community. Consistent with this

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[29] Minister's letter of 30 April 2003.
[30] (1991) 4 TCLR 473, 531.

[31] The High Court in the AMPS-A decision rejected the view '…that profits earned by overseas investment in this country are necessarily to be regarded as a drain on New Zealand. New Zealand seeks to be a member of a liberal multilateral trading and investment community. Consistent with this stance, we observe that improvements in international efficiency create gains from trade and investment which, from a long-run perspective, benefit the New Zealand public'.

stance, we observe that improvements in international efficiency create gains from trade and investment which, from a long-run perspective, benefit the New Zealand public.

2.99 The High Court considered, that '…functionless monopoly rents, supranormal profits that arise neither from cost savings nor from innovation, and which accrue to overseas shareholders' should 'be counted as a detriment to the New Zealand public'. The argument for a distinction in the treatment of functionless monopoly rents accruing to foreign shareholders is based on an assumption that the supranormal profits (excess returns) obtained by New Zealand shareholders stay within New Zealand, but that those obtained by foreign shareholders flow overseas.

2.100 The Commission sought submissions on the extent to which regard should be had to the issue of foreign ownership in the Inquiry. Among the matters raised by submitters in response were:

- the payment of excess profits does not amount to the exploitation of the NZ community but rather represents a 'normal' return on the amount paid for the shareholding;
- any excess profits are not 'functionless'; and
- any decision to base a control decision on the shareholders' country of origin would have a significant detrimental impact on future overseas investment in New Zealand.

2.101 The Commission considers that there can be no absolute rule in relation to wealth transfers; rather, their treatment will depend on the particular circumstances. After consideration of the submissions, the Commission has concluded that in the circumstances of this Inquiry it is not appropriate to distinguish between firms that have a foreign shareholding and those that do not. It notes that each foreign shareholder has acquired its interests in an equities market in which both acquirers and sellers can be taken to have been informed of the earnings potential of the firm, and that the seller (in each case a New Zealand-based party) would have been likely to have been fully compensated in the price it received for its loss of its share of future earnings of the firm. Further, the Commission notes that the sale of interests to foreign parties has not affected the market power of the firms concerned or their ability to charge prices above competitive levels. Accordingly, for the purposes of the Inquiry, the Commission makes no adjustment in its base case analysis for foreign shareholding.

Other Relevant Matters

2.102 At Chapter 4 (Overview of Assessment Principles and Approach), the Commission reports on its view as to other matters the Minister may wish to consider in coming to a view as to whether a control recommendation should be made to the Governor General for an Order in Council imposing control.

2.103 The Commission considers that the Minister, who has a wider jurisdiction than the Commission, may consider:

- Alternative regulatory regimes distinct from control under Part V;

- the desirability of a review and possible strengthening of disclosure requirements applicable to the gas businesses; and
- the implications of the proposed purchase of NGC by Vector.

3 COMPETITION ANALYSIS

Introduction

3.1 As noted in Chapter 2 (Legal Framework) control may be introduced only if goods or services are supplied or acquired in markets in which competition is limited or is likely to be lessened. It therefore follows that the definition of the relevant markets and the analysis of competition within those markets lies at the heart of any control inquiry under the Commerce Act.

Defining Markets

3.2 For the purpose of assessing competition, a market is defined to include all those suppliers, and all those buyers, between whom there is close competition, and to exclude all other buyers and suppliers. The focus is on those goods and services that are close substitutes in the eyes of buyers, and upon those suppliers who produce, or could easily switch to produce, those goods or services.

3.3 Within this broad approach, the Commission defines relevant markets in a way that best assists the competition analysis of the matter before it, bearing in mind the need for a commonsense, pragmatic approach to market definition.

3.4 Once the market is defined, the Commission then considers such matters as:

- the number, size and strength of existing market participants, and their potential to expand;
- the potential for new parties to enter the market; and
- the constraint on market participants from the countervailing power of acquirers, or from the regulatory regime, or from any other source.

Market Definition Principles

3.5 Section 3(1A) of the Commerce Act provides that:

> {T}he term 'market' is a reference to a market in New Zealand for goods and services as well as other goods and services that, as a matter of fact and commercial commonsense, are substitutable for them.

3.6 The purpose of defining a market under the Commerce Act is to provide a framework within which to analyse the extent of competition, or its antithesis, which is market power. The concept of a market is thus considered by the Courts to be an instrumental one. The definition of a market is not an end in itself; rather it is an exercise to assist with the analysis of the market behaviour at issue. In *Queensland Wire* the Court stated:[32]

> In identifying the relevant market, it must be borne in mind that the object is to discover the degree of the defendant's market power. Defining the market and evaluating the degree of power in that market are part of the same process, and it is for the sake of simplicity of analysis that the two are separated …

[32] *Queensland Wire Industries Pty Ltd Co Ltd v The Broken Hill Propriety Company Ltd & Anor* (1989) ATPR 40-925.

3.7 The process of identifying the relevant market(s) should keep the objective in mind. In the present case, the objective is to determine whether any of the gas pipeline businesses operate where competition is limited and that they therefore have the potential to exert undue market power.

3.8 From a technical perspective, the process of establishing market boundaries can be seen as one of identifying the smallest area of product, geographic and functional space over which a hypothetical monopolist could exert a significant degree of market power. This approach focuses attention on any close substitutes that would prevent a hypothetical monopolist from exercising market power by raising its price or reducing quality. All such substitutes must be included in the market.

3.9 An appropriately defined market will include products that are regarded by buyers as being similar or close substitutes ('product' dimension), and in close proximity ('geographical' dimension), and are thus products to which they could switch if a single supplier were to attempt to exert market power. It will also include those suppliers currently in production who are likely, in that event, to shift promptly to offer a suitable alternative product even though they do not do so currently.[33]

3.10 In addition to the product and geographical dimensions, markets can be defined in relation to functional level, in recognition of the fact that the supply chain typically consists of a number of distinct functional levels. For example, the market between manufacturers and wholesalers might be called the 'manufacturing market', that between wholesalers and retailers is usually known as the 'wholesaling market', and that between retailers and end-customers the 'retailing market'.

3.11 Finally, markets may be defined in relation to time. A time element may be appropriate where trading conditions are likely to differ in identifiable ways at different future periods.

3.12 Despite the criteria discussed above, markets are not always easy to define in practice. Transactions in the economy do not always fall neatly into a series of discrete and easily observable markets. Hence, it may not be practical - nor, indeed, always necessary - to identify the precise boundaries of the particular activities to analyse their competitive impact. Moreover, as already noted, it is appropriate to tailor the definitions used to meet the requirements of the case in hand.

Markets Relevant to the Gas Control Inquiry

3.13 The subject of this Inquiry is gas services, in particular those services directly related to gas transmission and gas distribution.

[33] These have been referred to by the Commission as 'near entrants', to be distinguished from 'new entrants'. See: *The Commission's Approach to Adjudicating on Business Acquisitions Under the Changed Threshold in Section 47 – A Test of Substantially Lessening Competition*, Commerce Commission Practice Note 4, 2001, p 19.

3.14 For the purpose of competition analysis in New Zealand gas related cases in the past[34], gas has been placed in a discrete product market. In each it has been concluded that while gas and other fuels (such as electricity, coal, LPG, wood waste or fuel oil) are substitutable on occasions, they are at best imperfect substitutes.

Product and Functional Markets

3.15 During the course of the Commission's Inquiry, a number of interested parties argued that other energy forms provided gas users with viable alternatives to gas and that they provided an effective constraint on any market power which might otherwise be held by gas pipeline owners. Vector, for instance, has advocated that the Commission recognize the substitutability between energy forms and use an 'energy' product market for the purpose of the Inquiry. Vector has argued that LPG in particular provides strong competition to natural gas for residential and commercial consumers.

3.16 The Commission accepts that at today's prices of gas and other energy forms some substitution is occurring. A considerable amount of anecdotal evidence of substitution was presented to the Commission. However, while substitution between energy forms is a prerequisite for an 'energy' market, that is not necessarily sufficient in itself. The extent and ease of substitution is critical. In addition, the Commission recognises that it is possible that alternative fuels may be substitutable for gas only because gas is priced up to the price where substitution occurs. The so-called 'cellophane fallacy'[35] has to be avoided.

3.17 Thus, it is necessary to consider whether a hypothetical single supplier of gas is constrained by substitution possibilities from exercising undue market power by, for instance, charging higher than competitive prices and earning supra-normal profits.

3.18 The degree and scope of substitution, factors which are relevant to the issue of market definition, are also among the principal factors which must be taken into account when determining the level of competition. In some respects market definition and competition analysis are two sides of the one coin.

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[34] These cases include *Power New Zealand Ltd v Mercury Energy Ltd* (1996) 1 NZLR 686; *Shell (Petroleum Mining) Company Limited and Another v Kapuni Gas Contracts Limited and Another* (1997) 7 TCLR 463; Commerce Commission, *Decision No.270: NGC/ Enerco*, dated 22 November 1993, Commerce Commission, *Decision No.330: NGC/Powerco,* dated 11 November 1998, Commerce Commission, *Decision No.333: Contact Energy/Enerco*, dated 10 December 1998, Commerce Commission, *Decision No.340:TransAlta/Contact Energy,* dated 12 February 1999, Commerce Commission, *Decision No.345: UnitedNetworks/TransAlta,* dated 11 March 1999, Commerce Commission, *Decision No.380: UnitedNetworks/Orion,* dated 23 December 1999, Commerce Commission, *Decision No.408: Shell/Fletcher Challenge Energy,* dated 12 October 2000.

[35] The 'cellophane' fallacy can occur when a substitutability test is used to determine whether a firm has monopoly power. The fallacy refers to the conclusion being drawn that two products fall within the one market because they are substitutable where in fact they are only substitutable because the monopolist supplier of one of the products has elected to raise its prices to the point where the two products become substitutable, whereas they would not be substitutable at competitive prices for both. It takes its name from the US Supreme Court decision in United States v E.I. du Pont Nemours & Co. 351, 76 S.Ct. 994 (1956) which placed cellophane wrapping in the same market as other wrappings, and allegedly overlooked the above-competitive prices being charged by the dominant supplier of cellophane.

Competitive interaction determines the boundary of markets while competition (and market power) is assessed within the framework of those market boundaries so determined.

3.19 As the High Court noted in the AMPS-A decision[36], "'market' is an instrumental concept designed to clarify the sources and potential effects of market power that may be possessed by an enterprise". What is important is that the market definition assists the achievement of the purpose of the exercise.

3.20 In this case that purpose is, initially, to assess whether the competition faced by providers of gas services is limited or likely to be lessened.

3.21 The Commission considers that this purpose can be achieved more efficiently in this particular case by, in the main, adopting markets made up of narrow component parts. By doing so, it allows the particular market features of each part to come more clearly into focus. This approach does not prevent full recognition being given to constraints on market power from goods or services which fall outside the defined market.

3.22 Accordingly, in the analysis below it has defined the 'product' component as that for gas alone. The constraint that other delivered energy forms place on gas is considered under the 'Interfuel Competition' sub-heading.

3.23 The functional components of the market are defined as that for the provision of transmission services and that for the provision of distribution services.

Metering

3.24 As discussed in Chapter 2 (Legal Framework), the Commission considers that gas meters connected to a gas transmission or distribution system are included within the scope of the Inquiry when they are owned by the same person who owns the transmission or distribution system. Other meters are outside the scope of this Inquiry.

3.25 There are important variations in how the metering function is organised and its cost recovered. In the case of NGCT metering is an integral part of transmission services and metering costs are recovered in the transmission charge. In the case of MDL, the cost of metering services is recovered in the bundled delivered gas price. Meters attached to NGCD networks, are predominantly owned by a separate business unit of NGC which enters into supply agreements with the retailers utilising the networks, and charges separately for that service. This NGC business unit also owns meters attached to other networks. Vector has no direct role in the provision of metering services. Rather, retailers using Vector's network negotiate metering arrangements direct with the supplier of these services (such as Contact Energy or NGC's metering arm). Wanganui Gas and Powerco own the great majority of the meters on their networks and treat them as an aspect of their distribution business.

[36] *Telecom Corporation of New Zealand Limited v Commerce Commission* (1991) 4 TCLR 473.

3.26 NGC has pointed out that the largest supplier of meters is Contact Energy, which does not own any distribution network, and NGC has therefore argued that metering is a contestable activity. However, the Commission notes that there is little indication of vigorous competition on a day-to-day basis for the provision of meters, and there are very few examples of one supplier's meters being replaced by a similar meter from another supplier. The Commission considers that competition for the provision of meters is limited.

3.27 The Commission recognises that the supply of metering services is clearly different from that of operating other aspects of gas pipeline businesses. These differences are such that the Commission would be likely to place metering services in a discrete market for the purpose of assessing the competitive impact of a business acquisition or a trade practice, for instance. However, in this instance, separate consideration of metering would cause practical problems and would not assist the Commission's overall assessment.

3.28 Therefore, the Commission considers it appropriate to treat metering as one component of the gas services markets, rather than placing it within a discrete market. It emphasises that while this is the most pragmatic approach, it also provides the most satisfactory means of assessing the issues relevant to the Inquiry. The Commission has incorporated in the analysis of each company the capital value of its meters on its networks and the income and expenditure associated with it providing metering services on its own networks.

3.29 The Commission considers that while there is a degree of contestability for the supply of meters, in practice little substitution occurs. Consumers face a significant cost if they wish to have an existing meter removed and a new one installed. As the Commission considers that competition is limited, metering meets the threshold for control in s 52(a) of the Act.

3.30 The Commission concludes that for the purpose of the Inquiry it is appropriate to treat metering as one component of the various gas service markets, rather than placing it within a discrete market.

Geographic Markets

3.31 In respect of the geographical component of the gas market, the Commission considers that it is appropriate to place each principal gas network in discrete geographic markets. This recognises that, with limited exceptions, networks do not compete against each other. For practical reasons, where a firm owns more than one network and they have common competition characteristics, those networks (and markets) are considered together.

3.32 The existence of bypass pipelines in some limited areas gives those areas competitive characteristics which differ from those applying in other areas. At least to date bypass competition has been largely limited to the supply to commercial and industrial consumers. Accordingly, the Commission has placed the supply to the consumers in these areas in a discrete market (called the bypass market).

3.33 The Commission recognises that there are other areas where bypass opportunities exist, but which do not have bypass pipelines in place. These areas are not sufficiently identifiable to define them specifically. Rather the competitive constraint provided by bypass possibilities is considered as a generic issue affecting distribution markets in general.

3.34 In respect of gas transmission, the Commission has placed the area between North Taranaki and Huntly in a discrete market. The Maui pipeline runs alongside NGC's Kapuni North pipeline between these two areas. The question arises as to whether the two transmission pipelines have the potential to compete against each other over that distance, and the Commission considers that the question can be best addressed by placing the distance covered by the Maui pipeline in a separate market.

Summary

3.35 In summary, the Commission considers that it is appropriate to assess whether competition is limited or likely to be lessened within the framework provided by markets defined as follows:

- the market for the provision of gas transmission services between North Taranaki and Huntly;
- the market for the provision of gas transmission services for the rest of the North Island;
- separate markets for the provision of gas distribution services in the area encompassed by each incumbent gas network; and
- the market for the provision of gas distribution services to commercial and industrial consumers in the vicinity of bypass networks.

Generic Competition Issues

3.36 The different gas services markets have a number of important characteristics in common. These common characteristics, and their impact on competition in general, are discussed below. The conclusions reached are then incorporated in the individual company chapters where separate assessments are made as to whether or not competition faced by each gas service provider is limited.

Introduction

3.37 Gas transmission and distribution are undertaken by way of networks. In common with many other networks, they are characterised by a high level of sunk costs and economies of scale. Claims have been made that these characteristics have given transmitters and distributors monopoly power which has led to high prices being charged for the transport of gas and supra-normal profits being earned by transmitters and distributors[37].

3.38 Any excessive prices for the transport of gas would flow through to acquirers of the gas. These acquirers include gas electricity generators, the petrochemical industry, industrial companies and gas retailers. Gas retailers in turn would be likely to pass on excessive transport charges to their industrial, commercial and domestic consumers of gas.

[37] See, for instance, the Minister of Energy, *Gas Sector Review,* 2002 which cites Simon Terry Associates.

3.39 The demand for gas transmission and distribution services is a derived demand – it comes from the demand for gas.

3.40 Networks for the distribution and transmission of natural gas typically require significant investments which are irreversible, 'lumpy' and have a high degree of specificity meaning that infrastructure investments are, for the very large part, sunk. As with many network service providers, gas distributors and transmitters have high fixed or sunk costs and low variable costs. In these circumstances, it is possible that one firm in any area is able to undertake the distribution or transmission function at a lower average cost than two or more firms. That is, the network may be a natural monopoly.[38]

3.41 At any rate, incumbent networks tend to have a considerable competitive advantage over any new entrant. This is reflected in the fact that network markets tend to be dominated by only a few firms or, more often, a single firm.

3.42 However, there are a range of factors applying to gas distribution and transmission in New Zealand which, it has been suggested, ensure that network owners do not have the level of market power normally associated with natural monopolies. These factors include:

- constraint from competing networks;
- constraint from new entry;
- constraint from alternative energy forms;
- constraint from the countervailing power of gas users; and
- constraint from the regulatory regime.

3.43 These matters are considered separately below.

Competing Transmission Pipelines

3.44 The gas transmission systems transport gas at high pressures[39] from the outlet of gas processing plants to large industrial and commercial consumers in the gas wholesale market and to local gas distribution systems.

3.45 The systems considered in this Report are identified in the table below.

Table 3.1: Transmission Businesses

Company	Pipe Systems
NGCT	South, North, Kapuni to Rotowaro, Bay of Plenty, Morrinsville, Frankley Road
Maui Development Limited (Shell, Todd, OMV)	Oaonui to Huntly (Maui pipeline)

[38] For discussion on sunk costs and natural monopolies see, for instance, Baumol, W.J. and Willig, R.D., Fixed Costs, Sunk Costs, Entry Barriers, and Sustainability of Monopoly, *Quarterly Journal of Economics,* 96 (August 1981), pp 405-31 and p 406.
[39] Transmission systems generally operate at pressures over 2000 kPa.

Todd Petroleum and Shell	Kapuni to Hawera
Todd Taranaki	McKee Production Station to Faull Road
Swift Energy	Rimu to NGC South, Waihapa to New Plymouth and TCC power stations
Westech Energy	Surrey Road to NGC LTS

3.46 There are two areas where two gas transmission pipelines coexist. These areas are between North Taranaki and Rotowaro where the NGCT and MDL pipelines run alongside each other and in mid-Taranaki where there are several gas-gathering pipelines in reasonable proximity to each other. The extent to which coexisting pipelines provide competitive conditions is discussed in the individual company chapters.

New Entry - Transmission

3.47 In previous decisions the Commission described high pressure gas transmission networks as in general having natural monopoly characteristics. For instance, the Commission stated in Decision No. 387, dated 17 March 2000, "the {NGC transmission} network has been characterised by high capital costs and large sunk costs and there appears to be surplus capacity in most parts of the system. New {competitive} entry is considered most unlikely."[40]

3.48 NGC was among the parties which suggested that this position needed to be reassessed. In its submission of 20 August 2003 it argued that:

- the sunk cost risk is manageable using entry into a term contract with customers;
- existing facilities focus on Maui, and new discoveries will require new transmission infrastructure; and
- although there are no capacity constraints in the transmission system, there would not be sufficient capacity for a major load such as a new generator plant.

3.49 The Commission is not persuaded that the above points are suggestive of ease of entry.

3.50 First, to avoid the sunk cost risk, a prospective new entrant pipeline owner would need to have in place contracts with gas purchasers for the transport of a quantity of gas which equates to a significant proportion of the planned pipeline's capacity. However, before entering into any contract the purchasers would be likely to require the prospective new entrant to bid against the incumbent network owner. Provided the incumbent had surplus capacity (or is able to increase its capacity relatively cheaply), it would be likely to have a significant advantage in the bidding process, as its pipeline costs are sunk. This advantage may generally be sufficient to deter any prospective new entrants. The Commission acknowledges that where a bidding scenario is

[40] Commerce Commission, *Decision No. 387, Natural Gas Corporation Holdings Limited/ TransAlta New Zealand Limite*d, 17 March 2000, p 28.

possible, an important competitive benefit arises (irrespective of who wins the bidding or whether the prospective new entry actually constructs a pipeline). However, it would require actual entry to produce an on-going competitive climate. The Commission notes that no significant new entry in the transmission market has occurred in recent years.

3.51 Second, it is not certain that new discoveries will require major new transmission infrastructure, particularly if the new discoveries are found in the Taranaki region and if the MDL pipeline has open access arrangements in place. It appears likely that existing pipelines will have sufficient capacity to carry the gas from newly discovered fields. If, however, new production fields are developed outside the existing gas production regions, a new transmission pipeline will be required, but as it is in a new region it is unlikely that it will provide a competitive option for existing pipeline users. Thus, new entry in these circumstances would not affect the underlying state of point-to-point competition.

3.52 Nevertheless, the Commission accepts that if the pipeline from the discovery in a new area carried significant quantities of gas to the major markets, that pipeline would be placing competitive pressure on existing pipelines. However, at present there is not a discovery in a new area, or an associated new pipeline on the horizon.

3.53 In respect of possible capacity constraints, it has been suggested to the Commission that increased demand for gas in the Auckland region by a major user (as a result, for instance, of a new gas-fired electricity generating plant being established in the region) may result in a transmission capacity constraint between Rotowaro and Auckland, and that this could lead to the construction of a new transmission pipeline between those points. However, it may be that a lower cost means of overcoming the capacity constraint would be to expand the capacity on the existing pipeline by raising pressure. In any event, new entry in response to an on-going capacity constraint would be a reflection of a significant change in demand in a particular area and would not in itself indicate that entry in general was sufficiently straight-forward to deter an incumbent pipeline owner from exercising any market power.

3.54 With the possible exception of the area between Rotowaro and Auckland, the Commission has received no indication that new competitive transmission pipelines are likely in the foreseeable future.

Competing Distribution Networks

3.55 Gas distribution systems transport gas at low pressure (relative to transmission networks) from the outlet of the transmission pipelines to end use consumers. The owners of the regional distribution networks are set out in the table below.

Table 3.2: Distribution Businesses

Company	Region
NGCD	Northland, Whangaparaoa, South Auckland, Waikato, Bay of Plenty, Rotorua Taupo, Gisborne, Kapiti Coast
Powerco	Napier and Hastings area, Southern Hawke's Bay, Taranaki, Manawatu, Levin and Foxton, Hutt/Mana and Wellington
Vector	Greater Auckland, Tuakau and Ramarama
Wanganui Gas	Wanganui/Rangitikei
Nova Gas	Wellington, Porirua, Hutt Valley, Hastings, Hawera, Papakura and Manakau City

3.56 As with transmission pipelines, gas distribution networks have historically been viewed as having natural monopoly characteristics. Typically, investments in gas pipelines are irreversible, lumpy and have a high degree of specificity meaning that infrastructure investments are, for the very large part, sunk. High sunk costs and economies of scale have generally meant that it has not been economically viable for a competitor to duplicate an existing network in its entirety. However, in limited areas, competition for distribution to large customers has developed over recent years principally through the use of bypass pipelines.

3.57 Bypass opportunities tend to be limited to areas where there is a concentration of medium to large industrial and commercial consumers who are close to the transmission pipeline, where an existing bypass network can expand its scope or where there is an alternative source of gas (e.g. landfill gas). Bypass distributors seldom compete for domestic consumers.

3.58 Wanganui Gas prepared a policy statement in 1999 (which it stated is still operative) which said:

> By-pass
>
> A candidate for bypass is one that:
>
> - is physically close to the gate;
> - has high consumption;
> - close proximity to other medium to high consumption gas users;
> - there is a fuel switching capability which "caps" the acceptable gas service costs (inter-fuel competition); and
> - it is considered highly possible that RMA consents would be gained.

3.59 Vector has stated[41] that the cost of installing bypass pipelines can be reasonably modest. It submitted that, in normal ground conditions, a 100mm diameter pipeline can be installed for approximately $50 per metre. This submission is reasonably consistent with the Ministry of Economic

[41] Vector, *Gas Control Inquiry: Submission on Commerce Commission's Draft Framework Paper of 16 July 2003*, 20 August 2003, para 1.20

Development's Draft ODV Handbook which suggests the maximum replacement cost of a medium pressure 100 mm pipeline in suburban standard ground conditions is $65 per metre.

3.60 Bypass and the potential for bypass can have an important impact on the pricing behaviour of gas distributors. Vector, in a submission to the Commission,[42] stated that in recognition of the threat of bypass, it: had restructured its prices for commercial and industrial consumers into three pricing zones; had responded to particular bypass threats on a case by case basis; and had developed a method of securing contractual commitment (termed a Line Charge Agreement) with the consumer on price and length of term for the distribution service, where the retailer is interposed between Vector and the consumer for all other contractual matters.

3.61 Contact Energy stated at the Framework Conference:

> We have been aware of instances where threatening to bypass has elicited significant reductions in charges for affected customers, and simultaneously charges have moved elsewhere upwards for other customers.

3.62 Contact Energy also stated however:

> … bypass competition is only going to be feasible where bypass is a real threat, and that obviously doesn't apply to the greater parts of most networks, it's really where there is concentrated load such as CBDs or high industrial areas.

3.63 Powerco, at the Framework Conference, noted that the pricing impact of bypass has been limited to the general location of the actual or potential bypass pipeline.

3.64 Nova Gas owns and operates the major bypass networks and retails gas carried over that network, as well as gas carried by other networks. Nova Gas does not make its networks available to other gas retailers.

3.65 Nova Gas has bypass pipelines in Wellington, Hawera, Hastings and South Auckland which compete with networks owned by Powerco and Vector. However, in each area Nova Gas bypasses only a small percentage of the total incumbent network. Nova Gas has estimated[43] that only [ ] of total North Island commercial and industrial load is supplied to customers in competitive bypass markets. In the case of Auckland, Nova estimates that approximately [ ] PJ per annum of gas or [ ] of the total Auckland volume of [ ] PJ per annum is supplied to customers within [ ] of Nova's existing network.

3.66 NGCD has small pipelines in South Auckland which lie close to Vector's networks. It supplies a small number of mainly horticultural end consumers over these pipelines. Vector has stated to the Commission that there have been few if any instances of customer switching in the area. The Commission considers that the South Auckland situation provides some competitive advantage for the small number of customers in the area, although in practice

[42] Vector (2003) para 4.47.
[43] Nova Gas, *Nova Gas Limited Response to Submissions on the Draft Framework Paper*, confidential cross submission, 16 August 2004.

competition between NGC and Vector in this area appears considerably less intense than that found in close proximity to Nova's networks.

3.67 The Commission considers that evidence of vigorous competition in the bypass markets is strong. Each pipeline owner in these markets has invested large sunk costs into its network and faces the risk of its network being 'stranded' should it lose its customers to its competitor. In these circumstances there is a strong incentive on both the incumbent and the bypasser to compete against each other for supply contracts, at least as long as the price in the contract covers their variable cost of supply. Information received by the Commission, both in the context of the Inquiry and from its general industry oversight, supports the view that competition in bypass markets has had a very significant impact on prices.

3.68 The Commission has considered the potential for the competitors in the bypass markets to co-ordinate their market behaviour and thereby lessen the intensity of competition. Co-ordination covers both explicit agreements and tacit forms of behaviour such as price signalling, conscious parallelism and price leadership, and can be found in highly concentrated markets. Mr Horton, for Powerco suggested at the conference[44] that bypass competition is bound to be oligopolistic and that one might expect it to produce a sort of game solution result rather than a pure competitive result. In this instance, however, the Commission considers that there are features which make such behaviour unlikely.

3.69 These features include the fact that there are major differences between the two competitors in each bypass market. Compared to the incumbent network operator, Nova Gas has a network which is very much smaller, it does not have an unbundled distribution charge, it does not make its network available to other retailers, and its principal activity is gas retailing. The Commission recognises that Nova Gas has a reputation as a 'maverick' in the market. These factors significantly reduce the potential for coordinated behaviour in the future.

3.70 NGCD and Vector both have pipelines in Whangaparaoa. This situation traces back to the late 1990s when NGCD and Enerco (whose gas network assets were subsequently acquired by Vector) both concluded that Whangaparaoa was a growth area which offered potential for gas retailing. Both firms invested in distribution pipelines and approximately one third of the area had two pipelines in reasonable proximity to each other.[45] However, this has not produced a strongly competitive environment. Until recently, Vector's pipelines were not connected to the gas transmission pipeline but were supplied by means of CNG tankers and then injected into Vector's distribution system. This may have limited Vector's ability to compete vigorously. In any event, Vector has noted[46] that in the areas of overlap, NGC and Vector's pipelines are on

[44]Commerce Commission, *Transcript of Conference on Draft Report,* 22 July 2004, p 11.
[45]Commerce Commission, *Decision No.470: Natural Gas Corporation Holdings Limited/United Networks Limited*, 23 August 2002.
[46] Application to the Commerce Commission by Vector for clearance under s 66 of the Act to acquire NGC Holdings Ltd, 11 October 2004.

opposite sides of the street and in many areas it is not economic to lay a service across the road.

3.71 NGCD has advised the Commission that there has been minimal competition between the networks in Whangaparaoa. It has described the duplication of pipelines as 'a ludicrous and expensive' exercise which was unlikely to continue.[47]

3.72 Because of the very limited competitive interaction in the area, for the purpose of this report Whangaparaoa has been treated as falling outside the 'bypass markets'.

New Entry – Distribution

3.73 As with transmission pipelines, distribution networks have significant natural monopoly characteristics. Sunk costs and economies of scale in particular ensure that each existing network is unlikely to face competition across the network from new entry, at least while the network remains capacity unconstrained.

3.74 There continues to be potential for new 'bypass' entry where there are suitable conditions (usually where there is a cluster of large customers close to a transmission pipeline), the scale of this entry is likely to be limited. Nevertheless, the mere potential is likely to have had an important influence on prices in these areas, albeit they equate to a small part of the area covered by each incumbent's network.

3.75 The Commission sought evidence on likely new competing pipelines. It received nothing to suggest that new pipelines are sufficiently likely to be relied on to act as a competitive constraint in the foreseeable future.

Interfuel Competition

<u>Switching Energy Forms</u>

3.76 In its submission to the Commission dated 20 August 2003, NGC stated:

> Demand for pipeline services is derivative from the demand for gas. Manifestly gas does compete with electricity for heating, water heating, air conditioning and cooking in domestic and industrial sectors. New applications such as heat pumps, which have three to one efficiency advantage over direct heating are competing directly with gas in the domestic and small commercial market sector (such as hotels, motels and office buildings). Gas also competes with coal and biomass for applications that require heat for drying or steam raising.
>
> It is NGC's view that the Commission seriously understates the actual future level of interfuel competition, and the impact of participants such as Genesis and Contact who retail gas and electricity, and have the ability to burn gas to generate electricity instead of selling the gas to end user consumers via the transmission and distribution networks.
>
> New Zealand is at the end of an era of low gas prices due to the winding down of the Maui field. NGC expects its entitlements to Maui gas to end before 2007. There is a real prospect of gas shortages in the near future, as no new fields the size of Maui have been discovered, nor are likely to be for some time. This

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[47] Ibid.

> increases the viability of alternative fuels, and the value to electricity generators of using gas to generate electricity. The wholesale price is expected to increase significantly. In fact, the energy component of delivered price has almost doubled for some industrial consumers. This creates a significant incentive for industrials to switch to coal.

3.77 In its submission dated 2 July 2004 on behalf of NGC, CRA argued that the competitive constraints on gas pipeline companies are increasing as the price of gas rises. It suggested that there seems to be a significant amount of evidence that interfuel competition and bypass potential places a constraint on a reasonably significant proportion of gas customers and volumes transported. It stated:

> Whether this is sufficient to constrain prices to the workable or effective level of competition is of course, still an empirical question, but it is clear that many customers have real alternatives to gas.[48]

3.78 CRA had earlier submitted on the potential for interfuel competition in both the commercial and industrial sector and in the household sector. In respect of the commercial and industrial sector it noted:

- NGC had negotiated a number of special transport deals with retailers where customers had provided direct evidence of an ability to switch to alternative fuel types. Examples come from forestry, dairy, meat processing, food manufacturing, food growing (glass houses), grain drying, asphalt, hospitals, electricity generation, etc;
- while currently the number of special deals negotiated to keep customers on the network and to attract new customers is relatively small as a proportion of customers on posted terms and conditions, a number of factors including gas price uncertainty and the likelihood of material price increases, is likely to increase the number of customers that can economically switch to alternative energy sources; and
- the energy component of delivered gas prices has almost doubled for some industrial customers. That along with such factors as improved coal boiler technologies (and the consequent improvement in environmental effects) means that the barriers to customers switching to alternative fuels has reduced.

3.79 Powerco, in its submission to the Commission on the Draft Framework paper,[49] gave examples of where it had lost customers following changes in its tariffs, although it noted that its information about why this had occurred and which energy form benefited was largely anecdotal.

3.80 In its subsequent submission on the Draft Report, Powerco argued that the commercial viability of interfuel substitution is demonstrated by the fact that similar businesses differ in their choices as to whether or not they use reticulated natural gas, and that this is the case even when they are located within close proximity to an existing gas network. Powerco added:

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[48] Charles River Associates, *Review of the Commerce Commission's Gas Control Inquiry Draft Report*, 2 July 2004, p 108.

[49] Powerco Ltd, *Powerco's Submission to Commerce Commission on Gas Control Inquiry Draft Framework Paper*, August 2003 paras 3.28-3.41

> This means that for suppliers of reticulated natural gas such as Powerco to retain and grow their share of the overall energy market, they need to offer a value proposition to their customers that is at least as attractive as other energy types. This is particularly true at the point in time when a customer is making choices with respect to plant and equipment that is designed for a limited set of energy types.[50]

3.81 Vector submitted[51] that it competes with the following delivered energy options:

- LPG (bottled or reticulated);
- electricity; and
- diesel, wood and coal.

3.82 Vector's comments on each energy option, which are substantially in line with what the Commission has been told by a range of industry parties, are as follows:

> **LPG**
>
> From the consumer's perspective, LPG is just another form of gas. Consumers typically consider whether or not they wish to use gas, with the type of gas and the form of delivery being of secondary importance.
>
> LPG is widely available in bottled form and can be readily reticulated in commercial and industrial areas.
>
> For residential use, the bottled form ranges from a single 10 kg bottle often used for hobs, space heating, or barbeques, to larger twin pack bottles situated outside the house and used for water heating, space heating, cooking and so forth. Unlike reticulated natural gas, bottled LPG does not require trenching or the installation of a pipe from the nearest network supply point to the house.
>
> For commercial and industrial users, LPG can be reticulated from a central supply point, which is refilled by tanker. This overcomes the limited capacity of transportable bottles for large consumers of energy.
>
> An important feature of LPG is that it can be used to fuel the same appliances and plant that are fuelled by natural gas. In most cases a switch between the two gases requires simply changing nozzles in the appliance. Thus the consumer faces very low switching costs between reticulated natural gas and LPG.
>
> **Electricity**
>
> Electricity as an energy option has a number of features which place it in a very strong position in the market, relative to reticulated natural gas. These features include:
>
> Electricity is almost universally available in homes and is also reticulated within homes, resulting in it being the most convenient, default energy choice.
>
> Electrical appliances generally have a much lower upfront cost than equivalent gas appliances. While gas energy costs are usually lower, consumers with limited funds often find the lower initial outlay for electrical appliances more attractive, even when longer-term savings from using gas can be demonstrated.
>
> It is easy and practical to replace faulty gas-fuelled appliances with electrical equivalents. This decision is often driven by the relatively lower cost of electrical appliances.

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[50] Powerco Ltd, *Submission to the Commerce Commission on the Gas Control Inquiry Draft Report*, July 2004, p 10.

[51] Vector Ltd, *Submission on Commerce Commission's Draft Framework Paper*, 20 August 2003, para 1.10

> All new subdivisions are reticulated with electricity and all properties are connected to the electricity network. However the same does not apply to gas connections, even in areas close to the gas distribution network. Developers view gas as a non-essential service and are typically reluctant to contribute to the installation costs of a gas network in the manner they do for installation of electricity networks.
>
> For commercial and industrial uses, energy efficient electrical technologies are eroding the ability of gas to compete (e.g. heat pump, microwave and infra-red technology for heating and drying).
>
> **Diesel, wood and coal**
>
> In the residential market diesel, wood and coal are used typically for space heating.
>
> In the Commercial and industrial market, these fuels are used for a wide range of heating processes (e.g. many schools continue to use coal for heating). Further heat from such processes is often used to power electricity co-generation plants.

3.83 There have been a number of estimates of the relative cost to consumers of different energy options. In respect of the household sector, CRA noted that while in the past gas was seen as a cheaper fuel alternative to electricity, the cost to households of using bottled LPG and wood heating are similar to cost of using gas. CRA provided the following table based on an assessment made in 2001:

Table 3.3: Comparative Costs

Heating Types	Total Annual Energy Costs
All Electric	$1,587
Gas Heating + Hot water	$1,217
LPG Heating and Hot water	$1,224
Wood heating and gas hot water	$1,213

Source: ACIL, *Review of the New Zealand Gas Sector*, Appendix A4, p 9, (2001).

3.84 CRA suggested that this table indicates that interfuel substitutes for gas were competitively available in the environment of low Maui gas prices. There also appear to be relatively low barriers to marginal customers diverting from gas to alternative fuel sources.

3.85 Vector in its cross-submission dated 13 August 2004 stated:

> Delivered price of LPG is approximately 7% more expensive per GJ than the delivered energy price of natural gas in residential applications. Unlike LPG, connection costs must be factored into the total price. The low price differential underscores consumer indifference between natural gas and LPG (leaving final choices as to such issues as the timeliness of installation).[52]

3.86 NGC provided the Commission with confidential internal papers for its July 2004 Energy Sector Pricing Review. It shows the following prices of delivered energy for households with average consumption:

[52] Vector Ltd, *Gas Pipeline Inquiry Cross Submission*, 13 August 2004, para 25.

Table 3.4: Relative Cost of Household Energy

Energy	Residential	Commercial	Industrial
Gas	[ ]	[ ]	[ ]
LPG	[ ]	[ ]	[ ]
Electricity	[ ]		
Coal	[ ]		[ ]
Wood	[ ]		
Pellets	[ ]		
Diesel		[ ]	[ ]
Geothermal			[ ]

3.87 The NGC's internal review made the following points in respect of the residential sector:

- [ ]

3.88 Its comments in respect of the commercial sector included:

- [ ]

3.89 Its comments in respect of the industrial sector included:

- [ ]

3.90 The NGC internal review also noted the following non-price factors which it considered relevant to choice of energy form:

- [ ]

3.91 The review's conclusions included:

- [

]

3.92 At the earlier conference on the Draft Framework paper Contact Energy commented that the potential for interfuel competition was very limited in respect of large users because:

> Almost without exception, they have large sunk specific assets that are really dependent on gas, whether that be for making processed heat, petrochemical production, or power generation. And so for them it's not really a viable option to switch to another fuel in the short-term.

3.93 Contact Energy also stated:

> For smaller users it is a bit more realistic, but nonetheless they too tend to have some sunk assets. So I guess our view is that there is scope for competition, but it is not huge.

Commission's Conclusions

3.94 The above information is consistent with the view that in the supply to all sectors – domestic, commercial and industrial, other energy forms compete with gas in certain circumstances. The competing fuel may however vary according to the sector.

3.95 The price information suggests that for some domestic customers the cost of gas and LPG are reasonably comparable at certain consumption levels. However, high users, whose fixed component of delivered gas prices is a relatively small percentage of the total price, are likely to favour gas over LPG. Conversely, small users who would be likely to favour LPG as it has a much lower fixed cost component. For each group the other energy form would not be a reasonable substitute.

3.96 The choice of energy form can also be decided on non-price factors. Restaurants and cafes, for example, prefer gas because of its controllability. It may be that gas and LPG are reasonable substitutes for these users (depending on availability and consumption levels), but electricity would not be irrespective of the price of electricity.

3.97 Most energy consumers are only infrequently in a position to switch energy forms. During the economic life of their plant or appliances they are unlikely to switch. The ACIL Report listed a range of factors relevant to the choice of energy.[53] They include:

- whether it is a new or existing house;
- the availability of gas;
- the relative price of gas and electricity;
- the age of the appliance, the cost of the replacement and the likely life of the appliance;

[53] ACIL *Review of the New Zealand Gas Sector. A Report to the Ministry of Economic Development*, October 2001, Attachment A4, paragraph A4.3.

- the perceptions of the advantages and disadvantages of electricity and gas;
- the availability of appliances; and
- the discount rate adopted by the consumer.

3.98 As ACIL (and Contact) noted, gas users tend to make choices between energy forms only when their plant or appliances approach the end of their economic life. There are exceptions to this – some plant is dual fuel, with the most important example being the Huntly power station which has a capacity of 1,000 MW, and it can, and does, switch between gas and coal depending on the availability and price of the two forms of energy. Nevertheless, these examples of ready switching are relatively rare.

3.99 The Commission accepts that competition to supply new energy users or users whose plant or appliances have come to the end of their economic life does provide an on-going competitive constraint on energy suppliers. Further, it accepts that if a reasonable proportion of energy users were in a position to make a switch at any time, and if it was not possible for a gas supplier to distinguish between them and other users, competitive benefits would flow to all users. However, the Commission considers that the constraint provided by the existing ability of energy users to switch energy forms falls short of that found in a market which has workable or effective competition.

3.100 In its consideration of interfuel competition and its ability to constrain transmission and distribution charges, the Commission took account of the comment of Mr Wilson, Transportation Manager, NGC at the conference[54] that only 38% of the gas transported by NGCT was at its posted prices. The remaining gas is transported at lower prices set in recognition of the risk of physical transmission bypass opportunities and of losing gas consumers to other energy forms. Mr Wilson cited waste wood, coal, LPG and fuel oil. This suggests that there is a ceiling placed on transmission prices by interfuel competition (and physical bypass potential) or by NGCT's customers' countervailing power. (NGCT has only around [ ] customers made up of gas retailers and large industrials). However, it does not necessarily indicate that this ceiling matches that which would be in place in a workably competitive market. NGCT's ability to earn supra-competitive returns over an extended period (as assessed by the Commission and described in Chapter 12), supports the position that interfuel and bypass competition does not constrain transmission prices to competitive levels.

3.101 In addition, the Commission's view that the constraint interfuel competition places on suppliers of gas distribution services is less than the constraint found in markets which are workably competitive is supported by the fact that each distributor is found to have earned supra-competitive returns.

<u>Price Elasticities of Demand</u>

3.102 The information available to the Commission suggests that the demand for gas is relatively price inelastic, although the Commission acknowledges that the assessments it has seen to date have limitations. There appears to have been

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[54]Commerce Commission, *Transcript of Draft Report Conference*, 26 July 2004, pp 74-79.

few recent elasticity studies of the New Zealand market and none of the parties at the conference were able to provide data about which they were confident.

3.103 In its October 2003 publication *New Zealand Energy Outlook to 2025*, the Ministry of Economic Development used an estimate of the demand elasticity for energy as a whole, in the absence of reliable elasticity information for individual energy forms. (The price elasticity for Other Industrial and Commercial was short-run -0.06 and long-run -0.28) and for Residential was short-run -0.08 and long-run -0.21). It noted that these assessments were based on historical data and may not be fully applicable in today's circumstances.

3.104 Covec, in its paper on Natural Gas Pipeline Regulation[55], has used elasticities -0.1 (short-run) and -0.5 (long-run). However, the Commission has not been able to discover the bases of these assessments.

3.105 Professor Carol Dahl of Colorado School of Mines[56] considered elasticities in various countries where the gas sector had some similar characteristics to the New Zealand sector. She stated that making inferences from other countries for New Zealand was difficult because of the uniqueness of New Zealand's economy, but suggested that those countries which have similarities provide some useful inferences. She suggested these included that the residential sector in New Zealand might be quite elastic. In the industrial sector she found that countries with the most similar consumption patterns were Australia, Austria, Canada and the USA, but that price controls had distorted the picture in the USA. She concluded that Australia may have had an elastic demand while Austria and Canada may have had inelastic demands. Since Austria and Australia were closest in consumption to New Zealand, she concluded that New Zealand's own price elasticity might have been near those of Austria and Australia, but with a somewhat larger share, it might have a less elastic demand or its elasticity might be less than -1.25.

3.106 Dahl's conclusions included:

> There is overwhelming evidence that natural gas does respond to prices. And, except in supply constrained situations, either because of the regulatory framework or the physical constraints of a new market, demand is inversely related to own price. The magnitude and timing of this response appears to vary by sector, prices of alternative fuel sources and maturity of the market. However, as of yet, I do not have a good feel for the magnitude of these responses in many cases.
>
> Young markets appear to have higher own price elasticities. One young market is the residential market. I would expect in most countries such a young market to have an elastic own price response ….

3.107 The Australian Bureau of Agricultural and Resource Economics (ABARE) undertook a study[57] in 1996 which showed that in Australia each of the

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[55] Covec, *Natural Gas Pipeline Regulation*, July 2002, page 10

[56] Dahl, C., *A Survey of Econometric Estimates of Natural Gas Demand Elasticities: Implications for Natural Gas Substitution in New Zealand,* August 1995.

[57] The Australian Bureau of Agricultural and Resource Economics, *Price Elasticities of Australian Energy Demand*, September 1996.

industrial, residential and commercial market segments were relatively unresponsive to changes in the price of gas electricity and other fuels. ABARE's assessment was: Industrial -0.29 (short run) and -0.30 (long run), Residential -0.78 and -0.78, and Commercial -0.09 and -0.10. The study found that residential customers were highly likely to reduce their gas consumption if electricity prices fell (cross price elasticity of 0.83), however were less willing, or perhaps able, to reduce electricity consumption if gas prices fell (elasticity of 0.15).

3.108 In commenting on the ABARE study, ACIL in its 'Review of the New Zealand Gas Sector' said that there were important differences between Australia and New Zealand and consequently the study might not reflect the New Zealand situation.

3.109 An Australian study by Akmal and Stern[58] stated that their estimate of the gas price elasticity in the Australian residential sector is -0.70, but did not reject the null hypothesis of unitary elastic demand.

3.110 A paper by Gang Liu[59] on gas demand in OECD countries suggested for the residential sector a short-run elasticity of -0.102, and a long-run of -0.364, while for the industrial sector, short-run of -0.067 and long-run of -0.243.

3.111 As noted above, none of this information is totally satisfactory for the Commission's purposes. However, the new material is reasonably consistent with the conclusion the Commission reached in preparing its Draft Report that the demand for gas is relatively price inelastic (less than -1) and probably no more than -0.7 overall.

3.112 The assessments relate to the price of, and demand for gas. The Inquiry is not into gas as such, but rather into intermediate components – gas transmission and gas distribution. Typically, transmission accounts for around 10% of the price of delivered gas and distribution around 40%. Thus, a large percentage increase in the price of transmission services or distribution services will have a much smaller proportional impact on the price of, and therefore demand for gas, even if the increase was fully passed on. This means that the price elasticities of demand for gas transmission and distribution are expected to be much lower than that for delivered gas, implying that gas users are not likely to be persuaded to switch to another energy form by even a large percentage increase in distribution charges.

3.113 If the price elasticity of gas is -0.7, the price elasticity of distribution would be 40% of that or -0.28 (rounded to -0.3), and that of transmission 10%, or -0.07 (rounded to -0.1), assuming that transmission and distribution channels are utilised at current levels.

3.114 Because of the limitations of the studies on which it bases its calculations, the Commission has not placed a lot of weight on them. Rather, it merely notes

[58] Akmal, M. and Stern, D.I., *Residential Energy Demand in Australia: An Application of Dynamic OLS*, October 2001.
[59] Gang Liu, *Estimating Energy Demand for OECD Countries; A Dynamic Panel Approach*, March 2004.

that they do not add support to any argument that network charges are strongly constrained by interfuel competition.

3.115 For its modelling in later sections of this report, the Commission has been required to adopt an elasticity figure for distribution services. It has chosen a price elasticity of -0.3 for distribution and -0.1 for transmission, in the absence of reliable information pointing to other figures. The Commission has subjected its modelling to sensitivity testing.[60]

Overseas Guidance

3.116 When considering the significance of interfuel competition the Commission has looked for guidance from overseas authorities. It acknowledges that no country has identical circumstances to New Zealand (although most have many common features) and that the information from them cannot be determinative of the Commission's approach. The Commission notes, however, that it has been unable to find any jurisdiction where the competition authority has found competition to be sufficiently strong to justify placing natural gas and other energy forms in a common product market.

ODV Analysis

3.117 In its Draft Report the Commission noted that both NGC and Vector had economic valuation (EV) assessments undertaken for them. Both companies apply an ODV methodology when valuing their networks. In accordance with the ODV rules, the lesser of the optimised depreciated replacement costs (ODRC) and the EV determines the ODV. The EV will be less than the ODRC value for those parts of its network where the company cannot achieve its WACC on the ODRC value. This may arise if, for instance, prices are severely limited by the presence of competing pipelines or by competing fuels.

3.118 The assessments were interpreted by the Commission in the Draft Report as suggesting that the two companies' current prices were not constrained by competing energy forms. Both companies suggested that it was inappropriate for the Commission to draw conclusions on competition from EV assessment which was prepared for a specific and different purpose.

3.119 The Commission accepts there may be some risk of misinterpretation arising from using inferences from the EV assessments in the competition analysis. Accordingly, it has not used these assessments in reaching its conclusion on whether or not competition is limited in the relevant markets.

Conclusion on Interfuel Competition

3.120 The Commission accepts that interfuel competition places some constraint on all sectors of the gas industry, including gas pipeline services. However, for the reasons set out above, the Commission does not consider that interfuel competition can be characterised as strong.

[60] In Chapter 6 (Assessment Approach) the Commission models the dynamic efficiency loss associated with control by analysing a hypothetical 'missing market' made up of potential new gas customers who are unable to be supplied because new investment has been deterred by the imposition of control. The elasticity used in that analysis is based on a multiple of the elasticity of existing markets. This is discussed further in Chapter 6.

3.121 In addition, even if there was a significant constraint on delivered gas prices, there would not be an equivalent constraint on distribution and transmission prices. On average, distribution and transmission represent perhaps 40% and 10% respectively of the delivered price of gas. The competitive constraint which may be faced by gas retailers would be dissipated by these percentages when it got to gas distributors.

3.122 This means that if, for example, interfuel competition placed a 5% ceiling on increases in delivered gas prices, this increase could all be captured by the distributor in the form of a 12.5% increase (being 5% divided by 40%) in distribution prices. Alternatively, the 5% increase in delivered gas prices could all be captured by the transmitter in the form of a 50% increase (5% divided by 10%) in transmission prices. Thus, even if delivered gas prices were reasonably constrained, suppliers of transmission or distribution services may still be able to apply a significant increase to their prices.

3.123 Consequently, the Commission is not satisfied that the competitive constraint from interfuel competition is sufficient in itself to ensure that the relevant markets are workably competitive.

Constraint from Countervailing Power of Gas Users

3.124 In its submission, CRA,[61] for NGC, suggested that the Commission should consider the ability of large gas customers to enter into long-term contracts prior to investing in assets that use gas. It noted that electricity generators or other large industrial and commercial customers have locational options before they determine to locate on a particular network.

3.125 CRA also suggested that some price sensitive customers may exit the market altogether (and perhaps relocate overseas) if faced with high pipeline service charges.

3.126 At the framework conference Professor Evans, of CRA for NGC, noted that long-term contracts are a feature of gas transport.

3.127 The Commission accepts that long-term contracts entered into when the gas user undertakes its initial investment would provide that user with a measure of protection from the use of market power, provided that user has fuel and/or location options at the time it entered the contracts. However, the Commission is not convinced that this protection would necessarily flow beyond the period of the contract or to other gas users.

Constraint from Regulatory Regime

3.128 The Commission has accepted in the past that the regulatory regime applying to the gas sector provides some constraint on those in the gas sector. The regulatory regime is described in Chapter 1 (Background).

3.129 The Commission considers that the regime can have a valuable impact on the behaviour of firms in the relevant markets. However, the Commission does not

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[61] Charles River Associates, *Response to Gas Control Inquiry Draft Framework Paper*, 20 August 2003, para 2.4.

consider this, or other regulatory regimes, can replicate the sort of constraint faced by firms which operate in competitive markets.

3.130 In itself, the regulatory regime does not provide a satisfactory proxy for workable or effective competition.

Interests in Other Fuels

3.131 Two of the gas distributors, Powerco and Vector, have important interests in the electricity sector through ownership of electricity networks, while NGC and Todd Energy (the owner of Nova Gas) have significant LPG interests.

3.132 The Commission has considered whether these interests in other energy forms have impacted on the level of competition these companies face as providers of gas distribution services. As noted above, it has concluded that delivered electricity and LPG provide only a limited degree of competition to delivered gas.

3.133 Accordingly, the Commission's conclusion on whether or not competition in the gas services market is limited has not been affected by the interests of Powerco, Vector, NGC and Todd Energy in other energy forms.

Conclusions on Generic Competition Issues

3.134 Outside the limited areas where there are bypass networks, users of transmission and distribution networks do not have a choice of networks. However, distributors and transmitters are constrained to some extent from exercising market power. The constraints come from interfuel competition, the initial freedom of gas users to choose their location, from gas users' countervailing power and from the regulatory regime. However, these constraints together do not remove the potential for distributors and transmitters to exercise market power. Further, new entry is not sufficiently likely to act as an effective constraint.

3.135 The analysis of generic competition issues has led the Commission to conclude that there is workable or effective competition in bypass markets, but that in other relevant markets competition is limited. The extent to which these generic conclusions are applicable to individual firms in the markets is discussed in the company specific chapters.

4 OVERVIEW OF ASSESSMENT APPROACH

Introduction

4.1 Chapter 2 (Legal Framework) set out the terms of reference and the statutory framework for the Inquiry. It describes the legal tests that must be met before the Commission may or should recommend control. This chapter, Chapter 3 (Competition Analysis), Chapter 5 (Assessment Principles for Efficient Pricing) and Chapter 6 (Assessment Approach) discuss how the Commission implements the legal tests. Chapter 3 (Competition Analysis) describes the Commission's approach to determining whether s 52(a) is met; i.e., whether goods or services are supplied in a market in which competition is limited. This chapter provides an overview of the Commission's approach to the provisions in s 52(b) and s 56(1) and s 56(2). Chapters 5 (Assessment Principles for Efficient Pricing) and Chapter 6 (Assessment Approach) expand on these matters.

4.2 S 52(b) provides that goods or services may be controlled if it is necessary or desirable in the interests of acquirers. The Commission terms this the net acquirers benefit test (NAB test). In applying this test the Commission assesses the net benefits to acquirers of control (the factual) relative to the situation with no control (the counterfactual). If the Commission finds that there are net benefits to acquirers from control, then it can recommend that control may be imposed.

4.3 In reporting to the Minister on whether control *should* be imposed, the Commission may have regard to all matters it considers necessary or desirable (s 56(1) and s 56(2)). Thus, in considering whether control should be imposed, the Commission is able to take into account wider considerations than whether control is likely to result in net benefits to acquirers. The Commission can therefore weight other factors against the net benefits to acquirers.

4.4 In reaching its decisions on whether control may or should be imposed, the Commission has relied on quantitative analysis, using a model developed for this purpose, and qualitative analysis in developing the framework of the model, and in choosing parameters used in the model. The Commission considers that the model is useful to the degree that it focuses attention on key assumptions regarding the characteristics of the market. The Commission's view is that the value of the model is not in its ability to produce 'proof' that it is necessary or desirable that goods or services be controlled, nor to supplant the Commission's exercise of judgement, but rather in providing support to the Commission's deliberations by:

- focusing parties' attentions on verifiable economic arguments;
- making transparent the values of the key parameters and assumptions in the analysis; and
- producing quantitative estimates of the results of a given transaction or arrangement.

4.5 The Commission's qualitative assessment ensures that it has taken into account the cumulative effect of all relevant considerations.

4.6 The Commission's approach to determining whether control *may* be imposed (the NAB test) is outlined in the section below. Its approach to determining whether control *should* be imposed is discussed in the following section.

Control May be Necessary or Desirable in Interests of Acquirers

Net Acquirers Benefit Test (NAB)

4.7 The NAB test is used by the Commission to determine whether to recommend to the Minister under s 52(b) that control may be necessary or desirable in the interests of acquirers.

4.8 The net benefits to acquirers of control are estimated by:

- identifying the potential benefits of control;
- identifying the potential costs of control; and
- balancing one against the other.

4.9 The benefits to acquirers of control broadly emerge from reducing any excess returns or inefficiencies associated with the counterfactual (i.e., in the absence of control) less any costs of control. An analysis of company performance in the counterfactual compared to an efficiently operating market is used to measure the potential benefits of control.

4.10 The costs of control emerge in terms of compliance and administration costs for the business and the regulator (direct costs) and the control mechanism's effect on efficiency incentives (indirect costs).

4.11 The Commission has constructed a spreadsheet model to assist in the calculation of NAB. In its modelling of NAB, the Commission has assumed the regulation that would be imposed under Part V of the Commerce Act would take the form of a price cap established through a building blocks process.

Benefits of Control

4.12 In determining whether there are likely to be benefits from control, the Commission must form a view on whether the prices set by the gas pipeline businesses exceed prices that would prevail in a workably competitive market. To achieve this, the Commission relies primarily on a building blocks analysis. The building blocks approach involves determining the:

- efficient level of capital required by the business (asset value);
- efficient rate of return on capital (WACC);
- efficient return of capital (depreciation); and
- the efficient level of non-capital (or operating) costs.

4.13 The Commission judges the behaviour of the suppliers of gas services against an 'efficient prices' standard, which also involves a benchmark of 'normal returns' to be earned by businesses. The sources of potential benefits of control include:

- excess returns being reduced by control, with a consequent transfer of wealth from suppliers to acquirers (being a net benefit to acquirers). Transfers occur as a result of a reduction in prices;
- allocative inefficiency being reduced by control. As prices are moved by control towards the competitive level, allocative efficiency is improved;
- productive inefficiency being reduced by control. Control may provide additional incentives for businesses to control costs; and
- dynamic inefficiency being reduced by control, because of better utilisation/allocation of resources, better investment incentives or continued/improved availability of services over time.

Costs of Control

4.14 The Commission has taken the position that most of the costs of control would ultimately fall on acquirers.[65] The costs of control can be broken down into two types: direct and indirect costs.

4.15 Direct costs involve those that fall on market participants (compliance costs) and those borne by the regulator (regulator's costs).

4.16 Indirect costs of control incorporated into the Commission's analysis include the following:

- unrecoverable excess returns and unachievable allocative efficiencies. These costs reflect the possibility that control would move prices towards the efficient level, but would not replicate the competitive price. This might happen, for example, where a price path allows businesses to retain efficiency gains for a period or the Commission allows an implicit margin on WACC under control;
- productive inefficiencies created by control. This reflects the potential for control to weaken the incentives of businesses to reduce costs; and
- dynamic inefficiencies from reductions in service quality and deterred new investment as a result of control being imposed.

Assessing Whether Control May be Imposed

4.17 The Commission quantifies both the costs and benefits of control using its model. In assessing the net acquirers benefit, the Commission weights the transfers of wealth from shareholders to consumers achieved by reducing excess returns equally with the efficiency gains and losses from control.

4.18 The efficiency benefits of control are generally small compared to the efficiency costs of control. Thus, under the Commission's approach, control is

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[65] The exceptions are the producer surplus (additional excess returns) forgone in the missing market as a result of control and the producer surplus recovered by control when prices are set below the competitive level. These costs and benefits of control are discussed in Chapter 6 (Assessment Approach). They are included in the Commission's analysis of the costs to the economy of reducing excess returns.

generally assessed as reducing efficiency, but the reduction in efficiency is more than offset by the reduction in excess returns that is achieved.

4.19 In quantifying NAB, the Commission uses a base case reflecting the Commission's view as to its best estimate of all of the relevant parameters. The Commission has also undertaken sensitivity analysis of the key parameters affecting the assessment of NAB. The sensitivity tests undertaken include the following:

- WACC;
- the asset base using historic cost for Wanganui Gas, the only business able to provide the relevant data;
- common costs;
- growth during the forecast period;
- self-insurance (for those businesses not obtaining insurance externally);
- dynamic inefficiency (a cost of control);
- the magnitude of the excess returns considered unrecoverable; and
- tax (for businesses affected by transactions).

4.20 The sensitivity analysis informs the Commission as to the robustness of NAB found in the base case. Sensitivities have been selected on the basis of feasible alternative scenarios, based on the Commission's judgment. If positive NAB is found in the base case and in all of the sensitivity analyses, the Commission is more confident that control would result in positive benefits to acquirers than if NAB is negative in some of the scenarios.

4.21 The Commission recognises that there are limitations to the quantitative analysis.

4.22 The data used in the model may be inaccurate and forecasts provided by the businesses are inherently uncertain. The Commission has undertaken checks on the data where possible. However, the Commission is aware that further checks would be desirable if control were to be recommended and accepted. The Commission handles the possible inaccuracies in the data through sensitivity analysis in the modelling. Also, the Commission notes that the poor quality of the data made available by the businesses during the Inquiry, indicates that there would be substantial benefits from strengthening the information disclosure regime.

4.23 The Commission notes that it has particular concerns that the businesses may have over-allocated common costs to their gas activities and provided overly conservative forecast information. On the other hand, a lack of information has precluded the Commission adjusting the base case for self-insurance and for some tax effects for particular businesses. Although the latter may be to the disadvantage of some of the companies, overall the Commission's view is that the base case assumptions about data are conservative (in favour of the businesses).

4.24 Natural variations in demand and costs can mean that outcomes differ substantially from expectations. Thus observed excess returns may be the result of unexpected market conditions rather than a business seeking to earn excess returns. Concerns about natural variations in the data are ameliorated in the model by the relatively long period of analysis undertaken by the Commission.

4.25 The Commission notes also that it measures returns over part of the life of the assets assuming a particular profile of recovery of capital costs, treatment of asymmetric risks and other pricing behaviour. The businesses may have used a different approach in setting prices while still not earning excess returns over the life of the assets. Where the assessment approach is different to the company's approach, it is possible to reach false conclusions about the level of returns. The long period of assessment reduces this concern to some degree. However, in the modelling this concern is mainly catered for by the Commission ensuring that the implicit margin on WACC provided by the costs of control is sufficiently large to prevent a false finding for control.

4.26 The costs of control allow businesses to earn an implicit margin on WACC before the Commission would find net acquirers benefit. The Commission has used the mid-point of the WACC distribution in its base case analysis, on the basis that the implicit margin provided by the costs of control protects against the Commission wrongly recommending control. The implicit margin on WACC provided by the costs of control is discussed in more detail in Chapter 6 (Assessment Approach).

4.27 A key parameter in the analysis, WACC, cannot be observed but must be estimated. The estimate of WACC involves substantial uncertainty and the adoption of a WACC that is too low may result in a false finding for control. This risk is partly dealt with through sensitivity analysis, and also through the protection provided by the implicit margin on WACC for the costs of control.

4.28 The Commission is also of the view that the imposition of control under Part V of the Commerce Act would involve asymmetric risks, with the costs of wrongly imposing control likely to be higher than the costs of not imposing control when it is justified. This related concern is also handled by considering the implicit margin on WACC provided by the costs of control.

4.29 While it is helpful to incorporate considerations as to the risks associated with imposing control or not imposing control through the quantitative analysis, and to handle concerns about data accuracy through sensitivity analysis, the Commission believes that a qualitative review of all relevant factors is also necessary. This allows the Commission to weigh up the magnitude of any NAB and to draw in factors that may not be fully captured by the modelling. Such factors include the observation that past revaluation gains have been ignored in the analysis and that no gold plating occurred, assumptions that favour the businesses. It also allows the Commission to review whether the risks associated with its modelling approach have been adequately reflected in the results.

4.30 If a positive NAB is found, and the additional qualitative considerations are consistent with this finding, the Commission has determined that it can recommend that control may be imposed.

Should Control be Imposed

4.31 Having determined that it can recommend that control may be imposed, the Commission then conducts further analysis to determine whether to recommend that control should be imposed. In determining whether it should recommend control, the Commission considers wider issues.

Costs of Control to the Economy

4.32 The NAB is calculated by determining the allocative, productive and dynamic efficiency benefits achieved by control, as well as the reduction in excess returns. The latter involves a transfer of economic rents from gas businesses' shareholders to gas consumers. The costs of control that are assumed to affect consumers, which consist of allocative, productive and dynamic efficiency reductions, are subtracted from the benefits of control to give the net acquirers benefit. Some additional costs of control affect producers only, and are included in the efficiency analysis discussed below.

4.33 In the assessment of whether control may be imposed, efficiency costs and reduced excess returns (reduced economic rents) are weighted equally and added together. However, efficiency and reduced excess return effects are substantially different in nature, and a case can be made for assigning different weightings to them. In the case of reduced excess returns, one party's (consumers') gain of a dollar is another's (gas business shareholders') loss of a dollar. In comparison, a reduction in efficiency results in a dollar lost to the economy, and no corresponding gains. These considerations suggest that excess returns might be discounted, compared to efficiency effects if a broader (New Zealand wide) perspective than acquirers' interests were adopted.

4.34 The Commission presents information on the efficiency and excess return effects in the company chapters. The approach it adopts is illustrated using a hypothetical example. Suppose the following costs and benefits are assessed for a company:

Excess returns benefit	$3,000
Net efficiency costs	$1,000
Net benefits	$2,000

4.35 In this scenario, $3,000 of transfer benefits are achieved at an efficiency cost of $1,000 (i.e., a loss to the economy of that magnitude). That is, the transfer involves a 33% efficiency cost. Another way of viewing this is that there would be no net benefits to acquirers if efficiency costs were weighted at 3 times the excess returns benefits.

4.36 The Commission notes that it has concerns about the costs of achieving reductions in excess returns when the ratio of the cost to the economy relative to the reduction of excess returns gets high and that such concerns increase as the efficiency costs increase.

4.37 The efficiency costs of transfers are likely to be larger for small businesses, where the costs of control are large relative to the transfer benefits. The efficiency costs are also higher where a business's excess earnings are moderate.

Size of the Benefits

4.38 The Commission undertakes analysis to indicate the rate of return earned by individual businesses, the impact of control on the transmission and distribution price and the delivered prices for gas, and in terms of individual customer benefits. This provides a sense of the scale of the benefits.

Impact of a Recommendation of No Control

4.39 The Commission notes that to the extent the costs of control imply that businesses can earn an implicit margin on WACC before a control finding will be made, businesses may form the view that they can increase their prices in the absence of control. Concerns about the efficiency costs of reducing excess returns, which also might lead to a decision not to control, could provide businesses with comfort that they could further increase their prices without control being declared. These considerations act to weaken the constraints imposed on businesses by the threat of control. The Commission notes that because of these concerns, it is important to maintain the threat of control, even if control under Part V is not declared. Options available to the Minister for achieving this, if control under Part V were not declared, include increased monitoring and disclosure or implementation of an alternative regulatory regime, such as that which applies to large electricity lines businesses under Part 4A of the Commerce Act.

Consideration of Other Matters

4.40 In considering whether control *should* be imposed, the Commission is able to take a broader perspective of the risks (and their impacts) that might arise from control. Thus, it is able to take greater account of the risks that fall on parties other than acquirers of gas services in such an analysis. It therefore conducts a further qualitative review of the likely impact of control, the risk that circumstances may differ from the assumptions underlying the model, and the likely impact on the various stakeholders.

4.41 In the Commission's modelling, the Commission assumes that price cap regulation would be imposed under Part V of the Commerce Act. The Commission observes that Part V of the Commerce Act is a relatively heavy-handed regulatory approach, with substantial associated costs. If a declaration of control were made, the Commission would need to immediately grant a provisional authorisation (under s 71), because gas services could not be sold without an authorisation or undertaking. The Commission would then be required to undertake the analysis necessary to make a final determination under s 70.

4.42 In contrast, different forms of regulation may be more effective at delivering the potential benefit of control to acquirers. Although the Commission has not formally modelled different forms of regulation, the Commission considers it likely that under alternative forms of control, the costs of control could reduce substantially more than the benefits of control, thereby raising the net benefits. The Commission observes, for example, that the regime applying to large electricity lines businesses has provided a flexible means of applying different degrees of constraint to different businesses, without necessarily subjecting them to formal control.

4.43 The Commission, in deciding whether to recommend control for the individual gas pipeline businesses, has considered the costs of imposing control under Part V of the Commerce Act, relative to regulatory alternatives.

Other Matters which the Minister Could Consider

4.44 The Commission notes that it would be highly desirable for the disclosure requirements applying to the gas businesses to be reviewed and strengthened. The Commission has had considerable difficulty obtaining robust comparable data with which to conduct its qualitative analysis.

4.45 The Minister can consider regulatory alternatives to control under Part V of the Commerce Act, alternatives may offer a better balance between the costs and benefits of control.

4.46 The Commission has not considered in detail the possible implications of the purchase of NGC by Vector. When the outcome of this transaction is clearer, the Minister might like to give further consideration to its consequences.

4.47 The Commission has given weight to the government's policy statement issued under s 26 of the Commerce Act. The Commission notes, however, that the Minister may wish to give different weightings to the various aspects of the statement.

4.48 The Minister has asked the Commission to report on net public benefits (NPB). NPB information is presented in Chapter 20 (Recommendations).

4.49 Net public benefits (NPB) are calculated by considering only the efficiency effects of control. They incorporate the efficiency costs borne by both producers and consumers.

4.50 The NPB are largely included in the NAB test. The relationship between the two calculations is:

NAB = NPB + 80%*ER - PE

Where ER are excess returns (transfers) and the excess returns are discounted by 20% to reflect the likelihood that regulation would not transfer all of the economic rents measured at a normal WACC.[66] PE includes efficiency effects that impact on producers and not consumers. It comprises the producer surplus foregone (i.e., additional excess returns foregone) as a result of control discouraging investment (discussed in Chapter 6 (Assessment Approach)) and

[66] Where excess returns are negative, 100% of the negative excess returns are included in the calculation of NAB.

the effect on producer surplus when businesses' prices are set below the competitive level (this is an additional benefit of control to producers).

5 ASSESSMENT PRINCIPLES FOR EFFICIENT PRICING

Introduction

5.1 The Commission considers that, as part of the process of considering whether there are net acquirers benefit (s 52(b)), it must judge the behaviour of the suppliers of gas services against an 'efficient prices' standard, which also involves a benchmark of 'normal returns' to be earned by businesses. The Commission uses these principles as the basis for estimating the potential benefits of control.

Determining Efficient Prices and Normal Returns

5.2 Having determined that particular services are provided in a market that has limited competition, there are two broad approaches to determining the extent to which the prices for those services are efficient. One approach is to determine efficient prices using economic principles and theoretical models adapted for the particular circumstances, combined with known or estimated data on the relevant costs of providing the services. This approach is called the 'building blocks approach'.

5.3 The other approach involves comparing the prices charged by the businesses under investigation with those for comparable services provided in other markets that either have effective competition, or in which the prices are otherwise known or assumed to be efficient. By implication the returns earned in such other markets would also be considered 'normal'.

5.4 In determining whether there are likely to be benefits from control, the Commission must form a view on whether the prices set by the gas businesses exceed prices that would prevail in a workably competitive market. The Commission can obtain insights into this issue either through undertaking building blocks analysis or through benchmarking of the New Zealand businesses against comparable businesses in other markets that might be pricing efficiently.

5.5 Because of the difficulties with benchmarking of New Zealand's gas businesses (described in more detail in Chapter 11 (Comparative Benchmarking), the Commission's preferred approach for this Inquiry is the building blocks approach. This was also the approach used by the Commission in the Airports Inquiry. It is consistent with assessing both the net benefits to acquirers and the net public benefits. As discussed in the previous chapter, the building blocks approach involves determining the:

- efficient level of capital required by the business (asset value);
- efficient rate of return on capital (WACC);
- efficient return of capital (depreciation); and
- the efficient level of non-capital (or operating) costs.

5.6 The Commission also engaged consultants to undertake comparative benchmarking between New Zealand and Australian gas pipeline businesses.

The results of the benchmarking are presented and discussed in Chapter 11 (Comparative Benchmarking). The reasons why this approach was not preferred are explained in that chapter.

5.7 The remainder of this chapter discusses the relevant principles for determining efficient prices and normal returns under the building blocks approach. These principles relate to the three aspects of efficiency, namely allocative, productive, and dynamic efficiency, and to normal returns. A general application of these principles to gas pipeline businesses is also provided.

Allocative Efficiency

5.8 Allocative efficiency is determined by various factors. The key considerations are the level and structure of prices, cross-subsidisation and service quality.

Level and Structure of Prices

5.9 Allocative efficiency is achieved when the price paid by any consumer reflects the costs incurred in meeting their demand. 'First best' efficient pricing requires that consumers be charged a price equal to the marginal cost of supply. Marginal cost is the additional cost incurred when an additional unit of output is produced.

5.10 Fixed costs are costs that are static and do not change as a result of changes in output in the short-run. However, these costs may change in the long-run as a result of, for example, future capital investments.

5.11 For suppliers with a high proportion of fixed costs, marginal cost is likely to be below average cost, which means marginal cost pricing would yield insufficient revenue to cover all costs. While a business could survive for some time by pricing at marginal cost, it would be unable to replace fixed assets or expand fixed capacity into the future. As a result, marginal cost pricing does not comply with allocative efficiency requirements over time (i.e., dynamic efficiency).

5.12 Suppliers providing more than one product or service would also typically have common costs. These are costs that are incurred regardless of whether one or both products/services are produced. While common costs are generally unlikely to be as significant as fixed costs, their impact is effectively the same. They would not contribute to variable costs, and so marginal cost pricing would not allow them to be recovered.

5.13 In so far as any form of pricing can be said to relate to a particular standard of competition, marginal cost pricing could be seen as representing a perfect competition standard, where there are no fixed costs. However, such an approach would not allow total costs to be recovered. The Commission does not consider marginal cost pricing therefore to be consistent with a workable competition benchmark. This decision leaves the issue of the most appropriate second-best pricing alternative, which is now discussed.

5.14 Generally speaking, demand differentiated pricing is a 'second best' approach to determining allocatively efficient prices. It allows the recovery of total costs, while minimising the distortion to allocative efficiency by linking prices paid by different acquirers to their demand characteristics. Examples of these approaches include Ramsey pricing and two-part tariffs.[67] The Commission has found that most gas pipeline businesses use combinations of the following:

- multi-part tariffs in which some prices vary according to volume transported, in combination with fixed charges for connection or access; and
- Ramsey pricing, under which some prices vary between specific consumers or consumer groups according to demand elasticities, which in turn reflect the threat of competition from pipeline bypass or from natural gas substitutes.

5.15 Another possible 'second best' pricing approach is average cost pricing. This approach would be used where demand differentiated pricing is impractical (e.g., there is a lack of information on individual consumers' demand preferences) or undesirable (e.g., significant administration costs can be involved with Ramsey pricing). Average cost pricing is simpler in practice than demand differentiated pricing, but less effective in terms of minimising departures from allocative efficiency. This is because it ignores potential efficiency gains that can be made from structuring prices to take account of differing demand characteristics.

5.16 The Commission has adopted an average cost pricing approach, in preference to demand differentiated pricing in its modelling purely as a practical matter. The structure of prices can reduce any allocative inefficiency measured under an average cost approach although under the approach adopted by the Commission, any effect is likely to be modest. The Commission includes this qualitatively in its analysis.

Cost Allocation

5.17 Prices must be structured in such a way that cost recovery is met without cross-subsidisation. Over-recovery and cross-subsidisation across activities and/or individuals is inefficient.

5.18 Differentiated pricing across groups of individuals does not of itself imply cross-subsidisation. Cross-subsidisation can be said to exist where the incremental revenue earned from the sale of a given product is either below the incremental cost of supplying a customer or group of customers or above the stand-alone cost of supplying that product. Three potential concerns can emerge:

- if a supplier were to charge a price lower than the incremental costs of supply, its revenue would not cover its cost. If, at the same time, the supplier were still cost recovering overall, this would suggest that the consumers of one product were supporting the consumers of another

[67] For descriptions of Ramsey pricing and two-part tariffs see: W.J. Baumol and R.D. Willig, Pricing Issues in the Deregulation of Railroad Rates, in: J. Finsinger (ed.), *Economic Analysis of Regulated Markets, London*, 1983, p 92; and J. Vickers, Regulation, Competition, and the Structure of Prices, *Oxford Review of Economic Policy*, vol.13, No.1, 1997.

product. This does not send appropriate signals for resource allocation and use;

- if a supplier were to charge a price above the stand-alone cost of supply, it would imply over-recovery. Once again, inappropriate signals for resource allocation and use would be created; and
- if the concept of stand-alone costs makes no allowance for the economies of scope that can be gained from providing several products together, and if a monopolist charges for each activity up to its notional stand-alone costs, it could over-recover, even though cross-subsidisation may not be found using the test above. This could possibly be an issue where businesses provide both electricity and gas services or provide both transmission and distribution services. Thus, an additional test might be needed in these circumstances.

5.19 The application of the avoidable cost allocation methodology proposed by the Ministry of Economic Development (MED) for the gas industry and adopted by some of the gas businesses to determine the expenses for their respective business units can help the identification of cross subsidisation.[68] Nevertheless, the Commission is concerned that the gas businesses, in allocating common costs between gas and other activities, have loaded a disproportionate share to their gas activities. The Commission considers that the allocation must be reasonable, particularly when the common costs relating to the gas activities are being compared.

5.20 Cost allocation is discussed further in Chapter 7 (Modelling Issues and Sensitivity Tests).

Service Quality

5.21 For a price to be allocatively efficient, the quality of service supplied must be of a standard that reflects consumers' preferences. The demand differentiated principle can also be applied here, to the extent that prices can be differentiated on the basis of demand for quality.

5.22 In markets where suppliers have limited ability or incentive, to differentiate on the basis of quality, the quality actually delivered may not be optimal (i.e., quality may be too high or too low). If there are limited substitutes for the service, consumers may also have little choice but to accept the service quality offered. Gold-plating refers to the construction of assets which deliver a higher level of quality than that demanded by consumers. Conversely, consumers may feel they are paying too high a price for the quality of service offered. Over time, product quality can be a material consideration for the assessment of both allocative and dynamic efficiencies.

5.23 Service quality issues are likely to be limited in this Inquiry. Gas conveyance activities are of a relatively standard and stable nature. They are also constrained by safety considerations, which are separately regulated. For large

[68] The avoidable cost allocation methodology has been included in a proposed update of the Gas Disclosure Regulations. These changes have not been enacted.

customers, system stability issues appear to be negotiated directly between the gas pipeline businesses and customers.

5.24 Gold-plating issues within the industry would be difficult to judge without undertaking an audit of the gas pipeline asset bases and valuations. In deciding whether to undertake an audit of this type the Commission considered the influence safety and design specifications have on the design and construction of gas pipeline assets, the feedback from consultants reviewing the businesses' ODV reports, and the evidence the Commission received during the Inquiry stakeholder interviews. These factors led the Commission to decide not to undertake an audit on the businesses' asset bases and valuations to ascertain whether there is gold-plating.

Normal Returns

5.25 Underlying allocatively efficient pricing is an understanding that businesses in competitive markets will earn normal returns on average over time. The Commission considers that normal returns means returns achieved in competitive markets which are commensurate with the risks faced. The weighted average cost of capital (WACC)[69] is used for the purpose of determining the risks faced by businesses and the commensurate returns in percentage terms. The WACC is then applied to an appropriate asset base to determine normal returns in dollar terms. The calculation of WACC is discussed in Chapter 9 (Weighted Average Cost of Capital).

5.26 In competitive markets, any returns in excess of (or less than) normal could reflect superior (or inferior) performance. In markets where competition is limited, it can be difficult to distinguish superior performance from monopoly (excess) returns, because of the lack of an appropriate comparator.

5.27 The Commission's assessment approach is based on the assumption that on average (over time) only normal returns will be earned by businesses that operate efficiently. In the absence of an assessment of whether a business is a superior performer, any above normal returns are judged to represent excess returns. Similarly, any below normal returns (not resulting from inferior performance) are offset against any excess returns over the Commission's assessment period. The Commission considers this approach reasonable, and a necessary compromise to be able to conduct its assessments.

<u>Assessing Normal Returns Over Time</u>

5.28 Normal returns need to be assessed over a period of time, so that singular events do not bias the results and thereby unduly influence the Commission's recommendations. However, assessing returns over time can be a difficult issue.

5.29 A particular problem with assessing returns over time is the treatment of revaluation gains/losses on assets.[70] Over the life of an asset it is possible to

[69] The Commission's methodology for determining the weighted average cost of capital for gas pipeline businesses is covered in Chapter 9 (Weighted Average Cost of Capital) of this report.
[70] Note that a revaluation loss here means a reduction in asset values due to changes in replacement costs. This is distinguished from reductions in asset values to correct for gold-plating or imprudent

apply a principle such that the returns discounted by an appropriate WACC earned on the asset over its life should equal the initial investment amount. This is referred to as the NPV=0 principle and is a principle the Commission has adopted for the purposes of this Inquiry.

5.30 However, applying the NPV=0 principle for assets that are part way through their useful lives can be difficult, given that businesses may adopt a variety of different time profiles for the recovery of capital costs while still achieving NPV=0. Ideally the Commission would assess returns against each business's chosen recovery path. However, these are usually unknown. To overcome any potential problems with this, the Commission has examined as long a period as possible, and made adjustments for any significant changes by the businesses in approach (e.g., significant changes in depreciation method) when applying the NPV=0 principle.[71]

5.31 In principle, two approaches the Commission could use for applying the NPV=0 principle are :

- using an historic cost asset base and multiplying this by a nominal WACC (historic cost approach); or
- using a replacement cost asset base (e.g., ODV or ODRC) and multiplying this by a nominal WACC, and then subtracting any revaluation gains/losses on the assets (the spreading revaluations approach) .[72]

5.32 The equivalence of the two approaches in theory was discussed during the Commission's review of asset valuation methodologies (the review).[73] The lack of historic cost data, however, makes assessments based on the historic cost of assets impractical in the present circumstances. Accordingly, the Commission has used the replacement cost asset base used by the gas pipeline businesses together with a nominal WACC and spread asset revaluation gains/losses over the years between formal revaluations.[74] Only in the case of Wanganui Gas is a historic cost approach adopted as a sensitivity test to the results under the spreading revaluations approach. Asset valuation data issues are explained further in Chapter 8 (Asset Valuation).

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investments, which should not be compensated. These distinctions are discussed further in Chapter 8 (Asset Valuation).

[71] The potential problems of conducting an analysis of an asset part way through its life may also be reduced by the fact that the gas pipeline businesses hold a variety of assets with different ages, so that on average any effects could offset each other. However, some construction would be concentrated during particular short periods in the past and hence the ages of some groups of assets would be related.

[72] A business can benefit from revaluation gains on assets if these can be reflected in prices and thereby in cash flows.

[73] Commerce Commission, *Review of Asset Valuation Methodologies: Electricity Lines Businesses' System Fixed Assets, Discussion Paper*, 1 October 2002. Achieving consistency of analysis using historic cost and replacement cost valuation methods was also discussed in the Commission's *Airports Inquiry: Final Report,* 1 August 2002, pp121-122.

[74] If a revaluation gain were attributed solely to the year in which it was recorded, yet relates to a number of preceding years, then returns in the year in which it is recorded would look overstated, while in other years, returns would look understated. Over- or under-statement of returns as a result of revaluation gains appears to have been an issue with the Return on Investments (ROIs) calculated under the information disclosure requirements for both electricity and gas networks in New Zealand.

5.33 Additional approaches, such as using a replacement cost asset base and multiplying this by a real WACC (the real WACC approach), or using an indexed historic cost asset base with a real WACC, were also discussed in the review. [75] Using an indexed historic cost asset base with a nominal WACC and treating revaluation gains as income is another option.

5.34 In Australia, the equivalence of different approaches in theory has been noted by the ACCC and IPART.[76] The ACCC has accordingly adopted the spreading revaluations approach for its revenue cap decisions for electricity transmission networks,[77] and a real WACC approach in reference-tariff decisions under the gas access regime for transmission businesses.[78]

5.35 Submissions made the point that a strict NPV=0 approach could never be applied in practice as any analysis would always be conducted part way through the asset's life. The Commission recognises this above and notes that its NPV=0 principle is not intended to provide a strict application of an NPV=0 approach. Rather, it is a useful principle in deciding how to deal with particular issues in a consistent manner and in a manner that moves the outcomes closer to, rather than further away from a NPV=0 approach.

5.36 The Commission notes that depreciation profiles will be important for applying the NPV=0 principle. There is no inherently efficient depreciation profile for this purpose, although with sufficient information on other factors, such as consumer preferences, it may be possible to infer an efficient price path and therefore a depreciation profile to encourage the achievement of such a price path. Defining an efficient depreciation profile is, however, more an issue for how control would operate than for assessing whether control should be recommended. What is likely to be more relevant is whether a business has changed its depreciation approach, as this can lead to over- or under-recovery. Therefore, consistency in the depreciation approach is of primary concern for the Commission in conducting its assessments. Where there have been changes in depreciation approach, the Commission may have to make appropriate adjustments for these.

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[75]Lally, M., *Review of Asset Valuation Methodologies: Electricity Lines Businesses' System Fixed Assets, Discussion Paper*, 1 October 2002, p 38. Dr Lally also explains the theoretical equivalence and practical issues of the different approaches in his advice. See Lally, M., *The Weighted Average Cost of Capital for Gas Pipeline Businesses*, 5 November 2004.

[76] See for example, ACCC, *Final Decision, Access Arrangement by Transmission Pipelines Australia Pty Ltd*, 6 October 1998, pp 24-25. IPART, *Weighted Average Cost of Capital Discussion Paper*, August 2002, pp 1-2 & 5-6. In the United Kingdom a similar equivalence is noted by Whittington, G., Current Cost Accounting: Its Role in Regulated Utilities, *Fiscal Studies*, vol.15, no.4, 1994, pp 88-101.

[77] The ACCC in its revenue cap decisions for electricity transmission networks, typically expresses both WACC and the asset base in nominal terms, and treats the expected revaluation gains on assets as an adjustment to depreciation (a negative depreciation charge), which is equivalent to treating the revaluation gains as income as the Commission has done under this approach.

[78] See for example, ACCC, *Final Decision, Access Arrangement by Transmission Pipelines Australia Pty Ltd*, 6 October 1998. The Queensland regulatory authority also adopted this approach for its revenue cap decision for Powerlink (a Queensland electricity transmission network) in 2000.

Optimisation

5.37 Capital efficiency can also be an important factor in determining allocative efficiency, normal returns and dynamic efficiency.[79]

5.38 Capital efficiency adjustments can be made for three reasons, namely for:

- gold-plating or imprudent investment; or
- reduced use of assets (stranding or optimisation) due to by-pass competition, uneconomic lines, demand decreases, or changes in technology that leave excess capacity.

5.39 It would not be efficient to reward a business for gold-plating or imprudent investments. Therefore, the Commission does not consider a return should be allowed on the gold-plating element of any investment. As stated earlier, the Commission decided not to undertake an audit to ascertain whether asset values are efficient as part of this Inquiry. Consequently, the Commission does not attempt to identify the separate capital efficiency components within each of the gas pipeline businesses optimisation amounts, although it notes that any optimisation may reflect either or both types of capital efficiency adjustment.

5.40 However, for assets that become stranded simply due to a fall in demand or other factors outside the businesses' control, an NPV=0 approach necessarily requires either an ex-post or ex-ante compensation. The Commission's preferred approach for any compensation is described in Chapter 6 (Assessment Approach).

Capital Contributions

5.41 Capital contributions from customers are treated as income in the calculation of the businesses' returns (as to do otherwise would mean customers essentially paying twice for the assets they have contributed to) and the assets are included in the regulatory asset base. Capital contributions generally take two forms, namely cash contributions and gifted assets. In the case of cash contributions the customer provides a contribution of cash for connection but the gas pipeline business undertakes the construction. In other cases, such as during the creation of subdivisions, the subdivider constructs the final length of pipe and connections, and then gifts these assets to the pipeline businesses.

5.42 Evidence provided by the gas pipeline businesses suggests most treat capital contributions from customers appropriately as income.

Gain on Sale of Assets

5.43 The treatment of the gain on the sale of network assets has arisen with the sale of some pipeline assets by NGC Distribution in 1999. NGC argued in submissions that the gain on sale should be ignored given that the asset enters the purchaser's regulatory asset base at ODV rather than transaction value (i.e., the purchaser's loss was matched by the seller's gain to give NPV=0) and the

[79] Capital efficiency is a broad term used to discuss capital efficiency issues. It covers such issues as optimisation, prudency tests, and used and useful tests. Capital efficiency was discussed in the Commission's review of asset valuation methodologies for electricity lines businesses, Commerce Commission (1 October 2002).

assets stayed within the industry. The Commission concurs with NGC's submissions, and does not treat the gain on the sale of NGC Distribution assets as income within the analysis period.

Productive Efficiency

5.44 Productive efficiency means meeting demand at the lowest possible costs, including minimising transaction costs. In the short-run, this involves choosing and making best use of the appropriate level of variable inputs. Over time, it involves making appropriate investment choices that ensure that costs can continue to be minimised.

5.45 In evaluating whether costs are efficient, it is important to assess whether firms can further reduce costs. This evaluation could be done by considering the mechanisms and incentives that may operate to encourage cost minimisation. Competition forces firms to minimise costs, subject to consumers' quality demands, or risk losing customers to other providers. However, where competition is lacking, other factors would have to be considered to determine whether sufficient incentives for cost minimisation remain.

5.46 A producer who faces limited competition in a market may lack the competitive pressures to remain efficient in production. Organisational slack may creep into its operations, bureaucracy may expand, principal-agent problems (agency problems) may arise, salaries may become inflated, and waste may occur, all because a satisfactory level of profit is assured even when the business is less than fully efficient. Further, rent seeking behaviour may be undertaken to maintain (or gain) a monopoly position. As a result, costs in general may increase. The increase in costs is a measure of the value of resources used unproductively, which in turn indicates the value of the output foregone by the economy as a whole from those resources not being employed more productively and efficiently elsewhere.

5.47 Agency problems may be constrained by shareholders and their boards using a number of options. Options include the use of external benchmarking of the businesses' performance, the use of outside directors and the use of incentive schemes for managers. The threat of takeover (market for managers) provides a further external constraint.

5.48 The Commission considers that for the purposes of the present Inquiry, costs would ideally be benchmarked in various ways to determine the true strength of the incentives facing businesses to be productively efficient and whether cost minimisation has been achieved. Benchmarking has its own difficulties, however, and a judgement on the results of such exercises would need to be made.

Dynamic Efficiency

5.49 Dynamic efficiency means maintaining allocative and productive efficiency over time. In practice, this means making investments and innovating so that costs continue to be minimised and prices over time generally reflect this.

5.50 For industries where new and improved products and production processes could be expected to be introduced relatively frequently, dynamic efficiency is largely about ensuring such improvements are introduced in a timely fashion.

5.51 For industries characterised by large long-term investments, and slow innovation in 'new and improved' products and production processes, dynamic efficiency is largely about appropriately managing new investment, particularly investment choices and the timing of investment. Determining appropriate costs over time requires considering whether current and prospective investments are necessary. Over- or under-investment should be avoided. In practice, evaluating dynamic efficiency precisely in quantitative terms is difficult. The Commission may have to make judgements on the prudency of existing, or proposed, investments as part of its assessments. In this inquiry the Commission has assumed all investments are prudent.

5.52 Innovations are unlikely to be a significant issue for gas conveyance activities, although incremental improvements may still be expected over time, such as in product offerings. Investment planning by gas pipeline businesses represents the key criteria in evaluating their dynamic efficiency. Given the large, sunk, long-lived investments associated with gas conveyance activities, and the fact that they often supply an input (gas) into other industries, their investment behaviour is of critical importance. Over- or under-investment will have direct implications for the stability and capacity/congestion of gas pipelines.

5.53 While congestion is generally considered not to be a problem currently by the industry, new investment may be necessary to service new areas. A possible offset to the need for new investment is the fact that gas supplies are currently in decline, and may not be sufficient to meet any expansion over time. The possibility of reducing supplies of gas is already indicated by the rising wholesale price of gas. As a result, there is significant uncertainty over the general level of future investment needs.

Generic Pricing Principles and Efficiency Assessments

5.54 Given the above considerations, the Commission considers the following generic pricing principles are suitable for determining efficient prices and evaluating supplier performance:

- allocatively efficient prices should be aimed for over time. Allocatively efficient prices are prices which track the marginal costs incurred in meeting demand. When there are fixed or common costs, businesses should adopt, to the extent possible, appropriate demand differentiated pricing policies;
- normal returns should be earned over time. These are calculated on an appropriately determined asset base and suitable rate of return, and cover efficient operating costs, and no more;
- productive efficiency should be maintained over time. This requires the adoption of least cost production practices; and
- dynamic efficiency should be maintained over time. This requires that over- or under-investment be avoided.

5.55 The above principles should not be seen as being independent, but rather as inter-related considerations for evaluating efficiency.

5.56 Prices, costs and returns can be susceptible to short-term fluctuations in market conditions. The principles above are expressed 'over time', so that such short-term fluctuations do not distort judgements on whether prices are efficient, returns are at a normal level and suppliers have been behaving efficiently. However, long-term fluctuations or changes that were not predicted at the time of investment could still occur. Thus, any assessment of efficient prices and returns requires the exercise of judgment.

5.57 The Commission considers that both the level of prices and the structure of prices are relevant to the efficiency of prices. However, the quantitative analysis in Chapter 6 (Assessment Approach) solely focuses on the efficient level of average prices and normal returns. It is assumed that businesses will have sufficient incentive to implement efficient pricing structures.

5.58 In considering the efficient price level and normal returns the Commission will give particular regard to the NPV=0 principle. That is, the Commission proposes to consider current and prospective future prices in the context of past prices, while taking account of the possibility that past prices may reflect above- or below-normal returns.

Conclusion

5.59 The Commission considers that the generic pricing principles set out above are appropriate for gas pipeline businesses. There are certain characteristics of gas pipeline businesses that require careful consideration in seeking to apply the principles, but they nonetheless provide a benchmark against which the Commission can determine the extent of inefficiency and/or excess returns of the gas pipeline businesses assessed in this Report.

6 ASSESSMENT APPROACH

Introduction

6.1 Section 52(b) of the Commerce Act requires the Commission to assess whether control is necessary or desirable in the interests of acquirers. The Commission terms this the net acquirers benefit test (NAB test). In applying this test the Commission must assess the net benefits to acquirers of control (the factual) relative to the situation with no control (the counterfactual). The benefits to acquirers of control broadly emerge from reducing any excess returns or inefficiencies associated with the counterfactual less any costs of control.

6.2 The Minister's terms of reference also require the Commission to undertake a net public benefits assessment. In practice, the net acquirers benefit test includes most of the efficiency effects captured in the net public benefits test. The substantive difference between the NAB and net public benefits assessment is that the net public benefits assessment disregards the transfer of income from suppliers to acquirers resulting from a reduction in excess returns. The NAB treats the reduction of excess returns as a benefit to acquirers.

6.3 This chapter presents the models used to assess the outcomes under both the factual and counterfactual, which provide the basis for the Commission's recommendations. These models draw on Chapter 5 (Assessment Principles for Efficient Pricing) and the framework presented in Chapter 4 (Overview of Assessment Approach). The chapter begins by considering the potential benefits of control, then considers the potential costs of control. The final section considers specific aspects of the Commission's modelling.

Potential Benefits of Control

Introduction

6.4 As noted above, the Commission's approach involves considering the potential benefits of control separately from the potential costs. This approach is adopted for clarity of exposition.

6.5 The sources of potential benefits of control include:

- excess returns being reduced by control, with the resulting transfer of wealth from suppliers to acquirers (being a net benefit to acquirers);
- allocative inefficiency being reduced by control. Inefficient levels of service quality for the price charged could also be addressed through control;
- productive inefficiency being reduced by control; and
- dynamic inefficiency being reduced by control, because of better utilisation/allocation of resources, better investment incentives or continued/improved availability of services over time.

Model of Potential Benefits from Control

6.6 The Commission has developed models to assist in the quantification of the benefits of control and to test their sensitivity to key variables. Figure 6.1 provides a stylised presentation of the Commission's main building blocks model that was used to quantify the possible allocative inefficiencies and excess returns that could arise in the counterfactual. Appendix A contains the specific variables and formulae used in the model.

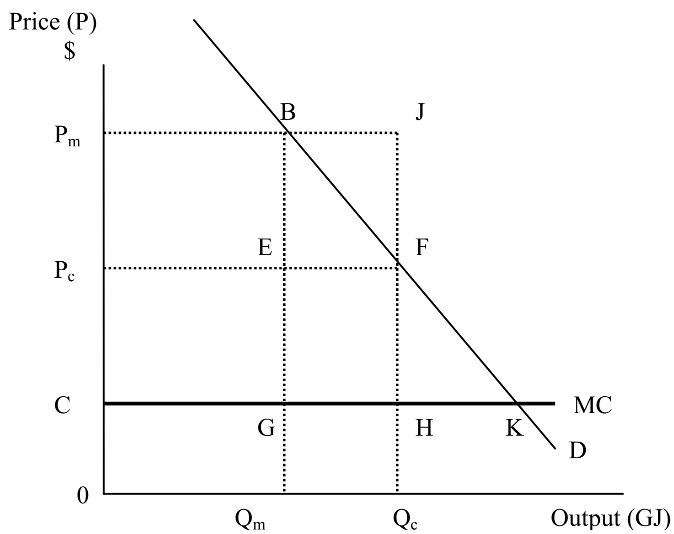
6.7 The Commission's model has adopted a long-run perspective to efficient pricing. The key distinction between a short-run and long-run perspective is that in the long-run all of the business's costs are variable, whereas in the short-run some of its costs are fixed. This means that in the long-run a business can adjust the scale of its operations to match demand by investing or disinvesting in capital.

6.8 What follows is an explanation of the model, and of the differences between a short-run and long-run perspective on pricing, using a standard economic framework.

6.9 Figure 6.1 shows a market demand curve (D), which is assumed to be linear for simplicity. Gas pipeline output (Q) is represented by gas conveyed in gigajoules (GJ),[80] while prices (P) are measured on a per GJ basis. A distinction is made between the actual price (P_m) and quantities (Q_m) a business supplies, and the efficient price (P_c) and quantities (Q_c) that the Commission may determine. Inefficient or excessive average pricing would be reflected in the price charged being raised above the efficient level (i.e. $P_m>P_c$) and consumption (output) being lower than the efficient level (i.e. $Q_m<Q_c$), as represented in Figure 6.1.

[80] The Commission notes that this is a simplification of the outputs that are produced by the gas pipeline businesses. The benchmarking work uses gas conveyed and customer numbers as output measures. While the choice of output variable may affect the results of the benchmarking work, it does not affect the aggregate allocative inefficiencies measured by the building block model, as the output variable is merely a scalar in this model.

Figure 6.1: Assessing Possible Allocative Inefficiency in the Gas Pipeline Services Markets



6.10 In the short-run the total costs of gas services are largely fixed in nature, resulting in marginal costs (MC) being generally very low, particularly where excess capacity exists. As discussed in the previous chapter, if allocative inefficiency were measured with regard to short-run MC at D = MC (at point K in Figure 6.1), the business in question would not be able to earn enough to cover its fixed costs. This in turn would jeopardise capital replacement in the long-run. Hence, the efficient price might be set at the higher point P_c where the downward-sloping average cost (AC) curve (not shown) cuts the D curve at point F. While not maximising allocative efficiency in the short-run, this would give the lowest single price that would cover the firm's costs.

6.11 If the business in question were actually charging a price in excess of P_c at P_m, the reduction in consumption (output) from Q_c to Q_m would represent a socially inefficient loss of consumption (output). Consumers would value that output at BFQ_cQ_m, whilst the inputs saved would be GHQ_cQ_m, resulting in a net (deadweight) loss of BFHG. Of this, EFHG would be lost producer surplus, and BFE would be lost consumer surplus. In addition, there would be a transfer from consumers to suppliers represented by P_mBEP_c.

The Long-run Perspective: The Commission's Approach

6.12 The difficulty with the above characterisation of the issue of excessive pricing is that it is based on short-run MC and AC. However, a key concern, as reflected in the Commission's decision that P_c>MC (in contradiction to the efficiency rule of P_c=MC) should apply even in the short-run, is with the long-run issue of capital replacement.

6.13 The short-run framework can be explicitly adapted to represent a long-run perspective, by assuming for simplicity that long-run MC (LRMC) is constant and lies along P_cEF.[81] Allocative efficiency would be achieved at the price P_c

[81] Under certain assumptions LRMC exceeds SRMC, because in the long-run all costs are variable, including those that are fixed in the short-run and hence are not part of SRMC. The assumption that

and output Q_c as under the short-run presentation, but this time it would be where P_c=LRMC=LRAC, so that all costs (including a normal return) would be recovered.

6.14 Viewed with this long-run perspective, the elevation of price from P_c to P_m would result in the following welfare effects:

- a loss of consumer surplus (a deadweight allocative efficiency loss) of BFE; and
- a transfer of surplus (excess returns) to the supplier from consumers, depicted by area P_cP_mBE, which in efficiency terms is assumed to be neutral, since one party gains at the expense of the other.

6.15 The Commission has adopted this long-run approach. Hence, the benefits of control from reducing prices from P_m to P_c would be a gain in allocative efficiency in the gas services market, represented by the area BFE. Control could also reduce the excess returns (area P_cP_mBE) obtained by suppliers. The model used by the Commission measures these two areas.

6.16 CRA, on behalf of NGC, note that using a long-run model implies that NGC is capacity constrained or that if demand were to fall, NGC could save on capital costs, which is not the case. They suggest that a short-run model be used, even though it would result in increased estimates of the benefits of control.

6.17 The Commission notes that its approach is a simplification of a complex reality. However, it believes that its approach best signals its view that businesses should be allowed to earn a return on sunk assets to ensure that incentives to invest in sunk assets are not undermined. Therefore, this decision is to the advantage of the businesses.

Potential Benefits of Control

Excess Returns

6.18 In this Inquiry the level of any excess returns has been the key driver as to whether net benefits to acquirers are found. In Figure 6.1 it is clear that for any given margin of P_m over P_c, the rectangle P_mBEP_c will always be much larger than triangle BFE if excess returns and efficiency effects are given the same weighting.

6.19 Any excess returns are measured as the difference between what the gas pipeline business is currently earning and what the Commission considers is a normal return for such a business. The calculation can be expressed mathematically as:

Excess returns = Net Earnings – (Asset base x WACC).

LRMC is constant ensures that LRMC=LRAC. This analysis assumes for simplicity that the LRAC curve is actually horizontal, rather than (perhaps more realistically) downward sloping, in the range between points E and F. In any case, given the price inelastic demand curve, the output difference between the two points is unlikely to be significant, so that the average costs at those two points are likewise not expected to differ significantly.

6.20 Net earnings equal the earnings before interest of the gas pipeline businesses less tax, depreciation and operating expenses plus any revaluation gains/losses and any capital contributions from customers. Net earnings can be calculated on an actual or forecast basis. Any proposed price changes over the forecast period that the Commission is aware of have been included in the modelling.

6.21 The calculation of any revaluation gain/loss is necessary where the analysis involves using a replacement cost valuation methodology and a nominal WACC. The replacement costs of the gas network have generally been increasing, and at a rate comparable to or exceeding the rate of inflation. This means that revaluation gains, as opposed to losses, are anticipated in the future. The Commission has assumed that assets will revalue in line with inflation. Where the businesses have forecast revaluation gains below CPI, the Commission has included this differential as additional revaluation gains. It has also allowed these additional revaluation gains to be offset by the businesses' forecasts of future optimisation, and higher incremental depreciation charges and allowed revenues.

6.22 Where revaluations are only done periodically (e.g. every three years), the revaluation gain calculated is spread back over the period to which it relates, and the asset base is also smoothed. These adjustments provide results as if revaluations were done every year, rather than periodically, and effectively smooth out any spikes in returns that could result from periodic revaluations. There are various ways the spreading could be implemented. For simplicity, the revaluation gains are evenly apportioned over the relevant years in the model (without discounting).

6.23 It would not be efficient to reward a business for gold-plating or imprudent investments. The Commission considers a return should not be allowed on gold-plating. As noted in the Chapter 5 (Assessment Principles for Efficient Pricing), the Commission does not have evidence of gold plating, and has not undertaken detailed analysis of this issue.

6.24 For assets that are optimised or have become stranded but not as a result of gold plating, the application of the NPV=0 approach necessarily requires either ex-post or ex-ante compensation. Where compensation is deemed appropriate, the Commission's preference has been to treat changes in the level of optimisation and economic value adjustments on an ex-post basis as income (e.g. any increases in the level of optimisation or economic value adjustment have been treated as a negative income and therefore result in a credit to the businesses within the Commission's model).

6.25 The Commission is satisfied that where actual optimisations and strandings are approximately in line with expectations, and where overall these events are relatively modest, there is likely to be little difference between an ex-ante and an ex-post approach. In these circumstances, the ex-post approach is preferred because of its relative simplicity. This is the approach that has been taken by the Commission for the distribution businesses and NGCT in most circumstances. The Commission's treatment of the reoptimisation of Kapuni North, which is a somewhat atypical event, is discussed in NGCT's chapter.

6.26 The WACC and asset base figures are those determined by the Commission. The asset base used is the 'beginning year' (i.e. as at the start of the business's nominated financial year). Given that capital contributions are treated as income, the assets that are built (with capital contributions) or gifted are included in the asset base. The WACC and asset bases used in the model are discussed in the Asset Valuation and WACC chapters (Chapters 8 and 9 respectively), as well as in the business-specific chapters.

Allocative Inefficiency

6.27 The level of the allocative inefficiencies calculated using the model above is driven largely by the degree to which price exceeds average costs (which include a normal return), and the price elasticity of demand for pipeline services between points B and F.

6.28 The price elasticity of demand for gas pipeline services is generally expected to be small due to the service (or the product consumed in complement with it) being an essential service (necessity), and because of its being an intermediate input and comprising only a fraction of the total cost (i.e. retail, distribution, transmission and production of gas) of delivered gas. Demand in such cases tends to be very inelastic, suggesting *a priori* that allocative inefficiencies measured by BFE will be small.

6.29 The Commission assumes an elasticity of -0.3 for the gas services provided by each of the gas distribution businesses, and -0.1 for transmission. This elasticity is considered to be a long-run estimate, and the model therefore includes any spillover effects to other industries.[82] The basis for the elasticity estimates is discussed in more detail in Chapter 3 (Competition Analysis).

6.30 The allocative inefficiencies estimated using the Commission's model are relatively small. These figures may be further reduced by recognising that an unregulated profit-maximising business may have incentives to establish an efficient structure of prices based on demand differentiated pricing principles. The gas pipeline businesses appear to apply certain demand differentiated pricing approaches, which suggests that the allocative inefficiencies estimated by this model, even though they are small, may still be somewhat overstated. The impact of this is likely to be modest, particularly since the Commission's analysis is based on long-run analysis.

6.31 The business-specific chapters provide the allocative inefficiencies quantified for each business.

Productive Efficiency

6.32 A productively efficient business is one that meets demand at the lowest possible cost. An unregulated profit-maximising business generally has strong incentives for cost efficiency since all the benefits of cost reduction are

[82] For example, where gas is used as an input into production in another sector, higher prices could cause a reduction in that sector's consumption over time, and therefore the output of that sector. Initially, the margin on outputs in these other sectors would allow the business to absorb a price rise in input costs, but if these markets are competitive, it is likely that they would look to alternative sources of supply over time.

retained by the business and translate into increased profits. However, if competition is lacking, agency and rent-seeking problems may emerge.

6.33 Internationally, incentive regulation (e.g. CPI-X regulation) has been introduced to try and encourage businesses to make productivity improvements, while allowing businesses to retain for some period any savings greater than those the regulator believes them capable of achieving (as indicated by the size of the X factor).[83] If an X is established by a regulator that is 'too ambitious', then to meet the costs savings target, the business may have to reduce service quality or be faced with a below normal return (assuming it was at a normal level to start with).

6.34 In the case of assessments under Part IV of the Commerce Act the Commission is concerned with the general level of productive efficiency of the gas pipeline businesses, rather than the specific mechanisms that may encourage this over time.

6.35 The Commission engaged Meyrick and Associates to undertake a comparative benchmarking study of gas pipeline businesses' costs. The results of this study are presented and discussed in the Chapter 11 (Comparative Benchmarking). As explained in that chapter, the lack of data has limited the conclusions that can be drawn from this study. As a result, the Commission is not in a position to form a strong view on the productive efficiencies of the individual gas pipeline businesses.

6.36 To obtain an indication of the order of magnitude of possible efficiency gains for the overall industry, the Commission asked Meyrick & Associates to examine the productivity growth for NGCD (selected because of the availability of information over the period 1996-2008) as an indicator of productivity growth of the industry as a whole. [

]

6.37 The Commission also considered the approach for setting the relative productivity component (C1 factor) in the Commission's electricity thresholds regime. In the electricity threshold regime businesses achieving low productivity levels are assigned a positive C1 factor of 1%.

6.38 Submissions were received on the Draft Report that questioned the level of benefits that control would generate in terms of productive efficiency. The gas businesses argued that control would reduce the incentives to make costs savings thereby creating net productive inefficiencies, or at best be neutral in their effect.

6.39 PEG presented an econometric analysis of the productive efficiency of Vector and Powerco. Using cost data for 40 US gas distribution utilities over 1997-

[83] Whether the X factor actually creates the efficiency incentive (e.g., by encouraging businesses to 'look again' at their costs, or by encouraging businesses to set more ambitious cost reduction targets, thereby reducing agency problems), or is a sharing mechanism, is perhaps a moot point, as the ultimate outcome is the encouragement of productive efficiency.

2002, PEG developed an econometric cost model, which was used to predict the costs of NGCD and Vector, given the business conditions that they faced. This analysis indicated that NGCD's and Vector's total costs were 30% and 21% below the predicted values (i.e. they were more cost efficient than predicted). These results were statistically significant, leading PEG to conclude that both businesses were superior cost performers, relative to US gas distribution businesses.

6.40 The Commission notes that data problems are a major limitation to forming robust conclusions as to the scope for control to improve the productive efficiency of the gas businesses. It observes also that the reports by the Commission's and NGCD/Vector's experts provided conflicting evidence as to the efficiency of the businesses. The Commission's judgment, nevertheless, is that control would result in businesses achieving modest improvements in productive efficiency. Given uncertainty about the quality and limits on the quantity of data, the Commission has made a reduction in its assessment of the potential productive efficiency benefits that might be achieved through control compared with the Draft Report. It considers that regulation could result in all businesses achieving productivity improvements of 2.5% of operating costs (reduced from 3.0%) or 0.83% (reduced from 1.0%) of total costs above the trend rate of improvement.[84]

6.41 Total costs are used to be consistent with the Commission's long-run model.[85] In a long-run model the business does have some control over its fixed costs and productive efficiencies are therefore measured against total costs.

Dynamic Efficiency

6.42 In general, the Commission did not identify any major dynamic inefficiencies with regard to gas pipeline businesses' investments and no evidence was presented of over- or under- investment that could be corrected through regulation. The Commission notes that a more competitive open access regime may have benefits and that Government and industry initiatives are in train to address access issues. No weight is therefore given to these potential benefits in the Commission's framework since these potential benefits are implicitly included in both the factual and the counterfactual.

Costs of Control

6.43 The costs of control can be broken down into two types: direct and indirect costs. The definition of these terms, and the methods used to calculate them, are explained below.

6.44 The Commission has taken the position that the costs of control would generally ultimately fall on acquirers.[86] Therefore costs of control are not

[84]This percentage accumulates marginally by an increment of the previous year's savings. For example, the benefits in year 1 are 0.83%, in year 2 they are 0.8369% (i.e., 0.83*(1+0.83)), and so on. The costs are accumulated in a similar way, see below.

[85] During the Airports Inquiry the Commission used a medium-run model, where the fixed costs were assumed to be uncontrollable by the businesses and productive inefficiencies were measured relative to operating expenses.

generally excluded from the analysis merely because they may not 'immediately' fall on acquirers.

Direct Costs

Introduction

6.45 In general, the direct costs of control are of two kinds: those that fall on market participants (compliance costs), and those borne by the regulator (regulator's costs). The direct costs of control are those that would be additional to costs of the existing regulatory regime. The existing regime gives rise to direct costs in terms of the disclosure obligations on gas pipeline businesses, and through the threat of control, which requires businesses to participate in inquiries such as this. Were control to be introduced, clearly the threat of control would cease, as would the costs associated with it. But disclosure requirements would likely continue (perhaps in a more detailed form) and costs associated with determining the form of control, and the actual control regime, would be incurred. It is the net change in these costs overall that is relevant to determining the costs of control.

6.46 The Commission considers that an inquiry into the form of control would be required prior to any control regime being established. The costs resulting from such an inquiry would be one-off costs incurred prior to the start of the control regime. The Commission has used the costs of this Inquiry and the costs of designing the electricity thresholds regime as the basis for estimating the one-off costs associated with determining the form of control.

6.47 For this Inquiry the Commission has assumed that the costs of a form of price cap regulation are indicative of the costs associated with a control regime. Under price cap regulation the direct costs of control for all parties occur largely at the time of price reviews and price-resetting. At these times, the costs may be substantial. At other times, the regulatory body largely has a monitoring role, while the regulated entity must ensure that compliance is maintained. Users may also engage in monitoring activity. The intention of price cap regulation is that price reviews are conducted infrequently, and at pre-set intervals. For the purposes of calculating the direct costs associated with the control regime the Commission has assumed one review year and four non-review years in a control cycle.

6.48 This section continues by explaining how the Commission has estimated the two components of the direct costs. At the end of the section the compliance and the regulator's costs are combined to present the total direct costs for each business.

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[86] The exception is the producer surplus forgone in the 'missing market' which is included only in the NPB test, and a small producer surplus impact when prices fall below the competitive level. The reasons for this approach are discussed in more detail in the dynamic inefficiency from control section.

Compliance Costs

6.49 Gas pipeline businesses have indicated that they draw on both internal and external resources to support their position presented at regulatory reviews, or inquiries such as this.[87]

6.50 The Commission sought submissions on compliance costs of control under the existing regulatory regime in its Draft Framework Paper, in a s 70E notice to gas pipeline businesses and in submissions on the Draft Report. Though a few submissions to the Draft Framework Paper were received by the Commission, they were of a very general nature and gave little detail about the specific costs faced by the market participants. The s 70E responses, in contrast, provided business-specific data, and are therefore used as the primary basis for the compliance cost estimates. Further information was provided in submissions on the Draft Report.

6.51 To determine the compliance costs for each business the Commission has estimated the costs of determining the form of control, the costs of the control regime for a review year and the costs of the control regime for a non-review year.

6.52 The Commission based the estimates of the costs of the control regime for a review year on the increase in disclosure costs incurred in complying with a post control disclosure regime, the costs of participating in the review year consultation process and the legal costs associated with contesting the regulator's determination.

6.53 The Commission based the estimate of the one-off costs associated with determining the form of control on the costs of this Inquiry. The costs for a non-review year are considered to consist of the increase in disclosure costs as above and the costs of complying with the control regime requirements. In the Draft Report, the Commission assumed that the non-review year control regime requirements would be 30% of the costs of this Inquiry.

6.54 In order to determine annual average direct costs of control the estimated one-off form of control costs have been spread over the Commission's analysis period. The Inquiry costs were removed from the businesses' expenses in the modelling, as applying the costs of control in addition to these costs would involve double-counting.

6.55 The Commission took into account the observation that a smaller business such as Wanganui Gas was likely to incur lower costs, but recognised that a significant portion of the costs would be fixed, with a higher detrimental affect upon smaller regulated entities.[88]

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[87] Powerco Limited, *Submission to Commerce Commission on Gas Control Inquiry Draft Framework Paper*, August 2003, pp 45-46.

[88] Wanganui Gas Limited, *Submission on the Draft Framework Paper for Gas Control Inquiry*, August 2003, pp 7-8.

6.56 The Commission concluded in the Draft Report that Wanganui Gas would incur annual compliance costs in the order of $128,000, with the other businesses incurring costs in the order of $249,000.

6.57 NGC and CRA (on behalf of NGC) suggested that the Commission had substantially underestimated the compliance costs while Vector suggested that the Commission had underestimated both the compliance and regulator's costs. The Commission notes that businesses are likely to collect much of the information noted below by CRA for management purposes in the absence of control, although it accepts that control would increase costs.

6.58 CRA on behalf of NGC stated:

> We also consider that using the current inquiry costs as evidence of the costs of price cap control is inappropriate. The level of detail involved in a control inquiry pales into insignificance relative to price cap regulation. To suggest that NGC's costs of compiling expert reports on forecast investments, demand, costs, inflation, cost of capital, etc, from engineers, economists and accountants not to mention drafting of substantial submissions, appearing at Commission conferences and procuring legal advice, would amount to $400,000 is simply not realistic.
>
> NGC inform us that AGL, its major shareholder, spends around $AU4 million in a review year for its regulated Australian pipeline businesses. While there is a scale difference between AGL and NGC, regulatory costs are not likely to be affected much by scale economies - the costs of preparing a demand forecast, for example, would be little different regardless of the gas delivered or customers connected. Nevertheless, given that we have limited evidence on this, we adopt a conservative estimate. In variations to the Commission's model we assume that direct costs of $NZ1 million would be incurred by each of NGC's transmission and distribution business units in a price control review year, and adopt the Commission's assumptions for non-review year costs.

6.59 Vector stated:

> … Vector considers that the Commission's estimates of both compliance costs and regulator's costs from control are too low. A more detailed review of the costs involved in control would lead to higher estimates. Higher estimates would also be more consistent with the level of costs regulators in overseas jurisdictions incur in practice.

6.60 With respect to compliance costs, Vector suggested the Commission should include costs likely to result from the relative inexperience of the Commission and any regulated firms in determining the appropriate form of control. They suggest implementing a CPI-X regime would involve substantially more analysis of costs than the present inquiry. Setting the X factor, revision of the ODV Handbook and implementing detailed regulations were identified as key issues not currently considered by the Commission.

6.61 With respect to the regulator's costs, Vector suggest that these tend to rise steeply through time. They point to the total costs of Ofgem, IPART, and ESC as supporting this suggestion.

6.62 The Commission also reviewed the material contained in the Productivity Commission's review of the gas access regime in Australia, released on 11 June 2004.[89]

6.63 The Productivity Commission considered that compliance costs consisted of preparing access arrangements, responding to the regulator's information requirements, and preparing submissions to inquiries. While noting that the measurement of direct costs was difficult due to an absence of quality data, some of the participants to the Productivity Commission's inquiry provided estimates of the relevant costs. These suggested that compliance costs in a review year ranged between $A250,000 to $A2,500,000 depending on the size of the business.

6.64 Based on the businesses' submissions and the information from the Productivity Commission, the Commission has decided to revise its estimates of the likely compliance costs in review and non-review years.

Table 6.1: Revised Compliance Cost Information ($000 / 2004)

Business	Disclosure Costs	Review Year Costs	Non-Review Year Costs	Form of Control Costs+	Annual Average Compliance Costs++
Wanganui Gas	30	200	50	17	127
NGCT	50	750	150	35	355
NGCD	50	750	150	35	355
Powerco	50	750	150	35	355
Vector	50	750	150	35	355

+ Form of control Inquiry costs spread over ten-year analysis period.
++ Based on one review year and four non-review years in the control cycle, plus the disclosure costs and costs associated with determining the form of control.

6.65 The key change from the Draft Report is the review year compliance costs have been increased from $400,000 to $750,000 for NGCT, NGCD, Powerco and Vector. Wanganui Gas's review year costs remain unchanged. This adjustment brings the compliance costs for the major gas pipeline businesses into line with compliance costs in Australia. This increases the annual average compliance costs for NGCT, NGCD, Vector and Powerco from $249,000 to $355,000 per annum. The non-review year costs have also been increased for all of the businesses other than Wanganui Gas.

<u>The Regulator's Costs</u>

6.66 The Commission has used the costs of this Inquiry as the primary basis for determining the regulator's costs of control. It looked at several overseas examples of regulatory costs, but considers that the regulatory environment and businesses in those jurisdictions are significantly different to those in New Zealand.

6.67 The Commission's costs for this Inquiry are approximately $2 million exclusive of GST. Although the Inquiry was conducted over a two-year period,

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[89] Productivity Commission, *Review of the Gas Access Regime*, 11 June 2004.

the Commission has assumed that the $2 million would be spent in a single review year. These costs are indicative of the administrative costs of control in a review year under price cap regulation and the one-off costs incurred to determine the form of control. During the Inquiry the Commission has investigated seven businesses, with five of those businesses being included in the more detailed NAB test. The Commission therefore considers that the regulatory cost per gas pipeline business in a review year would be approximately $400,000 in 2004 dollars ($2 million divided by five businesses). The costs for a non-review year are taken as 30 per cent of the costs of a review year. The Commission considers that the annual regulatory cost per gas pipeline business to determine the form of control would be approximately $40,000 in 2004 dollars ($2 million divided by five businesses and the ten year analysis period). Assuming one review year and four non-review years in a control cycle, the annual average regulatory cost would be $216,000 per business i.e., (1 x (400 + 40) + 4 x (120 + 40))/5.

6.68 Vector submitted that the regulator's costs would be higher than this. However, the Commission believes that these estimates, presented below in Table 6.2 provide a reasonable estimate of the likely costs.

6.69 The figures presented in Table 6.2 are indicative of the annual regulatory costs of control for price cap regulation.

Table 6.2: Regulator's Costs ($000 / 2004)

Business	Review Year Costs	Non-Review Year Costs	Form of Control Costs	Annual Average Regulator's Costs
Wanganui Gas	400	120	40	216
NGCT	400	120	40	216
NGCD	400	120	40	216
Powerco	400	120	40	216
Vector	400	120	40	216

6.70 The Commission notes that the $216,000 annual regulatory cost assumed is a fixed amount for each gas pipeline business. Other things being equal, this gives a greater likelihood that NAB would not be found for relatively small businesses compared to large ones. While the costs to the regulator may vary to some degree according to the size of the regulated business, the Commission considers the difference is likely to be limited.

6.71 Although Vector provided some information suggesting that the regulator's costs are likely to increase over time, the Commission believes that the Inquiry costs provide a good basis for determining likely control costs.

6.72 In addition to the regulator's costs of $216,000 per annum, the Commission has estimated the costs of collecting the funds it may need to regulate gas pipeline businesses. According to Freebairn,[90] most studies of this issue put

[90] For a review of the literature see Freebairn, Reconsidering the Marginal Welfare Cost of Taxation, *The Economic Record*, vol. 71, June 1995, pp 121-131.

the marginal welfare cost of an extra dollar of taxation at 20 cents or more. The Commission considers that these costs could be minimised through alternative methods of collection such as industry levies, which incentivise parties to keep the costs of collection down. Nonetheless, for the purposes of this analysis, the Commission considers that each dollar of funds raised to support the regulator in carrying out control generates an additional 20 cents of cost to the wider economy. The additional collection costs increase the annual average regulatory cost to $259,000 per business.

Direct Costs of Control Used in the Inquiry

6.73 The direct costs of control (being the sum of the compliance and regulator's costs) for each business used within the Commission's model are presented in Table 6.3.

Table 6.3: Annual Average Direct Costs ($000 / 2004)

Business	Compliance Costs	Regulator's Costs	Total Direct Costs
Wanganui Gas	127	259	386
NGCT	355	259	614
NGCD	355	259	614
Powerco	355	259	614
Vector	355	259	614

Adjustment for Inflation

6.74 In the Commission's model the direct costs of control figure for each business is adjusted for inflation. This is calculated by taking the annual average direct costs of control figures in Table 6.3 and discounting for the years 1997 to 2003 and inflating for the years 2005 to 2008 using the annual rate of change of the CPI.

Indirect Costs

Introduction

6.75 The Commission has adopted the following approaches in estimating the indirect costs of control:

- for allocative inefficiency and income transfers not achieved, the Commission has used a scaling approach, i.e. the costs of control are estimated as a percentage of the potential benefits;
- for productive inefficiency, the likely impact of control on total costs/operating costs is estimated; and
- for dynamic inefficiency, the potential costs of control in terms of an increase in interruptible supply and a 'missing market' are modelled and estimated.

6.76 These are discussed in more detail below.

Allocative Efficiency Benefits not Achieved

6.77 The Commission has assumed in its modelling that control would reduce prices towards the competitive level, but would not exactly replicate efficient prices. The 'gap' between controlled and efficient prices is used to calculate the costs of control arising from allocative inefficiency and income transfers not achieved.

6.78 For the purposes of this Inquiry the Commission has adopted a factor of 20% to discount the potential allocative efficiency and income transfer benefits of control for this Inquiry.[91] This is equivalent to assuming the prices move 80% of the way from the monopoly price to the competitive price. This implies that the indirect costs pertaining to allocative efficiency constitute 36% of any deadweight loss of consumer surplus (which is the algebraic result of reducing the price and output gap between P_m and P_c by 80%).

6.79 This approach of scaling the benefits of control provides a reasonable estimate of the likely inability of control to achieve competitive prices, when monopoly prices are significantly above competitive prices. However, it suggests that the indirect costs of control would be small if counterfactual prices were close to the competitive level even though the costs of control may not be lower in these circumstances. Although the Commission recognises the possible difficulty with scaling in these circumstances, no explicit allowance for this is included in the Commission's modelling of allocative efficiency costs.

6.80 It was noted earlier that the use of demand differentiated pricing could potentially reduce the allocative efficiency benefits of price control. The Commission is of the view that businesses under price cap control would still have incentives to adopt an efficient structure of prices, so that there would not be any potential increase in efficiency costs from this source.

6.81 A further aspect of allocative efficiency is the provision of the quality of service preferred by customers. The Commission has considered the possible impact of regulation on quality over time in the section below that discusses dynamic inefficiency.

Reduction of Excess Returns Benefits not Achieved

6.82 One of the benefits under the NAB test is that control could potentially reduce the transfer of monopoly rents compared to the counterfactual. However, it is unlikely that control would remove excess returns entirely, i.e. it is unlikely that control would result in businesses exactly earning the efficient level of return (given the uncertainties over determining what this level might be and the Commission's likely adoption of a margin on WACC in a control

[91] The Airports and LLU Inquiries adopted a 25% discount factor (equivalent to assuming a 75% movement towards the efficient price). In the Airports Inquiry, dynamic inefficiencies were assumed to be a proportion of the benefits of control so that costs could never exceed the benefits. By measuring and including in the analysis more costs independently of the benefits of control in this Inquiry, the Commission believes that the 25% used in the Airports Inquiry would be too high. Further, the Commission notes that there is likely to be some in-built conservatism in the data provided by the gas pipeline businesses which suggests that the estimate of excess returns (and allocative inefficiencies) is likely to be conservative.

situation). Thus, the Commission has scaled down the potential reduction in excess return benefits for the NAB test. In the absence of strong evidence, the Commission has adopted a 20% scaling factor to reflect the likely imperfection of control in reducing transfers. In reaching the Commission's final position, sensitivities were run around the 20% figure to determine the effect of this variable on the NAB test.

6.83 For the assessment of net public benefits required by the Minister, the 20% cost factor does not apply. The net public benefit analysis does not include the potential reduction in excess returns as a benefit of control, so no indirect costs related to income transfers emerge. The other indirect costs (the efficiency effects) are measured in the same manner for the NAB test.

6.84 Given all the uncertainties of estimating the normal rate of return, there is a further risk that regulation may result in overall returns being set below a normal return. Such transfers would arguably be to the long term detriment of consumers because they would likely reduce dynamic efficiency by discouraging investment. These effects are largely captured through the consideration of the impact of regulation on dynamic efficiency, and are discussed in a later section.

Productive Inefficiency from Control

6.85 Incentive regulation such as CPI-X regulation attempts to harness the incentives provided by profit-maximisation to induce productive efficiency gains, but can weaken these incentives by reducing the net gains achieved by businesses for productivity improvements. Over the longer term, prices tend to be linked to costs under price control, weakening incentives for businesses to make cost savings.

6.86 Price cap regulation may provide some incentives for productive efficiency by restricting free cash flows (through price caps) or by benchmarking performance. However, private sector business shareholders and boards have similar tools (e.g. increased debt, higher dividends and incentive payments to management) so any additional benefits from control may be limited. Nonetheless, even private sector businesses may lack competitive disciplines, and in cases of limited, or only recent, private sector involvement, or limited competitive constraint, the scope for productive inefficiency remains important.

6.87 Thus, although there are potential avenues for price cap regulation to improve productive efficiency, there are offsetting incentives arising from the fact that regulation reduces the benefits that flow to a business from reducing costs. Overall, it is possible that control could either improve or result in inferior productive efficiency outcomes than in the counterfactual. An adverse outcome would be relatively more likely if the businesses were already operating efficiently.

6.88 As with the estimate of the potential benefits of control, the consideration of potential detriments focuses on total costs, determined in the same way.

6.89 The Commission considers that control could impose productive inefficiency costs in the order of 0.33% of total costs. The factor of 0.33% of total costs is comparable to a 1% factor applied to operating costs.[92]

Dynamic Inefficiency from Control

6.90 The achievement of dynamic efficiency can be considered as maximising consumer and producer surplus over time. It is focused on the benefits arising from investment and innovation over time. The discussion in this section focuses on 'investment efficiency' on the assumption that innovation is not a significant consideration over the timeframe of the Commission's analysis.

6.91 As noted above, the Commission has not identified any dynamic inefficiency in relation to the gas pipeline businesses, so there can be no potential dynamic efficiency benefits from imposing price cap control on the gas industry.

6.92 However, the imposition of price cap regulation may discourage future investment. Under price cap regulation there is a risk that investors will not be able to earn an adequate return on investment, given various factors: the difficulty for the regulator of estimating a 'normal return', the possibility that asymmetric risks will not be compensated (for example, stranded assets), and the potential asymmetry of allowed returns (high returns may be truncated, but low returns will be borne by investors). Uncertainty as to the future operation of the regulatory regime may increase business risks. Actions by the regulator that are perceived by investors as preventing them from earning adequate returns might lead to a reluctance to invest in regulated industries, or to investment choices that manage regulatory risk (e.g. by making smaller investments involving less sunk cost capital solely to manage regulatory risk).

6.93 The Commission could address many of these concerns through the design of the regulatory regime. For example, it could adopt a WACC from above the 50th percentile of the WACC range when setting a price path under control to reduce the probability that dynamic inefficiencies occurred. Such an adjustment would reduce both the benefits of control (particularly reductions in excess returns that would be achieved) and the costs of control (particularly the dynamic efficiency costs which would be smaller than if the WACC at the 50th percentile were chosen). In the Commission's analysis, the benefits of control are estimated assuming the 50th percentile WACC. Consistent with this, the dynamic inefficiencies are estimated on the same basis. The Commission believes that this approach gives the best indication of the potential costs of control for the purposes of the Commission's modelling.

6.94 In the case of the gas services market, the following investment may be affected:

- increases in capacity on existing sections of the transmission and distribution network to service increased demand;
- extension of the pipeline into new geographic areas; and

[92] This percentage accumulates marginally by an increment of the previous years costs. For example, the costs in year 1 are 0.33%, in year 2 they are 0.3311% (i.e., 0.33*(1+0.33)), and so on.

- investment to improve the current service, provide new types of service or to reduce the costs of supply (innovation).

6.95 As no obligation to serve is placed on gas businesses, a substantial proportion of capital expenditure is discretionary, although continued expenditure is likely to be necessary to meet safety requirements.

6.96 Under-investment might result in increased congestion on the existing network, or to a delay in supplying new customers through extension of the network. These possibilities are considered in turn.

6.97 In relation to the first point, CRA, on behalf of NGC, proposed in its submission on the Draft Framework Paper that insufficient investment could lead to some customers not being served, or to load shedding at particular times, and that empirical studies of the value of lost load (i.e. the costs borne by the customer when supply is temporarily interrupted) could be combined with scenario analysis to obtain an estimate of the potential costs.[93]

6.98 The Commission agrees in principle that such costs could potentially be modelled through scenario analysis of a loss in quality (increased congestion), although the Commission has only limited information to undertake such an analysis. The Commission is not aware of any New Zealand studies of the value of lost load for gas.

<u>Increased Interruptibility</u>

6.99 The Commission notes that some gas customers contract for interruptible supply. Differences in the price of gas with and without interruptibility may provide an indication of the value to customers of interruptible versus firm supply, reflecting the value to customers of lost load. Such an approach provides an estimate of the cost of lost load to the marginal customer, where interruptibility is planned.

6.100 The cost of unplanned interruptions to inframarginal customers is likely to be higher, but is not considered in the discussion below. NGC noted in its submission on the Draft Report that unplanned interruptions may increase as well, and that the costs of such interruptions could be high[94]. The Commission agrees that this could potentially occur, but believes that such risks could be minimised through increases in planned interruptions. NGC also noted that other quality problems could arise, so that, for example, pipelines that underinvest may not be able to supply customers using appliances that require high gas pressure. The Commission acknowledges that such issues could arise, and would involve potential costs. It notes, however, that its estimate of the dynamic efficiency costs resulting from increased interruptibility is sufficiently broad to encompass these other concerns.

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[93] Charles River Associates, *Response to Gas Control Inquiry Draft Framework Paper*, August 2003, p 49.

[94] NGC Holdings Limited, *Commerce Commission Gas Control Inquiry: Submission in Respect of the Draft Report*, July 2004.

6.101 In determining the discount applying to interruptible supply, the Commission drew on evidence from an International Energy Agency (IEA) report[95]. This report suggested that interruptible gas supply contracts were available at a discount of between 2 to 20% per year compared with firm contracts. The Commission does not have New Zealand-specific information, but presumes that a similar discount might apply in New Zealand. Although discounts may reflect the poorer quality of service associated with interruptibility, they might also include elements of Ramsey pricing to customers whose demand is more elastic than the average. Thus, the discounts may overstate the detriment associated with interruptibility.

6.102 Drawing on these figures, a rough estimate of the annual value of reduced quality could be obtained. For the purposes of this Inquiry the Commission considers that the discount offered for interruptible supply in New Zealand is in the order of 10%, which falls in the IEA range of between 2 and 20%.

6.103 The report also notes that around 15% of sales in Europe are interruptible, with interruptible sales in the US and UK being around 25%. These figures relate to interruptibility caused by both gas supply and pipeline capacity constraints.

6.104 Regulation could increase the risks of investment, which could lead to under-investment in maintaining the current transmission and distribution networks, and in reinforcing the networks to meet additional demand. After a period, under-investment could result in reduced quality, assumed to manifest itself as greater interruptibility of service.

6.105 The possible impact of regulatory uncertainty on investment, and the resultant impact on quality is, with the information available to the Commission, unknown. However, suppose that the risks associated with regulation resulted in a deterioration in quality that resulted in 5% of sales moving from firm to interruptible supply. A 5% increase in interruptibility would be a moderately severe result from under-investment in the pipeline given that the 15 to 25% interruptibility figures in the IEA report relate to both the network and gas supply.

6.106 The annual loss in value to consumers as a result of diminished quality could be approximated by multiplying the additional sales subject to interruptibility as a result of regulation by the estimated loss in value associated with interruptibility, i.e. $(0.05 \times Q_m) \times (0.1 \times P_m)$ for each business, where $(0.05 \times Q_m)$ is the additional output subject to interruptibility and $(0.1 \times P_m)$ is an estimate of the per unit reduction in value associated with interruptibility. The figures chosen may be indicative of the possible impact over the narrow range of outcomes anticipated by the model.[96]

6.107 The estimates obtained from this methodology potentially overstate the impact of regulation on quality because price cap regulation is likely to include

[95] International Energy Agency, *Flexibility in Natural Gas Supply and Demand*, OECD, 2002, pp 69-70.

[96] The indirect costs of service quality would need to be held constant in any sensitivity testing over a broader range of outcomes, particularly for the net public benefits analysis, where this indirect cost is a relatively more important variable in that analysis.

specific regulatory controls aimed at preventing the deterioration of quality. For example, a CPI – X + S mechanism (where S is a service quality variable) could be adopted with service quality issues explicitly addressed within the regime. As well, it should be noted that safety requirements will ensure a minimum level of investment by the pipeline businesses.

6.108 Wanganui Gas questioned whether the purchase of interruptibility contracts at the distribution level was a realistic option, and noted that re-engineering of the network might be required to achieve this option. They also questioned the proposed magnitude of the discount that would be required to induce customers to accept an interruptible contract.[97] The Commission acknowledges these concerns. However, it remains of the view that the modelling approach is sufficiently broad to provide an estimate of the potential dynamic inefficiencies that might arise as a result of increased congestion.

<u>Missing Market</u>

6.109 In relation to extensions of the network, CRA suggested in comments on the Draft Framework Paper that where customers are willing to pay for connection to the network, but suppliers are not willing to invest because of the uncertainties associated with control, the efficiency foregone could be measured as the difference between the willingness to pay and the cost, i.e. the area between the demand and supply curve created by investment.[98]

6.110 The Commission agrees in principle that such an approach (termed 'missing market') can provide an estimate of the potential efficiency costs of a failure to supply new customers.

6.111 In the Draft Report, the Commission modelled the potential costs that might arise if regulatory risk resulted in a deferral of new investment by building upon the approach presented in Figure 6.1 earlier in this chapter. In the Commission's analysis in the Draft Report, the long-run marginal cost and average cost of supplying customers was assumed to be the same as for servicing existing customers (i.e. equal to P_c), and the demand elasticity of these consumers was assumed to be the same as for existing consumers. P_m was also assumed to be the same as in Figure 6.1. No concerns were raised about these assumptions in submissions on the Draft Report.

6.112 The Commission also assumed that the slope of the demand curve in the missing market was the same as the slope in the existing market. In addition, it calculated the missing market as 0.5% of the existing market, which was held as a constant proportion of total demand over the assessment period.[99] Submissions on the Commission's approach raised the following concerns with these assumptions:

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[97] Wanganui Gas, *Cross-Submission Relating to the Gas Control Inquiry Draft Report of 21 May 2004*, August 2004, p 4.

[98] Charles River Associates, *Response to Gas Control Inquiry Draft Framework Paper*, August 2003, p 49.

[99] The capital expenditure submitted by the businesses was not adjusted as a result of the missing market calculation. If demand were deterred by control, it is possible capital expenditure could also be reduced. This effect is likely to be small (and to the businesses' benefit) in the Commission's framework.

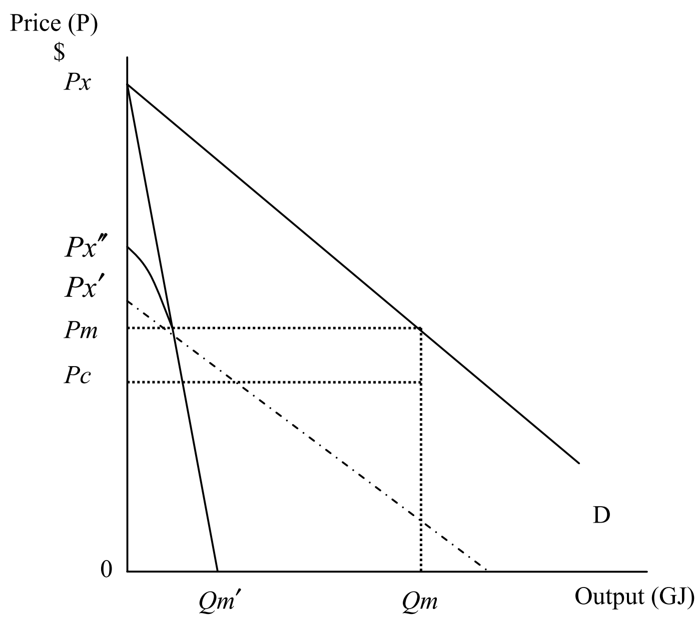
- the demand curve assumed in the missing market was too elastic; and
- the size of the missing market should increase over time rather than remaining as a fixed proportion of existing demand.

6.113 These issues are considered below.

Elasticity of Demand

6.114 The Commission obtained the elasticity of demand for the missing market by applying the slope (rather than the elasticity) of the existing demand curve to the missing market at the quantity of demand foregone assumed for the missing market. This is illustrated on the graph below where the outer solid line denotes the demand curve in the overall market. The dashed line indicates the demand curve in the missing market if the slope of the line were the same as in the overall market. P_x' is the price at which demand falls to zero under this assumption. The Commission's assumption effectively resulted in a very elastic demand curve in the order of -50 and a small estimate of the consumer surplus foregone in the missing market.

Figure 6.2: Demand Curve in Missing Market



6.115 The Commission believes that the consumers in the missing market may have a weaker preference for gas. However, the Commission's assumption that the demand curve in the missing market has the same slope as in the existing market is likely to have been too conservative.

6.116 CRA, in its submission on behalf of NGC, suggested that P_x should be found by linear extrapolation of the demand curve in the existing market or equivalently, by applying the same elasticity of demand (-0.3) to the missing market.[100] This assumption is illustrated on the graph as P_x. The volume of demand that would not be served because of regulation is assumed to be Q_m'. Under these assumptions, demand for gas would fall to zero when prices rose to around 3 to 4 times the current monopoly price (note that the graph is not drawn to scale). CRA's approach effectively assumes that customers in the missing market would have the same demand profile/cost of supply as those in the existing market.

6.117 Vector proposed an alternative approach in which $P_{x''}$ was constrained to not exceed twice P_c, and a smooth curve was fitted from the monopoly price. This is illustrated on the graph above at $P_{x''}$.[101] Vector's approach results in the consumer surplus loss lying between that assessed by the Commission in the Draft Report and that proposed by CRA.

6.118 The Commission's view is that customers in the missing market are likely to have more elastic demand than the average customer in the existing market, but that such elasticity is likely to be less than that assumed in the Draft Report. Consumers in the missing market have not committed to sunk investments in gas specific equipment. Their demand response is therefore likely to be more flexible than in the existing market where many customers are committed to particular technologies. Thus, elasticity demand in the missing market is likely to be more akin to the long run elasticity of demand in the existing market. Further, the consumers in the missing market might, to some extent, have a weaker preference for gas, since those with the highest demand would tend to be supplied first. Further such customers may have a higher cost of supply – something that the Commission has not modelled (a higher cost of supply would move P_c upward). These considerations also suggest that their demand for gas would likely be more elastic than the average existing customer (and their cost of supply higher).

6.119 In the modelling for the final report, the Commission has assumed that elasticity in the missing market is three times that of the existing market. Thus, it has adopted an elasticity of -0.9 for distribution businesses and -0.3 for the transmission businesses in assessing the potential dynamic inefficiency costs of control. The slope of the demand curve for the missing market therefore lies between that proposed by CRA and that used by the Commission in the Draft Report, and is similar to that proposed by Vector.

Size of the Missing Market

6.120 In the Draft Report, the Commission estimated the quantity of customers not served at a constant 0.5% of current demand (which would increase or decrease only as demand increased). The Commission assumed no demand was foregone for transmission [ ]

6.121 CRA argued that the reduction in investment would have a cumulative effect over time. They proposed that each year an additional 0.5% of demand foregone be added. Thus, in the second year, demand not served would be 1.0% of current demand, in year three 1.5% and year four, 2.0%.

[100] CRA, *Review of the Commission's Gas Control Inquiry Draft Report*, prepared for NGC, July 2004.
[101] Vector, *Gas Pipelines Inquiry Cross Submission*, August 2004, Annex D.

6.122 CRA's approach is approximately similar to suggesting that the expected 2% per annum growth in the total market would be reduced to 1.5% per annum growth whereas the Commission's approach assumed that the missing market started at 0.5% of the total market, and then grew in line with the growth in the total market. Thus, if growth was 2%, the Commission's missing market would grow by 2% per annum.

6.123 The Commission concurs with the submissions which suggest that the missing market should be compounded on an annual basis. It has therefore revisited its assumptions about the likely growth in output over the analysis period, and the impact that price cap control might have on investment required to achieve that growth.

6.124 In the Draft Report, the Commission considered the rates of growth forecast by the businesses over the period 2003-2008. As discussed in Chapter 7 (Modelling Issues and Sensitivity Tests), the Commission's view is that the total of the past and the future analysis provides the best estimate of the likely future of the gas businesses. Based on information provided by the businesses on their growth (output and kilometres of pipeline) the Commission has revised its growth assumptions by considering the whole of the analysis period. For Wanganui Gas, the assumed rate of growth is [ ] per annum. For NGCD, Powerco and Vector, the assumed rate of growth is 3.5%. In the case of NGCT, the Commission has assumed growth in demand for transmission of [ ]

6.125 The Commission has also revised its assumptions as to the size of the missing market. The estimate of this effect is largely a matter of judgment. The Commission's view is that regulation is likely to deter around 10% of expected growth. This is a reduction from the previous assumption that 25% of growth would be deterred, but the 25% was in the context of being a fixed proportion of total demand. By compounding the missing market each year, the result is a substantial increase in the overall size of the missing market over the analysis period and an increase in the calculated dynamic inefficiencies compared to the Draft Report. Given the uncertainty over the appropriate level, the Commission has modelled different assumptions in its sensitivity analysis (discussed in more detail in Chapter 7 (Modelling Issues and Sensitivity Tests)).

6.126 The Commission believes that the impact of regulation on the incentives for businesses to invest will be moderated by a number of factors. Investments in new pipelines dedicated to particular customers are likely to be governed by individual contractual arrangements that may be outside the price cap controls, particularly if developed under conditions of contestability. Arrangements such as this are likely to feasible for major new customers on both distribution and transmission networks.

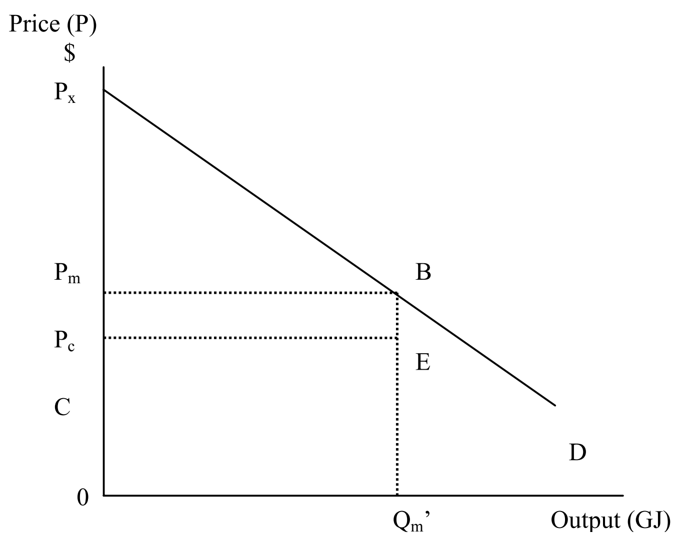
6.127 Customers themselves could own dedicated assets, or contribute towards the costs if uneconomic. Some capital contributions are made by customers, although NGC presented evidence that suggested a reluctance for customers to make a significant capital contribution. Expansion of the network by Nova Gas and new entrants would likely continue to be outside the scope of regulatory control, as would investments by developers of new gas fields. In addition, investments involving relatively low (systematic) risks are likely to be largely unaffected by the regulatory controls.

Calculating Dynamic Inefficiency Costs from the Missing Market

6.128 Figure 6.3 illustrates the potential consumer and producer surplus forgone in the missing market. The long-run marginal cost and average cost of supplying the missing market customers is assumed to be the same as for existing customers (i.e. equal to P_c). P_m and P_c are assumed to be the same as in the existing market.

6.129 In the analysis of the missing market, the Commission has adopted an elasticity of -0.9 for distribution customers and -0.3 for transmission customers. Using these elasticities it is possible to estimate the consumer and producer surplus forgone from deterred investment. This is illustrated in Figure 6.3.

Figure 6.3: Cost of New Investment Being Deterred By Control



6.130 Q_m' in Figure 6.3 represents an estimate of the quantity of future output that would not be served as a result of regulation. The growth in demand for distribution services is assumed to be approximately [ ]% for Wanganui Gas and 3.5% for the other distribution businesses per annum (based on system length and GJ growth figures provided by the businesses to the Commission over the analysis period 1997-2008). For transmission, growth is around [ ].

6.131 For distribution and transmission, the Commission has assumed output growth was 10% of expected. Thus, in the first year of existence of the missing market, it is assumed that [ ]% of total demand for Wanganui, and 0.35% for the other distribution businesses and [ ]% for transmission is forgone. An amount Q_m' is obtained in the first year, based on the demand in the existing market in that year. For distribution, Q_m' = [ ]*Q_m for Wanganui Gas and

0.0035* Q_m for the other distribution businesses; for transmission Q_m' = [ ]*Q_m. The missing market compounds each year, so that in the second year, an increment of the same amount of total demand in that year is added to the first year Q_m'. Similar increments are added in the subsequent years. For the transmission market, demand forgone in the missing market [

].

6.132 It is assumed that the monopoly price at Q_m' is the same as the price prevailing at Q_m and that P_c is unchanged. Given that the Commission is using a different elasticity in the missing market than in the existing market, the relationship between P_m and P_c is likely to change. However, given the approximate nature of the calculation, any difference is unlikely to materially affect the results.

6.133 The price where the demand curve intersects the price axis is P_x (the price at which demand for gas conveyance falls to zero) and is not known. P_x would depend on the cost of gas (including transport charges) relative to the cost of substitutes. The Commission obtains an approximation for P_x by assuming that the demand curve is linear (as shown). It extrapolates the demand curve from P_m using the assumed elasticities of the demand curve in the missing market.

6.134 As the deterrent effect of regulation on investment is presented in Figure 6.3 as a new market that would not exist if regulation were introduced, the consumer surplus forgone is the entire area below the demand curve but above the monopoly price (i.e. the triangular area P_mBP_x). This represents a potential cost of control.

6.135 Producers would also face costs in terms of foregone producer surplus (additional excess returns) of P_mP_cEB. The Commission includes the foregone producer surplus as a potential cost of control under the net public benefits assessment, but does not include this as a potential cost under the NAB test. The Commission has adopted this approach because, in its view, the additional excess returns should not fall on consumers. In the absence of regulation, producers capture the surplus by charging prices above monopoly levels. Consumers do not capture any of the benefits in the absence of regulation as these accrue to producers as excess returns. Regulation results in reduced excess returns to producers, but the position of consumers is unchanged.

6.136 The Commission has not observed significant innovation in gas pipeline businesses, although there have been some developments in terms of packaging of offerings to customers. At this stage, the Commission is of the view that while control might have a negative impact on the incentives of the businesses to innovate, any resulting detriment would not be significant.

6.137 The benefits and costs of control for each gas pipeline business are detailed in the business specific chapters.

Taking Account of the Asymmetric Risks of Imposing Control

6.138 The Commission recognises that the risks associated with imposing control are asymmetric: that is, the costs of imposing control when it is not justified are likely to be higher than the costs of not imposing control when it is justified. Under a control regime, the Commission may recognise this asymmetry through adopting a WACC that is above the mid point. In assessing whether control should be imposed, the Commission also takes account of this asymmetry.

6.139 Further, in assessing whether control is justified the Commission needs to ensure consistency with its likely approach if control were declared. To ensure consistency between assessment and control, the parameters adopted in assessment must provide a sufficient margin to ensure that control is not recommended when it would not be binding in practice (i.e., control would not have an impact). This might happen, for example, if the Commission assessed excess returns using a WACC of 7% but adopted a WACC of 8% when setting a control price path.

6.140 The Commission notes that is of the view that a margin on WACC should apply in determining whether to impose control on the gas businesses to address concerns about asymmetric risk. However, the Commission observes there are features of the modelling which provide an effective margin on WACC, which need to be taken into account in assessing whether an additional WACC margin is required.

6.141 The effective margin on WACC is provided by the inclusion of the direct and indirect costs of control in the Commission's modelling. The costs of control are included to protect consumers from the inappropriate imposition of control. However, the costs provide an effective margin which helps ensure that the Commission does not impose control when it should not, or which would be non-binding in practice. The costs of control can be expressed in terms of their equivalence to a margin on WACC. Businesses can effectively obtain these margins as higher returns because control will not be recommended when earnings are in the range of mid-point WACC plus the control margins.

6.142 Table 6.4 provides a hypothetical example of the margin effect of the costs of control. The returns allowed (before any positive NABs are found) is determined by adding to the normal return the margin provided by the costs of control. Suppose, for example, that the costs of control are estimated at $1 million dollars per year and the ODV value of the assets is $100 million. The costs of control would then translate into 1% in WACC terms. Assume also that the costs of control do not change with different WACCs.[102] The result is that at the 50th percentile of WACC (i.e. the mid point), the returns allowed before any positive NABs are found is equal to 7.2% plus 1%, or 8.2%.

[102] Efficiency benefits are also ignored for simplicity, so that the removal of excess returns represents the only benefit of control.

Table 6.4: Impact of Margin for Control on WACC

	50th percentile	60th percentile	70th percentile	80th percentile
Normal return (WACC)	7.2%	7.5%	7.8%	**8.2%**
Returns allowed before any positive NAB are found	**8.2%**	8.5%	8.8%	9.2%

6.143 In the example above, the statistical distribution of WACC values is presented. With a WACC of 7.2%, there is a 50% probability that WACC is at or lower than 7.2% and a 50% probability that WACC lies above that rate. At 8.2% there is an 80% probability that the WACC is at or lower than this point.

6.144 The bold figures show how choosing the mid point of WACC (50th percentile) as the base case, and allowing businesses to earn a 1% margin equal to costs of control before NABs are found, effectively allows businesses to earn a return equal to the 80th percentile of the WACC range.

6.145 The sizes of the implicit margins provided by the costs of control differ between the businesses. Thus, the margin provided by the direct costs of control (compliance and regulator's costs) is relatively high for a small business like Wanganui Gas and relatively small for NGCT. The margin provided by the 20% discount of excess returns is larger for businesses earning large excess returns.

6.146 Table 6.5 indicates the implicit margin over WACC provided by the costs of control in the Commission's analysis for the different businesses, given the businesses' current level of profits (the costs of control vary depending on the businesses' actual earnings) based on the base case results. The table distinguishes between the effects of the direct costs of control (compliance and regulator's costs) and the indirect costs of control (allocative, productive and dynamic efficiency effects along with 20% discount of excess returns). With the exception of Wanganui Gas, the margin provided by the indirect costs of control is typically the greater.

Table 6.5: Implicit Margins on WACC Provided by the Costs of Control

	Direct costs margin	Indirect costs margin	Total implicit margin[103]
WGL	2.1%	0.8%	**2.8%**
NGCD	0.5%	0.8%	**1.3%**
NGCT	0.2%	0.4%	**0.6%**
Powerco	0.5%	1.3%	**1.8%**
Vector	0.3%	1.4%	**1.6%**

6.147 The Commission's view is that a margin, equivalent to the 75th percentile of the WACC range (0.8%) should be sufficient to protect against the asymmetric risk of imposing regulation when it is not justified and to ensure that the Commission does not find for control, when control would be non-binding.

6.148 Given the margin provided by the costs of control in the present circumstances, the only business that is not provided with a WACC margin of sufficient magnitude by the costs of control is NGCT. Rather than adding a margin on WACC for NGCT, the Commission, in assessing whether control is justified, has examined whether NGCT's actual returns over the review period, exceed the WACC at the 75th percentile. If they do, then it is unlikely that a declaration of control would result in the imposition of non-binding control or the imposition of control when it is not justified.

6.149 The Commission is satisfied that using the mid point of WACC is appropriate for all businesses, although the margin provided by the costs of control varies by business with some receiving a significantly larger margin. Further discussion on these issues is contained in the business specific chapters.

[103] Note there may be rounding differences when adding the direct and indirect cost margins to get the total margin.

7 MODELLING ISSUES AND SENSITIVITY TESTS

7.1 The Commission considers that a key tool for analysing the issues regarding control is the development of models that quantify the potential effects of its decisions. However, it is the nature of such models that they simplify a complex reality. In addition, the quality of the data used as inputs into the modelling influences the robustness of the final results. Therefore, these models are used to inform the Commission, which still has to exercise its judgement in its overall recommendations.

7.2 Sensitivity testing assists the Commission in understanding the significance of certain assumptions and modelling limitations. Therefore, sensitivity testing assists the Commission in exercising its judgement.

7.3 This chapter discusses modelling issues and the key sensitivity tests undertaken.

Modelling Issues

7.4 The model used by the Commission is an adaptation of the basic model from the Airports Inquiry. Significant refinements to the approach have been made for the present circumstances.

Quality of Data

7.5 The Commission has sought data for its modelling from the gas pipeline businesses and the information required was extensive. Appendix B contains a data template that the businesses were required to complete. In all cases the Commission needed to clarify with the businesses the data provided. Such clarification and refinement of data is a natural part of the modelling process.

7.6 Generally raw data from the businesses was used unless evidence suggested that some adjustment was necessary. The purpose of the analysis was to give the Commission an indication of whether or not control was warranted. Data for control purposes would need to be audited and would require a greater degree of transparency and definition than was available to the Commission in the timeframe for this Inquiry.

7.7 Since the Draft Report, the Commission has obtained additional information upon which to undertake sensitivity tests. However, a few gaps remain in the information. For example, historic cost information of assets was limited in most cases, and did not allow the Commission to undertake a complete analysis using an historic cost approach to the valuation of the asset base. The inflation rate and risk free rate for the forecast period has also been revised based on more recent data from the Reserve Bank of New Zealand.

7.8 In certain instances, the Commission has changed its modelling approach since the Draft Report after all the issues were canvassed in submissions. This has changed the sensitivity around the affected variables.

Period of Analysis

7.9 The period of analysis typically ranged from 1997-2008, with the exception being Vector whose analysis covered the period 2000-2008. In all cases the analysis period includes both actual and forecast outcomes.

7.10 Some submissions from businesses on the Draft Report suggested that forecast information should be given greater weighting. They argue that the Commission incorrectly assumes that a combination of the past (1997-2003) and future (2005-2008) data best represents the future. In contrast Powerco preferred that only historical data be used in the assessment.

7.11 The Commission disagrees with both these views and continues to consider that a combination of past and future data best represents the likely situation in the future. There is an incentive for the businesses to provide forecast information that is conservative or perhaps pessimistic about their future prospects. This possibility needs to be balanced with actual historic information.

7.12 A combination of past and forecast information extends the period of analysis and ensures the most reliable information is used. The Commission therefore considers that past and forecast data should both be used.

Presentation of Results

7.13 The Commission's approach to compounding and averaging of net benefits in the Draft Report was:

- the nominal net benefits to acquirers in the individual years of the analysis period were compounded to 2004 dollars using the nominal WACC. The compounded NABs were then added to obtain a total NAB in 2004 dollars; and
- the total NAB above was divided by twelve (number of years in the analysis period) to give an average annual net benefit to acquirers in 2004 dollars.

7.14 NGC's submission on the Draft Report suggested the compounding approach adopted by the Commission determines the benefits of control in 2004 dollars from a control regime operating between 1997 and 2008.[104] NGC argued the Commission's approach does not provide a measure of the benefits from imposing control over the next 10 years, which is the true factual, rather it calculates the benefits, in 2004 dollars, from a control regime that has been operating for the past eight and next four years.

7.15 While the Commission's approach does not reflect the situation that may occur if the Minister were to impose control (any control regime would operate from 2005), it still provides a meaningful approach to assessing whether there are likely benefits of control in the first instance. Also, at this stage it cannot be determined for how long and what form any control regime would take. The

[104] Note CRA represented NGC on this matter.

Order in Council provides an initial indication, but there is also scope to shorten or lengthen this period.

7.16 NGC also argue that taking a straight average of the compounded total net benefits of control to get the annual average net benefit of control is technically incorrect. The Commission agrees with this point and has therefore adopted an annuity approach for the Final Report.

7.17 The Commission is aware that the presentation of the results can affect perceptions of their significance. For example, presenting results in 1997 dollars would make any NAB seem significantly smaller than NAB presented in 2008 dollars.

7.18 The results of the Commission's modelling are now presented using two figures. The first (which is unchanged from the Draft Report) is the total NAB over the analysis period in 2004 dollars. The second is an annuity of the first figure. The approach for calculating the two figures is:

- compound the nominal net benefits to acquirers in the individual years of the analysis period to 2004 using the nominal WACC. The compounded NAB's are then totalled to obtain a total NAB in 2004 dollars (same as the Draft Report); and
- use the total NAB in 2004 dollars to calculate an annuity in 2004 dollars.

7.19 The calculation of the total NAB in 2004 dollars allows the results contained in the Final Report to be readily compared with the Draft Report. However, as discussed the calculation of the total NAB in this manner postulates the net benefits from a control regime that operates between 1997 and 2008. Because of this point the Commission recommends the use of the annuity figure over the total NAB figure.

7.20 An annuity figure is a constant annual payment figure. It is the constant figure in 2004 dollars that would need to be paid each year to get the NPV of the total NAB calculated. The annuity figure, expressed in 2004 dollars, can be calculated using the NPV of net benefits expressed in 1997, 2004 or 2008 dollars (the annuity figure would be the same).

7.21 The calculation of an annuity figure is effectively stating that the combination of the past eight years (past four years for Vector) and the next four years is the best measure of the yearly net benefits that could be obtained from a control regime in the future. The annuity figure can be simply used to estimate the NPV of imposing control for some future one year period.

Key Variables

7.22 Table 7.2 lists the key variables of the model and their impact on benefits and/or costs. The Commission has developed a 'base case' in its model. This base case contains the Commission's best judgements regarding the various variables. Those variables that were significant drivers of the modelling results were subjected to separate sensitivity testing. The sensitivities are tested against the base case.

Table 7.2: Key Variables and the Effects on Key Results

Variable	**What it affects in the building blocks model**
Revenues and other income (e.g., capital contributions, including actual and forecast revenues)	Past and forecast revenues clearly influence the returns the business earns over time. These revenues are influenced in turn by the expected level of demand and the prices charged by the businesses.
Expenses (including operating expenses, common costs, and tax)	Past and forecast expenses incurred by the business will influence the net returns a business earns over time. It also affects how productively efficient they are. Operating expenses, tax and common costs have proved to be significant components of expenses that the Commission has had to examine.
WACC	The net returns a business earns are analysed against a normal return (WACC) on their investment. The higher the WACC (other things being equal) the greater the level of returns that would be considered normal and therefore the lower the likelihood of a business earning excess returns.
Asset Values	The level of normal returns is determined by multiplying the WACC by the asset value for each period. The higher the asset values (other things being equal) the greater the level of net returns that can be earned and therefore the lower the likelihood of a business earning excess returns.
Revaluation gains/losses (including actual and forecast)	Changes in the value of assets are treated as a return to the asset owner. The higher the level of revaluation gains (other things being equal) the greater the returns to the business and the more likely excess returns may be found. Offsetting this are the greater depreciation charges and allowed revenues the businesses can earn on the higher asset base.
Costs of control	Control will involve a cost to the businesses by raising their compliance costs and to the public by having to fund a regulatory body to develop and administer the control regime. The higher the estimated costs of control (other things being equal) the less likely the potential benefits of control will exceed the costs and the higher the returns the businesses are also allowed to earn.
Dynamic inefficiency costs of control	The elasticity of demand for the missing market, the growth assumed and the level of growth assumed to be deterred by control all influence the significance of this cost variable.
Excess returns unrecoverable	The indirect costs of control calculations include a factor for the percentage of excess returns that are unrecoverable. The higher the percentage of excess returns that are assumed to be unrecoverable (other things being equal) the greater the costs of control.

Monte Carlo Analysis

7.23 In its Draft Report submission CRA (on behalf of NGC) presented a Monte Carlo simulation approach which was designed to capture the effects of uncertainty and volatility in the key outputs going forward. CRA argue that this probabilistic model should form the basis of calculating the benefits and costs of regulation instead of the Commission's deterministic modelling based on the companies' best forecasts of future demand.

7.24 CRA provided the results of their Monte Carlo analysis, but not their underlying model in their submission on the Draft Report. After the conference, the Commission reviewed the CRA Monte Carlo model and met with CRA to discuss and better understand their proposed approach. The Commission also requested Meyrick and Associates to comment on the CRA Monte Carlo model, the Monte Carlo approach and its suitability for the Inquiry.

7.25 The Commission agrees with the conclusions reached in the attached paper by Meyrick and Associates. Specifically, the Commission considers:

- there is limited information on the key parameters chosen in the CRA Monte Carlo model;
- if the Commission were to use the CRA model it would need to fully understand the key parameters, modelling assumptions and choices made within the model. The Commission would need to be comfortable that it could recreate the model from the ground up;
- the CRA model is restricted by the limited amount of data available. Seven annual observations is a small number of observations on which to base the sampling distribution;
- because of the modelling assumptions and limited observations in the CRA model the Commission would need to build its own model if it were to use the Monte Carlo approach. It would be required to compile a robust and defendable model that could be used in the decision making process;
- compiling a detailed Monte Carlo model using the data currently available is unlikely to produce robust results. To do this, additional information would be required;
- the key additional information required would consist of disaggregated firm specific information from the New Zealand gas pipeline businesses and the views of industry experts;
- one of the key issues within the Inquiry to date has been the difficulty in obtaining robust information from the businesses. It took approximately three months to obtain usable base information for the current cost benefit model with the Commission checking and revising this data over the last six months;
- the time frame for obtaining useable information, compiling a Monte Carlo model, discussing and deciding on the key parameters is likely to be several months;
- in addition to the timing issue, disaggregated firm data is likely to overstate the variability occurring, while using industry experts' views on variability would lack transparency;
- the current cost benefit model in the Draft Report uses forecast data provided by the businesses. In compiling this forecast information management are likely to have made the best use of available information;
- the Monte Carlo approach has the potential to provide useful information on the likely impact of concurrent changes in the variables of interest. However, multiple sensitivity tests can also be run within the

Commission's model In addition, the Monte Carlo approach is less transparent (than the current cost benefit model) on how changes to a particular output will change the results; and

- while the Monte Carlo approach could have the potential to provide useful insights into the volatility of key outputs, given the data limitations and availability, the substantial investment in time to compile a robust model and the advanced state of the Inquiry, the appropriate approach is to refine the existing cost benefit model. The Monte Carlo approach should ideally have been considered at the framework development stage of the inquiry, but was not raised at that time.

7.26 Given these considerations, the Commission focused on refining its own model, which it has developed over the course of consultation.

Sensitivity Tests

7.27 Sensitivity tests were run on numerous variables in the modelling including:

- WACC (25^{th} and 75^{th} percentiles), discussed in business specific chapters;
- asset base, using historic cost for Wanganui Gas, the only business able to provide the relevant data. This is discussed in their business specific chapter;
- self-insurance (for those businesses not obtaining insurance externally);
- common costs;
- growth during the forecast period;
- the magnitude of the excess returns considered unrecoverable;
- dynamic inefficiency costs of control; and
- tax (discussed in the Powerco and Vector chapters).

7.28 The range of sensitivities presented for each variable above was a matter of Commission judgment. More extreme outcomes could be extrapolated from the ranges presented.

Common Costs

Background

7.29 There are numerous cost allocation methodologies that have been used overseas and over the years in regulated industries. The most common forms of cost allocation models are fully distributed cost methods (FDCM). The avoidable cost allocation methodology (ACAM) has been adopted relatively recently in New Zealand for information disclosure purposes.

7.30 ACAM has been accepted for information disclosures of electricity lines businesses, where it replaced the ad hoc approaches businesses had previously used. It has also been proposed by the Ministry of Economic Development (MED) for disclosures for gas pipeline businesses.

7.31 In the Draft Report, the Commission expressed concerns at the fitness of ACAM for the purpose of assessing the returns of monopoly businesses.

ACAM's application by the gas pipeline businesses was also questioned.[105] The Commission identified common costs as a key sensitivity and stated that it was minded to reduce the level of common costs claimed by the businesses by 10 – 30%.

7.32 Businesses submitted that the onus was on the Commission to prove the businesses had claimed an unreasonably high level of common costs (indirect costs).

<u>The Issues</u>

7.33 The first issue regarding common costs is the issue of whether submitted common costs are 'truly' common costs. Economically, true common costs can only ever be allocated arbitrarily. However, common costs are frequently not truly common and can often be separated at least notionally.

7.34 A disclosure regime requires all businesses to allocate common costs on a standard basis to assist comparability across businesses. For electricity disclosures and the proposed gas disclosure regime, stand-alone costs have been used as the standard. However, while stand-alone costs may provide an upper bound on the allocation of common costs, they do not necessary represent a reasonable allocation within a broader economic range. Further, stand-alone costs should not be applied repeatedly across activities, because that can result in over-recovery of common costs.

7.35 How over-recovery occurs can be illustrated with a simple example. Imagine two activities, A and B, which if provided by independent suppliers would incur overheads of $100 each. Imagine now that a business begins conducting the two activities together and through economies of scale and scope the joint overheads of these two activities are $180. If stand-alone costs are attributed to both these activities, the business over-recovers by $20 (i.e. 2*$100-$180). No over-recovery occurs if one activity is attributed a stand-alone cost of $100 and the other activity is allocated an incremental cost of $80.

7.36 An economically efficient allocation of common costs would notionally lie between stand-alone and incremental costs. ACAM is based on this notion and allows this range of outcomes. However, this range can be quite wide and leaves significant discretion for businesses and regulators.

7.37 CRA (on behalf of NGC) provided a submission on common costs that argued for stand-alone costs to be used. They argued that 100% of the gains from economies of scale and scope should accrue to the businesses, so as to provide an incentive for businesses to adopt additional competitive activities. If incremental costs are used the business retains 0% of the economies of scale and scope.

[105] The Airports Inquiry questioned the appropriateness of ACAM, although the issue was not addressed in detail as its impact was less significant. The Commission proposes to review the information disclosure requirements for electricity lines businesses next year, when ACAM will also be reviewed. The Commission has recommended FDCM (activity based approaches) be used in telecommunications regulation for the calculation of TSLRIC.

7.38 The Commission considers it is unlikely that 100% of the gains from economies of scope need accrue to businesses to provide them with an incentive to undertake additional activities. Indeed, it could be argued that the monopoly activities should have common costs allocated on an incremental basis, with the competitive activities allocated the stand-alone costs, thereby preventing the business from gaining advantage over businesses in competitive markets simply due to economies gained through their monopoly activities. Finally, over-recovery will occur if stand-alone costs are used as the basis for allocating costs across all activities.

7.39 Ultimately, the Commission considers it has to allow an allocation that is reasonable to both businesses and consumers, within the bounds of stand-alone and incremental costs.

Analysis

7.40 Subsequent to the Draft Report, the Commission undertook further analysis and required businesses to provide information on assets, revenue, direct and indirect costs of the gas, electricity and other businesses operated by the multi-activity businesses. The indirect costs represent the common costs.

7.41 Three issues were explored, namely: (i) whether the allocations of common costs appear reasonable against various measures, (ii) how the businesses' cost allocation approaches have changed over time, particularly against earlier disclosures, and (iii) whether there is over-recovery of common costs across the businesses' activities.

7.42 Several analyses were conducted by the Commission, including a ratio analysis, a comparison with past disclosures, and a comparison with electricity lines businesses.

Ratios

7.43 Table 7.3 summarises the results of the key ratio figures. It indicates that the businesses have been allocating higher indirect costs to gas pipeline activities than justified by the asset, revenue and direct cost ratios for those activities. Wanganui Gas and NGCT are exceptions based on a comparison of their asset base ratios.

Table 7.3: Ratio Analysis (2004)

Company	Indirect Cost	Asset Ratio	Revenue Ratio	Direct Cost
Powerco	36%	22%	15%	12%
Vector	19%	10%	8%	3%
NGCD	18%	15%	6%	2%
Wanganui Gas	50%	76%	14%	34%
NGCT	37%	46%	18%	7%

7.44 The revenue and assets ratios can be thought of as crude activity based measures, and could be used as a yardstick for adjusting the indirect costs. The businesses generally consider that the asset and revenue ratios are too crude to be meaningful.

<u>Comparison to Electricity Lines Businesses</u>

7.45 The Commission looked at electricity lines businesses of comparable size and density to the gas distribution businesses. The electricity lines businesses examined were a mix of stand-alone and multi-activity businesses.[106] Transmission was not included in the analysis.

7.46 Table 7.4 provides a comparison of electricity lines businesses' and gas pipeline businesses' indirect costs per connection for 2003. It shows that on average the submitted common costs of gas pipelines are higher than electricity lines per connection and largely explains why the total opex per connection (i.e., indirect costs per ICP plus direct costs per ICP) is also relatively higher for gas pipeline businesses.

Table 7.4: Comparison of Gas Distributors and Electricity Distributors

	Indirect cost/ICP		**Total opex per ICP**	
	electricity	gas	electricity	gas
Highest cost business	82	168	175	275
Lowest cost business	30	25	116	76
Average	**60**	**88**	**148**	**178**
Standard deviation	17	51	18	72

<u>Cross Company Comparisons</u>

7.47 The Commission also engaged Meyrick & Associates (Meyrick) to conduct a cross company analysis. NGCT was not included in the analysis because of a lack of an appropriate comparator. Table 7.5 presents the results of this analysis.

Table 7.5: Gas Distribution Productivities

		Multilateral partial productivity indexes				*Common/ Direct cost*	*Common cost/ customer*
Firm	*MTFP*	*Direct cost*	*Common cost*	*Total opex*	*Capital*	*Ratio*	*\$/customer*
NGCD	1.000	1.000	1.000	1.000	1.000	0.78	90.78
Powerco	1.049	1.687	1.116	1.378	0.880	1.18	73.30
WGL	1.623	1.769	2.747	2.096	1.376	0.50	30.10
Vector	0.733	1.704	0.505	0.835	0.673	2.63	174.92

7.48 Meyrick's analysis suggests Wanganui Gas is relatively efficient on all the measures examined.

7.49 Vector stands out as the worst performer on common costs (50% worse than NGC and 60% worse than Powerco). Although Vector is relatively efficient in terms of its direct costs, it is the worst performer in terms of total costs (16% less efficient than NGCD and 60% less efficient than Powerco).

[106] The electricity lines businesses included in the analysis were: Aurora Energy, Unison, Electra, Orion, UNL (2002), Powerco, Vector (2002), WEL Network.

7.50 Powerco appears relatively efficient (in terms of the three large businesses) on the three partial productivity measures (direct costs, common costs and total opex). NGCD's performance is between that of Powerco and Vector.

7.51 The common cost/direct cost ratio indicates that Vector is an outlier, with its ratios over twice those of the firm with the next biggest ratio. Powerco's is 50% higher than NGCD's. An adjustment to bring the other businesses to the common cost/direct cost of NGCD (the most efficient performer on this measure) would require Powerco to reduce its common costs by 34% and Vector by 70%.

7.52 In contrast, the common cost/customer ratio indicates that NGCD would have to reduce its common costs by 10% to match Powerco's partial productivity, and Vector would have to adjust its common costs by 50%. However, this ratio, which is driven largely by customer numbers, favours Powerco, which has a lower throughput than NGCD, but twice the customer numbers. The data is supportive of the proposition that Vector is over-reporting its common costs.

7.53 Finally, it should be noted that Meyrick's analysis is a relative one and therefore does not address the issue that even the best performing firm under each measure may still have inflated common costs.

Past Disclosures

7.54 The Commission compared past disclosures with current figures submitted. It was found that NGCD, NGCT, and Vector have changed their approaches to cost allocation and reallocated past common costs. This has resulted in an increase in common costs claimed by these businesses. These business specific issues are discussed in the business specific chapters.

Base Case Adjustments

7.55 The Commission has found over-recovery on the part of Powerco and has therefore adjusted its base case. For example, Table 7.6 shows over-recovery of common costs by Powerco in 2004 from gas and electricity. Powerco's indirect expenses across the group were [ ] million in 2004. Powerco allocated $8 million to gas and [ ] million to electricity leading to an over-recovery of $3.7 million in 2004 from gas and electricity. The allocation of common costs to the 'other' business category has been effectively done on a residual basis, after having allowed stand-alone costs to be allocated to both electricity and gas activities.

Table 7.6: Over-Recovery of Common Costs by Powerco (2004)

	Gas (million)	Electricity (million)	Other (million)	Total (million)
Common Cost	$8.037	[ ]	-$3.7	[ ]

Balancing item showing over-recovery

7.56 Powerco over-recovered in three out of the eight years analysed (1997-2004). The extent of over-recovery and the approach the Commission has taken to correct for this are outlined in Chapter 13 (Powerco).

7.57 The Commission considers that Vector's approach to the allocation of common costs requires a base case adjustment. The Commission considers that, based on the evidence above, and further information contained in Chapter 14 (Vector), Vector's common costs should be reduced by 20% in its base case.

7.58 For both Powerco and Vector, the Commission considers their base case adjustment to represent the minimum adjustment for this issue. In addition, further sensitivity tests are run, as for the other businesses.

Sensitivity Tests

7.59 The Commission considers the evidence above is sufficient to suggest that sensitivity testing of all businesses should be conducted. The Commission continues to run the same sensitivity tests on common costs as in the Draft Report for all businesses, namely to reduce common costs by 10%, 20% and 30%.

7.60 For Powerco and Vector these sensitivity tests are in addition to the adjustments to their base case.

Conclusion

7.61 The Commission has found over-recovery on the part of Powerco and an over-allocation of common costs on the part of Vector. The Commission considers these matters significant enough to include an adjustment in the base cases for these businesses. In addition, the Commission runs sensitivity tests on common costs for all businesses. These sensitivities are presented in the business specific chapters.

Self-insurance

7.62 Internationally, regulators are generally reluctant to allow self-insurance costs to be included in allowed annual returns, and tend to encourage external insurance when this is efficient or allow pass-through when events occur.

7.63 When self-insurance is allowed significant caveats are often attached by regulators. The ACCC, for example, requires the following matters to be established:[107]

- confirmation of a board resolution to self-insure;
- confirmation that the business is in a credible position to self-insure (i.e. the business has sufficient resources to absorb the event on its own);
- provision of self-insurance details setting out the categories of risk for which the business has resolved to self-insure;
- a report from an appropriately qualified insurance consultant verifying the calculation of the risks and corresponding insurance premiums;

[107] ACCC, *Draft Decision: Statement of Principles for the Regulation of Electricity Transmission Revenues*, 18 August 2004, p 22. Alternatively, the ACCC allows the business to pass through the costs of certain pre-agreed events (this is equivalent to an ex-post approach).

- confirmation that the risk is not already compensated for in the forecast operating expenditure or other revenue cap costs; and
- confirmation that the allowance takes account of positive asymmetric risks as well as negative.

7.64 The Queensland Competition Authority (QCA) may also allow self-insurance where a business can "provide an actuarial assessment of the relevant risks, establish that it has the financial capacity to absorb expected losses (even before it has accumulated self-insurance premiums), and demonstrate that self-insurance premiums will remain in a dedicated self-insurance fund." [108]

7.65 In the Commission's modelling, insurance premiums paid by the businesses are included in the businesses' costs, as are any costs resulting from uninsured events that have occurred during the analysis period.

7.66 However, the Commission's approach does not include the costs to the businesses of self-insuring against the risks of catastrophic adverse events, where no such events have occurred in the assessment period. In effect, the Commission's approach assumes that businesses recover costs ex-post, i.e. if and when they occur. Thus, it assumes that businesses would raise prices after a disaster to recover the costs incurred or some other form of assistance, say from councils or government, would be provided.

7.67 The gas businesses argue that raising prices ex-post is unlikely to be feasible and is not the basis for their pricing. They argue that they recover the costs of such self-insurance on an ex-ante basis, i.e., they effectively recover a self-insurance premium in their annual revenues.

7.68 However, evidence provided by NGCT suggests that their recent price increases were motivated in part by costs incurred due to flooding, so the businesses' approach might combine both ex-ante and ex-post elements. It is not clear therefore whether businesses are setting their prices to recover disaster costs on an ex-ante basis, or whether their prices reflect an ex-post approach. Although the businesses suggest they are using an ex-ante approach, it is likely that they would use a combined approach, i.e. they would raise prices ex-ante to some extent to recover self-insurance costs, but they would also seek to recover some of the costs of an adverse event were it to occur.

7.69 In addition, if the Commission were to include an allowance for self-insurance 'premiums', the costs of adverse events if and when they occurred should be removed from the analysis (otherwise there would be double counting of the impacts). Only NGC has indicated that it has faced major adverse events during our analysis period. The costs actually incurred by NGC for such events should already be included in the analysis and therefore further compensation for NGC is not required.

7.70 Vector, Powerco and Wanganui Gas largely self-insure their networks against major risks of earthquakes, etc, but no self-insurance costs are included in the

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[108] Queensland Competition Authority, *Assessment of Pricing Principles for Infrastructure Investments in Response to Extraordinary Circumstances*, Draft Report, March 2004, p 7..

analysis, and no large events are captured in the cost data. This results in an asymmetry in treatment between these businesses and NGC in the cost benefit analysis.

7.71 The businesses were invited to provide information and evidence as to the extent of the self-insurance risks and costs they face. The evidence they provided was relatively weak. The types of criteria the ACCC or QCA use for deciding whether to allow self-insurance were not satisfied by the businesses, although this need not suggest that some self-insurance should not be recognised.

7.72 Based on [ ] insurance premiums and the relative asset values, the cost of self-insurance for Vector, which appears to face similar risks to [ ], could be in the order of $[ ], assuming the recovery of such costs solely on an ex-ante basis. If a combined ex-ante/ex-post approach were contemplated by the businesses, a lower annual cost would obtain.

7.73 The implied cost of insurance for Powerco is more difficult to estimate because its earthquake risks are likely to be substantially higher than [ ]. If its risks were [ ] those of [ ], an implied premium of around $[ ] might be reasonable, if Powerco recovered the costs of insurance on an ex-ante basis. Powerco's broker, on the other hand, suggested that insurance would cost in the order of $[ ]. This would be justifiable if Powerco's risks were [ ] times those of [ ], which seems extremely unlikely.

7.74 Wanganui Gas also self-insures to some degree. Based on a similar calculation to Vector and Powerco, their self-insurance premium could be of the order of [ ].

<u>Conclusion</u>

7.75 The Commission has included possible costs of self-insurance for disasters by Vector, Powerco and Wanganui Gas in sensitivity tests in their business specific chapters. These possible costs are not included in the base case, given the uncertainties as to the magnitude of the costs, the limited information the businesses provided, and uncertainty as to whether the businesses follow an ex-ante or ex-post insurance approach. Overseas, strict criteria are also usually established prior to any self-insurance claim being allowed by a regulator. The figures are based on the assumptions that the business would recover only a modest proportion of costs ex post, and that no other sources of compensation (e.g., government) would eventuate, if such events were to occur. NGC insures externally for floods and other events so no self-insurance sensitivity is required.

Growth Forecasts

7.76 Since the Draft Report all businesses have provided their 2004 actual revenue and expenses and, with the exception of NGC, have revised various forecast figures over the remaining analysis period.

7.77 It is difficult to determine revenues in the forecast period. They are a function of both price and output. The Commission has considered the sensitivity of net revenues to growth forecasts. It has assumed that prices do not change and has therefore focused on the output effect.

7.78 For all businesses their historic rate of growth in output was greater than their forecasts. This could be explained by either a general expected slow-down in growth for the sector or by the businesses taking a conservative view on their future prospects. The actual output provided by Vector and NGC for 2004 has exceeded the forecast previously submitted for the Draft Report and was more in line with historical trends. Wanganui Gas and Powerco have not revised their 2004 output figures since the Draft Report. The 2004 actuals and all revised forecasts are included in the base case.

7.79 To sensitivity test whether businesses may be underestimating their growth and therefore net revenues, the Commission compared the overall growth rates over the analysis period with the rates they forecast. The overall growth rates are the ones used for the dynamic inefficiency calculation (to be consistent).[109] They are based on both past and forecast information. Including forecast growth in the calculation of overall growth obviously introduces a circularity, in that, if forecast growth is understated, then this overall growth will also be understated. However, the Commission has accepted this compromise.

7.80 The difference in output between the overall and forecast output amounts is multiplied by the prevailing price to determine the potential additional revenue. From this additional revenue were subtracted any additional expenses needed (i.e., the difference between forecast expense increases and expected) and the 20% excess returns unrecoverable factor, to give the net NAB effects.

7.81 For simplicity the overall growth rate was assumed to be the same for both output and expenses. An alternative would be to link the growth of expenses to inflation rather than the overall growth of output. As the growth rate exceeds inflation for Vector, Powerco and NGCD the Commission is being somewhat conservative in their sensitivity tests. The opposite is true for NGCT and Wanganui Gas in their sensitivity tests.

7.82 The NAB effects of the above calculation are presented as a sensitivity test in the business specific chapters.

Excess Returns Unrecoverable

7.83 As explained in the previous chapter, the Commission includes an excess returns unrecoverable factor in its analysis.

7.84 In the Draft Report the Commission provided sensitivity testing of the excess returns unrecoverable factor of 20%. That sensitivity testing is updated for the Final Report and is based on a range of 10% to 25%. These results are presented in the business specific chapters.

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[109] With the exception of NGCT, all the businesses' historic and forecast growth figures for their missing market are the same. In NGCT's case, however, growth of [ ] is used in the dynamic inefficiency calculation for 1997-2002, while [ ] growth is used for 2003-2008. A figure of [ ] growth is therefore is used in NGCT's growth sensitivity.

7.85 The choice of an excess returns unrecoverable percentage has a significant impact on the costs of control, and therefore, the implicit margin on WACC provided by the costs of control.[110] This effect is also presented in the business specific chapters.

Dynamic Inefficiency Costs of Control

7.86 The Commission's cost benefit analysis assumes that control, if it were imposed, would deter some new investment, resulting in some new customers not being served (termed the 'missing market'). The dynamic inefficiencies that would arise are included in the costs of control in the Commission's modelling.

7.87 The impact of the changes is to increase the measured costs of control, compared to the figures used in the Draft Report.

7.88 The approach taken to the measurement of deterred investment is sensitive to the amount of growth assumed to be deterred and the elasticity of demand for the missing market. These sensitivities are presented in the business specific chapters.

[110] The excess returns unrecoverable factor also affects the ratio of recoverable excess returns to net efficiency effects. In the absence of regulation a business would aim for higher excess returns in the knowledge that ex-post these excess returns would be discounted.

8 ASSET VALUATION

Introduction

8.1 As described in Chapter 5 (Assessment Principles for Efficient Pricing), the valuation of assets is a key variable in the assessment of normal returns, since capital charges are a significant proportion of the total costs of a capital intensive business.

8.2 This chapter begins by discussing in general terms, the different approaches that may be used to value assets. It then compares the relative merits of historic and replacement cost valuation approaches for the purposes of the Gas Inquiry. The following sections examine the issues involved in obtaining consistent historic cost and ODV valuations for each of the businesses. Detailed discussion of the asset valuations of individual businesses can be found in the business-specific chapters of the draft report.

Asset Valuation Approaches

8.3 The Commission's preference is to use opportunity cost to value non-sunk assets, and a cost-based approach (either historic cost or ODRC/ODV) to value sunk assets. These approaches are discussed below.

Opportunity Cost

8.4 From an economic perspective, the 'cost' of an asset (resource) is not necessarily the payment actually made for it, but rather its opportunity cost (although the two may be the same). Opportunity cost is defined in standard economics textbooks as:[111]

> ...the amount lost by not using the resource (labour or capital) in its best alternative use.

8.5 Opportunity costs are relevant to decisions involving the efficient allocation of assets between alternative uses. By committing an asset to one use, all other possible uses are excluded. Some of these excluded uses may be more valuable than others. Asset owners are assumed to want to maximise the returns they get from an asset. The return owners forgo from not employing an asset in the next best alternative use is its opportunity cost. Opportunity cost is thus the highest alternative use value of assets used up or pre-empted.[112]

8.6 In competitive markets, the value of an asset that is non-specialised, and which therefore has multiple uses, is not likely to be much greater, if at all, than in its next best use. In these circumstances, the maximum amount a user would be prepared to pay for the asset would not differ significantly from its opportunity cost, and so the amount paid would be a good measure of that opportunity cost. The minimum amount needed to keep an asset employed in its current use, called the asset's 'transfer earnings', is determined by its opportunity cost.

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[111] Begg, D., Fischer, S. and Dornbusch, R., *Economics* (2nd edition), London: McGraw-Hill, 1987, p 118.

[112] Solomon, D., Economic and Accounting Concepts of Cost and Value, in Backer, M. (ed.), *Modern Accounting Theory*, 1966, Chapter 6, p 127.

8.7 Any payment below opportunity cost will result in an asset being moved to its best alternative use. Any payment above opportunity cost is an economic rent, a return over-and-above the minimum necessary to keep the asset in its current employment. A feature of competitive markets is that they tend to constrain existing use values to opportunity cost at the margin, although rents may be earned on units below the margin or on scarce resources. However, when markets are not competitive, there may be potential for businesses to earn significant monopoly rents.

8.8 When an asset is so specialised that it has few, if any, alternative uses, the opportunity cost of the asset is low. This is likely to be the case with pipeline assets. Once the investment in creating the asset has been made, the outlay cannot be recouped by re-selling the asset for some other use. The asset, or that portion of its value that cannot be recouped, is 'sunk' and the opportunity cost in relation to alternative uses of the asset is very low or even zero, as the owner forgoes very little in its present use.

8.9 If a regulator were to set a zero or low valuation for a pipeline on the grounds that this would reflect its opportunity cost, the investors who had purchased the asset in the expectation of earning at least a normal (or competitive) return would not be able to do so or would be assessed as earning excessive returns. As long as the regulator allowed the investor to earn a return above the opportunity cost of the asset, it would be in the interests of the owner to keep it employed in its current use. However, investors, finding the value of their investments reduced or eliminated, would be unwilling to replace the asset when it wears out.[113] Alternatively, if investors were aware of the regulator's intentions, the asset would never be built in the first place. Continuity of supply would therefore be put in jeopardy, and dynamic efficiency would in consequence be jeopardised.

8.10 The usual solution to this problem for the valuation of specialised assets is to assign a value to them that exceeds their 'alternative use' opportunity cost, on the grounds that continuity of supply and dynamic efficiency are very important in a capital-intensive, utility-type industry. The two options considered in the following sections are the historic cost and replacement cost valuation approaches.

Historic Cost

8.11 In the historic cost approach, the current value is derived from past capital expenditures (or the efficient level of such past expenditures) associated with the assets. The strict application of this approach requires information dating back to when the oldest assets in service were first commissioned. For long-lived pipeline assets, this may be some time ago, and the relevant information may not be readily available, although it may be possible to estimate values. Historic costs may be calculated either using original cost or original cost indexed to inflation.

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[113] For example, Armstrong, M., Cowan, S. and Vickers, J., *Regulatory Reform: Economic Analysis and British Experience*, Cambridge, Mass.: MIT Press, 1994, pp 85-86, 186-187.

8.12 When information is limited, an option is to choose an opening date from the point in time at which robust data is available, and to roll this forward on an historic cost basis.

8.13 The information needed to establish a starting valuation may be obtained from various sources including statutory financial statements, tax accounts, regulatory accounts, business and asset management plans. In using the data, two issues need to be borne in mind.

8.14 First, the values must relate only to the relevant business activities - in this case gas transmission or distribution activities. Where businesses providing gas services have also been involved in other activities, identifying relevant pipeline assets and expenditures may be difficult.

8.15 Secondly, if the relevant assets have been traded, current statements of financial position (following a trade) may reflect the value at which they were traded, rather than a value consistent with past capital expenditures. Such values could incorporate expectations of monopoly earnings. The Commission, therefore, does not support basing historic cost values on transaction values for regulatory purposes.

Replacement Cost Approaches

8.16 Replacement cost (RC) is defined as the present day cost of acquiring a substantially similar present day asset that could provide a similar level of service to the asset in question. Replacement cost is based on current market values and technology of the day. Depreciated replacement cost (DRC) recognises the write-down of replacement costs for depreciation. Optimised depreciated replacement cost (ODRC) is an estimate of the depreciated cost of the most efficient, lowest-cost combination of assets that could replace existing assets and offer the same utility or level of service, or the level of service customers prefer (whichever is the lowest).

8.17 ODV differs from the ODRC methodology by the inclusion of an ‘economic value’ test. An asset’s ODV may be lower than its ODRC where, in practice, the owner would not replace it if deprived of it (i.e. where the future free cash flows associated with an asset would not support the ODRC).

8.18 A replacement cost approach reflects the value of an asset to consumers hypothetically, if they were faced with deprival, and assuming they had the option of constructing or acquiring another asset of equivalent service potential. Alternatively, it could be considered the ‘shadow price’ a cost-minimising asset manager would give to an existing asset, when considering whether to replace or refurbish it. It also reflects the price that a hypothetical new entrant would pay for assets to enter the market and satisfy existing demand.

8.19 An important consideration in the replacement cost valuation approach is the extent to which demand will be long-lasting, such that each relevant asset will be maintained and then refurbished or replaced as it reaches the end of its economic life. Assuming demand is long lasting, the value of an asset at any time is the value of deferring future capital renewal and associated operating expenses. For example, the value of an asset with five years' remaining life is the difference, in net present value terms, between the future expenses (capital and operating) associated with a new or refurbished asset and the future expenses associated with the existing asset (which include the cost of its replacement or refurbishment in 5 years' time).[114]

8.20 When considering whether to refurbish or replace an existing asset, a replacement cost valuation should take into account all practical factors relevant to determining the future costs. For example, if an existing cast iron pipe can be refurbished by inserting a plastic liner, its replacement cost value should reflect the relatively lower cost of that relining operation compared with open trenching.

8.21 There may be some uncertainty about the future demand for services provided by an asset. In principle, this uncertainty, or the estimated risk of future stranding, could be reflected in the rate of depreciation.

Comparison of Historic and Replacement Cost Approaches for Commission's Purposes

Normal Returns

8.22 As discussed in Chapter 5 (Assessment Principles for Efficient Pricing), a business could set prices to achieve a normal return on and of capital over the life of the assets using either an historic cost or ODV approach. Desirably, the Commission would assess excess returns on the same basis (i.e. the Commission would use an historic cost approach to assess a business which set its prices using the historic cost methodology, and similarly for ODV). If the Commission matches the approach used by individual businesses, it could determine year by year whether a company was earning excess returns.

8.23 If the Commission assesses returns on a different basis to that used by the company to set prices, then the assessment of excess returns part way through the life of the assets may result in misleading findings of excess or deficient returns even though the NPV of the business' earnings over the life of the assets might be zero. These assessment problems could arise, for example, where the company sets prices on an ODV basis and accounts for revaluation gains, but the Commission assesses returns on a historic cost basis. This is because the return of capital profiles are different.

8.24 Where a business sets prices and/or claims depreciation on an inconsistent basis (e.g. on the basis of revalued assets, but does not account for revaluation gains as income), then the Commission should not use the same methodology as the company for assessing excess returns.[115] In that case the Commission must make the assessment by applying either of the approaches (i.e. ODV or historic cost approaches) in a consistent manner.

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[114] This concept is discussed in a report for the ACCC prepared by NERA, *Depreciation within ODRC Valuations*, September 2002.

[115] Lally, M. *The Weighted Average Cost of Capital for Electricity Lines Businesses*, 4 August 2003, p 57.

8.25 If a business changes its valuation and price setting methodology part way through the life of the assets, and does not treat revaluation gains consistently, then it might earn excess or deficient returns, or the assessment of such returns could be obscured. In the gas industry, some businesses have moved from an historic cost to ODV valuation method for statutory reporting purpose. Excess returns may also be disguised where historic cost valuations are based on transaction values (excess returns may be capitalised into the sale price).

8.26 The Commission does not have information for the whole life of the gas assets and must therefore assess returns on the basis of a subset of the life of the assets. Further, the Commission does not have clear information on the pricing methodologies adopted by the different businesses. Businesses do not appear to base prices on a 'pure' historic cost or ODV basis. The Commission cannot be confident that it is assessing returns on the same basis as that used by the businesses to set prices.

8.27 The Commission is therefore of the view that it should assess returns using the two methodologies described in the Chapter 5 (Assessment Principles for Efficient Pricing). The first methodology considers returns against an historic cost asset base. The second uses an ODV asset base.

8.28 However, given issues as to availability of data, the Commission has had to rely on the ODV approach. Only Wanganui Gas was able to provide historic cost data and a historic cost approach in their case is presented as a sensitivity test to the ODV approach. The relevant considerations in choosing whether to use ODV or historic costs for this Inquiry are discussed further below.

8.29 The major weakness of using ODV in this analysis compared with historic cost approaches is the possibility of obscuring excess returns that might have arisen for those gas pipeline businesses that switched from historic cost to ODV valuation prior to the period the Commission is analysing, assuming that they did not incorporate the change in their prices. If such a switch occurs during the period of analysis, the revaluation can be treated as income in assessing returns.

Availability and Comparability of Information

8.30 Information on asset valuation is incomplete and lacks robustness in some respects for both the historic cost and ODV valuation approaches. However, these concerns are greatest with the historic cost data of the businesses under investigation.

8.31 The ODV valuations are more robust than historic cost valuations and reasonably comparable between the businesses. Powerco's ODV valuations are an exception to this. Powerco's most recent formal valuations are relatively old (1999-2000) and were undertaken by the various owners of the assets at that time using different valuers. The Commission's advisers are of the view that Powerco's valuation is not robust and should be updated. Powerco have provided estimates (and forecasts) of ODV values from 1996 through to 2008 in response to the Commission's s 70E information request.

The Commission notes that it still has concerns as to the robustness of these values.

8.32 The quality and availability of historic cost information is much more variable than the ODV valuations. Good information is available for Wanganui Gas, but little historic cost information is available for the other businesses. Powerco uses historic costs in its statutory accounts, but these are based on the transaction values for the assets they have purchased, and are not therefore appropriate for the Commission's purposes. Historic cost data that Vector holds on assets obtained from UnitedNetworks also reflects transaction values. Determining the actual historic cost value for such assets is difficult, and the information produced is unlikely to be robust.

Emulating a Competitive Market

8.33 NERA, in commenting on the Commission's draft Framework paper, argues that a replacement cost-based valuation better mimics the working of a competitive market than historic cost and is therefore more consistent with the Commission's benchmark of workable competition.[116]

8.34 NERA propose that the Commission should adopt a 'hypothetical new entrant test' (HNET), in which valuation is based on the assets that a hypothetical new entrant that had access to depreciated but modern assets would use. The value of such assets would be approximated by ODRC. The HNET would abstract from the past behaviour of the businesses, since entry is a forward-looking concept.

8.35 The HNET was considered by the National Competition Council in Australia when reviewing whether the Sydney to Moomba pipeline should remain covered by the access regime.[117]

8.36 A hypothetical new entrant, in considering the returns needed to earn its cost of capital, should include expected revaluations in asset value, given that returns are based on asset value. Thus, the HNET would be broadly consistent with the second approach to assessing returns that the Commission proposes to use (i.e. the approach that uses an ODV asset base and includes revaluation gains). The main difference is that the HNET would look forward only whereas the Commission's analysis considers both past and forecast periods. However, because past information is inevitably used in assessing future returns, in practical terms, the differences between the HNET and the Commission's approach may be relatively slight.

8.37 The Commission notes that the HNET approach provides useful insights into the analysis, and that this supports to some extent the use of the ODRC/ODV approach.

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[116] NERA, *Asset Valuation for the Gas Control Inquiry: A Report for NGC Holdings*, August 2003, pp 2-3.
[117] NERA (2003) pp 23-24.

Optimisation

8.38 In a competitive market, businesses would not be able to earn a return on assets that were not needed to meet customer demand. Arguably, companies that operate in less competitive markets should not be allowed a return on redundant assets. To do otherwise would underwrite poor investment decisions, and introduce moral hazard (lack of responsibility for poor decisions undermining incentives to invest prudently).

8.39 Under the historic cost approach, it is common in overseas regulatory jurisdictions such as the United States to require assets to meet two criteria before they are allowed in the asset base: the assets must be 'prudently acquired', and they must be 'used and useful'.[118] These tests are normally applied in the context of cost of service or pure rate of return regulation. Such an approach does not adjust for changes in technology.

8.40 Optimisation is an intrinsic part of the ODV valuation process. The optimisation approach used under ODV is generally more systematic and detailed than that which may be applied under historic cost. However, the ODV approach does not eliminate the difficulty of determining whether assets were imprudently acquired or involved gold-plating in the approach we are proposing (where optimisations are treated as negative revaluations except when they result from gold-plating). As noted in Chapter 5 (Assessment Principles for Efficient Pricing), businesses subjected to optimisation should be compensated either through a margin on WACC or treating revaluation losses as income, except where the assets have been imprudently acquired. In the Commission's analysis, optimisations have been treated as negative income.

8.41 Thus, while the ODV approach to optimisation may be "more consistent with workably competitive market outcomes than the 'used and useful' and 'prudently acquired' principles" as suggested by NERA,[119] neither is clearly preferable in the context of assessing excess returns under an NPV = 0 approach.

Regulatory Contract

8.42 NGC suggested that the Government had encouraged the gas businesses to adopt ODV as part of the regulatory arrangements put in place in the early 1990s, and that in response to these signals NGC adopted ODV from as early as 1991.[120]

8.43 The Commission notes that it is not unreasonable for businesses to have adopted ODV as the basis for valuing their assets. If businesses have set prices on the basis of ODV and have treated revaluation gains as income, then it would be appropriate for the Commission to assess their performance using the ODV methodology. The Commission remains concerned, however, that the move from historic cost to ODV valuation could obscure the earning of excess returns. This could arise, for example, if businesses based their prices and

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[118] Armstrong, Cowan and Vickers (1994) p 87.
[119] NERA (2003) p 3.
[120] NGC Holdings Limited, *Commerce Commission Gas Control Inquiry: Submission in Respect of the Draft Framework Paper*, 20 August 2003, p 49.

depreciation on asset values, but did not treat revaluation gains as income for price setting purposes, or if revaluations were undertaken prior to the assessment period.

Summary

8.44 The Commission has relied on the ODV-based methodology in the Gas Inquiry. This is largely based on the greater availability of data that is more robust and comparable for this methodology compared with the historic cost approach.

8.45 Most submissions supported the use of ODV for the regulatory asset base. Mighty River Power though, suggested that the use of ODV as a methodology should be subject to further debate.[121] Powerco argued that its regulatory asset base should be based on the acquisition value of assets and that such a valuation could be consistent with the Commission's NPV = 0 approach[122]. Vector supported the use of ODV, but was of the view that the ODV Handbook should be updated to ensure optimal ODV values were used in the analysis.

8.46 The Commission remains of the view that ODV is an appropriate valuation methodology for assessing excess returns in the current context. While it would be desirable to have robust ODV valuations based on an up-to-date ODV Handbook, the Commission did not consider it feasible to achieve this in the timeframe of the analysis. The Commission is not persuaded that acquisition value should be used as the regulatory asset base, given the potential for monopoly rents to be capitalised into the sale price.

Gas Pipeline Businesses' Asset Bases

Introduction

8.47 This section summarises the issues involved in reconstructing historic cost and ODV values, and adjustments made to the data in deriving the values used in the Commission's analysis of returns using the historic cost and ODV approaches. It also discusses how the Commission has valued easements and non-system fixed assets.

Historic Cost Asset Bases

Adequacy of Historic Cost Data

8.48 The Commission sought advice on the issues that would be involved in reconstructing historic cost values for the gas businesses from Cranleigh Strategic.[123] Cranleigh reached the following conclusions:

- reconstructing a historic cost valuation for NGC would be difficult prior to 1996. NGC has reasonable accounting records from 1996 that should allow the reconstruction of historic costs;

[121] Mighty River Power, *Commerce Commission Gas Control Inquiry – Mighty River Power Submission June 2004*, 2 July 2004.
[122] Powerco, *Powerco's Submission to the Commerce Commission on the Gas Control Inquiry Draft Report*, July 2004.
[123] Cranleigh Strategic, *Gas Control Inquiry Asset Valuation – the Historic Cost Approach*, April 2004.

- prior to 2000, the entities making up the current Powerco were separate businesses. Historic cost data from the earlier period is likely to be unreliable. Powerco used transaction values to establish historic cost values in 2000, an approach that is not appropriate for the Commission's purposes. Obtaining actual historic costs for those assets is likely to be somewhat difficult, and the data may be unreliable. Satisfactory historic cost data is available for the post-2000 period;
- Vector obtained its gas assets by acquiring UnitedNetworks in 2002. The assets were previously acquired by UnitedNetworks from Orion and Enerco in 2000. Vector has reasonable historic cost information from 2000, but information prior to that date would have to be estimated, and is therefore likely to be less reliable. The 2000 historic cost values are based on the transaction values of the assets bought by UnitedNetworks. The actual historic cost figures would have to be estimated given the lack of access to actual data;
- Wanganui Gas has good historic cost records back to 1992, although gas pipeline assets can only be separately identified from 1997;
- Nova Gas has not recorded historic cost values, but rather has applied a discounted cash flow approach to valuing its assets. Obtaining a historic cost valuation would be difficult; and
- MDL does not have detailed historic cost data, and reconstruction of historic cost accounts would be difficult.

8.49 The Commission also sought historic cost information directly from the companies under the provisions of s 70E of the Commerce Act. Only Wanganui Gas was able to provide historic cost information. Vector, NGC and Powerco have been unable to supply historic cost (original cost) data.

8.50 Accordingly, a historical cost analysis was only undertaken for Wanganui Gas. This analysis is presented as a sensitivity to the ODV approach, which was adopted for all the gas pipeline businesses.

ODV Asset Bases

<u>Adequacy of ODV data</u>

8.51 The Commission sought advice on the adequacy and consistency of the ODV valuations that had been conducted by the gas businesses from Energy Market Consulting Associates (EMCa).[124]

8.52 EMCa compared the businesses' asset values against the draft gas ODV Handbook (Handbook) released by the Ministry of Economic Development in 2000.[125] The Handbook has not been formally published by the Ministry of Economic Development nor has its use by gas pipeline businesses been required. EMCa noted that some adjustments would need to be made to ensure the valuations were consistent with one another and/or with the Handbook. In

[124] EMCa, *Gas Control Inquiry: Consistency Review of ODV Network Asset Valuations*, May 2004.
[125] Ministry of Economic Development, *Handbook for Optimised Deprival Valuation of System Fixed Assets of Gas Pipeline Businesses*, First Edition, 2000.

most cases, the information needed to make such adjustments was available or could probably be obtained from the businesses.

8.53 ODV valuations were undertaken in 2003 for Vector, NGC transmission, Wanganui Gas, and NGC distribution. For MDL, an ODRC valuation was completed in 2002.

8.54 The most recent valuations for Powerco's three networks were conducted in 1999, 2001 and 2001 by valuers working for the previous owners. Valuation reports were not available for all the networks, but where they were, they appeared to have been conducted on a simpler basis than adopted by other businesses. As noted earlier, the consultants concluded that Powerco's ODV valuations were not robust.

8.55 The Commission sought ODV information directly from the companies under the provisions of s 70E of the Commerce Act. The Commission has relied on the information provided in the s 70E responses in its modelling of excess returns for each of the businesses. It has, however, smoothed the revaluation gains over prior periods as explained in Chapter 5 (Assessment Principles for Efficient Pricing).

8.56 Vector noted that the application of the ODV methodology had changed over time, so that the earlier valuations of its assets were less robust than later ones. It proposed that the earlier valuations be updated to be consistent with the later ones and then used in assessing the revaluation gains over the period. Such an assessment would have resulted in a reduction in the revaluation gains observed over the assessment period. The Commission does not accept this proposition. The ODV valuations were adopted by the business at the time, and would have been part of the context for decisions made, including decisions on pricing, while the valuations were in place. Selectively changing aspects of the past is likely to distort the assessment of past behaviour.

<u>Optimisation of Asset Base</u>

8.57 All the businesses, in preparing ODV valuations, have conducted optimisations which have affected their asset bases.

8.58 Some of the businesses have optimised on the basis of a longer planning horizon than recommended in the Gas ODV Handbook. Adjustment to correspond to the Gas ODV Handbook would result in relatively small changes. Given that the appropriateness of the planning horizon in the Gas ODV Handbook could be debated, and the relatively minor impact of any adjustment, the Commission has used the treatment of optimisation adopted by the businesses. Important business-specific optimisation decisions, [ ], are considered in the business-specific chapters.

<u>Replacement Costs</u>

8.59 The Commission has accepted the businesses' estimates of replacement costs, where estimates above the maxima appear to be supported by careful analysis rather than imposing the maxima specified in the draft Gas ODV Handbook. This position is taken due to there being in most cases both 'unders' and 'overs' in the replacement cost valuations that tend to offset each other and because any change in valuation is picked up as a revaluation gain/loss during the analysis period. EMCa has reviewed the replacement costs used for each of the businesses. These are discussed in the business-specific chapters.

Financial Costs During Construction

8.60 Financial costs during construction are included in the valuations at replacement cost. The Gas ODV Handbook is silent on the treatment of these costs. The Commission notes that work in progress should either be included in the asset base, or capitalised into the cost of capital expenditure to ensure that businesses earn a normal return on investment.

Found Assets

8.61 The Commission has not included in revaluation gains assets that have been identified as being 'found' during the assessment period. This is justified on the basis that businesses should be allowed to earn a return on all of the assets they have invested in to produce the gas service outputs. Bringing assets that already exist into the asset base involves recognition of already existing value.

Depreciation

8.62 The Commission has adopted the asset lives used by the businesses.

8.63 Depreciation has been based on either the data provided by the businesses or previously disclosed depreciation amounts in their ODV reports. The depreciation used by the Commission for each of the businesses is noted in the business-specific chapters.

Spreading of Revaluation Gains

8.64 Where the businesses have revalued their assets periodically under the ODV approach (e.g. every three years) the Commission has spread the revaluation gains calculated at that time over the period to which they relate and has smoothed the asset base. These adjustments provide results as if revaluations had been undertaken every year. For simplicity, the revaluations are evenly apportioned over the relevant years in the Commission's model.

8.65 NGC noted that the Commission's approach of smoothing revaluation gains may introduce a bias, as the model compounds revaluation gains forward as excess returns. Wanganui Gas also expressed concern about the impact of backward spreading of revaluation gains.[126] The Commission notes that any adjustment to the asset value would be at the rate of asset inflation and would therefore be relatively small. Further, there are offsetting effects on asset value and depreciation, which mean that any bias is likely to small.

Easements and Non-System Fixed Assets

Easements

8.66 Prior to 1982, gas distribution businesses had relatively ready access to construct and maintain works on private land without the need for consent from

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[126] Wanganui Gas Limited *Submission to the Commerce Commission in Response to its Gas Control Inquiry Draft Report 21 May 2004*, July 2004.

affected land owners, subject to payment of compensation. In 1982, the Gas Act came into force and the statutory right of access to private land was lost. Since 1982, gas distribution businesses have been required to negotiate with land owners for access to private land. Gas pipeline businesses continue to enjoy broad statutory powers to construct and maintain their distribution networks in road reserve.

8.67 Up until 1991, gas transmission owners had the right to require the grant of an easement over private land under the Petroleum Act 1937, subject to the payment of compensation. Gas transmission businesses lost the statutory right of access to private land in 1991 when the Petroleum Act was replaced by the Crown Minerals Act 1991. Since 1991, gas transmission businesses have generally been required to negotiate with land owners for access to private land.

8.68 Easements could possibly be valued using a historic cost, replacement cost or opportunity cost approach. The relative merits of these options are discussed briefly below.

8.69 Under an opportunity cost approach, revaluations of easements would be treated as income in the assessment of excess profits.

8.70 Given that easements cannot be transferred to a third party, they would only have value to the associated land owner. Transferring the easement back to the land owner would return the land to its next best use. The opportunity cost of the easement would be reflected in the difference between the encumbered and unencumbered value of land to the owner. Determining opportunity costs is likely to be costly given the number of properties and the differing land types involved. For rural land the opportunity cost value is likely to be low. An opportunity cost approach would ignore the past transaction costs incurred by the pipeline owners in acquiring easements, so that the opportunity cost would be lower than the replacement cost and likely to be lower than the historic costs of easements other things being equal.

8.71 The valuation of easements at replacement cost would involve a number of subjective judgments. It would result in a value being attributed to assets that would in some cases greatly exceed the cost of acquisition (particularly for easements obtained using earlier statutory powers). If the Commission were to accept the valuation of easements at replacement cost, then any associated revaluations should be included in the assessment of excess returns. Depending on the timing of revaluations, determining a basis for spreading the gains over the period of analysis may be difficult, and data limitations is likely to make this an impractical option.

8.72 A historic cost valuation approach would allow businesses to earn a normal return on the investment in easements that they have made, and would allow businesses to earn normal returns on future easement acquisitions. Valuation on a historic cost approach is likely to be relatively straightforward, and does not require subjective judgments to be made.

8.73 Where historic costs are unavailable, and the Commission is satisfied that some compensation had been paid for the easement, the Commission may discount a replacement cost for easements to a particular date in the past (the date by which the majority of current easements is thought to have been acquired) and use this value as a proxy for historic cost for easements.

8.74 NGC disagreed with the Commission's decision to value easements at historic cost, preferring instead ODV. NGC did not agree that it would be difficult to calculate a replacement cost for easements, or that such an assessment would be any more subjective than the valuation of other system fixed assets.[127] Powerco's view was that easements should be valued on the same basis as other assets.[128] Vector considered that on practical grounds, the use of historic cost to value easements was satisfactory for the Inquiry.[129]

8.75 The Commission has decided to adopt an historic cost approach to valuing easements under both the historic cost and ODV approaches to the assessment of returns. This is consistent with the approach to valuing easements in the updated ODV Handbook for electricity assets and allows businesses to earn a normal return on the investments in easements that they have made.

<u>Non System Fixed Assets</u>

8.76 Non-system fixed assets relevant to running the gas businesses have been included in the asset base. Such assets include motor vehicles, computers and head office. These are valued at historic cost for both the historic cost and ODV approaches, consistent with the approach adopted by the businesses.

Conclusions on Asset Valuation

8.77 Asset valuation is critical to the building blocks approach of assessing returns since capital charges are a significant proportion of the total costs of a capital intensive business.

8.78 As noted in Chapter 5 (Assessment Principles for Efficient Pricing), normal returns can be assessed using either an historic cost or replacement cost asset valuation methodology as long as the relevant methodology is applied consistently using an NPV=0 principle.

8.79 In the current context, however, the Commission has relied on the ODV-based methodology. This is largely based on the greater availability of more robust and comparable data for this methodology compared with the historic cost approach.

8.80 The major weakness of using ODV is the possibility of obscuring excessive returns that might have arisen for those businesses that switched from historic cost to ODV valuation prior to the period of analysis, and did not adjust prices accordingly. The Commission's assessment of returns, which ignores past

[127] NGC Holdings Limited, *Commerce Commission Gas Control Inquiry: Submission in Respect of the Draft Report*, July 2004.
[128] Powerco (2004).
[129] Vector, *Submission on the Commerce Commission's Gas Control Inquiry Draft Report*, July 2004, Annex A.

revaluation gains, may potentially underestimate the total of excess returns earned in the past.

8.81 Detailed discussion of the asset valuations used by the Commission for each of the businesses is provided in the business-specific chapters of this report.

9 WEIGHTED AVERAGE COST OF CAPITAL

Introduction

9.1 This Chapter examines the weighted average cost of capital (WACC) for gas pipeline businesses. WACC is relevant to assessing the performance of gas pipeline businesses and in particular their earnings net of the cost of capital ('excess returns').

9.2 The Commission's decisions on WACC have been informed by advice from Dr Martin Lally, whose report, the *Weighted Average Cost of Capital for Gas Pipeline Businesses*, November 2004, has been released with this Final Report.[130]

WACC Methodology

The Choice of Model

9.3 For this Inquiry, the Commission has adopted the WACC model that it used in the Airports Inquiry.[131] The model has also been applied by the Commission in respect of regulation of the telecommunications industry under the Telecommunications Act 2001, the electricity lines businesses under the Commerce Act 1986, and in establishing raw milk prices for Fonterra under the Dairy Industry Restructuring Act 2001 and Dairy Industry Restructuring (Raw Milk) Regulations 2001.[132]

9.4 The weighted average cost of capital is defined as the weighted average of the costs of equity and debt, with the latter net of the corporate tax deduction:

$$WACC = k_e(1-L) + k_d(1-T_c)L \tag{1}$$

where k_e is the cost of equity, k_d is the current interest rate on debt, T_c is the corporate tax rate (33%) and L is the leverage ratio. The cost of debt, k_d, is estimated as the sum of the current risk-free rate (R_f) and a premium (p) to reflect marketability and exposure to the possibility of default:

$$k_d = R_f + p \tag{2}$$

9.5 The Commission has used a simplified version of the Brennan-Lally Capital Asset Pricing Model (CAPM) to calculate the cost of equity:

$$k_e = R_f(1-T_I) + \phi\beta_e \tag{3}$$

where T_I is the average (across equity investors) of their marginal tax rates on ordinary income, ϕ is the tax-adjusted market risk premium (TAMRP),[133] and β_e is the beta of equity capital. This model is a simplified version of that in

[130] Lally, M., *The Weighted Average Cost of Capital for Gas Pipeline Businesses*, paper prepared for the Commerce Commission, November 2004.
[131] Commerce Commission, *Final Report Part IV Inquiry into Airfield Activities at Auckland, Wellington, and Christchurch International Airports*, 1 August 2002.
[132] The cost of equity formula was modified to reflect Fonterra's tax position.
[133] The tax-adjusted market risk premium is defined as the expected return on the market portfolio less the tax-adjusted risk-free interest rate.

Lally[134] and Cliffe and Marsden,[135] in which it is assumed that capital gains taxes are zero, companies attach maximum imputation credits to their dividends and shareholders can fully utilise the imputation credits. The model also assumes that national share markets are closed to foreign investors.

9.6 The equity beta is sensitive to the leverage ratio L. It is generally agreed that the relationship is:

$$\beta_e = \beta_a \left[1 + \frac{L}{1-L} \right] \tag{4}$$

where β_a is the asset beta, i.e., the equity beta in the absence of debt.

9.7 Equations (1) and (2) are uncontroversial, and accord with generally accepted practice. There are alternative specifications of the cost of equity capital (equation (3)) including the standard version of the CAPM,[136] the Officer[137] model, and models that recognise international investment opportunities.[138]

9.8 LECG, on behalf of NGC, support the Commission's use of the simplified Brennan-Lally model.[139]

9.9 NECG[140] argue for using the Officer version of the CAPM, noting that it is used by regulatory bodies in Australia.

9.10 The Commission's view is that the simplified Brennan-Lally model better reflects the personal tax regime operating in New Zealand than the standard CAPM version (which assumes that all forms of personal income are equally taxed) or the Officer version (which assumes that interest and capital gains are equally taxed – and therefore is not a good characterisation of the New Zealand taxation regime).[141]

9.11 NECG[142] reject the use of New Zealand data for estimating the market risk premium on the grounds that it reflects segregation of the New Zealand market

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[134] Lally, M., The CAPM Under Dividend Imputation, *Pacific Accounting Review* 4, 1992, pp 31-44.
[135] Cliffe, C. and Marsden, A., The Effect of Dividend Imputation on Company Financing Decisions and the Cost of Capital in New Zealand, *Pacific Accounting Review*, 4, 1992, pp 1-30.
[136] Sharpe, W., Capital Asset Prices: A Theory of Market Equilibrium Under Conditions of Risk, *Journal of Finance*, vol. 19, 1964, pp 425-42; Linter, J., The Valuation of Risky Assets and the Selection of Investments in Stock Portfolios and Capital Budgets, *Review of Economics and Statistics,* vol. 47, 1965, pp 13-37.
[137] Officer, R., The Cost of Capital of a Company under an Imputation Tax System, *Accounting and Finance*, vol. 34, 1994, pp 1-17.
[138] For example, Solnik, B., An Equilibrium Model of the International Capital Market, *Journal of Economic Theory*, vol. 8, 1974, pp 500-24.
[139] LECG, *Response to the Commerce Commission's Gas Control Inquiry Draft Framework Paper: Estimation of the Weighted Average Cost of Capital*, 20 August 2003, p 5; and LECG, *Response to the Commission's Gas Control Inquiry Draft Report: Estimation of the Weighted Average Cost of Capital*, paper prepared for NGC, Powerco and Vector, 2 July 2004.
[140] NECG, 2003, *Weighted Average Cost of Capital*, paper attached to *Powerco's Submission to the Commerce Commission on Gas Control Inquiry Draft Framework Paper*, August 2003, p ii.
[141] Lally, M., *The Weighted Average Cost of Capital for Electricity Lines Businesses*, report for the Commerce Commission, August 4 2003.
[142] NECG (2003) p xi.

from international capital flows, and this segregation no longer applies. Their comment implies that an international version of the CAPM might be more appropriate than the simplified Brennan-Lally CAPM model.

9.12 The Commission notes that the simplified Brennan-Lally CAPM model assumes that national equity markets are completely closed whilst the international model assumes that they are completely integrated. The truth is clearly between these two extremes although evidence suggests investors exhibit substantial home bias.[143]

9.13 The Commission also considers that the international CAPM would be difficult to apply in practice. Estimates of the required parameters are much less reliable than their domestic counterparts and there is no consensus on them. The Commission notes, however, that use of an international CAPM, where investors diversify risk across world markets, would likely provide a lower cost of capital compared to a domestic CAPM. Thus, the assumption of a domestic CAPM is favourable for the companies.[144]

9.14 The Commission acknowledges that a number of the assumptions underlying the CAPM violate real world conditions.[145] The Commission is also aware that the pricing of unsystematic risk is subject to both theoretical and empirical debate. However, the Commission believes that adjusting the CAPM to compensate for unsystematic risk would be arbitrary and ad hoc.[146] If unsystematic risks were to be compensated, an alternative model to the CAPM would be required. A study by Wright, Mason and Miles[147] identified no clear successor to the CAPM for practical cost of capital estimation.

9.15 Arguments for an increment to WACC to compensate for the loss of investment flexibility and the regulatory stranding of assets are addressed in the later section titled 'Allowances for Other Issues'.

Risk-free Rate

9.16 The risk-free rate is used in calculating both the cost of debt and the cost of equity.

9.17 The risk-free rate is the interest rate that an investor would require to willingly invest in a riskless asset. The risk-free rate is proxied by the yield to maturity on government bonds.

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143 Cooper, I. and Kaplanis, E., Home bias in equity portfolios, inflation hedging and international capital market equilibrium, *Review of Financial Studies* 7, 1994, pp 45-60.

144 See, Lally (2004) pp 62-66.

145 As already noted the simplified Brennan-Lally CAPM assumes markets are completely segregated when this clearly is not the case.

146 As noted by Malkeil and Xu (2002) only the undiversified part of a security's unsystematic risk matters and not necessarily the security's total unsystematic risk. This is the amount of unsystematic risk that is not eliminated (and remains with investors) if diversification opportunities are limited. See Malkiel, B. and Xu, Y., *Idiosyncratic risk and security returns*, Working paper, University of Texas at Dallas, 2002.

147 Wright, S., Mason, R. and Miles, D., *A study into certain aspects of the cost of capital for regulated utilities in the UK*, Report commissioned by the UK economic regulators and the Office of Fair Trading, 2003.

9.18 The major issue in determining the risk-free rate is the maturity of government bonds to use. The other issue is the period of averaging of observed returns. These issues are discussed below.

Appropriate Maturity

9.19 The CAPM is a single period model which provides little guidance as to the appropriate maturity of the risk-free rate. Regulators have typically chosen a maturity that matches:

- the lifetime of the assets used in providing the regulated service on the basis that this reflects the planning horizon of investors in those assets;
- the duration of the regulator's determination or the price setting period given that the risk-free rate will be adjusted in any subsequent reset; or
- the bond term used to measure the market risk premium.

9.20 The Commission has previously considered the appropriate term of the risk-free rate and made the following decisions:

- in the Airports Inquiry, the Commission adopted a maturity aligned with the period over which prices were set (three to five years), reflecting formal and informal understandings on this question;
- for the electricity lines businesses, the Commission proposed aligning the bond term with the pricing period without specifying a particular period.[148] Lally[149] noted that a one to five-year range for resetting prices was probably reasonable, but no particular maturity has been chosen;
- in the TSO case, the Commission chose a maturity that matched the price setting period of one year; and
- in determining Fonterra's cost of equity, the Commission used a 10-year bond rate on the basis that the discount rate used in determining the wholesale milk price must be that used for valuing the shares, according to the regulations governing that determination.[150] For this purpose, a long-term risk-free rate was appropriate.

9.21 Under price control, regulatory decisions should attempt to ensure that the value of future cash flows is equal to the initial investment. The Commission terms this the NPV = 0 principle. To meet the NPV = 0 test, the term of the risk free rate needs to match the price setting period. Although the current situation is an assessment of whether price control may or should be recommended rather than the imposition of control, returns are assessed against the NPV = 0 principle in a comparable way. For the unregulated business, the price setting period is as determined by the business.

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[148] Commerce Commission, *Regulation of Electricity Lines Businesses: Draft Assessment and Inquiry Guidelines (Process and Analytical Framework)*, 7 August 2003, p 39.
[149] Lally (2003) p 18.
[150] Section 9(1) of the Dairy Industry Restructuring (Raw Milk) Regulations 2001.

9.22 Lally[151] demonstrates that adopting the time period between regulatory reviews (the price reset period) ensures that the present value of the future cash flows equals the cost of the initial investment. Lally argues that using long-term bond rates in excess of the regulatory period will lead to revenues being too large ex-ante if the term structure is upward sloping due to a liquidity premium. If the term structure of interest rates is non-flat due to predicted changes over time in the short-term spot rate, ex-ante revenues will sometimes be too large and sometimes too small if long-term rates are used to set output prices.

9.23 Lally[152] demonstrates the case for matching the risk-free rate to the regulatory (or price reset) period as follows.

> That the choice of the risk free rate should be governed by the frequency with which prices are reset, rather than according to the duration of the firm's assets, can be demonstrated through an example appearing in Lally (2001a). Suppose that the period for which prices are set is five years commencing now, i.e.,, from time 0 till time 5. In five years, prices will be reset then for a further five years, and so on. The duration of the firm's assets is ten years. Also, suppose that the five year bond rate is currently 5% and the ten year bond rate is currently 7.5%, the latter due to expectations that interest rates in five years will be 10%. Suppose these expectations are certain to be vindicated, i.e.,, in 5 years, the bond rate will be 10% for all terms to maturity. If prices were set using the risk free rate matching the period for which prices are fixed, then a rate of 5% would be used for the next five years, followed by the use of 10% thereafter. By contrast, if prices were set using a rate matching the asset duration, the rate used would be 7.5% for the first five year period, followed by 10% thereafter. The latter approach then leads to double-dipping in the sense of the firm being rewarded for future high interest rates not only when they occur but also in anticipation of it.

9.24 The Commission's view is that the term of the risk-free rate should match the term for which prices are fixed, on the basis that charges should reflect expected costs and risks over the term for which prices are fixed but not be affected by the expectations of costs and risks beyond that point. The Commission has adopted a three-year term for the risk-free rate for gas pipeline businesses on the basis that this most closely approximates the likely time horizon of price setting in the gas pipeline industry.

9.25 The principal argument against the Commission's approach is that the term should be based on the life of the business' assets.[153] LECG, however, concede that using a rate that exceeds the price setting period would sometimes result in under or over recovery, consistent with the Commission's concerns. However, they argue that over time the over and under recoveries may be expected to balance out except if interest rates are expected to continue rising or to remain constant after rising.[154] The Commission notes that if these exceptional circumstances occur, balancing would not happen. Further, even if the over and under recoveries offset in frequency, they may not do so in present value terms.

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151 Lally, M., Regulation and the Choice of the Risk Free Rate, *Accounting Research Journal*, vol.17, 2004, pp 18-23.

152 Lally (2004) p 19.

153 NECG (August 2003), LECG (August 2003), NECG, *Response to WACC Issues in Commerce Commission's Draft Report on the Gas Control Inquiry,* report prepared for Powerco, June 2004, pp 20-21.

154 LECG (2004), p 12.

9.26 LECG argue further that use of a short-term rate introduces an additional degree of uncertainty into the business. However, if businesses recognise prevailing interest rates at the time they reset prices, their revenues will reflect these shorter term interest rates. So, the use of the shorter term rate in assessing excess returns will better match the cost of capital to the business's revenues thereby reducing rather than increasing interest rate risk. Use of a long-term rate may provide certainty in terms of interest costs but exposes businesses to real interest rate shocks through their revenues.

9.27 NECG[155] note that while businesses may borrow long-term to protect themselves against re-contracting risk, they could use hedging arrangements to alter the term of the debt to manage interest rate risk.[156] Such hedging arrangements involve costs which NECG suggest should be included in the allowed costs. The Commission agrees that such costs should be included in the analysis, but notes that such costs are likely to be already reflected in cash flows. It also notes that NECG's argument is consistent with the view that the appropriate risk free rate is the one that matches the price resetting period, rather than the long-term rate.

Average Rates

9.28 Rates could be averaged over one day or a larger number of days prior to the regulatory period. The Commission considers that a one month period is appropriate for 3-year government stock, to trade-off the timeliness of the data against smoothing of abnormal effects.

9.29 NECG[157] argue for the rate on a single day, apparently on the basis that the appropriate rate is at a point in time. If so, one should choose the last transaction of a particular day since using a daily rate also involves averaging. Thus, the debate is over the length of averaging rather than the principle of averaging. The Commission prefers to average over a longer period to reduce the exposure to unusual rates, and in the case of the Gas Inquiry believes that averaging over a month is appropriate.

Tax-Adjusted Market Risk Premium (TAMRP)

9.30 The TAMRP represents the additional premium that investors require to hold the market portfolio – a diversified basket of 'risky' assets – over and above the return that they can obtain from investing in risk-free assets subject to adjustments for personal taxes. It is not affected by company-specific factors. Continuing debate exists about the appropriate size of the TAMRP.

9.31 A number of approaches can be used to estimate TAMRP. The common approach is to observe ex-post risk-free rates, tax rates, and market returns, and calculate an arithmetic average over a number of years. Other methods include estimating the relationship between TAMRP and market volatility changes

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155 NECG, *Appendix 1: Further Advice on the WACC Received from Jerry Bowman*, 2004a.

156 NGC, *Treasury Memorandum*, attachment to their July 2004 submission, notes that NGC borrows to gain a spread of maturities, including long-term debt, and then uses swaps to target a five-year duration for interest rate hedging purposes.

157 NECG, *Weighted Average Cost of Capital*, attached to *Powerco's Submission to Commerce Commission on Gas Control Inquiry Draft Framework Paper*, 2003, p vii.

over time, forward-looking approaches that estimate the TAMRP consistent with the current value of shares and expected growth in market dividends, and survey evidence. Evidence from both domestic and foreign markets is generally considered.

9.32 In estimating the TAMRP from averaging historical returns, a time period for the analysis has to be chosen. The choice involves a trade-off between using more data (which potentially improves the statistical precision of the TAMRP estimate), and using potentially less relevant data (by using data that is too historic). Whatever period is used, there will always be some statistical uncertainty surrounding the estimate.

9.33 Dr Lally reviews the estimates of the TAMRP using the historical averaging of the Ibbotson and Siegel approaches, the constant reward to risk methodology of Merton, forward looking approaches and survey evidence using information from both New Zealand and foreign markets. He summarises the evidence as follows:[158]

> {T}he New Zealand results are .073 for the Ibbotson approach (standard deviation .027), .056-.063 for the Siegel approach (standard deviation for each point in the range is .028), .083 from the Merton approach (standard deviation .015), .054-.075 for Cornell's forward-looking approach, and .073 (.088) from survey evidence from academics (practitioners). The corresponding US results are .087 from the Ibbotson approach (standard deviation .020), .068-.078 from the Siegel approach (standard deviation for each point in the range is .020), .063 from Cornell's forward-looking approach, and .053 (.058) from survey evidence from academics (practitioners). In respect of other foreign markets the results are .084 for the Ibbotson approach (average standard deviation .022) and .059-.069 for the Siegel approach (average standard deviation for each point in the range is .023). Using mid-points in the case of range data, and forming a simple average of the survey results for each of New Zealand and the US, the results in ascending order are as follows.

New Zealand	.059, .064, .073, .080, .083	(median = .073)
US	.055, .063, .073, .087	(median = .068)
Other	.064, .084	(median = .074)

> Across the entire set of results, the range is .055 to .087 with a median of .073. For those approaches amenable to estimation of a standard deviation on the estimate, the estimated standard deviations range from .015 to .028. All of these figures invoke the ten year risk free rate… If the five year rate was used instead then, on the basis of the July 2003 differential between New Zealand five and ten year bond yields (.004), the estimate of the market risk premium would rise by .003…If the two year risk free rate was used…the estimate of the market risk premium would rise by a further .001…Such adjustments are not inconsequential, but are indicative only in view of the inability to adjust most of the estimates.

9.34 LECG[159] argue for a TAMRP of 0.09, on the grounds that the Ibbotson approach is the best methodology, and that primary reliance should be placed

[158] Lally (2004), pp 15-16.
[159] LECG (2003).

on United States data. NECG[160] also argue that the TAMRP should be estimated using the Ibbotson methodology with US data, subject to corrections for differences between the United States and New Zealand markets, and for the different CAPM models used leading to an estimate of 8.5 to 12%.

9.35 The Commission's view is that all of the different methodologies have advantages and disadvantages, but that all provide insights into the appropriate TAMRP. It therefore prefers to consider a wide range of estimation approaches.

9.36 NEGC[161] suggested that the Commission should include statistical confidence intervals around the estimated parameters. The Commission and the Commission's adviser, Dr Lally, have adopted this suggested approach. Accordingly, Dr Lally has provided an estimate of the standard deviation of the TAMRP of 0.015. NECG argue for a standard deviation around the point estimate of the TAMRP of 0.020 based on the range of point estimates observed. However, NECG's approach to estimating the standard deviation draws on less evidence than considered by Dr Lally, and the latter's estimate is therefore preferred by the Commission.

9.37 The Commission's conclusion, based on Dr Lally's analysis, is that the appropriate point estimate for the TAMRP is 0.07 with a standard deviation of 0.015. The range taking one standard deviation is therefore 0.055 - 0.085.

Consistency and Risk Free Rate in TAMRP

9.38 The risk-free rate R_f appears in two places in the CAPM formula. The first R_f appears by itself in the first term of the equation while the second R_f term is a component of the TAMRP. In determining an appropriate TAMRP, consideration needs to be given as to whether the maturity of the second R_f term, relative to which the market risk premium is measured, should be consistent with the first term of the CAPM equation.

9.39 The CAPM is a single period model with an unspecified investment horizon, which is often assumed to be five to ten years. Strictly speaking, the model is not applicable to multi-period analysis or to a single period differing from investors' investment horizon. The model says nothing about the adjustments that should be made when considering periods that do not equate to the investment horizon.

9.40 As discussed above, the Commission is of the view that the first R_f should match the price resetting period, considered here to be three years. This raises the issue of whether:

- the term of the second R_f should match the term of the first R_f (achieving consistency in the risk-free rates); or

[160] NECG, *Response to WACC Issues in the Commerce Commission's Draft Report on the Gas Control Inquiry,* prepared on behalf of Powerco, 2004.
[161] NECG (2004a).

- the term of the second R_f should not be altered, i.e., it should continue to match the generally assumed term for the investor horizon in the CAPM (5-10 years), which is independent of the particular price resetting period.

9.41 The first approach assumes that the expected return per year on the market portfolio (E_m) is invariant to the particular future period in question, even if the R_f varies in accordance with the particular future period in question. If the former is constant whilst the latter varies, then the TAMRP will also vary in line with the particular future period in question. Thus, with an upward sloping yield curve, the TAMRP measured using a three-year R_f would be higher than if the ten-year R_f was used. However, the argument for consistency rests on the assumption that the expected market return E_m is the same for all future periods, despite the observation that the risk free rate varies according to its term.

9.42 The second approach assumes that E_m would vary with the particular future period in question, in line with the R_f, to yield a constant TAMRP. This approach assumes that E_m has a term structure akin to that applying to the risk-free rate. Thus, the E_m for a one year horizon may differ to the E_m for a five-year horizon. Given that interest rates vary according to their term, and that expected market returns are likely to be related to interest rates, it appears likely that E_m would vary according to the particular future period in question.

9.43 Neither of the assumptions of the two approaches above appears likely to hold for all circumstances i.e., that E_m is invariant to the future period in question, or that it always changes in line with changes to R_f.

9.44 An advantage of the second approach is that it uses the same market risk premium irrespective of the regulatory situation. Further, the historical methodologies used to calculate the TAMRP have generally (but not always) used a five or ten-year R_f. If the first approach was adopted, and in the face of a three-year price resetting period, the TAMRP would have to be re-estimated using the three-year R_f, and this would present data collection difficulties. Another advantage of the second approach is that it also minimises the adjustments that must be made to the CAPM model, changing only those aspects of the model (the first R_f) that need to be changed in order to fit the particular regulatory situation.

9.45 LECG[162] argue that "using different risk free rates is not the CAPM" and that the risk free rate should match the life of the assets. Given that the life of the assets varies for different businesses, this would imply variations in the market risk premium across regulatory situations, which is also not compatible with the theoretical CAPM. Thus, the choice is between imperfect alternatives, given the inflexible nature of the theoretical CAPM.

9.46 The issue of whether the risk-free rates in the CAPM model should be consistent was considered in a recent decision by the Australian Competition

[162] LECG (2004) p 14.

Tribunal (Tribunal), *Application by GasNet Australia (Operations) Pty Ltd*[163] (*GasNet Australia* decision).

9.47 The *GasNet Australia* decision concerned the National Third Party Access Code for Natural Gas Pipeline Systems (Code). The Code required GasNet Australia (Operations) Pty Ltd (GasNet Australia), as a service provider, to submit to the relevant regulator, the Australian Competition and Consumer Commission (ACCC) in this case, a proposed access arrangement and access arrangement information (access arrangement). GasNet Australia was required to design an access arrangement that was consistent with the Code and to lodge it with the ACCC.

9.48 GasNet Australia had a choice of methodology for establishing the revenue to be generated from the sales of all services under the access arrangement period. It chose the 'Cost of Service' approach, which required determining a rate of return on the value of capital assets that formed the covered pipeline. GasNet Australia chose to use CAPM to determine the rate of return. The only issue for the ACCC to determine in respect of the rate of return was whether GasNet Australia had used the CAPM model correctly.

9.49 The Tribunal noted that "{w}hile it is no doubt true that the CAPM permits some flexibility in the choice of the inputs required by the model, it nevertheless requires that one remain true to the mathematical logic underlying the CAPM formula. In the present case, that requires a consistent use of the value of r_f in both parts of the CAPM equation where it occurs so that the choice was either a five-year bond rate or a ten-year bond rate in both situations".[164] It determined that a ten-year rate was in accordance with the conventional use of the model.

9.50 The Commission notes that the Tribunal did not specifically discuss in its decision, whether adopting a risk-free rate in the first term of the CAPM equation that was longer than the regulatory or price setting period would result in the business over or under recovering its returns. If it is accepted that the risk-free rate in the first term of the CAPM equation should be matched to the regulatory or price reset period, then it becomes difficult to achieve consistency between the two risk-free rates in the CAPM model (as discussed above).

9.51 As discussed above, in the *GasNet Australia* decision the only issue for the ACCC was whether GasNet Australia had used the CAPM model correctly (i.e., whether it had used the CAPM to produce a rate of return which was consistent with the conventional use of the model). The Tribunal found that it was not open to the ACCC to choose a model other than CAPM on the basis that it would produce a better outcome in terms of the objectives. The Tribunal does not state that GasNet Australia's approach was the only or best approach to use, only that the ACCC had no grounds not to approve it.

9.52 The Commission's view is that the legal framework underlying the *GasNet Australia* decision is distinguishable from that of the Commission's powers

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[163] Australian Competition Tribunal (2003) p 6.
[164] Australian Competition Tribunal (2003) pp 17-18.

under the Commerce Act. Unlike the ACCC in the *GasNet Australia* decision, the Commission in the Inquiry is able to choose the methodology that it considers most appropriate for the purposes of the Inquiry.

9.53 The Commission concludes that the application of the theoretically ‘pure’ version of the CAPM model is not possible in all circumstances and that some adaptation of the model is inevitable. Further, the Commission’s view is that the NPV = 0 principle requires the first R_f to match the price setting period, assumed in the current circumstance to be three years. This leaves the issue of whether the second R_f should match the first. The Commission notes that the case for consistency rests on the assumption that there is a flat ‘term’ structure for the market return E_m, but that this is unlikely. Further, the problem of data availability argues for use of a five- to ten-year risk free rate, consistent with the values used to calculate the market risk premium in empirical analysis. Thus, the Commission’s view is that the second R_f should continue to match the assumed investment horizon of the E_m, which is usually assumed to be five to ten years.

Beta

9.54 Beta measures the sensitivity of an investment’s return to the market return. Risk relates to the possibility that return may deviate from the expected return. The total risk of an asset or business is made up of both diversifiable risk and undiversifiable risk.

9.55 Diversifiable (or unsystematic) risk is unique to the asset or company and can be eliminated by diversification. The risk associated with technology obsolescence, increasing competition, patent approval, antitrust legislation, labour contracts, management styles and geographic location are all examples of diversifiable risks.

9.56 Undiversifiable (or systematic) risk is market risk, which is not unique to the company. Such risk cannot be eliminated by diversification. It is related to, and dependent on, the state of the economy as a whole. The sources of risk include changes in real GNP, inflation, market risk aversion and the long-term real interest rate, with the impact of changes to real GNP dominating the other impacts in terms of explaining variation in betas across businesses. The more systematic risk that is inherent in the operations of a company, the higher will be the cost of any equity used to fund its operations.

9.57 Under the framework of the CAPM, only the undiversifiable risk is relevant in determining the cost of equity. Investors are not compensated through CAPM for diversifiable risk. The CAPM framework implies that investors hold a diversified portfolio that eliminates diversifiable risk.

9.58 Beta measures the sensitivity of an asset’s return to market returns - its undiversifiable risk.[165]

[165] Non-systematic risks necessarily have no effect on beta. However, they may affect the expected cashflows and should, therefore, be dealt with there. For example, the expected cashflows may incorporate no allowance for the possibility of an adverse event, such as an earthquake. If this has a probability of 1% and will lower cashflows by $100 million in the event of it occurring, the expected

9.59 The asset beta (β_a) measures the sensitivity of a company's return to market returns when the company has no debt. The greater the extent of this systematic risk, the greater the asset beta.

9.60 As noted earlier, the equity beta is related to the asset beta by the following formula (where *L* is leverage or proportion of debt in total capital):

$$\beta_e = \beta_a \left[1 + \frac{L}{1-L} \right]$$

9.61 If a company has no debt (i.e., it is entirely financed by equity and *L*=0) then its asset and equity betas are identical. The level of undiversifiable risk associated with equity (the equity beta) is magnified according to the proportion of debt in the funding mix. The greater the proportion of debt, the greater the systematic risk associated with the residual cashflows available to shareholders, and the greater the difference between its asset and equity beta. For otherwise identical investments, a company with more debt in its capital structure will have a higher equity beta and a higher required rate of return on equity than a company with less debt.

Factors Influencing Asset Betas

9.62 Differences in asset betas across companies arise primarily from differences in the sensitivity of unlevered returns to unexpected changes in real GNP. The relevant factors that impact on asset betas are identified below.

- **Industry, i.e., the nature of the product or service**. Companies producing products with low income elasticity of demand (necessities such as energy) should have lower sensitivity to unexpected changes in real GNP than companies producing products with high income elasticity of demand (luxuries), because demand for their product is less sensitive.

- **Nature of the customer**. There are a number of aspects to this.

  The split between private and public sector demand – companies producing a product whose demand arises exclusively from the public sector should have lower sensitivity to unexpected changes in real GNP than companies producing a similar product demanded exclusively by the private sector, because demand should be less sensitive to real GNP.

  The personal/business mix, with the former likely to be less sensitive to unexpected changes in real GNP in the case of gas businesses.

  The residency mix, with demand from foreigners tending to be less sensitive to New Zealand's real GNP shocks.

- **Pricing Structure**. Companies with revenues comprising both fixed and variable elements should have lower sensitivity to unexpected changes in real GNP than companies whose revenues are entirely variable. Fixed charges are an important part of the pricing structure of gas pipeline businesses.

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cashflows should be reduced by $1 million if such risks are handled on an ex ante rather than an ex post basis.

- **Duration of contract prices with suppliers and customers**. The effect of this upon beta depends upon the nature of the shock. In the presence of a positive demand shock, a company with long term output price contracts will be unable to increase its prices upward, reducing its beta. On the other hand, its inability to increase prices in response to a cost shock increases its beta. Gas pipeline businesses generally have some long-term contracts with their customers and suppliers.
- **Presence of price or rate-of-return regulation**. Companies subject to rate-of-return regulation should have lower sensitivity to unexpected changes in real GNP, because the regulatory process is geared towards achieving a fair rate of return. Price regulation will have a similar effect, providing prices are frequently reset. However, as the reset interval increases, the price adjustment to adverse cost shocks is increasingly delayed, and this should raise the asset beta.
- **Degree of monopoly, i.e., price elasticity of demand**. So long as companies act to maximise their cash flows, theory suggests the direction of impact depends on company-specific characteristics. If monopolists do not optimise their cash flow, they can use the cushion provided by suboptimal pricing and cost control to respond to unexpected changes in demand. As a result, their returns should exhibit less sensitivity to demand, and hence to unexpected changes in real GNP.
- **Nature of the company's real options**. The existence of growth options (investments which create opportunities for valuable follow-on investments) permitting expansions of the company (adopting a new product, expanding existing operations, etc) should increase the company's sensitivity to unexpected changes in real GNP, as the values of these growth options should be more sensitive to such changes than equity value exclusive of them, and these two value components should be positively correlated. By contrast, the existence of options permitting contractions of the company should reduce the company's sensitivity to unexpected changes in real GNP, because the option value should be negatively correlated with equity value exclusive of it. By their nature, gas pipeline businesses in New Zealand do not appear to have significant growth options arising from new products. However, their networks are incomplete and therefore the option to expand their existing networks may be significant.
- **Operating leverage**. If companies have linear production functions and demand for their output is the only random variable, then companies with greater operating leverage (higher fixed to total operating costs) should have greater sensitivity to unexpected changes in real GNP because their cash flows will be more sensitive to demand.
- **Market weight**. Increasing an industry's weight in the market proxy against which its beta is defined will draw its beta towards 1, although not necessarily in a monotonic fashion. Even for a market weight as low as 5%, the effect can be substantial. Gas pipeline businesses and possible comparators have very limited weights in market indexes. Consequently, this point is not significant to gas pipeline businesses. Nevertheless, the composition of the rest of the market index may affect the beta for a given

industry (e.g. the impact of the technology stock bubble in recent years which temporarily lowered the betas of the other industries).

9.63 Comparators ideally should be similar in the above respects. However, so long as differences can be corrected for, this is not strictly necessary (and will therefore expand the set of comparators, with resulting improvement in the statistical reliability of the beta estimate).

Beta Estimates

9.64 The equity beta for a company may or may not be able to be estimated directly, by a regression of its return on the market return. Betas can only be directly estimated for listed companies. Where a beta cannot be estimated directly, a proxy or surrogate beta can be estimated from those of comparable companies, after making adjustments for differences in gearing. While such an approach is useful, it is often difficult to find comparable companies.[166] Estimation of betas invariably involves an element of judgement. Even if a beta can be estimated directly, one should still seek comparators because the statistical reliability of beta estimates for single companies are poor, due to high variability in equity returns.

9.65 Asset beta estimates for the gas pipeline businesses can be obtained from the following sources:

- the gas businesses themselves;
- comparable United States gas distribution businesses;
- comparable United States utilities, and in particular electricity utilities;
- United Kingdom gas and electricity distribution businesses; and
- comparable New Zealand companies namely electricity lines and airfield businesses.

9.66 Only one of the gas pipeline businesses is currently listed (NGC). Trading in Powerco's shares ceased in November 2004 while a third (UnitedNetworks) was listed until the end of 2002. Beta estimates have been obtained from 1999. The average of the asset betas for the three companies for the three years from January 2000 to January 2003 is around 0.2. However, given the short period of analysis, and the fact that the businesses had activities other than gas transmission or distribution, little reliance is placed on the average value obtained.

9.67 United States gas distribution businesses would be a good comparator if the New Zealand businesses operated in a largely cost-plus fashion. United States gas distribution businesses are similar in their activities and regulatory regime to United States electric utilities with the latter being more numerous. Estimates from both industries are used in drawing conclusions about the

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[166] Beta estimates in New Zealand are further complicated by the relatively small number of businesses listed on the New Zealand Stock Exchange.

appropriate beta for New Zealand gas pipeline businesses. Estimates of betas for United States electricity and gas distribution businesses, when adjusted for differences in market leverage and tax regime between New Zealand and the US are obtained from a number of sources and are summarised in Table 9.1 below.[167]

Table 9.1 Asset Beta Estimates for US Businesses

Source	Data Period	Electric	Gas	Overall
Value Line	1999-2003	.35	.17	.29
Value Line	1994-1998	.26	.26	.26
Bloomberg	2002-2003	.27	.20	.25
Alexander	1990-1994	.33	.22	.27
Ibbotson	1999-2003	.12	.06	.11
Ibbotson	1993-1997	.32	.33	.32
S&P	1999-2003	.18	.19	.19
S&P	1994-1998	.19	.32	.26
S&P	1989-1993	.34	.29	.32
Median		.27	.22	.26

9.68 While the median for the gas distribution businesses is less than for electric utilities, the difference is within one standard deviation and therefore not considered significant. The recent Ibbotson results appear to be an outlier. A possible explanation is provided by Annema and Goedhart[168] who suggest that equity betas (and values) for the telecommunications, media and technology stocks were unusually high during the period 1998-2001, and other betas correspondingly low. However, if this is the explanation, it does not appear to have affected the S&P results to the same degree, or the Value Line results at all. Ignoring all data from the period 1998-2001 raises the median of the overall results from 0.26 to 0.30. Overall, an estimate of around 0.30 for the United States gas distribution and electric utilities is indicated. Given that such businesses are subject to rate of return regulation, this is considered to set the lower bound for the New Zealand gas pipeline business beta estimate.

9.69 United Kingdom price regulated gas distribution and electricity businesses, when they were subject to five-year price resetting in the period 1990-1994,[169]

[167] A more detailed description of the data sources and associated issues can be found in Lally (2004) pp 39-43.

[168] Annema, A. and Goedhart, M., Better Betas, *McKinsey on Finance*, Winter 2003, pp 10-13.

[169] Following this period, they were subject to revenue capping which would have reduced their exposure to volume shocks.

provide useful information on the effect of price capping over a period longer than one year. There was only one listed United Kingdom gas distribution company during this period and that is not sufficient to draw conclusions from. Drawing on work by Alexander et al,[170] Lally estimated an increment for United Kingdom-style regulated companies over United States rate-of-return regulated businesses at 0.2 in relation to electricity lines businesses.[171] A similar margin might be expected to apply to gas distribution businesses.

9.70 Lally suggests that New Zealand's regulatory regime would likely result in a beta impact between that with rate of return regulation and price cap regulation. Thus, the impact of the New Zealand regulatory regime on beta is likely to be less than for United Kingdom price capped businesses and greater than for the United States rate of return controlled businesses. An adjustment to the United States businesses of around 0.10 is considered appropriate to reflect regulatory differences.

9.71 In deriving the beta for New Zealand gas distribution businesses, it is also necessary to consider whether differences between gas and electricity businesses in New Zealand justify different asset betas. Gas pipeline and electricity lines businesses are similar in respect of many of the underlying factors that influence betas, namely pricing structure (use of both fixed and variable charges), their exposure to the threat of regulation, their operating leverage and size relative to the market.

9.72 However, unlike electricity lines businesses which have largely exhausted the opportunity to expand their networks, the gas businesses have significant options to expand their networks, which may raise their betas. Further, gas supply is more heavily tilted towards commercial and industrial users (as opposed to residential users) than for electricity. Consequently, the demand for gas is likely to be more sensitive to real GNP shocks than electricity. This suggests that gas pipeline businesses warrant a modestly higher asset beta than the lines businesses, and a margin of 0.1 is assumed.

9.73 Overall, the Commission believes that the asset beta for the gas businesses is in the order of 0.5 calculated as 0.30 (US companies) + 0.10 (adjustment for regulatory environment) + 0.10 (adjustment for risk of New Zealand gas businesses relative to electricity lines businesses). The components comprising the asset beta are estimated with an associated statistical distribution. Assigning standard deviations to each of these components of the asset beta implies a standard deviation of 0.14 for the estimated asset beta.[172]

9.74 A number of parties have argued that greater reliance should be placed on particular data sources. LECG, for example, argued for a higher asset based using the most recent Value Line data.[173] MEUG argued for a lower beta

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170 Alexander, I., Mayer, C. and Weeds, H., *Regulatory Structure and Risk: An International Comparison*, 1996, paper prepared for the World Bank.

171 Lally (2003) p 26.

172 See Lally (2004) pp 47-48 for further discussion of the standard deviations for each component of the beta estimate.

173 LECG (2003).

drawing on the most recent Ibbotson data.[174] However, since any single estimate is subject to estimation error, the Commission prefers to draw on a number of sources and has included both the Value Line and Ibbotson data in its analysis.

9.75 NECG[175] suggest a standard deviation of 0.3 on the asset beta, higher than the figure derived by Dr Lally. However, they present no evidence to support this proposition.[176]

9.76 Overall, the Commission's view is that a point estimate of 0.5 is appropriate for the asset beta, with a standard deviation of 0.14. Although the characteristics of gas transmission and distribution differ in some respects, there is insufficient information available to justify applying different betas.

Tax Rates

9.77 There are two tax rates used in the WACC model: the investor tax rate in the simplified version of the Brennan-Lally model, and the corporate tax rate in the cost of debt term.

9.78 The investor tax rate is the marginal ordinary tax rate on investor income, which may include interest, dividends and capital gains. Under the simplified version of the Brennan-Lally model it is assumed that capital gains taxes are zero, companies attach maximum imputation credits to their dividends, and shareholders can fully utilise their credits. The Commission uses an ordinary tax rate of 33% in computing the cost of equity, and the statutory corporate tax rate of 33% (which in the late 1980s was 28%) in computing the after-tax cost of debt.

Leverage Weights

9.79 Two main options exist with respect to selection of the weights used to determine WACC[177]

- proportions present in the company's financial structure;
- optimal leverage inferred from the proportions present in the financial structure of comparator private sector companies (used to estimate β_a).

9.80 All these ratios involve market values rather than book values.

9.81 If a business's actual costs are used in assessing excess profits, then ideally the actual company leverage should be used to ensure consistency. If efficient costs are used to assess excess profits, then optimal leverage should be used. The Commission's analysis uses a mix of actual and efficient costs. Thus, it is unclear whether actual or optimal leverage should be used. However, the use of actual leverage is complicated by the difficulty of its measurement when a

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[174] MEUG, *Cross Submission Following Gas Control Inquiry Conference*, 2004.
[175] NECG (2004a).
[176] Other issues were raised in submissions and are considered in detail in Lally (2004).
[177] Treasury, *Estimating the Cost of Capital for Crown Entities and State-Owned Enterprises*, October 1997, p 33.

business is not listed. This suggests that optimal leverage should be used, and this is the approach adopted by the Commission.

9.82 The optimal leverage cannot be directly determined but can be inferred from examining the average level amongst relevant companies. The Commission has adopted an optimal leverage of 40% based on analysis of comparable businesses.[178] This leverage is used in calculating the debt premium and for weighting debt in the WACC.

Cost of Debt

9.83 The cost of debt is the interest rate required by investors. It is determined by way of a margin over the risk-free rate. Computed in this way, the cost of debt (k_d) is expressed by the following formula:

$$k_d = R_f + \text{Debt Premium}$$

The margin here can be estimated from the yield observed when debt is traded, less the risk-free rate at that time for bonds of the same term to maturity.

9.84 The debt premium reflects the marketability of the corporate bonds, expected default losses, and compensation for systematic risk.

9.85 The size of the debt premium is linked to a business's leverage. If a business's leverage increases, then the debt premium might also be expected to increase.

9.86 In determining the debt premium, the Commission has considered the actual premiums that the businesses pay above the risk-free rate, as well as costs to businesses with similar credit risk. The Commission is of the view that a debt margin of 0.012 would be appropriate for the gas businesses, assuming leverage of 40%. No adjustment is allowed for the cost of raising debt, given that such costs when spread over the term of the debt have a relatively small impact on WACC, and that it is difficult to remove debt issue costs from the businesses' cash flows (to ensure consistency).[179]

9.87 The cost of debt is estimated for the same period as that used to determine the risk-free rate (the period for which prices are fixed and not the duration of the gas pipeline businesses assets or its debt).

WACC Estimates

9.88 A WACC estimate can be derived drawing on the estimates for the various parameters discussed above. The market risk premium is assessed at 0.07. The suggested risk-free rate is the three-year rate for government bonds, which should in principle be set at the beginning of each pricing period and then reset every three years.[180] The three-year rate (averaged over July 2003) is 0.050. The asset beta, $ß_a$, is assessed at 0.5. Leverage is assumed to be 40% and the

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[178] Lally (2004) pp 53-54.

[179] Lally (2004) pp 54-57.

[180] Because the Commission does not know when the assumed three-year pricing periods have commenced for each business, it has updated the three-year rate each year, rather than assuming a start date and updating the three-year rate triennially.

debt premium 0.012. These parameter values translate into a cost of equity of 0.092 and a WACC of 0.072. The resulting estimate for the standard deviation of WACC is 0.012.

9.89 The point estimate on WACC reflects five parameters over which there is significant uncertainty i.e., the market risk premium and the four components of the asset beta. Such parameter uncertainty results in uncertainty over WACC and this can be formalised in a probability distribution for WACC. In translating the uncertainty over parameter values into a distribution for WACC, it has been assumed that the parameters are independent.[181]

9.90 Assuming 'normality' in the WACC distribution, the percentiles of the WACC distribution are derived as shown in Table 9.2 below.

Table 9.2: Percentiles of the WACC Distribution

Percentile	50^{th}	60^{th}	70^{th}	80^{th}	90^{th}	95^{th}
WACC	.072	.075	.078	.082	.087	.092

9.91 Thus, if one wished to choose a WACC for which there is only a 20% probability that the true value was less than this (80^{th} percentile), that WACC value would be 8.2%.

9.92 The Commission notes concerns about the asymmetric nature of errors in assessing WACC, i.e., underestimation is the more serious error because it may lead to underinvestment by the regulated companies. These considerations are taken into account in the Commission's judgment as to whether there are likely to be net benefits to acquirers from control. The Commission has used the 75^{th} percentile of the WACC distribution as the basis for judging whether there are likely to be net benefits to acquirers, but in so doing also takes into account the implicit margins that the cost of control provide. This leads the Commission to using the mid-point WACC, because the implicit margins provided by the cost of control provide protection against the Commission wrongly finding for control. The issue of the implicit margins provided by the costs of control is explained in more detail in Chapter 6 (Assessment Approach).

9.93 Other uncertainties concerning the WACC that are not incorporated in the distribution estimated above include the possibility that CAPM does not fully describe expected returns, that the version used is inappropriate and the possibility of error arising from the fact that the 'market' portfolio in the CAPM is proxied by listed equity. It is possible to quantify one of these uncertainties which is the use of a domestic rather than an international CAPM. The effect is to increase the WACC by up to .01 and such an impact is likely to outweigh other possible errors (which could be in either direction) in the upper reaches of the WACC distribution.[182]

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[181] See Lally (2004), pp 59-62 for a more detailed discussion of the derivation of the WACC distribution.

[182] For further discussion of the quantification of the impact of using a domestic rather than international version of CAPM see Lally (2004) pp 63-67.

Allowances for Other Issues

Asymmetric Risks

9.94 Asymmetric risks include the risk of assets being stranded, of assets being optimised out by a regulator (for reasons other than gold plating or imprudent investment) and of miscellaneous exposures to events such as natural disasters.

9.95 A business can deal with potential adverse events, either by raising prices ex post when assets are stranded or an adverse event occurs, or by raising prices ex ante to cover expected costs (akin to receiving an insurance premium). The latter approach could be characterised as adopting a margin on WACC.

9.96 Ideally, in assessing excess returns, the Commission would know which approach the businesses had adopted, and would then assess returns in a corresponding way.

9.97 Thus, if businesses raised prices ex post when assets were stranded, optimised or an adverse event occurred, the increased revenues would offset the increased costs and there would be no net effect on profits. Thus, the Commission would not be required to make any adjustments to its assessments. The Commission's view is that assuming businesses recover their costs ex post provides the most straightforward way of handling the risks of asset stranding and optimisation in the assessment of excess profits. In relation to stranded assets, this approach assumes that the businesses are able to increase their prices to remaining customers, if a stranding occurs. The Commission notes that it has adopted this approach for practical reasons. Where actual strandings and optimisations are similar to expectations, there is unlikely to be a substantial difference between an ex ante and an ex post approach. Where actual events are atypical an ex post approach may not be appropriate.

9.98 If businesses raise their prices ex ante, assessing excess earnings is difficult. If businesses have adjusted their prices in anticipation of adverse events but the frequency of events differs from expectations, then the measure of excess earnings could be misleading. This impact is ameliorated to some extent by conducting assessments over a period that is long enough to average such impacts. If averaging is not sufficient, the Commission would need to form a judgment as to whether any excessive profits detected could be explained by extreme events that were under-represented. This requires some judgment about an appropriate ex ante revenue increment to accommodate these costs. In addition, where adverse events occurred, the impact of these events would need to be taken out of costs to ensure that businesses were not overcompensated. Making such adjustments is likely to be difficult.

9.99 If a business was exposed to the possibility of assets being optimised out, and could not raise prices ex post, then some ex ante allowance might be warranted. Likewise, if asset stranding was possible (for example, because of a collapse in demand) and this could not be rectified through the business raising prices ex post, then businesses could be expected to raise prices in anticipation of this.

9.100 The Commission notes that if stranding or optimisations occur as a result of removal of 'gold-plated' assets or imprudent investment, no allowance to revenues or margin on WACC should be allowed.[183]

9.101 Overall, as noted above, the Commission believes that the most straightforward way of handling the risks of adverse events such as stranding is to adjust cash flows when these events occur. Where strandings that occur are similar to expected strandings, there is likely to be little difference between an ex ante and an ex post approach. Thus, for the most part the Commission has treated asset stranding and optimisation in the same way as it treats revaluation gains, i.e., they are considered as (negative) income at the time they occur. An exception to this has been the treatment of NGCT's reoptimisation of the Kapuni North pipeline. This is discussed in more detail in Chapter 12 (NGC Holdings Ltd – Transmission (NGCT)). The Commission has modelled the costs of self-insuring for other adverse events such as natural disasters as a sensitivity for those businesses that do not externally insure against such risk. In so far as uninsured events may have occurred in the past, the Commission notes that the costs of these events would be included in the data provided to it by the businesses and therefore included in the analysis.

Market Frictions and the Cost of Financial Distress

9.102 LECG has suggested that shareholders are exposed to the unsystematic risk that losses on a particular project may make it:[184]

> … costly or even impossible to raise further funds from the capital markets. Yet without such funds, the firm may have to forgo future valuable projects or shut down existing ones. This potential loss of value on other investments represents an additional cost to the firm's providers of capital for which they require compensation.

9.103 The risk in this situation is asymmetric and akin to that relating to adverse events discussed above. If the adverse event is catered for by an ex post adjustment to prices, then no further action is required by the Commission.

9.104 If the company addresses the problem through an ex ante adjustment to its prices, then the Commission would need to form a view on the appropriate ex ante adjustment. Further, it would need to remove from the company's costs, any costs of this type that were actually incurred.

9.105 The Commission notes that it has no evidence that businesses make ex ante adjustments to their prices, rather than recovering these costs as they incur. Further, if an ex ante allowance is allowed, actual costs resulting from these adverse events need to be netted out of other costs. As well, it considers that the burden of proof in demonstrating that an adjustment should be made lies with the industry. However, it has not been presented with any evidence that directly relates to the gas industry. Thus, the Commission has not made an adjustment to WACC for the costs of financial distress borne by shareholders.

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[183] Refer to Chapter 5 (Assessment Principles for Efficient Pricing) for further discussion of this matter.

[184] LECG (2003) p 20.

<u>Timing Flexibility</u>

9.106 LECG argue that where businesses have an option to delay investment, commencing a project involves not only the cost of the project itself, but also the indirect costs of using up the option. They suggest that the sacrifice of the option is an additional cost for which the company's providers require compensation, effectively raising the project's cost of capital.[185] CRA in the context of the telecommunications TSLRIC work has characterised the value attributable to the option to delay investment as additional capital on which a return should be earned.[186]

9.107 The general principle that timing options exist and that the businesses' optimal response is to delay until the expected rate of return exceeds the traditionally defined WACC by some margin is not controversial. However, the significant issue is whether this margin should be applied by the Commission in assessing excess profits.

9.108 If a business generates a surplus when assessed using traditionally defined costs, with the cost of capital defined in the traditional way, this surplus will be identified as excess returns. Such identification is appropriate if the timing option and therefore the surplus is a manifestation of market power.

9.109 However, LECG argues that timing options may arise even in a competitive market, in which case it may be argued that the returns should not be assessed as excess. Distinguishing this scenario from the exercise of market power is problematic. Furthermore, if a business had not benefited from a timing option, or had benefited in respect of some assets only, then applying a margin across all assets could disguise the earning of excess returns. Further, if the sacrifice of a timing option warrants an increase to the WACC, then the creation of growth options through investment might also warrant a reduction in the WACC.

9.110 The Commission considers that the businesses are in the best position to assess whether timing options are significant, and they have incentives to overstate their importance. The Commission concludes that the burden of proof lies with them. The Commission has not been persuaded by the evidence presented that an adjustment is justified. In particular, the businesses have not demonstrated that any timing option has been exercised, that it had applied to all of their assets, that it was unrelated to the exercise of market power, and that it was not offset by the creation of other options. The Commission has not therefore added a margin to WACC to account for timing flexibility options.

9.111 The Commission notes that there is a socially optimal point at which to invest, and regulators should be careful not to obstruct that. However, the present regulatory exercise is not one of price setting, but rather one of examining past profits. Even if the regulatory process involved the setting of a price, it is not clear that adding a margin to WACC as suggested would ensure that the businesses invested at the optimal time. In fact, given that the business would receive the margin irrespective of when it invested, it would, if it had market

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[185] LECG (2003), p 20.
[186] Charles River Associates, *TSLRIC Pricing – Financial Issues*, 16 August 2002, p 7.

power, be encouraged to invest at the earliest possible time to ensure that it maximised the period for which the margin was earned.

Business Resource Constraints

9.112 LECG also argue that some companies are unable to undertake all desirable projects because of resource constraints such as limited managerial talent. Thus, undertaking one project may sacrifice other good projects and this "foregone opportunity is an additional capital cost of the current project".[187] The Commission notes that the argument is similar to the timing option argument discussed above, and is likewise rejected because of the absence of proof.

Conclusion

9.113 The Commission's model estimates the cost of equity using a simplified version of the Brennan-Lally CAPM.

9.114 The risk-free rate is used in calculating both the cost of debt and the cost of equity. The Government bond rate is used as a proxy for the risk free rate. The term of the risk-free rate should match the term for which prices are fixed. The Commission has adopted a three-year maturity for the risk-free rate. The Commission considers that rates should be averaged over a one-month period to trade-off the timeliness of data against smoothing of abnormal effects.

9.115 The various approaches to estimating the TAMRP all provide insights that should be taken into account in determining the market risk premium. The Commission's view is that the point estimate of the market risk premium is 0.07 with a standard deviation of 0.015.

9.116 The Commission has used an ordinary tax rate of 33% in computing the cost of equity, and the statutory corporate tax rate (which in the late 1980s was 28%) in computing the after-tax cost of debt.

9.117 In selecting comparators to determine beta, the Commission considers a number of factors. In the case at hand, the regulatory environment is an important factor considered in choosing comparators. The Commission has relied primarily on beta estimates for United States gas and electric utilities, with adjustments made to reflect differences in the New Zealand and United States regulatory environments. The Commission's view is that the asset beta for the gas pipeline businesses is 0.5 with a standard deviation of 0.14.

9.118 The cost of debt is estimated for the same period as that used to determine the risk-free rate (the period for which prices are fixed and not the duration of the gas pipeline business's assets or its debt). The cost of debt is determined as a premium over the risk-free rate. The Commission's view is that a debt premium of 0.012 is appropriate for the gas pipeline businesses assuming leverage of 40%.

[187] LECG (2003) p 11.

9.119 Using these parameter values, and the average July 2003 three-year risk free rate of 5.0%, the point estimate for WACC is 7.2% with a standard deviation of 1.2%. Given that the consequences of judging excess profits to exist when they do not are more severe than the contrary error, the Commission has used as a benchmark the WACC value from the 75th percentile of the WACC distribution in judging whether there are likely to be net benefits to acquirers, but in doing so has also taken into account the implicit margin that the costs of control provide. This leads the Commission to using the mid-point WACC, because the implicit margins resulting from the cost of control provide protection against the Commission wrongly finding for control.

9.120 The Commission has handled the asymmetric risks arising from assets being stranded or optimised out of the asset base (for reasons other than gold plating or imprudent investment) through adjustments to the cash flow (i.e., on an ex post basis) for the most part. Its exception is the treatment of the reoptimisation of Kapuni North, which is explained in Chapter 12 (NGC Holdings – Transmission (NGCT)). The Commission has included sensitivity analysis of the costs of self-insurance of catastrophic events for those businesses not purchasing external insurance. It has not allowed adjustments for costs of financial distress, timing flexibility or company resource constraints.

10 TREATMENT OF TAX IN COST BENEFIT ANALYSIS

Introduction

10.1 During consultation on the Commission's Draft Report, interested parties indicated that some of the tax numbers provided by the gas pipeline businesses subject to the inquiry did not correctly incorporate the interest tax shield. The Commission acknowledged the potential error in the tax figures in a notice released on 22 June 2004 and in a statement by the Chair at the commencement of the gas conference held in July 2004. The Commission released a paper *Gas Control Inquiry: Tax Treatment in the Commerce Commission's Cost Benefit Analysis*, (Tax Paper) on 8 September 2004 and sought submissions on the paper. Submissions were provided by the four gas businesses i.e., NGC, Powerco, Vector and Wanganui Gas.

10.2 This chapter describes the Commission's approach to the treatment of tax in the cost benefit modelling.

10.3 The Commission's decisions on tax have been informed by Dr Martin Lally, whose reports *The Treatment of Gains on the Sale of Assets* (2 September 2004) and *The Interest Tax Deduction and the Calculation of Excess Earnings* (6 September 2004) were released with the Tax Paper. A further paper by Dr Lally, *Review of Submissions on Tax Treatment in the Commerce Commission's Cost Benefit Analysis* (4 November 2004) has been released with this report.

Economic Principles Underlying the Commission's Approach

Background

10.4 Businesses are required under the Financial Reporting Act 1993 to prepare financial accounts based on generally accepted accounting principles (GAAP). These accounts form the basis of reporting to shareholders and the financial community. Businesses also prepare separate tax reconciliations based on the requirements of the Income Tax Act 1994. The Commission has also constructed a set of regulatory accounts for each of the gas businesses based on the information provided by the businesses under the s 70E notices served by the Commission. The tax expense calculated using the regulatory accounts is described in this paper as prima facie tax and is based on net profit derived according to accounting rules. Tax payable is the tax obligation calculated in accordance with the Income Tax Act. Differences between these two tax numbers arise because of permanent differences and timing differences as explained in more detail below.

Principles

10.5 The Commission's assessment approach assumes that on average (over time) businesses that operate efficiently earn only normal returns. The Commission assesses the gas business' returns over time using a weighted average cost of capital considered appropriate for the gas businesses' risks. The Commission refers to this as the NPV = 0 principle.

10.6 To ensure that returns are correctly assessed and consistent with the NPV = 0 principle, the tax payable derived from taxable net profits, needs to be used in the analysis of excess returns, rather than the prima facie tax based on the profit in the regulatory accounts.

10.7 In using tax payable rather than prima facie tax, the Commission believes that businesses should pass on any benefits of lower tax payable (relative to prima facie tax) to customers and recover the costs of higher tax payable as these arise. The circumstances in which tax payable deviates from prima facie tax, and the adjustments that the Commission has taken into account in its modelling are discussed in the sections below.

10.8 An alternative approach would be for the Commission to use prima facie tax in assessing excess returns rather than tax payable. This would mean that businesses would keep the benefits of lower tax payable, and would bear the costs when these were reversed. Businesses would earn higher returns earlier on and lower ones in the future (due to diminishing value depreciation being used for tax purposes). However, such an approach deviates from the NPV = 0 principle because of the timing of the tax benefits and the possibility that when a business is growing, taxes benefits may be retained for an extended period.[188]

10.9 A further principle adopted by the Commission is that to the extent possible impacts outside the period of analysis are not taken into account in the analysis.

10.10 LECG,[189] on behalf of Vector, argued for the use of prima facie tax rather than tax payable on the following grounds: it would simplify the treatment of tax losses; it would be consistent with the use of ODV value as the regulatory asset base; and it would be more ‘time consistent’.

10.11 LECG notes that if prima facie tax is used, only small tax losses arise, which can be used up in the assessment period. This would simplify the treatment of tax losses.

10.12 However, the Commission notes that the use of prima facie tax in determining tax expense leads to excess earnings whose present value diverges from the present value of cash flows, resulting in a bias in assessing excess earnings. For that reason, the Commission prefers to use tax payable.

10.13 LECG’s second argument is that the Commission should use ODV for calculating tax payable because it has adopted ODV for the regulatory asset base. This argument was considered in detail by the Allen Consulting Group, on behalf of Powerco, and is discussed in more detail further below.

10.14 LECG’s third argument is that tax payable is likely to be low early in the years of an asset’s life and higher later on. Thus, tax payable in the past may not be a good predictor of future tax payable. The Commission may conclude that past

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[188] Lally, M., *The Treatment of Gains on the Sale of Assets*, 23 August 2004, provides worked examples that demonstrate that use of regulatory depreciation in calculating the tax expense is inconsistent with the NPV = 0 principle.

[189] Van Zijl, T., *Measurement of Income Tax for the Purposes of the Gas Inquiry Analysis*, LECG report to Vector, 23 September 2004.

prices are too high because tax payable is low. However, the same prices may be acceptable in the future when tax payable is higher. This may give rise to time inconsistencies in the Commission's decisions. In contrast, prima facie tax based on accounting rules follows a more consistent profile.

10.15 The Commission notes that if businesses set prices in accordance with the profile of tax payable and the Commission assesses returns on this basis, prices would be expected to increase as tax payable increases over time, and there would be no time inconsistency.

10.16 On the other hand, if businesses set their prices on a different basis, e.g., they smooth prices over long time periods, the assessment of excess returns part way through the life of the assets using the Commission's approach may result in misleading conclusions.

10.17 The potential for a mismatch between the Commission's assessment approach and the businesses' actual pricing methodology is a general issue and it has been considered by the Commission in relation to different valuation approaches as well as the ex ante versus ex post treatment of stranding and adverse events. These issues are discussed in Chapter 8 (Asset Valuation) and Chapter 9 (Weighted Average Cost of Capital).

Treatment of Differences between Prima Facie Tax and Tax Payable

10.18 Differences between prima facie tax calculated on the basis of the regulatory accounts and tax payable based on tax rules arise because of permanent differences and timing differences. These are discussed below.

Permanent Differences

10.19 Permanent differences arise from the differing treatment of revenue and expenses between the regulatory and tax accounts. For example, legal costs recognised as an expense under accounting rules are not always allowed as a deductible expense according to tax rules. On the income side, 'capital contributions' may be recorded as income under accounting rules, but are not assessable as income for tax purposes. These differences do not reverse over time.

10.20 In the Commission's analysis, permanent differences arising from non-assessable income and non-deductible business expenses have been taken into account in determining tax payable.

Timing Differences

10.21 Timing differences between the regulatory and tax accounts arise when the financial period in which some revenue and expenses are brought to account differs for tax and accounting purposes.

10.22 Tax rules allow depreciation on network assets at rates that are generally faster than provided by accounting rules. The diminishing value method of depreciation is predominately used for tax purposes whereas the straight-line method is used in the regulatory accounts. Asset lives under tax rules may also be shorter. This results in depreciation for tax purposes being higher than in the regulatory accounts in the earlier part of an asset's life, resulting in lower assessable income and lower tax payable in earlier periods. Tax payment is effectively deferred until later years. The result is the creation of a deferred tax liability early in an asset's life.

10.23 In the later part of the asset's life, as the tax book value and tax depreciation approach zero, the resulting tax payable is higher than the prima facie tax, reducing the deferred liability to zero.

10.24 In the Commission's analysis, timing differences relating to depreciation only have been taken into account. Other timing differences are not considered material to the analysis.

Treatment of Sale of Assets and Change in Continuity of Ownership

Sale of Assets

10.25 If physical assets are transferred or sold at arms' length, the purchase price is recorded as the opening tax book value by the purchaser. Thus, the sale of assets above the existing tax book value allows the purchaser to claim tax depreciation on a higher asset base.

10.26 If an asset is sold above its existing tax book value, tax rules assume effectively that the seller has claimed too much depreciation in the past, and the excess depreciation is then 'clawed' back. The depreciation can only be clawed back to the extent of the amount of accumulated depreciation recorded in the vendor's tax accounts, and is treated as income, which is subject to taxation at the standard rate.

10.27 The Commission, in its analysis, recognises the tax implications of the claw back of depreciation on sale.

10.28 Aside from the tax effects, the Commission does not allow businesses to use acquisition values in calculating allowed returns, and has not treated the gain on intra-sector sale of assets above ODV as income. This is consistent with the Commission's adoption of ODV as the regulatory asset base. Effectively, the Commission's approach assesses businesses as if they were only allowed a return on the ODV value of the assets and no more.

10.29 In the Commission's approach, businesses that have paid more than ODV for network assets are required to pass on to consumers the net tax benefits (taking account of tax claw back) that arise from basing tax depreciation on the acquisition value. This is achieved by using the acquisition value of the assets to calculate tax depreciation and resulting tax payable. In the Commission's analysis the tax benefits that result from high acquisition values are taken into account in assessing excess returns as they arise in the years following the acquisition. However, as discussed below, the Commission considers that for intra-sector asset sales the tax claw back upon sale of assets should be attributed to the buyer of assets, so that only the net impact of a sale on tax is considered in assessing the buyer's returns. Data limitations have prevented the adoption of this approach in the base case analysis.

10.30 The tax payable calculated on the basis of the acquisition value is generally lower than the value that would be estimated using the ODV value. Using the ODV value to assess tax payable would mean that the net tax benefits created by a transaction would be ignored in the Commission's analysis. This would be inconsistent with the Commission's NPV = 0 principle.

10.31 The Allen Consulting Group (ACG)[190] in a late submission on behalf of Powerco[191] argues that intra-sector asset sales should be ignored both for the determination of the regulatory asset base (as adopted by the Commission) and for the determination of the tax expense. Further, they argue that the tax book value at the beginning of the assessment period should match the regulatory book value i.e., it should be based on ODV).

10.32 ACG's first argument for ignoring the impact of intra-sector transactions on the tax payable is the additional complexity that results. However, the Commission notes that ignoring the tax implications of such transactions violates the NPV = 0 rule and is not therefore preferred.

10.33 ACG also argues that "prices should be set independently of the regulated entities' actual financing decisions to the extent possible"[192] to preserve incentives for businesses to adopt optimal taxation strategies. The Commission agrees that while the preservation of such incentives might be important in a regulatory setting, it is less relevant in the current circumstances where the Commission is assessing excess returns. In this assessment, the Commission has largely relied on actual costs, including actual taxation costs, rather than attempting to determine efficient costs.

10.34 ACG also suggests that the Commission has ignored the costs that arise from the claw back of tax upon sale of an asset. However, this is not the case, with the Commission explicitly recognising this effect.[193]

10.35 ACG suggests that the full gains on sale would be taxed, and that the claw back of tax has a net negative tax impact. However, the claw back of tax in New Zealand is only partial. It is limited to the extent of depreciation paid, rather applying to the full sale value (in contrast to the situation in Australia). Because the gains on sale are only partially taxed in New Zealand, a transaction above tax book value generally (but not always) results in a net tax benefit, in contrast to ACG's assumption of a net negative impact. Thus, ignoring the tax effects of the transaction would result in excess returns that arose from a transaction being ignored. This would violate the NPV = 0 rule.

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[190] Balchin, J., *Calculation of Tax Depreciation Allowances for Regulatory Purposes: Statement for Powerco*, the Allen Consulting Group, October 2004.

[191] The submission by the Allen Consulting Group, on behalf of Powerco, was received well after the closing date for submissions on the Commission's Tax Paper.

[192] Balchin (2004) para 41.

[193] Because of the difficulty of obtaining relevant data on tax claw backs from businesses that have left the industry, the Commission has modeled the impact as a sensitivity, rather than including it in the base case. The Commission also notes in Chapter 7 (Modeling Issues and Sensitivity Tests) the impact on NAB of basing tax payable on ODV value.

10.36 The Commission notes that businesses are unlikely to anticipate the sale of their assets and any associated tax claw back when they are setting prices to their customers. Thus, including the tax claw back in the assessment of the sellers' excess returns may result in misleading conclusions as to excess returns. Instead, the impact of any tax claw back is likely be reflected in the sale price of the assets and in the future revenues of the purchaser, rather than the revenues of the seller, i.e., the purchaser's revenues would be likely to alter to the extent of the net impact of the tax (with the tax claw back effect partially offsetting the tax benefit). Thus, the Commission's view is that to properly identify excess profits, the increased tax obligation of the seller (tax claw back) should be attributed to the buyer, with the aggregate tax effect of the change in ownership of the assets being attributed to the buyer.

10.37 Assessing the net impact of the tax effect upon sale poses difficulties when a transaction occurs outside the assessment period or assets are sold by an entity that is no longer in the industry because in both cases relevant data is not available to the Commission. In these situations, the initial tax disadvantage is not captured in the analysis, but the tax benefits of the transaction are, which may bias the analysis towards finding excess returns when they would not exist if the tax claw back were taken into account.

10.38 The Commission notes that this is a potential problem for the assessment of Vector and Powerco. The Commission does not have information on the tax claw back paid by the previous owners of the assets that are no longer in the industry, or for transactions that occurred outside the analysis period, and so is not able to make an adjustment for this impact. Therefore, the Commission has not adjusted the base case of Vector and Powerco to add back the clawed back tax. It has instead included some sensitivity testing of this potential impact for Vector and Powerco.

10.39 ACG also argue that the tax book value at the beginning of the assessment period should match the regulatory book value, which is ODV. By contrast, the Commission has used the tax book value, which reflects the purchase price of assets. ACG refer to the actions of the Victorian Essential Services Commission at the time of resetting output prices of the Victorian electricity distributors in 2001 in support of their position. One reason given by the Victorian regulator for this approach was the difficulty in obtaining the tax book values for the assets in question at the beginning of the regulatory period (1994). This point does not seem relevant to the New Zealand gas pipeline businesses. Another argument presented by ACG in support of their position is that use of the ODV value would provide a revenue stream that has a present value equal to the regulatory asset base.[194] However, as discussed above, the tax book value which reflects the purchase price of assets must be used to meet the NPV = 0 test.

[194] ACG note that the Victorian Essential Services Commission adopted this approach at the time of resetting the output prices of the Victorian electricity distributors in 2001. The argument noted above was suggested by the Victorian Essential Services Commission.

Change in Continuity of Ownership

10.40 Tax losses accumulate when a business is unable to apply them against its current year's profits or against the current year's profits of another company in the tax group. If the shares of a business are sold, then the tax book value of the assets does not change. However, if there is a change in the continuity of ownership (current tax law requires 49% continuity), the business forfeits tax losses that it has accumulated to that point.

10.41 The Commission has taken into account the forfeiture of tax losses in its tax modelling. This affects Powerco and is discussed in more detail in Chapter 14 (Powerco Limited (Powerco)).

Modelling the Tax Effects of the Interest Tax Shield

10.42 In the Commission's approach, excess earnings are calculated as follows:

Excess earnings = regulatory revenue – regulatory expenses excluding interest and tax – regulatory depreciation – tax rate x *(tax revenue – tax expenses excluding interest and depreciation – tax depreciation) – WACC* x *asset base.*

10.43 The Commission has constructed regulatory accounts for each of the gas businesses consistent with the objectives of Part IV of the Commerce Act. Regulatory revenue, expenses and depreciation used in the calculation of excess returns are derived from the regulatory accounts. To ensure that monopoly rents are not capitalised into asset values, the Commission has used ODV valuations in the regulatory asset base. Regulatory depreciation is calculated as straight-line depreciation on the ODV value.

10.44 In calculating excess earnings, the Commission follows standard practice in incorporating the interest tax deduction in the WACC. WACC is defined as the weighted average cost of an additional dollar of equity and debt raised at the margin, with the latter net of the corporate tax deduction:

$$WACC = k_e(1-L) + k_d(1-T_c)L \qquad (1)$$

where k_e is the cost of equity capital, k_d is the current interest rate on debt capital, T_c is the corporate tax rate (33%) and L is the leverage ratio (debt to total capital).

10.45 Consequently, the tax payable appearing in the calculation of excess earnings is the tax payable in the absence of debt (unlevered tax).

10.46 If the levered tax payable is positive, the unlevered tax payable is simply the levered tax payable plus the interest tax shield. Given that unlevered tax is defined as the tax payable in the absence of debt, it should be calculated as if there were no debt. If levered tax is not positive, then this relationship may break down.

10.47 The Commission notes that multi-utility businesses calculate tax on a group rather than individual business unit basis. Additional complexities arise from the notional allocation of expenses to the regulated businesses. Therefore, the tax figures the businesses have provided the Commission are notional in nature and bear limited relationship to the actual tax paid.

10.48 Because of these issues, the Commission has calculated the unlevered tax from the regulatory accounts and tax reconciliation information assuming the businesses have no debt, rather than adding the interest tax shield to the levered tax payable. If the unlevered tax payable is positive, this approach provides a straightforward estimate of the unlevered tax payable, which is used in the Commission's analysis. However, the interest tax shield may exceed this unlevered tax payable, thereby placing the firm in a tax loss position, i.e., levered tax payable is negative.

10.49 If the entity is in a tax loss situation (because unlevered tax is negative or the interest tax shield is large enough to outweigh positive unlevered tax) the treatment is more complex. There are three possible ways of dealing with a tax loss situation:[195]

- the first approach assumes that any tax benefit from a tax loss is used immediately, i.e., there is no deferral of the tax benefit to the future. Thus, if the unlevered tax payable is negative then the full amount is taken into the analysis of excess returns in that year rather than modelling the spread of such tax benefits into the future. In addition, the WACC incorporates the standard tax deduction for interest. This process assumes that the tax benefit from the tax loss can be used entirely in the year it arose, either in the gas business or in the wider group. Past tax losses are therefore irrelevant to the calculation in any given year;
- the second approach is similar to the first approach, except that values for the unlevered tax (if negative) and the interest tax deduction term in WACC are shifted towards zero to reflect the deferral of the tax benefit (i.e., an NPV approach to the future benefit is adopted). Past tax losses would continue to be irrelevant; and
- the third approach models the unlevered tax consistent with the actual timing of the tax payments, with associated adjustments to the WACC. Thus, if unlevered tax payable was negative in year one and could not be used until year two, that timing would be recognised in the calculation of unlevered tax i.e., zero in year one with recognition of the tax benefit in year two. It would follow that the interest tax shield for year one would be deleted from WACC, and an additional deduction would arise in the future year in which it could be used..

10.50 While the second and third approaches recognise the true timing of the tax benefits from debt, they are potentially much more complex, particularly in relation to the adjustments to WACC that would be required. Further, under the third approach, the assessment of excess earnings would reflect events in earlier years, which is not desirable when the Commission is assessing earnings part way through the life of the assets.

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[195] Lally, M., *The Interest Tax Deduction and the Calculation of Excess Earnings*, 6 September, 2004, provides some worked examples of these different approaches.

10.51 The Commission believes that the first approach is appropriate when the deferral of tax benefits is for relatively short periods, although it results in an overstatement of excess returns to some degree. Where deferral for a large number of years occurs, then the impact of deferral may be material and the second approach would be preferred. The Commission has adopted the first approach, unless there is evidence that tax benefits are likely to be deferred for a number of years, and that this deferral would have a material impact on the assessment of excess returns. Where the unlevered tax payable is negative, that negative amount is taken into the analysis of excess returns, i.e., it is assumed that an immediate refund of the full amount is received.

10.52 LECG, in their submission for Vector, suggest that levered tax needs to be considered in determining whether there is a tax loss position. The Commission notes that both the unlevered and levered tax payable need to be considered in determining whether there are tax losses.

10.53 Thus, in determining the treatment of tax for the individual businesses, the Commission has tested whether any unlevered tax losses that are created can be used in the analysis period (or beyond). In all cases, the Commission finds that such tax losses can be used, either within the gas business or the company's other businesses within the analysis period. Thus, in the cost benefit analysis the Commission employs the negative figures for Tax_u without any present value adjustment.

10.54 The Commission also tests whether the interest tax benefits from the interest tax shield (using the Commission's assumed debt equity ratio of 40%) can be offset against positive unlevered tax in the analysis period. If the interest tax benefits can not be offset within a reasonable period, the Commission has adjusted the interest rate term in the WACC equation. The most extreme assumption would be to judge that the interest tax benefits would never be offset, in which case the tax deduction in the cost of debt term within the WACC would be removed. Alternatively, the T_c term in the WACC equation can be adjusted by discounting T_c at the risk free rate to reflect the period in which it is used. The Commission has adopted the latter approach where relevant.

10.55 Thus, the Commission has adjusted Powerco's WACC in the years 2005-2008 to reflect its inability to make full use of the interest tax deductions over those years, on the assumption that the tax benefits can be used in 2010. No adjustments were made for the other businesses.

11 COMPARATIVE BENCHMARKING

Background

11.1 The Commission, in its Draft Framework Paper, discussed the potential role of comparative benchmarking in its assessment of pipeline pricing efficiency. In that paper the Commission noted it had reservations about the ability to properly account for different cost drivers, but indicated it would consider the use of comparative benchmarking to supplement its building block approach.

11.2 The Commission invited interested parties to comment on the potential for using the benchmarking approach, and four parties addressed this question in their submissions on the Commission's Draft Framework Paper.

11.3 NGC, CRA (on behalf of NGC), Powerco and Wanganui Gas indicated qualified support for the use of comparative benchmarking within this Inquiry. However, the support was conditional on the Commission addressing a number of issues inherent to international benchmarking. The primary issues related to the use of robust data, recognising controllable and uncontrollable factors and normalising for operating conditions.

11.4 After considering these submissions, the Commission engaged Meyrick & Associates (Meyrick) to undertake a comparative benchmarking study of New Zealand and selected Australian gas pipeline businesses. The Meyrick report[196] was released with the Commission's Draft Report.

11.5 During consultation on the Draft Report the Commission received submissions on the Meyrick report from Wanganui Gas and Pacific Economics Group (PEG), on behalf of NGC and Vector, and a benchmarking analysis undertaken by PEG that compared two New Zealand gas distributors (Vector and NGC) to forty US gas distributors.

11.6 The Meyrick report comparing New Zealand and Australian businesses and the PEG report comparing New Zealand and US businesses are discussed in the sections below.

Comparison with Australian Pipeline Businesses (Meyrick Report)

11.7 Meyrick's study of gas distribution businesses used data from each of the New Zealand firms and ten Australian gas distributors. Meyrick used the multilateral TFP index method applied to 2003 data to obtain a snapshot of comparative performance of distribution businesses. Some additional time-series results were also presented for transmission pipeline comparisons.

11.8 In its submission to the Commission PEG suggested that "TFP level indexes do not generally control as well as econometric techniques for differences in the scale of output(s) on expected cost" and basing a benchmarking study on one year of data, which could include anomalies or outlier conditions, is generally not as robust as those based on multi-year models. PEG also suggests it is

[196] Meyrick and Associates, *Comparative Benchmarking of Gas Networks in Australia and New Zealand, Report prepared for the Commerce Commission*, 14 May 2004.

important to look beyond Australia and New Zealand in order to obtain broader samples of gas distributors and potentially undertake a wider range of benchmarking techniques.[197]

11.9 The Commission notes that controlling for differences in scale is a key issue particularly when the subject businesses have large differences in size. Although econometric methods have the potential to control for differences in scale, their ability to do so will depend on the characteristics of the sample they are estimated for, how well they fit the data and the absence of multicollinearity. Meyrick has attempted to overcome the scale issue, to some extent, by limiting comparisons to Australian gas pipeline businesses which are more similar in size and are considered to face relatively similar operating environment conditions. Meyrick and the Commission consider scale problems are likely to be much more severe between New Zealand and the US samples (PEG international benchmarking study) than between New Zealand and Australia (Meyrick international benchmarking study).

11.10 Meyrick used the 2003 New Zealand Disclosure Data[198] and responses to information requests (made under s 70E of the Commerce Act) as the primary information sources for the New Zealand distribution businesses: NGC Distribution, Powerco, Wanganui Gas and Vector. Final approvals by Australian state regulators and associated access arrangement information filings were used as the primary data sources for the Australian comparators: Envestra Albury (NSW), Envestra Queensland, Envestra South Australia, Allgas Queensland, Country Energy Wagga (NSW), Envestra Victoria, Multinet (Victoria), TXU Networks (Victoria), AGLGN (NSW) and ACTEW–AGL (ACT).

11.11 For transmission, Meyrick used the New Zealand Disclosure Data and responses to the s 70E information request as the primary information sources for NGCT and final approvals by the Australian Competition and Consumer Commission (ACCC) and associated access arrangement information filings for 7 Australian gas transmitters: EAPL Moomba to Sydney, Epic Moomba to Adelaide, APT Central West (NSW), Envestra Riverland (South Australia), GasNet and VENCorp (Victoria), NT Gas Amadeus Basin to Darwin (Northern Territory) and Goldfields Transmission (Western Australia).

11.12 Meyrick estimated a distribution model containing two outputs (throughput and customer numbers), and made adjustments to allow for differences in energy and customer density. Meyrick notes that system capacity is also an important output, which would ideally be included in the distribution model. However, data limitations precluded its inclusion in this study. For the transmission model Meyrick used as outputs, throughput and a proxy for system capacity. Both the distribution and transmission models had two inputs – operating and

[197] Pacific Economics Group, *Comments on Meyrick and Associates Reports Prepared for the Commerce Commission's Inquiry into New Zealand Gas Transmission and Distribution Sectors*, June 2004, p 4.
[198] Information that is publicly disclosed pursuant to the Gas (Information Disclosure) Regulations 1997.

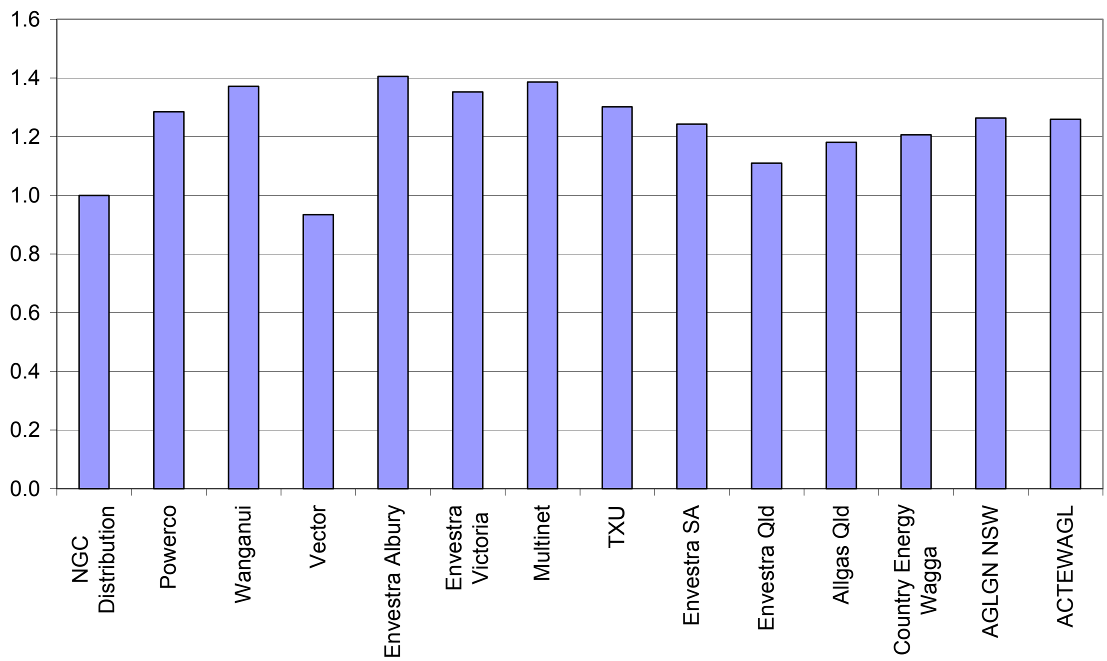
maintenance expenditure and capital. Pipeline length was generally used as a proxy for capital quantities.

11.13 Meyrick also note that further input from the sampled firms would be necessary to ensure consistent coverage of data across the sample, particularly relating to operating and maintenance expenditure.

11.14 Meyrick concludes in its report to the Commission, that while the approaches adopted make the best use of the data available, the results of the study should be considered indicative rather than definitive. Details of Meyrick's benchmarking analysis are not reproduced here, but are described in Meyrick's report to the Commission.[199]

11.15 Meyrick's results, using the distribution TFP model together with an adjustment for customer and energy density, suggest New Zealand distributors are, on average, about 21 per cent less productive than the Australian comparators. Making no allowance for customer density differences leads to the Australian distributors having over twice the productivity of the New Zealand distributors on average. The adjusted distribution TFP results are shown in Figure 11.1.

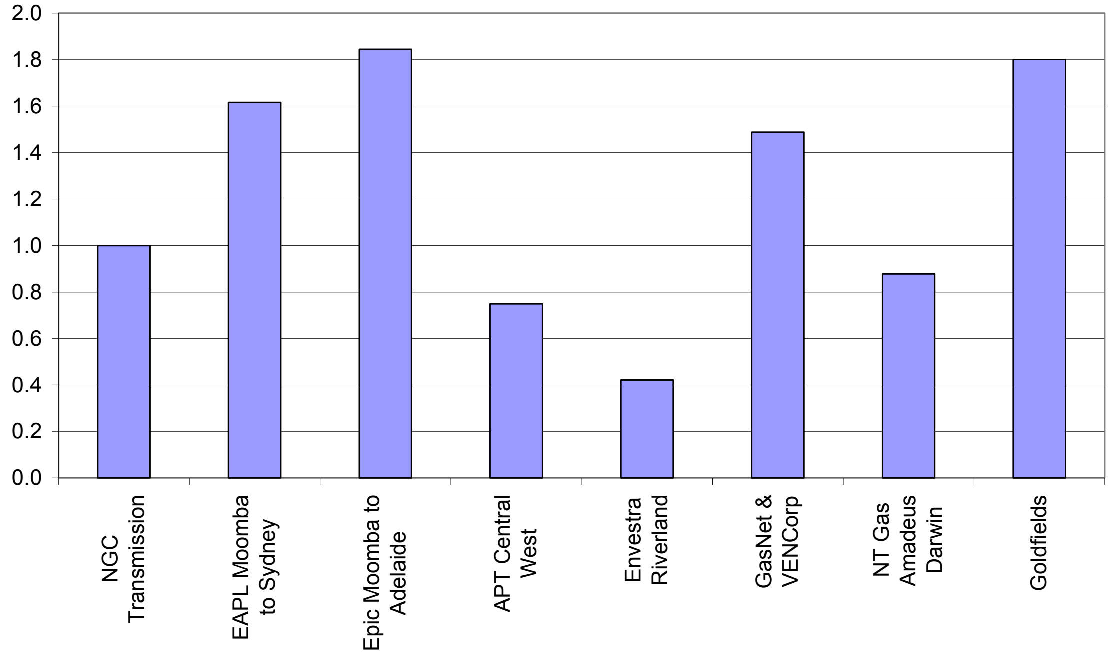
Figure 11.1: Distributor Adjusted TFP Indexes for 2003



11.16 The results from the transmission model suggest that NGCT is about 57 per cent less productive than the Australian comparators, on average. However, Meyrick notes that the transmission model is less developed than the distribution model and data constraints prevented operating conditions being accounted for, which makes interpreting the results difficult. The transmission TFP results are shown in Figure 11.2.

[199] Meyrick and Associates, *Review of PEG Gas Inquiry Papers*, 19 November 2004.

Figure 11.2: Transmission TFP indexes, 2003



11.17 PEG suggest that the Meyrick study does not control adequately for differences in customer density and where Meyrick attempts to control for differences in customer density it uses the relationship PEG estimated between total cost and outputs rather than between operating and maintenance costs and outputs.[200]

11.18 The Commission acknowledges that while Meyrick's method of analysis for distribution businesses sought to normalise for important uncontrollable factors such as energy and customer density, the limited number of observations available for the study meant that such normalisation could not be made with a high degree of confidence. Also, the choice of outputs in Meyrick's TFP model was severely limited by the available data, and the measurement of capital inputs was similarly constrained. In particular, there were no robust or consistent measures of system capacity available. With respect to the use of the PEG estimated relationship between total cost and outputs, this was the only relationship available from PEG's published results and Meyrick considered this to be a good approximation as operating and maintenance costs are more likely to be influenced by customer numbers than throughput, as reflected in the 86 per cent weight given to customer numbers.

Comparison with US Pipeline Businesses (PEG Report)

11.19 In addition to the review of the Meyrick benchmarking study, PEG, on behalf of Vector and NGC, undertook an analysis on the overall cost performance of Vector and NGC relative to US utilities. PEG's research can be briefly summarised as follows. Data from US and NZ utilities were used to estimate econometric cost functions. This process yielded estimates of the underlying

[200] Pacific Economics Group, *Comments on Meyrick and Associates Reports Prepared for the Commerce Commission's Inquiry into New Zealand Gas Transmission and Distribution Sectors*, June 2004, pp 5 and 7.

'drivers' of gas distribution costs. These estimates, together with a set of operating conditions facing New Zealand gas distribution businesses, were used to generate predictions for the total cost of providing gas distribution services. The performance of Vector and NGC could then be evaluated by comparing the businesses total cost predictions to the businesses actual costs.[201]

11.20 PEG suggests that the results of the analysis indicate that for the 1997-2002 period, NGC's total costs were 30.3% below its predicted value and for the 2000-2002 period Vector's total costs were 21.4% below its predicted value. The results were statistically significant leading PEG to conclude that both businesses were superior cost performers.

11.21 The Commission engaged Meyrick to review and comment on the PEG study. The Meyrick report entitled Review of PEG Gas Inquiry Papers has been released with this Final Report.

11.22 Taken at face value, the results of PEG's analysis suggest that Vector and NGC are efficient operators compared to the US distributors. However, as discussed in the Meyrick review of the PEG analysis, there are a number of factors that need to be considered in assessing the results of the PEG study.

11.23 The principal concern with the PEG analysis is the large difference in size between the US and New Zealand businesses. PEG's US sample of 40 distributors includes only one distributor (Central Hudson Gas and Electric) which has fewer customers than Vector (the largest New Zealand business used in the PEG study) and over a quarter of the US sample are over 10 times larger than Vector in terms of customer numbers. The largest distributor in the US sample (Southern California Gas) is over 70 times larger than Vector based on customer numbers and the average of PEG's US sample has around twelve times the customer numbers of Vector.

11.24 Another factor raised by Meyrick is the PEG analysis only includes two operating environment variables other than input prices. As noted above, scale adjustments will be problematic given the fact that the New Zealand distributors are well outside the US size range. However, equally important is the fact that the key operating environment differences between New Zealand and the US are not included. These environment differences include climatic differences, the presence of perma–frost, differences in industrial usage, population density and lifestyle influences. While environmental factors will affect the New Zealand and Australian comparison they will be more pronounced in the New Zealand and US comparison given the contrasting conditions in those countries.

11.25 Meyrick provides further comment on the PEG report in its paper entitled Review of PEG Gas Inquiry Papers.

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[201] Pacific Economics Group, *New Zealand Gas Distribution Cost Performance: Results from International Benchmarking*, June 2004, p 1.

11.26 Overall the Commission considers the PEG study and the issues identified by Meyrick highlight how difficult it is to make robust comparisons between businesses in different countries.

Conclusion

11.27 Taken at face value, the results of the Meyrick and PEG analyses provide conflicting evidence on the efficiency of the New Zealand distribution businesses.

11.28 While Meyrick's method of analysis for distribution businesses sought to normalise for important uncontrollable factors such as energy and customer density, the limited number of observations available for the study means that such normalisation could not be made with a high degree of confidence. Also, the choice of outputs in Meyrick's TFP model was severely limited by the available data, and the measurement of capital inputs was similarly constrained. In particular, there were no robust or consistent measures of system capacity available. Meyrick also note that internationally there have been very few efficiency studies undertaken on gas transmission pipelines and performance measurement is not yet well developed for this activity.

11.29 With respect to the PEG analysis the Commission is primarily concerned with the large difference in size and environmental conditions between New Zealand and the US and PEG's ability to normalise for these factors.

11.30 As a result of the conflicting evidence and the unresolved factors associated with the two analyses, the Commission draws no definitive quantitative conclusions from the benchmarking analyses undertaken to date. Overall the Commission considers that the benchmarking analysis undertaken by Meyrick and PEG reinforces its prior reservations, and those expressed in submissions by interested parties on the Draft Framework Paper, about the ability in such studies to make like for like comparisons given the data currently available.

12 NGC HOLDINGS LTD – TRANSMISSION (NGCT)

Introduction

Company History / Ownership

12.1 Natural Gas Corporation Limited was established in 1967 as a state-owned entity for the purpose of buying, processing and wholesaling Kapuni natural gas. In 1969, gas transmission pipelines were constructed by Natural Gas Corporation linking Kapuni with Auckland and Wellington, and in 1970 Natural Gas Corporation commenced transmitting gas in bulk following the completion of the Kapuni Gas Treatment Plant (KGTP).

12.2 In 1978 the Government established Petroleum Corporation of New Zealand (Petrocorp) as a state-owned company. Natural Gas Corporation in turn became a wholly owned subsidiary of Petrocorp. Petrocorp became a publicly-listed company in 1987 following a 30 per cent sell down by the Government. By 1988 Fletcher Challenge had acquired 100 per cent of the shares in Petrocorp.

12.3 In 1991 Natural Gas Corporation Limited acquired Natural Gas Corporation of New Zealand Limited and other associated companies. In 1992 Natural Gas Corporation Holdings Limited was established as the new parent company and acquired Natural Gas Corporation Limited. In 2002 Natural Gas Corporation Holdings Limited formally changed its name to NGC Holdings Limited (NGC) and adopted its current corporate brand. NGC is majority owned (66.05%) by the Australian Gas Light Company (AGL) and its wholly owned subsidiaries, with the public and institutions owning the remaining 33.95%. Vector has recently made an offer to buy AGL's shareholding in NGC. The Commission has assessed NGC on the basis that it operates as a company separate from Vector's operations.

Extent of Vertical Integration

12.4 NGC's main business activities today are gas transmission and distribution, accounting for approximately [ ] of assets and [ ] of revenues. NGC transports natural gas from Taranaki to locations throughout the North Island, and from the northern end of the Maui pipeline at Rotowaro to the north of the North Island. NGC's gas transmission network is made up of four main pipeline systems and is approximately 2,200 km in length. NGC also owns and operates medium and low pressure gas distribution networks which distribute natural gas from transmission pipelines to end customers.

12.5 NGC owns and operates the KGTP in Taranaki, which treats and conditions raw gas so that it meets retail market specifications. NGC sells LPG, natural gasoline and carbon dioxide, produced as by- products of the treatment process.

12.6 NGC has wholesaled between [ ] and [ ] PJ of gas per annum over the last three years to non-affiliated gas retailers, independent power producers, petrochemical producers, approximately 500 large industrial and commercial sites throughout the North Island and for NGC internal purposes.

12.7 NGC has discontinued its activities in the gas retail mass market (sold to Genesis Power Limited in 2002), but continues to retail gas to commercial/industrial consumers with annual consumption above [ ].

12.8 In 2001 NGC withdrew from the electricity retail market (selling its South Island electricity customers to Meridian Energy and the North Island customers to Genesis power), and in 2002/2003 NGC withdrew from the electricity generation market (with sales of its interests in the Southdown Generation Station and Rotokawa Geothermal Station output to Mighty River Power, the Taranaki Combined Cycle Power Station to Contact Energy, and the Cobb Hydro Station to Trustpower). However, NGC continues to hold a small interest in electricity generation through its joint venture interest in the Kapuni Cogeneration Station (KCS). The KCS is a 50:50 joint venture between NGC and Bay of Plenty Electricity (which Todd Energy Limited has a 50% interest in) and has a rated output of 25 MW of which 20 MW is exported to the national grid.

12.9 NGC also continues to hold a 25.1% interest in Wanganui Gas Limited. NGC purchased the shareholding from the Wanganui District Council in 1992. Wanganui Gas distributes and retails gas in Wanganui, South Taranaki and the Rangitikei. It also retails gas (under the Direct Energy New Zealand brand) in Whangarei, Auckland, Gisborne, Hawke's Bay, Taranaki and Manawatu.

Gas Transmission Activities

12.10 NGC's transmission activities are referred to as NGCT within this report. NGCT transports natural gas from Taranaki to locations throughout the North Island, and from the northern end of the Maui pipeline at Rotowaro to the north of the North Island. NGCT's high pressure natural gas transmission network is made up of the following major sub-systems:

- North & Central: Starting at Kapuni and extending north to Rotowaro (near Huntly), through Auckland to Henderson and further north to Whangarei and Kauri (810.7 km);
- Bay of Plenty: Starting at Pokuru (near Te Awamutu) and extending east to Tauranga, Taupo, Rotorua, Whakatane, Opotiki and Gisborne (608.3 km);
- South: Starting at Kapuni and extending south to Wellington with a branch extending east to Palmerston North and Hastings (696.1 km); and
- Frankly Road: Starting at Frankly Rd (near New Plymouth) and taking gas from the Maui pipeline to large customers in Taranaki and to the KGTP (72.3 km).

12.11 NGCT's natural gas transmission network is approximately 2,200 km in length and predominantly supplies gas to the petrochemical and electricity generation industries, as well as to other gas distributors and retailers. In 2003 the total number of NGCT customers was [ ]. Sales made by NGCT represented around [ ] of NGC's total sales revenue.

12.12 NGCT is also employed by MDL to operate the onshore Maui pipeline which runs between the Oaonui Production Station in Taranaki to the Huntly Power Station just north of Hamilton.

Table 12.1: NGCT Pipeline Statistics (year ended 30 June 2003)

System	Length (km)	Total Gas Conveyed (GJ)
North & Central	810.7	47,617,430
Bay of Plenty	608.3	11,638,711
South	696.1	12,962,102
Frankly Rd – Kapuni	72.3	21,092,803
Total	**2,187.4**	**93,311,046**

Competition Analysis

Introduction

12.13 The generic competition issues applying to gas services in general are discussed in Chapter 3 (Competition Analysis). However, each gas services market has distinguishing characteristics, and accordingly, the networks of each business are considered separately in this Report.

12.14 NGCT operates what it describes as a neutral non-discriminatory open access regime for its transmission networks. It is a signatory to the New Zealand Gas Pipeline Access Code of July 1998 (Code). It states that it understands that the dispute resolution procedure in the Code has never been invoked.

Competition

12.15 The markets in which NGCT operates are that for the provision of gas transmission services between North Taranaki and Huntly (North Taranaki to Huntly market) and that for the provision of gas transmission services for the rest of the North Island (North Island market).

12.16 As discussed in Chapter 3 (Competition Analysis), gas transmission has natural monopoly characteristics. Transmission operators incur high fixed and sunk costs and relatively low variable costs. In these circumstances it is possible that one firm in any area is able to undertake the transmission function at a lower average cost than two or more firms. This is likely to deter more than peripheral entry, except where the existing pipelines are utilised to their full capacity. NGC in its submission to the Commission on the Draft Framework Paper stated that there are currently no capacity constraints in its transmission system, although there would not be sufficient capacity in the system between Huntly and Auckland to accommodate a major additional load such as a new generation plant in the Auckland region. It is possible that in order for a new electricity generator to receive transmission services near Auckland, a new pipeline would be required, and this could be provided by a new entrant to the market (although NGCT would be likely to have an advantage over other potential transmitters when it came to constructing the new pipeline if it could use its existing easements). In any event, the Commission considers that potential entry is not sufficiently certain or likely to make a material difference to how it views the competitive situation in the transmission markets in the relevant timeframe.

12.17 The Commission has received a number of submissions on the extent to which other fuel forms compete with gas and therefore constrain the price which can be charged for transmission and distribution services. Examples were provided of instances where users of gas had switched to electricity, coal, LPG, diesel and wood.

12.18 The Commission accepts that some energy users do have a choice of fuels, although for many this may be limited to when their energy specific plant or appliance is nearing the end of its economic life. However, the information provided to the Commission and discussed in the Generic Competition Issues section of Chapter 3 (Competition Analysis) suggests that interfuel competition is not sufficient in itself to place strong competitive pressure on gas suppliers.

12.19 In addition, the Commission notes that transmission accounts for perhaps 10 per cent of the final price of gas. Therefore, the competitive constraint other energy forms place on gas prices is dissipated in its impact on the transmission function.

12.20 The Commission accepts that large gas users may have entered long-term transmission contracts when they undertook their original investment (and when they still had discretion over location and fuel choice). These contracts may give these gas users protection against transmitters of gas exercising market power.

12.21 The existing regulatory regime, including information disclosure and the threat of regulation, may also provide some constraint on NGCT. However, the Commission does not consider that these constraints, taken together, match the constraints faced by a firm in a market which has workable or effective competition.

North Island Market

12.22 In the North Island market (i.e., excluding North Taranaki to Huntly) there are no competing transmission pipelines. Further, the Commission considers that entry into the market by a competing transmitter of gas is not likely in the foreseeable future.

12.23 NGCT is constrained to a limited extent in the North Island market by interfuel competition, by existing contractual obligations, by the countervailing power of purchasers and by the regulatory regime. However, for the reasons described above, the Commission considers that the constraints on NGCT in this market fall well short of the constraints found on businesses in a market where competition is workable or effective.

12.24 The Commission concludes that competition is limited in the North Island market.

The North Taranaki to Huntly Market

12.25 Between North Taranaki and Huntly the NGCT pipeline (known as the North line) and MDL's Maui pipeline run parallel to each other.

12.26 NGC has submitted that there is potential for competition between the two pipelines in this market.

12.27 The North line is 200 mm in diameter, was built in 1969 to carry Kapuni gas and is capable of carrying 10 to 11 PJ per annum. The Maui pipeline was constructed in 1978 to carry Maui gas, is 700 mm in diameter, and is capable of carrying 125 PJ per annum.

12.28 In terms of the current contractual arrangements only Maui gas can be carried in the Maui pipeline. However, the parties to the Maui Gas Contract are currently negotiating to amend the contract to allow for the carriage of both Maui contract gas and other gas under an open access arrangement.

12.29 Since the Maui pipeline was established and until 2001, the only gas going north from Taranaki was Maui gas carried on the Maui pipeline as far as Huntly. The Kapuni to Rotowaro portion of the North line was used for storing gas, not for the transmission of gas. However, since 2001 the North pipeline has been used to carry non-Maui gas north, and is currently operating at capacity. Because the North line is now used to transport gas, NGCT reoptimised it back into its asset base.

12.30 NGC stated in its submission dated 20 August 2003 that it considers that there is competition between the Maui pipeline and the North line as far as Rotowaro and that the existence of this competition means that a control recommendation in respect of that part of the North pipeline could not be justified.

12.31 PEANZ in its submission on the Draft Framework Paper of 20 August 2003 (para 36) stated that it disagreed with the view that the two pipelines would compete with each other. It noted that the difference in capacity between the two pipelines is significant and that a gas user requiring anything other than relatively small volumes of gas to be transported would not be able to use the North line. PEANZ suggested that the North pipeline will, at best, provide only minimal constraint on pricing and behaviour of the Maui pipeline. In response CRA, for NGC, argued that while PEANZ might be correct in that view, it does not mean that the North pipeline is not constrained by the Maui pipeline.

12.32 The Commission accepts that the Maui pipeline provides some competition to NGCT in this market, and that competition is likely to intensify when the proposed Maui open access arrangements are put in place. However, there are important differences between the pipelines. Only the NGCT pipeline can be used for transporting non-Maui gas north until the open access regime is introduced. Second, the North pipeline is used primarily to carry gas to areas north of Huntly which, of course, is beyond the extent of the Maui pipeline.

12.33 The Commission considers therefore that there is some constraint placed on the North pipeline by the Maui pipeline, but that this constraint is limited.

12.34 The Commission also accepts that some limited competitive constraint in this market arises from interfuel competition and from the regulatory regime. However, this constraint falls short of that faced by firms in markets where competition is workable or effective.[202]

Conclusion on Competition

12.35 Having regard to the above matters, the Commission's view is that the requirement in s 52(a) of the Commerce Act is satisfied. It considers that competition for the provision of the transmission services provided by NGCT is limited. This applies in respect of the market for the provision of gas transmission services between North Taranaki and Huntly, and the market for the provision of gas transmission services for the rest of the North Island.

Benefits and Costs of Control

Introduction

12.36 The Commission outlined its approach to deriving estimates of the potential benefits and costs of controlling gas services in Chapter 6 (Assessment Approach). The models presented in that chapter are now applied to the gas services supplied by NGCT.

12.37 The remainder of this chapter identifies the key inputs and assumptions within the cost benefit analysis; any adjustments made to the business specific data provided; the results and sensitivities from the cost benefit model; and additional issues in considering whether control should be introduced.

12.38 All figures are for the year ended 30 June, the balance date nominated by NGCT. Appendix C contains the NGCT analysis and results from the Commission's cost benefit model.

Inputs and Assumptions

12.39 The Commission required all the gas pipeline businesses to complete a data template for the years 1996-2008. A specimen of the template is included as Appendix B. The data sought by the template related to revenues, expenses and the asset base.

12.40 NGCT completed the data template with a few exceptions, which are noted below. The data provided by NGCT was reviewed by the Commission with clarification or further background information being obtained from NGCT as required. NGCT has provided actual results for 2004 since the Draft Report.

12.41 The Commission made adjustments to the data where it considered this necessary for the purposes of the benefits and costs of control assessment. Specific issues and adjustments to the NGCT data are explained below.

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[202] Interfuel competition is discussed in more detail in Chapter 3 (Competition Analysis).

Revenues and Other Income

12.42 [

]

12.43 NGCT has excluded from its revenues income earned from Maui, LTS deferred income, and third party services. Each of these adjustments is material.

12.44 NGCT treats capital contributions as income. The level of capital contributions has been insignificant.

12.45 The Commission considers that forecast revaluation gains will be at least in line with CPI. [

] It has allowed these additional revaluation gains to be offset by the businesses' forecasts of future optimisation and higher incremental depreciation charges and allowed revenues.

Operating Expenses

12.46 [ ] The bulk of the variation appears to be in the 'common costs' and 'other operating costs' categories. NGCT provided an explanation for this increase in operating expense and a breakdown that reconciled the operating costs provided for this Inquiry with the total operating costs contained within the gas information disclosure accounts. NGCT's operating costs have been used in the Commission's analysis.

Common Costs

12.47 The Commission has reservations as to the common cost allocation of all the gas pipeline businesses. This is discussed in Chapter 7 (Modelling Issues and Sensitivity Tests).

12.48 In NGCT's case, the Commission has not made an adjustment to the base case at this time.

12.49 However, the Commission still has reservations as to the allocation of common costs by NGCT. The indirect cost ratio for NGCT is substantially higher than the comparable revenue and direct cost shares for gas transmission vis à vis other activities, although NGCT notes that based on an asset ratio it could potentially allocate further indirect costs to its pipeline activities. Evidence provided by NGTC also indicates it has changed the way it allocates common costs, which has resulted in an increase in indirect costs when compared to its previous disclosures. This increase has ranged from $1.5m to $4.5m per annum over the period 1997 to 2003.

12.50 The Commission has accordingly included a sensitivity of the results that measures the effect of assuming common costs were 10%, 20% or 30% lower than the figures provided.

Self-insurance

12.51 NGCT insures externally for major risks such as earthquake, storms, etc. It has also experienced some risk events during our analysis period. The costs of NGCT's insurance and the costs of events which are not fully covered by insurance are included in the Commission's analysis. NGCT has also explained that its recent price increases are due in part to such events.

Tax

12.52 NGCT's tax was calculated using the Commission's approach outlined in Chapter 10 (Treatment of Tax in Cost Benefit Analysis). NGCT provided the tax book value movements including acquisition value, current depreciation, accumulated depreciation and written down tax book value which were used in the Commission's analysis.

12.53 [

]

Inquiry Costs

12.54 NGCT included Inquiry costs in its s 70E response for 2003 - 2005. The Commission has removed NGCT's Inquiry costs from the operating expenses as the Commission includes Inquiry costs within the direct costs of control calculation across the entire analysis period.

Asset Base and Depreciation

12.55 NGCT has owned its transmission assets for the entire duration of the analysis period. NGCT adopted ODV to value its asset base in its statutory accounts in 1997, but the first ODV valuation of the transmission assets was undertaken in 1991.[203] The ODV values provided by NGCT within the data template were based on disclosure data for the years in which it undertook ODV valuations (1997, 2000, and most recently 30 June 2003).

12.56 NGCT's ODV valuation approach differs from the draft Gas ODV Handbook (the Handbook) dated June 2000 in some respects. [

] NGCT's approach leads to both 'unders' and 'overs' in its ODV value compared to what may be expected under the Handbook. On balance, the Commission considers that the ODV value can be used for the purposes of this Inquiry and has therefore not made adjustments for the differences between NGCT's approach and the specifications in the Handbook.

[203] Cranleigh Strategic Limited, *Gas Control Inquiry: Asset Valuation – the Historic Cost Approach*, April 2004, p 1.

Re-optimisation of Kapuni North

12.57 In the Draft Report the Commission treated optimisation and re-optimisations symmetrically as decreasing or increasing asset values with accompanying income losses and gains within its model as these events occurred, i.e., it adopted an ex-post approach to assessing such events.

12.58 NGC has suggested that optimisation should be treated on an ex-ante basis. In this approach, positive and negative optimisations would enter the asset base but would not be treated as positive or negative income. The companies would bear the risk of the level of optimisation turning out greater or less than expected, with the Commission including an ex-ante premium over WACC as compensation.

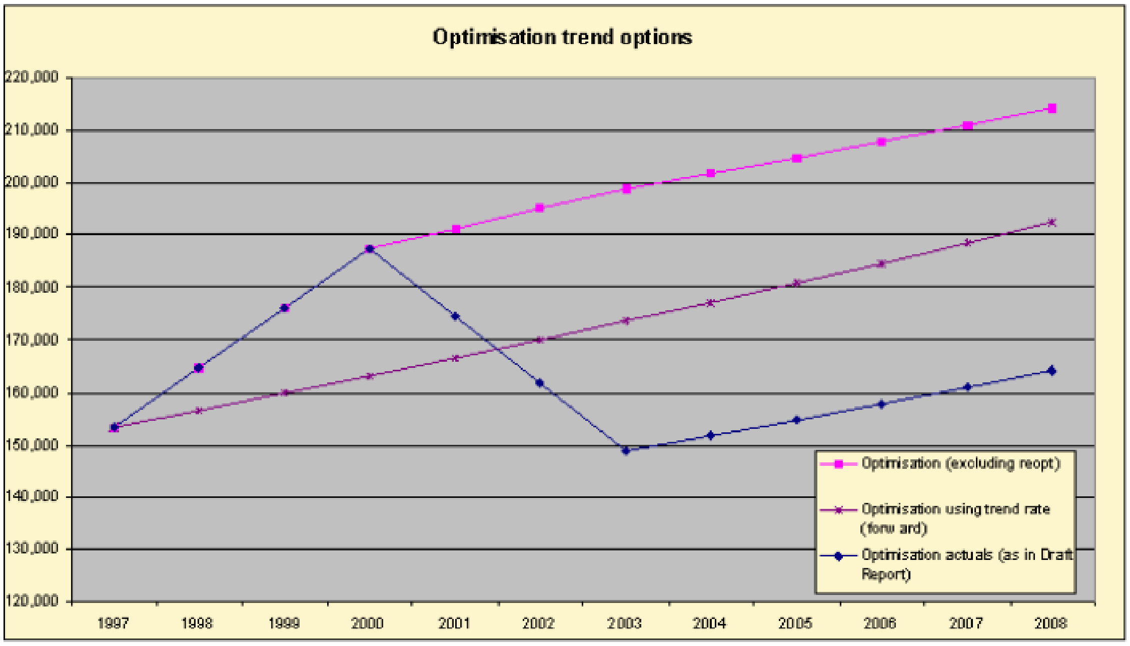
12.59 Where optimisations are reasonably steady over time, there is likely to be little difference between an ex-ante and ex-post approach. This is because the costs of actual events are likely to match the ex-ante premium that would apply to an ex-ante approach (assuming that an ex-ante premium can be accurately estimated). However, where there are one-off events, or events that are not evenly distributed over the analysis period, there is likely to be a divergence between the ex-ante and ex-post approaches. In this case, the ex-ante premium will also be more difficult to accurately estimate.

12.60 NGCT suggests the [ ] re-optimisation of the Kapuni North pipeline is a one-off event that is not evenly distributed over time. Under NGC's proposed ex-ante approach the re-optimisation of the Kapuni North pipeline would be allowed back into the asset base without it being treated as income.

12.61 The Commission's preference is still for an ex-post approach. However, as a result of the NGC submission the Commission considered a number of approaches for dealing with the Kapuni North pipeline re-optimisation. The Commission considers the best approach is to establish an ex-ante trend for optimisations based on the ex-ante expectations included in NGCT's own forecasts of future optimisation amounts. The Commission has decided to adopt this approach in NGCT's case regarding the Kapuni North pipeline.

12.62 Over the forecast period (2004 – 2008) NGCT expects optimisations to grow at [ ] per cent per annum. The Commission has taken the 1997 optimisation figure provided by NGCT and inflated this over the entire analysis period at NGCT's [ ] per cent optimisation trend rate (middle line at 2008 in graph below).

Figure 12.1 Optimisation Approaches ($000)



12.63 The main reasons for the trend rate approach being the preferred option are:

- the proposed approach is consistent with the ex-ante approach NGCT claim to use;
- the Commission has not undertaken an audit of the asset base or ODVs, making judgements and adjustments for single optimisation events difficult and potentially inconsistent. The Commission considers that the approach adopted overcomes the issue of considering and making judgements on a number of optimisation events such as the following:
  - whether the whole of the Kapuni North pipeline re-optimisation necessarily represented an outlier in the period. The Commission did not fully agree with NGCT that the entire Kapuni North Pipeline re-optimisation should be ignored;
  - there were other changes in optimisation amounts that could be equally challenged as being outliers (e.g., the level of optimisation for compressors increased $19 million or 600% from 1997 to 2000 with this amount being booked as a negative income in NGCT's favour in the Draft Report); and
  - although the optimisation of Kapuni North pipeline occurred before the analysis period, and therefore this revaluation loss is not treated as income, it should be noted that overall there were net revaluation gains in the past, which saw NGC with a $110m revaluation reserve in 1997.[204] The Commission has chosen to ignore this gain to NGC's advantage.

[204] Natural Gas Corporation Holdings Limited, *Annual Report,* 1997, pp 23 and 32.

- the proposed approach uses NGCT's forecast information to determine the trend.

12.64 The Commission allows changes in optimisation to be treated as income. Therefore, both the income and the asset base are affected by restating the optimisation figures using the NGCT's optimisation trend rate.

12.65 The Commission considers that the trend rate approach is the best option, because it is more consistent with an ex-ante approach to optimisation (which NGC claim it is using), uses NGCT's own forecast information and overcomes the issue of considering and making judgements on individual optimisations.

Depreciation

12.66 The depreciation values provided by NGCT for this Inquiry were higher than those recorded in the 2000 and 2003 NGCT ODV reports. The Commission has adjusted the NGCT depreciation figures provided so that they are consistent with the depreciation figures that appear in the ODV reports.

Easements

12.67 NGCT values its easements using a replacement cost methodology. The Commission sought, but was unable to obtain, historic cost information on easements from NGCT.[205] In the absence of this information the Commission calculated a notional historic cost value for easements in the Draft Report by deflating the 1997 easement valuation provided to 1974 using the CPI. On this basis NGCT easements were valued at [ ].

12.68 NGCT submitted that to estimate the 'historic' cost value of its easements in 1997, the Commission should deflate one third of the easement's replacement cost in 1997 to 1974 values and deflate the remaining two thirds of the replacement cost to 1983, as this would better reflect when the pipelines were installed. The Commission has accepted this approach as reasonable and revised the valuation of easements for NGCT to [ ]

Other Asset Valuation Issues

12.69 Within the information provided, the value of the non-network fixed assets [ ] over the period 2004-2008, but the associated depreciation [ ] over the period. The Commission has assumed a constant non-network depreciation policy for the period. The Commission has held the 2004 depreciation rate fixed between 2004-2008 as a proxy for the constant depreciation policy.

12.70 NGCT data includes the transmission metering assets, which NGCT considers intrinsic to the gas transmission business.

12.71 SCADA and control systems, and stores and spares have been recorded at depreciated historic cost.

12.72 NGCT was unable to provide historic cost information on its overall asset base for this Inquiry.

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[205] Refer to Chapter 8 (Asset Valuation) for the discussion on the Commission's decision to value easements at historic cost.

Summary of Base Case Variables

12.73 The Commission has developed a 'base case' in its model. The base case includes the adjustments to the input data noted above, the mid-point of WACC, an excess returns unrecoverable factor of 20%[206], and elasticity of demand of -0.1.

12.74 Table 12.2 presents the key variables of the analysis, using the base case in 2003 as an example.

Table 12.2 **Key Variables - NGCT**	**Figures (2003)**
Revenue ($000)	78,466
Net earnings (NE) ($000)	38,069
Actual quantities (Q_m) TJ	90,762
Actual price (P_m) $/GJ[207]	0.86
Efficient quantities (Q_c) TJ	91,923
Efficient price (P_c) $/GJ	0.75
Elasticity	-0.10
WACC	7.19%
Asset base ($000)	394,607
ODVS system assets ($000)	386,450
Other non-system assets ($000)	8,157
Revaluation gains/loss spread ($000)	11,234

Net Acquirers Benefit (NAB)

Introduction

12.75 Given the Commission's view that NGCT faces limited competition in the market for its services, the Commission must consider whether the requirement in s 52(b) of the Commerce Act is satisfied; whether control is necessary or desirable in the interest of acquirers. In order to determine whether s 52(b) is met the Commission carries out a NAB test. The Commission's recommendations on whether gas services may be imposed are based on the results of the NAB test.

12.76 The benefits and costs of control measured for the purposes of the NAB test are explained in detail in Chapter 6 (Assessment Approach). In summary, the benefits of control relate to improvements in efficiency (in terms of allocative, productive, and/or dynamic efficiency) and the reduction of any excess returns that might be achieved by control. The costs of control include the direct costs of control (quantified in Chapter 6) and the indirect costs associated with the creation of any additional inefficiencies (i.e., productive inefficiency, service

[206] Refer to the Indirect Costs section of Chapter 6 (Assessment Approach) for a discussion of the excess returns unrecoverable factor.
[207] The 'actual' price is a notional average price based on NGCT's revenue and gas throughput.

quality deterioration, and/or new investment foregone) and/or the potential benefits not being fully realised in practice (measured as the unrecoverable excess returns and the allocative efficiency not achieved).

The Results

12.77 Table 12.3 presents the results of the Commission's base case of the NAB test over the period 1997 - 2008.

Table 12.3 **NAB Results - NGCT**	**($000)**
Benefits	
Excess returns	4,536
Allocative efficiency - consumer surplus	25
Productive efficiency	609
Dynamic efficiency	0
Costs	
Direct Costs	
Compliance cost	-347
Regulator's cost	-253
Indirect Costs	
Excess return unrecoverable	-1,084
Allocative efficiency not achieved	-13
Productive inefficiency	-236
Service quality deterioration	-375
New investment foregone	-498
Key Results	
Annuity	2,364
NPV (1997-2008)	31,946

12.78 The largest component within the potential benefits of control is the removal of excess returns. The potential efficiency benefits (in terms of allocative, productive, and dynamic inefficiency) are modest in comparison to the potential benefits of removing excess returns.

12.79 The largest component within the potential costs of control is the indirect costs of control, in particular the amount of excess returns that are unrecoverable by control, in NGCT's case.[208] The sensitivity of the results to the unrecoverable excess returns has been modelled below.

Sensitivities

12.80 The Commission has tested the sensitivity of the results of the benefits and costs modelling to changes in key variables. The sensitivities tested were the WACC range, the unrecoverable excess returns of control, NGCT's common costs, forecast growth and dynamic inefficiency.

WACC

12.81 The WACC represents an approximation for the opportunity cost of committed funds.

12.82 The sensitivity of the result to the WACC values was tested by using 75th and 25th percentile of the WACC distribution in the model.[209] Table 12.4 presents the results of this sensitivity testing and the base case of the mid-point of WACC in annuity terms.

Table 12.4 Sensitivity to WACC - NGCT	**75th**	**Mid-point**	**25th**
NAB ($000s) annuity	-263	2,364	4,913

12.83 The Commission's view is that the mid-point of WACC is appropriate when it is recognised that the costs of control also allow NGCT to effectively earn above that point. NGCT is able to earn a margin of 0.6% above the mid point because of the costs of control. At the 75th percentile of WACC, NGCT can earn an additional 0.8% before NAB is found (i.e., NGCT can earn 1.4% above the mid-point of WACC before NAB are found). The Commission does note, however, that NGCT gets the lowest implicit margin from the costs of control, although it is still significant.

Growth

12.84 Chapter 7 (Modelling Issues and Sensitivity Tests) notes that NGCT's forecast growth rates were below those historically achieved, and that 2004 actuals suggested a greater growth rate than had been previously forecast.

12.85 The Commission compared the expected growth rates for NGCT [ ] with the rates they forecast [ ]. The Commission's expected growth rates are the ones used for its dynamic inefficiency calculation (to be consistent).[210]

12.86 The difference between the expected and forecast output amounts is multiplied by the prevailing price to determine the potential additional revenue. From this additional revenue were subtracted any additional expenses needed (the

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[208] For a further breakdown of the costs of control refer to Chapter 6 (Assessment Approach).
[209] Refer to Chapter 9 (Weighted Average Cost of Capital) for a discussion on the WACC range.
[210] In NGCT's case growth of [ ] is used in the dynamic inefficiency calculation until 2002. [ ] growth in the missing market is assumed going forward from 2002.

difference between forecast expense increases and expected)[211] and the 20% excess returns unrecoverable factor, to give the net NAB effects.

12.87 [ ] The effect on the NAB of NGCT would be to increase it by $1.141m in annuity terms if [ ] growth were used.

Unrecoverable Excess Returns

12.88 The unrecoverable excess returns factor represents the amount of excess returns that is considered to be unrecoverable by control and is labelled an indirect cost of control in the Commission's assessment.

Table 12.5 Sensitivity to Unrecoverable Excess Return Factor - NGCT	**25%**	**20%**	**10%**
NAB ($000s) annuity	2,090	2,364	2,912

12.89 The sensitivity of the results to unrecoverable excess returns by control was tested by using figures of 10% and 25%. The unrecoverable excess returns factor's sensitivities are measured with regard to the mid-point of WACC (the base case). Table 12.5 presents the results for this sensitivity testing and the base case of 20%.

12.90 As noted in Chapter 7 (Modelling Issues and Sensitivity Tests), the implicit margin provided by the costs of control is most significantly affected by the choice of excess returns unrecoverable. In NGCT's case the implicit margin at 25%, 20% and 10% excess returns unrecoverable is respectively 0.62%, 0.56% and 0.43% in WACC terms.

Common Costs

12.91 The Commission has reservation as to the level of common costs being claimed by NGCT. Table 12.6 presents three sensitivities of the base case results reducing the level of common costs by 10%, 20%, and 30%.

Table 12.6 Sensitivity to Common Cost Reduction - NGCT	**10%**	**20%**	**30%**
NAB ($000s) annuity	2,738	3,112	3,486

Dynamic Inefficiency (Missing Market)

12.92 The dynamic inefficiency costs of the missing market for NGCT were modelled assuming growth in overall demand of [ ] per annum in the period [ ] and [ ] thereafter, an elasticity of -0.3 and output forgone of 10% of growth in total demand [ ] compounded each year. Sensitivities around the missing market elasticity and the output foregone effect were run. These are presented below in Table 12.7.

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[211] For simplicity the expected growth rate was assumed to be the same for both output and expenses.

Table 12.7: Sensitivity to Dynamic Inefficiency Cost - NGCT			
Missing market elasticity	NAB ($000) annuity	Missing market output effect	NAB ($000) annuity
-0.2	2,115	0.15	2,115
-0.3	2,364	0.10	2,364
-0.4	2,488	0.05	2,613

12.93 Overall, sensitivity testing on the NAB test reveals that net benefits to acquirers would remain under all but one of the major sensitivities tested, including the unrecoverable excess returns factor, the adjustments for common costs, forecast revaluation gains, growth forecasts and dynamic inefficiency. Negative NAB were only found when WACC at the 75th percentile was used, although at this WACC the costs of control provide an additional implicit margin of 0.6%.

Conclusion on Net Benefits to Acquirers

12.94 Over the analysis period the Commission's view is that the requirement of s 52(b) of the Commerce Act is satisfied. The Commission is satisfied that it is in the interests of acquirers for NGCT's gas services to be controlled.

'May' Control be Introduced

12.95 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for NGCT's gas services is limited and control of these services is necessary or desirable in the interests of acquirers.

12.96 The Commission's view is that the gas services supplied by NGCT may be controlled.

'Should' Control be Introduced

12.97 Having determined that the Commission may recommend control, it has conducted further analysis to determine whether it 'should' recommend control. The matters considered for whether control 'may' be recommended remain relevant. However, there are also additional matters the Commission considers relevant. The additional issues for whether control 'should' be introduced include:

- the net efficiency cost to the economy of reducing excess returns;
- the size of the benefits; and
- the impact of a recommendation of no control.

12.98 Each of these issues is explained below and then weighed against one another prior to recommending whether the gas services provided by NGCT should be controlled.

Net Efficiency Costs of Reducing Excess Returns

12.99 The NAB is calculated by summing the net efficiency costs and the recoverable excess returns. The net efficiency costs to the economy of achieving a reduction in excess returns were calculated as $1.096 million in annuity terms over the analysis period.[212] The recoverable excess returns were calculated as $3.629 million in annuity terms.[213]

12.100 The costs to the economy of achieving transfers can be compared to the transfer benefits (the reduction in excess returns) that control would provide to consumers. This calculation is conducted by dividing the costs of achieving transfers by the excess returns that can be recovered for consumers.

12.101 In NGCT's case the calculation gives a transfer cost ratio of 0.30. This figure can be interpreted as suggesting that transferring $1 of recoverable excess returns back to consumers costs the economy $0.30.

The Size of the Benefits

12.102 The size of the net acquirers benefit can be assessed in various ways, including;

- return on capital employed;
- its effect on the average price of transmission and the average final delivered gas price to consumers; and
- its effect on consumers' annual line charge bills.

12.103 Each of the above is discussed in turn.

12.104 NGCT earns a return of approximately 9.1% on average on the capital it employs over the analysis period. This return is 0.5% over the returns allowed by the mid-point of WACC (8.0%) plus the costs of control (0.6%), and reflects the positive NAB found. [214]

12.105 In terms of the effect on the price of transmission services, the NAB of NGCT suggests that transmission prices could be reduced by as much as 3.5%.

12.106 The transmission charge affects the final price of delivered gas in all regions. The final delivered gas price depends on three components of the final price. It depends on the change in transmission charge, the change in distribution price and the relative shares of both of these in the final delivered gas price. Our

[212] The net public benefits of control are used as the net efficiency costs. The Commission notes that some additional benefits and costs of control affecting producers are included only in the net public analysis, not the NAB test. In NGCT's case the additional benefits and costs are insignificant at $0.011m and $0.018m in annuity terms respectively.

[213] Recoverable excess returns are calculated as the total excess returns less 20% thereof, as this proportion is considered unrecoverable.

[214] The return is calculated on an average basis. Averaging of returns is sometimes problematic, which is why the Commission places primary reliance on the annuity. However, this calculation of returns is done in the same way as the calculation of the implicit margin on WACC provided by the costs of control and the average mid-point WACC. Therefore the difference between the returns and the mid point of WACC plus the implicit margin of the costs of control, is still reflective of the NAB found in annuity terms, although the two are not technically comparable.

calculations have assumed that transmission and distribution make up 10% and 40% respectively of the final delivered gas price. Reducing NGCT's transmission charge by 3.5% would lower the average final delivered gas price by 0.35% in all regions.

12.107 Alternatively, the reduction can be considered in terms of its effect on line charges. NGCT's direct customers can be broadly classified into two types; large industrials and gas retailers. Based on figures supplied by NGCT the average annual transmission charge over the analysis period is [ ] per direct customer. The reduction in transmission charge would save the average direct customer approximately [ ] p.a. This represents a 3.5% reduction in their annual transmission bill. For direct industrial customers operating in competitive markets such savings can be expected to be passed on to their customers. A number of NGCT's direct customers are retailers. The reduction in transmission charges to gas retailers will likely be dispersed over a great number of consumers. The figures above (calculated by use of a simple average) can hide significant variation on an end consumer basis. The Commission has no further information upon which to conduct a more customer specific assessment.

12.108 It should be noted that the calculations in this sub-section are made on the basis of bringing NAB back to zero, not to where the efficient level of price may be if the costs of control were ignored.

Impact of a Recommendation of No Control

12.109 If control was not introduced, any downward pressure on prices resulting from the threat of control would be reduced. The Commission's base case assumes that NGCT will not raise prices over the period 2005-2008, beyond those it has recently implemented.

12.110 In terms of the size of the benefits, careful consideration must be given to the materiality threshold chosen. For example, if the current transfer cost ratio of 0.30 was judged to be too high to warrant control being imposed, it may be possible for NGCT to raise price up to the point at which the transfer ratio makes control desirable.

12.111 There may be spill over effects to other monopoly businesses (including MDL) who may feel they are able exercise any market power they have without the threat of control.

Conclusion on Whether Control Should be Introduced

12.112 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for NGCT's gas services is limited and control of these services is necessary or desirable in the interests of acquirers. The Commission's view is that the gas services supplied by NGCT may be controlled under Part V of the Commerce Act.

12.113 The Commission's view is that control under Part V is a high cost form of control relative to other regulatory options, particularly in light of the extent of excess returns reflected in NGCT's pricing. As the Commission's report relates to Part V it has included the benefits and costs associated with a Part V control regime in its analysis. Clearly different forms of regulation would be more or less effective at delivering the potential benefits of control to acquirers. Although the Commission has not formally modelled different forms of regulation it considers a less intrusive regulatory option (such as a targeted control regime) may offer a more favourable trade off between costs and benefits.

12.114 In addition to the considerations under s 52 of the Commerce Act the Commission has had regard to the costs to the economy associated with transferring recoverable excess returns to acquirers. The costs to the economy associated with control can be weighed against the excess returns that could be recovered for consumers. The net costs of achieving transfers are 30% of the recoverable excess returns in NGCT's case (or equivalently, the recoverable excess returns are 3.3 times the net efficiency effects). The Commission considers that an efficiency loss ratio of 30% is of some concern.

12.115 Various indicators can be used to evaluate the size of the NAB. NGCT's actual return on capital over the analysis period is 9.1%. This return is 0.5% over the returns indicated by the midpoint of WACC (8.0%) plus the costs of control (0.6%), and reflects the positive NAB found. The absolute size of the NAB in NGCT's case is $2.364 million in annuity terms. This NAB equates to a 3.5% average price reduction. The benefits from this average price reduction for NGCT's large industrial customers are likely to be passed on to their customers to the extent that they operate in competitive markets and any transmission charge reduction to gas retailers will affect the final delivered gas price in all regions, albeit having a relatively modest impact on individual retail customers.

12.116 If control under Part V is not introduced then any downward pressure on prices resulting from the threat of control, would be reduced, potentially resulting in an increase in the current excess returns. Finally, there may be spill over effects to other monopoly businesses, such as the Maui network, if NGCT is not controlled.

12.117 After considering and weighing up the above matters the Commission has formed the view that Part V of the Commerce Act could be used to control NGCT, but that such control would likely not be a cost effective mechanism for dealing with the concerns raised by NGCT's market power and behaviour compared with alternative approaches to regulation.

12.118 Therefore, the Commission considers that an Order in Council under s 53 of the Commerce Act to impose control on NGCT under Part V should not be made, notwithstanding that the s 52 requirements for control are met.

Overall Recommendation

12.119 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by NGCT may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on NGCT under Part V of the Commerce should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

12.120 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on NGCT should be strengthened and requests the Minister consider applying to NGCT, a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A.

12.121 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

12.122 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

12.123 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

Other Matters for the Minister to Consider

12.124 The Commission has not considered the implications of Vector's proposed acquisition of NGC. The Minister may need to consider the implications of that acquisition should the acquisition proceed.

13 NGC HOLDINGS LTD – DISTRIBUTION (NGCD)

Introduction

Company History / Ownership

13.1 NGC's history, ownership and broader gas interests are commented on in Chapter 12 (NGC Holdings Ltd – Transmission (NGCT)).

Gas Distribution Activities

13.2 NGC's distribution activities are referred to as NGCD within this report. NGCD owns and operates over 2,700 km of intermediate, medium and low pressure gas distribution pipeline networks connected to its high pressure transmission systems. NGCD's distribution networks are located in the regions of Northland, Auckland, Waikato, Bay of Plenty and Kapiti. NGCD supplies gas through its distribution networks to residential as well as industrial and commercial customers. As at 30 June 2003 NGCD's distribution network serviced 55,938 customers throughout the North Island. Of the gas carried over its networks, [ ] goes to residential customers, [ ] goes to industrial customers and [ ] to commercial customers.

13.3 NGCD's business accounts for around [ ] of NGC's total revenue.

Table 13.1: NGCD Network Statistics (year ended 30 June 2003)		
System	**Length (km)**	**Total Gas Conveyed (GJ)**
Distribution Network	2,739	11,061,901

Competition Analysis

Introduction

13.4 There are a number of competition issues which are relevant to all gas distribution networks. In addition, each gas services market has distinguishing characteristics and accordingly, the networks of each distributor are considered separately in this report.

13.5 Perhaps the key features of NGCD's networks that distinguish them from other networks are the vertical integration with NGCT, and the absence of bypass competition.

13.6 The gas meters connected to NGCD networks and owned by NGC are incorporated in the competition analysis.

Competition

<u>Generic</u>

13.7 In its submission on competitive constraints, CRA on behalf of NGC stated:

> A holistic view of the constraints on gas prices is required. There is unlikely to be any single type of constraint that limits the ability to raise prices above the competitive level, but rather the constraints arise from a combination of:
>
> - Interfuel competition;

- Long-term contracts;
- Bypass; and
- Customer price sensitivity, e.g., those customers that compete in international markets.

> It is the combined weight of these potential constraints that must be considered in determining whether or not competition is limited.[216]

13.8 In addition CRA stated:

> Overall, there seems to be a significant amount of evidence that interfuel competition and bypass potential places a constraint on a reasonably significant proportion of gas customers and volumes transported. Whether this is sufficient to constrain prices to the workable or effective level of competition is of course, still an empirical question, but it is clear that many customers have real alternatives to gas.
>
> Furthermore, the Commission's task is to look forward to predict whether or not price control would be appropriate. As the price of gas rises, the pressure on gas transporters can only increase.[217]

13.9 As discussed in the Chapter 3 (Competition Analysis), gas networks have natural monopoly characteristics. Distributors incur high fixed and sunk costs and relatively low variable costs. In these circumstances it is possible that one firm in any area is able to undertake the distribution function at a lower average cost than two or more firms. This is likely to deter other than bypass entry, or entry where the existing pipelines are utilised to their full capacity. The Commission understands that capacity constraints on distribution networks are relatively rare and in limited areas of the network.

13.10 Bypass opportunities tend to be limited to where there is a concentration of medium to large consumers who are close to an offtake point on the transmission pipeline, where an existing bypass network can expand its scope or where there is an alternative source of gas (e.g. landfill gas).

13.11 As noted in the Chapter 3 (Competition Analysis) the immediate areas where a bypass operator is competing with the incumbent have been placed in a discrete market. In these markets the Commission considers that there is strong evidence of vigorous competition for industrial and commercial customers.

13.12 The Commission recognises that in other markets the threat of bypass entry can have an important competitive impact, but it considers that this threat (and impact) exists in only small pockets of the area covered by the incumbent's network. This competitive threat in these pockets is mainly limited to the supply to industrial and commercial customers, albeit these customers are the largest users of distribution services in the pockets.

13.13 The Commission has received a number of submissions on the extent to which other fuel forms compete with gas and therefore constrain the price which can be charged for transmission and distribution services. Examples were provided

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[216] CRA, *Review of the Commerce Commission's Gas Control Inquiry Draft Report*, report on behalf of NGC, 2 July 2004, Appendix A2 p 105
[217] Ibid p108

of instances where users of gas had switched to electricity, coal, LPG, diesel and wood.

13.14 The Commission accepts that some energy users do have a choice of fuels, although for many this may be limited to when their energy specific plant or appliance is nearing the end of its economic life. However, the information provided to the Commission (and discussed in Chapter 3 (Competition Analysis) suggests that interfuel competition is not sufficient in itself to place strong competitive pressure on gas suppliers.

13.15 In addition, the Commission notes that distribution only accounts for perhaps 40% of the final price of delivered gas. Therefore, the competitive constraint other energy forms place on gas prices is dissipated in its impact on the distribution function.

13.16 The Commission accepts that some large gas users may have entered long-term distribution contracts when they undertook their original investment (and when they still had discretion over location and fuel choice). These contracts may give these gas users protection against distributors of gas exercising market power during the period of the contract. However, the Commission considers that any such protection is likely to be limited to a small number of large gas users.

13.17 The existing regulatory regime, including information disclosure and the threat of regulation, may also provide some constraint on distributors. However, for the reasons discussed in the Chapter 3 (Competition Analysis), the Commission does not consider that these constraints, taken together match the constraints faced by a firm in a market which has workable or effective competition.

NGCD

13.18 As discussed above, for the most part gas retailers and consumers do not have options available to them for the distribution of gas. Exceptions are in areas which are served both by the incumbent distributor and by a bypass distributor. These areas are relatively small (the bypass networks comprise around 115 km of pipelines throughout the North Island) and have been placed in a discrete market for the purpose of the Inquiry's competition analysis. None are within the areas covered by NGCD's networks.

13.19 While NGCD's networks do not face direct competition from actual bypass operators, the Commission accepts that they remain vulnerable to new entry bypass. NGC, at the Draft Framework Conference,[218] described how NGC has models that identify clusters of larger customers within a network where it believes that there are bypass prospects, and has adjusted its prices to those customers to head off actual bypass. NGC also indicated[219] that the threat of bypass, and the threat of customers switching to alternative fuels can result in those customers receiving a price advantage of 20% or more. However, the Commission notes that these customers represent only a small portion of all customers on NGCD's networks (albeit they tend to be relatively large users of

[218]Transcript from Conference on Draft Framework Paper, p 340.
[219] Ibid p 320.

distribution services), and the price advantage they receive does not flow through to other customers.

13.20 The Commission recognises that the threat of bypass can provide a constraint similar to that provided by actual competition. Consideration was given to separately analysing areas where the threat of bypass is strong. However, there are difficulties in identifying the areas of bypass threat in a satisfactory way. As NGC has submitted:[220]

> Any attempt to deal with the problem of which customers have or have not benefited from inter-fuel and bypass competition is likely to be fraught with difficulty and complications, as it would effectively entail segregating groups of customers into distinct markets and regulating only some of those markets.

13.21 Accordingly, the Commission has not attempted to isolate those areas where bypass is a realistic threat. Rather it has regarded the threat of bypass as being an important constraint on the exercise of market power in respect of a small proportion of total customers on NGCD's networks.

13.22 There are two areas where NGCD operates in the vicinity of other networks. These are in Whangaparaoa and South Auckland.

13.23 In Whangaparaoa, NGCD has a network which in some parts runs adjacent to a limited Vector network. The Vector network is now connected to the gas transmission pipeline but until recently its gas was provided by means of a CNG tanker. The Whangaparaoa situation is discussed in more detail in the Competing Distribution Networks section of Chapter 3 (Competition Analysis). The Commission concludes that additional entry in that area is unlikely to be economically rational and that future competition between NGCD and Vector will be minimal, at best.

13.24 In South Auckland, NGCD has a very limited bypass network which delivers gas to a limited number of horticultural businesses. Vector is the incumbent network owner in the region. The size of NGCD's bypass operations is sufficiently small to make it not material to the Commission's analysis.

13.25 The Commission accepts that NGCD faces some competitive constraint from alternative forms of delivered energy. The Commission also accepts that the regulatory regime and the threat of additional regulation provide some constraint on gas service providers, albeit relatively small. However, for the reasons described in the generic competition section, these constraints together are not considered to be equivalent to the constraint faced by a firm in a market which has workable or effective competition.

13.26 It has been argued by some industry participants[221] that NGC's vertical integration inhibits competition in gas markets as NGC can use its market power in one market to obtain an advantage in upstream or downstream

[220] NGC, *Cross-Submission in Respect of Submissions on the Draft Framework Paper*, 19 September 2003, para. 30
[221] For example Todd and Contact, as discussed in Commission Decision No.470 (*NGC/United Networks)*, 23 August 2002).

markets. Nova Gas noted that it has not engaged in bypass competition against a NGCD network.

13.27 For the purpose of this Inquiry, the Commission has not given weight to any anti-competitive effects which are claimed to arise from NGC's vertical integration. Such claims have not been proven at this stage, but even if they were, they would support, not counter, the Commission's conclusion on whether competition is limited in the relevant markets, which is set out below.

13.28 The Commission has found no unique features about distribution markets in which NGCD operates which would make them significantly more competitive than other distribution markets.

Conclusion on Competition

13.29 The Commission accepts that the factors which can impact on an incumbent network operator may vary from region to region. In this instance it has taken into account factors which are peculiar to the markets in which NGCD operates.

13.30 Having regard to these factors, and to the more generic factors discussed above, the Commission concludes that NGCD is constrained to some extent in its behaviour by such factors as the potential for bypass pipelines in some limited areas, by interfuel competition, and by the current regulatory regime. However, the Commission considers that this constraint falls short of that which would be faced by a firm in a market which has workable competition.

13.31 Accordingly, the Commission's view is that the requirement in s 52(a) of the Commerce Act is satisfied. It considers that competition for gas services provided by NGCD is limited.

Benefits and Costs of Control

Introduction

13.32 The Commission outlined its approach to deriving estimates of the potential benefits and costs of controlling gas services in Chapter 6 (Assessment Approach). The models presented in that chapter are now applied to the gas services supplied by NGCD.

13.33 The remainder of this chapter identifies the key inputs and assumptions within the cost benefit analysis; any adjustments made to the business specific data provided; the results and sensitivities from the cost benefit model; the level of net acquirers benefit; and the Commission's recommendation on whether control is required.

13.34 All figures are for the year ended 30 June, the balance date nominated by NGCD. Appendix D contains the NGCD analysis, and results from the Commission's cost benefit model.

Inputs and Assumptions

13.35 The Commission required all the gas pipeline businesses to complete a data template for the years 1996-2008. A specimen of the template is included as Appendix B. The data sought by the template related to revenues, expenses and the asset base.

13.36 NGCD completed the data template with a few exceptions, noted below. The data provided by NGCD was reviewed by the Commission with clarification or further background information being obtained from NGCD as required. NGCD provided actuals for 2004 since the Draft Report.

13.37 The Commission made adjustments to the data where it considered this necessary for the purposes of the benefits and costs of control assessment. Specific issues and adjustments to the NGCD data are explained below.

<u>Revenues and Other Income</u>

13.38 [

]

13.39 NGCD has excluded from its revenues income earned from AGL NZE gas meters.

13.40 In its submission on the Draft Report NGCD argued that the gain on sale of assets to Powerco in 1999 should not be treated as income. As explained in Chapter 5 (Assessment Principles for Efficient Pricing), the Commission accepts this position and has removed this from the analysis. The removal of the gain on sale as income reduced excess returns by approximately [ ] in annuity terms.

13.41 NGCD treats capital contributions as income. The level of capital contributions has been insignificant.

13.42 [

] The Commission considers that forecast revaluation gains will at least be in line with CPI. As NGCD has forecast revaluation gains below CPI, the Commission has included this differential as additional revaluation gains. It has allowed these additional revaluation gains to be offset by the businesses' forecasts of future optimisation, and higher incremental depreciation charges and allowed revenues.

<u>Operating Expenses</u>

Inquiry Costs

13.43 NGCD included Inquiry costs in its s 70E response for 2003 - 2005. The Commission has removed NGCD's Inquiry costs from the operating expense as the Commission includes Inquiry costs within the direct costs of control calculation across the entire analysis period.

Common Costs

13.44 The Commission has reservations as to the common cost allocation of all the gas pipeline businesses. This is discussed in Chapter 7 (Modelling Issues and Sensitivity Tests).

13.45 In NGCD's case, the Commission is satisfied that no adjustment to the base case is necessary.

13.46 However, the Commission still has reservations as to the allocation of common costs by NGCD. The indirect cost ratio for NGCD is substantially higher than the comparable revenue, asset and direct cost shares for gas distribution vis à vis other activities. Evidence provided by NGCD also indicates they have changed the way they allocate common costs, which has resulted in an increase in indirect costs when compared to what was previously disclosed.

13.47 The Commission has accordingly included a sensitivity of the results that measures the effect of presuming common costs were 10%, 20% or 30% lower than the figures provided.

Insurance

13.48 NGCD insures externally for major risks such as floods, etc. The costs of its insurance and any costs resulting from uninsured events are included in the Commission's analysis. No further adjustments were made for elements of self-insurance that were not matched by adverse events in the assessment period.

Tax

13.49 NGCD's tax was calculated using the Commission's approach outlined in Chapter 10 (Treatment of Tax in the Cost Benefit Analysis). The tax book value movements including acquisition value, current depreciation, accumulated depreciation and written down tax book value which were used in the Commission's analysis were provided by NGCD.

13.50 [

]

Asset Base

13.51 NGCD has owned its distribution assets for the entire duration of the analysis period and has submitted data for the entire analysis period. NGCD adopted ODV for its statutory accounts in 1997. Its first ODV of its distribution assets was conducted in 1994.[222] NGCD's ODV approach was broadly consistent with the Handbook, with differences reducing its valuation relative to what would be allowed by the Handbook.

[222] Cranleigh Strategic, *Gas Control Inquiry Asset Valuation – the Historic Cost Approach*, February 2004 p 5.

13.52 NGCD's asset base includes the NGC meters on its own networks (but excludes NGC meters connected to other networks). Although NGC placed metering activities into a separate business unit in 2003, they remain under NGCD's control. Because the metering business remains under NGCD's control, the Commission has included them in the analysis. This has required NGCD to make some assumptions for the 2003 and forecast years to include metering with distribution.

13.53 In submissions on the Draft Report NGCD argued that meters would not be revalued going forward. The Commission has accepted this view. However, it includes the one off revaluation gain of [ ] in 2003 when the meters were transferred to the separate business unit.

13.54 The depreciation values provided by NGCD within the data template were higher than those recorded in the 2000 and 2003 NGCD ODV reports. The Commission has adjusted the NGCD depreciation figures provided so that they match the depreciation figures that appear in the ODV reports.

13.55 [

] The Commission has assumed a constant non-network depreciation policy for the period. The Commission has held the 2004 depreciation rate fixed between 2004-2008 as a proxy for the constant depreciation policy.

13.56 [ ]

13.57 NGCD was unable to provide historic cost information on its asset base.

<u>Summary of Base Case Variables</u>

13.58 The Commission has developed a 'base case' in its model. The base case includes the adjustments to the input data noted above, the mid-point of WACC, an excess returns unrecoverable factor of 20%,[223] and elasticity of demand of -0.3.

13.59 Table 13.2 presents the key variables of the analysis, using the base case in 2003 as an example.

[223] Refer to the Indirect Costs section of Chapter 6 (Assessment Approach) for discussion on the unrecoverable excess returns factor.

Table 13.2 Key Variables - NGCD	Figures (2003)
Revenue ($000)	28,546
Net earnings (NE) ($000)	15,908
Actual quantities (Q_m) TJ	11,062
Actual price (P_m) $/GJ[224]	2.58
Efficient quantities (Q_c) TJ	11,894
Efficient price (P_c) $/GJ	1.93
Elasticity	-0.30
WACC	7.19%
Asset base ($000)	129,393
ODV system assets ($000)	126,162
Other non-system assets ($000)	3,231
Revaluation gains/loss spread ($000)	7,394

Net Acquirers Benefit (NAB)

Introduction

13.60 Given the Commission's view that NGCD faces limited competition in the market for its services, the Commission must consider whether the requirement in s 52(b) of the Commerce Act is satisfied; and whether control is necessary or desirable in the interest of acquirers. In order to determine whether s 52(b) is met the Commission carries out a NAB test. The Commission's recommendations on whether gas services may be controlled are based on the results of the NAB test.

13.61 The benefits and costs of control measured for the purposes of the NAB test are explained in detail in Chapter 6 (Assessment Approach). In summary, the benefits of control relate to improvements in efficiency (in terms of allocative, productive, and/or dynamic efficiency) and the reduction of any excess returns that might be achieved by control. The costs of control include the direct costs of control (quantified in Chapter 6 (Assessment Approach) and the indirect costs associated with the creation of any additional inefficiencies (i.e., productive inefficiency, service quality deterioration, and/or new investment foregone) and/or the potential benefits not being fully realised in practice (measured as the unrecoverable excess returns and the allocative efficiency not achieved).

[224] The 'actual' price is a notional average price based on NGCD's revenue and gas throughput.

Table 13.3 NAB Results - NGCD	($000)
Benefits	
Excess returns	3,069
Allocative efficiency - consumer surplus	85
Productive efficiency	222
Dynamic efficiency	0
Costs	
Direct Costs	
Compliance cost	-347
Regulator's cost	-253
Indirect Costs	
Excess return unrecoverable	-614
Allocative efficiency not achieved	-31
Productive inefficiency	-86
Service quality deterioration	-141
New investment foregone	-304
Key Results	
Annuity	1,600
NPV (1997-2008)	21,623

13.62 The largest component within the potential benefits of control is the removal of excess returns. The potential efficiency benefits (in terms of allocative, productive, and dynamic inefficiency) are modest in comparison to the potential benefits of removing excess returns.

13.63 The largest component within the potential costs of control is the indirect costs of control, in particular the amount of excess returns that are unrecoverable by control, in NGCD's case.[225] The sensitivity of the results to the unrecoverable excess returns has been modelled below.

Sensitivities

13.64 The Commission has tested the sensitivity of the benefits and costs model results to changes in key variables. Three key sensitivities tested were the WACC range, the unrecoverable excess returns by control, common costs, forecast growth and dynamic inefficiency.

[225] For a further breakdown of the costs of control refer to Chapter 6 (Assessment Approach).

WACC

13.65 The WACC represents an approximation for the opportunity cost of committed funds.

13.66 The sensitivity of the result to the WACC values was tested by using the 75th and 25th percentiles of the WACC distribution in the model.[226] Table 13.4 presents the results of this sensitivity testing and the base case of the mid-point of WACC.

Table 13.4 **Sensitivity to WACC - NGCD**	**75th**	**Mid-point**	**25th**
NAB ($000s) annuity	783	1,600	2,390

13.67 The NAB for NGCD is positive across the Commission's WACC range. The Commission's view is that the mid point of WACC should be used in assessing the benefits of control for NGCD. NGCD is able to earn a margin of 1.3% above the mid-point because of the costs of control. At the 75th percentile of WACC, NGCD can earn an additional 0.8% before NAB is found (i.e., NGCD can earn 2.1% over the mid-point of WACC before NAB are found). The costs of control mean NGCD is able to earn significantly above the return implied by the mid-point of WACC before any NAB are found.

Growth

13.68 Chapter 7 (Modelling Issues and Sensitivity Tests) noted that NGCD's forecast growth rates were below those historically achieved, and that 2004 actuals suggested a greater growth rate than had been previously forecast in the Draft Report.

13.69 The Commission compared the overall average growth rates for NGCD, Powerco and Vector (3.5%) with the rates they forecast [ ]. The Commission's overall average growth rates are the ones used for its dynamic inefficiency calculation (to be consistent). They are based on both past and forecast information.[227]

13.70 The difference in output between the overall average and forecast output amounts is multiplied by the prevailing price to determine the potential additional revenue. From this additional revenue were subtracted any additional expenses needed (the difference between forecast expense increases and expected)[228] and the 20% excess returns unrecoverable factor, to give the net NAB effects.

13.71 The effect on the NAB of NGCD would be to increase it by $0.780m in annuity terms.

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[226] Refer to Chapter 9 (Weighted Average Cost of Capital) for a discussion on the WACC range.
[227] Including forecast growth in the calculation of expected growth obviously introduces a circularity, in that, if forecast growth is understated, then this expected growth will also be understated.
[228] For simplicity the expected growth rate was assumed to be the same for both output and expenses.

Excess Returns Unrecoverable

13.72 The unrecoverable excess returns factor represents the amount of excess returns that is considered to be unrecoverable by control and is labelled an indirect cost of control in the Commission's assessment.

13.73 The sensitivity of the results to excess returns unrecoverable by control was tested by using figures of 10% and 25%. The unrecoverable excess returns factor's sensitivities are measured with regard to the mid-point of WACC (the base case). Table 13.5 presents the results for this sensitivity testing and the base case of 20%.

Table 13.5 **Sensitivity to Unrecoverable Excess Return Factor - NGCD**	**25%**	**20%**	**10%**
NAB ($000s) annuity	1,440	1,600	1,921

13.74 As noted in Chapter 7 (Modelling Issues and Sensitivity Tests), the margin provided by the costs of control is most significantly affected by the choice of excess returns unrecoverable. In NGCD's case the margin at 25%, 20% and 10% excess returns unrecoverable is respectively 1.4%, 1.3% and 1% in WACC terms.

Common Costs

13.75 The Commission has reservation as to the level of common costs being claimed by NGCD. Table 13.6 presents three sensitivities of the base case results in which the level of common costs is reduced by 10%, 20%, and 30%.

Table 13.6 **Sensitivity to Common Cost Reduction – NGCD**	**10%**	**20%**	**30%**
NAB ($000s) annuity	1,788	1,976	2,165

Dynamic Inefficiency (Missing Market)

13.76 The dynamic inefficiency costs of the missing market for NGCD were modelled assuming growth in the overall market of 3.5% per annum, output foregone of 10% of the growth in overall demand (i.e. 0.35%) compounded each year and an elasticity of -0.9. Sensitivities around the missing market elasticity and the output foregone effect were run. These are presented below in Table 13.7.

Table 13.7 Sensitivity to Dynamic Inefficiency Cost – NGCD			
Missing market elasticity	NAB ($000) annuity	Missing market output effect	NAB ($000) annuity
-0.6	1,448	0.15	1,448
-0.9	1,600	0.1	1,600
-1.2	1,676	0.05	1,752

13.77 Overall, sensitivity testing on the NAB test reveals that net benefits to acquirers would remain under all the major sensitivities tested, including the WACC, the unrecoverable excess returns factor, adjustments for common costs, forecast growth and dynamic inefficiency.

Conclusion on Net Benefits to Acquirers

13.78 Over the analysis period the Commission's view is that the requirements of s 52 (b) of the Commerce Act is satisfied. There is evidence that it is necessary or desirable in the interests of acquirers for NGCD's gas services to be controlled.

'May' Control be Introduced

13.79 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for NGCD's gas services is limited and control of these services is necessary or desirable in the interests of acquirers.

13.80 The Commission's view is that the gas services supplied by NGCD may be controlled.

'Should' Control be Introduced

13.81 Having determined that the Commission may recommend control, it has conducted further analysis to determine whether it 'should' recommend control. The matters considered for whether control 'may' be recommended remain relevant. However, there are also additional matters the Commission considers relevant. The additional issues for whether control 'should' be introduced include:

- the net efficiency costs to the economy of reducing excess returns;
- the size of the benefits; and
- the impact of recommendation of no control.

13.82 Each of these issues is explained below and then weighed against one another prior to recommending whether the gas services provided by NGCD should be controlled.

Net Efficiency Costs of Reducing Excess Returns

13.83 The NAB is calculated by summing the net efficiency effects and the recoverable excess returns.[229] The net efficiency costs to the economy of achieving a reduction in excess returns were calculated as $0.913 million in annuity terms over the analysis period. The recoverable excess returns were calculated as $2.455 million in annuity terms.[230]

13.84 The net efficiency costs can be compared to the reduction in excess returns that control would provide to consumers. This calculation is conducted by dividing the net efficiency costs by the excess returns that can be recovered for consumers.

13.85 In NGCD's case the calculation gives a transfer cost ratio of 0.37. This figure can be interpreted as suggesting that transferring $1 of recoverable excess returns back to consumers costs the economy $0.37 in net efficiency terms.

The Size of the Benefits

13.86 The size of the net acquirers benefit can be assessed in various ways, including;

- return on capital employed;
- its effect on the average price of transmission and the average final delivered gas price to consumers; and
- its effect on consumers' annual line charge bills.

13.87 Each of the above is discussed in turn.

13.88 NGCD earns a return of approximately 10.5% on the capital it employs. This return is 1.2% over the returns allowed by the mid-point of WACC (8.0%) plus the costs of control (1.3%), and reflects the positive NAB found. [231]

13.89 In terms of the effect on the price of distribution services, the NAB of NGCD suggests that distribution prices could be reduced by as much as 5.6%.

13.90 The effect on the final price of delivered gas in the NGCD region depends on three components of the final price. It depends on any change in transmission charge, the change in distribution price (noted above) and the relative shares of both of these in the final delivered gas price. The Commission's calculations have assumed that transmission and distribution make up 10% and 40% respectively of the final delivered gas price. Reducing NGCD's distribution

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[229] The Commission notes that some additional benefits and costs of control affect producers only, and are included in the efficiency analysis. In NGCD's case the additional benefits and costs are insignificant at $0m and $0.058m in annuity terms respectively.

[230] Recoverable excess returns are calculated as the total excess returns less 20% there of, as this proportion is considered unrecoverable.

[231] The return is calculated on an average basis. Averaging of returns is sometimes problematic, which is why the Commission places primary reliance on the annuity. However, this calculation of returns is done in the same way as the calculation of the implicit margin on WACC provided by the costs of control and the average mid point WACC. Therefore the difference between the returns and the mid-point of WACC plus the implicit margin of the costs of control, is still reflective of the NAB found in annuity terms, although the two are not technically comparable.

charge by 5.6% would lower the average final delivered gas price by 2.2% in the NGCD region.

13.91 Alternatively, the reduction can be considered in terms of its effect on average charges. Based on figures supplied by NGCD the average charge over the analysis period is $518 per customer. The annual line charge is made up of transmission plus distribution charges. The reduction in distribution charge would save a typical consumer $29 or a 5.6% reduction in their annual line charge bill.

13.92 It should be noted that the calculations in this sub-section are made on the basis of bringing NAB back to zero, not to where the efficient level of price may be if the costs of control were ignored.

Impact of a Recommendation of No Control

13.93 If control was not introduced, any downward pressure on prices resulting from the threat of control, would be reduced. The Commission's base case assumes that NGCD will not raise prices over the period 2005-2008, beyond those it has recently implemented.

13.94 In terms of the size of the benefits, careful consideration must be given to the materiality threshold chosen. For example, if the current transfer cost ratio of 0.37 was judged to be too high it may be possible for NGCD to raise prices to the point at which the transfer ratio makes control more desirable.

13.95 There may be spill over effects to other monopoly businesses who may feel they are able exercise any market power they have without the threat of control.

Conclusion on Whether Control Should be Introduced

13.96 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for NGCD's gas services is limited and control of these services is necessary or desirable in the interests of acquirers. The Commission's view is that the gas services supplied by NGCD may be controlled under Part V of the Commerce Act.

13.97 The Commission's view is that control under Part V is a high cost form of control relative to other regulatory options, particularly in light of the extent of excess returns reflected in NGCD's pricing. As the Commission's report relates to Part V it has included the benefits and costs associated with a Part V control regime in its analysis. Clearly different forms of regulation would be more or less effective at delivering the potential benefits of control to acquirers. Although the Commission has not formally modelled different forms of regulation it considers a less intrusive regulatory option (such as a targeted control regime) may offer a more favourable trade off between costs and benefits.

13.98 In addition to the considerations under s 52 of the Commerce Act the Commission has had regard to the costs to the economy associated with transferring recoverable excess returns to acquirers. The costs to the economy associated with control can be weighed against the excess returns that could be recovered for consumers. The net costs of achieving transfers are 37% of the recoverable excess returns in NGCD's case (or equivalently, the recoverable excess returns are 2.7 times the net efficiency effects). The Commission considers that their efficiency loss ratio of 37% is of some concern.

13.99 Various indicators can be used to evaluate the size of the NAB. NGCD's actual return on capital over the analysis period is 10.5%. This return is 1.2% over the returns indicated by the midpoint of WACC (8.0%) plus the costs of control (1.3%), and reflects the positive NAB found. The absolute size of the NAB in NGCD's case is $1.600 million in annuity terms. This NAB equates to a 5.6% average price reduction.

13.100 If control is not recommended then any downward pressure on prices resulting from the threat of control, would be reduced, potentially resulting in an increase in the current excess returns. Finally, there may be spill over effects to other monopoly businesses.

13.101 After considering and weighing up the above matters the Commission has formed the view that Part V of the Commerce Act could be used to control NGCD, but that such control would likely not be a cost effective mechanism for dealing with the concerns raised by NGCD's market power and behaviour compared with alternative approaches to regulation.

13.102 Therefore, the Commission considers that an Order in Council under s 53 of the Commerce Act to impose control on NGCD under Part V should not be made, notwithstanding that the s 52 requirements for control are met.

Overall Recommendation

13.103 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by NGCD may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on NGCD under Part V of the Commerce should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

13.104 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on NGCD should be strengthened and requests the Minister consider applying to NGCD, a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A.

13.105 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

13.106 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

13.107 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

Other Matters for the Minister to Consider

13.108 The Commission has not considered the implications of Vector's proposed acquisition of NGC. The Minister may need to consider the implications of that acquisition should the acquisition proceed.

14 POWERCO LIMITED (POWERCO)

Introduction

Company History / Ownership

14.1 The original Powerco Ltd was formed in 1993 when the Wanganui Rangitikei Electricity Power Board was corporatised. Since that time Powerco has incorporated a number of other gas and electricity companies into its business, including:

- Taranaki Energy Ltd – 1995;
- Egmont Electricity Ltd – 1997;
- NGC's Taranaki gas network – 1998;
- Wairarapa Electricity's network – 1999;
- CentralPower – 2000;
- Australian Gaslight Ltd's Hutt gas network – 2001; and
- UnitedNetworks (Eastern Electricity and Central Gas) – 2002.

14.2 Powerco's main office is now based in New Plymouth. Powerco is predominantly an energy distribution company, with gas and electricity networks throughout the North Island. Powerco's major shareholders until recently were New Plymouth District Council (38.16%), Taranaki Electricity Trust (11.79%), Powerco Community Trust (3.69%), with the remaining 46.36% shareholding spread across approximately 19,000 shareholders. Prime Infrastructure has recently completed a takeover of Powerco, securing in excess of 90% of the company's shares in early November 2004.

Extent of Vertical Integration

14.3 Powerco owns and operates gas distribution networks. Powerco does not have any significant interests in the production and processing, wholesale, transmission or retail gas markets in New Zealand.

14.4 Powerco has recently begun operating in the Australian gas and electricity markets. Powerco Tasmania Pty Ltd has been formed to build, own and operate a gas distribution network connecting industrial and commercial users to supplies on the Duke Energy pipeline from Victoria. In September, Powerco and the Tasmanian Government announced a further agreement to extend gas into specified residential and commercial areas within the State making gas available to approximately 38,500 smaller gas users. Powerco is also active in the Queensland electricity lines network contracting industry through its recently established subsidiary Powerco Australian Holdings Pty Ltd.

Gas Distribution Activities

14.5 Powerco owns and operates 6 major gas distribution networks (Wellington, Hutt Valley, Porirua, Palmerston North, Hastings/Napier and New Plymouth) as well as 30 smaller distribution networks throughout the central and lower regions of the North Island. The natural gas for each network is supplied by NGC's transmission network.

14.6 Powerco's gas distribution network is approximately 5,368 kms in length and services approximately 109,000 customers. The majority [ ] of Powerco's customers are in the residential and small commercial market. However, Powerco also distributes gas to a significant number of commercial and industrial customers. Based on 2003 figures, [ ] of Powerco's revenue is derived from its gas pipeline business.

Table 14.1: Powerco – Distribution Network Statistics (year ended 31 March 2004)

System	Length (km)	Total Gas Conveyed (GJ)
Distribution Networks	5,368	10,082,000

Competition Analysis

Introduction

14.7 There are a number of competition issues which are relevant to all gas distribution networks. In addition, each gas services market has distinguishing characteristics and accordingly the networks of each distributor are considered separately in this report.

14.8 As noted, Powerco has distribution networks in the Napier and Hastings area, Southern Hawke's Bay, Taranaki, Manawatu, Levin and Foxton, Hutt/Mana and Wellington. Each of these areas comprises a discrete geographic market. However, to the extent practicable they are considered together below. The other relevant market is the bypass market, as Nova Gas has a number of pipelines which bypass Powerco's networks.

14.9 A distinguishing feature of Powerco's gas services business is that it faces greater bypass competition than faced by other gas service providers. Nova Gas bypasses, to some extent, Powerco's networks in Wellington, Hutt Valley, Hastings and Hawera.

Competition

<u>Generic</u>

14.10 As discussed in Chapter 3 (Competition Analysis), gas networks have natural monopoly characteristics. Distributors incur high fixed and sunk costs and relatively low variable costs. In these circumstances it is possible that one firm in any area is able to undertake the distribution function at a lower average cost than two or more firms. This is likely to deter other than bypass entry, except if the existing pipelines are utilised to their full capacity. The Commission understands that capacity constraints on distribution networks are relatively rare and in limited areas of the network.

14.11 Bypass opportunities tend to be limited to where there is a concentration of medium to large consumers who are close to an offtake point on the transmission pipeline, where an existing bypass network can expand its scope or where there is an alternative source of gas (e.g., landfill gas).

14.12 As noted above, the immediate areas where a bypass operator is competing with the incumbent have been placed in a discrete market. In these markets the

Commission considers that there is strong evidence of vigorous competition for industrial and commercial customers.

14.13 The Commission recognises that in other markets the threat of bypass entry can have an important competitive impact, but it considers that this threat (and impact) exists in only small pockets of the area covered by the incumbent's network. This competitive threat in these pockets is mainly limited to the supply to industrial and commercial customers, albeit these customers are the largest users of distribution services in the pockets.

14.14 The Commission received a number of submissions on the extent to which other fuel forms compete with gas and therefore constrain the price which can be charged for transmission and distribution services. Examples were provided of instances where users of gas had switched to electricity, coal, LPG, diesel and wood.

14.15 The Commission accepts that some energy users do have a choice of fuels, although for many this may be limited to when their energy specific plant or appliance is nearing the end of its economic life. However, the information provided to the Commission (and discussed in Chapter 3 (Competition Analysis) suggests that interfuel competition is not sufficient in itself to place strong competitive pressure on gas suppliers.

14.16 In addition, the Commission notes that distribution only accounts for perhaps 40% of the final price of delivered gas. Therefore, the competitive constraint other energy forms place on gas prices is dissipated in its impact on the distribution function.

14.17 The Commission accepts that some large gas users may have entered long-term distribution contracts when they undertook their original investment (and when they still had discretion over location and fuel choice). These contracts may give these gas users protection against distributors of gas exercising market power during the period of the contract. However, the Commission considers that any such protection is likely to be limited to a small number of large gas users.

14.18 The existing regulatory regime, including information disclosure and the threat of regulation, may also provide some constraint on distributors. However, for the reasons discussed in Chapter 3 (Competition Analysis), the Commission does not consider that these constraints, taken together match the constraints faced by a business in a market which has workable or effective competition.

<u>Powerco</u>

14.19 In its submission at the Conference on the Draft Report, Powerco argued that the gas distribution market is more competitive than the Commission has recognised. It noted that gas is not an essential fuel and that consumers have a great deal of choice in the form of alternative fuels and bypass. It has also noted that the fact that gas can be substituted for by other energy types is illustrated by the fact that classes of businesses in New Zealand are located both in areas which do have gas and in areas where gas is not reticulated.

14.20 In his submission on behalf of Powerco, Mr Horton noted:

> There is little competition in gas pipeline markets. Even where there is bypass an oligopolistic game equilibrium might be expected.

14.21 At the Conference on the Draft Report, Mr Horton acknowledged that he was not an expert in the New Zealand energy market but said that he thought the market should be defined narrowly.

14.22 Powerco's networks are bypassed by Nova Gas in Wellington, Hutt Valley, Hastings and Hawera. As discussed in the Market Definition section of Chapter 3 (Competition Analysis), the areas which are served by bypass networks (as well as the incumbent's network) have distinct competition characteristics and accordingly have been placed in a discrete bypass market for the purposes of analysis.

14.23 The Commission considers that competition in the bypass market is vigorous[232] and places a very significant downward pressure on prices for industrial and commercial gas users. Further, the Commission considers that there is little potential for coordinated behaviour between Powerco and Nova Gas.[233] Accordingly, in the bypass market the Commission has concluded that competition for gas services is workable and effective. In this situation the Commission cannot recommend control for services provided in the bypass market.

14.24 For practical reasons however, the Commission in its detailed assessment of the costs and benefits of control below has not separated that part of Powerco's network which falls within the bypass market (which represents only a very small part of its total network) from the rest of its network. As NGC noted in respect of its networks, any attempt to separate the two parts is likely to be fraught with difficulty. Considering the bypass market and the other distribution markets where Powerco has a presence together, the lower prices in the competitive bypass market produce an overall average price (and return) which is likely to be slightly less than that which would be found if its non-bypass markets were considered separately.

14.25 The Commission recognises that outside the existing bypass market, Powerco faces some threat of new bypass entry. The more real this threat is, the greater the competitive constraint. However, the threat of new bypass entry would impact on only small pockets of Powerco's total networks and only on industrial and commercial customers within those pockets.

14.26 The Commission accepts that Powerco faces some limited competitive constraint from alternative forms of delivered energy. The Commission also accepts that the regulatory regime and the threat of additional regulation provide some constraint on gas service providers, albeit relatively small. However, for the reasons described in Chapter 3 (Competition Analysis), these constraints together are not considered to be equivalent to the constraint faced by a business in a market which has workable or effective competition.

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[232] See the discussion in Chapter 3 (Competition Analysis).
[233] Ibid, para. 3.69

14.27 The Commission has considered the particular characteristics of the markets in which Powerco operates. The existence of a significant number of existing bypass pipelines suggest that the threat of further bypass would be taken seriously by Powerco, and would act as an important constraint in areas close to the transmission pipeline and where there are concentrations of medium to large industrial and commercial gas consumers. However, notwithstanding this feature, the Commission considers that competition in the market as a whole remains less than workable and effective.

Conclusion on Competition

14.28 The Commission accepts that the factors which can impact on an incumbent network operator may vary from region to region. In this instance it has taken into account factors which are peculiar to the geographic markets in which Powerco operates.

14.29 Having regard to these factors, and to the more generic factors discussed above, the Commission concludes that Powerco is constrained to some extent in its behaviour by such factors as the potential for bypass pipelines in some limited areas, by interfuel competition, and by the current regulatory regime. However, the Commission considers that this constraint falls short of that which would be faced by a business in a market which has workable or effective competition.

14.30 Accordingly, the Commission's view is that the requirement in s 52(a) of the Commerce Act is satisfied. . It considers that competition for gas services provided by Powerco is limited

Benefits and Costs of Control

Introduction

14.31 The Commission outlined its approach to deriving estimates of the potential benefits and costs of controlling gas services in the Chapter 6 (Assessment Approach). The models presented in that chapter are now applied to the gas services supplied by Powerco.

14.32 The remainder of this chapter identifies the key inputs and assumptions within the cost benefit analysis; any adjustments made to the business specific data provided; the results and sensitivities from the cost benefit model; the level of net acquirers benefit; and the Commission's recommendation on whether control is required.

14.33 All figures are for the year ended 31 March, the balance date nominated by Powerco. Appendix E contains the analysis, results and sensitivity from the Commission's cost benefit model.

Inputs and Assumptions

14.34 The Commission required all the gas pipeline businesses to complete a data template for the years 1996-2008. A specimen of the template is included as Appendix B. The data sought by the template related to revenues, expenses and the asset base.

14.35 Powerco submitted data on its networks for the years 1996-2008. The data provided by Powerco was reviewed by the Commission and clarification or further background information was obtained from Powerco as required. Since the Draft Report, Powerco has provided actual results to March 2004 and revised its forecasts.

14.36 The Commission made adjustments to the data where it considered this necessary for the purposes of the benefits and costs of control assessment. Specific issues and adjustments to the Powerco data are explained below.

Revenue and other income

14.37 The Commission has used Powerco's revenue forecasts. These have been revised by Powerco since the Draft Report.

14.38 Data provided by Powerco suggests the level of capital contributions have been insignificant.

14.39 The Commission considers that forecast revaluation gains will at least be in line with CPI. As Powerco has forecast revaluation gains below CPI, the Commission has included this differential as additional revaluation gains. It has allowed these additional revaluation gains to be offset by the businesses' forecasts of future optimisation, and higher incremental depreciation charges and allowed revenues.

Operating Expense

14.40 Generally, it was difficult to ascertain how the data provided by Powerco had been determined. The historic information provided lacked a clear relationship to auditable figures. The standard of the information provided made it necessary for the Commission to make certain assumptions and estimates.

Inquiry Costs

14.41 Powerco included an allowance for regulatory expense and utility rates in its operating costs. As no further details were available on these expenses the Commission has assumed that approximately half of this cost [ ] results from the forecast regulatory expense. The Commission has removed this cost from the operating expense as it includes the cost of control in the direct costs of control calculation across the entire analysis period.

Common Costs

14.42 The Commission has reservations as to the common cost allocation of the gas pipeline businesses. This is discussed in Chapter 7 (Modelling Issues and Sensitivity Tests).

14.43 In Powerco's case, the Commission considers an adjustment to the base case is necessary because it has over recovered its total common costs.

14.44 Table 14.2 shows the over recovery by Powerco and the adjustment for over recovery in each year. Between 1997 and 2004 Powerco over recovered common costs across all its activities by $4.8m. Apportionment of this over recovery to gas pipeline activities has been based on the indirect cost ratio in

2004 of 36%.[234] For the forecast period a simple average of the past over recovery has been assumed.

Table 14.2: Adjustment to Powerco's opex ($000)

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Adjustment	0	-632 *0.36	-499 *0.36	0	0	0	0	-3,697 *0.36	-217	-217	-217	-217

14.45 In addition, the Commission has reservations as to the allocation of common costs by Powerco. The indirect cost ratio for Powerco is substantially higher than the comparable revenue, asset and direct cost shares for gas distribution vis-à-vis other activities.

14.46 The Commission has accordingly included an additional sensitivity test of the results that measures the effect of presuming common costs were 10%, 20% or 30% lower than the figures provided.

Rates

14.47 In the Draft Report, the Commission reduced Powerco's forecast rates from [ ] to [ ] for 2004 to 2008. Powerco suggested to the Commission that the [ ] figure should be used as there were councils that were contemplating charging or increasing rates on Powerco.

14.48 The Commission sought further information from Powerco, and found Powerco's actual rates for 2004 were [ ]. [

] The Commission contacted these councils to determine their intentions in relation to rating Powerco.

14.49 The Commission found that these councils were calculating rates using either land value or capital value. Councils that base rates on capital value charge utility network businesses substantially higher rates than councils that use land value. [

] None of the councils contacted indicated an intention to increase rates on Powerco.

14.50 The Commission has therefore used Powerco's actual rates for 2004 and indexed this figure for inflation over the period 2005 – 2008.

Self-insurance

14.51 Powerco self-insures. No adjustments were made to the base case to take into account the costs to Powerco of self insurance. The Commission adopted this approach because the information provided by Powerco was not sufficiently

[234] Using the indirect cost ratio is done for convenience and is considered reasonable. Given the indirect cost ratio depends on the allocation of common costs there is a circularity in using this measure.

robust to justify an adjustment. However, the Commission included the costs of self-insurance as a sensitivity test.

Tax

14.52 Powerco's tax was calculated using the Commission's approach outlined in Chapter 10 (Treatment of Tax in Cost Benefit Analysis). Powerco provided the tax book value movements including acquisition value, current depreciation, accumulated depreciation and written down tax book value which were used in the Commission's analysis.

14.53 Powerco's company reorganisation in August 2000 resulted in assets being brought back into the tax and accounting books at a value around [ ] higher than the previous book value. At the time, the accumulated tax depreciation that had been claimed was [ ] on these assets. Upon restructuring, the claw back of tax on this past depreciation would have been [ ] assuming the standard tax rate of 33%. However, some of the depreciation related to years prior to the analysis period. For the purposes of the gas inquiry, the Commission has taken into account the claw back of tax only on the [ ] depreciation claimed in the inquiry period. It has therefore included a tax claw back amount of [ ] in the tax payable which was recognised in the year in which it occurred.[235]

14.54 The Commission's assessment of tax payable going forward has been based on the new tax book values (i.e. inclusive of the [ ] increase in value).

14.55 The tax payable from 2002 is based on the tax book value which includes the acquisition value of the UnitedNetwork assets acquired by Powerco. However, Powerco Group wrote off future income tax benefits in 2004 because of the anticipated changes to the continuity in the shareholding signalled by its major investors. The Commission's modelling indicates that Powerco's gas business was in a tax loss situation in 2002-2004. However, in light of the tax benefit write off in 2004, the Commission has adopted a conservative position and assumed that none of these tax benefits were available to Powerco. The Commission's tax modelling has accounted for the loss of future taxation benefit, by adjusting Powerco's tax payable in 2002-2004 from a negative value to zero (i.e. increasing the tax payable in those years) and adjusting the WACC to remove the interest tax deduction term for the last six months of 2002 and all of 2003 and 2004.

14.56 The tax payable for the subsequent years is based on Powerco's tax book value (i.e. including the acquisition value of the UnitedNetworks assets).

14.57 The Commission has discounted Powerco's company tax rate (0.33) used in the period 2005 to 2008 inclusive to 2010 using the risk free rate on the assumption that unlevered tax losses can be used in the analysis period, but that levered tax losses will not be used until 2010.

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[235] The Commission notes that in its sensitivity analysis of the impact of acquisitions on tax payable, it includes the full tax claw back amount but spreads the adverse impact over the future. This latter approach is preferred by the Commission, but its application to the above situation is unlikely to have a material impact.

Asset Base

14.58 Powerco provides a bundled distribution and metering service. The ODV of Powerco's meters is estimated at between [ ][236]

14.59 There have been substantial changes to Powerco's asset base resulting from the acquisition of assets/networks over a number of years. The most recent ODV valuations undertaken for Powerco's assets were in 1999 (Wellington, Hawke's Bay, and Manawatu) and 2001 (Taranaki, Hutt Valley/Porirua).

14.60 [ ] Powerco's valuations have been conducted by different owners, different consultants and at different times, and are now quite dated (up to five years old, which predates the Handbook). [ ] An updated ODV valuation would be required to ensure a consistent valuation for Powerco's assets.[237]

14.61 No optimisation and EV adjustments were provided by Powerco and no adjustments were made in the analysis for this.

14.62 The Commission's modelling has used the DRC valuations supplied by Powerco.

14.63 Non-system assets, such as property, plant and equipment, are valued at cost less accumulated depreciation.

14.64 In the years 1998-99 and 2001-03 the end of year asset base was used in the analysis to enable the Commission to carry out analysis on the time weighted figures provided by Powerco. This approach was used to overcome the possible overstatement of any excess returns due to timing issues associated with merger activity. For the other years the opening asset base is used.

14.65 The Commission also modified the revaluation spread formulae in the years mentioned above to remove the timing error introduced by the merger activity.

14.66 Powerco was not able to supply historic cost data on its assets for this Inquiry.

14.67 [ ]

Summary of Base Case Variables

14.68 The Commission has developed a 'base case' in its model. The base case includes the adjustments to the input data noted above, the mid-point of

[236] EMCa, *Gas Control Inquiry: Consistency Review of ODV Network Asset Valuations*, May 2004, p 28.

[237] Ibid, p 29.

WACC, an excess returns unrecoverable factor of 20%,[238] and elasticity of demand of -0.3.

14.69 Table 14.3 presents the key variables of the analysis, using the base case in 2003 as an example.

Table 14.3 **Key Variables - Powerco**	**Figures (2003)**
Revenue ($000)	29,254
Net earnings (NE) ($000)	20,795
Actual quantities (Q_m) TJ	5,650
Actual price (P_m) $/GJ[239]	5.18
Efficient quantities (Q_c) TJ	6,197
Efficient price (P_c) $/GJ	3.51
Elasticity	-0.30
WACC	7.99%
Asset base ($000) [240]	[ ]
ODV system assets ($000)	[ ]
Revaluation gains/loss spread ($000)	7,192

Net Acquirers Benefit (NAB)

Introduction

14.70 Given the Commission's view that Powerco faces limited competition in the market for its services, the Commission must consider whether the requirement in s 52(b) of the Commerce Act is satisfied; and whether control is necessary or desirable in the interest of acquirers. In order to determine whether s 52(b) is met the Commission carries out a NAB test. The Commission's recommendations on whether gas services may be controlled are based on the results of the NAB test.

14.71 The benefits and costs of control measured for the purposes of the NAB test are explained in detail in Chapter 6 (Assessment Approach). In summary, the benefits of control relate to improvements in efficiency (in terms of allocative, productive, and/or dynamic efficiency) and the reduction of any excess returns that might be achieved by control. The costs of control include the direct costs of control (quantified in Chapter 6 (Assessment Approach) and the indirect costs associated with the creation of any additional inefficiencies (i.e., productive inefficiency, service quality deterioration, and/or new investment foregone) and/or the potential benefits not being fully realised in practice

[238] Refer to the Indirect Costs section of Chapter 6 (Assessment Approach) for discussion on the unrecoverable excess returns factor.
[239] The 'actual' price is a notional average price based on Powerco's revenue and gas throughput
[240] There is a negative work in progress of -$80,000 in this year, which creates a difference between the asset base and the ODV of system assets.

(measured as the unrecoverable excess returns and the allocative efficiency not achieved).

The Results

14.72 Table 14.4 presents the results of the Commission's base case over the period 1997 - 2008.

Table 14.4 **NAB Results - Powerco**	**($000)**
Benefits	
Excess returns	5,493
Allocative efficiency - consumer surplus	231
Productive efficiency	168
Dynamic efficiency	0
Costs	
Direct Costs	
Compliance costs	-347
Regulator's costs	-253
Indirect Costs	
Excess return unrecoverable	-1,119
Allocative efficiency not achieved	-84
Productive inefficiency	-64
Service quality deterioration	-117
New investment foregone	-188
Key Results	
Annuity	3,719
NPV (1997-2008)	50,260

14.73 The largest component within the potential benefits of control is the removal of excess returns. The potential efficiency benefits (in terms of allocative, productive, and dynamic inefficiency) are modest in comparison to the potential benefits of removing excess returns.

14.74 The largest component within the costs of control is the indirect costs of control, in particular the amount of unrecoverable excess returns by control, in Powerco's case.[241] The sensitivity of the results to the unrecoverable excess returns has been modelled below.

[241] For a breakdown of the cost of control refer to Chapter 6 (Assessment Approach).

Sensitivities

14.75 The Commission has tested the sensitivity of the results of the benefits and costs modelling to changes in key variables. The key sensitivities tested for Powerco were the WACC, the unrecoverable excess returns by control, the common costs, self-insurance, forecast growth rates, dynamic inefficiency and tax.

WACC

14.76 The WACC represents an approximation for the opportunity cost of committed funds.

14.77 The sensitivity of the result to the WACC values was tested by using the 75th and 25th percentile of WACC in the model.[242] Table 14.5 presents the results of this sensitivity testing and the base case of the mid-point of WACC.

Table 14.5 **Sensitivity to WACC - Powerco**	**75th**	**Mid-point**	**25th**
NAB ($000s) annuity	2,925	3,719	4,542

14.78 The NAB for Powerco is positive across the Commission's WACC range. The Commission's view is that the mid-point of WACC should be used in assessing the benefits of control for Powerco. Powerco is able to earn a margin of 1.8% above the mid-point because of the costs of control. At the 75th percentile of WACC, Powerco can earn an additional 0.8% before NAB is found (i.e., Powerco can earn 2.6% above the mid-point of WACC before NAB are found). The costs of control mean Powerco is able to earn significantly above the return implied by the mid-point of WACC before any NAB is found.

Growth

14.79 The Commission compared the overall average growth rates for Powerco, NGCD and Vector (3.5%) with the rates they forecast [ ]. The Commission's overall average growth rates are the ones used for its dynamic inefficiency calculation (to be consistent). They are based on both past and forecast information.[243]

14.80 The difference in output between the overall average and forecast output amounts is multiplied by the prevailing price to determine the potential additional revenue. From this additional revenue were subtracted any additional expenses needed (the difference between forecast expense increases and expected)[244] and the 20% excess returns unrecoverable factor, to give the net NAB effects.

14.81 The effect on the NAB of Powerco would be to increase it by $1.301m in annuity terms.

[242] Refer to the Chapter 9 (Weighted Average Cost of Capital) for a discussion on the WACC range.
[243] Including forecast growth in the calculation of expected growth obviously introduces a circularity, in that, if forecast growth is understated, then this expected growth will also be understated.
[244] For simplicity the expected growth rate was assumed to be the same for both output and expenses.

Self Insurance

14.82 Powerco largely self insures its network against major risks such as earthquake damage. Where adverse events have occurred and resulted in costs, these are included in the Commission's analysis. However, Powerco has informed the Commission that no large scale cost events have occurred during the analysis period.

14.83 The Commission has included as a sensitivity test, an estimate of the possible costs to Powerco of self insurance. Based on market information for insurance for similar risks, the Commission has assumed that self-insurance by Powerco would involve an annual cost of [ ].

14.84 The inclusion of the costs of self-insurance reduces the NAB of Powerco by [ ] in annuity terms.

Excess Returns Unrecoverable

14.85 The unrecoverable excess returns factor represents the amount of excess returns that is considered to be unrecoverable by control and is labelled an indirect cost of control in the Commission's assessment.

14.86 The sensitivity of the results to excess returns unrecoverable by control was tested by using figures of 10% and 25%. The excess returns unrecoverable factor's sensitivities are measured with regard to the mid-point of WACC (the base case). Table 14.6 presents the results for this sensitivity testing and the base case of 20%.

Table 14.6 Sensitivity to Unrecoverable Excess Return Factor – Powerco	**25%**	**20%**	**10%**
NAB ($000s) annuity	3,421	3,719	4,318

14.87 As noted in Chapter 7 (Modelling Issues and Sensitivity Tests), the margin provided by the costs of control is most significantly affected by the choice of excess returns unrecoverable. In Powerco's case the margin at 25%, 20% and 10% excess returns unrecoverable is respectively 2.1%, 1.8% and 1.2% in WACC terms.

Common Costs

14.88 The Commission has adjusted the level of common costs being claimed by Powerco to remove the over-recovery of total common costs. In addition to the reduction in common costs for over-recovery noted above, Table 14.7 presents three sensitivities of the base case results by reducing the level of common costs by a further 10%, 20%, and 30%.

Table 14.7 Sensitivity to Common Cost Reduction –Powerco	**10%**	**20%**	**30%**
NAB ($000s) annuity	3,978	4,237	4,497

Dynamic Inefficiency (Missing Market)

14.89 The dynamic inefficiency costs of the missing market for Powerco were modelled assuming growth in overall demand of 3.5% per annum, output foregone of 10% of the growth in overall demand (i.e. 0.35%) compounded each year and an elasticity of -0.9. Sensitivities around the missing market elasticity and the output foregone effect were run. These are presented below in Table 14.8.

Table 14.8
Sensitivity to Dynamic Inefficiency Cost - Powerco

Missing market elasticity	NAB ($000) annuity	Missing market output effect	NAB ($000) annuity
-0.6	3,625	0.15	3,625
-0.9	3,719	0.10	3,719
-1.2	3,766	0.05	3,813

Tax

14.90 The Commission's base case modelling assumes that Powerco benefits fully from the tax advantages that arise from the purchase of assets above the tax book value, and that the tax disadvantages are borne by the seller. When an asset is sold above its tax book value, tax rules assume that the seller has claimed too much depreciation in the past. The excess depreciation is treated as income and subjected to tax (tax claw back).

14.91 The Commission acknowledges that the claw back of tax is likely to be reflected in the acquisition price of assets and in the prices set by the purchaser for gas services into the future. It has therefore modelled as a sensitivity, the impact of attributing to Powerco the claw back of tax on assets purchased by Powerco. Instead of using the acquisition price as the new tax book value, the Commission calculates an adjusted acquisition price (AAP) taking into account the tax claw back effect. The Commission spreads the adverse impact of the tax claw back over the rest of the life of the assets, so that the NPV of the adverse tax effect spread over time is equal to the initial tax claw back paid by the seller.

14.92 Thus, the Commission derives an adjusted acquisition price as follows:

$$AAP = AP - (HC - TB)(d + WACC)/d$$

where

AAP is the adjusted acquisition price
AP is the acquisition price

HC – TB is the difference between historic cost and tax book value at the time of sale
d is the diminishing value depreciation rate.

14.93 The new acquisition value AAP is then used to calculate depreciation throughout the analysis period, and the tax paid, with the sellers' tax claw back included.

14.94 The Commission does not have detailed information on the actual tax claw backs which occurred for the assets purchased by Powerco (since the entities involved generally are no longer in the industry) and therefore has had to make an estimate for the purposes of the sensitivity analysis.

14.95 The Commission has modelled three tax claw back scenarios in which the depreciation claimed, calculated as the difference between the historic cost (HC) and tax book value (TB) of the assets is $10 million, $20 million and $30 million. It has assumed that transactions occurred in 2002 and 2003 and has spread the impact between these.

14.96 The impact is shown in Table 14.9.[245]

Table 14.9 Impact of Attributing Tax Claw Back to Powerco

Combined HC-TB ($000)	10,000	20,000	30,000
NAB ($000) annuity	3,595	3,475	3,355

14.97 Overall, sensitivity testing on the NAB test reveals that net benefits to acquirers would remain under all the major sensitivities tested, including the WACC, unrecoverable excess returns factor, adjustments for common costs, self-insurance, forecast growth rates, dynamic inefficiency and tax.

Conclusion on Net Benefits to Acquirers

14.98 Over the analysis period the Commission's view is that the requirements of s 52 (b) of the Commerce Act is satisfied. There is evidence that it is necessary or desirable in the interests of acquirers for Powerco's gas services to be controlled.

'May' Control be Introduced

14.99 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for Powerco's gas services is limited and control of these services is necessary or desirable in the interests of acquirers.

14.100 The Commission's view is that the gas services supplied by Powerco may be controlled.

[245] Powerco suggested that the Commission should use the ODV value as the tax book value. The Commission modelled this approach, and obtained NAB annuity ($000) of $3,060 for Powerco. Thus, while such an approach would reduce the NAB somewhat, it would not change the Commission's recommendations.

'Should' Control be Introduced

14.101 Having determined that the Commission may recommend control, it has conducted further analysis to determine whether it 'should' recommend control. The matters considered for whether control 'may' be recommended remain relevant. However, there are also additional matters the Commission considers relevant. The additional issues for whether control 'should' be introduced include:

- the net efficiency costs to the economy of reducing excess returns;
- the size of the benefits; and
- the impact of recommendation of no control.

14.102 Each of these issues is explained below and then weighed against one another prior to recommending whether the gas services provided by Powerco should be controlled.

Net Efficiency Costs of Reducing Excess Returns

14.103 The NAB is calculated by summing the net efficiency effects and the recoverable excess returns.[246] The net efficiency costs to the economy of achieving a reduction in excess returns were calculated as $0.732 million in annuity terms over the analysis period. The recoverable excess returns were calculated as $4.395 million in annuity terms.[247]

14.104 The net efficiency costs can be compared to the reduction in excess returns that control would provide to consumers. This calculation is conducted by dividing the net efficiency costs by the excess returns that can be recovered for consumers.

14.105 In Powerco's case the calculation gives a transfer cost ratio of 0.17. This figure can be interpreted as suggesting that transferring $1 of recoverable excess returns back to consumers costs the economy $0.17 in net efficiency terms.

The Size of the Benefits

14.106 The size of the net acquirers benefit can be assessed in various ways, including;

- return on capital employed;
- its effect on the prices of distribution and the final delivered gas price to consumers; and
- its effect on consumers' annual line charge bills.

14.107 Each of the above is discussed in turn.

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[246] The Commission notes that some additional benefits and costs of control affect producers only, and are included in the efficiency analysis. In Powerco's case the additional benefits and costs are insignificant at $0.002m and $0.080m in annuity terms respectively.

[247] Recoverable excess returns are calculated as the total excess returns less 20% thereof, as this proportion is considered unrecoverable.

14.108 Powerco earns a return of approximately 12.7% on the capital it employs. This return is 2.9% over the returns allowed by the mid-point of WACC (8.0%) and the costs of control (1.8%), and reflects the positive NAB found. [248]

14.109 In terms of the effect on the price of distribution services, the NAB of Powerco suggests that distribution prices could be reduced by as much as 12.2%.

14.110 The effect on the final price of delivered gas in the Powerco region depends on three components of the final price. It depends on any change in transmission charge, the change in distribution price (noted above) and the relative shares of both of these in the final delivered gas price. Our calculations have assumed that transmission and distribution make up 10% and 40% respectively of the final delivered gas price. Reducing Powerco's distribution charge by 12.2% would lower the average final delivered gas price by 4.9% in the Powerco region.

14.111 Alternatively, the reduction can be considered in terms of its effect on average charges. Based on figures supplied by Powerco the average per customer charge over the analysis period is $415 per customer. The annual line charge is made up of transmission plus distribution charges. The reduction in distribution charge would save a typical consumer $51 or a 12.2% reduction in their annual line charge bill.

14.112 It should be noted that all the calculations in this sub-section are made on the basis of bringing NAB back to zero, not to where the efficient level of price may be if the costs of control were ignored.

Impact of a Recommendation of No Control

14.113 If control was not introduced, any downward pressure on prices resulting from the threat of control would be reduced. The Commission's base case also assumes that Powerco will not raise prices over the period 2005-2008, beyond any included in the forecasts.

14.114 In terms of the size of the benefits, careful consideration must be given to the materiality threshold chosen. For example, if the current transfer cost ratio of 0.17 was judged to be too high it may be possible for Powerco to raise prices to the point at which the transfer ratio makes control more desirable.

14.115 There may be spill over effects to other monopoly businesses who may feel they are able exercise any market power they have without the threat of control.

[248] The return is calculated on an average basis. Averaging of returns is sometimes problematic, which is why the Commission places primary reliance on the annuity. However, this calculation of returns is done in the same way as the calculation of the implicit margin on WACC provided by the costs of control and the average mid-point WACC. Therefore the difference between the returns and the mid-point of WACC plus the implicit margin of the costs of control, is still reflective of the NAB found in annuity terms, although the two are not technically comparable.

Conclusion on Whether Control Should be Introduced

14.116 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for Powerco's gas services is limited and control of these services is necessary or desirable in the interests of acquirers. The Commission's view is that the gas services supplied by Powerco may be controlled under Part V of the Commerce Act.

14.117 The Commission's view is that control under Part V is a high cost form of control relative to other regulatory options. As the Commission's report relates to Part V it has included the benefits and costs associated with a Part V control regime in its analysis. Clearly different forms of regulation would be more or less effective at delivering the potential benefits of control to acquirers. Although the Commission has not formally modelled different forms of regulation it considers a less intrusive regulatory option (such as a targeted control regime) may offer a more favourable trade off between costs and benefits.

14.118 In addition to the considerations under s 52 of the Commerce Act the Commission has had regard to the costs to the economy associated with transferring recoverable excess returns to acquirers. The costs to the economy associated with control can be weighed against the excess returns that could be recovered for consumers. The net costs of achieving transfers are 17% of the recoverable excess returns in Powerco's case (or equivalently, the recoverable excess returns are 6 times the net efficiency effects). The Commission considers that their efficiency loss ratio of 17% is not of concern.

14.119 Various indicators can be used to evaluate the size of the NAB. Powerco's actual return on capital over the analysis period is 12.7%. This return is 2.9% over the returns indicated by the midpoint of WACC (8.0%) plus the costs of control (1.8%), and reflects the positive NAB found. The absolute size of the NAB in Powerco's case is $3.719 million in annuity terms. This NAB equates to a 12.2% average price reduction.

14.120 If control is not recommended then any downward pressure on prices resulting from the threat of control, would be reduced, potentially resulting in an increase in the current excess returns. Finally, there may be spill over effects to other monopoly businesses.

14.121 After considering and weighing up the above matters the Commission has formed the view that Part V of the Commerce Act should be used to control Powerco. Therefore, the Commission considers that an Order in Council under s 53 of the Commerce Act to impose control on Powerco under Part V should be made.

Overall Recommendation

14.122 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Powerco may be controlled.

- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Powerco under Part V of the Commerce should be made.

Advice on Relevant Matters

14.123 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. If the Minister were to introduce alternative mechanisms for NGCT, NGCD and Wanganui Gas (such as a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A), there may be benefits in having all businesses, including, Powerco, under the same regime.

14.124 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

14.125 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

14.126 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

15 VECTOR LIMITED (VECTOR)

Introduction

Company History / Ownership

15.1 In 1994, the Auckland Electric Power Board was corporatised and became Mercury Energy Limited (Mercury Energy), following government reforms introduced by the Energy Companies Act 1992. Mercury Energy was owned by the Auckland Energy Consumer Trust (AECT). The AECT was created in 1993 and has as its beneficiaries, customers in the Auckland, Manukau and Papakura regions (Income Beneficiaries) as well as the Auckland City, Manukau City and Papukura District Local Authorities (Capital Beneficiaries).

15.2 Further electricity industry reforms were introduced by the Electricity Industry Reform Act 1998 which prompted Mercury Energy in 1999 to divest itself of its interests in electricity generation and retail. Mercury Energy then changed its name to Vector Limited (and Mighty River Power Limited took over the brand name 'Mercury Energy').

15.3 Vector acquired 100% of the shares in UnitedNetworks Limited (UNL) in October 2002, thereby gaining ownership of UNL's Auckland gas networks. (In a separate transaction UNL concurrently sold its Wellington and Manawatu/Hawke's Bay gas distribution networks to Powerco). UNL was officially amalgamated into Vector on 1 July 2003.

15.4 Vector's main energy activities include electricity distribution in Auckland, North Auckland and Wellington, and gas distribution in the Auckland region.

15.5 Vector has reached an agreement with AGL to acquire AGL's 66.05% shareholding in NGC. However, the transaction has not yet been completed.

15.6 For the purposes of its analysis the Commission has assessed Vector and NGC as if they were separate entities.

Extent of Vertical Integration

15.7 The core business activities of the Vector and its associated companies include a natural gas distribution business (in Auckland), an electricity distribution business (in Auckland and Wellington), and a telecommunications network business (in Auckland CBD and Wellington CBD and in other parts of Vector's electricity network area). In addition, Vector operates a training business for people working in the electricity and gas industries, has a 70% interest in an electricity metering services business, and a 50% interest in a tree and vegetation management company.

15.8 Vector does not have any significant interests in the production and processing, wholesale, transmission or retail gas markets in New Zealand.

Gas Distribution Activities

15.9 Vector owns and manages gas networks in the greater Auckland region. The networks are bounded by Helensville, Orewa and the Hibiscus coast to the

North and by Pukekohe and the Bombay Hills to the South. Vector has separate physical networks in the greater Auckland area, Henderson, Tuakau, Ramarama, Whangaparaoa, Alfriston, Hunua, Drury, Pukekohe, Kingseat and Waiuku.

15.10 Vector delivers natural gas from the transmission system owned by NGC through its network on behalf of a number of retail companies as well as directly to some major customers. Vector's gas network is approximately 5,000 km in length, supplying 68,000 consumers, or approximately 16% of Auckland homes and businesses. Around [ ] of its customers are residential and they take [ ] of the gas carried on the network. Industrial and commercial customers, who are [ ] by number, take around [ ] of the gas carried.

15.11 Based on 2003 figures, around [ ] of Vector's revenue is derived from its gas pipeline business.

Table 15.1: Vector (UNL) – Distribution Network Statistics (year ending 31 December 2002)

System	Length (km)	Total Gas Conveyed (GJ)
Gas Distribution Network	5,008	11,555,000

Competition Analysis

Introduction

15.12 There are a number of competition issues which are relevant to all gas distribution networks. In addition, each gas services market has distinguishing characteristics and accordingly each distributor's networks are considered separately in this report.

15.13 Of the total gas connections in the greater Auckland area, approximately 85% are connected to Vector's network. The areas in Auckland covered by Vector's network are largely considered together below (and referred to collectively as the Auckland network).

15.14 Vector has suggested that there are distinguishing features about its business which should be considered when the competition it faces is assessed. Unlike NGC, it does not have a transmission business. It is not a gas retailer. It operates in Auckland where the penetration of reticulated natural gas is more limited than in many other centres (only 16% of all households and businesses in Auckland are connected to Vector's gas distribution network. Of those that pass by the network only 26% take gas). Auckland has some large commercial gas users (and a growing concentration thereof), and around [ ] of Vector's customers are manufacturing based. Many of these industrial and commercial customers are close to the transmission lines, making bypass a possibility. Vector currently faces bypass competition from two firms – Nova Gas and NGC. It is a relatively new network – over 50% is less than 10 years old and 80% is less than 20 years old. There has been a significant increase in LPG penetration in recent years (accounting for 23% of total gas sales to the residential sector in 2002 compared with 12% in 1999). Auckland is the largest urban market by far and has expanded rapidly. Large areas of Auckland are built on volcanic cones making the laying of pipes expensive. Demand for gas is affected by its relatively temperate climate in the winter and by the growth in apartment buildings which are non-owner occupied.

Competition

15.15 The markets of relevance to Vector's competition analysis are those for the provision of gas services in Auckland, and for the provision of gas services in bypass markets.

<u>Generic</u>

15.16 As discussed in Chapter 3 (Competition Analysis), gas networks have natural monopoly characteristics. Distributors incur high fixed and sunk costs and relatively low variable costs. In these circumstances it is possible that one firm in any area is able to undertake the distribution function at a lower average cost than two or more firms. This is likely to deter other than bypass entry, except where the existing pipelines are utilised to their full capacity. The Commission understands that capacity constraints on distribution networks are relatively rare and in limited areas of the network.

15.17 Bypass opportunities tend to be limited to where there is a concentration of medium to large consumers who are close to an offtake point on the transmission pipeline, where an existing bypass network can expand its scope or where there is an alternative source of gas (e.g. landfill gas).

15.18 As noted above, the immediate areas where a bypass operator is competing with the incumbent have been placed in a discrete market. In these markets the Commission considers that there is strong evidence of vigorous competition.

15.19 The Commission recognises that in other markets the threat of bypass entry can have an important competitive impact, but it considers that this threat (and impact) exists in only small pockets of the area covered by the incumbent's network.

15.20 The Commission has received a number of submissions on the extent to which other fuel forms compete with gas and therefore constrain the price which can be charged for transmission and distribution services. Examples were provided of instances where users of gas had switched to electricity, coal, LPG, diesel and wood.

15.21 The Commission accepts that some energy users do have a choice of fuels, although for many this may be limited to when their energy specific plant or appliance is nearing the end of its economic life. However, the information provided to the Commission (and discussed in Chapter 3 (Competition Analysis)) suggests that interfuel competition is not sufficient in itself to place strong competitive pressure on gas suppliers.

15.22 In addition, the Commission notes that distribution only accounts for perhaps 40% of the final price of delivered gas. Therefore, the competitive constraint other energy forms place on gas prices is dissipated in its impact on the distribution function.

15.23 The Commission accepts that some large gas users may have entered long-term distribution contracts when they undertook their original investment (and when they still had discretion over location and fuel choice). These contracts may give these gas users protection against distributors of gas exercising market power during the period of the contract. However, the Commission considers that any such protection is likely to be limited to a small number of large gas users.

15.24 The existing regulatory regime, including information disclosure and the threat of regulation, may also provide some constraint on distributors. However, for the reasons discussed in Chapter 3 (Competition Analysis), the Commission does not consider that these constraints, taken together, match the constraints faced by a firm in a market which has workable or effective competition.

<u>Vector</u>

15.25 Within the area covered by the Vector network, Nova Gas has limited bypass networks at Hunua, Wiri, East Tamaki, and Managere. In addition, NGC has limited bypass pipelines in the South Auckland area. As discussed in the Market Definition section of Chapter 3 (Competition Analysis), the areas which are served by bypass networks (as well as the incumbent's network) have distinct competition characteristics and accordingly have been placed in a discrete bypass market for the purposes of analysis.

15.26 The Commission considers that competition faced by Vector in the bypass market is vigorous and places a very significant downward pressure on prices. Further, the Commission considers that there is little potential for coordinated behaviour between Vector and Nova Gas.[249] Accordingly, in the bypass market the Commission has concluded that competition for gas services is workable and effective. In this situation the Commission cannot recommend control for services provided in the bypass market.

15.27 For practical reasons however, the Commission in its detailed assessment of the costs and benefits of control below has not separated that part of Vector's network which falls within the bypass market (which represents only a very small part of its total network) from the rest of its network. As NGC noted in respect of its networks, any attempt to separate the two parts is likely to be fraught with difficulty. Considering the Auckland and bypass markets together, the lower prices in the competitive bypass market produce an overall average price (and return) which is likely to be slightly less than that which would be found if the Auckland market was considered alone.

15.28 In Whangaparaoa, Vector has a limited network which in some parts runs adjacent to a limited Vector network. The Vector network is now connected to the gas transmission pipeline but until recently obtained its gas by means of a CNG tanker. The Whangaparaoa situation is discussed in more detail in the Competing Distribution Networks section of Chapter 3 (Competition Analysis). The Commission concludes that there is no evidence of strong competition

[249] See Chapter 3 (Competition Analysis), paragraph 3.70.

between Vector and NGC in Whangaparaoa, despite the relative proximity to each other.

15.29 In South Auckland, NGCD has a very limited bypass network which delivers gas to a limited number of horticultural businesses. Vector is the incumbent network owner in the region. The size of NGCD's bypass operations is sufficiently small to make it not material to the Commission's analysis.

15.30 The Commission recognises that where a threat of bypass is real, Vector is constrained. However, this threat applies to only small pockets of Vector's network and gas users outside those pockets are not affected.

15.31 Vector provided a considerable amount of helpful information to the Commission relating to interfuel competition. It focussed in particular on the supply of gas and of LPG (particularly to the residential sector) and suggested that the delivered price of LPG was about 7% more expensive than that for gas, and that LPG has the same functionality, being used for space heating, water heating and cooking amongst other things. It noted that LPG can be delivered through pipelines (as in the South Island) or in bottles or tanks. It noted that businesses which use gas compete against businesses which use LPG (for instance in the South Island where gas is not available).

15.32 The Commission accepts that these points are relevant to its consideration, although it notes that, as discussed in Chapter 3 (Competition Analysis), other estimates of the relative prices of gas and LPG suggested a larger margin than 7%. The Commission also notes however, that gas tends to be significantly cheaper for larger users as the important fixed cost component in the price of delivered gas is recovered over greater volumes of gas. Conversely of course, LPG may have an important price advantage for small users.

15.33 Having given full consideration to all the arguments raised by Vector and others, the Commission has concluded that the constraint provided by interfuel competition is not sufficient to ensure that gas is delivered at competitive prices.

15.34 The Commission also accepts that the regulatory regime and the threat of additional regulation provide some constraint on gas service providers, albeit relatively small. However, again it has concluded that this constraint falls well short of the constraint faced by a firm in a market which has workable or effective competition.

15.35 The Commission has considered the particular characteristics of the Auckland market in which Vector operates. The feature which may have an important bearing on the level of competition is the potential for bypass, which for the supply to some customers (particularly commercial and industrial customers in clusters) in some areas (close to the transmission network) may be greater than that found elsewhere. However, notwithstanding this feature, the Commission considers that competition in the market as a whole remains less than workable or effective.

Conclusion on Competition

15.36 The Commission accepts that the factors which can impact on an incumbent network operator may vary from region to region. In this instance it has taken into account factors which are peculiar to the Auckland market in which Vector operates.

15.37 Having regard to these factors, and to the more generic factors discussed above, the Commission concludes that Vector is constrained in its behaviour by such factors as the potential for bypass pipelines in some limited areas, by interfuel competition, and by the current regulatory regime. However, the Commission considers that this constraint falls short of that which would be faced by a firm in a market which has workable or effective competition.

15.38 Accordingly, the Commission's view is that the requirement in s 52(a) of the Commerce Act is satisfied. It considers that competition for gas services provided by Vector is limited.

Benefits and Costs of Control

Introduction

15.39 The Commission outlined its approach to deriving estimates of the potential benefits and costs of controlling gas services in Chapter 6 (Assessment Approach). The models presented in that chapter are now applied to the gas services supplied by Vector.

15.40 The remainder of this chapter identifies the key inputs and assumptions within the cost benefit analysis; any adjustments made to the business specific data provided; the results and sensitivities from the cost benefit model; the level of net acquirers benefit; and the Commission's recommendation on whether control is required.

15.41 All figures are for the year ended 31 December, the balance date nominated by Vector. Appendix F contains the Vector analysis and results from the Commission's cost benefit model.

Inputs and Assumptions

15.42 The Commission required all the gas pipeline businesses to complete a data template for the years 1996-2008. A specimen of the template is included as Appendix B. The data sought by the template related to revenues, expenses and the asset base.

15.43 Vector submitted data on its networks for the years 2000-2008. Vector acquired its gas assets through the purchase of UNL in November 2002. The network was acquired by UNL from Orion NZ in April 2000. Vector has provided both bundled and unbundled information for assets owned and operated by UNL. Ownership of some of these assets is with Vector, while other assets were acquired by Powerco. From 2002 onwards the information pertains only to assets owned by Vector.

15.44 The data provided by Vector was reviewed by the Commission with clarification or further background information being obtained from Vector as required. Since the Draft Report, Vector has provided 2004 actual results and revised its forecasts.

15.45 The Commission made adjustments to the data where it considered this necessary for the purposes of assessing the benefits and costs of control. Specific issues and adjustments to the Vector data are explained below.

Data

15.46 Vector has submitted data from 2000 onwards. The Commission considers that the Vector's analysis should cover the period 2000-2008 and that the shorter period of analysis (i.e. 9 years, rather than 12 years for most of the others gas pipeline businesses) does not affect the results for Vector.

15.47 The data held by Vector for 2000 covers only nine months of the year. Vector has adjusted this to give full year figures.

Revenue and Other Income

15.48 The Commission has used Vector's revenue forecasts. These have been revised by Vector since the Draft Report. The Commission requested this revision after 2004 actuals were significantly greater than forecast.

15.49 Vector treats capital contributions as income. The level of capital contributions have been approximately [ ] p.a..

15.50 The Commission considers that forecast revaluation gains will at least be in line with CPI. [ ] the Commission has included this differential as additional revaluation gains. It has allowed these additional revaluation gains to be offset by the businesses' forecasts of future optimisation, and higher incremental depreciation charges and allowed revenues.

Operating Expenses

15.51 Vector sold a substantial part of UNL assets to Powerco in 2002, [ ].

Common Costs

15.52 The Commission has reservations as to the common cost allocation of all the gas pipeline businesses. This is discussed in Chapter 7 (Modelling Issues and Sensitivity Tests).

15.53 In Vector's case the Commission notes that Vector has changed its common cost allocation approach from that used by UNL (previous owners of Vector's gas assets). Vector claims to have moved from treating gas pipelines as an incremental business to treating them as a standalone business. This has resulted in a significant increase in the level of common costs claimed. For example, in 2002 the common costs of Vector were [   ] greater than those previously disclosed by UNL for the same assets.

15.54 As stated in Chapter 7 (Modelling Issues and Sensitivity Tests) the Commission undertook ratio analysis, comparisons across the gas pipeline businesses (Meyrick analysis) and comparisons with electricity lines businesses.

15.55 Based on these analyses Vector stands out as having consistently high common costs across all comparison bases and compared to similar figures for electricity lines businesses.

15.56 Vector common costs comprises of all items other than maintenance and direct costs, e.g., accommodation, employment related costs, administration, computer costs, advertising and promotions etc.

15.57 When comparing Vector to the other gas pipeline businesses (Meyrick analysis) Vector's common costs are 50% higher than NGC and 60% higher than Powerco. Although Vector is relatively efficient in terms of its direct costs, it is the worse performer in terms of total operating costs (16% less efficient than NGCD and 60% less efficient than Powerco).

15.58 As a result of the analyses undertaken the Commission considers that Vector's common costs have been over-allocated to its gas pipeline activity and has therefore reduced its allocated common costs by 20%.

15.59 The Commission believes that further adjustments to common costs might be justified and accordingly has included a sensitivity of the results that measures the effect of presuming common costs were 10%, 20% or 30% lower than the adjusted figures.

Self-insurance

15.60 To a large extent, Vector self-insures against the risks of catastrophic events such as earthquakes and volcanic activity. No adjustments were made to the base case to take into account the costs to Vector of self-insurance. The Commission adopted this approach because the information provided by Vector was not sufficiently robust to justify an adjustment. However, the Commission included the costs of self insurance as a sensitivity test.

Tax

15.61 Vector's tax was calculated using the Commission's approach outlined in Chapter 10 (Treatment of Tax in Cost Benefit Analysis). Vector provided the tax book value movements including acquisition value, current depreciation, accumulated depreciation and written down tax book value which were used in the Commission's analysis.

15.62 [

]

Asset Base

15.63 In its modelling, the Commission has used the ODV values provided by Vector. The most recent ODV valuation of Vector's gas assets was undertaken as at 31 March 2003. [

][250]

15.64 [

] These adjustments have been carried out to exclude these assets from the revaluation gain calculations.

15.65 [

]

15.66 Vector has no involvement in metering on its network, so its asset base excludes metering.

15.67 Vector was unable to provide historic cost data. Historic cost records are not held by Vector for the gas assets that it now owns. The Commission explored the possibility of getting some of the information from Orion NZ, the previous owner of the Auckland gas distribution network, but there was insufficient information to conduct a robust analysis.

Summary of Base Case Variables

15.68 The Commission has developed a 'base case' in its model. The base case includes the adjustments to the input data noted above, the mid-point of WACC, an unrecoverable excess returns factor of 20%,[251] and elasticity of demand of -0.3.

15.69 Table 15.2 presents the key variables of the analysis, using the base case in 2003 as an example.

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[250] EMCa (2004) p 15.

[251] Refer to the Indirect Costs section of Chapter 6 (Assessment Approach) for discussion on the unrecoverable excess returns factor.

Table 15.2 **Key Variables - Vector**	**Figures (2003)**
Revenue ($000)	43,945
Net earnings (NE) ($000)	26,441
Actual quantities (Q_m) TJ	11,555
Actual price (P_m) $/GJ[252]	3.80
Efficient quantities (Q_c) TJ	12,520
Efficient price (P_c) $/GJ	2.74
Elasticity	-0.30
WACC	7.19%
Asset base ($000)	207,787
ODV system assets ($000)	198,989
Other non-system assets ($000)	8,798
Revaluation gains/loss spread ($000)	3,800

Net Acquirers Benefit (NAB)

Introduction

15.70 Given the Commission's view that Vector faces limited competition in the market for its services, the Commission must consider whether the requirement in s 52(b) of the Commerce Act is satisfied; and whether control is necessary or desirable in the interest of acquirers. In order to determine whether s 52(b) is met the Commission carries out a NAB test. The Commission's recommendations on whether gas services may be controlled are based on the results of the NAB test.

15.71 The benefits and costs of control measured for the purposes of the NAB test are explained in detail in Chapter 6 (Assessment Approach). In summary, the benefits of control relate to improvements in efficiency (in terms of allocative, productive, and/or dynamic efficiency) and the reduction of any excess returns that might be achieved by control. The costs of control include the direct costs of control (quantified in Chapter 6 (Assessment Approach) and the indirect costs associated with the creation of any additional inefficiencies (i.e., productive inefficiency, service quality deterioration, and/or new investment foregone) and/or the potential benefits not being fully realised in practice (measured as the excess returns unrecoverable and the allocative efficiency not achieved).

The Results

15.72 Table 15.3 presents the results of the Commission's base case of the NAB test over the period 2000 - 2008.

[252] The 'actual' price is a notional average price based on Vector's revenue and gas throughput.

Table 15.3 NAB Results - Vector	($000)
Benefits	
Excess returns	9,361
Allocative efficiency - consumer surplus	403
Productive efficiency	283
Dynamic efficiency	0
Costs	
Direct Costs	
Compliance cost	-287
Regulator's cost	-210
Indirect Costs	
Excess return unrecoverable	-1,872
Allocative efficiency not achieved	-145
Productive inefficiency	-110
Service quality deterioration	-185
New investment foregone	-316
Key Results	
Annuity	6,921
NPV (2000-2008)	76,909

15.73 The largest component within the potential benefits of control is the removal of excess returns. The potential efficiency benefits (in terms of allocative, productive, and dynamic inefficiency) are modest in comparison to the potential benefits of removing excess returns.

15.74 The largest component within the costs of control is the indirect costs of control, in particular the amount of excess returns that are unrecoverable by control, in Vector's case.[253] The sensitivity of the results to the unrecoverable excess returns has been modelled below.

Sensitivities

15.75 The Commission has tested the sensitivity of the results of the benefits and costs modelling to changes in key variables. The sensitivities tested were the WACC range, the unrecoverable excess returns by control, common costs, dynamic inefficiency and self-insurance.

[253] For a further breakdown of the costs of control refer to Chapter 6 (Assessment Approach).

WACC

15.76 The WACC represents an approximation for the opportunity cost of committed funds.

15.77 The sensitivity of the result to the WACC values was tested by using the 75th and 25th percentiles of the WACC distribution in the model.[254] Table 15.4 presents the results of this sensitivity testing and the base case of the mid-point of WACC.

Table 15.4 **Sensitivity to WACC – Vector**	**75th**	**Mid-point**	**25th**
NAB ($000s) annuity	5,692	6,921	8,215

15.78 The NAB for Vector is positive across the Commission's WACC range. The Commission's view is that the mid point of WACC should be used in assessing the benefits of control for Vector. Vector is able to earn a margin of 1.6% above the mid point of WACC because of the costs of control. At the 75th percentile of WACC, Vector can earn an additional 0.8% before NAB is found (i.e., Vector can earn 2.4% above the mid-point of WACC before NAB are found). The costs of control mean Vector is able to earn significantly above the return implied by the mid-point of WACC before any NAB is found.

Growth

15.79 [

]. There is only a minor impact on the NAB of Vector for this sensitivity.

Self Insurance

15.80 Vector largely self insures its network against major risks such as earthquake damage. Where adverse events have occurred and resulted in costs, these are included in the Commission's analysis. However, no large scale cost events have affected Vector during the analysis period.

15.81 The Commission has included as a sensitivity test, an estimate of the possible costs to Vector of self insurance. Based on market information for insurance for similar risks, the Commission has assumed that self-insurance by Vector would involve an annual cost of [ ].

15.82 The inclusion of the costs of self-insurance reduces the NAB of Vector by [ ] in annuity terms.

Excess Returns Unrecoverable

15.83 The unrecoverable excess returns factor represents the amount of excess returns that is considered to be unrecoverable by control and is labelled an indirect cost of control in the Commission's assessment.

254 Refer to Chapter 9 (Weighted Average Cost of Capital) for a discussion on the WACC distribution.

15.84 The sensitivity of the results to excess returns unrecoverable by control was tested by using figures of 10% and 25%. The unrecoverable excess returns factor's sensitivities are measured with regard to the mid-point of WACC (the base case). Table 15.5 presents the results for this sensitivity testing and the base case of 20%.

Table 15.5 Sensitivity to Unrecoverable Excess Return Factor - Vector	**25%**	**20%**	**10%**
NAB ($000s) annuity	6,422	6,921	7,926

15.85 As noted in Chapter 7 (Modelling Issues and Sensitivity Tests), the margin provided by the costs of control is most significantly affected by the choice of excess returns unrecoverable. In Vector's case the margin at 25%, 20% and 10% excess returns unrecoverable is respectively 1.9%, 1.6% and 1.1% in WACC terms.

Common Costs

15.86 The Commission has adjusted the level of common costs claimed by Vector by 20% in the base case. In addition, Table 15.6 presents three sensitivities in which the level of common costs is reduced by a further 10%, 20%, and 30%.

Table 15.6 Sensitivity to Common Cost Reduction -Vector	**10%**	**20%**	**30%**
NAB ($000s) annuity	7,522	8,125	8,730

Dynamic Inefficiency (Missing Market)

15.87 The dynamic inefficiency costs of the missing market for Vector were modelled assuming growth in overall demand of 3.5% per annum, output foregone of 10% of the growth in overall demand (i.e. 0.35%) compounded each year and an elasticity of -0.9. Sensitivities around the missing market elasticity and the output foregone effect were run, and are shown in Table 15.7.

Table 15.7
Sensitivity to Dynamic Inefficiency Cost – Vector

Missing market elasticity	NAB ($000) annuity	Missing market output effect	NAB ($000) annuity
-0.6	6,763	0.15	6,763
-0.9	6,921	0.10	6,921
-1.2	7,000	0.05	7,079

Tax

15.88 The Commission's base case modelling assumes that Vector benefits fully from the tax advantages that arise from the purchase of assets above the tax book value, and that the tax disadvantages are borne by the seller. When an asset is sold above its tax book value, tax rules assume that the seller has claimed too much depreciation in the past. The excess depreciation is treated as income and subjected to tax (tax claw back).

15.89 The Commission acknowledges that the claw back of tax is likely to be reflected in the acquisition price of assets and in the prices set by the purchaser for gas services into the future. It has therefore modelled as a sensitivity, the impact of attributing to Vector the claw back of tax on assets purchased by Vector (or UNL before it). Instead of using the acquisition price as the new tax book value, the Commission calculates an adjusted acquisition price (AAP) taking into account the tax claw back effect. The Commission spreads the adverse impact of the tax claw back over the rest of the life of the assets, so that the NPV of the adverse tax effect spread over time is equal to the initial tax claw back paid by the seller.

15.90 Thus, the Commission derives an adjusted acquisition price as follows:

$$AAP = AP - (HC - TB)(d + WACC)/d$$

where

AAP is the adjusted acquisition price
AP is the acquisition price
HC – TB is the difference between historic cost and tax book value at the time of sale
d is the diminishing value depreciation rate.

15.91 The new acquisition value AAP is then used to calculate depreciation throughout the analysis period, and the tax paid, with the sellers' tax claw back included.

15.92 The Commission does not have detailed information on the actual tax claw backs which occurred for the assets purchased by Vector (since the entities involved generally are no longer in the industry) and therefore has had to make an estimate for the purposes of the sensitivity analysis.

15.93 The Commission has modelled three tax claw back scenarios in which the depreciation claimed, calculated as the difference between the historic cost (HC) and tax book value (TB) of the assets is \$10 million, \$20 million and \$30 million. It has assumed that the transaction occurred in 2000.

15.94 The impact is shown in Table 14.9.[255]

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[255] Vector suggested that the Commission should use the ODV value as the tax book value. The Commission modelled this approach, and obtained a NAB annuity (\$000) of \$5,427 for Vector. Thus, while such an approach would reduce the NAB somewhat, it would not change the Commission's recommendations.

Table 15.8 Impact of Attributing Tax Claw Back to Vector

HC-TB ($000)	10,000	20,000	30,000
NAB ($000) annuity	6,626	6,325	6,024

15.95 Overall, sensitivity testing on the NAB test reveals that net benefits to acquirers would remain under all the major sensitivities tested, including the WACC, the unrecoverable excess returns factor, adjustments for common costs, forecast growth, self-insurance, dynamic inefficiency and tax.

Conclusion on Net Benefit to Acquirers

15.96 Over the analysis period the Commission's view is that the requirements of s 52 (b) of the Commerce Act is satisfied. There is evidence that it is necessary or desirable in the interests of acquirers for Vector's gas services to be controlled.

'May' Control be Introduced

15.97 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for Vector's gas services is limited and control of these services is necessary or desirable in the interests of acquirers. The Commission's view is that the gas services supplied by Vector may be controlled.

'Should' Control be Introduced

15.98 Having determined that the Commission may recommend control, it has conducted further analysis to determine whether it 'should' recommend control. The matters considered for whether control 'may' be recommended remain relevant. However, there are also additional matters the Commission considers relevant. The additional issues for whether control 'should' be introduced include:

- net efficiency costs to the economy of reducing excess returns;
- the size of the benefits; and
- the impact of recommendation of no control.

15.99 Each of these issues is explained below and then weighed against one another prior to recommending whether the gas services provided by Vector should be controlled.

Net Efficiency Cost of Reducing Excess Returns

15.100 The NAB is calculated by summing the net efficiency effects and the recoverable excess returns..[256] The net efficiency costs to the economy of achieving a reduction in excess returns were calculated as $0.702 million in

[256] The Commission notes that some additional benefits and costs of control affect producers only, and are included in the efficiency analysis discussed below. In Vector's case the additional benefits and costs are at $0m and $0.134m in annuity terms respectively.

annuity terms over the analysis period. The recoverable excess returns were calculated as $7.489 million in annuity terms.[257]

15.101 The net efficiency costs can be compared to the reduction in excess returns that control would provide to consumers. This calculation is conducted by dividing the net efficiency costs by the excess returns that can be recovered for consumers.

15.102 In Vector's case the calculation gives a transfer cost ratio of 0.09. This figure can be interpreted as suggesting that transferring $1 of recoverable excess returns back to consumers costs the economy $0.09 in net efficiency terms.

The Size of the Benefits

15.103 The size of the net acquirers benefit can be assessed in various ways, including;

- return on capital employed;
- its effect on the prices of distribution and the final delivered gas price to consumers; and
- its effect on consumers' annual line charge bills.

15.104 Each of the above is discussed in turn.

15.105 Vector earns a return of approximately13.5% on the capital it employs. This return is 3.9% over the returns allowed by the mid-point of WACC (8.0%) and the costs of control (1.6%), and reflects the NAB found. [258]

15.106 In terms of the effect on the price of distribution services, the NAB of Vector suggests that distribution prices could be reduced by as much as 18.5%.

15.107 The effect on the final price of delivered gas in the Vector region depends on three components of the final price. It depends on any change in transmission charge, the change in distribution price (noted above) and the relative shares of both of these in the final delivered gas price. Our calculations have assumed that transmission and distribution make up 10% and 40% respectively of the final delivered gas price. Reducing Vector's distribution charge by 18.5% would lower the average final delivered gas price by 7.4% in the Vector region. If the reduction in transmission charge were also achieved, prices would be further reduced in the Vector region.

15.108 Alternatively, the reduction can be considered in terms of its effect on average per customer charges. Based on figures supplied by Vector the average annual charge over the analysis period is $617 per customer. The annual line charge is

[257] Recoverable excess returns are calculated as the total excess returns less 20% there of, as this proportion is considered unrecoverable.
[258] The return is calculated on an average basis. Averaging of returns is sometimes problematic, which is why the Commission places primary reliance on the annuity. However, this calculation of returns is done in the same way as the calculation of the implicit margin on WACC provided by the costs of control and the average mid point WACC. Therefore the difference between the returns and the mid-point of WACC plus the implicit margin of the costs of control, is still reflective of the NAB found in annuity terms, although the two are not technically comparable.

made up of transmission plus distribution charges. The reduction in distribution charge would save a typical consumer $114 or an 18.5% reduction in their annual line charge bill.

15.109 It should be noted that all the calculations in this sub-section are made on the basis of bringing NAB back to zero, not to where the efficient level of price may be if costs of control were ignored.

Impact of a Recommendation of No Control

15.110 If control was not introduced, any downward pressure on prices resulting from the threat of control, would be reduced. The Commission's base case also assumes that Vector will not raise prices over the period 2005-2008, beyond any it has recently implemented.

15.111 In terms of the size of the benefits, careful consideration must be given to the materiality threshold chosen. For example, if the current transfer cost ratio of 0.09 was judged to be too high it may be possible for Vector to raise prices to the point at which the transfer ratio makes control more desirable.

15.112 There may be spill over effects to other monopoly businesses who may feel they are able exercise any market power they have without the threat of control.

Conclusion on Whether Control Should be Introduced

15.113 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for Vector's gas services is limited and control of these services is necessary or desirable in the interests of acquirers. The Commission's view is that the gas services supplied by Vector may be controlled under Part V of the Commerce Act.

15.114 The Commission's view is that control under Part V is a high cost form of control relative to other regulatory options. As the Commission's report relates to Part V it has included the benefits and costs associated with a Part V control regime in its analysis. Clearly different forms of regulation would be more or less effective at delivering the potential benefits of control to acquirers. Although the Commission has not formally modelled different forms of regulation it considers a less intrusive regulatory option (such as a targeted control regime) may offer a more favourable trade off between costs and benefits.

15.115 In addition to the considerations under s 52 of the Commerce Act the Commission has had regard to the costs to the economy associated with transferring recoverable excess returns to acquirers. The costs to the economy associated with control can be weighed against the excess returns that could be recovered for consumers. The net costs of achieving transfers are 9% of the recoverable excess returns in Vector's case (or equivalently, the recoverable excess returns are 10.7 times the net efficiency effects). The Commission considers that their efficiency loss ratio of 9% is not of concern.

15.116 Various indicators can be used to evaluate the size of the NAB. Vector's actual return on capital over the analysis period is 13.5%. This return is 3.9%

over the returns indicated by the midpoint of WACC (8.0%) plus the costs of control (1.6%), and reflects the positive NAB found. The absolute size of the NAB in Vector's case is $6.921 million in annuity terms. This NAB equates to a 18.5% average price reduction.

15.117 If control is not recommended then any downward pressure on prices resulting from the threat of control, would be reduced, potentially resulting in an increase in the current excess returns. Finally, there may be spill over effects to other monopoly businesses.

15.118 After considering and weighing up the above matters the Commission has formed the view that Part V of the Commerce Act should be used to control Vector. Therefore, the Commission considers that an Order in Council under s 53 of the Commerce Act to impose control on Vector under Part V should be made.

Overall Recommendation

15.119 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Vector may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Vector under Part V of the Commerce should be made.

Advice on Relevant Matters

15.120 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. If the Minister were to introduce alternative mechanisms for NGCT, NGCD and Wanganui Gas (such as a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A), there may be benefits in having all businesses, including, Vector, under the same regime.

15.121 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

15.122 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

15.123 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The

Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

16 WANGANUI GAS LIMITED

Introduction

Company History / Ownership

16.1 Wanganui Gas was formed as a private company in 1879. The business was subsequently acquired by the Wanganui Borough Council in 1902. Wanganui Gas continued to operate as a council department until it was formed into a public limited liability company in December 1992.

16.2 Wanganui Gas is majority owned (74.9%) by the Wanganui District Council with the remaining 25.1% shareholding owned by NGC Holdings Ltd. Wanganui Gas is a distributor of gas and is also involved in retailing electricity, natural gas, Compressed Natural Gas (CNG) and consumer energy appliances.

Extent of Vertical Integration

16.3 As well as being a distributor of gas, Wanganui Gas retails gas throughout the North Island using both its Wanganui Gas and Direct Energy New Zealand brands. Wanganui Gas wholesales gas to Mighty River Power in the Auckland region.

16.4 Wanganui Gas is also involved in retailing, CNG, and natural gas appliances, as well as selling electricity in the Wanganui and Rangitikei regions through its relationship with Mighty River Power.

16.5 Wanganui Gas does not have any significant interest in the production and processing, wholesale or transmission gas markets in New Zealand.

Gas Distribution Activities

16.6 The distribution division of Wanganui Gas trades as GasNet. Wanganui Gas owns or operates 6 gas distribution networks situated in Wanganui, Kaitoke (managed by GasNet but not owned by Wanganui Gas), Marton, Lake Alice/Bulls, Flock House and Waitotara. Wanganui Gas's network has remained at approximately 350 km in length since 1999. There are approximately [ ] residential customers (who take [ ] of gas carried), [ ] commercial customers ([ ] of gas carried) and [ ] industrial customers ([ ] of gas carried).

16.7 Based on 2003 figures, the gas pipeline business accounts for [ ] of Wanganui Gas's total revenue.

Table 16.1: Wanganui Gas – Distribution Network Statistics (year ended 30 June 2003)

System	Length (km)	Total Gas Conveyed (GJ)
Distribution Network	354	1,107,666

Competition Analysis

Introduction

16.8 The generic competition issues applying to gas services are discussed in Chapter 3 (Competition Analysis). However, each gas services market has distinguishing characteristics and accordingly the networks of each distributor are considered separately in this report.

Competition

16.9 Wanganui Gas was formed in 1879 to produce and distribute coal gas, and since 1902 has been majority owned by Wanganui Council. It currently retails both gas and electricity, and retails more gas off-network than on-network. Its gas network has a high penetration rate compared with other distributors.

16.10 There are currently no pipelines bypassing Wanganui Gas's network. However, at the Draft Framework Conference,[260] Mr Goodwin of Wanganui Gas noted that there was a somewhat unique situation in Wanganui as the point of delivery off the transmission network is in the centre of Wanganui's industrial area, and he suggested that this enhanced the risk of bypass.

16.11 The market of relevance to the analysis of the degree of competition faced by Wanganui Gas is the provision of gas services in Wanganui/Rangitikei and South Taranaki.

16.12 At the conference on the Draft Report, Wanganui Gas made the following comments relevant to the competition assessment:

- Electricity and LPG can substitute for gas – the reverse is difficult
- Increasing wholesale prices may make gas less competitive
- Dual fuel retailers can alter their behaviour to promote the fuel that provides the most economic return.

16.13 As discussed in the Generic Competition section in Chapter 3 (Competition Analysis), for the most part, gas retailers and consumers do not have options available to them for the delivery of gas. Exceptions are in areas which are served by both the incumbent distributor and by a bypass distributor. However, as noted, there is currently no distributor bypassing Wanganui Gas's network.

16.14 The Commission recognises that the threat of bypass, as well as actual bypass, can provide an important constraint on gas distributors. [ ] However, he noted subsequently,[261] [ ]

16.15 The Commission accepts that Wanganui Gas faces some competitive constraint from alternative forms of delivered energy. The Commission also accepts that the regulatory regime and the threat of additional regulation provide some constraint on gas service providers, albeit relatively small. However, for the

[260] Transcript from Conference on Draft Framework Paper, 2 September 2003, p 281.
[261] Letter from Wanganui Gas to Commission, 11 September 2003.

reasons described in Chapter 3 (Competition Analysis), these constraints together are not considered to be equivalent to the constraint faced by a firm in a market which has workable or effective competition.

Conclusion on Competition

16.16 The Commission accepts that the factors which can impact on an incumbent network operator may vary from region to region. In this instance it has taken into account factors which are peculiar to the geographic markets in which Wanganui Gas operates.

16.17 Having regard to these factors, and to the more generic factors discussed above, the Commission concludes that Wanganui Gas is constrained to some extent in its behaviour by such factors as the potential for bypass pipelines in some limited areas, by interfuel competition, and by the current regulatory regime. However, the Commission considers that this constraint falls short of that which would be faced by a firm in a market which has workable or effective competition.

16.18 Accordingly, the Commission's view is that the requirement in s 52(a) of the Commerce Act is satisfied. It considers that competition for gas services provided by Wanganui Gas is limited.

Benefits and Costs of Control

Introduction

16.19 The Commission outlined its approach to deriving estimates of the potential benefits and costs of controlling gas services in Chapter 6 (Assessment Approach). The models presented in that chapter are now applied to the gas services supplied by Wanganui Gas.

16.20 The remainder of this chapter identifies the key inputs and assumptions within the cost benefit analysis; any adjustments made to the business specific data provided; the results and sensitivities from the cost benefit model; the level of net acquirers benefit; and the Commission's recommendation on whether control is required.

16.21 All figures are for the year ended 31 March, the balance date nominated by Wanganui Gas. Appendix G contains Wanganui Gas's analysis, results and sensitivity from the Commission's cost benefit model.

Inputs and Assumptions

16.22 The Commission required all the gas pipeline businesses to complete a data template for the years 1996-2008. A specimen of the template is included as Appendix B. The data sought by the template related to revenues, expenses and the asset base.

16.23 Wanganui Gas completed the template with a few exceptions, discussed below. The data provided by Wanganui Gas was reviewed by the Commission with clarification or further background information being obtained from Wanganui

Gas as required. Since the Draft Report, Wanganui Gas has revised actual results for 2004 and revised certain forecast information.

16.24 The Commission made adjustments to the data where it considered this necessary for the purposes of the benefits and costs assessment. Specific issues and adjustments with the Wanganui Gas data are explained below.

Missing Data

16.25 Wanganui Gas was unable to provide 1996 data. In the absence of 1996 data from Wanganui Gas, available information (e.g. company reports, disclosures) has been used to make estimates of required figures. The figures that were required for the analysis related to the asset base.

Revenue and Other Income

16.26 The Commission has used Wanganui Gas's revenue forecasts. These have been revised by Wanganui Gas since the Draft Report.

16.27 Wanganui Gas treats capital contributions as income. The level of capital contributions has been insignificant.

16.28 The Commission considers that forecast revaluation gains will at least be in line with CPI. As Wanganui Gas have forecast revaluation gains below CPI, the Commission has included this differential as additional revaluation gains. It has allowed these additional revaluation gains to be offset by the businesses' forecasts of future optimisation, and higher incremental depreciation charges and allowed revenues.

Operating Expense

Inquiry Costs

16.29 Wanganui Gas included Inquiry costs in its s 70E response. Inquiry costs have been removed from the operating expenses submitted by Wanganui Gas as the Commission includes these costs within the direct cost of control calculation across the entire analysis period.

Common Costs

16.30 The Commission has reservations as to the common cost allocation of the gas pipeline businesses. This is discussed in Chapter 7 (Modelling Issues and Sensitivity Tests).

16.31 In Wanganui Gas's case, the Commission is satisfied that no adjustment to the base case is necessary.

16.32 The Commission does not have significant concerns with the allocation of common costs by Wanganui Gas. It nonetheless has run the same sensitivity as for the other businesses, namely a 10%, 20% and 30% reduction of common costs.

Self-Insurance

16.33 Wanganui Gas self-insures against catastrophic risks such as earthquakes. No adjustments were made to the base case to take into account the costs to Wanganui Gas of self insurance because the information provided by the company was not sufficiently robust to justify an adjustment. However, the Commission included the costs of self-insurance as a sensitivity test.

Tax

16.34 Wanganui Gas's tax was calculated using the Commission's approach outlined in Chapter 10 (Treatment of Tax in Cost Benefit Analysis). The tax book value movements including acquisition value, current depreciation, accumulated depreciation and written down tax book value which were used in the Commission's analysis were provided by Wanganui Gas.

16.35 [ ]

<u>Asset Base and Depreciation</u>

16.36 Wanganui Gas's most recent ODV is dated June 2003. ODVs were also conducted in 1997 and 2000. Wanganui Gas has used ODV in its statutory accounts since 1997.[262]

16.37 In preparing the ODV, Wanganui Gas has used the methodology described in the Draft ODV Handbook (the Handbook) as a guideline. Wanganui Gas has included an allowance for the historic costs associated with easements, and has excluded assets at gate stations. [ ][263] The Commission has not adjusted Wanganui Gas's valuation for these differences from the Handbook for the purposes of this analysis.

16.38 Wanganui Gas's asset base includes metering as it operates both distribution and retail businesses.[264] Wanganui Gas provided bundled data and estimates of unbundled data for analysis.

16.39 Other fixed assets include office equipment, plant, tools, vehicles, PC hardware, and capitalised software and so on. All these other fixed assets are recorded at historic cost.

16.40 [ ][265]

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262 Cranleigh Strategic (2004) p 4.
263 EMCa (2004) pp 29-31.
264 EMCa (2004) p 30.
265 Wanganui Gas Limited: Information for Disclosure Pursuant to the Gas (Information Disclosure) Regulations 1997, *New Zealand Gazette*, 24 November 2003, p 4380.

16.41 Wanganui Gas provided an estimate of ODV depreciation for each year for the purposes of modelling. [

]

16.42 Wanganui Gas provided a range of [ ] for work in progress (WIP) figures. WIP has been assumed to be [ ] for modelling purposes.

16.43 In revised figures since the Draft Report, Wanganui Gas has removed a revaluation gain of [ ] in 2006 from its forecasts. They consider this revaluation gain will no longer be realised.

16.44 Wanganui Gas has provided the Commission with historic cost asset values, which have enabled the Commission to undertake an historic cost based assessment. This has provided information on the sensitivity of the results to the assumed asset base.

<u>Summary of Base Case Variables</u>

16.45 The Commission has developed a 'base case' in its model. The base case includes the adjustments to the input data noted above, the mid-point of WACC, an unrecoverable excess returns factor of 20%,[266] and elasticity of demand of -0.3. Table 16.2 presents the key variables of the analysis, using the base case in 2003 as an example.

Table 16.2 **Key Variables - Wanganui Gas**	**Figures (2003)**
Revenue ($000)	3,409
Net earnings (NE) ($000)	1,872
Actual quantities (Q_m) TJ	1,108
Actual price (P_m) $/GJ[267]	3.08
Efficient quantities (Q_c) TJ	1,169
Efficient price (P_c) $/GJ	2.51
Elasticity	-0.30
WACC	7.19%
Asset base ($000)	18,412
ODV system assets ($000)	17,987
Other non-system assets ($000)	425
Revaluation gains/loss spread ($000)	1,881

[266] Refer to the Indirect Costs section of Chapter 6 (Assessment Approach) for discussion on the unrecoverable excess returns factor.
[267] The 'actual' price is a notional average price based on Wanganui Gas's revenue and gas throughput.

Net Acquirer's Benefit (NAB)

Introduction

16.46 Given the Commission's view that Wanganui Gas faces limited competition in the market for its services, the Commission must consider whether the requirement in s 52(b) of the Commerce Act is satisfied; and whether control is necessary or desirable in the interest of acquirers. In order to determine whether s 52(b) is met the Commission carries out a NAB test. The Commission's recommendations on whether gas services may be controlled are based on the results of the NAB test.

16.47 The benefits and costs of control measured for the purposes of the NAB test are explained in detail in Chapter 6 (Assessment Approach). In summary, the benefits of control relate to improvements in efficiency (in terms of allocative, productive, and/or dynamic efficiency) and the reduction of any excess returns that might be achieved by control. The costs of control include the direct costs of control (quantified in Chapter 6 (Assessment Approach)) and the indirect costs associated with the creation of any additional inefficiencies (i.e., productive inefficiency, service quality deterioration, and/or new investment foregone) and/or the potential benefits not being fully realised in practice (measured as the excess returns unrecoverable and the allocative efficiency not achieved).

The Results

16.48 Table 16.3 presents the results of the Commission's base case over the period 1997 - 2008.

Table 16.3 **NAB Results - Wanganui Gas**	**($000)**
Benefits	
Excess returns	659
Allocative efficiency - consumer surplus	20
Productive efficiency	27
Dynamic efficiency	0
Costs	
Direct Costs	
Compliance costs	-125
Regulator's costs	-253
Indirect Costs	
Excess return unrecoverable	-132
Allocative efficiency not achieved	-7
Productive inefficiency	-10

Service quality deterioration	-18
New investment foregone	-6
Key Results	
Annuity	155
NPV (1997-2008)	2,091

16.49 The largest component within the potential benefits of control is the removal of excess returns. The potential efficiency benefits (in terms of allocative, productive, and dynamic inefficiency) are modest in comparison to the potential benefits of removing excess returns.

16.50 The largest component within the costs of control is the direct costs of control in Wanganui Gas's case. This can be explained in part by the relatively high compliance costs of control that would fall on a business of Wanganui Gas's relatively small size and the regulator's costs.[268]

Sensitivities

16.51 The Commission has tested the sensitivity of the benefits and costs model results to changes in key variables. Sensitivities tested were the WACC, growth, self insurance, unrecoverable excess return by control, common costs and asset valuation methodology.

WACC

16.52 The WACC represents an approximation for the opportunity cost of committed funds.

16.53 The sensitivity of the results to the WACC values was tested by using the 75th and 25th percentiles of the WACC distribution in the model.[269] Table 16.4 presents the results of this sensitivity testing against the base case of the mid-point WACC.

Table 16.4 **Sensitivity to WACC - Wanganui Gas**	**75th**	**Mid-point**	**25th**
NAB ($000s) annuity	47	155	264

16.54 The NAB for Wanganui Gas are positive across the Commission's WACC range. The Commission's view is that the mid point of WACC should be used in assessing the benefits of control for Wanganui Gas. Wanganui Gas is able to earn a margin of 2.8% above the mid point because of the costs of control. At the 75th percentile of WACC, Wanganui Gas can earn an additional 0.8% before NAB is found (i.e., Wanganui Gas can earn 3.6% over the mid-point of WACC before NAB are found). Wanganui Gas gets the greatest benefits of the

[268] For a breakdown of the cost of control refer to Chapter 6 (Assessment Approach).
[269] Refer to Chapter 9 (Weighted Average Cost of Capital) for a discussion on the WACC range.

costs of control (due to its size), being able to earn substantially above the return implied by the mid-point of WACC before any NAB is found.

Growth

16.55 The Commission compared the overall average growth rates for Wanganui Gas [ ] with the rates they forecast. The Commission's overall average growth rates are the ones used for its dynamic inefficiency calculation (to be consistent). They are based on both past and forecast information.[270]

16.56 The difference in output between the overall average and forecast output amounts is multiplied by the prevailing price to determine the potential additional revenue. From this additional revenue were subtracted any additional expenses needed (the difference between forecast expense increases and expected)[271] and the 20% excess returns unrecoverable factor, to give the net NAB effects.

16.57 The effect on the NAB of Wanganui Gas would be to increase it by $0.019m in annuity terms. This result is driven by the relatively high expense growth of Wanganui Gas in the forecast period [ ].

Self-insurance

16.58 Wanganui Gas largely self insures its network against major risks such as earthquake damage. Where adverse events have occurred and resulted in costs, these will be included in the Commission's analysis. However, no large scale cost events have occurred during the analysis period.

16.59 The Commission has therefore included as a sensitivity test, an estimate of the possible costs to Wanganui Gas of self insurance. Based on market information for insurance of similar risks, the Commission has assumed that self-insurance by Wanganui Gas would involve an annual cost of [ ]. The effect would be to reduce Wanganui Gas's NAB by [ ] in annuity terms.

Unrecoverable Excess Returns

16.60 The unrecoverable excess return factor represents the amount of excess return that is considered to be unrecoverable by control and is labelled an indirect cost of control in the Commission's assessment.

16.61 The unrecoverable excess returns factor's sensitivities are measured with regard to the mid-point of WACC (the base case) and are presented in Table 16.5.

Table 16.5 **Sensitivity to Unrecoverable Excess Return Factor - Wanganui Gas**	**25%**	**20%**	**10%**
NAB ($000s) annuity	120	155	224

[270] Including forecast growth in the calculation of expected growth obviously introduces a circularity, in that, if forecast growth is understated, then this expected growth will also be understated.
[271] For simplicity the expected growth rate was assumed to be the same for both output and expenses.

16.62 As noted in Chapter 7 (Modelling Issues and Sensitivity Tests), the margin provided by the costs of control is most significantly affected by the choice of excess returns unrecoverable. In Wanganui Gas's case the margin at 25%, 20% and 10% excess returns unrecoverable is respectively 3%, 2.8% and 2.5% in WACC terms.

Historic Cost of Assets

16.63 The Commission conducted a sensitivity test using the historic cost asset values supplied by Wanganui Gas. Table 16.6 presents the sensitivity of the NAB test results to asset valuation methodology.

Table 16.6 Sensitivity to Asset Valuation Methodology - Wanganui Gas	**ODV**	**DHC**
NAB ($000s) per annum	155	24

16.64 The NAB test results are dependent of the asset valuation methodology chosen, but this makes little difference to the overall outcome.

Common Costs

16.65 Wanganui Gas used ACAM to calculate common costs. Table 16.7 presents three sensitivities of the base case results in which the level of common costs is reduced by 10%, 20%, and 30%.

Table 16.7 Sensitivity to Common Cost Reduction - Wanganui Gas	**10%**	**20%**	**30%**
NAB ($000s) per annum	173	192	211

Dynamic Inefficiency (Missing Market)

16.66 The dynamic inefficiency costs of the missing market for Wanganui Gas were modelled assuming growth in the overall market of [ ]% per annum, output foregone of 10% of the growth in demand (i.e. [ ]%) compounded each year and an elasticity of -0.9. Sensitivities around the missing market elasticity and the output foregone effect were run. These are presented below in Table 16.8.

Table 16.8
Sensitivity to Dynamic Inefficiency Cost – Wanganui Gas

Missing market elasticity	NAB ($000) annuity	Missing market output effect	NAB ($000) annuity
-0.6	152	0.15	152
-0.9	155	0.10	155
-1.2	156	0.05	158

16.67 Overall, sensitivity testing of the NAB reveals small net benefits to acquirers under all of the major sensitivities tested, including the WACC, the unrecoverable excess returns factor, and the historic cost asset base.

Conclusion on Net Benefits to Acquirers

16.68 Over the analysis period the Commission's view is that the requirement of s 52 (b) of the Commerce Act is satisfied. However, the amount of NAB is small.

'May' Control be Introduced

16.69 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for Wanganui Gas's gas services is limited and control of these services is necessary or desirable in the interests of acquirers.

16.70 The Commission's view is that the gas services supplied by Wanganui Gas may be controlled.

'Should' Control be Introduced

16.71 Having determined that the Commission may recommend control, it has conducted further analysis to determine whether it 'should' recommend control. The matters considered for whether control 'may' be recommended remain relevant. However, there are also additional matters the Commission considers relevant. The additional issues for whether control 'should' be introduced include:

- the net efficiency costs to the economy of reducing excess returns;
- the size of the benefits; and
- the impact of recommendation of no control.

16.72 Each of these issues is explained below and then weighed against one another prior to recommending whether the gas services provided by Wanganui Gas should be controlled.

Net Efficiency Costs of Reducing Excess Returns

16.73 The NAB is calculated by summing the net efficiency effects and the recoverable excess returns.[272] The net efficiency costs to the economy of achieving a reduction in excess returns were calculated as $0.374 million in annuity terms over the analysis period. The recoverable excess returns were calculated as $0.527 million in annuity terms.[273]

16.74 The net efficiency costs can be compared to the reduction in excess returns that control would provide to consumers. This calculation is conducted by dividing the net efficiency costs by the excess returns that can be recovered for consumers.

[272] The Commission notes that some additional benefits and costs of control affect producers only, and are included in the efficiency analysis. In Wanganui Gas's case the additional benefits and costs are insignificant at $0m and $0.002m in annuity terms respectively.
[273] Recoverable excess returns are calculated as the total excess returns less 20% there of, as this proportion is considered unrecoverable.

16.75 In Wanganui Gas's case the calculation gives a transfer cost ratio of 0.71. This figure can be interpreted as suggesting that transferring $1 of recoverable excess returns back to consumers costs the economy $0.71 in net efficiency terms.

The Size of the Benefits

16.76 The size of the net acquirers benefit can be assessed in various ways, including;

- return on capital employed;
- its effect on the average price of transmission and the average final delivered gas price to consumers; and
- its effect on consumers' annual line charge bills.

16.77 Each of the above is discussed in turn.

16.78 Wanganui Gas earns a return of approximately 11.8% on the capital it employs. This return is 1% over the returns allowed by the midpoint of WACC (8.0%) plus the costs of control (2.8%), and reflects the positive NAB found.[274]

16.79 In terms of the effect on the price of distribution services, the NAB of Wanganui Gas suggests that distribution prices could be reduced by as much as 0.2%.

16.80 The effect on the final price of delivered gas in the Wanganui region depends on three components of the final price. It depends on any change in transmission charge, the change in distribution price (noted above) and the relative shares of both of these in the final delivered gas price. Our calculations have assumed that transmission and distribution make up 10% and 40% respectively of the final delivered gas price. Reducing Wanganui Gas's distribution charge by 0.2% would lower the average final delivered gas price by 0.1% in the Wanganui region.

16.81 Alternatively, the reduction can be considered in terms of its effect per customer average charges. Based on figures supplied by Wanganui Gas the average per customer charge over the analysis period is $323 per customer. The annual line charge is made up of transmission plus distribution charges. The reduction in distribution charge would save a typical consumer $1 or a 0.2% reduction in their annual line charge bill.

16.82 It should be noted that the calculations in this sub-section are made on the basis of bringing NAB back to zero, not to where the efficient level of price may be if the costs of control were ignored. It should also be noted that in Wanganui

[274] The return is calculated on an average basis. Averaging of returns is sometimes problematic, which is why the Commission places primary reliance on the annuity. However, this calculation of returns is done in the same way as the calculation of the implicit margin on WACC provided by the costs of control and the average mid-point WACC. Therefore the difference between the returns and the mid-point of WACC plus the implicit margin of the costs of control, is still reflective of the NAB found in annuity terms, although the two are not technically comparable.

Gas's case the costs of control have provided a significantly larger margin than for the other businesses.

Impact of a Recommendation of No Control

16.83 If control was not introduced, any downward pressure on prices resulting from the threat of control would be reduced. The Commission's base case also assumes that Wanganui Gas will not raise prices over the period 2005-2008, beyond any included in the forecasts.

16.84 There may be spill over effects to other monopoly businesses who may feel they are able exercise any market power they have without the threat of control.

Conclusion on Whether Control Should be Introduced

16.85 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for Wanganui Gas's gas services is limited and control of these services is necessary or desirable in the interests of acquirers. The Commission's view is that the gas services supplied by Wanganui Gas may be controlled under Part V of the Commerce Act.

16.86 The Commission's view is that control under Part V is a high cost form of control relative to other regulatory options, particularly in light of the extent of excess returns reflected in Wanganui Gas's pricing. As the Commission's report relates to Part V it has included the benefits and costs associated with a Part V control regime in its analysis. Clearly different forms of regulation would be more or less effective at delivering the potential benefits of control to acquirers. Although the Commission has not formally modelled different forms of regulation it considers a less intrusive regulatory option (such as a targeted control regime) may offer a more favourable trade off between costs and benefits.

16.87 In addition to the considerations under s 52 of the Commerce Act the Commission has had regard to the costs to the economy associated with transferring recoverable excess returns to acquirers. The costs to the economy associated with control can be weighed against the excess returns that could be recovered for consumers. The net costs of achieving transfers are 71% of the recoverable excess returns in Wanganui Gas's case (or equivalently, the recoverable excess returns are 1.4 times the net efficiency effects). The Commission considers that an efficiency loss ratio of 71% is of considerable concern.

16.88 Various indicators can be used to evaluate the size of the NAB. Wanganui Gas's actual return on capital over the analysis period is 11.8%. This return is 1.0% over the returns indicated by the midpoint of WACC (8.0%) plus the costs of control (2.8%), and reflects the positive NAB found. The absolute size of the NAB in Wanganui Gas's case is $0.155 million in annuity terms. This NAB equates to a 0.2% average price reduction.

16.89 If control is not recommended then any downward pressure on prices resulting from the threat of control, would be reduced, potentially resulting in an increase in the current excess returns. Finally, there may be spill over effects to other monopoly businesses.

16.90 After considering and weighing up the above matters the Commission has formed the view that Part V of the Commerce Act could be used to control Wanganui Gas, but that such control would likely not be a cost effective mechanism for dealing with the concerns raised by Wanganui Gas's market power and behaviour compared with alternative approaches to regulation.

16.91 Therefore, the Commission considers that an Order in Council under s 53 of the Commerce Act to impose control on Wanganui Gas under Part V should not be made, notwithstanding that the s 52 requirements for control are met.

Overall Recommendation

16.92 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Wanganui Gas may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Wanganui Gas under Part V of the Commerce should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

16.93 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on Wanganui Gas should be strengthened and requests the Minister consider applying to Wanganui Gas, a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A.

16.94 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

16.95 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

16.96 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

17 MAUI DEVELOPMENT LIMITED (MDL)

Introduction

Company History / Ownership

17.1 MDL was incorporated in October 1973. MDL is a service company that was established under the Maui Joint Venture Agreement. There is common ownership of MDL and the Maui Mining Companies (MMCs) which comprise the Joint Venture.

17.2 The current MMCs and their level of ownership and interest in MDL are as follows:

- Shell Exploration NZ Limited (SENZ) - 38.75%;
- Energy Petroleum Investments Limited (EPIL) - 20%;
- Shell (Petroleum Mining) Company Limited (SPM) - 18.75%;
- OMV New Zealand Limited (OMV) - 10%;
- Taranaki Offshore Petroleum Company Limited (TOPCO) - 6.25%; and
- Todd Petroleum Mining Company Limited (TPMC) - 6.25%.

17.3 However, it should be noted that SENZ, EPIL, SPM and TOPCO are all Shell companies. Thus, Shell effectively has an 83.75% interest in MDL and in the Joint Venture.

17.4 Under the terms of the Maui Gas Contract, MDL was appointed to act as seller agent for the MMCs. MDL's initial role was to manage and fund the works required to develop the Maui Field and ensure transportation of Maui gas to the Crown at the contractually agreed 'Points of Delivery'.

Extent of Vertical Integration

17.5 MDL employs Shell Todd Oil Services (STOS) to operate all of the gas production and processing facilities associated with operation of the Maui Field.

17.6 Currently all Maui gas is sold by MDL directly to the Crown under a long term take-or-pay contract (which expires in 2009). The Crown then onsells Maui gas to a small number of companies known collectively as the downstream gas users. These companies are NGC, Contact Energy and Methanex.

17.7 As part of its obligations to transport Maui gas to the Crown, MDL built the Oaonui/Huntly high pressure gas transmission pipeline. The Oaonui/Huntly pipeline is known as the Maui pipeline. MDL remains the legal owner, but employs NGC to operate the Maui pipeline on its behalf.

17.8 MDL does not have any significant interest in the gas distribution or gas retail markets in New Zealand.

Gas Transmission Activities

17.9 MDL owns the Maui pipeline which runs from the Oaonui Production Station in Taranaki to the Rotowaro Compressor Station in Waikato (approximately 313 km in length). The pipeline includes laterals to Huntly and New Plymouth power stations, the Mokau compressor station and 17 intake and offtake stations together with other stations, valves and metering facilities.

17.10 The Maui pipeline has a capacity to deliver in the vicinity of 125 PJ per annum into the Waikato area. It is paralleled by part of the NGC system – the Kapuni to Rotowaro pipeline – which has a capacity of 10 to 11 PJ per annum into that same area. The two pipelines carry gas from different production sources and currently the gas has different specifications.

17.11 The Maui pipeline was installed in 1978 for the purpose of delivering gas to the buyer under the Maui Gas Contract. Deliveries commenced in 1979, and the pipeline has, since then, been used solely for delivering gas under the Maui Gas Contract.

17.12 To deal with issues that have arisen as the Maui field moves closer to depletion, the parties to the Maui Gas Contract reached an agreement with the Crown in June 2004 to vary provisions in that Contract.

17.13 Under the agreed amendments the gas reserves to be delivered at the Maui price are guaranteed by the MMCs at 367 PJ, the amount identified by an independent expert as economically recoverable from the field at the price in the Maui Gas Contract.

17.14 In addition the arrangements will enable the MMCs to develop further reserves in the Maui field, which will be sold at market price. Of the further reserves, 40 PJ of gas will be reserved for Methanex. Contact Energy and NGC will have a right of first refusal over other additional gas.

17.15 In the March 2003 Government Policy Statement (GPS), the Government invited MDL and Maui Downstream Gas Users to present it with a proposal to enable open access to the Maui pipeline. As set out in the GPS, the Government's key requirement is that the open access regime should provide non-discriminatory access to all shippers. In particular, the regime should not be biased towards those with existing contractual interests in the Maui pipeline. The GPS also stated that the regime should enable the Crown to maintain its existing rights and not be exposed to further risks.

17.16 The regime is still being negotiated by the parties and it is discussed further below. However, it is apparent to the Commission that the new regime will mean that there will be two categories of pipeline services provided over the Maui pipeline:

- transport of gas supplied to the buyer pursuant to the Maui Gas Contract (referred to in this Report as 'Contract gas'; and
- transport of gas other than that supplied pursuant to the Maui Gas Contract (referred to in this Report as 'non-Contract gas').

Competition Analysis

Competition

17.17 The market in which MDL operates is that for the provision of gas transmission services between North Taranaki and Huntly.

17.18 In this market MDL's Maui pipeline and NGCT's North pipeline run parallel to each other. The Maui pipeline is 700 mm in diameter, and is capable of carrying 125 PJ per annum, while NGCT's pipeline is 200mm in diameter and is capable of carrying 10 to 11 PJ per annum.

17.19 As discussed in the Chapter 3 (Competition Analysis), gas transmission has natural monopoly characteristics. Transmission operators incur high fixed and sunk costs and relatively low variable costs. In these circumstances it is possible that one firm in any area is able to undertake the transmission function at a lower average cost than two or more firms. This is likely to deter more than peripheral entry except where the existing pipelines are utilised to their full capacity.

17.20 An example of substantial new entry is the construction in 1978 of the Maui pipeline to carry Maui gas to Huntly. NGC's Kapuni North pipeline constructed earlier to carry Kapuni gas along a similar path did not have the capacity to carry the Maui gas. With both pipelines in place there now appears to be sufficient capacity to meet demand on that route at most times and the Commission considers that further new entry to serve that route is unlikely in the foreseeable future.

17.21 The Commission has received many submissions on the extent to which other fuel forms compete with gas and therefore constrain the price which can be charged for transmission and distribution services. Examples were provided of instances where users of gas had switched to electricity, coal, LPG, diesel and wood.

17.22 The Commission accepts that some energy users do have a choice of fuels, although for many this may be limited to when their energy specific plant or appliance is nearing the end of its economic life. However, the information provided to the Commission (and discussed in Chapter 3) suggests that interfuel competition is not sufficient in itself to place strong competitive pressure on gas suppliers.

17.23 In addition, the Commission notes that the transmission component only accounts for, on average, perhaps 10% of the final price of delivered gas. (This percentage may be higher for the large customers obtaining direct supply from the Maui pipeline, as they would not face a distribution component in their prices). The competitive constraint other energy forms place on delivered gas prices would be dissipated in its impact on the transmission function.

17.24 The Maui Gas Contract was signed in 1973. This contract effectively removes any freedom for MDL to exercise market power in the delivery of Maui

Contract gas. The constraint on MDL in its carriage of Maui gas will continue for the length of the contract. However, as noted above, it is anticipated that in future the Maui pipeline will also carry other gas and the price of providing transmission service for this gas will not be subject to the Maui Gas Contract.

17.25 NGC has submitted that there is potential for competition between the Maui pipeline and the NGC North pipeline once the Maui pipeline is able to carry non-Contract[275] gas.

17.26 However, the Petroleum Exploration Association of New Zealand (PEANZ) in its submission to the Commission on the Draft Framework Paper stated that it disagreed with the view that the two pipelines would compete against each other. It noted that the difference in capacity between the two pipelines is significant and that a gas user requiring anything other than transport of relatively small volumes of gas would not be able to use the NGC pipeline. PEANZ suggested that the NGC pipeline will, at best, provide only minimal constraint on pricing and behaviour of the Maui pipeline.

17.27 The Commission considers that once the proposed Maui open access arrangements are put in place, there is some potential for competition between NGCT and MDL in the North Taranaki to Huntly market. However, it accepts the view of PEANZ that the relatively small size of the NGCT pipeline, particularly compared with the Maui pipeline, means that competition between them is unlikely to be vigorous, particularly for large loads. The Commission notes that even this level of competition is dependent on an open access regime being negotiated for the Maui pipeline, and these negotiations have not yet been completed.

17.28 Interfuel competition is likely to place some limited constraint on MDL in the future, as may the regulatory regime in its present form. In addition it is anticipated that the Maui pipeline will be providing services to a small number of large customers and many of these customers will have some countervailing power. MDL will remain contractually constrained in respect of the carriage of Contract gas. However, overall the Commission does not consider that these constraining factors, taken together, are sufficient to match the constraint faced by a firm in a market which has workable or effective competition.

Conclusion on Competition

17.29 Having regard to the above matters, the Commission concludes that competition in the market for the provision of gas transmission services between North Taranaki and Huntly is limited. Accordingly, the requirement of s 52(a) of the Commerce Act is satisfied.

Future Use of the Maui Pipeline

17.30 When it released the Gas Sector Review in November 2002, the Government noted that open access to the Maui pipeline has a critical role to play in

[275] The term non-Contract gas in this Report refers to gas which is not subject to the Maui Gas Contract. It includes residual gas from the Maui field (that is, any Maui gas beyond the 367 PJ committed to the contract) as well as gas from other fields.

promoting the efficient delivery of gas, especially for electricity generation. The Commission agrees, and notes that any delay in achieving efficient access for the transport of non-Contract gas could give rise to a risk that demand for gas delivered north of Taranaki may not be met. In short, there may be a critical time dimension to the assessment of costs and benefits associated with Maui open access.

17.31 In line with the Government's invitation in March 2003 to MDL, NGC, Contact Energy and Methanex to present it with a proposal to enable open access to the Maui pipeline, an open access regime is being developed.

17.32 In a speech dated 30 August 2004 to the Gas Industry Reform Conference 2004, the Minister of Energy stated:

> In the March 2003 policy statement, the Government invited Maui Development Limited and the Maui downstream parties to develop a proposal for the implementation of open access arrangements.
>
> Development of these arrangements has taken longer than I had hoped. However, I appreciate that the details of implementing the regime are more complex than first thought and in reality could not proceed at any real rate until the renegotiation of the Maui contracts were concluded.
>
> I understand that development of an open access regime is now proceeding at some pace and that Maui Development Limited is targeting implementation by the first quarter of next year. The Crown is watching progress very closely.

17.33 As part of the process, MDL on 6 May 2004 issued the Maui Pipeline Information Memorandum to industry parties and sought their comments. The Memorandum describes a draft access regime for non-Contract gas. It is understood that the draft regime in the Memorandum has been amended in part in response to submissions from industry parties.

17.34 In the section below, the Commission considers separately the transmission of gas which is subject to the Maui Gas Contract and the transmission of gas which falls outside the Maui Gas Contract.

Transport of Gas Pursuant to the Maui Contract

17.35 Transmission services on the Maui pipeline provided to the buyer under the Maui Gas Contract are bundled together with the supply of Maui gas. The Maui Gas Contract will continue to have effect until the agreed 367 PJ of gas has been delivered.

17.36 In general, the Commission considers that acquirers of transmission services are protected from the exercise of market power if the acquisition is subject to a long-term contract which was freely entered into and the market was workably competitive at the time of agreement. In these circumstances where it is unlikely the contract price would be above competitive prices, control may have little impact.

17.37 Based on its analysis of the Maui White Paper,[276] the Commission considers that, while the market may not have been workably competitive at the time the contract was entered into, the parties to the Maui Gas Contract nevertheless had some important countervailing power. The parties to the contract committed considerable resources to the development of the Maui gas field, which contributed greatly to the development of the gas market we have today.

17.38 In addition, the Commission notes that the delivered price of Maui gas (that is, the price which encompasses both the gas component and the transmission component) does not suggest that either component is priced excessively.

Transport of Non-Contract Gas

17.39 In relation to the second category of Maui Pipeline services – the transport of non-Contract gas – the Commission has considered whether control would be in the interests of acquirers (accepting that the services are to be provided in a market with limited competition).

17.40 Non-Contract gas which is transmitted through the Maui Pipeline will soon amount to a significant proportion of all gas. Thus future prices for access to the Maui pipeline will have a very important influence on the gas sector as a whole. To the extent those prices could be set above an efficient level, there is potential for detriment to acquirers.

17.41 The Commission takes at face value the statement that the parties to the Maui Gas Contract intend to provide for open access to the Maui Pipeline in the very near future. In that sense, Maui open access is common to the Commission's factual and the counterfactual, although the price of access may differ in those scenarios. In this context, the Commission has not explicitly assessed the costs and benefits of bringing forward or delaying the commencement of the open access regime. However, other things being equal, the Commission considers it likely that earlier commencement of the Maui open access regime would be beneficial for the parties requiring access and to the economy.

17.42 In order to model whether control of the Maui open access regime would be in the interests of acquirers, the Commission requested MDL to complete a data template for the years 1996-2008. The data sought by the template related to revenues, expenses and the asset base. MDL stated that the absence of a separate pipeline business to date and the immature state of the definition of the pipeline business going forward meant that it was not possible to provide all the data requested by the Commission.

17.43 In the absence of detailed information the Commission has focused its analysis on the open access proposal and associated information. This is discussed below.

[276] The Maui White Paper is the paper released by the Government in 1973 which describes contractual and other decisions relating to the development of the Maui field.

Maui Open Access Proposal

17.44 As noted above, the Maui Joint Venture released on 5 May 2004 a paper entitled Maui Pipeline Information Memorandum (the Memorandum) which describes how third parties may transport gas on the Maui pipeline under an open access regime. The paper was released to facilitate consultation with interested parties, some of whom have made submissions on it. It is understood that amendments may be made to address some of the issues raised in the submissions. For the purpose of the discussion below, the Commission has focused on the Memorandum.

17.45 The Memorandum states that MDL is faced with the challenge of designing a solution that:

- satisfies the legacy rights of the Maui Buyer under the Maui Gas Contract;
- provides third party access on a non-discriminatory basis;
- meets the reasonable revenue aspirations of the Maui Pipeline owners (the Maui Mining Companies);
- strikes a balance between the commercial rigour required to maintain operational balance and the commercial flexibility that allows new entrants to access the Maui Pipeline on a reasonable commercial basis (recognising that there has been a general lack of exposure to these issues in New Zealand to date and that there may be some resistance to convincing all parties on the need for such commercial rigour);
- does not expose the Maui Pipeline or its users to commercial or operational risks stemming from activities on interconnected networks; and
- is pragmatic and robust in the face of an evolving industry.

17.46 The Memorandum notes that MDL considers that a common carriage[277] access regime, based upon variable, commodity related transportation tariffs and balanced via a mechanism of cost reflective incentives, meets these requirements. The proposed regime will provide:

- continuity for the Maui Gas sales arrangements;
- a cost reflective transportation tariff for Shippers;
- a flexible transportation service that does not expose Shippers to significant financial commitments; and
- non-discrimination between third party users.

[277] The Memorandum defines 'Common Carriage' and 'Contract Carriage. Common carriage is predicated on the basis that the transporter will transport gas for all technically qualified parties until all available capacity is used, either on a first-come-first-served or pro-rated basis. Tariffs, as a consequence, are dominated by a throughput, or 'commodity' basis. Common carriage regimes will tend to occur where there is either no realistic constraint on capacity or, where the transporter cannot guarantee a firm service for technical reasons, but not to the extent that the regime qualifies as interruptible.

17.47 In proposing a common carriage open access regime for the Maui Pipeline, MDL:

- recognises that it may be desirable to migrate to a capacity related (contract carriage) regime in future. MDL notes that this is not achievable in the near term because of the priority provided to the Maui Buyer. MDL commits to review the cost and benefits of moving to a capacity reservation model when the Maui arrangements have expired. The review will be undertaken in consultation with the industry; and
- confines its role to controlling its own system balance and overall integrity by managing interconnection agreements with Welded Parties[278] on the assumption that interconnected systems will manage their own balancing issues.

17.48 As described in the Memorandum if pipeline capacity is limited for any reason, MDL will reduce excess demand on a non-discriminatory pro-rata basis according to shippers' monthly forecasts of nominations, subject to the conditions that:

- the buyer under the Maui Gas Contract will always have priority for delivery of its accepted nominations; and
- a party who elects to build or fund any of Maui's infrastructure to expand capacity will have priority (second only to the buyer under the Maui Gas Contract) to the extent of that additional capacity.

17.49 The Memorandum envisages that transport services will be priced to recover costs including the cost of capital. The price will include throughput charges and mismatch charges. The throughput charges will consist of:

- Tariff 1, providing a return on assets, determined by the number of GJ of gas transported and the distance over which the gas has been transported. Payments in respect of Tariff 1 are calculated by reference to the product of the net quantity of gas transported on behalf of the shipper multiplied by the distance transported along each segment of the pipeline, regardless of the physical direction of flow.

  The determination of the cost of capital is made in a manner consistent with the methodology and rates of return available to other New Zealand network owners, that is, based on rate of return on the pipeline's Optimised Deprival Value (ODV).

  The required revenue has been converted into Tariff 1 on a cents/(GJ.km) basis using the following equation:

$$\text{Variable Tariff} = \frac{\text{required revenue for return on ODV}}{\sum_{\text{all delivery points}} (\text{estimated delivery quantity} \times \text{distance to delivery point})}.$$

[278] A Welded Party is any person who owns gas pipeline infrastructure or plant which is physically connected to the Maui pipeline and who is a party to an interconnection agreement.

Tariff 2, recovering operating costs, is determined by the number of GJ of gas transported.

17.50 The Memorandum notes that in the event that its total revenues are more or less than its required revenue for return on ODV, then the tariff for the following year may be adjusted accordingly.

17.51 The proposal in the Memorandum does not specify precisely how the primary tariff would vary over time in response to changing throughput. Nor does it specify the form of depreciation used, or how frequently an ODV is to be undertaken. The Commission understands that depreciation is proposed to be calculated on a straight line basis, and the formula above suggests the tariff could rise or fall each year depending on movements in forecast throughput.

17.52 The Commission considers that the Memorandum's description of how tariffs will be calculated and how the regime itself will operate are insufficiently certain to be relied on for more than an indication of how the transport of non-Contract gas may be priced in the future. Details need to be filled in. In any event, the regime spelt out in the Memorandum remains merely a proposal and is subject to change.

Provisional Prices

17.53 On 15 November 2004 MDL posted on its web site what it called provisional throughput charges for the 2005 calendar year. In the time available the Commission has not had the opportunity to analyse these tariffs in any depth. The web site statement is as follows:

Provisional Throughput Charges for 2005 calendar year

Disclaimer: The Throughput Charges, as posted on the MDL IX, are provisional only and may be adjusted, for example, where necessary to accord with any guidelines issued by the Commerce Commission and any associated revisions to ODV, or where necessary to cover the cost to MDL of obtaining balancing gas in accordance with this Operating Code

Tariff-1 Rate
The provisional Tariff-1 rate is 0.1149 cents per GJ kilometre.

Variable tariff rate (cents/GJ)	
Oaonui to Frankley Road - tariff	5.0430
Oaonui to Waitara - tariff	7.5014
Oaonui to Huntly - tariff	34.3823
Frankley Road to Te Kuiti - tariff	17.2543
Frankley Road to Pirongia - tariff	22.2285
Frankley Road to Rotowaro - tariff	28.3398
Frankley Road to Huntly - tariff	29.3393
Waitara to Frankley Road – tariff	2.4583
Waitara to Pirongia - tariff	19.7701
Waitara to Rotowaro - tariff	25.8815
Waitara to Huntly - tariff	26.8809

Tariff-2 Rate
The provisional Tariff-2 Rate, applied irrespective of distance of energy transported, is 9.6000 cents per GJ.

Efficient Prices for Access to the Maui Pipeline

17.54 The Commission has considered how it might apply the analytical framework it has used for other companies in this Report to MDL. It has considered the historic cost approach described in the Commission's framework, but this approach is problematic because of difficulties in distinguishing the transmission component of gas prices under the Maui Gas Contract. It has looked to draw inferences from prices under the Contract and from MDL's financial statements, but has not been able to draw robust conclusions from them as to what may be efficient access prices. It has only briefly considered the tariffs set out above, but notes that they are provisional only.

17.55 Submissions received on the Draft Report provided only a very limited indication on how MDL's future prices may be assessed and analysed.

17.56 The Commission has concluded that the information available to it does not provide a satisfactory basis for assessing whether MDL's future prices may be at an efficient level.

Comparison with other Transmitters of Gas

17.57 The Commission considers that up to the present MDL has been constrained from exercising any market power by the Maui Gas Contract. In the future the Maui pipeline will carry both Contract and non-Contract gas. In undertaking transmission of this gas MDL will not face workable or effective competition. While it will be constrained to some extent by the presence of the relatively small NGCT North pipeline, by interfuel competition and by countervailing power in the hands of large gas users, together these factors are not sufficient to ensure that prices will be at competitive or efficient levels.

17.58 The Commission considers that the competitive conditions faced by MDL in respect of the transmission of non-Contract gas, and the amount of market power available to it, will reasonably approximate those of NGCT. Each transmits similar quantities of gas to a limited number of customers. They face some limited direct competition from one another, but are unlikely to face additional direct competition. Both face some limited competition from other energy forms.

17.59 In the absence of reliable information which can be used to predict MDL's future behaviour in respect of the transmission of non-Contract gas, the Commission has looked to NGCT as a guide. It recognises that the conclusions drawn from NGCT about MDL must be treated with some caution.

17.60 As described in Chapter 12, the Commission has concluded that NGCT is achieving excess returns. It earns a return of approximately 9.1% on the capital it employs over the analysis period. This return is 0.5% over the return allowed by the mid-point of WACC (8.0%) plus the cost of control (0.6%) and reflects the positive NAB found. The Commission has calculated that control may result in a reduction in `NGCT's transmission prices of around 3.5%.

17.61 In its Information Memorandum in the discussion on throughput charges, MDL states that in its proposed pricing basis:

> The determination of the cost of capital is made in a manner consistent with the methodology and rates of return available to other New Zealand network owners, that is, based on a return on the pipeline's ODV.

17.62 Having regard to this statement, to MDL's future market power and to the pricing behaviour of NGCT (which has a similar level of market power), the Commission considers that MDL has the potential to earn excess returns on the transmission of non-Contract gas. Further it considers that control could result in lower prices for transmission services. It notes that it has estimated that control on NGCT would reduce prices by around 3.5%, which gives an indication of the possible impact that control might have on MDL's prices for the transmission of non-Contract gas.

Common Carriage and Contract Carriage

17.63 In its submission to the Commission and at the conference, Contact Energy stated that it had substantial concerns about the intention of MDL to adopt a common carriage regime rather than a contract carriage regime for the Maui pipeline. It argued that common carriage had poor characteristics in relation to economic efficiency and that it could lead to an increasing dominance of parties who are vertically integrated in both the upstream gas market and the transmission market. It said that common carriage does not create the right environment to facilitate investment in the upstream and downstream gas sector.

17.64 The Commission recognises that there may be practical difficulties in operating a pure contract carriage regime in this case as in terms of the Maui Gas Contract the Crown has pre-emptive rights to all the pipeline capacity up to the 367 PJ committed under the Contract. Further, it notes that not all gas users favour contract carriage over common carriage. Contract carriage may favour existing gas users, but not those who wish to obtain access in the future after contract rights have been allocated.

17.65 The Commission notes that at the recent Gas Industry Reform Conference,[279] John Hancock of Cap Gemini argued that there were few examples of pure contract carriage or pure common carriage, but that most regimes, including that proposed by MDL, fell somewhere in between. In contrast with submissions to the Commission by Contact Energy, he suggested that many countries similar to New Zealand had adopted regimes which fitted closer to the common carriage end of the spectrum.

17.66 The Maui pipeline access regime is still the subject of consultation and some changes have already been made from what was initially proposed. The Commission in this Report has not taken a position at this time on the merits of the access regime currently being proposed. While the Commission considers that pipeline access terms fall within the ambit of the Inquiry, it has no basis for concluding at this time that the regime being suggested will in itself raise additional competition or market power concerns.

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[279] The 2nd Annual NZ Gas Industry Reform Conference, 30-31 August 2004.

Net Acquirers Benefit

Introduction

17.67 Given the Commission's view that MDL faces limited competition in the market for its services, the Commission must consider whether the requirement in s 52(b) of the Commerce Act is satisfied; whether control is necessary or desirable in the interest of acquirers. In order to determine whether s 52(b) is met the Commission carries out a NAB test. The Commission's recommendations are based on the results of the NAB test.

17.68 The benefits and costs of control measured for the purposes of the NAB test are explained in detail in Chapter 6 (Assessment Approach). In summary, the benefits of control relate to improvements in efficiency (in terms of allocative, productive, and/or dynamic efficiency) and the reduction of any excess returns that can be expected by the imposition of control. The costs of control include the direct costs of control and the indirect costs associated with the creation of any additional inefficiencies (i.e., productive inefficiency, service quality deterioration, and/or new investment foregone) and/or the potential benefits not being fully realised in practice (measured as the unrecoverable excess returns and the allocative efficiency not achieved).

The Results

17.69 For reasons noted above, the Commission has not been able to obtain information on MDL's revenues and costs to undertake a reliable quantitative analysis of the costs and benefits of control. Its assessment in this case relies more on a qualitative assessment, and the Commission has been assisted in this regard by the data relating to NGCT. The Commission considers that MDL's market power and its ability to charge excess prices in the future for non-Contract gas will be reasonably proportionate to that of NGCT.

17.70 Further, the Commission considers that it can be reasonably guided by its NGCT assessment in determining the benefits and costs of control for MDL.

17.71 Future use of the Maui pipeline will be dependent on such factors as the rate at which the Maui field is depleted and the time and rate at which new gas fields, such as Pohokura and Kupe, come on-stream. As an approximation, it has assumed that the pipeline may carry around 100 PJ of gas next year, around the same as the amount transported by NGCT though its various transmission networks.. MDL's revenue for 2005 is anticipated to be in the [ ] million range compared with [ ] million for NGCT). The ODV value of MDL's assets is [ ] million compared with [ ] million for NGCT. NGCT's pipelines extend 2,817 km compared with 313 km for the Maui pipeline.

17.72 As noted above, the Commission has concluded that MDL in respect of the transmission of non-Contract gas may be able to charge prices approximately 3.5% above what they would be under control.

17.73 Further, the Commission considers that the benefits and costs of control of MDL would be reasonably proportionate to those of NGCT. (It is possible the direct costs of control for MDL may be higher proportionately than for NGCT, given its smaller size. However, this difference is not considered likely to be of such magnitude as to alter the conclusion.) As discussed in Chapter 12, control of NGCT has a positive net acquirers benefit. The Commission considers that the same would be the case with MDL.

Conclusion on Net Benefit to Acquirers

17.74 The Commission's view is that the requirement of s 52(b) of the Commerce Act is satisfied. The Commission is satisfied that it is in the interests of acquirers for MDL's services to be controlled.

'May' Control be Introduced

17.75 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for MDL's gas services is limited and control of these services is necessary or desirable in the interests of acquirers.

17.76 The Commission's view is that the gas services supplied by MDL may be controlled.

'Should' Control be Introduced

17.77 Having determined that it may recommend control, the Commission has conducted further analysis to determine whether it 'should' recommend control. The matters considered for whether control 'may' be recommended remain relevant. However, there are also additional matters the Commission considers relevant. The additional issues for whether control 'should' be introduced include:

- The net efficiency cost to the economy of reducing excess returns;
- the size of the benefits;
- the impact of a recommendation of no control; and
- the uncertainty of projections relating to MDL.

17.78 In addition the Commission has considered MDL's submission to the Commission dated 2 July 2004 in which it stated its willingness to commit to pricing principles.

17.79 Each of these issues is explained below and then weighted against one another prior to recommending whether the gas services provided by MDL should be controlled.

Net Efficiency Costs of Reducing Excess Returns

17.80 The Commission has assessed that control of MDL would result in a net benefit to acquirers. It would lead to a transfer of economic rent from MDL to gas consumers.

17.81 The costs to the economy of achieving transfers can be compared to the transfer benefits (the reduction in excess returns) that control would provide to consumers. This calculation is conducted by dividing the costs of achieving transfers by the excess returns that can be recovered for consumers.

17.82 In NGCT's case the calculation gives a transfer cost ratio of 30%. This figure can be interpreted as suggesting that transferring $1 of recoverable excess returns back to consumers costs the economy $0.30.

17.83 The Commission considers that the transfer cost in the case of MDL may be similar to that in the case of NGCT.

The Size of the Benefits

17.84 The size of the net acquirers benefit can be assessed in various ways, including;

- return on capital employed;
- its effect on the average price of transmission and the average final delivered gas price to consumers; and
- its effect on consumers' annual line charge bills.

17.85 A quantitative assessment of the net acquirers benefit is very difficult in the case of MDL because of the absence of data. The Commission has therefore used its assessment of the net acquirers benefit calculated in respect of NGCT as a guide for its MDL assessment.

17.86 Control could have the effect of reducing NGCT's transmission prices by as much as 3.5%. This would flow through to gas users through a reduction in the average final delivered price of gas of perhaps 0.35%. (Transmission typically represents around 10% of the delivered price of gas.)

Impact of a Recommendation of No Control

17.87 If control was not introduced, any downward pressure on prices resulting from the threat of control would be reduced.

17.88 In terms of the size of the benefits, careful consideration must be given to the materiality threshold chosen. For example, if the current transfer cost ratio of 30% was judged to be too high to warrant control being imposed, it may be possible for MDL to raise price up to the point at which the transfer ratio makes control desirable.

17.89 There may be spill over effects to other monopoly businesses who may feel they are able exercise any market power they have without the threat of control.

Uncertainty of Projections Relating to MDL

17.90 In the absence of more direct information relating to MDL's prices and costs, the Commission has used NGCT as an indicator of the extent to which MDL's prices may be reduced under control. The Commission recognises that this means that there is a greater uncertainty about the MDL assessment than that for other companies.

Commitment by MDL

17.91 In its submission the Commission on the Draft Report dated on 2 July 2004, MDL stated:

> Through its draft report, the Commission has clarified what it considers to be a reasonable pricing approach. MDL takes this opportunity to state its preparedness to commit to such pricing principles should they be retained in the Commission's final report.

17.92 And

> In regard to the setting of revenue requirements, MDL is willing to make policy commitments to the effect that it would calculate the required revenue in accordance with the final building block principles established by the Commission and applied to those parties that are to be ultimately regulated under section 53 of the Commerce Act. (Note that, as observed by the Commission itself, this commitment would apply to *average* annual revenue as, unlike other pipeline operators, MDL's pricing structure would be based on forecast loads rather than reservations, and hence may require compensatory adjustment in subsequent years). MDL undertakes that it will make a public commitment to this policy in the final draft of its Information Memorandum.

17.93 In respect of MDL's commitment relating to pricing principles in this Report, the Commission considers the relevant principles are:

- prices, set from time to time, reflect a reasonable return on ODV plus depreciation and reasonable operating costs;
- ODV calculated in accordance with the principles reflected in this report, including a rigorous assessment of economic value;
- easements valued at historic costs, rather than replacement value;
- WACC within the range calculated in the same way as used to obtain the WACC range used in this Report; and
- asset revaluations explicitly accounted for in price setting, albeit smoothed over several years (as per this Report's methodology for measuring excess revenues).

17.94 In the absence of a specific regulatory regime applying to MDL, the Commission considers that the commitment would be desirable. The risk to acquirers that MDL's prices would be excessive may be lessened if MDL complied with its commitment. The Commission notes, however, that compliance with the commitment would need to be carefully monitored, and in this respect, subjecting MDL to effective information disclosure requirements would be of considerable assistance.

17.95 While the Commission considers that the commitment is helpful, it does not consider that it is sufficient on its own to remove the possibility of MDL exercising market power to the disadvantage of gas consumers.

Conclusion on Whether Control Should be Introduced

17.96 Both requirements in s 52 of the Commerce Act have been satisfied. Competition for MDL's gas services is limited and control of these services is necessary or desirable in the interests of acquirers. The Commission's view is that the gas services supplied by MDL may be controlled under Part V of the Commerce Act.

17.97 The Commission's view is that control under Part V is a high cost form of control relative to other regulatory options, particularly in light of the extent of excess returns projected for MDL. As the Commission's report relates to Part V it has included the benefits and costs associated with a Part V control regime in its analysis. Clearly different forms of regulation would be more or less effective at delivering the potential benefits of control to acquirers. Although the Commission has not formally modelled different forms of regulation it considers a less intrusive regulatory option (such as a targeted control regime) may offer a more favourable trade off between costs and benefits.

17.98 In addition to the considerations under s 52 of the Commerce Act the Commission has had regard to the costs to the economy associated with transferring recoverable excess returns to acquirers. The costs to the economy associated with control can be weighed against the excess returns that could be recovered for consumers. In the case of NGCT, the net costs of achieving transfers have been assessed as 30% of the recoverable excess returns in NGCT's case (or equivalently, the recoverable excess returns are 3.3 times the net efficiency effects). The Commission considers that an efficiency loss ratio of 30% may reasonably approximate the equivalent ratio for MDL, and is of concern at that level.

17.99 In the case of NGCT, the assessed NAB equates to a 3.5% average price reduction. An equivalent reduction for the transmission of non-Contract gas by MDL is possible. The benefits from this average price reduction for MDL's non-Contract, large industrial customers are likely to be passed on to their customers to the extent that they operate in competitive markets and any transmission charge reduction to gas retailers will affect the final delivered gas price in all regions, albeit having a relatively modest impact on individual retail customers.

17.100 If control under Part V is not introduced then any downward pressure on prices resulting from the threat of control, would be reduced, potentially resulting in an increase in potential excess returns. Finally, there may be spill over effects to other monopoly businesses if MDL is not controlled.

17.101 After considering the above matters the Commission has formed the view that Part V of the Commerce Act could be used to control MDL, but that such control would likely not be a cost effective mechanism for dealing with the concerns raised by MDL's future market power and behaviour compared with alternative approaches to regulation.

17.102 Therefore, the Commission considers that an Order in Council under s 53 of the Commerce Act to impose control on MDL under Part V should not be made, notwithstanding that the s 52 requirements for control are met.

Overall Recommendation

17.103 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by MDL may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on MDL under Part V of the Commerce should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

17.104 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on MDL should be strengthened and requests the Minister consider applying to MDL, a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A.

17.105 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

17.106 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

17.107 While MDL has stated that it is willing to commit to pricing principles contained in this Report, acceptance of the commitment would not be desirable should the above approach be adopted.

17.108 The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

18 NOVA GAS LIMITED (NOVA GAS)

Introduction

Company History / Ownership

18.1 Nova Gas commenced operations in 1995. Todd Petroleum Mining Company Limited (TPMC) purchased its first initial shareholding in 1996, and then increased its shareholding again in 1998 and 2000. On the 6 April 2000 Nova Gas Limited was officially amalgamated with Todd LPG Limited. The amalgamated entity then changed its official name to Nova Gas Limited. Today, Nova Gas is majority owned (98.7%) by TPMC.

18.2 Nova Gas is involved in landfill gas extraction and the reticulation of both landfill gas and natural gas to [ ] customers throughout the North Island.

Extent of Vertical Integration

18.3 Nova Gas is involved in the production and processing of gas through its landfill gas plant in Porirua. Landfill decomposition produces landfill gas which is a mixture of methane gas, carbon dioxide and nitrogen. Nova Gas gathers and treats the landfill gas on site in specially constructed landfill gas plants. Further landfill-to-gas facilities are planned by Nova Gas at the Southern landfill (Wellington) and the Whitford landfill (Manakau City).

18.4 Nova Gas has been steadily growing its business as a gas retailer since agreement to purchase Kapuni gas was reached in 1996. Nova Gas continues to purchase gas from the Kapuni Mining Companies (Shell and Todd) and then supplies its customer base through gas transmission and distribution networks owned by other companies (pursuant to transmission agreements with the owners of those networks) or via its own bypass network. Nova Gas also acts in a limited capacity as a gas wholesaler.

18.5 Nova Gas is a subsidiary of Todd Energy. Todd Energy through its joint ownership of MDL has a significant interest in the production and processing of Maui gas, as well as the transmission of Maui gas via the Maui pipeline. Todd Energy has further significant interests in the production and processing of gas through its 50:50 ownership of the Kapuni gas field with joint venture partner Shell New Zealand.

18.6 Todd Energy also holds a 50% interest in Shell Todd Oil Services Ltd (STOS), which is employed to operate both the Maui and Kapuni gas fields. Todd Energy was also involved in retailing gas until June 2003 when Fresh Start was sold to Genesis Energy.

Gas Distribution Activities

18.7 Nova Gas treats its landfill gas to specification for reticulation either directly to customers on a Nova Gas network or commingled with Kapuni gas for supply to customers outside of a Nova Gas network. Nova Gas supplies predominantly commercial and industrial consumers in Wellington, Porirua, Petone, the Hutt Valley, Hastings, Hawera, Papakura and Manakau City through its own bypass gas distribution networks. Nova Gas currently owns and operates approximately 100 km of bypass pipelines throughout the North Island.

Competition Analysis

Introduction

18.8 Nova Gas has [ ] customers throughout the North Island, of which [ ] are considered industrial, [ ] commercial and [ ] domestic.

Table 17.1: Nova Gas – Distribution Network Statistics (year ended 30 June 2003)		
System	**Length (km)**	**Total Gas Conveyed (GJ)**
Gas Distribution Network	100	[ ]

18.9 It is understood that almost all gas users connected to its pipelines had previously been connected to the network of the incumbent network operator in each area. Nova Gas has advised the Commission[281] that it was offering these customers savings of [ ] compared with the rates quoted by the incumbent gas suppliers. At the Conference on the Draft Report, Nova Gas stated[282] that it has typically been able to offer customers savings of 50% on the distribution component of prices.

18.10 Typically a gas user on Nova Gas's network has a fixed term contract for delivered gas. Once the contract has expired, these customers are able to switch to an alternative gas retailer and gas distributor, should they wish.

18.11 Nova Gas does not generally separate the price for its distribution service from that of the gas carried on its pipelines. It does not make its networks available to competing gas retailers.

18.12 The incumbent networks bypassed by Nova Gas are owned by Powerco (Wellington, Hawera and Hastings) and Vector (South Auckland).

18.13 At the Draft Framework Conference,[283] a gas retailer, Contact Energy, noted that because of the bypass nature of Nova Gas's distribution business, it is reasonable to assume that Nova Gas faced competition.

Competition

18.14 The market which the Commission has utilised to assess whether or not Nova Gas's competition is limited is that for the provision of gas services to commercial and industrial consumers within the vicinity of bypass networks (the bypass market).

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[281] Nova Gas Limited, *Confidential letter to Commission,* 7 August 2003, para. 1.3.
[282] Nova Gas Limited, *Presentation to Commerce Commission Draft Report Conference*, 27 July 2004, slide 13.
[283] Commerce Commission, Transcript of Gas Control Inquiry Draft Framework Conference, 1-3 September 2003, p 10.

18.15 The Commission accepts the submissions of gas retailers, incumbent distributors and Nova Gas that there are important competitive pressures in the bypass market.

18.16 Sunk costs, scale economies and low variable costs are significant features of network businesses, including gas distribution networks. Where two networks pass the same customer it can generally be anticipated that the network owners would compete vigorously against each other for contestable customers, at least as long as the supply to these customers made some contribution towards the supplier's fixed costs.

18.17 As noted in Chapter 3 (Competition Analysis), information received by the Commission, both in the context of the Inquiry and from its general industry oversight, supports the view that competition in bypass markets has had a very significant impact on prices.

18.18 The Commission's assessment is that the level of competition for customers in the bypass market can be described as vigorous.

18.19 Distributors in the bypass market also face some constraint from interfuel competition and from the regulatory regime. However, this constraint is much less than that arising from the direct pipeline on pipeline competition.

18.20 At the Conference on the Draft Report,[284] Mr Horton, for Powerco, suggested that bypass competition is bound to be oligopolistic. The Commission has considered the potential for oligopolistic outcomes and for the competitors in the bypass markets to co-ordinate their market behaviour and thereby lessen the intensity of competition. Co-ordination covers both explicit agreements and tacit forms of behaviour such as price signalling, conscious parallelism and price leadership, and can be found in highly concentrated markets. In this instance, however, the Commission considers that there are features which make such behaviour unlikely.

18.21 These features include the fact that there are major differences between the two competitors in each bypass market. Compared to the incumbent network operator, Nova Gas has a network which is very much smaller, it does not have an unbundled distribution charge, it does not make its network available to other retailers, and its principal activity is gas retailing. The Commission recognises that Nova Gas has a reputation as being a maverick in the market. These factors significantly reduce the potential for coordinated behaviour and for oligopolistic outcomes.

Conclusion on Competition

18.22 The Commission has taken into account both the structure of the bypass market and the evidence of competitive behaviour in that market. It considers that the level of competition is strong.

18.23 Accordingly, the Commission considers that Nova Gas faces workable or effective competition in the market where it provides gas services. That is,

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[284] Commerce Commission, *Transcript of Draft Report Conference,* 22 July 2004, p 11.

competition is not limited in this market. The requirement in s 52(a) of the Commerce Act is therefore not satisfied.

Conclusion

18.24 As the Commission has concluded that competition is not limited, the requirement in s 52(a) of the Commerce Act for the imposition of control has not been met. Therefore the Commission advises that gas services provided by Nova Gas may not be controlled.

Recommendation

18.25 The Commission recommends to the Minister that he:

18.26 The requirements of s 52 of the Act are not met and therefore gas services supplied by Nova Gas through its pipelines may not be controlled.

19 TARANAKI PIPELINES

Introduction

19.1 In addition to the major transmission pipelines owned by NGCT and MDL there are a number of pipelines of smaller length situated in Taranaki which fall within the ambit of the Inquiry. There are also other pipelines in the Taranaki area which are 'gas gathering' pipelines or are currently carrying liquids. They are not included in the scope of the Inquiry, although some, at least, could be readily converted to be used to transport gas to customers.

19.2 The pipelines discussed in this chapter are predominantly used to transport gas from gas production stations to single (or sometimes more) large customers, or to feed into another transmission pipeline. In most cases, the pipeline is owned by a party which has an ownership interest in the field from which the gas is drawn.

19.3 The pipelines are shown at the end of the chapter in the schematic provided by NGC.

LTS Pipeline (NGC)

19.4 The LTS pipeline has been used to supply non-specification, high CO2 gas from NGC's Kapuni gas treatment plant to Methanex's Waitara Valley methanol plant. NGC stated in its submission of 20 August 2003[285] that although the LTS pipeline technically fits within the definition of a transmission system, it has never considered that it is a transmission pipeline.

19.5 The gas has been supplied to Methanex under two contracts. In terms of one contract (which was originally between NGC and the Crown), Methanex was required to pay transmission operating costs. That contract expired in September 2003. In terms of the other contract, NGC was required to provide delivered gas at the contract price; that is, there was no distinct transmission charge. That contract ended in early May 2004.

19.6 NGC has advised that following the completion of the second contract, the pipeline was shut down for maintenance work. From late August 2004 it then used it as a gas gathering line taking Kahili gas to the Kapuni gas treatment plant. That is, the direction of the pipeline was reversed so that rather than taking gas from the treatment plant to a customer, it was taking gas from a gas field to the treatment station.

19.7 As the pipeline is no longer being used to carry gas to a gas customer or for distribution, it falls outside the definition of transmission system under the terms of reference and is therefore outside the ambit of the Inquiry. Accordingly the Commission does not have jurisdiction to recommend control in respect of the LTS pipeline.

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[285] NGC Holdings Limited, *Commerce Commission Gas Control Inquiry – Submission in Respect of the Draft Framework Paper*, 20 August 2003, para. 50.

Frankley Road Pipeline (NGC)

19.8 The Frankley Road pipeline is owned by NGC and runs from the Maui pipeline at Frankley Road to the Kapuni treatment statement, a distance of 47 km. The 20-inch pipeline carries specification gas, is able to carry Maui gas to the NGC's South transmission pipeline and, with open access to the Maui pipeline would be able to carry Kapuni, Rimu and Kauri gas to the Maui pipeline. The Commission regards it as being an integral part of NGC's transmission network and has included it in its analysis of NGC Transmission.

Kapuni to Hawera Pipeline (Todd Petroleum and Shell)

19.9 The Kapuni to Hawera pipeline is a purpose built pipeline constructed by Shell and Todd to transport untreated gas from their Kapuni field to the Kiwi Joint Venture co-generation plant (Kiwi) at the Fonterra site in Hawera. The parties to the joint venture are Todd and Fonterra. Use of the pipeline was expanded when Shell and Todd entered into an agreement to supply untreated Kapuni gas to Taranaki By-Products which is also in Hawera.

19.10 The pipeline is not an open access pipeline – it is not available to other shippers of gas. As the gas it carries is non-specification, it would not be possible to carry specification gas in the pipeline for other users.

Competition

19.11 The NGC South pipeline runs from Kapuni and passes Hawera and therefore runs parallel to the Shell/Todd pipeline. However there are limits to the competition arising from this situation. The Shell/Todd pipeline carries high CO2 gas while the NGC pipeline carries specification gas. If the Kiwi Joint Venture and Taranaki By-Products were to switch to taking gas from NGC South, they would be required to adjust their plant so that they could operate on specification gas. In addition, if the switch occurred NGC might face capacity problems on its South pipeline.

19.12 In its submission dated 5 July 2004, Todd submitted that the Shell/Todd pipeline is subject to competition from both the adjacent NGC South pipeline and that the threat of a new competitor installing a new pipeline and supplying Kiwi once the contract with Todd and Shell has expired. Todd further submitted that although the NGC South pipeline carries gas of different specification, it would be viable to alter the Kiwi plant to enable it to run on treated gas. In addition it argued that NGC has previously indicated that the South pipeline has a sufficient capacity to supply Kiwi and that it would consider building a link from the NGC South pipeline to the Kiwi plant. Todd noted that the Kapuni to Hawera pipeline is approximately 22 km long and it estimated that the cost to replace it would be approximately [ ].

19.13 The Commission accepts that the NGC South pipeline places an important, but limited, competitive constraint on the Shell/ Todd pipeline. However, notwithstanding this, the Commission considers that there may still be some potential for Shell/Todd to earn excess returns. The potential for new entry is a possible additional constraining factor, but the Commission does not consider new entry is likely in the foreseeable future.

19.14 While it has reached the conclusion that competition to the Shell/Todd pipeline is limited, the Commission has not analysed the present prices charged for transmission services provided by the pipeline. These services are not charged for separately but are bundled with the gas component in a delivered gas price. The assessment of the transmission component alone would therefore be difficult. In view of the conclusion the Commission has reached on the question of interests of acquirers (discussed below) it is considered that such an analysis is not necessary.

Interests of Acquirers

19.15 Both acquirers of gas delivered by Shell/Todd's pipeline have long-term contracts for that gas delivered to their plant. The contract for the supply to the Kiwi plant expires in [ ] and that for the supply to Taranaki By-Products expires in [ ]. The prices in the contracts are for delivered gas – there is no distinct transmission component in the price.

19.16 The Commission considers that it is likely that the existing contracts were signed in a reasonably competitive environment when the NGCT pipeline provided an acceptable alternative option to the two gas users. Thus, it considers that if there are any excess returns available in present prices they are unlikely to be substantial. Further, the Commission considers that there is likely to be some competitive constraint on Shell/Todd when the contracts come up for renewal.

19.17 In these circumstances any benefit to acquirers from control are likely to be small. On the other hand, a control regime would add cost to all parties, including the acquirers.

19.18 It is the Commission's view that in this situation where the pipeline is small and the potential for excess earnings is limited, the cost of control would outweigh any benefit.

19.19 The Commission, having regard to the provisions of s 52 of the Act, therefore advises that control may not be imposed on gas services provided by means of the Kapuni to Hawera pipeline.

McKee Production Station to Faull Road (Todd Taranaki)

19.20 The two gas pipelines from the McKee production station to the Faull Road mixing station are owned by Todd Taranaki Ltd (TTL) and are dedicated to transporting gas from TTL's McKee and Mangahewa gas fields to Methanex. Gas and transmission are provided on a bundled basis. Both lines are 6 inches and are approximately 10 kilometres long. The second line was added to debottleneck the system to accommodate extra production from Mangahewa.

19.21 TTL currently supplies Methanex with gas from the McKee and Mangahewa gas fields under a [ ] supply contract. The contract expires [

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Competition

19.22 Methanex has obtained gas carried by a range of pipelines including the Faull Road line, the Maui pipeline, NGC's LTS pipeline and from NGC's North pipeline. Each of these pipelines provides a measure of competitive constraint on each other for the supply to Methanex.

19.23 In its submission to the Commission dated 5 July 2004, Todd Taranaki[286] stated:

> In the Draft Report the Commission noted that NGC's LTS and North pipelines provide a competitive constraint on the McKee Pipelines. This is correct and will be particularly evident when Methanex has used its 40 PJs of Maui gas and requires additional supply. At this time Methanex will have a choice of suppliers for both gas and distribution services as noted above. The Maui pipeline and NGC's LTS pipeline are both alternatives to the McKee Pipelines and there is also the threat of bypass. In the future, the Pohokura production station will be built next to Methanex's Motonui plant and it would be possible for Methanex to be supplied direct from the production station. The prices that TTL will be able to charge for distribution will be constrained both by competition between the pipelines able to supply Methanex and by the maximum price Methanex can pay before running the methanol plant becomes uneconomic.
>
> The Commission noted in the Draft Report that the McKee Pipelines could have market power if Methanex became dependent on the McKee field for supply. Given the size of the McKee and Mangahewa gas streams and Methanex's other options for supply, this is extremely unlikely.

19.24 The Commission notes that the change in direction of the LTS line means that pipeline is no longer an option for the supply of gas to Methanex. Nevertheless the Commission accepts that other pipelines provide an important constraint on TTL in respect of the delivery of McKee gas. The amount of gas supplied through the McKee pipelines is relatively small in comparison with the total gas taken by Methanex and, in addition the pipelines are dedicated to supplying Methanex. In these circumstances, Methanex would have a significant amount of countervailing power in future negotiations with TTL. In addition the existing contracts for the supply of McKee and Mangahewa gas to Methanex will provide short-term protection against TTL exercising any market power which might exist. Competition for pipeline services is not an issue relevant to the McKee pipelines.

19.25 For the purpose of the Inquiry, the Commission has concluded that competition is not limited in the relevant market. The requirement in s 52(a) of the Commerce Act is therefore not satisfied.

Rimu to NGC's South Pipeline (Swift)

19.26 This pipeline is owned by Swift Energy New Zealand Limited (Swift). It runs from the Rimu production station located south of Hawera to a tie-in point on the NGC south transmission line. The pipeline is approximately 600 meters long with a nominal diameter of 150 mm.

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[286] Todd Taranaki Limited, *Submission in Response to the Gas ControlDraft Report (21May 2004)*, 5 July 2004, paras. 9-10.

19.27 The pipeline is used almost exclusively for the purpose of transmitting gas produced from the Rimu field and test production from the Kauri wells that has been processed in the Rimu production station, to NGC's transmission line. From time to time small amounts of gas are imported along the pipeline from the NGC transmission line to the production station in order to facilitate the start up of the production station following a shut-down.

19.28 The connection to the transmission line and the sale of Rimu gas are the subject of contracts between Swift and NGC and Genesis Energy.

19.29 The Energy Data File[287] indicates that 1.66 PJ of gas was produced by the Rimu field in the 2003 calendar year.

Competition and Interest of Acquirers

19.30 As noted, the pipeline is of very limited length and is dedicated to transport Swift's gas from Swift's production station at the Rimu field to the closest transmission pipeline. The Rimu field is a relatively small one, while the production station is one of six in the Taranaki region.

19.31 Ownership of the pipeline gives Swift very little opportunity, if any, to exercise market power. Other suppliers of gas to the NGC transmission pipeline provide an effective constraint on the delivered price of Rimu gas. The Commission considers that there is likely to be very little potential for a third party to use the pipeline. It will remain a dedicated pipeline. Consequently competition for pipeline services is not an issue relevant to this pipeline.

19.32 For the purpose of the Inquiry, the Commission has concluded that competition is not limited in the relevant market. The requirement in s 52(a) of the Commerce Act is therefore not satisfied.

The TAW Pipeline (Swift)

19.33 Swift acquired Southern Petroleum (New Zealand) Ltd (Southern) from Fletcher Energy Limited in November 2001. The TAWN gas fields (now called the TAW fields with the depletion of Ngaere) and related assets including the Waihapa production station and the TAW pipeline are the principal interests of Southern.

19.34 The TAW pipeline runs from the Waihapa production station through Stratford and on to the New Plymouth power station. In its submission to the Commission,[288] Swift pointed out that there are two distinct pipelines – one from Waihapa to close to the Contact Energy's Taranaki Combined Cycle (TCC) power station at Stratford and one from TCC to New Plymouth. However, Swift deals with these pipelines together in its submission, and the Commission believes that it efficient to do likewise in this report.

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[287] NZ Ministry of Economic Development, *Energy Data File*, July 2004.
[288] Swift Energy New Zealand Limited, *Submission to the Commerce Commission – Gas Control Inquiry*, 20 August 2003.

19.35 The TAW pipeline has been used to supply TAW gas to the TCC station and to the New Plymouth Power Station both under a contract with Contact Energy. The pipeline includes connection points for the Kaimiro production station (owned by Greymouth Petroleum Limited) and the Omata tank farm, close to New Plymouth. Southern's contract for the supply of gas to Contact Energy enables Contact Energy to nominate delivery of natural gas from Waihapa at either TCC or New Plymouth power station. However the New Plymouth station now operates principally on fuel oil and requires only small quantities of gas. Nevertheless, Swift has stated that until the contract between Southern and Contact Energy expires, there will be capacity constraints on the use of the pipeline as a result of Southern's obligations to Contact Energy.

Competition

19.36 As noted, the TAW pipeline has been used principally to meet Southern/Swift's contractual commitments to supply gas from Swift's TAW fields to TCC and New Plymouth power station. Nevertheless the pipeline has strategic importance because it is able to carry non-specification gas and also it crosses both the Maui and NGC North pipelines.

19.37 The amount of gas currently carried on the pipeline is not substantial, particularly in the northern part of the pipeline, and the gas users taking gas from the pipeline have alternative sources of gas available to them. In addition, the TAW pipeline runs in parallel for a significant part of its route with NGC's Frankley Road pipeline. Nevertheless the pipeline is an important means of getting gas from the TAW, Radnor (near Stratford), Kaimiro and Ngatoro fields to the market. Concerns about obtaining access to the pipeline have been raised with the Commission by one party.

19.38 [

]

19.39 [

]

19.40 [

]

19.41 The Commission has not reached a conclusion as to the merits of the competing arguments on this matter. It is, initially, a commercial matter for the parties to settle. If appropriate the provisions of the Commerce Act could be utilised in the settlement process. The fact that the TAW pipeline is not on an open access pipeline and there are access disputes supports the view that there is some market power associated with ownership of the pipeline.

19.42 The Commission has concluded that competition faced by the TAW pipeline is limited.

Interests of Acquirers

19.43 While the Commission has concluded that competition is limited, there are a number of factors which appear likely to limit any benefits to acquirers which could arise from control. Firstly, the pipeline does not carry a substantial amount of gas. Secondly, the downstream users of that gas appear to have alternative sources of gas which are not reliant on the TAW pipeline and consequently are not likely to be substantially disadvantaged by Swift attempting to exercise any market power. Thirdly, options available to gas producers close to the pipeline (including converting gas to specification gas and using NGC's Frankley Road pipeline, or constructing their own pipeline) place a ceiling on Swift's access prices.

19.44 A control regime would add cost to all parties, including acquirers of pipeline services whether they are gas producers, gas retailers or gas users.

19.45 It is the Commission's view that in this situation where the pipeline carries only a limited amount of gas and the potential for exercise of market power is limited, the cost of control would outweigh any benefit.

19.46 The Commission, having regard to the provisions of s 52 of the Act, therefore recommends that control may not be imposed on gas services provided by means of TAW pipeline.

Surrey Road Pipeline (Westech Energy)

19.47 The Surrey Road pipeline carries non-specification gas from the Surrey gas field to NGC's LTS pipeline, a distance of around 1.2 km. The Surrey field is currently producing slightly less than 1 PJ of gas per annum.

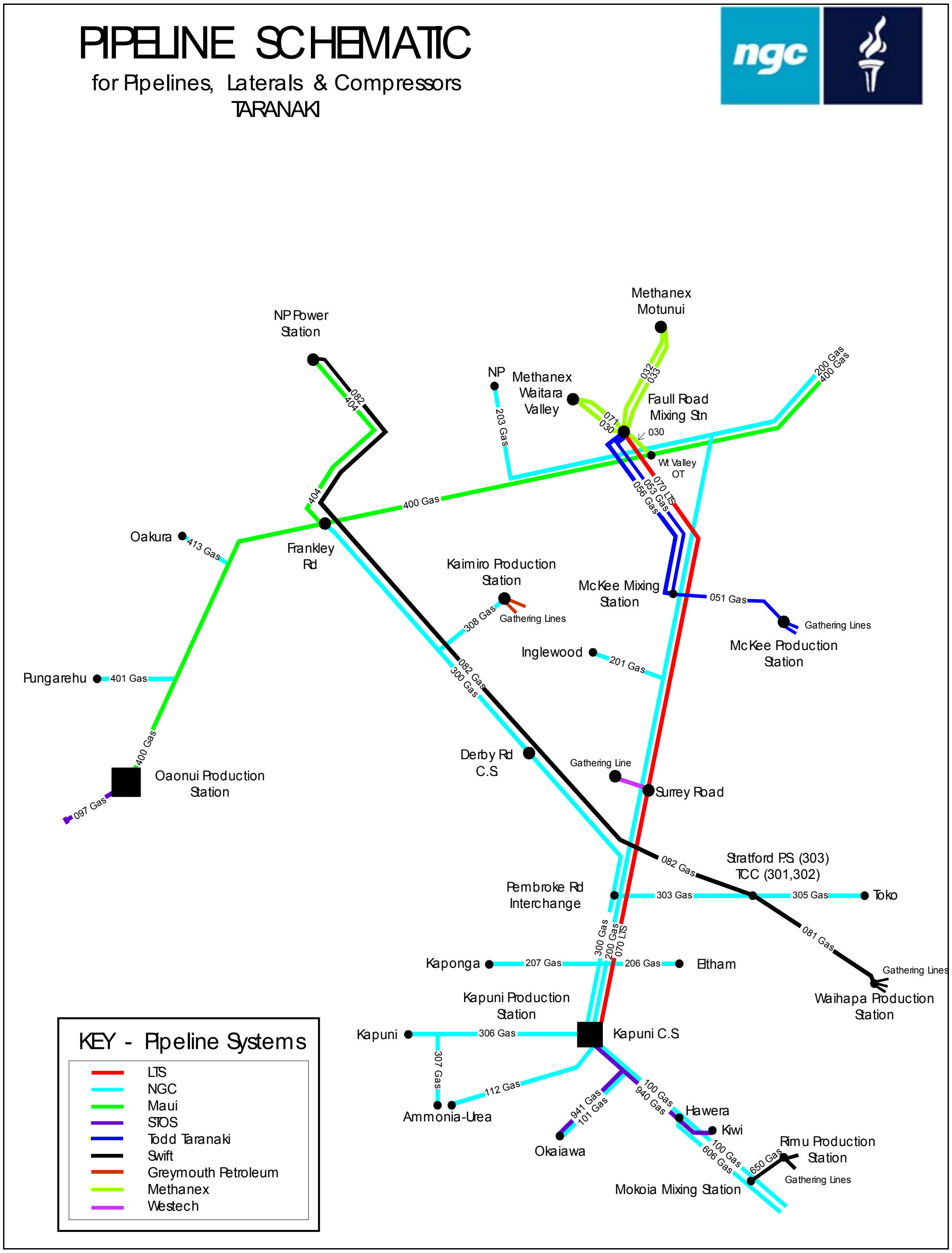
19.48 The gas is sold to NGC at the point of delivery into the LTS pipeline. In the past this pipeline delivered the gas to Methanex. However, with the change of direction of the LTS pipeline, the gas now goes to the Kapuni production station for treatment.

19.49 As the Surrey Road pipeline is now no longer being used to carry gas to a gas customer or for distribution, it falls outside the definition of transmission system under the terms of reference and is therefore outside the ambit of the Inquiry. Accordingly the Commission does not have jurisdiction to recommend control in respect of this pipeline.

Overall Recommendations

19.50 The Commission recommendations are set out below.

- The Commission advises that LTS pipeline falls outside the ambit of the Inquiry and therefore gas services supplied by NGC through that pipeline may not be controlled.
- The Commission advises in respect of the Kapuni to Hawera pipeline that the requirements of s 52 of the Act are not met and therefore gas services supplied by Todd Petroleum and Shell through that pipeline may not be controlled.
- The Commission advises in respect of the McKee Production Station to Faull Road pipeline that the requirements of s 52 of the Act are not met and therefore gas services supplied by Todd Taranaki through that pipeline may not be controlled.
- The Commission advises in respect of the pipeline running from Rimu to NGC's South pipeline that the requirements of s 52 of the Act are not met and therefore gas services supplied by Swift through that pipeline may not be controlled.
- The Commission advises in respect of the TAW pipeline that the requirements of s 52 of the Act are not met and therefore gas services supplied by Swift through that pipeline may not be controlled.
- The Commission advises in respect of the Surrey Road pipeline, that the pipeline falls outside the ambit of the Inquiry and therefore gas services supplied by Westech Energy through that pipeline may not be controlled.


PIPELINE SCHEMATIC
for Pipelines, Laterals & Compressors
TARANAKI
ngc
Methanex Motunui
NP Power Station
NP
Methanex Waitara Valley
Faull Road Mixing Stn
Wt Valley OT
200 Gas
400 Gas
032
033
071
030
203 Gas
082
404
070 LTS
053 Gas
056 Gas
Oakura
413 Gas
Frankley Rd
Kaimiro Production Station
308 Gas
Gathering Lines
McKee Mixing Station
051 Gas
McKee Production Station
Inglewood
201 Gas
Pungarehu
401 Gas
082 Gas
300 Gas
Oaonui Production Station
097 Gas
Derby Rd C.S
Gathering Line
Surrey Road
Stratford P.S (303)
TCC (301,302)
Pembroke Rd Interchange
303 Gas
305 Gas
Toko
081 Gas
200 Gas
Kaponga
207 Gas
206 Gas
Eltham
Waihapa Production Station
Kapuni Production Station
Kapuni
306 Gas
Kapuni C.S
307 Gas
112 Gas
Ammonia-Urea
941 Gas
101 Gas
Okaiawa
100 Gas
940 Gas
Hawera
Kiwi
606 Gas
650 Gas
Rimu Production Station
Mokoia Mixing Station
KEY - Pipeline Systems
LTS
NGC
Maui
STOS
Todd Taranaki
Swift
Greymouth Petroleum
Methanex
Westech

20 CONCLUSION

Request from the Minister

20.1 The request from the Minister requires the Commission to report on whether or not an Order in Council under s 53 of the Act should be made in relation to the goods and services connected with either gas transmission or gas distribution or both.

20.2 In reaching its view on whether control should be introduced, the Minister requested specific advice on:

- whether gas services may be controlled in terms of s 52 of the Commerce Act;
- the methodology that the Commission considers appropriate for valuation of pipeline assets for the purposes of its advice on the matters covered in the terms of reference;
- the net benefits to the public of control; and
- any other matter that the Commission may think relevant to a decision on whether control should be introduced.

20.3 If the Commission recommends that gas services should be controlled, the Minister requires the Commission's specific advice on the technical provisions relating to declaration of control as set out in s 57A of the Commerce Act.

20.4 The Commission's advice and recommendations are set out below.

Comparative Business Information

Net Acquirers Benefit

20.5 The benefits, costs and net acquirers benefit assessed at the 25th percentile, mid and 75th percentile points of WACC for NGCT, NGCD, Vector, Powerco and Wanganui Gas are set out in Table 20.1.

Table 20.1: Net Acquirers Benefit

	Annuity ($000)		
	25th WACC	**Mid WACC**	**75th WACC**
NGCT			
Total benefits	8,278	5,170	2,062
Total costs	3,365	2,806	2,325
NAB	**4,913**	**2,364**	**-263**
NGCD			
Total benefits	4,376	3,375	2,386
Total costs	1,986	1,775	1,603
NAB	**2,390**	**1,600**	**783**
Powerco			
Total benefits	6,927	5,892	4,896
Total costs	2,386	2,173	1,972
NAB	**4,542**	**3,719**	**2,925**

Vector			
Total benefits	11,721	10,047	8,457
Total costs	3,507	3,126	2,766
NAB	**8,215**	**6,921**	**5,692**
Wanganui Gas			
Total benefits	844	706	570
Total costs	580	551	523
NAB	**264**	**155**	**47**

Net Efficiency Costs to the Economy of Reducing Excess Returns

20.6 The Commission has found NAB for all businesses investigated. The positive NAB has been driven by excess returns as the net efficiency effect of control is always found to be negative. Table 20.2 highlights the trade off between the net efficiency effects and recoverable excess returns for each business.

Table 20.2: Net Efficiency and Recoverable Excess Returns Trade-off[289]

	NGCT	NGCD	Powerco	Vector	WGL
Recoverable excess returns ($000)	3,629	2,455	4,395	7,489	527
Net efficiency effect ($000)	-1,096	-913	-732	-702	-374
Net cost of $1 transfer to acquirers	$0.30	$0.37	$0.17	$0.09	$0.71
Times recoverable excess returns exceed efficiency effect	3.3	2.7	6.0	10.7	1.4

Size of the Benefits

20.7 Table 20.3 shows the average returns earned by the businesses over the analysis period. The mid point of WACC was 8% on average over the same period.

Table 20.3: Average Returns of the Businesses

Company	Average Returns on Capital
WGL	11.8%
NGCD	10.5%
NGCT	9.1%
Powerco	12.7%
Vector	13.5%

20.8 Table 20.4 shows the change in transmission and distribution prices to reduce the positive NAB for each business back to zero.

Table 20.4: Effect on Transmission/Distribution Prices

Company	Price Effect
NGCT	-3.5%
NGCD	-5.6%
Vector	-18.5%
Powerco	-12.2%
WGL	-0.2%

[289] Recoverable excess returns are calculated as the total excess returns less 20% thereof, as this proportion is considered unrecoverable. The efficiency costs include costs that fall on producers and acquirers.

20.9 Table 20.5 shows the impact in dollar terms of reducing prices to the point where NAB = 0 relative to the average annual consumption per connection.

Table 20.5: Reduced Annual Charges per Connection

	Average annual gain per acquirer	Average annual charge per acquirer
WGL	$1	$323
NGCD	$29	$518
NGCT	[ ]	[ ]
Powerco	$51	$415
Vector	$114	$617

20.10 Table 20.6 shows the potential change in the delivered gas price to retail customers if both distribution and transmission prices were reduced to a point where NAB=0 in the Commission's model. This calculation assumes that transmission's share in the delivered gas price is 10%, while distribution's share is 40%.

Table 20.6: Effect on Final Delivered Gas Price (Transmission and Distribution Combined)

Company	Price Effect
NGCD	-2.6%
Vector	-7.8%
Powerco	-5.2%
WGL	-0.4%

20.11 It should be noted that the calculations in this sub-section are made on the basis of bringing NAB back to zero, not to where the efficient level of price would be if the costs of control were ignored.

Recommendations and Advice

NGCT

Recommendations

20.12 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by NGCT may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on NGCT under Part V of the Commerce Act should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

20.13 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on NGCT should be strengthened and requests the Minister consider applying to NGCT, a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A.

20.14 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

20.15 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

20.16 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

NGCD

Recommendations

20.17 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by NGCD may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on NGCD under Part V of the Commerce Act should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

20.18 Control under PartVis high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on NGCD should be strengthened and requests the Minister consider applying to NGCD, a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A.

20.19 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

20.20 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

20.21 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

Powerco

<u>Recommendations</u>

20.22 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Powerco may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Powerco under PartVof the Commerce Act should be made.

<u>Advice on Relevant Matters</u>

20.23 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. If the Minister were to introduce alternative mechanisms for NGCT, NGCD and Wanganui Gas (such as a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A), there may be benefits in having all businesses, including, Powerco, under the same regime.

20.24 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

20.25 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

20.26 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The

Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

Vector

Recommendations

20.27 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Vector may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Vector under Part V of the Commerce should be made.

Advice on Relevant Matters

20.28 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. If the Minister were to introduce alternative mechanisms for NGCT, NGCD and Wanganui Gas (such as a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A), there may be benefits in having all businesses, including, Vector, under the same regime.

20.29 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

20.30 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

20.31 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

Wanganui Gas

Recommendations

20.32 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by Wanganui Gas may be controlled.
- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on Wanganui Gas under Part V of the Commerce Act should not be made, notwithstanding that the s 52 requirements for control are met.

Advice on Relevant Matters

20.33 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on Wanganui Gas should be strengthened and requests the Minister consider applying to Wanganui Gas, a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A.

20.34 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

20.35 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

20.36 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

Maui Development Limited

Recommendations

20.37 The Commission's recommendations are set out below.

- The Commission advises that the requirements of s 52 of the Commerce Act for the introduction of control have been met and therefore the gas services provided by MDL may be controlled.

- The Commission recommends that an Order in Council under s 53 of the Commerce Act to impose control on MDL under Part V of the Commerce Act should not be made, notwithstanding that the s 52 requirements for control are met.

<u>Advice on Relevant Matters</u>

20.38 Control under Part V is high cost relative to other regulatory options. The Commission notes that the Minister has a wider discretion than the Commission to consider other matters including alternatives to control under Part V. The Commission considers the regulatory constraints on MDL should be strengthened and requests the Minister consider applying to MDL, a regime comparable to the targeted control regime used for electricity lines businesses under Part 4A.

20.39 While the Commission has not carried out a detailed analysis of the costs and benefits of applying to the gas pipeline businesses a regime analogous to the targeted control regime applying to the electricity lines industry under Part 4A, the Commission has considerable experience of the implementation and operation of the Part 4A regime. The Commission's view is that such a regime has the potential to offer a more favourable trade-off between costs and benefits of regulatory intervention than control under Part V.

20.40 If the Minister were minded to consider adopting a regime comparable to the Part 4A targeted control regime applying to electricity lines businesses, consultation with interested parties as to its relative merits may be necessary or desirable.

20.41 In addition the Commission notes the poor quality of business specific data available through the Gas (Information Disclosure) Regulations 1992. The Commission considers there would be substantial benefits from requiring the businesses to disclose consistent and robust information and therefore, requests the Minister to consider strengthening the gas pipeline information disclosure regime.

Nova Gas

20.42 With respect to s 52(a) of the Commerce Act, the Commission's assessment is that Nova Gas faces workable or effective competition in the market in which it provides gas services. That is, competition is not limited in this market.

20.43 The Commission advises that the gas services supplied by Nova Gas Limited may not be controlled.

Taranaki Pipelines

20.44 In addition to the 'principal' transmission pipelines discussed above there are a number of pipelines of smaller length, all situated in Taranaki.

20.45 The LTS pipeline owned by NGC and the Surrey Road pipeline owned by Westech Energy are considered to fall outside the definition of 'transmission system' in the terms of reference and are therefore outside the ambit of the Inquiry.

20.46 The Frankley Road pipeline owned by NGC is included in the analysis of NGCT.

20.47 With respect to the McKee Production Station to Faull Road pipeline (Todd Taranaki) and the Rimu to NGC South pipeline (Swift) the Commission's assessment is that competition to these pipelines is not limited. The Commission advises that the gas services provided by these pipelines may not be controlled.

20.48 With respect to the Kapuni to Hawera pipeline (Todd Petroleum and Shell), and the TAW pipeline (Swift Energy) the Commission's assessment is that competition is limited but that there is unlikely to be net benefit to acquirers from control. The Commission advises that the gas services provided by these pipelines may not be controlled.

Other Requests from the Minister

Appropriate Valuation Methodology for this Inquiry

20.49 The Commission investigated the use of both historic cost and replacement cost valuation approaches for this Inquiry. The historic cost information was found to be generally unavailable. ODV/ODRC valuations were readily available and relatively robust compared to the historic cost information. Therefore, the Commission considers that the appropriate valuation methodology for this Inquiry to be ODV/ODRC.

Net Benefits to the Public of Control

20.50 The Minister requested the Commission to advise him on the net public benefits of control. The net public benefits assessment measures only efficiency effects. The efficiency effects under the net public benefits assessment are largely the efficiency effects within the NAB test.[290]

20.51 The benefits, costs and net public benefits assessed at the mid-point of WACC for NGCT, NGCD, Vector, Powerco and Wanganui Gas are set out in Table 20.7.

[290] The Commission notes that two additional benefits and costs of control affect producers only, and are included in the net public benefits analysis. These two additional matters are explained at the end of Chapter 4 (Overview of the Assessment Approach). They have proved generally immaterial in the present Inquiry.

Table 20.5: Net Public Benefits

Company	Mid WACC (Annuity $000)
NGCT	
Total efficiency benefits	644
Total efficiency costs	1,740
Net Public Benefits	**-1,096**
NGCD	
Total efficiency benefits	306
Total efficiency costs	1,219
Net Public Benefits	**-913**
Powerco	
Total efficiency benefits	401
Total efficiency costs	1,134
Net Public Benefits	**-732**
Vector	
Total efficiency benefits	685
Total efficiency costs	1,388
Net Public Benefits	**-702**
Wanganui Gas	
Total efficiency benefits	47
Total efficiency costs	421
Net Public Benefits	**-374**

Technical Provisions Relating to Section 57A of the Commerce Act

<u>Description of Services</u>

20.52 The Order made under s 53 of the Commerce Act may identify the services to which it relates:

- by a description of the services; or
- by a description of the kind or class to which the services belong.

20.53 The Order may apply to services:

- supplied in or for delivery within specified regions, areas, or localities in New Zealand;
- supplied in different quantities, qualities, grades or classes;
- supplied by or to or for the use of different persons or classes of persons.

20.54 The Commission would identify the services in the Order by the suppliers of the gas services. Accordingly the Order would refer to the services supplied by some or all of NGC Holdings Limited (Transmission), NGC Holdings Limited (Distribution), Powerco Limited, Vector Limited, Wanganui Gas Limited and Maui Development Limited in markets directly related to either a natural gas transmission system or a natural gas distribution system or both.

20.55 Where 'transmission system' is defined as:

> Transmission system means that part of a system that conveys gas from the point where the gas leaves a gas processing facility to the boundary of the gasworks or gate station outlet flange supplying gas-
>
> (a) for distribution; or
>
> (b) to a gas customer, where the gas does not enter a distribution system.

20.56 Where 'distribution system' is defined as

> Distribution system means all fittings, whether above or below ground, under the control of a gas distributor and used to distribute gas from-
>
> (a) The boundary of the gasworks or gate station outlet flange supplying gas for distribution; or
>
> (b) The outlet of the container in which gas for distribution is stored-
>
> to the outlet of the gas measurement system of the place at which the gas is supplied to a consumer or gas refueller (or, where no such gas measurement system is provided, to the custody transfer point of the place at which the gas is supplied to a consumer or gas refueller); and, for the purposes of any regulations made under section 54 of this Act relating to odorisation or the measurement of calorific value, includes a gas transmission system.

20.57 In addition, the Commission considers that gas meters (as described in paragraph 2.18) should be separately identified in any Order.

<u>Date of Expiry</u>

20.58 The Order made under s 53 of the Commerce Act must specify the date on which it expires (s 57A(4)).

20.59 The Commission acknowledges that it can be problematic to set a period of control without determining the form of control. It considers, however, that the appropriate period for expiry of an Order declaring control would be 11 years.

20.60 If a shorter period was adopted then another inquiry would have to be undertaken if control were to be extended. The Commission has the ability itself to vary authorisations and the form of control under Part V and also has the ability under s 56 of the Commerce Act to recommend amendment or revocation of the Order that declares control, should a shorter period of control become desirable.

Other Matters for the Minster to Consider

20.61 The Commission has not considered, in the context of the Inquiry, the implications of Vector's proposed acquisition of NGC. The Minister may need to consider the implications of that acquisition should the acquisition proceed.

APPENDIX A: VARIABLES AND EQUATIONS OF THE MODEL

Variables	Equations
Key inputs	
Elasticity (ϵ)	Distribution -0.3 Transmission -0.1
Actual Quantities (Q_m)	Gas Companies' transported actual and forecasts in GJ for each year
Actual Price (P_m)	$P_m = Revenue_t / Q_m$
Efficient Quantities (Q_c)	$Q_c = Q_m + (Q_m*(P_c - P_m)*\epsilon)/P_m$
Efficient Price (P_c)	$P_c = P_m - (NE_t - WACC_t * Asset\ Base_{t-1})/ Q_m$
Net Earnings (NE)	$NE_t = Revenue_t - Opex_t - Tax_t - Depreciation_t$ $+ Revaluations\ gains/losses\ spread_t$
Asset Base (AB)	$AB_t = ODVS_t +$ Other non-system $assets_t$ + Work in $progress_t$ (WIP) Where Optimised Deprival Value smoothed (ODVS) – preferred for this inquiry Depreciated Historic Cost – only used where available as sensitivity test
Revaluation Gains/Losses Spread (RS)	$RS_t = AB_t - AB_{t-1} + Depreciation_t - Capex_t + Disposals_t$ No revaluation gains/losses on other non-system assets have been calculated as these assets are typically recorded at historic cost.
Key findings	
Excess Returns (ER)	$ERt = NE_t - AB_{t-1} * WACC_t$
Allocative inefficiency benefit	Consumer surplus foregone + Producer surplus forgone (PS)
Consumer surplus forgone (CS)	$CS_t = 0.5 * (P_m - P_c) * (Q_m - Q_c)$ in absolute value terms
Producer surplus forgone (PS)	If Pm>Pc, PS = 0 as a long run model used. If Pm<Pc, $PS = (P_c - P_m) * (Q_m - Q_c)$
Productive inefficiency (PI) benefit	PI_t = Productive efficiency factor * Total $Costs_t$ (TC_t) Where $TC_t = Opex_t + 12.5\% * ODVS_t$, and Productive efficiency factor = 0.83%, the midpoint in a x-x% range

Dynamic inefficiency (DI) benefit	$DI_t = 0$, as no dynamic inefficiencies were identified by this inquiry.
Direct costs (DC)	DC_t = Compliance costs + Regulators costs Both figures are estimated from available data
Indirect Costs (IC)	IC = + Allocative efficiency benefit not achieved = 36% * CS_t + Excess returns unrecoverable = 20% * ER_t + Productive inefficiency = Productive inefficiency factor * TC_t Productivity inefficiency factor = 0.33%, midpoint in a 0-0.66% range + Forgone new investment costs = [consumer surplus foregone] = $[0.5\ (P_x - P_m)\ Q_{m'(t)}]$ where: The increment in forgone demand in year (t) is $IQ_m'_{(t)}$ and the total foregone demand is $Q_{m'(t)}$. $IQ_m'_{(t)} = [0.035\%]*Q_{m(t)}$ for Vector, NGC and Powerco; $[0.005\%]*Q_{m(t)}$ for WGL and $[0.01\%]*Q_{m(t)}$ for NGCT in the relevant years; Total foregone demand in year (t) $Q_{m'(t)} = IQ_{m'(1)} + \ldots IQ_{m'(t)}$ P_x (price at which demand is zero) is derived from the assumption as to the elasticity of demand at P_m $P_x = P_m(1-1/\varepsilon)$ where ε is the elasticity of demand for gas services The ε is assumed to be -0.9 for distribution businesses and -0.3 for transmission in the missing market. + Forgone investment resulting in increased congestion (interruptibility) = increase in interruptible sales (5%) x reduction in unit value of interruptible sales (10%) $= 0.05 * Q_m * 0.1 * P_m$
Total Benefits	Total Benefits = $ER_t + CS_t + PS_t + PI_t + DI_t$
Total Costs	Total Costs = $DC_t + IC_t$
Net Acquirer's Benefit (NAB)	NAB = (Total Benefits – PS_t) – Total costs
Net Public Benefit (NPB)	NPB = (Total Benefits – ER_t) – (Total Costs - Indirect costs of excess returns not recoverable)

APPENDIX B: DATA TEMPLATE

Information required from <<Company>>	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Nominated balance date (e.g. 30 June)													
Revenues and expenses													
Revenue ($000)													
Price per GJ ($)													
Gas conveyed (GJs)													
Operating expenses (excluding tax, depreciation and interest)($000)													
include a break down by - common costs													
maintenance													
other operating expenses													
Interest expense ($000)													
Tax expense ($000)													
Marginal Cost per GJ ($)													
Connections (number)													
System length (km)													
System Assets													
Additions/deletions													
Capital expenditure (Capex) ($000)													
Value of any deletions ($000)													
Any gain or loss on the sale of deleted assets ($000)													
ODV calculations													
Replacement Cost of system assets (excluding Capex for that year & any takeovers for that year) ($000)													
include a break down by - pipelines													
stations													
valves													

This balance date should be consistent across all years and for all figures presented herein.

The inclusion of Price is largely for the forecast figures so as to make more transparent any planned price changes into the future and as an additional check.
Price should be able to be derived by dividing Revenue by Gas conveyed. Simiarly, Revenues could be derived by multiplying Price by Gas conveyed.

Where available, the forecast figures should be those used for the most recent ODV report should be presented. If not available, the alternative source of forecasts noted.

Any information sought that is left aligned in the first colum refers to aggregate figures, while any following left aligned figures refer to a break down of the aggreate figure by the following categories.

Marginal costs per GJ means the additional cost of conveying an additional GJ of gas. In practice, marginal costs per GJ could be the variable charge component under a two part tariff structure, where all the fixed costs are recovered through a fixed charge. Where the variable charge also covers fixed costs, these fixed costs should be removed to estimate marginal costs per GJ.

scada/control systems													
stores and spares													
easements													
Total value of system assets valued at residual value ($000)													
Optimisation ($000)													
Economic Value adjustment ($000)													
Revaluation gain/loss (excluding EV & Optimisation & Capex for that year & any takeovers for that year) ($000)													
Accumulated depreciation ($000)													
Annual depreciation under ODV ($000)													
ODV ($000)													
Any revaluation reserve ($000)													
Historic cost calculations													
HC of system assets (excluding capital expenditure for that year) ($000)													
break down by - Any unused system assets ($000)													
easements ($000)													
Other used system assets ($000)													
Accumulated depreciation under HC ($000)													
Annual depreciation under HC ($000)													
DHC of sytem assets ($000)													
Works in progres s													
Works in progress - system fixed assets ($000)													
Takeovers and mergers													
ODV of acquired system assets immediately prior to acquisition ($000)													
Any premium paid over ODV of the acquired system assets ($000)													
Other fixed assets													
Other fixed assets ($000)													
include a break down by - common assets													
other specific assets													
Annual depreciation of other assets ($000)													

This is intended to discern what amount of the total replacement cost of the network in accounted for by assets valued at a residual value.

This was additional information sought after initial 70e notice.

Where actual HC records don't exist, assume the same asset lives and approach to depreciation as under the ODV calculation.

This was additional information sought after initial 70e notice.

This should be equal to the HC of system assets minus accumulated depreciation of system assets in each of the relevant years.

Please complete the required information for takeovers and mergers in the relevant year.

Please include a comment on the types of assets included here.

This was additional information sought after the initial 70e notice.

Appendix C

NGC Transmission - Benefits & costs analysis

Year to 30 June	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Annuity
Net earnings - including depreciation & RS ($000)	[redacted]													
Asset base - ODVS + Others + WIP ($000)														
WACC		8.5%	8.5%	7.6%	8.4%	8.1%	7.9%	7.2%	7.9%	7.9%	7.9%	7.9%	7.9%	
Elasticity		- 0.10	- 0.10	- 0.10	- 0.10	- 0.10	- 0.10	- 0.10	- 0.10	- 0.10	- 0.10	- 0.10	- 0.10	
Pm per GJ ($)		[redacted]												
Pc per GJ ($)														
Qm [TJs per year]														
Qc [TJs per year]														
Excess returns ($000)		[redacted]												
Excess returns ($000) indexed														**4,536**
Consumer surplus ($000)														
Consumer surplus ($000) indexed														**25**
Producer surplus ($000)														
Producer surplus ($000) indexed														**11**
Productive efficiency ($000)														
Productive efficiency ($000) indexed														**609**
Dynamic efficiency ($000)														
Dynamic efficiency ($000) indexed														**0**
Total benefits ($000)		9,896	-7,007	6,847	10,887	6,164	5,913	10,757	1,854	5,601	2,115	1,773	4,095	
Total benefits ($000) indexed		**16,990**	**-11,089**	**9,985**	**14,758**	**7,706**	**6,838**	**11,530**	**1,854**	**5,190**	**1,816**	**1,411**	**3,019**	**5,180**
Net Acquirer's Benefit test														
Direct costs ($000)		539	548	546	557	575	591	600	614	623	633	642	652	
Indirect costs ($000)		2,506	724	2,064	3,021	2,176	2,309	3,385	1,635	2,443	1,719	1,641	2,109	
Total costs ($000)		3,045	1,273	2,610	3,578	2,751	2,899	3,984	2,249	3,067	2,352	2,283	2,761	
Total costs ($000) indexed		**5,227**	**2,014**	**3,806**	**4,850**	**3,439**	**3,353**	**4,271**	**2,249**	**2,842**	**2,019**	**1,816**	**2,035**	**2,806**
Net benefits to acquirers ($000) nominal		6,851	-8,369	4,237	7,309	3,413	3,014	6,772	-394	2,535	-237	-510	1,335	
Net benefits to acquirers ($000) indexed		**11,762**	**-13,245**	**6,179**	**9,908**	**4,267**	**3,485**	**7,259**	**-394**	**2,349**	**-204**	**-406**	**984**	**2,364**
Net Public Benefit test														
Direct costs ($000)		539	548	546	557	575	591	600	614	623	633	642	652	
Indirect costs ($000)		648	710	822	1,001	1,088	1,284	1,432	1,401	1,491	1,443	1,429	1,445	
Total costs ($000)		1187	1258	1368	1558	1663	1875	2032	2015	2115	2076	2071	2097	
Total costs ($000) indexed		**2,038**	**1,991**	**1,995**	**2,112**	**2,079**	**2,168**	**2,178**	**2,015**	**1,959**	**1,782**	**1,647**	**1,546**	**1,740**
Net benefits to public ($000)		-626	-727	-811	-942	-1,056	-1,215	-1,309	-1,358	-1,405	-1,381	-1,389	-1,414	
Net benefits to public ($000) indexed		**-1,074**	**-1,151**	**-1,183**	**-1,278**	**-1,320**	**-1,404**	**-1,403**	**-1,358**	**-1,302**	**-1,186**	**-1,105**	**-1,043**	**-1,096**

Appendix D

NGC Distribution - Benefits & costs analysis

Year to 30 June	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Annuity
Net earnings - including depreciation & RS ($000)	[redacted]													
Asset base - ODVS + Others + WIP ($000)														
WACC		8.5%	8.5%	7.6%	8.4%	8.1%	7.9%	7.2%	7.9%	7.9%	7.9%	7.9%	7.9%	
Elasticity		- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	
Pm per GJ ($)		[redacted]												
Pc per GJ ($)														
Qm [TJs per year]														
Qc [TJs per year]														
Excess returns ($000)		[redacted]												
Excess returns ($000) indexed														**3,069**
Consumer surplus ($000)														
Consumer surplus ($000) indexed														**85**
Producer surplus ($000)														
Producer surplus ($000) indexed														**0**
Productive efficiency ($000)														
Productive efficiency ($000) indexed														**222**
Dynamic efficiency ($000)														
Dynamic efficiency ($000) indexed														**0**
Total benefits ($000)		363	2,584	632	5,523	6,433	7,033	7,657	579	2,264	2,240	2,271	2,312	
Total benefits ($000) indexed		**624**	**4,090**	**922**	**7,487**	**8,042**	**8,133**	**8,207**	**579**	**2,097**	**1,923**	**1,807**	**1,704**	**3,375**
Net Acquirer's Benefit test														
Direct costs ($000)		539	548	546	557	575	591	600	614	623	633	642	652	
Indirect costs ($000)		278	772	429	1,516	1,693	1,919	2,092	649	1,170	1,247	1,336	1,431	
Total costs ($000)		817	1,321	975	2,073	2,268	2,509	2,691	1,263	1,793	1,879	1,978	2,082	
Total costs ($000) indexed		**1,402**	**2,090**	**1,422**	**2,810**	**2,835**	**2,902**	**2,885**	**1,263**	**1,662**	**1,614**	**1,574**	**1,535**	**1,775**
Net benefits to acquirers ($000) nominal		-454	1,264	-343	3,450	4,165	4,524	4,965	-684	470	361	293	229	
Net benefits to acquirers ($000) indexed		**-779**	**2,000**	**-500**	**4,677**	**5,207**	**5,231**	**5,322**	**-684**	**436**	**310**	**233**	**169**	**1,600**
Net Public Benefit test														
Direct costs ($000)		539	548	546	557	575	591	600	614	623	633	642	652	
Indirect costs ($000)		244	317	346	550	583	725	810	587	829	918	1,009	1,105	
Total costs ($000)		783	865	892	1107	1158	1316	1410	1201	1452	1550	1651	1757	
Total costs ($000) indexed		**1,344**	**1,369**	**1,301**	**1,500**	**1,448**	**1,522**	**1,511**	**1,201**	**1,346**	**1,331**	**1,314**	**1,295**	**1,219**
Net benefits to public ($000)		-593	-644	-701	-772	-736	-868	-907	-973	-1,188	-1,276	-1,368	-1,464	
Net benefits to public ($000) indexed		**-1,018**	**-1,020**	**-1,022**	**-1,047**	**-920**	**-1,004**	**-972**	**-973**	**-1,101**	**-1,096**	**-1,088**	**-1,079**	**-913**

Appendix E

Powerco - Benefits & costs analysis

Year to 31 March	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Annuity
Net earnings - including depreciation & RS ($000)	[redacted]													
Asset base - ODVS + Others + WIP ($000)														
WACC		8.5%	8.5%	7.6%	8.4%	8.1%	8.3%	8.0%	8.7%	8.2%	8.2%	8.2%	8.2%	
Elasticity		- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	
Pm per GJ ($)		[redacted]												
Pc per GJ ($)														
Qm [TJs per year]														
Qc [TJs per year]														
Excess returns ($000)		[redacted]												
Excess returns ($000) indexed														**5,493**
Consumer surplus ($000)														
Consumer surplus ($000) indexed														**231**
Producer surplus ($000)														
Producer surplus ($000) indexed														**2**
Productive efficiency ($000)														
Productive efficiency ($000) indexed														**168**
Dynamic efficiency ($000)														
Dynamic efficiency ($000) indexed														
Total benefits ($000)		-388	1,390	952	4,449	-439	3,586	10,061	12,930	15,542	13,810	11,860	10,454	
Total benefits ($000) indexed		**-667**	**2,200**	**1,388**	**6,031**	**-548**	**4,147**	**10,784**	**12,930**	**14,401**	**11,856**	**9,435**	**7,706**	**5,895**
Net Acquirer's Benefit test														
Direct costs ($000)		539	548	546	557	575	591	600	614	623	633	642	652	
Indirect costs ($000)		63	363	282	1,049	143	939	2,443	3,226	3,881	3,616	3,310	3,122	
Total costs ($000)		602	911	828	1,606	718	1,529	3,043	3,840	4,504	4,248	3,952	3,774	
Total costs ($000) indexed		**1,033**	**1,441**	**1,208**	**2,177**	**897**	**1,769**	**3,261**	**3,840**	**4,174**	**3,647**	**3,144**	**2,782**	**2,173**
Net benefits to acquirers ($000) nominal		-1,000	479	124	2,843	-1,167	2,057	7,019	9,090	11,037	9,561	7,908	6,680	
Net benefits to acquirers ($000) indexed		**-1,717**	**759**	**180**	**3,854**	**-1,458**	**2,378**	**7,523**	**9,090**	**10,227**	**8,209**	**6,291**	**4,924**	**3,719**
Net Public Benefit test														
Direct costs ($000)		539	548	546	557	575	591	600	614	623	633	642	652	
Indirect costs ($000)		61	110	114	298	134	306	661	902	1,166	1,245	1,313	1,399	
Total costs ($000)		600	658	660	855	708	897	1261	1516	1789	1878	1955	2050	
Total costs ($000) indexed		**1,030**	**1,042**	**963**	**1,159**	**886**	**1,037**	**1,351**	**1,516**	**1,658**	**1,612**	**1,556**	**1,511**	**1,134**
Net benefits to public ($000)		-543	-581	-603	-460	-636	-684	-625	-794	-773	-985	-1,180	-1,346	
Net benefits to public ($000) indexed		**-932**	**-920**	**-880**	**-624**	**-796**	**-791**	**-670**	**-794**	**-716**	**-846**	**-938**	**-992**	**-732**

Appendix F

Vector - Benefits & costs analysis

Year to 31 December	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Annuity
Net earnings - including depreciation & RS ($000)			[redacted]											
Asset base - ODVS + Others + WIP ($000)														
WACC					8.4%	8.1%	7.9%	7.2%	7.9%	7.9%	7.9%	7.9%	7.9%	
Elasticity					- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	
Pm per GJ ($)					[redacted]									
Pc per GJ ($)														
Qm [TJs per year]														
Qc [TJs per year]														
Excess returns ($000)					[redacted]									
Excess returns ($000) indexed														**9,361**
Consumer surplus ($000)														
Consumer surplus ($000) indexed														**403**
Producer surplus ($000)														
Producer surplus ($000) indexed														**0**
Productive efficiency ($000)														
Productive efficiency ($000) indexed														**283**
Dynamic efficiency ($000)														
Dynamic efficiency ($000) indexed														**0**
Total benefits ($000)					7,604	20,951	11,122	13,081	8,582	10,868	11,408	12,639	13,237	
Total benefits ($000) indexed					**10,308**	**26,193**	**12,861**	**14,021**	**8,582**	**10,070**	**9,795**	**10,055**	**9,757**	**10,047**
Net Acquirer's Benefit test														
Direct costs ($000)					557	575	591	600	614	623	633	642	652	
Indirect costs ($000)					1,866	4,818	2,810	3,310	2,465	3,038	3,267	3,645	3,899	
Total costs ($000)					2,423	5,392	3,401	3,909	3,079	3,661	3,899	4,287	4,551	
Total costs ($000) indexed					**3,284**	**6,741**	**3,933**	**4,190**	**3,079**	**3,393**	**3,348**	**3,410**	**3,355**	**3,126**
Net benefits to acquirers ($000) nominal					5,181	15,559	7,720	9,172	5,503	7,207	7,509	8,352	8,686	
Net benefits to acquirers ($000) indexed					**7,024**	**19,451**	**8,928**	**9,831**	**5,503**	**6,678**	**6,447**	**6,644**	**6,402**	**6,921**
Net Public Benefit test														
Direct costs ($000)					557	575	591	600	614	623	633	642	652	
Indirect costs ($000)					472	1,101	831	1,027	990	1,199	1,364	1,569	1,757	
Total costs ($000)					1029	1676	1421	1627	1604	1822	1997	2211	2408	
Total costs ($000) indexed					**1,395**	**2,095**	**1,644**	**1,743**	**1,604**	**1,688**	**1,715**	**1,759**	**1,775**	**1,388**
Net benefits to public ($000)					-517	35	-717	-781	-1,043	-1,129	-1,275	-1,417	-1,583	
Net benefits to public ($000) indexed					**-701**	**43**	**-829**	**-837**	**-1,043**	**-1,046**	**-1,095**	**-1,128**	**-1,167**	**-702**

Appendix G

Wanganui Gas - Benefits & costs analysis

Year to 30 June	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Annuity
Net earnings - including depreciation & RS ($000)	[redacted]													
Asset base - ODVS + Others + WIP ($000)														
WACC		8.5%	8.5%	7.6%	8.4%	8.1%	7.9%	7.2%	7.9%	7.9%	7.9%	7.9%	7.9%	
Elasticity		- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	- 0.30	
Pm per GJ ($)		[redacted]												
Pc per GJ ($)														
Qm [TJs per year]														
Qc [TJs per year]														
Excess returns ($000)		[redacted]												
Excess returns ($000) indexed														**659**
Consumer surplus ($000)														
Consumer surplus ($000) indexed														**20**
Producer surplus ($000)														
Producer surplus ($000) indexed														**0**
Productive efficiency ($000)														
Productive efficiency ($000) indexed														**27**
Dynamic efficiency ($000)														
Dynamic efficiency ($000) indexed														
Total benefits ($000)		938	791	572	774	868	895	674	573	298	291	433	692	
Total benefits ($000) indexed		**1,611**	**1,251**	**834**	**1,049**	**1,085**	**1,035**	**723**	**573**	**276**	**249**	**345**	**510**	**706**
Net Acquirer's Benefit test														
Direct costs ($000)		340	345	344	351	362	372	378	387	393	399	405	411	
Indirect costs ($000)		215	185	139	184	205	211	166	148	93	94	124	179	
Total costs ($000)		554	530	483	535	567	584	544	535	486	492	529	590	
Total costs ($000) indexed		**952**	**839**	**704**	**725**	**709**	**675**	**583**	**535**	**451**	**423**	**421**	**435**	**551**
Net benefits to acquirers ($000) nominal		384	261	89	239	301	312	131	38	-188	-202	-96	102	
Net benefits to acquirers ($000) indexed		**659**	**412**	**130**	**324**	**377**	**361**	**140**	**38**	**-174**	**-173**	**-76**	**75**	**155**
Net Public Benefit test														
Direct costs ($000)		340	345	344	351	362	372	378	387	393	399	405	411	
Indirect costs ($000)		39	37	33	40	43	46	42	43	42	44	48	55	
Total costs ($000)		378	382	377	391	406	418	420	430	434	442	452	465	
Total costs ($000) indexed		**650**	**605**	**550**	**530**	**507**	**483**	**450**	**430**	**403**	**380**	**360**	**343**	**421**
Net benefits to public ($000)		-322	-335	-340	-343	-353	-362	-375	-390	-401	-408	-413	-415	
Net benefits to public ($000) indexed		**-553**	**-531**	**-496**	**-465**	**-441**	**-419**	**-402**	**-390**	**-372**	**-350**	**-329**	**-306**	**-374**

APPENDIX H: LIST OF ABBREVIATIONS

ABARE	Australian Bureau of Agricultural and Resource Economics
AC	Average Cost
ACAM	Avoidable Cost Allocation Methodology
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AECT	Auckland Energy Consumer Trust
AGL	Australian Gas Light Company
Airports Inquiry	Part IV Inquiry into Airfield Activities at Auckland, Wellington, and Christchurch International Airports, 1 August 2002
Bill	Electricity and Gas Industries Bill
CAPM	Capital Asset Pricing Model
CNG	Compressed Natural Gas
Commerce Act	Commerce Act 1986
Commission	Commerce Commission
Cost Benefit Model	The Commission's excel model measuring the costs and benefits of control
CPI	Capital Price Index
CRA	Charles River Associates
Cranleigh	Cranleigh Strategic
DHC	Depreciated Historic Cost
Draft Framework Paper	Gas Control Inquiry Draft Framework Paper, Commerce Commission, 16 July 2003
Draft Report	Gas Control Inquiry Draft Report, Commerce Commission, 18 May 2004
DRC	Depreciated Replacement Cost
EPIL	Energy Petroleum Investments Limited
EV	Economic Value
EMCa	Energy Market Consulting Associates
Gas	Natural Gas
GasNet Decision	*Application by GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6 (Australian Competition Tribunal)
GJ	Giga Joule
GNP	Gross National Product
GPS	Government Policy Statement
GST	Goods and Services Tax
Guidelines	Commerce Commission Merger and Acquisition Guidelines
Handbook	Ministry of Economic Development Draft Handbook for Optimised Deprival Valuation of System Fixed Assets of Gas Pipeline Businesses (June 2000)
HNET	Hypothetical New Entrant Test
IEA	International Energy Agency
Inquiry	Gas Control Inquiry
IPART	Independent Regulatory and Pricing Tribunal
KCS	Kapuni Cogeneration Station

KGTP	Kapuni Gas Treatment Plant
Km	Kilometre
LECG	Law & Economic Consulting Group
LPG	Liquefied Petroleum Gas
LRMC	Long-Run Marginal Cost
M&A	Meyrick & Associates
MC	Marginal Cost
MDL	Maui Development Limited
MED	Ministry of Economic Development
Mercury Energy	Mercury Energy Limited
MEUG	Major Electricity Users Group
Minister	Minister of Energy
MMC	Maui Mining Companies
MW	Mega Watt
NAB	Net Acquirers' Benefit
NECG	Network Economics Consulting Group Pty Ltd
NERA	NERA Economic Consulting
NGC	NGC Holdings Ltd
NGCD	NGC Holdings Ltd Distribution
NGCT	NGC Holdings Ltd Transmission
Nova Gas	Nova Gas Limited
NPB	Net Public Benefit
NPV	Net Present Value
NSW	New South Wales
NZIER	New Zealand Institute of Economic Research
ODV	Optimised Deprival Value
ODRC	Optimised Depreciated Replacement Cost
OECD	Organisation for Economic Co-operation and Development
OMV	OMV New Zealand Limited
Order	Order in Council (Part IV of the Commerce Act 1986)
P.A	Per Annum
PEANZ	Petroleum Exploration Association of New Zealand
Petrocorp	Petroleum Corporation of New Zealand
PJ	Petajoule
Powerco	Powerco Limited
PWC	Pricewaterhouse Cooper
QMCA	Australian Trade Practices Tribunal decision *Re Queensland Co-operative Milling Association Ltd: Re Defiance Holdings Ltd* (1976) 8 ALR 481
RC	Replacement Cost
ROI	Return On Investment
SCADA	Supervisor Control and Data Acquisition System
SENZ	Shell Exploration NZ Limited
SPM	Shell (Petroleum Mining) Company Limited
SRMC	Short-Run Marginal Cost
SSNIP	Small yet significant and non-transitory increase in price
STOS	Shell Todd Oil Services
TAMRP	Tax-Adjusted Market Risk Premium

Terms of Reference	Letter of request from the Minister of Energy dated 30 April 2003, the Commission's letter seeking clarification dated 20 June 2003 and the Minister of Energy's reply dated 9 July 2003
TFP	Total Factor Productivity
The Regulations	Gas (Information Disclosure) Regulations 1997
TJ	Tetra Joule
TOPCO	Taranaki Offshore Petroleum Company Limited
TPMC	Todd Petroleum Mining Company Limited
Tribunal	Australian Competition Tribunal
TSLRIC	Total Service Long Run Incremental Cost
TSO	Telecommunications Service Obligations
UNL	UnitedNetworks Limited
UK	United Kingdom
US	United States of America
Vector	Vector Limited
WACC	Weighted Average Cost of Capital
WGL	Wanganui Gas Limited
WIP	Work In Progress