Regulation of Electricity Lines Businesses Resetting the Price Path Threshold – Comparative Option

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CONTENTS

EXECUTIVE SUMMARY

Meyrick and Associates has been engaged by the New Zealand Commerce Commission to assist with developing the quantitative basis for implementing the comparative option in resetting the price path threshold for electricity lines businesses (ie distribution businesses and Transpower). The comparative option involves decomposing the X factor into two components: a 'B' factor reflecting the overall or average productivity trend for electricity lines businesses and a 'C' factor broadly reflecting the circumstances of each distribution business or a small number of groups of distribution businesses.

Factors to be taken into account in determining the C factor may include the operating environment factors faced by each business which are beyond management control, relative productivity performance, the price charged by the business and the level of service quality provided by the business. Those distributors performing better than the industry average would possibly be set a less onerous X factor (ie be allocated a negative C factor) and those performing worse than the industry average would possibly be set a more onerous X factor (ie be allocated a positive C factor).

The overall X factor for a given distributor would be made up of an amalgam of its B and C factors. The B factor would be common to all distributors and the C factors could be determined either individually for each distributor or for broad groups of distributors. For Transpower, only the B factor would be applicable.

The data source used in this report is the lines business Disclosure Data covering the March years 1996 to 2002. Despite the wide range of items now reported in the Disclosure Data, the consistency and quality of the data is quite variable. The distributors appear to have interpreted what is required differently leading to apparent inconsistencies across distributors and there is, in many cases, considerable variability from year to year for the one distributor. A number of the key variables that would normally be required for productivity analyses are missing. For instance, there is effectively no useful labour data. There are some coverage gaps in years where distributors have amalgamated due to a requirement that data only has to be provided for entities existing at the end of the financial year. Despite these problems, the Disclosure Data provide a useful starting point for productivity analysis. Wherever possible we have used alternative methodologies to confirm the broad results to enable us to have reasonable confidence despite the inherent variability in the data for individual distributors.

The first issue to be resolved in undertaking productivity studies is the specification of industry outputs and inputs. Early electricity supply productivity studies simply measured output by system throughput. However, this simple measure ignores important aspects of what lines businesses really do. Like all network infrastructure industries, a major part of lines business output is providing the capacity to supply the product. In this sense, there is an analogy between an electricity distribution system and a road network. The distributor has the responsibility of providing the 'road' and keeping it in good condition but has little, if any, control over the amount of 'traffic' that goes down the road. Consequently, the distributor's output should also be mainly measured by the availability of the infrastructure it has provided and the condition in which it has maintained it. Other outputs the distributor provides are directly related to its number of connections and include provision of local transformers ('local access roads') as well as call centre operations responding to queries, connection requests, etc.

To capture these multiple dimensions of lines business output we measure distribution output in this study using three outputs: throughput, system line capacity and connection numbers. This has the advantage of incorporating the major density effects directly into the output measure. Inputs are broken into five categories: operating expenses, overhead lines, underground cables, transformers and other capital. Transmission output is measured by throughput and system capacity and inputs by operating expenses, lines and transformer capital.

We use the Fisher total factor productivity (TFP) index method to calculate the productivity performance of distribution as a whole and transmission. For the 7 year period 1996 to 2002 aggregate distribution TFP increased at a trend annual rate of 3.2 per cent. For the same 7 year period transmission TFP increased at a trend annual rate of 2.3 per cent, just over two thirds the trend growth rate of distribution TFP. Taking productivity and input price differences relative to the economy as a whole into account leads to a distribution B factor of 2.6 per cent. Given the quality of the data on which the analysis has had to be based and the results of sensitivity analyses, it would be more appropriate to round this B factor down than up. Applying a similar analysis to transmission leads to a B factor estimate of 1.7 per cent for Transpower.

The Commerce Commission (2003) raised the possibility of using an ad hoc regression of prices against output quantity, output quality, input prices and business condition variables as the means of determining C factors for distribution businesses. However, these equations are sensitive to the specification used and do not provide either a theoretically well–developed or a sufficiently empirically robust means of determining C factor allocations. Rather than relying on the price equation to try and simultaneously capture the two main components of the C factors – relative productivity performance and profitability taking service quality into account – we use a two stage analysis. The first stage allocates distributors to C factor groupings based on relative productivity performance while the second stage uses additional analysis to review the initial C factor allocations based on quality and profitability information.

We have used two alternative methods to examine the productivity levels and growth rates of the individual distribution businesses. These are multilateral TFP (MTFP) indexes which allow us to calculate productivity levels as well as growth rates and an econometric cost function. A mixture of urban and rural based distributors with both high and low energy density are found to have the highest MTFP levels. Load growth and scale do not appear to be good indicators of a distributor's 2002 MTFP level ranking with distributors with both high and low load growth being found near both the top and bottom of the rankings. Small and large distributors are also dispersed through the rankings. The econometric cost function efficiency results broadly confirm the findings of the MTFP results despite being derived from a different methodology. Because the MTFP results are more robust where there is data of variable quality and because they allow the calculation of B and C factors in an integrated framework, we use the MTFP results in developing our recommended C factors.

We derive initial productivity based C factors (denoted by C_1) by dividing the distributors into groups of around one third each. These groupings generally coincide with step points in the MTFP scores for 2002. We use groupings of 9, 11 and 9 distributors to define high, average and low levels of productivity, respectively, and allocate them initial C factors of –1, 0 and 1 per cent, respectively. These C factors are consistent with those required to bring the average distributor in the top and bottom groups to the same productivity level as the middle group average over 10 years and assuming the middle group's TFP increases annually at 2.5 per cent. A 10 year adjustment period is required for a capital intensive industry with long lived assets.

We have investigated the scope to use price/quality equations to make adjustments to initial productivity based C factor allocations. However, at this time the price/quality regression concept does not provide either a theoretically well–developed or a sufficiently empirically robust means of adjusting the initial C factor allocations due to the difficulty in defining a statistically robust model, the sensitivity of its specification, and the lack of a theoretical basis for preferring one econometric model over another. The relationship between quality and cost measures is complex and requires more investigation. As predicted by economic theory, costs and a broad measure of output (comprising throughput, system line capacity and connections) are the primary drivers of price with quality measures playing a secondary role. Consequently, we have incorporated profitability differences between the businesses using residual rates of economic return as a basis for making adjustments to the initial C factor allocations.

This analysis leads to groups of 10, 9 and 10 distributors being classed as earning high, average and low rates of return, respectively. These groups are allocated C factor adjustments (denoted by C_2) of 1, 0 and –1 per cent, respectively. These factors are designed to 'glide path' distributors earning high and low rates of return towards the average return deadband over one regulatory period (assumed to be five years).

The C factors resulting from using the MTFP scores in conjunction with the residual rate of return estimates are presented in table A. There are a mixture of business types in each of the three C factor groups with urban high density, urban low density, rural high density and rural low density businesses appearing in each of the low, middle and high C factor groups.

Looking ahead to future regulatory resets, the priority for future work in this area is improving the quality and quantity of relevant data available. This involves requiring the disclosure of data on the price and quantity of all major outputs and inputs, including labour and broad asset categories. It also includes gaining more accurate information on the allocation of costs between the major output types. Much of the Disclosure Data currently required from businesses is not used for developing comparative performance measures that would be relevant for forming B and C factors. The usefulness of this data should be reviewed with a view to reducing the amount of data required but making its composition more relevant.

Table A: **Illustrative distributor C factor recommendations**

ELB	C_1	C_2	C	*ELB*	C_1	C_2	C
Alpine Energy	0	1	1	Powerco	0	0	0
Centralines	1	0	1	The Lines Company	0	0	0
Counties Power	0	1	1	Top Energy	1	–1	0
Dunedin Electricity	1	1	1[a]	UnitedNetworks	–1	1	0
Eastland Network	1	1	1[a]	Westpower	1	–1	0
Horizon Energy	0	1	1	Electricity Invercargill	–1	0	–1
MainPower	1	0	1	Network Waitaki	0	–1	–1
Marlborough Lines	1	0	1	Northpower	–1	–1	–1[b]
Orion New Zealand	0	1	1	Otago Power	–1	–1	–1[b]
WEL Networks	0	1	1	Scanpower	–1	0	–1
Buller Electricity	1	–1	0	The Power Company	0	–1	–1
Electra	0	0	0	Unison	0	–1	–1
Electricity Ashburton	1	–1	0	Vector	–1	0	–1
Nelson Electricity	–1	1	0	Waipa Networks	–1	–1	–1[b]
Network Tasman	–1	1	0				

[a] Limited to 1 per cent
[b] Limited to –1 per cent
Source: Meyrick and Associates estimates

Finally, the results of this study confirm that the approach proposed by the Commerce Commission (2003) of building up the thresholds for individual businesses by summing up separate B and C factors reflecting industry productivity trends and individual productivity performance, profitability and quality considerations, respectively, is both sensible and feasible. Greatest confidence can be placed on the industry productivity trend information. Confirming broad individual productivity and profitability rankings through the use of alternative methodologies means we can place reasonable confidence in the C factor recommendations despite the inherent variability in the data for individual distributors. It would be unwise to include a separate price/quality trade–off factor at this time given the lack of understanding of the relationship between quality and costs. The range of ownership and governance structures of the distribution businesses also make understanding the drivers of prices charged problematic and reinforce the importance of using productivity and profitability information as the primary basis for determining the thresholds for individual businesses.

1 INTRODUCTION

The New Zealand Commerce Commission is currently assessing options for resetting the parameters of the price path threshold to apply to electricity lines businesses in accordance with Part 4A of the Commerce Act. The Commission has set two thresholds: a price path threshold of the CPI–X form and a quality threshold. The Commission is focussing on two broad options for resetting the price path threshold to apply to distribution businesses from 1 April 2004: a comparative (or 'benchmarking') option and a non–comparative (or 'partial building blocks') option. With respect to the comparative option, the Commission is considering including the following factors in its reset of the CPI–X price path: an adjustment for expected gains in industry productivity based on total factor productivity (TFP) analysis; and, for distributors, an adjustment which would reflect business–specific cost efficiencies and the relative price/quality performance of individual lines businesses based on econometric benchmarking analysis.

Meyrick and Associates has been engaged by the Commission to assist with developing the quantitative basis for implementing the comparative option. The comparative option involves decomposing the X factor into two components: a 'B' factor reflecting the overall or average productivity trend for electricity lines businesses and a 'C' factor broadly reflecting the circumstances of each lines business or a small number of groups of lines businesses. Factors to be taken into account in determining the C factor may include the operating environment factors faced by each business which are beyond management control, relative productivity performance, the price charged by the business and the level of service quality provided by the business. Those distributors performing better than the industry average would possibly be set a less onerous X factor (ie be allocated a negative C factor) and those performing worse than the industry average would possibly be set a more onerous X factor (ie be allocated a positive C factor).

1.1 The approach adopted in setting C factors

In its recent discussion paper the Commerce Commission (2003) raised the possibility of using an ad hoc regression of prices against output quantity, output quality, input prices and business condition variables as the means of determining C factors for distribution businesses. This specification would in essence be similar to a cost function except that cost is replaced by price (or revenue) as the dependent variable. It was argued that using this single function approach may make more efficient use of the data and obviate the need to consider separate P_0 adjustments.

The residual term from the ad hoc price function was hypothesised in the discussion paper to reflect a combination of productive inefficiency, 'excess profit' after taking service quality into account and random factors. While the Commission did not propose disentangling these three components, in practice doing so to gain a full understanding of observed differences would not be straightforward, as is confirmed by the extensive analysis outlined later in this report.

While ad hoc regressions of price against service quality and other factors have some appeal, they are less defensible in terms of underlying microeconomic theory than benchmarking models which compare distributor productivity and cost performance given output quantities, quality and operating environment conditions. In particular, the use of ad hoc price functions as the primary analytical method for determining C factors does not provide a way of calculating the B and C factors in an integrated quantitative framework. The range of ownership and governance structures and associated objectives of the distribution businesses also make understanding the drivers of prices charged somewhat problematic and reinforce the importance of using productivity and profitability information as the primary basis for determining the thresholds for individual businesses.

Rather than relying on the price equation to try and simultaneously capture the two main components of the C factors – relative productivity performance and profitability taking service quality into account – it is more appropriate to proceed with a two stage analysis. The first stage allocates distributors to C factor groupings based on relative productivity performance while the second stage uses additional analysis to review the initial C factor allocations based on service quality and profitability considerations.

The approach that allows the B and C factors to be calculated in an integrated and consistent framework (based on efficiency performance) is the multilateral TFP method. This indexing method allows us to estimate TFP levels as well as growth rates and is, thus, ideally suited to calculating the 'stretch' C factors. It is a robust technique which can produce accurate results (subject to data quality) with a small number of observations. It provides scope to incorporate key operating environment condition differences, such as energy and customer density, directly by a judicious choice of outputs in an analogous fashion to multiple output cost functions. We use the multilateral TFP method as our primary means of determining C factor allocations based on distributor–specific productivity performance. We also estimate econometric cost functions for the distributors as an alternative means of determining relative productivity performance.

In the second stage analysis we examine the scope to use an ad hoc price/service quality function to identify businesses that appear to have high and low price levels given their service quality levels and costs and review their initial allocation to C factor groups based on relative productivity performance. However, despite extensive investigation, the price/quality regressions are sensitive to the specification used and are unable to separately identify the contribution of service quality to price. To be able to do this with confidence we need a much more detailed model of the relationship between service quality and input levels than it has been feasible to develop given both the data and time available for this project.

Having rejected the price/quality regressions as a basis for incorporating profitability and service quality considerations jointly, we move on to review available evidence on the businesses' residual rates of economic return as a basis for adjusting their allocation to broad C factor groupings taking profitability into account as well as comparative efficiency. This is equivalent to setting a 'glide path' where prices are adjusted over a period of several years to bring the business closer to a position of earning a normal return.

The overall C factor that a business is set, thus, consists of two components: a relative productivity–based component plus an additional component aimed at gradually eliminating excess profits or restoring normal returns, as the case may be.

1.2 Structure of the report

The following section of the draft report reviews the rationale for using productivity results in forming the parameters of CPI–X regulation, the strengths and weaknesses of using measures of past industry TFP performance and overseas experience with using TFP in utility regulation. Section 3 examines the available estimates of New Zealand's economy–wide TFP performance and of lines business TFP. Section 4 then reviews previous econometric and other analytical studies of the lines businesses while section 5 reviews a number of major measurement issues in analysing lines business performance. In section 6 we review the data used in the study and the limitations placed on the analysis by the available data.

In section 7 we present estimates of overall distribution industry TFP and separate transmission TFP estimates for Transpower. We also review input price changes for the electricity industry and the economy as a whole. Based on this information we then derive the implied B factors for distribution and transmission lines businesses. In section 8 we investigate the performance of the 29 distribution lines businesses existing in 2002. We use a range of quantitative techniques to rank the efficiency performance of the lines businesses. These include multilateral TFP indexes and econometric cost function estimation. We also investigate the role of service quality and price differences before allocating the distributors to one of three different C factor groupings. We then review data requirements for using a wider range of quantitative techniques in the next round of threshold setting and make recommendations for changes to the Disclosure Data process in section 9. Finally, conclusions are drawn in section 10.

2 THE USE OF PRODUCTIVITY IN THRESHOLD SETTING

The principal objective of CPI–X thresholds is to mimic the outcomes that would be achieved in a competitive market. Competitive markets normally have a number of desirable properties. The process of competition leads to industry output prices reflecting industry unit costs, including a normal rate of return on the market value of assets. Because no individual firm can influence industry unit costs, each firm has a strong incentive to maximise its productivity performance to achieve lower unit costs than the rest of the industry. This will allow it to keep the benefit of new, more efficient processes that it may develop until such times as they are generally adopted by the industry. This process leads to the industry operating as efficiently as possible at any point in time and the benefits of productivity improvements being passed on to consumers relatively quickly.

Because infrastructure industries such as the provision of the electricity network are often subject to decreasing costs, competition is normally limited and incentives to minimise costs and provide the cheapest and best possible quality service to users are not strong. The use of CPI–X thresholds in such industries attempts to strengthen these incentives by imposing similar pressures on the network operator to the process of competition. It does this by constraining the operator's output price to track the level of estimated efficient unit costs for that industry. The change in output prices is 'capped' as follows:

(1) $$\Delta P_O = \Delta P - X \pm Z$$

where Δ is the mathematical symbol for 'proportional change in', P_O is the maximum allowed output price, P is a price index taken to approximate changes in the industry's input prices, X is the estimated productivity change for the industry and Z represents relevant changes in external circumstances beyond managers' control which the regulator may wish to allow for. There are several alternative ways of choosing the index P to reflect industry input prices. Perhaps the best way of doing this is to use a specially constructed index which weights together the prices of inputs by their shares in industry costs. However, this price information is often not readily or objectively available, particularly in regulatory regimes that have yet to fully mature. A commonly used alternative is to choose a generally available price index such as the consumer price index or GDP deflator.

In choosing a productivity growth rate to base X on, it is important that the productivity growth rate be external to the individual firm being regulated and instead reflect industry trends at a national or even international level. This way the regulated firm is given an incentive to match (or better) this productivity growth rate while having minimal opportunity to 'game' the regulator by acting strategically. External factors beyond management control that the regulator may wish to allow for in the Z factor include changes in government policy such as community service obligations and tax treatment.

Drawing on Kaufmann and Lowry (1997), the framework that underlies the CPI–X approach can be illustrated as follows. The objective is to have the proportional change in industry revenue (R) tracking the proportional change in industry costs (C):

(2) $\Delta R = \Delta C.$

But mathematically the proportional change in revenue is approximately equal to the sum of the proportional changes in its component parts, prices (P) and quantities (Q):

(3) $\Delta R = \Delta P + \Delta Q.$

Rearranging (3) we have:

(4)
$$\begin{aligned} \Delta P &= \Delta R - \Delta Q \\ &= \Delta C - \Delta Q \quad \text{using (2) above;} \\ &= \Delta UC \end{aligned}$$

where UC is the industry's unit cost.

By using an analogous result for costs to that used above for revenue, we can rewrite the above using proportional changes in input prices (W) and input quantities (X):

(5)
$$\begin{aligned} \Delta UC &= (\Delta W + \Delta X) - \Delta Q \\ &= \Delta W - (\Delta Q - \Delta X) \\ &= \Delta W - \Delta TFP \end{aligned}$$

where ΔTFP is the industry's total factor productivity change, the difference between its proportional change in output and input quantities (the objective of productivity improvement being to produce a greater quantity of output from each unit of input).

The next issue to be considered in operationalising (5) is the choice of the price index to reflect changes in the industry's input prices, W. The most common choice for this index is the consumer price index (CPI). But this is actually an index of output prices for the economy rather than input prices. Normally we can expect the economy's input price growth to exceed its output price growth by the extent of economy–wide TFP growth (since labour and capital ultimately get the benefits from productivity growth):

(6) $\Delta W_E = \Delta CPI + \Delta TFP_E$

where the E subscript denotes the corresponding economy–wide variable.

We are now in a position to operationalise the CPI–X method to derive a price cap for the industry being regulated as follows:

(7) $$\begin{aligned}\Delta P_O &= \Delta W - \Delta TFP \\ &= \Delta CPI + \Delta TFP_E - \Delta TFP + [\Delta W - (\Delta CPI + \Delta TFP_E)] \\ &= \Delta CPI - [(\Delta TFP - \Delta TFP_E) - (\Delta W - \Delta W_E)] \\ &= \Delta CPI - X\end{aligned}$$

where $X = [(\Delta TFP - \Delta TFP_E) - (\Delta W - \Delta W_E)]$ and the variables without E subscripts refer to the relevant industry level variable for the regulated industry.

What equation (7) tells us is that the X factor can effectively be decomposed into two differential terms. The first differential term takes the difference between the industry's TFP growth and that for the economy as a whole while the second differential term takes the difference between the firm's input prices and those for the economy as whole. Thus, if the regulated industry has the same TFP growth as the economy as a whole and the same rate of input price increase as the economy as a whole then the X factor in this case is zero. If the regulated industry has a higher TFP growth than the economy then X is positive, all else equal, and the rate of allowed price increase for the industry will be less than the CPI. Conversely, if the regulated industry has a higher rate of input price increase than the economy as a whole then X will be negative, all else equal, and the rate of allowed price increase will be higher than the CPI.

In the New Zealand thresholds setting context, setting the B factor involves a similar process to that for setting the general X described above. It requires information on the differences between the industry and economy TFP trends and input price trends. However, given the differing operating environments of the New Zealand lines businesses and the fact that the industry is still evolving and likely to have a wide range of productivity performance levels, there is a strong case for supplementing the underlying B factor by a C factor which takes account of the circumstances of each business or groups of similar businesses. This concept is similar to the productivity 'stretch' factors used in many US regulatory decisions.

The productivity stretch factor approach has usually been adopted where industry wide data are used to determine the productivity growth rate and input price growth rate in determining the X factor for a number of firms in the industry. The productivity stretch factor is then used to tailor the regulatory regime to the circumstances of each particular firm. It distinguishes between productivity levels and productivity growth rates. Normally, firms which are at the forefront of industry performance have high productivity levels but low productivity growth rates. This is because they have removed almost all unnecessary slack from their operations and are only able to increase productivity at the rate of technological change for the industry.

Conversely, laggard firms normally have low productivity levels but are potentially capable of high productivity growth rates. This is because they can make some easy gains by removing the slack from their operations to mimic the operations of the industry's best performers. Consequently, they can achieve productivity growth far in excess of the rate of technological change for the industry for an interim period while they catch up to the productivity levels of the best performing firms. As a result of this catch up process, the best performing firms in the industry will, ironically, not be able to match the average productivity level growth rates for the industry (although they have superior productivity levels) while laggard firms will be able to outperform the industry average productivity growth rate.

In a regulatory context, if a firm is a long way from best practice (after allowing for operating environment and service quality differences) then a positive stretch factor may be applied to allow for the fact that the firm should be able to make some easy 'catch up' gains and exceed the average industry productivity growth rate. This ensures the firm's consumers receive some of those initial catch up benefits. In subsequent regulatory periods we would expect the firm to move closer to the average industry productivity performance and so the size of the productivity stretch factor would diminish. Conversely, for a firm that is already close to best practice, a negative stretch factor may be set to allow for the fact that this firm is unlikely to be able to match industry average productivity growth performance as it cannot make easy catch up gains and is instead only able to grow its productivity at the rate of technological change. In the long run, as competition and the regulatory framework drive all firms towards best practice, the industry average productivity growth rate will draw close to the rate of technological change in the industry.

Provided the stretch factor is set at the start of the regulatory period and not changed frequently, it is unlikely to have adverse incentive effects as the firm is unable to influence it within the regulatory period and still has a strong incentive to minimise costs and grow its business.

To operationalise equation (7) a few subtle measurement difficulties need to be recognised. The main difficulties are:

- The CPI is an index of after–tax commodity prices. It is the revenues actually received by the utility that are relevant for productivity analysis, ie before–tax prices.
- If a tax–adjusted CPI is chosen as the economy–wide output price index, then the corresponding input price index is not an index of primary input prices – it is equal to an index of primary input prices plus import prices less export prices less investment prices less a price index for deliveries to government.

- If a tax–adjusted CPI is chosen, it follows that the usual TFP index – consumption plus government purchases plus investment plus exports minus imports divided by labour plus capital – will not be the correct one. The correct TFP index in this case is consumption divided by (labour plus capital plus imports minus exports minus investment minus government purchases). The corresponding rate of TFP growth will be larger than the traditional one because the denominator will be smaller. This could lead to unfair comparisons with the target utility if the TFP measure for the utility is equal to gross output divided by labour plus capital plus intermediate inputs. In theory, however, this last difficulty should not be a problem if TFP and the net input price measure for the economy are measured correctly.

In practice, analysts use the standard economy–wide TFP and input price index measures to operationalise the CPI–X formula (7). Like all approximations, this process may involve some degree of error. Consequently, when translating standard productivity and input price index measures into implemented price caps or thresholds, it is appropriate to adopt a conservative approach to allow for potential approximation errors.

Equations (5) and (7) can alternatively be derived starting with the index number definition of TFP growth:

$$(8) \qquad \Delta TFP \equiv [Y^1/Y^0]/[X^1/X^0]$$
$$= \{[R^1/R^0]/[P^1/P^0]\}/\{[C^1/C^0]/[W^1/W^0]\}$$
$$= \{[M^1/M^0][W^1/W^0]\}/[P^1/P^0]$$

where R^t (C^t) is revenue (cost) in period t, M^t is the period t markup and $R^t = M^t C^t$. Thus, rearranging the above equation gives:

$$(9) \qquad P^1/P^0 = \{[M^1/M^0][W^1/W^0]\}/ \Delta TFP$$

where W^1/W^0 is the firm's input price index (which includes intermediate inputs). Equation (9) is approximately equal to:

$$(10) \qquad \Delta P = \Delta M + \Delta W - \Delta TFP.$$

This derivation produces equation (10) which is approximately equal to equation (5) but with the addition of a change in monopolistic markup term. Thus, if the regulator wants to keep the monopolistic markup constant (so that $\Delta M = 0$), then the admissible rate of output price increase ΔP is equal to the rate of increase of input prices ΔW less the rate of TFP growth. Similarly, this approach can be further extended to produce the equivalent of equation (7) but again with the additional change in monopolistic markup term. The markup growth term could be set equal to zero under normal circumstances but if the target firm was making an inadequate return on capital due to factors beyond its control, this term could be set equal to a positive number. On the other hand, if the target firm was making monopoly profits or excessive returns, then this term could be set negative. This effectively sets a 'glide path' to bring firms closer to earning a normal or average rate of return and is the theoretical basis for the C_2 component used in section 8 of the report.

2.1 Past productivity performance as a guide to the future

The rationale behind CPI–X threshold setting involves setting the B and C factors to reflect likely future productivity performance. However, we are only able to empirically observe past productivity performance and this is usually used as an indicator of possible future improvements by a process of extrapolation. The question then arises as to how reasonable a guide past productivity performance is likely to be for what will be achievable in the future.

There are two situations where past productivity performance may not be a good guide to future performance. The first of these is where there is a 'regime change' occurring in the form of regulation with the new regulatory regime offering more powerful incentives for the firm to improve performance. An example of this is the movement from traditional rate of return regulation or cost based regulation in the US to performance based regulation. In rate of return regulation firms have limited incentive to improve performance, as the benefits will be taken from them in the next annual review. With performance based regulation such as CPI–X price capping, firms have an incentive to outperform the targets set as they can keep the gains until at least the next regulatory reset and regulatory resets are usually several years apart. Changing from one regime to the other is likely to see a 'step' increase in productivity performance and this was the original rationale for using productivity stretch factors in the US. However, since New Zealand lines businesses have been subject to ongoing reforms for the past several years, it is less likely there would be a step increase in average productivity performance going forward to the new thresholds but rather a continuation of higher productivity growth rates.

The other situation where past performance may not be a good guide to future performance is where the industry as a whole nears feasible best practice. After more rapid, catch–up productivity growth, future growth may slow to the rate of technological change in the industry once most avenues for catch–up have been exploited. This would lead to feasible future productivity growth being less than past performance. Given that the New Zealand lines businesses have only recently acquired a separate identity and a more commercial focus, it is unlikely that many, if any, are sufficiently close to best practice that feasible future productivity growth will be significantly less than that achieved in the past.

Evidence from Australia where reform of the electricity industry has been underway since the early to mid 1980s also indicates that higher trend productivity growth rates have been sustained for long periods although this has been characterised by acceleration of TFP growth after the introduction of each round of reforms followed by a period of consolidation. Lawrence (2002) notes that 'this pattern of TFP moving in 'fits and starts' is common in infrastructure reform as the easy gains are made early on in the reform process and then productivity growth returns to a more 'normal' level until the next set of institutional roadblocks are removed'. As the New Zealand electricity reform process has generally been underway for a shorter period than corresponding reforms in Australia, it is likely that the 'catch–up' period of achieving higher trend productivity growth rates still has some time to run.

The alternative to using observed past productivity performance as a guide to future performance is to undertake engineering studies of the scope for future improvements. However, these studies face asymmetric information problems, may be relatively subjective between different assessors and are not as readily replicable or transparent as studies based on past performance.

Given these considerations it is our view that quantifying recent past productivity performance provides the best way of estimating likely future productivity performance for use in setting the thresholds.

2.2 TFP indexes as a means of calculating productivity

TFP indexes have been the most common technique used to derive estimates of past economy–wide and industry level productivity performance. A TFP index is generally defined as the ratio of an index of output growth divided by an index of input growth. Growth rates for individual outputs and inputs are weighted together using revenue and cost shares, respectively. In other words, the TFP index is essentially a weighted average of changes in output quantities relative to a weighted average of changes in input quantities. This is necessary because most economies have a diverse range of outputs (agricultural products, manufactures, services and exports) and an equally diverse range of inputs (eg labour, capital, land, inventories and natural resources). Calculating TFP requires a means of adding together these diverse output and input quantities into measures of total output and total input quantity. The different types of outputs and inputs cannot be simply added (eg it is not meaningful to add the number of employees to the number of petajoules of energy consumed). Changes in the TFP index tell us how the amount of total output that can be produced from a unit of total input has changed over time.

TFP indexes are a relatively simple and robust technique that have an interpretation consistent with the normal operation of competitive forces when used in setting X factors. They can be formed from a small number of observations whereas econometric cost and profit functions, on the other hand, require much longer time series to allow sufficient degrees of freedom to facilitate estimation. TFP indexes also provide maximum detail on year–to–year changes in performance but allow the flexibility to form smoothed trend rates of change over time.

The main advantage of the index number approach to the measurement of TFP is its reproducibility, ie different investigators will obtain the same productivity estimates (provided that they use the same data and use a 'superlative' or flexible index number formula to aggregate up the data). On the other hand, econometric estimates of TFP change will be much more open to challenge. Different econometricians will choose different functional forms for the production function or the dual unit profit function or the dual unit cost function; different econometricians will choose different break points for splines (differential time trend variables) and different econometricians will choose alternative stochastic specifications and methods of estimation. These differences will lead to different estimates of TFP.

TFP indexes have a rigorous grounding in economic theory. As noted in Diewert and Lawrence (1999), the two most commonly used approaches to the problem of finding the 'best' functional forms for the TFP index are the economic and the axiomatic approaches. The economic approach selects index number formulations on the basis of an assumed underlying production function and assuming price taking, profit maximising behaviour on the part of producers. For example, the Törnqvist index used extensively in past TFP studies can be derived assuming the underlying production function has the translog form (a flexible function with good ability to approximate production relationships) and assuming producers are price taking revenue maximisers and price taking cost minimisers.

The axiomatic approach to the selection of an appropriate index formulation specifies a number of desirable properties an index formulation should possess. Potential indexes are then evaluated against the specified properties and the index that passes the most tests would be preferred for the analysis. The tests used to evaluate the alternate indexes include:

- the constant quantities test: if quantities are the same in two periods, then the output index should be the same in both periods irrespective of the price of the goods in both periods;
- the constant basket test: if prices are constant over two periods, then the level of output in period 1 compared to period 0 is equal to the value of output in period 1 divided by the value of output in period 0;
- the proportional increase in outputs test: if all outputs in period t are multiplied by a common factor, λ, then the output index in period t compared to period 0 should increase by λ also; and
- the time reversal test: if the prices and quantities in period 0 and t are interchanged, then

the resulting output index should be the reciprocal of the original index.

When evaluated against the tests listed above, only the Fisher index method passes all four tests. The older Laspeyres and Paasche indexes which use constant weights fail the time reversal test while the Törnqvist index fails the constant basket test. On the basis of these tests the Fisher index is now the index of choice for time series TFP work although, in practice, the Törnqvist index can also be used as it closely approximates the Fisher index.

If applied properly, TFP indexes place a discipline on the analyst to ensure that the data used balances, ie that price times quantity equals the dollar value for each output and input and the sum of input costs equals total cost and the sum of output revenues equals total revenue. This discipline is absent with other techniques such as data envelopment analysis. TFP indexes are also more easily communicated to industry participants than most other techniques and appear as less of a 'black box'.

Like any quantitative method, TFP indexes have limitations as well as advantages. These include the fact that they are a non–parametric technique and, hence, cannot produce confidence intervals and other statistical information, the need to aggregate heterogeneous outputs and inputs and the need to estimate the annual physical input and cost of capital goods.

Aggregation is an inevitable part of making any modelling exercise tractable and TFP indexes provide a consistent framework within which this can be done. Also, to make sure that businesses' decisions are being accurately modelled it is necessary to calculate the annual physical input and cost of capital as these key input variables are a fundamental component of producers' decision–making processes, particularly in a capital intensive network industry.

While statistical methods provide useful information, they are best suited to larger data sets where the data errors and inconsistencies have largely been eliminated. In the early stages of developing regulatory databases and frameworks, particularly where there are a limited number of observations available, there is a strong case for using a non–parametric technique that enables the ready identification of likely data problems while not distorting the results for other observations. Plotting TFP index results provides a ready way of identifying unexpected results that may be less easy to identify in econometric approaches. Where only a limited number of observations are available the use of statistical methods may be problematic or limited to restrictive functional forms.

2.3 Overseas experience with using TFP in regulation

TFP analysis has been used extensively in the setting of price path parameters in the USA, Canada, the UK and Australia. In most cases TFP has been used to inform discretionary price cap decisions rather than forming the basis for mechanistic price caps. A selection of representative case studies of international experience in using TFP for regulatory purposes is reviewed in this section.

2.3.1 United States of America

The USA has made widespread use of TFP analysis in CPI–X 'performance based' regulation. TFP has been used as an input to setting X factors in the rail, telecommunications and electricity distribution industries.

Rail

The case for including TFP considerations in the setting of the maximum rail freight rates was first put to the Interstate Commerce Commission (ICC) in 1981. Initially the ICC rejected using an industry–wide productivity factor citing unstable earning levels in the industry and the risk that an inappropriate productivity factor would reduce incentives. This decision launched seven years of debate and analysis of the applicability of TFP measurement to the rail industry. This debate included a recommendation to utilise a five year moving average of TFP as the basis for the X factor culminating in the ICC's 1989 determination that it was fair and reasonable for the price cap to reflect rail industry TFP and that the industry was then mature enough to have moved past its period of financial uncertainty.

The moving average industry–wide factor was chosen in order to smooth out year–to–year fluctuations and to provide strong performance incentives for each firm. This very light–handed regulatory stance has, in effect, no end to the regulatory period and the regulator does not examine the earnings performance of individual firms. The ICC's decision to use an industry–wide TFP measure was justified because each firm's returns would directly reflect its TFP performance relative to the industry average.

Telecommunications

TFP based performance regulation of telecommunication has a relatively long history in the United States. In approving the AT&T price plan in 1989 the Federal Communications Commission analysed industry–wide TFP estimates extensively and the subsequent plans reflect both a productivity factor and a consumer productivity dividend. In the market for interstate services by local exchange carriers price caps have been the form of regulation and the use of industry–wide TFP measurement is mandatory.

Electricity Distribution

The regulation of electricity distribution businesses in the US is undertaken by state Public Utility Commissions. Performance based regulation has been adopted by a number of states as an alternative to the long established cost of service regulation and TFP studies have been used in a number of these states as input to setting the X factor. The data used in these studies is generally sourced from data all US distribution companies provide to the Federal Energy Regulatory Commission. While the data are mostly accepted by all parties as being accurate at a firm level, there remains significant debate regarding the use of a nation–wide sample to calculate TFP given the variance in company structures and operating conditions.

The first CPI–X regulation plans for power distributors were in California. Southern California Edison Company conducted a TFP study of their business and submitted to the Californian Public Utilities Commission that their long run TFP growth trend was 0.9 per cent per annum. The Commission accepted this figure and set an X factor containing this productivity growth trend and a factor accounting for customer dividends rising from 0.3 to 0.7 per cent per annum over the regulatory period. While the Commission accepted the distributor's estimate, it noted that industry–wide TFP measurement would have been preferred to allow the regulation to more closely mimic an unregulated market.

Industry–wide TFP was subsequently used as the basis for regulating the San Diego Gas and Electric Company in a 1994 decision. The company commissioned studies of industry TFP trends and found that power distribution TFP was increasing at 0.92 per cent per annum. The Utilities Commission accepted this evidence and added an average consumer dividend of 0.55 per cent per annum.

2.3.2 Canada – Ontario

Electricity reform in Canada, as in the United States, has occurred at different paces in the different provinces. Ontario has led the way in utilising TFP studies in setting price caps in electricity distribution as well as other regulated industries.

The Ontario Energy Board (1999) undertook an electricity distribution TFP study prior to its first performance based regulation determination in 2000. The study found an average annual change in TFP across Ontario distribution utilities over the period 1988 to 1997 of 0.86 per cent with a median of 1.14 per cent. For the most recent five year period (1993 to 1997), the average annual change in TFP was 2.05 per cent, with a median of 1.97 per cent.

The Board took this analysis into account in making its decision but determined that, given the need for simplicity and the fact that distribution utilities required time to ease themselves into performance based regulation, it was most appropriate to specify a single productivity factor of 1.5 per cent for the first period of price regulation.

At the federal level in Canada, the Canadian Radio–Television and Communications Commission (1997) in developing the price cap plan for the Sentor telecommunication companies referred to the American experience with TFP based regulation. They noted the US approach was particularly strong in its ability to replicate the competitive market. In the Sentor price cap plan the Commission also noted the benefits of using data that was independent of the actions of one company when setting the X factor. The Commission further observed that the use of an industry wide X factor provided superior incentives and rewards for productivity gains.

2.3.3 United Kingdom

The UK began performance based regulation in the early 1990s using an RPI–X approach. In the first regulatory period different X factors were established for each distributor ranging from 0 per cent to –2.5 per cent. This led to favourable conditions for the companies and resulted in high levels of profitability. The price control regime was tightened considerably in the second determination of 1995.

In the 1995 review, the regulator used benchmarking studies in conjunction with assessment of best practice operations to estimate the efficient level of the distributors' capital and operation costs for the next period while allowing for operating conditions beyond management control. The outcome of this analysis was a common X factor of 2 per cent for the industry and reductions in the distribution price cap in the first year of between 11 and 17 per cent (OFFER 1995).

In a recent report Britain's National Audit Office (NAO 2002) undertook a review of performance–based regulation. The NAO concluded that, overall, RPI–X regulation had delivered significant benefits to consumers and noted that electricity prices had fallen on average by 24 percent in 2000–01. The NAO also found that power supply interruptions had been reduced. The report also noted some problems with RPI–X regulation creating incentives for firms to reduce costs declines towards the end of the regulatory period and the potential for biases in the treatment of operation and capital expenditure.

2.3.4 Australia

Indexing approaches have been utilised in the regulation of electricity distribution in most Australian states. In the case of Victoria, distribution related charges have been subject to CPI–X caps set using the 'building block' approach since 1995. In this approach the X factor is selected to ensure that the expected revenue over the regulated period covers each company's expected costs including a return on the depreciated optimised replacement cost of assets plus expected net investment, current cost accounting depreciation expenses and operation and maintenance costs. The overall cost expectations included expected productivity gains for each distributor leading to different X factors across firms. The expected productivity gains were largely determined using engineering analyses. In the most recent regulatory period the scheme was expanded to include an earnings sharing mechanism to counter the disincentive for firms to make productivity improvements towards the end of the regulatory period and a service quality incentive scheme to counter the incentive for firms to achieve productivity improvements by reducing service quality.

In 1999 the Independent Pricing and Regulatory Tribunal of New South Wales commissioned London Economics (1999) to assess the efficiency performance of the NSW distributors to inform its pricing determination. This study used a range of techniques including data envelopment analysis, stochastic frontier analysis and TFP indexes to compare the NSW distributors' efficiency with that of a sample of international distributors. The study found that the NSW distributors would have to reduce their input use by between 13 and 41 per cent to achieve best practice given comparable operating environments. Subsequent review of the study by the distributors found a number of data and measurement errors (Lawrence 1999).

In its 2000 electricity distribution price determination the Queensland Competition Authority used TFP index studies by Tasman Asia Pacific (2000a,b) and cost function studies by Pacific Economic Group (2000a,b) to inform its decision.

3 PAST TOTAL FACTOR PRODUCTIVITY STUDIES

As outlined in section 2, to form an estimate of the B factor we need estimates of the recent productivity performance of the economy as a whole and of lines businesses as a whole. We also need corresponding estimates of trend changes in input prices. In this section we review previous studies of New Zealand's economy–wide TFP performance and of the electricity supply industry. While some of these studies do not provide the exact TFP specification required by the fully specified CPI–X framework, they provide the basis for making informed decisions on the magnitude of the B factor.

3.1 Economy–wide TFP studies

Early New Zealand TFP studies

There were around a dozen studies of New Zealand's productivity and growth performance undertaken during the 1990s culminating in the detailed report by Diewert and Lawrence (1999). This interest in New Zealand's productivity performance was driven in part by the view that New Zealand had undertaken more radical economic reforms than other western countries during the mid to late 1980s and early 1990s. Diewert and Lawrence provide a detailed review of the earlier studies and Mawson, Carlaw and McLellan (2003) provide a brief review of earlier New Zealand TFP studies.

Most of the earlier studies used the standard Solow (1957) growth accounting approach to estimating productivity growth. In the growth accounting approach TFP is computed as a residual – the residual that results from separately evaluating the contributions of specified factors to output growth and then subtracting these measured contributions from the total growth of output. However, this method is based on the use of the relatively inflexible Cobb–Douglas (1928) production function and, hence, the results obtained with this methodology must be viewed with caution. Because of this and the earlier time period covered by these studies we will only briefly review a selection of their results.

Philpott (1995) used the Solow growth accounting method to examine New Zealand's performance between 1985 and 1994 and obtained a TFP growth rate of 1.5 per cent per annum for this period. Janssen (1996) used a similar methodology and obtained TFP growth rates of 0.9 per cent per annum for the longer period 1956 to 1996 and of 1.3 per cent per annum for the shorter period 1991 to 1996. Hall (1996) looked at peak–to–peak TFP growth rates and found a growth rate of 1.2 per cent per annum for the period 1978 to 1985 but only 0.4 per cent per annum for the period 1985 to 1993. The time periods examined by most of these studies finished before the period of more rapid economic growth observed in New Zealand in the second half of the 1990s.

One of the more unusual New Zealand TFP studies from the 1990s was that of Färe, Grosskopf and Margaritis (1996) who used the linear programming based Malmquist index and data for 20 New Zealand industries for the period 1972 to 1994. Diewert and Lawrence raise a number of interpretational issues with the approach used in this study and also question the way the overall productivity growth rate is reported. Färe, Grosskopf and Margaritis report the unweighted mean of their TFP indexes over 20 industries. However, taking an average of the industry TFP growth rates weighted by their average GDP shares for the period 1978 and 1997 produces a growth rate of only 0.4 per cent instead of the reported 1.46 per cent.

Diewert and Lawrence (1999)

In 1998 The Treasury, the Reserve Bank of New Zealand and the Department of Labour commissioned Diewert and Lawrence to review New Zealand's recent TFP performance. This work culminated in the 1999 Treasury Working Paper looking at the productivity performance of the New Zealand economy up to 1998. The report contains two sets of economy–wide TFP estimates – one using an 'official' database supplied by Treasury and another using the Diewert–Lawrence database constructed from a wider range of sources – plus sectoral TFP estimates derived from the official database.

Diewert and Lawrence's results for the New Zealand economy are summarised in table 1. For the 20 year period 1978 to 1998 the trend rates of TFP growth obtained were 1.26 per cent per annum for the Diewert–Lawrence database and 1.09 per cent per annum for the official database. For the more recent period 1993 to 1998 the trend TFP growth rates were around 1.5 per cent per annum for both databases. However, this more recent period covered the start of more rapid TFP growth that may not have been sustained subsequently.

Diewert and Lawrence also undertook extensive sensitivity analyses of alternative input and output specifications and data sources. New Zealand labour data was found to be unexpectedly variable between different official sources. The Diewert–Lawrence database used a combination of OECD data on labour numbers and Statistics New Zealand Census data on hours worked by occupation that produced the expected result of declining average hours per person over time. However, switching to the Statistics New Zealand Household Labour Force Survey (HLFS) data produced the counterintuitive result of increasing average hours per person and subsequently lower productivity growth. A range of output and capital specification options were also tried using the official database which produced trend TFP growth rate estimates ranging from 0.6 to 1.3 per cent per annum for the 20 year period to 1998 and from 1.5 to 1.6 per cent per annum for the 5 year period to 1998.

National Accounts based productivity estimates are often biased downwards because of outdated conventions used in the measurement of output in some service sectors where output is hard to measure. As a result some statistical agencies, including the Australian Bureau of Statistics (ABS), exclude the Finance and Community Services sectors from their official estimates. Diewert and Lawrence produced an 'ABS equivalent' estimate from the official database which showed stronger TFP growth trends of 1.56 per cent per annum for the 20 year period to 1998 and 2.38 per cent per annum for the 5 year period to 1998. The latter period was one of above longer–term trend growth rates and this growth rate is unlikely to have been sustained subsequently.

Table 1: **Diewert and Lawrence trend TFP growth rates (per cent per annum)**

	1972–84	*1978–84*	*1984–93*	*1993–98*	*1972–98*	*1978–98*
Diewert–Lawrence Database						
Diewert–Lawrence Preferred	–0.35	1.80	0.07	1.47	0.81	1.26
Diewert–Lawrence with HLFS Hours	–1.19	1.18	–0.15	1.17	0.36	0.95
Official Database						
Preferred Base Case		1.19	0.76	1.46		1.09
Highest Estimate		1.28	1.00	1.48		1.25
Lowest Estimate		0.34	0.14	1.63		0.58
'ABS Equivalent' for NZ		1.12	1.35	2.38		1.56

Source: Diewert and Lawrence (1999)

The Diewert and Lawrence report was the most comprehensive study of New Zealand's productivity undertaken up to 1999 and the extensive sensitivity analyses undertaken mean that considerable confidence can be placed in the preferred estimates from that study. The major development since the report was done has been the release of official capital stock estimates by Statistics New Zealand. These capital stock estimates should, in principle, be more robust than the estimates used by Diewert and Lawrence and are consistent with the approach now used by the ABS and a number of other statistical agencies. Statistics New Zealand has also made other improvements to its data over the last few years including the introduction of chained volume indexes for outputs. Some more recent studies have used these new data series.

International Monetary Fund (2002)

In February 2002 the International Monetary Fund produced a report on selected issues in the New Zealand economy as part of its 2002 Article IV Consultation with New Zealand (IMF 2002). Chapter 1 of this report deals with comparative productivity performance between New Zealand and Australia and explores reasons for the apparent divergence in performance.

The IMF study uses a relatively standard application of the Solow growth accounting framework extended to include changes in human capital and intercountry comparisons. While the main focus of the paper is on intercountry comparisons between New Zealand and

Australia, estimates of New Zealand's trend rate of productivity change for the period 1988 to 2000 can be derived from the database used in the study. The database is based on Statistics New Zealand's new chain volume output series and new capital stock estimates.

The trend rate of TFP growth for New Zealand obtained from the IMF study's database is 1.11 per cent per annum.

Shapiro (2003)

In recent work for the Reserve Bank of New Zealand, Shapiro (2003) has used The Treasury's update of the Diewert and Lawrence official database using the new Statistics New Zealand chain volume indexes and capital stocks to compare New Zealand's productivity performance to that of the US. Shapiro uses the traditional Solow growth accounting model although few details are given of either the methodology or data used. If, as appears to be the case, the study uses the traditional Cobb–Douglas functional form then some reservations have to be placed on the robustness of the results.

Shapiro presents TFP growth rate results for three different periods from 1992 onwards. For the decade from 1992 to 2002 Shapiro finds a trend TFP growth rate of 1.1 per cent per annum. For the period from 1992 to 1995 he finds a higher TFP growth rate of 1.5 per cent per annum but this falls to 0.8 per cent per annum for the period from 1996 to 2002.

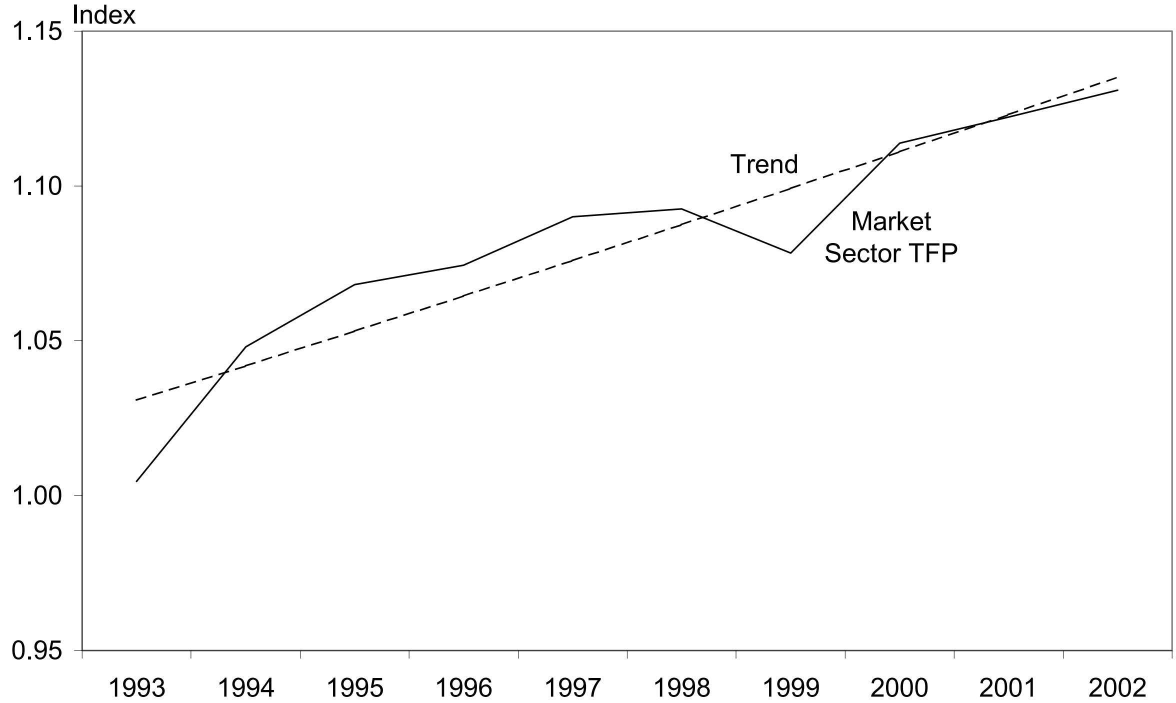
Black, Guy and McLellan (2003)

The Treasury has recently released a staff working paper updating the work of Diewert and Lawrence to 2002 (Black, Guy and McLellan 2003). As well as adding an extra four years to the time series, the paper incorporates Statistics New Zealand's new chain volume indexes and capital stock estimates. While some refinements remain to be made to the database used, the TFP estimates contained in this paper are the most recent available for New Zealand. One refinement remaining to be made is using annual user costs to weight the capital stock components together instead of simply adding up the constant dollar quantities. Some of the sectoral results presented in the paper also appear counterintuitive and warrant further investigation. Despite these outstanding refinements, the estimates presented are likely to be relatively robust.

The economy–wide TFP estimates presented are close to the official database estimates of Diewert and Lawrence for the overlapping period, 1988 to 1998. Capital productivity estimates diverge somewhat towards the end of this period reflecting the different sources of capital data used. The Treasury paper undertakes some of the same sensitivity analyses reported in Diewert and Lawrence with similar results.

Calculation of an 'ABS equivalent' TFP series excluding hard to measure service sectors again boosts New Zealand's observed TFP performance somewhat and leads to a similar pattern of productivity change to that reported by the ABS for Australia over this period.

Figure 1: **Treasury market sector TFP and trend, 1993 to 2002**



While there appear to be some inconsistencies in the TFP growth rates reported in the Treasury paper, calculation of the trend rate growth rate for the last decade, from 1993 to 2002, from the TFP index values reported yields a figure of 1.1 per cent per annum. This trend is plotted against the actual reported TFP series in figure 1.

The trend appears to be an accurate representation of economy–wide TFP performance over this period. The steep increase in TFP between 1993 and 1994 is discounted as a more steady increase between 1994 and 1998 takes place. The drop in TFP in 1999 associated with the 'Asian crisis' and the steep recovery in 2000 do not affect the trend and the increases observed in the last two years are very much in line with the trend. It appears, therefore, that a trend TFP increase of 1.1 per cent per annum for the economy as a whole is the most appropriate figure to use as input to determining the B factor. This is also consistent with the results of the IMF and Shapiro using the new data and with the longer term rates in Diewert and Lawrence.

3.2 Lines business–related TFP studies

There has been little direct estimation of the TFP performance of New Zealand lines businesses undertaken previously. The main TFP estimates relevant to lines businesses are sectoral estimates derived by Diewert and Lawrence (1999) and Black, Guy and McLellan (2003) for the electricity, gas and water sector. These estimates are derived from relatively high level National Accounts data and due to the difficulty of accurately identifying flows of intermediate goods in the economy are far less robust than the corresponding economy–wide level measures. This sectoral level work is at best a very rough guide to the performance of lines businesses given the range of other activities included quite apart from likely data problems. In this section we review the two major sectoral TFP studies. We supplement the limited information available on New Zealand by examining electricity industry TFP studies that have been done in comparable countries such as Australia, Canada, the US and the UK as a check on figures obtained from the higher level sectoral TFP series.

Diewert and Lawrence (1999) sectoral results

Diewert and Lawrence (1999) presented individual TFP indexes for each of the 20 market sectors included in their official database. The sectoral level TFP indexes were formed using production GDP, a composite labour series and net capital stocks using length of life assumptions from Philpott (1992). The real rate of return was calculated separately for each sector to ensure the value of the sector's inputs equalled its value of output.

Lines businesses fall within the electricity, gas and water sector in the National Accounts. Separate information is not available on the electricity supply industry, let alone lines businesses from this source. Diewert and Lawrence found a relatively high TFP growth rate in the electricity, gas and water sector of 3.5 per cent per annum for the 20 year period to 1998. For the more recent period from 1986 to 1998 the TFP growth rate was even higher at 4.1 per cent per annum. Diewert and Lawrence attributed these high TFP growth rates to New Zealand's reform of its electricity, gas and water industries with corporatisation of electricity followed by vertical and horizontal disaggregation and some introduction of competition. Privatisation and deregulation of gas utilities also occurred in the late 1980s and corporatisation and tendering out requirements affected water supply operations.

Diewert and Lawrence cautioned against placing much weight on the sectoral productivity results presented compared to the aggregate market sector results, particularly those obtained from the real GDP final demand expenditures approach. The reasons for this relate to inherent weaknesses in the sectoral data.

In principle, using sectoral value added as the output concept is satisfactory provided double deflation of gross outputs and intermediate inputs is used with a superlative (flexible) indexing formula. This involves using a superlative index number formula to simultaneously aggregate over gross output components and intermediate input components. The quantity of each intermediate input component (including imports) is indexed with a *negative* sign; all other prices and quantities are positive. An alternative procedure would be to separately construct quantity indexes of outputs and intermediate inputs (this is the first stage of aggregation) and then aggregate the first stage aggregates using the same index number formula (the aggregate intermediate input is indexed with a negative sign).

However, the problem is that it is very difficult to get accurate information on:

- the prices of some sectoral gross outputs in the service sector; and
- the prices and quantities of intermediate inputs in all sectors except perhaps some manufacturing sectors.

Diewert and Lawrence included the following quote from Statistics New Zealand (1996, p.23) that indicates that there is little accurate information on the value *flows* of intermediate inputs let alone accurate price or quantity deflators for them:

> "Double deflation, however, is not suitable to all practical situations. It demands a high level of reliability in the current price production accounts and in the price and quantity data used for deflation. In those situations where the data may not meet the required standard, the technique introduces the possibility of numerous and compounding measurement errors. For example, in those industries where the value added is the difference between two relatively large flows subject to measurement error, value added in constant prices derived by double deflation may fluctuate widely over time because of the cumulative effect of the errors. … Until recently the data required for double deflation has not been widely available in New Zealand. The Producers Price Index, although covering most of the economy, has not been available at a sufficient level of detail, especially for inputs. Similarly, there are only limited cases where input volume data is available."

While both Statistics New Zealand and the ABS are making progress on improving information on interindustry flows of intermediates, estimates relying on this data need to be interpreted with a considerable degree of caution.

Particular problems are likely to arise with the interindustry flows of new inputs and new ways of organising production such as the use of business services and leased capital where information will be poor. Also, under present national accounts conventions, leased capital resides in the sector of ownership, which is generally the finance sector, not the sector using the capital.

Other problems with using sectoral data include the impact of changes in the industrial classification of a firm (something that is likely to be more of a problem with ongoing industry restructuring and technological change), the use of different survey instruments to collect different variables with scope for inconsistencies in coverage and the scope for differences in coverage and classification across countries.

At the level of the entire market economy, intermediate inputs collapse down to just imports plus purchases of government and other nonmarket inputs. This simplification of the complex web of interindustry transactions of goods and services explains why the real GDP final demand expenditures approach to measuring aggregate output is likely to be more accurate than the GDP real value added industry approach.

Black, Guy and McLellan (2003) sectoral results

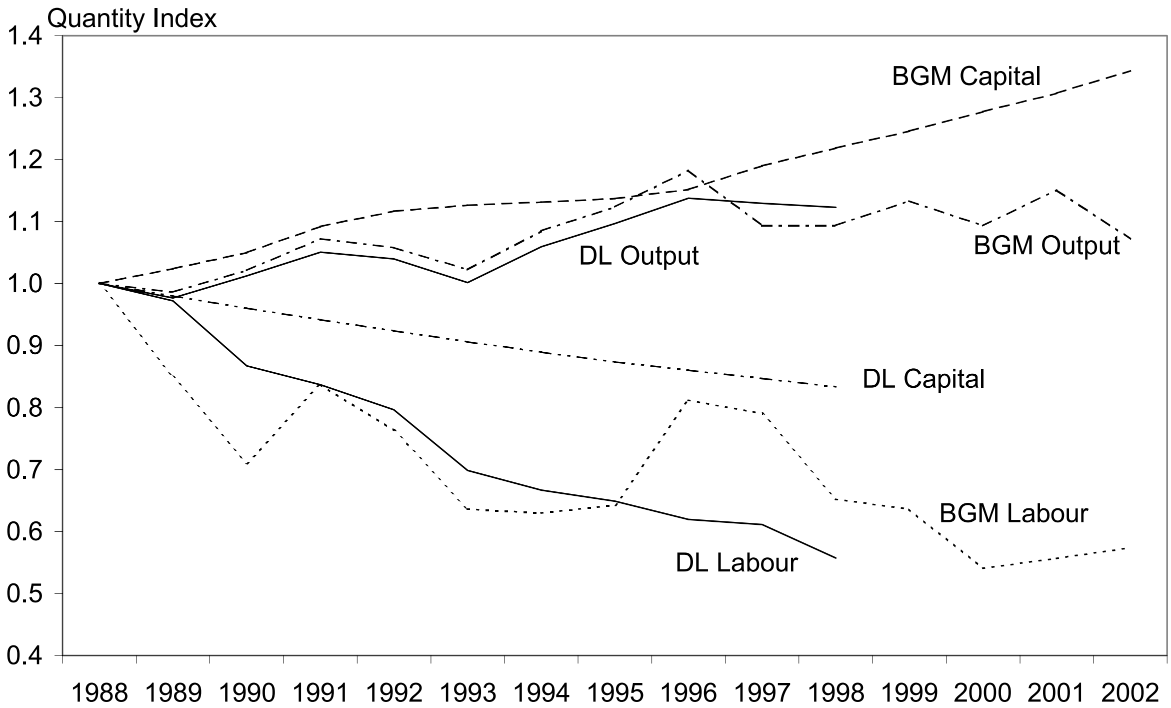
The recent update of Diewert and Lawrence by Black, Guy and McLellan (2003) includes a reduced number of sectoral results due to industrial classification changes. However, the electricity, gas and water sector is one of the 9 sectors reported.

Black, Guy and McLellan report the implausible result that the electricity, gas and water sector's TFP has actually *reduced* at a trend rate of 0.21 per cent per annum between 1988 and 2002. The sector's TFP is reported as having increased at a trend rate of 1.11 per cent per annum between 1988 and 1993 before *decreasing* at a trend rate of 0.93 per cent per annum between 1993 and 2002. This result appears most unlikely given the reforms that have occurred in these key infrastructure industries and warrants further investigation.

In figure 2 we compare the electricity, gas and water (EGW) sector output, labour and capital quantity indexes from Diewert and Lawrence and Black, Guy and McLellan (BGM) from 1988 onwards. The two output quantity indexes follow a similar pattern up to the end of the Diewert and Lawrence time series in 1998. Surprisingly, the sector's output quantity has remained relatively flat since 1996. More discrepancies emerge in the respective input indexes. The BGM labour quantity index follows a roughly similar pattern to that of Diewert and Lawrence but exhibits much more volatility. Whereas the Diewert and Lawrence labour quantity declines gradually over the period and is consistent with what one would expect from an ongoing reform process, the BGM labour quantity index displays implausible increases in 1991 and 1996.

Much greater discrepancies emerge, however, in the capital quantity index series. Whereas Diewert and Lawrence found a steady but modest decline in the quantity of capital employed in this sector between 1988 and 1998, BGM find a steady and more rapid increase in the quantity of capital over the whole period from 1988 to 2002. The BGM result appears at odds with what would normally be expected in an infrastructure sector during a period of ongoing major reform where the emphasis is on cost–cutting and the removal or erosion of 'gold plating' which may have occurred under earlier periods of government ownership with different incentives. The continuing strong growth in the capital quantity index after 1996 when output flattens out is particularly difficult to explain. Electricity industry TFP studies from Australia show continuing strong improvements in the partial productivity of capital whereas the BGM result implies declining capital productivity for the New Zealand EGW sector. Part of the recent EGW sector result presented by BGM could also be driven by increasing investment in water supply capacity and wastewater infrastructure which would not be reflective of electricity industry performance.

Figure 2: **Diewert and Lawrence and Treasury EGW sector quantity indexes**

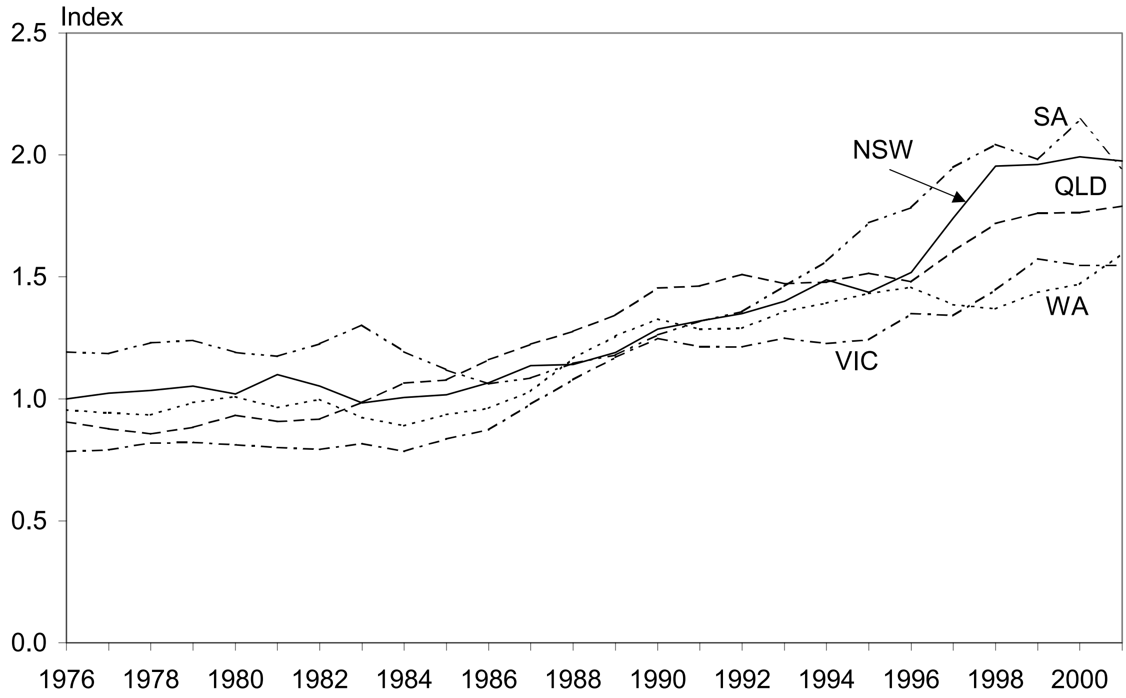


In light of the implausible sectoral TFP growth result obtained by BGM driven by a questionable capital quantity index, we place more emphasis on the sectoral result from Diewert and Lawrence as providing a reasonable high level indicator of likely TFP growth in the lines businesses.

Australian electricity supply TFP studies

TFP measurement for the electricity supply industry has a much longer history in Australia with several major studies having been undertaken since 1991. The pioneering electricity industry TFP study in Australia was that of Lawrence, Swan and Zeitsch (1991). This was subsequently updated in Bureau of Industry Economics (1996) and, most recently, in Lawrence (2002). These studies looked at the TFP performance of each of the five mainland state electricity supply systems. They examined the combined performance of generation, transmission, distribution and retail within each state using consistent data that were collected and reported over a long period by the Electricity Supply Association of Australia (ESAA). The most recent study also drew on ABS data to supplement gaps in the ESAA data from 1993 onwards.

Figure 3: **Australian state electricity industry multilateral TFP indexes, 1976–2001**



Source: Lawrence (2002)

Lawrence (2002) covers the 26 year period from 1976 to 2001. The industry's total output is measured by the gigawatt hours of electricity consumed, which increased steadily over the entire period. Input use is measured as an aggregate of four broad input categories: labour, capital, fuel, and materials and services. TFP increased at a trend annual rate of 3 per cent for the entire period and at a trend rate of 3.3 per cent per annum since 1990. After remaining almost flat for the decade from 1976 as outputs and inputs moved in unison, it increased rapidly during the second half of the 1980s as reforms started to be implemented in the lead–up to corporatisation. The rate of TFP growth then slowed markedly during the first half of the 1990s before again growing strongly between 1995 and 1998 with the move to privatisation in some states and the introduction of a national electricity market. Multilateral TFP indexes for the individual state systems are presented in figure 3. Multilateral TFP indexes provide information of TFP levels as well as growth rates whereas the indexes discussed earlier only provide information on TFP growth rates.

Australian electricity industry labour productivity has increased rapidly since the mid–1980s, growing at a trend annual rate of 7.5 per cent over the 26 years and an even higher 9.5 per cent since 1990. Capital productivity has also grown relatively strongly in this capital–intensive industry with a trend annual increase of 3 per cent. Materials and services partial productivity has fluctuated but grown at a trend annual rate of 1.5 per cent reflecting a substitution between in–house labour and contracting out of a wider range of activities.

London Economics (1993) undertook a TFP study of the Australian state electricity supply systems using a similar approach and data to that used by Lawrence, Swan and Zeitsch (1991). They found that TFP had increased at a trend annual rate of 3.1 per cent for the system as a whole for the nine years up to 1991. Transmission and distribution TFP were found to have increased at 5.1 and 3.7 per cent per annum, respectively. This was more rapid than generation's trend annual increase of 2.9 per cent for the same period.

London Economics (1999) calculated TFP changes for the New South Wales distributors using very limited data for the three years to 1997 using the DEA–based Malmquist index method. They found average annual TFP changes ranging from 1.4 per cent for Integral Energy to 4.1 per cent for NorthPower.

Denis Lawrence has undertaken a series of TFP studies of Australian distributors including Tasman Asia Pacific (2000a,b). While this detailed database now contains 11 of the 16 Australian distributors, the focus to date has been on cross sectional rather than time series comparisons so no TFP growth rates have been derived.

Electricity supply TFP studies from the US, Canada and the UK

Kaufmann and Lowry (1999) estimated the TFP of the US electricity distribution industry using an index number approach for the period from 1985 to 1996. The sample included 124 businesses and data was assembled from detailed Federal Energy Regulatory Commission returns and information provided by the US Department of Commerce and Whitman, Requardt, and Associates.

Kaufmann and Lowry's outputs included the number of customers served, peak demands and volumes delivered to different customer groups. As revenue information on the different output components is not available for weighting purposes, Kaufmann and Lowry relied on an econometric approach to weighting where each output's cost elasticity was divided by the sum of all output–related cost elasticities to determine weights for the output quantity index.

The results suggest that TFP for the US distribution industry grew at a rate of 0.9 per cent per annum for the decade to 1996. This was almost 3 times the rate of TFP growth found for the US economy over the same period. The lower TFP growth rate for the US industry probably reflects its relative maturity and is consistent with earlier studies such as BIE (1996).

Cronin, King and Colleran (1999) calculated TFP for electricity distributors in Ontario for the Ontario Energy Board. They analysed 40 utilities (12 large, 15 medium and 13 small) to calculate TFP growth for the period 1988 to 1997. This study used capital, labour, materials, and line losses as inputs weighted by total cost attributable to each. The output measures used were a weighted average of customer numbers by class and kWh by class with quantity indexes weighted by their contribution to revenue.

The study found that the average growth in distribution TFP from 1988 to 1997 was 0.9 per cent per annum. However, for the more recent period 1993–97 the industry's annual TFP growth increased significantly rising to 2.1 per cent.

London Economics (1999) estimated the TFP of the distribution industry in England and Wales for the period 1991 to 1997 using linear programming based Malmquist indexing technique. They found average annual TFP growth over the period was in the order of 3.5 per cent. This increased to in excess of 7 per cent per annum in 1996 and 1997.

Another study completed over practically the same period (1991 to 1998) by Tilley and Weyman–Jones (1999) found a similar pattern of results with average annual TFP growth for the distribution industry of 6.3 per cent. This analysis was based on a sample size of 12 businesses. The inputs used were operating expenditure, total length of the distribution network in each of the business's areas and the transformer capacity of the business. The outputs used were electricity distributed across the network, the number of customers served by each business and the maximum demand for each network. Again TFP growth was found to have accelerated in the second half of the 1990s. The higher TFP growth rates found in the UK relative to the US probably reflect the fact that the UK industry was still undergoing regulatory reform.

4 ECONOMETRIC STUDIES OF THE LINES BUSINESSES

In this section we briefly review some of the main quantitative studies of the New Zealand lines businesses undertaken in recent years. In particular, we review the work of Gale and Strong (1999a,b,c), Giles (1999) and NZIER (2001). We then briefly review available quantitative evidence on the impact of operating environment differences on lines business costs.

Gale and Strong (1999a,b,c) and Giles (1999)

The three Gale and Strong papers written in 1999 for the Ministry of Commerce all involve attempts by the NZIER to apply stochastic frontier modelling techniques to data on electricity lines businesses to benchmark these businesses for regulatory purposes. Respectively, the three papers were commissioned to:

- consider the case for using a more sophisticated econometric approach to benchmark electricity lines businesses;
- advise on the practicality of normalising performance measures for circumstance outside the control of the lines business; and,
- evaluate the performance on lines businesses along four performance dimensions – reliability, total cost per customer, operating cost per customer and profitability.

All of Gale and Strong's work relies on one method of performance benchmarking, stochastic frontier analysis (SFA). They note the existence of data envelopment analysis (DEA) as another mainstream method, but there is no examination of the relative merits of DEA or total factor productivity (TFP) relative to SFA.

Prior to discussing the conclusions reached in these papers it is important to first review the application of performance measurement to the lines businesses in terms of the method used, the need for normalisation and the data required. We can then analyse the conclusions of these papers in light of changes to both the disclosure of information and the approach to threshold setting.

The SFA econometric approach to performance benchmarking of lines businesses was used by the NZIER in their attempt to test the proposition that price and reliability can be explained by:

- inefficiencies of the particular business;
- one–off effects that the business cannot control such as cyclones; and
- fixed circumstances outside management control.

SFA is an econometric approach which can attempt to adjust for nominated features that lie outside the control of management in order to identify the component of total costs per customer that are related to management inefficiencies. This process is loosely called ‘normalisation’. If normalisation can be achieved the performance of each lines business can be benchmarked, regardless of varying factors such as size, density, demand and input prices.

As discussed throughout the three 1999 papers, the application of SFA is highly reliant on good quality data. The main findings of the reports were that there is a strong statistical relationship between the performance of the lines businesses and factors outside their control and that normalisation is required to allow reasonable like–with–like comparisons. However, little confidence could be placed in the outcomes of the SFA application to normalise the costs of the lines businesses and, thus, the ranking of businesses in terms of their efficiency performance due to limitations on the quality and breadth of the data available at the time. In particular they concluded that the quality of the data contained in the early information disclosures was varied and they expressed concerns that companies were not fully optimising their network values and misallocating costs between line activities and retail or generation activities. There were problems with the comprehensiveness of the data being disclosed.

Giles (1999) was commissioned to review Gale and Strong (1999a,b). He found that SFA was an appropriate model but that further work was required to improve both the quality and breadth of the data. He noted that certain variables that would be of use to a normalisation modelling exercise such as topographical and climatic information are not recorded. He also noted concern that different businesses had interpreted the reporting requirements differently. Giles concluded that Gale and Strong’s modelling work was sound and they had achieved optimal outcomes albeit constrained by poor data. However, he noted some of the potential problems in using SFA such as the fact that the random error term has two components – the first is due to measurement and specification error and, if this is high it can effectively ‘swamp’ the second component which identifies the firm’s technical inefficiency. Giles agreed that effective normalisation of the lines businesses’ performance was required though to allow meaningful threshold setting.

Since the 1999 reports were completed there have been a number of important data and regulatory developments. Firstly, the separation of the distribution businesses from retail and generation activities in 1998 and early 1999 means that reported distribution cost data relates specifically to separate distribution businesses from 1999 onwards. This should ensure that costs are not misallocated between business units in the last four years.

Secondly, the comprehensive ODV revaluation and recalibration undertaken in 2001 means that asset values should now be available on a more consistent basis with more rigorous optimisation estimates built in. Thirdly, greater data disclosure requirements have added more breadth to the available data, particularly in terms of financial detail available and provisions for the consistent reporting and treatment of rebate payments to customers. Finally, the regulatory regime has evolved from the 'specific' thresholds envisaged by the then regulator, the Ministry of Commerce, to the comparative option now being considered by the Commerce Commission. While the comparative option is a more sophisticated and soundly based regime than the earlier specific thresholds proposal, the type of information the 1999 studies were attempting to produce remains highly relevant.

NZIER (2001)

The objectives of NZIER (2001) produced for the Ministry of Economic Development were to assess:

- whether there were any significance changes in costs due to distortions in the allocation of costs between electricity line and retail businesses pre and post 1999;
- whether there were any significant changes in costs resulting from economies of scale as a consequence mergers and acquisitions; and
- whether there was any value in replicating the previous stochastic frontier modelling exercise with the inclusion of more recent data.

This report was required in the context of two main industry changes. Firstly, electricity line and retail businesses had been separated in 1998 and early 1999 and, secondly, a number of amalgamations had occurred since the last studies were undertaken which may have resulted in economies of scale being achieved. There were also further changes made to the data requirements in 1999 that meant that more explicit and consistent information relating to rebates became available.

To assess the impact of these industry changes, NZIER investigated changes in total costs in 1999 and 2000 for four groups of businesses: those businesses that did not amalgamate; those that did not amalgamate and had historically recorded the value of rebates to customers; those businesses that undertook geographically close amalgamations; and, businesses that undertook amalgamations that were geographically separate.

In regard to whether amalgamations and separation of businesses had led to any significant changes in costs, the report found that there was some evidence of distortions in costs due to the misallocation of costs between electricity line and retail businesses before 1999. This was because costs were lower for those firms that had not amalgamated. Also, no evidence was found that total costs were reduced as a result of economies of scale where there were mergers and acquisitions. This may have been because insufficient time had passed to allow the realisation of these economies through the replacement of 'legacy' systems.

NZIER (2001) was of the view that it was appropriate to repeat the 1999 SFA study using the new data. The authors found that the previous conclusions from the SFA modelling may have been biased as a result of the potential misallocation of costs between line and retail businesses before 1999. They were of the view that future SFA applications should be limited to data from 1999 onwards where there was more certainty about allocation of costs and rebate data.

4.1 Normalisation studies

In this section we briefly review a number of studies that have analysed the impact of operating environment conditions on distribution costs, concentrating on the type of operating environment conditions included in the studies.

Zeitsch, Lawrence and Salerian (1994)

Zeitsch, Lawrence and Salerian (1994) developed and applied a methodology to incorporate operating environment variables in the measurement of TFP using an econometric input requirements function. The methodology was used to compare the productivity of the Queensland electricity supply industry (QESI) with that achieved by the New South Wales electricity supply industry (NSWESI) using data for the period 1976 to 1990. When no account was taken of operating environments, the QESI was found to be 13 per cent more productive than the NSWESI in 1990. It was also found to have a more sparsely settled distribution area that was estimated to have increased its input requirements by 6 per cent. When performance was adjusted for the relatively large area serviced by the QESI the productivity advantage it had over the NSWESI expanded to about 20 per cent. It was concluded that operating environments have a large impact on the productivity performance of Australia's electric utilities.

Gale and Strong (1999a,b,c)

Gale and Strong's economic assessment concluded that there was a very strong statistical relationship between unavoidable network features and the performance of the lines businesses. They noted that the total cost function could be affected by:

- length of lines (and whether they are overhead or underground);
- transformer capacity;
- system peaks (affecting wear and tear);
- number of customers (affecting the number of poles and the number of connections required);

- square kilometres of reticulated area;
- the price of capital; and,
- the price of labour.

Using the stochastic frontier modelling approach Gale and Strong found that the lengths of lines, transformer capacity and the extent of underground cabling may be associated with the degree of efficiency. Gale and Strong (1999b) found that the variance was mainly due to the following factors that were outside the control of the business:

- customer density (systems with fewer customers per square kilometre systematically exhibit higher costs per customer);
- load per customer; and,
- the degree to which cables are underground.

Pacific Economics Group (2000a,b)

In their review of the US distribution businesses, Pacific Economics Group (PEG) allowed for the following operating conditions deemed outside the control of management in their cost function estimation:

- total number of retail customers served;
- total retail delivery volumes (in kWh);
- total miles of distribution line; and,
- percentage of kWh sales to non–industrial customers.

The following factors were not included, however, due to data quality problems or lack of statistical significance:

- load factors;
- square miles of service territory served;
- revenue sharing cost weighted index;
- percentage of lines underground; and,
- precipitation (as a measure reflecting increased vegetation and lightning).

PEG notes that in its first review of the power distribution cap in 1996, the UK Office of Electricity Regulation (OFFER) used benchmarking studies to estimate the efficient level of the distributors' operating and capital costs. This included consideration of a number of factors outside management control including:

- the number of customers served;
- volumes distributed at low and high voltage; and,
- customer density within the territory served.

Productivity Commission (2001)

The Australian Productivity Commission (2001) commissioned UMS Group to collect cost driver information and associated cost data from selected utilities to assist in determining the operating environment factors that impact on the costs of electricity transmission and distribution in Australia. UMS surveyed distribution and transmission businesses to determine the factors of importance and to develop estimates of the likely significance of the factor on prices to users. The outcomes of this study are outlined in the table below.

Factor	Indicative impact upon costs (per kWh)	Likely significance as explanator of price difference
Airborne pollution	0.003–0.098	small
Vegetation growth and management	0.030–0.090	small
Requirement to bury cable	0.01–0.09	small
Contributed assets	Unavailable	
Economies of output density	Unavailable	large
Economies of customer density	Unavailable	moderate (urban)
	Unavailable	large (rural)
Economies of size	Unavailable	none to small
Economies of scope: vertical integration	Unavailable	
Energy losses	0.410–1.760	small to moderate

5 MEASUREMENT ISSUES

Measuring the performance of electricity lines businesses presents a number of challenges, not the least of which is defining exactly what a lines business's output is. This is a non–trivial exercise for lines businesses given the network nature of the industry and the peculiar characteristics of electricity as a product including its non–storability. In this section we examine a number of difficult measurement issues including how to define lines business output and how to measure capital inputs.

5.1 Measuring lines business outputs

The main challenge in calculating TFP for a lines business is the specification of exactly what a lines business's outputs are and how to measure the quantity and value of each of them. Distribution output can be measured from either a 'supply side' or a 'demand side' perspective. At the simplest level, the output would be the amount of energy 'throughput' and its value would be the distributor's total revenue. This approach essentially treats the distribution system in an analogous fashion to a pipeline and was a common approach of early studies of electricity distribution using TFP or other comprehensive indicators. It simply concentrates on the demand for the final product delivered by the distribution network. However, there are other important dimensions to a distributor's output that need to be taken into account. These include the reliability and quality as well as the quantity of the electricity supply and the coverage and capacity of the system (ie the fact that the system is there to meet the highest potential peak as well as actual day to day demand).

A number of distributor representatives in Australia have drawn the analogy between an electricity distribution system and a road network. The distributor has the responsibility of providing the 'road' and keeping it in good condition but it has little, if any, control over the amount of 'traffic' that goes down the road. Consequently, they argue it is inappropriate to measure the output of the distributor by a volume of sales or 'traffic' type measure. Rather, the distributor's output should be measured by the availability of the infrastructure it has provided and the condition in which it has maintained it – essentially a supply side measure.

This way of viewing the output of a network industry can be extended to a number of public utilities. For instance, a number of analysts have measured the output of public transport providers using both a 'supply side' and a 'demand side' measure of output. The supply side measure of a passenger train system, for instance, would be measured by the number of seat kilometres the system provides while the demand side output would be measured by the number of passenger kilometres. In the case of public transport this distinction is often drawn because suppliers are required to provide transport for community service obligation and other non–commercial reasons. Using the supply side measure looks at how efficient the supplier has been in providing the service required of it without disadvantaging the supplier as happens with the demand side measure because of low levels of patronage beyond its control.

In previous work on distribution efficiency we have estimated both supply side and demand side output models. In the Australian context, the demand side models tend to favour urban distributors with dense networks while the supply side models tend to favour rural distributors with sparse networks (but long line lengths). In Tasman Asia Pacific (2000a,b) and other recent work in Australia we have further advanced the output specification by combining the key elements of the demand and supply models to form a comprehensive output measure which contains three components – throughput, network line capacity and the number of connections. The connection component recognises that some distribution outputs are related to the very existence of customers rather than either throughput or system line capacity. This will include customer service functions such as call centres and, more importantly, connection related capacity (eg having more residential customers requires more small transformers and poles). This three output specification has the advantage of incorporating key features of the main density variables (customers per kilometre and sales per customer).

There is also a fourth dimension to a lines business's output. This is the quality of supply which encompasses reliability (the number and duration of interruptions), technical aspects such as voltage dips and surges and customer service (eg the time to answer calls and to connect or reconnect supply). Reliability is likely to be the most important of these service quality attributes and the one for which the most data is available. However, previous attempts to include reliability measures as a fourth output have proven unsuccessful due to the way output is measured. As both the frequency and duration of interruptions are measured by indexes where a decrease in the value of the index represents an improvement in service quality, it would be necessary to either include the indexes as 'negative' outputs (ie a decrease in the measure represents an increase in output) or else to convert them to measures where an increase in the converted measure represents an increase in output. Most indexing methods cannot readily incorporate negative outputs and inverting the measures to produce an increase in the measure equating to an increase in output leads to non–linear results. Measuring reliability by the time on supply each year rather than the time off supply effectively produces a constant as the time off supply is such a small proportion of the total time each year. Given these difficulties we again omit service quality as an explicit output.

Of the three outputs that can readily be included, energy throughput can be measured by the number of kWh of energy delivered. The line capacity of the system can be measured by the number of MVA–kilometres formed by summing the product of line length for each voltage capacity and a conversion factor based on the voltage of the line. This measures not only the length of line but also its overall capacity. Finally, the connections variable can be measured by the number of connections or customers.

To aggregate the three outputs into a total output index using indexing procedures, we have to allocate a weight to each output. For most industries which produce multiple outputs these output weights are taken to be the revenue shares. However, in this case we cannot observe separate amounts being paid for the different output components. In this case we can either make some arbitrary judgements about the relative importance of the output components or we can draw on econometric evidence. One way of doing this using econometrics is to use the relative shares of cost elasticities derived from an econometric cost function. The latter approach is often used in industries not subject to high levels of competition because the cost elasticity shares reflect the marginal cost of providing an output. For instance, using Pacific Economics Group's (2000a,b) cost elasticity shares derived from their large sample of over 100 US distributors over several years implies cost shares for throughput of 47 per cent, for network length of 20 per cent and for customers of 33 per cent. Using the cost function we estimate for the 29 New Zealand distributors in section 8, we find output cost shares for throughput of 18 per cent, for network line capacity of 34 per cent and for connections of 48 per cent.

From an engineering perspective we would expect there to be a lower cost share for the throughput output than found in either of these cost function studies. To consider this, extend the network analogy for the three outputs as follows:

- the main 'road' system; ie the wires and poles/underground cable system that will enable delivery of electricity from supply points to major demand points;
- the system of transformers and 'pumping' equipment that will deliver the electricity from supply points to demand points; and,
- the local access road system that gives access to individual properties and also proxies the customer service system to respond to customer connection needs, enquiries, complaints, etc.

There are costs associated with each of the above three components of the distribution system. Hence, continuing the analogy with the road network, the distribution system also incorporates aspects of the 'trucking' industry, which has output in tonne kilometres. In terms of the trucking industry, the output of the first part would be measured in kilometres of road of standard width, segmented by type of construction (asphalt versus concrete) and possibly segmented by type of terrain.

In terms of the relative importance of the three components of output and cost listed above, the first component is likely to be a large part of cost as the capital costs associated with constructing the network are large. Each customer will specify a peak load that they want delivered and the distributor has to supply the wire that can carry the peak load to major demand points. Hence, the distributor's costs of serving a particular demand point will be equal to the cost of the wire that can carry the peak load times the length of wire from that location to the distributor's network lines plus a share of the network overhead to be attributed to the customer (these are the network main 'road' costs). Note that these costs will be independent of demand. If all customers had identical connection characteristics, these costs would be proportional to some measure of line capacity times length of the network.

The costs of the second output do depend on demand, being roughly proportional to the demand of the consumer. From the viewpoint of the final demander, it is this volume of energy delivered that is the most important measure of final demand but from the network's perspective the marginal costs associated with supplying another unit of power (ie the 'pumping' costs) are very low once the network is in place. However, one could argue that even if consumption of electricity was zero in any given time period (such as might occur for a seasonal business or a weekender), the final demander would still place an option value on having the right to have electricity supplied even though momentary demand was zero. Hence, both the throughput and line capacity outputs are valuable to the final demander even though the costs to the distributor are much higher for line capacity.

The connection output costs (ie the costs of accessing each property by local road) are also largely independent of the amount of throughput. Quite apart from the spatial impact on operating and capital costs from a larger number of connections, dedicated asset costs of connection are a significant network cost and are driven by customer numbers more than line capacity. The other aspect of connection related outputs – customer service functions – are also real although one could argue that the corresponding 'output' is less important to the final demander although they will again place an option value on being able to receive good customer service when they need it.

This discussion gives us some insights into how to build up the various parts of the three types of costs. The line capacity costs include most of the line and transformer costs plus the associated maintenance costs. Throughput costs are likely to be relatively small and may be limited to extra maintenance costs for transformers. Connection costs can be attributed to local transformers and poles plus the workers in the customer service departments plus the associated vehicles and office buildings.

Based on this analysis it would be reasonable to expect the network line capacity output and the connections output to each have relatively high cost shares and the throughput output to have a relatively low cost share. The fact that the two econometric studies, particularly the US based study, allocate higher than expected cost shares to throughput may reflect multicollinearity problems in the respective data sets. However, wherever possible our strategy is to rely on New Zealand empirical evidence in the first instance. In section 8 we undertake a number of sensitivity analyses on the specification of outputs.

5.2 Normalisation for operating environment conditions

As outlined in section 4, operating environment conditions can have a significant impact on lines business costs and productivity and in many cases are beyond the control of managers. Consequently, to ensure we have reasonably like–with–like comparisons it is desirable to 'normalise' for at least the most important operating environment differences. Likely candidates for normalisation include energy density (energy delivered per customer), customer density (customers per kilometre of line), customer mix, the degree of undergrounding, the availability of alternative energy sources, and climatic and geographic conditions.

As noted in section 4.1, energy density and customer density are generally found to be the two most important operating environment variables in normalisation studies. Being able to deliver more energy to each customer means that a distributor will usually require less inputs to deliver a given volume of electricity as it will require less poles and wires than a less energy dense distributor would require to reach more customers to deliver the same total volume. Offsetting this to some degree may be the requirement for the higher density distributor to have larger transformers to service its higher consumption customers but again it will require a smaller number of transformers than its less dense counterpart.

A distributor with lower customer density will require more poles and wires to reach its customers than will a distributor with higher customer density but the same consumption per customer making the lower density distributor appear less efficient unless the differing densities are allowed for. Most studies incorporate density variables by ensuring that the three main output components – throughput, system capacity and customers (or connections) – are all explicitly included. This means that distributors who have low customer density, for instance, receive credit for their longer line lengths whereas this would not be the case if output was measured by only one output such as throughput.

There has been some debate over whether reliability should be included as a form of operating environment condition. By rights, reliability should be included as a fourth type of output as noted in the previous section as it is something that is ultimately under the distributor's control. Attempts to include reliability as an operating environment variable often result in the reliability indicator acting as a proxy for unmeasured geographic and climatic conditions. Distributors operating in mountainous terrain, areas where there is rapid vegetation growth and more storm–prone areas will have to expend higher amounts of operating expenditure and possibly capital expenditure to achieve a given reliability level than their peers operating in flat, drier areas.

There is also some uncertainty about the direction of causation and associated lags between input use and changes in reliability. On the one hand, it may take some time for reliability problems to be recognised and solutions to be approved and implemented. This would point to a relationship between current productivity performance and the reliability performance of, say, two years previously. On the other hand, distributors in remote locations with large service areas have argued that it takes around three years for them to complete a suite of projects addressing the performance of their worst performing feeders. This would point to a relationship between current input use and reliability performance three years into the future. The complexities of the relationship between reliability and efficiency performance point to the need for this issue to be addressed in a separate study.

In this study we have information on the three output components and the degree of undergrounding. Information on the split of customers between residential and industrial/commercial was available for one year only making it difficult to use this information in estimation. This information gave only an indication of the number of residential customers, without associated energy consumption data, and without data on other customer types. Data on geographic and climatic conditions and competition from alternative energy sources is not available. Consequently, our main focus in normalisation will be the key density variables and the degree of undergrounding.

5.3 Level of cost analysis

Most regulatory approaches involving price controls analyse efficiency performance at a relatively disaggregated level. In most cases operating and maintenance cost performance is assessed separately from capital efficiency. This separate analysis is argued to be appropriate given the approach to building up an estimate of efficient total costs from separate components. It does, however, run the risk of coming up with unrealistic estimates of potential cost reductions if the interrelationships between operating expenditure and capital expenditure are not adequately taken into account. For instance, a utility that has invested heavily in new automated capital systems may have very low operating expenditure but high capital costs. An otherwise comparable utility may have let its capital run down and be facing high operating expenditure but low capital costs. If a third utility was benchmarked against these two and costs were compared separately there is a risk that the benchmarks of the first distributor's low operating costs and the second distributor's low capital costs could be chosen when the two taken together are clearly infeasible. Comparing total costs would help avoid this problem.

There is also a risk that comparing operating costs and capital costs separately may create incentives for the distributors to distort their input use to appear better on one measure than they otherwise would but to the detriment of their overall performance.

Where possible, it is desirable to undertake the analysis with respect to total costs rather than separating out operating and capital costs. This is particularly the case with the thresholds regime which is inherently light handed compared to the conventional building blocks approach. It is appropriate to conduct the analysis and set the thresholds at a higher level which allows the distributors greater scope to make the decisions they see fit subject only to one overall constraint rather than a number of separate lower level constraints.

Given the usually higher level of difficulty associated with accurately measuring capital costs there may be a case for concentrating on operating costs in some instances. However, as will be discussed in section 6, there are also significant problems with the operating expenditure data available for the New Zealand lines businesses that largely negate this potential advantage of analysing the costs separately.

5.4 Capital inputs and depreciation

There are a number of different approaches to measuring both the quantity and cost of capital inputs. The quantity of capital inputs can be measured either directly in quantity terms (eg using a measure of line length) or indirectly using a constant dollar measure of the value of assets. Similarly, the annual cost of using capital inputs can be measured either directly by applying the sum of an estimated depreciation rate and a rate reflecting the opportunity cost of capital to the optimised deprival value (ODV) of assets or indirectly as the residual of revenue less operating costs.

Some analysts have argued that measuring the quantity of capital by the deflated asset value method provides a better estimate of total input as it better reflects the quality of capital and can include all capital items, not just lines and transformers. There are two potential problems with this approach. Firstly, it is better suited to more mature systems where the asset valuations are very consistent over time and across organisations. If the asset valuation process is still being bedded down, as it is in New Zealand, then the estimated quantity of capital inputs in likely to be artificially variable using this approach. Secondly, approaches using the capital stock to reflect the quantity of inputs usually incorporate some variant of the declining balance approach to measuring depreciation. Electricity line business assets tend to be long lived and to produce a relatively constant flow of services over their lifetime. Consequently, their true depreciation profile is more likely to reflect the ‘one hoss shay’ or ‘light bulb’ assumption than that of a declining balance. That is, they produce the same service each year of their life and until the end of their specified life rather than producing a given percentage less service every year. In these circumstances it is better to measure the quantity of capital input by the physical quantity of the principal assets. This approach is also invariant to different depreciation profiles that may have been used by different lines businesses. In this study we use direct physical asset measures to proxy the quantity of capital inputs wherever possible, ie we adopt the ‘one hoss shay’ assumption.

The direct approach to measuring capital costs involves applying a constant percentage reflecting depreciation and the opportunity cost of capital to the value of assets. Normally this asset value would be built up using investment data over a number of decades using the perpetual inventory approach (see Lawrence 2002). In the case of the New Zealand lines businesses, however, capital information is only available for a short number of years and even this has been subject to some major revaluations. Consequently, the way of implementing the direct approach that is most consistent with the perpetual inventory approach used in earlier studies is to multiply the ODV by a percentage reflecting depreciation and opportunity costs.

Following NZIER (2001) we assume a common depreciation rate of 4.5 per cent of ODV and an opportunity cost rate of 8 per cent of ODV in calculating the cost of capital inputs. This approach is consistent with a declining balance depreciation profile where 10 per cent of asset value is left after 50 years. It produces an estimate of depreciation costs which is somewhat higher than the current regulatory accounts figure based on optimised replacement cost for all but three of the distributors. Again, this approach abstracts from the different depreciation profiles that may have been used by individual distributors. The use of an 8 per cent opportunity cost rate is consistent with previous infrastructure TFP studies in Australia. It should be noted, however, that the opportunity cost concept used here is not comparable with either disclosed return on investment or weighted average cost of capital figures. This is discussed further in section 8.6.

The indirect approach of allocating a residual or ex post cost to capital of the difference between revenue and operating costs has been favoured by some regulatory agencies such as the US Federal Communications Commission (1997). However, estimating productivity using a direct estimate of the cost of capital is more consistent with the underlying producer theory where an ex ante measure is required. The indirect approach may also be problematic where firms are earning a wide range of rates of return or where, as is the case with New

Zealand lines businesses, some firms provide low prices to customer/owners as a form of dividend.

5.5 Trusts and rebates

The variety of ownership arrangements applying to the distribution businesses presents some problems for assessing performance. This is because there is a mixture of commercial firms and locally owned trusts that return their dividends to the local community either explicitly through rebates and line charge holidays or implicitly through lower prices. Consequently, two lines businesses may have the same underlying efficiency but one may have higher prices because it is privately owned and provides a dividend to its shareholders through normal channels while the other is a locally owned trust that aims to both minimise its tax liability and provide an implicit rebate to its owner–customers by charging lower prices.

Provided rebates explicitly paid to customers (and other community groups) are excluded from operating costs, the form of ownership should not present problems for cost based comparisons. Similarly, by making price comparisons before explicit rebates are paid we will have reasonable comparability between commercial lines businesses and those trusts making explicit rebates but not between these two types of businesses and those trusts providing implicit rebates through lower prices. Given that it is not possible to make completely like–with–like comparisons across the three types of businesses with the data currently available, this approach appears to offer the least distortionary basis for making comparisons.

5.6 Average versus frontier estimation

There are arguments for and against using both the average and frontier approaches. The average approach does appear to replicate the market outcome more closely but runs the risk of too low a target being set. On the other hand, frontier approaches (including stochastic frontier analysis) are more sensitive to data errors and can lead to unrealistically high and, indeed unachievable, targets being set. Given the scarcity of relevant data for the New Zealand lines businesses, using an average estimation approach is likely to be more appropriate and minimise the impact of data errors and omissions. Frontier approaches may be contemplated in the future once data quality and availability improves.

6 DATA

The data source for this study is the official electricity lines business Disclosure Data required under the *Electricity (Information Disclosure) Regulations 1994 and 1999*. This data was first required for the 1995 March year and included physical, service quality and financial information. Legal (as opposed to reporting) separation of distribution and retail activities occurred from 1998, and the disclosure data requirements were revised at this time

Despite the wide range of items now reported in the Disclosure Data, the consistency and quality of the data is extremely variable. The distributors appear to have interpreted what is required differently leading to apparent inconsistencies across distributors and there is, in many cases, considerable variability from year to year for the one distributor. A number of the key variables that would normally be required for productivity analyses are missing. For instance, there is effectively no useful labour data. There are some coverage gaps in years where distributors have amalgamated due to a requirement that data only has to be provided for entities existing at the end of the financial year. Despite these problems, given the short time we have had to complete this exercise we have adopted the policy of using the official data as it was presented rather than making ad hoc changes to correct apparent anomalies. Some corrections were made to reflect the businesses' responses to the opportunity to comment on the data set. As a result of the shortcomings of the data, the results of the study should be considered indicative rather than definitive.

The consistency problems in the data were at their worst in 1995, the first year the data were required. The changes introduced in 1999 have generally improved the quality of the data although significant problems remain. While there is a case for only using the four data years 1999–2002 on the grounds of better consistency, this provides only four years over which to establish trends and limits the scope to carry out econometric analyses. To provide a better basis for establishing trend rates of change and to increase the degrees of freedom available for econometric analysis we have used the seven data years 1996–2002. The 1995 data year was discarded due to the apparent teething problems with providing data in the first year and the absence of ODV estimates.

Extensive work has been required to assemble a database for the 29 distributors existing in 2002 for the seven year period. The procedures adopted to assemble the database are summarised in appendix A. The key variables for the 203 observations in the database are listed in appendix B.

6.1 Output and input definitions

The distribution productivity analyses reported in sections 7 and 8 of the report generally contain three outputs and five inputs.

Output quantities

Throughput: The quantity of the distributor's throughput is measured by the number of kilowatt hours of electricity supplied. This is similar to the output measures used in most early TFP studies of distribution.

System line capacity: The quantity of the distributor's system capacity is measured by its total MVA kilometres. The MVA kilometres measure seeks to provide a more representative measure of system capacity than either line length alone or the simpler kilovolt kilometres measure. Low voltage distribution lines were converted to system capacity in MVA kilometres using a factor of 0.6, high voltage distribution lines using a factor of 14, SWER lines using a factor of 4.6, 66 kV lines using a factor of 35, and 110 kV lines using a factor of 100. These factors are the same as those used by Tasman Asia Pacific (2000a,b) and attempt to capture values typical of the actual MVA capacity for lines of various voltages. They reflect the fact that the effective capacity of an individual line depends not only on the voltage of the line but also on a range of other factors, including the number, material and size of conductors used, the allowable temperature rise as well as limits through stability or voltage drop.

Connections: Connection dependent and customer service activities are proxied by the distributor's number of connections.

Output weights

To aggregate a diverse range of outputs into an aggregate output index using indexing procedures, we have to allocate a weight to each output. For most industries which produce multiple outputs these output weights are taken to be the revenue shares. However, in this case we cannot observe separate amounts being paid for the different output components. As discussed in section 5.1, in this case we can either make some arbitrary judgements about the relative importance of the output components in costs or we can use the estimated output cost shares derived from an econometric cost function. We have chosen to rely on New Zealand based empirical evidence wherever possible in this study and use the output cost shares derived from the econometric cost function reported in section 8.4. A weighted average of the output cost shares is formed using the share of each observation's estimated costs in the total estimated costs for all distributors and all time periods. This produces an output cost share for throughput of 18 per cent, for system line capacity of 34 per cent and for connections of 48 per cent.

Total distributor revenue is taken to be 'deemed' revenue comprising total operating revenue plus AC loss rental revenue received less payment for transmission charges less AC loss rental expense paid to customers.

Input quantities

Operating expenditure: The quantity of the distributor's operating expenses is derived by deflating the sum of the grossed up values of direct costs per kilometre and indirect costs per customer by the index of labour costs for the electricity, gas and water sector. The grossed up values of direct costs per kilometre and indirect costs per customer are used as the value of operating costs because these measures best reflect the purchases of actual labour, materials and services used in operating the lines business. They exclude rebates and other accounting constructs included in the Disclosure Data's total operating expenses variable. The index of labour costs for the electricity, gas and water sector is used as the price of operating expenditure as it directly measures the price of a major component of operating expenditure. Possible alternative measures such as the input producer price index for electricity generation and supply contain a major distortion in 2002 due to the effects of the drought which do not reflect the price of distribution inputs.

Overhead network: The quantity of poles and wires input in the overhead network is proxied by the distributor's overhead MVA kilometres calculated using the same factors as listed above. At this point in time there is inadequate information available to use the alternative indirect measure of a constant price ODV for poles and wires.

Underground network: The quantity of underground cables input is proxied by the distributor's underground MVA kilometres calculated using the same factors as listed above. Again, at this point in time there is inadequate information available to use the alternative indirect measure of a constant price ODV for underground cables.

Transformers: The quantity of transformer inputs is proxied by the KVA of the distributor's installed transformers.

Other assets: The quantity of other capital inputs such as computers and control systems, etc is proxied by their ODV where the share of total ODV attributable to these assets is estimated for the average of distributors having disaggregated ODV information in each of four groups (rural high density, rural low density, urban high density and urban low density). The shares of other assets in total ODV range from 2 to 4 per cent. The price of other assets is assumed to remain unchanged over the period.

Input weights

The value of total costs is formed by summing the estimated value of operating expenditure and 12.5 per cent of total ODV. As discussed in section 5.4, we follow NZIER (2001) in assuming a common depreciation rate of 4.5 per cent and an opportunity cost rate of 8 per cent for capital assets. Disaggregated ODV data is only available for a subset of distributors. To allocate ODV to the four asset classes used here we take the weighted average shares for the distributors that have this data in each of four groups (rural high density, rural low density, urban high density and urban low density) and apply these shares to all distributors in the respective group. This information was available for 7 of the 8 rural high density distributors, for 7 of the 12 rural low density distributors, for all 3 of the urban high density distributors and for 3 of the 6 urban low density distributors. Input weights were then formed from the share of the cost of each of the five inputs in total cost.

Transpower data

Forming consistent time–series data for Transpower has proven to be particularly challenging given changes in reporting over time, particularly the different approach to reporting security product costs and associated changes in the reporting of wholesale market activity costs. The same basic approach to output and input specification used for the distributors has been followed. Two outputs are used: throughput measured by the number of kilowatt hours supplied and system capacity approximated by the number of MVA kilometres based on transformer capacity and line length. Throughput is allocated a weight of one third while system capacity is allocated a weight of two thirds. These ratios have been drawn from the distribution results excluding the connections component.

Three inputs are used: operating expenses, system capacity and transformer capacity. Operating expenses are taken directly from the Gazetted Transpower Disclosure Information with adjustments to exclude the security product. System capacity is measured by MVA kilometres formed by extending the conversion factors reported above for higher voltages and transformer capacity is measured by the installed capacity in KVAs. Capital costs are again approximated by 12.5 per cent of the reported ODV and the ODV is allocated two thirds to lines and one third to transformers. These ratios are broadly in line with the available results for the distributors and are used in the absence of other information.

6.2 Key characteristics of the distributors

The key characteristics of the 29 distributors in 2002 are presented in table 2. Two of the distributors, UnitedNetworks and Vector, account for over 40 per cent of throughput. UnitedNetworks has subsequently been split between Vector, Powerco and Unison. The five largest businesses in terms of throughput in 2002 account for around 65 per cent of energy delivered. The smallest business in terms of throughput, Scanpower, accounts for only 0.3 per cent of energy delivered.

Table 2: **Distributors' key characteristics, 2002**

ELB	Deemed revenue	Energy	Customer numbers	Line length	Trans-formers	Energy density	Cust. density
	$m	*GWh*	*'000*	*kms*	*MVA*	*kWh/cust*	*cust/km*
Alpine Energy	19.96	565.29	28.38	3,687	274.51	19,921	7.70
Buller Elec	3.25	93.18	4.11	595	27.82	22,683	6.90
Centralines	6.02	111.12	7.43	1,615	71.49	14,953	4.60
Counties Power	22.22	418.09	30.82	3,385	237.73	13,567	9.10
Dunedin Elec	43.92	1,240.26	71.43	4,743	725.94	17,363	15.06
Eastland N/W	18.27	290.31	25.55	3,679	224.97	11,361	6.95
Electra	17.46	383.91	38.29	2,127	273.58	10,026	18.00
Elec Ashburton	12.67	342.70	14.56	2,579	262.74	23,541	5.64
Elec Invercargill	9.84	264.56	16.85	688	140.77	15,704	24.49
Horizon Energy	20.55	594.50	23.09	2,383	185.65	25,745	9.69
MainPower	19.43	382.19	25.05	4,327	257.48	15,259	5.79
Marlborough	13.38	303.56	21.04	3,050	222.36	14,429	6.90
Nelson Elec	6.16	146.92	8.58	241	78.19	17,134	35.58
N/W Tasman	21.21	684.84	31.29	3,122	276.45	21,885	10.02
N/W Waitaki	6.81	175.81	11.34	1,911	125.11	15,503	5.93
Northpower	20.42	852.23	46.71	5,337	397.45	18,244	8.75
Orion	111.94	2,901.02	168.46	11,506	1,495.44	17,221	14.64
Otago Power	10.44	348.37	14.43	4,191	130.63	24,136	3.44
Powerco	106.88	2,077.34	157.45	15,960	1,312.24	13,194	9.87
Scanpower	3.84	88.47	6.62	872	55.63	13,374	7.59
The Lines Co	15.23	286.25	25.71	4,602	188.80	11,133	5.59
The Power Co	17.63	608.06	31.80	7,540	298.00	19,121	4.22
Top Energy	15.48	316.15	27.04	4,834	180.90	11,690	5.59
Unison	24.25	867.33	58.07	3,903	557.00	14,936	14.88
UnitedNetworks	332.33	6,873.04	505.06	30,022	3,887.57	13,608	16.82
Vector	203.44	5,115.12	274.00	8,579	2,349.45	18,668	31.94
Waipa N/W	6.33	316.48	20.29	1,764	160.30	15,595	11.50
WEL Networks	45.07	962.39	72.94	4,692	495.12	13,194	15.55
Westpower	10.30	197.99	12.07	1,972	104.36	16,401	6.12
Total	1,164.70	27,807.49	1,778.46	143,905	14,997.67	15,636	12.36

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

There is a high degree of correlation between energy supplied and the number of customers with a correlation coefficient of 98.5 per cent in 2002. There is less correlation between energy delivered and line length with a correlation coefficient of 87 per cent reflecting differences in customer density between distributors. This correlation falls to 58 per cent when the alternative line capacity measure of MVA kilometres (not shown in table 2) is compared to energy supplied. There is, however, a very close relationship between transformer capacity and energy delivered with a correlation of over 99 per cent.

The highest average consumption per customer or energy density is found in Horizon Energy, Otago Power, Electricity Ashburton, Buller Electricity and Network Tasman with average consumption of between 20,000 and 25,000 kWh. While these distributors are all predominantly rural, they each have significant industrial facilities located in their territory. The three rural distributors Electra, Eastland Networks and The Lines Company have the lowest energy densities with around 11,000 kWh average consumption.

The distributors exhibit a wide range of customer densities with the Auckland based Vector and the smaller urban based Nelson Electricity and Electricity Invercargill each having over 24 customers per kilometre of line. The rural distributors Centralines, Electricity Ashburton, MainPower, Network Waitaki, The Lines Company, The Power Company and Top Energy have the lowest customer densities at less than 6 customers per kilometre.

In table 3 we present the change in output and input quantities between 1996 and 2002. Interestingly, some of the rural distributors have experienced the largest increases in throughput over the 7 year period with Electricity Ashburton, Otago Power, Top Energy, Centralines and Alpine Energy all experiencing over 30 per cent increases in throughput. Electricity Invercargill experienced the smallest throughput increase with only 3 per cent and Westpower, Nelson Electricity, Powerco and Buller Electricity all experienced less than a 5 per cent increase. Overall, energy throughput increased by 13 per cent for the industry as a whole.

There have been a wide range of changes in MVA kilometres over the period ranging from around 25 per cent for MainPower and Counties Power to falls of over 10 per cent for Vector and Eastland Networks. MVA kilometres for the industry as a whole increased by 5 per cent. A large part of this increase was made up by increased underground line capacity which exhibited an overall 17 per cent increase, although starting from a small base. Customer numbers increased by 8 per cent overall with some distributors losing significant numbers of customers, presumably due to restructuring.

There have been some very large reductions in the quantity of operating expenditure observed although at least some of this reflects problems with the Disclosure Data. For instance, Nelson Electricity is observed to have reduced its real operating expenditure by 72 per cent over the six years but this distributor appears to have particularly inaccurate data with large swings in the first several years. Horizon Energy, Eastland Networks, Network Tasman, Network Waitaki, The Lines Company and Unison are all observed to have reduced real operating expenditure by in excess of 40 per cent. Only Buller Electricity had a sizable increase in real operating expenditure of over 20 per cent. For the industry as whole real operating expenditure fell by 28 per cent.

Table 3: **Change in output and input quantities, 1996 to 2002**

ELB	Energy %	MVA kms %	Customer numbers %	OpEx %	Overhead lines %	U/ground lines %	Trans-formers %
Alpine Energy	33.0	3.9	5.3	-2.8	2.4	29.9	11.2
Buller Elec	4.9	5.6	-3.1	21.9	4.9	155.8	11.1
Centralines	34.1	4.8	-4.1	-17.7	4.7	15.9	21.1
Counties Power	12.1	23.5	3.2	-21.6	17.3	308.2	20.7
Dunedin Elec	5.8	15.1	5.0	-12.7	11.5	37.5	13.6
Eastland N/W	8.1	-11.1	-36.9	-47.2	-11.3	-3.9	-1.5
Electra	19.7	9.9	9.9	-15.5	6.7	30.2	5.1
Elec Ashburton	46.0	13.8	12.0	-20.4	11.9	80.5	27.3
Elec Invercargill	1.9	2.9	0.8	-21.3	-36.2	22.2	-0.1
Horizon Energy	10.6	4.4	5.6	-59.7	1.8	47.1	-2.1
MainPower	7.9	25.1	5.7	-27.5	24.0	67.4	27.1
Marlborough	9.3	8.0	9.0	2.6	6.7	81.8	31.4
Nelson Elec	3.8	-4.8	3.0	-72.0	-27.6	2.2	8.9
N/W Tasman	23.4	3.1	8.6	-45.7	1.8	26.7	7.9
N/W Waitaki	10.9	4.6	-3.7	-43.0	3.8	74.5	13.2
Northpower	17.1	4.5	8.3	-14.6	3.1	71.1	24.3
Orion	15.7	7.4	10.4	-34.8	7.6	7.0	-4.1
Otago Power	43.0	8.4	3.0	-23.6	8.2	906.8	-10.3
Powerco	3.7	2.9	0.8	-38.1	2.5	21.7	1.9
Scanpower	16.0	-1.3	-1.3	-1.0	-1.4	25.0	2.2
The Lines Co	13.2	-6.4	1.7	-44.2	-6.6	6.9	-37.1
The Power Co	27.4	-5.8	-3.5	-39.3	-6.1	29.1	14.3
Top Energy	39.7	3.3	13.3	-12.6	2.3	66.7	21.8
Unison	22.8	9.3	5.8	-42.6	6.7	24.5	10.8
UnitedNetworks	6.0	13.8	13.2	-36.1	8.4	34.7	13.4
Vector	14.9	-13.1	12.4	4.9	-20.5	-9.5	-17.1
Waipa N/W	24.3	-0.7	2.8	-26.0	-0.3	-12.6	0.0
WEL Networks	21.5	21.2	12.3	1.0	18.5	34.5	4.9
Westpower	2.9	12.1	6.3	-32.9	11.9	24.0	-34.5
Total	12.8	5.0	7.7	-28.4	3.6	17.1	2.5

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Transformer capacity increased by only 2.5 per cent for the industry as a whole. The Lines Company and Westpower had sizable reductions in transformer capacity of in excess of 30 per cent. Centralines, Counties Power, Electricity Ashburton, MainPower, Marlborough Lines, Northpower and Top Energy all had increases in transformer capacity in excess of 20 per cent.

6.3 Data limitations

As noted at the start of this section, the consistency and quality of the Disclosure Data is quite variable. Despite these difficulties, the Disclosure Data do provide a useful starting point for analysis. Importantly, it is only by starting to use this data in a manner that will directly impact the businesses' future rather than merely reporting their past for information purposes that existing errors will be discovered and corrected and lines businesses will have an incentive to ensure accurate data is provided. Looking ahead to future regulatory resets, it would be desirable to have at least price and quantity data on the major output and input components. As noted earlier, the main item missing from the Disclosure Data at the moment is any information on the quantity of labour inputs and reliable information on the cost of labour inputs. This has been made more problematic by the emergence of increased amounts of contracting out over time. In the interim, working at the level of aggregate operating and maintenance costs does provide an alternative option.

To illustrate the variability present in the Disclosure Data we present the operating expenditure data for all distributors and years in figure 4.

Figure 4: **Operating expenditure, all distributors, 1995–2002**

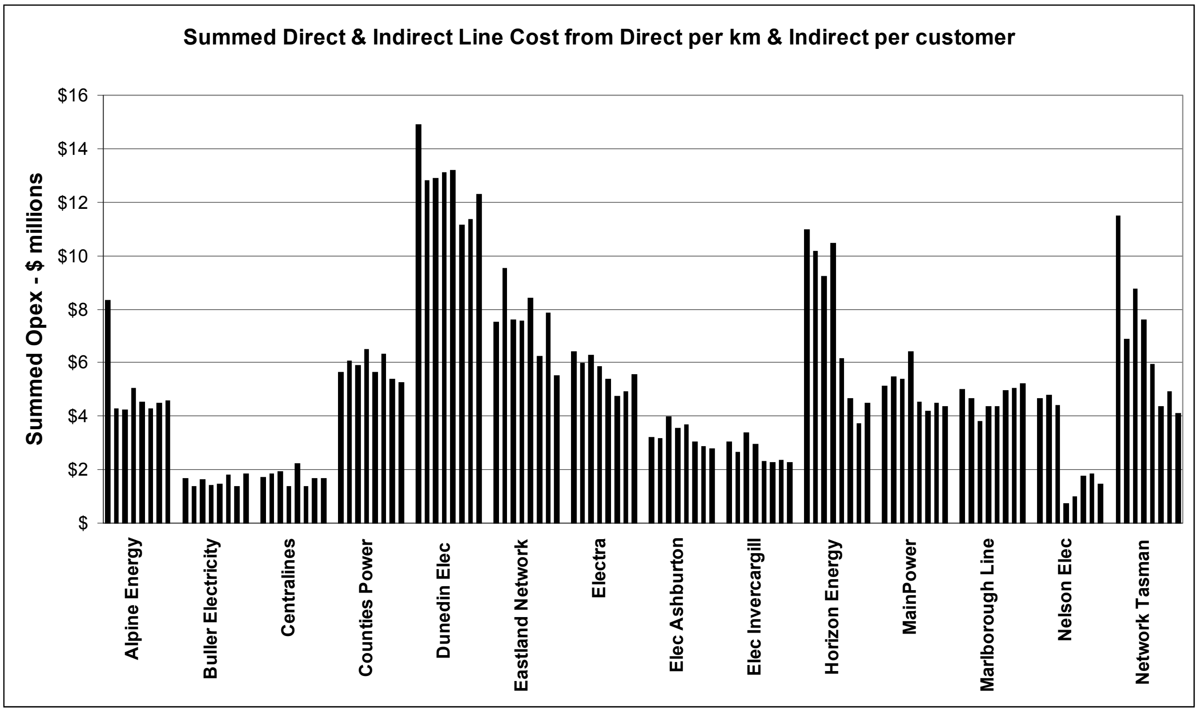
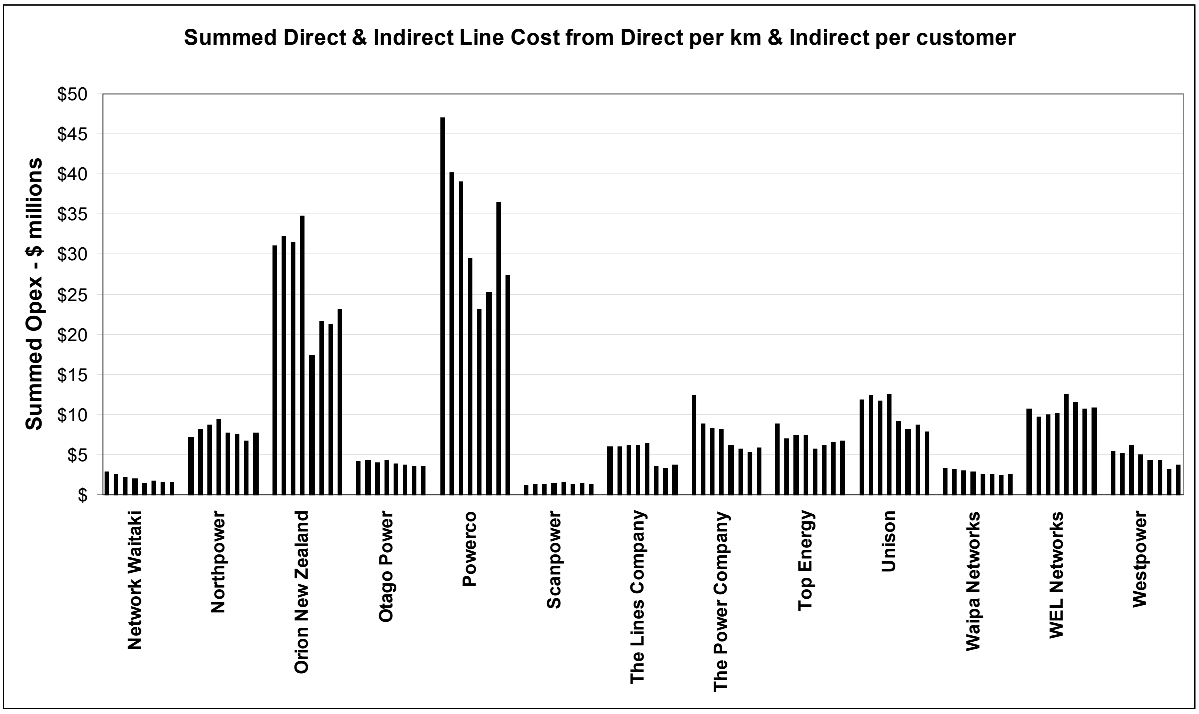
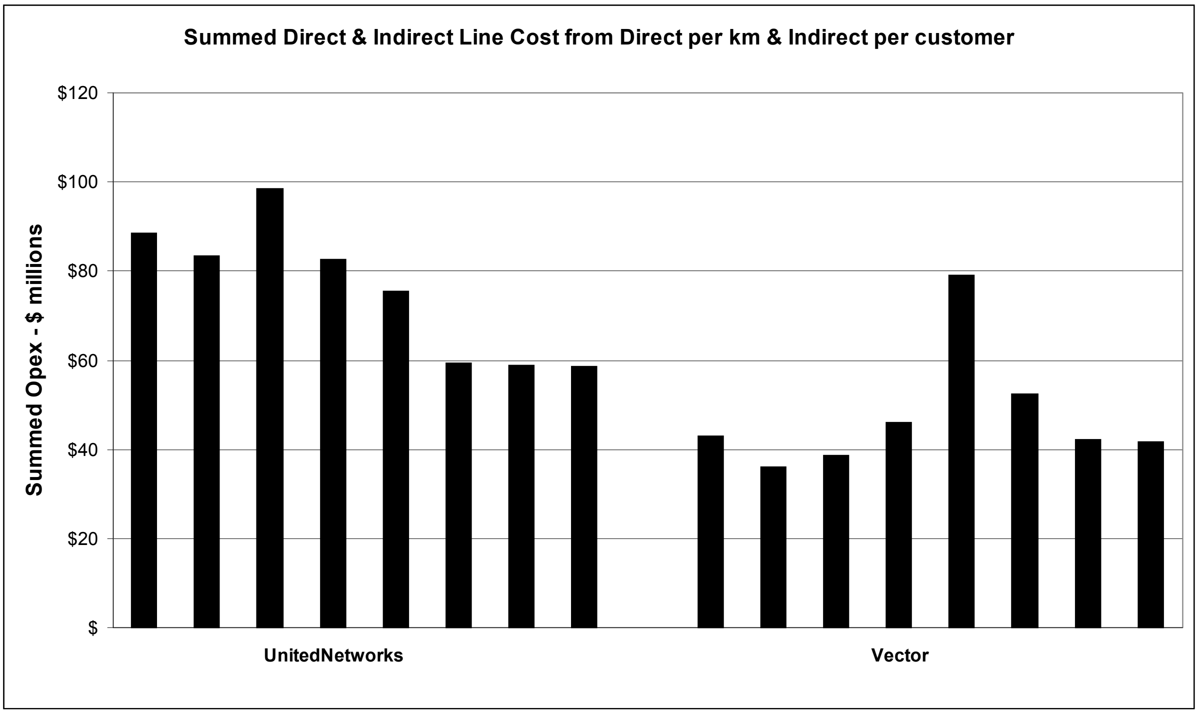


Figure 4: **Operating expenditure, all distributors, 1995–2002 (cont'd)**





Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

The data are presented in a triplet of graphs – the first two are for distributors generally, but exclude the two biggest – UnitedNetworks and Vector – to make a reasonable scale. The third graph contains only UnitedNetworks and Vector. The graphs cover the period 1995–2002 for each distributor that existed in 2002 and incorporate the data for separate merged entities that may have existed in earlier years.

There seem to be discontinuities in the data for almost all the distributors:

- some (eg Alpine Energy, Dunedin Electricity and, to a lesser extent, Network Tasman, and The Power Company) show a high value for the 1995 year – possibly being the first attempt at this data assembly and dissection;
- some show relatively uniform values (possibly excluding the 1995 year), eg Alpine Energy, Buller Electricity, Marlborough Lines, Otago Power, Scanpower, Waipa Networks and WEL Networks;
- some show relatively uniform lessening of the amount, eg Counties Power, Electra (except a turn up recently), Electricity Ashburton, Electricity Invercargill, Network Tasman, The Power Company, Unison and UnitedNetworks;
- some show differences roughly across the 1998–1999 divide, eg Horizon Energy, Nelson Electricity, Network Tasman and Orion New Zealand;
- some show what appear to be anomalous years, eg Vector in 1999 (due to a major cable failure blacking out the Auckland CBD for a number of weeks), Eastland Networks in 2001 and Powerco in 2001; and,
- the data for some distributors, such as Nelson Electricity, is quite unstable.

The data for other variables show similar, although generally less pronounced, variability with the data relating to physical variables generally being more stable than that for financial based variables. This supports our approach of relying on direct, physical measures of input quantities rather than indirect, value deflated proxies wherever possible. While we have to do the latter with operating expenditure, there is sufficient data available on the quantity of the key capital items – overhead lines, underground lines and transformers – to use direct quantity measures.

An important advantage of the primary method we use – TFP indexes – is that they are non–parametric and enable the ready identification of likely data problems while not distorting the results for other observations. Plotting TFP index results provides a ready way of identifying unexpected results that may be less easy to identify in econometric approaches.

While we have omitted data for the 1995 year to reduce variability, the obvious inaccuracies remaining in the data will limit the accuracy of estimated productivity measures and the scope to derive robust econometric results. We expect the data for the most recent years to be more accurate than the data for earlier years given that the lines businesses have had more time to refine their data provision and the separation from retail activities has removed the need for 'cost allocation' between the activities.

7 INDUSTRY PRODUCTIVITY AND THE B FACTOR

In this section we use the Fisher TFP index method to calculate the productivity performance of distribution as a whole and transmission for the seven March years 1996 to 2002. We then examine evidence on input price changes before deriving implied B factors for distribution and transmission.

7.1 The Fisher TFP index

TFP is defined as the change in total output divided by the change in total inputs used between two periods. Mathematically, this is given by:

(11) $TFP = \Delta Q / \Delta I$

where ΔQ is the proportional change in the quantity of total output between the current period and the base period and ΔI is the corresponding proportional change in the quantity of total inputs.

To operationalise this concept we need a way to combine changes in diverse outputs and inputs into measures of change in total outputs and total inputs. To aggregate these changes in diverse components into a total change, index number methodology essentially takes a weighted average of the changes in the components. Different index number methods take this weighted average change in different ways. As indicated in section 2.2, alternative index number methods can be evaluated by examining their economic properties or by assessing their performance relative to a number of axiomatic tests. The index number which performs best against these tests and which is being increasingly favoured by statistical agencies is the Fisher ideal index.

Mathematically, the Fisher ideal output index is given by:

(12) $Q_F^t = [(\sum_{i=1}^{m} P_i^B Y_i^t / \sum_{j=1}^{m} P_j^B Y_j^B)(\sum_{i=1}^{m} P_i^t Y_i^t / \sum_{j=1}^{m} P_j^t Y_j^B)]^{0.5}$

where:

Q_F^t	is the Fisher ideal output index for observation *t*;
P_i^B	is the price of the *i*th output for the base observation;
Y_i^t	is the quantity of the *i*th output for observation *t*;
P_i^t	is the price of the *i*th output for observation *t*; and
Y_j^B	is the quantity of the *j*th output for the base observation.

In this case we have three outputs (so $m = 3$) and seven years (so $t = 1, \ldots, 7$).

Similarly, the Fisher ideal input index is given by:

(13) $I_F^t = [(\sum_{i=1}^n W_i^B X_i^t / \sum_{j=1}^n W_j^B X_j^B)(\sum_{i=1}^n W_i^t X_i^t / \sum_{j=1}^n W_j^t X_j^B)]^{0.5}$

where: I_F^t is the Fisher ideal input index for observation *t*;

W_i^B is the price of the *i*th input for the base observation;

X_i^t is the quantity of the *i*th input for observation *t*;

W_i^t is the price of the *i*th input for observation *t*; and

X_j^B is the quantity of the *j*th input for the base observation.

In this case we have five inputs (so $n = 5$) and seven years (so $t = 1, \ldots, 7$).

The Fisher ideal TFP index is then given by:

(14) $TFP_F^t = Q_F^t / I_F^t$.

The Fisher index can be used in either the unchained form denoted above or in the chained form used in this study where weights are more closely matched to pair–wise comparisons of observations. Denoting the Fisher output index between observations *i* and *j* by $Q_F^{i,j}$, the chained Fisher index between observations 1 and *t* is given by:

(15) $Q_F^{1,t} = 1 \times Q_F^{1,2} \times Q_F^{2,3} \times .... \times Q_F^{t-1,t}$.

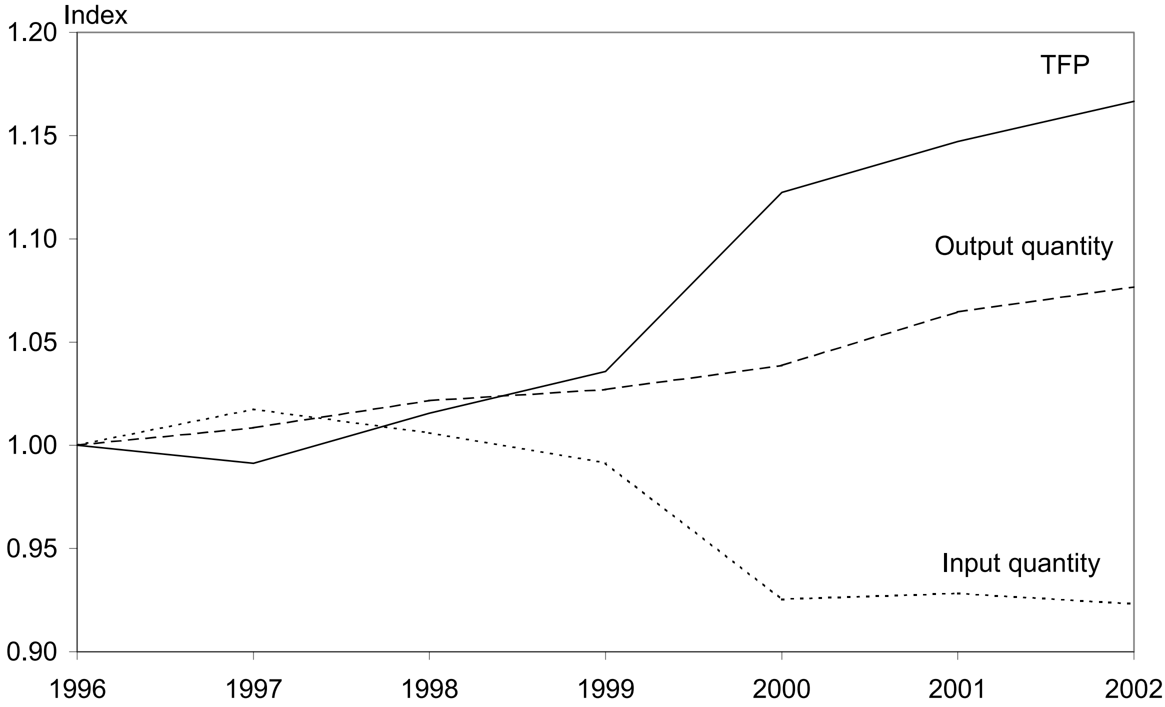
7.2 Aggregate distribution productivity

Our model of aggregate distribution TFP involves the three outputs and five inputs defined in section 6.1. The outputs are energy delivered in kilowatt hours, system line capacity in MVA kilometres and connection numbers. The five inputs are operating costs, overhead lines capital, underground lines capital, transformer capital and other capital items.

TFP results for the aggregate distribution industry are presented in figure 5 and table 4 using the chained Fisher indexing method and the seven years of available data from 1996 to 2002. Output quantity increases steadily over the period although somewhat more rapidly after 2000. Input quantities were initially relatively flat through to 1999 before falling markedly in 2000 and again remaining flat for the last two years. The TFP index increased by 4 per cent between 1996 and 1999. The fall in input use in 2000 produced an 8 per cent increase in TFP in that year. TFP then increased by another 4 per cent through to 2002, driven mainly by increased output quantities. For the 7 year period aggregate distribution TFP increased at a trend annual rate of 3.1 per cent. This rate is very similar to the trend rate of increase found in Lawrence (2002) for the Australian electricity supply industry.

In figure 6 and table 4 we present the five aggregate distribution partial productivities – the output quantity index divided by the relevant input quantity index. The partial productivity of operating costs has increased rapidly over the period – increasing by around 50 per cent between 1996 and 2002. Transformer partial productivity has also increased over the period but by a more modest 6 per cent.

Figure 5: Aggregate distribution output, input and TFP indexes, 1996–2002



Source: Meyrick and Associates estimates

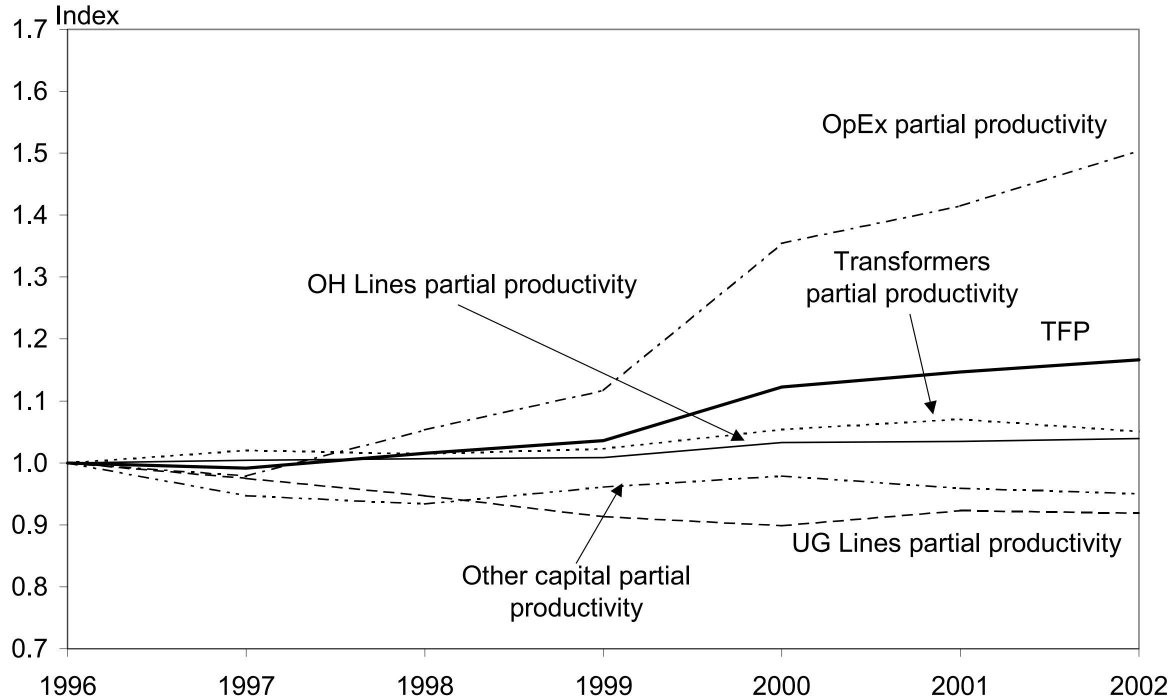
Table 4: **Aggregate distribution TFP and partial productivity indexes, 1996–2002**

	Quantity indexes			Partial productivities				
	Outputs	Inputs	TFP	OpEx	O/H lines	U/G lines	T'formers	Other
1996	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
1997	1.008	1.017	0.991	0.979	1.004	0.975	1.020	0.947
1998	1.022	1.006	1.016	1.053	1.007	0.947	1.014	0.933
1999	1.027	0.992	1.036	1.117	1.008	0.913	1.023	0.961
2000	1.039	0.925	1.122	1.355	1.033	0.898	1.054	0.979
2001	1.065	0.928	1.147	1.415	1.035	0.923	1.070	0.959
2002	1.077	0.923	1.166	1.504	1.039	0.919	1.051	0.950

Source: Meyrick and Associates estimates

The partial productivity of overhead lines has increased by 4 per cent as output quantity has increased faster than the capacity of overhead lines over the 7 years. The partial productivity of underground lines has decreased by 8 per cent reflecting the increasing use of undergrounding while the partial productivity of the small other capital component has decreased by 5 per cent over the period. TFP is essentially a weighted average of these five partial productivities and lies above the four capital partial productivities but below the rapidly increasing operating cost partial productivity. TFP lies closer to the capital partial productivities reflecting the relative weights used in constructing the TFP index.

Figure 6: Aggregate distribution partial productivity indexes, 1996–2002



Source: Meyrick and Associates estimates

Table 5: **Distribution TFP using alternative output specifications, 1996–2002**

	Output specification			
	kWh only	MVAkms only	Connections only	3 outputs
TFP indexes				
1996	1.000	1.000	1.000	1.000
1997	1.011	0.990	0.984	0.991
1998	1.042	1.015	1.006	1.016
1999	1.050	1.038	1.029	1.036
2000	1.165	1.104	1.120	1.122
2001	1.214	1.123	1.140	1.147
2002	1.222	1.137	1.167	1.166
Growth rates				
1996-2002	3.85%	2.57%	3.09%	3.05%
1999-2002	4.64%	3.05%	4.00%	3.79%

Source: Meyrick and Associates estimates

To examine the sensitivity of the TFP estimates to the choice of output specification we present the TFP estimates derived from using each of the three outputs on their own in table 5 along with the TFP index reported above based on using all three outputs.

Using energy throughput as the sole output measure produces the highest increase in distribution TFP over the period with a 22 per cent increase between 1996 and 2002. Using connection numbers as the sole output measure produces the next highest increase of 17 per cent while using the system capacity measure produces a slightly lower increase of 14 per cent. In terms of trend growth rates for the seven year period, the throughput based TFP index increases at 3.9 per cent per annum while the connection and system line capacity based TFP indexes increase at 3.1 and 2.6 per cent per annum, respectively. The trend rate of increase for the three output based TFP index of 3.1 per cent per annum is effectively a weighted average of the three single output based rates. From this information we conclude that the TFP index is relatively insensitive to the output specification and weighting of the output components and that the trend TFP increase slightly in excess of 3 per cent per annum for the distribution industry is reasonable using the aggregate Disclosure Data.

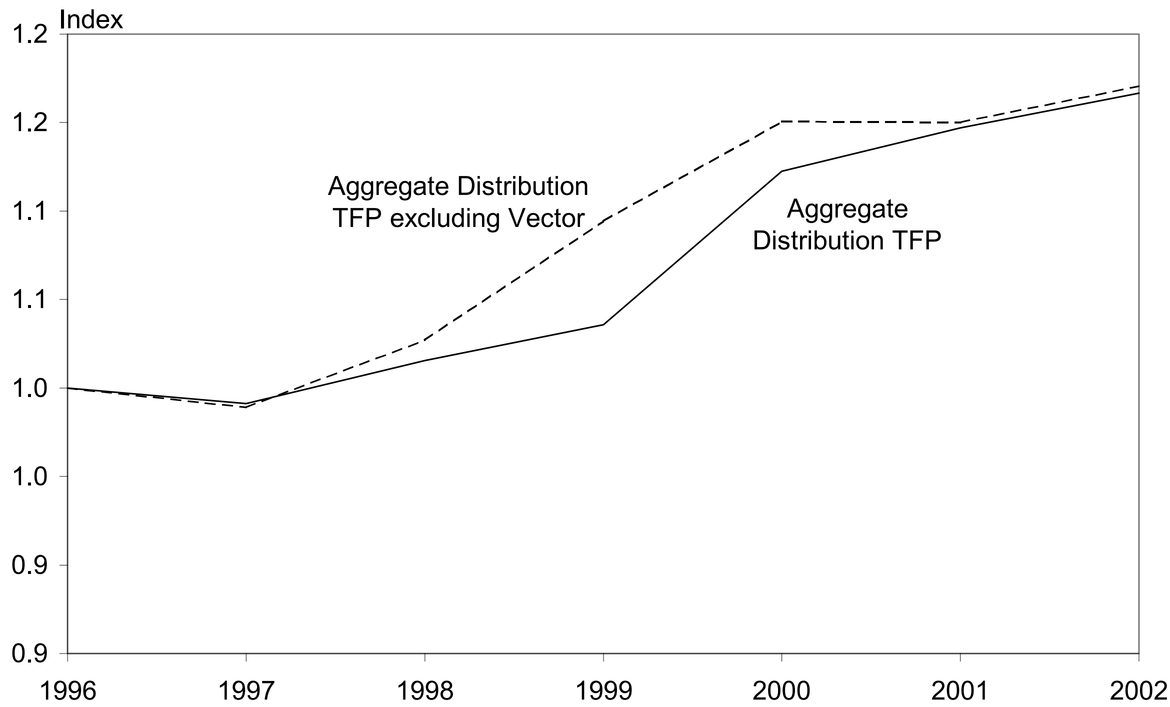
In all cases we observe higher trend TFP growth rates for the most recent four years from 1999 to 2002. The three output based measure, for instance, has a trend annual TFP growth rate of 3.8 per cent for the last four years compared to 3.1 per cent for the whole period. This is driven by the sizable decrease in input use which occurred during the year to March 2000 causing a relatively large increase in TFP in that year. This reduction in total input use was driven almost entirely by a 17 per cent reduction in real operating expenditure in that year. While this large reduction occurs within the last four years when the data is believed to be of better quality, the variability in operating expenditure reported in section 6.3 means that not too much emphasis should be placed on year to year variations in this item. Consequently, we believe it is more prudent to take the trend annual TFP growth rate for the whole seven year period as being more representative of recent distribution industry productivity performance.

As additional sensitivity analyses, we have also examined the impact of two unusual events in 1999 which may have distorted the aggregate distribution industry TFP results. The first of these relates to the Auckland CBD cable failure while the second relates to a possible discontinuity in reported data due to the separation of distribution and retail activities in 1999.

A strong argument can be made that the Auckland CBD cable failure in 1999 was an abnormal event that should be excluded from the aggregate distribution industry results. It affected New Zealand's largest city with the CBD losing power for a number of weeks. This led to Vector's operating expenditure increasing by over 70 per cent in 1999. This increase accounted for around 10 per cent of total distribution industry operating expenditure in that year. Vector's costs were also above trend in 2000 as the cable replacement process continued (see figure 4).

To see what impact the Auckland cable failure had on distribution productivity we have recalculated TFP for all distributors excluding Vector. This TFP series and associated partial productivities are reported in table 6 and the TFP series is compared with that for all distributors in figure 7.

Figure 7: Distribution TFP indexes including and excluding Vector, 1996–2002



Source: Meyrick and Associates estimates

Table 6: **Distribution TFP and partial productivity excluding Vector, 1996–2002**

	Quantity indexes			Partial productivities				
	Outputs	Inputs	TFP	OpEx	O/H lines	U/G lines	T'formers	Other
1996	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
1997	1.010	1.021	0.989	0.982	1.005	0.967	1.005	0.942
1998	1.022	0.995	1.027	1.089	1.006	0.945	0.998	0.914
1999	1.024	0.936	1.094	1.316	1.006	0.918	0.973	0.940
2000	1.038	0.902	1.150	1.494	1.031	0.862	1.008	0.960
2001	1.065	0.926	1.150	1.495	1.032	0.844	1.020	0.959
2002	1.075	0.918	1.171	1.589	1.034	0.844	1.003	0.950

Source: Meyrick and Associates estimates

The effect on aggregate distribution TFP of excluding Vector is to produce a smoother TFP increase from 1997 through to 2000. The adverse impact of the cable failure in 1999 can be seen by comparing the significantly lower TFP levels for the industry as whole in 1999 and 2000 with those of all distributors excluding Vector. In terms of trend annual TFP growth rates, we now observe 3.2 per cent for the series excluding Vector for the whole 7 years and 3.1 per cent for the last four years. Thus, excluding the Auckland cable failure gives us a more even productivity pattern over the two halves of the period and does not effectively change the aggregate result.

The second abnormal event that occurred in 1999 was the dividing of the distribution and retail activities into separate businesses. While this should have made no difference to the reported distribution data in principle, some change may be observed in practice as the impact of differential cost allocation rules and strategies across businesses was removed. As noted in section 6.3, a distinct change in reported operating expenditure levels pre and post 1999 can be seen for some distributors (eg Orion New Zealand, Horizon Energy and Network Tasman) but not others. It is difficult to remove the impact of any resulting reporting differences given the information available.

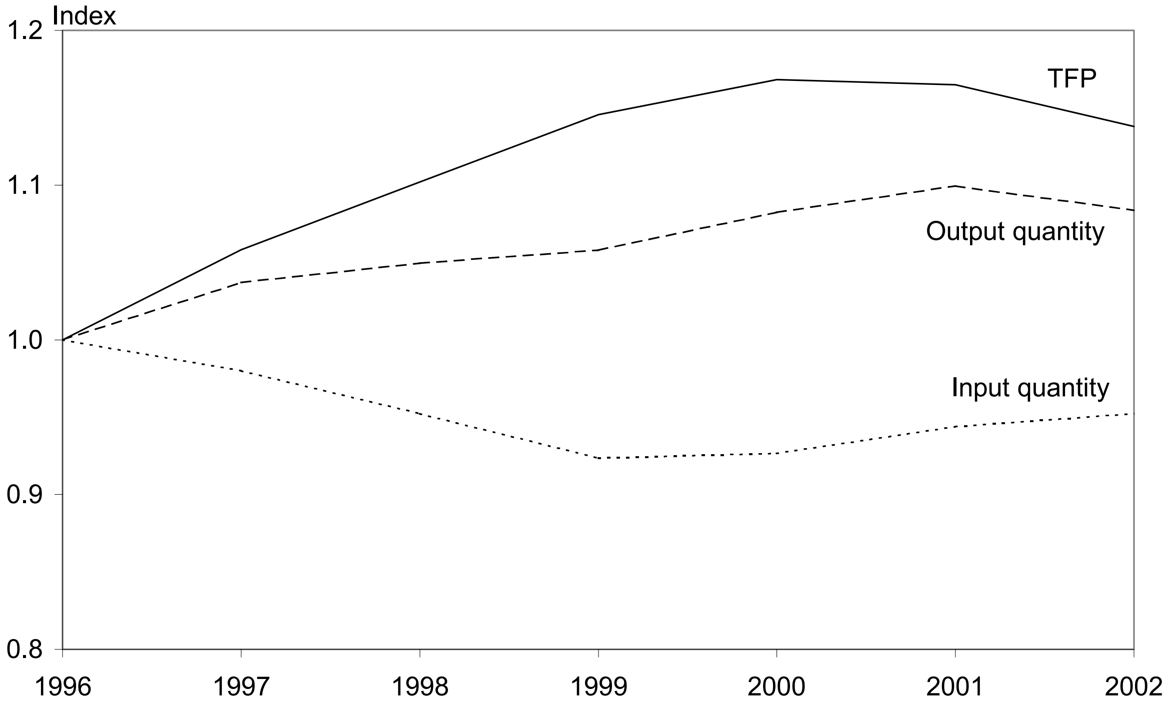
To gauge the possible sensitivity of the aggregate distribution TFP trend rate of change to artificial rather than real reported data changes pre and post 1999, we have recalculated the trend annual TFP change for aggregate distribution excluding Vector assuming that the same proportional increase in the TFP index as observed between 1997 and 1998 also applied between 1998 and 1999. The same proportion change in TFP from year to year for years following 1999 was then applied as observed in the original series. The effect of this is to reduce the level of the TFP index in 1999 and subsequent years by 2.5 per cent. The impact of this on the trend annual growth rate in the TFP index for the 7 years is to reduce it from 3.2 per cent to 2.6 per cent.

We take the trend annual TFP growth rate for all distributors excluding Vector of 3.2 per cent as our preferred estimate of distribution TFP performance but note the possible impact of data reporting irregularities pre and post 1999.

7.3 Transmission productivity performance

Obtaining consistent data for Transpower has proven to be particularly challenging with a number of changes in reporting methods, particularly the approach to reporting ‘security’ product costs, and several major revaluations of ODV. We have constructed a model of transmission TFP that includes two outputs (throughput in kilowatt hours and a transformer capacity based estimate of MVA kilometres) and three inputs (operating costs, line capacity in MVA kilometres and transformer capacity in KVAs). As outlined in section 6.1, the throughput and system capacity outputs are allocated weights of one third and two thirds, respectively, in line with the cost function distribution estimates excluding the connections output. It has been necessary to smooth operating expenditure for 1997 and 1998 to remove the impact of reporting changes associated with the separation of market operations and security product costs which were not included from 1999 onwards, to exclude abnormal industry related costs in 2002 relating to the Electricity Governance Establishment Committee and to convert transformer capacity to a common reporting measure for the seven year period.

Figure 8: Transmission output, input and TFP indexes, 1996–2002

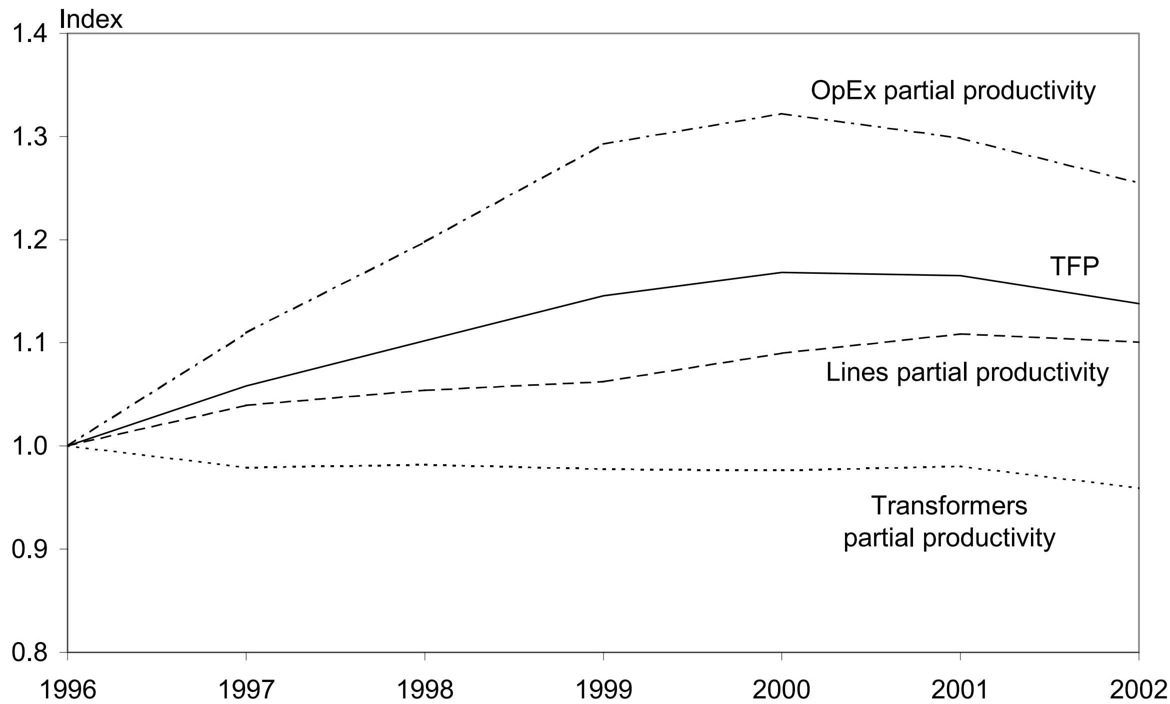


Source: Meyrick and Associates estimates

TFP results for transmission are presented in figure 8 and table 7 using the chained Fisher indexing method and the seven years of available data from 1996 to 2002. Output quantity increased steadily up to 2001 although less rapidly in 1998 and 1999 than the other years. Output fell marginally in 2002 due to reduced throughput associated with the drought and small reductions in the line length employed. In 2002 output was 8 per cent above its 1996 level. Input quantities fell steadily through to 1999 before flattening out and increasing in the last two years. By 2002 input use was 2 per cent below its 1996 level. The TFP index increased by 17 per cent between 1996 and 2000. TFP fell by 2 per cent in 2002 due to a combination of reduced outputs and increased input usage. For the 7 year period transmission TFP increased at a trend annual rate of 2.3 per cent, just over two thirds the trend growth rate of distribution TFP over the same period.

In figure 9 and table 7 we present the three transmission partial productivity indexes. The partial productivity of operating costs increased by 32 per cent between 1996 and 2000 but has subsequently fallen back as real operating expenditure again increased. It finished up 26 per cent above its 1996 level in 2002. The partial productivity of lines has been more steady and increased by 10 per cent as output quantity has increased faster than the capacity of overhead lines over the 7 years. Transformer partial productivity has decreased over the period by 4 per cent as transformer capacity has increased faster than output quantity. TFP is essentially a weighted average of these three partial productivities and lies above the two capital partial productivities but below the operating cost partial productivity. TFP again lies closer to the capital partial productivities reflecting the relative weights used in constructing the TFP index.

Figure 9: Transmission partial productivity indexes, 1996–2002



Source: Meyrick and Associates estimates

To examine the sensitivity of the TFP estimates to the choice of output specification we also present the TFP estimates derived from using each of the two outputs on their own in table 6. Using energy throughput as the sole output measure produces an increase in transmission TFP of 12 per cent between 1996 and 2002. Using the system capacity measure produces a slightly higher increase of 15 per cent. In terms of trend growth rates for the seven year period, the throughput based TFP index and the system capacity based TFP index both increase at 2.3 per cent per annum, the same rate as for the two output specification. Hence, transmission TFP is relatively insensitive to the output specification and using any of the output specifications produces a trend rate of TFP growth for transmission that is lower than the trend TFP growth rate for distribution as a whole.

Table 7: **Transmission TFP and partial productivity indexes, 1996–2002**

	TFP indexes			Quantity indexes		Partial productivity indexes		
	kWh only	Cap. only	2 outputs	Outputs	Inputs	OpEx	Lines	T'formers
1996	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
1997	1.020	1.078	1.058	1.037	0.980	1.110	1.039	0.979
1998	1.074	1.116	1.102	1.049	0.952	1.198	1.054	0.982
1999	1.107	1.165	1.145	1.058	0.923	1.293	1.062	0.977
2000	1.139	1.183	1.168	1.082	0.927	1.322	1.090	0.976
2001	1.154	1.170	1.165	1.099	0.944	1.298	1.109	0.980
2002	1.121	1.146	1.138	1.084	0.952	1.255	1.101	0.959
Growth rates								
1996–2002	2.33%	2.26%	2.28%					
1999–2002	0.53%	–0.60%	–0.23%					

Source: Meyrick and Associates estimates

In all cases we observe substantially lower trend TFP growth rates for the most recent four years from 1999 to 2002. The two output based measure, for instance, has a trend annual TFP growth rate of –0.2 per cent for the last four years compared to 2.3 per cent for the whole period. This is driven by a small increase in input use in 2001 and 2002 and a fall in output in 2002. The increase in total input use was largely driven by a 5 per cent increase in real operating expenditure in the last two years. The drop in output in 2002 resulted from a 2 per cent reduction in throughput and 1 per cent reduction in system capacity. Despite these changes occurring within the last four years when the data is believed to be of better quality, we believe the variability in operating expenditure reported in section 6.3 for distribution is also likely to reflect the quality of the transmission data. Indeed, if anything, the transmission data appears to be less reliable than the distribution data due to changes in reporting. This again means that not too much emphasis should be placed on short term variations in this item.

As a further sensitivity test we have examined the impact of reduced output in 2002 due to the drought on trend growth rates. This could have an impact on the trend TFP growth rate as the trend will be more sensitive to such a temporary change at the end of the series compared to the middle of the series. There could also be a case for examining this if the change in transmission output in 2002 was different to the change in aggregate distribution throughput in that year. This is in fact the case with aggregate distribution output remaining largely unchanged in 2002 while transmission throughput decreased by 2 per cent. This difference could be explained by Transpower's direct industrial customers bearing a larger share of electricity consumption reductions during the drought. To examine the impact of this, we have rerun the transmission TFP analysis assuming that transmission throughput also remained unchanged in 2002. The impact of this change, however, is quite small with TFP now falling by just under 2 per cent in 2002 instead of just over 2 per cent. The trend TFP growth rate remains 2.3 per cent.

We again believe it is more prudent to take the trend annual TFP growth rate for Transpower of 2.3 per cent for the whole seven year period as being more representative of recent transmission TFP performance but note the possible impact of data reporting changes over the period.

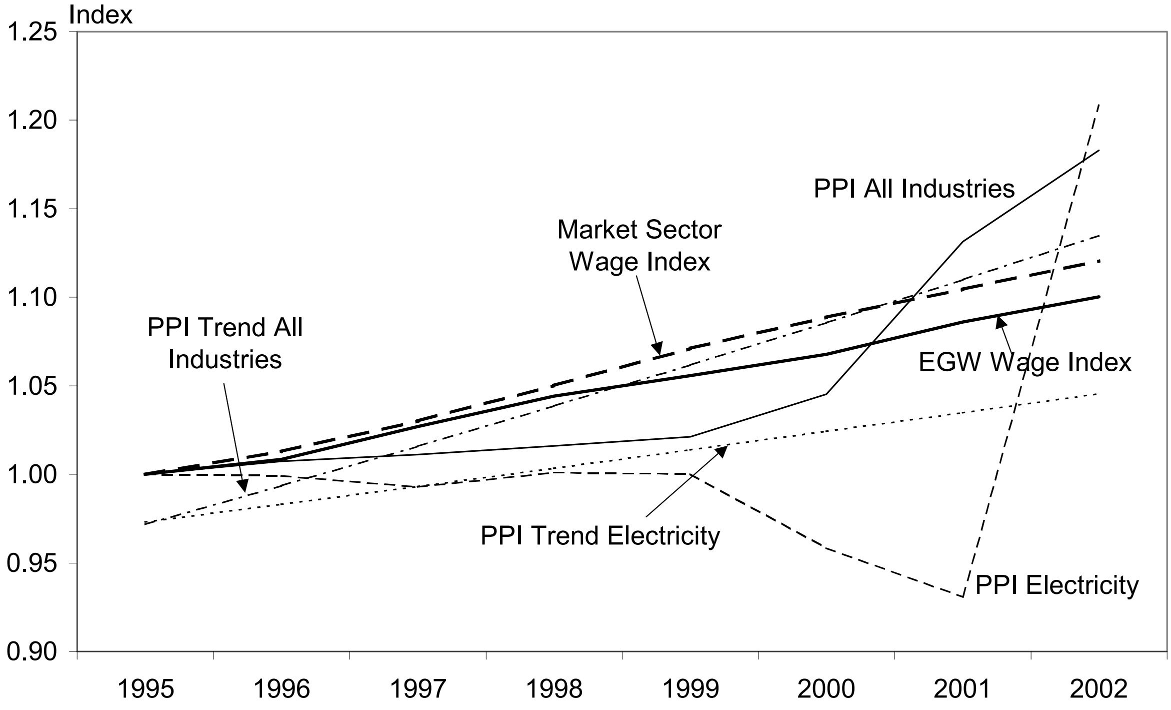
7.4 Input price changes

As well as information on the difference between the productivity performances of the electricity industry and the economy as a whole, we also require information on the difference between the electricity industry's and the economy's input price growth rates to derive the B factor. Statistics New Zealand has compiled relatively detailed producer price indexes since the June quarter 1994, one of which covers the 'electricity generation and supply' industry. While broader than simply lines businesses, this index could provide a reasonable representation of price movements facing the lines businesses. However, the producer price index will only reflect the price of intermediate inputs used and not input prices more broadly.

The two producer price indexes and their trend rates of change are shown in figure 10. Whereas the economy–wide productivity trend fitted the data well, we observe some unusual movements in the producer price indexes, particularly that for the electricity generation and supply industry. The electricity industry PPI actually declined between 1995 and 2001 before increasing sharply – by nearly 30 per cent – in 2002. The PPI for all industries, on the other hand, increased slightly between 1995 and 1999 before increasing more rapidly through to 2002. The two PPIs finish up at almost the same point but because of their very different patterns of movement, the least squares logarithmic trend line for the electricity industry PPI is much less steep than that for all industries – 1.03 per cent per annum trend rate of change for the electricity industry versus 2.22 per cent for all industries.

The very sharp increase in the electricity industry PPI in 2002 is most likely driven by an increase in generation input costs associated with the drought. As such, it is unlikely to be representative of general input price movements in electricity lines businesses. Consequently, we have investigated alternative lines business input price indexes. One option is to use a measure of unit labour costs as a measure of input prices. Statistics New Zealand publishes a labour costs index for the electricity, gas and water industry. The overall index for salary and ordinary time wage rates for both public and private EGW sectors is presented in figure 10. It shows a steady increase over the whole period and increased at a trend annual rate of 1.4 per cent. As this index will be representative of a significant proportion of the lines businesses' costs and does not exhibit the volatility of the electricity generation and supply inputs PPI, we believe this index better represents recent changes in lines businesses' input prices.

Figure 10: **Producer price and labour cost indexes, 1995 to 2002**



Source: EconData (2002)

The equivalent labour cost index for the market sector of the economy is also plotted in figure 10. This index again increases more smoothly than the producer price index for all industries. The trend rate of increase for the market sector labour cost index is 1.9 per cent. In the interests of consistency we use the market sector labour cost index as being representative of input costs in the economy as a whole.

The difference in the trend rates between the EGW labour cost index and the market sector labour cost index amounts to 0.5 per cent per annum. We believe it is advisable to use a trend rate of change over about a decade when calculating the components of the B factor to avoid short term changes having an undue influence. In this instance the trend rates of change are formed over 8 years, the maximum time data is available for the labour cost indexes.

7.5 B factor conclusions

Based on the review of available information for the lines businesses in this section and for the economy and the sector in section 3, we can now draw conclusions on the appropriate size of the B factors for distribution and transmission. In both forming and using these conclusions we need to be cognizant of both the less than perfect quality of the data they are based on and the fact that the available measures only approximate the fully specified components of the B factor as discussed in section 2.

An important issue to be resolved in drawing conclusions on the B factors is whether distribution and transmission should have the same or different B factors. In section 2 we noted that it is desirable wherever possible to set X factors on the basis of information external to the business being regulated. This creates a problem for transmission in New Zealand where we only have one large firm. The options for setting the B factor externally are to bring overseas transmission companies into the sample or to aggregate transmission with distribution and set a composite B for both sectors. At this time it is not feasible to include overseas transmission companies in the sample. Aggregating the two sectors to form an overall TFP estimate presents a number of practical difficulties given that we have different output and input specifications for the two activities. Such an exercise would also have to be careful to avoid double counting outputs.

Apart from the practical difficulties of calculating a combined transmission and distribution TFP series and, hence, B factor, there are also some conceptual issues that have to be addressed. Firstly, even though transmission and distribution businesses are both lines businesses, there may be fundamental differences in the nature of the activities that make it inappropriate to treat them as being the same activity, ie distribution companies may have more avenues at their disposal to improve productivity which are simply not available to transmission. This may well be the case in New Zealand where the existence of a relatively large number of small distribution businesses means they have scope to merge and achieve economies of size not available to the transmission company. A related point is the distance of Transpower and the average distribution company form their respective technically efficient frontiers. If the average distribution company is much further from the frontier than Transpower then it would be unrealistic to expect Transpower to be able to match the productivity performance of distribution going forward. The lower TFP growth observed for transmission over the last 7 years lends some support to this hypothesis. Against this, Transpower may have been subject to less competitive pressure than distribution and still be relatively far from its efficient frontier.

At this stage we have insufficient information available to judge whether it is appropriate to set a common B factor for both transmission and distribution. To answer this with confidence would require the introduction of overseas comparators into the sample. The New Zealand situation is also complicated by the as yet uncertain regulatory role of the Electricity Commission. For this report we proceed by drawing conclusions on separate B factors for distribution and transmission. For transmission this involves relying on information on Transpower's past productivity performance to draw B factor conclusions.

In terms of the two productivity components, we have the preferred annual growth rate for TFP in the New Zealand economy of 1.1 per cent using the trend rate derived from the indexes reported in the Treasury update of Diewert and Lawrence. For the distribution lines businesses we have derived a trend annual TFP growth rate of just over 3 per cent from the Disclosure Data. This figure is also consistent with the sectoral results from Diewert and Lawrence and recent Australian electricity supply industry results in Lawrence (2002).

The annual input price trends observed in the preceding section are 1.9 per cent for the economy as a whole based on the labour cost index for the market sector and 1.4 per cent for the lines businesses based on the labour cost index for the EGW sector.

Substituting these figures in equation (7) we obtain the following for distribution:

$$\begin{aligned} B &= [(\Delta TFP - \Delta TFP_E) - (\Delta W - \Delta W_E)] \\ &= [(3.2\% - 1.1\%) - (1.4\% - 1.9\%)] \\ &= [(2.1\%) - (-0.5\%)] \\ &= 2.6\% \end{aligned} \tag{16}$$

However, given the quality of the data on which the analysis has had to be based, the results of the sensitivity analyses and the scope for the available productivity and price measures to differ from their fully specified equivalents discussed in section 2, we believe it would be prudent to adopt a conservative approach to setting the B factor. Consequently, it would be more appropriate to round the B factor in (16) down than up.

For transmission the trend rates of change are the same except that transmission's trend annual productivity growth rate is 2.3 per cent instead of distribution's 3.2 per cent. Substituting these figures in equation (7) we obtain the following for transmission:

$$\begin{aligned} B &= [(\Delta TFP - \Delta TFP_E) - (\Delta W - \Delta W_E)] \\ &= [(2.3\% - 1.1\%) - (1.4\% - 1.9\%)] \\ &= [(1.2\%) - (-0.5\%)] \\ &= 1.7\% \end{aligned} \tag{17}$$

8 DISTRIBUTOR PRODUCTIVITY AND C FACTORS

As well as the industry productivity growth related B factor, the Commerce Commission (2003) envisaged using a number of additional considerations in setting distributors' X factors. These distributor–specific considerations were to be represented by a C factor for each distributor reflecting the distributor's comparative productivity performance and 'excess profit' after taking service quality into account. Those distributors performing better than the industry average on productivity levels and those earning low rates of return would be set less onerous overall X factors compared to those performing near the industry average. Those performing worse than the industry average on productivity levels and those earning high rates of return would be set more onerous overall X factors compared to those performing near the industry average. These comparisons should ideally take account of differences in distributors' operating environments to the maximum extent possible.

The overall X factor for a given distributor is made up of an amalgam of its B and C factors. The B factor is common to all distributors and the C factors could be determined either individually for each distributor or for broad groups of distributors.

The Commerce Commission (2003) raised the possibility of using an ad hoc regression of prices against output quantity, output quality, input prices and business condition variables as the means of determining C factors for distribution businesses. It was argued that using this single function approach may make more efficient use of the data and obviate the need to consider separate P_0 adjustments. The residual term from the ad hoc price function was hypothesised to reflect a combination of productive inefficiency, 'excess profit' after taking service quality into account and random factors. While the Commission did not propose disentangling these three components, in practice doing so to gain a full understanding of observed differences would not be straightforward.

The use of ad hoc price functions as the primary analytical method for determining C factors also does not provide a way of calculating the B and C factors in an integrated quantitative framework. Consequently, rather than relying on the price equation to try and simultaneously capture the two main components of the C factors – relative productivity performance and profitability taking service quality into account – we proceed with a two stage analysis. The first stage allocates distributors to C factor groupings based on relative productivity performance while the second stage uses additional analysis to review the initial C factor allocations based on service quality and profitability considerations.

In this section we initially concentrate on the comparative productivity performance of the 29 distributors using two alternative measurement techniques. The first is an extension of the TFP index concept used in section 7 to enable 'multilateral' comparisons using combined time series, cross section or 'panel' data. The second is an econometric cost function based approach. We then examine the scope to incorporate information on distributor price/quality trade–offs and profitability levels before using all this information to allocate distributors to three broad C factor groups.

8.1 Multilateral TFP

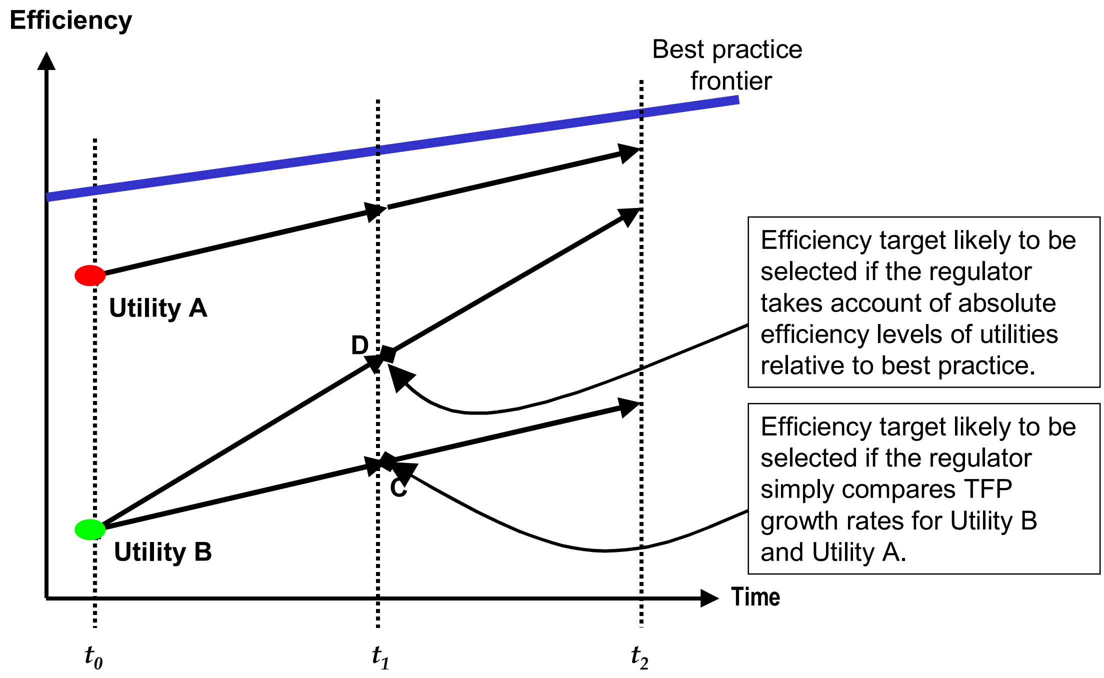
The advantages of the standard TFP indexes were outlined in section 2.2. These include the following:

- indexing procedures are simple and robust;
- they can be implemented when there are only a small number of observations;
- the results are readily reproducible;
- they have a rigorous grounding in economic theory;
- the procedure imposes good disciplines regarding data consistency; and
- they maximise transparency in the early stages of analysis by making data errors and inconsistencies easier to spot than using some of the alternative techniques.

For benchmarking purposes we need to extend the time series indexing methods discussed in the earlier sections to include analysis of productivity levels as well as growth rates. The reasons for this can be illustrated using figure 11 where the efficiency performance of two similar utilities is plotted relative to a best practice frontier. Utility A is initially performing at close to best practice efficiency as reflected by its closeness to the best practice frontier while Utility B is initially well below best practice efficiency. Say we are reviewing the utilities at time t_1 and setting price caps for the period through to t_2. Because Utility A is close to best practice initially it will have limited options for efficiency improvement and so its productivity growth rate will consist of small movements towards the frontier plus movement of the frontier due to technical change which will be relatively slow in industries like electricity distribution. Utility B, on the other hand, has the potential to make large catch–up changes to its operations and so could achieve a much higher productivity growth rate than Utility A although it is starting from a much lower productivity level.

If Utility B had a low productivity growth rate in the period up to t_1 getting only to point C then in the absence of yardstick competition we would have no way of distinguishing Utilities A and B. Extrapolating the low productivity growth rate would be appropriate for Utility A but inappropriate for Utility B. Rather, Utility B should be set a higher X factor to provide it with an incentive to move closer to the frontier. If, on the other hand, Utility B had had a higher growth rate in the period up to t_1 getting to point D then extrapolating this growth rate in setting the X factor would be appropriate. However, setting an X factor of that magnitude would be inappropriate and indeed unachievable for Utility A. Only by examining the utilities' productivity levels as well as their growth rates can we set appropriate X factors for them.

Figure 11: Efficiency levels and growth rates



Traditional measures of TFP such as those discussed earlier in the report have enabled comparisons to be made of rates of change of productivity between organisations but have not enabled comparisons to be made of differences in the absolute levels of productivity in combined time series, cross section data. This is due to the failure of conventional TFP measures to satisfy the important technical property of transitivity. This property states that direct comparisons between observations *m* and *n* should be the same as indirect comparisons of *m* and *n* via any intermediate observation *k*.

Caves, Christensen and Diewert (1982) developed the multilateral translog TFP (MTFP) index measure to allow comparisons of the absolute levels as well as growth rates of productivity. It satisfies the technical properties of transitivity and characteristicity which are required to accurately compare TFP levels within panel data. Lawrence, Swan and Zeitsch (1991) and the Bureau of Industry Economics (BIE 1996) have used this index to compare the productivity levels and growth rates of the five major Australian state electricity systems and the United States investor–owned system. Zeitsch and Lawrence (1996) use the method to compare the efficiency of coal–fired electricity generation plants in the United States, Canada and Australia.

The Caves, Christensen and Diewert (CCD) multilateral translog index is given by:

$$(18) \qquad \log (TFP_m/TFP_n) = \Sigma_i (R_{im}+R_i^*) (\log Y_{im} - \log Y_i^*)/2 - \Sigma_i (R_{in}+R_i^*) (\log Y_{in} - \log Y_i^*)/2 - \Sigma_j (S_{jm}+S_j^*) (\log X_{jm} - \log X_j^*)/2 + \Sigma_j (S_{jn}+S_j^*) (\log X_{jn} - \log X_j^*)/2$$

where R_i^* (S_j^*) is the revenue (cost) share averaged over all utilities and time periods and $\log Y_i^*$ ($\log X_j^*$) is the average of the log of output *i* (input *j*). In the main application reported in the following section we have three outputs (throughput, system line capacity and connections) and, hence, *i* runs from 1 to 3. We have five inputs (operating expenses, overhead lines, underground cables, transformers and other capital) and, hence, *j* runs from 1 to 5. The Y_i and X_j terms are the output and input quantities, respectively, described in section 6.1. The R_i and S_j terms are the output and input weights, respectively, from section 6.1.

The formula in (18) gives the proportional change in MTFP between two adjacent observations (denoted *m* and *n*). An index is formed by setting some observation (usually the first in the database) equal to one and then multiplying through by the proportional changes between all subsequent observations in the database to form a full set of indexes. The index for any observation then expresses its productivity level relative to the observation that was set equal to one. However, this is merely an expositional convenience as, given the invariant nature of the comparisons, the result of a comparison between any two observations will be independent of which observation in the database was set equal to one.

This means that using equation (18) comparisons between any two observations *m* and *n* will be both base–distributor and base–year independent. Transitivity is satisfied since comparisons between the two distributors for 1999 will be the same regardless of whether they are compared directly or via, say, one of the distributors in 2002. An alternative interpretation of this index is that it compares each observation to a hypothetical average distributor with output vector $\log Y_i^*$, input vector $\log X_j^*$, revenue shares R_i^* and cost shares S_j^*.

With the index number MTFP approach there is some scope to capture density related operating environment conditions by the specification of multiple outputs. For example, in previous studies, output specifications that focus on energy delivered have tended to favour dense urban distributors while output specifications that have focused on the network's capacity as measured by MVA–kilometres have tended to favour low density rural distributors (Meyrick and Associates 2003). Incorporating both the energy delivered and network capacity measures of distribution output leads to a more even–handed treatment of urban and rural distributors. By choosing multiple outputs such as energy delivered, MVA–kilometres and connection numbers, it is possible to incorporate aspects of density such as customers per kilometre and energy delivered per customer into the MTFP measure directly in an analogous fashion to how this is captured in multiple output econometric cost functions (see Tasman Asia Pacific 2000a,b and Pacific Economics Group 2000a,b).

A number of econometric techniques can also be used to adjust TFP scores for additional operating environment differences subject to a number of technical assumptions such as separability. One of these is the use of the input requirements function that relates input usage to scale and operating environment characteristics. The input requirements function adjusts total input usage for a range of operating environment factors using relatively standard regression techniques. This then permits the calculation of the input usage that would be required by each distributor if they all faced the same values of the specified operating environment variables. These adjusted input usage levels can then be fed back into the multilateral TFP index to calculate efficiency differences that are adjusted for the operating environment conditions included in the econometric estimation. This method has been used to adjust for a small number of operating environment differences in Australian electricity systems (see Zeitsch, Lawrence and Salerian 1994).

The multilateral TFP index has some important advantages. It is a robust technique which is relatively insensitive to data errors, does not require a large number of observations, provides information on productivity levels as well as growth rates and can be readily communicated to non–technical audiences. In the following section we present the results of the MTFP analysis and include a number of sensitivity analyses for alternative output specifications.

8.2 MTFP results and sensitivity analyses

The database we used in section 7 to calculate the overall distribution industry productivity performance was formed by aggregating the individual data for the 29 distributors. In this section we use the same data from the 29 distributors for the seven years 1996–2002 but look at individual distributor results. We again use three outputs (throughput in kilowatt hours, system line capacity in MVA kilometres and connection numbers) and five inputs (operating costs, overhead line capacity, underground line capacity, transformer capacity in KVAs and other capital). The main decision we have to make again relates to how to weight the three outputs together. Our preferred weighting method relies on New Zealand empirical evidence. Pending better information becoming available on direct cost allocations in the future, we use the weighted average estimated output cost shares derived from the econometric cost function reported in section 8.4. The weighted average output cost shares are 18 per cent for throughput, 34 per cent for system line capacity and 48 per cent for connections.

We present the MTFP results using the three outputs and weighted average cost function shares in table 8. The index values indicate the productivity level relative to the performance of Alpine Energy in 1996. The results are invariant to this choice of the 'base' observation. The distributors are listed by decreasing MTFP level in 2002.

Table 8: **MTFP indexes using 3 outputs, average cost function weights, 1996–2002**

ELB	Multilateral TFP indexes							Growth rates	
	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*96–-02*	*99–02*
El Invercargill	1.181	1.078	1.164	1.308	1.337	1.380	1.472	4.62%	3.86%
Waipa N/W	1.088	1.126	1.158	1.217	1.212	1.282	1.280	2.83%	2.10%
Scanpower	1.252	1.236	1.220	1.163	1.271	1.234	1.253	0.15%	1.95%
Nelson Elec	0.533	0.572	1.480	1.381	1.098	1.069	1.233	12.38%	-3.65%
N/W Tasman	0.933	0.844	0.897	0.983	1.142	1.140	1.221	5.89%	6.49%
Vector	1.045	1.048	1.005	0.829	1.020	1.144	1.195	2.11%	12.09%
Northpower	1.104	1.083	1.052	1.137	1.134	1.194	1.153	1.44%	0.95%
Otago Power	1.160	1.256	1.023	1.064	1.079	1.132	1.141	-0.73%	2.55%
UnitedNetworks	0.939	0.893	0.966	0.989	1.102	1.124	1.131	4.11%	4.22%
Horizon Energy	0.698	0.763	0.716	0.940	1.056	1.136	1.082	8.94%	4.94%
The Lines Co	0.820	0.722	0.815	0.811	1.058	1.087	1.076	6.77%	8.75%
Counties Power	1.079	1.010	0.982	1.039	0.986	1.044	1.060	0.07%	1.18%
Alpine Energy	1.000	1.019	0.971	1.015	1.048	1.051	1.056	1.07%	1.19%
Orion	0.846	0.857	0.832	1.046	1.036	1.061	1.052	4.64%	0.42%
WEL Networks	1.006	1.023	1.027	0.949	1.011	1.035	1.044	0.43%	3.10%
N/W Waitaki	0.951	1.015	1.039	1.113	1.075	1.070	1.041	1.47%	-2.05%
Unison	0.822	0.866	0.846	0.968	1.021	0.999	1.041	4.21%	1.97%
Electra	0.927	0.915	0.952	1.010	1.071	1.059	1.035	2.64%	0.61%
The Power Co	0.934	0.946	0.947	0.984	1.003	1.037	1.021	1.81%	1.44%
Powerco	0.871	0.889	0.974	1.054	1.026	0.904	1.016	1.96%	-2.36%
Centralines	0.959	0.959	1.054	0.886	1.042	1.015	1.015	0.97%	3.81%
Dunedin Elec	0.931	0.932	0.925	0.919	0.968	0.973	0.960	0.80%	1.38%
MainPower	0.926	0.921	0.864	0.916	0.956	0.973	0.955	1.08%	1.41%
Top Energy	0.834	0.854	0.859	0.941	0.925	0.907	0.920	1.74%	-0.88%
Eastland N/W	0.858	0.789	0.772	0.740	0.844	0.806	0.905	1.04%	5.57%
Marlborough	0.919	0.979	0.902	0.902	0.876	0.901	0.877	-1.20%	-0.54%
Westpower	0.669	0.680	0.762	0.817	0.810	0.908	0.855	4.91%	2.52%
Buller Elec	1.036	0.967	1.000	0.992	0.885	0.997	0.849	-2.35%	-3.47%
Elec Ashburton	0.794	0.754	0.804	0.798	0.822	0.846	0.835	1.44%	1.64%

Source: Meyrick and Associates estimates

A mixture of urban and rural based distributors with both high and low (energy) density are found to have the highest MTFP levels. We define rural distributors as those having less than 13 connection points per kilometre while low density distributors have an average consumption of less than 16,000 kilowatt hours per customer. The urban low density distributor Electricity Invercargill has the highest productivity level in 2002. This is followed by two rural low density distributors, Waipa Networks and Scanpower. The urban high density distributor, Nelson Electricity, has the next highest MTFP level followed by the rural high density distributor, Network Tasman. While Nelson Electricity has highly variable data, we assume that its data for the 2002 year is (relatively) accurate. The two large urban distributors, Vector and UnitedNetworks, also have MTFP levels in the top third of the sample.

The distributors with the lowest MTFP levels in 2002 also reflect a mixture of distributor types. The rural high density distributors, Electricity Ashburton and Buller Electricity, have the lowest MTFP levels followed by four rural low density distributors (Westpower, Marlborough Lines, Eastland Network and Top Energy) and the urban high density Dunedin Electricity.

Load growth does not appear to be a good indicator of a distributor's 2002 MTFP level ranking with Electricity Invercargill, the distributor with the highest MTFP level, having one of the lowest increases in energy throughput between 1996 and 2002 (see table 3). Conversely, Electricity Ashburton, the distributor with the lowest MTFP level in 2002, had the highest increase in electricity throughput over the same period. The two large urban distributors, Vector and UnitedNetworks, have only had mid–range increases in throughput over the period although they had among the highest increases in customer numbers. Generally, rural high density networks have achieved the highest increases in throughput. With the exception of Westpower, the rural low density distributors that have lower MTFP levels in 2002 do not appear to have had unusually low load growth over the period.

Scale of operations also does not appear to be a major determinant of MTFP levels in 2002 with the smallest distributor in terms of throughput (Scanpower) appearing near the top of the list and the second smallest distributor (Buller Electricity) appearing near the bottom. The five largest distributors (UnitedNetworks, Vector, Orion, Powerco and Dunedin) are spread across the top, middle and bottom thirds of the sample.

The unweighted average trend annual growth rate of MTFP for the distributors in the top third of the sample (excluding the anomalous Nelson Electricity results) is around 2.6 per cent for the seven year period and 2.3 per cent for the last four years (excluding the anomalous result for Vector). The corresponding unweighted average trend rates for the middle third of the sample are 2.9 per cent and 1.9 per cent, respectively. Lower trend growth rates are found in the bottom third of the sample with unweighted averages of 0.9 per cent and 1.0 per cent, respectively. The average trend growth rate for the middle third of the sample is close to the result for the distribution industry as a whole reported in section 7. Generally, the individual distributor MTFP indexes exhibit more volatility over time reflecting the variability of the underlying data at the distributor level. In many cases this will tend to reduce trend growth rates for individual firms compared to the aggregate of all firms.

We now proceed to assess the sensitivity of the results to output specification by looking at the corresponding MTFP indexes if each of the three outputs was used in isolation. We then examine an alternative three output specification using cost shares derived from the results of a Pacific Economics Group econometric cost function study using US data.

Table 9: **MTFP indexes using throughput as the sole output, 1996–2002**

ELB	Multilateral TFP indexes							Growth rates	
	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*96–-02*	*99–02*
El Invercargill	2.422	2.356	2.522	2.727	2.706	2.834	3.025	3.95%	3.58%
Nelson Elec	1.186	1.281	3.299	3.157	2.541	2.448	2.834	13.03%	-3.61%
Vector	2.179	2.136	2.030	1.675	2.130	2.621	2.768	4.20%	17.15%
N/W Tasman	1.266	1.160	1.247	1.365	1.658	1.742	1.874	8.12%	10.00%
Horizon Energy	1.118	1.188	1.081	1.489	1.783	1.886	1.810	10.25%	6.43%
Orion	1.290	1.304	1.263	1.621	1.610	1.674	1.683	5.50%	1.50%
UnitedNetworks	1.360	1.341	1.430	1.344	1.578	1.606	1.550	3.04%	4.46%
Waipa N/W	1.088	1.234	1.284	1.350	1.360	1.469	1.515	5.00%	4.24%
Northpower	1.326	1.339	1.337	1.454	1.443	1.551	1.496	2.62%	1.59%
Dunedin Elec	1.379	1.375	1.355	1.314	1.396	1.425	1.387	0.43%	1.84%
Unison	0.953	1.067	1.071	1.220	1.299	1.282	1.349	5.72%	2.86%
Alpine Energy	1.000	1.041	1.040	1.154	1.216	1.293	1.285	4.80%	3.84%
WEL Networks	1.183	1.275	1.308	1.177	1.320	1.289	1.277	0.93%	2.21%
Otago Power	0.945	1.006	0.876	0.916	1.054	1.169	1.196	4.26%	9.05%
Counties Power	1.198	1.105	1.078	1.108	1.138	1.157	1.186	0.41%	2.21%
Buller Elec	1.335	1.285	1.316	1.296	1.186	1.306	1.135	-1.99%	-3.02%
Electra	0.904	0.892	0.935	1.048	1.124	1.109	1.082	4.14%	0.82%
Scanpower	0.946	0.986	0.969	0.927	1.054	1.045	1.081	2.15%	4.54%
Elec Ashburton	0.788	0.834	0.996	1.007	0.928	1.077	1.025	4.39%	2.04%
The Power Co	0.682	0.806	0.828	0.866	0.894	0.957	0.945	4.99%	3.30%
N/W Waitaki	0.772	0.828	0.881	1.005	0.953	0.970	0.923	3.32%	-2.39%
MainPower	0.866	0.829	0.749	0.788	0.823	0.908	0.858	0.89%	3.54%
Marlborough	0.842	0.909	0.839	0.808	0.783	0.847	0.807	-1.20%	0.76%
Powerco	0.670	0.691	0.746	0.850	0.806	0.712	0.794	2.31%	-3.27%
Westpower	0.649	0.685	0.737	0.767	0.763	0.860	0.793	3.90%	2.18%
Centralines	0.583	0.607	0.681	0.586	0.712	0.790	0.789	5.28%	9.96%
The Lines Co	0.490	0.233	0.539	0.515	0.699	0.714	0.722	13.08%	10.36%
Top Energy	0.507	0.614	0.614	0.668	0.650	0.668	0.686	4.04%	1.07%
Eastland N/W	0.447	0.543	0.526	0.493	0.595	0.580	0.654	4.99%	8.19%

Source: Meyrick and Associates estimates

The MTFP indexes using throughput as the sole output are reported in table 9. We now see a predominance of high density and urban distributors in the top half of the ranking and mainly rural low density distributors in the bottom half of the ranking. Electricity Invercargill retains its highest ranking on this measure and the large urban distributors move closer to the top. Waipa Networks is the only rural low density distributor in the top half of the table. There is now a much wider spread in MTFP levels than was the case using the three output based measure. The finding that the throughput based output measure favours high density and urban distributors is consistent with the findings of similar studies in Australia. It reflects the fact that these distributors can deliver a given amount of electricity using fewer inputs than distributors who have to serve more customers and/or traverse greater distances to deliver the same total volume of electricity.

Table 10: **MTFP indexes using line capacity as the sole output, 1996–2002**

ELB	Multilateral TFP indexes							Growth rates	
	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*96–-02*	*99–02*
Otago Power	1.983	2.106	1.732	1.774	1.804	1.898	1.903	-1.04%	2.61%
The Power Co	1.525	1.563	1.568	1.583	1.565	1.588	1.560	0.35%	-0.28%
Centralines	1.449	1.433	1.569	1.348	1.573	1.535	1.532	1.10%	3.60%
The Lines Co	1.168	1.155	1.187	1.197	1.477	1.469	1.424	4.62%	5.16%
Scanpower	1.357	1.325	1.311	1.254	1.354	1.306	1.320	-0.29%	1.17%
N/W Waitaki	1.139	1.193	1.235	1.338	1.301	1.294	1.284	2.05%	-1.30%
Powerco	1.080	1.103	1.200	1.293	1.246	1.124	1.272	2.01%	-1.53%
MainPower	0.976	0.988	1.005	1.129	1.148	1.123	1.121	2.87%	-0.45%
Eastland N/W	0.887	1.012	0.995	0.958	1.048	0.924	1.066	1.51%	1.96%
Top Energy	1.064	1.041	1.034	1.142	1.108	1.068	1.064	0.43%	-2.50%
Westpower	0.786	0.780	0.904	0.985	0.988	1.107	1.046	5.88%	2.95%
Alpine Energy	1.000	1.015	0.968	0.992	1.009	1.004	1.004	0.12%	0.33%
Elec Ashburton	0.978	0.911	0.947	0.933	0.985	0.987	0.991	0.86%	1.82%
Waipa N/W	0.816	0.830	0.849	0.903	0.894	0.919	0.908	2.05%	0.45%
Marlborough	0.958	1.013	0.963	0.967	0.930	0.929	0.908	-1.32%	-1.89%
Northpower	0.850	0.835	0.814	0.873	0.896	0.896	0.856	0.92%	-0.58%
N/W Tasman	0.685	0.619	0.654	0.714	0.815	0.798	0.847	4.87%	4.93%
Buller Elec	0.949	0.880	0.914	0.908	0.810	0.931	0.812	-1.69%	-1.99%
Horizon Energy	0.524	0.563	0.535	0.702	0.744	0.838	0.801	8.56%	5.13%
Counties Power	0.631	0.616	0.605	0.651	0.571	0.679	0.688	1.42%	3.39%
Unison	0.462	0.478	0.465	0.533	0.575	0.563	0.583	4.41%	2.44%
WEL Networks	0.509	0.508	0.503	0.482	0.504	0.543	0.548	1.28%	4.59%
Dunedin Elec	0.493	0.495	0.494	0.496	0.535	0.541	0.539	1.89%	2.59%
Electra	0.453	0.447	0.464	0.482	0.509	0.517	0.498	2.39%	1.13%
UnitedNetworks	0.407	0.385	0.418	0.434	0.477	0.496	0.497	4.44%	4.45%
Orion	0.395	0.400	0.393	0.495	0.482	0.485	0.479	4.15%	-0.97%
El Invercargill	0.287	0.257	0.278	0.317	0.327	0.338	0.361	5.03%	4.28%
Vector	0.309	0.310	0.301	0.254	0.292	0.293	0.297	-0.95%	4.75%
Nelson Elec	0.126	0.135	0.350	0.313	0.247	0.243	0.276	11.38%	-3.95%

Source: Meyrick and Associates estimates

Moving to table 10, where we present the MTFP results using system capacity as measured by MVA kilometres as the sole output, the results are reversed. The rural distributors now occupy the top two thirds of the table while all the urban distributors are in the bottom third. This is because rural distributors require more line length to reach their customers compared to urban distributors and will, hence, do better when output is only measured by system capacity.

Table 11: **MTFP indexes using connections as the sole output, 1996–2002**

ELB	Multilateral TFP indexes							Growth rates	
	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*96–-02*	*99–02*
El Invercargill	2.459	2.222	2.402	2.711	2.783	2.853	3.038	4.58%	3.66%
Nelson Elec	1.100	1.177	3.046	2.897	2.309	2.236	2.609	12.86%	-3.46%
Vector	1.881	1.903	1.814	1.475	1.883	2.203	2.339	3.51%	15.41%
UnitedNetworks	1.476	1.391	1.508	1.576	1.740	1.752	1.796	4.26%	3.98%
Electra	1.548	1.528	1.590	1.675	1.776	1.723	1.702	2.28%	0.17%
Orion	1.239	1.257	1.210	1.507	1.509	1.559	1.541	4.67%	1.00%
Waipa N/W	1.331	1.350	1.389	1.445	1.439	1.543	1.532	2.59%	2.47%
WEL Networks	1.530	1.545	1.552	1.413	1.498	1.505	1.526	-0.34%	2.37%
Unison	1.168	1.219	1.184	1.352	1.399	1.366	1.424	3.53%	1.31%
Counties Power	1.513	1.384	1.336	1.409	1.375	1.362	1.379	-1.01%	-0.75%
N/W Tasman	1.037	0.935	0.992	1.092	1.263	1.255	1.350	5.80%	6.32%
Northpower	1.240	1.203	1.154	1.251	1.227	1.328	1.294	1.38%	1.79%
Scanpower	1.311	1.277	1.262	1.198	1.301	1.261	1.275	-0.28%	1.55%
Dunedin Elec	1.262	1.262	1.250	1.243	1.286	1.279	1.260	0.17%	0.36%
Horizon Energy	0.718	0.804	0.755	0.977	1.116	1.169	1.109	8.74%	4.27%
The Lines Co	0.772	0.784	0.727	0.729	0.973	1.026	1.022	5.97%	10.69%
Alpine Energy	1.000	1.015	0.948	0.985	1.019	1.007	1.018	0.39%	0.84%
Powerco	0.823	0.838	0.927	0.988	0.977	0.847	0.950	1.79%	-2.62%
N/W Waitaki	0.905	0.976	0.977	1.014	0.983	0.971	0.939	0.38%	-2.44%
Top Energy	0.844	0.839	0.853	0.931	0.928	0.905	0.925	1.83%	-0.45%
Eastland N/W	1.065	0.759	0.743	0.716	0.824	0.825	0.908	-0.74%	7.14%
MainPower	0.914	0.910	0.819	0.836	0.887	0.902	0.887	-0.10%	1.95%
Marlborough	0.923	0.982	0.884	0.894	0.875	0.903	0.883	-1.11%	-0.07%
Centralines	0.860	0.855	0.935	0.767	0.897	0.833	0.832	-0.69%	1.71%
Buller Elec	1.005	0.931	0.964	0.957	0.846	0.947	0.789	-2.94%	-4.67%
Otago Power	0.857	0.947	0.748	0.785	0.759	0.778	0.782	-2.34%	0.13%
The Power Co	0.743	0.705	0.698	0.738	0.765	0.791	0.779	1.67%	1.96%
Westpower	0.604	0.615	0.684	0.733	0.720	0.806	0.763	4.60%	2.34%
Elec Ashburton	0.688	0.636	0.663	0.657	0.693	0.696	0.687	0.78%	1.37%

Source: Meyrick and Associates estimates

The MTFP results using connection numbers as the sole output reported in table 11 again favour the urban distributors who occupy the top third of the rankings with the exception of the rural low density distributor, Waipa Networks, which lies in seventh place. The other rural distributors occupy the bottom two thirds of the ranking with the exception of the urban high density Dunedin Electricity which is in the middle of the ranking.

Table 12: **MTFP indexes using 3 outputs, PEG cost function weights, 1996–2002**

ELB	Multilateral TFP indexes							Growth rates	
	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*96–-02*	*99–02*
El Invercargill	1.588	1.484	1.597	1.769	1.790	1.857	1.980	4.38%	3.75%
Nelson Elec	0.739	0.794	2.051	1.933	1.544	1.497	1.731	12.64%	-3.63%
Vector	1.405	1.398	1.336	1.101	1.374	1.597	1.676	2.94%	14.09%
N/W Tasman	1.048	0.953	1.016	1.114	1.315	1.337	1.435	6.70%	7.77%
Waipa N/W	1.098	1.174	1.213	1.274	1.274	1.359	1.373	3.61%	2.90%
Horizon Energy	0.830	0.899	0.834	1.115	1.283	1.369	1.308	9.41%	5.46%
UnitedNetworks	1.098	1.057	1.138	1.130	1.283	1.307	1.296	3.72%	4.30%
Northpower	1.187	1.176	1.153	1.249	1.243	1.321	1.275	1.87%	1.22%
Orion	1.005	1.017	0.986	1.248	1.238	1.276	1.271	4.96%	0.84%
Scanpower	1.132	1.139	1.123	1.072	1.188	1.163	1.188	0.86%	2.88%
Unison	0.882	0.950	0.937	1.070	1.131	1.110	1.161	4.73%	2.27%
WEL Networks	1.088	1.130	1.143	1.046	1.135	1.141	1.144	0.58%	2.74%
Otago Power	1.062	1.143	0.953	0.994	1.053	1.126	1.141	1.02%	4.82%
Alpine Energy	1.000	1.027	0.994	1.063	1.106	1.132	1.133	2.41%	2.15%
Counties Power	1.138	1.059	1.031	1.078	1.055	1.098	1.118	0.14%	1.47%
Dunedin Elec	1.090	1.090	1.078	1.062	1.121	1.133	1.113	0.64%	1.50%
Electra	0.940	0.928	0.968	1.048	1.115	1.101	1.076	3.17%	0.67%
N/W Waitaki	0.879	0.941	0.976	1.068	1.025	1.028	0.991	2.10%	-2.19%
The Power Co	0.824	0.880	0.889	0.927	0.950	0.995	0.980	2.97%	2.14%
Buller Elec	1.135	1.071	1.104	1.092	0.983	1.098	0.941	-2.24%	-3.35%
The Lines Co	0.677	0.479	0.697	0.683	0.905	0.930	0.927	9.04%	9.43%
Powerco	0.789	0.809	0.881	0.971	0.937	0.826	0.926	2.08%	-2.71%
Centralines	0.795	0.807	0.894	0.756	0.900	0.918	0.917	2.47%	5.96%
MainPower	0.903	0.885	0.818	0.863	0.902	0.945	0.915	0.96%	2.22%
Elec Ashburton	0.787	0.776	0.862	0.861	0.853	0.916	0.892	2.49%	1.77%
Marlborough	0.890	0.953	0.878	0.866	0.841	0.881	0.851	-1.19%	-0.04%
Westpower	0.659	0.679	0.749	0.794	0.788	0.886	0.827	4.53%	2.38%
Top Energy	0.696	0.756	0.760	0.830	0.813	0.811	0.826	2.59%	-0.15%
Eastland N/W	0.683	0.687	0.669	0.637	0.742	0.715	0.803	2.40%	6.60%

Source: Meyrick and Associates estimates

Finally, we present an alternative three output based set of MTFP indexes in table 12 using output cost shares derived from the coefficients of an econometric cost function estimated using US distributor data reported in Pacific Economics Group (2000a,b). The implied output cost shares are 47 per cent for throughput, 27 per cent for system capacity and 33 per cent for customers. Compared to the cost functions results reported in section 8.3 using the New Zealand data, the US results place considerably more weight on throughput and less on system capacity and customer numbers. As a result, while the results in table 12 are broadly similar to the results of table 8 using the New Zealand estimates the results in table 12 marginally favour urban and high density distributors by comparison.

There are a number of reasons why we might expect the results of US based empirical distribution studies to differ from those based on New Zealand data. Firstly, there are significant differences in network technical characteristics between the US and New Zealand with different voltages and transformer options used. Secondly, the PEG study is based on investor–owned utility data which will contain few, if any, small rural distributors which are much more common in New Zealand. Much of the equivalent rural distribution in the US is handled by cooperatives rather than investor–owned utilities. Finally, vertically integrated utilities are much more common in the US and so a number of cost allocation decisions have to be made to obtain distribution data.

Based on the discussion in section 5.1 of the appropriate definition of distribution output and the above sensitivity analyses, we conclude that the MTFP results reported in table 8 provide the most appropriate measure of individual distributor productivity performance given information currently available. It may be possible to refine these estimates in future if more direct information on cost allocation between outputs becomes available. The sensitivity analyses reported above also illustrate how using the MTFP specification with three outputs and using weighted average output cost shares derived from New Zealand data goes a large way towards normalising for different density dimensions across the different types of distributors.

The multilateral input index and the multilateral output indexes for the five alternative specifications reported in this section are presented in appendix C.

8.3 Input requirements functions

Using the multilateral TFP indexing method in isolation it is only possible to incorporate aspects of density operating environment variables. While the review of previous distribution studies in section 4.1 indicated that density variables are likely to be the main cost drivers beyond management control that should be taken into account, there may be other influences such as the degree of undergrounding, the proportion of non–industrial consumption and geographic and climatic factors that should be taken into account. Input requirements functions are one means of supplementing MTFP estimation with econometric analysis to adjust for additional operating environment variables, subject to a number of separability assumptions.

It was also noted in section 5 that service quality is a potentially important output dimension that should be incorporated in the analysis but which it is not feasible to include directly in calculating MTFP indexes given the way service quality measures are presented. A possible alternative we investigate in this section is incorporating service quality measures as a form of operating environment variable using an inputs requirements function. While not an ideal option, the hypothesis is that providing more reliable service will require the use of more inputs (particularly capital inputs through better strengthening of the network) and so we would expect to see a negative relationship between the reliability variables (where a reduction in the measure represents an improvement in quality) and the level of input use.

The scope to include other operating environment characteristics in the analysis is relatively limited given the quantity and quality of the available data. Robust and objective information on climatic and geographic factors affecting distributors' territories is rarely available and New Zealand is no exception. Data on the split between residential and non–residential customers was only available for one year and there was no information available on residential versus non–residential consumption. While we were able to estimate the consumption split for one year based on an assumed average consumption per residential customer, this proved unhelpful for econometric estimation as the resulting variable of the proportion of non–residential sales was a constant for each distributor. It is worth noting that most attempts to adjust for operating environment variables using econometric methods are usually limited to one or two factors beyond the density variables due to multicollinearity problems. For instance, despite having access to relatively 'clean' data for around one hundred US distributors over several years, Pacific Economics Group (2000a,b) were only able to include the proportion of non–residential sales and three output variables to capture density differences due to statistical difficulties.

Christensen *et al* (1985) first used the input requirements function technique to adjust measured productivity in the United States postal system for changes in the number of delivery points in the postal network. They estimated Diewert's (1974) factor requirement function and this model was adapted to adjust measured productivity in electricity supply for differences in environmental factors by Zeitsch, Lawrence and Salerian (1994) who specified a function of the form;

(19) $$I = C / W = \mathrm{f}(Y, M, C, t)$$

where I is an aggregate index of inputs used by the distributor, C is total cost incurred by the distributor, W is a measure of distributor's unit input prices, Y is an index of sales of electricity, M is the capacity of the distributor's system, C is the number of the distributor's customers and t is a time trend representing structural improvements.

Equation (19) can be rearranged to show that it is based on the joint cost function having the following separable form:

(20) $C(W, Y, M, C, t) = c(W)\,f(Y, M, C, t)$

where c is a unit cost function (estimated via index number theory) and f is the input requirements function. Zeitsch, Lawrence and Salerian used a single output MTFP model based on throughput and then used the input requirements function to adjust for differences in the system capacity per kilowatt hour of throughput for two systems, one of which had a much larger and more sparsely settled territory than the other. Attempts to include the customer variable failed due to its high correlation with the throughput variable.

Estimated input usage that would be required by each distributor if they both faced the same system capacity to throughput density was then calculated and the adjusted input usage level was then fed back into the multilateral TFP index to calculate efficiency differences adjusted for this particular operating environment condition.

Table 13: **Inputs requirements functions regression results**

Variable	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6
Constant	–12.188	–12.624	–12.538	–12.645	–11.898	–12.289
	(–28.45)	(–28.69)	(–29.23)	(–28.93)	(–29.90)	(–31.07)
Time	–0.025	–0.020	–0.021	–0.019	–0.029	–0.023
	(–3.66)	(–2.89)	(–3.08)	(–2.86)	(–4.55)	(–3.69)
Throughput	0.168	0.184	0.177	0.182	0.183	0.203
	(4.01)	(4.49)	(4.36)	(4.48)	(4.75)	(5.48)
System capacity	0.426	0.399	0.400	0.395	0.531	0.506
	(33.78)	(26.15)	(27.35)	(25.76)	(22.63)	(21.85)
Connections	0.437	0.448	0.452	0.453	0.295	0.299
	(10.21)	(10.76)	(10.85)	(10.92)	(6.16)	(6.55)
SAIDI		0.051		0.027		0.060
		(3.01)		(1.16)		(3.91)
Lagged SAIDI			0.045	0.032		
			(3.16)	(1.47)		
% Underground					0.092	0.099
					(5.15)	(5.78)
Adjusted R^2	0.987	0.988	0.988	0.988	0.989	0.990
Normal statistic	–7.582	–6.414	–6.404	–7.064	–7.250	–5.917

Source: Meyrick and Associates estimates

In this study we have estimated a number of inputs requirements functions incorporating the three outputs (and, hence, density dimensions), service quality variables and the extent of undergrounding. The regression results are presented in table 13 estimated for the 29 distributors over the five years 1998 to 2002. The shorter estimation period is used to accommodate lagged variables. All variables are in natural logs except for the time trend.

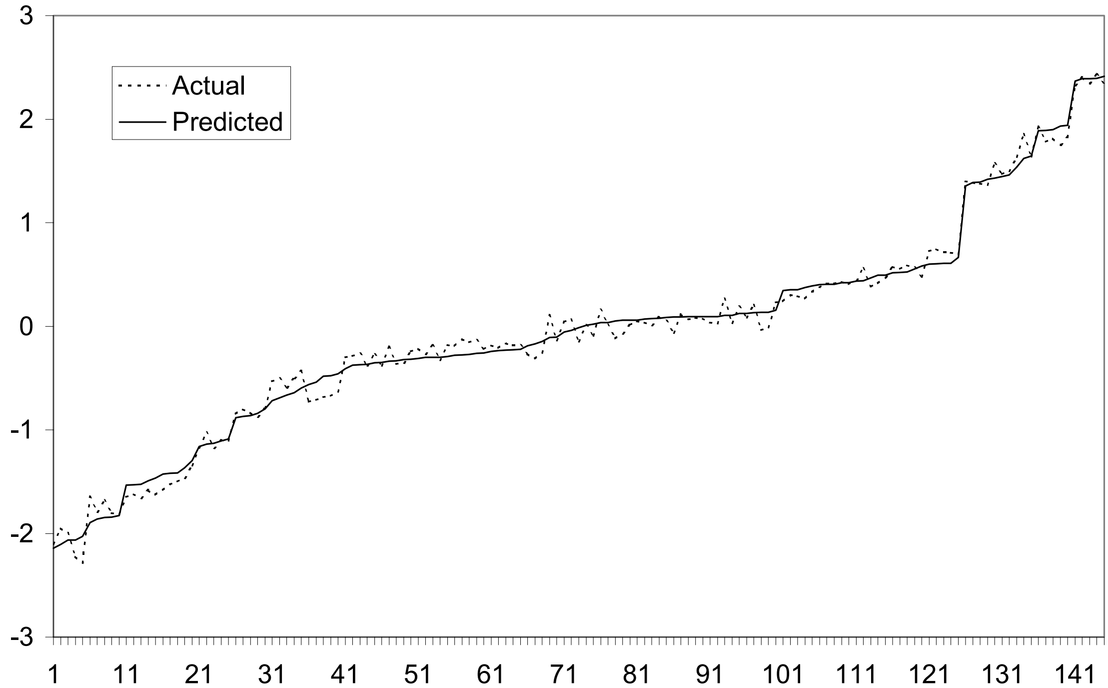
The regression results show that input requirements are decreasing at the rate of between 2 and 3 per cent per annum, all else unchanged. These rates are broadly consistent with the rates of productivity improvement reported elsewhere in the paper. The coefficients on the three output variables are all positive as is required for a well behaved function. This means that increased production of any of the three outputs requires more inputs, all else unchanged. The relative elasticities on the three outputs are also broadly in line with the output cost shares obtained in the cost function estimated in the following section. The system capacity coefficient has by far the highest significance level.

Contrary to the effect initially expected, the coefficients on the service quality variables all have positive signs and are significant. While we would normally expect the provision of a more reliable service to require more inputs (and, hence, a negative sign in this instance), there are also some plausible explanations for a positive sign. In particular, if reliability worsens in a particular year then the distributor may need to use more operating expenses in that year to respond to outages. While this would not affect capital inputs, it would account for an increase in inputs being associated with a worsening of reliability. However, the relationship between capital inputs and reliability is considerably more complex. Some distributors in remote parts of Australia have observed that it normally takes around three years for capital expenditure aimed at improving the performance of worst feeders to have a significant effect. This is because it takes time to complete interrelated projects aimed at strengthening the system overall. This would point to a relationship between input use now and reliability performance in two to three years' time. Others have observed that the lag may go in the opposite direction as it takes time for distributors to recognise problem areas, get approval for expenditure and then to implement the work program. This would point to a relationship between input use now and reliability performance two years ago.

To test the backwards lag relationship we have included SAIDI lagged two years in some regressions. However, the sign and magnitude of the coefficient are unchanged. Including the proportion of underground lines leads to a positive relationship with input use which is plausible as underground lines are more capital intensive but generally require less operating expenditure.

In figure 12 we plot the actual and predicted dependent variables for model 6. While the models all have relatively high R^2 values, there is still considerable variation of the actual dependent around the predicted. This differs from the application of Zeitsch, Lawrence and Salerian where the predicted dependent variable fitted the actual series very closely. This was most likely due to that application only having two distributors and around 15 years of relatively clean data for each. The fact that we have 29 distributors here and only five years of relatively variable data on each makes it harder to fit the equation closely. Attempts to improve the fit by including distributor specific dummy variables failed as the non–negativity requirement on the output coefficients was not met. This implies that the production of an output can be increased by reducing input usage or that a so–called 'free lunch' exists. The models also fail the normality test although the main implication of this is the resulting unreliability of the significance tests.

Figure 12: Actual and predicted logarithm of input use, model 6



Given the poor statistical properties of this model, the fact that the complex interactions of service quality and input use do not appear to be adequately captured and the inability to estimate a model with distributor specific dummy variables that satisfies the necessary non–negativity properties, we conclude that the separability conditions to support this approach are not satisfied. Consequently, the allowance for density differences implicit in the multi–output MTFP model appears to offer a better way of incorporating density effects in our assessment of comparative productivity performance than the input requirements function approach.

To further advance econometric estimates of productivity differences and to provide an alternative approach to verifying the multi–output MTFP rankings, in the following section we estimate cost function based efficiency scores.

8.4 Cost function efficiency scores

The sophistication of the cost function model we are able to estimate is limited by the number of observations we have for each distributor and the range of variables available. In particular, we have no information on the price individual distributors pay for their operating expenses and have assumed they face a common price given by the EGW labour cost index. Further, as noted earlier, we effectively have no labour data at all which precludes including the input common to nearly all cost function studies.

To overcome these problems, we estimate a multi–output Leontief cost function. This functional form essentially assumes that distributors use inputs in fixed proportions for each output. We include the three outputs of throughput, system line capacity and connections. We include four of the five inputs used earlier: operating expenses, overhead lines, underground lines and transformers. We exclude the other capital item which only makes up between two and three per cent of total costs to conserve degrees of freedom. To improve the statistical properties of the model we change to measuring system line capacity by a transformer capacity and line length based measure rather than the line length and voltage based measure used earlier. This change is made to reduce the potential for linear dependence between the system line capacity output quantity and the overhead line and underground cable input quantities. We retain the line length and voltage based measure for the overhead and underground lines capital input quantities.

The Leontief cost function is given by:

(21) $$C(y^t, w^t, t) = \sum_{i=1}^{4} w_i^t \, [\sum_{j=1}^{3} (a_{ij})^2 \, y_j^t \, (1 + b_i t)]$$

where w_i is an input price, y_j is an output and t is a time trend representing technological change. The input/output coefficients a_{ij} are squared to ensure the non–negativity requirement is satisfied, ie increasing the quantity of any output cannot be achieved by reducing an input quantity. This means we have to use non–linear regression methods. To conserve degrees of freedom we impose a common rate of technological change for each input across the three outputs but this can be either positive or negative.

The estimating equations are the four input demand equations:

(22) $$x_i^t = \sum_{j=1}^{3} (a_{ij})^2 \, y_j^t \, (1 + b_i t); \quad i = 1,..,4; \; j = 1,2,3; \; t = 1,..,7.$$

where the *i*'s represent the four inputs, the *j*'s the three outputs and *t* the seven years, 1996 to 2002.

The input demand equations are estimated separately for each of the 29 distributors using the non–linear regression facility in Shazam (White 1997) and data for the years 1996 to 2002. Given the limited number of observations and the absence of cross equation restrictions, each input demand equation is estimated separately. This leads to a total of 116 separate regressions, the results of which are reported in appendix D.

From the estimated equations we can derive information on each distributor's rate of productivity change and its relative efficiency. The period t productivity change estimate for a distributor is equal to (the negative of) the amount of cost reduction due to the passage of one period:

(23)
$$\begin{aligned} Tech^t &= -[\partial C(y^t, w^t, t)/\partial t]/C(y^t, w^t, t) \\ &= -[\textstyle\sum_{i=1}^4 w_i^t [\sum_{j=1}^3 (a_{ij})^2 b_i y_j^t)]/\{\sum_{i=1}^4 w_i^t [\sum_{j=1}^3 (a_{ij})^2 y_j^t (1+b_i t)]\} \end{aligned}$$

The efficiency of a particular distributor in a particular year can be derived by comparing its estimated cost for that year with a 'benchmark' cost using a numeraire observation's technology (or estimated parameters) but the distributor's actual output quantities:

(24)
$$E_n^t = C(b, y_n^t, w_n^t, t)/C(n, y_n^t, w_n^t, t)$$

where b is the benchmark observation and n is the distributor whose efficiency we are calculating. Thus, if distributor n can produce its output quantities at lower cost using its own technology than it could using the benchmark distributor's technology then E will be greater than one and n will be more efficient than the benchmark. Conversely, if n could produce its output quantities more cheaply using the benchmark distributor's technology than it can using its own then E will be less than one and n will be less efficient than the benchmark.

The problem with equation (24) is that the efficiency scores and rankings are likely to vary depending on which observation we choose as the benchmark or numeraire. To overcome this problem we take the benchmark to be a weighted average of the technologies of all the observations in the sample where the weights are given by the share of the observation's estimated cost in the total cost for all distributors and all time periods:

(25)
$$E_n^t = [\textstyle\sum_{b,t} s_b^t C(b, y_n^t, w_n^t, t)]/C(n, y_n^t, w_n^t, t)$$

where:

(26)
$$s_b^t = C(b, y_b^t, w_b^t, t)/\textstyle\sum_{b,t} C(b, y_b^t, w_b^t, t).$$

Equations (25) and (26) use an analogous idea to the multilateral TFP method in that the benchmark is taken to be a weighted average of all observation's technologies. This means the efficiency scores will be invariant provided the sample is not changed.

We can also derive the output cost shares for each output and each observation as follows:

(27)
$$h_j^t = \{\textstyle\sum_{i=1}^4 w_i^t [(a_{ij})^2 y_j^t (1+b_i t)]\}/\{\sum_{i=1}^4 w_i^t [\sum_{j=1}^3 (a_{ij})^2 y_j^t (1+b_i t)]\}.$$

We then form a weighted average of the estimated output cost shares using equation (26) to form an overall estimated output cost share. This process produces output cost share estimates of 18 per cent for throughput, 34 per cent for system line capacity and 48 per cent for connections. This procedure will produce more robust and stable estimates of the cost shares given the limited number of observations available than the alternative of running one set of regressions on the aggregated data. It is also necessary to run the regressions separately for each distributor to derive efficiency scores and thus forming the output cost share estimates in this manner is consistent with the way the efficiency scores are derived.

We present the efficiency scores derived from the cost function model in table 14. Again the distributors are listed by declining efficiency score in 2002. We also include the average productivity growth rates obtained from equation (23) for the seven year period 1996 to 2002 and for the last four years 1999 to 2002.

The cost function efficiency scores cover a wider range than the corresponding three output MTFP indexes but the ranking of distributors is broadly similar. Vector is now found to be the most efficient distributor in 2002 followed by Nelson Electricity, UnitedNetworks and Electricity Invercargill. Westpower, Buller Electricity, Eastland Network and Electricity Ashburton now have the lowest efficiency scores.

Of the 29 distributors, the rankings of around seven distributors have changed noticeably compared to the MTFP rankings for 2002. Three have moved up the scale somewhat with Orion and Powerco moving from the middle third to the top third, and Dunedin Electricity moving from the bottom third to the middle third. Waipa Networks and Network Tasman have moved from near the top of the MTFP ranking to the middle of the cost function ranking while The Lines Company and Network Waitaki move from the top third of the MTFP rankings to the bottom third of the cost function rankings. Generally, the cost function rankings tend to favour urban and large distributors marginally more than the MTFP rankings. The differences in ranking in 2002 can be explained by the greater smoothing occurring in the cost function due to the use of regression techniques, some different smoothing occurring in the MTFP model due to the use of common output cost shares and the use of a slightly different output specification in the cost function to make estimation more tractable.

Excluding Nelson Electricity, the unweighted average productivity growth estimated by the model is 2.6 per cent per annum for the top third of distributors over the seven year period and 3.2 per cent for the last four years. The productivity growth for the middle third, excluding Horizon Energy which appears to have an unusually high growth rate, is 3.2 per cent per annum for the seven years and 3.5 per cent for the last four years. Productivity growth has again been somewhat lower for the bottom third of distributors with 2.5 per cent per annum for the last seven years and 2.7 per cent for the last four years.

Table 14: **Cost function efficiency scores using 3 outputs, 1996–2002**

ELB	Efficiency score							Prod. change	
	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*	*96--02*	*99–02*
Vector	4.371	4.278	4.410	4.178	4.232	4.449	5.031	2.54%	2.66%
Nelson Elec	1.581	1.733	2.277	2.451	3.011	3.515	4.942	16.88%	21.10%
UnitedNetworks	3.077	3.223	3.417	3.743	3.914	4.357	4.869	4.80%	5.44%
Elec Invercargill	2.965	3.025	3.121	3.266	3.599	4.193	4.846	3.63%	3.98%
Orion	2.158	2.314	2.407	2.513	2.493	2.580	2.693	4.16%	4.55%
Scanpower	3.271	3.200	2.931	2.777	2.715	2.611	2.636	-0.67%	-0.65%
Otago Power	9.065	8.309	1.656	1.562	1.641	1.708	1.803	1.08%	3.38%
Powerco	1.426	1.471	1.505	1.542	1.561	1.604	1.678	2.77%	2.95%
Unison	0.999	1.036	1.082	1.127	1.184	1.258	1.337	5.35%	5.96%
Northpower	1.181	1.191	1.225	1.263	1.250	1.287	1.331	3.85%	4.21%
WEL Networks	1.157	1.201	1.241	1.210	1.254	1.262	1.289	2.42%	2.55%
Dunedin Elec	1.134	1.148	1.162	1.174	1.205	1.246	1.268	0.60%	0.66%
The Power Co	1.078	1.112	1.147	1.174	1.186	1.210	1.240	3.57%	3.38%
Electra	0.994	1.034	1.080	1.113	1.151	1.157	1.205	3.29%	3.43%
Waipa Networks	0.988	1.011	1.026	1.065	1.081	1.199	1.198	2.29%	2.37%
Network Tasman	0.826	0.855	0.880	0.914	1.008	1.105	1.196	5.98%	6.92%
Counties Power	1.263	1.042	1.067	1.076	1.068	1.060	1.069	1.60%	1.81%
Horizon Energy	0.558	0.607	0.648	0.716	0.797	0.897	1.031	10.07%	11.64%
Alpine Energy	0.840	0.855	0.865	0.883	0.909	0.929	0.945	1.80%	1.88%
Centralines	0.942	1.003	0.976	0.970	0.984	0.981	0.943	2.22%	2.48%
The Lines Co	0.824	0.808	0.835	0.834	0.916	0.912	0.917	0.24%	0.22%
MainPower	0.776	0.799	0.788	0.800	0.833	0.880	0.909	5.58%	6.09%
Network Waitaki	0.923	0.913	0.929	0.934	0.951	0.886	0.883	2.43%	2.65%
Top Energy	0.763	0.770	0.782	0.789	0.798	0.807	0.827	3.37%	3.62%
Marlborough	0.858	0.841	0.778	0.772	0.772	0.807	0.787	0.98%	0.99%
Elec Ashburton	0.627	0.633	0.653	0.679	0.696	0.716	0.726	3.74%	4.01%
Eastland N/W	0.656	0.570	0.618	0.646	0.648	0.680	0.704	3.90%	3.99%
Buller Electricity	1.210	1.180	0.939	0.924	0.816	0.736	0.697	-0.77%	-0.59%
Westpower	0.523	0.524	0.562	0.634	0.642	0.654	0.680	4.39%	4.32%

Source: Meyrick and Associates estimates

The econometric cost function efficiency results broadly confirm the findings of our preferred MTFP results despite being derived from a different methodology.

8.5 Price/quality trade–off considerations

We now move on to the second stage analysis and examine the scope to use an ad hoc price/service quality function to identify businesses that appear to have high and low price levels given their service quality levels and costs as a means of reviewing their initial allocation to C factor groups based on relative productivity performance alone. We undertake a number of regressions of price against service quality and a range of other variables to better understand the relationship between price and service quality. We confine the analysis to the last four years we have data for – 1999 to 2002 – as the data are somewhat more stable and better defined for this period.

The first issue that has to be resolved is what measure of price should we use? Electricity prices usually include a fixed component and a per kilowatt component. This would point to expressing the price as either revenue per customer or revenue per kilowatt hour. However, as discussed earlier in this report, distribution output really comprises at least three dimensions – throughput, system line capacity and a connection related component. To be consistent with methodologies used in the preceding sections, we express price as revenue divided by the three output multilateral output index. Price is, thus, revenue per unit of an amalgam of the distributor's throughput, system line capacity and connection numbers. Furthermore, in the interests of consistency we include only pre–rebate revenue for those trusts which offer explicit rebates.

There are also a number of alternative measures of service quality that can be used. While service quality comprises three main components – reliability, technical voltage characteristics and customer service – reliability is usually the main focus of attention in analytical studies as it is the principal concern of most customers. It is also the aspect that the most objective and consistent data is available for. But reliability can be measured by either the total time an average consumer is off–supply each year (measured by SAIDI) or the frequency of interruptions the average consumer faces each year (measured by SAIFI). The correlation between these two measures for the 29 distributors and 4 years is 86 per cent. We have obtained somewhat better statistical results using the frequency variable rather than duration and so only report the results using SAIFI to conserve space.

The relationship between reliability and distribution costs is relatively complex and is likely to involve a number of lagged effects that variously relate current costs to both past and future reliability performance. Adequately modelling this relationship would require a much more detailed model of the relationship between service quality and input levels than it has been feasible to develop given both the data and time available for this project. A number of analysts and distributors have speculated, however, that it should be possible to observe a negative relationship between reliability and price once operating environment differences, particularly energy and customer density, have been allowed for. The negative relationship arises from the way reliability is measured. An improvement in service quality is associated with a reduction in the frequency and duration of interruptions which means a reduction in

SAIFI and SAIDI. Higher quality or more reliable supply would normally be associated with a higher cost and this could be expected to feed through to a higher price. Conversely, all else equal, one would expect to pay less for a less reliable service (characterised by higher SAIFI and SAIDI values).

The results of the price/quality regressions are presented in table 15. The regressions use ordinary least squares and the figures in parentheses are *t*–statistics. All variables are in natural logarithmic form except for the time trend. It should be noted that the models do not pass the normality test and refinement of the estimation method may be a worthwhile area for future work. The effect of the normality assumption not being satisfied mainly affects inferences about significance levels.

Table 15: **Price/quality regression results**

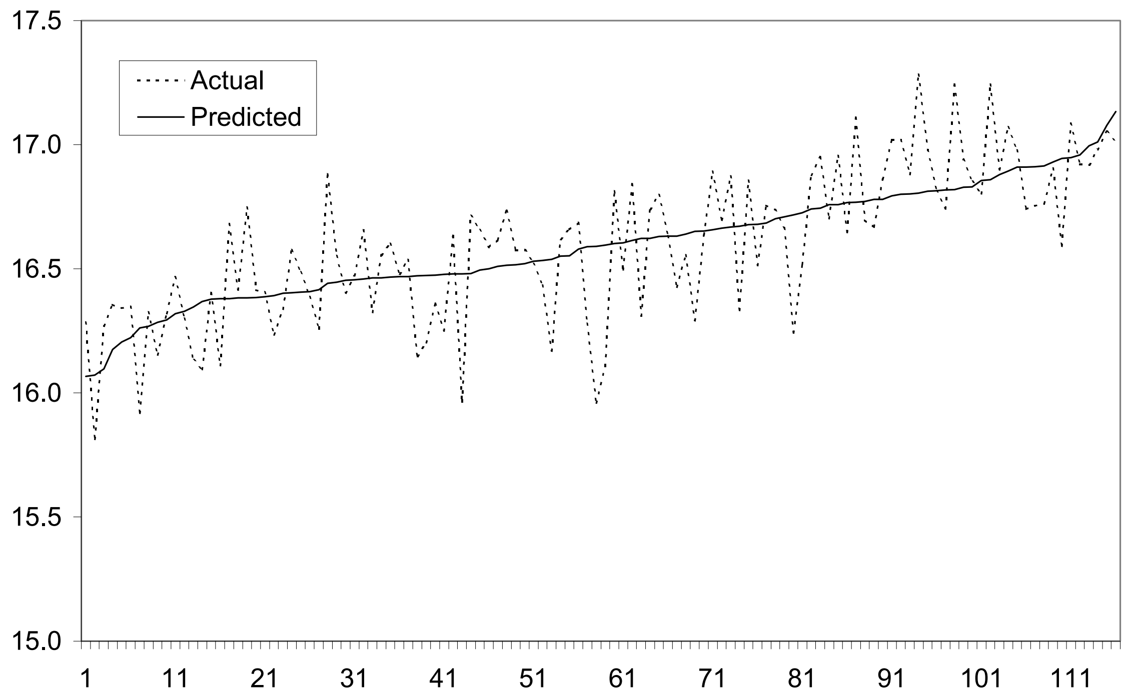
Variable	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6
Constant	5.958	16.291	16.254	19.058	18.555	5.048
	(3.14)	(139.60)	(109.60)	(15.520)	(19.240)	(2.12)
Time	0.071	0.0619	0.062	0.059	0.065	0.077
	(4.03)	(3.16)	(2.48)	(2.45)	(3.41)	(4.65)
Total cost	0.625					0.719
	(5.45)					(6.06)
Output index	–0.653	–0.150			–0.158	–0.751
	(–7.00)	(–8.46)			(–8.54)	(–7.57)
SAIFI	–0.794	–0.040	0.002	–0.074	–0.053	–0.044
	(–2.38)	(–1.10)	(0.05)	(–1.38)	(–1.27)	(–1.21)
Energy density				–0.258	–0.242	–0.104
				(–2.12)	(–2.54)	(–1.20)
Customer density				–0.109	0.032	0.127
				(–2.06)	(0.71)	(3.05)
Adjusted R^2	0.533	0.413	0.051	0.106	0.451	0.583
Normal statistic	–4.805	–5.383	–7.249	–6.153	–5.407	–4.661

Source: Meyrick and Associates estimates

In the first model we include a time trend to pick up movements in price levels over the four years, total cost to reflect the fact that one would expect to see higher prices from distributors who face higher cost structures, the output index to pick up scale and density effects (as the output index includes the three separate output dimensions) and SAIFI. The regression has an R^2 of 0.53 reflecting the greater variability of prices compared to costs and hence a worse overall fit than we obtained for the inputs requirements functions in section 8.3. This is illustrated in figure 13 where we plot the actual and predicted values of the dependent variable.

The time trend coefficient indicates that prices have increased on average by around 7 per cent per annum over this period. As expected, the unit price has a significantly positive relationship with total cost. It has a significantly negative relationship with total output reflecting a degree of scale economies or volume discounting. While we would expect to see this relationship with throughput where larger customers typically obtain cheaper rates and larger distributors are able to spread fixed costs over a larger number of customers, the effect is probably reinforced by rural distributors who have longer line lengths charging below commercial prices. Including the three output quantities separately led to less precise results due to the high correlation between throughput and connection numbers. Finally, we find a significant negative relationship between price and SAIFI as hypothesised although this variable has lower significance than for the other included variables.

Figure 13: Actual and predicted logarithm of unit price, model 1



In model 2 we exclude total cost from the first model. The explanatory power of the model falls markedly with the R^2 now 0.41. The significance of the reliability variable also falls markedly. In model 3 we also exclude total output and the explanatory power of the model and significance of the reliability variable both collapse. We conclude from this that it is necessary to include the output term to capture scale and density effects and to include the total cost term to capture the relationship between price and cost. Failure to include either of these terms leads to a model far inferior to the first model.

In model 4 we examine an alternative approach which explicitly includes energy and customer density variables and leaves out the output index. The explanatory power of this model is again very poor with an R^2 of only 0.11 and the reliability variable is again insignificant. The two density variables are both marginally significant and negatively related to price. The negative relationship can be explained by increasing throughput per customer and increasing customers per kilometre of line both enabling distributors to spread their fixed costs more effectively as the delivery of a given quantity of output requires less inputs. In model 5 we include the output index which increases the explanatory power considerably but the customer density variable changes sign and becomes insignificant, probably reflecting the fact that we are now in some ways double counting the density effect given the definition of the output index. In model 6 we also include total costs and the explanatory power of the model again increases with an R^2 of 0.58. However, the energy density variable now becomes insignificant and the customer density variable remains positive as in model 5 but becomes significant. In the two models where we have included both total output and cost, the coefficient on output is close to the negative of that on total cost implying that the composite explanatory variable for price is unit cost, as theory would predict. Including energy density and customer density as well as these variables then simply leads to multicollinearity problems. SAIFI remains negative but insignificant in model 6.

On the basis of these results we believe model 1 performs best. It most clearly captures the negative relationship between price and SAIFI while avoiding double counting of density effects. It demonstrates that we also need to include total cost as an explanator to adequately explain prices.

We now examine whether each business's price has been above or below that predicted by model 1 based on its characteristics. We do this by regressing the residuals from model 1 on a set of business specific dummy variables. The coefficient on the dummy variable then indicates the average deviation of the business's actual prices from those the model predicts for it over the four years 1999 to 2002. This enables us to rank the businesses from those with actuals most above the predicted price on average through to those with actuals most below the predicted price on average.

The results are presented in table 16 and show that WEL Networks, Horizon Energy, Counties Power and Eastland Network are the distributors with actual prices most above those predicted by the model while The Power Company, Northpower, Otago Power and Waipa Networks are those with actual prices most below those predicted.

The ranking in table 16 matches the ranking based on rates of return presented in table 17 in the following section relatively closely. Only six of the 29 distributors have rankings that differ noticeably between the two tables. The Lines Company and MainPower receive a higher ranking using the price equation compared to the rate of return while UnitedNetworks, Orion, Dunedin Electricity and Alpine Energy receive a lower ranking based on the price equation than they do based on the rate of return. This again highlights the relative importance of costs and profitability in determining prices compared to differences in service quality although the latter may be important for some distributors.

Table 16: **Difference between actual and predicted prices, average 1999–2002**

ELB	*Coefficient*	*ELB*	*Coefficient*
Actual price above predicted		***Actual price above predicted (cont'd)***	
WEL Networks	0.2426	Vector	0.0281
Horizon Energy	0.2363	Buller Electricity	0.0170
Counties Power	0.1925	Scanpower	0.0162
Eastland Network	0.1886	***Actual price below predicted***	
Nelson Electricity	0.1290	Dunedin Electricity	-0.0036
The Lines Company	0.1208	Alpine Energy	-0.0050
MainPower	0.0876	Powerco	-0.0314
UnitedNetworks	0.0772	Top Energy	-0.0377
Network Tasman	0.0724	Electricity Ashburton	-0.1285
Centralines	0.0668	Network Waitaki	-0.1418
Electra	0.0558	Unison	-0.1831
Electricity Invercargill	0.0464	Waipa Networks	-0.2211
Orion New Zealand	0.0408	Otago Power	-0.2589
Westpower	0.0367	Northpower	-0.3038
Marlborough Lines	0.0297	The Power Company	-0.3695

Source: Meyrick and Associates estimates

While the price/quality regressions provide useful information, they are sensitive to the specification used and are unable to separately identify the contribution of service quality to price. To be able to do this with confidence we need a much more detailed model of the relationship between service quality and input levels than it has been feasible to develop given both the data and time available for this project. This remains a priority for future research. At this time the price/quality regression concept does not provide either a theoretically well–developed or a sufficiently empirically robust means of adjusting the initial C factor allocations due to the difficulty in defining a statistically robust model, the sensitivity of its specification, and the lack of a theoretical basis for preferring one econometric model over another. It also does not provide a way of making the adjustments in a framework that is integrated with the productivity analysis. To do this, we look at using the economic rate of return in the following section.

8.6 Profitability considerations

Having rejected the price/quality regressions as a basis for incorporating profitability and service quality considerations jointly, we move on in this section to review available evidence on the businesses' residual rates of economic return as a basis for adjusting their allocation to broad C factor groupings taking profitability into account as well as comparative efficiency.

If a business is currently earning 'excessive' profits (a return higher than its weighted average cost of capital plus a margin for error), it can sustain a higher level of real price reduction than that indicated solely by its relative productivity performance. Conversely, if a business is currently earning a 'low' return then there is an arguable case for easing the tightness of its threshold based purely on productivity considerations to allow it to return to earning normal rates of return.

Profitability issues are often addressed separately from productivity issues by the setting of a 'P_0' factor separately from the X factor. While the X factor is based on relative productivity considerations as usual, the P_0 adjustment is applied as an additional adjustment in the first year of the regulatory period to bring the business's profitability back to 'normal' levels. P_0 adjustments have been the subject of much controversy in other countries. By sometimes placing a large adjustment burden on the distributor in a short space of time there is a risk that this process can place undue financial distress on the lines business and endanger the ongoing security of supply. They also assume that the regulator has full information which is rarely the case.

A more reasonable approach to addressing the profitability problem is setting a 'glide path' where prices are adjusted over a period of several years to bring the business to a position of earning a normal return. The overall X factor that a business is set will then consist of two components: the usual productivity–based component plus an additional component aimed at gradually eliminating excess profits or restoring normal returns, as the case may be. This concept is illustrated diagrammatically in Hawke's Bay Network/NECG (2003, p.7).

The range of ownership types and associated objectives complicates assessing the profitability of New Zealand lines businesses. The businesses can be broadly divided into three groups: commercial businesses that issue dividends to shareholders in the normal way; trusts which offer 'dividends' to their consumers/owners in the form of explicit rebates which may take the form of line charge holidays; and, trusts which provide a 'return' to their consumers/owners implicitly in the form of lower prices. This makes assessing profitability against normal commercial criteria such as the rate of return difficult. However, we do not have enough information to attempt to adjust for ownership influences. Instead we assess businesses on the basis of pre–rebate prices. This is equivalent to treating the explicit trust rebates as a form of dividend to 'shareholders'. Trusts that offer implicit rebates in the form of low prices would be encouraged to adopt more transparent methods of providing a return to their owners by this assessment method.

To be consistent with the MTFP and cost function analyses reported earlier in this section, we assess profitability by examining the residual rates of return implied by our database. The residual rate of return is derived by subtracting operating expenses (derived by grossing up direct line costs per kilometre and indirect costs per customer) and estimated depreciation (calculated as 4.5 per cent of ODV) from 'deemed' revenue (comprising total operating revenue plus AC loss rental revenue received less payment for transmission charges less AC loss rental expense paid to customers).

It must be stressed that this rate of return measure is a totally different concept from the weighted average cost of capital (WACC) measure used for regulatory purposes. Under New Zealand's information disclosure regime for lines businesses, the WACC estimated for the business is notionally comparable with a return on investment (ROI) value calculated for the business as a whole and covers a wider range of 'inputs' and assets than are included in our database. For instance, our analysis focuses on system fixed assets only and excludes many accounting based items such as goodwill and income from revaluations. The residual rate of return derived from our database approximates the economic return to capital used in distribution taking account of actual direct revenues from distribution sales and expenditure on inputs actually consumed each year in the direct production of distribution services.

The residual rates of return derived from our database are presented in table 17. To provide an approximate basis for comparison with a WACC measure and to assist with setting appropriate 'deadbands', we also include a pre–rebate estimate of disclosed ROI excluding the impact of revaluations in table 17. In both cases the figures are an average for the three years 2000 to 2002.

The residual rates of return are generally higher than the corresponding adjusted ROI reflecting the fact that the residual rate of return is a more basic measure with fewer 'cost' deductions and a narrower range of assets as the denominator. Despite this, the broad rankings between the two measures are similar for most businesses.

We divide the businesses into three groups – high, medium and low rates of return – with approximately one third of the businesses in each group. This also corresponds with the WACC deadband of around 6 to 8 per cent recommended for New Zealand lines businesses by Lally (2003). This leads to businesses with low rates of return being those with a residual rate of return of less than 10 per cent and those with high rates having residual rates of return in excess of 13.5 per cent. Only four of the 29 businesses would have changed groups if we had used the adjusted ROI with cut–offs of 6 and 8 per cent instead of the residual rate of return with cut–offs of 10 and 13.5 per cent. Eastland Network would move from the high group to the medium group while Electra would move from the medium to the high group and Marlborough Lines and Scanpower would move from the medium to the low group.

Table 17: **Residual rate of return and adjusted ROI estimates, average 2000–2002**

ELB	*M&A Residual rate of return*	*Adjusted ROI*	*ELB*	*M&A Residual rate of return*	*Adjusted ROI*
High rate of return			***Medium rate of return (cont'd)***		
Nelson Electricity	25.19%	10.14%	Marlborough Lines	11.04%	4.45%
UnitedNetworks	19.93%	12.00%	MainPower	10.80%	6.41%
WEL Networks	17.22%	9.46%	Powerco	10.61%	7.82%
Horizon Energy	17.16%	10.54%	Scanpower	10.55%	5.10%
Network Tasman	16.37%	8.55%	***Low rate of return***		
Orion New Zealand	15.33%	8.85%	Network Waitaki	9.17%	4.05%
Alpine Energy	15.17%	8.77%	Unison	8.53%	4.40%
Counties Power	13.72%	10.35%	Westpower	7.54%	5.54%
Eastland Network	13.61%	7.74%	Buller Electricity	7.53%	4.31%
Dunedin Electricity	13.57%	9.24%	Electricity Ashburton	7.39%	3.90%
Medium rate of return			Waipa Networks	6.68%	4.09%
Electricity Invercargill	13.40%	7.76%	Northpower	6.37%	4.82%
Vector	12.66%	7.49%	Top Energy	5.95%	6.06%
Centralines	12.16%	6.05%	Otago Power	5.92%	3.12%
The Lines Company	11.62%	8.82%	The Power Company	2.97%	1.71%
Electra	11.17%	10.35%			

Source: Meyrick and Associates estimates

The distributors earning the highest residual rates of return include a mixture of listed businesses, trusts, consumer trusts and council owned entities. Nelson Electricity has the highest residual rate of return although, as noted earlier, the data for this distributor generally appears erratic. UnitedNetworks, WEL Networks, Horizon Energy and Orion have the next highest residual rates of return. The businesses in the low rate of return group are all trusts plus the consumer cooperative Otago Power. The Power Company, Otago Power, Top Energy and Northpower have the lowest residual rates of return followed by Waipa Networks which ranked highly in the MTFP rankings.

8.7 Load growth and investment considerations

Two factors that could affect businesses' allocations to C factor groupings, and the magnitude of C factors, are expected future load growth and the requirement to undertake new investment programs during the next regulatory period.

Depending on the output specification used, load growth could be an important driver of measured productivity going forward. This will be more relevant where output is measured by throughput or where throughput receives a high weighting in multi–output measures. Consequently, distributors with low load growth could be placed at a disadvantage, even if they are currently operating at high levels of efficiency, if throughput receives a high weighting. Conversely, distributors who have the benefit of high load growth will receive something of a 'free' boost to their productivity using this measure up to the point where their system becomes fully utilised and additional investment is required to expand capacity. Consequently, it is important to look at productivity trends over a longer rather than a shorter period to ensure these short term fluctuations are evened out.

Examining the growth in throughput for the 29 distributors over the period 1996 to 2002 we observe no discernable pattern between load growth and productivity performance using either the MTFP or cost function methods. Distributors with both high and load growth history over the last seven years populate the top, middle and bottom thirds of the productivity rankings. From this we conclude that there is no case for adjusting distributors' allocations based on load growth history. However, we are conscious of the need to set targets that are feasible for distributors to achieve and the need to err on the side of conservatism given the inherently poor quality of the data we have to work with and its incompleteness in some areas.

Future investment requirements for businesses expecting to install large relative additions to their capital stock as they move to expand coverage or replace large sections of their existing capital have also been raised as potential cases for special treatment. However, these investment needs should not require special treatment provided price caps are set on the basis of long run efficient costs and returns to capital.

Distributors have an incentive to undertake cost–saving investment under price cap incentive regulation as it enables them to reduce operating and/or capital costs. This will be an even stronger incentive under thresholds regulation compared to a building block based system and even those with earnings sharing mechanisms. Similarly, replacement investment for existing assets nearing the end of their lives should not be discouraged provided the thresholds are set to reflect long run efficient costs and returns. It is then up to each distributor to decide whether their service potential is best maintained by further maintenance of old assets or replacing those assets with new ones to save operating and maintenance costs associated with the higher maintenance requirements of old assets.

Where major additions to capacity are required to accommodate areas of high load growth, distributors face large upfront capital costs but an ongoing stream of revenue from the additional demand. Capital markets address these issues in all industries and provide finance to even out the distributors' costs over time. Again, provided the thresholds are set at levels which reflect long run efficient costs and returns, no special treatment is required. Indeed, on the contrary, special treatment is likely to provide perverse incentives for distributors to substitute new capital for other inputs, including extending the lives of older assets by remedial action, which may have been lower cost responses. Special treatment for new investment may also discourage distributors from promoting demand side management initiatives.

While the case for special treatment for new investment appears questionable at best, we again acknowledge that it is better to err on the side conservatism in target setting given the uncertainty surrounding the quality of the data at our disposal and the industry's stage of evolution. This should again preclude the need for special treatment of individual distributors.

8.8 C factor recommendations

We are now in a position to assemble the information presented in section 8 on productivity levels, profitability and prices and form recommendations for C factors. Before doing this, it is necessary to again reiterate that the relatively poor quality and coverage of the Disclosure Data limits our scope to make definitive judgements on the potential for individual distributors to achieve productivity improvements and price reductions. Consequently, the recommendations presented in this section should be treated as being illustrative of relative productivity and profitability performance rather than being precise estimates. We have also adopted what we consider to be conservative targets in light of the relatively small amount of information we have to work with in this instance.

Given the capital intensive nature of electricity lines businesses and the long lived nature of the assets involved, it is unrealistic to expect lines businesses to be able to remove large productivity gaps in a short space of time. Rather, a timeframe of a decade, or two five–year regulatory periods, is likely to be necessary for businesses performing near the bottom of the range to lift themselves into the middle of the pack. This timeframe would allow sufficient time for asset bases to be adjusted significantly, new work practices to be adopted and bedded down and for amalgamations and rationalisations to be implemented and consolidated. It is, however, reasonable to expect profitability levels to be adjusted over a shorter period, say one regulatory period of five years. This should allow sufficient time for adjustment in a sustainable fashion without incurring the risk of financial stress or failure resulting from large P_0 adjustments.

For productivity adjustments we form the distributors into three groups with high, medium and low productivity levels. In 1996 the high productivity group was 15 per cent more productive on average than the middle productivity group which was in turn around 15 per cent more productive than the low productivity group. Using the distribution B factor of around 2.5 per cent derived in section 7 for the middle group and a 10 year timeframe, the average productivity of the bottom group would have to increase by 4 per cent annually to reach the same average productivity level as the middle group after 10 years. Conversely, the high productivity group would have to increase its average TFP by 1 per cent annually to reach the same average productivity level as the middle group after 10 years. This implies overall X factors of 1, 2.5 and 4 per cent for the three groups or C factors of –1.5, 0 and 1.5 per cent, respectively. Given the need for a conservative approach based on the relatively poor quality of the available data, we reduce the range of C factors to –1, 0 and 1 per cent.

The same range of C factors (–1, 0 and 1 per cent) would imply a more rapid adjustment towards normal residual returns for low, medium and high return groups, respectively. This is because the rate of return component will usually make up less than half of total annual costs. Therefore a 1 per cent change in total revenue has a magnified effect on the residual rate of return. These C factor rates are consistent with moving the low and high return groups towards the middle group within around 5 years, or one assumed regulatory period.

To recap, distributors performing near the industry average on all counts would receive a C factor of zero while those achieving high productivity levels (taking their density characteristics into account) and/or low rates of return would be set the less onerous C factor of –1 per cent. Distributors achieving low productivity levels taking their density characteristics into account and/or high rates of return would be set the higher C factor of 1 per cent.

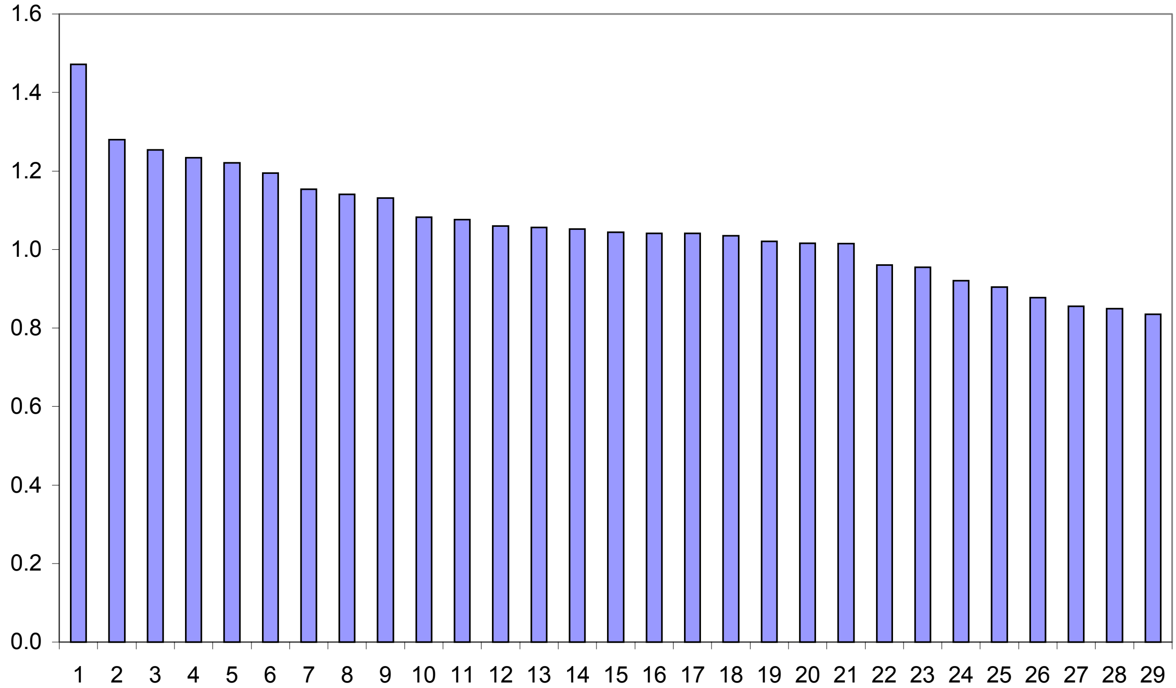
We use the information from the multilateral TFP indexes using three outputs and the cost function based output cost shares to allocate initial C factors based on the productivity levels estimated for 2002. For clarity, we will refer to these as C_1 components.

There is insufficient analytical information available to determine robust adjustments to the C_1 components based solely on the relationship between price and service quality. We can, however, proceed to make adjustments (which we will call C_2 components for convenience) by relying on the residual rate of return information to adjust for differences in profitability or by using the estimated price equation to make adjustments on what is effectively a combination of profitability and quality effects. Given the sensitivity of the econometric price function to the exact specification and estimation method used, we adopt the former approach as being relatively more robust. In practice, however, the two approaches give broadly similar results with differences in grouping for only four of the 29 distributors.

We proceed by generally dividing the distributors into groups of around one third each. These groupings generally coincide with step points in the MTFP results. The residual rate of return groupings also coincide with the 'deadband' in the adjusted ROI of 6 to 8 per cent recommended by Lally (2003).

In any exercise of this nature there will be boundary issues where discrete changes are made in the factors between the three groups. Making the change in the C_1 or C_2 components more graduated can reduce these boundary issues. For instance, the top and bottom groups could be each divided into another three groups each receiving a change of one third of one per cent instead of the group as a whole receiving a change of 1 per cent. However, this comes at the expense of simplicity and requires further allocation decisions to be made within these two larger groups. For illustrative purposes we use step changes of 1 per cent for the top and bottom one third groupings in this section.

Figure 14: **MTFP indexes using 3 outputs, average cost function weights**, 2002



Source: Meyrick and Associates estimates

Turning to the C_1 components, we present the MTFP efficiency scores for 2002 in figure 14 in decreasing order. The indexes decrease steadily down to distributor 9 and then step down and flatten out between distributors 10 and 21. There is then another step down and continued decrease from distributor 22 onwards. We use these groupings of 9, 11 and 9 distributors to define high, average and low levels of productivity, respectively, and allocate them C_1 components of –1, 0 and 1 per cent, respectively.

To determine the C_2 component groupings we use the 'adjusted ROI deadband equivalent' cut–offs on the residual rate of return of 10 and 13.5 per cent. This leads to groups of 10, 9 and 10 distributors being classed as earning high, average and low rates of return, respectively. These groups are allocated C_2 components of 1, 0 and –1 per cent, respectively. These components are designed to 'glide path' distributors earning high and low rates of return towards the average return deadband over the assumed five year regulatory period.

Again, these components are most likely conservative for most of the affected distributors but are considered appropriate given the quality of relevant information available. The closeness of the rates of return around the two cut–offs, particularly the upper cut–off, mean it may be particularly appropriate to consider a more graduated scale for the C_2 component.

Table 18: **Illustrative distributor C factor recommendations**

ELB	C_1	C_2	*C*	*ELB*	C_1	C_2	*C*
Alpine Energy	0	1	1	Powerco	0	0	0
Centralines	1	0	1	The Lines Company	0	0	0
Counties Power	0	1	1	Top Energy	1	–1	0
Dunedin Electricity	1	1	1[a]	UnitedNetworks	–1	1	0
Eastland Network	1	1	1[a]	Westpower	1	–1	0
Horizon Energy	0	1	1	Electricity Invercargill	–1	0	–1
MainPower	1	0	1	Network Waitaki	0	–1	–1
Marlborough Lines	1	0	1	Northpower	–1	–1	–1[b]
Orion New Zealand	0	1	1	Otago Power	–1	–1	–1[b]
WEL Networks	0	1	1	Scanpower	–1	0	–1
Buller Electricity	1	–1	0	The Power Company	0	–1	–1
Electra	0	0	0	Unison	0	–1	–1
Electricity Ashburton	1	–1	0	Vector	–1	0	–1
Nelson Electricity	–1	1	0	Waipa Networks	–1	–1	–1[b]
Network Tasman	–1	1	0				

[a] Limited to 1 per cent
[b] Limited to –1 per cent
Source: Meyrick and Associates estimates

The C factors resulting from using the 2002 MTFP scores to derive the C_1 components and the average residual rate of return estimates for 2000–2002 to derive the C_2 components are presented in table 18. For two distributors the C factor components sum to 2 per cent but these are limited to 1 per cent. Similarly, for three distributors the C factor components sum to –2 but are limited to –1 per cent to retain the C factor groupings of –1, 0 and 1 per cent.

There are a mixture of business types in each of the three C factor groups with urban high density, urban low density, rural high density and rural low density businesses appearing in each of the low, middle and high C factor groups.

As noted earlier, there are minor differences in groupings based on our preferred MTFP productivity method and the alternative cost function based estimates reported in section 8.4. These minor movements between groups highlight that a conservative approach is warranted, especially given the limited quantity and quality of data there is to work with at this time. However, the broad similarity in C_1 component allocations between the preferred MTFP and the alternative cost function methods is reassuring as is the broad similarity between the residual rate of return and the price equation method allocations for the C_2 components.

Until better quality data becomes available the allocations to C factor groups should be treated as being illustrative of relative productivity and profitability performance rather than being precise estimates. The steps necessary to improve the quality and quantity of relevant data available for future regulatory resets are addressed in the following section.

9 DATA REQUIREMENTS

As expected, the analysis presented in this report has identified many shortcomings in the Disclosure Data currently available that has limited the extent of the analysis that can be undertaken and its robustness. In this section we examine the options available for increasing the amount and quality of relevant data available for future regulatory resets starting with a brief review of international data sources and then looking at changes that may be required to the Disclosure Data.

9.1 International data availability

There are a number of international data sets which have been established for benchmarking purposes in the electricity supply industry. These data sets are either fully or partially comprised of 'off–the–shelf' products. These are databases of regulatory disclosure information developed and maintained by commercial organisations for the purposes of commercial resale. The most commonly referred to database of this type is the CD–ROM produced by the Platts/UDI Products Group (formerly Utility Data Institute), a division of McGraw–Hill (UDI 2003). The CD–ROM contains regulatory data back to 1982 and provides a user–friendly data retrieval package (DAR-WIN). McGraw–Hill's regular publication *Electricity World* also publishes electricity distribution data that has been used to develop data sets for comparison purposes.

Another international data set is the UMS (2003) *Performance and Competitive Excellence* (PACE) benchmarking tool. PACE was originally developed as an internal benchmarking tool to find out where opportunities lie for improvements in business practices. The data set includes over 300 utilities from North America, South America, Europe, Australia, New Zealand and the Pacific Rim. Distributors 'sign up' to the process and provide UMS with detailed information on their firm's costings, assets and revenue on a confidential basis. In return for the information UMS then provides the participating firm with analysis of that firm's position compared with other distributors. UMS use a number of transformation processes to attempt to compare like with like but these processes are generally not transparent and there is a heavy reliance on the holder of the information, in this case UMS, to ensure that like with like comparisons are in fact being made and that the information on each organisation is complete and accurate. The UMS database has been more commonly used by utilities for micro–level operating and engineering studies than for regulatory purposes.

When using such data sets for benchmarking purposes, regulators are faced with a number of issues to ensure that the comparisons are accurate and reasonable. These include:

- differences in accounting standards and the specification of what constitutes a network. For instance, examination of US Federal Energy Regulatory Commission (FERC) Form 1 returns indicates that the allocation of overheads between categories changes significantly from year to year while total costs remain roughly the same. While these changes in accounting conventions may have little impact on the outcome for a vertically integrated utility, they can significantly influence distribution comparisons unless properly allowed for.
- data inconsistencies between the off–the–shelf source and primary sources.
- failure to distinguish between generation and distribution peak demands for vertically integrated overseas utilities.
- failure to allocate sub–transmission assets consistently across utilities. For instance, US companies do not tend to nominate a separate subtransmission category.
- treatment of overseas multiutilities. For instance, as in New Zealand, some US companies provide more than one infrastructure service (eg electricity and gas) and thus obtain synergies and efficiencies that cannot be replicated by specialist electricity distributors.
- treatment of corporate overheads and costs of retailing as opposed to distribution – understanding how privately owned, vertically integrated multiutilities allocate a share of corporate overheads to their electricity distribution units is often difficult. Ensuring that this is unwound and reconstructed on a like basis to the distributors being analysed in the study is even more difficult.

These problems are likely to be compounded when the primary data is taken from a number of different databases. They highlight the overriding importance of ensuring that the data used is accurate and that like functions within the overall electricity supply chain are being compared. This can generally only be done effectively with a relatively small group of utilities. Furthermore, a large off–the–shelf database which contains many dozens of distributors usually provides a false sense of security regarding robustness of the results. In Australian studies which have used large off–the–shelf databases there have only been a handful of overseas utilities which have ended up being roughly comparable to the Australian distributors.

Our experience is that the best results in benchmarking are obtained from international comparisons using data specifically collected for the purpose from a relatively small group of overseas utilities (see, for example, Zeitsch and Lawrence 1996). This is the only way to ensure that data has been collected for exactly comparable activities and similar costs have been treated similarly. The latter is particularly important for the allocation of overheads where more vertically integrated overseas firms are included. The use of large 'off–the–shelf' databases is fraught with difficulty in both these regards. There are often too many utilities included for the analyst to be able to verify the data for all the overseas utilities.

An example of the shortcomings from using large off–the–shelf databases was a data envelopment analysis (DEA) exercise carried out for the Electricity Supply Association of Australia in the early 1990s where best practice for some Australian black coal generators turned out to be a US utility that used only gas turbines. Another example was the London Economics (1999) distribution DEA study for IPART where much of the data used for EnergyAustralia's main peers turned out to differ from primary sources (Lawrence 1999).

A number of benchmarking studies have been completed using a data set developed and maintained by Pacific Economics Group (PEG). This data set is focused on US energy utilities and uses a number of sources including the FERC Form 1 returns and information from the US Energy Administration, the US Department of Commerce and an engineering consultancy, Whitman, Requardt, and Associates. PEG has spent considerable time 'cleansing' their US electricity utility database to ensure the accuracy of data and consistency of treatment of different activities. While narrower in geographic coverage than the large commercial databases, the quality control in the PEG database is much higher making it a potential option.

In Australia, Meyrick and Associates' staff have formed a comprehensive database for 11 of the 16 Australian distribution businesses based on a direct survey of the businesses and subsequent detailed discussions with the businesses to ensure comparability of data treatment.

9.2 The need for disaggregated data

Disaggregating the lines businesses' data by key characteristics has considerable attraction in terms of increasing the information available to conduct comparative studies. A major deficiency identified in this study is the lack of information available on the costs incurred in producing each of the four major distribution outputs: throughput, provision of system line capacity, connections and service quality. In this study we have relied on statistical estimates of this cost allocation derived from an econometric cost function. However, it would be highly desirable to have this information directly available to use as a primary data source or to at least use as a basis for verifying the reasonable of econometrically derived estimates.

The other basis for requesting disaggregated data that has been suggested is dividing each network into non–contiguous, urban, rural, suburban and CBD components, on the basis of feeder or other characteristics. This information would be useful and allow more detailed comparisons of similar activities within each business.

The benefits of having access to more disaggregated data have to be weighed against the compliance costs for businesses in providing data that may not otherwise be collected or collated. In many cases there could also be problems with data consistency based on the way overheads and other joint costs are allocated between the nominated activities. Even if detailed guidelines are developed, different businesses will tend to interpret them in different ways either in good faith or to try and gain a strategic advantage.

The current Disclosure Data provisions require businesses to provide large amounts of data. From the perspective of comparative performance studies, most of this data is either unused or unusable. Some pundits have observed that there is usually an inverse correlation between the quantity of data required to be presented and its quality. This does appear to be the case for the current Disclosure Data. Unless there is a compelling use for the bulk of the current Disclosure Data, there would be significant benefits from reducing the overall quantity of Disclosure Data required but refocusing it to information that is more useful for comparative performance analyses, including disaggregation across output types and geographic characteristics.

9.3 Future New Zealand data needs

As discussed earlier in the report, data on the price and quantity of the major outputs and inputs is required to implement all of the major benchmarking methods – TFP, DEA, stochastic frontier analysis and econometric cost functions – in a consistent way along with data on key operating environment and service quality variables.

The main omissions from the Disclosure Data currently are information on:

- customer numbers and consumption by type of customer (domestic, commercial, large industrial (over 10 GWh per annum), small industrial, public lighting and other);
- revenue by customer type;
- labour usage and cost (including labour component of contracted services);
- quantity and cost of own labour used on capital construction projects;
- purchase of materials and services (ie operating expenses excluding labour);
- prices paid for standard type of labour and standard major opex items;
- capital expenditure and asset values by type of asset (overhead lines, underground cables, transformers, system control, and other);
- value of work in progress by asset type;
- prices paid for standard major capital items;

- allocation of operating and capital costs to output types; and
- information on operating environment conditions (climatic, geographic and availability of alternative energy sources).

Extension of the Disclosure Data to include these items and culling of data items currently not used would facilitate more comprehensive comparative analyses at the next reset both between New Zealand businesses and between New Zealand and overseas lines businesses.

Obtaining accurate labour data has become one of the most problematic aspects of comparative studies given the move to increasing levels of contracting out and other forms of outsourcing. With different businesses engaging in contracting out to greatly differing extents, direct comparisons of directly employed labour can be quite misleading. This is likely to be even more the case once overseas comparisons are introduced. One response to this in Australia has been to request distributors to estimate the labour content of contracted out services (eg Meyrick and Associates 2003). While somewhat speculative and subject to some error, this approach does offer a better way forward in terms of obtaining like–with–like comparisons but may require more interaction with distributors to ensure data is supplied in a consistent way.

Considerably greater effort needs to be allocated to ensuring consistency of interpretation and reporting both between businesses and even within the same business over time. The fact that the data is now being used in a manner that will directly impact the distributors' future rather than merely measuring their past for information purposes should help focus attention on the need for more comprehensive and better quality data.

10 CONCLUSIONS

In this report we have used the Disclosure Data for New Zealand's electricity distribution and transmission lines businesses to form estimates of threshold B and C factors. These factors relate to industry productivity trends, and individual business productivity performance and profitability considerations, respectively. We have also investigated the scope to include a C factor component based on price/quality trade–offs but conclude that the data and our understanding of the complex relationship between quality and costs are insufficient to support robust estimates at this point in time.

The industry productivity trends indicate that distribution has had stronger productivity growth over the last seven years than transmission. While some uncertainty still surrounds the quality of the disaggregated Disclosure Data, more confidence can be placed in the aggregate productivity results than the results for individual businesses where there is considerably more variability in the data. We find that applying the standard formula leads to a distribution B factor of 2.6 per cent. Given the quality of the data on which the analysis has had to be based and the results of the sensitivity analyses, we believe it would be more appropriate to round this B factor down than up. Applying a similar analysis to transmission leads to a B factor estimate of 1.7 per cent for Transpower.

We have used two alternative methods to examine the productivity levels and growth rates of the individual distribution businesses. These are multilateral TFP indexes and an econometric cost function. These methods produce broadly similar results but there are material differences in rankings for several businesses. Density differences between the businesses are incorporated by the use of a three output specification which includes throughput, system capacity and customer numbers. Because the MTFP results are more robust and because they allow the calculation of B and C factors in an integrated framework, we use the MTFP results in developing our recommended C factors.

With respect to future regulatory resets, the priority for work in this area is improving the quality and quantity of relevant data available. This involves requiring the disclosure of data on the price and quantity of all major outputs and inputs, including labour and broad asset categories. It also includes gaining more accurate information on the allocation of costs between the major output types. Greater effort will be required to ensure businesses report data in a consistent manner both across businesses and over time. Much of the Disclosure Data currently required from businesses is not used for developing comparative performance measures that would be relevant for forming B and C factors. The usefulness of this data should be reviewed with a view to reducing the amount of data required but making its composition more relevant. The addition of more years and better price and quantity data will allow the estimation of more sophisticated econometric cost functions.

We have investigated the scope to use price/quality equations to make adjustments to initial productivity based C factor allocations. However, the relationship between quality and cost measures is complex and requires more investigation. As predicted by economic theory, costs and comprehensive output are the primary drivers of price with quality measures playing a secondary role. The range of ownership and governance structures and associated objectives of the distribution businesses make understanding the drivers of prices charged somewhat problematic and reinforce the importance of using productivity and profitability information as the primary basis for determining the thresholds for individual businesses. Consequently, we have incorporated profitability differences between the businesses using residual rates of economic return as a basis for making adjustments to the initial C factor allocations. Despite the fact that we have not been able to establish a sufficiently robust relationship between price and quality to use this as the sole basis for making adjustments to the productivity based C factor allocations, the results of the price equation which takes costs and quality jointly into account largely confirms the findings of the residual rate of return analysis.

Finally, the results of this study confirm that the approach proposed by the Commerce Commission (2003) of building up the thresholds for individual businesses by summing up separate B and C factors reflecting industry productivity trends, and individual productivity performance, profitability and quality considerations, respectively, is both sensible and feasible. Greatest confidence can be placed on the industry productivity trend information. Confirming broad individual productivity rankings through the use of alternative methodologies means we can place reasonable confidence in the C factor recommendations despite the inherent variability in the data for individual distributors. It would be unwise to include a separate price/quality trade–off factor at this time given the lack of understanding of the relationship between quality and costs.

APPENDIX A: DATA SOURCES AND MANIPULATION

This appendix outlines the sources of data used in the analysis and the combination from the various sources into a collated data set.

Reporting requirements

Data has been collected from the published data according to the various Electricity (Information Disclosure) Regulations in force with amendments and revisions since 1995. The various amendments and refinements to the Regulations aim to improve the quality of the data collected, but come at the cost of some discontinuities in extent or definition as discussed below. The base files of financial and system data for the Electricity Lines Businesses (ELBs) have been collated and entered within the Ministry of Economic Development (MED) while the data for Transpower has been collated and entered by this consultancy.

Segregation of system data into voltage classes etc has also been collated as part of this consultancy from the reporting data. Asset valuation by asset class has also been extracted from hard-copy Asset Register reporting, but the detail available varied between ELBs.

Details of the reporting data Field Name, Broad Description and Specific Description are included below.

ELB data files

Early data comes as a combination of financial data in a separate data collation from the MED while the system data had been included in the general MED data summary. The various items have been “aligned and combined” to form the fuller data set used here. Data relating to system elements by voltage class has been added as has some limited data relating to residential customer numbers although the latter was not used in the final analysis.

Where ELBs have amalgamated, data for previous years of the subsumed ELB has been combined with the persisting ELB below the table proper and reproduced as a single entry for the current ELB. As mentioned below, there may be some deficiencies due to reporting of only a part year for the combining ELB.

These data files have been extended to allow extraction of normalised data and data items for use in the analysis.

The tabulations of ODV by asset class and Line Length by voltage class and being overhead or underground are presented in separate source files, and have been combined into the general data file.

Some irregularities

Over the period since data has been collected, certain of the ELBs have combined, but data requirements apply only to entities relevant at the end of the (March) financial year reporting period, and the Regulations contain methodologies for 'pro–rata' reporting where assets, income etc have been within the reporting entity for only part of the year.

This has resulted in presentation of 'partial period' data for absorbed ELBs in the enduring ELB and apparent loss of data for the subsumed ELB for the combining year.

Some definitional changes have occurred, such as that in the 2001 Amendment which required energy throughput to be reported as energy entering the network (ie before losses) rather than energy leaving the network to the ELB customer. This has required adjustment (by the MED) for data consistency.

Asset valuation is required according to the Valuation Handbook under an Optimised Deprival Value (ODV) methodology, with regular revaluations. Thus, a series of asset values can show little change for the several years following a valuation, with a sharp change after the revaluation. The base rates used in the valuations may also not properly reflect changing replacement costs.

Asset recording has itself been refined over the period, resulting in some differences in line lengths, etc as deficiencies in previous data recording are rectified.

ELB alterations

With the exception of pre–1999 financial data, the Commerce Commission has advised ELBs of the collated data, and invited each to examine its data, and to highlight any alterations required for a correct representation of their situation.

Any alterations submitted by ELBs have been taken at face value and incorporated by this consultancy.

Transpower data

This consultancy has collated data for Transpower from the *Information for Disclosure* supplements to the New Zealand Gazette.

Again changes, eg to exclude the 'Security Product' costs from 'Lines Business' reporting from 1999 and to changes in line lengths or system transformer rating due to disposals or improved data accuracy, result in what may be discontinuities in the data stream.

Reduction in energy transfer in the most recent year because of 'low hydro inflows in the winter of 2001 and the combination of high prices and government and industry initiatives' are coupled with an Opex increase due to 'an increase in salary related costs primarily relating to industry reforms and a $15m provision for Industry related costs' to produce variability in measured productivity.

Data Reporting Categories

The following indicates the categories of data collected by the Information Disclosure Regulations. This is the format following the revised 1999 Regulations but earlier data was available separately for financial items and for performance items.

This table shows data Field Names with the MED descriptive columns. The Col Ref item indicates the Field location on the data spreadsheets.

Col Ref	Field Name	Broad Description	Specific Description
A	LineOwner	Name of line company	Line Company name as at year of disclosure
B	AssignedTo	Name of relevant line company owner	The line company that purchased the company subsequent to year of disclosure
C	Year	Year of disclosure	Disclosure for the year ended 31 March
D	CABank	Current Asset	Cash and bank balances
E	CASTInvest	Current Asset	Short term investments
F	CAInvent	Current Asset	Inventories
G	CATrade	Current Asset	Accounts receivable
H	CAOther	Current Asset	Other current assets
I	CATotal	Subtotal	Total current assets
J	FASystem	Fixed Asset	System fixed assets
K	FABilling	Fixed Asset	Consumer billing and information systems assets
L	FAMotor	Fixed Asset	Motor vehicles
M	FAOffice	Fixed Asset	Office equipment
N	FALand	Fixed Asset	Land and buildings
O	FACapex	Fixed Asset	Capital works under construction
P	FAOther	Fixed Asset	Other fixed assets
Q	FATotal	Subtotal	Total fixed assets
R	TAOther	Subtotal	Other tangible assets
S	TangibleTotal	Subtotal	Total tangible assets
T	IAGoodwill	Intangible Asset	Goodwill assets
U	IAOther	Intangible Asset	Other intangible assets
V	IATotal	Subtotal	Total intangible assets
W	TotalAssets	Total	Total assets
X	CLOD	Current Liability	Bank overdraft
Y	CLBorrow	Current Liability	Borrowings
Z	CLPayable	Current Liability	Payables and accruals
AA	CLDividend	Current Liability	Dividends payable
AB	CLTax	Current Liability	Income tax
AC	CLOther	Current Liability	Other current liabilities
AD	CLTotal	Subtotal	Total current liabilities
AE	NCLPayable	Non Current Liability	Payables and accruals
AF	NCLBorrow	Non Current Liability	Borrowings
AG	NCLDefTax	Non Current Liability	Deferred tax
AH	NCLOther	Non Current Liability	Other non-current liabilities
AI	NCLTotal	Subtotal	Total non-current liabilities
AJ	EShareCap	Equity	Share capital
AK	ERetained	Equity	Retained earnings
AL	EReserves	Equity	Reserves
AM	ETotalSH	Equity	Total shareholders' equity
AN	EMinority	Equity	Minority interests in subsidiaries
AO	ETotal	Subtotal	Total equity
AP	ECapNotes	Equity	Capital notes
AQ	ETotalCap	Subtotal	Total capital funds
AR	TotalLiabilities	Total	Total equity and liabilities

Col Ref	Field Name	Broad Description	Specific Description
AS	RevLine2	Revenue	Revenue from line/access charges
AT	RevOthServices	Revenue	Revenue from "Other" business for services carried out by the line business (transfer payment)
AU	RevShortTerm	Revenue	Interest on case, bank balances, and short-term investments
AV	RevRebates	Revenue	AC loss-rental rebates
AW	RevOther	Revenue	Other operating revenue
AX	RevTotal	Total	Total operating revenue
AY	ExpTrans	Expenses	Payment for transmission charges
AZ	ExpMaint	Expenses - transfer	Transfer payments to the "Other" business for asset maintenance
BA	ExpConnect	Expenses - transfer	Transfer payments to the "Other" business for consumer disconnection/reconnection services
BB	ExpMeter	Expenses - transfer	Transfer payments to the "Other" business for meter data
BC	ExpCtrl	Expenses - transfer	Transfer payments to the "Other" business for consumer-based load control services
BD	ExpRoyalty	Expenses - transfer	Transfer payments to the "Other" business for royalty and patent expenses
BE	ExpAvoidTrans	Expenses - transfer	Transfer payments to the "Other" business for avoided transmission charges on account of own generation
BF	ExpOthBusServices	Expenses - transfer	Transfer payments to the "Other" business for other goods and services
BG	ExpTotalOther	Subtotal	Total transfer payments to the "Other" business
BH	ExpExtMaint	Expenses to non-related parties	Expenses to entities that are not related parties for asset maintenance
BI	ExpExtConnect	Expenses to non-related parties	Expenses to entities that are not related parties for disconnection/reconnection services
BJ	ExpExtMeter	Expenses to non-related parties	Expenses to entities that are not related parties for meter data
BK	ExpExtCtrl	Expenses to non-related parties	Expenses to entities that are not related parties for consumer-based load control services
BL	ExpExtRoyalty	Expenses to non-related parties	Expenses to entities that are not related parties for royalty and patent expenses
BM	ExpExtTotal	Subtotal	Total of specified expenses to non-related parties
BN	ExpPayroll	Expenses	Employee salaries, wages and redundancies
BO	ExpBilling	Expenses	Customer billing and information system expenses
BP	ExpDepnFA	Expenses	Depreciation expense on system fixed assets
BQ	ExpDepnCapWorks	Expenses	Depreciation expense on assets other than system fixed assets
BR	ExpDepnTotal	Subtotal	Total depreciation
BS	ExpGoodwill	Expenses	Amortisation of goodwill
BT	ExpAmortIA	Expenses	Amortisation of other intangibles
BU	ExpAmortIATotal	Subtotal	Total amortisation of intangibles
BV	ExpAdmin	Expenses	Corporate and administration
BW	ExpHR	Expenses	Human resource expenses
BX	ExpMarketing	Expenses	Marketing/advertising
BY	ExpMerger	Expenses	Merger and acquisition expenses
BZ	ExpTakeoverDef	Expenses	Take-over defence expenses
CA	ExpRD	Expenses	Research and development expenses
CB	ExpConsult	Expenses	Consultancy and legal expenses
CC	ExpDonations	Expenses	Donations
CD	ExpDirFees	Expenses	Directors' fees

Col Ref	Field Name	Broad Description	Specific Description
CE	ExpAuditTotal	Subtotal	Total auditors' fees
CF	ExpCostofCredit	Subtotal	Total cost of offering credit (bad debts written off and increase in estimated doubtful debts)
CG	ExpRates	Expenses	Local authority rates expense
CH	ACRebateExp	Expenses	AC loss-rental rebates (distribution to retailers/customers) expense
CI	RebateExp	Expenses	Rebates to consumers due to ownership interest
CJ	ExpSubvention	Expenses	Subvention payments
CK	ExpUnusual	Expenses	Unusual expenses
CL	ExpOther	Expenses	Other expenditure
CM	ExpTotal	Total	Total operating expenditure
CN	OSBIIT	Earnings	Operating surplus before interest and income tax
CO	OSBIITAdj	Derivation	Operating surplus before interest and income tax adjusted pursuant to regulation 18
CP	ExpIntBorrow	Interest expense	Interest expense on borrowings
CQ	ExpIntLease	Interest expense	Finance charges related to finance leases
CR	ExpIntOther	Interest expense	Other interest expense
CS	ExpInterest	Total	Total interest expense
CT	OSBT	Earnings	Operating surplus before income tax
CU	ExpTax	Expenses	Income tax
CV	NetProfit	Earnings	Net surplus after tax from financial statements
CW	NetSurplusAdj	Derivation	Net surplus after tax adjusted pursuant to regulation 18
CX	SFADepnBV	Derivation	Depreciation of system fixed assets at book value
CY	SFADepnODV	Derivation	Depreciation of system fixed assets at ODV
CZ	SubTaxAdj	Derivation	Subvention payment for tax adjustment
DA	IntTaxShield	Derivation	Interest tax shield
DB	Revaluations	Derivation	Revaluations
DC	NumROF	Derivation	Numerator ROF
DD	NumROE	Derivation	Numerator ROE
DE	NumROI	Derivation	Numerator ROI
DF	AvgFunds	Derivation	Average total funds employed
DG	AvgEquity	Derivation	Average total equity
DH	AvgUnderCons	Derivation	Average total works under construction
DI	AvgGoodwill	Derivation	Average total intangible asset
DJ	AvgSubvention	Derivation	Average subvention payment and related tax adjustment
DK	AvgFABook	Derivation	Average value of system fixed assets at book value
DL	AvgFAODV	Derivation	Average value of system fixed assets at ODV
DM	DenROF	Derivation	Denominator ROF
DN	DenROE	Derivation	Denominator ROE
DO	DenROI	Derivation	Denominator ROI
DP	ROF	Financial performance measure	Return on funds
DQ	ROE	Financial performance measure	Return on equity
DR	ROI	Financial performance measure	Return on investment
DS	RC	Valuation	Replacement cost
DT	DRC	Valuation	Depreciated replacement cost
DU	ODRC	Valuation	Optimised depreciated replacement cost
DV	ODV	Valuation	Optimised deprival valuation of system fixed assets
DW	LineValue	Valuation	Valuation of the line business
DX	DirLineKm	Efficiency performance	Direct line costs per kilometre

Col Ref	Field Name	Broad Description	Specific Description
		measures	
DY	IndirLineCust	Efficiency performance measures	Indirect line costs per customer
DZ	LoadFactor	Energy delivery efficiency performance measures	Load factor
EA	LossRatio	Energy delivery efficiency performance measures	Loss factor
EB	CapUtil	Energy delivery efficiency performance measures	Capacity utilisation
EC	KmSystem	Statistics	Total system length
ED	KmOH	Statistics	Total overhead length
EE	kmUnder	Statistics	Total underground length
EF	TransCap	Statistics	Transformer capacity
EG	MaxDemand	Statistics	Maximum demand
EH	TotElecSupplied	Statistics	Total electricity supplied from the system (before losses)
EI	TotCustomers	Statistics	Total consumers
EJ	ClassA	Reliability performance measure	Total interruptions, Class A
EK	ClassB	Reliability performance measure	Total interruptions, Class B - planned by lines business
EL	ClassC	Reliability performance measure	Total interruptions, Class C - unplanned within lines business
EM	ClassD	Reliability performance measure	Total interruptions, Class D
EN	ClassE	Reliability performance measure	Total interruptions, Class E
EO	ClassF	Reliability performance measure	Total interruptions, Class F
EP	ClassG	Reliability performance measure	Total interruptions, Class G
EQ	ClassH	Reliability performance measure	Total interruptions, Class H
ER	ClassI	Reliability performance measure	Total interruptions, Class I
ES	TotInt	Reliability performance measure	Total interruptions
ET	PlannedInt	Reliability performance measure	Target planned interruptions for next year
EU	UnplanInt	Reliability performance measure	Target unplanned interruptions for next year
EV	PlannedInt4	Reliability performance measure	Target planned interruptions for next 5 years
EW	UnplanInt4	Reliability performance measure	Target unplanned interruptions for next 5 years
EX	NotRestoredIn3	Reliability performance measure	Portion of interruptions not restored within 3 hours
EY	NotRestoredIn24	Reliability performance measure	Portion of interruptions not restored within 24 hours
EZ	SAIDITot	Reliability performance measure	SAIDI for the total interruptions
FA	SAIDIPlanInt	Reliability performance measure	SAIDI target for planned interruptions for the following year
FB	SAIDIUnplanInt	Reliability performance	SAIDI target for unplanned interruptions for the

Col Ref	Field Name	Broad Description	Specific Description
		measure	following year
FC	SAIDIPlanInt4	Reliability performance measure	Average SAIDI target for planned interruptions for the next 5 years
FD	SAIDIUnplanInt4	Reliability performance measure	Average SAIDI target for unplanned interruptions for the next 5 years
FE	SAIDIA	Reliability performance measure	SAIDI for class A
FF	SAIDIB	Reliability performance measure	SAIDI for class B - planned by lines business
FG	SAIDIC	Reliability performance measure	SAIDI for class C - unplanned within lines business
FH	SAIDID	Reliability performance measure	SAIDI for class D
FI	SAIDIE	Reliability performance measure	SAIDI for class E
FJ	SAIDIF	Reliability performance measure	SAIDI for class F
FK	SAIDIG	Reliability performance measure	SAIDI for class G
FL	SAIDIH	Reliability performance measure	SAIDI for class H
FM	SAIDII	Reliability performance measure	SAIDI for class I
FN	SAIFITot	Reliability performance measure	SAIFI for the total interruptions
FO	SAIFIPlanInt	Reliability performance measure	SAIFI target for planned interruptions for the following year
FP	SAIFIUnplanInt	Reliability performance measure	SAIFI target for unplanned interruptions for the following year
FQ	SAIFIPlanInt4	Reliability performance measure	Average SAIFI target for planned interruptions for the next 5 years
FR	SAIFIUnplanInt4	Reliability performance measure	Average SAIFI target for unplanned interruptions for the next 5 years
FS	SAIFIA	Reliability performance measure	SAIFI for class A
FT	SAIFIB	Reliability performance measure	SAIFI for class B - planned by lines business
FU	SAIFIC	Reliability performance measure	SAIFI for class C - unplanned within lines business
FV	SAIFID	Reliability performance measure	SAIFI for class D
FW	SAIFIE	Reliability performance measure	SAIFI for class E
FX	SAIFIF	Reliability performance measure	SAIFI for class F
FY	SAIFIG	Reliability performance measure	SAIFI for class G
FZ	SAIFIH	Reliability performance measure	SAIFI for class H
GA	SAIFII	Reliability performance measure	SAIFI for class I
GB	CAIDITot	Reliability performance measure	CAIDI for the total interruptions
GC	CAIDIPlanInt	Reliability performance measure	CAIDI target for planned interruptions for the following year
GD	SAIDIUnplanInt	Reliability performance	CAIDI target for unplanned interruptions for the

Col Ref	Field Name	Broad Description	Specific Description
		measure	following year
GE	CAIDIPlanInt	Reliability performance measure	Average CAIDI target for planned interruptions for the next 5 years
GF	SAIDIUnplanInt4	Reliability performance measure	Average CAIDI target for unplanned interruptions for the next 5 years
GG	CAIDI	Reliability performance measure	CAIDI for class A
GH	CAIDI	Reliability performance measure	CAIDI for class B - planned by lines business
GI	ACIDIC	Reliability performance measure	CAIDI for class C - unplanned within lines business
GJ	CAIDID	Reliability performance measure	CAIDI for class D
GK	CAIDIE	Reliability performance measure	CAIDI for class E
GL	CAIDIF	Reliability performance measure	CAIDI for class F
GM	CAIDIG	Reliability performance measure	CAIDI for class G
GN	CAIDIH	Reliability performance measure	CAIDI for class H
GO	CAIDII	Reliability performance measure	CAIDI for class I

APPENDIX B: THE DATABASE USED

Table B1: **Total deemed revenue ($m), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	10.245	11.856	13.920	13.720	14.372	18.419	19.955
Buller Electricity	1.800	2.026	2.348	2.824	2.914	3.497	3.246
Centralines	2.906	4.759	4.549	3.124	3.941	7.223	6.023
Counties Power	15.960	14.698	17.010	17.472	19.164	21.785	22.220
Dunedin Electricity	28.872	29.927	30.594	34.174	34.412	39.245	43.920
Eastland N/W	14.290	13.540	15.218	15.526	15.182	17.710	18.268
Electra	10.958	14.565	16.583	16.471	14.435	15.844	17.455
Electricity Ashburton	7.163	8.229	8.468	9.043	10.054	11.605	12.672
Electricity Invercargill	6.288	6.491	7.623	7.437	7.523	8.501	9.840
Horizon Energy	13.861	14.976	17.668	21.193	16.641	17.722	20.554
MainPower	14.426	16.720	18.445	17.456	15.698	18.239	19.430
Marlborough Lines	9.455	10.743	10.114	9.858	16.646	17.499	13.379
Nelson Electricity	2.105	1.975	2.014	1.658	5.281	6.120	6.155
Network Tasman	20.681	25.708	20.649	16.714	17.427	21.566	21.206
Network Waitaki	4.278	4.064	3.984	4.474	6.640	7.346	6.806
Northpower	19.421	19.546	16.076	15.423	19.053	18.977	20.424
Orion New Zealand	82.487	88.221	100.074	98.596	98.890	109.941	111.936
Otago Power	8.428	7.751	7.274	7.154	7.867	9.304	10.444
Powerco	79.225	86.717	92.505	84.254	96.182	58.903	106.879
Scanpower	2.681	3.103	3.189	3.580	3.557	3.704	3.839
The Lines Company	11.740	12.278	13.193	12.715	13.323	13.396	15.226
The Power Company	14.701	14.927	15.509	15.661	14.967	17.684	17.628
Top Energy	11.580	12.359	11.411	12.303	12.255	14.434	15.477
Unison	15.103	19.288	14.482	20.293	20.483	23.896	24.252
UnitedNetworks	216.625	252.764	270.098	171.384	291.879	306.157	332.334
Vector	140.116	149.448	169.259	181.117	166.896	186.375	203.441
Waipa Network	6.410	6.255	6.013	6.828	7.659	8.517	6.332
WEL Networks	32.233	35.306	38.433	43.365	43.545	43.227	45.065
Westpower	8.801	9.786	10.125	10.289	8.770	9.563	10.298

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B2: **Energy throughput (GWh), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	425.00	441.50	472.40	507.68	523.75	563.55	565.29
Buller Electricity	88.79	92.22	91.47	90.61	93.75	92.65	93.18
Centralines	82.88	86.68	89.34	89.55	93.37	111.17	111.12
Counties Power	373.10	377.34	388.14	382.60	397.74	409.30	418.09
Dunedin Electricity	1,172.20	1,180.83	1,176.56	1,152.38	1,189.99	1,233.77	1,240.26
Eastland N/W	268.46	285.44	281.30	274.30	269.88	289.56	290.31
Electra	320.70	325.19	331.26	358.64	365.73	378.70	383.91
Electricity Ashburton	234.76	272.19	317.06	327.77	292.31	348.95	342.70
Electricity Invercargill	259.53	281.65	279.05	267.37	256.56	261.65	264.56
Horizon Energy	537.37	517.58	511.62	551.38	580.95	586.63	594.50
MainPower	354.15	337.18	357.66	339.83	353.20	406.68	382.19
Marlborough Lines	277.72	285.20	296.51	285.58	290.48	308.09	303.56
Nelson Electricity	141.57	143.53	142.46	145.42	147.15	148.10	146.92
Network Tasman	554.96	566.92	580.69	586.50	626.41	674.18	684.84
Network Waitaki	158.50	163.28	168.98	177.93	174.42	179.02	175.81
Northpower	727.69	758.23	792.98	809.07	828.62	839.89	852.23
Orion New Zealand	2,506.69	2,529.52	2,582.05	2,692.69	2,735.27	2,821.60	2,901.02
Otago Power	243.68	245.29	267.40	273.63	311.66	338.97	348.37
Powerco	2,003.64	2,025.62	1,962.57	2,080.62	2,032.13	2,083.15	2,077.34
Scanpower	76.28	81.57	81.19	80.85	85.28	87.73	88.47
The Lines Company	252.84	121.78	276.93	269.62	285.97	283.82	286.25
The Power Company	477.24	551.12	565.42	558.91	557.82	591.69	608.06
Top Energy	226.24	280.93	283.92	280.19	284.03	305.51	316.15
Unison	706.21	770.14	798.86	797.13	828.81	848.45	867.33
UnitedNetworks	6,482.54	6,916.75	6,922.50	6,317.63	6,864.05	7,120.43	6,873.04
Vector	4,453.65	4,367.12	4,432.17	4,568.06	4,632.09	4,990.01	5,115.12
Waipa Network	254.56	284.11	289.86	289.06	295.53	301.14	316.48
WEL Networks	791.88	858.84	894.27	901.26	975.85	965.82	962.39
Westpower	192.33	210.35	203.11	197.51	196.17	201.94	197.99

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B3: **System line capacity in MVA kilometres, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	42,121	42,640	43,580	43,240	43,073	43,369	43,773
Buller Electricity	6,255	6,259	6,296	6,296	6,347	6,546	6,605
Centralines	20,417	20,291	20,389	20,417	20,447	21,414	21,389
Counties Power	19,475	20,852	21,577	22,293	19,788	23,811	24,051
Dunedin Electricity	41,530	42,131	42,495	43,161	45,216	46,424	47,789
Eastland N/W	52,756	52,781	52,781	52,781	47,101	45,750	46,911
Electra	15,935	16,149	16,281	16,358	16,404	17,502	17,517
Electricity Ashburton	28,852	29,472	29,866	30,096	30,765	31,670	32,824
Electricity Invercargill	3,043	3,044	3,046	3,078	3,074	3,096	3,130
Horizon Energy	24,963	24,311	25,102	25,773	24,027	25,834	26,060
MainPower	39,548	39,860	47,534	48,250	48,845	49,860	49,456
Marlborough Lines	31,313	31,488	33,715	33,859	34,175	33,460	33,830
Nelson Electricity	1,490	1,497	1,498	1,430	1,416	1,459	1,418
Network Tasman	29,745	29,972	30,188	30,392	30,495	30,596	30,670
Network Waitaki	23,181	23,314	23,465	23,484	23,596	23,676	24,246
Northpower	46,236	46,852	47,862	48,145	50,986	48,074	48,314
Orion New Zealand	76,105	76,835	79,672	81,515	81,131	80,972	81,743
Otago Power	50,660	50,870	52,409	52,497	52,881	54,545	54,904
Powerco	320,264	320,235	312,675	313,680	311,324	325,992	329,548
Scanpower	10,847	10,868	10,884	10,842	10,857	10,859	10,704
The Lines Company	59,772	59,766	60,498	62,126	59,931	57,860	55,972
The Power Company	105,728	105,961	106,145	101,249	96,773	97,271	99,543
Top Energy	47,071	47,218	47,342	47,522	47,956	48,400	48,635
Unison	33,971	34,172	34,356	34,525	36,357	36,922	37,142
UnitedNetworks	192,190	196,680	200,497	202,441	205,650	218,026	218,640
Vector	62,607	62,880	65,203	68,666	62,825	55,198	54,418
Waipa Network	18,929	18,933	18,989	19,159	19,261	18,657	18,800
WEL Networks	33,780	33,886	34,094	36,599	36,910	40,298	40,954
Westpower	23,075	23,735	24,712	25,118	25,160	25,762	25,875

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B4: **Connection numbers, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	26,945	27,283	27,317	27,486	27,829	27,806	28,376
Buller Electricity	4,238	4,238	4,250	4,243	4,241	4,258	4,108
Centralines	7,750	7,745	7,769	7,432	7,454	7,432	7,431
Counties Power	29,860	29,977	30,478	30,859	30,470	30,546	30,817
Dunedin Electricity	68,034	68,749	68,827	69,131	69,494	70,208	71,431
Eastland N/W	40,525	25,299	25,200	25,232	23,694	26,128	25,552
Electra	34,827	35,288	35,713	36,338	36,651	37,302	38,292
Electricity Ashburton	12,997	13,164	13,365	13,564	13,843	14,285	14,558
Electricity Invercargill	16,706	16,839	16,852	16,856	16,733	16,701	16,847
Horizon Energy	21,867	22,201	22,636	22,931	23,061	23,046	23,092
MainPower	23,701	23,486	24,786	22,859	24,140	25,638	25,047
Marlborough Lines	19,300	19,517	19,804	20,025	20,572	20,805	21,038
Nelson Electricity	8,322	8,359	8,341	8,461	8,476	8,579	8,575
Network Tasman	28,806	28,982	29,272	29,750	30,246	30,790	31,293
Network Waitaki	11,782	12,205	11,881	11,385	11,409	11,372	11,341
Northpower	43,146	43,202	43,371	44,158	44,674	45,589	46,712
Orion New Zealand	152,553	154,678	156,878	158,673	162,543	166,556	168,455
Otago Power	14,012	14,637	14,480	14,861	14,231	14,297	14,434
Powerco	156,151	155,597	154,576	153,305	156,220	157,120	157,451
Scanpower	6,700	6,700	6,700	6,626	6,675	6,707	6,615
The Lines Company	25,292	25,948	23,700	24,199	25,259	25,846	25,712
The Power Company	32,941	30,589	30,212	30,204	30,273	31,005	31,800
Top Energy	23,870	24,337	24,980	24,779	25,700	26,234	27,044
Unison	54,907	55,740	56,000	56,000	56,594	57,331	58,070
UnitedNetworks	446,156	454,704	463,014	469,953	479,972	492,387	505,057
Vector	243,765	246,684	251,155	255,010	259,577	265,895	274,000
Waipa Network	19,748	19,706	19,872	19,612	19,824	20,050	20,293
WEL Networks	64,961	65,985	67,265	68,580	70,202	71,473	72,942
Westpower	11,355	11,979	11,964	11,954	11,729	11,996	12,072

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B5: **Operating expenditure ($m), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	4.271	4.212	5.050	4.515	4.262	4.470	4.565
Buller Electricity	1.372	1.628	1.418	1.438	1.782	1.355	1.838
Centralines	1.823	1.923	1.350	2.217	1.379	1.683	1.648
Counties Power	6.068	5.890	6.483	5.642	6.329	5.369	5.231
Dunedin Electricity	12.790	12.906	13.109	13.192	11.125	11.355	12.276
Eastland N/W	9.499	7.578	7.573	8.389	6.240	7.858	5.516
Electra	5.982	6.275	5.845	5.367	4.750	4.894	5.554
Electricity Ashburton	3.174	3.974	3.547	3.682	3.021	2.875	2.775
Electricity Invercargill	2.637	3.374	2.936	2.286	2.250	2.335	2.280
Horizon Energy	10.150	9.207	10.445	6.150	4.656	3.722	4.491
MainPower	5.472	5.394	6.413	4.518	4.177	4.480	4.360
Marlborough Lines	4.632	3.781	4.372	4.340	4.946	5.026	5.224
Nelson Electricity	4.769	4.404	0.722	0.997	1.745	1.828	1.466
Network Tasman	6.877	8.743	7.575	5.945	4.332	4.888	4.105
Network Waitaki	2.599	2.181	1.961	1.459	1.694	1.530	1.627
Northpower	8.172	8.714	9.346	7.760	7.499	6.649	7.674
Orion New Zealand	32.176	31.546	34.752	17.429	21.605	21.203	23.042
Otago Power	4.304	4.022	4.319	3.801	3.722	3.507	3.612
Powerco	40.209	39.039	29.480	23.066	25.202	36.517	27.368
Scanpower	1.243	1.350	1.378	1.528	1.285	1.417	1.352
The Lines Company	5.963	6.137	6.130	6.433	3.505	3.215	3.658
The Power Company	8.848	8.289	8.060	6.142	5.722	5.238	5.905
Top Energy	6.964	7.370	7.408	5.654	6.074	6.617	6.685
Unison	12.408	11.696	12.557	9.157	8.150	8.628	7.834
UnitedNetworks	83.374	98.482	82.670	75.376	59.430	58.825	58.566
Vector	36.157	38.710	45.971	79.141	52.416	42.236	41.683
Waipa Network	3.129	3.033	2.845	2.507	2.618	2.470	2.544
WEL Networks	9.734	10.027	10.148	12.596	11.492	10.713	10.804
Westpower	5.101	6.166	5.002	4.266	4.217	3.098	3.764

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B6: **Overhead MVA kilometres, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	39,785	40,275	41,072	40,553	40,201	40,446	40,739
Buller Electricity	6,226	6,230	6,251	6,251	6,292	6,475	6,530
Centralines	20,298	20,186	20,270	20,298	20,326	21,293	21,251
Counties Power	19,058	19,886	20,421	21,008	18,381	22,183	22,350
Dunedin Electricity	35,875	36,227	36,327	36,720	37,365	38,752	40,012
Eastland N/W	51,137	51,147	51,147	51,147	45,627	44,302	45,355
Electra	13,770	13,798	13,840	13,883	13,898	14,698	14,698
Electricity Ashburton	28,058	28,563	28,927	29,123	29,656	30,342	31,392
Electricity Invercargill	1,010	994	965	949	868	742	645
Horizon Energy	23,538	22,791	23,449	24,063	22,145	23,781	23,964
MainPower	38,593	38,859	46,234	46,841	47,365	48,288	47,856
Marlborough Lines	30,737	30,847	32,747	32,859	33,113	32,588	32,782
Nelson Electricity	350	352	352	307	281	295	253
Network Tasman	28,156	28,337	28,517	28,581	28,624	28,635	28,656
Network Waitaki	22,917	23,019	23,172	23,191	23,302	23,257	23,785
Northpower	45,299	45,859	46,889	47,159	49,654	46,658	46,712
Orion New Zealand	48,731	49,029	51,101	52,207	51,465	51,523	52,457
Otago Power	50,651	50,861	52,318	52,390	52,781	54,449	54,811
Powerco	313,056	312,853	305,374	306,200	302,824	315,924	320,776
Scanpower	10,828	10,848	10,863	10,821	10,835	10,835	10,680
The Lines Company	58,695	58,690	59,369	60,980	58,478	56,509	54,821
The Power Company	105,082	105,300	105,468	100,543	96,040	96,495	98,709
Top Energy	46,308	46,433	46,485	46,582	46,889	47,238	47,364
Unison	28,985	29,127	29,239	29,309	30,776	30,863	30,934
UnitedNetworks	153,238	155,157	157,554	158,284	156,837	166,630	166,155
Vector	20,419	20,398	20,050	20,289	19,393	18,330	16,242
Waipa Network	18,314	18,315	18,344	18,496	18,567	18,178	18,263
WEL Networks	27,933	27,930	28,016	30,102	30,176	32,810	33,092
Westpower	22,661	23,308	24,298	24,704	24,718	25,278	25,362

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B7: **Underground MVA kilometres, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	2,336	2,365	2,508	2,688	2,872	2,923	3,034
Buller Electricity	29	29	44	44	55	71	75
Centralines	119	105	119	119	121	122	138
Counties Power	417	966	1,156	1,285	1,407	1,629	1,701
Dunedin Electricity	5,656	5,905	6,167	6,441	7,850	7,672	7,777
Eastland N/W	1,619	1,634	1,634	1,634	1,474	1,447	1,556
Electra	2,166	2,351	2,441	2,475	2,507	2,804	2,819
Electricity Ashburton	794	909	940	973	1,109	1,328	1,432
Electricity Invercargill	2,033	2,050	2,081	2,129	2,206	2,353	2,485
Horizon Energy	1,425	1,520	1,653	1,710	1,881	2,053	2,096
MainPower	956	1,001	1,300	1,409	1,480	1,572	1,600
Marlborough Lines	576	641	968	1,000	1,063	872	1,048
Nelson Electricity	1,140	1,145	1,145	1,123	1,135	1,164	1,165
Network Tasman	1,589	1,635	1,672	1,811	1,870	1,961	2,013
Network Waitaki	264	294	294	293	295	419	461
Northpower	937	993	972	986	1,331	1,416	1,603
Orion New Zealand	27,374	27,806	28,572	29,308	29,667	29,449	29,286
Otago Power	9	9	90	107	100	96	93
Powerco	7,208	7,381	7,301	7,480	8,500	10,068	8,772
Scanpower	19	20	21	22	22	24	24
The Lines Company	1,076	1,076	1,128	1,146	1,453	1,350	1,151
The Power Company	646	661	677	705	734	776	834
Top Energy	763	785	857	940	1,067	1,163	1,271
Unison	4,985	5,046	5,117	5,217	5,581	6,059	6,208
UnitedNetworks	38,952	41,522	42,944	44,157	48,813	51,396	52,486
Vector	42,188	42,482	45,153	48,378	43,432	36,868	38,176
Waipa Network	615	617	645	663	694	479	537
WEL Networks	5,847	5,955	6,078	6,496	6,734	7,488	7,861
Westpower	413	427	413	413	442	484	513

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B8: **Transformer capacity (MVA), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	246.80	250.44	258.29	258.62	259.18	261.56	274.51
Buller Electricity	25.05	24.57	25.93	26.64	26.88	27.38	27.82
Centralines	59.02	61.79	63.18	63.99	64.64	69.84	71.49
Counties Power	197.00	229.81	217.41	217.98	231.03	229.98	237.73
Dunedin Electricity	638.92	661.04	666.56	668.31	686.99	708.48	725.94
Eastland N/W	228.44	219.43	218.67	220.48	191.22	209.99	224.97
Electra	260.18	261.48	262.35	266.16	267.07	271.08	273.58
Electricity Ashburton	206.35	213.03	221.50	235.05	239.17	253.79	262.74
Electricity Invercargill	140.85	140.84	139.35	137.88	138.48	139.48	140.77
Horizon Energy	189.56	163.00	166.83	178.16	187.00	186.82	185.65
MainPower	202.59	202.36	208.42	214.83	229.01	247.22	257.48
Marlborough Lines	169.21	178.07	192.36	200.56	204.05	211.86	222.36
Nelson Electricity	71.82	72.52	70.47	72.27	72.27	76.54	78.19
Network Tasman	256.28	277.85	296.48	314.72	271.27	272.61	276.45
Network Waitaki	110.49	112.67	113.54	117.43	117.57	120.69	125.11
Northpower	319.62	328.14	360.62	376.19	386.20	393.00	397.45
Orion New Zealand	1,559.04	1,603.05	1,639.99	1,686.10	1,505.10	1,487.58	1,495.44
Otago Power	145.64	126.46	118.16	124.85	128.01	127.84	130.63
Powerco	1,288.37	1,230.56	1,217.64	1,268.01	1,256.90	1,320.12	1,312.24
Scanpower	54.43	53.16	54.32	54.51	54.60	52.56	55.63
The Lines Company	300.31	301.96	273.06	276.60	167.68	185.05	188.80
The Power Company	260.77	269.88	280.65	283.33	286.40	291.96	298.00
Top Energy	148.48	152.48	156.09	161.05	166.13	176.30	180.90
Unison	502.79	511.71	526.56	531.25	536.49	538.83	557.00
UnitedNetworks	3,428.02	3,485.54	3,598.55	3,739.31	3,735.47	3,705.86	3,887.57
Vector	2,835.24	2,613.45	2,657.45	2,274.64	2,276.80	2,240.28	2,349.45
Waipa Network	160.31	161.09	162.37	147.55	149.53	156.16	160.30
WEL Networks	471.98	468.32	479.20	487.50	492.33	489.90	495.12
Westpower	159.32	93.93	93.93	97.48	99.71	107.13	104.36

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B9: **Optimised deprival value of assets ($m), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	65.79	65.79	65.79	69.72	68.37	66.78	66.00
Buller Electricity	12.93	12.93	13.20	13.20	12.84	12.92	13.18
Centralines	25.09	25.09	28.89	27.85	27.92	24.26	24.35
Counties Power	54.45	54.45	75.16	74.87	79.30	83.97	89.72
Dunedin Electricity	132.16	127.26	132.03	145.28	149.87	153.36	154.40
Eastland N/W	33.72	33.72	67.13	63.13	53.25	54.02	66.05
Electra	50.05	56.36	65.30	60.97	61.64	72.45	73.52
Electricity Ashburton	55.00	58.30	58.30	58.30	63.18	68.66	83.71
Electricity Invercargill	35.53	35.53	33.28	32.54	32.72	35.09	37.75
Horizon Energy	56.83	66.95	66.95	64.47	65.47	64.84	63.99
MainPower	68.74	68.74	88.17	82.22	84.67	87.36	91.04
Marlborough Lines	75.10	75.10	75.54	70.12	69.29	68.46	70.83
Nelson Electricity	13.67	13.67	18.74	14.54	14.22	14.17	13.84
Network Tasman	90.39	107.91	93.42	86.92	86.99	70.42	71.65
Network Waitaki	41.65	43.21	44.14	39.82	40.23	38.21	38.37
Northpower	105.40	105.40	115.16	113.90	114.37	110.93	111.84
Orion New Zealand	387.87	477.57	477.99	448.46	405.98	435.51	442.84
Otago Power	37.06	37.06	51.31	53.37	55.38	52.70	53.44
Powerco	332.08	352.94	397.29	376.89	388.18	376.11	377.16
Scanpower	17.52	17.52	16.01	15.12	15.15	15.87	15.81
The Lines Company	60.99	66.81	62.86	57.96	65.29	65.06	65.46
The Power Company	89.53	89.53	93.90	142.91	143.94	149.91	152.42
Top Energy	66.29	66.29	69.62	70.84	72.73	71.56	73.71
Unison	115.80	115.80	118.16	100.58	101.43	116.35	118.98
UnitedNetworks	1,026.97	1,097.65	1,075.26	1,018.30	1,005.30	1,037.00	1,040.86
Vector	765.75	783.50	715.38	710.14	707.58	852.33	879.06
Waipa Network	42.66	42.66	42.66	43.29	42.92	44.94	45.47
WEL Networks	105.77	105.77	129.44	133.92	139.37	156.55	160.26
Westpower	32.67	32.67	32.67	50.33	49.37	48.13	48.55

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B10: **Annual user cost of overhead lines ($m), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	4.915	4.915	4.915	5.209	5.108	4.989	4.930
Buller Electricity	0.966	0.966	0.987	0.986	0.960	0.966	0.985
Centralines	1.839	1.839	2.118	2.041	2.047	1.778	1.784
Counties Power	3.991	3.991	5.509	5.488	5.812	6.154	6.576
Dunedin Electricity	4.991	4.806	4.986	5.486	5.660	5.792	5.831
Eastland N/W	2.471	2.471	4.920	4.627	3.903	3.959	4.841
Electra	2.573	2.897	3.357	3.134	3.169	3.725	3.779
Electricity Ashburton	4.109	4.355	4.355	4.355	4.720	5.130	6.254
Electricity Invercargill	1.827	1.827	1.711	1.673	1.682	1.804	1.941
Horizon Energy	4.246	5.002	5.002	4.817	4.891	4.844	4.781
MainPower	5.038	5.038	6.462	6.026	6.206	6.403	6.672
Marlborough Lines	5.504	5.504	5.536	5.139	5.079	5.018	5.191
Nelson Electricity	0.516	0.516	0.708	0.549	0.537	0.535	0.523
Network Tasman	6.753	8.061	6.979	6.493	6.499	5.261	5.353
Network Waitaki	3.053	3.167	3.235	2.919	2.949	2.800	2.812
Northpower	7.874	7.874	8.604	8.509	8.544	8.288	8.355
Orion New Zealand	19.940	24.551	24.573	23.055	20.871	22.389	22.766
Otago Power	2.769	2.769	3.833	3.987	4.137	3.937	3.992
Powerco	24.339	25.868	29.119	27.623	28.451	27.566	27.643
Scanpower	1.284	1.284	1.174	1.108	1.111	1.163	1.159
The Lines Company	4.470	4.897	4.607	4.248	4.786	4.769	4.797
The Power Company	6.689	6.689	7.015	10.677	10.753	11.200	11.387
Top Energy	4.858	4.858	5.103	5.192	5.331	5.245	5.402
Unison	5.953	5.953	6.075	5.171	5.215	5.981	6.117
UnitedNetworks	52.796	56.429	55.278	52.350	51.682	53.311	53.510
Vector	28.918	29.588	27.016	26.818	26.721	32.188	33.197
Waipa Network	3.127	3.127	3.127	3.173	3.146	3.294	3.333
WEL Networks	5.438	5.438	6.654	6.885	7.165	8.048	8.239
Westpower	2.395	2.395	2.395	3.689	3.619	3.527	3.558

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B11: **Annual user cost of underground cables ($m), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	0.844	0.844	0.844	0.895	0.877	0.857	0.847
Buller Electricity	0.166	0.166	0.170	0.170	0.165	0.166	0.169
Centralines	0.461	0.461	0.531	0.512	0.513	0.446	0.448
Counties Power	1.001	1.001	1.382	1.376	1.458	1.544	1.649
Dunedin Electricity	4.746	4.570	4.742	5.217	5.382	5.507	5.545
Eastland N/W	0.620	0.620	1.234	1.161	0.979	0.993	1.214
Electra	1.768	1.991	2.307	2.154	2.178	2.560	2.597
Electricity Ashburton	0.706	0.748	0.748	0.748	0.811	0.881	1.074
Electricity Invercargill	1.255	1.255	1.176	1.150	1.156	1.240	1.334
Horizon Energy	0.729	0.859	0.859	0.827	0.840	0.832	0.821
MainPower	1.264	1.264	1.621	1.511	1.557	1.606	1.674
Marlborough Lines	1.381	1.381	1.389	1.289	1.274	1.259	1.302
Nelson Electricity	0.491	0.491	0.673	0.522	0.511	0.509	0.497
Network Tasman	1.160	1.385	1.199	1.116	1.116	0.904	0.920
Network Waitaki	0.766	0.794	0.812	0.732	0.740	0.702	0.705
Northpower	1.353	1.353	1.478	1.462	1.468	1.424	1.435
Orion New Zealand	13.703	16.872	16.887	15.844	14.343	15.386	15.645
Otago Power	0.476	0.476	0.659	0.685	0.711	0.676	0.686
Powerco	6.105	6.488	7.304	6.928	7.136	6.914	6.933
Scanpower	0.322	0.322	0.294	0.278	0.279	0.292	0.291
The Lines Company	1.121	1.228	1.156	1.065	1.200	1.196	1.203
The Power Company	1.149	1.149	1.205	1.834	1.847	1.924	1.956
Top Energy	1.219	1.219	1.280	1.302	1.337	1.316	1.355
Unison	4.091	4.091	4.175	3.554	3.584	4.110	4.204
UnitedNetworks	36.282	38.779	37.988	35.975	35.516	36.636	36.772
Vector	27.499	28.136	25.690	25.502	25.410	30.608	31.568
Waipa Network	0.784	0.784	0.784	0.796	0.789	0.826	0.836
WEL Networks	3.737	3.737	4.573	4.731	4.924	5.531	5.662
Westpower	0.601	0.601	0.601	0.925	0.908	0.885	0.892

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B12: **Annual user cost of transformers ($m), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	2.172	2.172	2.172	2.301	2.257	2.204	2.178
Buller Electricity	0.427	0.427	0.436	0.436	0.424	0.427	0.435
Centralines	0.718	0.718	0.826	0.796	0.799	0.694	0.696
Counties Power	1.557	1.557	2.149	2.141	2.268	2.401	2.566
Dunedin Electricity	6.394	6.157	6.388	7.029	7.251	7.420	7.470
Eastland N/W	0.964	0.964	1.920	1.805	1.523	1.545	1.889
Electra	1.661	1.870	2.167	2.023	2.045	2.404	2.439
Electricity Ashburton	1.815	1.924	1.924	1.924	2.085	2.266	2.763
Electricity Invercargill	1.179	1.179	1.104	1.080	1.086	1.164	1.253
Horizon Energy	1.876	2.210	2.210	2.128	2.161	2.140	2.112
MainPower	1.966	1.966	2.521	2.351	2.421	2.498	2.603
Marlborough Lines	2.148	2.148	2.160	2.005	1.982	1.958	2.025
Nelson Electricity	0.661	0.661	0.907	0.704	0.688	0.685	0.670
Network Tasman	2.984	3.562	3.083	2.869	2.871	2.324	2.365
Network Waitaki	1.191	1.236	1.262	1.139	1.150	1.093	1.097
Northpower	3.479	3.479	3.801	3.760	3.775	3.662	3.692
Orion New Zealand	12.869	15.845	15.859	14.879	13.469	14.449	14.692
Otago Power	1.223	1.223	1.694	1.762	1.828	1.740	1.764
Powerco	9.496	10.093	11.361	10.778	11.100	10.755	10.785
Scanpower	0.501	0.501	0.458	0.432	0.433	0.454	0.452
The Lines Company	1.744	1.911	1.798	1.657	1.867	1.861	1.872
The Power Company	2.955	2.955	3.099	4.717	4.751	4.948	5.031
Top Energy	1.896	1.896	1.991	2.026	2.080	2.046	2.108
Unison	3.842	3.842	3.920	3.337	3.365	3.860	3.948
UnitedNetworks	34.073	36.418	35.675	33.785	33.354	34.405	34.533
Vector	37.049	37.908	34.612	34.358	34.235	41.238	42.531
Waipa Network	1.220	1.220	1.220	1.238	1.227	1.285	1.300
WEL Networks	3.509	3.509	4.295	4.443	4.624	5.194	5.317
Westpower	0.934	0.934	0.934	1.439	1.412	1.376	1.388

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B13: **Annual user cost of other capital ($m), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	0.293	0.293	0.293	0.310	0.304	0.297	0.294
Buller Electricity	0.058	0.058	0.059	0.059	0.057	0.058	0.059
Centralines	0.119	0.119	0.137	0.132	0.132	0.115	0.115
Counties Power	0.257	0.257	0.355	0.354	0.375	0.397	0.424
Dunedin Electricity	0.389	0.374	0.388	0.427	0.441	0.451	0.454
Eastland N/W	0.159	0.159	0.317	0.299	0.252	0.255	0.312
Electra	0.255	0.287	0.332	0.310	0.313	0.368	0.374
Electricity Ashburton	0.245	0.260	0.260	0.260	0.281	0.306	0.373
Electricity Invercargill	0.181	0.181	0.169	0.165	0.166	0.178	0.192
Horizon Energy	0.253	0.298	0.298	0.287	0.292	0.289	0.285
MainPower	0.325	0.325	0.417	0.389	0.400	0.413	0.430
Marlborough Lines	0.355	0.355	0.357	0.332	0.328	0.324	0.335
Nelson Electricity	0.040	0.040	0.055	0.043	0.042	0.042	0.041
Network Tasman	0.403	0.481	0.416	0.387	0.387	0.314	0.319
Network Waitaki	0.197	0.204	0.209	0.188	0.190	0.181	0.181
Northpower	0.469	0.469	0.513	0.507	0.509	0.494	0.498
Orion New Zealand	1.972	2.428	2.430	2.280	2.064	2.214	2.252
Otago Power	0.165	0.165	0.229	0.238	0.247	0.235	0.238
Powerco	1.570	1.669	1.878	1.782	1.835	1.778	1.783
Scanpower	0.083	0.083	0.076	0.072	0.072	0.075	0.075
The Lines Company	0.288	0.316	0.297	0.274	0.309	0.308	0.310
The Power Company	0.399	0.399	0.418	0.636	0.641	0.668	0.679
Top Energy	0.313	0.313	0.329	0.335	0.344	0.338	0.349
Unison	0.589	0.589	0.601	0.511	0.516	0.592	0.605
UnitedNetworks	5.221	5.581	5.467	5.177	5.111	5.272	5.292
Vector	2.253	2.305	2.105	2.089	2.082	2.507	2.586
Waipa Network	0.202	0.202	0.202	0.205	0.203	0.213	0.215
WEL Networks	0.538	0.538	0.658	0.681	0.709	0.796	0.815
Westpower	0.155	0.155	0.155	0.238	0.233	0.228	0.230

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B14: **Transformer capacity based MVA kilometres ('000), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	873	896	942	941	940	978	1,012
Buller Electricity	14	14	15	15	16	16	17
Centralines	90	95	97	99	100	113	115
Counties Power	578	688	700	719	725	770	805
Dunedin Electricity	2,567	2,695	2,743	2,789	2,966	3,283	3,443
Eastland N/W	862	829	827	833	668	743	828
Electra	495	503	510	521	526	576	582
Electricity Ashburton	466	492	519	556	581	640	678
Electricity Invercargill	97	97	97	97	96	96	97
Horizon Energy	397	345	356	382	418	442	442
MainPower	640	645	830	872	947	1,054	1,114
Marlborough Lines	422	449	550	577	594	639	678
Nelson Electricity	16	16	15	17	17	19	19
Network Tasman	777	849	913	976	845	851	863
Network Waitaki	206	211	214	221	223	229	239
Northpower	1,574	1,637	1,819	1,907	2,038	2,077	2,121
Orion New Zealand	16,964	17,630	18,489	19,353	17,340	17,070	17,207
Otago Power	679	593	480	510	525	532	547
Powerco	20,243	19,368	18,760	19,609	19,418	20,215	20,944
Scanpower	54	53	54	54	54	52	49
The Lines Company	1,456	1,464	1,342	1,395	799	826	869
The Power Company	2,152	2,230	2,321	2,227	2,140	2,190	2,247
Top Energy	686	707	728	757	789	846	874
Unison	1,821	1,864	1,927	1,952	2,052	2,086	2,174
UnitedNetworks	77,322	80,826	85,206	90,561	93,052	106,900	116,712
Vector	24,332	22,553	23,420	20,505	19,834	18,921	20,155
Waipa Network	296	298	301	276	282	273	283
WEL Networks	1,678	1,678	1,732	2,049	2,088	2,245	2,323
Westpower	270	171	177	187	192	210	206

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B15: **Energy density (kWh/customer), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	15,773	16,182	17,293	18,470	18,820	20,267	19,921
Buller Electricity	20,951	21,761	21,523	21,355	22,105	21,758	22,683
Centralines	10,694	11,192	11,500	12,049	12,526	14,958	14,953
Counties Power	12,495	12,588	12,735	12,398	13,053	13,399	13,567
Dunedin Electricity	17,230	17,176	17,095	16,670	17,124	17,573	17,363
Eastland N/W	6,625	11,283	11,163	10,871	11,390	11,083	11,361
Electra	9,208	9,215	9,276	9,870	9,979	10,152	10,026
Electricity Ashburton	18,062	20,677	23,723	24,165	21,116	24,427	23,541
Electricity Invercargill	15,535	16,726	16,559	15,862	15,333	15,667	15,704
Horizon Energy	24,574	23,313	22,602	24,045	25,192	25,455	25,745
MainPower	14,942	14,357	14,430	14,866	14,631	15,863	15,259
Marlborough Lines	14,390	14,613	14,972	14,261	14,120	14,809	14,429
Nelson Electricity	17,011	17,171	17,079	17,187	17,360	17,263	17,134
Network Tasman	19,265	19,561	19,838	19,714	20,710	21,896	21,885
Network Waitaki	13,453	13,378	14,223	15,628	15,288	15,743	15,503
Northpower	16,866	17,551	18,284	18,322	18,548	18,423	18,244
Orion New Zealand	16,432	16,353	16,459	16,970	16,828	16,941	17,221
Otago Power	17,391	16,758	18,467	18,413	21,900	23,709	24,136
Powerco	12,831	13,018	12,696	13,572	13,008	13,258	13,194
Scanpower	11,385	12,175	12,118	12,202	12,776	13,080	13,374
The Lines Company	9,997	4,693	11,685	11,142	11,322	10,981	11,133
The Power Company	14,488	18,017	18,715	18,504	18,426	19,084	19,121
Top Energy	9,478	11,543	11,366	11,308	11,052	11,645	11,690
Unison	12,862	13,817	14,265	14,235	14,645	14,799	14,936
UnitedNetworks	14,530	15,212	14,951	13,443	14,301	14,461	13,608
Vector	18,270	17,703	17,647	17,913	17,845	18,767	18,668
Waipa Network	12,891	14,418	14,586	14,739	14,908	15,019	15,595
WEL Networks	12,190	13,016	13,295	13,142	13,901	13,513	13,194
Westpower	16,938	17,559	16,976	16,522	16,725	16,834	16,401

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B16: **Customer density (customers/kilometre), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	7.62	7.63	7.49	7.56	7.67	7.43	7.70
Buller Electricity	7.46	7.46	7.40	7.39	7.33	7.18	6.90
Centralines	5.09	5.06	5.05	4.82	4.83	4.61	4.60
Counties Power	10.18	10.01	9.46	9.36	9.70	9.13	9.10
Dunedin Electricity	16.93	16.86	16.73	16.56	16.10	15.15	15.06
Eastland N/W	10.74	6.70	6.67	6.67	6.78	7.38	6.95
Electra	18.29	18.34	18.38	18.55	18.60	17.56	18.00
Electricity Ashburton	5.76	5.70	5.71	5.73	5.69	5.67	5.64
Electricity Invercargill	24.28	24.44	24.32	24.05	24.08	24.35	24.49
Horizon Energy	10.43	10.49	10.61	10.68	10.32	9.74	9.69
MainPower	7.51	7.37	6.22	5.63	5.84	6.01	5.79
Marlborough Lines	7.74	7.74	6.92	6.96	7.07	6.90	6.90
Nelson Electricity	38.53	38.52	38.33	35.54	35.46	35.30	35.58
Network Tasman	9.50	9.49	9.51	9.59	9.71	9.86	10.02
Network Waitaki	6.33	6.52	6.31	6.04	6.02	5.98	5.93
Northpower	8.76	8.66	8.60	8.71	8.47	8.63	8.75
Orion New Zealand	14.02	14.06	13.92	13.82	14.11	14.51	14.64
Otago Power	3.01	3.12	3.57	3.64	3.47	3.44	3.44
Powerco	9.94	9.89	10.03	9.91	10.11	10.26	9.87
Scanpower	6.74	6.73	6.72	6.67	6.71	6.73	7.59
The Lines Company	5.21	5.35	4.82	4.80	5.30	5.79	5.59
The Power Company	3.99	3.70	3.65	3.84	4.05	4.13	4.22
Top Energy	5.17	5.25	5.35	5.27	5.41	5.46	5.59
Unison	15.16	15.30	15.30	15.24	14.80	14.81	14.88
UnitedNetworks	19.78	19.61	19.55	19.40	19.27	17.07	16.82
Vector	28.40	28.59	28.50	28.29	29.80	31.48	31.94
Waipa Network	10.70	10.65	10.71	10.48	10.52	11.46	11.50
WEL Networks	18.27	18.41	18.62	16.31	16.55	15.59	15.55
Westpower	6.70	6.57	6.34	6.24	6.11	6.11	6.12

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B17: **Total distribution SAIDI (planned and unplanned), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	72.0	47.0	63.0	67.0	46.4	75.2	69.0
Buller Electricity	608.0	476.1	324.8	381.5	364.9	313.7	279.6
Centralines	284.0	160.0	101.0	253.0	326.0	378.0	355.0
Counties Power	466.5	414.0	238.7	225.8	124.0	132.0	61.7
Dunedin Electricity	125.8	101.7	85.1	92.8	194.6	79.1	75.3
Eastland N/W	618.2	741.4	649.1	428.5	231.4	667.1	187.9
Electra	169.7	115.5	93.8	66.3	99.5	104.4	65.8
Electricity Ashburton	215.9	258.0	180.5	197.4	131.3	128.9	228.6
Electricity Invercargill	57.0	78.1	105.6	51.1	33.7	35.0	36.0
Horizon Energy	403.0	304.0	294.0	253.0	121.0	118.0	214.0
MainPower	385.5	191.6	225.1	190.3	93.6	152.0	160.7
Marlborough Lines	150.0	157.0	227.0	244.0	171.6	177.8	184.9
Nelson Electricity	53.5	28.3	51.6	51.0	76.0	41.0	38.7
Network Tasman	228.5	230.4	247.9	269.3	184.0	105.0	70.8
Network Waitaki	89.0	103.6	87.4	63.3	46.1	72.2	78.1
Northpower	227.5	287.9	240.5	216.7	109.0	159.1	188.6
Orion New Zealand	76.9	113.5	81.6	67.7	51.8	62.2	38.0
Otago Power	150.6	196.1	453.0	340.6	320.8	197.4	171.9
Powerco	160.1	176.6	144.5	149.3	101.5	84.4	129.9
Scanpower	74.3	125.3	109.2	104.8	66.1	70.2	92.2
The Lines Company	552.6	599.5	403.3	539.6	445.8	528.9	464.3
The Power Company	366.2	484.1	744.4	337.4	413.5	146.0	137.8
Top Energy	465.0	591.0	432.0	737.0	460.0	329.0	335.0
Unison	111.8	164.4	163.8	162.4	103.9	140.0	100.8
UnitedNetworks	121.3	140.2	110.7	166.4	98.2	122.9	119.4
Vector	115.8	107.7	153.3	81.2	57.1	49.4	51.2
Waipa Network	353.9	328.0	253.6	242.2	293.6	245.7	349.3
WEL Networks	163.0	175.8	147.8	137.3	111.2	131.1	76.2
Westpower	671.3	399.1	321.4	224.6	153.2	219.9	126.9

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B18: **Total distribution SAIFI (planned and unplanned), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	0.76	0.78	1.01	1.23	0.77	1.39	1.00
Buller Electricity	2.81	3.41	3.90	3.30	3.10	2.14	1.77
Centralines	2.76	1.53	0.91	2.73	4.94	6.45	8.05
Counties Power	5.55	7.40	4.30	3.65	2.43	2.64	2.20
Dunedin Electricity	1.90	1.89	1.83	2.01	1.74	1.30	1.63
Eastland N/W	5.21	6.10	7.17	5.11	3.03	4.01	2.57
Electra	4.10	3.47	2.30	1.52	2.06	2.12	1.31
Electricity Ashburton	1.82	2.74	1.65	2.45	1.11	1.22	1.55
Electricity Invercargill	0.98	2.22	1.33	1.34	0.64	1.12	1.16
Horizon Energy	4.50	4.35	4.20	3.21	1.90	1.55	1.65
MainPower	2.32	3.06	3.68	1.78	1.66	2.08	1.24
Marlborough Lines	2.28	1.75	2.10	2.20	1.50	2.20	1.80
Nelson Electricity	3.10	0.82	0.53	0.93	1.30	1.78	1.00
Network Tasman	2.04	2.67	2.78	3.79	2.66	1.63	1.00
Network Waitaki	1.05	0.93	1.45	1.38	0.86	1.02	1.00
Northpower	4.30	5.29	4.03	4.74	2.08	3.27	2.86
Orion New Zealand	0.96	1.34	1.01	0.84	0.83	0.60	0.60
Otago Power	1.86	1.72	3.34	2.45	2.62	2.43	1.76
Powerco	2.91	2.62	2.28	2.55	2.03	1.57	2.24
Scanpower	0.90	1.15	0.91	1.25	0.67	0.86	1.13
The Lines Company	8.69	7.81	5.53	7.65	6.16	5.54	5.39
The Power Company	4.00	5.61	7.54	6.04	6.45	2.89	2.87
Top Energy	12.00	13.40	5.80	9.80	6.70	5.30	5.10
Unison	1.97	3.13	2.71	2.38	1.47	2.75	2.14
UnitedNetworks	2.72	2.70	1.92	2.11	1.64	1.89	1.78
Vector	1.91	1.84	1.72	1.19	1.01	0.99	0.80
Waipa Network	4.27	5.02	2.85	3.24	2.85	3.29	3.24
WEL Networks	2.50	3.19	2.18	1.89	2.37	2.62	1.49
Westpower	3.45	2.52	2.74	1.93	1.22	2.47	1.33

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B19: **Total overhead line length (kilometres), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	3,172	3,207	3,263	3,223	3,196	3,247	3,244
Buller Electricity	556	556	561	561	564	577	579
Centralines	1,498	1,506	1,512	1,514	1,516	1,586	1,583
Counties Power	2,753	2,770	2,992	3,055	2,874	2,955	2,985
Dunedin Electricity	3,360	3,385	3,395	3,423	3,426	3,706	3,797
Eastland N/W	3,524	3,525	3,526	3,526	3,267	3,291	3,421
Electra	1,465	1,467	1,471	1,475	1,477	1,493	1,493
Electricity Ashburton	2,119	2,157	2,182	2,197	2,225	2,263	2,304
Electricity Invercargill	246	243	239	235	189	136	119
Horizon Energy	1,815	1,828	1,836	1,843	1,890	1,981	1,995
MainPower	2,949	2,968	3,692	3,743	3,790	3,855	3,827
Marlborough Lines	2,403	2,413	2,721	2,730	2,748	2,835	2,845
Nelson Electricity	49	51	50	43	44	45	42
Network Tasman	2,639	2,649	2,660	2,658	2,655	2,645	2,626
Network Waitaki	1,816	1,824	1,835	1,836	1,844	1,846	1,853
Northpower	4,682	4,726	4,793	4,814	4,993	4,957	4,979
Orion New Zealand	5,781	5,786	5,929	6,003	5,944	5,796	5,682
Otago Power	4,644	4,674	4,040	4,063	4,082	4,139	4,168
Powerco	14,207	14,198	13,858	13,896	13,765	13,609	14,158
Scanpower	962	962	962	958	958	956	832
The Lines Company	4,664	4,664	4,718	4,846	4,512	4,268	4,359
The Power Company	8,116	8,122	8,126	7,712	7,321	7,346	7,379
Top Energy	4,150	4,157	4,155	4,160	4,180	4,203	4,212
Unison	2,682	2,693	2,702	2,707	2,652	2,663	2,669
UnitedNetworks	16,023	16,224	16,474	16,696	16,876	18,550	19,340
Vector	3,212	3,203	3,164	3,140	3,215	3,304	3,283
Waipa Network	1,691	1,693	1,696	1,704	1,711	1,643	1,650
WEL Networks	2,800	2,800	2,806	3,081	3,088	3,334	3,360
Westpower	1,763	1,737	1,801	1,830	1,831	1,871	1,877

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B20: **Total underground cable length (kilometres), 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	364	369	383	415	431	494	443
Buller Electricity	12	12	14	14	15	16	16
Centralines	24	25	26	27	27	28	32
Counties Power	181	225	229	243	266	392	401
Dunedin Electricity	658	691	720	750	891	927	946
Eastland N/W	250	252	255	255	228	247	257
Electra	439	457	472	484	493	631	634
Electricity Ashburton	139	152	159	170	206	257	275
Electricity Invercargill	442	446	454	466	506	550	569
Horizon Energy	282	288	298	303	343	384	388
MainPower	208	217	291	316	345	409	500
Marlborough Lines	96	108	139	148	163	180	205
Nelson Electricity	167	166	167	196	195	198	199
Network Tasman	393	405	419	443	458	477	496
Network Waitaki	46	50	49	49	50	55	58
Northpower	244	261	252	257	285	327	358
Orion New Zealand	5,100	5,214	5,345	5,476	5,578	5,678	5,824
Otago Power	15	15	21	21	22	22	23
Powerco	1,505	1,541	1,524	1,562	1,684	1,704	1,803
Scanpower	32	33	35	36	37	40	40
The Lines Company	186	186	195	198	256	196	243
The Power Company	138	141	145	148	151	155	161
Top Energy	467	482	512	540	572	598	622
Unison	939	950	958	967	1,172	1,209	1,234
UnitedNetworks	6,534	6,965	7,204	7,523	8,035	10,296	10,682
Vector	5,370	5,427	5,649	5,874	5,497	5,142	5,296
Waipa Network	154	158	160	167	174	106	114
WEL Networks	755	784	808	1,124	1,154	1,250	1,332
Westpower	53	87	86	86	89	92	95

Source: Meyrick and Associates database formed from MED consolidation of Disclosure Data

Table B21: **Transpower data, 1996–2002**

Variable	*1996*	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Revenue ($m)	534.873	511.863	505.203	494.932	483.879	437.420	468.335
Throughput (GWh)	33,430	33,400	34,190	34,170	35,280	36,420	35,700
Operating expenses ($m)	291.334	276.844	262.354	247.864	252.248	264.293	276.446
Price of Opex (index)	1.000	1.017	1.028	1.040	1.058	1.071	1.099
MVA kilometres ('000)	2,567	2,562	2,556	2,556	2,549	2,546	2,527
Transformers (MVA)	7,605	8,055	8,130	8,230	8,430	8,530	8,590
Lines user cost ($m)	239.894	237.750	193.465	174.954	175.038	165.741	167.081
Transformer user cost ($m)	118.157	117.101	95.288	86.171	86.213	81.634	82.294
Transformer KVA kms ('000)	134,664	142,238	143,129	144,881	147,576	148,721	146,975

Source: Meyrick and Associates database formed from Disclosure Data

APPENDIX C: MULTILATERAL OUTPUT AND INPUT INDEXES

Table C1: **Output indexes using 3 outputs, average cost function weights, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	1.000	1.017	1.038	1.052	1.063	1.079	1.093
Buller Electricity	0.162	0.164	0.164	0.163	0.165	0.167	0.164
Centralines	0.320	0.322	0.325	0.318	0.321	0.336	0.336
Counties Power	0.790	0.811	0.831	0.844	0.811	0.869	0.879
Dunedin Electricity	1.863	1.884	1.890	1.897	1.943	1.983	2.021
Eastland N/W	1.209	0.975	0.971	0.967	0.900	0.946	0.944
Electra	0.773	0.783	0.792	0.812	0.819	0.849	0.863
Electricity Ashburton	0.557	0.580	0.603	0.612	0.610	0.646	0.658
Electricity Invercargill	0.298	0.303	0.303	0.302	0.298	0.300	0.303
Horizon Energy	0.790	0.783	0.798	0.821	0.811	0.833	0.838
MainPower	0.891	0.881	0.970	0.930	0.965	1.026	1.000
Marlborough Lines	0.714	0.722	0.750	0.750	0.764	0.771	0.776
Nelson Electricity	0.150	0.151	0.151	0.150	0.150	0.152	0.151
Network Tasman	0.963	0.972	0.983	0.995	1.016	1.039	1.051
Network Waitaki	0.460	0.471	0.469	0.464	0.463	0.465	0.467
Northpower	1.425	1.443	1.468	1.490	1.534	1.522	1.547
Orion New Zealand	3.868	3.913	4.003	4.087	4.140	4.209	4.267
Otago Power	0.704	0.721	0.736	0.748	0.752	0.773	0.783
Powerco	6.124	6.125	6.022	6.069	6.082	6.223	6.249
Scanpower	0.237	0.240	0.240	0.239	0.242	0.244	0.241
The Lines Company	0.995	0.883	0.985	0.999	1.018	1.015	1.003
The Power Company	1.538	1.524	1.523	1.495	1.474	1.509	1.547
Top Energy	0.875	0.919	0.933	0.929	0.950	0.975	0.997
Unison	1.433	1.469	1.485	1.487	1.532	1.556	1.575
UnitedNetworks	10.526	10.832	11.000	10.934	11.271	11.716	11.796
Vector	5.027	5.045	5.166	5.325	5.224	5.125	5.198
Waipa Network	0.599	0.610	0.615	0.613	0.620	0.618	0.629
WEL Networks	1.583	1.620	1.651	1.709	1.758	1.824	1.851
Westpower	0.467	0.491	0.495	0.495	0.490	0.502	0.502

Source: Meyrick and Associates estimates

Table C2: **Output indexes based on throughput only, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	1.000	1.039	1.112	1.195	1.232	1.326	1.330
Buller Electricity	0.209	0.217	0.215	0.213	0.221	0.218	0.219
Centralines	0.195	0.204	0.210	0.211	0.220	0.262	0.262
Counties Power	0.878	0.888	0.913	0.900	0.936	0.963	0.984
Dunedin Electricity	2.758	2.778	2.768	2.712	2.800	2.903	2.918
Eastland N/W	0.632	0.672	0.662	0.645	0.635	0.681	0.683
Electra	0.755	0.765	0.779	0.844	0.861	0.891	0.903
Electricity Ashburton	0.552	0.640	0.746	0.771	0.688	0.821	0.806
Electricity Invercargill	0.611	0.663	0.657	0.629	0.604	0.616	0.623
Horizon Energy	1.264	1.218	1.204	1.297	1.367	1.380	1.399
MainPower	0.833	0.793	0.842	0.800	0.831	0.957	0.899
Marlborough Lines	0.654	0.671	0.698	0.672	0.684	0.725	0.714
Nelson Electricity	0.333	0.338	0.335	0.342	0.346	0.349	0.346
Network Tasman	1.306	1.334	1.366	1.380	1.474	1.586	1.611
Network Waitaki	0.373	0.384	0.398	0.419	0.410	0.421	0.414
Northpower	1.712	1.784	1.866	1.904	1.950	1.976	2.005
Orion New Zealand	5.898	5.952	6.075	6.336	6.436	6.639	6.826
Otago Power	0.573	0.577	0.629	0.644	0.733	0.798	0.820
Powerco	4.714	4.766	4.618	4.896	4.782	4.902	4.888
Scanpower	0.180	0.192	0.191	0.190	0.201	0.206	0.208
The Lines Company	0.595	0.287	0.652	0.634	0.673	0.668	0.674
The Power Company	1.123	1.297	1.330	1.315	1.313	1.392	1.431
Top Energy	0.532	0.661	0.668	0.659	0.668	0.719	0.744
Unison	1.662	1.812	1.880	1.876	1.950	1.996	2.041
UnitedNetworks	15.253	16.275	16.288	14.865	16.151	16.754	16.172
Vector	10.479	10.276	10.429	10.748	10.899	11.741	12.036
Waipa Network	0.599	0.669	0.682	0.680	0.695	0.709	0.745
WEL Networks	1.863	2.021	2.104	2.121	2.296	2.273	2.264
Westpower	0.453	0.495	0.478	0.465	0.462	0.475	0.466

Source: Meyrick and Associates estimates

Table C3: **Output indexes based on system line capacity only, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	1.000	1.013	1.014	1.020	1.033	1.032	1.053
Buller Electricity	0.157	0.157	0.158	0.158	0.157	0.158	0.153
Centralines	0.288	0.287	0.288	0.276	0.277	0.276	0.276
Counties Power	1.108	1.113	1.131	1.145	1.131	1.134	1.144
Dunedin Electricity	2.525	2.552	2.554	2.566	2.579	2.606	2.651
Eastland N/W	1.504	0.939	0.935	0.936	0.879	0.970	0.948
Electra	1.293	1.310	1.325	1.349	1.360	1.384	1.421
Electricity Ashburton	0.482	0.489	0.496	0.503	0.514	0.530	0.540
Electricity Invercargill	0.620	0.625	0.625	0.626	0.621	0.620	0.625
Horizon Energy	0.812	0.824	0.840	0.851	0.856	0.855	0.857
MainPower	0.880	0.872	0.920	0.848	0.896	0.952	0.930
Marlborough Lines	0.716	0.724	0.735	0.743	0.764	0.772	0.781
Nelson Electricity	0.309	0.310	0.310	0.314	0.315	0.318	0.318
Network Tasman	1.069	1.076	1.086	1.104	1.123	1.143	1.161
Network Waitaki	0.437	0.453	0.441	0.423	0.423	0.422	0.421
Northpower	1.601	1.603	1.610	1.639	1.658	1.692	1.734
Orion New Zealand	5.662	5.741	5.822	5.889	6.032	6.181	6.252
Otago Power	0.520	0.543	0.537	0.552	0.528	0.531	0.536
Powerco	5.795	5.775	5.737	5.690	5.798	5.831	5.843
Scanpower	0.249	0.249	0.249	0.246	0.248	0.249	0.246
The Lines Company	0.939	0.963	0.880	0.898	0.937	0.959	0.954
The Power Company	1.223	1.135	1.121	1.121	1.124	1.151	1.180
Top Energy	0.886	0.903	0.927	0.920	0.954	0.974	1.004
Unison	2.038	2.069	2.078	2.078	2.100	2.128	2.155
UnitedNetworks	16.558	16.875	17.184	17.441	17.813	18.274	18.744
Vector	9.047	9.155	9.321	9.464	9.634	9.868	10.169
Waipa Network	0.733	0.731	0.738	0.728	0.736	0.744	0.753
WEL Networks	2.411	2.449	2.496	2.545	2.605	2.653	2.707
Westpower	0.421	0.445	0.444	0.444	0.435	0.445	0.448

Source: Meyrick and Associates estimates

Table C4: **Output indexes based on connection numbers only, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	1.000	1.013	1.014	1.020	1.033	1.032	1.053
Buller Electricity	0.157	0.157	0.158	0.158	0.157	0.158	0.153
Centralines	0.288	0.287	0.288	0.276	0.277	0.276	0.276
Counties Power	1.108	1.113	1.131	1.145	1.131	1.134	1.144
Dunedin Electricity	2.525	2.552	2.554	2.566	2.579	2.606	2.651
Eastland N/W	1.504	0.939	0.935	0.936	0.879	0.970	0.948
Electra	1.293	1.310	1.325	1.349	1.360	1.384	1.421
Electricity Ashburton	0.482	0.489	0.496	0.503	0.514	0.530	0.540
Electricity Invercargill	0.620	0.625	0.625	0.626	0.621	0.620	0.625
Horizon Energy	0.812	0.824	0.840	0.851	0.856	0.855	0.857
MainPower	0.880	0.872	0.920	0.848	0.896	0.952	0.930
Marlborough Lines	0.716	0.724	0.735	0.743	0.764	0.772	0.781
Nelson Electricity	0.309	0.310	0.310	0.314	0.315	0.318	0.318
Network Tasman	1.069	1.076	1.086	1.104	1.123	1.143	1.161
Network Waitaki	0.437	0.453	0.441	0.423	0.423	0.422	0.421
Northpower	1.601	1.603	1.610	1.639	1.658	1.692	1.734
Orion New Zealand	5.662	5.741	5.822	5.889	6.032	6.181	6.252
Otago Power	0.520	0.543	0.537	0.552	0.528	0.531	0.536
Powerco	5.795	5.775	5.737	5.690	5.798	5.831	5.843
Scanpower	0.249	0.249	0.249	0.246	0.248	0.249	0.246
The Lines Company	0.939	0.963	0.880	0.898	0.937	0.959	0.954
The Power Company	1.223	1.135	1.121	1.121	1.124	1.151	1.180
Top Energy	0.886	0.903	0.927	0.920	0.954	0.974	1.004
Unison	2.038	2.069	2.078	2.078	2.100	2.128	2.155
UnitedNetworks	16.558	16.875	17.184	17.441	17.813	18.274	18.744
Vector	9.047	9.155	9.321	9.464	9.634	9.868	10.169
Waipa Network	0.733	0.731	0.738	0.728	0.736	0.744	0.753
WEL Networks	2.411	2.449	2.496	2.545	2.605	2.653	2.707
Westpower	0.421	0.445	0.444	0.444	0.435	0.445	0.448

Source: Meyrick and Associates estimates

Table C5: **Output indexes using 3 outputs, PEG cost function weights, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	1.000	1.025	1.063	1.100	1.120	1.161	1.172
Buller Electricity	0.178	0.181	0.181	0.180	0.183	0.183	0.182
Centralines	0.266	0.271	0.276	0.272	0.278	0.304	0.304
Counties Power	0.834	0.851	0.873	0.876	0.868	0.914	0.927
Dunedin Electricity	2.181	2.202	2.203	2.192	2.250	2.308	2.341
Eastland N/W	0.964	0.850	0.843	0.833	0.792	0.840	0.839
Electra	0.785	0.796	0.807	0.843	0.854	0.885	0.898
Electricity Ashburton	0.551	0.596	0.645	0.660	0.632	0.698	0.702
Electricity Invercargill	0.401	0.417	0.416	0.408	0.399	0.403	0.408
Horizon Energy	0.939	0.922	0.929	0.971	0.983	1.002	1.011
MainPower	0.869	0.848	0.919	0.876	0.911	0.997	0.959
Marlborough Lines	0.691	0.703	0.730	0.720	0.734	0.754	0.753
Nelson Electricity	0.208	0.209	0.209	0.210	0.210	0.213	0.211
Network Tasman	1.081	1.096	1.113	1.126	1.169	1.218	1.234
Network Waitaki	0.425	0.436	0.440	0.445	0.441	0.447	0.445
Northpower	1.532	1.567	1.609	1.636	1.680	1.682	1.709
Orion New Zealand	4.593	4.643	4.744	4.879	4.949	5.061	5.156
Otago Power	0.644	0.656	0.685	0.698	0.733	0.768	0.782
Powerco	5.553	5.575	5.455	5.595	5.559	5.687	5.696
Scanpower	0.215	0.222	0.221	0.220	0.226	0.230	0.229
The Lines Company	0.823	0.589	0.843	0.842	0.872	0.869	0.866
The Power Company	1.356	1.417	1.429	1.408	1.395	1.447	1.484
Top Energy	0.730	0.814	0.826	0.819	0.836	0.873	0.897
Unison	1.538	1.612	1.644	1.644	1.698	1.729	1.757
UnitedNetworks	12.311	12.831	12.963	12.503	13.132	13.631	13.527
Vector	6.755	6.725	6.862	7.068	7.030	7.151	7.286
Waipa Network	0.605	0.636	0.644	0.642	0.652	0.656	0.675
WEL Networks	1.714	1.791	1.839	1.884	1.974	2.012	2.028
Westpower	0.459	0.490	0.486	0.481	0.477	0.489	0.486

Source: Meyrick and Associates estimates

Table C6: **Input indexes using 5 inputs, 1996–2002**

	1996	*1997*	*1998*	*1999*	*2000*	*2001*	*2002*
Alpine Energy	1.000	0.998	1.069	1.035	1.013	1.025	1.035
Buller Electricity	0.157	0.169	0.164	0.165	0.186	0.167	0.193
Centralines	0.335	0.336	0.309	0.360	0.309	0.331	0.331
Counties Power	0.733	0.804	0.847	0.813	0.823	0.832	0.830
Dunedin Electricity	2.000	2.021	2.043	2.064	2.006	2.038	2.104
Eastland N/W	1.413	1.238	1.260	1.309	1.067	1.175	1.045
Electra	0.835	0.857	0.834	0.805	0.766	0.804	0.835
Electricity Ashburton	0.701	0.768	0.749	0.766	0.741	0.762	0.787
Electricity Invercargill	0.252	0.281	0.260	0.231	0.223	0.217	0.206
Horizon Energy	1.131	1.025	1.113	0.872	0.767	0.732	0.773
MainPower	0.962	0.958	1.123	1.015	1.010	1.055	1.048
Marlborough Lines	0.776	0.738	0.831	0.832	0.873	0.856	0.885
Nelson Electricity	0.281	0.264	0.102	0.108	0.136	0.142	0.122
Network Tasman	1.031	1.150	1.096	1.011	0.889	0.911	0.860
Network Waitaki	0.483	0.464	0.451	0.417	0.431	0.435	0.448
Northpower	1.291	1.333	1.395	1.310	1.352	1.274	1.340
Orion New Zealand	4.571	4.566	4.810	3.908	3.997	3.966	4.056
Otago Power	0.607	0.574	0.718	0.703	0.696	0.682	0.685
Powerco	7.038	6.893	6.189	5.760	5.932	6.888	6.153
Scanpower	0.190	0.195	0.197	0.205	0.190	0.198	0.193
The Lines Company	1.215	1.229	1.210	1.233	0.963	0.935	0.933
The Power Company	1.646	1.610	1.607	1.519	1.468	1.455	1.515
Top Energy	1.050	1.077	1.088	0.988	1.028	1.076	1.085
Unison	1.744	1.698	1.756	1.537	1.501	1.558	1.513
UnitedNetworks	11.215	12.136	11.393	11.064	10.236	10.431	10.437
Vector	4.810	4.812	5.137	6.417	5.118	4.479	4.348
Waipa Network	0.551	0.542	0.531	0.504	0.512	0.482	0.492
WEL Networks	1.575	1.585	1.608	1.802	1.740	1.763	1.774
Westpower	0.697	0.723	0.649	0.606	0.605	0.552	0.587

Source: Meyrick and Associates estimates

APPENDIX D: COST FUNCTION REGRESSION RESULTS

Table D1: **Alpine Energy cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.003	0.002	0.000
	(–0.00)	(3.88)	(3.23)	(0.00)
a_{i2}	0.072	0.005	0.000	0.013
	(54.01)	(16.68)	(0.00)	(7.12)
a_{i3}	–0.000	0.673	–0.216	1.985
	(–0.00)	(6.94)	(–4.32)	(5.45)
b_i	–0.029	–0.018	0.021	–0.001
	(–4.05)	(–8.24)	(1.51)	(–0.50)
R^2	0.546	0.900	0.978	0.963
Normal statistic	–0.912	–1.213	–0.364	1.215

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D2: **Buller Electricity cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.125	0.006	0.000	0.003
	(23.78)	(6.47)	(0.00)	(0.83)
a_{i2}	0.000	0.015	0.001	0.039
	(0.00)	(7.717)	(15.22)	(15.87)
a_{i3}	–0.000	0.000	0.000	0.791
	(–0.00)	(0.00)	(0.00)	(2.78)
b_i	0.007	–0.010	0.316	–0.004
	(0.35)	(–2.92)	(4.65)	(–1.54)
R^2	0.220	0.742	0.965	0.983
Normal statistic	1.334	–1.213	1.334	–0.912

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D3: Centralines cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.005	0.000	0.000
	(–0.00)	(1.09)	(0.00)	(0.00)
a_{i2}	0.146	0.007	0.000	0.018
	(17.52)	(1.08)	(0.63)	(14.22)
a_{i3}	–0.000	1.335	0.108	–1.985
	(–0.00)	(7.10)	(3.69)	(–16.71)
b_i	0.057	–0.001	0.031	0.014
	(–3.12)	(–0.07)	(0.88)	(3.84)
R^2	0.175	0.841	0.548	0.995
Normal statistic	0.485	–0.364	0.485	2.183

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D4: Counties Power cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.125	0.004	–0.000	0.012
	(3.88)	(0.99)	(–0.00)	(2.31)
a_{i2}	0.034	0.004	0.001	0.016
	(0.49)	(2.01)	(12.57)	(6.85)
a_{i3}	–0.000	–0.448	0.000	0.000
	(–0.00)	(–1.66)	(0.00)	(0.00)
b_i	–0.048	–0.004	0.210	–0.015
	(–4.48)	(–0.24)	(3.21)	(–2.63)
R^2	0.640	0.506	0.923	0.837
Normal statistic	1.215	1.215	–0.912	1.334

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D5: Dunedin Electricity cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	–0.000	0.002	0.014
	(–0.00)	(–0.00)	(0.94)	(7.93)
a_{i2}	–0.000	0.002	0.000	0.000
	(–0.00)	(11.46)	(0.00)	(0.00)
a_{i3}	14.123	0.600	–0.178	–2.458
	(70.22)	(26.47)	(–0.66)	(–14.77)
b_i	–0.035	–0.004	0.066	0.012
	(–6.00)	(–1.52)	(4.19)	(16.03)
R^2	0.677	0.991	0.867	0.993
Normal statistic	–0.364	0.485	–0.364	–0.912

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D6: Eastland Network cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.136	0.012	0.002	0.015
	(1.79)	(6.52)	(6.64)	(44.73)
a_{i2}	0.033	0.004	0.001	0.013
	(0.30)	(2.89)	(4.91)	(90.28)
a_{i3}	10.094	0.000	–0.000	–0.732
	(2.91)	(0.00)	(–0.00)	(–25.83)
b_i	–0.046	–0.024	–0.013	0.004
	(–2.72)	(–3.60)	(–2.05)	(6.85)
R^2	0.724	0.744	0.707	0.999
Normal statistic	1.215	–1.213	–1.213	–0.912

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D7: Electra cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.000	–0.000	–0.000	0.011
	(0.00)	(–0.00)	(–0.00)	(9.87)
a_{i2}	0.099	0.004	0.002	0.006
	(0.62)	(39.60)	(4.57)	(5.03)
a_{i3}	6.772	–0.338	0.107	2.416
	(0.20)	(–16.29)	(1.032)	(35.84)
b_i	–0.056	–0.012	0.016	–0.010
	(–3.25)	(–23.89)	(2.52)	(–14.12)
R^2	0.725	0.996	0.959	0.994
Normal statistic	–0.364	0.485	0.485	0.485

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D8: Electricity Ashburton cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.110	–0.000	0.000	0.005
	(4.81)	(–0.00)	(0.00)	(1.86)
a_{i2}	0.043	0.000	0.001	0.021
	(1.34)	(0.00)	(50.07)	(52.69)
a_{i3}	0.000	1.473	0.000	–0.000
	(0.00)	(449.39)	(0.00)	(–0.00)
b_i	–0.078	–0.002	0.042	–0.020
	(–13.42)	(–2.00)	(4.35)	(–19.21)
R^2	0.807	0.977	0.968	0.994
Normal statistic	1.334	–0.364	–1.213	–0.912

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D9: **Electricity Invercargill cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.108	0.001	0.000	–0.000
	(35.47)	(0.25)	(0.00)	(–0.00)
a_{i2}	–0.000	0.000	0.004	0.038
	(–0.00)	(0.00)	(93.08)	(340.68)
a_{i3}	0.000	0.249	0.000	–0.000
	(0.00)	(3.16)	(0.00)	(–0.00)
b_i	–0.050	–0.054	0.041	0.000
	(–4.85)	(–9.12)	(7.31)	(0.15)
R^2	0.778	0.889	0.905	0.240
Normal statistic	–0.364	–1.213	–1.213	–1.213

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D10: **Horizon Energy cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.000	0.000	0.000	0.010
	(0.00)	(0.00)	(0.00)	(4.73)
a_{i2}	–0.000	0.003	0.001	0.018
	(–0.00)	(1.50)	(3.92)	(10.84)
a_{i3}	23.086	–0.966	–0.221	0.151
	(25.605)	(–11.34)	(–17.55)	(0.177)
b_i	–0.110	–0.009	0.067	–0.019
	(–10.66)	(–1.41)	(10.08)	(–8.60)
R^2	0.836	0.004	0.986	0.955
Normal statistic	0.152	1.215	0.485	–0.364

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D11: **MainPower cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.000	0.000	0.011
	(–0.00)	(0.00)	(0.00)	(1.19)
a_{i2}	0.041	0.008	0.001	0.005
	(1.26)	(160.18)	(63.98)	(0.97)
a_{i3}	14.736	0.000	0.000	–2.399
	(6.33)	(0.00)	(0.00)	(–3.71)
b_i	–0.069	–0.049	–0.012	0.023
	(–4.19)	(–25.65)	(–2.05)	(1.00)
R^2	0.739	0.968	0.968	0.928
Normal statistic	0.152	0.485	–1.213	1.215

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D12: **Marlborough Lines cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.000	–0.000	–0.000
	(–0.00)	(0.00)	(–0.00)	(–0.00)
a_{i2}	0.000	0.005	0.001	0.012
	(0.00)	(14.89)	(19.10)	(10.00)
a_{i3}	14.581	–1.005	–0.000	2.383
	(35.30)	(–23.79)	(–0.00)	(17.89)
b_i	0.007	–0.028	–0.002	0.003
	(0.588)	(–10.18)	(–0.12)	(0.71)
R^2	0.356	0.945	0.737	0.993
Normal statistic	–1.213	–0.912	–1.213	1.334

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D13: **Nelson Electricity cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.121	–0.000	–0.000	0.000
	(0.21)	(–0.00)	(–0.00)	(0.00)
a_{i2}	–0.374	–0.000	0.000	0.043
	(–0.22)	(–0.00)	(0.00)	(3.28)
a_{i3}	0.001	0.214	–0.370	2.265
	(0.00)	(65.82)	(–220.81)	(5.110)
b_i	–0.124	–0.048	–0.002	–0.005
	(–4.40)	(–8.80)	(–1.20)	(–0.58)
R^2	0.469	0.855	0.236	0.789
Normal statistic	–1.213	0.485	–0.912	–0.912

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D14: **Network Tasman cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.053	0.001	0.000	0.003
	(0.60)	(0.64)	(0.00)	(0.59)
a_{i2}	0.094	0.002	0.000	0.018
	(2.90)	(5.38)	(0.50)	(82.89)
a_{i3}	0.000	–0.935	–0.229	–0.248
	(0.00)	(–12.28)	(–31.83)	(–0.15)
b_i	–0.092	–0.012	0.031	–0.006
	(–8.26)	(–4.37)	(12.31)	(–3.39)
R^2	0.816	0.709	0.985	0.999
Normal statistic	–0.364	0.485	–0.364	–1.213

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D15: Network Waitaki cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.002	–0.000	0.002
	(–0.00)	(0.95)	(–0.00)	(0.50)
a_{i2}	–0.000	0.001	0.001	0.023
	(–0.00)	(8.76)	(16.21)	(108.01)
a_{i3}	14.495	–0.549	0.000	–0.000
	(30.50)	(–2.28)	(0.00)	(–0.00)
b_i	–0.067	–0.013	0.095	–0.004
	(–5.96)	(–3.09)	(2.52)	(–18.30)
R^2	0.781	0.796	0.775	0.999
Normal statistic	0.485	1.334	–1.213	–0.364

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D16: Northpower cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.112	0.000	0.000	0.009
	(42.14)	(0.00)	(0.00)	(2.10)
a_{i2}	–0.000	0.005	0.000	0.013
	(–0.00)	(10.35)	(0.00)	(8.88)
a_{i3}	0.000	–0.521	0.132	0.000
	(0.00)	(–3.41)	(20.68)	(0.00)
b_i	–0.057	–0.032	0.127	–0.009
	(–7.26)	(–7.31)	(3.88)	(–2.08)
R^2	0.671	0.732	0.876	0.992
Normal statistic	–0.364	1.334	–0.912	–0.364

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D17: Orion New Zealand cost function regression results

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.000	0.002	0.000	0.009
	(0.00)	(1.71)	(0.00)	(0.94)
a_{i2}	–0.000	0.001	0.000	0.009
	(–0.00)	(14.93)	(6.69)	(38.16)
a_{i3}	15.149	0.365	–0.366	–0.705
	(19.84)	(2.93)	(–17.93)	(–0.39)
b_i	–0.078	–0.001	0.000	–0.013
	(–5.08)	(–0.40)	(0.19)	(–5.13)
R^2	0.577	0.958	0.845	0.984
Normal statistic	–0.364	1.334	–1.213	–0.364

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D18: **Otago Power cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.094	0.009	–0.000	0.014
	(2.72)	(16.94)	(–0.00)	(3.89)
a_{i2}	0.000	–0.000	–0.000	0.011
	(0.00)	(–0.00)	(–0.00)	(13.95)
a_{i3}	13.087	1.491	–0.026	0.841
	(3.26)	(29.65)	(0.95)	(1.02)
b_i	–0.062	–0.015	1.567	–0.020
	(–4.98)	(–5.21)	(0.42)	(–1.57)
R^2	0.868	0.964	0.611	0.898
Normal statistic	0.485	0.485	–1.213	0.485

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D19: **Powerco cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.002	–0.000	0.013
	(–0.00)	(0.17)	(–0.00)	(2.30)
a_{i2}	0.045	0.003	–0.000	0.006
	(19.58)	(5.33)	(–0.00)	(7.74)
a_{i3}	–0.000	–1.077	–0.205	–1.024
	(–0.00)	(–5.08)	(–29.14)	(–1.14)
b_i	–0.058	–0.001	0.058	0.001
	(–3.35)	(–0.65)	(3.08)	(0.49)
R^2	0.489	0.734	0.703	0.874
Normal statistic	–0.364	–0.364	–0.364	0.152

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D20: **Scanpower cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.000	–0.000	–0.000	0.000
	(0.00)	(–0.00)	(–0.00)	(0.00)
a_{i2}	0.142	0.004	0.000	0.000
	(0.533)	(5.73)	(0.083)	(0.00)
a_{i3}	5.704	1.207	–0.052	2.831
	(0.104)	(50.84)	(–13.37)	(113.71)
b_i	0.006	0.001	0.049	0.003
	(0.14)	(1.37)	(13.06)	(0.80)
R^2	0.114	0.860	0.981	0.212
Normal statistic	0.485	1.334	1.334	1.215

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D21: **The Lines Company cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.006	0.001	–0.000
	(–0.00)	(4.56)	(2.36)	(–0.00)
a_{i2}	0.066	0.003	–0.000	0.013
	(49.22)	(5.17)	(–0.00)	(56.76)
a_{i3}	–0.000	1.227	0.188	1.213
	(–0.00)	(10.70)	(10.63)	(6.62)
b_i	–0.009	0.002	0.018	–0.007
	(–0.81)	(0.13)	(0.85)	(–1.33)
R^2	0.967	0.226	0.413	0.994
Normal statistic	–1.213	–1.213	0.485	–0.912

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D22: **The Power Company cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.000	0.004	0.001	0.012
	(0.00)	(1.53)	(12.74)	(1.90)
a_{i2}	0.051	0.006	–0.000	0.007
	(2.60)	(11.09)	(–0.00)	(2.22)
a_{i3}	10.667	–0.956	0.122	1.631
	(1.61)	(–11.26)	(45.70)	(4.55)
b_i	–0.073	–0.017	0.043	0.013
	(–11.08)	(–6.56)	(21.46)	(1.30)
R^2	0.910	0.984	0.997	0.897
Normal statistic	–1.213	0.152	1.334	–0.912

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D23: **Top Energy cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.105	0.002	–0.000	0.003
	(1.68)	(0.76)	(–0.00)	(3.68)
a_{i2}	–0.000	0.006	0.001	0.014
	(–0.00)	(4.57)	(98.51)	(34.15)
a_{i3}	13.931	0.968	0.000	–0.524
	(2.81)	(4.02)	(0.00)	(–1.55)
b_i	–0.049	–0.025	0.062	–0.007
	(–5.23)	(–5.87)	(11.39)	(–6.05)
R^2	0.576	0.734	0.991	1.000
Normal statistic	–0.912	–0.912	0.485	–1.213

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D24: **Unison cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.090	0.000	0.000	0.011
	(0.58)	(0.00)	(0.00)	(2.03)
a_{i2}	–0.000	0.004	0.001	0.010
	(–0.00)	(274.34)	(1.48)	(1.55)
a_{i3}	11.85	0.000	–0.162	2.098
	(0.76)	(0.00)	(–0.670)	(1.83)
b_i	–0.080	–0.015	0.019	–0.004
	(–5.11)	(–10.72)	(0.85)	(–0.41)
R^2	0.865	0.902	0.925	0.946
Normal statistic	0.485	–0.364	–1.213	–0.364

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D25: **UnitedNetworks cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.099	0.002	0.001	–0.000
	(1.91)	(8.87)	(6.14)	(–0.00)
a_{i2}	0.022	0.001	0.000	–0.000
	(1.04)	(15.06)	(0.00)	(–0.00)
a_{i3}	–0.000	0.476	–0.226	2.787
	(–0.00)	(294.01)	(–9.38)	(146.36)
b_i	–0.085	–0.017	0.042	–0.001
	(–4.90)	(–7.64)	(11.40)	(–0.45)
R^2	0.856	0.923	0.988	0.849
Normal statistic	–0.364	0.485	–0.364	–0.364

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D26: **Vector cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.000	0.000	0.010
	(–0.00)	(0.00)	(0.00)	(2.14)
a_{i2}	0.000	–0.000	0.000	0.010
	(0.00)	(–0.00)	(0.00)	(14.03)
a_{i3}	13.720	0.302	–0.439	–0.000
	(8.38)	(70.42)	(–35.33)	(–0.00)
b_i	–0.012	–0.043	–0.035	–0.009
	(–0.25)	(–8.39)	(–3.35)	(–0.97)
R^2	0.027	0.715	0.205	0.964
Normal statistic	–0.912	–1.213	–1.213	–1.2137

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D27: **Waipa Networks cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	–0.000	0.003	0.002	–0.000
	(–0.00)	(1.52)	(28.68)	(–0.00)
a_{i2}	0.101	0.000	0.000	0.021
	(6.41)	(0.00)	(0.00)	(5.19)
a_{i3}	2.894	0.904	–0.000	1.117
	(0.345)	(10.15)	(–0.00)	(0.93)
b_i	–0.038	–0.008	–0.046	0.005
	(–6.49)	(–1.66)	(–3.74)	(0.75)
R^2	0.948	0.366	0.283	0.670
Normal statistic	–0.912	–0.912	–1.213	–1.213

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D28: **WEL Networks cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.011	0.000	–0.000	0.008
	(0.04)	(0.00)	(–0.00)	(3.99)
a_{i2}	0.081	0.003	0.001	0.006
	(3.79)	(4.63)	(2.19)	(3.61)
a_{i3}	–0.000	–0.504	0.251	2.401
	(–0.00)	(–7.36)	(6.70)	(21.30)
b_i	–0.047	–0.005	0.023	–0.016
	(–3.95)	(–0.64)	(1.78)	(–5.23)
R^2	0.493	0.950	0.955	0.920
Normal statistic	–1.213	–1.213	–1.213	1.215

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

Table D29: **Westpower cost function regression results**

Variable	OpEx	Overhead Lines	Underground Cables	Transformers
a_{i1}	0.175	0.000	0.001	–0.000
	(37.85)	(0.00)	(20.44)	(–0.00)
a_{i2}	–0.000	0.002	0.001	0.024
	(–0.00)	(2.51)	(7.13)	(125.53)
a_{i3}	–0.000	1.367	0.000	0.000
	(–0.00)	(57.50)	(0.00)	(0.00)
b_i	–0.072	0.014	0.047	–0.023
	(–8.26)	(5.32)	(6.51)	(–6.91)
R^2	0.848	0.900	0.891	0.994
Normal statistic	1.334	–1.213	–1.213	–1.213

Source: Meyrick and Associates estimates. Figures in parentheses are *t*–statistics.

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