Relative risk and the cost of equity

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1. EXECUTIVE SUMMARY

1.1. Introduction

This paper:

- reviews the evidence presented by Ofgem and Oxera on the relative risk of gas distribution and transmission companies;
- responds to comments by Oxera about CEPA's use of Market Asset Ratios (MAR) in assessing the cost of capital; and
- notes the recent cost of capital determinations by the Competition Commission (CC) and their implications for the Gas Distribution Networks (GDNs).

1.2. Relative risk of gas distribution and transmission businesses

Bottom-up analysis: Ofgem, in the Updated Proposals, presented the findings of its own study of relative risk. The study focused on relative risk measured as differences between allowed and actual costs across the categories of capital expenditure, replacement expenditure, operating expenditure and tax. Their analysis concludes that the cost variability faced by GDNs is higher than that faced by Transmission Operators (TOs) and this difference is statistically significant.

Our analysis concludes that there is significant doubt about the robustness of the results of the Ofgem analysis. Ex post differences between actual and allowed costs are not a valid measure of differential non-diversifiable (i.e. systematic) risk. Large cost differences can arise simply because companies are less efficient than they should be. Cost risks can be de-composed into input price and input volume risk. While the former are, in part, systematic risks (for example, unanticipated cost inflation affecting the entire industry), the latter are principally diversifiable and largely controllable risks. Furthermore, the Ofgem analysis excludes major determinants of differential systematic risk, namely volume and income risks.

The Ofgem results were derived using assumed standard deviations for the cost categories. The results are very sensitive to these assumptions and it is difficult to establish 'correct' point estimates that ought to be used. When their analysis is repeated using the measured standard deviations of their sample of companies (rather than their assumed values), the differences in their measure of risk between transmission and distribution over the price review period is far smaller than that presented by Ofgem.

Top-down analysis: Oxera presented analysis to Ofgem that showed a higher asset beta value for gas distribution companies than for transmission companies. The apparent conclusion is as likely to be explained by differences in regulatory regime across countries as by differences in systematic risk of transmission and distribution within a common regulatory regime. Therefore, in our view, the apparent conclusion that gas distribution has higher systematic risk than gas transmission in the UK is not supported by their analysis.

When we repeated Oxera's analysis, we were unable to find the conclusion that there was a statistically significant difference between gas transmission and gas distribution companies. Moreover, their cross-country analysis omitted a potentially important variable, namely, differences in the regulatory regime. CEPA also undertook further analysis to include a variable reflecting the nature of the financial risks arising from the form of the regulatory regime. Specifically, regulatory regimes are classified as either 'high-powered' incentive regimes, 'low-powered' rate of return regimes or 'medium-powered' hybrid regimes. When we did so, the Oxera results were further weakened. Therefore, in our view, the conclusion that gas distribution has higher systematic risk than gas transmission in the UK is not supported by Oxera's work.

Overall, our conclusion is that the evidence presented to suggest that gas distribution companies have higher systematic risk than gas transmission companies is not robust. Considerably more work would be needed before firm conclusions, one way or the other, could be reached.

1.3. MAR analysis

Oxera's note of 30th August 2007 on MAR values alleges that CEPA has 'disregarded the impact of certain important drivers of MAR' and 'does not appear to be consistent with commonly accepted principles for valuing financial assets'. This paper rebuts these claims and explains why the MAR does provide important relevant direct market evidence about the cost of capital of regulated businesses.

Ofgem, in its Updated Proposals, suggests that the use of high MAR premia in other UK regulated sectors cannot be used to inform the cost of capital of GDNs. Specifically, Ofgem considers that there are too many degrees of freedom between the MAR and cost of capital. Inference from the MAR about the cost of capital requires assumptions about investors' expectations for performance against operational targets, their expectations about funding costs and their views on future cost of capital policy by the regulator. Further, Ofgem believes that the insights from MAR are limited by GDNs and transmission networks not being traded on the UK market and so it can only act as a sense check.

CEPA's view is that direct market evidence about the cost of capital is an essential input into Ofgem's decision processes. There is extensive evidence of high MAR premia across all the regulated industries, evident in transaction valuations (including very recent ones) and the share prices of listed companies. The magnitude of the premia, as the paper illustrates, can only be plausibly explained by a significant 'gap' between the allowed cost of capital and the (lower) actual cost of capital. Although there is no direct read-across to GDNs from other industries, Ofgem is bound to take account of this relevant evidence when forming its judgement about the cost of equity for GDNs. In our view, that evidence indicates that the highest plausible value for the cost of equity for GDNs is 7%.

1.4. Cost of equity

The recently published CC report on BAA set out economy-wide (i.e. non-sector specific) cost of capital parameters. The cost of equity for the equity market portfolio, according to the CC, lies in the range 5% - 7%. This is made up of a risk free rate of 2.5% and an equity risk premium of 2.5% - 4.5%. Since it is implausible that the market's view is that the risk of GDN exposure is greater than the risk of exposure to the entire equity market portfolio as a whole, it follows that the highest plausible cost of equity for GDNs is 7%.

1.5. Conclusion

There is no robust evidence to support the contention that gas distribution companies are viewed by the markets as having higher systematic risk than gas transmission companies. CEPA's early estimate of the range of cost of equity (6.5% - 7.0%) therefore remains valid, and is supported by the conclusions about the cost of equity of the equity market portfolio.

2. INTRODUCTION

This paper updates CEPA's response on the appropriate cost of capital for the GDNs. In particular, it considers:

- the evidence on relative risk, both bottom-up and top-down, between gas distribution and gas transmission companies;
- the evidence for the cost of equity set out in the recommendations of the CC; and
- the rationale for using MARs to determine the cost of capital and the implications of observed MAR values for the cost of capital.

The paper concludes that there is no robust evidence to support the contention that gas distribution companies have a higher cost of capital than gas transmission companies. It also concludes that CEPA's earlier estimate of the cost of equity (6.5% - 7.0%) remains valid.

3. RELATIVE RISK

This section considers the evidence on relative risk presented by Ofgem in its operational risk review and by Oxera in its review of market data. In the Updated Proposals, Ofgem suggests that the GDNs should be viewed as being at least as risky as transmission. Ofgem's conclusion is that GDNs need a cost of equity that is not lower than that set for transmission operators and it has not ruled out the possibility that the needed cost of equity may be higher. The assertion about the relative riskiness of the GDNs is in part driven by the relative risk analysis undertaken by Ofgem and Oxera.

3.1. Ofgem operational risk analysis

Ofgem carried out its own study of relative risk of GDNs and TOs. It was a bottom up analysis of differences between actual and allowed expenditure across the cost categories of capital expenditure, replacement expenditure, operational expenditure and tax. The difference between actual and allowed spends is measured as a 'standard deviation' – capturing the variation between the amounts of actual expenditure versus allowed expenditure across GDNs and over time. The differences are weighted by the 'incentive strength' that Ofgem has constructed for the cost category as well as its relative size compared to the opening RAB. Their analysis concludes that risk differential between transmission and gas distribution is 1.1% on a price review basis and 0.3% on an annual basis[1]. However, the difference is only statistically significant for the annual results and not on the five year price review basis.

After reviewing Ofgem's write-up of the analysis and the spreadsheets it used to carry out the analysis, we have a number of significant concerns about the robustness of the methodology and the interpretation of the results. In our view, further work is needed before robust conclusions about relative systematic risk can be made.

Emphasis on cost variances: We question whether, in principle, ex post cost variances across companies are a valid measure of ex ante relative systematic risk. Ex post 'upward' cost variances can arise because some companies in the sample are less efficient than was expected by the regulator. It would be paradoxical if higher cost variances arising from inefficiency resulted in a higher allowed cost of capital than that for an efficient notional business.

Cost risks can be de-composed into input price risks and input volume risks. The former are in part systematic risks, to the extent that unanticipated cost inflation affects the entire industry.[2] However, the input volume risks are largely controllable and diversifiable. Robust

[1] Price review refers to analysis carried out on the basis of the whole review period whereas annual refers to analysis carried out on the basis of individual years in the review period.

[2] In RPI-X regulated industries price rises must not only be unanticipated but also this cost inflation should not be compensated in the RPI inflation.

conclusions about differential systematic risks need to be based on a more sophisticated analysis of the causes of the cost differences observed in the datasets.

The Ofgem analysis ignores an important determinant of systematic risks, namely volume and revenue risks. Ofgem has not incorporated revenue variance into its analysis and has not considered the likely impact of the proposed removal of the volume driver on GDN relative risk. Therefore, in our view, the 'bottom-up' analysis undertaken to date by Ofgem cannot be used to derive robust conclusions about differential systematic risk.

Implications of cost variance analysis: Ofgem recognises that it is considering total risk rather than systematic (non-diversifiable) risk. Ofgem addresses this point by noting that from a financial viability point of view, it is total risk that matters. However, for determining the cost of capital (and the risk premium to be added to the risk free rate), it is not total risk that matters. It is systematic (non-diversifiable) risk.

Total risk matters when financeability is being addressed. Rightly, regulatory precedent focuses on setting the cost of capital for an efficiently operated and financed business. A subsequent step is to consider whether financeability concerns may justify an allowed revenue adjustment for certain companies. If such an adjustment were deemed appropriate, it should be NPV-neutral. A change that would result in an increase in the ex ante allowed cost of capital as proposed by Ofgem would be NPV positive. Using risk analysis of cost variances in the way that Ofgem has done may be a sensible way to assess financeability risks. However, it is not a robust methodology for assessing differential ex ante systematic risks that give rise to differences in the ex ante allowed cost of capital.

Robustness of methodology: Our analysis indicates that the size of the observed risk differential is highly sensitive to the standard deviation assumptions. The risk differential falls from 1.1 per cent to 0.2 per cent for the price control period if the standard deviations calculated by Ofgem for the set of transmission and distribution companies are used (9.2 per cent and 6.0 per cent respectively) rather than the 10 per cent that Ofgem assumes for both based on different information.

Basis of standard deviation calculations: While it is true that variances between actual and allowed spend are a source of risk for investors, it is not clear how this risk should be measured. Is it the absolute difference (average) or the uncertainty (variance) that is important? Are investors more concerned about differences that occur between companies across a price review period or those that occur on an annual basis? Whichever method is chosen to calculate the standard deviation, it should be consistently applied wherever possible and clearly described.

Testing of statistical significance: It seems that Ofgem base their conclusion that the risk differential is statistically significant on an annual basis by applying a Monte Carlo programme from Excel on a point estimate. This choice of method may not be robust because it:

- ignores the information contained in the actual variation data (as discussed above) and utilises a different assumed figure; and
- requires assumptions about an underlying continuous probability distribution, which may not be realistic given the lumpy nature of some of the cost categories, such as capital expenditure.

Before robust conclusions can be drawn, it would be necessary to first explore the use of confidence intervals which establish a credible range for the true value:

- at an earlier stage of the analysis and that can be argued to capture true variation better; and
- using non-parametric techniques, such as "bootstrapping" or "jack-knifing", which do not require assumptions about the underlying probability distribution.

3.2. Oxera relative risk analysis

Two reports have been prepared by Oxera on behalf of the GDNs[3]. Only the second of these has been placed in the public domain. These reports use a variety of measures to show that under certain circumstances gas distribution would appear to have a significantly higher asset beta value than that for transmission.

The cross-country analysis undertaken by Oxera omits a key variable, namely the form of regulatory regime. Clearly, one important determinant of systematic risk is the way a regulatory regime adjusts revenues to take account of actual costs: 'high powered' incentive regimes, such as those in the UK, impose greater risks than, for example, cost-plus or rate of return regimes. CEPA has repeated the Oxera analysis taking account of the differences in regulatory regimes in different countries.

In this section we:

- briefly consider the Oxera approach;
- report our attempt to replicate the Oxera results; and
- report the results of an extended analysis that takes account of differences in regulatory regime.

3.2.1. Oxera's approach

Below, we briefly set out Oxera's approach before describing our extension to it. There are two main elements to Oxera's analysis: 1) 'pure-play' and 2) 'mixed' comparator analysis. The pure-play analysis was based on a sample of companies that had more than 50% of their

[3] Oxera 2007, 'Is there a risk differential between energy networks? Results from "pure-play" comparator analysis', July and Oxera 2007, 'Is there a risk differential between energy networks? Quantitative and qualitative analysis of systematic risk', September.

business in the relevant activity. This work examined the average values for the asset betas. The mixed comparator analysis was based on a larger sample and employed regression analysis.

Our focus has been on the mixed comparator analysis, but it is worth noting here that we have some concerns about the pure-play analysis. In particular, in relation to the pure-play analysis, it seems unlikely that that any robust conclusions can be reached from a sample size of 5. Further, we question whether Oxera have erroneously treated coefficient estimates as averages in order to carry out their hypothesis testing.[4]

For the mixed comparator analysis, Oxera has run regressions such that each company's asset beta is determined by the share of its business in network and production activities for gas and electricity. The segment share is measured by one of three measures: profit, revenues or asset size (see Annex 2 for further information). It is cross-sectional analysis that is based on ordinary least squares (OLS). There are four key models, which differ from one another in terms of the amount of information that they contain about the firms activities. Model 1 contains the most information (or has the greatest separation between network and production data) while models 3 and 4 have the least. For these regressions, the company's asset beta and the proportion of the company's various business segments are inputs. The coefficient estimates on the business segments are outputs, which are then used to test whether the asset beta of various companies differ according to the size of their distribution and transmission activities for gas and electricity. The model specifications are reproduced below:

Model 1: Company asset beta = β_{EG}(electricity generation) + β_{ET}(electricity transmission) + β_{ED}(electricity distribution) + β_{GP}(gas production) + β_{GT}(gas transmission) + β_{GD}(gas distribution)

Model 2: Company asset beta = β_{ET}(electricity transmission) + β_{ED}(electricity distribution) + β_{GP}(gas production) + β_{GT}(gas transmission) + β_{GD}(gas distribution)

Model 3: Company asset beta = $\beta_{transmission}$(electricity and gas transmission) + $\beta_{distribution}$(electricity and gas distribution)

Model 4: Company asset beta = $\beta_{electricity}$(electricity transmission and distribution) + β_{gas}(gas transmission and distribution)

3.2.2. CEPA's approach

In our approach, we followed the procedure below:

- replicating the Oxera database as closely as possible (explained in Annex 1);

[4] We have not spent much time considering this issue but the test statistic that they have used (2 sample unequal variance t-test) works favourably in terms of rejecting the null hypothesis. However, the coefficient estimates they have applied it to cannot be truly described as averages. Instead, it may be necessary to carry out this hypothesis testing using a standard regression approach in a panel framework.

- running Oxera's original regression;
- hypothesis testing whether the asset beta for gas distribution is statistically different from the asset beta for gas transmission at the 5 per cent significance level;[5]
- hypothesis testing whether the asset betas for electricity and gas distribution are jointly different from those from electricity and gas transmission at the 5 per cent significance level; and
- examining the impact of adding a USA dummy and regulatory regime ordinal variable. The USA dummy takes the value of one when the company is based in the USA and zero when it is not. The regulatory ordinal variable is one when the regulatory regime is incentive regulation, three when it is rate of return and two when the regulatory approach is a mixture or the company is affected by both types of regulation[6].

The results of our hypothesis testing are set out in the Tables 3.1 to 3.4 below. Table 3.1 shows that in our hypothesis testing, we were not able to conclude that the asset betas for gas distribution and transmission were statistically different from one another, which was Oxera's conclusion. However, we were able to conclude that asset betas are different for distribution and transmission in relation to gas and electricity jointly.

[5] Typical significance tests occur at the 1%, 5% and 10% levels and can be one tailed or two tailed. The higher the percentage value for the test the lower the threshold being set for accepting a result that differs from the null hypothesis (the base line assumption which in this case is that the beta values are the same). A one tailed test is used when the difference is expected to be in one specific direction – so one value is either higher or lower than the other. A two tailed test is used when there is no presumption about the direction of the difference. We have used two tailed tests.

[6] The results were not sensitive as to whether we used an ordinal variable or separate dummies so we have presented the ordinal variable to keep the tables as simple as possible. This issue of incorporating the regime into the equation specification is but one of the issues related to incorporating regimes into the analysis. Only one of the approaches considered is reported here. We tested different approaches and different values, such as reversing the ordinal values so that high-powered regimes took the value 3 while low-powered took the value 1, and found Oxera's reported results were not robust.

Table 3.1: Model 1

Business segments	**Oxera results**	**CEPA results**	**USA dummy**	**Regulatory regime**
Electricity generation	0.58*	0.67*	0.63*	0.37
Electricity transmission	0.28*	0.34*	0.31	0.02
Electricity distribution	0.56*	0.72*	0.63*	0.44*
Gas production	1.08*	1.16*	1.08*	1.00*
Gas transmission	0.32*	0.47*	0.44*	0.18
Gas distribution	0.68*	0.72*	0.64*	0.38*
USA	-	-	0.07	-
Regulatory regime	-	-	-	0.11*
Observations	50	48	48	46
R^2	0.84	0.89	0.89	0.90
$\beta_{GD} - \beta_{GT}$	0.36	0.25	0.20	0.20

* denotes statistically significant at the 5 per cent level

Table 3.2 below shows that in our hypothesis testing, we were not able to conclude that the asset betas for gas distribution and transmission were statistically different from one another. However, we were able to conclude that asset betas are different for distribution and transmission in relation to gas and electricity jointly at the 10 per cent significance level.

Table 3.2: Model 2

Business segments	Oxera results	CEPA results	USA dummy	Regulatory regime
Electricity transmission	0.31	0.40	0.27	-0.26
Electricity distribution	0.96*	1.07*	0.65*	0.24
Gas transmission	0.43*	0.52*	0.40*	-0.06
Gas distribution	0.71*	0.82*	0.49*	0.15
USA	-	-	0.26*	-
Regulatory regime	-	-	-	0.20*
Observations	50	48	48	46
R^2	0.73	0.76	0.80	0.85
$\beta_{GD} - \beta_{GT}$	0.28	0.29	0.10	0.21

* denotes statistically significant at the 5 per cent level

Table 3.3 below shows that in our hypothesis testing, we were able to reject the null hypothesis that the asset betas for distribution and transmission for electricity and gas are the same as one another. However, this result was reversed by including the USA dummy in the model - it was then possible that the asset betas for distribution and transmission for electricity and gas are the same.

Table 3.3: Model 3

Business segments	Oxera results	CEPA results	USA dummy	Regulatory regime
Transmission	0.38*	0.49*	0.35*	-0.13
Distribution	0.77*	0.89*	0.52*	0.17
USA	-	-	0.28*	-
Regulatory regime	-	-		0.20*
Observations	50	48	48	46
R^2	0.72	0.75	0.79	0.20
$\beta_D - \beta_T$	0.39	0.40	0.17	0.30

* denotes statistically significant at the 5 per cent level

Table 3.4 below shows that the results from the fourth model do not drive any conclusion about asset betas being different for transmission and distribution. However, the regression results are reported here for completeness, even though we did not extend the analysis nor carry out hypothesis testing.

Table 4.4: Model 4

Business segments	Oxera results	CEPA results
Electricity	0.63*	0.80*
Gas	0.63*	0.73*
Observations	50	48
R^2	0.68	0.72

3.2.3. Results

We found the results below:

- In spite of missing two observations and difficulties with establishing which exact measure Oxera used to quantify the business segments, we appear to have been able to broadly reproduce their regression results in relation to coefficient estimates and R^2s.[7] Our sample of companies is set out in Annex 1 and the process for establishing the values is given in Annex 2.
- Our analysis indicates that Oxera's finding that asset betas are different for distribution and transmission is generated only by testing electricity and gas jointly. The data does not support the conclusion that asset betas for gas distribution and transmission are statistically different from one another in any other model. Our approach to hypothesis testing is described in Annex 3.
- Including additional variables, such as dummies for USA based companies or an ordinal variable for the regulatory regime, reduced the absolute difference between the gas transmission and gas distribution coefficients. It seems that the regulatory regime variable not only tends to be statistically significant, but it reduces the statistical significance of other independent variables, which provides some evidence of an important omission from the Oxera modelling. Further, including the USA dummy eliminates the model 3 finding that transmission is different to distribution.

3.2.4. Conclusions

In conclusion, while we do not believe that the results of our work are sufficiently robust to draw conclusions from about relative risk, they do show clearly that the Oxera analysis cannot be used in its existing form to support a difference in the asset beta. Further work on refining the regulatory variable, including the appropriate option for incorporating the regime into the equation and expanding the data set would be necessary before any definitive statement about whether gas distribution has a different asset beta to gas transmission could be made.

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[7] We were not able to include Cascade Natural Gas and Iberdrola due to a merger and lack of gearing data respectively.

4. MAR ANALYSIS

4.1. Introduction

A key element of the analysis that CEPA presented on the appropriate rate for the allowed cost of capital was an analysis of the values of MAR observed in its markets. This work was criticised in a note by Oxera prepared on behalf of the GDNs. In particular Oxera took issue with two aspect of the CEPA methodology[8]:

1. Are the calculations consistent with the accepted principles for valuing cash flow streams? And
2. Are factors that drive MARs overlooked in the calculations?

Subsequently the implications of CEPA's work were downplayed by Ofgem.

In this section we:

- review the note prepared by Oxera;
- develop a model to show the extent to which different factors can affect the MAR value;
- illustrate the types of value that the different factors would need to take to have a material impact on the MAR; and
- review the earlier MAR analysis in the light of this more comprehensive model.

Our original analysis drew on market evidence from both the GDNs sale prices and trading transactions valuations in other regulated sectors. We continue to believe MAR values provide important information about the cost of capital.

4.2. The OXERA critique

Oxera's note of 30th August 2007 on MAR values alleges that we 'disregard the impact of certain important drivers of the MAR'. This is not the case, we are fully aware that opex and capex outperformance can, in principle, give rise to a MAR premium. However, in practice the markets are well aware that opex and capex outperformance during each 5 year price review period is likely to be substantially eroded at the subsequent price control review. Also, in the case of the water companies, there is reduced opportunity for consistent opex and capex outperformance now that much of the 'easy' cost cutting has been done and the market attributes little permanent value to the remaining opportunities. We, like many city analysts, have made calculations which indicate that, assuming some regulatory erosion of the opex and capex outperformance, only a few percent of the observed MAR premia can be attributed to the NPV of expected out-performance – this is discussed in more detail below.

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[8] Oxera, *Do market-to-asset ratios provide reliable evidence on the cost of capital?*, August 2007, Pg 5.

The note also alleges that our methodology 'does not appear to be consistent with commonly accepted principles for valuing financial assets' and specifically says that our MAR calculations do not take proper account of the growth in RAB. Our methodology is entirely consistent with principles for valuing financial assets, indeed it is the basis used by almost all city analysts for valuing regulated assets[9].

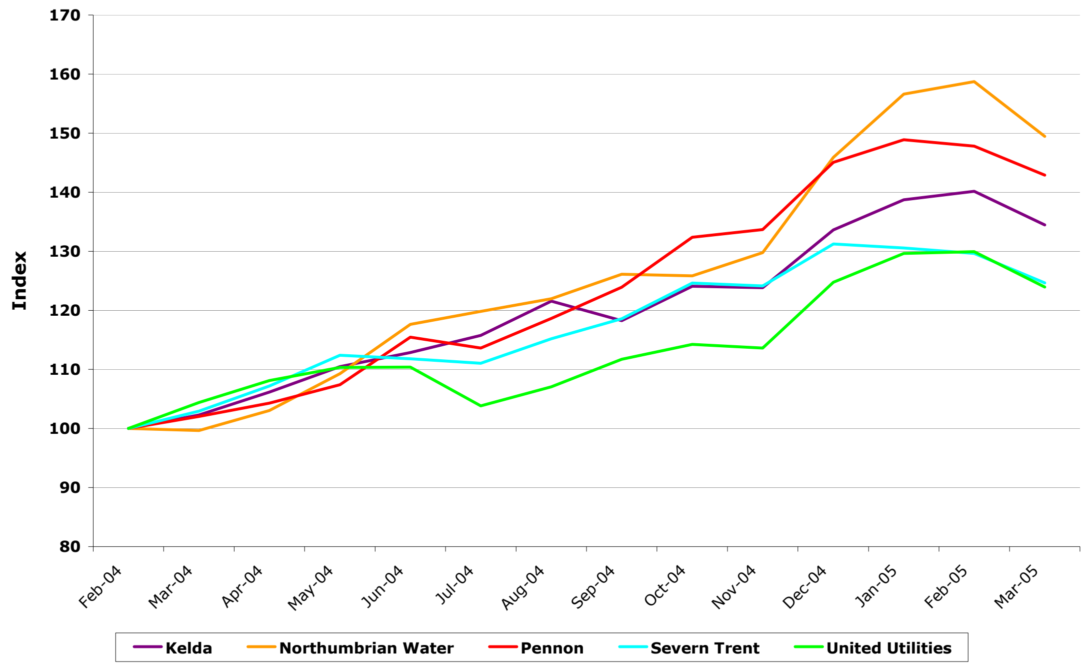
As for RAB growth, Oxera have neglected to take account of the negative incremental cashflows (i.e. the sunk capital) associated with the increase in the RAB. Correctly taking account of sunk capital confirms the approach that CEPA and city analysts take on this issue. It is true that any "unanticipated" capex efficiency will lead to an increase in the MAR value. However, these effects generate a small MAR premium (like opex efficiency gains). (See Annex 4 for a worked example.)

The Oxera note also says that we should have allowed for the capitalised value of positive financeability uplifts. Since these are transitory, they cannot explain more than a tiny percentage of the observed large MAR premia. Moreover they only apply to a few of the companies whereas the large MAR premia are observed for all the companies we evaluated.

That changes in the 'gap' between the allowed and actual cost of capital are the main driver of the MAR value (as opposed to explanations based on opex and capex out-performance or other factors) is supported by the movement in share prices and MAR values following the 2004 review of water companies as illustrated in Figure 4.1 below. There was no abrupt change in expectations about those 'other factors' but there was a significant change in the allowed cost of capital. Figure 4.1 illustrates a steep increase in the share prices of all the water companies in the second half of 2004 as the market began to price in the expected and actual outcome of the PR04 review process. Consequently, the MAR value of the water sector rose significantly immediately following the review from about 0.95 to about 1.05.

[9] CEPA, *The Allowed Cost of Capital: GDPCR 2008 - 13*, July 2007' provides a fuller description of our methodology.

Figure 4.1: Indexed share prices for UK water companies 2004 - 2005



In fact, the CEPA methodology is distinctly conservative. There is good reason to believe that the markets are expecting regulators to reduce the allowed cost of capital at future price reviews not least because of the large 'gap' in recent years between the allowed cost of debt and the actual cost of debt. In our calculations, we assumed that the current 'gap' between the allowed and actual cost of capital would continue into the future. If, in fact, the markets expect some compression of the real allowed return then the current MAR premia imply an even lower actual cost of capital than implied by our calculations.

In summary, we consider the arguments advanced by Oxera as marginal and in some cases without foundation. The methodology that we have employed is sound and the inferences about the cost of capital valid based on the market evidence. We note that CEPA's approach appears to be supported by Dieter Helm's 12th June 2007 commentary which states that 'it is highly unlikely (indeed implausible) that the value of these unanticipated gains [from opex and capex efficiencies] could be worth 20% of the RAB' (20% is the premium quoted for the sales of Anglian Water, South East Water and Thames Water)[10].

4.3. CEPA analysis of the impact of other factors on the MAR

In this section we analyse the relative importance of the key factors that determine the magnitude of the MAR premium. Our approach has been to develop a simple model that estimates the magnitude of the premium for differences between actual and expected values for each of four key factors.

[10] Dieter Helm 2007, 'Note on Issue of Sale of Utilities' in the *Response to Gas Distribution Price Control Review*, Fuel Poverty Advisory Group 2007.

The base case assumes that all actual values for opex, capex and the cost of capital equal their expected values when the price determination was made. Therefore, in this case the market value of the regulated assets equals the RAB and the MAR value is 1.

The base case parameter values are set out in Table 4.1 below.

Table 4.1: Value of key parameters

Parameter	Value
RAB	£M 1,000
Capital expenditure	£M 56 per annum
Operating expenditure	£M 77 per annum
Depreciation life	40 years
Allowed Cost of Capital	6.0% (vanilla cost of capital)
Actual rate of return	6.0%
RAB growth rate	0%
Corporate tax rate	28.0%
Implied Market Value	RAB + NPV of post-tax additional cash flows

The magnitude of the impact of the above-mentioned factors depends on the size of operating expenses and capital expenditure as well as on the degree of "unanticipated" efficiency. The model assumes that operating expenses are equal to 7.7% of the RAB and capital expenditure equal to 5.6% of the RAB.

The model runs a range of scenarios when the actual values of key parameters diverge from the expected values and computes the new MAR value. The key factors considered are:

- differences in allowed and actual rate of return;
- unanticipated additional operating efficiency savings in excess of regulatory expectations;
- unanticipated additional capex efficiency savings in excess of regulatory expectations; and
- positive and negative incentives to reward/penalise over/under performance.

The model considers the magnitude of 'outperformance' of each of the four key factors (separately) that would be necessary to generate a 5% MAR premium and, alternatively, a 20% MAR premium. Results are calculated assuming that 'overperformance' benefits are retained: (i) for 5 years then entirely removed; (ii) for 10 years in full then entirely removed; (iii) for 15 years in full then entirely removed; and (iv) in perpetuity.

The results are shown in Table 4.2 and in Table 4.3 below. A more detailed explanation of each of the scenarios is given in section 4.3.1 below.

Table 4.2 shows, for example that if a 5% MAR premium were attributable wholly to opex outperformance and the markets expected the benefits to be regulated away after 5 years, then it would imply 7.2% lower opex costs than assumed by the regulator in each year of the price control period. For observed MAR premia of approximately 20%, the 'required' opex outperformance would be roughly 29% lower in each year.

The results in Table 4.2 suggest that up to a 5% MAR premium might reasonably be explained by the market's expectation of modest opex outperformance and incentive payments for outperformance and the assumption that these cash flow gains will be retained over the long term.

The results in Table 4.3 suggest that market expectations of opex or capex outperformance and incentive payments for outperformance cannot explain a MAR up to 20%, even under the assumption that they will be retained over the long term. Instead, only a significant difference in the allowed and actual rates of return might reasonably explain up to a 20% MAR premium, especially if it is assumed that the markets expect that the difference will be retained over the long term.

Table 4.2: Amount needed to achieve 5% MAR premium

Years	Difference in rate of return	Efficiency savings in opex (%)	Capex efficiency savings (%)	Reward for overall performance (%)
5	1.2	7.2	75.6	9.4
10	0.9	4.1	43.3	5.4
15	0.6	3.1	32.8	4.1
Perpetuity	0.3	1.8	17.6	2.5

Table 4.3: Amount needed to achieve 20% MAR premium

Years	Difference in rate of return	Efficiency savings in opex (%)	Capex efficiency savings (%)	Reward for overall performance (%)
5	4.5	28.9	*	37.6
10	2.8	16.5	*	21.5
15	2.2	12.5	*	16.3
Perpetuity	1.1	7.2	70.3	9.8

Note: * when the model estimates a needed amount above 100%.

Our conclusion is that up to about 5% of the MAR premium can be plausibly explained by opex and capex outperformance and the value of incentive payments. The balance of the observed MAR premium (15-20%) must be explained by a significant divergence between the allowed cost of capital and the (lower) actual.

4.3.1. Model scenarios

The scenarios run in the model are described below, and then reported in the columns in Tables 4.2 and 4.3.

Difference in rate of return

In the first scenario, it is assumed that the actual rate of return is lower than the allowed cost of capital. Given that the assumed 6.0% allowed cost of capital is assumed to be a "Vanilla" cost of capital, the positive cash-flows generated by the different rates of return on both existing RAB and capital expenditure are tax-adjusted at a tax rate of 28.0%.

To achieve a 5% market premium the necessary additional post-tax profit arising from a difference in the actual and allowed rates of return can then be estimated.

Efficiency saving in operating expenses

This scenario presents the value of efficiency savings on operating expenses that should be anticipated by the market in each year to generate an impact on the implied market value and on the RAB equal to the 5% premium.

It is reasonable to expect that the market anticipates benefits from efficiency savings to be kept for five years only. Nevertheless, the worked example also produces the estimate of the impact of anticipated efficiency over longer periods of ten and fifteen years and in perpetuity. In these cases, the underlying assumption is that notwithstanding the changes of the allowed operating expenses to reflect the achieved efficiency, the market still anticipates that new efficiency will be achieved on the re-set allowed operating expenses.[11] Efficiency savings are shown as a percentage against allowed opex.

Efficiency saving in capital expenditure

This scenario presents the value of efficiency savings on capital expenditure that should be anticipated by the market in each year to generate an impact on the implied market value and on the RAB equal to the 5% premium. The capital efficiency saving is calculated as the saving in required return on and of capital as against the allowed return (again on and of capital), and it is assumed that any savings are kept for a minimum of five years.

Reward (penalty) for overall positive (negative) performance

This scenario presents which value of reward (penalty) should be anticipated by the market in each year to generate an impact on the implied market value and on the RAB equal to the 5% premium. The reward for overall performance is shown as a percentage of allowed revenue.

[11] The model incorporates x% efficiency savings in the first year of each price control period and a further x% for each of the remaining four years.

4.4. Outperformance benefit tapers over time

It is worth noting that the above-described analysis is based on the assumption that the various impacts have the same likelihood to happen over 5, 10, 15 years or even in perpetuity. A more realistic approach would be to take account of the likelihood that the above-reported impacts will decrease over time.

4.5. Conclusion

Overall, what is clear from our analysis is that the dominant factor in any significant MAR value above 1 has to be a divergence in the allowed cost of capital from the true value. Other factors have to take implausibly large values for them to have a material impact. Consequently the thrust of the results of the original analysis hold, although the precise numbers change in a non-significant way. As such, we continue to contend that MAR analysis is supportive of the other forms of analysis, such as CAPM, in terms of suggesting a cost of equity of between 6.5% and 7%.

5. COST OF EQUITY

5.1. Overview

The recent CC report on BAA sets out relevant evidence for the economy-wide parameters of the cost of capital.

The CC's estimate of the cost of equity of the equity market portfolio is 5% - 7%.

Risk free rate

The CC estimated the risk free rate at 2.5%. The CC notes that this estimate strikes "a sensible balance between giving recognition to the recent changes in financial markets and avoiding an over-cautious view of the long-term implications of investors' attitudes towards risk".

Equity risk premium (ERP)

The CC has reviewed the evidence on the ERP and concluded that the appropriate range is 2.5% - 4.5%.

5.2. Conclusion

The CC estimates set a cost of equity for the equity market portfolio in the range 5-7%. Since it is implausible that GDNs are regarded by the equity markets as having higher systematic risk than the equity market portfolio, the maximum value for the cost of equity for GDNs is 7%.

6. COST OF DEBT

For completeness, in this section we restate our conclusions on the cost of debt from CEPA's July 2007 submission to Ofgem on the allowed cost of capital for GDPCR 2008 – 2013[12]. Our analysis showed that, in the absence of a trigger mechanism, the appropriate point estimate for Ofgem is likely to be **3.0%.**

This was based on:

- risk free rate of 1.5-2.0% for nominal debt[13];
- risk free rate of 1.8% for index-linked debt;
- an efficiently financed GDN employing 25% index-linked debt; and
- debt premium of 1.0% for solid investment grade debt.

We had also considered these returns against evidence on actual issuance of long-dated index-linked debt. This suggested that the all-in cost of index-linked debt for comparable regulated utilities in recent years is below 2%. Set against this, we were aware that the risk free rate on nominal bonds has very recently increased, particularly at the shorter end of the yield curve – this, together with evidence from 10 year averages, indicates a range of 2.0-2.5%.

Taken together, we believed that this analysis clearly points towards an appropriate cost of debt for GDNs that is significantly below the 3.75% allowed in TPCR 2006.

Based on the above evidence, we believed that a defensible range for the cost of debt is 2.5% - 3.25%. This range takes account of the opportunity for regulated companies to benefit from the lower cost of debt in the index-linked markets. The lower end of the range places greater weight on the actual cost of index-linked issuance at the moment and five year averages for the real interest rate implicit in nominal gilts. The higher end of the range assumes significant mean reversion over the next five years.

Our judgement was that an appropriate point estimate for Ofgem, in the absence of a trigger mechanism, is 3.0%. The introduction of a trigger mechanism should allow Ofgem to set the cost of debt in the lower end of the range.

[12] CEPA, *The Allowed Cost of Capital: GDPCR 2008 – 2013*, July 2007. See Section 4 for a full analysis on the cost of debt.

[13] Assuming expected inflation of 2.5-3.0%.

ANNEX 1: SAMPLE AND DATA USED IN THE RELATIVE RISK STUDY

This annex summarises the sample and data used in our relative risk study. In particular the annex shows:

- CEPA estimates of the proportions of companies' activities attributable to a range of energy business segments;
- CEPA assessment of sample companies' regulatory regimes; and
- estimated asset betas for the sample companies.

The abbreviations and acronyms below provide a description of the table headings overleaf.

The approach used to produce this sample is outlined in Annex 2.

Abbreviations and Acronyms

Categories of regulatory regime (RR)

Regulatory Regime 1	High-powered regimes
Regulatory Regime 2	Medium-powered regimes
Regulatory Regime 3	Low-powered regimes

Categories of business segment

ET	Electricity Transmission
ED	Electricity Distribution
GT	Gas Transmission
GD	Gas Distribution
EN	Electricity Networks (T+D)
GN	Gas Networks (T+D)
TN	Transmission Networks (E+G)
DN	Distribution Networks (E+G)
AN	Energy networks (E+G and T+D)
EG	Electricity Generation
GP	Gas Production
OS	Other Sectors

Table A1: Sample of firms used in relative risk study (rotate for pdf)

Company Name	Country	Asset beta	RR	Proportion of firm activities attributable to business segment											
				ET	ED	GT	GD	EN	GN	TN	DN	AN	EG	GP	OS
AGL Resources	USA	0.459	3	-	-	-	0.74	-	0.74	-	0.74	0.74	-	-	0.26
Allegheny Energy	USA	0.705	3	0.10	0.33	-	-	0.43	-	0.10	0.33	0.43	0.54	-	0.03
American Electric Power Company	USA	0.428	2	0.17	0.27	-	-	0.44	-	0.17	0.27	0.44	0.40	-	0.16
Atmos Energy	USA	0.365	3	-	-	0.15	0.85	-	0.99	0.15	0.85	0.99	-	-	0.00
Black Hills Corporation	USA	0.672	2	0.03	0.17	-	0.04	0.20	0.04	0.03	0.21	0.24	0.33	0.22	0.21
Cascade Natural Gas Corporation	USA	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dynegy	USA	0.765	-	-	-	-	-	-	-	-	-	-	0.95	-	0.05
EDP	Portugal	0.673	2	-	0.33	-	0.10	0.33	0.10	-	0.43	0.43	0.44	-	0.13
Emera	Canadian	0.104	2	0.15	0.28	-	-	0.43	-	0.15	0.28	0.43	0.49	-	0.08
Enagas	Spain	0.566	3	-	-	0.94	-	-	0.94	0.94	-	0.94	-	-	0.06
Enel	Italy	0.525	1	-	0.37	-	0.05	0.37	0.05	-	0.41	0.41	0.41	-	0.17
Energen Corporation	USA	0.876	2	-	-	-	0.48	-	0.48	-	0.48	0.48	-	0.52	-
Energy West	USA	0.263	3	-	-	-	0.67	-	0.67	-	0.67	0.67	-	0.02	0.31
Energy South	USA	0.745	2	-	-	0.38	0.59	-	0.97	0.38	0.59	0.97	-	-	0.03
Equitable Resources	USA	0.831	2	-	-	-	0.28	-	0.28	-	0.28	0.28	-	0.50	0.22
FirstEnergy Corp	USA	0.471	2	0.03	0.34	-	-	0.37	-	0.03	0.34	0.37	-	-	0.63
Fortum	Finland	0.658	1	-	0.25	-	-	0.25	-	-	0.25	-	0.50	-	0.25
Gas Natural	Spain	0.880	2	-	-	-	0.54	-	0.54	-	0.54	0.54	0.21	0.14	0.11
Gaz de France	France	0.726	2	-	-	0.15	0.18	-	0.33	0.15	0.18	0.33	-	0.06	0.61
Iberdrola	Spain	-	1	-	-	-	-	-	-	-	0.21	0.21	-	-	0.79
IDACORP	USA	0.567	3	0.17	0.31	-	-	0.48	-	0.17	0.31	0.48	0.44	-	0.08
ITC Holdings Corp	USA	0.544	2	0.61	-	-	-	0.61	-	0.61	-	0.61	-	-	0.39
Kinder Morgan	USA	0.244	2	-	-	0.65	0.07	-	0.72	0.65	0.07	0.72	-	-	0.28
National Fuel Gas Company	USA	0.605	2	-	-	0.21	0.39	-	0.60	0.21	0.39	0.60	-	0.32	0.08
New Jersey Resources	USA	0.702	1	-	-	-	0.66	-	0.66	-	0.66	0.66	-	-	0.34
Nicor	USA	0.733	3	-	-	-	0.93	-	0.93	-	0.93	0.93	-	-	0.07
Northeast utilities	USA	0.416	2	-	0.55	-	0.08	0.55	0.08	-	0.63	0.63	0.04	-	0.33
Northwest Natural Gas	USA	0.728	-	-	-	0.02	0.98	-	0.99	0.02	0.98	0.99	-	-	0.01
NSTAR	USA	0.448	2	0.11	0.43	-	0.07	0.54	0.07	0.11	0.50	0.61	-	-	0.39
OGE Energy Corp	USA	0.595	3	0.11	0.11	0.58	-	0.22	0.58	0.69	0.11	0.80	0.11	-	0.09
Piedmont Natural Gas	USA	0.634	3	-	-	-	0.80	-	0.80	-	0.80	0.80	0.01	-	0.19
Progress Energy	USA	0.399	2	0.06	0.16	-	-	0.22	-	0.06	0.16	0.22	0.28	-	0.50

Company Name	Country	Asset beta	RR	Proportion of firm activities attributable to business segment											
				ET	ED	GT	GD	EN	GN	TN	DN	AN	EG	GP	OS
Red Electrica	Spain	0.021	3	0.81	-	-	-	0.81	-	0.81	-	0.81	-	-	0.19
SEMCO Energy	USA	0.169	2	-	-	-	0.95	-	0.95	-	0.95	0.95	-	-	0.05
Sempra Energy	USA	0.896	3	0.08	0.08	0.03	0.36	0.16	0.39	0.11	0.44	0.55	0.20	-	0.25
Snam Rete Gas	Italy	0.369	2	-	-	0.98	-	-	0.98	0.98	-	0.98	-	-	0.02
South Jersey Indust.	USA	0.781	3	-	-	0.11	0.77	-	0.88	0.11	0.77	0.88	0.08	-	0.04
Southern Company	USA	0.454	2	-	0.27	0.14	-	0.27	0.14	0.14	0.27	0.41	0.51	-	0.08
Southern Union Company	USA	0.456	3	-	-	0.58	0.15	-	0.73	0.58	0.15	0.73	-	-	0.27
Southwest Gas Corporation	USA	0.589	3	0.03	0.84	-	-	0.84	-	0.03	0.84	0.87	-	-	0.13
Terna	Italy	0.369	2	0.92	-	-	-	0.92	-	0.92	-	0.92	-	-	0.08
The Empire District Electric Company	USA	0.626	3	0.13	0.39	-	0.09	0.52	0.09	0.13	0.48	0.61	0.37	-	0.02
Lacled Group	USA	0.850	3	-	-	-	0.85	-	0.85	-	0.85	0.85	-	-	0.15
TransCanada Corporation	Canadian	0.330	2	-	-	0.71	-	-	0.71	0.71	-	0.71	0.25	-	0.04
TXU Corp	USA	0.684	3	0.03	0.31	-	-	0.34	-	0.03	0.31	0.34	0.61	-	0.05
UIL Holdings Corporation	USA	0.751	2	0.08	0.92	-	-	1.00	-	0.08	0.92	1.00	-	-	-
Union Fenosa	Spain	0.542	2	-	0.10	-	0.09	0.10	0.09	-	0.19	0.19	0.33	-	0.48
UniSource Energy Corporation	USA	0.270	2	0.15	0.31	-	0.08	0.46	0.08	0.15	0.39	0.54	0.35	-	0.11
United Utilities	UK	0.274	1	-	0.21	-	-	0.21	-	-	0.21	0.21	-	-	0.79
WGL Holdings Inc	USA	0.753	3	-	-	-	0.92	-	0.92	-	0.92	0.92	-	-	0.08

Note: Cascade Natural Gas and Iberdrola not included in final sample for 'mixed' comparator analysis. Cascade Natural Gas excluded due to merger with MDU Resources Group, Inc. Iberdrola excluded due to unavailability of gearing data.

RR is Regulatory Regime

ANNEX 2: METHODOLOGY SECTION

In this section we review the approach used by Oxera to compile a sample for their 'pure-play' and 'mixed' comparator analysis. We then outline the methodology used by CEPA to reproduce and extend the Oxera sample.

A2.1 Oxera sample for 'pure-play' and 'mixed' comparator analysis

The Oxera analysis takes as a starting point 29 EU- and 76 US-listed energy companies. For each firm in this sample the latest financial statements were analysed, and from this analysis, Oxera obtain the proportion of firm's activities attributable to the following business segments:

- electricity transmission;
- electricity distribution;
- gas transmission;
- gas distribution;
- other sectors (eg telecoms, electricity generation and supply, and gas production and supply).

The proportions of each of the above activities were measured in terms of segment-wise reporting of operating profits, fixed assets, or revenues. Where segment-wise reporting was not sufficient or detailed enough to separate out a firm's energy transport activities and / or there existed a lack of information from which to derive an estimate of the firm's asset beta, the company was excluded from the final sample. Following this screening process, 50 energy firms (38 US and 12 EU) were included in Oxera's final sample.

From the 50 companies included in the final sample, Oxera generate a sample of companies for 'pure-play' comparator analysis by classifying firms into energy network groupings. This is based on the information collected on the proportion of firms' activities attributable to the various business segments described above. Pure-play comparators for each segment were defined as the companies for which the proportion of business activities attributable to an individual segment was higher than 50%.

Firm asset betas used for both 'pure-play' and 'mixed' comparator analysis were derived from Bloomberg-reported equity betas and net-debt-to-asset ratios (gearing[14]) according to the Millar transformation.

[14] Oxera gearing ratios are based on book values of debt and equity.

A2.2 CEPA sample for relative risk study

Based on the information provided in Oxera's September report, we have attempted to reproduce the sample used in the 'pure-play' and 'mixed' comparator analysis. As a starting point, we have taken the 50 energy companies included in Oxera's final sample and attempted to reproduce the following:

- the proportion of each firms' activities attributable to various energy business segments from the 2006 financial statements;
- estimates of firm asset betas at the time of the Oxera analysis.

In order to extend the Oxera analysis, we have also classified each company by:

- country; and
- regulatory regime.

A summary of the data derived from the above analysis is provided in Annex 1. The approach used to collect this information is explained in more detail in the sections below.

A2.2.1 Business segment analysis

We have attempted to reproduce Oxera's approach and analysis of the proportion of firms' activities attributable to various business segments. 2006 financial statements were collected for all the 50 energy companies and the proportions of each business activity were measured in terms of segment-wise reporting of operating profits, fixed assets, or revenues. Where available, fixed assets were the preferred measure. Table A2 compares the CEPA and Oxera analysis by contrasting pure-play comparators for energy network business segments.

Table A2: CEPA and Oxera pure-play comparators

Business Segment	CEPA No. of Companies	Oxera No. of Companies
Electricity Transmission	3	3
Electricity Distribution	3	4
Gas Transmission	6	5
Gas Distribution	13	16
Electricity networks	8	10
Gas Networks	20	23
Transmission Networks	9	8
Distribution Networks	16	20
Energy networks	30	34

Note: Assumes a 50% pure-play threshold ; Cascade Natural Gas not included in the CEPA analysis.
Source: CEPA calculations; Oxera calculations.

A2.2.2 Company asset betas

We have estimated asset betas for each of the 50 companies in three steps:

- establish a firm equity beta value;
- ascertain the gearing for the company; and
- derive the firm asset beta according to the Millar transformation.

The approach used at each stage of this process is discussed below.

Establishing the company asset beta

Equity beta values were derived for each company as follows:

- collect daily share price information from May 2005 – May 2007;
- collect values for the appropriate market index for the company from May 2005 – May 2007;
- estimate the daily returns for the company and the index through the simple calculation of the percentage change in share price for each day;
- remove all non-trading days, i.e. bank holidays etc. when no trades occur across the whole market; and
- regress the daily returns for the company against the daily index returns to estimate beta from the following equation.

  $$R_i = a + \beta R_m$$

  where R_i is the return on the company and R_m is the return on the market.

Calculating company gearing

We have used Reuters-reported net debt-to-enterprise value ratios to obtain company gearing (*g*). The ratio is calculated as follows:

$$g = \text{Net debt} / \text{Enterprise Value}$$

where :

Net debt = Total Debt - Cash and Short Term Investments

Enterprise Value = Total Market Cap + Net Debt

Estimating the asset beta

Following stages 1 and 2, asset betas were calculated for each of the companies in the final sample using the following formula:

$$\beta a = \beta e \times (1 - g)$$

where βa is the asset beta and βe is the equity beta.

A2.2.3 Country

Each of the 50 companies in the final sample was classified by country. The location of the firms major market listing was used as the criteria for classifying each company into country groupings.

A2.2.4 Regulatory regime

For each of the 50 companies in the final sample we have also attempted to establish the structure and detail of the regulatory regime. Three categories of regulatory regime were used in the classification process:

- high-powered regimes – regimes where significant incentives for companies to reduce costs are established through CPI – X type regimes (price-caps, revenue caps etc.);
- medium-powered regimes – regimes involving incentivisation of companies, but normally through hybrid schemes and less explicit regulatory regimes; and
- low-powered regimes – standard rate-of-return type approaches to regulation.

ANNEX 3: HYPOTHESIS TESTING

We have used the following tests to investigate whether the asset beta for distribution is statistically different from that for transmission for:

- Gas, using a t-test; and
- Gas and electricity jointly, using an F-test.

We use model 2 to outline our hypothesis testing, which takes the form:

Company asset beta = $\beta_{ET}X_{ET} + \beta_{ED}X_{ED} + \beta_{GT}X_{GT} + \beta_{GD}X_{GD}$

Where X denotes the business sector size, which may be measured by assets, profits or revenue, β is the coefficient, G is gas, E is electricity, T is transmission and D is distribution.

6.1. Gas only

Hypothesis test: $H_0: \beta_{GT} = \beta_{GD}$ and H_1 is $\beta_{GT} \neq \beta_{GD}$
Alternatively, H_0: $\beta_{GD} - \beta_{GT} = 0$ and H_1 is $\beta_{GD} - \beta_{GT} = \theta$ or $\beta_{GD} = \theta + \beta_{GT}$

Substituting in:

$$\begin{aligned}\text{Company asset beta} &= \beta_{ET}X_{ET} + \beta_{ED}X_{ED} + \beta_{GT}X_{GT} + (\theta + \beta_{GT})X_{GD} \\ &= \beta_{ET}X_{ET} + \beta_{ED}X_{ED} + \beta_{GT}X_{GT} + \beta_{GT}X_{GD} + \theta X_{GD} \\ &= \beta_{ET}X_{ET} + \beta_{ED}X_{ED} + \beta_{GT}(X_{GT} + X_{GD}) + \theta X_{GD}\end{aligned}$$

Decision rule: reject H_0 if $\theta/se(\theta) > 2$.

Test statistic: 1.474705

Conclusion: therefore, cannot reject H_0 at the 5 per cent significance level i.e. the βs could be the same for gas transmission and distribution.

6.2. Electricity and gas jointly

Hypothesis test: $H_0: \beta_{GT} = \beta_{GD}$; $\beta_{ET} = \beta_{ED}$ and H_1 is $\beta_{GT} \neq \beta_{GD}$; $\beta_{ET} \neq \beta_{ED}$

Substituting in:

$$\begin{aligned}\text{Company asset beta} &= \beta_{ED}X_{ET} + \beta_{ED}X_{ED} + \beta_{GD}X_{GT} + \beta_{GD}X_{GD} \\ &= \beta_{ED}(X_{ET} + X_{ED}) + \beta_{GD}(X_{GT} + X_{GD}) \\ &= \beta_{ED}(X_{\text{Electricity network}}) + \beta_{GD}(X_{\text{Gas network}})\end{aligned}$$

Decision rule: reject H_0 if

$$((RSS_R - RSS_{UR})/m) / (RSS_{UR} / (n-k)) > 3.23$$

where m is number of linear restrictions, k is number of parameters in unrestricted regression, n is number of observations.

Test statistic: ((4.70-4.03)/2)/(4.70/(48-4))
= 0.033/0.107
= 3.10

Conclusion: therefore, cannot reject the H_0 at the 5 per cent significance level i.e. the betas could be the same across transmission and distribution for both electricity and gas.

ANNEX 4: MARS AND RAB GROWTH: A SIMPLE WORKED EXAMPLE

Steady state example

In this example, there is no growth in the RAB over the period.

Table 1

Period	1	2	3
RAB	100	100	100
Allowed cost of capital of 6% (assumed)	6	6	6

- Perpetuity value is 6/0.06, which gives a NPV = 100, so MAR = 1.0
- If in this case the actual cost of capital is 5%, then the NPV = 6/0.05 = 120, so MAR = 1.2

Growing RAB example

In this example, the RAB grows by 10 in period 2 and then remains at 110 in period 3.

Table 2

Period	**1**	**2**	**3**
RAB	100	100 + 10	100 + 10
Allowed cost of capital of 6% (assumed)	6	6 + 0.6	6 + 0.6

- Perpetuity value period 1 is 6/0.06, so NPV = 100 and MAR = 1.0
- Perpetuity value of incremental cash flow in period 2 = 0.6/0.06 = +10
- But incremental cash outflow in period 2 = -10 (which increases the RAB by 10)
- In period 2 the NPV of the incremental investment in the RAB = -10 + 10 = 0

Therefore in period 1 the NPV of expected cash flows relating to both the sunk RAB and the expected increment to the RAB is 100, and the RAB is 100, so the MAR is 1.0, despite the expectation of a growing RAB.

Note that as the additional investment in the RAB becomes 'sunk' in period 2 (increasing it to 110), so the PV of the incremental positive cash flows increases by +10, such that the MAR in that period remains at 1.0 on the larger RAB of 110.

If in this example actual cost of capital is 5%, then the perpetuity value period 1 NPV = 6/0.05 = 120. The perpetuity value of the incremental cash flow in period 2 = 0.6/0.05 = +12. So the incremental NPV in period 2 = -10 +12 = +2, so the NPV in period 1 is 121.9 and the observed MAR is 1.219. Note that in this case, the only reason that the MAR increases relative to the base year is because of the assumption that the 'gap' between the allowed and actual cost of capital exists and persists indefinitely.

Explanation

In period 1 if the allowed cost of capital equals the actual cost of capital, then the incremental NPV of additions to the RAB is zero and consequently a MAR of 1.0 in period 1 remains throughout, but as the additional capital is 'sunk' into the RAB, so the PV of the incremental positive cash flow increases in line with increases in the RAB.