Oxera
Celebrating 25 years

Is there a risk differential between energy networks?

Quantitative and qualitative analysis of systematic risk

Prepared for the gas distribution networks

September 5th 2007

Contents

List of tables

List of figures

1 Introduction

The aim of this report is to investigate what, if any, differences in systematic risk—as measured by the CAPM asset beta—may exist between energy networks. The report does not necessarily provide direct evidence of the appropriate level of the asset beta for gas DNs or the other energy networks. Furthermore, it is intended to be read in conjunction with Oxera's earlier analysis of risk differentials among energy networks.[1]

The specific objectives of this report are to:

– present further evidence on the magnitude of risk differentials between energy networks;
– analyse regulators' previous policy positions on the analysis of risk differentials between regulated sectors;
– assess qualitatively the risk drivers that could affect the relative systematic risk of energy networks.

The key results from these investigations suggest that there is indeed a risk differential between gas distribution and transmission (electricity and gas). Specifically, gas distribution asset betas are estimated to be around 0.2 higher than electricity and gas transmission asset betas. This implies that gas distribution equity betas should be around 0.5 higher than transmission, assuming 60% gearing.

The importance of the analysis of risk differentials between energy networks is underlined by Ofgem's statement that it does not expect to make a simple read-across from TPCR to GDPCR:

> it does not follow that the TPCR cost of capital must be an appropriate rate to apply to gas distribution[2]

because:

> the risk and reward profile of GDPCR may be materially different from that which the transmission companies will face in their price control.[3]

Moreover, Ofgem has stated that:

> On the drivers of risk, we do not consider that a more detailed analysis of the variability of returns (or covariance with systemic factors) would be likely to change our view on average returns or to lead us to a split cost of capital approach. However, such analysis could be useful in informing our views on differences in risk across sectors (and possibly even between companies). We have begun to analyse these differences in the energy network sectors and would expect to develop this during the current GDPCR. We will also share ideas with Ofwat in this area.[4]

[1] Oxera (2007), 'Is there a Risk Differential between Energy Networks? Results from 'Pure-play' Comparator Analysis', report prepared for the gas DNs, July 20th.
[2] Ofgem (2005), 'Gas Distribution Rollover', p. 48.
[3] Ofgem (2006)', 'Gas Distribution Price Control Review: Third Consultation Document', November, p. 61.
[4] Ofgem (2006), 'Financing Networks', open correspondence from David Gray, October 27th, p. 4.

The above quotations, together with Ofgem's fourth GDPCR consultation document,[5] confirm that it is actively investigating the potential for developing a different cost of capital for the gas DNs. Ofgem also highlights that comparator analysis is perhaps primarily useful for estimating the appropriate level of beta; nonetheless, it may also be useful as a means to determine the beta differential.[6]

In light of Ofgem's earlier statements and Oxera's previous analysis of 'pure-play' comparators, this report presents the 'top-down' evidence of risk differentials for energy networks. In addition, the report reviews the relevant regulatory precedents, and assesses qualitatively the risk differentials that may exist between energy networks.

The remainder of this report is structured as follows:

– section 2 gives the quantitative analysis of risk differentials;
– section 3 discusses the relevant regulatory precedents;
– section 4 presents the qualitative analysis of risk differentials; and
– section 5 concludes.

[5] Ofgem (2006), 'Gas Distribution Price Control Review: Third Consultation Document', March 26th.

[6] Oxera (2007), op. cit.

2 Quantitative analysis of risk differentials

This report extends the analysis of risk differentials between energy networks. Oxera has used a number of methodologies to investigate the existence and magnitude of any risk differential, as follows:

– ‘pure-play’ comparator analysis;
– ‘mixed’ comparator analysis;
– econometric estimation of the explanatory factors of asset betas.

This section reviews, for each of the above methodologies, the analytical approach, data sources, and key findings.

2.1 Summary of ‘pure-play’ comparator analysis[7]

The key result from the analysis of pure-play comparators is that there is a risk differential between gas distribution and transmission (electricity and gas). Specifically, gas distribution asset betas are estimated to be around 0.2 higher than electricity and gas transmission asset betas.

The starting point for this analysis was a sample of 29 EU- and 76 US-listed energy companies that had significant involvement in electricity generation, gas production, transmission, distribution, and supply. For each firm in this sample the latest financial statements were collected and analysed.[8] The outcome of the analysis was to obtain, for each of the 105 companies, the proportion of their business portfolios that is attributable to:

– 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 the segment-wise reporting of operating profits, fixed assets, or revenues. Where segment-wise reporting was not sufficient to separate out energy transport activities, these firms were excluded from the final sample. Consequently, the screening of the initial sample of 105 firms resulted in 50 firms (38 US and 12 EU) being included in the final sample used for the calculations and analysis described below. Notably, a large number of firms were excluded from the final sample due to insufficiently detailed reporting (on the profits, assets, and revenues) of distribution and supply activities, and transmission and generation/production activities. Some firms were removed from the final sample due to the lack of reliable information from which to derive an estimate of the asset beta. See Appendix 1 for the list of the firms in the final sample.

[7] This section provides a high-level summary of the ‘pure play’ comparator analysis presented in Oxera (2007), op. cit.
[8] In most cases, these are 2006 financial statements.

Based on the information collected on the proportion of firms' activities attributable to the various business segments described above, each of the 50 companies in the final sample was further classified according to the following groups:

- electricity transmission;
- electricity distribution;
- gas transmission;
- gas distribution;
- electricity networks (transmission and distribution, or T+D);
- gas networks (T+D);
- transmission networks (electricity and gas, or E+G);
- distribution networks (E+G);
- energy networks (E+G and T+D).

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%. In other words, pure-play comparators for each business segment were defined as those firms having a majority of their business involved in a particular line of business.

Asset betas were calculated for each of the 50 companies in the final sample, derived from Bloomberg-reported equity betas and net debt-to-asset ratios (ie, gearing)[9] according to the Miller transformation, as follows:

asset beta = equity beta * (1 – gearing)

Table 2.1 presents the results of the betas found for each groupings listed above.

Table 2.1 Expected value and standard deviation of business segment asset betas

Segment	Number of companies, (N)	Expected beta, E(β)	Beta standard deviation, SD(β)
Electricity transmission	3	0.31	0.06
Electricity distribution	4	0.50	0.16
Gas transmission	5	0.35	0.08
Gas distribution	16	0.55	0.19
Electricity networks (T+D)	10	0.41	0.16
Gas networks (T+D)	23	0.52	0.20
Transmission networks (E+G)	8	0.34	0.07
Distribution networks (E+G)	20	0.54	0.18
Energy networks (E+G and T+D)	34	0.49	0.19

Note: Assumes a 50% pure-play threshold.
Source: Oxera calculations.

Based on the above pure-play comparators' asset betas, several tests were completed to determine whether statistically significant differences in expected betas exist. Specifically, the hypothesis that the difference between expected betas of different segments is zero was tested at the 5% significance level. Rejecting this hypothesis suggests that there can be 95%

[9] Based on book values of debt and equity.

confidence that any two segment asset betas are indeed different. On this basis, the presence of a risk differential can be confirmed. Table 2.2 shows the results of the statistical tests.

Table 2.2 Pure-play comparator asset betas, assuming 50% pure-play threshold

Pure-play > 50%	Electricity	Gas	E + G	Test H_0: $E(\beta_E)=E(\beta_G)$
Transmission	**$E(\beta) = 0.31$** N = 3 $SD(\beta) = 0.06$	**$E(\beta) = 0.35$** N = 5 $SD(\beta) = 0.08$	**$E(\beta) = 0.34$** N = 8 $SD(\beta) = 0.07$	Cannot reject H_0
Distribution	**$E(\beta) = 0.50$** N = 4 $SD(\beta) = 0.16$	**$E(\beta) = 0.55$** N = 16 $SD(\beta) = 0.19$	**$E(\beta) = 0.54$** N = 20 $SD(\beta) = 0.18$	Cannot reject H_0
T + D	**$E(\beta) = 0.41$** N = 10 $SD(\beta) = 0.16$	**$E(\beta) = 0.52$** N = 23 $SD(\beta) = 0.20$	**$E(\beta) = 0.49$** N = 34 $SD(\beta) = 0.19$	Cannot reject H_0
Test H_0: $E(\beta_T)=E(\beta_D)$	Cannot reject H_0	Reject H_0	Reject H_0	

Note: Assumes a 50% pure-play threshold. Asset betas reported. All hypotheses tested with $1 – \alpha = 95\%$. Also able to reject H_0: $E(\beta_{ET})=E(\beta_{GD})$ at the 5% significance level (ie, $1 – \alpha = 95\%$).
Source: Oxera analysis.

The key results from the above tests are as follows (all based on a 50% pure-play threshold):

– a risk differential of 0.2 (on an asset beta basis) exists between gas distribution and gas transmission (ie, the gas distribution asset beta is higher);
– a risk differential of 0.24 (on an asset beta basis) exists between gas distribution and electricity transmission networks (ie, the gas distribution asset beta is higher); and
– a risk differential of 0.2 (on an asset beta basis) exists between distribution (E+G) and transmission (E+G) networks (ie, the distribution asset beta is higher).[10]

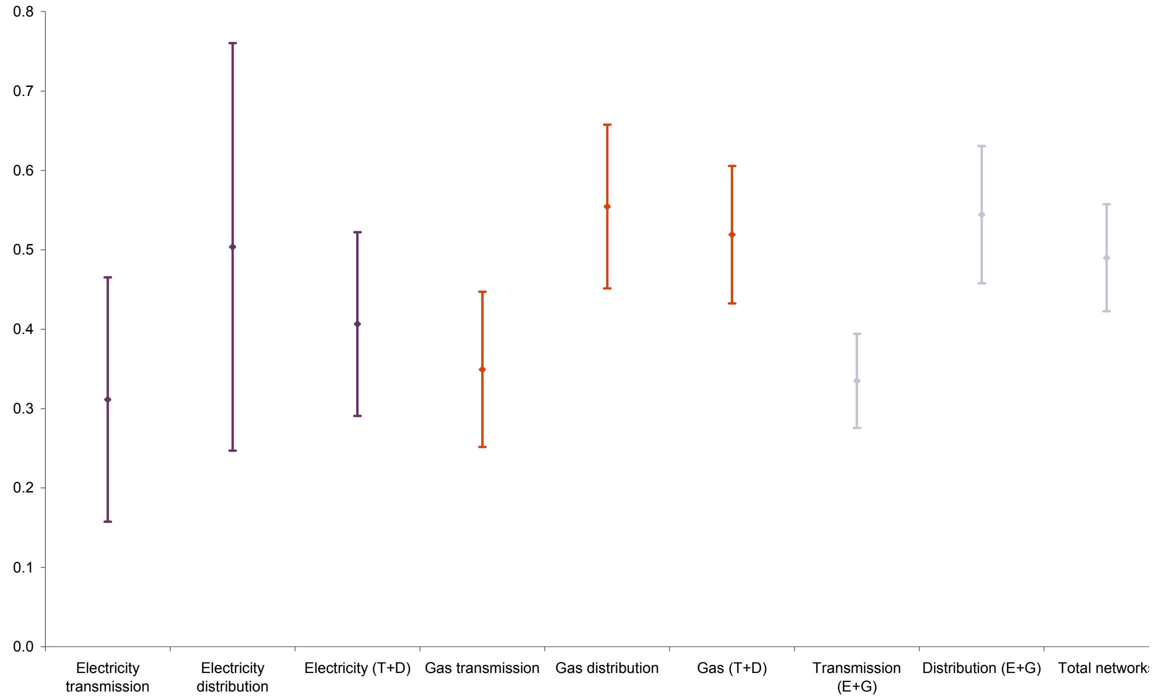
Figure 2.1 shows the 95% confidence intervals for each of the business segments analysed. Confidence intervals give a broader perspective on the level of certainty around the asset beta estimates of each business segment.

Key points to note from Figure 2.1 are that confidence intervals:

– for gas distribution asset betas are between 0.45 and 0.65;
– for gas transmission asset betas are between 0.25 and 0.45;
– for electricity transmission asset betas are between 0.16 and 0.46.

[10] This result was also confirmed when using a 70% threshold level. That is, a statistically significant (5% significance level) risk differential of 0.22 was also found to exist between energy distribution and energy transmission networks. See Oxera (2007), op. cit.

Figure 2.1 Confidence intervals (95%) for pure-play comparators' asset betas



Note: Assumes a 50% pure-play threshold.
Source: Oxera calculations.

2.2 'Mixed' comparator analysis

The key result from the analysis of mixed comparators is that there is likely to be a risk differential between gas distribution and gas transmission. Gas distribution asset betas (≈0.7) are found to be generally higher than gas transmission asset betas (≈0.4) when considering a range of econometric models. Importantly, this analysis provides some evidence that gas distribution and gas transmission asset betas are statistically different (when considering the 95% confidence interval), implying that gas distribution asset betas are around 0.15–0.28 higher than gas transmission asset betas. However, the results from this analysis are highly sensitive to the precise model specification, especially the inclusion of a constant term and ancillary activity weights.

The starting point for this analysis was the sample of energy companies described in section 4.1 (see also Appendix 1). Using the same dataset containing asset betas and business segment weightings for 50 EU and US energy firms, the mixed comparator analysis has attempted to estimate asset betas for transmission and distribution activities by examining how group betas vary between firms. Since these firms also differ in their relative weighting of activities in the electricity and gas sectors, this cross-sectional data arguably also provides information on the risks of individual business segments.

Several cross-sectional models were tested with the following form:

$$\text{Company asset beta} = \beta_1 \text{ (elec. gen.)} + \beta_2 \text{ (elec. trans.)} + \ldots + \beta_n \text{ (other)}$$

where the company asset beta is observed from market evidence (ie, the equity beta is de-levered using the Miller transformation); the sectors (eg, electricity generation, transmission, and distribution) represent individual business segment weightings; and betas (β) are estimated by ordinary least squares (OLS). Appendix 2 presents the results from the four model specifications used.

Table 2.3 shows the asset betas estimated across all four models for each business segment.

Table 2.3 Mixed comparator asset betas

	Electricity	Gas	E + G
Transmission	Model 1: 0.28* Model 2: 0.31	Model 1: 0.32* Model 2: 0.43**	Model 3: 0.38**
Distribution	Model 1: 0.56** Model 2: 0.96**	Model 1: 0.68** Model 2: 0.71**	Model 3: 0.77**
T + D	Model 4: 0.63**	Model 4: 0.63**	

Note: * indicates that the asset beta is different from zero with 95% confidence. ** indicates that the asset beta is different from zero with 99% confidence. Red text indicates that asset betas for transmission and distribution within a given sector are different from *each other* with at least 95% confidence.
Source: Oxera analysis.

The key points to note from Table 2.3 are as follows.

– Distribution asset betas are typically higher than transmission asset betas for all sectors, although the magnitude of this difference varies considerably (ie, from 0.28–0.65) depending on the specific model used and the sector.

– Nearly all the asset betas estimated were found to be statistically different from zero at either the 95% or 99% confidence levels (with the exception of the electricity transmission asset beta estimate found in Model 2).

– Distribution asset betas were found to be statistically different from transmission asset betas using either Model 1 or Model 2 (all at the 95% confidence level). Gas distribution had an asset beta that was 0.36 higher than gas transmission (and statistically significant at 95% confidence) using Model 1.

– Energy (ie, electricity and gas, 'E+G') distribution asset betas were found by Model 3 to be 0.39 higher than energy transmission asset betas (and statistically significant at the 95% confidence level).

– Model 4 found no evidence of a sector-specific risk differential between electricity and gas companies.

The above findings may support the presence of a risk differential between gas distribution and gas transmission of around 0.36. However, this finding is moderated by the observation that the result of the econometric modelling is highly sensitive to the precise model specification (see Appendix 2 for the results of alternative specifications of Model 2). In particular, if a constant term is inserted into the regression formula, the explanatory power of the model is much reduced (as measured by a lower R^2 value), and the estimated business segment betas are statistically indistinguishable from zero. That said, it is important to note that there is perhaps no theoretical reason why a constant term is required in the regression models used in the mixed comparator analysis. This is because it would not be expected that the asset betas of the companies in the sample should be constant after controlling for the β impacts of energy network businesses.[11]

The results presented in Table 2.3 are also sensitive to the inclusion of 'other' business segment weightings in the regression models.[12] Appendix 2 shows that if other business segment weights are included in Model 2, gas distribution has an asset beta 0.15 higher than for gas transmission. Importantly, when other business segment weights are included in Model 2, the pattern of results is generally the same as seen in Table 2.3—that is:

– distribution asset betas are typically higher than transmission asset betas for all sectors (the magnitude of this difference being 0.15–0.47); and
– all the asset betas estimated were found to be statistically different from zero at the 95% confidence level; but
– distribution asset betas were not found to be statistically different from transmission asset betas.

2.3 Explanatory factors of beta

The key result from the analysis of the financial and economic factors that are likely to predict the variation of asset betas is that gas DNs typically exhibit those features that are associated with greater systematic risk (on average) than UK transmission companies (eg, National Grid electricity and gas transmission companies). This finding is mainly driven by the fact that gas DNs have relatively high levels of CAPEX (measured as a multiple of free cash flow, FCF), and earnings before interest and tax (EBIT) are relatively low (measured as a percentage of gross sales). This evidence suggests that, on average, gas DNs may have asset betas that are up to 0.13 higher than National Grid's electricity and gas transmission assets (ie, NGET and NGGT, respectively). It is important to note that this methodology is not based on the same theoretical foundations as the CAPM, although it could be argued that this approach reflects more accurately the drivers of investors' risk preferences in practice.

This section discusses the use of an econometric model to derive estimates of asset betas based on selected financial characteristics that are likely to be proxy measures of business risk. The analysis should be considered in the context of the overall approach to the estimation of risk differentials between energy networks, since the absence of market data represents a challenge for the estimation of asset betas for the gas DNs. While this method is an indirect approach to beta estimation, and might not be regarded as the preferred method in an environment free from data limitations, in the context of unlisted companies it might be viewed as providing a useful reference point in conjunction with other methodologies.

The approach of linking betas with financial ratios is not new. Notably, Ismail, Kirk and Kim (1994), Kulkarni, Powers and Shannon (1991), and Mohr (1985) have all employed this methodology to improve beta estimates and to estimate betas of individual business segments.[13] These studies have used this methodology to explore the relationship of the

[11] For example, if the sample of companies contained firms that only invested in energy networks, the regression constant in Model 2 would be expected to be zero. However, for the sample of firms used for this analysis (see Appendix 1), the portfolio of businesses these firms are invested in (outside of energy networks) is variable, thereby making the regression constant inappropriate. That is, after controlling for the β impacts of energy networks, there is no 'constant' level of β that is common across sample firms.

[12] The use of 'other' business segment weights is consistent with the mixed comparator analysis used by Ofcom in the disaggregation of BT's beta. See PricewaterhouseCoopers LLP (2005), 'Disaggregating BT's Beta', prepared for Ofcom, June.

[13] Ismail, B., Kim, M. and Kirk, F. (1994), 'Accounting Data and the Prediction of Risk in the Extremes', *Review of Financial Economics*, **4**:1, 55–68; Kulkarni, M., Powers, M. and Shannon, D. (1991), 'The Use of Segment Earnings Betas in the

beta with a variety of factors, such as intensity of CAPEX, leverage profitability, and size. The underlying assumption is that a set of financial ratios might be a good proxy for the systematic risk component, for which investors need to be compensated.

This analysis determines the relationship between a set of financial variables and beta estimates for a large sample of comparators, and then uses the model to estimate the betas of individual firms for which these financial variables are known. The analysis examines a number of possible models linking beta estimates to specific corporate financial indicators by utilising different econometric techniques. The models explored are as follows:

– panel data models using fixed and random effects;
– pooled cross-sectional regression models;
– panel data models (with fixed and random effects), using lagged betas as dependent variables (three-quarter and eight-quarter cases were examined);
– pooled cross-sectional regression models using lagged betas as the dependent variable (three-quarter lag was used); and
– cross-sectional regression models using the time series averages for the explanatory variables.

The models selected for the analysis have the following specifications:

– Model 1: pooled cross-sectional regression;
– Model 2: cross-sectional regression with time-series average of explanatory variables;
– Model 3: pooled cross-sectional regression, beta with two-year lag; and
– Model 4: pooled cross-sectional regression, beta with three-year lag.

The sample used for model estimation is composed of 1,825 observations spanning 73 companies over the period Q1 2000 to Q1 2006 (25 instances across time, 73 cross-sectional observations). The following sectors are represented in the sample: utilities, telecoms, industrials, retail, and real estate. These sectors are often selected as comparators for infrastructure assets due to the underlying mix of business activities.

Table 2.4 Sample size by sector

	Industrial	Real estate	Retail	Telecoms	Utilities
Number of companies	13	19	20	9	12

Source: Datastream.

The actual data used for dependent and independent variables is detailed in the following table. All data used in the analysis, with the exception of the sector dummy variables, is both time- and company-variant.

Formation of Divisional Hurdle Rates', *Journal of Business Finance & Accounting*, June, and Mohr, R. (1985), 'The Operating Beta of a U.S. Multi-Activity Firm: An Empirical Investigation', *Journal of Business Finance and Accounting*, **12**:4, 575–94.

Table 2.5 Data types used

Measure	Comments
Asset beta	Market estimates
Market value	Proxy for size
EBIT/total sales	Gross margin
Operating profit/total sales	Operating margin
CAPEX/free CFO	CAPEX funding
CAPEX as a percentage of fixed assets	Fixed assets formation
CAPEX as a percentage of total assets	Growth

Source: Oxera calculations and Datastream.

In addition to the above, the analysis made use of sector dummies to capture any sector-specific effects.

The choice of different financial measures to be included in the model as independent variables was based on the examination of potential relationships between financial indicators and general business risk characteristics corresponding to the systematic risk component of required returns (in line with finance theory, corporate finance practice and commonly accepted principles of financial analysis). The selection used in the models was also based on a review of the results from academic research employing similar techniques—only measures that proved significant in other studies were explored, in line with the implicit approach of moving from general to specific.

The data for 'operating profit/sales' and 'EBIT/sales' posed some additional challenges. For these two explanatory variables, the data is available on an annual rather than quarterly basis (ie, the same figure is used for all quarters within a year for each individual company). This also constitutes the basis for the time-series data used throughout the analysis. This issue does not preclude the use of any advanced econometric techniques, although, in principle, it could increase the standard errors of estimated parameters, leading to larger confidence intervals.

The results of different models' estimations are reported in Appendix 3. The models estimated were subsequently used to derive beta estimates for individual energy network companies using corresponding financial characteristics of these firms based on data from regulatory accounts.

As shown in Appendix 3, all four models provide reasonable goodness of fit (R^2 ranging from 0.52 to 0.69) and display a number of intuitive properties. In short:

– the CAPEX-to-fixed-assets percentage coefficient is positive in all models and significant in three of them;
– market value coefficients all bear a negative sign (although they are statistically insignificant);
– the sector dummy variables (not reported in Appendix 3) are significant in three of the four models and also suggest an intuitive risk premium for each sector examined.

The analysis did not make use of the results of more advanced panel data techniques for two main reasons. Due to the method used by Datastream to estimate betas (using a 60-month rolling-forward period with overlapping observations across the time series), the appropriate panel data estimation technique would be fixed effects. This way, the fixed group-specific effect created due to the use of the Datastream-estimated betas could be controlled for. However, the fixed effects estimation cannot make use of the sector-specific dummy variables, which are expected to be significant from a theoretical and a statistical perspective, as these are time-invariant. The sector dummies could only be included in a 'random effects' specification, which would be inappropriate due to the beta estimation method used, as mentioned above. Therefore, the use of panel data techniques was discarded in favour of the simpler pooled OLS regression.

Once the sensitivities of asset beta to individual financial parameters were determined, accounting information was collected from transmission and gas distribution licensees in order to calculate the 'predicted' asset betas from the econometric modelling.[14] The lowest, highest, and midpoint asset beta estimates are reported in Table 2.6.

Table 2.6 Implied asset beta differentials between gas distribution and transmission (electricity and gas)

Company (sector)	Average risk differential between gas distribution and gas transmission	Average risk differential between gas distribution and electricity transmission
National Grid Gas Distribution	0.04	–0.01
Northern gas networks	0.09	0.04
Wales and West Utilities	0.13	0.07
Scotia gas Networks	0.13	0.07

Notes: Figures show differentials in firms' asset betas (ie, averages of the highest and lowest risk differentials across all models tested). A positive risk differential indicates that gas distribution has a higher risk than either gas or electricity transmission.
Source: Oxera analysis.

Table 2.6 shows that individual gas DNs have predicted asset betas that are up to 0.13 higher than energy transmission companies.

2.4 Summary

This section has used three quantitative methods to develop estimates of the risk differentials between energy networks (as measured by the asset beta). Importantly, this analysis has employed direct capital market evidence to estimate the magnitude of systematic risk differentials. The evidence on systematic risk derived from these quantitative methods suggests that gas distribution is more risky than transmission, and that this result is statistically significant for some models. Greater weight should be placed on the estimates of asset betas from the 'pure-play' and 'mixed' comparator analysis since these methods are relatively less sensitive to concerns over data and model interpretation. Consequently, the market evidence suggests that gas DNs' asset betas should be around 0.2 higher than for transmission (including electricity and gas).

[14] The following figures were taken directly from the regulatory accounts of the relevant licensees: CAPEX, gross fixed assets (property, plant, and equipment), EBIT, and turnover. Free cash flow was calculated as EBITDA less changes in working capital (taken here to be the change in net current assets) less CAPEX, since this is broadly consistent with the Datastream definition used in the construction of the dataset. Market value was approximated by the notional equity share of the opening RAB (ie, assuming 60% gearing).

3 Regulatory precedents

This section summarises the main findings from the review of relevant precedents on risk differentials between energy networks, including Ofgem's review of NGC (2001), DPCR4 (2004), the Scottish TO extension (2004), the NGET extension (2005), and TPCR (2006). In addition, this section considers the relevant statements by the NIAER on NIE's transmission and distribution price controls in 2005. Specifically, it focuses on reviewing policy statements on the CAPM beta—that is, the parameter that would be expected to reflect differences in systematic risk. Table 3.1 summarises the regulatory precedents on risk differentials for the above reviews.

Table 3.1 Regulatory precedents on risk differentials

Regulator, sector	Company (year)	Equity beta	Gearing (%)
Ofgem, electricity transmission	NGC (2001)	1	60
Ofgem, electricity distribution	DPCR4 (2004)	1[1]	57.5
Ofgem, electricity transmission	Scottish TOs (2004)	1	57.5
Ofgem, electricity transmission	NGET (2005)	1	60
NIAER, electricity transmission	NIE (2005)	0.3–0.6	50–60
NIAER, electricity distribution	NIE (2005)	1[2]	60[2]
Ofgem, electricity and gas transmission	TPCR (2006)	1[1]	60

Notes: [1] Implied by the use of an overall cost of equity assumption. [2] Based on Ofgem (DPCR4).
Sources: Ofgem, NIAER, and Oxera analysis.

3.1 NGC (2001)

In its draft proposals Ofgem considered the issue of risk differentials between NGC and the Scottish integrated public electricity suppliers (PESs) since these firms' regulatory controls encompassed transmission, distribution, and supply activities. Several factors were considered by Ofgem to be possible drivers of the relative predictability of returns, including the scale (size) and scope of business activities, the form of the regulatory regime, cost volatility, and other business and operational factors.

In relation to scale and scope, these factors were considered to make NGC more capable of bearing unanticipated financial shocks and to realise financial synergies (eg, lower equity and debt issuance costs due to more liquid trading of its securities).

NGC's revenue cap and proportionately higher fixed costs were also considered by Ofgem to mitigate the risk when compared with the higher-volume exposure and cost structures of the PESs. Similarly, the relative uncertainty in NGC's CAPEX was thought by Ofgem to be substantially alleviated by the presence of an error correction mechanism that was not included in the PES controls.

Overall, Ofgem therefore considered that NGC's returns were more predictable than was the case for the PESs, although it did recognise that it was a matter of judgement as to the degree to which this qualitative evidence should be considered in the WACC determination. Ofgem stated that it would attach some weight to the above arguments in setting NGC's WACC, although it remains unclear how much.

3.2 DPCR4 (2004) and Scottish TOs price control extension (2004)

At DPCR4, Ofgem maintained that the most appropriate estimate of the cost of equity was 7.5%, based on overall market returns. The key point to note about the cost of equity determination is that a market average beta of 1 was implicitly assumed to hold. No point estimates for the key parameters (ie, RFR, ERP, equity beta) were given.

Subsequently, the Scottish transmission companies were the first to receive an extension to their existing price controls.[15] The key point to note from this determination for SPT and SHETL was that Ofgem adopted a consistent WACC determination between the DNOs (DPCR4) and Scottish TOs, at least as measured on a pre-tax basis.

Crucially, Ofgem stated that:

> In terms of the underlying factors affecting the cost of capital, an analysis carried out as part of the price control reviews in 1999 found no conclusive evidence that the Scottish transmission companies were, in financial terms, significantly different from the electricity distribution companies. Given the similarity in transmission and distribution activities, Ofgem does not consider that different cost of capital considerations should apply to the Scottish transmission companies compared to the electricity distribution companies.[16]

Interestingly, in its review of the Scottish PESs, Ofgem considered that there could have been some justification for different cost of equity determinations for the regional transmission and distribution companies. For example, in its June 1999 consultation paper, the regulator had stated that:

> A number of factors suggest that the beta value for transmission may be lower than for distribution. Both revenues and costs are more fixed in nature and revenues come from a range of sources, suggesting relatively lower non-diversifiable risks for transmission.[17]

This was corroborated by Ofgem's finding that asset betas for distribution companies at the time were in the range 0.45–0.55, whereas the regional (ie, Scottish) transmission companies had asset betas in the range 0.4–0.5.[18]

The above statement by Ofgem is somewhat ambiguous. While it is the case that relatively constant, stable, or 'fixed' costs and revenues imply lower systematic risk when measured against the market average, this does not come about from having a wider customer base, because this *is* a diversifiable risk. That is, this risk is not necessarily systematic from the point of view of investors.

Therefore, given a consistent gearing assumption of 50% for distribution and regional transmission companies, the lack of 'conclusive' evidence of any difference in the level of systematic risk, and the lack of any consensus in its consultation responses, Ofgem adopted an equity beta assumption of 1 for all PESs in December 1999.[19] This would suggest that it placed relatively little weight on observed beta estimates compared with a qualitative analysis of the activities of distribution and regional transmission companies. Alternatively, it

[15] Ofgem (2004), 'Transmission Price Controls and BETTA: Final Proposals and Impact Assessment', December.

[16] Ibid., p. 23.

[17] Ofgem (1999), 'Reviews of Public Electricity Suppliers 1998 to 2000: Scottish Transmission Price Control Review—Consultation Paper', June, p. 36.

[18] Ibid., p.36.

[19] Ofgem (1999), 'Review of Public Electricity Suppliers 1998 to 2000: Scottish Transmission Price Control Review—Final Proposals', December, p. 14.

is possible that the asset beta estimates for distribution and regional transmission companies were sufficiently close to have had overlapping confidence intervals.

The implication of the above policy for the GDPCR would be that, in the absence of information on differential risks between transmission and distribution firms, a similar WACC should apply.

3.3 NGET price control extension (2005)

After the Scottish TO price control extension was published in December 2004, NGET's price control extension was completed in November 2005.[20] The key point to note from this determination was that it was consistent with NGC's last price control review, as it retained a (real) pre-tax WACC of 6.25%.

Limited market evidence was presented in the initial proposals,[21] and Ofgem noted that it would conduct a full cost of capital analysis during the 2006 TPCR.

3.4 NIE's transmission and distribution price control (2005)

NIAER's proposals on the WACC for NIE's transmission and distribution business were published on December 14th 2005.[22]

A key factor influencing the current proposals was Ofgem's determination for DPCR4. Interestingly, the NIAER stated that it 'does not believe that the cost of capital for NIE is necessarily the same as that estimated by Ofgem for the DNOs'.[23] That said, the NIAER admitted that it has taken a 'pragmatic' position on NIE's WACC, which effectively agreed that Ofgem's estimate was appropriate.

The key difference between the Ofgem and NIAER positions of relevance to this report relates to the equity beta, which, as the NIAER suggested, is lower for NIE than for DNOs due to the lower LBS estimates. The NIAER noted that NIE's non-networks businesses (ie, generation and supply) are likely to have greater systematic risk, thereby implying that the observed betas are overestimating the level of the transmission and distribution beta.

This presumed bias, combined with the uncertainty over the 'instability' of betas described by Ofgem in DPCR4, led the NIAER to adopt a WACC assumption equivalent to that of the DNOs (ie, 4.8%, measured on a post-tax basis) for NIE's distribution RAB. However, the NIAER applied a lower WACC (ie, 4.49%, measured on a post-tax basis) to NIE's transmission RAB, based on an equity beta of 0.3–0.6. Derived from the relative sizes of the transmission and distribution RABs, the 'blended' WACC was 4.78%, measured on a post-tax basis.

The NIAER stated that avoiding a reference to the Competition Commission was a key factor in adopting this 'blended' WACC approach. However, no discussion was provided as to why the lower WACC was explicitly applied to NIE's transmission RAB.

[20] Ofgem (2005), 'Extending NGET's Transmission Owner Price Control for 2006/07: Final Proposals', November.

[21] Ofgem (2005), 'Extending NGET's Transmission Owner Price Control for 2006/07: Initial Proposals', September.

[22] NIAER (2005), 'Northern Ireland Electricity: Transmission and Distribution Price Control 2007–2012', December 14th.

[23] Ibid., p. 11.

3.5 TPCR (2006)

For TPCR Ofgem did not present any market evidence or other quantitative analysis specifically addressing risk differentials between energy networks. Instead, it made a general statement on its intention to maintain a consistent treatment of common parameters such as the risk-free rate and ERP across the different network price controls.[24] In addition, Ofgem referred to the Smithers & Co. (2006) report by stating that there was no evidence of differences in the risks faced by Scottish TOs, something for which one or both of SPW and SSE argued.[25] Arguably, the wide confidence limits for the betas of the Scottish TOs and National Grid reported by Smithers & Co. (2006) showed that not only were there no differences in the risk between companies, but that Ofgem could not even be sure that any betas were different from the market average (ie, a beta of 1). For example, Ofgem stated in its TPCR Final Proposals that:

> We have carried out an initial assessment of the relative levels of risk faced by investors in our regulated transmission and distribution network companies, and have received views from respondents on this issue. While there is some evidence to suggest that transmission is a lower risk activity than distribution, a view that is also supported by credit rating agencies, we do not believe this analysis is sufficiently robust to quantify this difference accurately. As such, we propose to undertake an exercise to assess differential risk between transmission and distribution next year.
>
> In Initial Proposals, we set out our view that the same cost of capital should be applied to each of the transmission companies (previously the Scottish TOs were given a premium to National Grid), given the absence of evidence to show that the Scottish TOs face a higher degree of risk. Although the Scottish TOs have argued that they face a higher risk, we do not consider that there is sufficient justification for different treatment.[26]

The 'initial assessment of the relative levels of risk faced by investors' in regulated energy networks referred to in the above quotation has not, to Oxera's knowledge, been published. No further discussion of risk differentials materialised throughout TPCR.

3.6 Summary

The analysis of the most recent and relevant regulatory precedents on risk differentials between energy networks suggests that this issue is relatively under-explored, at least in terms of its quantification. Where there has been qualitative analysis of this issue, or where there have been differences in Ofgem's determination, these have suggested that distribution firms carry more systematic risk than transmission firms.

[24] Ofgem (2005), 'Transmission Price Control Review: Initial Consultation', July; and Ofgem (2005), 'Transmission Price Control Review: Second Consultation', December.

[25] Wright, S., Mason, R., Satchell, S., Hiro, K. and Baskaya, M. (2006), 'Report on the Cost of Capital Provided to Ofgem', September 1st.

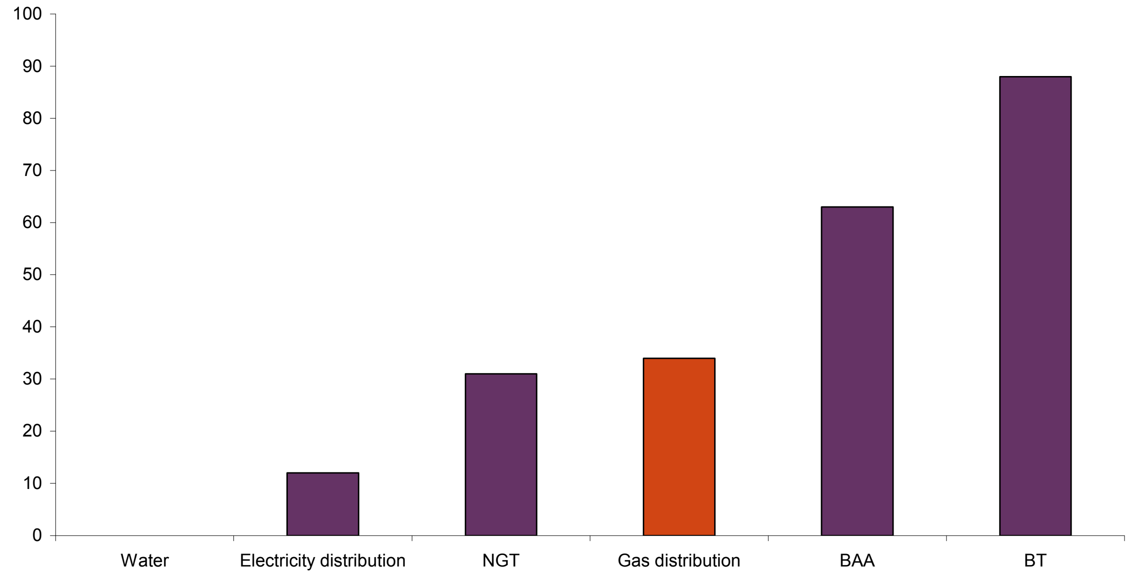
[26] Ofgem (2006), 'Transmission Price Control Review: Final Proposals', December 4th, p. 53.

4 Qualitative assessment of risk characteristics

The CAPM predicts a linear relationship between the systematic risk and the expected return of an asset. Within the CAPM framework, any differential in the allowed rates of return for energy networks would need to be justified by evidence of a corresponding differential in systematic risk.

One piece of evidence that could suggest that investors consider UK gas DNs to be materially more risky than many other UK regulated utilities—and hence might imply that more weight should be attached to the risk differentials estimated in section 2—are the results of the Water UK investor survey.[27] In this survey, investors were asked whether they considered investing in various other companies/sectors as more or less risky than investing in the UK water sector. Figure 4.1 presents the difference between the percentage of investors who considered that the alternative was more risky than the water sector and the percentage who thought it less risky. In other words, the higher the column, the greater the number of investors who perceived the alternative to be riskier than the England and Wales water sector.

Figure 4.1 Perceived riskiness of utility investments compared with the England and Wales water sector (%)



Source: Water UK investor survey and Oxera calculations.

A striking finding from this survey is that, compared with the water sector, more investors considered the gas distribution sector to be riskier than either the electricity distribution sector or NGT.[28] Assuming that investors would be expected to be aware of both systematic and idiosyncratic risks, this evidence suggests that at least some of the risk differential identified by investors is systematic.

[27] Whelan, A. (2005), 'Water UK Investor Survey 2005 Key Findings', March.

[28] It is also of note that investors appear to perceive both NGT and electricity distribution as riskier than water.

In light of this, the following section attempts to determine whether this investor sentiment is supported by qualitative analysis of underlying risk drivers in the gas distribution sector. While it is not possible to examine exhaustively all the factors that might affect risk differentials, and hence the appropriate cost of equity in a given sector, some key factors can be identified. The factors considered in this report are:

– operational gearing;
– investment 'intensity' and the nature of the CAPEX programme; and
– long-term volatility in demand.

4.1 Operational gearing

The impact of relatively higher CAPEX and REPEX is likely to be a significant driver of the total risk (including systematic risk) faced by a regulated firm. This is in part due to the fact that greater fixed costs caused by a larger, inflexible capital programme could increase 'operational gearing', which has the effect of making returns more volatile in a similar way to financial gearing, although this may depend on the regulatory regime. Also, any proportionate change in capital investment due to unexpected changes in workload requirements or unit costs would make individual firms' returns more volatile.

CAPEX is not a purely discretionary investment for regulated energy networks, and neither is it as capable of being deferred, at least not to the same degree as for other (unregulated) firms. It is also possible that network investment is less discretionary for gas distribution compared with transmission companies because of licence obligations concerning the quality of service, and the extent of safety-related infrastructure expenditure. In addition, the potential ability of transmission firms to trade off system operation costs against infrastructure capacity may mean that they have an inherently more flexible capital programme over the course of any given quinquennium. To the extent that transmission firms are more able to 'flex' investment expenditure (eg, reducing non-load-related expenditure or deferring load-related expenditure) in response to external shocks that result in greater workload requirements, they would be expected to have lower systematic risk than gas distribution companies.

The above highlights another important systematic risk associated with network investment—namely the potential for unit costs to be positively related to macroeconomic growth. For example, contractor prices would be expected to be positively related to the business cycle, since increased economic activity is likely to be associated with lower (contractor) capacity margins. Equally, prolonged macroeconomic expansions could also result in higher commodity costs, directly affecting input costs.[29] As above, to the extent that gas distribution investment programmes are less 'flexible', the impact of this systematic risk factor would be expected to be more significant.

In summary, the above risk factors highlight the possibility that higher asset betas for gas distribution found in section 2 could be explained by differences in operational gearing between energy networks.

[29] Contractors' prices may be positively related to macroeconomic growth even though direct input costs may not be. This is because 'tighter' capacity margins in the contractor market could enable these firms to increase margins (assuming supply constraints are not alleviated by capacity expansions). That said, the extent to which energy network operators rely on external contractors is ultimately a controllable cost, through the development of 'in-house' engineering and construction capacity.

4.2 Investment 'intensity'

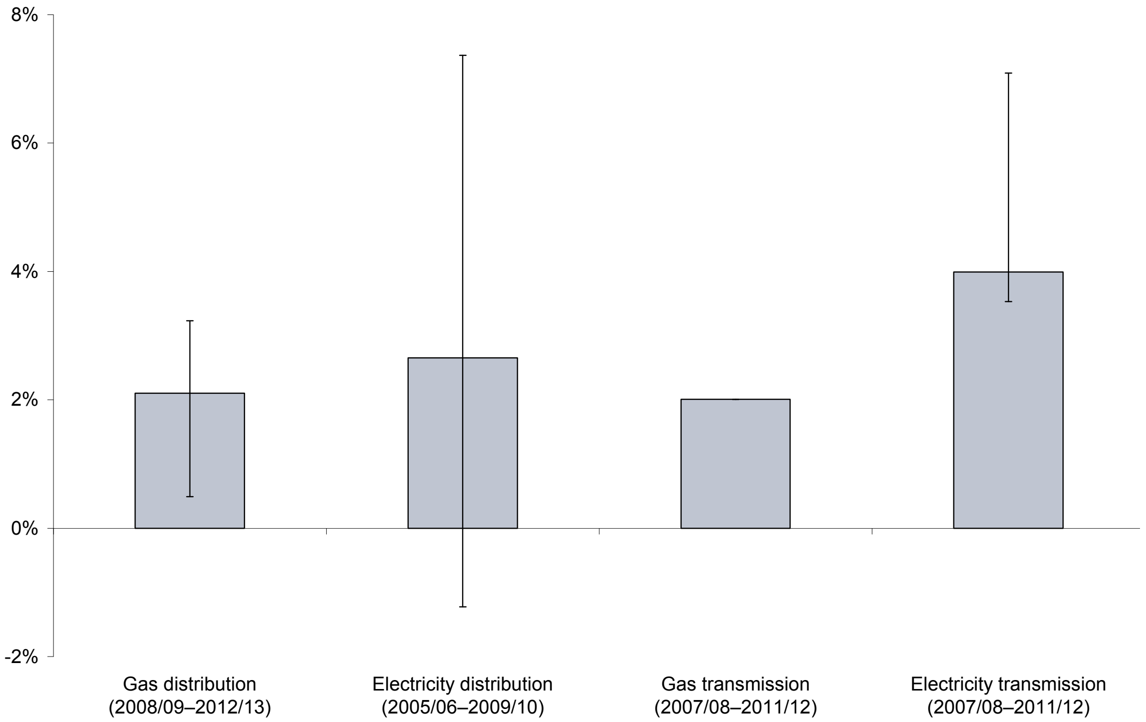
A widely discussed potential driver of the cost of capital that can be relatively easily compared across energy networks is the magnitude of future investment requirements. As Ofgem recognised in DPCR4, investment intensity would also be expected to have a bearing on the appropriate allowed rate of return for a sector, since this may need to be higher to provide a sufficient marginal incentive on companies to undertake the investment. Although investment intensity may not, strictly speaking, explain the observed differences in asset betas shown in section 2, this could nonetheless have an impact on investors' risk perceptions.

Figures 4.2 and 4.3 present the results of an analysis of the capital intensity of the GB transmission and distribution companies. The average 'gross' capital intensity of the gas distribution sector is broadly comparable with the gas transmission sector, although for some individual gas DNs this may be lower than for other energy networks.

While the ratio of gross CAPEX to RAB provides an indication of the relative size of all new CAPEX, it might be argued that a more appropriate proxy measure of the relative size of a regulated firm's investment programme is the ratio of 'net' CAPEX to the RAB. This is because by taking CAPEX net of depreciation allowances, the relative size of any additional financing requirements may be measured.

Figure 4.2 presents a graphical illustration of the net CAPEX to RAB ratio for GB energy transmission and distribution companies.

Figure 4.2 Net CAPEX to opening RAB (annual averages)

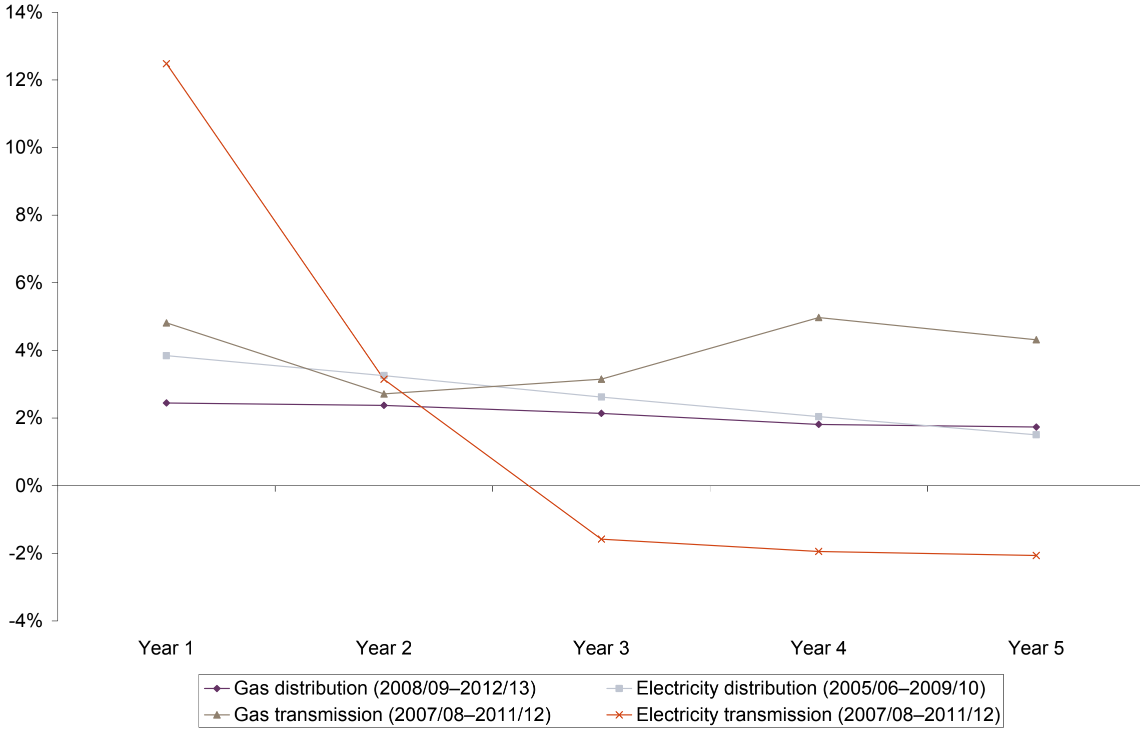


Note: Gas distribution CAPEX includes 50% of REPEX. Sector average capital intensity is indicated by the solid bar, with the overlying lines showing the range of capital intensity for individual licensees.
Sources: Ofgem and Oxera analysis.

Figure 4.2 shows that gas distribution sector is of comparable 'investment intensity' to the electricity distribution or gas transmission sectors, although the gas distribution sector is markedly less investment-intensive than electricity transmission. Figure 4.2 would suggest that the gas DNs, on average, would have broadly similar capital funding requirements to the electricity distribution and gas transmission sectors. That said, Figure 4.2 shows that individual electricity DNOs vary widely in terms of their net new funding requirements, with some DNOs potentially having a negative net CAPEX to RAB ratio.

Moreover, on a forward-looking basis, the gas DNs would be expected to have a higher net CAPEX to RAB ratio than even electricity transmission after 2008/09, as seen in Figure 4.3.[30] Accordingly, it could be argued that the ‘investment focus of the gas distribution sector is higher than for electricity transmission, and broadly similar to other energy networks from 2008/09.

Figure 4.3 Trend of net CAPEX to RAB



Note: Gas distribution CAPEX includes 50% of REPEX.
Sources: Various regulatory reports and Oxera calculations.

In summary, gas DNs appear to have similarly sized CAPEX programmes to other energy networks, although the above evidence may be understating the actual CAPEX risk since this evidence excludes 50% of REPEX. In addition, this analysis is based on Ofgem’s figures presented in the initial proposals, which may be materially lower than the gas DNs’ own views on the appropriate level of investment. Overall, this suggests that there could be some qualitative arguments to support a higher degree of risk for the gas DNs than for other energy networks, although this is not conclusive.

4.3 Demand volatility

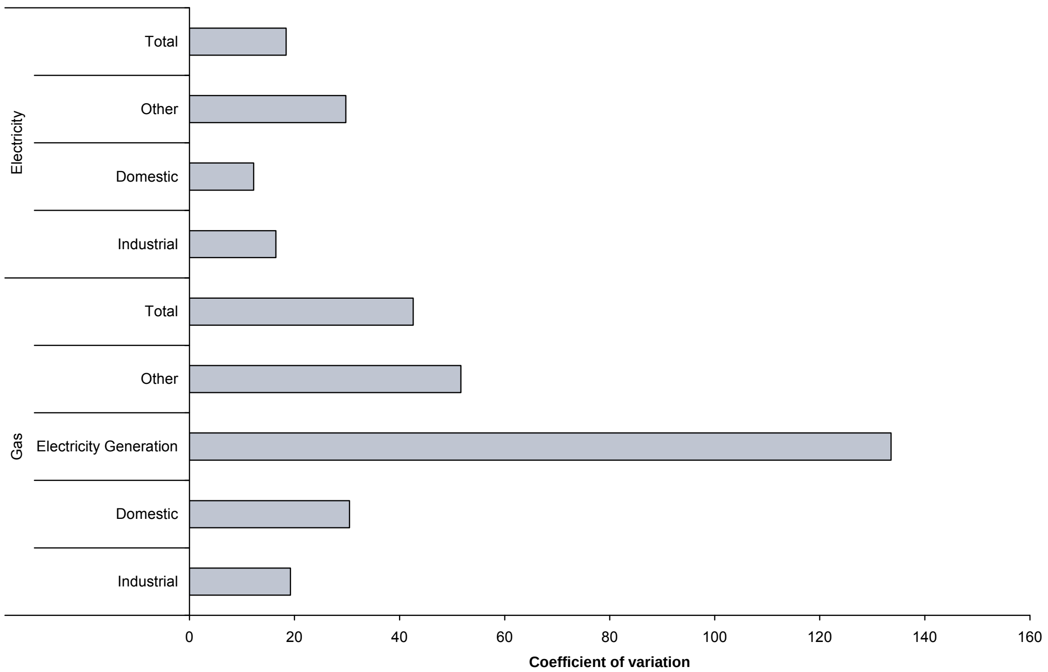
Demand volatility, particularly over the long term, is another factor that is likely to have a direct impact on investors’ perceptions of risk. Whereas the regulatory regime (especially the

[30] Figure 4.3 shows how the net CAPEX to RAB ratio is expected to evolve. Notably, it shows that in 2008/09 the net CAPEX to RAB ratios of all GB energy networks are broadly similar at around 2–3%. Note that 2008/09 corresponds to ‘Year 1’ for gas distribution, ‘Year 2’ for both gas and electricity transmission, and ‘Year 4’ for electricity distribution.

adoption of revenue caps) may impact on the extent to which demand volatility within a control period affects investors' returns (eg, seasonal demand volatility), over the course of several control periods it is unclear whether the regulator can commit to counteract fully the effects of secular trends in energy consumption. This is because revenue caps counteract the changes in volume partly by enforcing inverse unit price changes, something that might not be sustainable over the regulatory asset lives of energy network.

Figure 4.4 shows the volatility of gas and electricity consumption, broken down by domestic, industrial, and other sectors for the period 1970–2005.[31] The data shows that only the volatility of industrial gas and electricity consumption are close in value, while the volatility of gas consumption is around double that of electricity consumption in all other areas. In terms of total gas and electricity consumption, gas is around twice as variable than electricity over the sample period.

Figure 4.4 Volatility of UK energy consumption, by fuel and sector (TWh, 1970–2005)



Sources: Department of Business, Enterprise and Regulatory Reform (formerly the DTI) and Oxera analysis.

4.4 Summary

This section has qualitatively assessed a range of risk factors that would be likely to affect the systematic risk of gas DNs compared with that of other energy networks. For example, it is possible that the relatively higher asset betas for gas distribution seen in section 2 could reflect an inherently less flexible cost structure. Ofgem has in the past recognised that greater operational gearing could result in greater risk, although this depends on the nature of the regulatory regime. In addition, greater volatility in gas consumption relative to electricity could also help to explain the presence of greater systematic risk for gas distribution.

[31] Volatility in this context has been measured using the coefficient of variation, which is the mean adjusted standard deviation of an annual time series of levels of consumption in each sector.

By their nature, qualitative risk analyses cannot (dis)prove the presence of systematic risk differentials or provide a definitive guide to their magnitude. However, it is clear that there could be some explanations to support the quantitative analysis presented previously.

5 Conclusion

This report has considered three major strands of evidence, including quantitative evidence of systematic risk differentials, regulatory precedent, and qualitative analysis.

- The quantitative evidence suggests that gas DNs may face greater systematic risk. For example, the analysis of 'pure-play' and 'mixed' comparators suggest that gas DNs may have asset betas that are around 0.2 higher than for transmission (electricity and gas). This would imply that equity betas for gas DNs should be around 0.5 higher than for transmission, assuming a notional gearing level of 60%.

  Given the fact that these methodologies have given statistically significant results that are broadly consistent both in terms of their directional impact and the magnitudes of any risk differential, greater emphasis has been placed on these findings. Notably, these findings are also consistent with the analysis of the explanatory factors of asset betas, although the magnitude of the risk differential reached using this methodology was somewhat lower (ie, up to 0.13).

- The analysis of the most recent and relevant regulatory precedents on risk differentials between energy networks suggests that this issue has perhaps not been explored fully. Ofgem has thus far not adopted a risk differential between transmission and distribution companies, or among the different transmission firms. This appears to be largely due to the lack of robust methods for quantifying the risk differentials, rather than a refutation that these differences exist.

- The analysis has also considered a range of risk factors that would be likely to affect the systematic risk of gas DNs relative to other energy networks. The qualitative analysis of risk differentials provides some arguments to support the evidence of higher asset betas for gas DNs compared with other energy networks. By their nature, qualitative risk analyses cannot (dis)prove the presence of systematic risk differentials or provide a definitive guide to their magnitude. However, it is clear that there could be some explanations to support the quantitative analysis presented previously.

Appendix 1 Sample of firms used in the 'pure-play' and 'mixed' comparator analyses

- AGL Resources Inc.
- Allegheny Energy, Inc.
- American Electric Power Company, Inc.
- Atmos Energy Corporation
- Black Hills Corporation
- Cascade Natural Gas Corporation
- Dynegy Inc.
- EDP
- Emera Inc.
- Enagas
- Enel
- Energen Corporation
- Energy West, Inc.
- EnergySouth, Inc.
- Equitable Resources, Inc.
- FirstEnergy Corp.
- Fortum
- Gas Natural
- Gaz de France
- Iberdrola SA
- IDACORP, Inc.
- ITC Holdings Corp.
- Kinder Morgan, Inc.
- National Fuel Gas Company
- New Jersey Resources Corporation
- Nicor Inc.
- Northeast Utilities
- Northwest Natural Gas Company
- NSTAR
- OGE Energy Corp.
- Piedmont Natural Gas Company, Inc.
- Progress Energy, Inc.
- Red Electrica
- SEMCO Energy, Inc.
- Sempra Energy
- Snam Rete Gas
- South Jersey Industries, Inc.
- Southern Company
- Southern Union Company
- Southwest Gas Corporation
- Terna
- The Empire District Electric Company
- The Laclede Group, Inc.
- TransCanada Corporation Ltd
- TXU Corp.
- UIL Holdings Corporation
- Union Fenosa
- UniSource Energy Corporation
- United Utilities
- WGL Holdings, Inc.

Appendix 2 'Mixed' comparators modelling results

Model 1

Company asset beta = β_1 (elec. gen.) + β_2 (elec. trans.) + β_3 (elec. dist.) + β_4 (gas. prod.) + β_5 (gas. trans.) + β_6 (gas. dist.)

Sector (business segment weighting)	Asset beta	95% confidence interval
Electricity generation	0.58	0.32, 0.83
Electricity transmission	0.28	0.19, 0.54
Electricity distribution	0.56	0.25, 0.88
Gas production	1.08	0.32, 1.84
Gas transmission	0.32	0.05, 0.59
Gas distribution	0.68	0.53, 0.83

Notes: Observations = 50, R^2 = 0.84.
Source: Oxera calculations.

Model 2

Company asset beta = β_1 (elec. trans.) + β_2 (elec. dist.) + β_3 (gas. trans.) + β_4 (gas. dist.)

Sector (business segment weighting)	Asset beta	95% confidence interval
Electricity transmission	0.31	–0.02, 0.63
Electricity distribution	0.96	0.63, 1.29
Gas transmission	0.43	0.11, 0.76
Gas distribution	0.71	0.52, 0.90

Notes: Observations = 50, R^2 = 0.73.
Source: Oxera calculations.

Model 2 (with constant)

Company asset beta = constant + β_1 (elec. trans.) + β_2 (elec. dist.) + β_3 (gas. trans.) + β_4 (gas. dist.)

Sector (business segment weighting)	Asset beta	95% confidence interval
Constant	0.59	0.44, 0.74
Electricity transmission	–0.3	–0.56, –0.04
Electricity distribution	–0.17	–0.53, 0.18
Gas transmission	–0.25	–0.53, 0.02
Gas distribution	–0.03	–0.25, 0.20

Notes: Observations = 50, R^2 = 0.16
Source: Oxera calculations.

Model 2 (with other business segments)

Company asset beta = β_1 (elec. trans.) + β_2 (elec. dist.) + β_3 (gas. trans.) + β_4 (gas. dist.) + β_5 (other)

Sector (business segment weighting)	Asset beta	95% confidence interval
Electricity transmission	0.33	0.06, 0.61
Electricity distribution	0.80	0.52, 1.09
Gas transmission	0.39	0.12, 0.66
Gas distribution	0.54	0.36, 0.71
Other	0.81	0.45, 1.17

Notes: Observations = 50, R^2 = 0.82.
Source: Oxera calculations.

Model 3

Company asset beta = β_1 (elec. and gas trans.) + β_2 (elec. and gas dist.)

Sector (business segment weighting)	Asset beta	95% confidence interval
Electricity and gas transmission	0.38	0.16, 0.61
Electricity and gas distribution	0.77	0.61, 0.93

Notes: Observations = 50, R^2 = 0.72.
Source: Oxera calculations.

Model 4

Company asset beta = β_1 (elec. trans. and dist.) + β_2 (gas trans. and dist.)

Sector (business segment weighting)	Asset beta	95% confidence interval
Electricity transmission and distribution	0.63	0.42, 0.84
Gas transmission and distribution	0.63	0.47, 0.79

Notes: Observations = 50, R^2 = 0.68.
Source: Oxera calculations.

Appendix 3 Econometric results for explanatory factors of asset betas

Model 1
Cross-sectional regression

Variable	Coefficient value	95% confidence interval
Constant	5.47E-01	2.70E-01, 8.30E-01
Market value	6.90E-06	–1.10E-05, 2.50E-05
CAPEX/FCF	n/a	n/a
CAPEX/fixed assets	1.12E-02	–5.30E-03, 2.80E-02
EBIT/sales	–5.62E-01	–1.04E+00, -8.50E-02

Notes: Observations = 29, R^2 = 0.69.
Source: Oxera calculations.

Model 2
Cross-sectional modelling with time-series average of explanatory variables

Variable	Coefficient value	95% confidence interval
Constant	1.73E-01	–1.54E-01, 5E-01
Market value	1.48E-05	2.29E-05, 5.24E-05
CAPEX/FCF	4.91E-04	–4.1E-03, 5E-03
CAPEX/fixed assets	4.31E-02	1.24E-02, 7.37E-02
EBIT/sales	–1.42E-01	–7.19E-01, 4.36E-01

Notes: Observations = 29, R^2 = 0.66.
Source: Oxera calculations.

Model 3
Pooled cross-sectional regression, beta with two-year lag

Variable	Coefficient value	95% confidence interval
Constant	2.33E-01	1.08E-01, 3.57E-01
Market value	5.03E-06	–1.23E-05, 2.24E-05
CAPEX/FCF	5.22E-04	–1.03E-03, 2.08E-03
CAPEX/fixed assets	9.01E-03	2.26E-03, 1.58E-02
EBIT/sales	–4.45E-02	–1.39E-01, 5E-02

Notes: Observations = 140, R^2 = 0.55.
Source: Oxera calculations.

Model 4
Pooled cross-sectional regression, beta with three-year lag.

Variable	Coefficient value	95% Confidence interval
Constant	2.69E-01	1.6E-01, 3.78E-01
Market value	–1.13E-06	–.55E-05, 1.33E-05
CAPEX/FCF	–1.63E-05	–.4E-03, 1.37E-03
CAPEX/fixed assets	8.26E-03	2.18E-03, 1.43E-02
EBIT/sales	–6.80E-02	–.64E-01, 2.75E-02

Notes: Observations = 186, R^2 = 0.52.
Source: Oxera calculations.

Park Central
40/41 Park End Street
Oxford OX1 1JD
United Kingdom

Tel: +44 (0) 1865 253 000
Fax: +44 (0) 1865 251 172

Stephanie Square Centre
Avenue Louise 65, Box 11
1050 Brussels
Belgium

Tel: +32 (0) 2 535 7878
Fax: +32 (0) 2 535 7770

www.oxera.com