BGÉ'S COST OF CAPITAL

A Final Report for the Commission for Energy Regulation

Prepared by NERA

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TABLE OF CONTENTS

1. INTRODUCTION

1.1. Methodology

In this report, we have applied best practice methodology to estimate Bord Gáis Éireann's (BGÉ's) cost of capital for its transmission and distribution activities. We have based our estimations on the company's weighted average cost of capital (WACC). The cost of equity was calculated using the CAPM given that, despite its limitations, it is the most widely used model for the calculation of the cost of equity in regulated industries both by regulator's and practitioners. We have attempted to achieve a robust estimation by:

- working with range estimates rather than specific point values where necessary;
- drawing data from alternative sources and a broad range of European comparators; and
- making use of alternative estimation procedures whenever possible.

1.2. Structure of Report

The remainder of the report is structured as follows:

- Section 2 summarises the main principles guiding our methodology for estimating the cost of capital for each of these companies;
- Section 3 discusses the principles for estimating the cost of equity;
- Section 4 presents our estimation of the cost of equity;
- Section 5 presents our estimation of the cost of debt and the appropriate gearing level;
- Section 6 discusses the issue of taxation;
- Section 7 summarises our findings and contains estimated values for the cost of capital;
- Appendix A presents background information on companies used as comparators for BGÉ.

2. PRINCIPLES FOR CALCULATING THE COST OF CAPITAL

In this Section, we review the principles underlying our cost of capital calculation and we highlight the main choices that need to be made in order to reach an agreement at the level of principles. We start by reviewing issues with the general methodology and then turn to methodological issues affecting specific components, i.e. estimating the cost of equity and the cost of debt and their aggregation using the gearing ratio.

2.1. General Methodology

The Weighted Average Cost of Capital (WACC) methodology, as defined below, is now widely accepted in European markets as a suitable method for calculating the cost of capital. The generic formula used for calculating a pre-tax WACC is as follows:

(2.1) Pre-tax $WACC = r_e * \frac{E}{E+D} * t_{adj} + r_d * \frac{D}{E+D}$

where:

E is a firm's equity;
D is a firm's debt;
r_e is the post tax return on equity;
r_d is the gross return on debt; and

t_{adj} is the tax adjustment factor used to convert the post-tax cost of equity to a pre-tax figure. As interest on debt is tax deductible, this is applied to r_e only. This is usually calculated as 1/(1-corporate tax rate);

The WACC formula reflects the fact that companies can raise capital through either debt or equity and that the returns required by the market for each of these two elements are likely to be different. The true cost of capital for a company is a weighted average of the two.

There are two expressions for the "post-tax" WACC of a firm as follows:

(2.2) Post-tax $WACC = r_e * \frac{E}{E+D} + r_d * (1-t) * \frac{D}{E+D}$

where:

t is the corporate tax rate.

Investors will demand a rate r_d on debt (on which they themselves will usually be taxed) but in most countries, interest on debt is accounted for as an expenditure and is tax deductible. The cost to the firm on its debt once corporate taxes are accounted for is then $r_d * (1\text{-}t)$.

An alternative definition of the post tax WACC, the "Post Tax Vanilla WACC", otherwise referred to as the post tax gross of debt tax shield WACC, is defined as:

(2.3) "Vanilla" Post Tax WACC = $r_e*(E/D+E)+r_d*(D/D+E)$

The Vanilla post tax is the return to capital after both corporate tax and any imputation credits have been accounted for elsewhere in a business's cash flows. The Vanilla WACC is the correct post tax WACC to use in setting a company's revenue requirement if tax costs are assessed as an operating cost after taking into account of the tax deductibility of interest payments.

In Section 6 we consider the issue of pre vs. post tax WACC in more detail.

2.1.1. Use of local vs. international market benchmarks

The cost of capital reflects the return that investors require in order to invest. The cost of capital required on any investment is influenced by the whole portfolio of stocks (and other assets) to which an investor can gain access. This return will partly depend on where investors are located and the type of markets to which they have access.

It is common practice to estimate several of the parameters in the cost of capital calculation with respect to the local market in which the companies operate. For example, betas are usually defined as the statistical relationship between equity returns on the company under consideration and the market in which it is traded. The implicit assumption behind this is that investors only diversify their investments within the local stock market.

However, in practice, investors are not limited to the local stock market but they can invest in any stock market around the world. As the cost of capital reflects the return that investors require in order to invest, it will be influenced by all the markets to which investors have access and although a marginal investor in an Irish gas company has broader investment opportunities than the Irish stock market, these opportunities can impose additional costs in the form of transactions costs and currency risks. It is difficult to estimate these costs objectively and so were they are expected to be large, the appropriate reference market is, in practice, constrained. Within the Eurozone, movements of funds are easier than movements of funds worldwide (e.g. through lower transaction costs), and investors can diversify across borders without currency risk. Difficulties inherent in valuing these transaction costs and currency risks and assessing their impact on the cost of capital make estimates of the cost of capital less accurate when the reference market is global rather than the Eurozone, in which transaction costs are small and currency risks are absent.

Accordingly, the Eurozone area may provide a more appropriate reference market for BGÉ than the domestic or global market. It is therefore important to estimate the cost of capital components with respect to the European market. This applies to several of the parameters in the cost of capital calculation and so, where applicable, we calculate the cost of capital on the basis of a European-wide benchmark.

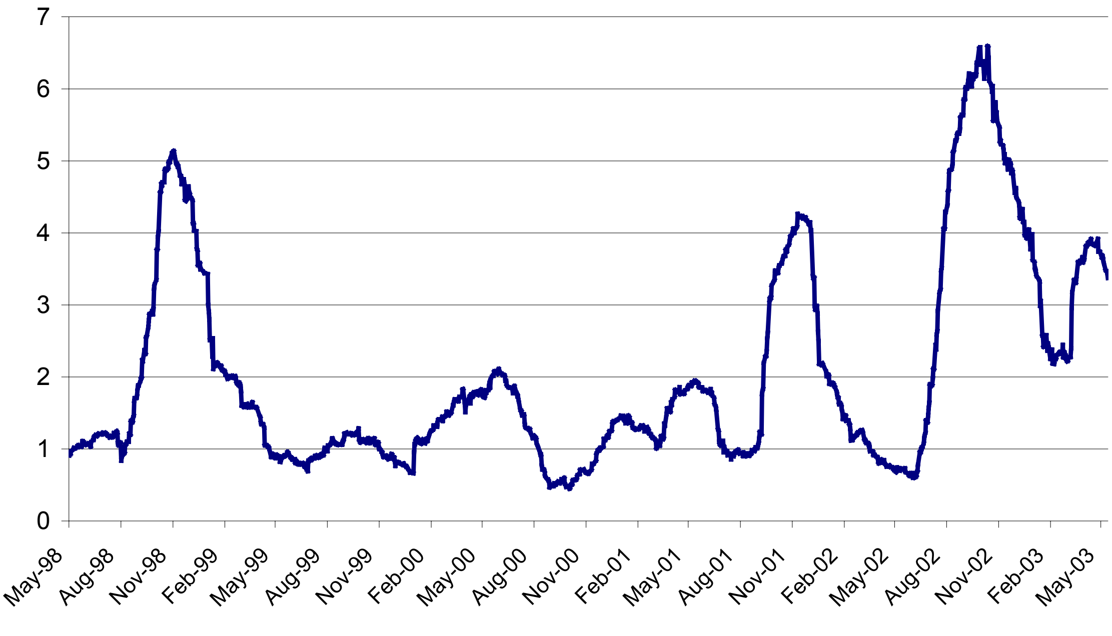
2.1.2. The use of current or historical evidence

Since the CAPM is an expectational model, the risk free rate that is used should reflect investors' expectations of the risk free rate over the relevant time period. Likewise the equity risk premium and beta parameters should reflect investors' expectations of these parameters over the relevant time periods.

An important issue in applying the CAPM is whether current or historic evidence should be used as the basis for the parameter estimates. A key issue here is the degree of market volatility that has recent been observed on global stock markets.

Figure 2.1 shows the historical volatility of the Dow Jones European 600 Index over the past five years. In this chart, volatility is measured on an historic basis using the variance of daily returns over the three months prior to the date on the chart. The variance is the average squared deviation from the mean daily return over the 3-month period.

Figure 2.1
3 Month Rolling Variance of Daily Returns on Dow Jones European 600 Index



Source: Bloomberg

The chart shows three clear periods where the market has been highly volatile. The first of these immediately followed the Russian currency crisis in August 1998. During this period, the variance of daily returns reached over 5%. The second period of high volatility occurred in the aftermath of the terrorist attacks of September 11, 2001. The variance of daily returns reached just over 4% at its peak. The most recent period of volatility began around June 2002 and peaked in late 2002 and early 2003 at over 6.5%. Uncertainty over the military position regarding Iraq was probably the main driving factor for this period of market turbulence. Market volatility has remained at a higher level during the whole of the 2003 period.

Recent market commentary[1] confirms a widespread belief that current volatility is higher than average and excessive in nature, unjustified by the fundamentals.[2] Our analysis supports the assertion that current measures of market volatility are high by comparison to historic levels.

The level of volatility in the stock market has implications for estimating the cost of capital. In general, investors will respond to increased market turbulence by switching their holdings away from volatile assets such as equity and into less risky assets such as government bonds. The effect of this behaviour, known as the "flight to quality", is to simultaneously raise the price of government bonds and lower the price of equity, which reduces the yields of government bonds and raises the expected return on equity.

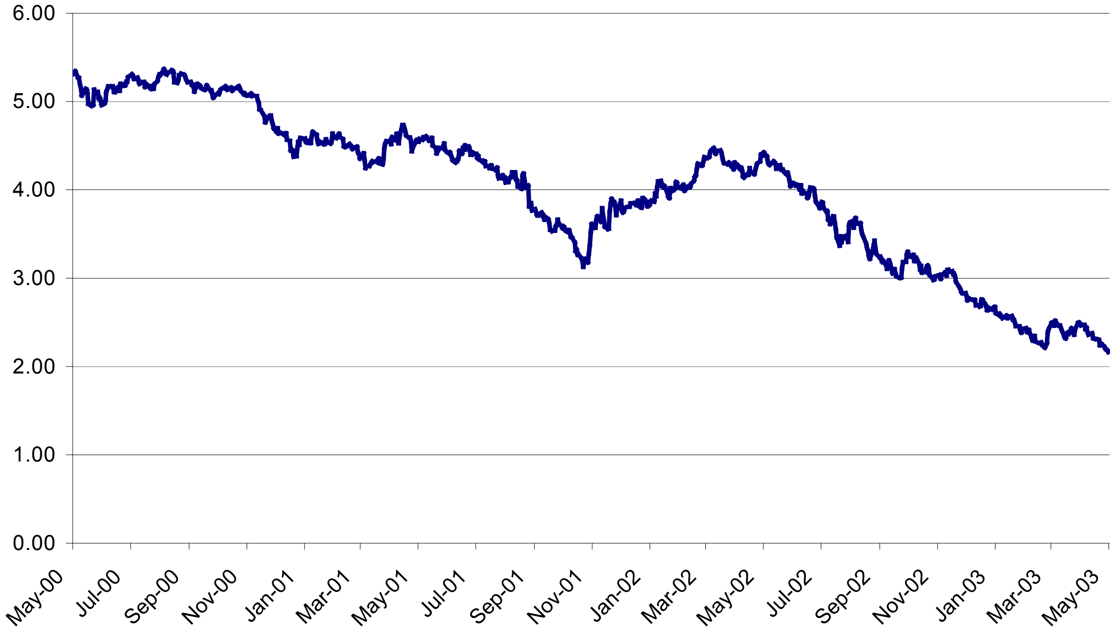
Figure 2.2 below shows evidence of this effect in the daily yield-to-maturity on a generic euro-denominates sovereign (German) government bond with 1 year to maturity.

1 See for example The Business (3 February 2003) "*The huge volatility that has been the defining feature of world's financial markets*".

2 The recent collapse in stock market prices has led to some commentators to suggest that the correction of the 1990s bubble may have led to stock prices undershooting fundamentals. This would imply measures of undervaluation in current markets. Sornette and Zhou (2002) have even suggested the current presence of an "anti-bubble", where bubble growth is negative as opposed to positive in the 1990s. A recent poll by Citywire Week (March 2003) indicated that nearly two thirds of fund managers believed the market to be undervalued. This is in addition to a Goldman Sachs report that suggested that the European market was undervalued by 10% (May 2003).

Figure 2.2

German Generic Government Bond Yield to Maturity (1 year to maturity, daily yields)



Source: Bloomberg

The yield to maturity declined sharply between 2000 and 2003, which is consistent with the predicted flight-to-quality effect. Moreover, between November 2001 and May 2002 the yield-to-maturity increased by around 40-45% before continuing to decline. In Figure 2.1, we see that this period corresponds with a significant fall in the volatility of the Dow Jones Europe 600 index. Yields have continued to fall during 2003 while volatility has remained high.[3] This evidence supports the proposition that there is an inverse correlation between the returns on safe bonds and the level of volatility in the stock market.

The second implication of the flight to quality effect is that in times of high volatility there will be an increase in the expected rate of return on equity. Anecdotal market evidence supports the notion that increases in perceived equity risk has led to increases in the returns demanded by investors as compensation. For example, the Bank of England states in its February 2003 Inflation Report: *"…a fall in expected future dividend payments may explain some of decline in world equity markets since 2002. But it seems likely that an increase in the perceived level of uncertainty, and a corresponding rise in the equity risk premium, also played a significant role."*[4, 5]

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3 In theory, the correct measure of market volatility that impacts investors' portfolio decisions is *expected* volatility rather than *ex post* volatility. Measures of expected volatility can be derived through analysis of options prices, although we do not do so in this paper.

4 Inflation Report, Bank of England, February 2003, p3

5 The LEX column (21 April 2003) in the FT noted that "*After hitting all-time peaks last October, stock market volatility has remained high for most of this year*".

Whilst the impact of increased volatility on the risk free rate can be measured by examining yields on government bonds, there is no easy way to measure the impact of excess volatility on the equity risk premium. Regulators typically estimate the ERP by relying on long run historical data and/or survey evidence that is often out of date and is not consistent with the current high equity market volatility. The absence of an objective and verifiable current measure of the current equity risk premium may therefore lead to a downward bias in the estimation of WACC at times of high market volatility.

Since there is clear evidence that the equity risk premium and risk free rate parameters are inversely correlated, it would be internally inconsistent to measure the risk free rate using a spot current yield but to measure the equity risk premium using long run historical data. Account must be taken of the appropriate trade-offs between the various WACC parameters – this may be easier to do through the use of time series evidence than the use of "spot" market evidence. We address this issue in the estimation of the relevant parameters in the remainder of this report.[6]

[6] A second issue with the use of current stock market data concerns *market efficiency*. The efficient markets hypothesis (EMH) states that current prices will embody all information regarding the value of assets. Under this hypothesis, the prices of assets are characterised by a "random walk" process whereby current yields are the best guide to investors' expectations of future yields. Failure of the EMH to explain current stock market behaviour would imply that current "spot" prices do not provide complete information regarding expected future values. There is evidence to suggest that the EMH does not hold, particularly in light of recent stock market turbulence. A number of recent academic papers have found that the EMH cannot fully explain the continuous stock price volatility observed on daily equity stock markets. Some empirical studies have shown that the variance of the actual stock price is five times higher than the variance of the fundamental value and have argued that stock prices regularly display evidence of "excess" stock volatility. The presence of excess volatility that cannot be explained by the EMH implies that current market data may not be the best estimate of true expected future values.

3. PRINCIPLES FOR ESTIMATING THE COST OF EQUITY

The post-tax cost of equity is the return on equities (either through dividends or through an increase in the value of shares) that is required to persuade investors to bear the risk associated with the company's equity. In general, two main models are used to calculate the cost of equity, the Capital Asset Pricing Model (CAPM) and the Dividend Growth Model (DGM). We review both methods below. However, in practice DGM is infrequently used by regulators, because one of its key components, the expected growth in companies' dividends, is unobserved. Thus, to calculate BGÉ's cost of equity we follow regulatory precedent and use the more generally accepted financial model, CAPM, to determine equity costs. The following section discussed the CAPM.

3.1.1. Capital Asset Pricing Model (CAPM)

3.1.1.1. General principles

The CAPM model estimates the required post (corporate) tax returns on the equity of a company in the following way:

(3.1) $$E[r_e] = E[r_f] + \beta(E[r_m] - E[r_f])$$

where,

$E[r_e]$ is the expected return on equity
$E[r_f]$ is the expected return on a risk-free asset
$E[r_m]$ is the expected rate of return for the market; and,
β is a measure of the systematic riskiness of the asset.

An important aspect of the CAPM model is the underlying assumption that people can diversify their investment portfolio through purchasing other assets. The risk associated with equity in the CAPM model (captured through the value of β) reflects the non-diversifiable risk of that equity. It is therefore a measure of the strength of the relationship between the expected returns on an asset and the expected returns on a broad portfolio of assets. If the assumptions of the OLS technique are met by the data, the slope coefficient is a "best-fit" unbiased estimate of the equity beta.

In theory, a full range of assets are available to investors and returns to all assets should be included in the model. However, in practice, the returns to the stock market are used in the calculation as a proxy for the returns to all assets. In Section 2.1.1 above we discussed whether only national or also international stocks should be included in the estimation of general market returns.

Formally, beta is defined in the following way:

(3.2) $$\beta = \frac{cov(r_i, r_m)}{var(r_m)}$$

where;

r_i is the return on a specific stock; and

r_m is the return on the market as a whole

3.1.1.1.1. Estimation period

In practice, forward looking estimates of returns on particular stocks and on the market as a whole are not readily available therefore we use historic returns as a proxy for expectations about the future.

However, using historic returns to estimate future values of beta raises the question of which is the correct period to use in the sample. It is argued that, since we are using historical data as a proxy for forward-looking expectations, we should choose the most recent period possible, since this will embody market expectations about future returns. This would lead us to look at, for example, daily data over the past one or two years.

It is also argued that the values of beta fluctuate systematically over the business cycle. Therefore taking only a recent period (i.e. less than one complete business cycle) risks missing information and biasing the results. According to this argument, betas should be calculated over as long a period as possible to smooth out the effects of long-run cycles.

There are some very practical considerations with respect to the choice of periodicity of data collection. In order to generate a statistically significant estimate of the value of beta, it is important to have a data set of a reasonable size. If the estimate of beta is based on recent historical data, then daily or weekly data is required in order to provide a sufficiently large sample size. However, if the value of beta is to be estimated over a longer period, then monthly data is sufficient. The disadvantage of daily data is that it can introduce a variety of biases associated with thin trading, serial correlation of market returns and asynchronous price adjustment processes. Studies have shown that infrequently traded securities are likely to be biased downwards for these reasons.

3.1.1.1.2. Business risk and financial risk

The equity or 'levered' betas are calculated on the basis of the relationship between the stock price of the companies and the local stock market as a whole, and thus the value of the equity beta reflects two types of risks:

- Business risk: As the level of business risk increases, profit streams become more sensitive to changes in general economic conditions and hence company returns become more highly correlated with market returns.

- Financial risk: As the gearing ratio (D/(D+E)) rises and the company issues more debt, the fixed interest costs on debt increases, meaning that profit streams also become more volatile and leads to a rise in the beta estimate.

In order to be able to compare levels of business risk across companies, it is necessary to calculate the asset or 'unlevered' beta of the company. The unlevered beta of the company is defined as the value of beta for the company on the assumption that the company holds no debt. Standard formulae are normally used to adjust the unlevered beta for the level of gearing of the company.

In the CAPM framework, the traditional way to account for the impact of a change in gearing on the cost of equity is to adjust the beta coefficient in a linear manner, reflecting the fact that the variability of equity returns is directly proportional to the amount of profits paid out as interest payments. Unlevering of the equity beta is undertaken using the following formula[7]:

(3.3) $$\beta_{equity} = \beta_{asset} \, (1 + (\text{Debt}/\text{Equity}))$$

As a company's gearing increases, the greater the variability of equity returns, since debt represents a fixed prior claim on a company's operating cashflows. For this reason, increased gearing leads to a higher cost of equity, reflected in a company's (equity) beta value.

In the event that a company is expected to increase its level of gearing in the future, it is necessary to adjust the observed equity beta for the higher level of financial risk that will result form the higher gearing. In practice this is done by first calculating an unlevered beta based on the current (and historic) gearing levels and then lever the beta for the higher (or expected) future gearing levels. It is important to emphasise that the value of beta needs to be consistent with the assumed level of gearing, in order that equity holders are rewarded for the levels of financial risk to which they are exposed.

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[7] By using this formula, we assume that the beta of debt is zero. This is a reasonable assumption because the credit spread on debt is mainly influenced by firm specific risk (e.g. default risk) and not by market risk, which is captured in beta.

4. COST OF EQUITY

NERA's approach to calculating the cost of debt for BGÉ is to use the CAPM model. This section presents our results.

4.1. Risk Free Rate

The risk-free rate is a measure of expectations about future returns on a risk-free asset. In theory this is captured by the current yields on benchmark government bonds, as current rates would best capture expectations about future returns. In countries where index-linked bonds exist these can be used as an estimator of the real risk free rate.

As discussed in Section 2.1.1, NERA recommends estimating the risk free rate so as to reflect the risk free rate in the Eurozone market. In the absence of a "Eurozone Government Bond", NERA has used German government bonds as proxies to estimate this parameter. German government debt has the lowest yields reflecting its strong economic fundamentals and the market's low expectations of sovereign default. NERA believes that the YTM of a euro denominated German government bond provides the best estimate of a risk free rate for the Euro area.[8]

A number of additional issues should be considered in estimating the risk free rate: (i) the appropriate maturity; and (ii) the use of historic vs. current rates. We discuss each of these factors below.

4.1.1. Maturity

The correct type of bond to use as the risk-free rate is a subject that generates a considerable amount of debate when determining the cost of capital. From a theoretical point of view, the time horizon considered could either reflect the life of the relevant regulated assets or the regulatory review period.

Increasingly regulators around the world tend to use 10-year bonds. The main reason underlying this choice is that the 10-year bond is typically the security that has the closest maturity to the 15 year plus investment profile of utility assets whilst also maintaining a certain liquidity and market depth. On the other hand, one may look at a combination of the longer-year bonds in order to provide some recognition of the useful life of the assets as well as the investment profile of investing in gas assets. However, it is NERA's experience is that average debt maturities for efficiently financed utility companies are generally in the region of 10 years.

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8 The French government issues IL debt which could in principle be used as a measure of the real risk free rate.

4.1.2. Historic vs. current yield

We argued in section 2.1.2 there is reason to believe that current yields on risk free assets are abnormally low as a result of high equity market volatility. For that reason, NERA considers it appropriate to calculate a risk free rate based on a short to medium term average of recent bond market yields rather than use current "spot" rates. We base our risk free rate estimate on 1 year average yields to maturity – although an even longer period could be justified.

Consequently, NERA's estimate of the risk free rate is based on 1 year average (daily) yields to maturity for 10 year German government bonds denominated in Euros.

Bloomberg provides a generic German bond yield curve, which is based on the German 10 year benchmark bond. Details of the average yields to maturity on Bloomberg's generic German government bond indices are presented in Table 4.1.

Table 4.1
Average Yields on Generic German bond

	Current, % (30/04/2003)	**3 month average, % (Feb 03 - Apr 03)**	**1 year average, % (May 02 - Apr 03)**
1 Year	2.33	2.40	3.04
2 year	2.43	2.47	3.18
3 year	2.72	2.76	3.42
4 year	3.02	3.04	3.67
5 year	3.27	3.26	3.84
6 year	3.42	3.44	4.02
7 year	3.66	3.66	4.20
8 year	3.85	3.84	4.34
9 year	3.99	3.97	4.43
10 year	**4.09**	**4.06**	**4.48**
15 year	4.41	4.39	4.77
20 year	4.78	4.73	N/a
30 year	4.84	4.78	5.03

Source: Bloomberg

This table shows that yields to maturity have fallen significantly over the last year. Current yields at May 2003 are in the order of 40-60 basis points (bps) lower than the average over the past year. For the purpose of estimating BGÉ's WACC, NERA's best estimate of the nominal risk free rate is 4.48% based on the 10 year maturity bond.

4.1.3. Conclusion on the value of the nominal risk-free rate

In summary NERA recommends that the risk free rate to apply for BGÉ should be based on the following:

- A bond with a 10 year maturity.
- The appropriate "reference" market is the Euro-zone. In the absence of a Eurozone bond, a Euro denominated German government bond should be used as a proxy.
- The risk free rate should be calculated using a 1 year (arithmetic) average of (daily) yields to maturity on the relevant "benchmark" bond.

NERA recommends using a nominal risk-free rate of 4.48%, based on a 1 year average of daily yields to maturity of a 10 year German government bond.

4.2. The Equity Risk Premium

The equity risk premium (ERP) is the difference between the expected return on the market portfolio and the expected return on a risk free asset, (formally stated as $E[r_m] - E[r_f]$ in Section 3.1.1.1).

Consistent with prevailing views amongst both academics and finance practitioners, NERA's approach to estimating the ERP relies primarily on the results obtained from the analysis of the average difference over the long term between realised returns on the market portfolio, and those on a risk free asset (the so-called ex-post approach). NERA also follows prevailing practice in favouring the use of the arithmetic rather than the geometric mean in deriving an average measure of returns to each type of asset. The arithmetic mean approach is consistent with the hypothesis that financial markets are generally efficient, with equity returns serially independent.[9]

In the following two sections we summarise the findings from analyses of historical returns (Section 4.2.1) and ex-ante evidence on expected returns (Section 4.2.2), derived either from surveys of informed market participants and from market data on share prices and expected dividend growth. Section 4.2.3 examines recent academic evidence, and Section 4.2.4 examines recent regulatory precedent. Section 4.2.5 concludes.

4.2.1. Ex-Post Approach

The ex ante approach calculates the average differences between *realised* (i.e. historical) returns on (a proxy for) the market portfolio and *realised* returns on (a proxy for) the risk free asset. This presumes that the expected ERP is constant over time and that realised premiums converge towards this expectation when averaged over sufficiently long periods (i.e.. there is no systematic bias between expectations and outturns).

[9] The possibility that equity market may exhibit "excess volatility" over short periods of time does not weaken the argument for use of an arithmetic mean of a long time series for estimating an ERP. The use of a geometric mean is based on the assumption that markets exhibit long term mean reversion. So long as "bubbles" are short lived they do not imply long term mean reversion.

Estimates of the ERP derived using this approach are sensitive to a number of factors. These include: (i) the choice of historic time period; (ii) the choice of reference market; and (iii) the choice of averaging period. We discuss each of these below.

4.2.1.1. *Choice of Historic Time Period*

Using long term historic averages is most likely to overcome the possibility of systematic bias between expectations and outturns. Long term averages of returns are most appropriate if it is assumed that the equity risk premium is constant over the measurement period and will remain constant in the future.

A number of recent studies have shown that there are good theoretical and empirical reasons why the equity risk premium may change over time, and are specifically correlated with changes in interest rates, inflation, the business cycle, and pension fund weightings. To ensure consistency with estimates of other WACC parameters derived in this report, we present in the following we will consider estimates of the ERP based on historic data over long periods of time. In the following we will consider estimates of the ERP based on historic data over 100 years.

4.2.1.2. *Choice of Market*

To ensure consistency with the risk free rate we will present equity risk premia for a number of Eurozone markets. In addition, we also present evidence for the US market.

4.2.1.3. *Choice of Averaging Process*

Substantial debate has taken place over whether average realised historical equity return should be calculated using either geometric or arithmetic averages. Market efficiency implies that equity returns are serially independent (i.e. no mean reversion and no method of predicting future returns). In these circumstances, the correct estimator of the future market return is the long term ex post arithmetic mean. Thus, the debate over whether arithmetic or geometric averages should be used derives from whether one believes markets are efficient and how one believes investors behave.

On balance NERA favour the use of the arithmetic rather than the geometric mean in deriving an average measure to calculate the ERP using historical data. We believe this is consistent with the majority academic viewpoint and current evidence regarding the efficiency of equity markets. However, for completeness this paper presents estimates of the ERP using both arithmetic and geometric averages.

4.2.1.4. *The evidence from historical returns*

Table 4.2 below presents ex post ERP estimates published in a LBS / ABN AMRO publication, which reports the returns on equity markets around the world over the last 101 years, and compares them against the returns on treasury bills and bonds. The evidence suggests long term global ex post ERP in the range of 5% to 7% (using arithmetic averaging).

Table 4.2
LBS/ABN AMRO estimates of the equity risk premium

	ERP relative to Bills			**ERP relative to Bonds**		
	Arithmetic	**Geometric**	**Std. dev.**	**Arithmetic**	**Geometric**	**Std. dev.**
UK	6.5%	4.7%	19.4%	5.6%	4.4%	16.7%
Ireland	6.7%	4.3%	23.2%	6.0%	4.0%	20.4%
Germany[1]	10.3%	4.9%	35.3%	9.9%	6.7%	28.4%
USA	7.5%	5.6%	19.8%	6.9%	5.0%	19.9%
World average[2]	7.5%	5.2%		6.7%	4.6%	

Source: LBS / ABN AMRO "Millennium Book II, 101 years of investment returns", 2001. 1: The estimates are based on 99 years of data, with 1922/3 excluded where hyperinflation had a major impact on the risk premia and bills returned –100%. 2: The countries included in this average are: Australia, Belgium, Canada, Denmark (from 1915), France, Germany, Ireland, Italy, Japan, Netherlands, Spain, Sweden, Switzerland (from 1911), UK and USA.

4.2.2. Ex-ante approach

A second alternative is the "full ex ante approach", where the ERP is calculated as the difference between the current observable *expected* returns on a proxy for the market portfolio (eg. taken from a survey of investors' expectations) and observable current (or recent) *expected* yields on a proxy (or proxies) for the risk free asset.[10]

4.2.2.1. Survey Evidence

Table 4.3 below summarises the results of surveys, in both the UK and US, which have been referred to in a regulatory context. We summarise comments made on the robustness of these results.

It is clear from Table 4.3 that the estimates of the ERP derived from US surveys tend to be higher than the results from UK surveys. This can be hard to justify given that casual evidence shows stock market returns between the UK and the US to be highly correlated.

NERA would argue that more weight should be put on the US than on UK survey evidence for the following reasons:

- First, the US data is based on larger sample sizes;

[10] At times, averages of expectations over some historical period are used, modified for changes in economic circumstances.

- Second, the US data has regularly been used as evidence on the appropriate allowed cost of equity in US rate cases, and as such, has been subject to careful scrutiny and systematic testing to a larger extent than the UK material.

The US data shows that the estimate of the ERP of 6.0% derived from historical data (ex-post approach) is within the range derived from US survey evidence.

Table 4.3
Survey Evidence Regarding Equity Risk Premium

Survey	Equity risk premium: findings	Robustness / comment
UK SURVEY EVIDENCE		
UK Strategy Forecasts at Investment banks	range of 2% - 5% reported	Range of market premia from UK strategists from SSSB, Deutsche Bank and Morgan Stanley.
NERA 1998 UK Analysis	3% – 4% mean estimate	Sample size of six analysts only. Answers show wide variation
Credit Lyonnais Securities (CLSE) 1998	2.75% - 7.2%, based on estimates on required returns on water equity	The survey did not ask investors for direct estimates of equity risk premium OFWAT/OFGEM interpreted a range of 2.7-4.2%. The LBS suggested the range could be approx. 3% higher
PriceWaterhouseCoopers (1998)	7 funds reported 2 – 3% 3 funds reported -1 - 1% 2 funds reported 6 – 8%	Polled 12 big pension fund managers in the UK on their expected market premium in the next 15 years.
MMC / Bgas 1993	3.37% - 3.5%, based on reported average 7.0% for expected equity returns.	Sample size of eight fund managers' responses considered.
US SURVEY EVIDENCE		
Welch 1998 (US Financial economists)	6% mean estimate	70 financial economists; estimates varied between 4% and 8%
Harvard Business review (1995)	Most corporations used 5%; M&A groups used 7%, based estimates on historic rather than forward-looking data.	Best practices study among investment banks, M&A groups and 27 leading North American corporations.
Carleton and Harlow (1993), US, using database of analysts' forecasts	6.5% for period 1982 – 1990; 7.5% for period 1989 – 1993	Methodology approved in US rate setting cases
Harris and Martson (1992), US, using IBES database of analysts' forecasts	6.5%, based on expected return for equity market minus long term yields on government bonds	Methodology approved in US rate setting cases

4.2.2.2. *Evidence from Price-Earnings Ratios*

An alternative method to using survey data to estimate the ERP on a forward-looking basis is to use the dividend growth model. This model offers an alternative approach to deriving an *ex-ante* estimate of the ERP by using market data on actual share prices and earnings per share, in conjunction with forecasts of the growth in earnings, to derive an implied cost of equity. This approach does not require historical data, nor is it necessary to correct for differences in country risk. Assuming that:

> *Share Price = Expected earnings per share next period / (Required return on equity – expected growth rate)*

This implies that the required return on market equity (r_e) is given by:

$$r_e = (\textit{Expected earnings / market price}) + \textit{expected earnings growth rate};$$

Using this model to calculate the required return on the market index, defining the required return on the market portfolio (r_m) as the sum of the market ERP (r_m-r_f) plus the risk free rate, it therefore follows that the market ERP can be expressed as:

$$ERP = (E/P)_{MARKET\ INDEX} + (\textit{expected earnings growth rate})_{MARKET\ INDEX} - r_f$$

Table 4.4 shows the implied equity premia implied by the P/E ratios for the Eurozone, UK and US equity market indices. ERP estimates are based on the current P/E ratios of the index, a real current risk-free rate of 2.53%, and an expected real long run earnings growth rate of 2%-3%.

Table 4.4
Implied equity risk premia based on current P/E ratios

Index	Country	Current P/E	Implied ERP[1] (LR growth: 2%)	Implied ERP[1] (LR growth: 3%)
FTSE All-Share	UK	17.5	5.2%	6.2%
DJ Industrials	US	22.1	4.0%	5.0%
European Average (excl UK)	**Europe**	**13.6**	**6.8%**	**7.8%**

Source: NERA analysis of Financial Times data [30 April 2003]. 1: Based on a real risk-free rate of 2.53% and real annual earnings growth rates of 2% and 3%.

Using this methodology, the implied average ERP is between 6.8% and 7.8% for the Eurozone market.

4.2.3. Academic and Practitioners' view

The equity risk premium has attracted significant recent academic debate, partly in response to the bullish equity markets observed in the US economy in the late 1990s and the recent falls in equity market prices. Table 4.5 presents evidence on recent ERP estimates undertaken by academics. There does not appear to be any convergence on the choice of estimation technique, time period or reference risk free rate and country, thereby leading to very different estimates of the ERP.

Table 4.5
Recent Academic Evidence on the Equity Risk Premium

Source	ERP estimate	Details
Brealey and Myers (2000)	8.5%	Long run historical data
Franks (2001)	5%	Expert advice given to Oftel (2001) for estimating BT's cost of capital
Dimson, Marsh and Staunton (2001)	5%-7%	Ex post estimates based on 101 years of data.
	4-5%	Forward looking estimates based on lower volatility assumption.
Fama and French (2001)	2.6%-4.3%	Estimates derived from dividend and earnings growth models over 2nd half of 20th century. Compares with estimate from average returns of 7.43%.
Ibbotson and Chen (2001)	5.9-6.2%	Historical and supply side models.
Oxera (undated)(1)	4.7%-8.5%	Ex post estimates of one year and five years returns averaged using various periods over the last 100 years. Using the whole period the ERP was around 5%
Smithers and Co (2003)	4%-5%	Based on a cost of equity for the market of 6.5%-7.5% and a risk free rate estimate of 2.5%, on the basis of their preference of arithmetic averages.

(1) cited in Franks and Mayer (2001).

Of these studies, the Ibbotson and Chen (2001) study is widely quoted in international regulatory contexts.[11] The authors used historical evidence and supply side models (eg. dividend growth models) to predict future equity risk premia. The authors conclude:

> *"Contrary to several recent studies that declare the forward-looking equity risk premium to be close to zero or negative, we find the long term supply of equity risk premium to be only slightly lower than the pure historical return estimate. The long term equity risk premium is estimated to be about 6% arithmetically and 4% geometrically. Our estimate is in line with both the historical supply measures of public corporations (i.e. earnings) and the overall economic productivity (GDP per capita)".*

[11] See IPART discussion paper and submissions DP56, August 2002.

4.2.4. Regulatory precedent on the equity risk premium

4.2.4.1. *Irish regulatory precedent on the ERP*

Recent decisions by Irish regulatory authorities on the ERP are summarised in Table 4.6.

Table 4.6
Recent Irish Regulatory Precedent on the ERP

Inquiry	ERP	Evidence Considered
Commission for Electricity Regulation (CER) (2003) "*Best New Entrant Price*"	5.3%	Historic data, price-earnings analysis, survey evidence and international regulatory precedent
Commission for Aviation Regulation (CAR) (2002) "*Determination and Report on the Maximum Levels of Aviation Terminal Services Charges that may be imposed by the Irish Aviation Authority*"	6.0%	Based on ERP used in estimating Aer Rianta's cost of capital (2001).
Commission for Aviation Regulation (CAR) (2001) "*Determination and Report on the Maximum Levels of Airport Charges*"	6.0%	Historic, academic and practitioner studies including US evidence such as Ibbotson, Bloomberg, Datasteam, Reuters, and the LBS "Millennium Book".
Commission for Electricity Regulation (CER) (2001) "*Determination of Distribution Allowed Revenues-ESB*"	5.4%	Historic, semi ex-ante and surveys. US survey evidence relied upon more heavily in methodology as considered more robust.

Recent Irish regulatory precedent on the ERP ranges from 5.3% (CER 2003) to 6% (CAR, 2001 and 2002). The CAR and the CER have each considered a wide range of evidence to inform recent decisions. The evidence considered has included historic data on returns, price-earnings ratio analysis, academic and practitioner studies and international regulatory precedent.

4.2.4.2. *International regulatory precedent on the ERP*

Recent UK regulatory decisions by Ofwat, Ofgem, CAA, the ORR and the Competition Commission (CC) have consistently placed the UK ERP at a low level, in the range 3.0-4.0%.[12] In most cases, some consideration has been given to evidence on historic average

[12] A notable exception is Oftel's 2001 price controls for BT. Oftel, using both long-run historical and forward-looking survey evidence, and relying on advice from Professor Julian Franks of the LBS, allowed BT an equity risk premium of 5%, noting that "*A low rate of return on capital can bring benefits to consumers in the short term in the form of lower prices. However, it could damage consumers' longer-term interests. The telecommunications industry depends on high levels of discretionary investment to support innovation and rapid market growth. The funds for such investment are often*

returns, however UK authorities have generally judged that the historic ERP overstates the current risk premium. Estimates of the ERP have generally relied heavily on small sample survey evidence on the expectations of investors. Surveys that have been considered by the authorities include CLSE (1999), Price Waterhouse (1998), NERA (1998) and other evidence from investment bank analysts. The reliance on survey evidence has prevailed despite the CC itself recognising that *"this evidence may be subject to biases that are difficult to quantify and assess"* (Competition Commission, 2000a, paragraph 8.28).

The most recent CC decisions have placed the ERP in the range 2.5% - 4.5%. In both the Vodafone, O_2, Orange and T-Mobile (2003) case and the BAA (2002) case, the CC considered historical averages of the ERP as well as forward looking measures based on survey evidence. The CC concluded that the ERP had been falling over recent years, although noting that exact extent of this was uncertain and it might rise in future. "*In view of this uncertainty*" the CC did not wish to implement the full fall in its estimate of the ERP relative to previous decisions, and subsequently allowed "*a degree of smoothing of the downward trend in the equity risk premium*" through a 25bp upwards adjustment to the real pre-tax WACC (Competition Commission, 2003).

Table 4.7 presents a summary of recent UK regulatory ERP decisions.

internationally mobile.. Too low a figure for the cost of capital could deter such investment, thus disadvantaging consumers in the longer term." (Oftel, 2001, p.45-46).

Table 4.7
Recent UK Regulatory Decisions on the Equity Risk Premium

Institution	Case	ERP	Basis for Decision
MMC	Cellnet / Vodafone, 1998	3.5%-5%	Most weight given to longer term averages of historic data.
Ofwat	PR1999	3.0%-4.0%	Most weight given to survey evidence on expectations of City institutions and investors.
Ofgem	PES, 1999	3.5%	Most weight given to survey evidence on expectations of City institutions and investors.
Ofgem	NGC, 2000	3.5%	Most weight given to survey evidence on expectations of City institutions and investors.
ORR	Railtrack, 2000	4.0%	Recent CC decisions.
CAA	NATS, 2000	3.5%-5%	Based on MMC's conclusion in Cellnet / Vodafone (1998) case.
Competition Commission	Mid-Kent Water Plc; and Sutton and East Surrey Water Plc, 2000	4.0%	Considers arithmetic and geometric averages of 100 year returns against gilts and bills. And considers survey evidence from Price Waterhouse (1998), NERA (1999), Merrill Lynch (1998) + Director's own consultations within the city. Conclusion that ERP is currently lower than historical average.
Ofgem	Transco, 2001	3.5%	Recent CC decisions, past trends, recent surveys and modelling.
Oftel	BT, 2001	5%	Considers historical and survey evidence from UK and US and expert evidence provided by Professor Julian Franks (2001)
Competition Commission	BAA 2002	2.5%-4.5%	Historical evidence over various periods from 10 years to 100 years against gilts and bills. Most weight given to survey evidence. Allowance of 25bp to real pre tax WACC for smoothing of downward trend in ERP.
Competition Commission	Vodafone, O_2, Orange and T-Mobile, 2003	2.5%-4.5%	Historical evidence over various periods from 10 years to 100 years against gilts and bills. Most weight given to survey evidence. Allowance of 25bp to real pre tax WACC for smoothing of downward trend in ERP.

Outside the UK, in countries including the US, Australia and the Netherlands, the ERP has generally been set at a higher level. In the US, although the CAPM is not widely used to estimate the cost of equity, it is often used as a check on the DCF results. The most widely quoted source used in US hearings to assess the level of the ERP is the Ibbotson data. The method recommended by Ibbotson is to compute the arithmetic average of stock market returns against long-term treasury bond yields.

Table 4.8 presents a summary of recent US decisions on the ERP.

Table 4.8
Recent US Decisions on the Equity Risk Premium

Institution	Case	ERP	Comments on Decision
Connecticut Department of Public Utility Control	Southern Connecticut Gas Company, 2000	6.13%	Used a Risk Premium Method to check DCF. The ERP is the arithmetic average from 1974-1998.
Connecticut Department of Public Utility Control	Connecticut Power & Light Company, 2002	6.52%, 5.89%	Different witnesses performed the CAPM calculation with different ERPs. These submissions were approved by the Commission.
Maine Public Utilities Commission	Central Maine Power Company, 1999	7.40% - 8.90%	The Commission uses CAPM analysis as a check on the DCF method, and employs this range of ERPs, based on witnesses' recommendations.
Public Service Commission of Utah	Pacificorp, dba Utah Power and Light, 1999	7.8%	CAPM used as check to DCF model.
Public Utility Commission of Oregon	Northwest Natural Gas, 1999	8.5%	Commission chose this ERP for use in CAPM.

Source: Public Utility Commission Dockets, US State Regulators.

In Australia, recent regulatory cases have concluded that the market risk premium is most likely to lie in the range of 5.0% to 7.0%. The most recent regulatory decision by the ACCC used an ERP of 6% for the Victorian transmission network revenue caps for 2003-2008.

In the Netherlands, the electricity regulator DTe published its guidelines for price cap regulation in the period from 2000 to 2003 whereby it "*considers it reasonable to fix the market risk premium between 4% and 7%*[13]". This range was derived on the basis of the available data and responses from the sector.

4.2.5. Conclusions on the equity risk premium

In our 2001 report on the cost of capital for electricity NERA assumed an equity risk premium of 5-7%. In the last year, equity markets have exhibited significant volatility and index prices at mid 2003 are generally trading at lower levels in general by comparison to mid year 2001. This could be taken as an indication that equity markets are seen as more risky than 2001, and hence that the equity risk premium has increased and/or lower earnings growth forecasts.

[13] "Guidelines for price cap regulation of the Dutch electricity sector in the period from 2000 to 2003", Netherlands Electricity Regulatory Service, February 2000

The CER used an ERP of 5.4% at 2001. Since then CAR has assumed a higher equity risk premium for setting the cost of capital for regulated activities in Ireland. Market evidence of increased volatility suggests that the ERP has increased since 2001.

Overall, we believe that an ERP of 5-7% remains appropriate as an estimate of the ERP for calculating BGÉ's cost of capital. Our preferred estimate of the ERP for calculating BGÉ's cost of capital is 6%, higher than that assumed by CER for electricity in 2001, consistent with increased equity market volatility over 2002-2003.

4.3. Beta

The CAPM estimates the appropriate cost of equity by only taking account of "systematic" (non-diversifiable) risks. The model is based on the premise that investors do not require a premium for company specific risks since these risks are diversifiable by holding a broad portfolio of assets.[14] In the CAPM framework, the direct measure of systematic riskiness is the beta coefficient, which is a measure of the co-movement of a particular asset or portfolio with the overall market portfolio, as defined in Section 3.1.1.

In theory, since the CAPM is an expectational model, the beta measure which is of relevance in using the CAPM to estimate the cost of equity is the current *expected* beta. However, in practice, as forward-looking estimates of returns on particular stocks and on the market as a whole are not readily available, historic returns are generally used as a proxy for expected future returns.

In general, we can estimate *quoted* companies betas by observing their share price behaviour relative to the relevant stock market index. Because of concerns about the robustness of a single regression result, it is also common to compare a beta result with "comparator" companies who operate in the same economic sector and are likely to face similar business risks. In the case of unquoted companies, we have to rely exclusively on "comparator" companies as a proxy estimate. Since BGÉ is not quoted, it is necessary to estimate the beta factor of BGÉ's regulated gas transmission and distribution activities by reference to observed equity betas of quoted "comparator companies".[15]

There are thus two principal considerations that have to be made in estimating an equity beta for BGÉ:

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14 The central notion of CAPM is that in the limit as the portfolio becomes as well diversified as possible, changes in specific risk will have no affect on the portfolio. Systematic risks cannot be diversified so easily. Most companies' profits go down in a recession, for example. Investors cannot protect themselves against the risk of recession by holding shares in a range of companies. As a result, investors require a premium on the expected return in compensation for being exposed to this systematic risk.

15 The estimated equity beta coefficients are then adjusted for differences in the financial riskiness of these comparator companies ("unlevering") to calculate an asset beta which reflects the fundamental business riskiness of BGÉ's gas transmission and distribution activities.

- First, since BGÉ's equity beta cannot be estimated from market data, which comparator companies should be used to derive a proxy for its beta?
- Second, over what time period should the equity betas for comparator companies be estimated?

We consider each of these in turn below (in Sections 4.3.1 and 4.3.2). In Section 4.3.3 we present the empirical results and in Section 4.3.4 we examine recent regulatory precedents regarding beta. Section 4.3.5 concludes our discussion on beta.

4.3.1. Comparator companies

In order to select relevant comparators for BGÉ, we have looked at a number types of comparator companies:

- European gas companies with significant transmission and distribution activities;
- Integrated European utilities;
- European transmission and vertically integrated electricity companies; and
- US pipeline operators.

4.3.2. The appropriate estimation time frame

There are two key issues that are relevant to the estimation period.

- the "economic relevance" of the estimation period to the expected operating environment over the next control period; and
- the need for a sufficiently long time period to ensure the regression results are robust.

It is normal practice to estimate betas using a range of time periods:

- 2 years to reflect the short term;
- 5 years to reflect the medium to long term; and
- 10 years to reflect the longer term.

NERA generally favours the use of longer time periods, such as 5 or 10 years, to estimate beta because:

- longer term estimates average out the system fluctuations in beta over the business cycle; and

- longer-term estimates of companies' betas are more efficient (and have lower standard errors) than estimates over a shorter time period. In short, they tend to be more robust estimates of the actual beta.

4.3.3. Empirical results

Below, in Table 4.9, we present the range of betas for the set of comparators. Individual and composite asset betas are presented for the three different time periods discussed above, i.e. 2 years, 5 years and 10 years. We favour the use of the estimates over longer periods, as set out above.

To ensure that our estimates are robust we use weekly company share and market returns in the regression equation. We regress each European company's return against a European index (the Dow Jones Europe Stoxx Price Index (SXXP)), consistent with our overall approach of calculating BGÉ's beta in the context of a European market.[16] The exception to this are the betas for the US pipeline companies, which are have been derived using a US index, the Standard & Poor 500.

16 It is a widely observed empirical finding that a security's true beta move towards the market average (of 1) over time. A range of arguments are offered to explain this tendency such as: betas vary over the course of the business cycle, high risk firms diversify to reduce their riskiness over time and vice-versa (conglomerate theory), etc. To improve the forecast of betas, we therefore adjust raw equity betas (or historical equity betas, i.e. those betas obtained from the regression of the company's stocks against the market index) according to a simple deterministic formula: $\beta_{adjusted}$= (0.67)*β_{raw} + (0.33)*1.0. This approach follows Blume (1971) and is widely used, for example by Bloomberg, Merrill Lynch and Value Line (see Patterson (1995)). We note that recent testimonies from Kolbe on the cost of capital for US electric utilities suggest the Blume adjustment may not fully correct for possible downward biases in beta estimates for electric utilities that results from the fact the electric stocks are highly sensitive to interest rate changes. This sensitivity is not captured by the normal calculations of beta that use the stock market (rather than all assets) as the definition of the "market". An even larger adjustment than is implied by the Blume formula may therefore be appropriate.

Table 4.9
Estimates of beta for European and US utilities over 2, 5 and 10 year periods

	Debt/ Equity ratio	10 year estimate (weekly)		5 year estimate (weekly)		2 year estimate (weekly)	
		Equity beta	Asset beta	Equity beta	Asset beta	Equity beta	Asset beta
European Gas Companies							
BG Group Plc[1]	0.13	0.60	0.42	0.57	0.43	0.58	0.52
Gas Natural SDG SA	0.32	0.79	0.61	0.72	0.53	0.42	0.30
Average	**0.23**	**0.70**	**0.52**	**0.65**	**0.48**	**0.50**	**0.41**
European Utilities (with gas transmission and/or distribution activities)							
OMV AG	0.27	0.68	0.47	0.58	0.42	0.46	0.36
RWE AG	2.18	0.82	0.6	0.78	0.48	0.86	0.35
Electrabel SA	0.21 (2001)	0.61	0.52	0.59	0.52	0.58	0.48
Endesa SA	2.03	0.8	0.45	0.73	0.33	0.84	0.31
EVN AG	0.42	0.49	0.4	0.39	0.29	0.29	0.21
Average	**1.02**	**0.68**	**0.49**	**0.61**	**0.41**	**0.61**	**0.34**
European Integrated Electricity Companies							
Viridian Group Plc	1.04	na	na	0.4	0.26	0.5	0.28
Union Fenosa SA	1.96	0.74	0.27	0.69	0.34	0.73	0.28
Iberdrola SA	0.91	0.61	0.31	0.51	0.31	0.49	0.26
Enel SPA	0.87	na	na	na	na	0.76	0.43
Electricidade De Portugal SA	1.64	na	na	0.57	0.33	0.67	0.30
National Grid Transco Plc[1]	1.03	na	na	0.7	0.46	0.57	0.32
Scottish & Southern Energy Plc	0.21	0.57	0.48	0.46	0.38	0.62	0.50
Average	**1.09**	**0.64**	**0.35**	**0.56**	**0.35**	**0.62**	**0.34**
US Pipeline Companies							
Western Gas Resources Inc	0.3	0.66	0.35	0.68	0.36	0.72	0.54
NiSource Inc	1.44	0.50	0.25	0.47	0.21	0.67	0.26
Dynegy Inc	14.4	na	na	1.3	0.31	1.85	0.22
EL Paso Corp	4.45	0.9	0.41	0.95	0.38	1.49	0.42
Duke Energy Corp	1.28	0.65	0.44	0.64	0.4	0.96	0.51
Equitable Resources Inc	0.34	0.56	0.38	0.57	0.42	0.65	0.50
Oneok Inc	1.62	0.70	0.34	0.71	0.29	0.88	0.30
PG&E Corp	3.00	0.57	0.24	0.56	0.19	0.61	0.17
Questar Corp	0.52	0.62	0.42	0.58	0.37	0.76	0.46
Williams Cos Inc	9.97	0.99	0.37	1.09	0.3	1.41	0.22
Average	**3.73**	**0.68**	**0.36**	**0.76**	**0.32**	**1.0**	**0.36**

Source: NERA analysis of Bloomberg data. These betas are calculated over the following periods: 05/01-05/03; 05/98-05/03; and 05/93-05/03. Betas have been estimated using the SXXP Index for European stocks and the SXP for US stocks. Raw equity betas have been adjusted as discussed in Footnote 16, and, as discussed in Section 3.1.1.1.2, unlevered using the Miller formula: Asset beta = Equity beta/(1+D/E).

(1) In October 2000, the transmission activities of British Gas were demerged into Lattice Group. Lattice has since been integrated into National Grid Transco.

Examining the different betas, we observe the following:

4.3.3.1. European Gas Transmission and Distribution Companies

NERA have identified British Gas (UK) and Gas Natural (Spain) as the closest quoted comparators for BGÉ, as both have significant gas transmission and distribution activities (BG's main transmission and distribution activities were demerged in October 2000 in Lattice, and thus the period before that date provides the better comparator – we discuss this below).[17] Over the five-year period, the estimates of these companies' asset betas are 0.43 and 0.53 respectively.

In using these two companies as comparators, the extent to which the risks faced by these companies differ from the risks faced by BGÉ should be considered. In particular, we highlight the following key considerations:

1. Additional business activities

Both British Gas and Gas Natural operate activities other than gas transmission and distribution. In the case of Gas Natural, in Q1 2003 gas transmission accounts for around 28% of the groups' EBIT with gas distribution accounting for another 57%. BG's main transmission activities in the form of Transco were demerged in October 2000 (into Lattice), and thus the period before that date provides the better comparator. In 1999, transmission and distribution activities accounted for around 74% of British Gas's revenues and 74% of profits. The following year, these figures had decreased to 32% and 11%, respectively. Prior to 1997 (the year in which British Gas's supply activities were demerged), transmission activities accounted for a smaller percentage of the company's revenues. Currently (Q1, 2003) only 18% of turnover (and 4% of profits) derive from transmission and distribution. Overall, NERA believes that the period prior to October 2000 can provide a satisfactory comparator estimate for BGÉ.

In order to take account of the change in business riskiness of BG over the period, Figure 4.1 shows British Gas's 5 year (weekly) rolling asset beta from 1988 against the FTSE 100. British Gas's beta is markedly higher in the earlier periods following its privatisation, falling steadily from around 0.5 following privatisation to around 0.4 in later periods. The average over the period is 0.45. This decline in beta may reflect a number of factors that include: (i) the increased maturity of the regulatory regime; (ii) a reduction in business/revenue risk of BG; (iii) the increased riskiness of the stock market as a whole and a reduction in relative riskiness of utility stocks.

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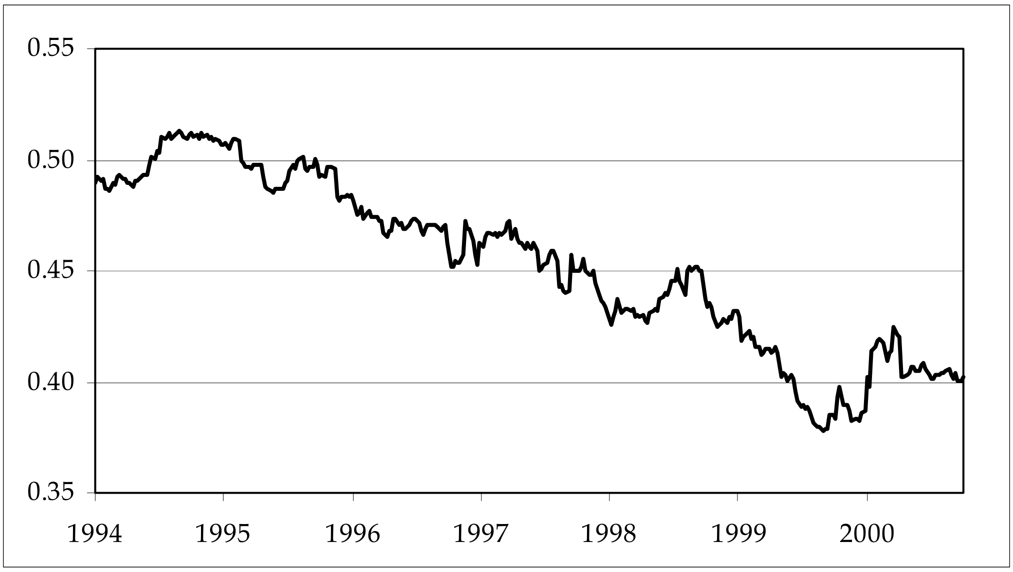
[17] Two additional potential comparators are Distrigaz (Belgium) and Lattice (UK),the latter for the period after the demerger from BG and before the merger with National Grid Group. However, as discussed above, we prefer the use of medium to long term beta estimates. For both of these companies less than 2 years of share price data is available.

Figure 4.1
BG Group, 5 Year Weekly Rolling Asset Betas



Source: NERA analysis of Bloomberg data.

We consider the relevance of the beta estimates for BG and Gas Natural for estimating BGÉ's beta in the sections below.

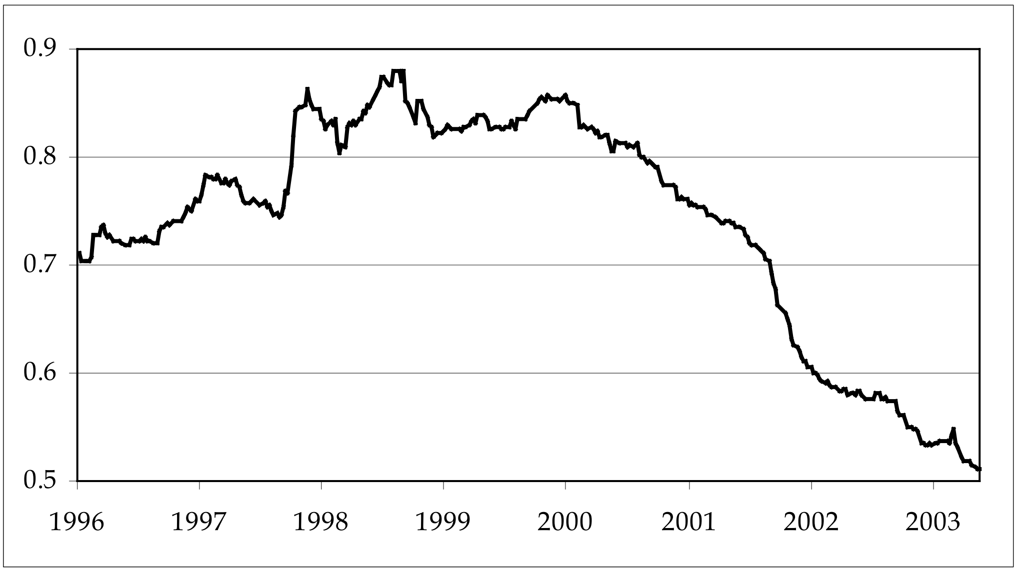
2. Maturity of Regulatory Regime

The regulatory regime in Britain is more mature than those in either Spain or Ireland. In Britain, the regulatory regime for gas has been in place since 1986 and regulatory practice is becoming well established, with mechanisms in place to spread best practice between regulators. In contrast, in Spain, new legislation was passed in 1998, with subsequent Decrees and Orders being issued regarding TPA tariffs, grid codes, etc.

This could have significant implications for the cost of capital. For example, regulatory risks in the UK are likely to be lower as greater experience of regulatory processes has made them more certain. As discussed above the fall in British Gas' beta observed over 1988 to 2000, as illustrated in Figure 4.1 above, could be a reflection of investor perception that regulatory risk has reduced as the regulatory regime matured and investors became familiar with the regulator's methodology for setting tariffs.

Figure 4.2 presents evidence on Gas Natural's rolling 5 year weekly beta against the IBEX 35 Index, over the period since 1996. It is clear Gas Natural's beta has fallen significantly since 1998, from around 0.85 in 1998 to around 0.50 currently (May 2003), with an average over the period of 0.74.

Figure 4.2
Gas Natural, 5 Year Weekly Rolling Asset Betas



Source: NERA Analysis of Bloomberg data

It could be argued that the betas observed for BG and Gas Natural at the early stages following privatisation could be seen as more relevant as a basis for estimating a beta for BGÉ now since BGÉ's regulatory framework is still in its infancy. However, it is clear that international regulators have been able to learn from other regulators' experiences in international settings and it is unlikely that investors' perceptions of the regulatory risks associated with investing in BGÉ now would be as high as the regulatory risks of investing on BG or Gas Natural in their early stages of privatisation.

3. Additional Considerations

In order to appropriately determine the cost of capital for BGÉ, it is important to understand the company's operating and regulatory environment, and to determine the extent to which various risks faced by the company will impact on its cost of capital, and the extent to which this will differ between transmission and distribution. In particular, NERA considers that a number of factors, which we understand are still undecided in the regulatory framework, could potentially influence BGÉ's cost of capital including:

- The length of the regulatory period – risk increases as the review length increases as the company is more exposed to risks of unanticipated costs and revenues. We understand that the final decision over the length of the regulatory review period is yet to be made however, the Commission is minded to adopt a three year review period for both transmission and distribution activities.

- Provisions for stranded assets – the risk that assets will be "stranded" if they are not used would increase the cost of capital of the company. We understand that there is current uncertainty with regard to whether *all* existing assets that BGÉ has historically financed will be included in the regulatory asset base with a full rate of return allowed on these assets.[18] The decision to prevent full cost recovery of existing assets could increase the cost of capital for BGÉ going forwards.

- We understand a characteristic of the Irish regulatory regime is that for a pipeline to be built a 'Consent' must first be sought from the regulator. In the absence of a Consent the investment cannot go ahead. However, if CER awards a Consent, then it is anticipated that the investment will directly enter into the asset base of the company. In other words, the company will face little uncertainty as to whether investments will be allowed to enter its asset base and earn a regulated rate of return, as they will know in advance of the decision to proceed with the investment.

- Tariff Structure and Tariff Profiles - will influence the degree of revenue risk to which the company is exposed through changes in demand and usage.

    - We understand the existing transmission charge is divided between capacity (90%) and commodity (10%) components. Decisions over the structure of future transmission tariffs have yet to be made. We understand the Commission has consulted on whether to introduce a capacity/commodity split that more closely resembles the split in BGÉ's costs between fixed and variable costs (thereby reducing revenue risks to BGÉ) than the existing 90:10 split. A revenue cap is currently envisaged though, again, no final decision has been made.

    - We understand gas transmission tariffs for 2002/3 were calculated using costs and demand over a ten-year period and were set to be constant, in real terms, over a ten-year period. With large capex programmes at the start of this ten-year period and rising demand, this has the effect of BGÉ 'under-recovering' revenues relative to costs in the earlier part of the ten-year period, but 'over-recovering' towards the end of the ten-year period.

    - An interim gas distribution tariff is in effect from July 2002 until September 2003. We understand tariffs in 2002/3 are based on an 80:20 capacity/commodity split. We understand the commission will retain a capacity/commodity split, but the proportions of the split are yet to be decided.

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18 We understand the revenues to be allowed for IC2 have been subject to considerable debate and the one option for setting revenues for IC2 includes establishing a separate, not for profit, company as owner of IC2. This may impact on the allowed rate of return on the IC2 investment which, if the allowed rate of return were set to be lower on IC2 than for the rest of BGÉ's regulated asset base, could be regarded by investors as tantamount to "partial stranding".

Further clarification of these issues is required before we are able to provide a more definitive beta estimate for BGÉ's transmission and distribution activities.

4.3.3.2. European Energy Utilities (with gas transmission and/or distribution activities)

NERA have identified a second group of comparators that includes integrated European utilities which undertake some gas transmission and/or distribution activities. The average unlevered betas for this group is 0.49 when estimated over 10 years and 0.41 over 5 years. As these companies undertake various other activities it is not clear to which extent their betas will differ from that of a "pure" gas transmission and distribution company.

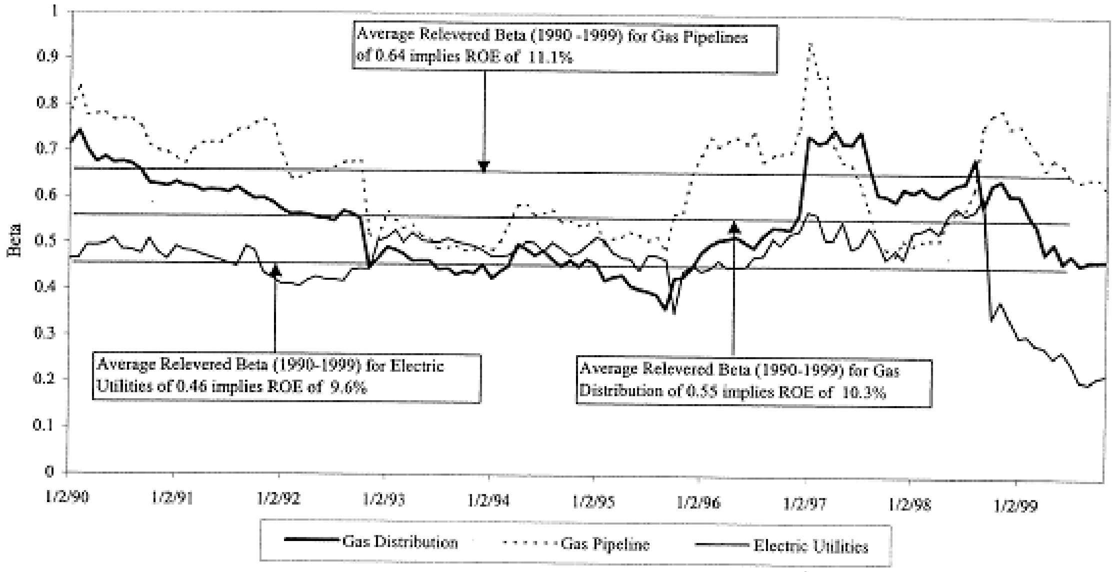
4.3.3.3. Integrated Electricity Companies

The third comparator group included are integrated electricity companies. Over the five-year period, the average estimated asset beta of this group is 0.35. This figure is lower than the beta of 0.48 of the two gas companies which we consider to be the closer comparators to BGÉ.

There is evidence to suggest that gas transmission and distribution activities have higher betas than vertically integrated electricity utilities. For example, Figure 4.3 reproduces a diagram from Cragg, Lehr and Rudkin (2001) that shows betas for three different groups of companies from 1990 to 1999: (1) vertically integrated electricity utilities; (2) gas distribution; and (3) gas transmission.[19] Over this period, the average *equity* beta of gas pipelines (0.64) was higher than the average beta of gas distribution (0.55), both of which were higher than the beta of integrated electricity utilities (0.46).

[19] Betas were computed as rolling 5-year monthly values. The betas were unlevered and then relevered at the projected Transco debt structure of 60/40.

Figure 4.3
Relevered beta comparisons for energy utilities, 1990-1999



Source: Figure 1, pg 83, Cragg, M., Lehr, W. and Rudkin, R. "Assessing the Cost of Capital for a Standalone Transmission Company", Electricity Journal, Vol. 14, No. 1, 2001.

Both our own calculations and the findings from Cragg, Lehr and Rudkin (2001) illustrate that betas from vertically integrated electricity companies are lower than betas for gas transmission/distribution companies. Electricity companies are therefore not necessarily good comparators for gas transmission activities.

4.3.3.4. US Gas Pipeline Companies

Our final group of comparator companies are US gas pipelines. The average asset beta for the sample of US pipeline companies we have estimated has been relatively stable at 0.36, 0.32 and 0.36 over the 10 year, 5 year and 2 year periods, respectively. Although these values are low relative to those quoted for the two European gas companies, significant differences in the regulatory regime makes it difficult to draw meaningful comparisons.

In part, this reflects the fact that regulatory practice in the US is well established. Procedures for establishing the return on equity are largely unchanged over the past twenty years since the application of new financial theories (i.e. CAPM and DGM) to return on equity determinations. Moreover, risks are reduced as determinations are based on actual and independent sources of data. For example, there is little dispute over betas as they are based on published, independent sources such as Value Line or Merill Lynch. For these reasons, NERA would consider these estimates to provide an absolute lower bound on the beta for a European gas company.

4.3.4. Regulatory precedent on beta

In this section we present recent regulatory precedent on beta estimates for gas distribution and gas transmission.

In Transco's price review Ofgem, considered 3 methods for determining Transco's beta (1) beta decomposition; (2) comparator companies; and (3) regulatory precedent. Ofgem commented "*The evidence that is available suggests an asset beta for Transco in the range of 0.4 to 0.5.*"[20] This contrasts with the asset beta set by Ofgem for NGC, the electricity transmission company, of 0.3 to 0.4 in September 2000. This would indicate that Ofgem took the view that the beta of gas transmission is higher than that of electricity transmission.

In June 2001, the Italian regulator (*Autorità per l'energia elettrica e il gas*) set the WACC for gas transmission at 7.94%. In comparison the regulators' set a WACC of 5.6% for electricity transmission and 7.4% for electricity distribution. Implicit within this is the view that betas for gas transmission are higher than for electricity transmission. The regulator's decision document for the regulation of gas transmission does not contain details regarding the beta that was assumed. However, using estimated values of the other parameters of the WACC and CAPM, it is possible to induce from the WACC a range of values for beta. This leads to an estimate for the implied equity beta in the range of 0.59-0.76. In comparison the regulator set an equity betas of 0.43 and 0.76 for electricity transmission an distribution activities respectively (February 1999). This evidence suggests the Italian regulator believes gas transmission to be a riskier activity than electricity transmission, but similar to electricity distribution.

Australian regulators have tended to set asset betas for gas distribution and transmission companies in a range of 0.4-0.6. Table 4.10 presents data on recent Australian regulatory decisions on the ERP for gas companies. There appears to be no discernible difference between the asset betas set for gas distribution and gas transmission.

20 Ofgem (2001) "Review of Transco's price controls from 2002 onwards Final Proposals", September; paragraph 5.17.

Table 4.10
Australian Gas Regulatory Precedent on Gas Transmission and Distribution Betas

Regulator/ company	Date	Debt beta	Asset beta	Equity beta
ACCC / Transmission Pipelines (T)	October 1998	0.12	0.55	1.20
ACCC / Transmission Access Arrangements (T)	January 2003	0.18	0.50	1.0
ECS/ Gas Access Arrangements (D)	October 2002	0-0.23	0.40-0.54	1.0
ACCC / AGL Pipelines (D)	June 2000	0.00	0.60	1.50
IPART / Albury Gas Company (D)	December 1999	0.06	0.4-0.5	0.9 – 1.1
OffGar / Parmelia Pipeline (D)	October 1999	-	0.60	1.00
ORG / Multinet, Westar and Stratus (D)	October 1998	-	0.55	1.20
IPART / AGL Gas Networks (D)	October 1999	0.06	0.4-0.5	0.9 – 1.1

Note: (T) denotes transmission company decisions; (D) denotes distribution company decisions;

4.3.5. Conclusions on Beta

NERA's analysis of the beta for BGÉ is based on consideration of a range of evidence on beta for "comparator" companies including BG (UK), Gas Natural (Spain) and a range of European integrated utility companies with gas transmission and distribution activities.

NERA favours the use of longer-term estimates of beta for several reasons:

- longer-term estimates average out system fluctuations in beta caused by the business cycle; and
- longer-term estimates of comparable companies' betas are more efficient (and have lower standard errors) than estimates over a shorter time period;
- longer term estimates of the beta for BG and Gas Natural are more appropriate as a basis for estimating the beta for BGÉ than short term estimates because the latter beta estimates, for BG especially, reflect a regulatory regime that is more mature than the regulatory regime in place in Ireland. (BG's most recent beta estimates are also not very relevant for the beta estimates for BGÉ because of the demerger between BG and Lattice in 2000).

In summary, we consider the closest comparators to BGÉ are British Gas and Gas Natural. We note that British Gas's 5 year beta prior to October 2000 was on average around 0.45. Gas Natural's current 5 year beta is around 0.50.

We note that there are a number of features of BGÉ's regulatory framework that still require clarification before a more precise estimate of beta can be derived in particular, the tariff structure formulae, length of regulatory period and clarity over treatment of IC2 pipeline. The degree to which the tariff structures reflect the true proportion of fixed and variable costs for transmission and distribution will influence the relative degree of risk to which each activity is exposed.

In light of the evidence presented NERA proposes using an asset beta in the range 0.45 to 0.55 to estimate BGÉ's WACC for both transmission and distribution. The lower value (of 0.45) corresponds to the average 5-year estimate of British Gas's asset beta prior to the demerging of Lattice. The upper value (of 0.55) corresponds to the current 5-year beta estimate for Gas Natural. This range is consistent with BGÉ's operating in a less mature regulatory environment than Transco (for which Ofgem allowed an asset beta of 0.4-0.5). It is also consistent with the lower end of the range of asset betas allowed by in recent Australian regulatory decisions on gas transmission and distribution companies.

A transparent regulatory regime with cost reflective tariffs and investor surety over the full cost recovery of future investments, may justify the use of a beta estimate of around 0.45 for setting the WACC for both transmission and distribution. This would be consistent with Ofgem's beta estimate for Transco 2001.

4.4. Forecast Inflation

To derive a real cost of capital we need a measure of the projected inflation rate. To ensure consistency, our inflation forecast has to match the term of our bond.

The inflation forecast estimate used to derive the real risk free rate from the nominal estimate, is derived from Consensus Economics' most recent annual Global Outlook publication (October 2002). The average inflation forecast over 2003 to 2012 is presented in Table 4.11.

Table 4.11
Consensus Economics' Inflation Forecasts over 2003-2012 (Consumer Prices; Average % Change on Previous Calendar Year)

	2003	2004	2005	2006	2007	2008-2012
Eurozone	1.9%	1.9%	2.0%	1.9%	1.9%	1.9%

Source: Consensus Economics (October 2002) "Consensus Forecasts Global Outlook: 2002-2012"

In conclusion, to calculate a real WACC from our nominal values, we prefer the forecast average inflation based on the consensus of private sector financial practitioners and non-governmental institutions ("the Consensus Forecasts"). This is equivalent to 1.9% per annum to 2012.

4.5. Conclusions on Cost of Equity Parameters

Bringing together the discussion in Sections 4.1, 4.2, 4.3, 4.4 and 4.5, Table 4.12 summarises NERA's recommended values for the four key parameters of the cost of equity for BGÉ. The asset beta has been be re-levered to give an equity beta estimate using the Miller formula, with the level of gearing determined as discussed in the following section.

Table 4.12
Cost of Equity Parameters

Parameter	**Best Estimate**
Nominal Risk free rate	4.48%
Equity Risk Premium	6%
Asset Beta	0.45
Inflation	1.9%
Real Cost of Equity	**8.53%**

5. COST OF DEBT

5.1. Principles for Estimating the Cost of Debt

The cost of debt can be expressed as the sum of the risk free rate and the company specific debt premium. The company specific debt premium is driven by the ratings that specialist credit rating agencies, such as Standard & Poor's (S&P), assign to that company.[21]

In essence, credit ratings are based on a number of financial characteristics such as market capitalisation, earnings volatility, and business risks specific to the company and/or the sector. However, particular regard is paid to the following two financial ratios:

- Funds From Operations (FFO) interest coverage; and
- Interest Coverage defined on earnings basis (EBIT).

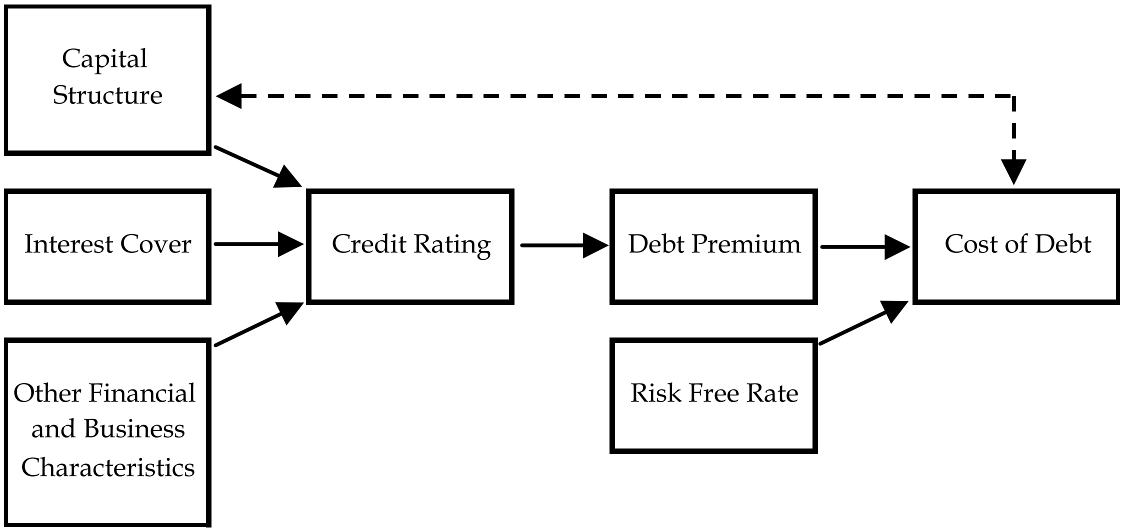
Interest cover, defined as the number of times by which a company can meet its interest payments out of operating profits, is essentially a measure of the surety of interest payments being met. A company with low interest cover is less likely to maintain a premium credit rating, since the probability of default on interest payments will be relatively high. S&P's particularly emphasises funds flow interest coverage as a rating criterion.

A company with a high gearing ratio is also less likely to maintain a premium credit rating. This reflects the fact that the probability of default on interest payments will be higher if gearing is high. It is clear that credit rating agencies, in determining credit ratings, are concerned primarily not with capital structure per se, but rather with debt service coverage levels, measured on both a cash flow and earnings basis.

Relationships between gearing and interest coverage will differ across companies according to the specific finance arrangements. Figure 5.1 summarises the postulated relationships between gearing and interest cover, credit ratings, other business and financial characteristics and the debt premium and cost of debt.

21 Some companies, particularly large and well known, choose not to be rated but still access the capital markets for debt at appropriate levels.

Figure 5.1
Relationship between capital structure, interest cover, credit rating and cost of debt



5.2. Principles for Estimating Gearing

Finance theory says that the appropriate discount rate for expected future cash flows is the Weighted Average Cost of Capital (WACC) that represents a weighted average of the expected costs of debt, equity and hybrid financing.

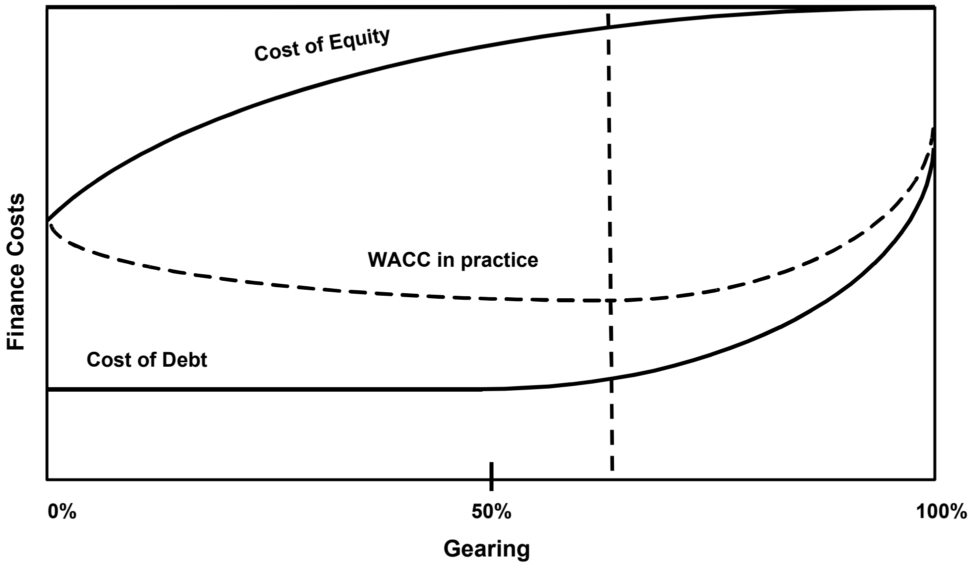
It is now generally accepted that changes in the proportion of debt and equity in the balance sheet can, in practice, have significant implications on a company's overall costs of finance. This is the result of a number of factors that occur when gearing is changed:

- Debt risk and interest rate changes;
- Equity risk changes;
- Probability of future default changes;
- Tax position (personal and corporate) changes;
- Investment strategy may change.

Academic theory cannot predict what proportion of overall finance should be raised through debt or equity. In general terms, debt is advantageous because of its low costs and tax deductibility but can be disadvantageous where personal taxes and bankruptcy costs are concerned. The optimal capital structure of a company will normally consist of a mixture of debt and equity finance.

Companies with stable cash flows and low risk profiles can absorb more debt into their balance sheets than most other types of companies. However, to assess the optimal capital structure of a utility, an empirical analysis is required that examines market evidence on how the perceptions of investors, credit rating agencies and financial markets in general are affected by capital structure changes.

Figure 5.3
Does Capital Structure Matter?



In assessing "optimal" capital structure it is important to focus not only on central case scenarios but also on downside scenarios. The possibility, for example, that capital expenditure may be substantially above central case projections may mean that an "optimal" capital structure will allow for unused borrowing capacity to increase debt in adverse circumstances. Some trade-off is likely to exist between minimising the average cost of new finance and minimising the *possibility* of financial distress and bankruptcy.

5.3. Market Based Evidence on the Cost of Debt

The cost of debt can be expressed as the sum of the risk free rate and the company specific debt premium. The company specific debt premium is driven by several factors, most notably actual (or implied) credit ratings based on financial characteristics such as market capitalisation, earnings, volatility and business risk (specific to the company and/or the industry). As a company's gearing increases the debt premium will tend to increase, reflecting the increased financial riskiness of the company.

NERA's approach to estimating a cost of debt for BGÉ is to consider market based evidence of the cost of capital for a selection of comparator companies, taking account of their credit rating and their level of gearing. In addition, we also take account of recent regulatory precedent on the cost of debt for gas companies.

BGÉ is a statutory body owned entirely owned by the Irish State. Although its issuer credit rating[22], A- by S&P (2002) and Baa by Moody's (2002), does not appear to reflect any implicit sovereign guarantee, it seems likely that that the company's cost of debt would be likely to reflect the company's its state owned enterprise status.[23]

NERA has used an estimate of BGÉ's 'market' based cost of debt instead of BGÉ's actual cost. The WACC is predicated on the "market" opportunity cost of investing funds. The CAPM approach is a market based approach focussed on estimating the market cost of equity. Competitive neutrality calls for the use of a market based measure of the cost of capital. It is not appropriate to assume that the WACC for BGÉ should be based on either the government borrowing rate or the company's embedded debt costs which are likely to reflect an element of implicit sovereign guarantee. The lower rate of return paid by the government reflects the guarantee provided by taxpayers to lenders. If BGÉ's allowed rate of return does not adequately compensate for its risks then it would be implicit that the government, and hence taxpayers, would bear shortfalls in the event that cash flows were low.

There is regulatory precedent in Ireland for taking this approach to estimating the cost of debt. CER used this approach to set the debt premium for ESB transmission and distribution in 2000. Likewise CAR used this approach for setting Aer Rianta's debt premium in 2001.

NERA's estimate of the cost of debt and optimal gearing for BGÉ is based on the assumption that BGÉ must maintain a single A- credit rating status in order to be able to raise finance in all economic conditions. This is consistent with the assumptions generally made of other regulated utilities, and is consistent with BGÉ's current credit ratings.

5.3.1. Empirical Evidence on the Cost of Debt

In this Section we present evidence on the cost of debt for a variety of maturities for a number of comparator companies which have A and A- rated bonds. In addition to the comparator companies presented in Section 4.3 for the purpose of estimating BGÉ's beta, we also present debt premia for a number of additional comparative utilities, such as UK water companies.

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22 Although as of yet BGÉ is yet to issue traded debt.

23 S&P (2002) notes with regards to BGÉ's credit rating that "The company is a statutory body owned directly by the Irish government and, although Bord Gáis' creditworthiness benefits from the support provided by its owner, the potential for the company to be privatised in the not too distant future means that a material uplift beyond its

Ideally one should match the bonds used to estimate the debt premia to the maturity of the bond(s) used to estimate the risk free rate. Consistent with the discussion of the risk free rate the medium to long term issues are the most relevant. For that reason we believe that a bond with 10 years to maturity is an appropriate reference point. To ensure consistency with the estimation of other CAPM parameters, we believe that the average spread over the last year provides a better measure of the debt premia than current spreads.

In the following we present evidence on debt premia for medium to long term (5 to 10 years to maturity or more) A rated debt issues. Table 5.1 presents evidence on debt denominated in euros.

standalone rating is not appropriate. On the assignment of the rating, no privatisation plans had been made or announced" (p.2).

Table 5.1
EUR Denominated Comparator Debt, A & A- Rated

Name	Industry Subgroup	Gearing (D/D+E)	Issue Date	Maturity Date	S&P Rating	Coupon (%)	Spot YTM (%)	Spot premia (bps)	3 month average premia (bps)	1 year average premia (bps)
International Endesa BV	Electric-Integrated	0.67	04/05/2001	04/05/2021	A	6.10	5.29	41	125	134
Telefonica Europe BV	Telephone-Integrated	0.40	14/02/2003	14/02/1933	A	5.88	5.93	127	116	na
RWE Finance BV	Electric-Integrated	0.69	20/04/2001	20/04/2016	A+	6.25	4.61	50	77	76
Long term (>10 years) average		0.58						**72**	**106**	**105**
Enbw International Finance BV	Electric-Integrated	0.47	28/02/2002	28/02/2012	A	5.88	5.99	230	214	171
Enbw International Finance BV	Electric-Integrated	0.47	12/06/2002	09/06/2010	A	5.00	4.12	65	77	na
International Endesa BV	Electric-Integrated	0.67	21/02/2003	21/02/2013	A	5.38	5.52	174	151	na
Telefonica Europe BV	Telephone-Integrated	0.40	14/02/2003	14/02/2013	A	5.13	4.55	77	95	na
AWG Plc	Water	0.71	07/02/1999	07/02/2009	A-	5.38	5.24	202	174	na
GIE Suez Alliance	Water	0.68	20/02/2002	20/02/2009	A-	5.50	4.15	101	121	99
GIE Suez Alliance	Water	0.68	26/11/2002	26/11/2012	A-	5.50	4.32	56	65	na
PowerGen U.K. PLC	Electric-Generation	0.59	07/08/1999	07/08/2009	A-	5.00	3.87	64	91	94
Suez SA	Water	0.68	13/10/1999	13/10/2009	A-	5.88	4.30	102	136	110
Telenor ASA	Telecom Services	0.41	02/04/2002	02/04/2009	A-	5.75	3.95	81	78	95
Telenor ASA	Telecom Services	0.41	12/05/2002	12/05/2012	A-	5.88	4.36	60	91	na
United Utilities Water Plc	Water	0.50	18/03/1999	18/03/2009	A-	4.88	4.91	175	141	na
Gas Natural Finance BV	Gas-Distribution	0.24	02/10/2000	02/10/2010	A+	6.13	3.80	43	52	60
RWE AG	Electric-Integrated	0.69	06/03/2002	06/03/2009	A+	5.63	3.87	67	70	79
RWE Finance BV	Electric-Integrated	0.69	26/04/2002	26/10/2012	A+	6.13	4.91	115	95	na
Medium term (5-10 years) average		**0.55**						**107**	**110**	**101**

Source: Bloomberg

The evidence shows that for euro denominated A rated long term debt the spread on relevant government benchmarks is currently around 70 basis points (bps), wheras the average over the last year has been around 105 (bps). Medium term debt premia have stayed reasonably constant, around 100-110 basis points. Overall, this suggests that the debt premia is around 105bp, based on the spread of corporate yields over risk free rates in the last year.

There is however a problem in interpreting this evidence, due to the low number of long maturity A rated utility bonds. The Euro market is still relatively immature, and the availability of long term debt (>10 years) is limited.

Evidence from the UK debt markets can therefore provide us with a useful check on the euro evidence presented above. The UK market is deeper for longer maturity bonds, as evidenced by the significant number of long term maturity utility bonds issued within the last couple of years. The sterling market is generally the main source of finance for UK utilities, particularly for long term (> 10 years) debt.

Table 5.2 summarises evidence on the debt premia for UK Sterling (GBP) denominated debt, for a number of UK utilities.[24]

Table 5.2
GBP Denominated Comparator Debt, A & A- Rated

Name	Industry Subgroup	Gearing (D/(D+E))	Maturity Date	S&P Rating	Coupon (%)	Average Spot YTM (%)	Spot Premia (bps)	3month average premia (bps)	1 year average Premia (bps)
National Grid Co Plc (average)	Electric - transmission	0.51	2006 – 2028	A	4.25-8	5.16	94	118	125
Transco Plc (average)	Gas-Distribution	0.50	2006-2028	A	5.375-8.875	4.89	81	100	104
Average A Rated		**0.51**				**4.97**	**82**	**104**	**109**
AWG Plc (average)	Water	0.71	2006 – 2030	A-	6.293 – 8.25	5.18	93	103	117
Dwr Cymru	Water	0.93	2021	A-	6.907	5.53	111	118	118
PowerGen U.K. (average)	Electric-Generation	0.59	2024	A-	6.25	5.62	125	153	133
Transco Holdings Plc	Gas-Distribution	0.50	2024	A-	7	5.71	126	143	160
United Utilities (average)	Water and Electric Distribution	0.50	2010- 2027	A-	5.25-8.875	5.18	83	105	107
Average A- Rated		**0.65**				**5.30**	**97**	**121**	**123**

Source: NERA analysis of Bloomberg data

24 More detail on these bonds are provided in Appendix B.

Table 5.2 shows that for GBP denominated debt the spread on relevant government benchmarks is currently around 80 basis points (bp) on average for A rated debt, with A-rated debt on average around 100bp. It is also clear that the average debt spread has fallen in recent times. Average debt spreads for A- rated companies over the period May 2002 – May 2003 are around 100-125bp. Overall current spreads are around 25bp lower that the average over the last year. This is likely to be result of the current high levels of equity market volatility. For the bonds in Table 5.2 which have 10 or more years to maturity the average current spread is 103bp, with the average over the previous year being 128bp.

The table also provides evidence that on average there is a around 15bp difference between the debt premia on A and A- rated bonds.

This would suggest that the average 105bp debt premium found on long term euro denominated bonds above, which were rated A and A+, would correspond to around 120bp for an A- rated bond. This is thus consistent with the evidence from the UK market.

Overall, the evidence suggests a debt premia for an A- rated company of around 125bp.

Based on the overarching principle underlying the estimation of the cost of debt, we consider it useful to examine the extent to which the cost of debt compares to coupons on recently issued debt issues. It is clear from the previous tables that recent coupons lie in a range of 5.13% to 5.88% (both issued by Telefonica), with Endesa's recent bond coupon in the middle of that range and United Utilities at the higher end of the range. Our overall estimate of the cost of debt (excluding issuance costs), using the nominal risk free rate estimated in Section 4.1 of 4.48% and the debt premium of 125bp is 5.73%. This estimate is therefore consistent with recent coupons observed in the euro and sterling debt markets on long term utility debt.

5.3.1.1. Transaction costs

It is important to emphasise that the costs of debt finance quoted above exclude the costs of issue, bank, legal, trustee and paying agent fees. In addition, corporate issues are usually made at a discount to par to meet investors preferred tax positions (the discounted part of returns is treated as capital gain) and it is market practice to round the coupon payment to the nearest $^1/_8$% (0.125%). We understand that this typically adds an extra 10-15 basis points to coupons for fees and discounting arrangements.

5.3.1.1.1. Regulatory precedent for inclusion of debt issuance costs in the allowed cost of debt

In its review of Mid Kent Water and Sutton and East Surrey Water, the Competition Commission (2002a, 2002b) noted that the *"cost of debt should include both interest payments and fees"*, although it did not disclose its estimates of the magnitude of any such costs for MKW and SESW. The CAA (2001) has also noted that fees should be considered: *"fees are a factor to* *be taken into account, however, if fees were to be incurred they should clearly be treated as* *one-off costs*" (p31).

It is common for US rate of return decisions to incorporate a flotation cost adjustment to account for the direct expenses and underwriting fees when estimating the allowed return on equity. However, the cost of debt for regulated utilities in the US is computed by determining companies' actual level of interest obligations based on specific outstanding debt instruments, with allowances usually being made for issuance costs, premia or discounts at the time of issue as well as sinking fund and call provisions being taken into account (see Morin (1994) and Phillips (1993)).

In Australia a number of regulatory decisions have allowed an adjustment to the cost of debt to allow for non-margin debt issuance costs. The ACCC has recently allowed margins for bank fees and dealer swap margins incurred in the raising of debt finance. For example, in its price review the South Australian electricity transmission network service provider, ElectraNet, the Australian Competition and Consumer Commission (ACCC) added 10.5 basis points to the benchmark cost of debt, from a range of 10.5-12.5bps under the assumption that A-rated companies would lie at the lower end of the cost range (ACCC, 2002). For the access arrangements of GasNet ACCC allowed 12.5bps for such costs as swap cists, dealer fees and legal fees (ACCC, 2003). Likewise, in its recent review of gas access arrangements the Essential Services Commission (ECS) in Victoria made an allowance of 5 basis points to reflect the non-margin establishment costs of debt issuance (ECS, 2002).

5.3.2. Gearing

Gearing is a measure of the ratio of debt to debt plus equity. Since the market returns on debt and equity vary, as do tax implications of each, the gearing ratio can have a significant impact on the final WACC. Companies take on debt because interest payments can be offset against their corporate tax liability- the "tax shield" effect. However, a company that operates in a lower tax environment has less incentive to increase debt, because the relative value of the tax shield is lower. Thus in a low tax regime the tax shield effect is reduced.

It is important to ensure that the gearing level used to estimate the cost of capital is consistent with the assumed credit rating used to estimate the debt premia.

Table 5.1 and Table 5.2 present actual market gearing ratios for the comparator companies used to estimate the debt premia. This shows that the gearing levels of these companies lie in a range of 0.24 (Gas Natural) to 0.71 (AWG), with an average of around 0.57.

NERA has estimated the cost of capital (and levered BGÉ's estimates asset beta) on the basis of an assumed optimal gearing level of 55%. This is slightly lower than BGÉ's current gearing level of around 60%. However, it is in line with BGÉ's projected target gearing level. S&P's (2002) report on BGÉ's suggests that the current book gearing level (2003-2004) is around 60% but will be reduced over time to the company's preferred gearing level of 50%-55%.[25]

5.4. Regulatory Precedent on the Cost of Debt and Gearing

Regulatory precedent on cost of debt decisions for utilities have little relevance for the best estimate of the (market) cost of debt for BGÉ as the future cost of raising debt finance changes over time as it reflects changing market conditions and changes in the economic cycle. However, we note that CER estimated a cost of debt for ESB in September 2001 of 150bp, based on companies with *"a similar mix of assets to ESB, and facing similar commercial and regulatory risks"* (p19). CER based its cost of capital estimate on an optimal gearing level of 50%.

5.5. Conclusion on the Cost of Debt and Gearing

NERA has estimated the debt premia for BGÉ on the assumption that BGÉ must maintain a single A- credit rating status in order to be able to raise finance for its capital investment programme in all economic conditions. In the light of the evidence presented above on the cost of debt for BGÉ comparator companies averaged over the last year, NERA's estimate of BGÉ's debt premium would be in the region of 125 basis points for a maturity of 10 years (which is the maturity used for estimating the risk free rate). To this we add an allowance for debt issuance costs. The evidence suggests that this is in a range of 10-15bp. We estimate the cost of debt using the middle of this range, 12.5bp. Our overall debt premium for BGÉ is therefore 137.5bp. Added to a nominal risk free rate of 4.48%, this corresponds to an overall cost of debt for BGÉ of 5.86%.

Overall, NERA believes that for the purpose of estimating BGÉ's cost of capital a gearing of 55% is appropriate. A gearing figure of 55% is slightly higher than the 50% CER used for electricity transmission and distribution. However, it is consistent with the gearing level on which BGÉ's credit ratings are based and also with the debt premium derived above.

[25] Standard and Poor's (2002) "Bord Gais Eireann", Infrastructure Finance, 5 August.

6. WACC AND TAXATION

Investors are concerned with the post tax returns, and according to finance theory, will supply capital in a manner that will maximise the expected after tax return from their investments. A company must return to its investors the post tax return that is appropriate for the risk associated with that investment. Shareholders and debt holders will supply capital in the manner that will maximise the expected post tax returns from their investment. The presence of taxation drives a wedge between the returns that the company receives and the returns received by the providers of finance. Regulators need to ensure that required revenues cover both a reasonable post-tax rate of return on the assets involved, and cover the corporate income taxes that businesses are required to pay (which will itself be a function of the allowed rate of return and the asset base).

The discussion below explains the difference between the different definitions of the WACC.

6.1. Post Tax Net of Debt Tax Shield

The standard expression for the "post-tax" WACC of a firm, often referred to in regulatory decisions, is the "post tax WACC net of debt tax shield" as defined as follows:

(6.2) Post Tax WACC "Net of Debt Tax Shield" = r_e*(E/D+E)+r_d*(1-t)*(D/D+E)

where:
- r_e is the declared/regulatory real post tax cost of equity;
- r_d is the real declared/regulatory cost of debt;
- D is a firm's debt;
- E is a firm's equity; and
- t is the debt tax shield rate.

The "Post Tax WACC Net of Debt Tax Shield" specifies the cost of debt in a manner which reflects the tax deductibility of interest payments, by multiplying the gross cost of debt by (1-debt tax shield rate).

As an allowed return, the "Post Tax Net of Debt Tax Shield" WACC is appropriate if the regulator makes no allowance for the tax deductibility of interest payments in the allowance for taxation. The Post Tax Net of Debt Tax Shield WACC can differ significantly across companies if the debt tax shields of companies are different.

6.2. The Post Tax "Vanilla" WACC

An alternative definition of the post tax WACC, the "Post Tax Vanilla WACC", otherwise referred to as the post tax gross of debt tax shield WACC, is defined as:

(6.1) "Vanilla" Post Tax WACC = r_e*(E/D+E)+r_d*(D/D+E)

The Vanilla post tax is the return to capital after both corporate tax and any imputation credits have been accounted for elsewhere in a business's cash flows.

If the WACC is set on a post-tax "Vanilla" basis, this seemingly avoids the need for a complex conversion formula. In this case, however, taxation costs need to be directly incorporated in allowed revenue, as an additional operating cost. Tax costs can be estimated using a financial model of expected cashflows. In a real, RPI-linked regulatory system, projections of the cost of tax require an assumption on the expected rate of inflation, and the cashflows allowed to cover the cost of tax then need to be deflated by the expected inflation rate.

The tax treatment of interest payments is a main determinant of the capital structure of companies, and in turn *could* affect the calculated Vanilla WACC. The precise impact on the Vanilla WACC of differences in capital structures of companies is unclear and a large body of theoretical literature has considered this issue without reaching a true consensus.[26]

6.3. Pre Tax Approach

The generic formula used for a re-tax WACC is as follows:

(6.2) Pre-tax $WACC = r_e * \frac{E}{E+D} * t_{adj} + r_d * \frac{D}{E+D}$

where:

t_{adj} is the tax adjustment factor used to convert the post-tax cost of equity to a pre-tax figure. As interest on debt is tax deductible, this is applied to r_e only.

The pre-tax approach focuses on "scaling-up" the post-tax rate of return to a pre-tax rate of return. The problem of scaling-up from a post-tax to a pre-tax WACC is fundamentally an algebraic one. Various conversion formulas are used to try and reconcile pre- and post- tax WACC formulations. Normally these calculations make certain assumptions about, for example, the extent of any tax allowances. However, none of the conversion formulae commonly proposed are generally complex enough to account of all interacting factors. Issues of timing are frequently ignored, as this approach attempts to approximate the tax position of the company in long run equilibrium. There is, therefore, a trade-off between the

[26] See for example *Myers, S.C. "Determinants of Corporate Borrowing" Journal of Financial Economics, November 1977, 147-176. Jensen, M., "Agency Costs of Free Cash Flow, Corporate Finance, and Takeovers," American Economic Review, May 1986, 76, 323-329.*

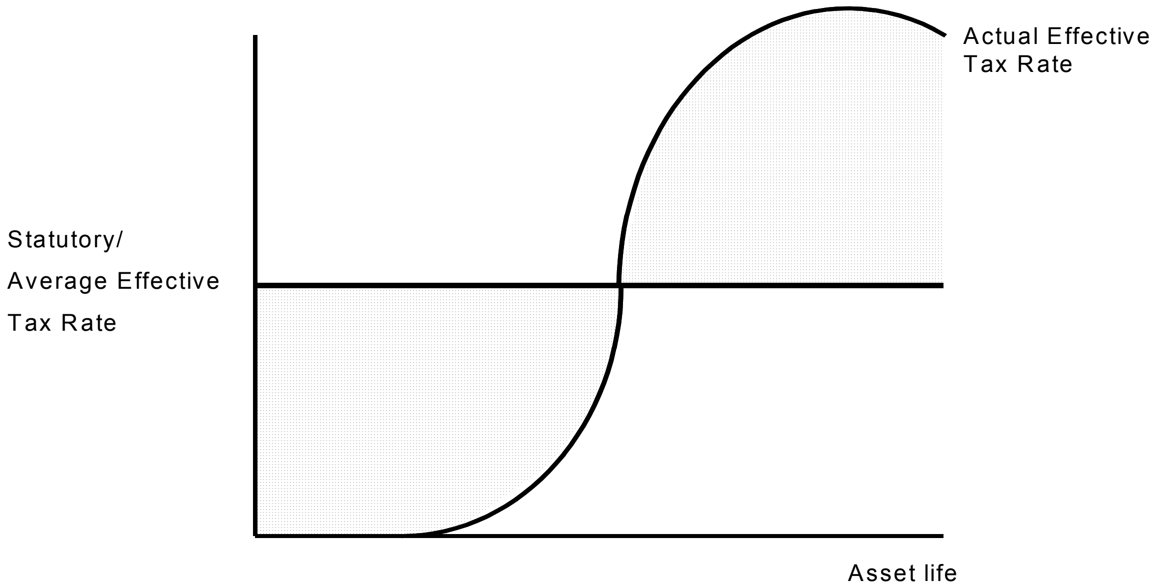
complexity of the formula and its degree of accuracy in accounting for the full impact of taxation on the return earned.

6.4. The Use of a Pre Vs. Post Tax WACC

In assessing whether a pre or a post tax WACC should be used, the tax position of the company should be taken into account. The pre tax methodology applies a constant tax rate over the regulatory period, whereas the post tax methodology requires explicit tax modelling and can thus result in an uneven tax profile. In cases where the tax paying position of the company is uncertain due to significant capital allowances, the use of actual tax cash flow modelling may be preferable.

The proponents of a post tax WACC approach argue that since this approach aims to set the tax allowance to equal actual tax liabilities, then it would ensure that the post tax cash flows to investors would be equal to the estimated post tax WACC over the regulatory period.

Figure 6.1
The "S" Curve Effect



Proponents of a post tax WACC approach argue that it is important from an allocative efficiency perspective to ensure that tax allowances are set in accordance with actual tax liabilities to ensure that marginal investment decisions are not distorted. It is argued that the financial consequences of the "S" curve under a pre-tax WACC system, where regulated businesses receive cash from customers for tax liabilities in advance of their actual payment, would be to encourage "over-investment" in early years (when post-tax returns are higher than necessary) and potentially causing under-investment when post-tax returns fall below the market requirement.

Examination of BGÉ's 2002 accounts shows that the company has significant capital allowances, which results in its actual cash tax payments having been very low over 2001 (approximately 4%) and 2002 (0% before disposal of assets).

For the purpose of setting the cost of capital, NERA therefore recommend that the Commission may consider using a "Vanilla" post tax WACC rather than a pre tax WACC and set tax liabilities akin to an "operating cost" through financial modelling of projected tax liabilities.

For illustrative purposes NERA has derived a pre-tax WACC estimate, using the statutory Irish corporation tax rate of 12.5%[27]. As noted above, however, this does not take account of of the actual tax paying position of BGÉ, or any change thereto for example the extent to which the future capital expenditure programme and the related planned increase in gearing will lead to significant changes in capital allowances etc. NERA suggest that the regulator consider supporting their decision on the appropriate pre tax and/or post tax WACC with financial modelling of BGÉ's projected tax liabilities.

[27] KPMG (2003) "Corporate Tax Survey 2003", January.

7. SUMMARY: COST OF CAPITAL FOR BGÉ

Table 7.1 summarises NERA's our estimate for the likely range of BGÉ's cost of capital in the context of a European market. NERA's best estimate of BGÉ's real pre tax WACC is 6.54%.

Table 7.1
NERA's estimated range for BGÉ's cost of capital

		Low	High	Best estimate	Calculation
1	Risk free rate (nominal)	4.48%	4.48%	4.48%	
2	Inflation	1.90%	1.90%	1.90%	
3	Risk free rate (real)	2.53%	2.53%	2.53%	(1+[1])/(1+[2])-1
4	Debt premium (incl. issuance costs)	1.38%	1.38%	1.38%	
5	Cost of debt (real)	3.91%	3.91%	3.91%	[3] +[4]
6	ERP	5.0%	7.0%	6.0%	
7	Tax	12.5%	12.5%	12.5%	
8	Asset beta	0.45	0.55	0.45*	
9	Equity beta	1.00	1.22	1.00	[8]*(1+[12])
10	**CoE (real, post tax)**	**7.53%**	**11.09%**	**8.53%**	[3]+[9]*[6]
11	Gearing (D/D+E)	0.55	0.55	0.55	
12	Leverage (D/E)	1.22	1.22	1.22	[11]/(1-[11])
13	**Real Vanilla WACC**	**5.54%**	**7.14%**	**5.99%**	**[11]*[5]+(1-[11])*[10]**
14	Real post tax WACC (NDTS)	5.27%	6.87%	5.72%	[11]*[5]*(1-[7])+(1-[11])*[10]
15	**Real pre-tax WACC**	**6.02%**	**7.85%**	**6.54%**	[14]/(1-[7])

(*) Note, that NERA's best estimate of BGÉ's asset beta of 0.45 is subject to the comments made in Section 4.3 regarding pending clarification on aspects of the regulatory regime.

On a pre tax basis, NERA's best estimate of BGE's real cost of capital is 6.54% assuming an effective tax rate of 6.54%. On a post tax basis, NERA's best estimate of BGE's real cost of capital is 5.99%.

APPENDIX A. COMPARATOR COMPANIES

As BGÉ is not a publicly quoted company, it is not possible to directly estimate the company's beta. Instead, we rely on rely on beta estimates for "comparator" companies to derive a proxy beta estimate for BGÉ. This is described in more detail in Section 4.3.1. In this section, we present the brief descriptions of the comparator companies.

Table A.1
Comparator Information

Company name	**Brief Description**	**Sales by region (%) 2002**	**Sales by activity (%) 2002**
EUROPEAN GAS TRANSMISSION COMPANIES			
BG GROUP PLC	BG Group plc specializes in the exploration, production, transmission and distribution of gas, oil and liquefied natural gas. The Group also develops, owns and operates gas-fired power generation plants, in addition to providing underground and offshore gas storage facilities. BG has interests in some 20 countries, encompassing operating assets on four continents.	Domestic 50%	Transmission & Distribution 21%
GAS NATURAL SDG SA	Gas Natural SDG, S.A. distributes natural gas in Spain and Latin America. The Company also operates gas storage facilities, owns and operates a fiber optic backbone telecommunications network, markets energy management products and household gas appliances, and installs gas heating systems.	2001 Domestic 80%	2001 Natural gas sales 75%
EUROPEAN UTILITIES (with gas transmission and/or distribution activities)			
OMV AG	OMV AG explores for and refines crude oil and natural gas. The Company sells refined products through gas stations and distributors. The Company also manufactures plastics such as polyolefins and technical plastics. Customers are in the automotive, electrical, and construction industries.	Domestic 57% Other Europe 41%	Gas 21% Refineries & marketing 69%
RWE AG	RWE AG operates energy businesses and offers municipal services. The Company generates electricity, mines coal, produces natural gas, refines petroleum, offers waste disposal and recycling services, supplies drinking water, manufactures printing presses, decommissions nuclear power plants, and disposes of nuclear waste.	Domestic 57%	Energy 66%
ELECTRABEL	Electrabel SA generates and sells electricity and distributes natural gas. The Company distributes electricity to consumers and industrial customers, distributes fuel to nuclear power stations, and manages the nuclear fuel cycle. Electrabel also produces and distributes steam and drinking water to customers and offers cable television services.	Domestic 46%	Gas 24%
ENDESA	Endesa, S.A. generates, distributes, and trades electricity in Spain and Latin	Domestic 67%	

Company name	Brief Description	Sales by region (%) 2002	Sales by activity (%) 2002
	America. The Company distributes natural gas, operates co-generation plants, treats and distributes water, and, through subsidiaries, offers telephone, Internet access, and cable and digital television services.		
EVN AG	Second largest Austrian regional gas and electricity utility; part-privatised in 1989-90; State retains 51 per cent of capital. EVN AG generates and distributes electricity, heat, and gas. The Company buys most of its electricity from other companies, and operates thermal and hydroelectric generating plants and a wind power park. EVN also distributes water.	Domestic 100%	Gas Distribution 37%
EUROPEAN INTEGRATED ELECTRICITY COMPANIES			
VIRIDIAN GROUP PLC	Viridian Group PLC operates a utility company which procures, transmits, distributes and supplies electricity. The Group's main subsidiary, Northern Ireland Electricity plc, buys energy in bulk from independent power generating companies and distributes it to other retail suppliers and customers in Northern Ireland. Sx3 is the Group's information technology and business support services group.	Domestic 100%	Electric Services 100%
UNION FENOSA SA	Union Fenosa, S.A., produces, transmits, and markets electricity. The Company also designs and develops water supply and waste treatment systems. Through subsidiaries, Union Fenosa operates security systems and telecommunications, electrical equipment, and real estate management businesses.	Domestic 67%	Electric Utility 100%
IBERDROLA SA	Iberdrola S.A. generates, distributes, trades, and markets electricity in Spain, Portugal, and Latin America. The Company operates nuclear, hydroelectric, oil-fueled, coal-burning, and combined cycle natural gas plants. Iberdrola also markets natural gas, constructs, promotes, and operates wind farms, and offers engineering, real estate, and telecommunications services.	Not reported by Company	Electric Services 100%
ENEL SPA	Enel S.p.A. generates, transmits, distributes, and trades electricity. The Company operates hydroelectric, geothermal, and other generating plants. Enel, through subsidiaries, also provides fixed-line and mobile telephone services, installs public lighting systems, and operates real estate, factoring, insurance, telecommunications, and Internet service provider businesses.	Domestic 94%	Electric Services 74% & Natural Gas 3%
ELECTRICIDADE DE PORTUGAL SA	EDP - Electricidade de Portugal, S.A. generates, transmits, and distributes electricity in Portugal. Through subsidiaries, the Company also operates in the telecommunications, natural gas, water and sewage treatment, and information technology industries. EDP also operates in Latin America, Africa, and Asia through its control over energy distribution companies.	2001 Domestic 81%	2001 Electric Power 92%

Company name	Brief Description	Sales by region (%) 2002	Sales by activity (%) 2002
NATIONAL GRID TRANSCO PLC	National Grid Transco PLC owns, operates and develops electricity and gas networks. The Group's electricity transmission and gas distribution networks are located throughout United Kingdom and in the north-eastern section of the United States. They also own liquefied natural gas storage facilitites in Britain and provide infrastructure services to the mobile telecom industry.	Europe 39% , US 61%	Transmission & Distribution 79%
SCOTTISH & SOUTHERN ENERGY	Scottish and Southern Energy plc generates, transmits, distributes and supplies electricity to industrial, commercial and domestic customers in England, Wales and Scotland. The Group also provides electrical and utility contracting services, environmental control systems for the pharmaceutical and manufacturing sectors, and supplies natural gas.	Domestic 100%	Electricity Sales 91%
US PIPELINE COMPANIES			
WESTERN GAS RESOURCES INC	Western Gas Resources, Inc. gathers, processes, transports, and produces gas, as well as markets energy. The Company designs, constructs, owns, and operates natural gas gathering, processing, and treating facilities in the major gas-producing basins of the United States. Western Gas Resources also trans-ports and produces gas in the Powder River Coal Bed Methane Development.	Domestic 100%	Gas Distribution 100%
NISOURCE INC.	NiSource Inc. is a holding company, whose operating companies engage in all phases of the natural gas business from exploration and production to transmission, storage and distribution, as well as electric generation, transmission and distribution.	Domestic 100%	Gas distribution 45% transmission 16%
DYNEGY INC.	Dynegy Inc. produces and delivers energy, including natural gas, power, natural gas liquids, and coal, through its owned and contractually controlled network of pipelines and other physical assets. The Company serves its customers by aggregating production and supply, and also by the physical generation of electricity.	Domestic 86%	Transmission and distribution 27% Midstream services 59%
EL PASO ENERGY CORPORATION	El Paso Corporation conducts operations in natural gas transportation, gas gathering and processing, and gas and oil production. The Company also has operations in power generation, merchant energy services, international project development, and energy financing.	Domestic 89%	Pipelines 20% Merchant energy 67%
DUKE ENERGY CORPORATION	Duke Energy Corporation is a diversified multinational energy company with an integrated network of energy assets and expertise. The Company manages a portfolio of natural gas and electric supply, delivery, and trading businesses.	Domestic 86%	Gas Transmission 15%

Company name	Brief Description	Sales by region (%) 2002	Sales by activity (%) 2002
	.		
EQUITABLE RESOURCES INC.	Equitable Resources, Inc. is an integrated energy company with natural gas production in the Appalachian area, natural gas transmission and distribution, and energy management services. The Company also has a passive investment in Westport Resources Corporation.	Domestic 100%	Utilities 61%
ONEOK INC.	ONEOK, Inc. provides environmentally clean fuels and products. The Company purchases, gathers, compresses, transports, and stores natural gas for distribution to consumers. ONEOK also drills for and produces oil and gas, extracts and sells natural gas liquids, and markets gas. The Company distributes natural gas to customers in Oklahoma and Kansas.	Domestic 100%	Distribution 43%
PG&E CORPORATION	PG&E Corporation provides energy services throughout North America. The Company owns a regulated utility in addition to natural gas transmission facilities, electric generation facilities, commodity trading operations, and a retail energy services company.	Domestic 100%	Gas services 16% Gas utility 19%
QUESTAR CORPORATION	Questar Corporation is an integrated energy services holding company which operates through its market resources and regulated services divisions. The Company develops and produces energy, gathers and processes gas, and trades wholesale gas, electricity, and hydrocarbon liquids. Questar also conducts interstate gas transmission and storage activities.	Domestic 100%	Gas distribution and transmission 56%
WILLIAMS COS INC.	The Williams Companies, Inc. is involved in energy-related activities. The Company transports and stores natural gas, explores for and produces oil and natural gas, and transports petroleum products. Williams also refines petroleum products, produces and markets ethanol, processes and treats natural gas, and markets and trades energy and energy related commodities.	Domestic 85%	Gas Pipelines 25% Midstream Gas & Liquid 33%

Source: Bloomberg and company annual reports

APPENDIX B. COMPARATOR DEBT

Table B.1
A & A- Rated Comparator Debt Issues: Yield to Maturity and Debt Premia

Name	Industry Subgroup	Issue Date	Maturity Date	S&P Rating	Coupon (%)	Maturity type	Coupon type	Spot YTM (%)	3 month average (%)	1 year average YTM (%)	Spot premia (bps)	3 month average premia	1year average premia
National Grid Co Plc	Electric-Transmission	02/07/1996	29/03/2006	A	8	At maturity	Fixed	4.18	4.39	4.90	60	77	78
		20/03/2003	12/10/2010	A	4.75	At maturity	Fixed	4.63	5.00	5.00	55	na	na
		02/02/1999	02/02/2024	A	5.875	At maturity	Fixed	5.38	5.69	5.89	94	117	127
		27/07/2001	27/07/2028	A	6.5	At maturity	Fixed	5.48	5.71	5.86	102	119	124
Average								5.16	5.47	5.58	84	118	125
Transco Plc	Gas-Distribution	21/12/2000	12/07/2006	A	6.125	At maturity	Fixed	4.36	4.58	5.05	67	81	82
		12/07/2001	12/07/2007	A	5.625	At maturity	Fixed	4.57	4.77	4.78	76	na	na
		07/08/1993	07/08/2008	A	8.875	At maturity	Fixed	4.53	4.81	5.25	66	89	91
		03/11/1999	12/07/2009	A	5.375	At maturity	Fixed	4.65	4.96	5.37	67	86	93
		30/01/2002	06/07/2017	A	6	At maturity	Fixed	5.29	5.55	5.81	95	115	121
		27/06/1995	27/06/2025	A	8.75	At maturity	Fixed	5.45	5.71	5.86	100	120	125
		10/02/1998	10/02/2028	A	6.2	At maturity	Fixed	5.36	5.60	5.71	98	108	109
Average								**4.89**	**5.14**	**5.40**	**81**		
Average A Rated								**4.97**	**5.24**	**5.46**	**82**	**104**	**109**
AWG Plc	Water	30/07/2002	30/07/2030	A-	6.293	At maturity	Fixed	5.52	5.74	5.81	107	na	na
		29/11/1996	29/11/2006	A-	8.25	Callable	Fixed	4.37	4.57	5.09	69	81	86
		21/08/1998	21/08/2023	A-	6.875	Callable	Step cpn	5.38	5.63	5.94	95	112	132
		15/01/1999	15/01/2029	A-	6.625	Callable	Step cpn	5.45	5.69	5.94	101	117	132
Average								5.18	5.41	5.70	93	103	117
Dwr Cymru	Water	05/10/2001	31/03/2021	A-	6.907	Callable	Fixed	5.53	5.70	5.80	111	118	118
PowerGen U.K. Plc	Electric-Generation	29/04/1999	29/04/2024	A-	6.25	At maturity	Fixed	5.62	6.05	5.95	126	153	133
		29/04/1999	29/04/2024	A-	6.25	At maturity	Fixed	5.62	6.05	5.95	125	153	133
Average								5.62	6.05	5.95	125	153	133

Name	Industry Subgroup	Issue Date	Maturity Date	S&P Rating	Coupon (%)	Maturity type	Coupon type	Spot YTM (%)	3 month average (%)	1 year average YTM (%)	Spot premia (bps)	3 month average premia	1year average premia
Transco Holdings PLC	Gas-Distribution	14/12/1999	16/12/2024	A-	7	Callable	Fixed	5.71	5.95	6.22	126	143	160
United Utilities	Water & Electric Distribution	22/10/2002	22/01/2010	A-	5.25	At maturity	Fixed	4.46	4.81	5.04	48	na	na
		14/05/2003	14/05/2018	A-	5.375	At maturity	Fixed	4.99	na	na	65	na	na
		08/03/1995	25/03/2026	A-	8.875	At maturity	Fixed	5.25	5.55	5.68	82	103	106
		08/03/1995	25/03/2026	A-	8.875	At maturity	Fixed	5.25	5.58	5.71	81	106	109
		20/12/2002	20/12/2027	A-	5.625	At maturity	Fixed	5.37	5.54	5.50	93	na	na
		14/04/2003	20/12/2027	A-	5.625	At maturity	Fixed	5.73	na	na	128	na	na
Average								5.18	5.37	5.48	83	105	107
Average A- Rated								**5.30**	**5.57**	**5.72**	**97**	**121**	**123**

Source: Bloomberg