Oxera

What is the cost of equity for RIIO-T1 and RIIO-GD1?

Prepared for Energy Networks Association

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Executive summary

The next electricity and gas transmission price control review and the next gas distribution price control review (RIIO-T1 and RIIO-GD1 respectively) are the first price controls that will reflect the new RIIO (Revenue = Incentives + Innovation + Outputs) model.

Ofgem is taking a different approach to setting allowed returns in the RIIO model than in the past. The key changes include:

– annual indexation of the cost of debt;
– setting the gearing assumption for each regulated company based on an assessment of that company's cash-flow volatility.

In addition, the RIIO model introduces other fundamental changes to regulatory asset lives, capitalisation policy and depreciation profiles, which have the effect of increasing the time until CAPEX is recovered from customers through depreciation of the regulatory asset value (RAV), which in turn increases the duration of cash flows.[1]

In its December 2010 consultation, Ofgem has relied on the capital asset pricing model (CAPM) to estimate its initial cost of equity range, as in previous determinations. However, a number of changes since the last electricity and gas transmission and gas distribution price control reviews make the use of the CAPM approach to determine the cost of equity more challenging for the RIIO-T1 and GD-1 reviews. For the next round of reviews, Ofgem will need to consider how to:

– take into account the impact of the financial crisis;
– assess the fundamental risk exposure of regulated energy networks given the shortage of relevant market data, not least because of the de-listing of Scottish Power in 2007;
– set an appropriate allowance to mitigate the risk of creating an underinvestment problem during the longer eight-year control period;
– evaluate the impact of the RIIO proposals in relation to incentives, uncertainty mechanisms, and asset lives, which will affect the profile and risk of the companies' cash flows.

This report estimates the cost of equity using the CAPM framework, which produces a real post-tax cost of equity with a range of 5.1–7.5%. However, the lower end of this range is based on estimates of beta over the past two years, which are significantly lower than estimates over the past five years. Without independent evidence that there has been a fundamental decrease in the risk profile of the assets of these network companies over this period, it is prudent to place more weight on the upper end of this range, or to rely on data calculated over a longer time period.

Furthermore, taking into account the challenges of applying the CAPM framework in the current financial and regulatory context, this range is cross-checked against two alternative sources of information on the level of returns required by equity. The first cross-check is the estimates produced from applying the dividend growth model to the two most directly relevant publicly listed comparators: National Grid and Scottish & Southern Energy. This produces a range of 8.7–9.2% based on assumed long-run real dividend growth of 2.2%, or 6.5–7.0% based on the highly conservative assumption of zero long-run dividend growth.

[1] See Oxera (2010), 'What is the impact of financeability on the cost of capital and gearing capacity?', report prepared for Energy Networks Association, June 9th.

The second cross-check is whether the premium for equity risk implied by the CAPM range is sufficiently high relative to the debt premium (ie, spread) over gilt yields at which debt issued by regulated energy networks is currently trading. The premium for equity risk that corresponds to a cost of equity estimate within the CAPM framework of 5.1% is 1.26%, which compares to an average debt spread of 124bp for a sample of energy network bonds. The lower end of the CAPM range is therefore comparable to the level of premium currently required by debt-holders. Although this comparison does not allow for any loss given default, such a 'raw' comparison would provide evidence to equity-holders which suggests too low a premium relative to the risks borne.

Both cross-checks therefore suggest consideration of a higher range than that generated by applying a one-period CAPM approach to the market evidence. Furthermore, the size of the discrepancy between the CAPM range and the cross-checks suggests that it is prudent and necessary to consider whether the CAPM is systematically failing to capture factors that determine the returns required by equity investors in regulated energy networks. One such factor that is relevant to the RIIO proposals is the link between cash-flow duration and the cost of equity.

As a one-period model, which assumes that discount rates and risk premiums are constant over time, fundamentally the CAPM cannot capture the impact of time profiling of cash flows on the required rate of return. This is not to say that the CAPM cannot be used in estimating the cost of capital in a regulatory context, but rather that it is an oversimplification, and, when faced with substantial policy changes that have the potential to have a significant impact on the profile of cash flows, as the current proposals do, it is necessary to consider whether alternative models can offer fresh insights.

Oxera's earlier report for the ENA in June 2010 presented a theoretical framework indicating that, for regulated energy networks, there are strong grounds for believing that an increase in the duration of cash flows of the order implied by the changes proposed for the RIIO-T1 and GD1 price controls will lead to a material increase in the cost of capital. This report provides an explanation for why the critique provided by CEPA does not diminish the validity of the conclusion of the earlier Oxera report.

The theoretical framework presented in Oxera's June 2010 report used an inter-temporal capital asset pricing model (ICAPM), which forms part of a substantial body of literature on the ICAPM. The ICAPM is by no means a departure from standard finance theory. Instead, it can be viewed as an extension of the CAPM to a multi-period setting where certain restrictive assumptions of the CAPM are relaxed. Furthermore, this report sets out how alternative approaches to addressing the question of how the required rate of return varies with cash-flow duration produce a consistent prediction—for companies with relatively low short-term cash-flow risk, such as regulated energy networks, an increase in the required rate of return would be expected to accompany an increase in cash-flow duration, a conclusion that is intuitively expected in any case.

Moving beyond the theoretical frameworks, there is a substantial body of empirical evidence suggesting a relationship between cash-flow duration and required returns. Moreover, the evidence is consistent with the relationship being positive for regulated energy networks. Set against the weight of this evidence, the event study analysis provided by Europe Economics provides only a small sample of data points, which, by the authors' own admission, is inconclusive. The very narrow body of evidence presented by Ofgem's advisers cannot answer the question posed by Ofgem as to how changes in the profile of cash flows will affect the cost of equity capital for energy networks. This conclusion is even more relevant considering the wide body of existing literature that points to a material effect of increased duration on the required return to be earned by investors.

More evidence and analysis are needed on the changes to cash-flow profiles expected under RIIO-T1 and GD1, including the impact of transitional arrangements and the interaction between changes in cash flows and debt indexation, to firm up the magnitude of the duration effect on the cost of capital. It will not be easy to predict with confidence the effect of such changes on investors. At this stage in the price control process, it is appropriate to consider, at the very least, estimates towards the top end of the range for the real post-tax cost of equity of 5.1–7.5% generated by an application of the one-period CAPM.

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1 Introduction

The Energy Networks Association (ENA) commissioned Oxera to undertake an independent assessment of the initial range of the cost of equity for the next electricity and gas transmission price control review and the next gas distribution price control reviews (RIIO-T1 and RIIO-GD1 respectively).

These are the first price controls that will reflect the new RIIO (Revenue = Incentives + Innovation + Outputs) model introduced by Ofgem as part of a comprehensive review of the existing RPI – X regulatory framework.

Starting in April 1st 2013, RIIO-T1 and GD1 will run until March 31st 2021. Ofgem has indicated that it may be possible to fast-track some companies through and conclude the price review process in February 2012. This explains why Ofgem is consulting on the appropriate cost of equity at such an early stage in the process.[2]

Ofgem is taking a different approach to setting allowed returns in the RIIO model than in the past. The cost of debt will be indexed annually to a trailing average of a cost of debt index. The gearing assumption used in setting the overall allowed return will be based on an assessment of the cash-flow volatility of each regulated company, and will not be determined until companies submit their business plans. This suggests that the gearing assumption will depend on companies' underlying business risks, including projected levels of capital expenditure (CAPEX) and risks inherent in the package of regulatory incentives. Consequently, the gearing assumption may vary between and within sectors.

The RIIO model introduces other fundamental changes to the way allowed revenues are set, which may have implications for estimating the cost of equity. These changes include:

- setting regulatory asset lives (and thus the duration of regulatory depreciation profiles) on the basis of the expected economic lives of the relevant assets. For electricity networks, regulatory asset lives are to be extended from 20 years to 45–55 years;
- capitalising 100% of REPEX for gas distribution networks—in contrast, in previous price controls only 50% of REPEX was capitalised, with the other 50% expensed in the year it was incurred. Over time, the impact of this change in capitalisation policy on the timing of cash flows will be offset to some extent by the accelerated depreciation profile that will be applied to new investment in gas distribution.

Both these changes have the effect of increasing the time until CAPEX is recovered from customers through depreciation of the regulatory asset value (RAV), which increases the duration of cash flows.[3] There are strong theoretical and empirical grounds for expecting the cost of equity for a regulated utility to increase with a longer-duration cash-flow profile.[4]

In its December 2010 consultation, Ofgem has relied on the capital asset pricing model (CAPM) to estimate its initial cost of equity range, as in previous determinations. While the analysis contained in the present report estimates the cost of equity using the CAPM framework, it also draws on insights from research using the inter-temporal CAPM (ICAPM), which captures the dynamics in the cost of capital over time. This is because the link

[2] Ofgem (2010), 'Consultation on strategy for the next transmission price control – RIIO-T1 Overview paper'; 'Consultation on strategy for the next gas distribution price control – RIIO-GD1 Overview paper', December 17th.
[3] See Oxera (2010), 'What is the impact of financeability on the cost of capital and gearing capacity?', report prepared for Energy Networks Association, June 9th.
[4] Ibid.

between cash-flow duration and the cost of equity cannot be captured in the standard CAPM framework. The CAPM assumes that discount rates and risk premiums are constant over time. As a one-period model, fundamentally the CAPM cannot capture the impact of time profiling of cash flows on the required rate of return.

With the start of the price controls more than two years away, this report estimates an initial relatively wide range for the cost of equity, to reflect the uncertainty in how market conditions may evolve between now and the start of the price controls. Given the level of uncertainty this early on in the process, this report does not consider the risk differentials between the transmission and gas distribution sectors. Instead, a single cost of equity range for both sectors is estimated based on the evidence presented.

The overall philosophy of the RIIO model is to place greater emphasis on the long term, with one consequence being that companies may need to adapt to increased short-term cash-flow volatility. Combined with longer-duration cash flows and the substantial investments required to deliver a sustainable and secure low-carbon energy sector, this philosophy suggests that increased equity participation will be required in the financing mix of the energy networks. Therefore, when interpreting the wide initial range for the cost of equity and deliberating on an appropriate point estimate from within that range, it is crucial to ensure that the allowed cost of equity is sufficient to attract the necessary equity investment into the sectors.

The report is structured as follows:

– section 2 considers the real risk-free rate;
– section 3 addresses the equity risk premium;
– section 4 presents evidence on the equity beta;
– section 5 presents the theory and evidence on the relationship between cash-flow duration and the cost of equity, and considers the impact of increasing the duration of cash flows for a regulated energy network;
– section 6 combines the ranges for the parameters using a standard CAPM framework and conducts cross-checks.

2 Risk-free rate

With the increasing intensity of the financial crisis towards the end of 2008 following the collapse of Lehman Brothers, capital markets in general and index-linked gilt (ILG) yields in particular have been characterised by a large increase in volatility relative to the pre-crisis period. This volatility presents a significant challenge for regulators seeking to determine the risk-free rate to use in a price control. This challenge is particularly great for Ofgem when approaching the RIIO-T1 and GD1 price controls, for two reasons:

– the business planning process requires the cost of equity for companies that are candidates for being fast-tracked through the price review to be determined substantially in advance of the price control period;

– under RIIO, the price control period is being extended from five to eight years.

Looking at current market rates, this section puts the experience of the past two years into historical context. Given that a range is being established for the cost of equity more than two years in advance of the start of the RIIO control periods, the section then considers the expected level of ILG yields that is implied for April 2013 as the basis for the central forecast.

Lastly, the high levels of volatility in ILG markets since mid-2008 suggest that it would be appropriate to allow some ‘headroom’ on top of the central forecast. The section finishes with an assessment of the appropriate amount of headroom, taking into consideration the lengthening of the price control period.

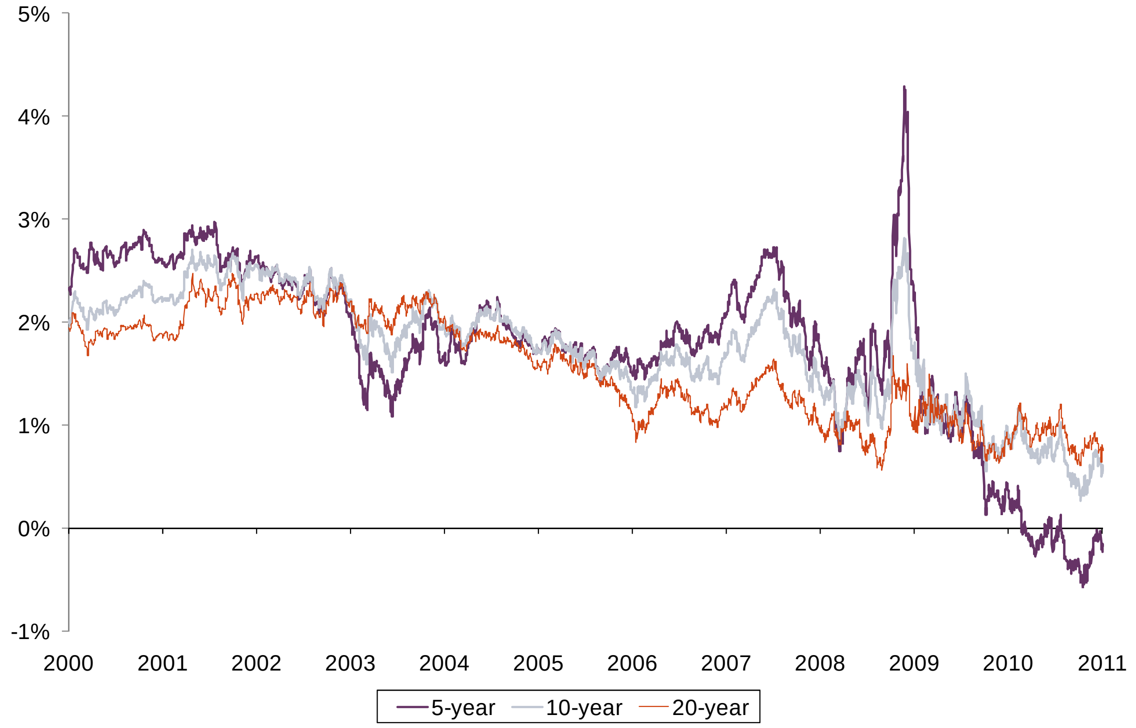
2.1 Current rates

The real risk-free rate measures the expected return on an investment free of default risk—ie, where the realised return on the investment will be equal to the expected return. The real risk-free rate measures the time value of money given that it represents the compensation that investors require in order to forgo current consumption in favour of future consumption.

In developed economies with minimal sovereign default risk, the risk-free rate is typically estimated with reference to government bond yields because these instruments are assumed to be risk-free. In the UK, the risk-free rate is often measured as the yield to maturity on government-issued ILGs. These gilts are assumed to be notionally free of default risk, and their yields are expressed in real terms, circumventing the need for inflation expectations.

Figure 2.1 below shows the historical evolution of ILG yields for benchmarks with maturities of five, ten and 20 years.

Figure 2.1 UK ILG yields (%)



Source: Bank of England.

Figure 2.1 shows that, in contrast to the relative stability over the 2000–08 period, since mid-2008 there have been extremely large movements in real yields—in particular, there has been a marked decline in yields on shorter-dated indices. This effect is evident when comparing the two-year averages to the five- and ten-year averages—see Table 2.1.

Table 2.1 UK ILG yields (%)

	5-year	10-year	20-year
Current (January 7th 2011[1])	–0.24	0.53	0.77
2-year average	0.37	0.88	0.93
5-year average	1.32	1.32	1.06
10-year average	1.68	1.70	1.51

Note: January 7th 2011 is used throughout the report as the cut-off point for the analysis.
Source: Bank of England and Oxera calculations.

There are a number of possible explanations for the marked departure of yields in the past two years from their levels in the period preceding the financial crisis:

– **loose monetary policy**—official interest rates have been at a very low level of 0.5% since March 2009. The Bank of England has also completed £200 billion of asset purchases (in a programme referred to as ‘quantitative easing’), which has put additional downward pressure on government bond yields;[5]

– **increased demand for government bonds** as a consequence of a reduction in investors’ risk appetite;

[5] See, for example, Joyce, M., Lasaosa, A., Stevens, I. and Tong, M. (2010), ‘The financial impact of quantitative easing’, Bank of England, Working paper No. 393, July.

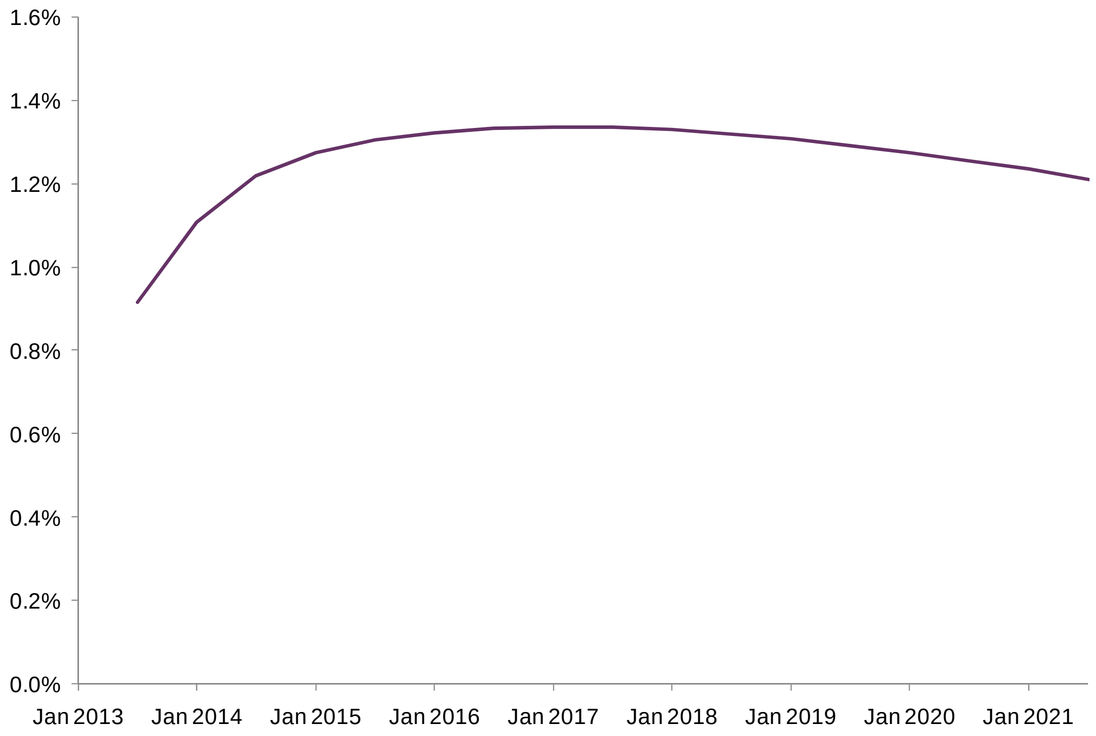
– **sovereign debt concerns in Continental Europe** may have increased demand for UK government bonds, which are perceived as less risky than government bonds of other European economies with more severe public debt problems.

It is not clear whether current yields reflect a structural shift in capital markets that can reasonably be expected to persist until even the start of the eight-year RIIO-T1 and GD1 price control periods in April 2013, or whether they reflect a short-term deviation relative to pre-crisis levels. Therefore, it is also relevant to consider information on forward rates—specifically, where the market expects the real risk-free rate to be in April 2013.

2.2 Forward rates

Figure 2.2 shows a series of forward rates derived from the current yield curve. The forward rate at time t is the interest rate for borrowing money for a specified term that is expected at time t. For example, in the figure, the forward rate for one-year borrowing in July 2013 is shown to be 0.92%—ie, markets expect the real interest rate to be 0.92% for a one-year loan in July 2013.[6]

Figure 2.2 Real forward rates for one-year borrowing (%)



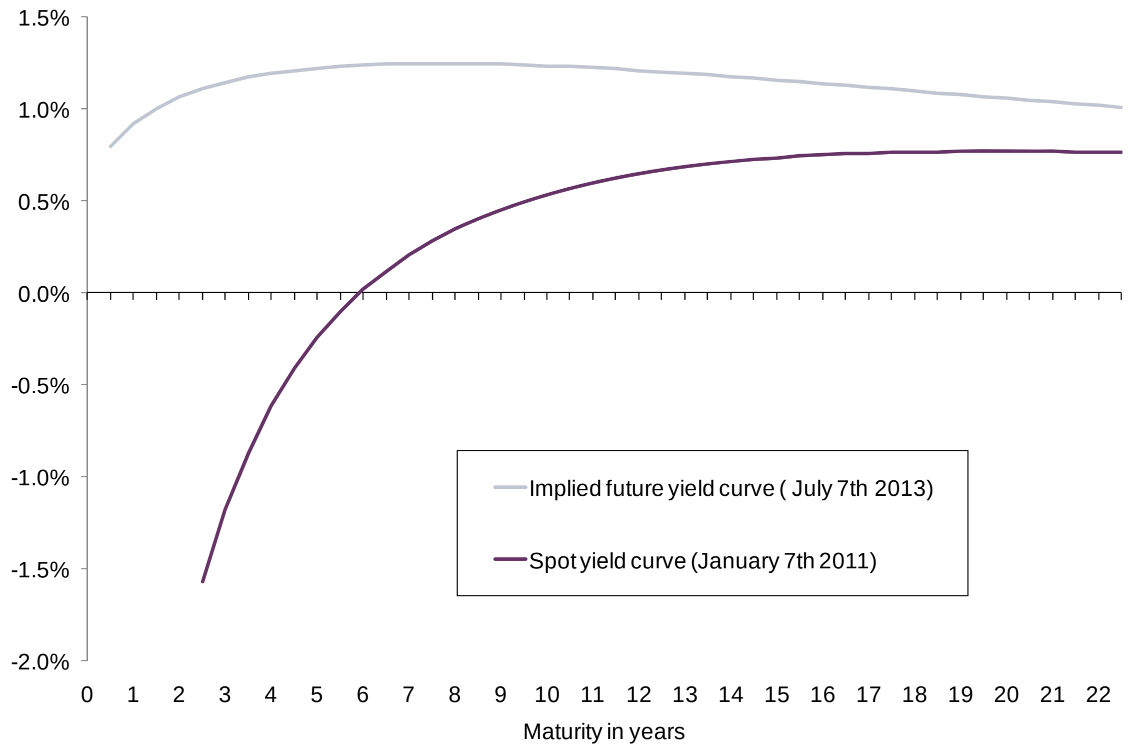
Source: Bank of England and Oxera calculations.

Figure 2.2 illustrates that markets expect short-term (one-year) interest rates to increase between now and 2018, but to decline after 2018; however, the forecasts are still markedly higher than current rates.

[6] The forward rate denoted $f_{t,T}$ is the return on the investment made at time t maturing at time T. In other words, it is the interest rate expected at time t for a period of (T – t). It can be derived from spot interest rates for maturities t and T, denoted r_t and r_T using the no arbitrage condition. Mathematically, this is denoted as: $f_{t,T} = \left[\frac{(1+r_T)^T}{(1+r_t)^t}\right]^{\frac{1}{T-t}} - 1$.

Using the current yield curve, the entire expected term structure of interest rates for 2013 can be constructed. Figure 2.3 compares this expected yield curve to the current yield curve.[7]

Figure 2.3 Current and future real yield curve implied for mid-2013 (%)



Source: Bank of England and Oxera calculations.

Figure 2.3 shows that interest rates are expected to increase significantly from current levels for borrowings across all maturities, as can be seen by the gap between the current and the implied future yield curve for mid-2013. The difference is particularly large for short- to medium-term borrowing.

As noted in section 2.1, the short end of the current yield curve may currently be distorted due to quantitative easing—an effect that has also been recognised by the Competition Commission (CC).[8] However, the CC has also previously noted that the longer end of the curve may be distorted due to accounting rules and strong demand by institutional investors.[9] This suggests that, in the current market, medium-term gilts may provide the most suitable basis for estimating the risk-free rate.

Based on the implied future yield curve shown in Figure 2.3, the ten-year ILG yield that markets are forecasting for mid-2013 is 1.23%. This is 70bp higher than the current ten-year rate of 0.53%. This level of forecast interest rates is cross-checked using evidence on yields in the US Treasury Inflation Protected Securities (TIPS) market (see Appendix 1), which suggests that markets expect real interest rates for ten-year borrowing to rise above 2.0% in the USA by 2013.

[7] The Bank of England provides data on the zero-coupon real spot yield curve for maturities from 2.5 up to 25 years. The implied future spot yield curve is constructed using forward rates based on the same definition as in the previous footnote, with t = 2.5 years and T = 3.5 to 22.5 years.

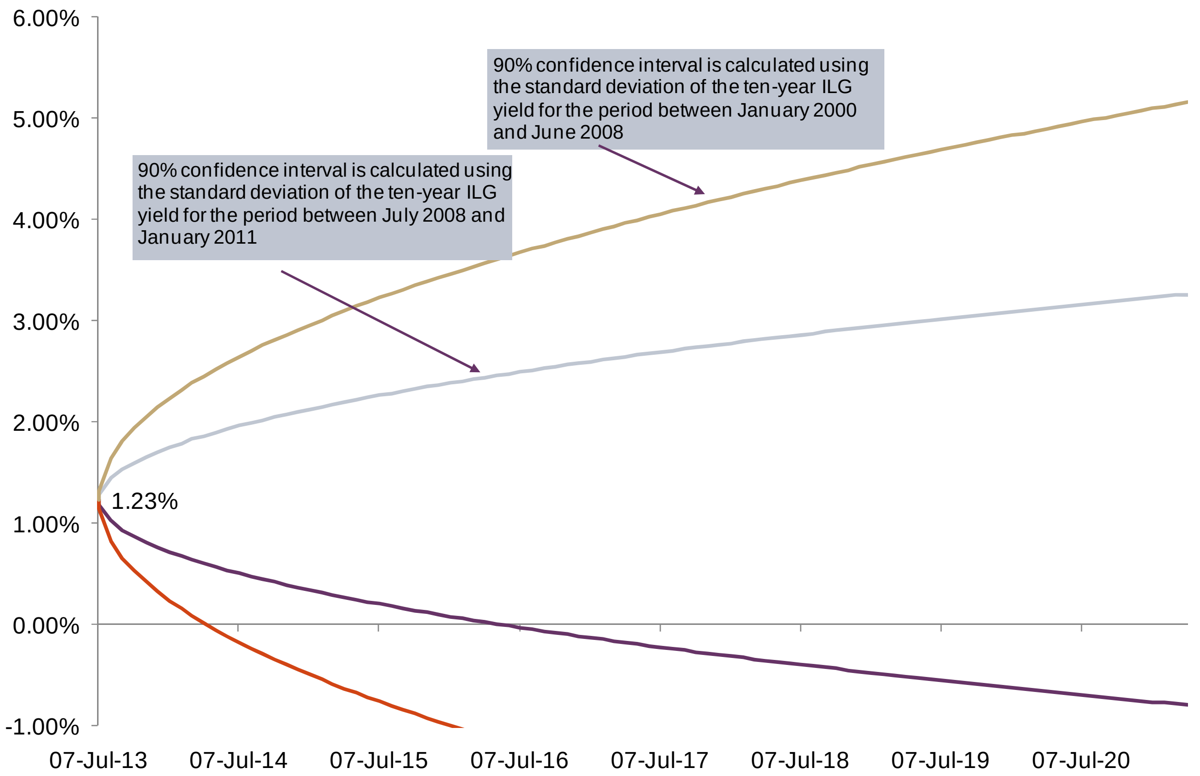
[8] Competition Commission (2010), 'Bristol Water plc—A reference under section 12(3)(a) of the Water Industry Act 1991', August 4th, Appendix N, p. N19.

[9] See, for example, Competition Commission (2008), 'Stansted Airport Ltd—Q5 price control review', Appendix L, Cost of Capital, p. L11.

2.3 Volatility

While current evidence suggests that markets expect the ten-year ILG yield to be about 1.25%[10] around the start of the RIIO-T1 and GD1 price control periods, as noted in section 2.1 the past two years have seen a marked increase in the volatility of yields. As a consequence, there is now substantially higher risk of significantly underestimating the risk-free rate that will prevail during the price control period. Figure 2.4 demonstrates the increase in risk by the widening of the confidence interval around forecasts of the risk-free rate. The chart is illustrative and, for example, does not allowed for a skewed distribution of outcomes, which recent research suggests might currently be the case.[11]

Figure 2.4 Uncertainty in the risk-free rate



Source: Bank of England and Oxera calculations.

Given the heightened volatility in yields, forward rates alone may be insufficient in setting the appropriate regulatory allowance for the risk-free rate to apply for an eight-year period.

To address the uncertainty in forecasting the risk-free rate and reduce the risk of significantly underestimating the risk-free rate that will prevail during the price control period, regulators have tended to set the risk-free rate substantially above current market rates. Such an approach is based on a view that the costs of over- and underestimating the risk-free rate are asymmetric, and specifically that greater weight should be attributed to the risk that an increase in market rates during the price control period could make equity investment a negative net present value decision, and hence create an underinvestment problem.

Table 2.2 below shows the difference ('headroom') between the real risk-free rate in regulatory determinations in the UK in the past two years and the ten-year ILG yields at the time of the decision.

[10] Rounding to the nearest five basis points (bp).

[11] Bank of England (2010), 'Financial Stability Report', December, Issue No. 28, p. 20.

Table 2.2 Recent regulatory precedent on the real risk-free rate

Year	Regulator	Sector	Description	Real risk-free rate (%)	Headroom (%)[1]
2009	CAA	Airports	BAA—Stansted (2008–13)	2.00	0.74
2009	Ofcom	Telecoms	BT Openreach	2.00	0.93
2009	Ofwat	Water	Price review (2010–15)	2.00	1.33
2010	CC	Water	Bristol Water reference	2.00	1.57
2010	CAA	Air services	NATS CP3	1.75	1.03
2011	Ofcom	Telecoms	Proposals for WBA charge control	1–2.00	0.77[2]
Average					**1.06**

Note: [1] Calculated as the difference between the real risk-free rate allowed by the regulator and the spot ten-year ILG yield on the date the decision was published. Where the exact publication date was not known, the first day the month in which the decision was published was taken as the reference date. [2] Calculated with reference to the midpoint of the proposed range by Ofcom.
Source: Various regulatory decisions, Bank of England and Oxera calculations.

This table shows that regulators have, on average, allowed a risk-free rate 106bp higher than the prevailing market rate at the time of the decision. However, whereas these decisions related to price control periods of five years or under, the Ofgem decision will apply to an eight-year control.[12] As such, Ofgem is at greater risk of significantly underestimating the risk-free rate when compared with other regulators, which suggests that it would be appropriate to allow headroom towards the upper end of the range of recent precedents.

While, in theory, the introduction of debt indexation can reduce the required amount of headroom in the allowed cost of debt, as no form of indexation is proposed for the cost of equity, it is still necessary to consider an appropriate level of headroom for the cost of equity.

Acknowledging the risk of creating an underinvestment problem suggests that it is appropriate to allow at least some degree of headroom on top of the central forecast for the risk-free rate. Table 2.2 suggests that a conservative range for the headroom allowance would be 25–75bp, although the top end of this range is at the bottom end of the range allowed in recent regulatory determinations, and does not take into account the increased risk of the longer price control period.

2.4 Summary

Current market data implies that markets expect the real risk-free rate for ten-year borrowing to be approximately 1.25% around the start of the price controls in April 2013. This is substantially higher than the current rate of around 0.5%. It is important to note that 1.25% is the expected rate and reflects solely the central forecast for how rates will change over the two-year period until the start of RIIO-T1 and RIIO-GD1. It does not incorporate any allowance for the high volatility of yields experienced since mid-2008.

The high volatility of yields since mid-2008 implies that there is a substantial probability in the current market environment of underestimating the risk-free rate that will prevail over the price control period and hence creating an underinvestment problem. Recent regulatory decisions have allowed average 'headroom' of 106bp over market rates prevailing at the time of the decision. The longer RIIO control period of eight years suggests that Ofgem may need to allow greater headroom than regulators that have determined the cost of capital for shorter regulatory periods.

[12] Although Ofgem proposes to index the cost of debt, the cost of equity will remain fixed for the price control period.

Overall, the evidence suggests that, at this stage, the mean expected value of the real risk-free rate for the start of the RIIO price control period is 1.25%. Factoring a conservative allowance for headroom on top of the mean expected value suggests a range of 1.50–2.00%.

3 Equity risk premium

As with fixed-income markets, equity markets have also been significantly affected by the increase in volatility since the start of the financial crisis. While equity market volatility has declined since the peak of the crisis, it nevertheless remains higher than at the time of the last transmission and gas distribution reviews. The challenge with estimating the equity risk premium (ERP) to use in the RIIO price controls is to determine how the financial crisis has affected the returns required by investors as compensation for taking on exposure to equity risk.

The ERP is not directly observable and must be inferred from the evidence. There are three main methods that are commonly used to estimate the ERP for mature equity markets:

– **historical evidence**—estimated using long-run averages of realised equity returns in excess of the risk-free rate;

– **forward-looking evidence**—inferred from the current prices of traded assets using dividend and earnings growth models;

– **survey-based evidence**—surveying practitioners and investors on their expectations for future required returns to equity.

This section reviews the most recent estimates based on these three sources of evidence.

3.1 Historical evidence

The most widely cited source of historical evidence on the ERP is the annual publication by Dimson, Marsh and Staunton (DMS) which estimates historical ERP for 19 countries using a comprehensive dataset on annual excess equity returns since 1900.

The precision of the estimates increases as the sample size increases (in this case, as the time horizon over which historical market returns are averaged increases). However, even with 110 years of data, the DMS estimates have a standard error of 1.6%, which is large relative to the value of point estimates. This is because annual equity returns are very volatile—over the entire DMS data sample, the minimum and maximum returns on the UK stock market were –38.4% and 80.8% respectively.[13] This is why it is important to consider a very long time horizon when estimating the historical ERP and why the DMS estimates are often used, given the size of their dataset.

Table 3.1 shows the latest historical ERP estimates for mature financial markets. The estimated ERP for the UK relative to bonds is 3.9% and 5.2% based on geometric and arithmetic averages respectively.

[13] Dimson, E., Marsh, P. and Staunton, M. (2010), 'Credit Suisse Global Investment Returns Sourcebook 2010', February, Table 10.

Table 3.1 Dimson, Marsh and Staunton 2010 ERP estimates (%)

Country	Geometric mean	Arithmetic mean	Standard error
Belgium	2.6	4.9	1.9
France	3.3	5.7	2.2
Germany	5.4	8.8	2.8
Ireland	2.6	4.7	1.9
Italy	3.8	7.3	2.8
Netherlands	3.5	5.9	2.1
Spain	2.4	4.4	2.0
UK	**3.9**	**5.2**	**1.6**
USA	4.2	6.3	2.0
Europe	3.9	5.2	1.6
World	3.7	4.9	1.5

Note: The ERP is estimated relative to bonds.
Source: Dimson, Marsh and Staunton (2010), op. cit., Table 10.

Historical ERP can be calculated as a geometric or an arithmetic average of past excess returns. Geometric averages are by construction lower than arithmetic averages as they do not take into account the volatility of annual excess returns over the averaging period. While there is debate around which is the most appropriate averaging method in any given context, the weight of opinion is supportive of using arithmetic averages for selecting the ERP to use when estimating required equity returns. Indeed, Dimson, Marsh and Staunton (2010) themselves recommend the arithmetic average 'for use in asset allocation, stock valuation, and corporate budgeting applications'.[14] This is consistent with a number of analytical studies that suggest that greater weight should be placed on arithmetic than on geometric estimates of returns. Cooper (1996) noted:

> The use of the arithmetic mean ignores estimation error and serial correlation in returns. Unbiased discount factors have been derived that correct for both these effects. In all cases, the corrected discount rates are closer to the arithmetic than the geometric mean.[15]

Cooper (1996) referred to Blume (1974)[16] who derived an 'approximately unbiased estimator of M^N, the true expected return over N periods', which is a 'weighted average of the compounded geometric and arithmetic means'.[17] The weight on the arithmetic average is:

$$\alpha = \frac{(T-N)}{(T-1)}$$

where T is the number of years used to calculate the estimated average return and N is the number of years in the forecast horizon. The weight on the geometric average is (1-∝).

Therefore, when forecasting the return for one year, all the weight should be on the arithmetic mean. As the forecast horizon increases, more weight should be placed on the geometric mean. With an eight-year forecast horizon for RIIO-T1 and GD-1 and 110 years of

[14] Dimson, Marsh and Staunton (2010), p. 34.
[15] Cooper, I. (1996), 'Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting', *European Financial Management*, **2**:2, p. 157.
[16] Blume, M.E. (1974), 'Unbiased estimators of long-run expected rates of return', *Journal of the American Statistical Association*, **69**:347.
[17] Cooper (1996), op. cit., p. 157.

data used by DMS to calculate their estimates, $\propto$ is approximately 94%. As Cooper (1996) noted 'although the arithmetic mean is biased, the bias is small for most practical applications.'

Jacquier, Kane and Marcus (2005) further examine the statistical properties of arithmetic and geometric estimators and reach a similar conclusion on optimal weighting as Cooper (1996).[18] In addition, the authors find that when the ratio of N/T is less than 0.1, the arithmetic average estimator is more efficient (precise) than the geometric estimator (N/T is 0.07 for RIIO-T1 and GD1).

The DMS dataset therefore suggests that an ERP of no less than 5% would be an appropriate assumption for the RIIO-T1 and GD1 price controls at this stage in the process. For the purpose of selecting the ERP to use in estimating required equity returns, it is not appropriate to place substantial weight on geometric averages.

3.2 Forward-looking evidence

The main weakness of using historical returns to estimate the ERP is that this approach is inherently backward-looking. Historical performance is not necessarily a good indicator of the risk premium required by investors to hold equities going forward.

Especially in times of heightened market volatility, historical estimates of the ERP can provide counterintuitive results. As an example, 2008 was one of the worst years for equity markets on record. Including the strongly negative equity return in the calculation of historical ERP lowers the premium significantly. Between 2008 and 2009, the DMS ERP estimate based on arithmetic averages for the UK decreased from 5.4% to 5%.[19] As noted by Damodaran (2010), this result is counterintuitive:

> In effect, the historical risk premium approach would lead investors to conclude, after one of worst stock market crisis in several decades, that stocks were less risky than they were before the crisis and that investors should therefore demand lower premiums.[20]

This is why forward-looking models can provide a useful cross-check on the historical estimates. Using current, rather than historical, market data may provide estimates that are more representative of the forward-looking ERP.

The basic concept behind forward-looking models is the assumption that the current market price of an asset represents the expected discounted value of all future cash flows to this asset. The general multi-period dividend growth model (DGM) is formulated as follows:

$$P_o = \frac{D_1}{(1+r)^1} + \frac{D_2}{(1+r)^2} + \cdots + \frac{D_t}{(1+r)^t} + \frac{D_t}{(r-g) \times (1+r)^t}$$

where P_0 is the current market price; D_n is the n-year ahead dividend forecast; r is the cost of equity; and g is the long-term dividend growth rate.

To estimate the ERP, this equation is calculated for a broadly diversified market index ('the market portfolio') and is solved for r—ie, the expected market return. As inputs, the model requires the current index value, dividend forecasts for the index, and a long-term growth

[18] Jacquier, E., Kane, A. and Marcus, A. (2005), 'Optimal estimation of the Risk Premium for the Long Run and Asset Allocation: A Case of Compounded Estimation Risk', *Journal of Financial Econometrics*, **3**:1.

[19] Dimson, E., Marsh, P. and Staunton, M. (2008), 'London Business School / ABN AMRO Global Investment Returns Yearbook 2008', February. Dimson, E., Marsh, P. and Staunton, M. (2009), 'Credit Suisse Global Investment Returns Sourcebook 2009', February.

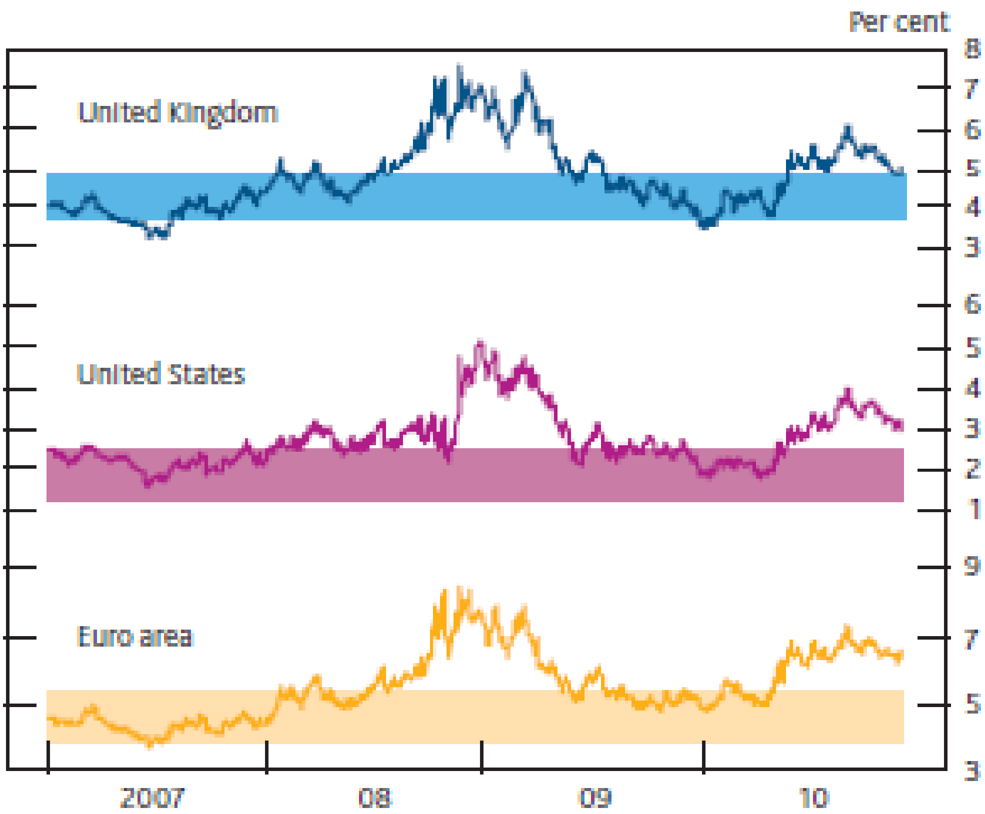
[20] Damodaran, A. (2010), 'Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2010 Edition', February, p. 26, New York University - Stern School of Business.

rate assumption. The ERP is then calculated by subtracting a measure of the risk-free rate from the estimate of the expected market return.

In the RIIO-T1 and GD1 consultation, Ofgem presents forward-looking ERP estimates taken from the Bank of England's June 2010 Financial Stability Report.[21] These estimates are produced using a variant of the multi-period DGM described above. In the near to medium term, dividend growth is proxied by earnings growth based on consensus earnings forecasts from the Institutional Brokers' Estimate System (IBES), The long-term growth rate is equal to an estimate of the potential growth of the economy. As the risk-free rate measure, 'rates inferred from zero-coupon government bond yield curves at maturities up to ten years' are used.[22]

Figure 3.1 updates the evidence presented by Ofgem and shows the Bank of England's latest ERP estimates from the December 2010 'Financial Stability Report'.

Figure 3.1 UK equity risk premia



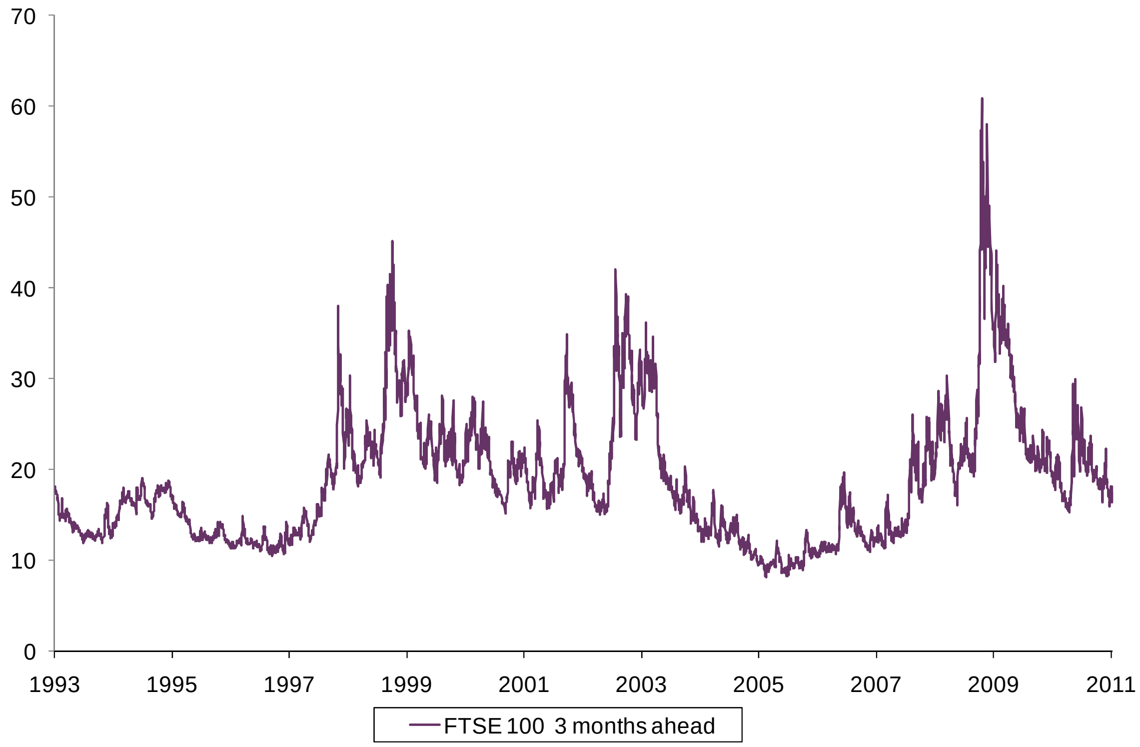
Note: The ERP here is as implied by the multi-stage dividend discount model. The shaded area shows interquartile ranges for implied risk premia since 1998.
Source: Bank of England (2010), 'Financial Stability Report', December, Issue No. 28, Chart 2.8, p. 19.

The latest Bank of England estimate is approximately 5%, which is lower than the June 2010 estimate presented by Ofgem. Equity indices rose in the second half of 2010, partially explaining the downward trend in the ERP estimates generated by discounted cash-flow models.

[21] Ofgem (2010), 'Consultation on strategy for the next transmission and gas distribution price controls—RIIO-T1 and GD1 Financial Issues', Figure 3.12, p. 40.
[22] Inkinen, M., Stringa, M. and Voutsinou, K. (2010), 'Interpreting equity price movements since the start of the financial crisis', *Bank of England Quarterly Bulletin*, **50**:1, pp. 24–33.

Another indicator of trends in the ERP is equity market volatility. Academic literature shows that the volatility of equity markets is positively correlated with the ERP.[23] While equity market volatility does not provide a direct estimate of the ERP, it can be used indirectly to provide information on trends in the ERP. Figure 3.2 below shows the expected volatility of the FTSE 100 index over the subsequent three months as implied by option prices since 1993.

Figure 3.2 Implied volatility of the FTSE 100 index (%)



Source: Bank of England.

As Figure 3.1 shows, equity market volatility has decreased from the levels observed in June 2010, consistent with the decrease in the Bank of England's estimate of the ERP. Nevertheless, equity market volatility is still somewhat higher relative to the pre-crisis period. It is not immediately obvious from this evidence that 'both the UK economy and financial markets are expected to return to pre-crisis conditions by the start of RIIO-T1 and RIIO-GD1'.[24]

As an additional cross-check on the Bank of England numbers, Table 3.2 shows estimates of the ERP based on a simple, one-stage DGM, which reduces to this expression:

$$r = \frac{D_1}{P_0} + g$$

[23] Campbell, J.Y. and Hentschel, L. (1992), 'No News is Good News. An Asymmetric Model of Changing Volatility in Stock Returns', *Journal of Financial Economics*, **31**, pp. 281–318; Scruggs, J.T. (1998), 'Resolving the Puzzling Intertemporal Relation Between the Market Risk Premium and the Conditional Market Variance: A Two Factor Approach', *Journal of Finance*, **53**:2; Copeland, M. and Copeland, T. (1999), 'Market Timing: Style and Size Rotation Using the VIX', *Financial Analysts Journal*, **55**, pp. 73–81; Guo, H. and Whitelaw, R. (2006), 'Uncovering the Risk–Return Relationship in the Stock Market', *Journal of Finance*, **61**, pp. 1433–63; Graham, J.R. and Harvey, C.R. (2007), 'The Equity Risk Premium in January 2007: Evidence from the Global CFO Outlook Survey', working paper, Duke University; Banerjee, P.S., Doran, J.S. and Peterson, D.R. (2007), 'Implied volatility and Future Portfolio Returns', *Journal of Banking & Finance*, **31**:10, pp. 3183–99, October.

[24] Ofgem (2010), 'Consultation on strategy for the next transmission and gas distribution price controls—RIIO-T1 and GD1 Financial Issues', para 3.67.

In effect, the expected market return is equal to the sum of the expected dividend yield on the market index and the long-term dividend growth rate. The long-term growth rate is proxied by the long-term average expected GDP growth rate.

Table 3.2 Forward-looking ERP estimates based on a one-step DGM

	ERP
January 7th 2011	4.7%
Six-month average to January 7th 2011	4.9%

Note: The ERP is calculated using a long-term dividend growth assumption of 2.2%. This is based on the average forecasts of GDP growth for the UK over the 2011–14 period provided by the HM Treasury survey of independent forecasters.
Source: Datastream; HM Treasury (2010), 'Forecasts for the UK Treasury: a comparison of independent forecasts', November; and Oxera calculations.

The results of the one-step DGM suggest an ERP of 4.7–4.9% using the most recent six months of data. This model assumes that dividends grow at the long-term growth rate from year one, and does not take into account potentially higher expected dividend growth in the medium term. However, the ERP estimates presented in the table appear to be broadly in line with the results from the Bank of England.

Using current market data may provide estimates that are more representative of the forward-looking ERP. However, this technique can produce volatile results that are sensitive to assumptions about the risk-free rate and long-run growth rates of dividends or earnings. The ERP estimates from such models are therefore useful mostly as a cross-check on historical estimates.

3.3 Survey-based evidence

A second form of forward-looking evidence on the ERP comes from surveys of market practitioners. However, there are a number of issues with interpreting survey evidence:

– respondents' answers may be influenced by the way the questions are phrased—for example, whether the question asks about required returns to equity or expected returns on a specified stock market index;

– there is a tendency for respondents to extrapolate from recent realised returns, making the estimates not entirely forward-looking;

– the results are based purely on judgement and are less reliable than estimates based on direct market evidence on pricing.

The above concerns notwithstanding, Table 3.3 summarises the evidence from two recent surveys of practitioners and investors.

Table 3.3 Survey evidence on the ERP

Author	Survey	ERP estimate (%)	Standard deviation (%)
Fernandez and Campo (2010)	Average UK ERP used by analysts (31 answers)	5.2	1.4
	Average UK ERP used by companies (30 answers)	5.6	1.8
	Average UK ERP used by professors (49 answers)	5.0	1.6
Graham and Harvey (2010)	Quarterly survey of US CFOs (June 2010)	3.0	3.07

Source: Fernandez, P. and del Campo, J. (2010), 'Market risk premium in 2010 used by Analysts and Companies: a survey with 2,400 answers', May 21st; Fernandez, P. and del Campo, J. (2010), 'Market risk premium in 2010 used by Professors: a survey with 1,500 answers', May 15th; Graham, J.R. and Harvey, C.R. (2010), 'The Market Risk Premium in 2010', August 9th.

The Fernandez and Campo survey asks the respondents for the ERP 'used to calculate the required return on equity'.[25] The results of this survey are consistent with both ERP estimates based on historical evidence and forward-looking DGM estimates.

In contrast, Graham and Harvey frame the question differently when they survey US CFOs on a quarterly basis about their expectations of the ten-year return on the S&P 500 index (ie, the question is about expected returns on the stock market rather than required returns). The annual return expected by respondents according to the June 2010 survey is the lowest in the history of the survey, leading to a very low estimate of the ERP. There is also a record high level of disagreement and uncertainty in the estimates, measured by the high standard error of 3.07%.[26]

The survey evidence is mixed and it therefore seems inappropriate to place significant weight on this evidence. This view is shared by Ofcom:

> as in the past, we afford this analysis relatively little weight since participant surveys do not provide the same quality of evidence as market-based measures.[27]

3.4 Summary

Overall, historical estimates of the ERP suggest a value no lower than 5.0% based on arithmetic averages. For the purpose of selecting the ERP to use in estimating required equity returns, it is not appropriate to place substantial weight on geometric averages and hence to set the lower end of the range at 4.0%.

A central estimate of 5.0% for the ERP is broadly consistent with recent forward-looking evidence derived from current market data. The survey evidence is mixed and the results are not necessarily very reliable.

The consistency between the historical and the forward-looking estimates based on current market data suggests that 5% is an appropriate estimate for the long-run ERP averaged over both relatively benign and crisis periods in capital markets.

The cost of equity is being estimated for an eight-year price control, the start of which is two years away. There is still much uncertainty in the capital markets, and it would be premature

[25] Fernandez, P. and del Campo, J. (2010), 'Market risk premium in 2010 used by Analysts and Companies: a survey with 2,400 answers', May 21st, p. 2.
[26] Graham and Harvey (2010), op. cit., pp. 3–4.
[27] Ofcom (2011), 'Proposals for WBA charge control—Consultation document and draft notification of decisions on charge control in WBA Market', January 20th, p. 93.

to conclude on a point estimate. The evidence suggests that a symmetric range for the ERP of 4.5–5.5% around the central estimate of 5.0% would be appropriate at this early stage of the price control deliberations.

4 Equity beta

RIIO-T1 and GD1 introduce some significant changes which will affect energy networks' risk exposure and are likely also to affect their asset betas. These include:

– greater use of incentives, which to some extent is likely to represent an increase in exposure to sources of non-diversifiable risk;

– a longer price control period, thereby amplifying the impact of any systematic risks that have a persistent effect on value;

– an increase in the duration of cash flows (as discussed in section 2).

The particular challenge in reaching an appropriate allowance for the equity beta of the regulated transmission and gas distribution networks is that none of the nine regulated networks that are the subject of the RIIO-T1 and GD1 price controls has a separate equity market listing. This makes it difficult to determine with confidence both the current risk exposure and how it might alter under the significant changes being introduced under RIIO.

This section estimates the equity beta to apply to regulated energy networks within the framework of the one-period CAPM. Given the lack of directly relevant market data, it is prudent to consider a broad range of evidence in order to reach an appropriate range for the equity beta based on the regulated energy networks' current risk exposure, controlling for differences in capital structure. This is the approach taken in this study.

While the impact of the significant changes under RIIO is likely to increase risk for the average company (although individual companies may propose incentive packages of varying strengths), this section focuses solely on the networks' current risk exposure. However, as described in section 5, the increase in the duration of cash flows is likely to create a material increase in the risk exposure and the cost of capital for a regulated energy network. As these effects cannot be captured in the framework of the one-period CAPM, they are considered separately in section 6.

4.1 Methodological approach

In the CAPM framework, the equity beta represents the extent to which shareholders of a company are subject to risk arising as a result of correlation with the returns of the market as a whole, known as 'systematic risk'.

More specifically, the CAPM shows that, under a number of assumptions, the expected excess return on any security, i, is linearly related to the expected excess return of the market portfolio, as in the following equation:

$$E(R_i) - R_f = \beta_i(E(R_m) - R_f)$$

The expected excess return is the expected return over and above that provided by holding a 'risk-free' security. The excess return therefore reflects the premium required to take on the risk associated with holding a particular security. To apply the CAPM in practice, historical realised returns replace expected excess returns in the above equation. The beta of the security is then estimated using ordinary least squares regression.

An equity beta can be measured directly for any company with publicly listed equity that is actively traded.[28] To estimate the beta of companies that are not publicly listed, it is necessary to take an indirect approach, by selecting listed companies with similar characteristics to the company in question. The relevant characteristics to consider are those that affect companies' exposure to systematic risk, the most important of which are the company's business mix and the regulatory framework under which it operates.

There are only two listed companies that own energy networks subject to the RIIO-T1 and GD1 price controls: National Grid and Scottish & Southern Energy. While both also have significant unregulated businesses (see Table 4.1), they provide the most directly relevant measures of the risk exposure of the RIIO-T1 and GD1 networks.[29]

Table 4.1 Operating profit from UK regulated activities

	UK regulated	Non-UK and/or unregulated
National Grid	68%	32%
Scottish & Southern Energy	37%	63%
Average	**52%**	**48%**

Note: Figures represent the percentage of earnings before interest and tax (EBIT) produced by the regulated operations in the UK.
Source: Scottish & Southern Energy, 2010 Annual report; National Grid 2010/11 half-year results; and Oxera calculations.

National Grid and Scottish & Southern Energy are therefore used as the primary comparator set in the analysis presented in this report. However, given both the extremely small sample size and the inherent uncertainty in estimating beta, particularly for a segment of a company that is exposed to a range of different sectors with potentially differing risk characteristics, three groups of secondary comparators are also reviewed as a cross-check:

– integrated energy companies with generation and retail activities in addition to networks;
– international energy network companies, excluding North American companies;
– North American network companies.

All the evidence is then considered when reaching an appropriate range for the asset beta to apply to the transmission and gas distribution sectors.

Equity betas have been estimated using daily data on total returns over both the two- and five-year periods ending January 7th 2011. The FTSE All-share index is used as the benchmark when estimating the betas of UK companies. The respective national stock market indices were used to estimate the betas of comparators that are listed outside the UK.[30]

Using a two-year horizon applies considerable weight to data over the most intense period of the financial crisis. There has been significant volatility in equity markets over this period. To the extent that utilities may have been affected by a temporary 'flight to quality', this would have reduced these companies' beta estimates. However, this effect is not certain and any impact would be difficult to quantify.

[28] The risk associated with holding illiquid securities is generally not fully captured in a company's beta. As a consequence, betas for these securities are often close to zero.
[29] In addition to the networks covered by the RIIO-T1 and GD1 controls, Scottish & Southern Energy generates income from unregulated activities such as generation and supply, and National Grid operates gas and electricity distribution assets in the USA that are subject to a different regulatory framework to that in the UK.
[30] Australia: S&P/ASX 200, USA: S&P 500, Canada: S&P/TSX 60, Italy: FTSE MIB, Spain: IBEX 35, Germany: DAX 30, France: CAC 40, Portugal: PSI 20, New Zealand: NZX 50.

4.1.1 Beta estimation adjustments

The inherent uncertainty in estimating beta, combined with the tendency for company betas to regress towards one, has led some to argue in favour of applying adjustments to beta estimates.[31] The two most common adjustments are:

- the **Blume** adjustment, which applies a weight of 0.67 to the estimated beta and a weight of 0.33 to the market average beta of 1;
- the **Vasicek** adjustment, which takes a weighted average of the estimated beta and a 'prior' beta—where 'prior' represents a belief about the distribution of the beta being estimated. The weights vary depending on the precision of the betas being estimated, calculated as the ratio of the prior variance of the betas in the population to the sum of that prior variance and the standard error of the beta being calculated.

The Vasicek adjustment is more sophisticated because the weights are based on the precision of the beta estimates. However, it is not straightforward to implement due to the need to make a prior assumption about the distribution of the beta.

The Blume adjustment assigns weights that could be considered somewhat arbitrary, but it is more commonly used because it is straightforward to implement. However, it should be noted that the adjustment is not intended to reflect a prior belief that the true value of the beta is one, but rather that the value of the beta is expected to regress towards one over time. Put differently:

> Betas in the forecast period tend to be closer to one than the estimate obtained from historical data[32]

The appropriate weight to place on adjusted betas may vary according to circumstance. For example, while the average beta of the market as a whole is equal to one by definition, it is not necessarily reasonable to assume that the average beta of a particular sector is equal to one. In particular, one would expect regulated utilities to be exposed to less systematic risk than the average company.

4.1.2 Gearing

Variability in observed equity returns can be attributed to two primary sources of risk: business risk and financial risk, where the latter results from the choice of capital structure. For this reason, equity betas cannot be compared across companies unless adjustments are made to standardise gearing. This adjustment involves 'de-levering' the equity beta to calculate an asset beta—which reflects the systematic risk associated with the business, independent of capital structure. De-levering is performed using the following formula:

$$\beta_{asset} = (1 - g) * \beta_{equity} + g * \beta_{debt}$$

where g is equal to the level of gearing for the entity to which the equity beta corresponds. Once an appropriate asset beta has been determined for the companies or sectors of interest, this can then be 're-levered' to yield an equity beta that is unaffected by the different capital structures of the comparator companies.

In this report, actual gearing has been estimated using the average ratio of net debt to enterprise value over the period for which the equity beta is estimated. Asset betas have been re-levered to gearing of 65%, which is consistent with what was estimated in the fifth

[31] Blume, M. (1971), 'On the assessment of risk', *Journal of Finance*, **26**, pp. 1–10.

[32] Elton, E., Gruber, M., Brown, S. and Goetzman, W. (2007), *Modern Portfolio Theory and Investment Analysis*, chapter 7, p. 144, 7th edition, John Wiley & Sons.

distribution price control review (DPCR5).[33] Debt betas are assumed to be zero, although the sensitivity of the analysis to this assumption is tested in Appendix 2.

4.2 Results

Equity betas for all comparators were calculated using total return index data[34] from January 7th 2009 to January 7th 2011 for the two-year estimates, and from January 7th 2006 for the five-year estimates. Table 4.2 presents both raw and Blume-adjusted equity betas for National Grid and Scottish & Southern Energy. The two-year betas are lower than the five-year betas, which may reflect the impact of the financial crisis. Without independent evidence that there has been a fundamental decrease in these two companies' risk profiles over this period, it is prudent to consider both the two- and the five-year betas.

Table 4.2 Equity beta estimates of UK comparators

	Raw equity beta	Adjusted equity beta	Gearing
National Grid	0.51	0.67	59%
Scottish & Southern Energy	0.42	0.61	34%
Average (2-year)	**0.47**	**0.64**	**46%**
National Grid	0.65	0.76	49%
Scottish & Southern Energy	0.63	0.75	24%
Average (5-year)	**0.64**	**0.76**	**37%**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of the table presents beta estimates using five years of data, calculated using daily data over the two- and five-year periods ending January 7th 2011.
Source: Datastream, Bloomberg, and Oxera calculations.

Table 4.3 presents the equity betas for National Grid and Scottish & Southern Energy after being de-levered to produce raw and adjusted asset betas, and then re-levered at gearing of 65% to produce comparable equity betas.

Table 4.3 Asset and re-levered equity betas of UK comparators

	Raw asset beta	Adjusted asset beta	Raw re-levered equity beta	Adjusted re-levered equity beta
National Grid	0.21	0.28	0.60	0.79
Scottish & Southern Energy	0.28	0.41	0.80	1.16
Average (2-year)	**0.25**	**0.34**	**0.70**	**0.98**
National Grid	0.33	0.39	0.95	1.12
Scottish & Southern Energy	0.47	0.57	1.35	1.62
Average (5-year)	**0.40**	**0.48**	**1.15**	**1.37**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of the table presents beta estimates using five years of data, calculated using daily data over the periods ending January 7th 2011. Equity beta re-levered assuming 65% gearing.
Source: Datastream, Bloomberg, and Oxera calculations.

For the primary comparator set, the estimated asset beta range is 0.25–0.34 for the 2-year period and 0.40–0.48 for the 5-year period.

[33] Ofgem (2009), 'Electricity Distribution Price Control Review Final Proposals—Allowed Revenues and Financial Issues', Table 1.6.
[34] The exceptions were Red Electrica and Enagas, for which price data was used. This is because total return index data was unavailable for the IBEX 35 Spanish stock market index.

As discussed above, three groups of secondary comparators have also been reviewed as a cross-check. European integrated energy companies provide the first cross-check in Table 4.4.

Table 4.4 Beta estimates for integrated energy companies

	Raw asset beta	Adjusted asset beta	Raw re-levered equity beta	Adjusted re-levered equity beta
Centrica	0.44	0.59	1.25	1.68
International Power	0.37	0.39	1.07	1.11
RWE	0.50	0.60	1.43	1.72
GDF Suez	0.59	0.62	1.68	1.78
Enel	0.27	0.29	0.76	0.84
Average (2-year)	**0.43**	**0.50**	**1.24**	**1.43**
Centrica	0.55	0.66	1.58	1.90
International Power	0.28	0.31	0.81	0.87
RWE	0.65	0.67	1.86	1.91
GDF Suez	0.39	0.40	1.12	1.15
Enel	0.56	0.64	1.60	1.83
Average (5-year)	**0.49**	**0.54**	**1.39**	**1.53**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of the table presents beta estimates using five years of data, calculated using daily data over the periods ending January 7th 2011. Equity beta re-levered assuming 65% gearing.
Source: Datastream, Bloomberg, and Oxera calculations.

The estimated range of asset betas over the two-year period is 0.43–0.50, and over the five-year period 0.49–0.54. Both ranges are substantially higher than that of the primary set of comparators. Integrated energy companies tend to have business segments that are not subject to economic regulation, such as generation. Such companies might be thought to be more exposed to systematic risk than pure regulated network businesses, and therefore be considered to provide an upper bound on the asset beta estimates for UK networks.

Publicly listed energy networks from outside the UK provide a second cross-check. Table 4.5 presents asset beta estimates for energy networks from Europe, Australia, and New Zealand.

Table 4.5 Beta estimates for international network comparators

	Raw asset beta	Adjusted asset beta	Raw re-levered equity beta	Adjusted re-levered equity beta
Australian Pipeline Trust	0.19	0.25	0.55	0.71
Envestra	0.17	0.19	0.50	0.55
Snam Rete Gas	0.10	0.25	0.27	0.71
Terna	0.12	0.27	0.34	0.77
Vector	0.18	0.27	0.51	0.76
REN	0.20	0.28	0.58	0.81
Enagas	0.32	0.40	0.91	1.15
Red Electrica	0.32	0.42	0.92	1.21
Average (2-year)	**0.20**	**0.29**	**0.57**	**0.83**
Australian Pipeline Trust	0.27	0.31	0.78	0.90
Envestra	0.18	0.21	0.50	0.60
Snam Rete Gas	0.13	0.28	0.37	0.80
Terna	0.21	0.35	0.60	1.00
Vector	0.25	0.31	0.71	0.89
Enagas	0.39	0.48	1.11	1.36
Red Electrica	0.35	0.44	1.01	1.26
Average (5-year)	**0.25**	**0.34**	**0.73**	**0.97**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of the table presents beta estimates using five years of data, calculated using daily data over the periods ending January 7th 2011. Equity beta re-levered assuming 65% gearing. REN is excluded from the five-year sample as it was not listed until July 2007.
Source: Datastream, Bloomberg, and Oxera calculations.

The estimated range of asset betas over the two-year period is 0.20–0.29, and over the five-year period 0.25–0.34. These are lower than the ranges produced by the primary set of comparators. These networks would be expected to have varying degrees of exposure to systematic risk according to the different forms of economic regulation under which they operate. Furthermore, country-specific factors might have a notable impact on the beta estimates of energy networks. In particular, concerns over sovereign risk would be expected to have affected the beta estimates of some of the European comparators.

Energy networks in North America provide the third cross-check. These are regulated under a ‘cost of service’-based regulatory framework. This type of regulation is generally considered to expose networks to less risk than if they were regulated under price or revenue cap systems. For this reason the betas of the North American comparators would be expected to provide a lower bound on the asset betas for the UK networks.

Table 4.6 Beta estimates for North American network comparators

	Raw asset beta	Adjusted asset beta	Raw re-levered equity beta	Adjusted re-levered equity beta
Emera	0.14	0.26	0.40	0.75
Kinder Morgan	0.27	0.37	0.76	1.07
Atlanta Gas Light	0.29	0.36	0.83	1.03
ITC Holdings	0.32	0.38	0.91	1.09
Northwest Natural Gas	0.33	0.43	0.96	1.23
Piedmont Natural Gas	0.37	0.47	1.07	1.33
TC Pipelines	0.29	0.42	0.82	1.19
Average (2-year)	**0.29**	**0.38**	**0.82**	**1.10**
Emera	0.14	0.28	0.41	0.79
Kinder Morgan	0.31	0.42	0.89	1.19
Atlanta Gas Light	0.35	0.41	0.99	1.18
ITC Holdings	0.43	0.47	1.22	1.34
Northwest Natural Gas	0.41	0.48	1.16	1.37
Piedmont Natural Gas	0.50	0.55	1.42	1.58
TC Pipelines	0.33	0.46	0.95	1.32
Average (5-year)	**0.35**	**0.44**	**1.01**	**1.25**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of the table presents beta estimates using five years of data, calculated using daily data over the periods ending January 7th 2011. Equity beta re-levered assuming 65% gearing.
Source: Datastream, Bloomberg, and Oxera calculations.

The estimated range of asset betas is 0.29–0.38 over the two-year period, and 0.35–0.44 over the five-year period. The two-year range is higher than that of the UK comparators, while the five-year range is lower. Table 4.7 summarises the asset beta estimates for the primary set of comparators plus the three secondary comparator sets.

Table 4.7 Summary of comparator beta estimates

	Raw asset beta	Adjusted asset beta	Raw re-levered equity beta	Adjusted re-levered equity beta
National Grid	0.21	0.28	0.60	0.79
Scottish & Southern Energy	0.28	0.41	0.80	1.16
Average (2-year)	**0.25**	**0.34**	**0.70**	**0.98**
Integrated networks and generation	0.43	0.50	1.24	1.43
International networks	0.20	0.29	0.57	0.83
North American networks	0.29	0.38	0.82	1.10
Average (2-year)	**0.31**	**0.39**	**0.88**	**1.12**
National Grid	0.33	0.39	0.95	1.12
Scottish & Southern Energy	0.47	0.57	1.35	1.62
Average (5-year)	**0.40**	**0.48**	**1.15**	**1.37**
Integrated networks and generation	0.49	0.54	1.39	1.53
International networks	0.25	0.34	0.73	0.97
North American networks	0.35	0.44	1.01	1.25
Average (5-year)	**0.36**	**0.44**	**1.04**	**1.25**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of the table presents beta estimates using five years of data, calculated using daily data over the periods ending January 7th 2011. Equity beta re-levered assuming 65% gearing.
Source: Datastream, Bloomberg, and Oxera calculations.

4.3 Summary

Focusing on the raw asset beta range for the primary comparator set of National Grid and Scottish & Southern Energy suggests an asset beta range of 0.25–0.40. The lower end is based on two-year estimates and the upper end is based on five-year estimates.[35] This range encompasses the two- and five-year estimates based on the secondary comparator sets (0.31–0.36). Overall, an asset beta range of 0.28–0.35 is in line with the market evidence.

This range is at the lower end of the CC's assessment of the risk of utilities relative to other sectors, as shown in Table 4.8 below. The proposed range of 0.28–0.35 is broadly consistent with the CC's assessment of the asset beta for the water and sewerage companies as part of the recent reference of Bristol Water's determination for the next price control period (AMP5).[36]

[35] To the extent that the adjusted betas represent an assumed tendency for betas to revert towards a value of one, this assumption would be consistent with a situation where the impact of the financial crisis has been to reduce betas temporarily below their long-term average values.
[36] The CC assumed a debt beta of 0.1 in the Bristol Water reference.

Table 4.8 Recent precedents for asset beta

Regulator	Regulated company(ies)	Date of determination	Asset beta
Competition Commission	Bristol Water	2010	0.32–0.43
Competition Commission	Water and sewerage companies	2010	0.27–0.36
Ofgem	DPCR5	2009	0.24–0.34
Competition Commission	UK utilities	2007	0.30–0.45

Note: The CC assumed a debt beta of 0.1 in the Bristol Water reference. The range for Bristol Water includes an estimate of the risk differential relative to water and sewerage companies.
Source: Competition Commission (2010), 'Bristol Water plc, a reference under section 12(3)(a) of the Water Industry Act 1991' Appendix N, para. 119; Ofgem (2009), 'Electricity Distribution Price Control Review Final Proposals—Allowed Revenues and Financial Issues', p. 14; Competition Commission (2007), 'BAA Ltd, A report on the economic regulation of London airport companies (Heathrow Airport Ltd and Gatwick Airport Ltd)', Appendix F, p. 30.

Table 4.9 shows the proposed equity beta range that results from levering the asset beta range to the level of gearing assumed at DPCR5. Overall, it seems appropriate to consider a range of 0.80–1.00 for the equity beta at this stage in the RIIO-T1 and GD1 price control process. The lower end of this range, however, is based on estimates of beta over the last two years, which are significantly lower than estimates over the last 5 years. Without independent evidence that there has been a fundamental decrease in the risk profile of these companies over this period, it is prudent to put more weight on the upper end of this range.

Table 4.9 Equity beta range

	Low	High
Asset beta	0.28	0.35
Gearing	65%	65%
Equity beta	**0.80**	**1.00**

Source: Datastream, Bloomberg, and Oxera calculations.

5 Cash-flow duration

The RIIO-T1 and GD1 proposals include a number of changes to the profiling of cash flows:

- in the electricity transmission sector, there is a move away from the current approach of using accelerated depreciation profiles, which will be implemented by setting regulatory asset lives according to the expected economic lives of the relevant assets. For electricity networks, regulatory asset lives are to be extended from 20 years to 45–55 years;[37]

- in the gas distribution sector, there is a move away from the current approach of capitalising 50% of REPEX and expensing the other 50% in the year it was incurred. The RIIO-GD1 strategy document proposes capitalising 100% of REPEX, which will have the effect of moving cash flows from the current regulatory period to future regulatory periods.[38] This effect will be partially offset by the accelerated depreciation profile that will be applied to new investment, although this offsetting effect will initially be small.

Both these changes have the effect of increasing the duration of cash flows. For a single cash flow, duration is simply the time to realisation of that cash flow. For cash flows at multiple points in time, duration is the money-weighted average time to realisation.

Many market practitioners have a sense that there is a relationship between the duration of cash flows and the cost of equity. This intuition is inconsistent with the assumptions of the CAPM. Specifically, the CAPM is a one-period model, and hence by construction is unable to predict whether a change in the time profile of cash flows will affect the required return on equity, which is a multi-period problem.

Multi-period models, such as the ICAPM, do exist; moreover, they are generalisations of the CAPM, not completely new models. The CAPM is a specific case of the ICAPM where the risk-free rate and risk premium are assumed to be constant over time. These models provide robust, peer-reviewed frameworks for understanding the relationship between the time profile of cash flows and the cost of equity.

In June 2010, Oxera applied the ICAPM framework to understand the implications for the cost of capital of increasing the duration of cash flows for a regulated energy network.[39] The findings of this report were then subject to a critique by Cambridge Economic Policy Associates (CEPA). A detailed rebuttal to CEPA's challenge is contained in Appendix 3. In summary, the critique by CEPA does not undermine the validity of the earlier analysis undertaken by Oxera.

The theoretical multi-period models are calibrated on large datasets spanning a wide range of industry sectors, usually including utilities, over many decades. The empirical evidence is supportive of the theoretical prediction that, for companies with low cash-flow risk, an increase in duration is associated with an increase in expected return.

[37] Ofgem (2010), 'Consultation on strategy for the next transmission price control – RIIO-T1 Overview paper', p. 38.

[38] Ofgem (2010), 'Consultation on strategy for the next gas distribution price control – RIIO-GD1 Overview paper', p. 40.

[39] Oxera (2010), 'What is the impact of financeability on the cost of capital and gearing capacity?', report prepared for Energy Networks Association, June 9th.

When setting the cost of equity for utilities based on the CAPM, it is therefore appropriate to consider whether there is a systematic error, and, moreover, whether this error is exacerbated by an increase in cash-flow duration.

This section provides a brief recap on the theoretical basis for believing that an increase in the duration of cash flows is likely to lead to a material increase in the cost of capital for regulated utilities. The section then considers the empirical evidence advanced by both CEPA and Europe Economics in the context of the theoretical framework, together with examples from the large body of technical studies on the empirical relationship between duration and cost of capital.

5.1 Recap on the theoretical framework

For risk-free bonds, it is a well-established relationship that the sensitivity of the bond price to changes in interest rates increases with duration.[40] This risk is posited as an explanation for the 'term premium' in long-term relative to short-term rates.[41] Merton (1973) develops this relationship further and provides one of the first studies that analyse the relationship between duration and the risk premium in the term structure of interest rates for risky corporate debt.[42]

Intuitively, there should also be a relationship between the sensitivity of the value of a company to changes in discount rates, which depends on the duration of the underlying cash flows. However, unlike risk-free bonds, for companies the discount rate is the cost of capital. As the cost of capital comprises both a risk-free rate and a risk premium, the overall impact on expected return depends on the sensitivity of asset values to changes in these components over time.

The intuition that there is a relationship between duration of cash flows and the cost of capital as a result of variation over time in both the risk-free rate and the risk premium is inconsistent with the assumptions of the CAPM. Specifically, the CAPM is a one-period model which assumes that investment decisions are made at the start of the period and that all cash flows from the investments are received at the end of the period. Therefore, by construction the one-period CAPM assumes that all cash flows happen at a single point in time and cannot capture the impact of assuming different time profiles for cash flows and whether this will affect the required return on capital. Comparing the cost of capital for two series of cash flows with different time profiles is fundamentally a multi-period problem.

There is a substantial body of technical literature on multi-period models, such as the ICAPM. These models can be used to understand how time profiling of cash flows affects the cost of capital; moreover, they are generalisations of the CAPM rather than completely new models. The ICAPM is by no means a departure from standard finance theory. Instead, it can be viewed as an extension of the CAPM to a multi-period setting where certain restrictive assumptions of the CAPM are relaxed. For example, Campbell (1987) draws on a discrete time version of the ICAPM to show that uncertainty in short-term interest rates and time-varying risk premia are important factors in pricing stocks and bonds.[43]

In an ICAPM, factors that affect the cost of capital as expressed by the CAPM parameters—the real risk-free rate and the slope of the capital market line (ie, the Sharpe ratio[44])—are allowed to vary over time. Therefore, in addition to short-term cash-flow risk (the sensitivity of cash flows to market returns), the ICAPM captures the sensitivity of expected returns to changes in the real risk-free rate and the Sharpe ratio.

[40] Brealey, R.A. and Myers, S.C. (2008), *Principles of Corporate Finance*, 9th edition, pp. 63–67.

[41] Brealey, R.A. and Myers, S.C. (2008), *Principles of Corporate Finance*, 9th edition, pp. 71–72.

[42] Merton, R. (1973), 'On the pricing of corporate debt: the risk structure of interest rates', *Journal of Finance*, **29**:2, pp. 449–70.

[43] Campbell, J.Y. (1987), 'Stock Returns and the Term Structure', *Journal of Financial Economics,* **18**:2, pp. 373–99.

[44] The Sharpe ratio (the market price of risk) is defined as expected excess returns on the market portfolio scaled by the standard deviation of returns.

In a recent report, Europe Economics (2010) suggests that the argument that duration affects the cost of capital can be interpreted as an argument for using different costs of capital for different phases of a project, which have different risk characteristics and cash-flow profiles (eg, research phase, development phase, production phase).[45] This describes a different effect to that of the ICAPM framework because the results of the ICAPM framework do not depend on an assumption that the risk of the asset varies over its lifetime. Rather, it is market parameters—the risk-free rate and risk premium—that are assumed to vary in the ICAPM.

In simple terms, the 'duration effect' can be broken down into two parts: the impact of duration on the sensitivity of expected returns to the real risk-free rate (the 'term premium' effect); and the impact of duration on the sensitivity of expected returns to the Sharpe ratio (the 'beta' effect). These effects are summarised below and explained in greater detail in Oxera's earlier report.[46]

5.1.1 Term premium effect

An approximation of the net impact of the term premium component on the overall weighted average cost of capital (WACC) for a regulated energy network can be given by considering the impact for a 100% equity-financed company. On this basis, the impact on the cost of capital would be to increase the risk-free rate by the term premium and decrease the risk premium by the product of the term premium and the asset beta. For the UK, using a proxy for the term premium based on the difference between realised returns on long-maturity government bonds compared with short-maturity bonds over the period 1900–2009 gives an estimate of 1.0% for the term premium.[47] Assuming an asset beta of 0.4, an effect of the term premium on the cost of capital (and both the costs of debt and equity) of the order of 60bp would be expected.

Furthermore, since it is proposed under RIIO that the cost of debt be mechanically tied to an index, there is no scope for making an allowance for the impact of duration on the cost of debt when setting the regulatory allowance for the cost of debt. Indeed, the change to an indexation approach is likely to entail a step reduction in the cost of debt allowance as a result of reducing the headroom over current market rates that has tended to be built into past regulatory determinations.

The impact of duration on the level of returns required by investors in both debt and equity will therefore be disproportionately large on equity relative to its share in the capital structure. This is consistent with the philosophy of RIIO, whereby a key principle is that the onus be placed:

> on companies to manage short-term requirements and to provide equity where necessary[48]

The disproportionate effect on required equity returns may be mitigated in the short run by transitional arrangements, and in the long run by updating the cost of debt index, assuming that this index picks up any re-pricing of the cost of debt due to the increase in duration.

5.1.2 Beta effect

In the ICAPM adopted by Brennan and Xia (2006), hereafter the 'BX framework', higher duration increases not only the sensitivity of the asset value to changes in interest rates, but

[45] Europe Economics (2010), 'The Weighted Average Cost of Capital for Ofgem's Future Price Control—Final Phase 1 Report', December 1st, p. 88.
[46] Oxera (2010), 'What is the impact of financeability on the cost of capital and gearing capacity?', report prepared for Energy Networks Association, June 9th.
[47] Dimson, E., Marsh, P. and Staunton, M. (2010),'Credit Suisse Global Investment Returns Sourcebook 2010', February.
[48] Ofgem (2010), 'Handbook for implementing the RIIO model', October 4th, p. 10.

also the sensitivity to the Sharpe ratio.[49] As duration increases, for some assets the greater sensitivity to changes in the risk-free rate (the term premium effect) may be offset by the greater sensitivity to changes in the Sharpe ratio. As a result, although in the BX framework the security beta increases with duration, the instantaneous expected return may increase or decrease.[50]

Brennan and Xia state that expected returns are more likely to increase with duration for assets where the systematic risk of the cash flows (the cash-flow beta) is lower. In particular, the BX framework implies that expected excess returns increase with duration for cash-flow betas of less than 0.5.

For regulated energy networks, cash flows in any given year would be expected to be relatively insensitive to returns on the market portfolio in that year. Moreover, empirical estimates, presented later in this section, indicate cash-flow betas substantially below 0.5 for utilities, and hence that expected excess returns will increase with duration for utilities.

5.2 Empirical evidence

CEPA and Europe Economics have both advanced empirical evidence in an attempt to test whether there is a relationship between duration and the cost of capital.

– presenting evidence on a single bond issued by Phoenix Natural Gas, CEPA concluded that the debt spread on this bond did not represent risk that derived from cash-flow duration;[51]

– Europe Economics presented two sets of time-series evidence on equity betas for companies—oil companies and companies involved in electricity distribution—and concluded that there was little evidence that changes in cash-flow duration had had an impact on equity betas.[52]

CEPA concludes that the higher debt spreads on bonds of Phoenix Natural Gas compared with debt spreads on bonds of UK regulated networks are likely to reflect greater demand risk in the Northern Irish gas market, rather than the longer duration of Phoenix Natural Gas's cash flows.[53] The Phoenix Natural Gas bond used in CEPA's analysis has a maturity of eight years and a coupon of 5.5%. This means that it would have a duration of approximately seven years,[54] and is therefore uninformative about the returns required by investors for long-duration cash flows.

Europe Economics (2010), in an attempt to test the theoretical prediction that duration increases the cost of capital for regulated utilities, examines rolling equity betas for a number of oil companies during periods of sector-specific changes to capital allowances, which may have altered the cash-flow duration for these companies. It presents similar analysis for companies involved in electricity distribution around the period when accelerated depreciation was introduced in this sector. Europe Economics itself recognises that 'interpretation of these results is not straightforward' and that the evidence is inconclusive:[55]

[49] Brennan, M. and Xia, Y. (2006), 'Risk and Valuation under an Intertemporal Capital Asset Pricing Model', *Journal of Business*, **79**:1.

[50] Brennan and Xia (2006), op. cit., p. 18.

[51] CEPA (2010), 'Cashflow profiles and the allowed WACC', July.

[52] Europe Economics (2010), op. cit., para 8.44.

[53] Europe Economics (2010), op. cit., para 8.13.

[54] Bond information obtained from Dealogic.

[55] Ibid., para 8.18.

> This statistical study is not in itself decisive, and if there were good theoretical grounds for supposing that betas are, in fact, affected by duration then a more extensive statistical analysis might be warranted.[56]

The theoretical grounds for believing that betas are affected by the duration of cash flows have been summarised in section 5.1. The extensive statistical analysis that supports this theoretical prediction is provided by Brennan and Xia (2006), who calibrate their model based on realised inflation and nominal yields on zero-coupon US Treasury bonds of maturities ranging from three months to 15 years over the period 1983–2000. Data on equity returns is taken from the Centre for Research in Security Prices (CRSP) dataset.

Using a different analytical approach, further empirical evidence in support of a positive relationship between betas and the duration of cash flows is presented by Bernardo, Chowdhry and Goyal (2007). The authors use a comprehensive dataset spanning the period 1977–2004 using NASDAQ stocks in 37 industries to decompose asset betas into betas of assets in place and betas of growth opportunities.

> Since firms with more growth opportunities have cash flows with longer duration, their values are more sensitive to changes in interest rates and thus should have higher betas.[57]

In their model, growth opportunities represent a proxy for cash-flow duration. Therefore, the findings apply to an increase in the cash-flow duration for utilities regardless of whether this is accompanied by net growth in the RAV. The empirical findings suggest that the beta of growth opportunities is greater than the beta of assets in place for virtually all industries in the sample. Moreover, the asset betas of firms with above-average growth opportunities (ie, those with longer-duration cash flows) are higher than for firms with below-average growth opportunities within the same industry. This evidence supports the intuition that duration affects risk and the cost of capital, and, moreover, that longer duration is associated with higher asset and equity betas. The effect persists even once industry sector is controlled for. In addition, Bernardo, Chowdhry and Goyal (2007) note that:

> the failure to account for [the impact of duration] can lead to misestimating the cost of equity by as much as 3% depending on the industry.[58]

This failure of betas estimated using a market-model regression to explain equity returns when returns are predicted using a one-period CAPM framework is well established in the literature.[59] Brennan, Wang and Xia (2003) test empirically whether this failure can be attributed to the absence in the CAPM of factors that relate the duration of cash flows to returns. Specifically, the authors test the power of their specification of the ICAPM to explain cross-sectional variation in returns in comparison to both the standard CAPM and the Fama–French three-factor model.[60]

The study statistically compares the difference between the predicted excess returns from each model and the actual realised excess returns for 30 industry portfolios. For utilities, the mispricing of utility excess returns under the standard CAPM is positive (ie, the CAPM underpredicts returns), while, in comparison, the ‘mispricing’ under the ICAPM is found to be

[56] Ibid., para 8.45.

[57] Bernardo, A.E., Chowdhry, B. and Goyal, A. (2007), ‘Growth options, beta, and the cost of capital’, *Financial Management*, summer, p. 6.

[58] Ibid., p. 2.

[59] Fama, F.E. and French, K.R. (1988), ‘Dividend yields and expected stock returns’, *Journal of Financial Economics*, **22**, pp. 3–25; Fama, F.E. and French, K.R. (1989), ‘Business conditions and expected returns on stocks and bonds’, *Journal of Financial Economics*, **25**, pp. 23–49; Ferson, W.E. (1989), ‘Changes in expected security returns, risk, and the level of interest rates’, *Journal of Finance*, **44**:5, pp. 1191–217; Ferson, W.E. and Harvey, C.R. (1991), ‘The variation of economic risk premiums’, *Journal of Political Economy*, **99**:21, pp. 385–415.

[60] Brennan, M. Wang, A. and Xia, Y. (2003), ‘Estimation and Test of a Simple Model of Intertemporal Capital Asset Pricing’, *Journal of Finance*, **59**, pp. 1743–75.

negligible. The reduction in the pricing error achieved by using the ICAPM instead of the CAPM is approximately 0.2 percentage points per month (approximately 2.4 percentage points per year).[61]

Brennan, Wang and Xia (2003) also compare the pricing performance of the ICAPM to that of the Fama–French three-factor model, a model which has previously been demonstrated as having greater explanatory power for stock returns.[62] It is notable that, while Brennan, Wang and Xia (2003) find a modest improvement in the explanatory power for utility returns of the Fama–French model relative to the CAPM, this is far exceeded by the improvement under the ICAPM. This suggests that the modelling of changes over time in the risk-free rate and the Sharpe ratio under the ICAPM directly addresses risk factors that are highly relevant to utilities in a way that the Fama–French model can only capture indirectly (through the book-to-market ratio).

In a more recent study following an alternative analytical approach, Da (2009) comes to a very similar conclusion using a two-factor version of the consumption CAPM, where the expected excess return is a function of the covariance of cash flows with aggregate consumption and the duration of cash flows relative to aggregate consumption. The two-factor model, including duration, is found to explain up to 82% of the cross-sectional variation in average returns for portfolios sorted according to size and book-to-market ratios. This model significantly outperforms the CAPM, Fama–French and the traditional consumption CAPM in explaining cross-section variation in returns.[63]

In Da's model, the impact of duration on expected returns is dependent on the degree to which the cash flows to the security co-vary with aggregate consumption in the short term—ie, it depends on the 'cash-flow beta'. The expected excess return increases with duration for assets where the cash flow co-varies less relative to aggregate consumption than aggregate consumption co-varies with itself. This is consistent with the predictions of the BX framework, which implies that expected excess returns increase with duration for assets with low cash-flow risk—specifically, those with cash-flow betas of less than 0.5.

Campbell and Mei (1993) decompose the market beta[64] into three components: the beta that results from unexpected changes in the firm's cash flows; the beta that results from unexpected changes in future real interest rates; and the beta that results from unexpected changes in the firm's expected future excess returns.[65]

The attraction of this decomposition is that it is not based on any particular asset pricing model. Instead, it is based on a linear approximation of the fundamental present-value relationship between stock prices, expected future cash flows and discount rates. Intuitively, it is similar to the BX framework as it also attributes the sensitivity of returns to changes in cash flows, the interest rate and market excess returns (which has a similar interpretation to the Sharpe ratio).

Using data from 1952 to 1987, Campbell and Mei estimate the three beta components for 12 industry portfolios. The estimated cash-flow beta for the portfolio of utility stocks is –0.125 and not statistically significantly different from zero.[66] Campbell and Mei note that their results are intuitively plausible:[67]

[61] Brennan, Wang and Xia (2003), Table 5.

[62] Fama, E.F. and French, K R. (1993), 'Common risk factors in the returns on stocks and bonds', *Journal of Financial Economics*, **33:**1, February, pp. 3–56.

[63] Da, Z. (2009), 'Cash Flow, Consumption Risk, and the Cross-section of Stock Returns', *Journal of Finance*, **64**:2, April.

[64] Defined as the sensitivity of the unexpected excess return on an asset to the unexpected excess return on the market.

[65] Campbell, J. and Mei, J. (1993), 'Where do betas come from? Asset price dynamics and the sources of systematic risk', *The Review of Financial Studies*, **6:**3, pp. 567–592.

[66] Ibid., Table 1.

[67] Ibid., p. 575.

> Cyclical industries such as basic industries, capital goods, and textiles have high cash flow betas, whereas stable industries such as utilities and services have low (indeed slightly negative) cash flow betas.

Moreover, Campbell and Mei test whether the CAPM fits their results and find that the restrictions placed by the CAPM are statistically rejected. This is consistent with other studies described in this section that show that the variation in excess returns cannot be explained by the CAPM alone.

5.3 Summary

Intuitively, there is a relationship between cash-flow duration and returns required by investors. However, the one-period CAPM is not a framework that can provide theoretical understanding of this relationship or a prediction for how changes in duration may affect required returns. This is not to say that the CAPM cannot be used in estimating the cost of capital in a regulatory context, but rather that it is an over-simplification, and, when faced with substantial policy changes, it is necessary to consider whether alternative models can offer insights.

The theoretical framework presented in Oxera's earlier report indicates that, for regulated energy networks, there are strong grounds for believing that an increase in the duration of cash flows of the order implied by the changes proposed for the RIIO-T1 and GD1 price controls will lead to a material increase in the cost of capital. The critique provided by CEPA does not diminish the validity of this conclusion.

There is a substantial body of empirical evidence suggesting a relationship between cash-flow duration and required returns. Moreover, the evidence is consistent with the relationship being positive for regulated energy networks. Set against the weight of this evidence, the event study analysis provided by Europe Economics provides only a small sample of data points, which, by the authors' own admission, is inconclusive.

There remain strong grounds to believe that an increase in the duration of cash flows for regulated energy networks will lead to a material increase in the cost of capital. An indicative estimate of the magnitude of one of the components of the duration effect is 60bp.

More evidence and analysis are needed on the changes to cash-flow profiles expected under RIIO-T1 and GD1, including the impact of transitional arrangements and the interaction between changes in cash flows and debt indexation, to firm up the magnitude of the duration effect on the cost of capital. Nevertheless, at this stage in the price control process, it is appropriate to consider, at the very least, estimates towards the top end of the range for the cost of equity.

6 Overall evidence on the cost of equity

This section brings together the evidence on the estimates of the individual CAPM parameters to produce a range for the cost of equity within the one-period CAPM framework. Table 6.1 indicates that this range is 5.10–7.50%.

Table 6.1 CAPM real post-tax cost of equity estimates

	Low	High
Real risk-free rate (%)	1.50	2.00
ERP (%)	4.50	5.50
Equity beta	0.80	1.00
Real cost of equity (%)	**5.10**	**7.50**

Source: Oxera calculations.

Section 6.1 provides cross-checks for the range produced within the CAPM framework, while section 6.2 considers how this evidence can be interpreted and applied, given the regulatory context.

6.1 Cross-checks

The cross-checks suggest consideration of a higher range than that generated by applying a one-period CAPM approach to the market evidence.

6.1.1 Dividend growth model

The ranges are cross-checked against the cost of equity calculated by applying a simple one-step DGM to the UK listed utility networks. Table 6.2 presents the cost of equity estimates. The one-year-ahead dividend forecasts are based on average analyst forecasts provided by IBES. The long-term dividend growth rate is proxied by the long-term average expected GDP growth rate (2.2%).[68]

Table 6.2 DGM cost of equity estimates, long-term growth rate = 2.2%

	Cost of equity (%)		
	January 7th 2011	Latest six-month average up to January 7th 2011	Six-month average gearing (%)
National Grid	9.2	9.1	59
Scottish & Southern	8.7	9.0	29
United Utilities	7.6	7.6	55
Pennon Group	6.2	6.4	51
Northumbrian Water	6.8	6.6	61
Severn Trent Water	7.0	7.2	58
Range	**6.2–9.2**	**6.4–9.1**	**29–61**

Note: Gearing is calculated as net debt/enterprise value.
Source: Datastream, HM Treasury and Oxera calculations.

[68] HM Treasury (2010), 'Forecasts for the UK Treasury: a comparison of independent forecasts', November. The same growth rate assumption is used in section 4 in estimating a one-step DGM for the market index.

The latest estimates of the cost of equity for listed UK utilities under the DGM are in the range of 6.2–9.2%. The companies have broadly similar gearing of around 60%, with the exception of Scottish & Southern and Pennon Group, which have somewhat lower gearing. The two companies with UK energy networks have an estimated cost of equity in the range of 8.7–9.2%, which is substantially in excess of the range presented in Table 6.1.

Estimates of the cost of equity under the DGM are highly sensitive to the model inputs, especially to the long-term growth rate assumption. Table 6.3 shows DGM estimates of the cost of equity, assuming a long-term growth rate of zero. This is equivalent to assuming that forward-looking, long-run growth in dividends is zero—a highly conservative assumption.

Table 6.3 DGM cost of equity estimates, long-term growth rate = 0%

	Cost of equity (%)		
	January 7th 2011	Latest six month average up to January 7th 2011	Six month average gearing (%)
National Grid	7.0	6.9	59
Scottish & Southern	6.5	6.8	29
United Utilities	5.4	5.4	55
Pennon Group	4.0	4.2	51
Northumbrian Water	4.6	4.4	61
Severn Trent Water	4.8	5.0	58
Range	**4.0–7.0**	**4.2–6.9**	**29–61**

Note: Gearing is calculated as net debt/enterprise value.
Source: Datastream, HM Treasury and Oxera calculations.

The latest estimates of the cost of equity under a no-growth scenario are in the range 4.0–7.0%—significantly lower than the estimates presented in Table 6.2. The cost of equity estimates for National Grid and Scottish & Southern reduce to 7.0% and 6.5% respectively. Even under this highly conservative assumption, these estimates still lie towards the upper end of the CAPM range presented in Table 6.1.

6.1.2 Comparison to debt spreads

Another approach is to check the equity risk component from the CAPM cost of equity relative to the actual debt premium. The average spread currently observed in a sample of corporate bonds issued by the regulated energy networks is 124bp (see Appendix 5).

The unlevered ERP component from the CAPM cost of equity is equal to the asset beta multiplied by the ERP. The estimates of this component based on the figures presented in Table 6.1 yield 1.26% at the low end of the range and 1.93% at the high end.

The unlevered ERP component implied by the low end of the range of cost of equity estimates in the CAPM framework is in line with the current level of debt premium for bonds issued by regulated energy networks. Given the lower priority of equity relative to debt in terms of claims on cash flows, as the lower end of the CAPM range is comparable to the level of risk premium currently required by debt-holders, it is therefore not appropriate to consider estimates of the cost of equity below the midpoint of the CAPM range.[69]

[69] This comparison is simplified and makes no adjustment for expected loss or debt beta.

6.2 Conclusion on the initial range

This report has considered a wide body of evidence in determining an initial range for the RIIO-T1 and GD1 price controls. Based on an application of the standard one-period CAPM framework this range is 5.1–7.5%.

At this stage in the process it is premature to settle on a point estimate within the range. Indeed, the point estimate may vary between sectors and even between companies, according to both their intrinsic business risk and the balance of risk and uncertainty mechanisms proposed in the companies' business plans. However, it is crucial to ensure that the allowed cost of equity is sufficient to attract the equity investment that is necessary to deliver the RIIO objectives and to be consistent with the significant policy changes that are being introduced.

The lower end of the CAPM range, however, is based on estimates of beta over the last two years, which are significantly lower than estimates over the last five years. Without independent evidence that there has been a fundamental decrease in the risk profile of these companies over this period, it is prudent to put more weight on the upper end of this range.

The cross-check of the CAPM range against DGM estimates suggests that, even assuming no long-run dividend growth, the cost of equity for regulated energy networks is above the midpoint of the CAPM range.

Furthermore, as the equity risk component of the lower end of the range is comparable to the level of risk premium currently required by debt-holders, the lower end of the CAPM range does not appear to be realistic.

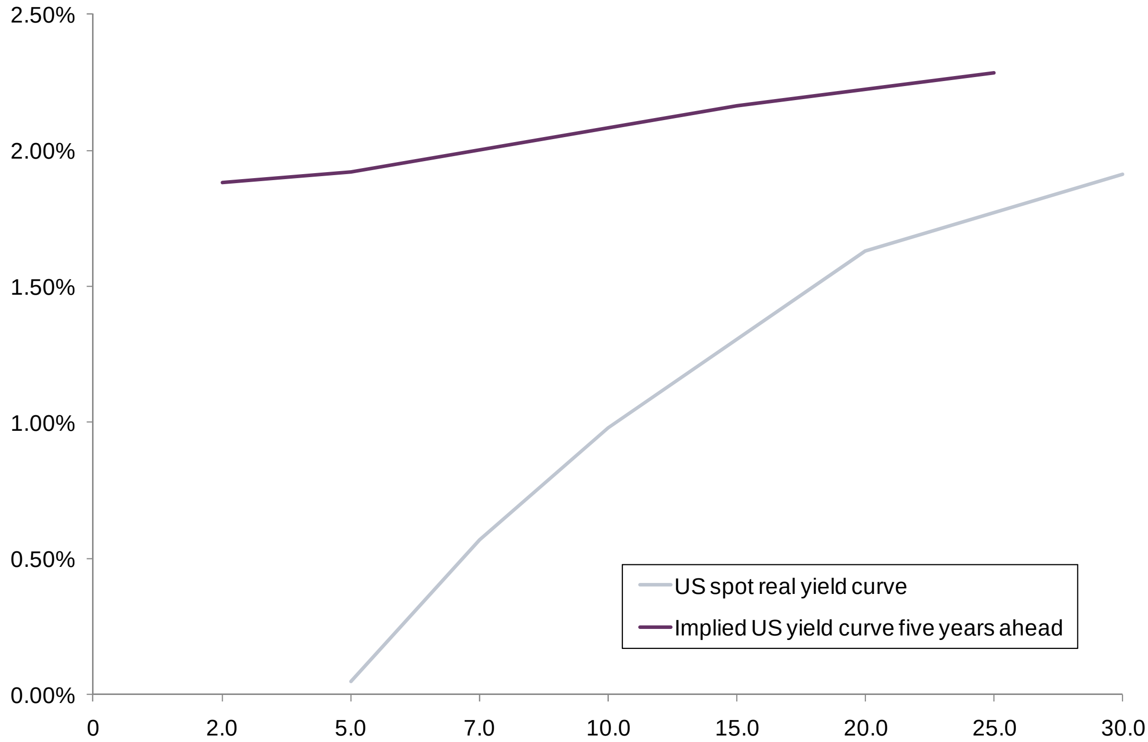
Moreover, the wide body of theoretical and empirical evidence presented in section 5 suggests that there are strong grounds to believe that increases in the cash-flow duration of the magnitude proposed for the RIIO-T1 and GD1 price controls are likely to materially increase the returns required by investors in regulated energy networks.

Taking into account both the cross-checks and the regulatory context therefore suggests that it is appropriate to consider estimates from the top half of the range generated by an application of the one-period CAPM to market evidence.

A1 Market expectations of the real risk-free rate in the USA

Figure A1.1 shows the US real yield curve as at January 7th 2011 and the implied future yield curve in five years' time, using data on US TIPS.[70]

Figure A1.1 US TIPS curve and implied future yield curve five years ahead (%)



Source: US Treasury and Oxera calculations.

[70] Five years is the shortest maturity for which the US Treasury provides data on zero-coupon real yields.

A2 Alternative beta estimates

A2.1 Equity beta estimates for secondary comparator sets

Table A2.1 Equity beta estimates for integrated energy companies

	Raw equity beta	Adjusted equity beta	Gearing
Centrica	0.49	0.66	11%
International Power	0.88	0.92	58%
RWE	0.62	0.74	19%
GDF Suez	0.85	0.90	30%
Enel	0.77	0.84	65%
Average (2-year)	**0.72**	**0.81**	**37%**
Centrica	0.62	0.75	11%
International Power	0.81	0.88	65%
RWE	0.94	0.96	30%
GDF Suez	0.92	0.95	58%
Enel	0.69	0.79	19%
Average (5-year)	**0.80**	**0.86**	**37%**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of table presents beta estimates using five years of data, calculated using daily data over the two- and five-year periods ending January 7th 2011.
Source: Datastream, Bloomberg and Oxera calculations.

Table A2.2 Equity beta estimates for international network comparators

	Raw equity beta	Adjusted equity beta	Gearing
Australian Pipeline Trust	0.54	0.69	64%
Envestra	0.76	0.84	77%
Snam Rete Gas	0.17	0.45	45%
Terna	0.20	0.47	42%
Vector	0.40	0.60	56%
REN	0.45	0.63	55%
Enagas	0.55	0.70	42%
Red Electrica	0.51	0.67	37%
Average (2-year)	**0.45**	**0.63**	**52%**
Australian Pipeline Trust	0.70	0.80	61%
Envestra	0.63	0.75	72%
Snam Rete Gas	0.22	0.48	42%
Terna	0.33	0.55	37%
Vector	0.56	0.70	56%
Enagas	0.59	0.73	34%
Red Electrica	0.57	0.71	38%
Average (5-year)	**0.51**	**0.67**	**48%**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of table presents beta estimates using five years of data, calculated using daily data over the two- and five-year periods ending January 7th 2011. REN removed from five-year sample due to insufficient data.
Source: Datastream, Bloomberg and Oxera calculations.

Table A2.3 Equity beta estimates for US network comparators

	Raw equity beta	Adjusted equity beta	Gearing (%)
Emera	0.28	0.51	49%
Kinder Morgan	0.45	0.63	41%
Atlanta Gas Light	0.57	0.71	49%
ITC Holdings	0.62	0.75	49%
Northwest Natural Gas	0.54	0.69	38%
Piedmont Natural Gas	0.58	0.72	35%
TC Pipelines	0.42	0.61	32%
Average (2-year)	**0.49**	**0.66**	**42%**
Emera	0.26	0.51	46%
Kinder Morgan	0.49	0.66	37%
Atlanta Gas Light	0.64	0.76	46%
ITC Holdings	0.77	0.85	45%
Northwest Natural Gas	0.65	0.76	37%
Piedmont Natural Gas	0.75	0.83	34%
TC Pipelines	0.46	0.64	28%
Average (5-year)	**0.57**	**0.71**	**39%**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of table presents beta estimates using five years of data, calculated using daily data over the two- and five-year periods ending January 7th 2011.
Source: Datastream, Bloomberg and Oxera calculations.

A2.2 Sensitivity to debt beta assumption

Table A2.4 Ranges for asset beta and equity beta assuming debt beta of 0.05

	Raw asset beta	Adjusted asset beta	Raw re-levered equity beta	Adjusted re-levered equity beta
National Grid	0.24	0.31	0.59	0.79
Scottish & Southern	0.28	0.41	0.71	1.07
Average (2-year)	**0.26**	**0.36**	**0.65**	**0.93**
National Grid	0.36	0.42	0.93	1.10
Scottish & Southern	0.49	0.58	1.30	1.56
Average (5-year)	**0.42**	**0.50**	**1.11**	**1.33**

Note: The upper half of the table presents beta estimates using two years of data, and the lower half of table presents beta estimates using five years of data, calculated using daily data over the two- and five-year periods ending January 7th 2011. Assuming debt beta = 0.05. Equity beta re-levered assuming 65% gearing.
Source: Datastream, Bloomberg and Oxera calculations.

A2.3 Beta estimates based on five-year weekly data

Table A2.5 Equity beta estimates using 5-year weekly data

	Raw equity beta	Adjusted equity beta	Gearing
National Grid	0.68	0.78	49%
Scottish and Southern	0.64	0.76	24%
Average	**0.66**	**0.77**	**37%**

Note: Calculated using data over the period January 7th 2006 to January 7th 2011.
Source: Datastream, Bloomberg and Oxera calculations.

Table A2.6 Asset beta estimates using 5-year weekly data

	Raw asset beta	Adjusted asset beta	Raw re-levered equity beta	Adjusted re-levered equity beta
National Grid	0.35	0.40	0.99	1.15
Scottish & Southern	0.48	0.57	1.38	1.64
Average	**0.41**	**0.49**	**1.18**	**1.39**

Note: Calculated using data over the period January 7th 2006 to January 7th 2011. Equity beta re-levered assuming 65% gearing.
Source: Datastream, Bloomberg and Oxera calculations.

A2.4 Share of regulated activities for comparator companies

Table A2.7 Share of regulated activities for comparator companies

	Country	Type of regulation	% share of regulated activities
Australian Pipeline Trust	Australia	Price cap	86
Envestra[1]	Australia	Five-year price cap	100
Emera[2]	Canada	Cost of service	11–90
Snam Rete Gas	Italy	Four-year price cap	98
Terna	Italy	Four-year price cap	95
Vector	New Zealand	Price cap	60
REN	Portugal	Cost of service	99
Enagas	Spain	Four-year revenue cap	90
Red Electrica	Spain	Four-year revenue cap	100
National Grid	UK	Four-year revenue cap	68
Scottish & Southern	UK	Four-year revenue cap	37
Atlanta Gas Light	USA	Cost of service + performance-based adjustments	58
ITC Holdings	USA	Cost of service	100
Kinder Morgan	USA	Cost of service + negotiated agreements	66
Northwest Natural Gas	USA	Cost of service	95
Piedmont Natural Gas	USA	Cost of service + performance-based adjustments	75
TC Pipelines	USA	Cost of service + negotiated agreements	100

Note: [1] No segmental revenue available for Envestra, but there is no mention of any non-distribution business in the annual report. [2] The percentage of earnings from networks is unclear for Emera. Investor presentation suggests 90% of earnings from regulated activities. The share of regulated activities represents the 'best' segmental data available in the order of EBIT, assets, and then turnover.
Source: Company accounts, Emera investor presentation, Bloomberg, and Oxera calculations.

A3 Cash-flow profiles and the allowed weighted average cost of capital—a response

In an earlier report, Oxera conducted an analysis of the implications of Ofgem's financeability proposals for the cost of capital of regulated energy networks.[71] The main findings of the report were as follows.

– There are strong theoretical and empirical grounds for expecting the cost of capital for a regulated utility to increase if the duration of cash flows were to increase, for example, due to the impacts of sensitivity to changes in the risk-free rate and in the market price of risk (the Sharpe ratio).

– The inherent uncertainty in being unable to write a 'complete' regulatory contract covering all eventualities results in a time-inconsistency effect that increases the cost of capital for longer-duration cash flows.

– Financeability checks can form a useful cross-check on the allowed rate of return, given the uncertainties when estimating the cost of capital for a regulated utility.

– The greater business risk under the proposals suggests that the optimal level of gearing may decrease, with associated transitional costs and a lower-value tax shield of debt.

– An increase in the duration of the cash-flow profile is likely to lead to a change in the investor base, which will entail transitional costs. Furthermore, the pool of investors may be insufficiently large to support the market in utility equity given the changes in the cash-flow profile implied by the proposals. Nevertheless, a change in the investor base would not be expected to mitigate the likely increase in the cost of capital resulting from the longer-duration cash-flow profile.

Ofgem subsequently published a paper by its advisers,[72] responding to Oxera's analysis. The main points in the response, as illustrated in the following quotes, can be summarised as follows.

1) **The duration of the cash-flow profile is irrelevant to the allowed WACC for a regulated energy network**:

> the allowed WACC is predicated on a longer term basis in the first place, i.e. through returns earned [over the life of] the regulatory asset base, and not based upon advancing cash flows [from one regulatory period to another].[73]

2) **An increase in the duration of cash flows would be immaterial for a regulated energy network**:

> the right comparison would be of the difference in long and very-long dated maturity debt. Given the profile of risk-free rates this would have a

[71] Oxera (2010), 'What is the impact of financeability on the cost of capital and gearing capacity?', report prepared for Energy Networks Association, June 9th.
[72] CEPA (2010), 'Cashflow profiles and the allowed WACC', July.
[73] Ibid., p. 1.

> much smaller impact—the yield curve is quite flat at this longer end and consequently any impact would be smaller.[74]

Also, with respect to the Brennan and Xia (2006) framework:

> [the increase in] duration from around 10 to 30 years appears to have a negligible impact on discount rates in the framework of the model.[75]

3) **The cash-flow beta for regulated utilities may not be in the region where expected returns increase with the duration of cash flows**:

> Even though utility company returns are less sensitive to the market it is not clear that this sensitivity will be sufficiently low to ensure that beta [increases] with duration.[76]

4) **The process by which uncertainty over cash flows is resolved suggests that extending the duration of cash flows will decrease the cost of capital**:

> intuitively the rate of arrival of information would appear to be falling rather than rising over time. This suggests lower rather than higher discount rates in the B&X framework.[77]

These points fall short of demonstrating that the cost of capital for regulated utilities is likely to be unaffected as a result of Ofgem's proposals. Fundamentally, Ofgem and its advisers have so far not provided the evidence to support their contention that the risks associated with 'time-inconsistent' behaviour by regulators can be mitigated, nor have they produced detailed and credible proposals demonstrating how this might be achieved.

Furthermore, there are some issues with the points raised by Ofgem's advisers (listed above) regarding the particular technical framework used by Oxera to understand the intuition behind why the cost of capital might be higher for longer- rather than shorter-duration cash flows. These points are responded to below, together with a demonstration that they do not undermine the validity of Oxera's analysis.

Specifically, the increase in duration of the cash flows that will arise from Ofgem's proposals is likely to occur over a relatively steep part of the yield curve, and, hence, is likely to have both a relevant and a material impact on the cost of capital for a regulated energy network. If the CAPM holds, this effect unambiguously increases the cost of capital.

If the CAPM does not hold then, in the ICAPM framework implemented in the BX framework, the cash-flow betas for regulated energy networks are likely to be comfortably in the range within which the BX framework predicts that expected returns will increase with duration. Furthermore, for a regulated energy network, it would seem reasonable to expect that the rate of information arrival will be higher for longer-duration cash flows, which, in the BX framework, exacerbates the impact of increasing duration on raising the cost of capital.

Overall, there remain strong reasons to believe that the Ofgem proposals are likely to materially increase the cost of capital for regulated energy networks.

[74] CEPA (2010), 'Cashflow profiles and the allowed WACC', July, p. 4.

[75] Ibid., p. 9.

[76] Ibid., p. 8. There appears to be a typographical error in the CEPA paper where the sentence is concluded as 'sufficiently low to ensure that beta falls with duration'.

[77] Ibid., p. 9.

A3.1 Time inconsistency

The essence of the time-inconsistency problem is that regulators cannot offer binding commitments that their successors will honour in full any pledges that they make today regarding expected future returns. Oxera's analysis distinguished three categories of time inconsistency in terms of uncertainty about:

– how the regulator will act in the future, given the current regulatory framework;
– whether the regulatory framework will resist political pressure;
– how to address events not covered by the current regulatory framework.[78]

An earlier paper prepared by Ofgem's advisers considered two mechanisms by which regulatory commitment might be increased: ex ante rules and contractual commitment.[79] While, in theory, mechanisms could be designed that mitigate the first two categories of time inconsistency by constraining future actions of the regulator and strengthening the regime against political pressure, neither Ofgem nor its advisers have provided the detail or evidence required to assess the extent to which this would occur in practice.

It is highly unlikely that sufficient rules and contractual commitments can be created to remove entirely these sources of uncertainty. Given the broad and complex remit of economic regulators, constructing a complete 'regulatory contract' between companies and the regulator that specifies in advance the course of action in every possible state of the world is a considerable challenge. It is therefore inevitable that residual uncertainty will remain and regulated companies will be exposed to the time-inconsistency risk that future regulators are unable or unwilling to honour in full their predecessors' commitments.

The issue of time-inconsistency is relevant regardless of whether regulatory risk is systematic or not.

First, even if regulatory risk is not a factor priced by investors (as assumed by the CAPM), it would be expected to have an impact on the expected (probability-adjusted) cash flows and hence the value of the regulated company. It will be necessary to include an allowance for this effect in the determination of allowed revenue. Whether this is incorporated in the regulatory allowance for the cost of capital or elsewhere in the price control is a separate issue.

Second, the ICAPM shows that investors price risks not captured by the CAPM. If the exposure of future cash flows to regulatory risk is priced by investors, there would be an impact on the return they require for investing in regulated networks, and, hence, on the cost of capital. The BX framework provides a means of thinking about the impact of regulatory risk on asset pricing. More details are provided in section A3.3.2, but the implication is that regulatory risk suggests a further increase in the cost of capital from increasing the duration of the cash flows for regulated utilities. This effect is over and above the term premium and beta effects discussed in section 6, as it is an incremental impact from overlaying the regulatory context on the BX framework.

A3.2 Increase in cash-flow duration under RIIO

The first two points raised by Ofgem's advisers in respect of the BX framework are whether:

– the duration of the cash-flow profile is relevant to the allowed WACC for a regulated energy network;

[78] Oxera (2010), op. cit.
[79] CEPA (2010), 'RPI-X@20: Providing financeability in a future regulatory framework', May.

– an increase in the duration of cash flows would be material for a regulated energy network.

Duration is a cash-flow metric and, in this context, represents the average time to realisation of cash flows to investors. When determining the cost of capital for a regulated company, there are two benchmarks for the duration of cash flows:

– the duration of cash flows in the regulatory period;
– the duration of cash flows over the lifetimes of the assets.

If there is no time-inconsistency problem—and hence no risk that regulatory pledges today will not be honoured in the future, and regulatory cash flows are spread over the lifetimes of the assets—the relevant benchmark is the duration of cash flows over the asset lives. However, where there are concerns about the risk of time-inconsistency, the duration of cash flows in the regulatory period will be relevant to both creditors and equity investors. It is therefore prudent to consider the impact of the proposals on both benchmarks.

As explained below, for electricity transmission the increase in duration may be of the order of 5 or 7 years based on the regulatory lifetimes of the assets (dependent on the final assumption for asset lives), and closer to 4 or 5 years based on cash flows in the regulatory period.

For gas distribution networks, the likely impact on duration from the change in the capitalisation policy on REPEX is not quantified, although it is clear that the proposed change increases cash-flow duration (albeit, it will be partially over time mitigated by the front-loaded depreciation profile for new investments).

With cash flows over the lifetimes of the assets, the increase in duration for electricity networks is likely to occur over the part of the yield curve that represents maturities between six and 13 years; for cash flows in the regulatory period, the increase is likely to occur over the part representing maturities of less than five years.[80] In the BX framework, quantification of the impact depends on how the model is calibrated against capital market data. Nevertheless, where the duration of the cash-flow profile is increased, the increase is likely to occur over a relatively steep part of the yield curve, and hence have a relevant and material impact on the cost of capital for a regulated energy network.

A3.2.1 Cash flows in the regulatory period

With fixed-length regulatory periods, investments in regulated energy networks could be perceived as being in effect investments in the stream of cash flows remaining in the current regulatory period, where the terminal cash flow is the value of the RAV at the end of the regulatory period.

This benchmark is not dissimilar to the way in which many market participants (particularly debt analysts and investors) analyse regulated utilities. For example, although, when determining credit ratings, credit-rating agencies do consider the outlook for cash flows beyond the current regulatory period, in general less weight is placed on projections of financial metrics after the current regulatory period has finished. The primary reason for this difference in approach towards cash flows within and after the period is the ‘re-set risk’ associated with the periodic review, and acknowledged by both Ofgem and its advisers.[81]

The maximum duration of cash flows to investors in the current regulatory period is the remainder of the price control.[82] Under the current regulatory framework with five-year

[80] Although the link between duration and cost of capital in the BX framework does not operate solely through the yield curve.

[81] Ofgem (2010), ‘Regulating energy networks for the future: RPI-X@20—Current thinking working paper—Financeability’, May 19th, paras 2.5–2.7; CEPA (2010), ‘Cashflow profiles and the allowed WACC’, July, p. 6.

[82] This period is five years, assuming investment at the start of the price control period—the maximum duration would be shorter for investments partway through a period.

regulatory periods, the status quo for the duration of cash flows from which any increase is measured must therefore be five years at most, and is likely to be in the region of three years.

The RIIO proposals would transfer cash flows from within the period to the end of the period by increasing the terminal value of the RAV. Moreover, in addition to increasing the duration of cash flows, the regulatory periods would be extended from five to eight years. The increase in duration of the current regulatory period's cash flows is therefore likely to be approximately four or five years.

A3.2.2 Cash flows over the lifetimes of regulated assets

Alternatively, the benchmark could be the duration of cash flows over the lifetimes of the regulated assets.

A key factor in determining the duration of cash flows to investors is the regulatory depreciation profile. Regulated electricity networks in Great Britain have regulatory asset lives of 20 years applied to post-privatisation assets. An electricity network that has acquired assets evenly over the period since privatisation would now have a mixture of assets with remaining asset lives distributed approximately uniformly between one and 20 years. Stylised modelling indicates that, under this scenario, the duration of cash flows from the current asset base will be approximately six years.[83]

Extending this stylised modelling indicates that comparing the duration of cash flows over the average remaining asset life when regulatory asset lives are 45 or 55 rather than 20 years is therefore approximately equivalent to an increase in duration from seven to approximately 11 or 13 years respectively.

A3.3 Interpretation of the Brennan and Xia framework

The third and fourth points made by Ofgem's advisers relating to the BX framework are whether:

– the cash-flow beta for regulated utilities is in the region where expected returns increase with the duration of cash flows;
– the process by which uncertainty over cash flows is resolved suggests that extending the duration of cash flows will increase the cost of capital.

A3.3.1 Cash-flow betas for regulated utilities

The BX framework employs the ICAPM, which allows for variation over time in factors that affect the parameters of the CAPM. Although the ICAPM framework is more general than the CAPM, Brennan and Xia (2006) state the restriction under which the ICAPM and CAPM are aligned:

> if the CAPM holds so that the pricing kernel is perfectly correlated with the return on the market, then the security market beta depends only on the market beta of the underlying cash flow.[84]

If this restriction holds, there is a further set of conditions under which the security-market beta will increase with duration.[85] Brennan and Xia verify that these conditions are met by empirical data, and hence that, if the CAPM holds, an increase in duration will be associated with an increase in beta and in the instantaneous expected return.

[83] See Appendix 4 for details.
[84] Brennan and Xia (2006), op. cit., p. 11.
[85] In the context of the cost of equity, the security-market beta refers to the equity beta. In the context of the WACC, the security-market beta refers to the asset beta—the weighted average of the equity and debt betas.

If the pricing kernel[86] is less than perfectly correlated with the return on the market, the CAPM does not hold, and although the security beta will still increase with duration, the instantaneous expected return may increase or decrease.[87] In the BX framework this is because the pricing kernel co-varies negatively with the real risk-free rate and positively with the Sharpe ratio (ie, expected excess returns on the market portfolio scaled by the standard deviation of returns). Intuitively, these co-variances describe a set of relationships where the price of risk increases and short-term interest rates decrease as prospects for economic growth worsen.

As duration increases, for some assets the increase in the sensitivity to changes in the risk-free rate may be offset by the increase with duration of sensitivity to changes in the Sharpe ratio. Brennan and Xia state that expected returns are more likely to increase with duration for assets where the systematic risk of the cash flows (the cash-flow beta) is lower. In particular, the BX framework implies that expected excess returns increase with duration for cash-flow betas of less than 0.5.

When discussing this aspect of the BX framework, Ofgem's advisers mention that equity betas in the range of 0.5–0.7 have been estimated for energy transmission, and then imply that cash-flow betas may be in excess of 0.5—the threshold above which the cost of capital increases with duration.[88] However, for the purpose of the WACC, it is necessary to understand the likely range for cash-flow betas to all investors. This requires two steps:

– estimation of asset betas by de-levering the equity beta estimates;
– understanding the relationship between asset betas and cash-flow betas.

The process for de-levering equity betas is well understood and therefore not covered here; however, the relationship between asset and cash-flow betas is less familiar. Cash-flow betas can be understood as the correlation between changes in cash flows to investors and the pricing kernel (or equivalently the return on the market portfolio in a CAPM context). Where the duration of cash flows is short, the security beta is approximately equal to the cash-flow beta:

> the security market beta is very close to the cash flow beta when the time horizon is short and the other components of the market beta become important for long horizons.[89]

Figure 3a of Brennan and Xia (2006) shows that the security beta increases with duration for all values of the cash-flow beta between 0 and 1.[90] Therefore, in this framework, the equity betas for regulated energy networks would consist of the cash-flow beta plus a positive net contribution from the other components (sensitivity to the risk-free rate and the Sharpe ratio) of the security beta. Campbell and Mei (1993) estimate that cash-flow betas for utilities are close to zero,[91] which is comfortably within the range for which the BX framework predicts expected returns to increase with duration.

A3.3.2 Pattern of information arrival for regulated utilities

The BX framework also suggests that where information on longer-duration cash flows arrives faster than that on shorter-duration cash flows, the cost of capital will be higher for the former. The rate of information arrival is represented in the BX framework by the standard

[86] The pricing kernel is effectively a formula that maps asset payoffs to observable asset prices, taking into account the uncertainty surrounding these payoffs. Changes in the pricing kernel can therefore occur as a result of changes in asset payoffs or the probabilities of these payoffs.
[87] Brennan and Xia (2006), op. cit., p. 18.
[88] CEPA (2010), 'Cashflow profiles and the allowed WACC', July, p. 8.
[89] Brennan and Xia (2006), op. cit., p. 18.
[90] Ibid.
[91] Campbell and Mei (1993), op. cit.

deviation of the cash-flow expectation—higher rates of information arrival mean higher standard deviation of the cash-flow expectation.

For regulated utilities, the standard deviation is likely to be greater for longer- than shorter-duration cash flows. A simple comparison of two otherwise identical assets—where the first is being constructed and the second is halfway through its operational life (and furthermore assuming that risks are identical during the construction and operational phases)—would suggest that uncertainty about expected cash flows is greater for the former than for the latter. This effect would be exacerbated by the time-inconsistency problem, when cash flows for the former asset span more regulatory periods than the latter asset, and hence are exposed to more instances of regulatory re-set risk. As assets age and their cash-flow duration increases, the standard deviation of the cash-flow expectation is also likely to decrease.

The pattern of information arrival has an incremental effect on the relationships between duration and cost of capital described earlier in the Brennan and Xia paper, and suggests that the impact of regulatory time inconsistency on the cost of capital can be technically formulated using a higher standard deviation of expectations for longer-duration compared with shorter-duration cash flows. Such a relationship suggests a further increase in the cost of capital if the duration of the cash-flow profile for regulated utilities were to be increased.

A4 Duration of cash flows over the lifetimes of the regulated assets

The duration of cash flows from the current asset base is calculated under the following assumptions:

- the network has acquired assets evenly over a period of 20 years;
- after 20 years, the network incurs no further CAPEX;
- all assets are depreciated on a straight-line basis using an asset life assumption of 20 years;
- the RAV is indexed annually at a constant rate of inflation of 2.5%;
- returns are calculated using a real vanilla WACC of 5.05% (the real WACC allowed by Ofgem at the last electricity and gas transmission price review in 2006;[92]

The duration is calculated for all the cash flows (return and depreciation) generated by the current assets after year 20, in accordance with the standard definition of Macaulay duration for bonds:[93]

$$Duration = \frac{\sum_{t=1}^{T} t \cdot PV\ (CF_t)}{\sum_{t=1}^{T} PV(CF_t)}$$

where $PV\ (CF_t)$ is the present value of the cash flow in year t.

Under these assumptions, the duration of cash flows from the current asset base will be approximately six years. This number represents the weighted average time to realisation of cash flows generated by existing assets that have been acquired evenly over the period since privatisation.

To calculate the duration of cash flows when regulatory asset lives are 45 or 55 years rather than 20 years, the remaining useful lives of existing assets in place in year 20 are extended proportionally to reflect the change in the asset life assumption. The longer asset lives spread the cash flows from existing assets over a longer time period, leading to an increase in cash-flow duration from six to approximately 11 or 13 years respectively.

The increase in duration from increasing the asset lives is based on the assumption that the change is applied to existing assets, which reflects Ofgem's current thinking. However, Ofgem notes that applying the longer asset lives to new assets only could be a possible transitional arrangement.[94]

[92] Ofgem (2006), 'Transmission Price Control Review: Final Proposals', December 4th, para 2.22.

[93] Brealey, R.A. and Myers, S.C. (2008), *Principles of Corporate Finance*, 9th edition, p. 64.

[94] Ofgem (2010), 'Consultation on strategy for the next transmission and gas distribution price controls—RIIO-T1 and GD1 Financial Issues', para 2.47.

A5 Spreads on energy network bonds

Table A5.1 Spreads on energy network bonds

Issuer	Coupon (%)	Issue date	Maturity date	Current spread (bp)
National Grid Electricity Transmission plc	5.9	02-Feb-1999	02-Feb-2024	119
	6.5	27-Jul-2001	27-Jul-2028	109
	5.0	01-Mar-2005	01-Mar-2035	103
	7.4	10-Feb-2009	13-Jan-2031	116
	7.4	13-Jan-2009	13-Jan-2031	111
National Grid Gas plc	7.1	08-Feb-1994	08-Feb-2044	100
	8.8	27-Jun-1995	27-Jun-2025	111
	6.2	02-Oct-1998	02-Oct-2028	106
	7.0	14-Dec-1999	16-Dec-2024	111
	6.0	30-Jan-2002	07-Jun-2017	124
	6.4	03-Mar-2008	03-Mar-2020	116
	6.0	13-May-2008	13-May-2038	106
	6.4	17-Mar-2009	03-Mar-2020	239
Northern Gas Networks Limited	4.9	15-Nov-2005	15-Nov-2035	130
Southern Gas Networks plc	4.9	21-Oct-2005	21-Mar-2029	129
	4.9	21-Oct-2005	21-Dec-2020	136
	6.4	15-May-2008	15-May-2040	124
	5.1	02-Nov-2009	02-Nov-2018	144
Average				**124**

Note: Current spread is measured on January 7th 2011. Sample consists of bonds paying nominal coupons.
Source: Datastream.

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