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An Estimate of the GD17 Costs of Capital

Prepared for the Utility Regulator

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1. Introduction

This report contains First Economics' estimates of the costs of capital for Phoenix Natural Gas's (PNGL's) and firmus energy's (FE's) gas distribution businesses. It is intended to inform the Utility Regulator's calculation of allowed returns for the GD17 price controls covering the period 2017 to 2022.

The paper is structured into seven main parts:

- section 2 outlines the methodology that we have used in our work;
- section 3 assesses the risk that investors in the networks carry and puts forward estimates of the networks' betas;
- section 4 proposes figures for gearing;
- section 5 provides calculations of the cost of debt;
- section 6 contains estimates of the two generic parameters in the cost of equity calculation – the risk-free rate and the return on the market portfolio;
- section 7 deals with tax; and
- section 8 brings all of the preceding inputs together into overall estimates of the costs of capital.

2. Approach

The costs of capital that we consider in this paper are forward-looking estimates of the returns that the networks need to provide to investors in order to attract and retain capital within the businesses. In line with the terms of reference that were given to us by the Utility Regulator, and consistent with regulatory practice more generally, we have deliberately sought to estimate this cost of capital independently from PNGL's and FE's current ownership arrangements so that the return on offer through the price control is capable of supporting any reasonable and efficient investor set.

The cost of capital is a weighted average of two components: the cost of equity (K_e); and the cost of debt (K_d), where the weightings (gearing or g) reflect the relative importance of each type of financing in a firm's capital structure.

$$\text{pre-tax WACC} = g \,.\, K_d + (1 - g) \,.\, K_e / (1 - t)$$

The cost of debt is directly measurable and in the analysis that follows we explain how the Utility Regulator might use empirical evidence to set the appropriate values for K_d for each business. The cost of equity, by contrast, cannot be directly observed and we have instead modelled the returns that we would expect a shareholder to demand in exchange for holding shares in the networks. The primary tool that we have used in our analysis is the CAPM, which relates the cost of equity to the risk-free rate (R_f), the expected return on the market portfolio (R_m), and a business-specific measure of investors' exposure to systematic risk (beta or β_e):

$$K_e = R_f + \beta_e \,.\, (R_m - R_f)$$

The two equations together show that our costs of capital calculations are based on estimates of six parameters: g, K_d, R_f, R_m, beta and tax. In putting specific figures against each of these inputs we have sought to draw as far as possible on primary market data. We have also taken account of recent regulatory precedent, giving particular attention to the views that the Competition Commission (CC), now the Competition & Markets Authority (CMA), expressed in its 2014 determination of NIE's electricity network price controls. Inevitably, in many areas we have had ultimately to exercise a degree of judgment in order to be able to select precise numbers from the evidence we have collected, but we have tried in the analysis that follows to give a clear explanation for these judgments and to make our thinking as transparent as possible in order to assist the parties to the GD17 price control review.

3. Riskiness and Beta

We start deliberately with an assessment of the networks' risk profiles and betas on the basis that the analysis that follows will also be a key input into a number of the other cost of capital assumptions.

3.1 Preliminaries

Methodology

A firm's equity beta is a measure of the riskiness of a firm – or more specifically, a measure of the systematic risk that a firm presents – relative to the market portfolio. Firms that exhibit a beta of more than 1 can be considered more risky than the average firm in the portfolio and need to pay their investors a higher-than-average return; firms with a beta of less than 1 are less risky and warrant lower returns; and firms with a beta of exactly 1 are seen by investors as being of equal risk to the market portfolio and are expected to generate a return in line with R_m.

Empirical estimates of beta are usually obtained by measuring the covariance between movements in a company's share price and movements in the value of the stock market as a whole. However, in this report we are interested in obtaining beta estimates for two unlisted networks and cannot use market data directly. The next best alternative that we have is to collect beta estimates for companies that look to be in some sense similar and to make a judgment about the value of PNGL's and FE's betas on the basis of this comparator evidence. This is an approach that has been deployed in an increasing number of periodic reviews, including several CC inquiries, during recent years as the number of regulated companies with a stock market listing has declined, and is regarded as a robust and reliable way of assessing beta in the absence of direct stock market data.

Asset beta

When comparing the betas of different firms, one has to be careful to take account of the different gearing levels that firms choose since, all other things being equal, a firm with higher gearing will exhibit a higher equity beta. Unless one controls for this effect, there is a danger of confusing the risk that comes from high leverage with the underlying business risk that a firm faces by virtue of the nature of the activities it is carrying out.

This is where the concept of an asset beta proves useful. An asset beta is a hypothetical measure of the beta that a firm would have if it had no debt and were financed entirely by equity. By comparing different firms' asset betas it becomes possible to isolate the underlying systematic risk that a company has and carry out an assessment of the relative riskiness of different businesses.

The asset beta is calculated using the following formula:

$$\beta_a = (1 - g) \cdot \beta_e + g \cdot \beta_d$$

where β_a is a firm's asset beta, g is gearing and β_d is the firm's debt beta.[1]

A firm's actual gearing is something that is easily calculated using reported debt figures and the firm's market capitalisation, but a firm's debt beta is not something that is directly observable. We have assumed in our work that β_d is a constant of 0.1 (a value that the CC used in its inquiries for companies with approximately the same gearing and nominal cost of debt as we identify in sections 4 and 5).

Confidence intervals

This provides a complete description of our methodology for estimating asset betas. The only other point we must make is that beta estimates are exactly that: estimates. Every estimate that we identify comes with a standard error and the figures that follow must be regarded as mid-points within wider confidence intervals.

3.2 Comparator Analysis

Our comparator set comprises three types of data:

- calculated betas for comparator firms with a stock market listing;
- the beta estimates that regulators have made in recent periodic reviews; and
- the beta that Scotia Gas Networks (SGN) used in its application for the Gas to the West licence, as evidence of perceptions of risk revealed via a competitive process.

In the first of these groups we have collected beta estimates[2] for the last remaining network-dominated companies with a UK stock market listing – National Grid, Pennon Group, Severn Trent and United Utilities – which we have averaged over the last five years to be consistent with recent CC/CMA practice. The second group comprises the most recent assessments by the CC, Ofgem and Ofwat of betas for the UK's regulated networks and the Commission for Energy Regulation's calculation of Bord Gais's beta.

The comparator data is presented in tables 1 to 3.

Table 1: Calculated asset betas

	Average asset beta
National Grid	0.37
Pennon Group	0.36
Severn Trent	0.33
United Utilities	0.31

Source: First Economics' calculations.

[1] For those that have not come across this concept before, a debt beta is similar to the equity beta, but rather than measuring the systematic risk taken by the company's shareholders, it represents such risk presented to the company's lenders.
[2] Our calculations use two years of daily share price data.

Table 2: Beta estimates used in recent periodic reviews

	Year	Regulator's estimates of asset beta
Commission for Energy Regulation, Bord Gais	2012	0.35
Ofgem, gas distribution networks	2012	0.38
Ofwat, water and sewerage networks	2014	0.30
Ofgem, electricity distribution networks	2014	0.38
CC, NIE	2014	0.40
CC, GB regulated networks	2014	0.31 to 0.40

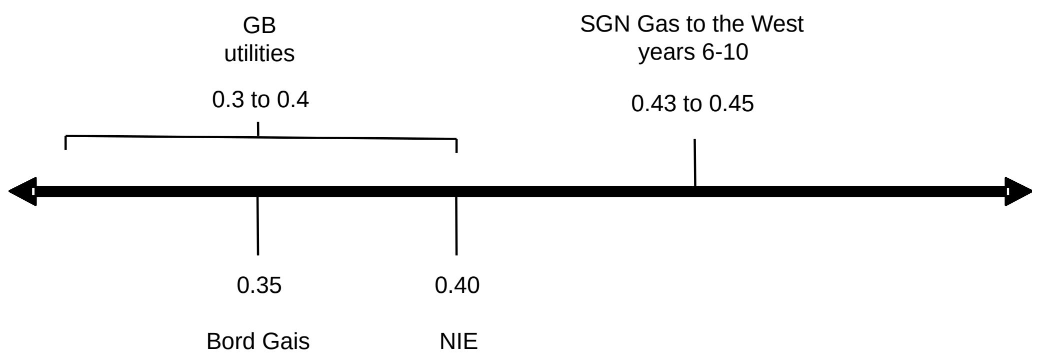
References: CC (2014), Northern Ireland Electricity Ltd price determination; Ofgem (2014), RIIO-ED1 draft determination for the slow-track electricity distribution companies; Ofwat (2014), Setting price controls for 2015-20 – risk and reward guidance; Ofgem (2012), RIIO-GD1 initial proposals; CER (2012), Decision on October 2012 to September 2017 transmission revenue for Bord Gais Networks.

Table 3: Beta estimate in successful Gas to the West licence application

	Year	Company's estimate of asset beta
SGN, low pressure application, years 6-10	2014	0.43 to 0.45

Figure 4 simplifies the picture that emerges from this analysis.

Figure 4: Summary of comparator analysis



The chart shows that the comparator betas sit in a relatively narrow range, bounded by the conventional utilities at the bottom end and SGN's estimate of its years 6-10 beta at the top end. The task that we face is to position PNGL and FE at an appropriate point in this spectrum.

3.3 Northern Ireland Gas Network Betas

Approach to comparisons of riskiness

In working through this task it is useful to highlight four main determinants of the (systematic) risk that shareholders bear through their ownership of the networks.

- Demand variability – the networks operate in markets where demand for network access is very closely correlated to the overall demand for energy. This demand will in turn be sensitive to macroeconomic conditions, insofar as a downturn in the economy will cause both households and businesses to use less energy while strong growth will bring about increases in consumption. The Northern Ireland networks also face uncertainty more generally about new connections and volume growth.

- Cost variability – networks rely heavily on direct and indirect staff to carry out their functions. As labour becomes more expensive costs will go up, and as labour becomes less expensive costs will go down. Similarly, the networks are exposed to changes in the costs of other inputs like materials and business rates.

- Regulation – the two previous risk factors cannot be looked at in isolation from the important role that regulation plays in determining the way in which changes in volumes or costs translate into changes in profit. Through its design of the price controls and associated incentive mechanisms, a regulator has a significant degree of control over the degree to which shareholders are exposed to risk – a situation that distinguishes regulated companies from unregulated companies. In particular, revenue caps may offer investors quite significant protection against changes in demand, while a regulator's design of opex and capex incentives are a key determinant of exposure to cost risk.

- Cost/revenue structure – a final consideration is the sensitivity of profit to out-/under-performance against the networks' price control assumptions. In particular, it is now widely acknowledged in regulation that companies which have small regulatory asset bases (RABs) in comparison to ongoing revenues present shareholders with greater risk than companies which have large RABs in comparison to ongoing revenues.

The first three items on this list are fairly straightforward to understand, but the fourth merits a slightly more detailed explanation. In the worked example below, we depict two companies with identical ongoing expenditures. They differ only insofar as company A has a small investor capital base and company B has a large investor capital base, as measured by their RABs. Both companies set charges so as to be able to cover their expenditure plus a return on the RAB. For the purposes of this illustration, let us assume initially that both companies seek a return of 10% per annum.

Table 5: Illustrative worked example

	Company A	**Company B**
RAB	£100m	£1,000m
Expenditure	£200m	£200m
Return on RAB @ 10%	£10m	£100m
Revenues	£210m	£300m

Now consider what happens to these companies when they experience the same percentage cost overrun or the same percentage revenue loss. Although the absolute £m loss of profit is similar in both companies, the percentage loss is far greater for company A with the small RAB than it is for the company B with the larger RAB.

Table 6: Revenues, costs and profits after a 2% cost shock

	Company A	Company B
RAB	£100m	£1,000m
Revenue	£210m	£300m
Expenditure	£204m	£204m
Profit	£6m	£96m
Profit as % of RAB	6%	9.6%

Table 7: Revenues, costs and profits after a 2% revenue shock

	Company A	Company B
RAB	£100m	£1,000m
Revenue	£205.8m	£294m
Expenditure	£200m	£200m
Profit	£5.8m	£90m
Profit as % of RAB	5.8%	9.4%

An exactly analogous story can be told of the effects of unexpected cost reductions and about revenue gains, insofar as a given cost or revenue shock causes a greater percentage change in returns for companies with small RABs.

This provides important insights into the riskiness of different firms because it shows that the variability in out-turn profits is not just a function of the likelihood and scale of cost and demand shocks, but also the size of the capital base. Holding all other things equal, shareholders in a regulated company with a small RAB relative to ongoing costs are likely to suffer proportionately more when downside shocks occur (and gain more following upside events) in comparison to shareholders in firms whose RABs are large relative to ongoing costs.

This higher potential volatility in profits makes companies with high 'operational gearing' more risky in the eyes of shareholders. Consequently, a firm with a small RAB would not have the same cost of capital and would not seek the same return as a company with a large RAB. It would instead need to factor a higher cost of capital upfront into its charges.

Comparison of risk profiles

It follows that in order to understand how much risk the different shareholders in our sample of firms are exposed to one has to look holistically at the potential volatility in demand and costs, take the range of outcomes that one can envisage through the sector's regulatory rules and then examine the impact on each comparator's profits. It is not possible to evaluate riskiness without taking the full chain of events into account – in particular, we would caution anyone from making judgments about a business's risk profile on the basis of perceptions of pure demand and cost variability alone.

Despite their similarities, the UK's regulated companies are not identical in any of the above respects, as table 8 demonstrates.

Table 8: Characteristics of regulated companies

	Exposure to demand risk	Exposure to cost risk	Operational gearing – average annual totex-to-RAB ratio
GB electricity distribution	Low – companies have revenue caps	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates incentive rates of around 55%.	Low – around 15-20%
GB gas distribution	Low – companies have revenue caps	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates an incentive rate of around 60%.	Low – around 15-20%
England & Wales water and sewerage	Low – companies are likely to have: - for the water service, a revenue cap with adjusters for volume and new meter connections: - for the sewerage service, a pure revenue cap	Low to moderate – costs are mainly repeated opex and capital works, but with some major enhancement schemes. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates incentive rates of around 50%.	Low – around 10-15%
NIE	Low – company has a revenue cap	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates an incentive rate of 50%.	Low – around 15%
Bord Gais	Low – company has a revenue cap	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design exposes company to consequences of under- and over-spending for five years	Low – around 10%

SGN Gas to the West years 6-10	Moderate in period – current assumption is that the company will have a price cap Moderate long-term – company faces the risk that customer numbers will not grow to a sufficient base to enable investors to recover their capital in full	Low – year 6-10 costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle.	tbc

Source: First Economics' analysis.
Note: the totex-to-RAB metric is intended to capture the observations we made earlier about the higher riskiness of firms with small RABs/profits. A high totex-to-RAB ratio implies that profits are fairly resilient in the face of shocks and a small totex-to-RAB ratio implies that returns can be affected quite significantly by even small variations in costs and revenues.

We make the following observations about the entries in this table:

- the conventional network businesses all exhibit negligible revenue risk, relatively low cost risk, and have sizeable RABs. This largely explains why they sit at the left-hand side of the spectrum that we drew in figure 4;
- NIE is not obviously dissimilar to the GB utilities on the three highlighted criteria. Its slightly higher beta reflects a view from the CC that NIE ought to be positioned at the top end of the conventional utilities range due to the differences that there are in the frameworks of regulation in Great Britain and Northern Ireland; and
- SGN's higher beta is a reflection of the greenfield nature of the company's investment in a new network, particularly the risks around volumes and recovery of investment that the business will face in years 6-10.

The position of the PNGL and FE networks depends crucially on the regulatory framework that the Utility Regulator puts in place for GD17. We have been told to assume that both networks will:

- be subject to a revenue cap, which will give them an revenue entitlement irrespective of the volumes on the system;
- be given six-year allowances for opex and capex, subject to an uncertainty mechanism that is linked to actual outputs, with capex under- and over-spending to be retained by the company on a rolling basis; and
- In the case of FE, either FE or the Utility Regulator have the ability to ask for a special or informal review if certain conditions are met in terms of under-/out-performance in relation to opex or capex.

We can therefore add two further entries to the list in table 8 as follows.

Table 9: Characteristics of regulated companies

	Exposure to demand risk	Exposure to cost risk	Operational gearing – average annual totex-to-RAB ratio
PNGL	Low in period – company will have a revenue cap Low long term – discussed below	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates uncertainty mechanisms and a rolling incentive mechanism for capex.	Very low – around 5%
FE	Low in period – company will have a revenue cap Low long term – discussed below	Low – costs are mainly repeated opex and capital works. Costs have high labour content, with some exposure to commodity prices and the construction cycle. Price control design incorporates uncertainty mechanisms, a rolling incentive mechanism for capex, plus a reopener for material changes in opex or capex.	Low – around 10%

The two most important entries in the table are the entries for long-term revenue risk and the totex-to-TRV ratios.

- Long-term revenue risk – investor perceptions of business maturity are central to the GD17 cost of capital assessment. The question to ask is ”have the businesses have reached the point where investors can be reasonably confident that they will recover the value of their historical and prospective investments in full?”. The question does not typically arise in a utility setting because a regulated company normally supplies an essential product and will have a large, captive customer base. By contrast, the Northern Ireland gas networks are slightly different because they have grown quite quickly from a zero base and have had to persuade customers of the merits of taking an unfamiliar product.

  We have worked with the Utility Regulator to understand the scenarios in which PNGL or FE might find that they cannot recover a return of and on investments in full. The scenarios we have had to construct are very extreme. This is perhaps best seen in model runs which show that charges would need to rise by only 4.4% and 2.0% in PNGL’s and FE’s areas respectively if the network was to see zero future connection growth and zero future volume growth, equivalent to a 1.5-2.0% and 0.5-1.0% increase in total customer bills. Note, by way of a sense check, that the draft determination forecast is for volume growth of upto 40% and 80% respectively over the companies’ full revenue recovery periods. These do not look like the kind of numbers that one would need to see in order to conclude that investments will be rendered unrecoverable in the face of what would have to be very unfavourable circumstances.

For investment to become stranded, we have to assume that the business suffers a catastrophic loss of customers to the point where the remaining customer base is too small to bear the charges that full cost recovery would entail. It is hard to envisage how this could happen or, more pertinently, why PNGL and FE should more be exposed to such collapses than other regulated utilities.

We are therefore very reluctant to say that the risk around recovery of investment is clearly higher for PNGL and FE than it is for other regulated networks. It is for this reason that we mark PNGL's and FE's long-term revenue risk as 'low' in table 9. In doing so, we are taking a different view from that which has been advanced by the company. We draw this out more clearly in annex 1.

- Totex-to-RAB ratio – FE's totex-to-RAB ratio is fairly typical for a regulated utility. PNGL's ratio is unusually high, however, due to the under-recoveries that the business has accumulated within its RAB over the last two decades. When we look at the amounts that PNGL will be charging over the next 30 years, we see a company that is pricing first and foremost to recover the capital that investors have in the business rather than a company that is seeking to recover current costs. With a revenue cap, this results in a more durable profile of cashflows that is not as vulnerable to day-to-day shocks as compared to the position in other regulated industries, for the reasons set out in tables 6 and 7.

These observations help us to position the two companies in figure 4.

PNGL's and FE's greater maturity mean that the firms' beta must sit somewhere to the left of the SGN years 6-10 beta of 0.43 to 0.45. In comparison to PNGL and FE, SGN at year 6, as the newest network, will face the greatest uncertainty about its ability to attain the critical mass of connections that it will need in order to recover a full return of and on investment and therefore exhibits the highest risk among the three networks.

A comparison to NIE and the GB energy networks could mark PNGL as the less risky business: the companies all have revenue caps; there is little to distinguish ongoing cost risk; but PNGL, crucially, has a much lower totex-to-TRV ratio, meaning that percentage shareholder returns will be much less sensitive to any shocks that the business encounters in the coming years. Insofar as investors value a stable and predictable return, it could be said that PNGL will naturally have a lower beta. Quantifying the differential in risk is not straight-forward, but we could envisage a downward adjustment of up to 0.05 from, say, the NIE beta of 0.4.

Set against this, we cannot rule out the possibility that investors will see PNGL and FE as marginally riskier investments. This might be as much due to perceptions of riskiness as actual riskiness. We have had to work quite hard in this assignment to get straight in our minds the positions that PNGL and FE currently have in their markets, including, crucially, the extent to which the recovery of investment is or is not still dependent on yet greater connection numbers. Insofar as investors' lack of familiarity with the Northern Ireland gas industry can be described as a risk factor, there is an argument that PNGL and FE could be viewed as slightly higher risk investments.

Our conclusions, therefore, are as follows:

- PNGL could reasonably be judged to have an asset beta of as low as 0.35 if we put weight on its very low totex-to-TRV and consequent profile of cashfows. Alternatively, there may be an argument for positioning beta as high as 0.4 or 0.425 (but not beyond this level) if we allow for the possibility that investors, rightly or wrongly, perceive PNGL to be more risky than, in turn, the GB energy networks and NIE; and

- the same ceiling of 0.425 applies to FE. Because it has a more normal totex-to-TRV ratio, the lower bound on FE's asset beta is 0.38 as Ofgem's estimate of the beta for the GB gas distribution networks.

4. Optimal gearing

Assumptions about gearing affect directly the weightings of the cost of debt and cost of equity components of the weighted average cost of capital calculation. They are also important inputs to the calculation of the cost of debt and cost of equity themselves as, all other things being equal, a higher level of gearing will increase the risk to both debt and equity holders, causing them to demand a higher return in exchange for making capital available.

Regulatory precedent in this area is shown in table 10. In each case the regulator concerned sought to select a figure for gearing which is consistent with the regulated company maintaining an A-/A3 to BBB+/Baa1 credit rating.

Table 10: Gearing assumptions in relevant regulatory reviews

Decision	Gearing assumption	Year
Ofgem, gas distribution	65%	2012
Ofgem, gas transmission	62.5%	2012
Ofgem, electricity transmission	60%	2012
CER, Bord Gais	55%	2012
CC, NIE	45%	2014
Ofgem, electricity distribution	65%	2014
Ofwat, water and sewerage	62.5%	2014

The relevant gearing assumptions, with the exception of NIE, lie in a relatively narrow range of 55% to 65%.

In comparing PNGL to FE against these other companies, it is important first of all to be cognizant of the assessment of relative risk given in section 3. This tells us that there is no particular reason to think that the two Northern Ireland gas networks should not be 'in the pack' with the other regulated utilities.

One possible distinguishing feature is that the GD17 price control calculation for PNGL and FE provides for a Profiling Adjustment through which the companies' revenue entitlements are to be smoothed over a 30-year and 20-year period respectively. The effect of this Profiling Adjustment in the GD17 period is that a proportion of the revenue that the business would be entitled to under a conventional building block price calculation is to be deferred to subsequent control periods. This may impact on certain short-term, cashflow-based credit metrics and serve to limit the amount that lenders permit the networks to borrow in the near term.

In the circumstances, we consider that is prudent to select conservative gearing assumptions. The pre-tax WACC calculation is not especially sensitive to the choice of capital structure, but there is a danger of introducing an inconsistency within the WACC calculation if we go for a level of gearing that the companies do not go on to practically attain.

On this basis, we think it is prudent to select gearing of 55% from the above 55% to 65% range for both networks.

5. Cost of debt.

The interest that lenders demand from companies – unlike the returns required by shareholders – is something that is directly observable. Our task in putting a value to the cost of debt is to use available data to benchmark the interest that we would expect efficiently financed businesses with an A3/A- to Baa1/BBB+ rating to pay on their borrowings.

In previous cost of capital reports, we have expressed a preference for focusing on the interest paid by the real-life company as the natural starting point in this analysis. Although we would not want to go as far as to match pound-for-pound the monies paid by a regulated company in all circumstances, we think that regulators should also feel comfortable about drawing information from the actual borrowing arrangements a company has entered into at times when it has encountered externally driven financing challenges. If we can say that a company has responded to those challenges in the way that any normal commercial company would when faced with the same situation, it would seem logical to take the resulting interest payments as the efficient costs of financing the networks. We note that this is also consistent with the approach taken by the CC/CMA in recent inquiries.

In the cases of PNGL and FE, there is an obstacle to this approach in GD17 because both companies are due to undertake major refinancing activities over the course of the next control period (at mid-2017 in the case of PNGL and at mid-2019 in the case of FE). This means we can observe the companies' actual costs of debt at the start of the price control, but do not and cannot know what interest costs the business might be paying at the end of the period. We therefore suggest to the Utility Regulator in annex 2 to the paper that there are a range of possible ways of updating the estimates that follow in-period once the companies' (new) actual cost of borrowing are known.

Pending the Utility Regulator's decision on this matter, we can construct a forecast of the companies' costs of debt as follows. Table 11 starts with PNGL's and FE's current interest costs.

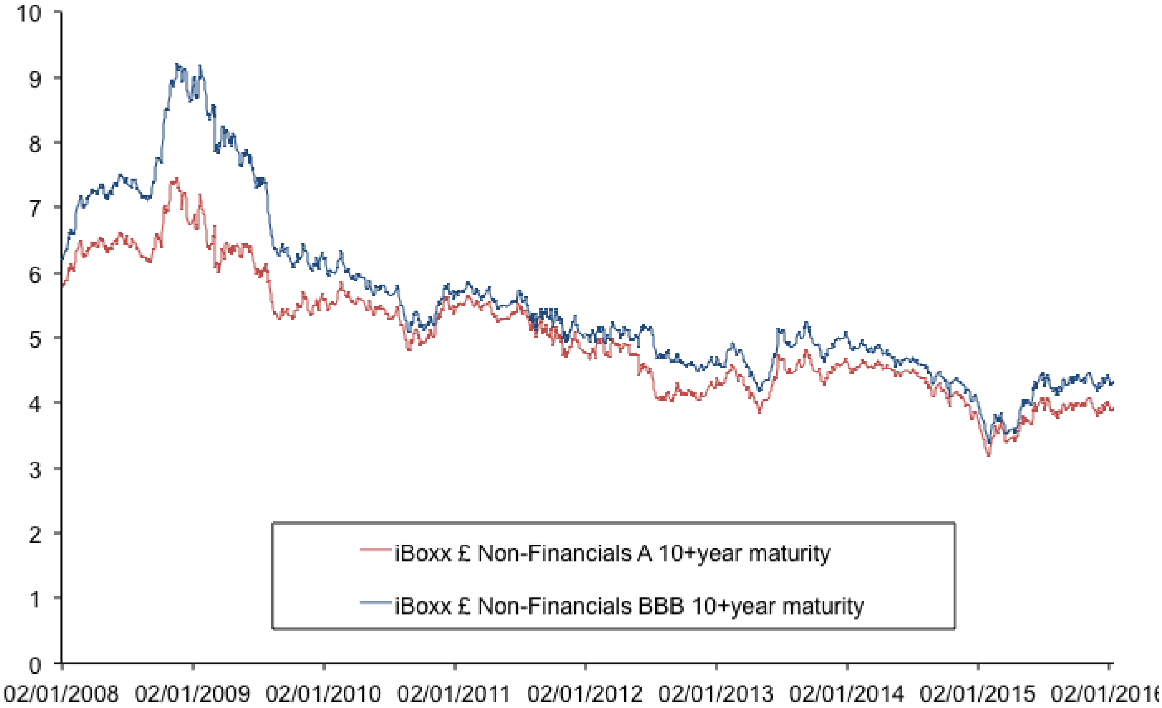
Table 11: Embedded debt costs, excluding transaction costs

	Nominal interest costs, existing borrowings
PNGL	£275m bond, coupon 5.5% £65m bank debt, hedged at 4.2% £104m bank debt, LIBOR plus 2%
FE	intra-group pass-down of around £100m of bank debt, average cost 2017-19 4.1%

The forecast weighted average nominal cost of debt for PNGL is 4.3%. The forecast nominal cost of debt for FE is 4.1%.

Looking forward to the likely costs that the companies will incur at refinancing, figure 12 shows the yields on A and BBB rated UK corporate bonds with a 10+year maturity.

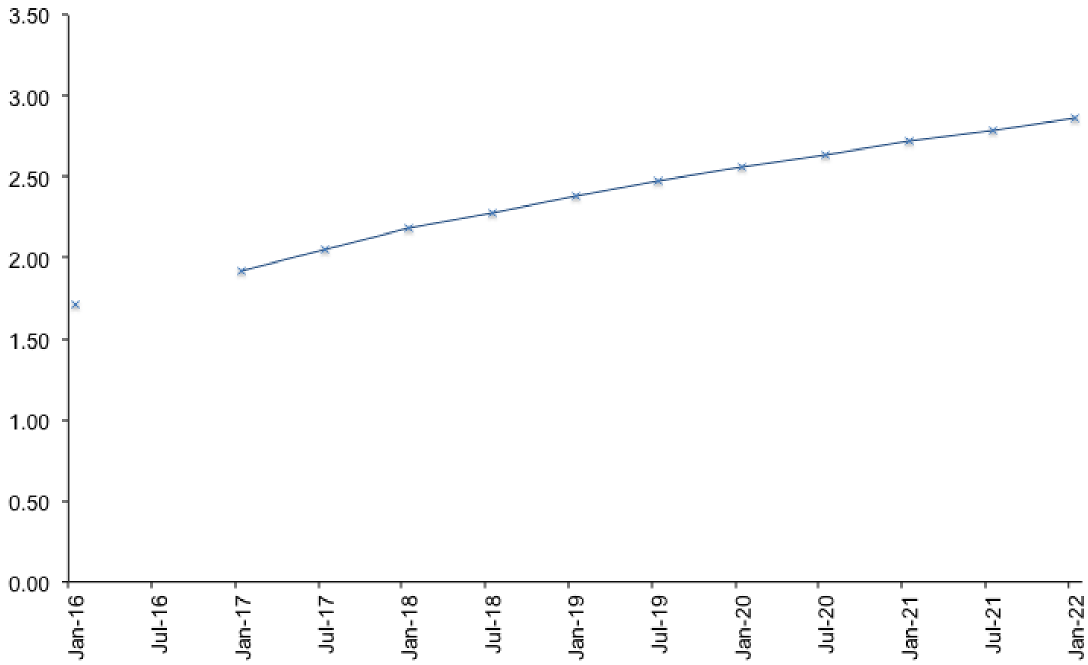
Figure 12: iBoxx bond yield indices



Source: iBoxx.

The yield on the BBB index at 31 December is 4.4%. This would be an appropriate benchmark for PNGL and FE if market interest rates were expected neither to rise or fall ahead of their refinancings. A sense of market expectations can be obtained by looking at forward gilt rates. These are shown in figure 13.

Figure 13: Forward rates for 10-year nominal gilts



Source: Bank of England website and First Economics' calculations.

The curve shows that markets are currently pricing in a 40 basis points increase in gilt rates by mid-2017 and a 80 basis points increase by mid-2019. All other things being equal, we might expect similar upward pressure on corporate interest rates, suggesting that it is prudent to increase the 4.4% estimate of market interest rates by 0.4% and 0.8% respectively.

On top of this, there is evidence from a simple comparison of the secondary market yield on PNGL's bond versus the yield on similar bonds issued by GB networks that lenders require a small premium for holding PNGL's debt. This likely reflects illiquidity in comparison to the more actively traded GB debt. Recent evidence (i.e. since the resolution of PNGL's CC reference in 2012) indicates that a premium of around 40 basis points ought to be factored into the forward-looking cost of debt.

Finally, it is necessary to make allowance for transaction costs. We initially provide for 30 basis points for PNGL and 60 basis points for FE to be consistent with information that the companies have supplied about the costs incurred when raising their existing debt. We use the same 30 basis points for PNGL's new debt, but allow for a slightly lower 40 basis points for FE's new borrowing to reflect the likely benefit of a higher quantum of borrowing. We note that further discussion with the Utility Regulator is likely to be required on these costs, having regard to factors such as the type, quantum and tenor of debt that the companies propose to raise through their refinancings.

The preceding numbers come together into the following calculations of the overall costs of debt.

Table 14: Forecast average costs of debts for GD17

Company	**Average nominal cost of debt, GD17**
PNGL	Current market rates 4.4% Forward rate adjustment 0.4% Average interest costs 4.3% — Illiquidity premium 0.4% Transaction costs 0.3% — Transaction costs 0.3% Embedded debt 4.6% — Cost of new debt 5.5% 10:90 weighted average Weighted average cost of debt = 5.4%
FE	Current market rates 4.4% Forward rate adjustment 0.8% Average interest costs 4.1% — Illiquidity premium 0.4% Transaction costs 0.6% — Transaction costs 0.4% Embedded debt 4.7% — Cost of new debt 6.0% 40:60 weighted average Weighted average cost of debt = 5.5%

The computed costs of debt are 5.41% for PNGL and 5.48% for FE. We need to convert from nominal figures to real figures for inputting into the cost of capital computation. We advise that the conversion for inflation should be consistent with the inflation forecasts that the regulator is using throughout the GD17 review. Pending detail on what these forecasts are we use an average annual inflation rate of just under 3.1% for the reasons set out in annex 3. This means that we convert the nominal costs of debt into real costs of debt of approximately 2.3%.[3]

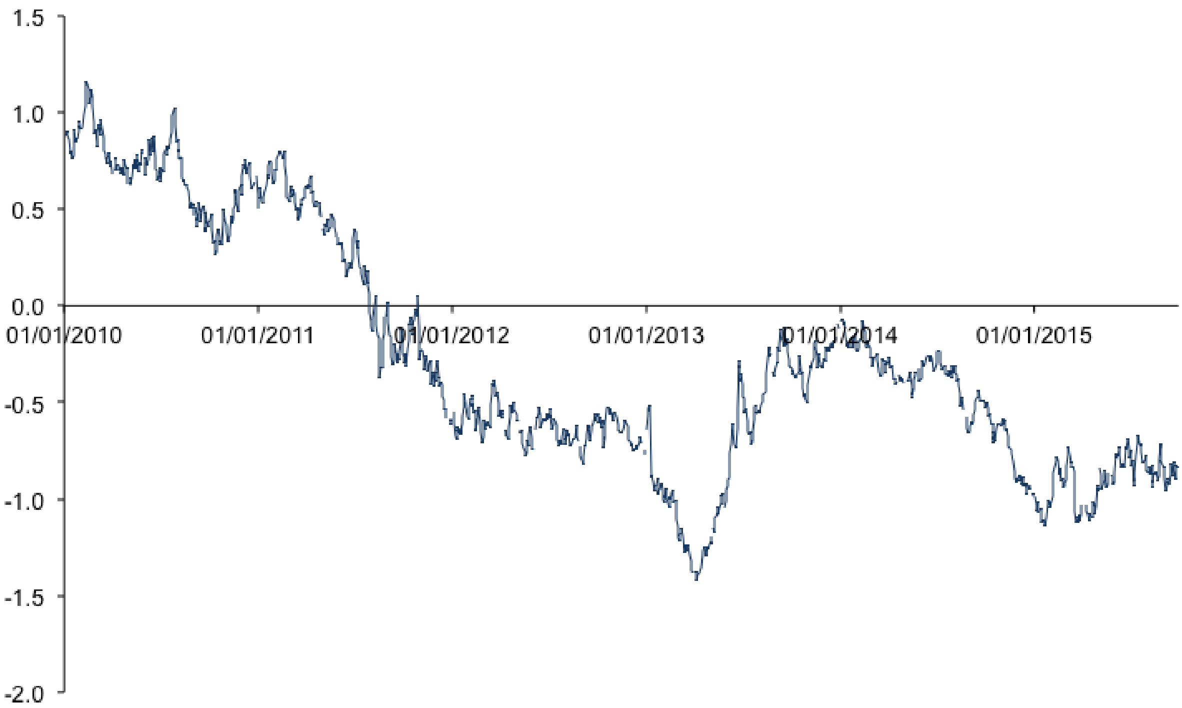
6. Generic cost of equity parameters

6.1 Risk-free rate

Having estimated the cost of debt directly, an estimate of the risk-free rate is needed solely for the purpose of estimating the cost of equity.

The approach used by regulators to assess the risk-free rate has in the past been to analyse yields on government-issued index-linked gilts. Figure 15 below plots the index-linked gilt yields over the last ten years, for three different maturities of bond.

Figure 15: Index-linked gilt yields



Source: Bank of England.

The chart shows that investors are currently willing to lend to the UK government at negative real (i.e. RPI-stripped) interest rates. This is partly a function of the panic that engulfed the markets in the wake of the Lehman Brothers collapse and consequent financial crisis, and partly a function of policymakers' response that crisis, particularly the programme of quantitative easing – a coordinated effort by central banks to intervene in financial markets and bring the returns on low-risk assets down in an effort to divert capital to more productive uses.

[3] The conversion formula is (1 + real cost of debt) = (1 + nominal cost of debt) / (1 + forecast inflation).

It is uncontroversial to state that yields on government bonds have been distorted by these actions. The Bank of England made the following estimate in a 2011 paper:[4]

> Based on analysis of the reaction of financial market prices and model based estimates, we find that asset purchases financed by the issuance of central bank reserves—which by February 2010 totalled £200 billion—may have depressed medium to long term government bond yields by about 100 basis points

It is also uncontroversial to state that yields are likely to move upwards when policymakers end and then reverse their interventions. The unknowns are: when this shift will occur; and the level at which risk-free rates will settle when the transition back to 'normal' market conditions is complete.

In the circumstances, the UK's economic regulators have tended to allow for positive risk-free rates in recent cost of capital assessments. Relevant data points are summarised in Table 16 below.

Table 16: Risk-free rate assumptions in relevant regulatory reviews

Decision	Risk-free rate assumption	Year
CAA, Heathrow/Gatwick Airports	0.5%	2014
Competition Commission, NIE	1.5%	2014
Ofgem, RIIO-ED1	1.5%	2014
Ofwat, PR14	1.25%	2014
Ofcom, mobile networks	1.0%	2015
CMA, Bristol Water	1.25%	2015

We do not think that there is any single 'right' answer to the question: what will the risk-free rate be in the 2017-22 regulatory period? Predicting market shifts is not an exact science and the table above shows that the Utility Regulator can justify a risk-free rate anywhere in the range 0.5% to 1.5%. We recommend selecting a 1.25% point estimate from within this range to align with the CMA's recent estimate.

We note that if this figure turns out to be too high or too low, the effect on the overall cost of capital calculation is very small.

6.2 Market return/ Equity risk premium

The final input into CAPM is R_m, the return on the market portfolio. Some cost of capital studies arrive at a value for R_m only indirectly by estimating an equity-risk premium and adding this figure to the risk-free rate. Like the CMA, we prefer to estimate R_m directly so as to ensure that there is no inconsistency in the cost of equity calculation.[5]

[4] Joyce, Lasaosa, Stevens, Tong (2011), The financial market impact of quantitative easing in the United Kingdom.

[5] The main risk of inconsistency comes from using an R_f in the derivation of an equity-risk premium that differs from the choice of R_f that we made earlier (note that R_f appears twice in the CAPM formula and should take the same value each time). Among other things inconsistencies can arise due to the measurement of R_f over different times periods or as a result of using data from different 'risk-free' securities when deriving an equity-risk premium.

Recent regulatory assumptions for the overall market return for equities are given in table 17 below.

Table 17: Equity market return assumptions in relevant regulatory reviews

Decision	Equity market return assumption	Year
CAA, Heathrow/Gatwick Airports	6.25%	2014
Competition Commission, NIE	6.5%	2014
Ofgem, RIIO-ED1	6.5%	2014
Ofwat, PR14	6.75%	2014
Ofcom, mobile networks	6.3%	2015
CMA, Bristol Water	6.5%	2015

This body of precedent presents a fairly narrow range for the market return of 6.25%% to 6.75%. This is mainly a function of the statements that the Competition Commission made about the value of R_m in its determination for NIE:

> The interpretation of the evidence on market returns remains subject to considerable uncertainty. The CC said in recent regulatory inquiries that 7 per cent is an upper limit for the expected market return, based on the approximate historical average realized return for short holding periods. We think that it may be appropriate to move away from this upper limit based on historical realized returns and place greater reliance on ex ante estimates derived from historical data which tend to support an upper limit of 6.5 per cent. We note the following points in support of setting an upper limit for the market return of 6.5 per cent:
>
> (a) We consider that the return on the market is a more stable parameter than the ERP. However, it remains the case that it exhibits considerable volatility and cannot therefore be regarded as fixed over time.
>
> (b) We note that past returns necessarily incorporate, inter alia, revisions in expectations for future cash flows and discount rates. DMS (2007) attempted to address this issue directly by decomposing past realized returns. We share its view that some elements of the return, in particular the historical expansion in valuation ratios, is unlikely to be repeated in the future.
>
> (c) In applying the CAPM, we seek to derive the expected return on the market. This is not necessarily the same as the realized return, even over long time horizons, if unexpected events occur. In this regard we note that attempts to estimate the historical expected ex ante return suggest that this is considerably lower than the realized return.
>
> (d) A forward-looking expectation of a return on the market of 7 per cent does not appear credible to us, given economic conditions observed since the credit crunch and lowered expectations of returns.
>
> We consider that the appropriate upper limit for the market return is 6.5 per cent.

Given this strong steer from the CC, we do not think it is credible for us to recommend a different value to the Utility Regulator. Our proposed R_m therefore matches the CC/CMA figure of 6.5%. When taken alongside the proposed risk-free rate of 1.25%, this gives a value for the equity-risk premium of 5.25%.

7. Tax

Because our costs of capital are pre-tax costs of capital, we need to uplift our CAPM cost of equity calculations by this amount if we are to ensure that charge controls cover return shareholders their full cost of equity after the payment of tax on profits.

The prevailing corporation tax rate at the time of writing is 20%. We understand that the Utility Regulator is proposing to put in place an adjustment mechanism if there is a reduction in this rate during the GD17 period.

8. Overall Cost of Capital Calculation and Conclusions

Table 18 combines our individual component estimates into ranges for the overall pre-tax costs of capital.

Table 18: Proposed range for the PNGL and FE GD17 WACCs

	PNGL		FE	
	Low	**High**	**Low**	**High**
Gearing	0.55	0.55	0.55	0.55
Cost of debt (%)	2.3	2.3	2.3	2.3
Risk-free rate (%)	1.25	1.25	1.25	1.25
Market return (%)	6.5	6.5	6.5	6.5
Asset beta	0.35	0.425	0.38	0.425
Equity beta	0.66	0.77	0.72	0.83
Post-tax cost of equity (%)	4.7	5.3	5.0	5.6
Tax rate	20	20	20	20
Pre-tax cost of equity (%)	5.9	7.0	6.3	7.0
Pre-tax WACC (%)	3.9	4.4	4.1	4.4

The calculations give a real pre-tax cost of capital of 3.9% to 4.4% for PNGL and 4.1% to 4.4% for FE.

These figures are lower than the current rate of return of 7.5%, reflecting the networks development in recent years from higher risk greenfield investments to more conventional regulated utilities.

The ranges are lower than Ofgem's RIIO-GD1 implied 2016/17 pre-tax WACC of 4.5% because:

- the GB networks have comparatively expensive embedded debt costs locked in for the whole of the 2013-21 control period. The opportunity that PNGL and FE have to refinance at still historically low rates of interest results in an allowed cost of debt that is slightly lower than Ofgem's indexed cost of debt; and
- Ofgem in 2012 used a value for R_m that sits higher than current best regulatory practice (including in Ofgem's own 2014 RIIO-ED1 determination).

Finally, the figures are lower than the RP5 NIE cost of capital because NIE also had comparatively expensive embedded debt costs locked in for the whole of the RP5 period.

In selecting a point estimate from our table 18 range, our advice to the Utility Regulator is that it needs to consider the potential risk factors that we highlight in section 3. A rate of return in the lower half of the range for PNGL will only be appropriate if the regulator wishes to put weight on the observations that we have made about PNGL's very low totex-to-TRV ratio. A rate of return above the mid-point of the PNGL range and above the low point of the FE range can be justified if the regulator considers that PNGL and FE are more risky networks in the eyes of investors when compared to conventional utility companies.

Annex 1: Further Discussion of PNGL's and FE's Risk Profiles

In their WACC submissions to the Utility Regulator, PNGL and FE both made arguments that they are higher risk utility network businesses. Our observations on these arguments are set out below.

Size of the current customer base and future volume risk

PNGL and FE both highlighted in their submissions that they are relatively new networks whose current penetration rates sit noticeably below uptake of gas in Great Britain. Both companies also drew attention to the risks that they face around future connection numbers.

We note that a comparison between current customer numbers and the maximum customer base is not a conventional measure of risk. There are a variety of firms that supply a minority of customers in any geographical area that are considered very low risk, including some regulated businesses (e.g. in the rail and telecoms sectors). What matters is not so much how many consumers a firm does not supply, but what characteristics the existing customer base exhibits as regards (in)sensitivity to price and other market risks.

Similarly, it may well be the case that the uncertainties around volumes are higher in the Northern Ireland gas industry in comparison to other regulated industries. However, it is not necessarily the case that shareholders are exposed to greater uncertainty of return as a consequence. As we noted in section 3, the Utility Regulator is attempting to shield investors from in-period volume risk through the setting of revenue caps, which give the networks a fixed entitlement to collect revenues from customers irrespective of demand.

The key question, to our mind, is whether PNGL or FE face any real risk of not being able to collect on that revenue requirement because they cannot feasibly charge up to the level of their revenue entitlements, both within the GD17 period and thereafter.

Neither PNGL nor FE considers this matter in detail in their June 2015 submissions. Both companies state with conviction that their investors are exposed to long-term cost recovery risk, but without adducing any evidence to support this position or to quantify how serious this risk now is. In the absence of such detailed analysis, we have explored with the Utility Regulator what would have to happen for the networks to be unable to recover their full RABs, as recorded in the main body of this paper.

Profiling Adjustment

PNGL and FE drew attention to the Profiling Adjustment within their price control formulae, both as support for their arguments about maturity but also as a risk factor in its own right.

It is correct to note that the Profiling Adjustment, and the equalisation of charges over multiple control periods more generally, is a non-standard feature of revenue cap regulation. However, when one digs deeper, it is apparent that the thinking that lies behind the Profiling Adjustment is no different to the thinking that underpins the selection of non-standard depreciation profiles / RAB run-off rates or adjustments to the balance between fast and slow money in other regulated sectors. The GD17 Profiling Adjustment, in its effect, seeks to ensure that the costs of building the network are shared out equitably across several generations of customers, recognising that a standard straight-line depreciation of the RAB might impose too high a cost on consumers in the early years (when volumes are smaller) and too low a cost of consumers in later years (when volumes are likely to be higher).

It is difficult to see that equalisation of charges, implemented for reasons of inter-generational equity, is an indicator of riskiness or contributes to heightened risk in its own right, any more than Ofgem's or Ofwat's non-standard depreciation rules increase risk. Provided that revenue entitlement that is moved between customers is rolled up at the WACC, companies are being asked only to accept a NPV-neutral reprofiling of revenues for the sake of treating successive cohorts of customers fairly.

Historical under-recovery of revenues

FE in its submission also highlighted the historical accumulated under-recovery of revenues under the Profiling Adjustment as a risk factor.

It is not clear to us how the historical operation of the price control operation can be said to affect investors' exposure to risk in GD17 and beyond. The fact that FE might have under-recovered in the past may say something about the risk that FE was facing historically, but it does not, of itself, tell us anything about the risks that the business faces in the future.

As noted above, what matters is whether investors can be reasonably confident that they will be able to collect the full value of the investment that they have made in the business. The fact that some of that investment is classified in the regulatory system as past investment in fixed assets while some is classified as revenue Profile Adjustment may be a matter of historical interest to some. However, investors are likely to be far less concerned with the historical derivation of the FE RAB compared to the likelihood of being able to collect a full return of and on that capital going forward.

Annex 2: Possible Approaches to the Cost of Debt

There are several possible ways of setting the allowed cost of debt

Option 1 – Fixed Allowance

The Utility Regulator has in the past set fixed rates of return for the vast majority of the companies it regulates. Under this approach, the regulator makes a forward-looking estimate of the remuneration that a firm requires in order to cover its interest costs and this percentage cost of debt allowance is locked in for the whole of the price control period.

The default option is to use this same approach in GD17.

Pros: the main advantage of this approach is its familiarity and conventionality, certainly in comparison to the three options that follow. A fixed cost of debt allowance also gives the companies strong incentives to drive down their borrowing costs within period (since shareholders take any difference between the allowed cost of debt and the actual cost of debt), which may yield benefits that the regulator can capture for customers at future reviews.

Cons: a particular issue arises when attempting to set fixed costs of debt for these two specific companies in the specific year 2016. With PNGL due to refinance the whole of its existing debt in 2017, and with FE due to follow suit with a refinancing of its debts in 2019, the cost of debt workstream essentially becomes an exercise in forecasting the rates that the two companies might be able to get from the markets in the years ahead. This is a difficult position for a regulator to be in because the chances of mis-forecasting are very high. If the Utility Regulator sets the allowed cost of debt above the interest cost that the companies actually achieves, customers pay prices that, with hindsight, are too high and shareholders enjoy excess returns until the next price control reset in GD23 (i.e. approximately 5.5 years in the case of PNGL and 3.5 years in the case of FE). Conversely, if there is an under-estimation, customers pay prices that are too low and shareholders suffer sub-normal returns (assuming that the companies do not appeal the Utility Regulator's decision). It may be different to reconcile such windfall outcomes with the Authority's statutory duties.

Option 2 – Indexed Cost of Debt

Ofgem has taken in recent reviews to setting a cost of debt allowance that indexes up and down within period in line with movements up and down in prevailing market interest rates. There are currently three different versions of this approach:

- Ofgem's original index, which involves measuring and updating a ten-year trailing average of the average yield on two iBoxx bond yield indices;
- a modified version of the original index which Ofgem gave SSE's transmission business in the RIIO-T1 review, in which bespoke weightings are given to each year in the ten-year trailing average to match SSE's investment profile; and
- the RIIO-ED1 version of the index, colloquially known as the 'trombone', in which the trailing average calculation has a fixed start date of 1 October 2004.

It is open to the Utility Regulator to apply an indexed cost of debt, using one of these indices or a variant thereof, in GD17.

Pros: like option 1, this approach would be backed by good regulatory precedent. Also like option 1, the companies would have strong incentives to drive down their borrowing costs (they cannot influence the value of the index and so will consider their allowance to be 'exogenous', thereby focusing their attention on coming in as far below the index as possible). The added advantage over option 1 is that the allowed cost of debt will fall naturally if interest rates fall unexpectedly ahead of the companies' refinancings, and vice versa in the event that market interest rates rise.

Cons: thinking again about PNGL's and FE's actual borrowing arrangements, the likelihood is that both companies will be locked into one fixed rate of interest prior to their financings and a different fixed rate of interest after refinancing. It is not clear that it makes sense to index the allowed cost of debt up and down on an annual basis if the companies' cost of debt is not itself moving year by year. As a rule, allowing for an indexed cost of debt when a company's interest costs are fixed will tend to leave companies under-remunerated when market interest rates are falling (because the value of allowed cost of debt falls, but the company's actual interest costs stay constant) and over-remunerated when market interest rates are rising. More generally, it will also be very difficult to start the value of the index (or indices) on 1 January 2017 in alignment with the companies' actual borrowing costs at this point in time and nearly impossible to bring about a match the companies' new borrowing costs at the point of refinancing, giving rise to the same sorts of concerns about windfall sub-normal and super-normal returns that we identified under option 1.

Option 3 – Target Cost and Pain-/gain-sharing

Ofgem's modifications of its original cost of debt index for SSE and the electricity DNOs were motivated by a sense that the allowed cost of debt should normally match actual borrowing costs (i.e. the revised indices were essentially the best possible backfit to the actual/projected cost of debt). The Utility Regulator may wish to focus on this principle rather than the mechanics of Ofgem's calculations, which have been tailored for specific GB companies and should not be expected to 'fit' PNGL and FE.

A matching of the companies' allowed costs of debt and actual borrowing costs would require the Utility Regulator to:

- set initial, company-specific fixed costs of debt in line with the fixed interest rates on the companies' existing borrowings; then
- step up or step down to new fixed costs of debt when each company's refinancing is complete and the interest payable on the new debt is known and observable.

In making the step up or step down, the Utility Regulator would wish to ensure that the companies have an incentive to minimise costs. This might point towards some sort of initial expected/target cost of debt, set during GD17 or separately in advance of each refinancing, and for 80:20 or even 90:10 pain-/gain-sharing of any over or under during the control period.

Pros: in comparison to the two preceding options, this approach minimises the extent to which there can be a mismatch between the amount of revenue that the companies collect from customers and the amounts that the companies pay to lenders. The pain-/gain-sharing ought to be able to preserve efficiency incentives.

Cons: it is a novel approach which, to our knowledge, has not been applied to any other UK regulated company. Note, however, that PNGL's sister company, South East Water, offered a sharing mechanism of this type to Ofwat during the recent PR14 price review.

Option 4 – A Pass-through Mechanism

As a final option, it is possible to make interest a pass-through item. Rather than set any sort of allowance or target cost estimate in GD17, the Utility Regulator would simply pass-through actual, observed interests costs to customers on an annual basis.

Pros: this would be the simplest of all the options to administer.

Cons: PNGL's and FE's incentives to borrow efficiently in their financings would be undermined if they know that there is to be a straight pass-through of costs. The Utility Regulator might respond to this problem by undertaking to pass-through only the interest on borrowings that have been efficiently and prudently incurred. But this would put the regulator in the position of second-guessing the companies' actions with the benefit of hindsight, which may be uncomfortable.

Annex 3: Inflation

In our analysis of the cost of debt we need to convert a nominal rate of interest to its real equivalent. We recommend that the Utility Regulator uses the RPI forecasts that it is using across the GD17 review in this conversion; pending these forecasts, we set out below a ‘holding assumption’ that permits us to put forward indicative cost of debt and cost of capital calculations.

Our calculations make use of the Office of Budget Responsibility November 2015 forecasts. Although these are by no means the only possible assumptions about the future direction of inflation, they have the quality of being the underpinning to all of the public-sector forecasting currently being carried out in the UK. We think this means that they carry an authority which any alternative forecast we might otherwise choose will lack.

The November 2015 forecasts are set out in table A1 below.

Table A1: RPI forecasts

	2017	**2018**	**2019**	**2020**	**Long term**
% change	2.9	3.2	3.2	3.2	3.0

Source: OBR economic and fiscal outlook.

The figures show quite elevated rates of inflation, due in part to the recent shift up in the ‘formula effect’ difference between CPI and RPI inflation and in part due to expectations that there will be a small bounce-back in mortgage interest rates during the GD17 period.

If we average inflation over the five-year period, we find that the appropriate inflation rate for our cost of debt calculations is 3.08%.