Cost of capital of National Grid’s GB electricity and gas transmission businesses

Note by National Grid

I Introduction

1 Ofgem is currently reviewing the price controls of the GB electricity and gas transmission businesses, including National Grid’s National Grid Electricity Transmission (NGET) and National Grid Gas National Transmission Systsem (NGG NTS), the latter hereafter referred to as NGG.

2 In the review to date, Ofgem has focused on the historic and projected operating and capital costs of the businesses, with the intention that discussion of the main financial issues (cost of capital, financeability, tax and pensions) will be held over to the latter part of the review.

3 This paper represents National Grid’s position on what cost of capital should be assumed for National Grid’s two GB transmission businesses for the purposes of setting their respective TO price controls for the five years from April 2007. The paper is structured as follows:

- In Section II, and as a prelude to the main analysis, we examine the nature of the questions which need to be answered, given that the questions which Ofgem and other regulators have sought to answer are not the same as those which a City analyst, for example, is typically trying to answer when trying to estimate a company’s cost of capital.
- Against this background:
  - In Section III, we give our views as to how the ‘traditional’ UK regulatory approach to cost of capital – i.e. a ‘bottom-up’ aggregation of the individual components of cost of capital within a Capital Asset Pricing Model (CAPM) framework - could be applied to this review.
  - In Section IV, we explore a different ‘top-down’ approach in which the cost of capital actually used by investors in valuing comparable utility businesses is inferred from the value ascribed by investors to particular utilities at particular points in time.
- In Section V, we consider possible implications of the questions raised in Section II for the analysis contained in Sections III and IV.
- In Section VI, we summarise our conclusions.

II The questions to be answered

4 One of the key questions being continually posed by sell-side City analysts is the cost of capital which should be used in valuing particular companies. As often as not, such analyses are based on the Capital Asset Pricing Model (CAPM) - and plug into the standard CAPM framework:

(a) a spot estimate of the company's cost of debt;

(b) the company's current or (if a transaction is being appraised) prospective (i.e. post-transaction) gearing; and

(c) a view of the cost of the company's equity which combines a beta estimate with the analyst's estimate of the long term (or 'underlying') equity risk premium

5 Such estimates of cost of capital pose as many questions as they answer – not least the question of the internal consistency of combining spot costs of debt with a longer term cost of equity, especially when debt costs are unusually low and when cost of equity cannot be directly observed. Consistency is even more of an issue if one believes, as Ofgem believed during DPCR4, that debt costs – or at least the risk free component of debt costs - and the equity risk premium tend to be inversely related.

6 However, regardless of the technical adequacy, or otherwise, of such analysis, the fact remains that, when City analysts estimate a company's cost of capital, they are asking a different question from the one which utility regulators are typically answering when estimating a company's cost of capital as part of a price review. The analyst is, at least in principle, looking to estimate the cost of capital which a potential equity investor should be using at a particular point in time. Regulators, on the other hand, will be asking a number of questions. (Ofgem itself listed a large number of factors/questions to be taken into account in para 8.38 of its Final Proposals for DPCR4.) For the transmission reviews, these questions may include, inter alia, some or all of the following:

(a) **What is likely to be the company's cost of capital, <u>on average, over the five year period of the company's next price control</u>, as opposed to what is it now?**

Attempts to estimate a cost of capital for the medium term have led, for example, to some regulators (including Ofgem) using rolling averages of past cost of capital inputs, implicitly on the basis of an expectation of some degree of mean reversion through time.

(b) **How far should Ofgem be influenced by the size of the capital spend programme which is being envisaged for the company in question?**

This was a consideration which Ofgem invoked in DPCR4 as justification for going towards the higher end of the range of cost of capital estimates then being considered. More generally, there is the question of whether any non-regulated company would even think of carrying out a substantial investment programme with the prospect of a return only equal to its cost of capital. This is one reason why the question to be asked is probably not so much "What is the company in question's cost of capital?". Rather, the right question is probably more like "What rate of return should a company reasonably need in order to undertake a substantial investment programme which will be remunerated over a period of up to 45 years and with no firm commitments on that remuneration beyond the next five years?". In other words, what rate of return is needed to compensate for long asset life or 'terminal value' risk (the core of what most people mean when they talk about 'regulatory risk') when increased capital expenditure is increasing that risk?

(c) **How far will the relevant cost of capital be linked to how the regulator deals with 'financeability'? In other words, what will be the impact on cost of capital of how the regulator <u>profiles</u> the company's revenue through time in order to keep the company's financial ratios within certain pre-defined bounds?**

Just as increased capex increases terminal value risk, so it also, other things being equal, stretches a company's financial ratios. Ofgem's regulatory practice over past reviews has given investors confidence that Ofgem would set price controls to maintain network utilities' financial ratios within certain bounds. Any move away from this policy at a time of increased capital expenditure, combined with some uncertainty as to the circumstances in which the Special Administrator regime would be invoked, might be expected to impact negatively on company credit ratings and on cost of capital more generally.

(d) **To what extent is the company's cost of capital likely to be different in the future from what it has been in the past, not least as a result of changes in the regulatory regime which Ofgem is proposing?**

For example, Ofgem has recently proposed a penalty-only incentive regime for NGG to deliver on time the network extension and reinforcement required to transport gas from the LNG terminals being built at Milford Haven. In the same vein, Ofgem's Third Consultation document for this review suggested a penalty-only scheme to encourage network reliability on the electricity transmission system. In principle, new penalty-only schemes – and, more generally, a regulatory regime which is characterised increasingly by sticks rather than carrots – might be expected to increase the base rate of return which a company needs to earn.

Ofgem is also proposing major changes in how NGET and NGG should be remunerated for load-driven capital expenditure. Different aspects of these proposals could be expected to affect the companies' risk profiles and cost of capital in different ways. It will be easier to take a view on the likely net impact of these proposals on companies' cost of capital when the proposals themselves become more concrete and more detailed.

(e) **How far should Ofgem take into account returns which transmission licensees could make from investing in activities other than GB transmission?**

Again, the issue of alternative investment opportunities for licensees was raised by Ofgem in DPCR4. Whatever its relevance to the current review, it is a matter of fact that regulated returns on equity in non-GB jurisdictions in which National Grid has substantial operations are, on a like-for-like basis, around 140 to 200 basis points above those assumed in DPCR4[1].

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[1] This range is after equalising for different gearing assumptions and assumes expected US inflation around 2.5% (close to both the five year and ten year average US inflation rates).

(f) **How far should Ofgem be influenced by past regulatory estimates of cost of capital (both those made by the same regulator and those made by other regulators)?**

GB regulators have been keen to emphasise the value of regulatory consistency, not least as a way of reducing regulatory risk and, thereby, reducing cost of capital. The need for consistency (which does not necessarily mean coming to the **same** answer as in the past) is particularly important in relation to those parts of the cost of capital calculation where a relatively great amount of subjectivity is involved. This is because changes in these areas cannot so easily be justified by changes of fact and therefore more easily give the impression of inconsistency.

7 Against the background of the above, we use the next two sections to examine two different ways of estimating what would be a reasonable rate of return to assume for the new NGET and NGG price controls, prior to returning (in Section V) to how the above issues should affect the assumed return.

III Bottom-up estimation of NGET's/NGG's cost of capital

8 This section is structured, as with most recent regulatory analyses of cost of capital, as a build from the components of:

(a) cost of debt and

(b) cost of equity with the issue of

(c) capital structure/gearing informing both of these elements and providing the weights for adding the two elements up to an estimate of

(d) weighted average cost of capital (WACC).

Cost of debt

9 The cost of debt is usually broken down between:

(a) the risk-free rate, usually approximated by the yield on index-linked gilts (ILGs); and

(b) an appropriate debt premium for the particular company, reflecting, in particular, the company's credit rating which reflects, in turn, both:

(i) the company's underlying business risk; and

(ii) the company's actual and prospective financial ratios.

Risk-free rate

10 Although ILG yields vary with maturity, and the yield curve is currently inverted, it is reasonable to use 10 year instruments as a proxy for the various maturities in existence, not least because:

(a) 10 years is close to the average maturity of National Grid's current debt book;

(b) 10 years is around the average maturity of what one might expect for a network utility's bonds; and

(c) yields on 10 year ILGs are close to the arithmetic average of ILG yields over a range of maturities.

11 At the time of writing, the yield on 10 year ILGs is around 1.7%.

12 However, it would **not** be reasonable to use this spot rate as the basis for building up a cost of capital for price controls which will run through to 2012. This is because:

(a) **Even if yields were expected to continue at this level for the whole of the next price control period**, this would not be an appropriate estimate of the risk-free rate. This is because of the current relationship between yields on ILGs and those on conventional gilts. For the 10 year gilt, the current breakeven rate of RPI inflation (the rate of inflation which would equate the return on ILGs and conventional gilts) is slightly above 3%. However, the general expectation for long term RPI inflation is around 2.5% (i.e. the RPI inflation rate consistent with the Bank of England's CPI inflation target of 2%).

One implication of this anomaly is that, if National Grid's cost of capital was set on the basis of the spot ILG yield, and even if this yield (and the associated nominal yield and breakeven inflation rate) lasted through the next price control period, the implied return would be inadequate. This is because the nominal risk free rate would have stayed at around 4.7% but the equivalent allowed return would have been around 4.2% (i.e. the assumed real risk free rate compounded by RAV indexation at 2.5%).

(b) As recently opined by just about all pundits in this area, from the Governor of the Bank of England downwards, it is unlikely that ILG yields will remain around the current level through the next price control period. Since January of this year, yields on 10 year gilts have risen by around 70 basis points and both the Bank of England and the Federal Reserve Board are indicating that interest rates are likely to rise in the short to medium term.

Debt premium

13 NGET index-linked bonds, rated single A by Moody's, currently trade at around a 65 basis points spread to the relevant ILG. However, as with the risk-free rate, it would be unwise to project such a spread through the next price control period. If anything, the reasons for expecting spreads to rise are more clear cut than for the risk-free rate. In particular, global default rates have only been lower than now once in the last 24 years. As a result, any tendency back towards more normal default rates can be expected to lead to widening of spreads.

How to allow for rates being so far below 'normal' levels

14 One way of dealing with this issue, often used by both sector utility regulators and the Competition Commission, has been to look at average yields over a period of time. For DPCR4, Ofgem's analysis took into account ILG yields over a five to six year period.

15 Building on this, we have calculated average returns on government bonds (with an average maturity of 10 years) on two bases over the period 2000 to February 2006. First, we have used ILGs. This produces an **average risk-free rate of 2%**.

16 However, as a basis for setting a return on RPI-indexed RAV assets, such an approach suffers from the problems identified in paragraph 12 above, i.e. that real yields have, for at least part of this period, been characterised by unrealistic breakeven inflation rates with conventional gilts. We have, therefore, also calculated a five year average yield for a conventional gilt with an average maturity of 10 years, and assumed that investor RPI inflation expectations were consistent with the Bank of England's CPI inflation target – i.e. investors were assumed to expect an RPI inflation rate of 2.5%. This calculation suggests **an average risk-free rate of 2.2%**. We suggest that, if a five year average (or some longer term average) is going to inform an appropriate risk-free rate for a price review cost of capital calculation, it should be done on this basis.

17 At the same time, it is worth noting that, at the time of writing conventional gilts suggest a real risk-free rate of around 2.2%, assuming expected RPI inflation of 2.5%, with the prevailing expectation that interest rates will rise over the short to medium term.

18 In terms of calculating a **five year average for the debt premium**, the constraints of National Grid's debt book mean that it has not been possible to calculate the debt spread on a 10 year bond, as no suitable bond exists. We have, therefore, calculated spreads from bonds with an average maturity of around 20 years. For Transco Holdings, this results in an average cost of debt of 3.6% and, for NGET, an average

cost of dent of 3.2% (albeit that, for part of the period, NGET had an A+ credit rating which would appear to be an unlikely basis for setting the new price control). Given a risk-free rate of 2.2%, this implies a **debt premium between 1% and 1.4%**.

19 The above analysis would therefore imply a cost of debt (at gearing and credit rating levels consistent with the past) of **between 3.2% and 3.6%**. However, such analysis by itself ignores the issue of the cost of National Grid's existing debt book, i.e. the issue of 'embedded debt'.

Cost of embedded debt

20 Starting with our existing debt book and using forward Libor curves, and anticipated debt retirement and cash flows, we estimate that, over the next price control period, the average cost of debt (across NGG and NGET) will be around 3.4%.

21 As such, this would be consistent with the cost of debt estimates generated by the above averages of risk-free rates and National Grid debt premia. However, an implication of these embedded debt projections is that small changes in future interest rates (beyond those reflected in the existing forward curves) **would** take our cost of debt above the range from paragraph 19 above.

22 In the past, regulators have sometimes ignored the cost of embedded debt, sometimes on the ground that forward-looking debt costs were, in any event, likely to be above the cost of embedded debt or on the basis that some or all of the embedded debt was inefficiently incurred.

23 It would be our contention, however, that:

(a) all of the debt in NGG and NGET was efficiently incurred at the time that the debt was taken on; and

(b) efficiently incurred costs should not be disallowed.

24 We therefore think that allowance should be made for the high risk that our actual debt costs will exceed the range suggested in paragraph 19 above. Our estimate is that conservative estimates of future Libor movements (and of spreads around those movements) could add a **further 45 basis points** on to our overall cost of debt.

Cost of debt overall

25 On the basis of the above, and including the assumption that gearing stays broadly in a similar range to actual gearing in the recent past for both NGG and NGET, one could therefore deduce a range for our debt costs through the next price control period as falling in the range **3.4%** (on the above five year moving average basis) to **3.85%** (making an extra allowance for the impact of small interest rate movements on the cost of embedded debt). This compares with the rate of 3.75% assumed in the NGET mini review and 4.1% assumed in DPCR4).

Cost of equity

The use of CAPM by utility regulators

26 When regulators, including Ofgem, have approached the debt component of WACC, they have broadly tried to link their proposals directly to facts about companies' costs of borrowing. This relatively direct factual link has, by and large, not been so prominent in approaches to the cost of equity. This difference has been for good reasons. In particular:

(a) regulators have tried to keep their analysis broadly within a CAPM framework; and

(b) any attempt to use the CAPM approach in any simple way produces estimates of cost of equity which are clearly contradicted by the valuations which investors put on utility shares.

27 This latter point can be illustrated by comparing CAPM estimates of utility costs of equity with dividend yields over the period used to estimate betas. Figure 1 below compares, averaged over the network utilities covered in the Smithers report to Ofgem as part of the NGET mini review:

(a) dividend yield over the last five years; and

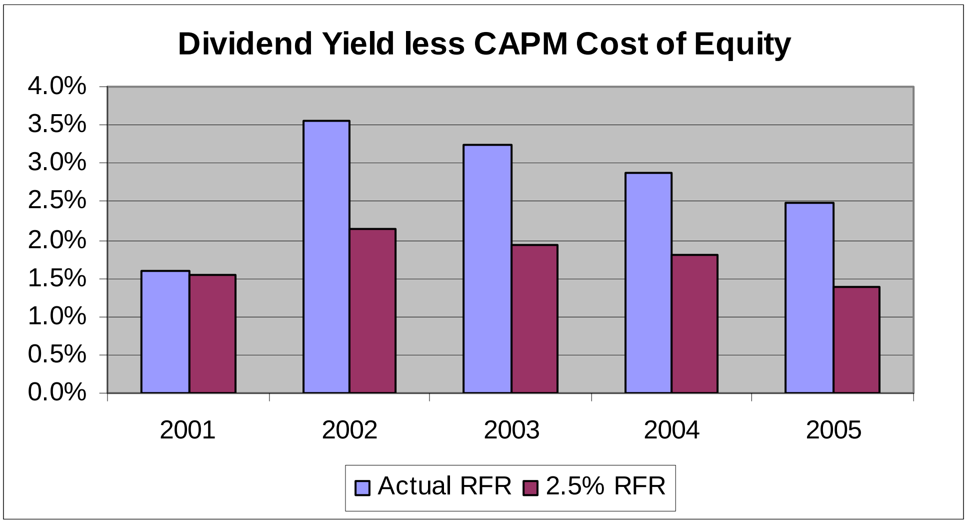
(b) estimates of cost of equity, using:

(i) the betas in the Smithers report;

(ii) either actual risk-free rates in the year in question or a 2.5% long run risk-free rate; and

(iii) a 5% equity risk premium, the top of the range used by GB utility regulators.

Figure 1



28 Figure 1 shows that, even with the long run risk-free rate assumption (to go with the long run basis of the equity risk premium), CAPM estimates of cost of equity are, on average, around 1.75 percentage points below the dividend yield.

29 If the CAPM estimates (based on the long term risk-free rate) were seen as correct, then this would seem to imply that investors were expecting a long term real decline in dividends of around 1.75% per annum, whereas, since 2001, the dividends in the sample have grown at an average rate of 2.6% per annum in real terms

30 The inference from the above would seem to be that:

(a) betas are an inadequate representation of relevant risk; and/or

(b) investors require an annual real post-tax return on equities as a whole of more than 7.5%.

Ofgem's approach to DPCR4

31 Against the background of the inability of any relatively simple application of CAPM to produce sensible numbers for the cost of equity, Ofgem explored a rather different approach in DPCR4. This approach, which leaned heavily on the work done for Ofgem by Smither & Co, had the following main elements:

(a) the assumption that total equity returns are more stable through time than the equity risk premium, implying, inter alia:

(i) an inverse relationship between the risk-free rate and the equity risk premium; and that

(ii) if the risk-free rate is determined independently, then the equity risk premium is the difference between the assumed total equity returns and that risk-free rate;

(b) the assumption of (real, post-tax) total equity returns of 7.5% (at the top end of a range of 6.5% to 7.5%, with this justified on the basis of "the investment focus of the review"); and

(c) the (implicit) assumption that, at 57.5% gearing, equity risk for the DNOs equalled the average for the economy as a whole. Given the very much higher gearing assumed than for the economy as a whole, this still implied that **business** risk for the DNOs was much lower than for the economy as a whole.

Justification for the Ofgem/Smithers view

32 In our view, 7.5% is a reasonable assessment of the real post-tax cost of equity **both for the market as a whole and for an A rated UK utility**. This is for three main reasons:

(a) The current **market expected earnings yield** for 2006/7 is 7.5%.

(b) Assuming an equity beta of 1 at 57.5% debt to RV implies that the underlying **utility asset beta** is less than half as risky as the market as a whole.

(c) **Dividend yield and growth evidence for utilities** supports a cost of equity of 7.5% real.

Each of these points is elaborated below.

Market earnings yield

33 The earnings yield of the market can be assessed by looking at the accounting earnings of the FTSE and dividing the value by the market capitalisation of the index.

34 Broadly speaking, it is reasonable to assume that companies will be able to grow earnings in line with inflation without needing to reinvest additional capital. Companies' earnings can either be distributed to shareholders, or reinvested in driving real earnings growth going forward. If reinvestment on average earns the companies' cost of equity, the earnings yield provides a forward looking indication of the markets view of the cost of equity.

35 The earnings yield is an alternative way of expressing the price earnings ratio of the market. An earnings yield of 7.5% is consistent with a p/e ratio of 14 – the same level as the prospective p/e based on analyst consensus of the FTSE all share at the time of writing. As a result, 7.5% real appears to be a reasonable forward looking estimate of **market returns**.

Utility risk relative to the market

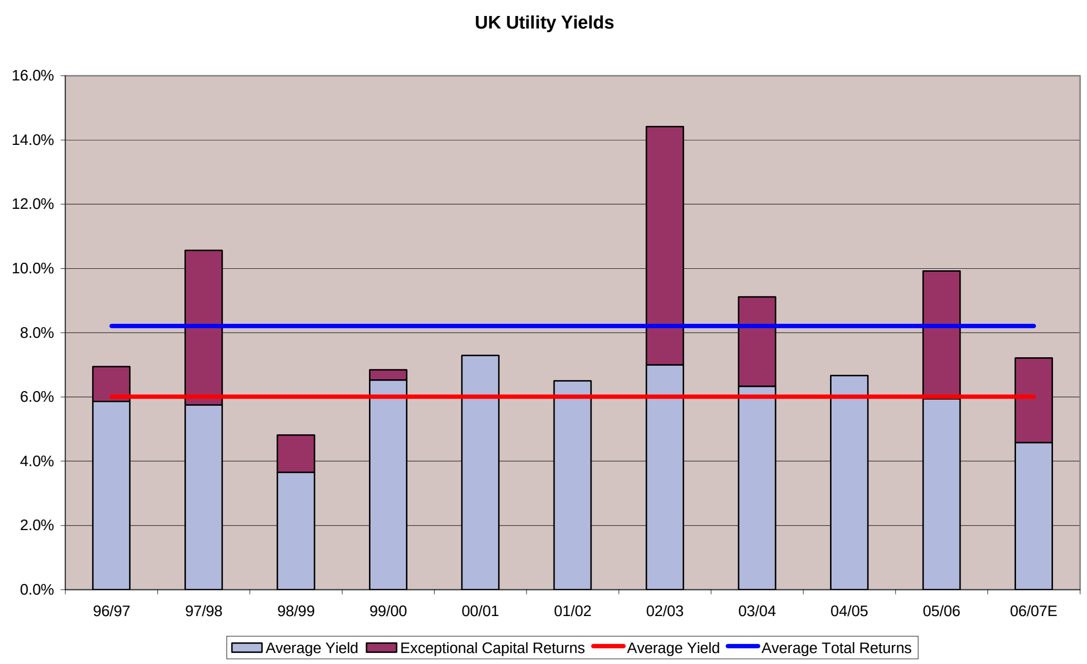
36 An assumption of an equity beta of 1 at 57.5% debt to RAV, implies an asset beta of 0.43. The equivalent market gearing for industrial and commercial companies in the FTSE 100 is just 10%, implying an asset beta of 0.9. Therefore, the proposed cost of equity already assumes that utility assets are less than half as risky as the market as a whole.

37 Given the very large differences in gearing, it does not seem unreasonable to expect the **return on equity** for utilities to be similar to the market as a whole.

Dividend yield and growth evidence for GB utilities

38 The average yield on UK utilities over the last ten years is shown in Figure 2 below.

Figure 2



39 Over the last ten years, the average yield of UK utilities has been around 6%. The yield has declined during two periods, when investor expectations of future dividend growth opportunities grew considerably – first, during a period of significant out-performance in the late 1990s and, more recently, following the last water and electricity distribution reviews. Consequently, whilst yields in the utility sector are currently at historic lows, it is likely that dividend growth expectations are at historically relatively high levels.

40 Furthermore, the extent to which returns have been increased through exceptional buybacks over the period can be seen in the graph. Including the effect of exceptional returns, the cash yield to utility investors has been over 8% during the last ten years.

41 Taking the average yield of the sector over the last ten years (even excluding buybacks) implies that a dividend growth assumption of only 1.5% is required to justify a cost of capital of 7.5% real. This looks undemanding against the current growth prospects for the utilities.

42 Alternatively, and starting from where we are at the time of writing, the current yield of 4.75% is consistent with a cost of equity of 7.5% for the following reasons:

(a) It is reasonable to assume that dividends can grow in line with earnings.

(b) Consensus analyst expectations for real earnings growth across the utilities is around 6.5% per annum for the next three or four years.

(c) To get from (a) and (b) above to a cost of equity of 7.5% implies that, after the next three or four years, earnings grow at 2.2% per annum.

(d) This does not look unreasonable from the point of view of:

(i) the likely rate of growth of the GB economy as a whole;

(ii) more relevant, the likely rate of RAV growth across the utility sector against the background of demands network extension, reinforcement and replacement; and

(iii) the combination of utilities actually earning real rates of return (i.e. returns on an RPI-indexed RAV) and accounting rules which force utilities to charge nominal interest costs in the profit and loss account. Against the background of rising investment, this combination depresses current dividends whilst enabling faster real growth in the future as indexation of the RAV flows to the equity holders, enabling above-inflation growth in future dividends even without growth in the underlying business.

(e) In any event, to draw reasonable conclusions from dividend yield, at least some allowance needs to be added in for share buybacks.

Applying the above to NGG and NGET

43 On the basis of the above, the case for assuming real post-tax equity returns of 7.5% for network utilities as a whole would seem to be supported by both regulatory precedent and market evidence. The question is, then, whether there is any reason why this assumption should not apply to NGG and NGET for the purpose of the current price reviews.

44 We can see two possible reasons why Ofgem could, in principle, choose a different assumption. Specifically:

(a) Ofgem could decide that the sort of issues which were being addressed in DPCR4, especially the importance of network investment, are less applicable to NGG and NGET and that, therefore, the reason which Ofgem gave in DPCR4 for going to the top of the range of 6.5-7.5% would not apply to the current transmission reviews.

(b) NGG and NGET could be perceived by the market as being significantly less risky than other utilities, thus not requiring a commensurate rate of return.

45 In our view, neither of these two positions is sustainable.

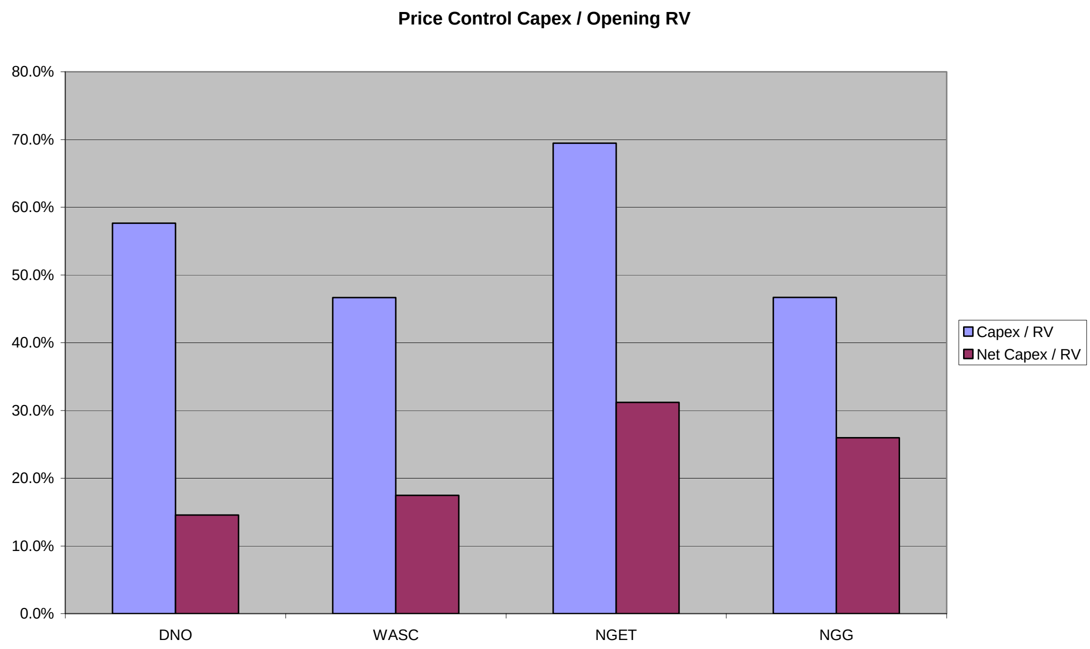
Capex and cost of capital

46 **First, Ofgem has clearly confirmed the "investment focus" of the current review**. As stated in the Third Consultation Document, "The key theme for this review is investment". Applying the logic used in DPCR4, there would therefore seem to be no good reason for assuming a level of real, post-tax **market** equity returns other than 7.5%.

47 On top of this, the impact of capex on cost of capital will probably be higher for NGG and NGET than for DNOs and water companies at their last price reviews. This is because one of the main channels through which capex impacts on utility risk is through increasing the amount (and proportion) of the company's NPV which is in the terminal value in the standard price control calculation – and therefore exposed to future regulatory decisions which are not covered by the commitment embodied in proposals for the current price review. This is illustrated in Figure 3 below by the bars showing ratios of net capex (capex minus regulatory depreciation) to RAV[2].

[2] It should be noted that the net capex figures for NGET are lower than they otherwise might be because we have assumed a reduction in NGET's regulatory asset lives sufficient to fill the revenue 'hole' left by the expiry of regulatory depreciation on pre-privatisation assets in 2010. To the extent that this hole is not completely filled, then NGET's ratio of net capex to RAV will be higher.

Figure 3



NGG's and NGET's relative risk

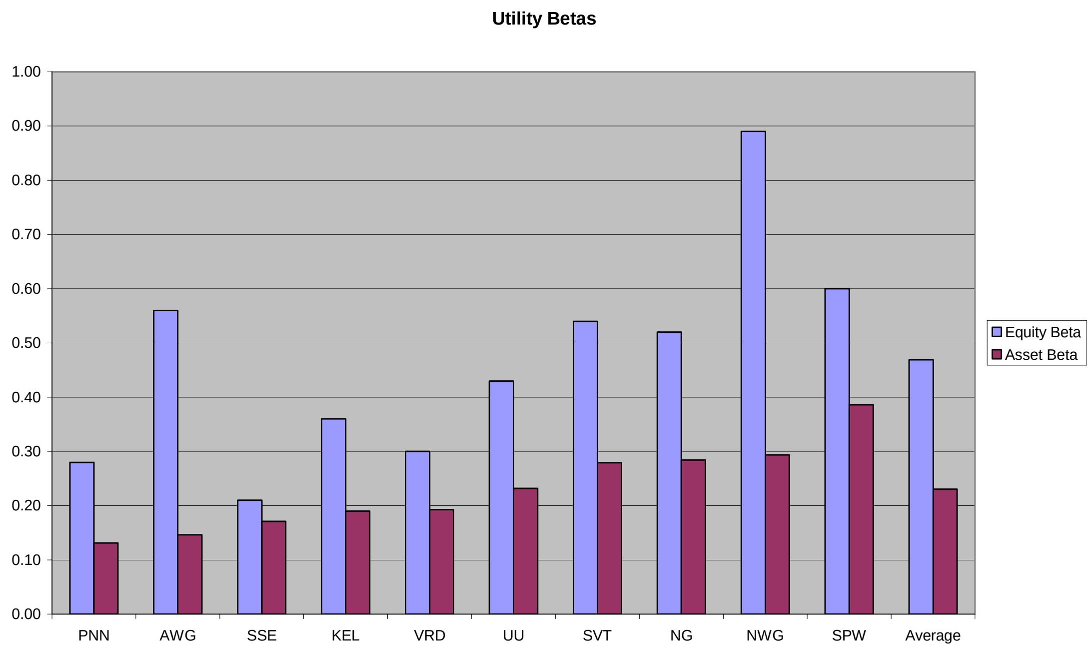
48 **Second, there is no convincing evidence that either the business or equity risks facing NGG and NGET are significantly different from those facing the DNOs or other UK regulated network utilities**. The obvious potential evidence is that provided by betas and by credit spreads.

49 As suggested above, **betas** would not seem to produce plausible cost of capital estimates (although this could be due to using the 'wrong' equity risk premium as well as to unreliable betas) and Ofgem itself has cast doubt on their usefulness in DPCR4. However, it is worth displaying current beta evidence to show that, even though it may not provide a reliable basis for drawing conclusions about the risks facing any particular company, it equally provides no justification for arguing that the National Grid companies are less risky than the available relevant comparators. (In other words, the data does not justify a positive conclusion but, equally, cannot justify a negative conclusion about National Grid's perceived relative risk exposure.)

50 Figure 4 below shows both equity betas[3] and asset betas for: Scottish and Southern Energy (SSE); Pennon (PNN); Viridian (VRD); Kelda (KEL); United Utilities (UU); AWG; National Grid (NG); Severn Trent (SVT); Scottish Power (SPW); and Northumbrian Water (NWG). The companies have been ranked by their asset betas.

[3] Sourced from the London Business School Risk Measurement Service for April – June 2006.

Figure 4



51 What the graph shows is that, **to the extent that betas are giving useful evidence of relative risk about the quoted entities**, then National Grid is well in the pack and, if anything, towards the upper end of that pack in terms of relative perceived risk.

52 Obviously, the graph begs the question about whether the relative risks of the network businesses, embedded within the quoted entities, are likely to be any different from those suggested for the quoted entities themselves. Several of the companies in this sample do have extensive interests apart from their UK wires and pipes businesses, e.g. electricity generation and supply, waste disposal or, in the case of National Grid, non-UK network businesses.

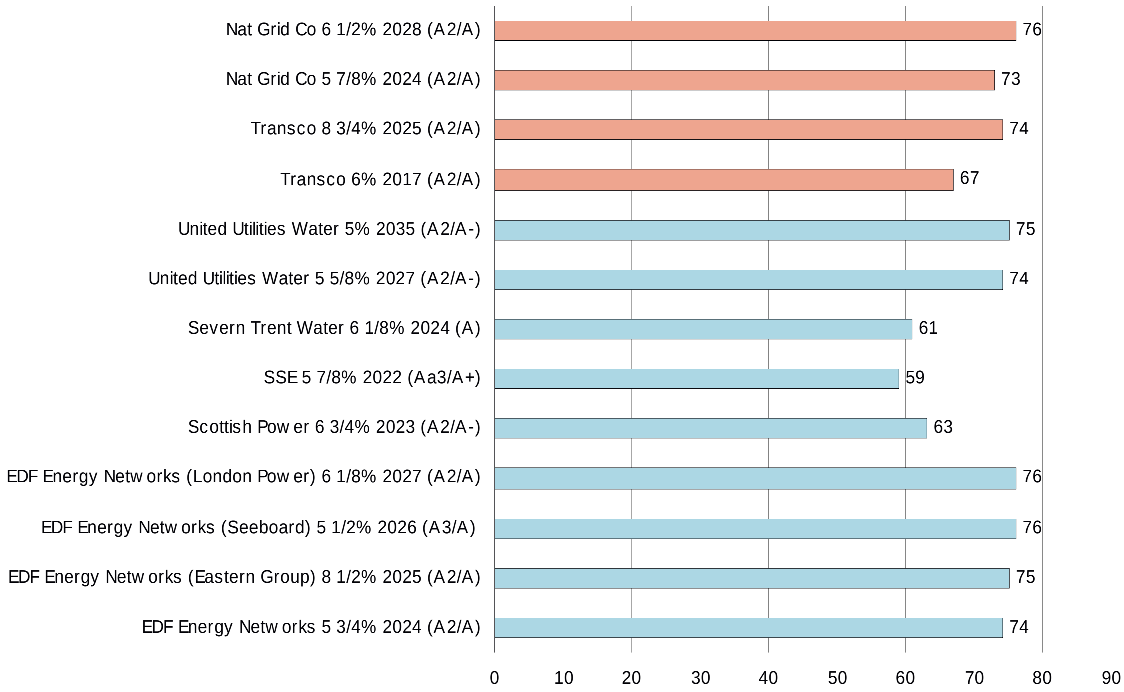
53 However, it is unlikely that consideration of these aspects would reduce the ranking of the National Grid businesses. This is because, whereas it is possible that those companies with generation, supply or competitive business activities might have their corporate betas inflated by these activities (although this would not look from the graph to be very likely for Scottish and Southern, for example), National Grid's other activities are overwhelmingly other regulated network businesses.

54 Further evidence for the lack of a risk differential between the National Grid entities and the relevant comparators is also shown by **credit spreads**. As shown by, inter alia, the work done by Ofgem's own consultants for the NGET mini review, there is simply no significant difference between the spreads on National Grid debt and the debt of the other main GB network utilities.

55 Recent analysis conducted by Morgan Stanley for National Grid of the current spreads on representative bonds for National Grid, United Utilities, Severn Trent, Scottish and Southern Energy, EDF Energy Networks is shown in Figure 5 below and demonstrates that there is currently no evidence that National Grid bonds trade with tighter spreads than those of DNOs or other GB network utilities:

Figure 5

Current Trading Levels
Spread to Gilts



56 Thus, **whether one looks at equity evidence or debt evidence**, there is simply no basis for concluding that National Grid is regarded by the market as measurably less risky than DNOs or other network utilities. Therefore, given that

(a) for the reasons given in paragraphs 32-42 above, it would seem reasonable to maintain the DPCR4 assumption of total post-tax market equity returns of 7.5%;

(b) at 57.5% gearing, Ofgem has already judged that DNOs could be seen as facing average equity risk (and, given how much higher this level of gearing is than for the market as a whole, this would seem to be a reasonable conclusion);

(c) there is no evidence that the market regards National Grid as less risky than DNOs; and

(d) subject to the question of appropriate gearing for NGET and NGG discussed below,

it would seem unreasonable to assume a cost of equity for NGET and NGG lower than the 7.5% assumed for DNOs as part of DPCR4.

Gearing

57 All of the elements of WACC are interactive. It would therefore be possible to assume a wide variety of gearing levels (gearing defined as the ratio of net debt to RAV) for

the National Grid transmission businesses. At one level, it would be necessary only to ensure that the different elements were mutually consistent.

58 However, as already noted, both we and Ofgem see the key question for the current price review as being investment. This was also seen as the key question for DPCR4. Against this background, Ofgem stated that it was setting price controls "consistent with the regulated companies being able to maintain credit ratings that are comfortably within investment grade"[4].

59 It is not totally clear what, if any, specific credit rating Ofgem was targeting in DPCR4 in assuming gearing of 57.5%, albeit that, in the DPCR4 Second Consultation Document, Ofgem made reference to the view that gearing in the range 60-65% (compared with average actual DNO gearing of around 70%) would be consistent with an A- credit rating[5]. This arguably implies that Ofgem was effectively assuming a credit rating of Single A for the purposes of financial modelling and cost of capital estimation.

60 As shown above, there is nothing to indicate from existing evidence on credit spreads that credit providers regard the National Grid businesses as significantly less risky than the other GB network utilities. For what it is worth, NGG is currently rated Single A at a gearing level of around 50% and would probably be rated around A-/BBB+ at 57.5% gearing.

61 Overall, and in the absence of clear reasons why the National Grid transmission businesses should be treated differently from the DNOs, we think it reasonable to assume 57.5% gearing for the purposes of financial modelling and estimating cost of capital.

WACC

62 On the basis of the above analysis, a reasonable range of bottom-up estimates for the cost of capital of the National Grid transmission business through the next price control period might be as indicated in Figure 6 below (in the same format as for Ofgem's DPCR4 proposals and including Ofgem's DPCR4 proposals for comparison).

Figure 6

	NG1	**NG2**	**Ofgem DPCR4**
(Pre-tax) cost of debt	3.4%	3.85%	4.1%
Cost of equity	7.5%	7.5%	7.5%
Gearing	57.5%	57.5%	57.5%
Post-tax WACC	4.6%	4.7%	4.8%

[4] DPCR4 Final Proposals, paragraph 8.71

[5] DPCR4 Second Consultation Document, paragraph 7.48

63 The rationale for the NG cases is as follows:

(a) NG1 is characterised by:

(i) the bottom end of the debt range from paragraph 25 above. This implies a high probability that our actual debt costs will exceed this level because of the impact of relatively small variations in market debt rates on the cost of **existing** floating rate debt; and

(ii) the combination of a gearing of 57.5% with a cost of equity of 7.5%, which implies the same asset beta risk for the National Grid transmission businesses as was assumed for DNOs.

In our view, the second of these assumptions is justified by the analysis in this section but the first assumption would **not** seem to be reasonable for the reasons given above, i.e. the existing debt was efficient at the time that it was incurred and therefore should not be stranded.

(b) NG2 is as for NG1 but also assumes a more reasonable allowance for embedded debt costs.

64 For the avoidance of doubt, neither of these cases, **by itself**, represents our view as to what rate of return should be assumed for our transmission businesses for the next price control period. This is because it is our view that this assumption should also be informed by the factors which are considered in Sections IV and V below.

65 However, within the framework of the traditional regulatory analysis, it is our view that anything less than the above case NG2 – a post-tax real cost of capital of 4.7% - would be unreasonable for the reasons given in this section.

IV Top-down estimation of cost of capital

66 In the previous section, we have tried to use the sort of bottom-up estimation of WACC which has tended to predominate in the price reviews conducted by Ofgem and other UK regulators. As has been recognised by all regulators, this approach is problematic, not least for some of the reasons alluded to in the section, i.e.:

(a) A 'substantive' CAPM approach, using estimated betas and long run equity risk premia, does not seem to produce plausible results.

(b) There is no other generally accepted alternative approach.

(c) The result has been a somewhat uneasy mix of approaches - including CAPM, dividend growth and total equity returns.

67 In this section, we explore an alternative approach in which we take instances where investors have had good information about the medium term cash flows of regulated businesses and examined the business valuations which have resulted. The implied required rate of return for investors is then derived from the ratio of (1) the expected rate of return to (2) the ratio of market value to RAV. Thus, if a company has an expected real post-tax rate of return of, say, 6%, and if the market to RAV (MAR) ratio is 1.15, the implication is that the required real rate of return is around 5.2%.

68 We have applied this approach to, in the first instance:

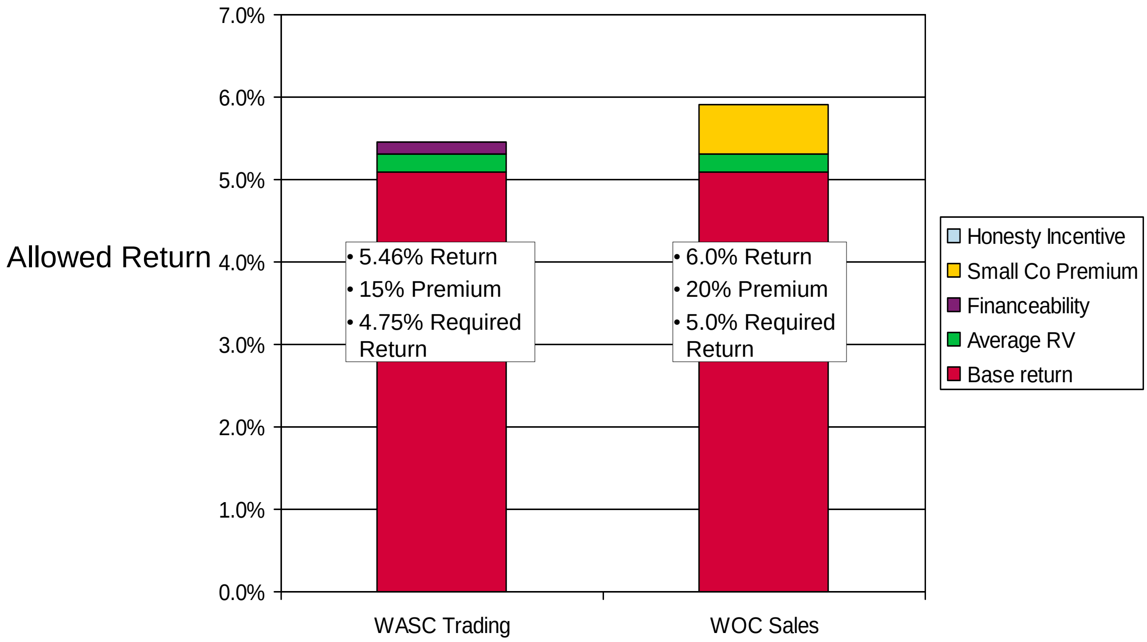
(a) ongoing market valuations of water and sewerage companies (WASCs);and

(b) transaction values for some water only companies (WOCs).

This is on the basis that, in both of these cases, investors/purchasers have had a high degree of certainty about the medium term cash flows of the companies in question.

69 The results of this analysis are summarised in Figure 7 below:

Figure 7



70 In this graph:

(a) Each bar shows the post-tax real rate of return on RAV which investors could have reasonably expected (for the reasons which are described below).

(b) The implied return, required by investors, is then inferred from combining the expected return with observed premia to RAV.

The basis for each of the cases is described below.

WASCs

71 The basis of the WASC numbers in the table is as follows:

(a) The estimated **premium to RAV** is averaged over the six quoted companies, as at 31 March 2006, having allowed for the valuation of non-regulated businesses on the basis of analyst estimates. (It should be noted that the then premium of around 15% has come down somewhat since then.)

(b) The **expected return** is built up from

(i) the basic 5.1% real post-tax return quoted in Ofwat's final proposals; plus

(ii) 16 basis points for financeability revenue (assessed over the six companies); plus

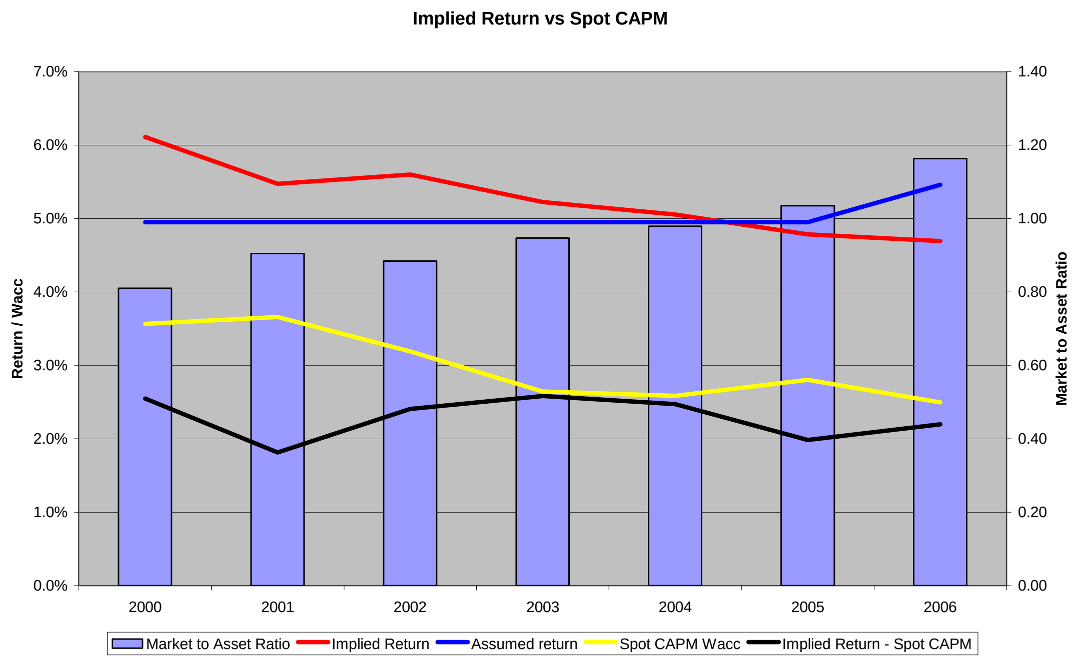
(iii) 20 basis points to allow for the benefit to the companies of allowing the specified return on 'average RAV' through the year, compared with Ofgem's 'movement in RAV' methodology.

72 The WASCs provide the biggest body of data to analyse what sort of discount rates (WACCs) investors use when valuing GB regulated network businesses. **Of the two cases examined, they probably provide most confidence in using this approach to estimating cost of capital, not least because the data is available over a period of time and is less distorted by bid premia.** Having said that, the required rate of return will be under-estimated from this data to the extent that investors are still factoring in, for example, continuing out-performance against the opex assumptions in the relevant price controls.

73 Given all of the above, Figure 8 below shows how required rates of return have moved since 2000, while also showing how the required rate of return has compared with a 'spot' CAPM estimate of WACC[6].

[6] The 'spot' CAPM estimates of WACC have been made on the basis of: risk-free rates at the relevant time; debt premia for A credit ratings at the time; London Business School betas for the relevant year; and an equity risk premium of 5%.

Figure 8



74 What this table shows is that, inter alia:

(a) The required rate of return has declined from the levels which it reached in the wake of the 1999 Ofwat price review (which is generally thought to have damaged investor confidence in the sector, albeit temporarily).

(b) The gap between the inferred required rate of return and the CAPM estimate of WACC has averaged 2.3 percentage points.

WOC sales

75 For the WOC sales:

(a) The **premium to RAV** has been derived from the relevant transactions, with minor adjustments for non-regulated activities.

(b) The **expected returns** have been built up from:

(i) the basic 5.1% return, as for the WASCs; plus

(ii) 20 basis for the average RAV adjustment, again as above; plus

(iii) 60 basis points (on average) for the small company premium.

76 There clearly is an argument for saying that the small company premium represents a real additional cost for the WOCs. However, the main basis for the small company allowance was for the impact of illiquidity of shares. However, this was not likely to have been a significant factor for the companies actually buying the WOCs (the likes of CKI, Deutsche Bank etc).

77 In addition, to the extent that opex out-performance was expected and to the extent that WOC transactions attracted ‘pure’ bid/control premia, then the required rate of return shown in the table here will under-estimate the returns required by investors on an ongoing basis.

Other potential cases studies - gas distribution network (GDN) sales

78 A further case study which could be used to apply the above approach would be the sale of GDNs by National Grid. The main problem with this transaction for the current purpose is that there was, at the time of the transactions, rather less certainty about the medium term revenues than for the water companies, not least because the current GDN price controls expire in March 2007.

79 Trying to infer the discount rate used by purchasers to value the sold GDNs might proceed as follows:

(a) **Expected rate of return.** Investors might have assumed an ongoing post-tax real rate of return on RAV (before allowing for opex out-performance) of around 5%. This might have been on the basis of the following:

(i) The latest DPCR4 document at the time that bids were made (the Initial proposals) assumed a 4.6% base rate of return.

(ii) To make this equivalent to Ofgem’s current method of calculating allowed revenue, one adds around 20 basis points to allow for the fact that the Initial Proposals were based on the so-called ‘average RAV’ method, rather than the ‘movement in RAV method which Ofgem now uses (and did use for the DPCR4 Final Proposals).

(iii) Ofgem’s ‘Honesty Incentive’ mechanism offered another 20 basis points.

(b) **Premium to RAB.** The premium of sales prices over RAV (RAV as at 31 March 2005) was around 14%. However, this is based on the RAV numbers used to set the current price controls, whereas the GDNs have, during the current price control period, incurred substantially more capital expenditure than was assumed in setting the current controls. It is likely that buyers effectively assumed that all of the over-spend would go into RAV, not least because:

(i) They were in possession of material on the causes of the spend.

(ii) During the sales process, Ofgem issued an open letter to the effect that efficiently incurred over-spend would be allowed into the RAV at the start of the next price control period (and that, in certain circumstances, companies would be compensated for depreciation and/or return foregone on the over-spend during the current price control period)[7].

(iii) The network sales process was a highly competitive auction in which a number of bidders failed to acquire the assets. It is therefore likely that successful bidders made relatively aggressive assumptions.

[7] Letter dated 16 March 2004

On the basis of the over-spend being allowed into the RAB, the sales premium to RAB reduces to 10%

(c) **Further adjustments.** Beyond the above adjustment, at least two further factors would need to be allowed for in inferring GDN purchasers' required rate of return:

(i) It is likely that bidders assumed significant opex out-performance in their bid prices, not least because two of the successful consortia would have envisaged benefiting from synergies with existing operations.

(ii) The assets were sold with debt-free balance sheets and faced none of the embedded debt costs facing National Grid. A 50 basis points reduction in the cost of debt would reduce WACC by 20 basis points with 57.5% gearing.

80 Taking all of the above in into account, one could make a reasonable case for increasing the expected rate of return to a level which would suggest a required rate of return consistent with the range suggested by the WASCs and WOCs analysis. However, the analysis probably should not be given the same weight for the reasons given, particularly the relative lack of certainty about medium term revenue.

Overall

81 On the basis of the WASCs and WOCs analysis above, and even though none of these bits of analysis are free of contention, 4.8% would seem a reasonable central estimate of the rate of return required by investors – and would, from this angle, therefore be a reasonable rate of return to be assumed in setting the NGET and NGG price controls. In other words, the conclusions of the top-down analysis would seem to be broadly consistent with, but probably slightly above, those of the bottom-up analysis in Section III.

V The wider context

82 In Sections III and IV above, we suggest that a combination of traditional regulatory analysis of cost of capital and an alternative top-down approach – based on inferring required rate of return from investors' valuations of utilities (and closer to the NPV approach used in some US rate settings) – imply a real post-tax cost of capital of 4.7-4.8% for the forthcoming NGET and NGG price controls.

83 However, in Section II above, we also suggested (as has Ofgem in the past) that a large number of factors need to be considered in deciding what is a reasonable rate of return to assume in setting utility price controls, only some of which have been explicitly or implicitly considered in Sections III and IV above. In particular, we highlighted the following:

(a) The rate of return needs to make reasonable allowance for how financial market conditions will move through to March 2012.

(b) A higher level of capital expenditure can be expected to increase cost of capital from what it has been in the past, partly through any impact on financial ratios but, more important, through the impact on 'terminal value' and regulatory risk.

(c) Ofgem is contemplating significant changes in the framework of incentives for transmission licensees. These changes, which are largely at the conceptual stage at the moment, may (or may not) increase cost of capital.

(d) Regulatory precedent is important because consistency with it should avoid the sort of premium required rate of return which results from the perception of a high risk of regulatory 'bad outcomes' (like the 1999 water review).

(e) Many regulated utilities now operate in multiple regulatory jurisdictions – and therefore the returns allowed in other jurisdictions do represent at least one dimension of the opportunity cost of investing in GB networks.

84 Each of these issues – and their potential implications for the rate of return to be assumed in the NGG and NGET price controls – is discussed below.

Setting the price controls through to 2012

85 Setting a price control for a future five year period involves forecasting not only efficient levels of opex and capex but also the costs of financing. As recognised in Section II above, and also by Ofgem and other regulators when setting price controls, future financing costs may be significantly different from those prevailing when price controls are set

86 This issue was explicitly acknowledged in Section II above and was explicitly addressed through the replication of the recent regulatory practice of using 5 year averages of key variables (risk-free rate and debt premium). However, although 5 year averages should capture an element of mean reversion, it is worth noting (as we have done in Section III) that, for example, risk-free rates – at least as measured by adjusting conventional gilts for a reasonable rate of expected inflation – are already close to that average, with a widespread expectation that real rates will rise.

87 Therefore, although 5 year averages represents one perfectly reasonable way of trying to exclude what seem to be outlying spot values, there is still plenty of scope for real interest rates to move above these averages through the next price control

period. This will be particularly true if, as would now seem to be the case, the world economy is towards the end of a period of exceptionally low rates.

88 Thus, although we have suggested using a cost of debt above the 5 year average, on the basis of allowing for the cost of embedded debt, a good case could also be made for the higher number on the basis of where we (probably) are in the interest rate cycle.

Capex, terminal value risk and regulatory risk more generally

89 As noted in Section III above, Ofgem attributed its DPCR4 cost of capital assumption partly to the investment focus of DPCR4 and has also acknowledged the investment focus of the current transmission reviews. However, it is important to separate out some of the different ways in which a large capex programme can impact on cost of capital - in particular, the impact on:

(a) financial ratios/financeability; and

(b) long life asset/'terminal value' risk.

Capex and financial ratios

90 A large capex programme may stretch a company's **financial ratios**, with implications for its credit rating and for its cost of capital more generally. Certainly, if Ofgem followed a more 'relaxed' approach to financial ratios than in the past (as mooted in the current Ofgem/Ofwat consultation on financing networks), then, in the context of the projected capital programmes for the next price control period, this might be expected to impact on the cost of capital of both NGG and NGET – and would tend to push cost of capital above the levels suggested in Sections III and IV above.

91 However, Ofgem has the option to mitigate this impact by following the approach to financeability which it followed in DPCR4 and in the last Transco price review – i.e. keeping financial ratios within defined bounds through either tilting of regulatory depreciation (DPCR4) or through partial expensing of capex for regulatory purposes (Transco).

Terminal value risk

92 One of the other effects of a large capex programme for a regulated network utility is, however, to increase the amount of a company's NPV which lies outside the next price control period (and is therefore not covered by the regulatory commitment embodied in the new price control). In other words, one of the effects of a large investment in long life assets (and the current regulatory asset lives are 40 years for NGET and 45 years for NGG) is to increase a company's **terminal value risk** (i.e. the amount of value which appears in the terminal value of Ofgem's standard price control calculation).

93 Although Ofgem could again mitigate this impact by reducing regulatory asset lives (potentially as one way of addressing the above financeability issue), this will make very little difference to the fact that, because regulatory asset lives will continue to be far longer than a price control period, the proportion of the NGET's and NGG's value which is in the price control calculation's 'terminal value' will rise. The bigger the capex programme the bigger this effect will be - and the more that investors are being asked to expose themselves to future regulatory decisions (which are not covered by the 'regulatory commitment' embodied in price control final proposals). **Because of this effect in particular, a large capex programme can be expected to increase perceived risk and, therefore, the returns required by investors**.

Regulatory risk more generally

94 Terminal value risk lies at the heart of the more general issue of **regulatory risk** and whether this is adequately accounted for in conventional analyses of cost of capital. The question arises because some have argued that regulatory risk is not systematic or 'beta' risk – and, therefore, does not need to be allowed for in cost of capital.

95 This argument confuses the following two questions:

(a) Is regulatory risk systematic risk?

(b) To the extent that it is not, is it, in some sense, 'free' risk which regulators do not need to allow for in setting price controls.

96 In our view, the correct way of answering both of these questions is summarised by Brealey and Myers in their standard corporate finance textbook, as follows:

"We have defined risk, from an investor's viewpoint, as the standard deviation of portfolio return or the beta of a common stock or other security. But in every day usage *risk* simply equals 'bad outcome'. People think of the project as a list of the things than can go wrong. For example

(a) A geologist looking for oil worries about the risk of a dry hole

(b) A pharmaceutical manufacturer worries about the risk that a new drug which cures baldness may not be approved by the Food and Drug Administration

(c) The owner of a hotel in a politically unstable part of the world worries about the political risk of expropriation

Managers often add fudge factors to discount rates to offset worries such as these. This sort of adjustment makes us nervous. First, the bad outcomes appear to reflect unique (i.e. diversifiable) risks that would not affect the rate of return demanded by investors. Second, the need for a discount rate adjustment usually arises because managers fail to give bad outcomes their due weight in cash flow forecasts."[8]

97 In other words, 'bad outcome risk' should not affect the cost of capital/discount rate – but it should be allowed for in a project's cash flows. On this basis, it would not affect a company's beta – **but it would affect the cash flows which an investor should assume when valuing a company**. This is one potential explanation of why the cost of capital estimates implied by the approach used in Section IV above are above those implied by a straight CAPM approach (even one which has consistent assumptions for risk-free rates and equity risk premia). It is interesting, for example, that, in Figure 8 above, the required rate of return for WASCs seems to have declined as investors have got more comfortable with the water regulatory regime, whereas CAPM estimates of WACC seem to have shown no comparable trend.

98 Our overall conclusion on this issue (of capex, financeability, terminal value risk and regulatory risk) is, therefore, that:

(a) Ofgem was right in DPCR4 to use high capital spend as a reason for assuming a cost of capital higher than it otherwise would have done.

[8] Brealey and Myers, Principles of Corporate Finance, Seventh Edition, Page 235

(b) This reasoning should apply even more to the transmission reviews, not least because the level of required capex in transmission will lead to more terminal value risk for both NGG and NGET than was the case for DNOs or water companies at their last reviews.

(c) Against this background of high terminal value risk, it would be inadvisable for Ofgem to follow a more relaxed approach to financial ratios than it did in DPCR4.

Impact of potential changes in the transmission regulatory regime

99 Most **evidence** on perceived risk will be historic. It is therefore possible that **future changes** in the transmission regulatory regime could either increase or reduce the risk facing the transmission licensees, compared with what has been faced in the past.

100 In our view, no real view can be taken on this issue at this stage. Ofgem has consulted on a variety of changes in how regulation – and, in particular, how regulatory incentives – might work in the future. However, it is not currently clear whether these changes will take place or, if they do, what financial parameters they will have. We would simply note that:

(a) Proposals for **penalty-only incentive schemes** (as have been mooted in relation to Milford Haven for NGG and in relation to transmission reliability incentives for NGET) would, by themselves, tend to increase perceived risk and, thereby, cost of capital.

(b) Certain features of the proposed **remuneration for load-related capex** (e.g. five year rolling incentives which are not brought back to reality at the end of a price control period) might be expected to increase risk but other mooted features could reduce risk or be risk neutral.

(c) **Capex input prices** (both materials and the cost of contactors) have both increased markedly in real terms in the recent past and show every sign of continuing to do so. National Grid's required rate of return will depend on how the risks of future real change in input prices are to be shared with customers – for example, by assuming a fixed rate of real increase and/or by defining an Income Adjusting Event if price increases (or reductions) out-turn outside prescribed limits.

101 Given that none of these issues have yet been resolved, we suggest that the issue of regulatory change needs to be kept under review for its cost of capital implications – but that, at this stage, it cannot be inferred whether there will be a significant impact for this review or what the direction of that impact might be.

Implications of regulatory precedent

102 As previously noted, respect for precedent in regulatory decisions is important in that, otherwise, investors would assume a higher probability of 'bad outcome' risk than would otherwise be the case – and would therefore require higher rates of return than would otherwise be the case. At the same time, consistency with past decisions does not mean that the decisions will necessarily be the same. As facts change, so decisions are likely to change.

103 The main relevance of this to any discussion of cost of capital in the context of a price review is that some parts of the cost of capital debate are more fact-based than

others. In particular, there is far more factual information about cost of debt than there is about cost of equity.

104 For this reason, it is our view that, whereas price review analyses of cost of debt will necessarily take account of observed market movements - albeit still (as note above) needing to make judgements as to how those **facts** influence **forecasts** over the next price control period – the need for consistency with precedent is greater on the equity side.

105 Thus, and as noted in Section III above, the final proposals for DPCR4 involved the propositions that:

(a) Total real equity returns are more stable than the equity risk premium and, over the long term, have averaged between 6.5% and 7.5% (post tax).

(b) At 57.5% gearing, DNO equity risks could be assumed to be equal to those for the market as a whole.

(c) The top of the range of 6.5% to 7.5% was appropriate in the context of the investment requirements of the DNOs.

106 As also already noted, the first of the above propositions also implies that the equity risk premium is inversely related to the risk-free rate.

107 In Section III above, we have also contended that there is neither evidence nor a compelling prima facie basis for concluding that the risks facing the National Grid transmission businesses are any lower than those facing the other GB (energy and water) network businesses. That is for discussion during this review. However, it would be unfortunate for regulatory predictability if Ofgem re-opened the propositions in paragraph 105 above.

Implications of alternative rates of return available to network operators

108 Many of the owners of regulated energy networks in GB also own networks in other countries. Although, it is clearly the case that all GB licensees have licence obligations to develop their networks efficiently (which implies the obligation to invest adequately and efficiently in those networks), it is also true that the returns available in other countries also represent one element of the opportunity cost of investing in GB.

109 Against this background, we offer evidence relating to our main overseas network assets in New England and in New York State. Although the regimes in both these states have strong incentive elements - and therefore the scope for earning more or less than the base rates of return which are used – the base rates of return themselves are somewhat higher than those assumed in DPCR4.

110 As is normally the case in the US, the relevant rate of return is a post-tax nominal return on equity (as against a post-tax real rate of return on capital, as for the current DNO and NGET controls). To make these returns comparable with DPCR4, for example, involves assuming an expected rate of inflation for the US and also re-leveraging to adjust for differences in gearing assumptions. Adjusting the base rates of return from our New England and New York state businesses to 57.5% gearing and assuming expected inflation in the US of 2.5% (close to both historic 5 year and 10 year averages), implies real post-tax equity returns which are between around 140 basis points and around 200 basis points higher than those assumed in DPCR4.

VI Conclusions

111 The conclusions which we would draw from the preceding sections of this paper are as follows:

(a) Replicating Ofgem's DPCR4 analysis in the light of capital market changes since the end of 2004 suggests that it would be **inappropriate** to assume a real post-tax WACC for the forthcoming NGG and NGET price controls of less than 4.7%.

(b) Inferring a required rate of return from share price movements and transaction prices for water companies suggests a figure of around 4.8%.

(c) Broader considerations, of the sort considered in Section V above, tend to underpin the above range, and suggest the upper, rather than the lower, end. This is particularly the case in relation to the substantial terminal value risk which investors in the transmission businesses will have to bear (over and beyond what is inherent in a regime characterised by long asset lives and short price controls) as a result of the large amount of capital spend which will be required during the next price control period and beyond.

(d) The required rate of rate may need to be increased to take account of changes in the transmission regulatory regimes which Ofgem is considering as part of this review.

National Grid
17 May 2006