National Grid plc Response to Transmission Price Control Review Third Consultation Document

I Introduction

1 We welcome the opportunity to comment on Ofgem's Third Consultation Document. Our detailed response is structured as follows:

- In **Section II**, we provide our response to each chapter in the consultation. This section is designed to address what we see as the most important issues in each of Ofgem's chapters but we do not attempt to answer each of Ofgem's specific questions in this section.

- In **Section III**, we provide answers to each of the questions posed by Ofgem in each **chapter** of the consultation. There is substantial duplication between the material in Section II and Section III.

- In **Section IV**, we provide answers to each of the questions posed by Ofgem in Appendices 10 and 12 of the consultation. Again, there is duplication with material in Section II.

- A final **Pensions Appendix** contains a numerical illustration of one of the main points covered in our response to Ofgem's discussion on pensions issues in the consultation document.

2 In advance of the detailed response, we would like to emphasise the following points:

(a) We believe that the level of spend that we have proposed for the period 2007-2012 is, as with the achieved spend in the current price control periods, in the interests of customers. In particular, we see this spend as underpinning:

(i) **long term network reliability**, not least through timely replacement of ageing assets on the electricity transmission system;

(ii) **overall energy security of supply**, not least through extension of the gas network to accommodate new entry points and reinforcement of the network to cope with what will inevitably be increased variability in gas flow patterns across the system (resulting from, inter alia, the increased importance of flows through interconnectors and LNG terminals in the overall makeup of gas supply into GB); and

(iii) **the achievement of government environmental and climate change objectives**, not least through: reduced emissions of CO2 and NOx from our gas compressor fleet; reduced emissions of SF6 from our switchgear; reduced oil leaks from our cable network; and the extension and reinforcement of the electricity transmission system to

transport renewable electricity from remote locations within GB.

(b) We believe that the cost to customers of our proposals is modest in relation to the benefits. If the proposed costs were directly passed on to final customers, they would lead to bills rising by £2.20 per annum for an average domestic gas customer and by £1.25 per annum for an average domestic electricity customer.

(c) We are in broad agreement with Ofgem's proposed approach of designing new price control and incentive mechanisms to both accommodate changed requirements on the transmission networks (as these evolve through the next price control period) and to encourage us to respond to those changed requirements in a timely way. The overall impact of new mechanisms on the risks that we face will only be clearer when the proposals become more concrete and detailed in this area.

3 Finally, we would like to make the point that it is essential that, over the course of this review, there is sufficient scope for interaction between licensees, Ofgem and Ofgem's consultants in relation to the analysis of licensees' actual and projected operating and capital spend. To the extent that there is scope only for limited interaction in the near future, then this should be reflected in appropriate qualification of Ofgem's initial proposals at the end of June. On the same basis, and given that there has been little discussion, to date, of financial issues, we would not expect that initial proposals would significantly narrow the range of feasible options in this area.

II Chapter by chapter response

Chapter 2 - Form and structure of the price Control

4 Our response to this chapter sets out our current thoughts on the form and structure of the transmission price control to take effect from 1 April 2007. It highlights our views on the proposed refinements to the standard RPI-X framework, commenting on:

(a) the proposed increased use of revenue drivers;

(b) the potential use of rolling incentives; and

(c) the potential inclusion of an information quality incentive mechanism.

5 Views are also provided on other issues covered by Ofgem in Chapter 2 of the consultation document, including:

(a) the issue of the starting RAV, including whether LNG assets should be brought back inside the RAV for NGGT;

(b) the use of differential rates of return; and

(c) SO incentives.

6 Overall, whilst we consider the third consultation document helpful in narrowing down the options consulted upon in the second consultation on the form of control and gas and electricity incentives, there still remains a range of potential options which could either increase or decrease the risks being borne by the transmission licensees. The acceptability of the proposals on the form of control will therefore only become known once all the elements of the price control are brought together.

7 In addition, and in the light of the potential extent and complexity of the changes in the form of transmission price controls, it will be particularly important to see licence drafting for these changes as early as possible. In the absence of such drafting, there is a risk that Ofgem and the licensees will be talking at cross purposes about the extent of agreement or disagreement about the proposed changes.

Increased use of revenue drivers

8 As detailed in our previous responses, we are supportive of the proposed increased use of revenue drivers (and, by implication the increase use of more sophisticated revenue drivers than exist in the current NGET TO control) as a mechanism to deal with the uncertainties associated with load related capex in gas and electricity. We are supportive of the proposal contained in the summary of the consultation document that the base price control allowance should provide for known investment requirements, (e.g. where a user commitment has been provided) and revenue drivers should adjust funding in response to less certain developments during the price control period. We believe such an approach should be consistent across gas (entry and exit) and electricity.

9 Until further work on the detailed design of the revenue drivers has been undertaken in both gas (entry and exit) and electricity, it is difficult to ascertain the risks associated with an increased use of revenue drivers. However, examples of the potential risks associated with revenue drivers that were not envisaged at the time of setting the **current** price control include:

(a) high baselines leading to investments not being funded during the price control period (as they were needed to support below-baseline entry capacity bookings);

(b) low UCAs being set for new entry points, thereby exposing National Grid to potential under-recovery of revenues;

(c) UCAs being fixed for 5 years and becoming unreflective of actual costs due to changing circumstances such as shifting supply and demand patterns and increased steel prices (as recognised in Ofgem's recent consultation document: "*Adjusting National Grid's revenue allowances when large new entry points convert to the gas transmission system*");

(d) the designed revenue driver in electricity (Gt) not catering for actual drivers of investment costs during the price control; and

(e) the revenue drivers generally not catering for the new renewable generation in Scotland and the subsequent need for TIRG.

10 Although it may be possible to attempt to cater for these previous experiences in designing the new regime, there remains an inherent risk with revenue driver mechanisms which are set ex-ante based on a set of assumptions for a 5 year period. In addition, the risk to a transmission licensee associated with revenue drivers will be greater:

(a) the larger the amount of revenue exposed to the revenue driver, as currently being proposed from 1 April 2007; and

(b) the longer is the exposure to the revenue driver, e.g. as a result of using rolling incentives which would increase exposure to, say, five years, as against an average of 2.5 years if the exposure lasts only to the end of the price control period in question.

11 As mentioned in our response to the second consultation document, we would support a model that recognises that revenue drivers should **not** be determined solely by user commitments (i.e. user commitment is sufficient but not necessary for revenues to adjust) due to both practical limitations of revenue drivers and also the need for investments to meet wider obligations. As such, a revenue driver mechanism other than user commitment needs to be agreed for investments that are driven by the requirements of our broader licence obligations. Revenue drivers may therefore need to be linked, at least in part, to an output measure such as additional capacity released or additional km of pipes or wires rather than purely to the existence of a user commitment. We would welcome further discussion with Ofgem on this topic in advance of the initial proposals document in June.

12 In the light of all of the above, particularly the risk that revenue drivers will turn out to be **incorrect and/or incomplete**, we think that consideration should be given to accompanying the use of revenue drivers with a formal licence condition that would trigger a focused interim determination in the event that revenue drivers turned out to be 'wrong' **by some pre-set minimum amount**. Such a condition could be modelled on provisions in the water regulatory regime and could, for example, kick in if the expected difference between (a) a licensee's actual costs and (b) the revenue produced by the relevant revenue drivers over the relevant period is at least equal to 10% of the licensee's relevant annual turnover.

13 One final point on this issue. This is the question of the **timing** of the revenue being received by the transmission licensee. All things being equal we would support a model whereby the trigger for the revenue driver would be the licensee receiving a user commitment (e.g. TEC in the electricity regime). Such an approach has the benefit of linking the revenue trigger to the investment trigger and would be closest to the current status quo in relation to the profiling of costs and revenues.

Rolling incentives

14 In addition to the proposed increased use of revenue drivers, the potential use of rolling incentives is another significant change from the current status quo in both gas and electricity. In both gas and electricity, the current regime involves a "true-up" of efficiently incurred actual costs at the time of the next price control (this is effectively achieved in the gas entry regime via the "TO adjustment" mechanism). In addition, Ofgem have stated in open letters[1] that, under the current regimes, they will also consider incorporating efficient overspends into the RAV from the year in which they were incurred and allowing the licensee to recover the associated depreciation and/or return if the expenditure provides significant benefits to customers.

15 Against this background, and in the context of the above discussion of revenue drivers, a rolling five year mechanism could be expected to have at least two effects which would need to be taken into account in any final proposals for this price review:

(a) Such a mechanism would, other things being equal, increase the risks faced by a transmission licensee by increasing the time for which the licensee was exposed to differences between actual costs (including cost of capital) and revenue.

(b) Applying rolling incentives to capex would increase the incentives on licensees **not** to invest in their respective transmission systems and would therefore further increase the tension (which already exists in the current regulatory framework) between, first, meeting the licence obligation to develop an efficient transmission system and, second, making a rate of return which covers the licensee's cost of capital

[1] Open letters relating to the Gas Distribution price controls (March 2004 and December 2005)

Information Quality Incentive Mechanism

16 For the DNOs, Ofgem have introduced a mechanism which rewards companies for incurring capital spend in line with what has been deemed to be necessary by Ofgem (and their consultants). In deciding whether to introduce such a mechanism for transmission, and in particular whether such a mechanism has anything to do with improving the quality of information provided by licensees, it is worth noting that the proposed mechanism would seem to be based on a significant internal contradiction. Thus:

(a) Ofgem's main reason for proposing this incentive is that Ofgem believe that they will always be faced with an information asymmetry in relation to licensees – i.e. licensees will always know more than Ofgem about what spend is required on their respective transmission systems. But, at the same time

(b) the proposed mechanism financially incentivises a licensee to spend what Ofgem thinks the licensee should spend, even though the starting point for the incentive is that the licensee knows better than Ofgem what the licensee should be spending.

17 On the basis of the above, the proposed incentive would seem to have little to do with improving incentives for either spending the right amount of money on the transmission system in question or for giving accurate information to Ofgem. However, this does not mean the proposed mechanism, or at least some variation on it, would not be potentially useful. What the mechanism does is to allow Ofgem to commit to a **range** of required spend, rather than a fixed number. In the DPCR4 version of the mechanism, the company would earn a lower incremental rate of return if it spends at the top of that range, implicitly because Ofgem thinks that the 'right' number is at the bottom end of the range. However, there is no reason in principle why the rate of return should not be invariant over the range, implicitly on the basis that Ofgem is genuinely uncertain what the right number is within the range. Such a variant of the mechanism would, in our view, be useful, albeit that it should be called something other than an information quality incentive mechanism.

Starting RAV

18 In this part of the consultation document (para 2.7), Ofgem raise two types of issue, i.e.:

(a) the issue of how actual and expected capex through to the end of March 2007 impacts on the RAV as at 1 April 2007; and

(b) in the case of NGGT, whether LNG assets should be reincorporated into the RAV.

19 On the **first of these issues**, it is our view that all NGET and NGGT capex during the current price control period has been, or will be, efficiently incurred and, therefore, should go into the RAV at 1 April 2007. In addition, the following need to be considered:

(a) the inclusion of foregone depreciation and return on NGET's 'excess' capital spend through to 2005/06 (i.e. capital spend in excess of Ofgem's assumption in setting the price control from 2001/02 to 2005/06) and on NGGT's excess spend (on the same basis for 2002/03 to 2006/07) on the basis that such spend was in customers' interests; and

(b) the inclusion of foregone depreciation and return on NGET's expected excess spend in 2006/07 (relative to the mini review outcome) on the basis that, in addition to the spend being in customers' interests, the mini review outcome was explicitly a provisional outcome in respect of capex.

20 In respect of NGGT's LNG assets, Ofgem need to take account of the inequity of the current regulatory treatment of these assets. They are not in the RAV but, to a large extent, the return on the assets is subject to direct price control.

21 What is required is a consistent regulatory treatment which depends on whether the assets are:

(a) in effect, playing in a competitive market (and are not, as a result, subject to specific regulation), with the NGGT SO able to pay the market value for the services which it consumes from these assets; or

(b) there is very limited scope for the SO to find adequate substitutes for the services purchased from the LNG assets. In this case, the assets should be in the RAV - which would broadly both cap and collar the return on the assets.

22 It is at least arguable that the NGGT SO will find it relatively easy, over time, to find substitutes for the services provided by some of the LNG plants – but much more difficult in respect of others. In this case, a hybrid regulatory treatment might be appropriate (i.e. some in the RAV and some able to play in the market).

Differential rates of return

23 Although Ofgem do not devote much space in the consultation document to this issue, they do pose the question of whether certain activities should be relatively highly rewarded to the extent that they are riskier – and specifically the question of whether new investment should attract a higher return than assets which are already in the starting RAV. We would expect this issue to be reviewed at greater length when Ofgem address cost of capital (expected to be mainly in the wake of Initial Proposals). However, the main point which we would make at this stage is that a presumption that starting RAV assets should be funded with 100% debt (and with the cost of debt at a modest premium to the relevant risk free rate) would seem to be unrealistic in the context of five year price controls (and the resulting maximum length of 'regulatory commitment', therefore, of five years) and assets which have regulatory lives of 40 years or more.

SO incentives

24 We note Ofgem's request for views relating to SO Incentives and offer the following comments with regard to the existing form of SO Incentives, including the structure and duration of incentives. Further to this, we would welcome clarity and confirmation from Ofgem as to the proposed timescales for future consultations and target dates for initial and final proposals on SO schemes from1 April 2007.

Managing wider market uncertainty

25 With regard to Electricity SO incentives on NGET, we would agree that the current uncertainty within the wholesale gas and electricity markets has made it more difficult to predict the level of day-to-day balancing costs and that this leads to greater uncertainty and difficulty in setting targets. However, we remain fully supportive of incentives and support the continued development of incentives to target those areas of costs within the control of the SO. In line with Ofgem's comments, more uncertain elements outside the SO's control could be removed from the scheme through the use of correction mechanisms to alter the incentive.

26 For the 2006/07 Electricity Incentive scheme we proposed indexing the incentive target to the electricity wholesale market price to remove the significant cost uncertainty driven by variations in the market that are outside NGET's control. Moreover, the application of mechanisms to remove uncertainty and variations in cost drivers outside the SO's control should facilitate the establishment of longer duration schemes (See below). We would support further work and discussion with Ofgem and the industry on the understanding of cost uncertainties and the development and application of such mechanisms in future schemes.

Duration of schemes

27 We welcome Ofgem's consideration of longer duration incentive schemes. Incentives on NGET to balance the Electricity system have been of one year duration whereas the current incentive on NGG is of 5 years duration. We agree with Ofgem that the establishment of longer duration schemes should, where appropriate, lead to an improved incentive to reduce costs and that the longer duration of the incentive may reflect longer timescales required to realise the benefits of certain investments in, for example, the training and recruitment of specialist staff, and/or IT infrastructure.

28 Within the establishment of a longer duration scheme, a key element would be the development of appropriate mechanisms to adjust the target to reduce uncertainty and volatility caused by cost drivers outside of the SO's control (see above discussion on managing uncertainty). Examples of drivers outside of the control of the SO include would include, for example:

(a) wholesale market prices (an increase or decrease in wholesale prices has a knock-on effect on balancing costs); and

(b) modifications to industry codes (changes to codes may alter the prices paid for a service or may change behaviour in the market resulting in a change in costs for the SO).

29 Changes in these drivers could lead to significant variation in costs that, if uncorrected, could lead to windfall profits or losses under the incentive scheme. We have previously proposed price indexation as a way of removing uncertainty from NGET's incentive and we would support further work, within the TPCR process, to examine possible mechanisms to manage such uncertainty and thereby facilitate the delivery of longer term schemes.

Chapter 3 – Electricity incentives

30 We are supportive of Ofgem's current preferred option for the design of electricity revenue drivers, namely to develop locational revenue drivers. We agree that this option should enable allowed revenues to adjust in a more sophisticated manner than the existing revenue driver for NGET. Having said this, we would also accept that, although such a mechanism should be a more cost-reflective approach, it is unlikely that the mechanism will capture all factors influencing costs.

31 We would therefore support an approach whereby the two technical options contained in the consultation document (accommodating generation in various zones of the system[2]; or increasing the capacity for flows across key system boundaries) should be further developed and assessed against past events and a range of future scenarios. This analysis is clearly important to understand the robustness of the revenue drivers, for both recovering the level of costs likely to be incurred by the licensee for load related investments and as a basis for setting incentives. The robustness of the revenue drivers will be an important factor in understanding the risks that are likely to be borne by the transmission licensees in the next price control period.

32 The analysis should also consider revenue drivers in relation to **demand** as well as generation. It is unanticipated changes in demand which have been one of the key issues in NGET's over-spend against price control assumptions in the current price control period.

33 In addition to considering the robustness of the revenue drivers it will be necessary to further consider other revenue elements such as the trigger point for the revenue driver and the stranding risks being taken by NGET under any revised final sums policy. These two elements are considered further below.

Trigger point for the revenue driver

34 Under the proposed enduring access regime, we would support the revenue driver trigger being linked to the licensee receiving commitment from the user for their desired TEC. Such an approach has the benefit of linking the revenue trigger to the investment trigger and would be closest to the status quo in relation to the profiling of revenues relative to the profile of costs.

35 We believe any alternative model of linking the revenues to the capacity being delivered suffers from a lagging effect of revenues tracking costs but, more important, also from the potential double jeopardy of penalty payments for late delivery under the likely incentive arrangements being coupled with a delay in receiving the base capex costs.

Stranding risks under any revised final sums policy

36 Our views on the specific elements of the revised transmission access arrangements are covered in the section below. However, a core element of any revised final sums regime will be the risk being assumed by the

[2] We believe this should be expanded to include national demand revenue drivers

transmission licensee for any cost incurred which has not been secured by the transmission users. We assume from the consultation document that the risks associated with any unsecured sums during the construction phase will be borne by customers as a whole, rather than by the transmission licensee. Confirmation of this point by Ofgem would be required before any revised final sums policy could be implemented.

Transmission access arrangements

37 It is important to note that the existing electricity access arrangements which are built on the principle of user commitment prior to access release and a first-come first-served approach to access dates, have worked very well since privatisation. They have facilitated the timely and efficient connection of a vast number of new power stations and new demand loads over the years and served to provide significant benefits to end consumers.

38 However, we agree that the access regime has come under pressure from the vast amount of new connection and access applications that arose as part of the transition to the BETTA arrangements and from the significant new interest in renewable forms of generation. We believe that such an influx of interest would have created significant pressure on any access regime. Not withstanding this point, we believe that there is strong merit in considering enhancements which could address some of the concerns that have been identified.

39 We believe these issues fall into three areas:

Final Sums

40 We support the need to develop alternative options for final sums liabilities. We are developing a strawman which we hope will be considered by the ARODG Group and indeed is discussed further in our GB Queue consultation document.

41 We are focusing on improving the certainty of liabilities, and looking at models with less than 100% commitment to full investment costs (assuming Ofgem confirm that this will not be detrimental to investments going into RAV). We would suggest that an appropriate way forward might be to define a Final Sums methodology statement, under a potential licence obligation, which could be approved by Ofgem and which would be akin to a charging methodology and referenced from the CUSC.

User commitment

42 We agree that it would be beneficial to get longer term commitments from existing users and for new users. Such an approach would enable investment decisions to be based on more accurate information.

43 We believe that this longer term commitment could take the form of a rolling commitment to pay x year TNUoS charges.

44 We note Ofgem's desire for firmer dates to be provided for access release. Whilst we agree this is a sensible aspiration, and ideally it would be helpful to

have a period of time beyond which an unconstrained release of capacity is possible, this is problematic for two main reasons:

(a) The consenting issues associated with both generating stations and transmission infrastructure makes it very difficult to determine a "standard" construction timescale.

(b) When large infrastructure upgrade or reinforcement projects are contemplated, system access issues make it very difficult to determine a standard period.

45 Hence, it will be important for any "user commitment" and capacity release mechanism to recognise these issues.

46 These same issues apply equally to any user commitment from existing users, and to the associated notice period which would help inform investment decisions. For some projects, this would need to be a very long period to ensure investment would be avoided. For others, it would be short. It will, therefore, be necessary to recognise these limitations in any model which sets a fixed X years of TNUoS user commitment.

47 It will be important that any new Final Sums policy is consistent with any new User commitment approach

Short term access

48 In the constrained period, where investment is not possible, short term rationing of available capacity is required. We note there are already two within-year capacity products available for use which aim to allow release of "spare capacity" for these periods. These are again based on a similar framework to the longer term products, i.e. first come, first served. We are exploring, through the ARODG group, whether there are alternative models which could be used to allocate any shorter term Spare capacity which perhaps could facilitate new entry earlier.

49 However it must be noted that short term capacity is likely to be heavily constrained given the limitations of providing additional TEC. Hence these options will need to consider how trading of capacity with existing parties can be facilitated as this may the only way to create "spare" capacity at shorter timescales. The gas entry short term access framework may offer some ideas of a way forward in this area.

Other issues – system reliability incentives

50 Ofgem have stated that their provisional view is that there is merit in exploring a 'penalties only' scheme. We disagree with this approach, and see no justification as to why Ofgem have completely changed their stance from the approach adopted less than two years ago in the development of the original scheme (and less than six months since a similar scheme was introduced for Scottish transmission licensees).

51 Regarding the current incentive arrangements, Ofgem themselves pointed out in their final proposals for the current incentive scheme that:

"The proposed arrangements seek to provide NGC with a reasonable balance of risk and reward, while protecting consumers' interests by setting incentives that will encourage NGC to maintain and improve its performance in the future and will penalise it for a deterioration in performance relative to the baseline level described above." [3]

52 We believe that the potential to reward success, as well as penalise failure, is an important feature of a well designed incentive scheme (and had hitherto believed that this was also Ofgem's view, not least after a protracted debate about just this issue in relation to performance incentives for DNOs). However, in the event that Ofgem continue with the proposed penalties only scheme, the potential of a loss without any potential upside would need to be taken into account in setting the cost of capital. Such a scheme would perfectly fit what Brealey and Myers refer to (in their standard corporate finance textbook) as 'bad outcome risk'.

[3] Electricity transmission network reliability incentive schemes – Final Proposals, December 2004.

Chapter 4 – Gas entry incentives

53 We are broadly supportive of the current proposals contained in the consultation document relating to the gas entry regime, both in terms of revenue drivers and developing the commercial regime. We believe that Ofgem are seeking to address some of the issues that have arisen under the current entry regime and, subject to resolution of the detailed design issues detailed below, we think that the proposals should improve the workings of the entry regime.

Proposed capacity release mechanism

54 In general, we support Ofgem's proposed change to remove fixed obligations to release pre-specified baselines in the licence and to remove an explicit link between prices in an auction and the Unit Cost Allowance (UCA) in the price control. We believe that this will provide additional flexibility to encourage maximum capacity release and remove restrictions on the commercial options that could be available to the industry surrounding capacity release.

55 We would envisage defining a capacity release methodology (probably taking the form of an extension of the current Incremental Entry Capacity Release Methodology) which would be consulted on and approved by Ofgem against a set of objectives set out in the licence. In addition, we believe that such a methodology would usefully set out rules for both long term (in an unconstrained period) and short term (within a constrained period) release. In this way, it could incorporate some of the ideas presently being discussed in the Transmission workstream with regard to capacity trading in the constrained period. The overarching principles behind the methodology would be a methodology based on National Grid **not** being obliged to release more capacity than the network system capability. However, we believe that further work needs to be carried out to ensure that all the details and implications of moving to such a regime are fully understood, and we look forward to working with Ofgem and the industry to achieve this in advance of any final policy decisions.

56 In line with some of the issues we raised in our response to Ofgem's second consultation document, regarding our concerns over the sole reliance on user commitments, such a methodology could also consider any criteria that could be used to release capacity and underpin investment in the absence of timely user commitment. We believe that providing a mechanism for such flexibility would be useful, especially given the ongoing work associated with the Energy Policy Review.

57 We note that, within paragraph 4.7, Ofgem have recommended that we should face "a new licence obligation to develop a transparent capacity release methodology – and to publish a network model to enable shippers to understand how the methodology is being applied". Whilst we understand Ofgem's desire for transparency, we do not believe that it would be possible to publish a model which would simultaneously be a reasonable representation of network complexities and be sufficiently user-friendly to be any help to network to shippers.

Setting of baselines

58 The setting of appropriate baselines, for revenue purposes, is clearly going to be an important factor in the overall acceptability of the price control proposals. As detailed in our response to Chapter 2, the setting of baselines, in addition to the setting of UCAs, is a key factor in ensuring sufficient revenue is received when investment is necessary, following user commitment. In order to meet the objective of providing sufficient revenue for necessary investments, it will be crucial that the baselines do **not** exceed the capability of the system, whilst recognising the interaction of capabilities between nodes. In this regard we wish to make it clear that the system capability is **less than** the summation of the nodal totals in Appendix 12 of the consultation document.

59 We recognise that further work is required on understanding the capability of the network and the sensitivity of nodal capabilities to differing supply pattern assumptions. We will therefore continue to work with Ofgem to model network capabilities under differing assumptions in order to arrive at an appropriate set of baselines.

Setting of UCAs and the decoupling of pricing

60 We support the proposal to decouple UCAs and pricing, and agree that this change will allow pricing to be more flexible and more cost reflective than has been the position in this price control. We note, however, that, while the proposals will enable pricing to be more flexible, Ofgem's current intention is to continue to set UCAs as part of the price control for a five year period.

61 Although we can understand Ofgem's desire to set UCAs for the full price control period, it is important to recognise the experience during the current price control period of such a mechanism. As set out in Ofgem's consultation document "*Adjusting National Grid's revenue allowances when large new entry points convert to the gas transmission system*", UCAs set at the beginning of the last price control no longer provide an accurate estimate of the costs likely to be incurred by the transmission licensee due to significant changes in flow patterns, rising steel prices and a tightening of the contract market. In the event that Ofgem determine that significant elements of load related expenditure are subject to revenue drivers and National Grid is exposed to the differences between the ex-ante set UCAs for a full five years, then these risks will clearly need to be considered if National Grid is to be appropriately remunerated.

62 As noted in our response to Chapter 2 above, a compromise between fixed five year values and more continuously changing ones could be incorporated into an over-arching change mechanism whereby a focused interim determination would be triggered in the event that actual costs and UCAs diverged by more than a pre-specified amount.

63 As an example of the risks associated with fixing UCAs, work undertaken on a potential large new entry point has indicated that investment costs at this one point could vary by several hundreds of millions of pounds, depending upon the underlying supply and demand assumptions.

Buyback incentive

64 We support Ofgem's preferred approach to retain the current form of the buyback incentive but to limit its scope to exclude the costs of National Grid buying back rights in the event that incremental capacity is delivered late. We would agree with the comments raised by Ofgem that, when new capacity is provided on the network, there is, inevitably, a degree of risk attached to the date of delivery and that currently entry shippers are in a strong bargaining position in any negotiation with NGG NTS to buy back such capacity rights.

65 We would therefore support a revised set of arrangements for dealing with buying back capacity associated with the late delivery of incremental capacity. We believe the model outlined in paragraph 4.25 of the consultation, which effectively sets out a standard set of arrangements, recognising the elements which are significantly outside the control of National Grid, but also providing the flexibility to vary the standard terms with all associated costs and revenue being treated as excluded income for the purposes of the price control, has merit and warrants further development.

Chapter 5 – Gas offtake incentives

66 Our response to this chapter sets out our current views on the proposals for baselines, revenue drivers and incentives within the next price control period, both before and after 1 October 2010, which is the date on which enduring NTS capacity offtake arrangements are expected to be introduced. We also provide our views on the ongoing issues associated with developing the enduring NTS capacity Offtake arrangements.

Transitional arrangements (revenue drivers, baselines and incentives)

67 As outlined in our response to Chapter 2, we believe that the base price control allowance should provide for known investment requirements (e.g. where a user commitment has been provided or there is a clear case for investment to meet the 1 in 20 licence obligation) - and revenue drivers should adjust funding in response to less certain developments during the price control period. Given the timing of the transitional period, this would suggest that certain investments due to connect in the transitional period (e.g. Langage) should be remunerated in the base price control allowance. In contrast to this overall approach, Ofgem appear to be suggesting, for both the transitional and enduring regime, that revenue drivers should fund all incremental investments above the existing network. We therefore do not support Ofgem's proposal for setting baselines at the level of the current network and remunerating incremental investment solely via revenue drivers in the transitional period.

68 In relation to the incentives to apply in the transitional period, we note that Ofgem have suggested removing the incentive associated with "charges foregone". Whist we agree with Ofgem that the licence could be simplified by the removal of this element of the incentive, we would stress that we believe that it is important to retain the concept of "charges foregone". The concept of the revenue associated with "charges foregone" is based on the exit capacity charges which interruptible customers do not pay by electing to have an interruptible rather than a firm exit capacity service. This revenue is then used to offset against the firm exit capacity charges levied on shippers which are set to recover the proportion of the TO allowed revenue recoverable through exit charges (currently 50%). Therefore, removal of the concept of "charges foregone" would result in firm exit capacity charges needing to increase to cover this allowed revenue.

69 We note that Ofgem believe that the CLNG incentive should carry on in its current form and that the >15 day incentive should be retained, but that the capacity buyback incentive should be removed for the transitional period. We agree with the need for incentives to cover CLNG costs and >15 day costs, but believe that the capacity buyback incentive should be retained for this period as there are still cost liabilities linked with the provision of exit capacity which exist within the UNC that need to be financed and it appears that the appropriate vehicle for this is the capacity buyback incentive. In addition, it seems a rather odd policy decision to remove this incentive, as it was structured in a way to allow National Grid flexibility to seek out the most efficient solution to dealing with any exit capacity constraint (i.e. it allowed for both turn-down and turn-up type of contracts). We believe that Ofgem should always strive to set the incentives with this in mind - i.e. they should be

sufficiently flexible to encourage us to make appropriate trade-offs in order to seek out the most economic and efficient solutions.

Enduring arrangements

Baselines and revenue drivers

70 We agree with Ofgem that baselines should be set to reflect the actual capability of the system and that practical maximum physical capacity is probably the appropriate way forward as it takes into account the interactions between the different points on the system. However, we believe that it is important to recognise that there are also interactions between the capability which applies at offtake and that at entry. We would therefore only be able to agree to any exit baselines once the proposals for the entry baselines and the allowances under the main price control are known.

71 In relation to the level of the baselines to apply, we do not agree with Ofgem that the baselines should be flat across the formula period as we believe that any project for which we have already seen a user commitment should be included within the fixed network assumption (and hence would imply a rising baseline level) with funding being provided via the TO control.

72 We remain supportive of using revenue drivers to provide revenue for uncertain investments at the time of setting the price control. We see particular benefit in using nodal revenue drivers to cater for power station projects which have been identified as potentially connecting towards the back end of the price control. Assuming that the revenue driver is set appropriately, this would provide National Grid with sufficient revenue to undertake necessary investments, should the power station wish to connect, but would protect customers from funding investment allowances which may not be required.

73 As mentioned in our response to Chapter 3 (electricity incentives), we would support the revenue driver trigger being linked to the licensee receiving commitment from the user for their desired capacity. Such an approach has the benefit of linking the revenue trigger to the investment trigger and would be closest to the status quo in relation to the profiling of costs and revenues.

Commercial regime

74 We note Ofgem's conclusion that they believe the Gas offtake arrangements should contain obligations to release specified baselines over all timescales and, in addition, should include obligations to explore all nodal substitution options prior to release of capacity and investment. We are not persuaded by the arguments presented by Ofgem as to why gas offtake merits a different approach form that proposed for gas entry. It seems from the arguments presented that there is an assumption that user behaviour will not change on gas offtake, that baselines will be set much higher than physical capacity and, hence, that there is a need for the SO to optimise capacity release across offtakes before investment. This sounds very similar to the debates which preceded the introduction of the entry capacity regime and indeed could create the issues that are trying to be addressed in Ofgem's proposals for entry. For example, our understanding was that one of the arguments for gas

offtake reform was to encourage the distribution companies to consider their investment plans and hence potentially change behaviour.

75 On the basis of the above, we do not see why a different approach should be adopted to the entry proposals contained in Chapter 4. We would therefore support a similar framework to that proposed for gas entry with a methodology (which may have the added benefit of being very similar and have consistent principles) for releasing exit capacity.

76 In relation to other elements of the commercial regime, we support the conclusion of a nodal product. As noted above, we are not sure that explicit substitution obligations need to be applied but support the need to ensure capacity release is maximised in any release methodology. We believe that the incentive regime needs to be designed such that the SO is appropriately driven to trade-off effectively substitution and investment.

77 We agree that the "prevailing rights model" which we presented to Ofgem's EOWG meeting is worthy of further development given the industry discussions on this to date. This meets Ofgem's stated requirements for common products at exit, would support the Option 2A payment flow of DN pays, and provides a mechanism for all users to provide a longer term financial commitment for access and common access release methodology.

78 As outlined in our response to Ofgem's second consultation document, we still remain to be convinced that user commitment underpinning all capacity is the appropriate way forward and continue to believe that a clear assessment should be undertaken to understand the costs and benefits of moving away from the status quo position. Our initial view is that the greatest benefits are likely to arise in obtaining user commitment in relation to **incremental** capacity provision. Given our current investment plans, we do not believe that user commitment for all existing users is merited as it is not clear that it would actually reduce any stranding risk (either to the transporter or ultimately to end consumers). This is because we perceive there to be limited circumstances in which the signalling by users that they no longer require existing capacity on the network would lead to planned investment being avoided.

79 The key issues for further consideration are:

(a) the length of the user commitment (what value of x years of charges); and

(b) the appropriate notice period for relinquishment of rights (which should take into account the practical benefits associated with such signals in addition to the potential theoretical reasons).

80 In addition a decision needs to be defined with regards to the appropriate treatment of flexibility. As Ofgem note, we are undertaking some detailed analysis which will help to inform the key issues in this area. Prior to the resolution of this work, we do not believe that any solution should be ruled out (i.e. a flat product with zero slope could be the right answer). The debate will centre round an appropriate peak baseline capacity and how flows can be managed away from peak. We note Ofgem's desire for information to be released to the industry in early May. We will provide an update on our progress at the early May EOWG update but it will be important to ensure we

get the right treatment of flexibility and hence, if this requires further supporting analysis, then this should be undertaken.

81 From a theoretical point of view, we support Ofgem's conclusions on the appropriate interruptions regime, as restricting this just to the short term will minimise any potential undermining of the long term commitment regime. However it will be important to ensure this is a workable regime for the industry.

Chapter 6 - Expenditure analysis: capital expenditure

82 This section is structured in three parts:

(a) **capex assessment programme** – takes stock of the programme to date, and sets out the key areas that need to be addressed in the phase prior to initial proposals to June;

(b) **overview of capex** – discusses the drivers of expenditure, and sets the expenditure in the context of the scale and condition of the networks; and

(c) **assessment of capex and asset management** – reviews the discussions with Ofgem to date, and the approach to assessment of expenditure both historic and future

Capex assessment programme

83 Following submission of our HBPQ and FBPQ data tables and narrative in late 2005, we have worked closely with Ofgem and their consultants through numerous workshops and extensive written answers to formal questions to provide the fullest possible picture of our historic capital expenditure. With initial proposals scheduled for June and final proposals for September, the publication of Ofgem's March Third Consultation Document is an opportunity to take stock of the capex assessment programme and consider the key areas that must be addressed fully prior to the publication of initial proposals in June.

84 As we follow on from the gas transmission FBPQ workshops, and look to provide a detailed picture of our electricity transmission FBPQ in the coming weeks, we believe that workshops continue to be the most appropriate way in which to cover the key issues with Ofgem and its consultants, and we believe that it essential that sufficient time is provided to undertake workshops in order for Ofgem's consultants to gain a thorough understanding of our plans.

85 A June deadline is clearly a challenging one for all parties concerned. At this stage, we have not yet had feedback on initial findings from Ofgem's consultants. We believe that the problems which arose from lack of timely feedback provided a key learning point from NGET's price review extension process. It is therefore essential that National Grid and Ofgem work closely together over the coming weeks to ensure that such feedback takes place in an appropriate manner so that misunderstandings can be resolved prior to the publication of initial proposals.

Overview of capex

86 In Ofgem's overview of historical and forecast capex, Ofgem contrast historic and forecast expenditure for the three licensees, and the significant increases that these forecasts represent. We would like to reinforce the fact that these increases are driven by issues which are well understood and known within the relevant industries, as follows:

(a) **Electricity load related.** As Ofgem state, the main driver for this is the unprecedented proliferation of wind generation, mainly located in Scotland and northern England. Inevitably, in order to accommodate this increase in renewable generation, in line with the government's desire to increase the proportion of power delivered from renewable sources, all three licensees will need to invest extensively in their transmission networks to carry the power from the north to the main sources of demand in the south of England. Indeed, this investment has been discussed extensively with Ofgem over a number of years.

In addition, we believe that there are strong reasons for the development of new gas fired generation stations across England and Wales in order to replace closing generation and to meet demand growth. Indeed, a number of projects are currently under development, with some well progressed.

(b) **Electricity non-load related.** The bulk of National Grid's transmission assets were installed in the 1950s and 1960s, with asset lives of the order of 40 to 50 years. It is inevitable, therefore, that a proportion of the asset base has deteriorated in condition, and will need to be replaced over the course of the forthcoming price control period, in order to maintain the reliability, safety and environmental performance of the network. In addition, given the age profile of the assets, it is inevitable that the rate of replacement should increase significantly, even though the link between age and condition is not a simple one and varies substantially between different categories and sub-categories of assets.

Our replacement plans represent a continuation of the replacement policies, based on detailed condition information, which have applied during the current period - i.e. there is no step-change in our approach to asset replacement. It should be noted that, during the current price control period, we have incurred capex at a level significantly higher than that allowed for in the current price control, thus demonstrating the strength of our conviction as to what is required to maintain the longer term performance of the network.

(c) **Gas load related.** The development of new **entry** projects around the country is proceeding at a far higher rate than in the recent past. This requires significant investment in order to provide sufficient transmission capacity to enable new sources of gas to enter the market, facilitating competition and improving security of supply. The need for this investment has been verified through the sale of capacity in both long and shorter term capacity auctions.

Investment in **exit** capacity is based on National Grid's obligation to comply with the 1 in 20 peak criteria. Whatever mechanisms are derived for release of exit capacity should ensure that National Grid is remunerated for investment required to comply with this obligation.

(d) **Gas non-load related.** A large proportion of gas non-load related expenditure is required in order to comply with emissions legislation, as applied by the Environment Agency and Scottish Environmental Protection Agency. We will, over the course of the forthcoming price

control period, replace a number of compressors with electric drive or low emission gas compressors in order to drastically reduce the levels of emissions from the compressor fleet. In addition, an increased level of expenditure is required in order replace assets associated with the compressor fleet in order to maintain reliability and safety performance.

87 Thus, whilst it is true that the investment plans represent a significant increase over the allowances and expenditure in the current period, there are clear reasons for this expenditure. In addition, we believe that the scale of the plans should be properly compared to the scale of the networks. The current replacement cost of the entire electricity transmission system would exceed £20bn, whilst the gas transmission system would exceed £9bn. When set in this context, we believe our plans, particularly in regard to non-load related expenditure, are proportionate, and entirely consistent with the age and condition of the assets.

Assessment of capex and asset management

88 On the assessment of **historical** capex, we have presented our case that all expenditure has been efficiently incurred.

89 For **load related investment**, all expenditure, on both the electricity and gas transmission systems, has been driven by new generation connections, increase in demand, increased flows or through sales of long term and shorter term gas entry capacity. For all such investment, we believe that it should be assessed on the basis of the information available at the time that investment was committed, and that such an assessment should be in the context of the obligations placed on us. This is particularly the case for gas entry investment, where investment should be assessed against the firm requirement to offer baseline capacity at all times, with capacity being sold up to the gas day and not just in long term auctions, and the potential for shippers to take advantage of any inability to deliver baseline capacity through charging high buyback costs.

90 On **non-load related investment**, we have presented very detailed condition information underpinning the decisions to replace assets, and demonstrated that asset replacement has not exceeded the volumes of replacement that we anticipated at the time of the last price reviews. In the absence of any clear evidence that replacement was carried out inefficiently, **all** replacement expenditure should be incorporated in the relevant RAVs (this being the practice in price reviews and the basis on which other price control parameters, including cost of capital, were set).

91 The specific approaches which Ofgem has proposed using to analyse historical capex are:

(a) variance analysis;

(b) high level review of licensees' capex planning processes; and

(c) detailed assessment of capex efficiency at both the aggregate level and at the level of individual schemes.

92 We agree that **variance analysis** should be used to analyse the major factors influencing the differences between actual capex incurred and the projections made at the time of setting the last price controls. We believe that such analysis will show, inter alia:

(a) the extent to which Ofgem's analysis at the last NGC price review under-estimated the need for asset replacement on the electricity transmission system;

(b) the extent to which both Ofgem and we failed to anticipate the major factors driving load related investment on the electricity transmission system;

(c) the difficulty of forecasting UCAs for investment projects five or more years into the future, including the difficulty of forecasting the scope of such projects and the costs of key inputs; and

(d) the extent by which key investment input costs have been rising in real terms.

93 However, whilst we support this approach, we believe that care should be taken in use of variance analysis to ensure that the analysis indicates genuine variances, rather than simply differences in reporting, or movements of costs between schemes or categories.

94 With regard to the **high level review of capex planning processes, and the detailed assessment of individual schemes**, we have given Ofgem and their consultants full access to the extensive condition information underpinning the schemes, and delivered detailed workshops on the application of that information and the way in which capital schemes are planned and delivered. We believe that we have demonstrated that this information is as comprehensive as it needs to be in order to make efficient decisions on investment, and that our capital planning processes are robust.

95 Ofgem state that the starting point for their analysis of **load related** capex is the licensee's best view of capex requirements. We acknowledge that the "best view" is merely a forecast of future developments, and is likely to be wrong. We therefore support Ofgem's view that there is uncertainty, and that revenue drivers should be developed to adjust the licensee's revenues within the price control period to better reflect the actual level of expenditure required. These revenue drivers should be set at a level which reflects the efficient level of expenditure for a given change in the generation and demand background. However, as we have said earlier in our response, we believe that revenue drivers will themselves turn out to be inaccurate and that, at least beyond a pre-defined tolerance, there should be scope for their adjustment within a price control period.

96 On **non-load related capex**, the conventional top-down assessment of our electricity capex plans would reveal that the planned replacement volumes are in line with the broad volumes that modelling of asset life and population data would indicate as being required, and represent a continuation of the profile of asset replacement from the current period.

97 However, we accept that Ofgem wish to gain assurance that the asset management processes, underlying the asset replacement elements of forecast capital expenditure, are appropriate. We believe that our asset management practices represent a world leading approach. This has been verified through a number of external audit processes, including the DTI's Resilience study, Ofgem's Asset Risk Management study, and most recently, our successful PAS55 audit by Lloyd Register, culminating in NGET becoming the first utility in the world, and the first company in Europe, to achieve this standard. Further, we are committed to continuous improvement of these practices (not least through extensive involvement with cross-sector asset management organisations) and to the application of such practices across our gas and electricity transmission and distribution businesses.

Chapter 7 – Expenditure analysis: operating expenditure

98 The section is structured in four parts:

(a) **Opex assessment programme** - takes stock of the programme to date and sets out key areas that need to be addressed in the phase prior to initial proposals in June.

(b) **Historical controllable opex** - draws on the information provided in our HBPQ submission and subsequent discussions with Ofgem to set in context the performance versus allowances data that has been presented for NGET and NGG.

(c) **Unit cost trends** - considers Ofgem's analysis of Real Unit Operating Expenditure ("RUOE") and sets out our inferences from the analysis, considers data normalisation issues and the limitations of the analysis in informing the opex assessment programme.

(d) The final section provides our response to Ofgem's thoughts in relation to:

(i) **non-operational capex**; and

(ii) **non-controllable costs**.

Opex assessment programme

99 Following submission of our HBPQ and FBPQ data and narratives in the latter part of 2005, we have worked closely with Ofgem and their consultants through workshops and extensive written answers to formal questions to provide the fullest picture possible of our historical opex performance.

100 The publication of Ofgem's Document is an opportunity to take stock of the opex assessment programme and consider the key areas that need to be fully addressed prior to the publication of initial proposals in June.

101 The opex assessment programme has four main elements:

(a) Business Services Functions – where the review of our HBPQ would appear to have been largely completed;

(b) Gas Operations – where the review of our HBPQ has been completed and Ofgem and its consultants are actively engaged on reviewing our FBPQ;

(c) Electricity Operations – where a limited amount of work has been undertaken on the HBPQ which we understand is likely to be revisited as part of a combined review alongside our FBPQ; and

(d) Information Systems, Property and Insurance – which are subject to separate timetables of review with specialist consultants.

102 Against the above background, a June deadline for initial proposals is challenging. At this stage of the review, we have not yet had feedback on initial findings from Ofgem's consultants, either for fact checking or in order to provide appropriate challenge and review. We believe this to be an essential part of the work that needs to take place over the coming weeks in order for Ofgem to arrive at well-founded conclusions.

103 Our FBPQ submission is the result of a comprehensive and highly detailed bottom up build. As we will touch on in our response to Ofgem's unit cost trend analysis, we do not believe that an accurate assessment of our operating expenditure requirements can be established through currently available top down analysis.

104 Bottom up analysis of our FBPQ submissions for both our Electricity Operations and Business Services activities should be the basis for setting our forward opex allowances and should form a key part of the next stage of work prior to initial proposals.

Historical controllable opex

105 NGET and NGG performance against price control allowances is presented in figure 7.1 of Ofgem's Document without the context and explanation supplied in our HBPQ narrative, workshops undertaken with Ofgem and their consultants and responses to written questions. The following paragraphs summarise this contextual information for both NGET and NGG and set out the key issues.

106 **NGET** performance against price control allowances for the HBPQ period was shaped by the contrasting forces associated with:

(a) major change programmes associated with our asset management and field force operations that have provided a platform for significant efficiency improvement;

(b) significant "costs to achieve" associated with developing and implementing those change programmes in the short term;

(c) savings in our shared support functions arising from the National Grid/Lattice merger;

(d) rising input costs - not least in respect of insurance post "9/11", pensions costs and the prices in key support markets such as those for tower painting, vegetation management and civil works;

(e) increased levels of direct Transmission related activity coupled with the emergence of new "quasi-capex" operating costs such as for circuit breaker refurbishment that share similar drivers to those of our increasing capital investment programme.

107 **NGG** underwent similar levels of change over the same period and also benefited from cost reductions associated with the National Grid/Lattice merger.

108 The apparent out-performance versus allowances presented in figure 7.1 of Ofgem's Document, however, is primarily associated with the inaccuracy of the estimation of cost drivers between Distribution and Transmission activities at the time of the last price control review.

109 Distribution and Transmission costs had not previously been separated and estimated drivers for implementing the split have not been borne out by reality and, as a result, Transmission can now be seen to have been allowed too great an allowance to the expense of the Distribution business as the total Transco allowance is as Ofgem intended.

Unit cost trends

110 We acknowledge that comparative benchmarking of the type undertaken by Ofgem in their analysis of Real Unit Operating Expenditure ("RUOE") presented in figure 7.2 of their Document has a role in regulation. However, we believe that great care needs to be taken in interpreting any such analysis and that it is of limited value in deducing an appropriate forward opex allowance.

111 Our conclusion (from analysis that we believe replicates Ofgem's data) is that there is **no significant difference between NGET's unit cost performance and that of the DNOs** since privatisation.

112 We have reached this conclusion following consideration of three specific issues :

(a) The inherent limitations of the analysis. Most notably in respect of :

(i) "normalisation" of NGET and DNO datasets to enable reasonable comparison;

(ii) the swing in costs between Distribution and Supply that took place with separation;

(iii) marked differences in capitalisation practices across the industry; and

(iv) the selection of 1991 as a base year for the analysis.

(b) NGET is not a DNO and has a cost base that reflects the critical differences between Transmission and Distribution.

(c) The operating cost performance of NGET in latter years needs to be set in the context of material known issues such as the implementation of NETA.

113 Each of these above issues is considered in turn.

Inherent limitations of the analysis

(i) Normalisation of data

114 The analysis of Real Unit Operating Expenditure ("RUOE") trends seeks to compare the cost performance of NGET with DNOs, SHETL and SPT over the period 1990 – 2005.

115 National Grid has not been provided access to the source data used for this analysis but we believe that it has been based on published Regulatory Accounts data and GWh of electricity transported supplied by NGET.

116 Our response is therefore based on our own analysis of published Regulatory Accounts data in order to replicate the results achieved by Ofgem and we have concluded that the series of costs used is a combination of:

(a) **controllable costs** - the focus of the opex assessment programme; and

(b) **network rates** – which are currently treated as a pass-through item in our price control formula and which would not generally be regarded as an area for comparative efficiency assessment.

117 The inclusion of network rates leads to significant distortion of the comparative results owing to:

(a) the fact that the ratio of network rates to Controllable Costs is significantly higher in NGET than in DNOs; and

(b) the fact that network rates have followed a broadly flat profile in real terms since privatisation.

118 The inclusion of network rates therefore loads the analysis for NGET with a significantly higher proportion of what is effectively a fixed (and uncontrollable) cost than is the case for DNOs.

119 We believe that the data should be corrected for network rates if Ofgem believe this form of analysis is to be used in further developing its thoughts on NGET's future operating costs.

(ii) Separation of distribution and supply activities

120 The analysis for DNOs displays marked cost reduction between 2000 and 2001, coinciding with the legal separation of the former Public Electricity Supplier ("PES") distribution and supply activities.

121 In presenting the RUOE analysis for DNOs, Ofgem advance two potential lines in figure 7.2 of their Document from 2001 onwards:

(a) the "DNO Unadjusted" series which appears to be based on data collected from published Regulatory Accounts; and

(b) the "DNO Adjusted" series which Ofgem state takes some account of the change in cost allocation that took place between Distribution and Supply at the point of their separation.

122 We believe that the "DNO Adjusted" series has been arrived at by making an adjustment to the years 2001 to 2005 based on the levels of cost reallocation out of Distribution to Supply set out by Ofgem in their DPCR3 final proposals (some £260m or 18% of controllable operating costs).

123 Given that this reallocation did in fact take place, and can clearly be shown in Ofgem's own documents for DPCR3 to have been very significant, we find Ofgem's assertion that true DNO cost performance could be closer to the "DNO Unadjusted" series to be incomprehensible.

124 The "DNO Adjusted" series, however, remains striking for the following reasons:

(a) Unit costs in the period 1998 to 2000 prior to the separation of Distribution and Supply were broadly flat in real terms.

(b) Unit costs in the period 2002 to 2005 mirror their behaviour in the period 1998 to 2000 and remain broadly flat in real terms.

(c) Unit costs in the intervening period between 2000 and 2002 exhibit an unusual reduction.

125 We believe that the unusual reduction in the "DNO Adjusted" series between 2000 and 2002 could still, in part, be associated with the impact of Distribution and Supply separation. Therefore, if Ofgem believe this form of analysis is to be used in further developing its thoughts for NGET's future operating costs, we believe that the "DNO Adjusted" data should be reviewed in much more detail to determine if it truly represents real cost reduction.

(iii) Marked differences in industry capitalisation practice

126 We are aware that capitalisation practices across the electricity industry have progressively diverged over the period under review and believe that the differences are now so marked that a reasonable comparison can no longer be undertaken without significant analysis and adjustment to source data. This issue was clearly acknowledged by Ofgem in the DPCR4 process and is clearly of material value.

127 The differences are most apparent in two key areas:

(a) **Fault Costs** – where DNOs have a greater proportion of assets subject to "fix on fail", a regime that lends itself to capitalisation of a betterment element associated with maintenance and repair. NGET's processes are, by comparison, dominated by inspection, asset management and preventative maintenance costs that are, due to their nature, straight opex under the terms of FRS15; and

(b) **Support Costs** – where DNOs, in part owing to the takeover activity in the sector, often have legal structures where a parent company acts

as a service provider to the DNO, facilitating greater levels of overhead capitalisation. NGET support service costs are, in the main, expensed.

128 NGET adopts a policy of strict compliance with the terms of FRS15 and we think that, if Ofgem plan to use this form of analysis in further developing its thoughts for NGET's future operating costs, the comparative data will need to be adjusted to take account of differing accounting practices.

(iv) Base year for analysis

129 The Ofgem analysis of RUOE indexes NGET and DNOs to a common starting point in 1991 as a basis for comparison stretching forward some fourteen years. The issues driving costs at the starting point are therefore as influential in the analysis as the issues driving costs at its end point.

130 NGET, unlike the former RECs which were already stand-alone entities at privatisation, was created as part of the break-up of the former Central Electricity Generating Board ("CEGB"). As a result, the early years of NGC (as it then was) were characterised by the establishment of functions which effectively had not existed (at least in anything other than a very interim sense) before privatisation. The cost of establishing these functions was that much higher because NGC had to carry out activities - in particular, the commercial interaction with generation and the facilitation of new entry into generation (in a period characterised by the first "dash for gas") – which had simply not been a part of the activities of the CEGB.

131 We believe that Ofgem need to recognise that the 1991 data for NGET did not reflect the cost base for a fully fledged stand-alone entity. We believe that if Ofgem wish to use this form of analysis to further develop its thoughts for NGET's future operating costs, the data should be adjusted to account for this issue.

NGET is not a DNO

132 We do not agree that NGET and DNOs have faced similar cost and operational pressures since privatisation. NGET has certain specific characteristics that further prevent true like for like comparison such as the following:

(a) The RUOE analysis presented by Ofgem is based on our TO and SO activities. Our SO role (now GBSO) role forms over 30% of the NGET cost base and features activities and costs that not directly comparable to DNOs such as:

(i) system and energy balancing activities that are unique to the SO (GBSO);

(ii) active flow, voltage and frequency management where DNO systems are generally acknowledged to be more passive in nature and distribute electricity radially from Grid Supply Points to sources of demand; and

(iii) balancing services management activities where successive regulatory regimes since 1997 (culminating in the BSIS scheme) have facilitated investment in increased operating expenditure to leverage significantly greater savings for customers in balancing services costs.

(b) The asset management activities of our TO business are different to a DNOs as they have a far greater proportion of assets subject to "fix on fail". NGET's processes are, by comparison, dominated by inspection, asset management and preventative maintenance costs

(c) NGET face operating cost pressures associated with generation churn in addition to demand growth / demographic drivers faced by DNOs.

133 In addition it is important to remember that there is **(as Ofgem have always intended that there should be**) a trade off of SO internal and external costs for the benefit of customers, recognising that this could entail **increased** SO internal costs. Ofgem's RUOE analysis takes no account of this.

134 We believe that if Ofgem wish to use this form of analysis to further develop its thoughts for NGET's future operating costs that Ofgem need to identify the impact of these differences material differences between NGET and DNOs.

Recent specific considerations of NGET performance

135 The role of NGET in the industry has continually evolved since privatisation. The most marked change in our role, however, took place with the implementation of New Electricity Trading Arrangements ("NETA") in 2001 and the formation of separately regulated TO and SO activities.

136 NETA involved significant incremental expenditure in Transmission in respect of:

(a) pre go-live development of new processes and information systems;

(b) post go-live re-development of interim measures to provide more robust enduring solutions;

(c) new post-go live enduring costs associated with both the operation of our new trading function and revised control room roles and responsibilities;

(d) significant "participant support costs" incurred by agreement with Ofgem in order to assist other market participants in their developments necessary to achieve the go-live date; and

(e) the absorption of the activities and costs of the former Ancillary Services Business in Transmission.

137 In addition we have already discussed the contrasting forces that shaped the performance of NGET versus allowances over the HBPQ period and touched on the impact of the short term "costs to achieve" associated with developing and implementing major change programmes

138 These incremental costs impact the performance of NGET from 2001 onwards.

139 We believe that it is inappropriate to draw detailed inferences from the RUOE analysis without proper adjustment for recent considerations of NGET's cost performance in order to reflect the true underlying levels of operating cost.

Conclusions

140 We would draw three main conclusions from the above:

(a) Informed interpretation of Ofgem's basic analysis of Real Unit Operating Expenditure demonstrates that NGET's unit cost performance has broadly tracked that of DNOs since privatisation.

(b) We completely reject Ofgem's assertion that the analysis may point to a comparative under-performance by NGET versus DNOs as we do not believe that the analysis is sufficiently robust or considered to draw such inferences.

(c) As stated earlier in this section, our FBPQ submission is built on detailed activity analysis and costing and believe that, especially in the light of the inadequacies of the top down analysis, bottom up analysis is the correct basis for setting our forward opex allowances.

Non-operational capex

141 In managing our business, we do not make a distinction between "operational" and "non-operational" capital expenditure. We do, however, believe that it would be appropriate for a distinction to be made in respect of regulatory treatment of capital investment in respect of **asset lives**. This would be consistent with both the economic value of the relevant assets and our normal accounting practice. In this respect, items considered by Ofgem to be "non-operational capex", such as commercial vehicles or potentially some information systems investment, are depreciated over shorter periods than "operational capex".

142 Therefore, we believe that the most appropriate method for future remuneration of non-operational capex would be to follow the precedent set by Ofgem at the last price control review for the Electricity System Operator and establish a separate "short-life" RAV (of seven years) to capture and remunerate defined categories of "non-operational" capex. This would have benefits of:

(a) aligning remuneration with useful economic life;

(b) aligning remuneration with accounting depreciation; and

(c) facilitating the allocation of costs to the correct generation of customers over time.

143 This treatment would only be appropriate if the definition of non-operational capex is addressing material lines of expenditure. It should also be noted that

the definition should be pragmatic in order to avoid unnecessary incremental costs associated with data capture, analysis and reporting.

Non-controllable costs

Rates

144 We note Ofgem's comments with regard to network rates and acknowledge that regulated companies have a degree of influence over the valuations applied to their networks as part of period rating reviews.

145 The degree of influence that we are able to exercise over network rates costs, however, is not comparable with that with which we are able to exercise over our controllable cost base. Network rates primarily differ from controllable costs because they cannot be avoided, mitigated, substituted or managed over time through innovation or management expertise.

146 The limited influence that we have over valuation is also periodic in nature - at the point of either a rating review or an appeal in respect of a rating review. This further distinguishes network rates from our controllable cost base which is subject to rigorous ongoing downward pressure by management. Inclusion of network rates as a controllable cost would also distort the ongoing annual application of regulatory incentives.

147 We believe that consideration of network rates as a controllable cost is inappropriate and that the existing pass-through arrangement as a non-controllable cost should continue.

148 We acknowledge, however, that network rates influence end prices to electricity and gas consumers and wish to discuss with Ofgem a mechanism for Licensees to recover one-off incremental costs that would necessarily be incurred to appeal network valuations. Without such a mechanism Licensees would be penalised for pursuing the interests of customers.

Chapter 8 – Financial issues

Cost of capital

149 The cost of capital cannot be considered in isolation, but needs to take into account the business environment, the financial environment and other elements of the overall price control outcome.

150 The forthcoming **business environment** is dominated by the need to incentivise substantial capex programmes in both the gas and electricity Transmission businesses. As a result, it is important that the cost of capital allowance provides sufficient incentive to encourage the investment that the networks require.

151 The current **financial market environment** is characterised by interest rates that are exceptionally low by historical standards. It is important that the cost of capital allowance reflects, inter alia: the risk of future interest rate movements being heavily weighted towards an increase; and the fact that we have not been able to issue debt historically at the current very low interest rates.

152 In addition, it is important that the eventual cost of capital assumption reflects the overall impact on risk of wider aspects of the price control outcome. In particular, the allowed return should be consistent with the risks associated with the very long timescales involved in transmission investment, the impact of regulatory incentive regimes (including new incentives resulting from the current review) and the debt capacity of the business, given decisions taken regarding financeability.

153 Consistent with Ofgem's overall timetable for addressing the cost of capital issue, our main submission on this issue will be tabled in early May. However, our positions on the specific issues which are raised in Ofgem's consultation are set out in our detailed response.

Pensions

154 The pensions issues touched upon in the Third Consultation Paper are broadly as follows:

(a) the level at which to benchmark employment costs i.e. whether benchmarking total employment costs is the best means of incentivising licensees to control pension costs;

(b) the legacy / Centrica liabilities issue;

(c) the past use of surplus in severance / early retirement programmes; and

(d) over and under funding, as compared to price control allowances.

155 Ofgem's views and our response are set out below.

The level at which to benchmark employment costs

156 The Consultation Paper asks a specific question in respect of the level at which to benchmark/incentivise pension costs. We believe, as Ofgem have previously stated, that the best approach is to consider the efficiency of remuneration costs as a package, and consequently that companies should be incentivised to control their costs at the level of total employment costs.

157 Employers will typically aim to attract and retain staff with a remuneration package consisting of a salary, pension arrangements, bonus payments, other incentives and benefits in kind. However, the relative importance of the different elements of the package will vary within any given employer, depending on the type of staff and their level of seniority, and between employers depending on the nature of their business and the remuneration policy of each company.

158 Consequently, when assessing whether or not the level of a company's employment costs is efficient, it would seem advisable to consider employment costs in the round, rather than considering any element of the remuneration package in isolation, including pension costs. If this approach is not followed, and for example an efficient package is calculated from the lower of market median and actual cost for each individual type of remuneration cost, then the deemed efficient package will be artificially low, and not represent what is efficiently achievable.

The legacy / Centrica liabilities issue

159 Ofgem's stance is set out in paragraph 8.28 of the Consultation Paper as follows: "Our position is that liabilities relating to the non-regulated businesses should not be recovered through the price controls of the regulated business". Some explanation of this stance is provided by paragraph 8.32 of the paper, although this is appears inconsistent with what is stated in paragraph 8.30.

160 Our comments in the area of Legacy Pensioner issues are in respect of:

(a) a concern that Ofgem have not, as yet, publicly addressed most of the arguments that we have raised; and

(b) the lack of clarity in the explanation of Ofgem's stance, as set out in the Consultation Paper.

Ofgem have not, as yet, publicly addressed our arguments

161 We are concerned that, although the Third Consultation paper lists the reasons why we believe that legacy pension costs should be funded by the price control, the paper only addresses one of those arguments, as described below. Given the importance of the issue, we believe that **all** the arguments need to be publicly considered by Ofgem so that a proper process can be followed, and be seen to be followed.

162 For the avoidance of doubt, a summary of National Grid's key arguments is as set out below:

(a) For a transaction which was actively encouraged by Ofgas, and in the light of information available at the time, British Gas (BG) could not have been expected to act in any way other than to keep all the pensioners and deferred pensioners within the LGPS which was in substantial surplus at the time – a surplus which the MMC and Ofgem have used for the benefit of gas network customers. In addition, any expectation that BG should have put in place a risk sharing mechanism would have been at variance with normal practice at the time and would have been an efficient action only with the benefit of hindsight.

(b) To penalise National Grid now for this decision would be inconsistent with the regulatory treatment adopted at the last two price control reviews and inconsistent with the principle that the efficiency of a company's actions should be judged in the light of the information available at the time those actions were taken.

(c) Transportation consumers have had the benefit of the surplus now argued to relate to Centrica activities for those two price controls.

163 We hope that Ofgem will address these arguments in its next consultation paper.

The lack of clarity in the explanation of Ofgem's stance

164 In addition, we believe that there is a lack of clarity in the explanation of Ofgem's stance on legacy pensioner issues, as set out by the consultation paper. Specifically:

(a) First, the paper moves towards accepting that previous transportation price controls were set using the benefit of the legacy / Centrica surplus, and that Ofgem will need to consider the implications of this in deciding its approach. Paragraph 8.30 explains this as follows: "We acknowledge the argument that the pension contribution rates underlying the allowances made in previous price controls implicitly took account of the levels of scheme surplus that were apparent at that time, and that any surplus may in part have arisen from contributions previously made in respect of Centrica members. On this basis it is possible that earlier price controls may have reflected an inappropriate allocation of costs. It will be important to consider the implications for this review of any inappropriate allocations which may have been made in the past."

In passing, we disagree with the level of uncertainty implied by the language in the second part of paragraph 8.30. It is not only "possible" that earlier price controls reflected what Ofgem now considers to be an inappropriate allocation of costs - in our view, it is certain that this was the case.

(b) Contrary to the above, the consultation paper rejects the suggestion that transportation customers have benefited from the legacy / Centrica surplus. Instead, it argues that shareholders would have benefited from the legacy / Centrica surplus, and that consequently, consumers should not pay for the presently anticipated deficit.

> Paragraph 8.32 states that "The costs and benefits of the demerger accrued to shareholders in each company in accordance with the disposition made by the Scheme of Arrangement. Accordingly any increase in the value of the attributable share of scheme assets relative to the value of the Centrica liabilities would have accrued (directly or indirectly) to shareholders. Our view, therefore, is that it would be inappropriate for consumers of NGG to bear any of the costs of repairing the deficit that has subsequently emerged as a result of the Centrica liabilities now being greater than the attributable share of scheme assets."

165 The first and second statements above are mutually inconsistent. Either, as in paragraph 8.30, previous transportation price controls have been set using the legacy / Centrica surplus, or, as in paragraph 8.32, shareholders have had the benefit of that part of the surplus.

166 We believe that, on reflection, Ofgem should recognise that the statement in paragraph 8.30 of the paper is correct, i.e. that transportation consumers have, in previous price controls, had the benefit of the legacy surplus. Therefore, for reasons of consistency and symmetry, consumers should also fund the deficit.

The past use of surplus in severance / early retirement programmes

167 The consultation paper states that, in principle, Ofgem views Early Retirement Deficiency Costs (ERDCs) as being a cost for shareholders, but leaves the precise application of this principle open to further consideration. In the case of the DNO price control review, Ofgem clawed back 30% of past use of surplus through the non-payment of ERDCs.

168 Paragraph 8.33 states that "We note that the circumstances of NGG are different to the DNOs in that NGG currently has an explicit pensions allowance and has already made greater contributions than the allowance. It is therefore unlikely that there will be a direct read across from DPCR, in which there was an interaction between the approach to ERDCs and the decision not to apply the over / under funding principle to past periods. The manner in which this principle is to be applied is therefore a matter for further consideration."

169 At a general level, in respect of the claw-back of the historic use of surplus to part fund severance programmes, we believe that:

(a) Such second bites at a given regulatory action are not good regulatory practice.

(b) Customers have benefited substantially from severance programmes which have been beyond those assumed when price controls were set.

170 However, if, despite these arguments, Ofgem are determined to follow this policy through, we suggest that a number of company-specific factors should be taken into account, as follows:

(a) When considering NGET's past use of surplus, Ofgem should bear in mind that:

(i) NGET's price controls have typically been shorter than those of the DNOs, thus increasing customers' share of the opex savings resulting from severance programmes.

(ii) Ofgem have known specifically about NGET's past use of surplus for more than a decade – we have already submitted a weighty file of evidence, including: submissions to Ofgem and their consultants; extracts from accounts; and publicity surrounding the legal case over the use of surplus which ended at the House of Lords. For Ofgem to claw back NGET's use of surplus would involve Ofgem changing their view of information which they have had for many years.

(b) When considering NGG's past use of surplus, we believe that Ofgem should bear in mind that:

(i) As Ofgem acknowledge, typically the company **did** pay ERDCs into the LGPS. The company's past use of surplus through non-payment of ERDCs is far less than its actual payments made.

(ii) Since privatisation, despite its use of surplus, it is likely that NGG has paid more into the LGPS than allowed in price control outcomes. This is largely because of the lump sum payment of £275m paid into the LGPS on 31st March 2002, and the payment of over £700m of severance related pension costs over the period 1994/5 – 1996/7. It would seem highly unlikely that regulatory allowances were sufficient to cover costs of this scale. This position is in contrast to that of the DNOs, where Ofgem believed it likely that they had paid less into their pension schemes since privatisation than was assumed when price controls were set (Distribution Price Control Review, Policy Document, March 2004, paragraph 7.39).

171 In this context, we welcome Ofgem's statement that they are still considering how to apply this principle, and urge Ofgem to take account of the above arguments.

Over and under funding compared to price control allowances

172 We are also concerned over the relatively minor reference in the Consultation Paper to the overpayment by NGG in the present price control period, and the lack of any reference to NGG being able to recover that overpayment in future. We estimate that the recoverable amount for NGG should be in the order of £345m for this price control period, including lost return, of which we believe that £245m should be recoverable via Transmission, and £100m via Distribution.

173 Our views on this issue are summarised below:

(a) The "under and overs" regime **should** apply to this price control period for NGG, as Ofgem have stated previously, for example in their Position Paper dated 9th August 2004 (not least because, unlike with other companies, there is a clear audit trail for this period as to what Ofgem assumed in respect of pension contributions).

(b) To work in the manner intended, the regime needs to include **pension related severance costs** because:

(i) At the level of principle, they represent cash which companies put into pension schemes exactly as with ongoing contributions.

(ii) To do otherwise would probably entail NGG being treated more harshly for making ERDCs than for not having made them. Following the precedent of Ofgem's treatment of the DNOs, NGG would only lose a proportion of any non-payment of ERDCs. In contrast, if no credit is given for the ERDCs paid in this period, NGG will lose the whole amount.

(iii) If, as Ofgem stated in DNO Final Proposals, the unders and overs regime will work by comparing the £m allowance for pension costs with actual costs, then, on a purely mathematical basis, the calculations do not work logically if they are excluded, and indeed would be expected to disincentivise companies from carrying out severance programmes (see the Pensions Appendix in Section V below).

(c) The regime should cover the relevant proportion of **related party** costs, as stated previously by Ofgem

(d) The regime should not go back beyond the present price control period, as previously stated by Ofgem, not least because of the lack of a clear audit trail for the earlier period.

(e) If, however, calculations were performed prior to the present price control period, we believe that they would show that NGG in particular has paid **more** into its pension schemes than assumed when price controls were set.

174 The above text contains arguments which have been summarised from our response to the Second Consultation Paper. More detailed versions of these arguments are contained within our response to that document.

Ex-post tax adjustments

175 The tax charge faced by the licensee will be impacted by:

(a) the tax treatment of transactions as determined by tax law, accounting treatment etc; and

(b) the level and nature of expenditures.

176 It follows that the tax allowance set should be consistent with the allowances set for expenditure and the prevailing tax treatment relevant to the licensee.

177 It would be appropriate to make ex post adjustments to the tax allowance if:

(a) the tax treatment was to change materially from that used to set the allowance;

(b) underlying expenditure changes materially in respect of cost pass-through items; and

(c) to deal with changing levels of expenditure that are remunerated by revenue drivers. At this point in time, it is not clear what Ofgem is proposing to do in respect of assumed tax allowance for capital expenditure which will be covered by revenue drivers.

178 If underlying expenditure differs from allowances simply due to over or under-performance against allowances, then no ex post adjustments should be made to the tax allowance.

III Response to Ofgem’s questions embedded in chapters

Chapter 1: Introduction

There are no questions specific to this chapter.

Chapter 2: Form and structure of the price control

Question 2.1	Do you think the standard RPI-X framework needs to be refined or augmented in its application to the transmission licensees?

179 As detailed in our response to Chapter 2, we support some refinement to the standard RPI-X framework. Further work, however, is required to understand whether the potential options increase or decrease the risks being borne by the transmission licensees. The overall acceptability of the proposals on the form of control will therefore only become known once the overall elements of the price control are brought together and the licensees can consider the overall risk and return associated with the price control.

180 In addition, and in the light of the potential extent and complexity of the changes in the form of transmission price controls, it will be particularly important to see licence drafting for these changes as early as possible. In the absence of such drafting, there is a risk that Ofgem and the licensees will be talking at cross purposes about the extent of agreement or disagreement about the proposed changes.

Question 2.2	Do you think that rolling incentive mechanisms are the most appropriate way to deliver a consistent strength of incentives over time, and do you think they are applicable to transmission licensees?

181 The potential use of rolling incentives is another significant change from the current status quo in both gas and electricity. In both gas and electricity, the current regime involves a "true-up" of efficiently incurred actual costs at the time of the next price control (this is effectively achieved in the gas entry regime via the "TO adjustment" mechanism). In addition, Ofgem have stated in open letters[4] that, under the current regimes, they will also consider incorporating efficient overspends into the RAV from the year in which they were incurred and allowing the licensee to recover the associated depreciation and/or return if the expenditure provides significant benefits to customers.

182 Against this background, and in the context of the above discussion of revenue drivers, a rolling five year mechanism could be expected to have at least two effects which would need to be taken into account in any final proposals for this price review:

(a) Such a mechanism would, other things being equal, increase the risks faced by a transmission licensee by increasing the time for which the licensee was exposed to differences between actual costs (including cost of capital) and revenue.

[4] Open letters relating to the Gas Distribution price controls (March 2004 and December 2005)

(b) Applying rolling incentives to capex would increase the incentives on licensees **not** to invest in their respective transmission systems and would therefore further increase the tension (which already exists in the current regulatory framework) between, first, meeting the licence obligation to develop an efficient transmission system and, second, making a rate of return which covers the licensee's cost of capital

Question 2.3	Given the large bids made by some licensees for asset replacement expenditure, how do you think the regulatory regime should look? Do you think that a "information quality incentive mechanism" is the best way to improve our information on efficient costs, by rewarding licensees more if they accept more challenging cost targets?

183 For the DNOs, Ofgem have introduced a mechanism which rewards companies for incurring capital spend in line with what has been deemed to be necessary by Ofgem (and their consultants). In deciding whether to introduce such a mechanism for transmission, and in particular whether such a mechanism has anything to do with improving the quality of information provided by licensees, it is worth noting that the proposed mechanism would seem to be based on a significant internal contradiction. Thus:

(a) Ofgem's main reason for proposing this incentive is that Ofgem believe that they will always be faced with an information asymmetry in relation to licensees – i.e. licensees will always know more than Ofgem about what spend is required on their respective transmission systems. But, at the same time

(b) the proposed mechanism financially incentivises a licensee to spend what Ofgem thinks the licensee should spend, even though the starting point for the incentive is that the licensee knows better than Ofgem what the licensee should be spending.

184 On the basis of the above, the proposed incentive would seem to have little to do with improving incentives for either spending the right amount of money on the transmission system in question or for giving accurate information to Ofgem. However, this does not mean the proposed mechanism, or at least some variation on it, would not be potentially useful. What the mechanism does is to allow Ofgem to commit to a **range** of required spend, rather than a fixed number. In the DPCR4 version of the mechanism, the company would earn a lower incremental rate of return if it spends at the top of that range, implicitly because Ofgem think that the 'right' number is at the bottom end of the range. However, there is no reason in principle why the rate of return should not be invariant over the range, implicitly on the basis that Ofgem is genuinely uncertain what the right number is within the range. Such a variant of the mechanism would, in our view, be useful, albeit that it should be called something other than an information quality incentive mechanism.

Question 2.4	Are additional measures needed to promote innovation? What is the scope for innovation by transmission licensees to benefit consumers?

185 With its pivotal role in the industry, National Grid makes a substantial contribution to energy research across the whole sector. As the facilitator of both the gas and electricity marketplaces, we have taken a lead role in both sustainability and strategic planning within the energy sector, for example, identifying impacts of emerging technologies, changing generation sources and environmental/climate change ultimately benefiting end consumers.

186 Through the current price control period, we have maintained an active R&D programme and adopted a proactive approach to supporting Government agencies and helping steer their research agenda. We are well placed to continue to influence and benefit from a targeted energy research programme

187 A broader range of influences and uncertainties potentially impact our business than in the current price control period. Relevant R&D topics may include:

(a) hydrogen economy;

(b) new generation forms and their characteristics;

(c) global energy markets;

(d) emissions trading; and

(e) energy efficiency.

188 National Grid's R&D current programme is driven by developing sustainable solutions to managing risk and solving problems. The R&D outputs form an integral part of National Grid's core asset management activities, allowing National Grid to find cost effective solutions to problems such as:

(a) understanding the impact of changing generation sources;

(b) avoiding in-service failures of equipment;

(c) understanding the risks associated with new technology;

(d) establishing the condition of equipment to feed into the capital plans; and

(e) finding ways to manage the impact of our operations on the environment.

189 In particular, the challenges posed by the ageing transmission networks need to be understood and addressed to ensure maximum life is achieved for

existing assets and spending on replacement is optimised. R&D in this area has clear potential benefit for the end consumer.

190 Productive initial discussions have already taken place with Ofgem in relation to the potential application of a similar Innovation Funding Initiative (IFI) to that introduced in DPCR4 and we support further discussions to develop the concept for Transmission because:

(a) R&D delivers benefits in the longer term and IFI effectively segregates R&D expenditure from the often shorter term cost reduction pressures, associated with our controllable cost base, under which R&D currently has to compete for funding.

(b) Harmonised incentives to undertake appropriate levels of R&D across the industry make sense and will facilitate further exploration of jointly funded initiates where appropriate.

Question 2.5	Should the current form and scope of System Operator (SO) incentive schemes be adopted in the next price control period?

191 We note Ofgem's request for views relating to SO Incentives and offer the following comments with regard to the existing form of SO Incentives, including the structure and duration of incentives. Further to this, we would welcome clarity and confirmation from Ofgem as to the proposed timescales for future consultations and target dates for initial and final proposals on SO schemes from 1 April 2007.

Managing wider market uncertainty

192 With regard to Electricity SO incentives on NGET, we would agree that the current uncertainty within the wholesale gas and electricity markets has made it more difficult to predict the level of day-to-day balancing costs and that this leads to greater uncertainty and difficulty in setting targets. However, we remain fully supportive of incentives and support the continued development of incentives to target those areas of costs within the control of the SO. In line with Ofgem's comments, more uncertain elements outside the SO's control could be removed from the scheme through the use of correction mechanisms to alter the incentive.

193 For the 2006/07 Electricity Incentive scheme, we proposed indexing the incentive target to the electricity wholesale market price to remove the significant cost uncertainty driven by variations in the market that are outside NGET's control. Moreover, the application of mechanisms to remove uncertainty and variations in cost drivers outside the SO's control should facilitate the establishment of longer duration schemes (See below). We would support further work and discussion with Ofgem and the industry on the understanding of cost uncertainties and the development and application of such mechanisms in future schemes.

Duration of schemes

194 We welcome Ofgem's consideration of longer duration incentive schemes. Incentives on NGET to balance the Electricity system have been of one year duration whereas the current incentive on NGG is of 5 years duration. We agree with Ofgem that the establishment of longer duration schemes should, where appropriate, lead to an improved incentive to reduce costs and that the longer duration of the incentive may reflect longer timescales required to realise the benefits of certain investments in, for example, the training and recruitment of specialist staff, and/or IT infrastructure.

195 Within the establishment of a longer duration scheme, a key element would be the development of appropriate mechanisms to adjust the target to reduce uncertainty and volatility caused by cost drivers outside of the SO's control (see above discussion on managing uncertainty). Examples of drivers outside of the control of the SO include would include, for example:

(a) wholesale market prices (an increase or decrease in wholesale prices has a knock-on effect on balancing costs); and

(b) modifications to industry codes (changes to codes may alter the prices paid for a service or may change behaviour in the market resulting in a change in costs for the SO).

196 Changes in these drivers could lead to significant variation in costs that, if uncorrected, could lead to windfall profits or losses under the incentive scheme. We have previously proposed price indexation as a way of removing uncertainty from NGET's incentive and we would support further work, within the TPCR process, to examine possible mechanisms to manage such uncertainty and thereby facilitate the delivery of longer term schemes.

Question 2.6	To what extent should incentives applying to Transmission Owner (TO) costs and SO internal costs be equalised? Should these costs (e.g. staff costs and IT spend) form part of the TO price control?

197 The creation of a set of definitions, allowances and incentives for System Operator forms of control at the start of the current price control provided a clear differentiation between the roles and obligations of a Transmission Owner and a System Operator within an integrated transmission company.

198 The System Operator forms of control recognise that a transmission company is subject to a specific set of obligations and costs associated with the needs and wishes of the energy markets. These relate to, inter alia:

(a) the residual balancing activities;

(b) management of the external costs of system operation (including transmission capacity services) in line with obligations and incentives; and

(c) facilitation of industry development.

199 Obligations and costs associated with these activities are different in nature to those borne in the Transmission Owner role and represent a distinct subset of a transmission company's responsibilities within a wider set of shared interests and objectives.

200 The distinction between the roles has been accentuated by the creation of the GBSO for the successful implementation of BETTA in April 2005. From this point onwards, the GBSO became responsible for the Balancing Services Activity across England, Wales and Scotland, with the two Scottish Transmission Owners fulfilling the TO roles in Scotland.

201 The GBSO role represented a material expansion of the duties and obligations of the Electricity System Operator and, as such, necessitated a review of licence definitions and of system operator revenue. A similar review should be considered in the event of future material changes to gas and electricity system operator obligations. Areas which are currently under consideration and could constitute a material expansion include:

(a) residual balancing responsibilities;

(b) obligations under energy emergency conditions; and

(c) expansion of the GBSO role to include offshore networks.

202 These potential developments co-exist with a continuing need to develop industry frameworks, whilst meeting the challenges of operating with changing patterns in gas supply and in electricity generation.

203 The System Operator and Transmission Owner boundary is set by the definitions given in the respective licences. These definitions and our obligations for the appropriate allocation of revenues and costs mean that costs cannot be moved freely from one form of control to another.

204 Against the above background, we offer below two sets of reasons why Ofgem might think carefully before either equalising sharing factors for TO and SO internals costs and/or incorporating internal SO costs into the TO control.

Transparency of costs to industry

205 The distinction between System Operator and Transmission Owner forms of control gives clear messages as to where transmission related costs are being incurred. This allows the industry to make better informed decisions on transmission related issues.

206 In Electricity for example, the 'user pays' principle is promoted with Balancing Mechanism participants paying BSUoS charges to meet the full cost of the Balancing Services Activity. The loss of the System Operator form of control for internal costs would provide incomplete messages on the costs of system operation.

207 Clarity is important when considering the costs of the effective development of the commercial frameworks in both gas and electricity. These developments

are intended to deliver (and successfully achieve) significant financial benefits to consumers and improvements to the long term security of energy supplies.

208 Changes to the commercial frameworks generally trigger an increase in workload within one or other of the System Operators. This relates to the development and maintenance of new processes associated with new products, checking compliance with new standards or with the provision of additional information. In a limited number of cases there is an impact on the Transmission Owner although this is less frequent and represents a small proportion of the overall activity base.

209 The System Operator form of control is a useful mechanism for dealing with these costs, which are outside of the direct control of the transmission company, allowing them to be treated differently to the bulk of the controllable costs base.

210 Small to medium scaled developments during the current price controls have been handled within fixed revenue allowances by means of a sharing factor between the transmission company and the industry. Our forward looking business plans do not contain additional provision for developments which have not yet been scoped. Therefore a form of revenue driver related to the costs of specific initiatives needs to be considered to ensure that costs are met and desirable change sustained.

211 In the future, we believe that the costs associated with industry development should be more explicitly managed by the parties benefiting and promoting the change. This would promote a considered and complete approach to the economic case for industry development and better planning and prioritisation of ongoing improvements. The resulting costs would fit best within a System Operator form of control.

Alignment of incentives and obligations

212 The System Operator internal incentives during the current price controls have made use of a sharing factor to derive incentive payments. The sharing factors have been aligned with those applied to external (shallow) System Operator incentives – and this was a direct result of Ofgem wanting us to be incentivised to trade off internal and external SO costs (in the context of a view that scope for reducing the latter was greater than the scope for reducing the former). Incorporation of what are now SO internal costs within the TO control (or simply equalising the respective sharing factors) would shift the balance of our incentives from (a) reducing SO external costs to (b) reducing TO internal costs – in effect, placing more reliance than now on more general licence obligations (plus the SO external shallow incentives themselves) to achieve the optimal reduction in SO external costs.

Summary

213 The system operator internal incentives have provided a valuable distinction between the (full range of) costs of system operation and those associated with managing the transmission infrastructure asset base. BETTA has made this distinction stronger.

214 The TO/SO split is a function of the activities and obligations relating to the respective forms of control. The appropriateness of current definitions needs to be considered fully in the light of ongoing obligations and these need to be as clear and unambiguous as possible.

215 Any change in the System Operator internal cost incentives (especially in relation to sharing factors) needs to be assessed against the weakening of incentives to optimally trade off SO internal costs against SO external costs.

Chapter 3: Electricity incentives

Question 3.1	Do you agree with our conclusion that the use of locational revenue drivers is the most appropriate way to set allowances for the electricity transmission licensees in the context of significant uncertainty over the future demand (and location of that demand) for network capacity?

216 We are supportive of Ofgem's current preferred option for the design of electricity revenue drivers, namely to develop locational revenue drivers. We agree that this option should enable allowed revenues to adjust in a more sophisticated manner than the existing revenue driver for NGET. Having said this, we would also accept that, although such a mechanism should be a more cost-reflective approach, it is unlikely that the mechanism will capture all factors influencing costs.

217 We would therefore support an approach whereby the two technical options contained in the consultation document (accommodating generation in various zones of the system[5]; or increasing the capacity for flows across key system boundaries) should be further developed and assessed against past events and a range of future scenarios. This analysis is clearly important to understand the robustness of the revenue drivers, for both recovering the level of costs likely to be incurred by the licensee for load related investments and as a basis for setting incentives. The robustness of the revenue drivers will be an important factor in understanding the risks that are likely to be borne by the transmission licensees in the next price control period.

218 The analysis should also consider revenue drivers in relation to **demand** as well as generation. The failure to consider the potential impact that changes in demand have on transmission investment has been one of the key issues in NGET's over-spend against price control assumptions in the current price control period.

219 In addition to considering the robustness of the revenue drivers it will be necessary to further consider other revenue elements such as the trigger point for the revenue driver and the stranding risks being taken by NGET under any revised final sums policy. These two elements are considered further below.

Question 3.2	What factors should we bear in mind in drawing the boundary between fixed baseline revenue allowances and variable revenue allowances to be set through the revenue drivers?

220 We are supportive of the proposal contained in the summary of the consultation document that the base price control allowance should provide for known investment requirements, (e.g. where a user commitment has been provided) and revenue drivers should adjust funding in response to less

[5] We believe this should be expanded to include national demand revenue drivers

certain developments during the price control period. We believe such an approach should be consistent across gas (entry and exit) and electricity.

221 In determining the amount of revenue subject to allowances set through the revenue drivers, Ofgem should consider previous experiences which would indicate that there remains an inherent risk with revenue driver mechanisms which are set ex-ante based on a set of assumptions for a 5 year period. In addition, the risk to a transmission licensee associated with revenue drivers will be greater:

(a) the larger the amount of revenue exposed to the revenue driver, as currently being proposed from 1 April 2007; and

(b) the longer is the exposure to the revenue driver, e.g. as a result of using rolling incentives which would increase exposure to, say, five years, as against an average of 2.5 years if the exposure lasts only to the end of the price control period in question.

Question 3.3	Should we seek to true-up the allowances generated by revenue drivers at the end of a 5-year control period? What factors should we take into account?

222 In both gas and electricity, the current regime involves a "true-up" of efficiently incurred actual costs at the time of the next price control (this is effectively achieved in the gas entry regime via the "TO adjustment" mechanism). In addition, Ofgem have stated in open letters[6] that, under the current regimes, they will also consider incorporating efficient overspends into the RAV from the year in which they were incurred and allowing the licensee to recover the associated depreciation and/or return if the expenditure provides significant benefits to customers.

223 Against this background, and in the context of the overall discussion on revenue drivers, a rolling five year mechanism could be expected to have at least two effects which would need to be taken into account in any final proposals for this price review:

(a) Such a mechanism would, other things being equal, increase the risks faced by a transmission licensee by increasing the time for which the licensee was exposed to differences between actual costs (including cost of capital) and revenue.

(b) Applying rolling incentives to capex would increase the incentives on licensees **not** to invest in their respective transmission systems and would therefore further increase the tension (which already exists in the current regulatory framework) between, first, meeting the licence obligation to develop an efficient transmission system and, second, making a rate of return which covers the licensee's cost of capital

[6] Open letters relating to the Gas Distribution price controls (March 2004 and December 2005)

Question 3.4	When should we supplement the revenue drivers with other mechanisms to top-up revenue allowances in exceptional circumstances where major investment is needed? How might these other mechanisms work?

224 Given the risks that revenue drivers will turn out to be incorrect and/or incomplete (as outlined in our response to Chapter 2), we think that consideration should be given to accompanying the use of revenue drivers with a formal licence condition that would trigger a focused interim determination in the event that revenue drivers turned out to be 'wrong' **by some pre-set minimum amount**. Such a condition could be modelled on provisions in the water regulatory regime and could, for example, kick in if the expected difference between (a) a licensee's actual costs and (b) the revenue produced by the relevant revenue drivers over the relevant period was at least equal to 10% of the licensee's relevant annual turnover.

Question 3.5	Do you agree that, in the current market context, it is important to explore options to change transmission access arrangements? Do you agree with the process we have set out to progress this work?

225 It is important to note that the existing electricity access arrangements which are built on the principle of user commitment prior to access release and a first-come first-served approach to access dates, have worked very well since privatisation. They have facilitated the timely and efficient connection of a vast number of new power stations and new demand loads over the years and served to provide significant benefits to end consumers.

226 However, we agree that the access regime has come under pressure from the vast amount of new connection and access applications that arose as part of the transition to the BETTA arrangements and from the significant new interest in renewable forms of generation. We believe that such an influx of interest would have created significant pressure on any access regime. Not withstanding this point, we believe that there is strong merit in considering enhancements which could address some of the concerns that have been identified.

227 We agree with the process that Ofgem have set out to progress this work but believe we will need to be mindful of developing revenue drivers such that they are capable of being implemented in the event that changes to the access regime cannot be implemented by 1 April 2007.

Chapter 4: Gas entry incentives

Question 4.1	Do you agree with our plans to change the nature of NGG NTS's licence obligations to release entry capacity? What particular measures are needed to ensure that the regime is transparent, and ensure against capacity being held back unnecessarily?

228 We broadly support Ofgem's plans to remove the prescriptive obligations from NGG's NTS GT licence and to replace these obligations with the requirement to prepare and consult on a methodology statement which would determine the amount of capacity to be made available for sale to shippers at the relevant time. We believe that it has been demonstrated at several entry points throughout the current PCR period that it is not appropriate to have strict obligations and rules which require an inflexible amount of capacity to be made available for sale to shippers over the whole formula period. We also firmly believe that it is important that the methodology should be based on the principle that any obligation to release capacity should take into account the physical capability of the network.

229 In addition, we believe that it would be appropriate to replace the licence condition which specifies the need for the Incremental Entry Capacity Release (IECR) Methodology statement (Special Condition C15) with a new licence condition which would spell out the need for a methodology which covers the release of all capacity (whether baseline or incremental). However, we also believe that it is not appropriate or necessary to replicate the audit conditions which currently exist within Special Condition C15 as we believe that these do not serve any useful purpose.

Question 4.2	Do you agree with our plans to refine how the revenue drivers work in cases where NGG NTS provides extra entry capacity, where it is requested by network users?

230 We are broadly supportive of Ofgem's policy for revenue drivers in that NGG NTS would receive extra revenue for providing additional capacity above a fixed trigger level at a particular entry point. We believe that it is very important that the baselines (or trigger levels) are set in an appropriate manner in order to ensure that incremental revenue is triggered when additional capacity above that level is provided. We have given Ofgem data which provides estimates of the physical capability of the network under different supply scenarios with associated 'free increment' levels in order to inform this baseline debate. However, it should be remembered that these 'free increment' figures are mutually exclusive and cannot be provided in addition to the base network figures under all supply scenarios due to the interaction between the different entry points. As there is an interaction with how the baseline levels are set on the exit side, we would only be able to agree to entry baselines once the proposals for exit baselines and the allowances under the main price control are known.

231 As we mentioned in our response to the second document, we do not believe that user commitment is a necessary and sufficient condition for us to receive remuneration for providing extra revenue if there are other reasons which lead us to believe that the incremental capacity is warranted.

232 We are broadly supportive of decoupling of UCAs (as revenue drivers) from reserve prices. We believe that this will allow our pricing to be more flexible and cost reflective into the future as it will be easier to reflect the effects that the changing supply patterns have on the estimates of costs for providing incremental capacity on the network. However, we believe that the form of the revenue drivers need to take account (as outlined in Ofgem's recent consultation document on UCAs for large entry points[7]) of the potential impact of steel prices and changing flows on the system in order to ensure that NGG is appropriately remunerated.

233 In the event that Ofgem determine that significant elements of load related expenditure are subject to revenue drivers and we are exposed to the differences between the ex-ante set UCAs for a full five years, then these risks will clearly need to be considered if we are to be appropriately remunerated.

Question 4.3	Do you agree that changes are a need to the arrangements for buying back capacity rights, in particular to ensure a different sharing of risk between shippers, NGG NTS and consumers in respect of capacity which is dependent on large investment projects?

234 We agree with Ofgem's assertions within paragraph 4.21 that the current arrangements for compensation seem to be unduly favourable to shippers and believe that the principles of the model for buy-back arrangements to deal with incremental capacity, as outlined within paragraph 4.25, are broadly appropriate. We are pleased to see that Ofgem are recommending that NGG should only be incentivised on events within our control (e.g. that buy-backs would not be triggered by delays in obtaining relevant consents).

235 We note in Appendix 5, paragraph 1.29, that Ofgem believe that "it is not appropriate for the generality of customers to bear the costs of planning risks incurred by TCCs as it is the TCCs that are responsible for making the siting decision". We believe that this statement also implies that it is not appropriate for NGG NTS to bear this risk and that this is an argument which is as equally applicable to entry as to offtake.

[7] Adjusting National Grid's revenue allowances when large new entry points connect to the gas transmission system – Ofgem Ref: 50/06, 29 March 2006

Chapter 5: Gas offtake incentives

Question 5.1	Is our proposed approach for the transitional period appropriate?

236 As outlined in our response to Chapter 2, we believe that the base price control allowance should provide for known investment requirements (e.g. where a user commitment has been provided or there is a clear case for investment to meet the 1 in 20 licence obligation) - and revenue drivers should adjust funding in response to less certain developments during the price control period. Given the timing of the transitional period, this would suggest that certain investments due to connect in the transitional period (e.g. Langage) should be remunerated in the base price control allowance. In contrast to this overall approach, Ofgem appear to be suggesting, for both the transitional and enduring regime, that revenue drivers should fund all incremental investments above the existing network. We therefore do not support Ofgem's proposal for setting baselines at the level of the current network and remunerating incremental investment solely via revenue drivers in the transitional period.

237 In relation to the incentives to apply in the transitional period, we agree with Ofgem that we should keep the concept of "charges foregone" counting towards the TO allowed revenue in order to prevent the need for firm charges to be increased to recover that allowance. We note that Ofgem believe that the CLNG incentive should carry on in its current form and that the >15 day incentive should be retained, but that the capacity buyback incentive should be removed for the transitional period. We agree with the need for incentives to cover CLNG costs and >15 day costs, but believe that the capacity buyback incentive should be retained for this period as there are still cost liabilities linked with the provision of exit capacity which exist within the UNC that need to be financed and it appears that the appropriate vehicle for this is the capacity buyback incentive. In addition, it seems a rather odd policy decision to remove this incentive, as it was structured in a way to allow National Grid flexibility to seek out the most efficient solution to dealing with any exit capacity constraint (i.e. it allowed for both turn-down and turn-up type of contracts). We believe that Ofgem should always strive to set the incentives with this in mind – i.e. they should be sufficiently flexible to encourage us to make appropriate trade-offs in order to seek out the most economic and efficient solutions.

Question 5.2	Do you agree with the assessment, set out in this document, of the high level options in the Second Consultation?

238 We broadly agree with Ofgem's assessments of the options consulted upon within the Second Consultation. However, we are not convinced by the arguments that Ofgem has put forward as to why there should be different approaches applied to entry and offtake with regards to the obligations placed upon National Grid. We believe that there is no need to include specific obligations within the GT licence for National Grid to both substitute capacity rather than invest or to release capacity by a specific date, as this could all be

included within the Capacity Release Methodology statement which is being advocated on the entry side.

Question 5.3	Is the high level option proposed appropriate?

239 We broadly agree with the form of the high level option being proposed, but as outlined in the responses to the other questions with respect to offtake, we have several issues with some of the details.

Question 5.4	Do you agree with our thoughts on baselines, revenue drivers and payment flows given an emphasis on user commitments?

240 We agree with Ofgem that baselines should be set to reflect the actual capability of the system and that practical maximum physical capacity is probably the appropriate way forward as it takes into account the interactions between the different points on the system. However, we believe that it is important to recognise that there are also interactions between the capability which applies at offtake and that at entry. We would therefore only be able to agree to any exit baselines once the proposals for the entry baselines and the allowances under the main price control are known.

241 In relation to the level of the baselines to apply, we do not agree with Ofgem that the baselines should be flat across the formula period as we believe that any project for which we have already seen a user commitment should be included within the fixed network assumption (and hence would imply a rising baseline level) with funding being provided via the TO control.

242 We remain supportive of using revenue drivers to provide revenue for uncertain investments at the time of setting the price control. We see particular benefit in using nodal revenue drivers to cater for power station projects which have been identified as potentially connecting towards the back end of the price control. Assuming that the revenue driver is set appropriately, this would provide National Grid with sufficient revenue to undertake necessary investments, should the power station wish to connect, but would protect customers from funding investment allowances which may not be required.

243 As mentioned in our response to Chapter 3 (electricity incentives), we would support the revenue driver trigger being linked to the licensee receiving commitment from the user for their desired capacity. Such an approach has the benefit of linking the revenue trigger to the investment trigger and would be closest to the status quo in relation to the profiling of costs and revenues.

244 We are pleased to see that Ofgem are considering combining the change of payment flows (such that GDNs pay for their capacity) with the introduction of the enduring regime. We believe that this is the correct decision as it should result in the least costs being imposed on the industry, rather than having to introduce two different changes to the regime at different times.

Question 5.5	Are the proposals for a gas offtake buyback incentive appropriate?

245 We agree with Ofgem that there should be a common approach to incentives for buybacks whether they be at entry or offtake and look forward to working with Ofgem to further develop any proposals.

Chapter 6: Expenditure analysis: capital expenditure

Question 6.1	Do you have any comments on our approach to assessing historic and forecast capex? Are there any other factors we should take into account?

246 National Grid's forecast submission represents a reasonable 'best view' picture of the likely level of capital expenditure, given the projected changes in demand, gas supply and power generation, legislative requirements, and the need to maintain the performance of the system given the age and condition of the main transmission system assets.

247 When assessing forecast and historic capex, it is vital that Ofgem consider the overall interests of consumers, not just in terms of cost, but also reliability, and environmental and safety performance.

248 We have undertaken a number of workshops with Ofgem and its consultants to date, and have further such sessions planned. The feedback from these sessions has been positive and we believe that such workshop sessions are a very useful means of communication and enable all the key issues relating to forecast and historic capex to be explored in great detail. Going forward, we believe that Ofgem should seek to maximise the amount of time allocated to workshops.

249 The scope of work for all consultants working for Ofgem is not always completely clear, and we believe that some further clarification here would be useful. In addition, there should be clearer management of the consultants by Ofgem, in order to ensure co-ordination, thus minimising the burden of duplicating work for both Ofgem and National Grid.

250 A key learning point from NGET's price review extension process, is that Ofgem should provide appropriate feedback to the licensees on their consultant's findings, such that any areas of misunderstanding or lack of clarity are highlighted as soon as possible. This would enable such issues to be discussed further, thereby maximising the effectiveness and accuracy of the consultant's findings. We also think that it would be desirable to have a workshop with Ofgem's consultants to discuss their findings, in advance of publication of their reports.

Question 6.2	Should some degree of alignment be adopted for capitalisation of forecast costs across the transmission licensees, or should, especially in the case of the Scottish licensees, the approach be consistent with DPCR?

251 We are aware that capitalisation practices across the electricity industry have progressively diverged and believe that the differences are now so marked that a reasonable comparison can no longer be undertaken.

252 The differences are most apparent in two key areas:

(a) **Fault Costs** – where DNOs have a greater proportion of assets subject to "fix on fail", a regime that lends itself to capitalisation of a betterment element associated with maintenance and repair. NGET's processes are, by comparison, dominated by inspection, asset management and preventative maintenance costs that are, due to their nature, straight opex under the terms of FRS15; and

(b) **Support Costs** – where DNOs, in part owing to the takeover activity in the sector, often have legal structures where a parent company acts as a service provider to the DNO, facilitating greater levels of overhead capitalisation. NGET support service costs are, in the main, expensed.

253 We believe that whilst alignment of capitalisation costs across transmission and distribution licensees would be conceptually desirable it is unrealistic to believe that this can be achieved in this transmission review.

254 However we do believe there is an opportunity within the transmission review to use an approach to RAV capitalisation which would improve alignment between regulatory calculations (specifically, those relating to capitalisation into RAV) and the economic characteristics of key items of expenditure, certainly when compared with the treatment defined under UK GAAP (FRS 15). In particular, this would entail RAV capitalisation of what we have referred to in our FBPQ submission as "quasi-capex".

255 This "quasi-capex" builds to some £30m per annum by the end of the period of our FBPQ and comprises:

(a) **opex directly associated with capex schemes** – such as preparatory refurbishment of tower steelwork or foundations prior to capex reconductoring and decommissioning of substations, lines, cables or compressor stations following capex asset replacement; and

(b) **opex with the more general economic nature of capex** – where significant sums of opex are committed in order to provide long term economic benefits in a similar way to a capex investment including:

(i) circuit breaker refurbishment as an alternative to capex asset replacement;

(ii) overhead line component replacement or the refurbishment of air intakes and exhaust stacks at gas compressor stations;

(iii) our asbestos removal programme that is an essential investment required to ensure the long term future operation of six key substation sites; and

(iv) tower painting where the long term economic benefits versus potential asset replacement are clear.

256 We believe that the most appropriate regulatory treatment of quasi-capex is for it to be remunerated through the RAV.

257 Our response to question 7.2 in relation to “non-operational capex” proposes the adoption of a separate “short-life” RAV in respect of such items as information systems developments and commercial vehicle purchases as an alternative, in this instance, to a potential regulatory treatment that would see accounting capex remunerated as regulatory opex.

258 We believe that, taken together, these two proposals represent a significant first step towards improved alignment of regulatory accounting and economic reality.

Question 6.3	Should some adjustment be made to network flexibility margins, particularly for the NTS 5% planning flow margin?

259 We note Ofgem's question about the continuing suitability of the network flexibility margins, particularly for the NTS 5% flow margin. We agree that it is appropriate to review this. However, the use of imported LNG and the greater choice of potential supply patterns in the future could **significantly increase** our design and operational uncertainties. The flow margin exists to provide a margin of cover for a list of effects or events wherein the actual flows and pressures on the NTS will differ from those in the base case design. This margin takes the form of a percentage increase in flows used for network analysis. There are two components to the flow margin:

(a) a transient component; and

(b) a transmission capacity component

260 The transient component is 2.5% and encompasses compressor trips, forecasting errors, suppliers' alerts, producer variation in rates of delivery and changes in operational configuration to meet changing supply and demand patterns.

261 The transmission capacity component is 2.5% and is intended to protect against changing patterns of supply and demand between the point at which the NTS design, including new infrastructure requirements is committed, and the time of actual gas flow which is generally around 3-years later. In this respect, gas flows within baselines continue to be subject to forecasting uncertainties – **user commitment for capacity does not give any commitment for actual flows**.

262 Finally, the flow margin is an integral component of our safety case. Should any change to the safety case occur, it would require HSE approval – hence, we would anticipate that the HSE would be included in such discussions. We look forward to engaging with Ofgem (and, potentially, with the HSE) on this issue.

Question 6.4	In carrying out cost-benefit analysis to assess the efficient level of transmission capacity to accommodate wind generation, what new factors need to be taken into account?

263 The particular characteristics of wind generation that are important to a cost-benefit analysis of transmission expansion are:

(a) the particular probability distribution of wind generation output (featuring a relatively low probability of high output) which, due to the significant common mode aspect arising from widespread weather systems, features even for large regional or national wind generation portfolios; and

(b) the high economic value ascribed to wind generation output through the Renewable Obligation. This makes the constraining of wind with firm access rights in operational timescales a potentially expensive proposition even for modest volumes.

264 For transmission capacity serving just wind (including, for example, wind generation local connections), cost-benefit analyses undertaken by transmission licensees and by individual developers agree that capacity should generally match the expected full available capacity of the wind generation despite relatively low utilisation of this full capacity. (The issue concerning the appropriate security level for local connections is addressed in the following answer).

265 For areas where there is a mixed portfolio of wind and conventional generation, there is the potential in operational timescales to constrain the firm access rights of conventional generation at more favourable compensation rates than would be required by wind generators. As such constraints may have a limited volume, corresponding to those relatively low probability periods of high wind output, this combination of low volume (because of low frequency of high wind) and lower price (because fossil plant should be at the relevant margin) is important to consider in cost-benefit analyses.

266 However, if the option of incurring operational constraints is to be more efficient than the option to invest in additional transmission capacity, then it is important that cost reflective prices for constraint services will actually emerge. If conventional generation bids at the marginal price of constraint services (which will be dictated by wind generation in these constrained periods), then the expected lower constraint prices will not emerge and (as discussed in the previous paragraph) reduced network capacity is unlikely to be efficient. Cost-benefit analyses must therefore include a robust representation of the likely actual price of services, rather than rely on theoretical values.

267 Some analysis, which focuses on the statistical contribution that wind can make to securely meeting the national peak demand, suggests that it could be inefficient to provide transmission capacity that exceeds the wind capacity factor (i.e. a factor which depends on the proportion of wind in the system but which does not exceed the expected wind load factor - some 30% to 40%). While such analysis does highlight a particular aspect of the statistical properties of wind generation, it is incomplete in so far as it does not address the deemed high value of wind generation as it contributes to energy requirements year round. Reliance on such peak only considerations could result in the highly inefficient outcome of wind being connected but without sufficient capacity to permit satisfactory operation under normal

circumstances. (For this reason National Grid's representation of wind in peak demand studies uses a contribution factor of 60%).

268 Given the relatively low probability of high wind output, it has been suggested that it could be efficient to make wider use of system to generator intertripping schemes as an alternative to transmission investment. National Grid already uses intertripping extensively to manage the transmission system in operational timescales and will be using it extensively to manage the system at the Anglo-Scottish border and in the north of England prior to completion of approved reinforcements. The extent that intertripping may be used is subject to a number of technical restrictions and commercial factors. These issues must be appropriately incorporated in cost-benefit analyses.

269 Overall, both from a GB point of view and from our narrower commercial viewpoint, the key issue is to recognise the actual value of constraints which will be associated with different levels of network reinforcement – i.e. less investment will mean more constraints and the efficiency of this will depend on actual generator bidding behaviour which, depending on the degree of competition in the relevant generation market, may or may not be cost reflective.

Question 6.5	What would be the most appropriate approach to restoring the incentives for relevant parties to reach the most cost-effective connection design? How should the TPCR allowance take into account the various solutions?

270 This issue was acknowledged during the development of the shallow connection charging methodology in England and Wales. The disadvantage of a reduced driver for customers to consider design variation requests was thought to be outweighed by the advantages of removing barriers to new entry and protecting connecting customers from the costs associated with design decisions taken for wider system reasons. In extending the application of the shallow connection charging methodology to Scotland, there is potential for a greater number of connecting parties being interested in customer design variation requests, in particular the Scottish Island and Scottish onshore overhead line generation connection parties.

271 The main options to resolve this issue are listed below:

(a) no change to the existing Charging Methodologies with the exception of a one-off zonal approach implemented for the Scottish Island connections;

(b) an adjustment to the '2km rule' in the Connection Charging Methodology (for cables and overhead lines, connection assets are defined as those single user connection circuits equal to or less than 2km in length that are not potentially sharable);

(c) the introduction of a new access product for customer choice connections along with the associated changes to the Charging Methodology; and

(d) a fundamental change to the transport model and TNUoS methodology.

272 It is key that the concerns raised are thoroughly considered in full consultation with all the relevant industry parties and National Grid are taking this forward through the Charging User Group with the Transmission Owners and the Transmission Charging Methodologies Forum with Users. All the complex interactions between the various relevant statutory and license obligations must be considered to find the optimum solution without eroding the benefits of a shallow connection charging methodology.

Chapter 7: Expenditure analysis: operating expenditure

Question 7.1	Do you have any comments on our approach to assessing historic and forecast opex? Are there any other factors we should take into account?

273 Following submission of our HBPQ and FBPQ data and narratives in the latter part of 2005, we have worked closely with Ofgem and their consultants through workshops and extensive written answers to formal questions to provide the fullest picture possible of our historical opex performance.

274 The publication of Ofgem's Document is an opportunity to take stock of the opex assessment programme and consider the key areas that need to be fully addressed prior to the publication of initial proposals in June.

275 The opex assessment programme has four main elements:

(a) Business Services Functions – where the review of our HBPQ would appear to have been largely completed;

(b) Gas Operations – where the review of our HBPQ has been completed and Ofgem and its consultants are actively engaged on reviewing our FBPQ;

(c) Electricity Operations – where a limited amount of work has been undertaken on the HBPQ which we understand is likely to be revisited as part of a combined review alongside our FBPQ; and

(d) Information Systems, Property and Insurance – which are subject to separate timetables of review with specialist consultants.

276 Against the above background, a June deadline for initial proposals is challenging. At this stage of the review, we have not yet had feedback on initial findings from Ofgem's consultants, either for fact checking or in order to provide appropriate challenge and review. We believe this to be an essential part of the work that needs to take place over the coming weeks in order for Ofgem to arrive at well-founded conclusions.

277 Our FBPQ submission is the result of a comprehensive and highly detailed bottom up build. As we will touch on in our response to Ofgem's unit cost trend analysis, we do not believe that an accurate assessment of our operating expenditure requirements can be established through currently available top down analysis.

278 Bottom up analysis of our FBPQ submissions for both our Electricity Operations and Business Services activities should be the basis for setting our forward opex allowances and should form a key part of the next stage of work prior to initial proposals.

Question 7.2	How should non operational capex be treated with regard to 1) the assessment of efficiency of associated activities such as IT; 2) the treatment of historically incurred overspends; and 3) the approach to future remuneration?

279 In managing our business, we do not make a distinction between "operational" and "non-operational" capital expenditure. We do, however, believe that it would be appropriate for a distinction to be made in respect of regulatory treatment of capital investment in respect of **asset lives**. This would be consistent with both the economic value of the relevant assets and our normal accounting practice. In this respect, items considered by Ofgem to be "non-operational capex", such as commercial vehicles or potentially some information systems investment, are depreciated over shorter periods than "operational capex".

280 Therefore, we believe that the most appropriate method for future remuneration of non-operational capex would be to follow the precedent set by Ofgem at the last price control review for the Electricity System Operator and establish a separate "short-life" RAV (of seven years) to capture and remunerate defined categories of "non-operational" capex. This would have benefits of:

(a) aligning remuneration with useful economic life;

(b) aligning remuneration with accounting depreciation; and

(c) facilitating the allocation of costs to the correct generation of customers over time.

281 This treatment would only be appropriate if the definition of non-operational capex is addressing material lines of expenditure. It should also be noted that the definition should be pragmatic in order to avoid unnecessary incremental costs associated with data capture, analysis and reporting.

Question 7.3	Do you have any comments on our comparison of unit cost trends? Are there any reasons why transmission licensees should have performed differently to DNO's?

282 We acknowledge that comparative benchmarking of the type undertaken by Ofgem in their analysis of Real Unit Operating Expenditure ("RUOE") presented in figure 7.2 of their Document has a role in regulation. However, we believe that great care needs to be taken in interpreting any such analysis and that it is of limited value in deducing an appropriate forward opex allowance.

283 Our conclusion (from analysis that we believe replicates Ofgem's data) is that there is **no significant difference between NGET's unit cost performance and that of the DNOs** since privatisation.

284 We have reached this conclusion following consideration of three specific issues :

(a) The inherent limitations of the analysis. Most notably in respect of :

(i) "normalisation" of NGET and DNO datasets to enable reasonable comparison;

(ii) the swing in costs between Distribution and Supply that took place with separation;

(iii) marked differences in capitalisation practices across the industry; and

(iv) the selection of 1991 as a base year for the analysis.

(b) NGET is not a DNO and has a cost base that reflects the critical differences between Transmission and Distribution.

(c) The operating cost performance of NGET in latter years needs to be set in the context of material known issues such as the implementation of NETA.

285 Each of these above issues is considered in turn.

Inherent limitations of the analysis

(i) Normalisation of data

286 The analysis of Real Unit Operating Expenditure ("RUOE") trends seeks to compare the cost performance of NGET with DNOs, SHETL and SPT over the period 1990 – 2005.

287 National Grid has not been provided access to the source data used for this analysis but we believe that it has been based on published Regulatory Accounts data and GWh of electricity transported supplied by NGET.

288 Our response is therefore based on our own analysis of published Regulatory Accounts data in order to replicate the results achieved by Ofgem and we have concluded that the series of costs used is a combination of:

(a) **controllable costs** - the focus of the opex assessment programme; and

(b) **network rates** – which are currently treated as a pass-through item in our price control formula and which would not generally be regarded as an area for comparative efficiency assessment.

289 The inclusion of network rates leads to significant distortion of the comparative results owing to:

(a) the fact that the ratio of network rates to Controllable Costs is significantly higher in NGET than in DNOs; and

(b) the fact that network rates have followed a broadly flat profile in real terms since privatisation.

290 The inclusion of network rates therefore loads the analysis for NGET with a significantly higher proportion of what is effectively a fixed (and uncontrollable) cost than is the case for DNOs.

291 We believe that the data should be corrected for network rates if Ofgem believe this form of analysis is to be used in further developing its thoughts on NGET's future operating costs.

(ii) Separation of distribution and supply activities

292 The analysis for DNOs displays marked cost reduction between 2000 and 2001, coinciding with the legal separation of the former Public Electricity Supplier ("PES") distribution and supply activities.

293 In presenting the RUOE analysis for DNOs, Ofgem advance two potential lines in figure 7.2 of their Document from 2001 onwards:

(a) the "DNO Unadjusted" series which appears to be based on data collected from published Regulatory Accounts; and

(b) the "DNO Adjusted" series which Ofgem state takes some account of the change in cost allocation that took place between Distribution and Supply at the point of their separation.

294 We believe that the "DNO Adjusted" series has been arrived at by making an adjustment to the years 2001 to 2005 based on the levels of cost reallocation out of Distribution to Supply set out by Ofgem in their DPCR3 final proposals (some £260m or 18% of controllable operating costs).

295 Given that this reallocation did in fact take place, and can clearly be shown in Ofgem's own documents for DPCR3 to have been very significant, we find Ofgem's assertion that true DNO cost performance could be closer to the "DNO Unadjusted" series to be incomprehensible.

296 The "DNO Adjusted" series, however, remains striking for the following reasons:

(a) Unit costs in the period 1998 to 2000 prior to the separation of Distribution and Supply were broadly flat in real terms.

(b) Unit costs in the period 2002 to 2005 mirror their behaviour in the period 1998 to 2000 and remain broadly flat in real terms.

(c) Unit costs in the intervening period between 2000 and 2002 exhibit an unusual reduction.

297 We believe that the unusual reduction in the "DNO Adjusted" series between 2000 and 2002 could still, in part, be associated with the impact of Distribution and Supply separation. Therefore, if Ofgem believe this form of analysis is to be used in further developing its thoughts for NGET's future operating costs, we believe that the "DNO Adjusted" data should be reviewed in much more detail to determine if it truly represents real cost reduction.

(iii) Marked differences in industry capitalisation practice

298 We are aware that capitalisation practices across the electricity industry have progressively diverged over the period under review and believe that the differences are now so marked that a reasonable comparison can no longer be undertaken without significant analysis and adjustment to source data. This issue was clearly acknowledged by Ofgem in the DPCR4 process and is clearly of a material nature.

299 The differences are most apparent in two key areas:

(a) **Fault Costs** – where DNOs have a greater proportion of assets subject to "fix on fail", a regime that lends itself to capitalisation of a betterment element associated with maintenance and repair. NGET's processes are, by comparison, dominated by inspection, asset management and preventative maintenance costs that are, due to their nature, straight opex under the terms of FRS15; and

(b) **Support Costs** – where DNOs, in part owing to the takeover activity in the sector, often have legal structures where a parent company acts as a service provider to the DNO, facilitating greater levels of overhead capitalisation. NGET support service costs are, in the main, expensed.

300 NGET adopts a policy of strict compliance with the terms of FRS15 and we believe that, if Ofgem believe this form of analysis is to be used in further developing its thoughts for NGET's future operating costs, the comparative data will need to be adjusted to take account of our accounting practices.

(iv) Base year for analysis

301 The Ofgem analysis of RUOE indexes NGET and DNOs to a common starting point in 1991 as a basis for comparison stretching forward some fourteen years. The issues driving costs at the starting point are therefore as influential in the analysis as the issues driving costs at its end point.

302 NGET, unlike the former RECs which were already stand-alone entities at privatisation, was created as part of the break-up of the former Central Electricity Generating Board ("CEGB"). As a result, the early years of NGC (as it then was) were characterised by the establishment of functions which effectively had not existed (at least in anything other than a very interim sense) before privatisation. The cost of establishing these functions was that much higher because NGC had to carry out activities - in particular, the commercial interaction with generation and the facilitation of new entry into generation (in a period characterised by the first "dash for gas") – which had simply not been a part of the activities of the CEGB.

303 We believe that Ofgem need to recognise that the 1991 data for NGET did not reflect the cost base for a fully fledged stand-alone entity. We believe that if Ofgem wish to use this form of analysis to further develop its thoughts for NGET's future operating costs, the data should be adjusted to account for this issue.

NGET is not a DNO

304 We do not agree that NGET and DNOs have faced similar cost and operational pressures since privatisation. NGET has certain specific characteristics that further prevent true like for like comparison such as the following:

(a) The RUOE analysis presented by Ofgem is based on our TO and SO activities. Our SO role (now GBSO) role forms over 30% of the NGET cost base and features activities and costs that not directly comparable to DNOs such as:

(i) system and energy balancing activities that are unique to the SO (GBSO);

(ii) active flow, voltage and frequency management where DNO systems are generally acknowledged to be more passive in nature and distribute electricity radially from Grid Supply Points to sources of demand; and

(iii) balancing services management activities where successive regulatory regimes since 1997 (culminating in the BSIS scheme) have facilitated investment in increased operating expenditure to leverage significantly greater savings for customers in balancing services costs.

(b) The asset management activities of our TO business are different to a DNOs as they have a far greater proportion of assets subject to "fix on fail". NGET's processes are, by comparison, dominated by inspection, asset management and preventative maintenance costs

(c) NGET face operating cost pressures associated with generation churn in addition to demand growth / demographic drivers faced by DNOs.

305 In addition it is important to remember that there is **(as Ofgem have always intended that there should be**) a trade off of SO internal and external costs for the benefit of customers, recognising that this could entail **increased** SO internal costs. Ofgem's RUOE analysis takes no account of this.

306 We believe that if Ofgem wish to use this form of analysis to further develop its thoughts for NGET's future operating costs that Ofgem need to identify the impact of these differences material differences between NGET and DNOs.

Recent specific considerations of NGET performance

307 The role of NGET in the industry has continually evolved since privatisation. The most marked change in our role, however, took place with the

implementation of New Electricity Trading Arrangements ("NETA") in 2001 and the formation of separately regulated TO and SO activities.

308 NETA involved significant incremental expenditure in Transmission in respect of:

(a) pre go-live development of new processes and information systems;

(b) post go-live re-development of interim measures to provide more robust enduring solutions;

(c) new post-go live enduring costs associated with both the operation of our new trading function and revised control room roles and responsibilities;

(d) significant "participant support costs" incurred by agreement with Ofgem in order to assist other market participants in their developments necessary to achieve the go-live date; and

(e) the absorption of the activities and costs of the former Ancillary Services Business in Transmission.

309 In addition we have already discussed the contrasting forces that shaped the performance of NGET versus allowances over the HBPQ period and touched on the impact of the short term "costs to achieve" associated with developing and implementing major change programmes

310 These incremental costs impact the performance of NGET from 2001 onwards.

311 We believe that it is inappropriate to draw detailed inferences from the RUOE analysis without proper adjustment for recent considerations of NGET's cost performance in order to reflect the true underlying levels of operating cost.

Conclusions

312 We would draw three main conclusions from the above:

(a) Informed interpretation of Ofgem's basic analysis of Real Unit Operating Expenditure demonstrates that NGET's unit cost performance has broadly tracked that of DNOs since privatisation.

(b) We completely reject Ofgem's assertion that the analysis may point to a comparative under-performance by NGET versus DNOs as we do not believe that the analysis is sufficiently robust or considered to draw such inferences.

(c) As stated earlier in this section, our FBPQ submission is built on detailed activity analysis and costing and believe that, especially in the light of the inadequacies of the top down analysis, bottom up analysis is the correct basis for setting our forward opex allowances.

Question 7.4	How should we treat non-controllable costs? Should we take the same approach to network rates as in DPCR?

313 We note Ofgem's comments with regard to network rates and acknowledge that regulated companies have a degree of influence over the valuations applied to their networks as part of period rating reviews.

314 The degree of influence that we are able to exercise over network rates costs, however, is not comparable with that with which we are able to exercise over our controllable cost base. Network rates primarily differ from controllable costs because they cannot be avoided, mitigated, substituted or managed over time through innovation or management expertise.

315 The limited influence that we have over valuation is also periodic in nature - at the point of either a rating review or an appeal in respect of a rating review. This further distinguishes network rates from our controllable cost base which is subject to rigorous ongoing downward pressure by management. Inclusion of network rates as a controllable cost would also distort the ongoing annual application of regulatory incentives.

316 We believe that consideration of network rates as a controllable cost is inappropriate and that the existing pass-through arrangement as a non-controllable cost should continue.

317 We acknowledge, however, that network rates influence end prices to electricity and gas consumers and wish to discuss with Ofgem a mechanism for Licensees to recover one-off incremental costs that would necessarily be incurred to appeal network valuations. Without such a mechanism Licensees would be penalised for pursuing the interests of customers.

Chapter 8: Financial issues

Question 8.1	Are there other issues that the cost of capital study should address?

318 A wide range of evidence may be relevant to the consideration of the cost of capital, in addition to that outlined in Ofgem's consultation document. For example, previous reviews in the utility sector have considered market asset valuation evidence and dividend growth evidence.

319 Given the uncertainties in the current market environment, Ofgem should consider all available evidence pertinent to assessing the cost of capital.

Question 8.2	How should we approach our assumptions for the cost of debt? Should we use medium term historical averages?

320 Current real risk free rates and debt spreads are at extremely low levels by historical standards, and we do not believe that these levels are sustainable.

321 We think that medium term averages reflect one way of dealing both with this uncertainty and with the existence of embedded debt. Medium term averages should, therefore, inform the assumptions to be made about cost of debt for the five years from April 2007.

Question 8.3	How should we reflect the risk profiles of licensees in estimating the cost of capital? Are risks below the market average?

322 Ofgem should only assume that licensees' risk profiles are lower than the market if there is clear evidence that this is the case.

323 There remain significant concerns over the reliability of equity beta data and this evidence does not represent a prudent basis for concluding that utility risk is lower than the market at the gearing levels that Ofgem have assumed.

324 In addition, the available evidence (including that adduced by Ofgem as part of the NGET mini review) suggests that National Grid has a relatively high equity beta by UK utility standards and that therefore there is a stronger case for using an equity beta of one for National Grid than for the DNOs.

325 In any event, the equity beta assumption cannot be decoupled from the assumption being made about gearing.

Question 8.4	Should we still use conservative gearing assumptions and assume target ratings comfortably within investment grade when setting the cost of capital and assessing financial stability? What financial indicators should we use?

326 It is important that the assumptions which underpin the eventual assumption on cost of capital are consistent with Ofgem's approach to financeability.

327 Ofgem should continue to set assumed returns on the basis of a single A credit rating, and Ofgem's approach of assessing financeability based on appropriate credit rating thresholds remains appropriate.

Question 8.5	Which option (or combination of options) should be used to address the loss of income from pre-vesting assets becoming fully depreciated?

328 Ofgem's 'do nothing' option will have a significant impact on NGET's financeability ratios and its ability to sustain its current levels of debt.

329 Of the two options for fixing the cliff face, NGET prefer an approach based on tilting regulatory depreciation. This is due to the fact that resolving the problem through repex also requires convincing rating agencies to treat the opex element of repex in a way that it inconsistent with their treatment of gas distribution repex in the past. It cannot be guaranteed that the rating agencies would do this.

330 If Ofgem are concerned about the probability of a future cliff face, it may be possible to address this through, for example, using sum of the digits depreciation on any smoothing factor.

Question 8.6	Do the existing ring-fencing conditions provide adequate protection for consumers?

331 Yes in respect of gas network licensees. We have no objection to the extension of the 'cash lock-up' mechanism to the licence of NGET.

Question 8.7	Is benchmarking the level of total employment costs the best means to incentivise the licensees to control their pension costs?

332 We believe, as Ofgem have previously stated, that the best approach is to consider the efficiency of remuneration costs as a package, and consequently that companies should be incentivised to control their costs at the level of total employment costs.

333 Employers will typically aim to attract and retain staff with a remuneration package consisting of a salary, pension arrangements, bonus payments, other incentives and benefits in kind. However, the relative importance of the different elements of the package will vary within any given employer depending on the type of staff and their level of seniority, and between

employers depending on the nature of their business and the remuneration policy of each company.

334 Consequently, when assessing whether or not the level of a company's employment costs is efficient, it would seem advisable to consider employment costs in the round, rather than considering any element of the remuneration package in isolation, including pension costs. If this approach is not followed, and for example an efficient package is calculated from the lower of market median and actual cost for each individual type of remuneration cost, then the deemed efficient package will be artificially low, and not represent what is efficiently achievable.

Question 8.8	Should there be any ex post adjustments to the licensees' revenue allowances for tax payments?

335 The tax charge faced by the licensee will be impacted by:

(a) the tax treatment of transactions as determined by tax law, accounting treatment etc; and

(b) the level and nature of expenditures.

336 It follows that the tax allowance set should be consistent with the allowances set for expenditure and the prevailing tax treatment relevant to the licensee.

337 It would be appropriate to make ex post adjustments to the tax allowance if:

(a) the tax treatment was to change materially from that used to set the allowance;

(b) underlying expenditure changes materially in respect of cost pass-through items; and

(c) to deal with changing levels of expenditure that are remunerated by revenue drivers. At this point in time, it is not clear what Ofgem is proposing to do in respect of assumed tax allowance for capital expenditure which will be covered by revenue drivers.

338 If underlying expenditure differs from allowances simply due to over or under-performance against allowances, then no ex post adjustments should be made to the tax allowance.

IV Response to questions embedded in appendices

Appendix 10 - Gas entry modelling results

Question A10.1	What preliminary conclusions should we draw from the initial gas entry modelling results reported in this appendix, particularly in light of the preferred option for gas entry incentives presented in the main document?

339 Further work is required before any preliminary conclusions can be drawn from the modelling results reported in Appendix 10.

340 In the meantime, it is important that incorrect conclusions are not drawn from the information provided in the Appendix. As detailed in our response to Chapter 4, we believe that it is very important that the baselines (or trigger levels) are set in an appropriate manner in order to ensure that incremental revenue is triggered when additional capacity above that level is provided. We have given Ofgem data which provides estimates of the physical capability of the network under different supply scenarios, with associated 'free increment' levels, in order to inform this baseline debate. However:

(a) It should be remembered that these 'free increment' figures are mutually exclusive and cannot be provided in addition to the base network figures under all supply scenarios due to the interaction between the different entry points.

(b) As there is an interaction with how the baseline levels are set on the exit side, we would only be able to agree to entry baselines once the proposals for exit baselines and the allowances under the main price control are known.

Question A10.2	What options for further modelling work (if any) should we pursue, and which ones should we prioritise?

341 We believe the main element of further work is to convert the nodal capabilities provided in the appendix into zonal capabilities. This is required in order to determine the practical maximum capacity, given the interaction between nodes. We would suggest that this work should, in the first instance, consider both

(a) the best (i.e. maximum throughput by favourable adjustment of all other entry points); and

(b) the worst case (i.e. maximum throughput by the most unfavourable adjustment to other entry points).

342 This work would not be subject to merit orders or actual gas flows and expectations - but would set the range for the baselines. Having undertaken this work, alternative supply and demand patterns could be considered which

would highlight the potential buyback/investment risks associated with setting baselines above the worst case scenario.

343 In setting the proposed baselines, we would need to ensure that the proposals were not less than existing capacity commitments (i.e. where shippers had bought capacity through previous auctions).

344 In addition to the work highlighted above, we believe further work is also required to understand system capability in periods away from peak conditions.

Appendix 12 – Gas offtake technical details

Transitional period

Question A12.1	Do you agree that for the period from 1 April 2007 to 30 September 2010, baselines should: • not be specified for interruptible capacity? • not be specified for GDN flexibility? • be at the same level and degree of aggregation as during the enduring period (i.e. nodal and based upon practical maximum physical capacity)?

345 Within our response to the question posed in Chapter 5 regarding the transitional period, we agreed with Ofgem that we should keep the concept of "charges foregone" counting towards the TO allowed revenue in order to prevent the need for firm charges to be increased to recover that allowance. Within the current interim period, the mechanism to achieve this is driven by the baseline specified for interruptible capacity. If this baseline was to be removed, there would need to be a new means introduced into the licence to enable this to continue, which could take the form of a fixed allowance assumption counting towards the TO control which could then be collected from users via a separate TO charge. We believe that this issue probably warrants further thought and discussion.

346 By the time the price control is set, the last opportunity for GDNs to request increased flexibility for the transitional period will have passed. We therefore believe that, were specific investment identified to meet their needs, this investment should be included within the TO RAV and, if this were to be the case, we agree with Ofgem that there is no need to specify a baseline.

347 As outlined in our response to Chapter 4, we also believe that:

(a) The base price control allowance should provide for known investment requirements for flat NTS capacity (e.g. where a user commitment has been provided or there is a clear case for investment to meet the 1 in 20 licence obligation).

(b) Revenue drivers should adjust funding in response to less certain developments during the price control period.

348 Given the timing of the transitional period, this would suggest that certain investments due to connect in the transitional period (e.g. Langage) should be remunerated in the base price control allowance.

Question A12.2	Do you agree that incremental investment should be remunerated throughout the entire duration of the next price control period through the application of pre-specified revenue drivers?

349 As outlined earlier in our response, the base price control allowance should provide for known investment requirements (e.g. where a user commitment has been provided or there is a clear case for investment to meet the 1 in 20 licence obligation) - and revenue drivers should adjust funding in response to less certain developments during the price control period.

350 We remain supportive of using revenue drivers to provide revenue for uncertain investments at the time of setting the price control. We see particular benefit in using nodal revenue drivers to cater for power station projects which have been identified as potentially connecting towards the back end of the price control. **Assuming that the revenue driver is set appropriately**, this would provide National Grid with sufficient revenue to undertake necessary investments, should the power station wish to connect, but would protect customers from funding investment allowances which may not be required.

351 However, experience during the current price control period with the revenue drivers embedded in the gas entry remuneration arrangements suggests that there is a material risk of the **efficient** costs of particular projects being substantially different from those implied by pre-set drivers (the UCAs in the case of the gas entry incentives). As noted at various points in Section II of our response, we would favour a mechanism (possibly modelled on the Relevant Change of Circumstances regime in the water industry) which would cater for such eventualities.

Question A12.3	Do you agree that the charges foregone and investment incentive should: a. not apply to the transitional period? b. be removed for the period from 1 April 2007 to 30 September 2008?

352 As outlined in our response to question A12.1 above, we believe that the concept of "charges foregone" should be retained, but we agree with Ofgem that the licence could be simplified by the removal of this incentive element. Although we have agreed the incentives for the period from 1 April 2007 to 30 September 2008 we would consider removing the investment incentive for this period as well.

Question A12.4	Do you agree that the constrained LNG incentive should: a. be retained for the transitional period? b. apply to the enduring period?

353 We continue to believe that we should be able to recover the costs associated with our requirement to provide sufficient capacity in order to meet our wider licence obligations (such as 1 in 20). We can meet this licence obligation either through investing in the system or by entering into other arrangements. The use of CLNG provides one means to meet our licence obligations; however, it may not be the only way in which we can achieve this. We believe that Ofgem should set incentives on National Grid in a manner that continues to allow us to make those efficient trade-offs.

Question A12.5	What do you believe is the appropriate level for the constrained LNG target for formula years 2009/10, 2010/11 and 2011/12?

354 We would be happy to provide Ofgem with our estimates of the targets for constrained LNG in due course. However, given the interaction with the level of investment to be allowed as part of the price control and the increased uncertainty in providing forecasts for the later years of the price control, consideration should be given to the **timing** of setting the targets. It may, for example, be more appropriate to consider these costs in parallel with any consultations on the SO incentives to apply in that period.

Question A12.6	Do you agree that all buyback costs should be treated as excluded revenue within the transitional period?

355 We believe that further work is required in developing the proposals for buybacks (new investment buyback and operational buyback) in relation to both entry and exit (transitional and enduring). The acceptability of the proposals will therefore only become known once the overall elements impacting on buybacks are brought together and the licensees can consider the overall risk and return associated with the proposals.

356 It will clearly be important for National Grid to understand the overall potential exposure to buyback costs and the risks associated with incurring those costs. Having understood the risks of incurring some costs, we will clearly be interested in how we are remunerated for undertaking such a risk. Having understood the risk/reward balance, the appropriate regulatory 'pot' for any costs and revenues can then be determined.

Question A12.7	Do you agree that the greater than 15 day interruptions incentive should be retained?

357 We believe that, whilst liabilities still exist both within the UNC and under National Grid NTS' Transmission Transportation Charging Methodology, it is appropriate for this incentive to be retained. Given the arrangements outlined within section I of the UNC OAD (Offtake Arrangements Document) which deals with payment apportionment between the NTS and the GDNs, the setting of the target for this incentive needs to be informed by any developments in the reform the interruption arrangements for the GDNs.

Question A12.8	What are your views on the appropriate level of the target, cap and collar for the greater than 15 day interruptions incentive?

358 We would be happy to provide Ofgem with our estimates of the targets for greater than 15 day interruptions in due course. As with any incentive, the target should provide an appropriate balance of risk and reward.

Enduring period

Question A12.10	Do you agree that our emphasis on user commitment is appropriate?

359 As outlined in our response to Ofgem's second consultation document, we still remain to be convinced that requiring user commitment for all capacity is the appropriate way forward. We continue to believe that a clear assessment should be undertaken to understand the costs and benefits of moving away from the status quo position. Our initial view is that the greatest benefits are likely to arise in obtaining user commitment in relation to incremental capacity provision. Given our current investment plans, we do not believe that user commitment for all existing users is merited, as it is not clear that it would actually reduce any stranding risk (either to the transporter or ultimately to end consumers). This is because we perceive there to be limited circumstances in which the signalling by users that they no longer require existing capacity on the network would lead to planned investment being avoided.

Question A12.11	Do you agree with our assessment of the high level options in the Second Consultation? a. Do you agree that NTS exit capacity product(s) should be specified on a nodal basis? b. Do you agree that baselines should be specified on a nodal basis? c. Do you agree that NGG NTS should be subject to a substitution obligation? Do you agree that the approaches proposed for entry and exit strike an appropriate balance between complexity and cost?

360 We broadly agree with Ofgem's assessments of the options consulted upon within the Second Consultation. However, we are not convinced by the arguments that Ofgem have put forward as to why there should be different approaches applied to entry and offtake with regards to the obligations placed upon us. We believe that there is no need to include specific obligations within the GT licence for National Grid to both substitute capacity rather than invest or to release capacity by a specific date, as this could all be included within the Capacity Release Methodology statement which is being advocated on the entry side.

Question A12.12	Do you agree that NGG NTS should only be remunerated for incremental investment to the extent that there is an associated user commitment?

and

Question A12.13	Do you agree with our minded to position with regards to compliance with the 1 in 20 obligation?

361 We believe that it is appropriate to consider the two questions above together. As we have said elsewhere, we are not convinced that, in general, user commitment should be a necessary requirement for network investment to be triggered and remunerated – not least because of the scope for divergence between users' commitments and the wider licence obligations on us (notably the obligations to develop efficient transmission systems). However, in the context of gas exit and on the assumption that Ofgem clarify the interpretation of National Grid NTS' 1 in 20 obligation as outlined (i.e. that it is based on users' commitments which signal peak aggregate daily demand), we believe that it may be appropriate that remuneration (for the purposes of providing incremental gas exit capacity) should only be received in response to user commitment.

Question A12.14	Do you believe that there should be any other pre-conditions before incremental investment is remunerated, e.g. consideration of opportunities for long term buyback contracting, delivery of the investment?

362 We continue to believe that Ofgem should set incentives on National Grid in a way that encourages us to seek the most economic and efficient solutions. To that end, if it is cheaper to enter into long term buyback contracts instead of investing in the system, we believe that the incentive mechanisms should positively promote us to do so. We are concerned, however, that the form of the incentives should be set up in a way to allow us to make those trade-offs with certainty with respect to the revenue stream that will be received over the whole price control period.

Question A12.15	Do you agree that the level of baselines should be determined in accordance with the practical maximum physical capacity of the network?

363 We agree with Ofgem that baselines should be set to reflect the actual capability of the system and that practical maximum physical capacity is probably the correct way forwards as it takes into account the interactions between the different points on the system. However, it should not be forgotten that **there are also interactions between the capability which applies at offtake and that at entry**. We would therefore only be able to agree to any exit baselines once the proposals for the entry baselines and the allowances under the main price control are known.

Question A12.16	Do you agree that baselines should be static throughout the price control period?

364 Where we have investments which have already been underpinned by user commitment, we believe that it is appropriate for those investments to be

allowed within the TO price control and for the baselines to be adjusted accordingly.

Question A12.17	Do you agree that revenue drivers are an appropriate tool for the remuneration of incremental investment?

365 As outlined earlier in our response, the base price control allowance should provide for known investment requirements (e.g. where a user commitment has been provided or where there is a clear case for investment to meet the 1 in 20 licence obligation) - and revenue drivers should adjust funding in response to less certain developments during the price control period.

366 We remain supportive of using revenue drivers to provide revenue for uncertain investments at the time of setting the price control. We see particular benefit in using nodal revenue drivers to cater for power station projects which have been identified as potentially connecting towards the back end of the price control. Assuming that the revenue driver is set appropriately, this would provide National Grid with sufficient revenue to undertake necessary investments, should the power station wish to connect, but would protect customers from funding investment allowances which may not be required.

Question A12.18	Do you agree that the appropriate form of revenue drivers is: a. zonal revenue drivers for small capacity increments? b. project specific revenue drivers for large anticipated projects? c. licence modifications in the event of unanticipated investments which exceed a specified threshold or projects at new exit points?

367 We agree with Ofgem's proposals above that it is appropriate to set ex-ante revenue drivers (in the instances of no existing user commitment) where possible and that these should be zonal for small increments of capacity, but will need to be nodal for large projects. In the event that unplanned requests for large increments of capacity are received, it seems appropriate to issue licence modifications to include these within the GT licence.

Question A12.19	Do you believe that revenue drivers should be indexed with respect to the price of key inputs such as steel?

368 Within the consultation document on large UCAs for entry[8], Ofgem state that "in their role as revenue drivers, the purpose of the UCAs is to provide NGG with a reasonable additional revenue allowance, i.e. one that is neither inappropriately high nor inappropriately low. In other words, the additional revenue allowance should aim to provide NGG with a reasonable prospect of

[8] Adjusting National Grid's revenue allowances when large new entry points connect to the gas transmission system – Ofgem Ref: 50/06, March 2006

recovering the network reinforcement costs associated with accommodating the new entry point". We fully agree with this principle which is based on the premise that any revenue should be cost reflective. Given this principle, it seems appropriate that revenue drivers should include some form of indexation for key cost drivers, such as steel prices and contractor costs.

Question A12.20	Do you agree that revenue drivers negate the need for an NTS exit investment incentive?

369 It is difficult to answer this question without firm details of how the interactions between the revenue driver and the compensation mechanism which would apply to delivery of that capacity will work. Within the document, Ofgem mention creating a separate investment related buyback pot for 'new' investment. However, we are concerned as to how this would fit together with the proposals for exit that revenue is only earned once physical delivery of capacity is achieved. If it were assumed that the buyback scheme penalised National Grid for late delivery of capacity, it does not seem appropriate for National Grid to get penalised twice - once through the buyback scheme and once through not receiving incentive revenue from the obligation date (even though actual capex would have been spent).

Question A12.21	Do you agree that, with respect to buyback: a. investment related buyback costs should be treated as excluded revenue and subject to an administered buyback price? b. the costs of buybacks in the event of planned and unplanned outages should be subject to a sliding scale incentive regime?

370 We generally agree with the principle that there should be a limit on the amount of compensation which shippers are allowed to claim for any failure on National Grid's part to make capacity available. However, as outlined in the response to the previous question, we believe that further work is needed to understand the risks and rewards associated with any proposal, which should include ensuring that National Grid is not penalised twice for late delivery of capacity (i.e. penalised under any incentive scheme and a potential delay in the revenue driver trigger if it is linked to delivery of capacity). .

371 As to the form of the buyback incentive for 'operational' reasons, we believe that it is appropriate to base this incentive on the current entry capacity buyback or indeed the current exit capacity buyback and interruption incentive.

Question A12.22	What is your view in relation to: a. the extent of flexibility that NGG NTS should have over investment lead times? b. whether there is merit in implementing a cap on the total exposure associated with any individual, investment related, buyback action at exit? c. whether operational buyback costs should also be subject to an administered price?

372 The elements considered above will all impact on the risk being undertaken by National Grid upon which the associated remuneration should be based. We would currently support a revised set of arrangements for dealing with buying back capacity associated with the late delivery of incremental capacity and believe that, where possible, consistent approaches should apply to entry and exit. We believe the model outlined in paragraph 4.25 of the consultation, which effectively sets out a standard set of arrangements, recognising the elements which are significantly outside the control of National Grid, but also providing the flexibility to vary the standard terms with all associated costs and revenue being treated as excluded income for the purposes of the price control, has merit and warrants further development.

373 Ultimately, however, the acceptability of the proposals will only become known once all the elements impacting on buybacks are brought together and the licensees can consider the overall risk and return associated with the proposals.

Question A12.23	Do you agree that implementation of the "Option 2A" approach to payment flows should be postponed such that it coincides with the implementation of the enduring regime?

374 We are pleased to see that Ofgem are considering combining the change of payment flows (such that GDNs pay for their capacity) with the introduction of the enduring regime. We believe that this is the correct decision as it should result in the least costs being imposed on the industry, rather than having to introduce two different changes to the regime at different times.

V PENSIONS APPENDIX

375 This appendix contains an illustration of the argument developed in paragraph 173 above in relation to why severance-related pension contributions should be included in Ofgem's overs and unders calculation for NGG during the current price control period.

376 Take as an example the case of a company that, at a price control, is expected to have an ongoing pensionable salary cost of £1000, an employer ongoing cash pension cost of 25%, and no allowance for ERDCs. Its allowance for pension costs over the five year period of a price control would be £1,250, as shown below.

Allowance	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Pensionable salary	1,000	1,000	1,000	1,000	1,000	5,000
Ongoing pension cost @25%	250	250	250	250	250	1,250
ERDC	0	0	0	0	0	0
Pension Allowance	250	250	250	250	250	1,250

377 If this company, at the end of the first year of its price control, manages to reduce its pensionable salary by 20% through a severance programme, at a cost in ERDCs equivalent to one year's salary, actual costs would be £1,250 made of £1,050 ongoing costs and £200 ERDCs as shown below.

Actual	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Pensionable salary	1,000	800	800	800	800	4,200
Ongoing pension cost @25%	250	200	200	200	200	1,050
ERDC	200	0	0	0	0	200
Pension Cost	450	200	200	200	200	1,250

378 If ERDCs are excluded from the calculation of over and under provision, then the company would have to pay back to consumers the shortfall in its ongoing costs i.e. £200. However, the company has actually paid into the pension fund exactly the amount allowed by the price control, as shown below.

Variances	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Pensionable salary	0	(200)	(200)	(200)	(200)	(800)
Ongoing pension cost @25%	0	(50)	(50)	(50)	(50)	(200)
ERDC	200	0	0	0	0	200
Pension Cost	200	(50)	(50)	(50)	(50)	0

379 Clearly, such an outcome would be illogical, and would be expected to act as a disincentive to companies carrying out severance programmes.

National Grid
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