Transmission Price Control Review: Initial Proposals

Response by National Grid

24 July 2006

Contents

1 Summary and conclusions

1 Ofgem have published their Initial Proposals for the Transmission Price Review ("TPCR"). Updates of these proposals are expected in September and December of this year. Recognising that many of the current proposals may be modified over the next few months, we would like to put in on record that we would find the proposals, as they stand, totally unacceptable.

2 The reasons for this relate to all of the main building blocks of the proposals, i.e.:

(a) operating costs;

(b) capital expenditure;

(c) incentives and adjustment mechanisms;

(d) pensions; and

(e) cost of capital/financeability.

3 In the following chapters, we set out why we find the current proposals unacceptable and suggest ways in which they might be modified. In brief, our main points, under the above headings, are as follows:

Operating costs

4 By far and away our biggest single issue with the Initial Proposals in this area is what we see as a huge gap between:

(a) what Ofgem are proposing to assume for operating costs; and

(b) the analysis and conclusions of the various consultants appointed by Ofgem to review our historic and projected costs.

5 This point, along with other points of significant but lesser materiality, is elaborated in **Chapter 2** below.

Capital expenditure - electricity

6 With respect to **historic** electricity capex, we are pleased that Ofgem accept that there is no evidence of inefficient spend through to March 2005. Ofgem are still considering our more recent historic spend.

7 With respect to **future load-related** electricity capex, we recognise that it is Ofgem's intention that remuneration will, during the next price control period, largely be driven by a variety of adjustment mechanisms and 'revenue drivers' against a 'baseline' of system capacity and a 'baseline revenue allowance' to deliver that baseline capacity. That said, we do have issues with both:

(a) the consistency between what Ofgem are assuming for the baseline capacity of the electricity transmission system and the base level of spend which has been allowed for in the proposed TO price control; and

(b) what generation projects should be included in the baseline.

8 With respect to **future non-load related** electricity capex, we believe that the proposed revenue allowance hugely under-estimates what will be needed to maintain the reliability and safety of the transmission system. We believe that this gap between us results from:

(a) the assumption of unrealistic unit costs, linked to, inter alia;

(i) selective use of completed projects; and

(ii) the double-counting of ‘procurement efficiencies’;

(b) the mistaken omission of certain categories of spend where we believe that there is a large measure of agreement about the need for the spend; and

(c) the selection by Ofgem of the lowest level of expenditure recommended by **each** of their two consultants for **each** category of investment without any apparent efficiency rationale for this selection.

Capital expenditure - gas

9 With respect to **historic** gas capex, the proposed disallowance of £75m to provide entry capacity at St Fergus is completely unacceptable in the light of:

(a) the circumstances and obligations which existed at the time of the investment decision; and

(b) the proven ‘used and useful’ status of the assets since their installation.

We also note that Ofgem seem to have included the relevant - and to be unremunerated - capacity in the baseline capacity which we will be obliged to offer to shippers.

10 With respect to **future load related** gas capex, we are pleased that Ofgem’s consultants have endorsed our updated forecast costs for Milford Haven and look forward to these being reflected in the September Update. We have major issues with the proposed revenue drivers (see below) and, in addition, some issues with Ofgem’s exclusion from the baseline of certain projects which have a high degree of certainty and user financial commitment.

11 With respect to **future non-load related** gas capex, the biggest single issue is Ofgem’s (and their consultants’) view that we should be closing six compressor stations, and their assumption of reduced running hours at a further four sites. We think that, against the background of acute uncertainty as to what the future pattern of gas flows will be, now is not the time for such a reduction in the flexibility of the gas transmission system.

12 All the above points on capex are elaborated in **Chapter 3** below.

Adjustment mechanisms and incentives

13 Our major concerns with the proposed mechanisms and incentives include the following:

(a) We believe that Ofgem's approach to estimating the Unit Cost Allowances (UCAs) - which will drive the incremental revenue - is likely to lead to the UCAs being systematically below the costs which we would need to incur to provide adequately flexible transmission systems.

(b) The proposed gas entry revenue drivers would, under reasonable assumptions, see us exposed to the difference between such (too low) UCAs and actual costs for up to around 12 years from April 2007, whereas the current entry regime effectively remunerates us for (efficiently incurred) actual costs from the start of the next price control period.

(c) The proposed gas entry baselines are well above the actual capability of the gas transmission system (with implications for the remuneration of investment required to be able to provide baseline capacity and for the buyback costs which would be borne by customers) while the proposed collar on the losses which we could make from buying back capacity would be triple what it currently is.

(d) The proposals for a new gas investment incentive would expose us to massive downside risk (potentially hundreds of millions of pounds) – as a result of a default delivery timescale of three years, no carve out of the risks associated planning consents (a major theme of the Government's Energy Review) and no collaring of our total losses under the scheme - with no realistic upside.

(e) There is a general lack of upside with the new incentives – explicitly with the proposed electricity network reliability incentive, implicitly with incentives like the new gas investment incentive.

14 In short, the proposed incentive mechanism would not seem to offer any sort of reasonable balance between risk and reward and would look to be inconsistent even with a base rate of return very much higher than the proposed overall cost of capital of 4.2% (on which more below).

15 Our thinking on the proposals on adjustment mechanisms and incentives is set out in **Chapter 4** below.

Pensions

16 Our main concerns with the proposals on pensions are:

(a) We continue to believe that there are strong arguments – much stronger than for the DNOs – why customers should fund legacy/Centrica related pension liabilities.

(b) We think that Ofgem's stance on ERDCs is completely unsustainable, not least because both the proposal and the basis for the proposal completely contradict Ofgem's position on the same issue at DPCR4 and the basis for that position

(c) We do not believe that the data exists to do a robust retrospective ‘overs and unders’ calculation for NGET. We believe that the data exists for NGG for the current price control period alone and that, in the light of previous Ofgem statements on this issue, there **should** be a retrospective overs and unders calculation for NGG for the current price control period.

17 Our thinking on the pensions issues raised by Ofgem’s proposals is set out in **Chapter 5** below.

Rate of return/financeability

18 Ofgem make it clear in the Initial Proposals that they have yet to complete their work on cost of capital and that the main debate on this issue is likely to ensue once Ofgem have published the work being undertaken by their advisers on this issue. In the meantime, we focus in **Chapter 6** below on two areas of debate which are specifically prompted by the Initial Proposals, i.e.:

(a) the extent to which Ofgem have justified in this document the move from a 4.8% cost of capital for DNOs in DPCR4 to 4.2% for transmission licensees; and

(b) the implications for NGET’s and NGG’s cost of capital of Ofgem’s proposals in the round, not least:

(i) the proposals for incentivising load related network capital expenditure; and

(ii) the proposal that any financeability issues should be resolve by equity injection.

19 In short:

(a) We do not believe that Ofgem can justify why the proposal (or ‘modelling assumption’) of 4.2% is so different from the still quite recent conclusion on DNOs’ cost of capital.

(b) In any event, whatever the relevant cost of capital for the sort of business risks faced by DNOs and, hitherto, by transmission businesses, Ofgem’s broader proposals for the next price controls for NGG and NGET pose a range of wider risks which, if not otherwise resolved, will have to be reflected in the cost of capital to be assumed in setting the new controls for these two businesses.

The specific questions raised by Ofgem in the proposals

20 In general, we have tried to answer the specific questions raised by Ofgem within the main text of our response. However, when this has not been done, we have appended specific answers to the relevant chapters.

2 Operating Expenditure

I Introduction

21 As detailed in our previous responses, we are supportive of the proposed approach by Ofgem to determine an appropriate allowance for operating expenditure through being informed by a detailed (“bottom-up”) assessment of the efficiency of our actual and planned expenditure.

22 We believe the work completed over the last nine months by Ofgem and their five efficiency consultants accords with their stated approach and has been well structured and appropriate.

23 However, we have great concern regarding both the:

(a) practical application of Ofgem’s stated approach; and

(b) Ofgem’s interpretation of the output of the consultants’ conclusions as set out in the initial proposals.

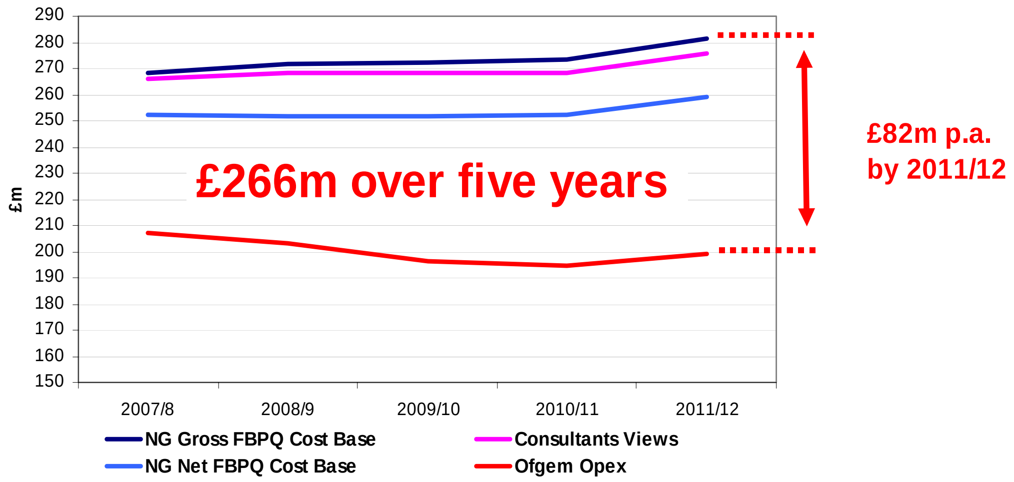
24 We believe these application and interpretation issues together have led to the proposals being unacceptable.

25 In overview, we believe that a balanced interpretation of the consultants’ conclusions (once necessary corrections on certain points of accuracy are made) together with only the true “normalisation” adjustments required to the base year would result in an operating expenditure allowance broadly consistent with our submission. Therefore, despite the difference between us in the initial proposals being highly material, we believe agreement on the appropriate allowance can be achieved with relatively little further work.

26 Our FBPQ submission factored in challenging, aspirational levels of saving in the form of our Transmission Efficiency Challenge programme. The Ofgem Initial Proposals, as they stand, demand an even greater requirement for cost reduction way beyond both these levels and those deemed reasonable by the consultants.

27 Ofgem’s approach to this review also seems to conflict with their approach to DNOs in DPCR4 where upper-quartile cost performance was used to establish the efficient frontier and DNOs that performed well were remunerated in line with their submissions.

28 The following graph sets the Ofgem Initial Proposals in the context of both our FBPQ submission and the consultants’ views. From the baseline of our gross cost base, i.e. prior to the Transmission Efficiency Challenge, the Initial Proposals would require us to save: ~£82m p.a. by 2011/12 and represent a further £266m reduction from our net submission for the entire period.



29 Savings of this magnitude are simply not deliverable without inconceivable reductions in all of our opex activities (in the order of 1000 staff and £40m of external expenditure) on a scale that would eliminate any capacity to undertake efficient, safe and reliable operation of our networks.

30 We set out the details of our response in eight sections.

(a) In **Section II**, we comment on our initial thoughts following receipt of the consultants' reports

(b) In **Section III**, we comment in detail on the assessment process

(c) In **Section IV**, we detail our thoughts in respect of the normalisation adjustments proposed

(d) In **Section V**, we comment on the efficiency improvements proposed

(e) In **Section VI**, we comment on the treatment of upward cost pressures proposed

(f) In **Section VII**, we comment on the proposed additional opex allowances

(g) In **Section VIII**, we comment on certain key issues that the Initial Proposals are silent on

(h) In **Section IX**, we comment on the individual questions posed in the operating expenditure chapter of the Initial Proposals

II Ofgem's Consultants' Reports

Overview

31 In aggregate, we believe the consultants appointed by Ofgem have generally developed fairly balanced central conclusions which reflect the current state of our operations.

32 Regrettably, we were not given any opportunity to review the findings of the consultants in advance of their use by Ofgem for the purposes of determining the Initial Proposals and in a small number of areas there are some critical errors which we believe need to be addressed that would increase their forecast level of expenditure.

33 However, despite these concerns, we broadly accept the general conclusion of the reports and believe that Compass's words in respect of their review of our IS activities sum up the general conclusion of all the consultants:

"as with any organisation there are areas where performance could be improved, but the overall conclusion is that NG is doing the majority of things well."

34 We believe a fair summary of the central conclusions of the reports is that:

(a) our support services are efficient;

(b) our IS costs are efficient and the contracting strategy underpinning these costs is leading edge;

(c) our engineering costs on both the electricity and gas networks are perhaps a little high but not unreasonable given the age and condition of our networks and the market place within which we operate;

(d) our insurance costs are lower than could be reasonably expected; and

(e) continuous improvements can be made to all these activities to incrementally improve them.

35 Thus, we believe that, taking these reports in the round, Ofgem should have "sense-checked" the proposed opex allowance that came out of the process they undertook to ensure that it properly reflected the central case recommendations proposed by the individual consultants. We believe that, if this "sense-check" had taken place, Ofgem would have recognised the vast discrepancy between their proposals and their consultants' recommendations along with the arithmetical flaws inherent in how those proposals were formed.

36 We also believe it is important to note that:

(a) Each consultant was clearly required to include a "high efficiency" case in their reports and that Ofgem have chosen to use these high efficiency cases as the basis of their proposals (albeit have used them incorrectly) without taking proper consideration of the significant caveats individual consultants placed around such cases.

(b) Several of the consultants also identified upward cost drivers and further risks to delivery of our business plan. Ofgem do not appear to have taken any account of these very real considerations.

37 Together, we believe these issues have led to a misrepresentation of the work of the consultants within the Ofgem proposals.

38 This section now goes on to summarise the key messages from each consultant. In addition to these summaries, we will comprehensively feed back our detailed comments on each of the reports in separate submissions to Ofgem.

Deloitte

39 Deloitte carried out four work packages on behalf of Ofgem, namely:

(a) accounting issues, to support the normalisation adjustments;

(b) business support services, to benchmark these activities;

(c) effect of the NGC/Transco merger; and

(d) top-down efficiency assessment

40 Below we set our individual comments in respect of each of these areas.

Accounting issues

41 Within this topic, we believe it is particularly important for Ofgem to note that:

(a) Deloitte identify that Ofgem need to complete **further work** in order to establish the validity of any normalisation adjustment in relation to “atypical” materials costs;

(b) Deloitte identify that Ofgem need to **consider separately** the allowance for environmental remediation costs; and

(c) in respect of employee share option costs (Sharesave schemes), Deloitte advise Ofgem that they should “take a view as whether to include them in ECOC **or to set up an alternative method of remuneration**”.

42 We believe that none of these issues have been properly addressed by Ofgem.

Business Support Services

43 In overview, we believe that the general conclusion drawn by Deloitte - that “The overall view from our analysis of the business support services is that the costs for 2004/05 compare favourably to our chosen high level benchmarks” – is reasonable.

44 However, despite this general endorsement, the consultant has been required to identify potential adjustments to cost areas. We note the following observations in

respect of these adjustments and the inconsistencies these present:

(a) **Corporate Centre. C**omparison with Electricity Distribution companies indicated that our overall costs are in the **top quartile** (i.e. the most efficient companies). Yet a **potential efficiency adjustment** was identified in respect of "corporate affairs" because of a single benchmark of "corporate affairs costs per FTE". We believe this is a highly tenuous potential adjustment, given the contradictory position stated by Deloitte that we "**perform well against the Corporate Affairs costs as a percentage of total operating costs**". Overall, we believe the benchmarking indicates that our corporate centre costs are efficient.

(b) **Communications.** Deloitte benchmarked communications costs against the "PR General Accepted Practices Study" published in 2005 by the Council of Public Relations Firms. Using this benchmark, they identify that National Grid spends double the level for companies with revenues above US$6bn. Whilst Deloitte do note "**the nature of NG's business places particular demands on its Communications function given contingency plans required for crisis management and the number of stakeholders it has to engage with as part of its business**", they go on to dismiss these considerations in their "high efficiency case" of reducing costs by 50%. We believe this case would be totally incompatible with delivering the services required of Communications, particularly given the increased level of our investment programme and the importance of good relationships with local communities to secure planning consents etc. (As is covered in Chapter IV below, Ofgem are currently proposing that the incentives which will apply to the delivery of new gas pipelines will not make any allowance for such planning applications even going to appeal and so would seem to be assuming a phenomenally effective and expensive communications machinery in that part of their proposals.)

(c) HR & Scheme Trainees – comparison with Electricity Distribution companies indicated that our overall costs are **lower** than those companies and that Deloitte state that the function "**performs above average relative to any sample**". Yet a **potential efficiency adjustment of up to 10%** was identified in respect of HR. We believe that this adjustment is completely unreasonable given the compelling (and accepted by Deloitte) evidence of efficient operation.

45 In summary, we believe that even the lower end of the scale of potential efficiency adjustments would be harsh, given the assessment of overall efficiency. We believe that all organisations, no matter how efficient, will always have some areas of activity that can be improved - but this is all part of the general requirement for continuous improvement. The level of improvement that can be expected should then be properly covered in both our own and Ofgem's requirement to deliver what is termed by Ofgem as "frontier shift".

Effect of NGC / Transco merger

46 In overview, we believe that the assessment made by Deloitte is reasonable in concluding that "It is clear from the HBPQ that merger savings have occurred, in particular for business support services over the 2002/03 to 2004/05 period. Savings in Corporate Centre, IS and Business Services appear to have exceeded NG's initial merger savings expectation. Therefore, it would appear that NG had managed to extract the bulk of merger savings from these areas."

47 We believe that this piece of work should provide Ofgem with the comfort that they require to be assured that we have extracted the benefits of merging these two organisations, with the benefits being passed to customers at the commencement of the next price control.

Top-down analysis

48 In overview we believe that Deloitte's conclusion "**Overall, it is not possible to conclude on the basis of this analysis that NGET is materially inefficient**" is fair. We believe this conclusion is valid because of both the level of our absolute efficiency and the generally accepted difficulty of finding comparator organisations.

49 By contrast, Ofgem's Third Consultation Document presented a subset of the numerical work undertaken by Deloitte, accompanying it with a statement concluding that "… this would mean that NGET's operating costs should be approximately £50 million lower than they are at present…" (relative to DNOs).

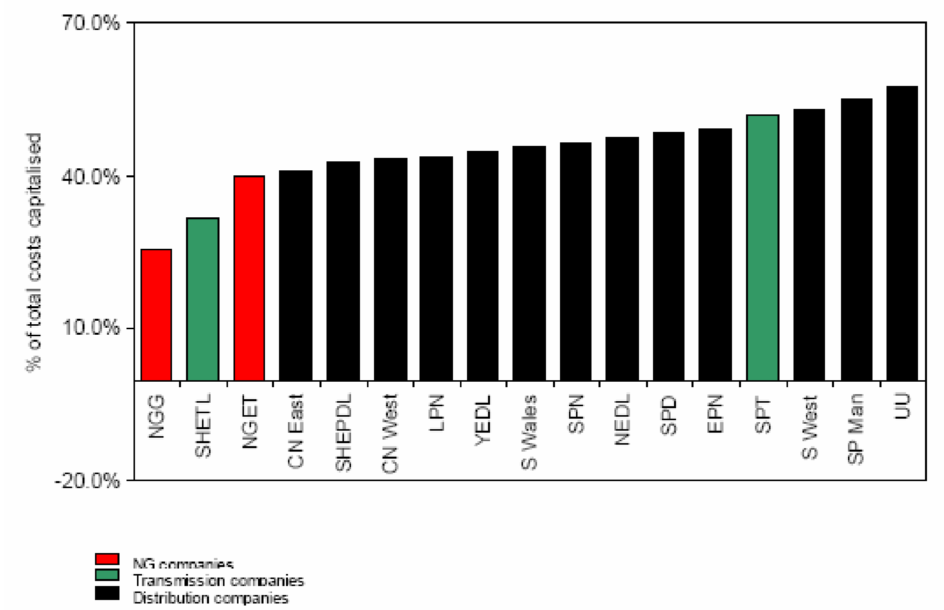
50 Our response to the Third Consultation Document presented a robust rebuttal of this assertion by Ofgem. However, we note that Ofgem's summary of our rebuttal in their Initial Proposals document is partial and does not properly represent the views that we expressed. For the avoidance of doubt, our rebuttal is summarised in the following paragraphs:

(a) The analysis had severe inherent arithmetic limitations most notably in respect of:

(i) the failure to properly normalise, i.e. make comparable the NGET and DNO datasets. The results of the study have been significantly distorted, in particular by the inclusion of network rates in the controllable cost base of NGET when these costs have been broadly flat in real terms since privatisation and the ratio of Network Rates to Controllable Costs is far higher in NGET than in any DNO;

(ii) the reallocation of costs between Distribution and Supply that took place with their separation (and that Ofgem openly acknowledged in their DPCR3 proposals) that does not appear to have been adequately corrected for;

(iii) the marked differences in capitalisation practice across the industry. We were generally aware that NGET capitalised a lower level of cost than most other companies in the industry at the time of our response to Ofgem's Third Consultation Document. However, the Deloitte report, which we received within the last few weeks, bears this out with a striking piece of analysis that shows NGET to be among the lowest "capitalisers" in the industry; significantly lower than the DNOs with which we were being compared. The chart summarising the Deloitte findings is reproduced below:



(iv) the selection of 1991 as a base year for an extrapolation stretching forward some 15 years when it is generally understood that National Grid was not a stand-alone entity pre-privatisation and was privatised with systems and processes running that were most interim in nature.

(b) NGET is not a DNO and has a cost base that reflects the critical differences between Transmission and Distribution. Most notably, the analysis presented included our System Operator ("SO") activities where the introduction of SO incentives by Ofgem was designed to encourage us to spend more on internal costs in order to leverage greater savings in external costs under successive Transmission Services or Balancing Services incentive schemes.

(c) No adjustment was made for the introduction of NETA by Ofgem in 2001 that drove incremental costs in our SO activities that were explicitly recognised and remunerated by Ofgem at the last price control review.

51 In our view the only informed interpretation of the analysis presented by Ofgem was that we had performed broadly in line with DNOs since privatisation.

52 Overall, we continue to believe that the limitations of the top-down analysis support our strongly held view that, in the absence of reasonable comparators, it is really only ever appropriate to use "bottom-up" analysis to determine an appropriate opex allowance.

Compass

53 In overview, we believe that Compass' assessment of our 2004/05 costs is reasonable and fair. We agree with Compass' overall conclusion that, **"As with any organisation there are areas where performance could be improved, but the overall conclusion is that NG is doing the majority of things well. Compass considers that both the CSC contract and the selective sourcing of the ADSM services are consistent with <u>leading practice</u> in sourcing of IT services."**

54 However, we believe the approach to our IS forecast costs is entirely unreasonable

and inappropriate, as detailed in the Information Services section of this document. The fragility of Compass' recommended savings is clearly highlighted by the following Compass caveat concerning our IS investment plan, **"A hypothetical reduction in the Investment Plan does yield savings, but this conclusion needs to be reviewed with caution, as the business impact of a reduced investment profile has not been assessed."** We do not believe that the Compass report forms any basis whatsoever to reduce our proposed IS plans and Ofgem have not sought to engage us in any form of business impact assessment of reducing our IS investment plan. Further specific comments regarding the apparent attribution of Compass savings to the Transmission business are also included in the section on Information Services.

Marsh

55 In overview, we welcome the conclusions of Marsh that:

(a) Our insurance costs in the benchmark year (2005/06) are almost £2m lower than the Marsh benchmark.

(b) Validates a projected trend of 5.8% annual growth in our insurance premia through to 2011/12.

(c) Our overall assessment of our total insurance premia projections are significantly lower than Marsh's own view.

56 Thus, we believe Marsh's report is supportive of our business plan submission, albeit with a general expectation that we have **under-estimated** insurance costs.

57 The one area where we do not concur with Marsh is their tentative proposition that an extrapolation of the Lloyd's of London Non-Marine market rate index may be a basis for determining an opex allowance. We believe the analysis is neither:

(a) statistically valid; nor

(b) representative of the actual costs that we are likely to incur.

58 Further discussion of this area is included in Section V of this chapter.

KEMA

59 In overview, we believe that KEMA's summary that "**NGET's costs are high but not unreasonable**" is fair.

60 We do believe there are some inconsistencies in the efficiency analysis KEMA use to propose some efficiency adjustments which would revise downwards their conclusions (details of these issues are included in Section V of this chapter). However, as evidenced in our own FBPQ submission, we accept that we will seek to secure further efficiencies and thus the general conclusion is valid.

61 We particularly welcome KEMA's general endorsement of the upward cost pressures within this area of expenditure and their central recommendation of an allowance that is significantly higher than that incurred in the base year (2004/05), and that is within £16m (prior to correction of inconsistencies) of NGET on a cost base of around

£500m.

TPA

62 In overview, we believe that TPA's general conclusion that "**Direct asset management and field related operating costs appear to be reasonable, reflecting the maturity of the business, and there are no significant areas that are candidates for material cost reductions unless assets are decommissioned**" is fair.

63 We do believe that TPA's "high efficiency" proposal in respect of decommissioning six compressor stations is unwise, given continuing volatility in the gas supply market and the enduring expectations of system security and reliability and we detail this in our response to TPA's capex proposals.

64 In the event, however, that TPA's proposals were deemed correct, then we also note TPA's correct observation that the costs of decommissioning would need to be considered. Since the best available estimate of these costs is £2m **per site** we highlight that the impact of this assumption (of decommissioning six compressor stations) would be to increase the opex allowance in this price control period, rather than decrease allowances as currently proposed.

65 We note TPA's comments in respect of contextualising their ranges for efficiency adjustments most notably the comments stating "**The analysis is presented as a <u>challenge</u> and the high efficiency adjustment is <u>aggressive</u>. The impact of the high adjustment would have to be carefully assessed and quantified as there is a risk that the core technical capability embedded within Network Strategy, whose role is design and development of the National Transmission System, would be adversely effected**". Again, we see no evidence of Ofgem taking due (or even any) regard of these comments.

66 We also welcome TPA's acknowledgement that there are material operating cost risks that National Grid is exposed to beyond the level of costs presented in our FBPQ. TPA's assessment particularly acknowledged three areas:

(a) risk of increased Pipelines Maintenance Centre ("PMC") costs in the event of a loss of income from independent gas distribution networks for planned maintenance and CEME services;

(b) risk of land and development quarry and loss of development rights compensation; and

(c) the need for an enhanced corrosion control programme for compressor sites.

67 This balanced evaluation of the risks and opportunities surrounding our FBPQ submission should be used as a model to determine the appropriate allowance. However, there is no evidence of Ofgem taking account of this information.

III Ofgem's Methodology

Principles

68 In Ofgem's presentation to analysts, they described their four stage approach to operating expenditure as:

(a) Stage 1 - Normalise 2004/5 base year

(b) Stage 2 - Consider scope for efficiency improvement (items identified by consultants)

(c) Stage 3 - Consider specific upward cost pressures

(d) Stage 4 - Consider scope for continuing efficiency improvement

69 Additionally, Ofgem further define their approach by stating

(a) "We have "normalised" 2004/5 (taken as our base year) operating costs by removing, amongst other things, non-recurring and atypical cost items. We have also made some adjustments for different accounting treatments of certain types of expenditure"

(b) "We have considered the scope for further efficiency improvements during the coming price control period <u>against the normalised level of base year controllable costs</u>"

(c) "We have considered upward cost pressures for some elements of operating cost and the need for additional allowances in respect of new categories cost"

Application

70 In **principle** we believe that the approach stated above is reasonable. Whilst we have developed a "bottom-up" business plan, setting out our forecast requirement for operating expenditure in each individual year of the plan period, the stated approach should still accommodate consideration of all the costs presented within our plan.

71 However, this agreement in principle assumes:

(a) **all** the efficiency improvements and upward cost drivers included in our business plan submission are considered and properly adjusted for; and

(b) all adjustments are **relative to the normalised base year** controllable costs.

72 Unfortunately, it is evident that Ofgem's initial proposals have failed to meet these requirements. Most significantly, the proposals:

(a) fail to recognise all of the upward cost drivers included in our business plan submission (not least the significant increase in work within direct opex associated with the expansion of our networks as a result of our increasing capital investment programme);

(b) have re-cast adjustments proposed by consultants – which are **relative to our business plan** forecast of costs - and mis-applied them by deducting these from the normalised level of base year controllable costs; and

(c) then apply a further frontier “shift” on top of all of these adjustments without taking into account the individual progressive efficiencies already included above.

73 All of the above factors have contributed to the presentation of a flawed and highly unrealistic series of opex allowance proposals.

IV Normalisation of 2004/05 Costs

74 The following table sets out the normalisation adjustments proposed by Ofgem to our 2004/05 Controllable Cash Costs in respect of NGET and NGG. A combined total is also shown.

Ofgem "Normalisation Adjustments"	NGET £m	NGG £m	Total £m
Controllable Cash Costs (National Grid)	**179.3**	**63.6**	**242.9**
- Disallowed Costs	(3.2)	(0.1)	**(3.3)**
- Non Cash Costs	(3.3)	(0.6)	**(3.9)**
- Atypical and Non Recurring Costs	(22.9)	(2.9)	**(25.8)**
Recurring Cash Controllable Costs (Ofgem)	**149.9**	**60.0**	**209.9**

75 This section now deals with each of the proposed Ofgem normalisation adjustments in turn.

Disallowed Costs

76 Disallowed costs are only a material issue in Ofgem's proposals in respect of NGET although the principles of this response are equally applicable to any regulated entity. The table below sets out Ofgem's disallowance for NGET:

Ofgem "Disallowed Costs"	NGET £m
- Onerous Lease Costs	1.4
- Related Party Margins	0.7
- Excluded Services Costs	1.1
Total Disallowed Costs	**3.2**

77 This sub-section now deals with each of Ofgem's proposed adjustments in turn.

Onerous Lease Costs

78 An onerous lease in accounting terms refers typically to a situation where a company has ongoing liabilities under a head-lease on a property but is either:

(a) unable to recover the appropriate offsetting sums under sub-lease(s) from tenants; or

(b) no longer has a substantial business requirement for the property.

79 We do not accept this adjustment for two reasons:

(a) Simply because one may have what the accountancy profession refer to as an "onerous" obligation does not mean that either the original business rationale for entering into the head-lease or (in this case) the business decision to vacate the property was invalid. We assume that this adjustment is associated with our former Brookmead site which we decided to vacate as part of the overall consolidation of our activities in our Refocusing change programme during the HBPQ period. Refocusing delivered substantial cost reductions for our customers and was positive NPV so it is difficult to see a rationale for the exclusion of this cost.

(b) In the limited time that we have had the full Deloitte report to examine we have not been able to conclusively analyse all of the numbers presented. We believe that this value may have effectively been deducted twice over. Further work will need to be undertaken in order to prove this point. However, irrespective of the outcome, our first reason for rejection still applies.

Related Party Margins

80 In principle we do not believe it is sound for Ofgem to exclude related party margins in the instances referred to in their initial proposals given that the associated services provided to NGET by the related parties are:

(a) negotiated at arms length;

(b) provided on a commercial basis; and

(c) priced competitively in relation to the external market.

81 In practice, we understand that Ofgem wish to apply a policy of disallowing related party margins in instances where less than 75% of related party business is with other entities, with the exception of our insurance captives where paragraph 7.28 of Ofgem's initial proposals explicitly state that these will be allowed given the overall efficiencies that the captives clearly generate for customers in insurance costs.

82 We do not believe that the "75% rule" is, in itself, a sufficient basis to determine the appropriate treatment, as Ofgem have acknowledged in the case of Insurance costs, and therefore, given that the commercial risk associated with these transactions lies with an entity outside of the regulated activity, the related party margin should be allowed as would be the case if these services were provided by any other external entity.

Excluded Services Costs

83 Excluded services are services provided by NGET in accordance with the terms of the Transmission Licence that remain outside of the scope of the RPI-X price control arrangements and include such services as where we are required to (and charge separately) for the relocation of HV equipment at the request of the Highways Agency.

84 Ofgem effectively have two options for the treatment of opex (and income streams) associated with the provision of excluded services. These are:

(a) to allow the costs of service provision projected by National Grid but ensure that the associated income streams projected by National Grid are offset prior to the setting of the RPI-X parameters to ensure that we are not effectively remunerated twice;

(b) to exclude the costs of service provision projected by National Grid and set the RPI-X parameters independently and without an offset for projected excluded services income.

85 Ofgem appear to have selected option (b) and we therefore highlight the need for Ofgem to ensure that they do not make a deduction to RPI-X income of the anticipated income (to offset projected excluded services income).

Non-Cash Costs

86 Ofgem's proposed non-cash adjustments for NGET £3.3m and NGG £0.6m relate entirely to FRS20 "Share Based Payments" required to reflect the fair value of options at the date of grant.

87 We do not believe this is an appropriate adjustment for two reasons:

(a) The costs are in fact cash, rather than non-cash, because the requirements of the Inland Revenue dictate that inter-company balances are settled in cash. These charges were made by National Grid Group (the issuer of shares) to operating companies including NGET and NGG and were therefore settled in cash.

(b) Extending the option to staff to join employee "sharesave" schemes reflects best remuneration practice and provides clear benefits associated with:

(i) aligning the financial interests of employees with share price performance and therefore implicitly ongoing performance improvement in terms of service provision and cost efficiency in line with regulatory objectives;

(ii) shifting the balance of staff reward away from collectively negotiated and contractually fixed salary and benefits packages to more performance-related and market-tested share based remuneration;

(iii) further shifting the balance of staff reward away from pensionable cash remuneration; and

(iv) attraction and retention of staff in a labour market that is becoming increasingly competitive in respect of the core skills that we rely on.

88 In their report, Deloitte point out that they have adjusted these costs out of the normalised cost base on the basis that they are non-cash to the National Grid Group (a point that we believe is not relevant for the assessment of the cash costs of the regulated entity). However, Deloitte also go on to recognise that Ofgem need to give consideration as to how the cost to National Grid shareholders of employee "sharesave" schemes should be remunerated and propose that Ofgem consider either:

(a) their re-inclusion in the 2004/05 base year i.e. the reversal of this adjustment; or

(b) the setting up of an alternative form of remuneration.

89 We propose option (a), a simple re-inclusion of these costs in the 2004/05 base year

as a proxy for the cost to shareholders of successive annual "sharesave" offerings to staff over the price control period rather than the introduction of a more complex mechanism.

Atypical and Non-Recurring Costs

90 The following table sets out the adjustments for "atypical" and "non-recurring " costs proposed by Ofgem as a deduction to our 2004/05 Controllable Cash Costs in respect of NGET and NGG. A combined total is also shown.

Ofgem "Atypical and Non Recurring Costs"	**NGET £m**	**NGG £m**	**Total £m**
- PLUGS	(12.1)		(12.1)
- Network Sales Related		(0.7)	(0.7)
Engineering Costs			
- Environmental Clean Up	(0.5)		(0.5)
- Littlebrook Subsidence Repairs	(0.6)		(0.6)
- Atypical Materials Costs	(5.0)		(5.0)
- Restructuring	(1.6)	(2.2)	(3.8)
- Severance	(0.1)		(0.1)
- Investment for Efficiency	(3.0)		(3.0)
Total Atypical and Non Recurring Costs	**(22.9)**	**(2.9)**	**(25.8)**

91 Each of these proposed adjustments is now considered in turn.

PLUGS

92 The impact of refunding capital contributions to our connection customers as part of the change to our connection charging methodology known as "PLUGS" was a one-off activity and we agree with this proposed adjustment.

Network Sales Related

93 The impact of Network Sales on regulated business costs was minimal and we accept this proposed adjustment.

Engineering Costs

94 As previously described, Ofgem's methodology involved both:

(a) "normalisation" adjustments to a 2004/05 base year undertaken by Deloitte; and

(b) assessment of both 2004/05 base year and future operating costs undertaken by other consultants.

95 Three of the adjustments proposed by Ofgem under the heading of "Atypical and Non-Recurring Costs" that were sourced from the Deloitte report were also examined in

great detail by KEMA.

96 We have reviewed the Deloitte and KEMA reports and how Ofgem have integrated these findings arithmetically in their Initial Proposals and two significant issues arise:

(a) Normalisation adjustments highlighted for potential inclusion in Ofgem's proposals by Deloitte appear to be strongly contradicted by the technical findings of KEMA; and

(b) There is serious logical flaw in how Ofgem have integrated the two sets of numbers in their proposals.

97 The logical flaw arises because:

(a) Ofgem have derived their future "engineering efficiency" adjustment from the KEMA findings. KEMA have reviewed our FBPQ submission as a freestanding document on its own merits and arrived at a judgement on an appropriate level of cost and have clearly expressed the "engineering efficiency" adjustment as the difference between:

(i) **Our FBPQ submission for engineering costs**; and

(ii) **KEMA's adjusted forecast for the same period**.

(b) Deloitte on the other hand have examined only the 2004/05 base year (and not our FBPQ submission) and highlighted a series of instances where costs have increased between 2003/04 and 2004/05 and have either badged these as "atypical and non-recurring" or highlighted them for further investigation. All of these items have been included by Ofgem in the normalisation adjustments for their Initial Proposals.

98 The effect of simply integrating the KEMA "engineering efficiency" adjustments and the Deloitte base year adjustments represents a logical contradiction, whereby the net effect is to reduce our future opex allowances significantly below the levels endorsed in the KEMA findings. It is important to remember that our FBPQ submission was a comprehensive and detailed bottom-up build and not an extrapolation of 2004/05.

99 As we have stated, the "engineering efficiency" adjustments in the KEMA report were expressed as savings **relative to our FBPQ submission**. In integrating these adjustments with their initial proposals, Ofgem should clearly have performed a calculation to re-base the adjustments in order to make them arithmetically relative to their flat extrapolation of our 2004/05 base year (referred to as Recurring Cash Controllable Costs or RCCC) that is at the baseline for their proposals. This arithmetical flaw compounds with the logical flaw previously explained and leads to gross understatement of our opex allowance in the Ofgem Initial Proposals.

100 These issues are now explored in detail under the headings of the three proposed adjustment which are:

(a) environmental Clean-Up;

(b) Littlebrook Subsidence Repairs; and

(c) atypical Materials Costs.

Environmental Clean Up

101 The environmental clean up costs identified as "atypical" for adjustment relate to addressing past contamination at substation sites relating primarily to fulfilling our legal obligations under the Water Resources Act (1991) and the Groundwater Regulations (1999).

102 We incurred costs of £0.5m in 2004/05 and charged these against an environmental provision in our accounts and the £0.5m cash utilisation of this provision was correctly added to our accounting costs for the year in the computation of ECOC in order to reflect the full cash costs for the year.

103 Deloitte concur with this treatment in paragraph 2.13.11 of their report where they state that our treatment of "**adding back the release of the provision to remove the effect of operating costs being reduced is correct**".

104 In paragraph 2.13.12 of the Deloitte report, however, they state that this "cash cost has been removed from ECOC in order to highlight the item". It is not clear to us why:

(a) Deloitte specifically wished to highlight this item to Ofgem; and

(b) why Ofgem have then used this as an adjustment to our 2004/05 base year.

105 The KEMA report states that "…given the existence of the legislation, this expenditure would seem necessary and the cost levels appear to be reasonable".

106 The table below illustrates how Ofgem's Initial Proposals integrate the findings of Deloitte and KEMA with the following points of note:

(a) the KEMA-endorsed forecast is in line with National Grid's FBPQ submission and KEMA have not proposed a resulting "engineering efficiency adjustment"; and

(b) the entire cost of past contamination works in 2004/05 has been deducted from Ofgem's extrapolation of RCCC.

107 The net effect is that Ofgem's initial proposals provide no remuneration whatsoever for past contamination works, whereas we believe an allowance of £8.8m has been validated as being necessary. As is the case with Ofgem's omission of the upward cost driver associated with SF6 leak reduction (discussed further in Section V of this chapter). Such an approach contrasts sharply with the tone of Chapter 12 of Ofgem's Initial Proposals where certain environmental impacts of transmission are discussed in relation to Ofgem's statutory duties.

Environmental Clean Up / Past Contamination Costs	2004/05 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m	Total 2007/08 - 2011/12 £m
National Grid FBPQ Submission		2.5	2.8	1.5	1.0	1.0	8.8
KEMA Endorsed Forecast (A)		**2.5**	**2.8**	**1.5**	**1.0**	**1.0**	**8.8**
KEMA "Engineering Efficiency" Adjustment		0.0	0.0	0.0	0.0	0.0	0.0
National Grid Base Year Cost	0.5						
Deloitte "Normalisation" Adjustment	(0.5)						
Ofgem Derived RCCC (B)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Under-Statement of Opex Allowance		**(2.5)**	**(2.8)**	**(1.5)**	**(1.0)**	**(1.0)**	**(8.8)**

Littlebrook Subsidence Repairs

108 The proposed £0.6m adjustment relates to emergency repair expenditure in 2004/05 associated with provision of a short term solution to ensure continued reliable operation of our Littlebrook substation in the face of severe subsidence issues.

109 The KEMA report states that “NGET has provided extensive information on this scheme in both the HBPQ and FBPQ Opex Workshops and the site evidence provided demonstrates the need for the expenditure … Furthermore **the proposed costs in the FBPQ period appear reasonable given the condition of the Littlebrook site and substation infrastructure**”.

110 The table below sets out the impact of how Ofgem have integrated the Deloitte and KEMA findings with the net effect of providing no remuneration whatsoever for rectification of the serious issues at the Littlebrook site:

Littlbrook Subsidence	2004/05 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m	Total 2007/08 - 2011/12 £m
National Grid FBPQ Submission		1.0	1.9				2.9
KEMA Endorsed Forecast (A)		**1.0**	**1.9**	**0.0**	**0.0**	**0.0**	**2.9**
KEMA "Engineering Efficiency" Adjustment		0.0	0.0	0.0	0.0	0.0	0.0
National Grid Base Year Cost	0.6						
Deloitte "Normalisation" Adjustment	(0.6)						
Ofgem Derived RCCC (B)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Under-Statement of Opex Allowance		**1.0**	**1.9**	**0.0**	**0.0**	**0.0**	**2.9**

Atypical Materials Costs

111 The Deloitte report to Ofgem included an adjustment to our 2004/05 base year costs relating to three large movements that they observed between 2003/04 and 2004/05 in the “materials” cost line in our management accounts. These related to:

Ofgem "Atypical Materials Costs"	**NGET £m**
- Site Care / Statutory Testing	1.9
- Cable Fault Rectification	1.9
- HV Plant Maintenance	1.2
Total	**5.0**

112 Deloitte stated that an “adjustment to ECOC in respect of these costs **may** be required in order to achieve a normalised cost base in the base year”. These adjustments appear to have been carried directly through to the Ofgem Initial Proposals without further investigation or validation in the context of the detailed KEMA findings in the relevant areas.

113 KEMA analysed our FBPQ submissions for Site Care/Statutory Testing and HV Maintenance costs as part of an overall benchmarking of total Substations costs. KEMA have also benchmarked total Cable costs and proposed future “engineering efficiency” adjustments in respect of both Substations and Cable activities.

114 The table below sets out National Grid’s FBPQ submission, the KEMA-endorsed forecast incorporating the “engineering efficiencies” and illustrates the combined under-remuneration versus the KEMA endorsed forecast that arises as a result of both:

(a) the additional incorporation of the Deloitte adjustments to the 2004/05 base year; and

(b) the failure by Ofgem to re-base the KEMA “engineering efficiency” adjustments to make them arithmetically relative to their flat extrapolation of RCCC.

Total Acticvity Costs and Material Cost Sub Component Adjustments	2004/05 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m	Total 2007/08 - 2011/12 £m
National Grid FBPQ Submission							
- Substations		41.2	44.7	45.3	43.8	44.2	219.2
- Cables		4.4	4.4	4.5	4.5	4.5	22.3
Total National Grid FBPQ Submission		**45.6**	**49.1**	**49.8**	**48.3**	**48.7**	**241.5**
KEMA Endorsed Forecast (A)		**43.9**	**46.4**	**46.1**	**43.7**	**43.1**	**223.2**
KEMA "Engineering Efficiency" Adjustment (B)		(1.7)	(2.7)	(3.7)	(4.6)	(5.6)	(18.3)
National Grid Base Year Cost							
- Substations	35.9						
- Cables	5.3						
Total National Grid Base Year Cost	**41.2**						
Deloitte "Normalisation" Adjustment to Materials Cost Sub-Component	(5.0)						
Ofgem Derived RCCC (C)	**36.2**	**36.2**	**36.2**	**36.2**	**36.2**	**36.2**	**181.0**
KEMA "Engineering Efficiency" Adjustment (B)		(1.7)	(2.7)	(3.7)	(4.6)	(5.6)	(18.3)
Ofgem Opex Allowance - (D) = (C) + (B)		**34.5**	**33.5**	**32.5**	**31.6**	**30.6**	**162.7**
Under-Statement of Opex Allowance (D) - (A)		**(9.4)**	**(12.9)**	**(13.6)**	**(12.1)**	**(12.5)**	**(60.5)**

115 The total-under remuneration for Substation and Cable activities in the Ofgem Initial Proposals amounts to some £60.5m over the period 2007/08 to 2011/12.

Restructuring, Severance and Investment for Future Efficiency

116 In aggregate for NGET and NGG the Ofgem Initial Proposals contain a £6.9m downward adjustment to our 2004/05 base year (and therefore a £34.5m downward adjustment for the entire price control period running from 2007/08 to 2011/12) that effectively excludes all remuneration associated with the “costs to achieve” future efficiency.

117 We agree with Ofgem that the **specific** “costs to achieve” incurred by NGET and NGG

in the 2004/05 base year will not necessarily represent those that will we incur across the forthcoming price control period and that they should therefore be adjusted out of ECOC / RCCC.

118 However, our future opex allowance clearly should contain an appropriate level for remuneration of costs that will allow us to achieve future efficiency savings for customers and we believe that this should be closely linked with Ofgem's proposed "Frontier Shift" adjustments because:

(a) for frontier shift to be a factor in future opex allowances a company clearly needs to be at the frontier in the first instance; and

(b) the costs associated with achieving frontier shift should clearly not be the burden of shareholders. In other words, these costs will, **by definition**, be efficiently incurred (they would be charged to customers in a competitive market) and there is therefore no reasonable basis for their disallowance.

119 This issue is explored in detail in Section V of this chapter in response to Ofgem's proposed future efficiency adjustments where we also set out an illustrative calculation of the future costs to achieve frontier shift. The average annual cost has been incorporated in our proposed adjustments to the base year.

Conclusions - Normalisation of 2004/05 Costs

120 The following table summarises the normalisation adjustments proposed by Ofgem in their initial proposals and the corrections set out in this response. As they stand, Ofgem's normalisation adjustments to our 2004/05 base year represent a major £81.2m under-funding across the period of the forthcoming price control.

Conclusions - "Normalisation Adjustments"	**NGET £m**	**NGG £m**	**Total £m**
Controllable Cash Costs (National Grid)	**179.3**	**63.6**	**242.9**
- Disallowed Costs	(3.2)	(0.1)	**(3.3)**
- Non Cash Costs	(3.3)	(0.6)	**(3.9)**
- Atypical and Non Recurring Costs	(22.9)	(2.9)	**(25.8)**
Ofgem Initial Proposals RCCC	**149.9**	**60.0**	**209.9**
- Disallowed Costs	2.1		**2.1**
- Non Cash Costs	3.3	0.6	**3.9**
- Atypical and Non Recurring Costs	9.0	1.2	**10.2**
Ofgem Initial Proposals RCCC (Corrected)	**164.3**	**61.8**	**226.1**
Intitial Proposals Under-Statement	**(14.4)**	**(1.8)**	**(16.2)**
Impact of Under-Statement 2007/08 to 2011/12	**(72.2)**	**(8.9)**	**(81.2)**

V Efficiency Analysis

121 The following table sets out the future efficiency adjustments proposed by Ofgem in respect of NGET and NGG. Combined totals are also shown.

Ofgem "Efficiency Adjustments"	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
NGET					
Shared Services	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)
Corporate Centre	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Engineering Opex	(1.5)	(2.8)	(4.1)	(6.4)	(7.7)
Information Services	(0.7)	(1.1)	(1.7)	(2.1)	(2.7)
Insurance	(3.3)	(4.8)	(3.5)	(1.7)	0.5
Frontier Shift	(2.2)	(4.5)	(6.6)	(8.8)	(10.9)
NGET Total	**(12.8)**	**(18.2)**	**(21.0)**	**(24.0)**	**(25.8)**
NGG					
Shared Services	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Corporate Centre	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)
Engineering Opex	(0.6)	(1.0)	(3.6)	(3.6)	(3.6)
Information Services					(0.1)
Insurance	(1.8)	(2.7)	(1.9)	(0.9)	0.3
Frontier Shift	(0.9)	(1.8)	(2.7)	(3.5)	(4.4)
NGG Total	**(4.8)**	**(6.9)**	**(9.6)**	**(9.6)**	**(9.3)**
NGET and NGG Combined					
Shared Services	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)
Corporate Centre	(5.1)	(5.1)	(5.1)	(5.1)	(5.1)
Engineering Opex	(2.1)	(3.8)	(7.7)	(10.0)	(11.3)
Information Services	(0.7)	(1.1)	(1.7)	(2.1)	(2.8)
Insurance	(5.1)	(7.5)	(5.4)	(2.6)	0.8
Frontier Shift	(3.1)	(6.3)	(9.3)	(12.3)	(15.3)
Combined Total	**(17.6)**	**(25.1)**	**(30.6)**	**(33.6)**	**(35.1)**

122 This section now deals with each of the proposed Ofgem efficiency adjustments in turn.

Shared Services

123 The assessment of our Shared Services functions was undertaken by Deloitte based on our costs in 2004/05. We have not been provided with a reconciliation of Deloitte's conclusions to the Ofgem Initial Proposals so detailed analysis of their validity has not been possible, however, we note that the Deloitte concluded that **"at a high level … the costs for 2004/05 compare well with our benchmarks"** and that the performance of a number of functions was clearly regarded as upper-quartile.

124 Given our planned transition to a UK Shared Services Organisation as set out in our FBPQ submission we regard the proposed adjustments as being challenging, but generally in line with the additional efficiencies that we aspire to achieve in these areas.

Corporate Centre

125 The table below sets out Ofgem's proposed efficiency adjustments in relation to our corporate centre. The numbers in each case represent only allocations to NGET and NGG of the total corporate centre costs for each department which are further allocated to the UK Distribution activities of NGG and our non-regulated and overseas activities.

Ofgem "Corporate Centre Effifiencies"	**NGET £m**	**NGG £m**
- Corporate Affairs	(1.0)	(0.3)
- Corporate Social Responsibility	(0.3)	(0.1)
- Finance	(1.1)	(0.3)
- General Counsel	(0.3)	(0.1)
- HR	(0.8)	(0.2)
- Investor Relations	(0.2)	(0.1)
- Media Relations	(0.1)	(0.0)
- Group Strategy	(0.2)	(0.0)
Total Annual Efficiency Adjustment	**(4.0)**	**(1.1)**

126 We note that the benchmarking review undertaken by Deloitte of Corporate Centre costs concluded that:

(a) "**…the Corporate Centre has not shown any evidence of major inefficiencies**"; and

(b) benchmarking versus DNO Corporate Centre costs **"…indicated that overall costs are in the top quartile…**".

127 Deloitte, however, did tentatively propose some potential future savings against the total Corporate Centre cost base in a range £0.9m to £3.3m. The table below illustrates how this range of savings would allocate to the Transmission activities of NGET and NGG;

Deloitte Corporate Centre Benchmarking	**Group Total £m**	**Other Functions £m**	**NGET £m**	**NGG £m**
Total Corporate Centre Costs	34.3			
Potential Savings Range				
- Low	(0.9)	(0.5)	(0.2)	(0.2)
- High	(3.3)	(2.9)	(0.2)	(0.2)

128 Ofgem, by contrast, state in their Initial Proposals that they have reviewed the costs on a departmental basis and considered whether:

(a) the services provided are duplicated by or could be absorbed without cost by our UK shared services functions already providing services to the UK regulated business; and

(b) the department is essential to the running of the UK regulated business.

129 We discussed this issue in great detail with Deloitte to demonstrate:

(a) the activities undertaken by each department and their often external drivers;

(b) the boundary between our UK shared services functions and our corporate centre and the absence of overlaps or duplications; and

(c) the rationale for why that boundary has been drawn (in each case) where it has in order to separate out those services that can be provided more economically to individual businesses through provision of international, Group-wide shared services as opposed to through our UK shared services functions.

130 We note that Deloitte did not highlight any need to further consider this issue in their report to Ofgem.

131 We totally reject Ofgem's assertion that these services provided are duplicated by or could be absorbed without cost by our UK shared services functions given that:

(a) there is no duplication;

(b) absorbing these quite distinct activities in our UK shared services functions would lose Group-wide economies of scale that we currently enjoy and lead to higher costs being allocated to UK regulated business customers;

(c) Ofgem's Initial Proposals are entirely at odds with the outcome of the review undertaken for them by Deloitte; and

(d) Ofgem's Initial Proposals discriminate against NGET and NGG versus DNOs where we can see no evidence of similar arbitrary exclusion of Corporate Centre costs in Ofgem's public documents associated with DPCR4.

132 Ofgem's approach also fails to recognise that there are certain departments (and costs carried within departments) where cost reduction is either:

(a) not possible because the cost in question is unavoidable;

(b) inconsistent with Ofgem's proposals in relation to other departments and approach to financeability; or

(c) in relation to activities supported by National Grid that, although not strictly "essential", remain highly desirable and part of a broader corporate agenda of "doing the right thing".

133 Each of these areas is now considered in turn.

Unavoidable Costs

134 The costs of Annual Report production and the Audit Fee for the National Grid Group

are costs that we will incur irrespective of organisation structure i.e. these are costs any stand-alone business would bear. Exclusion of these costs is therefore unwarranted and also seems inconsistent with the allowance that Ofgem have given for our Company Secretariat, given that costs in all of these areas are driven by similar statutory obligations. These costs and their respective allocations to NGET and NGG are set out in the table below:

Unavoidable Costs	**Gross £m**	**NGET £m**	**NGG £m**
- Annual Report (within Corporate Affairs)	1.2	0.2	0.1
- Audit Fee (within Finance)	1.5	0.3	0.1
Total	**2.7**	**0.5**	**0.1**

Inconsistencies

135 Ofgem's Initial Proposals in relation to "financeability" are predicated on our ability to raise and inject further equity. Such an equity injection would clearly require effective communication with our investors and, irrespective of this, it is entirely normal and efficient for a quoted company to undertake investor relations activity.

Inconsistencies	**Gross £m**	**NGET £m**	**NGG £m**
- Investor Relations	1.1	0.2	0.1
Total	**1.1**	**0.2**	**0.1**

Doing the Right Thing

136 The activities falling under this heading for which funding has been excluded by Ofgem are by no means mandatory activities for National Grid However, we consider it important for large companies to aspire do the right thing in wider social context and expect support from Ofgem in achieving these objectives. It is simply not good enough in today's context to run a major FTSE 100 company without regard for wider social impacts.

Doing The Right Thing	**Gross £m**	**NGET £m**	**NGG £m**
- Corporate Social Responsibility	1.7	0.3	0.1
- Young Offenders / Charitable Foundation	1.7	0.3	0.1
(within Corporate Affairs)			
Total	**3.4**	**0.7**	**0.2**

137 We also consider Ofgem's exclusion of our Corporate Social Responsibility budget discriminatory in the face of the very explicit incentive arrangement offered to DNOs that encompassed among other things reward for undertaking precisely such activities.

Conclusions – Corporate Centre

138 We do not believe Ofgem's Initial Proposals are sound with regard to our Corporate Centre costs. However, by contrast we believe proposals in line with the recommendations by Deloitte would be more balanced given that:

(a) they were based on objective benchmarking and a broad understanding of how large companies operate and what constitutes a reasonable level of cost; and

(b) they were clearly more in line with the previous treatment given by Ofgem to DNOs against whom we benchmarked very favourably.

Engineering Opex (Electricity)

139 We have reviewed Ofgem's initial proposals and a version (albeit a version where the figures do not reconcile precisely to the Initial Proposals) of KEMA's draft report to Ofgem.

140 Overall the findings of KEMA appear balanced and they state that "NGET's costs are high but **not unreasonable**". Despite this, Ofgem's Initial Proposals grossly under-fund our electricity engineering opex primarily as a result of an arithmetical flaw in how Ofgem have chosen to incorporate the findings of KEMA in their Initial Proposals.

141 In addition, we have a small number of more detailed areas where we differ with KEMA and this response now explores each of these areas in turn.

Arithmetical Flaw

142 The following table uses data extracted from the KEMA report to Ofgem and our FBPQ submission to:

(a) recreate the adjustment presented by Ofgem in their Initial Proposals;

(b) set out the arithmetical flaw made; and

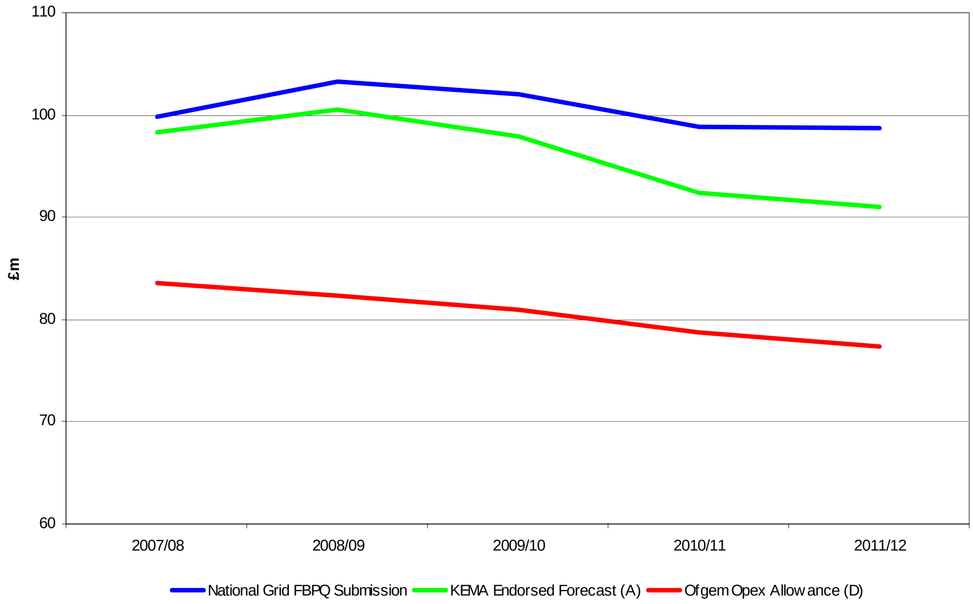
(c) illustrate the overall gap between National Grid's FBPQ submission and Ofgem's Initial Proposals.

NGET Engineering Opex	2004/05 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m	Total 2007/08 - 2011/12 £m
KEMA Assessment of Efficient Opex							
National Grid FBPQ Submission		99.8	103.3	102.0	98.8	98.6	502.5
KEMA Endorsed Forecast (A)		**98.3**	**100.5**	**97.9**	**92.4**	**90.9**	**480.0**
KEMA "Engineering Efficiency" Adjustment (B)		**(1.5)**	**(2.8)**	**(4.1)**	**(6.4)**	**(7.7)**	**(22.5)**
Ofgem Calculation of Opex Allowance							
National Grid Base Year Cost	91.2						
Deloitte "Normalisation" Adjustments							
- Environmental Clean Up	(0.5)						
- Littlebrook Subsidence Repairs	(0.6)						
- Atypical Materials Costs	(5.0)						
Ofgem Derived RCCC (C)	85.1	85.1	85.1	85.1	85.1	85.1	425.4
KEMA "Engineering Efficiency" Adjustment (B)		(1.5)	(2.8)	(4.1)	(6.4)	(7.7)	(22.5)
Ofgem Opex Allowance (D)		**83.6**	**82.3**	**81.0**	**78.7**	**77.4**	**402.9**
Under-Statement of Opex Allowance (D - A)		**(14.8)**	**(18.2)**	**(16.9)**	**(13.7)**	**(13.6)**	**(77.2)**

143 KEMA assessed NGET's FBPQ submission as a freestanding document on its own merits and identified efficiencies where they felt appropriate. These efficiencies have then been applied by KEMA **to NGET's FBPQ profile** in a logical manner. In the main, the drivers for NGET's rising profile have been acknowledged by KEMA and the proposed efficiencies explicitly mitigate the impact partially of some of these upward drivers.

144 The arithmetical flaw introduced by Ofgem arises because **they have deducted the KEMA efficiencies that were derived from their review of a rising cost base from a flat extrapolation of the Ofgem "normalised" 2004/05 cost base**. This arithmetical error, coupled with the flawed "normalisation" adjustments to the base year that we have already discussed, results in the Ofgem Initial Proposals under-remunerating the NGET engineering opex activities by some £77.2m over the period 2007/08 to 2011/12.

145 The scale of the discrepancy is illustrated in the following graph:



146 In addition to fundamentally understating our opex allowances for each year as a result of the flawed normalisation adjustments, the arithmetical flaw effectively removes all recognition of activity costs (endorsed by KEMA) that rise above their base level in 2004/05. A small **sample** of the types of activity being under-remunerated as a result are set out in the following paragraphs:

Tower Painting

147 We are forecasting increasing costs from £4.9m p.a. in 2004/05 to £7.9m p.a. by 2011/12 to achieve the volume of painting now necessary to arrest steelwork degradation and optimise the life expectancy of the towers.

148 KEMA have indicated in their assessment of our Tower Painting programme that no reduction is warranted and go on to say that "***it appears that NGET is increasing volumes to appropriate levels and unit costs are in line with those quoted by SPT***".

Site Locks Replacement

149 Patents controlling duplication of keys used for our national substations locking system expire over the next couple of years and locks and keys need to be replaced nationally as a result. KEMA have made no further efficiency recommendations to our numbers (and therefore implicitly accept them). Indeed, at our Engineering Services workshop with Ofgem and KEMA, Ofgem acknowledged that they understood the issues and drivers for the expenditure. The arithmetical error in Ofgem's application of their methodology effectively strips out any remuneration for this programme which seems particularly perverse given our ongoing discussions with Ofgem in relation to the security of Critical National Infrastructure.

Littlebrook Subsidence

150 A mid-life refurbishment scheme at Littlebrook is planned to address major environmental and performance issues at this strategically important substation. This refurbishment will take 4 years to complete with costs of £0.4m in 2005/06 rising to

£1.9m in 2008/09.

151 Ofgem have recognised the environmental issues facing the transmission companies and KEMA themselves have endorsed our plans for this scheme and state "***The need for these … has been thoroughly demonstrated and the costs are reasonable***".

HV Plant Maintenance

152 The increasing age and current condition of out networks, coupled with increasing volumes of assets arising from our capital investment programme, drive an increase in maintenance activity costs. Even with replacement of maintenance intensive equipment with modern day equivalents, requiring less invasive servicing, we forecast that HV Plant Maintenance costs will increase through to 2011/12. This is supported by KEMA, who state that "Against a background of an increasing asset base and ageing network, some increases in engineering opex are to be expected".

153 Ofgem have clearly recognised these issues, with increasing cost allowances being included in the Initial Proposals for the Scottish Transmission companies. KEMA also recognise this upward cost driver by saying in their report with regard to NGET's maintenance and inspection costs "***In summary, it appears that (i) NGET's costs are high but not unreasonable in the FBPQ period , (ii) NGET's costs have increased steadily and whilst this will reflect an ageing and expanding asset population, it may also reflect revised working practices***".

Post Delivery Support Agreements (PDSAs)

154 Driven by the increasing number of NICAP protection bays, rising from 1,300 in 2004/05 to over 3,100 in 20011/12, PDSA costs are forecast to increase by £3.1m pa by 2011/12.

155 Whilst KEMA have suggested that NGET should be able to extract some unit cost savings in the last two years of the FBPQ period due to economies of scale they recognised the importance of providing these agreements for the expanding number of bays and endorse a rising cost profile over the FBPQ period.

Plant Inspections

156 Inspections are one of the fundamental activities required for good asset management to maintain reliability and maintain or where appropriate improve safety and environmental performance. A suite of different checks are performed at various intervals on each equipment bay. An increasing network with more equipment bays will inevitably lead to increasing inspection costs. We forecast that these costs will increase by £0.5m pa by 2011/12.

Past Contamination

157 As discussed in Section IV of this chapter, past contamination schemes are driven by legislative requirements and we would ultimately be liable to prosecution should past contamination issues not be appropriately rectified. We identified a number of schemes in our FBPQ submission phased to remedy the worst affected and most environmentally sensitive sites.

158 KEMA's view on this element of expenditure is "given the existence of the legislation,

this expenditure would seem necessary and the cost levels appear to be reasonable".

SF6 Leak Reduction

159 Future environmental legislation relating to the management of fluorinated greenhouse gases is driving NGET to reduce the SF6 leak rate to less than 2% of the total mass of gas installed by 2010 and our FBPQ included a number of schemes designed to reduce leaks on ageing SF6 equipment.

160 Omission of the increasing costs that we will experience both for past contamination works and SF6 leak reduction conflict sharply with Chapter 12 of Ofgem's Initial Proposals (where they draw on information presented in our FBPQ submission to illustrate the issues associated with SF6 emissions) and discuss the environmental impacts of transmission in the context of their statutory duties in relation to the environment.

Vegetation Management

161 Our proposed vegetation management programme increases the number of spans to be cut p.a. and consequently costs by £1.7m pa from 2006/07. The programme is driven by the increasing number of spans, new legislation and the adoption of new integrated vegetation management techniques designed to bring longer term benefits and efficiencies.

162 KEMA recognise this increase in their report by saying "The need case for the increase in vegetation management seems sound and appears to be well supported by the documentary evidence provided by NGET" and consequently KEMA proposed no adjustment to these costs.

163 The effective omission of the increasing costs that we face for vegetation management contrasts sharply with the approach taken by Ofgem in DPCR4 where significant increases for vegetation management were given specific allowance.

Legislative Compliance

164 Safety and environmental legislation is becoming an increasing element of our site-care/occupier duties cost base and are set to rise over the coming period - both the introduction of known new pieces of legislation and increasingly stringent requirements from regulatory bodies to ensure compliance with existing legislation. We are forecasting increased costs associated with more extensive monitoring, inspection, testing and maintenance activities on what is an increasing plant base.

Adjustments Required to the KEMA Findings

165 KEMA have arrived at the engineering efficiencies through benchmarking NGET costs against standard costs of KEMA's own devising. We have identified that their benchmarking does not make entirely valid comparisons and would welcome the opportunity to discuss these in detail with KEMA prior to the finalisation of their draft report. The areas in question include the following:

(a) The NGET costs they have used for comparison mistakenly include the following items:

(i) **CNI security costs**. The requirement for increased security at

Critical National Infrastructure (CNI) sites is externally driven and will be reimbursed through a different mechanism. This increase is specific incremental cost to NGET, not within our control, and explains part of the increase of substation other costs.

(ii) **Site Locks**. This is a large one-off scheme that should be considered separate from core substation costs as part of quasi capex.

(iii) **Circuit Breaker Refurbishments**. This is a large separate programme which explains a significant part of the increase in substation costs. KEMA have accepted that this "refurbishment strategy seems the right thing to do and the expenditure is appropriate". Ofgem have allowed this expenditure as quasi-capex.

(iv) **Post Delivery Support Arrangement (PDSA) costs**. The increase in this area in the FBPQ is driven by the capital plan. The costs have been included in the NGET cost base for benchmarking, but have also been subject to a separate efficiency adjustment. Thus, to avoid double counting of efficiencies, the PDSA costs should be removed from the benchmarking process.

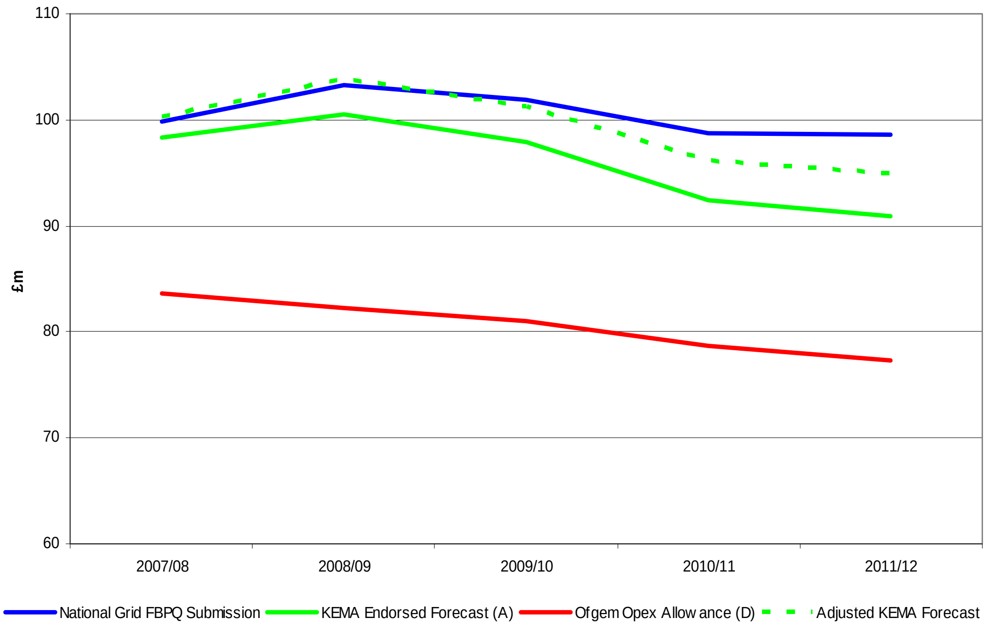
(b) KEMA do not seem to have properly taken into account NGET's **large population of air-blast or oil circuit breakers** in determining the benchmark for their cost profile.

(c) There are the issues surrounding the divergence of KEMA's benchmarking from the results of ITOMS benchmarking in the transformers area which shows our performance as world class.

166 The cost inputs to KEMA's benchmarking assessment that should be revised as a result (with consequent variations to their efficiency conclusions) are summarised in the following table:

Adjustments required to KEMA Benchmarking	**2007/08 £m**	**2008/09 £m**	**2009/10 £m**	**2010/11 £m**	**2011/12 £m**	**Total 2007/08 - 2011/12 £m**
Security	0.6	0.9	1.2	1.5	1.8	6.0
Site Locks	0.5	2.3	2.3			5.1
Circuit Breaker Refurbishments	1.3	2.4	2.1	2.2	2.1	10.1
PDSA's	5.2	5.8	6.2	6.6	6.7	30.5
Total Adjustment to Substation other costs	**7.6**	**11.4**	**11.8**	**10.3**	**10.6**	**51.7**

167 The following graph builds on our earlier graph for electricity engineering opex and shows a KEMA forecast adjusted for these issues:



Engineering Opex (Gas)

168 We have reviewed Ofgem's Initial Proposals and a version (albeit a version where the figures do not precisely reconcile to the Initial Proposals) of TPA's draft report to Ofgem.

169 Overall the findings of TPA appear balanced. Despite this, Ofgem's Initial Proposals represent a substantial under-funding of our gas engineering opex primarily as a result of an arithmetical flaw in how Ofgem have chosen to incorporate the findings of TPA in their Initial Proposals.

170 In addition, we have a number of more detailed areas where we differ with TPA and this response now explores each of these areas in turn.

Arithmetical Flaw

171 The following table uses data extracted from the TPA report to Ofgem and our FBPQ submission to:

(a) recreate the adjustment presented by Ofgem in their Initial Proposals;

(b) set out the arithmetical flaw made; and

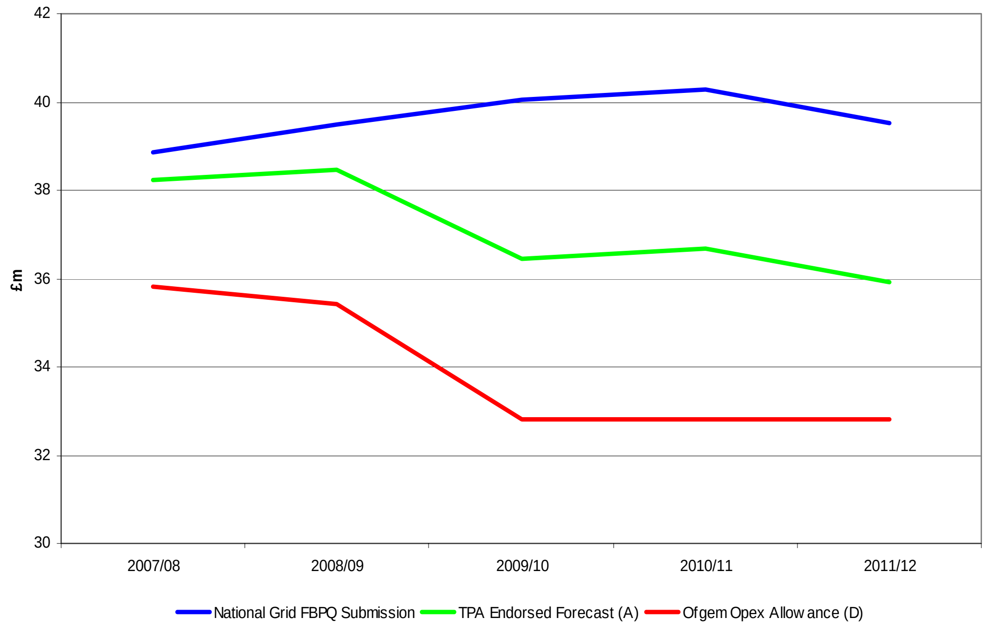
(c) illustrate the overall gap between National Grid's FBPQ submission and Ofgem's Initial Proposals.

NGG Engineering Opex	2004/05 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m	Total 2007/08 - 2011/12 £m
TPA Assessment of Efficient Opex							
National Grid FBPQ Submission		38.8	39.5	40.0	40.3	39.5	198.2
TPA Endorsed Forecast (A)		**38.2**	**38.5**	**36.4**	**36.7**	**35.9**	**185.8**
TPA "Engineering Efficiency" Adjustment (B)		**(0.6)**	**(1.0)**	**(3.6)**	**(3.6)**	**(3.6)**	**(12.4)**
Ofgem Calculation of Opex Allowance							
National Grid Base Year Cost	36.4						
Deloitte "Normalisation" Adjustments	0.0						
Ofgem Derived RCCC (C)	36.4	36.4	36.4	36.4	36.4	36.4	182.1
TPA "Engineering Efficiency" Adjustment (B)		(0.6)	(1.0)	(3.6)	(3.6)	(3.6)	(12.4)
Ofgem Opex Allowance (D)		**35.8**	**35.4**	**32.8**	**32.8**	**32.8**	**169.7**
Under-Statement of Opex Allowance (D - A)		**(2.4)**	**(3.1)**	**(3.6)**	**(3.9)**	**(3.1)**	**(16.1)**

172 TPA assessed NGET's FBPQ submission as a freestanding document on its own merits and identified efficiencies where they felt appropriate. These efficiencies have then been applied by TPA to NGET's FBPQ profile in a logical manner. In the main, the drivers for NGG's rising profile have been acknowledged by TPA and the proposed efficiencies explicitly mitigate the impact of some of these upward drivers.

173 The arithmetical flaw introduced by Ofgem arises because they have deducted the TPA efficiencies that were derived from their review of a rising cost base from a flat extrapolation of the Ofgem "normalised" 2004/05 cost base. This arithmetical error results in the Ofgem Initial Proposals under-remunerating the NGG engineering opex activities by some £16.1m versus the costs endorsed by TPA over the period 2007/08 to 2011/12.

174 The scale of the discrepancy is illustrated in the following graph:



175 The arithmetical flaw effectively removes all recognition of activity costs (endorsed by TPA) that rise above their base level in 2004/05. A small **sample** of the types of

activity being under-remunerated as a result are set out in the following paragraphs:

Compressor Maintenance

176 The importation of gas supplies through the new terminal at Milford Haven will necessitate the construction of a new compressor station in South Wales which will require maintenance from 2009/10. Costs are therefore planned to increase by £0.4m pa by 2011/12.

Pipeline Maintenance

177 In excess of 800 kilometres of high pressure pipeline will be added to the National Transmission System ("NTS"), representing an increase in route kilometres of **over 12%**. Such a large expansion will impact operation and maintenance costs.

178 TPA recognise this fact in their report and state that "It is accepted that increased maintenance costs will accrue as a result of increased asset base and the proposal as related to capex investment appears reasonable".

Gas Quality and Monitoring

179 NGG's responsibilities under the Gas Safety (Management) Regulations 1996 extend to policing the quality of gas admitted onto the gas transmission system. A number of incoming supplies are to be upgraded for improved sampling rates with installations of enhance monitoring equipment. This new equipment, requiring specialist calibration and maintenance activities, will increase costs by £1.7m pa by 2011/12.

180 TPA conclude that "NG must ensure that they monitor the quality at entry points and take appropriate action where unacceptable deviations from quality standards occur to protect both customers and the integrity of the network and the proposal is supported" and implicitly approve the costs by the absence of any proposed adjustment to our numbers.

Gas Safety and Compliance

181 We identified an increase in gas safety and compliance associated with changes to gas safety legislation which have come into effect during the previous review period. The assessment by TPA concluded that costs would indeed increase in this area.

Crop and Drainage Compensation

182 Our FBPQ includes compensation payments for crop loss and drainage remedial work as a result of pipeline construction. We are forecasting a increase of £0.5m pa between 2004/05 and 2006/07 in line with new pipeline construction in our capital programme.

183 TPA, in their report, recognise this driver and state "There are ongoing legacy issues and new costs included going forward for compensation as a consequence of new capex pipeline programme".

Compressor Electric Drives

184 Our FBPQ capex submission includes significant investment in electric variable speed drivers ("VSDs") at compressor stations to comply with the requirements of IPPC. New

support agreements for this technology will therefore be required given that we do not have the necessary specialist skills to support the technology in-house. Our opex business plan includes a £0.7m pa increase by 2011/12 for annual maintenance and support contracts.

Adjustments Required to the TPA Findings

Corrosion Control & Marker Posts

185 TPA supports the technical merit of implementing robust programmes of corrosion control for above ground pipework at compressor stations and Above Ground Installations and a programme to ensure the integrity of pipeline marker posts (section 7.2.3.1 refers). However, in arriving at its range estimates for efficient operating costs, TPA proposes to disallow some or all of the forecast costs that we have put forward for these activities.

186 We take issue with these range estimates and respond as follows:

(a) In so far as TPA consider that we have not spent enough opex in recent years on corrosion control and marker posts, then it follows that base year operating costs should be adjusted **upwards** to arrive at an expression of the economic level of operating cost rather than downwards as implied by TPA in section 4.2.15.

(b) TPA may have a misapprehension that we have not incurred any expenditure on corrosion control in recent years and that the £0.2m p.a. identified from the FBPQ is all "new" money. This is not the case and in the HBPQ years we can identify expenditure of between £0.2m to £0.5m p.a. in our National Support and Non-Routine Maintenance area. The FBPQ was set on the basis of continuing similar levels of activity in the absence of any more detailed assessment of future requirements at that time.

(c) We share TPA's stated view that well considered policies and programmes for corrosion control (painting and protective coatings) are necessary for above ground pipework at both AGIs **and compressor stations** / terminals. We have been carrying out a review of corrosion issues with support from Advantica in response to increasing evidence of deteriorating condition of above ground pipework. This review has gone into significant detail including evaluating the sometimes detrimental consequences of ill-considered application of coatings in prior decades. This analysis had not reached its conclusion in time for the FBPQ, but is now culminating in the development of more sophisticated maintenance policies. A compelling case for the introduction of a suite of carefully considered corrosion control measures has now emerged. **The cost implications of the anticipated programme of work arising from this review represent an increase of +£1m p.a. above the level the FBPQ submission.** We would welcome the opportunity to discuss these findings in more detail with Ofgem / TPA and we propose that, as a consequence, the efficient level of future costs be increased not decreased.

(d) As recognised by TPA, the matter of corrosion control on above ground pipework is crucial to achieving the optimal capex/opex life cycle cost outcome desired in a mature asset management organisation.

(e) TPA report that the absence of historical maintenance is the driver for our

£0.3m p.a. expenditure for the survey and replacement of marker posts and propose this as a potential efficiency adjustment as a result. This is not the case as we can prove historical expenditure ranging up to £0.1m p.a. for routine inspection and maintenance in prior years.

(f) We are experiencing increased third party interference and, following management review, our programme of surveying, standardising, replacing and installing additional marker posts will remedy legacy issues and non-preventable damage. TPA technically support the programme and accept that marker post standardisation will contribute to improved pipeline surveillance. We cannot accept that normal historical maintenance would have addressed such issues.

Compressor Station Closure Assumptions

187 The majority of the proposed engineering efficiencies in relation to NGG result from TPA's proposal to close six compressor stations after 2007/08. We do not feel that the case for the closure of the compressor sites has been made. Our response to the TPA case for closure is set out in detail in the capex section of this document.

188 In relation to **just the opex implications** of the TPA case for closure, the Ofgem Initial Proposals take a totally one-sided view of potential efficiencies to be gained from closure while failing to acknowledge (despite TPA's own acknowledgement of the issue) that there are significant costs that would be associated with complying with relevant legislation and planning consents in order to affect such closure.

189 Taking the reasonable assumption that the costs of de-commissioning these sites are at the same level as those associated with the Bathgate de-commissioning (which were accepted by TPA and feature within the quasi-capex numbers presented in the Ofgem Initial proposals) **an additional £2m per site or <u>£12m</u> in total should be allowed in our opex over the period 2007/08 to 2011/12** simply in order to make the Ofgem proposals whole.

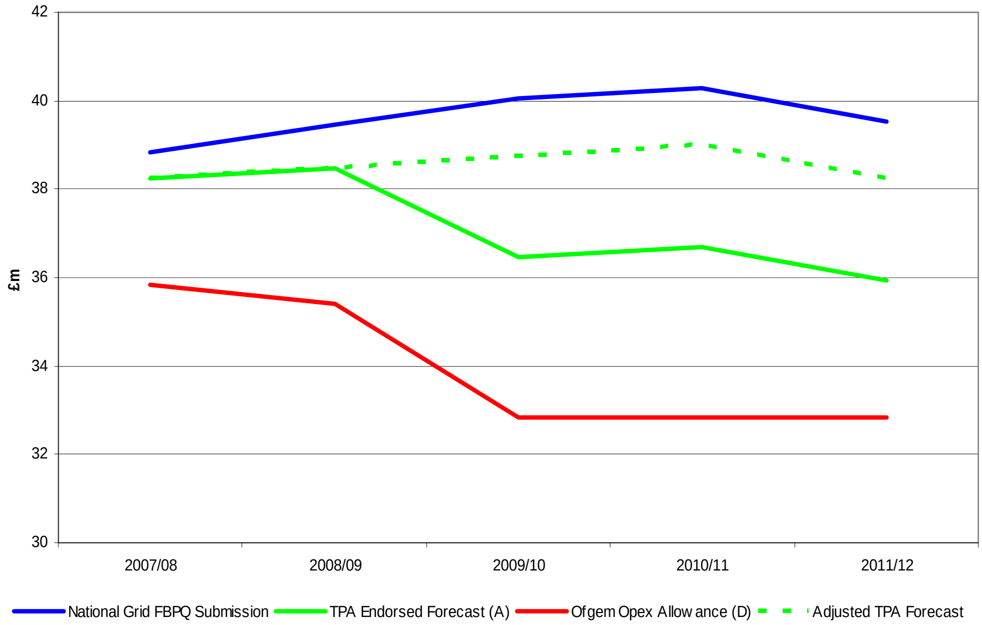
190 Future Ofgem proposals in this area need to at least be internally consistent and present either:

(a) No baseline expectation of potential compressor station closures; or

(b) Appropriate remuneration for closures, which would **increase** the opex allowance above the level necessary for operating the sites in the period.

However, for the avoidance of doubt, it is our view that, against the background of significant uncertainty as to what the future pattern of gas flows will be, we should not be closing six compressor stations.

191 The following graph builds on our earlier graph for gas engineering opex and shows a TPA forecast adjusted for these issues (and using the baseline expectation of no compressor station closures):



Information Services

192 We note Ofgem's reference to its IT consultant's report (IT Spending at National Grid, Compass, 26 May 2006) from the Information Technology section of its Initial Proposals (Ofgem's Initial Proposals, Appendix 8, Section 1.1.3).

193 We have reviewed the Compass report in detail but cannot replicate the efficiency adjustment made by Ofgem, for NGET and NGG – almost all of which was allocated to NGET (see Ofgem's Initial Proposals, Appendix 8, Tables 8.1 & 8.2).

194 Although we have not seen any audit trail reconciling the Compass report and the Ofgem efficiency adjustments, we strongly suspect that the efficiency adjustments will be subject to the same arithmetical flaw as the KEMA and TPA findings that we discussed in the previous two sections.

195 In the interests of transparency, National Grid would welcome an opportunity to review a detailed analysis demonstrating how the proposed IS efficiency adjustments have been derived and a further opportunity to respond to that analysis.

196 In regards to the Compass benchmarking of our 2004/05 IT Spend (Compass Report, Pages 15-67), National Grid is reasonably satisfied with Compass' overall conclusions, i.e.

> **"The sourcing strategy of NG clearly delivers benefits in terms of reduced costs to the organisation. As with any organisation there are areas where performance could be improved, but the overall conclusion is that NG is doing the majority of things well. Compass considers that both the CSC contract and the selective sourcing of the ADSM services are consistent with <u>leading practice</u> in sourcing of IT services."** (Compass Report, Page 9, Benchmark Results)

197 National Grid recognises that Compass had the time and capability to be able to conduct a thorough **benchmarking exercise** of our base year costs including

appropriate normalisation of our 2004/05 costs in order to allow proper comparisons with appropriate reference groups. Whilst we might disagree on some points of judgement we feel that overall this was a fair and useful exercise.

198 In contrast, National Grid has considerable concerns over what we believe has been a superficial and inappropriate assessment by Compass of our **forecast costs** (Compass Report, Pages 68-74).

199 Compass note that of National Grid's approach to the forecast period:

> **"…the FBPQ has been developed through an appropriately robust and detailed process. All assumptions are broadly in line with the market expectations, and the Investment Plan has been developed with close involvement of the business of NG."** (Compass Report, Page 10, Findings of Forecast Review)

200 However, following the benchmarking of our 2004/05 costs, Compass had extremely limited time remaining afterwards and was unable to create its own forecast of our future costs with any degree of analysis of activity needs or the actual, market-based costs of providing those services which we had used in creating our own detailed bottom-up plans. Therefore, Compass chose to extrapolate costs based on the information held on its database concerning IT costs over the past 25 years (Compass report, Page 68).

201 National Grid has continually expressed surprise at Compass' use of an extrapolation approach and we argue that our own forecasting model is likely to be far more reliable. We believe it is entirely inappropriate to forecast as Compass has done. The Compass methodology entirely fails to take account of any market changes in the costs of supply for services as well as the impacts of future upward cost pressures such as increased security requirements. We believe that Ofgem would, rightly, be critical of National Grid if it based future energy demand projections entirely on extrapolation from historical trends alone without looking at supply and demand pressures. We see no reason to adopt such an approach to forecasting future IT costs.

202 In its Initial Proposals document, Ofgem specifically cite three Compass findings from the forecasting exercise (Compass Report, Pages 71-72), in its explanation of the efficiency adjustments it has applied, and here we make an initial response to each of these in turn. However, we look forward to understanding from Ofgem how each of these savings has been applied in order to be able to give a fuller and more comprehensive response:

(a) **"Services – some limited savings were identified in NG's infrastructure support which is largely outsourced."** (Ofgem's Initial Proposals, Appendix 8, Page 27, Para 1.13)

(i) The above statement appears inconsistent with overall Compass findings on Infrastructure, i.e. **"Where it is possible to provide a direct like-for-like comparison, i.e. across the Desktop and Server towers, Compass observes a saving of £8.5 million, or 16.4% against the Reference Group."** (Compass Report, Page 8, Infrastructure Summary)

(ii) We agree with the overall Compass findings regarding the cost of providing Infrastructure Services. We are pleased to note that in the vast majority of Compass measures National Grid costs are lower than the Reference Group.

(iii) We would like to take this opportunity to highlight that the contract with CSC was negotiated, following competitive tender, in terms of an overall deal, which Compass agrees is **"leading practice"** (Compass Report, Page 67) and also acknowledges is highly competitive.

(iv) Understandably, in the context of our extensive contract with CSC, there are some measures where National Grid costs are higher than for the Reference Group. However, as the Compass report indicates these are by far outweighed by those where we are lower. Therefore, selecting those measures where we are higher above those where we are lower and penalising us on that basis is entirely unreflective of the overall net position and our extremely competitive contract with CSC.

(b) **"System Integrator (SI) Rates – SI rates charged to National Grid are significantly higher than the reference group."** (Appendix 8, Page 27, Para 1.13)

(i) The above statement needs to be considered within the context of the overall Compass findings in this area, i.e. **"Overall, NG spent 4% less on application development, support and maintenance per ADSM FTE than the Reference Group…the following points indicate <u>areas for investigation that may lead to further savings in the future</u>…[e.g.] higher daily rates for system integrator resources."** (Compass Report, Page 7, Application Development and Support)

(ii) National Grid would like to reiterate that its SI services are supplied under competitively tendered framework agreements.

(iii) Furthermore, our total SI **operating expenditure** for the base year (2004/05) was only £1.6m, none of which was allocated to NGET. Therefore, we believe any NGET adjustment to be inappropriate and likely to be overstated.

(c) **"Applications Support – This adjustment reduced the proportion of contractors to align with our consultant's view of best practice."** (Initial Proposals, Appendix 8, Page 27, Para 1.13)

(i) Again, the statement above should be considered within the context of the overall Compass findings for this area, i.e. **"Overall, NG spent 4% less on application development, support and maintenance per ADSM FTE than the Reference Group."** (Compass Report, Page 7, Application Development and Support)

(ii) And **"Whilst it is recognised that NG is delivering services in a more cost effective manner than the Reference Group, the following points indicate <u>areas for investigation that may lead to further cost savings in the future</u>…[e.g.] Reducing the proportion of external contractors, through the replacement of contractors with permanent staff, permanent staff cost less."**

(Compass Report, Page 45, Recommendations)

(iii) The contractors used in Application Support primarily support the SO electricity balancing mechanism system which is critical to market operation. As this is an SO system, we believe any NGET adjustment to be inappropriate.

(iv) In addition, in order to mitigate the significant security risks in this area we have chosen not to outsource under the standard Offshore Development Centre (ODC) framework agreements. Our use of UK contractors, over permanent staff is driven by market forces, i.e. we must retain access to the latest skills and specialist knowledge despite these being in relatively short supply. Sourcing the work this way also allows us to rapidly flex our capability in response to market change.

Insurance

203 We have reviewed the supporting analysis and reports developed by Ofgem's specialist consultants Marsh, in detail and we have three major areas of concern with the Initial Proposals:

(a) There is a gross arithmetical flaw in the way that Ofgem have chosen to incorporate Marsh's work in the Initial Proposals.

(b) The cyclicality in the insurance market outlook, introduced through an extrapolation by Marsh for Ofgem, is statistically unsound.

(c) Our own independent advice identifies that the outlook for the insurance market for NGET and NGGT is much more likely to lead to a linear rising trend than a trough period within a cyclical trend.

204 Each of these issues is now considered in turn:

Arithmetical Flaw

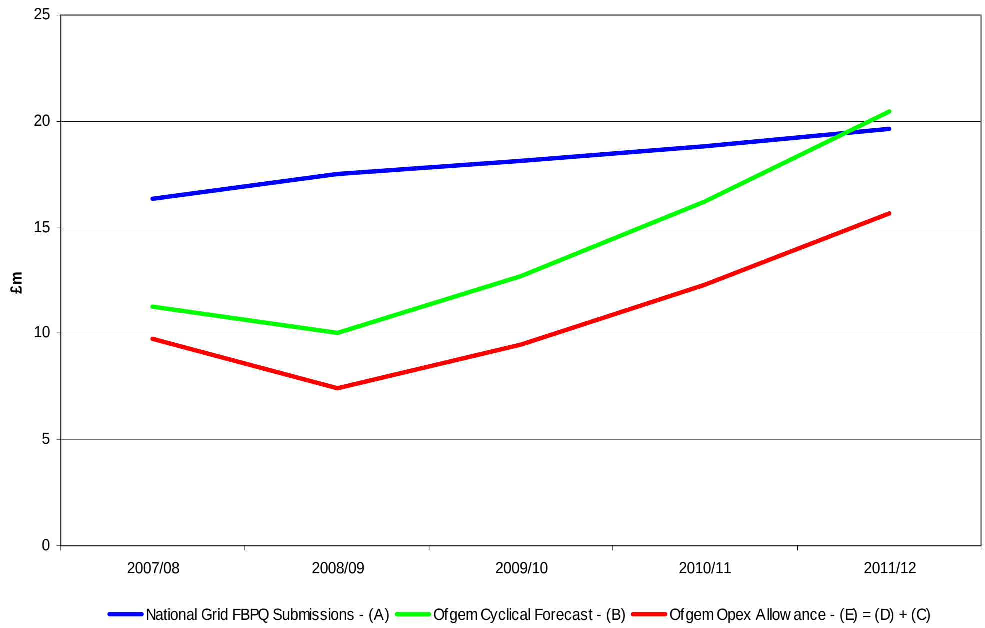
205 The following table uses data extracted from the Marsh report to Ofgem and our FBPQ submission to:

(a) set out the arithmetical flaw ; and

(b) illustrate the overall gap between National Grid's FBPQ submission and Ofgem's Initial Proposals.

Ofgem Insurance "Efficiency" Calculation of Arithmetical Flaw	2004/05 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m	Total 2007/08 - 2011/12 £m
National Grid FBPQ Submissions - (A)							
- NGET		10.5	11.3	11.7	12.2	12.6	58.4
- NGG		5.8	6.2	6.4	6.6	7.0	32.1
Total		**16.4**	**17.5**	**18.1**	**18.8**	**19.6**	**90.5**
Ofgem Cyclical Forecast - (B)							
- NGET		7.2	6.5	8.2	10.5	13.1	45.5
- NGG		4.0	3.5	4.5	5.7	7.3	25.1
Total		**11.3**	**10.0**	**12.7**	**16.2**	**20.4**	**70.6**
Ofgem Cyclical Adjustments - (C)							
- NGET		(3.3)	(4.8)	(3.5)	(1.7)	0.5	(12.8)
- NGG		(1.8)	(2.7)	(1.9)	(0.9)	0.3	(7.0)
Total		**(5.1)**	**(7.5)**	**(5.4)**	**(2.6)**	**0.8**	**(19.8)**
National Grid Base Year Costs							
- NGET	8.4						
- NGG	6.5						
Total	**14.9**						
Deloitte "Normalisation" Adjustment							
Ofgem Derived RCCC - (D)	**14.9**	**14.9**	**14.9**	**14.9**	**14.9**	**14.9**	**74.5**
Ofgem Cyclical Adjustments - (C)		(5.1)	(7.5)	(5.4)	(2.6)	0.8	(19.8)
Ofgem Opex Allowance - (E) = (D) + (C)		**9.8**	**7.4**	**9.5**	**12.3**	**15.7**	**54.6**
National Grid FBPQ Submissions - (A)		**16.4**	**17.5**	**18.1**	**18.8**	**19.6**	**90.5**
Arithmetical Flaw (E) - (B)		**(1.5)**	**(2.6)**	**(3.2)**	**(3.9)**	**(4.7)**	**(16.0)**
Ofgem Cyclical Adjustments - (C)		**(5.1)**	**(7.5)**	**(5.4)**	**(2.6)**	**0.8**	**(19.8)**
Ofgem Opex Allowance		**9.8**	**7.4**	**9.5**	**12.3**	**15.7**	**54.6**

206 The scale of the discrepancy is illustrated in the following graph that shows how Ofgem have taken the difference between their cyclical forecast and our FBPQ submission to establish an adjustment but then introduced an arithmetical error by deducting this not from our FBPQ submission to form an opex allowance but from their flat extrapolation of 2004/05 (RCCC):



Statistically Unsound Analysis of Cyclicality

207 Marsh presented two projections of the index for Ofgem in their report, one a linear extrapolation (which we believe objectively they would opine to be the more sound basis) and the other an attempt at extrapolating the historically cyclical nature of the insurance market. These are illustrated in the Marsh diagram that follows:

208 From simple inspection of the cyclical projection we note that the trough forecasted in 2008 is **significantly deeper** than the two trough observations in the historical data series (it should clearly be the mean of two).

209 Given this apparent discrepancy we have undertaken our own statistical analysis of the same data series and conclude that the Marsh projection is fundamentally flawed. Our own analysis concludes that:

(a) The trough in 2008 should register at around 134 on the index as opposed to around 99 in the Marsh analysis i.e. the potential reduction in insurance costs for this trough is grossly over-stated; and

(b) De-trending of the data to facilitate examination of the corrected oscillations around the trend shows them to be significantly diminishing over time i.e. converging with the linear.

210 Furthermore, Marsh acknowledge the statistical limitations of this projection in some detail in their report.

211 The cyclical view is one that both National Grid and Marsh recognise as having serious limitations. Our reading of the Marsh report is that they regard the linear view as being the most credible and this is something with which we concur. Ofgem, however, despite Marsh's acknowledgment throughout their report of the efficiency and effectiveness of our risk management and insurance functions have chosen to base their Initial Proposals on the harshest possible view of the market (and therefore the lowest probability outcome).

Insurance Market Outlook

212 The Marsh report documents certain limitations associated with their analysis of cyclicality for Ofgem. We note their view in relation to use the Lloyd's of London Non-Marine Index:

"Another counter-argument could be that the market cycle used is too generic as it covers all non-marine risks and therefore does not necessarily reflect the price of the individual risks that NG's insurance policies cover, which will each have their own characteristics"

213 We agree with Marsh's view for the following reasons:

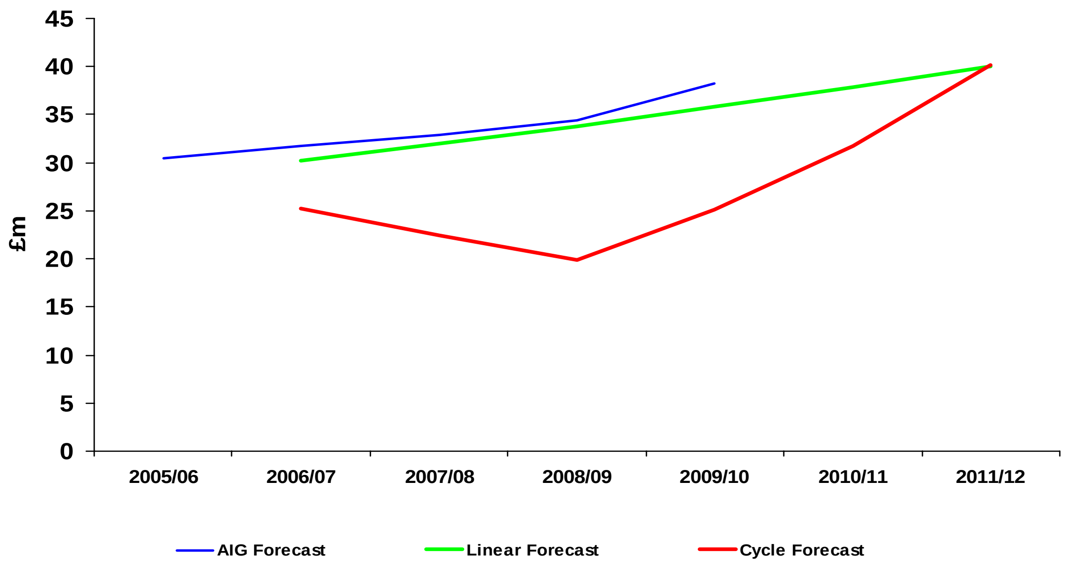
(a) The Lloyd's market underwrites only a very small percentage of National Grid's risk because it cannot offer the breadth of cover and limits obtained elsewhere. Given this, most of our captive reinsurance is placed in the Company Market.

(b) The Non-Marine index is too general and does not reflect the difficulties in obtaining appropriate insurance cover for National Grid.

(c) Non-Marine risks cover a wide variety of structures, ranging from buildings to factories and hence do not always include utilities (indeed these are often classed separately as energy risks and indices are available for this category of risk).

(d) Utilities have unique general liability and property damage / business interruption risks.

214 The National Grid FBPQ was based on price indications from current insurers, consultation with brokers and analysis of risk profiles as well as historical claims experience. We have benchmarked these price indications against a market quotation from AIG (a leading player in the Company Market) and set them out in the following graph as a comparison to the linear and cycle forecasts.



215 AIG's forecast is based on measuring National Grid's actual risks, taking many factors into consideration in their modelling. This forecast properly represents the risk exposures of National Grid that are insured outside of the Lloyd's Non-Marine market.

216 The graph clearly demonstrates that the AIG forecast insurance premiums (specific to National Grid's risks) are forecast to increase continually over the next price control.

Insurance - Conclusions

217 Ofgem's Initial Proposals under-remunerate our insurance costs by **£35.8m** for the period 2007/08 to 20011/12. This response has broken down this overall under-remuneration in terms of:

(a) £16.0m – gross arithmetical flaw associated with the way in which Ofgem have chosen to integrate the Marsh work in their Initial Proposals; and

(b) £19.8m – associated with the use of a statistically flawed (and only partially relevant) extrapolation of the Lloyd's of London Non-Marine Index in the face of:

(i) a more statistically sound linear extrapolation developed by Marsh;

(ii) quotations freely available in the Company Market for the actual risk portfolio that we carry;

(iii) the views of most insurance market observers; and

(iv) and the National Grid FBPQ submission.

218 We therefore propose that Ofgem accept the broad findings of Marsh that validate our FBPQ submission which remains the most accurate indication of our future insurance costs.

Frontier Shift

219 We note Ofgem's 1.5% per annum Frontier Shift proposal. Our response to this is in two parts:

(a) the applicability of 1.5% per annum in the markets that we operate in under RPI-X regulation; and

(b) the "costs to achieve" frontier shift.

220 This response now covers each of these areas in turn.

The Applicability of 1.5% p.a.

221 National Grid have commissioned an independent study from First Economics in relation to the likely level of future "frontier shift" that should be assumed for a UK based transmission licensee. We will separately submit this document in due course for consideration by Ofgem. However, the key points arising from this study are summarised below:

(a) The Ofgem initial proposals effectively assume that the industry's efficiency frontier would move in such a way as to permit annual real reductions in total opex of 1.5% per annum. Because economy-wide productivity savings and economy-wide input price inflation feed directly into the annual increase in the retail prices index ("RPI"), Ofgem's assumptions effectively imply that the transmission licensees will not only become more efficient, but also that they will do so at a significantly faster pace than other firms supplying goods and services to UK households.

(b) This is not something that should simply be taken for granted. The RPI basket includes a wide range of goods and services, all of which are subject to slightly different cost drivers. Since the late 1990s, it has become increasingly apparent that some sectors of the UK economy are benefiting from large productivity savings and extremely benign input prices. It is therefore crucial that Ofgem recognise the nature of the benchmark that RPI represents in forming their views on frontier shift.

(c) Disaggregating RPI into eight main subcomponents reveals that prices in the goods sector have been stable (i.e. constant in nominal terms) for a number of years. In particular, shifts in production from western economies to the developing world have led to steep reductions in the prices of manufactured, traded goods, while growth in the market share of supermarkets has meant that food prices have barely changed in five years. Asking any company to match the productivity gains and input price control that firms in these sectors are achieving represents a considerable challenge.

(d) Within the service sector of the UK economy, it is clear that very few companies have been able to even hold their costs constant in real terms. Companies that rely on a skilled, UK-based labour force typically exhibit lower productivity gains and/or much higher input price inflation and so see their costs rise well in excess of RPI-measured inflation.

(e) In understanding what might be expected of the transmission licensees, it is helpful to benchmark against comparable firms elsewhere in the UK economy. Under two different benchmarking approaches – one that involves excluding the contribution to RPI-measured inflation of firms that have obviously different cost drivers and one that involves creating a new, more applicable inflation index from scratch – it is apparent that firms with similar characteristics are seeing unit costs **rise** by around 1.75% above inflation.

(f) Before applying such comparisons to the setting of frontier shift assumptions, it is necessary to make adjustments for economies of scale/volume growth, quality improvement and capital substitution. Accounting for these factors produces **estimates for frontier shift in the range of zero to +0.75% per annum (in real terms)**. However, they fall well short of substantiating Ofgem's assumption that it should be possible for opex to fall in real terms.

222 Such conclusions do not in any way imply that the transmission licensees will not become more efficient during the course of the next control period. It simply highlights that real-terms cost reductions are only deliverable if a firm is able to out-perform other companies whose products are included in the RPI basket. Future efficiencies will still be delivered by NGET and NGG, however, it may not be the case that these will result in a relative downward cost movement versus RPI.

223 We would therefore welcome the opportunity to discuss the reasonableness of a 1.5% p.a. frontier shift assumption relative to RPI with Ofgem as part of the next phase of

the development of their proposals.

“Costs to Achieve” Frontier Shift

224 Both our HBPQ submission and response to Ofgem’s March Consultation Document explained our performance versus regulatory allowances in the HBPQ period very clearly and identified “costs to achieve” future savings as being one of the key reasons why we failed to out-perform our opex allowances in aggregate.

225 Costs to achieve comprise the typically opex investments required to implement major change programmes to generate future efficiencies and include such costs as:

(a) staff severance;

(b) re-organisation costs;

(c) training costs;

(d) outsource and negotiation costs; and

(e) IS investment where although such costs may be accounting capex, Ofgem’s proposals seek to remunerate IS investment for NGET and NGG TO activities as regulatory opex.

226 Our FBPQ submission for the period 2007/08 to 2011/12 clearly set out that we would be incurring costs to achieve the transition to a UK Shared Services organisation and indeed Ofgem, based on recommendations from Deloitte, have proposed future efficiency savings in this area. Ofgem, however, have explicitly excluded these costs to achieve in their Initial Proposals for opex.

227 As a principle we can see why regulators would choose not to remunerate costs to achieve associated with “getting to the frontier” (although given the findings of the Deloitte review of our Shared Services activity we believe we are already on it). The corollary of this, however, is that regulators must remunerate the costs to achieve ongoing frontier shift.

228 Costs to achieve future efficiencies have risen over time relative to the overall contraction of both NGET and NGG because implementation of properly managed, controlled, safe and reliable change against a background of reducing reserve capacity in the organisation only becomes more complex. The complexity of the Office in the Hand (“OITH”) and Work and Asset Management (“WAM”) information systems solutions and change management programmes required to facilitate our Staying Ahead and Ways of Working (“WoW”) change programmes in the HBPQ period has been documented extensively by KEMA and Compass for Ofgem.

229 Given our increasing capital investment programme and the premium that that this will place on safe and reliable operation with our systems more stretched than ever we see costs to achieve in the FBPQ period set only to rise further.

230 As Ofgem’s Initial Proposals stand, they are internally inconsistent and assume that frontier shift can be achieved **free of charge** and, irrespective of the fact that the First Economics study suggests a significantly lower level of frontier shift relative to RPI, we feel that proper recognition needs to be given to our future costs to achieve.

231 The following table takes the frontier shift proposed by Ofgem and makes a series of broad assumptions in order to derive an illustrative level of remuneration for costs to achieve as follows:

(a) incremental annual frontier shift savings are assumed to be 60% staff related and 40% non-staff related broadly in line with the savings achieved by past change programmes;

(b) an average cost per head of around £40k p.a. is then used to determine the approximate number of heads that would need to be severed to achieve this level of staff cost saving;

(c) £90k per head severance cost is then assumed;

(d) An aspirational zero cost to achieve non-staff related savings is assumed.

Frontier Shift	**2007/08 £m**	**2008/09 £m**	**2009/10 £m**	**2010/11 £m**	**2011/12 £m**	**Total 2007/08 - 2011/12 £m**
Ofgem "Frontier Shift" Proposal						
- NGET	(2.2)	(4.5)	(6.6)	(8.8)	(10.9)	**(33.0)**
- NGG	(0.9)	(1.8)	(2.7)	(3.5)	(4.4)	**(13.3)**
Total	**(3.1)**	**(6.3)**	**(9.3)**	**(12.3)**	**(15.3)**	**(46.3)**
Probable Composition of Savings						
-Staff Component (~60%)	(1.9)	(3.8)	(5.6)	(7.4)	(9.2)	**(27.8)**
-Non-Staff Component	(1.2)	(2.5)	(3.7)	(4.9)	(6.1)	**(18.5)**
Total	**(3.1)**	**(6.3)**	**(9.3)**	**(12.3)**	**(15.3)**	**(46.3)**
Incremental Annual Savings						
-Staff Component	(1.9)	(1.9)	(1.8)	(1.8)	(1.8)	
-Non-Staff Component	(1.2)	(1.3)	(1.2)	(1.2)	(1.2)	
Total	**(3.1)**	**(3.2)**	**(3.0)**	**(3.0)**	**(3.0)**	
"Costs to Achieve"						
-Staff Component	4.2	4.3	4.1	4.1	4.1	**20.7**
-Non-Staff Component	0.0	0.0	0.0	0.0	0.0	**0.0**
Total	**4.2**	**4.3**	**4.1**	**4.1**	**4.1**	**20.7**
Net "Frontier Shift" Adjustment						
- Ofgem "Frontier Shift" Proposal	**(3.1)**	**(6.3)**	**(9.3)**	**(12.3)**	**(15.3)**	**(46.3)**
- "Costs to Achieve"	4.2	4.3	4.1	4.1	4.1	**20.7**
Total	***1.1***	***(2.0)***	***(5.3)***	***(8.3)***	***(11.3)***	**(25.6)**

232 The resulting cost to achieve is, if anything, likely to be low given that it reflects severance costs only - but it is enough to significantly adjust the net level of frontier shift efficiency proposed by Ofgem. We wish to use this analysis as a starting point for discussion with Ofgem in relation to the total costs to achieve that we are likely to experience over the coming years.

VI Upward Cost Pressures

233 We note that Ofgem's Initial Proposals state that NGET and NGG identified the following issues as upward cost drivers:

(a) **Quasi-capex**;

(b) **Insurance**; and

(c) **Real wage growth**.

234 This is at best a partial summary of the cost drivers presented in our FBPQ submission and fails to reflect the breadth of issues presented to and discussed with both Ofgem and their consultants over the last nine months.

235 Our FBPQ represented a detailed bottom-up, activity based build that carefully considered a broad range of both upward and downward cost drivers. Ofgem's portrayal of our upward cost drivers in their Initial Proposals, however, omits reference to the following key drivers:

(a) **environmental and legislative impacts** (other than simply those associated with bulk asbestos removal);

(b) **capital programme development and delivery** of our increasing capital programme;

(c) **system expansion** and the management and maintenance of an expanded asset base as a result of our increased capital investment;

(d) **input cost pressures** (other than real wage growth and insurance); and

(e) **increasing workload** primarily associated with taking optimal asset management decisions.

236 The upward cost pressures that have effectively been omitted from Ofgem's Initial Proposals have to a great extent already been discussed in Section V (Efficiencies") of this chapter owing to the fact that their proper recognition has in general been subsumed within the arithmetical flaws associated with the derivation of Ofgem's proposed efficiency adjustments.

237 This section now goes on to deal specifically with those items that Ofgem have highlighted as upward cost drivers in their initial proposals and the following table sets out the numbers proposed by Ofgem in respect of NGET and NGG. Combined totals are also shown:

Ofgem Upward Cost Drivers	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
NGET					
Real Wage Growth			*Zero Assumed*		
- Atypical / New Costs / Quasi Capex	13.9	16.3	16.6	18.0	23.9
- Quasi Capex Transferred to Capex	(12.7)	(15.1)	(15.4)	(16.8)	(22.7)
Quasi Capex to Remain in Opex	1.2	1.2	1.2	1.2	1.2
NGG Total	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**
NGG					
Real Wage Growth			*Zero Assumed*		
- Atypical / New Costs / Quasi Capex	0.7	2.2	0.3	0.4	0.5
- Quasi Capex Transferred to Capex	(0.3)	(1.8)			
Quasi Capex to Remain in Opex	0.4	0.4	0.3	0.4	0.5
NGG Total	**0.4**	**0.4**	**0.3**	**0.4**	**0.5**
NGET and NGG Combined					
Real Wage Growth			*Zero Assumed*		
- Atypical / New Costs / Quasi Capex	14.6	18.5	16.9	18.4	24.4
- Quasi Capex Transferred to Capex	(13.0)	(16.9)	(15.4)	(16.8)	(22.7)
Quasi Capex to Remain in Opex	1.6	1.6	1.5	1.6	1.7
Combined Total	**1.6**	**1.6**	**1.5**	**1.6**	**1.7**

238 This section now deals with each of the proposed Ofgem upward cost drivers in turn.

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[redacted]

[redacted]

[redacted]

(e) [redacted]

Quasi Capex

245 We welcome Ofgem's recognition of the concept of "quasi capex" expenditure in their Initial Proposals. We believe that this will lead to:

(a) better regulation through the elimination of arbitrary accounting led divisions between capex and opex classifications in certain key areas; and

(b) more appropriate allocation of charges to generations of customers over time.

246 We have only two additional points to make in response to Ofgem's Initial Proposals. These are:

(a) That there is a numerical discrepancy between:

(i) the value transferred to capex in the opex section of the proposals; and

(ii) the value introduced as capex in the capex section of the proposals.

(b) We believe that there is an opportunity to extend the concept of quasi-capex further in the interests of better regulation.

Numerical Discrepancy

247 Ofgem's initial proposals include a deduction from opex of £82.7m but only £71.0m has been added to the capex proposals.

248 The Ofgem Initial Proposals state their intention to review our proposed quasi-capex spend at a later point in the review. Ofgem's consultants have made some references to quasi-capex in their efficiency reports. However, given that Ofgem make no reference to having deducted efficiencies in their proposals, we can only assume that a transcription error has been made.

Extending the Quasi Capex Concept

249 Quasi capex basically comprises:

(a) costs directly associated with capital schemes that under the terms of FRS15 are required to be treated as opex such as decommissioning costs; and

(b) opex investments with the general economic nature of capex such as tower painting.

250 At one point in their Initial Proposals, Ofgem cite tower painting as an example of quasi capex. However, tower painting costs are one of several specific costs that Ofgem have currently chosen **not** to include in quasi capex where we feel that their inclusion could lead to more logical and consistent regulation. These are set out in the table below:

Additional Quasi Capex Costs	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
Tower Painting	5.4	6.4	7.1	7.1	7.9
Littlebrook Substation Subsidence	1.0	1.9			
Site Locks Scheme	0.3	2.3	2.3		
HV Cable Fault Rectification	3.9	3.9	4.0	4.0	4.0
NGET Total	**10.6**	**14.5**	**13.4**	**11.1**	**11.9**
Gas Compression Fault Rectification	4.3	4.2	3.8	3.2	2.2
Corrosion Control	0.2	0.2	0.2	0.2	0.2
NGG Total	**4.5**	**4.4**	**4.0**	**3.4**	**2.4**
Combined Total	**15.1**	**18.9**	**17.4**	**14.5**	**14.3**

251 These costs and their potential treatment as quasi-capex have been discussed with Ofgem in detail. This response now considers each item again in turn:

(a) **Tower painting and other corrosion control measures in relation to gas assets** are major periodic investments. The numbers in the table above illustrate how the levels of tower painting we will be undertaking rise significantly over the period of our FBPQ. Inclusion of tower painting and corrosion control in quasi capex would help to smooth the allocation of these costs to customers over time

(b) The **permanent works required to arrest the deterioration of Littlebrook substation** are similarly substantial in nature and will ensure continued safe and reliable operation of the facility in the long term, taking due account of improving environmental performance through reduced SF6 leaks.

(c) The **site-locks scheme** relates to 20 year periodic replacement of locks in line with the expiry of key patents (and is complimentary to our CNI security enhancement programme) and represents another opportunity to smooth the impact of these costs to customers.

(d) **Fault rectification** on both HV cables (NGET) and gas compression equipment (NGG) is an area where the precise accounting treatment as capex or opex depends on the exact nature of the fault encountered and the method of rectification. This leads to some costs being treated as accounting capex and some costs being treated as accounting opex. Inclusion of these costs in quasi capex would give the added benefits of:

(i) clarity for both Ofgem and the licensees over where costs are being remunerated in the regulatory model; and

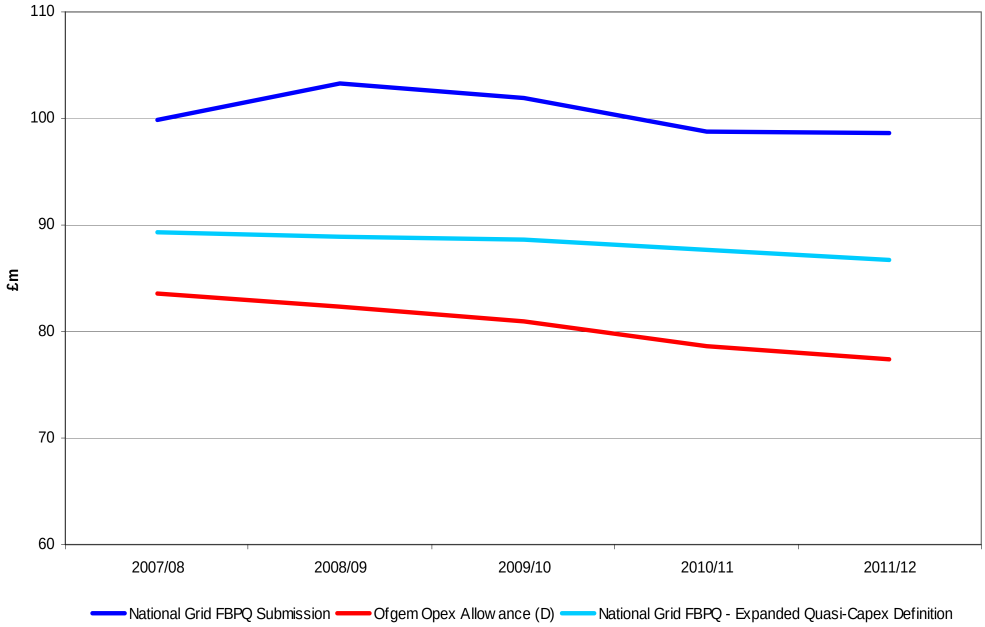
(ii) comfort for Ofgem that costs remunerated as opex cannot subsequently be capitalised in the RAV.

252 If Ofgem choose to develop the quasi-capex concept further and expand the definition in line with our proposals significant short-term benefits will accrue to customers associated with the reduction of our ongoing opex allowance.

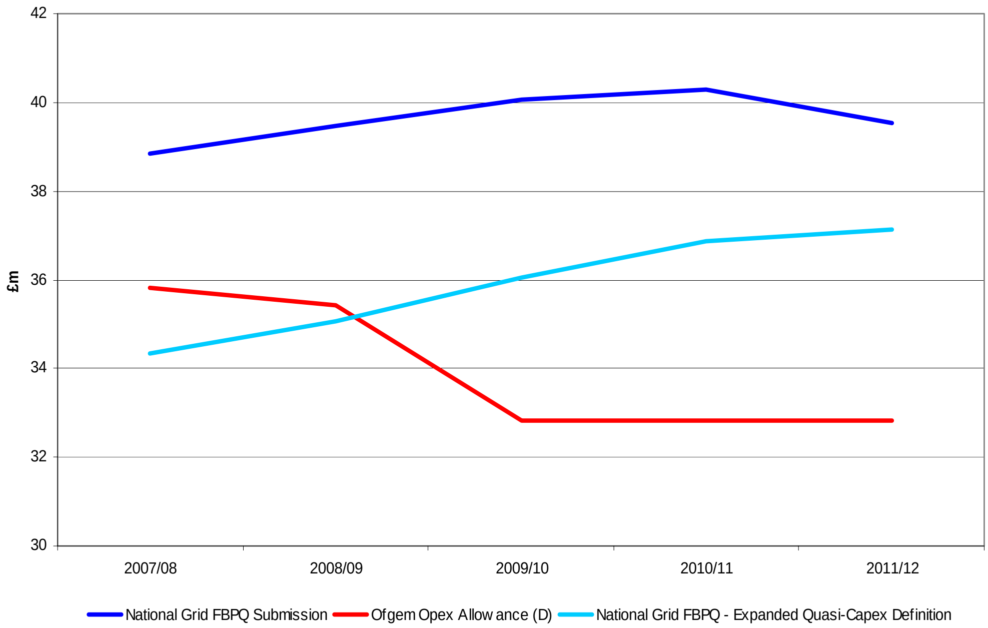
253 The following two graphs build on the previous graphs that we have used to illustrate the issues associated with gas and electricity engineering opex. In each case we have removed the “consultant endorsed forecast” and “adjusted consultant forecast” lines

for clarity as these were generally very close to the National Grid FBPQ submission line.

254 We show the effect of expanding the definition on quasi-capex by deducting it from our FBPQ profile in each case. The first graph illustrates the effect on NGET (KEMA) engineering opex:



255 The second graph illustrates the effect on NGG (TPA) engineering opex:



256 We believe extension of the quasi-capex concept would help towards ensuring that:

(a) customers continue to obtain the benefits of our underlying ongoing opex efficiencies in the short term; and

(b) proper recognition and remuneration of our quasi-capex costs is given in the longer term.

257 The graphs effectively illustrate that the gap between Ofgem's aspirations for short term ongoing opex allowance reductions to benefit customers and the levels of cost that we require / the consultants endorse can be substantially closed through extension of the quasi-capex concept with the balance of necessary remuneration reflected in future price control periods.

VII Additional Opex Allowances

258 The following table sets out the additional opex allowances proposed by Ofgem in respect of so-called “non-operational” capex expenditure for both NGET and NGG. Combined totals are also shown.

Ofgem Additional Opex Allowances	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
NGET					
Non-Operational Capex	*11.6*	*7.6*	*7.4*	*12.8*	*15.9*
NGG					
Non-Operational Capex	*2.5*	*3.2*	*5.5*	*3.4*	*5.0*
NGET and NGG Combined					
Combined Total	**14.1**	**10.8**	**12.9**	**16.2**	**20.9**

259 Our response to Ofgem’s non-operational capex proposal is in two parts:

(a) the FBPQ Period; and

(b) the HBPQ Period.

The FBPQ Period

260 We have attempted to reconstruct Ofgem’s proposed non-operational capex allowances in the absence of being provided with any form of audit trail that links their numbers to either:

(a) our FBPQ submission; or

(b) the detailed workshop material that we provided to Ofgem in this area.

261 The result of our reconstruction is set out in the following table. We have not been able to fully explain the numbers proposed by Ofgem therefore our ability to comment on their proposals is severely limited.

National Grid Reconstruction of Ofgem Additional Opex Allowances	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
NGET					
ETO IS Projects	6.2	4.3	3.8	8.0	11.2
Non-Operational IS Capex	4.9	2.6	1.9	3.7	3.9
Commercial Vehicles	2.4	2.4	2.4	2.6	2.4
Unexplained Differences	**-1.9**	**-1.7**	**-0.7**	**-1.5**	**-1.6**
Ofgem NGET Allowance	**11.6**	**7.6**	**7.4**	**12.8**	**15.9**
NGG					
GTO IS Projects	1.0	2.2	4.4	2.7	4.4
Non-Operational IS Capex	1.7	1.2	1.2	1.2	0.8
Commercial Vehicles	0.5	0.5	0.5	0.5	0.5
Unexplained Differences	**-0.7**	**-0.7**	**-0.6**	**-1.0**	**-0.7**
Ofgem NGG Allowance	**2.5**	**3.2**	**5.5**	**3.4**	**5.0**
NGET and NGG Combined					
Combined Unexplained Differences	**-2.6**	**-2.4**	**-1.3**	**-2.5**	**-2.3**
Combined Total Allowance	**14.1**	**10.8**	**12.9**	**16.2**	**20.9**

262 For the time being, we will have to assume that Ofgem have decided to treat three categories of capex as non-operational capex in order to remunerate them as opex rather than capex in their financial model. These are:

(a) genuine non-operational capex e.g. back office IS systems, IS infrastructure investment etc;

(b) ETO and GTO operational IS system capex e.g. developments associated with Office in the Hand ("OITH") and Work and Asset Management Systems ("WAM"); and

(c) commercial vehicles which were the basis of the definition for non-operational capex for the NGET TO at the previous price control review.

263 In our response to Ofgem's Third Consultation Document we clearly expressed a preference that Ofgem should:

(a) avoid arbitrary distinctions between different lines of capital expenditure; and

(b) seek to align their remuneration mechanisms with how we run our operations and remunerate IS capex according to asset life through a separate short-life component of the RAV (in line with the precedent set as part of the previous electricity system operator review).

264 We are disappointed that Ofgem are not considering this option as, in some senses, not to do so works against the good measures that they are proposing in relation to quasi-capex that help to smooth the impact of longer term investments to our customers over time.

265 Given that we are not entirely clear what Ofgem have chosen to include within non-operational capex we cannot make an effective response to their proposals for the FBPQ period. Ofgem will need to clearly set out the costs that they propose to treat as non-operational capex to facilitate a proper open process of challenge and review

prior to publication of their Final Proposals.

The HBPQ Period

266 We have fundamental disputes of principle with Ofgem in relation to their treatment of the HBPQ period. These are as follows:

(a) Ofgem are effectively failing to remunerate our TO IS development spend in the HBPQ period. This cannot be right in principle, especially as Ofgem propose to extract the benefits associated with our TO IS developments and pass them on to customers in the form of reduced opex allowances for the forthcoming period. This is inconsistent with not providing appropriate remuneration of the investment and effectively condemns efficient investment to a negative NPV “after the event”.

(b) We have very clearly set out to Ofgem that, in aggregate, we under-performed versus their opex allowances in the HBPQ. This was exclusive of IS capital investment that Ofgem would now seek to call regulatory opex. Factoring in these investments as additional opex costs in the HBPQ period points to a major under-performance versus allowances which appears entirely at odds with no material inefficiencies being identified by Ofgem’s consultants.

(c) Ofgem state that allowance was explicitly given to NGET for IS developments as non-operational capex as part of the previous price control review. This is simply not correct in our view and the facts are set out in the following sub-section.

Non-Operational Capex in the Last Price Control Review for NGET

267 Ofgem set out the following table in their Initial Proposals in support of their claim that both NGET TO IS developments and commercial vehicles were remunerated as non-operational capex at the previous price control review:

Ofgem Presentation of HBPQ Non-Operational Capex	**2001/02 £m**	**2002/03 £m**	**2003/04 £m**	**2004/05 £m**	**2005/06 £m**	**2006/07 £m**
Allowance	4.6	4.0	4.1	2.5	2.4	n/a
Actual / Forecast	5.1	13.2	19.6	18.6	8.7	
Difference	**0.5**	**9.2**	**15.5**	**16.1**	**6.3**	**0.0**

268 The following table is an extract from the numbers in our FBPQ submission relating to NGET commercial vehicle replacement only:

NGET FBPQ Commercial Vehcile Capex Projection	**2005/06 £m**	**2006/07 £m**	**2007/08 £m**	**2008/09 £m**	**2009/10 £m**	**2010/11 £m**	**2011/12 £m**
Commercial Vehicles	3.0	2.9	2.4	2.4	2.4	2.6	2.4

269 Staff numbers in our NGET field force (the users of commercial vehicles) decreased significantly as part of our Re-Focussing and Staying Ahead change programmes in the HBPQ period and reductions were indeed factored in to the numbers quoted by Ofgem from 2004/05.

270 It is obvious from a cursory examination of these two tables that the Ofgem non-operational capex allowance is broadly in line with the magnitude of our commercial vehicle replacement programme only.

271 The facts, as presented by Ofgem, are simply not correct in our view and we totally reject Ofgem's proposed treatment of our HBPQ period non-operational capex as a result. It is clear that investment of the scale seen during this price control was not anticipated within the Final Proposals in September 2000 and because of this lack of consideration for funding and given the enduring benefits of these investments to consumers, we believe the depreciated value of these investments should be included within the RAV from April 2007.

272 We are also concerned that the position Ofgem are taking on this issue is influencing their proposals in relation to the FBPQ period towards a less satisfactory regulatory treatment for customers.

VIII Key Areas Where the Initial Proposals are Silent

273 The Ofgem Initial Proposals on Opex are silent on three significant issues that formed key parts of our FBPQ submission and subsequent discussions with both Ofgem and their consultants. These are:

(a) Critical National Infrastructure ("CNI") Security relating to both NGET and NGG;

(b) Quarry & Loss of Development Claims relating to NGG only; and

(c) Capex Allowance / Opex Allowance Interactions.

274 We believe that Ofgem will need to clearly address all three of these issues in their Final Proposals. For convenience these are summarised again below:

Critical National Infrastructure Security

275 The Ofgem Initial Proposals appear to distinguish for potentially separate treatment the capex associated with CNI investments outside of the TO baseline for both NGET and NGG. The Initial Proposals do not, however:

(a) set out how this capex will be remunerated; or

(b) make any reference to the associated opex (in fact we can see that Ofgem have stripped all CNI related opex out of their tables).

276 Our FBPQ submission identified (as a "new" controllable cost) some £6.2m of security related opex by 2011/12 linked specifically with our planned capital investments and based on the number of sites that we predict will be granted CNI designation.

277 Our discussions with the DTI and Security Services over CNI designation and prioritisation remain ongoing and further developments relating to infrastructure criticality and security requirements have led to changes in the number of likely CNI designations and unit costs per site since our FBPQ submission.

278 We recognise that, because of these ongoing discussions with the DTI and Security Services, it has been difficult to specify precisely the number of CNI designated locations requiring security enhancing investment. Our FBPQ submission represented our view at the time which has to some extent been overtaken by changes in the estimated number of CNI locations and more detailed cost information.

279 Given the fluidity of the situation and the continued absence of any clarity over how these investments will be remunerated National Grid now propose that all CNI driven capex and opex costs be remunerated on a pass through basis with the following characteristics:

(a) the pass through mechanism will need to commence on 1st April 2007 by means of new adjuster terms in the RPI-X formulae for NGET and NGG;

(b) the initial pass through in the 2007/08 financial year will include those costs incurred in good faith prior to April 2007 by National Grid in addition to the forecast cost for 2007/08;

(c) annual audit certifications will commence at the end of the 2007/08 financial year to verify the sums of money spent versus forecast (and the sites that they were spent at) with any consequent adjustment for under or over-spend being corrected in the subsequent year.

280 We would like to discuss this potential mechanism with Ofgem **prior** to publication of their Final Proposals.

Quarry & Loss of Development Claims

281 It is particularly difficult to predict accurately the incidence or quantify the magnitude of future liabilities imposed on National Grid under the terms of legacy arrangements. A particular example of this is in respect of pipeline deeds entered into many years ago by predecessor organisations.

282 Under the terms of these deeds, Land owners and/or Land Users are entitled to seek compensation for mineral extraction or development restrictions imposed because of the presence of gas pipelines. In recent years, National Grid has experienced claims of increasing volume, value and complexity.

283 National Grid carries out careful assessment of each claim on its merits in order to establish legal validity and minimise the quantum. Settled claims include those relating to caravan sites, housing development, lowered water tables leading to a loss in market value of property and mineral claims.

284 National Grid was recently subject to civil action by a quarry developer who sought compensation for both inability to extract minerals and subsequently the inability to use the quarry for landfill operations.

285 The claimant was successful in its case against National Grid. We are currently appealing this decision and on the outcome of the appeal hangs a potential settlement of [redacted] coupled with the direct precedent being applied to [redacted] of further claims that have already been lodged along with any new claims that may be lodged in the future.

286 TPA acknowledged in their report that "**Legitimate claims will arise due to sterilisation of land opportunities**" and our desire to see a new regulatory treatment for the associated costs.

287 As Ofgem are aware we have made no financial allowance in our FBPQ tables for any potential cash settlements (following the commencement of our new Price Control arrangements in April 2007) in relation to either current or potential future claims, given the difficulty associated with estimating with sufficient accuracy:

(a) the outcome of the current appeal;

(b) the timing of future claims; and

(c) the quantum of future claims.

288 Our FBPQ proposed the introduction of a "certified pass-through" mechanism to remunerate such costs. Subsequent discussions with Ofgem have explored options

such as a baseline opex allowance as part of the NGG price control coupled with a pass through or an incentive style arrangement. At present there are no active discussions taking place in relation to this issue.

289 In the event that a new mechanism is not arrived at as part of the Price Control Review process, it would be necessary for an estimated cash cost in relation to potential future settlements to be included in our base operating cost allowance.

290 Again we would like to discuss this potential mechanism with Ofgem **prior** to publication of their Final Proposals.

Capex Allowance / Opex Allowance Interactions

291 As explained to Ofgem and their consultants through the workshop and Q&A process NGET's FBPQ submission represented an integrated view of future capex and opex requirements that carefully considered the impact of asset management decisions on both capex and opex. Ofgem's Initial Proposals take no account of the interaction between their capex and opex allowance proposals and thereby further understate our opex allowance owing to their proposed capex reductions.

292 The integrated nature of the NGET submission must be taken into account by Ofgem when arriving at adjustments to our FBPQ. In particular, potential efficiency adjustments by Ofgem in capex may significantly impact on and increase our opex requirements.

293 This section now goes on to illustrate the issue with a series of **examples**.

Increased Fault and Defect Levels

294 NGET's capex submission is based around the policy of replacing assets immediately before failure and, by doing so, maintaining the level of network risk at the historic levels expected by consumers. Ofgem's proposals to reduce the volumes of assets to be replaced (particularly transformers and circuit breakers) increases the numbers of assets on the system that will be subject to an increased level of defects, faults and potential failures. This will have direct impact on asset unreliability (evident in measures of average circuit unreliability and unplanned unavailability). The rectification of this increased level of defects will require additional opex which was not part of our initial submission and has not been taken into account in Ofgem's initial proposals.

KEMA Opex Efficiencies Based on FBPQ Plant Mix

295 KEMA have suggested opex efficiencies resulting from their benchmarking of engineering Opex. This benchmarking was based on plant populations included in our FBPQ submission. The impact of these changing plant populations (particularly the impact of replacing air blast and oil circuit breakers with SF_6 breakers which are less expensive to maintain) was taken into account in our FBPQ submission. Obviously, KEMA's capex proposals to reduce the level of asset replacement of old air-blast and oil circuit breakers will result in more of these expensive to maintain assets on the system. Ofgem need to reflect the impact of their capex proposals in the opex benchmarking, and an opex additional allowance would be required.

Increased Transformer Movements and Maintenance

296 The reductions in transformer asset replacement will result in a higher degree of transformer failures among the system population. The asset management solution to these failures is to replace the failed transformer with another. Where the replacement transformer cannot be sourced from the manufacturer's works which is not always the case, the costs incurred from moving the transformer are opex. The cost of such opex moves was reflected in the FBPQ submission which assumed one such transformer move per annum. The increased number of transformer failures will result in more transformer moves, and an additional opex allowance would be required.

297 In addition, KEMA did not adjust their Opex benchmarking for the impact of maintaining older transformers on the system.

Increased Cable Fault / Leakage Cost Rectification

298 The reduced allowance for cable replacement will result in some relatively high leakage rate cables remaining on the system. As with all asset categories, the cable submission was a balanced asset management package including both capex and opex. If NGET is to meet its environmental targets for cable oil leak reduction it will have to manage the leaks on these cables which are not being replaced which would require an additional opex allowance for leak location and management.

Increased Piecemeal OHL Component Replacement

299 The efficiencies proposed for OHL asset replacement will result in a higher level of faults and defects on components of the OHL conductor systems such as spacers and insulators. The Opex FBPQ submission had anticipated a rising level of such faults and defects through the "Component Replacement" workload of £1.2m pa. KEMA have proposed an efficiency of £0.5 pa. This efficiency does not take into account the capex reductions proposed by Ofgem, which will increase rather than decrease the requirement for component replacement work. Accordingly, we believe that KEMA should review their proposed efficiency savings in the light of Ofgem's capital proposals.

TPA Capex Efficiencies Based on Increased Opex Plant Relocation

300 TPA have suggested capex efficiencies resulting from relocating plant between compressor sites. The process of relocating plant would inevitably entail additional opex costs. These opex costs should have been included by TPA in their consideration of their proposed capex efficiencies in order for a proper balance between capex and opex asset management solutions to be maintained. As the TPA proposals stand, an additional opex allowance is required simply in order to make them whole.

Capex Allowance / Opex Allowance Interaction – Conclusions

301 We would like to discuss with Ofgem the process for factoring in the required adjustments to their opex allowances associated with any potential adjustments that they may propose that diverge from our capex FBPQ **prior** to publication of their Final Proposals.

IX Answers to Specific Ofgem Questions

Introduction

302 This section deals with the specific questions set out by Ofgem in their Initial Proposals on a by exception basis only in those instances where we have not already provided our response in full elsewhere in this document.

Question 7.4

Do you think that we need to allow explicitly for the possibility of re-opening the price controls for specific single events where the timing and level of such costs is uncertain and driven by third party decisions? If so, what might such events be and why?

303 Section VIII of this chapter has set out the issues surrounding Critical National Infrastructure Security and Quarry and Loss of Development claims in full. We propose that each of these be handled, not by re-opening of price controls as such, but rather through agreed pass through mechanisms that facilitate adjustment to overall RPI-X revenues for NGET and NGG.

304 The impact of BT 21^{st} Century Network, however, has not already been covered elsewhere in this document. Ofgem in their Initial Proposals refer to it as a candidate item for a future re-opener and we are open to this treatment subject to certain caveats. The issues and our proposals are summarised below.

BT 21^{st} Century Network

305 BT has made public its intention to change out its existing core network with IP-based technology which will be unable to meet our specific requirements for tele-protection of the NGET transmission system.

306 Despite ongoing dialogue, there is a distinct lack of clarity around BT's programme for migration to its new network with respect to the impact on BT tail circuits (the remotest parts of the network), specifically on the Megastream 2 circuits. BT have indicated that they will review the Megastream 2 position in 2008 and have provided informal assurances that these circuits are likely to remain on the legacy infrastructure until 2011. However, National Grid has been unable to obtain any firm commitments to this effect.

307 Our planned investment for BT21CN risk avoidance is intrinsically linked with our overall strategy for the OpTel network. The other key factors for consideration are:

(a) The current contract with C&W is due to expire January 2011; and

(b) We will need to begin refreshing the ageing OpTel network assets during the next price review period and in preparation for commencement of the new contract.

308 Given the five-year lead time on a network re-build, National Grid expects to have to make a decision in 2006/07 on whether to begin an open tender exercise in 2007/08 which is highly likely to be ahead of any clarification around the BT21CN issue. Our strategy has always been to bundle the asset refresh requirements with the options for

BT21CN risk avoidance under the new contract.

309 Given the uncertainty around BT21CN, National Grid would value Ofgem's further support in forcing clarity around the scope and timescales of BT21CN for the BT tail circuits.

310 However, until BT can provide a definitive statement on the long term future of Megastream 2 services **we propose holding a checkpoint meeting with Ofgem every three months** to review progress leading up to our critical decision point to launch an OpTel re-tender exercise (to include provision for BT21CN risk mitigation) in 2006/07.

311 In order for National Grid to feel confident that BT21CN is excluded from the Transmission Price Control and instead treated as an item for a re-opener we will need to see the following in Ofgem's Final Proposals:

(a) recognition that the investments for BT21CN risk mitigation and OpTel network asset refresh may be most efficiently incurred under a single programme;

(b) agreement to our proposal for ongoing period meetings with Ofgem;

(c) a clearly defined, agreed and documented mechanism by which incremental expenditure driven by BT21CN is remunerated **during** the new price control period to 2011/12 i.e. National Grid will not accept Final Proposals where the treatment of BT21CN expenditure is:

(i) left vague or open to interpretation; or

(ii) where Ofgem propose that NGET fund the required works, with Ofgem reviewing such spend for potential inclusion in the opening RAV as part of the next price control review.

312 Clearly this whole issue would benefit from substantive discussion with Ofgem **prior** to the publication of their Final Proposals.

Question 10.3

Is our approach to funding for innovation appropriate and necessary?

313 The principle of innovation funding to encourage investment in research and development (R&D) within the electricity transmission sector is fully supported by us. We welcome the proposed introduction of an "Innovation Funding Incentive" for electricity transmission of up to 0.5% of TO allowed revenue and the opportunity to feed back on the issues relating to the funding mechanism.

314 National Grid's proposals for R&D funding reflect:

(a) our substantial and productive ongoing R&D programme;

(b) our central role as energy market facilitator;

(c) our role as custodian of the transmission networks and the responsibility we have to our customers;

(d) the fact that the R&D programme forms a base feeder for the capital investment programme and the management of an ageing asset base;

(e) our established links with universities and other R&D providers;

(f) the need to utilise skilled staff to manage R&D including implementation; and

(g) our active involvement with other utilities, suppliers, academia and government with respect to future technical staff and the government's energy programme.

315 Based on our experience of delivering an R&D programme in the transmission sector that provides value to the customer, we believe that it is essential that the scheme reflects the following issues:

(a) The identification of ring-fenced funding for innovation of up to 0.5% of allowed revenue is in our view a very sensible development to maintain R&D is undertaken to meet the key business challenges facing National Grid. Competing priorities in our opex spend limit R&D within the transmission business both in terms of external spend and in particular internal spend to manage the R&D effectively.

(b) The assessment of R&D benefits given a significant proportion of the benefits from National Grid's R&D are associated with avoiding costs and managing risk within the transmission business, with benefits from past and current R&D being incorporated into business plans. For example:

(i) Cost avoidance represents the largest single benefit category of the R&D programme, for example reductions to failure rates in assets through understanding of failure mechanisms leading to avoided manpower and replacement asset costs.

(ii) Direct savings are identifiable in specific cases for example deferral of tower foundations upgrades due to investigations into the dynamic resistance of tower footings

(iii) The management of risks is critical in the areas of health, safety and environmental R&D for example the development of an oil in soil or water monitor to enable more efficient remediation of leaks

(iv) The final area of benefit relates to the strategic R&D which delivers potential long term benefit and enables strategic guidance for both industry, academia and government for example support for a multi-partner EU project to investigate the potential of remote sensing based on satellite surveillance – the benefit will derive from the results being taken up by a potential supplier but the R&D would not have happened without being driven by utilities.

(c) Our experience with maintaining and developing an effective R&D programme informs us that as a percentage of our total R&D expenditure the internal cost of managing the programme if set at 15% is too low. Experience from the DNO's suggest that 30% would be more appropriate if trials of new technology on the networks are included.

(d) As National Grid has a developed programme with obligations to support academic research it is believed that a mechanism allowing cost recovery in the current year which recovers the full allowance is applicable to continuing a balanced R&D programme

316 Based on Ofgem's initial proposals and those stated above National Grid would welcome further discussion on the form of the scheme, project eligibility criteria and reporting guidelines.

Question 11.4

Is there a case for an innovation incentive for NGG NTS?

317 National Grid believes there is a very strong case for innovation funding incentive (IFI) for gas transmission. Without an IFI the potential areas for innovation that would have reduced likelihood of progression due to competition with other non-R&D opex priorities include:

(a) environmental initiatives, both energy utilisation and emissions (also addressed in answer to question 12.3);

(b) gas flow and related activities;

(c) understanding the ageing network;

(d) optimisation of the network;

(e) the introduction of new technology from basic materials to major assets; and

(f) improved asset management.

318 In line with our comments in response to Question 10.3 relating to IFI for electricity the identification of discrete funding for innovation of up to 0.5% of allowed revenue is in our view a very sensible development to ensure R&D is undertaken to meet the key business challenges facing National Grid, as the current competition with opex priorities limits R&D both in terms of external spend and in particular internal spend to manage the R&D effectively.

319 We consider that an IFI for NGG NTS is necessary and would deliver value to customers. The basis of the requirement is effective and economic asset management related to establishing technical asset lives – this issue is not and will not be addressed (as stated in the Ofgem Initial Proposals) by manufacturers and contractors in collaboration with organisations such as Advantica but will necessarily be driven and funded by National Grid. Specific examples of projects driven by National Grid to the benefit of the industry include the development of automatic welding, up-rating of pipelines to challenge and extend the IGE design code, developments in X80 pipeline material and techniques for managing un-piggable pipelines.

320 The gas transmission network, largely due to being younger than the electricity network, has a less mature replacement policy. The requirement at this time is to develop a better technical understanding of asset condition and performance through

R&D in order to understand technical asset lives. Targeted R&D to develop this understanding for electricity has been developed over at least the last 15 years and has resulted in a more cost effective capital replacement programme. Implementation of an IFI will provide a stronger incentive to carry out R&D work in these areas in contrast to short timescale problem solving projects with immediate benefit and a high likelihood of success.

321 In terms of eligibility criteria and reporting guidelines we refer to our response to question 10.3. National Grid's R&D programme addresses both gas and electricity requirements under the same prioritisation and management process with projects relating to energy impacting on both the electricity and gas networks and their customers. Project proposals for future research show an increase from 20% being related to energy generically in 2007/8 to over 30% in 2011/2 – this indicates not only the importance of combined energy issues but also the need for long term strategic R&D on combined energy issues.

322 We would welcome further discussion on the requirement for an Innovation Funding Incentive for NGG NTS.

Question 12.1

Part 1: Do you agree with our assessment for the main impacts of the transmission system?

Part 2: What are the most important impacts from the perspective of the consumer?

323 National Grid agrees with the assessment of environmental impacts in the Ofgem Initial Proposals document although we believe there to be important omissions including:

Electric & Magnetic Fields (EMF)

324 Public concern around the health risks associated with exposure to the electric and magnetic fields ("EMFs") produced by the operation of the electricity transmission system continues to grow.

325 In 2004 the NRPB (now the Radiation Protection Division of the Health Protection Agency) published advice to government that the UK should adopt the guidelines published by the International Commission on Non-Ionising Radiation Protection (ICNIRP). The ICNIRP guideline levels are lower than the previous NRPB 1993 levels, and National Grid is working with the DTI to establish whether any modifications to the electricity transmission system are required to ensure compliance with the new guidelines.

326 The Department of Health has commissioned the Stakeholder Advisory Group on Extra Low Frequency ("ELF") EMFs (SAGE) to report on whether any precautionary action to further restrict public exposure to fields is required. It will be for government to judge whether any action is required on behalf of the transmission network owners based on the contents of the SAGE report.

327 Any actions will be additional to the planned asset replacement programme as submitted in our FBPQ. The increased public and governmental concern on this subject will result in National Grid dedicating more resources to day-to-day management of this topic.

Oil Leaks

328 Management of cable insulating oil is seen as a significant challenge within National Grid, and significant resources are allocated in this direction. This includes R&D projects looking at better ways of locating leaks more quickly, trying to prevent oil migrating to the wider environment and identifying improved methods for remediating ground following oil spills, in addition to cable maintenance expenditure.

329 Another notable omission is the containment of insulating oil from substation equipment, primarily transformers. National Grid has invested £76m over the last 10 years improving the oil containment facilities in substations, to ensure that equipment leakages do not escape into the environment. We intend to invest a further £40m over the next 6 years.

330 Additionally, as referred to in Section IV of this chapter above, National Grid has an ongoing opex programme to remediate ground at operational sites that are contaminated through past activities.

Question 12.2

Should emissions of SF_6 be subject to a separate incentive scheme, given that they are currently outside the scope of the European Emission Trading Scheme (EU-ETS)?

331 It should be noted that in May 2005, Defra appointed Future Energy Solutions to carry out research to inform their decision on the scope of the EU emissions trading scheme for phase II to include non CO_2 greenhouse gases, including SF_6.

332 If SF_6 remains outside of the scope of the EU – ETS then in principle, National Grid would be supportive of a mechanism to encourage the continued reduction of SF_6 emissions.

333 The following points would need to be considered and resolved to the satisfaction of all parties before any proposal could be accepted:

(a) It must be recognised that in relation to any proposal to contain the emissions of SF_6 that there is currently no available alternative to SF_6 as an arc interruption medium at transmission voltages (above 132kV). In addition, for some applications, GIS (Gas Insulated Substations) designs are both safer and more practical to build when considering asset replacement however our preference would always be to install conventional air insulated switchgear albeit containing SF_6 for arc interruption. Consequently National Grid's installed SF_6 inventory is planned to increase for the foreseeable future and leak rate performance should therefore be measured against the installed mass.

(b) Early equipment containing SF_6 was not designed or manufactured to the same leak rate specifications as modern equivalents and therefore an underlying leak rate will be inevitable until such time as this equipment is replaced. A zero leak rate would not be achievable even with the best available technology and to achieve the targeted leak rate of below 2% of our mass installed by 2010 would require the replacement of early designs of equipment. Any future incentive scheme would need to balance the environmental objectives with efficient capital expenditure (i.e. replacing assets ahead of their anticipated asset life to reduce emissions).

(c) Leak rates are determined by monitoring the quantity of SF_6 used when topping-up leaking equipment. Any future scheme should not be an additional administrative burden and include recovery of costs associated with recording and maintaining records. National Grid has voluntarily chosen to comply with the reporting requirements of the recent EU Regulation 842/2006 (effective from 4 July 2007). This regulation will require National Grid to report any quantities of SF_6 added or recovered during maintenance, or disposed of during decommissioning. Any future scheme should not impose reporting requirements that are inconsistent with other organisations (e.g. Defra & DTI) which may require large amounts of data re-packaging.

(d) Any future incentive scheme should take into account the voluntary reduction in leak rates achieved during previous regulatory periods. The worst performing equipment has either been replaced or repaired in the current review period and it must be recognised that it will be increasingly difficult to achieve similar levels of performance in the future. Similarly the financial treatment of mid-life refurbishment of early designs of GIS substations needs to be agreed prior to the implementation of any incentive scheme. The scheme should, as a minimum, allow National Grid to recover its costs both opex and capex associated with reducing emissions.

(e) National Grid has publicly stated its ambition to achieve a leak rate of less than 1% of mass installed by 2025 with an intermediate target of less than 2% by 2010. Any proposal to accelerate these dates would require additional early asset write-off in respect of equipment replaced ahead of their anticipated asset life on purely environmental grounds. In any case, the scheme should focus on long-term targets as year-on-year specific reductions are dependant upon such factors as system access, resource availability, leak repair solutions, one-off defects and unforeseeable failures.

(f) In terms of the recovery, recycling and reclamation of SF_6, currently available technology has an efficiency limit of approximately 95% and recovery beyond that level would be technically very difficult and arguably unnecessarily costly. Any incentive proposed would need to take this into account.

334 In summary National Grid is committed to the protection and enhancement of the environment, seeking new ways to minimise the environmental impacts of our past, present and future activities. National Grid fully agrees with and supports the overall objective to reduce emissions of SF_6.

Question 12.3

Should there be additional measures to promote innovation in support of environmental benefits, either as part of the proposed incentive scheme for innovation for NGET, SPT, and SHET or as a separate measure?

335 National Grid strongly supports measures to incentivise the delivery of environmental benefits, and this is inline with the emphasis on environmental issues within the Government R&D agenda.

336 Environmental drivers form part of the current R&D prioritisation scheme within National Grid and as such, our existing and planned R&D programmes include a number of environmental projects. Our preference, for administrative efficiency, would be for environmental improvements to be funded through the inclusion criteria under a

single IFI scheme (one for each licence).

337 As referred to in answer to Question 10.3 projects to minimise environmental impact, upon our customers and as part of the global climate change initiative, enable National Grid to manage environmental risk. Projects to promote environmental studies beyond a regulatory requirement are inevitably prioritised below those delivering short term business benefit. Measures to promote additional environmental innovation need to consider more than the cost benefit of a specific project and recognise the long term global value of environmental benefit. An additional fund to enable environmental related innovation to be addressed would be beneficial not only to the operation of the networks but also deliver indirect benefit to all consumers via understanding and implementing methods to limit global climate change.

338 We would welcome further discussion of the environmental eligibility criteria for an “Innovation Funding Incentive” for both electricity and gas networks.

3 Capital Expenditure

I Introduction

339 This section of our response provides our views on Ofgem's Initial Proposals with respect to historic and future capital expenditure allowances for both National Grid Electricity Transmission (NGET) and National Grid Gas NTS (NGG).

340 As discussed in our response to the Third Consultation document, we are generally supportive of Ofgem's approach to assessing the efficiency of both historic and future capital expenditure requirements. We believe the work completed over the last nine months by Ofgem and their three principal efficiency consultants is consistent with this stated approach.

341 However, we have great concern regarding both the:

(a) application of that stated approach; and

(b) interpretation of the output of the consultants' conclusions as set out in the initial proposals.

342 We believe these application and interpretation issues together have led to the proposals being entirely unacceptable. In addition, it is clear from the consultants' reports that insufficient time has been allocated to the assessment of a number of key issues, not least of which is the unit costs at which our capital schemes can be carried out.

343 In overview, we believe that the initial proposals are unacceptable because they would require:

(a) very substantial reductions in both gas and electricity **non-load related** planned expenditure, which will lead to:

(i) deterioration of the performance and flexibility of networks which are vital to the national economy, and

(ii) creation of an unrecoverable backlog of replacement work;

(iii) non-compliance with our legislative requirements, both in terms of safety and environmental performance of transmission assets;

(b) significant reductions in the planned level of **baseline load related** expenditure, despite high levels of certainty and commitment from transmission users, contradicting Ofgem's own definition of what should be included in the baseline allowances.

344 Our response is divided into sections as follows:

(a) **Section II – Ofgem's assessment process**, covering both electricity and gas transmission capital expenditure we comment on the process Ofgem have used to determine the proposed capex allowances.

(b) **Section III – National Grid electricity transmission.** In particular, we comment on what we believe are wholly inadequate allowances for expenditure on asset replacement, particularly with regard to overhead lines and switchgear. In addition we comment on Ofgem's proposed baseline allowances for load related expenditure.

(c) **Section IV – National Grid gas transmission.** In particular we comment on the proposed disallowance of historic expenditure relating to the provision of capacity at the St. Fergus entry point, the proposed reduction in expenditure on emissions reduction and condition related asset replacement on the basis of an imprudent assumption that some compressor sites can be closed, and the inconsistent setting of baseline allowances.

II Ofgem’s assessment process

Approach

345 From the Initial Proposals we can see that Ofgem intend to broadly follow the following four stages in order to determine an appropriate allowance for capital expenditure in each of the respective categories (electricity and gas, load and non-load):

(a) Stage 1 – Ask expert consultant(s) to assess Licensees’ proposed plans / processes and advise Ofgem on their view on likely expenditure.

(b) Stage 2 – Ofgem consider consultant(s) report and evaluate an appropriate allowance.

(c) Stage 3 - Consider specific scope for improved procurement effectiveness

(d) Stage 4 – Consider the approach / treatment of forecast above inflation increases in input costs.

346 We note that Ofgem have yet to address the fourth stage and we look forward to working with Ofgem to consider this issue prior to the determination of updated proposals in September.

Application

347 In **principle**, we believe that the approach stated above is reasonable and, in order to facilitate an objective review process, we have sought to understand the requirements of both Ofgem and their consultants, such that we can provide as much information and assistance as they required.

348 However this agreement in principle assumes that:

(a) all issues are considered to an appropriate level of depth such that real issues can be identified and errors / mis-understanding can be eliminated;

(b) a balanced view is taken to identify the appropriate allowance;

(c) all efforts are taken to avoid double-counting of adjustments.

349 Unfortunately, it is evident that Ofgem’s Initial Proposals have failed to meet these requirements. Most significantly:

(a) We were not given any opportunity to review the findings of the consultants in advance of Ofgem’s use of those findings for the purposes of determining the Initial Proposals. In a small number of areas, it is evident that insufficient time has been allocated to feedback between the consultants and ourselves, leading to some critical errors in analysis, which must be addressed. The correction of these errors would materially increase the forecast level of expenditure proposed by the consultants.

(b) The proposals appear to be based around the lowest level of expenditure recommended by **each** consultant for **each** category of investment. This approach (which seems to be driven by a desire to find the lowest number anywhere in the consultants' reports, rather by any notion of efficiency) is entirely inappropriate for determining a reasonable view of the likely expenditure levels on networks which are vital to the national economy

(c) The proposals have clear double-counting of savings in respect of procurement costs as all the consultants' proposals for expenditure in each category have imposed their own unit cost projections into their modelling. Ofgem have then applied their own further 5% efficiency adjustment for improved procurement on top of these reduced costs.

All of the above contribute to determining a totally unrealistic level of allowance being proposed.

350 We also note, in the Initial Proposals, Ofgem's treatment of "historic" costs as being those costs up to 2004/05, with "forecast" costs being those costs from 2005/06 onwards. Clearly, 2005/06 is also complete, and therefore these costs should also be treated as "historic". We welcome Ofgem's statement of intent that the outcome of the review of 2005/06 capex review will be set out in the September Update.

351 However, the capital expenditure in 2006/07 is also well progressed, and as such we would expect Ofgem to provide an updated view on the level of 2006/07 capex, recognising the advanced status of this expenditure in the September Update.

III National Grid Electricity Transmission (NGET)

352 We are extremely concerned at the proposed allowances for expenditure on the England and Wales electricity transmission system, and provide more detailed comments on our concerns below. In summary:

(a) **Asset Replacement - We do not believe that these are sufficient to maintain the performance of the transmission system, specifically in terms of system reliability, resilience to events such as storms and safety to the public.** We believe the vast discrepancy in proposed expenditure has arisen because:

(i) the asset replacement modelling carried out by the consultants contains unrealistically low unit costs because of a lack of full consideration of this issue within the review process;

(ii) the asset replacement modelling carried out by the consultants contains a small number of significant errors and omissions that materially impact certain categories. We believe this is largely because no evaluation period was allowed between National Grid and the consultants to check the output for factual accuracy, and because we were not informed by Ofgem that one of the consultants were carrying out modelling.

(iii) Ofgem have selectively chosen the low end of the consultants' modelling of each individual category;

(iv) Ofgem have then applied a 5% procurement efficiency to reduce further the individually selected low case values (which already incorporate the consultants' estimates of effcicient procurement costs).

It is important to note that in addition to the reasons set out above, the consultants have, in certain categories, chosen to impose their own asset lives and methodology for modelling replacement volumes. Whilst we maintain our belief that our asset lives and modelling are more relevant for assessing the need for replacement on our network, these differences are not the largest source of the vast discrepancy in proposed expenditure between our FBPQ and the Initial Proposals.

(b) **Load related -** we have a number of concerns with the basis of the deductions from our forecast expenditure, in terms of the way in which the "baseline" has been set, the application of a 5% procurement efficiency, the assertions that we had double counted expenditure, and included avoidable early replacement expenditure in the forecast.

353 Our comments below are structured as follows:

(a) "historic" expenditure;

(b) unit costs and procurement efficiency;

(c) "forecast" volume of non-load related expenditure;

(d) “forecast” schemes of load related expenditure.

Historic expenditure

354 We welcome Ofgem’s conclusion that Ofgem and their consultants have found no evidence of inefficient expenditure on electricity transmission in the period 2000/01 to 2004/05. However, Ofgem state that they consider that we could have managed the expenditure in this period within the Price Control allowances without significant consequences in terms of system performance.

355 We would like to clarify that we take our responsibilities as a transmission licensee with the utmost seriousness, and therefore carry out investment on the transmission system where it is required. The majority of the overspend in this period was due to **load related requirements** i.e. investment which we were obliged to carry out to meet customers requirements.

356 For us to have kept total capital expenditure within the Price Control allowances, we would have needed to **cut expenditure on asset replacement to a level well below that which was agreed at the last Price Review.** We do not believe that this would have either been efficient or prudent, given the condition of the assets. Whilst the Price Control allowances clearly place a capital constraint on the licensee, we do not believe that Ofgem expect us to defer necessary replacement purely in order to stay within the Price Control allowances, unless Ofgem are indicating a desire to see greater risk taken with the transmission system, with the Price Control allowances set by Ofgem being the determinant of asset replacement activity. If so, we would contrast this view with that of the Trade and Industry Select Committee, which clearly did not believe that greater risk should be taken.

357 With regard to expenditure in **2005/06**, we welcome Ofgem’s statement that the actual costs will be considered and Ofgem’s views included in the September Update. In addition, we welcome PB Power’s view that, to a large extent, our forecast expenditure on demand connections and related infrastructure is reasonable, particularly as this was an issue of significant disagreement in the mini-review process. We would also point out that, by September, actual expenditure in **2006/07** will also be highly certain, such that this year should also be considered in terms of actual expenditure (rather than modelled volumes) in time for the September update.

Unit costs and Procurement efficiency

358 A significant part of the difference between the consultants’ views and our forecast is due to the application of different unit costs. We recognise that, whilst clearly an integral part of deriving any forecast on capital expenditure, this is a very difficult area to predict. We also note that there has been very limited discussion with the consultants on unit costs and we had not been made aware that there were material differences of view on unit costs prior to receipt of Initial Proposals.

359 It is clear from the consultants’ reports that we have not yet convinced the consultants on the validity of our unit costs. However, we do believe that our views are robust and can be extensively supported. We believe it is essential that this issue is now discussed in much greater depth with Ofgem and their consultants in the period prior to the determination of the updated proposals in September.

360 Prior to examination of the unit cost issues in each asset category, and consideration of the Deloitte report reviewing procurement effectiveness, it is very important to set-out together all the procurement related issues that are to be considered in this price

review, i.e.:

(a) historic and forecast unit costs;

(b) the potential for improvement in procurement effectiveness; and

(c) the potential for future increases in the real cost of labour and materials.

361 We believe that these three issues cannot be reviewed in isolation, and instead need to be considered in the round. This integrated approach will ensure that the proposals will be joined-up and their will be no double-counting of savings.

362 We believe that the Initial Proposals do not consider these issues appropriately, containing inconsistencies and vastly overstating the potential to reduce unit costs and achieve procurement efficiencies.

363 For the avoidance of doubt our position on the individual issues is:

(a) **Historic and forecast unit costs -** we welcome Ofgem and their consultants' assessment that our expenditure through to 2004/05 has been efficiently incurred. Our forecast unit costs are well grounded on the basis of current market trends that can be evidenced by recent and ongoing contracting activity. The procurement practices that underpin the contracting activity are consistent with those employed in the period through to 2004/5 (albeit the practices continue to evolve with best practice) and the assessment of the Historic unit costs should provide a significant degree of comfort that our forecast unit costs are reasonable.

(b) **The potential for improvement in procurement effectiveness –** we continually seek to improve the effectiveness of our procurement activity. This has been evidenced by a number of initiatives over the historical period and is further reinforced by the ongoing implementation of our "Alliance" model for delivering the majority of the forecast investment programme. However, improvement in procurement effectiveness does not automatically correlate with real reductions in the cost of goods and services, and our reasonable expectation is that the anticipated increase in our procurement effectiveness will be sufficient to secure capacity to deliver our programme and mitigate the specific inflationary pressures that are currently embedded in the particular segments of the market that we are largely dealing with.

(c) **The potential for future increases in the real cost of labour and materials –** Far from expecting to see cost reductions, we firmly believe, and there is much external evidence that this is a widely held view, that many of the broad components of our capital costs are either likely to continue to increase in price in the coming years, or are extremely volatile. In our FBPQ submission, we included forecast increases in capital costs driven by increases in civils, manpower, and steel costs, which are major components of our capital programme in electricity and gas. We believe there to be a strong case for including some element of indexation of the Price Control allowances to cover the impact of such cost increases.

364 We provide more detailed comments on each of these issues below.

Historic and forecast unit costs

365 Our comments on specific unit cost issues are provided below, in the following order:

(a) overhead line unit costs;

(b) switchgear unit costs;

(c) cable unit costs;

(d) transformer unit costs.

Overhead line unit costs

366 The impact of the consultants' choice of unit costs for overhead lines results in a material difference between our forecast and their forecasts. In summary the differences are:

(a) KEMA's choice of unit costs results in an approximate difference between our forecast and theirs of **£190m**;

(b) PB Power's choice of unit costs results in an approximate difference between our forecast and theirs of **£70m**;

367 It can be seen that these differences of views on unit costs result in very material differences in the proposed allowance. This has potentially serious consequences for the replacement of overhead lines as we do not believe that it is possible to deliver overhead line refurbishment schemes for the unit costs suggested by the consultants.

368 The differences result from a combination of the consultants' choice of lower unit costs than us for both full refurbishment and fittings only work. In summary, we believe that the consultants have arrived at inappropriate choices of unit costs because:

(a) some of their analysis of historic and future schemes costs is incorrect;

(b) the schemes selected for their analysis of historic and future costs are not representative of the range of costs of overhead line schemes;

(c) their analysis does not reflect the current cost of schemes evidenced through actual contract costs.

We discuss each of these in turn below, followed by a description of the process we follow to deliver overhead line schemes in the most efficient manner.

369 For **full refurbishment schemes**, the unit costs used by ourselves and the consultants are shown below:

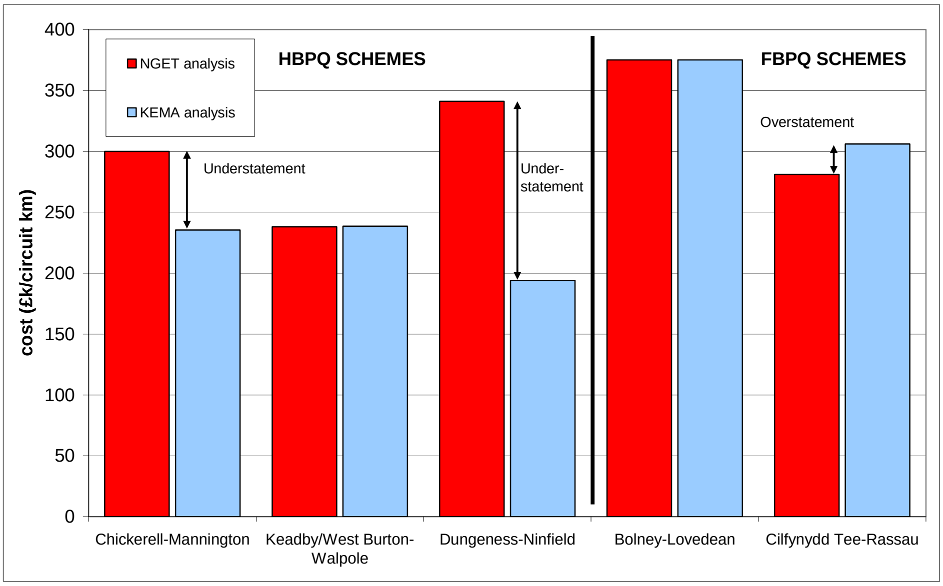
(a) NGET - £285k/circuit km;

(b) KEMA - £200k/circuit km;

(c) PB Power - £256k/circuit km (£140k/circuit km for twin Lynx conductor[1]).

370 We believe that the consultants' unit costs are inappropriate because:

(a) **Their analysis is wrong -** KEMA's view is based on comparing our forecast costs to our own historic costs, and KEMA present a graph showing the costs of four FBPQ refurbishment schemes at around £600k/route km (equivalent to around £300k/circuit km for a double circuit route[2]), compared to the costs of four historic refurbishment schemes at £230-480k/route km. We believe that the calculation of the unit costs from these schemes is incorrect. The graph below compares our analysis of the quad schemes (in cost per circuit km, rather than route km) with KEMA's analysis.



Essentially KEMA present the future schemes analysed as being significantly more expensive than the historic schemes, with, on KEMA's analysis the average historic cost of the three schemes being around £220k/circuit km and the average cost of the future schemes being around £340k/circuit km. However, KEMA appear to have miscalculated the average costs of 3 of these schemes, making 2 historic schemes appear less expensive than they really are, and one future scheme seem more expensive. In fact, the correct figures for these schemes are £290k/circuit km for the 3 historic schemes and £330k/circuit km for the 2 future schemes. This difference is illustrated in the chart below:

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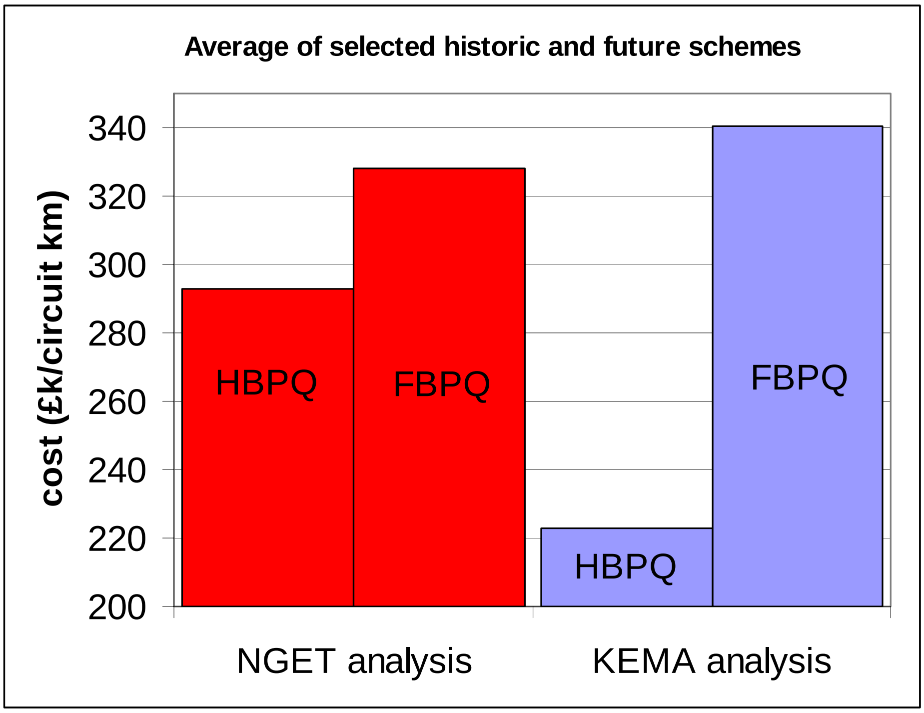
[1] NGET's overhead transmission lines are generally of either quad (consisting of four conductor wires per phase) or twin (consisting of two conductor wires per phase) construction.

[2] In general an overhead line route consists of two circuits, such that costs quoted as "per route km" are generally twice as much as costs quoted "per circuit km"



It can be seen, therefore, that after correcting the analysis, the three historic schemes support the average cost of the schemes in our submission of around £300k/circuit km, and the cost of the two future schemes is considerably closer to the average of the three historic schemes than KEMA imply.

We believe, therefore, that even on KEMA's limited analysis, an average scheme cost of £300k/circuit km is more justifiable than their unit cost of around £200k/circuit km.

(b) **Their analysis is not reflective of the range of scheme costs –** Both consultants have chosen a small sample of schemes on which to base their views on unit costs, which are not reflective of the range of scheme costs**.** Overhead line scheme costs are very dependent on:

(i) terrain;

(ii) environmental requirements;

(iii) number of road and rail crossings;

(iv) the length of the route (with shorter routes tending to have a higher per unit cost due to fixed costs of deployment);

(v) extent of tower steelwork replacement required.

These factors drive significant differences in the cost of individual schemes, potentially accounting half of the scheme cost, resulting in large differences in costs between schemes.

With regard to **quad** conductor, PB Power based their reduction of unit costs on analysis of effectively just two quad schemes, having effectively dismissed two other schemes as "atypical", and just two twin Lynx schemes. One of the schemes selected by PB Power as "representative" of average unit costs was the Keadby-Grimsby West scheme. Of the factors identified above, this scheme had the following characteristics:

– terrain = easy (open rural, mainly level ground)

– environmental impact = low (no environmentally sensitive areas)

– road and rail crossings = medium (trunk roads and single rail crossings)

– extent of steelwork replacement = medium (piecemeal replacement on <10% of tower)

Consequently, the specific cost of this scheme was £224k/circuit km. Given the relative ease of this scheme, it represents the lower end of the range of costs of overhead line schemes, rather than being representative of average costs. By comparison, the Chickerell-Mannington scheme, effectively dismissed as "atypical" and therefore ignored for purpose of setting unit costs, had the following features:

– terrain = easy (open rural, mainly level ground)

– environmental impact = high (More than 50% of route within environmentally-sensitive area)

– road and rail crossings = high (dual carriage ways, motorways, main line railways etc)

– extent of steelwork replacement = low (no significant steelwork required)

This scheme had a specific cost of £300k/circuit km. However, it can be seen that this scheme is not atypical, but is typical in reflecting the different cost drivers of overhead line schemes – whilst the terrain is easy and no significant steelwork was required, the high number of crossings and environmental sensitivity lead to the cost being significantly higher than for the Keadby-Grimsby West scheme. This illustration demonstrates that the costs of each scheme are driven by the particular circumstances of each route, and schemes should not be dismissed as "atypical" for the purposes of assessing an "average" unit cost.

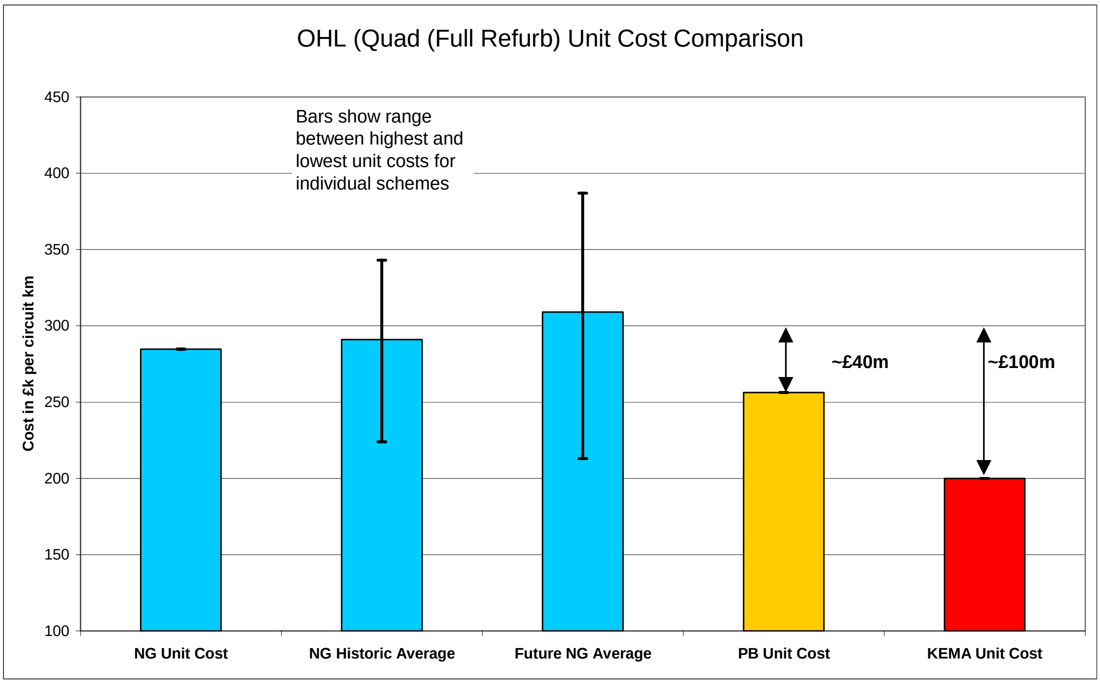
The schemes in our FBPQ submission have each been carefully costed to take account of such circumstances and, in the Annex to this chapter, we have provided a matrix of all historic and future schemes, showing the particular circumstances of each scheme against their specific costs – it can be seen that the specific cost correlates to the terrain, environmental impact, number of road and rail crossings and extent of steelwork replacement required, with some schemes having a specific cost significantly higher than the average, whilst some are lower, with the weighted average being around

£300k/circuit km.

With regard to **twin Lynx** conductor, the most recent of the schemes utilised by PB Power was contracted **six years ago** and closed four years ago, following which costs rose sharply. PB Power's unit cost of £140k/circuit km for twin Lynx does not, therefore, reflect the current cost of carrying out these schemes.

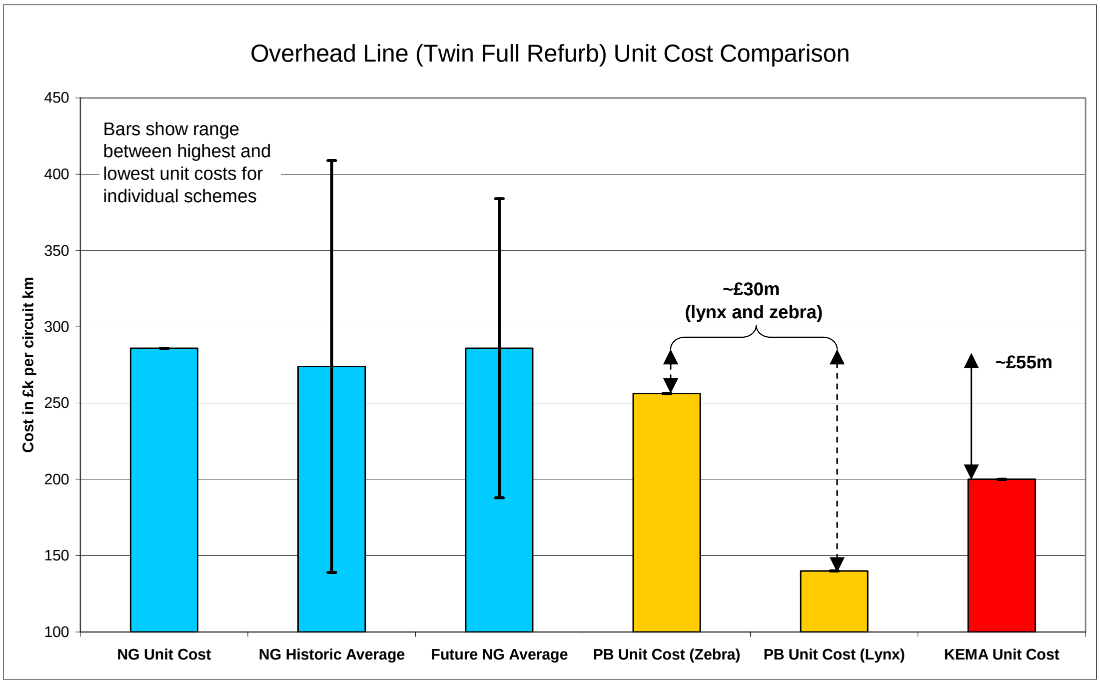
Similarly KEMA's analysis is based on a small number of schemes which do not reflect the range of costs of twin overhead line schemes.

To provide a more comprehensive analysis of overhead line costs, we have reviewed the costs of all historic schemes from the current period and all future schemes for the forthcoming period. This analysis is shown graphically below. The graphs show our unit cost alongside the average historic and future unit costs and the consultants unit costs. The error bars on the historic and future unit costs show the range of costs for actual schemes, i.e. the highest and lowest scheme cost in the period. The first graph shows this for quad conductor[3]:



The graph below shows the same information for twin conductor:

[3] The difference between the NG unit cost sand the average of the schemes in the FBPQ results from the fact that our unit cost of £285k/circuit km assumes that only 1% of steelwork on the route requires replacement. The schemes in the FBPQ contain provision to reflect the extent of steelwork required on that specific scheme. As a result, the average cost of schemes in the FBPQ is around £300k/circuit km.



As can be seen from the above charts:

– our average unit costs are consistent with the average cost of historic schemes;

– KEMA's unit cost for quad conductor is lower than the lowest cost historic scheme;

– PB Power's unit costs are significantly lower than the actual average historic cost;

– PB Power's unit costs for twin Lynx conductor are equal to the lowest cost historic scheme.

KEMA also compare with a number of schemes from the Scottish TOs. We note that this does not cover any quad schemes, and only shows three twin schemes, all costed at around £200k/circuit km. We have not been provided with any further information on these schemes, and so cannot tell whether these schemes are comparable (e.g. on the same types of towers, including tower steelwork and earthwire refurbishment), are historic or future, or are representative of the average costs of the Scottish TOs schemes. However, we would welcome a debate with KEMA as to the appropriateness of the comparison of these schemes.

We conclude, therefore, that neither consultants' unit costs are representative of the cost of delivering the overhead line full refurbishment schemes in our FBPQ, as evidenced by the range of actual historic costs, and the broad drivers of schemes costs.

(c) **Their unit costs do not reflect the current cost of overhead line schemes –** we follow a rigorous contracting process in order to deliver the most efficient cost for each overhead line scheme. In summary this process consists of:

(i) Development of an outline Framework Agreement to enable suppliers to tender a pricing schedule against indicative volumes of work, providing a “line-of-sight” to the suppliers of the workload ahead.

(ii) Once more detailed information and scope of actual schemes is available, suppliers are invited to competitively tender for the work.

Following this process, we arrive at the best costs available for each scheme available from the market at that time.

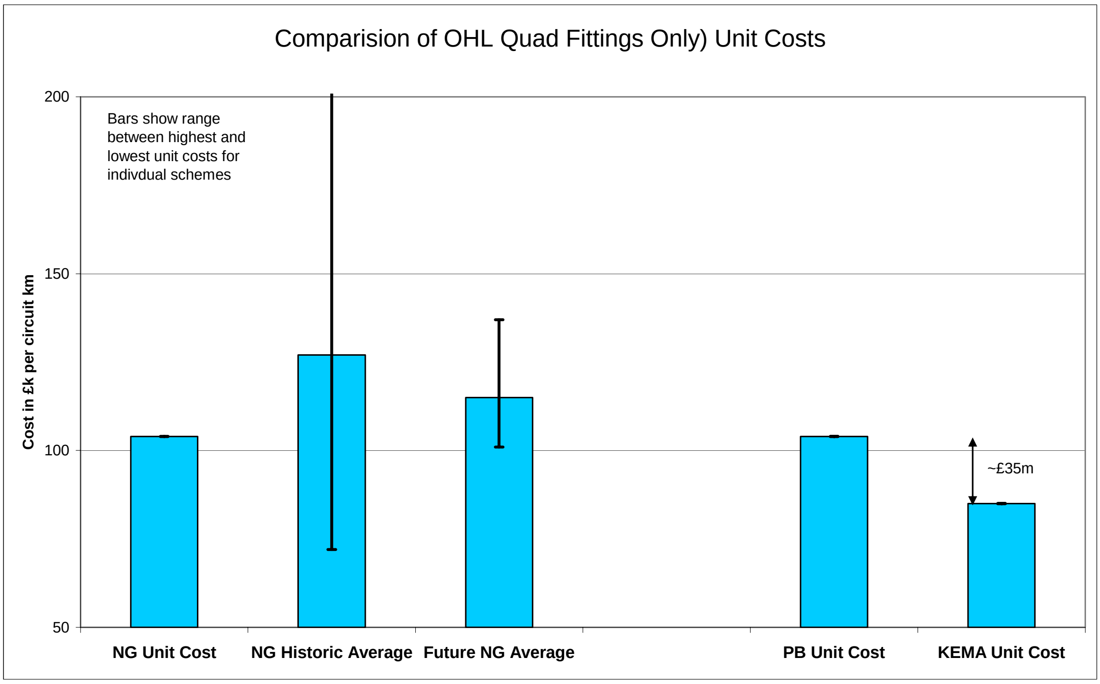
For both quad and twin full refurbishment schemes the average cost of schemes contracted in 2005 was in excess of £300k/circuit km. On this basis, our average cost of schemes in the FBPQ of around £300k/circuit km appears, if anything, to be conservative. However, the precise mix of cost drivers will fluctuate year on year and we maintain our belief that our forecast is appropriate.

We are currently competitively tendering overhead line schemes for 2007/08, and initial tender costs are consistent with those seen in 2006/07. This is indicative of the current state of the overhead line market, with relatively few suppliers, and an ever increasing volume of work from ourselves, the Scottish TOs and the DNOs. The volume of work is unlikely to abate during the forthcoming Price Control period, and therefore we believe that our assumption of flat unit costs across the Price Control period at the level currently seen is aggressive. We believe, therefore, that this does provide a compelling case for unit costs to be at a level of around £300k/circuit km.

371 For **fittings only schemes,** PB Power accept our unit costs, whilst KEMA adopt costs which are substantially (up to almost 30%) lower than ours. This represents an impact on allowance of around £35m, and is not justified by KEMA in their report. Given PB Power’s acceptance of our unit costs and the lack of justification from KEMA, we believe that our unit costs should be adopted, and we will seek to discuss this further with KEMA and Ofgem. Fittings only schemes are subject to the same competitive tendering process described above, and so we believe our costs are the best available from the market.

372 The chart below shows costs for historic and future quad fittings only schemes. As this shows, both historic and future costs are closely aligned with the unit cost adopted by both ourselves and PB Power, but significantly higher than that used by KEMA. We do not believe, therefore, that KEMA’s unit cost reflects the true cost of fittings only schemes[4].

[4] The NG unit cost represents the average cost of all (quad and twin) fittings only schemes in the period 2005/06 to 2011/12, whilst the historic average is of quad schemes only in the period 2001/02 to 2006/07, whilst the future average is the cost of quad schemes in the period 2007/08 to 2011/12.



373 So, in summary, we note that both consultants have used very basic analysis to determine the unit cost of overhead line for the purposes of their modelling. We believe this leads to a very material under statement of the likely cost of these schemes because

(a) Both KEMA and PB Power have used completely un-representative historic low values for out of date schemes as the basis for setting out forward looking allowance

(b) Both KEMA and PB Power failed to take into account the real external market increases that have over the last few years, and will continue to over the coming years, increase the cost of delivering overhead line schemes; and

(c) Both KEMA and PB Power failed to take proper account of the specific cost drivers of the particular schemes in our FBPQ.

(d) No account has been taken of

(i) current and recent contracted costs, following competitive tender; and

(ii) the volume of work expected in the overhead line market over the forthcoming Price Control period.

374 The impact of this is that KEMA have under costed their forecast for overhead lines by approximately **£190m**, whilst PB Power have under costed their forecast by approximately **£70m.** We believe that, in the face of such historic and current evidence in support of our overhead line unit costs, it would be entirely inappropriate for Ofgem to base their allowance for overhead lines on the consultants' unit costs.

Switchgear unit costs

375 The impact of PB Power's choice of unit costs for switchgear results in a difference of around **£60m** between our forecast and theirs. This is clearly material, and needs to be addressed.

376 KEMA's approach to modelling differs from ours (both in terms of volumes and unit costs), but overall this does not result in a material shortfall in KEMA's forecast. The main differences between ourselves and KEMA appears to be the omission of non-modelled expenditure, and if our unit costs are applied to KEMA's modelled volumes, the difference is only around 5%. We therefore we make no further comments on KEMA's unit costs for switchgear. Our comments in this section focus on PB Power's unit costs.

377 PB Power's adoption of a lower unit cost for switchgear is justified on the basis of:

(a) reducing the proportion of GIS by half, on grounds of "insufficient justification" of our proposals; and

(b) 400kV and 275kV costs being lower in our TR3 schedule.

378 In addition, PB Power state that the cost of protection associated with switchgear is not included in their unit costs for switchgear.

379 On the first issue, we believe PB Power's adjustment to be unjustified. In the FBPQ submission, we provided evidence of the drivers for a GIS solution at each of the sites in the FBPQ where a GIS solution is proposed, against a set of criteria used by us to determine the selection of GIS solution, the criteria including visual amenity, health and safety, land availability, cost and alignment with the DNO. This table is repeated below:

Scheme	Description	Voltage	Driver for GIS build						
			Visual Amenity	Complexity	Programme	Cost	Health & Safety	Land / Space	DNO Self Build
03606	Elstree 132kV	132	x		x	x	x	x	
6520	Stalybridge 275kV	275		x	x		x	x	
9526	Littlebrook 132kV	132			x	x	x	x	
10265	Beddington 132kV	132		x	x	x	x	x	X
11122	Walpole 132kV	132			x	x	x	x	
11124	Frodsham 132kV	132				x		x	X
11147	Redbridge 33kV	33	x		x	x	x	x	
11149	St John's Wood 275kV	275	x		x		x	x	
11150	Willesden 132kV	132			x	x	x	x	
11148	St Johns Wood 132kV	132	x			x		x	
11152	Willesden 66kV	66	x		x	x	x	x	
11278	Lackenby 275kV	275		x	x			x	
11332	Ealing 66kV	66	x		x	x	x	x	
11348	Iron Acton 132kV	132		x	x	x	x	x	
13742	West Melton 400kV	400		x	x		x	x	
15140	West Melton 275kV	275		x	x		x	x	
15529	Wimbledon 275kV - Phase 2	275	x		x		x	x	
20004	Rayleigh 132kV	132		x	x	x	x		X
15515	Penwortham 132kV East and West	132			x	x		x	X

380 In each case, the choice of GIS is justified against at least 3 of the criteria, and in two-thirds of the cases the choice of GIS could be justified on cost alone, given the complexity of an AIS solution.

381 The consultants would imply that they believe that our system exists in an idealised world, where we have full choice between construction of a new inexpensive AIS substation on an adjacent greenfield site or an expensive GIS substation. In determining the appropriate solution, we have to consider, amongst other things, the following:

(a) Can the switchgear be replaced utilising existing site infrastructure?

(i) What is the condition of the site infrastructure?

(ii) Does the site infrastructure have sufficient rating to match the current requirements?

(b) If not, can the substation be replaced in situ i.e. bay by bay on the existing site?

(i) Is there sufficient clearance to do this safely?

(ii) Can this be done without compromising the security of supplies during the transition phase?

(iii) How complex would such a scheme be?

(iv) How long would the programme be to carry out such a scheme?

(v) What would the cost of such a scheme be?

(c) If an in-situ repalcement is not possible or economic, is there sufficient land available to replace the substation with a new AIS substation on land close to the existing substation?

382 At the majority of sites, when considering the first question, the site infrastructure was installed at the same time as the switchgear being replaced, and is also in poor condition. If the switchgear was replaced on the existing infrastructure, it is likely that the infrastructure would not last for the life of the new switchgear, resulting in early asset write offs. Where this is the case, the whole life costs of both alternatives should be considered. Where the infrastructure is already beyond technical life, then clearly substation replacement is the appropriate option.

383 The next option considered is the replacement of the entire substation with AIS on the existing site. However, the reality is that, when considering the questions above, many of our sites are located in constrained, built up areas, and it is rare that replacement of this nature does not require some substation extension to allow system security to be maintained during the re-build or to migrate to modern standard bay arrangements. Where there is insufficient space work cannot be planned safely and securely.

384 The next option considered is the construction of a new AIS substation on existing land adjacent to the existing substation. Again, due to the location of many of our substations, there is not sufficient land to carry this out and there is simply not enough land available to construct a new full size AIS substation. In these circumstances, a GIS solution is required.

385 We believe, therefore, that as PB Power have not demonstrated that any of the schemes identified could be constructed with AIS, their reduction of the unit cost is unjustified. Indeed, of the 6 non-load related substation schemes reviewed by PB Power, 4 used GIS – for all of them PB Power concluded that the case for GIS was “justified” or did “not appear unreasonable”.

386 In conclusion, therefore, we do not believe that PB Power’s reduction of the content of GIS in the unit costs is justified or consistent with their own review of the GIS schemes.

387 The second reason quoted is the fact that costs in our TR3 document for 400kV and 275kV GIS are lower than the unit costs used in the FBPQ. As discussed with PB Power, we **do not** use TR3 for the purposes of scheme costing, as the costs in TR3 **do not include** engineering and civils costs associated with delivering a scheme – whilst they may reflect the cost of a unit of switchgear, they **cannot** be used to determine the cost of delivering a scheme.

388 Finally, PB Power state that their switchgear unit costs do not include the cost of protection systems, whilst our unit costs do. It is not clear from PB Power’s report whether the costs have been added to the switchgear cost, or included in the

protection and control category. If the latter is true, Ofgem should be careful not to cap their allowance at the lower of PB Power's view and our view, as appears to be their practice, as this would clearly underestimate the total investment need across the switchgear and protection and control categories.

389 In conclusion, therefore, we do not believe that PB Power's reduction of the content of GIS in the unit costs is justified or consistent with their own review of the GIS schemes, or that their comparison with the costs in TR3 is relevant. As a result, we believe the reduction in switchgear costs of around **£60m** is unjustified.

Cables unit costs

390 For cables, the impact of the consultants choice of unit costs is as follows:

(a) KEMA's "impression" that a 5% saving is possible results in a difference between their forecast and ours of **£30m**;

(b) PB Power appear to use a unit cost which is around 10% lower than ours for cables (excluding tunnel costs), resulting in a difference between their forecast and ours of **£25m**.

391 Neither KEMA nor PB Power offer any explanation for their adjustment to unit costs, although KEMA state that they have "the impression that a cost reduction of 5%" can be realised on cables. Given the materially of this issue, equating to around a £25-30m reduction, we believe the consultants need to provide a more robust reason for this reduction.

392 The costs in our schemes have been derived from our experience of the actual costs delivered through competitive tender processes for the cables, and where relevant for the construction of tunnels. Indeed, for schemes currently in progress, the costs in our FBPQ submission reflect the actual contracted costs. All of our scheme costs are therefore supported by actual market costs.

393 In conclusion, we believe the cost reduction of **£25-30m** .proposed by the consultants on the assumption of lower unit costs remains unjustified.

Transformer unit costs

394 For transformers, the impact of the consultants' choice of unit costs is as follows:

(a) PB Power's choice of unit cost results in a difference between their forecast and ours of around **£20m**;

(b) there appears to be very little difference between KEMA's unit cost and ours.

395 PB Power propose a reduction of our unit costs by 10%. As for overhead lines, this appears to be on the basis that PB Power have assessed a small number of schemes, that seem representative of the lower cost transformer schemes, whilst apparently dismissing a higher costs scheme, implying this to be atypical, requiring expenditure for civil works and noise enclosures.

396 We would point out that very few of our schemes require the simple replacement of a transformer, with most requiring other works (e.g. construction of access roads, reconfiguration of substation to accommodate new transformer, additional transport

costs, environmental works, cabling within the substation). In this regard, on the Uskmouth scheme chosen by PB Power to infer a lower unit cost, the cost quoted is only the cost for supply and installation of the transformers, and does not include any additional works, making these costs "atypically" low.

397 On this basis we do not believe that a 10% reduction in transformer unit costs is justified. Similarly, PB Power propose a reduction in the unit cost of reactors without justification. We would seek further discussions with Ofgem and PB Power to address this issue.

The potential for improvement in procurement effectiveness

398 Across electricity (and interestingly gas transmission to which we return later in this response), Ofgem indicate that they believe that we should be able to achieve a 5% reduction in real costs through procurement efficiencies, on the basis of an "assessment of our procurement policies and strategy" and comparison against "measures of best practice"[5]. This proposed reduction appears to have been mainly based on work carried out by Deloitte to assess our procurement effectiveness.

399 Our comments on Ofgem's proposed reduction for procurement efficiency and treatment of increases in input costs are given below, addressing:

(a) Deloitte's benchmarking of our procurement efficiency;

(b) the appropriateness of the reduction proposed by Ofgem in light of Deloitte's benchmarking exercise;

(c) Ofgem's application of the proposed efficiency;

(d) the "double-counting" of such efficiencies;

(e) Ofgem's proposed treatment of increases in input costs.

Deloitte's benchmarking of our procurement efficiency

400 Deloitte's assessment of our procurement efficiency was a desktop analysis of procurement efficiencies in other capitally intensive companies or large scale construction projects. Deloitte openly acknowledge in their report that they **did not actually assess the efficiency of National Grid**, just provided a number of "comparable" companies and projects. In Deloitte's assessment we note the following:

(a) For most of the comparator companies and projects referred to, the procurement savings are targeted savings, rather than savings actually delivered. It is not clear, therefore, that the procurement strategies employed have or will deliver the stated "target" savings.

(b) It is not clear that all the "savings" quoted in Deloitte's report are real reduction in costs, or just costs which are lower than would have otherwise been expected (i.e. the achievement of stable costs in the context of an increasing of cost base).

[5] Paragraph 3.14, main consultation document

(c) Deloitte themselves acknowledge that none of the companies or projects analysed are directly comparable with ourselves in terms of the type of equipment procured and work carried out, and state that **"it would not be reasonable for Ofgem to simply assume that what other organisations have already achieved could also be replicated in NGT's capital investment programme"**.

401 As the comparators are not involved in the electricity or gas transmission business (or even electricity or gas distribution), any comparisons do not take into account the specific factors affecting the industry. As acknowledged by Ofgem, we are already in, and will continue to be in, a period of intensive investment in both transmission and distribution systems. This is coupled with a period of intensive investment in new construction projects, not least the work related to the Olympics, which analysts agree will continue to drive the price of construction and manpower upwards. Against this background, it is difficult to see how we could drive the real costs of delivering projects downwards through improved procurement.

Appropriateness of Ofgem's application of the Deloitte efficienies

402 Our second point is on the appropriateness of Ofgem's application of procurement efficiencies. As noted above, on the basis of Deloitte's report, given the non-comparable nature of the companies and projects used and lack of assessment of our actual efficiency, it is difficult to see how Ofgem can justify any particular level of procurement efficiency. Further, whilst it may be appropriate for Ofgem to expect some level of gross efficiency to be achieved through improvements in procurement practice, we believe that, **at best**, the **net** effect of procurement efficiencies will be to partially offset expected increases in the real level of costs.

Ofgem's application of the Deloitte efficiencies

403 Our third point is on the manner in which Ofgem apply the proposed procurement efficiency across the period. Ofgem apply a flat 5% efficiency across the whole period, starting in 2005/06, a period which has already finished. On the basis that Ofgem and their consultants have reviewed electricity transmission capital expenditure up to 2004/05 and determined it to be efficient, there is no justification for effectively assuming a step change in procurement efficiency from 2005/06 onwards. It is also clearly impossible to achieve "retrospective" efficiency savings. For 2006/07 onwards, as recognised by Deloitte themselves, it can take many years to realise the full benefit of procurement efficiencies.

Double-counting of efficiencies

404 Our fourth point is that Ofgem have "double-counted" procurement efficiencies. The analysis of PB Power and KEMA is based on their view of unit costs, which presumably represent their view of the "efficient" unit cost. By basing the allowance in each category on the PB Power and KEMA unit cost analysis, and then applying a further procurement efficiency on top, Ofgem are effectively expecting us to deliver a 5% reduction on the costs that their consultants' view as efficient. This is a clear double-count, and is therefore clearly unreasonable.

In summary

405 In summary, therefore, we believe that:

(a) Ofgem's proposed reduction in the real level of costs of 5% through improved procurement efficiency is based on flawed analysis of:

(i) efficiencies in non-comparable companies;

(ii) a number of “targeted”, rather than actually achieved, efficiencies;

(iii) “savings” which may not result in real reductions in costs.

(b) The analysis fails to take into account the specific factors in our industry, which are driving increases in costs.

(c) The application of the efficiency as a flat reduction from 2005/06 is inconsistent with Ofgem’s view that our costs up to 2004/05 were efficiently incurred, and does not reflect that fact that, even if procurement efficiencies can be achieved, they do not immediately result in cost reductions.

(d) The application of procurement efficiencies double counts the reductions already applied by PB Power and KEMA in the unit costs used to determine their forecast costs.

Treatment of forecast increases in input costs

406 Our FBPQ submission included forecast cost increases in driven by increases in the costs of civils and manpower (and in the case of gas transmission, steel). These forecasts were based on an analysis of the proportion of our capital plans driven by each of these components, and a view of the likely trend in the cost of these services and commodities provided by independent consultants[6]. These forecasts show significant likely increases in these costs, driven by strong, verifiable drivers, such as:

(a) long term high demand for steel and increase in cost of raw materials, driving increasing prices for steel pipe;

(b) continued strong activity in UK construction, including large construction projects such as those required for the 2012 Olympics, driving up the general cost of civil engineering works;

(c) predicted above inflation wage rate increases for manpower utilised in engineering, design, management and site labour for transmission projects based on recent wage settlements.

407 We note Ofgem’s recognition of the issue and intention to review the treatment of such cost drivers as part of the Price Review process.

408 We have recently requested updates from our consultants, and these have served to confirm the expectation of price increases significantly above the rate of inflation over the course of the next Price Control period.

409 In addition, we identified that our capital costs are also subject to changes in costs of the raw materials of transmission equipment such as copper, aluminium and oil. These are traded on extremely volatile worldwide commodities markets, and so we did not include any forecast increase for these elements. However, these have also shown extremely steep increases recently, and may well also continue to rise.

[6] Gardiner and Theobald Fairway for electricity transmission, EC Harris for gas transmission

410 Given the evidence available in the markets, and the strong demand for both the individual commodities and transmission equipment, we believe that costs are highly likely to increase over the course of the next Price Control period, and, as discussed above, that whatever efficiencies we can deliver through improved procurement are likely to serve only to reduce an otherwise larger movement in overall market costs.

411 Ofgem suggest that their preferred treatment for such increases would be in the inclusion of an ex-ante allowance, rather than through indexation of the transmission Price Controls. We believe that it will be difficult for Ofgem and the licensees to agree on an appropriate level of ex-ante allowance for such cost risk, and **believe that some element of indexation would provide protection for both the licensees (in the event that costs increase) and consumers (in the event that costs fall)**.

412 We do not believe that the use of indexation against well established indices for certain costs would introduce additional complexity to the transmission licences, and in any event, any such complexity would be trivial compared with the mechanisms which Ofgem are currently proposing for driving revenue in respect of load related expenditure. We will continue to discuss this issue with Ofgem during the course of the Review.

Forecast non-load related expenditure

413 A significant amount of focus of this Transmission Price Review has been on the need to increase the amount of replacement of transmission system assets which are at the end of their life and in poor condition. This is clearly an extremely important part of the review for us, and so our comments in this area are extensive. The reductions to our forecast expenditure proposed by Ofgem are summarised in the table below.

All figures in £m, 2004/05 prices	2005/06-2006/07	% reduction	2007/08-2011/12	% reduction
NGET forecast	**601.3**		**2460.2**	
Ofgem deductions - by asset category				
- Overhead Lines	-86.1	34	-206.4	34
- Switchgear	-26.7	27	-151.4	27
- Transformers	-8.0	26	-45.7	26
- Underground Cables	-6.9	9	-44.2	9
- Protection and Control	0.0	0	0.0	0
- Substation Other	-4.0	9	-19.0	16
- Other TO	0.0	0	-34.1	16
Ofgem deductions - other				
- Unit cost increases	-1.6	100	-115.3	100
- Procurement efficiencies	-22.0		-91.7	
- Non-operational capex	-21.6		-55.0	
- Excluded costs	-6.8		-24.8	
- Quasi-capex	0.0		+68.9	
Ofgem baseline proposals	**417.6**	**31**	**1,741.5**	**32**
Total Difference	**-183.7**		**-718.7**	

414 On asset replacement expenditure, we do not believe that the Initial Proposals represent appropriate or well justified proposals, on two counts:

(a) Ofgem have seemingly chosen the lower of, or even lower than, the views of the two consultants for each category to produce a set of proposals which is even lower than either of the consultants' views.

(b) We believe the consultants have made a small number of significant errors and omissions in their analysis that are a major source of the material difference between our forecast and their projections.

415 Consequently, we believe that:

(a) the material differences between our forecast and Ofgem's Initial Proposals are based on unsound projections of asset replacement expenditure; and

(b) Ofgem have compounded the problem by not taking a balanced view of these projections.

416 The approximate breakdown of the difference between our forecast and Ofgem's Initial Proposals for the main plant categories (overhead lines, switchgear, cables, transformers, protection and control, substation other) is shown below:

	Approximate difference (£m)
Ofgem Selection of low view from consultants	80-90
Difference between lowest consultants view and our forecast	
- Inappropriate unit costs	Up to 300
- Lower modelled volumes	Up to 210
- Omission of non-modelled items	Up to 160

417 As can be seen, the differences between the consultants vary considerably, showing little consistency of approach between the two. However, a significant additional reduction of between £80m and £90m is arrived at simply through Ofgem's choice in each category of a figure around the lowest of the two consultants' views.

418 We have already commented extensively on the consultants choice of unit costs above, and so our comments here are divided into two main sections:

(a) Ofgem's translation of the consultants' views into the Initial Proposals

(b) the consultants' own analysis of modelled volumes;

(c) the consultants' treatment of non-modelled costs; and

(d) consequences of investing at the levels proposed by Ofgem

Ofgem's electricity transmission capex proposals

419 The Initial Proposals represent a drastic cut in proposed expenditure. Ofgem have also provided us with draft reports from the two consultants, PB Power and KEMA. These reports are extensive, and we have not had opportunity to fully appraise these reports and so intend to respond in full to each report in due course. However, we have had the opportunity to review the expenditure proposed by the consultants, and compare it to Ofgem's Initial Proposals. The replacement expenditure proposed by the consultants for the main transmission plant types is shown in the table below, compared to our forecast, and Ofgem's Initial Proposals.

Forecast expenditure 2005/06 to 2011/12 £m, 2004/05 prices	NGET	PB Power	KEMA estimate	Ofgem Initial Proposals
- Transformers	209.6	155.9	178.2	155.9
- Substation Other	165.7	165.2	149.5	142.7
- Switchgear	654.6	437.6	556.4	476.5
- Overhead Lines	871.6	677.0	566.6	579.1
- Underground Cables	595.7	549.2	565.9	544.6
- Protection and Control	244.3	248.8	207.6	244.3
Total	**2741.5**	**2233.7**	**2224.2**	**2143.1**

420 The highlighted cells in the table above show the consultants' value closest to Ofgem's Initial Proposals. It can be seen that, with the exception of Protection and Control, Ofgem have chosen a value which is either towards or at the lower of the two consultants views, or, in the case of cables and substation other, is actually lower than either consultant's view. This results in Ofgem's Initial Proposals being some £80-90m below even their consultants' views – and this before any additional "procurement efficiency" factors are applied. Ofgem have offered no justification for this.

421 Indeed, whilst Ofgem have clearly used the consultants' reports as a basis for the Initial Proposals, it is not clear that the consultants themselves would have intended for Ofgem to do this in the way that Ofgem have. For example, it is clear that KEMA's analysis completely omits any non-modelled expenditure with the exception of cable tunnels, which across all plant types amounts to **over £300m**. KEMA may have expected Ofgem to adjust for this before using their figures as the basis for the proposals.

422 We note Ofgem's deduction of costs associated with security and BT 21st Century networks. For these items, we support the approaches proposed (i.e. separate treatment for security costs, BT 21st Century network costs subject to an explicit re-opener).

423 We also note:

(a) Ofgem's recognition of the concept of Quasi-capex;

(b) Ofgem's proposed exclusion of costs deemed to be non-operational capex.

424 Our comments on quasi-capex and non-operational capex are presented in Chapter 2 above on operating expenditure

Comments on consultants' analysis of modelled volumes

425 As discussed above, in addition to concerns over Ofgem's application of the consultants' views, we believe the consultants' views are themselves based on some small, but highly material, areas of erroneous analysis. Our comments in this response are confined to the most material issues affecting the proposals derived by Ofgem. However, we have more extensive comments on the full reports, which we will seek to discuss with Ofgem and the consultants as part of the ongoing process ahead of Ofgem's updated proposals in September.

426 Our comments are on the consultants' analysis of modelled volumes are ordered as follows:

(a) overhead lines;

(b) switchgear;

(c) cables;

(d) transformers;

(e) protection and control.

427 In general, we believe that the consultants modelled volumes are reasonably closely aligned with our own, subject to:

(a) the omission of the “backlog” of switchgear;

(b) the omission of a volume to cover the random level of failures of transformers;

(c) their adjustment of asset lives / the use of inappropriate asset lives.

428 We believe that the omission of the switchgear backlog and transformers are clearly errors, whilst we believe the adjustment of asset lives are unsupportable in light of evidence. As for unit costs, we discuss overhead lines and switchgear in detail below, and discuss the other plant types briefly.

Overhead Lines

429 With regard to modelling of overhead lines:

(a) For full refurbishment:

(i) KEMA arrive at a volume around 10% below our own;

(ii) PB Power using “adjusted” lives arrive at a volume around 25% below our own.

(b) For fittings only:

(i) KEMA do not appear to have modelled the replacement need, but propose a volume significantly below our volume;

(ii) PB Power have modelled overhead line fittings, and project a required volume very closely aligned with our own.

430 For full refurbishment, KEMA use their own asset lives which KEMA state are based on their “international experience and expert knowledge”. We understand KEMA utilising this knowledge in their modelling, but believe that their asset lives are less valid than our own because:

(a) Our lives for overhead lines are based on analysis of National Grid’s assets in the environmental conditions experienced in the UK, which is a very important factor in overhead line deterioration. We believe therefore that our asset lives are more appropriate for reflecting the replacement need of our assets.

(b) Our asset lives are disaggregated into 16 separate life definitions to reflect different environmental conditions, a feature which is commended by KEMA. KEMA's modelling uses just 2 life profiles, representing core-only and fully greased conductor. Based on KEMA's own comments, therefore, we would see our own modelling as a more rigorous, detailed and robust basis on which to base the Price Control allowances.

431 Notwithstanding these issues, the volume arrived at by KEMA for full refurbishment is within 10% of the volume of overhead line replacement in our plans. In conclusion KEMA state that **"there is a slightly different view on the number of overhead line conductors which need to be replaced, but this is of marginal importance"**. We believe, therefore, that given the greater rigour and detail in our modelling, and the limitations of KEMA's modelling, the closeness of KEMA's modelling to our own should be seen as a validation of our volumes, and hence **our** volumes should be used for the purpose of setting the allowance.

432 For full refurbishment, PB Power, by contrast, effectively use our life profiles, shifted by one year "to match the actual lives in the historic replacement". PB Power do not offer a condition based justification for this adjustment to the lives. Clearly, we need to review the analysis of PB Power in arriving at the extension to asset lives of one year. By contrast, we have demonstrated the condition based evidence for all of our assets lives, providing full access to the consultants to our Asset Health Review which contains the condition data used, in part, to establish and verify asset lives.

433 In addition, to justify extending the asset lives by one year assumes that the level of risk and performance associated with overhead lines in the current period has been acceptable. We have shown, through the Review process, several metrics which show that the performance and risk have not been acceptable. For overhead lines, one such measure is the proportion of the network with manual re-close restrictions, implemented on lines in poor condition as a safety measure to prevent control room staff from manually re-closing lines which may have fallen to ground. At present around a quarter of the overhead line network is subject to such restrictions. We do not believe that this is an acceptable risk to carry going forwards, and offers no justification for an extension of asset lives.

434 For fittings only, KEMA do not appear to have modelled volumes, and it is therefore unclear how they arrive at a volume, particularly one which is so far below both our own volume and that derived by PB Power. In combination with a reduction in unit costs, this results in KEMA's analysis for fittings only being more than £100m below PB Power's analysis. Given the materiality of the difference, the fact that PB Power **have** modelled fittings, and that their modelling validates our own, it would appear to be a more appropriate basis on which to base the Price Control allowances.

435 In summary, therefore, we believe that:

(a) KEMA's modelling acts as a validation of our own, and as such our own volumes should be adopted given the additional sophistication and granularity in our own modelling over KEMA's;

(b) KEMA's modelling of fittings appears to be less sophisticated than either ours or PB Power's, and hence the volumes derived by us and PB Power should be used to form the basis of the allowances, increasing the allowance

(c) PB Power's extension of asset lives is not properly justified, and as such should not be used as the basis for Price Control allowances.

(d) Adjustment of these issues would increase KEMA's forecast by around **£50m**, and PB Power's forecast by around **£100m**.

Switchgear

436 For switchgear volumes, KEMA's volumes are largely in agreement with our own, subject to the correction of one issue. At face value, there are large differences between the views of ourselves and the views of PB Power, with their volume being almost 40% below ours. However, we believe that the difference would be relatively small, subject to the correction of a small number of material issues. We believe the differences between our own modelling and the consultants' are due to the following:

(a) the fact that neither PB Power nor KEMA's modelling will reflect the volume of pressurised head breakers being replaced;

(b) PB Power's omission of the "backlog" of switchgear that has been deferred from the current period, resulting in a shortfall of around 150 circuit breakers;

437 These issues are clearly the result of the modelling approach being unable to pick up the issue, or omission from the modelled volumes. In addition, a further difference results from the extension of asset lives by PB Power by one year to "match the actual lives in the historic replacement", resulting in a reduction of around 70 circuit breakers.

438 On the first issue, we informed the consultants that the asset life profiles did not reflect a small volume of pressurised head switchgear, that was refurbished early in its life, and now needs replacing earlier than would be expected from the asset life profiles. PB Power acknowledged this issue in their report, and assessed this as non-modelled expenditure. We discuss this further in the section on non-modelled expenditure.

439 With the exception of this issue, however, we believe KEMA's modelled volumes closely reflect our own, and therefore provide validation for our volumes. In particular we note KEMA's recognition of the fact that, as some mesh substations are being replaced with double bus substations, more circuit breakers are being installed than are being removed. As KEMA's model will model disposals, they have adjusted their modelled volumes to reflect this. We welcome their recognition of this issue, and adjustment of volumes to reflect this.

440 On the second issue, we believe that PB Power's modelling can not properly reflect the switchgear deferred from the current period that needs to be replaced in the next period, and differs significantly from their view in the mini review. In the mini review, PB Power's assessment of overall modelled switchgear investment requirements for the seven year period to 20011/12 was £412m. However, despite a significant increase in unit costs due to a move away from DPCR4 prices and the acknowledgement that an element of GIS replacement is appropriate, PB Power's modelled expenditure has reduced to £309.6m. In contrast, applying PB Power's revised costs to the volumes derived in the mini-review, this number could have been expected to rise to around £438m. We would like to discuss the reasons for this discrepancy with PB Power.

441 Whilst PB Power did not say how many circuit breakers their mini review modelling identified for the period 2008/09 to 2011/12, we have been able to back-calculate to

determine the approximate volume used, as the unit cost was stated. Based on this calculation it appears that in the mini review, taken over the full period from 2005/06 to 2011/12, the replacement volumes derived by PB Power broadly agreed with our own. Their modelling showed a need for more replacement in the period 2005/06 to 2007/08, and less in the period 2008/09 to 2011/12 – at the time we agreed with PB Power's assessment, but pointed out that we were not able to replace at the level predicted by PB Power's volume up to 2007/08, but planned to catch up by 2011/12.

442 However, we estimate that PB Power are now forecasting almost 150 **less** circuit breakers for replacement than they themselves forecast as part of the mini review process. This may be due to the way in which PB Power's model works, or the time period over which the model is run, which may lead to these circuit breakers being missed. Either way, this means that **PB Power's volume does not fully reflect the volume of work required.** Given the materiality of this issue, equating to over £100m it is extremely important that this issue is reviewed with PB Power and Ofgem over the coming months.

443 The third issue, rather than being a matter of omitted volume, results from PB Power's adoption of an alternative asset life. Whilst we understand that PB Power would consider their own view to be appropriate, we do not believe the adjustment to asset lives is appropriate. PB Power provide no condition based reason for extending the switchgear lives by one year. Again, we have presented extensive evidence to the consultants, and provided open access to the information on which our asset lives are based, but would seek to discuss the issue further with PB Power.

444 As for overhead lines, to justify extending the asset lives by one year assumes that the level of risk and performance associated with switchgear in the current period has been acceptable. We have shown, through the Review process, several metrics which show that the performance and risk has not been acceptable. For switchgear, one such measure is the number of safety risk management hazard zones in place. This has increased over the current period following a number of catastrophic failures of switchgear. We do not believe that this is an acceptable risk to carry going forwards. In addition, as KEMA note in their report, the average circuit unreliability of switchgear has risen by a factor of more than 2 over the period, providing an indication of deteriorating condition. These facts offer no justification for an extension of asset lives. We do not believe, therefore, that this extension to asset lives, and the resulting reduction in switchgear volume of around 70 circuit breakers, is justified.

445 In conclusion, therefore:

(a) Subject to the inclusion of the backlog of switchgear from the current period, and appropriate treatment of replacement of pressurised head switchgear as a non-modelled volume, we believe the consultants' volumes provide significant validation of our own volumes;

(b) The adjustment to asset lives by PB Power, resulting in a reduction to replacement volume of around 70 circuit breakers, is inappropriate given the condition and performance evidence from our switchgear assets.

(c) Adjustment of these issues would increase the consultants' forecasts by around **£100m**.

Cables

446 For cables, there is a large degree of agreement between our own modelling and

those of the consultants. KEMA's modelling of cables produces 93km, exactly the same volume of replacement as ours. PB Power produce a greater volume when using our parameters, but then adjust our asset lives as they did for overhead lines and switchgear, although in the case of cables they extended the lives by 3 years. This results in PB Power forecasting 9km less than us, around 10% of our planned replacement, equating to a difference in cost of just over **£20m**.

447 As with the other categories, we understand PB Power's consideration of their own view of asset lives. Again, however, we do not believe that this extension is supported by the actual condition and performance of our cable assets. We have experienced significant oil loss over the current period, resulting in a number of significant environmental incidents and deteriorating availability of cable circuits. Given the criticality of cable circuits to the predominantly urban environments in which they operate, often in close proximity to environmentally sensitive areas, we do not believe that any reduction to the cable replacement programme can be justified.

Transformers

448 For transformers, we again believe that there is a high level of agreement between our modelling and those of the consultants, subject to correction of one issue. PB Power model the requirement for replacement of 79 transformers, whilst KEMA model 81. In terms of asset replacement based on asset deterioration and poor condition alone, our own modelling would produce a volume of around 85 transformers.

449 However, we actually expect to replace 99 transformers in the period 2005/06 to 2011/12 (our FBPQ submission refers to the replacement 86 transformers, but this is for the period 2007/08 to 2011/12). We believe the difference is likely to arise from the fact that, included in the 99 transformers that we expect to replace, is an allowance for an expected random failure of 2 transformers each year i.e. 14 over the period. If these are added in the consultants' modelled volumes the correlation between us and them is very close, and the inclusion of these transformers would increase each consultants forecast cost by **£25-30m**, bringing each consultants' total forecast closely in line with our own. We would like to discuss this issue further with the consultants to verify if this is the cause of the difference.

Protection and control

450 PB Power's modelled volumes for protection and control closely align with our own, whilst KEMA derive a significantly lower volume, through application of a blanket 25 year life.

451 In this category, PB Power's modelling is significantly more sophisticated than KEMA's, and KEMA's 25 year life does not reflect the true asset lives of protection and control equipment, which is broken down into many categories. However, this issue does not impact on the proposed allowances, as Ofgem have adopted our own costs in the Initial Proposals, these being lower than those derived by PB Power.

Comments on consultants' treatment of non-modelled expenditure

452 Some elements of costs do not lend themselves to modelling, such as costs associated with site infrastructure, switchgear refurbishment and pre-sanction engineering costs for overhead lines. As such, these costs need to be added to any derived through replacement modelling in order to reflect the true expenditure required.

453 It was recognised during the mini review that is was sometimes not clear which costs were modelled and which were not. In response to this, we provided PB Power with a presentation to explain the breakdown of our costs into modelled and non-modelled items, and we recognise that PB Power have given due consideration to these costs. Unfortunately, we were not aware that KEMA were also producing a forecast of costs, and hence have not received the same presentation, which may explain their omission of the majority of these costs.

454 The main areas of non-modelled expenditure fall into three asset categories, and hence our comments are on the consultants' treatment non-modelled expenditure are ordered as follows:

(a) overhead lines;

(b) switchgear;

(c) substation other.

Overhead Lines

455 In total, just over £70m of the forecast overhead line expenditure falls into the category of "non-modelled", covering EMI works, pre-spend on schemes beyond 2011/12, and line diversions.

456 KEMA assessment of overhead line costs did not include this expenditure, reflecting only modelled volumes, possibly, as discussed above, because it may not have been clear to KEMA that a significant amount of expenditure fell into this category. KEMA's assessment should, therefore, be increased by just over **£70m** to reflect this expenditure if Ofgem are to use it as a basis for Price Control allowances.

457 For overhead lines, PB Power recognised the issue of non-modelled expenditure, and made allowance for just under £62m of expenditure on items such as EMI schemes, which would not be picked up by modelling. We welcome PB Power's recognition of this expenditure, but would like to discuss the reasons for the proposed reduction.

Switchgear

458 In switchgear, there are two major areas of expenditure which would not be reflected in the consultants' modelling:

(a) the allowance for replacement of pressurised head switchgear which was refurbished early in its life, amounting to around **£135m**;

(b) allowance for site infrastructure and switchgear refurbishment, amounting to **£67m.**

459 As for overhead lines, KEMA's analysis did not include any of this expenditure, and so their forecast is just over **£200m** lower than it would be if this expenditure was included. If included, KEMA's total forecast cost for switchgear would be substantially higher than our own, and as such we believe that, subject to this correction, KEMA's analysis validates our own total forecast for switchgear.

460 With regard to PB Power, we welcome the fact that they have recognised this as an issue which would not be picked up by their modelling, and made explicit allowance

for this.

461 However, having looked at the need case at one of the sites and viewing the need case as robust, they allowed only half of the expenditure on the remaining sites, a reduction of some £50m, on the basis that “some of the schemes have yet to be sanctioned and may not proceed as forecast”.

462 This is not a valid reason for not allowing the expenditure. We would not expect to sanction the vast majority of schemes until the year before they are due to commence. This fact does not give any indication that the schemes are not likely to progress. We do not believe that Ofgem should base a reduced level of allowed expenditure on such reasons, and would request that this is reviewed urgently.

463 Finally, on infrastructure and refurbishment, PB Power allowed £44m out of the total forecast of £67m. Whilst no explicit reason is given, the reduction may be related to a comment by PB Power on a scheme to carry out infrastructure works at Deeside, which read: “Can’t imagine that this is high priority work. Presumably if important it would have been done when CB’s were being replaced”. We find PB Power’s view surprising, particularly as in the case of Deeside the site is suffering from severe subsidence making infrastructure works a high priority.

464 Each of the schemes are supported by individual site condition assessments, and the need cases are robust. We would seek further discussion with PB Power on the need case for these works.

465 With regard to switchgear refurbishment, PB Power do not mention a specific reduction - we would certainly hope that the case for this has been established as efficient, as indeed KEMA believe it has (in their opex report).

Substation Other

466 In the substation other category, KEMA appear to have taken a view on the non-modelled expenditure, and suggest a reduced amount, although there is no explanation for the differences.

467 We welcome PB Power’s analysis of the non-modelled expenditure of £73.6m, and their inclusion of the full amount of expenditure.

468 We would like to discuss the issue further with KEMA, but on the basis that PB Power appear to have carried out a more rigorous assessment of these costs, we believe it would be more appropriate for Ofgem to base our allowances on their assessment, rather than a value 5% lower than KEMA’s.

Summary of review of consultants’ analysis

469 In summary, we believe the consultants analysis should be adjusted in light of:

(a) their use of unsustainable unit costs which do not reflect current costs or the types of assets being installed on the system;

(b) the omission of, or unjustifiable analysis of, non-modelled expenditure;

(c) not properly substantiated adjustments to modelled volumes and the omission of work carried over from the current price control period.

470 These adjustments are extremely material, amounting to the vast majority of the difference between their forecasts and ours, equivalent to more than £500m. We believe, therefore, that it is of the utmost importance that we are given the opportunity to discuss these issues with both Ofgem and the consultants over the coming months, such that agreement on the appropriate allowances can be achieved.

Consequences of investing at level proposed by Ofgem

471 Through the combination of unrealistic unit costs, lower modelled volumes, the omission of non-modelled expenditure, and Ofgem's choice of the lower of the consultants' values, the Initial Proposals do not provide sufficient funding for National Grid to carry out the asset replacement that we believe is required.

472 The consequences of not carrying out this work are as discussed below:

(a) **Increased safety risk -** we do not believe that investing at the level proposed by Ofgem would allow us to maintain an acceptable level of risk of injury to public or staff alike, particularly with regard to overhead lines. Our analysis, using a societal risk model similar to the one used to assess the need for gas distribution pipe replacement, shows that the risk of a falling overhead line causing a fatality would increase significantly by 2012 if overhead line replacement expenditure was restricted to that proposed by Ofgem, and would reach the level defined as "intolerable" by the Health and Safety Executive i.e. the point at which we would effectively have to take remedial action.

(b) **Increased risk of loss of supply -** if replacement expenditure on transformers and switchgear is reduced to the level proposed by Ofgem, the risk of loss of supply at some sites will increase significantly. Our analysis shows that the risk of loss of supply would increase by a factor of between two and five if switchgear and transformer replacement is deferred. We do not believe that this is an appropriate risk to take, or that this is a risk that is in the interests of consumers, particularly given the increasing focus on security of supply, as highlighted in the governments recent energy review documents. .

(c) **Decreased resilience of the network –** we believe Ofgem have overestimated the amount of redundancy in the transmission system and underestimated the extent of the reduction in the resilience of the network that could occur following even a single failure of an asset due to poor condition. Whilst the system is resilient to the faults on the transmission system, the occurrence of an increased level of asset **failures** would significantly increase the risk of the system failing to be resilient against system events, potentially causing widespread loss of supply.

The transmission system is designed to be secure for the loss of any double circuit. After a double circuit fault the system is at risk to another fault occurring before the network can be secured. In the event of a transient fault, the circuits will either automatically switch back in after a few seconds, or can be manually restored in a few minutes. During events such as a storm, it is expected that even healthy assets trip out as, for example, overhead lines swing around and wind-borne debris makes contact with circuits.

Double circuit faults are rare, but do occur two or three times a year.

However, overhead lines which are in poor condition may fail in storm conditions, as high winds cause the failure of fatigued or corroded conductors or worn fittings and insulators, causing conductors or earthwires to fall. In these circumstances it is possible that a double circuit may trip out for a much longer time **of hours or possibly days.** Depending on location, once this has occurred **the entire system may be at risk to the next fault.** Hence the risk to system security of failures occurring is a factor of a hundred or more greater than if the circuits only fault. We would like to emphasise this point – whilst the system has sufficient redundancy to cope with transient faults, it is significantly more vulnerable to collapse following the **failure** of an asset, and particularly an overhead line.

(d) **Risk of reaching an unrecoverable position –** If the volume of replacement delivered is decreased, the system is at risk of entering a "spiral of decline". If assets are allowed to decline and fail in service and increasingly more resources and outages are expended in "fixing" assets, reducing the resource and outages available for asset replacement, further compounding the issue. As the volume of replacement work required mounts up, network availability would have to be reduced in order to carry out remedial works, and the sheer volume of replacement work required may exceed the ability of suppliers to deliver. We believe that it is irresponsible to take this risk with infrastructure which is critical to the national economy, such as electricity and gas transmission systems.

473 We do not believe, therefore, that Ofgem's proposals provide an appropriate balance of costs, security and network performance, and that the proposals are biased towards short term cost minimisation, rather than securing the long term reliability, safety and environmental performance of the transmission system. We believe that Ofgem's assessment of the required level of expenditure on asset replacement is inappropriate, and would represent taking an unnecessary risk with the health of the transmission network, which would not be justified by the level of costs saved by consumers.

Forecast load related expenditure

474 Our comments on Ofgem's proposed baseline allowances for load related expenditure are structured as follows:

(a) Ofgem's "entry volume adjustment"

(b) The removal of load related expenditure to avoid "double-counting"

(c) The removal of expenditure categorised as "avoidable early asset replacement"

All figures in £m, 2004/05 prices	2005/06-2006/07	2007/08-2011/12
NGET forecast	**440.6**	**1336.9**
Ofgem deductions		
- "Entry volume adjustment"	-80.4	-170.4
- "avoidable early asset replacement"	-14.1	-24.5
- "double counting with NLR	0.0	-55.0
- Unit cost increases	-0.3	-24.6
- Procurement efficiencies	-17.3	-52.9
Ofgem baseline proposals	**328.5**	**1,005.7**

475 Ofgem's initial proposals for baseline load related expenditure are approximately £112m and £330m below our forecast expenditure for the periods 2005/06-2006/07 and 2007/08-2011/12 respectively, with the reasons for the adjustments shown in the table above. Our comments on the adjustments made on unit cost increases and procurement efficiencies have been discussed earlier. Our comments on each of the other three items of adjustment are discussed below.

"Entry volume adjustment"

476 Firstly, with regard to the "entry volume" adjustments made for 2005/06 to 2006/07, we do not agree that load related expenditure should be based on top-down modelling. Expenditure for 2005/06 has clearly already been incurred, and actual expenditure was in line with our FBPQ submission. With regard to this period, we welcome Ofgem's statement that work is still ongoing to assess 2005/06 actual expenditure, but trust that this analysis will also consider the latest forecast of costs in 2006/07, such that the Final Proposals will reflect the actual expenditure in 2005/06 and the latest forecast for 2006/07.

477 Ofgem have proposed an "entry volume adjustment" of £170.4m for the period 2007/08 to 2011/12. This appears to be entirely based on PB Power's assessment of the generation and demand background. Clearly, we recognise that the development of revenue drivers should deal with, at least approximately, the changes in the generation background. As both we and PB Power are simply attempting to arrive at a best view, both of which will inevitably turn out to differ from reality, a full critique of PB Power's views would largely be academic. However, there are a number of issues which do impact on the appropriate baseline allowance.

478 We note that PB Power support our assumptions on demand growth and generation closure. With regard to new generation opening, PB Power believe that two power stations, [redacted], will be deferred such that no expenditure occurs in the Price Control period. We do not believe that this is a sustainable assumption, [redacted] We would request, therefore, that PB Power review these assumptions, and that the entry related infrastructure expenditure associated with these projects should be included in the baseline allowance.

479 Clearly, PB Power's assumptions on the connection of new generation also impact on the levels of expenditure on the general transmission system infrastructure. In this regard, PB Power suggest that the level of expenditure on reactive compensation could be **reduced** by £127m due to their view on a lower level of generation connection. In fact the opposite is true – given the location of generation that PB

Power believe will not connect in the timescales indicated by us, our analysis shows that the need for reactive compensation is actually brought forward, and the overall expenditure would increase. The following table shows our analysis of the impact of PB Power's changes to the generation background on key boundary transfers, along with the change in the number of MSCs required.

	07/08	08/09	09/10	10/11	11/12
Effect on North to Midlands transfer	0	+369 MW	+561 MW	+338 MW	-330MW
Possible reactive change (number of MSCs required)	0	+2	+4	+2	-2

480 As can be seen, as PB Power's deferral of generation at the start of the period related to generation in the south, the boundary transfers actually increase, requiring additional investment. Clearly, therefore, PB Power's generation background is not consistent with a reduction in expenditure on reactive compensation of £127m, and their generation assumptions would result in a higher level of expenditure on infrastructure. In order to remain consistent with the background, therefore, we believe the baseline should be adjusted to at least reflect our forecast, if not a higher level to reflect the increased need for reactive compensation.

481 With regard to expenditure related to the connection of wind generation in Scotland, we welcome PB Power's view that the expenditure is justified.

"Double-counted" infrastructure

482 Ofgem state in their Initial Proposals that almost £59m was removed from the infrastructure expenditure to remove "double-counting between load related and non-load related capex", the implication of this being that we had included expenditure in its forecast twice. However, on reading the PB Power report, it is clear that this is not what PB Power meant at all, and so we believe Ofgem's characterisation of this deduction is mistaken.

483 The reason that PB Power removed this expenditure is that expenditure at one substation, categorised as load related because of the main driver, but also encompassing some asset replacement works, would be picked up in their analysis of non-load related expenditure i.e. it was removed to ensure that PB Power didn't double count it in their analysis.

484 In addition, we believe the £59m removed to be vastly overstated. Firstly, PB Power's report only suggests the removal of £56m associated with the Swansea scheme. This scheme is required for load related purposes, and we would not be undertaking the replacement of the substation at Swansea in the next Price Control period for condition driven asset replacement. The switchgear at Swansea was installed in 1972, and would not, therefore, be due for replacement until the price control period commencing in 2012/13 at the earliest. At most, two transformers could be adjudged to be requiring replacement in the next price control period – at most this would amount to around £4m. We believe, therefore, that the deduction is overstated, and that at least £54m should be added back to the baseline allowance.

“Avoidable early asset replacement”

485 PB Power removed some £38.6m from our expenditure on sole use demand connections on the basis that this reflected an assumed level of expenditure related to early asset replacement which could be avoided, equating to 10% of our expenditure in this category. PB Power base this view on the assessment of one scheme where they believe that £6m of the scheme is related to early asset replacement. In PB Power’s words “judicious maintenance planning should allow the work to be deferred and allow better value to be extracted from the existing asset base”.

486 The scheme in question is a demand connection at Mannington, from which PB Power suggest that £6m of expenditure could be avoided. In fact, on this scheme the work is phased, such that where assets are being replaced the date of replacement is actually aligned with their planned replacement date. **The actual level of “early asset write off” on this scheme is actually forecast to be just £0.4m, principally related to write off of some protection assets.** We believe, therefore, that the value of 10% which has been deducted from demand connection schemes is overstated, and that a figure of 1% would be the most that any analysis could support. On this basis we believe that £30-35m should be added back to the baseline allowance.

IV National Grid Gas NTS (NGG)

487 We do not believe that Ofgem has provided a balanced or consistent assessment of our forecast capital expenditure for the National Gas Transmission System (NTS) and provide more detailed comments on our concerns below, structured as follows:

(a) Historic expenditure

(b) Procurement efficiency and unit costs

(c) Forecast non-load related expenditure

(d) Forecast load related expenditure

Historic expenditure

488 Ofgem propose to disallow almost £75m of capital expenditure incurred in relation to the provision of capacity at St. Fergus. We firmly believe that the investment at St. Fergus carried out in the current Price Control period was economically and efficiently incurred and that the decision to proceed with the investment was made correctly at the time. The £75m that Ofgem propose to disallow consists of the following:

(a) approximately £55m in relation to the need case for construction of a pipeline from Aberdeen to Lochside;

(b) approximately £20m in relation to the need case and efficiency of delivery of the Avonbridge compressor station and the St. Fergus to Aberdeen pipeline.

489 Our comments on historic expenditure are therefore structured as follows:

(a) the case for the Aberdeen to Lochside investment;

(b) the case for the Avonbridge compressor;

(c) the efficiency of delivery of the St. Fergus to Aberdeen pipeline.

The case for the Aberdeen to Lochside pipeline

490 In relation to the Aberdeen to Lochside pipeline, we sanctioned and proceeded with this investment consistent with:

(a) our obligation to provide baseline capacity **all year round** in auctions held in various timescales from several years ahead to on the day;

(b) Ofgem's clear intent that we **should** invest to provide summer flexibility, indicated through discussions at the last Price Review and the fact that Ofgem allowed a significant capex allowance for summer flexibility investment;

(c) the signals given by users through the **consistent booking of high levels of capacity** up to baseline, albeit generally in shorter term auctions;

(d) the possibility of incurring significant buyback costs in the event that we were unable to physically provide baseline capacity.

491 Subsequently users have continued to book high levels of capacity and utilise the capacity provided by the Aberdeen-Lochside pipeline. **Based on this clear evidence we do not believe that Ofgem can justify the disallowance of this capital expenditure, either on the basis of the 'validity' of the investment decision at the time or the efficiency of the investment made on the system. Accordingly, NGG believe that this investment should be deemed as efficiently incurred on the basis of the signals available at the time (both from users and Ofgem) and therefore should be included in the RAV from 1st April 2007.**

492 In order to assess the validity of this expenditure, it is necessary to look at the four issues identified above i.e. the obligations placed on us in terms of provision of baseline capacity, the regulatory background to investment at the last Price Control review, the market signals that existed at the time that investment decisions were made and the potential for excessive buyback costs.

493 Ofgem have stated that, in their view, "when considered in the context of information derived from the long term capacity auctions"[7] they do not believe that we have demonstrated a need for the investment. This statement fails to recognise the four key issues discussed above.

(a) **The obligations on us –** Ofgem have failed to recognise that at each Aggregated System Entry Point (ASEP) we are obliged to offer for sale **all** available **baseline** capacity in a combination of long, medium and short term auctions up to and including the gas day, on every day of the year. Therefore, we have to be mindful of the need to meet the requirements for capacity as signalled in **all** timescales, not just the long term auctions. This is particularly the case at St. Fergus, as shippers have tended to purchase capacity in short term, rather than longer term auctions.

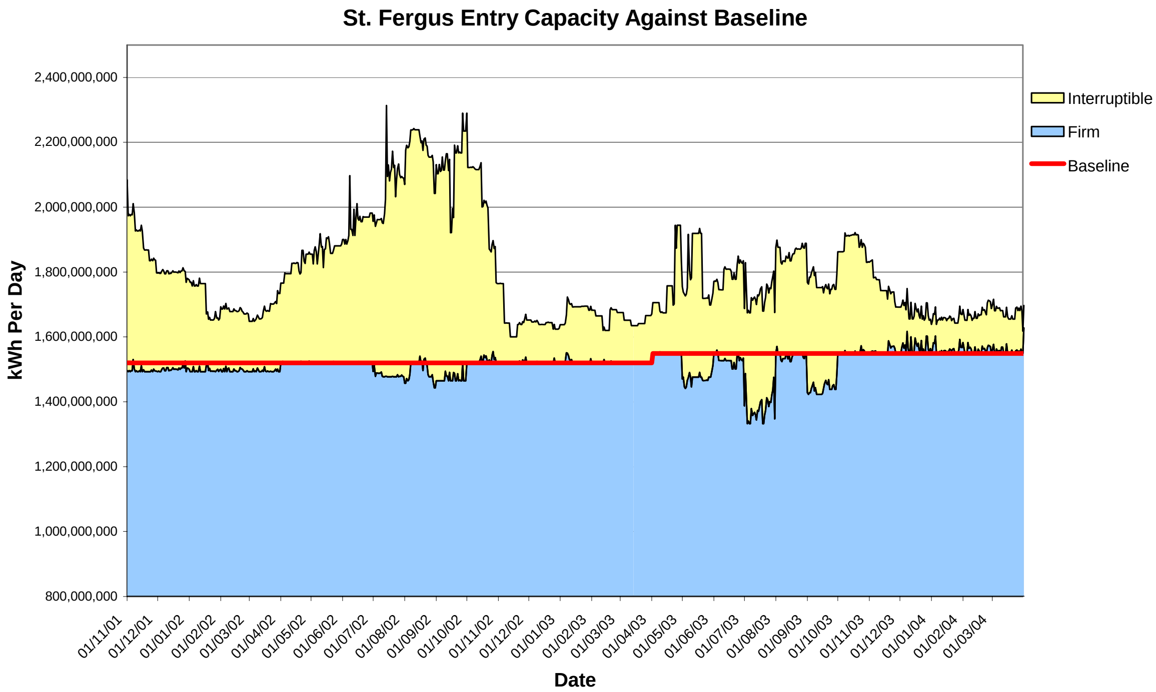
(b) **The regulatory background of the last Price Review -** at this time, Ofgem allowed a large amount of capital expenditure to provide "summer flexibility" i.e. investment to increase the level of capacity available towards baseline levels at system entry point at times other than the peak where, without investment, the capacity available at these times would be significantly lower than that which is available at peak. **The clear implication of this is that Ofgem expected us to invest in order to provide baseline capacity at off-peak times.** As shown below, nowhere was it more the case that summer flexibility was required by users than at St. Fergus.

TPA comment that in their view, we should have discussed the issue with Ofgem. However, given the fact that the Price Control was less than two years old at the point when significant liabilities were incurred, and given Ofgem's stance at the Price Review with respect to summer flexibility, we had every expectation that the investment would be deemed to be efficient and in line with its obligations.

(c) **The consistent booking of all baseline capacity by users -** at the time that the investment was sanctioned and through delivery of the project, there were clear market signals that capacity was required, albeit provided through shorter rather than longer term auctions. The graph below shows the level of

[7] Paragraph 6.5, main consultation document

capacity bookings at St. Fergus from November 2001 until March 2004, along with the SO baselines as defined in the transmission licence.



This graph above clearly shows that at the time the investment decision was made (in December 2002), firm bookings were consistently at or around 1520 GWh per day i.e. up to the 2002/03 baseline level, and beyond what could be physically delivered for much of the year. Against this background of users purchasing the full capacity available, we made what we believed to be a clearly efficient decision to continue with investment to enable this capacity to be provided, regardless of the longer term signals. This was particularly viewed to be the case given Ofgem's view on the provision of summer flexibility capacity at the last Price Review. Analysis undertaken at the time (which has been shared with Ofgem) indicated that the buyback benefits from constructing the Aberdeen to Lochside pipeline would be significant.

(d) [redacted]

[redacted]

[redacted]

494 On the basis of the obligations on us to provide an increasing baseline, the intent of the current Price Control allowances to drive investment to provide summer flexibility, the clear demand from users to provide baseline capacity year round, and the risk of buyback costs 20 or more times greater than the investment cost, **this investment should be deemed efficient and including in the RAV.**

495 A clear issue that Ofgem's proposal to disallow this investment brings up is the role of National Grid in provision of capacity – is it our role to provide capacity where users signal a need for it by purchasing it, or should we be predicting the market, only building capacity where it is convinced that users will actually flow gas?

496 In the case of St. Fergus, it is clear that users purchase the baseline capacity all year round, and that the offshore infrastructure exists to deliver against that capacity. If we could not provide physical capacity, as discussed above, we would be at risk of incurring significant buyback. Were this to occur, the costs to the consumer would far outweigh the cost of delivering the additional capacity.

497 However, should Ofgem persist in their view that the pipeline should not have been built, and that the expenditure should not be included in the RAV, there are a number of issues that we would need to be resolved:

(a) Firstly, should Ofgem decide to disallow the investment, then the extra capacity that this investment has provided should not form part of baseline capacity. In Ofgem's initial proposals, baseline capacity at St. Fergus includes the extra capacity provided by the Aberdeen-Lochside pipeline. Clearly, the decision to disallow the investment, and then to subsequently include the extra capacity into the baseline is inconsistent and inappropriate.

(b) Secondly, there is an issue with the treatment of the extra capacity provided through this investment going forward. As mentioned above, were the investment to be disallowed this should not be treated as baseline. One option would be to cap the pipeline at both ends and not use the extra capacity, effectively stranding the asset. This would seem perverse, because as mentioned above, the extra capacity provided has been used for prolonged periods in the time since construction. Another option would be for us to be able to sell this capacity on a non-obligated basis, and able to retain the proceeds of any sales, and with no obligation to offer this capacity for sale.

(c) Another important issue is the treatment of the buyback savings made as a result of the investment. Disallowing the investment should not be a 'zero-cost' option to the consumer. As discussed above, had the pipeline not been built, the level of buybacks would have been significantly higher, and therefore the customer has already benefited from the investment. Should Ofgem disallow the investment, we would expect that we would be allowed to recover the buyback savings enjoyed by the customer to date. In addition, we would expect to recover from the customer the non-obligated revenue derived from sales of this capacity, which have been shared between ourselves and the customer. However, even this would not properly reflect the fact that, through this investment, we have significantly reduced the risk that the customer would face very high buyback costs.

498 At the time of the last Price Control Review, the regulatory view was that we should

invest in order to provide year-round entry capacity, and significant allowances were made for summer flexibility in the last Price Control Review. Against this background, we responded to signals to provide year round entry capacity at St. Fergus, which has been incurred economically and efficiently. Subsequently, Ofgem have proposed to disallow this investment. This 'regulatory stranding' of assets has placed significant additional regulatory risk upon us, which we do not believe has been factored into the calculations of Ofgem's proposals for cost of capital. This point is picked up in our response on cost of capital in Chapter 6 below.

The case for the Avonbridge compressor

499 Ofgem also seek to disallow expenditure on the Avonbridge compression project. This would appear to be based on TPA's view that a station consisting of a single 45MW was required, rather than the duplicate 45MW (i.e. 90MW total capacity) that was built. The basis for this is similar to the views on Aberdeen-Lochside - TPA do not view as necessary the need to provide baseline capacity. We disagree with TPA on this point, as discussed above.

500 In any case, TPA note that by the time we knew that the Norwegian gas would be landed at Easington, it was too late to reduce the size of the Avonbridge compressor station.

501 Consequently, TPA conclude that the "incremental" element of the Avonbridge scheme had a "reasonable" business case, costed at £17.3m, whilst they deem the rest of the cost to have a "good" business case. On the basis that their consultant believe the costs to have at worst a "reasonable" business case, we do not believe that Ofgem's proposal to disallow any expenditure on the Avonbridge represents a balanced view of their consultant's analysis.

The efficiency of delivery of the St. Fergus to Aberdeen pipeline

502 TPA suggest potential inefficiencies in the delivery of these projects as they believe that we could have undertaken the conceptual design and land acquisition process earlier in relation to the St. Fergus to Aberdeen pipeline, and potentially avoided the costs incurred due to a change of interpretation of the Compulsory Purchase Order (CPO) process by the Scottish Parliament. TPA argue that we could have carried out such works as there reasonable expectation in 1998 that St. Fergus was to be the source of new gas supplies to the UK.

503 In response to this, we would note that we had no way of knowing in advance that the newly installed Scottish Parliament would interpret the CPO process in the way that they did, which effectively reversed the order in which consents and compulsory purchases needed to be carried out, effectively delaying the project and incurring additional cost. Against this background, and the usual timescales in which the DTI had historically processed CPOs, we had every reasonable expectation that our process would result in a timely and efficient completion of the project.

504 In general we seek to incur costs no earlier than required in order to avoid incurring expenditure which may turn out to be unnecessary. We believe therefore, that whilst in hindsight the process suggested by TPA may have resulted in avoided costs, there is no justification in the suggestion that we acted inefficiently at the time. As such, we believe there is no justification for Ofgem seeking to disallow any of the costs associated with this project.

Procurement efficiency

505 Ofgem apply the proposed 5% procurement efficiency, discussed in depth in the NGET section, across gas transmission as well as electricity transmission, despite the fact that Deloitte's assessment only referred to procurement of electricity transmission equipment. We do not believe, therefore, that there is any validity in applying such an efficiency to gas transmission expenditure on the basis of Deloitte's analysis.

506 The only rigorous review of gas transmission capital expenditure and procurement efficiency has been undertaken by TPA. Clearly, on the basis of TPA's analysis, Ofgem have proposed to disallow some historic expenditure, partly on the basis of alleged procurement inefficiency. However, in reviewing a number of future projects, TPA have concluded that the increases in project costs identified by National Grid were reasonable given the conditions in the market for supply and installation of gas pipe, and that we were "carrying out these projects as efficiently as it is possible to do so". The increase in project costs observed since the FBPQ submission is almost £220m, and is therefore a very material issue.

507 Following the conclusions of this review, we see no justification for Ofgem to apply a procurement efficiency across gas transmission for future expenditure.

Forecast non-load related expenditure

508 The table below shows our forecast for non-load related expenditure, alongside TPA's forecast and Ofgem's Initial Proposals.

Forecast expenditure 2005/06 to 2011/12 £m, 2004/05 prices	**NGG**	**TPA Lowest capex**	**TPA Highest capex**	**Ofgem Initial Proposals[8]**
- Emissions	248.4	176.8	186.8	168.0
- Other NLR[9]	287.8	215.3	243.3	207.2
Total	**536.2**	**392.1**	**430.1**	**375.2**

509 We note, however, that, as for electricity, Ofgem have effectively taken the lowest of the consultants proposed range of expenditure, and subsequently applied the 5% procurement efficiency reduction. In total, TPA's highest view of capex is some £55m higher than Ofgem's initial proposals. We do not believe, therefore, that Ofgem's initial proposals represent a fair reflection of their consultants' view. In addition, we do not believe that TPA's view represents a prudent level of investment, given the uncertainties and likely developments in gas entry projects. These views are discussed below.

510 With regard to TPA's analysis, the vast majority of the difference between our forecast and theirs relate to their view that a number of our existing compressor stations will not be needed in the future, and therefore that capital expenditure at these sites is not required. Further reductions are proposed on the basis of TPA's analysis of other specific projects. Our comments in this sections are therefore structured as follows:

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[8] Includes £19.8m of 'procurement efficiency' as set out in table 7.4 of Appendix 7 in Ofgem's initial proposals.

[9] Excludes expenditure on security and non-operational capex, as per table 7.4 in appendix 7 of Ofgem's initial proposals.

(a) the reduction of expenditure on the basis of reduced need case for certain compressors;

(i) proposed costs savings from re-location of assets;

(ii) proposed reduced expenditure on emissions reduction;

(iii) proposed reduced expenditure on asset replacement;

(b) proposed reductions to expenditure on other specific projects.

Rationale for reduced need for some compressor sites

511 TPA's main basis for reducing forecast expenditure on both emissions and asset replacement is that a number of compressor sites show few or no running hours under the three planning scenarios.

512 TPA's view is that those sites identified as having no running hours should be de-commissioned, with consequential capex (and opex) savings, and that capital expenditure should not be incurred at those sites with few running hours. In addition, TPA believe that further cost savings can be achieved through the relocation of assets from under-utilised sites.

513 **For the avoidance of doubt, we disagree with the view that these sites should be considered unlikely to be required and we do not believe that decommissioning of the sites identified is the right course of action.** The consequence of this view is that significant capital expenditure will be required at these sites in the next Price control period. The basis for our view is given below:

(a) **The planning scenarios used do not reflect the range of operating requirements –** the planning studies represent "snapshot" scenarios, which are used to determine the maximum duty points on the network, are limited in their ability to reflect the running hours required at each site for the following reasons:

(i) they are based on a small number of fixed views of potential supply;

(ii) they do not reflect the full range of potential flows from each of these supply points;

(iii) all the scenarios assume **idealised steady state conditions** (i.e. all compressors available, no non routine operations taking place, all supply points fully operational and delivering at steady state rates), and so do not reflect the range of operating conditions experienced, such as during planned or unplanned machine outages, management of linepack and management of changing supply profiles.

For planning purposes, the range of potential flows and operating conditions are catered for by use of the flow margin. As such the planning studies alone cannot provide a reliable guide to predict the requirements for compressor stations, and in particular cannot be used to predict with certainty that any compressor site is not required.

(b) **The planning scenarios do not reflect all credible potential supply projects –** whilst the scenarios reflect a view of the future, there are other credible new supply projects which would materially change the flows on the network, and hence change the requirements for a number of the compressors identified as having low running hours. Three of these highly credible projects are shown below, along with the compressors, currently identified as having low forecast running hours against the three snapshot planning scenarios, which would have significant running hours in the event that these new projects connect:

[redacted]

[redacted]

[redacted]

(c) **They do not reflect the current running hours of the compressor sites –** whilst it is recognised that the future pattern of supplies is likely to be very different to now, it is important to consider that a number of the sites identified as having few forecast running hours [redacted] are all currently running at levels consistent with their historic high level of usage. Of the other six sites, four ran for over 1000 hours in 2005.

514 The fact that some sites have few or no running hours in the three planning scenarios used by TPA, therefore, **does not mean that these sites are not required in the future. We do not believe, therefore, that it would be appropriate to set allowances on such a plan to decommission compressor sites on the basis of such limited rationale.** Closure of these sites would result in:

(a) the inability of the network to cope with the wide range of current and future supply patterns leading to increased constraints and reduced security of supply;

(b) loss of flexibility in the transmission system to deal with changes in flows, leading to increased constraints and reduced security of supply;

(c) the potential need to re-plant compressor sites when flow patterns change or new supply projects connect.

515 As a consequence, we believe that the proposed reductions in expenditure are unjustified. We do not believe that it is appropriate that small (relative to the multi-billion pound gas supply industry) capital efficiencies should be traded for security of supply on the basis of a small number of idealised "snapshot" scenarios. We do not believe, therefore, that TPA's assertion that a number of sites could be abandoned on the basis of these forecasts, in order to save a small amount of capex, is in the interests of customers.

Proposed cost savings through relocation of assets

516 As a result of their view on the potential to close some compressor stations, TPA forecast the potential for up to £30m of cost savings at the sites where expenditure is required through the relocation of assets from under-utilised sites. In the Initial Proposals, Ofgem deduct all of this potential saving.

517 As discussed above, we disagree that there is any potential to relocate assets, as we believe all sites to be needed going forwards. Even to the extent that any such savings were possible, we believe the potential savings have been vastly overstated, as:

(a) The only assets that could practically be transferred would be the Gas turbine and its associated Power Turbine. These have a capital cost of approximately £3m-£5m – this, therefore represents the starting point for calculating any potential savings.

(b) A unit may require overhaul prior to installation in a 'new' train at a cost of approx £1.2m, reducing the potential capital saving to £1.8m-£3.8m for each one.

(c) The gas turbines must be matched to a duty and compressor, and the potential sites identified for transfer capability are Wooler and Bishop Auckland as they are IPPC compliant plant. Only one identified site for investment has this power requirement (Carnforth) - all others have either a lower or higher power requirement, as such there is only one candidate where transfer could be considered.

518 In addition, transferring an existing asset to a new build construction project presents a very large risk to the contractor in terms of construction and commissioning of new plant, particularly in regard to performance guarantees from OEM manufacturers in terms of both power output and emissions performance. Contractors will not provide a warranty on any equipment directly connected to, or that could be influenced by the performance of the supplied units and would contest any warranty claims made, presenting a significant opex risk. Also, as the only existing plant that could be moved are gas turbines, these have a higher carbon cost and cost of overhaul than a new electric drive, such that the opex costs would be higher by up to £2m per annum.

519 We believe therefore that the highest capital saving that could be achieved through transferring assets is between £1.8m and £5m, and that this would come at the cost of a higher level of opex than a new electric drive. We believe this reduction is overstated by at least £25m, and almost certainly by the full £30m. We believe, therefore, that there is no justification for the proposed reductions, and the amount deducted for this unachievable saving should be added back in to the proposed allowances.

Proposed reductions to emissions expenditure

520 The implication of TPA's view on the future running hours at sites, they propose a reduction of £51.6m expenditure on emission reduction, specifically by not installing new electric drives at [redacted] TPA state that, in their view, the low forecast running hours at these sites is "a situation unlikely to change". We do not agree with this statement.

521 In relation to these sites, we believe that it is appropriate to continue to consider these

sites for emissions reduction investment. **At both of these sites, if they are required at all, investment will be required to bring them into compliance with emissions legislation** – if investment is not carried out, we will not be given a licence by the Environment Agency (EA) and Scottish Environmental Protection Agency (SEPA) to operate, and would have to close the sites.

522 Whilst the snapshot scenarios show no running hours at these sites, the running hours at each of these sites are highly sensitive to future supply developments. As shown above, we are aware of potential supply developments in [redacted] either of which would result in very high running hours at [redacted]

[redacted]

524 In conclusion it is far from clear that [redacted] and [redacted] will not be required at all in the future, and indeed we believe that it is highly likely that investment will need to be carried out at these sites. As such, we believe that Ofgem should reinstate the £51.6m in the proposed allowances to provide funding in the baseline for the replacement of these compressors.

Proposed reductions to replacement expenditure

525 For asset replacement expenditure, the implication of TPA's view on compressor running hours is the proposed reduction in expenditure of around £23m, consisting of the following reductions:

(a) protection and control - £10m reduction;

(b) gas generator overhauls - £6.5m reduction;

(c) power turbine refurbishment - £3.5m reduction;

(d) other compressor/terminal replacement – approximately £3m reduction.

526 As discussed above, we disagree with TPA's view that the low forecast compressor running hours for a number of sites means that they can be decommissioned, and hence no replacement expenditure incurred. If these sites are to be kept open, and the flexibility in the transmission system retained, capital expenditure will have to be incurred in order maintain them in serviceable and usable condition, as:

(a) it will be unacceptable to keep sites open where the Protection and Control systems, which are required in order to ensure the safe operation of the system;

(b) it would be unacceptable to not overhaul compressors which have achieved the running hours at which overhaul is required.

527 We do not believe, therefore, that it is reasonable for Ofgem to base their proposals on the assumption that these sites should be closed and no expenditure incurred.

528 In addition we would note that, whilst TPA have proposed a 10% decrease in expenditure across the category of "other" expenditure at compressor sites on the basis of low forecast running hours, around £11m of the £30m affected is **not** dependent on running hours at all (e.g. Cathodic Protection, Industrial Metering, Gas pre-heating and spares), and so we believe that the proposals should be adjusted accordingly.

Reductions to expenditure on other specific projects

Humber Crossing

529 Feeder No 1 pipeline crosses the Humber Estuary, and during the current Price control period the pipeline has experienced a number of occasions where the bed of the river has been scoured from under the pipeline, leaving unsupported spans. This has led to us carrying out remedial works on a number of occasions. The stability of the river bed is poor, and further, more permanent remedial work is required.

530 We welcome TPA's statement that they believe there to be a case for investment on the Humber Crossing pipeline. Whilst we note their view that expenditure could be in the range £5m to £28m (covering the range of potential remedial options up to installing a new pipeline in a tunnel), we believe that Ofgem's choice of the low end of TPA's forecast means that they are again assuming that the lowest cost option turns out to be viable, and not representing a balanced view of their consultants' analysis. We believe that it is likely that we will need to incur significantly higher capital costs than those proposed, and as such do not believe that Ofgem's choice of the low end of TPA's assessment is appropriate.

Environmental Standards

531 In our forecast we identified a requirement to upgrade the environmental standards at our compressor and terminal sites to a level equivalent to that currently delivered on the electricity transmission system through the installation of oil interceptor tanks and additional site drainage. At a cost of £0.5m per site for 30 sites, we forecast a requirement for £15m of expenditure.

532 TPA proposed a reduction in our forecast expenditure on improving environmental standards of between £5m and £10m, out of a forecast of £15m, of which Ofgem again adopt the lower end of the range to include an unbalanced view of their consultants' analysis in the Initial Proposals. The clear implication of this is that we would need to abandon our plans to improve the standards at around 20 of our 30 sites. We do not believe that Ofgem's proposal to provide up with less than half of the amount necessary to upgrade our sites is consistent with Ofgem's stated commitment to ensuring the improvement of the environmental performance of the transmission systems.

Forecast load related expenditure

Derivation of baseline load related allowances

533 In deriving the proposed TO allowances, Ofgem have deducted around £420m of capital expenditure from our forecast expenditure in the period 2005/06 to 2011/12 through an "entry/offtake volume adjustment". We recognise that Ofgem have

removed this capital expenditure from the TO allowance on the basis that, subject to the receipt of sufficient commitment from a network user, required investment would be remunerated through revenue drivers. Whilst it is not made clear in the Initial Proposals document, we note that the amounts of expenditure removed exactly correspond to our forecast expenditure for new offtakes and demand growth, and therefore we have assumed that this expenditure only relates to exit expenditure.

534 However, we believe that where a high degree of certainty and associated user commitment exists, investment should be included in the baseline allowance, rather than remunerated through revenue drivers. In the Initial Proposals document Ofgem state that they have "excluded those **uncertain** user-driven investments"[10], proposing that these be captured by revenue drivers. However, with regard to the setting of baselines for offtake, Ofgem also state that the baselines should "act as a delineation between the funding of the **existing** NTS asset base and the remuneration of incremental investment".[11]

535 We believe that there is a contradiction between these statements, which divides investment into that which is **uncertain,** and is so excluded from the TO baselines and allowances, and that which has delivered the **existing** asset base, and so is included in the TO baseline and allowances. There is a third category of investment – that which is certain, but which has not yet been delivered.

536 In determining the baseline TO allowances, Ofgem have excluded investment which fits into this category i.e. for which user commitment has been received such that the need for investment is certain (i.e. an ARCA is in place with the connecting party committed at the level, but is currently in the process of being delivered. [redacted] This investment should clearly be included in the baseline allowance. [redacted] If this is the case, this should also be included in the baseline allowance.

Milford Haven costs

537 We welcome Ofgem's confirmation that the efficient actual and forecast capital costs for the Milford Haven project will be included in the RAV from April 2007. We also welcome TPA's conclusion that there are "reasonable grounds for the higher revised capex forecasts as a result of individual project circumstances and market conditions".

538 Further, TPA's conclusion does not only refer to the costs associated to Milford Haven, but also to the increases in costs seen on other projects since the submission of our FBPQ. In total, TPA conclude that an additional £218m should be allowed in light of these cost increases, which Ofgem did not include in the Initial Proposals. Following TPA's endorsement of our revised project costs, we would wish to discuss with Ofgem the reason for not including these costs in the Initial Proposals, and look forward to Ofgem's inclusion of our updated costs for this project in the September update.

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[10] Paragraph 2.6, main consultation document

[11] Paragraph 1.11, Appendix 16

Flow Margin

539 We note Ofgem's proposal to review the application of a 5% flow margin to our planning studies. As discussed in our response to the Third Consultation, we remain committed to working with Ofgem to review the appropriateness of the flow margin, and the appropriate level of such a margin.

540 However, we remain concerned that Ofgem clearly believe that any such review would only result in a "reduced flow margin". We do not believe that this is necessarily the case, and that any decisions on flow margin should only follow thorough review of the background to our planning studies including:

(a) The significant uncertainty over the location of supplies, and within year variability of gas flows;

(b) The form of entry and exit capacity release mechanisms, which may require us to "substitute" capacity between locations, leading to a tightening of the amount of capacity available in the network;

(c) The extent of potential decommissioning of compressor sites implied by the level of opex and capex allowed as part of this review i.e. if Ofgem remain of the view that some sites should be closed, this will also lead to a tightening of the amount of capacity available in the network.

541 These issues all need to be considered carefully in order to determine the appropriate level of margin to apply.

Annex to Chapter 3

Overhead line costs

Introduction

542 The following tables show all full refurbishment schemes carried out, or planned to be carried out, in the period 2000/01 to 2011/12. The characteristics of each scheme are shown in terms of the major drivers of overhead line scheme costs i.e. ease of site establishment, road, rail overhead line and river crossings, terrain, environmental impact, extent of tower steelwork replacement required, and whether a fibre optic replacement is required. As can be seen, the drivers differ by scheme, and so unsurprisingly, the specific costs of each scheme vary considerably (i.e. between £[redacted]k/circuit km and £[redacted]k/circuit km for future quad refurbishment schemes).

Quad Full Refurbishment Schemes

543 Note - all costs are in 2004/5 prices

Route	Total cost £M	Length (cct km)	Unit cost (£k/cct km)	Site Est.	Critical cross.	Terrain	Eco impact	Steel
SCHEMES DELIVERED OR IN DELIVERY BETWEEN 2000/1 AND 2006/7								
KEAD –GRIW (4KG)	[redacted]	[redacted]	[redacted]	Low	Med	Easy	Low	Med
WBUR-WALP (4ZM)	[redacted]	[redacted]	[redacted]	Med	Med	Easy	Low	Med
WYLFA-PENTIR	[redacted]	[redacted]	[redacted]	Low	Med	Easy	Med	Med
CHIC-MANN 4VN	[redacted]	[redacted]	[redacted]	Low	High	Easy	High	Low
CHTE-HIGM 1&2 (4ZV)	[redacted]	[redacted]	[redacted]	Med	High	Med	High	High
BURW-WALP OHL (4ZM)	[redacted]	[redacted]	[redacted]	Low	High	Diff	High	Med
DUNG-NINF	[redacted]	[redacted]	[redacted]	Med	High	Diff	High	High
PELH-BURW	[redacted]	[redacted]	[redacted]	Med	High	Diff	High	Med
SCHEMES TO BE DELIVERED BETWEEN 2007/8 AND 2011/12								
BRIN-THOM 4ZH	[redacted]	[redacted]	[redacted]	Low	Low	Easy	Low	Med
FERR-SKLG 1&2	[redacted]	[redacted]	[redacted]	Low	Low	Med	Med	Low
BRIN-CHTE 1&2	[redacted]	[redacted]	[redacted]	Med	Low	Med	Low	Med
ECLA-ENDE 1&2	[redacted]	[redacted]	[redacted]	High	Med	Med	Med	Med
CILF TEE - RASS	[redacted]	[redacted]	[redacted]	Med	Med	Med	High	Med
EXET-AXMI/CHIC (4YA)	[redacted]	[redacted]	[redacted]	Low	Med	Med	Med	Low
COVE-RATS & HAMH-WILE	[redacted]	[redacted]	[redacted]	Med	Med	Easy	Med	Low
BUST- DRAK 4YP 1 - 101	[redacted]	[redacted]	[redacted]	Med	Med	Easy	Med	Med
FIDF-FROD 1&2	[redacted]	[redacted]	[redacted]	Med	Med	Easy	High	Low
COTT-KEAD 1&2	[redacted]	[redacted]	[redacted]	Med	Med	Diff	Med	High
CAPE-DEES 1&2	[redacted]	[redacted]	[redacted]	Med	High	Diff	Med	High
ECLA-SUND	[redacted]	[redacted]	[redacted]	High	High	Diff	Med	Med
PENT - DEES 1 & 2 4ZB	[redacted]	[redacted]	[redacted]	Med	High	Diff	High	Med
FIDF-RAIN 1&2	[redacted]	[redacted]	[redacted]	Med	Med	Diff	High	High
CAPE-FROD 1&2	[redacted]	[redacted]	[redacted]	Med	Med	Diff	High	Med
BOLN - LOVE (4VF)	[redacted]	[redacted]	[redacted]	Med	Med	Diff	High	Med
PELH - RYEH - WALX (4ZM)	[redacted]	[redacted]	[redacted]	High	Med	Diff	High	Med
EGGB-PADI-MONF-BRAW	[redacted]	[redacted]	[redacted]	Med	Med	Diff	Med	High

Twin Full Refurbishment schemes

Route	Total cost £M	Length (cct km)	Unit cost (£k/cct km)	Site Est.	Critical Cross.	Terrain	Eco impact	Steel
SCHEMES DELIVERED OR IN DELIVERY BETWEEN 2000/1 AND 2006/7								
BLYTH-HARKER	[redacted]	[redacted]	[redacted]	Low	Low	Med	Low	High
PENN-RUGELEY	[redacted]	[redacted]	[redacted]	Med	Med	Med	Low	Low
COWB-PYLE 1&2	[redacted]	[redacted]	[redacted]	Med	Med	Med	Low	High
ABTH-COWB 1&2 (ZZS)	[redacted]	[redacted]	[redacted]	Med	Med	Med	Low	High
ELST-MILH	[redacted]	[redacted]	[redacted]	High	High	Med	High	High
SCHEMES TO BE DELIVERED BETWEEN 2007/8 AND 2011/12								
THOM-WMEL 1&2	[redacted]	[redacted]	[redacted]	Low	Med	Easy	Low	Low
MAGA - SWAN (VE 1-90)	[redacted]	[redacted]	[redacted]	Low	Easy	Med	Low	Low
BRIN -TEMP	[redacted]	[redacted]	[redacted]	Low	Low	Med	Low	Low
USKM-WHSO 1&2	[redacted]	[redacted]	[redacted]	Med	Med	Easy	Low	Med
ECLA-AMEM-IVER 2	[redacted]	[redacted]	[redacted]	Med	Med	Easy	Low	Med
WALX-BRIM-TOTT (4BC)	[redacted]	[redacted]	[redacted]	Med	High	Med	Med	Med
WALX-BRIM-TOTT (4BD)	[redacted]	[redacted]	[redacted]	Med	High	Med	Med	Med
CARR- (SMAN 2 & DAIN 2)	[redacted]	[redacted]	[redacted]	Med	High	Med	Med	Med
IROA-WHSO 1&2 (XL)	[redacted]	[redacted]	[redacted]	Med	Med	Med	High	Med
BISW-KITW 1&2 YK	[redacted]	[redacted]	[redacted]	Low	Med	Easy	Med	Med
BRLE-WWEY 1&2 (ZH)	[redacted]	[redacted]	[redacted]	High	High	Diff	Med	Med
ABTH-TREM (LL)	[redacted]	[redacted]	[redacted]	Med	High	Med	Med	High
MAGA-PYLE (VE 91-110)	[redacted]	[redacted]	[redacted]	Med	High	Diff	Med	High
BISW-KITW 1&2 (ZN)	[redacted]	[redacted]	[redacted]	Low	High	Easy	Med	High
KITW-OCKH/OLDB (YJ/ VT)	[redacted]	[redacted]	[redacted]	High	High	Diff	High	High

	More than 10% below unit cost
	Within +/- 10% of unit cost (£[redacted]k)
	More than 10% above unit cost

Definitions

544 Site Establishment

(a) High - Sites available at premium

(b) Med - Sites available

(c) Low - No impact

545 Critical crossings:

(a) High - Dual carriageway, Motorway, Main Line railway, 132kV Power lines & navigable river

(b) Med - Trunk road & single track rail crossings

(c) Low - Minor road crossing

546 Terrain:

(a) Easy - Open rural, mainly level

(b) Med - Suburban

(c) Diff - Urban, industrial or extreme changes in height

547 Eco-impact:

(a) High - More than 50% of route within environmentally-sensitive area, eg AONB, SSSI, etc

(b) Med - Anticipated problems with flora & fauna

(c) Low - No impact on designated environmentally-sensitive areas

548 Steel:

(a) High - Evidence of piecemeal steelwork replacement required on >90%l towers, and some new towers

(b) Med - Evidence of piecemeal steelwork replacement required on >10% of towers

Low - All evidence points towards no significant steelwork replacement

4 Adjustment mechanisms and incentives

General comments

549 As detailed in our previous responses, we are supportive of the proposed increased use of revenue drivers as a mechanism to deal with the uncertainties associated with load related capex in gas and electricity. However, as mentioned in our response to the third consultation document, overall acceptance of the revenue drivers remains highly dependent upon the detailed design of the revenue drivers.

550 In this respect, the details contained in the Initial Proposals document provide useful information to stimulate further discussion and analysis. Whilst we still believe that we have, in most areas, a common view on the objectives (e.g. cost reflective UCAs and baselines set in line with the physical capability of the system), the current methodologies do not meet these objectives.

551 Following further analysis, it should be possible to amend the proposals to better meet the objectives. In the meantime, and for the avoidance of doubt, we would not find acceptable the current proposals contained in the Initial Proposals document if they were put to us as a final set of proposals.

552 In advance of setting out our more detailed comments on the initial proposals for gas and electricity, we set out below our generic concerns associated with the current proposals:

- The initial design of the revenue drivers (electricity and gas) is leading to UCAs that are likely to be generically lower than the likely investment costs. This issue becomes more material given the proposed use of five year rolling incentives which, as currently envisaged by Ofgem, could expose us to the difference between UCAs and actual costs for very long periods of time – plausibly, to 2019 or beyond[12].

- The proposed gas baselines (entry and exit) are above system capability. In relation to gas entry, this is likely to trigger a significant buyback exposure to customers under certain supply scenarios. This would seem inconsistent with the Ofgem objective of developing a network with an appropriate degree of flexibility.

- The proposed timing of incentive-driven cash flows in gas could exacerbate financeability issues. The proposals concerning the timing of revenues for electricity should be applied to gas.

- The proposals for the new gas investment incentive would provide us with a massive downside risk (hundreds of million of pounds) with no realistic upside.

- There is a general lack of any upside in the proposed incentives which is either explicit in terms of the electricity system performance incentive or implicit in terms of the new gas investment incentive.

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[12] This is because the proposed five year rolling incentives start at the point of contractual delivery of new capacity. Thus, one could envisage the following sequence: (1) UCAs are fixed in December 2006 (as part of Ofgem's Final proposals) to last through to March 2012; (2) In the long term entry capacity auctions in September 2011, a shipper bids for new entry capacity for delivery in (say) October 2014; and (3) Rolling incentives then apply through to October 2019.

553 In summary the proposals are unacceptable to us in their current form as they would significantly increase the risks without the prospect of rewards commensurate with those risks.

554 In the following sections, we deal successively with the issues which we see as arising in respect of:

(a) gas entry;

(b) gas exit; and

(c) electricity.

Gas entry

555 As mentioned above, Ofgem's initial quantification of proposals relating to gas entry provides a useful reference point for consultation and further analysis ahead of the September document. We recognise that Ofgem have received a lot of data from National Grid and further time is required to fully interpret the data.

556 The section below highlights why the current proposals relating to **baselines**, **UCAs** and **new investment buybacks** are unacceptable to us. We give a description of the main issues with the current proposals and a suggested way forward on each of the issues.

Baselines

557 We have three major concerns over Ofgem's proposed methodology for calculating entry baselines. We recognise that Ofgem have acknowledged that certain elements of the methodology for calculating baselines are currently untested and therefore should be considered as a reference point for consultation. We therefore set out our concerns with the current proposals and a proposed way forward in that context.

Issues with the current proposals

558 We identify the following main issues with the current proposals:

(a) As we previously indicated in our response to the March document, it is wholly inappropriate to add the nodal free increments to the baseflow on the network (or indeed 90% of them). By calculating the baselines in this manner, the free increments have been counted several times and system capability has been greatly over stated. In essence, allocating 90% of the free increments would lead to baselines **not** being set in line with Ofgem's stated policy intent of setting baselines in line with system capability - in fact they would be more in line with the (rightly) rejected policy of "theoretical maximum physical capacity".

(b) The proposed baselines do not take into account the interactions between nodes as they have been set on the basis of analysis which considered each entry point in isolation.

(c) The proposed baselines do not take into account previously released obligated incremental entry capacity which has been signalled through the auction process. This would seem inappropriate, given that 'user commitment' has already been provided for that level of capacity.

Proposed way forward

559 In order to address these issues, we would propose the following:

(a) A more appropriate manner of setting nodal baselines, and one which is consistent with the policy intent of setting baselines in line with system capability, would be to consider the capability of the system at a **zonal** level and then to disaggregate to nodes after identifying the zonal constraints. Data has already been provided to Ofgem highlighting the zonal capabilities under various supply scenarios, all of which are materially below the baselines associated with the current proposals. We believe further analysis and dialogue around this zonal capability data is crucial in order to set baselines in line with system capability. If baselines were not adjusted in line with our proposed zonal methodology, then we would be obliged to release capacity beyond system capability which would expose customers to potential very high buyback costs[13].

(b) We believe baselines should be adjusted to take into account previously released incremental entry capacity signalled through the auction process. This would have the affect of increasing the baselines at certain entry points beyond those contained in the Initial Proposals document.

(c) Taking the above two points into account, we attach as an Annex to this chapter our initial views on a more appropriate set of baselines.

UCAs

560 From a policy point of view, we believe we share a common goal with Ofgem - to set UCAs which reflect the underlying costs of providing incremental entry capacity. However we believe that Ofgem's current proposed methodology for setting UCAs will not adjust revenue in line with a reasonable ex-ante view of the likely investment costs. We also believe the proposals will not lead to a flexible system designed to meet the potential future needs of a diverse pattern of gas supplies. We set out our concerns with the current proposals and a proposed way forward below.

Issues with the current proposals

561 The main issues with Ofgem's UCA proposals are that:

(a) The current proposals for setting UCAs, based on the average of the three TBE scenarios, will **not** ensure that the network is developed with an appropriate degree of flexibility (as Ofgem have suggested is a desirable objective in paragraph 11.20 of the Initial Proposals). In discussions with Ofgem, we have highlighted that, if National Grid followed a policy of investing based on the average of the three TBE scenarios, this would probably lead to significant constraints on the system under credible supply scenarios. The cost of these constraints could be significant and would be passed through to customers, in full or in part, through the operational buyback regime.

[13] Although National Grid currently has an incentive on Buybacks, these arrangements expire on 31 March 2007 and therefore, in the absence of new arrangements being agreed, customers would be exposed to 100% of buybacks.

(b) The current proposals continue to be that the UCAs are fixed at the beginning of the price control for the full duration of the price control. This is unacceptable for the following reasons:

(i) **Changing supply patterns.** As recognised in recent Ofgem consultation documents[14], it is clear that there have been significant changes in gas flow patterns over the current price control period which have led to UCAs becoming non cost reflective towards the end of the price control period. The current proposals contain the same risk that UCAs, set with the intent of being cost reflective as part of a price control, become non cost reflective during the price control period. This becomes increasingly important given the proposals on rolling incentives set out below.

(ii) **Pricing pressures.** As recognised in recent Ofgem consultation documents, the price of steel has increased significantly and the contract market has tightened. Neither of these factors has been taken into account in the current proposals for setting UCAs.

(iii) **Inconsistency with Ofgem's (in our view, correct) policy on setting future <u>prices</u> for new entry capacity.** In their recent decision document on UCAs for large new entry points[15], Ofgem describe the benefit of there being an opportunity in the future for "entry reserve prices to be updated for new cost information more frequently during the price control period than at present" (when the prices are, in effect, fixed for the whole of the price control period). We agree with Ofgem on this benefit. However, it is hard to understand why it should be a benefit for **prices** to be updated in the light of new cost information (including the impact of changes in the view on likely future patterns of gas supply and demand) but **not** a benefit for revenues to be updated in the same manner.

(c) The problems caused by setting the wrong UCAs and by setting them for the whole of the price control period would be substantially exacerbated by the proposed introduction of a five year rolling incentive in respect of the UCAs. In essence, it is being proposed that we should be exposed to the difference between UCAs and actual costs for five years from contractual delivery of the capacity in question. What this would mean, for example, is that, if new capacity was purchased in the long term capacity auctions in, say, September 2011 for delivery in October 2014, then we would be exposed **through to 2019** to UCAs which will be incorrect even when they are set in 2006. In our view, this would make no sense or would, at the very least, be inconsistent with the sort of risk profile which has thus far underpinned consideration of NGG's cost of capital.

(d) Although we continue to support the concept of user commitment in the investment process, we do not believe a 'pure' user commitment model to be the most appropriate mechanism for investment and associated remuneration. We believe that due to the lumpiness of investment there will be circumstances where it would be efficient to invest beyond the pure signals seen from the user commitment. It is therefore important that the process for setting revenue drivers is flexible enough to deal with efficient

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[14] Adjusting National Grid's revenue allowances when large new entry points connect to the gas transmission system, 29 March 2006.

[15] Determining Unit Cost Allowances (UCAs) for large new entry points & Section 23 notice for Fleetwood, 13 July 2006

investment beyond user commitment, **as is currently being proposed by Ofgem within the same Initial Proposals document in respect of electricity**.

(e) We note that the current proposals for gas entry differ from the proposals for electricity in terms of cashflow. The proposals for gas assume National Grid will fund the capex fully before obtaining revenue from the date of taking on the obligation to release incremental capacity, whereas the electricity proposals envisage cash flowing earlier in the process.

Proposed Way Forward

562 In order to address the issues set out above, we would propose the following:

(a) On the basis that Ofgem are aiming, as part of the price review, to set revenue drivers at levels consistent with meeting bookings of new capacity under a wide range of different flow scenarios, then the methodology of averaging the three TBE scenarios should be reviewed. We believe a methodology which sets UCAs based on the **highest** of the 3 TBE scenarios would be more consistent with ensuring a network is developed with an appropriate degree of flexibility. This would also seem to be more consistent with the Government's energy review. In the event that there was no change in the current proposed methodology, we believe the likely consequences would be that investment would be undertaken on that basis, with the associated risk of gas not being able to flow and higher buyback costs being borne by customers.

(b) Even if UCAs were set on the basis which we propose, there would still be the issue that the UCAs could (and almost certainly would) still become non cost reflective over the period of the price control, as has happened during this price control due to changing supply patterns and pricing pressures. To address this point, we propose that:

(i) Either a fixed additional allowance or some form of price indexation is developed in setting the UCAs to address the pricing pressures which are expected over the next price control period.

(ii) Consideration is given to re-opening UCAs **in the wake of the relevant capacity auctions** if supply patterns (as suggested by the auctions) suggest that the efficient level of investment is at least 10% more than the capital cost implied by the UCA set as part of the price control process. In this way, we would be more likely to be incentivised to beat a reasonable ex ante estimate of efficient costs (estimated at a point when more of the relevant information will be available than it is now).

(c) A process is developed whereby National Grid can propose to invest beyond the pure user commitment signal. Where Ofgem agree this would be efficient (e.g. due to the lumpiness of transmission investment) the UCA should be adjusted to reflect the increased investment and the associated increase in capacity being released.

(d) Given the potential size of spend on entry developments in the next price control period and the potential financeability issues relating to gas transmission, we propose that the cash flow mechanisms proposed for electricity are also adopted for the gas arrangements.

563 Finally, given the uncertainties described above and in particular the fact that UCAs may vary considerably due to circumstances outside National Grid's control (e.g. changing supply patterns), it would seem appropriate to re-visit the desirability of five year rolling incentives (which, as noted above, will effectively roll for a lot more than five years) . Whilst the policy of rolling incentives is theoretically beneficial in terms of maximising incentives on capital efficiency, it seems that, with the current proposals, performance is more likely to be driven by these uncertainties than by efficient actions taken by the transmission company. We would therefore suggest that one way to address the potential materiality of these issues is to have the UCAs only driving revenue up until the next price control (as per the current status quo).

New Investment Buyback Incentive

564 The current proposals relating to new investment buybacks are totally unacceptable and do not meet Ofgem's aim of ensuring that there should be an appropriate balance of risk between the transmission companies, network users and consumers. The current proposals completely fail Ofgem's stated aim of providing rewards for the companies commensurate with the risks they face. Our concerns with the current proposals and a proposed way forward are set out below:

Issues with the current proposals

565 The main issues with the current proposals are that:

(a) They fail to provide an appropriate balance of risk and reward. In terms of risk the current proposals have changed National Grid's total maximum combined exposure to buybacks (new investment and operational buyback) from a collar of £12.5m to an uncapped exposure. **Initial analysis of the proposals show a credible exposure to National Grid of over £1bn if National Grid was one year late in delivering a project the size of Milford Haven[16].** This is clearly inappropriate, given the cost of capital range being consulted upon.

(b) The current proposals place, as a default, the consents risks associated with delivery with National Grid. As detailed in our previous responses, we believe factors substantially outside of our control, such as the timing of necessary consents being granted, should be excluded from the incentive scheme. The ability to potentially claim an IAE if National Grid experience difficulties in obtaining consents is an unacceptable mechanism to deal with this risk, particularly given the potential exposure detailed in the first bullet.

Furthermore we believe that the Authority's view of local planning consent risk is entirely at odds with the Government's view, as expressed in the Energy Review. We would request that Ofgem consider the information contained in the Energy Review in developing proposals for the new gas investment incentive.

(c) The current default timescale for delivery of three years is unacceptable, especially when combined with the bullet points above. The three year default lead time associated with the gas entry regime was based on a 'normal' consents and construction program. The timetable clearly does **not** allow for the situation where planning permission is deferred for a significant amount of time by a Planning Authority or is rejected. Recent experience, which has been consulted upon, following the UNC mod to allow National

[16] Based on an assumption of 650 GWh/d, being one year late would entail an exposure of 650GWh/d * 0.52p/kWh *365 days = £1.2bn.

grid to apply a lead time greater than three years, has indicated that there are several reasons why investments may take longer than three years and this needs to be factored into the default arrangements. The ability to apply to the Authority to request longer lead times still leaves a default substantial buyback risk with National Grid.

(d) The current proposals provide no reward for taking on the substantial risks described above. The concept that National Grid may earn some additional revenue through entering into bi-lateral arrangements will, in practice, never materialise given the proposed default compensation arrangements and the default delivery timescales **(i.e. we do not believe there would be a mutually beneficial deal which we could offer, given the property rights embedded in the proposed default arrangements)**

(e) Finally, we do not believe that Ofgem's analysis, as outlined in Table 11.9 within Appendix 11 of the Initial Proposals, is correct. Given that the SAP price quoted is weighted average, it would seem more robust to treat the buyback prices in a similar manner. In addition, there appear to be some arithmetic errors in the determination of the monthly buyback prices; namely the entries for December 2004 and January 2005 appear to be summations, rather than averages. However, we are not convinced that using a price determined with reference to SAP is the correct approach as there is no statistically significant correlation between the WAP of prompt buybacks and SAP.

Proposed Way Forward

566 The proposed way forward examines both the risk and reward aspects of the current proposals - the aim being a set of proposals that provide rewards for the companies commensurate with the risks they face. In order to achieve an acceptable balance of risk and reward (i.e. high risk/high reward or low risk/low reward) we believe the following need considering as a package.

(a) Potential total exposure incorporating the key elements driving the exposure namely:

(i) the absolute potential exposure (£m), which given the cost of capital range must include the use of collars;

(ii) the default timescale for investment delivery. In order to have meaningful incentives on delivery it is necessary to agree ex-ante the default timescales for a generic set of investments, rather than rely on a request to the Authority to extend timescales. Our initial view, based on changes that have occurred in the consents process, is that the default timescale should be four years. Ofgem have already accepted this timescale for new greenfield compressor sites; and

(iii) the degree of control on delivery, in particular which party bears the risk associated with gaining consents for pipelines and planning permissions for above ground installations (AGIs). We believe Ofgem should consider the information contained in the Energy Review in developing proposals for the new gas investment incentive. Our preferred option is that any investment incentive is based on elements within National Grid's control (i.e. construction activities) and therefore the default timescales should commence once the necessary consents have been obtained (this places consents risk with the connecting party which provides an additional focus in their decisions on where to locate activities). In our view, any alternative model that places the consents risks with National Grid would have to explicitly exclude from the default timescales any factors that do not feature in a typical planning process (e.g. planning permission appeals etc) or considerably increase the default timescale.

(b) Potential reward for taking on the risks described above. This should consider:

(i) the absolute potential reward (£m) which could consider the use of caps;

(ii) whether the reward is in the form of an incentive payment or an enhanced rate of return for new investments. Our initial view is there is merit in considering an enhanced rate of return for timely investment delivery;

(iii) the trigger point for any reward (i.e. whether we are rewarded for delivering on time or only for delivering early). Our initial view is that customers value timely delivery rather than early delivery; and

(iv) the likelihood of achieving any reward which will be heavily dependent upon the default delivery timescales and who bears the risks associated with obtaining consents.

567 We believe discussions around the issues detailed above should provide the opportunity to change the proposals to provide a more balanced set of proposals. Given the potential magnitude of the costs involved in buying back capacity, we would suggest the first question addressed is around appropriate caps and collars.

568 The section above has considered our current issues and the proposed way forward on the proposals relating to baselines, UCAs and new investment buybacks. Our comments on the other main elements contained in the consultation document are considered briefly below:

Operational Buybacks

569 We note that Ofgem have set out their initial views on the operational buyback incentive in Appendix 11 of the Initial Proposals. We would support the proposed process outlined in Appendix 11 for undertaking analysis to determine the buyback target. We have already highlighted, in our response on baselines, that understanding the potential buybacks under various supply scenarios impacts on baseline setting, as well as setting an appropriate target for operational buybacks. In advance of undertaking this analysis, we think that it is premature to propose that the downside sharing factor should be increased to 50% to reflect the reduced risk associated with separating the buyback incentives and increasing the caps and collars to £36m.

570 We believe that the range of potential supply scenarios over the next price control will increase the potential range of buyback costs and would therefore increase, rather than decrease, the risks under any incentive scheme. It should also be noted that the current buyback scheme was not set to include an allowance for new investment buybacks and therefore we would not see the separation of the buyback schemes as a valid reason to increase the downside sharing factor.

571 We look forward to working with Ofgem to develop a set of buyback proposals that have the appropriate balance of risk and reward and are consistent with the overall package of TPCR proposals.

Capacity Release Obligations

572 We note that Ofgem have revised the proposals relating to capacity release obligations in light of responses to the Third TPCR consultation. The new proposals retain the concept of baseline capacity release obligations defined for each entry point, but introduce formal mechanisms to enable unsold baseline capacity to be reallocated. Whilst we understand the objective, which is to enable existing capacity (which to some extent can be substituted between different points on the network) to be allocated to where it is most in demand, we believe further work is required to ensure that all the details and implications of moving to such a regime are fully understood. In particular further thought is required on:

(a) the proposed licence obligations where we would be keen to explore what is meant by '*fully explore reasonable substitution opportunities*'. Removing ambiguity from this statement will be important, given that Ofgem have stated that "*to the extent that NGG NTS fails to convince the regulator that it has made all possible transfers of capacity to utilise capacity efficiently then it will not be remunerated for incremental capacity provided as a consequence of its decision"* (paragraph 1.82 in Appendix 12 of the Initial Proposals). Having clarity on what the obligation means in practice and trying to avoid complexity, wherever possible, will also be extremely important for customers;

(b) reconciling the proposals relating to transferring existing capacity with the objective of building a network with flexibility. These elements can be seen as potentially conflicting objectives as transferring capacity will reduce the flexibility of the network over time. Obligations to transfer capacity will also have an impact on setting an appropriate operational buyback target as it will transfer capacity from nodes where there was an ex-ante expectation that gas would not flow to a node where gas is more likely to flow;

(c) the likely impact of the proposals on customers who rely on the short term release of capacity, such as storage operators and LNG. Under the initial proposals, these customers will effectively need to buy capacity in the long term auctions. This will need to be factored into the discussions on LNG funding which are taking place as part of the TPCR; and

(d) any costs associated with entering into a PWA that subsequently become redundant if capacity is transferred instead of proceeding with the investment. Operating costs (Network Analysis) associated with fulfilling these obligations will also need to be considered.

Gas Exit

573 As with gas entry, our main comments relate to **baselines**, **UCAs** and **other incentive targets** (e.g. new investment incentive and Constrained LNG incentives). Our main issues with the current proposals and a suggested way forward on each of the issues are detailed below:

Baselines

Issues with the current proposals

574 As mentioned in our previous responses we support Ofgem's view that a practical maximum physical (PMP) capacity approach is appropriate to determine the level of nodal baselines. However, having set this policy, it seems both inconsistent and inappropriate to set baselines in the South West above what would be implied by the practical maximum physical approach. The rationale for Ofgem's change in policy from the third consultation document is based on an assumption that it will be cheaper to enter into long term interruption contracts than invest. We do not believe Ofgem have justified this assumption. Furthermore, we believe the process of creating an obligation to release capacity above the current capability of the system is ultimately increasing costs to consumers as either the cost of investment or the cost of interruption would be greater than setting the baselines for interruptible customers in the South West to zero, in line with the current capability of the system.

Proposed Way Forward

575 We believe further work is required on this issue in advance of the September document to fully understand both the revenue and commercial framework implications of setting baselines in the south west.

UCAs

576 We welcome the proposed change from the March document, suggesting that revenue drivers (for both the transitional and enduring periods) should apply from the contractual delivery of capacity rather than upon physical delivery of capacity. However, we would wish to discuss Ofgem's proposal that some form of oversight is necessary in the transitional period as we are not sure what this proposal actually means in practice. In addition, we believe that there are some issues with Ofgem's current proposals which we discuss below.

Issues with the current proposals

577 Our main issue, which covers both the south west issue detailed above and the allowances proposed for connecting Pembroke and Grain power stations, is that allowances have been set below the cost of investment, as it is deemed that contracting for interruption will be more efficient than investing. We believe such an assumption is currently based on 'feel' rather than analysis. We acknowledge this area is currently untested and therefore difficult to provide any definitive analysis. In the event that Ofgem determine, through setting the UCA, that remuneration should be limited to the cost of interrupting relevant loads, then we would have no choice (given the potential for stranding risk associated with investment) but to explore the cost of interruption, with our potential exposure effectively being capped to 20% of the UCA (i.e. the difference between the 100% allowance for investing and the proposed 80% allowance for interrupting).

578 Whilst we acknowledge that we have indicated in our FBPQ that we do not currently anticipate DN investment outside of the south west quadrant, we do not agree that, in the event exit investment is required outside the south west quadrant, then this is dealt with via an Income Adjusting Event. We would, instead, propose that any unanticipated expenditure for DN growth should follow a similar mechanism to that proposed for unanticipated large exit projects in paragraph 1.86 of Appendix 16 of the Initial Proposals – i.e. a UCA would be determined by Ofgem, as required, on a transparent and timely basis.

579 Most of the issues (fixing UCAs, rolling incentives, a pure user commitment model and cash flow implications) described in the section relating to Entry UCAs equally apply to Exit UCAs. The issues are not therefore re-stated here.

Proposed Way Forward

580 In addition to the comments contained in the section above, we believe the proposed way forward described in the section on UCAs for gas entry to be equally applicable to gas exit UCAs.

Other Incentive Targets

581 We comment below on the new investment incentive in relation to gas exit, CLNG targets and transitional Offtake incentives:

(a) **New investment incentive.** The issues with the current proposals and the proposed way forward detailed in the section on gas entry equally apply to the proposals for the gas exit regime.

(b) **Constrained LNG incentive.** The current proposal to set the CLNG target at the 2008/9 level of £2.1 m for the remainder of the next price control period is unacceptable. We believe there are some fundamental issues surrounding the topic of LNG which need careful consideration as part of the price control process and it is therefore premature to quote initial targets for CLNG in isolation. The issues that need further thought and consideration before setting a target for CLNG are, in brief:

(i) **LNG funding.** The whole topic of LNG funding is being reviewed as part of the price control process. This will fundamentally review the need for LNG services, the potential for alternative providers and will examine the current pricing for services. Further discussion on the area of LNG funding is therefore required in advance of setting targets for operating margins and CLNG.

(ii) The **volume requirement** which feeds into the CLNG target is a function of both the investments allowed as part of the price control and the assumptions relating to gas flows on the network. It is therefore important to be clear on the assumptions being made in relation in these areas before setting CLNG targets.

We would therefore re-iterate that it would be inappropriate to merely roll over existing targets, given the interactions with other elements of the price control. The targets already set within the licence for CLNG for the interim period were based on an assumption that investments within the south west quadrant (as outlined within our FBPQ submission) would be funded via the TO price control. Ofgem's policy is now for these investments not to be automatically funded. We therefore think that it would be appropriate to review the targets in the light of the current policy.

(c) **Transitional offtake incentives.** We broadly agree with the content of Ofgem's initial proposals in respect of the incentives to apply in the transitional period. However, there are two areas (in addition to CLNG which is covered in the section above) with which we still have concerns:

(i) **>15 day interruption incentive.** We do not agree that the target for this incentive should be zero as Ofgem are effectively creating yet another purely penal incentive scheme, with risks on us but with no commensurate reward. We agree with Ofgem that it is unlikely that the NTS would interrupt sites for >15 day for its own purposes but, as previously outlined to Ofgem, the costs which the NTS could face are not totally within its control; they are dependent (under the current arrangements) on the amount of interruption called by the DNs. Therefore, given that the DN interruption regime is currently under review, it would seem more sensible to remove the incentive for these payments on the NTS and to treat any costs incurred as pass through items.

(ii) **Removal of NTS buyback incentive.** As previously stated, we do not agree that this incentive should be removed. We continue to believe that there should be a means to recover any costs incurred in the event of our UNC liabilities. We note that Ofgem have stated that we could apply the income adjusting event provisions but, for that to be the case, we would wish that the £2m threshold be reduced.

Electricity

582 The section below sets out our views on the proposed adjustment mechanisms and incentives relating to electricity. As in our above response on gas issues, we would like to emphasis that we continue to support the policy of revenue drivers as a mechanism to deal with the uncertainties associated with load related capex in electricity. We would agree that the detailed design of the revenue driver mechanisms is still at the development stage and the development of the proposals requires further input from the licensees.

583 We believe that, following further dialogue and analysis as part of the price control process, it should be possible to amend the proposals. A description of our main comments on the current proposals, relating to **revenue drivers** and **incentives (system performance and innovation incentives)**, and a suggested way forward on each of the issues is detailed below:

Revenue Drivers

Comments on the current proposals

584 Our main comments on the current proposals are as follows:

(a) **Baselines.** We agree with the principles behind the current proposals relating to baselines (or more specifically, the assumed central scenario), which add the TIRG baseline projects and a number of additional deep reinforcement projects that have been allowed for as part of the TO allowance, onto the existing physical network. However we believe further work is required to fully understand the additional deep reinforcement projects allowed in the baseline allowance, such that the baselines and revenue drivers are set in a consistent manner with the TO allowance.

(b) **Revenue drivers.** We welcome the proposal for revenue driver options to be further developed in conjunction with the transmission licensees for more quantitative description in the September document. Our initial view would be that there is merit in adopting a simple functional form (i.e. a zonal £/kW UCA) and addressing the resulting inaccuracies by only applying the revenue driver to a proportion of costs - with the remainder of costs being allowed to be passed through. Although the simple functional form would mean that the connection and infrastructure components of a two-part driver would have very similar form, we agree that there are benefits in keeping these elements distinct in order to better define the baselines.

(c) **Trigger for revenue drivers.** We support the current proposals being developed on the trigger point for the revenue driver (i.e. based on a level of user commitment) and the timing of revenue allowances (i.e. a multi-stage mechanism). We would support the multi-stage mechanism, with the 'pass through' mechanism trailing costs with a lag of one formula year and the '£ per MW' being recoverable from contractual delivery. We believe that, for both consistency and financeability reasons, the same mechanisms should be considered in relation to the gas proposals.

(d) **Lumpiness.** We are pleased that Ofgem recognise that there may be large investments where it might be efficient for companies to respond to the need for additional capacity by investing a way which 'over-provides' capacity in the first instance (paragraph 10.14). This is because efficient transmission can involve large 'lumps' of new capacity being provided, eg if a new line is needed. In these circumstances there is a likelihood that the revenue adjustment will be too low if it is based on the average cost of providing the amount of additional capacity required by immediate users. We note the options to address this issue including the concept of a 'revenue driver adjustment event' (RDAE) mechanism to allow the companies to apply for the relevant revenue driver to be based on the additional capacity being provided rather than by the additional capacity being demanded by users. We believe this is worth further consideration for both electricity and gas in addition to considering the alternative option which would rely on the pass through mechanism detailed above.

(e) **Interaction of generation and demand.** Finally, our main concern with Ofgem's proposals (that the deep reinforcement revenue driver should be set on the basis of generation net of peak demand and act to both increase and decrease revenues) is that such an approach is likely to act in an inappropriate fashion under many circumstances unless additional features are incorporated. For example:

(i) Widespread demand growth across an area may not significantly reduce the reinforcements required to accommodate a new power station at a particular location. (A netting between new generation, closures and new demand should only be made where there is substitutability between nodes).

(ii) A driver which correctly reflects the beneficial effects of new demand in an area where new generation needs to be accommodated will tend to reduce revenues if that new demand occurs and the generation does not connect. (In exporting areas, new demand may offset future reinforcement costs but will not reduce already sunk costs).

(iii) A driver which correctly reflects the beneficial effects of new generation in an area where new demand needs to be accommodated will tend to reduce revenues if that new generation occurs but demand growth does not occur. (In importing areas, new generation may offset future reinforcement costs but will not reduce already sunk costs).

Proposed Way Forward

585 We are keen to contribute to further work on all of the issues described above in advance of the September document. Work is particularly required in relation to (e) above on the workings of the deep reinforcement revenue driver in order to ensure that the revenue driver provides a reasonable ex-ante view of likely investment costs (and any potential savings). In particular, the definition of suitable zones and the choice of cost adjustment factors which reflect the asymmetric impacts of departures from assumed developments will be important in developing a workable regime.

System Performance

586 We are disappointed that Ofgem's Initial proposals are proposing to move to a 'penalties only' scheme. We continue to 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). However, on the basis that Ofgem have rejected our representations and are proceeding with a penalties only scheme, the potential of a loss without any potential upside will need to be taken into account in setting the cost of capital. Such a scheme would fit what Brealey and Myers refer to (in their standard corporate finance textbook) as a 'bad outcome risk' which needs to be compensated for through additional revenue.

587 It will also be necessary to review all other aspects of the scheme such as National Grid's total exposure, the appropriate target and excluded events which will need to take into account the allowances being made in relation to capex and the fact it is a penal only scheme.

Annex to Chapter 4

Entry Baselines

Background

588 Ofgem have published within the Initial Proposals document[17] their proposals for baselines based on network analysis provided by National Grid. These baselines are calculated by taking the average of the 'baseflow' for each entry point and adding to it 90% of the average 'free increment' at each entry point (with the averages calculated over the three TBE supply scenarios, Transit UK, Global LNG and Auctions +). This methodology produces baselines that are in some cases higher than the current licence baselines and sometimes lower, but in aggregate are significantly in excess of analysis of zonal best and worst capabilities of the system which had been shared with Ofgem[18].

589 This note outlines our concerns with the approach adopted by Ofgem and provides our initial view of a more appropriate set of baselines which could apply. **However, it should be noted that this view of baselines does not equate to a zero buyback risk since our proposals are above our view of the worst capability of the system**.

Concerns with Ofgem's methodology

590 We have several concerns over Ofgem's methodology for calculating the proposed baselines. These include the following:

(a) As we previously indicated in our response to the March document, it is wholly inappropriate to add the 'free increment' to the 'baseflow' on the network (or indeed 90% of it). By calculating the baselines in this manner, the 'free increment' amounts have been counted several times and system capability has been greatly over stated;

(b) We believe that a more appropriate manner of setting nodal baselines is to consider the capability of the system at a zonal level and then to disaggregate to nodes after identifying the zonal constraints; and

(c) The proposed baselines do not take into account previously released obligated incremental entry capacity which has been signalled through the auction process. This seems inappropriate and inconsistent with Ofgem's Initial proposals relating to investments being backed by 'user commitment' for that level of capacity.

Rationale for Concerns and our Proposals

591 Examination of the data contained within the Initial Proposal document shows that the total of the proposed nodal baselines is far in excess of the physical capability of the system for the reasons outlined in the following paragraphs.

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[17] Transmission Price Control Review: Initial Proposals (104/06, 104b/06, 104c/06 and 104d/06), Ofgem 26 June 2006

[18] Contained within a Gas Entry Capacity Baselines presentation by National Grid on 25 April 2006 to Ofgem which has been reproduced in the Appendix

592 The Ofgem methodology seeks to optimise flow from each entry point in turn and therefore does not recognise the interconnectivity of the network. This can lead to the identification of 'free increments' for entry points that, if utilised at one location, should no longer be available at other entry points. The methodology therefore inherently overstates the capability of the NTS.

593 As part of the information shared with Ofgem, we indicated that in order to assess the capability of the NTS, we needed to consider the constraints on the system which are common across groups of nodes on the system. This analysis resulted in the calculation of zonal best and worst cases, a summary of which is shown in the table below with the full results tables reproduced in the Appendix.

Zones[19]	Zonal Capabilities at peak (GWh/d)		Zonal Capabilities on cold winter day (GWh/d)	
	Best Case	Worst Case	Best Case	Worst Case
East Coast	4127	3338	[redacted]	[redacted]
Northern Triangle	3142	1895	[redacted]	[redacted]
West UK	958	958	[redacted]	[redacted]
Total over these zones	**8227**	**6191**	**6431**	**4747**

594 As can be seen from the table above, network capability is not fixed across the year as it is highly dependent on the demands on the system. Analysis at demand days lower down the demand curve shows that the total capability of the network over these zones could drop as low as 3878 GWh/d.

595 Using the same definition of zones, the following table summarises Ofgem's Initial Proposals data and the current existing licence baselines:

[19] The definition of the zones is shown in the Appendix

Zones	Zonal Capabilities (GWh/d)	
	Ofgem's IPs	Existing Licence
East Coast (comprising):	5306	4757
Easington Area	2310	1711
South East Area	2545	2198
Theddlethorpe	451	848
Northern Triangle	3123	3249
West UK	878	1000
Total over these zones	**9307**	**9006**

596 As can be seen from the above two tables, **Ofgem's Initial Proposals baselines result in capability which is far in excess of our 'Best Case' analysis** (at either Peak or on Day 50 and also further down the demand curve). However, it should also be remembered that in order to arrive at Practical Max Physical (PMP) baselines, the 'Best Case' amounts in each zone cannot happen co-incidentally (as these figures are arrived at by effectively minimising the flow through the other entry points), so a total of 8227 GWh/d in aggregate for these zones is **not** achievable and indeed would leave a non trivial degree of buy back risk with NGG NTS and under the current arrangements also ultimately with end consumers.

597 Given that our obligations to offer capacity for sale exist for each gas day within the year up to and including the gas day, it is clear that any baselines set above the worst case capability on the lowest forecast demand day lead to a degree of buyback risk. However, in order to arrive at acceptable baselines which we believe are reflective of the PMP capability of the system under 'credible' supply and demand scenarios and which reflect existing auction commitments, we have examined these 'Best Case' and 'Worst Case' figures and have concluded that the zonal capabilities as indicated in the following table are set at an appropriate level.

Zones	Zonal Capabilities (GWh/d)
East Coast, set at	4127
with sub-constraints of:	
Easington Area	1679
South East Area	2221
Theddlethorpe	275
Northern Triangle	1895
West UK	958
Total over these zones	**6980**

598 It is clear that there are several ways of apportioning these zonal totals back to the nodes which are comprised within the zones, however, we present below a disaggregation of the zonal totals above, taking into account both the limit of the East Coast zone being a constraint which affects the two sub-zones (Easington Area and South East Area) which are comprised within it and also the existing auction signals which we have received through long-term auctions held to date.

599 The following table shows National Grid's initial views of what would be a more appropriate set of baselines and for comparison; we have also included Ofgem's Initial Proposal figures and the existing licence baselines:

ASEP	Ofgem's Initial Proposals		Existing licence baseline	National Grid Proposal[20]
	Mscm/d	GWh/d	GWh/d	GWh/d
Easington	136	1473	1062	1062
Hornsea	20	221	175	175
Garton	24	255	420	420
Hatfield Moor (storage)	33	360	54	22
Theddlethorpe	42	451	848	227
Bacton	196	2120	1745	1768
Isle of Grain	39	425	453	453
Barrow	62	669	712	240
Teesside	63	685	761	234
St. Fergus	163	1769	1677	1342
Cheshire	44	480	214	214
Hole House Farm	25	266	26	26
Burton Point	24	260	55	55
Milford Haven	81	878	950	950[21]
Barton Stacey	21	232	50	90
Total over these nodes	**973**	**10544**	**9292**	**7286**

[20] These baselines are based upon investment within the PCR to increase capability up to the existing licence baselines for Bacton, Easington and Isle of Grain with no further investment assumed. We are still to confirm the capex assumptions underlying Ofgem's baselines.

[21] From October 2007 until December 2008, the baseline should be 650GWh/d - and 950GWh/d from January 2009 onwards - in accordance with our obligations stemming from the long term capacity auctions.

We look forward to further discussions with Ofgem to meet the common objective of setting entry baselines at a level consistent with the practical capability of the system.

Definition of zones

Zone	Constituent Parts
East Coast	Easington Area
	Theddlethorpe
	South East
Easington Area	Easington
	Hornsea
	Garton/Aldborough
	Hatfield Moor
South East	Bacton
	Isle of Grain
Northern Triangle	St. Fergus
	Glenmavis
	Teesside
	Barrow
West UK	Milford Haven
	Dynevor Arms

5 Pensions

600 The pensions issues covered by Initial Proposals are as follows:

(a) the legacy / Centrica liabilities issue;

(b) treatment of ERDCs; and

(c) past over and under funding.

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

The legacy / Centrica liabilities issue

Ofgem's Position

602 Ofgem's stance is set out in paragraphs 8.9 and 8.10 of Initial Proposals. These state that "We only intend to provide an allowance to cover the proportion of deficit repair costs that relate to businesses that are regulated now i.e. we will disallow the Centrica figure…However, as previous price control allowances implicitly took account of scheme surpluses arising in part from past contributions relating to Centrica and other non-regulated activities, we also propose to assess the impact this surplus may have had on previous price control allowances and to allow for this when assessing deficit funding."

Our response

603 In respect of Ofgem's stance that they will not fund legacy pension costs, we remain concerned that Ofgem have still not publicly addressed most of the arguments that we have raised.

604 The legacy pensioners issue is highly important for this and future price control reviews because the proportion of the LGPS associated with former employees who performed activities now carried out by Centrica is significant, and would be expected to decline relatively slowly over time. In this context, we believe that there needs to be a proper process of consultation in order to provide transparency, and that this process cannot be undertaken without Ofgem considering publicly all the arguments.

605 A summary of National Grid's key arguments as to why legacy pension costs should be funded is as follows:

(a) It was not possible for British Gas (BG) to act in any way other than to keep all pensioners and deferred pensioners within the LGPS, which was in substantial surplus at the time.

(b) That surplus has been used by Ofgem and the MMC for the benefit of Transportation customers.

(c) 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 hindsight.

(d) Ofgas actively encouraged the transaction, an inevitable consequence of which was that pensioners and deferred pensioners remained with the LGPS. The 1993 MMC inquiry was held largely because Ofgas wanted BG's supply and transportation activities to be separately owned. Even after the President of the Board of Trade decided in December 1993 that divestment would not be required, the DG of Ofgas continued to urge that transportation be demerged from supply, the evidence for which we have given to Ofgem.

(e) To penalise National Grid now for this decision would be inconsistent with:

(i) the regulatory treatment adopted at the last two price control reviews; and

(ii) 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.

606 We believe that the above represent strong arguments, significantly stronger than those of the companies in DPCR4, for why legacy pension costs should be allowed in this and future price control reviews.

607 If, however, and despite the above arguments, Ofgem remain determined not to allow legacy pension costs, we acknowledge and welcome Ofgem's recognition that past price controls have been set using the legacy element of the surplus for the benefit of transportation customers, and that the legacy disallowance needs to be adjusted for this effect.

Treatment of ERDCs

Ofgem's Position

608 In Initial Proposals, Ofgem's stance on ERDCs is closely linked to their position on under and over funding of pension schemes as compared to historic regulatory allowances, and is explained between paragraphs 8.11 and 8.14 of the Initial Proposals.

609 The document places Ofgem's present views on these issues for Transmission businesses in the context of their decisions for the DNOs, as set out during DPCR4, at the end of which Ofgem disallowed 30% of past unfunded ERDCs[22].

610 Turning to the transmission companies, the document states that Ofgem intend to disallow 100% of unfunded ERDCs because some of these companies appear to have more robust pension data than the DNOs.

Our response

611 National Grid's response on the ERDCs issue can be divided into four main areas as follows:

(a) the need for Ofgem to address our arguments;

(b) comparison with DPCR4;

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[22] Ofgem, Electricity Distribution Price Control Review Final Proposals, November 2004, para 8.20

(i) inconsistency with Ofgem's stance in DPCR4;

(ii) Ofgem's rationalisation for its change of stance since DPCR4;

(iii) the issue of how the integrated Scottish companies are to be treated;

(iv) reasons why claw-back should be less than under DPCR4; and

(v) the position in the round.

(c) disincentives for regulatory co-operation; and

(d) rates of lost return.

The need for Ofgem to address our arguments

612 In respect of Ofgem's stance on unfunded ERDCs, as for legacy pension costs, we remain concerned that Ofgem have still not publicly addressed most of the arguments which we have raised in our responses to previous consultation papers. Given the importance of the issue for this price control review, 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.

Comparison with DPCR4

Inconsistency with Ofgem's stance in DPCR4

613 In Initial Proposals Ofgem have proposed a 0% allowance of past unfunded ERDCs, whereas in DPCR4, which concluded 20 months ago, Ofgem allowed 70% of unfunded ERDCs up to 31st March 2004. Ofgem made it clear in DPCR4 Final Proposals that[23], after this point, ERDCs would wholly be for the account of shareholders.

614 One factor which makes Ofgem's change of approach particularly surprising, is that the approach to the ERDC issue in the DNO review was not developed over a short period of time, but rather after a lengthy process of consultation, which began in the Network Monopoly Price Controls paper of February 2003[24], and ended in Final Proposals for DPCR4 of November 2004[25], nearly two years later.

615 Below we consider whether the change in Ofgem's change since DPCR4 can be justified rationally by the circumstances of the case.

Ofgem's Rationalisation for its change of stance since DPCR4

616 In the Initial Proposals, Ofgem state that they disallowed 30% of past unfunded ERDCs in DPCR4 because:

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[23] Ofgem, DPCR4 Final Proposals, November 2004, para 8.21

[24] Ofgem, Developing Network Monopoly Price Controls Update Document, February 2003, para 7.29

[25] Ofgem, Electricity Distribution Price Control Review, Final Proposals, November 2004

(a) in DPCR4 Ofgem could not retrospectively implement its “unders and overs” regime due to data quality issues; and

(b) a 30% disallowance gave the right answer “in the round”.

617 We believe that the explanation given for Ofgem’s stance in DPCR4 is incomplete, misleading and inconsistent with the explanations provided in documents published by Ofgem at the time. It is just incorrect, on the basis of the documents published by Ofgem at the time, to say that data quality issues in DPCR4 caused Ofgem not to be able to implement its “unders and overs” regime retrospectively, and that this caused Ofgem to only disallow 30% of past unfunded ERDCs. Furthermore, the explanation offered in the Initial Proposals is completely at odds with that published by Ofgem as part of the present Gas Distribution Price Control Review (GDPCR)[26].

618 When considering how Ofgem developed their stance on ERDCs during DPCR4, it is necessary to review what was stated by Ofgem during DPCR4 - the key documents being those of March, June, September and November 2004. For reasons of length, what was said in those documents is shown in the annex at the end of this chapter.

619 What does the evidence show? It shows that, in total, Ofgem gave four reasons why they changed their stance from disallowing 100% of unfunded ERDCs to disallowing 30%:

(a) because, in Ofgem’s view the treatment of unfunded ERDCs was not clear in earlier price controls;

(b) because mathematically, consumers had the greater part, around 70%, of the present value of opex savings arising from severance programmes;

(c) to reinforce the low risk position of the DNOs; and

(d) because it would not have been efficient for companies to have paid ERDCs at the time.

620 One reason **not** given was because Ofgem could not apply its “unders and overs” regime retrospectively. Indeed, given that Ofgem made the decision not to apply its “unders and overs” regime retrospectively in March 2004[27], but did not adopt the 70 / 30 treatment of unfunded ERDCs until September[28] of that year, two consultation papers later, purely as a matter of timing it would seem highly improbable that the two were linked.

621 The above evidence is reinforced by Ofgem themselves in the GDPCR consultation paper, published on 17th July 2006. In paragraph 5.27, it is stated that “Within DPCR4 final proposals, an allowance was given which split the cost of ERDCs between consumers and shareholders on a 70:30 basis. This was on the basis that the costs of ERDCs had not been considered at the time of the previous review, and that the benefits had also been shared between consumers and shareholders. In addition, this was to reinforce the low risk characteristics of the electricity distribution businesses.”

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[26] Ofgem, Gas Distribution Price Control Review, Second Consultation Paper, July 2006, para 5.27

[27] Ofgem, Electricity Distribution Price Control Review, Policy Document, March 2004, para 7.41

[28] Ofgem, Electricity Distribution Price Control Review, Update Paper, September 2004, para 5.17

622 In summary, the above evidence, both from Ofgem's documents published at the time of DPCR4, and also from the latest GDPCR document, demonstrates that the stance in Initial Proposals of disallowing 100% of unfunded ERDCs for Transmission companies cannot rationally be linked back to the policy of disallowing 30% of these costs in DPCR4. Consequently, Ofgem's proposed policy for transmission companies is inconsistent with its policy for DNO's without good reason, or, least, for no good reason set out in the Initial Proposals.

The issue of how the Integrated Scottish Companies are to be treated

623 One bizarre consequence of treating transmission companies differently to distribution companies without good reason is highlighted by the case of the two Scottish companies which carry out both transmission and distribution activities, typically with a common workforce.

624 Presumably, if these companies report actuarial deficits in DPCR5, then, as for the other DNOs in DPCR4, 30% of past unfunded ERDCs will be disallowed in respect of their distribution related activities. In contrast, in this and future transmission price control reviews, if these same companies have deficits Ofgem will propose to disallow 100% of past unfunded ERDCs in respect of their transmission related activities.

625 If Ofgem do not adapt their present position, a single past severance programme which has given rise to unfunded ERDCs, carried out on a common workforce at a given point in time, will be subject to very different regulatory treatments. That proportion of the cost which happens to be allocated to Transmission will be subject to a 100% disallowance, whereas that proportion of the cost which happens to be allocated to Distribution will be subject only to a 30% disallowance. This does not appear to be a sustainable position.

Reasons why claw-back should be less than at DPCR4

626 The above arguments set out why we believe that there are no valid grounds for Ofgem's present approach of treating National Grid less generously than the DNOs. In fact, we believe that the reverse is true, and that there are good reasons why National Grid should be treated more generously than the DNOs. In particular, 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' past 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[29], 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.

[29] National Grid, Transmission Price Control Review – Second Consultation Paper, Response by National Grid on pensions issues, January 2006

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

(i) As Ofgem have previously acknowledged[30], 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 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 1994/95 to 1996/97. 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, in the March 2004 DPCR4 consultation paper[31] believed that they had probably underpaid as compared to regulatory allowances.

The Position in the Round

627 In the DNO Price Control Review, for those companies with pension deficits, after deductions for unfunded ERDCs and legacy pension costs, on average 72% of the deficit was passed through to consumers, with a range of 61% to 100%[32]. During the DNO review, in respect of pension issues, Ofgem often described their approach as "proportionate", "reasonable" and "pragmatic".

628 In contrast, in these Initial Proposals, for NGG, around 17% of the Transmission related deficit is proposed to be allowed, and for NGET, around 52% of its projected deficit. For neither company, does Ofgem's proposed recovery rate come close to even the lowest of those for the DNOs, let alone the average.

629 There would also seem to be an implicit recognition by Ofgem that their proposed approach to pension issues is not "proportionate", "reasonable", or "pragmatic" as these terms are conspicuous by their absence in this document. The phrase "in the round" does appear, however this is a description of the DPCR4 outcome, rather than of Initial Proposals.

630 We have provided a number of arguments (see above) why the circumstances of National Grid should lead to a higher proportion of pension deficit costs being recoverable than for the DNOs, and yet Initial Proposals suggests a far harsher treatment.

Disincentives for Regulatory Co-operation

631 As set out in paragraphs 608-610 above, in the Initial Proposals Ofgem link the robustness of the data of some transmission companies to the proposal to disallow 100% of unfunded ERDCs. Given that National Grid is the only company with a

[30] Ofgem, Transmission Price Control 2007-2012: Third Consultation, March 2006, para 8.33

[31] Ofgem, DPCR4 Policy document, March 2004, para 7.39

[32] Ofgem, DPCR4 Final Proposal, December 2004, page 170

pension deficit, we believe that the "robust data" is likely to be, or at least to include, ours.

632 The area of historic pensions treatment is highly complex, in some areas subjective, and given the passage of time since many of the events happened, information is difficult to access, typically being held in paper form in archives, rather than in a computerised form.

633 We have put a considerable amount of time, effort and money into putting together the most robust information we can in order to assist the price control review. This has taken the form of:

(a) searching for, reviewing and retrieving old electronic files and paper documents from various organisations' archives;

(b) making heroic assumptions to reconstruct information in the form required by Ofgem where information is not held in that form;

(c) commissioning reports from actuaries[33] in order to provide additional information for the price control; and

(d) incurring additional costs associated with accelerating the timetable of the gas scheme actuarial valuation to better fit in with the price control timetable.

634 It would have been easier, and less costly, not to have searched so hard for old information, to have avoided making heroic assumptions in order to recut data for Ofgem and merely stated that it did not exist in that format, not to have commissioned additional actuarial reports, and not to have accelerated the timetable for the gas scheme actuarial review.

635 According to Initial Proposals, the "reward" we are to receive for our effort is to have 100% of our unfunded ERDCs disallowed, whereas if our data had been worse, only 30% would have been disallowed.

636 This sends out a clear message that in areas such as this, it is not in companies' interests to "go the extra mile" in order to provide the best information possible to Ofgem or, to put it more bluntly, Ofgem's proposals in this area seem to offer a strong incentive to companies to be dishonest in providing information for price reviews.

Rates of Lost Return

637 In Ofgem's calculations, a rate of lost return is used to update past use of surplus into today's terms. We believe that the discount rate used in Ofgem's calculations is that of the WM universe of pension schemes, which is higher than the actual returns of NGET's section of the ESPS and the LGPS.

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[33] Watson Wyatt reports "Apportionment of liabilities in respect of pre 31.3.98 leavers between former Centrica and BG / Lattice employees" dated 9th December 2005: "Report setting out advice to National Grid plc on the possible employers' contribution requirements stemming from the 2006 actuarial valuation" dated 26th May 2006: "Report setting out preliminary advice to National Grid plc on the possible employers' contribution requirements stemming from the 2006 actuarial valuation" dated 21st November 2005: Hewitt Bacon and Woodrow reports "Regulatory Projections" dated 12th December 2005: "Regulatory Projections" dated 25th May 2006

638 The reason it is higher is because pension schemes have different weightings of the various classes of asset, most notably between equities and bonds, depending largely on the profile of their liabilities, and typically less mature pension schemes than either of those of National Grid will have higher equity weightings, which would be expected to lead to higher but more volatile returns.

639 During the DNO Price Control Review, we believe that Ofgem used a "DNO average" scheme return. This was expected to be a good proxy to each scheme's rate of lost return, given that all of these pension schemes are associated with employers in the same industry, and are even in the same overall pension scheme, the ESPS.

640 If, as we believe, Ofgem's intention is to reflect the position which would have arisen had ERDCs been funded, then in the case of NGG and NGET, it is equitable and straightforward to apply each scheme's own rate of return, rather than a less accurate proxy. These figures are typically provided in the scheme accounts, of which Ofgem have a copy.

Past Over and Under Funding

Ofgem's Position

641 Ofgem's stance is described in paragraphs 8.12 to 8.14 of Initial Proposals, which state that Ofgem wish to calculate Past Over and Under Funding retrospectively if they can, although Ofgem have yet to finalise their view.

Our response

642 Our views on this issue can be divided between those on:

(a) whether the regime should apply before the present price control period; and

(b) what costs should be included.

643 In respect of **past** price control periods, we think that the over and under funding regime should **not** go back beyond the present price control period because:

(a) At a general level, the repeated review by Ofgem of a given past action is not good regulatory practice, it increases regulatory risk and consequently the return required by investors.

(b) Ofgem have previously stated that they did not intend for the regime to operate for Transco prior to 31st March 2002, and for the electricity transmission companies prior to the next price control periods[34].

(c) Probably more decisive than either of the above, although, using certain assumptions, it is possible to calculate what the actual level of cash costs has been for the regulated business, it would not seem possible (with the probable exception of Transco from 1997-2002) to calculate the level of regulatory allowance in a reliable manner. **The data does not exist.** This was highlighted during DPCR4 when Ofgem, who are in the best position to access whatever data does exist, used three different techniques to estimate regulatory allowances, which gave three significantly different answers.

[34] Ofgem, DPCR4 Policy Update, March 2004, para 7.41

Ofgem's recognition of the folly of basing material adjustments to allowed revenue on such calculations led to the decision not to implement the "unders and overs" regime except where there was an explicit allowance[35].

644 If, however, it were possible to perform robust calculations for periods prior to the present price control period, we believe that NGG in particular would have paid more into its pension scheme than assumed when price controls were set. This largely due to the payment of £275m into the LGPS on 31st March 2002, and also the payment of over £700m of pension related severance costs between 1994/5 and 1996/7.

645 In respect of the **present** price control period, we believe that the regime should not apply to **NGET** because:

(a) Ofgem have previously stated that the regime would not apply to the electricity transmission companies before the next price control period (see paragraph 643b above).

(b) There was no explicit pension costs allowance in this price control period, although, using a number of assumptions, an approximate figure could be calculated.

(c) Unlike for NGG (see below), there has been no history of events leading to an understanding that there could be any recovery of under or over provision.

646 In respect of the present price control period, we believe that the regime **should** apply to **NGG** because:

(a) It is the only price control review for which an explicit allowance for pension costs was given.

(b) That has been Ofgem's previous position, a position which has been developed over a significant period of time.

647 The stages in the development of Ofgem's policy are set out below:

(a) At the end of the last NGG price control review, pensions had been such a big issue that Ofgem gave the company a "letter of comfort"[36] in which Ofgem stated, that if material additional pension costs were incurred, "it would be prepared to consider re-opening the price control, but would not guarantee so doing in those circumstances".

(b) After the last NGG price control review Ofgem developed their pension policies more generally in both the Developing Network Monopoly Price Control series of consultation papers, and also during the DNO Price Control Review. From an NGG perspective, this led to the position within the March 2004 DPCR4[37] document that, although Ofgem would like to measure "unders and overs" since privatisation, for the DNOs, due to difficulty in assessing what allowances were made in previous price controls, Ofgem

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[35] Ofgem, DPCR4 Policy Update, March 2004, paras 7.38 - 7.41

[36] Ofgem, Summary of Letter of Comfort, October 2001

[37] Ofgem, DPCR4, Policy document, para 7.41

would do not so for periods prior to 31st March 2005, and for NGG it would not do so for the period prior to 31st March 2002.

(c) Subsequently, in the Addendum to the Ofgem position paper on pensions of August 2004[38], produced as part of Network sales, Ofgem confirmed that the "unders and overs" regime would apply to gas networks in this price control period as follows "Contributions made to an occupational pension scheme in respect of attributable DN employment performed in the future will be eligible for recovery from future price controlled revenues. To the extent that, in any particular period, the amounts contributed exceed or fall short of the amounts recovered (i.e. the allowance) the excess or shortfall will be taken into account in setting subsequent controls. The same principle will be applied to DN employment performed in the current price control period prior to the date of sale."

648 In respect of which costs should be included, we believe that the regime needs to include the relevant proportion of related party costs, as stated previously by Ofgem[39], and also severance related pension costs. We believe that the latter should be included because:

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

(b) To do otherwise would probably entail NGG being treated more harshly than the DNOs, assuming that Ofgem ultimately follow the precedent of DPCR4 and allow the recovery of a proportion of unfunded ERDCs. This is because, in these circumstances, NGG would only lose a proportion of any non-payment of ERDCs, whereas, in contrast, if no credit is given for ERDCs paid in this period, NGG would lose the whole amount.

(c) Ofgem have previously stated or implied that ERDCs would come under the scope of the "unders and overs" regime, either in whole or in part. In the June 2004 paper of DPCR4[40], Ofgem stated that "The March 2004 document explained that, in principle, there should be an adjustment for over/under funding for both ERDCs and normal contributions." By the time of DPCR4 Final Proposals, Ofgem had changed their view such that, only for those ERDCs incurred prior to 1st April 2004, would costs be met in the main by customers[41]. The latter position has just been reiterated in GDPCR as follows "We consider that it is appropriate from 1 April 2004 to apply the principle of disallowing the cost of ERDCs within GDPCR as part of the overall review of pension allowances."[42]

(d) If, as Ofgem stated in DNO Final Proposals[43] (although we understand this may change), the "unders and overs" regime will work by comparing the £m

[38] DN Sales: Ofgem position on pensions – supplement 9/8/2004

[39] Ofgem, DPCR4 Final Proposals, December 2004, para 8.28

[40] Ofgem, DPCR4 Initial Proposals, June 2004, para 7.21

[41] Ofgem, DPCR4 Final Proposals, para 8.21

[42] Ofgem, GDPCR Second Consultation Paper, July 2006, para 5.27

[43] Ofgem, DPCR4 Final Proposals, November 2004, para 8.28

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.

649 We have already submitted figures to Ofgem showing a pensions asset which should be recoverable in gas transmission, of around £245m in respect of this price control period.

Summary

650 We believe that there are strong arguments why customers should fund legacy/Centrica related pension liabilities, although we acknowledge and welcome that Ofgem have recognised that past transportation price controls have been set using the benefit of the legacy/Centrica surplus for customers.

651 In respect of the stance within Initial Proposals on unfunded ERDCs, not only does this completely contradict Ofgem's position (and the basis for that position) in DPCR4 for no good reason, but also we believe that there are strong arguments why the treatment of National Grid should be less harsh than for the DNOs.

652 In respect of Ofgem's position on the "unders and overs" regime, we firmly believe that the regime should be applied to NGG for this price control period. However, for all of NGET's price controls to date, and those of NGG before the present price control, we do not believe that it is desirable, or in most instances even possible, for the regime to be applied.

Annex to Chapter V

DPCR4 TREATMENT OF ERDCs

653 In the March 2004 document[44], Ofgem decided not to make an over/under funding adjustment for the period prior to 31 March 2005 for the reasons given in paragraphs 7.38 to 7.40, i.e. that;

(a) Quantification of over / underspend was difficult because, except for Transco in 2001, price controls did not contain specific allowances, although Ofgem believed that, over the period since 1995, DN's had probably contributed substantially less than was envisaged in setting the price controls (paragraphs 7.38, 7.39).

(b) Responses to the December 2003 paper had been generally opposed to any historic adjustment (paragraph 7.40).

(c) Ofgem were conscious of the desirability of achieving an appropriate balance in the overall treatment of pension deficits (paragraph 7.40).

654 The March 2004 document also addressed the issue of unfunded ERDCs in paragraphs 7.43 to 7.45. Here Ofgem stated that they interpreted the actions of companies which had not paid ERDCs as a being a deferral rather than an avoidance of cost in the absence of any agreement with Ofgem. Consequently, Ofgem were still not minded to allow any ex post pass through of these costs, although Ofgem would consider any new evidence or arguments put forward.

655 Paragraph 7.45 does link over/underfunding to unfunded ERDCs, stating that "In the context of the proposals for underfunding set out above, Ofgem considers that the approach proposed on the combination of issues represents, in overall terms, a proportionate approach to dealing with the costs of deficits that have arisen over the last few years."

656 In short, the March 2004 document stated that Ofgem would not retrospectively implement the "unders and overs" regime, that they were minded to disallow 100% of unfunded ERDCs, and that these represented a proportionate approach.

657 In the June 2004 document[45], in paragraph 7.21 Ofgem maintained the position of being minded not to make adjustments on under/over funding retrospectively, as it was difficult to quantify the allowance in previous price controls.

658 In respect of ERDCs, in paragraphs 7.22 to 7.25 the Ofgem position began to shift. An alternative approach was described in which the benefits of cost reductions associated with severances were shared between companies and consumers, pro-rata to the present value of opex saving – typically 70% belonging to consumers. Consequently, the argument followed that 70% of the cost of unfunded ERDCs should also be passed to consumers, and 30% passed to companies.

659 Although in this document Ofgem adhered to the disallowance of 100% of unfunded ERDCs, the ground had been prepared for a change. In paragraph 7.24 Ofgem:

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[44] Ofgem, DPCR4 Policy document, March 2004

[45] Ofgem, DPCR4 Initial Proposals, June 2004

(a) acknowledged that the treatment of unfunded ERDCs had not been clear in earlier price controls;

(b) acknowledged that it would have been inefficient for companies to fund ERDCs where they had not needed to; and

(c) in respect of the argument that 70% of the cost should be borne by consumers in line with the benefits of opex reduction, stated that this “may have some merit”.

660 In the September document[46], Ofgem adopted the treatment whereby companies were able to recover 70% of unfunded ERDCs. Ofgem explored mathematical arguments which could have led to the companies’ share of the benefit of opex reductions to be between 18% and 50%, but settled on 30%.

661 The decision to choose 30% was explained in paragraphs 5.16 and 5.17 “However, it is important to consider that the issue of pension deficit recovery in the context of the overall balance of risk and reward in the price control. For example, the capital asset pricing model contends that the risks that increase a company’s cost of capital are those which are correlated with market returns. Distribution companies are generally low risk in this context, but their pension funds are one area where they do bear risk that is correlated with overall financial market performance. In adopting an approach that provides the companies with additional protection in this area, Ofgem is reinforcing the low risk characteristics of the distribution business. This reduces the case for arguing that a higher cost of capital is now required to reflect pension related market risk being borne by the distribution companies.”

662 Final Proposals of November 2004[47] reinforced the above views. Paragraph 6.20 stated that “While there are reasonable arguments why the company’s share might be less [than 30%], the September update also set out more compelling reasons why a higher share could be justified. Ofgem remains of the view that the 70:30 split is an appropriate basis for sharing these costs between customers and shareholders in order to reinforce the low risk position of DNOs.”

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[46] Ofgem, DPCR4 Update Paper, September 2004

[47] Ofgem, DPCR4 Final Proposals, November 2004

6 Cost of capital and financeability

Ofgem's proposals

663 In their Initial Proposals, Ofgem make it clear that they have yet to undertake their main work on cost of capital. Whereas we have seen the draft reports prepared by Ofgem's consultants on a range of capex and opex issues, we have not yet seen the consultants' work on cost of capital.

664 Against this background, Ofgem have offered some initial thoughts and a post-tax real cost of capital of 4.2% "for modelling purposes, and to provide a reference point for consultation responses".

665 Ofgem also make clear that their final proposals will be informed by:

(a) the results of their consultants' further work;

(b) financeability assessments; and

(c) the overall balance of risks that companies will face under the revised controls[48].

666 Finally, Ofgem have also given as their current view that, apart from tilting NGET's regulatory depreciation profile to address the loss during the next price control period of income from the regulatory depreciation of pre-privatisation assets, financeability issues should be addressed through companies issuing new equity. Ofgem accept that, on this basis, the eventually assumed cost of capital will need to take account of the marginal cost of required equity injections, including transaction costs.

Our response

667 Prior to the publication of the Initial Proposals, we made an initial submission on cost of capital issues and Ofgem have put this on their web site. In this, we suggested the following two routes for estimating an appropriate cost of capital for NGET and NGG:

(a) an Ofgem-style 'bottom-up' analysis, building up an estimate of WACC from the various components in a way which we saw as consistent with the analysis of DNOs' cost of capital used by Ofgem in DPCR4; and

(b) an analysis which tried to infer the actual costs of capital used by investors in valuing water companies – the UK water sector having the advantage for such an analysis of having a significant number of quoted entities which are dominated by their regulated businesses.

668 On the back of these two types of analysis, we suggested a real post-tax cost of capital in the range 4.7-4.8%, albeit that this range would need to be informed, in due course, by any changes which Ofgem proposed for the wider regulatory regime.

669 Against this background - our previous submission, the fact that Ofgem have yet to complete their work in this area and the implication that the main debate on this issue will be in the Autumn - there would seem to us little point in a repetition and/or

[48] Initial Proposals para 8.6

elaboration of the generality of our previous arguments at this stage. **Rather, we think it useful to focus on two areas of the debate which are specifically prompted by Ofgem's Initial Proposals.** These areas are:

(a) the extent to which, and manner in which, past regulatory decisions should inform future decisions; and

(b) the implications for cost of capital of Ofgem's current proposals in the round, not least:

(i) the proposals for incentivising load-related network capital expenditure; and

(ii) the proposal that any financeability issues should be resolved by equity injection, rather than (as with most previous UK utility price reviews) through regulated revenue.

Regulatory consistency

670 Both regulators (and not just utility regulators) and regulated companies tend to talk a lot about the desirability of regulatory consistency, not least to avoid building in an additional risk premium into companies' cost of capital. This issue becomes particularly live when a particular regulatory proposal/decision seems to be sharply at odds with previous decisions. This would seem to us to be the case with Ofgem's initial proposals on cost of capital.

671 For the avoidance of doubt, it is worth stating up front that it is not our position that regulatory consistency requires regulatory decisions to be the same. In the current context, therefore, there is no necessary reason why Ofgem's estimate of the DNOs' cost of capital in DPCR4 should be the same as its estimate of transmission companies' cost of capital in the current review. In particular, in so far as the previous decision was based on facts, then one would expect changes in relevant facts to be reflected in the new conclusion.

672 However, it **is** our position that it is much more difficult to retain a claim to consistency if the reason for changes between one decision and the next seem to be subjective and even arbitrary. It is also our position that the transition from an estimate of DNOs' cost of capital of 4.8% (or even from Ofgem's modelling assumption of 4.6% in its earlier DPCR4 documents) to the current modelling assumption of 4.2% does involve a large measure of subjectivity and arbitrariness.

The DPCR4 outcome

673 To substantiate our position, it is necessary to review the basis of Ofgem's DPCR4 conclusion that DNO revenues should be based on an assumed real post-tax rate of return of 4.8%. This basis had the following main elements:

(a) **Cost of debt.** Ofgem assumed a cost of debt of 4.1%. At least in the DPCR4 Final Proposals, there is little in the way of justification for this number. There is no breakdown between the risk free rate and the debt premium. The justification for the chosen rate amounts to no more than the statement that "This decision reflects the fact that companies may need to raise a combination of debt and equity finance in order to fund their investment programmes"[49].

Going back over the preceding documents, there are clues as to what led to the 4.1% figure, notably in the March 2004 Policy Document and the separately published appendix on cost of capital[50]. For example:

(i) There is discussion of the risk-free rates and debt premia adopted in previous UK utility price reviews (including DPCR3).

(ii) It is noted that Competition Commission's most recent decisions had used a risk-free range of 2.5-2.75%.

(iii) It is noted that current risk-free rates are below long term averages but may rise through the next price control period.

(iv) Perhaps most important of all, it is stated that "The proposed ranges for cost of capital reflect the strong investment focus of this review. It is expected that in order to finance this investment companies might have to access debt and/or equity markets. This has been a determining factor in proposing the initial ranges for the cost of capital"[51].

Later in the DPCR4 process, at the Initial Proposals, the only other factor which seems to be acknowledged as determining the assumed cost of debt is "efficiently incurred embedded debt"[52].

(b) **Cost of equity.** The audit trail for Ofgem's use of a 7.5% post-tax cost of equity for DNOs is rather clearer than the genesis of the cost of debt assumption. In effect, and as summarised in paras 8.40-8.45 of the DPCR4 Final proposals, Ofgem:

(i) started from a range for total equity returns of 6.5-7.5%;

(ii) adopted the top end of this range, "given the investment focus of the review"; and

(iii) assumed that DNOs' equity risk was equivalent to the average of UK companies (in CAPM terms, it was assumed that DNOs had an equity beta of 1).

(c) **Gearing**. In the DPCR4 Initial Proposals, Ofgem assumed gearing of 60%. In the Final Proposals, Ofgem assumed 57.5%. "This is based on a judgement with respect to both the actual gearing level and the projected gearing level, and has given consideration to the levels of upstream guarantees given by licensees."

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[49] DPCR4 Final Proposals para 8.49.

[50] Electricity Distribution Price Control Review Policy Document, March 2004 and Electricity Distribution Price Control Review, Background information on the cost of capital, March 2004

[51] Electricity Distribution Price Control Review Policy Document, March 2004, para 7.19

[52] Electricity Distribution Price Control Review, Summary of responses to March Policy Paper, June 2004, para 6.91

TPCR Initial Proposals

674 Ofgem's modelling assumption of 4.2% is based on the following components:

(a) "a real pre-tax cost of debt of 3.4%, consistent with current 10 year trailing average data for gilt yields (2.3%) and the average spread of 'A' rated utility bonds with a ten year maturity (1.1%)";

(b) "a cost of equity of 7%, based on the midpoint of estimates of long run average total market returns that range between 6.5% and 7.5%" (albeit that the table in Appendix 9 of the Initial Proposals seems to imply that 7% has been derived by a different route, i.e. by assuming market returns of 7.5% and an equity beta for transmission of 0.9); and

(c) "a gearing level of 60% (in line with assumptions underlying the current controls)"[53].

675 As regards the **cost of debt**, it is not clear whether Ofgem are saying that the use of trailing averages was the basis of the DPCR4 conclusions – and that, therefore, the movement in those averages is a consistent explanation of its assumptions on debt. As noted above, the DPCR4 proposals gave few clues as to how Ofgem reached their conclusions on cost of debt - and such clues as there are seemed to be related more to regulatory precedent and the need to match the 'investment focus' of DPCR4 than to use of trailing averages.

676 Either way, Ofgem have not, thus far, explained what justifies a reduction in **70 basis points** in the assumed cost of debt, as compared with DPCR4. As already noted, some sort of minimum regulatory consistency does not require the current answers to be the same as the past answers but it does require some consistency of methodology. At the moment, Ofgem have not demonstrated this in respect of the cost of debt.

677 The lack of consistency is much clearer in respect of **cost of equity**, although the precise basis for the new conclusion is not clear. As already noted, the basis of the DPCR4 assumption of 7.5% was very clear cut – (1) the assumption of market returns of 6.5-7.5% (2) the choice of the top of that range to reflect the investment focus of the review and (3) an equity beta of 1.

678 The route by which Ofgem get from 7.5% in DPCR4 to 7% in TPCR is **not** clear. Specifically:

(a) Para 1.18 of Appendix 9 of the Initial Proposals states that the 7% is "based on long term averages", implying that Ofgem have selected the mid-point of the 6.5-7.5% range for average equity returns over time – and have assumed an equity beta of 1. This approach is confirmed in para 1.13 of the same appendix, where Ofgem state that "For TPCR, we ….are currently using a total market equity return of 7.0%, based on evidence that the long term arithmetic average of total equity market returns is between 6.5% and 7.5%.

(b) Table 9.2 (which is immediately below para 1.18), however, assumes an equity beta of 0.9, implying that Ofgem are still using the top of the 6.5-7.5% range for **market** returns.

[53] All quotes in this para from Initial Proposals para 8.5

679 However, **neither** of these explanations looks to be consistent with Ofgem's past practice for at least the following reasons:

(a) Given that Ofgem's reason for selecting the top of the 6.5-7.5% range was the investment focus of DPCR4, it is hardly as if the current transmission review is any less focused on investment – as Ofgem have made repeatedly clear throughout the transmission review to date. For example, on the first page of the Third Consultation Document for this review, Ofgem state "The key theme for this review is investment". There is, thus, not only no evidence that **long term** equity returns have declined over the last two years but no basis, consistent with their previous decision, for Ofgem selecting a different point within the given range for those returns.

(b) There is similarly no basis for assuming a different equity beta for transmission companies than was assumed for DNOs. As was made extremely clear in the work by Stephen Wright which Ofgem published as part of the NGET mini review, and which is on Ofgem's web site, National Grid's beta is probably, if anything, somewhat higher than that of most of the comparator companies selected.

680 On **gearing**, Ofgem have assumed 60% in the Initial Proposals, whereas they assumed 57.5% for DNOs. The justification for this difference is given in para 1.16 of Appendix 9 – "There is market evidence e.g. from the levels of gearing taken on by the independent gas distribution businesses (around 75%), that the companies have the ability to continue to increase borrowing without affecting credit ratings. As such, a higher gearing assumption than used in previous reviews may remain consistent with our normal requirement for a credit rating to remain comfortably within investment grade".

681 This is not a credible reason for changing the gearing assumption from DPCR4. This is not least because:

(a) Gearing in the utility sector is not now markedly different from either the average DNO gearing at the time of DPCR4 or from what one would have anticipated during the later stages of DPCR4.

(b) As far back as the Second Consultation for DPCR4, it was stated that **average** DNO gearing at the time was "close to 70%[54]".

682 In other words, there are no material differences of relevant fact which justify Ofgem's change of assumption.

683 **Overall, on the issue of regulatory consistency**:

(a) We can see no valid factual basis for the change in Ofgem's assumption on cost of equity or gearing from those used in DPCR4.

(b) On cost of debt, it is clear that facts have changed, albeit not in a simple way and not in a way which should obviously affect Ofgem's conclusions, given that the basis for the DPCR4 assumption on debt was unclear and seemed, at least from the published documents, to be as much influenced by the investment focus of DPCR (i.e. the same focus as for TPCR) as by facts on cost of debt.

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[54] DPCR4 Second Consultation, December 2003, para 7.48

Risk, reward implications of Ofgem's overall proposals

684 As noted in para 665 above, Ofgem have explicitly recognised that the assumed cost of capital for NGET and NGG will need to take account of any changes in the overall balance of risks that companies will face under the revised controls. As the proposals stand at the moment, there certainly will be major changes in that overall balance, e.g. with respect to:

(a) increased financial exposure (particular increased duration of financial exposure) to unit cost allowances (UCAs) for load-related capex;

(b) increased exposure to operational buybacks on gas entry;

(c) increased financial exposure to delivery of gas entry investment schemes;

(d) the increased use of penalty-only incentive schemes;

(e) increased risk of regulatory stranding of network assets;

(f) increased exposure to arbitrary regulatory decisions; and

(g) the proposed use of equity injections to resolve financeability issues.

685 Each of these is covered in turn.

Increased exposure to UCAs

686 At present, if NGG releases new permanent obligated incremental entry capacity in excess of the designated entry capacity baselines, it is initially remunerated, in effect, through specified 'Unit Cost Allowances' (UCAs), rather than on the basis of the actual investment costs incurred. Remuneration on this basis lasts for the rest of the price control period. From the start of the next price control period, remuneration is (again, in effect) through the incorporation of the actual investments costs (as long as they judged in the relevant price review to be efficiently incurred) into the regulatory asset base (RAB).

687 Ofgem is proposing a major change to how this mechanism will work in future. It is proposing that this new mechanism will apply to gas exit, as well as to gas entry, and we anticipate that something similar will also be applied in electricity. The proposed mechanism, alluded to in Chapter 4 above of this response, is that we would be remunerated via UCAs, rather than through actual cost incurred, on a five year rolling basis from the 'contractual delivery' of the new capacity. What this could mean can be illustrated by the following example:

(a) UCAs will be fixed in Final Proposals in December 2006. For the reasons given in Chapter 4 above, we think that these UCAs are likely to be below what we should be spending to create an adequately flexible gas transmission system.

(b) Shippers bid for new entry capacity in the long term entry capacity auctions in September 2011.

(c) Contractual delivery would be in October 2014, on the basis of Ofgem's assumed default delivery timescale of three years.

(d) Exposure to UCAs would last for the next five years, i.e. to October 2019.

688 Thus, on this basis, we would be exposed for over 12 years to assumed costs which we think are going to be wrong (too low) even when they are set in a few months time. Given the sort of variance in scheme costs which are likely to arise from changes in gas supply and demand scenarios, let alone variances due to likely above-RPI increases in investment input costs, this change in mechanism is likely to give rise to a substantial increase in risk faced by NGG and (to the extent that a similar mechanism is applied to electricity) NGET.

689 This exposure could be mitigated in a variety of ways (fixing UCAs after the relevant auctions, reducing the duration of exposure to UCAs to the current price control period only, indexation of UCAs to relevant indices of industry costs). However, in the absence of such mitigation, we would see the only way for this extra risk to be compensated would either be a higher assumed rate of return in the UCAs and/or in the returns assumed on RAB.

Increased exposure to operational buybacks

690 Under the current gas entry incentive arrangements, our maximum annual loss is collared at £12.5m. Ofgem are proposing that, in the next price control period, this annual collar should be increased to £36m. This is proposed at the same time as Ofgem are also proposing (and as is summarised in Chapter 4 above) that the baselines, against which we would have to buyback capacity, should be set substantially in excess of system capability. So, not only would maximum financial exposure over a five year period increase from around £60m to around £180m but the method of setting baselines means a systematic exposure to incurring losses under the incentives.

Increased financial exposure to late delivery of incremental capacity

691 At present, there is no separate buyback scheme in relation to the delivery of new investment schemes to delivery incremental capacity. As is detailed in Chapter 4 above, the current Ofgem proposals in this area are totally unacceptable in terms of the balance of risk and reward being offered. In effect, what is being proposed is a separate scheme for the buyback of capacity which has not been delivered within three years of the relevant capacity auction. It is currently proposed that there should be a formula which would determine the unit price of bought back capacity but no collar on the overall liability. In addition, we would bear all consent risk against a default delivery timetable (three years) which assumes, inter alia, that no planning applications go to appeal.

692 In effect, what is being proposed is a scheme with no upside and a bias to substantial downside. In Chapter 4, we suggest how being one year late with a large scheme (easy enough with planning consent going to appeal and the difficulty of doing many construction activities through the winter) could involve losses of hundreds of millions of pounds.

693 Finally in this section, it is worth noting the separately proposed penalty-only incentive scheme in relation to Milford Haven (Ofgem plan to wrap the licence modifications for this up with the overall TPCR licence modifications). This has an exposure of £36m for delivering the scheme one year late against a delivery period of slightly under three years from the relevant auctions, and with NGG bearing all the risk of local

planning applications going to appeal. It is also worth noting that the clear implication of the Government's Energy Review document is that such risks are currently difficult for any party to manage effectively.

Increased exposure to penalty-only incentive schemes

694 This section partly overlaps with the previous one – as both the proposed investment buy-back incentive and the specific Milford Haven incentive would fall into this category of penalty-only incentive schemes. But the category would also include the proposed network reliability incentive scheme for NGET. The current scheme for this offers the prospect of both profit and loss, whereas Ofgem are proposing the new scheme will be a loss-only scheme.

695 It is difficult to equate Ofgem's apparent desire to introduce balanced incentives on transmission licensees with this increased taste for penalty-only schemes. However, if penalty-only schemes are increasingly to be part of the overall regulatory package, then the only obvious place to restore overall consistency is through an appropriate increase in the overall cost of capital assumed in calculating TO regulated revenue.

Increased risk of regulatory stranding of assets

696 In Chapter 3 above, we cover Ofgem's proposed disallowance of £75m of capital spend on gas transmission assets related to St Fergus which have been constructed during the current price control period. Even though Ofgem have assumed that these assets are included in the relevant entry baselines, they are proposing to strand assets which have proved themselves to be 'used and useful' since being commissioned.

697 The arguments why such a stranding of assets would be unreasonable are summarised in Chapter 3 above. However, in the context of rate of return, the potential stranding of this spend also implies a more generalised uncertainty as to what spend will and will not go into RAB in due course. At this time, Ofgem seem to be developing their criteria for stranding of assets on the hoof – and it is this more general risk, as much as the specific issues surrounding the £75m, which will need to be priced into the overall transmission cost of capital, at least in the absence of substantial clarification of what are the rules of the game for assets being excluded from RAB. At the same time, if that clarification is going to be to the effect that only investment which is validated through relevant market signals will go into the RAB, then it will need to be clear that our overall licence obligations to develop efficient transmission systems are consistent with such a policy – i.e. we have no obligation to incur load-related capital expenditure in the absence of a relevant market signal.

Increased exposure to arbitrary regulatory decisions

698 It is part of the contention in this chapter that Ofgem's approach to cost of capital – and, in particular, to the transition from DPCR4 to the current review on cost of capital – looks to have significant elements of arbitrariness. However, there are other elements of the current proposals which look to be at least as arbitrary, including several of the other exposures listed in this chapter. Probably the most egregious example of this tendency in the proposals is the proposed treatment of ERDCs covered in Chapter 5 above of this response – a proposal which is in conflict not only with our own interpretation of the basis of the equivalent DPCR proposal but also with the interpretation given by Ofgem themselves in their Second Consultation for the Gas Distribution Price Control Review.

699 As with the other items on risk and reward in this chapter, Ofgem have the option of dealing with these issues in a way which mitigates or removes their risk implications. However, in the absence of such changes, the only obvious route for this risk to be dealt with is through the assumed cost of capital.

Financeability and equity injections

700 For some time now, investors in UK regulated network companies have become used to a standard two-stage way of setting price controls, i.e.:

(a) In the first stage, regulators calculate the NPV of revenue required to give an efficient company a reasonable rate of return.

(b) In the second stage, the regulator checks to see whether, at least on certain stylised assumptions, the company can maintain its various financial ratios at a level which would enable the company to finance its activities. If there are problems with the ratios, then revenue is increased (in a way which may, or may not, affect the NPV of expected future revenue).

701 Thus, and for example:

(a) The CAA have advanced (customers') cash to BAA to allow it to invest in Terminal 5 at Heathrow without breaching such ratios.

(b) Ofwat made substantial 'financeability' adjustments to the price controls which currently apply to water companies.

(c) Ofgem tilted the regulatory depreciation profiles for the DNOs at DPCR4.

702 Arguably, and leaving aside other arguments for the above practices, such financeability adjustments were logically required for those regulators who assumed 'optimal gearing' in calculating the cost of capital which they assumed in setting price controls. This is because if the regulator assumes fixed gearing at the optimal level, then the company has got to be able to achieve this gearing level to live within the assumed price control – and responsibility for enabling the company to maintain this gearing, in the face of changing capex requirements, effectively falls to customers.

703 Ofgem and Ofwat have now sought to escape from this logic and have recently consulted on various options for dealing with the financeability issue[55]. As yet, neither Ofgem nor Ofwat have announced the results of their deliberations on the issues raised in the paper. Despite this, Ofgem have decided that their initial view is that the solution for transmission companies "is that the appropriate approach is to assume that companies should be able to raise additional equity when necessary to meet funding requirements and maintain appropriate credit quality"[56], albeit that they have also decided (rightly in our view) that tilted depreciation is their preferred approach for dealing with the specific issues associated with the NGET 'depreciation cliff-edge'.

704 Ofgem accept that what is a major change in UK regulatory practice has implications for financing costs – "we will need to be satisfied that the allowance we make for the cost of equity appropriately takes account of the marginal cost of equity injections

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[55] Ofgem and Ofwat, Financing networks: a discussion paper, February 2006

[56] Initial Proposals para 8.19

required including transaction costs"[57]. However, what will need to be considered (and this is catered for by Ofgem's statement) will be not just the transaction costs of raising new equity but also any broader effects on the equity investor base. Investors have arguably got used to the current regulatory approach to financeability which helps to underpin a more stable dividend flow than might otherwise be the case. If Ofgem decide to follow their currently preferred approach to this issue, then the broader implications of the approach for cost of capital will need to be addressed.

Summary of this chapter

705 Overall, and in advance of the main debate on cost of capital (which we expect to take place after Ofgem's publication of its consultants' work on this subject), we have offered reasons in this chapter why we think that Ofgem's modelling assumption for NGET's and NGG's cost of capital is implausible. These reasons are, in summary, that:

(a) It is important that Ofgem can justify why the proposed modelling assumption is so different from the still quite recent conclusions on DNOs' cost of capital.

(b) For the reasons given in this chapter, we do not believe that Ofgem have offered such a justification.

(c) In any event, whatever the relevant cost of capital for the sort of business risks faced by DNOs and, hitherto, by transmission businesses, Ofgem's broader proposals for the next price controls for NGG and NGET pose a range of wider risks which, if not otherwise resolved, will have to be reflected in the cost of capital to be assumed in setting the new controls for these two businesses.

Specific questions asked by Ofgem

Should the Licencees' revenue allowances be set to avoid the need for any ex- post adjustments for tax?

706 We think that, in general, tax costs are not significantly different from other types of cost. As such, we believe that it is appropriate that the tax allowance should, as far as possible, be set with a view to avoiding the need for ex post adjustments.

707 Nevertheless, there may be a case for certain ex-post adjustments, in particular in the event of major changes in tax legislation or treatment and if a utility's gearing moves substantially above the levels assumed when setting the price control.

Are there any other methods that could be taken to remove perceptions of Regulatory risk and what level of risk do these regulated utilities carry relative to other plc's?

708 We have answered the first part of this question in the main text.

709 We believe that the systematic risk profile of regulated utilities differs from that of other plcs in two main respects:

(a) Regulated utilities have a more stable operating business

[57] Initial Proposals para 8.19

(b) Regulated utilities have substantially higher levels of gearing

710 According to conventional finance theory, these two characteristics work in opposite directions. As a result, we do not believe that it is possible to assert that theory would support an assumption that the **equity** beta of regulated utilities is necessarily lower than the market as a whole.

711 The monopoly nature of regulated utilities means that one would expect utilities to have a relatively low underlying business risk profile. This is due to the fact that utility cash flows can be expected to be relatively insensitive to wider economic conditions when compared to the market as a whole. Consequently, theory would predict that Regulated utilities have a relatively low **asset** beta.

712 However, Ofgem are assuming that the regulated utilities will have debt to market value ratios of around 60% in their cost of capital assumptions. The market gearing of non financial companies in the FTSE 100, on the other hand, is just 10%. Consequently, according to conventional finance theory, the impact of levering the asset beta to arrive at an equity beta will have a significantly larger effect on regulated utilities than on the market as a whole.

713 Given its capital structure, the market as a whole has an asset beta of 0.9. An equity beta of 1 combined with a gearing level of 57.5% would result in an asset beta of 0.425, less than half the level of the market as a whole. An equity beta of 0.9 at a gearing level of 60% would suggest an asset beta of 0.36, only 40% of the risk of the wider market.

714 Ofgem’s cost of capital calculations therefore already assume that the underlying businesses risk of regulated utilities is substantially lower than the market as a whole.