National Grid plc

Response to Transmission Price Control Review Initial Consultation

I Introduction

1 In this response we set out our views on:

(a) the key issues to be addressed;

(b) development of RPI-X incentives;

(c) cost assessment; and

(d) the forward work plan for the review.

2 In addition, we attach an appendix which details our individual responses to each of the questions asked at the end of each chapter.

II Key Issues

Network investment and its incentivisation

3 The biggest single issue in the transmission price reviews is the need for increased investment in the transmission networks. For National Grid, **the need on the electricity network** is primarily to replace existing assets, although there is also a continuing need to develop the network to deal with the changing demands of network users, particularly as a result of climate change initiatives. **On the gas side**, the main driver for investment is currently (and will, for the foreseeable future, be) the need to reconfigure the network to adapt to changing patterns of gas supply into GB.

4 However, as was recognised in DPCR4, this issue is not simply about Ofgem accepting any particular level of required 'baseline' investment but also about giving appropriate incentives to companies to efficiently scope and undertake investment programmes. This issue therefore embraces, inter alia:

(a) the incentive on companies to provide Ofgem with the best available information on future network requirements;

(b) the 'baseline' requirements accepted by Ofgem;

(c) the existence and effectiveness of mechanisms for adjusting regulated revenue, within a price control period, to material divergence of capex requirements from those discernible at the time of the previous price review; and

(d) the rate of return which companies can make from undertaking investment efficiently.

5 The issue of incentives is picked up in Section III below.

Cost of Capital

6 Consistent with DPCR4, the investment focus of the review will place even greater importance on determining the appropriate cost of capital for Transmission Licensees. National Grid support many of the approaches Ofgem used for setting the cost of capital in DPCR4. In particular, we support the use of a post tax method for setting a cost of capital, taking a long term view of the cost of debt.

7 As regards the method(s) used to estimate cost of capital, we recognise that CAPM remains the most frequently used framework, but also note that it has become increasingly a method for simply adding up the different elements of cost of capital – often with those elements themselves being derived from other approaches. We believe that total returns and dividend growth approaches are both useful checks on the plausibility of results from a nominally CAPM framework.

8 We believe that cost of capital for transmission should reflect wider considerations, such as the need for provide an appropriate incentive to invest on the scale required and the desirability of retaining equity in utility capital structures.

9 In addition, we believe that there are several reasons why the transmission business has a higher risk profile than the DNOs. These include the larger and more volatile capex programme, weaker cash flows due to lower regulatory depreciation and the additional risks associated with managing incentive programmes which do not themselves necessarily provide adequate compensation for those risks.

Pensions

10 We note Ofgem's intention to apply the pensions guidelines established during DPCR4 and look forward to discussing the application of those guidelines to transmission. However, we would point out two reasons why those guidelines may not be applicable to National Grid Electricity Transmission (NGET) and Transco NTS in any simple way:

(a) The circumstances which have given rise to at least part of the deficits in the relevant pension schemes are materially different from those which applied to DNO pension schemes. This is particularly true in relation to the circumstances in which Centrica de-merged from British Gas and the circumstances in which NGC used part of its pension fund surplus to part-fund severance programmes.

(b) Pensions regulation has developed since DPCR4, in particular with the implementation of the Pensions Act 2004. Although the implications are not clear at present, it is anticipated that cash payments into defined benefit pension schemes will increase materially, due to more prudent actuarial assumptions, faster deficit repair and the costs of the pension protection fund.

NGET regulatory depreciation

11 As with the DNOs, NGET's regulatory depreciation of pre-privatisation assets was set on the basis of straight line depreciation of a deemed regulatory asset value over a set period which broadly reflected the average remaining life of the assets at the time of privatisation. Given that electricity transmission is a substantially more capital intensive business than electricity distribution, it is not surprising that the termination of this revenue stream (in March 2010) will have a substantial effect on NGET's regulated revenue and on the ability of NGET to finance its licence obligations. We believe that Ofgem should make an adjustment to asset lives from 2010 to repair the depreciation allowance in a similar way to that used in DPCR4.

Consequences of extension of NGET's current price control through 2006/07

12 Partly in parallel with the setting of transmission price controls from April 2007, Ofgem are also engaged in extending NGET's current price control through 2006/07. As part of this extension, Ofgem are currently proposing to review certain decisions on NGET's past and future expenditure as part of the main review. Ofgem are also currently proposing that NGET will be held NPV-neutral to the postponement of these decisions. If this is to be achieved, there will need to be a clear audit trail in relation to the what has been assumed in the mini review proposals (e.g. on pensions), as well as sufficient disaggregation of the basis of Ofgem's final proposals for price controls from April 2007.

III Developments of RPI-X incentives for network investment

13 The main incentives which stem from 'vanilla' RPI-X in relation to network investment are for companies to:

(a) **over-bid** their requirements; and then

(b) **under-spend** against whatever Ofgem have assumed in setting the relevant price controls, regardless of whether, in the meantime, the requirements for network capex have increased, reduced or stayed the same as they were at the time of the price review. This incentive to under-spend is increased if so-called 'rolling' incentives are grafted on to vanilla RPI-X.

14 In part-recognition of the distortions which result from vanilla (or, even more, from rolling vanilla) RPI-X, Ofgem have introduced a variety of modifications to the price controls which currently apply to GB regulated energy network businesses. These include:

(a) an 'honesty' mechanism to encourage companies to provide accurate information on network capex requirements to the extent that they are apparent at a price review - the DNO sliding scale mechanism being the exemplar of this; and

(b) a variety of mechanisms which drive revenue in response to actual capex requirements being different from what was assumed in setting the current price control. Such mechanisms currently include:

(i) the Distributed Generation mechanism in the DNO price controls;

(ii) the Gt mechanism in the current NGET control; and

(iii) the Deep SO mechanism in the Transco transmission price control.

15 As regards **the honesty mechanism**, the DNO sliding scale represents an improvement on a world in which **any** spend above the level assumed by Ofgem in setting the price control means that the company earns a marginal rate of return below the assumed cost of capital. However, because of the way the mechanism is structured (specifically, the way it is anchored by Ofgem's view of a network's required capex), the mechanism is less an incentive to be honest than an incentive to agree with the view of Ofgem and their consultants as to how much capex is required on the network in question. In our view, any honesty mechanism for the GB transmission business should be restructured to better incentivise honesty (i.e. proximity between what a company says it intends to do and what it eventually does), rather than to encourage companies simply to agree with Ofgem's consultants.

16 As regards **the various existing revenue drivers**, each has, not surprisingly, issues associated with it. For example:

(a) Neither the DNO distributed generation mechanism nor Gt make any allowance for the different costs of connection and associated system reinforcement in different parts of GB.

(b) The Transco Deep SO mechanism **does** allow for nodal variation in unit costs but is unnecessarily complicated for what is, in essence, a nodal revenue driver mechanism. Ofgem's original plan (that incremental revenue would be driven by shipper bids, rather than by unit costs) has been undermined by the Deep SO mechanics – which enable shippers to calculate fairly precisely how much they need to bid in auctions for incremental capacity to secure that new capacity will be forthcoming.

17 It also needs to be recognised that all the revenue driver mechanisms, to date, are geared to remunerating, at least in part, investment to increase the capability of networks, i.e. 'enhancement' investment. None of them deal with replacement of existing assets. **As things stand at the moment, there is no alternative to Ofgem allowing sufficient revenue in TO price controls for required <u>replacement</u> investment to be undertaken, potentially helped in this regard by an appropriate honesty mechanism**.

18 As regards the incentivisation of enhancement investment, the transmission price review is an opportunity to conduct a major review of potential mechanisms. At the heart of any mechanism(s) should be two key elements:

(a) a mechanism for filtering out uneconomic enhancements (a role currently fulfilled by auctions in gas transmission and the requirement for 'final sums' in electricity transmission); and

(b) a mechanism for varying regulated revenue within a price control period as the requirements for new enhancement investment change. Our current view is that the nodal unit cost mechanism is worth preserving in gas and that it would be worth investigating a number of sub-national revenue driver mechanisms in electricity. There should always be the option of an interim price review (as with the recent TIRG process) when there are **major** changes in the requirement for network reinforcement which were not anticipated at the previous price review.

19 None of the above does away with the need for Ofgem to set reasonable baseline allowances for future network capital expenditure. Given the inevitable approximations entailed by whatever revenue drivers are finally decided (excepting 100% pass-through of actual costs incurred), the role of revenue drivers should be to deal with the unexpected, not with what is already well anticipated at the time of the price review.

20 Three other points are worth highlighting under this heading of incentives, namely:

(a) the need for clarity as to how more general licence obligations interact with the specific obligations created by incentive mechanisms;

(b) the extent to which transmission licensees should bear consents risk within a framework designed to encourage timely delivery of projects; and

(c) the question of consistency between exposing transmission operators to "risk of under-performance" and the potential rate of return from out-performance.

21 On the issue of **clarity of obligations**, the gas Deep SO mechanism has created significant ambiguity in this area. On the one hand, the mechanism itself requires Transco to base its investment plans on the results of the long term capacity auctions, i.e. demand for incremental entry capacity is only 'real' when manifested in an auction bid – and remuneration is only triggered by sale of capacity. However, Transco also has a general licence obligation to develop the NTS efficiently – which could be interpreted as using all available information on likely demand for transmission capacity. It will be important in the price review to clarify exactly what information is used as a basis for planning the system – and how remuneration is then linked to this clarification.

22 On the issue of **consent risk**, this is currently handled differently in gas and electricity. As environmental consents become an increasingly fraught issue for the construction of both gas and electricity network infrastructure, we would welcome further discussion of just how we should be exposed to the risk of delay in the securing of relevant consents.

23 On the issue of **risk and rate of return**, Ofgem suggest that "licensees bear an appropriate share of the risk of under-performance under the price controls in relation to, for example, the costs of buying back capacity rights if investment by a licensee is not focused and timely". Clearly, this issue is linked to the above issue of consents risk – but it is also linked to the issue of consistency with the potential rate of return from out-performance. At the moment, Ofgem's calculation of the 'base' cost of capital does not seem to factor in these extra risks, with the implication that the risk of being penalised for under-performance should be balanced by the scope for being rewarded for out-performance. However, the gas entry incentive scheme, despite its penalties for under-performance and its theoretical ceiling rate of return of 12.25% (in the first five years of a scheme), offers little scope for out-performance, not least because shippers have all the information which they need to effectively make their auction bids close to stipulated unit costs. Overall, if Ofgem is planning to impose significant downside risk on transmission operators for under-performance, then there needs to be a comparable upside and/or a higher base rate of return.

IV Cost Assessment

Capex

24 We believe there will be a continuing need for both the gas and electricity transmission systems over the medium to long term. Gas, the cleanest fossil fuel, is likely to experience significant demand growth over the medium term, whilst the electricity transmission system will play a key part in meeting the government's climate change objectives.

25 We accept that the future pattern of electricity generation is uncertain, with a wide range of possible generation scenarios that satisfy government emissions objectives, e.g. large scale nuclear or renewable generation remote from demand centres, or small scale generation close to load. However, the Royal Commission on Environmental Pollution outlined four possible scenarios within this range. Under **all** the scenarios, the need for transmission capacity would be at least as great as now and, in some cases, would be significantly greater.

26 We therefore believe that Ofgem's cost assessment process should be carried out on the basis of needing to maintain or enhance existing capability. Deferment of essential replacement until the future becomes clearer would imply the risk of unacceptable levels of reliability over the medium term. Transmission systems, given their strategic importance, cannot operate a policy of "replace on fail".

27 Against this background, the assessment of appropriate capex allowances should principally focus on a detailed assessment of the schemes proposed and expenditure plans by asset category.

Opex

28 We agree with Ofgem on the drawbacks of comparative benchmarking with the Scottish companies and also feel that top down benchmarking against international comparators is also likely to be unreliable, particularly because of the difficulties of ensuring consistent data but also because of the problem of standardising for different operating environments. We agree that, in certain areas, activity based benchmarking may be more robust – however, the relatively small size of the Scottish Transmission companies reduces their value as comparators. Furthermore, in the absence of early identification of the comparable activities, it is likely to be difficult to provide sufficiently robust and consistent data during the course of the review to undertake such analysis. This is something which Ofgem's cost reporting plans should make easier in future price reviews.

29 Against the background of all of the above, we believe that the assessment of efficient operating costs should be principally derived from a bottom-up assessment of the costs of NGET and Transco NTS.

30 On shared costs, we recognise the importance of this area and are keen to facilitate the assessment of National Grid's shared cost base, including the agreement of appropriate cost attribution, to ensure consistency of treatment between the Transmission and Gas Distribution price control reviews.

Cost Reporting

31 We recognise the benefits of developing a more comprehensive cost reporting framework, however we feel this cannot be determined until immediately after the price control review. When determining the specific nature of regulatory cost reporting, we believe it important that the information requested meets certain criteria, specifically:

(a) there should be a clear regulatory purpose in requiring the information; and

(b) the cost of providing that information should be proportionate to the regulatory benefit.

V Forward Work Plan

32 We welcome the publication of a clear programme timetable, and believe it is important that the programme is tightly managed to ensure that issues are resolved in a timely manner, consistent with the published timetable. We believe it is essential that any planned variances from the published dates are discussed with the Licensees in advance, due to the need to fully understand the impact of such variances.

33 We note that the initial plan is to publish five documents on the review, with an anticipation that there may be a sixth document in March 2006. We believe that it would be appropriate to have a consultation in March, particularly focused on the development of key policy issues, as in DPCR4.