

Transmission Price Control Review 2007 - 2012: Third Consultation

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Overview:

This document is the third of six consultation documents that will be published as part of the Transmission Price Control Review (TPCR). It follows on from the themes set out in the earlier consultation documents published in the Initial Consultation (July 2005) and Second Consultation (December 2005).

We set out our preferred options for the design of the price controls that will be put in place for 1 April 2007 and clarify our policy position on a number of financial issues. This document also sets out our views on the case for access reforms in electricity and gas transmission.

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Target Audience: Transmission licensees, Gas transporters and other interested parties.

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Context

Transmission networks play a key role in facilitating the competitive electricity and gas markets in Great Britain, and timely investment in the networks is essential to ensure their efficient operation.

There have been a number of changes in the external environment since the current transmission price controls were set and there is significant uncertainty concerning the future development of the networks. This uncertainty arises, in particular, from:

- changing patterns of gas supply resulting from the decline of UK gas production and its replacement by imports;
- changes in the electricity generation mix, particularly relating to the development of renewable generation; and
- changes in wider energy policy, including environmental factors.

Against this background, the objectives of the review will be to develop the incentives for investment in gas and electricity infrastructure, ensuring they are best able to promote efficient and timely investment and allocate risk appropriately.

Associated Documents

- TPCR 2007-2012: Third Consultation - Supplementary Appendices (Ref 51B/06)
- TPCR Initial Consultation, July 2005 (Ref No. 172/05)
- TPCR Second Consultation, December 2005 (Ref No. 277/05)
- TPCR Capital Expenditure Projections 2007-2012 (open letter), 1 February 2006 (Ref No. 21/06)

Table of Contents

Summary	1
1. Introduction	3
Main developments in the TPCR	4
Structure of the document	4
2. Form and structure of the price control	5
Introduction	5
The standard RPI-X framework	6
The starting RAV	6
Refinements to RPI-X	7
Rolling incentives	8
Information quality incentive mechanisms	8
Other possible mechanisms	9
Shorter or longer price control periods	9
Differential rates of return	9
Supplementary measures	10
Innovation incentives	10
System operator incentives	10
Background	10
Extending the SO incentive schemes	11
TPCR work underway	11
Environmental considerations	12
Use of impact assessments	12
3. Electricity incentives	13
Introduction	13
Revenue drivers	14
Background	14
Options	15
Transmission access and associated incentives	16
Background	16
Options	17
User commitment	18
Associated Incentives	19
System Reliability Incentives	19
Background	19
Options	20
4. Gas entry incentives	21
Introduction	21
NGG NTS's obligations to release capacity	21
Proposal	22
Revenue drivers	23
NGG NTS's charges for entry capacity	23
Buyback incentive	24
Background	24
Proposals	24
5. Gas offtake incentives	26
Introduction	26

The transitional regime	27
Introduction.....	27
Revenue drivers and baselines	28
Transitional incentives.....	28
The enduring regime	29
Introduction.....	29
Consideration of high level options in Second Consultation	29
Enduring offtake arrangements - EOWG discussions	31
Interaction of user commitment models with 1 in 20 obligation	31
Baseline derivation	32
Investment incentives and revenue drivers	32
Payment flows	33
Proposals for buyback incentive	33
Way forward	33
6. Expenditure analysis: Capital expenditure	34
Introduction.....	34
Overview of historical and forecast capex	35
Approaches adopted for capex assessment.....	36
Assessment of historical capex	36
Assessment of forecast capex.....	36
Assessment of asset management	36
Specific Issues	37
Cost allocation and capitalisation policy	37
The provision of network flexibility within baseline capex.....	37
Assessing transmission capacity for wind generation.....	38
Impact from "plugs" connection charging.....	39
Treatment of capex to support operational efficiency	40
7. Expenditure analysis: Operating expenditure	45
Introduction.....	45
Overview of historic and forecast controllable opex	45
Overall approach to assessing opex	48
Normalisation of cost data.....	48
Capitalisation of operating costs.....	49
Non-operational capital expenditure	49
Top down analysis	49
Benchmarking.....	51
Bottom up assessment	51
Engineering Opex	51
Support functions and overheads.....	52
Interactions between gas transmission and the GDNs	52
Non-controllable opex	53
8. Financial issues	54
Introduction.....	54
Financing of network businesses	55
Cost of capital.....	55
Latest market information.....	55
Differences between licensees	56
Financial stability.....	56
Our approach to financial stability	56
The impact of fully depreciated pre-vesting assets.....	57
Tilted depreciation	58

Do nothing.....	58
Repex	58
Financial security.....	59
Other financial issues	59
Pensions	59
Tax	61
9. Way forward.....	62
Document timetable.....	62
Workshops and working groups	62
Licensee reporting	62
Appendices	63
Appendix 1 - Consultation Response and Questions	64
Next steps.....	64
Appendix 2 - Feedback Questionnaire	69
Appendix 3 - The Authority's Powers & Duties	70
Appendix 4 - Glossary.....	72

Summary

The Transmission Price Control Review (TPCR) will set revised price controls for the electricity and gas transmission licensees to apply from 1st April 2007. The transmission networks in electricity and gas are the onshore networks of high voltage lines and cables and high pressure pipes that allow electricity and gas to be transported from producers to consumers. The main aim of this document is to set out our views on the design of the next price control regime for transmission.

This is the first occasion on which we have set price controls for the four transmission businesses at one time. Previously, price controls for electricity transmission in England & Wales, electricity transmission in Scotland and gas transmission in Great Britain have been set separately and have applied to differing 5-year periods. In this combined review we will, as always, seek to adopt an approach which is consistent with past price controls. Where appropriate we will also seek to achieve consistency of approach between the transmission licensees.

Major new investment while protecting consumers - The key theme for this review is investment. The transmission licensees have proposed investment programmes amounting to about £6.5 billion over the next five years. This represents an increase of more than 150% over their allowances for the previous 5-year periods. Investment is required both for the replacement of worn out network assets and in response to changing patterns of network use. New developments, such as the move from indigenous gas production to reliance on imports and the push to encourage renewable generation, will have major implications for the future shape of the networks and the investment they require.

The Authority's primary duty is to protect the interests of consumers. Increased investment will inevitably be reflected in higher costs to consumers and these costs will be felt particularly by the fuel poor at a time of rising energy prices. We therefore need to balance the need for investment against the cost to consumers and try to ensure that necessary investment is undertaken as efficiently as possible. This was also true in the recent Electricity Distribution Price Control Review, in which we made allowance for a 48% increase in capital expenditure by the distribution businesses. Investment is likely to be even more significant in this case.

Flexibility and 'future-proofing' - One difficulty we face is that much of the required investment will be driven by decisions made by users of the networks – in particular, new electricity generators, gas importers and gas storage schemes. It is important, for both users and consumers, that network investment is delivered when it is needed but it is difficult for us to forecast the timing of these requirements. One objective of this review is therefore to ensure that the regulatory system is sufficiently flexible to respond to users' requirements but also sufficiently robust to remain effective over the 5-year price control period without requiring us to intervene directly, other than in exceptional circumstances.

This has implications both for the design of the price control and for the arrangements governing access to the system for users.

In the case of the price control, we intend to increase the use of revenue drivers. These are automatic adjustment mechanisms to provide funding in response to user-driven investment. In principle, the base price control allowance should provide for known investment requirements and revenue drivers should adjust funding in response to developments during the period. We see this as a refinement of the existing "RPI-X" approach, making it more responsive to the needs of system users.

Improving access to networks, especially for renewable energy - In the case of access to the networks we see a strong case for reform of the existing arrangements, particularly in the case of connection of new generators to the electricity transmission network. The existing arrangements have worked well for most of the period since privatisation but have not proved to be as well suited to handling the surge of interest in renewable generation in response to the government's Renewable Obligation. At present the electricity transmission licensees provide access on a first come first served basis and require users to guarantee the full cost of new network assets, including the costs of deeper system reinforcement, during construction. This approach has failed to provide a mechanism to prioritise projects and is seen by many as a barrier to entry.

We would prefer to move towards a system which:

- clearly defines the access rights that users will receive;
- requires all users to make some commitment regarding their future use of transmission access rights to encourage efficient use of existing capacity and provide clear signals for transmission investment;
- facilitates timely connection of users; and
- reduces the burden on new users to guarantee the full costs of new network infrastructure while providing some protection to consumers against the risk of unnecessary investment.

The requirement for all users to provide some future commitment and the removal of the need to guarantee the full costs of new infrastructure should level the playing field for new and existing generators and make the access framework more responsive, particularly to future changes in the pattern and mix of generation.

Arrangements for access to the networks are not just a matter for Ofgem. They are subject to well-defined governance processes which require changes to be proposed by the industry and approved by the Authority. We therefore intend to work with the industry to facilitate the debate on access reform and we hope that this will result in the industry bringing forward proposed changes for implementation by 1 April 2007, in line with the introduction of the new price control arrangements.

Maintaining efficient and high quality transmission services - While we have placed a major focus on investment in this review, we are also considering the efficient level of costs and returns for the next review period and how the licensees should be incentivised to improve their efficiency. Incentives will also be required to ensure the existing high quality of network performance is maintained.

The next key stage in the price control review will be publication of our Initial Proposals in June of this year.

1. Introduction

Chapter summary

This chapter sets out background to the TPCR project and summarises the main developments since publication of the Second Consultation in December 2005.

Questions

There are no questions specific to this chapter.

1.1. The current (or extended) transmission price controls of the four gas and electricity transmission businesses are due to lapse on 31 March 2007. The TPCR will establish the form of the price controls to apply from 1 April 2007 onwards.

1.2. The main challenges for this price control review relate to determining the appropriate level of funding for capital expenditure. In particular:

- when and where users may want to connect to the network. This is very difficult to predict with any degree of accuracy; and
- the amount of transmission assets that may need to be replaced in the future.

1.3. The capital expenditure bids submitted by each transmission licensee is shown below.

Table 1.1 Bids for 2007-12, and current allowances (£m, 2004/5 prices)

	Non-load related capex bid	Load related capex bid	Total capex allowance last review	% increase
National Grid				
- Gas	424	698	892	26%
- Electricity	2460	1337	1453	161%
Scottish Power	366	347	152	369%
Scottish Hydro	56	766	71	1057%
Total	3307	3148	2568	151%

1.4. The traditional regulatory approach to dealing with capital expenditure requirements is to provide a fixed revenue allowance. However, there are always risks that in setting fixed allowances our expectations of the future will be incorrect. For licensees, this means that they bear the risk that the allowances will not be sufficient to fund all investments that are actually required. Consumers bear the risk that the allowances are too generous.

1.5. At this price control review there is significant uncertainty regarding the future requirements of new users, including the likely number and location of new network connections. To ensure that user driven investment is funded in an appropriate and timely manner, we are considering ways of structuring revenue allowances to

respond automatically to actual events through the use of 'revenue drivers'. Revenue drivers and other automatic mechanisms are discussed in Chapters 3 to 5.

Main developments in the TPCR

1.6. Since the publication of the Second Consultation in December 2005:

- the licensees have submitted their projections of future costs;
- we have held workshops on potential gas and electricity incentive regimes; and
- the licensees have made presentations to a sub-committee of the Authority.

1.7. We have continued to meet bilaterally with the transmission licensees and, upon request, with other stakeholders. We have also given presentations to publicise the TPCR at a number of conferences and industry events.

Structure of the document

1.8. This document should be viewed in the context of previous TPCR documents. The main purpose of this document is to:

- set out our preferred options for the form and scope of the new price controls;
- set out the case for access reform in gas and electricity;
- provide an update on the cost analysis of each of the licensees; and
- set out our current thinking on a number of the key financial issues.

1.9. The document is structured as follows:

- Chapter 2 - our current thoughts on how the price controls should be structured;
- Chapter 3 - electricity incentives - discusses the use of revenue drivers, sets out the case for changes to access arrangements, and addresses current system performance incentives;
- Chapter 4 - gas entry incentives - our initial conclusions on how the price controls should be structured to create appropriate incentives for National Grid Gas (NGG) in respect of transmission entry capacity;
- Chapter 5 - gas offtake incentives - discusses how the price controls should be structured to create appropriate incentives for NGG National Transmission System (NTS). It covers our proposals for baselines, revenue drivers and incentives within the next price control period both before and after 1 October 2010, which is the date on which NTS offtake arrangements are due for reform;
- Chapter 6 - provides an update on our work assessing the capital expenditure (capex) of the electricity licensees National Grid Electricity Transmission (NGET), Scottish Power Transmission Limited (SPTL) and Scottish Hydro-Electric Transmission Limited (SHETL), and the gas licensee (NGG).
- Chapter 7 - reviews the assessment of historic and forecast opex for the electricity licensees (NGET, SPTL and SHETL) and the gas licensee (NGG).
- Chapter 8 - discusses and updates our approach to financial issues for TPCR.
- Chapter 9 - sets out our plans for future documents and consultation workshops.

1.10. Our recently revised consultation style aims to improve the readability of our documents. While our normal document limit is 40 pages, this document has been extended to 60 pages, given the wide range of issues being addressed.

2. Form and structure of the price control

Chapter summary

This chapter sets out our current thoughts on how the transmission price controls should be structured to ensure that the licensees face stable and robust incentives to act efficiently. It highlights the potential benefits, in our view, of incentive measures which seek to maintain a consistent strength of incentive over time, and which seek to reward licensees more if they take on more challenging cost targets. The chapter also discusses potential measures aimed at promoting innovation.

Questions

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

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

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

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

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

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

Introduction

2.1. In setting a price control we aim to allow the network licensees to collect revenues consistent with the efficient operation of their network. The revenues need to cover efficient levels of operating costs and the depreciation of capital expenditure, and provide the company with a reasonable return on capital employed.

2.2. In setting the structure of the allowances we also aim to provide financial incentives for the licensees to do things more efficiently. Generally, this involves allowing the licensees to retain (for a period of time) a share of any efficiency savings they can deliver. The standard model is an RPI-X form of price control. Under this model each company is given a revenue allowance for the first year of each control period (which generally last five years). The price control then specifies that in each subsequent year the allowance will change by 'X' per cent in real terms.

If the company manages its costs such that it undercuts the revenue allowances, then the company retains the difference until the next price review. At that point, the efficiency savings are captured for consumers through a reduction, other things being equal, in the revenue allowance for the next period.

2.3. The RPI-X model means that the company is exposed to all of the difference between costs and revenues (which could be positive or negative) until the next review. An alternative approach also used by Ofgem is to expose the company to a share of the difference between costs and allowances - and to place an absolute cap on the total profits or losses in any period of time. This alternative approach is used currently for activities associated with real-time system operation. We believe that RPI-X and profit-sharing incentives have a continuing role to play for transmission in the next price control period.

2.4. Over recent years we have developed and applied certain refinements and complementary measures to the standard RPI-X form of control, most notably in the most recent Distribution Price Control Review (DPCR). A number of these refinements and innovations might also be applicable to the transmission licensees.

The standard RPI-X framework

2.5. There are a number of issues which need to be resolved in setting a price control under the standard RPI-X framework. Many of these relate to the assessment of efficient levels of costs, discussed in more detail in Chapters 6 and 7. We are continuing to analyse the data provided by the licensees to form a view on future efficient costs and will publish our Initial Proposals in June.

2.6. The other elements of calculating allowed revenues under an RPI-X framework include allowing the company to recover depreciation and to earn an appropriate return on its existing assets. This in turn requires us to establish the starting value for the initial stock of assets, or Regulatory Asset Value ('RAV'). The section below sets out how we propose to handle the setting of the initial RAVs for the transmission licensees.

The starting RAV

2.7. The normal method for setting a starting RAV is to adjust the starting RAV used for the previous price control review for additions relating to new (efficiently incurred) capital expenditure and deductions relating to depreciation of existing assets over the course of the relevant price control period. The following points should be noted in applying this basic method to the transmission licensees:

- we need to clarify what constitutes the starting point from the previous price control review. The price control extensions for SPTL and SHETL (2 years) and for NGET (1 year) used interim starting RAVs. These are being reviewed in this TPCR, and may be adjusted to reflect any differences between the interim opening RAVs that were used, and the interim opening RAVs that would have been used had we undertaken a full review at that time;

- we need to exclude from the new RAV any investment that was not efficiently incurred (having regard to the information that was available to the company at the time the investment decision was made); and
- we have been asked by NGG to extend the scope of its RAV to include Liquefied Natural Gas (LNG) storage sites that they own and operate. It has been argued that these were built as alternative to investment in the NTS and, as such, should be treated in the same manner as other NTS assets. They are not currently part of the RAV, and income from the operation of these facilities for NGG is treated as separate to allowed revenues under the price control. The facilities provide a mix of services, some of which can also be provided by other parties (e.g. commercial storage of gas).

Refinements to RPI-X

2.8. Over recent years we have developed and applied some refinements to the standard RPI-X form of control, most notably in the recent DPCR. Three significant refinements are:

- Rolling incentives - which seek to maintain a consistent strength of incentives during the price control period;
- An information quality incentive mechanism - which seeks to provide the greatest efficiency rewards to licensees who manage to deliver savings against the most demanding targets by, effectively, giving the licensees a degree of choice over their target costs. An objective here is to reduce the risk that the level of available rewards is set too high (or too low), given that, inevitably, the licensees have better information than us when the revenue allowances are set; and
- Revenue drivers - which seek to adjust revenue allowances automatically if there are changes in specified cost drivers, such as the amount of new generation wishing to connect to the network. Revenue drivers are useful where future events are uncertain.

2.9. The detailed design of revenue drivers is discussed further in Chapters 3, 4 and 5. We think revenue drivers have an important role to play in setting the new transmission price controls.

2.10. We think that rolling incentives and the information quality incentive mechanism should probably have a role to play in transmission over the next price control period. We recognise, however, that there are other ways in which consistency and strength of incentive could be structured. These mechanisms, and some of the alternative ways of addressing the same issues, are discussed further below.

2.11. The overarching objective is that we want to create stable, consistent and meaningful incentives for the licensees to find better, more efficient ways of doing things while ensuring that, over time, consumers share appropriately in these benefits. We need to be mindful that the licensees have better information than us on their costs and the scope for doing things better - and set measures which, as far as practicable, only reward genuine efficiencies.

Rolling incentives

2.12. Under the standard RPI-X framework the incentive for a company to implement efficiency savings is strongest just after a new price control has been set, and weakens over time. This is because the company only keeps (or bears) the difference between revenue allowances and actual costs until the next price control.

2.13. 'Rolling incentives' address this periodicity issue. The basic idea is that the company gets to keep (or bear) the difference between allowances and actual costs for a fixed period of time irrespective of when the difference occurs. This was implemented for capital expenditure allowances, but not for operating cost allowances, as part of DPCR.

2.14. We think an approach using consistent strength incentives is as applicable to transmission as it is to distribution. As such, we think the rolling incentives should be adopted in transmission if they can be demonstrated to be capable of operating robustly and without material adverse unintended consequences.

2.15. However, this does not mean that the detail of the mechanisms needs to be the same. For example, if we concluded that costs were less controllable and/or more uncertain for transmission licensees, then we might conclude that a shorter rolling retention period, say 3 years, was appropriate. Alternatively, we might conclude that only a proportion of the under (or over) spend should be retained for the full retention period - with the rest being reconciled to actual efficient costs at the time of the next price review. However, we are mindful that alternative approaches, like those above, may dilute incentives to invest efficiently.

Information quality incentive mechanisms

2.16. The standard RPI-X framework requires Ofgem to set a single revenue allowance for each company, and all variations between actual costs and allowed revenues are treated in the same way. The licensees will necessarily have better information than us when we set the allowances, and one potential problem is that some of the 'efficiency savings' might just reflect the allowances being set too generously. As a result, there is a risk of over-rewarding the licensees.

2.17. The information quality incentive mechanism aims to set different rewards for efficiency depending on how demanding the target allowance is. If the company agrees to revenue allowances which we consider to be demanding (in terms of the efficiency savings required to meet and beat the allowances), then available rewards should be higher. Conversely, the company should be rewarded less if it goes for relatively unchallenging revenue allowances.

2.18. During DPCR, we identified a number of issues relating to the capital expenditure bids provided by many of the distribution businesses and were concerned about providing allowances that may over-reward licensees for submitting inflated expenditure plans. We also noted the different attitudes to risk across the licensees and considered that it would be inappropriate to provide common returns across differing risk profiles. With this in mind, we put in place an information quality incentive mechanism along the lines described below.

2.19. The information quality incentive mechanism embodies a degree of choice for the licensees over whether to agree a more (or less) demanding revenue allowance. This choice will depend on the parameters of scheme we set. These parameters can only be firmed up once we have formed a view on what constitutes a more (or less) demanding revenue allowance. However, we think that the principle of providing the licensees with lower available rewards if they opt for less challenging revenue allowances is a robust one, and an appropriate means of seeking to protect consumers from the risk of over-rewarding the licensees.

2.20. We intend to develop such a scheme, in relation to the sizeable capital expenditure bids of the transmission licensees, in more detail ahead of our Initial Proposals in June. The licensees are likely to be provided with an opportunity to revise their cost forecasts (and the assumptions underpinning them) once the details of the scheme have been released.

Other possible mechanisms

2.21. Rolling incentives and the information quality incentive mechanism are two possible ways of seeking to refine the overall structure of the incentives for transmission licensees. There are, however, other approaches available to us. These include shorter or longer price control periods, and differential rates of return.

Shorter or longer price control periods

2.22. Traditionally, price controls have been set for 5-year periods (with the exception of extension reviews) and have therefore enabled licensees to retain the benefits of any efficiency savings (or bear the costs of any overspend) for a maximum period of five years. If we wish to increase the strength of the incentives we might wish to adopt longer review periods. Conversely, if we are concerned about potential volatility or inaccuracy in our cost forecasts, we might wish to adopt shorter review periods - with a resultant reduction in the strength of incentives.

2.23. The duration of price control periods was consulted upon in "Developing Network Monopoly Price Controls", where we concluded that 5-year price controls provided an appropriate balance between the interests of consumers and regulated companies. It is still our view that 5-year review periods remain appropriate, but we recognise that shorter periods might prove to be appropriate in certain specific circumstances, e.g. in respect of certain cost elements. However, our current view is that shorter (or longer) review periods are not the best means of addressing the issues of how we structure incentives, given the other tools available.

Differential rates of return

2.24. The standard RPI-X framework (and the refinements discussed above) assumes that all assets attract the same rate of return. An alternative approach would be to separate out classes of costs and apply different rates of return. For example, one rate of return could apply to existing assets, while another rate of return could apply to managing the delivery of new assets. The intention would be to provide an appropriate return on existing assets, while increasing the reward available to licensees in areas where they are taking relatively more risk.

Supplementary measures

2.25. We have also over recent years implemented a number of stand-alone incentive schemes designed to run along side, and supplement, the basic framework. These have generally been focused on specific areas of activity or performance.

2.26. The continuing structure and scope of certain performance incentives is discussed in more detail in the following chapter. In addition, we have been considering whether explicit measures to promote technical innovation by the transmission licensees are needed, and if so, how they should operate.

Innovation incentives

2.27. As part of the recent DPCR we introduced Registered Power Zones (RPZ) and the Innovation Funding Incentive (IFI). In December we indicated that, potentially, there was less need for such measures for the transmission licensees. It seems reasonable to expect the transmission licensees, irrespective of any formal incentive mechanisms, to adopt global best practice on technical matters and to actively explore R&D opportunities if required.

2.28. However, we are undertaking further work with the transmission licensees to understand what the potential value of additional measures might be. In making this assessment we will have regard to the evidence of research and development, and innovation more generally, by the licensees under the prevailing arrangements, and to factors that might indicate a change in the value of innovation and R&D in the future (given that there could be a prolonged period of network expansion and renewal over the next decade). We will provide an update on this work in June.

System operator incentives

Background

2.29. Under their transmission licences NGG NTS¹ and NGET are responsible for the following roles for Great Britain:

- Transmission Asset Owner and Operator (TO); and
- System operator (SO).

2.30. In its role as TO, NGG is responsible for developing and maintaining the high pressure NTS and associated equipment in an economic and efficient manner. In its role as SO, NGG is responsible for ensuring the efficient day-to-day operation of the transmission system. The price controls and SO incentive regime provide incentives for NGG to manage and reduce these costs effectively. NGET adopts a similar role as system operator of the GB electricity transmission system.

¹ National Grid Gas plc hold two gas transporter licences, one with respect to its National Transmission System (NTS) and one with respect to the four gas distribution networks that it continues to own following the sale of four other such networks on 1 June 2005. In this document, references to National Grid Gas are references to National Grid Gas plc in its capacity as holder of a licence in respect of the NTS.

2.31. The SO incentive schemes provide allowances for the costs that the SOs incur in performing their day-to-day functions, with associated profit sharing mechanisms to incentivise the efficient management of costs (subject to caps or collars that limit the overall exposure of the company and users to extreme cost variations).

2.32. Many of the costs incurred by the SOs relate to the external activities of contracting with market participants to keep the transmission systems in real time balance (external costs) and the internal costs of providing the SO function (staff, IT and buildings). We have also put in place further incentive schemes for NGG NTS (often referred to as the deep SO incentives) with respect to the costs of undertaking incremental capacity investment in a timely manner in response to the signals provided by system users.

Extending the SO incentive schemes

2.33. The current system operator incentive schemes are due to lapse on 31 March 2007 for NGG and 31 March 2006 for NGET. In February 2006, we proposed a one year extension to the SO incentive schemes for NGET. A statutory consultation on the licence modifications closed on 28 March 2006.

2.34. We are currently working towards setting revised SO incentive schemes to apply from 1 April 2007. We propose to issue a separate consultation on the external incentive schemes for both the gas and electricity SOs in due course. We envisage that this consultation will set out our initial thoughts regarding the form, duration and scope of the external incentive arrangements to apply from 1 April 2007.

2.35. We would welcome views from stakeholders on whether the existing form and scope of SO incentive schemes should continue from a TPCR perspective. We consider that there is merit in adopting incentive schemes with duration of greater than one year to provide stronger incentives to seek cost savings. We recognise, however, that the current uncertainties within the wholesale gas and electricity markets may make the level of day-to-day balancing activity more difficult to predict over a longer period of time. We are therefore considering whether the incentive scheme could be structured so that certain elements, which may be more uncertain, may be set for a shorter period of time than others.

TPCR work underway

2.36. The TPCR is already considering some of the deeper SO incentive arrangements with respect to gas transmission (e.g. capacity buyback arrangements and compressor fuel use) within the context of establishing appropriate cost allowances and incentives as part of the revised TO price control. We are also considering how best to incentivise the efficient management of internal costs of the electricity and gas SOs given the interrelationships with the costs of the TO function of the transmission businesses. Our work on assessing the capital and operating expenditure of the transmission businesses is also looking at the costs of the transmission businesses in the round and will enable us to form a view on the appropriate level of those SO internal costs in future years.

2.37. The split between the TO and SO functions of the transmission business is a notional one, and several cost activities of the transmission business are shared between them. Under the TO price controls, the benefits of outperforming the cost allowances is retained by the licensees in full and similarly they face all of the costs of any overspend. Under the SO incentive scheme, the benefits of outperforming the internal cost allowances are shared with users of the transmission system. We are mindful that the differential approach adopted towards similar costs may introduce perverse incentives to find ways of reclassifying costs across the boundary between the SO and TO functions. We are therefore considering whether the incentives to manage costs efficiently across the TO and SO functions should be made more consistent with each other. We would welcome views on this matter.

Environmental considerations

2.38. A number of the Authority's duties require it to consider the environment and/or environmental matters generally and specifically (e.g. in the context of National Parks legislation, for example the National Parks and Access to Countryside Act 1949). These duties include:

- the duty to have regard to the effect on the environment of activities connected with the generation, transmission distribution or supply of electricity, and with the conveyance of gas through pipelines;
- the duty to carry out certain of its functions in the manner which, amongst other things, is considered to be best calculated to (a) secure a diverse and viable long-term energy supply; and (b) contribute to the achievement of sustainable development;
- the duty to have regard, when carrying out certain functions, to any social and environmental guidance issued by the Secretary of State; and
- the duty to carry out and publish an assessment of the likely impact of implementing proposals which appear to the Authority to be important within the meaning of section 5A of the Utilities Act 2000 or to publish reasons for not doing so. A proposal is important if it would be likely to have a significant effect on the environment. An assessment under 5A must include an assessment of the likely effects on the environment of implementing the proposal.

2.39. We will comply with these duties, together with the Authority's other duties in developing its proposals under the TPCR. Details of our work programme to progress these issues are found in Appendix 9.

Use of impact assessments

2.40. In December 2005 we consulted on whether, in light of the experience of previous price control reviews, it is appropriate to adopt a different approach to Impact Assessments (IAs) in the context of this TPCR and the Gas Distribution Price Control Review (GDPCR). Having considered responses to the consultation, we propose to carry out formal IAs for all important new initiatives that are proposed as a part of the price control review, and on specific issues where it appears that an IA may be of benefit. We will not undertake a formal IA for all aspects of the price control where the approach and policy position is consistent with past price control reviews. We intend to produce a draft IA for the proposed reforms to gas offtake as part of the June Initial Proposals.

3. Electricity incentives

Chapter summary

This chapter sets out our initial conclusions on how the price controls should be structured to provide incentives for each of the three electricity transmission licensees. It discusses the use of revenue drivers (i.e. methods of linking allowances to future events or triggers) to deal with the uncertainties surrounding user needs, sets out our views on the need for changes to the access arrangements (recognising that responsibility for this lies with the industry) and highlights the need to review current incentives on system performance and reliability.

Questions

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

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

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

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

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

Introduction

3.1. This chapter sets out our present thinking on the issues associated with designing an appropriate package of incentives for each of the three electricity transmission licensees. It builds on the views we set out in the Second Consultation document, responses received to this consultation and views expressed at the Electricity Incentives seminar we hosted on 16 February 2006.

3.2. As mentioned in the Second Consultation, incentive design needs to recognise the different roles of each licensee and, in particular, the difference between NGET in its role as Great Britain System Operator (GBSO) and NGET, SPTL and SHETL in their roles as Transmission Owners. These issues will continue to be considered throughout the TPCR process.

3.3. This chapter sets out our views on the need for incentives to be designed to complement each other and form a consistent set of arrangements that will address:

- the inflexibility of revenue allowances to respond to unanticipated events;
- the problems associated with the GB connections queue;
- the lack of reliable information on future connection and disconnection available to the TOs and the market as a whole;
- the absence of incentivisation to provide capacity in a timely manner; and
- the relative lack of transparency in understanding the benefits provided for any given level of allowed revenue and ensuring that TOs face appropriate financial incentives in respect of system performance.

Revenue drivers

Background

3.4. The current price controls make only limited use of revenue drivers. NGET's allowed revenue adjusts in response to changes in total generation, while there is no adjustment mechanism in place for the Scottish transmission licensees. The inflexibility of the revenue restrictions contributed to the need to re-open the price control to fund the unanticipated increase in system reinforcement costs to accommodate renewable generation (Transmission Investment for Renewable Generation or TIRG²) during the last price control period. As respondents to the Initial and Second Consultation documents indicated, re-opening price controls dilutes the incentive properties of the price control.

3.5. An important advantage of revenue drivers is their ability to respond to unanticipated events, reducing the risk that capital expenditure forecasts set at the beginning of a price control period will turn out to be inappropriate given the levels of expenditure actually required. This protects consumers from funding expenditure which doesn't occur if forecasts are overly generous and removes volume risk from licensees, who may struggle to finance investments if allowances are unduly low. They may also reduce the likelihood of the price control needing to be re-opened.

3.6. Under a revenue driver approach, the price control will be structured with a fixed allowance to fund a 'baseline' network, and variable allowances (linked to actual demonstrated need for capacity) to fund differences from the baseline. The detail of what is included within the baseline is still being considered as part of our cost assessment analysis. It requires judgments on what (if any) investments, while not required to accommodate today's demand, will be required under a sufficiently large range of future demand scenarios.

3.7. The standard model of incentive regulation is that the company is exposed to the risks and rewards of actual costs being different to allowances for a period of time. At the end of this incentive period, the exposure is removed and the company is permitted to earn a regulated return on actual (efficiently incurred) capital costs.

3.8. We think that this standard model remains applicable to the transmission licensees. Alternative models exist which reduce or remove the exposure for the

² Transmission Investment for Renewable Generation, final proposals, December 2004, 288/04

companies during the incentive period. While this might be appropriate in some circumstances, we should recognise that this reduces the incentives on the companies to act efficiently and reduces the risk borne by the companies."

Options

3.9. In the Second Consultation, we set out three options for linking revenues to demand for network capacity:

- **Pure status quo** – retain the existing revenue driver for NGET. Whilst this option would involve minimal change, it has not coped well with the increase in renewable generation. It only adjusts revenues for a narrow set of cost drivers, does not reflect locational differences in costs, and only incentivises one of the three licensees.
- **Refinements to the status quo** – extend the use of high level revenue drivers to North and South Scotland, recognising the difference in total cost of connecting generation (or demand) in their respective areas. This option would allow revenues to adjust in a more sophisticated manner, but retains many of the failings of the pure status quo option.
- **Locational revenue drivers** – A locational revenue driver would recognise variations in the costs of accommodating increases in generation in different locations. Locational unit revenue allowances would incentivise licensees to connect additional generation at a cost lower than the allowance for each zone. This would enable allowed revenues to adjust in a much more sophisticated manner than at present, and is arguably a more cost-reflective approach. However, such a mechanism may not capture all factors influencing costs.

3.10. Our preferred option is to develop locational revenue drivers. We believe that linking revenue allowances to actual demand for capacity (rather than forecasts) better protects consumers. Forecasts are necessarily uncertain, with risks of windfall gains for the licensees (if we over estimate the required amount of works) and risks of having to re-open the controls (if we under estimate the required amount of works).

3.11. Because the cost of providing capacity at different points on the network varies, the revenue drivers should, as far as practicable, also vary by location. However, given the physical characteristics of electricity, we consider that it would be inappropriate to develop revenue drivers on an entry point specific basis. Once set, we think that the revenue drivers should be left unchanged for the duration of the price control. Revisiting the levels of the revenue drivers would dilute their incentive properties.

3.12. We are in the process of developing models of revenue drivers and discussing these with transmission licensees. Two broad methods of locational revenue drivers are being considered, based on the costs of:

- accommodating generation in various zones of the system, or
- increasing the capacity for flows across key system boundaries.

In addition, we are considering the ability of each of the models to capture the cost drivers outside the key output measure.

3.13. The revenue drivers for all three licensees would need to be set recognising that the total cost of connecting generation in a given area might involve works in more than one transmission area, i.e. the level of the revenue driver for SPTL and SHETL might need to be set at a different level to the analogous revenue driver for NGET.

3.14. In developing the detail of the revenue drivers, we are keen to make them robust to as many contingencies as possible. However, we recognise the possibility that in some instances, where there are exceptionally large investment needs, the revenue drivers might be demonstrably and materially inappropriate. For example, extension of the transmission system to the Western Isles, Orkney or Shetland might be difficult to accommodate within a revenue driver framework. In these cases (which we would anticipate being exceptional) there might be a need to supplement the automatic revenue adjustment mechanism with other mechanisms.

3.15. While any such mechanisms might take the form of separate revenue allowances (similar to TIRG), they have limited incentive properties for efficient asset delivery. Therefore, we would welcome views and proposals for potential alternative regulatory approaches that could efficiently deliver such investment, for example by considering different financing or operational approaches.

3.16. We will assess technical options for revenue drivers against past events and a range of future scenarios to see if the desired level of robustness can be met. We aim to publish this analysis as part of Initial Proposals in June.

Transmission access and associated incentives

3.17. 'Transmission access' is a generic term to describe the arrangements by which users of the transmission network obtain rights to use the network. The section above on revenue drivers proposes to link the revenue allowances of the three electricity transmission licenses, in part, to future changes in the demand for network capacity. How this works in practice depends on how the demand for network capacity is measured. The revenue drivers are likely to work better if the ways of measuring demand for capacity are accurate and stable over relevant investment timescales.

3.18. In our Second Consultation we highlighted some issues with the current transmission access arrangements, questioning whether the current arrangements were operating in the best interests of consumers and sketching out some generic alternative models as a means of stimulating debate. This section sets out our views on these issues in the light of consultation responses.

Background

3.19. All rights to use the electricity transmission system are allocated by NGET in its capacity as GB system operator. The main capacity product is Transmission Entry Capacity (TEC). TEC is expressed in megawatts. The holder of TEC has the right to export the specified number of megawatts onto the transmission system at any time,

and is eligible for compensation if NGET cannot accommodate this export on the network.

3.20. NGET operates an 'invest then connect' approach to allocating TEC to new generation. New TEC is only allocated when the necessary transmission assets are built (assuming that the needs of existing holders of TEC can be met). Transmission licensees have a requirement to offer terms to a prospective connectee, but there is no obligation concerning the time at which capacity must be provided. Consequently, it is not clear that access rights are always provided as quickly as practicable.

3.21. Applications for TEC are handled on a first-come-first-served basis, with competing requests being processed according to the date of application. In certain areas of the country, particularly Scotland, there are a lot of applications. More than 10GW of primarily renewable generation plant has applied for connection to the system. Offers for connection have been made by NGET for connections as late as 2015. The queue creates considerable administrative costs for NGET and it is unlikely that all the projects in the queue have secured the necessary consents or financing. Hence, efficient projects may be prevented from obtaining rights to use the network if they applied for a connection relatively late.

3.22. If the offering of TEC to a generator leads to a need for any investment, then the generator is required to post security to underwrite these costs, which can be large and variable. These Final Sums Liabilities (FSL) are designed to protect consumers from the risk of reinforcement works being undertaken unnecessarily, e.g. if the applicant decides, for whatever reason, not to connect to the network. FSL reflect the full deep cost of providing the capacity, including both the connection and deeper system reinforcement costs, during construction and accumulate as these costs are incurred.

3.23. In the period before any works are undertaken, an application for connection is a relatively costless exercise. As a result, the queue currently includes projects of widely varying states of readiness. In addition, a generator's FSL can be interactive with that of another prospective connectee if there are works common between them. This means that FSL can fluctuate because of events over which the generator has no control, thereby increasing risk. It should be noted that after the point at which a generator has connected, it is not required to provide guarantees or information about its future operational plans beyond one year, and only limited security for termination amounts.

3.24. Once TEC has been granted, a generator has an option to renew that capacity in the subsequent year. This free option leads to an assumption by NGET that a generator will generate at the same level in perpetuity.

Options

3.25. TPCR's Second Consultation highlighted these issues, and outlined a model based on greater 'user commitment' as a potential means of addressing some of these perceived issues. Such a model, perhaps complemented by appropriate accompanying incentives, may reduce barriers to entry and risk to generators, promote competition and increase the ability of transmission licensees to make

efficient investment decisions. The net effect of these impacts could be beneficial to consumers.

3.26. While it is appropriate for us to use the information available to us to characterise the operation of the current arrangement - and draw links between the perceptions and the interests of consumers - the development of any proposals to amend transmission access rules need to be industry led. This is because the transmission access arrangements are set out in industry codes and documents. Ofgem has a formal role in the governance of these codes and documents to approve or reject proposed changes once they have been through the relevant process of industry consultation.

3.27. However, we are firmly of the view that the existing access arrangements merit scrutiny and discussion - and that we can play an important role in facilitating and enabling debate. With this goal in mind we have recently set up an Access Reform Options Development Group (ARODG) to facilitate cross-governance discussion of access related issues. We hope that the group's discussions will inform views and allow interested parties to consider whether amendments to existing arrangements could better achieve the objectives of relevant industry codes. The group, which is chaired by Ofgem, is meeting on a regular basis throughout March and April with all discussions and information being made available via our website.

3.28. We are mindful that the timescales for progressing the transmission price control and any reforms to access arrangements may not necessarily be aligned. To account for this, we have separated elements of the price control that are contingent on access reform from those on the critical path to delivering the core control. While there would appear to be merit in developing options for access which are capable of being implemented by April 2007 in line with the new price control, we should retain the flexibility to respond should this not be the case. The group aims to publish a report by Easter for consultation.

User commitment

3.29. The commitments that current and prospective users make in respect of their future capacity needs provide important information to the transmission licensees as to how to plan investment on their networks. The current form of user commitment is FSL and a rolling obligation to pay annual use of system charges. Any changes to the form of this financial commitment, and indeed the nature of the capacity product to which the commitment relates, are dependent on the industry raising modifications to relevant industry codes and documents.

3.30. FSL embodies a high (and variable) commitment from the generator as investment is made. It falls away once the works are complete and the TEC is allocated. The potential adverse impact on competition of the current FSL arrangements means that alternatives should be considered as a matter of urgency. The arrangements, however, need to be considered in the round. We think the level, timing and potential volatility of different forms of user commitment all need consideration. Specifically, we would like to explore in more detail options which require a lower (and more stable) level of commitment during the period before TEC is granted (possibly front-loaded to deter speculative applications), combined with a continuing commitment once TEC has been granted. We recognise that this

involves, during the construction phase of connection, a degree of risk being transferred from generators to consumers.

3.31. We see considerable potential benefit in models adopting different forms of user capacity. Given that capacity is now scarce and there is a significant queue of generation wishing to connect to the transmission system, an economic basis on which to ration capacity would appear desirable. At present, efficient projects may be held back by the current arrangements. The wide range of quality of projects in the queue also make the identification of investment planning priorities much more difficult. Requiring a clearer commitment from users in return for being provided with capacity would appear to have the potential to address many of the issues in the present arrangements.

Associated Incentives

3.32. The form of any associated incentives will be dictated by the nature of any proposals to change the method by which capacity is allocated. It will be appropriate for Ofgem to respond to any models developed within the ARODG and consider whether any contingent incentives would be required to complement these.

3.33. To illustrate, a model might be proposed which required users to make a larger (but known and fixed) financial commitment when they applied for capacity but in return be granted a firmer date for the delivery of that capacity. Consequently, the price control would need to be developed to cope with an additional potential cost for NGET, i.e. the cost of buying back capacity which had not been delivered on time.

3.34. We are keen to keep the debate on access reform moving, and as such we will seek to give clarity to price control consequences of different models as they emerge from the process being managed through ARODG.

System Reliability Incentives

Background

3.35. Following the London and Birmingham transmission failures in 2004, we introduced reliability incentives in NGET's transmission licence. The rationale for introducing these incentives was to complement the existing regulatory and legislative framework by providing National Grid with direct financial incentives to meet network demand while minimising the extent and duration of interruptions to the supply of energy from its network. In January 2006, we extended the reliability incentives to apply to the Scottish Transmission Asset Owners, with various adjustments to the mechanism.

3.36. In our consultation process to modify the licences of SPTL and SHETL, we stated that the measures we were inserting should only be an interim measure, and would be assessed in the round as a bundle of system reliability incentives across the whole of GB, as part of the price control review. Both the England and Wales and the Scottish schemes are in place until March 31 2007, and will need replacing from April 2007.

3.37. Both NGET and the Scottish TOs' reliability incentives work on a sliding scale mechanism, with the licensees incentivised to outperform a given target, subject to sharing factors, caps and floors. However, the measures of reliability are assessed slightly differently to reflect the different scope of the GBSO and the TOs.

Options

3.38. As outlined in our Second Consultation document, there are several options for reforming the reliability incentives:

- a wider basket of output measures than reliability might be used; e.g. other output measures, such as the number and scale of unplanned outages, might be incorporated into the framework;
- a 'penalties only' scheme might be adopted; and
- more stringent reporting requirements might be introduced.

3.39. The issue of measuring and setting incentives related to a wider range of output measures is particularly relevant to the setting of allowances for non-load related capex. The sum of bids from the licensees for non-load related capex for the period between 2007 and 2012 is around £3 billion. The purpose of this investment would, presumably, be to maintain or improve an appropriate level of performance and reliability of the prevailing transmission network. However, system reliability and availability is also significantly influenced by operating expenditure. It is therefore appropriate for us to explore how non-load related capex and opex might be linked to more detailed reporting of system performance outputs, or to a refined incentive scheme. This would help provide a transparent link between the licensees' expenditure, which is paid for by consumers, and the improvements in system reliability which consumers can expect to receive in return.

3.40. Our provisional view is that there is merit in exploring a 'penalties only' scheme. The licensees already have licence obligations (e.g. to comply with the Security and Quality of Supply Standards, or SQSS) and incentives (through the main price controls) to maintain a high standard of network at efficient cost. A 'penalties only' scheme would supplement these measures by, in effect, specifying a minimum acceptable level of performance for consumers. We recognise that the financial sums involved are likely to be relatively small, but we also note that the incentive for the licensees in this regard is also reputational.

4. Gas entry incentives

Chapter summary

This chapter sets out our initial conclusions on how the price controls should be structured to create appropriate incentives for National Grid Gas NTS (NGG NTS). It covers the obligations to release entry capacity, and how revenue allowances should adjust with any provision of extra capacity that might be required by network users. It also discusses how allowances should be set in respect of costs incurred by NGG NTS in buying back entry capacity rights that have been sold but cannot be accommodated on the network. In addition to the specific questions here, Appendix 11 seeks views to inform our assessment of the impact of these proposals.

Questions

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

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

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

Introduction

4.1. The current price control for NGG NTS specifies quantities of entry capacity that they must release each year at each point on the network in return for a baseline revenue allowance. It also sets out complex mechanisms for adjusting revenues if extra capacity is released, and rules for how revenues adjust if NGG NTS needs to buy back capacity rights where, for whatever reason, the committed capacity is not available.

4.2. Our Second Consultation document highlighted a number of issues with the way these arrangements had operated in practice over the past price control period. An important insight has been that the detailed quantification of capacity release obligations, without the ability for network capacity to be substituted between existing and new entry points, has proven to be too inflexible. The development of large new entry points (unanticipated at the time of setting the current price control) has also highlighted potential issues with the buyback arrangements. This chapter sets out how we think the structure of the price control should be changed in the light of this experience.

NGG NTS's obligations to release capacity

Background

4.3. Rights to bring gas on to the NTS are defined (in the Uniform Network Code, 'UNC') separately for each entry point (or 'node') on the network, and are not transferable between points. We are assuming that this will continue to be the case during the next price control review period.

4.4. Currently NGG NTS has a set of obligations which require it to release for sale specified quantities of capacity rights at each node, in a series of short and longer term auctions. While we do not see any strong case at this time for fundamentally altering the way the auctions operate (recognising that they have only been in place for a relatively short period of time), we do think that the obligations on NGG NTS to release capacity should be changed.

4.5. The evidence from operation of the current arrangements has clearly indicated problems of inflexibility with annual nodal capacity release requirements. These would appear to have stifled the transfer of capacity across different points on the network, and might have provided shippers at some entry points with, in effect, a free reservation of cheap capacity.

Proposal

4.6. We are proposing quite a fundamental change. Under our proposed approach the amount of capacity to be released at any entry point at any point in time would not be set by us in advance. NGG NTS would still face an obligation to release all available capacity on the network, but would have discretion (subject to appropriate procedural safeguards) to decide what this meant in practice.

4.7. This approach would not place any explicit quantified obligations on NGG NTS to release entry capacity. Rather it would prescribe processes to be followed, and information to be disclosed, in determining the release of capacity on a dynamic basis. This will require consequential changes to the overall regulatory regime. Specifically, NGG NTS will face a new licence obligation to develop a transparent capacity release methodology - and to publish a network model to enable shippers (and other interested parties) to understand how the methodology is being applied. We would also expect NGG NTS to publish a range of scenarios to illustrate the capability of the network. These will provide important reference points to monitor the day-to-day release of capacity by NGG NTS under this framework.

4.8. The starting point for developing the new licence obligation is to apply the governance model that applies to other areas within transmission (for example, charging methodologies). This generic framework requires the licensee to develop proposals that meet certain specified objectives through consultation with the industry, and to submit them for our approval. The generic framework also requires the licensee to keep the methodology under review, and to propose changes where it believes that the objectives can be better met.

4.9. We would welcome views on this approach for a new capacity release obligation on NGG NTS, and on the process that NGG NTS should follow in developing its proposals. As a first step, we have invited NGG NTS to publish initial thoughts and a draft workplan.

Revenue drivers

4.10. The current price control has a complex set of calculations to adjust revenue allowances upwards if NGG NTS releases additional capacity on the network. An estimate of the cost of providing additional capacity (Unit Cost Allowance, or 'UCA') at each point on the network was set by us at the start of the price control, and new UCAs have been added as new entry points have been created. The extra revenue is calculated as consistent with a return on this deemed cost. The return is variable (based on bidding in the auctions) for the first five years, and fixed thereafter.

4.11. We believe that the principle of entry point specific revenue drivers should be retained, which would be fixed for five years. Because the cost of providing capacity at different points on the network varies, the revenue drivers should, as far as practicable, also vary by location. For the purposes of gas entry we consider that revenue drivers specific to each entry point is the most appropriate means of recognising the locational variation in costs. However, we think that the detailed workings of the revenue drivers can be made simpler.

4.12. Our preferred model is for us to define for each existing entry point (and each new entry point that we know about) the following:

- a trigger level of capacity at which the revenue driver would be activated; and
- a revenue allowance for long-run capacity sold over and above the trigger level.

4.13. The trigger level of capacity and the incremental revenue allowance for each entry point would be fixed for the duration of the price control. The detailed quantification of the revenue allowance, form of the revenue driver and the trigger levels for each entry point needs further work by us, and further analysis to be provided by NGG NTS. The analysis provided to date by NGG NTS on these issues is presented in Appendix 10.

4.14. Under this model the revenue allowance for NGG NTS would still be based on a return on the deemed cost of providing additional capacity, but the return would be fixed at the standard (to be determined) cost of capital for NGG NTS. Our initial thinking is that the return should be calculated on the deemed cost for a period of five years - and thereafter should be calculated on the basis of the actual efficient costs. This provides NGG NTS with a consistent incentive to beat the deemed cost, while ensuring that customers see the benefits of any efficiency savings after five years. In practice, this rolling mechanism will involve a degree of reconciliation at each price control review.

4.15. If a new (and unforeseen) entry point is created that we will need to set an additional trigger level of capacity and a revenue allowance.

NGG NTS's charges for entry capacity

4.16. NGG NTS is responsible for setting charges for using its network. This includes setting reserve prices in the auctions of entry capacity. Where capacity is not scarce, the reserve prices have similar characteristics to tariffs.

4.17. Custom and practice is such that the reserve prices in the auctions are set equal to the relevant UCA. This means that reserve prices reflect our view on the cost of incremental capacity five years ago. It also means that reserve prices have not changed since the auctions began. Arguably this is not appropriate in circumstances where costs might have changed. If reserve prices are to continue to be cost-reflective and provide appropriate signals on the cost of using different parts of the network (in absolute and relative terms), then it would appear they need to change more frequently.

4.18. We therefore think that custom and practice should change. This will require NGG NTS to take a more active role in setting reserve prices for entry capacity on its network, and will need to establish ways of doing this. The development of new methods of setting reserve prices from April 2007 onwards has already been initiated by NGG NTS through its Gas Transmission Charging Methodology Forum (GTCMF).

Buyback incentive

Background

4.19. The access arrangements in gas entry provide the holders of rights with compensation if the rights cannot be accommodated physically on the network. The compensation mechanism works by NGG NTS buying back the rights. The holder of the right sets the price at which he is willing to sell back his right. The price control is designed to share the costs of such transactions between NGG NTS and the generality of shippers (who in turn might be expected to pass the costs on to end consumers). When the costs in any given year reach a set limit (currently £12.5m), NGG NTS's share of the costs drops to zero.

4.20. The operation of these arrangements in practice has raised some significant issues for end consumers. The most material issue is the potentially large costs to consumers through capacity buy-back if large investment projects to provide additional capacity on the network are late (relative to timescales specified in the UNC). NGG NTS is required to deliver the capacity in relative tight timescales (ordinarily, three years). For large new entry points, if capacity is delivered late, the cap on NGG NTS's liabilities would potentially be reached very quickly - with the generality of shippers (and ultimately consumers) bearing the rest. Once NGG NTS's maximum liability is reached, it no longer has any financial incentive to manage buy-back costs efficiently. Further, in the circumstances where capacity at a new entry point has not yet been constructed, the holders of the capacity rights are likely to have significant bargaining power in any negotiation with NGG NTS to buy back capacity rights.

Proposals

4.21. When new capacity is provided on the network there is, inevitably, a degree of risk attached to the date of delivery. Planning issues might prove problematic, or the works might be delayed by poor weather or difficult terrain. Protecting shippers from any of this risk, and placing them in a very strong bargaining position in any negotiation with NGG NTS to buy back capacity rights, seems, with the benefit of hindsight, unduly favourable to the shippers. It is certainly unlike any set of

arrangements that might exist in a commercial setting. This is an important issue because this protection for gas shippers creates, in effect, a potentially significant (and uncapped) liability for end consumers. In comparison, the relevant shippers are fully protected and the maximum risk borne by NGG NTS is relatively small.

4.22. We are therefore proposing arrangements which provide for limits to be set on this potential liability for consumers.

4.23. Our preferred approach is to retain the current form of the buyback incentive but to limit its scope to exclude the costs of NGG NTS buying back rights because incremental capacity is being delivered late. We will come forward with quantified proposals for the main buy-back incentive in our Initial Proposals document.

4.24. For buy-back transactions associated with the late delivery of incremental capacity sold under the new arrangements, we think it is appropriate for NGG and the relevant shippers to share more of the risk, and for consumers to bear less of the risk. This requires separate arrangements. NGG NTS and shippers are the parties who are most able to manage the risk of late delivery and this should be reflected in how risk is shared.

4.25. The detail of how exactly the arrangements might work needs further consideration. One possible model (which we consider to have some merit) is outlined below, as a means of focusing debate:

- a new issue 'incremental' entry capacity right would have a right for NGG NTS to buy it back at a specified rates in certain circumstances;
- one buy-back price would apply for the period, say, 24 months after all necessary NGG NTS planning consents had been obtained;
- another much lower (possibly zero) buy-back price would apply if, for a reason outside the control of NGG NTS, (eg a systemic change in policy on planning consents), if the necessary system works had not been completed, say, three years after the capacity rights were due to be available for use;
- shippers could agree to vary the standard buy-back prices and delivery dates; and
- all associated costs and revenue for NGG NTS would be treated as excluded income for the purposes of the price control, ie. costs to other shippers (and end consumers) would be unaffected by how many new issue incremental capacity rights NGG NTS had to buy back.

4.26. Clearly there are a number of design issues that need further consideration. These include how the buy-back prices are set (and by whom) and what the specific conditions should be for the administered buy-back prices to be activated. We would welcome views on these issues.

4.27. Another design issue is whether the principle of placing restrictions on the level of buy-back compensation in certain circumstances for rights sold under any new arrangements should be applied more widely than buy-backs associated with the late delivery of new capacity. There is a risk that other types of capacity buybacks, such as buybacks associated with a large or persistent unplanned outage, may share similar characteristics to the circumstances described above.

5. Gas offtake incentives

Chapter summary

This chapter sets out our initial conclusions on how the price controls should be structured to create appropriate incentives for NGG NTS. It covers our proposals for baselines, revenue drivers and incentives within the next price control period both before and after 1 October 2010, which is the date on which enduring NTS capacity offtake arrangements are expected to be introduced.

We continue to believe that such enduring NTS capacity offtake arrangements should include a framework within which all NTS users provide signals to NGG NTS regarding their intended future use of the gas transmission network.

Questions

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

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

Question 5.3: Is the high level option proposed appropriate?

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

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

Introduction

5.1. This chapter outlines our current thinking on the incentive framework for NGG NTS with respect to the provision of capacity at NTS offtake points and the management of interruption and buy back at those points over for the next price control period. In a number of areas, our views have developed significantly since the Second Consultation as a result of responses received to this consultation and informal consultation undertaken since December through the Ofgem chaired Enduring Offtake Working Group (EOWG).

5.2. As part of the sale by NGG of four of the gas distribution networks (GDNs), we implemented incentives on NGG NTS for the period to 30 September 2008 (the "interim" period). These incentives were intended to ensure that NGG NTS manages interruption of supply points and buybacks of NTS offtake rights as efficiently as possible. In addition, the incentives were intended to ensure the efficient use of LNG facilities for the purposes of managing network constraints. Offtake arrangements are now in place for the intervening period from 1 October 2008 to 30 September 2010 (the "transitional" period), however incentives on NGG NTS have not yet been determined for the transitional period. As part of the TPCR it is therefore necessary to consider NGG NTS incentives for this period.

5.3. In the Second Consultation we also consulted on a number of options for the enduring offtake regime which will apply to the period from 1 October 2010. These included continuing with the present transitional offtake arrangements or moving to an enduring offtake model under which users would make long term commitments to securing offtake rights in order to obtain guaranteed access to the transmission network. We also set out the weaknesses we perceived in the transitional arrangements.

5.4. The Second Consultation noted that there were costs and a degree of complexity associated with the introduction of long term user commitment models. However, it also indicated that the release of a consistent framework of access products on a non-discriminatory basis over long term timescales, combined with the application of revenue drivers would help to address the deficiencies identified by the transitional arrangements. The Second Consultation therefore set out a number of options for the introduction of enduring offtake arrangements through long term user commitment models.

5.5. Having considered the views of respondents, we continue to propose that enduring offtake reform should take effect from 1 October 2007 and apply to the allocation of NTS offtake rights to NTS users from 1 October 2010 onwards (given investment lead times of approximately 3 years). However, we recognise industry concerns regarding cost and complexity and have sought to address these concerns in considering the options set out in the Second Consultation. These options are discussed in more detail below.

5.6. In the following sections of this chapter we firstly consider incentives relating to the transitional regime. We then consider the enduring regime including the high level options for long term user commitment models that were set out in the Second Consultation and the incentives that could be applied to investment and interruption under these models.

5.7. We note that further discussion of these issues can be found in Appendix 12. A summary of respondents' views is provided in Appendix 5.

The transitional regime

Introduction

5.8. In the Second Consultation, we considered the extent to which incentives and revenue drivers for the transitional period should represent a continuation of the interim NGG NTS incentives, and the extent to which they should be consistent with the enduring NGG NTS incentives eventually determined. Having considered responses to the Second Consultation, we continue to believe that, as a general principle, the transitional incentives should represent a continuation of the interim incentives already specified. However, we believe that it remains appropriate to consider:

- whether the existing interim NGG NTS incentives are appropriate for the transitional period; and
- whether there are any elements of the proposed enduring incentives framework that it would be appropriate to bring forward into the transitional period.

Revenue drivers and baselines

5.9. At present, incremental investment is remunerated by allowing the pass-through of NGG NTS estimates of financing and depreciation costs associated with such investment. However, it is our initial view that NGG NTS should have incentives to deliver incremental investment for the entire duration of the next price control period through the application of pre-specified revenue drivers.

5.10. Under a revenue driver approach, the price control would be structured with a fixed allowance to fund the existing network with revenue drivers applying to incremental capacity. On this basis it is necessary to establish offtake capacity baselines for the transitional period to 30 September 2010 in order to provide high level separation between baseline funding and remuneration of incremental investment.

5.11. At present, offtake baselines are specified at an aggregate level across GB for both firm and interruptible exit capacity until the end of the current price control period (i.e. until 31 March 2007). For the period from 1 April 2007 to 30 September 2010, it is our initial view that baselines should not be specified for interruptible capacity. Baselines should also be specified on a nodal basis in order to achieve consistency with the proposed enduring regime which is discussed further below.

5.12. It is our current view that it would not be appropriate to specify separate baselines for the GDN flexibility product in this period. If separate baselines are not specified for the GDN flexibility product then it will not be necessary to specify revenue drivers in relation to the flexibility product in advance of the enduring regime.

Transitional incentives

5.13. The NTS has a series of incentives that currently apply to it within the interim period. We consider that it would be appropriate to simplify the incentives that apply to NGG NTS for the transitional period relative to those that apply in the interim period. Our proposals are as follows:

5.14. *Foregone charges incentive.* Under this incentive NGG NTS is financially exposed to the level of revenues it forgoes through providing interruptible services, which are provided at a 100% discount to firm capacity charges. The exposure under this incentive is capped and collared at a minimal level (i.e. £1m) on a joint basis with the "exit capacity investment incentive" discussed below. We do not consider that it is necessary to continue with this incentive for the transitional period for reasons outlined in Appendix 12.

5.15. *Exit capacity investment incentive.* Under this incentive NGG NTS is rewarded for delivering incremental capacity. The exposure under this incentive is capped and collared at a minimal level (i.e. £1m) on a joint basis with the "foregone charges incentive" discussed above. We do not consider that it is appropriate to continue with this incentive for the transitional period for reasons outlined in Appendix 12.

5.16. *Constrained LNG incentive.* The purpose of this incentive is to ensure that NGG NTS uses LNG in an efficient manner when managing network constraints. We propose retaining it in its current form, and to update the incentive target value.

5.17. *NTS buyback and 15 day interruptions incentive.* Where NGG NTS interrupts a supply point for more than 15 days a transportation charge credit is paid in respect of that supply point. Under its incentives, NGG NTS is set a target cost for interruptions greater than 15 days and is exposed to the difference between the target and the actual costs of such interruptions. We are proposing to update the greater than 15 days interruption element of the incentive for the transitional period. The NTS also has a capacity buyback incentive under the interim regime. We are not proposing to continue with this incentive for the transitional period.

The enduring regime

Introduction

5.18. We continue to believe that it is appropriate to develop a framework within which all NTS users provide signals to NGG NTS regarding their intended future use of the gas transmission network. We believe that such signals should be made sufficiently far in advance of capacity requirements to allow NGG NTS to invest in the necessary system developments. Furthermore, in order to achieve robust signals, and reduce the likelihood of asset stranding, it is our view that such signals are only truly meaningful if backed by an appropriate financial commitment from users.

5.19. We recognise that different users of the gas transmission network have different characteristics. However, we continue to believe that it is possible to develop a common framework that provides consistent investment signals to NGG NTS yet is sufficiently flexible to allow users to tailor their capacity requests to their individual circumstances.

5.20. We also recognise that many respondents to the Second Consultation expressed concerns regarding the potential for unnecessarily complex arrangements. Our proposals have sought to address these concerns.

5.21. In this section we revisit the high level options presented as part of the Second Consultation and outline our preferred option. In Appendix 12, we outline our initial thinking on key aspects of the enduring offtake arrangements.

Consideration of high level options in Second Consultation

5.22. The Second Consultation considered high level options for user commitment models defined in relation to the spatial definition of both baselines and the capacity product(s) as summarised in Table 5.1 below.

5.23. As with the transitional period we consider that baselines in the enduring period should provide high level separation between TO revenue allowances and remuneration of incremental investment. However, for the enduring period we also consider that NGG NTS should have obligations to release capacity up to the baseline level determined by Ofgem.

Table 5.1 Options presented in the Second Consultation

	Status Quo	Long term user commitment models			
	Option Ex1	Option Ex2	Option Ex3	Option Ex3A	Option Ex4
Baseline	(LDZ)	Nodal	Zonal	Global/ network wide	Zonal
Product definition	Nodal	Nodal	Nodal	Nodal	Zonal
Substitution	x	✓	x	x	x

5.24. Following further consideration of the alternative options, and in the light of responses to the Second Consultation and a cost survey distributed to industry participants earlier this year, we have performed a qualitative cost benefit assessment of each of the options relative to the status quo, which is provided in Appendix 12.

5.25. We have concluded that the NTS exit capacity products offered to network users should be defined on a nodal basis. We consider that a nodal product, in contrast to a zonal product, would enable NGG NTS to receive long term user signals specific to each offtake point. This should provide precise investment signals and facilitate efficient investment with a resulting positive impact on security of supply.

5.26. The definition of zonal baselines allows the substitution of capacity across nodes without the need for the ex ante specification of nodal exchange rates or incentive payments to NGG NTS. However, it is our view that such arrangements could lead to significant complexity in the capacity allocation mechanisms and / or increased NGG NTS discretion. As such, and consistent with views expressed by respondents, we can see merits in adopting a nodal approach to baselines.

5.27. We therefore consider that Option Ex2 is an appropriate way forward with respect to the definition of the capacity product and baselines. However, we have identified a number of concerns regarding the introduction of an incentive on NGG NTS under Option Ex2 to substitute capacity across nodes in response to demand signalled by users. In particular, we consider that the introduction of such an incentive would involve :

- potentially costly incentive payments that would be necessary to discourage NGG NTS from investing instead of transferring capacity between nodes; and
- the potential need to specify nodal exchange rates ex ante and hence the potential for significant Ofgem involvement (or significant NGG NTS discretion).

5.28. We have therefore reached the view that a substitution obligation may be more appropriate under Option Ex2. Under such an approach:

- NGG NTS would have an obligation, where possible, to substitute capacity between nodes to meet demand and would only be remunerated for incremental capacity to the extent that all opportunities for substitution of nodal baselines had been exhausted; and
- where demand for capacity at another node could be met through substitution:

- NGG NTS would apply to Ofgem to adjust the baselines of the affected nodes in accordance with exchange rates calculated by NGG NTS as the need for such exchange rates arises; and
- the modified baselines would apply thereafter in terms of both the application of revenue drivers and capacity release obligations.

5.29. We acknowledge respondents' concerns that obligations should be placed upon NGG NTS to ensure the release of all available capacity at individual nodes. We consider that the obligation to offer for sale nodal baseline capacity levels and the proposed substitution obligation should mitigate such concerns.

Enduring offtake arrangements - EOWG discussions

5.30. Since January, we have undertaken significant informal consultation through a series of meetings of the EOWG. Discussions at these meetings have developed our views on a number of aspects of the enduring offtake arrangements, particularly regarding capacity allocation and the definition of offtake products.

5.31. In particular, proposals for the development of an appropriate way of allocating offtake capacity in the enduring offtake arrangements have been subject to debate. We note the views held by many industry participants that existing holders of capacity should be able to continue to roll over their existing capacity rights from year to year. In this respect our preliminary thinking is that the commitment required for new capacity should be the same regardless of whether such new investment is requested by a new or existing connectee. It is also our view that existing users should make a commitment in order to guarantee the retention of existing capacity for a fixed number of years with the number of years determined by NGG NTS following consideration of investment lead times, the profile of investment costs typically incurred within investment lead times, and asset stranding risk.

5.32. It is important to note that the nature of the capacity allocation model will ultimately need to be developed and consulted upon through industry code processes. However, we are of the view that Ofgem can facilitate debate on these issues and in this respect we intend to continue with EOWG meetings through to the release of the Initial Proposals consultation in June.

5.33. The EOWG has also debated the most appropriate way in which offtake capacity products should be defined in the enduring arrangements. Our initial view is that all NTS users should be offered the same set of offtake capacity products, and on the same terms. In addition, we consider users should signal their requirements for both "flat" and "flexible" NTS offtake capacity.

5.34. Appendix 12 describes our latest views on the definition both the flat and flexibility products, the allocation of NTS exit capacity in both the long and medium/short term and the appropriate arrangements for interruptions with respect to the enduring regime.

Interaction of user commitment models with 1 in 20 obligation

5.35. Given the proposed emphasis on user commitments for the enduring offtake arrangements, it has been necessary to consider the interaction between a full user commitment framework and NGG NTS's 1 in 20 licence obligation.

5.36. Standard Special Condition A9 of NGG NTS's licence requires it to build its pipeline system to meet aggregate daily demand which is likely to be exceeded only 1 year in 20. At present, in the absence of a framework for full user commitments, NGG NTS assesses demand from the GDNs, Transmission Connected Customers (TCCs) and other NTS users through a central planning process and invests in its pipeline system accordingly.

5.37. However, it is our initial view that, within a user commitment framework, it would only be appropriate for additional NTS capacity to be provided if NTS users have signalled that such capacity would be of value to them. In particular, in the case of the GDNs, it is our view that NTS exit capacity built for GDNs should be consistent with the GDNs' assessment of their NTS exit capacity requirements given their 1 in 20 obligation. As a result there would be greater clarity of responsibility between NTS users and NGG NTS. Furthermore, as the causality for investment would be unambiguous, users would be incentivised to provide long term investment signals.

5.38. We are therefore minded to propose that NGG NTS would only be remunerated for incremental investment to the extent that there is an associated user commitment. Furthermore, we note that compliance with NGG NTS's 1 in 20 obligation could be achieved by investing in line with user commitments which signal peak aggregate daily demand.

Baseline derivation

5.39. Appendix 7 of the Second Consultation explained the alternative approaches that could be adopted in determining baseline levels.

5.40. Given the view that user commitments should determine the long term view of 1 in 20 demand, we do not believe that it would be appropriate to determine baseline levels in accordance with an ex ante assessment of 1 in 20 demand. Instead, it is our initial view that baselines should reflect existing system capability.

5.41. We do not believe that an approach based on the theoretical maximum physical capacity of the system is appropriate as this would either lead to significant buyback exposure for NGG NTS and consumers or over-investment. Instead we believe that an approach based on practical maximum physical capacity is appropriate as it reflects the actual capability of the system and therefore recognises (at least on an approximate basis) that capacity in excess of baselines is likely to incur incremental investment costs that require funding, and capacity below such levels is not. NGG NTS has provided a preliminary indication of practical maximum physical capacity baselines which are provided for comment in Appendix 12.

Investment incentives and revenue drivers

5.42. The role envisaged for revenue drivers is outlined in Chapter 2. Given the emphasis on user commitments, it is our initial view that revenue drivers should

apply to all load related investments delivered in the next price control period, and that remuneration of such incremental investments should be contingent upon:

- an associated user commitment; and
- the capacity being physically delivered.

5.43. We consider that these arrangements should ensure that NGG NTS is remunerated for both efficient and timely delivery of incremental capacity.

5.44. As noted above, it is our view that nodal substitution opportunities should be exhausted before investment is remunerated. It is also our initial view that, where it is efficient to do so, NGG NTS should contract long term for the interruption of capacity before investing.

5.45. In determining revenue drivers, we hope to strike an appropriate balance between precision and simplicity. It is our initial view that it may be appropriate to:

- specify zonal revenue drivers for small capacity increments;
- specify project specific revenue drivers for anticipated large projects; and
- modify NGG NTS's licence in respect of unexpected projects above a certain size.

5.46. The application of revenue drivers to all load related capex implies that baselines should not increase within the price control period.

Payment flows

5.47. We continue to consider that GDNs should have a central role in the payments process, effectively acting as an intermediary for all NTS-related payments from GDN shippers. As such, payment flows would be simplified, minimising the number of payment interfaces between shippers and network owners. It is our initial view that this payment flows model should be implemented in parallel with the introduction of the enduring offtake regime (rather than in parallel with the transitional regime). This would provide industry participants with greater notice of this proposed change and allow the resulting systems changes to be coordinated with wider system changes as a result of enduring offtake reform.

Proposals for buyback incentive

5.48. The approach to buyback proposed for gas entry was articulated in Chapter 4. It is our current intention that a similar approach should be applied as part of enduring offtake reform, namely the exclusion of investment related buybacks from the price control (with safeguards in place to limit NGG NTS liability with respect to these costs) and the inclusion of operational buyback costs (as a result of planned and unplanned outages) within a sliding scale incentive.

Way forward

5.49. Our proposals in relation to gas offtake will be developed further following consideration of respondents' views, in our Initial Proposals document in June. In this document, we will also set out a draft impact assessment following discussion of the potential cost implications of our proposals with industry participants in the coming weeks.

6. Expenditure analysis: Capital expenditure

Chapter summary

This chapter provides an update on our capital expenditure (capex) assessment of the electricity transmission licensees NGET, SPTL and SHETL, and the gas transmission licensee NGG. It outlines the historical and forecast capex information submitted by the licensees, the assessment approaches we have adopted, and our further thoughts on specific capex issues raised in the Second Consultation.

Questions

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

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

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

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

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

Introduction

6.1. The Second Consultation document presented a summary of the capex information submitted by the licensees in response to our Historical Business Plan Questionnaires (HBPOs) relating to the period from the year before their most recent five-year full price control until 2004/05. It also consulted on a number of specific issues including:

- the approach to assess the efficient transmission investment for wind generation while the relevant treatment in the SQSS is under review;
- the impact of the "plugs" connection charging methodology for new connections;
- the need for network flexibility in assessing baseline capex; and
- the treatment of investment for electricity transmission system operation.

6.2. Shortly after the publication of the Second Consultation document, we received responses from the licensees to the Forecast Business Plan Questionnaires (FBPOs) relating to the period from 2005/06 to 2011/12. We also published an open letter on 1 February 2006 setting out high level capex forecasts.

6.3. We are progressing assessment work together with our consultants on both historical and forecast capex. As well as reviewing the HBPO and FBPO responses, we have raised supplementary questions and collected further relevant information from the licensees. We have held a series of meetings with the licensees and number of site inspections. This assessment work is continuing and further information is being collected from the licensees.

6.4. The outcome of the capex assessment will underpin the price control proposals by:

- establishing the level of efficient historical capex to enter the TO RAV;
- establishing the baseline capex allowances for the next price control period; and
- informing the development of revenue drivers and other incentive mechanisms.

Overview of historical and forecast capex

6.5. Figures 6.1 to 6.4 at the end of this chapter set out a high level overview of the capex information submitted by the licensees. They show the load related and non-load related capex incurred in the relevant historical periods until 2004/05 and licensees' "best-view" forecasts of these capex categories for the period from 2005/06 to 2011/12. **We have not made any adjustments to these costs.** A more detailed summary of their capex forecasts has been provided by each licensee and is included in Appendices 13 to 16 of this document.

6.6. For completeness, the figures for the electricity transmission licensees also show the total capex including allowances already made under the TIRG process. Similarly, the figures for the gas transmission licensee show the total network investment including those items triggered by entry capacity auctions.

6.7. The forecast capex submitted by all the licensees represents a significant increase over the latest full 5-year price control allowances or actual expenditure. For instance, the total forecast TO capex (i.e. excluding those funded from other mechanisms) for the 5-year period of 2007/08 to 2011/12 is £6.5 billion, in contrast with the £2.6 billion total allowance and £2.8 billion expected actual for the relevant latest 5-year price control periods.

6.8. According to the electricity transmission licensees, the key drivers for their load related capex are the development of new generation, especially from wind, regional demand increases, and a general increase in flows across the network. The key justification given for non-load related capex is an increased need to replace ageing and deteriorating assets.

6.9. For gas transmission, the load related capex submitted by the licensee is driven almost evenly by requirements from supply and demand. The higher non-load related capex is linked with the need to comply with the Integrated Pollution Prevention and Control regulations that recently came into force and the need to replace assets whose condition is deteriorating.

Approaches adopted for capex assessment

Assessment of historical capex

6.10. Our assessment of historical capex aims to establish the level of expenditure that has been efficiently incurred and to identify what this has delivered in terms of outputs. The review of the licensees' capex performance in the historical period also helps us to identify and understand issues that may impact on forecast capex. This work includes:

- variance analysis which examines the major factors influencing the differences between actual capex incurred and the projections made at the time of setting the last price controls;
- high level review of licensees' capex planning processes which enables us to assess any areas of major concern that would impact on the level, timing and efficiency of capital investment; and
- detailed assessment, at both aggregate and individual sample scheme level, of the efficiency of actual capex incurred in the relevant historical periods.

Assessment of forecast capex

6.11. The purpose of the assessment of forecast capex is to establish the efficient level of baseline capex required to deliver the relevant outputs into the future.

6.12. Similar approaches of aggregate and detailed analysis as those used in historical capex assessment are adopted here. A distinctive factor affecting the forecast capex assessment is the high degree of uncertainty in the drivers for future capex. We recognise that the transmission licensees have direct and detailed knowledge of many of the factors affecting investment in their network. We adopt the best view of future capital expenditure provided by the licensee as the starting point for our analysis.

6.13. Assessment of load related capex will involve examining the robustness of assumptions underlying the licensees' plans and the efficiency of their proposed investment programmes. It will also look into the likely range of requirements and identify how these drive the capex level. This work interacts closely with the work on developing the baseline and revenue drivers.

6.14. On non-load related capex, costs associated with asset replacement present a particular challenge in this TPCR, especially given the significant increase indicated by the licensees. To supplement the conventional top-down and sample scheme review approaches, an additional asset management work stream has been established. This is described in the following section.

Assessment of asset management

6.15. This work stream is dedicated to more in-depth review of licensees' asset management systems, covering the whole life cycle of network assets. It assesses key policies and processes e.g. organisation and resource levels, target setting and

optimisation of multiple objectives, work management, management of risk and procurement strategy.

6.16. A comprehensive assessment of the health of the licensees' asset base and the impact on system performance and risks is another key part of this work stream. This involves:

- assessment of licensees' asset condition performance measurement and monitoring records;
- inspection/audit visits to a number of representative sites for key asset categories;
- review of key system reliability performance record relevant to asset conditions; and
- examination of licensees' record of overall asset age and asset life profiles, and identification of any atypical pattern of need for asset replacement in the next price control period taking into account the findings of asset condition and wider impact on system performance.

6.17. This work stream also includes an assessment of the extent to which the licensees adopt the best practice in key areas of asset management in comparison with similar international or other GB organisations.

Specific Issues

Cost allocation and capitalisation policy

6.18. There are marked differences in the approach taken by the four transmission licensees in capitalising indirect costs (e.g. business and support overheads).

6.19. Previous price controls for the transmission licensees were conducted at different times - the most recent full price controls commenced in 2000/01 for SPTL and SHETL, 2001/02 for NGET and 2002/03 for NGG. In the separate past price control reviews, the capex and opex allowances took into account individual licensees' capitalisation levels. The assessment of historical capex and the decision on the increment to the RAV in this review would maintain this approach.

6.20. This approach could also be considered for the assessment of, and the allowance for, forecast capex. However, in the recent DPCR, the percentage of indirect costs capitalised was aligned across all the fourteen Distribution Network Operators (DNOs). We welcome views on whether a consistent approach should be adopted in this TPCR and whether, especially in the case of the Scottish licensees, the approach to them should be consistent with DPCR.

The provision of network flexibility within baseline capex

6.21. The Second Consultation document raised the issue of forecasting the need for flexibility in baseline network capacity to cope with alternative usage patterns. This relates to the provision of a headroom margin of capacity to ensure effective response to changes in the pattern of network usage due to either:

- the variation in the prevailing usage pattern itself, for example the different supply-demand matching for the same peak demand level; or
- a change in the usage pattern and level when the overall demand drops away from the prevailing peak level.

6.22. Licensees have adopted various measures to avoid investment being driven by a single view alone, ranging from the use of alternative scenarios including an average view of scaling supply to match demand, to full statistical modelling with cost-benefit analysis. In assessing the licensees' capex forecasts, we need to be satisfied that such measures appropriately reflect the level of uncertainty and the consequential impact on network investment.

6.23. One specific point worth noting here is the 5% margin applied by NGG on the 1 in 20 scenario peak day flow when planning future network capacity. It can be argued that this margin is now becoming less justified due to the following:

- entry-side user commitment regime (and soon a similar regime on exit-side) substantially reduces uncertainty of need for capacity;
- given the increase in system entry capacity, the cost for providing the margin on a greater overall base is more significant as it is more likely to trigger large lumpy capital investment;
- gas turbine compressors are being replaced with more reliable electrical compressors, which should provide greater certainty on operational gas flows; and
- better network data is being collected from enhanced telemetry and control systems.

6.24. However, a counter argument for continuing the application of the margin may be that the actual transmission flow pattern is less predictable, offshore failures are more frequent and the need for flexibility is therefore higher than in the past. In assessing NGG's forecast capex, we will therefore give due consideration to the continued suitability or otherwise of the 5% flow margin.

Assessing transmission capacity for wind generation

6.25. The majority of forecast new generation for the next price control period is wind generation. An important part of the capex assessment work, whether for baseline capex or parameters of relevant incentive mechanisms such as revenue drivers, is assessing the efficient transmission capacity required to accommodate wind generation. It has been widely acknowledged in the industry that it would not be appropriate to apply the same capacity scaling factor on wind generation as applies to conventional generation (normally around 83%) in assessing the transmission capacity required by the SQSS. While the SQSS does allow for different capacity availability scaling factors to be used for special types of generating plant such as wind, it does not specify the precise values to be used. As part of the recent TIRG work, we set out the need to review the treatment of wind generation in SQSS.

Cost benefit analysis to determine transmission requirements

6.26. The final TIRG conclusions were essentially based on cost-benefit studies to assess efficiency of network investment. We consider that it would be appropriate to

adopt a similar approach to determine relevant TPCR parameters, including baseline capex and/or parameters of relevant incentive mechanisms such as revenue drivers.

6.27. Cost-benefit studies would model the year-round availability of wind generation instead of an average view generated by applying scaling factors, and the impact of incremental transmission capacity for the whole project life time. They must take into account all efficient operational measures available to maximise the utilisation of existing transmission capacity. This will require a systematic and risk-managed approach that releases operational flexibility without unacceptable detriment to security of supplies or balancing costs. Such studies would require explicit evaluation of cost elements impacted by transmission investment such as constraints and losses. In TIRG, the following ranges of unit costs for constraining off generation were used:

- renewable generators eligible for ROCs and hydro plant installed pre 1990 and less than 20MW - a range of £65-75/MWh until 2027, after which it becomes £32-37/MWh;
- other renewable generators - a range of £25-33/MWh until 2027, after which it increases to £32-37/MWh; and
- conventional generators - a range of £10-15/MWh.

6.28. For transmission losses, the value was estimated in the TIRG work at a market-based price for replacement energy of £25-30/MWh.

6.29. The values assigned to transmission constraints and losses would have direct impact on the trade-off with transmission investment and hence influence the outcome of the assessment of efficient capex on a cost-benefit basis. It is therefore important that we take into account all the latest information. Views are welcome on the continued applicability of the above valuations and any additional factors to those considered in the TIRG work that should be included in the current TPCR capex assessment work.

Impact of changes to the SQSS

6.30. Academic research (sponsored by both DTI and the licensees) is currently being undertaken in relation to the treatment of wind generation in the SQSS. However, it is unlikely that any definitive proposals for changes to the SQSS will be ready for our approval within the TPCR timescale. It is possible that the review of the SQSS could lead to a different level of transmission capacity from that justified by our cost-benefit analysis. If the SQSS review leads to a higher level of transmission capacity being required than that shown by our analysis, derogations from the SQSS may need to be considered.

Impact from "plugs" connection charging

6.31. The implementation of the "plugs" connection charging methodology (April 2004 in England and Wales and April 2005 in Scotland) brought into the price control a substantial proportion of assets previously treated as post vesting connection assets and remunerated as excluded services. The Second Consultation highlighted an unintended and undesirable outcome of more transmission being built in the local infrastructure than was previously deemed to be economic and efficient.

6.32. The SQSS stipulates the normal level of security required for connecting a generator, and allows for variation in the local connection design so long as it is chosen by the connectee and does not adversely impact on other users' costs and security. Those generators connected in the "normal" manner obtain a firm connection and hence entitlement to compensation for interruption of access. Those choosing less secure designs are excluded from such compensation where interruption of access is caused by the connection design.

6.33. Before the adoption of "plugs" connection charging methodology, the majority of the costs for providing the local transmission assets were included in the connection charges. The generator could trade off its business risk of loss of transmission access against the savings in the connection charges and for many smaller generators this would result in the decision to choose a cheaper and less secure design. Since the adoption of the "plugs" connection charging boundary, most of the local transmission assets are categorised as infrastructure and charged out in the Transmission Network Use of System (TNUoS) charges, which currently has a degree of zonal and national averaging. The licensees reported that requests by generators for the cheaper and more economical connection designs have substantially reduced.

6.34. The difference in local infrastructure design is likely to have a significant impact on the network investment that is triggered by generation connection. In the extreme case, where (for example) connection circuits are provided by expensive under-sea cables, the impact of lack of customer choice could lead to installation of dual under-sea cables costing more than £100m.

6.35. The Second Consultation document stated that we would seek to determine allowances for capex on the basis that an efficient design is not constrained by the charging arrangements. We have already requested that NGET review the cost-reflectivity of TNUoS charges. Views are invited on whether there are any alternative measures to restore the incentives for relevant parties to reach the most cost-effective generation connection design, and on how the TPCR allowance should take into account the various possible solutions.

Treatment of capex to support operational efficiency

6.36. In the implementation of the British Electricity Trading & Transmission Arrangements (BETTA), price control allowances for capex aimed at improving the efficiency of system operation were made either explicitly (in the case of NGET's Transmission Service Scheme capex in its SO incentive) or implicitly (in the case of the Scottish TO licensees).

6.37. Under BETTA, the GBSO is responsible for operating the whole GB transmission system. Under the current division of TO and SO licence duties, GBSO is best placed to coordinate the trade-off between SO costs and network investment costs across the whole GB system. Instead of making separate allowances for individual TOs, it would appear more appropriate to include the remuneration for such investment directly within GBSO's incentives and to let it contract with the Scottish TOs for delivery. However, taking into account the responses to our Second Consultation, we will explore further any materiality and practicality issues regarding such a model with relevant parties in the process of developing the appropriate arrangements.

Figure 6.1 Summary of historic and forecast capex - NGG

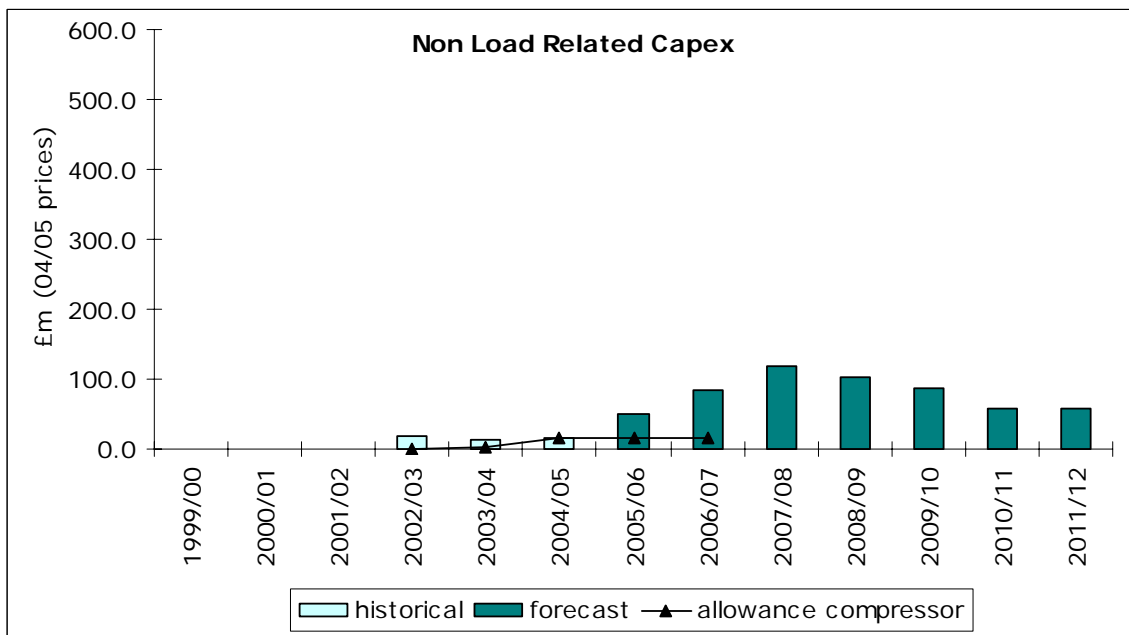
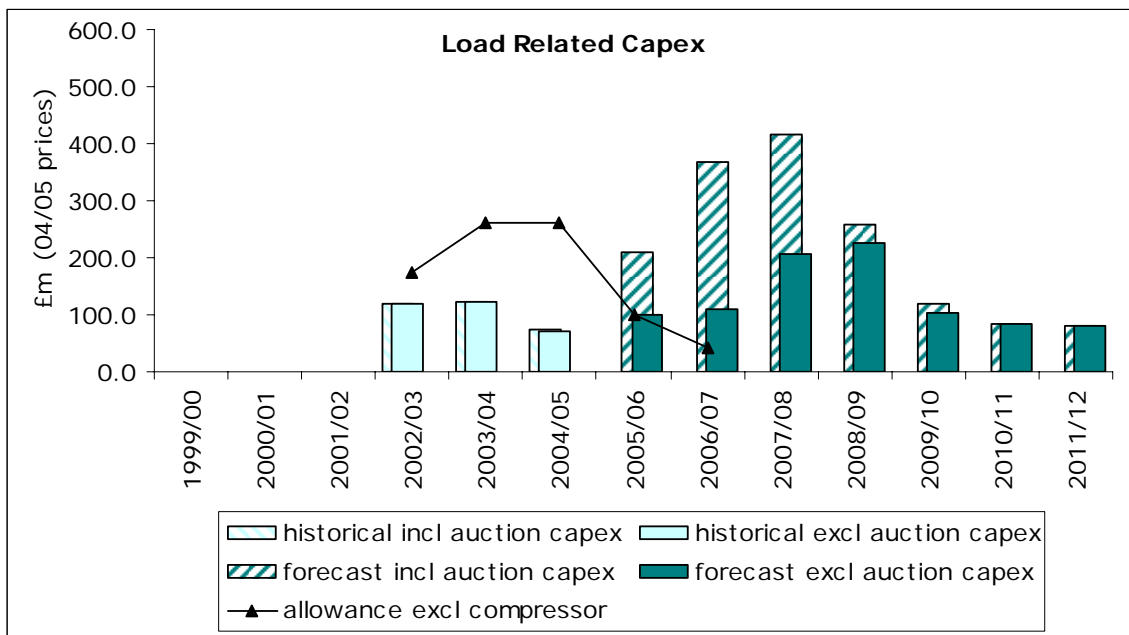


Figure 6.2 Summary of historic and forecast capex - NGET

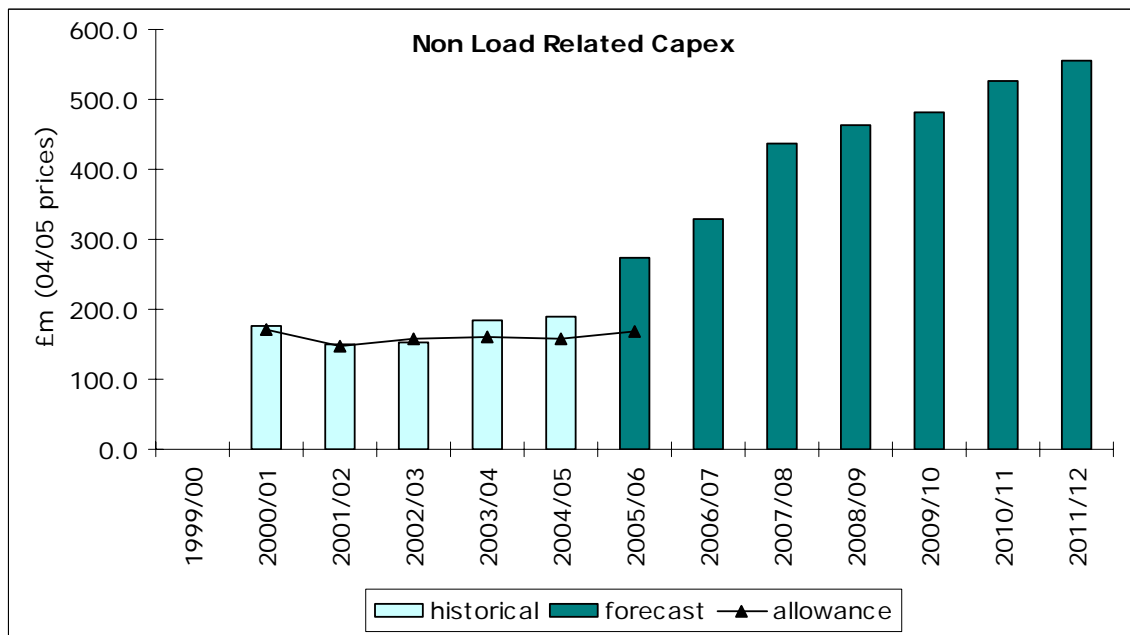
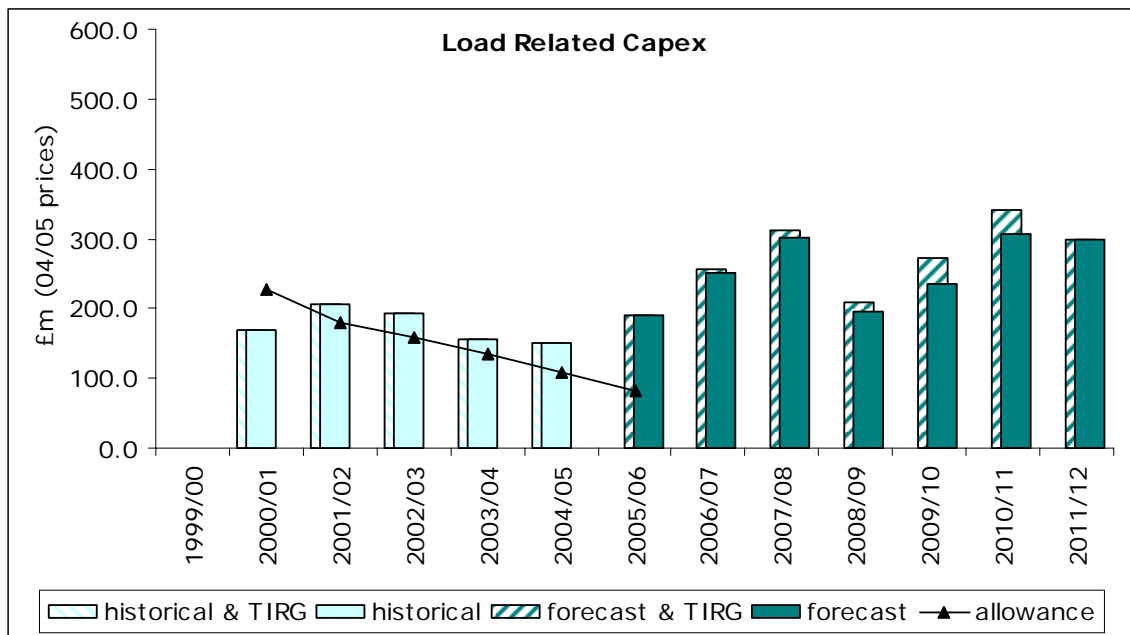


Figure 6.3 Summary of historic and forecast capex - SPTL

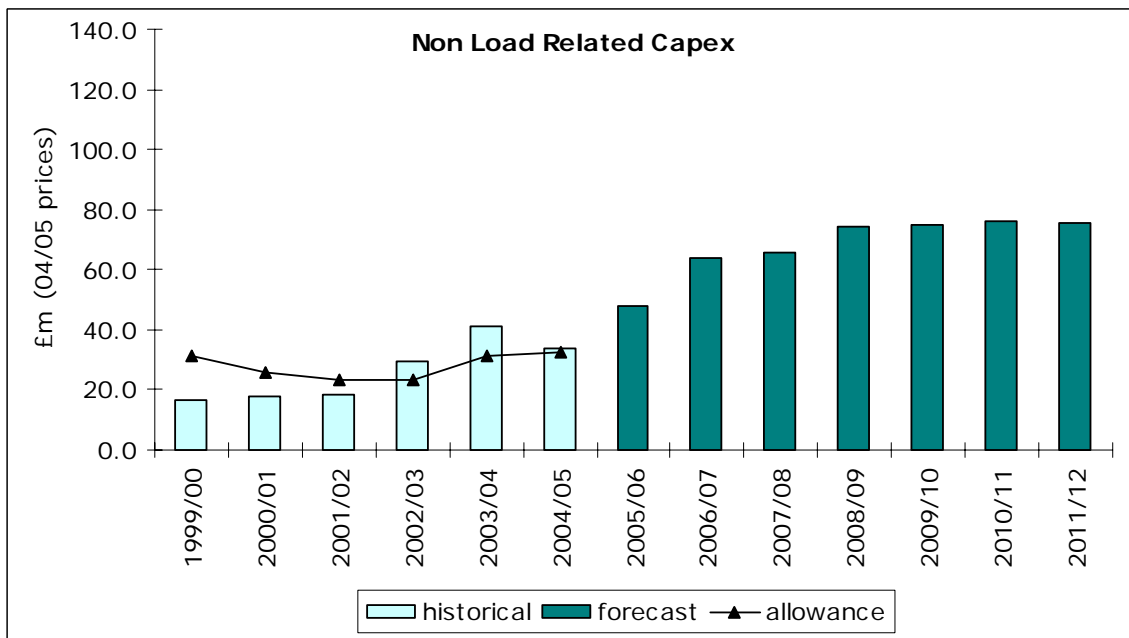
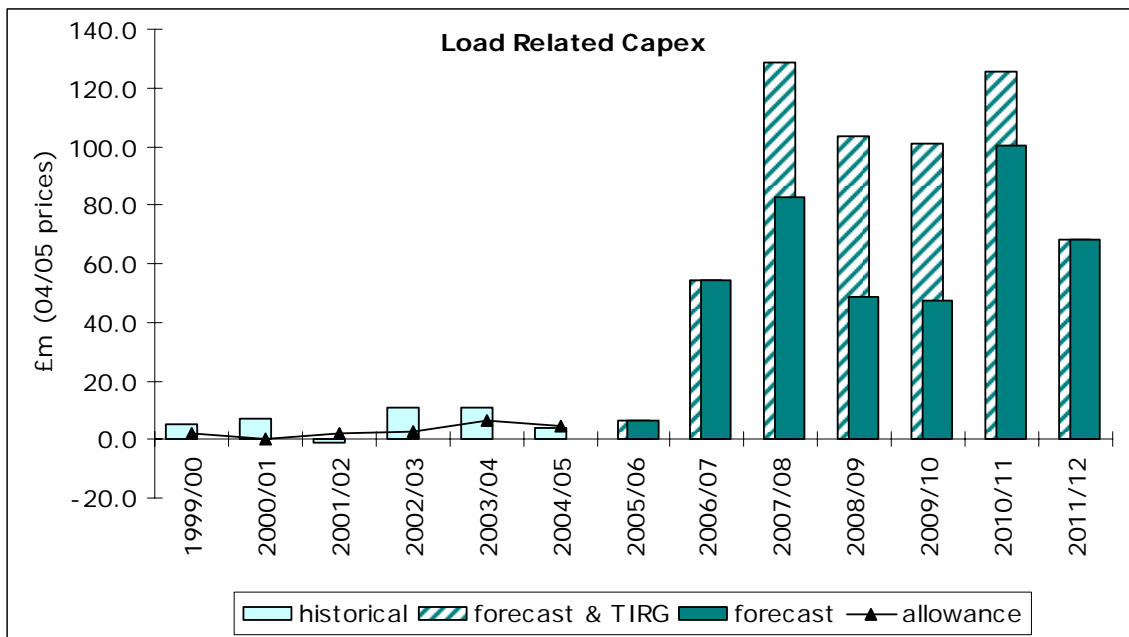
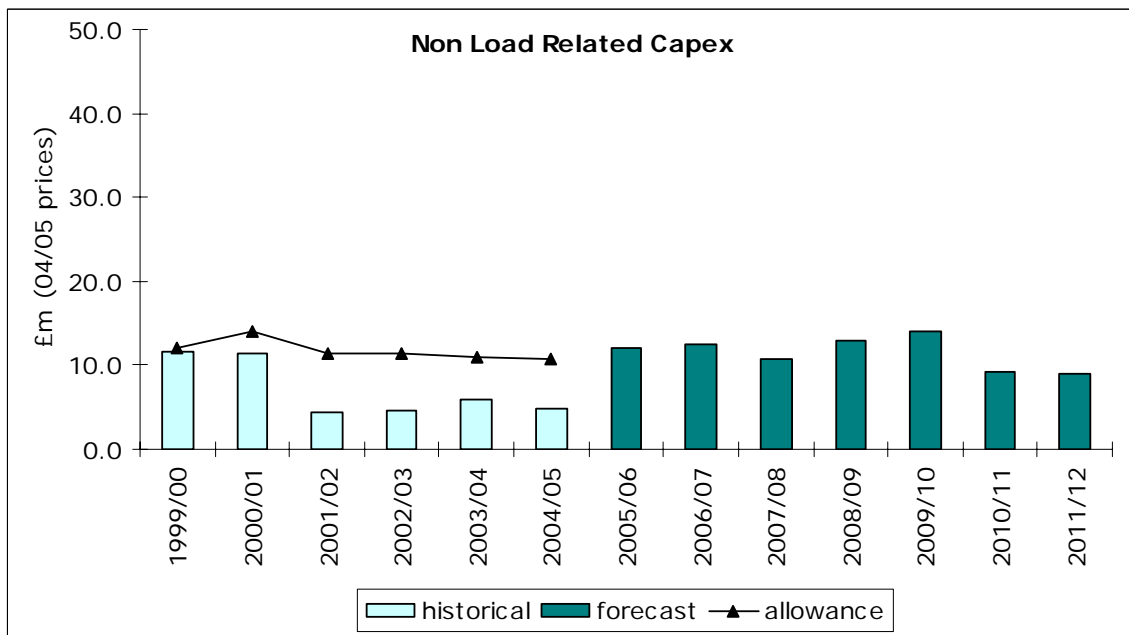
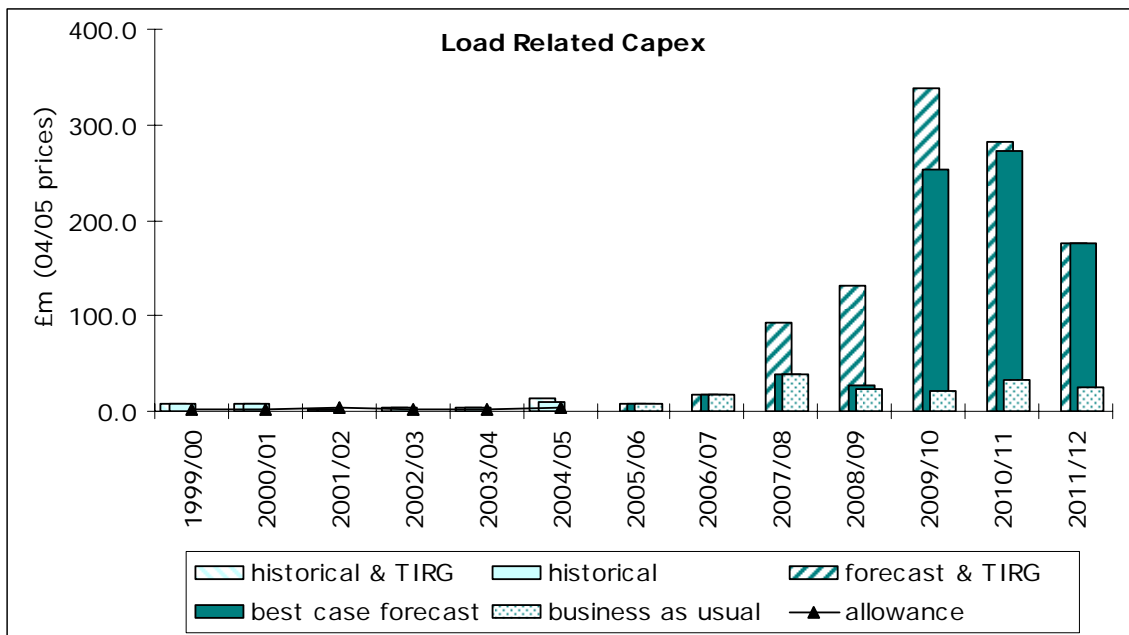


Figure 6.4 Summary of historic and forecast capex - SHETL



7. Expenditure analysis: Operating expenditure

Chapter summary

This chapter discusses the assessment of efficient historic and forecast opex for the transmission licensees for electricity (NGET, SPTL and SHETL) and gas (NGG).

Questions

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

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

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

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

Introduction

7.1. Operating costs relate to the activities required to maintain and operate the transmission networks. Operating expenditure (opex) can be split into:

- Controllable opex - these are the running costs of the business e.g. salaries and staff costs, materials, contractors, property costs etc. From an operational viewpoint this can be subdivided into the two broad categories of direct costs (engineering opex e.g. network asset inspections, maintenance, refurbishment etc), and support and overhead costs (e.g. IT, HR, finance, corporate costs etc).
- Non controllable opex - these are costs the transmission licensees have limited or no influence over, including network rates and licence fees.

7.2. In this chapter we set out our overall approach to assessing transmission operating costs, describing the work being undertaken and the key issues involved.

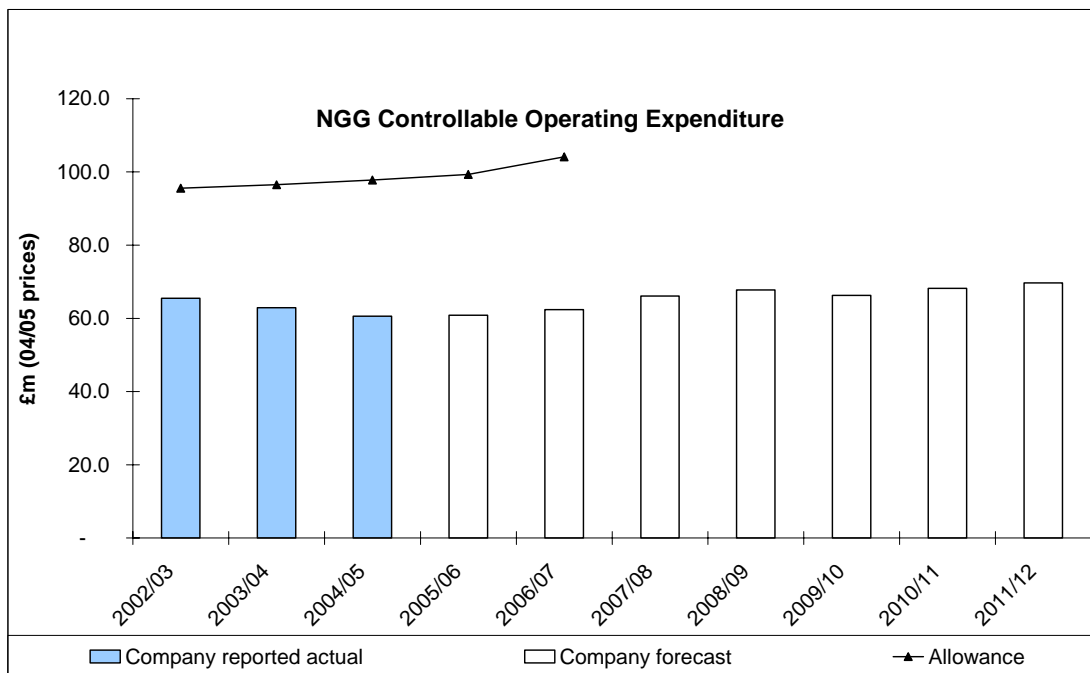
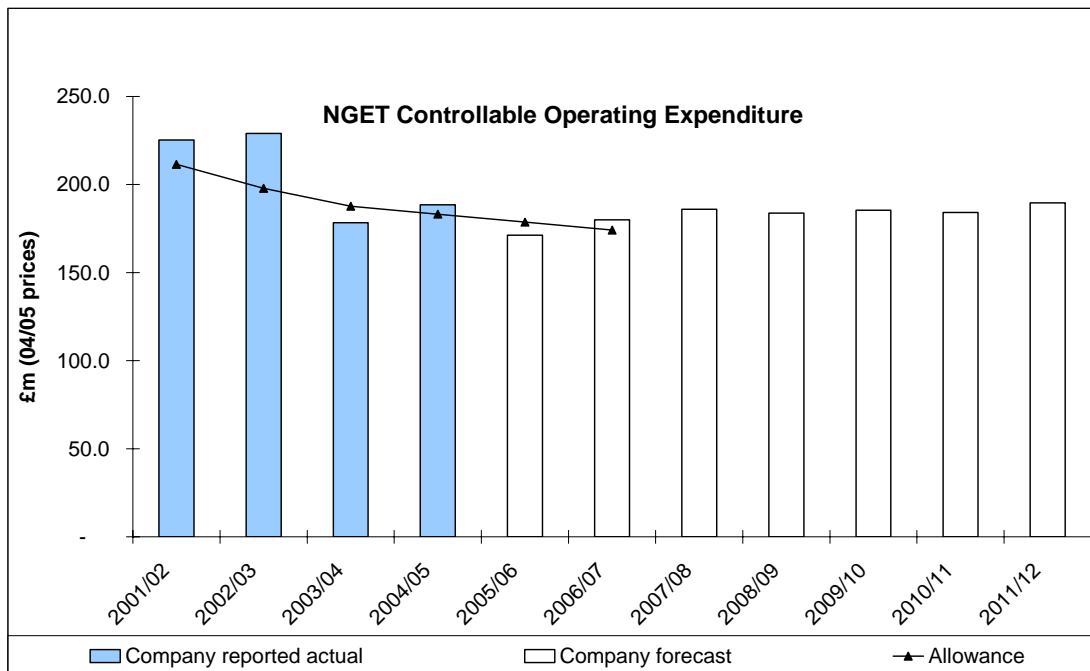
Overview of historic and forecast controllable opex

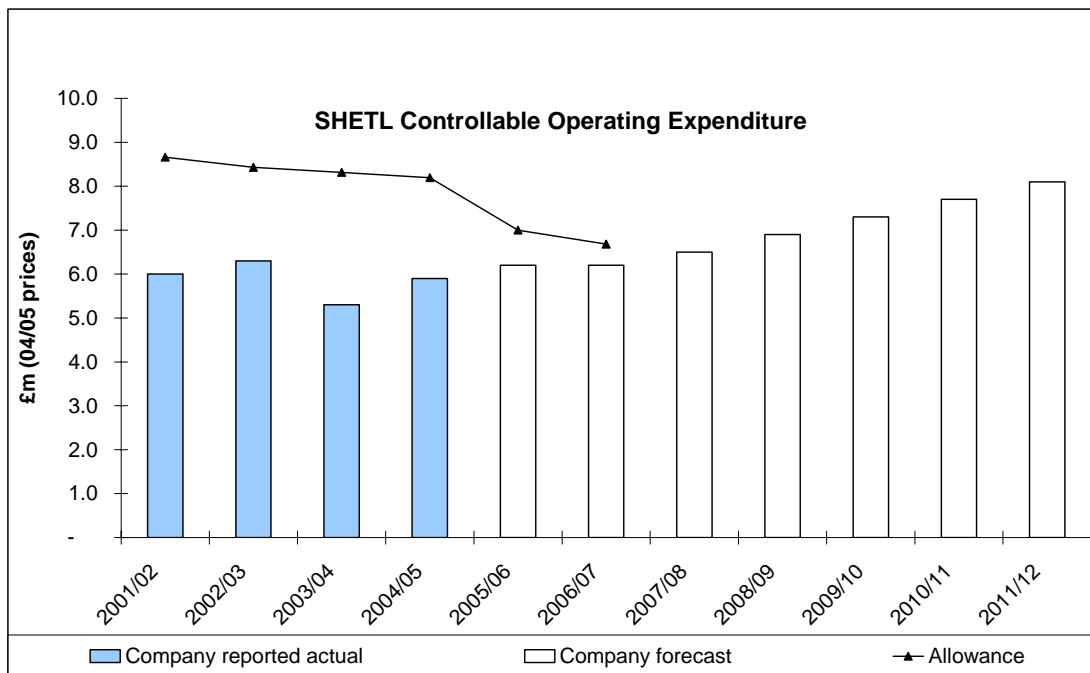
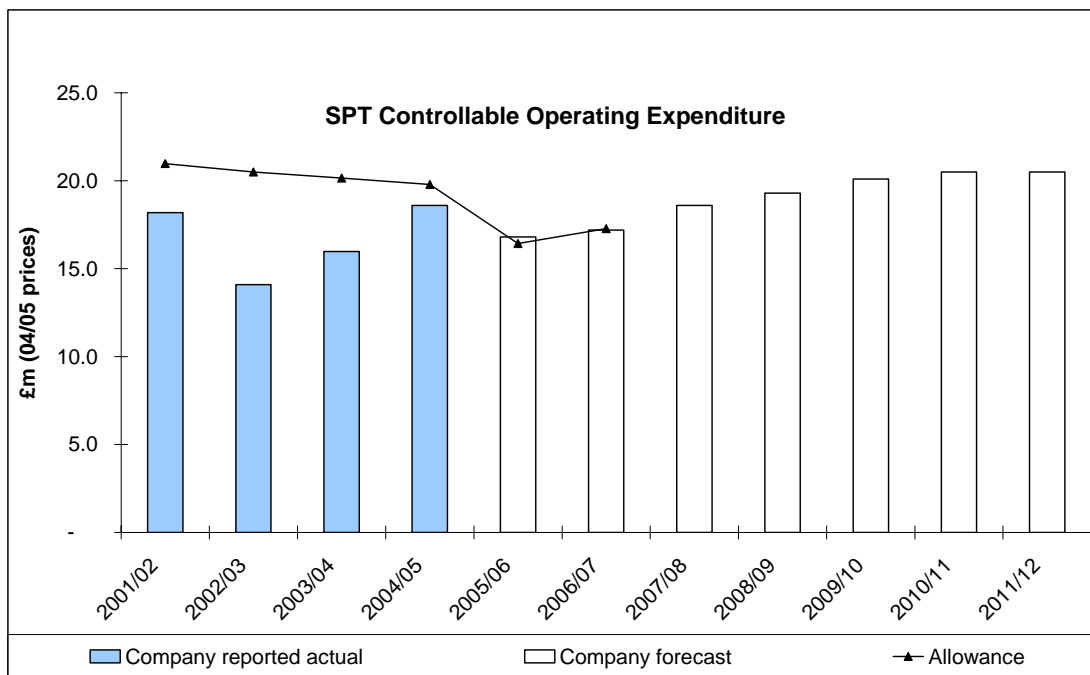
7.3. We will assess the licensees' historical performance and will seek to establish the efficiency the licensees could have achieved with respect to their historical costs. We will also examine whether any of the factors behind the licensees' historical performance have implications for their performance in the future.

7.4. Figure 7.1 below shows the transmission licensees' historical controllable opex together with their forecasts for 2007-12. In addition the charts also show the

existing price control allowances up to 2006-07. **We have not made any adjustments to these costs.** Further details are set out in Appendices 13 to 16, including narratives provided by the licensees.

Figure 7.1 Historic and forecast controllable costs (2004/05 prices)





7.5. Figure 7.1 shows that NGET appears not to have outperformed its price control allowance. Conversely NGG, SPTL and SHETL appear to have significantly outperformed the price control allowance. National Grid has stated that the figures for NGET and NGG include merger savings which were largely achieved by 2004/05.

Overall approach to assessing opex

7.6. There are a number of techniques and analyses that we can use to assess the transmission licensees' opex and determine their future allowances. These include:

- **Top down** - this is an assessment of the total cost base of the transmission licensees. For example, comparing productivity to other sectors of industry or benchmarking the transmission licensees against international companies. One advantage of this approach is that it can capture certain economy wide and sectoral factors such as technological development, labour and other input costs that could be missed at a more disaggregated level.
- **Bottom up** - this assessment splits the cost base into the key individual activities of the transmission licensees and then benchmarks across the various common activities, as appropriate, to identify the efficient level of costs that should have been incurred.

7.7. We will use a combination of top down and bottom up analyses to obtain a balanced view of the transmission licensees' opex requirements. We recognise that at the top down level there are a number of factors that will affect the extent to which comparisons can be made, particularly in relation to international comparators. While this overall approach is being applied to NGET, NGG, SHETL and SPTL, it will be important to balance the level of detail to which such costs are analysed for SHETL and SPTL against the actual scale of the costs being assessed.

Normalisation of cost data

7.8. The principal sources of cost data in the TPCR are the licensees' business plan questionnaires (BPOs). Appendices 13 to 16 set out the transmission licensees' historical and forecast opex. Before we can analyse these costs a number of "normalisation" adjustments may be required to ensure that what we are assessing reflects genuine and ongoing costs to the transmission businesses. These include:

- **Non-cash costs** - Price controls should only remunerate the transmission businesses for cash costs they incur. Therefore it is important that non-cash costs are removed from transmission opex. These items include depreciation, and certain provisions and accruals.
- **Disallowed costs** - These are costs that we do not include in controllable opex as part of the price control e.g. non trading recharges, other costs of sales, related party margins. There are also costs that are considered separately and so must be excluded from controllable opex e.g. network rates, pension costs etc.
- **Atypical costs and exceptional items** - These costs by definition do not reflect ongoing costs of the transmission businesses hence their inclusion would therefore lead to distorted analysis of operating costs. Certain costs relate to one off works of an atypically high or low level of activity (except where the activity is cyclical e.g. vegetation management). In addition, costs of restructuring, such as severance, are also excluded.

7.9. Much of our work to date on cost normalisation has focused on historical cost data for 2001-05, and this data will continue to be investigated. In addition we will consider whether similar adjustments should be made to licensees' forecast costs. We intend to assess the outturn costs for 2005/06 to verify these issues.

Capitalisation of operating costs

7.10. We are assessing the licensees' capitalisation policies relating to directly incurred costs and overheads and their impact on reported operating costs and capital expenditure. Following this assessment it may be necessary to make adjustments to opex and/or capex to ensure that these costs are not distorted.

Non-operational capital expenditure

7.11. Non-operational capital expenditure relates to items such as IT and property. Licensees capitalise such expenditure in their accounts to reflect the longer term benefits of such expenditure; e.g. IT may be depreciated over 3 to 7 years. The TO price controls for both NGET and NGG include non-operational capex as part of their RAVs, which means that such expenditure is being annuitised (and a return earned on it) over 40 years and 45 years respectively. In contrast, non-operational capex for SHETL and SPTL is included as part of opex in related party undertakings. The method of allocating costs to the transmission businesses means that some depreciation of these assets will be in the RAV.

7.12. We propose to undertake an assessment of total non-operational capital expenditure. In order to gain a complete view on the efficiency spend on items such as IT, it is necessary to assess the total costs involved i.e. the initial investment in the IT hardware/software, plus the resultant opex associated with maintenance and running costs. This will require licensees to identify all elements of historic and forecast non-operational capex.

7.13. With regard to the assessment of historic overspend, where such expenditure has been included in the RAV, we will have to consider whether overspend has been efficiently incurred and therefore how much, if any, should be allowed as part of the price control. Similar issues apply to operational capex, as discussed in Chapter 6.

7.14. The future regulatory treatment of non-operational capex applies both to historic overspend and future expenditure. There are three possible options:

- inclusion in the TO RAV. This would mean such expenditure being capitalised over 40 years (45 years for NGG);
- capitalisation over the true lifetime of such assets e.g. 3 to 7 years for IT; and
- expensing by inclusion in the opex allowance.

Top down analysis

Historical Productivity Trends

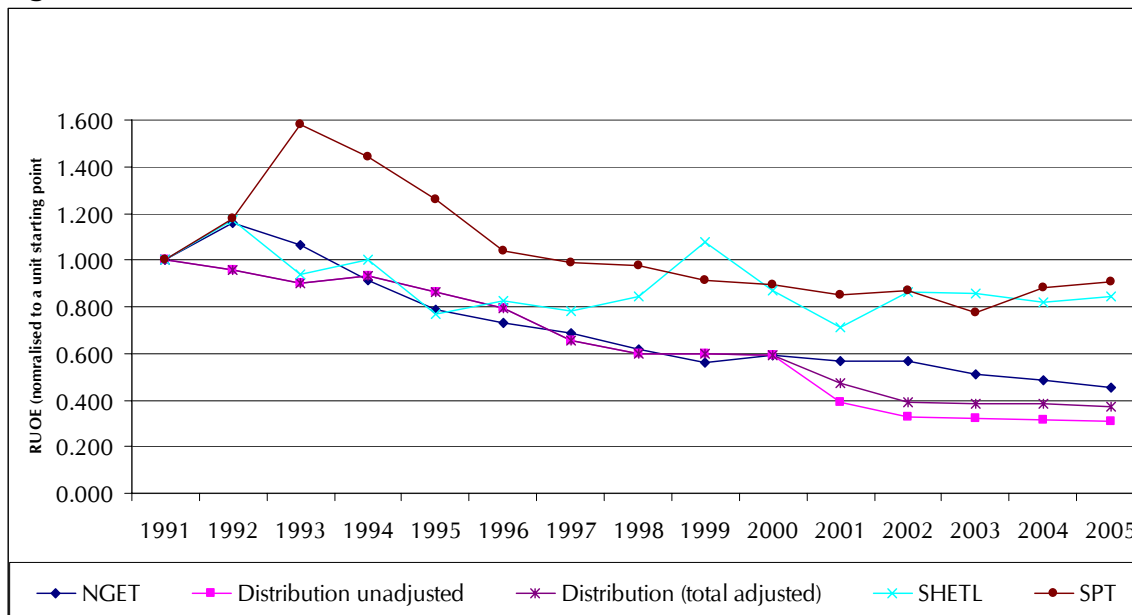
7.15. We are conducting a number of top down analyses that may provide some insights into the transmission licensees' operating costs. A common assessment is the analysis of historical productivity trends. In the case of electricity transmission, we have analysed the year-on-year reductions in real unit operating expenditure³ (RUOE) for NGET, SPTL and SHETL where consistent data is available since

³ Unit cost calculated using annual operating costs and GWh data

privatisation. We have compared these transmission licensees against the average of the DNOs, as the electricity distribution sector has experienced similar cost and operational pressures to electricity transmission since vesting. Figure 7.2 shows trends from 1990 to 2005.

7.16. NGG is not included as separate data is not available. It is intended that this will change in future with the production of separate regulatory accounts for gas transmission.

Figure 7.2 RUOE trends (1990 - 2005)



7.17. The above figure shows two series for the DNOs. The "adjusted" series addresses the possibility that some of the reduction in 2000 was due to a simple reallocation of costs out of the DNOs due to the legal separation of the former Public Electricity Suppliers (PES) supply and distribution businesses. The adjustment could be regarded as assuming a high impact of business separation, however there are a number of factors that suggest the impact is more limited and that the actual trend is closer to the "unadjusted series". The table below shows the (scale adjusted) compound annual reduction (CAR) for the whole period.

Table 7.1 Compound annual reductions in opex 1990-2005

	CAR in opex (%)
NGET	5.3
SPTL	0.2
SHETL	0.6
DNOs "adjusted"	6.5
DNOs "unadjusted"	7.7

7.18. The data shows that the reduction in operating costs has been limited in the case of the Scottish licensees. In the case of NGET, even based on the more conservative "adjusted" series for the DNOs, there is still a significant differential in

performance between NGET and the DNOs. If NGET were to match the "adjusted" series over the ten years between 1994/06 to 2004/05, this would mean that NGET's operating costs should be approximately £50 million lower than they are at present, and approximately £85 million for the "unadjusted" series.

7.19. As discussed earlier we will be considering a package of different opex analyses. Therefore we will consider this analysis together with other areas of assessment discussed in this chapter. Views are requested upon whether the transmission licensees should have performed at an equivalent level to the DNOs.

Benchmarking

7.20. We expect to make use of external benchmarking in certain areas of bottom up analysis, and where possible in our top down analysis. However, in considering whether to use international comparators at the total opex level, we recognise that there are differences that make such comparisons difficult; eg. accounting standards, operational models, network and demographic characteristics. We propose not to place significant weight on benchmarking total opex against international comparators in this TPCR. However, this is proposed as an area for development using the cost reporting framework to be introduced before the next price control.

Bottom up assessment

7.21. The bottom up assessment will focus on two key areas of operating costs: 1) engineering opex; and 2) support functions and overheads.

Engineering Opex

This is the core business activity, covering asset inspection, routine maintenance, repair and certain refurbishment. There are two primary drivers for these costs:

- Asset management policy - primarily in relation to maintenance and inspections. These policies should be continually refined as asset condition information is updated. Some policies are necessary for legislative and statutory requirements.
- Capital expenditure - in particular for asset replacement. This could include work required in advance of specific projects e.g. targeted inspections. In addition, there will be work that is undertaken as an alternative to asset replacement e.g. lighter asset refurbishment.

7.22. We are assessing historical and forecast costs for the electricity and gas transmission businesses. In general, our approach includes:

- an assessment of the licensees' historical performance including any business improvement initiatives that were implemented;
- assessing key policies and practices for each activity, in particular those which form part of the licensees' asset management system;
- where relevant, taking into account the scope for trade off between opex and capex (asset replacement versus refurbishment);
- assessing the efficiency of the licensees' unit costs for certain activities; and
- assessing the licensees' forecast costs and comparing this to our own analysis where possible.

7.23. We have met with the transmission licensees to assess the various aspects of engineering opex and to discuss data inputs for our assessment. We will continue to assess this area and further discussions are scheduled. Key issues include:

- the performance of the licensees in the present price control period - to what extent does this affect cost and activity levels in the next price control period?;
- the robustness and effectiveness of licensees' asset management policies and systems - do they directly support the licensees' forecast business plans?;
- the evidence for the impact of increasing capex on these costs; and
- the scope for (unit) cost efficiency in future.

Support functions and overheads

7.24. Support functions and overheads can have a significant impact on the overall efficiency and performance of the licensees. These functions range from IT to corporate services and may have varying degrees of direct relevance to the transmission businesses. Each has a different model for organising and running such functions. Some of these business areas may be regarded as easier in which to achieve further cost savings, often through rationalisation or outsourcing.

7.25. A key issue in relation to National Grid is the impact on these functions of the corporate restructuring through the merger and more recently the disposal of the four gas distribution networks (GDNs). National Grid's support functions cover all its UK regulated businesses (predominantly transmission and gas distribution). In order to gain a complete view of efficiency of these functions it will be necessary to assess their total costs. Cost allocation between transmission and gas distribution will then be another key issue.

7.26. We are assessing certain support functions in detail, particularly for National Grid given its substantial costs covering NGET, NGG and the GDNs. In general our approach includes the assessment of:

- the licensees' performance in a base year (in terms of cost efficiency) through external benchmarking. Costs can then be projected forward from this base year;
- the robustness and effectiveness of the licensees' policies and practices; and
- the licensees' planning assumptions.

7.27. We have held discussions with National Grid to get a deeper understanding of the relevant support functions and to discuss data inputs for the our own assessment. We will continue our work in this area and further discussions are scheduled with the licensees. The key issues include:

- the scope for further efficiency savings;
- the allocation of costs where these functions are run outside the regulated businesses; and
- the impact of corporate restructuring on these costs.

Interactions between gas transmission and the GDNs

7.28. There are a number of cost and service interactions between NGG's gas transmission business and its GDNs. It will be important to understand and quantify these costs to remove any duplication in setting the respective price controls. These interactions involve both the gas transmission TO price control and the SO internal arrangements. They include:

- the impact of DN sales in 2005/06 on shared support functions and overheads; and
- transitional agreements between NGG and their independent GDNs (IDNs) e.g. Front Office Management Services Agreed (FOMSAs), Pipeline Maintenance Centre (PMC) etc. An important issue will be whether these agreements are extended or renewed and the implications for cost recovery by NGG.

Non-controllable opex

7.29. These items are remunerated either by including an allowance as part of the price control or by allowing a pass through of these costs when they are incurred. The test for determining which items should receive this treatment is the extent to which transmission businesses can influence these costs.

7.30. Network rates are presently treated as non-controllable. However, the licensees can influence the valuation of their networks for the purposes of setting network rates for the following five year period. It is for consideration whether the treatment of network rates should be reviewed at the next rating valuation in 2010. This would be consistent with the approach adopted for the DNOs in DPCR.

8. Financial issues

Chapter summary

This chapter discusses and updates our approach to financial issues for the TPCR. In developing our policies in this area, we will have regard to the need for the transmission licensees to be able to finance the activities which are the subject of their statutory and licence obligations, provided these are efficiently conducted. We will also aim to provide appropriate incentives for licensees to make efficiency savings and, to the extent appropriate, allow customers to share in those benefits.

Questions

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

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

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

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

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

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

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

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

Introduction

8.1. The previous TPCR consultation documents have introduced our approach to a number of financial issues and invited views from interested parties. These are discussed in relation to the following three categories:

- **financing of network businesses** - the TPCR must provide a reasonable rate of return to debt and equity investors in order to enable licensees to finance their activities. Within this context, it is important to consider the impact of significant investment requirements on the financial stability of the transmission businesses;
- **financial security** - the emergence of more highly geared corporate structures raises questions of whether the regulatory regime provides sufficient protection for consumers with regard to the financial security of the regulated networks;

- **other financial issues** - we have identified a number of other financial issues including pensions and tax.

Financing of network businesses

Cost of capital

8.2. In setting revised transmission price controls, it is necessary to take a view on the appropriate allowed rate of return on assets (i.e. the cost of capital). Traditionally, the cost of capital has been calculated as the weighted average of the expected cost of equity and the expected cost of debt, for a given assumption about the proportion of investment that is debt financed (i.e. the level of "gearing").

8.3. The TPCR will consider a range of market indicators to determine appropriate estimates for the costs of debt and equity finance to inform our decision on the appropriate allowed return. We have engaged consultants to examine a range of issues surrounding our approach to cost of capital estimation and consider whether the traditional method adopted by regulators still remains appropriate. The terms of reference for this work can be viewed in Appendix 17, and we would welcome views on whether these are sufficiently complete. The consultants' conclusions will inform our high level approach to the cost of capital debate in both the TPCR and the forthcoming GPCR.

8.4. The existing price controls provide for differing real pre-tax allowed rates of return across the licensees - these are currently 6.25% for NGG and NGET, and 6.50% for the two Scottish licensees. The differences in allowed rates of return reflect two main factors:

- the timing of past electricity and gas transmission price control reviews - each review provides an opportunity to update the analysis based upon the latest market information and consequently the estimate of the cost of capital; and
- the size and structure of the transmission licensees - there are significant differences in the size and financial structure of the regulated businesses. In the past, this has informed differing views on the appropriate allowed returns according to the characteristics of the licensees.

8.5. In addition, we will consider whether the DPCR approach to estimating the cost of equity, using a long run total market return with a beta of near 1.0, is equally appropriate to TPCR or whether the evidence in the market of company specific risk differentials is now sufficient to justify or require a different approach. In particular, the introduction of TIRG and user commitment could reduce investment risk.

Latest market information

8.6. We will consider the latest market information and the conclusions of our consultants to help inform our decision on the appropriate allowed rate of return. In particular, the level of the risk free rate implied by current long term real government bond yields is very low by comparison with historical trends and would result in lower rates of return than currently used. We would welcome views on how we might approach this issue.

8.7. The recent DPCR adopted an approach of using medium term historical averages of debt costs to smooth out the effects of short term volatility, and thus obviate the need to:

- make special allowances for embedded debt; and/or
- guess the future direction and pace of market movements.

Differences between licensees

8.8. In determining the appropriate allowed rate of return, we must consider the extent to which differences across the transmission licensees might warrant differential rates of return. A key issue is the underlying risk profiles of the individual transmission licensees, which will influence the costs of debt and equity. Traditionally, we have assumed that licensees have a similar risk profile to the average company in the market (i.e. that the company beta is equal to 1) when estimating the cost of equity finance using the long run market return. However, recent estimates of company beta factors indicate that network utilities are considered to be less risky than the market as a whole.

8.9. We would welcome views on whether the estimation of the cost of capital should reflect differences, if any, in the risk profiles of the licensees. We would also appreciate comments on whether there are any other company specific factors that might be reflected in determining the appropriate allowed return.

Financial stability

Our approach to financial stability

8.10. In developing the price controls, we will have regard to the need for the transmission licensees to be able to finance the activities which are the subject of their statutory and licence obligations, provided these are efficiently conducted. In setting price controls, we determine cost allowances consistent with a well managed and efficient business. We recognise, however, that over the lifecycle of the network some network licensees will require substantial investment and may consequently experience periods of deteriorating credit ratios or apparent financial strain.

8.11. In our joint paper, "Financing Networks - a Discussion Paper", issued in February 2006, Ofwat and Ofgem discussed a range of approaches to issues of financial stability. We are committed to consulting again before making any changes to existing regulatory policy, and to allowing sufficient notice, before implementing any changes, to give licensees and markets time to adjust. We also recognised that any measures introduced in the context of the TPCR, before conclusions had been drawn from the "Financing Networks" process, would require us to consider carefully whether the benefits outweigh the costs of any change in approach.

8.12. As noted in previous chapters, the transmission licensees are projecting a significant investment requirement relative to the size of their asset base. We must examine carefully the impact that the anticipated investment requirements might have upon the ability of licensees to finance their networks appropriately. Within this context, and having regard to the growing convergence on the 'thin' equity model for monopoly infrastructure utilities, we would welcome views on:

- whether it is still appropriate for us to use a relatively conservative gearing assumption when assessing the cost of capital;
- whether it is still appropriate to assume a target credit rating 'comfortably within' investment grade when assessing the financial stability of the licensees and if so should we redefine what is meant by "comfortably within" investment grade; and
- what indicators should be examined when making this test, and what values for those indicators would be appropriate to meet the rating agencies' requirements. Table 8.1 below indicates the current position on these indicators.

Table 8.1 Financial indicators (Historical based on 2004/05)

Source:	NGG	NGET	SPUK	SHETL
S&P, except Moody & Fitch ratings				
Current Rating S&P, Moody, Fitch	A,A2,A	A,A2,NR	A-,A2,A-	A+,A3,NR
Funds from Operations/Interest	3.3	3.0	2.3	Na
Debt/Regulatory Asset Value	45%	58%	Na	Na
Funds from Operations/Debt	24%	24%	10%	Na

NR = Not rated, Na = Not available

The impact of fully depreciated pre-vesting assets

8.13. Investment in long life infrastructure assets can be financed either from

- **within the company** - from the cash flows generated by the company; or
- **external sources** - usually from finance provided by debt and equity investors.

8.14. In the Second Consultation document, we set out our concerns that, in respect of electricity transmission licensees, the regulatory depreciation associated with pre-vesting assets would cease in 2010 or 2012. The ending of regulatory depreciation on pre-vesting assets will potentially have a marked effect on the cash flow each licensee is able to generate from operations and will increase its requirement for external finance to fund future capital expenditure.

8.15. We are concerned that this increased pressure to obtain external funds may undermine the financial stability of the licensees at a time when they are seeking to undertake significant new investments. This issue does not arise in gas transmission, where a curved profile method was adopted for depreciation of pre-vesting assets instead of the straight-line method used in electricity transmission.

8.16. Table 8.2 below sets out the pre- and post-vesting components of the RAV, and the related depreciation allowances, for each of the electricity transmission licensees based on their historic capital expenditure. It also sets out the cash flow presently generated by the depreciation of pre-vesting assets of each company which will be lost once the assets have been depreciated fully. This is commonly known as the depreciation "cliff face".

8.17. It is for consideration whether this shortfall in cash flow should be addressed specifically, or whether it should be seen as part of a wider question about the ability of licensees to finance their activities. Three alternative approaches to addressing

the issue directly are set out in this section. We would welcome views on which option (or combinations thereof) is the most suitable.

Table 8.2 Depreciation of pre-vesting assets

Values in 2004-05	NGET	SPTL	SHETL
Post Vesting RAV	£3,880m	£353m	£169m
Post Vesting Depn. per annum	£110m	£9m	£4m
Pre Vesting RAV	£1,189m	£217m	£72m
Pre Vesting Depn. per annum	£238m	£43m	£10m
Operating Profit	£537m	£97m	£30m
Pre Vesting Depn. / Op. Profit	44%	44%	34%

Tilted depreciation

8.18. The depreciation cliff face is not a problem unique to electricity transmission. In the previous two electricity distribution price control reviews, we identified a similar cliff face problem in relation to pre-vesting distribution assets. We addressed this issue by accelerating the depreciation rate of post vesting assets to generate additional cash flows sufficient to fill much of the gap left by the ending of pre-vesting depreciation.

8.19. This approach of "depreciation tilting" could be applied to electricity transmission. However, its main disadvantage is that the resulting RAV may therefore diverge from the 'true' economic value of the regulated businesses, and lead to different equilibria between future depreciation and investment levels. This may have unintended or undesirable consequences. In particular, it may lead to more pronounced financial stability issues in the future, especially if investment requirements continue at high levels for a prolonged period or if there are future peaks in the next investment cycle.

Do nothing

8.20. Under this approach the regulatory depreciation of pre-vesting assets would be allowed to fall to zero and the resulting shortfall in revenues would be considered as part of the wider question of financing the licensees' activities. This approach would be inconsistent with our approach in the case of electricity distribution and, if no other compensating action were taken, may have implications for the cost of capital.

Repex

8.21. Under this approach, we would advance funding for future capital expenditure to replace the cash flow lost by ending the pre-vesting depreciation allowance. This could be achieved by having an operating cost allowance for a proportion of capital expenditure incurred to replace existing assets. This approach is already used in gas distribution to alleviate financial stability issues in relation to the mains replacement programme. A disadvantage of this approach is that it places an increased burden on present day consumers instead of sharing the burden with future customers who will equally share the benefits of the investment.

Financial security

8.22. The potential increase in gearing raises questions in relation to the existing ring-fence licence conditions. Views are sought on whether:

- the existing arrangements provide sufficient protection against licensees transferring debt from very highly geared holding companies to the regulated licensee with potential adverse consequences for consumers; and/or
- borrowing from within the group should take place on an arm's length basis and on normal commercial terms.

8.23. In both DPCR and at the time of NGG's (then Transco plc) sale of four of its GDNs we concluded that the existing financial ring-fence provisions are largely able to address these concerns. We proposed amendments to the licences of the DNOs, the GDNs and NGG's NTS business to include a 'cash lock-up' mechanism which, in certain circumstances, prohibits the company from entering into certain transactions which transfer cash or other valuable assets to affiliates and also made some other minor changes to the financial ring-fence conditions.

8.24. In our Second Consultation, we indicated that we would make corresponding changes to the licences of electricity transmission licensees. The appropriate drafting to implement these arrangements will take place over the coming months.

Other financial issues

Pensions

8.25. Each company has indicated an expectation of substantially higher ongoing pension contributions as a result of changing actuarial assumptions (in particular, those relating to future returns and longevity). National Grid has indicated that it expects larger deficits in its two funds at the next actuarial valuation. These factors, together with the shorter deficit recovery period which may be required by the Pensions Regulator are likely to result in substantially higher allowances for pension costs. We would welcome views on whether benchmarking the levels of total employment cost categories is the best means to incentivise the licensees to control their pension costs. The current position of the relevant pension funds is as follows.

Table 8.3 Pension fund data

Pension data	NGG (LGPS)	NGET (ESPS)	SPTL	SHETL
Date of last valuation	2004	2004	2003	2003
Assets	£11.9bn	£1.2bn	£1.7bn	£0.8bn
Members	113,943	11,300	18,625	6,541
Deficit at last actuarial valuation	£879m	£272m	£198m	£44m
Employer & employee contribution	23.7%	19.1%	20.0%	26.0%
Next actuarial triennial valuation	Mar 06	Mar 07	Mar 06	Mar 06

Note that the valuation dates differ, and the market increase between 2003 and 2004 virtually eliminated the deficits of the Scottish TO's.

8.26. As discussed in the Initial and Second Consultation documents, in determining the appropriate allowances for pension costs we will build on the approach established in Developing Network Monopoly Price Controls and applied in DPCR. In particular, we will apply the guidelines set out in Developing Network Monopoly Price Controls (Ofgem ref 54/03), which were reproduced in Appendix 1 of the Initial Consultation.

8.27. A major issue for this review is the allocation of deficits between attributable and non-attributable members of the relevant pension schemes. This is particularly important in relation to the Lattice Group Pension Scheme (LGPS), and specifically in relation to the treatment of liabilities ("the Centrica liabilities") which relate to employment in the former gas trading and metering activities of NGG's predecessor company, British Gas plc, prior to the de-merger of these activities in 1997 to form British Gas Trading plc (now a wholly owned subsidiary of Centrica plc).

8.28. Our position is that liabilities relating to the non-regulated businesses should not be recovered through the price controls of the regulated business. Guideline 6 (Ofgem ref 54/03) stated "Liabilities in respect of the provision of pension benefits that do not relate to the regulated business should not be taken into account in assessing the level of costs for which allowance is made in the price control." This view was restated for the DN Sales (Aug 2004) and for this TPCR (Dec 2005). National Grid has previously stated that it does not accept this principle.

8.29. National Grid has summarised its position as follows: "in respect of the stance on the legacy pensioners issue, that Ofgem does not wish to fund pension costs in respect of those pensioners who formerly carried out activities transferred to Centrica in 1997:

- for a transaction which was actively encouraged by Ofgas, and in the light of information available at the time, British Gas (BG) could not have been expected to act in any way other than to keep all the pensioners and deferred pensioners within the LGPS which was in substantial surplus at the time – a surplus which the MMC and Ofgem have used for the benefit of gas network customers. In addition, any expectation that BG should have put in place a risk sharing mechanism would have been at variance with normal practice at the time and would have been an efficient action only with the benefit of hindsight;
- to penalise National Grid Gas now for this decision would be inconsistent with the regulatory treatment adopted at the last two price control reviews and inconsistent with the principle that the efficiency of a company's actions should be judged in the light of information available at the time those actions were taken; and
- transportation customers have had the benefit of the surplus now argued to relate to Centrica activities for those two price controls".

8.30. We acknowledge the argument that the pension contribution rates underlying the allowances made in previous price controls implicitly took account of the levels of scheme surplus that were apparent at the time, and that any surplus may in part have arisen from contributions previously made in respect of Centrica members. On this basis it is possible that earlier price controls may have reflected an inappropriate allocation of costs. It will be important to consider the implications for this review of any inappropriate allocations which may have been made in the past.

8.31. At the time of the Centrica de-merger Ofgas did not make any public statements on the issue of pension liabilities because it was entirely a matter for the management, shareholders and their respective advisers. We understand that the Scheme of Arrangement made to implement the de-merger included provisions whereby the pension benefits of those active members of the LGPS whose employment was transferred to Centrica became liabilities of the Centrica pension scheme. Liabilities in respect of all pensioners and deferred pensioners, including those whose employment had been either partly or wholly in gas trading activities prior to de-merger were retained by the LGPS, together with the related share of scheme assets. We further understand that at the time of the de-merger, the attributable share of assets exceeded these liabilities.

8.32. We consider that, in agreeing to the terms of the de-merger, the directors of each of British Gas plc and Centrica plc must have considered (implicitly if not explicitly) that the de-merger terms fairly reflected this allocation of pension scheme assets and liabilities, and the attendant risk that their values may change in the future. The costs and benefits of the de-merger accrued to the shareholders in each company in accordance with the disposition made by the Scheme of Arrangement. Accordingly, any increase in the value of the attributable share of scheme assets relative to the value of the retained Centrica liabilities would have accrued (directly or indirectly) to British Gas (now NG) shareholders. Our view, therefore, is that it would be inappropriate for customers of NGG to bear any of the costs of repairing the deficit that has subsequently emerged as a result of the Centrica liabilities now being greater than the attributable share of scheme assets.

8.33. We consider that Early Retirement Deficiency Costs (ERDCs), are also for the account of shareholders (Guideline 7, Ofgem ref 54/03). In this context, the two National Grid transmission businesses appear to have adopted different approaches: in general LGPS had employer funding whereas the Electricity Supply Pension Scheme (ESPS) did not, often because it was in surplus at the time. We note that the circumstances of NGG are different to the DNOs in that NGG currently has an explicit pensions allowance and has already made greater contributions than the allowance. It is therefore unlikely that there will be a direct read across from DPCR, in which there was an interaction between the approach to ERDCs and the decision not to apply the over/under-funding principle to past periods. The manner in which the principle is to be applied at TPCR is therefore a matter for further consideration.

Tax

8.34. Work to assess the expected capital allowance pools of the licensees is continuing. Tax computations for 2004-05 have not yet been submitted to HM Revenue and Customs by all of the Licensees. We propose to maintain the ex ante approach to tax adopted for DPCR. Views are sought on whether we should make any ex post adjustments for changes that result from either:

- events out-with company control eg. tax law, tax consequences of other unavoidable events, disallowance of assumed treatments; or
- events within company control eg. gearing, choice of accounting policies, claiming allowances/offsets, and pensions; or
- where, due to changes during the price control period, actual tax payments differ materially from the assumed levels on which the price control is based.

9. Way forward

Chapter summary

This chapter provides an update on our workplan, including the future document schedule, and plans for further consultation workshops.

Questions

There are no questions relating to this chapter.

Document timetable

9.1. The TPCR document schedule following this Third Consultation is set out below:

- **Initial Proposals** - June 2006
- **Updated Proposals** - September 2006
- **Final Proposals** - December 2006

9.2. Further consultation documents, open letters and other methods of consultation (e.g. workshops) will continue to be added as appropriate.

Workshops and working groups

9.3. Over the last three months we have:

- convened the Enduring gas Offtake Working Group (EOWG);
- held a workshop on electricity incentives;
- held a seminar on enduring gas offtake reform; and
- convened the electricity Access Reform Options Development Group, (ARODG).

9.4. Our future workplan includes the continuation of the above working groups (EOWG and ARODG), as well as the following workshop:

- gas incentives workshop - scheduled for 19th April;
- cost assessment workshop - scheduled for 24th April;
- financial issues workshop - intended for July 2006; and
- final proposals workshop - intended for July 2006.

9.5. If you would like to attend either of the workshops to be held in April, please send an email to tpcr.responses@ofgem.gov.uk indicating clearly which workshop you are interested in. To ensure that there is balanced representation from stakeholder groups, places will be limited to one representative per licensee.

Licensee reporting

9.6. In our Initial Proposals, we also expect to discuss plans for improving the information available from licensees, including cost reporting (for capex and opex), financial regulatory reporting (in line with EU Directives), and system performance.

Appendices

Index

Appendix	Name of Appendix	Page Number
1	Consultation Response & Questions	64
2	Feedback Questionnaire	69
3	The Authority's Statutory Duties & Powers	70
4	Glossary	72

Index - Supplementary Appendices

Appendix	Name of Appendix
5	Responses to TPCR Second Consultation
6	Responses to TPCR Open Letter on capex projections
7	Responses to informal consultation events
8	Details of respondents
9	Environmental considerations
10	Gas entry modelling results
11	Assessing the costs of amending the gas entry capacity arrangements
12	Gas offtake technical details
13	Summary historic & forecast data (NGET)
14	Summary historic & forecast data (NGG)
15	Summary historic & forecast data (SPTL)
16	Summary historic & forecast data (SHETL)
17	Cost of capital study: terms of reference

Note that the Supplementary Appendices are found in a separate appendices document.

Appendix 1 - Consultation Response and Questions

1.1. In particular, we would like to hear from electricity transmission licensees, gas transporters and other interested parties.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 28 April 2006 and should be sent to:

Robert Hull
Director - Transmission
Office of Gas & Electricity Markets, 9 Millbank, London, SW1P 3GE
Tel: 020 7901 7050
E-mail: tpcr.responses@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in our library and on our website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. We shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

Next steps

1.6. Having considered the responses to this consultation, we intend to publish our Initial Proposals for the price controls in June 2006. These will set out our initial views of the revenue allowances for each of the transmission businesses. We will also quantify our proposals for the incentive framework that will apply to gas and electricity transmission. The Initial Proposals will be followed by Updated Proposals in September and Final Proposals in December.

1.7. To help inform the debate regarding the price controls, we intend to hold a series of workshops over the coming months. Further information on these will be made available throughout the review.

1.8. Any questions on this document should, in the first instance, be directed to:

Colin Green
Senior Manager - TPCR delivery assurance
Office of Gas & Electricity Markets, 9 Millbank, London, SW1P 3GE
Tel: 020 7901 7143
E-mail: colin.green@ofgem.gov.uk

CHAPTER 1: Introduction

There are no questions specific to this chapter.

CHAPTER 2: Form and structure of the price control

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

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

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

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

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

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

CHAPTER 3: Electricity incentives

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

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

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

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

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

CHAPTER 4: Gas entry incentives

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

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

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

CHAPTER 5: Gas offtake incentives

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

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

Question 5.3: Is the high level option proposed appropriate?

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

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

CHAPTER 6: Expenditure analysis: Capital expenditure

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

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

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

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

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

CHAPTER 7: Expenditure analysis: Operating expenditure

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

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

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

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

CHAPTER 8: Financial issues

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

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

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

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

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

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

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

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

CHAPTER 9: Way forward

There are no questions relating to this chapter.

Appendix 2 - Feedback Questionnaire

1.1. We consider that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

Selvi Jegatheswara
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
selvi.jegatheswara@ofgem.gov.uk

Appendix 3 - The Authority's Powers & Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.⁴

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly⁵.

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them⁶; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.⁷

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

⁴ entitled "Gas Supply" and "Electricity Supply" respectively.

⁵ However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.

⁶ under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.

⁷ The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed⁸ under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation⁹ and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

⁸ or persons authorised by exemptions to carry on any activity.

⁹ Council Regulation (EC) 1/2003

Appendix 4 - Glossary

A

Access Reform Options Development Group (ARODG)

Group set up by Ofgem which is intended to be a helpful pre-cursor to (and not substitute for) parties considering whether they wish to raise specific modification proposals to industry codes and is designed to stimulate debate and discussion. The group will meet weekly until Easter, when its ongoing role will be reviewed.

B

Baseline

Baselines define the amount of capacity that the transmission licensee is obliged to release. Baselines also determine the levels above which incremental capacity is defined.

British Electricity Trading and Transmission Arrangements (BETTA)

BETTA introduced a single GB-wide set of arrangements for trading energy and for access to and use of the transmission system which came fully into effect at BETTA go-live (1 April 2005).

C

Capital Expenditure (Capex)

Expenditure on investment in long-lived transmission assets, such as gas pipelines or electricity overhead lines.

Compound Annual Reduction (CAR)

Also known as Compound Annual Growth Reduction (CAGR). The cumulative year on year rate applied to an investment or other part of a company's activities over a multiple-year period.

D

Distribution Price Control Review (DPCR)

The price control review for the electricity distribution network operators conducted in 2003 & 2004. The resulting price control covers the years 2005 to 2010.

Distribution Network Operators (DNOs)

Holders of electricity distribution licences. Licences are granted for specified geographical areas. Currently in Great Britain there are seven companies who own the fourteen licensed distribution areas.

E

Early Retirement Deficit Costs (ERDC)

ERDCs are the costs of providing the additional pension benefits payable to a scheme member who retires before normal retirement date as a result of re-organisation or redundancy, over and above the benefits to which such a member would be entitled if he retired voluntarily at the same date. The rules of both the ESPS and the LGPS provide for the automatic enhancement of benefits to which a member becomes entitled on taking early retirement as a result of re-organisation or redundancy. Principal employer companies have often in the past used a pension fund surplus to cover part or all of these additional costs, subject to agreement with the trustees of the scheme. In the absence of agreement by the trustees, the employer must make additional contributions to the pension fund to cover the additional liability.

Electricity Supply Pension Scheme (ESPS)

A Retirement Benefit Scheme based upon benefits paid as a proportion of final salary. The Scheme is an exempt approved scheme (ICTA'88) and is subject to a trust document. The "Group" has many principal employers and is organised and defined by a set of rules, trustees and produces accounts annually and actuarial valuations at least every 3 years (triennially). The scheme is principally for people working in the Electrical Utility Industries. This scheme is one of the 26 separate tranches each actuarially independent.

F

Final Sums Liability (FSL)

The level of financial security a generator seeking connection to the network is required to post to cover the costs of works completed to connect them.

Front Office Management Services Agreed (FOMSAs)

An agreement between the gas distribution business retained by National Grid Gas plc and the IDNs with regards to the provision of certain IT services.

Forecast Business Plan Questionnaire (FBPQ)

Expenditure information requested by Ofgem from the licensees relating to the period from 2005/06 to 2011/12.

G[Gas Distribution Networks \(GDNs\)](#)

Gas Distribution Networks, of which there are eight, four of which are owned by National Grid Gas plc, and four of which were sold by Transco plc (now National Grid Gas plc) to third party owners on 1 June 2005.

[Gas Distribution Price Control Review \(GDPCR\)](#)

The review of the price control applying to gas distribution networks. The review will extend the existing price control for the year 2007-08 and reset the control for the period commencing 1 April 2008.

[Gas Transmission Charging Methodology Forum \(GTCMF\)](#)

A dedicated forum, established in January 2006, to allow National Grid NTS to provide information to the gas industry on its ongoing review of its Transportation Charging Methodology and other relevant charging methodologies and issues, and to provide an opportunity for users' views to be represented and discussed.

[Great Britain System Operator \(GBSO\)](#)

See SO.

H[Historical Business Plan Questionnaire \(HBPQ\)](#)

Expenditure information requested by Ofgem from the licensees relating to the period from the year before their most recent five-year full price control until 2004/05.

I[Independent Distribution Networks \(IDNs\)](#)

Gas Distribution Networks which were sold to third party owners by Transco plc (now National Grid Gas plc) on 1 June 2005. There are four such network companies, which are: Northern Gas Networks Ltd, Scotland Gas Networks plc, Southern Gas Networks plc and Wales & West Utilities Ltd.

[Information Quality Incentive Mechanism](#)

A form of incentive design adopted by Ofgem as part of the DPCR which provided companies with the potential for greater rewards if they chose more challenging cost targets.

Innovation Funding Initiative (IFI)

A mechanism to remunerate research & development expenditure by DNOs.

L

Lattice Group Pension Scheme (LGPS)

A Retirement Benefit Scheme based upon benefits paid as a proportion of final salary or for newer members contributions paid to the scheme. The Scheme is an exempt approved scheme (ICTA'88) and is subject to a trust document. The Scheme is organised and defined by a set of rules, trustees and produces accounts annually and actuarial valuations at least every 3 years (triennially). The Pension Scheme is principally for people working in the Gas Utility Industries.

Liquefied Natural Gas (LNG)

LNG consists mainly of methane gas liquefied at around -260 degrees Fahrenheit. Cooling and liquefying the gas reduces its volume by 600 times such that a tonne of LNG corresponds to about 1,400 cubic metres of methane in its gaseous state. LNG may be stored or transported by special tanker.

Load Related Capex

The installation of new assets to accommodate changes in the level or pattern of electricity or gas supply and demand.

M

Merger and Monopolies Commission (MMC)

The Competition Commission replaced the MMC on 1 April 1999. It is an independent public body. The CC conducts in-depth inquiries into mergers, markets and the regulation of the major regulated industries.

N

National Grid Gas (NGG)

The licensed gas transporter responsible for the gas transmission system, and four of the regional gas distribution companies.

National Grid Electricity Transmission (NGET)

The electricity transmission licensee in England & Wales.

National Transmission System (NTS)

The high pressure gas transmission system in Great Britain.

Non-Load Related Capex

The replacement or refurbishment of assets which are either at the end of their useful life due to their age or condition, or need to be replaced on safety or environmental grounds.

O

One in Twenty Obligation

A licence obligation imposed by Standard Special Condition A9 (Pipe-Line System Security Standards) upon both NGG NTS and the GDNs.

Operating Expenditure (Opex)

The costs of the day to day operation of the network such as staff costs, repairs and maintenance expenditures, and overhead.

Operating Margin (OM)

In relation to gas the OM is gas in storage which is reserved by the NTS to ensure the supply of gas is maintained in the event of a network emergency.

P

Public Electricity Suppliers (PESs)

The fourteen successor companies to which were transferred the electricity distribution and supply undertakings of the former area boards at privatisation. Each PES was required to provide distribution services and connections, and to provide a supply to consumers, in the geographical area (the 'authorised area') formerly served by the area board to which it was the successor. The duty to supply was progressively removed as competition was introduced, and was eliminated entirely by the Utilities Act 2000 which converted each PES licence into separate distribution and supply licences. The duty to provide distribution services and connections within its authorised area remains an obligation of the EDNO which, in each of the fourteen areas, is the present successor to the relevant PES.

Pipeline Maintenance Centre (PMC)

Internal NG group providing specialised maintenance and emergency services for high pressure gas pipelines.

Plugs Model

A method used by NGET to classify network assets (for the purposes of charging) as either general infrastructure assets or connection assets. The plugs model identifies connection assets as excluding any assets which are shared or sharable by another user. The cost of connection assets are used to derive connection charges, while the cost of infrastructure assets is used to derive use of system charges. See Transmission Network Use of System charges.

R

Real Unit Operating Expenditure (RUOE)

A measure of operating performance calculated by dividing the real operating expenditure in a year by an appropriate output measure.

Registered Power Zones (RPZ)

A mechanism to encourage the DNOs to develop and demonstrate new and more cost-efficient ways of connecting and operating generators on their systems.

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee's regulated transmission or (as the case may be) distribution business (the 'regulated asset base'). The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base at privatisation and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock. The revenues licensees are allowed to earn under their price controls include allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

Renewables Obligation Certificates (ROCs)

A mechanism implemented by the Government to promote generation by renewable energy sources. Generators are given certificates depending on the volume they generate and suppliers are required to source a % of their energy from renewable sources or pay a buyout price.

Repex

In this consultation this term describes the use of an operating allowance to fund each year's expected non load related capital expenditure.

RPI-X

The form of price control currently applied to network monopolies. Each company is given a revenue allowance in the first year of each control period. The price control

then specifies that in each subsequent year the allowance will move by 'X' per cent in real terms.

Re-openers

A process undertaken by Ofgem to re-set the revenue allowances (or the parameters that give rise to revenue allowances) under a price control before the scheduled next formal review date for the relevant price control.

Revenue Driver

A means of linking revenue allowances under a price control to specific measurable events which are considered to influence costs. An example might be to allow a specified additional revenue allowance for each MW of new generation connecting to the network. Revenue drivers are used by Ofgem to increase the accuracy of the revenue allowances.

Rolling Incentives

A measure which ensures licensees are able to retain the rewards of efficiency savings for a period of five years (consistent with the duration of the price control) irrespective of when the efficiency saving is made.

S

Security and Quality of Supply Standard (SQSS)

As referred to in the electricity Transmission Licence Standard Conditions C17 and D3, this is the standard in accordance with which the electricity transmission licensees shall plan, develop and operate the transmission system.

Scottish Hydro-Electric Transmission Limited (SHETL)

The electricity transmission licensee in northern Scotland.

Scottish Power Transmission Limited (SPTL)

The electricity transmission licensee in southern Scotland.

Sliding scale

This term is used generically to describe incentive schemes which involve profit (and loss) sharing around a fixed target costs, such as the current form of SO incentives in gas and electricity.

System Operator (SO)

The system operator has responsibility to construct, maintain and operate the NTS and associated equipment in an economic, efficient and co-ordinated manner. In its role as SO, NGG is responsible for ensuring the day-to-day operation of the transmission system.

T

Theoretical Maximum Physical Capacity

An approach to determining the level of baselines which can be characterised as the maximum amount of gas that can be taken through a particular entry or offtake point by reducing supplies at other nodes in order to balance the network but not taking into account interactions with flows elsewhere on the network.

Transmission Connected Customer (TCC)

A customer directly connected to the gas or electricity transmission system.

Transmission Entry Capacity (TEC)

Defines a generator's maximum allowed export capacity onto the transmission system. The holder of the TEC has the right to export the specified number of megawatts onto the transmission system at any one time, and is eligible for compensation if NGET cannot accommodate this export on the network.

Transmission Investment for Renewable Generation (TIRG)

In the context of this document, this means the regulatory mechanisms developed before the start of the next main price control in 2007, to fund a number of specific network enhancement projects required to provide transmission capacity for new renewable generation plants.

Transmission Owners (TO)

Companies which hold transmission owner licenses. Currently there are three electricity TOs; NGET, SPTL and SHETL. NGG is the gas TO.

Transmission Price Control Review (TPCR)

The TPCR will establish the price controls for the transmission licensees which will take effect in April 2007 for a 5-year period. The review applies to the three electricity transmission licensees, NGET, SPTL, SHETL and to the licensed gas transporter responsible for the gas transmission system, NGG

Transmission Use of System Charges (TNUoS)

Charges levied by NGET on users of the GB electricity transmission network to recover the costs of providing and maintaining the general network infrastructure

assets. TNUoS charges vary by location, and are different for generators and for suppliers.

U

Unit Cost Allowance (UCA)

A parameter of the current revenue restriction for NGG. A UCA is set for each entry point, and is intended to reflect the cost of providing additional capacity at that point on the network. The actual additional revenue entitlement for NGG if it releases such additional capacity at a particular entry point is a function of the UCA for that entry point. NGG also uses the UCAs as reserve prices in its auctions of entry capacity.

Uniform Network Code (UNC)

As of 1 May 2005, the UNC replaced NGG's network code as the contractual framework for the NTS, GDNs and system users.

V

Vesting Assets

Assets included in the RAV at the vesting date.

Vesting

The date at which the regulated gas and electricity transmission and distribution companies were privatised.