Regulating Energy Networks for the Future: RPI-X@20

History of Energy Network Regulation

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Target audience: Consumers and their representatives, gas and electricity transmission and distribution companies, generators and offshore producers, participants in offshore tendering process, energy suppliers, gas shippers, government, the city, academics and other interested parties.

Overview:

In March 2008 we announced RPI-X@20, the review of our current approach to energy network regulation. The review is considering whether the existing regulatory regime remains appropriate for the likely new challenges facing the energy networks. These challenges include the need to accommodate targets for tackling climate change, maintaining security of supply, and undertaking widespread maintenance and upgrading of our ageing networks.

The first in a series of consultation documents on the RPI-X@20 review was published today. This supporting paper complements the RPI-X@20 consultation by providing an overview of the history of energy network regulation. An understanding of the rationale for changes implemented within the regulatory regime over time will help inform our understanding of the way that this regime may be amended in the future to accommodate emerging challenges. This document therefore provides an overview of the way that the regulatory arrangements in place for the gas and electricity transmission and distribution networks have evolved since privatisation. It also seeks to summarise the status of the current regimes in place for these energy networks. This paper is not a consultation paper. No questions are posed in it and no comments are sought on it. The paper is being published as a high level information paper aimed at providing background to compliment as opposed to providing the main focus for the RPI-X@20 consultation.

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Table of Contents

Summary 2
1. Introduction and background 4
Purpose of this document 4
The structure of the gas and electricity industries 4
The process of RPI-X regulation since privatisation 5
Scope of the controls 7
Previous reviews of RPI-X 8
The role of the regulator 19
Structure of the document 9
2. Structure of the gas and electricity markets 11
Structure of the energy industry 11
The gas industry 11
The electricity industry 15
3. Overview of price cap regulation 21
Incentive regulation 21
Scope and form of the control 22
Calculating the price control 23
Providing incentives 26
Uncertainty 28
4. Calculation of the RPI-X control for electricity distribution 29
Background 29
Regulation since privatisation 31
The electricity distribution price control since privatisation 34
Regulation of electricity distribution today 42
The electricity distribution price control from 2010 44
Price controls for the IDNOs 45
5. Calculation of the RPI-X control for electricity transmission 47
Background 47
Regulation since privatisation 49
The electricity transmission price control since privatisation 50
Regulation of electricity transmission today 57
Transmission Access Review 58
6. Calculation of the RPI-X control for gas transmission 60
Background 60
Regulation since privatisation 62
The gas transmission price control since privatisation 64
Regulation of gas transmission today 68
7. Calculation of gas distribution price controls from 2002 71
Background 71
Changes in the gas distribution price control since 2002 73
Regulation of gas distribution today 78
Price controls for the IGTs 80
8. Structure of Charges 82
Appendices 86
Appendix 1 - SO incentives 87
Appendix 3 - Glossary 91

Summary

We have undertaken a detailed review of how energy network regulation has evolved since privatisation. This review spans the period 1986 to 2008, allowing us to understand how the regulatory framework operates now and how it has changed over time. This is by no means a complete history of the energy price controls since privatisation but rather an overview of the main events and developments.

The evolution of energy network regulation

The starting point for RPI-X@20 is an understanding of how each of the energy networks is currently regulated. The details of the 'RPI-X framework' vary across the energy networks and, an understanding of these, will help inform thinking as to whether there are lessons to be learned from certain regulatory frameworks that can be applied to others. We will also need to consider whether it remains appropriate to have different frameworks for the different networks in place in the future, or indeed whether further differentiation is warranted. Furthermore, we need to assess whether incentives are appropriately aligned along the networks, between the networks and across users of the networks and final customers.

Figure 1: Key Changes in the electricity price controls

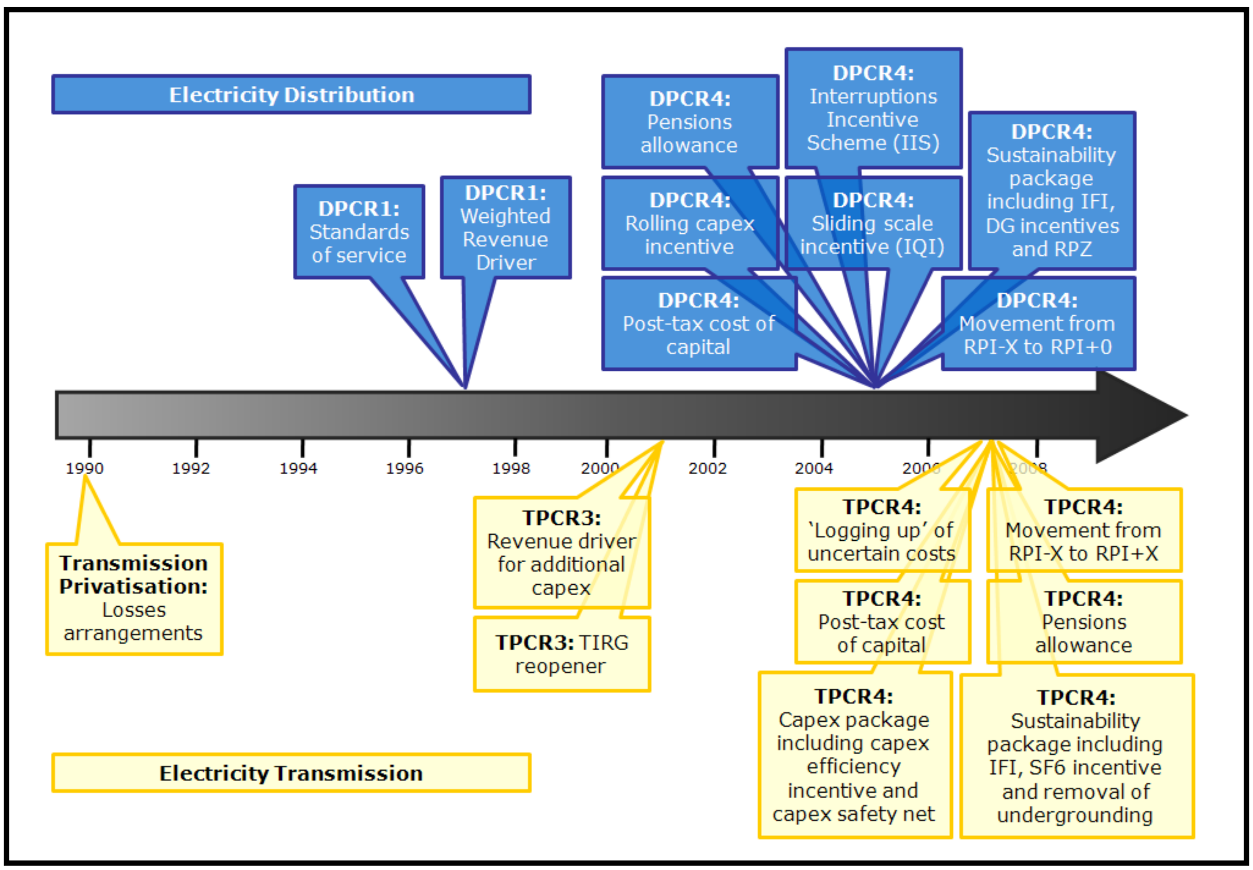
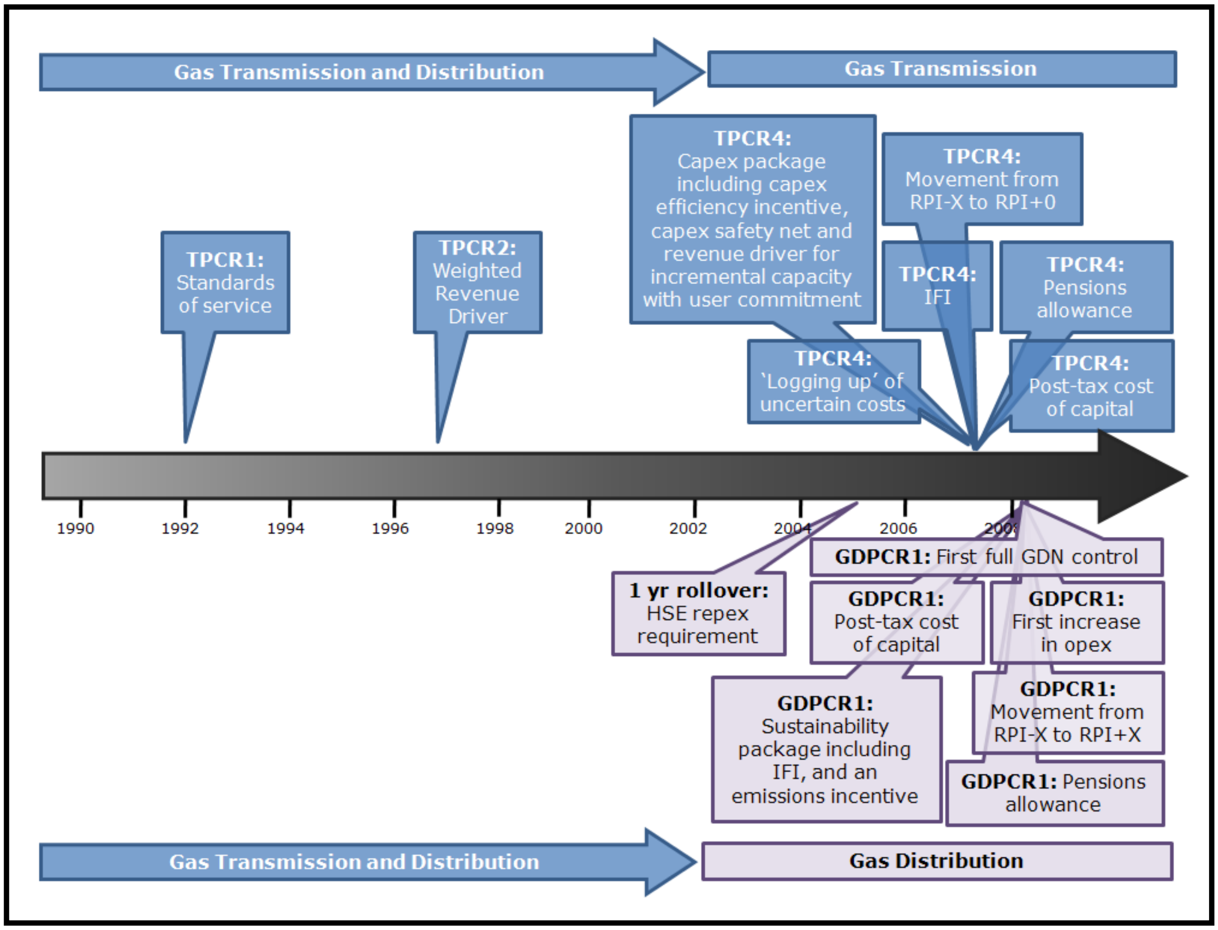


Figure 1 above and Figure 2 below highlight the key changes that have been made within the electricity and gas network price controls since implementation. The most significant changes were implemented as part of the recent price controls. Initiatives were put in place to further the sustainability agenda, facilitate capex efficiencies, innovation and improved service quality, as well as to reflect changes in financial aspects of the controls (e.g. pensions and cost of capital). Measures have also been introduced to reflect increased uncertainty about what networks need to deliver during a five-year price control period (resulting in more revenue drivers, re-opener arrangements and ex-post mechanisms such as the gas distribution Discretionary Reward Scheme). Planning and regulating long-term network investments has been a challenge and arguably more work is needed in this area. For example, in transmission, delays with planning consents may limit the extent to which investment requirements can be predicted.

Figure 2: Key Changes in the electricity price controls



Outside of the core price control framework, a number of tools have been used to control monopoly behaviour and incentivise networks. For example, competition in networks has been developed with the introduction of independent gas and electricity networks. We have also used competitive processes, such as tendering, when considering new projects (most notably the development of the offshore regime).

1. Introduction and background

Chapter Summary

This chapter gives an overview of the purpose and structure of this document. It provides background information regarding the structure of the energy industry, the energy network price controls, and the coverage of these controls.

Purpose of this document

1.1. The RPI-X@20 review provides us with an opportunity to 'take a step back' from the regulatory regime that is currently in place and consider whether it remains fit for purpose given the challenges that the networks will face over the next 20 years. Although we do not have any predetermined views regarding the outcome of this project, it is possible that either small or large scale change to the regulatory regime may be proposed. It therefore seems appropriate that any amendments that may be recommended as part of this review are considered against a background of the changes that have been made within the regime to date and the rationale for these.

1.2. In addition, we will only make changes to the existing regime where there is a clear rationale for doing so. It is therefore of crucial importance that we have a clear understanding of the way that the price controls operate at present and the way they have evolved over time. This document is therefore intended to act as a reference regarding the way in which the framework for energy network regulation, in the form of the RPI-X regime, has evolved since its implementation at privatisation. It provides an overview of the changes that have been implemented and, where appropriate, outlines the rationale that underpinned these amendments.

Structure of this chapter

1.3. This chapter provides background information regarding the price controls. It contains a high-level overview of the structure of the gas and electricity industries. It also contains a summary of the process that has been followed in terms of the price controls that have been implemented since privatisation. Changes in the scope of these controls are also described.

The structure of the gas and electricity industries

1.4. Despite the different characteristics of gas and electricity and the markets in which they operate, the broad structure of these industries is now fairly closely aligned. In this regard, both industries are characterised by competitive upstream production. In gas, this takes the form of competitive gas exploration and extraction while in electricity there is a competitive market for electricity generation.

1.5. Electricity and gas are both transported via national transmission systems which are run as monopoly businesses and are therefore subject to price control regulation. While in gas the transmission system is a high pressure network of pipes, in electricity the transmission system is a high voltage grid of wires. In each sector energy is transported to local demand centres via dedicated distribution systems. In gas this is achieved using the low/medium pressure Gas Distribution Networks (GDNs) and in electricity, the low voltage Distribution Networks (DNs) are in place. Similarly to transmission, distribution is also largely a monopoly activity and therefore separate distribution price controls are also in place.

1.6. Arrangements are made for gas and electricity to be transported to final consumers via gas and electricity suppliers. In the gas sector shippers act as intermediaries on the gas system, arranging for the transportation of gas on the transmission and distribution systems, and the supply of gas to final consumers.

1.7. At a very high level there are therefore a number of similarities between the structure of the gas and electricity industries. A fuller overview of the way that these industries operate is provided in Chapter 2 and this draws out further both the roles of the various players within the industry and the differences in the way that the two industries operate in practise. Details of how the industry structures have changed since privatisation can be found in the supporting paper 'Context of network regulation since privatisation'[1].

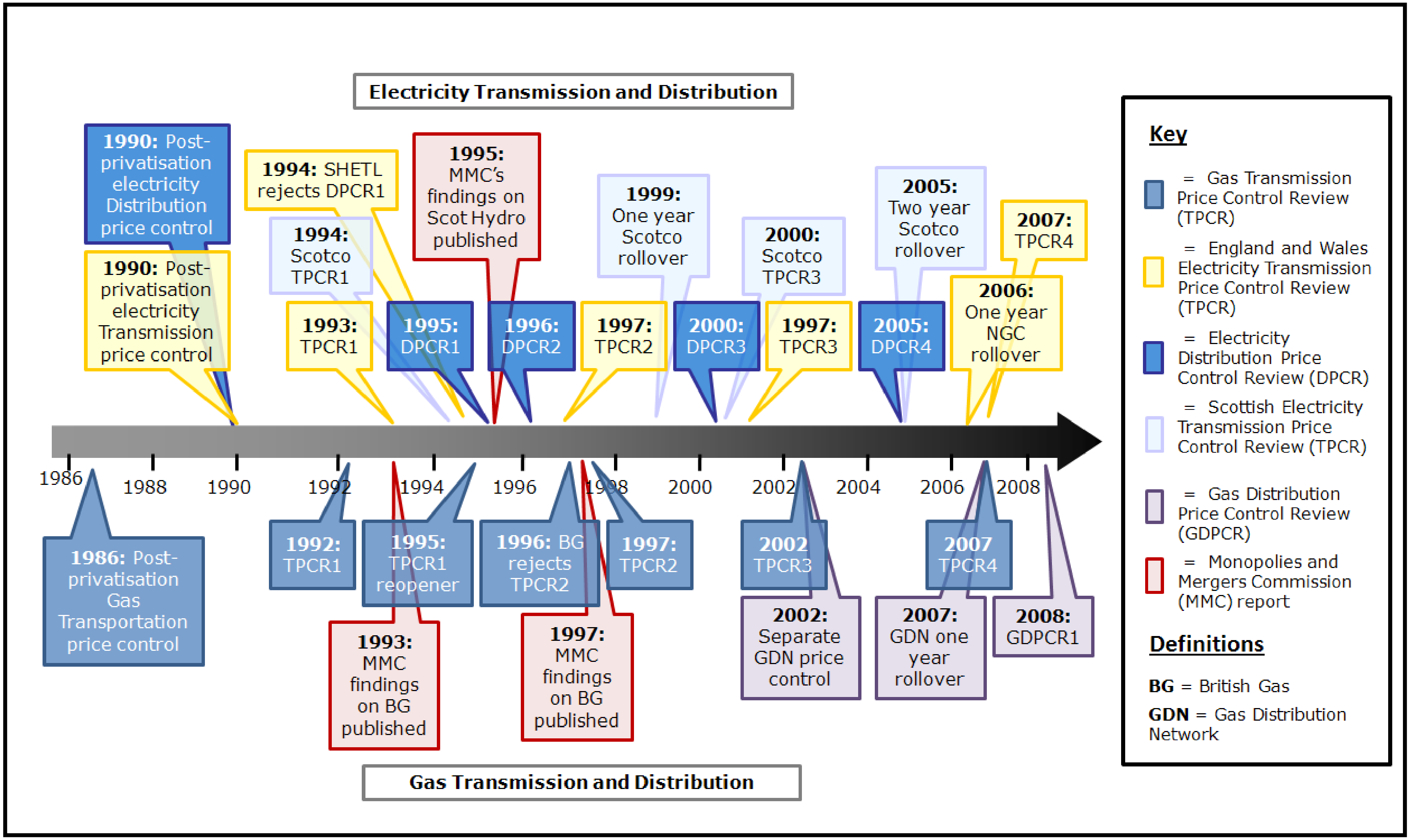
The process of RPI-X regulation since privatisation

1.8. The RPI-X regime was originally implemented following privatisation and its main objective was to provide strong incentives for efficiency as well as seeking to stimulate innovation and create the conditions to allow competition to develop. It was anticipated that this regime would involve a relatively low burden of regulation.

1.9. Figure 1.3 below provides an overview of the price controls, and Monopolies and Mergers Commission (MMC) cases that have been completed since privatisation of the gas industry in 1986 and of the electricity industry in 1989. Since then, each of the various energy networks has gone through approximately four rounds of price control reviews. Over this period, with the evolution of the industries, the onset of new challenges and the emergence of new issues, the form of the price controls have changed and their resulting level of complexity has increased. However, the reviews that have taken place have offered substantial learning opportunities in terms of both the process that has been followed and the policies that have been adopted to adapt to changing circumstances. We focus, in this paper, on the changes to the price controls that have been incorporated at each of these reviews.

[1] This document is available from:
http://www.ofgem.gov.uk/Networks/rpix20/publications/Pages/Publications.aspx

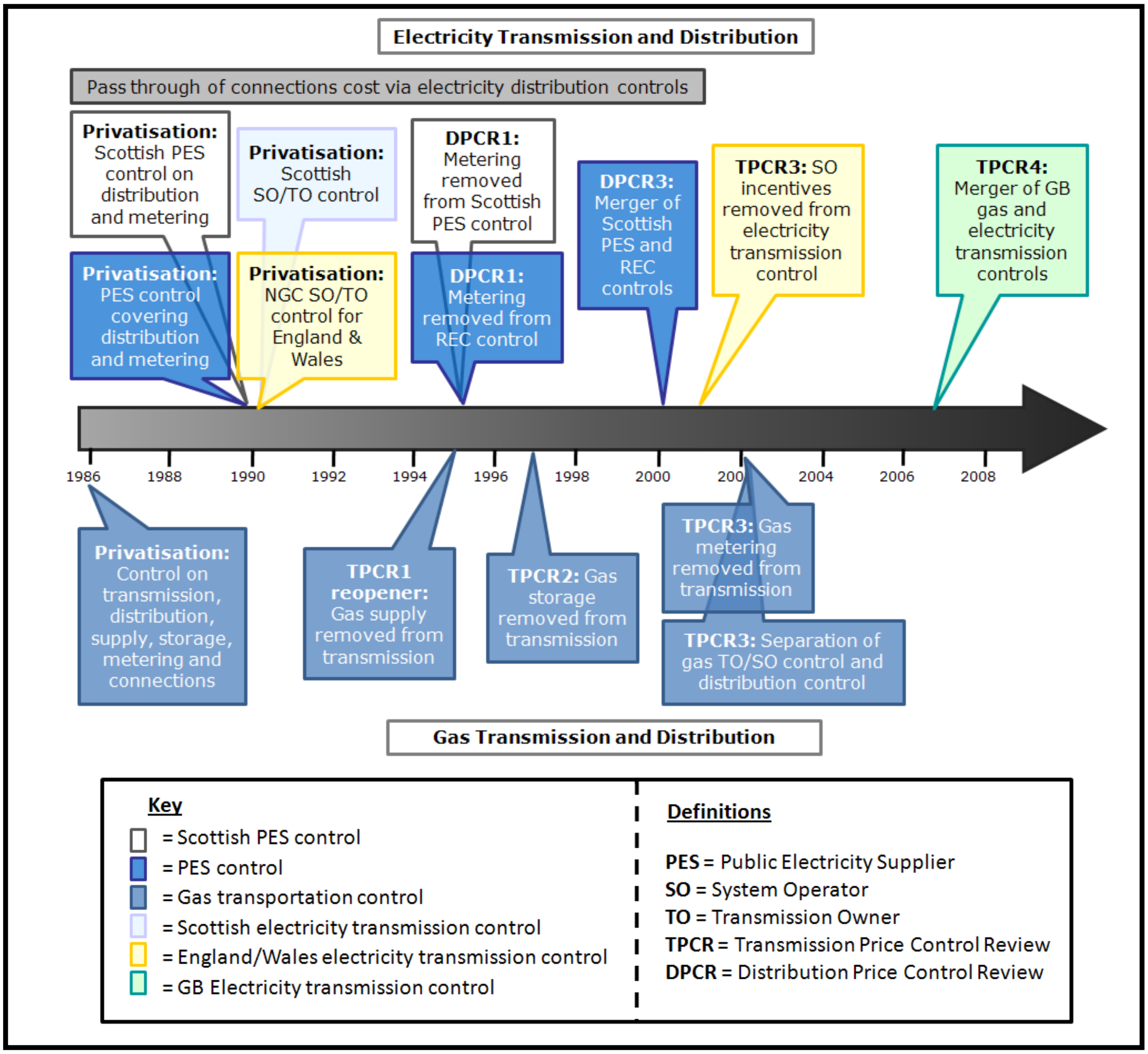
Figure 1.3: Energy price controls since 1986



Scope of the controls

1.10. Over the course of these price controls, there have also been various changes in the scope of the controls in terms of the elements of the supply chain to which they apply. This has reflected the changes in the industry structure that have been seen. Figure 1.4 below provides an overview of the changes that have taken place in terms of the application of the price controls to the various aspects of the supply chain.

Figure 1.4: Changes in the scope of the price controls since privatisation



1.11. The changes to the scope of the controls have been implemented either:

- to recognise changes in industry structure and to stimulate the development of competition in certain markets e.g. in the case of supply, metering and storage; or
- to align the timing of controls.

Previous reviews of RPI-X

1.12. In 2002/03, Ofgem engaged in a project[2] with stakeholders across industry to assess the processes followed in undertaking price controls for energy network companies and identify potential improvements that could be made in advance of distribution price control review 4 (DPCR4), the review for which was set to commence in 2003. Some of the key conclusions of this review are outlined below:

- There were concerns that efficiency incentives had reduced given that a proportion of the inefficiencies evident at privatisation had been removed and therefore the scope for efficiency savings was lower. There was also a perception that companies may have perverse incentives to achieve efficiency savings at the beginning of price controls due to their ability to retain the benefit of the cost saving until the next price control period. The review concluded that it would be appropriate to allow companies to retain efficiency savings (on capital expenditure (capex) and operating expenditure (opex)) for a fixed period of five years, equivalent to the period of the price control, regardless of when the saving was made. It was anticipated that this would improve efficiency incentives.

- There were concerns that incentives toward capex efficiencies were lower than those for opex. Proposed approaches to reduce these distortions included seeking to assess expenditure on an overall basis or to provide more balanced efficiencies between these costs. Following the review, Ofgem simply committed to undertake further work to address this issue and to continue to require the companies to accurately report their costs.

- Concerns were raised regarding the process followed in setting capex allowances and the fact that customers may be exposed to higher costs where companies effectively overstate their capex requirements. It was recognised that this issue was exacerbated by the absence of reliable output measures which would provide an indication of the efficiency of investment undertaken by the companies. Some potential solutions were suggested as part of the conclusions of the review but no firm proposals were reached about the best way to progress this issue.

- Recognising the inherent uncertainty that exists regarding expenditure required during a price control period, the review posed the question of whether formal arrangements should be implemented to allow interim adjustments to the price control arrangements to be made.

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[2] This was the series of consultations referred to as "Developing Monopoly Price Controls".

- Concerns were raised that the methodology used to set the cost of capital varied significantly between the regulators and therefore, in the conclusions of the review, Ofgem committed to adhere to a series of principles when estimating the cost of capital. This was intended to improve transparency and understanding.

- In the final quarter of the 20th century, pension values grew significantly faster than associated liabilities, leaving many pension funds in surplus and allowing companies to reduce their annual financial contributions. Pension costs had not therefore historically been a big issue but returns on these investments began to reduce after 2000 and mortality statistics indicated that people would be drawing on pensions for longer periods going forward which lead to many of the previous surpluses being eroded. As part of the review, Ofgem therefore developed a set of guidelines to frame its approach when considering pension costs.

1.13. Many of the conclusions of this review were implemented as part of DPCR4. These included the rolling incentive mechanisms and the use of reopeners to allow for areas of uncertainty at the start of the price control as well as the methodologies for the derivation of the cost of capital and appropriate pensions allowances. A number of these policies were also adopted via transmission price control review 4 (TPCR4) and gas distribution price control review 1 (GDPCR1), with the further introduction of 'logging up' mechanisms, as part of TPCR4, to allow for uncertain (but foreseen) cost areas in the price control.

1.14. As part of DPCR5 work is also being taken forward to address the inconsistency of incentives between opex and capex and to seek to develop output measures which would allow the efficiency of capex to be effectively assessed.

Structure of the document

1.15. Since privatisation, the price controls for gas and electricity transmission and distribution have been reviewed a number of times. There have also been changes over this period, in relation to the companies and the spectrum of the supply chain that each of the specific controls relates to.

1.16. This document provides an overview of the reviews that have been undertaken with respect to the energy network price controls on incumbents and the changes that have been made to the regulatory framework as a result. We do not discuss, in any detail, the arrangements for the Independent Distribution Network Operators (IDNOs) or Independent Gas Transporters (IGTs). Nor do we discuss the arrangements for offshore transmission. We outline the approach that has been adopted in setting the price controls, provide an overview of the key changes that have been implemented to each of the building blocks of the RPI-X regime over time and describe, at a high level, the key elements of the regime in place today.

Chapter 2 provides a description of the structure of the gas and electricity industries, including details of the key players and the roles that they play within the industry. Chapter 3 provides an overview of the principles underpinning price cap regulation while Chapters 4, 5, 6 and 7 provide details of the price control processes and policies that have been implemented in electricity distribution, electricity transmission, gas transmission and gas distribution respectively. Recognising the links between the structure of charges and price control arrangements, Chapter 7 provides a high-level overview of the way that the structure of charges are set for each of the energy networks as well as the regulatory developments with respect to the structure of charges that have been seen in each of these sectors. Appendix 1 outlines the way that the SO incentive arrangements have evolved.

2. Structure of the gas and electricity markets

Chapter Summary

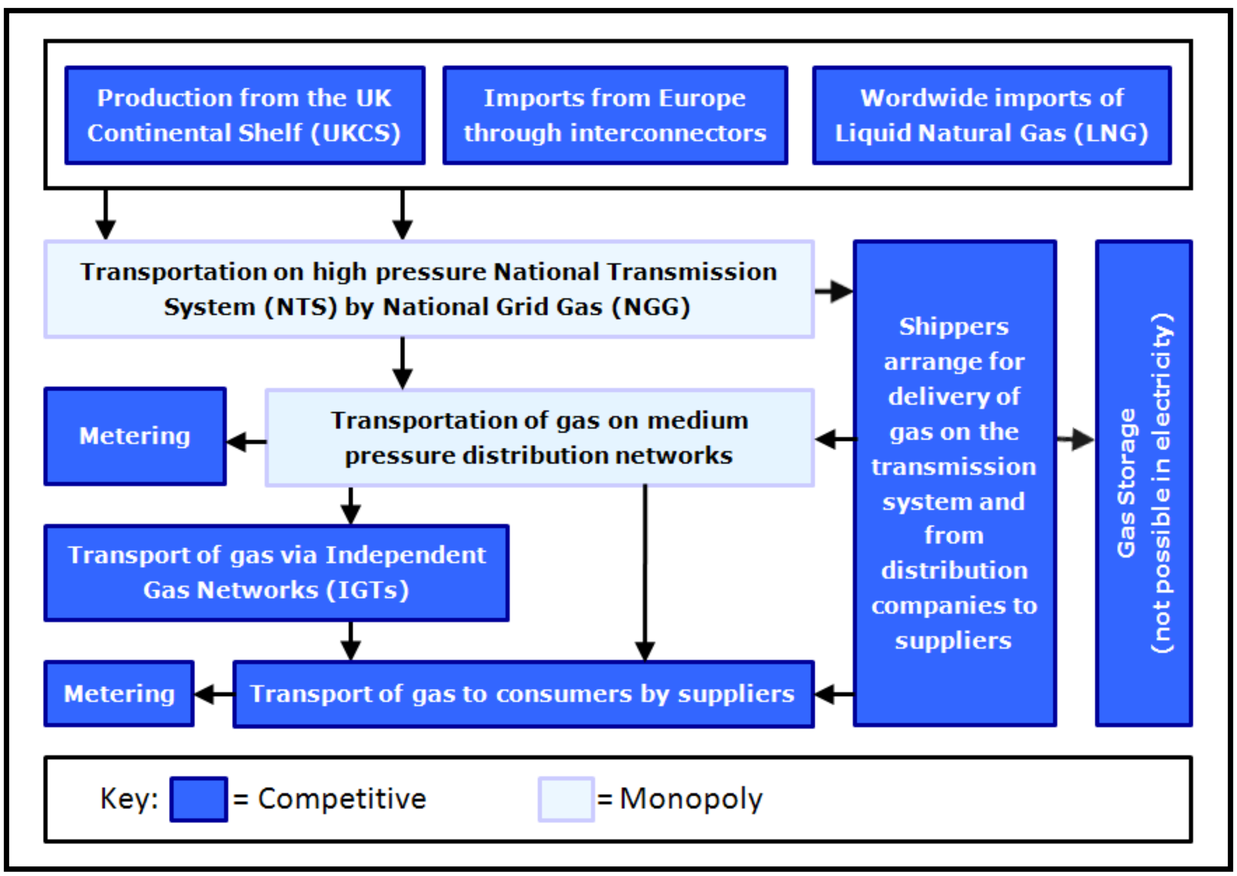
This chapter provides an overview of the structure of the gas and electricity industries. In particular, it contains details of the key market players, their roles and the way that they interact with one another.

Structure of the energy industry

2.1. To understand better the RPI-X regime and its application to energy networks, it is useful also to have an understanding of the structure of the energy industry.

The gas industry

Figure 2.1: High level overview of the structure of the gas industry



1.17. Figure 2.1 above illustrates, at a high level the structure of the gas industry including the key players within the industry and the way that they interact with one another.

The production of gas

1.18. At the production end, there are three main sources of supply: indigenous production from the UK Continental Shelf (UKCS); imports of gas from Europe; and imports of Liquefied Natural Gas (LNG) into LNG importation facilities, via tanker, which is subsequently converted into natural gas. The production of gas is a competitive activity and there are a number of players that operate in this area of the industry. However, as our indigenous sources of gas continue to decline, we are becoming increasingly dependent on imports, in the form of both pipeline gas and LNG.

Transportation of gas

1.19. Supplies of gas are transported, from the relevant entry terminals, where the gas producers and upstream suppliers land their gas, onto the high pressure National Transmission System (NTS) operated by National Grid Gas (NGG). NGG is both the System Operator (SO) and Transmission Owner (TO) for the NTS.

System Operation

1.20. In its role as SO, NGG has various responsibilities. Its key responsibility is to maintain the NTS within safe operating limits and NGG must therefore ensure that the inputs to, and offtakes from, the NTS remain balanced throughout the course of the gas day[3]. Each of the parties operating on the NTS - gas shippers - have a responsibility to ensure that their inputs to, and offtakes from, the system remain balanced over the course of the gas day and, where they are not compliant with this, they will be penalised according to the gas imbalance arrangements. However, NGG has a role as the residual balancer and therefore must take actions where the overall system is out of balance. Such actions include either having in place contracts for the delivery of gas which it can call upon when the system is out of balance or taking action to purchase or sell required gas in the On-the-day Commodity Market (OCM).

SO incentives

1.21. Each year, Ofgem sets an incentive scheme applicable to the costs associated with keeping the NTS in balance, managing any constraints on the system and in relation to NGG's purchase of gas to support its SO role e.g. for shrinkage and compressor operation. This scheme is known as the SO incentives scheme and,

[3] The gas day runs from 6am to 6am, for a 24 hour period.

since 2007, the process for setting SO incentives in gas and electricity has been merged. The gas SO incentives set a target level of costs for NGG in operating the NTS. If NGG succeeds in making savings against this cost level, it is permitted to save a proportion of these benefits, in line with pre-specified sharing factors. However, if actual costs exceed the target NGG is required to pay a share of the additional costs.

1.22. Historically, the consultation process for SO incentives has been led by Ofgem based on cost forecasts provided by NGG and National Grid Electricity Transmission (NGET (the electricity SO)), but for the 2008/09 review the process was amended to require that NGG and NGET take the lead on the process of consultation. As such, NGG and NGET were responsible for progressing the initial consultation regarding SO costs, following which Ofgem scrutinised cost forecasts as well as respondents' views and then issued its final proposals. Both Ofgem and respondents considered this new process to have been successful in facilitating further transparency and thought that it had provided opportunities for more bilateral discussions with NGG and NGET about their forecasts. As such, Ofgem has also adopted this approach to the review of SO incentives for 2009/10[4].

Transmission Owner

1.23. In its role as TO, NGG must ensure that sufficient capacity is available on the NTS to deliver security of supply and is required to perform its functions in an economic and efficient way to deliver the best deal for consumers. The costs of providing services are covered by the regulated price control and this includes incentives toward efficiency as well as incentives to deliver against a specified quality of service.

Distribution of gas

1.24. Gas is distributed to the majority of final consumers via 12 Local Distribution Zones (LDZs)[5]. These LDZs were historically owned and operated by NGG but, in May 2003, NGG announced that it wanted to sell some of these assets. Following Transco's reorganisation of its 12 LDZs into eight regional gas distribution networks (GDNs) in April 2002, the GDNs were offered for sale on the basis of the LDZs to which they related. Although this was a commercial transaction initiated by NGG, prior to the sale it was necessary for Ofgem to undertake extensive analysis and consultation with the industry to ensure that the required regulatory arrangements were in place to support such a sale, before regulatory approval could be granted.

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[4] A fuller explanation of the way that the SO incentive arrangements have evolved over time and the current scheme is contained within Appendix 1.
[5] The exception to this is large customers that are directly connected to the NTS, for example, large Industrial & Commercial (I&C) customers and power stations.

Following this process, in June 2005, four of the GDNs were sold to independent third parties and the remaining four GDNs stayed within NGG ownership[6].

1.25. The GDNs, similarly to shippers have a role in ensuring that their position remains in balance, in terms of inputs to and offtakes from the NTS. The GDNs also have a similar role to NGG in ensuring that required capacity is available to shippers wishing to convey gas on their system. Again, required revenues are made available to fund the provision of this capacity via the price control, which incentivises the GDNS to deliver this required capacity in the most economic and efficient way.

Independent Gas Transporters

1.26. An amendment to the Gas Act 1986 in 1995 introduced provisions to allow Independent Gas Transporters (IGTs) to develop, operate and maintain local gas transportation networks and thereby operate within the gas industry structure. The IGTs perform a similar role to the GDNs although their function is specific to local gas transportation networks rather than the LDZ. The new housing market constitutes the largest share of the IGT market, domestic infills and Industrial & Commercial (I&C) customers are also connected to IGT networks. Nine groups currently hold an IGT licence, although only six of these groups own and operate transportation assets.

Supply of gas

1.27. I&C customers are predominantly supplied by gas shippers, which is a competitive activity, while the supplies of gas to domestic consumers and Small and Medium Enterprises (SMEs) is largely undertaken by suppliers.

1.28. At the time of privatisation British Gas held a monopoly in the supply of gas and was subject to an RPI-X price control. However, by May 1998, competition had been rolled out to all domestic gas customers and in April 2002 the supply price control was lifted as competition was deemed to have developed sufficiently to protect the interests of consumers. By this time, British Gas's share of domestic gas supply, in terms of customer numbers, had reduced from 84% in 1998 to 67% in 2001 and there were around 20 suppliers offering domestic consumer tariffs. There are currently six large supply companies[7].

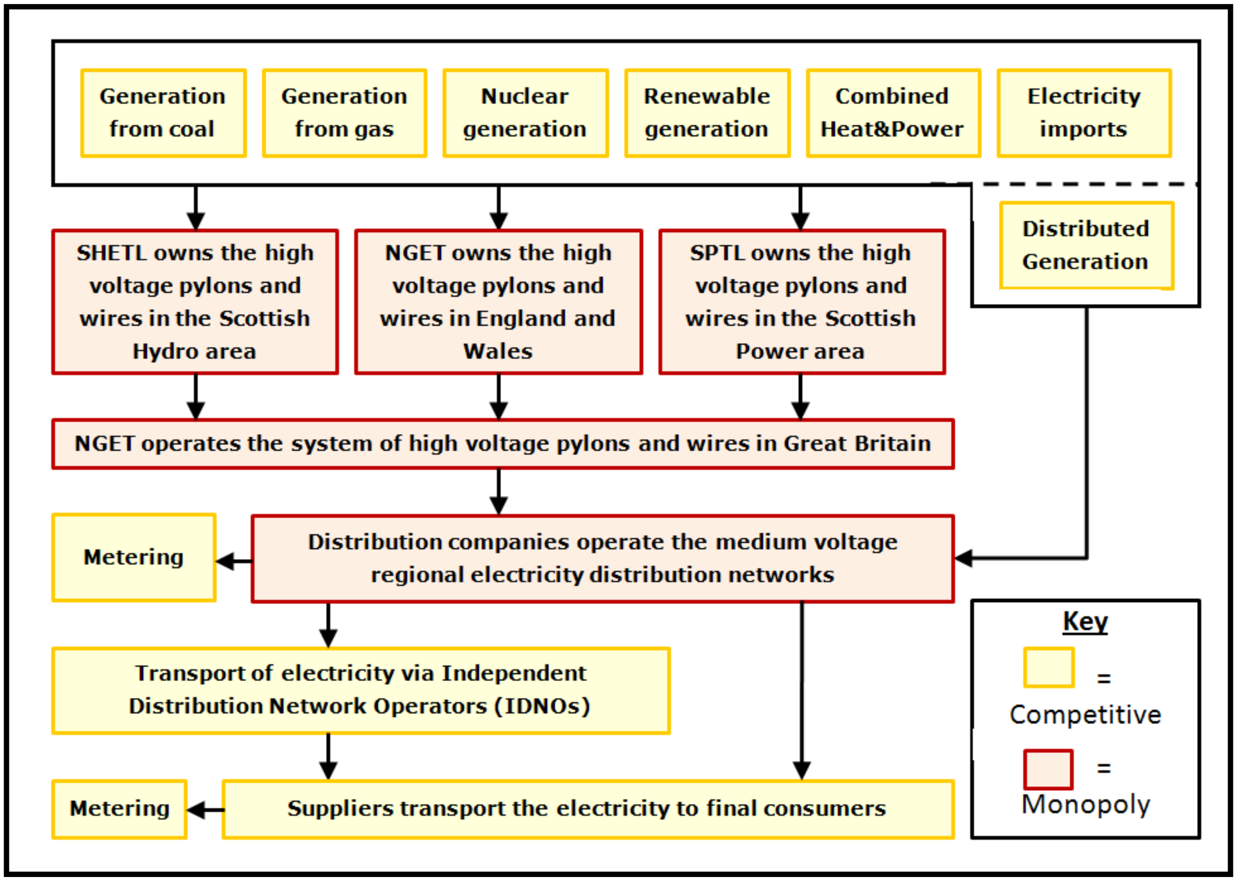
[6] Following the sale, the owners of the distribution networks are: North West, London, West Midlands and East of England (East Midlands LDZ & East Anglia LDZ) are owned and managed by National Grid; Scotland & South of England (South LDZ & South East LDZ) are owned and managed by Scotia Gas Networks; Wales and the West (Wales LDZ & South West LDZ) is owned and managed by Wales and West Utilities; North of England (North LDZ & Yorkshire LDZ) is owned by Northern Gas Networks.

[7] Further details regarding the development of the GB energy supply sector are contained within the Energy Supply Probe - Initial Findings Report.

1.29. Gas shippers arrange for the delivery of gas onto, and via, the NTS as well as the delivery of gas from the distribution system to suppliers. Shippers also have a role in the supply of gas to I&C customers. Provisions for the granting of licences to shippers were contained within the Gas Act 1995.

The electricity industry

Figure 2.2: High level overview of the structure of the electricity industry



1.30. Figure 1.2 above illustrates, at a high level, the key players within the electricity industry and the way that they interact with one another.

Generation of electricity

1.31. Unlike gas, electricity is not a primary fuel and therefore is produced via various types of generation. The traditional sources of fuel for electricity generation during the 1990s were coal, gas and nuclear but, with the increased focus on environmental concerns[8], there has been a push toward the production of more electricity from renewable sources.

1.32. Traditionally, electricity has also been generated via large power stations connected to the transmission system but, in recent years there has been increased focus upon the deployment of distributed generation (DG). DG is generation that is connected directly to the distribution networks and there are many different types of DG facilities including combined heat and power (CHP), wind farms and hydro power. DG could therefore help to facilitate the government's environmental targets.

1.33. Electricity generation is a competitive activity and there are a number of players that operate in this area of the industry. However, questions are increasingly being raised about security of supply in electricity as around 12GW of generation plant (8GW of Coal and 4GW of Oil) is set to switch off due to the environmental constraints imposed by the Large Combustion Plant Directive (LCPD). In addition, it is anticipated that some Nuclear power stations will switch off between now and the end of 2015. The targets on the percentage of electricity that should be sourced from renewables have also placed increasing pressure on investment in this area.

1.34. Questions about the potential future portfolio of electricity generation have led to significant uncertainty in the electricity networks, particularly on the transmission side, about the type and location of investment that should be undertaken to accommodate capacity/connection demands in the future. Indeed, in Scotland, there is currently a queue of renewable generators waiting to connect to the transmission network and these are being delayed due to difficulties associated with obtaining planning consents but also due to the lack of available capacity to connect to the transmission network. These issues, as well as the exploration of possible short-term solutions, were the principle driver behind the recent Transmission Access Review (the TAR) project. However, transmission access is an issue that will need to be addressed over the longer term and therefore will be one of the challenges that the regulatory regime will need to be sufficiently flexible to address in the future.

Transmission of electricity

1.35. Once electricity is generated, it is transported, via connections, onto the high voltage electricity transmission network which is owned by National Grid Electricity Transmission (NGET), Scottish Hydro Electricity Transmission Limited (SHETL) and Scottish Power Electricity Transmission Limited (SPTL). Despite the disparate ownership of the electricity transmission network, the overall GB system is operated by NGET.

[8] This has particularly been seen through initiatives such as the Large Combustion Plants Directive (LCPD), the aim of which is the regulation of emissions to air from Large Combustion Plants (LCPs).

System Operation

1.36. NGET is the electricity SO across Great Britain (GB). NGET only assumed the responsibility of GBSO since the implementation of the British Electricity Transmission and Trading Arrangements (BETTA) in 2005. Prior to this, SPTL and SHETL had responsibility for the SO roles in their respective areas in Scotland while NGET had responsibility as the SO in England and Wales. In line with the arrangements under BETTA, electricity generated via the various sources outlined above is transported, from power stations and smaller generation sites, onto the electricity transmission network which is operated by NGET.

1.37. As GBSO, NGET has responsibility for ensuring that the GB electricity transmission network remains in balance and within safe operational limits. As in gas, each of the parties that operate on the electricity transmission network have a responsibility to ensure that their position remains in balance (i.e. that the amount of electricity that they arrange to enter the system is equivalent to the amount that they take off of the system). Where their position, in this respect, is not in balance they will be penalised according to the electricity imbalance arrangements. NGET has responsibility as the residual balancer on the system. Therefore it must take actions to call on reserve contracts that it has in place for electricity or to enter the Balancing Mechanism (BM) to buy or sell the required electricity to ensure that the transmission system remains balanced.

1.38. In contrast to the gas NTS, which is balanced on a daily basis, due to the nature of electricity, participants operating on the system are required to remain in balance on a half hourly basis and NGET must ensure that the system remains in balance in real time. Keeping the electricity transmission system in balance on a real-time basis can involve NGET taking considerably more actions than NGG does in gas and requires more complex arrangements. This can also be complicated where system constraints arise and NGET is required to take actions to manage these constraints to ensure that they can be resolved. In addition, while it is possible to store volumes of gas which can be called upon as a flexible reserve at times when the system is short, due to the nature of electricity, it is not currently possible to store significant volumes of electricity (there is limited "pumped storage" on the system to deal with sharp increases in electricity use). NGET therefore needs to have reserve contracts in place with flexible plant that can quickly ramp up/down in response to changes in demand.

SO incentives

1.39. As in gas, NGET is subject to SO incentive arrangements, under which a target for SO costs, associated with its role as residual balancer and its other SO activities, is set. Under the provisions of the SO incentives, NGET is permitted to retain a proportion of savings against the targets set but must pay a proportion of any additional costs incurred, in line with the sharing factors agreed. Paragraphs 1.21 and 1.22 above provide further details regarding the way in which the SO incentive process is undertaken[9].

Transmission Owner

1.40. NGET owns the transmission network in England and Wales while SHETL and SPTL own the transmission networks in the Scottish Hydro and Scottish Power regions respectively. In England and Wales the transmission network operates at 275kV and 400kV while in Scotland, transmission also includes a lower voltage network operating at 132kV. In their roles as TOs, NGET, SHETL and SPTL must ensure that sufficient capacity is available on the GB electricity transmission network to deliver security of supply for consumers. In performing this function, the transmission companies must ensure that they act in an economic and efficient way to deliver the best deal for consumers. The costs of providing services that are covered by the regulated price control also include incentives toward efficiency as well as incentives to deliver against a specified quality of service.

Distribution of electricity

1.41. The electricity distribution networks are the medium voltage transportation networks which are used to convey electricity from the high voltage electricity transmission network to the majority of final customers. In line with the differential voltages for transmission in Scotland as compared with England and Wales, the distribution networks in England and Wales operate at a maximum voltage of 132kV while the Scottish distribution networks have the potential to operate at a maximum of 66kV.

1.42. There are 14 electricity Distribution Network Operators (DNOs) and these were all historically owned by the Public Electricity Suppliers (PESs) at privatisation, which also owned the corresponding supply business in their incumbent supply area. However, since privatisation, there has been significant merger/takeover activity and many of the electricity DNOs are now held within common ownership.

1.43. The DNOs, as parties operating on the electricity transmission network, have a role in ensuring that their positions remain in balance and that, in this respect, the volume of electricity that they input to the system is equivalent to the amount that they take off. The DNOs also have a role in delivering the required capacity to ensure that suppliers can transport electricity to their final consumers. Required revenues are made available to fund the provision of this capacity, via the price control which incentivises the DNOs to deliver this capacity in the most economic and efficient way.

[9] A fuller explanation of the way that the SO incentive arrangements have evolved over time and the current scheme is contained within Appendix 1.

Independent Distribution Network Operators (IDNOs)

1.44. The implementation of the Utilities Act 2000 in October 2001, included provisions which enabled Independent Distribution Network Operators (IDNOs) to operate within the electricity industry structure. Following the introduction of the this Act, distribution was designated as a separate activity requiring authorisation by licence and this facilitated the creation of IDNOs. The key difference between IDNOs and DNOs is that the DNOs have specified distribution areas corresponding to the former PES areas in which they operate, whereas the IDNOs generally own and operate electricity distribution network extensions, for example to new housing developments. Since the creation of the IDNOs, six licences have been granted authorising this activity.

Supply of electricity

1.45. At the time of privatisation, each of the PESs held an effective monopoly in the supply of electricity within their respective PES areas and therefore, similarly to British Gas, the PESs' were subject to an RPI-X price control. By May 1999, competition had been rolled out to all domestic electricity customers and in April 2002 the supply price controls were lifted as competition was deemed to have developed sufficiently to protect the interests of consumers. By this point, the domestic market shares of the PES's in their incumbent areas had reduced, as a proportion of customer numbers, from an average of 90% in September 1999 to 70% in September 2001. There were also between 12 and 14 suppliers offering domestic tariffs in each of the PES areas. There are currently six large energy supply companies[10].

The role of the regulator

1.46. Following privatisation, gas and electricity were initially regulated separately.

1.47. The Gas Act (1986) created Ofgas as the regulatory authority for the gas industry. In addition to the regulator, the Gas Consumer Council was set up to represent consumers and to investigate complaints made to it. The Director General (DG) of Ofgas was appointed by the Secretary of State for a five-year period, with the ability for reappointment. The Act set out the duties of both the Secretary of State and the DG.

1.48. The Electricity Act (1989) created the Office of Electricity Regulation (Offer), with the Director General of Electricity Supply (DGES) at its head. The Act

[10] Further details regarding the development of the GB energy supply sector are contained within the Energy Supply Probe - Initial Findings Report.

established the duties and objectives of the new electricity regulatory authority. It also established the duties of the Secretary of State.

1.49. Under the Utilities Act (2000) a single energy regulatory authority, the gas and electricity markets authority (GEMA) and its office (Ofgem), was created. The new regulatory office began operating in June 1999. The merger of the two previous regulators (Offer and Ofgas) was aimed at introducing an integrated approach to regulating the two industries; to allow for cross-industry challenges related to the social and environment agenda; and for competition in the energy sector to be considered in-the-round. The structure of management for the new regulator was also markedly different to either of its predecessors with a Chairman and Chief Executive as part of a board structure rather than an individual regulator or Director General. Details of current members of GEMA (the Authority) can be found on the Ofgem website.

1.50. Offer, Ofgas and Ofgem are all independent regulatory authorities. All regulatory decisions need to be taken in the context of the office's statutory duties. These duties have changed over time. The focus has been on protecting the consumer interest, promoting competition where feasible and ensuring that regulated businesses can finance their functions. The environment, and wider sustainability goals, have been incorporated within the duties, but have moved up in terms of prominence over time.

3. Overview of price cap regulation

Chapter Summary

This chapter provides a high-level overview of how incentive-based price control regulation works with respect to the GB energy networks. We provide a generic summary of how the price control is calculated in principle. Specific details of how price controls are calculated for each energy network are provided in subsequent chapters.

Incentive regulation

3.1. GB energy networks are regulated under an RPI-X framework. This is an incentive-based regulatory framework. Revenue allowances are fixed in advance for a fixed period (typically five years), with some adjustment during the period for specified variables (e.g. changes in the volume of energy transported, customer numbers or certain costs over which the networks have no control), and for inflation. A regulated network is able to retain financial benefits, if it outperforms the underlying assumptions of the allowed revenue calculation. Similarly, if a company underperforms, it must bear at least part of the associated cost.

3.2. Originally, the focus was on providing incentives to improve cost efficiency. Over time, additional objectives have been introduced into the framework. Networks are now provided with incentives to deliver target levels of quality of service and specific environmental or social related objectives (for example, connecting Distributed Generation (DG) and investing in innovation). Additionally there are certain types of costs that may be highly volatile and unpredictable where we have afforded the networks additional protection, such as the costs of funding defined benefit pension schemes.

3.3. The precise nature of these incentive mechanisms are presented in the chapters on each network industry. In most cases, the mechanism is based on a similar principle: set a target or assumed position ex-ante and allow the company to earn a reward if it outperforms the assumption. Regulated networks also face a penalty if they underperform relative to the targets assumed at the price review although historically most companies have outperformed the regulatory settlement. There is variation in the size of the reward provided and the time that it is provided (e.g. during the price control period or at subsequent price reviews). There is also variation in how 'outperformance' is determined. In some regulatory regimes networks actual performance is judged against what was assumed for that network at the price review. In other regimes, for particular incentives, performance is judged relative to other regulated businesses in the same industry. Some behaviour is encouraged or incentivised by providing the regulated energy network companies with specific allowances.

3.4. To understand how incentive regulation works, it is helpful to have an understanding of how the price control, and underlying ex-ante revenue allowances, are determined. We therefore describe below how allowed revenues and the price caps are calculated. We then discuss how incentives are provided through the regime.

3.5. The discussion is high level and generic in nature, based on the principles of price control regulation. The specific detail of how this approach has been applied in each of the energy network industries is described in subsequent chapters.

Scope and form of the control

3.6. A price control sets a limit on the amount by which 'prices' can change from one year to the next. Before calculating the size of this control, two regulatory decisions need to be made: what is the scope of the control and what is the form of the control?

Scope of the control

3.7. When a regulated business provides a range of services or products, some of which may be outside the remit of the regulated licence, the regulator must decide which services or products are going to be covered by the price control. If a network monopoly only provided a single service this would be a straightforward task.

3.8. In energy networks, the scope of the control has changed as particular competitive activities have been unbundled. For example, separate controls were introduced for gas supply and gas transportation and storage in 1994. Each control has a clear specification of what activities or services were to be included in that control. The scope of the control has also changed as the activities of the business have changed. For example, the electricity transmission control was separated into a transmission owner control and a separate incentive regulation regime for the system operator in 2002.

3.9. We describe how the scope of the control has varied for each of the energy networks in later chapters.

Form of the control

3.10. We know that regulated products, including those made available via the energy networks, don't typically have a single price. A decision therefore needs to be made about what the price control is going to be applied to. This is generally referred to as the form of the price control.

3.11. At one extreme, a separate control could be set on the prices of individual products. At another extreme, the control could be placed on total revenue. Other options include setting a control on average revenue, or on a tariff basket (a weighted basket of product prices). When average revenue controls are used a decision needs to be made about what the revenue driver is (i.e. what is the 'quantity' that revenue is divided by to get an 'average' price). Similarly, when a tariff basket is used a decision needs to be made about how to weight the prices of different products or services. When total revenue is used, there is often extra scrutiny or monitoring of the charging methodology.

3.12. Different approaches are used in different sectors. The decision on the form of the control can affect the behaviour of the regulated business. Most notably, it can affect the extent to which the business can choose to rebalance prices within an overarching price control. The choice of revenue driver in an average revenue calculation can also affect decisions. For example, if volume is used, a regulated business will have an incentive to sell more volume and if number of customers is used there will be an incentive to connect more customers. When choosing between different forms of control, there is also a trade-off to be made with respect to the simplicity and transparency of the price control formula.

3.13. We describe how the form of the control has varied for each of the energy networks in later chapters.

Calculating the price control

3.14. In simple terms, an ex-ante price control is calculated by estimating the required efficient costs of operating the network, including any necessary extensions and improvements and the costs of financing this expenditure, for the fixed period. The price control is set so that the net present value of allowed revenue equals the net present value of expected costs for the period. There is also an adjustment for under or over-performance in previous periods.

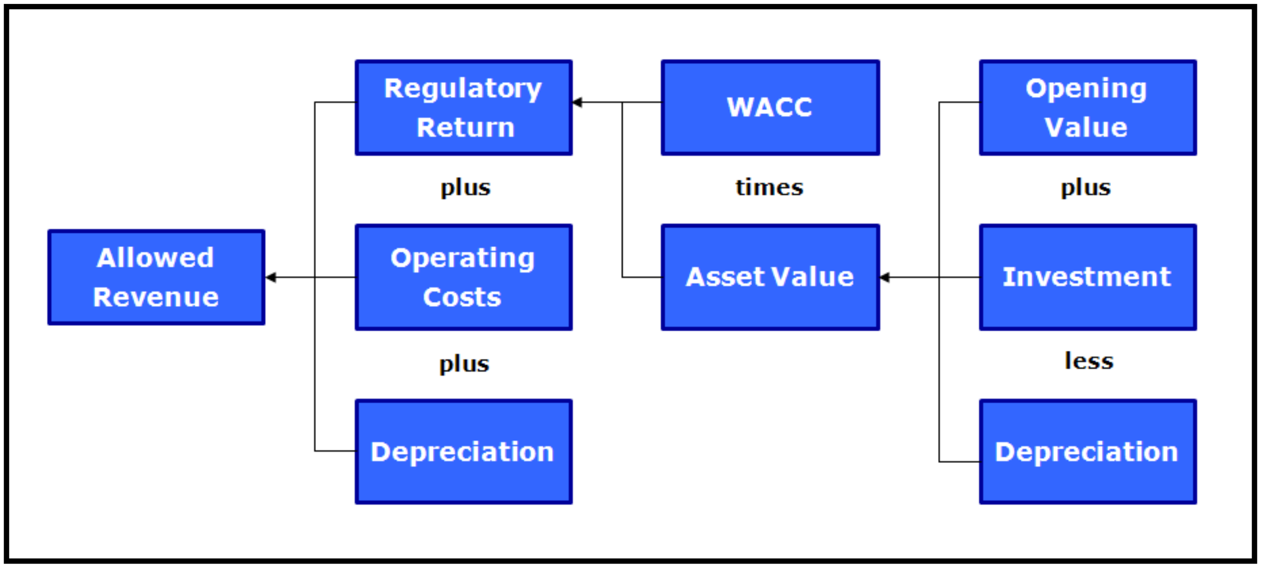
3.15. The price control can be determined by calculating costs and revenues in each year and setting a price control that is consistent with the year-on-year change in annual revenue. Alternatively, the focus can be on the net present value of revenues over the whole fixed period. Different price controls can be determined, with a range of profiling options, which ensure this net present value of revenue is provided. For example, a large upfront price cut followed by price increases could deliver the same net present value of revenue as a constant negative price control. When this approach is used, the annual change in allowed revenue reflected in the price control will not necessarily coincide with any calculation of expected annual changes in costs.

Allowed revenue

3.16. We describe below how allowed revenue is calculated. For simplicity, we focus on a stylised 'building block' approach. In the financial models used to calculate price controls, the calculations are often more detailed than presented here and the focus may be on the net present value of capital over time, rather than on the return of (depreciation) and return on capital. We refer interested readers to our financial models for DPCR4, GDPCR1 and TPCR for more information[11].

3.17. The building block approach is illustrated in Figure 3.1. Base allowed costs are calculated as the sum of forecast controllable operating expenditure (opex), forecast depreciation and the forecast return on the regulatory capital value. Total allowed costs are calculated by incorporating adjustments for specific incentive allowances and under or over-recoveries from the previous price control period. Forecast pass through-costs are added to this estimate of base allowed costs to determine the allowed price control revenue, but to the extent that these costs are different from that assumed in setting the price control, allowed revenue will flex to allow networks to recover the actual levels of such costs.

Figure 2.1: Stylised building blocks of RPI-X regulation



3.18. We briefly describe how each of the building blocks is calculated here.

- **Forecast base operating expenditure (opex):** in transmission, actual base controllable operating expenditure, from the most recent available annual data is adjusted to take account of exceptional items and expected increases in operating expenditure. Adjusted base operating expenditure is then rolled

[11] A guide to the draft financial model for DPCR4 is available from: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR4/Documents1/5090-DPCR4_FinancialModel_Guide_6nov03.pdf. The document on the TPCR4 financial model is available at: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/16695-TPCR%20Models%20Manual%20Final%20070119.pdf. The final proposals for the financial model used in GDPCR1 are available at: http://www.ofgem.gov.uk/Networks/GasDistr/GDPCR7-13/Documents1/GDPCR%202008-13%20-%20financial%20model%20for%20final%20proposals%20manual%20for%20publication.pdf

forward by an assumption about the expected efficiency improvement. In gas and electricity distribution, the starting base is a benchmarked view of costs, reflecting actual relative performance and a view on expected changes in overall productivity of the sector (frontier shift) and the extent of expected catch-up to the frontier (or to average performance or the upper quartile). The efficiency target can be based on a review of efficiency over time and/or benchmarking with other companies or other sectors. Bottom-up benchmarking, focusing on the potential efficiency of individual processes can also be used.

- **Other opex:** a number of different operating expenditure items are then added to base operating expenditure. These include allowances for pension deficits, tax and industry-specific factors (e.g. for example 50% of replacement expenditure (a capital investment) is treated as operating expenditure in gas distribution, primarily for financing reasons).

- **Depreciation:** the depreciation charge is calculated by making an assumption on the expected average life of the assets and applying this to the Regulatory Asset Value (RAV), usually on a straight-line basis. In energy different asset life assumptions have been made across the industry as well as between pre- and post-vesting assets, and profiling arrangements have changed over time.

- **Capital investment (Capex):** forecast capital investment is determined by reviewing business plans presented by the networks and adjusting these for expected efficiencies or for possible changes in the scale or timing of investment plans. Increasingly, we are linking the capital spend to specific outputs (see for example our work on DPCR5).

- **Regulatory asset value (RAV):** the RAV is calculated by determining the opening value at the start of the period and rolling this forward by forecast net capital investment (capital investment net of depreciation). The opening value of the RAV is calculated by taking the opening value at the previous period and rolling this forward by actual capital expenditure and inflation. The precise details of when forecast expenditure is replaced with actual expenditure in the RAV will depend on whether the adjustment is made at the start of a price control period or a rolling adjustment is made.

- **Return (WACC):** the return on the capital value is calculated by multiplying the RAV by the regulatory weighted average cost of capital (WACC). When tax allowances are included in the calculation of allowed revenue directly, a real post-tax WACC is used.

- **Allowances for specific incentives:** the allowed revenue calculation also includes allowances for specific incentive schemes. In the case of energy networks, these include allowances to be earned from the Information Quality Incentive (IQI) scheme and the Innovation Funding Incentive (IFI) scheme.

- **Under- or over-recovery adjustment:** an adjustment may also be made to the calculation of allowed costs to reflect over or under-recovery of allowances in the previous control period.

- **Pass-through items:** the expected cost associated with pass-through items will be added to allowed costs to determine price control revenue. These are items whose costs are considered to be outside of the control of the regulated business (e.g. licence fees to fund Ofgem) and the costs are passed on directly to consumers. If the actual costs are different to forecast, an adjustment is made to the price control revenue during the period (for pass-through items) or at the next price review.

- **Financeability:** financial models are used to determine whether the regulated energy network is financeable under the proposed control. Financeability is assessed using a range of different financial ratios (similar to those used by rating agencies to identify a company with a comfortable investment grade credit rating). If there are concerns, adjustments can be made to the control to ensure that the network can finance its functions.

3.19. We explain how each of these building blocks has been calculated for the energy network price controls since privatisation in subsequent chapters.

Year-on-year price control

3.20. As noted earlier, the price control can be set using annual expected allowed revenue estimates. In this case, the control is simply the change from one year to the next in the base 'price' (average revenue or a tariff basket). The starting base is the price at the end of the previous price control. Depending on what the form of the control is, the annual change in the price control may be different to the year on year change in allowed revenue.

3.21. As noted earlier, alternative approaches can be adopted which smooth the price control over the period, but still ensure that networks earn the allowed revenue on a net present value basis.

Providing incentives

3.22. Incentives are provided in two ways in the price control framework.

Efficiency incentives

3.23. Companies are incentivised to become more efficient by reducing costs below the level assumed in the allowed revenue calculation. If operating efficiency is higher than expected, the companies earn revenue based on expected costs but only spend the lower allowed level. This gives them additional profit during the price control period. Depending on the incentive schemes that are in place, this profit will then be shared with consumers at the end of the price control or through a rolling mechanism. In the event that a company were to overspend as compared with the allowances provided under the price control, they would likely be exposed to these additional costs throughout the course of the control. However, this overspend would be assessed at the next price control review and, where it was seen to be efficient , the companies may be compensated. For example, in TPCR4 provisions were included to allow for 'logging up' of costs over the period of the price control with adjustments to be made where the expenditure is deemed efficient.

3.24. If capital expenditure is lower than assumed, because of efficiency savings, the regulated business earns revenues based on expected depreciation and the return on expected capital costs but only needs to finance its actual costs. Again, additional profit is earned and retained either until the end of the price control period or until a fixed period in time if a rolling mechanism is used. Alternatively an explicit sharing rule can be used, which determines the proportion of the savings that the regulated business retains and the proportion that is shared with consumers. This has a similar effect to setting the length of time over which above normal returns are earned but is, arguably, more transparent.

3.25. A key issue with capital expenditure, and to a lesser extent operating expenditure, is identifying whether spend below the allowance reflects true efficiency savings. There is a risk that it simply reflects work not undertaken, and hence under-delivery of outputs. There may also be concerns about how expenditure is allocated, in accounts, between operating expenditure and capital expenditure. We review capitalisation policies on a regular basis and in DPCR5 we are considering options for treating opex and capex on a more consistent basis.

3.26. We explain how efficiency incentives have been provided in the energy network price controls since privatisation in subsequent chapters.

Specific incentive mechanisms

3.27. The price control can also include a range of specific incentive schemes. These are generally aimed at incentivising networks to undertake specific activities that are consistent with environmental or social policy or to deliver quality of service to consumers. For example, under DPCR4, TPCR4 and GDPCR1 an IFI was introduced which was intended to encourage investments in technological improvements that would facilitate the sustainable development agenda. The IFI makes available ring-fenced funding for this activity and is intended to stimulate Research and Development (R&D) which has been declining as a result of incentives toward the achievement of opex efficiencies under the RPI-X framework. Another example is the Interruptions Incentive Scheme (IIS), contained in DPCR4. This is intended to improve quality of service and encourages the Distribution Network Operators (DNOs) to reduce the incidence and duration of interruptions by rewarding/penalising performance relative to predefined targets.

3.28. These schemes specify what return a company can earn if it delivers the expected output (e.g. connects a certain amount of distributed generation or undertakes a particular research and development project). The return may be specified as a percentage of revenue or a particular pound amount. The incentive scheme may be symmetric, allowing rewards for over-performance and penalties for underperformance.

3.29. Although designed differently to the standard cost efficiency incentive in the price control framework, these mechanisms work on the same principle that regulated businesses can be incentivised to behave in particular way if there is a specified target and an expected return from 'beating' the target. The strength of the scheme will depend on how high the expected return is. The success of the scheme can be affected by a range of factors including how well it is understood (transparency and simplicity), the extent to which the target is challenging, the extent to which it is expected that the regulator will remain committed to the scheme over time, and the way in which it interacts with other incentive schemes.

3.30. We describe the range of incentive schemes that have been introduced for energy networks since privatisation in subsequent chapters.

Uncertainty

3.31. Ex-ante price controls are, by definition, based on forecasts of expected costs and required revenue. There will be an inevitable element of uncertainty about changes in costs, demand, and other factors during a price control period. Many of the changes can be adjusted for at subsequent price reviews.

3.32. Where there is significant uncertainty, either about the scale of costs or the timing of costs, provisions can also be included to make adjustments within the price control. A number of different type of mechanisms can be considered including:

- Pass-through: making automatic adjustments for costs that are considered to be outside the regulated company's control;
- Revenue drivers: adjustments to allowed revenue to reflect changes in specific parameters (notably volume, number of customers, or costs);
- Re-openers: these might be for specific events (e.g. a change in legislation) or for specific circumstances (e.g. a change in the financeability of a business as a result of a change in circumstance).

3.33. We describe the re-openers and revenue drivers that have been used in energy network regulation in subsequent chapters.

4. Calculation of the RPI-X control for electricity distribution

Chapter Summary

This chapter provides an overview of the way that the price controls in place for electricity Distribution Network Operators (DNOs) have evolved over time. It begins by outlining the timeline in terms of price controls that have been implemented since privatisation. The chapter then moves on to discuss the way in which the various 'building blocks' of the price control have evolved as well as summarising the price control that is currently in place. Finally, it provides an overview of the way that the current price control may be amended as part of the next price control review.

Background

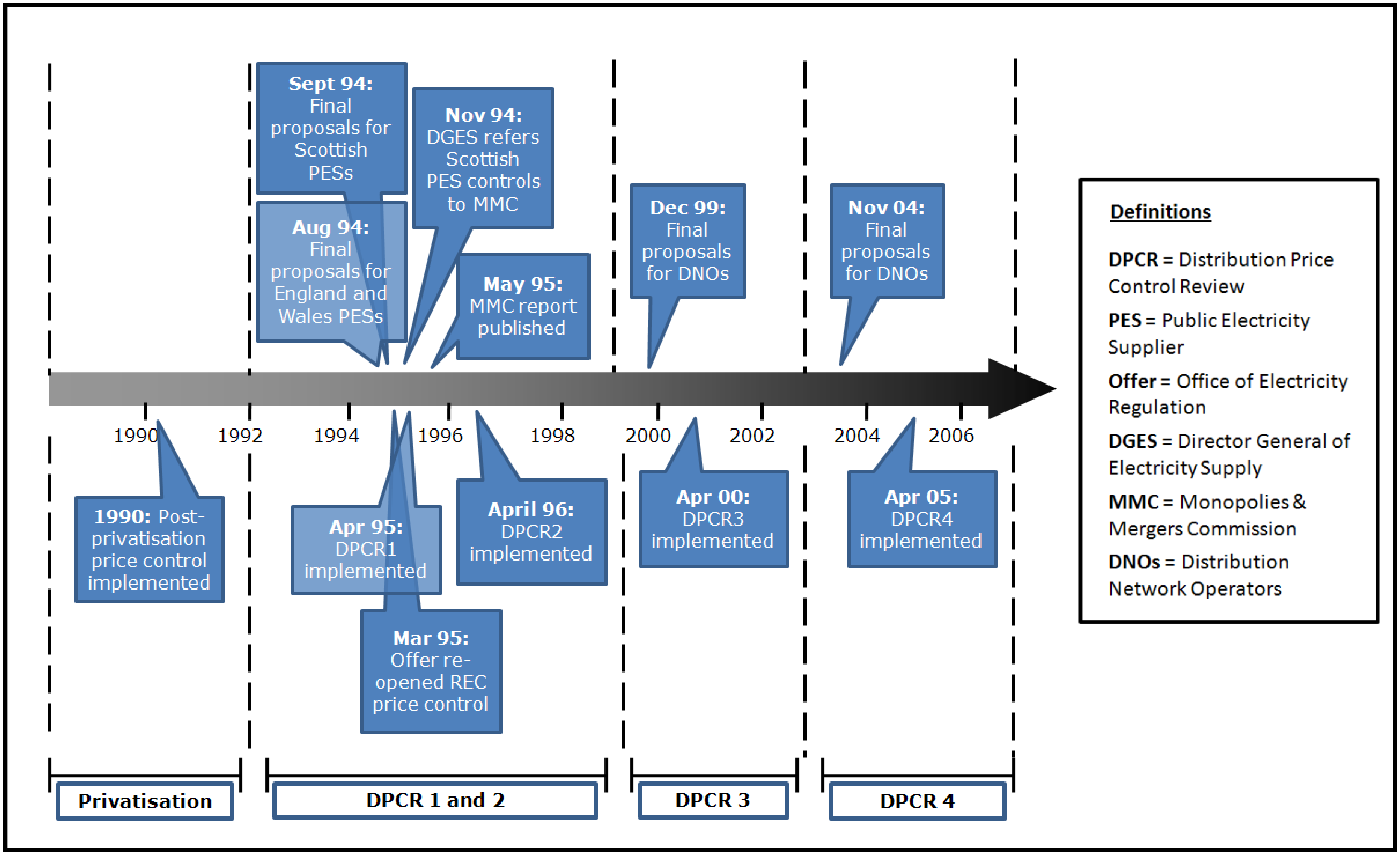
4.1. The electricity distribution networks convey electricity from the high voltage electricity transmission network to the majority of final customers. There are 14 electricity DNOs in GB. At privatisation, the DNOs were owned by Public Electricity Suppliers (PESs) which also owned the corresponding supply business in their incumbent supply areas. However, ownership of these companies has changed significantly since privatisation.

4.2. Figure 4.1 below illustrates the process that has been followed in setting price controls for the England and Wales PESs[12] and the Scottish PESs since privatisation in 1990. At the time of vesting, separate price controls were put in place for the transmission and distribution businesses, in recognition of the separate ownership of these companies between NGC and the PES businesses. The PES businesses were required to maintain separate accounts for distribution, supply, generation and any other businesses that they operated. In line with this, separate periodic reviews were carried out for the supply and distribution businesses.

4.3. Price control reviews were undertaken for the supply businesses, and associated settlements agreed, at vesting, in 1994, 1998 and 2000. Under the 2000 review, an RPI-X control on maximum prices to be charged for Standard Domestic tariffs was implemented with a link included to limit the changes to the prices of Prepayment Meter (PPM) tariffs that could be made relative to this. However, price restraints on Direct Debit tariffs as well as tariffs for Industrial & Commercial (I&C) customers were removed. This was intended to strike a balance between the immediate need to ensure the protection of consumers and the longer term aim of encouraging competition. The controls were implemented for two years reflecting the anticipated development of competition and, in April 2002, the supply price controls were removed altogether. This followed various market reviews, and subsequent analysis, which indicated that competition had developed sufficiently to protect the interests of consumers.

[12] These were previously called Regional Electricity Companies.

Figure 4.1: Timeline of Electricity Distribution Price control reviews



Regulation since privatisation

The distribution price controls

4.4. Since implementation of the RPI-X regime at vesting, the controls for the 12 PESs in England and Wales have been updated at five year intervals in 1995 (DPCR1), a reopener in 1995 (DPCR2), 2000 (DPCR3) and 2005 (DPCR4). Most of these price controls have followed a consultative format but the process that has been adopted has evolved significantly since privatisation. Despite these changing conditions, it has remained possible for the England and Wales PESs to agree to the package proposed by the regulator. However, following completion of DPCR2, there was a significant rise in the share prices of the England and Wales PESs as well as a takeover bid for Northern Electric. The combination of these events exposed the potential for the PESs operating in England and Wales to make significant cuts in opex and capex, significant increases in gearing and to provide substantial dividends to their shareholders. This led to concerns that the price control settlements were not sufficiently demanding.

4.5. As a result, shortly before the implementation of the revised control, the Director General of Electricity Supply (DGES) decided to review the settlement package that had been put in place. The results of this review confirmed the concerns that the DGES had expressed. As such, the DGES concluded that the price control should be tightened and therefore increased the required cost savings, changing the revenue control from RPI-2 to RPI-3 as well as requiring further cost reductions in the form of P_0 cuts[13].

The Scottish PES price controls

4.6. The settlements for the 2 Scottish PESs were initially agreed as part of a price control review process that was separate from the 12 PESs operating in England and Wales. In line with this, the Scottish PES controls were set separately at privatisation and a further separate process was followed in 1995, for the revision of the controls. Although the England and Wales and the Scottish price reviews for PESs in 1990 and 1995 were undertaken separately, the principles upon which the two controls were based were fairly similar. One notable difference, however, was that the reviews of the Scottish PESs included reference also to the controls in place for supply and the regulatory arrangements for generation, reflecting the vertically integrated nature of the businesses.

[13] P_0 cuts in this respect referred to the cost reductions that the PESs were required to pass on to customers at the beginning of the new price control period to reflect the change in allowances under the new price control as compared with the allowances that were available under the existing control.

The Scottish Hydro MMC review

4.7. Following the 1995 review of the Scottish PES price controls, Scottish Hydro-Electric informed the DGES that it could not sign up to the terms of the price control settlement package. Scottish Hydro Electric had concerns that allowed revenues for distribution and supply were insufficient, as well as concerns regarding the ongoing 'Hydro Benefit' arrangements[14]. Following notification from Scottish Hydro Electric that it could not accept the price control package, the DGES made a reference to the Monopolies & Mergers Commission (MMC).

4.8. Following its review, the MMC recommended a slight increase in the scale of the x-factor in RPI-X, and hence a reduction in price control allowances for Scottish Hydro Electric's distribution business on the basis that greater improvements in efficiency were achievable. The MMC also made recommendations on the supply price control that was applied to Scottish Hydro. In addition, the MMC recommended changes to the 'Hydro benefit' scheme, which required that the regulatory accounts must contain accurate information on the amounts transferred from the Hydro generation business to subsidise the distribution business. This was to ensure that only the profits from the Hydro generation business were used to fund the 'Hydro Benefit' subsidy and that the subsidy was equivalent to the amount required to cover the excess costs of distribution in the Scottish Hydro area. This was to ensure that the operation of the subsidy was not detrimental to the Hydro generation business and, equally, that it did not over-subsidise Scottish Hydro electric to the detriment of competition and consumers.

Effects of the MMC conclusions

4.9. Scottish Power subsequently made a request that the changes made to Scottish Hydro Electric supply price control be made to its supply price control. However, Offer rejected this request and Scottish Power therefore launched a Judicial Review. Although the High Court ruled in favour of Offer, following a subsequent referral to the Court of Appeal in 1996, the Court of Appeal ruled in Scottish Power's favour in February 1997. The DGES considered making a further appeal to the House of Lords, but decided to make the required amendments to Scottish Power’s licence.

GB distribution controls and Ofgem's position on mergers

4.10. In 2000 the processes associated with putting the price controls in place for the England and Wales PESs and the Scottish PESs were merged in light of the similarities of the issues considered and the outcomes determined.

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[14] At privatisation, special provisions were put in place to allow a 'Hydro Benefit' cross-subsidy from the generation business to the distribution and transmission businesses. This was intended to address concerns regarding the higher operating costs that Scottish Hydro Electric may face due to the sparsely populated area within which it operates as well as the difficult terrain that it faces.

Policy Developments following DPCR3

4.11. The Information and Incentives Project (IIP) was initiated in December 1999 and sought to strengthen the financial incentives on the DNOs to maintain or improve quality of supply. Three key indicators of quality of supply were chosen as part of the IIP on the basis that these were important to both domestic and business customers, and corresponding incentive schemes were implemented in relation to these. The areas were:

- the number of interruptions to supply;
- the duration of these supply interruptions[15]; and
- customer satisfaction.

4.12. As part of the IIP a framework for monitoring performance against these quality of supply metrics was also put in place as well as an associated process for measuring and auditing this information.

4.13. During the course of DPCR3, in May 2002 Ofgem released details of its treatment of future mergers in this sector in recognition of the increased number of mergers taking place between electricity distribution companies. Although Ofgem recognised that consumers can benefit from efficiency savings or quality improvements resulting from mergers, it noted that each merger would reduce the number of independent groups owning distribution companies and would therefore limit the role of comparisons within price control reviews. There were concerns that a reduction in the scope for comparative competition may result in further efficiency being achieved more slowly and therefore less benefits for consumers.

4.14. Ofgem considered that it would be appropriate for remedies to be used to offset this detriment[16]. Ofgem's approach required that, following any future merger of two or more distribution companies, a one-off reduction in regulated revenue would be imposed on the distribution companies that were held in common ownership as a result of the merger, and this would be spread over a period of five years.

[15] Details regarding the incentives in place for the number and duration of interruptions to supply are contained in the section below regarding Output measures.
[16] The size of the detriment associated with a merger was calculated using a comparison of the efficiency savings returned to customers via the price control review of NGC and Transco (where no comparisons were possible) with those returned to customers through the distribution price controls. This analysis suggested that the detriment from reduced comparators was the equivalent of £32 million for each further merger in the distribution sector. This view was also informed by the estimates produced in the water industry with respect to the detriment resulting from the loss of a comparator, amongst other things.

The current price control

4.15. A further price control review for all of the DNOs was undertaken in 2004, and the agreed settlement implemented in 2005 (DPCR4). DPCR4 comprises the price control settlement package that is currently in place for all of the DNOs[17]. A review of the existing price controls for electricity DNOs is currently underway, with the conclusions of this process set to be implemented from April 2010.

The electricity distribution price control since privatisation

4.16. The framework for the electricity distribution price control has changed significantly as compared with the regime that was put in place at privatisation. The following section provides an overview of the changes that have been implemented, grouped by each component part of the control.

- **Scope of the control:** Under DPCR1, the price controls were applicable to the metering and distribution elements of the PES businesses. A decision was taken, as part of this review, to separate out the components of the control related to metering and those relevant to distribution in light of the potential onset of competition in metering.

  In line with the conclusions reached in the Separation of Business consultation[18], as part of DPCR3 the metering business was split into five separate activities. These included meter reading, data processing and data aggregation, for which supply companies were given responsibility. The other activities were meter ownership and meter operation for which the distribution companies retained responsibility. However, while the distribution companies were responsible for meter ownership, they no longer had an obligation to provide metering services and therefore were required only to continue to provide existing meter assets and maintain those. This was largely a result of the anticipated development of a competitive market for metering. In addition to these existing responsibilities, a new metering obligation was placed on the distribution companies to provide a metering service of last resort.

  The number of costs that have been classified as 'excluded services' and subject to pass through arrangements (where these costs are efficiently incurred) has increased over time. The rationale for the exclusion of these services from the main price control was that either the DNOs were unable to influence the costs incurred or that there was uncertainty regarding the level of costs that would outturn due to a potential increase in competition. For example, excluded service

[17] The control that is currently in place for the DNOs is a hybrid rate of return and price cap mechanism. For the avoidance of doubt, it is referred to as a price cap control.
[18] This related specifically to the provisions that would be implemented to facilitate the separation of the PES distribution and supply businesses.

arrangements have historically been applicable to connections charges and NGC exit charges.

Charges for Extra High Voltage (EHV)[19] customers have also historically been subject to pass through arrangements. However, under DPCR3, it was recognised that the charges that EHV customers had faced since privatisation had not reduced at the same rate as price controlled charges. While it was considered inappropriate to include these charges within the overall price control, as this would not guarantee a reduction in prices for these customers, provisions were included to allow a cap to be placed on EHV charges. These provisions were strengthened under DPCR4 to provide extra protection to EHV customers. As such, changes were made to provide for EHV customers that were connected prior to the onset of DPCR4 to be included in the scope of the control. Those customers that connected during the course of the control, were to be treated as excluded service revenue until 2010, at which point they were anticipated to be included within the price control

As part of DPCR4, partial pass through arrangements were incorporated for the provision of network access for Distributed Generation (DG) which, in light of the increased emphasis on sustainability, was intended to encourage investment to facilitate DG.

- **Form of the control:** Until the completion of DPCR4, average revenue controls were implemented for the electricity DNOs but, as part of DPCR4, a decision was taken that it would be more appropriate to use a total revenue control.

  Under the original provisions of the price controls, implemented at privatisation, revenues were permitted to increase in line with the number of units distributed. However, as part of the analysis undertaken for DPCR1, the DGES recognised that these arrangements had the unintended effect of incentivising DNOs to increase the volume of units distributed. To address this, changes to the revenue driver mechanism were implemented under which the influence of units distributed was reduced to a weight of 50% with the other 50% linked to customer numbers.

  In line with the introduction of pass through arrangements for DG introduced under DPCR4, a £/kW revenue driver was also implemented as part of this control which was intended to further incentivise the connection of DG. The main purpose of the pass through, and associated revenue driver, arrangements was to reduce the risk for the DNOs associated with the connection of this type of generation whilst also incorporating incentives toward efficiency. Due to uncertainties associated with revenues that would be earned by the DNOs, under DPCR4 a revenue driver for meter operation was also introduced to recognise the potential reduction in this activity for DNOs as a result of the development of competition.

[19] This definition applies to customers connected at a voltage level greater than 22 kV or which are connected directly to a sub-station with a primary voltage of 66kV or above.

Reopener provisions were also incorporated as part of DPCR4 to address changes in legislation that may take place but the results of which were uncertain[20]. There are also provisions in place[21] to permit the DNOs to seek disapplication of the price control licence conditions, in whole or in part, where the Authority agrees to this change.

- **X Factor:** Under the original control put in place at privatisation, an average X factor was set for each year, equivalent to RPI+1.1.

  As part of DPCR1 a distinction between price cuts in the first year of the control (P_0) and ongoing price reductions (RPI-X) was introduced. The rationale was that this would allow out performance in the previous control period to be shared with consumers and relate subsequent reductions in allowed revenue more closely to productivity gains. When the distinction between P_0 and X was introduced in the mid 1990s, high values were assigned to P_0 but these were significantly lower by the time DPCR4 was completed.

  Since privatisation, the level of X increased from RPI+1.1 to a maximum of RPI-3 under DPCR2 and back to RPI+0 under DPCR4.

- **Operating expenditure (Opex) efficiency target:** The value of comparative analysis was recognised in DPCR1 and, as such, extensive comparisons were made between companies as part of this review. Over time, in line with the refinement of analytical techniques and the collation of an increased volume of information, the use of comparative analysis has increased.

  In deriving an opex efficiency target under DPCR1 the DGES sought to assess the path of opex over the coming price control. To facilitate this, he used the latest available actual opex figures from 1992/3, which had been adjusted to normalise the data across the distribution companies, and assumed that the companies would be able to reduce their controllable opex, on a per unit basis, by 17% between 1992/3 to 2000. In making this assumption, the DGES assumed that efficiency gains of 1.5% per annum would have been made in the final two years of the price control and therefore a 3% per annum reduction in costs was forecast for each year of DPCR1.

  In DPCR3, it was noted that an important factor driving distribution costs was the pattern of peak demands at different points within each PES's system. However, due to the difficulty of measuring these peaks, a composite scale variable (CSV) was constructed based on DNO customer numbers, units distributed and the length of their network, as the regulator recognised that these observed

[20] These were potential changes to the Traffic Management Act where the DNOs argued that there would be significant impact on their costs, but that the level of impact would be difficult to quantify in advance of implementation. They also included potential increased costs associated with overhead line clearances as a result of a review of the Electricity safety, Quality and Continuity Regulations (ESQCR) as well as any costs that may be incurred due to changes to the regulations themselves.

[21] These provisions are contained within Special Condition A4 of the electricity distribution licence.

measures also represented underlying cost drivers. On the basis of this analysis, the opex efficiency target was increased to 4.4% per annum while under DPCR4, there was quite a significant reduction in underlying efficient costs to 1.5%. This could be an indicator that the scale of opex efficiency improvements that are potentially available is reducing. The results of analysis carried out as part of DPCR5 will provide an indication of the trend in the reduction of costs due to efficiency improvements that may be seen in the future.

- **Opex efficiency incentive:** Under RPI-X regulation companies are provided with a strong incentive to reduce costs below the assumed level, as they earn the profit until the regulatory control shares the saving with consumers. We share the savings with consumers at the start of each price review period[22] by setting opex allowances based on benchmark historical costs. The value of the benefit to the company therefore depends on when the saving was made, performance relative to other DNOs and the efficiency target set. For example, if benchmark costs require companies to reach average performance, or 'upper quartile' performance, rather than the top performance ('the efficiency frontier') the top performing companies will be able to retain a proportion of their savings for a longer period.

  Concerns about the potential distortion of incentives, particularly in relation to the timing of cost savings led to the introduction of a rolling opex mechanism as part of DPCR4. Under this mechanism, DNOs would be allowed to retain the benefits of out-performance for a fixed five year period from (and including) the year in which the saving was originally made. Despite intentions to implement this on an ongoing basis, the mechanism was only applied to one year of the control due to concerns regarding the quality of data available and the tendency of the DNOs to capitalise costs which could skew the efficiency incentive. These issues are being considered as part of DPCR5.

- **Pension costs:** Prior to DPCR4[23], there had not been an explicit discussion of pension costs and the way that they should be funded as part of the price control. Instead, pension costs had been included as an element of the overall staff costs. As part of the review of monopoly price controls, it was recognised that pension costs was an area that would require increased focus in the future. The rationale for this was that previously pension funds had been in surplus but, due to insufficient contributions, had entered a period of deficit and specific allowances were needed to deal with this. Specific provisions were therefore included for pensions costs under DPCR4.

- **Capital expenditure (capex):** In determining the appropriate level of allowances for capex, scrutiny of the forecasts of Non Load Related Expenditure (NLRE) and Load Related Expenditure (LRE) have historically been undertaken, with advice from consultants where appropriate.

[22] The slight exception to this was the use of a five-year rolling incentive mechanism for the DNOs in 2003/04.
[23] Discussion of the pensions issue was also included in the 2003 Review of Monopoly Price Controls.

A specific incentive to encourage integrity in forecasting of costs was used as part of DPCR3 when a 0.25% reduction in allowed revenue was imposed for three companies that provided high and distorted forecasts of capex and opex. This principle was built on more recently under DPCR4 when, recognising information asymmetries that exist between the DNOs and Ofgem, the Information Quality Incentive (IQI)[24] was introduced. This was in response to Ofgem concerns about significant increases in capex forecasts received from the DNOs. In particular, there were concerns that where DNOs were less able to justify increases in capex and these were high as compared with the view of consultants, this might be due to inaccuracies in forecasting and could lead to the need for even greater spending during the course of the control.

Under the IQI, the DNOs that had less well justified capex forecasts, as compared with the views of Ofgem's consultants, would be permitted to spend above the amounts that they had justified to Ofgem but would receive relatively lower returns for underspending. In contrast, those DNOs that had better justified their forecasts, and were in line with the views of the consultants, would be rewarded with a higher rate of return and a stronger incentive for efficiency. As such, DNOs were permitted to choose from a range of capex options. Where they opted for a lower capex allowance, there were provisions to allow them to earn a higher incentive rate. However, where they chose a higher capex allowance, they would earn a lower incentive rate. Under these arrangements, the proportion of efficiency savings that the DNOs were permitted to retain would depend upon the capex allowance that they chose and the incentive rate associated with this.

The intent of the IQI was to mitigate the information asymmetry between Ofgem and the DNOs in capex forecasting and provide incentives to the DNOs to expose the most efficient level of capex for the requirements of the network over the period of the control. It sought to achieve this whilst retaining incentives for efficiency, reducing the risk of under-investment, reducing the opportunity for DNOs with high capex allowances to make high returns from underspend and by rewarding DNOs with low capex allowances for delivering against this.

As a complement to the IQI, as part of DPCR4 a rolling retention mechanism was introduced for capex, and applied retrospectively to the capex incurred in DPCR3. This mechanism provides that any capex efficiencies are retained for a fixed five period rather than adjustments being made at the start of the next control. It therefore provides an incentive, throughout the duration of the control, to secure efficiencies in capex as it will be possible for the DNOs to retain these for a fixed period. The percentage of benefits that the DNOs can retain via the capex rolling incentive is specific to each company and, as such, is aligned with the incentive rate inferred by the IQI mechanism. In choosing an appropriate allowance under the IQI, the DNOs had to consider any increased (reduced) revenues that may be

[24] This was referred to as the sliding scale incentive at the time of DPCR4.

achieved (incurred) as a result of the operation of the rolling retention mechanism.

- **Output measures:** The need to ensure that a given level of quality is retained has been noted alongside the need to continue to deliver improvements in efficiency. This was recognised at the time the Electricity Act was brought into effect and provisions were incorporated to permit the DGES to determine standards of performance in supply services. In line with these provisions, Guaranteed Standards of Performance (GSOPs) and Overall Standards of Performance (OSOPs)[25] were derived by the DGES in 1991 and associated payments to consumers were required to be paid where these standards were not met. The standards were extended and tightened in April 1993, with the level of associated penalties doubled, in light of the experience of using them. The electricity distribution companies were also required to have codes of practice in place, on which they needed to obtain approval from the DGES[26].

  Under DPCR1, the DGES committed to take companies performance on the GSOPs into account when setting price controls at the next period which meant that performance in this area could have a material impact on future allowances. Building on this principle, under DPCR3 adjustments to revenues to reward or penalise PESs with respect to their performance against a range of factors were proposed in order to give them incentives to improve the overall quality of service that they provided.

  In DPCR3, it was noted that work in this area would be taken forward as part of the IIP. The IIP was completed in 2001 and delivered the formalisation of a specific incentive scheme to minimise the number and duration of interruptions, known as the Interruptions Incentive Scheme (IIS). The IIS is a symmetrical penalty/reward scheme which set targets for the number of customers interrupted per 100 (CI) and number of customer minutes lost per customer (CML). Under DPCR4, targets for CI were set based on benchmarks derived for the number of interruptions experienced by customers, to which a 0.5% per annum improvement was applied (out to 2020) to reflect developments in technology and best practice. In terms of CML, benchmarks were set for average restoration times, which were applied to the targeted CI levels, to derive targets for CML to 2010. Under this scheme, 1.2 % of revenue is exposed associated with CI and 1.8 % associated with CML.

  Under DPCR4 amendments to the GSOPs were also made to provide for the implementation of enhanced incentives in relation to the restoration of supply

[25] The Guaranteed Standards were standards which the companies needed to achieve in dealing with customers. There were 10 Guaranteed Standards which related to the speed of restoration of supply after faults, the provision of supply and a meter, notice of supply interruptions and the keeping of appointments. There were eight Overall Standards and these specified minimum levels of service for customers in general. They included such standards as the minimum percentage of customers for whom a firm meter reading must be obtained at least once a year.

[26] These codes of practise related to the payment of bills by domestic customers, services for the elderly and disabled and guidance on the efficient use of electricity.

and telephony response as these were considered to be areas of crucial importance to consumers. Financial incentives on the quality and speed of telephony response were included and extended to reflect customer satisfaction. On this basis, a sliding scale incentive was introduced under which if customer satisfaction fell below certain predetermined levels, the DNOs would be subject to penalties of up to 0.25% of revenue. The scheme also incorporated provisions to allow for a small reward, equivalent to 0.05% of revenue for performance above a certain predetermined level.

- **Losses:** Since the original RPI-X regime was introduced at privatisation there has been reference to electricity losses within the framework. Under DPCR1 the DGES recognised further the importance of incentives to reduce losses and hence save energy. He therefore introduced provisions to double the incentive payments achieved by the DNOs for a reduction in losses, noting that this would still ensure that a significant proportion of benefits were passed to consumers.

  However, as part of DPCR3 Offer noted that the existing incentives on losses had been insufficient to prevent a noticeable rise in losses during DPCR2. Therefore provisions were made for an adjustment of base revenue allowances of up to 0.25%, on the basis of improved performance on losses. Further changes were made to the losses incentives under DPCR4 to make the associated payments more reflective of the costs imposed on the system from these lost units of electricity[27]. This subsequently meant a significant increase in the value of the incentive from £30/MWh to £48/MWh. A rolling retention mechanism was introduced to allow the DNOs to keep the benefit of losses reductions for a fixed five year period.

- **Other incentive measures:** As part of DPCR4 concerns were raised that the network companies were not investing in sufficient levels of R&D and that expenditure on R&D was actually declining as a result of the RPI-X framework which incentivised improvements in opex. To address these concerns, the Innovation Funding Incentive (IFI) was introduced. The IFI was intended to provide incentives toward investment in technologies that would reduce network company costs in the long-term but would not pay off for some time after investment. The IFI therefore made available funding for projects related to improvements in supply quality, the environment and safety.

  New initiatives were also introduced in relation to DG as part of DPCR4[28]. To provide further encouragement toward the deployment of these technologies, under DPCR4 financial incentives were introduced to stimulate the development of innovative Registered Power Zone (RPZ) solutions which could offer significant benefit to DG consumers.

[27] This included an estimation of the costs of the electricity units lost and the environmental costs as well as the transmission and distribution costs.
[28] Further details regarding the way that these incentives toward the connection of DG work are contained above in the section on the Form of the control.

In addition, a discretionary reward scheme was implemented as part of DPCR4. This scheme makes available a reward of up to £1 million per year, which can be awarded to DNOs on the basis of their performance in areas where high levels of performance are less easy to measure. This reward could therefore be awarded for performance demonstrated with respect to priority customer care or activities related to Corporate Social Responsibilities.

- **Return on RAV/WACC:** An appropriate cost of capital has largely been derived using the framework provided by the Capital Asset Pricing Model (CAPM)[29] as well as the Dividend Growth Model (DGM). Since 1990 the cost of capital has been set at a pre tax level of between 6.5% and 7%.

  A decision was taken as part of DPCR4 to adopt a post-tax approach to the cost of capital in line with changes that were set to be made to the Inland Revenue rules which would increase the tax burden on the DNOs. This approach was subsequently applied in transmission and gas distribution price controls. It entails two elements being incorporated into overall revenue allowances: a 'vanilla' Weighted Average Cost of Capital (vanilla WACC) return on the RAV (pre-tax debt, post-tax equity) and a specific tax allowance taking account of the likely tax treatment of a company's expenditure.

  In more recent years a significant increase in the level of notional gearing has been assumed (from 50% at DPCR3 to 57.5% at DPCR4) reflecting an increase in the debt to equity ratio of the DNOs.

- **RAV:** The RAV of the electricity DNOs was explicitly discussed as part of DPCR1 and was initially set to provide a broad reflection of the asset base of the companies which would need to be remunerated.

  In deriving the opening RAV for the DNOs, the DGES used an adjusted flotation value. In doing so, the DGES first took the value of the DNOs on the day of flotation, taking into account the values that would need to be attributed to other elements of the business e.g. National Grid Company (NGC) holdings, generation and supply. To also reflect the change in share value and changes in the cost of capital since privatisation, a 50% uprate was applied to the flotation value and allowance was made for the value of additional investment undertaken in the intervening period. However, following the reopener initiated by the DGES in 1995, he decided that the uprate of 50% was too generous. His decision was largely based on the conclusions reached by the MMC in the Scottish Hydro Electric case where it had determined that it was not appropriate to adjust flotation values to reflect a change in the cost of capital. Therefore, the uprate was reduced from 50% to 15% and was intended to reflect both shareholders expectations of rising dividends at privatisation and the relatively low value of the England and Wales PESs at flotation.

29 The CAPM is a model used to determine a theoretically required rate of return which takes account of the non diversifiable risk of the company.

There have been limited changes to the opening value of the RAV since this initial valuation. The RAV has been updated for allowed capex and adjusted at subsequent price controls to reflect the actual level of capex spend, subject to these costs meeting with efficiency conditions. As part of DPCR4, provisions were included to allow any efficiency savings identified to be retained on a rolling retention basis, for a fixed period of five years, to allow benefits to be retained by the DNOs even where these efficiencies were achieved late in the price control period.

Under DPCR4 the value of the metering element of the distribution business was excluded from the RAV, valued on a modern equivalent purchase price basis and depreciated in line with DNO depreciation policy. However, meter recertification costs from 2000 were included in the RAV in view of the DNOs ongoing role in this area. Some further changes were also made to the classification of capex and opex which impacted what was eligible for inclusion in the RAV. These changes included the exclusion, from the RAV, of:

- corporate costs;
- inter/intra company margins;
- depreciation on non-operational assets that had been capitalised.

In addition, concerns were expressed about potential overcapitalisation of indirect costs. Ofgem therefore requested information from the DNOs on this basis. Where there was evidence that a higher (or lower) than average proportion of indirect costs had been capitalised, adjustments to the RAVs of these DNOs were made to bring them within a specified range of capitalised costs.

- **Other issues:** Under DPCR4, new regulatory reporting requirements were introduced. These were intended to facilitate the collection of DNO information on a common basis, and to an appropriate degree of accuracy, to enable Ofgem to effectively monitor compliance with the price control conditions. This required the submission of Regulatory Reporting Packs (RRPs) on an annual basis, relating to costs, revenues, incentives and outputs.

Regulation of electricity distribution today

4.17. There has been significant change in the way the electricity distribution companies are regulated, since privatisation in 1990. Under the provisions of the most recent electricity DNO price control (DPCR4), companies are subject to a price control which will run until April 2010. This section provides details of the main provisions of the electricity distribution price control and the analysis that was undertaken to determine the scope of these provisions.

4.18. DPCR4 comprises an average revenue control under which the prices that DNOs charge are permitted to rise in line with inflation (RPI-0). The weighted revenue driver was retained under DPCR4 although changes were made to recognise actual customer numbers and the various voltage categories. This mechanism provides that revenues may increase proportionately in line with changes in the volume of units of electricity distributed and changes in customer numbers, with each of these factors given an equal weighting.

4.19. Calculation of allowed revenue for each of the DNOs required a determination of each of the following 'building block' elements:

- **Opex:** An assessment of forecasts of future opex was undertaken based on data submitted by the DNOs about projected spending, use of historic intra-company comparisons of opex and significant use of comparative benchmarking analysis. As a result of this analysis, a 1.5% reduction in underlying efficient costs was assumed.

- **Capex:** An assessment of future capex was carried out using company forecasts of LRE and NLRE as well as comparisons of this against previous spend, future spend given likely load growth and asset age. On the basis of this analysis, allowances of £5,215 million were included within the price control for capex as compared with an overall DNO forecast of £5,852 million at the beginning of the process.

  Incentives toward capex efficiency were also introduced under DPCR4, in the form of the IQI and associated capex rolling incentive[30].

- **Depreciation:** Under DPCR4 an allowance was incorporated for straight line depreciation of post-vesting assets. However, Ofgem recognised that some of the DNOs had seen a large reduction in their depreciation allowances during DPCR3 as vesting assets had become fully depreciated (the depreciation 'cliff-face'). In light of the fact that most of the DNOs would see vesting assets fully depreciated during DPCR4, a smoothing adjustment was applied. Under this adjustment mechanism, new asset lives were reduced from 33 to 20 years with a 15 year smoothing period used for assets that had been assigned a 33 year asset life to allow these to be depreciated over a 20 year period.

  The exceptions to the application of these provisions were SP Distribution and SSE Hydro where vesting assets were calculated on a longer asset life and therefore these DNOs would still have allowances for the depreciation of pre-vesting assets during DPCR4. Three of the DNOs had also previously had this methodology applied as part of DPCR3.

- **RAV:** The RAVs for each of the DNOs at the time of privatisation were determined as part of DPCR1[31]. These are adjusted at each price control period to reflect actual capex undertaken during the control, allowing for depreciation and adjusting for inflation. Actual capex is based upon figures from the first four years of the price control period and projections of spend in the final year of the control. The RAV is also rolled forward using forecasts levels for the next price control period.

[30] These mechanisms are explained in more detail in the section on Changes in the electricity distribution price control since privatisation.
[31] More detail regarding the way that the RAV was derived is contained within the section on Changes in the electricity distribution price control since privatisation.

- **WACC:** As part of DPCR4 a 'Vanilla' WACC[32] return on the RAV was used and this was set at 5.5% which was equivalent to a 6.9% pre tax level and therefore consistent with the previous levels of cost of capital set at around 6.5-7%. Notional gearing was assumed to be at 57.5%.

4.20. There are various incentive mechanisms in place to facilitate certain behaviours from the electricity DNOs. In particular, incentives to improve quality of supply are provided through the IIS, the use of guaranteed standards with associated payments to customers for failing to meet these and through the retention of key reporting requirements in line with the overall standards previously in place.

4.21. Investment is incentivised via the overall weighted revenue driver, the obligations with which the DNOs must comply and the quality of supply standards that they seek to achieve. In addition, more recent mechanisms were introduced under DPCR4, to connect DG and to innovate through the use of innovative RPZ solutions. These DG incentives are in line with the increased focus upon sustainability that was adopted as part of DPCR4 and are complemented with other sustainability incentives including the IFI, allowances for undergrounding and incentives to reduce losses. The rolling capex mechanism also provides incentives to innovate throughout the duration of the price control.

4.22. Uncertainty in the electricity distribution price control is, to some extent, dealt with through the continued use of revenue drivers. It is also addressed via the inclusion of provisions to allow the price control to be reopened under certain circumstances.

The electricity distribution price control from 2010

4.23. The current price control expires on 31 March 2010. The fifth Distribution Price Control Review (DPCR5) is currently underway, with a plan that final proposals will be published by December 2009. An initial consultation document regarding DPCR5 was published in March 2008, with a follow up policy paper issued in December 2008. A number of issues have been identified for resolution as part of DPCR5. These include:

- There are concerns that DNOs have historically treated capex allowances as budgets within which their spending must be confined and that, as a result, they may not be carrying out the investment required to maintain the condition of the network and meet customers needs. To address this, it is intended that under DPCR5 a predefined set of output measures will be developed against which the performance of the DNOs will be assessed. This should facilitate our understanding of whether DNO capex underspend that is observed is a result of

[32] The vanilla WACC represents the allowed cash return on the RAV. It is calculated as a pretax cost of debt and a post-tax cost of equity as a separate specific allowance for tax costs is calculated.

efficient decisions taken by the companies or whether their lower spending may be leading to a deterioration of the network.

- There is significant uncertainty over the role that the DNOs will play in facilitating the climate change agenda and, in particular, the way that these networks may need to de developed to adapt to this challenge. There is also uncertainty about outturn costs that will be seen as a result of the increase in financing costs due to the credit crunch as well recent changes in the price of key input costs. In addition, it is possible that the economic downturn will impact on load growth, materials costs, interest costs and inflation. To address these concerns, consideration is being given to the regulatory tools that are available to share, in the most appropriate way, the risks associated with the evident uncertainty. Such tools include, amongst other things, pass through provisions, sharing factors, volume drivers and reopeners. The decision on the categories of cost to which these various tools should be applied is dependent on where the risk lies, which party is best placed to manage this risk, the materiality of the issue and the practicality of measurement.

- The incentive schemes that are currently in place are largely proposed to be retained but with amendments to ensure that they are encouraging the behaviour that we are seeking to incentivise. The IQI, the IIS and the losses incentive were cited as specific instruments which would need to be examined. In particular, it was suggested that any rewards received should be more closely linked with the performance of the DNOs in delivering quality services to their consumers and that consideration needed to be given to potential implementation of caps and collars on the rewards/penalties that the DNOs may be exposed to. As part of DPCR5, steps are also being taken to seek to implement incentives which will encourage 'future proofed' innovations from the DNOs as well as taking steps to equalise the incentives in place for capex and opex where these have historically been distorted.

4.24. The responses to the DPCR5 policy paper were received in the middle of February and these are currently being considered by the DPCR5 team. We expect to publish an initial proposals consultation document in late July 2008.

Price controls for the IDNOs

4.25. While this document does not discuss, in detail, the price control arrangements in place for the Independent Distribution Network Operators (IDNOs), the following section provides a high-level overview of these arrangements, to give context to the electricity distribution price control.

4.26. Following the implementation of the Utilities Act 2000, from October 2001 it became possible for IDNO licences to be granted. These licences contained a price cap licence condition (Condition BA1) which required that charges levied by the IDNOs, for domestic distribution, could not exceed equivalent charges levied by the incumbent DNO in that area. The continued operation of this licence condition is therefore equivalent to the application of a Relative Price Cap (RPC) on the charges of the IDNOs[33].

[33] For further information regarding the development of Ofgem policy with respect to the regulation of IDNOs please see the following link: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/IDNOs/Pages/IDNOs.aspx

5. Calculation of the RPI-X control for electricity transmission

Chapter Summary

This chapter provides an overview of the way that the price controls in place for the electricity Transmission Operators (TOs) have evolved over time. It begins by outlining the timeline in terms of price controls that have been implemented since privatisation. The chapter then moves on to provide an overview of the price control that is currently in place and finally discusses the way in which the various 'building blocks' of the price control have evolved since privatisation.

Background

5.1. National Grid Electricity Transmission (NGET)[34] is the Transmission Owner (TO) for England and Wales while Scottish Hydro Electric Transmission Limited (SHETL) and Scottish Power Transmission Limited (SPTL) are the TOs in the Scottish Hydro and Scottish Power regions, respectively. As TOs they must ensure that sufficient capacity is available on the GB electricity transmission network to deliver security of supply for consumers. NGET is the electricity system operator (SO) across GB. NGET has only assumed the responsibility of GBSO since the implementation of the British Electricity Transmission and Trading Arrangements (BETTA) in 2005.

5.2. In April 2002 National Grid (as the owner of the National Grid Company (NGC)) and Lattice (the owner of Transco (the SO and TO for the gas system)) announced their intention to merge. In July 2002, the Secretary of State took the decision to clear the merger. This created one company, National Grid Transco, which retained ownership of NGET as the GBSO and the TO in England and Wales as well as NGG as the SO and TO for the GB gas system.

5.3. Figure 5.1 below illustrates the process that has been followed in setting TO price controls, since privatisation in 1990, for:

- NGET as TO for England and Wales;
- SPTL as TO for the ScottishPower area; and
- SHETL as TO for the Scottish Hydro area.

5.4. The following section provides an overview of the process followed and issues encountered in setting the TO price controls since privatisation in 1990.

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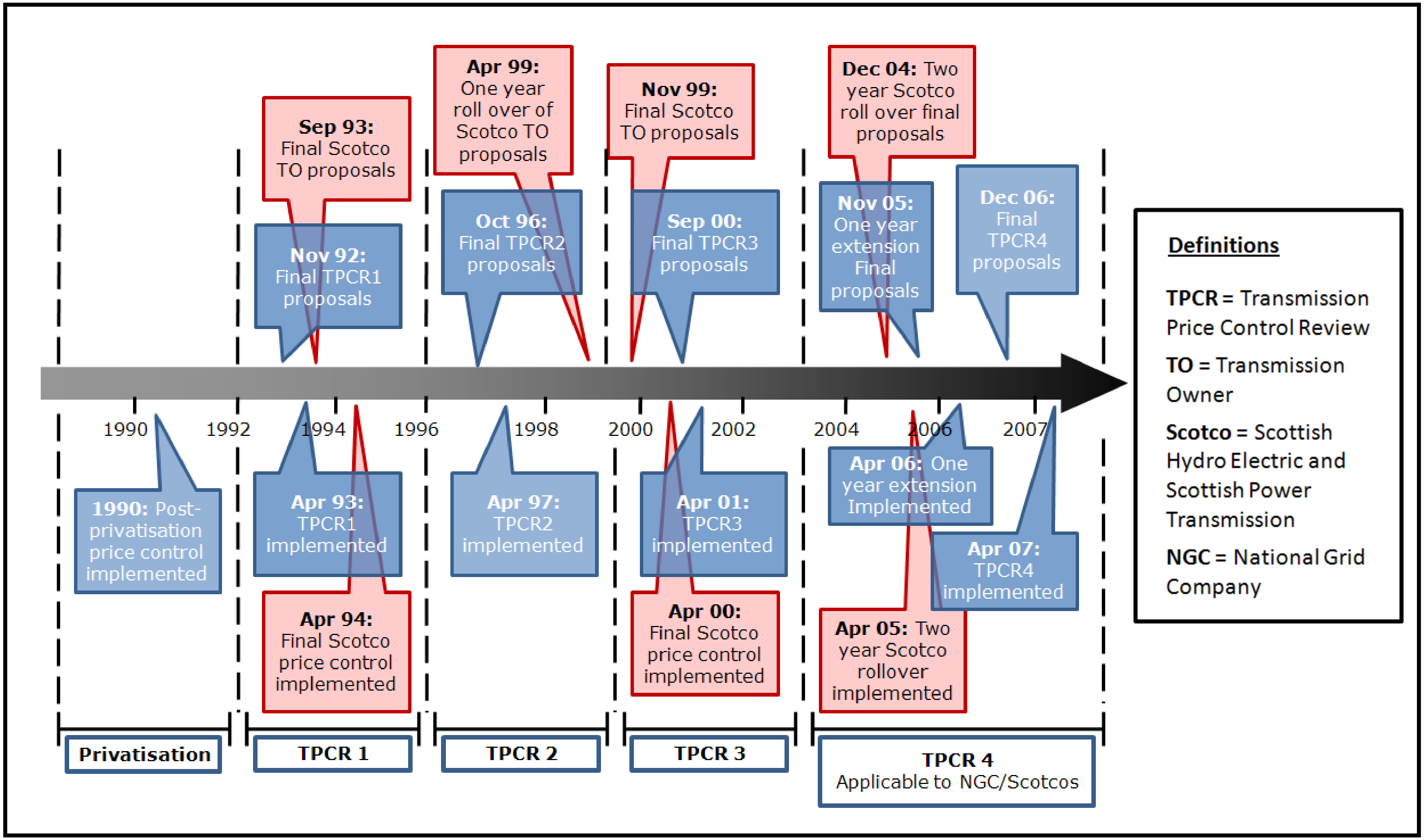
[34] Previously the National Grid Company (NGC).

Figure 5.1: Timeline of Electricity Transmission Price control reviews



Regulation since privatisation

The England and Wales TO price control

5.5. The National Grid Company's (NGC's) TO price control was originally implemented in 1991 and set for a three-year period until 1993. The next two price reviews set a control for four years: from 1993 to 1997 (TPCR1); and 1997 to 2001 (TPCR2). The control that was set in 2001 (TPCR3) was the first five-year regulatory period that had been used for NGC's price control and was set to expire in 2006. As part of this review, NGC's SO costs were separated out of the main control and therefore, from this point onwards, the control has solely covered costs associated with the TO function.

The Scottish TO price control

5.6. The price controls for the Scottish transmission companies were set for a four year period at privatisation, in 1990, and therefore were reviewed to allow the implementation of a new control in 1994. The second price control relating to the Scottish electricity transmission companies was set for a period of 5 years and was set to be reviewed in 1999. However, in 1999 the Director General of Electricity Supply (DGES) concluded that it would be appropriate to align the transmission, distribution and supply price controls across Scotland and therefore the transmission price control was rolled over for an interim one year period in 1999/2000. Under this one year rollover, the DGES determined that it would be appropriate to allow the Scottish transmission companies to earn the same level of total revenue in real terms as that allowed in 1998/99.

5.7. A further price control was set for the Scottish transmission companies in April 2000 and was set to cover the five year period until April 2005.

Merger of the transmission price controls

5.8. In 2003 a decision was taken to align the electricity and gas transmission price controls to include greater consistency of treatment of common costs and of incentive arrangements, and to reduce the need to duplicate work on common issues consistent with the Transco/NGC merger. To facilitate this alignment, a two year rollover was implemented for the Scottish Transmission companies (for 2005/06 and 2006/07) as well as a one year extension for NGC's price control (for 2006/07). This allowed both gas and electricity issues as well as issues across GB (in Scotland and England and Wales) to be considered in the round as part of TPCR4[35].

[35] The control that is currently in place for the electricity transmission companies is a hybrid rate of return and price cap mechanism. For the avoidance of doubt, it is a price cap control.

5.9. In the last two rounds of price controls for electricity TOs, one of the biggest issues has been the incorporation of provisions to ensure that sufficient revenues are available to fund required capex, especially in light of the required investment to support new renewables. This was particularly highlighted during TPCR3 when the Transmission Investment in Renewable Generation (TIRG) reopener was initiated due to an unexpected increase in the volume of investment required to accommodate new renewable generation. Learning from this experience, additional provisions were incorporated within TPCR4 to ensure that the revenues of all of the electricity TOs could vary in line with required new investment. This is discussed in further detail later in the chapter.

The electricity transmission price control since privatisation

5.10. The framework for the electricity transmission price control has changed significantly as compared with the regime that was put in place at privatisation. The following section provides an overview of the changes that have been implemented, grouped by each component part of the control.

- **Scope of the control:** As part of TPCR2, the transmission uplift costs incurred by NGC, in undertaking its role as system balancer, were moved from the arrangements under the Electricity Pool of England & Wales (the Pool)[36] into NGC's price controlled costs. However, as part of the 2001 review, and following the implementation of the New Electricity Trading Arrangements (NETA), SO internal costs were separated from the main transmission control and placed within a SO incentive scheme which was aligned to the SO external incentives and had effect for the five year period from 2001-2006.

  From TPCR1 the Scottish transmission companies comprised three activities: the core transmission business; an SO function; and the pre-vesting interconnector between Scotland and the England and Wales grid. While explicit arrangements existed for NGC's SO costs, the SO costs of the Scottish transmission companies were simply included within overall opex. With the implementation of BETTA in 2005, NGET took over the role of GBSO and these costs were therefore removed from the Scottish transmission price controls.

- **Form of the control:** Under the original price controls, the RPI-X regime was applied to customer charges per MW, in the form of an average revenue cap. However, this was amended to a total revenue cap as part of TPCR1 under which the price control was based on aggregate revenues. This was intended to remove any perverse incentives to increase the volume of gas throughput on the system.

  The same changes were implemented within the Scottish transmission controls as part of TPCR1. However, under TPCR3, concerns were raised that, as adjusted

[36] The Pool was established as a result of privatisation and created a mechanism to allow trading between generators and suppliers.

revenues did not vary with actual volumes of electricity transmitted, prices for some consumers had begun to increase driven by outturn units being less than the pre-set units on which the control was based. Provisions were therefore included to set initial levels of allowed revenue with an annual correction to allowed revenues dependent on the units of electricity transmitted.

As part of TPCR3, in England and Wales, a revenue driver mechanism was introduced to correct for uncertainties in the levels of new generation connections. Under this mechanism, a year-on-year revenue stream was made available for uncertain capex and, to facilitate this, a year-on-year projection of new generation connections was sought from NGC. A correction factor of £23 million per GW was applied as part of this revenue stream, based upon an assumption that 5GW of new generation would connect. However, provisions to allow capex revenues to vary for the Scottish Transmission companies were not included. This may have been a contributing factor in the TIRG reopener as the Energy White Paper suggested that there would be a substantial increase in windfarm capacity in Scotland and therefore significant capex was needed to support this.

A revenue driver provision for all of the electricity TOs was introduced under the 2007 review. This permitted revenues to vary proportionately in response to change in volumes of generation that wish to connect with the level of the revenue driver based on the unit cost of forecast levels of capex for connection of new generation. This is an automatic mechanism that is agreed in advance and permits allowances to increase in response to changes in demand. This is outlined in more detail in the section on capex below.

- **X Factor:** At privatisation there were limited price cuts for NGET but, as the price review process evolved and progressed, the scale of the RPI-X and P_0 component both increased. Both P_0 and X began to decline under TPCR3 until an index of RPI+2 was implemented in TPCR4, reflecting an increase in prices over and above the RPI as a result of the need to undertake greater volumes of transmission investment.

  For the Scottish Transmission companies, the scale of X has remained fairly low and constant over the course of the price controls, at between RPI-0.5 to RPI-1.5. Similarly to NGET however, a significant increase in the level of RPI-X was seen as part of TPCR4, when RPI+2 was implemented.

- **Opex efficiency target:** Opex allowances have been set using a fairly consistent but evolving methodology based on both an assessment of likely trends in opex undertaken by consultants as well as in-house analysis of the electricity TOs historic and forecast costs. Since the implementation of the price controls at privatisation the opex efficiency target has varied between 2.5 and 4% with the most recent target, under TPCR4, at 3%.

  The efficiency targets for the Scottish Transmission companies have historically been lower than those set for NGET but this has been attributed, to some extent, to the lower level of unit costs already achieved by the Scottish companies.

- **Opex efficiency incentive:** Under RPI-X regulation the electricity TOs are provided with a strong incentive to reduce costs below the assumed level, as they earn the profit until the regulatory control shares the saving with consumers. The savings are shared with consumers at the start of each price review period by setting opex allowances based on expected efficient costs. The value of the benefit to the company therefore depends on when the saving was made and the extent to which expected efficient costs for the next period are linked to actual historic costs.

- **Pension costs:** As part of TPCR4, explicit references were made to the inclusion of pension costs for all of the electricity TOs in line with the provisions included as part of DPCR4. In this regard, allowances were incorporated for ongoing pension contributions, based on actuarially recommended funding rates, as well as provisions for the repair of deficits. This deficit funding provided allowances to finance 70% of the early retirement deficit costs (ERDCs) but made clear that there would be no funding for deficits associated with the unregulated businesses.

- **Capex:** Since TPCR1, a mix of external consultants and in-house analysis has been used to assess capex, on the basis of load related expenditure (LRE) and non load related expenditure (NLRE).

  Since privatisation, there has been uncertainty over the volume of generation that will connect and therefore the level of LRE that will be required over the course of the price control. As such, this has led to uncertainty regarding the appropriate level at which capex allowances should be set. There are two key drivers behind this uncertainty.

  The first is the issues that have been encountered with the planning regime. Although it typically takes between three and four years to construct new renewable and non-nuclear generation, at present it can take between four and ten years to obtain planning consents. This means that there is significant uncertainty regarding when planning consents may be granted and therefore the timing associated with the need for additional transmission capacity.

  A further factor contributing to uncertainty with respect to capex allowances has been the lack of clarity on the development of policies regarding the environment. In this respect, during TPCR3, the government released an Energy White Paper which outlined its commitment to stimulating growth in renewable energy. In particular, it included targets for renewables to provide 10% of UK electricity in 2010, with an aspiration to double this by 2020. Although revenue drivers had been included as part of TPCR3 to accommodate generation capex[37] it became apparent, in 2003, that a significant amount of new investment would be needed to accommodate new renewable generation and that this would be needed prior to the onset of the next price control period. As such, Ofgem initiated the TIRG reopener. Following a process of review, Ofgem decided to

[37] The mechanics of this revenue driver are outlined in more detail in the 'Form of the control' section.

adjust allowed capex within the price control to provide funding for the additional investment that would be required to accommodate new renewable generation sources.

The issues associated with uncertainty regarding the volume of new generation that might connect over the course of the price control were also encountered, and ongoing, as part of TPCR4. To address this, the fixed "baseline" revenue allowances, set for each licensee, excluded uncertain user-driven investments. To accommodate these uncertain investments, flexibility mechanisms were incorporated which allowed the electricity TOs to earn additional capex allowances via revenue drivers which were linked to the amount of generation that connected over the price control period.

Under these provisions, for NGET, due to the size of the network and the differences in costs across it, revenues are adjusted on a zonal basis rather than by using a single unit cost revenue driver. As part of TPCR4, a profile of generation and demand was developed for each zone on the basis of baseline capex allowances. The revenue drivers would then be used to calculate adjustments to capex allowances where actual generation and demand, by zone, is different to the profile assumed in setting baseline capex allowances. The revenue drivers would be calculated at two levels:

- reflecting the local infrastructure costs incurred (or avoided) in connecting more (or less) MW of new connections than assumed in the baseline; and

- reflecting the wider network infrastructure impacts of changes in flows between each zone and the wider network.

Each aspect would be calculated on a £ per MW basis and the full scale of adjustments to capex allowances will only properly be known at the end of the price control.

The revenue drivers for SPTL and SHETL are also linked to the amount of generation that connects over the price control period but a £ per MW approach is used. Under this approach, Ofgem obtained an understanding of the volume of generation that would be connected under a baseline scenario and the costs associated with this. Ofgem also set a unit cost allowance (in £) for volumes of generation that connected above this baseline level.

Provisions were also included to allow foreseen but uncertain costs to be "logged up" over the period of the review, with an assurance that a corresponding revenue adjustment would be made at the end of the review, where the costs were deemed efficient. For NGET, this related to costs associated with potential undergrounding of cable tunnels and expenditure on telecoms infrastructure, while for SHETL and SPTL it related to costs associated with the connection of certain classes of wind generation as well as expenditure on telecoms infrastructure.

The incentives on capex efficiency were strengthened as part of TPCR4 with the implementation of arrangements which provided that the electricity TOs would bear 25 per cent of the cost, or receive 25 per cent of the saving benefit, arising from differences between allowed capex and actual capex during the course of the control. These would be retained on a rolling basis for a fixed period of five years.

Ofgem also expressed concerns as part of TPCR4 that, due to the limited output measures available, it may be possible for the electricity TOs to defer required investment as this would not immediately be reflected in a deteriorating network performance. To address this concern, a 'capex safety net' was introduced which provided that, where cumulative under-spend reached a level that was more than 20% of the capex allowance, a review would be triggered. This would assess whether the reduction in capex against forecasts reflected genuine efficiency savings or was potentially damaging to the integrity of the network. The review would therefore also consider whether it might be appropriate to adjust future capex allowances.

- **Output measures:** As part of TPCR4, Ofgem recognised that there had been a significant increase in both LRE and NLRE and outlined that it would be important that the measurement of overall network condition, underlying network risks and the impact on system performance was improved. In this respect, Ofgem noted that better output measures could also help the TOs to demonstrate efficiencies achieved or make a better case regarding the need for increased investment.

  These network output measures are currently being developed for the electricity TOs. Output methodologies have been produced by the TOs and the data underlying the measures will be incorporated into their regulatory reporting requirements. This work is ongoing and we will continue to look at ways to improve and develop the output measures.

- **Other incentive measures:** As part of TPCR1, capex allowances were included to permit undergrounding of transmission wires. However, under TPCR4 in 2007 these allowances had been removed on the basis that undergrounding in transmission incurs significantly higher cost than in distribution.

  Within TPCR3, the costs associated with Research and Development (R&D) were incorporated within opex allowances for NGET. However, recognising that R&D expenditure was declining due to the emphasis on opex efficiencies under the RPI-X framework, in line with the changes implemented within DPCR4, as part of TPCR4 the Innovation Funding Incentive (IFI) was implemented for all of the electricity TOs. This made available funding for projects related to technological improvements which could have environmental benefits or may further the sustainable development agenda.

  To provide incentives to the electricity TOs to operate efficiently under the EU Emissions Trading Scheme (EU ETS), as part of TPCR4 they were permitted to retain any savings that they achieved under this mechanism. In addition, in recognition of the fact that Sulphur Hexafluoride (SF_6) - an insulating ingredient used in high voltage switchgear - was not included under the provisions of the EU ETS, an incentive was introduced under TPCR4 which was intended to reduce emissions of this Green House Gas.

Prior to 2001, transmission losses were dealt with under the Pool arrangements and an associated incentive scheme was in place. Following the implementation of NETA in 2001, SO incentives were put in place relating to all costs associated with energy and system balancing services, including transmission losses. Under the provisions of the SO incentives, targets are set for the level of transmission losses, with the possibility for NGET to retain some of the benefits where it outperforms this target but to be exposed to some of the costs where it underperforms. There are also associated caps and collars in place.

The electricity transmission network reliability incentive scheme was introduced on 1 January 2005 following loss of supply incidents in London and Birmingham in 2004. The intention of the scheme was to strengthen the incentives on the TOs to maintain and improve the reliability and continuity of supplies on the transmission network, and to minimise disruption to customers. This incentive was retained under TPCR4 and set a target level of performance for each of the electricity TOs with penalises/rewards for performance that is below/above the target. The measure of reliability for NGET is based on the amount of energy lost through unplanned outages while for SPTL and SHETL it is based on the number of events that result in lost energy. This difference between the derivation of these targets is intended to reflect NGET's role as GBSO.

- **Return on RAV/WACC:** The cost of capital adopted in both TPCR1 and TPCR2 for NGC mirrored the cost of capital used in the DNO controls and was hence set at 7%. After this point, the cost of capital earned by the DNOs was set marginally higher than NGC's although it was on a par with the cost of capital for the Scottish transmission companies. As such, the cost of capital for NGC was set at a pre tax level of 6.25% while the cost of capital for the Scottish transmission companies was at 6.5%, in line with the DNOs.

  At the point that the Scotland, and England and Wales electricity transmission price controls were merged the same cost of capital was adopted for NGET, SHETL and SPTL. However, recognising that the Scottish transmission companies may require additional funding for TIRG investment or due to the operation of revenue drivers an ex ante allowance was included to fund the cost of issuing any required new equity.

  In line with DPCR4, a post-tax approach to the cost of capital was adopted as part of TPCR4. This entails two elements being incorporated into overall revenue allowances: a 'vanilla' weighted average cost of capital ('vanilla' WACC)[38] return on the RAV (pre-tax debt, post-tax equity) and a specific tax allowance taking account of the likely tax treatment of a company's expenditure. This was set at 5.05% which was equivalent to a 6.65% pre tax level and was a slight increase on the cost of capital set previously for both NGET and the Scottish transmission companies.

[38] The vanilla WACC represents the allowed cash return on the RAV. It is calculated as a pretax cost of debt and a post-tax cost of equity since a separate specific allowance for tax costs was caluculated.

Under TPCR2, Offer took the decision to use NGC's actual gearing level which, at that point was at 24%. However, subsequently in TPCR3 and TPCR4, a notional gearing level of 60% was used. This reflected an assumption that the debt to equity ratio within the electricity TOs had increased significantly over this period.

- **RAV:** When TPCR1 was undertaken, NGC was owned by the 12 PESs operating in England and Wales and therefore a measure of NGC's RAV was calculated based on the value of the England and Wales PES shareholdings at privatisation as well as current cost accounting (CCA) valuations. Following flotation of NGC in 1995, in TPCR3, the DGES noted that in valuing the RECs as part of DPCR1, he had stated that a CCA replacement value was not the most appropriate basis for calculating the RAV if a lower RAV could yield an adequate return to shareholders investment. As such, the DGES considered that it would be more appropriate to have regard to the money actually paid to purchase a company i.e. the flotation value of NGC. Adopting this approach led to an increase of £150 million in the size of the RAV and took the overall RAV of NGCs transmission assets to £4.15 billion in 1996/1997.

  In line with the separation out of the SO internal costs as part of the TPCR3, the value within the RAV attributable to the SO was transferred into the SO internal cost incentive.

  The RAV of the Scottish transmission companies was calculated at privatisation in line with CCA valuations. The RAV was maintained, at TPCR1, to ensure that the investors could earn the revenue streams expected at flotation.

  In line with changes made to treat non-operational capex (e.g. vehicles and IT) in a similar way to opex in ongoing reviews, as part of TPCR4 the non-operational capex that had historically been included within the RAV was removed.

  In line with the implementation of a requirement on the electricity TOs to produce a Regulatory Reporting Pack (RRP) as part of TPCR4, Ofgem committed to publish updated RAV information on an annual basis. This would allow a provisional view of the RAV to be set out, based upon the information obtained via the RRPs. However, it was noted that Ofgem still intended to undertake a detailed efficiency review of expenditure at the end of the review period which may highlight the need for further adjustments.

- **Other issues:** Under TPCR4, new regulatory reporting requirements for the electricity TOs were introduced in line with similar obligations put in place for the DNOs under DPCR4. As part of these arrangements, the TOs are required to produce an RRP, on an annual basis providing data on various regulatory issues. It was anticipated that the provision of data in this way would improve the quality of data on cost, revenue, incentive and output reporting to which Ofgem had access as well as facilitating performance monitoring and helping Ofgem to set future price controls and incentives.

Regulation of electricity transmission today

5.11. NGET, SHETL and SPTL have an allowed (maximum) revenue price control. The current Transmission Price Control (TPCR4) was implemented from 2007/08 and, as outlined above, this control represented the first time that an RPI+X index was permitted, at a level 2% above inflation. The main driver of this increase in allowed costs is the increased capital investment that will be required over the course of the control. This investment is largely required to ensure that additional connections, and associated reinforcement work (to deliver required capacity) can be undertaken.

5.12. The current transmission price control is due to be reviewed from 2010, with implementation scheduled to take place from 2012. It is likely that this control will also reflect increases in capex costs due to the increased demands on the system associated with the connection of renewable generation to meet the 2020 renewables targets, as well as the requirement to connect further sources of back-up generation to support the intermittency of renewables. In this respect, in 2008, the Renewables Advisory Board (RAB) estimated that, to meet the 2020 renewable targets, the capital investment from UK industry and property owners would be expected to exceed £100 billion.

5.13. The baseline revenue requirements for NGET, SHETL and SPTL are determined by considering the building blocks:

- **Operating costs:** Opex allowances were informed by a detailed analysis of the efficiency of controllable operating expenditure for each TO, using both bottom up and top down analysis. The scope for efficiency improvements as well as the potential upward pressure on costs was also considered. This assessment identified scope for efficiency savings for NGET, SHETL and SPTL of 3%, 1.1% and 1.5% respectively.

- **Capital expenditure:** A detailed efficiency and performance review of each licensee's capex programmes and associated asset management practices was undertaken. This assessment was undertaken on the basis of likely capex that would be needed with respect to LRE and NLRE[39].

  A number of new initiatives were introduced under TPCR4 to facilitate efficient capex. These included enhanced revenue drivers for uncertain investment, provisions for the 'logging up' of foreseen but uncertain cost items, strengthened capex efficiency incentives and the introduction of a 'capex safety net'[40].

[39] NLRE is capex which is required for 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. Remaining capex can be thought of as LRE and is capex required for the installation of new assets to accommodate changes in the level or pattern of electricity supply and demand.
[40] Further detail regarding these initiatives is contained within the section regarding The electricity transmission price control since privatisation.

- **Depreciation:** Straight-line depreciation is used to depreciate the regulatory asset base over a 20 year life time. In TPCR4 Ofgem recognised that NGET and SPTL's pre-vesting assets would become fully depreciated after 2009/10 and would therefore reach the depreciation "cliff edge"[41]. As such, for SPTL an adjustment mechanism was introduced under which new asset lives were reduced from 33 to 20 years[42] with a 15 year smoothing period[43] used for assets that had been assigned a 33 year asset life to allow these to be depreciated over a 20 year period. The same approach was adopted for NGET but a smoothing period of 50 years was used, reflecting the fact that less revenue was needed to offset the impact of the cliff edge.

- **RAV:** The RAV was estimated on the basis of NGC's 1995 flotation value as part of the 1997 review. Since 1997 the RAV has been rolled forward at the start of each new price control period to include capex incurred (subject to an efficiency assessment), asset disposals and the deduction of depreciation. At the start of each control, allowances are also included for capex during the coming period.

  Significant emphasis is placed on the ex post efficiency review of costs in the absence of evidence of user commitment in the case of LRE.

- **Return on RAV:** The WACC was determined using the Capital Asset Pricing Model (CAPM) as a guide. As part of TPCR4 a 'vanilla' WACC return on the RAV was used and this was set at 5.05%.

5.14. As part of TPCR4, certain incentive mechanisms were implemented, or retained from previous controls, which were intended to encourage specific behaviours from the electricity TOs. In particular, TPCR4 saw the introduction of the IFI (in line with the changes implemented under DPCR4), an SF6 incentive, a stronger capex efficiency incentive and the retention of the reliability incentive. A 'capex safety net' was also introduced under TPCR4 to address concerns on the lack of effective output measures in electricity transmission.

Transmission Access Review

5.15. The Transmission Access Review (TAR) was undertaken jointly with the Department for Energy and Climate Change (DECC) and was initiated following the Energy White Paper 2007. The objective of the review was to deal with the large (and growing) queue of electricity generators that have been unable to gain access to the transmission system for a number of years.

[41] When this happened, the companies would no longer receive depreciation allowances on these assets and revenue allowances would fall by £435m for NGET and £78m for SPTL during the last two years of the price control period.
[42] This was done to increase the level of the depreciation allowance related to these assets.
[43] This was done to spread, over a defined future period, the additional value of depreciation that would have been funded in the past had a shorter asset life been established at vesting.

5.16. The conclusions of the TAR were published in June 2008 and a range of measures were proposed to reduce or remove grid-related access barriers for renewable and other low carbon generators. All of the measures are aimed at accelerating the connection of new generation to facilitate the achievement of the UK's share of the 2020 EU renewable energy targets. The ongoing TAR work is comprised of a number of workstrands covering:

- **Short term improvements to the allocation of transmission capacity:** This includes the work that is being taken forward by the electricity TOs to better manage the connection queue;

- **The development of an enduring model of transmission access:** This is seeking to address the inefficiencies associated with the existing capacity allocation mechanism. These inefficiencies include the lack of user commitment which leads to potentially inefficient investment decisions and the "first come first served" allocation method which does not necessarily allocate capacity to those parties that value it most. In addition, there are perceived inefficiencies with the "invest and connect" principle which has caused delays in connection. There are also concerns that access is not being shared sufficiently which means that too many parties are denied the opportunity to access the system.

- **Steps being taken to help create an appropriate environment for the TOs to build infrastructure required for 2020 ahead of full user commitment:** As part of the TAR final proposals, Ofgem signalled an intention to develop enhanced incentives to allow the TOs to make investments ahead of user commitment in order to facilitate achievement of the 2020 targets.

1.51. An Impact Assessment on some of these potential solutions is set to be published in April. In taking forward this work, the TAR team have set out that arrangements for investments in future price control periods will be considered as part of the next transmission price control review, building on any recommendations that are developed as part of RPI-X@20.

6. Calculation of the RPI-X control for gas transmission

Chapter Summary

This chapter provides an overview of the way that the price controls in place for gas transportation have evolved over time. It begins by outlining the timeline in terms of price controls that have been implemented since privatisation. The chapter then moves on to provide an overview of the price control that is currently in place and finally discusses the way in which the various 'building blocks' of the price control have evolved since privatisation.

Background

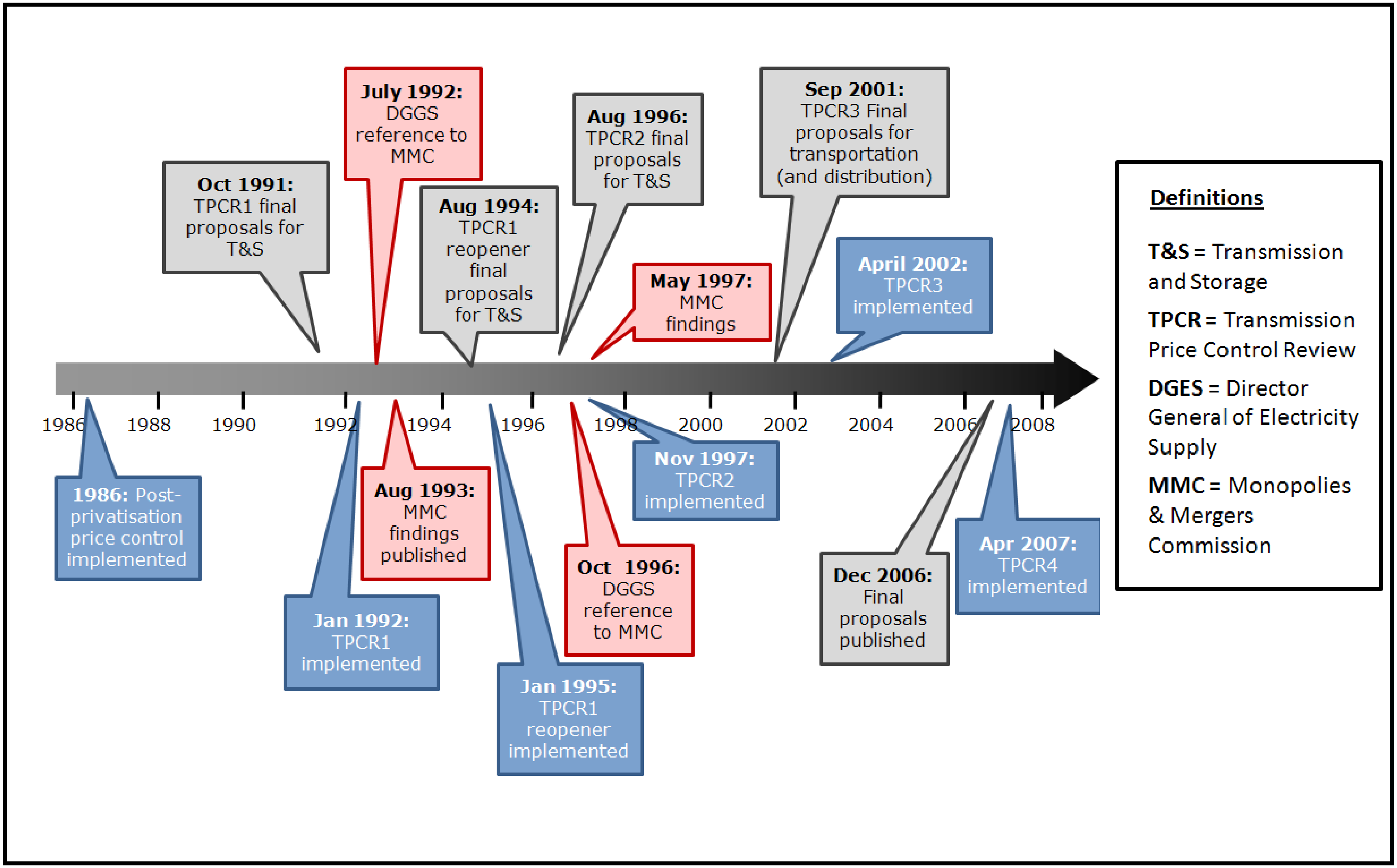
6.1. National Grid Gas (NGG)[44] is both the System Operator (SO) and Transmission Owner (TO) of the National Transmission System (NTS). In its role as SO, NGG's key responsibility is to ensure that the NTS remains within safe operating limits and, as such, NGG must ensure that the inputs to, and offtakes from, the NTS remain balanced throughout the course of the gas day. In its role as TO, NGG must ensure that sufficient NTS capacity is available to deliver security of supply for consumers.

6.2. Figure 6.1 illustrates the timeline of gas transmission price controls that have been implemented since privatisation in 1986. The diagram illustrates that price controls settlements for transmission (as well as other parts of the supply chain in many instances) were implemented in 1986, 1992 (TPCR1), 1995 (TPCR1 reopener), 1997 (TPCR2), 2002 (TPCR3) and, most recently, in 2007 (TPCR4). In addition to these price control settlement processes, two references were made to the Monopolies and Mergers Commission (MMC).

6.3. Each of the MMC references were made by the Director General of Gas Supply (DGGS) and the first, made in 1992, related to concerns regarding market structure and price controls. The conclusions reached by the MMC led to a reopening of TPCR1 and the completion of a reopener review, which took effect from April 1995. Within this review, transportation and storage were established as entities with separate accounts but subject to an overall price cap[45]. The second reference to the Monopolies & Mergers Commission (MMC) was in response to the rejection of TPCR2 by British Gas (BG).

[44] The gas transporter was British Gas (BG) from 1986 - 1997, Transco from 1997 - 2002 and National Grid Gas (NGG) following its merger with National Grid in 2002.
[45] Further details regarding the 1992 MMC reference are provided in the 'Industry structure' section of the supporting paper regarding 'The Context for Energy Network Regulation'. This is available from the following link: http://www.ofgem.gov.uk/Networks/rpix20/publications/Pages/Publications.aspx

Figure 6.1: Timeline of Gas Transmission Price control reviews



Regulation since privatisation

6.4. When the price control arrangements were implemented in 1986, at the time of privatisation, the storage, transmission, distribution, metering, connections and supply business of BG were contained within one entity and were subject to one overall price control. Following an Office of Fair Trading (OFT) review in 1991, BG agreed to undertakings requiring that it must establish a separate gas transportation and storage unit, with separate accounts, from its supply business. This was strengthened again by the MMC's 1993 conclusions, which required that BG must establish its transportation and storage business and its trading (supply) business as separate units by 31 March 1994.

6.5. In line with this, from April 1995 BG's transportation and storage businesses were subject to compliance with a separate price control while its supply business continued to be regulated under the terms of TPCR1, which were tightened following the MMC's 1993 conclusions. The first separate price control for the gas supply business was introduced in 1997 and remained in force until April 2002, at which point all supply price controls were removed.

6.6. In the conclusions from its 1993 report, the MMC also stated an explicit preference for separation of the storage and transportation parts of the business into separate units with separate ownership. However, the MMC recognised that there were not any options available to enforce this. Therefore, as part of the TPCR1 reopener, transportation and storage were established as entities with separate accounts but subject to an overall price cap.

6.7. As the onset of competition took hold in the mid-90s the DGGS considered it appropriate that specific aspects of BG's business were subject to separate price control arrangements or that provisions were put in place to allow the transition to full competition. As such, as part of TPCR2, Ofgas proposed that storage should be removed from the main transportation settlement with a view to removing controls on this activity altogether during the course of TPCR2. Provisions were also incorporated to allow for transitional arrangements, in the move towards competitive markets, for connections, metering, meter reading and supply point administration. However, in response to the publication of the final proposals from TPCR2, BG set out that it could not agree to the terms of the price control and the DGGS therefore made a reference to the MMC. In its conclusions, the MMC agreed that it would be prudent to have separate controls in place for transportation and storage but was of the view that the remaining elements that could be subject to competitive forces should remain within the scope of the overall transmission price control.

The introduction of capacity auctions

6.8. Until the introduction of the New Gas Trading Arrangements (NGTA) in 1999, capacity on the National Transmission System (NTS) was sold by Transco under a capacity booking mechanism, in line with the provisions under the Network Code. Under these arrangements, Transco sold unlimited capacity at a fixed price, equivalent to long run marginal cost (LRMC), irrespective of the actual capacity available. Where a capacity constraint arose, Transco simply scaled back the capacity rights previously booked by shippers to alleviate the constraint, with the costs of these actions passed back to consumers. These costs were additional to Transco's price controlled transportation charges.

6.9. Due to concerns that the existing arrangements were inefficient and potentially discriminatory, in 1999 primary auctions were introduced as a more efficient way to allocate gas entry capacity on Transco's NTS[46]. The rationale for the introduction of capacity auctions was that prices set in the auctions would reflect the value that companies place on the associated capacity and that this would therefore provide a more efficient mechanism for allocating the finite quantities of entry capacity available at entry terminals in the short term. The first auctions were held in September 1999.

6.10. The auction revenues earned by Transco were treated as price-controlled revenues and therefore total transportation charges did not increase as a result of the auctions. In the event that Transco 'over-recovered' entry capacity charges against its expectations, it was required to pay rebates on transportation charges to shippers to ensure that its total charges remained within the price control cap. As a result, the monies paid to Transco by shippers for entry capacity would not increase in aggregate although the relative prices paid for entry capacity by certain shippers at particular entry points were seen to increase in some cases. As such, if demand for capacity at certain entry points were to exceed supply, this would likely result in higher prices, as in any other competitive market. However, the relative entry prices also helped to inform the longer term requirements for investment on the system.

Further separation of the control

6.11. As part of the TPCR3, in light of the differing roles performed by the high pressure and low pressure transportation businesses, the transmission and distribution activities were separated and subject to distinct price controls, the process for which was undertaken concurrently. A separate price control was also implemented in relation to the SO activities that Transco undertakes with the intention that this would provide clearer incentives on Transco's SO and TO activities[47].

6.12. Under TPCR4, the gas TO control was merged with the electricity TO control to allow a holistic transmission price control to be carried out[48]. It was also undertaken completely separately from distribution and was implemented from 2007, at a time when the focus on the delivery of environmental targets was increasingly coming to the fore. This price control will remain in place until April 2012, at which point a new

[46] These auctions were introduced as part of the New Gas Trading Arrangements (NGTA).
[47] Further details regarding the SO incentives is contained within Appendix 1.
[48] The control that is currently in place for the DNOs is a hybrid rate of return and price cap mechanism. For the avoidance of doubt, it is a price cap control.

settlement package is scheduled to be implemented, possibly incorporating the recommendations delivered as part of RPI-X@20.

The gas transmission price control since privatisation

6.13. There has been significant evolution of the framework for gas transmission price controls since the regime was put in place at privatisation. The following section provides an overview of the changes that have been implemented, grouped by each component part of the control.

- **Scope of the control:** In line with the MMC decision reached as part of the 1993 review, supply was removed from the control as part of the TPCR1 reopener. In addition, as part of TPCR2, storage was removed from the main transportation price control with a separate settlement package put in place for storage which Ofgas anticipated the removal of within three years, with the onset of competition. In recognition of the onset of competition in other areas of the transportation business, for example in connections and the provision and installation of meters, a notional revenue provision was included for the transportation business. This incorporated provisions allowing that BG's revenues could be adjusted downwards to reflect the provision of services, by its competitors, that it had traditionally provided. Hence, this provision ensured that BG would not receive allowed revenues for services that it had not provided.

  When the price controls were initially implemented at privatisation, there was provision for BG to pass through increases or falls in its gas costs. In essence this meant that BG did not have any exposure to changes in the gas price under the control. In recognition of this, as part of TPCR1, gas costs were incorporated within the main price control with the intention being that this would encourage efficiency on the part of BG, in terms of its gas purchasing decisions.

  More recently, there was further separation of the transmission control under the TPCR3, with the removal of meter reading and daily metered meter reading as well as separate settlement packages for the GDNs and Transco in its SO role.

- **Form of the control:** As outlined above in the 'scope of the control' section, gas costs were originally treated as a pass through item within the gas transmission control. As such, the form that the control took was RPI-X+Y where Y represented the gas costs incurred. As part of TPCR1, Ofgas recognised that it would be appropriate that the gas costs that BG incurred were subject to control, to encourage efficiency in BG purchasing. Therefore, the formula was amended to include a new gas cost index and this took the form RPI-X+(Y-Z). However, to encourage further efficiency in the purchase of gas, as part of the TPCR1 reopener, gas costs were included within the overall formula.

  To encourage further efficiency in the transportation of energy by British Gas, as part of TPCR2, the control was amended to become a weighted price cap. As such, instead of revenue varying in line with the volumes of gas transported to final consumer, under these arrangements 50% of revenue was fixed and 50% was driven by gas volumes. In line with the conclusions reached by the MMC in its 1997 decision a distinction was also incorporated, within this revenue driver, between small and large user volumes connected to the system. This distinction was intended to remove a perverse incentive to transport larger volumes of gas to large users due to the relatively lower costs associated with the transportation of gas to these consumers.

As part of TPCR4, revenue drivers were introduced to provide funding for investment in incremental capacity. Under these arrangements, baseline levels of capacity at system entry points were set which determined the volume of capacity that Transco would have to offer for sale to system users. In the event that the auctions used to sell this capacity, indicated additional demand for capacity at a certain point, it was possible for additional investment to take place where this was underpinned by user commitment. Revenue drivers were put in place to fund this additional investment in incremental capacity.

- **X factor:** RPI-X began at relatively low levels, at RPI-2 in 1986, but increased under TPCR1 to RPI-5 and remained at this level under the TPCR1 reopener before reducing again at TPCR2 but with associated high levels of P0. More recently significant reductions in RPI-X and P0 have been seen with RPI-0 used at TPCR4.

- **Opex efficiency target:** Within the settlement package implemented at privatisation, there was limited distinction made between opex and capex allowances with non-gas costs used as a term to refer to costs incurred in constructing, maintaining and operating the pipeline system. To facilitate the process of putting in place price controls at privatisation, BG provided forecast non-gas figures which were audited by Ofgas, with allowances determined on the basis of this analysis. The process for determining opex allowances has become gradually more sophisticated over time with reference to a consultancy efficiency study on historic and future costs as part of the TPCR2. Under TPCR3, both top-down and bottom-up analysis of opex was undertaken alongside analysis of productivity improvements for comparable sectors and other privatised companies.

  The target level of efficiency gain for British Gas/Transco within the gas transmission price control have remained fairly stable since privatisation, with a target of 2.5% in the TPCR1 reopener and of 3% when the most recent control was set under TPCR4. However, in making such a comparison, it is important to remember that the scope of the price control, in terms of the elements of the business to which it was applicable, changed significantly.

- **Opex efficiency incentive:** Under RPI-X regulation NGG is provided with a strong incentive to reduce costs below the assumed level, as it earns any associated profit until the regulatory control shares the saving with consumers. The savings achieved are shared with consumers at the start of each price review period by setting opex allowances based on expected efficient costs. The value of the benefit to the NGG therefore depends on when the saving was made and the extent to which expected efficient costs for the next period are linked to actual historic costs.

  Under TPCR4, given the uncertainty associated with the likely level of pre-specified costs that may be incurred, a mechanism was introduced to allow uncertain opex costs to be effectively "logged up" over the period of the review. Details of these costs would be recorded by Transco within its annual Regulatory Reporting Pack (RRP) and a corresponding revenue adjustment would be made at the end of the review, where the costs were deemed efficient.

- **Capex:** As with opex, under the settlement package implemented at privatisation, capex was included within an overall category of non-gas costs. However, similarly to opex, the methods used to set efficient capex allowances have evolved over time. In this respect, as part of TPCR2, a capital expenditure efficiency study was commissioned and subsequently used as a guide in developing capex allowances. Under TPCR3, a distinction was made between load related expenditure (LRE) and non load related expenditure (NLRE) and the efficiency of historical capex, as well as the efficiency of forecasted spend were assessed on this basis.

  As outlined in the 'Form of the control' section, arrangements were introduced as part of TPCR4 to provide that capex allowances would be set according to the relative levels of user commitment achieved via auctions. In this respect, baseline capex allowances were limited to investments supported by user commitment with incremental investment to be funded by revenue drivers where evidence of user commitment emerged over the course of the control.

  To provide incentives towards efficiency in capex, in TPCR2, provisions were put in place to require an annual statement of capex to be published in which divergences between forecast and outturn capex would be explained. The intention was that this information would be used to determine capex allowances as part of future controls. The incentives on capex efficiency were strengthened under TPCR4 when arrangements were implemented which provided that NGG must bear 25 per cent of the additional cost, or receive 25 per cent of the saving benefit, arising from differences between allowed capex and actual capex. The mechanism permitted that this arrangement would apply for a fixed rolling five year period. This was applicable both to baseline levels of capex as well as to incremental capex that was undertaken following the trigger of the revenue driver mechanism and was intended to encourage efficiency in capex.

  Ofgem also expressed concerns in TPCR4 that, due to the lack of effective output measures within gas transmission, it may be possible for NGG to defer required investment as this would not immediately be reflected in a deteriorating network performance. To address this concern, a 'capex safety net' was introduced which provided that, where cumulative under-spend reached a level that was more than 20% of the capex allowance, a review would be triggered. This would assess whether the reduction in capex against NGG's forecasts reflected genuine efficiency savings or was potentially damaging to the integrity of the network. The review would therefore also consider whether it might be appropriate to adjust future capex allowances.

- **Output measures:** As part of the TPCR1 review a list of 'Key Service Standards' was established with which BG was required to maintain compliance. In the event that these standards were not maintained, Ofgas flagged that this would be grounds for reconsideration of the price control, potential reduction in prices or a possible reference to the MMC. Under these provisions, compensation payments to consumers would also need to be made where the standards were not met. Following the establishment of the Network Code in March 1996, under TPCR2, the standards of service to which British Gas was required to be compliant were referenced to those contained in the Network Code.

Network output measures are currently being developed for gas transmission. Output methodologies have been produced by NGG and the data underlying the measures will be incorporated into the regulatory reporting requirements. This work is ongoing and we will continue to look at ways to improve and develop the output measures.

- **Other incentive measures:** As part of TPCR1 a supporting document regarding 'The Environment and Energy Efficiency' was produced. This proposed the implementation of a code of practice on energy efficiency which was subsequently implemented and required better information to be made available to consumers regarding energy efficiency. In addition, the document proposed the inclusion of an 'E factor' which would effectively allow costs associated with energy efficiency to be passed through. The intent of this provision, which was later implemented, was to incentivise BG to take costs associated with energy efficiency into account.

  In line with the provisions included within DPCR4 and the electricity provisions contained within TPCR4, the IFI was also introduced for gas transmission as part of TPCR4. As in electricity transmission, this made available ring-fenced funding to facilitate investment in technologies that would have environmental benefits or would further the sustainable development agenda.

- **Return on RAV/WACC:** An appropriate cost of capital has largely been derived using the framework provided by the Capital Asset Pricing Model (CAPM), as evidenced from TPCR1 to the TPCR4. At the time of TPCR1 the cost of capital was set at a level between 5 and 7%. Since this review, the cost of capital has remained relatively stable at between 6.5 and 7%, with the only significant change to the treatment of cost of capital being the adoption of a post-tax approach, as part of TPCR4, in line changes made under DPCR4. This entails two elements being incorporated into overall revenue allowances: a 'vanilla' weighted average cost of capital ('vanilla’ WACC) return on the RAV (pre-tax debt, post-tax equity) and a specific tax allowance taking account of the likely tax treatment of a company’s expenditure. This was set at 5.05% which was equivalent to a 6.65% pre tax level and was therefore consistent with the cost of capital levels set previously.

- **RAV:** As part of TPCR1 an in-depth, bottom-up, consultancy study was commissioned which provided an independent assessment of the value of the BG pipeline. A further assessment of the RAV was also undertaken as part of TPCR2. In carrying out this analysis, attention was paid to the methodology adopted by the MMC in its 1993 report. As such, the starting RAV derived as part of TPCR1 was revalued on the basis of the ratio of BG’s market value to the current cost book value of the assets (the Market to Asset Ratio (MAR)). This was assumed to be at a level of 60%. To determine individual values for the respective elements of BG's business, an unfocused approach was adopted, under which all aspects of the British Gas business were assumed to have the same MAR value (set at 60%). This was considered a relatively conservative approach but was endorsed by the MMC in its 1997 review as the correct treatment for the valuation. The resulting RAV derived for BG at flotation was subsequently rolled forward to reflect investment that was undertaken in the intervening period, to deduct depreciation and to also revalue assets from 1991 in line with changes observed in the RPI.

There have been limited changes to the RAV since this initial valuation apart from updating the RAV with figures for allowed capex and adjusting this at subsequent price controls to reflect the actual level of capex spend, subject to these costs meeting with efficiency conditions. As part of TPCR4, provisions were included to allow any efficiency savings identified to be retained on a rolling retention basis, for a fixed period of five years, to allow benefits to be retained by the NGG even where these efficiencies were achieved late in the price control period.

In line with the implementation of a requirement on NGG to produce a RRP as part of TPCR4, Ofgem committed to publish updated RAV information on an annual basis. This would allow a provisional view of the RAV to be set out, based upon the information obtained via the RRPs. However, it was noted that Ofgem still intended to undertake a detailed efficiency review of expenditure at the end of the review period which may highlight the need for further adjustments.

- **Other issues:** Under TPCR4, new regulatory reporting requirements for NGG were introduced in line with similar obligations put in place for the DNOs under DPCR4. As part of these arrangements, NGG is required to produce an RRP, on an annual basis, providing data on various regulatory issues. It was anticipated that the provision of data in this way would improve the quality of data on cost, revenue, incentive and output reporting to which Ofgem had access as well as facilitating performance monitoring and helping Ofgem to set future price controls and incentives.

Regulation of gas transmission today

6.14. Under the provisions of TPCR4 National Grid Gas (NGG), as the gas TO, is currently subject to a price control which will run until April 2012. It is therefore, anticipated that the recommendations reached as part of RPI-X@20 will be applied to NGG at the next price control review, although this is dependent upon the scope of changes that are recommended under RPI-X@20. The following section provides details of the main provisions of the current gas transmission price control and the analysis undertaken to determine the scope of these provisions.

6.15. The package in place comprises an average revenue control under which the prices that NGG charge are permitted to rise in line with inflation (RPI-0). Under the provisions of the control, baseline capex allowances are set in line with the level of user commitment displayed, via capacity auctions, at the time that the price control is set. Revenue drivers are also in place to permit additional investment to take place where sufficient additional user commitment is demonstrated, via the signals provided through capacity auctions, during the course of the control.

6.16. Allowed revenue for NGG is calculated using the building block approach under which the following elements are determined in line with various principles:

- **Opex:** An assessment of forecasts of future opex was undertaken based on data submitted by the companies about projected spending in this area, the use of historic intra-company comparisons of opex and the scope for efficiency savings throughout the price control. A 3% reduction in underlying efficient costs was forecast as part of TPCR4.

- **Capex:** A detailed efficiency and performance review of each licensee's capital expenditure programmes and associated asset management practices was undertaken. In general terms, baseline capex is set in line with user commitment received at the time that the price control is set while incremental capex is permitted where sufficient user commitment emerges over the course of the control. At TPCR4, Ofgem highlighted that NGG did not face the same substantial increase in costs relating to baseline capital investment as the electricity TOs. It also set out that any increase in capex requirements would be triggered by user commitments under the gas access regimes and that the required revenue would therefore be provided through the revenue driver mechanisms.

- **Depreciation:** Straight line depreciation is permitted. Under this approach a single asset life of 45 years was assumed for NGG assets purchased after 2002. Assets purchased prior to 2002 were assumed to have accumulated evenly over time. An approach was used under which these assets were assumed to have a 56 year lifespan which was derived from the average of the expected useful economic lives of all assets. Given the accumulation of these assets over time, they were assumed to have an average remaining asset life of 28 years.

- **RAV:** The initial RAV was determined as part of TPCR2, on the basis of the ratio of the market value of the company to the current cost book value of the assets. An unfocused approach was also applied at this time which applied the discounted market to asset value equally to all elements of the business i.e. equally to storage and transportation. The RAV has been rolled forward at each price control period to recognise the efficient actual capex undertaken in the intervening years as well as the forecast capex for the coming price control.

- **WACC:** As part of TPCR4 a 'vanilla' WACC return on the RAV was used, in line with the changes made as part of DPCR4, and this was set at 5.05%.

6.17. There are various incentive mechanisms in place to facilitate certain behaviours from NGG as part of the price control. Investment is incentivised via the user commitment arrangements and efficiency in this investment is incentivised through the implementation of a mechanism allowing NGG to bear 25% of the cost or receive 25% of the benefits arising from differences in allowed and actual capex. In addition, provisions are included that allow NGG to retain 50% of the savings associated with any proactive investment that it undertakes that is not underpinned by user commitment. The main incentive in place to facilitate both sustainability and innovation is represented by the IFI which was implemented as part of TPCR4.

6.18. Uncertainty in the gas transmission price control is, to a large extent, dealt with through the use of revenue drivers which allow revenues to increase in response to the delivery of further user commitment.

7. Calculation of gas distribution price controls from 2002

Chapter Summary

This chapter provides an overview of the way that the price controls in place for the Gas Distribution Networks (GDNs) have evolved over time. It begins by outlining the timeline in terms of price controls that have been implemented since privatisation. The chapter then moves on to provide an overview of the price control that is currently in place and finally discusses the way in which the various 'building blocks' of the price control have evolved since privatisation.

Background

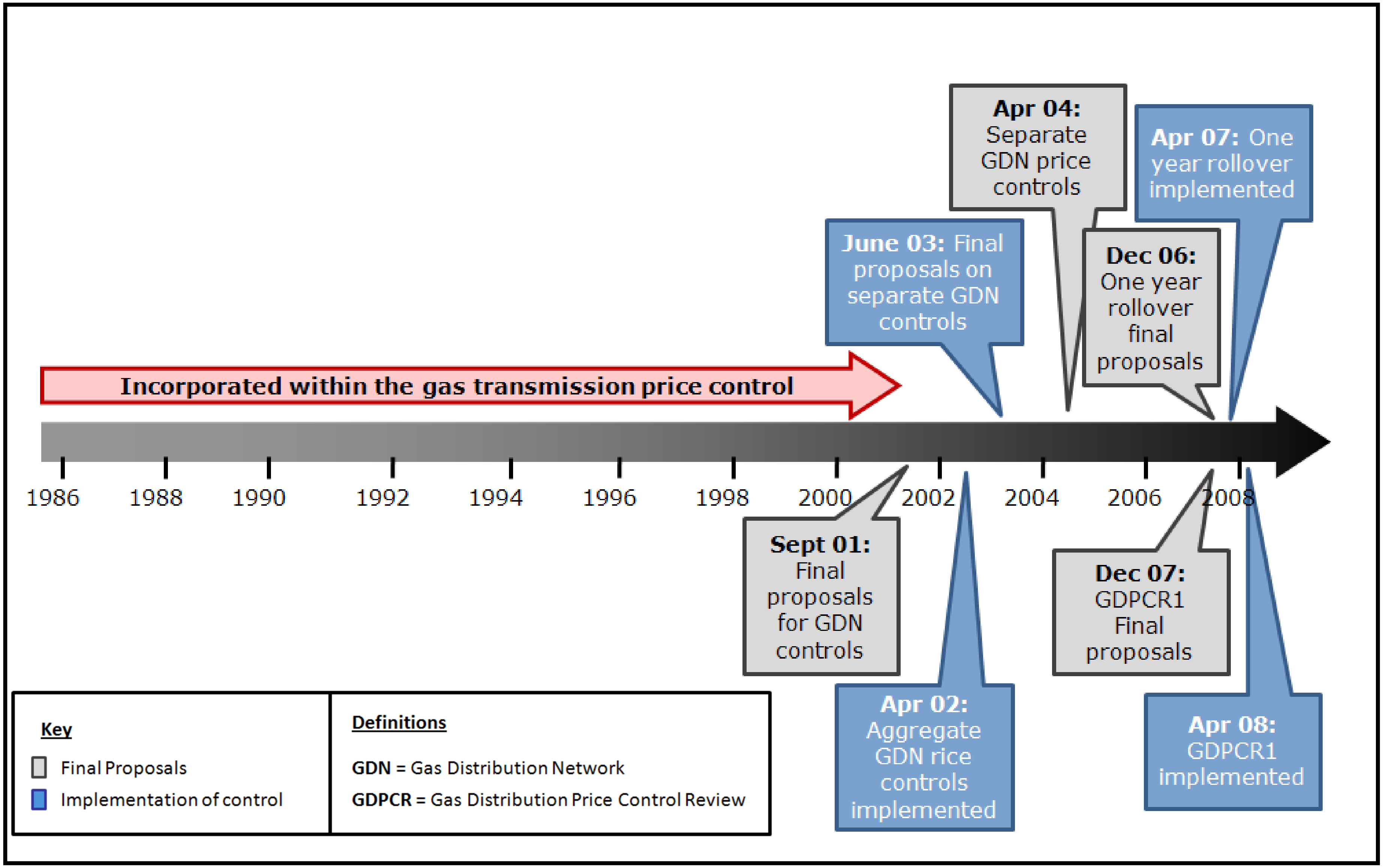
7.1. Figure 7.1 shows the way in which the price controls for the GDNs have evolved since privatisation in 1986. At privatisation and until the 2002 price control review (2002PCR), aggregate price controls were put in place covering gas transmission and distribution (known, collectively, as gas transportation). As such, the detail of the description regarding the way in which the determination of the RPI-X control for gas transmission has changed since 1986 is applicable to gas distribution, until 2002.

7.2. In recognition of the differences between the activities associated with operating the transmission and distribution networks, the 2002PCR began to calculate allowances separately for these two activities. Under the 2002PCR, the elements of the price control that related to gas distribution was separated from the elements relating to transmission and separate provisions were therefore put in place for the 12 Local Distribution Zones (LDZs), in aggregate.

7.3. In April 2002, Transco reorganised its 12 LDZs into eight regional networks on the basis that this new structure would promote further efficiency and cost reduction. Following this change, the controls implemented under the 2002PCR were separated further to derive provisions specific to each GDN. Additional separation of the price controls took place following the distribution network (DN) sales process in 2005, which enabled Transco to sell four of the eight regional gas distribution networks (GDNs) as part of a commercial transaction. Prior to the sale Transco had owned and operated each of these GDNs but, in June 2005, four of the GDNs were sold, to independent third parties while the remaining four GDNs stayed in NGG ownership.

7.4. Prior to completion of the sale, Ofgem had announced that it would extend the GDN provisions of the 2002PCR by one year to allow separate consideration of gas transmission and distribution price controls going forward. As such, a one year control was implemented for GDNs, for the period 2007/08, and many of the provisions of the 2002PCR were retained. The first full separate price control review for the GDNs, following DN sales, was undertaken as part of GDPCR1 and was implemented from 2008. This represented the first time that it had been possible to use comparative regulation techniques for the GDNs. At the time of DN sales it was estimated that there were potential savings, in NPV terms, of about £225 million as a result of DN sales which would accrue over 18 years and were largely attributable to the benefits associated with comparative regulation.

Figure 7.1: Timeline of Gas Distribution Price control reviews



Changes in the gas distribution price control since 2002

7.5. Figure 7.1 illustrates the recent changes that have taken place within the gas distribution price control, since its separation from gas transmission which was implemented as part of the 2002PCR. In the period from 2002 until GDPCR1, which took effect from 2008, there were significant changes in terms of the scope of the control but also with respect to the structure of the industry. In this respect, the price control changed from an average revenue cap applicable to all of the gas distribution networks (GDNs), to separate average revenue caps applicable to the specific circumstances of each of the individual GDNs, held under separate ownership[49].

7.6. The following section provides an overview of the changes that have been implemented since specific provisions for a gas distribution price control were implemented in 2002 and is structured according to the changes that have taken place with respect to each component part of the control.

- **Scope of the control:** The first separate gas distribution price control was undertaken in 2002 and applied to the GDNs in aggregate. While metering was considered a responsibility of the GDNs, a separate tariff cap was put in place for metering and daily metered meter reading services. These were intended to remain in place until metering became sufficiently competitive, at which point they would be removed. The one-year rollover that was implemented following the completion of the DN sales process in 2005 was the first time that a control had been implemented relevant to GDNs contained within separate ownership. However, the scope of analysis carried out under this review was limited due to the reduced duration of the control period. Therefore GDPCR1 represented the first full review of the GDNs using comparative regulation.

- **Form of the control:** Under the gas transmission price control, the GDNs had been subject to a weighted revenue driver whereby 50% of revenue was fixed and 50% varied in line with the volume of gas transported (throughput). As part of the 2002PCR, these figures were changed to 65% fixed and 35% volume related. The volume related element was based on an estimate of the costs that a GDN would incur, as a proportion of overall revenue, associated with the cost of additional LDZ capacity. Provisions were also included to adjust the revenue driver to take account of the relative difference in cost in transporting gas to large users. However, the volume driver was removed under GDPCR1. The rationale for implementation of a throughput based revenue driver was that the costs of operating the network increase as the overall capacity requirements increase. In contrast to this, analysis suggested that gas throughput had not increased steadily during previous controls but rather had varied in response to changes in weather and gas prices. These fluctuations had not necessitated

[49] The control that is currently in place for the DNOs is a hybrid rate of return and price cap mechanism. For the avoidance of doubt, it is a price cap control.

increases in capacity requirements and therefore gas throughput was no longer considered a strong proxy for this.

In recognition of the growing level of competition for meter-work, under GDPCR1 a revenue driver was incorporated which permitted revenues to increase in the event that significant levels of meter-work were lost to competitors which would effectively increase the cost of provision of emergency services.

Under GDPCR1 provisions were also included to permit a reopener to take place to allow for further revenue allowances dependent on the outcomes of the interruptions auctions. Further details on the interruptions auctions are provided in the section below on capex.

Further reopener provisions were included to allow for potential changes in the Traffic Management Act 2004 (TMA) as well as possible changes in tax treatment which may arise over the course of the control.

- **X factor:** Since implementation of separate GDN price controls under the 2002PCR, the level of RPI has changed quite significantly from RPI-2 to RPI+2. The reason for this is largely attributable to the enhanced repex programme with which the GDNs must comply, in line with HSE requirements on the replacement of mains[50].

- **Opex efficiency target:** Since the 2002PCR, considerable use of top-down and bottom-up analysis has informed the determination of opex allowances. From this time, provisions were also included to allow 50% of the repex associated with the replacement of mains, required by the HSE, to be included within opex.

  An target for the reduction of efficient opex costs of 2.5% was included for both the 2002PCR and GDPCR1. An opex efficiency target of 3.1% was set for the GDNs. However, due to increases in training and pension costs as well as waste charges and taxes an overall increase of +2.1% in opex was forecast as part of GDPCR1.

  GDPCR1 represented the first opportunity that there had been to undertake comparative analysis.

- **Opex efficiency incentive:** Under RPI-X regulation the GDNs are provided with a strong incentive to reduce costs below the assumed level, as they earn the profit until the regulatory control shares the saving with consumers. The savings are shared with consumers at the start of each price review period by setting opex allowances based on benchmark historical costs. The value of the benefit to individual companies therefore depends on the link between actual historic costs and benchmark costs.

[50] Further details regarding this HSE initiative are provided in paragraph 7.8.

Consideration was given, as part of GDPCR1, to the inclusion of an opex rolling incentive which would permit the GDNs to retain, for a fixed period of five years, any savings that were made as a result of efficiency improvements. However, due to the way that opex allowances were determined, using a combination of top down and bottom up benchmarking, these were not set relative to actual costs. Therefore, to avoid any potential for double-counting of efficiency savings, the rolling opex incentive was not included.

- **Pension costs:** Allowances for pension costs were explicitly included within the 2002PCR, equivalent to 8.5 per cent of pensionable wages and salaries. This was consistent with the accounting charges as well as the MMC's previous decision. As part of the one year rollover the allowances for pension costs were increased to ensure appropriate funding for pension deficits as well as ongoing contributions, in line with the provisions for pension costs in DPCR4. This treatment of pensions costs was also adopted in GDPCR1.

- **Capex:** In both the 2002PCR and GDPCR1 capex was set in line with an assessment of historic and forecast capex. Benchmarking of these costs between GDNs was also undertaken as part of GDPCR1 which was possible following the completion of the DN sales process.

  In a similar vein to the provisions introduced under DPCR4, an Information Quality Incentive (IQI) was implemented as part of GDPCR1. This was intended to provide incentives to the GDNs to expose the most efficient level of capex for the requirements of the network over the period of the control. The mechanisms used to achieve this outcome were the same as those employed for the IQI mechanism adopted as part of DPCR4[51].

  Under GDPCR1 a complex set of incentives were put in place to facilitate the efficient use, by GDNs, of the capacity management options available to them. The capacity management options available include investment in their pipelines, procurement of interruption and booking of flat/flexible capacity on the NTS. At the time that GDPCR1 came into force, the transitional offtake arrangements, and associated incentives, were set to expire in 2011 and therefore it was necessary to put in place an incentive mechanism covering the period 2011 to 2013. The following bullets provide details of the mechanisms put in place for each of the capacity management options available:

  - **Interruptions:** At the time of conclusion of GDPCR1, there was uncertainty regarding the interruptions arrangements that should be put in place as the first interruptions auctions were set to take place in 2008 with the associated product allocations from October 2011. As such, there was uncertainty over the likely prices that consumers would bid in for interruptible products or whether these interruptible products would be available. The decision was taken

[51] For further details regarding the workings of the IQI, please see Chapter 4 on the electricity distribution price control reviews.

to therefore base the interruptions incentive on the costs associated with upgrading of the relevant DN to allow all customers to be supported as firm on the assumption that procurement of the equivalent flat capacity would not be an appropriate substitute. To avoid potential windfall gains 50% sharing factors were introduced as part of this incentive, unconstrained by caps or collars. Provisions were also included for a reopening of the control under certain circumstances, following the outcome of the interruptions auctions.

- **Flat capacity:** An incentive was set based on the forecast flat capacity needs of each of the GDNs assuming that all supply points are held firm. Under this incentive a 50% sharing factor was introduced, consistent with the interruptions incentive, and associated caps and collars were put in place. The assumption was made that if GDNs could achieve gains by trading firm capacity for interruptible, they should do so and trade off against the interruptible incentive.

- **Flexible capacity:** Given that flexible capacity is an unconstrained product that is produced as a by-product of investment in flat capacity and NGG reserves the right to refuse requests for flexible capacity, it was not considered appropriate to introduce an incentive mechanism on this. However, NGG had concerns that GDNs may choose to book flexible capacity rather than invest in their networks and therefore provisions were included to require GDNs to write to Ofgem before increasing their flexibility bookings by more than 10%.

Under GDPCR1, replacement expenditure (repex) allowances, to allow GDNs to meet the HSE requirement to replace all iron mains within 30 meters of a domestic property within 30 years, were informed by historical cost comparisons. Provisions were retained from the 2002PCR to allow 50% of the repex associated with the replacement of iron mains, required by the HSE, to be included as capex spend which would then fall into the RAV.

- **Output measures:** Under the 2002PCR, provisions were put in place to require the GDNs to report, on an annual basis, on certain defined output measures. These outputs included the number and duration of supply interruptions, statistics on the resolution of shipper queries, details regarding progress of the mains replacement work required by the HSE and information on the peak capacity of the LDZs. The collation of the information required to be reported under the 2002PCR permitted the publication of a Gas Distribution Quality of Service Report. As part of GDPCR1, provisions were introduced for the reporting of quality of service indicators in the form of a 'balanced score card'. This was intended to provide an overview of GDN performance across a number of areas and it was noted that this may be used as the basis for a formal incentive scheme in the future.

On the basis of the GDN information collated under the 2002PCR, regarding interruptions, Ofgem committed to introduce a symmetric interruptions incentive scheme. However, it was recognised that lead-times would need to be permitted to develop the systems to measure this output and therefore Ofgem committed to undertake a consultation on the interruptions incentive scheme in 2003 once these systems were in place, with implementation of this scheme from 2004. As part of the process that was followed in 2002 to provide separate allowances under the GDN price controls, it was noted that work would shortly begin to audit Transco's measurement system data on interruptions. However, the results of this audit highlighted concerns regarding data quality and therefore a decision was taken not to introduce this incentive.

Under the 2002PCR GSOPS and OSOPS were set out for the GDNs. Although the GDNs had been required to comply with the majority of these standards under the gas transportation price control, they were explicitly set out as applicable to the GDNs in the 2002PCR. The GSOPS related to the restoration of supply following an unplanned outage, reinstatement of consumer premises and making and keeping of appointments. Provisions were also included for associated payments to be made to consumers where these standards were not met with one of the GSOPS specifying that the GDNs must notify customers of any such payments that were owed to them. The OSOPS, which set minimum annual levels of performance, included obligations on the speed of telephony response, notification of interruptions, acknowledgment of correspondence, gas emergencies and arrangements for visits. Under GDPCR1 the OSOPS were replaced with licence conditions or modifications to the GSOPS to enable the Authority to take appropriate enforcement action against the GDNs in the event of a failure to meet the prescribed level of performance. Amendments to the existing GSOPS were also implemented to tighten the arrangements in place.

- **Other incentive measures:** The GDNs are subject to compliance with shrinkage allowances which relate to the amount of gas that is lost in distribution. Under the 2002PCR and in GDPCR1, shrinkage allowances were set with the associated cost linked to actual market prices.

  A number of incentive measures were introduced as part of GDPCR1:

  - An environmental emissions incentive was introduced in line with the increased focus on environmental targets. Under this incentive, GDNs are exposed to the costs, in the form of the Social Cost of Carbon, associated with environmental damage from their CO_2 emissions.

  - An IFI was introduced in line with DPCR4 and TPCR4. This made available ring-fenced funding to facilitate investment in technologies with environmental benefits or in technologies that would further the sustainable development agenda.

  - A Discretionary Reward Scheme (DRS) was introduced which included provisions to reward initiatives that reduced the impact of gas distribution. For example, where initiatives were introduced which reduced shrinkage, improved network extension or promoted gas safety. Under this scheme £4 million was made available on an annual basis with the associated costs of any reward awarded to be recouped from the GDN customers that had benefited from this improved service.

  - Changes to the charging arrangements were implemented to facilitate connections to the fuel poor which were intended to address social concerns. Under these arrangements, For example, GDNs are incentivised to extend the gas network to specified deprived areas, with capital expenditure that is not recovered through discounted connection charges included in the RAV at the next price review.

- **Return on RAV/WACC:** The cost of capital has remained fairly stable between 2002 and 2008, at a pre tax level of between 6.25% and 6.65%. The key difference in the cost of capital between these two periods was the change from the use of a pre tax cost of capital to the use of a post tax cost of capital, in line with the treatment under DPCR4. This required two elements to be incorporated into overall revenue allowances: a 'vanilla weighted average cost of capital ('vanilla' WACC) return on the RAV (pre-tax debt, post-tax equity) and a specific tax allowance taking account of the likely tax treatment of the GDNs expenditure. This was set at 4.94% which was slightly lower than the cost of capitals allowed under DPCR4 and TPCR4 which were set at 5.5% and 5.05% respectively. Notional gearing in both reviews was set at 62.5%.

- **RAV:** The initial RAV for the GDNs, in aggregate, was determined as part of the 2002PCR using a market-to-asset ratio (MAR) adjusted value and unfocused approach; the same approach as that adopted in valuing the transportation and storage components in the 1997 transmission control. In allowing for additional investments undertaken since privatisation, Transco was permitted to earn a full return on allowed capital expenditure as there was no MAR adjustment to the investment made since 1991. The RAV was separated between the GDNs as part of the 2002 separation of the controls. In achieving this separation, the RAVs of the GDNs were estimated on the basis of the cash flows of each of the GDNs as Ofgem considered that this would represent the financial capital already invested in the business and minimise any unnecessary disturbance in charging levels. The RAV was rolled forward as part of the one year control and again, as part of GDPCR1, to reflect actual expenditure undertaken in the previous years and forecast expenditure under GDPCR1.

- **Other issues:** Similarly to the arrangements put in place under DPCR4 and TPCR4, under GDPCR1 provisions were include to require the GDNs to produce Regulatory Reporting Packs (RRPs) on an annual basis. This was intended to facilitate the provision of information to Ofgem regarding costs, revenues, incentives and outputs on a consistent and accurate basis. It was anticipated that these provisions would facilitate performance monitoring and help Ofgem to set future price controls and incentives.

Regulation of gas distribution today

7.7. The provisions of the current GDPCR will remain applicable to each of the GDNs until April 2013. It is therefore, anticipated that, the recommendations reached as part of RPI-X@20 will be applied to GDNs at part of the next GDPCR. Given our expectation that these recommendations will already have been applied to NGG, as part of the gas transmission control to take effect in 2012, it will be possible to learn lessons about the most appropriate way to apply the new regulatory package. The following section provides details of the main provisions of the current GDN price control and the analysis undertaken to determine the scope of these provisions.

7.8. Under the provisions of the GDPCR the prices that the GDNs could charge were permitted to rise at two per cent above inflation (RPI+2). The main contributors to this increase in the level of the cap were: increases in opex due to the impact of real price effects and the inclusion of new cost categories; the increase in the impact of mains repex; and the increase in other capex and repex. The main driver of the increase in repex was the replacement programme that was initiated, as part of the 2002PCR, in line with requirements imposed by the HSE which placed an obligation on GDNs to replace all iron mains within 30 meters of domestic properties within 30 years. Under the arrangements within the price control, GDNs were permitted to pass through costs incurred in seeking to meet the HSE requirement: 50% of which were treated as capex; and 50% as opex.

7.9. Allowed revenue for the GDNs was broadly determined using the following elements of the building block approach:

- **Opex:** The efficient level of opex was determined using a combination of bottom up benchmarking of specific activities and top down benchmarking of total opex. This was the first time it had been possible to make comparisons between GDNs. An underlying reduction in efficient costs of 3.1% was forecasts but it was recognised that overall opex would increase by around 2.1% in light of additional costs that would be faced.

- **Capex:** Capex was set using a combination of bottom up benchmarking of specific activities against the upper quartile of GDNs and a comparison of historical capex. Repex proposals were also reached using the same methodological approach. At the last price control, the IQI was also introduced.

- **Depreciation:** Straight line depreciation is permitted. Under this approach a single asset life of 45 years was assumed for NGG assets purchased after 2002. Assets purchased prior to 2002 were assumed to have accumulated evenly over time. An approach was used under which these assets were assumed to have a 56 year lifespan which was derived from the average of the expected useful economic lives of all assets. Given the accumulation of these assets over time, they were assumed to have an average remaining asset life of 28 years.

- **RAV:** The initial RAV for the GDNs was determined using a MAR adjusted value and unfocused approach; the same approach as that adopted in valuing the transportation and storage components as part of TPCR1. In allowing for additional investments undertaken since privatisation, these were valued at the depreciated replacement cost.

- **WACC:** In line with the approach adopted in DPCR4, under GDPCR1 a 'vanilla' WACC return on the RAV was used and this was set at 4.94%. Notional gearing was assumed to be at 62.5%.

7.10. There are various incentive mechanisms in place to facilitate certain behaviours from the GDNs as part of the price control. In particular, incentives on quality of supply are provided through the GSOP which place obligations on the GDNs with respect to their dealings with consumers. Investment is incentivised through a revenue driver and efficiency in this investment is largely driven by the implementation of a package of incentives which encourages GDNs to make efficient use of the capacity management options that are available to them. As such, it places incentives on the relative economic merits of investment in pipelines, procurement of interruption or booking of capacity from the transmission system. Incentives for compliance with the repex requirement are also provided to encourage efficient investment in replacement pipelines. A number of sustainability incentives are in place including the IFI, incentives on the minimisation of shrinkage and changes to charging arrangements to facilitate network connections to the fuel poor. In addition, an environmental emissions incentive was introduced under GDPCR1 which exposes GDNs to the costs imposed as a result of CO_2 emissions.

7.11. Uncertainty is dealt with through arrangements which permit re-openers to take place where there may be potential changes in legislation and to allow for unexpected outcomes from the interruptions auctions. The use of revenue drivers also allowed for changes in the level of demand to be accommodated over the course of the price control.

Price controls for the IGTs

7.12. While this document does not discuss in detail the price control arrangements in place for the independent gas transporters (IGTs), the following section provides a high-level overview of these arrangements, to give context to the gas distribution price control. There are two distinct types of regulation for IGTs.

- **'Legacy' charging arrangements:** Under these arrangements charges are unregulated and therefore customers are likely to incur higher charges than would have been the case if they were connected to the GDN. Approximately 580,000 premises are currently connected under these arrangements.

- **Relative Price Controls (RPC):** These were introduced in 2004 to regulate IGT charges. Under the RPC the level and structure of charges levied by the IGTs are subject to control by broadly capping charges to the level of equivalent charges levied by the GDN, subject to a pre-determined floor and ceiling. The levels of the floors and ceilings are defined relative to the expected path of the GDN charges over a 20 year period.

7.13. The applicability of these regimes is dependent upon the time that the customer connected to the network i.e. whether the customer was connected before or after the implementation of the RPC in 2004.

7.14. There are plans to phase out the legacy charging arrangements and therefore migrate legacy premises into RPC arrangements. Associated dates for this have been agreed with Ofgem. However, as this transition will take place on a revenue neutral basis, leaving the IGTs financially neither worse nor better off, the first IGT is not due to migrate to these arrangements until 2010 with the last migrating in 2018.

7.15. Given the ongoing applicability of the RPC to the IGTs, it is important that the implications of any recommendations reached as part of RPI-X@20 are considered with respect to their potential impact on the IGTs[52].

52 For further information regarding the development of Ofgem policy with respect to the regulation of IGTs please see the following link: http://www.ofgem.gov.uk/Networks/GasDistr/IGTReg/Pages/IGTReg.aspx

8. Structure of Charges

Chapter Summary

This chapter provides an overview of the way in which structure of charges are set for each of the energy networks as well as the developments that have taken place with respect to the structure of charges arrangements within each of these sectors.

8.1. Network companies use network charges to recover the allowed revenues set by Ofgem at price control reviews. While the form of the charging methodology must be approved by Ofgem we do not set or approve the level of individual charges. The level of charges faced by network users is currently determined by the structure of network charges which are derived independently of the price control review process.

- **Electricity distribution:** Electricity suppliers and generators pay use of system and connection charges to the DNOs. Each DNO currently uses its own methodology for setting these charges. Details of each DNO's charging structure can be found on the company websites.

- **Electricity transmission:** Users of the electricity transmission network pay use of system charges and connections charges. Both are set by National Grid Electricity Transmission for the whole of GB. Transmission use of system charges are set to recover the TO maximum allowed revenue set by the price control. They are calculated by splitting associated revenue between generation and demand (27% and 73% respectively). Separate use of system charges are in place for small generators. Charges are calculated using investment cost related pricing (ICRP), a methodology originally introduced by National Grid in 1993/94 for England and Wales. Details of NGET's charging methodology can be found on the National Grid's website.

- **Gas distribution:** The GDNs levy gas distribution charges on shippers and suppliers, which account for around 80% of the total gas distribution allowed revenue. Use of system charges (DUOS) (for those directly connected to the distribution network) are set on the basis of expected use of distribution network assets by a customer of a particular size and are not related to location on a specific network. Separate charges are set for connected system exit points, including connections to pipelines of other gas networks. Historically, 50% of revenue was recovered from DUOS capacity charges (applied to peak-day demand) and 50% was recovered from commodity charges (applied to annual demand). In December 2007 Ofgem approved a charging modification proposal from the GDNs which changed the charging methodology so that 95% of use of system revenue came from capacity charges and 5% from commodity charges.

- **Gas transmission:** Users of the gas NTS must buy entry capacity and exit capacity in order to flow gas on to and off the NTS. If they do not buy sufficient capacity for their flow of gas on to and off the NTS they incur overrun charges. Users pay the Transmission Owner (TO) entry capacity charges (per unit of capacity) entry commodity charges (per unit of gas) and exit capacity charges (per unit of capacity). Users also pay the System Operator (SO) entry commodity charges (per unit of gas) and exit commodity charges (per unit of gas). The TO allowed revenue is recovered 50:50 from TO entry and TO exit charges, after allowing for DN pensions deficit and NTS metering.

8.2. The Authority is required to assess any proposed modification to the network charging methodologies and to decide whether to approve or veto such a change. The Authority's decision is based on a consideration of whether the modification would better facilitate the relevant methodology objectives and our statutory duties. Modifications to network charging methodologies will not be made where the Authority has given a direction that the modification shall not be made. Network tariffs determined by the approved network charging methodology statement are effective from 1 April and will apply for the forthcoming financial year.

8.3. In the case of electricity transmission, National Grid is obliged to provide written notice of any revision to the Statement of Use of System Charges not less than 2 months from the beginning of a charging year (CUSC Section 3.20) to apply from 1 April. Further, if a modification proposal is developed by National Grid that proposes a mid-year change to the network charging methodology statement, with the effect of changing the level of network tariffs within charging year, then under the terms of the Electricity Transmission Licence (Condition C4 5(a)), NGET is required to give the Authority 150 days notice of any proposal (unless the Authority agrees to a shorter period). Practically, this requires National Grid to inform the Authority of any changes before 1 November of each charging year and limits National Grid to one mid-year network charging change per charging year.

8.4. A number of forums exist for industry to discuss networks charging arrangements. For example, Ofgem works with DNOs and stakeholders on the structure of charging through the Distribution and Charging Methodologies Forum (DMCF). In terms of electricity transmission network charging, National Grid has established the Transmission Charging Methodology Forum (TCMF). TCMF is an industry forum that discusses National Grid's charging methodologies and the GB-wide principles behind them. The aim of the forum is to allow Users to become involved in the development of National Grid's charging methodologies and enable National Grid to keep the methodologies under constant review. All existing or prospective CUSC parties are eligible to send one representative to the meeting. In addition, representatives from other industry bodies are invited by National Grid as appropriate. However, all industry parties are able to submit modification proposals and respond to methodology modification consultation proposals.

8.5. We do not provide a history of changes in the structure of network charges, or in the regulation of them, in this paper. However, in RPI-X@20 we will consider whether it is appropriate for there to be more coordination between the regulation of allowed revenues and the structure and level of charges. In particular, we will consider whether network users are provided with efficient price signals and whether incentives for efficient investment, affected by the charging structure and the allowed revenue calculation, are appropriately aligned.

8.6. When considering this issue we will be mindful of developments in each of the gas and electricity transmission and distribution industries.

- **Electricity distribution:** The structure of distribution charges have been reviewed a number of times since privatisation (e.g. 1993, 2000-2003, 2004-2009). Most recently, we have concluded that in many cases basic charging methods dated back a number of years and as such did not reflect the changing profile of system usage, particularly with respect to distributed generation. The principal objective of the structure of charges project is to bring about implementation of a revised cost reflective charging methodology which incentivises efficient use of the distribution system by demand and generation customers across all GB networks. In July 2008 we decided that it was necessary to introduce a formal licence obligation on DNOs to establish a single common, cost reflective distribution charging methodology with common governance arrangements by 1 April 2010. In October 2008 we held a statutory consultation on a proposal to introduce these obligations to each DNO's distribution licence. Four distribution licensees out of 19 objected to the proposal creating a blocking minority. Following defeat of our October proposal, in December 2008 we published a consultation seeking views on how best to progress the project. Following the close of this consultation in late January 2009, we are currently determining next steps. In the meantime, DNOs have been voluntarily progressing work on a common HV/LV charging methodology.

- **Electricity transmission:** Modifications to the electricity transmission charging methodology are discussed through TCMF and are subject to approval by the Authority. A number of network charging modifications are currently under consideration, as part of the Transmission Access Review, and we will consider any implications for the structure of charges going forward. More generally, changes in energy networks of the future, to facilitate delivery of a sustainable energy sector, may result in a need to change the pricing structure for transmission.

- **Gas transmission entry charges:** The revenue recovered by NGG from the entry capacity auctions may differ from the allowed revenue to be recovered from TO entry charges. In order to recover TO allowed revenue NGG makes up any shortfall by application of the TO entry commodity charge. This is set based on forecast auction revenues and forecast throughput. Should NGG find that it has over recovered excess revenue is returned through the entry capacity buy-back offset mechanism in the first instance. This involves crediting the surplus against any buyback incurred in year. After application of the Entry Capacity Buy-back Offset Mechanism, entry shippers would be rebated a proportion of their TO entry commodity charges (limited to 100% of TO Commodity charge). Any remaining surplus would be credited back to Shippers based on entry allocations which attract the TO entry commodity charge. Credits would be capped at the level of the SO commodity charge so that the combined impact of SO and TO entry commodity charges do not represent a net credit to Shippers. When considering the future regulation of gas networks in RPI-X@20, it will be important to consider interactions between the regulation of allowed revenue and the setting of entry charges, including the over-recovery mechanisms.

- **Gas transmission exit charges:** Currently exit users only pay TO exit capacity charges, based on long run marginal costs. Interruptible offtakes do not pay exit capacity charges. The revenue that they would have paid to recover TO allowed revenue for exit (revenue foregone) is recovered through SO charges for both entry and exit users. Exit reform will remove the revenue foregone arrangements for interruptible exit users. There are currently proposals to modify the transmission charging methodology in order to implement exit reform.

- **Gas distribution charges:** All GDNs are required to maintain a use of system charging methodology, which must explain to customers the principle of and methods used to calculate charges. Each gas transporter licensee has to ensure that the charging methodologies achieve certain objectives, for example that charges are: cost reflective; facilitate competition; and reflect developments in gas distribution. We undertake periodic reviews of the GDNs' structure of charges to ensure that they are consistent with these objectives and that they provide appropriate incentives on the GDNs, network users (shippers and suppliers) and consumers. The conclusion to the last review was published in February 2006.

  Since this review, as well as approving the change in the capacity/commodity split for DUoS charges, in March 2007 we directed implementation of UNC proposal 90 'Revised DN interruption arrangements'. Instead of allowing large distribution customers to nominate themselves as interruptible regardless of whether they provide a benefit to the network in being interruptible, via annual tenders, the reformed arrangements will allow the GDNs to contract for interruptible capacity only in the locations and volumes where they require it to meet their peak capacity system management obligations. This is expected to lead to a more efficient use of gas distribution networks and should deliver investment efficiency benefits.

  When considering future regulation of gas distribution networks in RPI-X@20 we will be mindful of any further developments in the structure of gas distribution changes.

Appendices

Index

Appendix	Name of Appendix	Page Number
1	SO incentives	88
2	Glossary	92

Appendix 1 - SO incentives

Introduction

1.1. System Operator (SO) incentive arrangements were historically included in both the gas and electricity transmission price controls. However, under the current arrangements, gas and electricity SO costs are both subject to separate incentive schemes. Despite the fact that these arrangements are distinct from the transmission price controls, it is important to have an understanding of the way that they currently work, and how they have evolved over time to ensure that we are aware of linkages with the main energy network price controls. This will inform our understanding of the likely implications of any changes that may be proposed as part of RPI-X@20.

1.2. This appendix therefore provides an overview of the evolution of both the gas and electricity SO incentive scheme as well as a summary of the schemes that are in place at present.

Electricity SO incentives

1.3. NGC's SO external costs, including the costs incurred in balancing the system and managing constraints as well as the costs associated with electrical losses on the system, are regulated and incentivised separately. At privatisation, this was done through the Electricity Pool of England and Wales (the Pool). The Pool was set up to schedule centrally available generation to meet forecast demand, on the basis of generators' price and availability bids, made at the day ahead stage.

SO incentives under the Pool

1.4. At vesting, uplift costs represented the difference between the price paid to generators (the pool purchase price) and that paid by suppliers (the pool selling price). Until 1994/95, Uplift costs were passed straight through to suppliers. However, Uplift costs more than doubled in real terms during the first four years of the Pool. As a result, a decision was taken to incentivise NGC to control the costs of those areas of Uplift that were judged to be under its influence.

1.5. From 1994 NGC was incentivised on three elements of uplift:

- **Transmission services uplift (TSU):** The transmission related costs associated with the difference between the day ahead unconstrained schedule of generation and real time dispatch (known as the Operational Outturn) as well as the costs of Ancillary Services (e.g. Response and Frequency Response);
- **Reactive power uplift (RPU):** The costs that arise from Ancillary Services contract payments for Reactive Power;

- **Energy uplift (EU):** The remaining Operational Outturn costs arising from generator availability changes, generator shortfalls and demand forecast errors.

1.6. Until NETA was implemented, RPU and TSU costs were regulated via the SO incentive arrangements. In contrast, EU provisions were arranged through the Pool. As such, costs incurred in this area were added to the Pool Purchase Price to give the Pool Selling Price. The costs associated with losses were also dealt with via the Pool and, under these arrangements, any costs incurred in this area were smeared back to suppliers by the application of a uniform scaling factor to demand. Losses were subject to a separate incentive arrangement which was incorporated within the Pool Rules and therefore any change to these arrangements needed to be agreed with all Pool members. Each of the incentive mechanisms were of a sliding scale form. As such, they comprised target levels, sharing factors to provide incentives to reduce costs below the targets, and caps and collars to limit the revenues and losses that would arise if costs were considerably below or above target.

Separation of the SO and TO controls

1.7. From 1997, the SO and TO roles were separated and Ofgem undertook to set separate incentive mechanisms for the SO, alongside the TO control, for a period of a year given uncertainties about the form of the control. The package of SO incentives was similar in scope to the provisions contained within the previous transmission price control and therefore retained the sliding scale form, although with tougher target levels and higher sharing factors to provide stronger incentives on NGC.

1.8. The first separate SO incentives arrangements were set for a period of two years from 1998, with a further set of SO incentive arrangements put in place in 2000 prior to the implementation of NETA in 2001. Both of these incentive schemes retained the sliding scale form, with sharing factors and caps and collars. However, transmission losses and EU provisions continued to be regulated via the Pool.

SO incentives under NETA

1.9. A new set of SO incentives were put in place following implementation of the NETA in 2001. Under this package, the different role that NGC would play as SO under NETA was recognised. While under the Pool, NGC was responsible for forecasting system demand, scheduling generation and centrally despatching generation, under NETA, market participants have responsibility for balancing their own contractual positions. As such, NGC is simply responsible for the residual purchase and sale of electricity to ensure the system remains in balance.

1.10. Under this package, the entirety of NGC's SO internal costs (associated with maintaining an SO function) and external costs (associated with balancing and managing the system) were contained in one overall scheme to increase the incentives on NGC to reduce the total costs of system operation. The control on the external costs was extended to include all costs associated with energy and system balancing services, including transmission losses53. The sliding scale form of incentives was retained with appropriate targets, caps, collars and sharing factors.

1.11. Since 2001, the SO incentive arrangements have been reviewed and updated on a yearly rolling basis. Under these schemes, NGET has been permitted to recover the actual costs of energy balancing, constraint management and system management, with an annual target established in relation to these costs. If actual costs are below the target NGET retains a proportion of the reduction in costs, set by a sharing factor (the upside factor), while if actual costs are above the target NGET incurs a proportion of the costs, set by a sharing factor (the downside factor). There are also caps and collars on the potential costs and benefits that NGG may earn via this mechanism.

1.12. There has only been one instance in which NGET decided that it was unable to agree to the package of SO incentives presented by Ofgem and therefore, during 2006/07, Ofgem undertook to monitor NGET's external costs under statutory and licence obligations. The gas and electricity incentive timetables were also merged from 2007/08.

Gas SO incentives

1.13. SO incentive arrangements have been in place, under the transmission price control, since October 1999. Prior to 1999, the costs of Transco's operational roles, aside from shrinkage, were recovered through gas balancing neutrality[54]. The SO incentive arrangements were introduced as part of the Reform of Gas Trading Arrangements (RGTA) to provide incentives to Transco to reduce its operational costs or maximise short run capacity availability. Under the SO incentive arrangements, a gas balancing incentive was set, based upon the differential between the price of Transco's marginal trade and the market average price. An entry capacity incentive was also introduced which exposed Transco to the costs of buying back capacity sold on a firm basis but which, for operational reasons, it was unable to make available. For both of these incentive schemes, associated sharing factors as well as caps and collars were put in place.

1.14. These SO incentive arrangements were retained until April 2002, when the first separate set of SO incentives was implemented for a period of five years which was intended to complement the TO regime that was put in place for Transco. The requirements that were placed upon Transco, as GB SO, with respect to entry and exit capacity were considered more sophisticated than the previous regime in place. In this respect, under the SO incentives, Transco was required to sell a proportion of

[53] The full list of these services included: energy (including forward energy contracts); reserve; frequency response; transmission constraints; black start; reactive power; and transmission losses.

[54] Under these arrangements, Transco was permitted to recoup monies from shippers, or was required to reimburse shippers for, costs incurred in balancing the system. As part of these arrangements, Transco needed to be held neutral to this i.e. Transco should not gain or lose from the arrangements.

baseline capacity, with firm rights, via long and short term auctions with the prices emerging from these auctions providing signals to the TO arm regarding the need for further investment in capacity. In the event that Transco SO was unable to deliver against these firm rights, it would need to buy back capacity.

1.15. The SO incentive arrangements were therefore applicable to the day-to-day costs of system balancing associated with the purchase of linepack and buy back costs. Arrangements were also incorporated with respect to overall system balancing costs associated with shrinkage and system reserve as well as Transco's internal SO costs. Under all of these arrangements, Transco was permitted to retain a proportion of the savings achieved as compared with targets but would be exposed to a proportion of the costs where it exceeded the targets. SO incentive

1.16. In 2007, the process for setting the SO incentives for gas and electricity were merged and, as such, the gas SO incentives were set for a period of a year and a further set of SO incentives were also implemented in April 2008. The incentive arrangements in both 2007 and 2008 were applicable to the same category of costs contained within the 2002 review but were extended also to include Quality of information incentives. Under these arrangements, if actual costs are below the target NGG retains a proportion of the reduction in costs, set by a sharing factor (the upside factor), while if actual costs are above the target NGG incurs a proportion of the costs, set by a sharing factor (the downside factor). There are also caps and collars on the potential costs and benefits that NGG may earn via this mechanism.

Appendix 2 - Glossary

A

The Authority/ Ofgem

Ofgem is the Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in GB.

B

Balancing Mechanism (BM)

The mechanism for the making and acceptance of offers and bids pursuant to the arrangements contained in the Balancing and Settlement Code (BSC).

British Transmission and Trading Arrangements (BETTA)

BETTA introduced a single GB-wide set of arrangements for trading energy and for access to and use of the transmission system.

Buy back

The process of compensating users if NGG NTS is unable to deliver entry capacity which is sold on a financially firm basis.

C

Capacity (Gas)

The amount of natural gas that can be produced, transported, stored, distributed or utilized in a given period of time under design conditions.

Capital Expenditure (Capex)

Expenditure on investment in long-lived distribution assets, such as underground cables, overhead electricity lines and substations.

Capital Asset Pricing Model (CAPM)

The CAPM is a model used to determine a theoretically required rate of return which takes account of the non diversifiable risk of the company.

Combined heat and power (CHP)

The simultaneous generation of usable heat and power (usually electricity) in a single process, therby discarding less wasted heat.

Composite Scale Variable (CSV)

A method of combining a number of different cost drivers into a single driver for regression analysis using fixed predetermined weights.

Connection and Use of System Code (CUSC)

A multi-party document creating contractual obligations among and between users of the GB transmission system, parties connected to the GB transmission system and national grid, in relation to their connection to and use of the transmission system.

Current cost accounting (CCA)

Current cost accounting attempts to provide more realistic book values. It encompasses a valuation method whereby assets and goods used in production are valued at their actual or estimated current market prices at the time the production takes place (sometimes referred to as "replacement cost accounting"). The more usual convention is historical cost accounting.

Customer interruptions (CIs)

The number of customers whose supplies have been interrupted per 100 customers per year over all incidents, where an interruption of supply lasts for three minutes or longer, excluding re-interruptions to the supply of customers previously interrupted during the same incident.

Customer minutes lost (CMLs)

The duration of interruptions to supply per year – average customer minutes lost per customer per year, where an interruption of supply to customer(s) lasts for three minutes or longer

D

Department of Energy and Climate Change (DECC)

The Department of Energy and Climate Change (DECC) was created in October 2008, bringing together energy policy (previously with the Department for Business Enterprise and Regulatory Reform (BERR)) with climate change mitigation policy (previously with the Department for Environment, Food and Rural Affairs (Defra)).

Depreciation

Depreciation is a measure of the consumption, use or wearing out of an asset over the period of its useful economic life.

Distributed generation (DG)

Distributed generation is also known as embedded or dispersed generation. It is an electricity generating plant connected to a distribution network rather than the transmission network.

Distribution network operator (DNO)

A DNO is a company which operates the electricity distribution network which includes all parts of the network from 132kV down to 230V in England and Wales. In Scotland 132kV is considered to be a part of transmission rather than distribution so their operation is not included in the DNOs' activities.

There are 14 DNOs in the UK which are owned by seven different groups:

CN West	Central Networks West plc licence holder for West Midlands
CN East	Central Networks East plc licence holder for East Midlands
ENW	Electricity North West Limited licence holder for North West England
CE NEDL	Northern Electric Distribution Limited licence holder for North East England
CE YEDL	Yorkshire Electric Distribution Limited licence holder for Yorkshire
WPD S Wales	Western Power Distribution (South Wales) plc, licence holder for South Wales
WPD S West	Western Power Distribution (South West) plc, licence holder for South West England
EDFE LPN	EDF Energy Networks (SPN) plc, licence holder for south east England
EDFE SPN	EDF Energy Networks (LPN) plc, licence holder for London
EDFE EPN	EDF Energy Networks (EPN) plc, licence holder for eastern England
SP Dist	SP Distribution Limited, licence holder for central and southern Scotland
SP Manweb	SP Manweb plc, licence holder for Merseyside and North Wales
SSE Hydro	Scottish Hydro Electric Power Distribution Limited, licence holder for northern Scotland
SSE Southern	Southern Electric Power Distribution Limited, licence holder for southern England

Distribution Price Control Review (DPCR)

The price control applicable to the electricity distribution network operators.

Distribution Use of System Charges (DUoS)

Charges used by generators and suppliers for the use of the distribution network.

Dividend Growth Model (DGM)

A financial model used to provide an estimate of equity returns by reference to the expected growth in dividends.

E

Early Retirement Deficit Costs (ERDCs)

The costs of providing the additional pension benefits payable to a scheme member who retires before normal retirement date as a result of reorganisation or redundancy, over and above the benefits to which such a member would be entitled if he retired voluntarily at the same date.

Electricity safety, Quality and Continuity Regulations (ESQCR)

The ESQCR specify safety standards, which are aimed at protecting the general public and consumers from danger. In addition, the regulations specify power quality and supply continuity requirements to ensure an efficient and economic electricity supply service to consumers.

Entry point

An Entry Point is a point on the NTS or LDZ at which gas can flow into the System.

EU Emissions Trading Scheme (EU ETS)

A cap and trade scheme in which EU Member State Governments are required to set emissions limits for all installations in their country covered by the scheme. It is an administrative approach used to reduce the cost of pollution control by providing economic incentives for achieving reductions in the emissions of greenhouse gases.

Excluded services

These are elements of the price control that are subject to pass through arrangements (where the costs are efficiently incurred).

Extra High Voltage (EHV)

Includes all voltage levels above 20kV up to but excluding 132kV.

F

Flat capacity

Flat capacity gives the holder the right to offtake a volume of gas during the day at a constant hourly rate.

Flexible capacity

Flexible capacity gives the holder the right to offtake a volume of gas according to a profile that varies over the day.

Fuel poor

A fuel poor household is defined as one that needs to spend at least 10% of household income on all fuel use in order to maintain a satisfactory heating regime.

G

Gas distribution networks (GDNs)

GDNs transport gas from the National Transmission System to final consumers and to connected system exit points. There are currently eight GDNs in Great Britain which comprise twelve local distribution zones, owned by four groups:

- NGG, the GT licence holder for the North West, West Midlands, East England and London GDNs
- Northern Gas Networks (NGN), the GT licence holder for Northern GDN
- Scotia Gas Networks (SGN), the GT licence holder for Southern GDN & Scotland GDN
- Wales & West Utilities (WWU), the GT licence holder for Wales & West GDN.

Gas Distribution Price Control Review (GDPCR)

The price control applicable to the gas distribution networks.

Guaranteed Standards of Performance (GSOPs)

Guaranteed Standards set service levels to be met in each individual case and are established by a Statutory Instrument. If the licence holder fails to provide the level of service required, it must make a payment to the customer affected subject to certain exemptions.

Gas transporter

The holder of a Gas Transporter's licence in accordance with the provisions of the Gas Act 1986.

Gearing

A company's net debt expressed as a percentage of its total capital.

H

Health and Safety Executive (HSE)

The Health and Safety Commission is responsible for health and safety regulation in Great Britain. The Health and Safety Executive and local government are enforcing authorities who work in support of the Commission.

I

Imbalance arrangements

These arrangements are designed to target the cost of energy balancing incurred by the SO to the parties who created those costs (i.e. those parties who did not balance their inputs and outputs within the relevant balancing period). As such, parties who are not in balance incur charges that reflect the costs incurred by the SO in addressing the imbalance.

Independent distribution network operators (IDNOs)

The Utilities Act 2000, included provisions enabling IDNOs to operate within the electricity industry. IDNOs generally own and operate electricity distribution network extensions and levy distribution charges on suppliers.

Independent gas transporters (IGTs)

IGTs are GT licence holders that own and operate small local gas networks and levy distribution charges on shippers.

Information Quality Incentive (IQI)

The IQI mechanism incentivises DNOs/GDNs not to inflate their forecasts. It does this in two ways: by giving additional income to companies who forecast spend close to our assessment; and by providing these companies with a higher incentive rate than those companies with higher capex forecasts, thereby increasing their rewards for outperformance.

Innovation Funding Incentive (IFI)

A mechanism to remunerate research & development expenditure by DNOs.

Interruptions incentive scheme (IIS)

This scheme provides financial incentives to DNOs with respect to the average quality of service they provide in terms of:

- the number of interruptions to supply; and
- the duration of interruptions to supply.

DNOs may be rewarded or penalised by up to 3% of revenue, depending on performance relative to their interruptions targets in each year of the scheme.

L

Large combustion plant directive (LCPD)

The LCPD aims to reduce acidification, ground level ozone and particles throughout Europe by controlling emissions of sulphur dioxide (SO2), nitrogen oxides (NOx) and dust (particulate matter (PM)) from large combustion plants (LCPs). These include plants in power stations, petroleum refineries, steelworks and other industrial processes running on solid, liquid or gaseous fuel.

Liquefied Natural Gas (LNG)

LNG is natural gas that has been condensed into a liquid at atmospheric pressure by cooling it to approximately -163 degrees Celsius. LNG is transported by specifically designed vessels and stored in specially designed tanks. LNG is about 1/600th the volume of natural gas, making it much more cost – efficient to transport over long distances where pipelines do not exist.

Load related expenditure (LRE)

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

Local Distribution Zone (LDZ)

LDZs are low pressure pipeline systems which deliver gas to final users and Independent Gas Transporters (IGTs). There are 12 LDZs which take gas from the high pressure transmission system for onward distribution at lower pressures.

M

Market to asset ratio (MAR)

The MAR represents the ratio between the market value of a regulated business and its RAV.

Megawatt-hour (MWh)

A measure of energy production or consumption equal to one million watts produced or consumed for one hour.

Monopolies & Mergers Commission (MMC)

The MMC was an independent organisation that investigated deferrals from the Director General of Fair Trading and the Secretary of State for Trade and Industry. These referrals related to the interests of the public in matters of anti-competitive or monopolistic behaviour by companies and to mergers under the provision of the Fair Trading Act 1973 and the Competition Act 1980. The MMC also acted as a court of appeal in the event of disagreement between the utilities and their regulators, particularly with respect to price control regulation. The MMC was replaced by the Competition Commission in 1999 following the Competition Act 1998.

N

National Grid Electricity Transmission (NGET)

NGET owns and maintains the high-voltage electricity transmission system in England and Wales.

National Grid Gas (NGG)

The gas transporter (GT) licence holder for the North West, West Midlands, East England and London GDNs. NGG also hold the GT licence for the gas transmission system.

National Transmission System (NTS)

The high pressure gas transmission system covering Great Britain, owned and operated by National Grid.

New gas trading arrangements (NGTA)

The New Gas Trading Arrangements (NGTA), were introduced in Great Britain from 1 October 1999. The NGTA saw the introduction of the on-the-day commodity market (OCM), price auctions of NTS entry capacity, new commercial incentives on BG relating to the capacity regime and its role as residual system balancer and improved incentives on shippers to balance their own positions.

Net present value (NPV)

Net present value is the discounted sum of future cash flows, whether positive or negative, minus any initial investment.

New Electricity Trading Arrangements (NETA)

NETA was introduced on 27 March 2001 and, for the first time, enabled generators, suppliers and customers to be able to choose how to contract for electricity, include on bilateral terms.

Non load related expenditure (NLRE)

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

O

On the day Commodity Market (OCM)

The on-the-day commodity market (OCM) was introduced as part of the New Gas Trading Arrangements (NGTA). It is a screen-based within-day gas market which allows gas shippers to fine tune their daily gas positions and BG Transco to purchase and sell gas to balance the NTS.

Operating Expenditure (Opex)

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

Overall Standard of Performance (OSOP)

Overall standards of performance set minimum average levels of performance in areas where it is not necessarily appropriate to put in place guarantees for individual consumers. These are determined separately for each gas transporter by the Authority.

P

Pass through

Under pass through arrangements a company is not exposed to the costs associated with a certain activity but rather these costs are transferred to consumers, subject to an economic efficiency test.

P_0

P0 refers to the level of cost reductions that regulated companies were required to pass on to customers at the beginning of new price control periods. The P_0 figure was intended to reflect the change in allowances under the new price control as compared with the allowances that were available under the existing control.

The Pool (the electricity pool of England & Wales)

The Pool was established as a result of privatisation and created a mechanism to allow trading between generators and suppliers.

Post tax equity

The proportion of a company's assets that shareholders own, after tax.

Prepayment meters (PPM)

With this type of meter, customers pay for the energy as they use it.

Pre tax debt

The level of a company's debt (finance from borrowing), before tax.

Public Electricity Supplier (PES)

The Public Electricity Suppliers (PESs) were the entities responsible for the distribution and supply of electricity, within their PES authorised areas, at privatisation. There were 14 PESs at privatisation, with 12 in England and Wales and two in Scotland.

Pumped storage

Pumped Storage is the most established form of large-scale electricity storage. These units pump water from a lower reservoir to a higher reservoir when there is a surplus of electricity. This can then be released at times of peak demand. Such units can be very effective at storing large volumes of energy.

R

Registered power zone (RPZ)

RPZs are focussed specifically on the connection of generation to distribution systems. RPZs are intended to encourage DNOs to develop and demonstrate new, more cost effective ways of connecting and operating generation that will deliver specific benefits to new distributed generators and broader benefits to consumers generally.

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee's regulated distribution or (as the case may be) transmission 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 for providing the capital.

Regulatory reporting pack (RRP)

The price control review information submitted annually to Ofgem in accordance with (and in a form prescribed by) the price control review reporting rules.

Relative Price Control (RPC)

Under relative price controls the level and structure of charges levied by the independent operator are subject to control by capping charges to an equivalent charge for the host operator, subject to a pre-determined floor and ceiling. The levels of the floors and ceilings are defined relative to the expected path of the host operator charges.

Reopener

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.

Repex

Repex refers to replacement expenditure required to upgrade existing assets on the energy networks.

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.

RPI-X

The form of price control currently applied to network monopolies. Each company is given a revenue allowance in the first year of the control period. The price control then specifies that in each subsequent year the allowance will move by 'X' per cent in real terms.

S

Safety net

A mechanism that would trigger a review of allowances in the event of a major shortfall of investment relative to allowances.

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.

Shrinkage

Shrinkage is a term used to describe gas either consumed within or lost from a transporter's system. e.g. Shrinkage can result from gas transmission companies using gas within their transportation systems to fuel gas compressors. Gas leaks from distribution mains are vented by certain types of equipment and shrinkage also occurs when gas is stolen or not charged for in error.

Sliding scale incentive

This term is used generically to describe incentive schemes which involve profit (and loss) sharing around a fixed target of costs.

Sulphur Hexafluoride (SF6)

A potent greenhouse gas frequently used in electrical equipment.

System operator (SO)

The entity responsible for operating the GB transmission system and for entering into contracts with those who want to connect to and/or use the transmission system. National grid is the GB system operator.

System operator incentive scheme

This is an incentive scheme which seeks to provide appropriate commercial incentives to SOs to operate their systems in an economic and efficient manner. As such, the SO incentive schemes establish cost targets that the SOs are expected to achieve in performing their SO roles. If actual costs are below these targets, the SOs are permitted to receive an incentive payment, and if actual costs exceed the target, each faces an incentive penalty. The size of this payment or penalty is determined by the relevant sharing factors that are agreed as part of the overall incentive schemes. The sharing factors are in place to strike a fair balance between the risks and rewards faced by the SOs and customers.

T

Traffic Management Act (TMA)

The Traffic Management Act is intended to provide better conditions for all road users through proactive management of the national and local road network.

Transmission Access Review (TAR)

Following the publication of the Energy White Paper 2007, Ofgem and BERR have convened a joint review of the current framework for access to the GB transmission system. The review will explore a range of issues associated with the technical, commercial and regulatory arrangements, with the chief aim being to better support the delivery of the government's aspiration of 20 percent of electricity supplied by renewable generation by 2020 and any targets that may be agreed at European Union level.

Transmission investment in renewable generation (TIRG)

The regulatory mechanisms developed before the start of TPCR4 in 2007, to fund a number of specific network enhancement projects required to provide transmission capacity for new renewable generation plants.

Transmission owner (TO)

There are three separate electricity high-voltage transmission Owners in Great Britain:

- National Grid Electricity Transmission plc (NGET) - owns and maintains the high voltage electricity transmission system in England and Wales. NGET also has the role of system operator (SO) across the whole of Great Britain.

- 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.

National Grid Gas NTS is the gas Transmission Owner.

Transmission Price Control Review (TPCR)

The price control applicable to the gas and electricity transmission networks.

Transmission System

The system of high voltage electric lines providing for the bulk transfer of electricity across GB.

U

United Kingdom Continental Shelf (UKCS)

The UKCS refers to the indigenous supplies of gas sourced from the from the North sea. The UKCS is the area of the sea bed over which the UK exercises sovereign rights of exploration and exploitation of natural resources. The limits of the UKCS are set out in orders made under section 1(7) of the Continental Shelf Act 1964.

V

Vanilla Weighted Average Cost of Capital (Vanilla WACC)

The weighted average cost of capital using a pre-tax cost of debt and a post-tax cost of equity.

Vesting

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

Vesting assets

Assets included in the RAV at the vesting date.

W

Weighted Average Cost of Capital (WACC)

This is the weighted average of the expected cost of equity and the expected cost of debt.