August 1999

# NGC Incentive schemes from April 2000

## An initial consultation

The Office of Gas and Electricity Markets

# NGC Incentive schemes from April 2000:

# An initial consultation

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# 1. Introduction

### *1.1 The Purpose of this Document*

1.1.1 This document sets out for consultation the scope, form and duration of the incentive schemes for the National Grid Company plc (NGC) from April 2000.

1.1.2 The existing schemes expire in March 2000 and will need to be revised for April 2000, prior to the introduction of the New Electricity Trading Arrangements. With the introduction of new trading arrangements, expected in Autumn 2000, the schemes will require more fundamental reform as many of the reference prices used in the schemes will cease to exist.

1.1.3 The new incentive schemes that are introduced with the new trading arrangements will also need to be consistent with the new NGC Price Control due to take effect from April 2001.

### *1.2 Current incentive schemes*

1.2.1 In order to maintain the electrical stability of the National Grid, generation capacity has to be matched with demand on a second by second basis and the voltage and frequency must be contained within prescribed limits. The costs of ensuring this dynamic balance are known as 'Uplift' under the existing trading arrangements. Last year total uplift costs were approximately £360m.

1.2.2 At vesting, the costs of uplift were passed through to suppliers and ultimately customers. The costs rose dramatically after vesting (they were £800m in 1994/95). As a result, it was decided to incentivise NGC to control the costs of those areas of uplift that were judged to be under its influence (approximately £272m of the £360m last year). The schemes have evolved over the years and NGC is currently incentivised on three elements of Uplift: Energy Uplift (£12m); Reactive Power (£50m); and Transmission Services Uplift (£210m). In addition, it is incentivised to minimise the cost of transmission losses (which were an additional £130m last year).

1.2.3 NGC is incentivised for both Energy Uplift and Transmission Losses through arrangements agreed with the Pool. Any change to these arrangements needs to be agreed with all Pool members. NGC is incentivised for both Reactive Power Uplift and Transmission Services Uplift through its Transmission licence. Any change to these arrangements needs to be agreed via a licence amendment.

1.2.4 The existing schemes are of the sliding scale type. NGC is set a target level of costs for each element of controllable uplift costs. If it manages to 'beat' this target it shares a proportion of any reduction in costs. If costs exceed the target, NGC pays a proportion of the additional costs.

1.2.5 The schemes have been a success: NGC has reduced total controllable uplift costs by over 50% in the last six years. NGC has also reduced each of the individual elements of controllable uplift costs over the same period.

1.2.6 However under the existing schemes NGC faces perverse incentives. The schemes are not consistent and NGC incentives are not fully aligned with the interests of customers. The parameters of the individual schemes may encourage NGC to focus its efforts on some elements of uplift at the expense of others.

## *1.3 The Development of NGC's Roles under the New Electricity Trading Arrangements*

1.3.1 In July, Ofgem published its document on 'The new electricity trading arrangements'[1] (NETA) setting out further details of the new electricity trading arrangements for England and Wales. These will replace the present Pool with market-based trading arrangements more like those in commodity markets and in competitive energy markets elsewhere. They place greater emphasis on bilateral trading between generators, suppliers, traders and customers. The new arrangements are designed to improve efficiency and provide greater choice for market participants while maintaining the security and reliability of the electricity system.

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[1] 'The new electricity trading arrangements; Volume 1', Ofgem, July 1999.

1.3.2 With the expected implementation of the new trading arrangements in Autumn 2000, there will be changes in the way in which NGC's roles of system operator (SO) and transmission asset owner (TO) are assigned and carried out. The SO function covers all the short-term operational activities required to keep the system in balance. The TO function relates to the maintenance and longer-term development of the transmission system. Ofgem's present view is that there may be scope for changes in the way the SO and TO functions are assigned and carried out. However, the economic linkages between the functions will make it important to establish an appropriate framework of incentives in both areas.

1.3.3 As outlined in the new electricity trading arrangements document, Ofgem's preliminary view, subject to consultation, is that a move to a single incentive scheme for the costs of providing SO services would have the fewest disadvantages and most advantages of the alternative approaches outlined in the new electricity trading arrangements document. The SO would be incentivised to minimise the overall costs it incurs in fulfilling its SO role thereby aligning its interests more closely with those of customers. To move towards this approach, the incentives currently negotiated through the Pool would need to be included in the NGC incentive schemes agreed with Ofgem. This is discussed in more detail in Chapter 5.

## *1.4 Incentives from April 2000*

1.4.1 This current review of NGC's incentives from April 2000 needs to anticipate the introduction of NETA, including whether steps can be taken now, in revising the current schemes that will move NGC's incentives schemes towards the form of schemes appropriate after the introduction of the new trading arrangements. There is also the question of the most appropriate duration for the new incentive arrangements. Consideration also needs to be given to changing some more detailed aspects of the new arrangements.

## *1.5 Outline of Document*

1.5.1 Chapter 2 outlines the regulatory environment within which NGC operates as SO. Chapter 3 sets out how the current services are provided, their costs, and related incentive schemes and issues arising from the current arrangements. It also examines

Income Adjusting Events (an aspect of the present incentive arrangements), their value and role. Chapter 4 includes suggestions on how the scope of the April 2000 incentives could be changed in preparation for the new trading arrangements. Chapter 5 outlines next steps and invites comments on the way forward.

### *1.6 The present and subsequent consultations on NGC's incentive schemes*

1.6.1 This is the initial consultation on NGC incentives, inviting views on the general scope, form and duration that NGC's incentives might take in April 2000, taking into account the present incentive schemes and anticipating the introduction of the new electricity trading arrangements in Autumn 2000 which will require a new approach.

1.6.2 This consultation will be followed by detailed preliminary proposals for new incentives from April 2000 which will be published in October. In November, a consultation document will be published on NGC incentives under the NETA. A decision document on the April 2000 incentives setting out final proposals will be published in December 1999.

### *1.7 Views Invited*

1.7.1 Views are invited on any aspect of NGC's incentive schemes from April 2000. Detailed views would be welcomed on:

- **whether the scope of the existing schemes remain appropriate and whether it is desirable to combine the existing four schemes into a single incentive scheme;**
- **whether the new incentive scheme should be of one year duration and on appropriate rules for winding up the scheme part way through the year;**
- **whether the form of existing schemes remains appropriate and whether alternatives to sliding scale should be considered;**
- **whether the asymmetric risk sharing under the existing schemes remains appropriate;**
- **whether there still remains a need for Income Adjusting Events and whether the scope of the existing Income Adjusting Events remains appropriate; and**
- **whether the need to revise existing contracts, agreements and software will limit the feasibility of any proposed changes by 1 April 2000.**

1.7.2 Any views should be sent no later than 17 September 1999 to:

Stephen Smith
Director, Trading Arrangements
Office of Gas and Electricity Markets
Stockley House
130 Wilton Road
London SW1V 1LQ.

1.7.3 Respondents are free to mark their replies as confidential although we would prefer, as far as possible, to be able to place responses to this paper in the Ofgem library. If you wish to discuss any aspect of this document, Tanya Morrison (0171 932 1679) will be pleased to help.

# 2. The Regulatory Framework

## *2.1 The Director General's Duties*

2.1.1 The general duties of the Director General of Electricity Supply ("the Director General") are set out in sections 1, 3, and 47 to 50 of the Electricity Act 1989. The Director General must exercise his functions in a manner he considers is best calculated to secure that all reasonable demands for electricity are met, that licence holders are able to finance their activities, and to promote competition in the generation and supply of electricity.

2.1.2 Subject to these primary duties, the Director General also has a duty to exercise his functions in the manner he considers is best calculated to protect the interests of consumers, to promote efficiency on the part of transmission and supply licence holders and the efficient use of electricity. In doing so, he has to take into account the effect on the environment of activities connected with the generation and supply of electricity, as well as the health and safety of those employed in the electricity industry.

2.1.3 The Government proposed in its review of utility regulation[2] that the Office of Gas Supply and the Office of Electricity Supply be merged. This process has commenced with the offices being combined to form the Office of Gas and Electricity Markets (Ofgem). Under the Government's proposed new utility legislation, the Director General's duties will be altered to make it clear that his primary duty is the protection of customers. The Government has also indicated its intention to enable the Director General to impose financial penalties on companies found to be in breach of their relevant licence under the Act.

## *2.2 UK Competition Legislation*

2.2.1 The Director General has concurrent powers with the Director General of Fair Trading under the Fair Trading Act 1973 and the Competition Act 1980. In relation to these concurrent powers, Ofgem works in conjunction with the Office of Fair Trading (OFT) under the terms of an agreement between the Director General and the OFT.

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[2] 'A Fair Deal for Consumers – The Response to Consultation', DTI, July 1998.

2.2.2 In exercising his functions under the competition legislation, the Director General must act in accordance with his specific duties under the Electricity Act 1989. These functions relate to monopoly situations, restrictive agreements and to courses of conduct which have or are intended to have or are likely to have the effect of restricting, distorting, or preventing competition in respect of licensed activities.

2.2.3 Under the new Competition Act 1998, the Director General will gain additional concurrent powers from March 2000. These will include the ability to impose financial penalties of up to 10% of turnover on companies infringing the prohibitions under the new Act. The Act prohibits anti-competitive agreements (Chapter I) and abuse of a dominant position (Chapter II).

## *2.3 The Electricity Act Licensing Regime*

2.3.1 The Electricity Act provides for the licensing of generators, transmission owners, Public Electricity Suppliers (PESs) and other (second tier) suppliers. These licences impose a number of duties in relation to market conduct.

2.3.2 NGC is the sole possessor of a transmission licence in England and Wales. It owns and operates the national grid, which transports electricity at high voltage from the generators to the Regional Electricity Companies' local distribution networks. NGC is also responsible for scheduling and co-ordinating power flows across the interconnectors between England and Scotland and the UK and France. NGC is required by its transmission licence to develop and maintain an efficient, co-ordinated and economical system of electricity transmission, and to facilitate competition in the generation and supply sectors. Under the Electricity Act, it also has a further duty to avoid any undue preference or discrimination in the connection to, and use of, the transmission system, and interconnections with Scotland and France.

## *2.4 Current Trading and Incentive Arrangements*

2.4.1 At the time of Vesting in 1990, the Electricity Pool of England and Wales 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.

2.4.2 Almost all electricity licences currently require the licensee to become a Pool member[3]. The Pool is an unincorporated association comprising all of the major generators and suppliers in the electricity market. At the heart of the Pool is the Pooling and Settlement Agreement (PSA), a document that sets out the exact procedures for operation of the Pool, including how payments are calculated and the obligations of each member.

2.4.3 In order to maintain system security and quality of supply on the NGC system, generation capacity is matched with demand, voltage and frequency are maintained within prescribed limits, and power flows are contained within the thermal limitations of the NGC system.[4] The costs of maintaining system security and quality of supply, together with costs for encouraging sufficient generation capacity to be made available to meet demand, and the costs associated with providing the sufficient capability for restoring the system following a blackout, are collectively known as Uplift[5] costs.

2.4.4 Until April 1997, all Uplift costs were dealt with under the terms of the PSA. However following a review jointly conducted by the Pool, OFFER and NGC and a determination by the Director General, NGC's responsibility for managing Transmission Services Uplift and Reactive Power Uplift became part of the company's licensed activities. This means that NGC now pays the Pool for the costs of these Uplifts and then recovers the costs directly from suppliers taking demand. Given NGC's responsibility for charging suppliers directly for Transmission Services Uplift and Reactive Power Uplift, a revenue restriction was included in Condition 4 (2) of NGC's

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[3] An exception to this is NGC. NGC is a licensee but is not a Pool member.

[4] These limits or security standards are set out in the Grid Code and Condition 12 of NGC's Transmission Licence.

[5] The actual costs that comprise uplift consists of Operational Outturn from the Pool (which can be divided into Energy Operational Outturn and Transport Outturn); Ancillary Services; Unscheduled Availability Payments; and Other. To come to the figures for the services which are incentivised, these actual costs are allocated to TSU, EU and RPU on the basis of models and assumptions: Energy Uplift is Energy Operational Outturn plus a portion of Other; Transmission Services Uplift is Transport Operational Outturn plus remaining Other and Ancillary Services less Reactive Power. Reactive Power is the remaining part of Ancillary Services. The glossary in Appendix 2 provides further information.

licence which embodies the incentives on it to manage Transmission Services Uplift and Reactive Power Uplift.

2.4.5 The payments by suppliers for the other components of Uplift, namely Energy Uplift and Unscheduled Availability Payments[6], are arranged through the Pool. That is, the costs are added to the Pool Purchase Price to give the Pool Selling Price. Given that NGC can influence the costs of Energy Uplift to an extent, the Pool negotiates directly with NGC incentive arrangements for Energy Uplift which are then incorporated into the Pool Rules.

2.4.6 Another cost borne by suppliers related to electricity transmission is that of transmission losses. Costs arising from transmission losses do not form part of Uplift. The costs associated with losses are smeared back to customers by the application of a uniform scaling factor to demand[7]. Transmission losses are however, subject to a separate incentive arrangement that is also incorporated into the Pool Rules. Any change to these arrangements needs to be agreed with all Pool members. Given that NGC can influence the costs of transmission losses, the Pool negotiates directly with NGC incentive arrangements for transmission losses, which are then incorporated into the Pool Rules.

2.4.7 Figure 2.1 sets out the payment flows for each of the different schemes between generators, suppliers, NGC and large demand-side customers.

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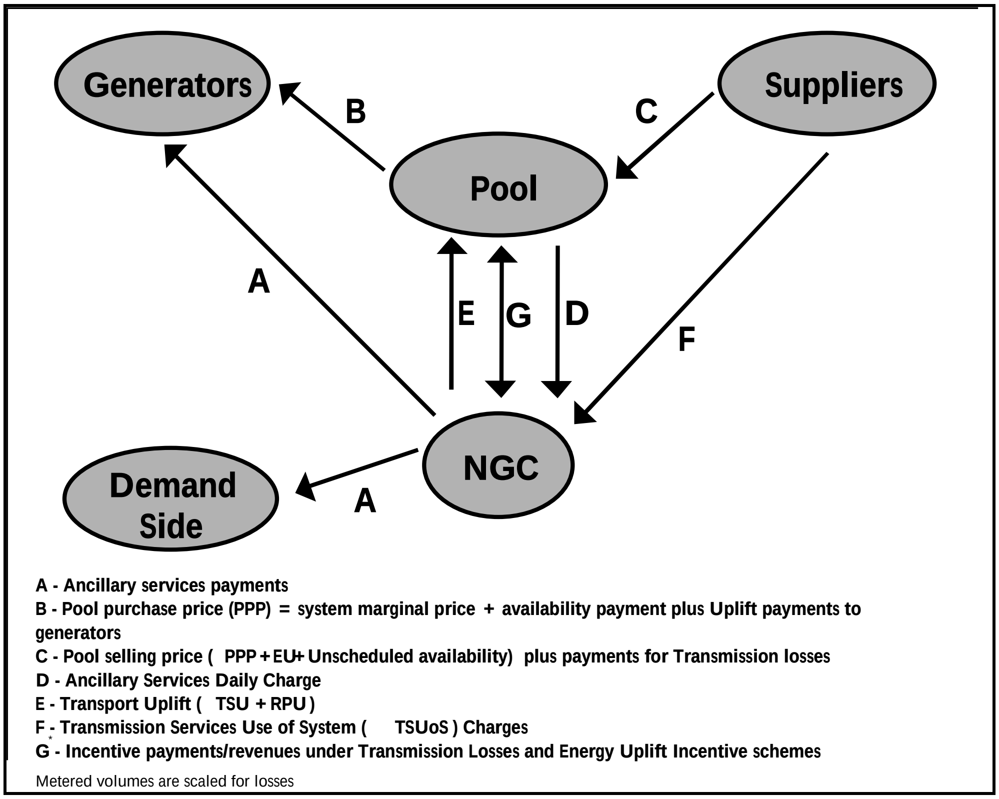
[6] Unscheduled Availability Payments form part of Uplift and are made to generators to encourage them to make plant available at the day-ahead stage. NGC does not have an incentive scheme associated with Unscheduled Availability Payments as it cannot directly influence the level of unscheduled availability payments.

[7] Pool members passed a resolution to introduce zonal loss factors that would vary by location. The resolution was appealed to the Director General who determined in favour of the proposal. The Director General's decision is currently under the process of judicial review.

**Figure 2.1 - Payment Flows Under the Existing Schemes**




## *2.5 The New Electricity Trading Arrangements*

2.5.1 In July 1999, Ofgem set out further details of the new electricity trading arrangements for England and Wales (NETA). These built on the proposals published by the Director General in July 1998.[8]

2.5.2 The SO will continue to contract for services such as reserve, frequency control and voltage support. Such contracts, together with its actions in the Balancing Mechanism[9], will enable it to balance the system after gate closure[10], thereby maintaining the quality and security of supply. The various instruments for balancing the system available to NGC as SO, which will include those activities currently designated Ancillary Services, will collectively be known as Balancing Services.

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[8] 'Review of Electricity Trading Arrangements: Proposals', OFFER, July 1998.

[9] The Balancing Mechanism will enable NGC to accept offers and bids to increase electricity production or reduce demand to keep the system in continual balance.

[10] The time at which the Balancing Mechanism opens.

2.5.3 Possible incentive schemes for NGC, as SO, under NETA were discussed in the July 1999 document. In addition, the possibility of incentivising NGC, as TO, to make available transmission capacity in an economic and efficient manner was raised. This might include the auctioning of transmission capacity. SO and TO incentive schemes will be considered together to ensure that NGC faces consistent incentives in both its roles under the new trading arrangements.

2.5.4 The new SO incentive schemes and the new transmission capacity regime will be considered alongside consultations on NGC's forthcoming price control. Any changes to the SO schemes or the transmission capacity regime will impact on how NGC prices transmission capacity and collects revenue from the sale of transmission capacity. Further consultations on developments to the incentive schemes for periods beyond the introduction of the new trading arrangements, on the new transmission capacity regime and on NGC's price control will be published in November 1999.

2.5.5 The new trading arrangements including new governance arrangements, will be incorporated in the Balancing and Settlement Code. As part of developing new incentive schemes for the SO under the new trading arrangements it will be necessary to consider where the new schemes should be incorporated within the Balancing and Settlement Code. As noted above, under the existing arrangements, two of the schemes are in NGC's licence and two of the schemes are arranged through the Pool.

# 3. Details of Current Incentive Schemes

This chapter describes the current incentive schemes in greater detail.

### *3.1 The form of the Incentive Schemes*

3.1.1 The incentive schemes in place are currently of the sliding scale type. In its simplest form, this comprises a target value for costs set in advance. If NGC manages to beat the target by delivering lower outturn costs, NGC keeps a proportion of the difference between the target and actual costs. If NGC does not manage to meet the target and delivers higher outturn costs, NGC pays a proportion of the difference between the target and actual costs.

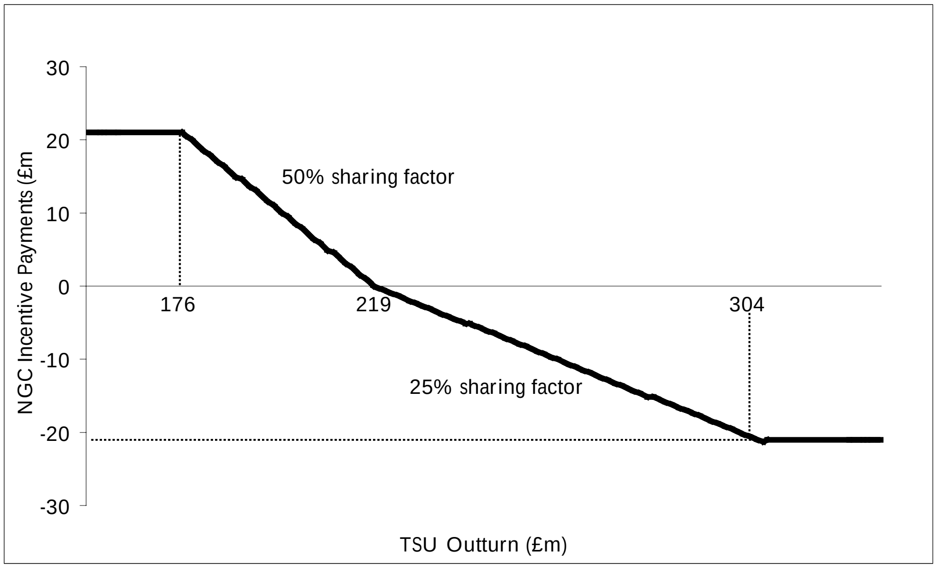
3.1.2 Under the existing schemes, the parameters include: a target value; a deadband range (where no sharing occurs); sharing factors (which may be different depending on whether costs are above or below target) and limits on the revenues (caps) and losses (collars) that can arise if outturn values of Uplift are either considerably below or above target.

### *3.2 Transmission Services Uplift (TSU)*

3.2.1 These costs arise out of the real time operation of a secure transmission system. The relevant NGC activities include the re-scheduling of plant, the holding and utilisation of frequency response capability, and the holding and utilisation of reserve, all of which reflect the physical limitations of the network. The incentive scheme for TSU is summarised in figure 3.1.

3.2.2 The current incentive arrangements for TSU were designed for two years with the targets being set by OFFER at £229m for 1998/99 and £219m for 1999/2000 (all figures in this paragraph expressed in 1999/2000 prices). The sharing factors were fixed at 50% for an outturn TSU below the target (i.e. NGC receives 50% of the benefit of lower outturn TSU costs up to the cap) and 25% for outturn TSU above the target level (i.e. NGC is allowed to pass through only 75% of additional costs down to the collar level). A ‘cap and collar’ is in place on revenues to or payments from NGC, set at plus and minus £20m. Thus, the range over which the incentive arrangements apply was £186 m to £315m in 1998/99 and £176 m to £304m in 1999/2000.

**Figure 3.1 - Transmission Services Uplift Incentive Scheme 1999/2000**




3.2.3 A default arrangement was also put in place, which would apply in 2000/01, should a revised arrangement for 2000/01 not be agreed. The default target for the year 2000/01 would be the mid-point between the level of the target for 1999/2000 and the actual level of those costs for the year 1999/2000 (approximately £198m based on 1998/99 outturn).

3.2.4 In addition to the basic TSU Incentive Scheme described above, NGC receives £535,000 of income in 1999/2000 (£1.136m in 1998/99) to cover certain capital and operating costs associated with management of TSU.

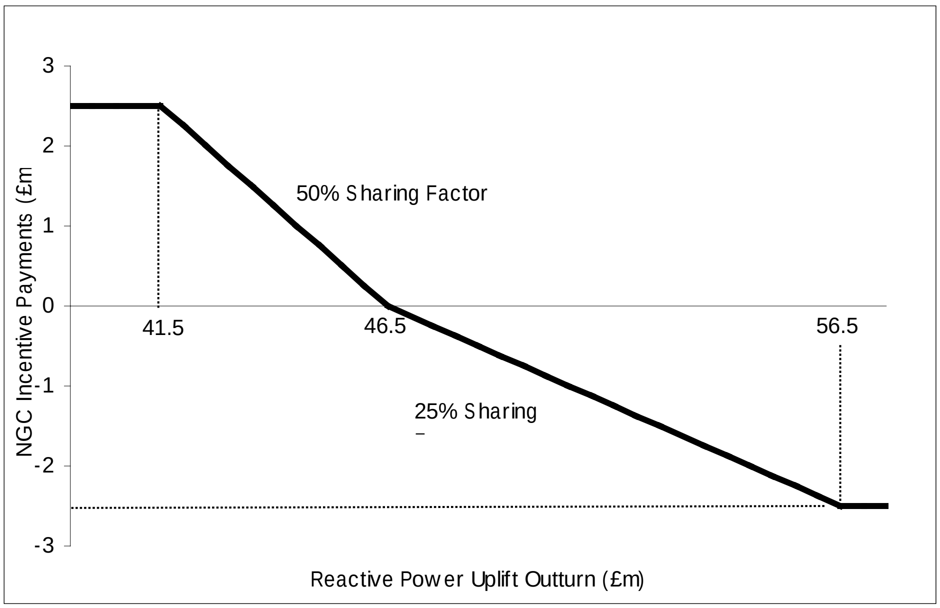
### *3.3 Reactive Power Uplift (RPU)*

3.3.1 Reactive power is a particular type of service which NGC requires in order to maintain system voltage within the limits prescribed in the Grid Code. NGC meets its reactive power requirements both through investment in specialist equipment, e.g. Static Var Compensators, and by contracting with generators. Investment by NGC in Static Var Compensators is remunerated under NGC's Transmission Price Control. The contracts with generators are remunerated through the incentive scheme.

3.3.2 In the last set of incentives negotiations, Pool Members and NGC developed arrangements for a market in Reactive Power. However, there was uncertainty regarding expected liquidity in this market and regarding the interactions between Reactive Power costs and the costs of constraints. It was therefore agreed that separate incentive arrangements should be implemented for Reactive Power and Transmission Services Uplift under NGC's licence.

3.3.3 NGC holds auctions every six months to meet its reactive power requirements. Any eligible service provider[11] can submit bids to NGC to provide reactive power services. Default arrangements, based on contract payments before the introduction of auctions, were put in place to allow bidders time to adjust to the new regime in the event that they do not bid or are unsuccessful in the auction, and to provide a ceiling to contract payments.

**Figure 3.2 - Reactive Power Uplift Incentive Scheme 1999/2000**




3.3.4 The incentive scheme for Reactive Power was designed for one year (April 1999 to March 2000) with the target value being set at £46.5m. The sharing factors were fixed at 50% for outturn Reactive Power Uplift below the target and 25% for outturn

[11] Eligible service providers are defined in Master Connection Use of System Agreement (MCUSA) but include centrally despatched generators, embedded generators and non-centrally despatched providers.

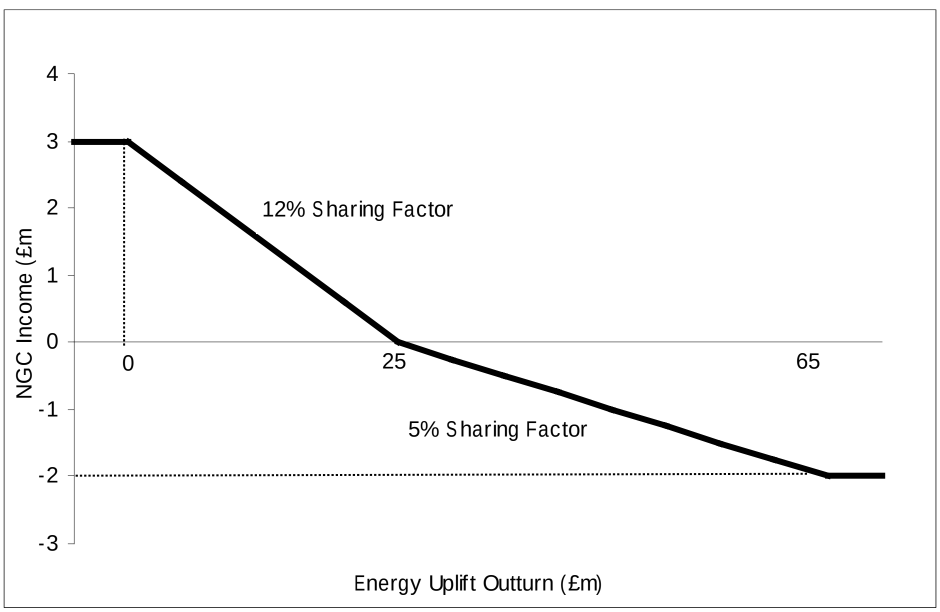
above the target. The cap on revenues to NGC, and the collar on payments by NGC, were both set at £2.5m. Thus, the range over which the incentive arrangements apply is £41.5m to £56.5m, as shown in figure 3.2 above.

3.3.5 As with the Transmission Services Uplift incentive scheme, default arrangements were also included in the reactive power scheme for a second year (2000/01) with the default target being the mid-point between the level of the target for 1999/2000 and the actual level of those costs for the year 1999/2000 (approximately £208m based on 1998/99 outturn).

### *3.4 Energy Uplift (EU)*

3.4.1 These costs represent the costs of demand forecast errors and generator shortfalls and redeclarations assuming perfect foresight, and ignoring the impact of transmission constraints. Figure 3.3 summarises the parameters of this scheme.

**Figure 3.3 Energy Uplift Incentive Scheme**

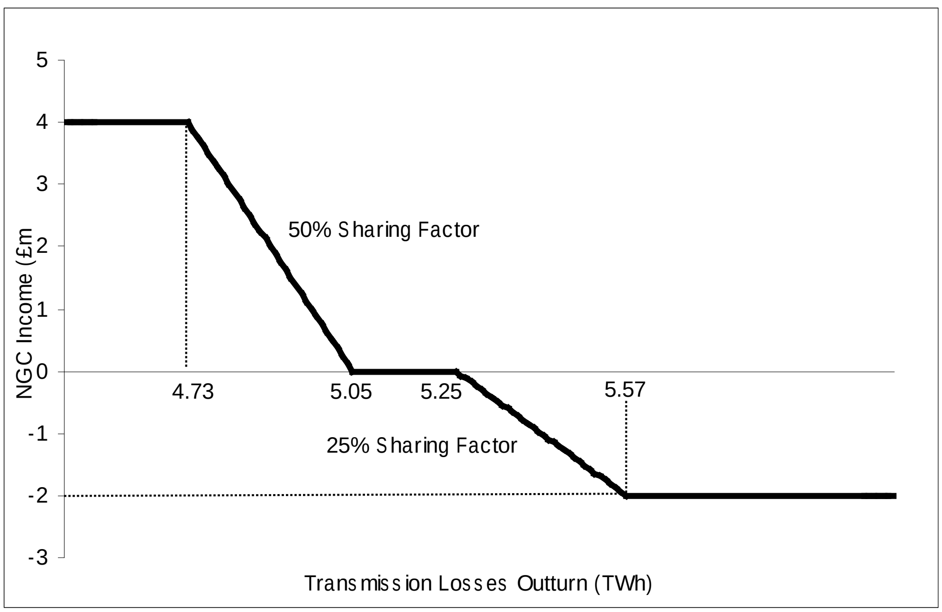



3.4.2 Energy Uplift incentive arrangements are negotiated between NGC and suppliers and are revised each financial year. The target value was £56m in 1998/99 and is £25m in 1999/2000. The reduction reflects the fall in the level of EU following the introduction of the Undergeneration Project[12] in February 1998. If EU is held below £25m, then NGC will retain 12% of the savings up to a maximum of £3m. If it is above £25m, NGC returns 5% of the difference up to a maximum of £2m.

### *3.5 Transmission Losses*

3.5.1 Currently transmission losses are charged through the Pool, with Pool members entering into an incentive arrangement with NGC to limit their extent. Such losses are presently calculated and recovered on a uniform basis from suppliers. The incentive scheme is targeted on the volumes of transmission losses. In order to calculate the financial value of losses, a value of £25.8/MWh for 1999/2000 has been agreed through the Pool as an average value for each MWh. The costs amount to approximately 2% of Pool Selling Price (PSP). Figure 3.4 summarises the parameters of the present scheme.

**Figure 3.4 - Transmission Losses Incentive Scheme**




3.5.2 The deadband range for transmission losses is 5.05 to 5.25TWh in 1999/2000. If transmission losses are held below 5.05TWh, NGC retains 50% of the savings up to £4m. To earn the maximum potential revenue of £4m, transmission losses for 1999/2000 need to be below 4.73TWh. If transmission losses are above 5.25TWh then

[12] The Undergeneration Project was a Pool initiative dependent on NGC software designed to ensure that generators repaid the costs of undergeneration back to the Pool.

NGC must return 25% of the additional costs to suppliers, up to a maximum payment of £2m. This maximum payment will arise if transmission losses are above 5.57TWh.

### *3.6 Current Incentives Schemes - Summary*

3.6.1 Table 3.1 summarises the current incentives schemes, their target ranges, caps and collars, sharing factors and the maximum gains and losses to NGC.

**Table 3.1 - Incentive Schemes 1999/2000 Summary (1999/2000 prices)**

| Scheme | Target | Incentivised range | Sharing factors | Maximum Gain/Loss |
|---|---|---|---|---|
| **Transmission Services Uplift** | £219m | £176m-£304m | 50% below target<br>25% above target | +/-£21m |
| **Reactive Power Uplift** | £46.5m | £41.5m-£56.5m | 50% below target<br>25% above target | +/-£2.5m |
| **Energy Uplift** | £25m | £0-£65m | 12% below target<br>5% above target | +£3m / - £2m |
| **Transmission Losses** | 5.05TWh – 5.25TWh | 4.73TWh-5.57TWh | 50% below target<br>25% above target | +£4m / -£2m |

### *3.7 Income Adjusting Events*

3.7.1 The present arrangements for TSU and Reactive Power Uplift RPU contain provisions to allow for Income Adjusting Events (IAE). These events are intended to cover events over which NGC has been deemed to have no control and which have a large material impact (over £2m). Such events may include 'Force Majeure' under the PSA or the MCUSA. The list of relevant events has previously been agreed between the Director General and NGC, and is set out in Appendix 1. If one of these events occurs, the Director General is able to adjust NGC's allowed revenue in respect of TSU or RPU.

### *3.8 Historic Uplift Costs*

3.8.1 Table 3.2, below, gives a breakdown of Uplift Costs for the categories outlined above. Historical data for these categories are only available from 1993/94 owing to changes in the definitions and scope of incentive schemes. Data for 1993/94 and 1994/95 are NGC estimates.

**Table 3.2 - Historic Uplift Costs (£m, April 1999 Prices)**

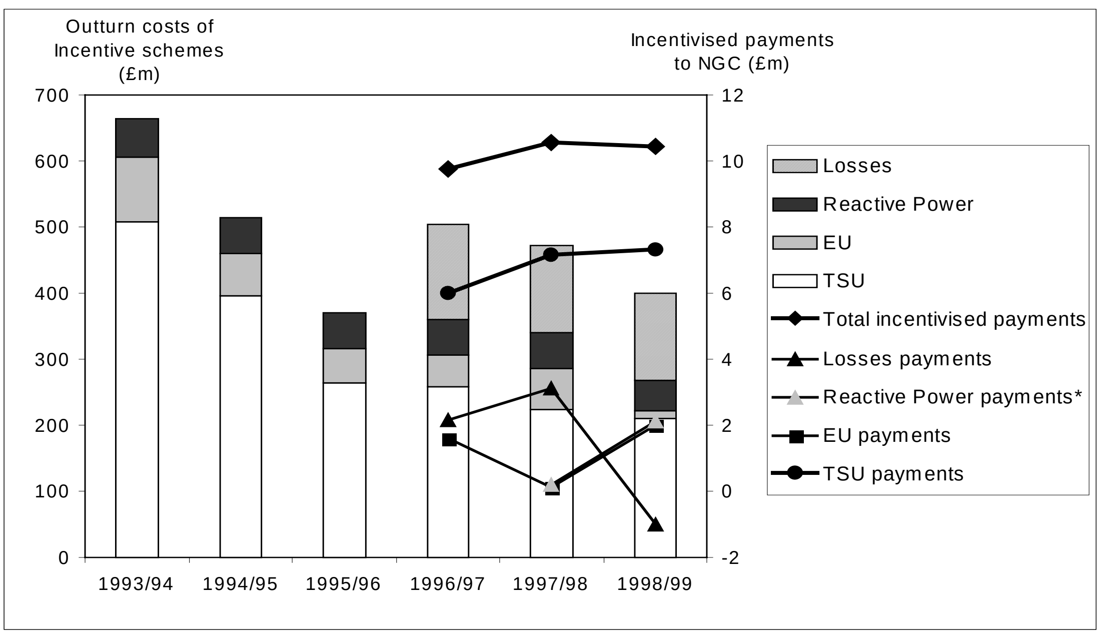
| | 1993/94 | 1994/95 | 1995/96 | 1996/97 | 1997/98 | 1998/99 |
|---|---|---|---|---|---|---|
| Transmission Services Uplift | 508.4 | 395.8 | 263.6 | 257.6 | 224.8 | 210.5 |
| Energy Uplift | 97.5 | 64.3 | 51.9 | 47.9 | 60.6 | 12.4 |
| Reactive Power | 58.6 | 54.8 | 54.4 | 54.4 | 54.3 | 44.6 |
| Unscheduled Availability Payments (B) | 24.8 | 273.1 | 329.4 | 270.9 | 77.4 | 92.9 |
| Total Uplift Costs (A) | 689.3 | 788.0 | 699.3 | 630.7 | 417.0 | 360.3 |
| Transmission Losses (C) | - | - | - | 143.3 | 132.0 | 132.4 |
| Total incentivised costs (A+C-B) | - | - | - | 503.1 | 471.6 | 399.8 |
| NGC Incentive Payment (D) | 0 | 28.4 | 25.4 | 9.8 | 10.6 | 10.4 |
| **Total Costs (A+C+D)** | - | - | - | **783.8** | **559.6** | **503.2** |

3.8.2 The table indicates NGC's success under the various incentive regimes in reducing total Uplift costs and individual elements of controllable Uplift costs. Over the past six years, NGC has consistently reduced Transmission Services Uplift Costs year on year, achieving a 59% reduction over the whole period. Energy Uplift has been more volatile over the six year period but with the introduction of incentives in 1997 and the recent under generation project, costs have been cut by 87% over the whole period and these costs are no longer a significant contribution to total Uplift costs. Reactive power costs have been reduced more slowly but are still down by 24% over the period as a whole. The cost of transmission losses to suppliers has fallen by 8% since incentives were introduced.

3.8.3 The element of Uplift that is not incentivised is Unscheduled Availability Payments. These payments depend on Loss of Load Probability (LOLP)[13] calculations and are volatile and unpredictable. 1995/6 saw the highest values of LOLP to date and total Uplift costs were £699m, of which just under half (47%) were Unscheduled Availability Payments. In recent years, the contribution of Unscheduled Availability payments to total Uplift costs has fallen significantly (to under 26% in 1998/99).

3.8.4 Figure 3.5 presents the historic trend in the costs of those transmission services for which NGC is incentivised (Uplift and losses). The trends in payments to NGC under each incentive scheme and under all the schemes in total are also shown for the last three years. Despite a net payment made by NGC in 1998/99 under the transmission losses incentive scheme, there has been a slight upward trend in payments to NGC in total. This, in part, reflects more efficient management of transmission services by NGC. However, the revenues that NGC has earned in total in the last three years from its incentive schemes are significantly lower than those it received in 1994/5 and 1995/6 under the previous schemes.

**Figure 3.5 - Historic Incentivised Costs and NGC Incentive Payments (April 1999 Money)**

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13 LOLP calculations are a complex set of algorithms used to determine the availability price paid to generators. The loss of load probability depends on a number of parameters including available capacity, forecast demand and other technical parameters.

### 3.9 Issues Arising from Current Uplift Incentives Schemes

3.9.1 The current system of separate incentive schemes (i.e. TSU, EU, RPU) for each of the main components of Uplift and for transmission losses has been useful in allowing the costs of the different areas of these services to be separately identified and in allowing specific schemes to be put in place to reduce the costs to suppliers and ultimately customers.

3.9.2 However, these different categories of uplift costs are allocated on the basis of assumptions and models from information on actual costs provided by the Pool. The accuracy of the determination of the incentivised 'costs' under each scheme is therefore heavily dependent on the quality of the models and assumptions.

3.9.3 NGC argues that it has very limited control over the costs of Energy Uplift as it is largely determined by the Pool Price (although it acknowledges that it can influence the volume term which is largely driven by demand forecasting errors). NGC also argues that there is no interaction between Energy Uplift and the other components of incentivised Uplift, and that the process for separating the different categories of costs is well defined in the PSA.

3.9.4 Ofgem agrees that the process for determining the different incentivised cost categories is well defined involving models that calculate the value of different cost categories based on assumptions outlined in the PSA. The models allow a stylised split of the costs assuming perfect foresight but they do not, for example, acknowledge that actions taken by NGC may influence both the level of Energy Uplift and Transmission Services Uplift.

3.9.5 This modelling approach is however, highly unlikely to lead to a perfect separation of Energy and Transmission Services related costs especially as many of the individual cost elements are cannot be accurately measured or identified directly. In the allocation for example, a residual component (Other) is added to both cost categories, which is not well defined.

3.9.6 Furthermore, Ofgem believes that NGC can indirectly influence the Pool price (albeit to a limited extent) through its actions as system operator. NGC's Ancillary Service contracts can be struck with generators to include option fees and Pool price related fees for calling the option. These contracts are similar to contracts between generators and suppliers in their commercial impact on the generators as they may result in fixed payments to generators and variable payments linked to output and the Pool price. The Ancillary contracts may therefore influence generator bidding behaviour and ultimately Pool prices.

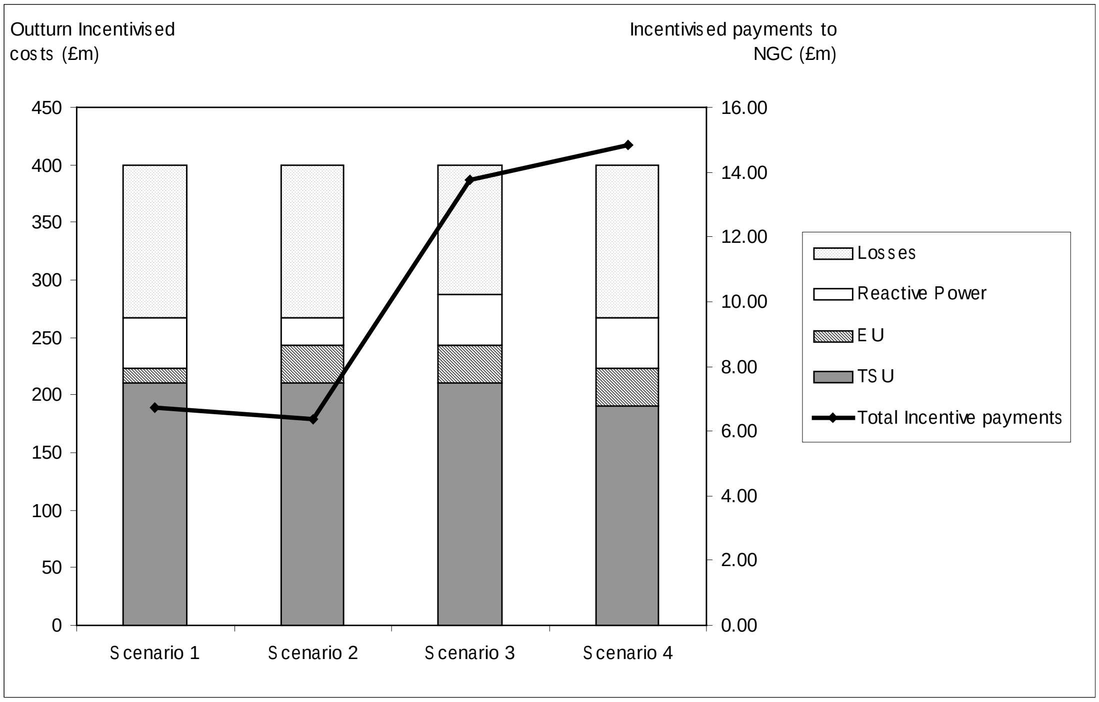
3.9.7 While NGC may to date have operated the transmission system more efficiently and reduced controllable Uplift costs, separate incentive schemes with different parameters and values could encourage NGC to explore ways to arbitrage between schemes. It is to be expected that NGC as a business will, where possible, seek to maximise its total incentive payments. Under the existing schemes, NGC does not maximise its payments when total controllable uplift costs, that are paid by suppliers and ultimately consumers, are minimised.[14] If NGC is able to shift costs between say, Transmission Services Uplift and Energy Uplift, it may be in its interest to do so.

3.9.8 NGC may be able to affect the split between Energy Uplift and Transmission Services Uplift by changing the configuration of the system . NGC may also be able to influence the split between Energy Uplift and Transmission Services Uplift by allowing fluctuations in the frequency and voltage of the transmission system within allowed limits.

3.9.9 The volume (and cost) of transmission losses will also be driven amongst other factors, by how NGC configures the system and chooses to deal with constraints. When managing a constraint, NGC often has some discretion about the volume and location of scheduled generation that must be reduced to alleviate the constraint. The location element will influence the level of losses. Decisions by NGC on how best to manage constraints will therefore have implications for constraint costs in TSU and the volume and cost of losses.

[14] Suppliers will pay the total costs identified in the final line of table 3.2.

**Figure 3.6 – An Illustration: NGC Incentive Payments Under Different Scenarios**




3.9.10 In order to assess how the different incentive schemes can interact, Ofgem has analysed the interactions between outturn costs under each scheme and the total revenues to or payments by NGC. Figure 3.6 illustrates how total payments to NGC might vary for the same level of total Uplift, if NGC were able to shift costs between the schemes. The analysis uses the outturn level of Uplift for 1998/99 and the parameters for the 1999/2000 schemes to demonstrate how payments to NGC might vary for the same level of total costs.

3.9.11 The graph shows the possible impact on total payments to NGC if it were able to shift £20m between the different cost categories. Scenario 1 shows the payments that NGC would receive in 1999/2000 if total Uplift remained at the 1998/99 level and the costs of the individual elements of Uplift also remained unchanged. Scenario 2 shows the impact of a decrease in RPU costs of £20m and a £20m increase in EU costs. Scenario 3 shows the impact of a decrease in the cost of losses of £20m and a £20m increase in EU costs. Scenario 4 shows the impact of a decrease in TSU costs of £20m and a £20m increase in EU costs.

3.9.12 The analysis is merely an illustration. However it demonstrates that, if NGC is able to influence where Uplift costs are realised by no more than £20m out of £400m, it could potentially increase its total payments by up to £8m. By reducing Transmission Services Uplift, NGC could potentially greatly increase its total incentive revenues, whilst keeping the overall cost to the industry the same. This might be achieved by allowing the costs of other incentivised costs to rise and making payments under the relevant incentive schemes. The form of the current incentive schemes means that a large reduction in TSU (and the associated revenues to NGC) can more than offset any payments under other schemes.

3.9.13 The analysis demonstrates that the form and parameters of the current control are somewhat arbitrary and can lead to incentives that are not necessarily consistent with reducing the costs of each component of Uplift currently incentivised or, more importantly, with reducing Uplift costs as a whole, which is in the interest of suppliers and customers. The interactions between incentive schemes is an area which Ofgem will analyse further and discuss in subsequent consultation documents.

# 4. Revising the Incentive Arrangements for April 2000 to October 2000

NGC's current incentive arrangements are due to expire on 31 March 2000. Given that there is expected to be a gap of around six months between the end of the current incentive schemes and the start of the new trading arrangements, Ofgem needs to consider the scope, duration and form of the incentive arrangements that are to apply after 31 March 2000.

## *4.1 Scope of Revised Incentive Arrangements*

4.1.1 As discussed in chapter 3, the revenue restriction in NGC's licence only encompasses the incentives on NGC to manage Transmission Services Uplift and Reactive Power Uplift. Incentive arrangements for Energy Uplift and transmission losses are negotiated separately by suppliers and NGC and are incorporated within the Pool Rules.

***Ofgem's Initial Views***

4.1.2 In revising these arrangements for April 2000, there are three options that might be pursued. The first option is simply to roll forward the current, separate schemes, possibly with revised caps and collars and revised sharing arrangements. The second option would be to apply the relevant default arrangements for Transmission Services Uplift and Reactive Power Uplift, as outlined above. The third option is that changes could be made to the current schemes to bring them together under a single umbrella scheme, thus moving them towards the type of framework envisaged for Autumn 2000 when the new electricity trading arrangements are introduced.

4.1.3 Based on our initial analysis, Ofgem would like to see the four schemes (TSU, RPU, EU and losses) brought together under a single incentive scheme that would encourage NGC to minimise total controllable Uplift costs and losses. A consolidated incentive scheme would ensure that NGC's incentives were consistent with customers' interests. Under such an approach, NGC's payments would be maximised when total controllable costs were minimised. This option would eliminate the need to continue the system for unbundling the costs of Uplift excluding unscheduled availability payments.

## *4.2 Duration of the incentive Arrangements*

4.2.1 Historically, NGC's incentive schemes have been set for one or two years. NGC has argued that the scheme's duration should be longer and more consistent with the Price Control duration. This would provide NGC with a greater incentive to invest in and develop systems that would further assist it in managing Uplift as it would have more certainty of cost recovery.

4.2.2 As has been mentioned previously, the revised schemes will have to be extensively revised when the new electricity arrangements are introduced in Autumn 2000. The duration of the April 2000 schemes is therefore expected to be approximately 6 months.

### *Ofgem's Initial Views*

4.2.3 Given the need to revise the schemes, it is Ofgem's initial view that it would be appropriate to set the April 2000 schemes for a period of one year with explicit rules in place for the schemes to be 'wound up' part way through the year when the new trading arrangements are put in place.

4.2.4 These rules could simply specify that the annual target and costs be pro rated for the number of months that the schemes operate. However, uplift costs may be profiled throughout the year, with say, a greater proportion of the costs being incurred in the winter months.

## *4.3 Form of Incentive Arrangements*

4.3.1 As noted above, past and present arrangements for Uplift incentive schemes are of the sliding scale form. Sliding scale regulation was introduced in recognition of the initial uncertainty in forecasting Uplift costs when the schemes were first introduced and the fact that most of the costs associated with Uplift can be influenced to some degree by NGC's conduct.

*Ofgem's Initial Views*

4.3.2 Given that a new incentive arrangement is required for only an interim period, it is Ofgem's preliminary view that the present form of incentive arrangements continues to be valid. This argument is reinforced by the successes of the schemes in reducing Uplift costs to date. These points suggest that it is appropriate to continue to rely upon the sliding scale approach, pending the wider review of SO and TO incentives that will be undertaken in conjunction with the review of the NGC price control (which needs to be renewed from April 2001) and the launch of NETA.

## 4.4 The Sharing Factor

4.4.1 All the present incentive schemes have asymmetrical sharing factors with NGC receiving a higher proportion of benefits when costs are below target than it pays out when costs are above target (see the figures in chapter 3).

*Ofgem's Initial Views*

4.4.2 Ofgem's initial view is that, given the experience with the operation of the incentive arrangements that is now available, a symmetrical sharing arrangement, which provides equal treatment to both the upside and downside, may be more appropriate for the revised schemes.

## 4.5 Income Adjusting Events

4.5.1 There are several issues that arise in connection with the reliance on income adjusting events. With the possible exception of the declaration of an emergency, it is arguable whether there needs to be a list of events agreed between the Director General and NGC at all. If such events occur and have a material impact, either to the benefit or detriment of NGC, the Director General may consider, *ex post*, whether this requires reopening questions concerning the parameters of the incentive schemes. However, given that the current incentive schemes are based on a sliding scale form with caps and collars, and given that current plans are for this to continue, NGC and its customers should, in any case, be partially protected from extreme costs due to unforeseen events. That is, the effects of such events are already taken account of by the setting of sharing factors that are considerably below 100% in value. Any risk to NGC is further mitigated by the collars that limit NGC's downside risk in absolute terms.

4.5.2 There also remain questions as to whether all the events listed are wholly outside of NGC's control. They may, for example, include events that NGC could have reasonably been expected to anticipate in the course of conducting of its business and that should, therefore, have been built into its planning processes.

4.5.3 In the gas industry, Transco has recently raised two modification proposals to its Network Code that would see the introduction of energy balancing and capacity incentives on Transco under the Reform of Gas Trading Arrangements.[15] The incentive schemes are analogous to NGC's existing schemes and seek to ensure that Transco carries out its SO role in an efficient manner. The issue of Income Adjusting Events was raised as part of the industry discussions and it was agreed that Income Adjusting Events would not be necessary given that Transco's gain and losses under the scheme were capped and collared in a similar manner to NGC's.

***Ofgem's Initial Views***

4.5.4 Given all of the above, Ofgem is of the initial view that there may be no need to take account of any Income Adjusting Events listed under NGC's current incentive schemes, apart from emergencies.

## *4.6 Implications of Revising the Incentive Arrangements*

4.6.1 Any changes to the existing incentive arrangements may have implications for NGC's licence, existing contracts, and existing systems and processes. The scope of any changes will depend on the extent to which, after consultation, Ofgem concludes that it is necessary to revise the existing arrangements. If the existing arrangements are left predominantly intact with, say, minor amendments to the parameters of the schemes, only a relatively minor amendment to NGC's licence will be required. We have set out the main implications of potential revisions below.

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[15] 'The New Gas Trading Arrangements', Ofgas, May 1999.

Draft Modification Report 313 – Development of energy balancing regime to facilitate implementation of the On the Day Commodity Market, BG Transco, August 1999.

Draft Modification Report 314 – Development of Entry Capacity Entitlements based upon an SND profile, BG Transco, August 1999.

***Changes to the Pooling and Settlement Agreement***

4.6.2 In order to change the scope and/or form of the incentive schemes, the Pooling and Settlement Agreement (PSA), Schedule 9 (the Pool Rules) of the PSA and the Pool Settlement Software would need to be changed prior to the commencement of the new schemes on 1 April 2000.

***Changes to NGC's Transmission Licence and Charging Statement***

4.6.3 Under any proposals to amend the existing schemes, it will be necessary to propose changes to NGC's transmission licence. In order to change the scope and/or form of the incentive schemes, Condition 4A of the licence which details the charging principles of the Transmission Services Activity would need to be changed. NGC would also have to modify its Licence Condition 10 Statement of Charges to reflect any changes to Transmission Services Use of System (TSUoS) charges.

***Changes to the Master Connection Use of System Agreement***

4.6.4 Ofgem do not believe that changes to the TSUoS charging principles would require changes to the MCUSA as it was not changed with the introduction of the incentive schemes in 1997. However under the Supplemental Agreements to the MCUSA, NGC would need to notify each User of any changes to the TSUoS charging principles (i.e. the scope and/or form of the new incentives) on or before 31 October 1999. NGC would then need to confirm the revised charging principles to each User on or before the 30 November. Users would then have a one month period in which to appeal against the proposed changes. NGC's initial view is that is that all Supplemental Agreements would need to be re-issued to reflect the revised charging arrangements and agreed before April 2000. In the event that agreements are not reached the matter would be referred to Ofgem for determination.

***Changes to NGC's systems***

4.6.5 Any change to the scope of the incentive schemes would require changes to NGC's TSUoS charging software.

***Ofgem's Initial Views***

4.6.6 Ofgem recognises that there are a number of systems and contracts that would need to be amended if the form or scope of the schemes are changed. Ofgem invites views and will explore further to what extent this may constrain any proposed changes to the schemes for April 2000.

## *4.7 Views Invited*

4.7.1 Ofgem would welcome views on the following issues, in relation to the revision of NGC's incentive schemes for April 2000:

- **whether the scope of the existing schemes remain appropriate and whether it is desirable to combine the existing four schemes in to a single incentive scheme;**
- **whether the new incentive scheme should be of one year duration and on appropriate rules for winding up the scheme part way through the year;**
- **whether the form of existing schemes remains appropriate and whether alternatives to sliding scale should be considered;**
- **whether the asymmetric risk sharing under the existing schemes remains appropriate;**
- **whether there still remains a need for Income Adjusting Events and whether the scope of the Income Adjusting Events remains appropriate; and**
- **whether the need to revise existing contracts, agreements and software will limit the feasibility of any proposed changes from 1 April 2000.**

# 5. Summary and Next Steps

## *5.1 Summary*

5.1.1 NGC is currently incentivised in four areas: Transmission Services Uplift; Reactive Power Uplift; Energy Uplift; and Transmission Losses. The schemes agreed through NGC's licence (Transmission Services Uplift and Reactive Power Uplift) are due for renewal in April 2000. Under the new electricity trading arrangements, due to be introduced in Autumn 2000, the ways in which secure system balancing is achieved will change. NGC's roles as SO and TO will become more clearly defined, and incentives on NGC in these roles will be developed to take these changes into consideration.

5.1.2 From April 2000, a new incentive scheme will need to be introduced, prior to the introduction of the new trading arrangements in Autumn 2000. This document has suggested that the current form of incentive scheme (i.e. reliance on the sliding scale approach) be continued, but has also outlined a number of possible adjustments to the way in which the approach is implemented. Views have also been invited on the scope and duration of the incentives.

## *5.2 Next Steps*

5.2.1 Ofgem will be considering responses to this initial consultation document before taking a view on the form, scope and duration of incentives for April 2000.

5.2.2 If after consultation, Ofgem decides to change the scope of the incentives and to combine the four existing schemes , NGC needs to provide details of the changes in the principles of transmission charges that this will entail to suppliers (MCUSA signatories) by the end of October 1999.

5.2.3 A further document will therefore be published in October which will set out our decision on whether to combine the schemes and on the form and duration of the schemes. The document will also consult on preliminary detailed proposals either on the new single scheme or the existing schemes: it will set out our proposed target cost levels and parameters either for the new combined scheme or the existing separate schemes.

5.2.4 Ofgem will publish a decision document on the April 2000 scheme(s) in December. This document will set out the targets and other parameters of the new scheme(s) and will give notice of the amendments to NGC's Transmission licence that will be required to put the new schemes in place.

5.2.5 If after consultation, Ofgem decides to continue with the present scope, the TSU and RPU schemes will be agreed with Ofgem and NGC and NGC will begin negotiations with suppliers in January to revise the Energy Uplift and Transmission Losses schemes. NGC would need to agree the new parameters with suppliers and submit a paper to the Pool Executive in early March for approval. Subject to approval, the new schemes would then also take effect from April 2000.

5.2.6 Over this same period, Ofgem will also be considering in more detail the incentive structure required for NGC under the new electricity trading arrangements. This will be the subject of an initial consultation document in November.

5.2.7 The renewal of NGC's price control in April 2001 will offer an opportunity to re-examine how NGC charges for transmission capacity on the grid, its incentives to make capacity available, and long term pricing and investment signals. These issues will also be considered in a November consultation document.

# Appendix 1

### Transmission Services Activity Income Adjusting Events

21 February 1997

a) The export from England to France through the interconnector in any period of 1 month of more MWh of Active Energy than are imported from France to England through the interconnector in such period;

b) A change of genset ownership, a change to the Pooling and Settlement Agreement, or any change to, or introduction of new, Agreed Procedures;

c) A change to the Grid Code, or the MCUSA (including any Supplementals thereto) and/or (without prejudice to the generality of the foregoing) any replacement of, or a change in, the schedule used in either the Settlement System or in Scheduling and Despatch;

d) A change pursuant to Condition 12 of the Transmission Licence in the transmission system security standards which were specified in paragraph 1 of Condition 12 of the Transmission Licence as at 31 December 1996;

e) A change to the planning and/or operational standards referred to or contained in the British Grid Systems Agreement and/or the Protocol with Electricité de France;

f) The grant, renewal or non-renewal of derogation to any authorised electricity operator or holder of a Transmission Licence in relation to the obligation to comply with any provision of the Grid Code, the Distribution Code, the distribution system planning standards, the transmission system security standards pursuant to Condition 12 of the Transmission licence or the system planning standards applicable to those holding a licence granted pursuant to Section 6(1)(a) of the Act;

g) Any amendment or re-enactment of the Electricity (Class Exemptions from the Requirement for a Licence) (No2) Orders 1995;

h) Any settlement, award or determination by either an arbitrator, a court, the Director or other competent authority with regard to any of the constituent elements used in the determination of Transmission Services Uplift or Reactive Power Uplift;

i) A change in the level of Transport Uplift due to a change in the amount of Primary Response and/or Secondary Response (as defined in the Grid Code) from that amount held at 1st April 1997 in order to meet paragraph 1(b) of Condition 12 of the Transmission Licence;

j) Failure of the Grid Operator and each Supplier (who is a network operator) to agree by 1st August 1997 the terms of an Agreement for the reimbursement to NGC of the costs associated with out of merit generation required only to support the stability of a local network;

k) If at any time the content of the Ex Post Unconstrained Schedule is determined by the Executive Committee in accordance with the province of Schedule 9 to the Pooling and Settlement Agreement;

Except as otherwise provided herein, and unless the content otherwise requires, words and expressions used herein shall have the same meaning as defined in the Pooling and Settlement Agreement and/or the Transmission Licence. In the event of conflict between definitions, the definition used in the Transmission Licence will prevail.

# Appendix 2

## Glossary of Terms

**Ancillary Services**

The dynamic nature of the system requires a complex range of management services. NGC therefore contracts with generators to provide frequency response and reserve, Hot Standby, Cancelled Start, Black Start and Reactive Power. These, excluding Reactive Power, form part of TSU.

**Black Start**

A component of ancillary services. This comprises the payments made to generators for the ability to start-up from shut-down and to energise a part of the system and to be synchronised to the system under instruction from NGC, within two hours, without an external power supply.

**Cancelled Start**

This is where a generator is instructed to start above "need" in anticipation that some plant will fail. If plant failure occurs, generation starts as instructed. If the generation is not required, the start instruction is cancelled.

**Constraint Costs**

Constraint costs form part of the Transmission Services Uplift components and refer to those costs that arise because transmission constraints on the National Grid prevent a least cost despatch of generation plant.

**De-loaded**

The state of a genset which has been instructed to reduce MW generation from full availability back to part-load operation.

**Energy Uplift**

These costs represent the unconstrained cost of meeting demand-forecast errors and generator re-declarations and breakdowns. These are subject to a separate incentive arrangement, which is negotiated between the Pool and NGC.

**Fast Reserve**

A component of Operating Reserve which in turn is part of ancillary services. This is a service provided predominantly by hydro plant. This service allows the operator to quickly start a unit and is used to manage demand spikes and manage demand uncertainty.

**Frequency Response**

The service of frequency response manages short-term imbalances resulting from small demand variation and instantaneous plant loss and falls into two components: Primary Response and Secondary Response. The short timescales necessitate response being an automatic service. The costs of frequency response arise contractually, under Ancillary Services, as payments made by NGC for the provision of response, and also in the Pool, under Transport Operational Outturn, as payments to gensets part-loaded to hold response.

**High Frequency Response**

The reduction of generator output, in response to a high system frequency.

**Hot Standby**

Hot Standby is an ancillary service where a generator is paid to burn fuel to keep a set warm such that it can achieve a faster start up time than if the set was cold.

**Loss of Load Probability**

This reflects the probability of supply being lost because (LOLP) generation is insufficient to meet demand.

**Operating Reserve**

The service of operating reserve arises from the necessity for NGC to hold a quantity of generating plant in reserve to cover long term imbalances between supply and demand, caused by demand forecast error; the failure of plant to start; and the uncertainty associated with times of rapid demand change. Reserve is also used to restore system frequency and response capability following a short-term loss. Components of Reserve are; Fast Reserve, Synchronised Reserve and Standing Reserve. The costs of operating reserve arise both contractually under Ancillary Services and via the Pool in Operational Outturn.

**Out-of-Merit Generation**

Gensets operate out-of-merit when they are not scheduled in the Pool Unconstrained run, but are nevertheless instructed to run by NGC as SO. The Pool then pays them bid price, which will be greater than SMP.

**Primary Response**

Component of Frequency Response and therefore of ancillary services. This is used to capture the fall in system frequency within 10 seconds of the instantaneous loss of generation and hold it for a further 20 seconds.

**Reactive Power**

These are costs within ancillary services associated with contractual arrangements for the provision of Reactive Power. This is a particular form of power, which NGC requires in order to maintain system voltage within limits prescribed in the Grid Code and the costs are subject to an incentive arrangement via a licence obligation on NGC.

**Revised Unconstrained Schedule**

A generation schedule which takes no account of transmission constraints but which has been adjusted to take account of Re-declared and Actual Availability.

**Secondary Response**

Component of Frequency Response. It is used to restore the system frequency to the minimum acceptable frequency. It is an automatic response to frequency changes which is available by 30 seconds from the initial frequency change to take over from the Primary Response and partially recover system frequency and must be maintained at this level for up to 30 minutes.

**Standing Reserve**

A component of Operating Reserve and therefore ancillary services. Standing Reserve refers to plant that typically has faster start up times than conventional steam turbine plant, such as hydro units, open cycle gas turbines and demand reducers.

**Synchronised Reserve**

A component of Operating Reserve and therefore ancillary services. This refers to the ordering of replacement plant, if plant failure is notified 5 hours in advance and is held on centrally despatched generators operating below their maximum output.

**Transmission Services Uplift (TSU)**

This comprises Transport Operational Outturn, Ancillary Services excluding Reactive Power, and other minor payments to generators. A licence obligation on NGC means that it is incentivised to manage these costs efficiently.

**Transport Operational Outturn**

A component of TSU and refers to the excess cost of running ‘out-of-merit’ generation, required for example because the transmission system is physically constrained (constraint costs) or because in-merit generation is de-loaded so as to allow a frequency response capability.

**Unconstrained Schedule**

The half-hour by half-hour schedule of gensets notionally required to meet forecast demand and to be held in reserve which is produced the day ahead of trading ignoring transmission constraints.

**Unscheduled Availability Payments**

At the day-ahead stage, generators offer to the Grid operator a level of capacity available to be called for generation. That portion which is not despatched may, nevertheless, still receive a payment called the Unscheduled Availability Payment. This is paid on the available capacity offered to the system by a generator in excess of its revised unconstrained capacity and is primarily related to the Loss of Load Probability (LOLP). It is designed as an inducement to generators to build extra capacity.