Structure of gas distribution charges

Initial proposals

July 2005

Summary

This paper summarises the responses to Ofgem's May 2004 document[1] and initiates a consultation on initial proposals for reform of the structure of gas distribution charges.

In particular, Ofgem would welcome views from interested parties on its initial proposals:

- **cost-reflectivity of use of system charges:** the advantages of moving away from the current charging model are not sufficient to justify introducing distance related charges at present, as lessons could be learnt from improved locational signals emerging from the separation of the gas distribution price control;
- **capacity and commodity split:** increasing the weighting of the capacity component of use of system charges would encourage a more efficient use of transportation assets and views are sought on two different options which include a 70:30 and a 99:1 capacity/commodity split together with the timing of implementation;
- **the Economic Test used to determine whether a new load should pay a contribution towards connection:** a number of parameters currently used to calculate the test would benefit from being updated and the gas distribution network operators should be required to publish a full description of the test as part of their statement pursuant to standard licence condition 4B (Connection charges etc.) of their Gas Transporter licence;
- **connected system exit point (CSEP) administration charge:** this charge has accurately reflected the costs incurred by Transco in managing CSEP information under the existing labour-intensive processes, however it should be kept under review to assess the net benefits of switching to an automated process;
- **customer charge:** this charge should be made more cost-reflective by levying it only on a capacity basis; and
- **surveys and auditing:** a number of key data sources which underpin the gas distribution charging models should be reviewed.

[1] *Review of Transco's structure of distribution charges. Consultation paper,* Ofgem, May 2004.

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1. Introduction

Purpose of this document

1.1 This document sets out Ofgem's initial proposals for reforms to the structure of charges for connection and use of the gas distribution networks (DNs). It also outlines the analysis underlying these proposals. Views are sought on a number of options for change to the existing arrangements.

1.2 In light of the major restructuring that the industry has undertaken as part of the sale of four of Transco's DNs, it is timely to consult on Ofgem's initial views on the existing structure of gas distribution charges.

1.3 Charges for transporting gas on the DNs account for approximately £2bn of distribution revenue and represent up to 24 per cent of an average household gas bill. Improving the charging methodology should lead to a more efficient use of the DNs, thus reducing the costs of developing and maintaining them. These lower costs should then be reflected in reduced transportation charges for all consumers.

Background

1.4 Transco plc (Transco) is currently the largest Gas Transporter (GT) in Great Britain (GB). Until 1 June 2005, it owned and operated both the National Transmission System (NTS) and eight DNs. On 25 May 2005, the Authority of Gas and Electricity Markets (Authority) gave its final consent to the sale of four of Transco's DNs.[2] On 1 June 2005, Transco completed the sale of four DNs, including Scotland, North of England, Wales and West, and the South.

1.5 DNs levy distribution charges on gas shippers. In addition to gas distribution, GTs are typically engaged in other activities within the gas industry, including the provision of connections and metering services. The cost of connection services can be recovered as up-front charges levied on the party requesting the

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[2] *Open letter: Gas distribution Network Sale – Final consent to sale of four of National Grid Transco's gas distribution networks*, Ofgem, 25 May 2005.

connection, as part of ongoing use of system (UoS) charges, or a combination of the two. The costs of transporting gas are generally recovered through ongoing UoS charges.

1.6 The structure of gas distribution charges defines the boundary between connection and UoS charges and determines how these charges are applied to DN users.

1.7 In May 2004 Ofgem published a paper, *Review of Transco's structure of distribution charges. Consultation document*, to seek views on a number of aspects of the structure of gas distribution charges. Responses to this consultation were placed on Ofgem's website and are summarised in chapter 2 of this document.

Other relevant documents

1.8 Final proposals governing the separation of Transco's distribution price control, which came into effect in April 2004, were published by Ofgem in June 2003 in the document *Separation of Transco's distribution price control - Final proposals*.

1.9 Ofgem's review on Independent Gas Transporters (IGT) transportation charging arrangements was concluded in July 2003 with the final proposals paper, *The Regulation of Independent Gas Transporter Charging*. The new charging arrangements for IGTs, including RPC arrangements, were implemented in January 2004.

1.10 In electricity distribution, Ofgem is currently developing the long term framework for the structure of charges. The latest update on Ofgem's views on the future of electricity distribution charges was published in May 2005. [3] In broad terms, the long term charging arrangements to be introduced in 2010 would be based on more cost-reflective use of system charges, while up-front contributions to reinforcement costs would no longer apply.

[3] *Structure of electricity distribution charges. Consultation on the longer term charging framework,* Ofgem, May 2005.

Structure of this document

1.11 This document contains the following chapters:

- Chapter 2 provides a summary of the responses received to the May 2004 document on the review of the structure of gas distribution charges;
- Chapter 3 discusses the impact assessment (IA);
- Chapter 4 outlines Ofgem's initial proposals; and
- Chapter 5 sets out the next steps.

1.12 This document also includes two appendices. Appendix 1 sets out the IA for the proposed changes to the capacity/commodity split. Appendix 2 provides a description of the Economic Test (ET).

Views invited

1.13 Views are invited from interested parties on the initial proposals discussed in this document. Responses should be received by **16 September 2005** and sent to:

Samanta Padalino
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1.14 Electronic responses should be sent to Samanta.Padalino@ofgem.gov.uk. All responses will be held electronically in Ofgem's Research and Information Centre. Non-confidential responses will be published on the Ofgem website. Where possible, respondents should put any confidential material in appendices to their responses.

2. Summary of responses

2.1 Ofgem received a total of 14 confidential and non-confidential responses to the May 2004 document. The respondents comprised a broad range of industry participants including gas shippers, gas suppliers, IGTs and representatives of large industrial gas users. Respondents were asked to provide their views on the following issues:

- whether distribution UoS charges should be made more cost-reflective;
- whether the capacity/commodity split should be changed;
- whether a shallower connection charging boundary should be adopted and ongoing charges increased to recover the additional costs of reinforcement;
- whether Transco's ET should be reviewed;
- whether the impact of RPC regulation of IGTs should be considered and Connected System Entry Point (CSEP)[4] charges reviewed; and
- the implications for this review of the separation of Transco's distribution price control and the sale of Transco's DNs.

2.2 The views of respondents on these issues are summarised below.

Cost-reflectivity

2.3 Several respondents supported improved cost-reflectivity of charges in principle. However, their support was qualified by the need for a balance between the benefits of cost-reflective charges and the costs of dealing with a more complex charging structure. It was recognised that the current charging model is simple and not costly to administer.

2.4 The majority of suppliers and shippers did not support the development of more cost-reflective charging arrangements on the basis of the large implementation

[4] A CSEP is a point on the system that comprises one or more individual offtakes that are not metered supply points. These include connections to pipeline systems operated by GTs other than Transco. There are currently

costs that such arrangements would impose on the industry. Implementing more cost-reflective UoS charges could require, for example, DNs, shippers and suppliers to invest in new customer billing systems. They also stated that increasing the complexity of the charging regime could create a barrier to the entry of new gas suppliers.

2.5 Some respondents stated that Transco should update a number of data sources that are used to establish its charging models, including the Activity Based Costing (ABC) analysis, i.e. the model used by Transco to allocate costs to its different business activities and that feeds into the charging functions.

Capacity and commodity split

2.6 Comments about changing the capacity and commodity split were divided between representatives of large industrial users who tended to favour a higher capacity weighting, and domestic shippers and suppliers who were opposed to it.

2.7 Respondents in favour of a higher capacity/commodity split maintained that the existing 50:50 ratio was not cost-reflective. They stated that, as a consequence of the existing ratio, high load users and interruptible users are cross-subsidising low load users and firm users. These respondents favoured a 99:1 split to better reflect that transporting gas within DNs involves a higher fixed cost business than the NTS. They suggested a phasing in of this split over time to minimise the distributional impact on low load factor users.

2.8 One respondent set out the need to have a sufficient capacity weighting in order to encourage large users to opt for interruptible contracts, thereby reducing the need to invest in new capacity.

2.9 Another respondent suggested widening the criteria used to measure the impact of changing the split (beyond the impact on different customer groups) to include other factors such as the seasonal impact on charges to shippers and frequency with which Transco may revise charges. One respondent considered that a forward looking assessment be completed first before deciding on any change.

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about 14,000 CSEPs with about 600,000 supply points connected to them.

2.10 A number of respondents did not favour any change citing the negative impact that a higher capacity split would have on the fuel poor. Therefore, the current split was favoured for striking a balance between cost-reflectivity and Ofgem's wider objective of reducing fuel poverty.

2.11 These respondents also claimed that the differential between what gas shippers would pay under a higher capacity weighting and what final consumers would be charged (based on throughput) could increase. As a consequence, suppliers might decide to introduce standing charges in the final bills of consumers.

2.12 Other respondents stated that any change to the split should only be considered after the IA on interruptions reform is concluded.

Connection boundary

2.13 The majority of respondents supported the existing shallowish connection boundary, whereby reinforcement costs are recovered through transportation charges but new connectees still pay for some connection assets. Respondents considered it fair that new connectees should pay towards the cost of connection. This prevents existing customers from cross-subsidising new connectees.

2.14 Further support of the existing boundary was based on:

- its consistency with the move towards a shallower connection boundary in electricity distribution from 2005; and
- the impracticality of having locational distribution UoS charges at this time, which would prevent cross-subsidisation between existing and new loads.

2.15 One caveat to supporting the existing boundary was that existing interruptible users that are forced to become firm should be exempt from paying reinforcement costs. Only two respondents supported moving to a shallower connection boundary claiming that reinforcement costs should be recovered through transportation charges.

2.16 Another respondent commented that it would be important to focus on seeking appropriate and transparent criteria for assessing where the charging boundary should be.

Economic Test

2.17 The majority of respondents supported a review of the ET. A lack of transparency with the existing test was a common theme with many respondents suggesting that publishing the full details of the test would prevent any potential discriminatory treatment of new connectees.

2.18 Some respondents suggested that the ET should reflect RPI-X efficiency savings as well as an updated ABC analysis. Another respondent suggested that the appraisal periods should be aligned more closely with the expected lifetime of a connection. One respondent went further in suggesting that the test should be applied to all connection types irrespective of whether reinforcement was needed.

2.19 Several respondents expressed their concerns regarding the asymmetry of the ET, whereby, if the ET is met, none of the excess transportation revenue expected from the new connection is used to reduce the connection charge. However, one of these respondents suggested that a change in the current asymmetry should only be considered if the sums involved were material.

2.20 Two respondents did not consider it appropriate to remove this asymmetry on the basis that there is no guarantee that a new load will consume the volume of gas expected over the appraisal period assumed in the ET. Therefore,

♦ there is no guarantee that any expected excess revenue would materialise; and

♦ transportation revenue could turn out to be insufficient to pay for the cost of connection, thus forcing DNs to recover the lost revenue from other users.

Impact of Relative Price Control

2.21 Some respondents said that the impact of RPC should be considered within the scope of this review. These respondents highlighted the need to:

♦ consider the stability of revenue for IGTs; and

- guard against re-balancing between CSEP and single supply point (SSP) charges.

2.22 Respondents identified some additional IGT issues which are not specifically related to RPC. These can be summarised as follows:

- CSEP charges are not cost-reflective as they assume that IGTs use more transportation assets than they actually do;
- the CSEP administration charge is an unfair surcharge on IGT shippers; and
- a review of the allocation of costs between pressure tiers would be desirable.

2.23 With respect to the latter concern, three specific issues were raised. Firstly, it was suggested that the costs associated with the installation and use of governors should not be allocated to the medium pressure (MP) tiers, because governors only serve customers connected to the lower pressure (LP) tiers. Secondly, it was maintained that the use of the network by CSEPs should be calculated based on the actual location of CSEPs rather than on their expected average use of transportation assets. Finally, concerns were raised that the use of pipe diameter for categorising the tiers to which a CSEP was connected led to errors.

Impact of Distribution Network sale

2.24 A major concern expressed by most respondents was the potential for diverging levels of charges and charging methodologies following the sale of Transco's DNs. These respondents stated diverging charges would require the adoption of multiple billing systems, thus imposing significant costs to shippers and suppliers. Some respondents maintained that these costs could outweigh the potential savings from the DN sale. On this basis they supported changes to Transco's charging methodology ahead of sell-off.

2.25 One respondent suggested that dealing with more than one DN could entail more difficulties for reviewing the charging methodology, thus it was important to press on with this review ahead of the DN sale.

2.26 Two respondents took the contrary view and suggested waiting for the completion of the DN sale to allow the new DN operators to have their say on the structure of charges. Another suggested that this review could create uncertainty with regard to transportation revenue and investment sums required for pipeline extension and reinforcement for potential purchasers.

2.27 One respondent suggested a further review of the structure of DN charges in three years time, having gained some experience about the working of the separated DN price controls.

3. Impact assessment

3.1 Ofgem is required to carry out an IA under section 5A of the Utilities Act 2000, as amended by the Sustainable Energy Act 2003. Section 5A requires that the Authority must carry out and publish an IA when:

- it proposes to do anything for the purposes of, or in connection with, the carrying out of any function exercisable by it under or by virtue of Part 1 of either the Electricity Act 1989 or the Gas Act 1986; and
- it appears to Ofgem that the proposal is important.

3.2 Section 5A defines a proposal as important where its implementation would be likely to lead to one or more of the following:

- involve a major change in the activities carried out by the Authority;
- have a significant impact on persons engaging in the generation, transmission, distribution or supply of electricity or gas;
- have a significant impact on persons engaged in commercial activities connected with the generation, transmission, distribution or supply of electricity or gas;
- have a significant impact on the general public of Great Britain or part of Great Britain; or
- have significant effects on the environment.

3.3 Where a proposal is not considered important, Ofgem would nonetheless endeavour to set out a summary of the impacts of the proposals.

3.4 It is important therefore to distinguish those initial proposals that require a full IA from those that do not. In broad terms, the analysis undertaken by Ofgem on the areas of work identified in the previous chapter has concluded that:

- a change to the capacity/commodity split may be appropriate; and

- a number of marginal improvements within the remaining areas of work would be beneficial and could be implemented at minimal cost.

3.5 Between these two sets of changes, the only proposal which appears important according to the criteria listed above is the change in the capacity/commodity split.

Overview of key issues

3.6 This review assesses whether the current structure of distribution charges complies with the objectives as set out in the Gas Act and the relevant objectives as outlined in standard special condition A5 (Charging - General) of the GT licence obligations.

3.7 In considering this, Ofgem is mindful that the existing charging structure and any proposals for change should meet the Authority's principal objective under section 4AA (1) of the Gas Act to protect the interests of consumers wherever appropriate by promoting effective competition between persons engaged in commercial activities connected with the shipping, transportation or supply of gas. Further, the Authority is required by section 4AA (2) of the Gas Act to have regard to

- the need to secure that reasonable gas demand in GB is met;
- the ability of licence holders to finance their activities; and
- the interests of vulnerable customers.

3.8 A number of issues remained outstanding from the review undertaken in 2000[5], including a possible change in the split between capacity and commodity charges. New issues have also emerged since then and a number of developments have taken place, most notably the completion of the latest Transco price control review in 2002, the separation of Transco's distribution price control, the conclusions on the review of IGT charges in July 2003 and the sale of four of Transco's DNs. The latter introduced RPC in January 2004 for new

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[5] *Review of Transco's LDZ charging methodology. A consultation document*, Ofgem, March 2000.

properties connecting to IGT networks. RPC caps IGT charges to a level that is broadly equivalent to Transco's charges.

3.9 Critical amongst the objectives of charging arrangements is that charges should reflect the costs that DNs incur.[6] In particular, charges levied in respect of network use should, where appropriate:

- reflect the costs that users impose on the network operator; and
- be targeted to those users who cause such costs to be incurred.

3.10 On this basis, cost-reflectivity of distribution charges should encourage the efficient use of the network. However, it is also important to strike a balance between cost-reflectivity and other relevant principles such as simplicity, ease of implementation and net benefits arising from any change.

Options for the relevant areas of work

3.11 In this section, we outline a summary of the impacts of the proposed changes in a number of areas relevant for the structure of gas distribution charges. A full IA on the proposed increase in the capacity/commodity charge is reported in appendix 1.

3.12 Chapter 4 outlines Ofgem's views and the reasoning behind our initial proposals. For a more detailed description of each element of the structure of gas distribution charges, we refer to Ofgem's May 2004 consultation document.

Cost-reflectivity of use of system charges

3.13 As outlined in chapter 4, Ofgem does not intend to propose any changes to UoS charges at this stage. Although we have considered the option to move to more cost-reflective charges through the adoption of 'location' or 'distance' related charges, we have concluded that it would not be appropriate to introduce this because:

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[6] The charging methodology should also take account of developments in the transportation business and facilitate effective competition between gas shippers and gas suppliers.

- the separation of DN price controls means that regional differences in gas distribution charges will start to emerge over time;
- there would be significant costs of such a change in terms of supplier billing systems, changes to the reconciliation by difference (RbD) process[7], metering arrangements, and IT equipment.
- the impact on domestic consumers residing in rural areas might be severe; and
- they were not supported by the respondents to the May 2004 consultation paper.

3.14 No impacts are then expected in this area of the structure of gas distribution charges.

Capacity and commodity split

Issues

3.15 DNs have a postalised system for setting distribution charges. Therefore, distribution charges are dependent on consumer load size (which acts as a proxy for the use of distribution assets) rather than consumer location within a DN. About 70 per cent of the allowed distribution revenue is recovered through UoS charges. The remaining 30 per cent is recovered through customer charges.

3.16 The process for setting UoS charges involves identifying the costs associated with each pressure tier on a DN. At present, it is assumed that 50 per cent of these costs relate to the provision of capacity (defined in terms of peak day kWh) and 50 per cent to the provision of commodity (defined as annual kWh).

3.17 The assumption that 50 per cent of costs relate to capacity and 50 per cent of costs relate to commodity has been criticised for not being cost-reflective, as most of DN costs relate to the provision of peak capacity and do not vary with throughput.

[7] RbD is a way of reconciling the difference between allocated and actual energy for small supply points, which have an annual quantity (AQ) of up to 73,200 kWh and are non-daily metered.

Ofgem's previous positions

3.18 On a number of previous occasions Ofgem stated that there is a strong case for increasing the capacity weighting. However, Ofgem has not asked Transco to implement such an increase in light of its potential distributional effects and pending changes to the interruption regime.

3.19 It was suggested that a higher capacity weighting would increase charges for domestic and small business consumers, while reducing the charges levied on larger consumers.

3.20 At present interruptible customers do not pay any capacity charges (even when they are not interrupted), which may over state the true value of interruptible services being provided. Therefore charging more on the basis of capacity and less on commodity would tend to exacerbate any discrepancy between the value of interruptions and the discount afforded to interruptible customers.

3.21 DNs have a reasonable endeavours obligation under their GT licence to introduce revised interruption arrangements by April 2006 or as soon as possible thereafter. These reforms would broadly include firm exit rights for all users and arrangements for interruptible services to DNs based on a pricing mechanism, which should allow the discovery of the value of interruptible services to DNs. As indicated in chapter 4, the deadline for finalising interruptions reform has been delayed to 1 April 2007 for implementation on 1 October 2007 alongside NTS enduring offtake arrangements.

Options

3.22 We have assessed the impact of the following three options:

- Option 1: status quo;
- Option 2: moving to a 70:30 split alongside interruptions reform; and
- Option 3: moving to a 99:1 split alongside interruptions reform.

3.23 The costs and benefits associated with these options and the justification for the proposed splits under option 2 and 3 are outlined in appendix 1. Although

Ofgem tends to support an increased capacity weighting, we have no final view on whether option 2 or option 3 would be preferable.

Economic Test

Issues

3.24 The ET, as described in appendix 2, is a financial assessment tool that was introduced by Transco in 1998 to identify whether a new load should pay a contribution towards the reinforcement required for its connection. This should prevent existing DN customers from subsidising the reinforcement costs of a new load.

3.25 The ET compares the incremental cost of connecting a customer to the gas distribution network with the expected revenue from transportation charges associated with that customer, using net present value (NPV) calculations.

Options

3.26 We have considered two options:

- Option 1: Status quo; and
- Option 2: Change the ET by
  - modifying/updating a number of parameters used in calculating the ET; and
  - requiring DNs to publish a full description of the ET.

3.27 Specifically, under option 2, we would require the DNs to:

- set the depreciation period used by the ET to 45 years;
- align the discount rate used in the ET with the prevailing allowed cost of capital at each price control review; and
- distinguish between process and non-process loads for which different appraisal periods would apply.

3.28 Changes to the ET would affect customers requesting connections to a DN who are expected to consume over 73,200 kWh per annum. Annually, there could be in the range of 4,500 new connections to DNs which are subject to the ET. Changes to the ET would also indirectly affect existing and potential new customers to the extent that they may contribute to the reinforcement costs of new loads through transportation charges.

Benefits

3.29 Under option 1 the ET will carry on as currently set with no additional benefits. The existing ET provides some locational signals on the costs of connections in certain parts of the network, which are not provided by UoS charges. UoS charges reflect transportation costs associated with an average load within specific end user categories, but they do not capture:

- the costs associated with loads exhibiting atypical profiles;
- the costs associated with loads located in areas where it is significantly more expensive to transport gas; and
- the risk of large loads disconnecting from the network before network assets are depreciated.

3.30 The ET can identify these loads and reduce the risk of other consumers cross-subsidising the costs that they could impose onto the system.

3.31 Under option 2 the ET would better fulfil its role as a provider of locational signals. Specifically:

- a depreciation period of 45 years would reflect the most recent estimates of the economic life of assets; and
- a discount rate aligned with the allowed cost of capital at each price control review would better reflect the opportunity costs of DN investment.

3.32 When compared to the existing ET, the overall effect of these changes would be to increase slightly the likelihood of a load passing the test and hence not having to pay for reinforcement costs.

3.33 As regards the distinction between different types of loads, we have considered whether the existing assumptions about the length of the appraisal period under the ET are inconsistent with the purpose of the test, which is to assess the economic risk associated with a new load. In this respect, we have identified:

- process loads for which there is a positive risk of disconnecting; and
- non-process loads for which the risk of disconnecting is minimal.

3.34 A process load is a load where gas is consumed as part of a manufacturing process (e.g. cement works, paper mills, glass factories). A non-process load is a load where gas is consumed to obtain energy as the final product. Non-process loads would include space heating loads, such as housing developments.

3.35 In our proposals, process loads would have an appraisal period shorter than the life of the assets (e.g. 20 years) to reflect the risk of disconnecting, while non-process loads should have an appraisal period equivalent to the life of the assets.

3.36 By better aligning the appraisal period to the economic risk associated with the load, the ET would better signal whether a new load is economic or should pay a contribution towards the reinforcement required for its connection.

3.37 When compared to the current ET, these changes would imply that it will be more likely for a new load to pass the ET, because Transco currently adopts shorter appraisal periods (15 years for loads greater than 50 million therms per annum and 10 years for non-large loads).

3.38 Finally, the publication of more information on the ET would improve transparency in the manner in which the test is applied, thus better informing the commercial decisions of new connectees on whether and where it would be economical to connect. This may help improve efficiency in the development of new connections.

Costs

3.39 By maintaining the status quo there is a risk that the existing ET would incorrectly assess the economic viability of new connections. This might imply that some economic loads may not pass the test and fail to be connected at all, while other uneconomic new connectees might pass the ET and end up being subsidised by existing loads.

3.40 Under option 2, implementation costs should be minimal as they would simply involve a change of a few parameters within an established model.

Distributional Impact

3.41 Any improvement to the effectiveness of the ET brought forward by option 2 would reduce the likelihood of existing loads subsidising new connections, which the ET, in its present form, might fail to identify as uneconomic loads.

Environmental Impact

3.42 These options would have minimal impact on the environment.

Other Impacts and Risks

3.43 There is a risk that distinguishing process and non-process loads would be difficult. This might trigger some disputes from potential new loads. The definition of these two types of loads must be robust in order to avoid the costs associated with any disputes or errors in assessing the economic viability of a new load.

3.44 Further, Transco has indicated that by publishing detailed information on the ET and its underlying calculation, new loads might find it easier to misrepresent the information about their gas demand in order to pass the ET and minimise their contribution towards the connection. The information provided to the public will need to balance the need for transparency with the risk of gaming by new connectees.

Conclusions

3.45 In light of the low implementation costs of option 2 and its advantages in terms of improved consistency and transparency of the ET, Ofgem supports implementation of option 2. It also seeks views on any issues raised by these proposals.

Customer charge

Issues

3.46 About 30 per cent of allowed distribution revenue is recovered through general customer charges. These charges reflect the costs of providing service pipes and supply point emergency services. Currently, the customer charge is levied on a commodity basis for domestic consumers (with an annual consumption of less than 73.3 MWh) and on a capacity basis for other consumers (with an annual consumption of more than 73.2 MWh).

3.47 As part of our analysis, we have identified the following issues with the customer charge:

- it exhibits a profile that does not necessarily reflect the underlying costs; and
- it should only be levied on a capacity basis because the underlying costs are not related to throughput.

Options

3.48 We have considered two options:

- Option 1: Status quo; and
- Option 2: Review the customer charge to create a function that is only capacity based.

3.49 Changes to the customer charge would affect consumers, shippers and suppliers active on the DNs.

3.50 By maintaining the status quo, there would not be any costs or benefits, except for missing out on the improvements that option 2 may introduce.

Benefits

3.51 Option 2 should simplify the customer charge and enable it to better reflect its underlying costs.

3.52 A review of the underlying costs of the customer charge is also timely in light of the separation of the distribution price control and the sale of Transco's DNs. As charges across DNs will start to diverge from 1 October 2005, option 2 would allow the customer charge to enhance the signalling of differences in the costs of providing service pipes and supply point emergency services across different DNs.

3.53 The use of a function that is only capacity based could also improve the stability of DN revenues since capacity-based charges are fixed during the gas year and are revised only once a year for non-daily metered (NDM) customers, such as domestic users, to incorporate new meter read information. Therefore DNs may need to adjust their charges less frequently to ensure that they recover their allowed revenue.

Costs

3.54 Implementation costs of this change should be low, including:

- a survey of the latest data on the costs covered by the charge; and
- some labour costs to determine the function that best fits the data.

Distributional Impact

3.55 The distributional impacts of the change would depend on the specific design of the new charging function. This will be subject to our review.

Environmental Impact

3.56 Very limited environmental impact would be expected as a result of option 2. In particular, switching to a capacity-based charge for domestic consumers would make their charges slightly less responsive to changes in their annual consumption. These consumers might therefore experience a weaker incentive to save energy. However, as the customer charge makes up only around 8 per cent of a typical domestic customer's gas bill, any adverse impact on the small users' incentives to save energy should not be significant.

Other Impacts and Risks

3.57 The introduction of a capacity based charge may encourage those suppliers that bill their domestic customers on a throughput basis to introduce standing charges for domestic consumers. Standing charges send out no incentives for customers to reduce gas consumption and may therefore have an adverse impact on the environment. However, as gas demand of domestic consumers tends to be very inelastic, the introduction of a standing charge should not have any significant impact on their pattern or level of consumption.

3.58 A standing charge may also cause an increase in the bills of the smaller users within the domestic consumer group. It would therefore be important to consider what proportion of these smaller domestic users represents vulnerable customers.

3.59 No impact on security of supply, health and safety issues or competition is expected as a result of changes to the customer charge.

Conclusions

3.60 Although Ofgem supports option 2, it recognises that the full impact of changing the existing function will depend on the final design of the new capacity-based charging function. Views are sought on any issue that option 2 may raise at this stage.

CSEP administration charge

Issues

3.61 The CSEP administration charge (£1.20 per connection) has been levied on shippers to IGTs to cover labour-intensive processes used by Transco in processing information relating to them. It was introduced in 1996 when Transco did not consider it cost-effective to incorporate IGT data into UK-link due to the limited number of supply points connected to IGTs. The charge has decreased over time from an initial £5.

3.62 Currently, xoserve[8] manages the invoicing of this charge to IGT shippers and the interface with IGTs on behalf of all DNs. Due to the timing of this analysis, which started in 2004, the IA is based on costs incurred by Transco before the creation of xoserve. This should represent a reasonable estimate of the costs incurred by xoserve in managing CSEP data, as this service company currently employs the same processes set up by Transco.

3.63 However, depending on the responses to this consultation, Ofgem may consider reviewing the assumptions made for the purpose of assessing initial proposals for the CSEP administration charge.

Options

3.64 We have identified two options:

- ♦ Option 1: Status quo, subject to requesting the DNs to:
  - review the costs of managing CSEP information and the CSEP administration charge once every two years;
  - undertake a cost-benefit assessment of switching to an automated system in the event that
    - o the unit cost of processing IGT data under the existing labour-intensive process starts to increase; or
    - o the existing process is about to reach its capacity limit;
  - introduce an automated system conditional on the outcome of the cost-benefit analysis;
- ♦ Option 2: remove the charge and introduce automated processes to be paid for from all shippers through general transportation charges.

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[8] xoserve Ltd is jointly owned by the DN and Transmission network operators. Since 1 May 2005, xoserve provides a number of services that support the contract and licence obligations of GTs. These services, which were previously delivered by Transco, include billing, SPA management and management of information systems.

Option 1

Benefits

3.65 Under option 1, CSEP shippers are likely to experience further decreases in the unit rate charge as the CSEP market continues to grow. Since its introduction in 1996, this charge has been revised downward several times to reflect decreasing unit costs of managing CSEP data.

3.66 Table 3.1 below shows the decrease in unit costs as the number of supply points has increased. There is continued expected growth in the CSEP market, thus it is anticipated that the cost per supply point will decrease until the existing system has reached its capacity limit. Currently, the charge should be reduced to reflect the decrease in unit costs experienced in the last year.

Table 3.1 Average CSEP Administration cost per supply point

	2002	2003	2004
Number of supply points	332559	431896	555625
Overall costs (£000s)	498	568	647
Cost per supply point (£s)	1.50	1.32	1.16

3.67 The charge is cost-reflective and it is targeted at those shippers for whom the costs are incurred. It is a simple and transparent mechanism by which DNs can fund the data management services to CSEPs.

3.68 If the capacity limit is reached, a cost/benefit analysis should inform the desirability of introducing new automated processes and revisiting the existing charge.

Costs

3.69 Transco incurred costs of approximately £650,000 in 2004 for CSEP administration processes. This compares to approximately £500,000 in 2002 and

£570,000 in 2003. A breakdown of these costs is given in table 3.2. This is also the order of magnitude of costs going forward assumed under option 1.

Table 3.2 Estimated CSEP Administration Costs 2002-04

		2002		2003		2004	
		Cost (£s)		Cost (£s)		Cost (£s)	
		Direct	238% Uplift	Direct	215% Uplift	Direct	215% Uplift
CPM costs	CPM Activity costs	£99,122	£335,033	£124,505	£392,189	£145,452	£458,172
	IS contractors	£82,000	£82,000	£89,000	£89,000	£95,000	£95,000
	Total CPM	£181,122	£417,033	£213,505	£481,189	£240,452	£553,172
Billing	Total Billing	£24,100	£81,459	£27,677	£87,183	£29,795	£93,855
Total		**£205,222**	**£498,492**	**£241,182**	**£568,372**	**£270,247**	**£647,027**

Note: CPM refers to Customer Portfolio Management within Transco. It does not apply to xoserve.

3.70 The percentage uplift highlighted in the table covers support and sustaining costs. It is based upon the ABC analysis.

3.71 The costs of complying with the conditions under option 1 should be minor, as Transco has already been performing an annual review of the charge. Some one-off costs would be needed to undertake a cost-benefit analysis of the existing process (if it becomes necessary).

Option 2

Benefits

3.72 After an initial outlay of approximately £1.1m, operating cost savings of approximately £400,000 could be made in the first year of implementing the automation.

3.73 With an automated system, processes and data management are likely to become quicker and more reliable.

Costs

3.74 The cost of automating the CSEP data management process within UK-Link was estimated to be just over £1.1 million in 2000. These set-up costs could be spread over a five year period. The annual operating costs were estimated at a quarter of a million. Transco expects that a broadly similar amount would be needed if the project were to be undertaken now.[9] The overall costs would be recovered across all shippers through transportation charges.

3.75 As processes are automated, network based information exchange is most likely to be needed. This would require IGTs to have access to the information exchange. In the past, Transco has been levying charges for access that would represent a substantial cost for IGTs and IGT shippers. As an example, costs for access to UK-link in 2004 were in a range between about £1,500 and £24,000 for connection and annual rental charges (varying from standard packages to packages with more advanced options).

Risks and uncertainties

3.76 There is no defined capacity limit to the current system. Therefore, under option 1, it is not possible to predict when this may trigger a cost-benefit analysis.

Other impacts

3.77 There is no impact on competition, health and safety, security of supply or the environment.

Conclusions

3.78 At present, the overall costs associated with option 2, including both the costs of establishing automated process and the costs of accessing a network based information exchange, do not seem justified by the benefits, which are expected to be gained in moving away from the current data management system.

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[9] A new survey would be needed to obtain more accurate up-to-date estimates of costs. Such survey would cost about £20,000 and last about 3 months. Ofgem has decided not to request any such survey at this stage.

3.79 In particular, option 2, when compared to the existing arrangements, is likely to introduce new costs to IGTs and/or IGT shippers since they would be required to access the new information exchange. Further, given that the unit cost of managing CSEP data is still decreasing as the CSEP market grows, IGT shippers should face a decreasing charge under the status quo.

3.80 The existing charge is also transparent and simple. As the number of CSEPs grows, the charge will need to be reviewed. Ofgem's initial proposals to implement option 1 would allow for the current arrangements to be kept under review and changed when it is cost-effective to do so.

Surveys and audits

3.81 There are a number of key data sources that Transco has been using as an input to its charging functions that could be usefully updated by Transco and new DNs.

3.82 A review of these sources would ensure that distribution charges are based on accurate data and therefore reflect underlying costs of transporting gas within each DN. This is also timely considering the separation of the distribution price control and the sale of Transco's DNs.

3.83 The costs associated with the proposed reviews would be one-off costs of auditing, running the surveys and employing some resources to analyse the outcome of such reviews.

3.84 No impact on security of supply, health and safety issues or competition is expected. Distributional and environmental effects, if any, would depend on the result of the reviews.

4. Initial proposals

4.1 In its May 2004 document, Ofgem described the current structure of gas distribution charges and highlighted some of the issues associated with the current arrangements. The consultation process has identified some issues which needed further review. In particular, Ofgem has focused its review on the following main areas of the structure of gas distribution charges:

- cost-reflectivity of UoS charges;
- capacity/commodity split;
- CSEP charging functions;
- CSEP administration charge;
- economic test;
- customer charge; and
- data sources used in the charging models.

4.2 The following chapter outlines Ofgem's analysis and initial proposals. Please refer to the May 2004 consultation document for a full description of the existing gas distribution charging arrangements.

Cost-reflectivity of use of system charges

4.3 Distribution UoS charges do not depend on customer location within a DN, but on customer size which acts as a proxy for the distribution assets a customer uses. About 70 per cent of the allowed distribution revenue is recovered through UoS charges. The remaining 30 per cent is recovered through customer charges, which are discussed in a subsequent section.

Ofgem's views

4.4 Ofgem has considered respondents' views that the current UoS charges provide a good balance between simplicity and cost-reflectivity. In broad terms, UoS charges reflect the costs associated with an average load for each specific end user category[10]. Further, they are derived using a model that is relatively straightforward to manage.

4.5 A move to more cost-reflective charges would likely require the adoption of location or distance related charges for customers with atypical loads or areas where it is more expensive to transport gas.

4.6 Distance-related charges could be established either for all customers or based on distance zones. Distance-related charges for all customers would require the calculation of the distance gas is transported to each supply point or, alternatively, the definition of notional distances to each supply point based on an assumed entry point where the gas is deemed to have entered the system.

4.7 Charging based on zones would require the average distance (actual or notional) gas is transported to supply points within the specified area. The costs of transporting gas would then be averaged across customers within a zone.

4.8 In either case, the use of actual distances would require regular updating, while the use of notional distance could lead to an arbitrary allocation of entry points, which would be likely to reduce the efficiency and cost-reflectivity of distribution charges. Calculation of distribution charges would become more complex and administration costs would increase.

4.9 As explained below, introducing locational signals into UoS charges would require revisiting the reconciliation by difference (RbD) process, with significant consequences on metering arrangements, IT equipment and billing systems for DNs, shippers and suppliers.

4.10 RbD is a way of reconciling the difference between allocated and actual energy for small supply points, which have an annual quantity (AQ) of up to 73,200 kWh and are non-daily metered. Distance-related charges would conflict with the existing RbD process, whereby non daily metered energy and associated transportation charges are allocated to domestic shippers on the basis of their domestic AQs in each Local Distribution Zone (LDZ). Under RbD the domestic

[10] There are currently nine end user categories.

AQ and peak loads are aggregated by shipper within each LDZ, regardless of the location of the domestic customers within an LDZ and the tier to which they are connected. These are used to allocate the known residual level of delivered energy to the LDZ between shippers, for the purpose of billing each shipper for their aggregate domestic load.

4.11 This simplification is possible because the unit capacity and commodity charges are the same for all domestic customers in a given LDZ. If distance-related charges were introduced, a new billing process would have to be introduced. Further, in order to identify the energy delivered to each supply point (or group of supply points if charging were done on a zonal basis) within the billing period it would be necessary to introduce new metering arrangements.

4.12 A change of this scale could imply significant implementation costs to DNs, suppliers and shippers and significant human resource commitment to the development of new complex business rules. Given the low cost of managing the existing charging model and the fact that it is already cost-reflective for typical customers, the benefits of moving to distance-related charges may not offset the costs to the industry at this time.

4.13 Further, increased locational signals will emerge from the separation of the DN price control and the divergence of charges between the eight regional networks. Ofgem has also indicated that it intends to develop with the industry more cost-reflective electricity distribution charges by 2010 and lessons could be learnt from the new electricity charging models. Once there is experience of the effects of the DN separation and revised electricity distribution charges, it may become appropriate to consider whether further changes would be beneficial.

4.14 Ofgem has also considered its statutory duties to protect the interests of vulnerable customers, including individuals residing in rural areas. In this respect, it is likely that moving away from the current postalised system would increase transportation charges levied on domestic customers in rural areas, as they are located in areas where transportation costs tend to be higher.

Capacity and commodity split

4.15 This section presents some background to the issues surrounding the capacity and commodity split. Costs and benefits of changing the capacity and commodity split are outlined in greater detail in appendix 1.

Issues

4.16 The process for setting UoS charges involves identifying the costs associated with each pressure tier on a DN. At present, it is assumed that 50 per cent of these costs relate to the provision of capacity (defined in terms of peak day kWh) and 50 per cent to the provision of commodity (defined as annual kWh). Transco then undertakes an assessment of the expected use of distribution assets by different groups of consumers (with these groups based on load size). The results of this assessment have been used to establish charging functions that reflect the costs associated with the expected use of distribution assets by a typical consumer in each group. These charges are then scaled so that the resulting capacity and commodity charges are consistent with recovering the distribution price control revenue.

4.17 Actual charges reflect the metering arrangements for different groups of customers. Charges for domestic customers are set on a kWh basis with only charges for larger consumers differentiating between peak and non-peak demand.

4.18 The assumption that 50 per cent of costs relate to capacity and 50 per cent of costs relate to commodity represents a relatively arbitrary split. In particular, the split has been criticised for not being cost-reflective, with most of Transco's costs relating to the provision of peak capacity and not varying with throughput.

4.19 Transco has forecast that DN peak day demand will rise 13 per cent over the period 2003 to 2013. Improvements in the cost-reflectivity of charges could therefore encourage the efficient use of transportation assets and help reduce future investment costs.

4.20 Detailed system analysis carried out by Transco[11] showed that:

- about 99 per cent of DN incremental costs are capacity related;
- as DNs benefit from large economies of scale, if transportation charges were set equal to its marginal costs, they would only recover about 40 per cent of its allowed price control revenue; and
- in order for DNs to recover their allowed revenue, mark-ups to their marginal costs are required:
  - with equi-proportional mark-ups (i.e. the mark-up is allocated in the same proportion as incremental costs) the appropriate capacity/commodity split would be about 99:1; and
  - with capacity and commodity incremental costs marked up by equal amounts, then the capacity/commodity split would be about 70:30.

Interruptions reform

4.21 On a number of previous occasions Ofgem stated that there is a strong case for increasing the capacity weighting. However, it had not asked Transco to implement such a change pending reforms to the interruption regime.

4.22 On 1 May 2005, new licence obligations for DN operators came into effect. Under standard special condition D8 (Reform of the Distribution Network interruption arrangements) of their GT licences, DNs have a reasonable endeavours obligation to bring forward reforms of the arrangements for the interruption of supply points by April 2006. If, despite using all reasonable endeavours, DNs are unable to develop a revised interruption regime, they should ensure that these reforms are implemented as soon as practicable thereafter.

4.23 On 12 July 2005, Ofgem published a letter setting out its decision on the most appropriate way forward for interruptions reform following the Authority's

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[11] *Capacity/Commodity Split*, Transco Pricing Discussion Paper PD4, 1999. Transco has confirmed that the conclusions of its 1999 analysis are unlikely to have changed.

decision to delay implementation of the NTS enduring offtake arrangements until September 2007.[12] In its letter, Ofgem decided that it would be preferable to undertake the reform of DN interruption arrangements in coordination with the development of NTS enduring arrangements. The reasons behind this decision are outlined in Ofgem's letter of 12 July 2005.[13]

4.24 On this basis, the development of DN interruptions reform should be finalised by April 2007, in time for implementing any associated changes to gas distribution charges from 1 October 2007. As a consequence, Ofgem indicated that it did not intend to enforce compliance with the deadline of 1 April 2006 included in standard special condition D8 of DNs' GT licence.

Options

4.25 There appear to be 3 options:

- Option 1: status quo;
- Option 2: moving to a 70:30 split alongside interruptions reform; and
- Option 3: moving to a 99:1 split alongside interruptions reform.

Ofgem's views

4.26 Although Ofgem considers that an increase in the capacity weighting would better reflect the actual balance of capacity and commodity related costs of gas transportation, such an increase could exacerbate the concerns with the existing interruption arrangements. Charging more on the basis of capacity and less on commodity would tend to widen any discrepancy between the value of interruptions and the discount afforded to interruptible customers.

4.27 For this reason it is important that any change in the capacity/commodity split is introduced in conjunction with the reform of the existing interruption regime. As a consequence, implementation of any change to the existing capacity/commodity split would be developed with a timetable that is consistent

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[12] *Enduring Offtake Arrangements*, Ofgem, 24 June 2005.
[13] *Reform of Distribution Network Interruption Arrangements*, Ofgem, 12 July 2005.

with the introduction of revised DN interruption arrangements by 1 October 2007.

4.28 Options 2 and 3 above are based on Transco's assessment that it could recover only about 40 per cent of total costs if it were to charge based on marginal costs. This assessment was based on an incremental cost study in which Transco identified a range of costs that would have to be incurred in order to meet a 10 per cent increase in demand. Marginal costs were approximated by dividing the average incremental costs by the increment in demand. By setting transportation charges equal to these estimated marginal costs, Transco concluded that it would not have been able to recover all its transportation costs.

4.29 The manner in which the remaining 60 per cent of transportation costs is used to mark-up charges based on marginal costs determines the two proposed splits. For this reason it is important to consider the robustness of Transco's assessment of the proportion of un-recovered costs under marginal cost pricing. Ofgem seeks views on this specific parameter affecting the proposals. In addition, Ofgem welcomes views on which of these three options, if any, seems most appropriate.

4.30 As highlighted in appendix 1, option 2 and 3 may encourage the introduction of a standing charge in the bills of those domestic and small Industrial and Commercial (I&C) customers that are currently billed on a throughout basis. Ofgem would welcome views on the risks and consequences of suppliers re-designing their bills to include standing charges.

CSEP charging function

4.31 Currently, UoS charges differ between charges to directly connected supply points and charges to CSEPs. A separate charging function for transportation to CSEPs was introduced in October 2000, in order to take account of the different costs of transporting gas to CSEPs and to directly connected supply points.

4.32 CSEP charges mirrors the charging functions for directly connected supply points, i.e. they reflect the expected average use of transportation assets made by a customer of a given size, rather than the actual use made by a customer at a particular location. Expected network use is derived from a series of steps that assess the probability of a particular customer type utilising specific components of the network. These probabilities are then applied to the costs of operating those components of the network to derive charges that are broadly cost-reflective.

Issues

4.33 Based on respondents' views, Ofgem has considered:

- Issue 1: whether the CSEP charging function has worked; and
- Issue 2: whether it would be appropriate to address a number of other issues raised by respondents, including:
    - the potential over-loading of low pressure (LP) tiers, i.e. the tendency of IGTs to connect to LP tiers although it may be more efficient to connect to higher pressure tiers;
    - the allocation of governors to LP rather than MP tiers;
    - the use of actual data on the location of CSEPs rather than probabilities; and
    - the use of pipe diameters for categorising the tiers to which a CSEP is connected.

Ofgem's views

4.34 As regards issue 1, the CSEP charging function has resulted in an overall reduction in charges of around £1million annually. This reduction has broadly reflected the lower average transportation costs of services to CSEPs with respect to comparable direct loads.

4.35 As regards issue 2, Ofgem considers that there is no evidence to support a change in the areas identified by respondents. This view is explained below.

4.36 The current process for connecting IGTs to DNs has been the subject of a public consultation undertaken by Transco. Under this process, DNs should encourage self-connection to all pressure tiers (except for the higher pressure tier) provided that the connecting party, such as an IGT, can demonstrate its competence to carry out the work. DNs have allowed IGTs to connect to any point on their network where capacity is available. This means that an IGT can decide whether it is more cost-effective to connect to a LP tier main that is further away or a MP main that is closer. Connection to LP tiers could be cheaper for an IGT, everything else being equal, because it avoids the need for gas pressure controlling equipment.

4.37 When the requested capacity is not available, DNs should evaluate alternative connection points as well as potential reinforcement options. If it is more economic to encourage connection at an alternative connection point rather than to reinforce, DNs encourage the connecting party to do this even if its proposed connection point is to a different pressure tier than the one initially requested. If the alternative connection point is further away from the proposed site, the DNs make a contribution towards additional costs incurred by the IGT. However, if the alternative connection point is closer to the IGT's site, the DN requires them to connect at that point without any contribution.

4.38 On this basis, there seems no evidence to conclude that there is a problem with the approach to allocating assets to LP tiers.

4.39 As regards the allocation of governors, Ofgem considers that since under the current methodology assets are allocated to different tiers on the basis of their physical location (which acts as a proxy for the actual use of the assets by a given tier), it would be inappropriate to cherry-pick certain assets and allocate them in a bespoke manner.

4.40 There are likely to be several transportation assets that serve tiers different from the one on which they are located. A consistent approach should be used for all assets. Allocating assets on the basis of which tier(s) each asset serves would introduce a judgemental element that would not allow a simple and transparent allocation of system costs to prevail.

4.41 Further, an analysis of the effects of allocating all governors costs to the LP tier rather than the MP tier indicates that the effect on CSEP charges would be minimal (table 4.1).

4.42 As regards the use of actual data for CSEPs rather than probabilities, Ofgem considers that it would be inappropriate since it would introduce discriminatory treatment between CSEPs and directly connected loads, whose charges are calculated using probable use of assets. Changing the methodology for over 20 million directly connected loads in order to introduce actual data would be impracticable. Further, as the number of CSEPs increases, the administration costs of managing and regularly updating actual data may become prohibitive.

Table 4.1 Comparison of Transportation Charges to Individual Properties on CSEPs

					Charge per Property p.a. CSEP LDZ Function	
		CSEP Data Property (typical value)	AQ	SOQ	Existing	Governor Costs Adjusted
0-2,500	Credit meter only	1	20,000	155	£51.55	£51.69
2,500-25,000	2,500 - 5,000	5	100,000	775	£47.75	£47.79
	5,000 - 10,000	10	200,000	1,550	£47.75	£47.79
	10,000 - 15,000	20	400,000	3,100	£47.75	£47.79
	15,000 - 20,000	25	500,000	3,875	£47.75	£47.79
	20,000 - 25,000	35	700,000	5,425	£47.75	£47.79
Firm contract >25,000	25,000 - 75,000	100	2,000,000	15,500	£36.55	£36.28
	75,000 - 100,000	130	2,600,000	20,150	£34.64	£34.33
	100,000 - 200,000	250	5,000,000	38,750	£30.33	£29.95
	200,000 - 500,000	500	10,000,000	77,500	£26.34	£25.97
	500,000 - 1,000,000	1,000	20,000,000	155,000	£22.86	£22.44

4.43 Finally, as regards the concerns about the reliability of using the pipe diameter for categorising the tiers to which a CSEP is connected, Ofgem considers that the data on the use of pipes of certain diameter has been updated regularly by Transco and broadly reflects actual CSEP connections.

4.44 In the cost analysis performed in 2001, which formed the basis of the CSEP charging functions introduced in October 2000, pipe diameter was used as a subdivision of the LP tier. LP costs were apportioned across the pipe diameter categories. The CSEP connection data used in the analysis included actual information. In late 2002 and early 2003, the actual data used for each IGT was sent to the IGTs so they could check it. Relatively few corrections were required and when they were made they made no significant difference to the charging functions. While a further update of the data used would be desirable, it is unlikely that it would lead to a substantial change to the charging functions.

4.45 Ofgem expects new DNs to prevent any deterioration in the data used to calculate distribution charging functions. For the CSEP charging function this would imply updating the information on the use of pipes of certain diameters from time to time.

CSEP administration charge

Issues

4.46 The CSEP administration charge was introduced in May 1996 as a result of Pricing Consultation 2 (PC2). Transco has been levying this charge on shippers serving customers who are situated on CSEPs.

4.47 There are approximately 21 million customers connected to the distribution pipe-line networks. The data associated with these customers has been updated and maintained on Transco's IT system until April 2005 and it is currently managed by xoserve. For the 600,000 customers situated on IGT networks, CSEP processes have been managed by Transco using off-line systems which are labour intensive and require the timely provision of data from IGTs. The type of information exchange to administer CSEPs involves transfer of data between multiple parties, i.e. shippers, IGTs and DNs.

4.48 As explained in chapter 3, this process is now managed by xoserve for all DNs. However, the underlying approach has not changed, with xoserve broadly mirroring the role that Transco previously had in managing IGT information.

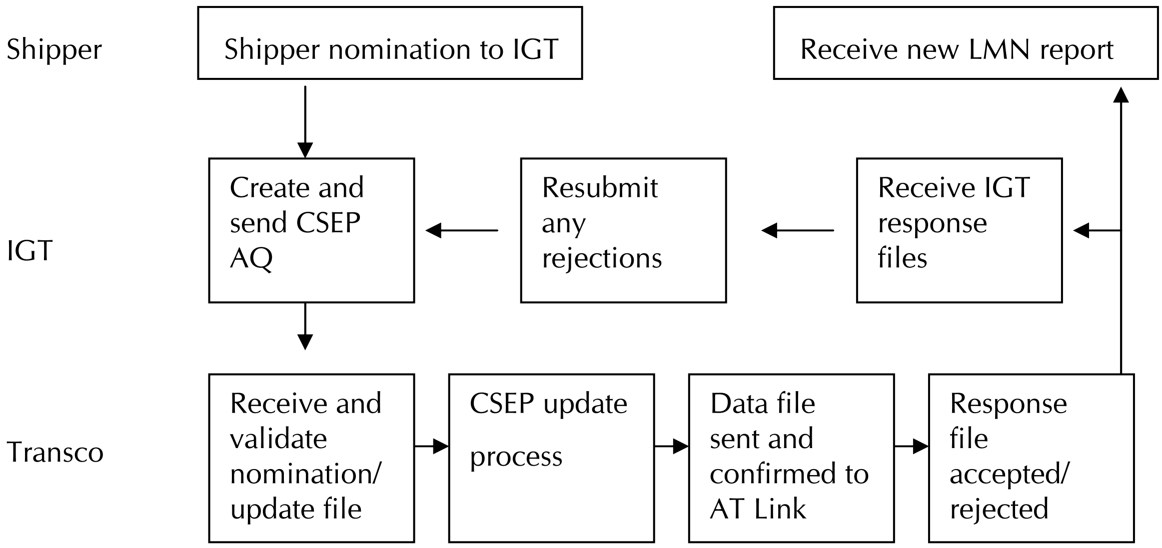
4.49 In 1997, the CSEP market was not seen as sufficiently developed to warrant the inclusion of IGT site specific data within the scope of Transco's IT systems. It is now expected that IGT networks will develop to serve more than 1 million customers by 2008, as shown in table 4.2.

Table 4.2 Forecast growth in the CSEP market

	2004	2005	2006	2007	2008	2009
Number of CSEPs	14,118	16,597	19,097	21,631	24,133	26,621
Number of individual supply points within CSEPs	607,058	713,655	821,187	930,141	1,037,733	1,144,696

4.50 The CSEP Administration process facilitates the allocation of gas transportation charges to shippers who ship gas to CSEPs. Each IGT manages customer Logical Meter Numbers (LMNs[14]) across their networks via the Supply Point Administration (SPA) process. Transco has been given by each IGT a weekly CSEP update which included supply point transfers which resulted in LMN change. This update has been the driver of the CSEP charges levied on shippers shipping gas to IGTs.

Figure 4.3 CSEP nomination process



[14]DNs create a Logical (or notional) Meter Number (LMN) for each Shipper serving supply points within a CSEP.

4.51 The flow diagram, figure 4.3, illustrates how the CSEP nomination process has worked. This sets out the roles of the relevant parties (shipper, IGT and Transco) and the flow of information between them. Transco's role has now been replaced by xoserve.

4.52 The last review of the charge took place in 2000. Following the review, the charge was reduced from £5 to £2 per supply point. Since then, a number of downward revisions have been made and the charge currently stands at £1.20 per supply point.

4.53 On the basis of concerns raised by respondents, Ofgem has considered whether:

- Issue 1: the charge is cost-reflective;
- Issue 2: the processes underlying the charge have been efficient, especially in light of the expected growth in the CSEP market; and
- Issues 3: there are alternatives to this charge and its underlying processes.

4.54 In doing so, Ofgem has been mindful of its duty, under the Gas Act, to ensure that licensed companies have the ability to finance their activities.

Ofgem's views

4.55 As regards issue 1, Ofgem considers that the charge has reflected the costs incurred by the DNs in managing CSEP information under the existing processes. The charge is also simple and transparent in establishing a direct relation to costs incurred by the DNs.

4.56 As outlined in chapter 3, Ofgem has considered removing the charge and including it in general transportation charges. This change could be associated with the introduction of new, more efficient, processes. However, the costs implied by such a change could be significant. In particular, the costs faced by shippers and IGTs for accessing an automated system could be substantially higher that the costs they currently incur.

4.57 Ofgem are aware that the existing processes have a limited capacity: as the number of IGT supply points grows, it will be necessary to switch to an automated system or face increased costs of maintaining the existing approach.

4.58 For these reasons, it is proposed that DNs should:

- review the costs of managing CSEP data and change the CSEP administration charge accordingly once every two years at a set date (e.g. 1 October);
- undertake (and consult on) a cost-benefit assessment of switching to an automated system in the event that:
  - the unit cost of processing IGT data under the existing manual process starts to increase; or
  - the existing processing is about to reach its capacity limit;
- introduce an automated system conditional on the outcome of the cost-benefit analysis.

Economic Test

4.59 The ET is a financial assessment tool that was introduced by Transco in 1998 with the purpose of ensuring that Transco meets its Gas Act obligations to "develop and maintain an efficient and economical pipeline system that meets reasonable demands for gas" (section 9(1)(a) of the Gas Act) and "to connect any premises to that system so far as it is economic to do so" (section 9(1)(b) of the Gas Act).

4.60 The ET is used to identify whether a new load could be considered 'uneconomic' and should therefore pay a contribution towards the reinforcement required for its connection. This should in turn prevent existing DN customers from subsidising the reinforcement costs of a new uneconomic load.

4.61 The ET compares the incremental cost of connecting a customer to the gas distribution network with the expected future stream of transportation income associated with that customer, using NPV calculations. The basic characteristics of the ET are:

- the NPV of expected annual income stream over the appraisal period is calculated assuming a discount rate of 7 per cent[15] (pre-tax real);
- the depreciation period is assumed to be 65 years, based on the accounting life of the assets at the time the ET was introduced;
- the net annual income stream is determined from transportation charges and incremental operating expenditure (OPEX) associated with the new load;
- both income and OPEX are assumed to be constant in real prices over the appraisal period, i.e. they do not take account of overall prices reducing under the RPI-X control or individual prices falling due to growth in volumes;
- the NPV of the annual income stream is the value of the reinforcement cost that Transco is willing to fund (allowable investment);
- the NPV is the sum of the annual income stream over the appraisal period and the residual (i.e. non-depreciated) asset value after the appraisal period;
- a 10 year appraisal period is applied to a typical load [16] and a 15 years appraisal to large loads;
- the costs of the reinforcement required to support the new load are compared to the allowable investment; and
- the new load is required to pay any positive difference between the costs of the reinforcement minus the allowable investment.

Issues

4.62 In its analysis, Ofgem has considered whether:

- Issue 1: the ET should be retained and why;
- Issue 2: the assumptions underlying the calculation of the ET reflect the purpose of the test;

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[15] 7 per cent was based on the allowed cost of capital at the time of the introduction of the ET.
[16] Transco was unable to define a typical load.

- Issue 3: the parameters of the test need updating; and
- Issues 4: the ET should be more transparent.

Ofgem's views

4.63 As regards issue 1, Ofgem considers that the ET should be retained since it provides some locational signals on the costs of connections in certain parts of the networks, which are not provided by UoS charges. While UoS charges reflect transportation costs associated with an average load within each end user category, they do not capture:

- the costs associated with loads exhibiting atypical profiles (e.g. testing facilities, which use large amounts of gas but only for a few days in one year);
- the costs associated with loads located in areas where it is significantly more expensive to transport gas; and
- the economic risk of large loads disconnecting from the network before the assets servicing them are fully depreciated (due, for instance, to closure of an industrial business).

4.64 The ET can identify these loads and reduce the risk of other consumers cross-subsidising the costs that they could impose onto the system by exhibiting atypical load profiles or by prematurely disconnecting from the distribution network.

4.65 However, the ET should be reviewed periodically in light of any development that could enable UoS charges to provide better locational signals. Further, the reform of the existing interruption arrangements may lead to a framework whereby longer term financial commitment to holding firm exit capacity rights may remove the need for the ET. This could happen as long term financial commitments could reduce, under certain circumstances, the risk of a new connection not paying for the capacity investment it has required.

4.66 As regards issue 2, we have concluded that the current assumptions about the length of the appraisal period are inconsistent with the purpose of the ET, which is to assess the economic risk associated with a new load. In this respect, we have identified two types of loads as defined in the IA:

- process loads for which there is positive economic risk; and
- non-process loads for which the economic risk is zero or minimal.

4.67 Ofgem considers that:

- process loads should have an appraisal period shorter than the life of the assets (e.g. 20 years) to reflect the positive economic risk of closure;
- non-process loads should have an appraisal period equivalent to the life of the assets (i.e. 45 years).

4.68 When compared to the current ET, these changes would both imply that it will be more likely for a new load to pass the ET.

4.69 However, Ofgem is aware that finding a robust definition of process and non-process loads might present some difficulties. Therefore, we would like to consult on the practicalities of distinguishing between these two types of loads. Ofgem seeks suggestions as to the most appropriate manner to define such loads for the purpose of calculating the ET.

4.70 As regards issue 3, Ofgem considers that some parameters of the ET need updating. In particular:

- the discount rate should be set equal to 6.25 per cent (which is the real pre-tax cost of capital allowed under the current price control) and revised on the basis of the prevailing allowed cost of capital at each price control review; and
- the depreciation period should be set equal to 45 year to reflect the most recent estimate of the average economic life of assets.[17]

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[17] *Review of Transco's Price Control from 2002. Final proposals*, Ofgem, September 2001.

4.71 When compared to the existing ET, the overall effect of these changes would be to increase slightly the likelihood of a load passing the test (or slightly reducing the contribution requested from the new load).

4.72 Ofgem has also considered respondents' concerns about the lack of transparency of the ET. The description of the ET that has been provided by Transco as part of its statement pursuant to standard licence condition 4B of its GT licence (4B statement) seems insufficient. Therefore, Ofgem proposes to require DNs to publish a full description of the ET (including a simple working example) as part of its 4B statement.

4.73 An example of the information that a DN would be required to publish is included in appendix 2. This description has been provided by Transco in February 2005. At present it does not include data on general additional costs for a new load. This additional information might be published at a later date depending on the outcome of the consultation. Ofgem would welcome views on whether the proposed format and content of appendix 2 would be helpful in addressing respondents' concerns about the lack of transparency in the ET.

4.74 Transco has indicated that the release of more detailed information used to calculate the ET (e.g. cost data) could lead to gaming by new connectees in declaring their expected gas demand. Ofgem seeks views from interested parties on these concerns about the potential for gaming.

Customer charge

4.75 About 30 per cent of the allowed distribution revenue is recovered through the general customer charge. This charge reflects the costs of providing service pipes and supply point emergency services. However, it is also scaled alongside other DN charges to reconcile actual revenue and maximum allowed revenue under the price control formula. Currently, the customer charge is levied on a commodity basis for domestic customers and on a capacity basis for the remaining customers.

Ofgem's views

4.76 Ofgem's views is that the customer charge:

- exhibits discontinuities that do not necessarily reflect the underlying costs; and
- should only be levied on a capacity basis because the underlying costs are unrelated to throughput.

4.77 For these reasons, Ofgem proposes to require DNs to review the customer charge to create a function that is only capacity based. This change should simplify the customer charge and enable it to reflect better its underlying costs. In light of the sell-off by Transco of four gas DNs, it is also timely to review the costs included in this charge on a DN basis and determine the charging function that best fits the latest cost information.

4.78 As indicated in the summary IA, a capacity-based customer charge for domestic customers would provide DNs with more predictable revenue and would make shippers and suppliers' costs more stable during the year.

4.79 Ofgem would consider the outcome of the review of the underlying costs carried out by DNs and the proposed new charging function in due course. At that time, any distributional impact that could result from the proposed change in the customer charge would be assessed to inform Ofgem's decision on the associated charging methodology change.

Surveys and audits

4.80 Some key data surveys which Transco has been using as an input to its charging functions were conducted a number of years ago and may therefore warrant a review. These include, for instance, the connection by pressure tier survey on which the level and structure of UoS charges are based. They also apply to data sources underlying the cost calculations for the ET and the CSEP administration charge.

4.81 In this respect, Ofgem has identified a number of data sources that should be updated. It is therefore proposed that DNs should:

- review the cost of growth figures used to derive the ET on a DN basis;

- review the connection by pressure survey, which is used to derive UoS on a DN basis, and adopting a larger sample of customers; and

- audit the ABC analysis, i.e. the model Transco uses to allocate costs to its different business activities and that feed into the charging functions.

4.82 Transco's ABC analysis has been transferred to new DNs. However, new DNs may decide to adopt their own cost allocation models. Ofgem intends to require DNs to audit any new models that might be adopted as an alternative to the ABC analysis.

Issues for consideration

4.83 Ofgem invites views on all aspects of its initial proposals and, more specifically, it would welcome views on the following issues:

- whether Transco's estimate that marginal cost charging would allow DNs to recover only 40 per cent of their costs is robust;

- which one of the proposed options would be more appropriate for the capacity/commodity split;

- what are the risks and consequences of all suppliers introducing a standing charge in the bills of final consumers under Ofgem's initial proposals for changing the capacity/commodity split;

- whether and how it would be possible to make a robust distinction between process and non-process loads under the ET;

- whether the publication of additional information on the ET in the format outlined in appendix 2 would be helpful; and

- whether such information on the ET would lead to gaming by potential new connectees.

5. Next steps

5.1 This section sets out a proposed timetable for the development of final proposals for reforms of the structure of gas distribution charges.

5.2 In light of the interactions between Ofgem's initial proposals for changing the capacity/commodity split and the development of new interruption arrangements, Ofgem considers that it would be desirable to align the timetable for the two projects. As a consequence, any changes in the level of charges and/or charging methodology associated with Ofgem's final proposals for the capacity/commodity split could be implemented on 1 October 2007. This would be consistent with standard condition D11 (Charging obligation) of DN licences which requires each DN to use reasonable endeavours to change charges only once a year, on 1 October, and with the expected implementation timetable for interruptions reform.

5.3 However, Ofgem does not consider it necessary to delay the implementation of proposals affecting other areas of the structure of charges, including the ET, the CSEP administration charge, the customer charge and any requirement for new surveys and audits.

5.4 Therefore, the proposed timetable for the review of the structure of gas distribution charges can be summarised as follow:

- 25 July 2005: publication of initial proposals;
- 16 September 2005: deadline for receipt of responses to the initial proposals document;
- December 2005: Ofgem publishes final proposals.
- 1 April 2006: implementation of final proposals in all areas of the structure of gas distribution charges except the capacity/commodity split;
- final proposals for the capacity/commodity split are implemented in parallel with interruptions reforms.

Appendix 1 IA on the proposed changes to the capacity/commodity split

Issues

1.1 The objective of this IA is to assess the potential costs and benefits of changing the split between revenue recovered through capacity charges and commodity charges in gas distribution.

1.2 DN UoS charges are split between a capacity and a commodity element. Broadly, capacity charges are designed to reflect a load's peak demand, while commodity charges depend on annual throughput. The appropriate balance between these should ideally reflect the structure of transportation costs so that consumers have incentives to use the system in an efficient manner.

1.3 As indicated earlier, the assumption that 50 per cent of costs relate to capacity and 50 per cent of costs relate to commodity has been criticised for not being cost-reflective, with most of Transco's costs relating to the provision of peak capacity and not varying with throughput.

1.4 Cost-reflective charges are particularly important because Transco predicts DN peak day demand and annual throughput to rise by 13 and 16 per cent respectively over the period 2002/3 to 2012/3. This is likely to require substantial investment in system capacity. Therefore, improvements in the cost-reflectivity of charges can have a significant impact on the efficient use of transportation assets and help reduce future investment costs. These savings would eventually be reflected in lower UoS charges to all consumers.

Options

1.5 Ofgem has considered three possible options:

- Option 1: status quo;
- Option 2: moving to a 70:30 split alongside interruptions reform; and
- Option 3: moving to a 99:1 split alongside interruptions reform.

1.6 The choice of a capacity/commodity split impacts on DNs, IGTs, gas shippers, suppliers and final consumers.

Benefits

More efficient use of the transportation system

1.7 The major benefit from increasing the capacity weighting under option 2 or 3 would follow from UoS charges that better reflect actual transportation costs. More cost-reflective charges should encourage a more efficient use of the system and, as a consequence, lower transportation costs and charges.

1.8 These benefits would depend on whether customers are daily metered (DM) or non-daily metered (NDM). [18]

1.9 For DM customers the capacity charge is based on the maximum peak day flow that is registered by a shipper with Transco to reflect the requirements of its DM loads. If a DM customer changes its requirements, the shipper can re-nominate a higher or lower peak day demand with Transco. Capacity charges are recalculated immediately after re-nomination. Actual peak-day demand is measured and verified. Therefore, capacity charges sends out a strong incentive to reduce peak day demand and redistribute demand to non-peak days.

1.10 By contrast, for NDM loads, peak day demand (SOQ) cannot be measured and verified and must be estimated. This estimate is based on the customer's annual consumption (AQ) and the applicable load factor. [19] The estimated SOQ is used to calculate capacity charges. Therefore, if the NDM customer reduces its peak day demand, this will not be reflected in lower capacity charges, unless it also lowers its AQ. The capacity charge therefore sends out an incentive to reduce AQ, rather than peak day demand[20].

1.11 Briefly:

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[18] For both DM and NDM customers, the commodity charge is calculated as: (annual demand)*(commodity charge unit rate). The capacity charge is calculated as: 365*(peak day demand)*(capacity charge unit rate).
[19] For NDM customers, SOQ = (AQ*100)/(365*LoadFactor).
[20] This works with a one year lag, as the SOQ is calculated on the basis of last year's AQ for each customer. The estimated SOQ is thus not adjusted in the current period, even if the AQ turns out lower than last year. However, in the subsequent year the lower AQ is used to calculate the SOQ and is therefore reflected in a lower capacity charge.

- for DM customers (whose peak day demand is measured) the capacity charge sends out a strong incentive to reduce peak day demand and redistribute demand to non-peak days; and

- for NDM customers (whose peak day demand is estimated on the basis of AQ) the capacity charge sends out an incentive to reduce annual consumption, rather than peak day demand.

1.12 The main benefits from increasing the capacity weighting will therefore arise from DM customers being encouraged to move their consumption from peak to non-peak days. This, in turn, should be reflected in savings on network investment.

1.13 Currently, DM customers account for about 11 per cent of the 1 in 20 winter peak day demand. Some of the larger NDM customers could also be encouraged to become daily metered to the extent that, under a higher split, any reduction in their peak day consumption would be rewarded through lower transportation charges. This would increase the benefits arising from options 2 and 3.

1.14 Innovation in the metering equipment in GB could also contribute to enhancing the benefits we would expect from changing the existing capacity/commodity split.

Stability of revenue and charges

1.15 Compared to commodity charges, capacity charges are more predictable to both Transco and shippers as they do not vary with annual throughput, which is largely determined by weather conditions.

1.16 In particular, capacity charges are based on the SOQ of a supply point. For DM customers the SOQ is the registered supply point capacity, which changes only if a shipper re-nominates a site to reflect new peak load requirements. For NDM customers, the SOQ depends on their AQs, which are fixed annually as part of the AQ review.

1.17 By increasing the proportion of allowed revenue to be recovered through capacity charges, DNs should therefore receive more stable income flows. This would be reflected in more predictable and less variable transportation charges.

Costs of increasing the capacity weighting

1.18 Options 2 and 3 should require low implementation costs since this change can be incorporated through the existing charging models with no major impact on billing or IT systems. Further, this change would be introduced alongside interruptions reform, thus benefiting from the cost synergies (e.g. in terms of IT and billing system changes) of modifying charging arrangements for two associated projects at the same time.

1.19 The most important adverse impacts that any increase in the capacity/commodity split could have are:

- distributional effects across customers of different sizes, i.e. certain customers could face higher gas bills; and
- environmental effects, i.e. reduced incentive to save energy as the capacity component of the bill increases.

Distributional impact

1.20 In the short term, under options 2 and 3, shippers would see increases in transportation charges to some customer groups and decreases in charges to other customers. This impact may or may not be fully reflected in the bills of final consumers.

1.21 Ofgem has considered the impact of the proposed changes to the capacity/commodity split both under the existing arrangements and under the assumption of a new interruption regime. We have also considered both the impact on transportation charges to shippers and the impact on the bills of final consumers, assuming that changes to transportation charges to shippers will be fully passed through to consumers. For simplicity, we have also assumed that there would be no change in the existing pricing structure faced by final consumers (e.g. the potential introduction of standing charges in the bills of domestic and I&C customers has not been assessed).

1.22 For the purpose of this IA, it has also been assumed that under the new interruption arrangements all users will hold firm exit capacity rights and pay capacity charges. Any interruptible services will be contracted separately between users and the DNs.

The payments under these interruptible contracts have not been included in the IA, since proposals for the new interruption regime have yet to be brought forward.

1.23 Table 1.1 summarises the results of our analysis. The table outlines the impact of option 2 and 3 under interruptions reform. It also includes for illustrative purposes the potential impact of increasing the capacity/commodity split in the absence of interruptions reform. However, increasing the proportion of capacity-related charges without interruptions reform has not been considered as a policy option at this stage, since it would tend to exacerbate any discrepancy between the value of interruptions to DNs and the discount afforded to interruptible customers.

1.24 The table shows that the distributional impact of an increased capacity weighting is sensitive to whether interruptions reform will be introduced. Interruptions reform is likely to reduce any increases in bills that options 2 and 3 may bring to domestic customers (e.g. under option 3 changes to charges would differ between a 0.64 per cent increase without interruptions reform to a 0.07 per cent fall with interruptions reform). They would also reduce the benefits to larger customers of options 2 and 3 by containing the reduction in UoS charges implied by either option.

1.25 Table 1.1 shows that the impact of option 2 and 3 on domestic consumers' bills is less than 1 per cent. The impact on larger users is also modest, with no increase in final bills of more than 2 per cent.

1.26 The underlying change in distribution charges to gas shippers is greater, with charges for some groups of consumer loads moving by 5 to 10 per cent. It is important to highlight that the largest increases refer to shippers with interruptible customers. These increases mainly result from assuming that, under interruptions reform, interruptible shippers will stop receiving a discount on transportation charges. These increases should therefore be offset by payments from DNs to interruptible shippers for the provisions of interruptible services under the new interruption arrangements.

1.27 In general, large industrial customers would tend to benefit from an increased capacity weighting through lower transportation charges. However, the benefit to interruptible industrial customers will depend on their ability to contract for interruptible services under any revised interruption arrangements.

Table 1.1 - Possible impact of options 2 and 3 on distribution charges and final consumer bill

		Impact on DN charges to shippers under interruptions reform (%)		Impact on consumers' annual gas bill under interruptions reform (%)		Impact on consumers' annual gas bill without interruptions reform (%)	
End User Category	**Average annual bill (£)**	**Option 2 70-30**	**Option 3 99-1**	**Option 2 70-30**	**Option 3 99-1**	**Option 2 70-30**	**Option 3 99-1**
0 - 73.2	338	-0.20	-0.43	-0.03	-0.07	0.13	0.64
73.2-293	1,524	2.13	5.13	0.44	1.07	0.65	1.29
293 – 732	5,304	1.09	2.60	0.23	0.55	0.44	0.47
732 - 2,196	11,921	2.58	6.21	0.54	1.31	0.77	1.22
2,196 - 5,860	32,244	0.71	1.76	0.13	0.31	0.30	0.25
5,860 - 14,650	65,957	-1.28	-2.91	-0.21	-0.48	-0.03	0.05
14,650 - 29,300	163,681	-2.46	-5.88	-0.34	-0.80	-0.18	-1.03
29,300 - 58,600	325,909	-3.11	-7.70	-0.37	-0.91	-0.25	-1.84
> 58,600	1,747,375	-5.26	-12.66	-0.46	-1.11	-0.36	-0.82
Existing interruptible	602,342	5.10	12.58	0.83	2.04	-2.58	-6.31

1.28 UoS distribution charges account for a small proportion of the total gas bill, i.e. up to 24 per cent for a small user and less than 10 percent for a DM user. The largest proportion of final bills is represented by the cost of gas (about 45 per cent for small users and up to 90 per cent for DM costumers). This explains the difference between the impact on transportation charges to shippers and to final consumers.

1.29 Furthermore, increases in UoS charges may not be fully passed on to consumers. This could result from the competition between relevant shippers and suppliers. It could also result from a commercial decision by shippers to absorb distributional changes within large portfolios of consumers.

Environmental Impact

1.30 Option 2 and 3 will impact on the incentive to save energy, thus affecting greenhouse gas emissions. This impact would differ between NDM and DM customers. In particular:

- since capacity charges for NDM customers are as responsive as the commodity charge to reductions in annual consumption, a higher capacity/commodity split would not adversely affect the incentive to reduce consumption; and

- since capacity charges for DM customers depend on peak demand and do not vary with annual consumption, an increased proportion of capacity-related UoS charges would be likely to reduce incentives to lower consumption.

1.31 Nevertheless, given that UoS charges represent a small proportion of DM customers' bills, the overall environmental effect should not be significant. Further, the most important incentive to save energy would still be provided by the cost of gas rather than distribution charges.

1.32 Some environmental benefits would arise as a higher capacity/commodity split would encourage more efficient investment in transportation assets: savings in investment could be associated with avoided construction work which, in turn, would help prevent any adverse impact that such work may cause to the environment.

Risks and Unintended Consequences

1.33 Option 2 and 3 would carry the risk of gas suppliers introducing a standing charge in the bills of domestic and small I&C customers. Most of these customers are currently billed on a throughput basis. The introduction of a standing charge may cause an increase in the bills of the smaller users within the domestic consumer group.

1.34 The introduction of a standing charge may also increase the impact on the environment by weakening the incentive of NDM customers to save energy. Ofgem is seeking views as to the risks and consequences of suppliers introducing a standing charge in the bills of final domestic and I&C consumers under its initial proposals. These views will inform Ofgem's final assessment of the options for changing the capacity/commodity split.

1.35 The distributional impact of the options for reforms of the capacity/commodity split could also be affected by the design of the revised interruption regime. As the form of the new arrangements is not yet known, Ofgem's initial proposals may require a reassessment as the new interruption regime is still being developed.

1.36 For this reason, Ofgem has decided to consider any change to the existing capacity/commodity split in coordination with the development of interruptions reform. These are now expected to be finalised by 1 April 2007 in time for implementing any associated changes to distribution charges and charging methodology by 1 October 2007. It is possible that the IA on any final proposals to change the capacity/commodity split will need to be revisited on the basis of the outcome of interruptions reform.

1.37 A further risk is related to the fact that capacity charges relate to peak day demand which is complex to estimate for NDM customers. For this purpose, the DNs use estimates of the SOQs based on load factors and annual quantities for every NDM customer. A higher capacity split may exacerbate any inaccuracies implicit in these estimations, since the SOQ would play a much larger role in calculating UoS charges.

1.38 Finally, the importance of accurate meter reads would increase under options 2 and 3, thus these options may send out stronger incentives to improve metering equipment and produce more accurate meter readings.

Other Impacts

1.39 No detrimental impact on security of supply is anticipated from any of the options. There is the possibility of a slight improvement in this respect under option 2 and 3 as peak capacity could be freed up in the shorter term.

1.40 No impact on health and safety or competition between shippers/suppliers is anticipated.

Conclusion

1.41 In light of the limited distributional and environmental effects of introducing a higher capacity weighting alongside interruptions reform, Ofgem would support an increase in the proportion of capacity-related charges. However, Ofgem is seeking views on the issues that have been highlighted as part of its initial proposals and on the most appropriate option for changing the capacity/commodity split.

Appendix 2 Description of the Economic test

Introduction

2.1 The ET is a financial assessment tool that is designed to ensure that Transco meets its Gas Act obligations to develop and maintain an efficient and economical pipeline system for the conveyance of gas (Gas Act, section 9(1)(a)) and to comply with any reasonable request to connect to its system any premises or any pipeline system operated by an authorised transporter (Gas Act, section 9(1)(b)).

2.2 The ET is used to identify new requests for capacity where the level of investment would be considered 'uneconomic', and so avoids existing DN customers subsidising the new firm load.

2.3 It compares the system reinforcement and additional operating costs of accommodating the new firm load with the transportation income that would be generated in respect of the load. When the additional cost is greater than the anticipated transportation income over the appraisal period, the customer is requested to pay a contribution towards the cost of the reinforcement to prevent the excess level of cost being subsidised by other customers.

2.4 Contributions are made by means of an up-front payment, enabling the standard transportation charges to be applied.

Economic Test Methodology

2.5 The ET methodology is only applied when there is a requirement to immediately reinforce the existing pipeline system in respect of a new load. The costs associated with a new load are split into two types: specific reinforcement costs and the assessed marginal cost of growth in respect of the load.

2.6 Specific reinforcement costs are the engineering costs of providing capacity for the new load. The treatment of specific reinforcement costs depends on whether they are upstream or downstream of the Connection Charging Point (CCP), which is the point on the transportation system that is deemed to have enough capacity to supply the new load disregarding existing loads. Specific reinforcement costs downstream of the CCP are always fully chargeable to the connectee and so are not included in the Economic Test, whereas those upstream of the CCP are included within the Economic Test. Specific reinforcement costs are assessed based on the particular work that will be required and are location, load and time specific.

2.7 The marginal costs of growth are the estimated costs that will be incurred throughout the system as a result of the new load. There are three components to these costs, which are based on national average values:

- Additional marginal operating costs
  These have been derived from Transco's ABC accounts.
- Costs of developing additional capacity within the system
  These costs have been calculated on a long run marginal cost basis distinguishing between the costs of developing capacity within the Local Transmission System (LTS) and below 7 barg. systems. The ET excludes below 7 barg. costs from consideration when a proposed load is to be connected to the LTS.
- Additional Formula Rates (Transco's business rates)
  These annual operating costs are calculated to be a fixed percentage of the capital expenditure. This reflects the fact that the amount of business rates that Transco has to pay is linked to the Regulatory Value of the business.

2.8 Capacity development and marginal operating costs are determined using the factors shown in Table 2.1. These factors are chosen as being the key cost drivers. For each factor the specific value for the new load is multiplied by a set unit cost for that factor to determine the typical one-off and ongoing operating costs and capital costs. The unit cost drivers for each factor are determined from a study of the cost of growth for various types of load.

2.9 The cost factors used are compatible with the 'Minimum Information Requirements' that apply in respect of site works requests, whilst at the same time ensuring the ET is able to take proper account of the various factors which affect the cost of connection and reinforcement.

2.10 The transportation income relating to the new load is determined using the transportation charges a shipper would pay to transport gas to a Supply Point(s) or CSEP, as appropriate.

Table 2.1 Factors used to Assess the General Additional Costs for a New Load

6. Description	7. Value for Load	8. Unit
Throughput		
Marginal cost of transporting additional gas volumes i.e. gas odourisation and LDZ Gas Shrinkage	AQ (Annual Quantity)	GWh/yr
NTS shrinkage	AQ	GWh/yr
Capacity (General Reinforcement)		
Cost of developing additional below 7 barg general reinforcement assets	SHQ (System Hourly Quantity)	MWh/hr
Cost of developing additional LTS general reinforcement assets	SOQ (System Offtake Quantity)	MWh/day
Maintenance of Assets		
Marginal cost of operating additional below 7 barg. assets (reinforcement and connection assets)	SHQ	MWh/hr
Marginal cost of operating additional LTS assets (reinforcement and connection assets)	SOQ	MWh/day
Other – related to the number of supply points		
Administrative cost of progressing a connection request	1 (for 1 connectn enquiry)	Number
Marginal cost of providing services to additional supply points irrespective of supply point type e.g. provision of emergency service	No. of supply points	Number
Marginal cost of administrating an additional CSEP	No. of CSEPs	Number
Marginal cost of administrating an additional domestic supply point	No. of dom supply points	Number
Marginal cost of administrating an additional I&C supply point	No. of I&C supply points	Number
Marginal Transco costs associated with daily meter reads including allocation of flows to shippers etc.	No. of DM supply points	Number

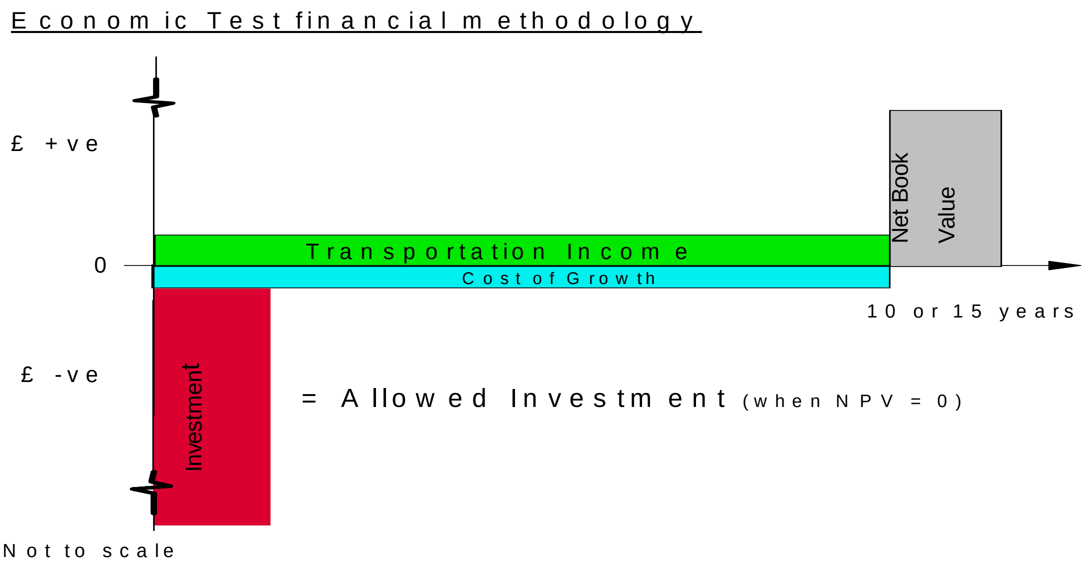
Comparison of Costs and Income

2.11 Since the costs involved include both one-off capital costs and ongoing costs the comparison is done using discounted cash flow (DCF) analysis as demonstrated in Diagram 1. The cost types, one-off OPEX, ongoing OPEX and CAPEX, and income are kept separate throughout the analysis in order to ensure the proper treatment of each with respect to the time value of money and tax.

2.12 The result of the analysis is the determination of a level of investment that would make the NPV zero. This determined level can be either positive or negative. If the determined level is positive then the new connection is economic without a contribution to the reinforcement costs. If the determined level is negative then this constitutes the level of contribution towards the reinforcement costs that is required from the connectee in order to make the new connection economic.

2.13 Note that within the ET itself, overheads are not applied in respect of specific reinforcement costs. However, if a contribution is payable under the ET, overheads are applied to the contribution at published rates. This approach is aligned to that applied in respect of other charges that Transco makes e.g. the charges applied to rechargeable diversions where there is betterment.

Diagram 1



2.14 Key points underlying the DCF calculation are:

- Both income and marginal OPEX costs (referred to as 'Costs of Growth' in the above diagram) are assumed to be constant in real prices over the appraisal period, i.e. they do not take account of overall prices reducing under the RPI-X control or individual prices falling due to growth in volumes;

- There is a 15 year appraisal period for loads greater than 50 million therms per annum (large loads) and an appraisal period of 10 years for non-large loads;

- It is assumed that the depreciated allowed investment costs ('Net Book Value' in diagram 1) will be recovered from all customers at the end of the appraisal period;

- A depreciation period of 65 years is applied. This means that for a 10-year appraisal period, it is assumed that around 15 per cent of the initial allowed investment is recovered during the appraisal period;

- The ET calculates the allowed investment so that the relevant, pre-tax cash flows discounted at 7 per cent p.a. (pre-tax real, based on Transco's rate of return in the 1997-2002 price control) generate an NPV of zero; and

- Costs and transportation income include both Distribution and National Transmission elements.

2.15 In order to compare the ongoing costs and transportation income with the one-off costs, a capitalisation factor is applied to the ongoing costs and transportation income to convert them to an equivalent one-off cost or revenue. The capitalisation factor is therefore a shorthand calculation tool. It is determined such that the NPV of net revenues (transportation revenue minus ongoing costs) over a 10 year period (or 15 years for large loads), is equal to the depreciation incurred over the same period for a one-off capital cost, using a total depreciation lifespan of 65 years. The capitalisation factor is a function of only the discount rate and the length of the appraisal and depreciation periods and therefore is a flexible tool, as shown by the examples below. With current parameters, it is 12.33 for small loads and 12.63 for large loads.

Examples

2.16 The following examples show how the ET is applied to different types of connection requests, namely a housing estate, a connected system (which is also a housing estate) and an industrial or commercial connection. While the connection details are fictional, the other numbers shown in these examples have been produced by the current ET.

Example 1 – Housing Estate

2.17 Connection details:

AQ: 2,800,000 kWh

SOQ: 22,560 kWh

SHQ: 1,800 kWh

No of Premises: 100 domestic properties

	Amount	**Units**
Load Income	12,640	£ p.a.
Marginal Opex	(650)	£ p.a.
Net annual income	11,990	£ p.a.
Income capitalisation factor	12.33	Number
Capitalised net income	147,778	£
One-Off Opex	(160)	£
General Reinforcement	(16,976)	£
Total One-off costs	(17,136)	£
Allowable Investment	130,642	£

Example 2 – Connected System operated by another GT

2.18 Connection details

AQ: 2,800,000 kWh

SOQ: 22,560 kWh

SHQ: 1,800 kWh

No of Premises: 100 domestic properties

CSEP example	**Amount**	**Units**
Load Income	6,350	£ p.a.
Marginal Opex	(850)	£ p.a.
Net annual income	5,500	£ p.a.
Income capitalisation factor	12.33	Number
Capitalised net income	67,788	£
One-Off Opex	(320)	£
General Reinforcement	(18,464)	£
Total One-off costs	(18,784)	£
Allowable Investment	49,004	£

Example 3 – Industrial or Commercial connection

2.19 Connection details

AQ: 800,000 kWh

SOQ: 5,480 kWh

SHQ: 450 kWh

No of Premises: 1 Non-Daily metered industrial premises

I&C example	Amount	Units
Load Income	2,390	£ p.a.
Marginal Opex	(160)	£ p.a.
Net annual income	2,230	£ p.a.
Income capitalisation factor	12.33	Number
Capitalised net income	27,485	£
One-Off Opex	(40)	£
General Reinforcement	(4,134)	£
Total One-off costs	(4,174)	£
Allowable Investment	23,311	£