# GAS TCMF PROGRESS REPORT

## Development of Alternative Methodologies for NTS Entry and Exit Capacity Charges

**Gas TCMF PR01**

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## Executive Summary

In January 2006 National Grid NTS instigated a review of the gas transmission transportation charging arrangements with the industry via the launch of the gas Transmission Charging Methodology Forum ("TCMF"). This was to ensure successful implementation of changes resulting from the Transmission Price Control Review (TPCR) (including exit reform) and to support adherence to National Grid NTS's Licence objective to keep the Charging Methodology under review at all times for the purposes of ensuring that it achieves the relevant objectives.

One of the key areas of the review is the methodology by which entry and exit capacity charges are determined, and the information made available to the industry to understand and replicate the charge setting process. This was instigated by Ofgem's open letter of 2nd December 2005 which proposed that, as part of the TPCR, NTS Entry Capacity Reserve Prices are decoupled from Entry UCAs and set on a dynamic basis from 1 April 2007. This would require a change to the National Grid Gas Transmission Transportation Charging Methodology (the "Charging Methodology"). Ofgem suggested that National Grid NTS therefore develop a charging model which is made available to the industry such that users can repeat the charge setting process. A single model for determination of all Entry and Exit capacity charges was stated to be desirable.

Rebalancing of exit capacity tariffs to reflect changes in supply/demand and network configuration has not been undertaken since 2001. This was due to the desire to delay rebalancing on the expectation that NTS exit reform would be implemented in 2002. Subsequent delays to reform have lead to a significant divergence in current tariffs and underlying LRMCs in certain locations. It would seem appropriate that exit prices are updated based on the same model as developed for entry prices from 1 April 2007 to allow simultaneous entry-exit charge setting.

In conjunction with the industry through the Gas TCMF, National Grid NTS has developed a range of options for determination of Long Run Marginal Costs (LRMCs) for capacity charging. We have developed and run six modelling options, detailed below, to allow comparison and better understanding of the options.

<table>
<tr><th>Model</th><th colspan="3">Transport Model</th><th colspan="2">Tariff Model</th></tr>
<tr><td>Model A</td><td>Transcost</td><td rowspan="2">Spare Capacity, No Backhaul</td><td rowspan="4">2.834 mscmd increment</td><td>Solver with non-negative constraint</td><td>Exit prices scaled to allowed revenue</td></tr>
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This report, and supporting analysis, has been placed on National Grid NTS's industry information website. This report has been made available to fully document the development of options within the Gas TCMF and in support of the forthcoming consultations on the Capacity Charging Methodology.

## 1. Introduction

1.1. In December 2005, Ofgem issued an open letter which proposed that, as part of the Transmission Price Control Review (TPCR), NTS Entry Capacity reserve prices are decoupled from Entry UCAs and set on a dynamic basis from 1 April 2007. Ofgem suggested that National Grid NTS therefore develops a charging model which is made available to the industry such that users can repeat the charge setting process. A single model for determination of all Entry and Exit capacity charges was stated to be desirable.

1.2. In addition, rebalancing of exit capacity tariffs to reflect changes in supply/demand and network configuration has not been undertaken since 2001. This was due to the desire to delay rebalancing on the expectation that NTS exit reform would be implemented in 2002. Subsequent delays to reform have lead to a significant divergence in current tariffs and underlying LRMCs in certain locations.

1.3. A review of the current NTS entry and exit capacity charging arrangements has therefore been undertaken in conjunction with the industry through the gas Transmission Charging Methodology Forum ("TCMF") and alternative models developed. This purpose of this document is to summarise progress in respect of the review and analysis that has been undertaken on alternative models in advance of any consultations which National Grid NTS may bring forward to seek to amend the current arrangements in light of the review.

1.4. The documents sets outs:

- An overview of prevailing capacity charging arrangements (Chapters 2 and 3);
- A review of the current arrangements – Chapter 4;
- An overview of identified issues – Chapter 5;
- A summary of the analysis we have undertaken;
- Links to the results published on the National Grid NTS Gas TCMF website;
- An assessment of the performance of each model.

## 2. NTS Exit Capacity Charging Methodology

2.1. The methodology for calculating NTS Exit Capacity Charges is contained within "The Statement of the Gas Transmission Transportation Charging Methodology". This section provides an overview of the key elements of the current methodology.

2.2. NTS Capacity Charges are determined based on application of the following two models: -

- The "Transport Model" – this estimates the long run marginal cost (LRMC) of reinforcing the system to provide a sustained notional increase in demand between each entry and exit point. An engineering-based model known as Transcost is currently used to determine such LRMCs.

- The “Tariff Model” - this converts the LRMCs from the Transport model into tariffs. This is currently based on application of an optimisation procedure using Microsoft Excel Solver.

**Transport Model**

2.3. Transcost is the model used by National Grid NTS to estimate LRMCs for the purposes of capacity charge determination. The key steps by which Transcost is used to determine LRMCs are summarised below:

<u>Inputs</u>

2.4. To determine LRMCs, Transcost firstly requires the following inputs;

<u>Network Model</u>

- Pipe lengths and diameters,
- Entry and Exit Points (max & min pressures)
- Compressors (power, max & min inlet and outlet pressures)
- Regulators (flow settings, max & min inlet and outlet pressures)

<u>Supply and demand scenario</u>

- Forecast demand for each offtake
- Forecast supply flows and CVs for each entry point

<u>Economic parameters</u>

- Pipe and Compressor investment costs
- Discount factor
- Increment size

<u>Incremental Investment Costs</u>

2.5. Based on the above input assumptions, Transcost first constructs a base network which is just sufficient to support the supply / demand balance for year 1 of the analysis. For each subsequent year of the analysis Transcost will reinforce the modelled network from the previous year by identifying the least cost set of additional assets such that it is just sufficient to support the peak day firm only supply / demand match for that year. Transcost is based on the same physical flow / pressure relationship as the Falcon asset planning model used by National Grid NTS and identifies sufficient additional pipe and compression to maintain system pressures given the supply/demand scenario and incremental flows.

2.6. The regulator flow settings of the network model must be optimised by the user for each of the ten years to ensure that the identified reinforcements are just sufficient. If this task is not carried out appropriately then the costs in later years will be understated due to the excess spare capacity generated.

2.7. There are therefore ten separate but related networks to be used in the analysis. Using an increment size of 2.834 mscmd (100 mscfd), Transcost calculates the least cost additional investment required in new pipelines and / or compressors to support a sustained notional increase in flow along each route. The more constrained a route is in terms of available capacity, the higher will be the level of investment necessary, however, spare capacity may lead to low or zero investment along a route. This analysis is carried out using the base case networks described above for each of the 10 years to result in entry-exit routes costs for each of these 10 years.

Aggregation into Exit Zones

2.8. Flow weighted averages of the route costs to NTS/LDZ Exit Points are then calculated to generate route costs for thirty-two LDZ Exit Zones. The route costs to directly connected NTS demands remain at a nodal level.

Project Management, Operating Costs and Anuitisation

2.9. Project costs (15%) and operating costs (1.5%) are then added and the route costs are then annuitised.

LRMC Matrix of Entry-Exit Route Costs

2.10. Using discounting, the cost results for the ten years are aggregated and divided by the sum of the discounted volumes to obtain a single matrix of the LRMCs for every entry-exit route combination.

**Tariff Model**

2.11. It is not practical to apply the full matrix of LRMCs for all the routes on the system directly as charges. Instead, an LRMC reflective charge is determined for each entry point and each exit point such that, when these are combined for any particular route, they replicate as closely as possible the calculated LRMC for that route.

2.12. An optimisation procedure (Microsoft Excel Solver) is used to determine the LRMC reflective entry and exit charge from the matrix of route costs. For each combination of entry point and exit point, the solver uses the route cost figure as the dependent variable in an equation that represents the sum of one entry charge and one exit charge.

2.13. The optimisation procedure calculates the best fit between the route costs and the estimated entry and exit cost pairs by minimising the sum of the squared error terms for all entry and exit combinations. To achieve a unique solution to the procedure, it is necessary to constrain at least one parameter. To achieve this, the optimisation is currently constrained such that there is a minimum permitted charge of 0.0001p/kWh/day. This process results in “unscaled” charges for each exit zone and for each entry point.

2.14. The unscaled NTS Exit Capacity Charges are scaled by a multiplicative factor to generate administered NTS Exit Capacity Charges aimed at recovering 50% of National Grid NTS’s allowable TO revenue (with the remaining 50% to be recovered from charges levied on entry users).

2.15. In addition, the existing methodology constrains any re-balancing of exit prices with the latest LRMC calculations. The re-balancing rules compare the latest prices with charges over the last two years, and smooth any changes, with movement limited by a given percentage:-

- If both the previous and latest scaled LRMC reflective charges are higher than the existing scaled charge, then the existing charge will be increased to a level no greater than the lower of the two scaled LRMC reflective charges;

- If both the previous and latest scaled LRMC reflective charges are lower than the existing scaled charge, then the charge will be reduced to a level no lower than the higher of the two scaled LRMC reflective charges;

- Scaled charges that are already between the previous and latest scaled LRMC reflective charges will remain unchanged except for scaling; and

- Charges are not permitted to move in either direction by more than a given percentage of their existing scaled value (+/- 30% in 2001).

2.16. The scaling and re-balancing operations are performed in this order to ensure that Users are not exposed to significant changes in charges due to changes in allowed revenue or to changes in the underlying LRMCs.

## 3. NTS Entry Capacity Charging Methodology

3.1. The methodology for calculating NTS Entry Capacity Baseline Reserve Prices are contained within the NTS Transportation Charging Methodology Statement whereas the methodology for calculating NTS Incremental Entry Capacity price schedules is contained within the Incremental Entry Capacity Release (IECR) Methodology Statement.

**Entry Capacity Baseline Reserve Prices**

3.2. National Grid NTS offers NTS Entry Capacity for sale in a series of long, medium and short term auctions. Currently, National Grid NTS has a Licence obligation to make available capacity up to a predefined baseline level at each ASEP by the end of the gas day.

3.3. National Grid NTS has an obligation to use all reasonable endeavours to ensure that obligated Entry Capacity is offered for sale in at least one clearing auction *providing that this does not contravene wider Licence obligations*. These include the requirement to ensure that reserve prices are set in a way that promotes competition, promotes efficient use of the system and avoids undue preference in the provision of transportation services.

3.4. National Grid NTS considers that auctions for NTS Entry Capacity should attract reserve prices for the following reasons:

- To ensure collection of formula revenue from Users of NTS Entry Capacity, thereby reducing the need to collect revenue from other Users by increasing other transportation charges

- To promote competition and allow capacity to be obtained in a non-discriminatory way by limiting the effects of market power

- To generate locational pricing signals for entry to the NTS, thereby allowing capacity to be allocated efficiently.

3.5. Since the introduction of long term Entry Capacity auctions, the baseline reserve price has been determined from the Licence defined Unit Cost Allowance (UCA) for each ASEP.

3.6. This principle applies to all long and medium term auctions (LTSEC, MSEC, and RMSEC) and was introduced to generate consistency between long and medium term capacity pricing for the first LTSEC auctions in January 2003 and MSEC auctions from 1 April 2003. It was anticipated that this approach would remove any potential market distortions that may arise by pricing long term and medium term capacity in different ways.

3.7. The exception to this is for new ASEPs for which there is no obligated baseline level for capacity set in National Grid's Gas Transporter Licence in respect of the NTS. Such ASEPs attract a zero baseline price until a permanent obligated capacity level is determined through the auctions.

**Entry Capacity Baseline Reserve Price Discounts for Daily Entry Capacity Auctions**

3.8. Baseline reserve prices for daily auctions currently attract a discount from the LTSEC/MSEC reserve prices that are set from entry UCAs. The discounts are 33.3% and 100% for Daily NTS Entry Capacity (DSEC) and Daily interruptible NTS Entry Capacity (DISEC) respectively.

3.9. The 33.3% discount for DSEC has evolved from the way previous applications of the charging methodology has linked Monthly NTS Entry Capacity (MSEC) and DSEC prices, and more recently MSEC and UCA prices.

3.10. From 1 October 1999 to 31 March 2003, MSEC reserve prices were set by discounting the entry charges calculated from the LRMC methodology by 25%. The LRMC based charges included a scaling factor to recover 50% formula revenue from the sale of Entry Capacity – effectively MSEC auction revenues were designed to recover 75% of target revenues from Entry Capacity.

3.11. From 1 October 2000, DSEC reserve prices were set on the same basis as MSEC reserve prices, except that a 50% discount was applied rather than a 25% discount. Prior to this, DSEC reserve prices had been linked to the MSEC clearing price to encourage participants to book monthly capacity. This link was removed as the Industry felt that it contributed to high MSEC auction prices.

3.12. Thus, the ratio of the discounts for MSEC and DSEC (75:50) initiated the practice of determining the DSEC reserve price as two thirds of the MSEC reserve price i.e. a discount of 33.3% on the MSEC reserve price.

3.13. The 100% discount for interruptible prices (i.e. a zero price) enables additional capacity to be released, where available, in the short term and recognises the right of the system operator to curtail interruptible Entry Capacity on the Gas Day. It should be noted that NTS Interruptible Entry Capacity is made available only where there is an expectation that there will be unutilised firm NTS Entry Capacity on a gas day.

**Unit Cost Allowances for Entry Capacity Investment**

3.14. Unit Cost Allowances (UCAs) are determined by Ofgem for use in the NTS Entry Capacity Investment Incentive scheme. The methodology that Ofgem applies to calculate UCAs is described in detail in Ofgem's May 2005 consultation document "Gas transmission – new NTS ASEPs[1], reserve prices in auctions and unit cost allowances (UCAs)".

3.15. Entry UCAs are currently used to determine:

- Revenue allowances for incremental capacity under the SO Incentive structure
- Baseline reserve prices for NTS Entry Capacity
- The release of permanent obligated incremental capacity in long term Entry Capacity auctions.

3.16. Although UCAs are used to determine reserve prices and as a test for releasing capacity, their primary function is to provide National Grid NTS with a revenue driver to incentivise the provision of incremental capacity in an efficient way.

3.17. The UCAs for ASEPs that existed at the start of the current Price Control were set using Long Run Incremental Cost (LRIC) analysis assuming the 1 in 20 supply/demand scenario applicable at the time and an incremental flow of 6 mscmd at each of the ASEPs. Ofgem determined these UCAs and associated baseline levels of capacity in order to incentivise Transco to invest in a timely manner to respond to demand for additional Entry Capacity.

3.18. Since the start of the current Price Control, a number of new ASEPs have been established. The UCAs for these points have required difficult judgements to be made about the likely demand for the capacity at that point, the expected reinforcement costs, the existing allowances for investment in the area under the TO Price Control and the desire to maintain stable prices.

3.19. In its decision on the May 2005 consultation, after seeking advice from an expert panel, Ofgem concluded that there was no strong reason to believe that the proposed Transcost derived UCAs based on Ofgem's supply/demand assumptions were any more cost reflective than the existing UCAs. In addition there was concern that the modelling process in Transcost was not transparent.

3.20. In December 2005, Ofgem issued an Open Letter on Charging suggesting that National Grid NTS give consideration to decoupling the link between Licence defined revenue drivers (Unit Cost Allowances) and reserve prices from 1 April 2007.

3.21. Discussions at the Gas TCMF are considering how this decoupling issue could be addressed.

[1] ASEP – Aggregated System Entry Point

**NTS Entry Capacity Incremental Prices**

3.22. National Grid NTS generates signals for investment in the NTS by holding annual long term Entry Capacity auctions for incremental levels of capacity above baseline levels set in its Licence.

3.23. The result of the bids placed in the auctions will determine how much incremental capacity is to be released, and on what basis (annual/permanent obligated or non-obligated).

3.24. The price structure for Incremental Entry Capacity is designed to allow Users to signal their demand for incremental capacity at different locations on the NTS, and to allow National Grid NTS to signal its supply curve of costs to provide the incremental flow.

3.25. A clearing price principle is applied, so that, although each User may place different bids in the auctions, it is possible to identify a single level of incremental capacity that meets both the cost of supply and the market demand for that capacity at any entry point, along with a single price for that capacity. This principle is different from the pay-as-bid auctions for medium and short term capacity release, which is designed to allocate up to a baseline level of capacity at a market price.

3.26. The price schedule applied comprises 20 price steps (labelled P1 to P20) above the baseline price step (P0). The price schedule must be monotonic i.e. always increasing or always decreasing from P1 to P20. The price step from P0 to P1 always reflects an increase in price. Decreasing price schedules are observed for large new ASEPs, where the P0 price is zero, P1 > P0, but the remaining price steps decrease in magnitude, due to the economies of scale generated from the calculation of long run costs.

3.27. The monotonic property of the price schedule allows a single clearing price to be calculated.

3.28. Since the introduction of long term auctions for incremental capacity in 2003, incremental price schedules have been determined by National Grid NTS's Transcost and FALCON modelling tools.

3.29. The analysis undertaken determines a set of Long Run Incremental Costs (LRICs) for each Entry Point, for increments of capacity above baseline. These LRICs are then converted to a price schedule.

3.30. Due to the complex nature of this process, Ofgem's Open Letter on Charging suggested it would be desirable that a single model were used to determine entry and exit pricing for all flow increments.

**NTS Entry Capacity Incremental Price Schedule Determination**

3.31. This section describes the current application of the models to the determination of incremental entry reserve prices.

3.32. The incremental entry price methodology has been established to provide a price schedule applicable to the release of aggregate quantities of Quarterly System Entry Capacity (QSEC) that are above the baseline quantities identified in National Grid NTS's GT Licence.

3.33. The objective of the methodology is to produce a range of price steps based on Long Run Incremental Costs (LRICs) which afford Users an opportunity to reveal their demand for Entry Capacity, but which also reveals National Grid NTS's supply curve i.e. the estimated construction costs potentially incurred for providing Entry Capacity at levels beyond the baseline quantities.

3.34. The methodology is designed to work in conjunction with the capacity allocation rules detailed in the IECR statement.

3.35. The LRIC approach derives entry to exit costs which represent the cost of providing capacity to transport increments of gas through the NTS. The LRIC methodology is broadly similar to the Long Run Marginal Cost (LRMC) methodology, except that whilst the LRMC methodology considers only one increment size of 2.834 mscmd, the LRIC methodology considers various increment sizes.

3.36. Increments are set such that the economic signals resulting from the LRIC process are clear, however, due to the simplifications made within Transcost, for some ASEPs both the Transcost and Falcon tools may be required for generating LRICs.

3.37. The Transcost analysis is carried out using the base case networks, described in section 2.5, for 10 years starting from the first year that new investments can be delivered given a three year planning horizon i.e. Gas Year Y+3.

3.38. Increments used in Transcost range from 1.5 mscmd through to 12 mscmd (or 50% of baseline if less than 12 mscmd). The lower value of 1.5 mscmd represents in general, around 2% to 10% of the flow along a route. The upper value of 12 mscmd represents a typical incremental flow when a new "greenfield" compressor station would be required along a route and more complex engineering analysis is required to decide where a greenfield compressor is best located.

3.39. The LRIC matrices generated (for each increment) are disaggregated to produce entry charges for each ASEP using the Microsoft Excel Solver as described in section 2.12. This results in a set of unscaled LRICs (for each increment of flow and for each ASEP)[2].

3.40. For larger increments (above 12 mscmd), more detailed network analysis using Falcon is undertaken, using the same asset cost parameters and same planning assumptions used by Transcost. As this is a manual process, it is not possible to replicate all routes generated by Transcost, and so a set of representative routes and years are analysed.

3.41. Routes for the Falcon analysis are identified from the Transcost analysis for which the reinforcement costs identified most closely represent entry costs.

3.42. Gas years Y+3, Y+5 and Y+8 are analysed, with interpolated costs generated for the intervening years. Costs for Year 8 are used to set the costs for later years.

[2] Scaling and rebalancing rules are not applied as for Exit Capacity prices, as Entry prices are intended to generate a pure locational signal for incremental capacity release. Revenue recovery for Entry is currently addressed through the TO Commodity Charge and PC65 mechanism.

3.43. Once reinforcement costs for all relevant ASEPs and increments of flow are known, the LRICs may be calculated by dividing by the increment size.

3.44. The LRICs calculated by Transcost and Falcon are used to generate a price schedule for each ASEP, at the appropriate percentage of capacity above baseline capacity. The LRICs cannot be directly applied as prices, as they reflect the unit costs of moving *from* a fixed baseline capacity *to* the increased capacity level, whilst incremental prices need to reflect the price at the incremental capacity level.

3.45. The incremental prices are also adjusted to reflect the estimated calorific value of gas at the entry point, since by their nature, Transcost and Falcon calculate reinforcement costs based on volumetric flows.

3.46. Finally, a logical progression of prices in either an ascending or descending direction is achieved by adjusting each price step to ensure there is a minimum difference of 0.0001 p/kWh/day between each price step. This rule is applied so that a clearing price may be identified in order to allocate capacity once bidding has taken place[3].

[3] If the price schedule was non-monotonic n(i.e. prices could increase or decrease at any point), it would be difficult to identify a unique clearing price.

# 4. Issues with the Prevailing Capacity Charging Methodologies

4.1. The following section summarises issues thast have been identified with the prevailing methodologies.

**Transport Model**

<u>Transparency and Repeatability</u>

4.2. Transcost was designed to estimate incremental costs for small increments of flow, where demands were increasing year-on-year and system flow patterns were stable. For larger increments (above 12 mscmd), Transcost does not produce reliable results and more detailed analysis using Falcon is undertaken. Charges generated from Transcost were reasonably stable while entry flows at the large beach terminals were forecast to increase steadily year-on-year to meet increasing demand *and* NTS flows represented a stable North/East to South/West flow.

4.3. The development in new entry flows at the Milford Haven and Isle of Grain LNG Importation Facilities coupled with declining flows at many of the large beach terminals has caused significant changes to system flow patterns. NTS flows are forecast to change direction as Milford Haven and Isle of Grain gas penetrate deeper into the system over the ten year planning period. This changing flow pattern means that the choice of ideal network configuration and compressor and regulator parameters within Transcost is less clear, and more of the decision making employed by planning engineers is required. As the model is sensitive to these settings, the increasing subjectivity of these settings will impact on pricing stability and repeatability.

4.4. In regard to the Transport Model, National Grid NTS is concerned that:

- The application of Transcost model is manually intensive and sensitive to user settings (particularly compressor and regulator parameters) leading to stability and repeatability issues;
- Transcost was designed to estimate Long Run Marginal Costs (LRMCs) and is not suited to incremental cost calculations for increments in excess of 12 mscmd, for which Falcon is used;
- The results are sensitive to the supply and demand forecasts chosen, particularly for the later years of the model, as the base networks in each year depends on the preceding year's base network;
- The increasing uncertainty over future supplies of gas means that it is more likely that inaccurate supply/demand forecasts will lead to inaccurate costs being calculated within Transcost;
- Experience shows us that Users do not find such engineering models to be user-friendly due to the level of expertise required.

<u>Supply and Demand Forecast</u>

4.5. In regard to the supply and demand data used in the Transport model, National Grid NTS believes that:

- The use of a ten year forecast combined with the difficulties in generating an accurate forecast may result in unstable prices

- The use of a ten year forecast results in prices being set for auctions that are effectively based on an assumed outcome of those auctions;

- The prices associated with annual (or sub-annual) capacity should represent the costs associated with making that annual capacity available and not a forecast of the costs that might be incurred making capacity available over a longer period than the contract period;

- The averaging of the ten year forecast distorts locational price signals and destroys the temporal pricing signals for incremental capacity e.g. an exit point locating close to a large new entry point *after* that entry point is commissioned generates more efficient investment signals and is less problematic from a security of supply perspective than if that exit point were to locate at the same site *before* the new entry point was flowing gas

- The nodal demand data, which is required, cannot currently be published due to confidentiality issues.

<u>Network Configuration</u>

4.6. Transcost cannot dynamically change multi-junction configurations and this can impact the costs generated.

4.7. The multi-junctions on the NTS allow for the feeders to be connected in a number of different ways such that gas flowing into a multi-junction may or may not flow through a regulator or compressor. The configuration of the network multi-junctions modelled by Transcost is fixed, and is based on the expected peak configuration in the first year identified by the planning analysts.

4.8. This assumption is not appropriate where changing flow patterns means that different configurations may be required for each year of the analysis, and it is impractical to identify which of the many possible configurations provide least cost estimates in each year's base network and incremental cost calculations.

<u>Flow Settings</u>

4.9. The configuration of Transcost in terms of regulator flow settings can impact the costs generated.

4.10. This is currently mitigated by ensuring that the regulator flow settings minimise the base network reinforcement costs generated. However this is a time consuming manual process, requiring significant understanding by users of network modelling and gas flow analysis.

4.11. In addition to this, it is possible to determine different sets of regulator flow settings for the model, which minimise base network reinforcement costs (to the same value) but which could have different effects on incremental reinforcement costs.

Pressure Settings

4.12. The configuration of Transcost in terms of compressor and regulator pressure settings can also impact the costs generated.

4.13. If the input supply and demand data determines stable flow patterns and stable or increasing demand, all compressor and regulator pressure settings may essentially be maximised (using design parameters) in the prevailing flow direction. When flow patterns change year-on-year and demands change (for example, due to changes in storage flows), it is less straightforward to determine what the pressure settings should be, and the choice is necessarily subjective.

**Tariff Model**

4.14. In regard to the Tariff Model, discussions at the Gas TCMF have highlighted that

- The constraint of a minimum permitted charge of 0.0001p/kWh/day which removes negative costs at the optimisation procedure stage may create instability in the entry-exit split which would then lead to distortions to the cost reflectivity of the resulting prices;
- The use of scaling to set Exit Capacity Charges that recover 50% of the allowed TO revenue may distort the locational differentials inherent in the LRMCs;
- The year-on-year price capping rules, applied to exit Capacity charging, restrict price movements. This does not seem the optimal way to support the objective of cost reflectivity over the longer term, recognising that costs will change from year to year as the supply and demand scenario changes as new entry and exit connections are commissioned.

**Rebalancing of NTS Exit Capacity Charges**

4.15. Rebalancing of Exit Capacity Charges to reflect changes in supply/demand and network configuration has not been undertaken since 2001 as a result of the implementation of PC76[4]. This was due to the desire to delay rebalancing on the expectation that NTS exit reform would be implemented in 2002.

4.16. Prior to this, changes to the administered exit prices were constrained by agreed mechanisms consulted on in PD2[5], PD6[6], PD11[7] and PC71[8]. Subsequent delays to reform have lead to a significant divergence in current exit tariffs and underlying LRMCs.

[4] PC76 NTS TO Entry Capacity Auction Reserve Prices and Exit Capacity Charges – November 2002
[5] PD2 NTS Capacity Charge Rebalancing – May 1998
[6] PD6 NTS Capacity Charge Rebalancing – May 1999
[7] PD11 NTS Capacity Charge Rebalancing – July 2000
[8] PC71 NTS Transmission Asset Owner Charges – November 2001

4.17. In March 2005, with the anticipated introduction of NTS exit reform, NGT issued PD18 that put forward a number of options for moving from administered prices to LRMC reserve prices. This paper highlighted the extent and financial materiality of the divergence between the prevailing exit capacity charges and updated LRMCs. Following the delay to NTS exit reform, however, the pricing discussion exercise did not lead to any firm proposals.

4.18. Due to the widening margin between exit capacity charges and true capacity costs, National Grid NTS considers that this increasing divergence should be addressed to ensure compliance with its licence obligations to set charges in a manner that best reflects costs, and to take accounts of developments in the business.

4.19. In addition, the timing of exit capacity charge rebalancing should be consistent with any update of NTS Entry Capacity Baseline Reserve Prices, which may be introduced from 1st April 2007 under the next Price Control. The current entry UCAs (with the exception of new ASEPs not identified in 2001) used as the entry reserve prices are based on LRMCs calculated at the same time as the LRMCs used in the last constrained re-balancing for the current administered exit prices. If NTS Entry Capacity prices are updated using the latest LRMCs as a result of the TPCR, then these would not be consistent with the current NTS Exit Capacity prices.

**NTS Entry Capacity Reserve Price determination**

4.20. In December 2005, Ofgem issued an Open Letter on Charging requesting that National Grid NTS give consideration to decoupling the link between Licence defined revenue drivers (Unit Cost Allowances) and reserve prices from 1st April 2007. National Grid NTS considers that it would be desirable to decouple UCAs and baseline Entry Capacity reserve prices, to remove the conflicting requirements that can arise for UCAs.

4.21. Since Ofgem must give consideration to such factors as likely demand for the capacity at an entry point and the existing allowances for investment in the area under the TO Price Control in deciding an appropriate UCA, the current UCAs used to set reserve prices are not necessarily a true indication of the relative locational price a User should pay at the entry point.

4.22. Analysis undertaken by National Grid NTS shows that LRMCs have diverged significantly from UCAs. This would indicate that UCAs have become less cost reflective over the course of the Price Control.

4.23. This loss of cost reflectivity may mean that locational pricing signals are being distorted, and hence investment may not be triggered in an efficient way.

**Short Term NTS Entry Capacity Reserve Price Discounts**

4.24. National Grid NTS currently sets baseline reserve prices for all long, medium and short term Entry Capacity auctions on the same basis but applies a discount for Users that purchase capacity in the short term auctions.

4.25. It has become evident to National Grid NTS that the use of discounted reserve prices in short term auction generates a disincentive to book capacity in the longer term, undermines locational signals for Entry Capacity in all auctions and can undermine long-term signals for incremental capacity. Analysis of Entry Capacity auction bookings is included within Appendix C.

4.26. Although shippers may argue that short term prices should not be distorted by use of a reserve price, National Grid NTS observes that a zero reserve price, though attractive when capacity is perceived to be in plentiful supply, can lead to high and unpredictable capacity prices when that same capacity becomes scarce. We note that the discussions with the industry via the Gas TCMF concluded that stable, or at least predictable, prices were preferable.

4.27. In addition, National Grid NTS has an obligation to ensure that Transportation Charges are cost-reflective. Applying a zero reserve price policy for short term auctions may have led to higher commodity charges as a result of under-recovery in the long term Entry Capacity auctions. We consider that it is not cost-reflective to levy a high TO commodity charge on Users where that charge was designed to correct for small discrepancies in auction revenues, as it results in a significant redistribution of charges from Users booking Entry Capacity (at a discounted rate) to those flowing gas.

4.28. National Grid NTS offers firm capacity for sale in medium term auctions and withholds 20%[9] of the SO baseline capacity for the shorter term. National Grid NTS notes that, where Users are not able to contract in the longer term for firm capacity rights, they are able to purchase capacity in monthly and daily bundles.

4.29. National Grid NTS believes that the Daily Interruptible NTS Entry Capacity product offers Users the ability to purchase capacity at a reduced price which reflects capacity availability and uncertainty.

4.30. Removal of the discounted reserve prices for short term capacity does not therefore remove the opportunity for Users to purchase capacity in the short term, but it does remove the possible cross-subsidy of daily firm capacity by other Users.

4.31. National Grid NTS considers that, in order for it to fulfil its obligations to invest in the NTS in an efficient and timely manner and to provide for obligated baseline levels of capacity as determined by its Licence, it may no longer be appropriate for reserve prices to attract a discount for short term auctions.

**A Single Model for NTS Charge Determination**

4.32. Transcost was designed to model small increments in order to estimate LRMCs. Transcost was not designed to accurately model relatively large increments and costs for providing increments above 12 mscmd, for entry price determination purposes, are estimated using the Falcon Network Analysis modelling program and the planning assumptions that are encoded within Transcost.

[9] The potential to reduce the quantity of capacity withheld for short term auctions to 10% has been discussed as part of the TPCR

4.33. Transcost is not suited to large increments as it considers an incremental increase in demand for every combination of entry and exit point. For many of these exit points a demand increase in excess of 12 mscmd represent more than doubling the local NTS capacity. As Transcost is based on duplicating existing assets it cannot produce reasonable cost estimates for these scenarios and it is for this reason that it does not produce reasonable cost estimates.

4.34. If a single model is to be used to calculate all capacity prices then a single approach must be adopted. The use of LRICs for incremental Entry Capacity pricing and LRMCs for exit pricing and is the key obstacle to a single charging model.

4.35. This obstacle could be overcome by considering the LRMC at a revised supply/demand scenario where an entry point was adjusted to an incremental flow rather than using prevailing LRIC methodology. This would allow LRMC based pricing of Entry Capacity increments and would result in all capacity prices being calculated on the same basis and would therefore facilitate the use of a single charging model. This approach is discussed in more detail in appendix A.

## 5. Key Questions for the Gas Charging Review

5.1. The table below summarises ten key questions which were identified as part of the Gas TCMF discussions in relation to the calculation of NTS Exit Capacity charges. For clarity, the prevailing methodology has been stated against each of these questions.

**Table 5-1: Key Questions for the Gas Charging Review**

| Model | Question | | Prevailing Exit Methodology | Prevailing Incremental Entry Methodology |
|---|---|---|---|---|
| TRANSPORT MODEL | 1 | S&D Scenarios: 1 Year or multiple Years? | Ten Years from Year 0 | Ten Years from Year 2 |
| | 2 | How should incremental costs be modelled? | Transcost | Transcost, Falcon for increments in excess of 12 mscmd |
| | 3 | How should spare network capacity be treated? | Spare capacity included. | |
| | 4 | Should decrement (back flow) costs be considered? | No backflow cost benefit included. | |
| TARIFF MODEL | 5 | How should entry and exit costs be disaggregated? | Solver using a non-negative constraint. | |
| | 6 | How should negative costs be treated? | Removed as part of the solver process. | |
| | 7 | Should costs be adjusted to 50:50 entry:exit and if so how? | LRMCs are not adjusted or constrained to be 50:50 entry:exit | |
| | 8 | Are zones required? | LDZ Exit Zones are used to map consumer exit points to the appropriate offtakes | Zones are not used for entry |
| | 9 | Should charges be adjusted to recover allowed revenue and if so how? | Charges are scaled to recover 50% of TO allowed revenue | Charges are not adjusted. |
| | 10 | Should year on year price changes be capped? | +/-30% year-on-year cap on Charges | Incremental capacity charges are not capped or discounted |

5.2. The following sections within Chapter 5 of this document present a summary of options to address each question which have been discussed at the Gas TCMF. As the questions are not independent, combined approaches are considered.

### Single Year or Multi-year Modelling and the Treatment of Spare Capacity

5.3. Currently, gas charges are based on network modelling over a ten year period. The modelling incorporates the actual capacity on the network – and hence, takes into account spare capacity. Alternative Transport models are discussed in detail in section 6.

5.4. The timescale of modelling and the treatment of spare capacity are two areas of the charging regime that are linked – changes in one area may require a change in the other in order to remain consistent.

5.5. If charges are only based on a single year of modelling, the inclusion of spare capacity will tend to result in unstable charges as a result of the lumpiness of network investment. There will tend to be step changes in investment costs as demand grows from one year to the next. In areas which started with spare capacity charges will start at or close to zero, and tend to remain at such levels until spare capacity is utilised; once capacity is fully utilised, charges will tend to reflect investment costs (assuming the approach did not change, this investment cost would be represented by the value of an annuity over the economic lifetime of the assets in question), and will tend to remain at this level until the network is reinforced; and following reinforcement, charges will tend to return to zero. This will result in volatile charges.

5.6. If the investment costs in such a regime were calculated as a 45 year annuity of total investment costs, then this would be likely to imply a significant under-signalling of long run marginal costs, as this 45 year annuity would only actually be payable for a small number of years in any investment cycle, hence, if charges are based on a single year of modelling, it may be appropriate to model the network with no spare capacity.

5.7. In considering the most appropriate approach in this area, there are two key areas to consider:

- The relative accuracy of multi-year vs. single year modelling; and
- Implementation Costs

<u>Relative accuracy of multi-year vs. single year modelling</u>

5.8. With a multi-year modelling period the demand growth is also modelled and hence the level of spare capacity in each year will tend to reduce. In areas where such spare capacity on the network exists, while in early years incremental flows will not result in significant investment costs, such costs will start to emerge in later years.

5.9. The alternative approach of using a single year of modelling but removing spare capacity will result in charges which are, in some areas, less reflective of the costs associated with flow increases as all incremental flows will be considered as resulting in investment immediately rather than bringing forward future investment and hence changing the present value of forecast investment requirements.

5.10. The multi-year approach may have inaccuracies as a result of forecast errors – it requires a supply and demand scenario covering 10 years into the future, and to the extent that this in incorrect, it will distort charges. Equally, the multi-year modelling makes the process of deriving charges more complex for participants to understand and replicate.

5.11. With a single year model, information regarding the development of charges over time is not necessarily lost to the industry. If the model and the charging methodology are transparent (including procedures for changing the methodology), users will be able to develop their own views as to the development of charges for the coming year and over longer time periods on the basis of their own forecasts of annual demand and supply. This is likely to provide a better view of charge developments than a process that relies upon a partially rules based forecast made by National Grid NTS combined with non-transparent application of the process to determine a central supply forecast.

Implementation costs

5.12. Single-year modelling and particularly the removal of spare capacity would require similar changes to Transcost as would be required to quantify the benefits of backhaul flows. This would cause significant implementation issues in terms of development time and costs. With a Transportation model approach (discussed later in section 6.6), single-year modelling and the removal of spare capacity would not present such issues.

**Counter Flows (Backhaul Benefit)**

5.13. At present, within Transcost, incremental flow against the prevailing flow is not considered to have any impact – in other words, it does not result in an incremental investment cost (since it reduces flows) and it does not result in any benefits (i.e. cost reductions) due to delayed investment.

5.14. An alternative approach would be to recognise that a benefit might accrue to a reverse flow equal to the negative of the investment cost which would have been associated with a forward flow. In simple terms, if an incremental flow provides a benefit then investment might be avoided.

5.15. In considering the most appropriate approach to charging in this area, there are three key issues to consider:

- the true valuation of counter flows;
- issues relating to the likelihood of counter flows materialising; and
- Implementation issues.

Realistic valuation of the counter flow:

5.16. When the actual impact of counter flows on the network and on future network planning is considered, the situation is ambiguous and depends on the wider context of the network route in question. For example:

- if supply or load growth is such that the flow on the network segments being considered is forecast with reasonable certainty to increase over time, then a counter flow would be likely to delay the requirement for future investment – and hence could be considered to have a positive NPV benefit;
- If supply or load growth is more uncertain and is such that the flow on the network segments is, under some scenarios, forecast to increase over time, then a counter flow would delay the requirement for future investment under

those scenarios. Hence, a counter flow could be considered to have an option value; and

- If supply or load growth is such that the flow is not projected to increase (i.e. there is not likely to be a future requirement to invest in the network in the area under consideration), then the counter flow would have no net benefit (assuming that physical disinvestment of assets is not possible).

5.17. The current assumption within Transcost is consistent with an assumption that supply or load growth is not projected to result in investment benefit. This is clearly an assumption that lies at one extreme end of the spectrum of possible assumptions.

5.18. Traditionally, flows on the NTS have tended to be from ASEPs in the North and East, such as St Fergus and Bacton, towards the South and West of Britain. With this pattern of flows, an incremental demand in South Wales is likely to induce incremental investments over many elements of the NTS, since the supply sources tend to be distant, therefore, the exit charge in South Wales would be positive.

5.19. With the decline of UKCS supplies and investment in LNG terminals the flow pattern is changing. In particular, gas entering at Milford Haven will tend to reverse flows so that the West of Britain changes from being a net importer to a net exporter of gas. With the new pattern of flows, demand in South Wales tends to reduce the need for network reinforcement between South Wales and the remainder of the system to the East. The effect on incremental costs depends upon the modelling assumptions. Transcost at present would associate a zero benefit to the reduced need for investment between South Wales and the remainder of the NTS towards the East.

5.20. The key question in relation to the approach to be taken in the future is which assumption is the most appropriate for the majority of the NTS at present.

<u>Materialisation of counter flows</u>

5.21. The above arguments all relate to the effect of a counter flow, however, since the cost estimates are being used to fix capacity based charges, there is a further issue relating to whether the counter flow which is facilitated by a capacity holding actually materialises. If a party holds capacity which facilitates an injection which results in a counter flow, but that party does not utilise the capacity, there is no benefit.

5.22. For parties whose capacity could cause a forward flow, payments based on capacity holdings ensure that the party bears a cost reflective proportion of the maximum cost they could impose on the system. The size of the capacity holding itself ensures they cannot (if charges are cost reflective) use the system in a way which creates more cost than they are bearing. For parties who could cause a reverse flow, however, payments based on capacity alone reflect the maximum possible benefit they could provide to the system but there is nothing to ensure that this benefit is realised.

5.23. There are two approaches to this solution:

- wherever positive benefits are factored into capacity based tariffs, ensure that for users whose charges take into account such benefits, there are obligations to flow at peak periods (those periods which drive investment requirements). This would increase the linkage of capacity and energy, going against the development direction of the gas regime.

- Assume that, at periods of system peak, the majority of parties with firm capacity holdings will use their capacity.

5.24. Constrained LNG ("CLNG") is an example of the current gas charging regime where credit is given for a flow that brings investment benefits. CLNG receives a benefit equal to the exit charge at an equivalent location. Broadly speaking, this benefit represents the saving in network investments due to the CLNG facility providing capacity to meet peak demand flows. It is assumed that the operation of the storage monitors and the SO balancing role will ensure the CLNG facility will flow at peak (as a result of the locational nature of their role, it cannot be assumed that energy market incentives would be sufficient).

<u>Implementation issues</u>

5.25. The option to take account of delayed investment resulting from an incremental counter flow is likely to encounter implementation issues with respect to Transcost. This is because a significant re-design of Transcost is required to allow it to scale-down the size of the network to match flows. For example, Transcost would need to be able to remove duplicate pipes and scale down pipeline diameters to reflect a reduced flow.

5.26. Accounting for network delayed investment would not raise implementation issues with a Transportation model since it is an inherent feature of such models as it would be dealt with via a reduction in flows being multiplied by an expansion constant.

5.27. If benefits are assigned to counter flows, the possibility of negative LRMC estimates increases since the locational spread of charges will be greater.

**Generating Entry and Exit Charges from Route Costs and the Entry-Exit Split**

5.28. In the current methodology, Excel Solver is used to generate entry and exit prices from a route cost matrix produced by Transcost. The solver iteratively calculates a set of entry and exit prices which minimise the sum of the squared differences or errors between the entry plus exit prices and the route costs estimated by Transcost.

5.29. In order to ensure a unique output which is not dependent on starting conditions, a further constraint that all entry and exit prices are non-negative is imposed. Alternative approaches would be to:

- Allow the solver to generate negative prices but place a constraint that there is a 50:50 split between average positive entry and exit prices;

- Calculate entry/exit prices with reference to costs of flowing to a reference node with the potential imposition of a 50:50 entry-exit split.

5.30. The approach which can be considered most appropriate in this area depends on a number of the other methodology step choices discussed above. These will determine whether it is true that, in the route cost matrix produced by the network model, for any combination of entry point A and exit point B, it is true that the route cost from A to B is equivalent to the route cost from A to C (where C can be any node) plus the route cost from C to B.

5.31. The following two features of a network model will result in this condition not being met. Firstly, if incremental flows against the prevailing flow direction are not treated as providing a benefit equal to the negative of the cost which would be incurred for a flow in the opposite direction; and secondly, if spare capacity is modelled on the network and if non-negligible increment sizes are considered. These conditions are not met by the current application of Transcost, but would be met under a Transportation model approach which inherently includes backhaul and no spare capacity.

<u>Backhaul Benefit, Spare Capacity Not Modelled</u>

5.32. If the above conditions hold, the choice of reference node will not impact the locational differentials between nodes. It will affect the entry-exit split, but since that is likely to be adjusted at a subsequent stage of the process, it is not an issue.

5.33. Equally, there will exist a set of Entry and Exit Capacity Charges which can perfectly reflect route costs (i.e. for all the route combinations, there will be entry and exit prices which, when summed, exactly equate to the route cost in the initial matrix). An unconstrained application of Solver (i.e. one which is not constrained to produce non-negative charges) will result in an objective function with zero value since all errors equal zero.

5.34. Finally, the relative differences between Entry and Exit Capacity Charges produced by an unconstrained application of Solver will be equal to those produced using a reference node approach – that is, from a cost reflectivity viewpoint, the reference node and unconstrained Solver approach are equivalent under such conditions.

5.35. The lack of a unique solution (which occurs in both approaches) can be addressed by imposing an entry-exit split by adding a uniform amount to all entry charges and subtracting the same uniform amount from all Exit Capacity Charges.

5.36. In contrast, the constrained Solver approach (where individual entry and Exit Capacity Charges are constrained to be non-negative) will produce a different outcome to that determined by use of a reference node and (since there are further constraints in the optimisation) result in an objective function with a positive value. This implies that the resulting entry and exit capacity charges are less representative of the underlying route costs contained in the matrix.

5.37. There is no difference (certainly from a cost-reflectivity viewpoint) to using the 50:50 solver approach, particularly since a non-negativity constraint can be applied later in the process where the probability of distorting locational cost differences is lower.

No Backhaul Benefit or Spare Capacity Modelled

5.38. If the above condition does not hold, which is the case in the current regime, then the choice of the reference node will impact on the relative differentials between Exit Capacity Charges. It ceases to be possible to derive a set of Entry and Exit Capacity Charges which exactly reflect the information contained in the cost matrix.

5.39. In this situation, a reference node approach would not be appropriate, and an approach which attempts to minimise the sum of the squared or absolute differences between the entry and exit prices and the information in the route cost matrix is likely to be more appropriate.

5.40. In the discussions above, it is noted that the constraint on negative charges, as applied at present in the Solver optimisation, may result in information derived from the route cost matrix being unnecessarily distorted – essentially action may be taken to remove negative charges in a way which distorts locational differentials when subsequent adjustments (particularly those to ensure revenue recovery) would have anyway removed the negative elements.

5.41. A summary of the above discussion on choice of reference node and entry-exit split is given below:

| **Does the reference node approach exactly equal the solver approach if prices are adjusted to 50:50?** | **Spare Capacity Included** | **No Spare Capacity Modelled** |
|---|---|---|
| **No Backhaul benefit** | No | No |
| **Backhaul benefit included** | No | Yes |

**NTS Exit Zones**

5.42. NTS Exit zones were defined such that a consistent price could be set for the NTS Exit charge component for consumers within a local distribution zone (LDZ). An LDZ consumer may receive gas from a number of NTS offtakes. Rather than setting NTS Exit Capacity Charges on an offtake specific basis and charging LDZ consumers based on the expected proportion of flow received from each offtake, the offtake zone allowed a single charge to apply to all LDZ consumers within the Exit Zone.

5.43. The allocation of LDZ consumers to NTS Exit Zones is a DN activity based on expected distribution network flows. The pattern of flows may vary across the year as a DNO may not wish to, or be able to, control the offtake flows in the same proportions. The allocation of LDZ consumers to NTS Exit Zones is based on peak flows as these tend to drive investment and hence are appropriate for capacity related charges.

5.44. As Users are to continue to pay NTS Exit Capacity Charges under the transitional arrangements and they have no influence as to which offtake they receive their gas from, then it would seem most appropriate to continue to charge on an NTS Exit Zone basis under the transitional arrangements. A Shipper cannot influence which NTS offtakes are utilised to supply an LDZ consumer.

**Approach to Recovering Allowed Exit Revenue**

5.45. The objective of Entry-Exit Capacity Charges is to provide price signals to Users in relation to the relative cost associated with providing flow capability at different locations around the network. This is National Grid NTS's interpretation of cost-reflectivity.

5.46. In addition, National Grid NTS needs to ensure that capacity and commodity charges together recover allowed revenue. This revenue recovery relates to sunk costs (i.e. the costs of existing investments in network, rather than any view of investments required in the future under particular assumptions), hence, from an economic efficiency viewpoint, it should be recovered in a way which is least likely to distort User behaviour.

5.47. In the current gas regime, Exit revenue recovery is achieved via a multiplicative scaling of charges. As an alternative, revenue recovery could be achieved by adding a uniform amount to entry and exit prices. The advantage of the alternative approach is that it preserves the locational differentials between entry and Exit Capacity Charges, and hence preserves the relative cost-reflectivity. Multiplicative scaling might distort these relativities.

5.48. An alternate less distortionary approach would be to leave NTS Exit Capacity charges unadjusted, and to recover residual revenue through a commodity based charge. In an administered charging regime (i.e. absent auctions), the choice between the two approaches comes down to a view as to which is likely to be least distortionary in terms of User behaviour.

**Negative Capacity Charges**

5.49. In the discussions above, it is noted that the constraint on negative charges, as applied at present in the Solver optimisation, may result in information derived from the route cost matrix being unnecessarily distorted; essentially action may be taken to remove negative charges in a way which distorts locational differentials when subsequent adjustments, particularly those to ensure revenue recovery, would have removed the negative elements anyway. If this is to be avoided, then the non-negativity constraint should be applied at the last point in the process.

5.50. Negative prices have no real meaning in a regime where capacity and energy are clearly separated. While there may be beneficial flows on the NTS such as those linked to Constrained LNG, it is the flow that provides the benefit and no amount of capacity held by a user will provide a benefit if it is not utilised.

5.51. Negative capacity prices would also give a perverse incentive to Users to book more capacity than would otherwise be required potentially leading to inefficient development and operation of the NTS.

**Capping of Year-on-Year Charges**

5.52. In considering the most appropriate approach in this area, the key issue to consider is stability vs. cost reflectivity

5.53. Capacity charge capping (i.e. placing constraints on the extent to which individual entry and exit points can change year on year) will clearly increase the stability of charges, however, over time, and particularly in the face of changing patterns of flow around the network, it will result in charges which are not as cost reflective.

5.54. The likely change in flow patterns around the Milford Haven area are a good example in this case. As a result of the LNG developments there, from an overall system viewpoint, location of load in Wales will be significantly less expensive in terms of future investment requirements than was previously the case. Following the commissioning of the LNG capacity, therefore, from a cost reflectivity viewpoint it would be appropriate to signal this through Exit Capacity Charges, that is, for Exit Capacity Charges in that part of the network to reduce significantly. This adjustment can only happen if year on year changes to entry and exit costs emerging from the process of adjusting the information resulting from the Transcost cost matrix are not constrained.

5.55. Over time, excessive emphasis on stability can result in a significant departure from cost reflectivity. A charge stability or predictability objective might be justified with reference to User cost-base planning ability. Provided that charges are not changing with sufficient frequency and in a sufficiently unpredictable way to imply that Users are often subjected to tariff “shocks”, it could be argued that cost-reflectivity should be the dominating objective.

## 6. Alternative Transport Models

6.1. Within the Gas TCMF three broad approaches to the development of a new or enhanced Transport model have been discussed, and are outlined below.

<u>Enhanced Transcost</u>

6.2. Transcost generates costs based on the optimum investment (pipe or compressor) identified to maintain minimum system pressures and inherently takes into account spare capacity. Alternative options have been identified based on enhanced versions of Transcost that look to model backhaul cost benefits and the removal of spare capacity. As with the current use of Transcost, the least cost additional investment required in new pipelines and / or compressors to support a sustained notional increase in flow along each route would be identified.

<u>Flow Model</u>

6.3. A flow model would retain the physical modelling of flows and pressures within the system. Incremental investment costs would be estimated by expansion constants expressed in terms of a daily rate of £/GWh km. These constants would be based on the optimum investment (pipe and compression) identified to transport gas over typical network distances travelled for different pipe diameters. By the nature of this type of model, spare capacity would not be modelled and incremental flows would lead to costs for every section of the network. The expansion constants would be applied to incremental flow distances calculated from a base network. The flow model allocates both base and incremental flows to the network to balance pressure loss over all routes.

6.4. The base network flows would represent a good approximation of physical reality, however where there are multiple routes between points that are not controlled by regulators; a flow model would allocate incremental flows to all such routes. In effect, the model would undertake a small reinforcement along all routes whereas in practice only the least cost route would be reinforced. In this case, the flow model would not identify the least cost route. This approach would also still rely on significant understanding by network users of how to set regulator and compressor parameters.

6.5. In the case of multiple paths that are necessarily controlled by regulators, the regulator settings would determine the gas flow path.

<u>Transportation Model</u>

6.6. The transportation model minimises GWh km flow of gas around the network given the assumed pattern of supplies and demands and the constraint that at any node, demand plus flow to other nodes must equal supply and flow from other nodes.

6.7. Any incremental flow down a line results in a reinforcement requirement, with a standard reinforcement cost for pipelines of similar diameter. It does not consider the way in which pressure, pipeline diameter / length and flow interact – it simply assumes that, for the standard reinforcement cost, incremental GWh kms can be routed down each existing pipeline route.

6.8. The marginal costs for demand and supply at each node give the incremental reinforcement cost to a reference node. These costs represent the nodal Entry prices and the negative of these costs represent the Exit prices.

6.9. The only network elements which are required for the transportation model are the network nodes, and the length and diameter of the pipeline segments between nodes. A transportation model would allocate both base and incremental flows to the shortest cost path.

6.10. Transportation models inherently do not include spare capacity as all incremental flows result in incremental costs.

6.11. While the base network flows may not be representative of physical reality, in that flows will in reality be driven by pressure gradients rather than path length, they are only required to ensure that incremental flow paths are identified on a least reinforcement cost basis and hence the model will always identify the least reinforcement route cost. It should be noted however that neither a transportation model nor Transcost can take into account variable pipe costs driven by geographic factors such as river and transport crossings and difficult terrain.

**Implementation issues**

6.12. A flow model could be developed from the flow and pressure modelling features of Transcost. As with the prevailing version of Transcost, the issues of automation would have to be addressed.

6.13. There are no off the shelf packages available that accurately model incremental costs of network flows taking into account physical realities of the system which do not rely on skilled user input. There are, however, widely available algorithms which would allow National Grid NTS to develop a Transportation Model within a spreadsheet interface such that it could readily be made available publicly in an easily useable form.

6.14. The Transportation Model would only require supplies, demands and pipes as the inputs. As a Transportation model would not include compressors or regulators, there would be no User settings and hence no automation issues.

### Charging Model Options

6.15. In conjunction with the industry through the Gas TCMF ("Transmission Charging Methodologies Forum"), National Grid NTS has developed a range of options for determination of Long Run Marginal Costs (LRMCs) for capacity charging. Out of the many options, the following table summarises the options selected by the group to be worthy of further exploration. An explanation of these models is provided in section 7.

6.16. These options are either based on Transcost (Options A to D) or a Transportation model (Options F1 & F2). The option of a flow model (Option E) had been discussed within the Gas TCMF meetings.

6.17. A flow model, as with Transcost, would retain the physical modelling of flows and pressures within the system but with incremental investment costs being estimated by an expansion constant as per the Transportation model.

6.18. The flow model would allocate both base and incremental flows to the network to balance pressure loss over all routes. The base network flows would represent a good approximation of physical reality, however, where there are multiple routes between points that are not controlled by regulators; a flow model would allocate incremental flows to all such routes. In effect, the model would undertake a small reinforcement along all routes whereas in physical reality only the least cost route would be reinforced.

6.19. Recognising this feature of such a flow model, the significant time that would be required to develop and construct a model and the level of user input required it was agreed by the Gas TCMF attendees that the model should not be included within the analysis options. We have therefore not pursued this option at this time.

**Table 6-1: Transport and Tariff Model Options**

| Option | A<br><br>(Status Quo) | B | C | D | F1 | F2 |
|---|---|---|---|---|---|---|
| **S&D Scenario** | 10 Years | 1 to n (<=10) year forecast | | | | |
| **Cost Model** | Transcost | | | | Transportation Model - Single Expansion Factors | Transportation Model - Multiple Expansion Factors |
| **Spare Capacity** | Spare capacity Included | | | Spare Capacity Excluded | | |
| **Backhaul** | No backhaul benefit | | Backhaul benefit included | | | |
| **Entry & Exit Disaggregation, ratio & Negative Prices** | Solver (non-negative constraint) | Solver with 50: 50 constraint (to allow negative prices to be removed at final step)* | | | Reference node with 50: 50 adjustment (to allow negative prices to be removed at final step)* | |
| **Zoning** | LDZ Exit Zones, No Entry Zoning | | | | | |

* NB Using the Solver with a 50-50 constraint or a reference node with a 50-50 adjustment has been shown to produce identical results for the transportation model.

### Explanation of Model Options

Model A ("current approach")

6.20. With Model A, LRMCs for each entry-exit route are calculated using Transcost, a model which seeks to replicate the actual physical network and gas flows. Individual entry and exit LRMCs are then determined assuming that prices must be non-negative to find the best fit to the determined entry-exit route costs. Exit tariffs are set to recover allowed revenue by multiplicative scaling of the exit LRMCs.

Model B

6.21. Model B is the same as Model A, except that entry and exit LRMCs are determined from route costs assuming the average of the non-negative entry and exit costs are the same i.e. there is a 50:50 split between entry and exit costs. Adjustment to the exit tariffs is by an additive constant adjustment to the exit LRMCs calculated such that the non-negative LRMCs recover the correct allowed revenue, with any negative prices removed at the final step.

Model C

6.22. Model C is the same as Model B, except that only those routes where there is a positive flow are considered and any route that is in the opposite direction to the prevailing flow is not used within the Entry Exit solver process. This is done in attempt to model the backhaul benefits associated with incremental flows against the prevailing system flows i.e. those beneficial flows that actually result in a reduced requirement to reinforce the system such as those flows resulting from small Exit points near large terminals or small ASEPs near areas of large demand.

Model D

6.23. Model D is the same as Model C, except that it attempts to remove spare capacity from the Transcost model by ensuring that the base network pressures at all compressor inlets are maintained within the incremental analysis such that all incremental flows result in additional costs.

Models F1 and F2 – "Transportation Models"

6.24. Models F1 and F2 are based on a simplified form of the actual network being comprised of network nodes, and the length (and diameter for model F2) of the pipeline segments between nodes.

6.25. The model minimises GWh km flow of gas around the network given an assumed pattern of supplies and demands and the constraint that, at any node, demand plus flow to other nodes must equal supply and flow from other nodes.

6.26. The model assumes that any incremental flow down a line results in a reinforcement requirement. Model F2 uses pipe diameter specific reinforcement costs for pipelines of similar diameter whereas model F1 uses a standard reinforcement cost for all pipeline routes.

6.27. The model does not consider the way in which pressure, pipeline diameter / length and flow interact as in Transcost – it simply assumes that, for the standard reinforcement cost, incremental GWh kms can be routed down each existing pipeline route. The marginal costs for demand and supply at each node give the incremental reinforcement cost to a reference node. These costs represent the nodal Entry prices and the negative of these costs represent the Exit prices.

# 7. Analysis

## Modelling Assumptions

7.1. Network Model – All models have been run with the same network model based on 2006/07 base network (including committed additions and system extension for Milford Haven and Langage.)

7.2. S&D Scenarios - All models have been run with the latest 10 year central forecast supply/demand scenario. However, the Transportation models were also run with the Global LNG scenario to assess the sensitivity of the results to the selected forecast scenario.

7.3. The calculation of the expansion constant used for the Transportation models is detailed in appendix B.

7.4. For models A to D based on Transcost an increment of 2.834 mscmd (30.7 GWh/d) was applied consistent with historical exit tariff determination. Due to the nature of the Transportation models (models F1 and F2) the costs calculated are true marginal costs and therefore represent the cost of a nominal 1 kWh increment

## Analysis

7.5. Each of these models has been developed and run to determine what NTS Exit Capacity Charges would have been if such models were to have been used to set the prevailing Exit prices.

7.6. LRMCs have been determined with each model for all exit (and by default entry) exit points for each of the 10 years of the supply demand forecast.

7.7. The Exit LRMCs for each year have then been scaled (model A) or adjusted (models B to F) to recover the TO Allowed Revenue implied by the prevailing Exit prices such that they represent what NTS Exit Capacity tariffs would have been from 1st April 2006.

7.8. The analysis results were presented at the 25th May 2006 Gas TCMF and can be found on the National Grid NTS's information website[10].

[10] See http://www.nationalgrid.com/uk/Gas/Charges/TCMF/ for analysis results

## Data

7.9. The following table summarises the data that has been generated and published on the National Grid NTS website[11] in relation to the 25th May 2006 Gas TCMF.

**Table 7-1: Transport and Tariff Model Analysis - Summary of Results Generated**

| **Model** | **Transport Model** | | | **Tariff Model** | |
|---|---|---|---|---|---|
| **Model A** | Transcost | Spare Capacity, No Backhaul | 2.834 mscmd increment | Solver with non-negative constraint | Exit prices scaled to allowed revenue |
| **Model B** | Transcost | | | Solver with 50 50 Constraint | Exit prices adjusted to 2006/7 allowed revenue |
| **Model C** | Transcost | Spare Capacity & Backhaul | | Solver with 50 50 Constraint | |
| **Model D** | Transcost | Backhaul and No-spare capacity | | Solver with 50 50 Constraint | |
| **Model F1** | Transportation Model | Backhaul and No-spare capacity | Single Expansion Factor | Reference node adjusted to 50 50 | |
| **Model F2** | Transportation Model | Backhaul and No-spare capacity | Pipe diameter specific Exp. Factors | Reference node adjusted to 50 50 | |

7.10. For each model the following data has been provided

- Nodal exit LRMCs (NB the Tariff model for model A sets a minimum value of 0.0001 p/kWh/day)
- Nodal and zonal exit prices with a minimum value of 0.0001 p/kWh/day adjusted to recover the 2005/6 allowed revenue.
- Nodal entry annuitised costs with a minimum value of 0.0001 p/kWh/day for comparison with Entry UCAs

7.11. All costs and prices are expressed in p/kWh/day. Data has been provided for a ten year period starting from winter 2005/6 along with a simple average, a standard deviation and a maximum and minimum value for each node/zone over the ten year period. This data has been published in full for the central case supply/demand scenario at the following link.

**TCMF LRMC Analysis - Central Case**

http://www.nationalgrid.com/NR/rdonlyres/C4619A41-2732-42E2-85DE-0CE83D56EEF9/7774/060517_GasTCMF_LRMCAnalysisResultsCENTRALCASEV3.xls

[11] See http://www.nationalgrid.com/uk/Gas/Charges/TCMF/ for National Grid NTS's Gas Transmission Charging Methodology website.

7.12. This data has also been published for models F1 & F2 for the Global LNG scenario.

**TCMF LRMC Analysis - Models F1 & F2, Global LNG Scenario**

http://www.nationalgrid.com/NR/rdonlyres/ADA56753-F787-456A-A146-997E2A349117/7527/060517_GasTCMF_LRMCAnalysisResultsGLOBAL_LNGV01.xls

7.13. A comparison has been made between the exit prices calculated for the central case and the prevailing exit prices applicable for all DN and DC exit points from 1st April 2006 at the following link.

**TCMF LRMC Analysis - Comparison with Prevailing Exit Prices**

http://www.nationalgrid.com/NR/rdonlyres/CFD5E91C-D64C-4445-87DC-77A30072E0E5/7526/EXITImpactofLRMCmodelchangescfApril06Pricesv1.xls

7.14. The information presented in the following spreadsheets relate to analysis undertake by National Grid NTS to inform the discussions at the 6$^{th}$ July 2006 Gas TCMF.

7.15. Indicative baseline prices have been generated from the proposed Entry Capacity Baseline Reserve Price methodology (entry flows individually adjusted to reflect baseline/obligated capacity levels with supply substitution balancing rules) Central case prices are based on unadjusted central case flows at all ASEPs and are presented for comparison.

060706 Gas TCMF

7.16. Data presented at 6 July 2006 Gas TCMF for Entry Capacity Reserve Price discussions. The expansion constant used to determine price data assumes:

- Latest compressor costs in line with assumptions for UCA analysis undertaken for Ofgem (and expected costs going forward) including project costs

- Pipeline costs as established in the April 2006 IECR consultation

- Corrected anuitisation factor using the current licence anuitisation (0.10772)

250506 Gas TCMF Cost Base

7.17. Data presented at 25 May 2006 Gas TCMF for entry-exit LRMC analysis discussions. The expansion constant used to determine price data assumes:

- Pipeline costs and compressor costs as established in the April 2006 IECR consultation

**Entry Capacity Baseline Reserve Price Analysis**

http://www.nationalgrid.com/NR/rdonlyres/046C1922-D9FA-41FF-83FB-8B0BCF1B526F/7807/20060706GasTCMFEntryCapacityBaselineReservePriceAn.xls

7.18. Please note that data and prices contained in all these spreadsheets are illustrative prices and do not necessarily represent the prices that National Grid NTS will apply in respect of future NTS Entry Capacity Charges

**Data Assessment**

<u>Model A – "Current approach"</u>

7.19. While the Entry flows at the large beach terminals were forecast to increase year on year to meet increasing demand and NTS flows represent a stable North and East to South and West flow the charges generated from Transcost were reasonably stable. The configuration of Transcost in terms of compressor and regulator settings involved little intervention due to this stable flow pattern. Essentially all compressor and regulators were maximised in the prevailing flow direction.

7.20. The introduction of Milford Haven and isle of Grain within the ten year plan coupled with declining flows at many of the large beach terminals has caused significant changes. NTS flows are forecast to change direction as Milford Haven and Isle of Grain gas penetrate deeper into the system over the ten year plan period. This changing flow pattern means that the choice of compressor and regulator settings within Transcost is less clear. As Transcost is sensitive to User set compressor and regulator settings, the increasing subjectivity of these settings appears to be impacting on pricing stability and repeatability.

7.21. The model A results indicate significant year-on-year Exit price variation when compared to the other models. This variation results largely from the solver constraints as the resulting LRMCs do not necessarily represent a 50:50 split between Entry and Exit and this split varies significantly from year to year. This variation is exacerbated by scaling, as opposed to adjusting, the LRMCs to generate Exit prices which recover the TO Allowed Revenue.

7.22. Some of the Exit prices are counter-intuitive, particularly Scotland and the North of England where non-minimal prices are being generated at a time when National Grid NTS believes that Exit Capacity in these areas could be made available with minimal reinforcement implications. Some of the southern Entry prices are also counter-intuitive as National Grid NTS believes that Entry Capacity in these areas could be made available with minimal reinforcement implications.

<u>Model B</u>

7.23. The results from Model B show less year-on-year variation than Model A due to the enhancements in the way in which route costs are converted to entry and exit LRMCs, but the issues regarding counter-intuitive Entry and Exit prices remain.

<u>Model C</u>

7.24. Although Model C might be expected to make the differences between geographic locations more distinct due to the inclusion of back-haul modelling, the results are not significantly different to model B, mainly due to the backhaul benefits not being significant due to the modelling of spare capacity.

Model D

7.25. Model D attempts to remove spare capacity from the Transcost model by ensuring that the base network pressures at all compressor inlets are maintained within the incremental analysis such that all incremental flows result in additional costs. While this has been successful in terms of making the differences between geographic locations more distinct, compared to the other Transcost models, the removal of spare capacity can only be approximated, making this model subjective and only partly successful in its aim.

Models F1 and F2

7.26. The Transportation models inherently do not include spare capacity as all incremental flows result in incremental costs. Where supplies are declining, removal of spare capacity therefore results in higher entry charges; reflective of costs that have been incurred and lower exit costs in the local vicinity. Year-on-year LRMC variations can be linked directly to supply/demand changes and are more easily explainable and potentially justifiable than the Transcost results. In addition, the results from these models are closer than the Transcost models to the prevailing exit prices and current Entry UCAs.

7.27. Model F1 uses a single cost expansion constant and results in the most stable year-on-year. Model F2 conceptually should be the most cost reflective as it uses pipe diameter specific expansion constants. However Model F2 will predict incremental costs based on the existing pipeline diameter which does not represent the fact that more recently National Grid NTS has been using 900-1200mm pipelines for reinforcement. This can be seen in the Milford Haven results where Model F1 is closest to the prevailing UCA which was based on the planned 1200mm expansion whereas the results from F2 result in a much higher price due to the prevalence of 600mm pipe in South Wales.

## APPENDIX A: LONG RUN COST ESTIMATION

### Long Run Marginal Costs

Long Run Marginal Costs (LRMCs) are estimates of the effect that a unit change in the quantity of a product has on the overall costs of production i.e. they are gradients of the cost curve at particular points on the curve. Long run costs assume that investment can be made in the network to accommodate a change in capacity[12]. Short run costs assume no change to the network is made.

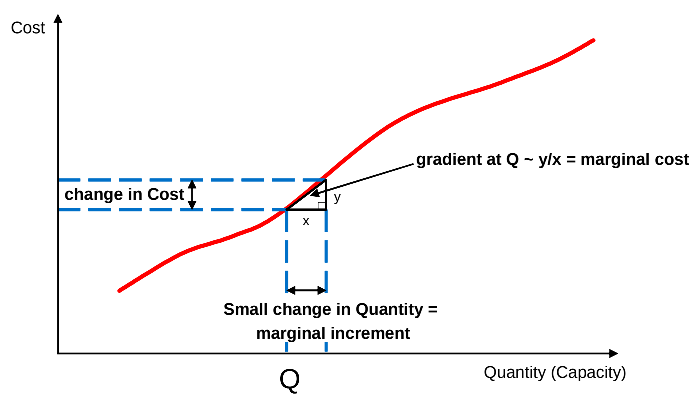
An advantage of using long run marginal costs for pricing NTS capacity is that they provide a means of generating locational pricing signals for capacity. This allows National Grid NTS to signal where it is most efficient to ship gas through the system, and where it is least efficient to do so.

National Grid NTS sets prices using marginal costs because they enable a proportion of revenue to be recovered based on a locational basis, and therefore provide a simple yet cost reflective basis for revenue recovery.

The way that National Grid NTS currently estimates LRMCs is to use Transcost with a "marginal" flow increment of 2.834 mscmd (or 100 mscfd). Strictly speaking, Transcost calculates a long run *incremental* cost matrix (see below), as it does not actually calculate the cost gradient of the curve, but the unit cost of investment required to increase flow from all entry points to all exit points.

In theory the smallest incremental flow through the network should approximate the true cost gradient; however, due to the lumpy nature of investment, stable pricing signals are only generated in Transcost for a reasonable increment. The increment of 2.834 mscmd was chosen for Transcost because it generated these stable pricing signals at the time the program was first introduced for marginal cost estimation. This represents, on average, approximately 10% of the flow in a feeder, and so is arguably not "marginal".

**Figure A-1: Long Run Marginal Costs**



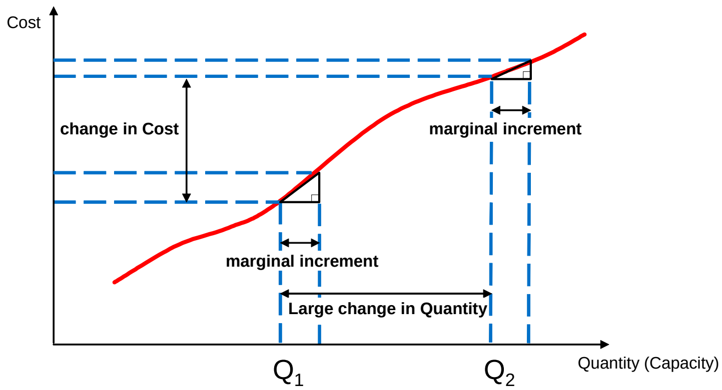

[12] Transcost estimates the reinforcement pipe and compressor costs to allow an increase in capacity. The Transportation Model assumes that capacity is unlimited along a route (therefore implicitly assumes the network could expand to accommodate additional flows).

- For a marginal increase (or decrease) in capacity from a point Q, the marginal cost at Q approximates the *gradient* of the cost curve at Q

- The price of capacity at the level Q is based on the marginal cost at Q

Since LRMCs are estimates of cost gradients at a point on the cost curve, they may in theory be applied at any point on the curve. Using this approach, the price at any capacity level can be directly estimated; therefore this approach can be used to price incremental capacity above a baseline level.

**Figure A-2: Long Run Marginal Costs for Estimating Incremental Capacity Prices**




- LRMCs at Q1 and Q2 are used to set prices for capacity levels of Q1 and Q2 respectively

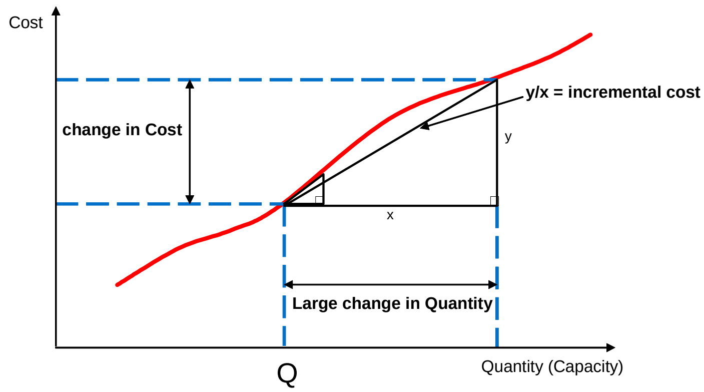
- Prices generated will signal costs of maintaining a higher capacity level ("forecast" LRMCs)

- The change in total cost can be also be estimated

**Long Run Incremental Costs**

Long Run Incremental Costs (LRICs) are currently used by National Grid NTS to calculate incremental price schedules for Entry Capacity. These represent the unit cost of investment for additional capacity, given a starting level of capacity. Due to the nature of LRICs, engineering models are required to estimate such costs for gas networks. Post processing of the LRICs is necessary to generate prices for use in long term Entry Capacity auctions.

**Figure A-3: Long Run Incremental Costs**




- In general, y/x no longer approximates the gradient of the cost curve at Q
- The interpretation given to y/x is the unit incremental cost of moving from the capacity level Q to the new capacity level
- The LRIC does not represent the price at the new capacity level (it is not a cost gradient)

## APPENDIX B: EXPANSION FACTOR CALCULATION

Expansion constants are utilised in the Transportation Model to represent the estimated typical capital cost of the transmission infrastructure required to transport 1 GWh over 1 km on a peak day. The incremental cost is then determined by multiplying pipe lengths by the appropriate expansion constant. Table B-1 below provides the expansion constants for all NTS pipe diameters and also an average of the 900mm, 1050mm and 1200mm pipe diameters. The expansion constants have been calculated based on the following assumptions:

- latest forecast cost of pipelines;
- 100km feeder duplication (parallel pipeline, same diameter) i.e. assumes compressor required every 100km on average;
- maximum inlet pressure per pipe section of 85bar;
- optimum outlet pressure per pipe diameter with a minimum of 38 bar

The single expansion constant for use in the Transportation model is based on an average of the expansion constants for pipe diameters of size 900mm, 1050mm and 1200mm typically used over recent years and planned to be built to reinforce the system.

**Table B-1: Expansion Factors used in the Transportation Model**

| Pipe Diameter (mm) | A. Pipe Cost (£M) | B. Compressor Cost (£M) | C. Maximum Daily Flow (GWh) | Expansion Factor (£/GWhkm)<br><br>=((A+B)/C)/100 |
|---|---|---|---|---|
| 300 | 36.01 | 1.78 | 33,192 | 11.39 |
| 350 | 42.27 | 2.66 | 49,695 | 9.04 |
| 450 | 54.77 | 5.13 | 95,958 | 6.24 |
| 500 | 61.03 | 6.77 | 126,439 | 5.36 |
| 600 | 73.54 | 10.91 | 203,796 | 4.14 |
| 750 | 92.30 | 18.70 | 362,817 | 3.06 |
| 900 | 111.06 | 25.49 | 567,649 | 2.41 |
| 1050 | 129.82 | 32.84 | 825,379 | 1.97 |
| 1200 | 148.58 | 40.61 | 1,137,851 | 1.66 |
| 900-1200 | 129.82 | 32.98 | 843,626 | 2.01 |

**Investment Cost Methodology**

- Pipelines –as recently approved IECR methodology.
- Compressors – based on historical cost and tenders

The estimated costs of pipeline and compressor investment used, including project costs, are set out below.

**Table B-2: Estimated Investment Costs**

| Description | Cost £M |
|---|---|
| Pipeline (per km length) | 0.0012507 × diameter (mm) - 0.01507 |
| Compressor – existing site (per MW) | 0.5[13] |

[13] The compressor cost of £0.5M/MW was used as the basis for calculating the £2013/GWhkm expansion constant used for the Gas TCMF analysis presented on 25th May 2006. In subsequent analysis this figure was updated to £0.875M/MW, based on more recent data, resulting in a revised expansion factor of £2223/GWhkm

## APPENDIX C: ENTRY CAPACITY AUCTION ANALYSIS

An analysis of the Entry Capacity auction bookings was undertaken to study the effects of the reserve price methodology over the long, medium and short term capacity products. Results are presented for the six large beach terminals for the period from April 2002 until July 2006[14]. These ASEPs make up the vast majority of capacity bookings (approximately 95% total bookings in the 2005/6 capacity year).

It was expected that "constrained" terminals (where total capacity offered was limited) with a high number of participants would show more capacity sales in the longer term, and high prices paid for short term capacity. ASEPs where there were few participants were expected to show high short term capacity sales but low within day clearing prices.

The results showed that only St. Fergus entry point might be considered to follow this trend. The majority of bookings at Barrow were made in the long term, which did not follow the expected trend considering the low number of participants. The remaining four terminals all showed significant bookings of within day capacity, at or close to the zero reserve price. An apparent change in market behaviour can be seen after zero reserve prices were first introduced by PC76[15] to apply from 1 October 2003, although the effect is not immediate. This may be due to previous medium term capacity bookings being in place and the policy being introduced at the start of the winter period.

Aggregate bookings at each of these four terminals show that capacity procurement is still far short of the baselines set within the Licence - probably due to baseline levels having been based on theoretical maximum physical capacity and buy back levels being low or non-existent. The analysis has also shown that the majority of capacity bookings are seen at the large beach entry terminals, and approximately 30% of the bookings for the 2005/6 capacity year were made within-day, compared to 50% bookings for the same period made through QSEC auctions.

This would seem to indicate that participants at the six large entry terminals benefit from being able to purchase capacity at a zero price, even though there is no indication that there is real competition for capacity at five of these terminals. It is possible that this is to the detriment of other Users, who may face higher TO entry commodity charges to offset revenue under-recovery from Entry Capacity.

Although, currently, there appears to be ample capacity at five of the six terminals, this situation may change. If capacity becomes scarce, high and/or volatile prices can result (where participants have not made long term purchases of capacity and are therefore dependent on purchasing large quantities of capacity at the day ahead/within day stage). It can be seen that higher long term bookings at Bacton and Easington have been made for the coming winter period (2006/7). If daily demand for capacity continues at the levels experienced in the last two years, it is possible that high/volatile within day prices may be seen at these terminals over this winter. It is possible that interruptible capacity could help meet this demand, but there is no guarantee that it will be available on any given day.

When a terminal is constrained and participants are facing high/volatile prices, it is not possible for National Grid NTS to alleviate the problem in the short term by investing

[14] QSEC auction results from 2006 are not included.
[15] PC76 NTS TO Entry Capacity Auction Reserve Prices and Exit Charges, November 2002

for incremental capacity due to the lead times required for NTS investment. The current arrangements mean that long term auction signals must be seen in order for National Grid NTS to release permanent obligated incremental capacity, therefore, high/volatile prices would continue to be observed where capacity is scarce until investment is made – this would take at least three years, if not longer.

Ofgem suggested in its decision letter on PC76 that, if Entry Capacity remained unsold or only sold at the reserve price, then this could mean that applying a reserve price in auctions was preventing the market from clearing. Ofgem considered zero reserve prices would enable the market to clear and allow price discovery at competitive terminals and that there was sufficient competition at the majority of large beach terminals to guard against significant revenue under-recovery. Also, Ofgem stated concerns about reserve prices affecting competition between terminals.

The pattern of capacity bookings since zero within-day reserve prices were introduced does not support these two assertions: capacity bookings are still significantly below baseline levels for all the large terminals, except for St. Fergus, and auction sales fail to recover sufficient revenues from entry.

In the future, there may be increased competition at more of the large beach terminals, which would support the use of a zero reserve price in the short term at those terminals. However, it is difficult to see how a zero reserve price could be applied in a practical and non-discriminatory way across competitive and non-competitive ASEPs.

For these reasons and for the desire industry participants have expressed for stable prices, National Grid NTS believes that discounts should be no longer be applied to baseline reserve prices for Entry Capacity in daily auctions.

**Figure C-1: Bacton Capacity Sales**

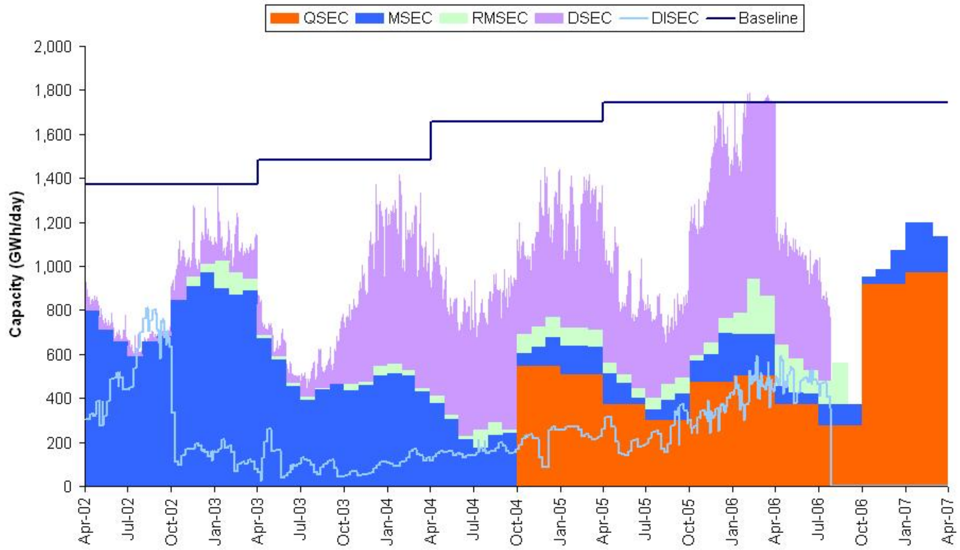



**Figure C-2: Barrow Capacity Sales**

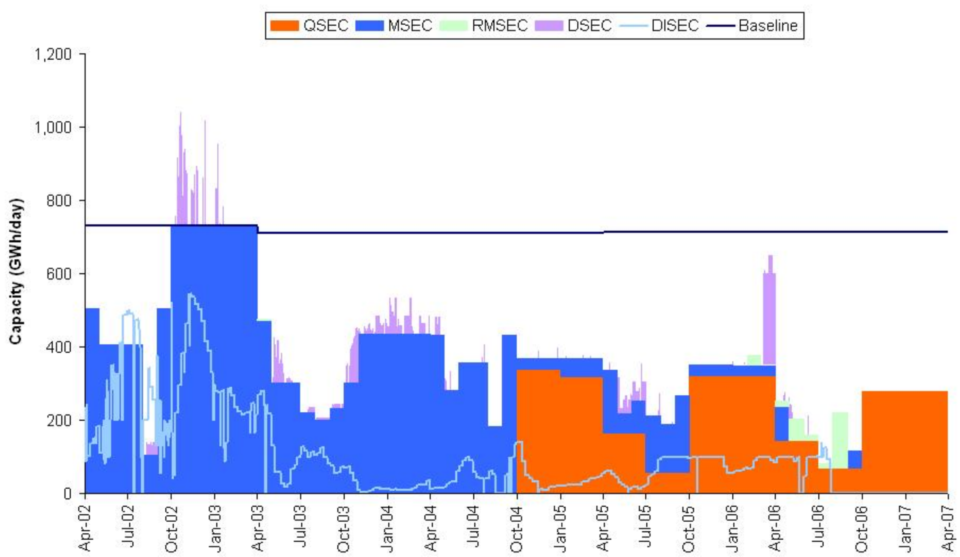


**Figure C-3: Easington and Rough Capacity Sales**

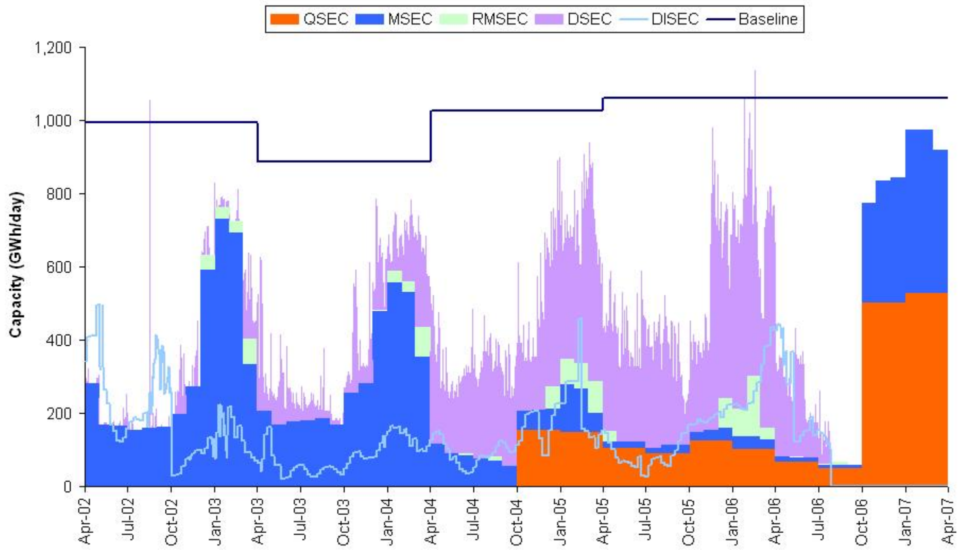



**Figure C-4: St Fergus Capacity Sales**

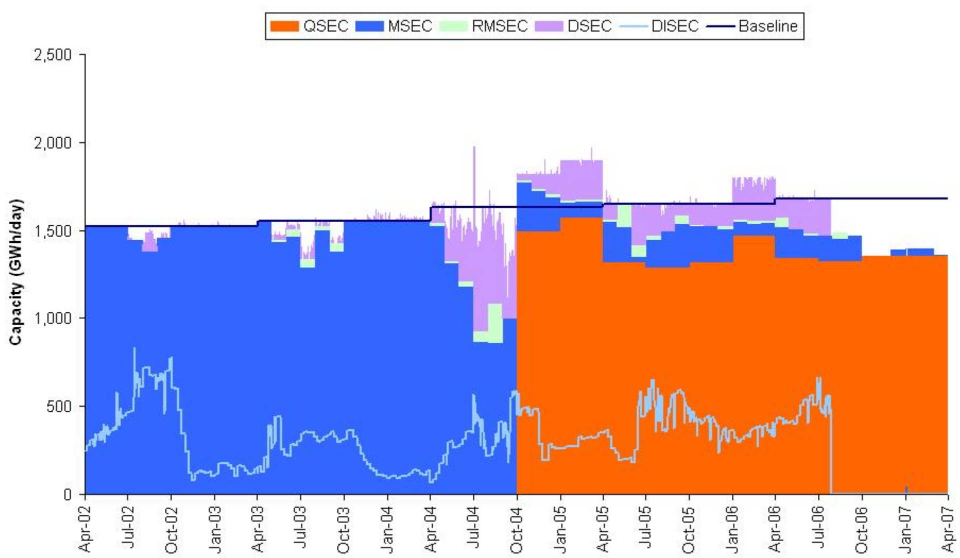


**Figure C-5 : Teesside Capacity Sales**

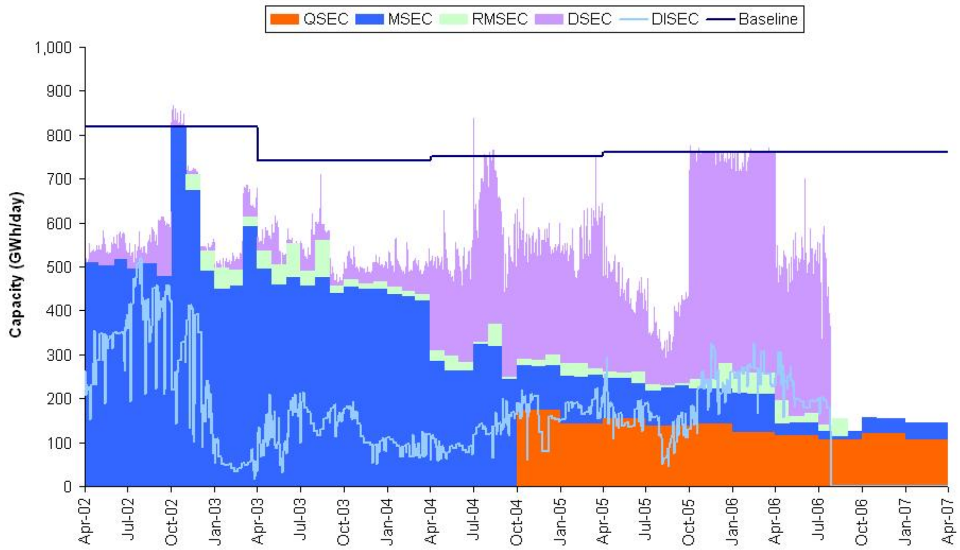



**Figure C-6: Theddlethorpe Capacity Sales**

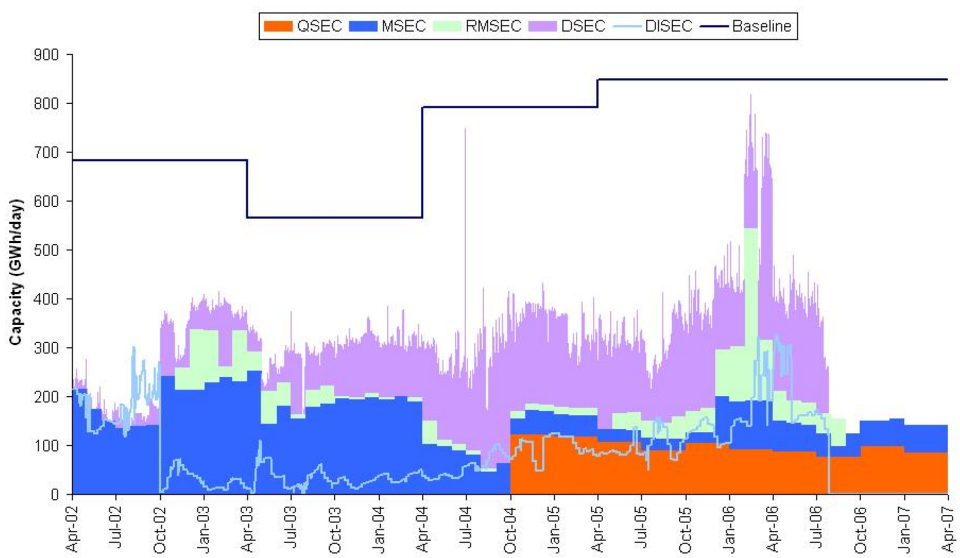


**Table C-1: UCAs and NTS Baseline Entry Capacity Reserve Prices**

| Terminal | Baseline Capacity 2006/7 (GWh/day) | Gross UCA from licence (£/kWh or £m/GWh) | UCA 2000 Price (p/kWh/day) | UCA 2006/7 Price (p/kWh/day) | 2006/7 LTSEC and MSEC Reserve Price (p/kWh/day) | 2006/7 DSEC Reserve Price (p/kWh/day) |
|---|---|---|---|---|---|---|
| ***Coastal Terminals and LNG Importation*** | | | | | | |
| Bacton | 1745 | 0.182 | 0.0054 | 0.0063 | 0.0063 | 0.0042 |
| Barrow | 712 | 0.014 | 0.0004 | 0.0005 | 0.0005 | 0.0003 |
| Easington/Rough | 1062 | 0.034 | 0.0010 | 0.0012 | 0.0012 | 0.0008 |
| Isle of Grain | 218 | 0.186 | 0.0055 | 0.0064 | 0.0064 | 0.0043 |
| Milford Haven | 0[16] | 0.257 | 0.0076 | 0.0089 | 0.0089 | 0.0059 |
| St Fergus | 1677 | 0.639 | 0.0189 | 0.0220 | 0.0220 | 0.0147 |
| Teesside | 761 | 0.059 | 0.0017 | 0.0020 | 0.0020 | 0.0014 |
| Theddlethorpe | 848 | 0.031 | 0.0009 | 0.0011 | 0.0011 | 0.0007 |
| ***Onshore Fields and Connections*** | | | | | | |
| Burton Point | 55 | 0.002 | 0.0001 | 0.0001 | 0.0001 | 0.0000 |
| Hatfield Moor | 55 | 0.042 | 0.0012 | 0.0014 | 0.0014 | 0.0010 |
| Hole House Farm | 26 | 0.002 | 0.0001 | 0.0001 | 0.0001 | 0.0000 |
| Wytch Farm | 3.2 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| ***Storage Sites*** | | | | | | |
| Barton Stacey | 0[17] | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Blyborough | 0 | 0.035 | 0.0010 | 0.0012 | 0.0000 | 0.0008 |
| Burton Agnes | 0 | 0.075 | 0.0022 | 0.0026 | 0.0000 | 0.0017 |
| Cheshire | 214 | 0.003 | 0.0001 | 0.0001 | 0.0001 | 0.0001 |
| Garton | 420 | 0.039 | 0.0012 | 0.0013 | 0.0013 | 0.0009 |
| Glenmavis | 99 | 0.532 | 0.0157 | 0.0183 | 0.0183 | 0.0122 |
| Hatfield Moor | 55 | 0.042 | 0.0012 | 0.0014 | 0.0014 | 0.0010 |
| Hornsea | 175 | 0.153 | 0.0045 | 0.0053 | 0.0053 | 0.0035 |
| Partington | 215 | 0.009 | 0.0003 | 0.0003 | 0.0003 | 0.0002 |
| Tatsfield | 0 | 0.083 | 0.0024 | 0.0029 | 0.0000 | 0.0019 |
| Winkfield | 0 | 0.083 | 0.0024 | 0.0029 | 0.0000 | 0.0019 |
| ***Constrained LNG*** | | | | | | |
| Avonmouth | 149 | 0.064 | 0.0019 | 0.0022 | 0.0022 | 0.0015 |
| Dynevor Arms | 50 | 0.000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |

[16] Permanent obligated NTS Entry Capacity of up to 950 GWh released
[17] Permanent obligated NTS Entry Capacity of 90GWh