ANNEX A

GAS TRANSMISSION TRANSPORTATION CHARGING METHODOLOGY

CHAPTER 1: PRINCIPLES

1.1 Price Control Formulae

The transportation price control treats the NTS
Transportation Owner (TO) and the NTS System Operator (SO) separately. The separate price controls and incentives determine the maximum revenue that National Grid may derive from each in a formula year, 1 April to 31 March.

The Maximum Allowed Revenue under the transportation controls and incentives is determined by a number of factors including:

- the volume of NTS entry and exit capacity made available;
- National Grid's performance under the various SO incentive schemes, covering a range of activities;
- the indexation factor - under the TO formula allowed revenue is adjusted each year by a factor equal to the rate of inflation, measured on a prescribed historical basis by reference to the Retail Price Index (RPI); and
- any under or over-recovery brought forward under each control from the previous formula year (expressed by means of a separate "K" factor within each control).

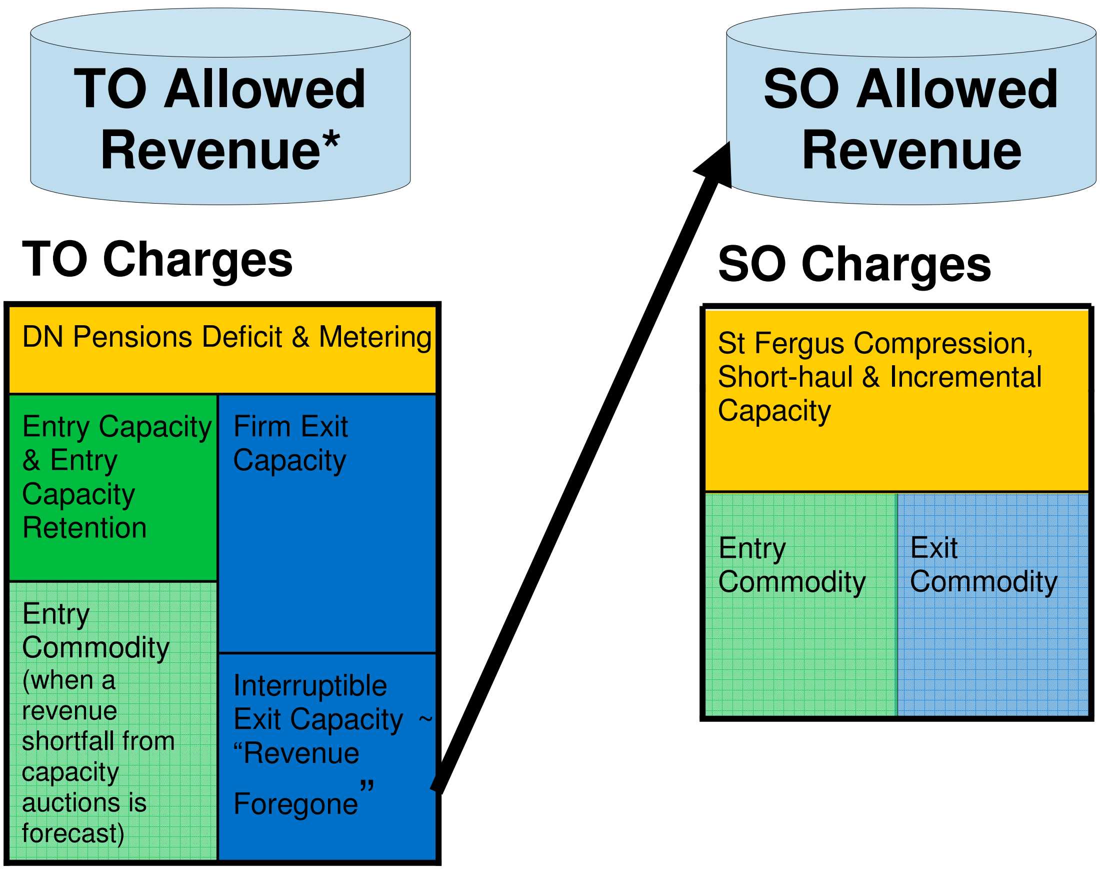
1.2 Structure of NTS Transportation Charges

Charges are set separately for those activities related to the Transportation Owner (TO) and to the System Operator (SO).

The maximum revenue to be collected from the NTS TO and NTS SO charges is determined by the TO and SO price controls, as described in Section 1.1 above. The NTS TO allowed revenue is collected by entry and exit capacity charges, with a TO commodity charge levied on entry flows where entry auction revenue is forecast to be under-recovered. The NTS SO allowed revenue is collected largely by means of a commodity charge levied on entry and exit flows.

Figure 1 below shows the relationship between the TO and SO allowed revenue and NTS charges.

Figure 1 NTS charges to collect TO and SO revenue



* Appendix B details the treatment of under/over-recovery.

50% of the NTS TO target revenue (excluding under/over-recovery from the previous formula year 'K', DN pensions deficit revenue and metering revenue[1]) plus entry specific under/over-recovery from the previous formula year, is assumed to be derived from non-incremental obligated entry capacity sales. Entry capacity sales are determined through auctions and are subject to reserve prices. Exit capacity charges are applied on an administered peak day basis, and are set so as to recover the other 50% of the TO target revenue level, plus exit specific under/over-recovery from the previous formula year, when they are applied to the registered Baseline firm and interruptible exit capacity levels. The interruptible "revenue foregone" i.e. that revenue that would be collected if interruptible capacity attracted the capacity charge, is collected through the SO price control in accordance with the Licence.

[1] Metering revenue here is revenue from the maintenance charge applicable to NTS direct connects where the metering installation is owned by National Grid, Further details can be found in the Statement of the Gas Transmission Metering Charges.

Both auction reserve prices and exit charges reflect National Grid's long run marginal cost (LRMC) methodology. The unpredictability of revenue from auctions means that the target 50:50 entry/exit split may not be achieved in practice. A TO commodity charge may be levied on entry flows where entry capacity auction revenue is forecast to be below the entry target level.

Commodity charges are payable on gas allocated. Capacity charges are payable when a right to flow gas is purchased, with payment due irrespective of whether or not the right is exercised. However, although the obligation to pay for capacity remains with the primary purchaser, all types of entry capacity can be traded between Shippers, such as Monthly System Entry Capacity (MSEC).

Having established, by the above methods, the target revenue to be derived from each main category of charge, the next stage is to set the charges[2] within each of these charge categories. The methodologies used to do this are described in the appropriate sections below.

[2] All charge rates are rounded to 4 decimal places.

CHAPTER 2: CAPACITY CHARGES

NTS capacity charges consist of charges for exit, entry and credits payable for constrained LNG.

The NTS Transportation Model is used in deriving the NTS capacity charges. The details of the Transport model and the Tariff Model which make up the charging model are available in section 2.5 below.

2.1 System Exit Firm Capacity

The terms on which exit firm capacity is sold are set out in the Transition Document Part IIC (Sections 9–12) of the UNC. Charges reflect the estimated long run marginal cost (LRMC) of reinforcing the system to transport additional gas between entry and exit points. The calculations are described in more detail below. At present, exit charges are applied only in respect of firm loads.

The setting of exit capacity charges from 1 October 2012 is set out in Appendix C.

2.2 System Exit Interruptible Capacity

In accordance with the UNC, NTS Interruptible Supply Points avoid the NTS (TO) Exit Capacity charge and are eligible for transportation credits where the number of days interruption for any Gas Year exceeds 15. The business rules for these arrangements are set out in Appendix 1.

2.3 System Entry Capacity

System Entry Capacity allocated by means of five principle related auction mechanisms.

- Quarterly (firm) System Entry Capacity (QSEC)
- Monthly (firm) System Entry Capacity (MSEC)
- Rolling Monthly (firm) Transfer and Trade System Entry Capacity (RMTTSEC)
- Daily (firm) System Entry Capacity (DSEC)
- Daily Interruptible System Entry Capacity (DISEC)

The reserve prices applicable to each type of auction are set out in section 2.3.1 below.

2.3.1: Reserve Prices in System Entry Capacity Auctions

System entry capacity is allocated by means of auctions as described in the UNC and outlined in Section 2.3 above. This approach includes various reserve prices below which bids will not be accepted.

QSEC reserve prices for obligated entry capacity are calculated each year through using the NTS Transportation Model as described in 2.5 below. QSEC step prices for release of additional (incremental) capacity are calculated with reference to the applicable reserve price and in accordance with the methodology for the determination of incremental step prices as set out in National Grid's Incremental Entry Capacity Release (IECR) methodology statement.

MSEC reserve prices are equal to the obligated capacity price for capacity offered in the auction of QSEC capacity.

Reserve prices are calculated by applying the following discounts to the MSEC obligated capacity prices:

- Day Ahead Daily System Entry Capacity (DADSEC); 33.3%
- Within Day Daily System Entry Capacity (WDDSEC); 100%
- Daily Interruptible System Entry Capacity (DISEC); 100%

Discretionary Release System Entry Capacity (DRSEC) released via auction is subject to the prevailing MSEC reserve price.

2.3.2: Entry Capacity Buy-Back Offset Mechanism

The entry capacity buy-back offset mechanism can be triggered as the initial means of managing excess entry TO revenue to avoid over-recovery.

The level of this excess revenue is available to be used to offset the costs of entry capacity buy-back that would otherwise be borne by shippers through the capacity neutrality mechanism. This is achieved by way of a credit in their entry capacity charges for each month (by the lower of the excess accrued in the financial year to date and monthly buy-back cost). The credit per shipper is paid on the same capacity holding on which neutrality is charged i.e. all firm capacity holdings. Any excess amount (of over-recovery) remaining for any month is carried forward to the next month.

Trigger

- The mechanism would be triggered if the revenue implied by NTS Entry Capacity auctions breached either the Licence obligation not to exceed the maximum NTS transportation owner revenue ($TOMR_t$) by more than 4% in any formula year or not to exceed the maximum NTS transportation owner revenue by more than 6% over any two formula years

- The process would be triggered at any point during the formula year based on the outcome of any NTS Entry Capacity auction that represented a TO revenue stream

Mechanism

- The over-recovery amount will be calculated as the difference between TO Entry Revenue and TO Entry Target Revenue.

- The full over-recovery amount would be available in relation to the first month for which the mechanism was triggered

- Any residual over-recovery at the end of the month would be rolled forward to the next month.

- Any residual over-recovery at the end of the formula year would be used to offset buy-back costs in those months within the formula period when buy-back costs had occurred and no credit had been paid or where the credit was less than the buy-back cost (un-credited buy-back costs)

    - Where the residual over-recovery is less than the aggregate un-credited buy-back costs,

        - Credits would be calculated for each month in proportion to the un-credited buy-back costs in each month.

    - Where the residual over-recovery is equal to or greater than the aggregate un-credited buy-back costs,

        - Credits would be calculated for each month equal to the un-credited buy-back costs in each month.

    - Credits in relation to un-credited buy-back costs in each month would be apportioned to each Shipper on the basis of its original capacity holdings for that month

- The credit would offset buy-back costs and hence daily capacity and over-run revenue could represent an additional credit through capacity neutrality

2.4 Constrained LNG (CLNG)

The credit is related to the peak booking by National Grid of CLNG; is based on the Long Run Marginal Cost (LRMC) at the CLNG node (ie the LRMC between the National Balancing Point (NBP) and the CLNG site.

The credit is made available via National Grid's LNG Storage business unit to those shippers booking the bundled storage service as offered via auction. Further details are available on request from National Grid's LNG Storage business unit.

2.5 Derivation of NTS Capacity Charges

The NTS Transportation Model comprises:

The Transport Model that calculates the Long Run Marginal Costs (LRMCs) of transporting gas from each entry point (for the purposes of setting NTS Entry Capacity Prices) to a "reference node" and from the "reference node" to each relevant offtake point.

The Tariff Model that adjusts the LRMCs to either maintain an equal split of revenue between Entry and Exit users (where entry prices are used to set auction reserve prices) or to recover a target level of revenue (where exit prices are set as administered rates).

Prices for each Gas Year are calculated using the relevant year's 1-in-20 peak base case supply and demand data and network model (e.g. if setting exit capacity prices for Gas Year 2010/11, the base case supply/demand forecast for 2010/11 and the base network model are used).

NTS Obligated Entry Capacity Reserve Prices are set by adjusting supply flows in the base case data to reflect the obligated flow at each NTS Entry Point.

2.5.1: The Transport Model

Model Input Data

The transport model calculates the marginal costs of investment in the transmission system that would be required as a consequence of an increase in demand or supply at each connection point or node on the transmission system, based on analysis of peak conditions on the transmission system. The measure of the investment costs is in terms of £/GWhkm, a concept used to calculate marginal costs, hence marginal changes in flow distances based on increases at entry and exit points are estimated initially in terms of increases or decreases in units of kilometres of the transmission system for a small energy injection to the system.
The transport model requires a set of inputs representative of peak 1-in-20 conditions on the transmission system:

- Nodal forecast supply and 1-in-20 peak day demand data (GWh)
    - Distribution Network (DN) and Direct Connection (DC) offtake demands

    - Aggregate System Entry Point (ASEP) supplies

- Transmission pipelines between each node (km)
    - Existing pipelines
    - New pipelines expected to be operational at the beginning of the gas year under analysis
- Identification of a reference node

Model Inputs

The nodal forecast supply data for the Transport Model is derived from the following sources of supply data such that:

- the Ten Year Statement will be used as the source of supply data for beach supply components.
- Physical capability will be used for all other supply components.
- ASEPs will be capped at the obligated entry capacity level.
- Section 4.6 of the Ten Year Statement will be used to identify eligible entry points and the year that they are due to become operational. New entry points are only included as available supply in future years if they are under construction.

The aggregate supplies are adjusted such that a supply and demand balance is achieved.

- supplies will be split into six groups[3] as follows:

    1. Beach supplies
    2. Interconnectors
    3. Long-range storage
    4. LNG Importation
    5. Mid-range storage
    6. Short-range storage

Each supply group is fully utilised in turn, in the order detailed above, and the supplies in the last required group scaled by an equal percentage to achieve a supply and demand match.
Nodal demand data for the transport model is based on demand that DN Users have forecast to occur at the National 1-in-20 peak day demand level and the booked capacity for directly connected consumers.

National Transmission System network data for the charging year is consistent with National Grid's most recent Ten Year Statement.

[3] See Appendix D for definitions.

Model Outputs

The Transport Model is an optimisation model that calculates the minimum total network flow distance (in GWhkm) given a set of supply and demand flows i.e. it takes the inputs described above and uses a transport algorithm to derive the pattern of balanced network flows that minimises distances travelled by these flows from a supply node or to a demand node, assuming every network section has sufficient capacity.

The marginal cost values are expressed solely in km as they are flow gradients i.e. they represent the sensitivity of the total network flow distance value to a change in supply or demand at any node.
Sum of flow times distance (GWh x km) divided by Change in Nodal flow (GWh) equals marginal cost (km)

The model computes a marginal cost for supply at each node (which may be positive or negative in relation to the reference node). The marginal cost for demand at each node is then the equal and opposite of the nodal marginal cost for supply. A negative marginal cost represents a marginal benefit or avoided cost at that point.

2.5.2: The Tariff Model

The Initial Nodal Marginal Distances

The key inputs to the Tariff Model are the marginal costs of supply and the marginal costs of demand calculated from the transport model. These are used to set the Initial Nodal Marginal Distances (InitialNMkm):

$$InitialNMkm_{Si} = LRMC_{Si} \quad \text{and} \quad InitialNMkm_{Dj} = -LRMC_{Dj}$$

Where

$InitialNMkm_{Si}$	=	*Initial nodal marginal distance for supply i (km)*
$InitialNMkm_{Dj}$	=	*Initial nodal marginal distance for demand j (km)*
$LRMC_{Si}$	=	*Long run marginal cost of flow to reference node from supply i (km)*
$LRMC_{Dji}$	=	*Long run marginal cost of flow to reference node from demand j (km)*

The Initial Nodal Marginal Distances are adjusted to either maintain an equal split of revenue between Entry and Exit users where prices are used to set auction reserve prices, or to recover a target level of revenue, where prices are set at administered rates. The adjustments made for entry and exit capacity charges are described in detail later in this document.

The adjusted marginal distances are converted into unit costs (£/GWh) by multiplying by the expansion constant (see below). These unit costs can then be converted into daily prices by applying the annuitisation factor[4] (which has been calculated assuming a 45 year asset life, an allowed rate of return of 6.25% on capital expenditure and 1% operating expenditure allowance) and then dividing by the number of days in the year. For entry prices, an adjustment to reflect the calorific value at the ASEP is also applied.

The Expansion Constant

The expansion constant, expressed in £/GWhkm, represents the capital cost of the transmission infrastructure investment required to transport 1 GWh over 1 km. Its magnitude is derived from the projected cost of an 85bar pipeline and compression for a 100km NTS network section.

Calculated from first principles, the steps taken to derive the expansion constant are as follows:

a) National Grid determines the projected £/GWhkm cost of expansion of 85bar gauge pressure pipelines and compression facilities, based on manufacturers' budgetary prices and historical costs inflated to present values.

b) An average expansion constant is calculated from the largest three pipeline diameter/compressor sections D_1, D_2, D_3 (network sections *n = 1, 2, and 3*). The selection of expansion constants calculated from these three network sections is based on recent and expected future projects on the transmission system. The pipe diameters used are:

$$D_1 = 900 \text{ mm}$$

$$D_2 = 1050 \text{ mm}$$

$$D_3 = 1200 \text{ mm}$$

c) The maximum daily flow that can be facilitated through each of the three network sections is calculated. This is based on assumptions of an 85bar_g inlet pressure and a minimum outlet pressure of 38bar_g and is calculated from the Panhandle A pipe flow equation (a standard flow equation used within the gas industry).

$$Q_n = K_{flow} \times \left(\frac{T_{std}}{P_{std}} \right) \times D_n^{2.6182} \times \left(\frac{P_1^2 - P_{2,n}^2}{G^{0.8538} \times T_{av} \times L \times Z_{av}} \right)^{0.5394}$$

Where

Q_n = *Flow for network section n (mscmd)*

[4] The annuitisation factor is no longer contained as a separate term in the Licence but is implicit within the revenue drivers. However, a factor of 0.10272 was agreed with the Authority as quoted in paragraph 1.82 of the Transmission Price Control Review: Final Proposals, Appendices, Ofgem, 4th December 2006, Ref: 206/06b.

K_{flow}	=	*Constant (0.0045965)*
T_{std}	=	*Standard temperature (291.4°K)*
P_{std}	=	*Standard pressure (1.01325 bar$_a$)*
D_n	=	*Diameter for network section n (mm)*
P_1	=	*Pipe absolute inlet pressure (86.01325 bar$_a$ = 85 bar$_g$)*
$P_{2,n}$	=	*Pipe absolute outlet pressure for network section n (bar$_a$ greater than or = 38 bar$_g$)*
G	=	*Gas specific gravity (0.6)*
T_{av}	=	*Pipeline average temperature (285.4°K)*
L	=	*Pipe length (100 km)*
Z_{av}	=	*Average gas compressibility (0.85)*

d) The maximum daily energy flow is calculated from the volumetric flow using a standard planning CV of 39 MJ/m3 and the planning flow margin of 5%.

$$Capacity_n = \frac{Q_n \times CV}{((1+FM)\times 3.6)}$$

Where

$Capacity_n$	=	*Daily capacity for network section n (GWh)*
Q_n	=	*Flow for network section n (mscmd)*
CV	=	*Calorific Value (39 MJ/m^3)*
FM	=	*Flow margin (5%)*
3.6	=	*Converts 10^6 MJ to GWh*

e) The compressor power requirement to recompress back to 85 bar$_g$ is calculated from the flow and the inlet and outlet pressures. The inlet pressure for the compressor is the outlet pressure of the pipe section for each pipe diameter D.

$$Power_n = \left(\frac{\gamma}{\gamma-1}\right)\frac{K_{power}\times Z_{av}\times T_{av}\times Q_n}{\eta}\left[\left(\frac{P_{out}}{P_{in,n}}\right)^{\frac{\gamma-1}{\gamma}}-1\right](1+FM)$$

Where

$Power_n$	=	*Compressor power for network section n (MW)*
$P_{in,n}$	=	*Compressor absolute inlet pressure for network section n(bar$_a$)*
P_{out}	=	*Compressor absolute outlet pressure (86.10325 bar$_a$)*
K_{power}	=	*Constant (0.0040639)*
Z_{av}	=	*Compressibility (0.85)*
T_{av}	=	*Average gas temperature (285.4°K)*
Q_n	=	*Flow for network section n (mscmd)*
γ	=	*Isentropic index (1.363)*

η	=	*Compressor adiabatic efficiency (80%)*
FM	=	*Flow margin (5%)*

f) The capital cost of the pipe for each network section is calculated from the pipe cost equation, the pipe diameter and the pipe length of 100km.

$$Pipe\_Cost_n = L \times (D_n \times Pipecost\_diameter\_factor + Pipecost\_constant\_factor)$$

Where

$Pipe\_Cost_n$	=	*Capital cost for pipe in network section n (£m)*
L	=	*Length (100 km)*
D_n	=	*Diameter for network section n (mm)*
Pipecost_diameter_factor	=	*Capital cost factor (£m/km/mm)*
Pipecost_constant_factor	=	*Capital cost factor (£m/km)*

g) The capital cost of recompression from the minimum pressure up to 85bar_g is calculated from the compressor power requirements

$$Compressor\_Cost_n = Power_n \times Power\_Unit\_Cost$$

Where

$Compressor\_Cost_n$	=	*Capital cost for compression in network section n (£m)*
$Power_n$	=	*Compression power for network section n (MW)*
Power_Unit_Cost	=	*Unit cost for additional power at existing stations (£m/MW)*

h) An allowance for engineering and project planning costs is included at 15%.

$$Project\_Cost_n = Project\_Factor * (Pipe\_Cost_n + Compressor\_Cost_n)$$

Where

$Project\_Cost_n$	=	*Project costs for network section n (£m)*
Project_Factor	=	*15%*
$Pipe\_Cost_n$	=	*Capital cost for pipe in network section n (£m)*
$Compressor\_Cost_n$	=	*Capital cost for compression in network section n (£m)*

i) The total cost is the pipe cost plus the compressor cost plus the project costs (£)

$$Total\_Cost_n = Pipe\_Cost_n + Compressor\_Cost_n + Project\_Cost_n$$

Where

$Total\_Cost_n$	=	*Total cost for network section n (£m)*
$Pipe\_Cost_n$	=	*Capital cost for pipe in network section n (£m)*
$Compressor\_Cost_n$	=	*Capital cost for compression in network section n (£m)*

j) The unit cost is the total cost divided by the maximum energy flow (£m/GWh)

$$Unit\_Cost_n = Total\_Cost_n / Capacity_n$$

Where

$Unit\_Cost_n$	=	*Total unit cost for network section n (£m/GWh)*
$Total\_Cost_n$	=	*Total cost for network section n (£m)*
$Capacity_n$	=	*Daily capacity for network section n (GWh)*

k) The expansion constant is calculated by dividing the unit cost by the pipe section length of 100km (£/GWhkm).

$$Specific\_Expansion\_Constant_n = 10^6 \text{ x } Unit\_Cost_n/L$$

Where

$Specific\_Expansion\_Constant_n$	=	*Expansion constant for network section n (£/GWhkm)*
L	=	*Length (100 km)*
10^6	=	*Conversion factor from £m to £*
$Unit\_Cost_n$	=	*Total unit cost for network section n (£/GWh)*

l) The final expansion constant is a simple average of the individual pipeline expansion constants

$$EC = \frac{\sum_{n=1}^{3} Specific\_Expansion\_Constant_n}{3}$$

Where

EC	=	*Expansion constant (£/GWhkm)*
$Specific\_Expansion\_Constant_n$	=	*Expansion constant for network section n (£/GWhkm)*

2.5.3: The Tariff Model for Determination of NTS Exit Capacity Charges

NTS Exit Capacity Charges are administered rates designed to recover 50% allowed TO revenue when they are applied to the firm and interruptible exit capacity (with the remaining 50% TO allowed revenue being recovered through Entry charges). The process for calculating NTS Exit Capacity Charges is described below.

Supply/Demand Scenario and Network Model

Prices for each Gas Year are calculated using the relevant year's base case supply data, 1-in-20 peak demand data, and network model (e.g. if setting exit capacity prices for Gas Year 2007/8, the base case supply/demand forecast for 2007/8 and the base network model for 2007/8 are used).

Revenue Recovery Adjustment

The total revenue to be recovered through Baseline Firm & Interruptible Exit Charges is determined each year with reference to the Price Control formulae stated in the Licence. A description of the principal formulae can be found in Appendix 2.

In any given year t, a target revenue figure for Firm Exit Capacity Charges (Target $TOExRF_t$) is set. An adjustment is made to compensate for any under or over-recovery from the previous year (TOK_t). For further information, please refer to Special Condition C8B and C8E of the Licence. The interruptible "revenue foregone" i.e. that revenue that would be collected if interruptible capacity attracted the capacity charge, is collected through the SO price control in accordance with the Licence.

Revenue from Incremental Exit Capacity Charges is treated as SO revenue within the Price Control formulae stated in the Licence (SOExRFt). For further information, please refer to Special Condition C8C of the Licence.

All NTS Exit capacity charges are set simultaneously through the Transportation Model such that target exit capacity revenue equals Baseline (TO) Exit Capacity Revenue plus Incremental (SO) Exit Capacity Revenue. The charges are set such that Baseline (TO) exit revenue, i.e. booked exit capacity up to the baseline level multiplied by the relevant offtake price, represent 50% of TO remaining allowed revenue after deducting non-capacity TO charge revenues including DN pensions charge revenue.

A single additive constant Revenue Adjustment Factor (RAF) is calculated using Microsoft Excel Solver which, when added to the Initial Nodal Marginal Distance at each demand, gives a revised marginal distance for each demand, such that the total revenue to be recovered from Baseline Firm (TO) exit charges equals the target revenue (i.e. $TOExRF_t$). The Incremental SO revenue (i.e. SOExRFt) can be calculated from the prices where incremental capacity is released.

The calculation simultaneously removes the negative marginal distances by collaring the revenue to that level implied by the minimum price of 0.0001 p/kWh.

$$ExitRev_{t,Dj} = Max\left[(0.0001/100)\times ExitCap_{Dj}\times 365, \frac{\left(InitialNMkm_{Dj}+RAF\right)\times ExitCap_{Dj}\times AnF\times EC}{10^6}\right]$$

$$ExitRev_{t,Dj,inc} = Max\left[(0.0001/100)\times ExitCap_{Dj,inc}\times 365, \frac{\left(InitialNMkm_{Dj}+RAF\right)\times ExitCap_{Dj,inc}\times AnF\times EC}{10^6}\right]$$

$$\sum_{Dj=1}^{n_D}\left(ExitRev_{t,Dj}\right)-\sum_{Dj=1}^{n_D}\left(Exit\,\mathrm{Re}\,v_{t,Dj,inc}\right)=TOExRF_t$$

$$SOExRF_t=\sum_{Dj=1}^{n_D}\left(ExitRev_{t,Dj,inc}\right)$$

Where

$ExitRev_{t,Dj}$	=	*Total exit capacity revenue from demand j (£m/year)*
$ExitRev_{t,Dj,inc}$	=	*Incremental exit capacity revenue from demand j (£m/year)*
$TOExRF_t$	=	*TO Exit firm allowed revenue for year t (£m)*
$SOExRF_t$	=	*SO Exit firm revenue for year t (£m)*
$InitialNMkm_{Dj}$	=	*Initial nodal marginal distance for demand j (km)*
RAF	=	*Revenue adjustment factor (km)*
$ExitCap_{Dj}$	=	*Nodal forecast daily exit capacity for demand j (GWh)*
$ExitCap_{Dj, inc}$	=	*Nodal incremental daily exit capacity for demand j (GWh)*
AnF	=	*Licence implied annuitisation factor (per year)*
EC	=	*Expansion constant (£/GWhkm)*
0.0001	=	*Minimum price (p/kWh)*
365	=	*Conversion factor from per day to per year*
100	=	*Conversion factor from p to £*
10^6	=	*Conversion factor from £ to £m*
n_p	=	*Number of exit points*

Nodal Exit Capacity Charges

The capital costs (£/GWh) are annuitised (using the annuitisation factor). The final step converts the result from £/GWh/year to p/kWh/day by dividing by 365, multiplying by 100 and dividing by 10^6.

$$ExitPrice_{Dj} = Max\left[0.0001, \left(\frac{(InitialNMkm_{Dj} + RAF) \times AnF \times EC \times 100}{10^6 \times 365}\right)_{4dp}\right]$$

Where

$ExitPrice_{Dj}$	=	*Exit price at demand j (p/kWh/day)*
$InitialNMkm_{Dj}$	=	*Initial nodal marginal distance for demand j (km)*
RAF	=	*Revenue adjustment factor (km)*
AnF	=	*Licence implied annuitisation factor (per year)*
EC	=	*Expansion constant (£/GWhkm)*
100	=	*Conversion factor from £ to pence*
10^6	=	*Conversion factor from GWh to kWh*
365	=	*Conversion factor from annual to daily price*
4dp	=	*Rounding to 4 decimal places of precision*

Zonal Exit Capacity Charges

The nodal exit capacity prices are amalgamated into exit zones by weighting them by their relevant exit capacity. The zonal exit capacity price for each zone is calculated as:

$$ZonalExitPrice_k = \left(\frac{\sum_{Dj=1}^{n_k}(ExitPrice_{Dj,k} \times ExitCap_{Dj,k})}{\sum_{Dj=1}^{n_k} ExitCap_{Dj,k}}\right)_{4dp}$$

Where

k	=	*Exit zone k*
Dj	=	*Demand j*
n_k	=	*Number of demands in zone k*
$ExitPrice_{Dj,k}$	=	*Nodal Exit price for demand j in zone k (p/ kWh/day)*
$ZonalExitPrice_k$	=	*Zonal Exit price for zone k (p/ kWh/day)*
$ExitCap_{Dj}$	=	*Nodal forecast daily exit capacity for demand j (GWh)*
4dp	=	*Rounding to 4 decimal places of precision*

The criteria used to determine the definition of the exit zones is based on DN analysis to identify the offtakes that supply a consistent subset of DN consumers.

2.5.4: The Tariff Model for Determination of NTS Entry Capacity Charges

NTS Entry Capacity Reserve Prices represent purely locational prices derived from the transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transportation of gas from the different entry locations. The issue of residual revenue recovery is addressed via the application of the TO commodity charge.

Supply/Demand Scenario

Prices for each Gas Year are set on the basis of the relevant year's base case supply and 1-in-20 peak demand data and network model, but with adjustments to the supply flows to reflect the capacity level in question (i.e. the obligated entry capacity level when setting the obligated entry reserve price for the relevant gas year). Demand flows remain unadjusted.

Where an entry point has a zero baseline capacity level (as defined in the Licence), but where permanent obligated capacity has been sold at the entry point in previous auctions, the level of permanent obligated entry capacity released within the Gas Year in question is used as the obligated entry capacity level.

To determine the entry reserve price at the obligated entry capacity level offered at an entry point, the supply scenario is adjusted for each entry point as follows:

- The supply flow is adjusted to the capacity level to be provided for the entry point in question
- All other supply flows are adjusted up or down in order of merit to balance the network back to the peak 1 in 20 demand level in the base case data

Each entry point will be analysed in this way in turn.

Supply Merit Order

The supply merit order for each NTS Entry Point reflects the least beneficial alternate supply flow, in terms of enabling capacity provision at that entry point.

The supply merit order is determined by use of the Transport Model with the base case scenario to calculate pipeline distances from each NTS Entry Point to every other entry point.

For NTS Entry Points where flow needs to be added to the base case flow to align with the required capacity level, the remaining entry point flows are reduced in order of pipeline distance merit, starting with the furthest entry point ending with the entry point with the nearest entry point.

For NTS Entry Points where flow needs to be reduced from the base case flow to align with the required capacity level, the remaining entry point flows are increased in order of pipeline distance merit, starting with the nearest entry point and ending with the furthest entry point.

Network Model

The appropriate network model for each period of capacity allocation is used i.e. the network model that includes sanctioned projects expected to be completed by the start of the Gas Year that is being modelled. All adopted connections that are fully depreciated are included at zero length.

Entry-Exit Price Adjustment

The first step of the Tariff Model is to adjust the Initial Nodal Marginal Distances (InitialNMkm) such that the predefined 50:50 split between entry and exit is obtained and so that the negative marginal distances are removed.

An additive constant Adjustment Factor (AF) must be calculated which, when added to each Initial Nodal Marginal Distance, gives a revised marginal distance for each supply (NTS ASEP) and for each demand (NTS offtake). The calculation simultaneously removes the negative marginal distances by collaring the Initial Nodal Marginal Distances at zero.

The Adjustment Factor is calculated such that the average marginal distances (flow distances) for supply and demand are equal.

$$\sum_{Si=1}^{n_S}\left(\frac{Max\left[0, InitialNMkm_{x,Si} + AF_x\right]}{n_S}\right) = \sum_{Dj=1}^{n_D}\left(\frac{Max\left[0, InitialNMkm_{x,Dj} - AF_x\right]}{n_D}\right)$$

The Nodal Marginal Distance (NMkm) for each supply is then the Initial Nodal Marginal Distance plus the Adjustment Factor. The Nodal Marginal Distance for each demand is then the Initial Nodal Marginal Distance minus the Adjustment Factor.

$$NMkm_{x,Si} = InitalNMkm_{x,Si} + AF_x \quad \text{and} \quad NMkm_{x,Dj} = InitialNMkm_{x,Dj} - AF_x$$

Where

$InitialNMkm_{x,Si}$	=	*Initial nodal marginal distance for supply i for price step x (km)*
$InitialNMkm_{x,Dj}$	=	*Initial nodal marginal distance for demand j for price step x (km)*
AF_x	=	*Adjustment factor for price step x(km)*
$NMkm_{x,Si}$	=	*Nodal marginal distance for supply i for price step x(km)*
$NMkm_{Dj}$	=	*Nodal marginal distance for demand j for price step x(km)*
n_S	=	*Number of supply charging points*
n_D	=	*Number of demand charging points*
x	=	*0 (the obligated level),1,2,….n(the highest capacity level considered for the supply or entry point).*

Entry Capacity Reserve Prices

The Nodal Marginal Distances are converted to capital costs by multiplying by the expansion constant, and annuitised using the annuitisation factor implied by the Licence. The final step converts the result from £/GWh/year to p/kWh/day by dividing by 365, multiplying by 100 and dividing by 10^6. Prices are adjusted to recognise the different calorific values of gas entering the system using ASEP specific calorific values.

The reserve price is collared at a minimum value of 0.0001 p/kWh/day.

$$EntryPrice_{Si} = Max\left[0.0001, \left(\frac{NMkm_{0,Si} \times AnF \times EC \times 100}{10^6 \times 365} \times \frac{39}{CV_{Si}}\right)_{4dp}\right]$$

Where

$EntryPrice_{Si}$	=	*Entry Reserve Price for supply i (p/kWh/day)*
$NMkm_{Si}$	=	*Nodal marginal distance for supply i (km)*
AnF	=	*Licence implied annuitisation factor (per year)*
EC	=	*Expansion constant (£/GWhkm)*
10^6	=	*Conversion factor from GWh to kWh*
100	=	*Conversion factor from £ to pence*
365	=	*Conversion factor from annual to daily price*
39	=	*Standard calorific value (MJ/m^3)*
CV_{Si}	=	*Calorific value for supply i (MJ/m^3)*
4dp	=	*Rounding to 4 decimal places of precision*

Incremental Entry Capacity Step Prices

This section describes how the nodal marginal distances are used to calculate entry long run incremental costs for each ASEP.

Long run incremental costs are calculated for an ASEP by determining the difference between adjusted nodal marginal distances for each incremental capacity level and the obligated capacity level.

The differences in the adjusted marginal distances are converted into unit (incremental) costs (£/GWh) by multiplying it by the Expansion Constant. These unit costs can then be converted into daily prices by applying the annuitisation factor[5]. An adjustment to reflect the calorific value at the ASEP is also applied.

The price schedule is established by adding each incremental price to the P_0 price to establish a price for each incremental level of capacity.

[5] The annuitisation factor is no longer contained as a separate term in the Licence but is implicit within the revenue drivers. However, a factor of 0.10272 was agreed with the Authority as quoted in paragraph 1.82 of the Transmission Price Control Review: Final Proposals, Appendices, Ofgem, 4th December 2006, Ref: 206/06b.

Incremental Distances

The Nodal Marginal Distances for each entry point being considered at each incremental capacity level are converted to Nodal Incremental Distances by calculating the difference between the Nodal Marginal Distance at the incremental level and the Nodal Marginal Distance at the obligated capacity level.

$$NIkm_{x,EntryPoint} = NMkm_{x,EntryPoint} - NMkm_{Obligated,\ EntryPoint}$$

Where

$NIkm_{x,EntryPoint}$	=	*Nodal incremental distance for the entry point for price step x (km)*
$NMkm_{x,EntryPoint}$	=	*Nodal marginal distance for the entry point for price step x (km)*
$NMkm_{Obligated,EntryPoint}$	=	*Nodal marginal distance for the entry point at the obligated capacity level (km)*
EntryPoint	=	*The entry point being analysed (a node in the set of supplies)*
x	=	*1,2,…n*
n	=	*the highest incremental capacity level considered for the entry point*

Entry Capacity Step Prices

The Nodal Incremental Distances are converted to capital costs by multiplying by the expansion constant, and annuitised using the annuitisation factor (which means that the cost is spread evenly over the expected life of the asset taking into account the required rate of return). Annuitised costs are converted from £/GWh/year to p/kWh/day by dividing by 365 multiplying by 100 and dividing by 10^6.

Annuitised costs are adjusted to recognise the different calorific values of gas entering the system using ASEP specific calorific values.

The initial incremental step price is calculated by adding the annuitised cost for the incremental capacity step to the obligated capacity (P0) reserve price.

$$Price_{0,EntryPoint} = Price_{Obligated,EntryPoint}$$

$$Price_{Obligated,EntryPoint} = Max\left[0.0001, \left(\frac{NMkm_{Obligated,EntryPoint} \times AnF \times EC \times 100}{10^6 \times 365} \times \frac{39}{CV_{EntryPoint}}\right)_{4dp}\right]$$

$$InitialPrice_{x,EntryPoint} = Price_{Obligated,EntryPoint} + \left(\frac{NIkm_{x,EntryPoint} \times AnF \times EC \times 100}{10^6 \times 365} \times \frac{39}{CV_{EntryPoint}}\right)_{4dp}$$

Where

$Price_{0,\ EntryPoint}$	=	*The P_0 price, being the Final Entry Price for the entry point for price step 0 (p/kWh/day)*
$Price_{Obligated,EntryPoint}$	=	*Price for the entry point at the obligated capacity level (p/kWh/day)*
$NMkm_{Obligated,EntryPoint}$	=	*Nodal marginal distance for the entry point at the obligated capacity level (km)*
$InitialPrice_{x,EntryPoint}$	=	*Initial Entry Price for the entry point for price step x (p/kWh/day)*
$NIkm_{x,EntryPoint}$	=	*Nodal incremental distance for the entry point for price step x (km)*
AnF	=	*Annuitisation factor (per year)*
EC	=	*Expansion constant (£/GWhkm)*
10^6	=	*Conversion factor from GWh to kWh*
100	=	*Conversion factor from £ to pence*
365	=	*Conversion factor from annual to daily price*
39	=	*Standard calorific value (MJ/m^3)*
$CV_{EntryPoint}$	=	*Calorific value for the entry point (MJ/m^3)*
4dp	=	*Rounding to 4 decimal places of precision*

EntryPoint	=	*The entry point being analysed (a node in the set of supplies)*
x	=	*1,2,…n*
n	=	*the highest incremental capacity level considered for the entry point*

New Entry Points

In the event that a connecting pipe is required to be provided by National Grid for a new entry point, the initial price schedule calculation in section "Entry Capacity Step Prices" will be replaced by the following calculation:

$$InitialPrice_{x,EntryPoint} =$$

$$Price_{Obligated,EntryPoint} + \left(\left\{ \frac{NIkm_{x,EntryPoint} \times EC \times 39}{10^6 \times CV_{EntryPoint}} + \frac{ConnectionCost_{x,EntryPoint}}{Capacity_{x,EntryPoint}} \right\} \times \frac{AnF \times 100}{365} \right)_{4dp}$$

Where

$InitialPrice_{x,EntryPoint}$	=	*Initial Entry Price for the entry point for price step x (p/kWh/day)*
$Price_{Obligated,EntryPoint}$	=	*Price for the entry point at the obligated capacity level (p/kWh/day)*
$NIkm_{x,EntryPoint}$	=	*Nodal incremental distance for the entry point for price step x (km)*
AnF	=	*Annuitisation factor (per year)*
EC	=	*Expansion constant (£/GWhkm)*
$ConnectionCost_{x,EntryPoint}$	=	*Estimate of the connection cost for the entry point for price step x (£m). This may require design and/or feasibility studies to be undertaken.*
$Capacity_{x,EntryPoint}$	=	*Capacity level for the entry point for price step x (GWh)*
10^6	=	*Conversion factor from GWh to kWh*
100	=	*Conversion factor from £ to pence*
365	=	*Conversion factor from annual to daily price*
39	=	*Standard calorific value (MJ/m*^{3}*)*
$CV_{EntryPoint}$	=	*Calorific value for the entry point (MJ/m*^{3}*)*
4dp	=	*Rounding to 4 decimal places of precision*
EntryPoint	=	*The entry point being analysed (a node in the set of supplies)*
x	=	*1,2,…n*
n	=	*the highest incremental capacity level considered for the entry point*

Ascending and Descending Price Schedules

There must be a difference of at least 0.0001 p/kWh/day between each incremental step price so that a unique clearing price may be determined for incremental capacity allocation.

If the ASEP has an ascending price curve the final incremental step prices are calculated (starting at P_0 and working forwards through the price steps) using the following equation:

$$Price_{x,EntryPoint} = Max\lfloor 0.0001 + Price_{x-1,EntryPoint}, InitialPrice_{x,EntryPoint} \rfloor$$

Where

$Price_{x,EntryPoint}$	=	*Final Entry Price for the entry point for price step x (p/kWh/day)*
$InitialPrice_{x,EntryPoint}$	=	*Initial Entry Price for the entry point for price step x (p/kWh/day)*
EntryPoint	=	*The entry point being analysed (a node in the set of supplies)*
x	=	*1,2,…n*
n	=	*the highest incremental capacity level considered for the entry point*

Otherwise, the ASEP has a descending price curve[6], so the final incremental step prices are calculated (starting from the highest price step and working backwards through the price steps) using the following equation:

$$Price_{n,EntryPoint} = InitialPrice_{n,EntryPoint}$$

$$Price_{x,EntryPoint} = Max\lfloor 0.0001 + Price_{x+1,EntryPoint}, InitialPrice_{x,EntryPoint} \rfloor$$

Where

$Price_{x,EntryPoint}$	=	*Final Entry Price for the entry point for price step x (p/kWh/day)*
$InitialPrice_{x,EntryPoint}$	=	*Initial Entry Price for the entry point for price step x (p/kWh/day)*
EntryPoint	=	*The entry point being analysed (a node in the set of supplies)*
x	=	*n-1,…2,1*
n	=	*the highest incremental capacity level considered for the entry point*

[6] For the avoidance of doubt, the P_0 price step remains unchanged in this process.

Estimated Project Values

For the purposes of determining the required commitment from bidders that would normally trigger the release of incremental capacity, as defined in the IECR, an estimated project value is calculated for each incremental capacity level from the initial incremental step prices[7] as follows:

$$ProjectValue_{x,EntryPoint} = InitialPrice_{x,EntryPoint} \times \frac{365}{100 \times AnF} \times IncCapacity_{x,EntryPoint}$$

Where

$ProjectValue_{x,EntryPoint}$	=	*Estimated project value for the entry point for price step x (£m)*
$InitialPrice_{x,EntryPoint}$	=	*Initial Entry Price for the entry point for price step x (p/kWh/day)*
AnF	=	*Annuitisation factor (year^{-1})*
100	=	*Conversion factor from £ to pence*
365	=	*Conversion factor from annual to daily price*
$IncCapacity_{x,EntryPoint}$	=	*Incremental capacity level for the entry point for price step x (GWh)*
EntryPoint	=	*The entry point being analysed (a node in the set of supplies)*
x	=	*1,2,…n*
n	=	*the highest incremental capacity level considered for the entry point*

Application of Entry Prices

The relevant gas year capacity reserve price is used to set prices in auctions as follows:

- For RMTTSEC and DSEC Reserve Prices, published in respect of a Gas Year (Gas Year Y), this means the network model including all projects expected to be completed for the start of the Gas Year.

- For MSEC Reserve Prices, published in respect of capacity allocation across three Gas Years (Gas Years Y, Y+1, Y+2), this means the network models including all projects expected to be completed for the start of each of these Gas Years.

- For QSEC Reserve Prices, published in respect of future Gas Years (Gas Years Y+2, Y+3 to Y+16), this means the network model including all projects expected to be completed for the start of Gas Year Y+2.

[7] The final incremental price steps differ from the initial incremental price steps only due to the application of the minimum price step differential (0.0001 p/kWh/day).

Table 1 summarises the use of network and supply/demand year models for calculation of NTS Entry Capacity Reserve Prices applicable from 1 October in calendar Year N (corresponding to Gas Year Y) in chronological order of auction dates and capacity release.

Table 1: Gas Years Modelled and Capacity Allocation Periods

Auction	Date Held	Gas Day - Capacity Allocation		Gas Year Modelled
		From	To	
QSEC	March [N]	1 Oct [N+1]	30 Sep [N+2]	Y+2
		1 Oct [N+2]	30 Sep [N+3]	Y+2
		1 Oct [N+3]	30 Sep [N+17]	Y+2
RMTTSEC	Sep [N] to Aug [N+1]	1 Oct [N]	30 Sep [N+1]	Y
DADSEC (Day Ahead)	30 Sep [N] to 29 Sep [N+1]	1 Oct [N]	30 Sep [N+1]	Y
WDDSEC (Within Day)	1 Oct [N] to 30 Sep [N+1]	1 Oct [N]	30 Sep [N+1]	Y
AMSEC	February [N+1]	1 Apr [N+1]	30 Sep [N+1]	Y
		1 Oct [N+1]	30 Sep [N+2]	Y+1

Network models for Gas Year Y+2 will be produced by 1 Jan calendar year N for the QSEC auction. Network models for Gas Years Y and Y+1 will be produced by 1 August in calendar year N for the remaining auctions.

Table 2: Gas Years Modelled and Capacity Allocation Periods for 2010 Auctions.

The table below summarises the price setting timetable from March 2010.

Auction	Date Held	Gas Day - Capacity Allocation		Gas Year Modelled
		From	To	
QSEC	March 2010	1 Oct 2011	30 Sep 2012	2012/13
		1 Oct 2012	30 Sep 2013	2012/13
		1 Oct 2013	30 Sep 2027	2012/13
RMTTSEC	Sep 2010 to Aug 2011	1 Oct 2010	30 Sep 2011	2010/11
DADSEC (Day Ahead)	30 Sep 2010 to 29 Sep 2011	1 Oct 2010	30 Sep 2011	2010/11
WDDSEC (Within Day)	1 Oct 2010 to 30 Sep 2011	1 Oct 2010	30 Sep 2011	2010/11
AMSEC	February 2011	1 Apr 2011	30 Sep 2011	2010/11
		1 Oct 2011	30 Sep 2012	2011/12

Network models for Gas Year 2012/13 will be produced, so that prices are generated at least two months ahead of the QSEC auction, during January 2010. QSEC prices are therefore set using the network model for the year prior to the first year of incremental release. Network models for Gas Years 2010/11 and 2011/12 will be updated by 1 August 2010 for the remaining auctions. Prices for auctions other than QSEC are therefore set using the network model for the year of capacity release.

New Entry Points

For new NTS Entry Points, where no permanent obligated entry capacity has been sold the entry capacity reserve price is set at the transportation model derived annuitized long run marginal cost for the relevant entry point with that entry point flowing at the obligated level.

CHAPTER 3: COMMODITY CHARGES

NTS commodity charges consist of charges per unit of gas allocated to shippers at exit and entry.

The commodity charges on gas flows at NTS Storage facilities, other than on the amount of gas utilised as part of the operation of any NTS Storage facility, known as storage "own use" gas are zero. "Own use "gas is the difference between the quantity that is injected into storage and the quantity that is available for withdrawal back into the system.

"Own use" gas is treated as leaving the NTS at that exit point, and hence attracts the standard NTS commodity charge (both TO and SO components). The quantity of storage own use gas attributed to Users is notified by the Storage Manager to National Grid in accordance with the terms of the Storage Connection Agreement in respect of the NTS Storage Facility.

3.1 NTS TO Entry Commodity Charge

This is a charge per unit of gas allocated to shippers at entry terminals but not storage facilities. The charge is levied where National Grid forecasts that the entry capacity auction revenue will be below the target revenue.

The charge will be set to zero where entry capacity auction revenue is at, or above, the entry capacity target level. National Grid will assess its forecast entry capacity auction revenue following the AMSEC auction and, if necessary, determine a 12 month schedule of TO commodity charges to apply from the following October. National Grid would only depart from this schedule under exceptional circumstances.

The setting of TO exit commodity charges from 1 October 2012 is set out in Appendix C.

3.2 NTS TO Entry Commodity Charge Rebate

The TO entry commodity rebate mechanism reduces any TO over-recovery resulting from NTS Entry Capacity auctions. The process may be triggered at the end of the formula year based on the outcome of all NTS Entry Capacity auctions that represent a TO revenue stream. This mechanism will only be triggered if there remains a residual over-recovery amount after taking into account any revenue redistributed by the buy-back offset mechanism as defined in 2.3.2 above and if this residual over-recovery is in excess of £1m (this equates to the minimum TO Entry Commodity price of 0.0001 p/kWh).

Trigger

- The TO Entry Commodity rebate mechanism will be triggered if there remains a residual over-recovery amount after taking into account any revenue redistributed by the buy-back offset mechanism

- The process will be triggered at the end of the formula year based on the outcome of all NTS Entry Capacity auctions that represent a TO revenue stream.

- Credits will only be paid if the residual over-recovery is in excess of £1M (this equates to the minimum TO Entry Commodity price of 0.0001 p/kWh)

Mechanism

- Any residual over-recovery revenue, taking into account any payments resulting from the buy-back offset process, will be available as a rebate to shippers

- The ratio of the remaining TO over-recovery amount and the TO Entry Commodity Revenue paid will be calculated

- The ratio will be capped at 1 i.e. only the TO Entry Commodity revenue received will be rebated

- A rebate of TO Entry Commodity charges paid will be calculated based on the ratio

- The rebate would be paid following the formula year

3.3 NTS TO Entry Commodity Charge Credit

Trigger

- The credit, which represents a retrospective negative TO Entry Commodity charge, will be used if there remains a residual over-recovery amount after taking into account any revenue redistributed via the TO Entry Commodity Rebate Mechanism (as described above).

- The mechanism will be triggered, in the event of TO over-recovery, even if the buy-back offset mechanism had not been triggered or the TO Entry Commodity Rebate Mechanism had been triggered but had not been utilised due to a zero TO Entry Commodity rate having applied.

- The mechanism will be triggered at the end of the formula year based on the outcome of all NTS Entry Capacity auctions that represented a TO revenue stream.

Mechanism

- Any residual TO entry revenue remaining after taking into account credits resulting from the Entry Capacity buy-back offset and the TO Entry Commodity Rebate mechanisms will be available as a credit to shippers .

- Credits will only be paid based on relevant entry allocations i.e. those allocations that attract the Entry Commodity charge.

- Credits will only be paid if the residual over recovery is in excess of £1m (this equates to the minimum TO Entry Commodity price of 0.0001 p/kWh)

- Each Shipper's credit will be calculated as a proportion of the total available credits based on the ratio of that Shipper's SO Entry Commodity charges to the aggregate of all SO Entry Commodity charges paid over the formula year e.g. if the value of the credits paid through the proposed mechanism represents 5% of all SO Entry Commodity charges paid then each Shipper will receive a credit representing 5% of the SO Entry Commodity charges that it has paid over the formula year. For the avoidance of doubt, this calculation excludes optional ("short-haul") entry commodity charges. The credit will be treated as TO for regulatory reporting.

- Credits will be paid following the end of the formula year. Note that NTS Entry Commodity charges for the last month of the formula year (March) are invoiced in the following May.

3.4 NTS SO Commodity Charge

This is a charge per unit of gas transported by the NTS and is applied uniformly on both entry and exit flows at all NTS system points. The target revenue to be raised by the charge is the NTS SO allowed revenue, including any incentive additions or deductions, less any revenue to be obtained from the St. Fergus compression charge and the Optional NTS commodity tariff.

The setting of SO and TO exit commodity charges from 1 October 2012 is set out in Appendix C.

3.5 NTS Optional Commodity Charge "Shorthaul"

Shippers can elect to pay the optional tariff as an alternative to both the entry and exit NTS SO commodity charges and the NTS TO commodity charge. The tariff is derived from the estimated cost of laying and operating a dedicated pipeline of NTS specification. A charging function has been calculated based on a range of flow rates and pipeline distances. The larger the load and the closer to an Entry point the smaller the NTS Optional Commodity Charge should be as this reflects the unit cost of laying a pipeline. Although the tariff is available to all daily-metered supply points, in practice it is therefore only attractive for large supply points situated close to terminals as at certain distances and loads it will become economic to pay standard Commodity charges.

In practice the Shipper nominates an Exit Point and a relevant (non-storage) entry point. Shippers can nominate a number of exit points against the same entry point but cannot nominate multiple entry points to the same exit point. The NTS Optional Commodity Charge is levied on the smaller of the two daily shipper allocations at these points, with the assumption made that any 'extra' gas must have come from another Entry point or alternatively flowed to another Exit point. For the purposes of invoicing all Exit throughput is charged at the NTS Optional Commodity rate with a reconciliation carried out a month later based on actual flows at these nominated points. To nominate an Exit point for the NTS Optional Commodity rate please contact the Unique Sites team at Xoserve.

3.6 Compression Charge

An additional charge is payable where gas is delivered into the NTS at a lower pressure than that required, giving rise to a need for additional compression. The compression charge is derived from an analysis of costs at the compressor site and the annual throughput at that site.

CHAPTER 4: OTHER CHARGES

4.1 Other Shipper Services Charges

There are other charges applied to services which are required by some shippers but not by all, for example special allocation arrangements. It is more equitable to levy specific cost reflective charges for these services on those shippers that require them. Income from these charges is included in the regulated SO transportation income. These charges include:-

- charges for the administration processes required to manage the daily operations and invoicing associated with CSEPs;
- charges for the administration of allocation arrangements at shared supply meter points and Interconnectors; and
- charges for specific services at Interconnectors.

The methodology used to calculate the appropriate level of these charges is based on an assessment of the costs, incurred by Xoserve, of the ongoing activities involved in providing the services. The charges are forward looking and take into account anticipated enhancements to the methods and systems used.

4.2 DN Pensions Deficit Charge

A specific annual cost allowance for the part-funding of the deficit in the NGUK Pension Scheme has been included in National Grid's TO price control formula. In respect of the share of this allowance that arises from pension deficit costs associated with former employees of the DNs, the allowed cost is recovered via the application of a DN Pensions Deficit Charge which is levied on each of the DNOs on a monthly basis. The actual monthly pension charges for each DN are given in National Grid's Statement of Charges and are in accordance with the total annual allowance as set out in Special Standard Condition C8B of the Licence.

As the "target revenue" is fixed for each of the formula years in the Price Control period 2007 - 2012, we would anticipate that this should equal the recoverable revenue for each formula year. Hence this should avoid any "carry over" of allowable revenue from one formula year to the next.

4.3 NTS Entry Capacity Retention Charge

NTS Entry Capacity Substitution is where National Grid moves unsold non-incremental obligated entry capacity from one (donor) ASEP to meet the demand for incremental obligated entry capacity at a different (recipient) ASEP. Users are able to exclude capacity at potential donor ASEPs from being treated as substitutable capacity without having to buy and be allocated the capacity. To do this they are able to take out a “retainer”.

The retainer is valid for one year, covering all QSEC auctions (including ad-hoc auctions) held in this period. National Grid will exclude the relevant quantity from the substitution process, but the retainer will not create any rights to the User to be allocated or to use the capacity. The retainer will not prevent Users (including the User taking out the retainer) from buying that capacity at the ASEP in question in the period covered by the retainer.

The retainer is subject to a one-off charge which is payable via an ad hoc invoice raised within 2 months of the QSEC auction allocations being confirmed. If a User wishes to protect capacity for more than one year then a further retainer must be obtained each year and a charge will be payable each year for which a retainer is taken out.

Where any capacity covered by a retainer is allocated, a refund of the retention fee may be made; for example, for a retainer taken out for gas year 2013/14 in January 2010, a refund can be triggered by an allocation at the relevant ASEP made during a QSEC auction in 2010, 2011 and 2012, and an AMSEC auction in 2013 and 2014. For a full description of the capacity retainer process, see the “The Entry Capacity Substitution Methodology Statement”[8].

NTS Entry Capacity Retention Charges, in regard to non-incremental obligated entry capacity, are calculated based on the minimal capacity charge rate of 0.0001 pence per kWh per day applying over a time period of 32 quarters; this equates to 0.2922 p/kWh of entry capacity retained.

NTS Entry Capacity Retention Charges and refunds in regard to non-incremental obligated entry capacity are treated as TO revenue; this would result in reduced TO Entry Commodity Charges in the case of charges incurred for retained capacity or increased TO Entry Commodity Charges in the case of subsequent refunds.

[8] The Entry Capacity Substitution Methodology Statement can be found on the National Grid website at; http://www.nationalgrid.com/uk/Gas/Charges/statements/

APPENDIX A - BUSINESS RULES FOR INTERRUPTIBLE SUPPLY POINTS

A.1: Introduction

1.1 Contracted interruptible exit capacity remains unchanged at 45-day standard. Sites nominated by National Grid as TNI can be interrupted for a greater period.

1.2 All interruptible supply points continue to avoid the NTS (TO) exit capacity charge and the capacity element of the LDZ standard charge. The optional LDZ charge, if chosen as an alternative to the standard LDZ charge, continues to be payable for interruptible supply points.

1.3 For each occurrence of nominated interruption beyond 15 days an additional credit will be offered. National Grid conducts determination of cumulative occurrences of nominated interruption on a site-specific basis.

1.4 These business rules became effective on 1 October 2002 and refer to additional interruption credits for above 15-day interruption.

A.2: Calculation of Payment

2.1 The credit will be calculated in accordance with National Grid's Pricing Methodology as established in PC74.

2.2 The charge quantity will be determined from the supply point registered interruptible exit capacity (SOQ) at the point of interruption multiplied by those qualifying occurrences of interruption in excess of 15 days as specified in sections A.3 and A.4.

2.3 The charge quantity of any Partial interruptible site, including shared supply points, being limited to that quantity (kWh rate) of exit capacity tranche(s) that was actually requested by National Grid for interruption.

2.4 Subject to 2.1 above, such shared supply point tranche(s) charge quantity will, where more than one interruptible shared user holds interruptible exit capacity at the shared supply point, be split by each user in ratio to such user's interruptible initial (D-1) gas flow nomination as a percentage of the total aggregate interruptible initial (D-1) gas flow nomination for the shared supply point.

2.5 The charge quantity of any Interruptible Firm Allowance (IFA) site being limited to that supply point registered interruptible exit capacity net of any firm exit capacity entitlement specified within each site IFA agreement.

2.6 The charge quantity of any interruptible NTS CSEP being limited to that quantity (kWh rate) of exit capacity that was actually requested on the day by National Grid for interruption.

2.7 Subject to 2.4 above, such NTS CSEP charge quantity will, where more than one interruptible user is registered at the NTS CSEP, be split by each user in ratio to such user's interruptible initial (D-1) gas flow nomination as a percentage of the total aggregate interruptible initial (D-1) gas flow nomination for the NTS CSEP.

2.8 For the avoidance of doubt, a shared user's interruptible supply point capacity (SOQ), or such tranche under 2.1 above, will be used for charge quantity purposes, and not the shared supply point aggregate interruptible capacity (SSP SOQ).

2.9 User proposed ratios as alternatives to mechanisms described under 2.2 and 2.5 above will not be allowed.

2.10 Supply point data at the point of interruption will be used for charge calculation purposes.

2.11 Payment constructed from charge quantities determined in accordance with this section 2 will not be the subject of later reconciliation should any component capacity subsequently change prospectively within the formula year.

2.12 The registered shipper at the point of interruption will be the qualifying shipper for receipt of any payment.

A.3: Count of Interruptible Days

3.1 A count of interruption occurrence will be maintained for each site within each formula year, with each day or part day of interruption representing an increment of 1.

3.2 The count will include such occurrence of qualifying interruption as defined within section A.4 below.

3.3 The count will start from zero on 1 April of each formula year beginning at April 2002.

3.4 The count will end on 31 March of each formula year.

3.5 This count will be used solely for determining the level of credit due, if any, for each site where the frequency of nominated interruption exceeds 15 days within any formula year, monitoring of transportation contract interruption will be maintained separately for each gas year.

A.4: Qualifying Interruption

4.1 The count of qualifying interruptible days under section A.3 above will increment, but subject to 4.3 below, where curtailment of gas supply was due to:

4.2 Interruption arising from an NTS or LDZ constraint within National Grid's transportation system;

4.3 Interruption arising for Test purposes as described within UNC section G 6.7.3 (ii).

4.4 The count of qualifying interruptible days under section A.3 above will not increment where curtailment of gas supply was due to:

- emergency interruption [emergency cessation of gas supply]; and
- any form of commercial interruption instigated by a shipper.

4.5 National Grid's determination of a site for interruption will increment that site's count of interruptible days under section A.3 above.

4.6 Where National Grid has called interruption, a User can request that an alternative site(s) should be interrupted as described in section G 6.8.2 of the UNC. In such circumstances National Grid will, for the purposes of section A.3 above, maintain a count based on the site National Grid originally nominated for interruption.

4.7 Failure to interrupt of the National Grid proposed site or shipper proposed alternative site(s), will result in a reduction by 1 (to a minimum of zero) of the site count of interruptible days determined under 4.3 above and such that:

- no payment will be made for the National Grid proposed and shipper accepted site that subsequently fails to interrupt;
- no payment will be made for the National Grid proposed site where shipper substituted for a matched target volume site that subsequently fails to interrupt; and
- where multiple sites are substituted by a shipper, the payment(s) made to National Grid proposed site(s) will be reduced by that shipper substituted target volume identified as failing to interrupt, with such volume reduction being applied in site highest unit charge rate ranked order.

A.5: Unit Rate

5.1 The unit rate will be expressed in pence per kWh of peak day capacity.

5.2 NTS unit rates will be 1/15th of the annual (daily rate × 365) NTS (TO) exit capacity rates valid at the point of interruption, and will be site-specific rates applied to occurrences of qualifying interruption in excess of 15 days.

5.3 Payment constructed from unit rates determined in accordance with this section 5 will not be the subject of later reconciliation should firm NTS (TO) exit capacity rates or any peak capacity component contained within such rate calculation, subsequently change within the formula year.

5.4 For the avoidance of doubt, User election of the optional LDZ tariff excludes such sites from qualification for LDZ payments in respect of interruption in excess of 15 days, such sites will still be eligible for receipt of any NTS component.

A.6: Invoice

6.1 Payment of all credits accrued in a calendar month will be made within the following month.

6.2 Subject to 4.4 above, National Grid will not issue a payment where it has reasonable grounds to believe that such payment is dependent upon the outcome of failure to interrupt investigation. Payment will be released as soon as practically possible should such failure to interrupt be disproved.

A.7: Information Provision

7.1 National Grid will publish the count of interruptible days as specified within section A.3 above where that supply point count exceeds 12 days, publication will be at an aggregate LDZ or aggregate NTS level. The information in 7.1 will be published on the National Grid web site and updated on a weekly basis.

APPENDIX B - TREATMENT OF UNDER/OVER RECOVERY ‘K’

The following table defines the calculations used to calculate separate entry and exit K from the reported TOKt term defined within the national Grid Licence in respect of the NTS.

<table>
<tr><th>Net Position</th><th>Exit</th><th>Entry</th><th>Calculation</th></tr>
<tr><td rowspan="3">Net Over Recovery</td><td>Exit Over recovery</td><td>Entry Under-recovery</td><td>TOKEnt = (TOREn t-1 – TOMAREnt-1) x (1+ IRt/100)
TOKExt = TOKt – TOKEnt</td></tr>
<tr><td>Exit Under-recovery</td><td>Entry Over recovery</td><td>TOKExt = (TOREx t-1 – TOMAREx t-1) x (1+ IRt /100)
TOKEnt = TOKt – TOKExt</td></tr>
<tr><td colspan="2">Over Recovery</td><td>TOKExt = (TORExt-1 – TOMAREx t-1) x (1+ (IRt + PIt)/100)
TOKEnt = (TOREnt-1 – TOMAREnt-1) x (1+ (IRt + PIt)/100)</td></tr>
<tr><td rowspan="3">Net Under Recovery
(or zero)</td><td>Exit Over recovery</td><td>Entry Under-recovery</td><td rowspan="3">TOKExt = (TORExt-1 – TOMARExt-1) x (1+ IRt /100)
TOKEnt = (TOREnt-1 – TOMAREnt-1) x (1+ IRt /100)</td></tr>
<tr><td>Exit Under-recovery</td><td>Entry Over recovery</td></tr>
<tr><td colspan="2">Under Recovery</td></tr>
<tr><td colspan="4">Where
TOKEnt ~ TO Entry Revenue adjustment factor in respect of formula year t for charging purposes
TOREnt-1 ~ TO Entry Revenue collected in year t-1
TOMAREn t-1 ~ TO Maximum Allowed Revenue allocated to Entry in the Charging Methodology
IRt ~ Percentage interest rate in respect of formula year t [Licence Special Condition C8B (3)(d)]
PIt ~ Penalty interest rate in respect of formula year t [Licence Special Condition C8B (3)(d)]
TOKt ~ Revenue adjustment factor in respect of formula year t [Licence Special Condition C8B (3)(d)]
TOKExt ~ TO Exit Revenue adjustment factor in respect of formula year t for charging purposes
TORExt-1 ~ TO Exit Revenue collected in year t-1
TOMAREx t-1 ~ TO Maximum Allowed Revenue allocated to Exit in the Charging Methodology</td></tr>
</table>

APPENDIX C - EXIT (FLAT) CAPACITY & COMMODITY PRICE SETTING FROM 1ST OCTOBER 2012

The following represents the changes to the Charging Methodology in regard to the setting of actual and indicative NTS Exit (Flat) Capacity and Commodity prices applying from 1st October 2012 as a consequence of the direction to implement UNC Modification Proposal 0195AV which is introducing exit reform from 1st October 2012.

Only those sections and paragraphs where changes are required to the prevailing methodology statement are documented. In addition Appendix A "BUSINESS RULES FOR INTERRUPTIBLE SUPPLY POINTS" will be deleted and all references to the Licence defined revenue foregone arrangements will be removed as these expire with Exit Reform.

The Charging Methodology as amended by this appendix will define the methodology for determining indicative NTS Exit (Flat) Capacity prices from 1st April 2009 in relation to capacity released from 1st October 2012. From 1st October 2012, the changes outlined in this appendix will be incorporated into the main body of the charging methodology statement and will be used for the setting of actual NTS Exit (Flat) Capacity prices applying from that date.

CHAPTER 2: CAPACITY CHARGES

2.1 System Exit Firm Capacity

The terms on which Enduring Annual, Annual and Daily firm NTS Exit (Flat) Capacity is sold are set out in the UNC Section B. Charges reflect the estimated long run marginal cost (LRMC) of reinforcing the system to transport additional gas between entry and exit points. The calculations are described in more detail below.

2.2 System Exit Off-Peak Capacity

The terms on which Off-peak NTS Exit (Flat) Capacity Enduring is sold are set out in the UNC Section B. Off-peak capacity is auctioned on a daily day-ahead basis with a zero reserve price.

2.5.1: The Transport Model

Model Input Data

The transport model calculates the marginal costs of investment in the transmission system that would be required as a consequence of an increase in demand or supply at each connection point or node on the transmission system, based on analysis of peak conditions on the transmission system. The measure of the investment costs is in terms of £/GWhkm, a concept used to calculate marginal costs, hence marginal changes in flow distances based on increases at entry and exit points are estimated initially in terms of increases or decreases in units of kilometres of the transmission system for a small energy injection to the system.

The transport model requires a set of inputs representative of the cost of providing capacity on the transmission system:

- Nodal supply and demand data (GWh)
    - Distribution Network (DN) and Direct Connection (DC) baseline plus obligated incremental exit capacity levels by offtake other than bi-directional sites where the demand will be zero
    - Aggregate System Entry Point (ASEP) supplies
- Transmission pipelines between each node (km)
    - Existing pipelines
    - New pipelines expected to be operational at the beginning of the gas year under analysis
- Identification of a reference node

Model Inputs

The nodal supply data for the Transport Model will be derived from the supply/demand data set out in the most recent Ten Year Statement for each year for which prices are being set. The aggregate storage and Interconnector flows will be adjusted such that a supply and demand balance is achieved. This initial supply and demand match is achieved by reducing supplies in a merit order to match the forecast demand. Supplies are reduced, until a match is achieved, using the following sequence; short range storage facilities (LNG), mid range storage facilities, long range storage facilities, Interconnectors, LNG Importation Facilities, and Beach Terminals. The supply figures at Storage and Interconnector entry points therefore may be set at a level less than or equal to the expected entry point capability.

Nodal demand data for the transport model will be the baseline plus obligated incremental exit flat capacity for DN offtakes and direct connections other than for bi-directional sites where the demand will be zero.

National Transmission System network data for the charging year will be based on data taken from National Grid's most recent Ten Year Statement.

2.5.2: The Tariff Model

The Expansion Constant

The expansion constant, expressed in £/GWhkm, represents the capital cost of the transmission infrastructure investment required to transport 1 GWh over 1 km. Its magnitude is derived from the projected cost of an 85bar pipeline and compression for a 100km NTS network section. The 100km distance was selected as this represents the typical compressor spacing on the NTS. The expansion constant derived in gas year N will be used to derive all indicative and actual prices for gas year N+4 e.g. the expansion constant derived in 2009 will be used to set all indicative and actual prices for gas year starting 1st October 2012. The table below details the expansion constant(s) used for each gas year.

Expansion Constant Used for Price Setting

Gas year	Expansion constant
2012/13	2437

2.5.3: The Tariff Model for Determination of NTS Exit (Flat) Capacity Charges

NTS Exit Capacity Charges are administered rates designed to recover 50% allowed TO revenue when they are applied to baseline NTS Exit (Flat) Capacity levels (with the remaining 50% TO allowed revenue being recovered through Entry charges). The process for calculating NTS Exit Capacity Charges is described below.

Supply/Demand Scenario and Network Model

Prices for each Gas Year are calculated using the relevant year's supply and demand data and network model (e.g. if setting exit capacity prices for Gas Year 20012/13, the base case supply/demand forecast for 20012/13 and the base network model for 20012/13 are used).

TO Revenue Recovery Adjustment

The total TO revenue to be recovered through baseline NTS Exit (Flat) Capacity and Commodity Charges is determined each year with reference to the Price Control formulae stated in the Licence.

In any given year t, a target revenue figure for Firm Exit Capacity Charges (Target $TOExRF_t$) is set. An adjustment is made to compensate for any under or over-recovery from the previous year (TOK_t). For further information, please refer to Special Condition C8B and C8E of the Licence.

Revenue from Incremental Obligated NTS Exit (Flat) Capacity Charges is treated as SO revenue within the Price Control formulae stated in the Licence (SOExRFt). For further information, please refer to Special Condition C8C of the Licence.

NTS Exit (Flat) Capacity prices are set through the Transportation Model such that target exit capacity revenue equals baseline (TO) Exit (Flat) Capacity Revenue. The charges are set such that baseline (TO) exit revenue, i.e. baseline NTS Exit (Flat) Capacity levels multiplied by the relevant offtake prices, represent 50% of TO remaining allowed revenue after deducting non-capacity TO charge revenues including DN pensions charge revenue. Any shortfall in TO Exit (Flat) Capacity revenue will be collected through the TO Exit (Flat) Commodity charge.

A single additive constant Revenue Adjustment Factor (RAF) is calculated using Microsoft Excel Solver which, when added to the Initial Nodal Marginal Distance at each demand, gives a revised marginal distance for each demand, such that the total revenue to be recovered from baseline (TO) Exit (Flat) Capacity charges equals the target revenue (i.e. $TOExRF_t$). The Incremental SO revenue (i.e. SOExRFt) can be calculated from the prices where incremental obligated exit flat capacity is released.

The calculation simultaneously removes the negative marginal distances by collaring the revenue to that level implied by the minimum price of 0.0001 p/kWh.

$$ExitRev_{t,Dj} = Max\left[(0.0001/100) \times ExitCap_{Dj} \times 365, \frac{\left(InitialNMkm_{Dj} + RAF\right) \times ExitCap_{Dj} \times AnF \times EC}{10^6}\right]$$

$$ExitRev_{t,Dj,inc} = Max\left[(0.0001/100) \times ExitCap_{Dj,inc} \times 365, \frac{\left(InitialNMkm_{Dj} + RAF\right) \times ExitCap_{Dj,inc} \times AnF \times EC}{10^6}\right]$$

$$TOExRF_t = \sum_{Dj=1}^{n_D} \left(ExitRev_{t,Dj}\right)$$

$$SOExRF_t = \sum_{Dj=1}^{n_D} \left(ExitRev_{t,Dj,inc}\right)$$

Where

$ExitRev_{t,Dj}$	=	*TO exit capacity revenue from demand j (£m/year)*
$ExitRev_{t,Dj,inc}$	=	*SO Incremental obligated exit flat capacity revenue from demand j (£m/year)*
$TOExRF_t$	=	*TO Exit firm allowed revenue for year t (£m)*
$SOExRF_t$	=	*SO Exit firm revenue for year t (£m)*
$InitialNMkm_{Dj}$	=	*Initial nodal marginal distance for demand j (km)*
RAF	=	*Revenue adjustment factor (km)*
$ExitCap_{Dj}$	=	*Nodal baseline exit flat capacity for demand j (GWh/day)*
$ExitCap_{Dj,\ inc}$	=	*Nodal incremental obligated exit flat capacity for demand j (GWh/day)*
AnF	=	*Licence implied annuitisation factor (per year)*
EC	=	*Expansion constant (£/GWhkm)*
0.0001	=	*Minimum price (p/kWh)*
365	=	*Conversion factor from per day to per year*
100	=	*Conversion factor from p to £*
10^6	=	*Conversion factor from £ to £m*

Zonal Exit Capacity Charges

[Section deleted]

CHAPTER 3: COMMODITY CHARGES

3.4 NTS SO Entry & Exit (Flat) Commodity Charge

This is a charge per unit of gas transported by the NTS and is applied uniformly on both entry and exit flows at all NTS system points. The target revenue to be raised by the charge is the NTS SO allowed revenue, including any incentive additions or deductions, less any revenue to be obtained from the St. Fergus compression charge and the Optional NTS commodity tariff.

[section relating to storage commodity charging moved]

3.5 NTS Optional Commodity Charge "Shorthaul"

Shippers can elect to pay the optional tariff as an alternative to both the entry and exit NTS (SO & TO) commodity charges.

3.8 NTS TO Exit Commodity Charge [New Section]

This is a charge per unit of gas allocated to shippers at exit points but not storage facilities. The charge is levied where National Grid forecasts that the exit capacity revenue will be below the target revenue.

National Grid will assess its forecast exit capacity revenue following the relevant application periods and, if necessary, determine a 12 month schedule of TO commodity charges to apply from the following October. National Grid would only depart from this schedule under exceptional circumstances.

3.9 NTS Exit Commodity Charging at Storage [New Section]

At present, National Grid does not levy commodity charges on gas flows at NTS Storage facilities, other than on an amount of gas, utilised as part of the operation of any NTS Storage facility, known as storage "own use" gas. This is effectively the difference between the quantity that is injected into storage and the quantity that is available for withdrawal back into the system. For the purposes of charging, the "own use" gas is treated as leaving the NTS at that exit point, and hence attracts both the standard NTS SO & TO Exit (Flat) Commodity charges. The quantity of storage own use gas attributed to Users is notified by the Storage Manager to National Grid in accordance with the terms of the Storage Connection Agreement in respect of the NTS Storage Facility.

TIMELINE FOR INDICATIVE & ACTUAL PRICES

The following tables show the indicative and actual prices that will be generated in each year from 2009 to 2012 starting from the first application period in summer 2009 in relation to the initial 1st October 2012 capacity release date. The prices required for 2012 represent all prices that would be required for later years.

Key
Actual prices and daily reserve prices
Indicative Prices

2009 – Applications

Gas Year Modelled	Used For	Gas Day - Capacity		Application Window / Date Auction(s) Held
		From	To	
2012/13	Enduring Annual NTS Exit (Flat) Capacity	1 Oct 2012	-	Summer 2009 Application Window
		1 Oct 2013	-	
		1 Oct 2014	-	

2010 – Applications

Gas Year Modelled	Used For	Gas Day - Capacity		Application Window / Date Auction Held
		From	To	
2012/13	Annual NTS Exit (Flat) Capacity	1 Oct 2012	30 Sep 2013	Summer 2010 Application Window
2013/14	Enduring Annual NTS Exit (Flat) Capacity	1 Oct 2013	-	Summer 2010 Application Window
		1 Oct 2014	-	
		1 Oct 2015	-	

2011 – Applications

<table>
<tr><th rowspan="2">Gas Year Modelled</th><th rowspan="2">Used For</th><th colspan="2">Gas Day - Capacity</th><th rowspan="2">Application Window / Date Auction Held</th></tr>
<tr><th>From</th><th>To</th></tr>
<tr><td>2012/13</td><td>Annual NTS Exit (Flat) Capacity</td><td>1 Oct 2012</td><td>30 Sep 2013</td><td>Summer 2011 Application Window</td></tr>
<tr><td>2013/14</td><td>Annual NTS Exit (Flat) Capacity</td><td>1 Oct 2013</td><td>30 Sep 2014</td><td>Summer 2011 Application Window</td></tr>
<tr><td rowspan="3">2014/15</td><td rowspan="3">Enduring Annual NTS Exit (Flat) Capacity</td><td>1 Oct 2014</td><td>-</td><td rowspan="3">Summer 2011 Application Window</td></tr>
<tr><td>1 Oct 2015</td><td>-</td></tr>
<tr><td>1 Oct 2016</td><td>-</td></tr>
</table>

2012 – Auctions/Applications

<table>
<tr><th rowspan="2">Gas Year Modelled</th><th rowspan="2">Used For</th><th colspan="2">Gas Day - Capacity</th><th rowspan="2">Application Window / Date Auction(s) Held</th></tr>
<tr><th>From</th><th>To</th></tr>
<tr><td rowspan="5">2012/13</td><td>Enduring Annual NTS Exit (Flat) Capacity</td><td>1 Oct 2012</td><td>30 Sep 2013</td><td>Capacity booked in Summer 2009 Application Window</td></tr>
<tr><td>Annual NTS Exit (Flat) Capacity</td><td>1 Oct 2012</td><td>30 Sep 2013</td><td>Capacity booked in Summer 2012 Application Window</td></tr>
<tr><td>Daily Firm NTS Exit (Flat) Capacity (Day Ahead)</td><td>1 Oct 2012</td><td>30 Sep 2013</td><td>30 Sep 2012 to 29 Sep 2013</td></tr>
<tr><td>Daily Firm NTS Exit (Flat) Capacity (Within Day)</td><td>1 Oct 2012</td><td>30 Sep 2013</td><td>1 Oct 2012 to 30 Sep 2013</td></tr>
<tr><td>Off-Peak Daily NTS Exit (Flat) Capacity</td><td>1 Oct 2012</td><td>30 Sep 2013</td><td>30 Sep 2012 to 29 Sep 2013</td></tr>
<tr><td>2013/14</td><td>Annual NTS Exit (Flat) Capacity</td><td>1 Oct 2013</td><td>30 Sep 2014</td><td>Summer 2012 Application Window</td></tr>
<tr><td>2014/15</td><td>Annual NTS Exit (Flat) Capacity</td><td>1 Oct 2014</td><td>30 Sep 2015</td><td>Summer 2012 Application Window</td></tr>
<tr><td rowspan="3">2015/16</td><td rowspan="3">Enduring Annual NTS Exit (Flat) Capacity</td><td>1 Oct 2015</td><td>-</td><td rowspan="3">Summer 2012 Application Window</td></tr>
<tr><td>1 Oct 2016</td><td>-</td></tr>
<tr><td>1 Oct 2017</td><td>-</td></tr>
</table>

APPENDIX D – CLASSIFICATION OF SUPPLY POINTS

Beach Supplies

- Bacton excluding BBL and IUK
- Barrow
- Burton Point (also known as "Point of Ayr)
- Easington including Langeled, excluding Rough
- St Fergus
- Teesside including Excelerate
- Theddlethorpe
- Wytch Farm (Onshore field)

Interconnectors

- BBL
- IUK

Long Range Storage

- Rough

LNG Importation (incorporating onshore storage)

- Isle of Grain
- Milford Haven

Mid-range Storage

Existing sites and those currently under construction, due to be operational in the relevant gas year, as outlined in Section 4.6 of the Ten Year Statement

Short-range Storage

- Avonmouth
- Glenmavis
- Partington

Glossary

1 in 20 Peak Day Demand	The peak day demand that, in a long series of winters, with connected load being held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, each winter being counted only once.
Obligated Entry Capacity	The amount of System Entry Capacity which National Grid is required to make available to Users pursuant to the Licence .
Capacity Year	The period from 1 April in any year until and including 31 March in the following year.
Exit Zone	Each Local Distribution Zone (LDZ) is divided into one or more NTS exit zones for determining charges.
Formula Year	The period from 1 April in any year until and including 31 March in the following year.
IECR Statement	The statement prepared and published by National Grid in accordance with Special Condition C15 of the Licence.
Local Distribution Zone (LDZ)	Part of the system, other than the NTS, for the time being designated by National Grid as such, and described in the Ten Year Statement, or (where the context requires) the area in which such part of the system is located.
National Transmission System (NTS)	Part of the system for the time being designated by National Grid as such, and described in the Ten Year Statement.
Supply Point	A System Exit Point comprising the Supply Meter Point or Supply Meter Points for the time being registered in the name of a User pursuant to a Supply Point Registration.
Ten Year Statement	A statement (or revised statement) required to be prepared by National Grid pursuant to Special Condition C2 of the Licence.