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Determining Revenue Drivers for Exit Points: Abernedd, Barking and Coryton

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Target audience: Network licensees, gas terminal developers, gas shippers, investors, gas storage developers, consumer representatives and other interested parties

Overview:
National Grid Gas (NGG) has requested revenue drivers be included in its gas transporter licence for exit points at Abernedd, Barking and Coryton. Revenue drivers are used to automatically flex NGG's allowed revenue upwards in response to demand for additional capacity which is financially backed by user commitment. This consultation invites comments on the proposed methodology to determine these revenue drivers. It discusses the three main issues in setting these revenue drivers which are the cost assumptions used, the treatment of the Fleetwood entry point in the modelling and how to account for contracting as a potential alternative to physical investment in delivering the incremental exit capacity requested. This document sets out our analysis of these different options. Our preference at this stage, subject to consideration of consultation responses, is to use the cost assumptions used at the Fourth Transmission Price Control Review (TPCR4), to exclude Fleetwood reinforcements from the modelling (and set Fleetwood flows at zero) and to apply a downward adjustment factor of 0.8 to incremental investment costs to account for contracting as an alternative to physical investment. We invite views on these proposals.

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Context

At the Fourth Transmission Price Control Review (TPCR4) revenue drivers were set for all existing and anticipated entry points to the National Transmission System (NTS), for specific large exit points from the NTS and for smaller incremental exit capacity amounts at exit points in the South-West Zone. Revenue drivers enable National Grid Gas's (NGG's) allowed revenue to flex in response to demand which is backed by financial commitment from users. Revenue drivers protect consumers and help to reduce the risks to which NGG is exposed. The link between revenue drivers and user commitment protects consumers from the risk of having to pay for new investment that is not required; it also assists NGG to form views about where and when to invest in network capacity. NGG also benefits because the risk that investment is disallowed at future price controls is reduced.

Two NTS points have had revenue drivers set since TPCR4 - Gilwern and Canonbie. NGG now seeks revenue drivers for three further exit points at Abernedd, Barking and Coryton. The development of these revenue drivers is the focus of this consultation.

We expect to make our conclusions on the actual revenue drivers in October 2009 and make any necessary Licence changes in November 2009.

Associated Documents

- Modification of Special Conditions C8D and C8E of National Grid Gas plc's gas transporter licence, 30 June 2009 (Ref 74/09 and 75/09)
- Notice of Modification of Special Conditions C8D and C8E of National Grid Gas plc's gas transporter licence in respect of its national transmission system under section 23 of the Gas Act 1986, 29 May 2009 (Ref 59/09 and 60/09)
- Determining revenue drivers for entry and exit points: Canonbie and Gilwern, 29 May 2009 (Ref 58/09)
- Determining Revenue Drivers for Entry and Exit Points: Canonbie and Gilwern, 8 April 2009 (Ref 37/09)
- Decision to modify the gas transport licence under Section 23 of the Gas Act 1986, 5 September 2007 (Ref 217a/07)
- Section 38A Notice in respect of reasons for the decision to modify the licence of National Grid Gas plc, 5 September 2007 (Ref 217b/07)
- Schedule to Decision to modify the gas transport licence under Section 23 of the Gas Act 1986, 5 September 2007 (Ref 217c/07)
- TPCR 2007-2012 Final Proposals, 4 December 2006 (Ref 206/06)
- TPCR 2007-2012 Final Proposals, Appendices, 4 December 2006 (Ref 206/06b)
- TPCR 2007-2012 Updated Proposals, 25 September 2006 (Ref 170/06)
- TPCR 2007-2012 Updated Proposals, Appendices, 25 September 2006 (Ref 170/06a)
- TPCR 2007-2012 Initial Proposals, 26 June 2006 (Ref 104/06)
- TPCR 2007-2012 Initial Proposals, Appendices, 26 June 2006 (Ref 104b/06)
- TPCR 2007-2012 Third Consultation, 30 March 2006 (Ref 51/06)
- TPCR 2007-2012 Third Consultation, Appendices, 30 March 2006 (Ref 51b/06)

Copies of these can be found on the Ofgem website (www.ofgem.gov.uk).

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Summary

Revenue Drivers

This consultation sets out our proposed methodology for deriving the revenue drivers at Abernedd, Barking and Coryton.

Revenue drivers enable National Grid Gas's (NGG's) allowed revenue to automatically flex upwards in response to demand that is backed by financial commitment from users. NGG earns the additional revenue driver amount for a fixed five year period. Essentially, the revenue drivers fund the depreciation and return on a deemed amount of capex, with an allowance for opex. At the price control following the contractual delivery of the incremental capacity we review NGG's spend with the aim of ensuring that NGG is appropriately remunerated for efficient expenditure.

NGG requires revenue drivers so that it has greater certainty over the additional revenue it will earn from releasing incremental capacity. This allows for more informed investment decisions.

At the time of the Fourth Transmission Price Control Review (TPCR4), which covers the period 2007-2012, revenue drivers were determined for existing and anticipated entry and exit points. However, since the completion of TPCR4, projects have come forward at Abernedd, Barking and Coryton requiring incremental exit capacity from the National Transmission System (NTS). Revenue drivers are now required so that NGG has greater certainty to inform the basis of its investment decisions.

Abernedd, Barking and Coryton

In deriving the proposed revenue drivers for these exit points a similar modelling approach as used for setting TPCR4 revenue drivers was adopted. One important difference in approach is that the reinforcements necessary to meet NGG's baseline exit obligations in the enduring period from October 2012 are included in the network model prior to determining the network reinforcements for these three exit points. This avoids the possibility that work necessary to facilitate the enduring period baselines would be incorrectly attributed to these new exit points.

In estimating these revenue drivers there are three key issues. First, we consider there are two possible approaches to cost assumptions:

- **Option 1a:** use the TPCR4 unit cost assumptions
- **Option 1b:** use NGG's unit cost forecast, which are higher than in Option 1a

Our provisionally preferred approach, subject to consideration of any relevant points raised in response to this consultation, is to use the cost assumptions implied by Option 1a. This is for reasons of consistency with the approach taken in TPCR4 and in our recent decision for setting revenue drivers at Canonbie and Gilwern.

Second, at Fleetwood, 650GWh/day of incremental entry capacity was triggered for delivery from October 2010, but the project was refused planning permission, leading to uncertainty over the project start date. There are three possible approaches to account for Fleetwood in the modelling; these are:

- **Option 2a:** Fleetwood reinforcements excluded from the modelling and zero flows assumed to originate at Fleetwood
- **Option 2b:** Fleetwood reinforcements included in the modelling and zero flows assumed to originate at Fleetwood
- **Option 2c:** Fleetwood reinforcements included in the modelling and 650 GWh/day entry flows assumed via Fleetwood

Subject to the consultation responses, our provisionally preferred approach is to use Option 2a. This would appear consistent with the current likelihood that Fleetwood will not be operational in 2012/13, since at this point in time planning permission has still not been received for that project.

Finally, to provide incremental exit capacity NGG can choose either to reinforce the NTS or it can enter into contracts with exit users (to reduce their offtake of gas) and/or entry users (to guarantee availability of gas at peak periods in lieu of physical reinforcement). There are two possible approaches for accounting for the potential for contracting to be used as an alternative to physical investment for each incremental exit capacity project, these are as follows:

- **Option 3a:** apply no downward adjustment to the incremental investment costs, which would imply little potential for contracting to be an efficient solution
- **Option 3b:** apply a downward adjustment factor of 0.8 to the incremental investment costs as it may be appropriate to reduce the revenue driver to reflect the potential lower costs from contracting. This is consistent with the approach used under TPCR4 for exit projects identified as having the potential for the use of contracting as an alternative to physical investment.

Our provisionally preferred approach is to apply a downward adjustment factor of 0.8, as in Option 3b, predominantly to ensure consistency with the TPCR4 approach where this method was applied to exit points in relative close proximity to entry points. It is difficult to pre-judge the potential for contracting. However, if a downward adjustment is not applied and the contracting solution is the most efficient solution then consumers will not benefit from the potential cost reduction. If an adjustment is applied but the most efficient solution was physical investment then NGG will still be able to recover any efficiently incurred additional costs via increased RAV and logged up costs. Therefore, applying a downward adjustment protects consumers in the face of this uncertainty whilst minimising risk faced by NGG.

We invite views on the above options and our analysis of the same.

Timeline

The consultation will close on 1 October 2009. We do not intend to provide another round of consultation before reaching our final decision. Where, in this document, we refer to Ofgem's views these are provisional views and are subject to further consideration of any points raised in this consultation process. Responses to this consultation will be carefully considered in reaching a decision on the appropriate methodology for deriving the revenue drivers at Abernedd, Barking and Coryton. We would envisage a decision to be made in October 2009 along with a Section 23 notice to modify NGG's gas transporter licence in November 2009.

1. Introduction

Chapter Summary

This chapter sets out why we are consulting on the methodology for setting revenue drivers at the exit points of Abernedd, Barking and Coryton.

It also gives a brief description of what is contained in each of the main chapters.

Purpose of this document

1.1. At the Fourth Transmission Price Control Review (TPCR4), which covered the period 2007-2012, Ofgem set revenue drivers for all existing and anticipated gas entry points to the National Transmission System (NTS). It also set revenue drivers for specific, large anticipated exit projects and for smaller anticipated incremental projects in the South-West zone. Since then, provision has been made in National Grid Gas's (NGG) gas transporter licence (the "Licence") for new revenue drivers at a new entry point at Canonbie and an existing exit point at Gilwern, which were not anticipated previously.

1.2. NGG is now progressing work for incremental capacity at three existing NTS exit points - Abernedd Power Station[1], Barking (Horndon) and Coryton 2 (Thames Haven) Power Station. These developments were not anticipated at TPCR4 and, therefore, NGG has requested that its Licence be amended to include revenue drivers for incremental capacity at the three exit points.

1.3. This document sets out the methodology for how Ofgem proposes to calculate the revenue drivers for exit points to be included in the Licence.

Overview of this document

1.4. This document is organised into the following chapters:

- Background - this explains both the role of revenue drivers in the current price control and the need for revenue drivers to be derived for Abernedd, Barking and Coryton.
- Derivation of revenue drivers - this describes the methodology used at TPCR4 for modelling the reinforcement work required for providing incremental exit capacity

[1] It is yet to be decided whether the project will offtake gas at Abernedd Power Station or Tonna.

on the NTS and explains how the cost for this work was estimated. It also sets out the approach we have taken for setting revenue drivers since TPCR4.

- Cost estimation - this sets out the different cost assumptions which might be applied to the reinforcement work needed for incremental capacity at the three exit points.
- Modelling approach for revenue drivers - this sets out the different modelling approaches that might be used to determine the reinforcement work required for providing incremental capacity at Abernedd, Barking and Coryton. It also sets out the alternatives to system reinforcement as a means to meeting the shipper capacity requirements.
- Way forward - this highlights both our future work in determining revenue drivers and our proposed timeline for including revenue drivers for these three exit points in the Licence.

2. Background

Chapter Summary

This chapter describes the current regimes by which users acquire capacity for the National Transmission System (NTS), particularly incremental exit capacity. It explains the role of revenue drivers in the current price control. This chapter also outlines the reasons why we are now consulting on deriving revenue drivers for incremental capacity at the three existing exit points of Abernedd, Barking and Coryton.

2.1. NGG owns and operates the high pressure gas transmission network in Great Britain, the NTS. Shippers bring gas from gas fields, as imports via interconnectors, via Liquefied Natural Gas (LNG) import terminals, or from storage facilities connected to the NTS. The gas can then be delivered direct to Transmission Connected Customers (TCCs), delivered to final consumers through the low pressure Gas Distribution Networks (GDNs) and systems operated by the Independent Gas Transporters (IGTs), exported via interconnectors, or put into storage.

2.2. In order to use the NTS, shippers must first buy entry capacity, to flow gas onto the NTS, and also exit capacity, to take gas off the NTS. If shippers do not buy sufficient capacity for the actual amounts of gas they flow, they will incur overrun charges, as set out in the Uniform Network Code (UNC)[2].

Booking exit capacity

2.3. Arrangements for booking exit capacity are set out in NGG's Exit Capacity Release (ExCR) methodology statement[3]. The arrangements differ between two periods:

- Transitional Period - this runs from 1 October 2008 until 30 September 2012, and relates to the exit capacity regime in place prior to implementation of exit reform[4]
- Enduring Period - this runs from 1 October 2012 onwards and relates to the exit capacity regime which the Authority recently approved for implementation.

[2] A copy of the UNC can be found on the website of the Joint Office of Gas Transporters i.e. www.gasgovernance.com.
[3] A copy of the current ExCR methodology statement can be found on NGG's website www.nationalgrid.com.
[4] For more information regarding exit reform see the Authority's decision 'Uniform Network Code (UNC): Reform of the NTS Offtake Arrangements (UNC 0116V, 0116BV, 0116CVV, 0116VD, 0116A) and Introduction of Enduring NTS Exit Capacity Arrangements (UNC 0195 and 0195AV)', published on 19 January 2009 on Ofgem's website www.ofgem.gov.uk.

Transitional Period

2.4. The process for booking NTS exit capacity in the transitional period depends on the type of exit site. There are different processes for the following types of site:

- NTS Supply Points - these include firm very large daily metered customers such as gas fired power stations
- NTS Connected System Exit Points (CSEPs) - these are offtake sites where gas is not used at the point of offtake and include mainly IGTs
- NTS Interconnectors
- Storage Sites
- Gas Distribution Networks (GDNs)

NTS supply points

2.5. Once shippers register their supply point capacity, NTS exit capacity is allocated to that supply point on an 'evergreen' basis. Shippers can make a request to NGG for an increase in their System Offtake Quantity (SOQ), or prevailing supply point capacity. Shippers can only reduce the capacity requirement at NTS supply points during the October to January period and cannot reduce this to below their maximum daily consumption in the previous winter.

NTS CSEPs

2.6. Shippers book NTS exit capacity at CSEPs on a 12-month rolling basis at any time during the year. Such applications cannot be submitted earlier than six months or later than four days in advance of being required.

NTS interconnectors

2.7. The rules for booking NTS exit capacity at interconnector sites are similar to those at CSEPs, except that gas exports to continental Europe and Ireland require Downstream Capacity Holder certificates. NGG maintains contact with the individual agent at each of the interconnectors and they give NGG a list of capacity holdings held downstream of the NTS which allows NGG to match upstream and downstream.

Storage sites

2.8. All storage sites have elected to be interruptible, this means that they do not have to book NTS exit capacity but do have to inform NGG of their intended flows through the nomination procedures.

Gas distribution networks

2.9. Each year NGG provides each GDN with an Offtake Capacity Statement (OCS) which sets out for each NTS offtake point for each gas year the following:

- An amount of NTS offtake (flat) capacity
- An amount of NTS offtake (flex) capacity
- Assured Offtake Pressures

2.10. In June or July, prior to the gas year, GDNs can request revisions to their existing capacity allocations (and offtake pressures). NGG then chooses to reject or accept (fully or in part) the requests and publishes revised Statements by 30 September. The OCS process covers four years of firm bookings and one year of indicative bookings.

Transitional period - existing exit capacity

2.11. NGG assesses requests for exit capacity at exit points to determine whether the requests can be accommodated by existing exit capacity. Existing exit capacity is a measure of the capability of the NTS and is determined by network analysis conducted by NGG. It includes allocated and unallocated exit capacity. If there is enough existing exit capacity to satisfy the demands, these are allocated on a first-come-first-served basis. If there is insufficient unallocated existing exit capacity to satisfy the requests, the available capacity may be allocated to partially satisfy the request.

2.12. However, if a party makes a request for existing exit capacity beyond 6 months and the request is greater than 20 million therms per annum then the party may request that NGG enters into an Advanced Reservation of Capacity Agreement (ARCA). ARCAs oblige NGG to release the amount of capacity agreed at the date agreed, whilst committing the booking party to pay NGG in respect of lost revenue, should it later decide it no longer wants the capacity on the date agreed.

Transitional period - incremental exit capacity

2.13. The process for dealing with requests for incremental exit capacity depends on whether the incremental exit capacity is required within the incremental exit capacity lead time, which is currently bilaterally agreed in the ARCA, or beyond the incremental exit capacity lead time.

2.14. If the request is for incremental capacity within the incremental exit capacity lead time then NGG assesses whether safe operation of the system can be maintained and whether it is economic and efficient to take any mitigating actions for any impairment to safe operation of the system. This is then used to assess whether NGG:

- can release all the incremental exit capacity requested (possibly with an ARCA)
- can release a partial amount of the incremental exit capacity requested (possibly with an ARCA)
- cannot release any of the incremental exit capacity requested

2.15. If the request is for incremental capacity beyond the incremental exit capacity lead time then NGG assesses whether NTS reinforcement is required and whether it requires an ARCA to be signed.

Enduring period

2.16. On 19 January 2009 Ofgem made its decision[5] to implement the UNC modification proposal UNC195AV regarding the NTS exit capacity regime in the enduring period. This regime will apply for all NTS exit capacity allocations for use from 1 October 2012.

2.17. The enduring NTS exit capacity regime that will be implemented as a result of UNC195AV will have two main types of NTS exit capacity products:

- NTS exit (flat) capacity - this gives holders the right to offtake daily quantities of gas at an NTS exit site with an implied obligation to offtake at an even flow rate across the day
- NTS exit (flexibility) capacity - this allows holders to depart from flowing at an even rate across the day. This can only be acquired by GDNs.

2.18. For NTS exit (flat) capacity there are four sub-products based on time and whether these rights are firm or interruptible, these products are:

- Enduring Annual NTS exit (flat) capacity - this is firm capacity for each day in the relevant and each subsequent gas year, unless holders notify NGG of a reduction in these enduring rights
- Annual NTS exit (flat) capacity - this is firm capacity for each day in that gas year
- Daily NTS exit (flat) capacity - this is firm capacity for one day only
- Daily off-peak NTS exit (flat) capacity - this is exit capacity for one day only which can be curtailed if NGG considers there to be a capacity constraint. This is comprised of:
    - Use-It-Or-Lose-It (UIOLI) exit capacity
    - Discretionary release
    - *(Maximum Supply Point Offtake Rate x 24) - Aggregate firm holdings*: this will be triggered for release when the day-ahead demand forecast is less than 80 per cent of the 1-in-20 peak day demand.

[5] See our decision 'Uniform Network Code (UNC): Reform of the NTS Offtake Arrangements (UNC 0116V, 0116BV, 0116CVV, 0116VD, 0116A) and Introduction of Enduring NTS Exit Capacity Arrangements (UNC 0195 and 0195AV)', published on 19 January 2009 on our website www.ofgem.gov.uk.

2.19. The enduring exit regime will mean that all types of exit capacity users[6] will go through the same processes in acquiring NTS exit (flat) capacity. There will be three processes for acquiring enduring annual NTS exit (flat) capacity, these are:

- The July application window - these run each year in July and allow users to acquire enduring annual NTS exit (flat) capacity in gas years[7] Y+4, Y+5 and Y+6
- Ad-hoc applications - NGG will receive ad-hoc applications from users between 1 October and 30 June each year for enduring annual NTS exit (flat) capacity from between 6 months in advance and up to 1 October Y+4. This is for new sites or existing sites requesting a large increment
- enduring annual NTS exit (flat) capacity can also be requested by developers via an ARCA

2.20.

2.21. The process for acquiring annual NTS exit (flat) capacity is through an application window held each July for capacity in gas years Y+1, Y+2 and Y+3. NGG will make available in these auctions any unsold NTS exit capacity that it is obligated to make available. As incremental exit capacity is not triggered through the application window for the annual NTS exit (flat) capacity product then revenue drivers are not required in the Licence prior to the process.

2.22. The other two NTS exit capacity products (daily NTS exit (flat) capacity and daily off-peak NTS exit (flat) capacity) will be allocated by means of auction at times specified in the UNC. As incremental exit capacity is not triggered through these auctions then revenue drivers are not required in the Licence prior to the auctions.

Role of revenue drivers in current transmission price control

2.23. Revenue drivers adjust automatically NGG's revenue allowances in response to demand. Revenue drivers seek to represent the opex, depreciation and return on a deemed amount of investment at a particular entry or exit point and to remunerate NGG accordingly.

2.24. The specific details of how the revenue drivers increase NGG's revenue allowance is set out in the Licence, a detailed summary of which is given in Appendix 2. Essentially, NGG's SO allowed revenue increases by the amount of incremental

[6] Users refer to UNC signatories.
[7] The Gas Year begins on 1 October each year and runs through to 30 September in the following calendar year.

capacity multiplied by the revenue driver[8]. The SO allowances are increased in this way for a period of five years.

2.25. One principle in setting revenue drivers is to reflect costs that NGG would incur in releasing incremental capacity. If the correlation between incremental revenue from the revenue driver and incremental costs to deliver the incremental output is poor then the incentives for delivering outputs can be distorted. If the revenue driver is too low and so does not recover the investment costs then NGG may choose not to invest and instead increase the risk that it incurs buy-back costs[9]. If the revenue driver is too high then NGG is remunerated by more than the cost of making the incremental capacity available the additional costs would ultimately be borne by consumers.

Need for revenue drivers at Abernedd, Barking and Coryton

2.26. At TPCR4, which covered the period 2007-2012, revenue drivers were calculated for all existing and anticipated entry points. However, a revenue driver was not calculated for all existing exit points as it was considered unnecessary to calculate revenue drivers at exit points which were unlikely to require incremental exit capacity. Therefore, revenue drivers were calculated only for large anticipated exit projects and smaller incremental exit projects in the South-West zone.

2.27. Since then NGG has received notifications that incremental capacity is to be requested at a number of exit points and so now NGG requests revenue drivers for additional projects at three such exit points, these are:

- for exit capacity at an exit point at Abernedd of 39.4 GWh/day
- for exit capacity at an exit point at Barking of 23.8 GWh/day
- for exit capacity at an exit point at Coryton of 42.6 GWh/day

2.28. As incremental exit capacity at these exit points was not anticipated at TPCR4 there are currently no revenue drivers included in the Licence. NGG has now requested that Ofgem provides revenue drivers for these projects. This will allow NGG greater certainty over its revenues resulting from the release of incremental capacity.

[8] However, for incremental exit projects anticipated at TPCR4 with a specific revenue driver the SO allowed revenue increases by the exit revenue driver amount once the specific anticipated level of incremental exit capacity has been delivered.
[9] If NGG is unable to deliver capacity which is sold on a financially firm basis then it can chose to buy-back some capacity rights from NTS users. This usually incurs buy-back costs.

3. Derivation of revenue drivers

Chapter Summary

This chapter describes the network modelling and cost estimation work which was undertaken at the Fourth Transmission Price Control Review (TPCR4), which covered the period 2007-2012, to set the revenue drivers for large anticipated exit projects and smaller incremental exit projects in the South-West zone. It also notes the approach used at the recent setting of revenue drivers for other projects not anticipated at TPCR4 i.e. Canonbie and Gilwern.

TPCR4

Network Modelling

3.1. Ofgem approached NGG to ask what reinforcement work would be required for each specific project of incremental exit capacity. NGG responded with a list of reinforcement works and estimated costs required for each project.

Cost estimation

3.2. The cost of the reinforcement works were calculated by applying unit cost figures to the different reinforcement works required. The total incremental investment cost figures were then converted into 2005/6 prices and some adjustments made for:

- Langage Phase I - downward adjustments made. This adjustment was required because funding had already been provided for this project in the previous price control period (from 2002-2007).
- Pembroke and Grain - In the case of two exit points - Pembroke (associated with the combine cycle gas turbine power station at this location) and Grain (associated with the gas fired combined heat and power station on the Isle of Grain) - downward adjustments[10] were made to investment cost data to account for the possibility of long term contract solutions, as an alternative to physical investment in providing incremental exit capacity. This is consistent with the approach adopted in TPCR4 analysis, which suggested there was no economic basis for pipelines for these projects and contracting with other users would provide a more economic way to meet the needs of users. This view, which was supported by the consultants that Ofgem used during TPCR4, was based on considerations including uncertainty over demand requirements, proximity to LNG importation facilities and local LNG storage, and potential flows at the exit points without any reinforcements.

[10] The revenue driver figure was multiplied by 0.8.

3.3. The figures were then annuitised to provide annual revenue driver figures, and in the case of the South-West zone revenue driver a per GWh/day value was calculated.

Canonbie and Gilwern revenue driver setting

3.4. We recently set revenue drivers at a new entry point at Canonbie and an existing exit point at Gilwern[11]. The approach we used employed the same method and cost assumptions as that used at TPCR4. However, for the specific annual exit revenue driver for Gilwern, a per GWh/day revenue driver was calculated. The revenue driver for Gilwern differed from the exit revenue drivers calculated at TPCR4 in that the latter are included in the Licence as a lump-sum amount of additional revenue which NGG receives for a specified amount of incremental capacity. However, for Gilwern the revenue driver was expressed in the form of a per GWh/day allowance as this is consistent with the approach taken for entry revenue drivers and small exit revenue drivers.

[11] See our decision 'Determining revenue drivers for entry and exit points: Canonbie and Gilwern', published on 29 May 2009 with reference number 58/09 on our website www.ofgem.gov.uk

4. Cost estimation

Chapter Summary

In this chapter we explain the two different unit cost assumptions. We also set out our provisionally preferred approach which is to use the unit cost assumptions employed at the Fourth Transmission Price Control Review (TPCR4).

Question box

Question 1: Do you agree with our provisionally preferred option regarding cost assumptions i.e. Option 1a which uses the unit cost assumptions used at TPCR4?
Question 2: Are there any other considerations which we have not highlighted which we should have taken into account?

4.1. On 1 May 2009 we asked NGG to conduct modelling in order to provide us with information on what reinforcement work would be required to facilitate incremental capacity at Abernedd, Barking and Coryton. We also asked NGG to provide costs of reinforcement works based on the two cost assumptions consulted on for setting revenue drivers at Canonbie and Gilwern. We requested cost information on the basis of both assumptions because at the time we made our request, we had not come to a view on the appropriate assumptions to be used in the case of Canonbie and Gilwern and we did not want to prejudge the outcome. The two cost assumptions are:

- Option 1a - the unit cost assumptions used at TPCR4
- Option 1b - NGG's forecast of unit costs

Cost Options

Table 1: Difference in Units Cost Assumptions

	% Increase in Option 1b over Option 1a
1200mm pipe (£m/km)	31%
900mm pipe (£m/km)	54%
Electric Compressors (£m/MW)	10%
Electric Compressors, fixed cost per site (£m)	n/a
Compressor re-wheel, 2 unit site (£m)	53%
Multijunction Modifications (£m)	100%

4.2. For reasons of commercial confidentiality we cannot publish the two sets of unit cost data. However, Table 1 shows (in percentage terms) the extent to which prices under Option 1b are higher than under Option 1a: prices under Option 1b are between 31 and 100 per cent higher than under Option 1a.

4.3. For Option 1b, NGG proposed that the cost of compressors should include fixed costs per site in addition to variable costs which are linked to the output in MW. The fixed costs include items such as buildings, electric drives and, where required, overhead cables - all of which are judged by NGG to not be dependent on compressor power levels. During TPCR4, NGG did not consider that compressors would give rise to fixed costs and therefore it is not possible to compare the costs under Option 1a and Option 1b for this category of expenditure. NGG considered that unit costs have increased beyond TPCR4 assumptions and that costs based on more recent information should be used.

Ofgem's view

4.4. On 29 May 2009 we made our decision regarding the setting of revenue drivers at Canonbie and Gilwern. We used the TPCR4 cost assumptions for setting these revenue drivers to be consistent with the approach adopted in the last price control and because we were not aware of any compelling evidence to imply it was appropriate to move away from these cost assumptions. We propose using TPCR4 unit cost assumptions for setting the revenue drivers at Abernedd, Barking and Coryton for consistency with our recent decision on setting revenue drivers for Canonbie and Gilwern. In this context we note that NGG's cost assumptions are based on the 2008 planning cycle and may therefore, in any case, require updating. We would welcome views on this proposed approach.

5. Modelling approach for Abernedd, Barking and Coryton

Chapter Summary

In this chapter we set out the modelling conducted to assess the reinforcement work for providing incremental capacity at Abernedd, Barking and Coryton.

We explain the different options regarding the treatment of the Fleetwood project in the modelling and the options regarding the potential for contractual approaches to be taken to deliver incremental exit capacity, as opposed to physical investment. We also set out our provisionally preferred options which are:

- ➔ to exclude the Fleetwood reinforcements from the network modelling, and
- ➔ to apply a downward adjustment factor of 0.8 to the incremental investment costs to account for possible contractual approaches to provide incremental exit capacity

This chapter also sets out what the unit revenue drivers would be on the estimated costs of providing the specific amounts of incremental exit capacity at Abernedd, Barking and Coryton.

Question box

Question 1: Do you agree with the modelling assumptions we instructed NGG to use?
Question 2: Do you agree with the approach taken to mitigate for potential double remuneration NGG could receive from meeting its exit capacity baseline obligations and providing the incremental exit capacity i.e. increasing local demand flow assumptions to baseline levels where possible?
Question 3: Do you have any opinions on the modelling approach taken by NGG to investigate possible interactions with the reinforcements required for Fleetwood? Specifically, do you have any views on the balancing assumptions used for Option 2c? Similarly do you have any views on whether a range of scenarios using different balancing points should have been considered given any time constraints?
Question 4: Do you agree with our provisionally preferred option regarding Fleetwood i.e. Option 2a to not include the Fleetwood reinforcements in the base network when modelling the incremental reinforcements required for each of the three exit projects?
Question 5: Do you agree with our provisionally preferred option regarding consideration of the potential for contractual solutions to deliver incremental exit capacity i.e. Option 3b to apply a downward adjustment factor of 0.8 to incremental investment costs to account for possible contracting solutions to provide incremental exit capacity?
Question 6: Are there any other issues which we have not highlighted which we should have taken into account?

Modelling request

5.1. Our request for NGG to undertake modelling of the reinforcement work required to meet incremental capacity at Abernedd, Barking and Coryton (see Table 2), included a request for the following information:

- Additional compressors (in MW)
- Additional NTS pipelines (by diameter and length)
- Additional gas telemetry measuring equipment and associated cost
- Any other relevant work and associated cost
- Information to indicate the potential for contracting options which might be employed as an alternative to actual physical investment. Indicators of the potential for contracting to be used may include what large entry and exit points are nearby and the number of days the new exit capacity is likely to be required and interrupted.

Table 2: Incremental exit project capacities

NTS Exit Point	Increment (GWh/day)
Abernedd	39.4
Barking	23.8
Coryton	42.6

5.2. We requested that the following assumptions were used in the modelling:

- Number of years modelled: 2012/13
- Base network: 2012/13 physical network using the information from the most recent Ten Year Statement (TYS) i.e. 2008
- Demand: 1-in-20 peak demand for 2012/13 from the 2008 planning cycle and the Gas Distribution Network obligations from the 2008 OCS
- Supply: 'Low Local Supply' scenarios from the most recent Planning Code i.e. 2008. In these scenarios, supply flows local to the exit point under consideration are at reduced levels.
- Supply and demand balancing: the assumptions set out in the most recent Planning Code i.e. 2008

5.3. We also asked NGG to confirm whether any connecting pipeline would be built by NGG itself or the developer (and, if so, whether this would then be sold to NGG or another gas network owner).

5.4. NGG identified an issue associated with our demand assumptions. The modelling focuses on 2012/13 when the enduring exit regime will be in place and NGG will have obligations to release specific amounts of baseline exit capacity which cannot be

reduced or substituted away[12]. NGG will have to meet these baseline obligations before considering incremental exit capacity. The problem NGG identified was that the reinforcement work required for each of the three exit projects would also include reinforcements necessary to meet its baseline obligations. Unless appropriate adjustments are made, this could result in some double remuneration of certain reinforcements to meet baseline obligations.

5.5. NGG's proposed solution was to start its analysis from the Base Case model which did not incorporate reinforcements to meet NGG's obligated capacity. NGG then proposed to make modelling adjustments to the Base Case which were representative of the reinforcements required to meet NGG's obligated exit baselines (the 'Obligated Case'). NGG then proposed to make further adjustments related to the incremental exit projects (the 'Incremental Case'). The difference between the costs for the reinforcements required for the Incremental Case and the costs of the reinforcements required to meet the Obligated Case was then calculated and used to derive the revenue drivers.

5.6. The Obligated Case was based on the following demand assumptions:

- **Gas Distribution Networks** (GDNs) demand was based on the bookings from the 2008 Offtake Capacity Statement (OCS) process. However, in the case of 'local' exit points[13] the higher of the 2008 OCS allocations or baseline obligations was used (as proposed in the Section 23 notice published on 4 June 2009 which modified the Licence on 16 July 2009).
- **Direct Connects** (DCs) demand was based on 2008 Transporting Britain's Energy (TBE) forecasts[14]. However, in the case of adjacent 'area'[15] demand, forecasts were assumed to be baseline obligations, plus any exit capacity secured through an Advanced Reservation of Capacity Agreement (ARCA) or commercial agreement.

5.7. We consider that this approach might be an appropriate means of avoiding a situation where consumers pay twice for the cost of NGG meeting its exit baseline obligations. We would welcome views on the approach adopted.

[12] NGG has an obligation to submit for approval an exit capacity substitution methodology statement by 4 January 2011 and Ofgem has two months after that date in which to approve it or not. Assuming a 36 month lead time after the first day of the gas year following the date on which the allocation occurs the earliest date for actual exit substitution would be October 2014.
[13] 'Local' is defined by NGG as group of neighbouring Local Distribution Zones (LDZs) to the LDZ in which the exit project being considered is located.
[14] Forecasts are based on data gathered through the Transporting Britain's Energy (TBE) process and contractual obligations (i.e. registered firm exit capacity). These forecasts are the same as used in the 2008 planning process.
[15] Adjacent 'area' is defined on a case-by-case basis depending on other DCs using the same feeder, compressor, etc.

Modelling output - initial response

5.8. NGG's modelling was based on the following:

- Base network: 2012/13 physical network including projects reflective of what was in the 2008 Ten Year Statement
- Demand: different assumptions depending on the type of exit point
  - GDN
    - Local demand[16] - the higher of OCS allocation or proposed exit baselines
    - Non-local demand[17] - 2008 OCS allocation
  - Direct Connected Customers
    - Adjacent demand[18] - exit baseline plus any exit capacity secured through an ARCA or commercial agreement
    - Non- Adjacent demand [19] - NGG demand forecasts[20]
- Supply: the 'Low Local Supply' scenarios from the 2008 Planning Cycle[21]. For Abernedd this was based upon NGG's supply forecasts with reduced entry flows in the South and West of the country and for Barking and Coryton this considered reduced supply flows for the South and East[22].
- Supply and demand balancing: the least helpful supply balancing was used when adding supply to meet incremental exit demand i.e. supply was balanced with demand by adding supply flows at entry points on the NTS which NGG considered provided a credible view of 'least benefit' (in terms of allowing NGG to incur lower network reinforcement costs). This approach usually involves the use of entry points which are furthest away from exit points being considered and for all three exit projects this assumed balancing supplies came from the Northern Triangle i.e. St. Fergus, Glenmavis, Teesside and Barrow.

5.9. NGG did not anticipate that any gas telemetry measuring equipment costs would arise from the three exit projects and at the time of responding did not have sufficient information regarding connecting pipelines required between the NTS and

[16] 'Local' has the same definition as in Footnote .
[17] 'Non-local' describes all other GDN exit points which are not defined as 'Local' as per footnote .
[18] ' Adjacent' has the same definition as 'Adjacent area' in Footnote .
[19] 'Non- Adjacent' describes all other DC exit points which are not defined as being 'Adjacent' as per footnote .
[20] The forecasts are based on data gathered through the Transporting Britain's Energy (TBE) process and contractual obligations (e.g. registered firm exit capacity).
[21] The Planning Cycle is the process used to determine NGG's investment plan and is detailed in the planning code which is available on NGG's website www.nationalgrid.com.
[22] Definitions of supply flows in the 'South', 'East' and 'West' were provided by NGG. These definitions were done on a case-by-case basis depending on which supplies interact with the exit point being analysed. Therefore, the definition of 'South' is potentially different when used for Abernedd as when used for Barking and Coryton.

any of the three sites. Connecting pipelines have therefore not been included in the reinforcement work and are therefore not remunerated through the revenue drivers.

Ofgem view

5.10. We considered that the modelling work undertaken by NGG reasonably reflects our original request and further conversations with NGG. The low local supply and the least helpful supply substitution assumptions would appear to be consistent with the approach to the modelling used for setting entry capacity revenue drivers at TPCR4 (which utilised 'difficult' flow scenarios to evaluate the impact of incremental flows).

5.11. However, we noted that the base network for 2012/13 did not include the reinforcements identified as being required for the Fleetwood storage project[23]. We have concerns that if planning permission was given to Fleetwood, such that it could be built by 2012/13, having the Fleetwood reinforcements in the network might result in less reinforcement being required for the three exit projects. Our concern was that the modelling approach of using the base network without Fleetwood reinforcements would overstate the reinforcements required for the three exit projects. We therefore requested that NGG conduct some further modelling of the reinforcements required for the three exit projects if the Fleetwood storage project was operational in 2012/13 - this would include Fleetwood reinforcements in the base network along with assumptions on the entry flows at Fleetwood.

Modelling output - additional response

5.12. NGG replicated its modelling analysis with the Fleetwood reinforcements. With these reinforcements in the base network NGG considered two flow assumptions: Zero flows at Fleetwood; and 650 GWh/day entry flows at Fleetwood[24]. This resulted in three options for the derivation of revenue drivers:

- Option 2a - this is when the Fleetwood reinforcements are excluded from the base network and when there are zero flows at Fleetwood
- Option 2b - this is when the Fleetwood reinforcements are included in the base network and when there are zero entry or exit flows at Fleetwood
- Option 2c - this is when the Fleetwood reinforcements are included in the base network and when there are 650 GWh/day entry flows at Fleetwood

[23] At the September 2006 QSEC auction 650 GWh/day of incremental entry capacity was triggered at the Fleetwood from October 2010. However, this storage project was refused planning permission and there is now a degree of uncertainty regarding the project start date.
[24] Under its obligations NGG will be required to provide 650 GWh/day of entry capacity at Fleetwood, therefore 650 GWh/day of gas flows entering at Fleetwood represents the maximum flows for which NGG will be obligated to provide capacity.

5.13. Table 3 summarises the revenue driver figures implied by these options (and the options to account for the potential contractual approaches to be used in delivering incremental exit capacity i.e. options 3a and 3b, which is discussed further below). The figures in the table use the TPCR4 unit cost assumptions i.e. Option 1a.

Table 3: Licence revenue driver figures under various options (£/GWh)

NTS Exit Point	Increment (GWh/day)	Without Fleetwood Reinforcement		With Fleetwood Reinforcement			
		Zero Fleetwood Flows		Zero Fleetwood Flows		650 GWh/d Fleetwood Entry Flows	
		Option 2a		Option 2b		Option 2c	
		No Contracting	*Contracting*	*No Contracting*	*Contracting*	*No Contracting*	*Contracting*
		3a	*3b*	*3a*	*3b*	*3a*	*3b*
Abernedd	**39.4**	110,547	88,438	61,740	49,392	143,085	114,468
Barking	**23.8**	213,582	170,866	213,582	170,866	n/a	n/a
Coryton	**42.6**	161,180	128,944	161,180	128,944	n/a	n/a

Barking and Coryton

5.14. The analysis included in NGG's additional response indicates that the revenue drivers for Barking and Coryton are not influenced by the assumption made about Fleetwood reinforcements and flows: the revenue drivers for these exit points are identical under Options 2a and 2b.

5.15. NGG did not consider it necessary to do any analysis for Barking and Coryton for Option 2c as it considered that the increased Fleetwood flows combined with reduced flows elsewhere would result in flows similar to those under options 2a and 2b. NGG's rational for this is summarised below.

5.16. NGG stated that in the analysis for Option 2a the incremental exit flows were supplied with the low local levels of supply (from Bacton and Isle of Grain) and that with the addition of Fleetwood reinforcements for Option 2b the incremental exit flows continued to be supplied locally. For the analysis for Option 2c the increased flows at Fleetwood would need to be matched by reductions elsewhere. NGG considered that flows could not be further reduced at local entry points as these were already at their low local supply levels and further reductions at these points would not represent a credible supply scenario. As Bacton and Isle of Grain were meeting the incremental exit flows NGG considered it largely irrelevant where to balance flows, as long as it was not one of the entry points affected by the low local supply assumption. NGG states that if it had chosen Milford Haven then this would have resulted in extra investment in South Wales being identified which would not be related to these exit points in the South East. NGG concludes it would have chosen to balance Fleetwood flows with St Fergus as this would not identify the need for additional investments that were unrelated to the exit points being considered.

Abernedd

5.17. Including the Fleetwood reinforcements and assuming zero flows at Fleetwood (Option 2b) resulted in less reinforcement being required at Abernedd than compared to Option 2a.

5.18. However, when 650 GWh/day of entry flows were assumed at Fleetwood (Option 2c), additional reinforcements were required compared to Option 2a. NGG has indicated that this effect is a result of the balancing assumption used in its modelling, which was to balance the flows at Fleetwood by reducing flows at Bacton by the same amount. NGG's rationale for this balancing assumption was that if St Fergus had been chosen to balance flows, then flows south of Fleetwood would be the same as Options 2a and 2b (as reduced flows at St Fergus are replaced by increased flows from Fleetwood). NGG therefore chose Bacton for reasons of providing a credible example of a supply pattern that could occur and where the required investment related to Abernedd.

Ofgem view

5.19. Our provisionally preferred option, subject to consideration of any points raised in response to this consultation, is to use the modelling which does not include the Fleetwood reinforcements in the 2012/13 base network model and has zero flows at Fleetwood. As the Fleetwood storage project currently does not have planning permission it is unlikely that it will be commissioned in 2012/13. Therefore we consider that our chosen approach best reflects how the network could look in 2012/13 and is therefore likely to be more cost reflective than the alternative of including Fleetwood reinforcements in the 2012/13 network model.

5.20. We note that if the Fleetwood storage project obtains planning permission and is available in 2012/13 we would not expect the revenue driver for Abernedd to be revised automatically to the figures in Options 2b or 2c. This is because the network reinforcements actually required for Fleetwood may differ from what was originally expected since there will have been reinforcement work done in the meantime which may be beneficial to Fleetwood flows. In such circumstances it would be open to NGG to request a revision to the revenue driver.

5.21. Furthermore, we note the different approaches NGG would have taken for the modelling work for Option 2c in the analysis for Abernedd compared to that for Barking and Coryton, specifically relating to the choice of balancing entry point. We seek views on this approach.

Contracting

5.22. In its response to our question on the potential for contracting solutions to be employed as an alternative to physical investment in delivering incremental exit capacity, NGG considered both supply and demand options available at the three exit points.

5.23. On the supply side it considered the proximity to large LNG terminals but noted that:

- Should the LNG terminals be able to offer a constrained LNG service to guarantee flows then there would be an upper limit to the level of gas that shippers would be willing to guarantee because of the opportunity cost of guaranteeing gas flows when this gas could potentially be delivered to other global LNG markets offering higher prices.
- As LNG imports to the UK compete with global demand for LNG there will be competition for LNG and the price of a constrained service from LNG import terminals would need to reflect these market circumstances.

5.24. On the demand side NGG noted proximate offtakes which have the capacity to offer load reduction services but NGG thought that these could be expensive as other users place a high price on load reduction.

5.25. NGG considered that several days of supply and demand responses would be needed to accommodate any of the three exit projects and that if a contractual solution is sought, then further analysis would be required at the time.

Ofgem views

5.26. When faced with a request for incremental exit capacity NGG will have to consider the most efficient approach to delivering this request. Possible options are physical investment, a contractual approach, or to do nothing. If NGG chooses to do nothing, it is likely to face increased exposure under the buy-back mechanism.

5.27. For all of the above approaches, NGG will earn an amount determined by the revenue driver for the fixed five year period. At the price control review following contractual delivery of the incremental exit capacity Ofgem reviews any investment and/or contracting costs in terms of their efficiency. This is for the purposes of setting funding allowances for the incremental exit capacity after the five year period when the revenue driver amount is earned. If Ofgem decides that any physical investment was efficient then after the five year period when the revenue driver amount is earned the efficient investment is added to the TO RAV. If Ofgem decides that investment in the incremental capacity was inefficient or was not required, the funding for the incremental capacity, or part of it, may be excluded from the TO RAV. We anticipate at the next price control review that there will be discussions as to how efficiently incurred contracting costs will be funded following the five year revenue driver period.

5.28. If the costs associated with investment are less than the costs associated with contracting, then physical investment will be the most efficient solution, and vice versa. Having the option to enter into contractual arrangements provides an alternative opportunity to deliver incremental exit capacity which should help protect consumers.

5.29. At TPCR4 Ofgem revised the revenue driver for Grain and Pembroke downwards by multiplying the drivers by a factor of 0.8. This was because analysis suggested that there was not a needs-case basis for pipelines to deliver the incremental exit capacity there and that contracting solutions may be more appropriate. The factor of 0.8 was not applied to the calculation of the revenue drivers in TPCR4 for other large, specific exit points at Marchwood and Langage because of the long distances on the NTS between these exit points and entry terminals, the proximity to the entry points allowing for increased certainty of flows at the exit points.

5.30. There are two broad options for the treatment of contracting approaches:

- Option 3a - do not apply a downward adjustment to the incremental investment costs to account for a possible contractual approach
- Option 3b - apply a downward adjustment to the incremental investment costs to account for a possible contractual approach. If this option is chosen then we would use the 0.8 factor used at TPCR4.

5.31. Option 3a would allow NGG the full amount of opex, depreciation and return on any anticipated reinforcement as the default position. If contracting was actually a more efficient means of providing the incremental exit capacity consumers would not benefit from the cost savings in the five year revenue driver period. The revenue driver figures implied by these options is included in Table 3 above.

5.32. The alternative of applying a downward adjustment factor may be consistent with the approach used in TPCR4. Abernedd, Barking and Coryton are close to significantly sized entry points. In this sense they are similar to the circumstances which applied for Pembroke and Grain. Applying the factor of 0.8 which was used in TPCR4 would sharpen the incentive inherent in the revenue drivers for NGG to deliver the incremental exit capacity at a cost lower than allowed through the revenue driver. This should encourage NGG to explore contractual solutions where appropriate which should deliver the potential benefits to consumers from less physical assets, which incur future depreciation and return. If the contractual route is not possible and physical investment is the most appropriate solution then there are a number of means by which any higher costs which have been efficiently incurred in delivering incremental exit capacity can be recovered by NGG. These include increases to the RAV and via the logging up mechanisms which were established in TPCR4.

5.33. It is up to NGG to explore the different options available to provide incremental exit capacity (either through physical investment or via contractual solutions) and make its decision based on cost efficiencies. Our provisionally preferred option is to apply a downward adjustment factor of 0.8 to the incremental investment costs. This allows NGG revenues to increase in line with making additional exit capacity available but encourages NGG to find the most efficient solution and further protects consumers from revenues for physical investment which may not be necessary. We continue to use the factor of 0.8 for consistency with the approach taken during TPCR4.

6. Way forward

Chapter Summary

This chapter sets out upcoming work we plan to do regarding developing a generic methodology for deriving entry and exit revenue drivers. It also sets out our envisaged timeline for this consultation and final decision.

Generic revenue driver methodology

6.1. We noted in our consultation for the setting of specific revenue drivers at Canonbie and Gilwern that we planned to develop a generic methodology for deriving entry and exit revenue drivers for the period until the end of the current price control period i.e. to 31 March 2012. However, due to the short notice request for revenue drivers at Abernedd, Barking and Coryton we have decided to postpone our work on a generic methodology until after this current consultation is complete. Once in place, the generic methodology would allow for more mechanistic determination of a revenue driver for each entry and exit point and therefore should allow a shorter time period between a request to NGG for a revenue driver and it being included in the Licence.

Timeline

6.2. We welcome views on all aspects of setting the revenue drivers at Abernedd, Barking and Coryton. The consultation will close on 1 October 2009 but we would welcome early responses. We do not intend to provide another round of consultation before reaching our final decision. Where, in this document, we refer to Ofgem's views these are provisional views and are subject to further consideration of any points raised in this consultation process. Responses to this consultation will be carefully considered before we decide on the appropriate methodology for deriving the revenue drivers at Abernedd, Barking and Coryton. We would envisage a decision document in October 2009 along with a Section 23 notice to change NGG's gas transporter licence in respect of the NTS in November 2009.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. In particular, we would like to hear from transmission licensees, gas transporters, users of the transmission networks, gas terminal developers, investors, gas storage developers, consumer groups and other interested parties.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 1 October 2009 and should be sent to:

Richard Miller
Senior Manager, Gas Transmission Policy
Ofgem
Third Floor, Cornerstone
107 West Regent Street
Glasgow, G2 2BA

Email responses should be sent to:
gas.transmissionresponse@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: Having considered the responses to this consultation, Ofgem intends to publish its decision in October along with a Section 23 notice to change NGG's gas transporter licence. Any questions on this document should, in the first instance, be directed to:

Richard Miller
Senior Gas Transmission Policy Manager
Ofgem
3rd Floor, Cornerstone
107 West Regent Street
Glasgow, G2 2BA
0141 331 6013

Email questions should be sent to:
gas.transmissionresponse@ofgem.gov.uk

CHAPTER: Four

Question 1: Do you agree with our provisionally preferred option regarding cost assumptions i.e. Option 1a which uses the unit cost assumptions used at TPCR4?
Question 2: Are there any other considerations which we have not highlighted which we should have taken into account?

CHAPTER: Five

Question 1: Do you agree with the modelling assumptions we instructed NGG to use?
Question 2: Do you agree with the approach taken to mitigate for potential double remuneration NGG could receive from meeting its exit capacity baseline obligations and providing the incremental exit capacity i.e. increasing local demand flow assumptions to baseline levels where possible?
Question 3: Do you have any opinions on the modelling approach taken by NGG to investigate possible interactions with the reinforcements required for Fleetwood? Specifically, do you have any views on the balancing assumptions used for Option 2c? Similarly do you have any views on whether a range of scenarios using different balancing points should have been considered given any time constraints?
Question 4: Do you agree with our provisionally preferred option regarding Fleetwood i.e. Option 2a to not include the Fleetwood reinforcements in the base network when modelling the incremental reinforcements required for each of the three exit projects?
Question 5: Do you agree with our provisionally preferred option regarding consideration of the potential for contractual solutions to deliver incremental exit capacity i.e. Option 3b to apply a downward adjustment factor of 0.8 to incremental investment costs to account for possible contracting solutions to provide incremental exit capacity?
Question 6: Are there any other issues which we have not highlighted which we should have taken into account?

Appendix 2 - How exit revenue drivers work in the licence

1.1. This appendix sets out in detail how the release of incremental capacity provides NGG with additional revenue allowances through application of revenue drivers.

1.2. The arrangements described below apply to both the transitional and enduring periods.

1.3. Once a user commitment signal for the release of incremental exit capacity has been received and that capacity has actually been released, NGG's SO maximum allowed revenue increases for a period of five years.

1.4. The Licence[25] sets out the calculation for how NGG's SO maximum allowed revenue is increased following release of incremental exit capacity. The incremental exit capacity projects are divided into three broad groups:

- Projects with specific revenue drivers - at the last price control specific revenue drivers were calculated for a number of larger projects which were anticipated over the price control period
- Projects in the South West zone (these are listed in the Licence) - at the last transmission price control a zonal revenue driver was only calculated for the South-West zone. There was no zonal revenue driver calculated for other zones as it was not anticipated that there would be any incremental exit requirements in zones other than the South-West in the 2007-2012 period.
- New Projects - this is a term for new projects which are not captured in the other two terms above i.e. those that were not anticipated at the TPCR4 and are not small projects in the South-West zone.

1.5. The incremental exit capacity revenue is equal to the sum of:

- Revenue allowed for projects with specific revenue drivers - in the Licence the anticipated projects' revenue drivers are listed along with the value of incremental exit capacity (see Table 4 below)
- Revenue allowed for projects in the South-West zone
- Revenue allowed for 'new' projects

1.6. The sum of these is then inflated by the general rate of inflation.

1.7. The revenue allowed from projects with specific revenue drivers is set out below, and draws from the figures in table 4 below.

Revenue Allowed for Projects with Specific Revenue Drivers[26] =

[25] Paragraph 1(d) of special condition C8E.

$$\sum_{\text{All Anticipated Projects}} \left(ProjectSpecificRevenueDriver \times InputPriceIndexationFactor \right)$$

Table 4: Anticipated Exit Projects

Anticipated Project	Project Specific Revenue Driver (£m/year, 2005/6 prices)
Langage Phase 1	9.5
Langage Phase 2	5.5
Marchwood	4.5
Pembroke	6.4
Grain	10.6

1.8. Where the sum of the incremental exit capacity for all projects in the South-West zone is less than 15 GWh/day in one formula year then:

Revenue allowed for projects in the South-West zone[27] =

$$\sum_{\text{All Anticipated Projects}} \left(IncrementalExitCapacity \times InputPriceIndexationFactor \right) \times £820{,}000$$

1.9. The revenue allowed from 'new' projects is calculated below.

Revenue allowed from 'new' incremental exit projects[28] =

$$\sum_{\text{All New Projects}} \left(IncrementalExitCapacity \times NewProjectRevenueDriver \times InputPriceIndexationFactor \right)$$

1.10. The amount of revenue earned by application of the exit revenue driver is earned over 5 years. At the next price control, after contractual delivery of the incremental exit capacity, any investment that NGG has made will be assessed to ensure that the investment reflected the actual demand for new capacity and was carried out efficiently. If Ofgem decides that the investment was efficient NGG is subsequently allowed to recover through its TO price control the (depreciated) cost of the actual efficient investment, logged up to include any loss in finance costs on the efficient investment i.e. the investment is added to the TO RAV. If Ofgem decides that investment in the incremental capacity was inefficient or was not required, the funding for the incremental capacity, or part of it, may be excluded from the TO RAV.

[26] The term InputPriceIndexationFactor indexes the cost to the specific year when the project is delivered to account for real changes in input prices for steel and contractors.
[27] The term IncrementalExitCapacity is measured in GWh/day and the term InputPriceIndexationFactor means the same as that in footnote .
[28] IncrementalExitCapacity is the amount of capacity delivered by the new exit project. NewProjectRevenueDriver is the revenue driver for the new exit capacity project in £/GWh/year. The term InputPriceindexationFactor means the same as that in footnotes and .

Appendix 3 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[29]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[30].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met
- the need to secure that all reasonable demands for electricity are met
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[31]
- the need to contribute to the achievement of sustainable development; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas[32]

[29] entitled "Gas Supply" and "Electricity Supply" respectively.
[30] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[31] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- promote efficiency and economy on the part of those licensed[33] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity, and
- secure a diverse and viable long-term energy supply

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- the effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity
- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice, and
- certain statutory guidance on social and environmental matters issued by the Secretary of State

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation34 and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[32] The Authority may have regard to other descriptions of consumers.
[33] or persons authorised by exemptions to carry on any activity.
[34] Council Regulation (EC) 1/2003

Appendix 4 - Glossary

A

The Authority

The Gas and Electricity Markets Authority (GEMA) is the body established by Section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in Great Britain.

G

Gas Distribution Network (GDN)

GDNs transport gas from the National Transmission System (NTS) to final consumers and to connected system exit points. There are currently eight GDNs in Great Britain, four of which are owned by National Grid Gas plc, and four of which were sold by Transco plc (now National Grid Gas plc) to third party owners on 1 June 2005.

I

Incremental Exit Capacity

In the transitional period this is exit capacity which is in excess of existing system exit capacity. In the enduring period this is exit capacity in excess of obligated levels.

Independent Gas Transporter (IGT)

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

N

National Grid Gas (NGG)

The licensed gas transporter responsible for the gas transmission system, and four of the regional gas distribution companies.

National Transmission System (NTS)

The high pressure gas transmission system in Great Britain.

O

Ofgem

Ofgem is the Office of Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (the 'Authority').

One in Twenty Obligation

This is a security standard for the licensee to have a pipeline network which meets peak aggregate daily demand at levels which would be expected to occur in one year in twenty when considering the historical weather data for at least the previous 50 years, and other relevant factors.

R

Regulated Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee's regulated distribution business (the 'regulated asset base'). The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base at privatisation and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

Revenue Driver

A means of linking revenue allowances under a price control to specific measurable events which are considered to influence costs. An example might be to allow a specified additional revenue allowance for each GWh/day of new entry capacity to the National Transmission System (NTS). Revenue drivers are used by Ofgem to increase the accuracy of the revenue allowances.

S

System Operator (SO)

The System Operator (SO) has responsibility to construct, maintain and operate the National Transmission System (NTS) and associated equipment in an economic, efficient and co-ordinated manner. In its role as SO, National Grid Gas (NGG) is responsible for ensuring the day-to-day operation of the transmission system.

T

Ten Year Statement (TYS)

Special Condition C2 (Long Term Development Statement) requires National Grid Gas (NGG) to annually publish a ten-year forecast of National Transmission System (NTS) usage and likely developments that can be used by companies, who are contemplating connecting to the NTS or entering into transport arrangements, to identify and evaluate opportunities.

Transmission Owners (TO)

These are companies that hold transmission owner licences. National Grid Gas (NGG) is the gas Transmission Owner (TO).

Fourth Transmission Price Control Review (TPCR4)

TPCR4 established the price controls for the transmission licensees and took effect in April 2007 for a 5-year period. The review applies to the three electricity transmission licensees, National Grid Electricity Transmission (NGET), Scottish Power Transmission Limited (SPTL), Scottish Hydro Electric Transmission Limited (SHETL) and to the licensed gas transporter responsible for the gas transmission system, National Grid Gas (NGG).

U

Uniform Network Code (UNC)

As of 1 May 2005, the UNC replaced National Grid Gas's (NGG's) network code as the contractual framework for the National Transmission System (NTS), Gas Distribution Networks (GDNs) and system users.

Appendix 5 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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