National Grid Gas NTS and other
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18 March 2010

Dear colleague,

Determining revenue drivers for exit points: Abernedd, Barking and Coryton

Ofgem[1] has consulted[2] on both National Grid Gas's (NGG's) modelling work to estimate costs of incremental capacity at three exit points. We have also consulted on our proposed approach to determining the revenue drivers for these points on the National Transmission System (NTS). The three exit points consulted upon were Abernedd, Barking and Coryton.

Having considered the responses to our consultation and having regard to the principal objective and statutory duties[3] of the Authority and for the reasons set out in this letter, the Authority is now proposing to set revenue drivers at Barking and Coryton[4].

This letter outlines:

- the background to revenue drivers, including why these are now required at the exit points listed;
- a summary of Ofgem's consultation proposals and the responses received to our consultation; and
- Ofgem's views and final proposals on the appropriate levels for these revenue drivers.

Background

Revenue drivers enable NGG's allowed revenue to automatically flex upwards in response to incremental capacity requests that are backed by financial commitment from users. They allow NGG to earn additional revenue for a fixed five year period[5]. Essentially, revenue drivers fund the depreciation and return on a deemed amount of capex, with an allowance for opex, over the five year period.

At the time of the Fourth Transmission Price Control Review (TPCR4), which covers the period 2007-2012, revenue drivers were determined for specific exit points which were

[1] Ofgem is the Office of Gas and Electricity Markets Authority. The terms 'Ofgem' and 'the Authority' are used interchangeably in this letter.
[2] See 'Determining Revenue Drivers for Exit Points: Abernedd, Barking and Coryton: Consultation', 21 August 2009, with publication number 106/09 on Ofgem website www.ofgem.gov.uk
[3] In particular those set out in Section 4AA of the Gas Act 1986, as amended.
[4] Uncertainty over capacity requirements at Abernedd means that we do not intend to set a revenue driver in the licence at this time.
[5] At the following price control period any investment is reviewed and the Regulated Asset Value adjusted appropriately to reflect any efficiently incurred investment.

expected to be associated with requests for significant incremental exit capacity during the price control period.

Since completion of TPCR4, there have been developments which require incremental exit capacity at exit points not anticipated at TPCR4. Ofgem has now been requested to provide revenue drivers so that NGG has greater certainty over its resulting revenues when allocating incremental exit capacity at these NTS points. Table 1 sets out the exit points where incremental exit capacity was requested and the amount that was initially requested.

Table 1: Exit points and initial incremental capacity requests

Exit Point	Initial Incremental Exit Capacity Request (GWh/day)
Abernedd	39.4
Barking	23.8
Coryton	42.6

The process undertaken for the determination of these three exit revenue drivers involved consideration of modelling work which was undertaken by NGG, an Ofgem consultation, and consideration of the issues raised by respondents to the consultation.

Consultation

In deriving the proposed revenue drivers we asked NGG to model what reinforcement work would be required for each of the incremental exit capacity requests for each exit point. We requested that NGG use the following assumptions in its 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 (GDN) obligations from 2008 Offtake Capacity Statement (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

NGG noted that in 2012/13 it will have baseline exit obligations and that any reinforcement work for incremental projects would include reinforcements necessary to meet the baseline obligations. NGG proposed a solution to avoid any potential double remuneration that may result - this was to take its base network for 2012/13 and model the reinforcements necessary for meeting its baseline obligations local to the exit point under consideration (the 'obligated network'). Following this, NGG would then conduct the modelling to identify the reinforcements that would be required for the incremental exit capacity requested which was additional to the base network (the 'incremental network'). NGG could then ascertain the incremental investment costs by subtracting the value of the reinforcements required for the obligated network from the incremental network.

In NGG's initial response we noted that the base network for 2012/13 did not include reinforcements for the project at Fleetwood (which had entry capacity obligations from October 2010 but for which the start date of the obligations was uncertain, due to refusal of planning permission). We noted that it was possible that Fleetwood could get planning permission and be operational by 2012/13. We therefore asked NGG to do further modelling to account for the uncertainty regarding the Fleetwood project.

We consulted on three main issues common to each exit point studied, these were:

(i) which **cost assumptions** to use for estimating the reinforcement costs;

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(ii) **modelling assumptions**, including how to account for the uncertainty over both: (a) whether Fleetwood reinforcement work would be completed by 2012/13 and (b) the level of the Fleetwood entry flows in 2012/13; and

(iii) how to account for the potential of **contracting solutions** which could be used as an alternative to physical investment for each incremental exit capacity project.

Cost Assumptions

In relation to the cost assumptions, Ofgem consulted on two different options:

- **Option 1a:** use TPCR4 unit cost assumptions; and
- **Option 1b:** use NGG's revised unit cost assumptions.

Ofgem's provisionally preferred approach was to use the TPCR4 unit cost assumptions (Option 1a).

Modelling Assumptions

In relation to the uncertainty regarding Fleetwood we consulted on three different options:

- **Option 2a**: Fleetwood reinforcements excluded from the modelling and zero entry flows at Fleetwood;
- **Option 2b**: Fleetwood reinforcements included in the base network in the modelling and zero entry flows at Fleetwood; and
- **Option 2c**: Fleetwood reinforcements included in the base network in the modelling and 650 GWh/day entry flows at Fleetwood.

Ofgem's provisionally preferred approach was to assume that Fleetwood reinforcements were not included in the base network in the modelling and that entry flows at Fleetwood were zero (Option 2a).

Contracting Solutions

In relation to contracting we consulted on two different options

- **Option 3a:** do not apply any adjustment factor to 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.

Ofgem's provisionally preferred approach was to apply a downward adjustment factor of 0.8 to the incremental investment cost to account for the potential for contracting to provide incremental exit capacity (Option 3b).

Table 2 sets out the revenue drivers that would result from the various options (this assumed that TPCR4 cost assumptions were used i.e. Option 1a).

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Table 2[6]: Licence revenue drivers for various options, as consulted on (£/GWh/year)

NTS Exit Point	Incremental Capacity (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	213,582	170,866
Coryton	**42.6**	161,180	128,944	161,180	128,944	161,180	128,944

Consultation responses

There were four responses to the consultation. A detailed summary of the responses is provided in Annex 1.

Cost Assumptions

All four respondents agreed with our provisionally preferred approach of using the unit cost assumptions used at TPCR4 i.e. Option 1a.

Modelling Assumptions

Two respondents agreed with our provisionally preferred approach of not including the Fleetwood reinforcements in the base network when modelling the incremental reinforcements required for the projects i.e. Option 2a. They argued that as the Fleetwood storage project did not have planning permission then it would be unlikely that the project would be commissioned by 2012/13.

The other two respondents supported Option 2b which was to include Fleetwood reinforcements and zero entry flows at Fleetwood. They argued that this avoided double remuneration for Fleetwood reinforcements, partially offsets the higher costs consumers face from Fleetwood capacity not being delivered and that zero flows reflect the lack of planning permission for the Fleetwood storage project.

Two respondents considered that the assumptions used created a 'worst case' scenario which resulted in higher revenue drivers and therefore higher costs to consumers. They suggested using the ten year base case scenario with sensitivities (based on the assumptions used in NGG's modelling) around this to ensure correct revenue drivers are used.

Contracting Solutions

Three respondents supported our provisionally preferred approach of applying a downward adjustment factor of 0.8 to incremental investment costs to account for possible contracting solutions to provide incremental exit capacity i.e. Option 3b. They argued this would be consistent with the approach taken at TPCR4.

The other respondent supported Option 3a which involves no adjustment factor to incremental investment costs. It argued that if investing is the most efficient solution there would be uncertainty over remuneration of the remaining 20 per cent of incremental investment costs not included in the adjusted revenue driver. It favoured not including any

[6] NGG noted that the revenue drivers for Barking and Coryton do not change for the different assumptions on Fleetwood between Option 2a and Option 2b. It therefore did not do any modelling for Option 2c as assumed that the revenue drivers would be the same. The consultation denoted this by inserting 'n/a' in the table under Option 2c for both contracting options at Barking and Coryton. However, they should be as per this table.

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adjustment for potential contracting solutions (Option 3a). It suggested that in this case if contracting was the most efficient solution that either the revenue driver in the licence could be modified or NGG's revenue could be reduced at the subsequent price control. It also noted that the application of the 0.8 factor could not be continually applied to setting exit revenue drivers in the longer term.

Other comments

Clarification was sought by respondents on a number of issues, including

- whether the GDN obligations from the 2008 OCS relate to 2008/9 firm or 2012/13 indicative bookings;
- whether the GDN baselines relate to the values pre- or post-16 July 2009 baseline modifications[7];
- how many years contracting should NGG consider when assessing whether to invest or use contracting.

Two respondents thought it may be appropriate to revisit the analysis using the results of the 2009 OCS booking process, as these would be available at the end of the consultation.

One respondent raised concern that revenue drivers are linked to the receipt of a signal for incremental exit capacity and not to the delivery of the project which would allow NGG revenue for projects that do not materialise. It thought that NGG should only earn a return on investments that have materialised.

Ofgem's view

Since the close of the consultation on determining revenue drivers, developers at Abernedd have indicated uncertainty over the quantity and timing of their capacity requirements. We have therefore decided to postpone setting the revenue driver at Abernedd until there is greater certainty. However, we plan to proceed with setting the revenue drivers at Barking and Coryton, neither of which should be delayed due to capacity uncertainty.

Since the consultation closed NGG has also received clarification on the capacity request at Coryton. The capacity request at Coryton should be for 46.2 GWh/day rather than 42.6 GWh/day which was modelled for the purposes of the consultation. We asked NGG to update its modelling for the revised capacity figure. As a result of this modelling work, NGG identified the need for some additional reinforcement work, however, as the costs of this work would be divided over a greater amount of capacity the unit revenue driver calculated by the methodology would have been marginally lower than the level we indicated in our consultation. NGG has also corrected the Retail Price Index figures that were used to calculate the unit revenue driver figures in the consultation, which has marginally increased the unit revenue driver figures.

Table 3: Licence revenue drivers under various options, revised (£/GWh/year)

NTS Exit Point	Request of Incremental Capacity (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*
Barking	**23.8**	214,868	171,895	214,868	171,895	214,868	171,895
Coryton	**46.2**	161,940	129,552	161,940	129,552	161,940	129,552

[7] On 16 July 2009 Ofgem directed NGG to change some exit baseline values in its licence, see 'Modification of gas transporter licence pursuant to Section 23 of the Gas Act 1986 (exit baselines)', 16 July 2009, on Ofgem website www.ofgem.gov.uk.

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The revised unit revenue driver figures for Coryton, along with the figures for Barking are shown in Table 3 (this assumes that TPCR4 cost assumptions are used i.e. Option 1a). These revised figures do not imply any change to the methodology we consulted on, they simply change the input figures into the methodology.

Having considered the responses to the consultation and its principal objective and statutory duties, Ofgem remains of the view that it is appropriate to use the TPCR4 unit cost assumptions in setting the revenue drivers for Barking and Coryton. This is for reasons of consistency with TPCR4 and other revenue driver determinations in the meantime. This was fully supported by consultation respondents.

As explained above, due to uncertainty over capacity requests at Abernedd we are now only setting revenue drivers at Barking and Coryton. The revenue drivers for these two exit points do not vary according to the different assumptions on Fleetwood reinforcements and flows. We therefore consider it appropriate to model the revenue drivers under the Option 2a approach, which excluded the effect of reinforcing the network at Fleetwood and a zero flow at the Fleetwood exit. The merit of this approach is reinforced by the fact that in January 2010 Lancashire County Council rejected the revised planning application for the gas storage facility at Fleetwood. It is therefore highly unlikely that the Fleetwood storage facility will be commissioned by 2012/13. We acknowledge the concerns of respondents that this approach might have led to a situation where NGG is remunerated twice for the same investment, however, if this circumstance arose, we would prefer to address it directly.

Ofgem continues to consider it appropriate to apply a downward adjustment factor of 0.8 to the incremental investment costs to account for the potential that contracting can be used as an alternative to physical investment to deliver incremental exit capacity (Option 3b). As previously argued this ensures consistency with TPCR4 when exit points close to large entry points had a downward adjustment factor of 0.8 applied to them to account for contracting possibilities in lieu of physical investment on the NTS. However, we acknowledge that it would be appropriate to consider this approach in the context of the next transmission price control review.

One respondent noted concern that if Option 3b was applied and physical investment was the most efficient means of providing incremental exit capacity then NGG would have uncertainty over whether it would receive the remaining 20 per cent of incremental investment costs. Where physical investment is the efficient solution there are then a number of routes available for NGG to recover any higher costs that have been efficiently incurred. These include increases to the Regulatory Asset Value (RAV) and via the logging up mechanisms which were established at TPCR4. The benefits from Option 3b are that if contracting is the most efficient solution then consumers benefit from the cost savings in the five years over which the revenue driver is applied. It also puts an incentive on NGG to explore more fully the potential for contracting solutions where they cost less than investing as this should result in benefits to consumers from less physical assets.

Clarity was sought on a couple of aspects of the modelling. The GDN bookings from the 2008 OCS process that were used in the modelling relate to the 2012/13 indicative bookings. Furthermore, the GDN baselines that were used in the modelling were those that resulted from the modification to NGG's licence on 16 July 2009.

As the incremental capacity requested for the exit points is to supply power stations, we consider that the incremental demands are unlikely to displace existing demands and so require increases in supply to match demand. The use of the least helpful entry point to meet this extra demand and the 'low local supply' assumptions provides credible 'difficult' flow scenarios which appropriately balances between ensuring remuneration of efficient costs and avoiding excessive buy-back risk.

From the 2009 OCS process there is indicative booking information available for 2012/13; however, actual bookings of exit capacity in 2012/13 were made at the July 2009

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Application Window, and these may provide a better view of demands in 2012/13. The results of the July 2009 Application Window show that demands local to Barking and Coryton would only be marginally lower than indicated in the 2008 OCS data and therefore it is not considered an appropriate use of resources to perform the modelling again.

One respondent expressed concern that revenue drivers might remunerate NGG for capacity that never materialises, which would result in costs being socialised across the industry. Though not explicitly stated in the Exit Capacity Release (ExCR) Methodology Statement, we understand that NGG consider that exit revenue drivers for capacity booked through ad-hoc applications and Advanced Reservation of Capacity Agreements (ARCAs) are only triggered by receipt of all demonstration information[8], where reinforcement works are required. For exit capacity triggered through Annual Application windows a user commitment amount will be associated with the capacity, which mitigates concern over large portions of revenue driver allowances being socialised across the shipper community.

We note that the 'low local supply' scenarios and the least helpful supply assumptions are not included in the planning code and that inclusion of these scenarios should be considered in the next review of the planning code.

Decision

Following consideration of the modelling work done by NGG and the consultation responses, and having regard to the Authority's principal objective and statutory duties, the Authority proposes setting revenue drivers for Barking and Coryton as per Table 4.

Table 4: Final licence revenue drivers

NTS Exit Point	Incremental exit Capacity (GWh/day)	Unit Revenue Driver (£/GWh/day)
Barking	23.8	171,895
Coryton	46.2	129,552

Accompanying this decision letter is a Section 23 Gas Act 1986 Notice setting out the proposed modifications to NGG's Gas Transporter Licence, the proposed effects and reasons. Any representations should be made by 19 April 2010. Subject to any representations and National Grid Gas's consent, Ofgem aims to modify the licence condition by late April 2010.

Yours sincerely,

Stuart Cook
Senior Partner, Transmission & Governance
Signed on behalf of the Authority and authorised for that purpose.

[8] NGG sets out a list of demonstration information (such as confirmation of planning consent, full financial backing for the project) and dates on which it must receive this information before it proceeds with significant reinforcement works triggered by a particular exit project.

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Annex 1: Consultation Responses

Cost estimation

Do you agree with our provisionally preferred option regarding cost assumptions i.e. Option 1a which uses the unit cost assumptions used at TPCR4?

All four respondents agreed with our provisionally preferred approach of using the unit cost assumptions used at TPCR4 i.e. Option 1. One respondent thought this would mean no incentive on NGG not to request revenue drivers at the early stage of development in the hope that more favourable revenue drivers would be set in the future.

Modelling

Do you agree with the modelling assumptions we instructed NGG to use?

One respondent considered that Ofgem's assumptions appear appropriate. It sought clarification on whether GDN obligations from the 2008 OCS relate to 2008/9 firm or 2012/13 indicative bookings as it considered it should be 2012/13 indicative bookings.

Two other respondents considered the assumptions created 'worst case' scenarios resulting in revenue drivers which are higher and therefore costlier to consumers. They noted these assumptions do not appear in the planning code and are:

- Low local supply scenario;
- Least helpful entry point being used to increase entry flows to match increased exit flow demands.

These respondents considered that the assumptions used created a 'worst case' scenario which resulted in higher revenue drivers and therefore higher costs to consumers. They suggested using the ten year base case scenario with sensitivities (based on the assumptions used in NGG's modelling) around this to ensure correct revenue drivers are used. They also considered that these assumptions should not be used simply because they were used for entry revenue drivers.

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?

One respondent agreed with the methodology employed to avoid double remuneration for reinforcement works required to meet NGG's baseline exit obligations and for any incremental exit obligations. This respondent questioned which baseline exit capacity obligations were used since at the time of the modelling work there was work underway to revise the exit baseline figures in the licence – it thought that the revised baseline exit obligations should be used.

Another agreed it appropriate to separate investments to meet NGG's existing baseline exit capacity obligations and any incremental requests. It thought that baseline exit capacity obligations could be met from the existing network and that 2008 OCS bookings do not give rise to incremental exit capacity obligations. It also noted confusion in the interchangeable use of the terms 'baseline capacity' and 'obligated capacity'.

The same respondent note that it would be interesting to know the results of the 2009 OCS bookings as these would be available at the end of the consultation and revisit the analysis if there is time and resources available. The other respondent commenting on this issue requested that the decision be delayed until this is available.

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?

One respondent thought that Fleetwood reinforcements must be included in the modelling with zero flows to avoid NGG being remunerated twice for the Fleetwood reinforcements and to be consistent with the regime where obligated incremental capacity becomes part of baseline exit capacity obligations.

Another thought that as the Fleetwood storage project did not have planning permission it is unlikely that it will be commissioned by 2012/13.

One respondent took comfort that for the modelling for Barking and Coryton a credibility test was applied to the low flow scenario – this being that Fleetwood entry flows could not be balanced by reducing entry flows local to Barking and Coryton since these were already at the low flow scenario level and to reduce them further would not be credible. Another thought it appropriate to use consistent balancing assumptions at Abernedd as notes that a least useful approach had been employed at TPCR4 and for modelling for Barking and Coryton. Though it noted that it could not identify if the least useful approach to balancing Fleetwood entry flows, for the Abernedd modelling, would be done at Bacton or St Fergus.

One respondent thought that it would be helpful if the analysis for Abernedd had balanced entry flows at different entry points for comparison purposes.

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?

Two respondents supported Option 2a arguing that the Fleetwood project did not have planning permission at the time and so is unlikely to be commissioned by 2012/13.

The other two supported Option 2b (including Fleetwood reinforcements and zero Fleetwood entry flows) as argued this avoids double remuneration and is consistent with NGG having to provide Fleetwood entry capacity. One respondent noted that in the absence of any downward adjustment to NGG's allowed revenues, to reflect the capacity not being delivered at Fleetwood, that Option 2b partly offsets the costs that consumers face. As there is no planning permission it was argued that there will be zero entry flows at Fleetwood as a result.

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?

Three respondents supported Option 3b. The reasons given for their support was that it would be consistent with TPCR4. One of these noted the lack of clarity on how many years contracting NGG should consider when assessing whether to invest or use contracting.

The remaining respondent did not support Option 3b. Its concern was that if investing is the most efficient means of delivering the incremental capacity then there is uncertainty over how, when and how much of the remaining 20 per cent of incremental investment costs NGG would recover. It suggested a revenue driver licence modification in these circumstances or proposed setting the revenue driver at 100 per cent of the incremental investment costs and if contracting turned out to be the most efficient means of providing the incremental capacity then for NGG's revenue at the next price control to be reduced accordingly. It also noted that if the application of the 80 per cent factor is continued in the long run it would ignore the limited ability and willingness of individual entry points to enter into multiple contracts.

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Are there any other issues which we have not highlighted which we should have taken into account?

One respondent thought it may be useful going forward to (i) gain understanding on whether or not NGG needs to have an agreed revenue driver before it releases incremental capacity at new or existing points and (ii) reconsider the timeline in which parties flag their intention to signal incremental exit capacity.

Another had concerns that revenue drivers are linked to the receipt of a signal for incremental exit capacity and not to project delivery as this allows NGG revenue for a project that may not have materialised. It thought that NGG should only earn a return on investments that have materialised.

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