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Dear Bob

BG Gas Services Limited Response to Transmission Price Control review 2007 - 2012. Initial Proposals.

BG Gas Services Limited ("BG") welcomes the opportunity to respond to Ofgem's third consultation on the Transmission Price Control. BG is active in the UK market as a gas shipper, marketing and trading gas on behalf of BG Group's UKCS production activities. In addition BG Group has both equity interests and capacity rights in the Dragon LNG terminal currently under construction at Milford Haven in south Wales. Our comments below therefore focus on the Price Control for National Grid Gas' transmission activities, with emphasis on the gas entry incentives. For comments on the financial aspects of the Price Control as outlined in Chapter 8 please see the response submitted jointly with Centrica, Centrica Storage, BP Gas Marketing, Statoil and Shell Gas Direct Limited.

Chapter 11. Adjustment mechanisms and incentives: gas.

Question 11.1: What do you think of Ofgem's revised proposals for setting entry capacity release obligation baselines, and for the proposed mechanisms to enable such baselines to be re-allocated in some circumstances?

BG agrees in principle with Ofgem's revised proposals for setting baselines and enabling re-allocation of capacity between terminals in certain circumstances. BG believes this approach will maximise use of the network and at the same time avoid unnecessary investment through optimisation of the network. The setting of baselines should ensure that National Grid Gas (NGG) releases a minimum level of capacity, a key element in ensuring that a regulated monopoly does not "game" its outputs.

However BG has two concerns on the details of the proposals. Firstly the baselines for the next Price Control are not yet defined. This potentially creates uncertainty for shippers making capacity booking decisions under the current price control, for example in the September auctions. It is also not clear what happens if bookings made under the price control exceed baselines in the future price control, as some of the baselines outlined in the Appendix are less than current baselines. Furthermore there is no mention of how the current rule, whereby 20% of capacity is held back for shorter term auctions, may be changed in order to accommodate the substitution of capacity. In summary there needs to be a clearer definition of how the transition from the current Price Control regime to the new one will be

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managed, to ensure NGG receives the right signals and to ensure a reasonable degree of regulatory consistency and certainty across Price Control periods.

Secondly the methodology for allocation of capacity that is “substituted” from one terminal to another is also unclear. Issues that need to be addressed include:

- The method of allocation of substitution capacity.
- The price of substitution capacity when transferred from the original terminal to the new terminal.
- Whether all substitution capacity requires a 3 year lead time or whether capacity can be substituted sooner than this.
- The amount of capacity that can be substituted from an under-booked terminal to one where there is demand for more capacity.

The last two points could impact incremental gas field developments. These developments can have short lead times and short life-spans. However they can represent a valuable contribution to UK security of gas supply at a time when the UKCS overall is in decline. Consideration of reform of the entry capacity regime should include whether there is a risk that reform may limit companies’ ability to bring this gas into the NTS.

Question 11.2: Are Ofgem’s proposals for revenue drivers for entry and off-take appropriate and proportionate, given the issues they are seeking to address?

BG agrees with the principles set out in paragraph 11.20 in the Initial Proposals. However it is not clear why “NGT should not be constrained to set reserve prices in auctions and conduct its NPV test on the basis of the revenue drivers set in the price control” (Paragraph 1.24 of Appendix 11). BG is concerned that this approach could lead to unnecessary instability in transportation charging. As BG understands the proposals NGG will be entitled to earn revenue based on the baselines plus any additional capacity for which there is sustained demand, with revenue drivers set as a value per unit of capacity. If NGG sets prices which diverge from these unit values there is a risk that NGG could end up either over or under recovering revenue when it sells entry capacity.

Currently NGG uses the TO charge to ensure that it recovers the revenue to which it is entitled. In October 2006 the TO Commodity Charge will double compared to the previous year. This is clearly not conducive to effective business planning by shippers. The proposals on entry capacity release should ensure that there is a closer match between capacity sold and NGG’s allowed revenue assuming that the price at which capacity sold is based on the revenue drivers. NGG’s ability to price capacity on a different basis potentially undermines this. BG believes that the aim should be to ensure pricing stability within the Price Control Period, by having as close a relationship as possible between the “regulated price / cost” of capacity as represented by the revenue drivers, and the prices charged by NGG in the auctions. Some adjustment both within and between Price Control Periods is inevitable due to differences between forecast and actual demand for capacity; however such adjustment should be kept to a minimum.

Comments on Ofgem’s proposals on buyback incentives.

BG agrees with Ofgem’s proposals to differentiate between buybacks associated with non delivery of incremental capacity and that associated with general operation of the network.

For buybacks associated with general operation of the network BG agrees that NGG should face a greater exposure. The reason for this is that operation of the network is part of NGG’s core business. Operational buybacks tend to be as a result of maintenance schedules or network failures. As NGG is able to control directly both the schedule for maintenance and the level of network failures (through how well they manage and maintain the network), NGG is able to manage directly its buyback exposure. The higher NGG's exposure to buyback risk the more it will be incentivised to manage the network efficiently. Given that Ofgem does not propose to set the buyback target to zero thereby protecting NGG from the risk that flow patterns may limit the amount of capacity available, BG believes NGG should have a higher sharing factor, reflecting its ability to manage its operational risks.

For buybacks associated with incremental capacity BG agrees with the principle of an administered price. However BG does not agree with the way Ofgem has calculated the price as described in Appendix 11. In this case buyback costs can be equated to liquidated damages, for example where a contractor is engaged to build a power station. In this example liquidated damages represent a genuine pre-estimate of the loss that occurs if the contractor fails to deliver the power plant at the agreed time. The pre-estimate of the loss is calculated based on an agreed price for electricity from the projects economic model and the electricity foregone as result of the contractor's failure to deliver. Following this logic buyback costs for NGG would be based on the full NBP price less entry costs. Furthermore it is not clear that historic NBP prices will be a suitable basis for setting buyback prices. Given the cyclical nature of capital intensive and commodity industries such as gas, the use of historic gas prices could underestimate the loss suffered by shippers unable to ship gas.

An alternative approach could be to set buyback prices based on NBP prices prevailing at the time of the non delivery of capacity. This would more properly reflect the cost to shippers of NGG's failure to deliver capacity. To avoid possible interaction between non-delivery of capacity impacting the supply of gas to the UK, and hence the NBP price, the buyback price could be set in advance based on forward prices. This could be done perhaps once a year, thereby ensuring a reasonably close relationship between the likely market price at the time of the buybacks and the buyback price. Although there would not be a perfect correlation between the administered buyback price and actual market prices, the relationship would be closer than that with historic prices predating the Price Control Period.

BG agrees that there should be scope for bilateral agreements to vary the buyback price, scope of work and timescales. In particular this makes sense for large projects in order to align the different project timescales within the gas chain. However if the default buyback regime is too lax there will be no incentive for NGG as a monopoly provider to negotiate. Hence the need to ensure that NGG is sufficiently exposed to buyback cost risks that are within its control.

The document makes no mention of the sharing factors that may apply to buyback costs associated with incremental capacity. However BG believes that NGG should bear a high proportion of any buyback costs based on its ability to manage project risks. As BG has noted in previous consultation responses project management for pipeline construction is a core part of NGG's business, and it is therefore logical that NGG bear the costs of poor performance. In the same vein BG accepts that there may be circumstances which are genuinely beyond NGG's control, and which could justifiably lead to an Income Adjusting Event. However such circumstances should be tightly defined.

Question 11.4: Is there a case for an innovation incentive for NGG NTS?

BG is not convinced that there is a case for an innovation incentive. The whole point of the RPI-X approach (often called incentive regulation to distinguish it from rate of return regulation) is that it provides a framework that incentivises regulated companies to improve their performance. If the overall framework is correctly judged NGG should already have sufficient incentives to pursue projects which improve its performance and reduce its costs through innovation. It is therefore not clear why a specific incentive is required. Indeed there is a risk that the more specific incentives are put in place the more a company will play to its incentives to maximise its revenue rather than manage the business efficiently.

I hope the above comments are useful. If you have any queries please do not hesitate to contact me on 0118 929 3442.

Yours sincerely,

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