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Robert Hull
Director, Transmission
Ofgem
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Cc Joanna Whittington Director, Gas Distribution

Dear Robert

TPCR Initial Proposals

I have pleasure in attaching Northern Gas Networks' (NGN's) response to the TPCR Initial Proposals. Our response does not address all the issues raised but focuses on the questions within the consultation where we feel we can usefully add to the debate.

I can confirm that our response can be placed in the public domain. Please don't hesitate to contact me if you would like to understand our views in more detail.

Yours sincerely

Alex Wiseman

Alex Wiseman
Regulation Director

<u>Northern Gas Network's response to TPCR initial proposals</u>

Question 6.1: Do you think our proposed approach to the costs incurred in the current price control period in respect of increasing capacity at St Fergus is appropriate?

NGN has not got access to the detail behind the decision on St Fergus. However, the principle of disallowing infrastructure investment below allowance seems inappropriate. The consequence will be that utility companies will avoid all investment where there is not a market signal but where there appears to the utility to be a risk of insufficient capacity. The implication is a risk to security of supply. Market signals are one indicator of capacity requirements but we would suggest that the market is not perfect and that it is legitimate to use appropriate business judgement in conjunction with market signals to ensure that infrastructure meets the potential future needs of customers. It should be noted that there is an asymmetric risk for customers on investment – the cost of investment that turns out post hoc to be surplus to requirement is far greater than the cost to customers of a lack of capacity. This applies both to the consideration of historic investment and the setting of capex allowances and suggests a conservative approach to allowed investment.

Question 7.1: Do you agree with our proposed treatment of non-operational capex?

We agree that depreciating non-operational capex such as IT and vehicles over 40 - 45 years would not be appropriate and that a better solution to ensure that appropriate incentives are placed on companies would be to include this expenditure as part of the operating costs. A reasonable alternative would be to depreciate the assets over their economic useful life which may be about 5 years for IT assets.

Question 7.2: Do you agree with our proposed approach to future input price changes and indexation? Is our assumption of a 1.5% annual efficiency saving for opex realistic and appropriate?

It should be recognised that there are substantive cost pressures on infrastructure businesses. Increasingly, the measure of RPI bears little relationship to the basket of goods and services that utility companies purchase. For example the price of clothing and leisure items has fallen sharply over the past few years whereas the cost of oil, raw materials, utilities and services has increased at a significantly faster pace than RPI. Consequently a 1.5% operating efficiency measured against the RPI is a significant challenge and represents a requirement to achieve efficiencies much greater than 1.5%. This will be tough for companies to achieve more than 15 years after privatisation when most of the efficiencies have already been taken out of these businesses. Indeed, RPI already allows for increases in general productivity across the economy and it is unclear why utility infrastructure businesses should be able to improve efficiency faster than the wider economy.

To assume that wages can be held to 0% real increases against a backdrop of higher increases in the wider economy is also a challenge and may not be achievable. There is a danger that the current shortage of power and gas engineers will become even more acute resulting in wage increases significantly higher than RPI.

Where there is an alternative index available, such as for construction prices, then this should be used to index that element of costs as this reduces risk for both companies and customers (both upside and downside).

Question 7.4: Do you think that we need to allow explicitly for the possibility of reopening price controls for specified single events where the timing and level of costs is uncertain and driven by third party decisions? If so, what might such events be and why?

Unexpected external events are very likely to be downsides rather than upsides for the company. Hence there is a risk that some of these events materialise and that companies are unable to earn their allowed cost of capital. Consequently, certain events, in particular legislative changes or events of a "force majeure" nature should be treated as reopeners. If construction prices were not linked to a construction price index then substantive differences between construction prices and RPI should be an opportunity for a reopener (either way) as is the case in the water industry.

Question 7.5: What do you think of our proposed options for setting incentives for efficient capital expenditure?

Rolling incentives that provide symmetry for upsides and downsides and ensure consistent incentives across the price review are appropriate mechanisms for incentivising capex. The rolling incentive should be for at least 5 years and we would advocate a <u>longer</u> period to strengthen the incentive on companies to return value to customers. The current 5 year period means that companies keep (or suffer) only around 70% of the benefits (or costs) of capex over (or under) performance. However, if considerable uncertainties exist in forecasting output requirements then there may be alternative mechanisms for that specific element of capex such as the repex matrix successfully implemented for GDNs.

Chapter 7: Additional comments

Paragraphs 7.4 and 7.5 suggest that the NTS should no longer apply a margin on the 1 in 20 scenario peak day when planning network capacity. Any reduction in this margin needs to recognise the impact on gas distribution companies in the event of a peak day if it reduces system flexibility and if it means that gas cannot be delivered to <u>each</u> offtake in the required capacity.

Question 8.1: Should the licensees' revenue allowances for tax payments be set to avoid any need for ex-post adjustments?

NGN fully concurs that the treatment of tax should be to avoid ex-post adjustments. This is entirely consistent with Ofgem's treatment of opex and maintains incentives on companies to be tax efficient which will ultimately benefit customers.

Question 8.2: Are there any other measures that could be taken to reduce the perceptions of Regulatory risk and what level of risk do these regulated utilities carry relative to other plcs?

As mentioned above, unexpected external events are more likely to be downsides rather than upsides and consequently the lack of reopeners or IDOKs as in water increases the regulatory risk and reduces the return that transmission companies (and distribution companies) are likely to make. This suggests that beta should be higher than for water when estimating the allowed cost of capital.

Unexpected issues such as the £75m proposed disallowance of spend on St. Fergus also increase the perception of regulatory risk. The speaker at the TPCR workshop, Ian Rowson, suggested that this issue alone adds 0.2 to beta.

Chapter 8: Further comments on financial issues

The ENA on behalf of all GDNs has submitted a response specifically on cost of capital and I would like to elaborate further on that response.

It is entirely appropriate to take a longer term view on the allowed return, firstly because markets have always proved to be cyclical and secondly because investment in existing assets have been undertaken on the basis of the then prevailing cost of capital. This stability is essential to minimise the market perception of regulatory risk.

In line with the findings of the Smithers & Co report to the Joint Regulators, we believe that it is premature at this stage to rule out using alternative techniques to the Capital asset Pricing Model (CAPM). Other models such as the Fama French three factor model and the Dividend Growth Model can be a useful cross-check on the outputs from the CAPM modelling.

Although there is some recent evidence that the risk free rate has declined, there are good reasons to consider the longer term historic averages. Firstly, because there is some doubt about how long the recent dip in the risk free rate will last, with, for example, Bank of England expectation of yields reverting to the mean. Secondly, any reduction from recent precedent will send strong signals about regulatory commitment. And thirdly, existing assets were constructed based on the historically allowed risk free rate.

Although the cost of debt appears to have declined in recent years, it is not clear that this is a longer term trend rather than the normal cyclical movement of indices. There continue to be artificial factors driving down the long term cost of debt, in particular the requirement for pension funds to match longer term assets with their liabilities and the switch from these pension funds from equity into debt. Longer term averages should be used and a debt premium of 1% appears low given the historical evidence. Certainly, debt rates have not reduced by 0.35% since DPCR4 as proposed in this regulatory settlement.

The recent discussions on the appropriate treatment of Financeability have highlighted the importance of ensuring that companies have adequate access to capital markets and, in particular, new equity. Consequently an equity risk premium (ERP) towards the top of the range is a welcome recognition of this issue. However, the reduction of the equity beta from 0.9 to 1.0 is less clear. Respondents to the Water UK survey of investors conducted in 2005 thought that both gas transmission and gas distribution were more risky than both water and electricity distribution. This suggests a <u>higher</u> beta than the 1.0 allowed for water and electricity DNOs. Also, the lack of reopeners compared to water highlighted earlier also points to a higher beta.

Transmission companies are competing with other utilities for capital. There is a danger that setting a cost of capital below that allowed for water and electricity DNOs will mean that access to capital will be harder to obtain by the transmission companies. As a consequence, the incentive from the capital markets will be to minimise investment in transmission, possibly to the detriment of customers.

Chapter 8: Further comments on pension issues

DPCR4 laid out a clear rationale and methodology for recovery of some of the ERDC payments and it would be entirely appropriate for transmission ERDCs to be funded in line with the principles established for the DNOs. It should be noted that some of the National Grid NTS ERDCs pre DN sale relate to DNs and consequently recovery of these should be part of the GDPCR and not the TPCR.

To achieve the efficiencies required by price reviews, rationalisation and redundancies are required. The cost to achieve the required efficiencies should be recoverable through the regulatory process as otherwise a company with costs in line with allowances will not be able to achieve its allowed cost of capital. This is clearly inequitable.

Question 10.3: Is our proposed approach to funding for innovation appropriate and necessary? Question 11.4: Is there a case for an innovation incentive for NGG NTS?

The innovation funding incentive appears to work well in electricity distribution to achieve innovations that benefit customers. We believe that this should be extended not only to electricity transmission companies but also to gas transmission and distribution companies.

Question 11.2: Are our proposals for revenue drivers for entry and offtake appropriate and proportionate, given the issues they are seeking to address?

We agree that revenue should accrue on the date on which NGG NTS has contracted to deliver capacity rather than the physical date of delivery. As a GDN, our planning assumptions will be based on this contractual date and NGG NTS should deliver its capacity commitments by that date.

NGN agrees that zonal revenue drivers for small capacity increments are an appropriate means of rewarding general demand growth around a group of geographically associated offtake points.

NGN is of the view that there is merit in indexing revenue drivers to the price of steel for similar reasons to our suggestion above of using construction price indices to reduce risk for both companies and customers. This adds little in complexity and can be simply implemented using an appropriate price index.

Question 11.3: Are our proposals for buy back for entry and offtake appropriate and proportionate given the issues they are seeking to address?

For offtake, the existing provisions where planned maintenance obligations do not require buy back actions should be retained. As stated in the initial thoughts document, the level of historic risk has been close to zero and as such no buy back scheme in this area is warranted at this time.

Any extension of lead times carries a risk to connected parties who may have their own contractual commitments based on originally agreed investment timeframes. Any proposed extensions to such a date should be agreed well in advance, and be capable of pass through to all parties in a contractual chain where the capacity delivery date was altered.

Question A 16.2: Do you agree with our initial proposals for baselines in the enduring period including the adjustments proposed?

NGN agrees that enduring baselines numbers should be consistent with the nodal baselines specified for the transitional period. There may be adjustments contingent on the detail of the proposed product definitions for the enduring period, but these should provide modest changes to the indicative baseline data represented in table 16.1.1. The setting of exit allowance also needs to take into account interruption reform which may significantly reduce the DN interruptibles and hence result in higher capacity requests from DNs.

Question A16.3: Do you agree with our initial proposals regarding the introduction of a substitution obligation on NGG NTS?

It is appropriate that NGG NTS are obliged to substitute available capacity where possible (as they have done for many years). Any permanent transfer of capacity allocation by substitution should be sanctioned by Ofgem and nodal baselines revised accordingly.

Question A16.5: Do you agree that our proposals for addressing entry / exit interactions are appropriate?

Exit baselines should be increased should investment at entry capacity generate increased capacity (applied in a similar way to any substitution baseline amendments).

Question A16.6: Do you agree with our proposals with respect to buy backs of offtake capacity?

We agree that on rare occasions NGG NTS may need some flexibility over investment lead teams. However, any delay should only be approved sufficiently in advance of the date the buy back is related to so as to ensure that DNs can plan accordingly and make their own buy back arrangements. Furthermore, any additional costs thus required by the DNs should be borne by NGG NTS.

Question A17.1: What are your views on the benefit analysis conducted?

We are only able to comment on some of the benefits and costs discussed in this appendix.

NGN notes Ofgem's comments regarding the potential for NG to discriminate in favour of its retained businesses. Clearly any discrimination is not in the interests of customers as well as being a breach of NG's licence. We would hope that NG and Ofgem would put into place policies and procedures to ensure that undue discrimination does not occur, either under the transitional arrangements or under any enduring exit reform.

The avoidance of ARCAs is welcome. However, it is difficult for us to confirm the estimate of the likely number of ARCAs in dispute and the expected cost savings that would arise.

We agree that allocation of risk will be improved and that it will be helpful to have longer term signals of capacity requirements from users.

Security of supply will be improved as suggested if GDNs are better able to forecast their demand requirements than NGG NTS. This should indeed be the case, but Ofgem will need to "approve" GDNs' forecasts to appropriately set incentives and there may be a challenge for Ofgem to ensure consistency between forecasting assumptions.

Question A17.2: What are your views on the cost analysis conducted?

There is clearly a danger in assuming that there are two shipper outliers when only five shippers have submitted data, and there may need to be further analysis of shipper costs before the final impact assessment.

Also, it has been difficult for gas transporters to estimate costs until the product definitions and regime structure are clarified. It may be possible to update these estimates before the final impact assessment as the final regime becomes clearer.

Paragraph 1.110 suggests that the costs associated with implementing enduring offtake arrangements should not be passed through to customers as these are costs of GDN sales. NGN considers that enduring offtake arrangements are entirely separate to sale and that efficiently incurred implementation costs should be borne by customers. These costs are incurred to ensure that customers achieve the benefits outlined in the impact assessment and hence should legitimately be passed through to customers in the same way as any other cost incurred for the benefit of customers.

Question A17.3: What are your views on our assessment of the potential environmental and social impact?

NGN concurs that there are likely to be no substantive environmental or social impacts, either positive or negative.