ROB BRYNGELSON
President and Chief Executive Officer

31 October, 2007

Mr. Robert Hull
Director, Transmission
OFGEM
9 Millbank
London SW1 P 3GE

RE: TPCR Baseline Re-Consultation

Dear Mr Hull,

I refer to the TPCR baseline re-consultation paper dated 3 October 2007 and reply on behalf of Excelerate Energy Limited Partnership and Seal Sand Gas Transportation Limited. This response is not Confidential.

The purpose of this response is to establish the necessity for a fair treatment for Teesside in the capacity allocation process. Specifically, we are looking for a process that recognises the impact of world gas markets on the UK, and supports both security of supply and competition in gas supply, thus significantly benefiting UK consumers as UKCS flows decline sharply.

As you are aware, we have now completed our facility at Teesside which has the capability to bring in 11 MCMD of gas this winter, rising to 16.5 MCMD from winter 08/09. By that time we expect to have four (4) ships capable of onboard regasification in operation with more under construction. For the UK to take advantage of the Teesside facility, we need the confidence that we can offload natural gas from our ships in a timely manner and when market conditions are favourable, which is likely to be in times of high UK demand.

In 2006, we chose to construct our GasPort in Teesside, in large part, because we received assurances that it had (and would continue to have) ample baseline entry capacity to accommodate the GasPort's requirements. We have invested significant capital in order to create this facility. The effect of the TPCR was to deny the GasPort access it requires to the NTS, and accordingly, to leave this high profile and costly facility stranded with no effective way to input gas into the UK.

We wait to see whether Teesside's entry capacity baseline is returned to 70 MCMD. In any outcome a significant amount of capacity headroom must be reinstated. This will not remove the full risk that we will not be able to obtain access to the NTS when we want it, but will put us on an equal footing with users at other ASEPs who only pay reserve prices for entry as their ASEPs have significant capacity headroom. This is unlike the current and recently changed situation at Teesside were there is now far more significant competition for capacity and hence higher prices.

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To that end, our comments are as follows:

CHAPTER 4: TPCR approach to baseline determination

Q4.1: Do you agree with the objectives of the TPCR baseline review?

R4.1 4.2 and 4.3 only identifies two objectives:

- "to set baselines that reflect the physical capability of the network, para 4.2".
    - We agree that this is one reasonable objective but it should not be the only one, especially given the difficulty in measuring the physical capability of the network and the need to rely on internal NGG assumptions such as flows at Bacton in order to calculate such capability.
- "to reduce the risk of buy-back costs having to be borne by consumers, para 4.4"
    - This is also a reasonable objective. However there must be a transparent review of buy-back costs in the period from 2002-2007 to ensure that parties can understand the scale of this perceived problem and understand how these buy-back costs have arisen given the very high capital expenditure allowances made in the 2002-2007 period.

In addition to these 2 objectives, we believe that the objectives of the TPCR review should have been significantly wider, taking into account the following:

- **Competition in gas supply** – the impact of actions on gas prices to consumers should be a key objective. At present the entry regime unfairly favours long term base users. Ofgem therefore needs to accommodate users such as Excelerate in its entry regime. Ofgem has acknowledged in relation to electricity transmission that it may need to develop tailored auction capacity products to reflect the operational profiles of particular types of power generators. Excelerate believes that the entry capacity regime for gas should also reflect a tailored approach. In other words, Ofgem needs to address the capacity requirements of Excelerate's particular operational model which furthers the energy needs of the UK and promotes Ofgem's own statutory objectives under section 4 of the Gas Act, namely (i) Ofgem's principal duty to protect consumers by promoting competition in the supply of gas; and (ii) Ofgem's duty to have regard to security of supply.

- **Security of supply** – the high gas prices and supply shortfalls in winter 2005/06 should be taken into account to act as a lesson for the future.

- **Reputation of UK regime** – stability of the regime and reputation are both important if the UK is going to be able to encourage investment and promote greater competition in Europe, and should be taken into account.

- **The previous level of baselines** – since previous baseline levels influenced shipper behaviour, as set out by Ofgem in 2.13, it is both reasonable and necessary to take them into account when setting new baselines.

- **Impact of baselines on the level of transportation charges** – the level of encouragement given to developers to land gas at places with capacity (such as Teesside) rather than creating new ASEPs with very high levels of reinforcement required should be taken into consideration.

- **Latest market developments** – new developments in 2006, which at the time would have included Excelerate's Teesside GasPort project and today would include the abandonment of the Troll project, must also be addressed (see further comments below).

We believe that any change to the 2002-07 baselines should have been assessed against the above objectives and we would urge Ofgem to take these into account in the current process.

Q4.2: Do you agree with the modelling approach we asked NGG NTS to carry out? If not, why not?

R4.2 2005 Ten Year Statement Scenarios:

We are concerned about reliance on the 10YS because of the difficulty NGG has in deciding how to select supplies to match the peak day. Inevitably, this becomes a highly subjective process as can be seen from comparing the 2005 and 2006 10YS's.

			2005 10YS								2006 10YS		Change from 2005 to 2006 10YS	
MCMD	Baselines		Auctions +		Global LNG		Transit		Average		Base Case			
	2002-07	2007-12	Year 8/9	Year 9/10	Year 8/9	Year 9/10	Year 8/9	Year 9/10	Year 8/9	Year 9/10	Year 8/9	Year 9/10	Year 8/9	Year 9/10
Bacton	161	164	161	161	184	183	184	183	176	175	87	81	51%	54%
IOG	20	38	20	20	13	13	32	36	21	23	25	30	-18%	-32%
Th'thorpe	78	56	24	18	24	18	24	18	24	18	20	24	14%	-30%
Easington	98	98	98	98	124	122	117	120	113	113	55	87	51%	23%
Milford	87	87	88	87	19	23	45	70	51	60	60	74	-19%	-22%
Teesside	70	33	25	25	25	25	25	25	25	25	24	18	7%	26%
Barrow	66	28	22	20	22	20	22	20	22	20	19	17	13%	14%
St Fergus	154	154	98	83	118	122	111	103	109	103	123	120	-13%	-16%
Total 1 in 20 peak day demand		0	577	592	577	592	577	592	577	592	552	556	4%	6%

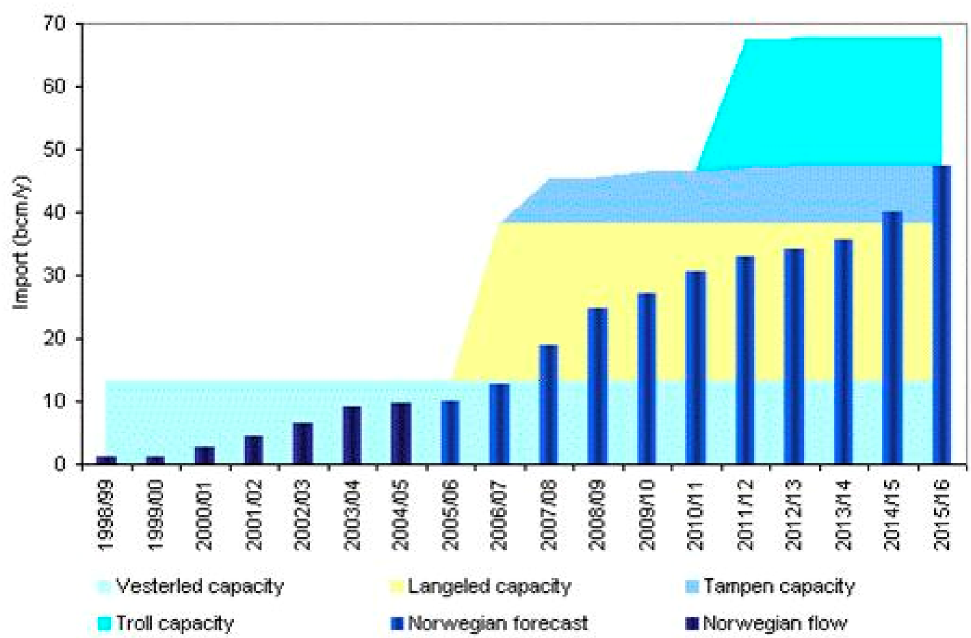
A -ve number means increase from 2005 10YS to 2006 10YS

The 2005 10YS used 3 supply assumptions, and we have taken an average of these. The flow assumptions for Bacton change significantly between the two 10 YS's (eg in the 2005 10YS the forecast for Year 2008/09 was 176 MCMD, and in 2006 it was 87 MCMD). This is a very important factor in the calculation used to set the 2007-12 baselines. At the same time, NGG's planning process was indicating that flows were likely to increase at St. Fergus by around 15% with a decline in flows at Easington.

NGG's Bacton and St. Fergus forecasts were not 'wrong' but neither were they 'right,' and it should have been made clear that both of these were subjective assumptions from NGG and both were critical in the analysis. Other commentators in 2005 would have predicted an increase in flows at Easington due to Ormen Lange and a corresponding reduction at St. Fergus, and NGG could equally have assumed much lower Bacton and St. Fergus flows. As such, the results would have been significantly different.

This suggests that there has been general industry apathy to forecasts 3 years ahead, which has led to NGG having imperfect data. Had it been known in 2005 that forecasts for 2008/9 were to be key in the setting of new baselines, then there would have been a higher level of interest and shipper feedback.

Given that the 2006 10YS forecasts that gas flows into St Fergus from the Troll field will increase significantly from 2010, recent announcements concerning the Norwegian's decision to abandon the Troll project is clearly a material change which NGG need to take account of in its modelling. The abandonment of the Troll project will result in a reduction of around 55 MCMD at St Fergus according to NGG's 2006 10YS.



Supply substitution

This is a reasonable approach, though we are aware that since the 2005 10YS was produced, a significant number of CCGTs have been approved and are being constructed. The impact of these CCGTs should have been considered as a sensitivity to the analysis.

“Least helpful” supply substitution merit order

This does result in a very low buy-back risk, which was the objective of the TCPR review as set out by Ofgem in para 4.2. However, had GEMA adopted wider objectives as we suggest (R4.1 above) some form of weighted average of ‘Least helpful’ and ‘Most helpful’ could be adopted. This would give different results.

Free increment

As above, we are concerned that the Bacton and St. Fergus assumptions are critical in the NGG planning process and the 2005 TYS.

Including Caythorpe and Welton illustrates the confusion in the process and a certain arbitrariness – if a shipper can convince NGG (ahead of any auction signals) that it is a credible project, it may be included in the TYS. We note that the Excelerate GasPort project was not included in the 2006 TYS even though it had by that time received planning permission and was substantially completed. Again, this appears to be somewhat arbitrary.

Modelling assumptions

We have commented above on these. In addition, however, we believe that the 5% flow margin (in effect a 5% capacity margin in all pipelines, over and above the 1-in-20 level) should have been taken out in this analysis so that the underlying capacity can be revealed. Any necessary margin could be added back later if it was required.

Given the aggregate of St. Fergus and Bacton baselines is around 320MCMD, 5% equates to 16 MCMD which is a significant number, equal for example to the flow-rate from Excelerate’s new ships that come into operation in 2008.

Q4.3: One of the main difficulties we faced in the run up to the Final Proposals was to account for zonal constraints. Are there any better ways accounting for zonal constraints?

R4.3 NGG has not presented any evidence as to where constraints exist or of their extent, and hence it is difficult to comment on the concept of zonal constraints.

It could reasonably be expected that by 2008/09, with investment for BBL, IOG Ph 2, IUK expansion, Langeled and Milford Haven all completed, there would no longer be any significant constraints.

Q4.4: Are there any other issues we should have considered in this chapter?

R4.4 We suggest a number of additional issues should have been considered:

i) Summer capacity issue

NGG have indicated that summer capacity constraints have given rise to the highest buy-back exposure. To reduce this risk, rather than reduce the level of peak day capacity (which can be provided due to peak day demands) in order to reduce the summer risk, consideration should have been given to options such as:

- lower summer baseline at certain ASEPs where there is a significant local demand impacting on capacity (St. Fergus in particular) and
- Potential for NGG to buy capacity in the AMSEC at a lower price (say 10% of prevailing reserve) for months of July and August only. NGG indicated that in the past it has signalled lower capacity to shippers in summer maintenance periods, and shippers have then tried to flow gas to exploit the constraint.

ii) Risk of constraints

Given that Teesside gas enters the NTS to the south of the major NTS compressor stations at St. Fergus, Kirriemuir, Bathgate/Avonbridge, Wooler and Bishop Auckland, it carries significantly less risk than St. Fergus in relation to buy-back costs. This should also have been taken into account. In addition, exporting gas from St. Fergus relies on demand in Scotland and so is susceptible to constraints in summer at low demand levels (as 1) above. There is a much lower risk at Teesside.

Geographically, Teesside is 390 miles from St. Fergus, but is only 85 miles from Easington (both as the crow flies). Hence it could reasonably be expected that buy-back risk is proportionately greater for St. Fergus flows. Given the compressor issue and the Scottish demand issue, it is reasonable to assume that a reduction of 1 MCMD capacity at St. Fergus could be expected to reduce buy-back risk by significantly more than a reduction of 1 MCMD at Teesside. So, for a given risk reduction, it would be more efficient to reduce capacity at St. Fergus rather than at Teesside.

iii) Sterilised capacity

Further to Para 2.15 which describes the St. Fergus-Easington situation, it appears that by not making any new investment for Langeled (October 2006) or Ormen Lange (October 2007), NGG has, in practice, reallocated capacity that is not being used to export St. Fergus gas southwards beyond Easington.

As St. Fergus flows have declined since 2004/05, as shown below, NGG has been able to flow up to the Easington baseline without having to make any new investment.

Year	St. Fergus Max Flow MCMD
2002/03	140
2003/04	139
2004/05	145
2005/06	131
2006/07	123

The physical capacity to move St. Fergus gas as far south as Bishop Auckland, and St. Fergus + Teesside gas from Bishop Auckland to the South Yorkshire area still exists, but by reallocating it to Easington, it appears to not be available to Teesside and hence assets between South Yorkshire and Teesside have been 'sterilised.' This should have been discussed with shippers.

Summary of comments on this section

In summary our key comments are:

- evidence should have been provided in relation to the extent of buy-backs in 2002-07 and the risk of buy-backs in 2007-12;
- as set out in R4.1 above, we believe that the objectives of the TPCR should have taken into account (i) Ofgem's statutory objectives under section 4 of the Gas Act, including (a) security of supply, and (b) competition in gas supply and (ii) other wider factors such as ASEP's previous entry capacity baselines and latest gas market developments;
- the critical importance of arbitrary NGG assumptions should have been highlighted, particularly in relation to Bacton and St. Fergus;
- the 5% Flow Margin should have been taken out in the analysis at the modelling stage;
- for any given flow, the risk of buy-back at St. Fergus is higher than at Teesside due to the NTS assets required to move St. Fergus gas to Teesside and the demand risk from Scotland; and,
- there are alternative ways to address the buy-back risk in summer at St. Fergus.

CHAPTER 5: Sensitivity analysis

Q5.1: Would you consider any of the alternative approaches for allocating the free increment as discussed in this chapter more or less appropriate than the approach adopted for the TPCR Final Proposals baselines, please give reasons why.

R5.1 Clearly, from our comments in response to Chapter 4 questions above, we do not accept the free increments were calculated appropriately. From the discussion at the Workshops in August 2007 it was generally accepted that such calculations are difficult.

However, even if the free increment methodology is accepted, there are a large number of ways to allocate the spare capacity in ways which have <u>no</u> reliance on 10YS data which, as explained above, can change dramatically from one year to the next. The following are 4 methodologies that can allocate the 1554 Gwh/d in ways that relate to known facts of (i) sales of capacity in the 2007 AMSEC, (ii) 2002-07 baselines, and (iii) actual historic flows.

1. Allocate the 1554 GWh/d based on a review of sales in the 2007 AMSEC auction. If all capacity at an ASEP was sold out then such ASEP would be given an additional tranche of capacity, prior to subsequent allocations, reflecting the value of the AMSEC user commitments and the fact that sold out ASEPS will have to pay more for capacity than ASEPS with spare capacity, which only pay the reserve price.

   For example, such an ASEP could receive a 25% increase in capacity providing such capacity did not breach the zonal or nodal maxima.

2. Allocate the 1554 Gwh/d based on a comparison of the previous baseline and the new one, reflecting a transitionary arrangement. An appropriate rule could be that no baseline will reduce by more than, say, 25% of its previous level.

3. Allocate the 1554 Gwh/d by comparing the maximum flow during winter 2006/7 with the proposed 2007-2012 baseline. If the maximum flow was higher than the proposed baseline then this would entitle the ASEP in question to a higher baseline allocation.

   The result of higher flows could be, for example, that for every 1% flow above baseline, the ASEP receives a 5% increase in baseline allocation (subject to zonal and nodal max).

4. Allocate the 1554 Gwh/d by comparing the maximum flow during any of the past 3 winters (2004/05, 2005/06 and 2006/07) with the proposed 2007-2012 baseline. If the maximum flow was higher than the proposed baseline then this would entitle the ASEP in question to a higher baseline allocation.

In addition, within any zone, the risk of buy-back should be taken into account. This would mean, for example, that there is a higher risk of buy-back at St. Fergus than Teesside due to use of assets and gas demand. Therefore, a higher weighting would be given to the lower risk ASEP.

In our response to the NGT Summary Report on the August/September Workshops we show some other methodologies that look at TBE data.

Q5.2: We allocated the Caythorpe and Blyborough (Welton) free increments to Hornsea and Thedddlethorpe respectively, do you agree with this approach or should the free increments have been allocated in a different way and if so, how and why?

R5.2 It would have been reasonable to allocate such capacity to Teesside given that the Excelerate GasPort project went ahead after the 2005 10YS data was gathered.

It is not economically efficient to allocate additional baseline to Theddlethorpe which already has around 140% spare capacity (baseline of 56 MCMD, flows of around 24 MCMD).

Q5.3: NGG NTS presented three principles in order to allocate baseline capacity, namely to (i) allocate in line with physical capacity, (ii) constrain not to exceed previous obligated levels and (iii) broadly commensurate with buy-back target. Do you agree with these principles? Please explain why or why not.

R5.3 Our comments:

(i) **Physical capacity** is difficult to define as discussed above and is subject to 10YS assumptions.

(ii) **Not to exceed previous obligated levels** is an acceptable principle as the need to book capacity to increase obligated (including baseline) levels was well understood.

(iii) **Buy-back target** is difficult to assess as no data has been provided in relation to buy-back risk and it is also subject to NGG 10YS assumptions.

Q5.4: NGG NTS presented slightly different ways of reallocating entry capacity to different entry points, would you find these approaches more or less appropriate? Please give reasons why.

R5.4 We do not like these approaches because most of them rely on 10YS data and are based on narrow objectives (reducing buy-back risk and related to physical capability), which is turn depends on NG 10YS assumptions because of the integrated nature of the NTS.

We believe that other methodologies such as in R5.1 could have been considered, and had a wider set of objectives been adopted (as we show in R4.1) then we believe these would have given a more efficient overall allocation of capacity.

Q5.5: Are there any other considerations which we have not highlighted which we should have taken into account?

R5.5 These are set out above in R4.1, R4.4 and R5.1.

CHAPTER 6:

Reallocating TPCR Final Proposals aggregate baseline capacity

Q6.1: Is our approach for allocating the free increment, taking zonal constraints into account appropriate given the premise that baselines need to reflect the physical capability of the system?

R6.1: In the absence of any data on buy-back risk and the location and extent of any constraints, it is not possible to comment meaningfully. What we do know is that historic buy-back has generally been limited to summer and that the physical capability of the system depends on assumptions from the 10YS planning process.

We also know that buy-back risk can be expected to fall as a £1.2 - £1.5 Billion NTS expansion programme is completed by end 2008 and the balance of supplies to the UK switches from St. Fergus to the Midlands and South.

Q6.2: Are there any other factors that we have not considered which should be assessed in considering an appropriate adjustment to baselines?

R6.2 These are set out above in R4.1, R4.4 and R5.1.

Q6.3: What are your views on the different options outlined for allocating capacity in a different way, whilst maintaining aggregate baselines at the current TPCR Final Proposals level of 7629 GWh/d.

R6.3 These are set out above in R4.1, R4.4 and R5.1.

Q6.4: What are the advantages and disadvantages of keeping baselines unchanged at their current TCPR Final Proposals level?

R6.4 **We see no advantages.**

Disadvantages that we see are that a wider set of objectives would not be taken into account including security of supply, competition in gas supply, regime reputation, UK investment deterrent and market developments. In addition, there will remain significant baseline capacity at Bacton, Theddlethorpe, Barrow and St Fergus that is significantly in excess of any foreseeable gas flows at these ASEPS as a result of UKCS decline. It is not efficient to leave all this surplus commercial capacity in place with no conceivable gas flows and no auction signals.

Increasing aggregate baseline capacity

Q6.5: If we were to increase the aggregate baselines how could we quantify possible increases in buy-back costs and/or capex allowance also given the timescales involved.

R6.5 We think an adjustment to the TPCR Final Proposals level can be made without impacting on the overall settlement by using the absence of substitution in 2007 and the Isle of Grain auction outcome in the September 2007 QSEC auctions.

Both Isle of Grain and Bacton are in the same NTS entry zone.

Given the large surplus of Bacton capacity over shipper requirements, with 45 MCMD unsold for winter 08/09 over and above the 16 MCMD held back, NGG can be given the income related to the IOG auction results (as they are entitled), but they can also be given a small reduction in the Bacton baseline (so NGG would not need to invest so much for IOG) so that the additional income received by NGG can compensate them for agreeing to a higher aggregate number overall.

This would provide the flexibility to give a higher baseline to Teesside, for example, with no adverse consequences to NGG or shippers generally.

Q6.6: If we were to increase the aggregate baselines how should we allocate the additional capacity? Which mechanism, if any, should we use.

R6.6 Our suggestions are in R5.1 above.

Q6.7: Are there any other considerations which we have not highlighted which should be taken into account if we were to increase aggregate baselines.

R6.7 As stated above at R4.1, we believe the following are important and should be taken into account:

- competition in gas supply ;
- security of supply;
- reputation of UK ;
- the previous level of baselines;

- impact of baselines on the level of transportation charges; and

- latest market developments.

In addition, we believe that if the Teesside baseline remains at the 33 MCMD level then the Transfer and Trade (T&T) process must take place on a daily basis in order to provide capacity to Teesside when it is needed. If the T&T auctions are limited to the monthly RMSEC, then this will not provide the flexibility to respond to market events. If T&T is only on a monthly basis, then a higher baseline at Teesside becomes essential for efficient market operation.

I trust the above is helpful, if however you wish to discuss any of the above points please do not hesitate to contact me.

Yours sincerely

Rob Bryngelson

Rob Bryngelson, President and CEO
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