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THE POWER OF ACTION

Conclusions Report to the Consultation On the proposed Methodology to determine Constraint Management Costs and Incremental Compressor Costs Related to Removal of an NTS Pipeline

February 2011
Updated April 2011

Executive Summary

Introduction

The Department of Energy and Climate Change (DECC) is holding a competition to demonstrate commercial scale Carbon Capture and Storage (CCS). National Grid's involvement in Carbon Dioxide (CO2) transportation is through offering onshore transportation services to one of the bidders in the DECC competition. These services will be offered by National Grid Carbon Limited (NGC), a wholly owned subsidiary of National Grid plc (National Grid) and independent of National Grid Gas plc (NGG). National Grid has identified a possible opportunity to participate in the competition by using some of the current National Transmission System (NTS) assets to provide onshore transportation of CO2 from a Scottish fossil fuel fired power station.

NGG is the holder of the Gas Transporter Licence (the "Licence") in respect of the National Transmission System (the "NTS") and, as owner and operator of the relevant pipeline assets, has approached Ofgem with a proposal for the disposal and possible alternative use of a section of NTS pipeline for this purpose. The assets in question are currently used to transport gas from the St. Fergus entry point. National Grid has stated that this section of pipeline will not be required to meet forecast capacity requirements at St Fergus.

In accordance with the Licence, NGG's proposal requires the Authority's consent to go ahead.

Ofgem have indicated that approval of any proposal would require (amongst other requirements) NGG to produce a methodology to determine the incremental cost of operating the NTS without the transferred pipelines. This methodology should reassure industry, and the Authority, that NGC will adequately compensate NGG (and hence Users and consumers) for additional costs determined in accordance with the methodology. A further requirement identified by Ofgem is that NGG should consult the wider industry on its proposed methodology. This should further reassure industry that costs will be correctly apportioned.

On 8th November 2010 NGG commenced its consultation on its proposed "Methodology to determine Constraint Management Costs and Incremental Compressor Costs Related to Removal of an NTS Pipeline". The consultation closed on 6th December 2010. This report provides a review of the responses received to the consultation and provides a response to the comments, including, where appropriate, changes to the methodology and/or a commitment to further review the issue raised.

Responses

Representations were received from the eight respondents listed below.

SGN	Scotia Gas Networks
Tot	Total E&P UK
BGT	Centrica Energy (excluding Centrica Storage Limited)
AEP	Association of Electricity Producers
SSE	Scottish and Southern Energy plc
RWE	RWE group of companies, including RWE Npower plc and RWE Supply and Trading GmbH
EdF	EdF Energy
NGC	National Grid Carbon

Only five of the respondents answered the questions posed in the consultation. These comments have been reproduced (a few have been summarised) in the following table together with a response from NGG. Where NGG is proposing a change to the proposed methodology as a result of comments received, this is indicated in the response. For full details of consultation responses please refer to the specific documents which can be found on National Grid's website.

The remaining three respondents limited their comments to specific issues. These are covered in a separate table towards the end of the report.

Two key issues have been raised through the consultation. These both relate to the scope of the methodology. NGG has proposed to exclude from the methodology incremental venting losses and certain aspects of compressor maintenance. We remain of the opinion that venting losses should not be included. In respect of compressor maintenance, the incremental cost of major overhauls have been included as part of the methodology. NGG is reconsidering whether annual maintenance and unplanned maintenance should be brought within scope prior to implementation.

These issues are covered in more detail in the appropriate section in the following tables.

April 2011 update.
Following further investigation NGG has decided it would be inappropriate to extend the scope of the maintenance activities covered by the methodology (see Q 26).
The compressors covered by the methodology in respect of the proposed Scottish pipeline disposal detailed in Annex 3 has been extended to include Wooler (see Q19)

Q1	Do you agree that future changes to the methodology should be restricted as envisaged in the proposal?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. It is important that NGG and the third party have a degree of cost certainty but also the ability to revise, by mutual agreement, as a result of regulatory changes for example.	Yes	The methodology is to be fixed with the exception of environmental legislation and major regime changes. SSE agrees that it is appropriate that future uncertainty is minimised for the pipeline owner provided that this does not transfer any risk to Users. In regard to any major regime changes, SSE believes that, to protect all parties, the methodology should be open to review, industry consultation and updated where required.	We welcome a longer term approach to the methodology as this does provide greater certainty. However, as this project is unprecedented, we would not want to exclude the possibility of some revision which may become necessary in light of events or outcomes currently unforeseen. It is also unclear how any such change would be initiated or progressed.	Yes in principle, but changes due to major regime change should not be limited to the capacity regime. It is possible that other changes could lead to increased cost to customers as a consequence of pipeline disposal. We welcome clarification as to whether proposed changes will be subject to industry consultation or only those arising from major regime change.
NGG response	We agree that long term certainty should be a key feature of the methodology. However, this should not preclude changes to the methodology if it fails to meet its objectives. Hence we agree that changes should not be limited to capacity regime changes (paragraph 10 will be amended accordingly), but should be considered wherever changes to gas transportation arrangements have the potential to have a significant effect on the costs covered by the methodology. It is unclear to NGG at this time whether there will be any regulatory oversight of the methodology after any asset disposal has been completed. However, notwithstanding that the methodology may fall outside the scope of the Licence, National Grid has indicated that any changes following major regime change (see paragraph 10) shall be subject to industry consultation. Whilst we accept that there is some uncertainty as to what constitutes “major regime change” we do not consider it necessary, nor efficient, to consult on every proposed change. NGG anticipates that most changes will be initiated by NGG. This may be triggered by: • UNC or Licence changes; • a review of the application of the methodology; • identification of an issue raised by any external party, e.g. Ofgem, User etc. However, changes may be initiated by the new pipeline owner if they believe calculated costs are inaccurate or excessive. They will need to demonstrate that this is the case before changes are agreed by NGG.				

Q2	**Do you agree that charges calculated according to the methodology should be open to challenge by the pipeline owner?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. A mechanism to challenge results ensures that appropriate due diligence is carried out prior to the pipeline owner being charged.	Yes	This seems reasonable	We do agree that a challenge should be available to the pipeline owner. However, with the same provisions to avoid spurious challenges etc., we believe that this challenge could be open to challenge by other parties due to their interest in the assets being utilised. For example, system users and gas consumers.	Yes We would welcome clarification in para 12 and 15 whether the costs borne by NGG are actually borne by NGG or recovered from shippers / customers
NGG response	We welcome agreement of this principle. It is not our intention that calculated charges will be published. Charges will be calculated in accordance with the methodology and invoiced to the other party. Hence, we believe it would be impractical for anyone to challenge the challenge. Where an independent analyst is required (paragraphs 12 and 15) and the challenge is upheld, the cost will be borne by NGG. However, it is expected that all analysis and validation work shall be undertaken by, or on behalf of, the regulated business. Hence the costs will originate from Users / customers, but there will not be any additional cost recovery in excess of that allowed by the Licence. There will, therefore, be no noticeable impact on Users / customers.				

Q3	**Notwithstanding your answer to 2, are the cut-off values used to prevent spurious challenges set at a fair and reasonable level?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	The principle of cut-off values appears sound, however the drafting may benefit from greater clarity so that any subjectivity in the application of these values is minimised. If there are any tolerances already applied to NGG core business activities, it would seem sensible that these are adopted, as already accepted by industry.	The values appear reasonable	In order to minimise the risk of spurious challenges, the pipeline owner will bear any additional costs if any error identified is less than a defined amount. The quantities stated are arbitrary and SSE does not know if they are cost reflective. The monetary limit specified differs for challenge of constraint management actions and compressor operation to reflect the relative value of likely costs. Ideally we would like more evidence of how the quantities have been evaluated. The costs incurred by NGC should never be capped.	We believe that these cut-off values are reasonable and prevent arbitrary and vexatious challenge.	Yes
NGG response	We note support for the principle of cut-off values and the values specified. As stated in the consultation document, NGG recognises that the quantities stated are arbitrary, but believes that they represent a fair balance. The monetary limit specified differs for challenge of constraint management actions and compressor operation to reflect the relative value of likely costs. For example, if an incremental capacity buy-back is required the cost is likely to be substantially higher than incremental CFU. The values have been selected, based on simple analysis of limited historical data, to be in the region of 15% of typical costs. NGG has reviewed the relevant sections (paragraphs 12 and 15) to see whether improved drafting can remove any perceived subjectivity. We do not believe that any changes are necessary. Under UNC disputes process (GT Section A) a different principle is used to determine costs. This is that each party bears their own costs, including the cost of external people and where an independent expert is employed the cost of the expert is shared, unless the expert determines otherwise. We believe that the costs arising from a dispute under the proposed methodology would fall predominantly on NGG; hence we believe it to be unreasonable to apply the principle used in UNC in this situation. We have therefore, proposed a process based on all costs being borne by one party.				

Q4	**Do you agree that administrative / processing charges incurred by xoserve should be included within the scope of the methodology?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Not as an additional item. NGC believes that there would be minimal (if any) incremental administrative / processing costs incurred by Xoserve as a result of this disposal, given these are all activities already undertaken by NGG to some extent. Any inherent costs should be considered by NGG as included within the upfront payment, and any subsequent impacts or terms are then for NGG to negotiate with Xoserve.	Yes	Yes	It is reasonable to include these necessary costs subject to these obligations being discharged in an efficient manner. xoserve would appear to be best placed to provide this efficient service.	Yes
NGG response	Activities undertaken by xoserve are increasingly becoming itemised, chargeable services. Hence, as a principle, if charges are incurred they should by paid by the new pipeline owner. However, we recognise that the charges could be minimal (or zero), but until the methodology is implemented we will not fully understand the magnitude. It is, therefore, appropriate to include these potential costs, and to review their inclusion at a later date. We disagree that these activities are already undertaken by NGG. Constraint management costs are borne by Shippers through “capacity neutrality”. By the time appropriate costs are calculated, invoiced and recovered from the pipeline owner Shippers may have been invoiced for “their” proportion of neutrality which could include the pipeline owner’s proportion. This will need rectifying when payment is received from the pipeline owner and is an activity not currently undertaken.				

<table>
<tr><td>Q5</td><td colspan="5">Do you agree that the application of the methodology to any specific pipeline disposal should be time limited?</td></tr>
<tr><td>Respondent</td><td>NGC</td><td>Tot</td><td>SSE</td><td>BGT</td><td>AEP</td></tr>
<tr><td></td><td>Yes, in cases where this is appropriate. A time limit ensures that any third party is not exposed to costs that would otherwise have been incurred by NGG / gas consumers when the asset would have been decommissioned or the regulatory arrangements changed. In the case of this disposal, there are very specific physical/tangible factors that support a time bound exposure (ie UKCS supplies, Shippers’ long-term capacity bookings).</td><td>Yes</td><td>The end-date is specified as being the earlier of:
· the date upon which the pipeline would have ceased to be used for the transportation of natural gas as part of the NTS.
In annex 3 this is defined as 2020, when Norwegian & UKCS supplies have declined. SSE understand external studies have been carried out to validate this view which we accept.
· the effective date of any reduction in the baseline quantity of any relevant ASEP.
This needs to be quantified such that only significant changes to Baseline result in a change and we agree that substitution impacts should be excluded.</td><td>Largely due to the uncertain development of this application on the network, it does make good sense to time limit this methodology. It is not clear whether this application is in line with any other decommissioning. We do have a concern about the longer term effect of the removal of a section of the NTS, As is inferred, this could affect baselines, although this in not a direct consequence. We are not convinced that this project can be totally ring-fenced from future changes on the NTS, given that there cannot be a clear division of ownership.</td><td>We agree the application of the methodology should be time limited, but would welcome further detail on how the date in Annex 3 has been determined in this instance and whether this approach is consistent for the decommissioning of pipelines in general. For example would the pipeline actually have been decommissioned in 2020 if there had been no disposal or would it have been retained as part of the transmission system for a further period. How are decisions made to decommission pipelines?

We are less convinced about the linkage to baselines and consider this requires some quantification so that if the baseline is reduced by a certain amount then the application of the methodology ceases whereas if the baseline is reduced by a lesser amount then it does not.</td></tr>
<tr><td>NGG response</td><td colspan="5">We appreciate the general acceptance of time limiting the methodology for specific projects. When drafting the methodology NGG gave serious consideration to the criteria for termination.

With regard to projected decommissioning: it would appear unreasonable to expect the pipeline owner to continue payments after the time when those costs would have passed to NGG (and Users) due to decommissioning (due to declining St Fergus flows, we expect that the costs would be negligible or zero anyway). It is difficult to be precise regarding the process for decommissioning NTS pipelines because, except for short sections, this has not previously arisen. However, the assessment has been based a combination of factors, including: forecast flows, asset design life, cost to extend asset lifetime, pipeline opex, and decommissioning costs. When a pipeline is no longer needed to transport natural gas an assessment will be made of the cost of retaining the pipeline against the cost of decommissioning. In this situation, the assessment is being made several years earlier than would normally be the case. However, National Grid is satisfied that by 2020 the pipeline will not be required and will have reached the end of its design life. As transferring the pipeline will remove future decommissioning costs it is reasonable to conclude that the cost to NGG (and the industry) of extending the lifetime would outweigh the cost of its disposal.

With regard to baselines: NGG believes that any future reduction to baselines will be in response to declining flows and will only be implemented if there is a high degree of confidence that lower flows will remain into the medium/long term, i.e. such reductions will be acknowledgement that the pipeline is no longer required. By excluding reductions due to substitution, reductions can only be made by the Authority following industry consultation. Any proposed reduction would take into account the network configuration and NGG’s funding arrangements at the time. We believe that this provides sufficient safeguards to Users and consumers.</td></tr>
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Q6	**Notwithstanding your answer to 5, do you agree with the proposed criteria for determining the duration of the methodology for specific projects?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes, in that for this specific proposal, NGC believes that appropriate incentives should be placed on NGG and gas consumers to ensure third parties are not penalised with long-running costs that discourage future innovative use of assets, beyond their reasonable and expected operational life.	Yes	See Q5	It would appear reasonable to retain the potential for alternative approaches, as considered, due to the unusual nature of this project.	See Q5
NGG response	NGG notes the support for the criteria defined. We agree that, due to the unusual nature of this project, there may be further reasons for terminating the methodology. However, rather than include a vague "catch all" criterion, we believe the criteria should be limited to those that can be clearly defined. Should an alternative become apparent in future, this could be accommodated through a review and revision to the methodology.				

Q7	**Do you agree that Users should not be compensated for any costs incurred as a result of the curtailment of interruptible capacity rights where the curtailment is triggered by a pipeline disposal and hence that NGG should not seek any payment from the pipeline owner?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. Interruptible capacity by its nature is not a firm product and the user takes the risk that this capacity right may be curtailed; hence no compensation should be payable for Interruption.	Yes	SSE is supportive of no compensation for interruption resulting from asset withdraw. An NTS made tighter through the disposal of an existing pipeline may result in the NTS being unable to accept gas for delivery at an affected ASEP or may result in gas being unavailable for offtake at an NTS Exit Point. System constraints can be managed through application of a number of tools available to NGG. The first of these would be the curtailment of interruptible (or off-peak) capacity rights. Users do not receive any interruption compensation under the UNC. Hence, there are no costs for the pipeline owner to compensate for. Users may incur cost and inconvenience as a result of curtailment, but this is an acknowledged risk of relying on low (or zero) cost interruptible capacity.	It is an accepted practice that interruptible capacity rights offer no compensation on curtailment. Transparency is relevant here also, not only in respect of the likelihood of interruption, but whether this is impacted by the use.	Yes. However it would be useful if the increased probability of interruption could be assessed and published.
NGG response	NGG notes support for no compensation. NGG will consider whether an assessment can be made of the increased probability of interruption. However, with numerous parameters to consider, it may be difficult to produce meaningful data.				

Q8	If you disagree with the proposal in question 7, what costs should be recovered, and how should these be determined?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	N/A	N/A	See Q7	N/A	N/A
NGG response	N/A				

Q9	Do you agree with an approach that models both the "with pipeline", and "without pipeline", scenarios to determine theoretical constraint management action quantities, and hence a theoretical incremental quantity?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes, as NGC believes that the new pipeline owner should not be exposed to costs that are not a direct result of the disposal. There must be some assurance for the pipeline owner that the industry is not collectively incentivised to pass through costs that would have been incurred anyway.	Yes	This appears a reasonable methodology. However, it will be time consuming and we have concerns about the time it takes NGG to complete network studies in particular for connections, 46 weeks for a feasibility study. If this process is paid for or resourced by NGC and has no impact on already long lead times for connection studies we would be supportive.	We believe that this approach is key to demonstration of the impact of removal of the pipeline from the NTS. Although it can only be theoretical, NG's modelling these constraints with and without the removed section applies proven methodology. We recognise that this is largely opaque to the industry but this need for wider understanding of NG's modelling is not unique to this application.	Yes this seems a reasonable approach to model the actual network and that which would have prevailed without pipeline disposal. The downside being it is complex and opaque to the industry but is likely to give a reasonable outcome. We do have concerns that network analyst time, which seems to be a limited resource within NG, could be diverted to this activity and away from other work related to connection or investment for example.
NGG response	We welcome support for the proposed approach which we feel is reasonable to all parties. We also share concerns regarding analysis time. However, we feel that in order to make a reasonable assessment of a constraint quantity some analysis is required and to repeat analysis for two scenarios (with, without, pipeline) should not result in a doubling of the resource requirement. In addition, with declining flows at St Fergus, we believe that there will be a low probability of constraints analysis being required. Notwithstanding this, NGG is looking to increase the number of analysts available for this, and related work.				

Q10	**Do you agree with the approach to scenario modelling that uses actual operational data? Are there any other criteria that should be considered?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. Furthermore, the use of operational data should also be reflected in the theoretical 'with pipeline' scenario in order to maintain consistency and fairness. NGG would need to be explicit that no additional compression or flow regulation was used in this analysis when these were not available (due to maintenance for example) on the constraint day.	Yes No more criteria	SSE agree that actual operational data should be used.	As with our answer to Q9, this is an accepted approach to have forms of " what/if" that use, wherever possible, operational data.	We agree with this approach, but would seek assurances that this will lead to the modelled constraint quantity matching the actual constraint quantity (subject to a tolerance) and an explanation of what happens if the modelling cannot reproduce the actual quantities for whatever reason.
NGG response	We are proposing that actual operational data be input to the analysis model. The same data will also be used for the with pipeline analysis. However, some data will not be transferable to the theoretical with pipeline scenario, e.g. downstream system pressures may be higher for the same upstream flow due to the use of additional compression. If the model does not accurately reproduce the constraint quantity, the difference will be the tolerance quantity. The tolerance quantity is variable being subject to operator judgement (see paragraph 33: tolerance quantity = Qt – Qr). Where the modelled quantity is greater than that actually taken, i.e. the tolerance is negative, or where the tolerance quantity appears to be excessively high (this will be subject to analyst judgement), operational data will need to be reviewed and, if necessary changed. Network modelling is not an exact science, but the aim will be to reproduce conditions experienced on the day with as much accuracy as is reasonably practical. NGG has reviewed the methodology and is proposing revisions to paragraph 37 to cover these circumstances.				

Q11	**Do you agree that the methodology should attempt to align the cost of those specific constraint management actions that result from incremental constraints or should an average of all constraint management actions at the relevant point be used, i.e. do you prefer "specific incremental" or WAP prices?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	NGC believes there should be an appropriate incentive in place to ensure that the third party is not exposed to an uncapped liability where there is no financial consequence to NGG and gas shippers, who are both incentivised to pass all costs through to the third party. A WAP-based approach alleviates this potential conflict and places an incentive on those who can influence constraint management costs - shippers (who price and place bids) and NGG (who accepts the price and volume).	Specific incremental offers a better approach	When a constraint arises the first element of that constraint will be due to the disposal of the pipeline, i.e. incremental. Hence it could be expected that the first actions taken should be attributable to the pipeline owner. However, these initial actions are likely to have the lowest price as NGG will take the most economic and efficient action. The last actions would normally be the most expensive and these actions would be avoided in the absence of an incremental quantity. SSE agrees with NGG who propose that the last actions taken are attributable to incremental actions and therefore paid for by NGC.	We agree that the methodology should to align cost of the specific constraints and it would seem to follow that specific incremental approach is going to be more representative than weighted average, as this will be a better representation of actual costs passed on to system users.	Where the constraint quantity in the absence of pipeline disposal is zero, these two prices are equal. Where some constraint action is necessary even if the pipeline had not been removed from service it is appropriate to use the specific incremental cost of the later actions as these are the actions that may otherwise have been avoided and therefore costs not passed onto shipper / consumers.
NGG response	NGG does not recognise the concern expressed by NGC. Whilst we recognise limitations, the proposed methodology attempts to identify specific costs and to align them to the appropriate party. We believe that this is not unreasonable. When constraint management actions are being undertaken, NGG is obliged to take the most economic and efficient actions. Furthermore, it will not be known whether the cost of any actions will be borne by NGG/Users or the pipeline owner until after the event when analysis has been undertaken. The proposed methodology does not allow NGG to "pass all costs through to the third party", only incremental costs. Hence, there is an incentive on NGG to minimise costs because it may be that NGG is exposed, in part, to those costs. This, and the Licence obligation, should provide reassurance to NGC, or any other pipeline owner.				

Q12	**Do you agree that attributing the later constraint management actions to incremental constraints and hence to the pipeline owner is a reasonable approach? If not, what criteria should be used? Is this approach unreasonable in that it exposes the pipeline owner to the most costly buy-back actions?**				
Respondent	**NGC**	Tot	**SSE**	**BGT**	**AEP**
	NGG's approach is understandable, though as explained in the answer to question 11 it should not be expected that a third party would be willing to accept an uncapped risk with no re-balance to NGG and gas shippers.	Yes N/A Do not believe it to be unreasonable.	See Q11	See Q11	See Q11
NGG response	As explained in the response to Q11 there is an incentive on NGG to control costs. Irrespective of that incentive, it is questionable as to whether NGG and/or Users should be exposed to the costs arising from the transfer of a pipeline to another party. The Authority have stated that this methodology should protect Users and consumers (and hence to some extent NGG) from the cost of pipeline disposal. To put a limit on the costs passed to the pipeline owner, above which costs would be borne by NGG/Users would appear to be in direct contradiction to that requirement. NGG recognised in the consultation document that an uncapped risk may be a concern to a new pipeline owner and that this might impact the pipeline sale price, which is outside the scope of the methodology. However, NGG believes that insufficient justification has been put forward for an alternative methodology. In addition, NGG notes that, in respect of NGC's specific project, NGC have stated that the risk of any constraint management actions being required are minimal, since which, St Fergus flows have declined more than forecast; hence the risk to NGC has also decreased. Notwithstanding this, NGG may consider entering arrangements that provide an additional incentive on NGG to minimise constraint management costs provided that this does not adversely affect Users. Any such arrangement would be outside the scope of this methodology.				

Q13	**Do you agree that the cost of any counter-balancing actions for locational sells/buys should be included in the determination of costs?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes, though only to the extent that (as for other scenarios) they can be directly attributed to the disposal.	Yes	SSE agrees with this aspect. To relieve a constraint NGG may decide to buy or sell gas from the NTS. Subsequently, NGG may need to take a counter action to maintain a balance. Hence the cost of any constraint management action should, ideally, take account of the counter action.	Again this is a relevant cost to be included	Yes
NGG response	NGG notes support for this aspect of the methodology.				

Q14	Do you agree that, in respect of locational actions where income exceeds costs, the surplus should not be paid to the pipeline owner?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes, it would seem fair that the System Operator has reasonable recompense for effective trading.	Yes (it should be smeared to Shippers)	SSE agrees with this aspect. NGG must separate the incremental actions from those that would have been taken anyway. Hence the most expensive buys (or least expensive sells) will be considered for balancing actions. It is possible that such counter actions results in a net income. SSE believes that the pipeline owner should not profit from its negative impact on pipeline capacity so agrees that negative costs will be ignored and no payment made. In this event any surplus will result in a benefit to Users.	Again this is a relevant cost to be included	Yes
NGG response	NGG notes support for this aspect of the methodology.				

Q15	To enable modelling of electrically driven compressors, is it appropriate to use the conversion factor of 3:1 taken from the Licence?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. NGC see that this conversion should remain consistent with NGG's licence.	Yes, but validity to be independently reviewed at appropriate interval	SSE agrees with this aspect.	The current ratio should apply, including any changes	Yes, but this should be updated if the value in the licence changes.
NGG response	NGG notes support for this aspect of the methodology. NGG proposes to amend the methodology to clarify that any changes to the factor used in the Licence shall apply to the methodology (footnote 4 to paragraph 53).				

Q16	**Do you agree with the look-up table approach to determination of incremental CFU quantity? Are there any practical alternatives?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. NGC believe that NGG should look to develop an automated approach as has been indicated in the text and that the suggested look-up table is a fair basis for this, being both transparent and simple.	Yes, no alternative identified.	SSE agrees with this proposal until the automated version described in annex 2 is developed. The cost of development of this automated model which runs on operational data is likely to be costly. Who will pay for this development, NGC? The model may have different applications other than just incremental CFU and SSE would like this list to be provided.	This is a practical solution which is relevant in the circumstances. An automated process would be more accurate but may not be practical at this time.	Yes, we agree this is a pragmatic way forward unless and until an automated network modelling approach is developed. We would seek clarification on whether such an automated modelling approach will have other applications within NG or if would just be specific to determining incremental CFU since this should influence how such development is funded.
NGG response	NGG notes support for this aspect of the methodology. We do not expect this methodology to be the driver for developing systems and skills necessary to implement an automated approach. However, if and when other business requirements justify the cost and time involved it would be appropriate to also apply the techniques to this methodology. We do not anticipate this happening in the short term.				

Q17	**Do you agree that an automated approach is preferable and should be used when available?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes	Yes	See Q16	An automated approach would be preferable and should be used if this becomes practical and economic.	See Q16
NGG response	Noted.				

Q18	**Based on the look-up table, do you agree that the two modelled quantities should be used to determine the incremental quantity by ratio, rather than by difference?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes	Seems reasonable	Modelling can be undertaken for "with pipeline" and "without pipeline" scenarios. The incremental CFU can be taken as the difference between the two scenarios. However, NGG believes it would be more accurate to use the two modelled values to determine a proportionate increase and to relate this to the actual metered CFU. SSE believe that Ofgem should satisfy themselves that this aspect in reasonable because we do not have access to the data or modelling results.	We recognise that a daily approach is necessary and can see the merit in determining a proportionate increase, rather than simply the difference between the with and without scenarios.	We consider it is appropriate to incorporate the actual CFU on the day into the calculation of the incremental CFU using the ratio of modelled values seems a reasonable way to do this and captures any variance between modelled CFU and actual.
NGG response	NGG notes support for this aspect of the methodology. In consideration of any proposed pipeline disposal, NGG expects that the Authority will take into account all sections of this methodology and whether it is reasonable in determining and apportioning cost.				

Q19	**Should analysis be limited to specified compressors as determined by paragraph 3.54? If not, which compressors should be included and how should such analysis be undertaken?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. Until proven that other compressors significantly impact on incremental CFU then only compressors along the pipeline route should be considered. Any additional compressors should have been considered at the point of external validation, and this may be a requirement of any expansion to the compressors included.	Yes, subject to remaining appropriate.	Ideally the entire network should be modelled to determine incremental CFU. However, these variations are likely to be much less significant than those adjacent to the disposed of pipeline. Further, the impact on remote compressors could be positive or negative. SSE believe that Ofgem should satisfy themselves that this aspect in reasonable because we do not have access to the data or modelling results.	It is appropriate to "draw the line" and include those units which are most directly affected.	Yes we agree that the analysis should be limited to those in the vicinity of the disposed pipeline, and that the method for determining which are relevant should be robust and consider the materiality.
NGG response	NGG notes support for this aspect of the methodology. In consideration of any proposed pipeline disposal, NGG expects that the Authority will take into account all sections of this methodology and whether it is reasonable in determining and apportioning cost. NGG believes it is appropriate to limit the extent of analysis. However, materiality may not be limited solely to those compressors adjacent to the pipeline to be transferred: downstream compressors may be significantly affected. As stated in the proposed methodology, NGG intends to undertake analysis of specific compressors prior to asset disposal to confirm materiality before excluding them from the list of compressors detailed in annex 3. **Update April 2011:** Further analysis has demonstrated little effect on Moffat compressor by the removal of the Scottish feeder, however increased flows occur down the feeders on the Eastern side of the country resulting in incremental use of Wooler compressor. As a result Wooler has been added to the list in annex 3 and the footnote (and reference to Moffat) deleted.				

Q20	Do you agree with the use of reference prices for the determination of incremental CFU price? Are there any practical alternatives that should be considered?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. In principle it seems a reasonable approach to use the reference price as it aligns with NGG's incentive and should represent a challenging price.	Yes Cannot identify alternatives	SSE believes the actual price paid by NGG for gas and electricity for its compressor fleet should be used and not those in the licence. Much of NGG's gas and electricity is purchased in advance and under a range of contracts. Under the Licence it is envisaged that 75% is obtained via the futures market and 25% prompt. If actual prices are to be used, it should be the last, higher priced, purchase that should be considered for the incremental CFU. However, not all costs result in fuel purchases, e.g. option contracts, but no quantification has been given and therefore we do not know how material this is. SSE believe that Ofgem should satisfy themselves that this aspect in reasonable because we do not have access to the data or modelling results.	This is appropriate and seems the most practical approach	Yes
NGG response	NGG notes the majority support for this aspect of the methodology. In consideration of any proposed pipeline disposal, NGG expects that the Authority will take into account all sections of this methodology and whether it is reasonable in determining and apportioning cost. NGG agrees with SSE in that "the actual price paid by NGG for gas and electricity for its compressor fleet should be used". However, as recognised by SSE, most of NGG's energy requirements are obtained in advance. It is impossible, therefore, to align fuel purchased (and its cost) to fuel use. It is equally possible that, because of the additional fuel requirements created by the pipeline disposal, a cheaper unit price could be obtained. On balance, NGG believes the approach proposed provides a practical solution.				

Q21	Do you agree that incremental compressor related costs that fall on Users should be included in the methodology statement? Have these been fully identified by NGG?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes, where these are directly attributed to the disposal and reflected within the disposal terms. The key costs in this case appear to have been identified. It is important to keep the methodology transparent and simple.	Yes TSO is best judge.	All increment compressor costs should be borne by NGC. Users and Shippers should not be exposed to incremental costs incurred by transferring assets to NGC. If costs have been omitted then they should be included in the methodology once identified. Ofgem should satisfy themselves that NGG have identified the appropriate costs.	This is appropriate to be included, we believe all are identified.	Yes
NGG response	NGG notes support for this aspect of the methodology. In developing the proposed methodology NGG has sought a compromise between identifying all relevant costs whilst keeping the methodology transparent and simple. These are often conflicting aims.				

Q22	Do you agree with NGG's proposal that incremental costs not falling on Users should be excluded from the methodology?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes	Yes	All increment compressor costs should be borne by NGC. Users and Shippers should not be exposed to incremental costs incurred by transferring assets to NGC. If costs have been omitted then they should be included in the methodology once identified. Ofgem should satisfy themselves that NGG have identified the appropriate costs.	Again this exclusion is sensible.	Yes
NGG response	NGG notes support for this aspect of the methodology. Whilst NGG agrees with the principle of SSE's statement that "all increment compressor costs should be borne by NGC", the question relates to specific costs not otherwise borne by Users. Hence, no matter which party pays these costs, it will not be Users. NGG may wish to recover certain costs, if any, which are incurred solely by NGG, but this can be dealt with outside this methodology.				

Q23	Do you agree with NGG's conclusion that incremental venting losses are likely to be small and not justifying of the additional resource required for their determination?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. It should be expected that NGG will minimise venting losses in accordance with its economic and efficient licence obligations and that the majority of the linepack value will be a benefit to gas consumers	Seems reasonable.	SSE does not agree, the incentive targets amount to approximately 3,500 tonnes/year. If gas price were to become more expensive the value of venting will increase.	The approach is reasonable.	Yes
NGG response	NGG notes the majority support for this aspect of the methodology. See also Q24.				

Q24	If in disagreement with 23, how would you suggest that incremental venting losses might be determined?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	N/A	N/A	The incremental losses associated with venting should be quantified and the costs passed to NGC.	We are in agreement	
NGG response	We note SSE's disagreement with the proposal to omit venting losses from the methodology. As stated in our response to Q21, the proposed methodology is a compromise between identifying all relevant costs whilst keeping the methodology transparent and simple. We believe that determination of incremental venting losses would be an extremely complex task. However, we would not use this as a reason for not attempting to determine relevant costs if these are likely to be significant. Whilst the increased work required of the relevant compressors as a result of pipeline disposal would increase run-time emissions, it is feasible that emissions fall as a result of less frequent start-up and depressurisation. These factors contribute greatly to the emissions total. However, losses are also a function of other factors such as supply/demand patterns and compressor age and type. All of these add uncertainty in terms of whether losses will increase or decrease. Overall, we believe that incremental venting losses will be minimal, at worst a few percent of the current level, and could even be negative. Whilst it may be possible, although bureaucratic, to record each compressor shut-down etc, and to monitor for any increased frequency post pipeline disposal, it would be impossible to determine whether any increase is due to the new NTS configuration or other operational reasons, such as gas flow rates, within day flow profiling, plant type and age, and local gas demand. For these reasons we considered, and still consider, it appropriate to exclude venting losses from the methodology.				

Q25	**Do you agree with the pass through of incremental shrinkage incentive costs as detailed?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes. Users should be compensated for the incremental costs associated with higher CFU and therefore emission costs under the shrinkage incentive. However, NGC would highlight that the shadow price of carbon would impact differently for electric and gas consumption.	Yes	All increment shrinkage costs should be borne by NGC. Users and Shippers should not be exposed to incremental costs incurred by transferring assets to NGC.	This is a further relevant cost and should be included.	Yes, whilst noting that incentives in this area are currently under review.
NGG response	NGG notes support for this aspect of the methodology.				

Q26	Do you agree that unplanned maintenance and routine annual maintenance should be excluded from the methodology?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes, as NGC believe that in some cases compression resilience will be increased in Scotland. These compressors may be run more consistently in line with their original design specification and therefore possibly incur less trips and/or maintenance.	No and no. If a causal relationship is demonstrated between feeder removal and unplanned maintenance, the cost of maintenance and buy-backs should be included. Whilst annual maintenance would occur irrespective of disposal, the work scope could broaden, the cost of this should be included.	SSE do not agree. Sale of the network to NGC will make compressors run harder for longer which will have an incremental impact on degradation and failure rates. Therefore, the incremental costs for unplanned and all planned maintenance should be borne by NGC and not customers.	Any routine maintenance due to normal operation should be excluded. However, these events should be monitored to ensure that additional maintenance is required as a direct consequence of higher usage.	Yes
NGG response	NGG notes the conflicting views on this issue which reflect the consideration given to the issue by NGG in developing its initial proposals. SSE suggests that the sale “will make compressors run harder for longer which will have an incremental impact on degradation and failure rates”. This is not necessarily the case: compressors are designed to operate continuously at high loading. Hence, decreasing supplies at St Fergus will have reduced the efficiency and reliability of the Scottish compressor fleet. Increasing the workload, through a feeder removal, should therefore, have a beneficial effect. Tot say that “if a causal relationship is demonstrated …. the cost … should be included”. This is a principle that NGG agrees with, however, demonstrating that relationship for maintenance (other than the major overhaul) is virtually impossible. It should be noted that any uncertainty that remains with the industry rather than being passed to the new pipeline owner should be reflected in the pipeline sale price. NGG would expect that the Authority would reassure itself that is the case. Notwithstanding the difficulty, and uncertain benefits, of determining incremental unplanned maintenance and annual maintenance, NGG will re-visit this area to see whether it is feasible to include these criteria within the methodology before submitting its final proposals. **April 2011 update.** Predominantly all routine maintenance take the form of functional checks and inspections, these are generally time based activities. There are a smaller number of overhaul tasks which are generally duty based activities, where the frequency is determined by equipment running hours. It is important to be aware that the majority of the maintenance activities at a Compressor Site are associated with testing and inspecting process safety devices and need to be carried out irrespective of the running hours or status (standby or running) of the units. NGG is not proposing to include routine maintenance within the scope of the methodology. Similarly, it is not possible to attribute unplanned maintenance (i.e. breakdowns) as either time based or running hours based. Consequently, NGG remains of the opinion that unplanned maintenance should not be included in the methodology.				

Q27	**Do you agree with the proposed methodology to determine incremental compressor running hours? If not, what alternatives would you propose?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes though the principle of only those directly resulting from the disposal must apply. However, the third party should not be exposed to costs where compressor units / stations are not available for long periods.	Yes	SSE agree with the proposal for network analysis to be undertaken to assess the number of operating compressors required in the two scenarios; with pipeline and without pipeline.	This is reasonable.	Yes
NGG response	NGG notes support for this aspect of the methodology. With the methodology as proposed, the third party should not be exposed to the cost of non-availability of compressors. To the extent that such non-availability results in increased constraint management actions, this will be reflected in both the with, and without, pipeline scenarios.				

Q28	**Do you agree that incremental compressor running hours should be re-assessed annually?**				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes as this should ensure the latest data and assumptions are factored into the analysis without adding too much to the workload.	Yes	Yes	This is a practical approach	Yes
NGG response	NGG notes support for this aspect of the methodology.				

Q29	Do you agree with the indexation of overhaul costs? Should an alternative, e.g. cost pass through, be used? Would this create unnecessary uncertainty?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	NGC believe that a cost pass through should apply as this ensures that the third party are exposed to the true costs of incremental compressor maintenance. The third party need to be content that NGG are appropriately incentivised that these costs are minimised. In the case of NGC, full transparency and perhaps even market sounding may be necessary to ensure their own cost recovery to the extent these are pass through costs.	Yes N/A	Yes	Increasing costs must be reflected and indexation seems a reasonable approach	Indexation seems a reasonable approach
NGG response	NGG notes the majority support for this aspect of the methodology and NGC's disagreement. We also note that NGC's proposal that cost pass through should apply as this ensures that the third party is exposed to the "true costs" of incremental compressor maintenance is inconsistent with their preferred approach to constraint management costs. NGG has taken the approach that all relevant costs should be quantified as accurately as possible and passed to the third party, except where such costs are considered to be insignificant and/or accurate assessment is overly complex. In this situation we believe that cost pass through is inappropriate because the scheduling of compressor overhauls every 25,000 running hours may mean that, during the duration of the methodology, the third party incurs more (or less) than their fair share of the cost. The proposed methodology effectively annualises costs so that part year (i.e. part overhaul) costs are correctly attributed. In addition, a cost pass through methodology would reduce (but not eliminate) the incentive on NGG to control costs and would not provide the certainty of future costs offered by the proposed methodology.				

Q30	Should full analysis of incremental compressor running time be assessed in advance, using projected demand and flow levels, or should the methodology be backward looking and use actual demand and flow?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Use of actual demand and flows against a 'lookup table' determined by NGG would seem more appropriate and should be relatively straight forward to apply.	Methodology should be retrospective to ensure accuracy.	A backward looking methodology will be simpler and reconciliation will allow it to be more accurate.	It would be more accurate to use actual data where this is available, combined with any anticipated increase or decrease for the forward period.	It would seem more appropriate to use actual data.
NGG response	NGG notes the support for a backward looking methodology as currently proposed. Network analysis shall be used to generate a lookup table. Incremental CFU shall be obtained from the table for the actual flow.				

Q31	Is the example useful and/or relevant?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes and it would be useful to see the example expanded to incorporate locational actions.	Yes		The examples are helpful in understanding the methodology	Yes to both.
NGG response	NGG will retain the example, and will consider whether further examples can be provided in a manner which is helpful.				

Q32	Do you agree that the automated approach to determining incremental CFU should be introduced when available or should the look-up table be continued?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes the automated approach should be used. This should ensure further accuracy once the models have been validated and approved.	If both are equally accurate, use automated when available.		See Q16	See 16
NGG response	NGG notes support for this aspect of the methodology.				

Q33	Is it appropriate to provide the information stated in Annex 3 in the methodology statement or should this be stated elsewhere? If not, where should it be stated?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	Yes as this provides a clear basis for the analysis of incremental costs. However, it should be noted that any contractual arrangement between NGG and the third party may override these.	It is helpful		This data is relevant to the methodology and should be published.	This data is relevant to the methodology and should be published somewhere, an Annex to the methodology statement is as good a place as any. Certain other fixed data and published in methodology statements the IExCR for example
NGG response	NGG notes support for this aspect of the methodology. Whilst noting the point made by NGC, NGG believes that the methodology will form the starting point for any contractual arrangements. However, to the extent that any contractual arrangements override the data provided in annex 3, we expect that the Authority will take this into consideration in deciding whether to approve any proposed pipeline disposal.				

Q34	Is the data provided in Annex 3 accurate and complete?				
Respondent	**NGC**	**Tot**	**SSE**	**BGT**	**AEP**
	NGC believes that further analysis is required by NGG to establish if any further data is significant enough to include in Annex 3.	Unable to say.		As far as we can be aware	Yes subject to the footnote and analysis being undertaken for Moffatt and Wooler compressors to determine materiality.
NGG response	NGG appreciates that this question is difficult for most respondents to answer. NGG agrees with AEP and NGC that further analysis is required. This will be undertaken prior to asset disposal (see also Q19). However, we note that any further analysis is unlikely to be undertaken before NGG submits its proposal for the pipeline disposal detailed in annex 3 and the Authority makes it decision. Hence, we would expect that in respect of any contractual arrangements that may override the data in annex 3 (see Q33) the Authority would take account of any analysis required to confirm or amend the data in the annex.				

The following table details the comments raised that were not in direct response to questions in the consultation document. NGG's responses to these comments are provided.

Issue reference	Respondent	Issue	NGG response	Change to proposed methodology
35	**RWE**	Please note that we are in agreement with the response sent to this particular consultation by the AEP, and the comments provided against the specific questions.	Noted	None
36	**RWE**	We agree with the methodology to model the Relevant Gas Day in the two scenarios of : - without the relevant pipeline (actual conditions), and - with the relevant pipeline (conditions that would prevail had the pipeline been retained). Where differences are identified between the two scenarios, we would welcome information on how these would impact on stakeholders such as shippers. We also consider that there has to be a degree of pragmatism and flexibility built into this approach, which should consider potential future changes in the regime such as : - increased gas flow being delivered to St Fergus - the natural lifespan and end-date of the pipeline - returning the pipeline to the NTS for gas transportation purposes.	Noted: this is covered by Q9 See NGG comment to Q10. We agree that the approach taken should be pragmatic and, without impacting transparency, flexible. We believe the proposed methodology satisfies the scenarios listed. • If flows increase at St Fergus there should be an expectation of more constraint management actions. The methodology will determine whether, and the extent to which, these would have occurred without the pipeline disposal, i.e. whether they are incremental or not. • An end date has been built into the methodology. • It is not anticipated that the pipeline is returned to NGG. If it is demonstrated that additional capacity is required, e.g. due to increased flows and consistent need for constraint management actions, NGC have indicated that they will finance suitable compression facilities.	None

37	**SGN**	…..we remain concerned that analysis is still required to determine the impact of disposal of these specific assets on assured offtake pressures and system flexibility for Users, particular SGN. We are concerned that there could be unforeseen consequences for DNOs and customers downstream of the offtake. Scotia Gas Networks has previously experiences problems with the provision of assured pressure that NGG NTS is committed to provide at the various NTS offtakes within Scotland. We are concerned that the proposed disposal of part of the NTS will exacerbate this problem further. In their letter dated 30 September 2010 Ofgem stated that they could not offer a formal minded to or consent until a formal written notification of intention is made by NG. We appreciate that this is conditional on the success of the DECC competition but it is right to progress as many areas of work as possible in the meantime. In their letter of 30 September 2010 Ofgem recognised that considerable further work was required. We understand analysis of the impact on NTS / LDZ offtakes would fall under this category and are keen that this is considered as soon as possible.	This methodology has been developed to define processes for aligning certain costs in the event that a pipeline is transferred from NGG to a new owner (e.g. NGC). Hence, the issue raised is outside the scope of this consultation: we believe that the Authority will consider the impact on assured pressures (and mitigating actions, if any) before giving consent to the disposal. As noted, such consideration will follow a formal proposal for asset disposal by NGG. We anticipate this will be in Jan/Feb 2011. Notwithstanding this, we note that problems have previously occurred. This is mainly due to declining flows from St Fergus. The assured pressures that are currently achieved will remain similar due to the use of additional compression. Hence, it is our view that the removal of one of the Scottish feeders will not exacerbate the situation.	None
38	**EdF**	We believe that it would be good industry practice for this methodology and any future changes … to be subject to regulatory approval providing Ofgem with a power of veto. This will ensure that any conflict of interests across the National Grid suite of companies is dealt with in an impartial manner. Currently the methodology only requires agreement from National Grid and National Grid Carbon for any changes which we feel does not provide us with confidence that this methodology is subject to appropriate governance arrangements.	See also Q1 As this methodology forms part of the conditions for disposal of an NTS pipeline it will be "approved" by the Authority if/when consent is given for the disposal. However, once ownership of the pipeline has been transferred the pipeline is not part of NGG's regulated assets. It is not clear, therefore, under what vires the Authority would be able to veto subsequent changes. However, the methodology does require industry consultation if changes are needed to align to industry regime changes.	None

39	**EdF**	In general we believe that the proposed methodology effectively ensures that the additional costs associated with the disposal of the NTS Pipeline are captured; although, we have some high level comments regarding some of the proposals.	Noted	None
40	**EdF**	It is not clear why National Grid has relied on modelled constraints rather than using historical constraint information and costs to model incremental costs. We note that since 2006 the constraints occurring in that part of the network has been very low, suggesting that it is an unconstrained area. We understand the need for a forward looking process, but there is a risk that relying on a model to identify constraints would create constraints when none had previously existed. ……… We believe that rather than relying on modelling, which may prove inaccurate at identifying constraints, National Grid should also use historic constraint information and costs to inform their quantification of any additional costs as a result of the disposal of the feeder. We believe that this would better reflect operational experience – which suggests that this is not a constrained area and ensure that costs are appropriately targeted. If a modelled approach is to be used then this should be subject to independent audit to provide certainty to the industry that the process has worked as expected. In the past Poyry has undertaken this role to validate the transfer and trade process.	As EdF notes, there have been few constraints and hence few associated actions. Hence, we have taken the view that there is insufficient historical data to guide future costs. In addition, historical costs can be driven by specific circumstances and may be vastly different (in terms of pence / unit) from those to be experienced in future. Although we recognise the potential for modelling to be inaccurate it should not create a constraint. Analysis will only be undertaken if/when a constraint has occurred. Analysis will be used to determine whether, and how much, constraint would have occurred without the pipeline disposal. There is a risk that modelling may present an inaccuracy here, but historical data will not provide a solution. We note the proposal for auditing of results but believe this to present an unnecessary cost. The audit undertaken by Poyry was not funded by NGG and did not find fault with NGG's analysis despite industry concerns. However, we would consider such an approach if funded was provided.	None

41	**EdF**	We understand that National Grid can forecast compressor usage when developing the shrinkage incentive; however, it has been unable to forecast compressor usage in order to identify the incremental costs. As a minimum providing forecasts would provide a useful means of testing the results of the modelling.	When developing the shrinkage incentive, which is set for future years, it was a fundamental necessity to forecast compressor usage: this was determined with the aid of network modelling. Being a forecast, assumptions would have been made, each adding a degree of inaccuracy to the projections. For incremental costs there is not the necessity to forecast: analysis can be undertaken after the event, using actual data (e.g. actual gas flows), hence accuracy should be improved. Both forward and backward looking approaches to determining incremental costs rely on network modelling. Forecasting provides certainty to the pipeline owner (assuming the forecasts are made prior to the pipeline sale) but is less accurate. Any inaccuracies would present a risk to Users and NGG.	None
42	**EdF**	It would be beneficial were National Grid to provide additional analysis and evidence to support some of the assumptions that they have made. Without this analysis and evidence it is hard to judge whether these assumptions are reasonable or not. ……. Finally we note that throughout the document National Grid has made a number of assumptions; although, these appear sensible, without any evidence or analysis against these assumptions it is hard to judge whether they are appropriate or not. For example the assumption in paragraph 39 that the later a constraint action is taken, the more expensive it will be. It would be beneficial for National Grid to support assumptions such as this with evidence or analysis.	We appreciate that the use of assumptions creates doubt over the accuracy of the methodology. However, to provide robust analysis and evidence would be resource and time consuming. As noted by EdF the assumptions made “appear sensible”. We have tried to avoid making assumptions that cannot be justified on the basis of logical expectation. As stated in Q21 and Q24 the methodology has been drafted as a compromise between simplicity and precision. We believe the assumptions made are justified in that context.	None

43	**EdF**	In the methodology Gas Shippers, and so consumers, are exposed to the risk that National Grid constrains more capacity than required. It would appear more appropriate for this risk to be shared by both National Grid Carbon and National Grid Gas. …… Within the methodology, National Grid recognises that when taken a constraint management action it may over purchase to ensure that there is a level of tolerance in its actions (paragraph 33). When no constraints would have occurred, then this risk is borne by National Grid Carbon; however, if there are incremental costs caused by the disposal, then this risk is transferred entirely onto Gas Shippers, and so consumers. We do not believe that this is appropriate, and should incremental constraints be caused by the disposal, then any risks should be shared.	See also Q10 We disagree that "should incremental constraints be caused by the disposal, then any risks should be shared". We believe the risk should lie entirely with the new owner. Where there is a tolerance on the constraint quantity it is appropriate that this quantity falls on the pipeline owner if there would have been no constraint without the pipeline disposal. However, if, without the pipeline disposal, constraints would have occurred, the same tolerance would have applied. This is the case now and presents cost to the entire industry. Hence, in future, if the "with pipeline" analysis suggests that constraints would have occurred, it is appropriate that the industry (including NGG) continue to bear the cost.	None
44	EdF	In relation to the specific methodology we note that the invoicing schedule outlined in paragraph 28 is not clear. In particular National Grid's proposal to invoice any constraint costs occurring between 1 April 1 and 31 March Y+1 by 30 June Y+1 relates to the Gas Year, but all references in this section are to the financial year. We believe that this requires further clarification.	We recognise the potential for confusion and propose an amendment to this paragraph.	Paragraph 28 amended.