CONSULTATION DOCUMENT

Methodology to Determine Incremental Constraint Management Costs and Incremental Compressor Costs Related to Removal of an NTS Pipeline

8th November 2010

Table of Contents

1 Executive Summary

This document is issued by National Grid Gas (NGG) in its role as Gas Transporter Licence holder in respect of the NTS (the Licence). It sets out, for consultation, National Grid's proposals for a "Methodology to Determine Incremental Constraint Management Costs and Incremental Compressor Costs Related to Removal of an NTS Pipeline".

NGG proposes through this consultation document that, in the event that an NTS pipeline is removed from service and transferred to a new owner, then the new owner shall be responsible for certain incremental costs arising from the removal of the pipeline from the NTS.

The incremental costs chargeable to the new pipeline owner will cover:

- Incremental constraint management actions;
- Incremental compressor fuel use;
- Incremental compressor maintenance; and
- Incremental costs incurred through emissions incentives defined in the Licence and relating to incremental CFU.

Implementation

It is proposed that, if approved by the Authority, the methodology statement shall apply from the date that any pipeline is first disconnected from the retained NTS, i.e. when the first valve is closed to prevent gas flow through the relevant pipeline.

Responses

National Grid Gas invites views on the proposed methodology statement, but specifically the questions listed in section 3. The closing date for submission of responses is 6th December 2010.

Your response should be e-mailed to:

andrew.fox@uk.ngrid.com and copied to

box.transmissioncapacityandcharging@uk.ngrid.com.

or alternatively it can be sent by post to

Transmission Commercial,
National Grid,
National Grid House,
Gallows Hill,
Warwick,
CV34 6DA.

If you wish to discuss any matter relating to this consultation, please call Andrew Fox☎ 01926 656217.

If you wish your response to be treated as confidential then please mark it clearly to that effect.

2 Introduction

2.1 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).

2.2 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, 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.

2.3 NGG's proposal requires the Authority's consent to go ahead. If consent for the disposal is granted then it is proposed that the assets cease to be used to transport natural gas and instead be used to transport CO2.

2.4 Ofgem, through their industry consultation[1], have identified that there may be downsides to the transfer of assets if they lead to bottlenecks on the network in the event of new gas supplies. They have stated that consumers should be protected from additional costs resulting from the disposal of NTS pipelines. Hence, where there are incremental costs to operate the NTS, and these costs are shared, through arrangements detailed in the Licence, with Users, these costs need to be determined.

2.5 Ofgem have indicated that NGG should 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. As it is NGG that will make the formal proposal to dispose of NTS assets, it is for NGG to develop an appropriate methodology.

2.6 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. This consultation is being held to satisfy this requirement.

2.7 The key objectives of this methodology are to ensure that:

as far as is reasonably practicable, relevant incremental costs are identified in a manner that is fair to User, consumers and NGC; and

it can be applied consistently to any similar future disposals, whether to NGC or any other third party.

[1] Proposed disposal of part of NTS for Carbon Capture and Storage - Second consultation and initial impact assessment – Ofgem ref 56/10 dated 6 May 2010

3 Discussion and Issues

3.1 The removal of an NTS pipeline is likely to reduce the capability of the NTS within the vicinity of that pipeline. Dependent upon actual gas flows this may or may not result in incremental costs in the operation of the NTS.

3.2 National Grid has stated that the risk of incremental constraints, and hence likely costs to relieve those constraints, occurring as a result of the pipeline disposal identified in paragraph 2.2, is low. However, the proposed methodology is intended to quantify relevant incremental constraint management costs irrespective of the likelihood of them being incurred.

3.3 Transporting a given quantity of gas through a reduced number of pipelines is likely to result in greater pressure drops and hence increased compressor usage, particularly at higher flow rates. The proposed methodology presents a process for determination of the incremental compressor fuel usage (CFU) and maintenance resulting from pipeline disposal.

3.4 Whilst the draft methodology statement presents a methodology that NGG believes presents a fair and practical approach to the determination of relevant costs, this consultation document presents alternative approaches that NGG considered. NGG is seeking views on whether the most appropriate methodology is being proposed. Hence, the consultation document should be read in conjunction with the proposed methodology statement (version 0.1).

3.5 In addition to seeking views on the details of the process to determine costs, NGG is seeking views on other aspects of the proposed methodology. As detailed in the following sections.

3.6 This consultation is structured to follow the lay-out of the proposed methodology statement.

Part A: General

3.7 Part A of the methodology statement provides an introduction to the methodology and details associated costs and processes, such as validation and costs for analysis work.

3.8 Sub-section a, “Background”, identifies potential impacts of a pipeline disposal covered by the methodology, i.e. a range of possible constraint management actions and increased compressor fuel usage.

3.9 To ensure that no User is exposed to additional costs any costs recovered from the pipeline owner will be channelled to the appropriate revenue stream. In respect of any incentives defined in the Licence, this will ensure that any caps are not breached and any cost sharing factors are not adversely impacted.

3.10 Sub-section b, fixes the methodology such that, with the exception of environmental legislation and major regime changes, on-going changes can only be made by agreement between NGG and the pipeline owner. NGG believes it is appropriate that future uncertainty is minimised for the pipeline owner provided that this does not transfer significant risk to Users. In regard to major regime changes, NGG believes that, to protect all parties, this means that the methodology must be reviewed and updated. However, NGG expects that any major changes to the capacity regime would take account of the NTS as it exists at that time, hence minimising the impact of such changes. NGG believes that the proposed methodology adequately defines incremental costs with sufficient robustness to limit the scope for future changes whilst providing a safeguard that necessary change can be made.

3.11 If applied conscientiously there should be limited scope for error in determining relevant costs. Notwithstanding this, NGG believes it is appropriate that the determined costs should be open to challenge. Such challenges should not be spurious, but should be on the grounds of a reasonable expectation of success.

3.12 Sub-section c allows for the challenging of identified costs. 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. 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.

3.13 Sub-sections d and e ensure that costs incurred in applying the methodology are also recoverable from the pipeline owner. The main cost is for analysts to undertake the necessary modelling and data handling. The cost of additional internal resources and/or external analysts may be incurred for validation and auditing.

3.14 As stated in paragraph 3.9, it is important to ensure that any revenue is correctly allocated. Where this requires data processing by xoserve that incurs a charge, those charges shall be passed to the pipeline owner.

3.15 Although remote, it is also possible that Users could incur interest charges under UNC that are originated by a pipeline disposal. For example, payments may be required from Users through capacity neutrality which would not have been required without the pipeline disposal. The compensating payments from the pipeline owner may feed through neutrality a month or more later. This misalignment of costs and corresponding refund to Users may result in interest payments. NGG believes that any such payments should not be borne by NGG or other Users.

3.16 NGG believes that the payment of incremental costs by the pipeline owner should be time limited. It would be inappropriate for payments to continue beyond the date when the pipeline would have been removed from service.

3.17 Sub-section f defines the end-date 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; and
- the effective date of any reduction in the baseline quantity of any relevant ASEP.

3.18 It would seem unreasonable for the new pipeline owner to be exposed to costs beyond the date when the pipeline would have been removed anyway. At this time, any incremental costs determined in accordance with the methodology would be incurred by NGG irrespective of the pipeline disposal. Hence they would not be “incremental” to the status quo of retaining the pipeline. Although it may be difficult to define a future date when a particular pipeline asset would be removed from service, NGG believes that, where it is possible, it is appropriate to specify that date. In respect of the pipeline disposal identified in paragraph 2.2 NGG has undertaken analysis and estimates that this pipeline would otherwise be decommissioned around 2020 given its expected life, forecast decline in UKCS, and the ultimate decline in Norwegian supplies. Hence an end date of 1st October 2020 has been proposed.

3.19 Irrespective of the ultimate removal of the pipeline from service in the absence of a disposal, it would appear unreasonable to require continued payment for incremental costs (or the analyst costs to demonstrate no incremental costs have been incurred) if the baseline at relevant ASEPs has been reduced. Any baseline reduction would be subject to regulatory oversight and industry consultation. It is expected, therefore, that a baseline reduction would only occur if there is industry confidence of a significant decline in flows to a level that can comfortably be managed without the disposed of pipeline. Although entry capacity substitution may reduce NGG’s obligation to make capacity available at the ASEP, substitution should not be a trigger for these arrangements ceasing to apply. Hence baseline reductions arising from entry capacity substitution have been excluded.

3.20 Alternative criteria for determination of an end-date have been considered.

- The depreciation of the Regulatory Asset Value to zero might be appropriate. However, in 2002/03 all NTS asset were given a 56 year regulatory life irrespective of the physical life expectancy.
- The end-date could be set to the implementation date of the next price control following disposal, i.e. potentially 2021. At this time it is likely that the impact of the disposal would be built into any settlement. However, any on-going arrangements to protect Users from this date would impact NGG. Recovery of costs under those future arrangements from the pipeline owner would require a separate agreement outside the regulatory framework. NGG believes it would be sensible to continue the existing methodology rather than produce new arrangements.

Questions

3.21 NGG would appreciate comments on Part A of the proposed methodology statement, but specifically the issues identified below. Please provide explanation for your answers.

1. Do you agree that future changes to the methodology should be restricted as envisaged in the proposal?
2. Do you agree that charges calculated according to the methodology should be open to challenge by the pipeline owner?
3. Notwithstanding your answer to 2, are the cut-off values used to prevent spurious challenges set at a fair and reasonable level?
4. Do you agree that administrative / processing charges incurred by xoserve should be included within the scope of the methodology?
5. Do you agree that the application of the methodology to any specific pipeline disposal should be time limited?
6. Notwithstanding your answer to 5, do you agree with the proposed criteria for determining the duration of the methodology for specific projects?

Part B: Constraint Management Actions

3.22 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. This will occur where flows exceed the reduced system capability. NGG could manage this risk by reducing the baseline capacity at relevant system points. However, in respect of the current proposal in Scotland (see paragraph 2.2), and potentially for any future proposals, NGG is not proposing any alteration to baseline quantities. This means that if future flows exceed forecast levels, those flows could still be within obligated levels, i.e. NGG has an obligation to make capacity available up to that flow level, but the flows could also be above the reduced system capability. Under this situation system constraints would occur.

3.23 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.

3.24 Although it may be possible to identify pipeline disposal as the trigger for the curtailment of interruptible capacity rights, NGG believes that the new pipeline owner should not be required to make any payment in respect of the curtailed rights because Users would not receive any compensation under 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. Hence it is proposed, in sub-section h, that no costs related to the curtailment of interruptible capacity rights will be recovered.

3.25 Irrespective of the constraint management tool used, NGG will need to identify the incremental constraint management quantity, i.e. the quantity of constraint management actions in excess of that that would have been required without the pipeline disposal, and the incremental price.

3.26 Sub-section i details the methodology proposed to be used to determine the incremental constraint management quantity.

3.27 It is proposed that network analysis is used to model the network in two scenarios. Analysis shall replicate the relevant Gas Day:

- Without the relevant pipeline, i.e. actual conditions;
- With the relevant pipeline, i.e. conditions that would have applied had the pipeline been retained by NGG.

3.28 Operational data, e.g. pressures, shall be obtained from appropriate systems to ensure the model replicates the "without pipeline" scenario as accurately as possible.

3.29 The proposed approach will generate two theoretical constraint quantities. The incremental constraint management quantity shall be determined by difference except as explained below in paragraph 3.30.

3.30 Where modelling of the "with pipeline" scenario shows that the network could have coped with the actual flows and that no constraint action would have been required, the incremental constraint management quantity will be the actual quantity taken by the control room rather than the modelled quantity.

3.31 This proposed approach ensures that any excess action taken by control room operators erring on the side of caution[2] would be attributed to the pipeline owner if the "with pipeline" analysis demonstrates no constraint. On the other hand, where there would have been a constraint, the approach assumes an equal "excess" constraint management action quantity under both with, and without, pipeline scenarios. Hence they cancel out and the theoretical, modelled, quantities are used.

3.32 An alternative approach was considered whereby only the "with pipeline" scenario would be modelled. The incremental quantity would be determined, in all cases, as the difference between the actual constraint quantity taken and the modelled value. This would save analysis time and cost. However, it would result in the incremental constraint management quantity being higher in some cases. NGG believes that this would not be fair to the pipeline owner unless:

- the difference between the two approaches is insignificant, and/or
- the reduction in analysis time is significant.

NGG is unable to confirm whether either of these criteria would be satisfied.

3.33 Irrespective of the constraint management tool used and the incremental constraint management quantity, NGG will also need to identify a unit price, i.e. the price per quantity of incremental constraint management action.

3.34 The price of constraint management actions will vary according to the terms offered by the counter-party to the action. Hence the correct price for the incremental constraint management actions must be determined. Paragraph 39 and sub-section j detail the methodology proposed to be used to determine the price for incremental constraint management actions.

3.35 Clearly it is impossible to be certain that any specific actions are attributable to incremental constraints unless all actions are attributable. Hence a number of principles have been proposed.

[2] As current operations are not modelled on a daily basis it is not possible to confirm whether, or to what extent, any constraint management actions err from that theoretically required.

3.36 When circumstances develop and 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. NGG is, therefore, proposing that the last actions taken are attributable to incremental actions.

3.37 NGG considered taking a weighted average price "WAP" of all constraint management actions taken on the relevant gas day (i.e. including those that would have been required in the absence of the pipeline disposal) but decided on the price of specific actions identified according to paragraph 3.36. We believe that this will correctly target higher costs to the pipeline owner thereby justifying the added complexity.

3.38 Whilst this approach will place added risk on the third party, i.e. they may be exposed to the cost of the most extreme buy-back actions, NGG believe that current Licence obligations to operate the NTS in an economic and efficient manner will ensure that costs are not unnecessarily incurred.

3.39 In earlier submissions[3], National Grid has stated that the risk of capacity constraints from a pipeline disposal would be low. This was supported by independent analysis by Poyry Energy Consulting[4]. This suggests that:

- The proposed methodology for determination of buy-back costs is likely to be rarely used;
- In the event that buy-backs do occur, it is highly likely that all the buy-back quantity is incremental, i.e. attributable to the pipeline disposal.

Hence, in practice, there should be a very low probability of any difference arising between WAP prices and specific incremental prices.

3.40 To a prospective new pipeline owner the pipeline assets may be valued higher with lower associated risks. As any asset sales revenues are expected to be shared between NGG and Users, a view may be taken that NGG should aim to maximise the asset sale price by minimising the associated risks, even if this means transferring those risks to NGG and Users. In this case, a WAP based methodology would be preferable to one based on incremental prices.

3.41 As such an approach would be less effective in targeting incremental costs NGG is not proposing a WAP based methodology. However, NGG would welcome views from industry participants.

3.42 In respect of capacity buy-backs and similar actions, it is proposed that the price of a particular buy-back is the actual price paid and recorded. However, for locational gas buys and sells determination of the appropriate price is not as simple.

3.43 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.

3.44 Again, 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 in respect of balancing actions. It is possible that such counter actions results in a net income. It could be argued that this sum should be credited to the pipeline owner. NGG believes that the pipeline owner should not profit from its negative impact on pipeline capacity so is proposing that negative costs will be ignored and no payment made. In this event any surplus will result in a benefit to Users.

---

3 Proposed disposal of part of NTS for Carbon Capture and Storage - Ofgem: ref 35/09 dated 8th April 2009.

4 Proposed disposal of part of NTS for Carbon Capture and Storage - Second consultation and initial impact assessment – Ofgem ref 56/10 dated 6 May 2010.

3.45 Any balancing actions would aim to maintain a daily balance so would, normally, be taken within the same Gas Day. However, this may not always be possible due to the nature, extent, and timing of a constraint. For simplicity, NGG is proposing that only balancing actions taken on the same Gas Day as the original action will be considered.

Questions

3.46 NGG would appreciate comments on Part B of the proposed methodology statement, but specifically the issues identified below. Please provide explanation for your answers.

7. 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?
8. If you disagree with the proposal in question 7, what costs should be recovered, and how should these be determined?
9. 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?
10. Do you agree with the approach to scenario modelling that uses actual operational data? Are there any other criteria that should be considered?
11. 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?
12. 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?
13. Do you agree that the cost of any counter-balancing actions for locational sells/buys should be included in the determination of costs?
14. Do you agree that, in respect of locational actions where income exceeds costs, the surplus should not be paid to the pipeline owner?

Part C: Incremental Compressor Fuel Usage (CFU)

3.47 As for constraint management actions, the determination of incremental CFU requires the calculation of an incremental quantity and a unit price.

3.48 Currently NGG's network analysis is unable to directly model electric drive compressors. Hence it is necessary to determine a gas equivalent CFU. For these compressors, models can be used to determine the expected CFU of an equivalent gas driven compressor and this can be converted to electricity usage via a conversion factor for different efficiencies.

3.49 Individual electric driven compressors may have different efficiencies, which may vary at different loading. NGG believes that, for simplicity, a single, average, value is required. The Licence (Special Condition C8F (2)(g)) uses a value of 3:1 and NGG is proposing to use this value.

3.50 Unlike capacity constraints, CFU is a daily occurrence so incremental CFU will also need to be determined daily. This suggests an automated approach will be required. Currently, this is not possible, but existing network modelling software may be capable of being adapted to facilitate this in the future. Hence, NGG is proposing that an automated approach should be used when available. This approach is described in Annex 2 of the methodology statement.

3.51 Until an automated approach is available, NGG is proposing a methodology based on a look-up table. Under this approach, a suitable reference node will be identified (e.g. St Fergus ASEP for a pipeline disposal in northern Scotland). For a range of flows at the reference node the network can be modelled to determine CFU at each relevant compressor station.

3.52 Modelling can be undertaken for “with pipeline” and “without pipeline” scenarios.

3.53 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. Hence the incremental CFU will be as detailed in paragraph 64 of the methodology statement.

3.54 NGG believes that the removal of a pipeline in one location could impact gas flows, and hence CFU in remote parts of the network due to the interactive nature of the NTS. Hence, 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. Hence NGG has concluded that analysis of incremental CFU should be limited to relevant compressors in the immediate location of the disposed of pipeline, i.e. those situated along retained pipelines used to transport the displaced gas flow plus those immediately downstream, where compressor inlet pressures may be reduced (and hence CFU increased) as a result of the pipeline disposal.

3.55 NGG has considered two options for the price of incremental CFU. These are:

- The **actual price paid by NGG for gas and electricity** for its compressor fleet. 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. Hence, NGG has concluded that it would be unduly complex to match specific fuel purchases and costs to incremental CFU quantities.

- Gas and electricity **reference prices defined in the Licence**. These prices are used in the incentives defined in the Licence, hence these prices should be challenging, but attainable. They should, therefore, be a reasonable proxy for the actual price paid by NGG. They have the advantage of being clearly defined, and as they are used for incentive reporting, they require no additional resource from NGG. In addition, they are linked to actual prices published independently. The reference prices will, therefore, vary according to real prices. Notwithstanding that there may be a slight difference between reference prices and actual price paid by NGG, NGG is proposing to use these values for determination of incremental CFU costs.

Questions

3.56 NGG would appreciate comments on Part C of the proposed methodology statement, but specifically the issues identified below. Please provide explanation for your answers.

15. To enable modelling of electrically driven compressors, is it appropriate to use the conversion factor of 3:1 taken from the Licence?
16. Do you agree with the look-up table approach to determination of incremental CFU quantity? Are there any practical alternatives?
17. Do you agree that an automated approach is preferable and should be used when available?
18. 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?
19. 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?

20. 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?

Part D: Incremental Compressor Emissions Costs

3.57 Consistent with all major energy using plants NGG's compressor fleet is subject to emissions legislation. Currently, any costs associated with compliance with emissions legislation are borne solely by NGG. Hence they fall outside the scope of this methodology statement which looks at protecting Users and consumers from incremental costs. If NGG wishes to recover any additional costs from the pipeline owner these will be covered through separate arrangements.

3.58 If, in future, the Licence is amended such that these costs fall, in part or in total, on Users, it is proposed that the methodology should be revised.

3.59 NGG is also required to minimise emissions through incentives in the Licence.

3.60 The NTS environmental incentive requires NGG to minimise venting losses from its compressor fleet. Venting is related to the mode of operation, particularly the frequency with which a compressor is pressurised and de-pressurised. Other factors, such as running hours, also affect venting losses.

3.61 The disposal of a pipeline is likely to increase overall compressor operation and this could reduce the frequency of start up. NGG has concluded that pipeline disposal could have both a positive and negative impact on venting losses. To determine the actual impact would be extremely complex and resource intensive and not justified by the potential costs identified.

3.62 To put this into context the incentive target for 2010/11 set in the licence for venting losses, for the entire NTS fleet is approximately £3.3m. The incremental quantity as a result of a pipeline disposal would relate to a fraction of the fleet and would, at most, be a small percentage of the target.

3.63 Venting, as defined by the Licence, is limited to venting from compressors. However, disposal of a pipeline would require the pipeline to be decommissioned resulting in the release of the gas contained in the pipeline. Currently, in respect of the project mentioned in paragraph 2.2, a separate one-off charge is being considered in relation to pipeline venting costs. It is assumed that this principle will extend to any future disposals. Hence pipeline venting costs have not been considered within the methodology.

3.64 The shrinkage incentive includes a component for CFU that is shared with Users. The cost of this incentive is independent of, and additional to, the incremental CFU. The applicable price is the uplift required to reflect the "shadow price of carbon" (SPCU) as defined in the Licence. NGG is proposing that this cost, as applicable to the incremental CFU quantity should be passed to the pipeline owner.

3.65 NGG is aware that the use of SPCU is being replaced by a traded cost of carbon in government policy. To protect against future changes, NGG is proposing that any changes to the price used in the shrinkage incentive is used in respect of this methodology statement.

Questions

3.66 NGG would appreciate comments on Part D of the proposed methodology statement, but specifically the issues identified below. Please provide explanation for your answers.

21. 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?

22. Do you agree with NGG's proposal that incremental costs not falling on Users should be excluded from the methodology?

23. 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?

24. If in disagreement with 23, how would you suggest that incremental venting losses might be determined?

25. Do you agree with the pass through of incremental shrinkage incentive costs as detailed?

Part E: Incremental Compressor Maintenance Costs

3.67 As well as increased fuel usage, the removal of a pipeline is likely to increase the maintenance requirements of a compressor. NGG has attempted to assess the incremental maintenance costs.

3.68 Maintenance works are either planned or unplanned. Planned works are scheduled as routine annual works undertaken irrespective of operating hours; and major overhauls based primarily on hours run.

3.69 NGG has taken the view that only major overhauls should be considered within the methodology.

3.70 Routine annual works will be required each year irrespective of whether a pipeline has been removed or not. Hence such works cannot be regarded as incremental and should not be borne by the new pipeline owner.

3.71 Unplanned works are, by their nature, unforeseen and their cost cannot be predicted. Although additional compressor operation may increase the likelihood of increased breakdowns NGG believes that adequate planned maintenance should prevent, or limit, breakdown costs and that the risk of unplanned maintenance being required is a factor that NGG considers when devising planned maintenance schedules. Hence NGG believes that no costs arising from unplanned maintenance should be borne by the pipeline owner.

3.72 A major overhaul is scheduled for every 25,000 hours of operation. This equates to almost 3 years continuous operation. Hence, in order to determine incremental compressor maintenance costs it is necessary to determine the incremental compressor running hours. Other factors, such as on/off switching, may increase or decrease this time period, but NGG believes that these effects will generally even out.

3.73 One option considered by NGG was to use the incremental CFU as a proxy for incremental running hours. This was dismissed because increased fuel usage will result from compressors working harder as well as longer. Incremental CFU does not discriminate between harder working and longer operation.

3.74 The alternative, which NGG is proposing in the methodology statement, is for network analysis to be undertaken to assess the number of operating compressors required in the two scenarios; with pipeline and without pipeline.

3.75 The analysis, to be undertaken annually, will assess requirements for a range of total system demand levels. For each demand level, a range of flows at the reference node will be considered. These flows will span the expected flow rates at the reference node for the demand level. Hence for a number of demand/flow scenarios the number of additional compressors (if any) required following pipeline disposal can be determined.

3.76 The number of additional compressors may vary for each scenario. In real time, control room operators may have a range of options available to them to manage the NTS in a safe, reliable, economic and efficient manner. This means that a forecast of future compressor running time will inevitably involve an element of subjectivity. However, from the results of the analysis, NGG will assess the equivalent level of additional compressors required to be continuously operational in excess of that required before the pipeline disposal.

3.77 It should be noted that this assessment does not imply that the same compressor(s) will be operating continuously. There will be different relevant compressors, including different units at the same location, operating, depending upon the demand and flow levels. In addition, there will be times when more compressors may be required and other times when fewer, or no, additional compressors would be needed.

3.78 The quantity of additional compressors running will vary dependent upon the scenario considered. NGG will determine a weighted average based on an assessment of the likelihood of each demand/flow scenario occurring. The average quantity of additional compressors required can then be used to determine the additional major overhauls required and hence the incremental compressor maintenance cost.

3.79 NGG is proposing an annual assessment of incremental compressor running time as this would ensure that incremental costs are updated to reflect future changes to the network and hence will be more accurate. This approach is consistent with that proposed for determination of incremental CFU and NGG believes that the increased accuracy justifies the added workload and the increased uncertainty for the pipeline owner.

3.80 NGG is proposing that incremental compressor maintenance costs will be determined as stated in paragraph 94 of the methodology statement. It is proposed that this cost will be indexed from the cost determined for the first year of operation without the pipeline, using Retail Price Index. NGG believes that it is reasonable to expose the new pipeline owner to costs that can only be increased to a predefined extent. Hence any escalating costs (or efficiency gains) will not be passed on.

3.81 The use of the RPI as defined in the proposed methodology statement has been used as it is consistent with similar indexing used in the Licence.

3.82 The approach proposed will determine incremental maintenance costs in advance of the relevant period of operation. Consistent with paragraphs 3.75 to 3.78 a forecast will be made of system demand and flow levels at the reference node. An alternative approach would be to undertake the analysis retrospectively.

3.83 In this ex-post arrangement, NGG would still undertake analysis to determine additional compressor requirements for a range of demand/flow scenarios in advance. However, instead of NGG determining a weighted average based on “an assessment of the likelihood of each demand/flow scenario occurring” (paragraph 3.78) NGG will analyse actual (i.e. for the previous year) demand and flows to develop a more accurate weighting.

Questions

3.84 NGG would appreciate comments on Part E of the proposed methodology statement, but specifically the issues identified below. Please provide explanation for your answers.

26. Do you agree that unplanned maintenance and routine annual maintenance should be excluded from the methodology?

27. Do you agree with the proposed methodology to determine incremental compressor running hours? If not, what alternatives would you propose?

28. Do you agree that incremental compressor running hours should be re-assessed annually?

29. Do you agree with the indexation of overhaul costs? Should an alternative, e.g. cost pass through, be used? Would this create unnecessary uncertainty?

30. 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?

Annexes

3.85 Annex 1 contains an example of how incremental constraint management costs would be determined.

3.86 Annex 2 contains details of the proposed automated approach to the determination of incremental CFU quantity? It is proposed that this methodology shall apply when appropriate and sufficient skills and knowledge are available within NGG.

3.87 Annex 3 specifies relevant information for specific pipeline disposals. Clearly there is only one such disposal being considered at the current time.

3.88 This Annex specifies relevant ASEPs and exit points for consideration when determining incremental constraint management costs. It also specifies relevant compressors for determination of incremental CFU and related costs.

3.89 Annex 3 also provides an end date for the application of this methodology for the specific pipeline disposal.

Questions

31. Is the example useful and/or relevant?
32. Do you agree that the automated approach to determining incremental CFU should be introduced when available or should the look-up table be continued?
33. 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?
34. Is the data provided in Annex 3 accurate and complete?

4 NGG's Proposal

4.1 NGG is proposing that in the event of the disposal of an NTS pipeline to another party that the new pipeline owner should pay for incremental costs incurred as a result of the removal of that pipeline from NTS service.

4.2 The incremental costs chargeable to the pipeline owner will cover:

- Incremental constraint management actions;
- Incremental compressor fuel use;
- Incremental compressor maintenance;
- Incremental costs incurred through emissions incentives defined in the Licence and relating to incremental CFU; and
- The costs incurred in determining the above costs.

4.3 NGG's proposal is as detailed in the "Methodology to Determine Incremental Constraint Management Costs and Incremental Compressor Costs Related to Removal of an NTS Pipeline" issue 0.1 dated November 2010. The proposal may be amended in the light of responses to this consultation.

4.4 The proposal shall apply to pipeline disposals irrespective of the new pipeline owner and future use of the pipeline.

4.5 The proposed methodology statement shall form part of any proposal to be made to the Authority for approval to dispose of any pipeline asset covered by the Licence.

4.6 It is proposed that, if approved by the Authority, the methodology statement shall apply from the date that any pipeline is first disconnected from the retained NTS, i.e. when the first valve is closed to prevent gas flow through the relevant pipeline.

5 Consultation Responses

5.1 National Grid invites views on the proposed methodology statement, but specifically the questions listed in section 3.

5.2 The closing date for submission of your response is 6th December 2010. Your response should be e-mailed to:

andrew.fox@uk.ngrid.com and copied to

box.transmissioncapacityandcharging@uk.ngrid.com.

or alternatively sent by post to

Transmission Commercial, National Grid, National Grid House, Gallows Hill, Warwick, CV34 6DA.

5.3 If you wish to discuss any matter relating to this methodology consultation then please call Andrew Fox☎ 01926 656217.

5.4 If you wish your response to be treated as confidential then please mark it clearly to that effect.