








Stage 04: Final Modification Report		At what stage is this document in the process?
<p>0498:</p> <p>Amendment to Gas Quality NTS Entry Specification at BP Teesside System Entry Point</p> <p>0502:</p> <p>Amendment to Gas Quality NTS Entry Specification at the px Teesside System Entry Point</p>		<div>01 Modification</div> <div>02 Workgroup Report</div> <div>03 Draft Modification Report</div> <div>04 Final Modification Report</div>
<p>0498: This modification will facilitate a change to the current contractual Carbon Dioxide limit at the BP Teesside System Entry Point, through modification of a Network Entry Provision contained within the Network Entry Agreement (NEA) between National Grid plc and Amoco (UK) Exploration Company LLC in respect of the CATS Terminal (BP Teesside).</p> <p>0502: This modification will facilitate a change to the current contractual Carbon Dioxide limit at the px Teesside System Entry Point, through modification of a Network Entry Provision contained within the Network Entry Agreement (NEA) between National Grid Gas and px (TGPP) Limited in respect of the px Teesside System Entry Point.</p> <p>Since these modifications are identical in nature, differing only in the impacted NEA, the Modification Panel requested a single report encompassing both. For simplicity, information in this report has been presented once but applies equally to both 0498 and 0502.</p>		
	Panel consideration is due on 20 August 2015	
	Medium Impact: Transporters, Shippers and Consumers	

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About this document:		
This combined Final Modification Report will be presented to the Panel on 20 August 2015.		
The Authority will consider the Panel’s recommendations and decide whether or not these changes should be made.		
The Workgroup recommended the following timetable:		
Initial consideration by Workgroup	01 May 2014	
Workgroup Report v1 presented to Panel	21 May 2015	
Report returned for further Assessment	21 May 2015	
Workgroup Report v2 presented to Panel	18 June 2015	
Draft Modification Report issued for Consultation	18 June 2015	
Consultation Close-out for representations	24 July 2015	
Final Modification Report published for Panel	27 July 2015	
UNC Modification Panel recommendations	20 August 2015	
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1 Summary

Are these Self-Governance Modifications?

The Modification Panel determined that these are not self-governance modifications because they are likely to have an impact on Shippers, Transporters or consumers of gas conveyed through pipes. The Workgroup agreed with the Modification Panel's determination on self-governance as these modifications may impact Shippers, Transporters or consumers of gas conveyed through pipes, as they potentially change the CO₂ limits at specific entry points to the NTS.

Why Change?

0498 - The current carbon dioxide limit at BP Teesside System Entry Point of 2.9 mol% is incompatible with the anticipated gas quality specification of some potential new offshore developments. While the inclusion of processing and treatment solutions to remove the excess carbon dioxide are being considered upstream of the National Transmission System (NTS), these would require significant investment and/or operating costs, reducing the economic delivery of those developments. Hence, this modification seeks to establish whether a change of one of the existing Network Entry Agreement (NEA) parameters would be a more efficient and economic approach to facilitate delivery of potential new supplies to the System, subject to ensuring no adverse impact on consumers or on the operation of the pipeline system.

0502 - The px Delivery Facility receives the same composition of commingled gas from the Central Area Transmission System (CATS) pipeline as the BP CATS Facility, and currently has the same carbon dioxide limit within its Network Entry Provisions.

These modifications should be considered as 'enabling', since the changes are to Network Entry Agreements between National Grid NTS and the sub-terminal operators. UNC TPD Section I 2.2 permits changes to such agreements via the use of an enabling modification.

Solution

Both modifications propose an amendment to a Network Entry Provision, to permit an increase in the CO₂ limit of gas delivered from the respective Entry Points into the NTS.

0498 - This modification, in accordance with UNC TPD I 2.2.3(a), proposes an amendment to a Network Entry Provision within the existing NEA in respect of BP Teesside System Entry Point. This amendment would increase the CO₂ limit of gas delivered from the BP Teesside System Entry Point into the National Transmission System to 4.0 mol% from the current limit of 2.9 mol% from October 2020. The rationale for making this change now is that with the long lead times required for offshore developments early implementation is essential to give the necessary confidence to the field owners that gas can be delivered to the NTS ahead of any key design decisions and consequently to encourage continued investment.

0502 - This modification, in accordance with UNC TPD I 2.2.3(a), proposes an amendment to a Network Entry Provision within the existing NEA in respect of the px Teesside System Entry Point. This amendment would increase the CO₂ limit of gas delivered from the px Teesside System Entry Point into the NTS to 4.0 mol% from the current limit of 2.9 mol% from October 2020. The rationale for making this change now is as per modification 0498.

Relevant Objectives

For both Modifications **0498** and **0502** it is believed that the increase to a higher CO₂ limit will permit economic delivery of additional UK Continental Shelf (UKCS) gas production, increasing GB supply security and reducing reliance on imported gas. This will contribute to the economic and efficient operation of the total system through maintaining a diversified supply base and by continued use of existing capacity.

It will provide greater competition between Shippers and between Suppliers by increasing gas availability in the market and also securing greater supply for consumers.

Implementation costs

No significant implementation costs have been identified with changing the Gas Entry Conditions in respect of BP Teesside System Entry Point or of px Teesside System Entry Point.

Implementation

The Workgroup suggests that the amendments are made at the earliest practical opportunity to increase the CO₂ limit in respect of BP Teesside System Entry Point and of px Teesside System Entry Point effective from 01 October 2020.

Do these modifications impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

These modifications do not affect the UK Link Replacement Programme delivery or any other change.

2 Why Change?

UNC TPD section I2.2.2 (a) (i) provides that certain Network Entry Provisions that apply in respect of a System Entry Point may not be altered without either:

- a) the written consent of all Users that hold NTS Entry Capacity at the relevant Aggregate System Entry Point on a specific date; or
- b) by way of a Code Modification

As has been typical of similar situations in the past, option (b) is proposed due to the practical difficulties of obtaining multiple consents from a potentially large number of Users. These modifications are therefore considered as 'enabling'.

0498 - With the increasing maturity of the UKCS as a gas production area, the accessibility of new fields and improved extractability from existing fields increase in importance to the UK. Some current production relies on blending with other fields in order to meet Gas Entry Conditions, and other potential new upstream developments are known to have CO₂ levels that exceed current limits. By analysing the CO₂ content of future gas production potentially entering the System at Teesside, BP has identified an increasing risk that, especially in summer months and from around 2020 onwards, the availability of sufficient blending gas cannot be guaranteed prior to entry into the NTS.

Under the prospect of reduced blending opportunities there would be an increasing risk of interruption of gas flows, which would affect gas production processes. This problem could be addressed by treating the gas for removal of CO₂ at the wellhead or at the terminal, but the investment to bring the quality in line with current specification would be significant, thus increasing materially the risk of making some upstream projects, currently being evaluated, less economic.

To assess the feasibility of a higher CO₂ content, BP has undertaken an analysis of the potential impacts and has engaged with National Grid NTS to understand whether a higher limit would be compatible with network safety and operational efficiency. The preliminary results of National Grid NTS and BP work have so far identified no material increase in risks in the NTS associated with 4.0 mol% carbon dioxide content. In addition, as there are some legacy arrangements in place granting a similar limit at some NTS Entry Points, it seems plausible that gas with higher CO₂ content could be potentially accommodated without impacting NTS integrity and/or consumers and/or cross border trade. It should also be noted that CO₂ is not a defined parameter in the Gas Safety (Management) Regulations 1996, and no amendment of GSMR is required.

Similar arguments for change have been put forward under [Modification 0502](#).

0502 - The px Delivery Facility receives the same commingled gas from the CATS pipeline as the BP CATS Facility, and therefore any changes to the commingled gas composition that may affect BP's processing ability, would have the same impact upon the px Delivery Facility. If Modification 0498 is approved and the specification in the pipeline changes as predicted by BP, then without this equivalent Modification 0502 to change the carbon dioxide limit at the px Teesside System Entry Point to align with BP, there is a risk that deliveries from the px Teesside System Entry Point will be curtailed when the CATS pipeline specification reaches the current CO₂ limit, resulting in the interruption of gas flows into the NTS. Therefore, this modification seeks, in the same manner as the BP modification, to use the most efficient and economical method of affecting the change through amending the Network Entry Provisions, assuming no adverse impact on the system or users of the system. Energy24 (the registered shipper, on behalf of px Ltd) understands that National Grid NTS has written to its likely affected customers to informally seek views as part of its response to the BP proposal, and it has considered risk to the NTS system. In addition, as a similar limit is in place at other System Entry Points, it seems plausible that gas with higher CO₂ content could be potentially accommodated without impacting the system or consumers. It should also be noted that CO₂ is not a defined parameter in the Gas Safety (Management) Regulations 1996, and no amendment of GS(M)R is required.

Industry engagement was sought, through this combined Workgroup, to assess more thoroughly the impact of the proposed changes under these modifications, in order to establish whether a higher CO₂ limit at the px Teesside System Entry Point, alongside the same higher limit proposed at the BP Teesside System Entry Point, would be beneficial for the GB market.

3 Solution

UNC (TPD Ref I 2.2.3(a)) states the following:

"2.2.3 Where

- (a) the Transporter and the relevant Delivery Facility Operator have agreed (subject to a Code Modification) upon an amendment to any such Network Entry Provisions, such Network Entry Provisions may be amended for the purposes of the Code by way of Code Modification pursuant to the Modification Rules"

Modification 0498

This modification seeks to amend a Network Entry Provision within the existing BP Teesside NEA. This amendment would increase the CO₂ upper limit for gas delivered from the BP Teesside System Entry Point into the NTS to 4.0 mol% from the current limit of 2.9 mol% from 1st October 2020.

Modification 0502

This modification seeks to amend the Network Entry Provision within the existing px (TGPP) Limited NEA. This amendment would increase the CO₂ upper limit for gas delivered from the px Teesside System Entry Point into the NTS to 4.0 mol% from the current limit of 2.9 mol% from 1st October 2020.

User Pays	
Classification of the modification as User Pays, or not, and the justification for such classification.	No User Pays service would be created or amended by implementation of either of these modifications and they are not, therefore, classified as User Pays Modifications.
Identification of Users of the service, the	Not applicable

proposed split of the recovery between Gas Transporters and Users for User Pays costs and the justification for such view.	
Proposed charge(s) for application of User Pays charges to Shippers.	Not applicable
Proposed charge for inclusion in the Agency Charging Statement (ACS) – to be completed upon receipt of a cost estimate from Xoserve.	Not applicable

4 Relevant Objectives

Impact of the modifications on the Relevant Objectives :	
Relevant Objective	Identified impact
a) Efficient and economic operation of the pipe-line system.	0498 and 0502 : Impacted
b) Coordinated, efficient and economic operation of (i) the combined pipe-line system, and/ or (ii) the pipe-line system of one or more other relevant gas transporters.	None
c) Efficient discharge of the licensee's obligations.	None
d) Securing of effective competition: (i) between relevant shippers; (ii) between relevant suppliers; and/or (iii) between DN operators (who have entered into transportation arrangements with other relevant gas transporters) and relevant shippers.	0498 and 0502 : Positive
e) Provision of reasonable economic incentives for relevant suppliers to secure that the domestic customer supply security standards... are satisfied as respects the availability of gas to their domestic customers.	None
f) Promotion of efficiency in the implementation and administration of the Code.	None
g) Compliance with the Regulation and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators.	None

The Workgroup concluded that there were impacts to two Relevant Objectives, a) and d):

a) Efficient and economic operation of the pipe-line system

A more efficient and economic operation of the pipeline system might be possible, due to an extended utilisation of the existing NTS assets at Teesside compared to potential curtailment of feasible supplies entering there. Some participants believed this represented a non-material impact on Relevant Objective a). National Grid NTS believe that, should these proposals be rejected and the gas flowed into the NTS at other

entry points, there is potential that alternative supplies of gas could trigger reinforcement costs elsewhere. Some participants understood that there was currently an amount of baseline capacity headroom and that any effects would be case-dependent; other management options are available to National Grid NTS.

d) Securing of effective competition between shippers

Some participants believe that securing additional indigenous supplies of gas could have a positive impact on competition amongst shippers as a result of the additional availability of gas supplies, and particularly at times of curtailment of flows during summer shutdowns.

Some Panel members believed that these proposals contribute to the overall security of supply position, furthering Relevant Objective d.

NOTE: The workgroup also noted that the modifications were predicated on the development of at least one new field with entry into Teesside. Some participants believed that, if these modifications are approved, any subsequent amendments to the related NEAs should take account of this dependency, such that the extended limit should not apply if a new development did not come on stream as described in the proposals.

Initial Representations

Initial representations were received from SSE, GrowHow and Tata Steel and are published alongside this report and views from Scotia Gas Networks were included in the minutes of 03 July 2014 Workgroup meeting (available [here](#)).

Issues raised in these representations include:

- Our CO₂ emissions increase as the additional CO₂ is emitted from our process in addition to the CO₂ we are generating ourselves (this would presumably take the form of an increased emissions factor on the metered incoming gas), leading to higher costs under EU ETS.
- There would be additional load on our CO₂ removal systems, which are already highly loaded at maximum production rates – so this could become a limit on production rate.
- Calorific value is reduced, so our volume of gas consumed needs to increase, this will increase pressure drop in the distribution pipework (both NG system and customers own distribution system).
- The CO₂ acts a diluent, so where we are trying to achieve high temperatures (e.g. in reformer furnaces) we have more mass to heat, which consumes more energy (minor effect).
- If the added CO₂ displaces a 'high' hydrocarbon the effect on these will be different to the displacement of a 'low' hydrocarbon. A quick calculation suggests that the move from 2.9% to 4%, with a reduction in methane (CH₄), will reduce the CV by about 1% and the Wobbe by 2%.
- Gas turbine combustion dynamics, emissions and operability are impacted by the total level of inerts (principally CO₂ and Nitrogen) contained in the gas. Certain gas turbine Original Equipment Manufacturers (OEMs) stipulate a maximum level of 4% inerts in their fuel gas specifications, operation outside this specification could invalidate the unit's warranty or service agreement. As a result this will prevent operation of the asset and result in lost revenue and less competition in the market for supplying electricity. Where new build is being considered, an increase in CO₂ to 4.0 mol% could restrict the selection of which future gas turbine manufacturer could be used, suppressing market competition.
- Increasing the level of inerts creates the potential for a greater range of gas composition and specification. Varying gas specification within this wider range will lead to a requirement for unpredictable gas turbine re-tuning in order to maintain combustion stability and dynamics within the OEM's specification to avoid warranty and Environment Agency breaches. Currently, re-tuning of gas turbine combustion systems takes around 4 hours, is costly as it requires the services of specialist OEM combustion engineers to retune the combustion system and prevents flexible, load following operation during that period. This lack of flexibility will not only impact on being able to support

intermittent generation and security of supply but lead to loss of revenue, the magnitude of which will be dependent upon when the gas composition changes. In addition changes in Gas Quality could result in gas turbine start up and transfer issues. This represents a real risk to the reliability of future operations especially for stations operating in a cyclic mode with implications for providing support for intermittent generation and hence electricity system security.

- The proposed increase in CO₂ of the gas composition will increase the amount of CO₂ released to the atmosphere and will lead to additional costs for gas turbine operators because they will have to pay for the increase in inherent CO₂ through EU ETS liabilities.

The Workgroup considered these issues as part of their overall assessment.

WORKGROUP ASSESSMENT

The Workgroup identified the issues raised by these modifications and collated them into a number of key themes, as follows:

- **Further Background to the Change**
- **Anticipated Impact on Gas Quality**
- **National Grid NTS' Assessment of their Operational Risks**
- **Impact on Consumers**
- **Impact on Storage Operators**
- **Carbon Cost Assessment**
- **Wider Considerations**
- **Conclusions**

Further Background to the Change

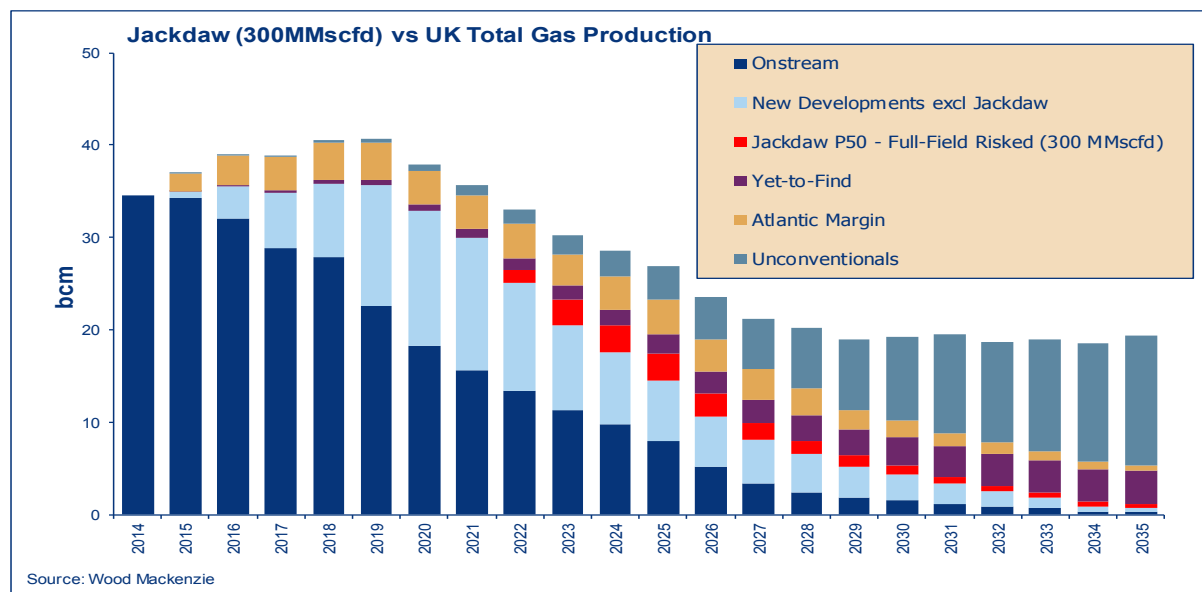
BP and TGPP consider that the current specification for CO₂ at the Teesside entry points is incompatible with the composition of some natural gas from potential upstream developments. At least one future development, Jackdaw, in the Central North Sea area defined by the CATS catchment area would benefit from an increase in the NTS entry specification at Teesside from 2.9 mol% to 4.0 mol%. Studies are currently underway to determine the optimal development plan for this discovery. The Jackdaw discovery was made in 2005 and is one of a number of significant gas discoveries in the area. Operated by BG Group plc (BG), the discovery is located in the ultra-High Pressure High Temperature (uHPHT) province of the Central North Sea. Given the uHPHT nature of the reservoir (with pressures above 1,200 bar and temperature above 200 degrees C), development costs for Jackdaw and other developments of the same type are high (estimated to be in the region of £3bn). In order for such projects to be developed it is essential the project costs are minimised; BG confirmed in October 2014 that the Jackdaw project has been delayed¹ while further studies on development options take place and the impact of additional tax allowances and incentives for uHPHT fields announced in the last Budget are considered. It is anticipated that a final investment decision will take place in 2017. The requirement for CO₂ processing is a key aspect of any decision. As a result, timing of first gas for the Jackdaw development may be expected to be in the early 2020s.

By 2020 DECC forecast UK gas production to be of the order of 30 billion cubic metres with demand at circa 67 billion cubic metres². With reserves of over 16 billion cubic metres and a plateau production rate of circa 2.6 billion cubic metres per year Jackdaw will have the ability to meet about 4% of UK gas demand in the early 2020s, and BG estimates that a development such as Jackdaw will account for up to about 10% of UK domestic production. The impact of Jackdaw on production from the UKCS as a whole is shown in figure 1 below:

¹BG Group 2014 Third Quarter Results (28 Oct 2014) http://files.the-group.net/library/bggroupp/files/transcript_576.pdf

² https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/287001/production_projections.pdf

Figure 1: Projected Jackdaw Production as a proportion of UK overall production



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
% of Total UK Gas Production	4%	9%	10%	11%	11%	9%	7%	6%	5%	4%	3%	3%	3%	2%

Chart courtesy of BG Group plc.

The significant size of the find could help underpin UK energy supply for more than a decade but the high cost associated with uHPHT developments makes developing this and other discoveries challenging. It is essential that the initial capital cost is kept as low as possible. The requirement to remove CO₂ from the Jackdaw gas would add to the development cost which may have an impact on a development decision.

Other UK sub-terminals, such as two (of the three) at St Fergus, currently have a firm 4.0 mol% NTS entry specification whilst the CATS and TGPP Network Entry Agreements (NEAs) have Reasonable Endeavours rights for short duration breaches of the 2.9 mol% CO₂ specification up to a maximum of 4.0 mol%. In practice, this right has never been used as the majority of the time CO₂ levels are managed by blending. While the duration available is not specified the general expectation is that the Reasonable Endeavours right is available to manage short, within-day specification breaches. As such, reliance on a third party Reasonable Endeavours service for managing flows over several days will be sub-optimal for operators of new developments. BG has noted that while a field such as Jackdaw could seek to manage the level of CO₂ in its export gas stream by means of blending with gas from other fields that also flow through the CATS system, this approach makes the field reliant on predicted future flows from other fields. Blending with other fields is clearly dependent on those fields actually flowing gas at any given time and is therefore subject to interruption during shut-downs and trips. Such a service could only be offered by the offshore pipeline operator on a Reasonable Endeavours basis. A key concern for BG is that in order to have an economically viable project that will compete successfully for investment funds there has to be a very high degree of confidence that gas can be exported on any given day. This equates to a requirement for a firm transportation and processing service. The provision of such a service requires either the provision of CO₂ removal equipment to ensure that export gas remains within current specifications which is costly and could further impact the economic viability of such a project, or a relaxation of the CO₂ specification at Teesside to mirror that of some of the other sub-terminals which provides a very high degree of certainty that gas can be exported on any given day at the lowest capital cost.

Increasing the current CO₂ specification at the Teesside entry points to 4.0 mol% would result in more efficient utilisation of existing infrastructure capacity and, by facilitating the development of discoveries such as Jackdaw, extend the useful life of existing assets through material contributions to operating cost, reduce

occurrences of existing gas field production restrictions and contribute significantly to Maximisation of Economic Recovery of oil and gas from the UK continental shelf (MERUK).³

Simplified Technical Explanation of impact of increasing CO₂ on Gas Quality at Teesside

CATS and TGPP adhere strictly to all NEA specifications which includes: Wobbe >48.14 <51.41; ICF <0.48; SI <0.60.

An assessment of the impact of CO₂ content on Calorific Value (CV), Wobbe Index (WI), Soot Index (SI) and Incomplete Combustion Factor (ICF) has been carried out by BP. The assessment is based on daily average flows between 01 January 2013 and 07 July 2014 and correlates CO₂ content of the NTS delivery gas to the parameter noted above. The findings were presented by BP at the Workgroup meeting on 07 August 2014 (<http://www.gasgovernance.co.uk/0498/070814>). The analysis shows that gas delivered into the NTS from the Teesside entry points will remain well within current NTS specification limits for GCV, Wobbe, ICF and SI even at the maximum requested CO₂ limit of 4.0 mol%. Detailed analysis can be found in figures A4.1 to A4.4 in Appendix 4.

Forecast Levels of CO₂ in gas at Teesside

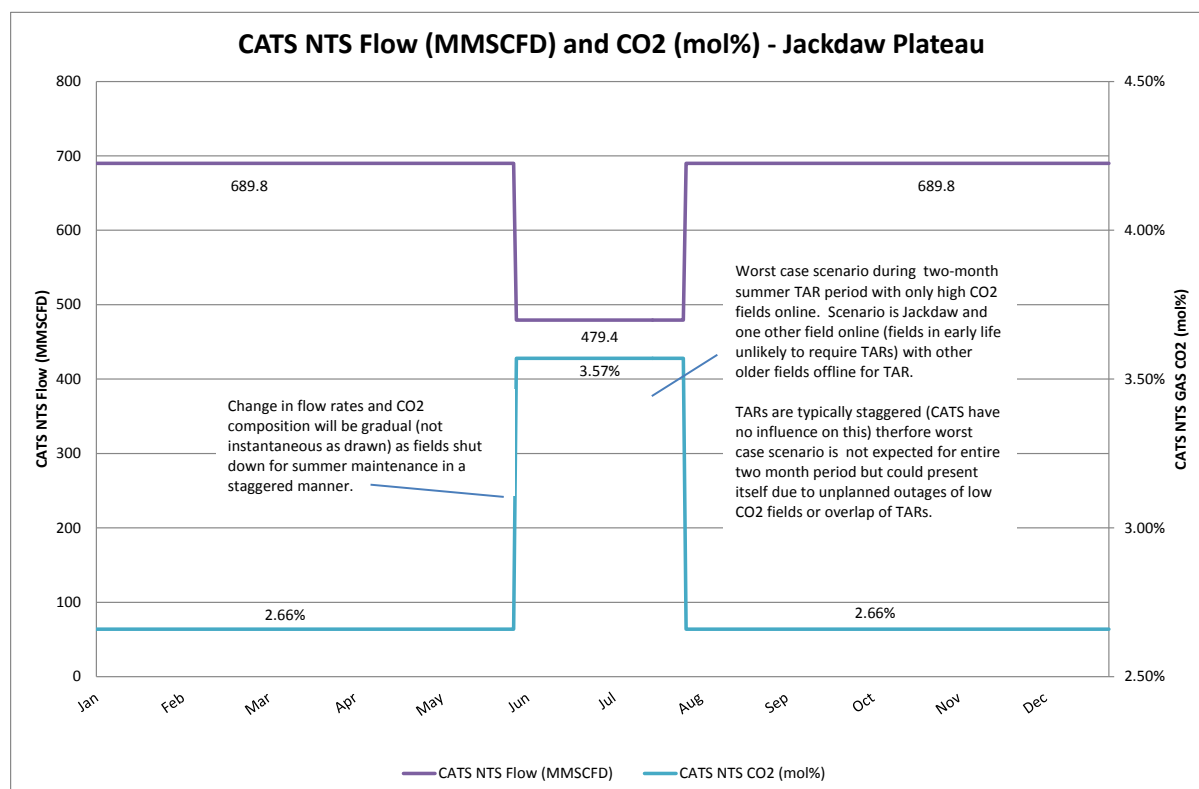
The average CO₂ content of gas entering the NTS at the px Teesside entry point over the last two years has been 2.18 mol%. Currently, there are days when CO₂ content exceeds the current specification limit and post 2019, there is the potential for development of at least one new field, Jackdaw, in the CATS catchment containing elevated levels of CO₂ in the produced gas. Analysis by BP and TGPP of forecast future gas production from offshore fields has shown that for the majority of time, the CO₂ content of gas entering the NTS at the Teesside entry points is likely to be similar to historical norms and well below the current 2.9 mol% specification limit. This is achieved through the blending of gas with high CO₂ content with gas low in CO₂ from other fields feeding into the CATS pipeline and being exported in the pipeline as commingled flow.

Issues may arise however, when fields are shutdown during summer maintenance periods or during unplanned production upsets at offshore fields when flows of gas in the CATS pipeline are reduced and there is insufficient gas low in CO₂ to blend the high CO₂ gas into specification.

With the development of a field such as Jackdaw in the early 2020s, CO₂ levels in CATS/TGPP export gas during the summer months are likely to range between 2.66 mol% and 4.0 mol% with CO₂ levels in non-summer months ranging between 2.66 mol% and 3.57 mol%. A representative example of the gas flow from the CATS plant and the associated CO₂ content of the gas for 2021 is shown in Figure 2 below. This is based on the high CATS pipeline flow rate (all fields producing including Jackdaw) scenario that BP has previously shared with the Workgroup.

³ <http://www.woodreview.co.uk/documents/UKCS%20Maximising%20Recovery%20Review%20FINAL%2072pp%20locked.pdf>

Figure 2: Representative forecast CATS flow and CO₂ mol% for “Plateau year” based on 30 days duration per annum



Note: TAR is turnaround (the annual shutdown)

Anticipated Impact on Gas Quality

Potential European Standard on Gas Quality

There are currently no regulatory CO₂ limits at cross border points. The European Committee for Standardisation (CEN) issued its draft gas quality standard to national standardising bodies in May 2014. British Standards Institute (BSi) conducted GB's consultation, ending on 31 August 2014, following which the CEN Working Group met in November/December 2014 to consider the consultation responses. Agreement could not be reached on a harmonised range for Wobbe-Index but was for all other components including CO₂.

The draft CEN standard (expected to be published before the end of 2015) currently states:

“At network entry points and cross border points the maximum mole fraction of carbon dioxide shall be no more than 2.5%. However, where the gas can be demonstrated to not flow to installations sensitive to higher levels of carbon dioxide, e.g. underground storage systems, a higher limit of up to 4% may be applied.”

The European Commission has stated its aspiration to see the eventual standard implemented by all Member States.

Gas Quality at NTS System Exit Points

Gas quality at a particular NTS Exit Point is dependent on:

- the quality of gas at System Entry Points
- which supply sources flow to the exit point on the network, and
- the degree to which different streams of gas co-mingle within the NTS between the relevant System Entry Points and the exit point in question.

Thus typically the gas quality at System Entry Points such as Teesside would be expected to be an influence on the gas quality at a particular NTS Exit Point, but it would unlikely be the sole influence. Approval of these modification proposals would support a change to the permitted level of Carbon Dioxide entering the NTS at Teesside but they would have only marginal influence on the other two dependencies. The supply sources that reach a particular exit point has complex dependencies on the variable pattern of NTS supply and demand, and these variations may happen on long term, seasonal, daily and within day time horizons.

National Grid NTS' Assessment of its Operational Risks

National Grid NTS has completed an exercise, supported by network analysis, to assess the possible NTS operational risks arising from higher CO₂ levels. National Grid NTS has assessed the risks (which are discussed further below) in terms of:

- **Safety**
- **Operations**
- **Contractual obligations and cross border flows**
- **Pre-engagement with parties downstream of the NTS.**

Safety

There is no prescribed regulatory limit for CO₂ in GB, and parts of the NTS (e.g. two of the St Fergus sub terminals) have had 4.0 mol% legacy contractual CO₂ limits for many years with no known evidence of additional corrosion (as expected from the “dry gas” NTS system), although it is noted that recent flows are well below this level. CO₂ levels in the NTS in Scotland are typically higher than in southern parts of the network, e.g. September 2013 to August 2014 – average from St Fergus ASEP of 2.0% CO₂, compared to average 1.1% CO₂ in Norfolk. See figures A1.1 to A1.4 in Appendix 1 for more information.

Operations

Risk assessment of engineering operations is similar in character to that of safety, i.e. there are no known issues arising from flows near entry points with 4.0 mol% CO₂ limits. Commercially the lower CV expected from higher CO₂ gas has been assessed with CV shrinkage modelling and was shown to be not material by National Grid NTS. Impact on CO₂ emissions from National Grid NTS' gas fired compressors is likely to be small and not material in the context of all the other variables that affect this.

Contractual obligations and cross border flows - considerations

The Workgroup also considered other, existing, relevant contractual obligations, which are noted below for reference only:

- IUK has an entry condition (exit from NTS) of 2.5% CO₂ (driven by Belgian limits⁴) but otherwise there are no CO₂ contractual obligations at NTS offtakes. Network analysis based on the range of scenarios indicated in the 2013 Gas Ten Year Statement (derived from Future Energy Scenarios) shows that gas from Teesside would expect to be little or no proportion of the flow offtaken at Bacton (IUK).
- Offtake of gas at Moffat to Ireland is in a part of the NTS that has had higher legacy CO₂ limits (than for Teesside) for more than a decade. Again Teesside gas would not typically be expected to be a substantial part of the flow at Moffat.

4

Pre-engagement with parties downstream of the NTS

Prior to these modification proposals being published National Grid NTS wrote out inviting comments from potentially impacted parties. National Grid NTS received 9 responses provided on a private basis and all⁵ substantive points have since been discussed in the Workgroup. National Grid NTS's network analysis also enabled publication via this Workgroup of maps (high demand and low demand) showing where Teesside gas is modelled to make up a proportion of 25% or more of the flow at NTS offtakes. Please see figure A2.1 in Appendix 2.

During the course of the development phase National Grid NTS has written out again encouraging potentially impacted parties to bring their views to this Workgroup.

Impact on consumers

Combined Cycle Gas Turbines (CCGTs)

CCGTs can only tolerate limited changes in gas composition (referenced as WI and/or Heating Value), dependent on the Original Equipment Manufacturer (OEM) and control systems. Each CCGT must be tuned to operate in a particular narrow band of gas composition to maximise efficiency and remain within environmental emissions limits.

The proposed increase to the level of inerts creates the potential for a greater range of gas composition. Within this wider range, the potential then exists for larger fuel composition variation. This can have a negative impact on CCGT operation despite the gas being within that range allowed by the Gas Safety (Management) Regulations (GSMR) and OEM specifications. Varying gas specification within this wider range will lead to a requirement for unpredictable gas turbine re-tuning in order to maintain combustion stability and dynamics to avoid Environment Agency breaches. If this is not possible the plant will trip to be protected from further damage, although the trip event is undesirable due to asset life reduction, loss of revenue, cash out and penalty regimes:

- The asset life will be reduced as a trip counts towards operating hours. A set number of operating hours are allowed before requiring major maintenance outages.
- In addition, the thermal shock of a forced outage trip, stresses metals and degrades performance, shortening asset life.
- The loss of revenue arising from a trip comes from the loss of generation of electricity.
- The electricity cashout penalty derives from the portfolio now being short following a trip on its nominated position.
- The penalty regime refers to the electricity Capacity Market Payments that will need to be repaid if plant is not available to generate when required.

The sensitivity of CCGTs to gas quality is more fully described in the document shared with the Workgroup in September 2014. The paper summarises the issue as follows:

Modern low emissions gas turbines are sensitive to variations in natural gas composition. As variations have typically been relatively small and slow this has not historically caused major problems. Throughout Europe, the increasing dependence on natural gas imports is leading to increased gas composition variation within the distribution system. Due to the increasing diversification of natural gas supply, variations in gas quality have the potential to be very rapid, e.g. a rate of change in Wobbe Index of 1%/minute has caused issues at one E.ON site. It is anticipated that fuel variability will be an increasing issue in the future.

⁵ At as 12th January 2015, a DN is considering whether or not a point is substantive and relevant.

Evaluation of operating data for a range of gas turbines within E.ON's UK gas turbine fleet has shown clear trends in pollutant emissions and combustion dynamics with changing fuel composition. These changes can result in forced reductions in power output. Rapid changes in composition have also resulted in emergency shutdowns due to control issues, which have an adverse impact on revenues and component life.

This paper presents real examples of the above findings for a range of gas turbines from most major manufacturers. It also discusses how these findings may inform our understanding of the risks associated with increased fuel composition variation. It concludes:

Manufacturers are increasing the fuel flexibility of new GTs and developing retrofit solutions to mitigate the risks associated with fuel composition variation. Operators need to be aware of these developments to ensure that the risks from future fuel variations are properly considered.

The examples described show that operators also need to be aware of these issues to ensure existing turbines are appropriately tuned.

It is clear from the examples that fuel composition variation can impact on GT operation despite being within that allowed in the National Transmission System and manufacturers' specifications. Such examples are becoming more common as the variability in gas composition has increased and are likely to become more significant as fuel imports and international gas trading increase and specifications widen. The examples in this paper are predominantly from E.ON's UK gas turbine fleet but these issues are becoming more common throughout E.ON's European fleet.

Mitigation measures exist to protect GTs against fuel quality variations. However, some of these measures have been developed in recent years and are not yet widespread. More experience with these techniques is required to fully assess their effectiveness at mitigating the increasing variability of gas quality around Europe. The mitigation measures that have been developed may not be sufficient to deal with gas containing significant levels of hydrogen.

H₂ injection into natural gas grids for energy storage purposes may have significant benefits, but this will provide some challenges for the power generation fleet. The impact on individual gas turbines will need to be assessed and appropriate mitigation measures taken.

Although Wobbe Index is an important and useful parameter it does not fully characterise the fuel. This deficiency will be even greater if significant amounts of hydrogen are introduced into natural gas supplies. Reliable parameters to describe the combustion behaviour of natural gas (including the effects of added hydrogen) need to be developed to allow more robust and reliable fuel specifications to be established.

It should be noted that references to Hydrogen in this paper are not relevant for these modification proposals. The full paper can be found here:

[http://www.gasgovernance.co.uk/sites/default/files/Impact of Natural Gas Composition - Paper_0.pdf](http://www.gasgovernance.co.uk/sites/default/files/Impact%20of%20Natural%20Gas%20Composition%20-%20Paper%200.pdf).

Currently, re-tuning of gas turbine combustion systems takes around 4 hours, it is costly as it requires the services of specialist OEM combustion engineers to retune the combustion system and prevents flexible, load following operation during that period. This lack of flexibility will not only impact on being able to support intermittent generation and subsequent security of supply but lead to loss of revenue, the magnitude of which will be dependent upon when the gas composition changes.

Estimated costs for fitting auto-tune capability to existing CCGTs to compensate for fuel quality changes.

To fit this technology an upgrade of the GT compressor is required.

Cost of compressor upgrade is £450k per GT

Cost of auto-tune technology is £302k for the first GT then £230k for subsequent GTs

Total for site with 2 GTs £1.662m.

Linking CCGT Trips to Changes in Gas Quality

A limited number of examples have been provided of times when plant has tripped (see figure A3.1 in Appendix 3).

Workgroup participants considered the material and observed that only 3 plant trips (in the sample of 9 dates in 2011/12) could be observed to have happened after a change in gas quality at the associated NTS Offtake.

It was felt that there was insufficient evidence to draw a firm conclusion, either to a direct linkage between gas quality variation and plant trips or for the wider propagation of such trips.

Effect of Increased Carbon Emissions

The proposed increase in CO₂ of the gas composition will increase the amount of CO₂ released to the atmosphere and will lead to additional costs for gas turbine operators because they will have to pay for the increase in inherent CO₂ through EU ETS liabilities.⁶ An estimate of this is included in the Carbon Cost Assessment.

Technical Complexity

The significance of WI is that for given fuel supply and combustor conditions (temperature and pressure) and given control valve positions, two gases with different compositions, but the same WI, will give the same energy input to the combustion system. Thus the greater the change in WI the greater the degree of flexibility in the control and combustion systems needed to achieve the design heat input. In addition to the WI, manufacturers also often specify limits on the Heating Value and other bulk properties of the fuel. GT manufacturers typically specify that their turbines are capable of operating over a range of WI and Heating Value. For some GTs a range as low as $\pm 2\%$ of the WI has been specified. The detailed composition also affects combustion performance including flame stability, emissions, flashback, and ignition properties. Manufacturers' specifications account for such compositional changes in different ways, but typically specify maximum levels of higher hydrocarbons (ethane, propane, butane etc), minimum methane and/or maximum inerts. These specifications aim to ensure that the fuel gas is predominantly methane, and that gases which contain both high levels of inerts and higher hydrocarbons, but are still within WI limits, are not allowed.

Flame Stability

To ensure flame stability, fuel injection is widely distributed and an air/fuel mixing zone is provided to ensure even mixing of the fuel and air. High quality mixing is essential to ensure an even temperature within the flame which leads to low NOX emissions when operating under lean conditions. Variable fuel composition and WI can affect the combustion and flame dynamics. The swirling flow tends to enhance mixing and generate the correct aerodynamic conditions for flame stabilisation in the combustor. The design must generate acceptable combustion performance by ensuring:

1. The flame stabilises at the burner exit at the upstream end of the combustor without propagating upstream into the mixing zone (flashback) or lifting from the burner and blowing-out.
2. Excessive combustion dynamics are not produced.
3. Flame temperature and temperature distribution do not deviate significantly from design values (to prevent component overheating or excessive thermal stresses).
4. Low levels of pollutant emissions.

⁶ http://ec.europa.eu/clima/policies/ets/monitoring/docs/gd1_guidance_installations_en.pdf (p80/81)

Combustion dynamics (acoustic pressure fluctuations within the combustor) can occur in any combustion device, but lean premix GT combustors are particularly susceptible. Combustion dynamics occur due to the coupling of acoustic pressure oscillations in the combustion system with the energy release within the flame. These oscillations can reach high amplitudes and induce vibration in the combustor components. This leads to increased wear, reduced component life or in extreme cases catastrophic component failure. Instances of component failure can occur particularly when the characteristic combustion dynamics frequency couples with the structural response of the system. The fuel composition together with the air fuel ratio, flow properties (e.g. flow speed, turbulence etc), fuel placement and mixing quality all have a significant influence on flame behaviour (flashback, blow-out, dynamics and emissions). The details of how these effects influence combustion performance depend on the details of the combustion system design and this is why different GT manufacturers have different fuel specifications and use a range of parameters to specify acceptable fuel quality.

Direct Costs for CCGT Trips/Retuning

Energy UK, on behalf of their member organisations who operate CCGTs, have indicated the following costs:

Re-tuning £22k

Trips £140k to £180k

Note: these are approximations based upon real examples, but are sensitive to gas prices, spark spread and electricity cashout costs.

Warranty Impacts

The Workgroup considered the potential CCGT warranty impacts as highlighted by SSE's initial representation. SSE provided the following extract from a technical report provided by their equipment supplier and confirmed that there were no residual concerns with respect to warranties:

The 'standard' fuel specification of this turbine supplier as part of the offer is relatively limiting when compared to other manufacturer specifications. In particular, an upper limit of 98% methane content (as a percentage of combustibles) and a 'preferred' maximum limit of 4.0 mol% inerts (nitrogen and CO₂) results in a large section of the UK GS(M)R specification being unacceptable.

However, written assurances have been given that the gas turbine combustion system can operate over a wider range of gases than stated in their standard specification.

There are two areas of the GS(M)R specification that would be expected to cause combustion issues with the combustion system. These areas include very lean gases (low higher1 hydrocarbon and high inerts content) and very rich gases (high higher hydrocarbon content). From gas property calculations and prior experience of typical gases on the UK gas network it is considered highly unlikely that these types of gases would be received.

The GT is therefore considered to be low risk in terms of combustion behaviour with regards to gas quality variations. However, it should always be noted that premixed combustion as employed for all large GTs, irrespective of manufacturer, will always have the risk of combustion instabilities.

Electricity Capacity Market

The electricity capacity market aims to bring forward new investment while maximising current generation capabilities. Generators who are successful in the auction will benefit from a steady, predictable revenue stream (capacity payments) that encourages them to invest in new generation or to keep existing generation available. In the event of a stress event on the electricity market, generators who hold a capacity obligation and that do not provide energy will incur a penalty. For the first delivery year, 2018/19, capacity awarded to

CCGTs constitutes 45% of the total awarded capacity. Any risks associated with changes to the gas composition and/or to the variability of CO₂ flows into CCGTs may not have been considered within the context of the electricity capacity market. For further information please see this National Grid Electricity Transmission report:

<https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf>

Downstream Consumers – impact on CO₂ Removal Systems

The Workgroup considered the initial representation provided by GrowHow Ltd and sought to quantify the issue. GrowHow confirmed:

- Its primary use of gas is as feedstock. The feedstock is converted to hydrogen and CO₂ by steam reforming and the water gas shift reaction. The CO₂ formed from feedstock is then captured by absorption in circulating solution and released when the solution is heated and lowered in pressure
- Its current CO₂ emissions were approximately 950,000 tonnes in a normal year.
- If the CO₂ content of the incoming gas increases from 2.0 mol% to 4.0 mol% all year round, then it estimates an increase in CO₂ emissions of 13,000 tonnes.
- This represents a direct additional EU ETS cost, which would obviously be dependent on the carbon price.

Workgroup participants noted that GrowHow had calculated its increase in carbon emissions based on an enduring increase in CO₂ to 4.0 mol%. Using the assumption of 30 days of >2.9 mol% of CO₂ (see 'Carbon Cost' section below) flows at Teesside, increased emissions at GrowHow would be c. 588 tonnes per year or 0.06%.

With respect to its CO₂ removal system:

Its CO₂ removal system captures approximately 2/3 of the total CO₂ emission figure (the remainder is combustion CO₂). This system does run heavily loaded when running at maximum production rate. At times this could restrict production*, by up to 2.0 mol% for an increase in CO₂ content from 2.0 mol % to 4.0 mol %. On average the reduction in production from this cause would probably be around 1%. The cost of expanding the CO₂ removal capacity to address this rate restriction would be much greater than the production loss would justify.

However, GrowHow has a greater concern that the additional CO₂ would increase the required flowrate and hence pressure drop through the plant. This is because CO₂ acts as an inert in the feed-gas. The process requires a fixed amount of hydrogen for any given production rate. Any additional CO₂ is a direct additional flowrate through the process from the gas supply pipe to the CO₂ removal section. As the plant runs to a pressure limit, they estimate that an increase in CO₂ content from 2.0 mol % to 4.0 mol % would result in the requirement to reduce production rate by approximately 2.8%.

Increase in CO₂ content in the feedgas from 2.0 mol % to 4.0 mol % would require an increase of 2.1% in feed gas flowrate.

This could cost GrowHow in excess of £1m p.a. in lost production.

Again, Workgroup participants considered this forecast using the assumption of 30 days of higher-level CO₂, believing the production impact to be closer to £45k per year.

* The primary restriction on this system is the CO₂ absorption capacity. CO₂ can start to slip through the absorber if too heavily loaded. The load is determined by throughput primarily and gas composition. Additional CO₂ in the feedstock directly adds to the amount of CO₂ that needs to be removed by absorption.

Impact on Storage Operators

The principal concern for Gas Storage Operators Group (GSOG) members relates to increases in the absolute levels of CO₂ in gas on the NTS, rather than speed of gas quality change, because of the increased risk of corrosion from higher CO₂ gas. This risk arises because higher CO₂ results in higher carbonic acid levels in the aqueous condensate. Increased carbonic acid increases the rate of corrosion in the underground pipework.

Should the changes at Teesside result in higher levels of CO₂, particularly for extended periods during the summer when storage sites are often injecting gas from the NTS, storage operators will need to increase corrosion monitoring and mitigation activities. The level of CO₂ will depend to some degree on the particular site, however GSOG members have noted that sustained levels of gas with greater than 1.7 mol% CO₂ will require them to reassess their carbonic acid monitoring and treatment programme. Others have noted that the 2.5 mol% level could create significant challenges for storage systems.

GSOG members have estimated that increased corrosion inspections and treatment cost could add a significant amount to the operating costs of affected storage facilities. By way of example, an increase in CO₂ levels by around 1 to 1.5mol% could add in the order of £225,000 per annum in operating costs. The exact cost will vary by facility, and will also depend on the volume of higher CO₂ that is ultimately injected into the facility. The higher the volume and CO₂ content, the greater the need for corrosion monitoring and mitigation activities.

GSOG members consider that the estimated costs of the £225,000 per annum is potentially conservative, and that Gas Storage System Operators (SSOs) may face additional costs even if average CO₂ levels are below the 1 to 1.5% specified. The effects of CO₂ levels and the need for monitoring the implications of the potential changes in gas quality may arise even if the actual number of high CO₂ days from Teesside is low. The implications cannot be fully assessed without Front End Engineering Design (FEED) studies at those storage sites likely to receive gas from Teesside. GSOG considers that the party seeking to land the high CO₂ spec gas should fund such studies, as they are the only party benefitting from the proposed change.

GSOG does not see the relevance of expressing this cost as a proportion of operation expenditure. The fact is that these are additional, material costs that SSOs may incur should the UNC modification be approved. Further, GSOG members do not expect any offsetting benefits (i.e. higher revenues due to an increase in spreads or volatility).

In addition to the risk associated with carbonic acid, increasing the CO₂ of gas also results in higher costs for storage operators because it means that higher volumes of gas needs to be injected into storage facilities in order to inject the same calorific value of the gas. This means that the storage operators will need to use more energy to get gas into and out of store. The increased use of fuel to move the gas will require more EU ETS permits.

GSOG notes that there are a number of storage facilities in the catchment area of Teesside gas. However, it is difficult for storage operators to provide an estimate of the likelihood that they will incur significant additional cost associated with Teesside gas given the information provided to the working group. As discussed at the working group, GSOG members are concerned that any such amendment to the CO₂ limit at Teesside may set a precedent for other system entry points on the network to seek higher CO₂ limits which could increase the likelihood of Storage Operators incurring additional corrosion-related costs.

Workgroup participants considered the views presented by GSOG, with some participants considering that the impacts have not been fully evidenced, that the FEED study (and its funding) is a question for future Consultation responses.

Carbon Cost Assessment

Options for addressing elevated levels of CO₂ in gas at Teesside

The options for addressing the possible increases in CO₂ levels in export gas are to either allow such gas to flow directly into the NTS up to an agreed level (4.0 mol%) or to remove the excess CO₂ above the current allowable specification using CO₂ removal technology. The CO₂ emissions and associated cost of such emissions are estimated in the Carbon Cost Assessment (see below).

If the CO₂ entry specification was not increased on Teesside then current excursions in CO₂ concentration in NTS export gas would be dealt with under the current specifications within the TGPP and CATS NEAs. This may lead to continued occasional short-term shut-in of certain fields as previously noted by the CATS Owner as the cost of providing CO₂ removal would not be cost effective. For new developments such as Jackdaw, the development owners would need to take a view on whether the provision of CO₂ removal technology is a cost effective solution. Other options could be to continue the field development accepting that flows could be restricted under certain circumstances or indeed not to develop the discovery at all. In terms of the former, while the decision will ultimately lie with the asset owners, it is TGPP's experience that having to commit substantial (>£3Bn) amounts of capital for a development on the scale of say, Jackdaw, the owners will require a high level of certainty that gas will flow to market in order to secure the projected cash flows. The potential for flow restrictions could lead to capital being deployed elsewhere on projects with a higher level of certainty of deliverability. This is unlikely to be in the UK. Not developing a discovery will have broader impacts on the UK economy in terms of reduction in security of supply (by importing additional gas to replace that which could have been produced domestically), balance of payments, taxation revenues from the field production and ultimately Maximum Economic Recovery of UK oil and gas (MERUK) as laid out in the Wood Report (<http://www.woodreview.co.uk/>).

See also Appendix 6 for the underlying detail.

Options for addressing increases in CO₂ Levels as detailed in the Carbon Cost Assessment

Option 1 - Flow gas up to 4.0 mol% CO₂ into the NTS

As noted above, flowing gas in excess of the current specification of 2.9 mol% is not expected to be for extended periods of time as it is anticipated that under normal operating conditions gas from any fields with gas of high CO₂ content would be blended in the offshore pipeline to ensure current delivery specifications are met. High CO₂ gas could result from maintenance of offshore fields during summer months or unplanned field operational outages when flows of gas into the CATS pipeline could be reduced and the capacity to blend high CO₂ gas reduced. The advantages to the upstream producers and the gas terminal operators is the removal of the need for significant capital expenditure and increased operating cost from the installation of CO₂ removal equipment which may be used for only a few days/weeks per year. This option would also prevent significant additional CO₂ being released to atmosphere from the use of process heat associated with the CO₂ removal technology.

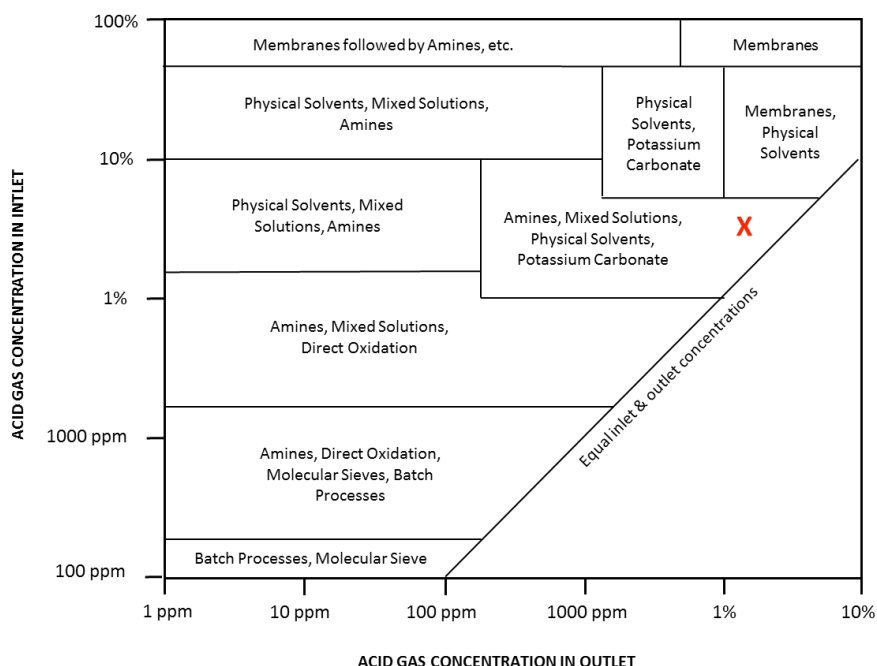
Removal of CO₂ above 2.9 mol% at the upstream platform or onshore at the terminals

Blend gas cannot be provided for the periods when concentrations of CO₂ exceed the current specification, as these periods will coincide with limited low CO₂ gas flowing in the CATS Pipeline. Storage of gas for blending during these periods cannot be provided for both technical and commercial reasons. The Proposers believe that the provision of physical storage is impractical due to the volume required, space constraints and cost, while the commercial provision of such gas would effectively require the creation of a small-scale gas storage business upstream of the terminal.

The most practical solution alternative to Option 1 outlined above is to remove the additional CO₂ in the gas before entry into the NTS at the Teesside entry points. This could be accomplished either offshore at the field or onshore at the terminal reception facilities at the landfall of the CATS Pipeline on Teesside.

In the technical study work for CO₂ removal at CATS, all feasible technologies were examined. In general CO₂ removal (and H₂S removal) technologies rely on either solution reaction (amine or other physical solvents) or pressure drop (membrane or molecular sieve technology). Technologies become optimal in different circumstances relating to the concentration (partial pressure) of CO₂ in the inlet stream against that required in the outlet stream (see figure 3). The red X shows the approximate concentrations of the CATS gas scenario under consideration.

Figure 3: Inlet/outlet relationships: CATS Gas concentration



Molecular sieve technology is typically used for removing trace contaminants from gas streams and very low outlet concentrations can be achieved. The loading of CO₂ on molecular sieve is relatively low, and the high feed gas CO₂ content in this case, will result in a physically large system with high regeneration requirements and correspondingly high capital and operating costs when compared to alternative technologies.

CO₂ can also be separated from natural gas using semi-permeable membranes. Membrane processes are best suited to “bulk removal”, typically from high levels of 10 mol% or higher, rather than removal at relatively low levels. Given the forecast levels of concentration there would be additional complexities relating to hydrocarbon losses and relatively “rich” dense phase gas as found in the CATS pipeline could cause fouling of the membrane.

The Proposers do not believe that either of the above processes would be suitable for the duty envisaged nor is any cost saving anticipated.

Physical solvents use chemicals other than amine but the adsorption process is similar. Most physical solvent processes have been applied in bulk removal applications from relatively high levels but their CO₂ loading capacity is low and for this duty we would expect that circulation rates could be up to three times that required by amine processes. This increases relative equipment sizes. Other technologies such as hot Potassium Carbonates or caustic washes are not considered suitable.

Hot Potassium Carbonates tend to require a large amount of feed heating and some processes use arsenic based additives, which are considered a safety hazard. Caustic solutions combine with CO₂ to form a non-re-

generable product which has to be discarded. This leads to high caustic consumption and disposal issues for the spent solution.

Given the likely concentration of CO₂ in the inlet gas a solution reaction technology is the optimal technology for CO₂ extraction and as noted, amine plants are tried and tested in the upstream industry. However, a Formulated Amine Process using proprietary amine technology that allows higher solvent concentrations and CO₂ loadings than commodity amines provide an optimisation of this technology. This provides lower circulation rates and more effective/smaller equipment and lower operating cost. In addition there is often an advantage of reduced corrosion rates compared to commodity amines.

The Formulated Amine Process consists of an absorber column and regeneration unit. A proprietary amine solution (formulated to optimise CO₂ removal) flows against the gas stream in an absorber column. CO₂ is absorbed producing a sweetened gas stream and CO₂ rich amine solution. Rich amine is routed to the regeneration unit where it is flashed to low pressure and heated producing a CO₂ stream for venting and lean solvent routed back to the absorber. Electrical power is required to drive pumps and control systems, whilst significant heat input is required to regenerate the amine and also to regenerate the TEG/MEG used to dehydrate the gas after passing through the amine unit. Heat is usually supplied by a hot oil system heated by natural gas - this generates further CO₂ emissions in addition to the CO₂ extracted from the natural gas. The process also releases a stream of Volatile Organic Compounds (VOC) such as benzene. These cannot be sent to atmosphere so further heat is required to ensure that any VOCs in the vented CO₂ stream are burnt before entering the atmosphere.

Option 2 – Installation of an amine unit on the offshore facility

In order to ensure that discoveries such as Jackdaw can be economically developed, it is essential that capital and operating costs be minimised. The fully installed cost of an offshore amine unit is likely to be in the order of £180m (£107m when discounted at a 10% discount rate as per the CO₂ Impact Assessment - see Appendix 6), which would be borne by the field owners while the additional equipment would increase the annual operating cost of the facilities (power, maintenance, etc). This cost could be higher if the production platform is required to be increased in size/weight to accommodate an amine unit.

The provision of an amine unit on a facility such as Jackdaw would allow the export of gas into the CATS pipeline that meets the CATS pipeline gas delivery specification for CO₂ at less than 2.9 mol%. As a result, it is likely that the CO₂ content of gas exported into the NTS from the Px Teesside and CATS entry points would remain unchanged from the current ranges observed.

It is possible that the requirement to provide an amine unit for removal of CO₂ on a facility such as Jackdaw could make the development project sub-economic for the field owners and development could be either delayed or postponed.

Option 3 – Installation of amine unit(s) onshore at the TGPP and CATS Facilities

If CO₂ removal facilities were not installed offshore, then in order to ensure that CO₂ levels remain within the NTS entry specifications it would be necessary to install an amine unit or units at the terminals. CO₂ removal facilities would need to be installed at the lower pressure (circa 65 bar) exit points of the terminals as the pipeline and terminal entry points operate at high pressure (circa 105 bar). The cost of installation of an amine unit at a Teesside processing facility is c. £200m (£122m when discounted at a 10% discount rate (see above)). The additional cost over an offshore unit is due to the requirement to process larger volumes of gas from the commingled pipeline stream. As with the offshore unit, the operating costs of the terminal facilities would increase through additional maintenance, the cost of which would be passed through to the user of the equipment.

It is anticipated that the amine unit (or units) would only be operated during those periods when the CO₂ content of the gas exported from the terminals exceeded 2.9 mol%. At present TGPP are discussing the operating parameters of amine units with the vendors to investigate if year round operation would be required or whether a unit could be put into “standby” when not in use. It is the view of the TGPP and CATS terminal operators that in general equipment subject to heat are more reliable when the heat is constant. Continued heating and cooling (as would be required if an amine unit were maintained on standby) tends to cause rapid degradation of equipment due continued thermal expansion and contraction leading to unreliability. This would be unacceptable for an amine unit as export gas would have to be curtailed if CO₂ spec could not be met. Continuous operation would add significantly to the CO₂ footprint due to the heat required. Having said that, we have considered a case where the amine unit could be put onto “standby” when not required. This would require storing the amine in a tank at about 20°C. This allows process emissions resulting from operation of the unit(s) to be reduced but the requirement to maintain the amine tank at about 20°C when the fluid is not in use, which BP and TGPP estimate requires about 3.6MW of process heat.

See figure A5.1 in Appendix 5 for a schematic of the likely layout.

Alternative options for powering onshore amine unit

Following discussion in the Workgroup, a number of options to provide power for the amine units have been assessed to establish whether there are any viable alternative sources of power generation other than fuel gas which could lower the CO₂ emissions of the onshore CO₂ removal option. However, all the alternative power options considered either introduce undesirable levels of additional complexity at the CATS reception facilities or are simply not feasible as an alternative power solution. Other options such as wind turbine or ground source or water sourced heat were not considered. Self-generation wind turbine cannot be achieved due to safety concerns related to the gas processing plants being top tier COMAH⁷ sites while ground source or water sourced heat are unlikely to be able to provide sufficient power on demand. The options considered and the issues attached to these are summarised in the figure 4.

Figure 4: Alternative options for powering an onshore amine unit

Hot Oil:	Existing hot oil heaters are at capacity. CO ₂ removal study indicated that a separate hot oil heater / system would be required for the amine unit. Hot oil is the option considered in the CO ₂ impact assessment (appendix 6)
	Any hot oil duty will be generated by burning fuel gas as this results in better thermal efficiency (>80%) than heating hot oil with electricity supplied from grid (<50%).
	Hot oil could provide heat in both duty and standby mode.
Electric Heater:	Standby mode: 3.5 MW duty for standby is considered to be a high duty for an electric heater application. The extra electrical load required would be supplied from the grid and would result in a lower thermal efficiency than heating with hot oil.
	Duty mode: The 14 MW required whilst on load is too high a duty for an electrical heater.
	CO ₂ emissions at source generation need to be considered in overall CO ₂ emissions. Higher overall CO ₂ emissions are anticipated if electric heating used vs hot oil.
Steam:	There is currently no steam on the CATS site and no waste heat at high enough temperatures to generate steam.
	Any steam generation would require a boiler to be installed, with steam generated from fuel gas.
	There is no desire to introduce steam generation to the CATS site due to the extra water treatment utilities required and increased complexity.
Direct Fired Heater:	Not feasible / recommended at amine temperatures required.
Low Level Heat:	Upto 1.4 MW low level heat available at high throughput – insufficient for standby duty alone. Heat available decreases with decreased plant throughput.
	Would require installation of new heat exchangers at increased capital cost to hot oil option (14MW hot oil heater still required for duty operation)
	Electric heater or increased hot oil duty required for deficit (with associated CO ₂ generation)

⁷ Control of Major Accidents and Hazards

Tabulation of Advantages/Disadvantages for CO₂ options

CO ₂ Option	Cost (£M)	Advantages	Disadvantages
<u>Option 1</u> Flow gas at up to 4.0 mol% CO ₂ into NTS	No equipment cost	Producers <ul style="list-style-type: none"> Lowest cost option for high pressure/high temperature fields with high development costs High CO₂ gas blended with other CATS gas for most of year Flow of high CO₂ gas for limited periods (Field maintenance, unplanned outages) Lower CO₂ emissions overall – no CO₂ released from process heat required for CO₂ removal No VOCs combusted Gas Consumers: <ul style="list-style-type: none"> Development of domestic gas sources gives improved security of supply compared to gas imports/LNG 	Gas Consumers: <ul style="list-style-type: none"> Higher CO₂ content gas enters NTS on some days (modelled as a max of 30 days) EU ETS Consumers: <ul style="list-style-type: none"> Potential for elevated emissions charges for consumers of gas from Teesside entry points that has not been fully diluted in NTS but limited impact on sites calculating annual CO₂ emissions from regional emissions factors or site specific calculated emissions factors rather than direct measurement of CO₂ emissions
<u>Option 2</u> CO ₂ Removal Offshore at source	c. £180M (£107M as a discounted Net Present Value at 10%) (NPV10)	Gas Consumers <ul style="list-style-type: none"> Removes additional CO₂ from specific high CO₂ gas before entering CATS Pipeline Allows CATS pipeline gas to remain within current specification CO₂ content of NTS gas remains within current specification Emission levels remain within current ranges 	Producers <ul style="list-style-type: none"> Additional capex cost to specific project and increases in annual operating costs may make specific project sub-economic at assumed commodity prices Specific project may be delayed or not developed Amine unit operational year round Additional CO₂ emissions from the use of process heat in addition to that removed from the gas Additional VOCs combusted during venting of CO₂ extracted from gas Increased emissions charges Ultimate recovery of oil and gas from UKCS is impacted Gas Consumers: <ul style="list-style-type: none"> Reduced security of supply if domestic project not developed and gas replaced by imports/LNG
<u>Option 3</u> CO ₂ Removal Onshore at CATS Pipeline Reception Facilities	Up to £200M (£122M as a discounted Net Present Value at 10%) (NPV10)	Gas Consumers <ul style="list-style-type: none"> High CO₂ content gas can be blended with low CO₂ content gas in the CATS pipeline for most of the year Most of year CO₂ content of NTS gas remains within current specification without specific action CO₂ removal equipment provides backstop if current CO₂ specification is exceeded Emission levels remain within current ranges 	Producers/Terminal Operators <ul style="list-style-type: none"> Additional capex cost to specific project and increases in annual operating costs may make specific project sub-economic at assumed commodity prices Specific project delayed or not developed. Costly equipment only required for short durations when blend gas unavailable Additional CO₂ released through process heat when operational and requirement to ensure amine maintained at 20°C when not in use May be required to operate continually to ensure continued reliability Increased emissions charges Ultimate recovery of oil and gas from UKCS is impacted Gas Consumers: <ul style="list-style-type: none"> Reduced security of supply if domestic project not developed and gas replaced by imports/LNG

Carbon Cost

A carbon cost assessment has been completed. The impact assessment compares the tonnage of CO₂ released in order for the forecast gas landed at Teesside to meet the current 2.9 mol% CO₂ NTS entry specification and the cost of this CO₂ mitigation to the tonnages that would be released by downstream consumers if the Teesside NTS entry specification were to be raised to 4 mol% and such gas were not diluted by other NTS flows.

A carbon cost assessment has been calculated for each of the CO₂ options:

- Scenario 1 – Non-removal of CO₂;
- Scenario 2 – Removal Offshore; and,
- Scenario 3 – Removal Onshore.

The detailed carbon cost assessment and assumptions are included in Appendix 6. All financial values are calendar year and on a pre-tax basis. The annual operating costs of onshore and offshore amine units have not been fully evaluated and therefore have not been included in the model. Were such costs to be considered, this would of course increase the cost of any CO₂ removal.

Whilst it is recognised that currently there are certain circumstances when the CATS operator has curtailed or suspended flows from certain existing fields, these occurrences are difficult to model. In order to simplify the model the carbon impact assessment has been made for the period 2021 to 2030, 2021 being the earliest a field with elevated CO₂ levels such as Jackdaw might be anticipated to start.

For Scenarios 1 and 3, it is recognised (as noted above) that for the majority of time the CO₂ levels are likely to be below the current CO₂ limit with CO₂ content above 2.9 mol% being possible during summer maintenance campaigns or for short periods of unplanned outages when gas with high CO₂ content cannot be blended in the CATS pipeline with gas with low CO₂ content. For the purposes of modelling the CO₂ impact assessment, the proposers have assumed that only Jackdaw would flow (using a representative flow profile) and that this period would be 30 days per year. As a result, for this period the CO₂ content of CATS gas has been assumed to be a maximum of 4.0 mol%. In reality this would be expected to be a worst case scenario. It is unlikely that Jackdaw would flow entirely on its own so some blending is likely to occur and therefore there is likely to be fewer days per year when CO₂ content is at the maximum assumed 4 mol%.

Estimated Incremental CO₂ Emissions above Current Specification 2021-2032

Figure 5 below displays a summary of the total estimated overall CO₂ emitted under the three modelled scenarios during the period 2021-2032:

Figure 5: Assessment of CO₂ emitted (tonnes equivalent) by scenario

Assessment of CO ₂ Impact from Teesside Gas (2021-2032)	Scenario 1 NTS Delivery at 4 mol % CO ₂	Scenario 2 Offshore CO ₂ Reduction	Scenario 3 Onshore CO ₂ Reduction
CO ₂ Removed by Amine unit (4 mol% to 2.9 mol%) (te)	0	462,881	38,045
CO ₂ in fuel gas consumed by Amine unit (te)	0	213,510	87,497
CO ₂ above 2.9 mol% emitted by consumers (te)	38,045	0	0
Total additional CO₂ emissions (te)	38,045	676,391	125,542

The removal of CO₂ offshore results in the greatest level of CO₂ emissions over the period (676 kte) as there is a requirement to treat the entire gas stream being exported from the production platform.

Removing CO₂ above the current 2.9 mol% limit at the terminals results in lower CO₂ emissions (125 kte) than an offshore solution as gas with high levels of CO₂ is blended with low CO₂ gas for most of the time and treatment may only be required for short periods. It has been assumed that an amine unit at the terminal/terminals would remain non-operational for much of the year but there is a requirement to maintain

the amine tank at about 20°C when the fluid is not in use. As a result, during the period of assessment, there is over 2.3 times more CO₂ released from process heat than is required to be removed from the gas to meet the current 2.9 mol% CO₂ limit for NTS gas. These emissions could increase if, following further work with the equipment vendor, the unit was required to be run continuously to ensure reliability and avoid stressing the system through thermal cycling.

The lowest level of incremental emissions over the period would result from allowing the gas with higher CO₂ content to flow onto the NTS. The model estimates that the direct flow of gas with higher CO₂ content onto the NTS results in a total additional 38 kte of emissions between 2021 and 2032. On an annual basis the modelled maximum annual incremental emissions above the current allowable specification in this case would be circa 4,600 te/yr (see Appendix 6) against a total UK forecast annual emissions total of over 300 million tonnes. By way of further comparison a single 1,000MW CCGT power station will emit circa 1,000,000 te of CO₂ per year based on a 30% load factor.

Estimated Cost of Incremental CO₂ Emissions above Current Specification 2021-2032

In terms of cost of abatement of the CO₂ generated above the current 2.9 mol% limit, it should be noted that there is no true abatement as the CO₂ associated with the gas above the 2.9 mol% limit will (if developed) be emitted at some stage. However, it is possible to consider abatement as the prevention of such CO₂ from entering the NTS but it should be noted from the table above that any prevention of the additional CO₂ entering the NTS results in the emission of significantly more CO₂ due to the operation of the CO₂ removal equipment.

The estimated cost of the emitted CO₂ for the three alternative scenarios are summarised in figure 6 below. For consistency, these data are shown on a Net Present Value (NPV) basis discounted to 1/1/15 using a discount rate of 10% (NPV10). A discount rate of 10% has been used in this case as a surrogate for the cost of capital available to a gas production organisation or terminal operator. In reality the cost of capital for individual organisations could be higher.

Figure 6: Cost assessment of CO₂ emitted by scenario

Cost Assessment of CO ₂ from Teesside Gas (2021-2032) (£ NVP10 1/1/15, Pre-tax basis)	Scenario 1 NTS Delivery at 4 mol % CO ₂	Scenario 2 Offshore CO ₂ Reduction	Scenario 3 Onshore CO ₂ Reduction
CO ₂ Total ETS Traded Cost	£23,416	£1,601,154	£299,936
CO ₂ Total Traded Cost with Carbon Price Support	£158,001		
Total CO ₂ Cost (Traded & Price Support)	£181,417	£1,601,154	£299,936
CO ₂ Total Non-Traded Cost (£/yr) (non-ETS consumption)	£478,416	£0	£0
Total Estimated Emissions Cost	£659,832	£1,601,154	£299,936
Estimated Fully Installed Cost of Amine Unit		£106,685,573	£121,644,132
Estimated Abatement Cost for additional CO ₂ prior to NTS entry		£108,286,727	£121,944,068
Cost per tonne (Emissions Cost/Total Additional Emissions)*	£17	£160	£971

* Includes capital costs for amine units

In terms of ETS traded costs where CO₂ emissions costs are measured against market prices, the highest cost option (NPV10 £1.60m) would be removal of CO₂ offshore as this option results in the largest volume of CO₂ emitted due to the requirement to operate an amine unit all year round in order for export gas to meet the offshore pipeline entry specification. The cost of removal of CO₂ onshore at the terminals is also significant (NPV10 £300k) due to the substantial amount of CO₂ emitted through process heat from operation of the onshore amine unit. The emissions cost is not as great as offshore removal as the model assumes

that any onshore removal unit would only be operated when gas with high CO₂ content could not be blended into specification although there would be additional emissions associated with process heat during operation of the amine unit and also for additional heating to prevent degradation of the amine when not in use.

Delivery of gas with 4.0 mol% CO₂ content onto the NTS is impacted by the requirement for power generators to pay substantially higher charges for emitted CO₂ due to the Carbon Price Support scheme. However at NPV10 £158k this is the lowest cost option given the forecast small number of days per year when such gas is being produced at the terminals.

It can be argued that the calculated emissions cost for delivery of high CO₂ gas onto the NTS (Scenario 1) are at the high end of a range as many ETS registered installations calculate CO₂ emissions using regional emissions factors or installation specific CO₂ emissions factors, (based on the average composition of the gas being consumed), regional emissions factors are annual averages and site specific factors may be annual, monthly or weekly. Given that any gas with elevated CO₂ content entering the NTS from Teesside is likely to be blended with other NTS gas before reaching consumers, such gas will only have a limited impact on the emissions costs paid by many consumers as the regional annual average assumptions for CO₂ content (and therefore regional emissions factors and installation specific emissions factors) will remain unaffected by the small amount of additional CO₂ once diluted.

If the impact of consumption of gas by non-ETS paying consumers is considered (using the DECC pricing assumption for Non Traded CO₂ emissions), the CO₂ emissions cost of NTS delivery of 4.0 mol% CO₂ gas increases to £660k.

If it is considered that the provision of CO₂ removal equipment either offshore or onshore is to “abate” the CO₂ entering the NTS then the total cost of providing that “abatement “ needs to be considered. While the capex figures used here are high level estimates and would be refined with further design work it is estimated that the fully installed cost of an amine unit on an offshore platform would be in the region of £180m and the cost of an onshore unit would be of the order of £200m. If required, the installation decision would be made at the same time as an investment decision for the offshore field. If a 2017 date for an investment decision these values equate to discounted NPV10 of £107m and £122m respectively. The lower cost for the offshore unit is due to the smaller size and lower pressure rating however it is possible that following further analysis this would be offset by the additional complexity of installing on a platform with limited space.

Including the cost of the amine units brings the total NPV of mitigating the increased CO₂ – which may be only in excess of the current 2.9 mol% for 30 days per year and most likely less – to between £108m and £122m. In the worst case this is about 180 times more costly than the £660k estimate if the CO₂ were delivered onto the NTS.

Wider Considerations

Maximising Economic Recovery

In the short briefing note submitted on 26 November 2014, Oil and Gas UK anticipated the announcement in the Autumn Statement of the new high-pressure, high-temperature (HPHT) Cluster Area Allowance to promote the development of HPHT resources, including the known reserves of natural gas in the central North Sea which underpin Modifications 0498 and 0502.

<http://www.gasgovernance.co.uk/sites/default/files/Mod%200498-0502%20Action%201106%20Oil%20&%20Gas%20UK.pdf>

In the Autumn Statement of 03 December 2014, the Chancellor confirmed the introduction of the new Cluster Area Allowance and set the rate at 62.5% of the qualifying capital expenditure at fields which meet the

minimum pressure and temperature thresholds (690 bar/10,000 psi and 1490 C/3000 F). The new allowance allows an amount equivalent to 62.5% of total capital spending to be offset against future Supplementary Charge (SC) levied at 30% and paid on top of Ring-Fence Corporation Tax (RFCT) of 30%. Details of the new allowance can be found in the HM Treasury publication 'Maximising Economic Recovery: Consultation on a Cluster Area Allowance' released in December.

The new fiscal allowance is one of several measures announced to maximise economic recovery of UKCS resources and was designed specifically after extensive consultation to promote additional investment in the technically challenging uHPHT projects in the central North Sea. The government has taken further measures in the Budget in March 2015 in order to restore the international competitiveness of the UKCS for upstream investors.

The Proposers believe that Modifications 0498 and 0502 are entirely consistent with the government's objectives in that they will lower the capital cost of development of uHPHT fields with high CO₂ content, promote greater energy security and bring wider economic benefits to the UK economy.

Risk of setting precedent

The Workgroup considered whether any decisions taken for Modification 0498 and 0502 set precedent for any other, future, requests at entry points. Participants concluded that there was such a risk, but that each request would be subject to an equivalent assessment under the UNC Modification Rules and then a decision taken by Ofgem based upon the merits of the individual case. On the basis of this individual objective assessment, the proposals were not believed to be discriminatory.

Conclusions

No clear conclusions have been achieved. Workgroup participants differed in their view of these changes, depending on the impacts they believed were most relevant to them. This report seeks only to document the arguments to inform further consideration within the UNC modification process (which assesses against the Relevant Objectives). Participants believed that there are other considerations, such as the wider UK interest and UK Government Policy, which are beyond the vires of a UNC modification.

5 Implementation

No direct costs have been identified and implementation on the earliest practical opportunity is requested, effective from 01 October 2020. As a backstop, implementation by 31 March 2017 is necessary to enable timely final investment decision-making. Implementation within the NEAs could be completed immediately following approval from Ofgem, through a bilateral agreement to amend the NEAs, and is envisaged that this would be done simultaneously for 0498 and 0502.

6 Impacts

Do these modifications impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

These modifications do not affect the UK Link Replacement Programme delivery or any other change.

7 Legal Text

No changes to the UNC are proposed under either Modification 0498 or 0502.

Suggested text to modify the Network Entry Provisions contained within the relevant NEA has been provided by each Proposer.

No issues were raised by the Workgroup regarding either content.

Suggested Text - Modification 0498

Given the relative simplicity of the legal change, the following legal text is suggested to modify the Network Entry Provisions contained within the NEA.

2.3 Gas tendered for delivery by System Users to the System at the System Entry Point shall not contain any solid, liquid or gaseous material which would interfere with the integrity or operation of the System or any pipeline connected to such System or any appliance which a consumer might reasonably be expected to have connected to the System. In addition, all gas delivered to the System at the System Entry Point shall be in accordance with the following values:

[...]

(k) Carbon Dioxide Not More than 2.9% before 1 October 2020 and not more than ~~2.9%~~ **4.0**
mol% from 1 October 2020

Suggested Text - Modification 0502

The following legal text is suggested to modify the Network Entry Provisions contained within the NEA:

2.3 (k) Carbon Dioxide not more than 2.9% before 1 October 2020 and not more than ~~2.9%~~ **4.0**
mol% from 1 October 2020

8 Consultation Responses

Modifications 0498 and 0502

All eleven respondents provided a combined response, treating both modifications as one in terms of comments, support or opposition.

Of the eleven (11) representations received four (4) supported implementation, one (1) offered qualified support, two (2) provided comments and four (4) were not in support.

Representations were received from the following parties:

Organisation	Response (0498/0502 Combined)	Relevant Objectives	Key Points
BG Group	Support	a - positive d - positive	<ul style="list-style-type: none"> Believes implementation is the most cost effective solution for the delivery of gas from future offshore production with higher CO₂ levels. These potential resources may not otherwise be developed if more costly treatment and processing solutions for CO₂ removal have to be considered in the investment decision. Provides certainty to investors that gas can get to market on any day and does not rely on production from other fields for comingling. Developing the UK's own domestic resources will enhance security of supply and reduce its reliance on imports. Implementation improves the economic case for developing new fields for delivery into Teesside will also mean that existing pipeline capacity and processing terminal infrastructure can continue to be utilised. Implementation will align the limits at Teesside with those in force at St Fergus. Notes that for the majority of the time, future gas flows at Teesside would be expected to remain within the current limits as gas from high CO₂ sources will be blended with those with a low CO₂ content. Any use of the higher proposed limit is expected to be for periods of limited duration (this does not justify the high investment cost needed for CO₂ removal at the well head or on shore). Supportive of an effective date of October 2020, and that the decision to make the change should be made now (will provide clarity on the future entry specification and allow the information to be considered when designing and making decisions on offshore investments).

BP Gas Marketing	Support	a - positive d - positive	<ul style="list-style-type: none"> Potential new upstream developments are known to have CO₂ levels that exceed current limits. As Proposer (0498) BP identified an increasing risk that especially in summer months and from around 2020 onwards, the availability of sufficient blending gas cannot be guaranteed prior to entry into the NTS. Flowing gas in excess of the current specification is not expected to be for extended periods of time as it is anticipated that under normal operating conditions gas from any fields with gas of high CO₂ content would be blended in the offshore pipeline to ensure current delivery specifications are met. Advantages to upstream producers and gas terminal operators are removal of the need for significant capital expenditure and increased operating cost from the installation of CO₂ removal equipment which may be used for only a few days/weeks per year. Implementation would negate the requirement for field developers to seek funding for an additional c. £200m to install an amine unit onshore - an additional cost that could jeopardise the economic case for progressing a development, particularly so with the recent drop in oil prices. (Funding and installation of an onshore amine unit would increase operating costs by several million pounds per annum due to energy, chemical costs, operating and maintenance costs of the unit). By amending the CO₂ entry specification in the NEA it would also prevent significant additional CO₂ being released into the atmosphere from the use of process heat associated with the CO₂ removal technology. Implementation at the earliest practical opportunity is requested, effective 01 October 2020. As a backstop, implementation by 31 March 2017 is necessary to enable timely final investment decision-making for new field developments. Implementation earlier than 2017 would assist current flows into Teesside. Revising the CO₂ spec to 4.0 mol% would avoid restricting throughput of existing gas fields as well as avoid the risk of potential new gas fields not being developed.
British Gas Trading Limited	Comments	a - no comment d - no comment	<ul style="list-style-type: none"> Can see the benefits of facilitating the delivery of further UKCS gas supplies, but remains uncertain as to the operational and financial downstream impacts. Unable to assess impacts and costs relating to gas off-taken at large NTS sites that might receive gas from the Teesside sub-terminals, without the support of extensive network analysis and supply scenario modelling. It is possible that higher emissions costs would be incurred by shippers as a result of the direct pass-through of higher quantities of CO₂ to the NTS but British Gas is unsure whether there would be any operational impact at large sites. Concerned that implementation would set precedents and enable other sub-terminals to easily increase the level of CO₂ in gas delivered to the NTS without a rigorous assessment of the downstream impacts, and seeks assurances that implementation would not

			<p>result in the potential for such a free-for-all.</p> <ul style="list-style-type: none"> Comments that the effective implementation date and application of the revised CO₂ limits in the relevant Network Entry Agreements should not be prior to October 2020, and believes that implementation should be conditional upon a justifiable and demonstrated need to increase the limits to facilitate the flow of gas from new offshore developments in accordance with the motivations explained in the modification proposals.
EDF Energy	Oppose	<p>a - no initial comment; expanded views provided in general response.</p> <p>d - no initial comment; expanded views provided in general response.</p>	<ul style="list-style-type: none"> Notes this amendment is the preferred approach for the upstream gas field developer of the prospective gas field 'Jackdaw' otherwise it claims it would require additional investment in infrastructure and/or operating costs. Points out the 'polluter pays' principle is the commonly accepted principle for charging policies such that those who cause environmental costs are made to pay the full cost of their actions. Notes if implementation is approved and Jackdaw is developed, affected onshore parties will be wholly liable for the costs to meet CO₂ limit requirements and the developer will not bear any of these costs. Believes it has not been demonstrated that affected onshore parties will benefit from proposed CO₂ limit changes and notes that shippers who have contracts with Jackdaw gas may have a small cross subsidy from those who have not, and other offshore operators will also be at a slight cost disadvantage. Costs are likely to be passed down from the developer to the end consumer. Recognises the Government's efforts to maximise assets/resources contained within the UK Continental Shelf (UKCS), however believes this must be balanced with the desire for the UK to meet its targets to reduce emissions and move toward a low-carbon economy. Believes it would be prudent to delay implementation, if approved, until developer confirms it will be linking Jackdaw to the Central Area Transmission System (CATS) pipeline infrastructure with flows entering the NTS at Teesside, and that the Network Entry Agreements (NEAs) should only be amended following a positive FID for Jackdaw.
Energy UK	Oppose	<p>a - no initial comment; expanded views provided in general response.</p> <p>d - no initial comment; expanded views</p>	<ul style="list-style-type: none"> Believes it has not been sufficiently demonstrated that, if rejected, the gas field (Jackdaw) containing elevated CO₂ will not be developed at all. Under the existing framework, which is sufficient for the 34 producing fields that are connected to the Central Area Transmission System (CATs), the developer's options are to either process the gas by removal of CO₂ or blend with gas from other fields on an interruptible basis to meet the existing specification. Notes the principle of 'polluter pays' will be side-lined if these modifications are approved since the costs of additional CO₂ entering the network will be passed onto end customers, particularly those needing to secure EU ETS permits for emissions. Approval

		provided in general response.	<p>would also relieve the field developer/gas processing facility operator of competitive pressure to seek the lowest cost/environmental impact means of removing CO₂ from gas flows delivered to the NTS.</p> <ul style="list-style-type: none"> Notes that if approved by Ofgem before 31 March 2017, the Proposers may wish to implement changes immediately. This would mean that an existing gas field which is currently curtailed (44 times in 2013) will no longer be restricted to 2.9%mol and therefore will be able to flow gas with higher CO₂. (Not modelled in the Proposers' assessments or extensively discussed at Workgroup.) Observes that the effective date requested is October 2020 and considers this is reasonable, but suggests that Ofgem does not take a decision until there is more clarity in how the European Commission (EC) plans to implement the proposed CEN gas quality standard which contains parameters for CO₂ and could be made legally binding (an EC decision is expected during 2016). Concerns emphasised by Energy UK members regarding precedent setting, that if these proposals were approved others may be raised which may seek approval on non-discrimination grounds. This may result in CO₂ levels in the NTS creeping higher and the potential for more fluctuations in gas quality with the impact on an increasing number of gas –fired plant. Also notes that it is not clear to what extent the potential growth in flows into Teesside as a percentage of total supply has been considered in the analysis, from 8 % today to potentially 16% in the mid 2020s. Draws attention to other suggestions (technical/commercial) for consideration, e.g. are new techniques being developed that may be viable by 2020, or might it be possible to capture the CO₂ for purification and sale, etc.
ESB	Oppose	<p>a - no comment</p> <p>d - no comment</p>	<ul style="list-style-type: none"> Believes that the proposed solution is not the most efficient and economically advantageous solution to the problem discussed, increasing materially the risk for CCGT consumers of gas and creating a potential conflict with maintaining electricity security of supply at efficient cost; it is fundamental to safeguard the interests of the wider industry and customer base and facilitate acceptable arrangements for the parties affected. If implemented, significant effort will be required from CCGTs to adapt to the changes and implement necessary control systems to cope with variability in fuel composition; sufficient lead-time prior to implementation should therefore be considered for the wider market to enable it to fully identify the implications of changing technical and commercial requirements. (ESB has provided further details on what this might involve.)
GrowHow UK	Oppose	a - negative	<ul style="list-style-type: none"> GrowHow is the largest industrial user of Gas in the UK, using 1% of UK gas each day (c. 2.5MCM). Gas

		d - negative	<p>is both feedstock and fuel within its process, and it is 68% of its variable manufacturing cost. It is concerned that implementation will drive up its cost base, adversely affecting its ability to compete against imported material manufactured in countries with much lower Natural Gas prices.</p> <ul style="list-style-type: none"> GrowHow has provided further details on the effects on its business operations of increasing the CO₂ limit.
National Grid NTS	Qualified Support	<p>a - positive; expanded views provided in general response.</p> <p>d - positive; expanded views provided in general response.</p>	<ul style="list-style-type: none"> National Grid NTS believes implementation would increase the future likelihood of additional UKCS gas supply into the NTS from one or more specific gas fields such as Jackdaw that feed into the NTS at Teesside (assumption e.g. 4% GB demand and 10% of UKCS production). Support for implementation is based on the successful development and delivery of the Jackdaw field by 2020 qualified on the Jackdaw field being delivered with a material volume of additional gas being made available to the market, and on other assumptions/assertions that may require further validation. Has considered concerns regarding combustion stability and emissions compliance expressed about gas fired power generation could arise in its own gas turbine compressor fleet and believes its plant is sufficiently different and so would not be as susceptible to these. Has also considered whether concerns that the need for increased corrosion inspections in storage facilities could arise in relation to the NTS pipeline system, and has concluded that as the NTS operates to the dry gas GS(M)R gas quality specification there is no material increase in corrosion risk within the NTS.
Oil & Gas UK	Support	<p>a - positive</p> <p>d - positive</p>	<ul style="list-style-type: none"> Believes implementation will enhance UK gas supply security and supply-side competition and facilitate development of known offshore gas reserves in accordance with the obligation in the UK Infrastructure Act 2015 to Maximise Economic Recovery of indigenous oil and gas resources (MER UK). Notes recent fiscal and regulatory reforms are designed to promote new field development and to maximise the economic benefits of remaining reserves for the entire UK economy. Even without new field developments, implementation will confer benefits through prevention of the occasional curtailment of gas production from existing fields already delivering gas to Teesside. Believes implementation will extend the economic life of offshore and onshore assets to the long-term benefit of UK gas consumers. Believes the wider impact on the entire NTS will be minimal and there is no reason to suggest the quality of gas will become more variable in the Teesside area than currently. Believes there is a financial benefit in lower capital and operating costs for new field developments fields

			<p>that far outweighs the incremental costs to be borne by local gas end-users.</p> <ul style="list-style-type: none"> • Believes the environmental case based on CO₂ emissions is also favourable (see additional details provided in response). • Believes that fear that implementation would set an unwelcome precedent for further CO₂ relaxation elsewhere is ill-founded. These applications have been based on the specific features at Teesside and of existing and prospective offshore fields in the CNS, which do not apply at other entry terminals.
Scotland & Southern Gas Networks	Comments	<p>a - unclear; insufficient evidence</p> <p>d - unclear; insufficient evidence</p>	<ul style="list-style-type: none"> • Re-stated its initial response, its primary concern being that the possible increase in CO₂ levels in gas delivered from the NTS relates to the potential increase in corrosion in metallic mains within its lower pressure tiered systems. Scotia Gas could face additional costs should a significant volume of this wider specification gas enter the system and cause higher corrosion levels in its network, and without knowing volumes or timescales it is unable to determine impacts in any further detail at present. • Observes these modifications have been developed with a certain customer in mind and it should be ensured that if implemented, any changes must not amend overall arrangements thereby potentially reducing the quality of gas currently flowing into the system.
Teesside Gas Processing Plant Limited (TGPP)	Support	<p>a - positive</p> <p>d - positive</p>	<ul style="list-style-type: none"> • Believes the relaxation of CO₂ gas specification at the Teesside entry point will facilitate the development of new oil and gas fields in the CNS region of the UKCS. Indigenous supplies are the lowest cost source of gas for the UK. • Implementation will assist in the reduction of offshore development cost and stimulate further investment in the region, contributing to the desired aims and goals of the UK Government for Maximum Economic Recovery (MER) of oil and gas reserves in the UK.

Representations are published alongside the Final Modification Report.

Views expressed in response to questions raised by UNC Modification Panel as part of this Consultation

Q1: Respondents are requested to quantify any additional costs they would incur as a result of a CO₂ excursion to 4.0 mol% at the Teesside terminal (flow maps are included to help respondents; see figures A2.1 to A2.4 in Appendix 2).

Organisation	Response
BG Group	No views expressed.

BP Gas Marketing	As pointed out by BP in the presentation given to the 07 August 2014 workgroup meeting ⁸ the Gross Calorific Value, Wobbe Index, Soot Index and Incomplete Combustion Factor will all remain within specification limits during period where CO ₂ peaks at 4.0 mol%. As this is the case there should be no material impact on costs, as systems should be designed to cope with current specifications.												
British Gas Trading Limited	Without the support of extensive network analysis and supply scenario modelling, British Gas is unable to assess impacts and costs relating to gas off-taken at large NTS sites that might receive gas from the Teesside sub-terminals.												
EDF Energy	It is difficult to assess the additional costs EDF would incur as the projected Jackdaw gas flow data and gas flow rates and the forecast interactions with existing fields have not been provided by the Proposers. However, the Draft Modification Report does provide a good overview of the impact on consumers.												
Energy UK	All gas-fired generating plant are susceptible to changes in gas quality since the plant is tuned to a certain pre-defined specification for optimum operating performance and low emissions. Where changes in the gas quality specification occur rapidly the plant may trip. Further details including estimated costs are included in the draft modification report. From the information provided by National Grid, simple flow maps for a single year, it is not possible to estimate the number of times that re-tuning may be necessary nor how many trips there may be.												
ESB	ESB broadly agrees with the current assessment of cost estimates provided in the report. However, it anticipates that these costs will be higher for any given CCGT. In addition, the costs are likely to differ significantly between old and new technologies.												
GrowHow UK	<p style="text-align: right;">Additional Cost £ P.A BASED ON 30 DAYS</p> <table> <tr> <td>CO2 Emissions</td><td>£500</td></tr> <tr> <td>Production Capability</td><td>£40,000</td></tr> <tr> <td>CO2 Removal Energy</td><td>£500</td></tr> <tr> <td>Reformer Heating Energy</td><td>£8,000</td></tr> <tr> <td>Nat Gas Feed Heating Energy</td><td>£6,000</td></tr> <tr> <td></td><td>£55,000</td></tr> </table>	CO2 Emissions	£500	Production Capability	£40,000	CO2 Removal Energy	£500	Reformer Heating Energy	£8,000	Nat Gas Feed Heating Energy	£6,000		£55,000
CO2 Emissions	£500												
Production Capability	£40,000												
CO2 Removal Energy	£500												
Reformer Heating Energy	£8,000												
Nat Gas Feed Heating Energy	£6,000												
	£55,000												
National Grid NTS	National Grid NTS does not expect to incur any material additional operational costs as a result of CO ₂ excursion to 4.0mol% at the level of flows stated by the Proposers.												
Oil & Gas UK	As an upstream industry association, Oil & Gas UK itself is not directly affected.												
Scotland & Southern Gas Networks	<p>Insufficient information has been made available to enable Scotia Gas to quantify costs at this time.</p> <p>Scotia Gas could face additional costs should a significant volume of this wider specification gas enter the system and cause higher corrosion levels in its network; without knowing volumes or timescales it is unable to determine impacts in any further detail at present.</p>												
Teesside Gas Processing Plant	The estimated costs to terminals/field owners are detailed in this Final Modification Report.												

⁸ http://www.gasgovernance.co.uk/sites/default/files/2014%2008%2007%20CATS%20CO2%20Presentation%20-%20Mod%200498_0.pdf

(TGPP)	
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Q2: Respondents are requested to quantify any wider benefits/dis-benefits for the UK economy that might be derived from these proposals.

Organisation	Response
BG Group	No views expressed.
BP Gas Marketing	The higher CO ₂ limit may result in the economic delivery of additional UKCS gas production, increasing GB supply security and reducing reliance on imported gas. A rejection of the proposals will put further economic pressure on any future sanction decision. This will contribute to the economic and efficient operation of the total system through maintaining a diversified supply base and by continued use of existing capacity.
British Gas Trading Limited	British Gas is unable to quantify this but consider that any UK-wide benefits from these proposals should not result in any undue costs being placed on particular shippers or consumers.
EDF Energy	<p>The Proposers have failed to quantify what the wider economic benefits to the UK economy would be if UNC 0498/0502 is implemented. The Proposers have provided detail on what tax allowances the UK government has offered and in DECC's maximising economic recovery document it is highlighted that DECC is seeking to support the development of ultra high pressure, high temperature (uHPHT) projects and to incentivise the most efficient development of processing hubs and offtake routes. DECC has set the cluster allowance to encourage significant investment, while ensuring a fair return for the Exchequer.</p> <p>The developer has publicly indicated that these incentives are not sufficient for Jackdaw and has delayed its FID from 2015 to 2017. Therefore at this stage, even if UNC 0498/0502 is implemented it does not necessarily mean Jackdaw will be developed to provide any benefits for the UK economy.</p> <p>Furthermore DECC's document also highlighted that associated exploration/appraisal wells of HPHT and uHPHT costing in excess of £100m (Jackdaw is estimated to be in the region of £3bn) carry up to a 90% probability of commercial failure without fiscal support.</p>
Energy UK	<p>Energy UK is aware that there are UK tax incentives to develop high temperature – high pressure fields, this is a government incentive to increase recovery from the North Sea reserves. However, the developer has previously stated that these incentives are not sufficient to move to development. Therefore the Proposers have not demonstrated how a change to the CO₂ upper limit will bring wider benefits to the UK economy.</p> <p>Furthermore, the Proposers indicate that changing the CO₂ upper limit will promote greater energy security. If implemented and the Jackdaw development goes ahead there may be greater gas production; however, this does not necessarily result in greater overall security of supply. Ofgem considered this in its gas security of supply report⁹:</p> <p><i>"This is because historically UKCS has not just provided domestic gas but worked as a flexible reserve of gas, with swing fields able to increase production during tight gas</i></p>

⁹ https://www.ofgem.gov.uk/sites/default/files/docs/2012/11/gas-sos-report_0.pdf

	<p>supply periods. The current emergency “command and control” arrangements are designed on the basis that there will be gas fields which can ‘ramp-up’ production should the supply and demand balance tighten.</p> <p>Traditional swing’ fields like Sean and Morecombe are in decline and it seems unlikely that any of the new finds will be able to ramp up production during times of scarcity in GB and fill the gap left if international sources were interrupted. On this basis, although supporting domestic production can result in a number of benefits such as protecting base load demand it would not necessarily deliver additional security of supply to the UK.”</p> <p>Energy UK therefore considers that the Proposers have not demonstrated how development of the Jackdaw field would provide additional security of supply.</p> <p>In any scenario appropriate investment signals should encourage upstream producers to develop projects to enable access to the cheapest source of gas supply irrespective of origin, this is ultimately in customers’ best interests.</p>
ESB	<p>As stated in the report, each CCGT must be tuned to operate in a particular narrow band of gas composition to maximise efficiency. The proposed changes create a potential for larger fuel composition variation thus impacting the operation and efficiency of many CCGTs within the areas affected. The sensitivities of CCGTs to gas quality vary depending on the OEM specification. Therefore, in addition to a number of technical difficulties such as the possibility of trip events, the plants will also face commercial and market disadvantages vis-à-vis plants that are not affected by the change.</p> <p>These disadvantages could take a form of lower thermal efficiency, and therefore higher fuel and operating costs as well as lost revenue due to decreased flexibility.</p> <p>Price competitiveness is critical for CCGT operators in the current market given the changing nature of revenue models.</p>
GrowHow UK	<p>Whilst identifying the adverse effects of these modifications on its business, GrowHow also recognises that security of supply is paramount to the operations of its business and welcomes diverse supplies into the NTS that offset dwindling UK continental shelf flows.</p>
National Grid NTS	<p>National Grid NTS is not in a position to quantify any wider benefits/dis-benefits in this area. It notes however that, to the extent wider carbon dioxide limits at Teesside NTS entry points lead to the development and delivery of additional indigenous gas supplies, this may improve GB security of supply.</p>
Oil & Gas UK	<p>In 2014, Teesside terminals delivered 5.8 bcm to the NTS out of total deliveries of about 67 bcm or 9% of the total volume. The average CO₂ content of Teesside gas was 2.2mol% compared to an estimated NTS average of 1.4mol%. Offshore fields in the CNS delivering gas to Teesside are ‘baseload’ suppliers with no ability or incentive to modulate their output. They undertake planned maintenance, usually in the summer months, and suffer occasional unplanned outages as part of their operations.</p> <p>These proposals would facilitate the development of the UK’s own undeveloped gas reserves by lowering the capital and operating costs associated with their development and conferring firm network access to undeveloped, higher-CO₂ CNS fields. This would confer benefits to offshore resource holders, to HM Treasury through higher tax revenues and to UK domestic and industrial consumers who would have additional supply security and a local source of gas feedstock.</p> <p>At present, higher-CO₂ fields on the Norwegian Continental Shelf are capable of development and delivery to St Fergus where two of the three terminals already have a maximum CO₂ content of 4.0mol%. (The average St Fergus CO₂ content from the three terminals is about 2.0mol% compared to 2.2mol% at Teesside). The proposed Modifications would create a ‘level playing field’ by allowing UK offshore fields in the CNS the same advantage enjoyed by Norwegian gas producers.</p> <p>Oil & Gas UK is sympathetic to the end-users in the Teesside area that would probably face higher <u>average</u> CO₂ in the gas they consume and, for those within the</p>

	<p>EU ETS, higher compliance costs. However, the data gathered by National Grid showed the effect of natural dilution in the NTS mitigates the effect of higher CO₂ at Teesside entry on any particular exit point from which end-users take gas.</p> <p>Furthermore, the identified incremental costs incurred by local end-users through operational inefficiencies and higher ETS compliance costs are relatively small under all plausible assumptions of the cost of carbon. These additional end-users' costs are not be diminished but their scale does not, in Oil & Gas UK's view provide the basis for rejecting the Modifications.</p>
Scotland & Southern Gas Networks	Scotia Gas is not able to answer this question without further industry analysis.
Teesside Gas Processing Plant (TGPP)	<p>These modifications will stimulate the further development of oil and gas reserves in the Central North Sea. Benefits will include:</p> <ul style="list-style-type: none"> • Extending the life of the onshore processing facilities thereby preserving jobs on Teesside in the long term. • Further long-term tax contributions from the development of new fields. • Contributing to the desired aims and goals of the UK Government for MER of oil and gas reserves in the UK. • Investment into the UK from domestic and overseas oil and gas production companies.

Q3: Respondents are requested to quantify the security of electricity supply risk to CCGTs. It would be useful to know how many CCGTs could be affected, when they might be impacted and what flexibility there is elsewhere in the system to accommodate.

Organisation	Response
BG Group	No views expressed.
BP Gas Marketing	<p>BP believes that as the increase in CO₂ will have no effect on the gas specification, which will remain within GSMR limits and so should have no material impact on CCGTs.</p> <p>The evidence presented in the workgroup report showing instances of CCGT trips is in BP's view misleading for the purpose of these modifications, as none of the instances shown can be linked to an increase in CO₂.</p>
British Gas Trading Limited	British Gas does not have any specific data to help answer this question but has some concerns that variability in gas quality could adversely impact the smooth operation of gas-fired generation plant. If, as a result, the reliability of such plant were to be seriously impacted then this would have a negative effect on the security of electricity supply.
EDF Energy	<p>The Capacity Market seeks to ensure sufficient investment in the overall level of reliable capacity (both supply and demand side) needed to provide secure electricity supplies at levels up to and including peak demand. The 2014 Capacity Market resulted in 46% of the total capacity provided by CCGTs for delivery in 2018/19. With the closure of other technology plant, there is expected to be an increased reliance on CCGTs to support National Grid Electricity Transmission (NGET) to abide by the security standard as prescribed by Secretary of State (currently three hours/year loss of load expectation).</p> <p>Changes to gas flows and/or variability of gas quality may lead to CCGTs facing</p>

	additional challenges to run. If CCGT plant is unable to run during a stress event, the capacity provider will be liable for a capacity penalty and NGET may have to undertake some emergency measures to secure electricity supplies.
Energy UK	<p>Gas demand from electricity generation is expected to increase as gas-fired power generation replaces coal-fired plants, and gas is increasingly necessary to provide flexible back-up for further deployment of intermittent renewables. Along with this increase in gas demand for power generation, demand reduction may become less flexible as the power sector becomes less able to switch to alternative forms of generation, such as coal, at times of high gas demand.</p> <p>The security of electricity supply risk will manifest itself if a gas quality excursion were to result in a trip at times of high electricity demand; at such times there would be limited flexibility elsewhere within the system to respond to a generation shortfall. This becomes particularly acute from the early 2020s when most coal plant is expected to close and additional nuclear capacity is decommissioned¹⁰ leaving gas-fired generation is the key source of flexible generation.</p> <p>The outcome of the capacity mechanism auction for 2018 resulted in 45%¹¹ of the capacity being provided by gas-fired plant, this is expected to increase in coming years.</p>
ESB	Not applicable.
GrowHow UK	Not applicable.
National Grid NTS	National Grid NTS is not in a position to quantify the security of electricity supply risk.
Oil & Gas UK	<p>The Modifications do not affect the GMSR limits and will have no discernible or material impact on CCGT operations.</p> <p>Oil & Gas UK believes the claim raised in the Workgroup that some end-users (including unidentified generators) would face greater short-term, within-day variability of gas quality and suffer costly trips if the Modifications were approved is entirely spurious, ill-founded and should be disregarded by the Modification Panel. No data was ever presented to the Workgroup regarding the variability of gas quality or the consequent alleged costs. The <u>daily</u> gas quality data assembled by National Grid at all major entry points and local exit points provided no support at all to these claims. The short-term, within-day variability of gas quality at any individual exit point is the result of the market-responsive fluctuations in demand and supply and the operational management of the NTS by National Grid Gas. There is simply no reason to believe that approving the Modification proposals would increase the variability of the key gas quality parameters (Wobbe index, GCV, soot index, etc.) at any individual exit point.</p>
Scotland & Southern Gas Networks	This is not a question relevant to Scotia Gas.
Teesside Gas Processing Plant (TGPP)	This is not TGPP's area of operation so it cannot comment directly. However, if this is an area of significant concern for generators TGPP questions why this impact has not already been quantified and shared with the Working Group for inclusion in the report.

¹⁰ EDF group Reference Document 2014 Annual Financial Report p94 ([link](#))

¹¹ <https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf>

9 Panel Discussions

10 Recommendation

Panel Recommendation

Having considered the Modification Report, the Panel recommends that:

- proposed Modification 0498 [should/should not] be made; and
- proposed Modification 0502 [should/should not] be made.

11 Appendices

- 1 **CO₂ Levels at NTS Entry Points**
- 2 **Teesside Flow Maps**
- 3 **CCGT Plant trips**
- 4 **Detailed analysis of the impact of increasing CO₂ on Gas Quality at Teesside**
- 5 **Teesside Schematic**
- 6 **CO₂ Impact Assessment**

Appendix 1 - CO₂ Levels at NTS Entry Points (plot is mol%)

Figure A1.1: CO₂ at St. Fergus

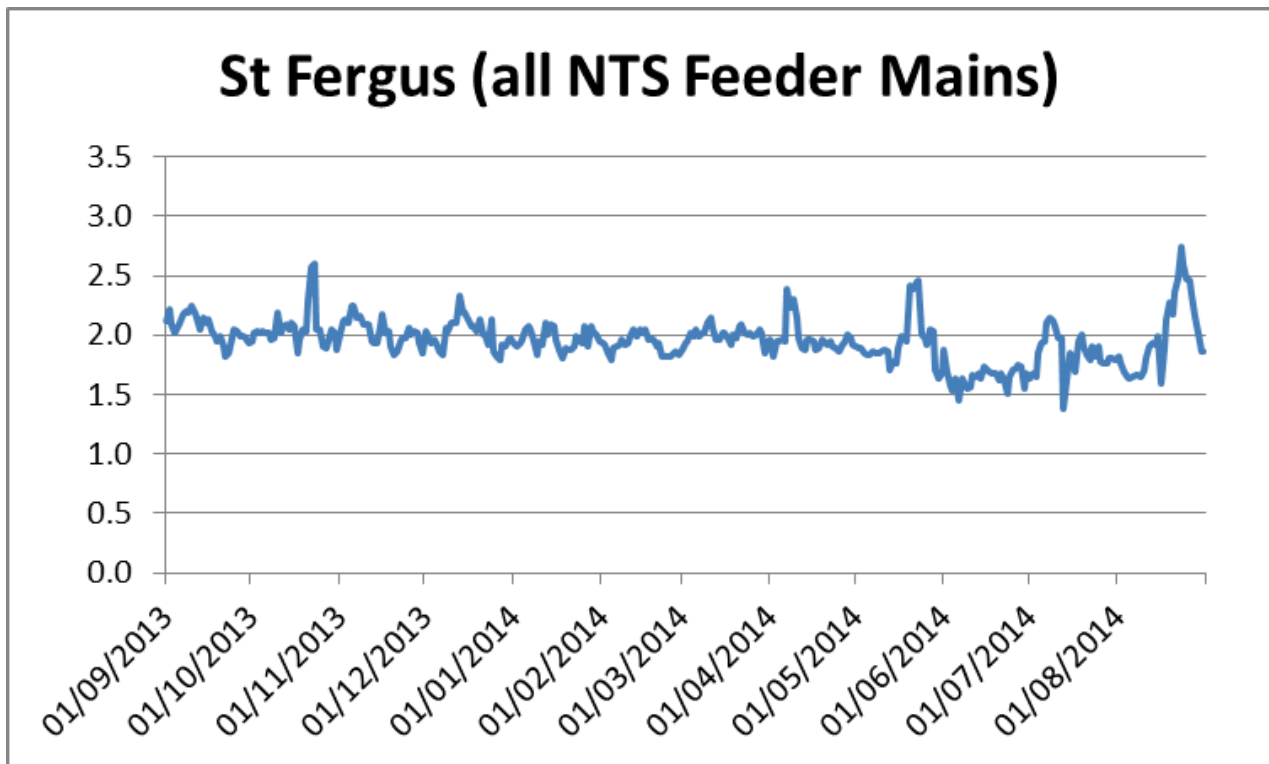


Figure A1.2: CO₂ at Teesside

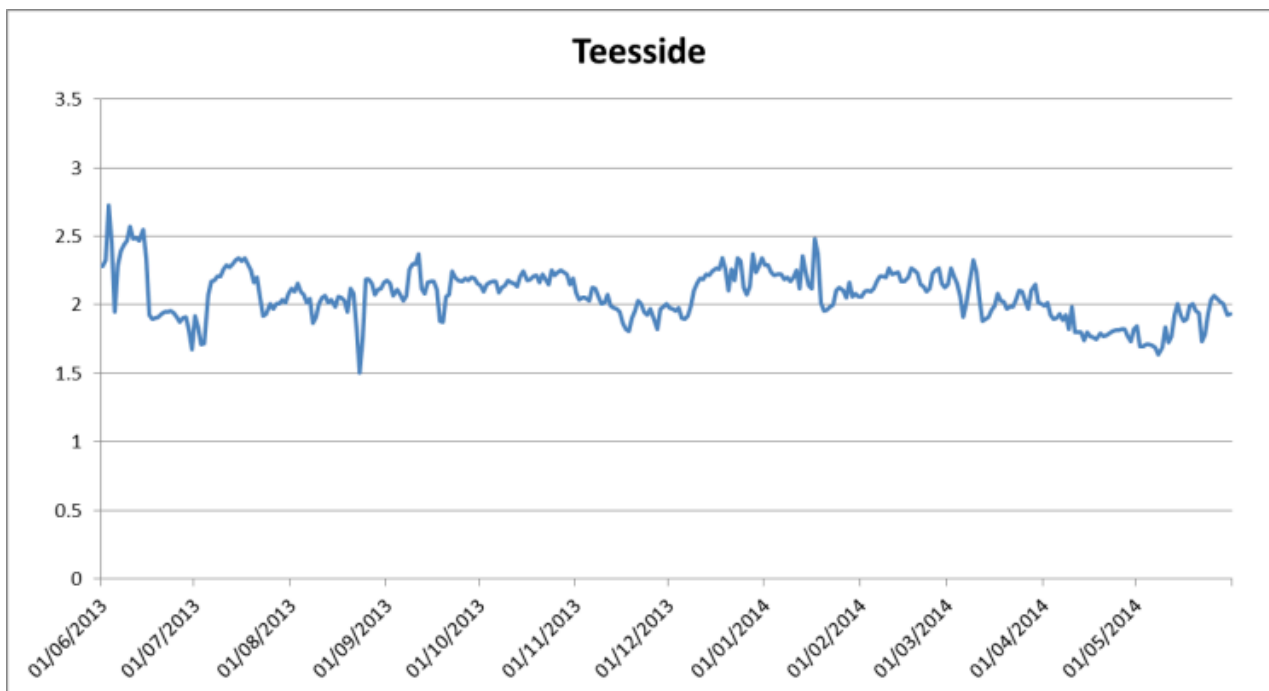


Figure A1.3: CO₂ at Easington

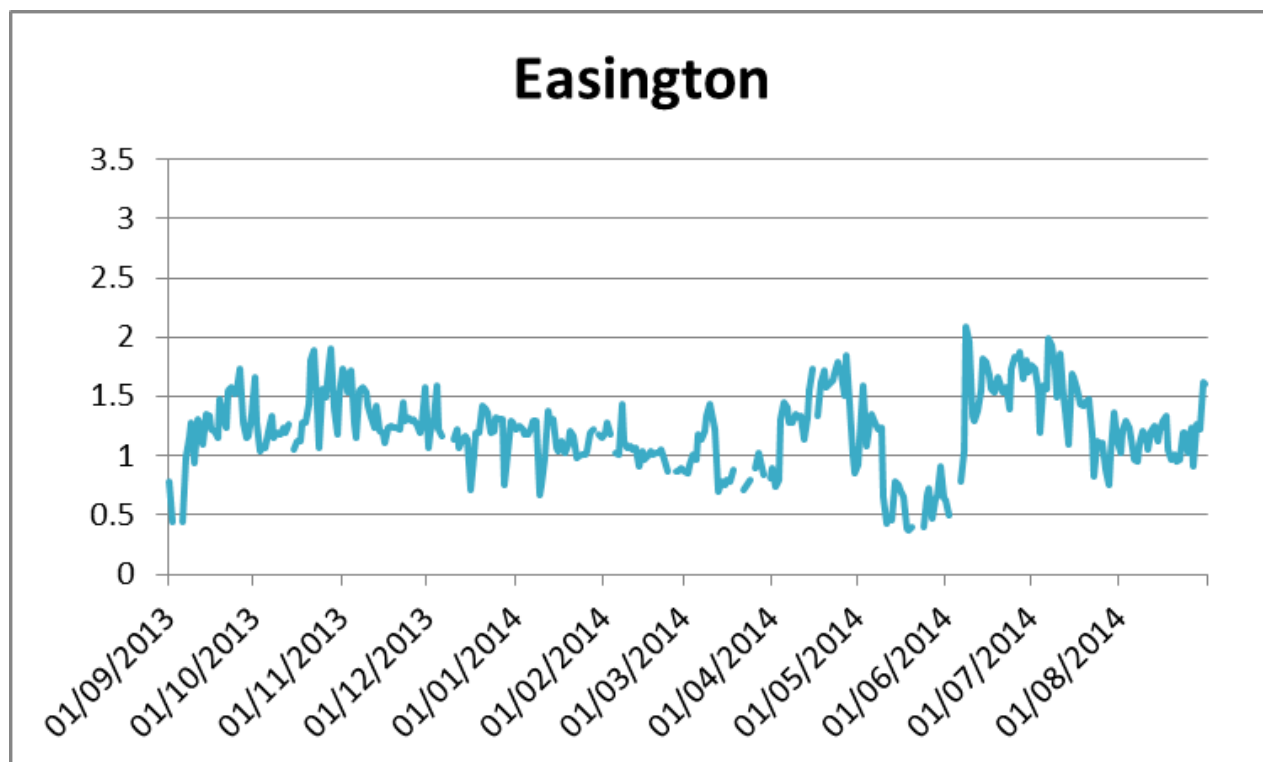
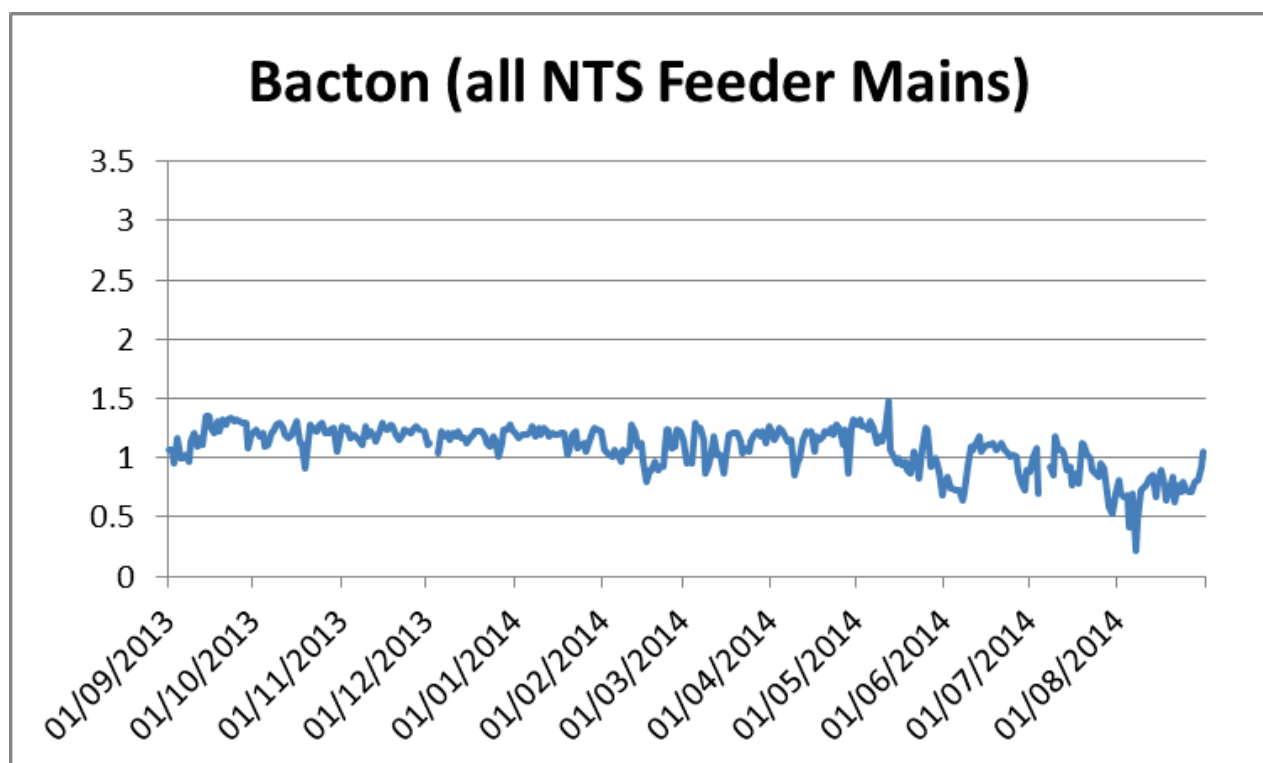
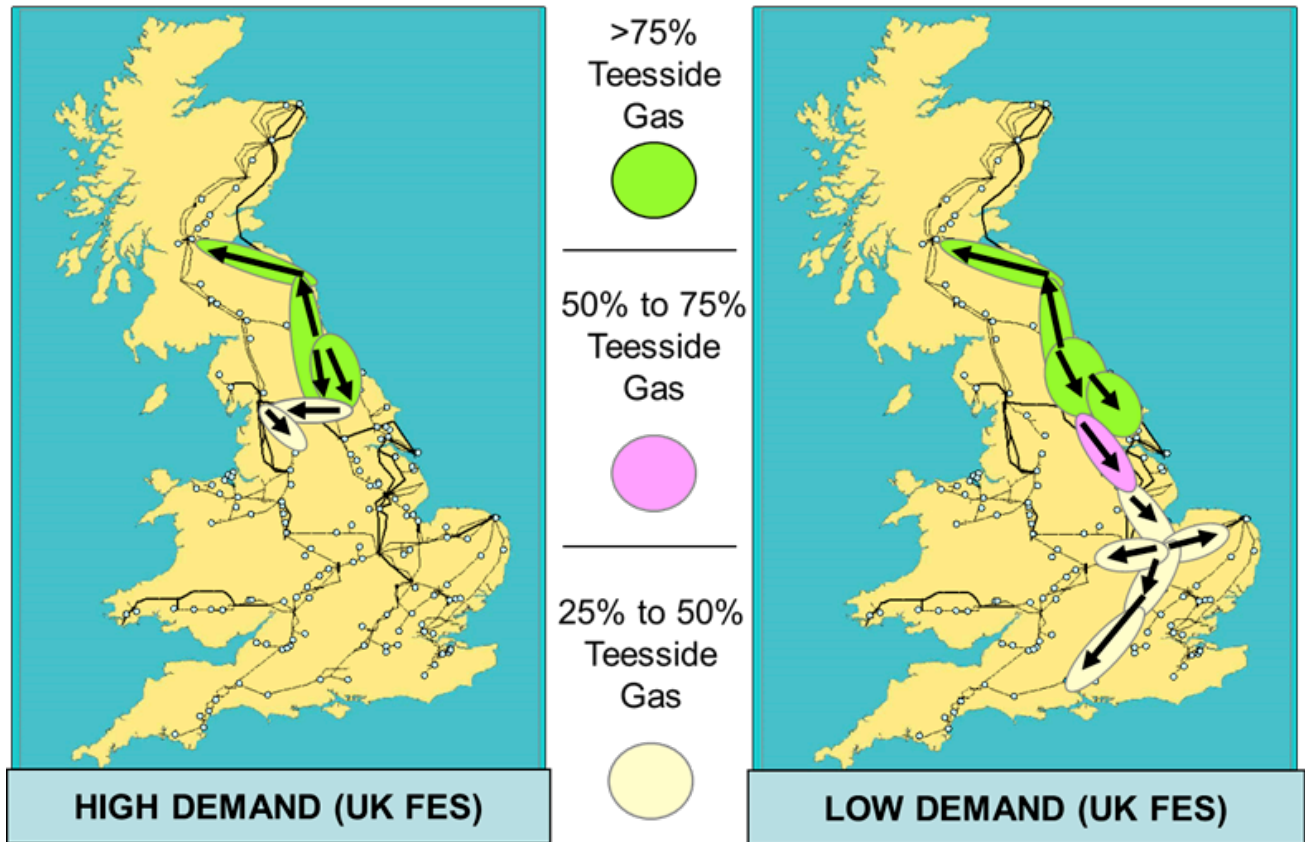


Figure A1.4: CO₂ at Bacton



Appendix 2 - Teesside Flow Maps

Figure A2.1: Indicative NTS Flows from Teesside Entry Point

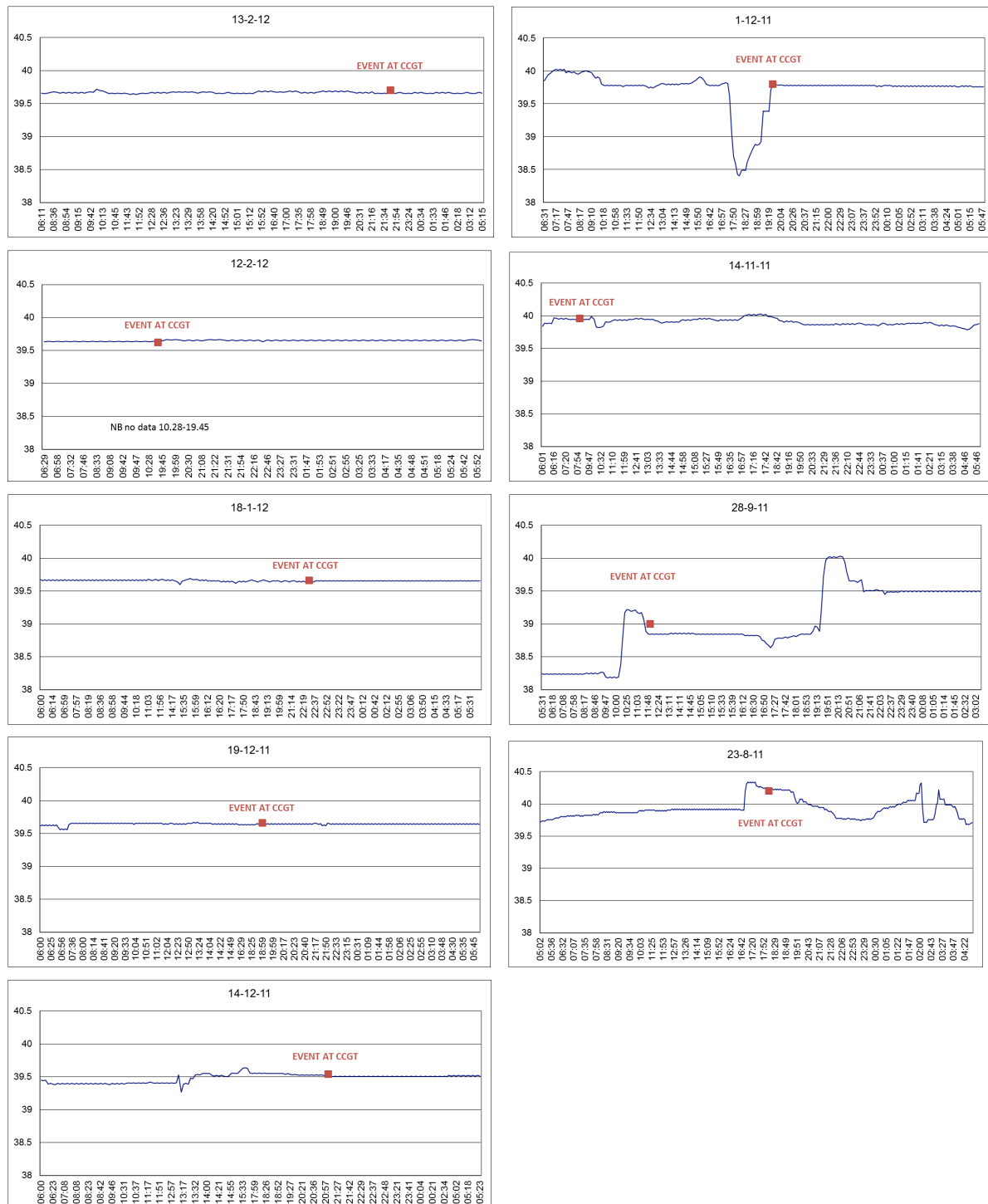


Appendix 3 – CCGT Plant trips

Figure A3.1: Trips at a CCGT located in the East of England (Data provided via Energy UK):

Date	Event	Wobbe Index, MJ/Sm ³	CO ₂ (mol%)
13/02/2012 21:36	Trip during shutdown - Loss of Flame	50.2	1.5
12/02/2012 19:30	Trip during shutdown - Loss of Flame	50.2	1.5
12/02/2012 03:57	Trip during shutdown - Loss of Flame	50.2	1.5
18/01/2012 22:29	Trip during shutdown - Loss of Flame	50.6	0.8
19/12/2011 19:02	Trip during shutdown - Loss of Flame	50.8	0.8
14/12/2011 21:06	Trip during shutdown - Loss of Flame	No data Next day value was 50.8	0.9
01/12/2011 19:27	Trip during shutdown - Loss of Flame	50.4	1.3
14/11/2011 08:02	Failure to Ignite	50.6	1.5
28/09/2011 14:01	Trip on start-up - Unable to increase speed	No data Next day value was 50	2.5
28/09/2011 12:18	Trip on start-up - Unable to increase speed	No data Next day value was 50	2.5
23/08/2011 18:04	Trip during shutdown - Loss of Flame	50.2	2

Figure A3.2: Within Day variation of CV at NTS offtake and CCGT trip events at a location in the East of England:



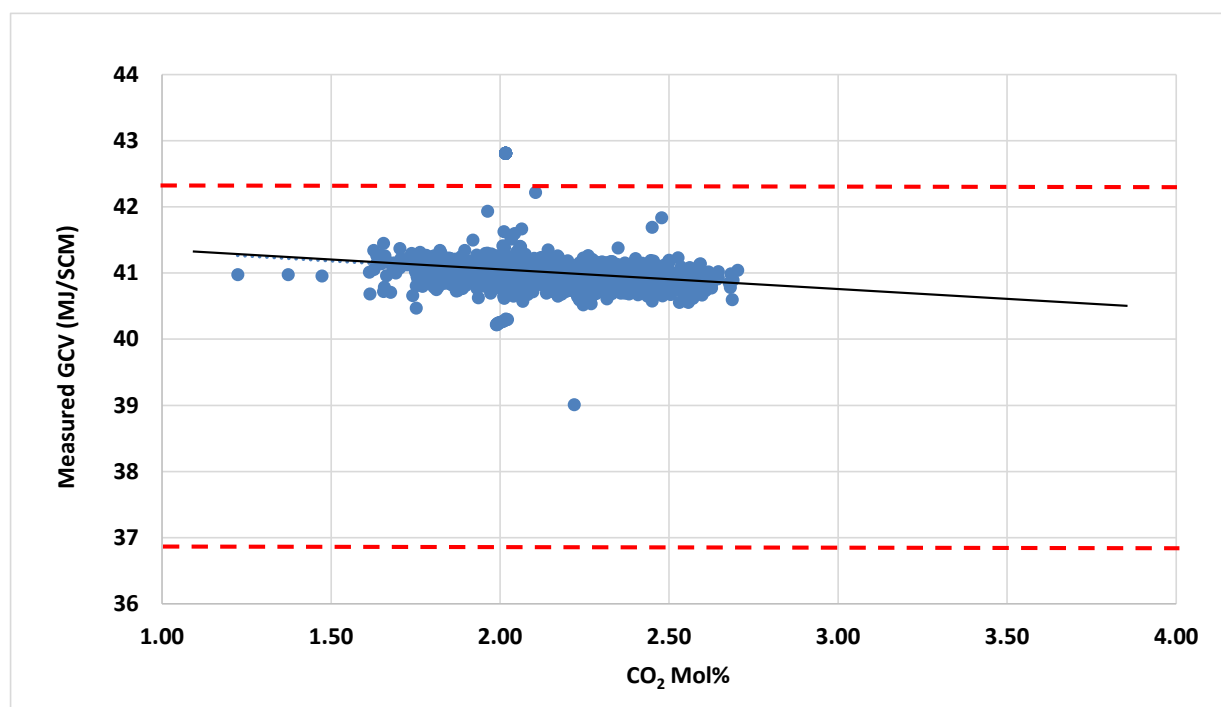
Appendix 4 – Detailed analysis of the impact of increasing CO₂ on Gas Quality at Teesside

Analysis of the impact of increasing CO₂ on gas quality at Teesside has been carried out by BP. The impact of the varying CO₂ content of CATS gas was analysed for its effect on Wobbe, Gross Calorific Value (GCV), Soot Index (SI) and Incomplete Combustion Factor (ICF) over a period of 42 months from January 2011 to June 2014 using daily average data. The findings were summarised in a presentation made to the Workgroup on 7th of August 2014 available [here](#).

Gross Calorific Value (GCV)

The impact of varying CO₂ on GCV is shown in figure A4.1 below. In normal operation, CO₂ varies between 1.6 mol% and 2.7 mol% with very little impact on GCV. Using a best fit line for these data it can be shown at every 1 mol% change in CO₂ content results in about 0.3 MJ/SCM change in GCV.

Figure A4.1: Impact of varying CO₂ on gross calorific value

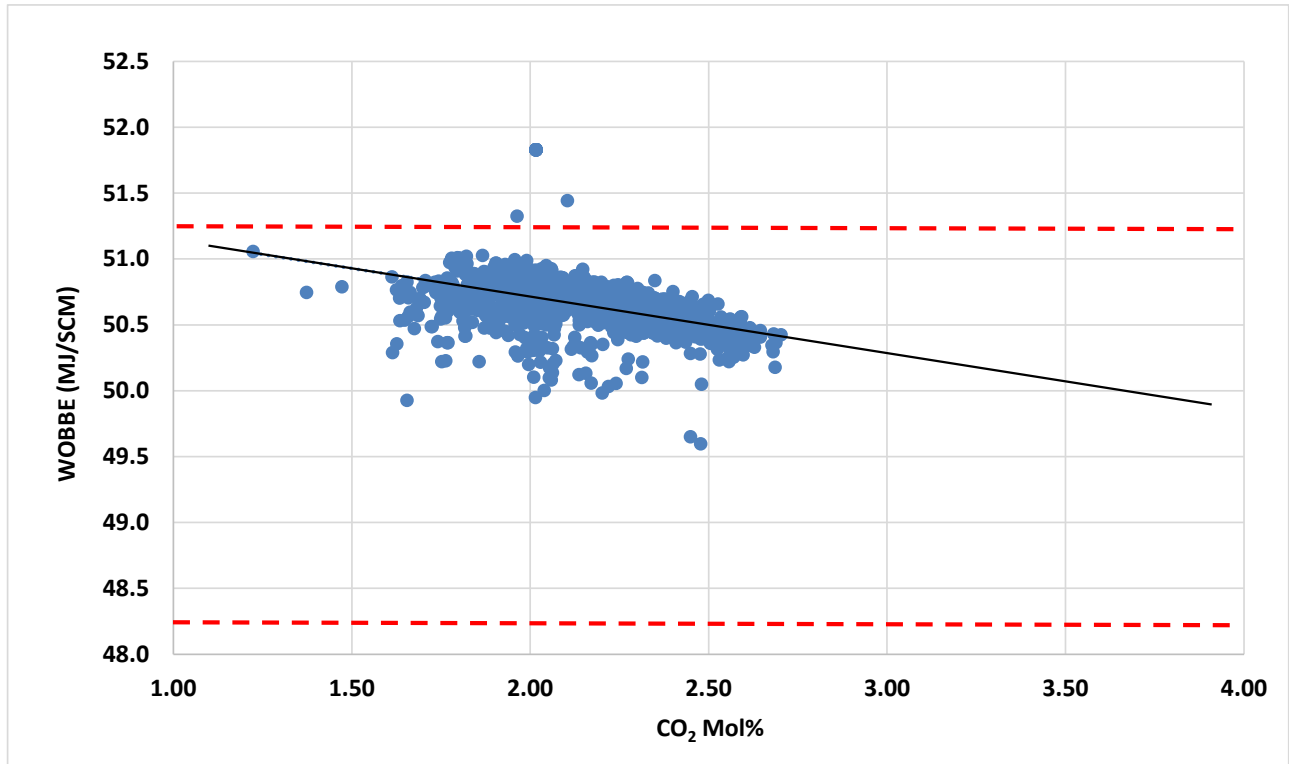


Extrapolating this to a max of 4 mol% would result in a forecast GCV of 40.4 MJ/SCM or a change of less than 1 MJ/SCM when CO₂ content of the gas is 1 mol%. The analysis shows that this GCV remains significantly within the range of GCV allowable in the NEA.

Wobbe Index (WI)

As shown in figure A4.2 below, the data tends to show more scatter than that of GCV in that there a wider range of WI values for any given CO₂ content but this is within normal operating conditions for the Teesside terminals.

Figure A4.2: Impact of varying CO₂ on Wobbe Index

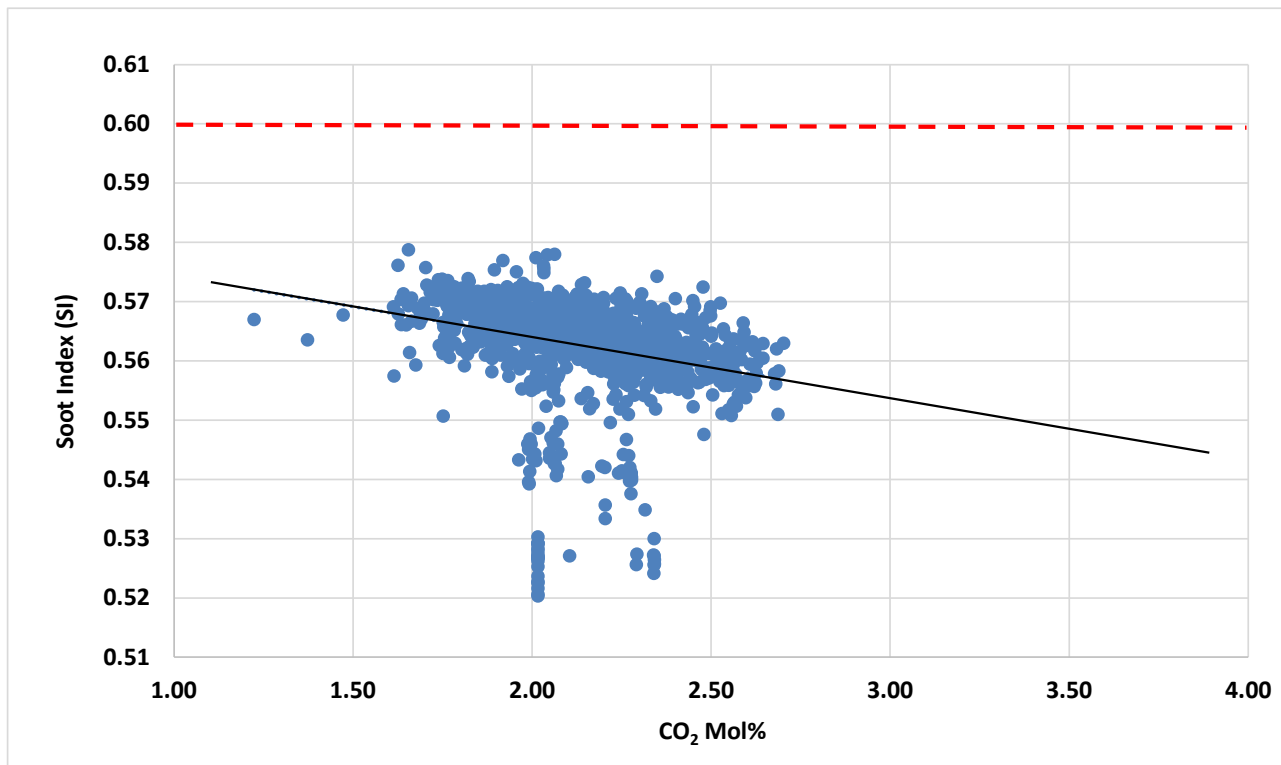


The impact on WI at 4 mol% CO₂ content remains well above the mid-point of the WI range allowable in the NTS gas specification. A move from CO₂ content of 2.9 mol% to 4 mol% would result in a decrease in WI of about 0.5 MJ/SCM.

Soot Index (SI)

As shown in figure A4.3 below, the data show slightly decreasing SI as CO₂ content increases. NTS gas specification has only an upper limit to SI so scatter below the upper limit is acceptable.

Figure A4.3: Impact of varying CO₂ on Soot Index

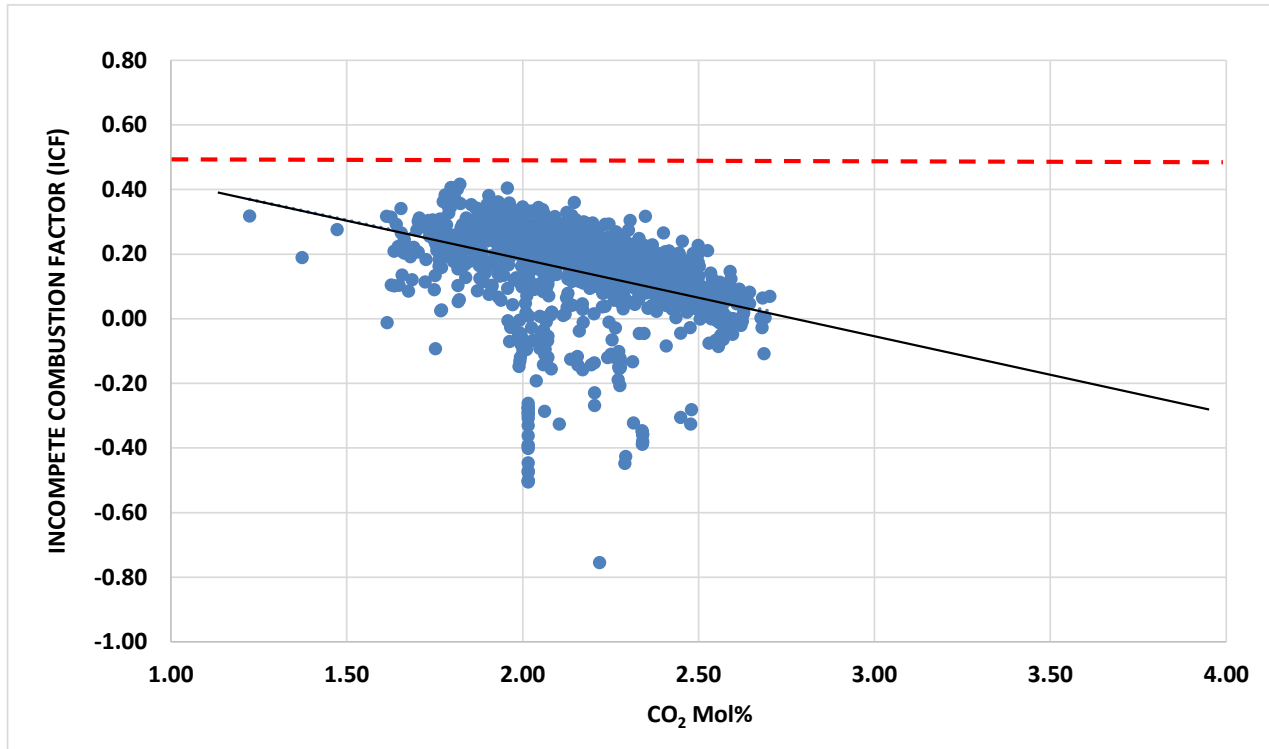


Moving from a CO₂ content of 2.9 mol% to 4 mol % results in a 0.01 reduction in SI.

Incomplete Combustion Factor (ICF)

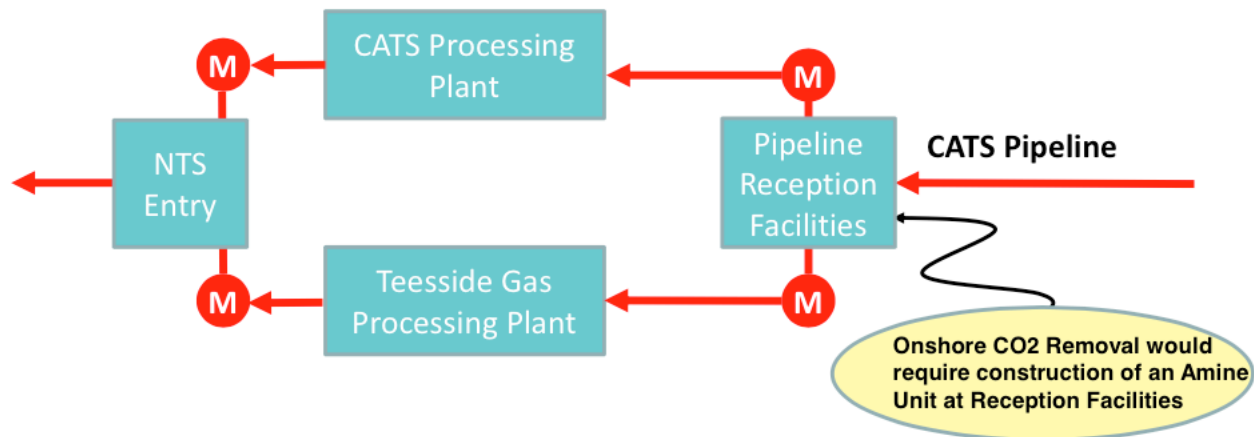
As can be seen in figure A4.4 below, the data for ICF show a similar scatter to that of SI. At 4 Mol% CO₂ the SI value would remain within the operational range recognised for CATS gas entering the NTS and well below the specification limit for NTS gas.

Figure A4.4: Impact of varying CO₂ on Incomplete Combustion Factor



Appendix 5 - Teesside Schematic

Figure A5.1: Schematic of Teesside facilities



Gas in dense phase is carried from offshore oil and gas fields to Teesside by the CATS Pipeline. The reception facilities contain flow & pressure control equipment, metering and H₂S & Hg guard beds. Gas is then processed in either the CATS terminal or Teesside Gas Processing Plant. Water and NGL is removed and NTS specification gas exported via metering equipment to the NTS entry points

Appendix 6 - CO₂ Impact Assessment

Summary

A carbon cost assessment has been calculated for the proposal. The least impact on CO₂ emissions from bringing gas with up to 4.0 mol% CO₂ content into the CATS system is for such gas to be allowed to flow into the NTS. Significantly more CO₂ is emitted by removing CO₂ from the gas due to the need for process heat to remove CO₂. The cost of installing an amine unit either at specific fields offshore or at the onshore terminals is considerable. Current estimates for the fully installed cost of an offshore amine unit is of the order of £200m (undiscounted). When this is taken into account, the mitigation cost increases significantly when compared to the costs to NTS gas consumers (including non ETS participants). On a tonnage basis the cost to an NTS gas consumer (both ETS and Non-ETS participants) is c. £20/te but the cost to mitigate the higher levels of CO₂ prior to gas entering the NTS could be over £1000/te.

Introduction

A carbon cost assessment has been calculated for the proposal. The impact assessment compares the tonnage of CO₂ released in order for the forecast gas landed at Teesside to meet the current 2.9 mol% CO₂ NTS entry specification and the cost of this CO₂ mitigation to the tonnages that would be released by downstream consumers if the Teesside NTS entry specification were to be raised to 4.0 mol% and such gas was not diluted by other NTS flows.

Three scenarios are therefore considered:

- Scenario 1 – Non-removal of CO₂, allowing flow at 4 mol% CO₂ into NTS when such gas cannot be blended with other CATS gas with lower CO₂ content;
- Scenario 2 – Reduction of CO₂ Offshore with an amine unit installed on an offshore production platform to ensure all gas entering the CATS pipeline from the specific field meets the current 2.9 mol% specification; and,
- Scenario 3 – Reduction of CO₂ Onshore with an amine unit installed at the CATS Pipeline reception facilities on Teesside to ensure that gas entering the Teesside Gas Processing Plant or the CATS terminal meeting the current 2.9 mol% specification.

Whilst it is recognised that currently, there are certain circumstances when the CATS operator has curtailed or suspended flows from certain existing fields, these occurrences are difficult to model. In order to simplify the model the carbon impact assessment has been made for the period 2021 to 2032, 2019 being the earliest a field with elevated CO₂ levels such as Jackdaw might be anticipated to start.

Where gas with an elevated CO₂ content flows into the CATS pipeline (Scenarios 1 and 3) this gas will be commingled with other gas with lower CO₂ content. As a result, it is expected that for the majority of time the CO₂ content of gas entering the Teesside NTS entry points is likely to be below the current limit. Increases above the current limit are most likely to be during summer maintenance campaigns or for short periods of unplanned outages when field outages means that gas flows at Teesside will be lower than normal and low CO₂ content gas for blending gas may be restricted. For the purposes of modelling the CO₂ impact assessment, we have assumed that only Jackdaw would flow (using a representative flow profile) and that this period would be 30 days per year. As a result, for this period the CO₂ content of CATS gas has been

assumed to be a maximum of 4 mol%. In reality we would expect this to be a worst case scenario. It is unlikely that Jackdaw would flow entirely on its own so some blending is likely to occur and therefore there a likely to be fewer days per year when CO₂ content is at the maximum assumed 4 mol%.

CO₂ Impact Assessment - Assumptions

The assumptions for the CO₂ impact assessment are detailed in figure A6.1 below.

Figure A6.1: Assumptions for the CO₂ Impact Assessment

Current maximum CO ₂ specification	2.9 mol%
Future maximum CO ₂ specification	4 mol%. Commingled CATS flow likely to be lower No account taken of any blending of Teesside sourced gas with other gas of low CO ₂ content in the NTS
Assessment period	2021 to 2032
Assessment basis	Calendar Year
Annual requirement for CO ₂ removal	Scenario 1 – Non removal Scenario 2 – Reduction to 2.9 mol% 365 days/yr Scenario 3 – Reduction to 2.9 mol% 30 days/yr
Gas production profiles	Offshore - representative production from field operator Onshore – representative flows during summer maintenance days
Amine unit costs	Estimates from BP for fully installed systems
Amine unit efficiency	97%
Temperature required for stored amine when not in use	20°C (manufacturer data)
Heating requirement for stored amine	3.7MW
Electricity, HC emissions	No account is taken of increased emissions from the electrical power required to operate CO ₂ removal equipment or from emissions from burning hydrocarbons emitted during CO ₂ removal
ETS Carbon Valuation	DECC Updated Energy & Emissions Projections - September 2014, 'Carbon Prices - Industry and Services' upto 2035 (2036+ Traded price equals non-traded price)
Carbon Valuation with Carbon Price Support	DECC Updated Energy & Emissions Projections - September 2014, 'Carbon Prices - Electricity Supply Sector' up to 2035 (2036+ inflated at 6% per year)

Carbon Valuation 'Non Traded'	DECC Appraisal Guide 2014, Table 1-20: supporting the toolkit and guidance - Central Prices
Total UK Forecast CO ₂ Emissions	DECC Updated Energy & Emissions Projections - September 2014, Annex B Carbon Dioxide Emissions by Source
Emissions cost by User Group	Gas Usage split by gas demand Users (ETS, Carbon Support, non-ETS) – National Grid, Future-Energy-Scenarios pg.168
Net Present Value Discount Factor	All costs have been discounted using a 10% discount factor back to a start date of 1/1/15
Tax Assumptions	All capex, opex and emissions values are on a pre-tax basis

Analysis

The summary of the output of the analysis is shown in figures A6.2 and A6.3 below.

The detailed analysis is shown in the source spreadsheet (see figures A6.4 to A6.8 in pages 58-62 of this report and Excel spreadsheet published alongside it).

Figure A6.2: Assessment of CO₂ emitted (tonnes equivalent) by scenario

Assessment of CO ₂ Impact from Teesside Gas (2021-2032)	Scenario 1 NTS Delivery at 4 mol % CO ₂	Scenario 2 Offshore CO ₂ Reduction	Scenario 3 Onshore CO ₂ Reduction
CO ₂ Removed by Amine unit (4 mol% to 2.9 mol%) (te)	0	462,881	38,045
CO ₂ in fuel gas consumed by Amine unit (te)	0	213,510	87,497
CO ₂ above 2.9 mol% emitted by consumers (te)	38,045	0	0
Total additional CO₂ emissions (te)	38,045	676,391	125,542

Figure A6.3: Cost Assessment of CO₂ emitted by scenario

Cost Assessment of CO ₂ from Teesside Gas (2021-2032) (£ NVP10 1/1/15, Pre-tax basis)	Scenario 1 NTS Delivery at 4 mol % CO ₂	Scenario 2 Offshore CO ₂ Reduction	Scenario 3 Onshore CO ₂ Reduction
CO ₂ Total ETS Traded Cost	£23,416	£1,601,154	£299,936
CO ₂ Total Traded Cost with Carbon Price Support	£158,001		
Total CO₂ Cost (Traded & Price Support)	£181,417	£1,601,154	£299,936
CO ₂ Total Non-Traded Cost (£/yr) (non-ETS consumption)	£478,416	£0	£0
Total Estimated Emissions Cost	£659,832	£1,601,154	£299,936
Estimated Fully Installed Cost of Amine Unit		£106,685,573	£121,644,132
Estimated Abatement Cost for additional CO₂ prior to NTS entry		£108,286,727	£121,944,068
Cost per tonne (Emissions Cost/Total Additional Emissions)*	£17	£160	£971

* Includes capital costs for amine units

Conclusions

- Over the life of the model (2021-2032), the least impact on overall CO₂ emissions from bringing gas with up to 4 mol% CO₂ content into the CATS system is for such gas to be allowed to flow into the NTS.
- Significantly more CO₂ is emitted by removing CO₂ from the gas. This is due to the fact that CO₂ removal using amine requires process heat. The highest level of emissions is attributed to reduction of CO₂ offshore (676 kte) as a result of operation of an amine unit on the total field gas export stream each day of operation. Onshore reduction of CO₂ has lower CO₂ emissions (125 kte) as the unit would only be used on days when CO₂ levels are expected to be elevated. However this is still significantly higher than an NTS delivery scenario as, when not in use, amine is required to be stored at 20°C to maintain its operational effectiveness and this requires further process heat and as noted in the assumptions there concerns by the vendor of the amine unit over the impact of thermal cycling on operational reliability of the amine unit.

3. It is usual for amine units to remain operational on small volumes of gas to ensure temperature stability to ensure reliability of unit. This would increase operational emissions from those noted in the model.
4. When considering the cost of emissions to ETS participants over the modelled period, transport of 4 mol% CO₂ gas onto the NTS remains the lowest cost option (£181k) while reduction of CO₂ content offshore is the highest cost option £1.60m due the continuous operation and the impact of the operational emissions. Removal of CO₂ onshore is less costly at £300k due to the reduced operation of the amine unit but is still more costly than 4 mol% gas entering the NTS on those occasions when such gas is not blended with other CATS gas.
5. If the cost of non-traded emissions is included (using the split of NTS gas usage calculated by DECC between consumers paying ETS charges, those paying emissions at the Carbon Price Support rate and those for which emissions are non-traded (largely domestic)) then the cost to consumers of the NTS gas from accepting gas with higher CO₂ content increases to £660k.
6. However, it can be argued that the calculated emissions cost for delivery of high CO₂ gas onto the NTS (Scenario 1) are at the high end of a range as the current mechanism for calculating emissions at ETS registered installations is made either using an average CO₂ assessment for a UK region or an installation specific CO₂ content, both of which are estimated using annual averages. Given that any gas with elevated CO₂ content entering the NTS from Teesside is likely to be blended with other NTS gas, the impact may be considered to have a limited geographical area therefore such gas will only have a limited impact on total overall emissions as the regional average assumptions for CO₂ content will remain unaffected.
7. If the provision of CO₂ removal equipment either offshore is considered to “abate” the additional CO₂ entering the NTS then the total cost of providing that “abatement “ needs to be considered.
8. While the capex figures used here are high level estimates and would be refined with further design work it is estimated that the fully installed cost of an amine unit on an offshore platform would be in the region of £180m and the cost of an onshore unit would be of the order of £200m (Discounted at NPV10, these values equate to £107m and £122m respectively).
9. Including the cost of the amine units brings the total NPV10 of mitigating the increased CO₂ – which may be in only excess of the current 2.9 mol% for 30 days per year and most likely less – to between £108m and £122m. In the worst case this is about 180 times more costly than the £660k estimated emissions cost if the CO₂ were to be delivered onto the NTS.
10. In tonnage terms, the cost of the additional CO₂ to a consumer of gas sourced from the NTS (both ETS payers and non-traded users of gas) is c. £17/te, but the cost to mitigate the additional CO₂ either onshore or offshore could be over £971/te due to the additional CO₂ created during the operation of the amine units to remove the additional CO₂.

Figure A6.4: CATS CO₂ Impact Assessment (Amine Unit Capex Excluded)

	Total CO2 (Tt)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total	Annual Average
Reference Data																						
Number of Days Terminals anticipate CO2 in excess of 2.9 Mol %									30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO2 content when in excess of 2.9 Mol%									4.0%	4.0%	4.0%	4.0%	4.0%	3.8%	3.6%	3.4%	3.4%	3.2%	3.2%	3.2%		
CO2 Emissions from warm Amine when unit not in use (Kg/hr)									718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51		
Carbon Valuation 'Traded' (£/te CO2)			5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	8	13	23		
Carbon Valuation 'Traded' with Carbon Price Support (£/te CO2)			20	22	22	22	22	27	33	39	44	50	56	60	65	69	74	78	86	93		
Carbon Valuation 'Non Traded' (£/te CO2)			62	63	64	65	66	67	68	69	70	71	72	73	74	75	77	78	85	92		
Gas Price (p/th)									58.00	60.29	62.57	64.86	67.15	69.44	71.73	72.54	73.35	74.10	75.11	76.37		72
Total UK Forecast CO2 Emissions (MtCO2)									370	349	339	329	324	317	306	300	296	292	296	293	6,609	300
Scenario 1 - NTS Delivery at 4mol%																						
Additional CO2 emissions from 4mol% to 2.9mol% (te/CO2)	38,045								2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	38,045	3,170
Cost of 'Traded' emissions (£)	£23,416		-	-	-	-	-	-	3,858	6,803	7,194	7,461	7,739	6,998	5,603	4,816	4,248	3,751	5,737	8,521	72,731	6,061
Cost of 'Traded' emissions with Carbon Price Support (£)	£168,042		-	-	-	-	-	-	21,157	42,183	49,349	55,688	62,027	58,405	48,428	42,897	38,840	35,070	33,639	32,517	520,201	43,350
Total Cost of Traded & Traded with Price Support emissions (£)	£191,458		-	-	-	-	-	-	25,015	48,986	56,543	63,150	69,766	65,404	54,031	47,712	43,088	38,821	39,377	41,039	592,932	49,411
Cost of 'Non Traded' emissions (£)	£478,416		-	-	-	-	-	-	90,518	156,404	162,044	164,617	167,189	148,009	115,992	97,550	84,192	72,714	69,378	67,063	1,395,668	116,306
Total Cost of emissions (£)	£669,874		-	-	-	-	-	-	115,533	205,389	218,588	227,766	236,954	213,413	170,023	145,262	127,280	111,535	108,755	108,102	1,988,600	165,717
Scenario 2 - Offshore removal																						
Field Forecast Flow (mscfd)									153	259	264	264	264	229	178	147	125	106	93	82		
Field Forecast Flow (mscf/year)									55,725	94,695	96,455	96,455	96,455	83,511	65,000	53,505	45,586	38,871	33,824	30,053	790,135	65,845
CO2 emissions from amine process to 2.9mol% content (te)	462,881								32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721	462,881	38,573
Additional CO2 emissions from Amine unit fuel gas (te)	213,510								15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174	213,510	17,792
Total CO2 emissions from Offshore removal (te)	676,391								47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895	676,391	56,366
Total cost of emissions (£)	£1,601,154		-	-	-	-	-	-	263,814	465,161	491,923	510,214	529,184	478,533	383,156	329,302	290,505	256,513	392,313	582,692	4,973,309	414,442
Scenario 3 - Onshore removal																						
Terminals Forecast Flow When Exceeding 2.9 mol% (mscfd)									153	259	264	264	264	229	178	147	125	106	93	82		
CO2 emissions from amine process (4 mol% to 2.9mol% content) (te)	38,045								2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	38,045	3,170
Additional CO2 emissions from Amine unit fuel gas (te)	17,549								1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672	17,549	1,462
Additional CO2 emissions from Amine when not in use (te)	69,948								5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	69,948	5,829
Total CO2 emissions from Onshore removal (te)	125,542								9,738	12,474	12,604	12,604	12,604	11,736	10,389	9,608	9,043	8,565	8,218	7,957	125,542	10,462
Total cost of emissions (£)	£299,936		-	-	-	-	-	-	54,019	71,770	75,217	78,013	80,914	78,142	71,746	68,816	67,180	65,996	110,923	179,057	1,001,794	83,483

Figure A6.5: CATS CO₂ Full Cycle Cost/Benefit Analysis

	Total CO2 (Tt)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total	Annual Average
Reference Data																						
Field Forecast export Flow (th/year)									590,761,403	1,003,907,057	1,022,564,639	1,022,564,639	1,022,564,639	885,340,417	689,091,121	567,229,096	483,272,579	412,084,603	358,584,168	318,603,522	8,376,567,881	698,047,323
Number of Days Terminals anticipate CO2 in excess of 2.9 Mol %									30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO2 content when in excess of 2.9 Mol%									4.0%	4.0%	4.0%	4.0%	4.0%	3.8%	3.6%	3.4%	3.4%	3.2%	3.2%	3.2%		
Carbon Valuation 'Traded' (£/te CO2)			5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	8	13	23		
Carbon Valuation 'Traded' with Carbon Price Support (£/te CO2)			20	22	22	22	22	27	33	39	44	50	56	60	65	69	74	78	86	99		
Carbon Valuation 'Non Traded' (£/te CO2)			62	63	64	65	66	67	68	69	70	71	72	73	74	75	77	78	85	92		
Gas Price (p/tn)									58.00	60.29	62.57	64.86	67.15	69.44	71.73	72.54	73.35	74.10	75.11	76.37		72
Total UK Forecast CO2 Emissions (MttCO2)									370	349	339	329	324	317	308	300	298	292	296	293	3,811	300
Scenario 1 - NTS Delivery at 4mol%																						
Additional CO2 emissions from 4mol% to 2.9mol% (te/CO2)	38,045								2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	38,045	3,170
Cost of 'Traded' emissions (£)	£23,416		-	-	-	-	-	-	3,858	6,803	7,194	7,461	7,739	6,998	5,603	4,816	4,248	3,751	5,737	8,521	72,731	4,041
Cost of 'Traded' emissions with Carbon Price Support (£)	£158,001		-	-	-	-	-	-	21,157	42,183	49,349	55,688	62,027	58,405	48,428	42,897	38,840	35,070	5,296	7,866	467,206	25,956
Total Cost of Traded & Traded with Price Support (£)	£181,417		-	-	-	-	-	-	25,015	48,986	56,543	63,150	69,766	65,404	54,031	47,712	43,088	38,821	11,033	16,387	539,937	29,996
Cost of 'Non Traded' emissions (£)	£478,416		-	-	-	-	-	-	90,518	156,404	162,044	164,617	167,189	148,009	115,992	97,550	84,192	72,714	69,378	67,063	1,395,668	77,537
Total Cost of emissions (£)	£659,832		-	-	-	-	-	-	115,533	205,389	218,588	227,766	236,954	213,413	170,023	145,262	127,280	111,535	80,411	83,451	1,935,605	107,534
Scenario 2 - Offshore removal																						
Field Forecast Flow (mscd)									153	259	264	264	264	229	178	147	125	106	93	82		
Field Forecast Flow (mscd/year)									55,725	94,695	96,455	96,455	96,455	83,511	65,000	53,505	45,586	38,871	33,824	30,053	790,135	65,845
CO2 emissions from amine process to 2.9mol% content (te)	462,881								32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721	462,881	38,573
Additional CO2 emissions from Amine unit fuel gas (te)	213,510								15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174	213,510	17,792
Total CO2 emissions from Offshore removal (te)	676,391								47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895	676,391	56,366
Capex of Amine unit (£)	£106,685,573		-	-	-	-	90,000,000	90,000,000	-	-	-	-	-	-	-	-	-	-	-	-	180,000,000	10,000,000
Total Cost of Emissions	£1,601,154		-	-	-	-	-	-	263,814	465,161	491,923	510,214	529,184	478,533	383,156	329,302	290,505	256,513	392,313	582,692	4,973,309	276,295
Total cost of emissions (£)	£108,286,727		-	-	-	-	90,000,000	90,000,000	263,814	465,161	491,923	510,214	529,184	478,533	383,156	329,302	290,505	256,513	392,313	582,692	184,973,309	10,276,295
Scenario 3 - Onshore removal																						
Terminals Forecast Flow When Exceeding 2.9 mol% (mscd)									153	259	264	264	264	229	178	147	125	106	93	82		
CO2 emissions from amine process (4 mol% to 2.9mol% content (te)	38,045								2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	38,045	3,170
Additional CO2 emissions from Amine unit fuel gas (te)	17,549								1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672	17,549	1,462
Additional CO2 emissions from Amine when not in use (te)	69,948								5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	69,948	5,829
Total CO2 emissions from Onshore removal (te)	125,542								9,738	12,474	12,604	12,604	12,604	11,736	10,389	9,608	9,043	8,565	8,218	7,957	125,542	10,462
Capex of Amine unit (£)	£121,644,132		-	-	-	50,000,000	50,000,000	100,000,000	-	-	-	-	-	-	-	-	-	-	-	-	200,000,000	11,111,111
Total Cost of Emissions	£299,936		-	-	-	-	-	-	54,019	71,770	75,217	78,013	80,914	78,142	71,746	68,816	67,180	65,996	110,923	179,057	1,001,794	55,655
Total cost of emissions (£)	£121,944,068		-	-	-	50,000,000	50,000,000	100,000,000	54,019	71,770	75,217	78,013	80,914	78,142	71,746	68,816	67,180	65,996	110,923	179,057	201,001,794	11,166,766

Figure A6.6: Scenario 1 – NTS Delivery at 4.0 mol%

Case
Full Field [MMSCFD]
Full Field [kSm ³ /hr]
Calculation of CO2 above 2.89 mol% delivered to NTS
CO2 Content In [mol%]
CO2 Content Out [mol%]
CO2 Removal Unit Flow [MMSCFD]
CO2 Removal Unit Flow [kSm ³ /hr]
CO2 Content Exit Unit [ppm]
Removal Unit Efficiency [%]
Quantities of CO2 removed [kg/hr]
Quantities of CO2 removed [te 30 days per annum]
CO2 Molecular Weight [kmol/kg]

Additional CO2 for Scenario 1 [te 30 days per annum]
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2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
153	259	264	264	264	229	178	147	125	106	93	82
180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1
4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8
51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1
1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023
2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457
44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01

2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457
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Emission
38,045

Figure A6.7: Scenario 2 - Offshore CO₂ Removal

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Full Field [MMSCFD]	153	259	264	264	264	229	178	147	125	106	93	82
Full Field [kSm ³ /hr]	180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1
CO2 Content In [mol%]	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
CO2 Content Out [mol%]	2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
Calculation of CO2 Removal to meet 2.89 mol% spec												
CO2 Removal Unit Flow [MMSCFD]	43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8
CO2 Removal Unit Flow [kSm ³ /hr]	51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1
CO2 Content Exit Unit [ppm]	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
Removal Unit Efficiency [%]	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023
Quantities of CO2 removed [te per annum]	32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721
CO2 Molecular Weight [kmol/kg]	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	13.54	23.02	23.48	23.48	23.48	20.47	15.80	13.09	11.14	9.48	8.28	7.37
Methane Molecular Weight [kmol/kg]	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	3.30	5.60	5.71	5.71	5.71	4.98	3.85	3.19	2.71	2.31	2.01	1.80
Benzene Molecular Weight [kmol/kg]	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11
Amine Unit Operational Data & Calcs												
Gas Flowrate [MMSCFD]	43.68675	74.26781	75.72496	75.72496	75.72496	66.02211	50.96799	42.23395	35.92241	30.58201	26.69963	23.78772
Sour Gas Processed, Q [MSm ³ /day]	1.24	2.10	2.14	2.14	2.14	1.87	1.44	1.20	1.02	0.87	0.76	0.67
Contact Pressure, P [kPa abs]	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33
Acid Gas Conc ⁿ , y [mole%]	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033
Amine Conc ⁿ , x [mass%]	20	20	20	20	20	20	20	20	20	20	20	20
mol acid gas pick-up per mol amine	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Amine Flow, [m ³ /hr]	86.84	147.63	150.52	150.52	150.52	131.24	101.31	83.95	71.41	60.79	53.07	47.28
Amine Flow, [m ³ /d]	2084.14	3543.05	3612.57	3612.57	3612.57	3149.68	2431.50	2014.83	1713.73	1458.96	1273.74	1134.83
Amine Flow, [GPM]	382.34	649.98	662.74	662.74	662.74	577.82	446.07	369.63	314.39	267.65	233.67	208.19
Amine Contactor Diameter, Dc [mm]	1140	1486	1501	1501	1501	1401	1231	1121	1034	954	891	841
Calculation of CO2 Emission from Fuel Gas Usage in Amine Unit												
Absorbed Reboiler Duty [MW]	8.08	13.73	14.00	14.00	14.00	12.21	9.42	7.81	6.64	5.65	4.94	4.40
Heater Duty [MW]	8.97	15.25	15.55	15.55	15.55	13.56	10.47	8.67	7.38	6.28	5.48	4.89
Thermal Efficiency at 90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fuel Gas HHV [MJ/kg]	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494
Fuel Gas Requirement [kg/hr]	653	1110	1131	1131	1131	986	761	631	537	457	399	355
CO2 Emissions Factor [kg CO2 per kg FG]	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626
CO2 Formed from Amine Unit FG [kg/hr]	1714	2913	2970	2970	2970	2590	1999	1657	1409	1200	1047	933
CO2 Formed from Amine Unit FG [te per annum]	15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174
Additional CO2 Emissions for Scenario 2 [te per annum]	47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895

Emissions
676,391

Figure A6.8: Scenario 3 - Onshore CO₂ Removal

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Full Field [MMSCFD]	153	259	264	264	264	229	178	147	125	106	93	82
Full Field [kSm ³ /hr]	180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1
CO2 Content In [mol%]	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
CO2 Content Out [mol%]	2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
Calculation of CO2 Removal to meet 2.89 mol% spec												
CO2 Removal Unit Flow [MMSCFD]	43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8
CO2 Removal Unit Flow [kSm ³ /hr]	51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1
CO2 Content Exit Unit [ppm]	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
Removal Unit Efficiency [%]	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023
Quantities of CO2 removed [te 30 days per annum]	2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457
CO2 Molecular Weight [kmol/kg]	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	13.54	23.02	23.48	23.48	23.48	20.47	15.80	13.09	11.14	9.48	8.28	7.37
Methane Molecular Weight [kmol/kg]	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	3.30	5.60	5.71	5.71	5.71	4.98	3.85	3.19	2.71	2.31	2.01	1.80
Benzene Molecular Weight [kmol/kg]	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11
Amine Unit Operational Data & Calcs	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA
Gas Flowrate [MMSCFD]	43.6867471	74.26781	75.72496	75.72496	75.72496	66.02211	50.96799	42.23395	35.92241	30.58201	26.69963	23.78772
Sour Gas Processed, Q [MSm ³ /day]	1.24	2.10	2.14	2.14	2.14	1.87	1.44	1.20	1.02	0.87	0.76	0.67
Contact Pressure, P [kPa abs]	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33
Acid Gas Conc ^o , y [mole%]	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033
Amine Conc ⁿ , x [mass%]	20	20	20	20	20	20	20	20	20	20	20	20
mol acid gas pick-up per mol amine	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Amine Flow, [m ³ /hr]	86.84	147.63	150.52	150.52	150.52	131.24	101.31	83.95	71.41	60.79	53.07	47.28
Amine Flow, [m ³ /d]	2084.14	3543.05	3612.57	3612.57	3612.57	3149.68	2431.50	2014.83	1713.73	1458.96	1273.74	1134.83
Amine Flow, [GPM]	382.34	649.98	662.74	662.74	662.74	577.82	446.07	369.63	314.39	267.65	233.67	208.19
Amine Contactor Diameter, Dc [mm]	1140	1486	1501	1501	1501	1401	1231	1121	1034	954	891	841
Calculation of CO2 Emission from Fuel Gas Usage in Amine Unit												
Absorbed Reboiler Duty [MW]	8.08	13.73	14.00	14.00	14.00	12.21	9.42	7.81	6.64	5.65	4.94	4.40
Heater Duty [MW]	8.97	15.25	15.55	15.55	15.55	13.56	10.47	8.67	7.38	6.28	5.48	4.89
Thermal Efficiency at 90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fuel Gas HHV [MJ/kg]	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494
Fuel Gas Requirement [kg/hr]	653	1110	1131	1131	1131	986	761	631	537	457	399	355
CO2 Emissions Factor [kg CO2 per kg FG]	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626
CO2 Formed from Amine Unit Fuel Gas [kg/hr]	1714	2913	2970	2970	2970	2590	1999	1657	1409	1200	1047	933
CO2 Formed from Amine Unit Fuel Gas [te (30 days)]	1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672
Calculation of CO2 Emissions from Fuel Gas Usage for Amine Standby												
Heater Duty for amine heating when non-operational [MW]	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664
FG Requirement for non-operational Amine Unit (kg/hr)	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000
CO2 Formed in Standby Mode [kg/hr]	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000
CO2 Formed in Standby Mode [te per annum (335 days)]	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829
Additional CO2 emissions Scenario 3 [te per annum]	9,738	12,474	12,604	12,604	12,604	11,736	10,389	9,608	9,043	8,565	8,218	7,957

Emissions
125,542

12 Glossary

ASEP	Aggregated System Entry Point (<i>where more than one entry point exists</i>)
BG	BG Group plc
BSi	British Standards Institute
Capex	Capital Expenditure
CATS	Central Area Transmission System (<i>ie from the UK Continental Shelf</i>)
CCGT	Combined Cycle Gas Turbine (<i>a gas-fired electricity generation unit</i>)
CEN	European Committee for Standardisation
CH ₄	Methane
CO ₂	Carbon Dioxide
CV	Calorific Value
EU ETS	EU Emissions Trading System (<i>multi-country, multi-sector greenhouse gas emissions trading system, see https://www.gov.uk/participating-in-the-eu-ets.</i>)
FEED	Front End Engineering Design
FES	Future Energy Scenarios (<i>document, available on nationalgrid.com</i>)
GSMR	Gas Safety (Management) Regulations
GSOG	Gas Storage Operators Group
H ₂ S	Hydrogen Sulphide
ICF	Incomplete Combustion Factor
kte	Kilo tonnes equivalent (<i>thousands of tonnes equivalent</i>)
MERUK	Maximisation of Economic Recovery of oil and gas from the UK continental shelf
mol%	Mole % (<i>a measure of the constituents in a mixture</i>)
NEA	Network Entry Agreement
NOX	Generic term for mono-nitrogen oxides (nitric oxide and nitrogen dioxide)
NPV10	Net Present Value discounted at 10%
OEM	Original Equipment Manufacturer
RE	Reasonable Endeavours
SEP	(NTS) System Entry Point
SI	Soot Index
SSO	Storage System Operator
TAR	Turnaround (annual shutdown)
te	Tonnes equivalent
TEG/MEG	Tri- and mono- ethylene glycols (<i>commonly used in dewatering applications</i>)
uHPHT	ultra-High Pressure High Temperature
VOC	Volatile Organic Compounds
WI	Wobbe Index (<i>an indicator of the interchangeability of gas</i>)