Stage 02: Combined Workgroup Report

0498:

Amendment to Gas Quality NTS Entry Specification at BP Teesside System Entry Point

0502:

Amendment to Gas Quality NTS Entry Specification at the px Teesside System Entry Point

At what stage is this document in the process?

01 Modification

02 Workgroup Report

03 Draft Modification Report

04 Final Modification Report

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).

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.

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.

The Workgroup recommends that these modifications should now proceed to consultation.

Medium Impact: Transporters, Shippers and Consumers

Contents

About this document:

This combined report will be presented to the Panel on 21 May 2015.

The Panel will consider whether these modifications should proceed to consultation or be returned to the Workgroup for further assessment.

The Workgroup recommends the following timetable:	
Initial consideration by Workgroup	01 May 2014
Amended Modification considered by Workgroup	n/a
Workgroup Report presented to Panel	21 May 2015
Draft Modification Report issued for Consultation	21 May 2015
Consultation Close-out for representations	11 June 2015
Final Modification Report published for Panel	12 June 2015
UNC Modification Panel decision	18 June 2015

Any questions?

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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.

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.

Solution

Both modifications propose an amendment to a Network Entry Provision, to permit an increase in the CO_2 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 CO_2 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%.

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 CO_2 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%.

Relevant Objectives

For both Modifications **0498** and **0502** it is believed that the increase to a higher CO_2 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 has not proposed a timescale for implementation of these modifications, but would suggest that they are implemented simultaneously at the earliest practical opportunity.

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

This does not affect the UK Link Replacement Programme delivery or any other change.

2 Why Change?

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 CO_2 levels that exceed current limits. The current CO_2 limit at Teesside already causes curtailments to production on certain days when insufficient blending gas is available and the current limit would be temporarily exceeded. In addition, by analysing the CO_2 content of future gas production potentially entering the System at Teesside, BP has identified an increasing risk that, especially in summer months and from 2019 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 CO_2 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 CO_2 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 CO_2 content could be potentially accommodated without impacting NTS integrity and/or consumers and/or cross border trade. It should also be noted that CO_2 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 CO_2 limit, resulting in the interruption of gas flows into the NTS.

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 CO_2 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 CO_2 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%.

Modification 0502

This modification seeks to amend the Network Entry Provision within the existing px (TGPP) Limited NEA. This amendment would increase the CO_2 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%.

User Pays
Classification of these modifications 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 proposed split of the recovery between Gas Transporters and Users for User Pays costs and the justification for such view.
None
Proposed charge(s) for application of User Pays charges to Shippers.
None
Proposed charge for inclusion in the Agency Charging Statement (ACS) – to be completed upon receipt of a cost estimate from Xoserve.
None

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.	**0498** and **0502**: Impacted
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**: Impacted
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.	**0498** and **0502**: Impacted
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

Impact on Relevant Objectives *(whole section to be considered and confirmed)*

The Workgroup concluded that there were impacts to four Relevant Objectives:
a) Efficient and economic operation of the pipe-line system
b) Coordinated, efficient operation of the offshore and onshore systems
d) Competition between relevant shippers
e) Incentives to provide gas for domestic customers in line with supply security standard.

Views differed between participants and no clear consensus was reached. In the following pages these views are explained further.

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 CO_2 emissions increase as the additional CO_2 is emitted from our process in addition to the CO_2 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 CO_2 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 CO_2 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 CO_2 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 (CH_4), 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 CO_2 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 CO_2 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 CO_2 of the gas composition will increase the amount of CO_2 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 CO_2 through EU ETS liabilities.

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

DECC Q1: Provide more information on whether downstream users can upgrade their CO2 removal systems to tackle the problem that systems are running at (near) full – LJ written to GrowHow 10/3/15

DECC Q2: Could we see more evidence from turbine manufacturers about the impact on warrantees? - EUK/CCGT operators to seek information

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**

DECC Q3: Please quantify the amount of gas Jackdaw will provide (total size, lifetime production, daily deliverability) – please provide some analysis to support the assertion that Jackdaw will improve security of supply. – See 'Further Background' para 1 below (DOD)

DECC Q5: Please quantify the benefits of Jackdaw in terms of efficient infrastructure utilisation and tax revenues – LJ include something to ref the consultation

DECC Q6: Please provide further details as to why the Jackdaw development cannot go ahead at 2.9% entry given the estimate that CO2 expected to exceed 2.9% only a limited number of days - covered on p15

DECC Q7: Please estimate the number of days CO2 might exceed 2.9% pre-2019 (as done for post-2019) – derive pre-2019 data for CO2 excursions and amend report (AP)

Further Background to the Change

BP and TGPP consider that the current specification for CO_2 at the Teesside entry points is incompatible with the composition of some natural gas from potential upstream developments. BP have observed that the current CO_2 limit is already causing interruption to existing production on certain days. At least one future development 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 the Jackdaw development. The Jackdaw discovery was made in 2005 and is one of a number of significant gas discoveries in the area. Operated by BG plc, 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 development costs are high (estimated to be in the region of £3bn). Timing of first gas for the development is expected to be in the late teens or early 2020s. Add here a chart showing UK production and details of Jackdaw size (Q3)

The significant size of the find will help underpin UK energy supply over twenty years but the high cost associated with uHPHT developments makes the developing this and other discoveries challenging. It is essential that the initial capital cost is kept as low as possible. The requirement to remove CO_2 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 at St Fergus, currently have a firm 4.0mol% NTS entry specification whilst the CATS and TGPP Network Entry Agreements (NEAs) have Reasonable Endeavours rights *(what are the impacts of this in practice? - DOD)* for short-term breaches of CO_2 up to a maximum of 4.0 mol%. Increasing the current CO_2 specification at the Teesside entry points to 4 mol% would result in more efficient utilisation of existing infrastructure capacity, extend the useful life of existing assets and, by facilitating the development of discoveries such as Jackdaw, contribute significantly to Maximisation of Economic Recovery of oil and gas from the UK continental shelf (MERUK).

Simplified Technical Explanation of impact of increasing CO_2 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 CO_2 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 CO_2 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 (available here). 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 CO_2 limit of 4.0 mol%. Detailed analysis can be found in Appendix 3.

Forecast Levels of CO_2 in gas at Teesside

The average CO_2 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 occasional days when CO_2 content exceeds the current specification limit and post 2019, there is the potential for development of at least one new field in the CATS catchment containing elevated levels of CO_2 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 CO_2 content of gas entering the NTS at the Teesside entry points is likely to be similar to historic norms and well below the current 2.9 mol% specification limit. This is achieved through the blending of gas with high CO_2 content with gas low in CO_2 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 CO_2 to blend the high CO_2 gas into specification.

Up to 2018 CO_2 levels could exceed 2.9 mol% for short periods (c.2-3 days) during summer maintenance periods. As a result, the overall annual average impact is forecast to be 0.03 mol%. Insert/amend here for DECC Q7 – forecast levels prior to 2019 (AP)

From 2019 onwards, CO_2 levels in CATS/TGPP export gas during the summer months are likely to range between 2.66 mol% and 3.6 mol% (max 4.0 mol%) with CO_2 levels in non-summer months ranging between 2.66 mol% and 3.0 mol% (max 3.57 mol%). It is important to stress that elevated CO_2 levels are not anticipated to be the norm and CO_2 levels in excess of 2.9 mol% are only expected to occur for short durations.

Anticipated Impact on Gas Quality

Potential European Standard on Gas Quality

There are currently no regulatory CO_2 limits at cross border points. The European Committee for Standardisation (CEN) issued its draft gas quality standard to national standardising bodies in May 2014. BSi conducted GB's consultation, ending on 31 August 2014, following which the CEN Working Group met in Nov/Dec 2014 to consider the consultation responses. Agreement could not be reached on a harmonised range for Wobbe-Index.

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."

Whilst the European Commission have stated their aspiration to see the eventual standard implemented by all Member States, there are currently no firm plans to achieve this.

National Grid NTS' Assessment of their Operational Risks

National Grid NTS has completed an exercise, supported by network analysis, to assess the possible NTS operational risks arising from higher CO_2 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 CO_2 in GB, and parts of the NTS (e.g. two of the St Fergus subterminals) have had 4 mol% legacy contractual CO_2 limits for many years with no known evidence of additional corrosion (as expected from the "dry gas" NTS system). CO_2 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% CO_2, compared to average 1.1% CO_2 in Norfolk. See Appendix 1 for more information.

Operations

This is similar to safety in terms of engineering operation. Commercially the lower CV expected from higher CO_2 gas has been assessed with CV shrinkage modelling and was shown to be not material by NTS. Impact on CO_2 emissions from 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% CO_2 (driven by Belgian limits[1]) but otherwise there are no CO_2 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 CO_2 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.

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 all[2] 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

1 http://www.fluxys.com/belgium/en/Services/Transmission/Contract/~/media/Files/Services/Transmission/ServicesAndModels/fluxys_ope

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

gas is modelled to make up a proportion of 25% or more of the flow at NTS offtakes. These maps are shown 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 cashout penalty derives from the portfolio now being short following a trip on its nominated position.
- The penalty regime refers to the 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 diversificiation 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.
>
> 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.
>
> H_2 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.

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.

Linking CCGT Trips to Changes in Gas Quality

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

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 CO_2 of the gas composition will increase the amount of CO_2 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 CO_2 through EU ETS liabilities.[3] 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 ±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

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.

DECC Q8: Please outline the costs of CCGT retuning, and potential costs of CCGT tripping. – provide data for both items (trips on 2 scenarios) JC/EUK

DECC Q9: Please 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, what flexibility there is

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

elsewhere in the system to accommodate. – Could be a consequential impact on the Elec market, but Capacity Market (effective 2018) addresses this by what…

Shipper identified…commercial and contractual issues – to be considered by shipper participants (potential trip leading to Elec Capacity Mechanism Impacts) – potentially part of Q9

Impact on Storage Operators *(AMi to work on quantifying impacts and costs)*

The principal concern for Gas Storage Operators Group (GSOG) members relates to increases in the absolute levels of CO_2 in gas on the NTS, rather than speed of gas quality change, because of the increased risk of corrosion from higher CO_2 gas. This risk arises because higher CO_2 results in higher carbonic acid levels in the aqueous condensate. Increased carbonic acid increases the rate of corrosion in the underground pipework.

The cost impact on storage operators is difficult to predict given the information provided in the development of these modifications. However, should the changes at Teesside result in higher levels of CO_2 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 CO_2 will depend to some degree on the particular site, however members have noted that sustained levels of gas with greater than 1.7 mol% CO_2 will require them to reassess of their carbonic acid monitoring and treatment programme. Others have noted that the 2.5 mol% level could create significant challenges for storage systems.

In addition to the risk associated with carbonic acid, increasing the CO_2 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.

DECC Q10: Report needs to quantify the 'significant challenges' for storage operators.

Carbon Cost Assessment

Options for addressing elevated levels of CO_2 in gas at Teesside

The options for addressing the possible increases in CO_2 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 CO_2 removal technology. The CO_2 emissions and associated cost of such emissions are estimated in the Carbon Cost Assessment (see below).

If the CO_2 entry specification was not increased on Teesside then current excursions in CO_2 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 CO_2 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 CO_2 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 (Ref - DOD).

See also Appendix 4 for the underlying detail.

Options for addressing increases in CO_2 Levels as detailed in the Carbon Cost Assessment

Option 1 - Flow gas up to 4.0 mol% CO_2 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 CO_2 content would be blended in the offshore pipeline to ensure current delivery specifications are met. High CO_2 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 CO_2 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 CO_2 removal equipment which may be used for only a few days/weeks per year. This option would also prevent significant additional CO_2 being released to atmosphere from the use of process heat associated with the CO_2 removal technology.

Removal of CO_2 above 2.9 mol% at the upstream platform or at the terminals

DECC Q12: Please outline why the Amine process is the most appropriate CO2 removal technology? – provide an explanatory paragraph – see para 2 below

DECC Q13: Have the Jackdaw developers considered whether there are alternative arrangements for managing the CO2 risk. I.e. could the terminal hold blending gas in storage for the (limited) number of days when offshore blended gas might not be available? – see Q12

There are a number of technologies available for removal of CO_2 from natural gas. The most suitable technology for a particular application depends on factors such as removal duty, inlet/outlet CO_2

concentrations, contaminants, operating conditions, volumetric flow, downstream processing requirements and relative capital / operating costs.

In their technical study work of CO_2 removal at CATS, BP started by examining all feasible technologies. They selected amine as the only robust technology for the large volumes being processed, the high pressure of the gas and the low concentration of CO_2 (and hence low mass flowrate of CO_2 vs mass flowrate of hydrocarbon gas). This eliminated other technologies such as membranes and molecular sieves. (Initial para provided, but needs to be reviewed/expanded as per WG discussions (AP/DOD. See also following existing para)

Based upon likely CO_2 partial pressures in the raw gas at the terminal and the required NTS entry specification, the most suitable technology to achieve a reduction in CO_2 from 4 mol% to 2.9 mol% for gas delivered to the Teesside entry point is a Formulated Amine Process.

The Formulated Amine Process consists of an absorber column and regeneration unit. Amine solution flows against the gas stream in an absorber column. CO_2 is absorbed producing a sweetened gas stream and CO_2 rich amine solution. Rich amine is routed to the regeneration unit where it is flashed to low pressure and heated producing a CO_2 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 CO_2 emissions in addition to the CO_2 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 CO_2 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 costs be minimised. The fully installed cost of an offshore amine unit is likely to be in the order of £180m (£129M when discounted at a 10% NPV), which would be borne by the field owners. 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 CO_2 at less than 2.9 mol%. As a result, it is likely that the CO_2 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 CO_2 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 CO_2 removal facilities were not installed offshore, then in order to ensure that CO_2 levels remain within the NTS entry specifications it would be necessary to install an amine unit or units at the terminals. CO_2 removal facilities would need to be installed at the lower pressure (c. 65 bar) exit points of the terminals as the pipeline and terminal entry points operate at high pressure (c. 105 bar). The cost of installation of an amine unit at a Teesside processing facility is c. £200m (£147M when discounted at a 10% NPV). The additional cost over an offshore unit is due to the requirement to process larger volumes of gas from the commingled pipeline stream.

It is anticipated that the amine unit (or units) would only be operated during those periods when the CO_2 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 CO_2 spec could not be met. Continuous operation would add significantly to the CO_2 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^{o}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^{o}C when the fluid is not in use, which BP and TGPP estimate requires about 3.6MW of process heat.

See Appendix 5 for a schematic of the likely layout.

Tabulation of Advantages/Disadvantages for CO_2 options *(DOD to break out into end-consumers and EU ETS consumers)*

CO_2 Option	Cost (£MM)	Advantages	Disadvantages
Option 1 Flow gas at 4 Mol% CO_2 into NTS	No equipment cost	• Low cost • High CO_2 gas blended with other CATS gas for most of year • Flow of high CO_2 gas for limited periods (Field maintenance, unplanned outages) • Lower CO_2 emissions overall – no CO_2 released from process heat • No VOCs combusted **End Consumers:** • Any? **EU ETS Consumers:** • Any?	• Some high CO_2 content gas enters NTS on occasional days **End Consumers:** • Any? **EU ETS Consumers:** • Possible slightly elevated emissions charges for consumers but limited impact on site specific annual average CO_2 levels
Option 2 CO_2 Removal Offshore at source	c. £180M (£129M as a discounted Net Present Value at 10%) (NPV10)	• Removes to CO_2 from specific high CO_2 gas • Allows CATS pipeline gas to remain within current specification • CO_2 content of NTS gas remains within current specification **End Consumers:** • Any? **EU ETS Consumers:** • Any?	• Additional cost to specific project • Additional CO_2 emissions from the use of process heat in addition to that removed from the gas • Additional VOCs combusted during venting of CO_2 extracted from gas • Increased emissions charges • Additional cost may make specific project sub-economic at assumed commodity prices • Specific project delayed or not developed • Ultimate recovery of oil and gas from UKCS is impacted **End Consumers:** • Any? **EU ETS Consumers:** • Any?
Option 3 CO_2 Removal Onshore at CATS Pipeline Reception Facilities	Up to £200M (£147M as a discounted Net Present Value at 10%) (NPV10)	• High CO_2 content gas can be blended with low CO_2 content gas in the CATS pipeline • Most of year CO_2 content of NTS gas remains within current specification without specific action • CO_2 removal equipment provides backstop if current CO_2 specification is exceeded **End Consumers:** • Any? **EU ETS Consumers:** • Any?	• Additional cost to specific project • Equipment only operational for short duration • Additional CO_2 released through process heat when operational and requirement to ensure amine maintained at 20^oC when not in use • May be required to operate continually to ensure continued reliability • Increased emissions charges • Additional cost may make specific project sub-economic at assumed commodity prices • Specific project delayed or not developed • Ultimate recovery of oil and gas from UKCS is impacted **End Consumers:** • Any? **EU ETS Consumers:** • Any?

Carbon Cost

A carbon cost assessment has been calculated for the proposal. The impact assessment compares the tonnage of CO_2 released in order for the forecast gas landed at Teesside to meet the current 2.9 mol% CO_2 NTS entry specification and the cost of this CO_2 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 CO_2 options:

Scenario 1 – Non-removal of CO_2;

Scenario 2 – Removal Offshore; and,

Scenario 3 – Removal Onshore.

The detailed carbon cost assessment and assumptions are included in Appendix 6.

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 2019 to 2030, 2019 being the earliest a field with elevated CO_2 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 CO_2 levels are likely to be below the current CO_2 limit with CO_2 content above 2.9 mol% being possible during summer maintenance campaigns or for short periods of unplanned outages when gas with high CO_2 content cannot be blended in the CATS pipeline with gas with low CO_2 content. For the purposes of modelling the CO_2 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 CO_2 content of CATS gas has been assumed to be a maximum of 4 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 a likely to be fewer days per year when CO_2 content is at the maximum assumed 4 mol%.

A summary of the overall CO_2 impact assessment is provided in the table below: *(updated for v0.8)*

Assessment of CO_2 Impact from Teesside Gas (2019-2030)	Scenario 1 NTS Delivery at 4 mol % CO2	Scenario 2 Offshore CO2 Reduction	Scenario 3 Onshore CO2 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 CO_2 emissions (te)	**38,045**	**676,391**	**125,542**

The removal of CO_2 offshore results in the greatest level of CO_2 emissions (676 kte) as there is a requirement to treat the entire gas stream being exported the production platform. Removing CO_2 above the current 2.9 mol% limit at the terminals results in lower CO_2 emissions (125 kte) than an offshore solution as gas with high levels of CO_2 is blended with low CO_2 gas for most of the time and treatment is only 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, there is a requirement to maintain the amine tank at about 20^{o}C when the fluid is not in use. As a result, during the period of assessment, there is over 2.3 times more CO_2 released from process heat than is required to be removed from the gas to meet the current 2.9 mol% CO_2 limit for NTS gas. This would 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. When this significant volume of CO_2 is considered, the overall level of CO_2 emissions remain significantly higher (125 kte in total) than allowing the gas to pass onto the NTS on the days when such gas flowed into the CATS system. In this model, the direct pass through of CO_2 results in an additional 38 kte of emissions between 2019 and 2030.

In terms of cost of abatement of the CO_2 generated above the current 2.9 mol% limit, it should be noted that there is no true abatement as the CO_2 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 CO_2 from entering the NTS but it should be noted from the table above that any prevention of the additional CO_2 entering the NTS results in the emission of significantly more CO_2 due to the operation of the CO_2 removal equipment.

These costs of the three alternative scenarios are summarised in the table below. For consistency, these data are shown on a Net Present Value 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. *(table updated for v0.8 – end column title needs amending to Scenario 3 DOD)*

Cost Assessment of CO_2 from Teesside Gas (2019-2030) (£ NVP10 1/1/15)	Scenario 1 NTS Delivery at 4 mol % CO2	Scenario 2 Offshore CO2 Reduction	Scenario 2 Onshore CO2 Reduction
CO_2 Total ETS Traded Cost	£24,728	£1,690,905	£304,418
CO_2 Total Traded Cost with Carbon Price Support	£161,371		
Total CO2 Cost (Traded & Price Support)	**£186,099**	**£1,690,905**	**£304,418**
CO_2 Total Non-Traded Cost (£/yr) (non-ETS consumption)	£559,424	£0	£0
Total Estimated Emissions Cost	**£745,523**	**£1,690,905**	**£304,418**
Estimated Fully Installed Cost of Amine Unit		£147,189,400	£129,089,543
Estimated Abatement Cost for additional CO2 prior to NTS entry		**£148,880,305**	**£129,393,961**
Cost per tonne	**£20**	**£220**	**£1,031**

In terms of ETS traded costs where CO_2 emissions costs are measured against market prices, the highest cost option (NPV10 £1.69m) would be removal of CO_2 offshore as this option results in the largest volume of CO_2 emitted. The cost of removal of CO_2 onshore at the terminals is also significant (NPV10 £304k) due to the substantial amount of CO_2 emitted through process heat. Delivery of gas with 4.0 mol% CO_2 content onto the NTS is impacted by the requirement for power generators to pay substantially higher charges for emitted CO_2 due to the Carbon Price Support scheme. However at NPV10 £186k 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 CO_2 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 CO_2 assessment for a UK region or an installation specific CO_2 content, both of which are estimated using annual averages (DOD to check the statement about using annual averages). Given that any gas with elevated CO_2 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 CO_2 content will remain unaffected.

If the impact of consumption of gas by non-ETS paying consumers is considered (using the DECC pricing assumption for Non Traded CO_2 emissions), the CO_2 emissions cost of NTS delivery of 4.0 mol% CO_2 gas increases to £745k.

If it is considered that the provision of CO_2 removal equipment either offshore or onshore is to “abate” the CO_2 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 (Discounted at NPV10, these values equate to £129m and £179m respectively).

Including the cost of the amine units brings the total NPV of mitigating the increased CO_2 – which may be in only excess of the current 2.9 mol% for 30 days per year and most likely less – to between £129m and £149m. In the worst case this is over 100 times more costly than the £745k estimate if the CO_2 were delivered onto the NTS. In tonnage terms, the cost of the additional CO_2 to a consumer of gas from the NTS (both ETS payers and non-traded users of gas) is c. £20/te but costs could be over £1000/te to mitigate the CO_2 prior to gas entering 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 3 December, 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. DOD to consider inclusion of a statement (or addressing this in the modelling?) to deal with the tax allowance question raised by JCx

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 HPHT projects in the central North Sea. The government has indicated that it will take further measures in the forthcoming Budget in March 2015 in order to restore the international competitiveness of the UKCS for upstream investors.

The new fiscal measures mark the clearest statement yet of the government's aim to maximise the economic recovery of the remaining oil and gas resources on the UKCS and to promote development of HPHT gas resources in particular. Modifications 498 and 502 are entirely consistent with the government's objectives in that they will lower the capital cost of development of HPHT 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.

Policy explanation of Carbon reduction vs sustainable UKCS (MH to consider and compile)

Conclusions *Views welcome*

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

The Workgroup has not proposed a timescale for implementation of these modifications, but would suggest that they are implemented *[simultaneously]* at the earliest practical opportunity.

6 Impacts

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

This does 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%~~ 4.0 mol%*

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~~ 4.0 mol%

8 Recommendation

The Workgroup invites the Panel to:

- AGREE that these modifications should be submitted for consultation.

[?? Any additional questions for UNC Modification Panel consideration / potential inclusion in the consultation focus ???]

1. Repondents are requested to quantify any additional costs they would incur as a result of an isolated CO2 excursion to 4 mol%.
2. Respondents are requested to quantify any wider benefits/disbenefits for the UK economy that might be derived from these proposals.

9 Appendices

1 CO_2 Levels at Entry Points

2 Teesside Flow Maps

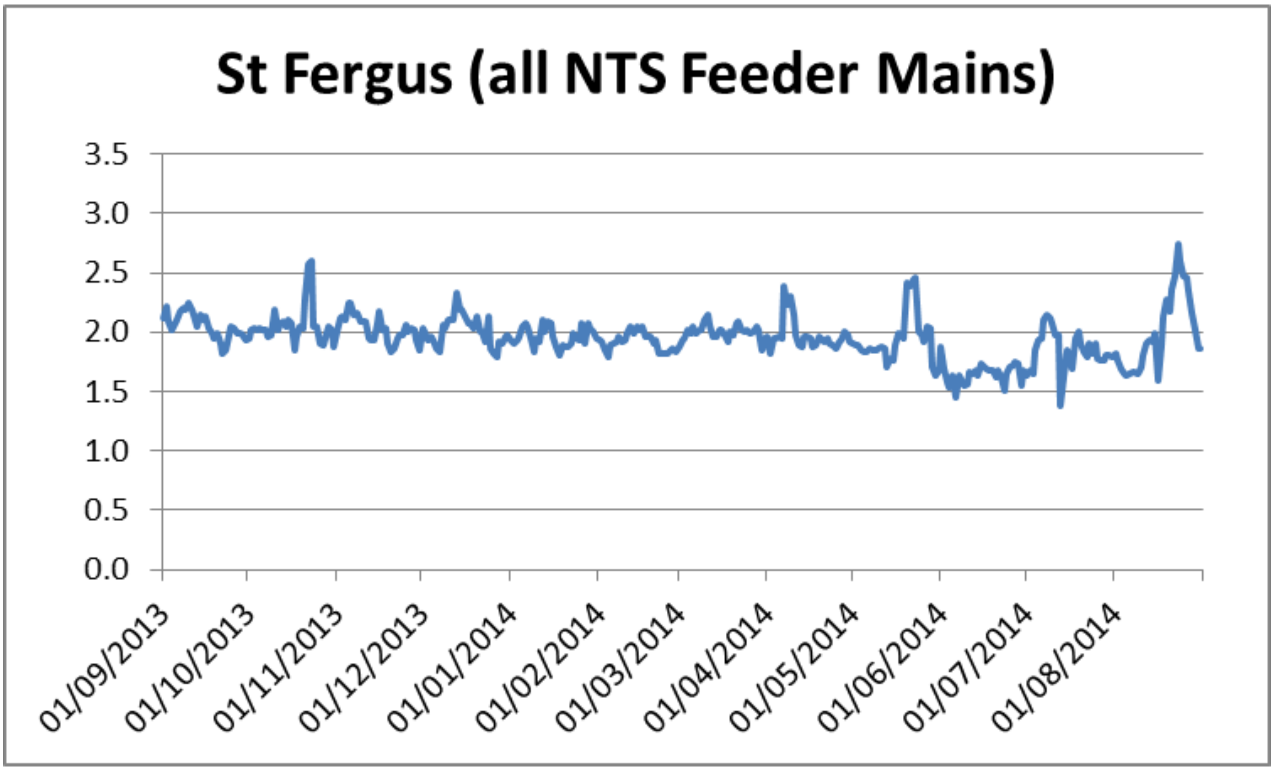
3 Plant trips at one CCGT located in the East of England

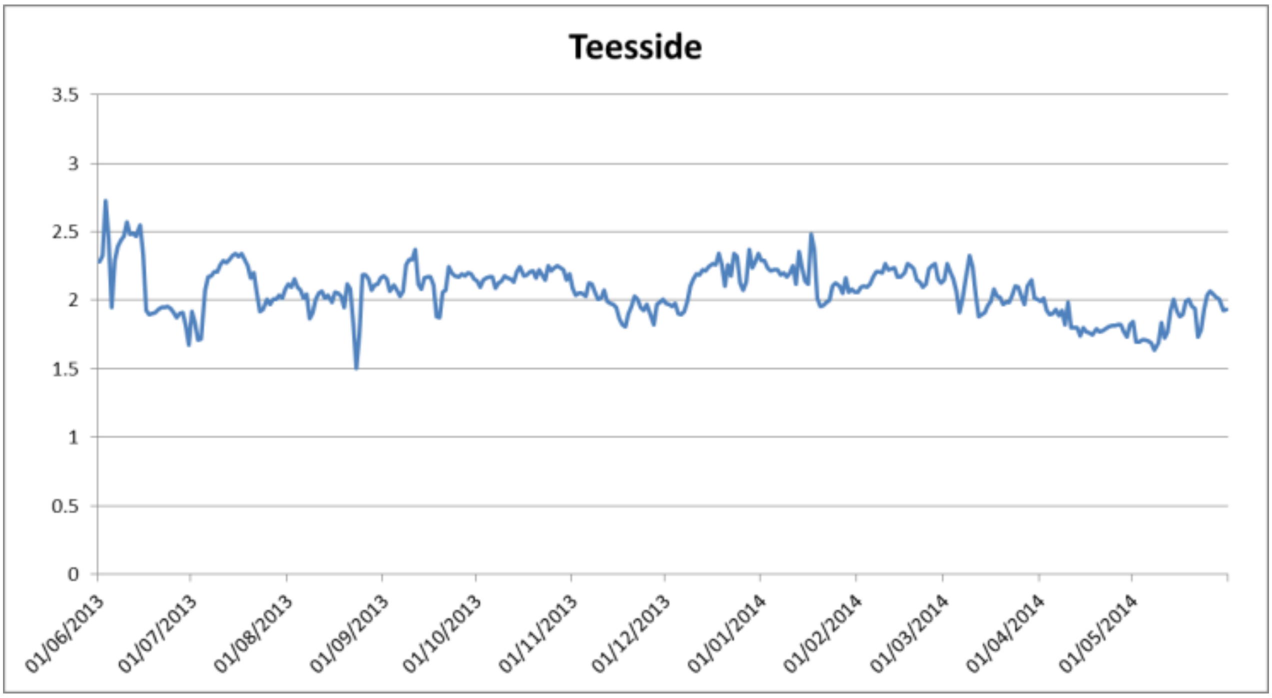
4 Detailed analysis of the impact of increasing CO_2 on Gas Quality at Teesside

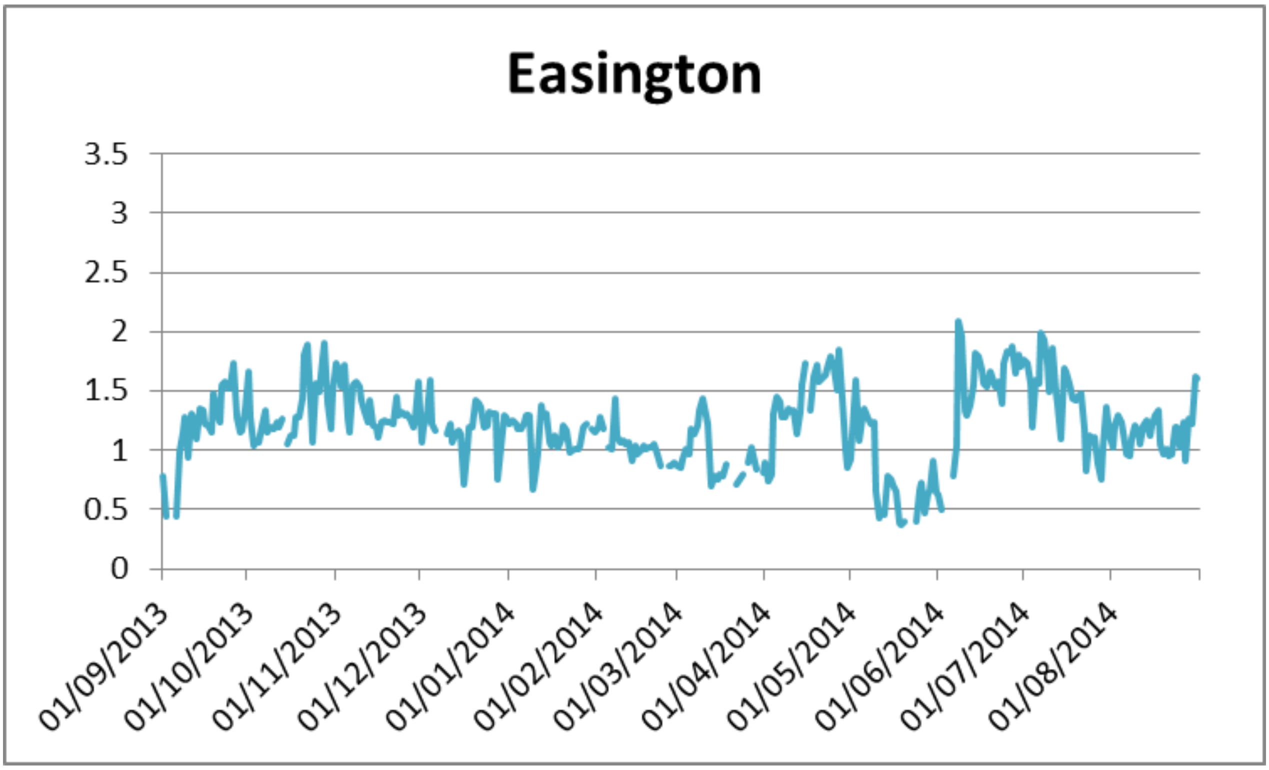
5 Teesside Schematic

6 CO_2 Impact Assessment

Appendix 1 - CO_2 Levels at Entry Points (plot is mol%)



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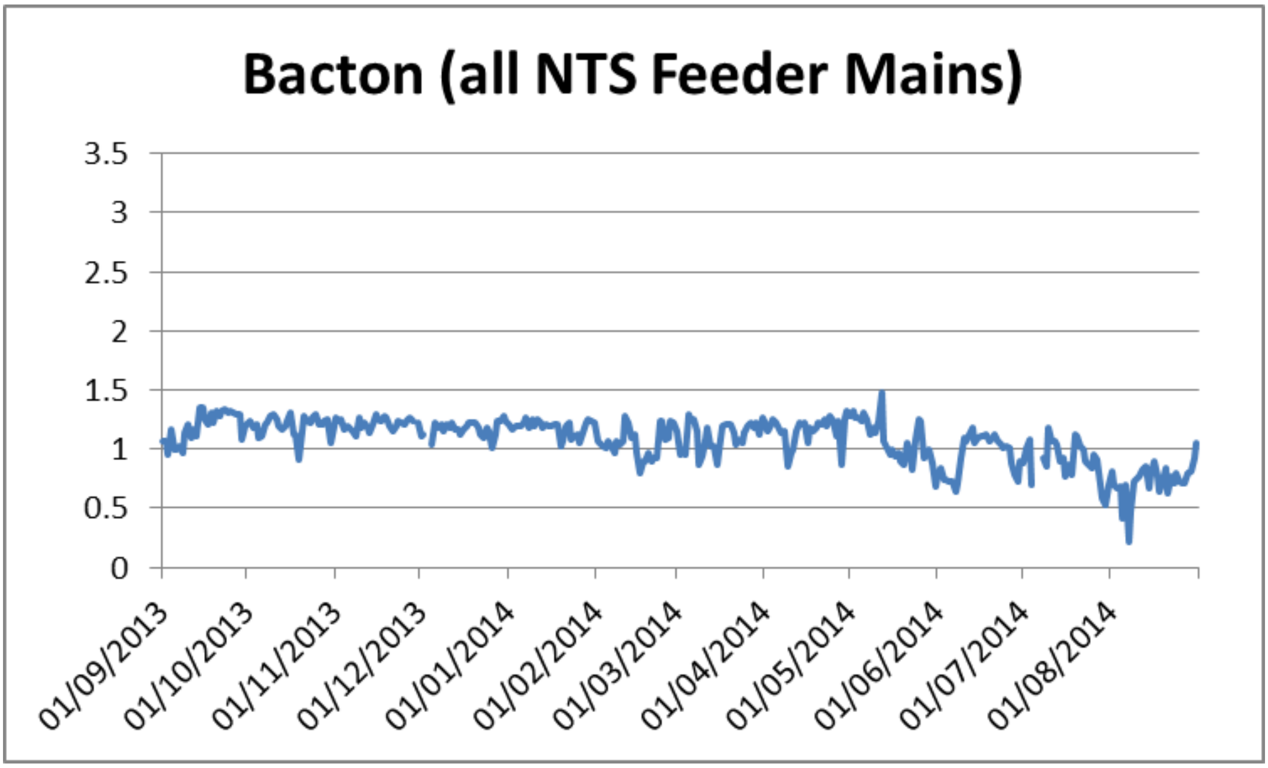
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01/12/2013
01/01/2014
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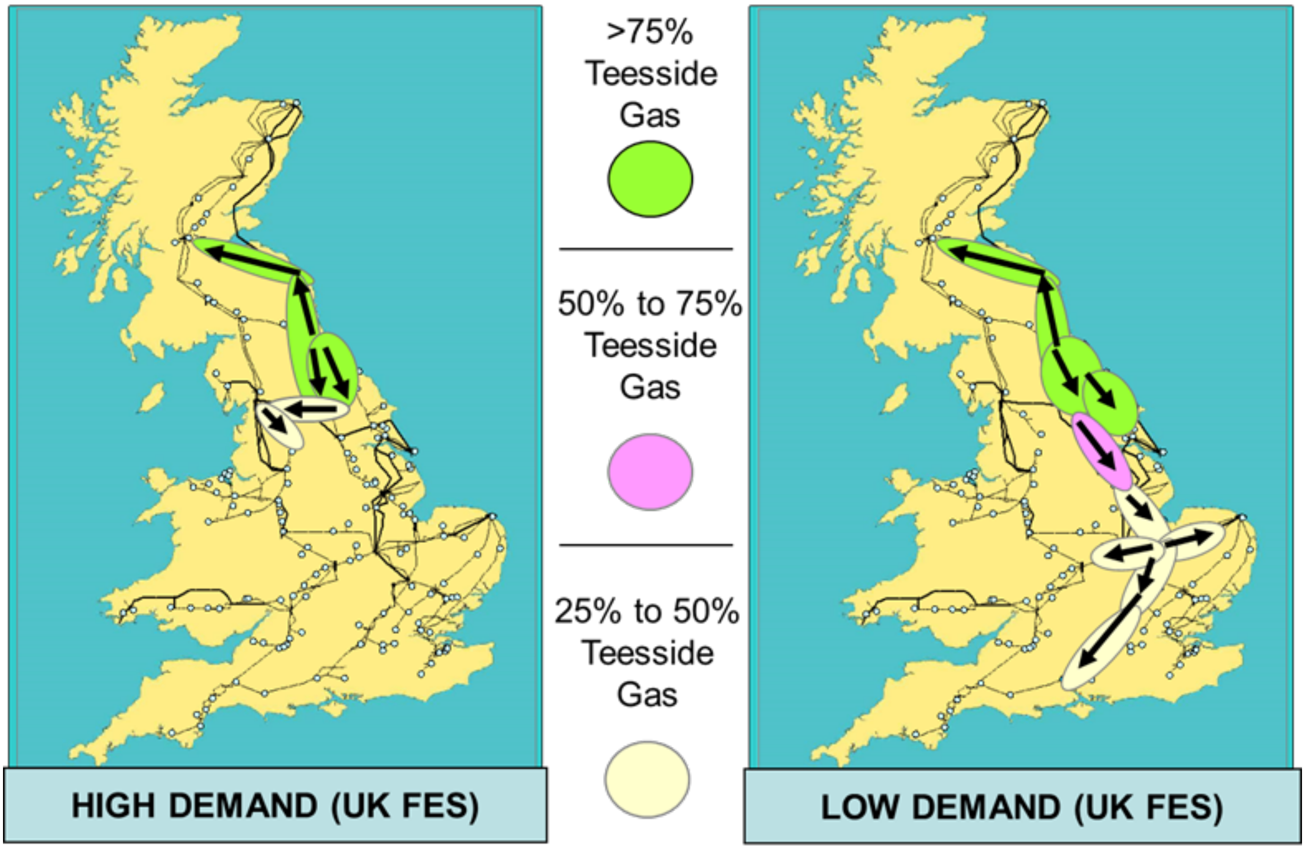
Appendix 2 - Teesside Flow Maps

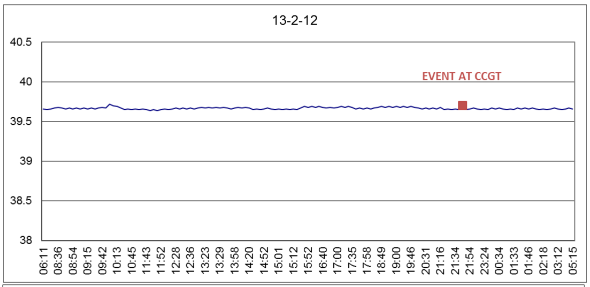


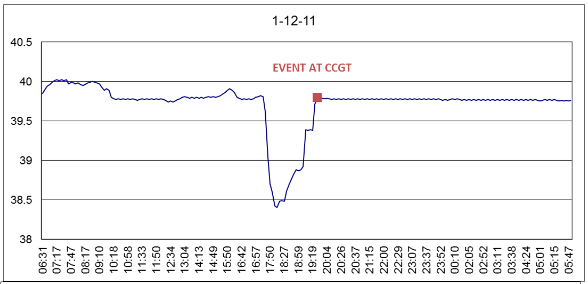
Appendix 3 – Plant trips at one CCGT located in the East of England

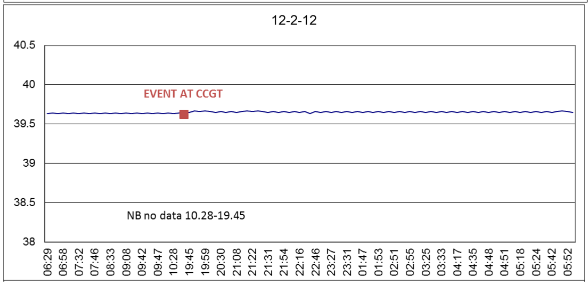
Data provided via Energy UK:

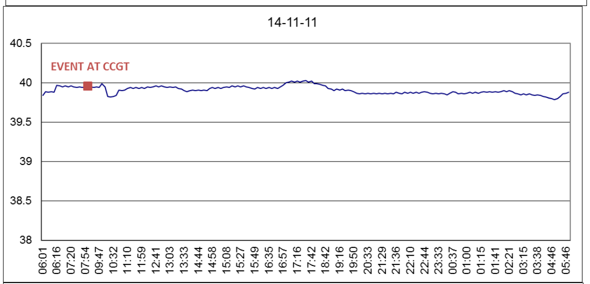
Date	Event	Wobbe Index, MJ/Sm^3	CO_2 (mol%)
13/02/2012 21:36	Trip during shutdown - Loss of Flame	50.2	1.5
12/02/2012 19:30	Trip during shutdown - Loss of Flame	50.2	1.5
12/02/2012 03:57	Trip during shutdown - Loss of Flame	50.2	1.5
18/01/2012 22:29	Trip during shutdown - Loss of Flame	50.6	0.8
19/12/2011 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

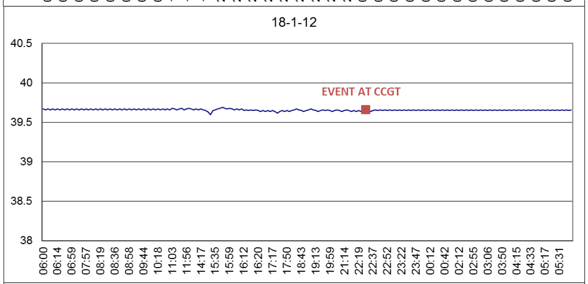
Within Day variation of CV at NTS offtake and CCGT trip events at a location in the East of England:

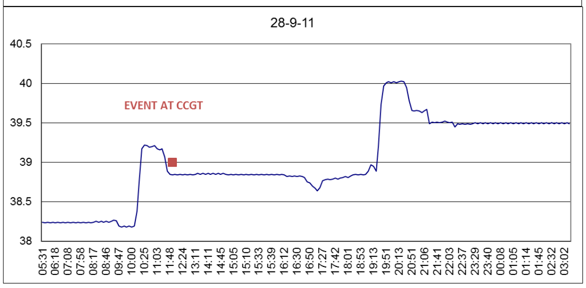


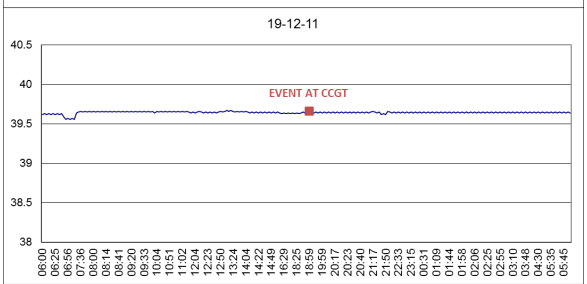


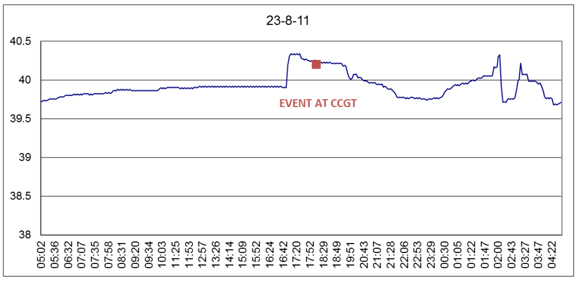


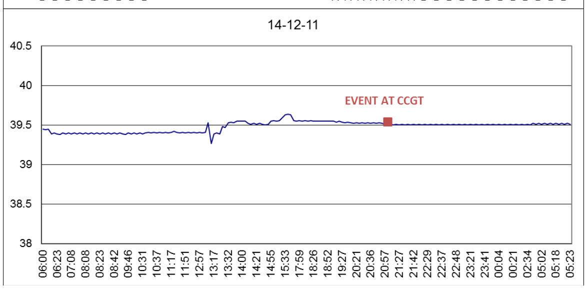










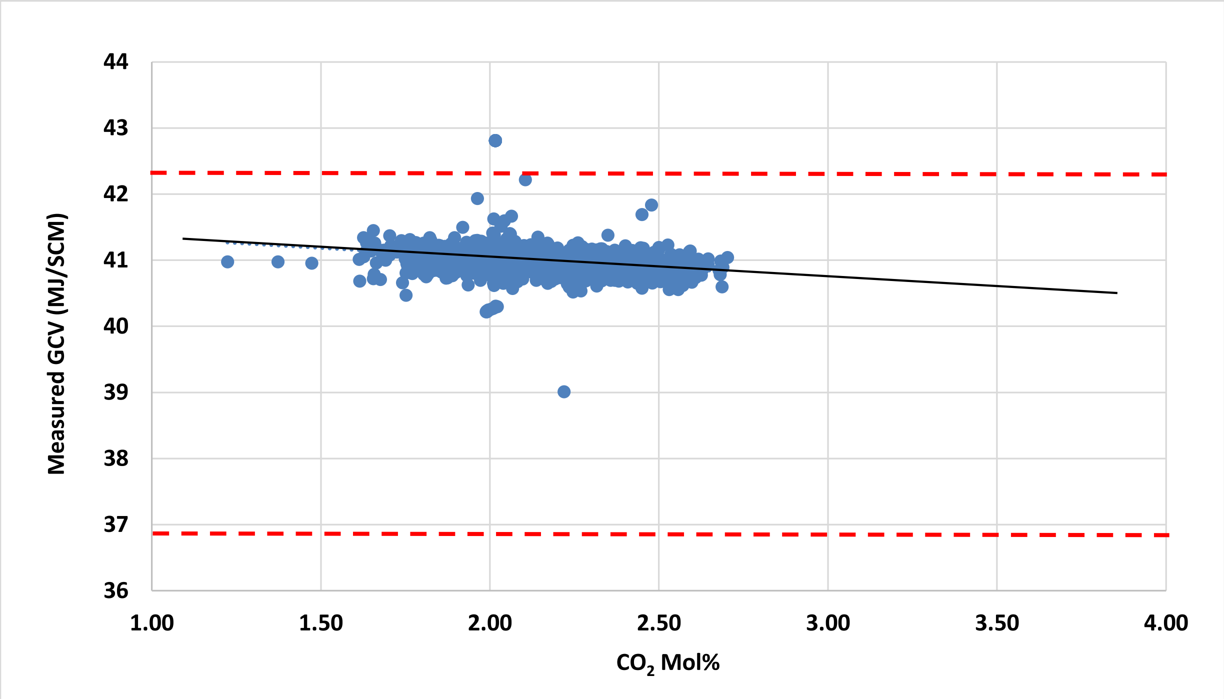


Appendix 4 – Detailed analysis of the impact of increasing CO_2 on Gas Quality at Teesside

Analysis of the impact of Increasing CO_2 on gas quality at Teesside has been carried out by BP. The impact of the varying CO_2 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)

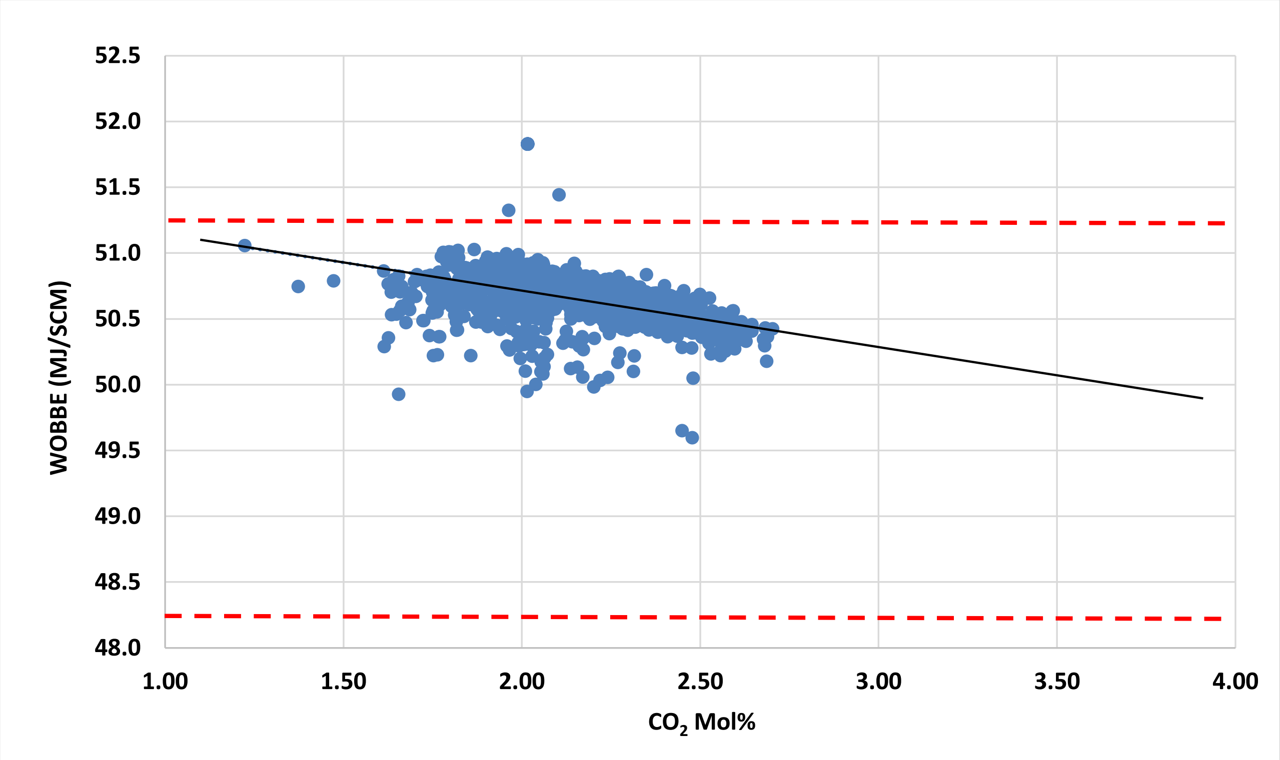
The impact of varying CO_2 on GCV is shown in the chart below. In normal operation, CO_2 varies between 1.6 mol% and 2.7 mol% with very little impact on GCV. Using a best fit line for these data it can be shown at every 1 mol% change in CO_2 content results in about 0.3 MJ/SCM change in GCV.



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 CO_2 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)

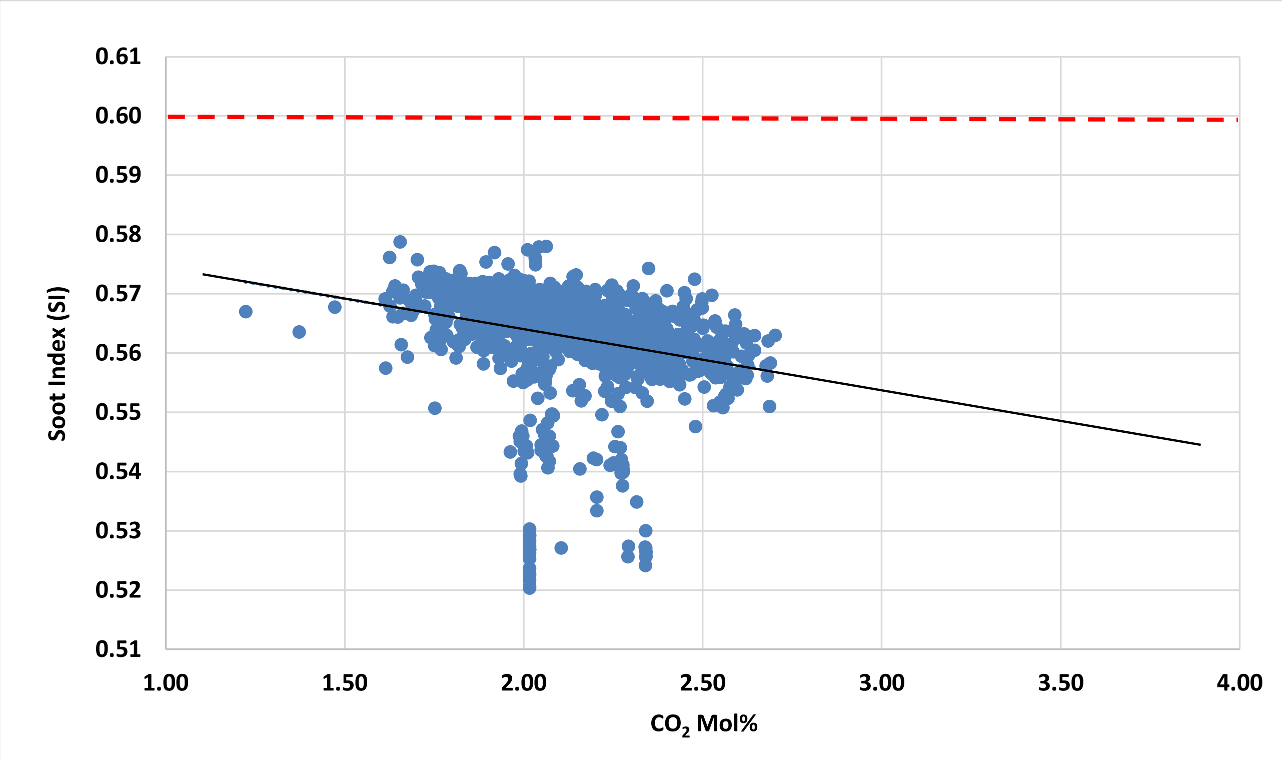
Overall, the data tends to show more scatter than that of GCV in that there a wider range of WI values for any given CO_2 content but this is within normal operating conditions for the Teesside terminals.



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 CO_2 content of 2.9 mol% to 4 mol% would result in a decrease in WI of about 0.5 MJ/SCM.

Soot Index (SI)

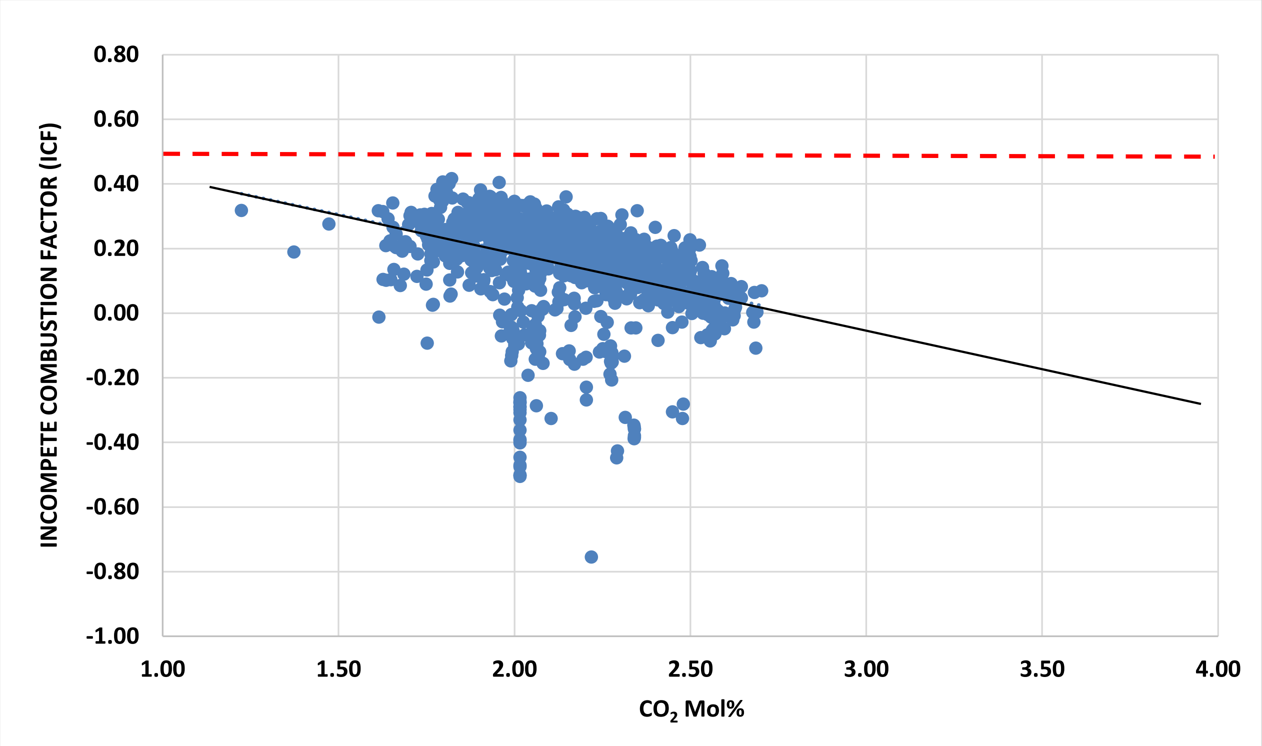
The data show slightly decreasing SI as CO_2 content increases. NTS gas specification has only an upper limit to SI so scatter below the upper limit is acceptable.



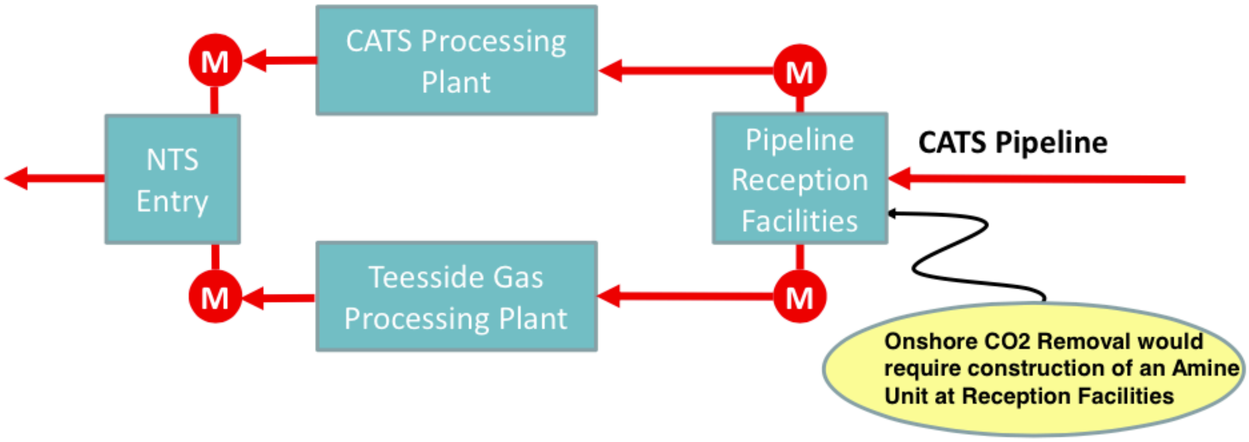
Moving from a CO_2 content of 2.9 mol% to 4 mol % results in a 0.01 reduction in SI.

Incomplete Combustion Factor (ICF)

The data for ICF show a similar scatter to that of SI. At 4 Mol% CO_2 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.



Appendix 5 - Teesside Schematic



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 of Teesside Gas Processing Plant. Water and NGL is removed and NTS specification gas exported via metering equipment to the NTS entry points

Appendix 6 - CO_2 Impact Assessment

Summary

A carbon cost assessment has been calculated for the proposal. The least impact on CO_2 emissions from bringing gas with up to 4.0 mol% CO_2 content into the CATS system is for such gas to be allowed to flow into the NTS. Significantly more CO_2 is emitted by removing CO_2 from the gas due to the need for process heat to remove CO_2. 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 CO_2 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 CO_2 released in order for the forecast gas landed at Teesside to meet the current 2.9 mol% CO_2 NTS entry specification and the cost of this CO_2 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 CO_2, allowing flow at 4 mol% CO_2 into NTS when such gas cannot be blended with other CATS gas with lower CO2 content;
- Scenario 2 – Reduction of CO_2 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 CO_2 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 2019 to 2030, 2019 being the earliest a field with elevated CO_2 levels such as Jackdaw might be anticipated to start.

Where gas with an elevated CO_2 content flows into the CATS pipeline (Scenarios 1 and 3) this gas will be commingled with other gas with lower CO_2 content. As a result, it is expected that for the majority of time the CO_2 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 CO_2 content gas for blending gas may be restricted. For the purposes of modelling the CO_2 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 CO_2 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 CO_2 content is at the maximum assumed 4 mol%.

CO_2 Impact Assessment - Assumptions

The assumptions for the CO_2 impact assessment are detailed in the following table.

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	2019 to 2030
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^oC (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

Analysis

The detailed analysis is shown in the accompanying tables and spreadsheet. The summary of the output of the analysis is shown in the following table:

Assessment of CO_2 Impact from Teesside Gas (2019-2030)	Scenario 1 NTS Delivery at 4 mol % CO2	Scenario 2 Offshore CO2 Reduction	Scenario 3 Onshore CO2 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 CO_2 emissions (te)	**38,045**	**676,391**	**125,542**

Cost Assessment of CO_2 from Teesside Gas (2019-2030) (£ NVP10 1/1/15)	Scenario 1 NTS Delivery at 4 mol % CO2	Scenario 2 Offshore CO2 Reduction	Scenario 2 Onshore CO2 Reduction
CO_2 Total ETS Traded Cost	£24,728	£1,690,905	£304,418
CO_2 Total Traded Cost with Carbon Price Support	£161,371		
Total CO2 Cost (Traded & Price Support)	**£186,099**	**£1,690,905**	**£304,418**
CO_2 Total Non-Traded Cost (£/yr) (non-ETS consumption)	£559,424	£0	£0
Total Estimated Emissions Cost	**£745,523**	**£1,690,905**	**£304,418**
Estimated Fully Installed Cost of Amine Unit		£147,189,400	£129,089,543
Estimated Abatement Cost for additional CO2 prior to NTS entry		**£148,880,305**	**£129,393,961**
Cost per tonne	**£20**	**£220**	**£1,031**

Conclusions

1. Over the life of the model (2019-2030), the least impact on overall CO_2 emissions from bringing gas with up to 4 mol% CO_2 content into the CATS system is for such gas to be allowed to flow into the NTS.

2. Significantly more CO_2 is emitted by removing CO_2 from the gas. This is due to the fact that CO_2 removal using amine requires process heat. The highest level of emissions is attributed to reduction of CO_2 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 CO_2 has lower CO_2 emissions (125 kte) as the unit would only be used on days when CO_2 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, transport of 4 mol% CO_2 gas onto the NTS remains the lowest cost option £24K while reduction of CO_2 content offshore is the highest cost option £1.69M due the continuous operation and the impact of the operational emissions. Removal of CO_2 onshore is less costly at £304K 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 CO_2 content increases to £745K.

6. However, it can be argued that the calculated emissions cost for delivery of high CO_2 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 CO_2 assessment for a UK region or an installation specific CO_2 content, both of which are estimated using annual averages. Given that any gas with elevated CO_2 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 CO_2 content will remain unaffected.
7. If the provision of CO2 removal equipment either offshore is considered to “abate” the additional CO_2 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 £129M and £147M respectively).
9. Including the cost of the amine units brings the total NPV10 of mitigating the increased CO_2 – which may be in only excess of the current 2.9 mol% for 30 days per year and most likely less – to between £129M and £148M. In the worst case this is over 200 times more costly than the £745K estimated emissions cost if the CO_2 were to be delivered onto the NTS.
10. In tonnage terms, the cost of the additional CO_2 to a consumer of gas sourced from the NTS (both ETS payers and non-traded users of gas) is c. £20/te.
11. The cost to mitigate the additional CO_2 could be over £1,000/te.

CATS CO_2 Impact Assessment (Amine Unit Capex Excluded)

	Total CO_2 (Te)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total	Annual Average
Reference Data																				
Number of Days Terminals anticipate CO_2 in excess of 2.9 Mol %							30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO_2 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%		
CO_2 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 C02)							5	5	6	6	6	6	6	7	7	7	7	8		
Carbon Valuation 'Traded' with Carbon Price Support (£/te C02)							22	27	33	39	44	50	56	60	65	69	74	78		
Carbon Valuation 'Non Traded' (£/te C02)							66	67	68	69	70	71	72	73	74	75	77	78		
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 C02 Emissions (MtC02)							370	349	339	329	324	317	306	300	296	292	296	293	6,609	**300**
Scenario 1 - NTS Delivery at 4mol%																				
Additional C02 emissions from 4mol% to 2.9mol% (te/C02)	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 (£)		**£24,728**	-	-	-	-	3,586	6,324	6,687	6,936	7,194	6,505	5,209	4,477	3,949	3,487	3,158	2,918	**60,431**	**5,036**
Cost of 'Traded' emissions with Carbon Price Support (£)		**£161,371**	-	-	-	-	13,843	29,750	36,672	43,011	49,349	48,553	41,748	37,362	34,132	31,062	28,868	27,279	**421,628**	**35,136**
Total Cost of Traded & Traded with Price Support emissions (£)		**£186,099**	-	-	-	-	**17,429**	**36,073**	**43,360**	**49,947**	**56,543**	**55,058**	**46,957**	**41,838**	**38,081**	**34,549**	**32,026**	**30,196**	**482,059**	**40,172**
Cost of 'Non Traded' emissions (£)		**£559,424**	-	-	-	-	88,273	152,339	157,646	159,964	162,283	143,510	112,348	94,389	81,383	70,220	62,941	56,804	**1,342,099**	**111,842**
Total Cost of emissions (£)		**£745,523**	-	-	-	-	**105,702**	**188,412**	**201,006**	**209,911**	**218,826**	**198,568**	**159,305**	**136,227**	**119,464**	**104,769**	**94,966**	**87,001**	**1,824,158**	**152,013**
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**
C02 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 C02 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 C02 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 (£)		**£1,690,905**	-	-	-	-	**245,238**	**432,408**	**457,285**	**474,288**	**491,923**	**444,838**	**356,177**	**306,115**	**270,049**	**238,451**	**215,920**	**199,524**	**4,132,216**	**344,351**
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		
C02 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 C02 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 CO_2 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 C02 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 (£)		**£304,418**	-	-	-	-	**50,215**	**66,717**	**69,920**	**72,520**	**75,217**	**72,640**	**66,694**	**63,971**	**62,450**	**61,349**	**61,050**	**61,312**	**784,055**	**65,338**

CATS CO2 Full Cycle Cost/Benefit Analysis

	Total CO2 (Te)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	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 C02)							5	5	6	6	6	6	6	7	7	7	7	8		
Carbon Valuation 'Traded' with Carbon Price Support (£/te C02)							22	27	33	39	44	50	56	60	65	69	74	78		
Carbon Valuation 'Non Traded' (£/te C02)							66	67	68	69	70	71	72	73	74	75	77	78		
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 C02 Emissions (MtC02)							370	349	339	329	324	317	306	300	296	292	296	293	6,609	**300**
Scenario 1 - NTS Delivery at 4mol%																				
Additional C02 emissions from 4mol% to 2.9mol% (te/C02)	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 (£)		**£24,728**	-	-	-	-	3,586	6,324	6,687	6,936	7,194	6,505	5,209	4,477	3,949	3,487	3,158	2,918	**60,431**	**3,777**
Cost of 'Traded' emissions with Carbon Price Support (£)		**£161,371**	-	-	-	-	13,843	29,750	36,672	43,011	49,349	48,553	41,748	37,362	34,132	31,062	28,868	27,279	**421,628**	**26,352**
Total Cost of Traded & Traded with Price Support (£)		**£186,099**	-	-	-	-	**17,429**	**36,073**	**43,360**	**49,947**	**56,543**	**55,058**	**46,957**	**41,838**	**38,081**	**34,549**	**32,026**	**30,196**	**482,059**	**30,129**
Cost of 'Non Traded' emissions (£)		**£559,424**	-	-	-	-	88,273	152,339	157,646	159,964	162,283	143,510	112,348	94,389	81,383	70,220	62,941	56,804	**1,342,099**	**83,881**
Total Cost of emissions (£)		**£745,523**	-	-	-	-	**105,702**	**188,412**	**201,006**	**209,911**	**218,826**	**198,568**	**159,305**	**136,227**	**119,464**	**104,769**	**94,966**	**87,001**	**1,824,158**	**114,010**
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**
C02 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 C02 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 C02 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 (£)		£129,089,543	-	-	90,000,000	90,000,000	-	-	-	-	-	-	-	-	-	-	-	-	**180,000,000**	**11,250,000**
Total Cost of Emissions		£1,690,905	-	-	-	-	245,238	432,408	457,285	474,288	491,923	444,838	356,177	306,115	270,049	238,451	215,920	199,524	**4,132,216**	**258,264**
Total cost of emissions (£)		**£130,780,448**	**-**	**-**	**90,000,000**	**90,000,000**	**245,238**	**432,408**	**457,285**	**474,288**	**491,923**	**444,838**	**356,177**	**306,115**	**270,049**	**238,451**	**215,920**	**199,524**	**184,132,216**	**11,508,264**
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	**2,165**	**180**
C02 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 C02 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 (£)		£147,189,400	-	50,000,000	50,000,000	100,000,000	-	-	-	-	-	-	-	-	-	-	-	-	**200,000,000**	**12,500,000**
Total Cost of Emissions		£304,418	-	-	-	-	50,215	66,717	69,920	72,520	75,217	72,640	66,694	63,971	62,450	61,349	61,050	61,312	**784,055**	**49,003**
Total cost of emissions (£)		**£147,493,817**	**-**	**50,000,000**	**50,000,000**	**100,000,000**	**50,215**	**66,717**	**69,920**	**72,520**	**75,217**	**72,640**	**66,694**	**63,971**	**62,450**	**61,349**	**61,050**	**61,312**	**200,784,055**	**12,549,003**

Scenario 1 - NTS Delivery at 4 mol%

Case	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
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
Calculation of CO2 above 2.89 mol% delivered to NTS												
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%
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

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	**Emission**
Additional CO2 for Scenario 1 [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	**38,045**

Scenario 2 - Offshore CO2 Removal

Case	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
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	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA
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
Contactor 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 Concn, 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

Scenario 3 - Onshore CO2 Removal

Case	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
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
Contactor 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 Concn, 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

10 Glossary

ASEP	Aggregated System Entry Point *(where more than one entry point exists)*
Capex	Capital Expenditure
CATS	Central Area Transmission System *(ie from the UK Continental Shelf)*
CCGT	Combined Cycle Gas Turbine *(a gas-fired electricity generation unit)*
CEN	European Committee for Standardisation
CV	Calorific Value
CH_4	Methane
EU ETS	EU Emissions Trading System *(multi-country, multi-sector greenhouse gas emissions trading system, see* https://www.gov.uk/participating-in-the-eu-ets.*)*
FES	Future Energy Supply *(document, available on nationalgrid.com)*
GSMR	Gas Safety (Management) Regulations
GSOG	Gas Storage Operators Group
H_2S	Hydrogen Sulphide
ICF	Incomplete Combustion Factor
kte	Kilo tonnes equivalent *(thousands of tonnes equivalent)*
MERUK	Maximisation of Economic Recovery of oil and gas from the UK continental shelf
mol%	Mole % *(a measure of the constituents in a mixture)*
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
SI	Soot Index
te	Tonnes equivalent
TEG/MEG	Tri- and mono- ethylene glycols *(commonly used in dewatering applications)*
uHPHT	ultra-High Pressure High Temperature
VOC	Volatile Organic Compounds
WI	Wobbe Index *(an indicator of the interchangeability of gas)*