Environment Agency

Evidence

Waste gas management at onshore oil and gas sites: framework for technique selection

SC170013

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Professor Doug Wilson
Director, Research, Analysis and Evaluation

Executive summary

The UK has been a major producer of oil and gas for many years. Although this has principally been from offshore fields, there is also a well-established, but significantly smaller onshore production capability. Historically these onshore oil and gas (OOG) operations have focused on conventional drilling and extraction. More recently the development of hydraulic fracturing technologies and horizontal drilling techniques has opened up the possibility of oil and gas exploitation from formations not previously considered financially or practically viable.

The potential for exploitation of oil and gas reserves from shale rocks has led to an increase in exploration developments in England, which may ultimately result in new production fields coming online. This expansion of the OOG sector is being supported by the government as a means of improving energy security and boosting the UK economy. However, the operations associated with OOG sites generally result in the production of gas that is considered waste or non-utilisable, and which may subsequently be released to atmosphere resulting in potential environmental damage.

Regulatory guidance for an industry sector is typically described in Best Available Techniques reference (BREF) documents issued by the European IPPC Bureau. However, no such BREF yet exists for the management of waste gas in the OOG sector. In recognition of this and the anticipated growth of the OOG sector in England, this study has reviewed potential waste management technologies to determine what should be considered Best Available Techniques (BAT).

A previous Environment Agency review in 2015 of the technologies and techniques that can be employed to successfully manage waste gas from the OOG sector focused on flaring. This study has undertaken a wider review of the potential technologies that can be used to manage waste gas.

Methodology

The study reviewed waste gas management technologies that have emerged globally, but particularly in the USA. Many of these are rapidly deployable variants of well-established technologies for gas handling and processing, as well as more established approaches to waste gas management. These technologies were compiled into a long list, which was subsequently screened to a list of candidate technologies that should be considered for detailed BAT assessment by operators.

The study also developed a method of assessing BAT for use by operators and the Environment Agency to provide a more consistent approach to the BAT decision-making process for future developments within the OOG sector.

The BAT assessment method developed uses a cost–benefit analysis to assess factors that can be monetised such as capital, pollutant damage and revenue. This quantitative assessment generates a Net Present Value for each option, enabling a side-by-side comparison. Factors that could not be monetised were assessed qualitatively against a base case. This qualitative assessment categorises each option in terms of a positive or negative impact for a given factor in a given location or scenario.

Two hypothetical, but realistic, case studies were developed to illustrate the use of the quantitative assessment approach and to provide information on which technologies were likely to provide the best environmental outcome.

Conclusions

There are many variables associated with individual OOG sites which will influence technology choice, including operational conditions or the phase of operation.

However, the study concluded that the following technologies can generally be considered as indicative BAT for the effective management of waste gas:

- flaring of gas using an enclosed ground flare system
- fuel gas for power generation, via a gas engine or gas turbine, for onsite use or for export to the grid
- heat recovery from power generation for reuse onsite or export to local users (for example via a combined heat and power system)
- gas turbine driven export of compressed gas to the National Transmission System

The approach developed by this study can be used by the Environment Agency and operators of onshore oil and gas facilities to enable structured, auditable and transparent decision-making on what might be the Best Available Techniques for their specific sites. This will help to support consistent and justifiable decisions on what techniques for waste gas management at onshore oil and gas facilities provide the best outcome for the environment.

Although there are numerous waste gas management technologies and techniques in use in global OOG sectors, many are not currently considered available or proven for use in England. It is recommended that this position is routinely reviewed, especially as the OOG sector in England develops and matures over the coming years.

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1 Introduction

1.1 Background

The UK has been a major producer of oil and gas for many years. Although production has principally been from offshore fields, there is also a well-established but significantly smaller onshore production capability. Historically, these onshore oil and gas (OOG) operations have focused on conventional drilling and extraction. More recently, the development of hydraulic fracturing technologies and horizontal drilling techniques has opened up opportunities for oil and gas developments that were previously not economically or practically viable.

The potential for the exploitation of oil and gas reserves from shale rocks has led to an increase in exploration developments in England, which may ultimately result in new production fields coming online. The expansion of the OOG sector is being supported by the UK government in England as a means of improving energy security and boosting the UK economy. But if not correctly managed, the potentially significant and rapid development of OOG operations may result in detrimental local and global environmental effects, including the release of waste natural gas to the atmosphere where it acts as a powerful greenhouse gas.

At present there is no Best Available Techniques reference (BREF) document to guide operators in the selection of waste gas management options at OOG sites, potentially leading to uncertainty in the permitting of waste gas management. The definition of Best Available Techniques given in the Industrial Emissions Directive (2010/75/EU) (IED) is given in Box 1.1.

Box 1.1: Definition of Best Available Techniques (BAT)

Article 3 of the IED defines the concept of BAT as follows.

> 'Best available techniques' means the most effective and advanced stage in the development of activities and their methods of operation which indicates the practical suitability of particular techniques for providing the basis for emission limit values and other permit conditions designed to prevent and, where that is not practicable, to reduce emissions and the impact on the environment as a whole:
>
> (a) 'techniques' includes both the technology used and the way in which the installation is designed, built, maintained, operated and decommissioned;
>
> (b) 'available techniques' means those developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages, whether or not the techniques are used or produced inside the Member State in question, as long as they are reasonably accessible to the operator;
>
> (c) 'best' means the most effective in achieving a high general level of protection of the environment as a whole;

1.2 About the study

This report builds on an earlier BAT study conducted for the Environment Agency (Mott MacDonald 2015). This review of the technology and techniques that can be used to successfully manage waste gas focused largely on flaring from OOG sites in England. Following the 2015 BAT study, the Environment Agency published 'Onshore Oil & Gas Sector Guidance' (Environment Agency 2016a), which detailed indicative BAT flaring techniques.[1]

1.2.1 Objectives

This study took a wider view of the potential technologies that may be used to manage waste gas. Its objectives were to:

- assess current technology and techniques that may represent indicative BAT for waste gas management in the OOG sector in England
- develop a decision-making methodology that operators and the Environment Agency can use to provide a consistent approach to determining what constitutes BAT and thus improve clarity in the decision-making process used for waste gas management

1.2.2 Scope of the work

This report is applicable to operations that make up the OOG sector in England.[2] These activities are defined as:

- gas developments
- oil developments with associated gas
- shale gas developments
- tight oil developments with associated gas
- coal mine methane (from abandoned coal mine workings)
- coal bed methane

Within these operational areas, the study examined options for the management of waste gas arising from the exploration, appraisal, production and decommissioning phases of OOG developments.

The project scope also applied to facilities such as oil and gas gathering stations, processing centres and receiving facilities, as these will also be regulated under environmental permitting legislation. The scope did not extend to oil refineries or underground coal gasification, nor did it address fugitive releases (that is, leaks), accidental releases or safety-related releases.

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[1] This report was withdrawn on 14 February 2019 when it was replaced by new online guidance (https://www.gov.uk/guidance/onshore-oil-and-gas-sector-guidance).

[2] Regulation and guidance in Northern Ireland, Scotland and Wales is covered by separate bodies or legislation, and so the specifics of this report cannot be taken as directly applicable to these regions.

The project team was tasked with considering all waste gas management techniques that were currently available and proven (either in the UK or elsewhere) and could be deployed within a 12–18 month horizon.

1.3 Structure of the report

The methodology, discussion, recommendations and conclusions that follow in this report are all made with reference to the definition of BAT given in Box 1.1.

Section 2 describes the approach adopted for the study and the activities undertaken including:

- deciding the scope of OOG operations to be covered
- producing a long list of potential waste gas management technologies
- the process used to screen these to generate a short list of technologies
- details of the technologies on the short list and a brief description of alternative technologies excluded from it
- how to take account of secondary pollutants of combustion when assessing BAT
- the approach used to develop an effective BAT decision-making framework featuring both quantitative and qualitative assessment
- the creation of 2 hypothetical case studies to illustrate the BAT assessment process

Section 3 presents the results of cost–benefit analyses (CBAs) conducted on the hypothetical case studies.

Section 4 discusses the study's results and Section 5 presents its conclusions.

Seven appendices provide greater detail on:

- waste gas releases by sector and phase (Appendix A)
- the technologies on the long list (Appendix B)
- technology screening for the extended flow testing phase (Appendix C)
- technology screening for the production phase (Appendix D)
- the CBA methodology (Appendix E)
- CBA input data for the 2 case studies (Appendix F)
- the qualitative assessment methodology (Appendix G)

Where the term 'gas' is used in this report, it should be taken as referring to natural gas unless specified otherwise.

2 Study approach and activities

2.1 Overview of the study approach

The study approach outlined in Figure 2.1 was structured to reflect the most important requirements of BAT – namely 'availability' and 'best' – in accordance with the IED definition of BAT (see Box 1.1).

For the availability test, this required a review of potential technologies to produce a long list which was subsequently screened to produce a BAT candidate short list.

Best performance was determined by the use of a combined qualitative and quantitative assessment developed by this study. This method was then applied to 2 hypothetical test cases to illustrate its use.

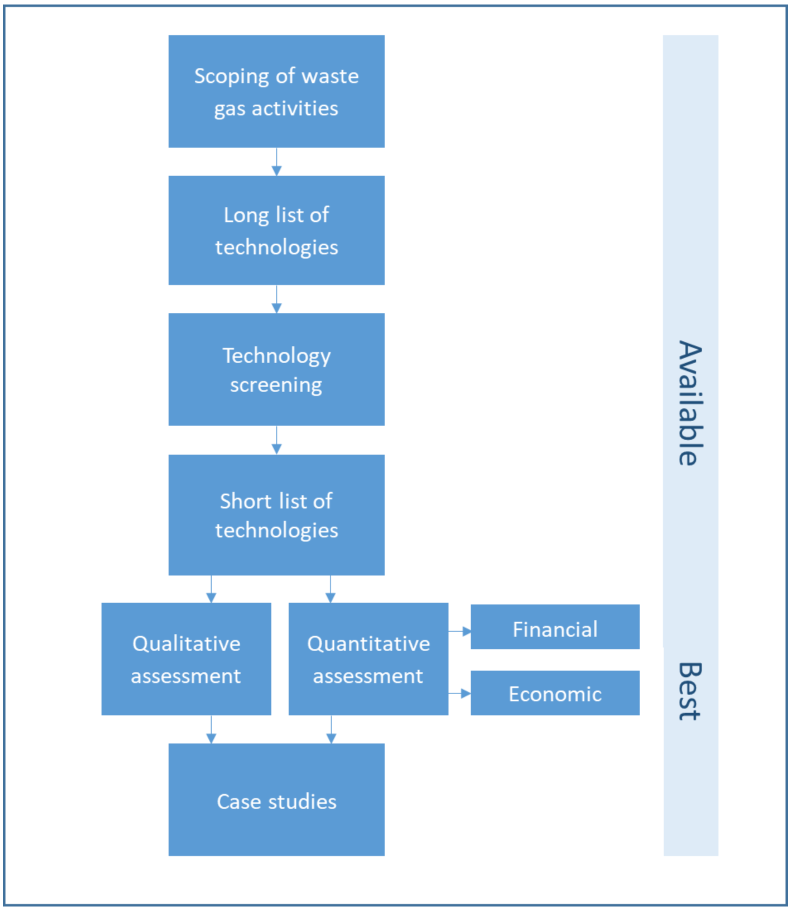

Figure 2.1 Schematic of overall study approach

The study approach is described in more detail in the following sections.

2.2 Scoping of waste gas activities

This study is applicable to all the OOG operation types in England listed in Section 1.2.2. However, an assessment was made of these OOG operations to determine which would most benefit from the implementation of new or improved waste gas management technologies.

The initial scoping stage of this study also assessed which development phases of an operation's lifecycle would most benefit from improvements in waste gas management technologies.

Implementation of waste gas management technologies that avoid direct release of natural gas to atmosphere, or reduce the volume and/or release frequency of releases, should be a goal during all phases of a development. However, there will be particular phases – such as well appraisal and production – that will have more potential impact on the environment than others, and these therefore formed the focus for this study.

The findings of this operations and development phase scoping review are detailed in Appendix A. The key observations from the scoping review are summarised below.

2.2.1 Exploration

Waste gas releases are very difficult to predict during oil and gas exploration (for example, during drilling and hydraulic fracturing). Any releases would typically be at a high flow rate, but of short duration and of unknown or variable composition (for example, a gas kick). This makes such releases very difficult to utilise or manage, and for this reason cold venting or flaring is likely to be the only practical way of managing these emissions.

2.2.2 Well appraisal

Well appraisal covers well clean-up and flow testing. It offers more potential for different waste gas management technologies to be implemented, since gas flows will be more predictable and will exist for longer periods.

Waste gas flow rates during well appraisal can vary between 1,000 and 5,000 standard cubic metres (Sm^3) per hour or more per well[3] depending on:

- the type of development (that is, dedicated gas or associated gas)
- the testing regime
- the capacity of the well

However, gas flow will still be relatively variable and unpredictable in terms of composition and pressure. Typically, flow testing will last from 2 weeks to 90–180 days[3] depending on the consistency and quality of the well testing data gathered.

2.2.3 Production

Oil or tight oil production facilities will primarily be associated with the recovery and stabilisation of the oil itself. This oil will be sent to an export pipeline or to storage tanks for subsequent export via road tanker. While being processed or in storage, volatile components of the oil will be released in relatively small quantities, which will typically be sent to flare or recovered to generate fuel gas.

If an oil or tight oil field contains associated gas, this gas will need to be separated from the oil stream. Such associated gas flows can potentially be significant at between 500 and 2,000Sm^3 per hour or more[3]. If no use exists for this gas then flaring is the lowest

[3] Information from the UK Onshore Oil and Gas (UKOOG) BAT study questionnaire responses. These questionnaires were sent to UKOOG members in order to establish baseline operating data for use in the BAT cases studies.

impact environmental option. But given that the potential lifetime of production operations may be up to 25 years, any sizeable gas flow becomes potentially financially viable for operators to recover and process for use as fuel gas for power generation or for export as a secondary product.

Waste gas releases from facilities dedicated to gas production (including shale gas, coal bed methane or coal mine methane sites) have less potential to improve their waste gas management during production operations. This is because the gas itself is the prime resource for such developments, and operators seek to keep losses to a minimum by recovering waste gas for recycling or re-entry into the production facilities.

In some production scenarios, it may not be economically viable or technically feasible for individual sites, which may have low waste gas flow, to implement more sophisticated or large-scale waste gas management techniques, or to utilise small amounts of gas. However, any significantly sized field would be expected to have multiple well pads operating which could be linked to a collection hub where waste gas can be processed on a larger scale. This is of course subject to distance between well pads, flow rate and so on.

On the basis of the output from the scoping study, it was agreed that the project would focus on:

- waste gas releases associated with well appraisal for a gas development
- production operations for an oil development generating associated gas

However, the principles and recommendations outlined in this study can be used to assess options for waste gas management arising from any OOG activity.

2.3 Long list of technologies

The Environment Agency provided a reference list of information about technologies that may be suitable for the management of waste gas. This reference information, along with the findings of the 2015 BAT flaring study (see Section 1.2), was used in conjunction with a wider literature review to generate a long list of potential waste gas management technologies. For full details of the long list, including an analysis of their pros and cons, see Appendix B.

The majority of reference information used to compile the technology long list was drawn from the OOG sector in the USA. This is a well-established industry and operates at a significant scale; as of 2016 there were 553,495 gas producing wells and 204,149 associated gas producing oil wells in the USA. The total output of gas from sources such as shale or tight oil plays was 28.3 billion m^3 per year, which represents 60% of the total gas output in the USA (EIA, undated).

Although many of the OOG developments in the USA occur in developed areas, where there may be good pipeline infrastructure in place, a significant proportion of developments exist in locations where it may not be economic to connect to a gas transportation network. Consequently, potentially utilisable gas would historically have been flared as the lowest environmental impact option.

However, the scale of development in the US OOG sector means there is clearly potential for widespread environmental damage to occur via the direct release of natural gas or its combustion products. There is also the fact that such ‘island’ waste gas releases represent significant lost revenue. These factors have led to the development of innovative technology to improve the capture and management of waste gas that would otherwise have been flared, and has driven the growth of a service/engineering sector. This sector is capable of supplying and supporting such technology to OOG operators in the USA from well appraisal through production to end of life.

The technologies developed to serve the US sector typically mimic existing large-scale processes which have been modularised for easy transport, rapid deployment and installation (Evans et al 2011, Sheffield 2018). Such technologies include:

- liquefaction of natural gas
- conversion of natural gas to fuel products
- recovery of natural gas liquids (for example, butanes and pentanes which have a higher commercial value than methane)
- high pressure gas compression for export via road tanker

Particularly useful reference sources which provide a high level appraisal of potential technical options for the management of waste gas releases are:

- the North Dakota State Government web resources (EERC, undated)
- the Global Gas Flaring Reduction (GGFR) Partnership (GGFR Partnership 2018)

Many of the technologies reviewed for use in England were considered unproven or novel, either because of their process being new or because of the nature of the modularisation required for field deployment. Consequently they did not pass the BAT screening test developed for this study (Section 2.4). However, they are included in the long list of technologies in order to identify their potential in the longer term.

The following is a summary of the technologies included in the waste gas management technology long list arranged by class/type:

- cold venting
- flaring
- heat generation
- power generation
- reinjection to well
- recycling through gas processing
- mini liquefied natural gas (LNG)
- conversion to fuels
- vapour recovery
- gas processing and natural gas liquids (NGL) recovery
- compressed natural gas (CNG)
- energy storage

A detailed appraisal of the long list is provided in Appendix B.

2.4 Technology screening

The technology long list included options that were not considered likely to meet the criteria of ‘best’ and ‘available’ as defined in the IED (see Box 1.1). To save effort in assessing unworkable options in the later detailed BAT assessments, a screening process was used to remove technologies which could not be justified, at a high level, to meet the minimum requirements of BAT. The criteria used for screening are detailed in Table 2.1.

In line with the conclusions of the scoping review, screening was carried out with reference to the well appraisal phase for a gas site, and to the production phase for an oil development producing associated gas.

Table 2.1 Screening criteria for technology long list

Criteria	Considerations	Type of test
Economic	Equipment capital/rental cost Infrastructure costs (site and export systems) Benefit/profit costs	Economic viability (order of cost)
Availability	Must be available for use within a 12–18 month horizon	Yes/No/May be
	Proven in OOG industry at global scale	Yes/No
	Proven technology/technique in the UK	Yes/No
	Market/outlet/user for product of waste gas	Yes/No
Environmental/ technical	Environmental performance	Comparative measure
	Land usage	Comparative measure
	Scale of operation	Comparative measure
	Proprietary technology	Yes/No
	Infrastructure requirements (for example, pipeline)	Comparative measure
	Additional service requirements (for example, steam)	Comparative measure

2.5 Short list of technologies

The technologies selected for detailed BAT assessment were:

- gas flaring – shrouded (pipe-in-pipe) flares and enclosed ground flares
- gas engine for onsite power generation (Incorporating combined heat and power systems)

- gas turbine for power export (gas-to-wire)
- gas turbine for gas compression and export (gas-to-grid)

The main reasons for rejecting technology options on the long list can be summarised as follows.

- The technology was not readily available for supply in England – either due to economics or the lack of a supplier base.
- The technology was considered unproven or novel.
- There was no widespread market for the product or resource produced.
- The working capacity of the technology did not match OOG sector requirements.

The technologies selected for the candidate BAT short list are considered below.

2.5.1 Gas flaring

Once an oil or gas development is at the well appraisal or production stage, and gas is flowing, a facility to flare waste gas will be required. This is irrespective of what other measures may be employed to utilise the waste gas (for example, power generation for onsite use or export). This is because alternative waste gas management techniques cannot be guaranteed to be available all of the time and/or may not be able to accommodate 100% of the waste gas flow. Therefore a flare may have to manage a constant balance of waste gas or full flow during a shutdown or emergency event.

Historically, flaring may have been achieved during well appraisal using shrouded (pipe-in-pipe) flares, which are easy to set up, offer good flexibility and are readily available for rental. The drawback with such flares is their potentially low combustion efficiency of 75–90% (Mott MacDonald 2015). To obtain the best combustion efficiency from this type of flare it is essential that the flare operates in its optimum flow range. Without combustion air assist or complex burner controls, efficiencies for shrouded flares can reduce significantly to outside their optimum flow range.

In contrast, enclosed ground flares offer superior combustion performance – typically 98% or better (Mott MacDonald 2015) through the use of multiple burner heads, staged flow, forced air assist and sophisticated burner control.

The capital or rental costs of enclosed ground flares will be higher than for shrouded flares but the additional cost, at least from a pollution damage cost perspective, will generally support the selection of this technology over less efficient combustion methods. Consequently, it is expected that the regulator would consider such flares as BAT for new OOG developments in England unless it can be shown by BAT assessment to be otherwise.

For production flaring, which will typically last the life of the facility (that is, 25 years), the benefits associated with enclosed ground flare systems mean that it would be very hard to justify using any less efficient approach to combustion.

One problem for production flares is that, where a flare is specified for both operational and safety duty, there may be a large turndown – meaning that it is harder to achieve high efficiencies across the full flow range. In such cases, it may be more efficient to have 2 smaller units rather than having one large enclosed ground flare. However, this does introduce additional challenges such as increased capital cost, more complex process control, increased footprint and increased emissions from gas pilots.

2.5.2 Onsite power generation

OOG sites may not be close to major power networks, or it may not be financially viable to connect to the electrical grid during well appraisal, before the development potential has been confirmed. Sites will, depending on their size and stage of development, have a typical maximum onsite power load of between 0.5 and 1.5MW.

During exploration, there will be no flowing gas and, if there is no grid connection, this load can be met only by mobile generation – typically diesel-driven systems. However, during well appraisal, sufficient gas should be available to fuel mobile gas engines. Such use would only take a small flow, with any balance going to a flare system, but it would make use of some of the waste gas that would otherwise be combusted without benefit. For appraisal phases, power generators driven by gas engines would be readily available to rent at capacities up to 1.5MW. Small micro-turbine driven power systems could also be used to generate power; however, these are not considered to be readily available as yet, particularly for rent, for the low electrical loads typical of most OOG sites.

When using gas engines for onsite power generation, there should be an opportunity to use combined heat and power (CHP) systems, which would potentially remove the need for separate process heating systems. The heat recovered through CHP could be used for process duty such as preheating gas prior to pressure let down, where cooling effects can lead to liquid drop out or freezing in untreated gas flows, or in extreme cases, failure of pipework due to low temperature embrittlement. Such heating may also be achieved electrically, in which case onsite power generation is still advantageous in order to meet this additional load.

It is likely that diesel generation systems will still be required as a back-up for ‘black’ starts and to maintain control and emergency systems if gas is unavailable. However, the capacity of such systems could be reduced, and the use of diesel fuel minimised if combined with gas-driven power generation.

2.5.3 Power export (gas-to-wire)

Use of waste gas as fuel for gas engines or gas turbine driven power generators for power export is a potentially attractive proposition for oil developments that generate associated gas during production operations. However, several factors affect the feasibility of power export.

- Flow rate of waste gas available. This determines the amount of energy that can be generated. If flows are low, export infrastructure costs may not be recovered.
- Distance to the power grid. Clearly closer is better.
- If a site is part of a single development, it may not be viable to export power. If there are other sites in close proximity to each other, these could be linked together at a gathering station to increase the total reserves and flow rate of gas to make power generation and export viable.
- Distribution network operator’s (DNO) connection cost. There is significant variability with electrical export schemes regarding connection to a DNO’s network. Depending on the DNO, and the capacity and set-up of any existing network connection, connection costs could vary from hundreds of thousands of pounds to over £10 million. Costs at the higher end of this range would reflect the need for new transformers, switchgear and buildings which may be required to accept a new export supply.

- Composition of the associated gas. Gas engines or gas turbines can generally accept associated gas as fuel without significant pre-treatment beyond standard pressure let down and liquids removal. However, additional treatment will generally be required if there is a high proportion of inert substances, higher weight hydrocarbons or contaminants such as hydrogen sulphide in the gas.

2.5.4 Gas export (gas-to-grid)

For sites that generate high flow rates of associated gas during production, the principal alternative to power generation is to export the gas to the National Transmission System (NTS).

This option would incorporate standard compression and pipeline export technology/techniques. The most important processing requirements will be to:

- clean up or treat the gas to meet the specifications of the Gas Safety (Management) Regulations
- achieve the pressure entry requirements for the NTS

Following gas processing, any associated gas is likely to be at pressures below the minimum NTS entry pressure of around up to 75 barg and so compression boosting will be required to export the gas. This is normally achieved using gas turbine driven compressors which utilise treated field gas as fuel gas.

As with power exportation, the available gas flow rate and the distance to an NTS connection are the principal economic drivers. There are approximately 7,600km of NTS pipeline in the UK (Dodds and McDowall 2013), which typically floats at pressures of between 50 and 75 barg. These high pressure/high capacity pipelines are concentrated along the eastern side of the UK, running down from Scotland to the south of the country. Given the distribution of the NTS throughout the UK, the potential for close approach to a NTS connection point may be limited, particularly when compared with the availability of electrical connections. There is likely to be better potential to access the medium pressure NTS (7–34 barg), which is much more widespread (approximately 47,000km) or even local distribution systems (approximately 233,000km of pipeline at up to 7 barg) (Dodds and McDowell 2013). However, the lower pressures that these systems operate at and the smaller line sizes limit the potential for linepacking, which may ultimately limit export flows during periods of low gas demand or take-off. As the NTS operates at up to 75 barg pressure and line sizes are large (900–1,200mm diameter), the overall system capacity is very large and therefore restriction of flow will rarely be an issue and an operator can effectively be guaranteed export capacity, whenever it is required.

An additional issue with accessing the medium and low pressure distribution systems is that the gas must be odourised to comply with the Gas Safety (Management) Regulations. The odorant used is mercaptan, which is exceptionally odorous and potentially flammable – both factors which make handling the material potentially difficult. There will also be a requirement to install and maintain additional equipment for the storage and dosing of odorant.

Associated gas is likely to have a higher heavy hydrocarbon content than gas from a dedicated gas development. This means it may be necessary to increase the capacity or complexity of gas treatment equipment to process, handle and store the heavy hydrocarbon components and gas condensate generated. Although this would incur increased capital outlay, there should also be additional revenue or income potential via the recovery and sale of higher value components such as ethane and butane.

2.6 Alternative technologies excluded from the short list

As indicated in the technology long list, there are many potential alternatives to flaring that could be used to manage waste gas at OOG sites in the England.

During well appraisal, the use of mobile or modular installations would be highly beneficial to capture the high flows of waste gas produced during testing. Use of alternative utilisation technologies has become well-established in the USA where the OOG sector is mature and at large scale. However, these technologies are not currently considered as available or supportable in England, or indeed in many cases widely proven in use. This will undoubtedly change in the future as the OOG market develops globally and in England, and therefore the status of the technologies excluded from the BAT options short list should be reviewed routinely. A summary of alternative technologies excluded from the short list is given in Table 2.2.

Table 2.2 Technologies excluded from short list

Potential technologies (production phase)	Notes
Heat generation (Industrial or community)	If onsite power generation is implemented, the resultant heat generated can be used to feed onsite requirements via a CHP system. For large onsite heat demands or for feeding to local users (for example, district heating schemes or industrial users), waste gas can be used in a fuel for boilers or water heaters or similar.
Organic Rankine cycle (ORC) (in conjunction with a gas turbine)	Waste heat from a gas turbine could provide an opportunity to generate power using the ORC, which is essentially a power generation plant where the working fluid is an organic compound rather than steam. The ORC turbogenerator largely operates in a similar manner to a traditional steam Rankine cycle (Turboden, undated) to transform thermal energy into mechanical energy and eventually into electricity in an electric generator.
Recovery of NGLs	This is a potential option for associated (rich) gas, particularly if there are nearby industrial users of heavier hydrocarbons (for example, petrochemicals manufacture).
Enhanced oil recovery	This involves reinjection of gas in to the oil well to enhance oil recovery (that is, by maintaining reservoir pressures or helping to reduce oil viscosity) (gas lift). It may be more common to use carbon dioxide or nitrogen but, if sufficient waste natural gas is available and the well/field conditions allow, reinjection of natural gas in to an oil field can be a practical and economic use of this waste gas.
Battery storage/mobile energy	This is not considered available at present, but development potential means this could be a future BAT option.
Recovery of vented gases	If significant quantities of heavier hydrocarbons are stored onsite with frequent filling and emptying operations (for example, to road tanker), vapour recovery may be worth considering, with vapour recovered for use as fuel gas for onsite power generation.

2.7 Taking account of secondary pollutants from combustion when assessing BAT

Waste management relating to flaring, power generation and gas compression for export all involve combustion technologies in various forms. Combustion converts methane and other hydrocarbon gases with global warming potential (GWP) to carbon dioxide, which has a GWP approximately 28 lower than methane over a 100-year time period (IPCC 2013), which is clearly advantageous from an environmental damage perspective.

However, combustion of natural gas may generate additional pollutants such as oxides of nitrogen (NOx), sulphur dioxide and carbon monoxide. These components have a range of detrimental environmental and health impacts, which may be felt both locally and further afield.

NOx is the key pollutant of concern. NOx production in gas combustion processes is highly temperature-dependent with emissions increasing rapidly beyond 1,400°C. The combustion temperature in gas engines and turbines will typically operate at or above such temperatures, and therefore will potentially produce large amounts of NOx. In comparison, the temperature of combustion in a flare is typically 800–1,000°C and therefore less NOx will be produced.

So, while switching to gas engines or turbines or other high temperature combustion process does have excellent efficiency benefits, the generation of secondary pollutants should be considered carefully. This may be an issue in areas where there are already high local pollutant levels and may either preclude such an approach or require additional abatement to be implemented.

Other than the capital cost of equipment required to meet any permitted emission limit values for combustion pollutants, there is no actual cost penalty for operators associated with combustion pollutants. However, there are environmental and societal damage costs associated with these releases; for example, for NOx this cost is assessed as being equivalent to £13,840 per tonne (Environment Agency 2016b).

2.8 BAT decision-making approach

The development of an effective BAT decision-making methodology was one of the project's principal goals. Such a methodology would need to:

- be user friendly – for operators and Environment Agency staff
- be applicable to a range of diverse scenarios and technologies
- address both quantitative and non-quantifiable/qualitative factors
- demonstrate flexibility

The development of the BAT assessment methodology was made with reference to existing approaches such as the Environment Agency Horizontal Guidance Note H1 (Environment Agency 2011) and the IED derogation tool (Environment Agency 2016b). Recent work by the Environment Agency (Georges 2013) and Costain's previous experience with BAT assessment were also used to develop the quantifiable elements of the methodology based around a CBA.

Non-monetisable factors such as noise, visual impact, local nuisance or disturbance, and odour can be key influencers when selecting indicative BAT. To assess these, a qualitative method was adapted from an approach developed by the Scottish Environmental Protection Agency (SEPA) (SEPA 2017).

Combining the quantitative and qualitative outputs appropriately will allow operators and the Environment Agency to present and review BAT justifications or decisions in a consistent manner.

2.8.1 Quantitative evaluation

The quantitative element of the BAT assessment methodology utilised a CBA approach. This generates a Net Present Value (NPV) for each option considered, where the highest NPV represents the best performance taking into account capital, operating costs, revenue and damage costs.

An important point to understand in the proposed CBA method is the difference between financial and economic analysis.

When pollutants are released, there is an impact on society in the form of health and environmental damage. To truly determine what represents 'best' performance, the full damage costs should therefore be used in a CBA whether these costs are borne by the operator or not. Such an approach constitutes an economic analysis.

In contrast, a financial analysis is based upon the private costs that an operator will actually be required to pay.

The CBA was carried out using a spreadsheet calculation/format broken down into 3 basic sections:

- **Direct costs**. How much has the development cost to design and install? How much does it cost to run and operate (including staff, maintenance and overheads)? How much will it cost to decommission?
- **Damage costs**. This is the economic cost to society and the environment either as equivalent or direct carbon emissions or as the damage costs of NOx or other local air pollutants e.g. SOx or particulates.
- **Income/benefits**. This could be the export of power or gas or a product made at site (for example, LNG) which is then sold. It would also include any benefits to the environment in terms of offsets (for example, pollutants generated via central power generation which would not be produced if local power generation and export were in place).

From these inputs, the net balance of value for each year of operation can be calculated. Because the value of money will change over the lifetime of the operation, the overall cost of an option is converted to a NPV using a discounted rate of 3.5% (HM Treasury 2018). Options that return the best NPVs can generally be said to represent best performance.

Using a spreadsheet calculation means the approach is accessible to all and is relatively easy to set up and tailor to an individual operator's requirements as long as the important inputs described above are captured. Initially, it may be that the input information is high level or estimated, but this should at least allow any outlying or clearly uneconomic options to be screened out at an early stage. The better the level or detail or accuracy of the input data, the better the result will be.

A spreadsheet-based calculation also easily allows for expansion of the calculation as more details become available. In addition, the method can be used to assess short-term scenarios (as would be seen during well appraisal) or for full life assessment (that is, production).

For the CBA, environmental damage costs were drawn from the Environment Agency's IED derogation tool (Environment Agency 2016b). Power costs for both the electricity used and the power sold to the grid were taken from rates published by the Department for Business, Energy and Industrial Strategy (BEIS) (BEIS 2017); sale prices for gas were taken from the same source. In both cases, wholesale prices were used based on a central band.

The CBA approach is set out in detail in Appendix E. Table 2.3 details some of the key inputs to the CBA.

Table 2.3 Description of inputs used in the CBA spreadsheet

Type	**Considerations**
Direct cost factors	
Capital	This is the cost to the operator of implementing and operating an OOG facility. This may be realised as a one-off cost incurred in the first year of operation. Alternatively, where the capital outlay may be considered too high for an organisation to finance from their balance sheet (for example, a new production development), it may be more likely that the capital cost will be spread over a 3–5 year period and that the finance will be drawn from commercial loans. In such a case, there will be interest to pay; this was set at 10% per year for the CBAs in this study. At the end of installation life, there may be a residual value associated with the plant or the site, which can be recovered; this can be added back into the capital calculation as a credit. More typically, there will be decommissioning or reinstatement costs at the end of the project life. These will cover clearance of the site, its clean-up and return to former use. Neither residual value nor decommissioning or reinstatement costs have been allowed for in the case studies but, in reality, these capital outlays should be included as they may be significant to the overall economic balance. Capital can also include costs associated with land purchase, civil engineering and buildings, export pipelines or electricity cables to the gas grid or power network. For power or gas export, the cost of export cabling or pipework will be needed, which depending on the distance to the connection point, can be significant. The capital estimate should also allow for the actual connection to their respective networks, which may be more expensive than the export cable or pipeline. This is particularly the case for electrical connections, where the cost of the DNO connection can vary significantly depending on the capacity of the system that is being connected to which could be 11kV, 33kV, 66kV or 132kV, and/or the capacity and configuration of the local electrical infrastructure.

Type	Considerations
Rental (assumed to apply to well appraisal only)	This is the daily, weekly, monthly or potentially annual cost of hiring or leasing equipment. Where rental costs are not readily available, it may be appropriate to take capital costs and then pro rata these over the intended period of operation. Rental would typically cover items such as flares, vents, packaged process equipment and generators.
Operating costs	Operating costs can cover items such as maintenance, staffing, materials, other resources and monitoring. Ideally it is best to add these as individual line items for transparency and to see how sensitivity analysis might affect the output from the CBA.
Power/gas/ water	Sites that are supplied directly with power or gas or water will incur service/utility costs. These should be estimated in line with published data. This information can be sourced from BEIS, which publishes historical and future costs for commodities.
Environmental cost factors	
Carbon dioxide	Carbon dioxide is a major greenhouse gas. To incentivise operators to release less carbon dioxide (or equivalent carbon dioxide, CO_2e), the European Union (EU) introduced the Emissions Trading Scheme (ETS), which requires operators to pay for the carbon dioxide they emit in the form of carbon credits. These credits (priced on a per tonnage basis) are made available by the EU ETS and are purchased at a market value which reflects supply and demand. The cost of this 'traded' carbon is currently very low, around £5 per tonne, which does not provide the intended incentive to reduce carbon emissions that the scheme originally envisaged. Consequently, to allow for fluctuations in the cost of carbon credits, the UK government has imposed a minimum carbon price known as the 'floor price' of £18 per tonne, which is current scheduled to be in place until 2021 (HMRC 2014). Only operators that have a total rated thermal input to combustion processes >20MW are required to pay for the carbon they release under the EU ETS. It is expected that most OOG operations in England would fall below this threshold and therefore would not pay for the carbon they release. Although the EU ETS carbon cost or the carbon floor price is the cost that an operator will actually pay for emissions, it is not the same as the carbon cost that should be used in policy analysis, which is based on the marginal cost of abating one tonne of carbon dioxide using currently available techniques. Therefore, the CBA assessment uses the 'non-traded' price. Future non-traded carbon cost can be obtained from BEIS (BEIS 2017).
Natural gas	Methane, which is the principal component of natural gas, has a GWP 28 times stronger than carbon dioxide over a 100-year time horizon (IPCC 2013). Any direct release of methane should be converted to tonnes equivalent of carbon dioxide by multiplying the release mass (in tonnes) by 28, and then costed using the non-traded price of carbon dioxide.

Type	Considerations
Combustion efficiency and methane slip	If natural gas is fed to a simple combustion processes such as a shrouded flare, the efficiency of combustion may be lower than for more optimised technologies such as ground flares or gas engines. This may be particularly evident where there is a large flow turndown, since combustion efficiencies may be reduced at the extremes of the flow range. In such circumstances, methane may be released uncombusted (methane slip), thereby reducing the benefit of combustion.
Gas composition	Depending on the source of the natural gas, the concentration of methane in the gas stream will vary. Other components may be inert gases such as nitrogen or carbon dioxide, or other hydrocarbon components such as ethane, butane and pentane. Heavier hydrocarbon components are more likely to be found at significant concentrations with associated gas than in gas produced from dedicated gas fields. For the purpose of this study, other components were not considered but in practice they should be, as they may have pollution impacts (for example, as precursors that form photochemical pollution) and/or because they are greenhouse gases in their own right. If other hydrocarbons are present in significant fractions, they should be assessed. This study also ignored hydrogen sulphide which, if present, will potentially affect the choice of waste management technologies that can be used since it is highly toxic and can cause accelerated corrosion of process equipment. Consequently, hydrogen sulphide will normally require removal for safety reasons, the exception being for elevated flares which can be designed to accommodate potential release of hydrogen sulphide release and dispersion (as may occur during a loss of a flare pilot).
NOx	NOx is produced in combustion processes, particularly those which occur at higher temperatures such as in gas engines or turbines. NOx can lead to poor air quality due to pollution effects such as photochemical smog and generate atmospheric nitric acid which could fall as acid rain. These are typically regional effects depending on the height of discharge and dispersion characteristics. The allowable release concentration of NOx will depend on the equipment’s combustion capacity, type and potentially efficiency. Unlike for carbon dioxide, there is no cost charged to an operator for NOx release but the operator will be subject to maximum permitted release concentrations. While there is no cost to the operator, there is an economic damage cost (established to be £13,840 per tonne of NOx - Environment Agency 2016b) and this should be used in a CBA involving combustion processes.
Calorific value	Different gas sources will have different calorific values depending on their methane content. Field gas can also have varying amounts of heavier hydrocarbons such as ethane and propane, and also inert gases such as carbon dioxide or nitrogen.

Type	Considerations
	In the CBAs carried out for the 2 case studies, the caloric value of gas, expressed as the lower heating value (LHV), was taken to be 35MJ per Sm^3 – an average value taken from data obtained from operators (UKOOG BAT study questionnaire responses). However, the LHV may go up or down due to the compositional variations of field gas. The effect of calorific value changes will be to increase or decrease the amount of gas required to meet a specific power output if used as fuel in a combustion process (for example, a gas engine). Hence, a higher LHV will result in more power being produced per standard volume of gas.
Benefits/income factors	
Power export	The income generated from power export (gas-to-wire) should be calculated on the basis of £ per MWh.
Gas export	The income from gas export (gas-to-grid) should be calculated on the basis of £ per MWh.
Carbon dioxide central power generation	The release of carbon dioxide which would otherwise be released from alternative/centrally generated power or gas transport/combustion can be offset against site activities.

2.8.2 Qualitative evaluation

The qualitative element of the BAT assessment methodology seeks to take account of local, regional or wider geographical factors that cannot be easily monetised and that could affect the acceptability of waste gas management techniques at a given site.

For a qualitative assessment, the following factors would generally be of importance:

- visual impact
- noise
- odour
- safety
- nuisance or disruption (for example, road transport impact)

Each technology should be assessed, using specific criteria, relative to a base case, generating either a positive or negative outcome.

Having determined whether an impact is negative or positive, the scale and magnitude of each factor is determined by assessing:

- the impact on receptors – people, flora and fauna or the wider environment
- how severely these receptors will be affected and for how long

The output from the qualitative assessment can be reported as a narrative result (for example, strong positive, medium positive, slight negative) However, for this study it was decided to convert the narrative results to a ranking score to make comparison between options easier (see Table 2.4).

A detailed description of the qualitative assessment approach is given in Appendix G.

Table 2.4 Ranking index for qualitative assessment

Magnitude output	Magnitude ranking score
Very large positive	10
Large positive	8
Medium positive	6
Small positive	4
Very small positive	2
Neutral	0
Very small negative	-2
Small negative	-4
Medium negative	-6
Large negative	-8
Very large negative	-10

2.9 Case studies

OOG operations in England encompass a wide range of development types. These can be characterised by factors such as:

- hydrocarbon resource type (oil/gas)
- phase of development (for example, drilling or production)
- proximity of infrastructure, other industries and/or other oil and gas production operations
- local factors (for example, proximity of residential areas or sensitive receptors)
- gas composition, flow rate and pressure

Given the range of potential variation in each of these factors, it was not practical to produce a representative case study for each conceivable scenario. Instead 2 hypothetical, but realistic, case studies were created for the purposes of this study to illustrate how the BAT decision-making method can be applied.

2.9.1 Case Study 1: Gas or shale gas – well appraisal phase

Summary

- Waste gas stream is wellhead gas from flow testing
- Maximum gas flow is 5,000Sm^3 per hour (per well tested)
- Fuel gas taken from well gas flow

- Unused gas sent to flare
- Onsite electrical load 750kWe
- 26 weeks operation

The source of waste gas is wellhead gas released during the flow testing of a well for a gas development. Well appraisal would generally last from a few days to around a month for an individual well, depending on the quality and stability of flow. Typically, there will be 2–4 test wells for a development, so overall testing could last from 90 to 180 days. Wells will normally be flow tested individually with other wells shut in.

Gas flow may be variable, but a peak flow of 5,000Sm^3 per hour per well tested is taken as the basis for this case. It is assumed that, during well appraisal, there is no opportunity to utilise this capacity of gas flow for sale or export due to lack of export infrastructure and/or because of the short flow window.

Well appraisal is assumed to follow drill stem testing (DST) and well clean-up. It should therefore yield low quantities of produced/returned water and condensate to manage and store. As such, gas release from liquids handling is expected to be low. Gas composition is assumed to be sweet (that is, no significant hydrogen sulphide content) and not to contain nitrogen or other inert gases at concentrations that would require rejection.

Decommissioning and reinstatement costs are not allowed for. Neither is any residual capital value of plant or infrastructure.

The procurement basis for well appraisal testing is that equipment will be rented or leased for the duration of the testing period (that is, up to 26 weeks).

For this waste gas management case study, the following options were assessed individually and in combination:

- shrouded (pipe-in-pipe) (base case)
- enclosed ground flare
- enclosed ground flare and onsite power generation via a gas engine

See Appendix F for more details on the inputs to Case Study 1.

2.9.2 Case Study 2: Oil or tight oil – production phase (associated gas)

Summary

- Associated gas flow during production operations
- Peak flow rate of 2,000Sm^3 per hour gas
- A pilot or minimum flow maintained to any safety flare systems
- No existing electrical export route to power distribution network is in place
- No existing gas export route to the NTS is in place
- 25 years of operation

Associated gas flow per well will decline throughout the life of the field development. A peak waste gas flowrate of 2,000Sm^3 per hour is taken for the first year of operation. It is then assumed to decline by 10% year-on-year for the first 10 years and then 2% per year thereafter. As this case study is for a dedicated oil production site, it is assumed that associated gas cannot be recycled or reinjected back through the production process.

The equipment used to utilise the associated gas flow will be sized to accept the maximum gas flow. If these utilisation systems are offline or partially unavailable, an alternative means of disposal will be required. Consequently, a flare system will always be required (sized for offline/safety-related scenarios) to take the full associated gas flow rate so that oil processing operations can be continued.

The distance to a connection point on the electricity grid is assumed to be 3km, and 10km for connection to the NTS. A cable capable of carrying up to 30MW is allowed for power export and a pipeline of 8–10 inch diameter and 75 barg for gas export.

The connection charges for either power or gas to the respective receiving systems are not allowed for. Decommissioning and reinstatement costs are also not allowed for. Neither is any residual capital value of plant or infrastructure.

The procurement basis for production operations is that equipment for waste gas management will be purchased and installed for the life of the plant (that is, 25 years).

For this waste gas management case study, the following options were assessed individually and in combination:

- enclosed ground flare (base case)
- enclosed ground flare and gas engine with power export to grid
- enclosed ground flare and gas turbine with power export to grid
- enclosed ground flare and gas turbine compression exporting gas to the NTS

Note: A shrouded flare is not considered for the production case as the lower efficiency cannot be justified compared with an enclosed ground flare over the life of the production operation (that is, up to 25 years).

See Appendix F for more details on the inputs to Case Study 2.

3 CBA results

This section presents the results of CBA for the 2 case studies detailed in Section 2.9. The case studies have only been subject to quantitative analyses as the variables relating to qualitative analysis for a test case are too extensive to make attempt to make realistic comparison. However, a worked example of the qualitative method is provided in Appendix G.

3.1 Case Study 1

Table 3.1 Case Study 1: well appraisal for a gas development (85% flare efficiency for base case)

Option	Description	Cost[1]	Cost versus base case
1	Shrouded flare (base case)	-£5,834,121	0
2	Enclosed ground flare	-£3,796,644	£2,037,476
3	Onsite power generation using a gas engine	-£4,246,245	£1,587,876

Notes: [1] Because the period of operation considered was only 26 weeks, it was not necessary to discount the costs and benefits.

The CBA showed that Option 2 (enclosed ground flare) returned the best economic result, providing a little over £2 million more value than the base case of a shrouded flare. The enhanced value of Option 2 is realised in spite of higher rental costs for an enclosed ground flare than for a shrouded flare (£4,285 versus £1,000 per day). This difference is offset by the economic benefit resulting from the superior performance of an enclosed ground flare compared with the base case (98% versus 85%), which means environmental damage costs are much lower.

The economic cost for Option 3, which includes 750kW for onsite power generation, is more beneficial than for Option 1 but inferior to that for Option 2. The reduction in economic value for Option 3 compared with Option 2 reflects the additional costs of gas engine power rental and the increase in NOx emissions resulting from using a side stream of field gas as fuel rather being burnt in the flare (NOx emissions from high temperature combustion processes such as a gas engine being higher than for a flare.) In reality this difference would be reduced by virtue of removing or reducing the requirement for back-up diesel power generation systems when gas is not flowing or to cover black start capacity; this was not taken into account in this calculation. Also, Option 3 does not assess the potential benefits of using CHP gas engines and generators, which would allow waste heat to be recovered and potentially used elsewhere in the facility (for example, to preheat the well gas prior to pressure let down to avoid low temperature embrittlement of pipework).

Option 3 covered an operating case where a fraction of the waste gas flow is used to power onsite electrical generation systems to meet an assumed site load of 750kW. Costs were allowed for rental of the electrical generator only. It is considered that the onsite infrastructure needed to manage and to distribute power (transformer, switchgear and cabling) will be broadly the same and required whether connected to a diesel-powered generator or a gas-powered generator or a mains electrical feed.

To demonstrate the effect of sensitivity, the combustion efficiency of the flare was varied from the base case of 85% to 80% (Table 3.2) and 90% (Table 3.3). In both cases, the ranking of the options by relative cost does not alter. However, the relative value changes in line with efficiency which in turn determines the value of emissions damage costs.

Table 3.2 Case Study 1: well appraisal for a gas development (80% flare efficiency for base case)

Option	Description	Cost	Cost versus base case
1	Shrouded flare (base case)	-£6,740,234	0
2	Enclosed ground flare	-£3,697,959	£3,042,275
3	Onsite power generation using a gas engine	-£4,153,462	£2,586,772

Table 3.3 Case Study 1: well appraisal for a gas development (90% flare efficiency for base case)

Option	Description	Cost	Cost versus base case
1	Shrouded flare (base case)	-£4,927,008	0
2	Enclosed ground flare	-£3,895,330	£1,032,678
3	Onsite power generation using a gas engine	-£4,339,028	£588,980

3.2 Case Study 2

Case Study 2 involved an oil production operation producing up to 2,000Sm^3 per hour of waste gas. Relative to the base case of an enclosed ground flare, the options that exported electrical power or gas returned NPVs with between £15 million and £39 million more value (Table 3.4). Although there is a significant difference in capital investment associated with the power or gas export options versus the base case (for the process plant, generation or compression systems and export infrastructure), this investment is offset by the income derived from the sale of power or gas over the 25-year operational life.

Table 3.4 Case Study 2: production oil development with associated gas

Option	Description	NPV	NPV versus base case
1	Enclosed ground flare	-£35,528,510	0
2	Power export using gas engine	£3,911,777	£39,440,287
3	Power export using gas turbine	-£11,834,452	£23,694,058
4	Gas export to NTS	-£20,640,631	£14,887,879

The other key contributor to the superior NPVs relative to the base case is the offsetting of emissions damage costs. Electricity generated and exported by an OOG operator to the electrical network will meet a demand or load that would otherwise have to be met by central generation. Central generation will be more efficient, and any offsetting can be adjusted to allow for this.

Emissions ‘offsetting’ also applies to gas export where the gas supplied by an OOG operator to the NTS effectively replaces gas that would otherwise be added to the NTS from other sources. Therefore, the emissions costs associated with compression and transport, as well as those associated with the eventual combustion of the gas, can be offset against the emissions that would be produced by another source supplying the NTS.

A cost that has not been accounted for in this assessment but which should be included in a real CBA is the connection cost to the power grid or NTS. For instance, while cable installation costs could be significant depending on the distance to a DNO connection point, it is the actual physical connection to the DNO system which may determine the viability of power export. There can be very significant variations in connection costs charged by a DNO, depending on what infrastructure capacity (for example, transformers, switchgear, buildings) is available at the point of connection. If this infrastructure is not available, this cost will have to be borne by the exporter. Consequently, connection costs could vary from less than £500,000 to more than £10 million.

The costs for fully installed export infrastructure were estimated to be:

- £3,000 per metre for an 8–10 inch diameter (75 barg) pipeline
- £1,500–£1,900 per metre for a 10MW or 30MW rated power cable

Capital costs for generation equipment, compressors and associated pipework were provided from vender budgetary quotations and/or derived using an in-house parametric estimating tool and have an accuracy of ±30%. Operating costs are all estimated.

4 Discussion

4.1 Case Study 1

The BAT assessments carried out for the case studies illustrate how NPV can be used as a mechanism for comparing different options. For Case Study 1, it was demonstrated that the efficiency benefits associated with an enclosed ground flare outweighed the additional rental or capital costs associated with this type of flare versus a shrouded system. A sensitivity analysis showed that, changing the base case flare efficiency from 85% to 80% or 90%, did not alter the relative ranking of the options and thus confirmed the general robustness of the result.

In practice there are a number of variables which should be tested for sensitivity. For Case Study 1, this would include factors such as field gas methane concentration, gas engine NOx emissions, gas engine efficiency, the duration of flaring and field gas flow rate.

From the direct costs perspective, only the flare rental and site electrical costs were included under the direct costs section of the CBA. In practice there will be process equipment (for fuel gas clean-up), civil engineering, land purchase, transport, set-up and decommissioning costs. For the example CBA, however, it is not considered that this would materially alter the results. For Option 3, the impact on back-up/black power sources needs to be considered. These systems could be reduced in capacity or removed altogether if a gas storage tank (for field gas used as fuel) was used to run the gas engines when gas was not flowing.

As Case Study 1 runs for less than a year, the price of carbon was assumed to be fixed and there was no need to apply discounting, hence the economic results are current and have no future component to them.

A key parameter for Option 3 would be to consider lower NOx emission gas engines. The study took a NOx emission level of 500mg per m^3, which is high but representative of many gas engines. Specifying a lower emission machine should be considered. There may be a higher rental outlay, but the decrease in NOx damage cost should offset the additional expenditure. Potentially, there are scenarios where NOx considerations may be a more significant factor than GWP; for instance, where the site operation may be in, or close to, an Air Quality Management Area within which pollution effects from NOx or sulphur dioxide may already be an issue. In such cases, there may be a requirement to consider additional pollution control measures such as exhaust gas treatment (for example, selective catalytic reduction of NOx), which will incur additional capital and operating costs.

Another factor not included in this case study was the impact of CHP systems. These would allow process heating or steam duty to be met without needing to provide dedicated or separate systems, thus improving overall efficiency and/or performance and reducing costs.

Although there are a number of variables requiring sensitivity checks, the results of the case study indicate that enclosed ground flares do represent BAT for well appraisal operations.

4.2 Case Study 2

For the production CBA, there is a clear and significantly positive CBA outcome for options 2, 3 and 4 compared with the base case of an enclosed ground flare. In principle, this is not surprising as these options return an income from the export of power or gas. However, this capability requires gas processing equipment to clean up or condition the gas in gas engines or gas turbines driving power generators or compressors. On top of this is the cost of the drivers, power generation and/or compression systems, which would represent a minimum investment of several millions of pounds.

As discussed previously, the cost of the export infrastructure, the export pipeline or cable, and connection will probably be the dominant factor in determining viability. Cable or pipeline costs are easy to estimate on a per metre installed basis, but this does not account for the need to cross roads and/or railways, terrain and so on, which may affect the capital cost.

As for Case Study 1, there are many factors which may alter the outcome of the CBA. For the production case, several influencing factors are time related. These include:

- the rate of decline of waste gas flow
- the number of gas engines or turbines required to process the gas
- the future price of carbon and energy

4.3 Quantitative assessment

The rate of decline of field gas flow will vary from field to field. This is particularly true for shale or tight oil developments where peak flow may only last from a few months to 2 years, and would require repeated hydraulic fracturing to restore gas flow. This study assumed a 10% year-on-year decline for the first 10 years and then 2% per year thereafter, but this may be very different in practice. For the case study, a starting flow rate of 2,000Sm^3 per hour was assumed. At this flow rate, the economics of the CBA are heavily in favour of power or gas export; a reduction in gas flow rate to 1,500Sm^3 per hour would lower the NPV for options 2 – 4 by between 34% and 44%. If DNO connection costs are at the higher end (~£10 million) or distances to a connection are longer than the assumed 10km for power and 3km for pipeline, the economics of export may become more marginal.

The future cost of non-traded carbon is set by BEIS and has been estimated up to the year 2100. The cost of non-traded carbon is set to increase significantly from around £70 per tonne, in 2020 up to £350 per tonne in 2075 (BEIS 2017). However, there is clearly uncertainty about these predictions and, to allow for this, the predictions are banded into ‘low’, ‘central’ and ‘high’, reflecting different rates of rise. For the CBA, a central band was used but, when carrying out a formal CBA, it is suggested that a sensitivity analysis is performed by applying all of the different bands. BEIS also predicts future energy prices up to the year 2100 and again sensitivity should be applied to the different rate of rise bandings.

Using an economic rather than financial approach means the results represent an assessment of what is best performance with respect to society and the environment as a whole. A purely financial appraisal will produce different outcomes in terms of absolute costs; the NPV for each option will be improved as the damage costs are effectively removed. There may also be a change in the ranking of options as the environmental performance benefits that may be associated with more expensive technology will not provide a direct gain to an operator if they are not required to pay for emissions. As a result, higher capital or operational costs may dominate selection.

4.4 Qualitative assessment

A worked example of qualitative assessment is provided in Appendix G. The methodology can be applied to any factor that cannot be easily monetised and may be performed using a comparative or absolute approach. The approach measures the scale and magnitude of an effect, which can be either negative or positive. The method can look at individual impacts side-by-side (for example, visual impact or noise) or the effect of each factor can be aggregated to give an overall outcome for each technology solution.

The qualitative methodology is useful in that it will help to support the screening of technology options that may not be suitable for some environments (for example, close to residential areas or sensitive environments). Alternatively, it may confirm that there are no significant differentiators which will then default the outcome of any BAT assessment to the CBA results.

When using the qualitative methodology, care should be taken to ensure that it does not double-count factors which have otherwise been assessed as part of the CBA. Calibration of the assessment criteria should be considered; this may not be the same from one development to the other but whatever is used it should be justifiable to the relevant regulatory authority.

4.5 Decision-making

When considering the output from the CBA and qualitative analysis, it is important that NPV results, scoring and ranking are not taken as absolute (that is, the highest score or ranking does not automatically equal best). This may be because a technology that performs well on a CBA basis may perform badly in a qualitative test and vice versa. Alternatively, results between may be marginal with no clear best option.

Users of the BAT methodology should take be aware that the method is an aid to the decision-making process and not the end of the process. Its importance is that the methodology provides operators and the Environment Agency with an open and consistent approach to BAT selection.

5 Conclusions

This study of waste gas management options for the OOG industry has highlighted the increasingly diverse methods being developed globally to utilise waste natural gas. However, many of these methods are not yet considered as indicative BAT for the OOG sector in England. From the long list of potential waste gas management technologies, which were then screened to a short list, the following should be considered as indicative BAT, either individually or in combination, for use in the OOG sector in England:

- enclosed ground flare (minimum requirement/base case)
- gas engine/gas turbine driven power generation for onsite duty
- gas engine/gas turbine driven power generation for power export (gas-to-wire)
- heat recovery from gas engines for reuse onsite or export to local users (for example, CHP)
- gas turbine driven for gas compression and export (gas-to-grid)

The selection of waste gas management technology, however, is influenced by a large number of factors including gas flow rate, composition, duration of flow, equipment efficiencies, site location, distance to potential users, capital costs and local receptor sensitivity. The BAT candidates listed above are therefore subject to the following provisos.

- Flaring of gas is the minimum requirement for waste gas management. The exception is where flow rates are expected to be sufficiently low or infrequent as to make maintaining a flare more environmentally damaging than cold venting.
- An enclosed ground flare should be considered as indicative BAT for flaring. This technology has high combustion efficiencies (98% or better), thereby minimising methane slip and the generation of odour and smoke.
- Consideration should be given to how multiple well site developments can be linked together (for example, within a single play) via a gathering station or a common processing facility. This may allow the selection of technologies that would otherwise not be practically or financially viable.
- The availability of equipment to utilise waste gas as a fuel for power generation, either for onsite use or for export to grid, should be considered indicative BAT where economics and practicalities permit. For gas-to-wire applications, this is likely to be dominated by the cost of connection and the amount of power that can be generated.
- An alternative to electrical power generation is gas export or gas-to-grid. Its viability will largely be determined by the cost of connection and compression systems, and the available flow rate of gas.
- Wherever waste gas is used as a fuel gas for gas-driven mechanical drivers, CHP systems should be considered BAT to provide heat for onsite users or local users.

- The use of alternative technologies or techniques such as those currently employed in the US OOG sector are not currently considered to be available or proven for use in England.
- The greatest opportunity for improvements in waste gas management is likely to be realised in oil production operations that generate associated gas. While there is an imperative to positively utilise waste gas produced during well appraisal, the lack of any new indicative BAT technology means that flaring combined with onsite power generation remains the best management approach.

The study has developed a method to support the process of determining what constitutes indicative BAT for waste gas management which can be used as an exemplar by operators and the Environment Agency. The method incorporates a CBA to assess factors that can be monetised such as capital, pollutant damage and revenue; it returns a NPV for each option considered enabling a side-by-side comparison to be performed. Non-monetisable factors can be assessed qualitatively against a base case and each other. This approach provides a good indication of the positive or negative impact that a particular technology will have in a given location or scenario.

The approach is easily adaptable for different scenarios, utilising a spreadsheet format. The basic mechanics of the approach are not novel, but the description of the approach detailed in Appendix E does provide a framework for operators and the Environment Agency to develop their assessments in a consistent and transparent manner.

Sitting alongside the CBA is a proposed approach for the assessment of non-monetised factors and impacts. Combined with the CBA, the qualitative analysis can be a useful aid to the selection of appropriate technologies, especially where sites are proposed to be located in sensitive locations or close to residential areas.

The overall BAT methodology, consisting of quantitative and qualitative analysis, represents an effective mechanism to aid the selection of the best technologies for the management of waste gas from OOG sites. However, it is important to recognise that the selection process is very dependent on:

- the assumptions made by the operator and the regulator
- the quality and accuracy of the input information and costs

Consequently, the output from the BAT assessment should not be seen as the conclusion of the selection process but rather as a starting point for informed discussion between an operator and the regulator.

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List of abbreviations

BAT	Best Available Techniques
BEIS	Department for Business, Energy and Industrial Strategy
BREF	BAT reference [document]
CBA	cost–benefit analysis
CHP	combined heat and power
CNG	compressed natural gas
COMAH	Control of Major Accident Hazards
DCF	discounted cash flow
DNO	distribution network operator
DST	drill stem test
EFT	extended flow test (well appraisal)
ETS	Emissions Trading Scheme
EU	European Union
GGFR	Global Gas Flaring Reduction [partnership]
GTL	gas to liquids
GWP	Global Warming Potential
IED	Industrial Emissions Directive
LHV	lower heating value
LNG	liquefied natural gas
LRVC	Long Run Variable Costs
NGL	natural gas liquids
NOx	oxides of nitrogen
NPV	Net Present Value
NTS	National Transmission System
OOG	onshore oil and gas
ORC	organic Rankine cycle
PV	Present Value
SEPA	Scottish Environment Protection Agency
SOx	oxides of sulphur
STG	syngas to gasoline
UKOOG	United Kingdom Onshore Oil and Gas

Glossary

Blowdown[1] To vent gas from a well or production system (either for operational, maintenance or emergency reasons).

Drill stem test[1] A procedure to determine the productive capacity, pressure, permeability or extent (or a combination of these) of a hydrocarbon reservoir. While several different proprietary hardware sets are available to accomplish this, the common idea is to isolate the zone of interest with temporary packers. Next, one or more valves are opened to produce the reservoir fluids through the drill pipe and allow the well to flow for a time. Finally, the operator kills the well, closes the valves, removes the packers and trips the tools out of the hole. Depending on the requirements and goals for the test, it may be of short (one hour or less) or long (several days or weeks) duration and there might be more than one flow period and pressure build-up period.

Gas lift[1] An artificial lift method in which gas is injected into the production tubing to reduce the hydrostatic pressure of the fluid column. The resulting reduction in bottom hole pressure allows the reservoir liquids to enter the wellbore at a higher flow rate. The injection gas is typically conveyed down the tubing-casing annulus and enters the production train through a series of gas-lift valves. The gas-lift valve position, operating pressures and gas injection rate are determined by specific well conditions.

Kick[1] A flow of formation fluids into the wellbore during drilling operations. The kick is physically caused by the pressure in the wellbore being less than that of the formation fluids, thus causing flow. This condition of lower wellbore pressure than the formation is caused in 2 ways. First, if the mud weight is too low, then the hydrostatic pressure exerted on the formation by the fluid column may be insufficient to hold the formation fluid in the formation. This can happen if the mud density is suddenly lightened or is not to specification to begin with, or if a drilled formation has a higher pressure than anticipated. This type of kick might be called an underbalanced kick. The second way a kick can occur is if dynamic and transient fluid pressure effects, usually due to motion of the drill string or casing, effectively lowering the pressure in the wellbore below that of the formation. This second kick type could be called an induced kick.

Linepack The amount of gas within the gas distribution system at any time is known as 'linepack'. The acceptable range over which the amount of gas in the network can vary and the ability to further compress and expand this gas is generally referred to as 'linepack flexibility'. Pressuring of the gas distribution system to a high linepack pressure effectively provides more capacity in the system. This is often done in advance of expected high gas demand (for example, during expected cold periods).

Play[1] An area in which hydrocarbon accumulations or prospects of a given type occur.

Rewheeling Rewheeling refers to the impellor on a centrifugal compressor. Impellors will be designed for a specific pressure and flow duty

	envelope. Ideally the envelope will mean that the compressor and its driver operate in the most efficient zone, but as flows or pressures change, the operational point may move to inefficient areas of the compressor duty envelope. In such a case it can be both technically practical and economically beneficial to rewheel a compressor (that is, the centrifugal impellor) to better match the future duty.
Tight oil[1]	Oil found in relatively impermeable reservoir rock. Production of tight oil comes from very low permeability rock that must be stimulated using hydraulic fracturing to create sufficient permeability to allow the mature oil and/or natural gas liquids to flow at economic rates.

Notes: [1] Schlumberger Oilfield Glossary (www.glossary.oilfield.slb.com).

Appendix A: Summary of waste gas releases by sector and phase

<table>
<tr><th rowspan="3">Sector</th><th colspan="6">Development/installation lifecyle stage</th></tr>
<tr><th colspan="3">Exploration</th><th>Appraisal</th><th rowspan="2">Production</th><th rowspan="2">Decommissioning</th></tr>
<tr><th>Drilling</th><th>Hydraulic fracturing</th><th>Drill stem test (DST)</th><th>Extended flow test (EFT)</th></tr>
<tr><td rowspan="5">Oil</td><td rowspan="5">Gas kick/drill underbalance or venting of formation gases – short duration event, negligible flows/volume and low pressure release. Usually seen at the drilling muds/gas separators.
Unpredictable but should be rare, especially where wells are in an established play.</td><td rowspan="5">Not applicable</td><td rowspan="5">Associated gas flow duration may range from a few minutes up to several days depending on the well characteristics and test stability.
Low to moderate gas flow rates. Pressures dependent on well depth but could be >200 barg. Produced fluids likely to have unpredictable composition, and pressure and flow characteristics.
Wells can be closed in following DST to minimise further releases until EFT or production phases commence.</td><td rowspan="5">Duration of 30–180 days, low to moderate flow rates. Pressures dependent on well depth but could be >200 barg. Produced fluids likely to have unpredictable composition, and pressure and flow characteristics.
Wells can be closed in following EFT to minimise further releases until the production phase commences.</td><td>Process (for example, stabilisation flash gas) – continuous; low pressure but potentially usable gas flows.</td><td rowspan="5">For the decommissioning, the production/handling installation releases will be analogous to those from maintenance activities.
Well plugging and abandonment should generate negligible waste gas. Waste gas volumes will be dependent on the residual pressure in the reservoir. Releases from plugging are likely to be of limited duration.</td></tr>
<tr><td>Equipment seals (for example, compressors) – continuous; low pressure and low flow rate). Larger compressors with oil seals may have usable waste flow.</td></tr>
<tr><td>Blanket gas – continuous; low to moderate pressure with potentially usable flow.</td></tr>
<tr><td>Production spill off – infrequent; downstream system unavailable, spill off maintains upstream operation while system is restarted.</td></tr>
<tr><td>Maintenance depressurisation – intermittent; low pressures but potential for large volume of gas to be released.</td></tr>
</table>

Sector	Development/installation lifecyle stage					
	Exploration			Appraisal	Production	Decommissioning
	Drilling	Hydraulic fracturing	Drill stem test (DST)	Extended flow test (EFT)		
					Emergency depressurisation – infrequent; could be significant large volume at pressures up to the well pressure upstream of any reduction.	
					Relief devices – infrequent; small to moderate volume.	
Gas	Gas kick/drill underbalance or venting of formation gases – short duration event, negligible flows/volume and low pressure release. Usually seen at the drilling muds/gas separators. Unpredictable but should be rare, especially where wells are in an established play.	Not applicable	Gas flow duration may range from a few minutes to several days depending on the well characteristics and test stability. Moderate to high gas flow rates. Pressures dependent on well depth but could be >200 barg. Produced fluids likely to have unpredictable composition, and pressure and flow characteristics. Wells can be closed in following DST to minimise further releases until EFT or production phases commence.	Duration of 30–180 days, moderate to high flow rates. Pressures dependent on well depth but could be >200 barg. Produced fluids likely to have unpredictable composition, and pressure and flow characteristics. Wells can be closed in following EFT to minimise further releases until the production phase commences.	As for oil but with lower process releases.	For the decommissioning, the production/handling installation releases will be analogous with those from maintenance activities. Well plugging and abandonment may generate waste gas. Waste gas volumes will be dependent on the residual pressure in the reservoir. Releases from plugging will likely be of limited duration.

Sector	Development/installation lifecyle stage					
	Exploration			Appraisal	Production	Decommissioning
	Drilling	Hydraulic fracturing	Drill stem test (DST)	Extended flow test (EFT)		
Gas (shale)	Gas kick/drill underbalance or venting of formation gases – short duration event, negligible flows/volume and low pressure release. Usually seen at the drilling muds/gas separators. Unpredictable but should be rare, especially where wells are in an established play.	Gas will start to flow on hydraulic fracturing. Potential for high gas flow but short duration. Wells can be closed in following hydraulic fracturing to minimise further releases until DST or EFT phases commences.	Gas flow duration may range from a few minutes to several days depending on the well characteristics and test stability. Moderate to high gas flow rates. Pressures dependent on well depth but could be >200 barg. Produced fluids likely to have unpredictable composition, and pressure and flow characteristics. Wells can be closed in following DST to minimise further releases until EFT or production phases commence.	Duration of 30–180 days, low to high flow rates. Pressures dependent on well depth but could be up to 300 barg. Produced fluids likely to have unpredictable composition, and pressure and flow characteristics. Wells can be closed in following EFT to minimise further releases until production phase commences.	As for oil but with lower process releases.	For the decommissioning, the production/handling installation releases will be analogous with those from maintenance activities. Well plugging and abandonment may generate waste gas, with volumes being dependent on the residual pressure in the reservoir.
Oil (tight oil)	Gas kick/drill underbalance or venting of formation gases – short duration event, negligible flows/volume and low pressure	Associated gas will start to flow on hydraulic fracturing. Gas flows low to moderate for short duration.	Associated gas flow duration may range from a few minutes up to several days depending on the well characteristics and test stability.	Duration of 30-180 days, low to moderate flow rates. Pressures dependent on well depth but flowrates are likely to be less than for shale gas. Produced fluids	As for Oil.	For the decommissioning, the production/handling installation releases will be analogous with those from

Sector	Development/installation lifecyle stage					
	Exploration			Appraisal	Production	Decommissioning
	Drilling	Hydraulic fracturing	Drill stem test (DST)	Extended flow test (EFT)		
	release. Usually seen at the drilling muds/gas separators. Unpredictable but should be rare, especially where wells are in an established play.	Wells can be closed in following hydraulic fracturing to minimise further releases until DST or EFT phases commences.	Low to moderate gas flow rates. Pressures dependent on well depth but could be >200 barg. Produced fluids likely to have unpredictable composition, and pressure and flow characteristics. Wells can be closed in following DST to minimise further releases until EFT or production phases commence.	likely to have unpredictable composition, and pressure and flow characteristics. Wells can be closed in following EFT to minimise further releases until the production phase commences.		maintenance activities. Well plugging and abandonment may generate waste gas, with volumes being dependent on the residual pressure in the reservoir.
Coal bed methane	Gas kick/drill underbalance or venting of formation gases – short duration event, negligible flows/volume and low pressure release. Usually seen at the drilling muds/gas separators. Unpredictable but should be rare, especially where	Not applicable			As for oil but with lower process releases but with lower stabilisation releases as gas purity is higher than for normal gas sources.	For the decommissioning, the production/handling installation releases will be analogous with those from maintenance activities. Well plugging and abandonment may generate waste gas. Waste gas volumes will be dependent on the residual pressure

Sector	Development/installation lifecyle stage					
	Exploration			Appraisal	Production	Decommissioning
	Drilling	Hydraulic fracturing	Drill stem test (DST)	Extended flow test (EFT)		
	wells are in an established play.					in the reservoir. Releases from plugging will likely be of limited duration.
Coal mine methane	Natural gas is extracted from mine workings via vertical shafts and mechanical ventilation.	Not applicable	Not applicable	Not applicable	Overall, very high flow rates but the coal methane is diluted to very low concentrations (below the Lower Explosive Limit) via ventilation systems. Gas typically feeds gas engines. Loss of engines may result in spill off.	Depends on the state of mine at abandonment. If coal seams are worked out, methane release should be negligible. If coal is left in situ there is potential to recover this gas.

Appendix B: Long list of technologies

Technology	Subtype	End product	Issues
Cold venting	Local vents/combined vents	Methane and volatile hydrocarbons	• Least blockers technically and commercially • Worst option environmentally, given GWP of methane, which also presents safety hazards due to release of uncombusted gas
Flaring	Ground flare Shrouded flare Elevated pipe flare Fully-enclosed ground flare Multi-point sonic pipe flare incinerators	Carbon dioxide and combustion products	• Better than cold venting as natural gas converted to carbon dioxide, so GWP significantly reduced. However, will produce NOx and carbon monoxide pollutants as well as other combustion pollutants depending on composition of feed stream and control of the flare.
Heat generation	Dedicated fired heaters or heat recovery on incinerators and so on	Heat for use in process or for export (for example, as steam or hot water)	• Availability of local users
Power generation	Turbine	Electricity for own use or export to grid or local market	• Generally mature technologies, though thermoelectric is a novel technology
	Gas engine		
	ORC		
	Thermoelectric material		
Collection and reinjection/recycling	Enhanced oil recovery	Carbon dioxide	• Potential issues for reservoir engineering • Availability of pipeline infrastructure
	Recycle to gas processing facilities or fuel	Methane	
	Recompression for delivery to pipeline	Methane	

Technology	Subtype	End product	Issues
Mini-LNG	Liquefaction to storage Liquefaction to truck tank Stirling cycle Closed loop refrigeration Joule–Thomson with refrigeration Methane expansion cycle	• LNG	• Lack of market for LNG • High costs of overall production and transport chain • Increased revenue from sale of LNG
Conversion	GTL	• Diesel, gasoline, kerosene • Ammonia • Propylene • Methanol • Synthetic crude • Fischer–Tropsch process • STG+ process • GasTechno process	• Low maturity • High capital cost • Cheaper transportation to market • Increased revenue from sale of liquid products
	GTL methane to gasoline via ethylene	• Gasoline	
	Catalytic cracking of higher hydrocarbons	• Methane and syngas	
	Cold-plasma-assisted, catalysed reforming to clean syngas	• Syngas	
	STG+ (Syngas to Gasoline Plus) GTL – based on Mobil technology	• Gasoline	
Vapour recovery	Flash gas tank recovery condensate	• Liquid product	• Mature technology

Technology	Subtype	End product	Issues
	Flash gas tank recovery crude oil		• Limited capacity
	Oxygen removal		
	Flare gas recovery		
Gas processing and NGL recovery	Mechanical refrigeration	• Ethane, propane, butane	
	Adsorbent (pressure swing)		
	Vortex recovery		
	NGL recovery		
	Membrane		
	Joule–Thomson		
	Cold box and fractionation		
CNG	CNG to truck	• CNG	• Potential safety issues with transport to market • High costs of transport to market • High capital cost
	CNG to pipeline		
	CNG storage for local users		
	Plug and play CNG fuelling station		
Thermal cracking of crude oil		• Liquid fuels	
Energy storage	Thermal	• Electricity	• Unlikely to be available technology within 12-month horizon
Energy storage	Batteries		

Appendix C: Technology screening for EFT phase

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
Venting	Direct release of gas to atmosphere	Vent line of sufficient height to allow for safe dispersion of natural gas to atmosphere.	• Simple. • Easy to set up/versatile. • Well proven. • Broadly unaffected by gas composition (except for hydrogen sulphide or heavy hydrocarbon components). • Inexpensive. • Can be sized to manage a large range of gas flow rates.	• Natural gas is a highly potent greenhouse (28 times more powerful than carbon dioxide). • Creates a potentially hazardous/flammable environment local to release. • Requires safe vent/sterile area to protect against toxic release or from thermal effects. • For station vents, height may be significant creating visual issues.	• Only considered suitable for small volume/low pressure releases for the purposes of infrequent maintenance or safety relief. • May be required on sites as a back-up to primary waste gas handling systems if they are offline or cannot handle safety release flows.	No
Combustion	Elevated flares (various types)	Piloted vent line of suitable height to enable safe dissipation of thermal radiation so as not affect personnel, plant and buildings, and also to enable safe dispersion of combustion products. Can be open pipe design, mixing assisted or sonic tip design.	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Can accommodate a large range of flow – up to 1,000–4,000 tonnes per hour, with a turndown ratio of up to 6:1. • Suitable for wide range of gas compositions. • Depending on flare type, flow rate and height requirements, elevated fares can be modular/ mobile solutions. Larger systems relatively simple to install. • Sonic systems can operate with high back pressures. • Sonic tip and mixing assist systems can be optimised to enable efficiency of 98% or greater. • Effective for sour gas duty as the height of the stack will be set to ensure that unburnt hydrogen sulphide is dispersed without affecting personnel. This is more likely to be of use with associated gas. • Simple installation and operation. • Costs are low to medium compared with other solutions – units are available for rental in UK at capacities that would meet most EFT needs.	• Release of carbon dioxide contributes to global warming. • Large visible flame – significant issue in rural/ non-industrial areas. • Typically, noisy >70dB(A), or very noisy >90db(A) for sonic flares. • Basic open pipe flares may only have efficiencies between 75% and 90%. • High combustion efficiencies require additional utilities such as steam, compressed air or high pressure gas to improve mixing, which increase energy usage. These services may not be available during EFT. • Requires optimisation to prevent smoke generation, especially if there are heavier components in the gas or at low flow rates. • Potentially requires a large sterile area to allow for ground level thermal effects on personnel, plant and buildings. • Higher risk of pilot blowout compared with shrouded/enclosed or ground-based systems. • Need a constant supply of gas for the flare pilot, which creates a constant combustion stream, potentially offsetting benefits. Would contribute to emissions covered by a site permit.	• Not generally considered suitable for EFT phase, unless the gas is sour, due to visual and noise impact as well as the footprint requirement for provision of a significant sterile area. • High efficiency systems require some form of mixing assist, which in turn necessitates additional plant and energy costs. • Generally, more suited for sour gas operation as it improves safety for operators. Otherwise visual and noise impacts, as well as the sterile area footprint, mean that elevated flares are not practical options.	No Height of flare, visible flame and noise mean that this technology cannot be considered as BAT at most sites. The exception may be for sour gas operation where personnel protection may take precedence.
	Shrouded flares	Piloted single piped flare housed within a larger pipe (shroud) assembly or suitable size and configuration to	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Can accommodate a large range of flow – up to 1,000–4,000 tonnes per hour, with a turndown ratio of up to 4:1. • Suitable for wide range of gas compositions.	• Release of carbon dioxide contributes to global warming. • Open pipe combustion is difficult to optimise. Typically, combustion efficiencies are between 70% and 90%. Increased potential for release of unburnt hydrocarbons or natural gas slip or smoke generation,	• Portable design and practical to implement. • Simple to install and operate. • Can be oversized without major cost penalty and therefore provides a good solution for safety-related releases. • Not the most efficient combustion option leading to potential hydrocarbon slip and increased release of NOx and SOx (oxides of	No Combustion efficiencies are low, resulting in significant potential for smoke generation and release of unburnt methane

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
		hide the flame and reduce thermal radiation effects.	• Particularly suitable for safety function because the open pipe design is less vulnerable to overpressure effects. • Height is generally lower than for elevated flares due to lower thermal effects because of the shroud, and therefore lower visual impact. • Low risk of pilot blowout compared with elevated flares. • Noise is generally lower than for elevated flares as the shroud provides a degree of noise attenuation. • Lower thermal radiation emissions and therefore smaller sterile area required. • Simple installation and operation. • Rental costs low compared with other solutions – typically £250 per day. Units are available for rental in UK at capacities that would meet most EFT needs.	particularly if there are heavy hydrocarbon components in the gas. • Efficiencies can fall significantly at low gas flow rates. • Low pressure duty only. • Requires optimisation to prevent smoke generation, especially if there are heavier components in the gas. • Potentially not suitable if hydrogen sulphide is present at hazardous concentrations due to health and safety considerations related to unburnt hydrogen sulphide. • Rental units may not fully shroud flame at high gas flows – depends on what is available in the market. • Need a constant supply of gas for the flare pilot, which creates a constant combustion stream, potentially offsetting benefits. Would contribute to emissions covered by a site permit. This would be a more significant issue for purely gas developments where a flare would need to be kept live for safety purposes.	sulphur) but has good flexibility in terms of flow rate and gas composition. • Cost model fits well with EFT phase operations, unless the flows are high (>5,000Sm^3 per hour) in which case the additional cost of more efficient systems may be merited. • Readily available for rental in the UK marketplace.	of heavy hydrocarbons. Unless site-specific conditions dictate, this is not considered as a BAT option.
	Enclosed ground flares	Piloted multiple burner system housed within a thermally insulated enclosure that will prevent local thermal radiation effects and hide the flame.	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Can accommodate a good range of flow– up to 1,000–2,500 tonnes per hour, with a turndown ratio of up to 4:1. • Suitable for a wide range of gas compositions. • Can be modularised and is therefore relatively straightforward to install and set up. • Burner design and control system monitoring allow high efficiencies to be achieved (>99%), meaning good emissions performance. • Low risk of pilot blowout compared with elevated flare. • Efficiency maintained across the wide turndown range (4:1). • No visible flame. • Lowest height for common flare systems – best visual impact. • Lowest noise for common flare systems <70dB(A). • Thermally insulated enclosure means no sterile area is required.	• Release of carbon dioxide contributes to global warming. • Not suitable if high hydrogen sulphide levels are present due to health and safety considerations related to unburnt hydrogen sulphide. • Need a constant supply of gas for the flare pilot, which creates a constant combustion stream, potentially offsetting benefits. Would contribute to emissions covered by a site permit. This would be a more significant issue for purely gas developments where a flare would need to be kept live for safety purposes. • May need to be operated with multiple units and a vent manifold to manage highly variable flowrates. • More expensive than alternative flare technology. • Suitable for low pressure duties only. • Increased maintenance and operation requirements. • Undersizing of burner nozzle configuration can cause backpressure build-up and damage, making such systems less suitable for safety duty, especially in 'wildcat wells' where peak flow data are lacking.	• Best performance characteristics due to control of burners and flow control. • Thermal enclosure means that no sterile area is required. • More expensive than shrouded or elevated units. • Not ideal for safety duty due to back pressure issues. • Potentially significant standby emissions from pilot burners if used for safety duty.	Yes

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
			• Best environmental performance for combustion based systems. • Available to rent at a cost of ~£6,000 per day in the UK.	• Significantly more expensive than alternative flare technology – either to rent or purchase.		
Heat generation	Incinerators/ boilers	Combustion of gas to generate heat, hot water or steam	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Uses waste gas instead of using imported or product gas to generate a site utility and/or an exportable utility to local users. • Can typically operate with a wide range of gas compositions and/or dual fuels (for example, gas or oil). • Modularised/self-contained. • Simple to install and set-up mobile units.	• Site loads for heat and hot water or steam may be limited during EFT, typical application being preheating before gas pressure reduction –therefore gas usage could be low and thus additional systems will be still required for excess waste gas management or when incinerators are unavailable. • If being used for heat export, a back-up gas supply (for example, propane or a natural gas piped supply) may be needed to keep incinerator/boiler operating when wellhead gas is not flowing. • Not suitable for safety duty. • Generally, not considered practical to export heat, hot water or steam unless users are very close to source (that is, <1km). • Creates additional safety hazards onsite by introducing new gas handling and hazardous zoning requirements.	• If there is a high demand for heat, hot water or steam onsite this could be worth considering but typically this will not be the case and other technologies could generate these utilities as a byproduct of their primary operation for example, a heat recovery unit/economiser on a gas turbine or engine (CHP). • If there are opportunities to export the heat that is, if close enough to industrial developments or large buildings this should be considered as a BAT option. • Will still require a cold vent or flare system for safety duty or balance of waste gas flow.	No
Power generation	Spark engines	Combustion of gas in a reciprocating engine driving an electrical generator	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Uses waste gas instead of using imported or product gas to generate a site utility and/or exportable utility. • Modularised/self-contained. • Simple to install mobile units. • Can typically operate with a wide range of gas compositions and/or dual fuels (for example, gas or oil). • Can recover exhaust heat to generate heat or hot water (that is, CHP generation). • Can replace diesel generator capacity. • Available for rent in the UK.	• Typical rental size limited to 2MW shaft power, which will only deal with direct site power needs, making export unlikely. • Site electrical load is only likely to utilise a small part flow of EFT waste gas flow and therefore additional waste management will still be required for unused gas. • Back-up waste gas management systems will need to be sized for gas flow when engine(s) are offline. • Not suitable for safety duty. • High noise output requires an acoustic enclosure to mitigate. • Back-up gas supplies (for example, propane) required or alternative power generation (for example, diesel generators) will be required if well gas is not available. • Creates additional safety hazards onsite by introducing mechanical moving systems with associated gas handling and hazardous zoning requirements.	• Well-understood technology readily available for rent and in modular form, so implementation straight forward. • May provide possibility to recover exhaust heat for other duties. • Potential noise issues. • Back-up gas fuel source or power generation may be required for periods when wellhead gas is not flowing. • Will still require a cold vent or flare system for safety duty or balance of waste gas flow.	Yes – in combination with a flare system
	Gas turbine	Combustion of gas in a gas turbine driving an electrical generator	• Combustion produces carbon dioxide which is a less harmful greenhouse gas than natural gas. • Modularised/self-contained.	• Gas turbine may be more sensitive to fuel composition changes than spark engines. • Back-up waste gas management systems will need to be sized for gas flow when turbine(s) are offline.	• Well-understood technology, readily available for rent and in modular form, so implementation straightforward. • May provide possibility to recover exhaust heat for other duties.	Yes – in combination with a flare system

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
			• Simple to install mobile units. • Can recover exhaust heat to generate heat or hot water (that is, CHP generation). • Can operate with dual fuels (for example, gas or oil). • Can replace diesel generator capacity. • Available for rent in the UK.	• Typical rental size limited to 2MW shaft power, which will only deal with direct site power needs, making export unlikely. • Site electrical load is only likely to utilise a small part flow of EFT waste gas flow and therefore additional waste management will still be required for unused gas. • Not suitable for safety duty. • High noise output requires an acoustic enclosure to mitigate. • Back-up gas supplies (for example, propane) required or alternative power generation (for example, diesel generators) will be required if well gas is not available. • Not considered practical to export power unless an accessible connection is available and an agreement to export is already in place. • Creates additional safety hazards onsite by introducing mechanical moving systems with associated gas handling and hazardous zoning requirements.	• Potential noise issues. • Back-up gas fuel source or power generation may be required for periods when the wellhead is not running. • Complex operating systems – need additional operator support. • Will still require a cold vent or flare system for safety duty or balance of waste gas flow.	
	ORC (waste heat recovery)	Recovers waste heat from process equipment for power generation	• Captures waste heat and converts to electricity for site use or export, instead of sending to atmosphere. • Mature technology.	• Impractical for EFT phase. Would typically recover heat from turbines, which would not have been constructed at EFT phase. • Payback period relies on continuous long-term operation, not the case for EFT phase.	• Well-understood technology • Not available for rent and in modular form, so implementation not straightforward.	No
Mini-LNG	Liquefaction of natural gas	Cryogenic liquefaction of natural gas through compression and expansion cycle	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Modularisable/mobile technology (in the USA). • Relatively simple to install and set up. • Bulk storage allows flexible logistics scheduling. • Allows export of liquid product, so pipeline not necessarily required.	• Requires bulk LNG storage tank(s) onsite, which increases hazard potential and, depending on size, may have implications under COMAH (Control of Major Accident Hazards) Regulations. • Location of system in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. May increase site footprint. • Potential for high number of road tanker movements to export product – increased risk of spills and releases. • Onsite containment required to protect against spillages and releases – increase in civil engineering costs. • May require nitrogen utility for liquefaction process, increasing process or operational complexity (delivery versus onsite generation). • Increased site electrical consumption. • Not suitable for safety duty. • May not handle entire waste gas flow rate and therefore additional waste management	• No established UK regasification infrastructure outside the 3 major port terminals. • LNG terminals (potential customer) are set up to receive marine deliveries not road tankers. • Road tanker delivery logistics use fuel and generate local pollutants, which will offset some of the emissions reduction benefits of gas liquefaction. • Not readily available to rent in UK (although rental concept exists in North Dakota in the USA).	No The lack of UK equipment and product market means that the LNG option is not currently considered available in the UK.

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
				will still be required for unused gas. Back-up waste gas management systems will need to be sized for full gas flow when system is offline. • Limited market – there are only 3 UK LNG terminals set up for bulk marine deliveries in the UK. Potential market through bottled gas supplies but untested. • Would require heat utility, which will increase overall complexity. • Not readily available to rent in UK.		
Conversion	Conversion of natural gas to liquids (GTL)	Various process routes	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Modularised/mobile technology possible. • Allows export of product where there is no piped export route. • May be used to fuel onsite vehicle/machinery requirements (that is, gasoline or diesel).	• Several different processing technologies are available. • Effectiveness is highly dependent on gas composition. • Some processes only work at large scale (for example, Fischer–Tropsch or ExxonMobil methanol to gasoline). • Requires bulk product storage tank(s) onsite, which increases hazard potential and, depending on size, may have COMAH implications. • Location of system in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. • Increased site electrical consumption. • Potential for high number of road tanker movements to export product – increased risk of spills and releases. • Onsite containment required to protect against spillages and releases – increase in civil engineering costs. • Not suitable for safety duty. • May not handle entire waste gas flow rate and therefore additional waste management will still be required for unused gas. • Back-up waste gas management systems will still need to be sized for full gas flow when system is offline. • Potentially not mature technologies at small scale. • Reliance on proprietary catalyst solutions. • Would require heat utility, which will increase overall complexity. • Not readily available to rent in the UK.	• Can be used to generate a range of different products from methanol, ammonia to gasoline and so on. • Market for diesel is declining. • Some processes are modularisable/ mobile, but others only suitable for large-scale operation, which would not be mobile. • Technologies often based on proprietary catalysts and reactor technology. • High complexity. • Some technologies need pairing with precursor processes such as gas to methanol (which is then used as a feedstock). • Not all options are technically mature or can be difficult to optimise. • Not all options are mature, at least in small mobile scale. • Would suit stable flow conditions and compositions which may not be the case during EFT. • Not readily available for rent in the UK.	No A combination of lack of rental infrastructure and potential product markets, diverse unproven technology, varying scale of operation and technology constraints mean that this approach is not currently considered available in the UK.
Gas processing	Recovery of NGLs from natural gas	Miniaturised compression of gas and three-	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide).	• Easier to export raw condensate for processing at a refinery.	• Potential option for rich gas (for example, associated gas), which cannot be fed directly into other utilisation technologies such as gas	No Lack of readily available rental

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
and NGL recovery		phase separation, and subsequent dewpointing, with stabilisation of NGL stream and collection in storage bullets	• Recovers NGL components to generate a saleable product. • Creates a lean gas stream that can be used to run gas engines/gas turbines for power generation or as feedstock for mini-LNG or conversion processes, or for compressed gas export. • Modularisable/mobile technology. • Allows export of a product where there is no pipeline route available.	• Highly dependent on gas composition; needs a rich gas stream to be considered practical and so best with associated gas. • Requires complex additional systems (for example, turbo expanders, fractionation columns, potentially nitrogen and mercury rejection). Impractical capital cost, operating complexity and footprint at EFT phase. • Requires bulk product storage tank(s) onsite, which increases hazard potential and, depending on size, may have COMAH implications. • Location of storage in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. • May increase site footprint. • Increased site electrical consumption. • Potential for high number of road tanker movements to export product – increased risk of spills and releases. • Onsite containment required to protect against spillages and releases – increase in civil engineering costs. • Not suitable for safety duty. • May not handle entire waste gas flow rate and therefore additional waste management will still be required for unused gas. • Back-up waste gas management systems will still need to be sized for full gas flow when system is offline. • Potentially not mature at modular/mobile scale. • Not readily available to rent in the UK.	engines or conversion processes, or for compression for export. • Based on established well-understood technology. • Good modularisation even at high flow rates >5,000Sm^3 per hour. • Can be fully self-contained. • Effectively a normal gas stabilisation process in modular/mobile form. • Not readily available for rent in the UK. • Export raw condensate to refinery considered a more practical option.	infrastructure in the UK means this approach is not currently considered available.
CNG	Compression to CNG for road tanker export	High pressure (>200 barg) compression of gas to fill in to a road tanker for export	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Modularisable/ mobile technology. • Allows export of product where there is no pipeline export route. • May be used to fuel onsite machinery.	• No established market for CNG via road tanker. • Works best with lean gas. Otherwise requires removal of heavy components, which adds to costs and complexity, and is therefore potentially not good for associated gas. • In conflict with the above, the most likely scenario where such an approach would be useful would be for an oil development with associated gas; however gas will need more clean-up. • As a compressed gas, export is significantly less efficient than for liquids. • Requires bulk product storage vessel(s) onsite, which increases hazard potential	• If the gas stream is lean and therefore does not require additional stabilisation, this option could be viable. • Suits oil developments where the economics or the practicality of associated gas export do not support an export pipeline. • If flow rates are high, the number of tanker movements may become problematic. • For high flow rates, may be better to consider piped export route. • Limited established infrastructure for compressed gas fuelling of vehicles in the UK. • Not readily available for rental in the UK. • Market for CNG for transportation may increase in the future.	No Logistics and lack of rental infrastructure in the UK mean that this option is not considered available.

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
				and, depending on size, may have COMAH implications. • Location of storage in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. • May increase site footprint. • Potential for high number of road tanker movements to export product – increased risk of releases. • Location of system in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. • Increased site electrical consumption. • Potential for high number of road tanker movements to export product – increased risk of releases. • Not suitable for safety duty. • May not handle entire waste gas flow rate and therefore additional waste management will still be required for unused gas. • Back-up waste gas management systems will need to be sized for full gas flow when system is offline. • Not readily available to rent in the UK.		
	Compression to CNG for export via pipeline	High pressure (>200 barg) compression of gas to a pipeline for export to a distribution network	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Modularisable/mobile technology. • Allows export of product.	• Works best with lean gas – otherwise requires removal of heavy components (NGLs) adding to costs. • Requires a pipeline to export and access to a distribution network. • Increased site electrical consumption. • Not suitable for safety duty. • Application process to export to network may be lengthy and complex. • Planning process for pipeline routing. • Cost of installation of pipeline may be prohibitive if none exists and operators may not want to commit until EFT completed.	• If the development is primarily for gas (not oil), then CNG will be the default product export route. However, it may not be economically viable to commit to this approach during EFT, unless an export line already exists (that is, a hub development or a gas network line is very close). • Receiving system, if part of the low pressure transmission system (7–32 barg) of the local distribution system (<7 barg), needs to be able to accommodate the gas export capacity. If this cannot be achieved, export will have to be controlled to reflect demand in the system or exported to the NTS, which operates at above 32 barg. • Availability of access to the NTS is much lower and would likely need compression boosting to achieve entry.	Yes Only considered BAT if readily available pipeline exists. This would then make the cost of renting modular compression systems viable.
Collection and reinjection/ recycling	Enhanced oil recovery	Injection of gas back into well to improve well performance	• Potential to boost oil flow in wells by maintaining well pressure by gas reinjection.	• Would only be of benefit where oil is being extracted at the same time. However, it would not be suitable during EFT phase as the intent is to gather data to understand the natural flow characteristics of a well.	• Not suitable for EFT phase.	No

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
				• Would require recompression equipment – additional cost, footprint, gas usage, noise and so on.		
	Recycling of waste gases	Recovery of vented gases for injection in to a separate processing step or feed recycling	• Established technology. • Ensures that gas losses are minimised. • Simple solution, which utilises existing plant. • Boosts product generation capacity. • Recovered gas could be used for fuel gas (for example, steam boiler, power turbine).	• Ideally gas needs to be at high pressure to allow it to be used elsewhere in the process. • Low pressure and flow rate releases are unlikely to be economic to recover and reprocess. • Less practical for oil developments which feature associated gas as less process options for reprocessing. • Process technology steps during EFT more limited than production and therefore less opportunity to reuse gas.	• Opportunities for waste gas reuse and reprocessing in the main processing train should form a fundamental requirement of the design basis of any operation.	Yes – subject to practical limitations where pressure and flow cannot be utilised
	Export via pipeline	Recompression of vented waste gas to supplement export flow	• Established technology – pipeline gas compression. • Simple installation and site infrastructure. • Mature supplier market. • Flexible flow solution. • Can be started and stopped with little penalty. • Can be used as part of heat recovery system to generate heat.	• Potentially not suitable where an export pipeline does not already exist (that is, associated gas; pipeline installation would be subject to assessment of the capital cost to connect in to the distribution network – a function of distance, and required pressure and capacity requirements). • If the development is gas and export is viable, then waste gas should be recovered and exported by the same route. For associated gas, adding a dedicated export line may not be economic. • Mercaptan odorant may need to be stored and delivered to site, which will potentially introduce new hazards and operational requirements. • Application process to agree export to network may be lengthy and complex. • Planning process for pipeline routing.	• If a pipeline already exists, this is should be a default option unless flows are very low. • If pipeline connection economics are not prohibitive and the receiving network can guarantee to take the export gas, this is the most practical solution for recovering and utilising waste gas.	Yes – subject to export line being available
Vapour recovery	Capture of vapour/gas from process operations	Recovery of vapour from separators or vessels, for reuse or fuel gas	• See entry for 'Recycling of waste gases' under the 'Collection and reinjection/recycling' option.	• Not likely to be significant during EFT (for example, limited process storage vessels).	• Not likely to be practical or economic on small scale/individual tank basis.	See CNG entries – recycling of vented gases
Energy storage	Electricity	Battery storage	• Portable power. • Easy to transport to customers.	• Requires a matched power generation system. • No developed infrastructure or market. • Novel – as yet, relatively unproven technology. • Storage capacity limitations may require multiple charging units and batteries to make viable use of waste gas. • Increase in vehicle movements. • Not available for rental in the UK.	• Could be viable in the future but not yet considered available. • Technology not mature. • Lack of market.	No

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward
	Thermal	Thermal storage	• Portable heat source. • Easy to transport to customers.	• Requires heat recovery systems to be in place (for example, CHP). • No developed infrastructure or market. • Novel – as yet, relatively unproven technology. • Storage capacity limitations may require multiple regeneration units and thermal cubes to make viable use of waste gas. • Increase in vehicle movements. • Technical limit on thermal storage time not known. • Customers need to be set up to recover energy. • Not available for rental in the UK.		No
Zero emission technologies	Valve actuators	Electric/ electrohydraulic/ compressed air valve actuators	• Does not use direct gas actuation – therefore no gas emissions. • Safer – no flammability risk.	• More expensive actuators. • Potentially bigger actuators (gas actuators can run at higher pressures and therefore tend to have smaller piston arrangements). • May have to install additional infrastructure (for example, instrument air compression and distribution network).	• Gas-actuated valves are easy to install and operate, but releases and safety hazards mean that direct acting gas valves are not considered as BAT. Zero emission valve actuation should always be chosen.	Yes

Appendix D: Technology screening for production phase

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward for detailed BAT assessment
Venting	Direct release of gas to atmosphere	Vent line of sufficient height to allow for safe dispersion of natural gas to atmosphere	• Simple. • Easy to set up/versatile. • Well proven. • Broadly unaffected by gas composition (except for hydrogen sulphide or heavy hydrocarbon components). • Inexpensive. • Can be sized to manage a large range of gas flow rates.	• Natural gas is a highly potent greenhouse (28 times more powerful than carbon dioxide). • Creates a potentially hazardous/flammable environment local to release. • Requires safe vent/sterile area to protect against toxic release or from thermal effects. • For station vents, height may be significant creating visual issues.	• Only considered suitable for small volume/ low pressure releases for the purposes of infrequent maintenance or safety relief. • May be required on sites as a back-up to primary waste gas handling systems if they are offline or cannot handle safety release flows.	No
Combustion	Elevated flares (various types)	Piloted vent line of suitable height to enable safe dissipation of thermal radiation so as not affect personnel, plant and buildings, and also to enable safe dispersion of combustion products Can be open pipe design, mixing assisted or sonic tip design.	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Can accommodate a large range of flow – up to 1,000–4,000 tonnes per hour, with a turndown ratio of up to 6:1. • Sonic systems can operate with high back pressures. • Sonic tip and mixing assist systems can be optimised to enable efficiency of 98% or greater. • Effective for sour gas duty as the height of the stack will be set to ensure that unburnt hydrogen sulphide is dispersed without impacting personnel. This is more likely to be of use with associated gas. • Simple installation and operation. • Costs are low to medium compared with other solutions.	• Release of carbon dioxide contributes to global warming. • Large visible flame – significant issue in rural/non-industrial areas. • Typically, noisy >70dB(A), or very noisy >90dB(A) for sonic flares. • Basic open pipe flares may have efficiencies of only between 75% and 90%. • High combustion efficiencies require additional utilities such as steam, compressed air or high pressure gas to improve mixing, which increases energy usage and means additional infrastructure is required. • Requires optimisation to prevent smoke generation, especially if there are heavier components in the gas. • Potentially requires a large sterile area to allow for ground level thermal effects. • Higher risk of pilot blowout compared with shrouded/ enclosed or ground-based systems. • Need a constant supply of gas for the flare pilot, which creates a constant combustion stream, potentially offsetting benefits. Would contribute to emissions covered by a site permit. This would be a more significant issue for purely gas developments where a flare would need to be kept live for safety purposes.	• High efficiency systems require some form of mixing assist, which in turn necessitates additional plant and energy costs. • Generally, more suited for sour gas operation as it improves safety for operators. Otherwise visual and noise impacts, as well as the sterile area footprint mean that elevated flares are not practical options.	No
	Shrouded flares	Piloted single piped flare housed within a larger pipe (shroud) assembly of suitable size and configuration to hide the flame and reduce thermal radiation effects	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Can accommodate a large range of flow – up to 1,000–4,000 tonnes per hour, with a turndown ratio of up to 4:1. • Suitable for wide range of gas compositions. • Height is generally lower than elevated flares, due to lower thermal effects because of the shroud; therefore, lower visual impact.	• Release of carbon dioxide contributes to global warming. • Open pipe combustion is difficult to optimise, with combustion efficiencies typically between 70% and 80%. Increased potential for release of unburnt hydrocarbons or natural gas slip or smoke generation, particularly if there are heavy hydrocarbon components in the gas. • Efficiencies can fall significantly at low gas flow rates. • Requires optimisation to prevent smoke generation, especially if there are heavier components in the gas.	• Simple to install and operate. • Can be oversized without major cost penalty and therefore provides a good solution for safety-related releases. • Not the most efficient combustion option – potential hydrocarbon slip and increased NOx and SOx release. • Low capital cost.	Yes

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward for detailed BAT assessment
			• Low risk of pilot blowout compared with elevated flares. • Noise is generally lower than for elevated flares as the shroud provides a degree of noise attenuation. • Lower thermal radiation emissions and therefore smaller sterile area required. • Simple installation and operation. • Capital costs are low to medium compared with other solutions (for example, enclosed flares).	• Potentially not suitable if hydrogen sulphide is present at hazardous concentrations due to health and safety considerations related to unburnt hydrogen sulphide. • Need a constant supply of gas for the flare pilot, which creates a constant combustion stream, potentially offsetting benefits. Would contribute to emissions covered by a site permit. This would be a more significant issue for purely gas developments where a flare would need to be kept live for safety purposes.		
	Enclosed ground flares	Piloted multiple burner system housed within a thermally insulated enclosure that will prevent local thermal radiation effects and hide the flame	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Can accommodate a good range of flow – up to 1,000–2,500 tonnes per hour, with a turndown ratio of up to 4:1. • Suitable for a wide range of gas compositions. • Burner design and control system monitoring allow high efficiencies to be achieved (>99%), meaning good emissions performance. • Efficiency maintained across the wide turndown range (4:1). • Low risk of pilot blowout compared with elevated flare. • No visible flame. • Lowest height for commonly used flare systems – best visual impact. • Lowest noise for commonly used flare systems <70 dB(A). • Thermally insulated enclosure means no ground level sterile area is required. • Best environmental performance for combustion based systems.	• Release of carbon dioxide contributes to global warming. • Not suitable if high hydrogen sulphide present due to health and safety considerations related to unburnt hydrogen sulphide. • Need a constant supply of gas for the flare pilot, which creates a constant combustion stream, potentially offsetting benefits. Would contribute to emissions covered by a site permit. This would be a more significant issue for purely gas developments where a flare would need to be kept live for safety purposes. • May need to be operated with multiple units and a vent manifold to manage highly variable flowrates. • More expensive than alternative flare technology.	• Best environmental performance due to efficient control of burners and flow control. • Thermal enclosure means that no sterile area is required. • More expensive than shrouded or elevated units. • Not ideal for safety duty due to backpressure issues. • Potentially significant standby emissions from pilot burners if used for safety duty.	Yes
Heat generation	Incinerators/ boilers	Combustion of gas to generate heat, hot water or steam	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Uses waste gas instead of using imported or product gas to generate a site utility and/or an exportable utility to local users. • Can typically operate with a wide range of gas compositions and/or dual fuels (for example, gas or oil).	• Site loads for heat or hot water or steam may be limited, typical applications being preheating before gas pressure reduction and dehydrator regeneration. Therefore gas usage could be low and thus additional systems will be still required for excess waste gas management or when steam/heat generation systems are unavailable. • If being used for heat export, a back-up gas supply (for example, propane or natural gas piped supply) may be needed to keep the incinerator/boiler operating when wellhead gas is not flowing. • Generally, not considered practical to export heat, hot water or steam unless users are very close to source (that is, <1km).	• If there is a high demand for heat, hot water or steam onsite, this option could be worth considering. But typically this will not be the case and other technologies could generate these utilities as a byproduct of their primary operation (for example, a heat recovery unit/ economiser on a gas turbine or engine (CHP)). • If there are opportunities to export the heat (that is, if close enough to industrial developments or large buildings), this should be considered as a BAT option.	No

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward for detailed BAT assessment
					• Will still require a flare system for safety duty or balance of waste gas flow.	
Power generation	Spark engines	Combustion of gas in a reciprocating engine driving an electrical generator	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Uses waste gas instead of using imported or product gas to generate a site utility and/or exportable utility. • Wide range of power generation capability from <1MW to 50 MW shaft power, which provides sufficient power for site needs and potentially export. • Can typically operate with a wide range of gas compositions and/or dual fuels (for example, gas or oil). • Can recover exhaust heat to generate heat or hot water (that is, CHP).	• Back-up waste gas management systems will need to be sized for gas flow when engine(s) are offline. • High noise output requires an acoustic enclosure to mitigate. • Back-up gas supplies (for example, propane) will be required if well gas is not available and power generation needs to be maintained to meet export commitments. • Viability of export depends on export cable power capacity for existing cables or distance to network high voltage connection. • Creates additional safety hazards onsite by introducing mechanical moving systems with associated gas handling and hazardous zoning requirements.	• Well-understood technology and readily available. • Possible to recover exhaust heat for other duties (that is, CHP). • Back-up fuel source may be required for periods when wellhead gas is not flowing. • Will still require a flare system for safety duty or balance of waste gas flow.	Yes
	Gas turbine	Combustion of gas in a gas turbine driving an electrical generator	• Compared with cold venting of natural gas, greenhouse gas emissions performance is improved as carbon dioxide is a significantly less harmful greenhouse gas. • Uses waste gas instead of using imported or product gas to generate a site utility and/or exportable utility. • Typical sizes from 3MW to 500 MW shaft power, which provides sufficient power for site needs and export. • Can operate with dual fuels (for example, gas or oil). • Can recover exhaust heat to generate heat or hot water (that is, CHP).	• Gas turbine may be more sensitive to fuel composition changes than spark engines. • Back-up waste gas management systems will need to be sized for gas flow when engine(s) are offline. • High noise output requires an acoustic enclosure to mitigate. • Back-up gas supplies (for example, propane) will be required if well gas is not available and power generation needs to be maintained to meet export commitments. • Viability of export depends on export cable power capacity for existing cables or distance to network high voltage connection. • Creates additional safety hazards onsite by introducing mechanical moving systems with associated gas handling and hazardous zoning requirements.	• Very good option where very large generation power generation capacities are required. • Well-understood technology and readily available. • Possible to recover exhaust heat for other duties (that is, CHP). • Back-up fuel source may be required for periods when wellhead gas is not flowing. • Will still require a flare system for safety duty or balance of waste gas flow.	Yes
	ORC (waste heat recovery)	Recovers waste heat from process equipment for power generation	• Captures waste heat and converts to electricity for site use or export, instead of sending to atmosphere. • Mature technology.	• Would typically recover heat from turbine, so depends on the inclusion of these in site scheme. • Payback period relies on continuous long-term operation, not the case for EFT phase.	• Payback period relies on continuous long-term operation, not the case for EFT phase.	No
Mini-LNG	Liquefaction of natural gas	Cryogenic liquefaction of natural gas through compression and expansion cycle	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Bulk storage allows flexible logistics scheduling. • Allows export of a product where there is no pipeline route available.	• High capital cost. • Requires bulk LNG storage tank(s) on site, which increases hazard potential and, depending on size/total storage capacity, may have COMAH implications. • Location of storage in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. May increase site footprint. • Potential for high number of road tanker movements to export product – increased risk of spills and releases.	• High capital cost and limited UK LNG infrastructure for road tanker handling mean that it is not an economic proposal • Road tanker delivery logistics use fuel and generate local pollutants, which will offset some of the emissions reduction benefits of gas liquefaction.	No

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward for detailed BAT assessment
				Potential restrictions on road tanker movements on some routes (for example, bridges and tunnels due extreme flammability risks). • Onsite containment required to protect against spillages and releases – increase in civil engineering costs. • May require nitrogen utility for liquefaction process, increasing process or operational complexity (delivery versus onsite generation). • Limited market – there are only 3 UK LNG terminals that are set up for bulk marine deliveries. There is a potential market through bottled gas supplies, but it is untested and would need development. • Would require heat utility, which will increase overall complexity.		
Conversion	Conversion of natural gas to liquids (GTL) – fuel base products	Various process routes	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Allows export of product where there is no piped export route. • May be used to fuel onsite vehicle/machinery requirements (that is, gasoline or diesel).	• High capital cost. • Several different processing technologies available. • Effectiveness is highly dependent on gas composition. • Some processes only work at large scale (for example, Fischer–Tropsch or ExxonMobil methanol to gasoline). • Process can be very difficult to optimise. • Requires bulk product storage tank(s) onsite, which increases hazard potential and, depending on size, may have COMAH implications. • Location of system in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. • Potential for high number of road tanker movements to export product – increased risk of spills and releases. • Onsite containment required to protect against spillages and releases – increase in civil engineering costs. • Reliance on proprietary catalyst solutions. • Would require heat utility, which will increase overall complexity.	• Can be used to generate diesel or gasoline or syngas. • Market for diesel is declining. • Technologies often based on proprietary catalysts and reactor technology. • High complexity. • Some technologies need pairing with precursor processes such as gas to methanol (which is then used as a feedstock). • Not all options are technically mature or can be difficult to optimise. • High capital cost. • Road tanker delivery logistics use fuel and generate local pollutants, which will offset some of the emissions reduction benefits of gas conversion process.	No
	Conversion of natural gas to liquids (GTL) – commodity products (for example, methanol, ammonia)	Various process routes	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Allows export of product where there is no piped export route. • May have higher value than fuel-based GTL.	• High capital cost. • Several different processing technologies available. • Effectiveness is highly dependent on gas composition. • Process can be very difficult to optimise. • Requires bulk product storage tank(s) onsite, which increases hazard potential and, depending on size, may have COMAH implications. • Location of system in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. • Potential for high number of road tanker movements to export product – increased risk of spills and releases.	• Potentially more attractive than GTL to fuels due to high value of products. • Technologies often based on proprietary catalysts and reactor technology. • High complexity. • Not all options are technically mature or can be difficult to optimise. • High capital cost. • Road tanker delivery logistics use fuel and generate local pollutants, which will offset some of the emissions reduction benefits of gas conversion process.	No

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward for detailed BAT assessment
				• On site containment required to protect against spillages and releases – increase in civil engineering costs. • Reliance on proprietary catalyst solutions. • Would require heat utility, which will increase overall complexity.		
Gas processing and NGL recovery	Recovery of NGLs (ethane, propane, butane and pentane) from natural gas	Recovery of gas condensate and then subsequent separation of high value products by refining processes	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Bulk storage allows flexible logistics scheduling • Allows export of a product where there is no pipeline route available.	• Competition from imported supplies means price point is low compared with the cost of processing in the UK. • Easier to export raw condensate for processing at a refinery. • Highly dependent on gas composition; needs a rich gas stream to be considered practical and so best with associated gas, • Requires complex additional systems (for example, turbo expanders, fractionation columns, potentially nitrogen and mercury rejection), meaning an increase in capital cost, operating complexity and footprint. • Requires bulk product storage vessel(s) onsite, which increases hazard potential and, depending on size, may have COMAH implications. • Location of storage in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. • May increase site footprint. • Onsite containment required to protect against spillages and releases – increase in civil engineering costs.	• Potentially option for rich gas (for example, associated gas), which cannot be fed directly into other utilisation technologies such as gas engines or conversion processes, or for compression for export. • Based on established and well-understood technology. • Economics capital and operating profit in competition with cheaper imports do not support this option. • Export of raw condensate to refinery considered a more practical option.	No
CNG	Compression to CNG for road tanker export	High pressure (>200 barg) compression of gas to fill in to a road tanker for export	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Bulk storage allows flexible logistics scheduling • Allows export of a product where there is no pipeline route available.	• No established market for CNG via road tanker. • Works best with lean gas. Otherwise requires removal of heavy components, which adds to costs and complexity, and therefore potentially not good for associated gas. • As a compressed gas, export via road tanker is significantly less efficient than for liquids. • Requires bulk product storage vessel(s) onsite, which increases hazard potential and, depending on size, may have COMAH implications. • Location of storage in relation to other systems and operatives needs careful consideration due to potential for accident escalation risks. • May increase site footprint. • Potential for high number of road tanker movements to export product – increased risk of releases.	• Lack of infrastructure or market for road tanker compressed gas. • Requires lean gas to keep process simpler and costs lower; would suit coal bed or coal mine methane or gas only developments. • If flow rates are high, the number of tanker movements may become problematic. • No established infrastructure for compressed gas fuelling of vehicles in the UK. • Road tanker delivery logistics use fuel and generate local pollutants, which will offset some of the emissions reduction benefits of gas compression.	No
	Compression to CNG for export via pipeline	High pressure (200 barg) compression of gas to a pipeline for export to a distribution network	• Removes need to vent any greenhouse gases at source (for example, natural gas or carbon dioxide). • Converts natural gas to a saleable product. • Allows export of product.	• CNG systems normally operate at higher pressures than receiving networks could accommodate. If gas is to be exported, this would be best achieved via traditional pipeline compression systems.	• Refer to ‘Export via pipeline’ entry under ‘Collection and reinjection/recycling’ option.	No

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward for detailed BAT assessment
Collection and reinjection/ recycling	Enhanced oil recovery	Injection of gas back into well to improve well performance	• Potential to boost oil flow in wells by maintaining well pressure by gas reinjection.	• Would only be of benefit in associated gas scenarios where gas can be used to enhance oil recovery.		No
	Recycling of waste gases	Recovery of vented gases for injection in to a separate processing step for feed recycling	• Established technology. • Ensures that gas losses are minimised. • Simple solution, which utilises existing plant. • Boosts product generation capacity • Recovered gas could be used for fuel gas (for example, steam boiler, power turbine).	• Ideally gas needs to come off at high pressure to allow it to be used elsewhere in the process. • Less practical for associated gas as there are less opportunities to recycle/reinject the gas in to the process. Better in these cases to seek use for gas as a fuel supply. See 'Power generation' entry.	• Opportunities for waste gas reuse and reprocessing in the main processing train should form a fundamental requirement of the design basis of any operation.	Yes
	Export via pipeline	Recompression of vented waste gas to supplement export flow	• Established technology – pipeline gas compression. • Simple installation and site infrastructure. • Mature supplier market. • Flexible flow solution. • Can be started and stopped with little penalty. • Can be used as part of heat recovery system to generate heat.	• Potentially not suitable where an export pipeline does not already exist (that is, associated gas); pipeline installation would be subject to assessment of the capital cost to connect into the distribution network – a function of distance, and required pressure and capacity requirements. • Pressure and capacity of receiving network needs to be suitable to ensure no restriction of flow from the site. • Mercaptan odorant may need to be stored and delivered to site, which will potentially introduce new hazards and operational requirements. • Application process to agree export to network may be lengthy and complex. • Planning process for pipeline routing.	• If a pipeline already exists, this is should be a default option unless flows are very low. • If pipeline connection economics are not prohibitive and the receiving network can guarantee to take the export gas, this is the most practical solution for recovering and utilising waste gas.	Yes
Vapour recovery	Capture of vapour/gas from process operations	Recovery of vapour from separators or vessels, for reuse or fuel gas	• See entry 'Recycling of waste gases' under the 'Collection and reinjection/recycling' option.	• See entry 'Recycling of waste gases' under the 'collection and reinjection/recycling' option.	• Specialist systems are available for the capture and processing of vapours. These would typically be associated with large storage facilities where there may not be associated process systems that could utilise/process the vapours or gases produced from filling and emptying storage tanks. • More attractive for rich gas or condensate storage tanks, as liquid product can be generated. • For OOG sites where gas processing equipment exists (particularly gas developments), dedicated vapour recovery systems are considered BAT as there are opportunities to recycle/reprocess vented gases of vapours.	No
Energy storage	Electricity	Battery storage	• Portable power. • Easy to transport to customers.	• Requires a matched power generation system. • No developed infrastructure or market. • Novel – as yet, relatively unproven technology.	• Could be a viable in the future but not yet considered available. • Technology not mature. • Lack of market.	No

Option description	Technology/ process	Description	Pros	Cons	Comments	Taken forward for detailed BAT assessment
				• Storage capacity limitations may require multiple charging units and batteries to make viable use of waste gas. • Increase in vehicle movements. • Not available for rental in the UK.		
	Thermal	Thermal storage	• Portable heat source. • Easy to transport to customers.	• Requires heat recovery systems to be in place (for example, CHP). • No developed infrastructure or market. • Novel – as yet, relatively unproven technology. • Storage capacity limitations may require multiple regeneration units and thermal cubes to make viable use of waste gas. • Increase in vehicle movements. • Technical limit on heat storage time not known. • Customers need to be set up to recover energy.	• Technology is not mature. • Lack of market.	No
Zero emission technologies	Valve actuators	Electric/ electrohydraulic/ compressed air valve actuators	• Does not use direct gas actuation – therefore no gas emissions. • Safer – no flammability risk.	• More expensive actuators. • Potentially bigger actuators (gas actuators can run at higher pressures and therefore tend to have smaller piston arrangements). • May have to install additional infrastructure (for example, instrument air compression and distribution network).	• Gas-actuated valves are easy to install and operate, but releases and safety hazards mean that direct acting gas valves are not considered as BAT. Zero emission valve actuation should always be chosen.	Yes

Appendix E: CBA methodology

This appendix details the steps necessary to develop and run a BAT assessment. The method can be used for:

- proposed developments
- improvements to existing sites

For existing sites, the information requirements should be easier to fulfil and there should be fewer uncertainties.

E.1 Steps involved in running a BAT assessment

1. Define the waste gas management case to be assessed.

   This should include:

   - flow rate
   - pressure
   - flow duration
   - operational duration
   - typical gas composition
   - site and/or operational constraints
   - offsite constraints

   When considering performance requirements such as flow, flow duration and composition, consideration should be given as to how these parameters may change throughout the life of the operation. For instance, flow rate may start at a maximum level and decline during future field life. In many cases, it may be possible via additional hydraulic fracking or other well optimisation methods to boost flow rates – potentially achieving several periods of peak output during the life of a field.

   It is therefore important to understand how a field's production profile might be managed. This will be based on well appraisal data; when assessing BAT options on the basis of the appraisal, it should be recognised that this information is being used to predict future performance, which is clearly not an exact science. Therefore, it is suggested that operators look to band their production profiles into 'upper', 'lower' and 'central' bands. If the central band represents the expected case, the upper and lower bands will represent cases better or worse than the expected performance respectively.

   Using this approach will allow sensitivity analysis to be performed on key operating variables to determine how robust the outcome of the CBA will be. While a change in predicted operating parameters will result in an absolute change in NPV, it may not change the relative ranking of technology options. This will confirm that a particular technology is representative of BAT across a wide range of conditions.

2. Perform a review of the technologies for waste gas management and compile a long list of options.

This report represents a good starting point for this step as it references a comprehensive selection of technologies drawn from global sources. The report also discusses the relative pros and cons of different waste management techniques, which will help operators to decide if they will be applicable to their activities. See Appendix B for full details of the technology long list and discussion.

3. Carry out a high level screening of technologies to remove those considered unlikely to meet the requirements of the BAT definition.

   This will usually be determined in relation to whether the technologies are ‘available’. A justification for screening out technologies at this stage should be recorded.

   As indicated in Section 2.4, some technologies were screened out from the long list (Appendix B) which could, depending on local opportunities, be considered as BAT. An example would be LNG production if a suitable user can be identified or heating exported to local properties or industry.

   Example assessment criteria and worked examples are provided in Appendices C and D for EFT and production respectively.

4. Develop a performance specification for the management of waste gas and contact vendors and/or suppliers of potential technologies to receive preliminary engineering and operational information.

   This information should include:

   - equipment dimensions and weight
   - efficiency
   - emissions produced
   - energy costs
   - utilities requirements
   - design limits
   - capital or rental costs (include for transport, installation, commissioning and so on)
   - maintenance costs
   - civil engineering and infrastructure requirements

   Consideration should also be given as to how equipment will be configured and sized. For instance, installing equipment that is sized for peak waste gas flow, which may only exist for a short duration (for example, 1–2 years), may result in inefficient or ineffective operation as gas flows decline during the life of a field. It may therefore be more cost-effective and more representative of BAT to install multiple smaller systems (for example, 2 × 4MW power generation systems rather than 1 × 8MW system). This would meet the required maximum power generation capacity at the start of field life, but would also allow units to be taken offline as field waste gas flows decline.

   Another option which should be considered is to identify opportunities for linking different well developments. This will provide economies of scale which would allow technologies to be applied that would not be viable on an individual well pad basis. Such an approach will be governed by the practicalities and costs of linking and tying back individual wells to a central collection and processing hub.

5. Set up a CBA calculation in a convenient format to enable comparisons for example, spreadsheet. Figure E.1 at the end of this appendix shows an example.

   An individual calculation should be set up for each option being assessed.

   One option should be designated the ‘base case’. This will usually be the case considered to be the minimum provision or the normal provision; this is likely to be an enclosed ground flare in most cases.

6. Identify and determine the constituents making up the 3 main components of the CBA, that is:

   - direct costs
   - pollution damage costs
   - income/benefits/offsets

   6.1 Direct costs

   The major direct cost will generally be the waste gas management technology itself (for example, a flare system, or a gas engine or turbine). These are generally standard equipment items and hence vendor pricing information should be relatively easy to obtain.

   Depending on the selected solution and the nature of the waste gas to be managed, a varying degree of gas processing equipment will be required to clean up and/or treat the gas before it can be used in any waste management system. At its simplest, this may just be basic liquids knock out prior to a flare or a gas engine or turbine. Where there are higher quantities of condensate, water or inert substances in the gas flow, more complex associated gas processing plant may be required.

   For more sophisticated waste management solutions, the associated processing plant may be significant. Given that any BAT assessment may be carried out early in the design process, the level of design development information may be limited. In such cases, estimating indices or tools should be used to provide costs for the CBA. When more accurate data can be generated, this information should be used to validate any previous assumptions.

   It may be helpful to determine other direct costs such as land, infrastructure, utilities, staff and materials as required or significant to the option being assessed. When providing these costs, credit should be allowed for any equipment provision that would be necessary irrespective of the proposed waste management technique. For instance, if waste gas is to be used for onsite power generation it is reasonable to disregard any common systems such as switchgear and electrical distribution. These will need to be provided irrespective of whether power is imported from the external grid or generated onsite via gas, diesel or dual fuel power systems.

   Other factors to consider may include:

   - modifications or tie-ins to existing processes, utilities, infrastructure
   - power and utility costs
   - land purchase
   - civil engineering and infrastructure
   - materials

- staff costs
- design and project management
- decommissioning
- end of life asset value
- land reinstatement

For a CBA performed for well appraisal phases, costs are likely to be assessed on a rental/lease model (where equipment is available under such arrangements). If equipment is purchased, the cost can be pro-rated across the period of the well appraisal tests.

For production operations, which will typically have a life of up to 25 years, most capital expenditure will occur early in the development. An operator will have to consider how this capital will be paid for, depending on the value of the capital outlay required. An operator may decide to pay for small capital items out of the balance sheet, in which case the capital value will generally apply only to the first year of operation. For large or expensive items, however, an organisation may take a commercial loan (typically over 5 years). In such cases, the cost of the capital, including interest repayments, should be spread across the period of the loan (that is, the first 3–5 years as applicable). Although spreading the cost in such a way will increase the overall project costs, it will reduce a company's capital exposure while maintaining manageable debt repayments.

Consideration should also be given to any major capital expenditure that may be required during the lifetime of the plant (for example, gas turbine replacement or compressor rewheeling) or to address falling gas flows.

There is also the scenario where, as field gas flows decline, waste gas management equipment may be taken offline to be used elsewhere, or its residual value may be recovered as gas flow declines (for example, power generation systems). At the start of production life, gas flow will clearly be at its highest allowing maximum power to be generated. As gas flow falls, the amount of power being generated will fall proportionally – subject to additional well optimisation management – throughout the remainder of the field's viable life. In such a case, it may not be cost-effective to have one power system to cover the gas flow over the production life due to high turndown. Consequently, operators may opt to start with 2 or more smaller capacity power generation units, which can be taken offline individually; their residual value can also be recovered or credited as the gas flow declines.

The cost for export facilities and connections may be the predominant factor in the viability of any export scheme. As detailed in this report, the base cable or pipeline costs can be relatively straight forward to estimate but connection to the network operator, particularly for the power grid, can vary significantly from one DNO or voltage system to another. For instance, it may be cheaper to run a longer export power cable to obtain a lower cost connection.

If any power or utilities are required to operate the waste gas management plant, their requirements should be established and then costed using the BEIS wholesale/long run variable costs (LRVC) indices (BEIS 2017).

Any future costs (for example, capital, services or materials) due to inflation should not be included. This is in line with the Green Book guidance on CBA, which states:

> 'Costs and benefits in appraisal of social value should be estimated in 'real' base year prices (that is, the first year of the proposal). This means the effects of general inflation should be removed' (HM Treasury 2018, Section 5.11).

6.2 Pollution damage costs

Pollution damage effects from waste gas emissions will generally arise from the following dominant mechanisms:

- direct natural gas release
- carbon dioxide release resulting from the combustion of natural gas
- NOx release resulting from the combustion process

The direct release of natural gas to atmosphere can only be considered acceptable for safety-related releases such as from local relief devices. Such releases should not be continuous in nature and/or of significant volume.

There are no directly attributable cost data prescribed for the methane GWP damage, so methane releases should be upscaled by a factor of 28 (IPCC 2013) to give an equivalent GWP in terms of carbon dioxide. Consequently, it will be preferable to combust any waste natural gas as the carbon dioxide produced will have a GWP 28 times lower than methane.

Combustion of natural gas will generate additional pollutants, which may have local or far field impacts; the most significant of these is NOx. The chemistry and kinetics of combustion processes are extremely complex and will potentially be very dependent on the fuel composition. It is therefore advisable to seek guidance from combustion equipment manufacturers on the composition of combustion pollutants for any given scenario or to take measurements from existing (analogous) systems.

Once the mass/concentration of carbon dioxide and NOx releases has been established, the relevant pollutant cost should be applied. As the CBA is set up as an economic case, the cost of carbon should be linked to non-traded costs to ensure that the real cost of pollution is considered. These costs will increase year-on-year according to indices published by BEIS (BEIS 2017). The non-traded carbon indices are separated into bands to reflect different potential damage scenarios. It is suggested that the central band is used as the base point, with the upper and lower bands being used to perform sensitivity analysis.

NOx costs are currently not linked to any future increases but are published via the IED derogation tool (Environment Agency 2016b), which was last updated in 2015. To adjust the historic NOx damage costs for the subject year, the table of deflators in the IED tool should be used. For the period 2015 to 2018, this gives a deflator value of 1.054. This increases the damage cost of NOx from £13,131 to £13,840 for 2018.

In addition to NOx, natural gas combustion will generate other pollutants such as carbon monoxide, SOx and particulates and, potentially, if selective catalytic reduction abatement is used, ammonia. These emissions may be subject to permit limits by the regulator, but currently there are no prescribed damage costs direct to the emitter. However, the IED tool does provide damage costs (as per NOx) for these releases. If these pollutants are generated, they should be included in the CBA and assessed in the same manner as for NOx.

Where relevant the damage cost of CO_2 produced from central power generation or gas distribution can be offset against what is generated at source by an operator e.g. in power generation and export. To do this the release of CO_2 can be calculated using a conversion factor (kg/kWh) provided in the BEIS toolkit (BEIS 2017).

6.3 Income/benefits

Income/benefits will be realised by the sale of a commodity exported from a development. This could be in the form of power, gas, heat or other form (for example, a manufactured product such as LNG).

The most likely export product route would be gas-to-wire or gas-to-grid. The income produced will be in direct proportion to the amount gas available for use as fuel to produce power or as gas that can be supplied to the NTS. For the CBA, revenue/income is calculated on the basis of MWh generated or exported. The sale price of gas or power should be taken from the BEIS Valuation of Energy Use and Greenhouse Gas Emissions Appraisal toolkit using wholesale/LRVC indices (BEIS 2017).

7. Calculate NPV

Where the duration of operation is longer than a year, the value of investment and return can be calculated in terms of a NPV value. This reflects future cash flow and the value of costs and benefits accrued in the future for decision makers in the present. The more distant in time that costs and benefits are realised, the less valuable they are compared against the present day.

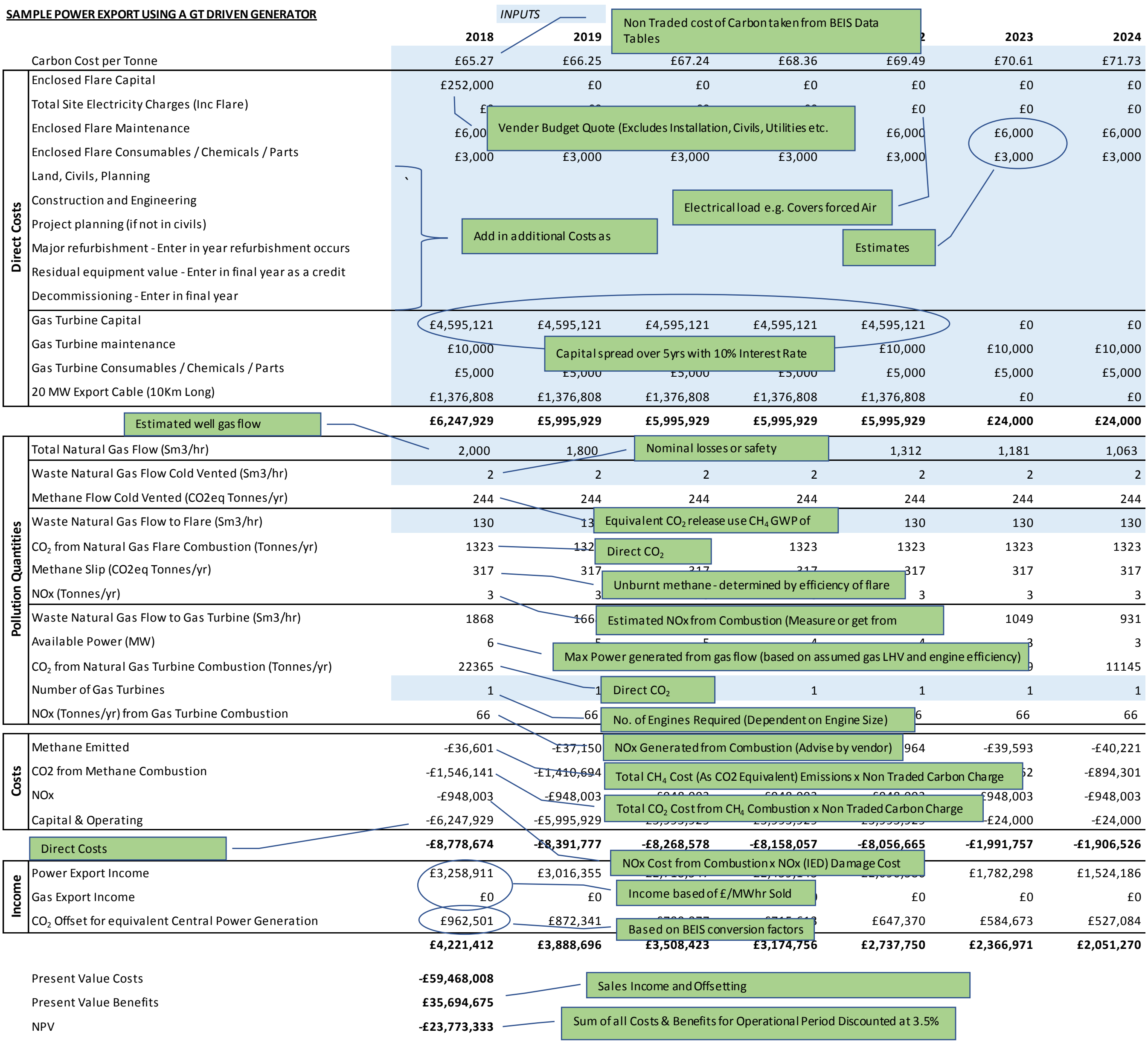
For each year of operation, a Present Value (PV), the difference between the costs and benefits. A discount rate should then be applied to each year's PV to give a discounted cash flow (DCF). These annual DCFs can then be summed to provide the NPV for a project.

To perform the NPV calculation for this report, a discount rate of 3.5% was used (that is, the reduction in value of future costs and benefits occurs at a rate of 3.5% per year). The value used was taken from the Green Book (HM Treasury 2018).

The NPV calculation can be set up a number of ways. In essence, however, the goal is to compare the NPV output derived from the base case (for example, an enclosed ground flare) against other potential options. Options that generate a positive difference (that is, a better return) should be viewed as providing improved performance and vice versa. However, it is important to bear in mind that:

- small changes in input variables or assumptions can have significant impact on the output from the CBA
- performing a sensitivity analysis is important to demonstrate the robustness of a result

It is also important to take the results of the CBA, however positive, in the context of the results of any qualitative analysis (see Sections 4 and 5, and Appendix G).



SAMPLE POWER EXPORT USING A GT DRIVEN GENERATOR

		2018	2019	[illegible]	[illegible]	[illegible]	2023	2024
	Carbon Cost per Tonne	£65.27	£66.25	£67.24	£68.36	£69.49	£70.61	£71.73
Direct Costs	Enclosed Flare Capital	£252,000	£0	£0	£0	£0	£0	£0
	Total Site Electricity Charges (Inc Flare)	[illegible]	[illegible]	[illegible]	[illegible]	£0	£0	£0
	Enclosed Flare Maintenance	[illegible]	[illegible]	[illegible]	[illegible]	£6,000	£6,000	£6,000
	Enclosed Flare Consumables / Chemicals / Parts	£3,000	£3,000	£3,000	£3,000	£3,000	£3,000	£3,000
	Land, Civils, Planning							
	Construction and Engineering							
	Project planning (if not in civils)							
	Major refurbishment - Enter in year refurbishment occurs							
	Residual equipment value - Enter in final year as a credit							
	Decommissioning - Enter in final year							
	Gas Turbine Capital	£4,595,121	£4,595,121	£4,595,121	£4,595,121	£4,595,121	£0	£0
	Gas Turbine maintenance	£10,000	[illegible]	[illegible]	[illegible]	£10,000	£10,000	£10,000
	Gas Turbine Consumables / Chemicals / Parts	£5,000	[illegible]	[illegible]	[illegible]	£5,000	£5,000	£5,000
	20 MW Export Cable (10Km Long)	£1,376,808	£1,376,808	£1,376,808	£1,376,808	£1,376,808	£0	£0
		£6,247,929	**£5,995,929**	**£5,995,929**	**£5,995,929**	**£5,995,929**	**£24,000**	**£24,000**
Pollution Quantities	Total Natural Gas Flow (Sm3/hr)	2,000	1,800	[illegible]	[illegible]	1,312	1,181	1,063
	Waste Natural Gas Flow Cold Vented (Sm3/hr)	2	2	2	2	2	2	2
	Methane Flow Cold Vented (CO2eq Tonnes/yr)	244	244	244	244	244	244	244
	Waste Natural Gas Flow to Flare (Sm3/hr)	130	[illegible]	[illegible]	[illegible]	130	130	130
	CO_2 from Natural Gas Flare Combustion (Tonnes/yr)	1323	[illegible]	[illegible]	1323	1323	1323	1323
	Methane Slip (CO2eq Tonnes/yr)	317	317	[illegible]	[illegible]	317	317	317
	NOx (Tonnes/yr)	3	[illegible]	[illegible]	[illegible]	3	3	3
	Waste Natural Gas Flow to Gas Turbine (Sm3/hr)	1868	[illegible]	[illegible]	[illegible]	[illegible]	1049	931
	Available Power (MW)	6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3
	CO_2 from Natural Gas Turbine Combustion (Tonnes/yr)	22365	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11145
	Number of Gas Turbines	1	[illegible]	[illegible]	1	1	1	1
	NOx (Tonnes/yr) from Gas Turbine Combustion	66	66	[illegible]	[illegible]	[illegible]	66	66
Costs	Methane Emitted	-£36,601	-£37,150	[illegible]	[illegible]	[illegible]	-£39,593	-£40,221
	CO2 from Methane Combustion	-£1,546,141	-£1,410,694	[illegible]	[illegible]	[illegible]	[illegible]	-£894,301
	NOx	-£948,003	-£948,003	[illegible]	[illegible]	[illegible]	[illegible]	-£948,003
	Capital & Operating	-£6,247,929	-£5,995,929	[illegible]	[illegible]	[illegible]	-£24,000	-£24,000
		-£8,778,674	**-£8,391,777**	**-£8,268,578**	**-£8,158,057**	**-£8,056,665**	**-£1,991,757**	**-£1,906,526**
Income	Power Export Income	£3,258,911	£3,016,355	[illegible]	[illegible]	[illegible]	£1,782,298	£1,524,186
	Gas Export Income	£0	£0	[illegible]	[illegible]	£0	£0	£0
	CO_2 Offset for equivalent Central Power Generation	£962,501	£872,341	[illegible]	[illegible]	£647,370	£584,673	£527,084
		£4,221,412	**£3,888,696**	**£3,508,423**	**£3,174,756**	**£2,737,750**	**£2,366,971**	**£2,051,270**

Present Value Costs	**-£59,468,008**
Present Value Benefits	**£35,694,675**
NPV	**-£23,773,333**

Figure E.1 Example CBA worksheet with guidance annotation

Appendix F: CBA input data

Table F.1 Assumptions and inputs for Case Study 1

Item	Value	Unit	Source
Hours per week	168	Hour	
Site electrical load	0.75	MW	Estimate/assumption
Methane gas density	0.71	kg per m^3	Approximate density at Standard Conditions
Methane GWP	28		IPCC (2013)
Methane to carbon dioxide conversion factor	2.75		Derived from chemical balance
Methane concentration	70%		Derived from UKOOG BAT study questionnaire responses
Combustion efficiency – shrouded flare	85%		Assumed value based on Mott MacDonald (2015)
Combustion efficiency – enclosed flare	98%		Mott MacDonald (2015)
Energy per unit volume of gas	35.00	MJ per Sm^3	Derived from UKOOG BAT study questionnaire responses
Gas engine efficiency	40%		Estimate/assumption
Engine electrical output	1.10	MW	Estimate/assumption
Damage cost of NOx	13,840	£ per tonne	Environment Agency (2016b)
Conversion of kWh to carbon dioxide in tonnes	0.30482	kg CO_2 per kWh	BEIS (2017)

Table F.2 Assumptions and inputs for Case Study 2

Item	Value	Unit	Source
Hours per year	8760	Hour	
Total site power load	1	MW	Estimate/assumption
Methane gas density	0.71	kg per m^3	Approximate density at Standard Conditions
Methane GWP	28		IPCC (2013)
Methane to carbon dioxide conversion factor	2.75		Derived from chemical balance
Methane concentration	70%		Derived from UKOOG BAT study questionnaire responses
Combustion efficiency – shrouded flare	85%		Assumed value based on Mott MacDonald (2015)
Combustion efficiency – enclosed flare	98%		Mott MacDonald (2015)
Energy per unit volume of gas	35.00	MJ per Sm^3	Derived from UKOOG BAT study questionnaire responses
Gas engine efficiency	40%		Estimate/assumption
Engine electrical output	4.40	MW	Estimate/assumption
Damage cost of NOx	13,840	£ per tonne	Environment Agency (2016b)
Gas turbine efficiency	33%		Estimate/assumption
Gas turbine electrical output	6.00	MW	Estimate/assumption
Conversion of kWh to carbon dioxide in tonnes	0.28088	kg CO_2 per kWh	BEIS (2017)

Appendix G: Qualitative assessment methodology

The qualitative assessment is based around a method developed by SEPA which describes qualitative factors in terms of the scale and magnitude of an impact (SEPA 2017).

G.1 Determining the scale of an impact

To determine the scale of an impact, it is first necessary to determine how many people might be affected. For instance, an impact could be excessive noise arising from an elevated sonic type flare which produces high noise levels. Noise effects are often omnidirectional, which means there will be a bigger general impact on local residents, particularly at night or if there are generally low background noise levels.

If a development requires frequent vehicle movements (for example, for removal of product such as LNG or NGL), in this case only residents who live close to the transport route may be adversely affected. This will need to be considered against the normal traffic levels and vehicle types. Thus, residents close to small rural routes may notice an increase while those close to busy through routes may not.

When assessing these criteria, a minimum tariff or level of effect has to be set beyond which individuals do not need to be counted.

When assessing the scale of impact, it is also necessary to consider disadvantaged groups. For instance, an increase in road traffic will increase localised pollution levels along a route. These higher levels will be more damaging to young people, the elderly and/or those who have an underlying health condition such as asthma.

For each option, such impacts should be considered relative to a base case and/or each other and will generate a positive or negative outcome. For instance, exporting gas via a pipeline to the NTS will have less of an impact on local communities in terms of transport. If the base case was flaring, this impact may not be a differentiator but compared with waste management technologies that utilise frequent road transport solutions it will be a benefit.

The scale of an impact can be determined by considering the size of the relative benefit or risk against the number of people likely to be affected. This will allow a scale value to be determined for each factor being considered (Table G.1).

Table G.1 Estimating scale of impact

Increase/ decrease in risk or benefit	Number of people likely to be affected					
	1–10	11–100	101–1,000	1,001–10,000	≥10,001	General population
	NA	NA	10–100	101–1,000	≥1,001	Disadvantaged groups
Very small (VS)	**NC**	**VS**	**S**	**S**	**M**	
Small (S)	**VS**	**S**	**S**	**M**	**M**	
Modest (M)	**S**	**M**	**M**	**M**	**L**	
Large (L)	**M**	**M**	**L**	**L**	**VL**	
Very large (VL)	**M**	**L**	**L**	**VL**	**VL**	

Notes: NC = no consequence or impact too small to consider further.

G.2 Determining the magnitude of an impact

The results obtained from Table G.1 should be fed into Table G.2 to determine the magnitude of each impact.

Using the information from Table G.1, Table G.2 seeks to determine the magnitude of an impact by assessing the duration and scale of an effect. The duration of effect can obviously vary significantly depending on the phase of development. During exploration or well testing, impacts should generally last for weeks to months or potentially a year or more but not multiple years. Consequently, it may be acceptable to tolerate impacts with a larger scale but for short periods.

Table G.2 Estimating the magnitude of an impact

	Scale of effect				
Duration of effect	**Very small**	**Small**	**Medium**	**Large**	**Very large**
A few days/one-off event	**VS**	**VS**	**VS**	**S**	**M**
Weeks/months or repeated event	**VS**	**VS**	**S**	**M**	**L**
Up to one year	**VS**	**S**	**M**	**L**	**VL**
1–3 years	**VS**	**S**	**M**	**L**	**VL**
4–6 years	**VS**	**M**	**L**	**L**	**VL**
More than 6 years	**VS**	**M**	**L**	**VL**	**VL**

Conversely, in production, which may last for 20 years or more, impacts will be less tolerable (that is, the overall magnitude of the effect is bigger). From Table G.2, the magnitude of an impact will be rated from ‘Very small’ to ‘Very large’.

Depending on what the option is being considered, the impact may be positive (for example, less land take and therefore less habitat destruction) or negative (for example, bigger footprint and therefore more habitat loss compared with the base case). To make ranking of these factors easier to compare, they can be converted to a numeric score as in Table G.3.

Table G.3 Calibration of magnitude to ranking score

Magnitude output	Magnitude ranking score
Very large positive	10
Large positive	8
Medium positive	6
Small positive	4
Very small positive	2
Neutral	0
Very small negative	-2
Small negative	-4
Medium negative	-6
Large negative	-8
Very large negative	-10

Each factor should be assessed in this way to allow side-by-side comparison.

The total ranking score for a technology can then be calculated to determine if there is an overall difference in ranking scores. It may be that the overall scores could be similar, but there may be variances in individual impacts which may be significant.

G.3 Presentation of the output

This section provides an example of how the qualitative output can be tabulated for presentation.

The case considered is a production facility requiring flaring capacity for safety and general waste gas management. The options considered are:

- enclosed ground flare
- shrouded (pipe-in-pipe) flare
- elevated (sonic) flare

The characteristics of each type of flare are described below.

G.3.1 Enclosed ground flare

Enclosed ground flare generally low in height and therefore will have a relatively low visual impact. However, they may be wider than other systems to accommodate multi-burner systems. Noise is generally low and is contained within the enclosure. There should be no flames visible and/or no smoke produced. These systems generally need forced air assist and staging equipment; they may also need a better quality of pre-treatment of the gas. The equipment footprint may therefore be bigger requiring, for example, more habitat take. This will generally be offset by the fact that minimal or no sterile areas will be needed around the plant.

G.3.2 Shrouded (pipe-in-pipe) flare

Shrouded (pipe-in-pipe) flares are similar to ground flares in terms of height; flame controls will be more limited and so a higher shroud may be required to ensure no flame visibility or no need for a sterile area. Noise should again be similar or a little higher. Combustion will be less efficient than an enclosed ground flare, resulting in more potential for smoke generation. The equipment footprint should be lower as there may be no need for a forced air system or staging, and pre-treatment requirements are generally less critical. Smoke generation is more likely than for a ground flare.

G.3.3 Elevated (sonic) flare

Elevated (sonic) flares have an uncovered flame and so the height of the flare will need to be set to ensure that the radiation does not affect ground workers and equipment. The chosen height will be a compromise between visual impact and dispersion, and the size of the associated sterile area. A higher flare gives a smaller sterile area and therefore a smaller land take, and vice versa. Equipment will also be required to supply the air or steam assist. This is likely to need to be positioned outside the sterile area, further increasing land take. Noise will be significant compared with the other 2 types of flare.

G.3.4 Assumptions

For this example it is assumed that the site is within 0.5–1km of a well-developed residential conurbation, with the affected population size being 101–1,000 people. The setting is semi-rural, but of relatively high value due to the adjacency to the local community. The development is assumed to be in operation for 25 years.

G.3.5 Side-by-side comparison

The results shown in Table G.4 are based on Table G.1 and the characteristics of the different flares outlined in Sections G3.3.1 to G3.3.3 and the assumptions outlined in Section G.3.4.

Table G.4 Results of scale comparative assessment for test scenario

Impact criteria	Enclosed ground flare	Shrouded (pipe-in-pipe) flare	Elevated (sonic) flare
Visual	0	-S	-L
Noise	0	-M	-L
Land take	0	+S	-M
Smoke	0	-M	-S

Notes: The base case is assumed to be the enclosed ground flare.

The results from Table G.4 can then be used in combination with Table G.2 to determine the magnitude of the effect for a duration of more than 6 years (because this is a production facility) (Table G.5).

Table G.5 Determination of impact magnitude for test scenario

Impact criteria	Enclosed ground flare	Shrouded (pipe-in-pipe) flare	Elevated (sonic) flare
Visual	0	-M	-VL
Noise	0	-L	-VL
Land take	0	+M	-L
Smoke	0	-L	-M

Notes: The base case is assumed to be the enclosed ground flare.

The results from Table G.5 can then be ranked using the calibration given in Table G.3. Table G.6 shows the magnitude of each impact as a numerical ranking. The results show that the shrouded (pipe-in-pipe) option is marginally worse than an enclosed ground flare while the elevated sonic flare is significantly worse than both the other options.

Table G.6 also shows the aggregate score for each technology, with the technologies scored against a base case (an enclosed ground flare). The qualitative assessment could also be carried out as an absolute test comparing outputs against an undeveloped site.

Table G.6 Numeric ranking of impacts

Impact criteria	Enclosed ground flare	Shrouded (pipe-in-pipe) flare	Elevated (sonic) flare
Visual	0	-6	-10
Noise	0	-8	-10
Land take	0	+6	-8
Smoke	0	-8	-6
AGGREGATE SCORE	**0**	**-16**	**-34**

Notes: The base case is assumed to be the enclosed ground flare.

Note that these results are very location-specific. If this site was located in a more industrial area away from residential properties, the negatives associated with an elevated flare would potentially not be an issue compared with other options. So if the gas being managed contained hydrogen sulphide, the elevated flare option might be preferable as it may be cheaper and would not require the additional plant that ground-based systems would need to remove the hydrogen sulphide before combustion unless the operator allowed for large ground-based sterile areas for unpiloted gas flow, which would significantly reduce the benefits associated with enclosed flares.

The calibration of the qualitative assessment method is suggested and is not intended to be obligatory. It should be reviewed to suit operators' needs, bearing in mind that a clear justification for the assessment and ranking criteria is required.

As was noted for the quantitative analysis (Appendix E), it is important to view the output from the qualitative assessment in the context of the CBA results.