Best Available Techniques Economically Achievable to Address Black Carbon from Gas Flaring:

EU Action on Black Carbon in the Arctic – Technical Report 3

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Citation
Best Available Techniques Economically Achievable to Address Black Carbon from Gas Flaring: EU Action on Black Carbon in the Arctic – Technical Report 3. October 2019. 47pp.

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Cover photograph
Black smoke from burning of associated gas, Leonid Ikan / Shutterstock

This report was prepared by Carbon Limits AS.

This project is funded by the European Union.

Project title Best Available Techniques Economically Achievable to Address Black Carbon from Gas Flaring

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Finalized: 31/05/2019

This document provides technical guidance on possible black carbon abatement measures when associated gas is flared during oil extraction activities. Abatement measures identified as part of this document have been described across seven broader Best Available Techniques Economically Achievable (BATEA) and may be considered particularly relevant towards demonstration and feasibility projects in the Arctic.

The report was prepared as one of the deliverables under the project *EU Action on Black Carbon in the Arctic*, funded by the European Union.

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Executive Summary

This document provides technical guidance on possible black carbon (BC) abatement measures when associated petroleum gas (APG) is flared during oil extraction activities. Abatement measures identified as part of this document have been described across seven broader categories of Best Available Techniques Economically Achievable (BATEA) and may be considered particularly relevant towards demonstration and feasibility projects in the Arctic. This deliverable aims to synthesize existing information from various sources, rather than provide an in-depth analysis of specific flare reduction cases, as the unique features of each situation can drastically impact the financial and environmental results achieved by BATEA. This report provides an updated and complete overview of the existing options available to national administrations and businesses to tackle this important source of BC emissions in the Arctic. Intended users of this overview include oil & gas (O&G) field operators and owners, investors, and other decision-makers that could influence and/or benefit from the implementation of BATEA. Equally, this document could assist national administrators contemplating enhanced environmental legislation regarding reductions in BC emissions from flaring, as well as other stakeholders involved in, or affected by, O&G operations in the Arctic.

A review of the technical and financial characteristics of the current methods available for reducing BC emissions from gas flaring identified seven main categories of BATEA for further analysis. The **1st BATEA category** uses all, or part of, APG to fuel on-site oil extraction activities requiring heat and/or power. These technologies have the potential to displace other more emission-intensive fuels, and significantly reduce BC emissions at oil production sites. They also have significant financial and environmental co-benefits related to the savings of procurement and transportation costs for fuels used in absence of APG. The **2nd BATEA category** describes opportunities related to the reinjection of gas for enhanced oil recovery (EOR) or underground storage, and has the potential to reduce or eliminate APG flaring at oil production facilities. Reinjecting gas can have a significant mitigating impact on BC emissions, although some emissions will be generated from the gas combustion required to power reinjection activities. If gas can be injected economically for EOR, reinjection has the potential to add revenues for the operator in the form of increased oil production. Gas injected for storage also has a speculative value to the operator related to the future use and sale of the gas. The **3rd**, **4th** and **5th BATEA categories** describe the technical opportunities related to recovering all, or a portion of, the APG that would otherwise be flared and exporting it from the site as unprocessed gas, other hydrocarbon fuels, chemicals, or electricity. These technologies have the potential to generate significant revenues from product sales and eliminate emissions from flaring, however, exporting gas and/or its related products will always generate some level of emissions from additional processing or transport. The **6th BATEA category** involves stripping the heavier natural gas liquids (NGLs) from APG prior to flaring. This technique may be used alone, or in addition to other BATEAs – the latter being the preferred course of action. When used in combination with other BATEA, this approach has the highest potential to mitigate BC emissions. If, however, other BATEA are deemed economically unfeasible, then at a minimum, NGLs should be stripped prior to the gas being flared. Simple stripping of NGLs prior to gas flaring is often economically feasible and has significant potential to reduce BC emissions. The **7th BATEA category** involves optimizing combustion conditions at the flare and can be considered applicable on its own or when routine flaring is partly, or completely, eliminated through implementation of other BATEA. While use of other BATEA to reduce BC is preferred, BATEA 7 should nonetheless be considered as a means to decrease BC emissions from the unexpected high-volume intermittent flaring that can commonly result from unstable gas production. BATEA 7 can be considered a valuable measure for mitigating BC emissions, however, it does not typically result in additional revenues for the operator.

Although discussed separately in this report, ideally, BATEA should be pursued in combination to maximize resources and revenue and minimize emissions (e.g. coupling NGL separation (BATEA 6), with reinjection (BATEA 2) or export of natural gas (BATEA 3), and optimizing combustion conditions (BATEA 7)).

While implementing BATEA comes with costs, many of them can also produce significant revenue. This report presents a detailed analysis of the site-specific field conditions that could benefit from BATEA to reduce flaring emissions and potentially uncover previously unrealized economic opportunities.

Although the effectiveness of BATEA largely depends on site-specific economic and technical parameters, they have substantial potential to reduce BC emissions and achieve meaningful and measurable benefits to the operator. Quantifying resultant reductions in BC emissions as a result of mitigation strategies remains challenging, however, implementing BATEA should still be considered a best practice for reducing flaring-associated BC emissions.

Introduction

1

As one of the deliverables for the *European Union Action on Black Carbon in the Arctic* initiative, this report aims to provide technical information on the costs and applicability of the Best Available Technologies Economically Achievable (BATEA) to address black carbon (BC) emissions from gas flaring. Rather than providing an in-depth analysis of specific flare reduction cases, this deliverable aims to synthesize existing information on BATEA for flaring-associated BC from several sources, including work undertaken by international and national oil companies, non-governmental organizations, academic researchers, technology providers, and financial institutions, among others. It provides an updated and complete overview of the existing options available to national administrations and businesses to tackle this important source of emissions in the Arctic. Specific implementation measures to reduce BC from upstream flaring during oil production activities should be an outcome of collaboration between public and private sectors, therefore, intended users of this overview include oil & gas (O&G) field operators and owners, investors, and other decision-makers that could influence implementation of BATEA. Equally, this document could assist government officials contemplating enhanced environmental legislation to reduce BC emissions from flaring, as well as other stakeholders involved in, or affected by, O&G operations in the Arctic.

The report consists of three main sections:

- Section 2 provides a general background on flaring operations and the variables most relevant for selecting BATEA for O&G operations in the Arctic.
- Section 3 describes the seven BATEA categories in detail. For each BATEA, a summary table highlights the key information while the accompanying text provides additional details and insights.
- Section 4 provides a simplified overview of the seven BATEA in table-form for easy comparison.

Drawing on previous successes from the Arctic and beyond, this document is intended to increase awareness regarding the availability of increasingly cost-effective and scalable technologies to reduce flaring-associated BC emissions. Applicable for a range of field sizes and conditions, this report is predominantly directed towards identifying BATEA for use at marginal production fields in the upstream O&G sector, where economically recoverable volumes of associated petroleum gas (APG, or 'associated gas') were not previously thought to exist. A substantial component of this report is dedicated to addressing the challenges associated with cost-effective reduction of BC emissions from flaring.

Although the effectiveness of BATEA largely depends on site-specific economic and technical parameters, they have a substantial potential to achieve meaningful and measurable environmental and financial benefits. Quantifying resultant reductions in BC emissions as a result of mitigation strategies remains challenging, however, implementing BATEA should still be considered a best practice for reducing flaring-associated BC emissions. Along with other newly available technologies, use of the BATEA described herein will support existing efforts to mitigate short-term climate change, as well as address other energy, environmental, and safety issues that are likely to result from gas flaring in Arctic regions.

Overview of Factors Involved in Gas Flaring and their Relevance to Mitigation Measures in the Arctic

2

Gas flaring is a challenging energy and environmental problem facing the Arctic today. Flaring is “a technique used extensively in the oil and gas industry to burn unwanted flammable gases[1].” While flaring is known to produce significant amounts of greenhouse gases, including methane (CH_4) and carbon dioxide (CO_2), the process also emits other pollutants including particulate matter (PM) in the form of BC, volatile organic compounds (VOCs), nitrogen oxides (NO_x), and sulphur oxides (SO_x), among others. All oil reservoirs contain associated gas, which is produced with oil, sometimes considered a waste product, and can be flared when there is no productive use. Historically, there have been a number of issues impeding the productive utilization of APG, including a lack of local gas infrastructure, long distance to markets, relatively small and variable gas volumes, and production profiles typified by a peak followed by a long, steady decline. These characteristics have posed stiff challenges to the reduction of APG flaring.

With ever-improving gas infrastructure across the Arctic regions, as well as concerns over the negative health and environmental impacts of flaring, APG utilization has improved in a number of regions. While there are ongoing attempts across Arctic countries to increase gas utilization and reduce flare levels, considerable space for improvement exists. Effective policies and measures to reduce flaring must be based on a good understanding of the current uses of flaring, its relationship with BC emissions, and the potential costs and benefits associated with solutions.

The appropriate use and effectiveness of the BATEA to reduce flaring-associated BC emissions ultimately depends on a number of technical and economic variables specific to each O&G operation, including the current use and frequency of flaring, size of available field and flare gas volumes, gas composition and utilization rates, remaining field life, and geographical conditions, among others. The main parameters relevant for a broad variety of BATEA and their relevance to BC mitigation measures in the Arctic are briefly described below before introducing the specific technologies thereafter.

2.1 Flare Use and Frequency

Gas that is co-produced with oil at upstream facilities is generally categorized as APG, however, sites may use gas flaring as an APG removal process either continuously or intermittently (Figure 1).

2.1.1 Continuous Flaring

Continuous flaring occurs primarily as a result of a complete, or partial, lack of a utilization route for APG (Figure 1). It is often referred to as routine flaring[2], although any precise and universally accepted definition of this term does not exist. Globally, the majority of continuous flaring is caused by a lack of market outlets, shortage of local demand or unsuitable geology for reinjection, and is accentuated by the physical, technical, and economic constraints of gas utilization. Flare reduction efforts primarily focus on this type of continuous flaring.

A second category of continuous flaring has operational causes related to use of pilot flames, purge gas, and degassing of produced water and glycol regeneration. These often produce smaller, but not necessarily insignificant volumes of APG, and can be reduced by use of purge reduction devices or the optimization of pilots, and even further by installation of a flare gas recovery unit (FGRU; Section 3.8.1.5), which can bring the utilization rate to almost 100%.

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[1] https://www.researchgate.net/publication/223963699_Black_carbon_particulate_matter_emission_factors_for_buoyancy-driven_associated_gas_flares

[2] Limiting the rate of extraction during the first year of production to avoid excessive flaring and recovery of both oil and gas may not be considered economical by the operator. Nevertheless, the speed at which the oil resources are exploited will have a direct impact on flaring if the gas infrastructure is not in place from day one.

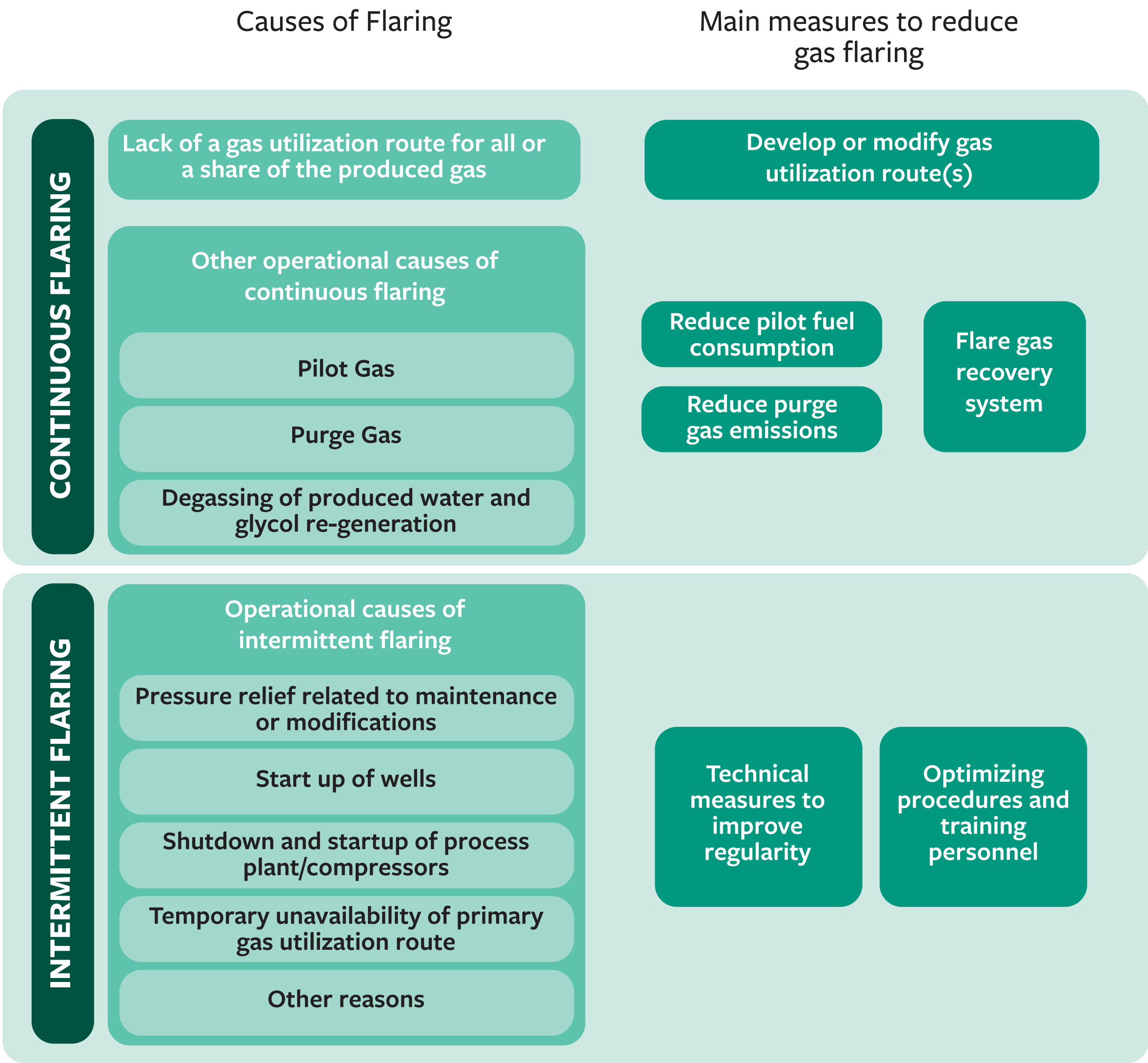


Figure 1. Overview of the various types of gas flaring and their associated mitigation measures (Adapted from: https://www.carbonlimits.no/project/assessment-of-flare-strategies-techniques-for-reduction-of-flaring-and-associated-emissions-emission-factors-and-methods-to-determine-emissions-to-air-from-flaring/)

Utilizing APG from continuous flaring is a natural solution to reduce BC and other pollutant emissions from gas flaring. In cases where it is uneconomical to recover and utilize some or all APG, BC emissions can only be reduced by optimizing combustion conditions. However, even when it is economical to utilize the associated gas, there will usually be some intermittent flaring.

2.1.2 Intermittent flaring

Intermittent flaring is undertaken for short periods of time for a variety of operational causes (Figure 1). Intermittent flaring can be further subdivided into:

- Exploration flaring, which occurs when large volumes of gas are combusted for short periods of time during a gas-oil potential test that is used to determine the production capacity of a well. While the volumes of APG flared can be considered significant, it is only temporary[3].
- Process flaring, which typically occurs at lower rates during routine gas processing (e.g. when some waste gases are removed from the production stream), is generally considered less significant, however, its frequency can vary during normal operations and plant failures.
- Emergency flaring, which can occur as a result of pressure surges, fires, or other disruptions in infrastructure (e.g. valve, compressor, or pipe failures), may result in the burning of large volumes of gas at high rates over a short duration of time.

[3] Drilling and completion typically last around a month. During that time flaring can be substantial. Tracking this data would allow the operator to estimate potential gas utilization later on.

The underlying causes of intermittent flaring can often be reduced by improving the regularity of operations and optimizing operational procedures. Such measures are usually win-win options and are commonly pursued by operators.

Routine flaring from a lack of gas utilization sources is the most important and largest source of BC emissions from flaring, however, intermittent flaring and continuous flaring for operational reasons can also be significant sources. This document focuses on routine flaring and its associated BC emissions. Gas flaring can occur at O&G extraction and production fields, refineries, gas processing plants, and petrochemical plants. The report focuses mainly on BATEA at upstream production fields, which represent by far the largest share of gas flaring both globally and in the Arctic.

2.2 Flare Gas Composition

APG contains a mixture of several gases, however, the relative composition and presence of impurities varies widely depending on the gas reservoir. Table 1 provides a non-exhaustive list of selected APG components based on previous flare recovery assessments and highlights the compositional variations that can exist between O&G extraction fields.

APG released from wells during oil production activities will primarily contain natural gas (NG), typically consisting of 50–90% lighter hydrocarbons with one (C_1) or two carbons (C_2), such as methane (CH_4), ethane, respectively. APG also contains a significant amount of natural gas liquids (NGLs), comprised of hydrocarbons with three to five carbons (C_3–C_5), including propane (C_3), iso-butane/butane (C_4), and pentane (C_5), and smaller amounts of heavier hydrocarbon molecules with greater than five carbons (C_5+; e.g. hexane, heptane, and octane).

Since APG streams can have large variations in gas composition and impurities they may require different technologies or levels of treatment before use. “Rich” or “wet” APG streams, contain a larger proportion of heavier hydrocarbons and are typically more valuable due to the higher heating values of NGLs (Table 1). However, some gas utilization options will be more effective when the recoverable gas stream is “lean” or “dry”.

In some instances, wells can also contain impurities. Corrosive “sour” gas[4], containing hydrogen sulphide (H_2S) and/or carbon dioxide (CO_2), can lead to the degradation and fouling of NG components and equipment. Sour gas must therefore be purified to remove acidic components – a process also known as gas “sweetening” – in order to produce an acceptable feedstock gas for use in gas engines and turbines, as pipeline-quality gas, and in other applications. Numerous processes have been developed to purify sour gas, and they typically fall into one of five categories: chemical solvents (amines), physical solvents, adsorption[5], membranes, and cryogenic fractionation. The

Table 1. Composition and heating values for associated petroleum gas (APG) from four different oil & gas extraction fields*.

APG Composition (mol %)		Field A	Field B	Field C	Field D
Carbon dioxide (CO_2)		1.15%	3.76%	1.32%	0.49%
Methane (CH_4)		73.57%	79.65%	49.90%	60.37%
Ethane (C_2H_6)		9.32%	7.26%	15.31%	2.39%
Propane (C_3H_8)		9.27%	5.31%	19.40%	9.26%
Butane (C_4H_{10})		4.44%	2.69%	9.24%	14.17%
Pentane (C_5H_{12})		1.34%	0.56%	2.05%	10.11%
Hexane (C_6H_{14})		0.18%	0.09%	0.26%	0%
Heptane (C_7H_{16})		0%	0%	0.08%	0%
Octane (C_8H_{18})		0%	0%	0.01%	0%
Nitrogen (N_2)		0.77%	0.57%	2.44%	2.55%
Water (H_2O)		0%	0%	0%	0%
Oxygen (O_2)		0%	0%	0%	0.65%
Hydrogen Sulphide (H_2S)		0%	0.11%	0%	0%
Net Calorific Value (NCV):	**(BTU/SCF)**	**1224.96**	**1071.47**	**1519.50**	**1612.59**
	(MJ/SCM)	**45.55**	**39.85**	**56.51**	**59.97**

BTU: British Thermal Unit; SCF: Standard Cubic Feet; MJ: Megajoules; SCM: Standard Cubic Meters
*Based on Carbon Limits analysis.

[4] Also commonly referred to as acid gas.
[5] When operators turn to absorption processes for acid gas removal, several factors affect their decision in choosing whether to use a chemical or

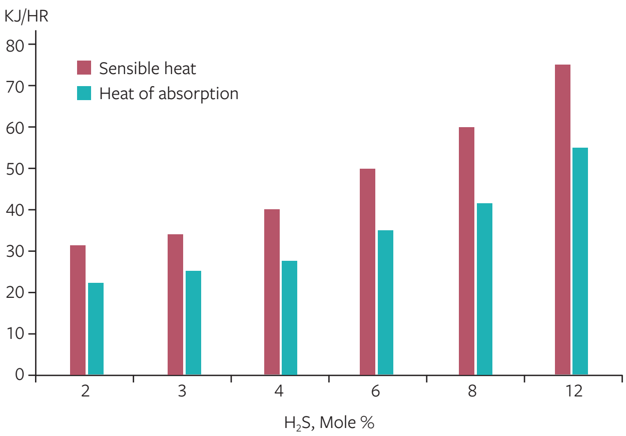


Figure 2. Effect of hydrogen sulphide (H_2S) inlet feed concentration on the energy demand of gas sweetening by amine stripping (Taemeh, A.N., A. Shariati, and M.R.K. Nikou. 2018. Analysis of energy demand for natural gas sweetening process using a new energy balance technique, Petroleum Science and Technology, 36 (12). https://doi.org/10.1080/10916466.2018.1447952).

method used to remove impurities depends on the types and amount of acidic components to be removed.

Amine stripping is commonly used to remove acidic components from gas. Amine plants are usually offered as complete modules, allowing for efficient transport and quick installation[6]. During this process, a solvent containing mildly basic amines[7] binds acidic components (i.e. H_2S and CO_2) present in gas. The acidic contaminants are thereafter removed from the solvent during a regeneration process using an energy-intensive heating process[8]. For example, a typical unit designed to treat 20 million standard cubic feet per day (MMSCFD) of low-sulphur NG would require approximately 37 kilowatt hours (kWh)/hour or 900 kWh/day for pumps and cooling[9].

The reboiler heat duty is the most important determinant of energy consumption during amine stripping (Figure 2). This includes the heat required to increase the temperature of the feed amine solution to the temperature of the regenerated solution from the reboiler (sensible heat), the heat required to strip the acidic components from amines (heat of absorption), and the condenser heat duty of the stripper for condensing water leaving the stripping section and returning as reflux (heat of vaporization)[10]. Some research suggests that heat of vaporization is the most important factor determining energy demand and is primarily driven by the H_2S to CO_2 molar ratio of NG[11]. Thus, the greater amount of H_2S, the more costly the treatment.

Another important consideration when using APG as a fuel source is the net calorific value (NCV), also known as the lower heating value (LHV)[12]. While a high-NCV APG can be considered a suitable fuel source for power generation both in turbines and engines, any change in gas composition will impact the NCV, and therefore and its use as a fuel source.

While various APG compositions can serve as acceptable fuel sources, it is important to note the strict requirements of compressors, reciprocating gas engines, and gas turbines for specific feed gas compositions[13]. Next to requiring a fuel source with a minimum LHV, they typically require a feed gas with a H_2S content[14] of less than 0.1%[15], although specialized microturbines can operate on APG with an H_2S content of 4–7%[16]. APG with a higher content of H_2S will customarily require additional capital expenses for fuel gas treatment systems and their operation[17].

physical absorption process from an economic standpoint. They take into account the required solvent circulation rate, which strongly influences the equipment size and energy needs required for solvent regeneration, and thus the capital and operating costs.

[6] Amine plants can also be utilized in split-stream applications in order to treat greater volumes of either H_2S or CO_2. Therefore, if wells stabilize and decrease in volume over time (and require less amine circulation), the excess plants can be removed. Similarly, if additional wells are added, excess modular units can be added.

[7] Amines are organic bases containing, and often based around, one or more atoms of nitrogen.

[8] At large scales, the most economical technology for converting H_2S into sulphur is the "Claus process". This process uses partial combustion and catalytic oxidation to convert approximately 97% of H_2S to sulphur. In a typical application, an amine treatment unit concentrates the H_2S before it enters the Claus unit, and a tail gas treatment unit removes the remaining 3% of the H_2S after it exits the Claus unit.

[9] https://perrymanagement.com/downloads/Basic_Design_and_Cost_Data_on_MEA_Treating_Units.pdf

[10] Maddox, R.N., J.M. Erbar, and J.M. Campbell. 1982. Gas Conditioning and Processing: Volume 4: Gas and Liquid Sweetening. Campbell Petroleum Series.

[11] Taemeh, A.N., A. Shariati, and M.R.K. Nikou. 2018. Analysis of energy demand for natural gas sweetening process using a new energy balance technique, Petroleum Science and Technology, 36 (12). https://doi.org/10.1080/10916466.2018.1447952

[12] Compared to the LHV, a higher heating value (HHV) includes the total amount of heat released during the combustion of fuel (i.e. the HHV includes the latent heat of vaporization which could be recovered in a secondary condenser).

[13] Turbines such as the Siemens SGT-300 and SGT-500 have high chrome content blade materials thus making them less susceptible to oxidation/sulphidation attack and therefore are suitable for fuels containing high levels of H_2S.

[14] Hydrogen sulphide is highly toxic and can pose unique challenges to operators as well as the operation of gas engines or turbines. In addition to health and safety considerations, H_2S can combust releasing SO_x emissions to the atmosphere. In the presence of moisture, SO_x emissions react to form weak acid (acid rain). Therefore, treatment of the gas at source to remove or reduce H_2S content is necessary.

[15] http://gazsurf.com/en/gas-processing/articles/item/associated-petroleum-gas-processing

[16] Ibid.

[17] Furthermore, the materials used (particularly in the hot gas path section of gas turbines) will determine the value of H_2S permissible in gaseous fuels without changing performance or impacting service regimes.

Although many gas engines[18] can run on NG of various compositions, the typical nominal design point is a gas that is 70–85% CH_4 by volume[19]. While engines can operate on gases with lower CH_4 content, a change in performance can be expected[20]. The minimum LHV typically required by engine manufacturers is approximately 750 British thermal units (BTU) per standard cubic foot (SCF), or 28 megajoules (MJ) per standard cubic meter (SCM)[21].

On the other hand, heavy-duty gas turbines have the ability to burn a wide classification of gaseous fuels, and only require a minimum LHV of 100–300 BTU/SCF[22], a minimum content of 85% CH_4, and a maximum of 15% of other gases (i.e. ethane, butane, argon, N_2, CO_2) by volume[23]. Experience from manufacturers and operators has shown that while "the quantity of sulphur is sometimes not limited by specifications, that fuel sulphur levels up to 1% by volume do not significantly affect oxidation/corrosion rates"[24]. Gas engines and turbines may also have set limits for other contaminants, such as trace metals[25].

Due to the large variations in APG composition that can exist between O&G extraction fields (Table 1), the selection of gas equipment for on-site APG gas utilization requires special consideration.

APG composition can also vary over time as a result of multiple factors, including the level of well depletion, changes in recovery techniques, and operating conditions. Temporal changes in APG composition are difficult to predict accurately, making it more challenging to design optimal recovery facilities and combustion technology for APG than for pure NG.

The inherent variability of APG composition means different streams will provide different product yields and thus different economic values, even when the same technological solutions are used. The suitability of specific BATEAs for certain gas compositions will be further discussed when addressing individual technologies (Section 3).

2.3 Flare Volume

The volume of APG flared from a single site will also affect the suitability of mitigation technologies. In some instances, certain technologies require a minimum volume of gas available over time. Economy of scale is key to the applicability and economic viability of many mitigation technologies; thus, the volumes of gas collectively available at oil production sites are a major contributing factor. The unitization of activities within an area could positively impact APG recovery rates, and coordination among different operators of neighbouring oil wells could provide the gas volumes and stability to make some mitigation measures viable. Joint ventures on APG recovery and monetization through clustering should be explored between multiple operators within an area, particularly at smaller flare sites.

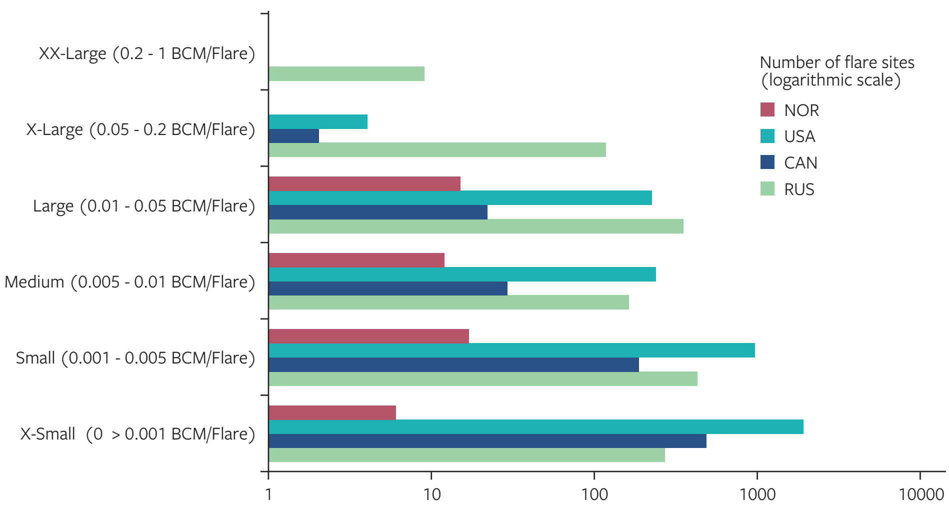


Figure 3. Number of associated petroleum gas (APG) flares in Arctic-bordering countries as determined by satellite in 2016 (NOAA flaring estimates produced by (VIIRS) satellite observations).

18 For example, Wärtsilä 50DF. http://cdn.wartsila.com/docs/default-source/Power-Plants-documents/w%C3%A4rtsil%C3%A4-50df.pdf

19 Refers to a gas with a minimum methane content of 70–88%.

20 Many gas engines can be designed for continuous operation without reduction in the rated output on gas qualities that meet the minimum methane content and with a H_2S concentration of <0.1%.

21 https://www.wartsila.com/products/marine-oil-gas/engines-generating-sets/dual-fuel-engines/definitions-and-notes

22 https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/technical/ger/ger-4601b-addressing-gas-turbine-fuel-flexibility-version-b.pdf

23 http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.143.6392&rep=rep1&type=pdf

24 Ibid.

25 For example, lead, vanadium, calcium, magnesium, etc.

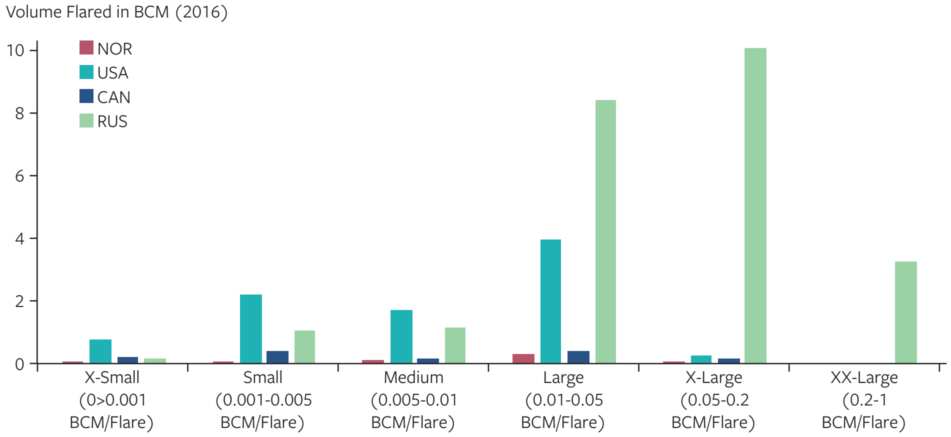


Figure 4. Volume of associated petroleum gas (APG) flares in Arctic-bordering countries as determined by satellite in 2016 (NOAA flaring estimates produced by (VIIRS) satellite observations).

Figures 3 and 4 highlight the disparity in the number and sizes of flare sites in Arctic-bordering countries. According to satellite data, most flare sites in Arctic nations are relatively small in size (<0.01 billion cubic meters (BCM) per flare). This document aims to present the best available techniques (BATs) applicable for reducing emissions at these smaller-sized flares, as they represent the majority of sites in the Arctic, and present opportunities for scaling up technologies when dealing with larger flares.

2.4 Remaining Field Life and Production Variability

APG productivity can vary over short- and long-time frames (Figure 5) and is an important factor for consideration in the selection and design of appropriate solutions.

Throughout the lifetime of an O&G field, gas pressure and volume can change significantly. The pressure of gas tends to decline over time with the natural depletion of oil reservoirs, causing the Gas Oil Ratio (GOR) and the production profile of oil (and thus gas) to vary widely during the field lifetime. Newer conventional oil producing fields are usually expected to last several decades, while shale fields may have a much shorter lifetime. For mature fields, the remaining field life needs to be considered as the available gas volumes will affect the applicability or sizing of technology.

Where long-term supply security is constrained, for example in mature fields, some technologies may have limited applicability as an investment, and may be attractive only with a guaranteed long-term supply of gas to provide enough time to make a return on investment (ROI). Therefore, the mobility and re-usability of technology must be considered, especially in mature fields.

Another important consideration is the short-term (i.e. instant or intraday) variability in APG production (Figure 5). In any given day, gas volumes and pressure can vary substantially. Production rates can increase up to ten times the monthly average and then drop substantially within minutes. Well availability can sometimes be as low as 60–80%, with days or periods of time with no APG production at all. These short-term variations represent a major operational challenge and safety issue, and they impact the selection and sizing of technologies for efficient flaring, gas recovery, and the value of gas utilization. Solutions, including those that optimize combustion conditions at flare stacks, must be able to deal with these constant changes of pressure, volume, and composition.

If a technology presents a very narrow gas volume operating window (turn-down ratio), it will not be able to accept both long-term decline and intraday variations. If a technology is able to handle these variations, it guarantees substantial gas recovery throughout the lifetime of the well.

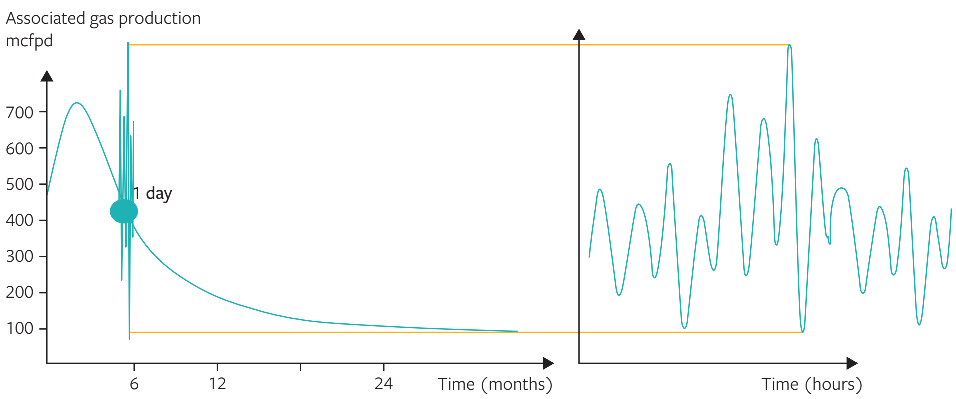


Figure 5. Illustrative associated petroleum gas (APG) production variability over time (https://www.carbonlimits.no/project/improving-utilization-of-associated-gas-in-us-tight-oil-fields/).

The clustering of nearby wells to provide a minimum feed gas volume could provide the stability of APG production to minimize flaring at a lower marginal investment cost.

2.5 Technology Scaling

Given the variability in gas production profiles (Section 2.4; Figure 5), selecting appropriately-sized technology for reducing flaring emissions is not straightforward. Installing too little capacity in new field developments would miss most of the potential recoverable value in the first years, which may yield low profitability. Installing capacity larger than average gas production volumes over the field lifetime does not necessarily guarantee capturing the first months of peak production and will leave a very large spare capacity after peak production due to the rapid decline profile.

Scaling technology in mature fields will depend on the forecasted future production, which can be estimated using reservoir models. The remaining field life will be a particularly important parameter to consider when appropriately scaling recovery solutions, especially for fields which have passed their peak or plateau production phase and are in a downwards decline.

It is important to assess how technologies, particularly those related to recovery, would be able to perform given an uncertain gas decline curve and different design strategies. Matching the expected volumes by adapting capacity, either in parallel or in series, is the best solution to optimize the total amount of gas and value recovered. Redeployment of technology may, however, induce continuous flaring events for short periods of time.

2.6 Gas Utilization Rate

Some mitigation strategies only enable the recovery of a portion of APG while excess volumes are sent to the flare, particularly in remote locations when demand for any products is intermittent and/or low. Other strategies could potentially recover as much as the installed technology allows; however, high-capacity technologies typically use significant amounts of energy, decreasing the final emission reductions. A careful assessment of the available utilization rate of the gas is an important factor in determining BATEA applicability and effectiveness.

2.7 Black Carbon Formation

Gas flares are essentially uncontrolled flames open to external influences that can generally be understood by studying the physical and chemical processes that occur during gas combustion. In addition to greenhouse gases (e.g. CH_4 and CO_2), all APG flares emit BC, however its formation is a complex process[26], comprised of several steps of particle

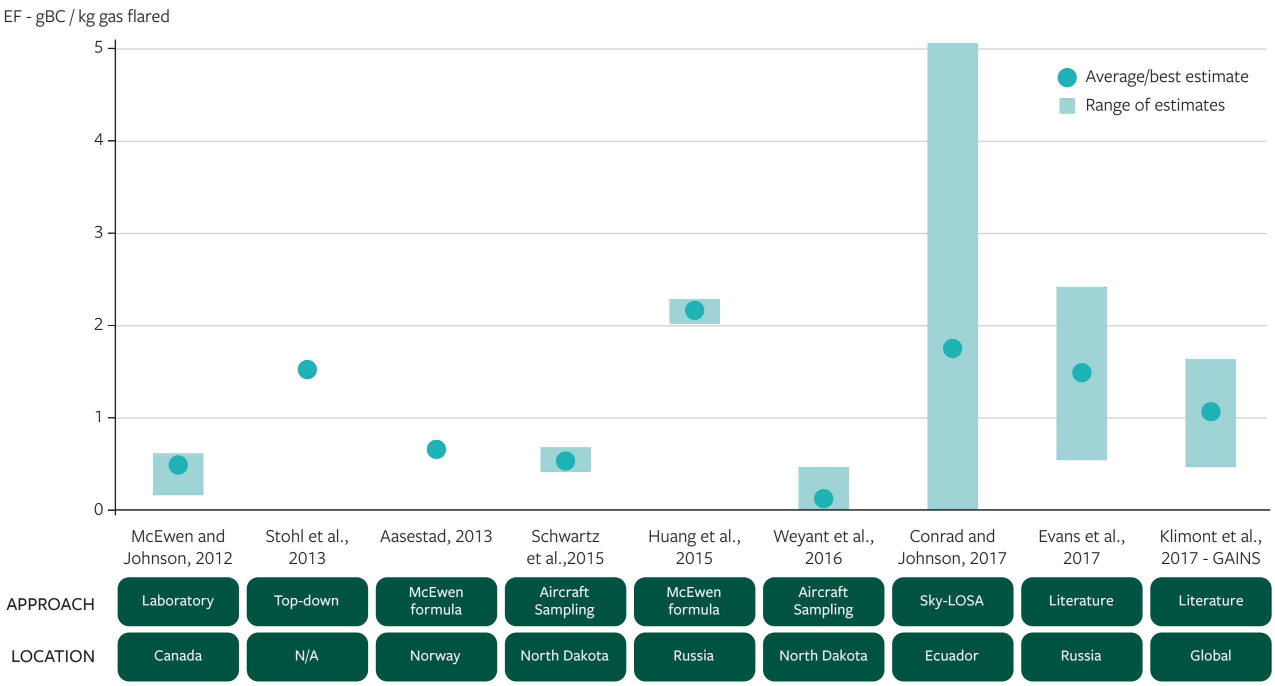


Figure 6. Summary of published black carbon emission factors (Based on Carbon Limits analysis performed under the project "Mitigation of short-lived climate pollutants from APG flaring" financed by the Arctic Council's Project Support Instrument.).

[26] Lowering BC emissions– when not recovering APG for utilization– will significantly depend on favorable combustion efficiencies (achieving good mixing at the flare between the fuel gas and air or steam) next to the absence of heavier hydrocarbon liquids.

growth and destruction that are still not fully understood. The amount of BC produced during flaring appears to be dependent on a number of physical and chemical factors (reviewed in Section 3.8) that may be able to be influenced by technological improvements, however, there is still much to be learned regarding controlling BC production.

A few research studies have been performed over the last decade to understand the relationship between gas flaring parameters and the quantities of BC emitted from flare stacks. Figure 6 summarizes recently published BC emission factors, which describe the amount of BC produced per volume of gas flared. Published values vary significantly, underscoring the inconsistent nature of this process. The large range in emission factors may be explained by the inherent variability of the flares studied (i.e. different gas compositions, flare technologies, etc.) but likely also by the different measurement approaches applied. This variability may complicate efforts to quantify the effectiveness of BC mitigation technologies, an area of inquiry for which there has been little research. A better knowledge of how flare design and flaring conditions influence BC yield would aid in identifying and prioritizing effective mitigation measures.

2.8 Well Location and Concentration

Onshore and offshore O&G fields exhibit important differences that will influence the appropriateness of certain BATEA to control BC emissions. As the cost of optimizing gas combustion or implementing recovery options can significantly vary between locations, and as distance to market is a very important criterion for assessing the viability of a solution, the suitability of mitigation technologies could differ significantly between onshore and offshore fields depending upon their unique requirements, and need to be evaluated on a case-by-case basis.

In the Arctic, the proximity to other wells and leases, as well as the distance to consumers or markets for export of products is vital when comparing applicability of BATEA. The viability of a mitigation strategy will be influenced by several location-related factors, but particularly the distance to gas gathering, power networks, and other infrastructure or end-users. As stated above, higher well concentrations enable economies of scale, and when several APG streams are combined, the overall stream is considered more stable (Section 2.5). Multi-well pads or several pads together would also improve the attractiveness of gas utilization options and make these solutions viable even when they are located further from markets.

Isolated well sites could also benefit from the sharing of utility and transportation infrastructure, which would result in cost savings. Collaboration between larger players within an otherwise isolated area could allow for the development of gas gathering systems and other gas utilization infrastructure that may have been uneconomical in seclusion. Although this strategy requires a high level of planning and cooperation between stakeholders, which will often include governments, oil companies, and other investors, it could also lead to improved field designs when it comes to gas utilization and flare reduction. If this type of field value optimization were to be turned into a separate business (perhaps through regulatory or tax benefit encouragements), technology suppliers could optimize field designs and operating conditions.

Collaboration among operators can also be complicated by a number of factors. Each particular well has a different APG production profile and every technology requires different levels of capital investment, operational expenses, expected revenues, and risk. Market variations can also change capital and operating cost of utilization options, and marketing and value of the products. Also, each operator will face different economic burdens (investment levels, operational cost, lack of gas handling skills, lack of midstream/downstream personnel, etc.) depending on the particular geographical location of a field.

2.9 Geographical Diversity in the Arctic

The Arctic is the northernmost region of Earth, spanning across the northern parts of Scandinavia, Russia, Canada, Greenland, United States, and the greater Arctic Ocean basin. It is largely covered by water, much of it frozen, with a varied landscape including mountainous terrain, ice sheets, fjords, grassland plateaus, tundra, forests and valleys.

Oil and gas operations are often dependent on weather, in particular when planning for the delivery and construction of gas utilization equipment and infrastructure. In the winter, machinery can freeze, and the frozen ground can be hard to operate on, drill, or excavate. Roads may also become inaccessible, which can affect the implementation of certain BATEA. As Arctic permafrost begins to thaw under a warming climate, required machinery and infrastructure can become unstable and damage the environment.

Oil production and gas recovery developments in the Arctic often require more expensive, tailored technologies, as well as safeguards adapted to the extreme climatic conditions. Furthermore, operating in remote environments can have additional costs and logistical constraints (e.g. delivery of equipment and infrastructure to isolated areas, slower emergency responses, and stricter containment requirements).

Best Available Techniques Economically Achievable (BATEAs) for Reducing Black Carbon Emissions from Gas Flaring

3

The BATEAs presented in this document demonstrate that a number of mature technologies are available to reduce BC emissions in the upstream O&G sector. As mentioned earlier in this document, the focus is on addressing APG flares during oil production, as most flare activities in the Arctic have been, and are projected to be, upstream in the foreseeable future. In most cases, the technologies presented are suitable for Arctic conditions and, when properly designed and maintained, can achieve significant BC emission reductions. The abatement options presented can also have positive or negative impacts on other pollutants, therefore the full environmental impact of implementation should always be considered.

3.1 Technology Overview

An overview of the potential routes to reduce BC emissions from gas flaring are summarized in Figure 7. Utilizing associated gas for on-site use or export (**BATEA 1 to 5**) is a natural solution to reduce BC and other flaring emissions, including CH_4 and CO_2. Associated gas utilization virtually eliminates BC emissions, however, flaring and low gas utilization rates are often common during the first years of production in new fields because decisions on gas infrastructure construction are often made only after production commences. In addition, even when it is economical to utilize APG, there will typically be some degree of flaring for safety or other operational reasons (Section 2.1). Finally, in some cases, no gas recovery solution will be available or considered feasible. Under these conditions, other options to minimize BC emissions exist: extraction of heavy components from the flared gas stream (**BATEA 6**) and optimization of flare design and combustion conditions (**BATEA 7**). The following sections provide detailed information about each of the seven BATEA categories.

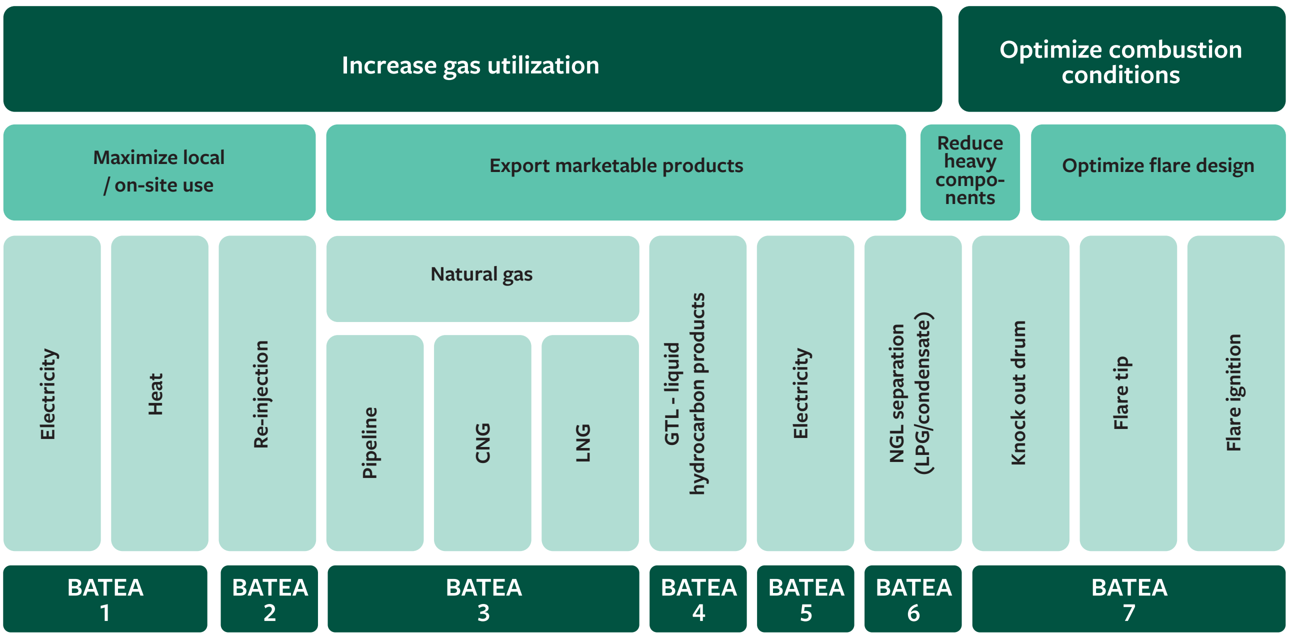


Figure 7. Overview of the Best Available Techniques Economically Achievable (BATEA) to reduce BC emissions from flaring.

3.2 BATEA 1: Maximize On-Site Use – Heat & Electricity Generation

Summary

Associated gas is recovered from the flare stack and re-routed for pre-treatment, (optional) NGL separation (BATEA 6), and then used as a fuel gas for heating and/or electricity generation (with optional waste gas heat recovery through a steam generator).

Applicability to the Arctic

- Remote areas without grid connectivity or long transport distance of alternative fuels for power generation (e.g. diesel)
- Areas with low ambient temperature and altitude (engines/turbines have slightly higher efficiency)
- Colder environments with higher general heating requirements concerning oil production activities
- Areas with high electricity tariffs (where electricity is used for power generation) or high fuel costs incurred in power generation

Effect on Emissions

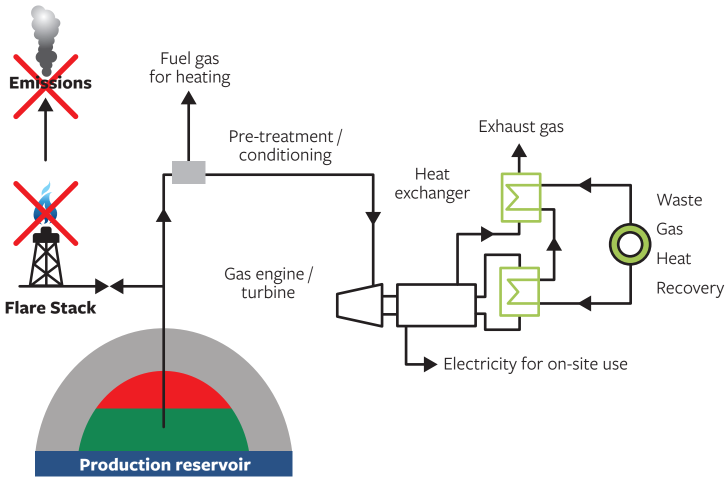
- Significantly reduces emissions of:
  - PM (including BC)
  - SO_x
  - Heavy metals
- Emissions of CO_2 are also reduced through the displacement of other emission sources (e.g. combustion of diesel in engines/turbines)

Benefits

- Maximizes use of resources
- Provides independent, on-site power supply
- Reduces costs of liquid fuels (e.g. diesel) or electricity for power generation

Infrastructure Requirements

- Gas pre-processing & conditioning equipment (depending on APG composition & impurities)
- Optional NGL separation infrastructure (**BATEA 6**)
- Compressors (if required to increase fuel gas pressure)
- Power generator (gas engine/turbine)
- Optional waste heat recovery system (e.g. steam turbine for higher efficiency in generating electricity from same fuel gas)
- Piping & related infrastructure (e.g. electricity lines/systems, transformers, switchgear, etc.)
- Back-up systems (grid connectivity or dual-fuel engines/turbines with back-up fuel supplies and storage capacity)



General Technical & Economic Considerations

- Possible gas composition constraints with additional requirements for gas conditioning (e.g. H_2S content)
- Economic viability of separating NGLs from APG prior to on-site use and using only dry NG for electricity & heat (depending on market value and availability of off-takers of NGLs – **BATEA 6**)
- Limited on-site heat & electricity demand (requirement typically <30% of what APG volumes could provide[27])
- Whether to flare excess APG supplies (assess viability to export excess gas or electricity – **BATEA 5**)
- Total available volumes over remaining field lifetime (also concerning considerations for selling excess electricity)
- Security of APG supply over time when utilizing maximum volume of APG available (declining APG supplies with oil production would affect medium- and long-term equipment sizing/scaling and investment cost)
- Back-up plans when APG availability is limited or temporarily off-line (to ensure uninterrupted power supply for operations)

Links to Further Relevant Information

- Industrial Gas Turbine Utilization with Associated Gases: https://docplayer.net/21479036-Industrial-gas-turbines-utilization-with-associated-gases.html
- Associated Gas Utilization using Gas Turbine Engine Performance Implication: http://file.scirp.org/Html/3-6201920_64571.htm
- Power Generation using Associated Gas: http://siteresources.worldbank.org/INTGGFR/Resources/578035-1164215415623/3188029-1324042883839/5_Power_Generation_using_associated_gas.pdf

[27] Power generation requirements on a typical site vs. generation potential based on Carbon Limits experience.

3.2.1 Technical Considerations

When considering strategies for implementing BATs to reduce BC emissions, a strong focus should be on the potential to maximize use of on-site resources to meet production needs. Upstream O&G production sites typically depend on a source of energy for electricity and heating requirements. Use of APG as an on-site energy source would make rational use of an otherwise wasted resource, reduce emissions from flaring, and displace the need for other energy resources. The degree of emissions reduction possible by BATEA 1 will depend on site-specific energy requirements, but in many cases, BATEA 1 has the potential to significantly curtail flaring activities.

The use of flared gas to generate electricity for on-site use can often be a viable option for the recovery of APG from flares, but this approach is not always economical and can be constrained by the long-term availability of APG supply and the usually limited on-site demand for electricity or heat. For these reasons, using APG to generate electricity only represents a partial solution to reduce flaring. In addition, oil production operations require a continuous power supply since any loss of power can result in revenue losses from production downtime, and in some cases, can also cause collateral damages (e.g. due to hole pumps not starting up again after a shutdown). When considering using APG for captive power generation it is therefore critical to take into consideration variables that would affect the stability and reliability of the potential power supply, including oil production, GOR, gas quantity, and gas quality (i.e. composition). Often, back-up fuel supplies and/or generation capacity are required, either in the form of additional non-associated gas (NAG) supplies, grid connectivity, or other stand-by generation equipment (e.g. diesel generators). This usually adds supplementary costs to the installation of APG recovery infrastructure, which can diminish the cost savings from utilizing this otherwise free energy source.

APG quality can vary from well to well, even within the same field (Table 1; Section 2.2). This variability can affect the performance of gas engines or turbines, which is in contrast to other fuels used for power generation that have uniform specified heat capacities. Quantities of APG available as fuel gas are also subject to change over time with declining oil production. Use of multiple, smaller power-generation units instead of one larger unit could mitigate this challenge, albeit at a cost in efficiency. Bi-fuel engines using gas in addition to diesel for power generation could be another approach[28].

3.2.1.1 Pre-treatment

While the composition of APG is often well-suited for heating and electricity generation, pre-treatment may be required in order to meet LHV requirements and remove impurities and condensable hydrocarbons. Commonly found APG impurities, such as H_2S and CO_2 can degrade and foul equipment (e.g. turbine blades; Section 2.2). Therefore, in some cases, APG must be treated to attain an acceptable fuel standard for engines and turbines before it can be considered a valuable fuel for independent power supply. Some equipment providers claim to offer more flexible engines/turbines that can accept wider ranges of gas compositions and can utilize APG with minimal pre-treatment.

3.2.1.2 Heat Generation

Heat and thermal exchanges are required for several stages of oil treatment and processing, including but not limited to, crude dehydration, sweetening, and in reboilers used for amine stripping and thermoelectric generators (TEGs). Oil production facilities also rely on steam generators to indirectly produce the heat needed to reduce crude oil viscosity, which is of particular relevance to Arctic oil fields that characteristically have high viscosity oil at low ambient temperatures.

To the degree that APG is not already utilized to produce heat for crude oil treatment and steam generation, the opportunity to switch from other energy sources (excluding recovered waste heat) can represent a productive way to increase APG utilization and reduce BC emissions on site[29]. However, where APG is already used to generate heat required for production operations, increased utilization may not be sufficient to significantly reduce flaring.

3.2.1.3 Electricity Generation

On-site power is needed during two phases of oil field development: drilling and completion[30], and oil extraction. Energy needs are large and variable during drilling and completion, and typically low and stable during the oil extraction. On-site electricity needs of oil fields are typically met by diesel generators due to their ease of transport, handling, and storage of the fuel. Diesel generators can reliably produce constant electricity to power all necessary equipment, need no special training, and require little maintenance, making them a practical and viable solution for long-term use. Power requirements

[28] This approach is technically straightforward when lean gas is used in engines. Bi-fuel engines should not exceed 30% of diesel substitution with raw gas. Coupling a buffering tower or NGL recovery with power generation is advised. If there is enough demand on site, this setup could yield substantial liquids revenue and diesel fuel savings with a short pay-back time.

[29] Any BC emissions from APG utilization would have likely also occurred from the fuel source displaced by APG use.

[30] Drilling and completion operations last around one month on average.

are also frequently met by purchasing electricity directly from the grid. When connection to an electrical grid is available, this has been a preferred option as it requires little up-front investment, is normally less expensive than diesel generators, and represents a reliable, hassle-free, and flexible source of electricity supply. These common practices must therefore be considered in direct competition with captive power generation from an economic perspective, despite APG being readily available in excess amounts on site.

When planning to substitute or complement current energy sources with APG recovery for power generation, the appropriate generators must be selected. Selection of generator types, reviewed in detail below, will depend on the fuel gas supply profile, gas quality, electrical system characteristics, and the demand for electricity (and heat, if applicable). In general, small and mobile containerized units complete with all peripheral systems are suitable for staged implementation of power-generation capacity (e.g. to meet local power demand) considering the expected volumes and qualities of excess APG for use as fuel. Use of mobile, trailer-based units would allow generation to be moved to new sites as APG is gradually depleted over time. Alternatively, larger, complex plants with combined-cycle generation can represent the most economical option at sites where gas can be sufficiently aggregated to provide a stable and reliable APG supply (and possibly also include NAG resources). Excess electricity can even be exported and sold (**BATEA 5**), if not all is required and assuming grid availability.

Gas Engines: Gas engines are internal combustion engines[31] suitable for the small-scale production of distributed power and require minimal processing of the fuel gas. Gas engines come in unit sizes up to 30 megawatts (MW)[32], achieve an electrical efficiency of up to 40–50%[33], and under preferable circumstances, can compete with gas turbines. Energy that is expelled as heat from the combustion process can be either recovered and used in a combined heat and power configuration or dissipated via dump radiators located close to the engine.

Reciprocating engines can run on a mix of gas and diesel, using what is commonly referred to as bi-fuel technology[34]. Using only lean gas after NGL recovery could provide potential fuel savings up to 70%, while coincidently reducing engine CO_2 emissions by 20–30%, in addition to decreasing BC emissions. This efficiency may be degraded with retrofits, although some technology providers report that performance is maintained[35]. Additionally, only under high quality fuel input, and stable, low-speed operating conditions are gas/diesel ratios of 70–95% feasible. Under typical conditions, a gas/diesel ratio of 60–65% can be achieved. APG can be used directly as fuel with little pre-treatment (at least dewatering), however gas/diesel mixtures with greater than 50% APG provokes knocking[36] on the engine, and variations in gas composition and volume may lead to the substitution rate being constrained even further, limiting the potential applicability of the raw gas for the engines.

Gas Turbines: Gas turbines are a type of internal combustion engine where fuel is combusted to drive a turbine[37]. They are available in various sizes and configurations including microturbines, aero-derivative turbines[38], and industrial gas turbines. Industrial gas turbines, applicable for typical small-scale APG utilization[39], come in power ranges starting around 5 MW[40], and typically achieve electrical efficiencies of approximately 30% in single cycle configuration (without heat recovery and secondary power generation in a steam turbine). APG can also be used to produce electricity in smaller microturbines and provide for smaller power requirements like pumping and compression machines.

Steam Turbines: A steam turbine[41] extracts thermal energy from pressurized steam and converts it into rotary motion, which can be used to drive an electrical generator. Steam can be generated in a heat boiler using APG as fuel gas, or by recovering waste heat from high-temperature exhaust gases using a heat recovery steam generator. Steam turbine plants are generally more complex in design and construction than gas turbines and are characteristically

[31] Internal combustion engines operate by using the force generated from gas combustion to turn a crank shaft within the engine. The crank shaft turns an alternator which results in the generation of electricity.
[32] https://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-advantages-of-modularity
[33] Ibid.
[34] A bi-fuel system operates by fumigating natural gas into the air intake of the diesel engine. Typical bi-fuel control systems monitor natural gas pressure, manifold pressure, temperatures, and engine vibration to control fumigated gas injection.
[35] https://cpower.com/PDF/InfoSheets/40.pdf
[36] An octane rating, or octane number, is a standard measure of the performance of an engine fuel. The higher the octane number, the more compression the fuel can withstand before detonating (igniting). Use of fuels (such as APG) with lower octane numbers may lead to the problem of engine knocking.
[37] The turbine converts the kinetic energy of the moving gas to mechanical energy, which is extracted in the form of shaft power and used to power a generator.
[38] Efficient mobile aero-derivative turbines are another option for reducing small flares and they should be carefully assessed against gas engines.
[39] APG can be burned to produce hot combustion gases that pass directly through the turbine, spinning the blades, and generating power.
[40] https://docplayer.net/21479036-Industrial-gas-turbines-utilization-with-associated-gases.html
[41] Steam turbines are one of the oldest and most versatile prime mover technologies.

only used to supplement the recovery of waste heat from gas turbines in a process known as combined-cycle generation. Combined-cycle plants can achieve efficiencies up to 50% higher than single-cycle operations that do not recover waste heat[42]. Engaging additional steam turbines can only be economically feasible[43] when APG supplies are limited (and when the demand for power exceeds the supply from potential APG), or when electricity can be exported and sold (when demand is beyond what can be generated through single cycle generation)[44].

Power-Generating Flare Combustors: Power generating flare combustors (PGFCs) directly use the heat from flared gas to generate electricity. These devices typically employ a regular flare combustor with a TEG cap to essentially create a semiconductor that converts heat into electricity. While electricity can be generated from these devices, thus reducing dependence on other sources of power, gas flaring often still occurs. Only additional measures in improving flare design (**BATEA 7**) would reduce BC emissions when deploying PGFCs.

Fuel Cells: Use of flared gas as a feed for fuel cells[45] can be considered a new approach to flare gas recovery[46]. Fuel cells, such as solid oxide fuel cells (SOFCs)[47], are power generation systems[48] that directly convert chemical energy of fuel to electricity in an environmentally-friendly manner[49].

3.2.2 Investment Considerations

While the decision to invest in the recovery of APG for power or heat generation needs to reflect current conditions, it is important to note that the preferred operating strategy, field development plans, framework conditions, and technologies are subject to evolve over time. Therefore, the viability of using excess APG for captive power generation may change under a new set of assumptions.

The prefabrication, construction, and material costs of small-scale power plants are highly variable and dependant on site-specific conditions. Equipment costs can nonetheless be estimated based on known technology and power generation requirements. Gas engines can be assumed as the most viable option for power requirements under 5 MW, and gas turbines of different sizes can be assumed for power needs of 5 to 30 MW and beyond[50]. Other parameters for consideration include the load profile (system requirements)[51], life cycle costs, ambient climate conditions that affect efficiency, such as temperature and altitude[52], maintenance requirements[53], reliability, efficiency (power to heat ratio), dual-fuel requirements, and in certain circumstances, the overall plant footprint[54]. Many of these parameters can have a significant influence on technical or economic feasibility.

The total capital expenditure (CAPEX) for small-scale power generation based on APG is estimated to be in the range of 1 to 3 million U.S. dollars (USD) per MW[55] installed capacity, including back-up power supply, local grid connections (as applicable), plant utilities, and control systems[56]. In terms of attractiveness, small-scale power generation based on APG is favourable in situations where grid electricity is not available as an alternative to diesel-based power generation. Under certain circumstances, it could also be attractive as a substitute for external power supply if supply capacity is constrained or purchase costs for electricity and/or penalties for flaring are high enough.

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[42] https://www.ge.com/power/resources/knowledge-base/combined-cycle-power-plant-how-it-works

[43] Due to the higher cost of generation per kWh.

[44] At locations close to industrial areas, gas turbine combined-cycle plants may benefit by selling steam to neighbor industries. The same logic applies to a gas engine plant with a combined heat and power configuration. Thermal energy provision to neighbor industries, or any district heating provider using advanced heat recovery systems to generate heat from hot water, can create extra profitability.

[45] Fuel cells are electrochemical devices that convert the chemical energy from methane in natural gas into electricity through a chemical reaction with oxygen (O_2).

[46] The fuel is converted to electricity and heat with a total system efficiency that can be much higher than other generation sources (given the same amount of fuel).

[47] SOFCs contain two porous electrodes, which are separated by a nonporous, oxide ion-conducting ceramic electrolyte. SOFCs operate at temperatures between 600–1000ºC and use a hydrogen (H_2) containing gas mixture as a feed and air as a source of O_2 to serve as an oxidant. The high operation temperature lends flexibility to the type of fuels that can be used, which can include methane, methanol, ethanol, and biogas among others.

[48] Fuel cells have no moving parts and a high energy efficiency, are quiet, and considered reliable with a durability of up to 20 years.

[49] SOFC technology reduces CO_2 emissions by about 55%. Additionally, there are approximately zero emissions of criteria pollutants (NOx, SOx, CO), particles, and organic compounds, and very low levels of noise emission.

[50] According to a case study, electricity generation with a gas turbine can provide 25 MW electricity from 4.176 MMSCFD of gas flared.

[51] Whenever limited operating hours and part-load phases (or even multiple starts and stops) dominate the load profile, a gas turbine and/or combined-cycle option may disqualify. In general, gas engines show advantages in single-cycle efficiency, offer highly efficient part-load operation, and have a very fast start-up performance. Reduced load operation (25% or lower) is also possible if needed.

[52] Gas engine technology is less sensitive to hot ambient temperatures and altitude in comparison to gas turbines.

[53] Gas engine maintenance costs are usually lower than those for turbines, depending on project parameters.

[54] Gas turbine plants typically benefit from a smaller footprint compared to engine-based power plants.

[55] Based on a review of published values.

[56] Engine-based power generation may further reduce capital- and operating-expenditures by eliminating the need for fuel gas compression. Low gas admission pressure requirements for engines (6 bar compared to 21–40 bar for turbines) reduces infrastructure costs and risks.

3.3 BATEA 2: Maximize On-Site Use – Reinjection

Summary

Associated gas is recovered from the flare stack and reinjected into either a production reservoir for Enhanced Oil Recovery (EOR) and pressure maintenance, or into other suitable, typically depleted reservoirs within close proximity, for temporary or permanent storage.

Applicability to the Arctic

- Mature oil fields in remote areas far from utilization infrastructure (e.g. pipelines, gas processing plants, electricity grids)
- Fields in close proximity to depleted reservoirs or other suitable formations for re-injection (e.g. salt caverns)
- Mature fields where EOR through reinjection could carry benefits such as increased or prolonged oil production
- Fields where future gas utilization or product conversion projects (e.g. GTL, LNG) are in development close by or where recovery and export could become economically viable in future

Effect on Emissions

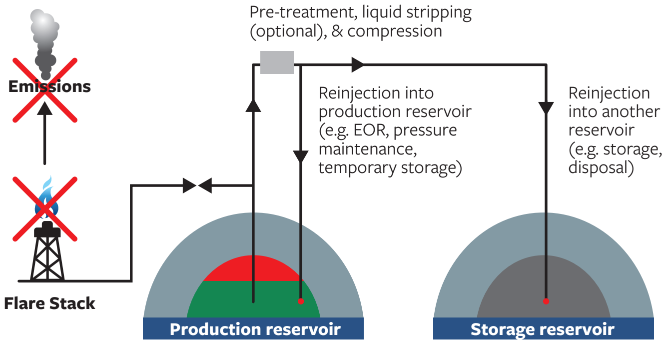
- Significantly reduces emissions of:
  - CO_2
  - PM (including BC)
  - SO_x
  - Heavy metals
- Some emissions, including CO_2, are created from combusting gas used for re-injection (e.g. compressors)

Benefits

- Reinjection into the same reservoir can, in some cases, provide EOR in mature fields resulting in increased oil production, and related economic benefits
- Reinjection of gas in other reservoirs could provide long-term storage for future use or sale, or short-term swing capacity

Infrastructure Requirements

- Gas pre-processing & conditioning equipment (depending on APG composition & impurities)
- Optional NGL separation infrastructure (**BATEA 6**)
- High-capacity compressors
- Injection wells (former production wells may be adapted in some cases)
- Piping & related infrastructure (particularly in consideration of gas transportation and injection at another site)
- Reservoir management & monitoring systems (especially for EOR schemes)



General Technical & Economic Considerations

- Gas compositional constraints with additional requirements for gas conditioning (e.g. H_2S content)
- Viability of separating NGLs from APG (**BATEA 6**) and reinjecting only NG gas (depending on economic value)
- Implementing only a partial reinjection scheme and utilizing the remainder (e.g. on-site use; **BATEA 1**)
- High capital cost of infrastructure, particularly depth of target reservoir and complexity of wells (cost estimation consideration)
- Volume of APG required to be injected for expected benefit in comparison to other solutions to avoid flaring (costs vs. returns from EOR or speculative value of preserving gas for future use need to be considered)
- Geographical location of field (e.g. offshore costs are significantly higher than onshore)
- Gas compression costs for reinjection activities (some gas will conceivably be used as fuel)

Specific Considerations for EOR

- Reservoir geology and configuration (e.g. miscibility: compatibility with reservoir fluids; capacity: available volumes; injectivity: reservoir pressure limitations)
- ROI for EOR schemes (high uncertainties regarding efficiency and added oil for recovery)
- Economic competitiveness of EOR schemes compared to alternative gas utilization approaches (i.e. availability and distance of gas gathering pipelines should be examined)
- Management and monitoring system requirements to analyze gas performance and movement towards producer wells in oil reservoirs (e.g. monitoring of reservoir behaviour; potential gas-cycling issues)

Specific Considerations for Storage & Disposal

- Economic drivers for disposal (only environmental unless cost savings in flare fines)
- Economic drivers for temporary storage (e.g. better utilization of transportation systems, improved delivery efficiency if limited gas offtake exists)
- Economic drivers for long-term storage (speculative future value)
- Higher capital cost of infrastructure, in particular considering required infrastructure to reach suitable reservoirs (could be located at a far distance from flare sites)
- Effects of unrecoverable or lost gas with storage (a portion of gas should be considered to be left/lost in the reservoir indefinitely)

Links to Further Information

- Immiscible Gas Reinjection in Oil Reservoirs: https://petrowiki.org/Immiscible_gas_injection_in_oil_reservoirs
- Miscible Gas Injection Study in a Naturally Fractured Reservoir – A Case Study: https://www.onepetro.org/conference-paper/SPE-132841-MS
- The Basics of Underground Natural Gas Storage: https://www.eia.gov/naturalgas/storage/basics/
- Economic Evaluation of Enhanced Oil Recovery: https://www.researchgate.net/publication/245277549_Economic_Evaluation_of_Enhanced_Oil_Recovery

3.3.1 Technical Considerations

Reducing emissions from gas flaring can be successfully achieved by reinjecting all, or a portion of, associated gas into either:

- A producing reservoir for enhanced oil recovery (EOR)[57]. Reinjection of gas into a crude oil reservoir increases pressure within the reservoir resulting in greater oil production.
- A geological formation[58] (underground reservoir) for temporary or permanent storage. Reinjection of gas underground permanently disposes of APG or stores it over short- or long-time periods for later use or sale.

Reinjection of APG back into the oil production reservoir or another, ideally depleted reservoir within the vicinity of the production wells requires pre-treatment facilities[59], compressors, reinjection wells[60], and other ancillary equipment and infrastructure. Systems for reservoir management and monitoring reservoir behaviour are also required[61], especially when gas is injected into a production reservoir for EOR. Valuable heavy hydrocarbon liquids (e.g. liquid petroleum gas (LPG) and condensate) could be separated (**BATEA 6**) prior to reinjecting only residual dry gas.

3.3.1.1 Enhanced Oil Recovery (EOR)

Reinjecting APG can be used as a mechanism to increase the recovery factor[62] in oil fields, or to maintain the pressure needed to improve immediate productivity[63]. The particular success of EOR using APG reinjection will depend on a variety of parameters including the displacement efficiency[64] and the aerial sweep efficiency[65] compared to other injection fluids (e.g. CO_2 or H_2O[66]). It is important to note that reservoir geology can differ significantly between Arctic regions and between individual oil fields, and many oil-producing reservoirs are not suitable for gas reinjection due to potential problems of gas break-through[67] and subsequent alterations of oil production regimes – the primary source of revenue in an oil field.

3.3.1.2 Underground Storage

Reinjecting APG into a production reservoir for storage purposes is not typically undertaken unless the field is mature and has the capacity to store a certain quantity of gas. Shallow geological formations, such as aquifers, depleted reservoirs, and salt caverns, located within close proximity to the oil-producing fields are considered to be more appropriate alternatives for storage[68] of wet or dry gas.

3.3.2. Investment Considerations

The ROI for an EOR reinjection scheme will primarily depend on the speculative value of increased or sustained oil production over time[69]. The economic incentive related to a reinjection scheme for storage will be limited to the speculative value of preserving the resource for potential use in the future and from any economic benefit from enhances in swing capacity, improved delivery efficiency, or gas supply stability. Cost savings or reduced risks related to the avoidance of flaring could also construe economic incentives. Productivity increases with APG injection are extremely variable and highly dependent on field and reservoir characteristics, and therefore cannot be generalized for all injection wells.

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57 Oil production is separated into three phases: primary, secondary and tertiary recovery, the lattermost also being known as EOR. Primary oil recovery is limited to hydrocarbons that naturally rise to the surface, or those that use artificial lift devices, such as pump jacks. Secondary recovery employs water and gas injection, displacing the oil and driving it to the surface. Tertiary recovery, or EOR, is a means to further increase oil production.

58 Refers to either the active production reservoir or other suitable reservoirs/caverns.

59 Pre-treatment facilities for gas cleaning and conditioning may be essential depending on the composition of the APG.

60 In some cases, defunct production wells can be converted into reinjection wells with some modification, reducing the cost of reinjection.

61 Reservoirs with strong natural water drives are unlikely to be good candidates for gas reinjection. In addition, since strong water drives often maintain reservoir pressure, there is always a danger that by additionally injecting gas, the cap-rock or reservoir seal could be breached, leading to gas leakage. This risk is also present when gas is injected into depleted reservoirs. Extensive geo-mechanical modelling is required to minimize the risk of leakage in these situations.

62 https://www.glossary.oilfield.slb.com/en/Terms/r/recovery_factor.aspx

63 Reinjecting APG will not only decrease the pressure decline rate in the reservoir, but also displace oil in its path and force it towards production wells.

64 Measurement of how well the reinjected APG displaces the oil.

65 The volume of the reservoir that the APG enters.

66 Using APG for EOR may be less effective than water injection as it has a relative high viscosity contrast against oil. However, in highly permeable reservoirs with a high column and a high dip, gravity segregation of the oil may allow APG injection to produce high recovery rates. Where reservoirs lack vertical permeability or relief required for effective gravity segregation, operators may opt to use a lateral drive (similar to water injection) called dispersed gas injection (likely to be more effective in thin reservoirs with little dip).

67 Which can lead to a substantial increase in the Gas Oil Ratio (GOR) and decrease oil production.

68 Storage may refer to temporary or permanent storage/disposal.

69 If gas is re-injected for EOR, the ROI should be assessed through a detailed reservoir model which will allow estimation of any additional oil expected to be produced over time.

3.3.2.1 Capital Expenditures (CAPEX)

Reinjection of gas requires significant compression capacity and potentially multiple injection wells which in turn implies substantial investment costs[70]. Estimated costs are generally based on the following:

- Required number and general complexity of reinjection wells (e.g. well profile, geological formation types, location, target depth).
- Required gas compressor capacities (to bring the gas pressure up to the required injection pressure).
- Other ancillary infrastructure (including pre-treatment facilities, power-generation equipment, pipeline(s) and any other facilities that may be required[71]).
- Gas treatment facilities (depending on sour gas content[72]).
- Reservoir management systems (e.g. software, tracers).

Total capital costs per well in onshore regions range from 4.9–8.3 million USD, including average completion costs of 2.9–5.6 million USD per well[73], however it should be noted that there is considerable cost variability between individual wells. Drilling offshore wells will always be more expensive than onshore wells, and key cost drivers include water depth, well depth, reservoir pressure and temperature, field size, and distance from shore. Drilling itself is a much larger share of total well costs in offshore development than in onshore development, where tangible and intangible drilling costs typically represent only about 30–40%[74] of total well costs[75]. The average drilling and completion costs for offshore wells is approximately 120–230 million USD, with the higher-end estimate related mostly to the technical challenges due to a combination of water depth, well depth, high temperature, high pressure, and geological features of the subsalt[76]. For these reasons, offshore wells inevitably incur higher costs.

3.3.2.2 Operating Expenditures (OPEX)

Operating expenditures (OPEX) can be estimated as a percentage of CAPEX[77] or specifically based on more detailed estimates from:

- Compressor and energy requirements.
- General maintenance requirements (e.g. gas treatment facilities).
- Monitoring and reservoir management system operations.

OPEXs will be primarily be related to compressor capacity (i.e. injection requirements), which in turn will be governed by the well depth, reservoir pressure and temperature, field size, and other parameters. Compressor operations should be expected to use around 5–20% of the APG produced for power requirements during injection activities[78].

Given the large site-specific variations, it is impossible to provide a general estimate of the costs (and benefits) associated with gas reinjection. Costs and benefits may also depend on the location of the facilities, especially for remote Arctic fields where contingencies may have to be considered to account for poor infrastructure among other challenges.

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[70] Injection well costs can vary significantly depending on a variety of parameters, particularly location and whether the target field/reservoir is onshore or offshore.
[71] Will vary from field to field.
[72] As well as the requirements for stripping other impurities contained within the APG.
[73] https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf
[74] Ibid.
[75] The rig and related costs account for 90–95% of total well costs for both drilling and completion, and primarily include the day rate of utilizing a drilling ship or a semi-submersible drilling rig for drilling, well completion, and all other rig related costs, such as the drilling crew, fuel, consumables, support vessels, helicopters, logging, cementing, shore base supplies, etc.
[76] Ibid.
[77] OPEXs normally consist of fixed- and variable-parts involved during operations and maintenance, and depend on the location of the facilities. For example, for remote Arctic regions, contingencies may have to be considered when applying standard OPEX estimates to account for poor infrastructure. The variable part of the OPEXs for oil and gas facilities is usually negligible since the energy demand is low compared to the overall OPEX and is not considered. Preliminary estimates of the OPEXs for any gas utilization concept could be made using historical factors from the specific region as a percentage of CAPEX. Typical values for upstream facilities should be used (and should be indicative of the expected costs for the Arctic). The percentages vary depending on the type of facility. Power cables and pipelines have low operating and maintenance costs compared with process facilities; the variations in percentage rates account for this. The factors used for the OPEX costs are normally in the following ranges:
• 1%–4% of CAPEX for pipelines and subsea cables.
• 4%–7% of CAPEX onshore facilities (excluding rotating equipment).
• 6%–8% of CAPEX for rotating equipment (e.g. compression).
Fields in difficult locations, should assume the upper range limits for OPEX.
[78] Based on Carbon Limits expertise and previous studies.

3.4 BATEA 3: Export Marketable Products – Natural Gas

Summary

APG is recovered from the flare stack and re-routed for pre-treatment and NGL separation (BATEA 6) before being exported for sale via pipelines, as compressed natural gas (CNG) or as liquified natural gas (LNG). Depending on market specifications, NGLs can either be separated on site and sold separately or transferred to a processing plant.

Applicability to the Arctic

- Areas within an economically feasible reach of NG networks
- Fields in the vicinity of existing processing plants with capacity
- Areas close to local markets with demand for energy (e.g. substituting CNG for other fuels such as gasoline or diesel could be a possibility)
- Fields in close proximity to each other (that could be clustered)
- Fields close to large, ongoing infrastructure developments (e.g. pipeline networks, large-scale LNG projects, etc.)
- Fields with accessible export routes for CNG/LNG (e.g. year-round, ice-free road, rail, or marine transport routes)

Effect on Emissions

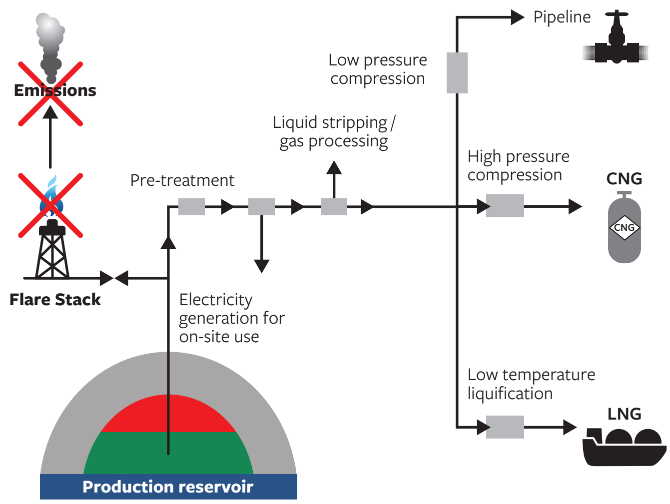
- Significantly reduces emissions of:
  - CO_2
  - PM (including BC)
  - SO_x
  - Heavy metals
- Some emissions, including CO_2, can be created from project-related activities (e.g. compression or liquification of gas)

Benefits

- Maximizes use of resources
- Provides revenue from gas sales to local/international markets
- CO_2 emissions possibly reduced from substitution/displacement of other fuels

Infrastructure Requirements

- Gas pre-processing & conditioning equipment (depending on APG composition & impurities)
- NGL separation infrastructure (BATEA 6) depending on gas market specifications
- Compressors for pipeline
- Compressing station for CNG export including high-pressure cylinders (e.g. trailer-mounted)
- Gas liquification plant for LNG export
- Piping & related infrastructure
- On-site storage facilities (vessels) as required (CNG cylinders/LNG tanks)
- Loading gantries and other sales facilities for CNG or LNG
- NGL storage and loading facilities (as required)



General Technical & Economic Considerations

- Possible requirements for gas pre-treatment (e.g. H_2S content)
- Requirements for NGL separation (to meet gas specifications of export method)
- Marketable volumes, distance to markets, and value of hydrocarbons
- Capital cost of gathering and export infrastructure (including accessibility/availability of any existing infrastructure, e.g., possible limits on gas trunk line capacity)
- Processing plant capacity (potentially limited need for direct APG export, if no NGL separation on site)
- Security of APG volumes/supply availability over time (influences ROI and general investment decisions on export methods)
- Gathering of scattered APG streams to increase economy of scale (pipelines, CNG, and LNG infrastructure could in many cases become viable with larger collective volumes)
- Economic viability of CNG or LNG transport in trucks, containers or ships for export
- Technical aspects related to pipeline routing (including terrain – e.g. subsea, buried, over-ground)

Links to Further Information

- LNG Export, CNG, Re-Exports and Long-Term Natural Gas Applications: https://www.energy.gov/fe/2015-lng-export-compressed-natural-gas-cng-re-exports-long-term-natural-gas-applications
- APG Utilization Overview: http://ccsi.columbia.edu/files/2014/03/Overview-APG-Utilization-Study-May-2014-CCSI1.pdf

3.4.1 Technical Considerations

Exporting marketable NG products has the potential to completely eliminate routine flaring[79]. Gas can either be exported as an energy feedstock to existing or new gas processing plants (GPPs)[80] in a wet[81] state (assuming no sour/acid gas is present[82]), or for local or international markets as a dry gas, compressed natural gas (CNG) or liquified natural gas (LNG). Exporting APG in a dry state requires gas conditioning and separation of the NGLs present in APG[83] (**see BATEA 6**) to match required gas profiles of NG pipelines, for CNG vessels, or as LNG. The export route chosen will be based on technical and economic considerations and has no effect on BC emissions reduced from the avoidance of flaring[84].

Methods for exporting NG from site include:

- Gas pipelines, either by means of introducing APG or NG into existing or new pipelines to GPPs or directly to off-takers (including existing wider gas grids).
- Production of CNG, which can be exported in truck trailers, containers, or ships.
- Production of LNG, which can be transported off-site by ships in large-scale developments or containerized for road and rail[85] export as mini/small-scale LNG solutions.

The technical and economic feasibility of the above options for gas export depend on numerous site-specific parameters including, but not limited to, the geographical location of the field, distances to market, site accessibility, available gas volumes, and the remaining lifetime of the field. Each field should be analyzed on a case-by-case basis to determine the best method of export.

3.4.1.1 Export Process

Before APG is exported, it must be centrally gathered, treated, and compressed or liquefied according to the following steps:

1. **Flare gas gathering (and compression)**: This initial stage of gas recovery is required for any export method. In many cases, it is essential to gather scattered APG flare gas streams and cluster them centrally before treatment, compression, and export in order to achieve better economic feasibility. Flare gas gathering can represent a non-negligible part of the costs if the flares are dispersed and the gas pressure is low.
2. **Gas pre-treatment and conditioning:** APG will generally require some form of pre-treatment before it can be exported through infrastructure. Treating the gas removes impurities (e.g. H_2S, H_2O), however, the level of treatment will depend upon site-specific conditions and technical circumstances.
3. **NGL separation (BATEA 6):** Most export specifications will require the prior separation of NGLs. Separation will also allow for increased transportability[86] of NG. In some cases, it will be possible to export wet APG directly to GPPs or power stations located off-site. Ideally, for export as CNG, NGLs will be separated before compression[87] as liquids will drop out under pressurization[88].
4. **Export Method:** After treatment and separation of the recovered flare gas, the last step in preparing the gas for export is determined by the mode of transport from the site and the required specifications of the chosen export method[89]:
   - **Pipeline:** After pressurization, gas can be exported either as wet[90] gas[91] (usually to an off-site processing plant[92]) or as dry gas after on-site NGL separation.

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[79] Safety flares are necessary for safe operations, nonetheless. Intermittent flares are generally not recoverable due to supply stability issues.

[80] APG can also be directly exported after conditioning in a wet state via pipeline for processing elsewhere (e.g. a GPP within a practical distance from oil production operations). This may be particularly applicable for flare gas recovery from offshore oil fields. Conditions need to be evaluated to avoid liquid dropouts, and thus are typically only implemented for short-distance evacuations (e.g. to a processing plant located in the near vicinity).

[81] APG containing a large share of NGLs (typically less than 85% methane and a higher share of ethane, propane, butane and other more complex hydrocarbons).

[82] Highly corrosive to pipelines, machinery, equipment and other infrastructure.

[83] Separating NGLs from wet APG streams can create other marketable hydrocarbon products including LPG and condensates.

[84] However, project emissions (including BC emissions) may vary based on export route.

[85] https://www.alaskarailroad.com/sites/default/files/Communications/2016_LNG_Transport_Demo_Project.pdf

[86] Gas without liquid hydrocarbons will have increased transportability, e.g. in pipelines where liquid dropouts can cause significant difficulties.

[87] Under 200–275 bar pressure of a CNG vessel, NGLs transform from a gaseous state to a liquid state and cause complications.

[88] As part of the refrigeration process.

[89] Depending on a project feasibility assessment and applicable technical and economic parameters. Method applicability may vary from site to site.

[90] APG stripped of impurities but not liquid hydrocarbons.

[91] Careful consideration needs to be taken when exporting wet APG containing hydrocarbon liquids. When slightly pressurized, NGLs can transform from a gaseous state to a liquid state and cause complications along the pipeline. This has to be carefully evaluated by process engineers.

[92] Midstream agreements between O&G operators and GPPs are important factors to consider when evaluating utilization options. There is generally an imbalance between O&G operators, especially small ones, and large midstream GPPs, with GPPs paying relatively low prices for rich APG given the amount of NGLs it contains. This should motivate O&G operators to opt for long-term gas utilization options instead of

Dry gas, after being processed on site to meet pipeline export specifications, could be introduced and sold into an existing gas grid, whereas wet gas would have to first undergo intermediary treatment at a GPP elsewhere (i.e. before introducing it as dry gas into wider gas grids).

- **CNG:** After removing impurities (including H_2O) and typically NGL separation, the gas is compressed for transport in suitable export vessels[93]. The extent of compression[94] and cooling required will vary based on source gas quality, export specifications and other parameters. The scope of a CNG production facility is generally a small fraction of that of a comparably-sized LNG facility. CNG can then be stored[95] and transported off-site in highly pressurized cylinders[96] via a range of transport solutions, including trailers (road transport), containers (road or rail transport), specialized barges (short-distance river, lake, or sea transport) and ships (short-to-medium distance seafaring routes).
- **LNG:** Liquefying gas primarily increases the transportability of gas, particularly over large distances. NGLs are typically separated before this process or are removed as part of the cooling process. The treated gas is initially subjected to a plurality of cooling stages by an indirect heat exchange with one or more refrigerants[97], whereby the gas is progressively reduced in temperature until complete liquefaction. The pressurized LNG is further expanded and sub-cooled in one or more stages to facilitate storage at slightly above atmospheric pressure[98]. Flashed vapors and boil-off gas are recycled within the process or can be used to run utilities of the O&G production operations. LNG storage tanks[99] will be required on site to enable constant utilization of the feed gas (i.e. to store sufficient volumes until the next batch can be exported, typically a few days of production).

3.4.1.2 Comparison of Export Methods

Pipelines are commonly used[100] to export APG from sites with sufficient remaining field life and are considered a long-term, permanent solution[101] for recovering flare gas. They are generally most applicable where volumes are sufficient over time and where export via pipelines is more economical and technically feasible than other alternatives. However, depending on a field's location and the geographical terrain[102], pipeline construction can take a considerable amount of time, including the time it may take to resolve any rights-of-way matters and have construction permits issued[103].

Exporting gas as CNG can circumvent permit requirements associated with pipelines, and may also prove more practical and viable than pipelines where road (or possibly

connecting "mature" (> one year) wells to gas gathering systems with newer wells. Mature wells can be knocked out often, resulting in pipeline-connected well flaring and line shutdowns. In general, there are a number of criteria that are key to the viability and proper selection of gas utilization technologies for an individual well site that is not already connected to a gas gathering system.

93 According to specifications of CNG cylinders/vessels.

94 CNG is typically pressurized to approximately 3000–4000 psi or 200–275 bar. The amount of compression required depends on the delivery pressure of the source and gas quality.

95 CNG storage solutions can be supplied as stand-by trailers, containers, or barges.

96 Typically, specialized steel or composite cylinders are used for CNG transport, but there have been recent advancements in transport systems (e.g. coil systems, where a steel coils are wrapped in circular configuration to avoid the need for valves and connections between individual cylinders).

97 APG will require initial treatment to remove H_2O, H_2S, CO_2, condensate, and other components that might freeze. The gas is cooled down through several stages, usually in a cryogenic cooling circuit and a main liquefier or "cold box", until it is liquefied (at approximately -162°C). The process also produces NGLs. The LNG is then routed to storage tanks and then periodically shipped using suitable vessels or tanks. The density of the LNG makes it particularly useful for storing large amounts, and shipping very long distances, where it becomes cheaper than pipeline and CNG deliveries.

98 Since LNG liquefaction requires a significant amount of refrigeration energy, the refrigeration system(s) represent a large portion of an LNG facility. A number of liquefaction processes have been developed with the differences mainly dependent on the type of refrigeration cycles employed. The most commonly utilized LNG technologies are the CoP LNG process, the propane pre-cooled mixed refrigerant process, and the single mixed refrigerant process. "The CoP LNG Process, formerly known as the Phillips Optimized Cascade LNG Process, utilizes pure refrigerant components in an integrated cascade arrangement. The process offers high efficiency and reliability. Brazed aluminium exchangers are largely used for heat transfer area, providing for a robust facility that is easy to operate and maintain. Refrigerants typically employed include propane, ethylene and methane. The propane pre-cooled mixed refrigerant process provides an efficient process utilizing a multi-component mixture of hydrocarbons typically comprising propane, ethane, methane, and optionally, other light components in one cycle. A large, spiral-wound exchanger is utilized for the majority of heat transfer area. A separate propane refrigeration cycle is utilized to pre-cool the natural gas and mixed refrigerant streams to approximately -35°C. The single mixed refrigerant process includes heavier hydrocarbons in the multicomponent mixture, e.g. butanes and pentanes, and eliminates the pre-cooled propane refrigeration cycle. The process presents the simplicity of single compression, which is advantageous for small LNG plants" – ConocoPhillips.

99 LNG is stored in double-walled tanks at atmospheric pressure. The storage tank is a tank within a tank that is filled with insulation. The inner tank, in contact with the LNG, is made of materials suitable for cryogenic service and structural loading of LNG. These materials include 9% nickel steel, aluminium, and pre-stressed concrete. The outer tank is generally made of carbon steel.

100 Depending on distance to the off-taker of the gas.

101 Assuming availability of pipelines with capacity for introduction.

102 Geographical terrain could provide challenges during construction.

103 Depending on the time required to issue permits and construct pipelines, CNG can often be a faster solution.

rail) infrastructure is readily available and accessible year-round. By compressing dry gas into cylinders/containers, it improves general mobility/transportability[104] and could offer a quick and/or temporary solution[105] for recovering flare gas. It can also present itself as a permanent solution where a field's remaining life and daily volumes are small. One advantage of CNG export over pipelines is that equipment and infrastructure can be re-positioned to other sites as an oil field's production declines[106].

On-site CNG storage (e.g. stand-by trailers) can be designed into gas export planning[107], however the aim should be to have a continuous rotational[108] export of gas to maximize export efficiency and minimize on-site storage. CNG solutions are mature and commercially available, particularly for export on trucks/trailers and containers. Seafaring solutions are available as well, and currently several new technological developments[109] are under development and testing[110], however, ocean transportation in the Arctic may be limited to a few months out of the year. Therefore, it is unknown whether CNG transport within the region is technically feasible, and under many circumstances there could also be considerable uncertainty as to the costs involved (Section 3.4.2).

LNG recovery infrastructure is more complex in nature than CNG and historically has been the domain of large-scale developments using gas from large, stand-alone NAG fields as a feedstock. Large-scale LNG developments cost billions of dollars, require large, long-term gas supplies (not typically given by APG), and may take years, or even decades, to develop. For those reasons, LNG has not traditionally been considered a suitable solution for flare gas recovery. However, mini/small-scale LNG solutions are increasingly becoming commercially available and are offering feasible alternatives for APG utilization, especially as technology matures and costs decrease.

With recent developments, mini/small-scale LNG[111] could provide a relatively fast export solution for bringing flare gas to local markets, allowing it to serve as a viable alternative to CNG[112]. Numerous, smaller APG flares are responsible for the majority of BC emissions (Figures 3 and 4), and implementing mini/small-scale LNG projects could offer a potential alternative for many flare sites that in the past were considered stranded due to technical issues (e.g. water depth or sub-surface terrain), or sites experiencing long-term economic challenges with pipelines (primarily relating to remaining field life and volumes available). Additionally, mini/small-scale LNG production improves transportability of NG[113] compared to pipelines[114]. Where transboundary barriers exist, further investigation into non-pipeline export methods such as mini/small-scale LNG or CNG export may be warranted.

In addition to weighing the technical and economic feasibility of export options for individual fields, the option to combine resources from several fields should also be considered (e.g. clustering of APG to reach sufficient volumes over time for larger projects[115] or combining NG from APG with NAG sources in the vicinity to co-develop a more economically feasible larger-scale project)[116].

3.4.2 Investment Considerations

An evaluation of the economic feasibility of exporting recovered APG needs to consider the value of the gas (i.e. revenues from off-takers), the available and remaining gas volume over time, and other site-specific costs. Feasible export methods should also be evaluated against each other (e.g. CNG vs. mini/small-scale LNG). The suitability of each method will also depend on the accessibility of field locations (i.e. availability of transport means, weather conditions), the distance and cost required to reach off-takers, and the potential value of gas relative to the required investment costs[117]. Detailed ROI calculations for each export method under consideration are necessary.

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104 Particularly over short distances.
105 For example, until a pipeline is laid.
106 Investment considerations should include the possibility of re-positioning and re-use of equipment.
107 Depending on gas offtake requirements and economic viability.
108 Rotational export refers to a constant offloading of CNG onto new trailers, containers, barges, or ships as the previous batch is exported and before it returns to site for refilling with a new load of CNG.
109 Particularly concerning a reduction in cost.
110 Many small- and large-scale sea-going CNG solutions are currently under development and foreseen to be commercially available in the near future.
111 https://www.strategyand.pwc.com/reports/small-going-big
112 Depending on the field.
113 Around 1/600th of the volume of natural gas in a gaseous state.
114 And over CNG where long-distance transport is required.
115 Costs per unit will reduce at a larger scale, i.e. economies of scale.
116 Project-specific analysis of feasibility will be required.
117 The investment cost for export infrastructure is highly variable and will ultimately depend on several factors including the method of export, volume of gas, geographical location of the planned infrastructure, distance to market, and other factors.

Apart from factors such as gas quantity and availability, the gas composition, and particularly the value of gas as a feedstock at intermediate markets, will be crucial for selecting an exportation strategy. In some cases, it may be more economical and profitable to export dry gas, but in other instances, it may make more practical and/or economic sense to export wet APG gas and leave processing (or conversion into other hydrocarbon products (**BATEA 4**) or electricity (**BATEA 5**)) to entities located further downstream in the value chain.

For a single well located a short distance from market or near existing infrastructure, investments in gas gathering can be usually considered the preferred option. The recovery and export of associated gas can generate additional revenues for an operator as it can be sold as either as raw APG, or as NG, CNG, or LNG (plus LPG & condensate) to third parties.

3.4.2.1 Pipeline

The distance to an off-taker and related pipeline infrastructure, including compressor requirements, are the most significant factors when it comes to evaluating CAPEX for gas pipelines[118]. Compressor stations (also called pumping stations) are facilities which help the transport of NG from one location to another and are needed to maintain constant pressure along the pipeline at intervals of 60–160 kilometers (km). The number of compressor stations needed will be dependent on the terrain and number of wells in the vicinity. Frequent elevation changes and a larger number of interconnected wells will require more stations[119].

Compressor stations are normally pressurized by turbines, motors, or engines and the size and number of compressors (i.e. pumps) will vary based on the diameter of the pipe and the volume of gas to be moved. Centrifugal or reciprocating compressors are typically driven by NG from the pipeline but can also be driven by a high voltage electric motor. The horsepower (HP) requirements will be dependent on the compressor capacity, which is in turn affected by location, transport distance, volume, pressure, and other parameters. Average unit costs are variable and can range from 300–2000 USD/HP, most of which is material costs[120] (approximately 50% of the total cost)[121].

The primary determinant of a compressor's technical and economic performance is its efficiency, which refers to the cost of the fuel consumed to bring gas from a suction pressure to a discharge pressure. In technical terms, this would be a unit with a high thermal efficiency (or low heat rate) for the driver and a high isentropic efficiency of the compressor. A compressor's efficiency will determine the fuel cost of the unit at given operating conditions.

It is also important to note that the cost of fuel gas is not the same as the end market price of the transported gas. Fuel cost will depend on how fuel usage and transport tariffs are related, and whether the operator owns the gas in the pipeline (making fuel cost an internal operating cost), or if the operator is simply transporting the gas belonging to another entity. In most installations where the operator is the owner of the gas, the fuel cost may account for more than two-thirds of the annual operating cost.

The amount of gas used as fuel for compression and pipeline transport will be highly variable and scenario-dependent, but can be generalized at 2–10% of the gas being transported[122].

The key determinants of pipeline construction cost[123] are the pipe diameter, operating pressures, distance, and terrain. Other factors, including climate, labour costs[124], degree of competition among contracting companies, safety regulations, population density, and rights-of-way, may also cause construction costs to vary significantly from one region to another. Pipeline operating costs vary mainly according to compression requirements, which can require significant amounts of fuel, however a portion of recovered gas can be used as fuel gas for on-site compressors.

As the majority of APG flares in the Arctic consist of small volumes of gas (<5 MMSCFD), in most cases export will be constrained to distances below 15–25 km. CAPEX estimates for a small APG flare reduction project from a marginal field range from 0.3–2.5 million USD/MMSCFD[125].

[118] As pipeline transportation is less complex than the LNG process for example, cost reductions have been less impressive. However, substantial improvements have been achieved in optimizing the project design and construction, resulting in a reduction of material costs and the duration of construction.

[119] https://www.hindawi.com/journals/ijrm/2012/715017/

[120] Capital costs for a project consist of first costs and installation costs. First costs include the cost of the driver and compressor, their skid or foundation, as well as the systems required for their operation, including filters, coolers, instruments, valves, and if reciprocating compressors are used, pulsation bottles. Capital spares, operational spares, and start-up and commissioning spares also have to be considered.

[121] https://www.researchgate.net/publication/275590240_Pipeline_compressor_station_construction_cost_analysis

[122] Based on Carbon Limits experience and internal evaluations.

[123] When conducting a feasibility study it is particularly important to consider pipeline sizing requirements. In many scenarios, a pipeline designed for the highest possible level of utilization and a high load factor will be critical for economic viability.

[124] Local economic conditions, especially labour costs, could be a significant factor depending on the location of the field.

[125] Based on Carbon Limits internal data and past projects.

3.4.2.2 Compressed Natural Gas (CNG)

Exporting CNG should be closely examined as an option for onshore fields that flare small volumes of APG, have a limited remaining field life, and a short distance to market. For offshore fields, seafaring export solutions can provide an economically attractive alternative to transport small- to medium-volumes of gas over short distances[126]. CNG also has an economic advantage over pipelines in that, in many cases, it can be marketed[127] directly to end-users[128], where it can often command a higher price than wholesale.

While the cost of delivered CNG depends on project-specific conditions, it can be considered economically viable for onshore volumes up to 5–15 MMSCFD and distances up to 800 km[129]. However, CNG export may also be considered more suitable than pipelines for stranded assets (>0.2 MMSCFD, but flexible) and transport distances between 15–200 km.

The first offshore CNG export projects[130] have recently been implemented for short distances and where export by pipeline was deemed not feasible for technical and economic reasons. CNG export by sea-going vessels[131] fills a gap left by pipeline and LNG export and can be considered to be economically feasible[132] for distances to market up to 2500 km away. Design[133] capacities[134] of vessels range between 75–1000 million standard cubic feet[135].

Investment costs associated with both onshore- and offshore-CNG export will largely depend on the field conditions, which can vary significantly between sites. For small-scale onshore projects, cost estimates range between 4–5 million USD/MMSCFD (+0.2% extra per km). Operating costs are mostly related to transportation and potential heating requirements (e.g. at unloading and for maintaining the heating distribution system), but also to the amount energy consumed during compression of the gas to 200–250 bar. Compression may consume 3–7%[136] of the NG being compressed, but is subject to variability depending on the feed pressure, volumes of gas, and hence the compressor capacity required[137]. It is important to emphasize that operational costs are, in general, very site-specific. Given the difficult climate conditions in the Arctic and the technical questions related to transport, an in-depth assessment is needed if this method is considered.

CNG trucking is a good option if technical and geographical factors are met. Outsourcing of CNG trucking could allow the operator to avoid up-front capital investment while still earning a profit on otherwise flared gas. The leasing and renting options are flexible, but accessing the market is difficult, and midstream agreements for "rich CNG"[138] may not be straightforward. Developing and implementing strategies to extract NGLs and deliver CNG can be more economical than waiting to connect to a gas gathering system strained by lack of capacity, and rapid variations in the volume, composition, and pressure of input gas.

3.4.2.3 Liquified Natural Gas (LNG)

While conventional large-scale LNG projects are not considered relevant for the recovery and export of APG, technological advances in mini/small-scale LNG facilities offer new opportunities for the recovery and utilization of smaller volumes of stranded APG[139]. The mini/small-

126 Relative to other export solutions.

127 Depending on licensing, market regulations, and other factors. Typically, a special purpose vehicle would be used to assess economic viability and implement gas marketing directly to end users. Various arrangements could be implemented, such as selling gas to the CNG entity, thereby keeping business models separate.

128 Particularly in cases where gas has a higher value to end users (perhaps displacing a more expensive fuel for power generation needs) or where wholesale gas prices for introduction into a pipeline network are low compared to the value towards an end-user. This option will need a detailed analysis of economic parameters as well as regulatory options when marketing CNG.

129 http://documents.worldbank.org/curated/en/210571472125529218/text/104200-V2-WP-CNG-commercialization-PUBLIC-Main-report-REPLACEMENT.txt

130 On January 25th, 2016 the world's first CNG carrier, the Jayanti Baruna, was launched. The ship transports gas from offshore Indonesian fields in East Java to communities on the island of Lombok, benefiting relatively remote communities that are not economically feasible to supply by pipeline.

131 Use of CNG at a larger scale is not yet commercially viable but is being investigated by several companies as an economically viable alternative to large-scale LNG.

132 The distance to market will affect the capacity configurations of CNG ships, and any gas recovery project needs to consider that multiple ships will be required on a rotational basis to maximize export efficiency.

133 Many technology providers are still at an advanced concept stage.

134 Depending on barge or ship design and configuration.

135 http://documents.worldbank.org/curated/en/210571472125529218/text/104200-V2-WP-CNG-commercialization-PUBLIC-Main-report-REPLACEMENT.txt

136 Based on Carbon Limits experience and internal assessments.

137 Compressor size and efficiency will vary with the volumes being compressed.

138 While options exist for exporting rich CNG, usually market specifications will dictate the compositional requirements. Typically, CNG will contain only NG, with NGLs having been stripped beforehand.

139 In the last ten years, efforts have been focused on the miniaturization and standardization of LNG technology so it is repeatable and scalable, with decreased cost. Considering that one metric tonne of LNG equals approximately 50 thousand cubic feet (MCF) of NG, we could

scale LNG chain is virtually identical to the conventional LNG chain and differs only in size. One difference is that for smaller gas volumes, LNG transport becomes feasible by using trailers, containers, barges, and smaller ships (as with CNG) rather than large expensive marine carriers. These plants are available in modular form and can process gas feeds of 1–40 MMSCFD and produce 0.01–0.3 million tonnes per annum (MMTPA) of LNG[140]. CAPEX estimates for commercially proven technologies[141] range from 4–25 million USD/ MMSCFD for mini-LNG plants processing 1–15 MMSCFD[142]. Liquification of gas requires reducing the temperature of the gaseous stream to -173°C and is considered a very energy intensive process that can consume 5–15%[143] of the gas being transformed into LNG. It is also important to note that the regasification process will also consume energy at the end-user stage, however, significantly less than for the liquification process.

Mini/small-scale LNG projects can be considered an alternative to CNG export in many situations, and both export methods should be evaluated against each other, considering their economic benefits, technical feasibility, and lead times to implementation. Environmental effects need to also be considered, including any project emissions originating from the energy requirements of each respective technology.

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extrapolate that the appropriate miniaturization of a plant under tight oil gas utilization conditions should be able to process 5–50 LNG metric tonnes/day. The best-case scenario would be several very productive wells in a remote location with more upcoming wells that continuously serve a mini-LNG plant with a processing capacity of at least 1000–5000 MCF per day. It would require a large storage space and hitting the LNG market in premium spots and locations. A worst-case scenario involves a lower than expected LNG price scenario and a company that has invested on an overdesigned unit, midstream delivery (trucking) of the products, and lack of LNG operation and maintenance expertise.

140 https://www.geoilandgas.com/sites/geog/files/ge-small-scale-liquefied-natural-gas-plants-guide.pdf

141 https://openknowledge.worldbank.org/bitstream/handle/10986/25919/112131.pdf?sequence=4&isAllowed=y

142 Ibid.

143 According to Carbon Limits expertise and other studies previously conducted.

3.5 BATEA 4: Export Marketable Products – Liquid Hydrocarbon Products

Summary

Associated gas is recovered from the flare stack and re-routed for pre-treatment, NGL separation (depending on composition and technology) and then converted via Gas-to-Liquid (GTL), Gas-to-Chemical (GTC), or ammonia (NH_3) production processes into valuable hydrocarbon liquid products including, but not limited to, fuels (diesel, gasoline, jet fuel), methanol, and agricultural fertilizer.

Applicability to the Arctic

- Regions too remote to access gas transmission networks (BATEA 3) or electrical grids (BATEA 5), but with local demand for liquid fuels, methanol, or ammonia[144]
- Areas with particularly high value of products (e.g. diesel, gasoline, etc.)
- Regions with a water source for steam generation (common in Arctic environments)
- Remote and/or offshore Arctic fields as potential candidates for new small-scale GTL/GTC technology

Effect on Emissions

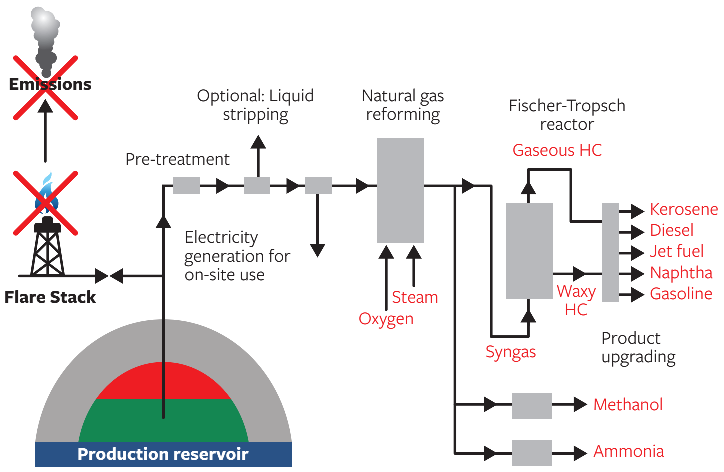
- Significantly reduces emissions of:
  - CO_2
  - PM (including BC)
  - SO_x
  - Heavy metals
- Increases plant CO_2 emissions from additional production processes
- Emissions of CO_2 could be reduced through the displacement of emissions from other fuel sources[145]

Benefits

- Maximizes use of resources
- Can produce products of higher economic value to end-users
- Resulting products are typically purer and burn cleaner than NG[146]

Infrastructure Requirements

- Gas pre-processing & conditioning equipment (depending on APG composition & impurities)
- NGL separation infrastructure (BATEA 6)
- NG reforming equipment to produce syngas intermediate (CO, H_2)
- GTL: Fischer-Tropsch (FT) reactor & other required elements (e.g. O_2, steam)
- GTC: Methanol production process equipment
- NH_3: Fertilizer production process equipment
- Piping & related infrastructure
- Product storage infrastructure
- Export & delivery infrastructure for products (e.g. loading gantries)



General Technical & Economic Considerations

- Possible gas composition constraints (requirements for gas conditioning – e.g. H_2S content)
- Requirements for NGL separation (depending on economic value and specific feed requirements in conversion process)
- Volumes available and security of APG supply over time (to support costly production processes)
- Opportunity cost for gas usage/export (e.g. capital and operating costs, as well as other parameters, including product premiums, shipping cost, and crude price indices)
- High capital costs of GTL/GTC plants (economic feasibility dependent on several factors, including product values on local vs. international market and price of crude oil relative to NG)
- Security of long-term off-takers and product values (distance to market, available volumes, and prices achievable at various markets have to be considered)
- Use of micro/small-scale GTL/GTC plants, particularly with current technological developments (although capital investment costs are still high compared to other gas utilization routes)

Links to Further Information

- General Information on GTL: https://petrowiki.org/Gas_to_liquids_(GTL)
- GTL: A Review of an Industry Offering Several Routes for Monetizing Natural Gas: https://www.sciencedirect.com/science/article/abs/pii/S1875510012000947
- GTL: A Technology for Natural Gas Industrialization in Bolivia: https://www.sciencedirect.com/science/article/abs/pii/S1875510010000739

[144] Could compete with products from large-scale plants located further away.
[145] For example, diesel derived from the Fischer-Tropsch (FT) process – unlike diesel derived from distillation of crude – has near-zero sulphur and nitrogen-oxide content, virtually no aromatics, burns with little-to-no particulate emissions, and has a high cetane value.
[146] For example, GTL technology could produce low-viscosity Arctic-grade diesel.

3.5.1 Technical Considerations

Flare gas can be chemically converted (usually via production of synthetic gas or 'syngas') into other valuable hydrocarbon products using technologically complex techniques including:

- **Gas-to-Liquid (GTL) processing** to produce liquid hydrocarbons including naphtha, kerosene, diesel, jet fuel, gasoline, and base oils (e.g. waxes/lubricants).
- **Gas-to-Chemical (GTC) processing** to produce methanol and methanol-derivatives (e.g. dimethyl ether (DME)).
- **Ammonia (NH_3) production** primarily for use as agricultural fertilizer.

Converting gaseous hydrocarbons into liquid form using these processes adds significant product value, creates products that can be marketed directly to end-users, and provides for easier evacuation from site.

3.5.1.1 Gas-to-Liquids (GTL)

GTL is a refinery process to convert NG or other gaseous hydrocarbons into longer-chain hydrocarbons[147]. Gases are converted into valuable liquid fuels (such as diesel[148]) either via a direct conversion or using syngas as an intermediate, for example, using the Fischer-Tropsch (FT) process. The FT process[149] is a catalysed[150] chemical reaction[151] in which carbon monoxide (CO) and hydrogen (H_2) are converted into liquid hydrocarbons of various forms[152]. Condensate and NGLs should be separated from natural gas[153]. Impurities such as sulphur and mercury must be removed, but N_2 and CO_2 can be tolerated in moderate concentrations. An initial pressurized feed gas is an advantage since the first step reformers run at medium pressures (~300 pounds per square inch (psi)). Gas feed rates must be as steady as possible. The principle purpose of this process is to produce a synthetic petroleum substitute (e.g. for use as synthetic lubrication oil or as a synthetic fuel.)

GTL technologies are mature, have been widely used at scale internationally, and in theory, can be implemented onshore or offshore in the Arctic, though the costs may vary significantly. Oil fields producing APG will need to have significant volumes available over time to consider these technologies as most GTL plants are usually very large, complex, and capital intensive. Remote locations and harsh climate conditions pose challenges in terms of site access (e.g. need for large equipment which may not be easily trucked), and plant design, construction, and assembly (e.g. need for insulation, availability of sufficient water for cooling, etc.). Due to low-margin economics, only a small fraction of oil fields meet these geographic criteria and are suitable for conventional GTL plants with competitive economics[154]. The GTL processes in operation today convert approximately ten thousand standard cubic feet (MSCF) of gas into slightly more than one barrel of liquid synthetic fuel.

Gas conversion to liquid fuels and chemicals is a capital-intensive industry where economy of scale has been critical. Today's world-scale GTC methanol plants which produce 5000 tonnes per day (TPD) of methanol, consume 150 MMSCFD of gas, while GTL FT plants center around 100,000 barrels per day (BPD) of liquid fuel production consuming 1000 MMSCFD of gas per day.

A number of companies have taken up the challenge to develop smaller plants using innovative technologies that allow process intensification, modularization, and skid mounting, among other improvements. With these fresh approaches, some of the challenges posed by APG can be overcome. For instance, changing production volumes can be accommodated by changing the number of process modules. Lighter and smaller units now fit onto offshore platforms, and FPSO's or barges make floating GTL units a reality. The major benefit of small-scale gas monetization opportunities is that they can be deployed in a phased manner and can be installed close to the existing gas source, thereby eliminating the need for significant expenditure in gas compression and transportation facilities.

Mini-GTL or downsizing of the GTL technology to a portable unit, is a longstanding goal being approached with new technology. A number of small-scale GTL solutions have been developed over the last few years, which offer solutions to produce high value products. However, small-

[147] GTL processing is not affected by the presence of N_2, CO_2, or O_2. Non-pipeline quality gas that has a high N_2 or CO_2 content is an ideal candidate for GTL conversion into diesel.
[148] Which can be sold as is, or blended with other fuels.
[149] Dry natural gas, mainly CH_4, can be used to produce liquid hydrocarbons, fuels, and chemicals. First, CH_4 is converted into syngas (CO and H_2) through steam reforming, which is further processed using FT reactions into liquids. In order to maximize production of high-value diesel or related liquids, a hydrocracking processing unit is typically coupled to the FT reactor.
[150] Typical catalysts used are based on iron and cobalt.
[151] The initial reactants (CO and H_2) can be produced by other reactions such as the partial combustion of hydrocarbons.
[152] The mixture of CO and H_2 is called synthetic gas or syngas. The resulting hydrocarbon products are refined to produce the desired synthetic fuel.
[153] Preferably, although C_2+ and higher could be accommodated with minor modifications.
[154] The most efficient GTL plant is Shell's Pearl project in Qatar, processing 1.6 billion cubic feet of NG to 260,000 barrels of products per day, and requiring $20 billion capital expenses: http:/www.shell.com/global/aboutshell/major-projects-2/pearl/overview.html

scale GTL solutions are capital intensive, and few have reached a commercial stage. For the last decade or so, a number of companies have been developing gas conversion technologies which are applicable to the challenges of associated gas with much lower volumes, steep production declines over time, and difficult locations with limited infrastructure. Three companies[155] have moved beyond the technology demonstration phase and are offering commercial solutions. The applications range from very small flares below 0.5 MMSCFD to larger volumes of 10 MMSCFD and beyond. Assuming 10 MSCF yields per barrel, 500–1000+ BPD would be achievable.

3.5.1.2 Gas-to-Chemical (GTC)

The manufacturing of methanol[156] is a specific type of gas conversion often referred to as GTC. Methanol is primarily used as a feedstock for other chemicals, however can also be further converted to DME or gasoline for potential use as a liquid energy carrier or transport fuel[157]. Methanol is usually produced by partial oxidation of gaseous hydrocarbons to CO and H_2 (syngas). Similar restrictions apply as with GTL, including the requirements for NGL separation and steady feed gas rates.

3.5.1.3 Ammonia (NH_3) Production

Ammonia, also referred to as urea, is a commodity chemical that can be produced by combining high-pressure H_2 and N_2 to produce fertilizer. N_2 is obtained from air, which is deoxygenated by the combustion of NG. While H_2 can be obtained from water hydrolysis, it is usually be produced via steam reforming, which converts gaseous hydrocarbons into a mixture of CO and H_2 (syngas). More complex treatment may be required to remove impurities before reforming and to maximize H_2 yield.

3.5.2 Investment Considerations

3.5.2.1 Gas-to-Liquids (GTL)

The products from GTL processes range from clean synthetic crude oil[158] to clean diesel fuel[159]. The value of these products, assuming a 100 USD per barrel (BBL) crude oil price is approximately 20 USD per million British Thermal Units (MMBTU)[160] and for many fields, is often considered attractive considering no-cost APG. This significant uplift in product value helps to provide attractive economics despite the lack of economy of scale. Offshore applications are available and can also be feasible[161].

As these technologies are beginning to mature, miniaturization of GTL technologies may play a role in improving APG utilization in remote areas with favourable local conditions. Key parameters determining the economic and technological efficiency and viability of these systems include:

- High utilization of capacity (i.e. having stable, long-term gas supplies or a modular/portable solution with good turn-down ratio). Gas processing equipment rarely accommodates more than 50% turn-down; in the case of GTL, operating time is closer to 80–90%.
- High pressure, since the first step reformers of most FT reaction routes of GTL run at elevated pressures (> 20 bar). Adding compression will add cost.
- Short transport distances to attractive market outlets at a significant premium.

The best-case scenario for GTL use would be a remote location with several very productive wells with more upcoming wells that continuously serve several small-scale FT units with a processing capacity of at least 5 MMSCFD. Diesel, or other GTL products, could then be trucked into premium price markets.

Economic returns for mini-scale GTL plants can look attractive thanks to the high value products associated with a high crude price, however, the delivery time for equipment and construction can be long. Since the feed gas for GTL is APG, the production profile is tied to the oil production, and therefore is not always stable.

The relative techno-economic assessment of various liquid fuels will be primarily related to the market demand and prices achievable at local conditions. Every assessment will be location specific. For example, an area with a higher relative value of one product over another – e.g. diesel vs. jet fuel – will determine the economic feasibility of producing one product over another.

155 CompactGTL, Velocys/Oxford Catalysts, and Gastechno.
156 The manufacturing of methanol is one of the oldest GTL technologies and there are a large number of methanol plants operating worldwide.
157 However, increasing shares of methanol end up as liquid transportation fuels such as methyl-tert-butyl-ether, bio-diesel, and DME. It has been predicted that within five years, more than half of the methanol supply will end up as a liquid energy carrier, eclipsing its use as a chemical.
158 CompactGTL.
159 Velocys.
160 https://openknowledge.worldbank.org/handle/10986/21976?show=full
161 CompactGTL has done a lot of working developing offshore oilfield solutions.

3.5.2.2 Gas-to-Chemicals (GTC)

The products from GTC include chemical feedstocks such as methanol and methanol derivatives[162] such as DME. The value of these products is dependent on the relative availability and/or requirement for them in the vicinity of production, and for many fields, can also be considered attractive considering no-cost APG. As the miniaturization of these technologies are beginning to mature, GTC may play an important role in improving APG utilization in remote areas where alternative product feedstocks such as methanol are needed in the vicinity of fields to circumvent the otherwise long transportation distances to reach end-users. Key parameters determining the economic and technological efficiency and viability of GTC systems are comparable to those of GTL systems.

The best-case scenario for GTC use would be several very productive wells in a remote location (with methanol demand in the close vicinity) that continuously serve several small-scale methanol units. Produced methanol can then be trucked to end-users (e.g. industrial entities requiring methanol) in the vicinity.

Economic returns for mini-scale GTC plants may present themselves as attractive because of the relative high value of locally-produced methanol compared to the displaced methanol that may require significant transport distances to the end-user. This in turn would give “local” methanol an economic advantage, since a significant cost of methanol stems from transportation.

3.5.2.3 Ammonia (NH_3) Production

Ammonia is widely used both on its own as fertilizer or refrigerant gas, or may serve as a feedstock for fertilizer, nitric acid, or cyanide production. It is also of interest as a transportation fuel[163]. Ammonia plants (or ‘fertilizer plants’) are usually quite large, complex, and placed close to stable feeds of NG, like pipelines or NAG fields. In the case of APG, small-scale ammonia plants, on the order of 10–100 TPD, may be attractive to reduce associated gas flaring. However, the capital cost of steam reforming plants is very high for small- to medium-size applications because the technology does not scale down well.

In modern plants with high efficiency, it is estimated that it takes 25 MMBTU (around 25 MSCF per day) of gas to produce one tonne of NH_3[164]. The capital cost of ammonia plants is about 700 USD per annual tonne of fertilizer produced. Low-cost plants typically use gaseous hydrocarbons as feedstocks and have a capacity of at least 0.5–1 MMTPA. A flare, or several flares clustered together, providing a feed gas rate of 10 MMSCFD could produce 0.2 MMTPA, and cost in the range of 100 million USD. This significant investment needs to be evaluated over time as available volumes and remaining field life changes.

162 Gastechno.

163 Its price is typically linked to the price of oil.

164 Reforming is expected to require 30–42 gigajoules energy and release 1.68–2.35 tonnes CO_2 per tonne NH_3. The CO_2 removal process is expected to release 1.2 tonnes CO_2 per tonne NH_3 or 0.027–0.05 tonnes CO_2 /MCF, which makes up around one-third of ammonia production emissions. This CO_2 can be captured quite easily, in contrast to the flue gas from fuel combustion, which requires cleaning. The average emission factor of NG from flaring is around 0.01–0.015 tonnes CO_2 /MCF, making ammonia production a gas utilization option that reduces flaring but increases CO_2 emissions on site. Lifecycle emissions and displacement of ammonia production are not considered in these guidelines.

3.6 BATEA 5: Export Marketable Products – Electricity

Summary

Associated gas is recovered from the flare stack and re-routed for pre-treatment, on-site electricity production (**BATEA 1**) if applicable, (preferably) NGL separation (**BATEA 6**) and then used as a feedstock for combustion in gas engines, gas turbines, or steam turbines for electricity generation for export. This process is also commonly known as Gas-to-Wire (GTW).

Effect on Emissions

- Significantly reduces emissions of:
  - CO_2
  - PM (including BC)
  - SO_x
  - Heavy metals
- Emissions of CO_2 may be reduced through the displacement of other more carbon-intensive feedstocks used for electricity production elsewhere (e.g. heavy fuel oil, light crude oil, diesel, coal)

Benefits

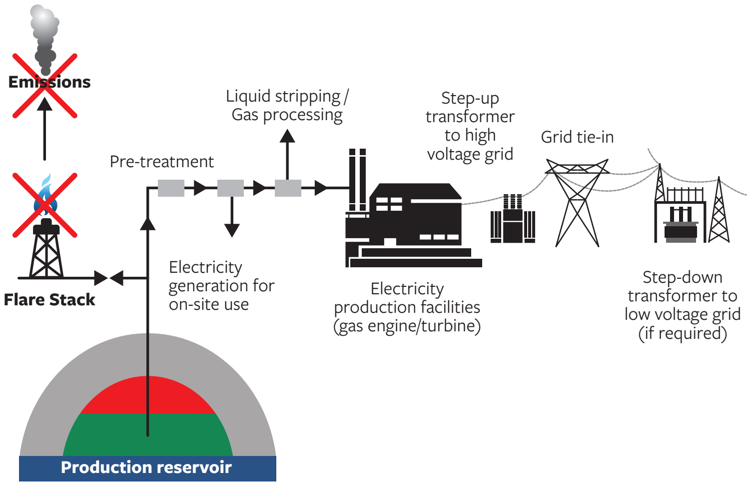
- Maximizes use of resources
- Can provide significant additional revenue from electricity sales

Applicability to the Arctic

- Remote areas without sea- or road- access, but where an electricity grid (transmission line or substation) is located within the vicinity (i.e. technically and economically feasible to reach)
- Areas of low temperature and altitude where power generation engines can achieve notably higher efficiency (but highly dependent on available APG volumes)
- Areas with high electricity tariffs where GTW could present a particularly attractive ROI compared to alternative recovery and utilization options

Infrastructure Requirements

- Gas pre-processing & conditioning equipment (depending on APG composition & impurities)
- Optional NGL separation infrastructure (**BATEA 6**)
- On-site electricity generation[165] equipment (e.g. gas engines/ gas turbines)
- Optional waste heat recovery system with steam turbine (for higher efficiency)
- Piping & related infrastructure
- Step-up transformers (as required & depending on voltage output for transmission)
- Low-, medium-, or high-voltage transmission lines to next substation or grid tie-in (depending on distance)
- Grid tie-in station or substation (as required)
- Further step-up/down transformers to electricity sales metering point (depending on sales point)



General Technical & Economic Considerations

- Possible gas composition constraints (requirements for gas conditioning - e.g., H_2S content) prior to combustion in engines or turbines
- Viability of separating NGLs from APG before combustion (depending on economic value; using only NG for power generation or using APG directly as a combustion fuel must be assessed)
- Security and volumes of APG available over time (for assessing viability and ROI)
- Re-usability and portability of power-generation equipment in mature fields (e.g. use of trailer-mounted/modular/containerized equipment and re-positioning possibilities after end of field life)
- Possibility for, and distance to grid tie-in (requires grid accessibility and permits to introduce power into system)
- Assuming grid availability, economic viability of general electricity demand and requirements (e.g. grid load factors and other related electrical parameters)
- Base-load vs. peak-load requirements (unless APG can be stored in off-peak times, electricity from APG during oil operations is typically considered a base-load option)
- Possible displacement of alternative low-carbon electricity generation sources (e.g. renewable energy sources, in particular when hydropower is used for base-load power generation)

Links to Further Information

- Exports of Oil and Gas: https://www.norskpetroleum.no/en/production-and-exports/exports-of-oil-and-gas/
- Large-scale Electricity Interconnections: https://www.iea.org/publications/freepublications/publication/Interconnection.pdf
- Development Prospects of the Association of Southeast Asian Nations (ASEAN) Power Sector: https://www.researchgate.net/publication/282860529_Development_Prospects_of_the_ASEAN_Power_Sector

[165] If a power station is to be located further away. A power generation facility for export could replace on-site generation (**BATEA 1**) in certain circumstances).

3.6.1 Technical Considerations

Following NGL separation (**BATEA 6**)[166], NG may be used as a fuel for combustion in gas engines or turbines to generate electricity for export sales, in a process known as Gas-to-Wire (GTW). GTW requires a connection to a nearby electrical grid with capacity[167] and the installation of processing and electricity-generating equipment on site. For safe and efficient operations, equipment specifications need to be based on the established gas composition and flow rates of the generators. The types of power-generating units have been covered under **BATEA 1** and will not be further addressed here, only any additional equipment and considerations applicable to the export of electricity will be discussed.

3.6.1.1 Grid Connection

Exporting electricity requires additional infrastructure beyond what is needed for electricity generation, including transformers[168] (typically step-up transformers to a higher voltage level) and transmission lines to the nearest tie-in possibility. Where an oil field is located close to a sub-station, electrical lines can be fed into the substation directly. If there is no substation in the near vicinity, then a tie-in into the closest transmission line will be required, however this will be significantly more expensive, take time to construct, and also necessitate an interruption to the power grid while construction is in progress[169].

In fields with a very small power generation potential, it may be possible to feed electricity directly into a local low-voltage (LV) grid, however feeding into a medium-voltage (MV) grid (ideally an existing substation) in close proximity to the production facilities is preferential. Generating electricity from medium- to large-sized flare gas feeds, due to the relatively large amount of electricity that could be generated, would be more ideally suited for introduction into high-voltage (HV) grids through a MV/HV substation or by constructing a purpose-built tie-in station intersecting MV and HV transmission lines. Particular attention concerning the economic viability and other parameters compared to the alternatives will be required, however this option could prove itself particularly attractive in remote[170] oil fields that have substations located in the near vicinity or with electrical transmission lines passing by.

3.6.2 Investment Considerations

In general, it can be considered possible to produce electricity at a low cost since the energy source is essentially available at no cost, and therefore, GTW can be considered competitive relative to other power generation sources, including thermal.

Additional infrastructure, including DC/AC converters, transformers, transmission lines and a grid tie-in connection will be required, therefore equipment costs could construe a key element in economic viability. The amount of electricity produced will ultimately influence the costs required to export it, and individual site-specific conditions will need to be assessed on a case-by-case basis. Potential power losses along transmission lines before custody metering must also be considered. The key determinants of costs related to the construction of ancillary facilities will also depend on voltage requirements, distance, and terrain. Other factors including climate, labour costs[171], the degree of competition among contracting companies, safety regulations, population density, and rights-of-way may also cause construction costs to vary significantly from one region to another. With regards to operating costs, it is assumed that both generators and the transmission power lines require an annual expenditure of around 3% of the initial investment, however suppliers often offer routine maintenance programs.

The price of gas generators increases almost linearly with size/capacity, providing limited economy of scale, however it can be considered more cost efficient to install, for example, a single 5 MW unit than a set with more adjustable capacity (5 x 1 MW units). Capital expenses can be estimated at approximately 1 million USD/MW for generation and ancillary equipment, although costs will vary based on the requirement for and distance of transmission lines to the nearest substation or grid.

The efficiency of generators (whether gas engines or turbines) is another important aspect to consider when performing a techno-economic analysis, as the conversion efficiency (from feedstock fuel to power) can range from 30–60% depending on the technology. Open-cycle turbines will generally have conversion efficiencies in the 30–40% range, whereas gas engines can achieve conversion efficiencies in the 50%–60% range. The choice of technology (and therefore efficiency) will depend on the achievable electricity price (feed-in tariff) relative to the cost of fuel.

166 Depending on NGL content and market value/off-takers.
167 It is important that the grid where power is fed into has the capacity to accept the additional electricity.
168 Often multiple transformers will be required to ensure backup voltage transformation. Lead times on transformers can be long if a replacement is required quickly.
169 A temporary bypass could be constructed, however at additional cost.
170 In particular fields far from existing pipelines, processing plants, and/or without adequate road or other accessible export routes.
171 Local economic conditions, especially labour costs, could present itself as an important factor depending on the location of the field.

Assuming an abundance of fuel and a relative low price per kWh of electricity, it may in certain instances make more economic sense to deploy cheaper, but less efficient power generators (leading to more CO_2 emissions). In other cases, a higher electricity price may allow for deployment of more efficient generators, and possibly even allow for the economic deployment of a combined-cycle setup containing waste heat recovery units (**BATEA 1**). A combined-cycle setup (where waste heat is used to power a steam turbine) may allow for conversion efficiencies as high as 50–60%[172].

One of the most important considerations in deciding to export electricity is the reliability of supply. Security of supply is especially crucial in cases where the generated electricity becomes the off-takers' only source of power and heat (which cannot be economically stored). Given the real risk of power system failure, off-takers solely reliant on electricity from site should be equipped with back-up generators and an adequate amount of fuel (e.g. diesel) to provide power while the system is restored. Additionally, intraday variation of associated gas production should be buffered on site as much as possible.

GTW technologies may become uneconomical due to the cost of balance of plant systems for smaller units, and lack of long-term incentives or power purchase agreements for electricity originating from APG utilization. GTW should only be considered for larger developments (>5 MMSCFD) from one or several gas streams clustered together.

[172] https://www.sciencedirect.com/science/article/pii/S1364032117309206

3.7 BATEA 6: Reduce Share of Heavier Components – NGL Separation

Summary

Associated gas is recovered from the flare stack and re-routed for pre-treatment (pre-processing & conditioning) before the NGLs are processed and separated into liquid petroleum gas (LPG) and condensate. NGLs can be used for oil spiking, or be exported and sold (optionally by fractionation of components into individual product streams according to market requirements). The remaining dry gas can be utilized (as per the other BATEA), or if there is no feasible alternative, sent to be flared.

Applicability to the Arctic

- Remote locations where there is no feasible solution for exporting APG in its entirety (available export possibilities for NGLs (e.g. road, sea) are still required)
- Marginal fields where NG export is not feasible, but where NGL demand (heating, cooking, transport fuels) exists, or could be created by replacing other hydrocarbon fuels

Effect on Emissions

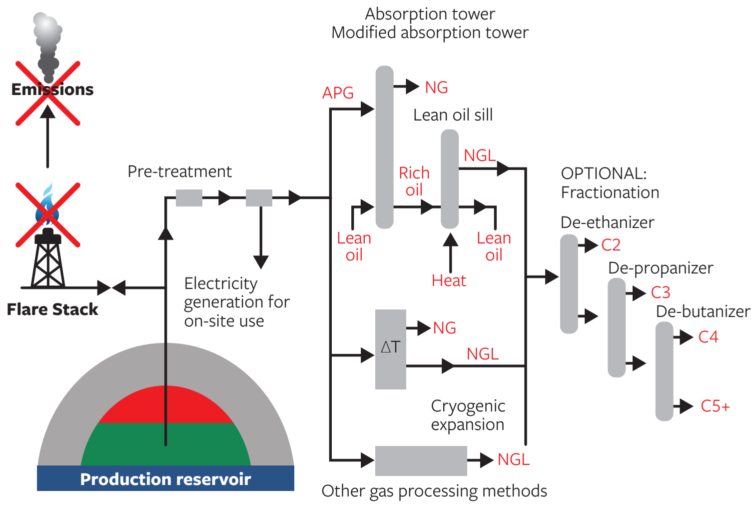
- Significantly reduces emissions of:
  - PM (including BC)
  - SO_x
  - Heavy metals
- Emissions of CO_2 are also reduced

Benefits

- Makes rational use of heavier hydrocarbons
- NGL export sales creates added economic value (e.g. LPG, condensate/natural gasoline)
- Recovered NGL can be used for oil spiking (to increase API gravity of oil, ultimately producing more barrels)
- Dry NG can be utilized according to other BATEA

Infrastructure Requirements

- Gas pre-processing & conditioning equipment (depending on APG composition & impurities)
- NGL separation infrastructure (e.g. cryogenic expansion chambers, absorption towers, lean oil sills, etc.), depending on efficiency & compositional requirements
- Optional fractionation towers for further separation of NGLs into specific components
- Piping & related infrastructure (e.g. heating, lean oil, other required inputs)
- NGL handling facilities (e.g. LPG/condensate storage vessels, loading gantries, and if required, spiking equipment)
- NG handling facilities (e.g. flare lines, re-injection, or export infrastructure, if feasible according to other BATEA)



General Technical & Economic Considerations

- Possible gas composition constraints for economic viability (amount of NGLs/heavier hydrocarbons in APG; ROI analysis)
- Economic viability of separating NGLs from APG prior to on-site use and using only dry NG gas for electricity & heat (depending on market value and availability of off-takers of NGLs – **BATEA 1**)
- Requirements for gas conditioning prior to introduction into NGL separation processing facilities (e.g. H_2S content)
- Security of APG supply volumes over time (equipment sizing, clustering potential, investment considerations)
- Technology selection (costs, required separation efficiency, purity of product streams)
- Market demand and prices (economic viability)
- Spatial requirements (large area needs for processing facilities; onshore/offshore constraints)

Links to Further Information

- Gas Processing & Fractionization: https://www.ihrdc.com/els/po-demo/module14/mod_014_02.htm
- NGLs – The Basics: https://www.eia.gov/conference/ngl_virtual/eia-ngl_workshop-anne-keller.pdf
- Improved Absorber-Stripper Technology for Gas Sweetening to Ultra-Low H2S Concentrations: https://www.researchgate.net/publication/241902570_Improved_Absorber-Stripper_Technology_for_Gas_Sweetening_to_Ultra-Low_H2S_Concentrations

3.7.1 Technical Considerations

Natural gas liquids (NGLs) are valuable, naturally-occurring components of APG. Separating NGLs from a flare gas stream is a particularly important consideration when evaluating alternatives to flaring, specifically for the purpose of reducing BC emissions[173]. NGLs, including propane, butanes, pentanes, and other complex hydrocarbons, are responsible for a significant share of BC emissions from flaring and removing them from the flare gas stream is considered an effective mitigation approach (however, the effect on BC reductions will depend on the APG composition[174]).

Leveraging existing NGL separation infrastructure or creating a new liquid hydrocarbon stripping infrastructure must be considered, particularly when there is no other feasible alternative for flare gas recovery in its entirety. A scaled-up commercial deployment of emerging technologies for liquid recovery from a flare gas stream could provide significant reductions in BC emissions. Additionally, hydrocarbon liquid recovery projects can generate significant economic opportunities[175].

Each gas reservoir exhibits a unique composition. Heavy components can be removed (condensed) as a liquid from a hydrocarbon stream that it is typically in a vapor phase (i.e. associated gas) and then transported using trucks, containers, or other suitable export vessels.

The remaining dry gas (mainly methane with ethane – as desired – and minute traces of other heavier hydrocarbons) can either be flared, used on-site, or exported. Thus, NGL recovery can be paired with other technologies discussed in this document to utilize the remaining dry gas and/or produce additional revenue streams.

NGL removal can be performed prior to:

- Use of APG as an on-site energy source (**BATEA 1**).
- Reinjecting APG (**BATEA 2**).
- Natural gas export (**BATEA 3**).
- Export of liquid hydrocarbon products (**BATEA 4**).
- Export of electricity (**BATEA 5**).
- Combustion optimization (**BATEA 7**).

When APG is used as an on-site energy source, dry gas can be combusted in engines and turbines[176]. However, if there is no solution for using dry gas[177], facilities can be designed to just recover heavier hydrocarbons and flare the residual dry gas[178]. While flaring dry gas will still result in CO_2 emissions, BC emissions will be limited (compared to flaring APG).

3.7.1.1 Gas Processing

Processing separates the wet[179] (rich) APG mixture into a dry (lean) gas[180] stream and another heavier hydrocarbon mixture consisting of NGLs. NGL products (e.g. LPG, condensate) can be recovered by gas processing or the use of micro-condensation units[181] and the required technology will depend on the specific gas composition, available volumes, and in particular, the desired degree of separation (which will primarily depend on market requirements/economic value of products)[182]. Separation of NGL components from the wet gas stream (and from one another) can be accomplished with membranes[183], refrigeration, or absorption systems[184]. Furthermore, fractionation towers allow for the distillation of individual NGL components (in series).

Refrigeration. Refrigeration (via refrigeration units or cryogenic expansion units) is the most common technique in gas processing for NGL separation and usually better suited for smaller scale applications[185]:

173 Research and associated pilot projects have shown that the formation of BC from flaring is correlated with the concentration of condensable, high-value hydrocarbon gases such as butane, pentane, or hexane in the flare fuel.
174 Specifically, the amount of heavier hydrocarbons in APG, which can vary significantly from field to field.
175 The potentially high value and readily condensable liquids from flared VOC-rich APG could add potentially significant revenues and profits.
176 Dry natural gas is cleaner burning than heavier hydrocarbons and will result in lower emissions on-site.
177 Where there is no feasible economic utilization.
178 While this option is not preferable, stripping heavier hydrocarbons before flaring residual dry gas would have a considerable effect in reducing BC emissions. It should only be considered where the only other option would be flaring of the APG.
179 A wet gas stream contains methane plus a mixture of the next heavier hydrocarbon molecules: ethane, propane, butanes, pentane, and some heavier molecules.
180 Dry stripped gas contains a very high percentage of methane with a controlled hydrocarbon dew point.
181 Micro-condensation units are currently undergoing testing.
182 See Section 2.2 on gas composition for further consideration.
183 Separation of heavier NGLs from lighter gas can be accomplished with pressurized membrane separation systems.
184 Liquid absorption (lean- and refrigerated lean-oil absorption) solvents and solid adsorption materials (silica gel, molecular sieves, and activated carbon) are very energy intensive, bulky, and expensive. Even though they could be considered for small facilities in remote areas, they are increasingly being replaced by expander units.
185 NGL expanders of a scale smaller than ~25 MMSCFD are not commercially available and therefore often reserved for larger scale operations; typically, ~75 MMSCFD is considered the low end for commercial design.

- **Mechanical Refrigeration Units (MRUs)**[186]: Refrigeration plants chill the incoming NG stream with an external, typically propane-based, refrigerant system. The condensed NGLs are separated in a three-phase cold separator, where injected glycol is removed from the NGLs. The product's cold residue gas exchanges heat with the warm feed NG stream resulting in pre-cooling. This technology can be applied to a very rich gas stream, low inlet gas pressures, and a wide range of gas rates. The capital and operation costs required are relatively low for this technology, but ethane is usually not separated from the gas stream and propane is only partially separated.
- **Joule-Thomson (JT) Units – Valve Expansion or Low Temperature Separation (LTS)**: JT plants use a self-refrigeration system that uses a drop in gas pressure to trigger gas expansion and create a cooling effect. The unit condenses heavy hydrocarbons out of the gas to meet required gas pipeline specifications. Excess liquids that can otherwise condense, drop out, and create problems during pipeline transport, are recovered and stored for fractionation into sellable hydrocarbon components. These automatically-operated JT units are more suitable when the inlet gas pressure is very high. The capital and operating costs are higher than for the external refrigeration technology, except when they are purely mechanical[187].
- **Joule-Thomson (JT) Units – Cryogenic Expansion or Turbo Expansion**: Cryogenic plants use a self-refrigeration system to recover ethane from the NG stream with virtually no loss of propane and heavier components[188]. Cryogenic plants operate using turbo-expansion to chill the feed gas in several steps to significantly lower temperatures than possible with standard refrigeration plants. A rich gas is cooled to a value between −138°C (the freezing point of iso-butane) and −89°C (the boiling point of ethane) leaving only methane in the overhead and all other hydrocarbon components as a liquid[189]. After the methane has been extracted, the liquid passes to the next vessel which is maintained at a temperature that will allow ethane to boil off, but keep the remaining hydrocarbons in liquid form.

Gas is typically chilled in several steps. Using two or more refrigeration cycles in series allows the gas to reach −68°C[190], compared to a conventional propane- or ammonia-based refrigeration cycle which uses one step to reduce the gas temperature to around −40°C. To reach the very low temperatures necessary for NGL processing, plants generally pre-cool the gas with refrigeration and then use a "turbo-expander" to "make the gas do work"[191]. A turbo-expander uses a pressure drop in the gas to spin a turbine wheel[192]. Turbo expanders typically represent the highest capital cost, but the lowest operating cost.

Cryogenic expansion is more flexible than other refrigeration technologies in terms of product specifications, in particular for ethane recovery/rejection, and recovery of C_3+ hydrocarbons. These automatically-operated JT units can be applied to lean gas streams, low inlet gas pressures, and very low gas rates. The capital and operating costs are higher than for the external refrigeration technology, but it can separate propane and most of the ethane[193].

Absorption. NGL separation can also be accomplished using absorption (including modified absorption processes). Lean oil absorption plants operate on the same principle as amine treating plants (reviewed in Section 2.2). However, instead of using an amine solution to selectively absorb H_2S or CO_2, a lean oil is used to selectively absorb heavier hydrocarbons[194].

An absorption plant begins with a mechanical separator followed by a contactor tower and a second mechanical

[186] Simplest and most direct process performed by passing counter-current gas streams through a gas-to-gas heat exchanger and then external or mechanical refrigeration, which is supplied by a vapor-compression cycle that typically uses propane as a refrigerant or working fluid.

[187] Based on expansion, cyclonic gas-liquid separation, and recompression in a compact tubular device.

[188] If ethane is separated along with the rest of NGLs it can decrease the price per litre of the NGL mixture, however, it can also substantially increase the volume of NGLs. Separation of ethane from methane is relatively difficult, and in general requires a cryogenic unit, making it much more expensive due to the need for more severe processing conditions to achieve high recovery rates. If left in the NG stream, ethane will decrease purity and increase the heating value, making the NG more challenging for gas utilization options like power generation.

[189] Temperatures colder than −138°C will result in iso-butane freezing into a solid. If there is any H_2O present, temperatures below 0°C will cause ice formation. If there is any CO_2 in the stream, temperatures below −56.6°C will result in dry ice formation. The direct transition from a gas to a solid and back occurs at a relatively high temperature and pressure, and can easily plug up piping, pumps, heat-transfer equipment, and vessels, even at a very low CO_2 concentrations (the common limit for CO_2 into a cryogenic process is 50 mg/L).

[190] Refrigeration cycles are nearly an isobaric process.

[191] The Joule-Thompson effect says that an isenthalpic pressure drop across a restriction will result in lower temperatures. https://www.sciencedirect.com/topics/engineering/low-temperature

[192] The work that the gas exerts on the wheel results in a large change in enthalpy that is represented by both dropping pressure and dropping temperature. These turbines are usually driving a compressor that will then (in a polytropic process) replace some of the pressure used in the turbine.

[193] Depending on the gas composition and the temperature reached, the chilling process will lead to varying degrees of condensation, and composition changes to the two resultant product streams. Typically, a portion of the propane and butanes, and essentially all the pentane and heavier hydrocarbons, will condense. By sufficiently reducing the temperature of the gas, ethane will also condense, allowing for recovery of 90–95% of the ethane originally in the gas.

[194] As is the case with amine treating, the working fluid becomes saturated and must be regenerated.

separator. The raw stream is brought into the bottom of the contactor tower and a chemical with an attraction to heavier hydrocarbons (a "lean oil") is pumped into the top. The pentane, butane, some of the propane, and a portion of the ethane is then absorbed by the lean oil. The methane, most of the ethane, and rest of the propane not absorbed will then exit the top of the tower, towards the outlet separator. The new absorption mixture (now called "rich oil") can then be fractionated to separate the hydrocarbon mixture into individual components. In some circumstances, absorption processes can be modified to increase recovery of NGLs:

- **Absorption**: Separation of NGLs from a wet gas stream is achieved with a dehydration agent (typically an absorption oil). The wet gas is first passed through an absorption tower and brought into contact with "lean oil"[195]. A high proportion of the NGLs are absorbed, or "soaked up", by the lean oil creating a new "rich oil" mixture consisting of absorption oil plus propane, butanes, pentanes, and other heavier hydrocarbons. The newly formed mixture is then fed to lean oil stills and heated to remove the NGLs[196]. The process allows for recovery of around 75% of the butanes and 80–90% of the pentanes and heavier molecules from the gas stream[197].
- **Modified Absorption**: Depending on requirements, a modified absorption process can be used to increase the absorption or recovery rate of NGLs from the wet gas stream. In this refrigerated absorption process, propane recovery can be upwards of 90%, while around 40% of the ethane can also be extracted if required. Extraction of other heavier NGLs include butanes, pentane, and heavier hydrocarbons can be close to 100% using the modified absorption process.

3.7.1.2 Fractionation

Fractionation separates out the individual NGL components from wet gas in a series of steps, where each fractionization (distillation) tower separates out a lighter hydrocarbon component (i.e. a de-ethanizer separates ethane, de-propanizer separates propane, etc). This could be used as an optional step following general refrigeration and absorption NGL separation by other methods (as described above), that allows the NGL mixture to be further split into specific hydrocarbon components for individual product streams[198]. Depending on the desired specifications, a fractionation train consisting of any number of fractionation towers[199] (typically 2 to 3 "stills") can be used to separate the inlet stream of mixed NGLs into individual products for separate marketing or use (e.g. ethane, butane, propane, a mixture of butane and propane as LPG[200], and the residual gas condensate). This allows for the sale of pure products directly to markets or export, and is a relatively quick, cost-effective way to optimize product value.

3.7.2 Investment Considerations

3.7.2.1 Gas Processing

For the purpose of recovering liquids from smaller APG flares, a typical solution would include one that can handle an average quality APG and be easily deployed. A skid-mounted, automatically-operated, MRU- or JT/LTS-based refrigeration unit is generally the most suitable technology for NGL recovery, except where cryogenic or turbine expansion methods are needed for ethane rejection.

Smallest units are in the range of 0.1–0.2 MMSCFD[201], and industrial larger-scale systems start at 10 MMSCFD[202]. Equipment costs for a typical APG composition of NGLs with a total APG feed of 5–10 MMSCFD, can be estimated to be in the range of 3–10 million USD[203] but will vary depending on site-specific parameters.

In general, there are large differences among NGL recovery systems in terms of investment. Installing simple NGL recovery stripping for C_5+ hydrocarbon recovery is fairly inexpensive. Since heavier liquids can also be blended into crude, the economics of this option are favourable. Recovering C_5+ products could be viable for volumes from 0.1 MMSCFD and cost 0.5–2 million USD/MMSCFD. Mechanical NGL recovery of C_3+ hydrocarbons also has a very short payback time and for volumes from 1–10 MMSCFD, has an estimated cost of 2–5 million USD/MMSCFD. Cryogenic (C_2+) recovery is the most expensive.

[195] The rich gas with hydrocarbon vapors enters the bottom of the absorber column, flows upwards, and comes in contact with counter-flowing lean oil, which preferentially absorbs the vapors from the gas, becoming enriched oil.
[196] The enriched oil is sent to a stripper where the absorbed vapors are removed by heating the rich oil and re-vaporizing the absorbed vapors. The rich oil becomes regenerated as lean oil and is recycled by the absorber to complete the process loop.
[197] The vaporized "vapors" are essentially liquified and can then be transferred to storage.
[198] According to market requirements, liquid hydrocarbons could be separated to into specific mixtures (e.g. LPG with 70% propane, 30% butane).
[199] These columns can be controlled to produce pure vapor-phase products from the overhead by optimizing the inlet feed flow rate, reflux flow rate, reboiler temperature, reflux temperature, and column pressure.
[200] In the specified- or required-LPG composition. Depending on the APG composition and the LPG composition, some residual propane or butane may result as well.
[201] Carbon Limits project-specific information.
[202] Recovering NGLs from smaller streams is usually performed using technologies such as straight refrigeration units or JT plants. Skid-mounted plants may be as small as 10–50 MMSCFD.
[203] Based on proven technology and Carbon Limits project-specific information.

If ethane is recovered, it is very expensive to transport and store because it has a larger volume than other NGLs, and requires high pressure or cryogenic tanks. Furthermore, ethane has a relatively low market price. In general, ethane recovery is not suggested unless the lean gas is going to be used for gas combustion. Other options for NGL recovery depend on the latter use of the APG (e.g. fractionation.)

Ancillary costs (e.g. compressors, pipelines, NGL/condensate stabilizer systems, storage, and loading facilities) will need to be assessed+[204] and could add significant costs to the overall project. The prefabrication, construction, and material costs[205] for NGL separation are site-specific and depend on a number of factors including:

- APG pressure, which will impact compression requirements.
- Size of the installation; smaller facilities typically have a larger cost per unit treated gas than larger ones.
- Degree of NGL separation (including the purity and number of products), which is highly dependent on the market value of end-products, and in turn influences the types of technology applied.
- Methods of NGL export (e.g. pipeline, cylinder, etc.).

Separating NGLs from APG will allow for easier transportability off-site, however a challenge with NGLs is they are expensive to handle, store, and transport compared to refined products[206]. While off-takers usually take delivery and custody of NGLs at the separation facilities, it could be feasible to transport[207] NGLs closer to more valuable market outlets, central storage facilities, or directly to end-customers (which could significantly affect investment costs). As they are highly flammable, it would necessitate the use of special trucks, ships, and storage tanks, which would increase overall investment costs. If no market outlets are available, or if NGL sales are technically or economically unfeasible, they can alternatively be blended into crude oil.

3.7.2.2 Fractionation

The extraction of heavy hydrocarbons in APG can create significant added value, especially if they are separated and marketed as individual products[208]. Sold separately, these NGLs have a variety of different uses, including as solvents for EOR in oil wells, increasing number of oil barrels[209] (e.g. blending the condensates with oil), providing raw materials for oil refineries or petrochemical plants, and as other sources of energy[210]. Off-takers require specific NGLs for a variety of applications, including:

- Ethane or ethylene for plastics production, petrochemical feedstock, anti-freeze, and detergents.
- Propane for residential and commercial heating, cooking fuel, and as a petrochemical feedstock.
- Butanes for use as refinery- and petrochemical-feedstocks, gasoline and propane blends, aerosols, and refrigerants.
- Pentane for use in natural gasoline and ethanol blends, as a blowing agent for polystyrene foam, and for bitumen production in oil sands.
- Pentane plus (also known as natural gasoline) for blending with vehicle fuel, and bitumen production in oil sands.

Applicable volumes for fractionation typically range from 10–50 MMSCFD and cost around 1.5–3 million USD/MMSCFD. Investment considerations will depend on the revenue achievable from individual NGL sales.

NGL fractionation uses simple principles but consumes large amounts of energy for the re-boiling of the fractionation columns (e.g. about 300 kWh/tonne NGL or around 3% on an auto-consumption basis[211]). There are several known techniques to minimize primary energy consumption, including process heat integration, and combining the fractionation of NGL with co-generation. These techniques can be improved with the recovery of waste heat from an external source, such as gas turbine exhaust gases, if available close to the fractionation unit.

[204] Will vary depending on a specific field's characteristics, in particular, location and distance to market.
[205] https://www.cbi.com/getattachment/81764aaa-9fed-472f-9e55-7cbd63d3938f/New-NGL-recovery-process-provides-viable.aspx
[206] NGLs require high pressure and/or low temperature to be maintained in their liquid state for shipment and handling.
[207] Should be taken into careful consideration at offshore facilities where gas is processed on site.
[208] Fractionation costs will primarily depend on the quantity of gas condensate to be processed and the number of fractionation towers required.
[209] Recovered NGLs could also be injected into an oil stream (i.e. oil spiking) and would have two benefits: increasing the API gravity of the oil, potentially increasing its netback value per barrel, and increasing the volume (number of barrels) of oil.
[210] Including combustion in heating applications, or blending into vehicle fuels.
[211] http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/2005/SDS_TIF/050215.pdf

3.8 BATEA 7: Optimize Combustion Conditions – Advanced Flare Design

Summary

Associated gas is recovered from the conventional flare stack and sent to an appropriately-sized and well-maintained knockout drum to remove heavier hydrocarbons from the flare stream before being directed to an improved flare stack where it is combusted using advanced flare tip and flare ignition technology.

Applicability to the Arctic

- Remote areas where there is no feasible technical or economic possibility for the recovery of APG for any other purpose
- Areas with below-freezing temperatures where air-assisted flares could present a good alternative to steam-assisted flares that plug up under freezing conditions (depending on the flare gas composition)

Effect on Emissions

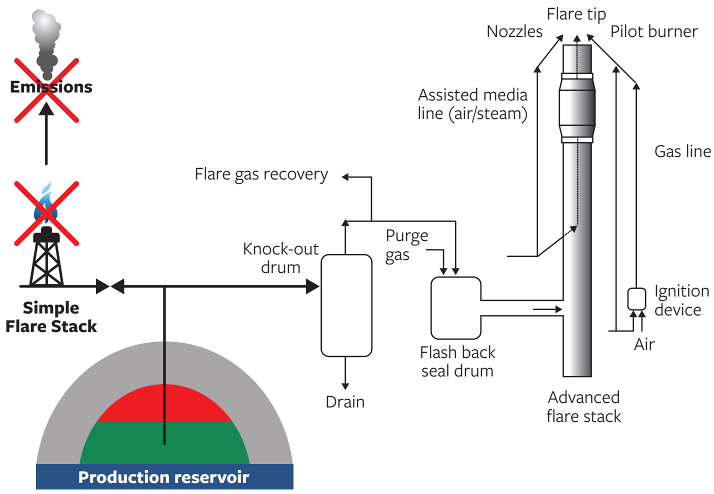
- Depending on design, can reduce emissions of:
  - PM (including BC)
  - CH_4 and non-methane VOCs
  - Other hazardous pollutants
- May conversely increase CO_2, NO_x, or other emissions (depending on design)

Benefits

- Provides technical alternatives for more environmentally-friendly flaring practices
- Provides a means to reduce BC emissions from non-routine, intermittent flaring

Infrastructure requirements:

- Knockout drum (to retrieve hydrocarbon liquids)
- Flash back seal drum (with consideration for equipment to reduce the need for purge gas)
- Advanced flare designs:
  - Pressure-assisted
  - Air-assisted
  - Steam-assisted
  - Sonic
  - Staged
  - Enclosed
- Advanced ignition system (manual/automatic pilot, ballistic)
- Measurement and control systems (e.g. for ignition and monitoring pilot burners)



General Technical & Economic Considerations

- Safety, environmental, and social requirements (safety is the primary objective)
- Geographic location and ambient conditions (e.g. onshore/offshore, wind, temperature)
- Selection of technology based on full range of flare operating conditions (e.g. gas flare rate, gas composition, and pressure can impact emissions production)
- Design and maintenance requirements (e.g. if not sized or maintained properly, inefficient combustion, smoke formation, and BC emissions can result)
- Technology cost (wide variation between flare system designs)
- Utility availability and costs (implications for equipment, installation & maintenance costs)
- Cost vs. revenue considerations (only offers non-financial benefits; no economic benefit to operator)

Links to Further Information

- Flare Gas Design for Efficient Control & Operation: https://www.flowcontrolnetwork.com/flare-gas-system-design-for-efficient-control-and-operation/
- Flare Systems – Design Alternatives, Components Key to Optimum Flares: https://www.ogj.com/articles/print/volume-90/issue-47/in-this-issue/refining/flare-systems-1-design-alternatives-components-key-to-optimum-flares.html
- Parameters for Properly Designed and Operated Flares: https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf
- Black Carbon Particulate Matter Emission Factors for Buoyancy-Driven Associated Gas Flares: https://www.researchgate.net/publication/223963699_Black_carbon_particulate_matter_emission_factors_for_buoyancy-driven_associated_gas_flares

3.8.1 Technical Considerations

During gas flaring, combustion primarily generates water vapor and CO_2, but also a number of pollutants including PM (including BC), NO_x, and SO_x. BC formation is the result of a very complex process, involving several steps of chemical and physical particle growth and destruction[212], governed by conservation of mass, momentum, and energy principles. This in turn is influenced by the exit velocity of gas from the flare[213], flare gas composition, flame stability[214], flare stack diameter, flame tip design[215], and other flare system design parameters, as well as wind conditions and other external influences. The final amount of BC emitted from a flare is a result of competing effects related to the formation and oxidation of these particles. Experiments have shown that BC formation tends to increase with gas density and flare tip diameter, but is most strongly correlated with gas heating values.

Flare vendors have developed technologies that burn gas in a safe and environmentally-friendly way. Historically, the focus of technical improvements has been on achieving high combustion efficiency and smokeless operation. Over the last 50 years, many technologies have been developed to achieve these goals, however in recent times, there has also been an increased focus on reducing pollutant emissions, including NO_x, SO_x, and particles, such as BC.

The selection and design of flare systems depend on their specific applications. Technical and safety criteria, as well as relevant environmental requirements and criteria, impact flare system choices. In this context, it is important to note that environmental requirements are never emphasized at the expense of safety. In addition, costs are critical factors in selecting the design of the flare system. For onshore flare systems, potential noise and light impacts on neighbours are also a consideration when designing the system.

Detailed information on high-pressure flares, low-pressure flares, vent flares, and flares with specific applications (e.g. maintenance flares, tank flares, H_2S flares) must be gathered before deciding on a strategy to reduce BC with combustion optimization. An analysis of current flare technology trends indicates that some new facilities are having flare gas recovery systems installed and operate without a pilot flame. In general, most older facilities still use pilot flames, even if most of the APG is recovered and utilized. Many older facilities and most newer facilities, both onshore and offshore, use of N_2 as a purge gas. Offshore practices lean towards using a higher gas velocity for improved combustion efficiency. Onshore, many facilities built within the last decade, use only simple and non-advanced flares. It is important to note that technologies used in Arctic regions show a wide range of designs, custom installations, and site-specific conditions.

Despite the increasing amount of published test data for gas flaring emissions, there is currently limited information on the mitigation potential of various technologies, particularly regarding BC. However, based only on visual assessments (i.e. smoke), the proper design and maintenance of flares will likely have a significant impact on BC emissions. Improving the quantitative understanding of BC emissions from gas flares would support the identification of affordable, short-term, and large-scale BC abatement options. The current BATEA is thus based on qualitative improvements reported by operators and flare combustion experts. Compared to other BATEAs presented in this document, information on BC reductions achievable through optimization of combustion conditions is relatively limited. Various international research groups are actively working to understand the relationship between the complex formation process of particulates and turbulent conditions in gas flares. Although the governing parameters are not yet fully understood, some important relationships have been identified.

3.8.1.1 Advanced flare system technologies

Decreasing flare emissions can be achieved by installing more appropriate or advanced flare systems. A wide variety of flare types are currently available from different flare manufacturers. The flare system selected for each application depends mainly on the gas stream rate, composition, pressure, utility costs and availability, and any safety, environmental, and social requirements. It is generally reported that flares can achieve smokeless operation and emit less than 2% unburned hydrocarbons

[212] Although the terms 'combustion efficiency' and 'destruction efficiency' are often used interchangeably, they represent different measurements. Destruction efficiency is a measure of the amount of original hydrocarbons destroyed during combustion, while combustion efficiency is the percentage of original hydrocarbons that burn completely to CO_2 and water vapor. Destruction efficiency is always larger or equal to combustion efficiency.

[213] Diffusion flames receive O_2 for combustion via the diffusion of air into the flame from the surrounding atmosphere. The high fuel flow rate in a flare may require air faster than simple gas diffusion can supply. This deficiency deserves consideration and suitable flare tip designs should be selected.

[214] Flame stability can be enhanced by advanced methods such as the incorporation of flame holder retention devices into the flare tip inner circumference. Burner tips with modern flame holder designs can have a stable flame over a wide range of flare gas exit velocities. In other words, in modern flare systems, the maximum capacity of a flare tip is usually limited by the vent stream pressure available to overcome the system pressure drop – not the flare stack or tip. As an indication, elevated flare diameters are sized to provide vapor velocities at a maximum throughput of about 40% of the sonic velocity of the gas subject to the constraints.

[215] In most cases, optimal design of the flare tip depends on local installation and site-specific conditions.

(including methane) when properly sized, maintained, and operated. On the other hand, poor design or poor maintenance can lead to over 30% unburned hydrocarbons and significant smoke formation.

Available flare systems, inclusive of advanced technologies, include:

- **Sonic/High-pressure:** When the waste gas is delivered at high pressure, sonic flares can be used to achieve smokeless/low radiation flaring by converting the internal energy of the high-pressure gas to kinetic energy, thereby increasing mixing and air entrainment. Multi-point sonic flare technology reduces low-pressure zones and burn-back inside the flare to increase efficiency and extend flare tip life[216].
- **Staged:** Groups of two or more flares or burners are controlled so that the number in operation is proportional to the relief gas flow.
- **Enclosed Ground Flares:** Multi-burner flares are designed specifically for application in O&G operations. Enclosed ground flares are more sophisticated than open pipe flares or shrouded ground flares. Their environmental performance is based on consistent pressures and flow rates. More advanced enclosed ground flares can achieve higher environmental performance but may still be specifically designed to function within a narrow operating window.
- **Steam/Water/Air-assisted:** Depending on the waste gas composition and utilities available for the flare, air- or steam-assisted tips can be used to increase mixing and air entrainment, actively promoting smokeless combustion of low-pressure waste gases. Steam-, water- and air-injection is often used in flares. High-velocity nozzles, usually positioned around the outer perimeter of the flare tip, increase gas turbulence in the flame boundary zones by drawing in more combustion air and improving combustion efficiency. In large flares, nozzles can also inject concentrically into the flare tip. The high-velocity injection into a flare flame can produce other results in addition to air entrainment and turbulence[217]. When using steam-, water- or air-assisted flaring, the amount of the assistance medium used should be controlled to minimize risks of under- and over-use of the medium.

All of the above are considered mature technologies and have been extensively used in operations globally. With the exception of ground flares, they can also all be installed offshore. For steam-assisted flares, freezing weather conditions in the Arctic regions could, however, cause the steam to condense and freeze, plugging up the flare tip. In this case, it is common to turn off the center steam and increase the purge gas flow rate. Air-assisted flares would represent a good alternative option in these conditions.

3.8.1.2 Diffusion Flame

In most flares, combustion occurs by means of a diffusion flame. In this set-up, air diffuses across the boundary of the combustion product stream towards the center of the fuel flow, forming an envelope of combusting gas around a fuel gas core. On ignition, this mixture creates a stable flame zone above the tip of the burner. Smoking can occur due to a deficiency of oxygen (O_2) or cooling of the carbon particles below their ignition temperature. In larger diffusion flames, a vortex can form around the burning portion of the gas which cuts the O_2 supply and causes localized instability or flickering of the flame that can be accompanied by BC formation. Ensuring adequate air supplies and mixing are therefore essential for minimizing smoke and maximizing combustion. The various flare designs differ primarily in their accomplishment of mixing.

3.8.1.3 Flare System Controls

Flare system control can be completely automated[218] or completely manual. Components of a flare system that can be controlled automatically include the auxiliary gas, the ignition system, and steam injection (if steam is used). Fuel gas consumption can be minimized by continuously measuring the vent gas rate and heat content, and automatically adjusting the amount of auxiliary fuel to maintain the required minimum total gas. Automatic ignition panels sense the presence of a flame with visual temperature measurements or thermal sensors, and reignite pilots when flameouts occur. Fuel consumption by the pilot flame should be minimized to the extent possible without compromising the ability to ignite the flare under all conditions.

[216] High-pressure nozzles create a sonic gas flow that increases air aspiration and greatly decreases radiation from the flame. Sonic flares combined with assisting media have been shown to reduce heat radiation and smoke creation.

[217] There are different mechanisms and theories to explain how steam reduces smoke formation. One theory proposes that steam minimizes polymerization by separating hydrocarbon molecules, forms oxygen compounds that burn at a reduced rate, and creates a temperature unconducive to cracking and polymerization.

[218] Automatic control based on flare gas flow, flame radiation, or other methods such as observing the flare by camera or thermal imaging, are effective for modern flares. Even the steam flow (for steam-injected flares) can be controlled in this way to maintain smokeless operation, provide a faster response to the need for steam, and a better adjustment of the quantity required. To optimize steam usage, infrared sensors that detect flame characteristics and adjust the steam flow rate automatically to maintain smokeless operation, are also available. Steam consumption can be properly minimized by controlling flow based on vent gas flow rate or visual smoke monitors.

3.8.1.4 Knockout Drum Design

The design and maintenance of a knockout drum can also impact BC emissions from flaring. A knockout drum is a separator used to remove any liquids from the gas stream prior to being flared. If it is not sized or maintained properly, some liquid droplets may be entrained by a waste gas stream, leading to smoke formation. Micro-condensation units (**BATEA 6**) to aid in recovering liquids, could be considered as a BC emission reduction option.

The economics of vessel design dictates the choice between a horizontal or vertical drum[219]. When a large liquid storage vessel is required and the vapor flow is high, a horizontal drum is typically more economical. Vertical drum separation is used when there is small liquid load, limited plot space, or where ease of level control is desired. It is assumed here that the drum is not sized for emergency releases and that liquid flow is minimal. Properly sizing and operating knockout drums can also have an immediate effect on BC emissions, and must be considered.

3.8.1.5 Flare Gas Recovery Units (FGRUs)

A "zero flaring" solution does not completely eliminate flare installations, which are an important safety device, but instead involves major changes in the design and operation of the flare system. Zero-flare installations, such as FGRUs, are designed to recover, or recycle, the waste gas generated during normal operations. Located upstream of the flare, FGRUs are designed to capture some, or all of, the waste gases before they are flared. Vent gases are recovered from the flare header and compressed before injection into the gas line. The FGRU can be associated with a flare line closure system and a reliable flare gas ignition, eliminating any continuous flame (i.e. a normally 'not lit' flare). FGRU and flare ignition systems are mature technologies implemented in a number of installations globally and can be integrated into existing flare systems both onshore and offshore.

3.8.2 Investment Considerations

Flare system costs vary significantly. Depending on the type of technology, the CAPEX for an advanced flare system can be 20% to several times higher than for a standard pipe flare. As the replacement of a flare tip usually involves a shutdown of the facility, flare tip lifetime is a key driver for the overall costs of a flare. The expected frequency of flare tip replacement varies depending on the flare type.

There still is insufficient knowledge on how flare design parameters influence the quantities of BC and CH_4 emitted from flare stacks. Furthermore, attempts to optimize combustion to reduce BC will have no real economic benefit to the operator, so making an investment decision to optimize flare combustion will be primarily related to non-financial benefits.

While existing techniques may meet the security safeguards at oil production facilities, many do not implement BATs for flaring and emissions reduction. When undertaking BATEA assessments, the costs[220] and benefits of alternative solutions should be considered.

[219] In vertical drums, liquid particles will separate when the residence time of the vapor is greater than the time required to travel the available vertical height at the dropout velocity of the liquid particles (i.e. the vertical gas velocity is slower than the dropout velocity). In addition, the vertical gas velocity must be sufficiently low to permit the liquid droplets to fall. Since flares are designed to handle small-sized liquid droplets, the allowable vertical velocity is based on separating droplets between 300–600 micrometers in diameter.

[220] These costs will be dependent on local conditions, particularly for older installations.

Summary of BATEA for Reducing Black Carbon Emissions from Gas Flaring

4

The following table provides a simplified overview of the BATEA discussed in this report.

Strategy	Summary	Applicability to the Arctic
BATEA 1: Maximize On-Site Use – Heat & Electricity Generation	Associated gas is recovered from the flare stack and re-routed for pre-treatment, (optional) NGL separation (**BATEA 6**), and then used as a fuel gas for heating and/or electricity generation (with optional waste gas heat recovery through a steam generator).	• Remote areas without grid connectivity or with a long transport distance of alternative fuels for power generation (e.g. diesel) • Areas with low ambient temperature and altitude where engines/turbines have slightly higher efficiency • Colder environments with higher general heating requirements concerning oil production activities • Areas with high electricity tariffs (where electricity is used for power generation) or high fuel costs incurred in power generation
BATEA 2: Maximize On-Site Use – Reinjection	Associated gas is recovered from the flare stack and reinjected into either a production reservoir for Enhanced Oil Recovery (EOR) and pressure maintenance, or into other suitable, typically depleted reservoirs within close proximity, for temporary or permanent storage.	• Mature oil fields in remote areas far from utilization infrastructure (e.g. pipelines, gas processing plants, electricity grids) • Fields in close proximity to depleted reservoirs or other suitable formations for re-injection (e.g. salt caverns) • Mature fields where EOR through reinjection could carry benefits such as increased or prolonged oil production • Fields where future gas utilization or product conversion projects (e.g. GTL, LNG) are in development close by or where recovery and export could become economically viable in future
BATEA 3: Export Marketable Products – Natural Gas	APG is recovered from the flare stack and re-routed for pre-treatment and NGL separation (**BATEA 6**) before being exported for sale via pipelines, as compressed natural gas (CNG) or as liquified natural gas (LNG). Depending on market specifications, NGLs can either be separated on site and sold separately or transferred to a processing plant.	• Areas within an economically feasible reach of NG networks • Fields in the vicinity of existing processing plants with capacity • Areas close to local markets with demand for energy (e.g. substituting CNG for other fuels such as gasoline or diesel could be a possibility) • Fields in close proximity to each other (that could be clustered) • Fields close to large, ongoing infrastructure developments (e.g. pipeline networks, large-scale LNG projects, etc.) • Fields with accessible export routes for CNG/LNG (e.g. year-round, ice-free road, rail, or marine transport routes)
BATEA 4: Export Marketable Products – Liquid Hydrocarbon Products	Associated gas is recovered from the flare stack and re-routed for pre-treatment, NGL separation (depending on composition & technology) and then converted via Gas-to-Liquid (GTL), Gas-to-Chemical (GTC), or ammonia (NH_3) production processes into valuable hydrocarbon liquid products including, but not limited to, fuels (diesel, gasoline, jet fuel), methanol, and agricultural fertilizer.	• Regions too remote to access gas transmission networks (**BATEA 3**) or electrical grids (**BATEA 5**), but with local demand for liquid fuels, methanol, or ammonia[221] • Areas with a particularly high value of products (e.g. diesel, gasoline, etc.) • Regions with a water source for steam generation (common in Arctic environments) • Remote and/or offshore Arctic fields as potential candidates for new small-scale GTL/GTC technology
BATEA 5: Export Marketable Products – Electricity	Associated gas is recovered from the flare stack and re-routed for pre-treatment, on-site electricity production (**BATEA 1**), if applicable, (preferably) NGL separation (**BATEA 6**), and then used as a feedstock for combustion in gas engines, gas turbines, or steam turbines for electricity generation for export. This process is also commonly known as Gas-to-Wire (GTW).	• Remote areas without sea- or road-access, but where an electricity grid (transmission line or substation) is located within the vicinity (i.e. technically & economically feasible to reach) • Areas of low temperature and altitude where power generation engines can achieve notably higher efficiency (but highly dependent on available APG volumes) • Areas with high electricity tariffs where GTW could present a particularly attractive ROI compared to alternative recovery and utilization options
BATEA 6: Reduce Share of Heavier Components – NGL Separation	Associated gas is recovered from the flare stack and re-routed for pre-treatment (pre-processing & conditioning) before NGLs are processed and separated into liquid petroleum gas (LPG) and condensate. NGLs can be used for oil spiking, or be exported and sold (optionally by fractionation of components into individual product streams according to market requirements). The remaining dry gas can be utilized (as per the other BATEA), or if there is no feasible alternative, sent to be flared.	• Remote locations where there is no feasible solution for exporting APG in its entirety (available export possibilities for NGLs (e.g. road, sea) are still required) • Marginal fields where NG export is not feasible, but where NGL demand (heating, cooking, transport fuels) exists, or could be created by replacing other hydrocarbon fuels
BATEA 7: Optimize Combustion Conditions – Advanced Flare Design	Associated gas is recovered from the conventional flare stack and sent to an appropriately-sized and well-maintained knockout drum to remove heavier hydrocarbons from the flare stream before being directed to an improved flare stack where it is combusted using advanced flare tip and flare ignition technology.	• Remote areas where there is no feasible technical or economic possibility for the recovery of APG for any other purpose • Areas with below-freezing temperatures where air-assisted flares could present a good alternative to steam-assisted flares that plug up under freezing conditions (depending on the flare gas composition)

[221] Could compete with products from large-scale plants located further away.

Annex: Review of Existing Technical Guidance Documents and Related National Legislation

A review of available BAT guidance documents reveals little to no mention of specific technologies to reduce BC emissions from upstream APG flaring. Some guidance documents refer to PM, but without addressing BC. Furthermore, no document sets emission limits specifically for BC. Flaring is often generalized and mention of reduction technologies in guidance documents could be intended for uses at other industrial facilities (e.g. refineries), which creates complications as solutions are often very site-specific and vary depending on the industrial process being

Country/ Region	BAT guidance document	Types of oil & gas activities covered	Does this document address flaring?	Are technologies for reducing flaring covered?	Cost information provided?	Emission types covered
European Union	EU IED BREF Refining of Mineral Oil and Gas	Refining	Yes	Yes	No	CO, CO_2, SO_2, NO_x, PM, VOCs
	EU IED BREF Energy Efficiency	Energy Efficiency	Yes	Partly; Implementation of flare gas recovery systems for waste gases	N/A	N/A
	EU IED BREF Emissions from Storage	Emissions from Hydrocarbon Storage	Yes	Partly; Implementation of recovery operations and processes for VOCs with option to flare	Limited; 9 to 625 EUR/ m^3/h for an elevated flare	VOCs
	BAT Guidance on Upstream Hydrocarbon Exploration and Production	Exploration and Production	Yes	Yes	No	Qualitative mention
	EU IED BREF Large Combustion Plants	Combustion Processes	No	N/A	N/A	N/A
Russia	Extraction (Production) of Natural Gas	Gas and Condensate Exploration and Production	Yes	Yes	No	CH_4, CO, NO_x, PM
	Extraction of Oil	Oil Exploration and Production	Yes	Yes	No	C_1-C_5, C_6-C_{10}, CO, CH_4, H_2S
	Refining of Oil	Oil Refining	Yes	Yes	No	No
	Processing of Natural and Associated gas	Gas Processing	No	N/A	N/A	N/A

used. There is also a general lack of cost information and applicability assessments for any technologies related to reducing BC emissions from flaring.

Flare reduction recommendations provided	Emission limits set?	Reference
Allow flaring only for safety reasons and non-routine operational conditions. “If unavoidable, correct plant design (applicable to new units, FGRU may be retrofitted in existing systems), plant management (generally applicable), correct flaring device design (new units), monitoring and reporting (generally applicable.)”	No	1
Use waste gases as fuel for all industries. “If there are toxic gases, an incinerator is considered more appropriate than a flare for waste gas treatment. The main advantage of a flare, however, is a much higher turn-down ratio than an incinerator. Any gas sent to flare is burned without recovery of the energy contained in the flare gas. It is possible to install a flare gas recovery system, which recovers this small flow and recycles it to the site fuel gas system.”	N/A	2
Employ technologies to control VOC emission from hydrocarbon storage, specifically “the management of primary seal emissive leakage from centrifugal compressors to a flare or recovery system.” “Technologies for the abatement of VOC emissions to atmosphere from storage operations include the oxidation of the vented vapours in process heaters, specially designed incinerators, gas engines or flares. Vapour leakage entering the containment chamber between the two seals for pumps can effectively be channelled to a plant flare or vapour recovery system, provide emission values typically below 0.01 g/h, achieving emission levels less than 10 ppm (<1 g/day) when emissions are fed to a flare or vapour recovery system.”	Partly; Range of VOC stream flow considered applicable is up to 1800000 nm^3/h	3
Refer to Chapters 11 and 21	No	4
N/A	N/A	5
Practice BAT for utilization of APG, including: - Export of APG to a GPP for processing - Gas pre-treatment and export to national gas pipeline - APG utilization for electricity and heat generation - APG utilization for own needs on site - APG reinjection	Yes; Current average emission rate of soot (g/s) for flaring installations, emission limit values for PM (in kg of pollutant per tonne of oil equivalent of production) are available for separation processes (absorption dehydration, LTS) and APG utilization	6
Practice BAT for utilization of APG, including: - Gas pre-treatment and export to national gas pipeline - APG utilization at GPP, power plant - APG utilization for own needs on site - APG reinjection - APG injection to underground gas storage facilities	Yes; Emission values for a number of pollutants (excl. soot or PM) are available in kg per tonne of oil equivalent of production	7
Minimize flaring to emergency situations and special operating events (start-up, shut-down of installations) Optimize flare design Continuous monitoring of amount and composition of gas sent to flare	No	8
N/A	N/A	9

[1] https://eippcb.jrc.ec.europa.eu/reference/BREF/REF_BREF_2015.pdf
[2] https://eippcb.jrc.ec.europa.eu/reference/BREF/ENE_Adopted_02-2009.pdf
[3] https://eippcb.jrc.ec.europa.eu/reference/BREF/esb_bref_0706.pdf
[4] https://ec.europa.eu/environment/integration/energy/pdf/hydrocarbons_guidance_doc.pdf
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[7] https://www.gost.ru/documentManager/rest/file/load/1520858330116
[8] https://www.gost.ru/documentManager/rest/file/load/1520858513552
[9] https://www.gost.ru/documentManager/rest/file/load/1520860549947

Abbreviations

API	American Petroleum Institute
APG	Associated Petroleum Gas
BATEA	Best Available Techniques Economically Achievable
BAT	Best Available Techniques
BBL	Barrels
BC	Black Carbon
BCM	Billion Cubic Meters
BPD	Barrels per Day
BTU	British Thermal Unit
CAPEX	Capital Expenditure
CH_4	Methane
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DME	Dimethyl Ether
EOR	Enhanced Oil Recovery
FGRU	Flare Gas Recovery Unit
FT	Fischer-Tropsch
GOR	Gas Oil Ratio
GPP	Gas Processing Plant
GTC	Gas-to-Chemicals
GTL	Gas-to-Liquids
GTW	Gas-to-Wire
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen Sulphide
HHV	Higher Heating Value
HP	Horsepower
HV	High Voltage
JT	Joule-Thomson
KM	Kilometer
KWH	Kilowatt Hour
LHV	Lower Heating Value
LNG	Liquified Natural Gas
LPG	Liquid Petroleum Gas
LTS	Low Temperature Separation
LV	Low Voltage
MJ	Megajoules
MSCF	Thousand Standard Cubic Feet
MMBTU	Million British Thermal Units
MMSCFD	Million Standard Cubic Feet per Day
MMTPA	Million Tonnes per Annum
MRU	Mechanical Refrigeration Unit
MV	Medium Voltage
MW	Megawatt
NAG	Non-Associated Gas
N_2	Nitrogen
NCV	Net Calorific Value
NG	Natural Gas
NGL	Natural Gas Liquids
NO_X	Nitrogen Oxides
O_2	Oxygen
O&G	Oil and Gas
OPEX	Operational Expenditures
PGFC	Power Generating Flare Combustors
PM	Particulate Matter
PSI	Pounds per Square Inch
ROI	Return on Investment
SCF	Standard Cubic Feet
SCM	Standard Cubic Meters
SO_X	Sulphur Oxides
SOFC	Solid Oxide Fuel Cells
TEG	Thermoelectric Generator
TPD	Tonnes per Day
USD	United States Dollars
VOC	Volatile Organic Compound

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