Carbon Limits

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BEST PRACTICES FOR REDUCTION OF METHANE AND BLACK CARBON FROM ARCTIC OIL AND GAS PRODUCTION







CONTENTS

EXECUTIVE SUMMARY..... i

1. INTRODUCTION AND METHODOLOGY..... 1

2. CH_4 & BLACK CARBON EMISSIONS IN THE OIL AND GAS SECTOR..... 2

3. GAS FLARING & VENTING..... 3
   - 3.1 INCREASE GAS UTILIZATION..... 4
   - 3.2 OPTIMIZE COMBUSTION CONDITIONS..... 6
   - 3.3 REDUCE GAS VENTING..... 7

4. METHANE EMISSIONS..... 8
   - 4.1 DEHYDRATION AND FLOW ASSURANCE RELATED SOURCES..... 8
   - 4.2 PNEUMATIC CONTROL DEVICES..... 10
   - 4.3 STORAGE AND LOADING OF HYDROCARBON PRODUCTS..... 11
   - 4.4 FUGITIVE METHANE EMISSIONS..... 15
   - 4.5 CENTRIFUGAL COMPRESSORS..... 17
   - 4.6 RECIPROCATING COMPRESSORS..... 18
   - 4.7 OTHER SOURCES OF METHANE EMISSIONS..... 18

5. BLACK CARBON EMISSIONS – BEST PRACTICES..... 19
   - 5.1 STATIONARY DIESEL ENGINE AND BOILERS..... 19
   - 5.2 SHIPS AND VESSELS EMISSIONS..... 21
   - 5.3 OTHER SOURCES OF BLACK CARBON..... 23

6. REDUCING BLACK CARBON & CH_4: BARRIERS AND ABATEMENTS COSTS..... 23
   - 6.1 ABATEMENT COSTS IN THE ARCTIC..... 23
     - *6.1.1 Factors influencing abatement costs in the Arctic conditions*..... 23
     - *6.1.2 Methodology to calculate the abatement costs*..... 24
     - *6.1.3 Abatements costs*..... 26
   - 6.2 OTHER BARRIERS TO PROJECT IDENTIFICATION OR IMPLEMENTATION..... 28

7. SUMMARY & CONCLUSION..... 30

8. WORKS CITED..... 32

APPENDIX 1 : COMPANIES/ ORGANIZATIONS INTERVIEWED.....A

APPENDIX 2: LIST OF ACRONYMS USED.....B

EXECUTIVE SUMMARY

CONTEXT AND OBJECTIVES

Oil and gas (O&G) production activities in the Arctic region are substantial and expected to increase with potentially significant methane and black carbon emissions. As a result, the "Arctic Council Task Force on Short Lived Climate Forcers" has identified the O&G sector as a focus area for mitigation of short-lived climate forcers (SLCF)[1]. In this context, as one of the members of the Arctic Council Task Force on SLCF, the Ministry of Environment of Norway has commissioned Carbon Limits to assess best practices to reduce black carbon and methane emissions from oil and gas production in the Arctic. The current study has three key objectives:

- Document the best available technologies to reduce black carbon and methane emissions
- Evaluate their abatement costs in Arctic conditions
- Document the current practices in different Arctic countries

The report is based on an extensive literature review as well as more than 50 interviews with various relevant stakeholders including representatives from oil and gas companies, technology and services providers, non-governmental organizations, and regulatory bodies.

EMISSIONS SOURCES OF BLACK CARBON AND METHANE

Black carbon and methane are classified as SLCF, as their atmospheric lifetime is relatively short. Black carbon emissions are caused by incomplete combustion of fossil fuels, biofuels and biomass. There are a number of different sources of methane emissions in the O&G sector, which are typically classified as vented (intended emissions) or fugitive emissions (unintended emissions/leaks).

The following figure presents an overview of main potential sources of methane and black carbon emissions.

FIGURE A: OVERVIEW OF MAIN POTENTIAL SOURCES OF METHANE AND BLACK CARBON EMISSIONS

	TRANSPORT	WELLS	OIL PRODUCTION	GAS PRODUCTION	STORAGE/LOADING
					
BLACK CARBON	• Vessels and ships • Land and air transport	• Drilling operations • Well tests	• Power/heat generation • Associated gas flaring	• Gas flaring	• Vessels and ships • Land and air transport
METHANE	• Vessels and ships • Land and air transport	• Completion/ testing • Well plugging and abandonment • Gas venting and flaring • Well tests	• Associated gas flaring • Associated gas venting • Fluid de-gasing • Casinghead gas venting	• Compressors • Dehydrator and pumps • Pneumatic devices • Fugitive leakages • Well blowdown • Well completion	• Storage tanks/ loading • Sea transport

< PRODUCTION >

< EXPLORATION >

KEY
- **Applicable both onshore and offshore**
- **Applicable offshore only**
- **Applicable only onshore**

BEST PRACTICES TO REDUCE BLACK CARBON AND METHANE EMISSIONS

The present study confirms that a number of mature technologies are available to reduce black carbon and methane emissions in the upstream O&G sector. In most of the cases, these technologies are suitable for Arctic conditions and, when properly designed and maintained, can achieve significant emission reductions. The abatement options

1 Also called "Short Lived Climate Pollutants" (SLCP)

presented have also positive or negative impacts on other pollutants and thus the full environmental impact should always be considered when reviewing them.

The following table provides a summary of the abatement options evaluated[2]

TABLE A: SUMMARY OF ABATEMENT OPTIONS EVALUATED

Emission Source	BC/ CH_4?	Technology /Practice	Maturity	Off/ Onshore	Applicable Exploration development?	Emission reduction	Additional Comments/ Other Impacts of Implementation
Centrifugal compressor	CH_4	Dry seal	H	BOTH	YES	94%	Retrofit requires long down-time
		Seal Oil Vapor Recovery System	H	BOTH		95%	(1)
Reciprocating compressors	CH_4	Economical replacement of rod packing	H	BOTH	YES	50%-65%	
		Collecting and using/flaring the vent	M			95%	
Gas Venting	CH_4	Flare instead of vent	H	BOTH	YES	Up to 98%[3]	↗ CO_2 and potentially ↗ BC
		Utilize the gas	H	BOTH	NO	Variable	
Storage and loading of hydrocarbon products	CH_4	Reduce operating pressure upstream	H	BOTH	NA	Up to 30%	↘ nmVOC up to 30% for -1 bar
		Increase tank pressure	L-M			10-20%	↘nmVOC up to 10-20% for >0.2 bar
		Change geometry of loading pipes	M			Poor data	↘nmVOC up to 50%
		VRU: Gas compression	H			95%	↘nmVOC by 95%
		VRU: Ejector	H			>95%	↘nmVOC >95%
		VRU: VOC condensation & gas recovery	M-H			95%	↘nmVOC by 95%
Glycol dehydration and flow assurance	CH_4	Install Flash Tank Separator (FTS) & Optimize glycol circulation rates	H	BOTH	NA`	90%	
		Use electric pump			NA	80%	
		Reroute Glycol Skimmer Gas			NA	95%	
Fugitive emissions	CH_4	Directed Inspection and Maintenance	H	BOTH	YES	60%-80%	
		Subsea leakages detection & repair	M	OFF	NA	Uncertain	
Pneumatic devices	CH_4	Replacement to low bleed devices	H	BOTH	NA	90%	
		Retrofit into low bleed	H		NA	90%	
		Replacement to air driven instrument	H		NA	100%	
Flare - Decrease flare emissions	BOTH	Install advanced flare systems	M-H	BOTH	YES	Uncertain	↗ $CO_2$and possibly ↗ NOx
	BC	Properly size/operate knock out drum	H				
Flare - Increase gas utilization	BC	Maximize local/onsite use	H	BOTH	NO?	Almost 100%	↘ CO2 emissions (& possibly NOx/SOx)
		Gas injection	H		NO		
		Export marketable products	M-H		NO		
		"Near-zero" flaring solutions	H		NO		
Ships/Vessels	BC	Scrubber	M-H	OFF	YES	20-70%	↘ SOx emissions ; ↗ Fuel
		Use Distillates Fuels	H		YES	0-80%	↘ SOx emissions. Fuel premium
		Use LNG	M		YES	88-99%	↘NOx, SOx and GHG
		Water in fuel emulsion	M		YES	50-90%	↘NOx emissions ; ↗CO2
		Slides valves	H		YES	10-50%	↘ NOx emissions; Simple retrofit
		Diesel Particulate Filter	L		YES	70-99%	↘ SOx emission; ↗CO2;
Diesel engines and boilers	BC	Convert to gas	H	BOTH	VARIES	Most	↘ CO_2
		Import power from grid	H	BOTH		Variable	Depends on the local power source
		Implement good combustion practices	M	BOTH	YES	Uncertain	↘ CO emissions and HC emissions
		Install diesel particulate filter	H	BOTH		60-99%	

2 Key for the table: H: High, M: Medium, L: Low; NA: Not Applicable

3 Depends on the combustion efficiency of the flare

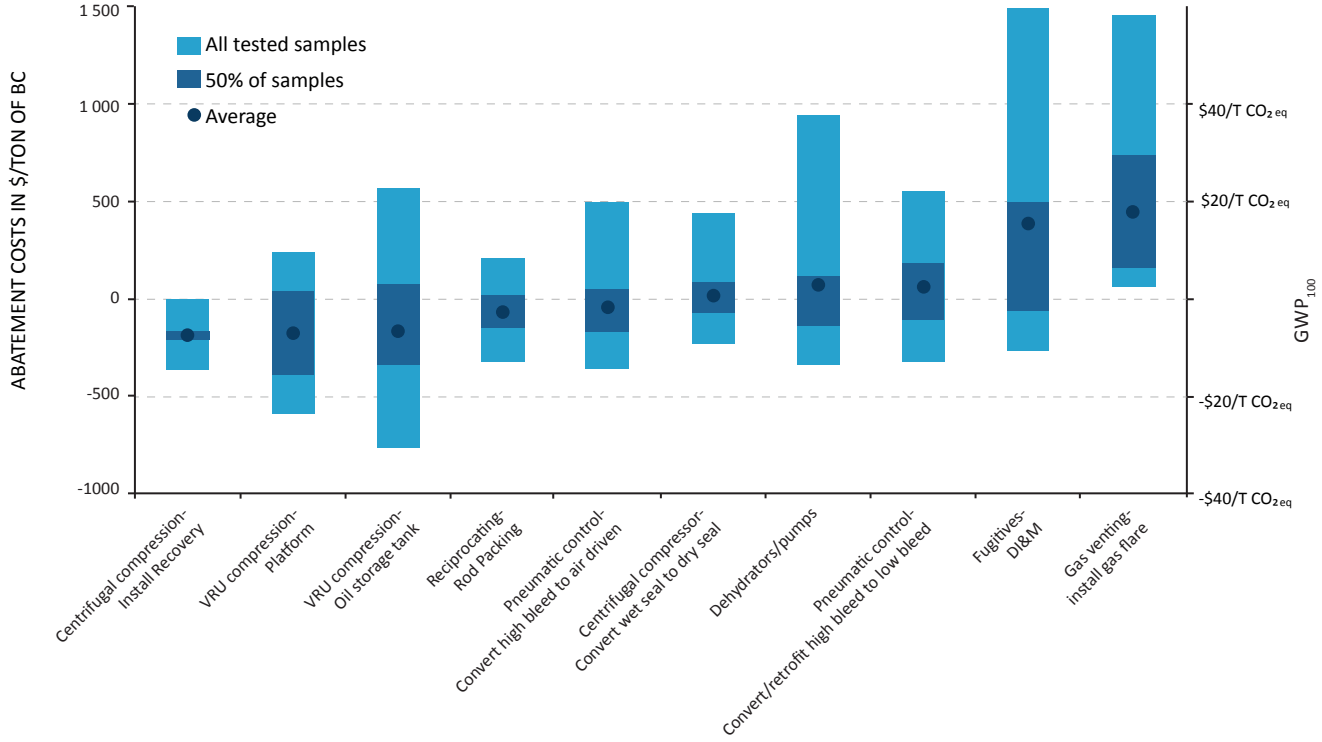
ABATEMENT COSTS IN THE ARCTIC

The business case for the application of the different abatement technologies is always site specific and abatement costs vary significantly depending on the local conditions. To reflect these variations, a number of different situations were evaluated to estimate a realistic range of abatement costs for each technology. Overall, the abatement costs for more than 850 cases were estimated.

METHANE EMISSIONS REDUCTION MEASURES

The following graph presents the abatement costs for methane emission reduction measures[4].

FIGURE B: ABATEMENT COSTS FOR METHANE EMISSION REDUCTION MEASURES



A large number of cases evaluated present negative abatement costs, i.e. methane emissions reduction can be made at an economic gain. However, there are also a range of situations where methane abatement in the Arctic require incremental costs compared to business-as-usual due to site specific factors such as low local gas value and high cost for transport, labor and other "logistic" costs. Nevertheless abatement cost for the vast majority of the cases evaluated are below $30/t$CO_{2eq}$. Although there appears to be a significant potential for low cost methane emission reductions in Arctic O&G sector activities, it is important to be aware that some options can be costly, depending on the location of the emissions.

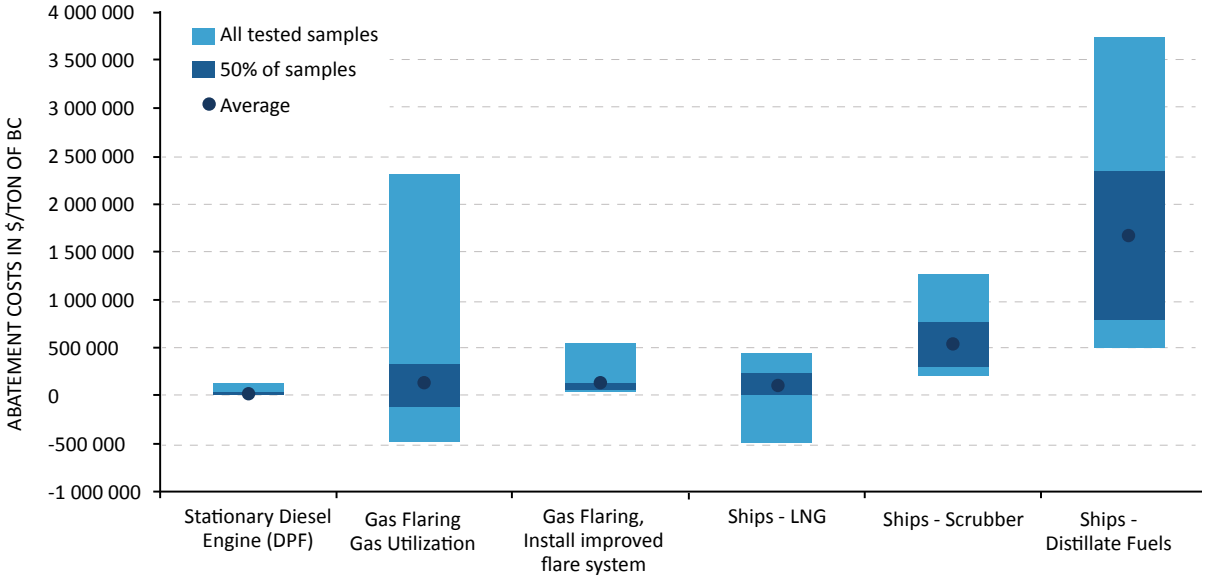
BLACK CARBON EMISSIONS REDUCTION MEASURES

Despite the importance of black carbon climate forcing in the Arctic, information on black carbon emissions in the O&G sector is scarce or indeterminate and interviewees were much less familiar with black carbon abatement options than with methane.

4 A few technologies with extreme abatements costs have been excluded from the graph to help the visual comparison.

The following figure presents the abatement costs for a number of black carbon emission reduction measures.

FIGURE C: ABATEMENT COSTS FOR BLACK CARBON EMISSION REDUCTION MEASURES



It has not been possible to make a direct comparison of the abatement costs for black carbon and methane, as there is currently no single indicator to assess the Arctic climate responses to change in black carbon emissions.
The analysis has however confirmed that black carbon abatement costs are, in many cases, significant. Gas flaring is most likely the largest source of black carbon emissions in the Arctic upstream O&G sector. Utilizing the gas is, of course, a natural option to reduce black carbon emissions. But in some cases, gas utilisation infrastructure may be costly or take considerable time to commission. Though the knowledge on black carbon emissions from gas flaring is very limited, it seems that opportunities exist to reduce soot emissions drastically by improving flaring systems and optimizing combustion's conditions.

IMPLEMENTATION BARRIERS

The interviews performed have also shed light on a number of barriers to the identification or to the implementation of emission reduction projects. In particular the following barriers have been highlighted: existing gaps in emissions data, insufficient data openness, lack of awareness of the energy losses, site accessibility issues, existing contractual conditions, down time required to retrofit a technology, or uncertainty regarding policies.

CURRENT PRACTICES

Overall, there are important variations in the level of uptake of the best practices or technologies across both different Arctic regions and also between different sites. More particularly:

- Gas flaring (both methane and black carbon): Most of the major international O&G companies have designed and are implementing flaring reduction programs. Large volumes of gas are still flared in Russia.
- Methane emission reductions: Some of the best practices reviewed have penetrated largely in Norway, North America and, in some cases, in Russia. Some key challenges remain however for smaller or dispersed sites.
- Black carbon emission reductions: Diesel engines are used mainly in remote areas (or on drilling rigs) and gas power is very common in the Arctic's region. When diesel engines are used, the installation of diesel particulate filters appears to be the exception.

1. INTRODUCTION AND METHODOLOGY

CONTEXT AND OBJECTIVES

O&G production activities in the Arctic region are substantial and expected to increase[5] with potentially significant methane and black carbon emissions. As a result, the "Arctic Council Task Force on Short Lived Climate Forcers" has identified oil and natural gas production as a focus area for mitigation of short lived climate forcers (SLCF). In this context, as one of the member of the Arctic Council Task Force on SLCF, the Ministry of Environment of Norway has commissioned Carbon Limits to assess the best practices to reduce black carbon and methane emissions from oil and gas production in the Arctic. The current report has three key objectives:

- Document the best available technologies[6] to reduce black carbon and methane emissions
- Evaluate their abatement costs in Arctic conditions
- Document the current practices in the different regions of the Arctic

METHODOLOGY AND APPROACH

The report is based on an extensive literature review as well as more than 50 interviews with various relevant stakeholders. Interviewees included representatives from oil and gas companies operating in the Arctic countries, technology and services providers, non-governmental organizations (NGO), and regulatory organizations[7]. The sample of interviews performed does not cover all the relevant stakeholders in, nor is it a representative sample of these. However, an effort has been made to perform a large number of interviews with experts having a variety of backgrounds, experience in different regions, and expertise in all the technologies covered. Policies and regulations are evolving in a number of the countries covered in this study and the report represents only a snapshot of the current situation.

STUDY SCOPE AND BOUNDARIES

There are many different definitions for the geographical boundaries of the Arctic. This report focuses on current and best practices in Norway, Russia, Canada and Alaska[8] covering both onshore and offshore operations in these regions. The report addresses the main technologies and practices, which can reduce black carbon[9] or/and methane (CH_4) emissions. When a technology or a practice has a positive or negative effect on other emissions (CO_2, NO_x, SO_x, etc.) these effects are also highlighted.

In terms of activities, this paper focuses on the oil and gas exploration and production sector as most activities in the high north (above 60 degrees N) are projected to be upstream in the foreseeable future. This includes exploration, drilling, production facilities, oil storage facilities, and transport. Downstream activities such a refineries, gas processing, liquefied natural gas (LNG) facilities, gas transmission and distribution pipelines, are not covered in the following sections. The report focuses mainly on so-called conventional oil and gas production, while unconventional hydrocarbons[10] are only briefly touched upon.

In the report, the numbers in parenthesis refer to reference documents. A list of the works cited is available as an appendix.

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5 According to the United States Geological Survey (USGS) (5) , about 90 billion barrels of oil, 1,669 trillion cubic feet of natural gas, and 44 billion barrels of natural gas liquids may remain to be found in the Arctic, of which approximately 84 percent is expected to occur in offshore areas.

6 In the context of this paper, best available technologies (BAT) does not refer to regulatory definitions in any of the jurisdiction covered. For this paper, BAT refers to a technology which is available on the market and relatively mature and which can have a positive impact on the emissions considered.

7 The full list of cooperating organizations is available in appendix 1

8 Though Greenland is believed to have some of the world's largest remaining oil resources; current activities are limited to exploration. Thus no specific interviews have been carried out regarding current practices in Greenland.

9 Black carbon is part of the elemental carbon fraction of particle matter (PM) and is a focus because of its ability to absorb radiation from the sun and turn it in to heat. There are currently a number of different definitions for black carbon: some study treats all EC or soot emissions as black carbon, while others have more stringent definitions of black carbon. For this paper, black carbon and soots are used indiscriminately. Please refer to each reference for the specific black carbon definition used in each study.

10 Unconventional hydrocarbon includes gas shale, tight gas sands, coal bed methane, oil shale, tar sands, heavy oil reservoirs, and methane hydrates.

2. CH_4 & BLACK CARBON EMISSIONS IN THE OIL AND GAS SECTOR

Black carbon and methane are classified as SLCFs, as their atmospheric lifetime is relatively short; black carbon remains in the atmosphere for days[11] while the atmospheric lifetime for methane is about 12 years.

Black carbon emissions have an additional impact on global warming when emitted in the Arctic with three distinct effects: a direct warming effect, by absorbing incoming solar radiation and converting it to heat; indirect cloud interaction effects, which can be warming or cooling, but are more likely warming when over snow or ice; and warming effects when black carbon is deposited onto snow or ices, darkening the snow / ice and reducing its reflectivity.

Methane emissions are also targeted in this paper as methane has an important short-term Global Warming Potential (GWP). (Methane is about 25 times[12] more powerful at warming the atmosphere than CO_2 by weight[13].) Methane is well-mixed in the atmosphere, and its warming impact is thus not related to the location of the emission sources. Due to their short atmospheric lifetime, reduced emissions of SLCF can have a positive impact on climate over a much shorter time frame than for CO_2.

BLACK CARBON

Black carbon emissions are caused by incomplete combustion of fossil fuels, biofuels and biomass. Three different sources of black carbon have been addressed in this study:

- Gas flaring: Gas is often produced with oil. When no market or utilization solutions have been identified, this “associated gas” (AG) is often burned;
- Transport: Sea, air and land transport generally uses petrol/diesel as fuel and hence is a potential source of black carbon emissions; and
- Power and heat generation (including drilling rigs)

METHANE

Oil and gas production is one of the largest anthropogenic sources of methane, and according to the US Environmental Protection Agency (EPA), it represents more than 20% of global anthropogenic methane emissions (2). Usually methane emissions are separated into two categories: (i) vented methane (intended or engineered emissions) and (ii) fugitive emissions (unintended emissions/leaks). Venting can occur during routine maintenance of equipment or during normal operational practices. Fugitive emissions (methane losses) can occur from leaks in the gas or oil infrastructure, for example, from the flanges, valves, pig traps and compressors.

In the following chapters, all the potential emissions sources are successively presented:

- Gas flaring is likely one of the largest sources of black carbon emissions from the O&G sector in the Arctic and also contributes to methane emissions (Chapter 3).
- Chapter 4 covers all the other sources of methane emissions. For each one, current practices, best practices, emissions reduction potential and costs are described.
- Finally, Chapter 5 covers all the other sources of black carbon emissions and presents current practices, best practices, and emissions reduction potential and costs.

The following figure presents an overview of main potential sources of methane and black carbon emissions[14].

11 The mean residence time in the atmosphere for black carbon varies regionally and with the season.
12 GWP of Methane (for 100 years) is 25 for the IPCC, and 21 for the US EPA and UNFCC.
13 The 100 year GWP of methane is 21, while the 20 year GWP of methane is 72.
14 The relative size of each emission source is not part of the current scope.

FIGURE 1 OVERVIEW OF DIFFERENT POTENTIAL SOURCES OF METHANE AND BLACK CARBON EMISSIONS IN THE UPSTREAM OIL AND GAS SECTOR



	TRANSPORT	WELLS	OIL PRODUCTION	GAS PRODUCTION	STORAGE/LOADING
BLACK CARBON	• Vessels and ships • Land and air transport	• Drilling operations • Well tests	• Power/heat generation • Associated gas flaring	• Gas flaring	• Vessels and ships • Land and air transport
METHANE	• Vessels and ships • Land and air transport	• Completion/ testing • Well plugging and abandonment • Gas venting and flaring • Well tests	• Associated gas flaring • Associated gas venting • Fluid de-gasing • Casinghead gas venting	• Compressors • Dehydrator and pumps • Pneumatic devices • Fugitive leakages • Well blowdown • Well completion	• Storage tanks/ loading • Sea transport

< *PRODUCTION* >

< *EXPLORATION* >

KEY
- **Applicable both onshore and offshore**
- **Applicable offshore only**
- **Applicable only onshore**

It should be noted that assessing and documenting actual practices in the different Arctic countries represents a challenge as they may vary significantly on a case by case basis. The assessments presented are based on the interviews' responses and may not reflect all practices applied in the countries' covered.

3. GAS FLARING & VENTING

Many oil reservoirs contain associated gas[15] (AG), which is produced with oil. When there is no productive use for this gas, it is generally flared or vented. Gas flares emit both methane and black carbon:

- Methane emission from gas flares is the result of incomplete combustion of the waste gas and thus is related to the destruction efficiency of the flares.
- Black carbon formation is the result of a very complex process, involving several steps of chemical and physical particle growth and then destruction[16]. Although the mechanisms of soot formation in gas flares are still not fully understood, key influencing parameters include exit velocity of gas from the flare, flare gas composition, wind conditions, flare stack diameter, and flare tip design (3).

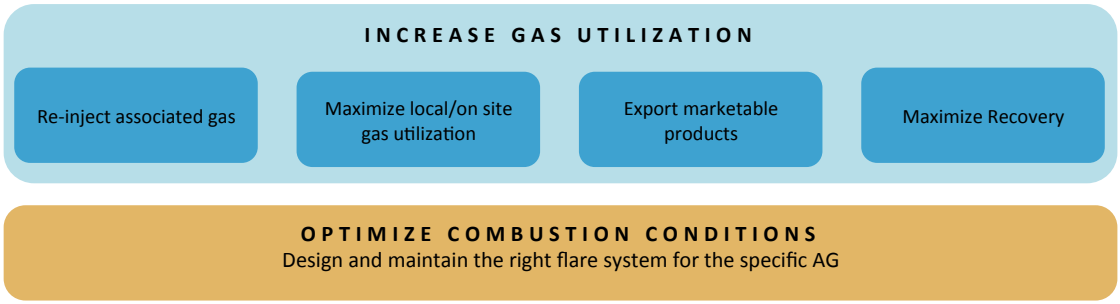
It is important to underline that the mechanisms involved in black carbon and methane emissions from gas flaring are different, and, these two sources of emissions are not necessary correlated (see Table 1). Over the last few years, there have been a number of publications focusing on methane and black carbon emissions from gas flaring (3) (4).

There still is, however, insufficient knowledge on how various parameters influence the quantities of black carbon and methane emitted from flare stacks. Figure 2 presents an overview of different routes to reduce black carbon and methane emissions from gas flaring and gas venting.

15 Either dissolved gas or as a free gas cap

16 There is an extensive work on soot formation mechanisms carried out by F. Mauss (Lund Univ), M. Frenklauch (Univ of Calif-Berkely), and R. Indstedt (Imperial College), among others.

FIGURE 2: GAS FLARING: OVERVIEW OF MITIGATION OPTIONS



Utilizing the associated gas is a natural solution to reduce black carbon (and CO_2) emissions from gas flaring (Section 3.1). But even when it is economical to utilize the associated gas, there will be some flaring, for example, for emergency reasons. Section 3.2 contains a discussion of options to reduce black carbon and CH_4 emissions from gas flaring. Finally the section 3.3 focuses on gas venting.

3.1 INCREASE GAS UTILIZATION

To avoid flaring of AG, new infrastructure can be established to recover the previously flared gas and supply it and/or other products that can be produced thereof for beneficial use. A number of alternative technical solutions exists and are briefly summarized in the following paragraphs.

MAXIMIZE LOCAL/ON SITE USE

One way to reduce flaring is to limit the amount of excess AG by finding additional productive ways to utilize the AG on-site. The share of produced AG which can be used on-site will vary from field to field, essentially from 0% to 100%. The following alternatives ways to increase AG utilization at the oil production site can be considered:

- **Electricity generation:** Depending on the local conditions, using excess AG for captive power generation could be a viable solution[17].
- **Heat generation:** To the degree that AG is not already utilized to produce heat for crude oil treatment or for steam generation, the opportunity to switch from using other energy sources[18] can represent a productive way to increase AG utilization on-site.
- **Re-injection:** One alternative to avoid flaring is to re-inject the AG in excess of what is required for any other beneficial use into the producing reservoir or alternative near-by reservoirs to increase production[19]. Re-injection of gas typically requires significant compression, and substantial investments are often needed. Re-injection is a critical technique for handling AG in remote fields. On a global basis, more than 400 billion cubic meter (bcm) of gas were re-injected into producing reservoirs in 2010 (5) , in particular in USA, North Sea, Algeria, and the Middle East.

EXPORT MARKETABLE PRODUCTS

Alternatives ways to utilize AG and to export valuable products to the local or international markets include:

- **Gas gathering (and compression):** This initial stage of gas utilization may be required for any of the other solutions described below. In many cases, gathering scattered gas streams, compressing the gas and injecting it into existing infrastructure represents a viable utilization option.
- **Gas treatment and products export:** AG will generally require treatment if it is to be utilized productively. Gas treatment increases transportability, removes impurities and separates the AG stream into different useful products. Liquid products (e.g. liquefied petroleum gas (LPG) and condensate) can be recovered through gas processing, or the use of micro-condensation units, and loaded in trucks, containers or ships

17 In Russia, for example, a large number of power plants using AG have been constructed over the past few years.
18 Excluding recovered waste heat
19 AG can also be injected in a non-producing reservoir to avoid gas flaring fines.

or transported by pipeline. Currently, while micro-condensation units[20] are undergoing testing, some gas processing plants only recover heavier hydrocarbons (and flare the methane-rich gas). Since heavy hydrocarbons play an important role in black carbon production (3), removing them from the flare stream is a very effective mitigation approach. Options for export of the gas portion of the treated AG include:

  - Long distance gas pipelines
  - Compressed natural gas (CNG): can be loaded in trucks, containers or ships for transportation.
  - LNG: New technologies are making smaller-scale LNG plants economically viable in some regions. LNG is typically transported by ships, but could also be transported by containers via roads and rail.
- **Electricity generation and export:** Electricity can be produced using AG as a fuel.
- **Heat Generation:** AG can be used as a fuel to produce heat for industrial consumers or population centers, potentially replacing other costly fuel sources. Gas quality requirements for use of AG as fuel in boilers are usually less stringent than for supplying gas transmission systems.
- **Gas To Liquid (GTL):** A number of small-scale GTL solutions have been developed over the last few years[21], which offer solutions to produce high value products. However, small-scale GTL solutions are capital intensive and are only at an early stage of commercialization.

Most of the technologies described above are mature solutions and have been widely used at-scale internationally. In theory, they can all be implemented offshore or in the Arctic, though the costs may vary significantly. Mini GTL, mini LNG, micro-condensation and fit-for-purpose small gas processing plant solutions are still at early commercial stage.

"ZERO" OR "NEAR ZERO" CONTINUOUS FLARING SOLUTIONS

A "zero flaring" solution does not eliminate flare installations, which are an important safety device, but involves major changes in the design and operation of the flare system. Essentially the zero flare installation is designed to recover or recycle the waste gas generated during normal operations. A Flare Gas Recovery Unit (FGRU) is located upstream of the flare to capture some or all of the waste gases before they are flared. The vent gases are recovered from the flare header and compressed before being injected into the gas line[22] (6) (7). The FGRU can be associated with a flare line closure system and a reliable flare gas ignition, eliminating any continuous flame (i.e. normally 'not lit' flare) (7). FGRU and flare ignition systems are a mature technology and have been used since 1992 in Norway (8), and are implemented in a number of installations both in Norway and globally. Flare gas recovery systems can be integrated into existing flare systems both onshore and offshore[23].

GAS UTILIZATION – EMISSIONS REDUCTION AND COSTS

Utilizing AG reduces virtually 100% of the black carbon emissions associated with gas flaring (and also CO_2 emissions[24]). In terms of methane emissions, most utilization options will be associated with some fugitives or vented methane emissions and thus utilising AG may not lead to any methane emission reductions[25]. Other emissions (such as NO_x) can also be reduced by utilizing the gas.

The economic attractiveness of the different utilization options is specific to any site and largely depends on local energy demand; the flare gas volume and its expected variation over time; the gas composition; the local gas and electricity price; the distances to relevant infrastructure; and the local regulatory regime. Capital expenditure (CAPEX) varies significantly depending on the option considered and on site specific characteristics[26].

20 Work ongoing as part of a NAMA (Nationally appropriate mitigation actions) project between Canada-Colombia-Mexico Oil & Gas Industry Col laboration Opportunities, 2012.

21 Compact GTL, Velocys and Gastechno for example

22 FRGU requires an existing gas utilization route.

23 A number of process optimizations can also be performed to reduce the volume of gas flared (e.g. minimizing risk of tripping of compressors, planning of startup).

24 Note that all the gas utilization options are associated with incremental energy consumption (for compression for example). However the incre mental CO2 emission is minimal compared to the overall CO2 emissions saved.

25 Methane emission's reduction will be case specific, depending on the destruction efficiency of the flare, of the technologies used for the gas utilization, and on the energy source displaced.

26 A number of cases have been performed in the abatement cost analysis.

GAS UTILIZATION – CURRENT PRACTICES ACROSS DIFFERENT REGIONS

Gas treatment, gas export, heat production and electricity generation are common practice in all the Arctic countries. The applicability of re-injection depends on the local geology; some reservoirs are not considered suitable for gas re-injection due to potential problems of gas break-through and distortions of oil production. Re-injection is standard in Norway and in Alaska for example, but only a few projects have been identified in Russia. According to interviewees, flaring appears to be currently increasing in Canada due to the low gas price, aging of the fields, unconventional oil production and distance to existing gas infrastructure[27].

Russia is the country with the largest flaring volume in the Arctic[28]. Following changes in the regulatory framework, most oil companies in Russia have developed and are implementing programs to increase AG utilization. Investments in gas gathering for centralized processing and use provide the most attractive solution in mature oil production regions. In remote areas and new production regions, captive power generation and re-injection projects are being pursued to limit flaring.

3.2 OPTIMIZE COMBUSTION CONDITIONS

INTRODUCTION OF PARAMETERS INFLUENCING EMISSIONS FROM GAS FLARING

The emissions from a gas flare depends on a number of parameters, in particular exit velocity of gas, gas composition, wind conditions, flare stack diameter, and flare tip design. The following table presents a very schematic and simplified view on how different parameters influence CO_2, black carbon, methane and NO_x emissions.

TABLE 1: EFFECT OF DIFFERENT PARAMETERS ON GAS FLARES' EMISSIONS

	CH_4 (+CO)	CO_2	BC	NOx
Combustion efficiency	↘	↗	?	↗
Flame temperature	↘	↗	?	↗
Heating value of the gas	↘	↗	↗	↗
Gas velocity	↘	↗	↘?	↗
Diameter of the flare tip	↗	↘	↗	↘
Turbulent mixing	↘	↗	↘	↗
Crosswind speed	↗ ?	↘?	?	↘

KEY

↘	An increase of A will lead to a decrease of B
↗	An increase of A will lead to an increase of B
→	An increase of A has no effect on B
?	Uncertain effect or two conflicting information sources reviewed

Two main conclusions can be drawn from this: (i) though flares have been studied since the 1980s, there are still significant uncertainties related to the magnitude of emissions in particular related to black carbon (ii) a number of conflicting effects have been identified (e.g. increased combustion efficiency will reduce methane emissions while increasing NO_x emissions).

OVERVIEW OF EMISSIONS REDUCTION TECHNOLOGIES[29]

A wide variety of flare types are currently available from different flare manufacturers[30]. The flare selected for each application depends mainly on the gas stream rate, composition & pressure, the utility costs and availability, and on safety, environmental and social requirements (9). Flares can achieve smokeless operation and less than 2% unburned hydrocarbon (including CH_4) when properly sized, maintained and operated. On the other hand, poor design or poor maintenance can lead to more than 30% unburned hydrocarbons and/or important smoke formation. Flare systems, including advanced technologies (pressure-assisted, air-assisted, steam-assisted, sonic, multi-tips, staged, and enclosed flared) are all mature technologies and have been extensively used internationally. With the exception of ground flares, they can all be installed offshore. For steam-assisted flares; freezing weather conditions can sometimes

27 Gas flaring has also increased significantly in USA in 2011 (NOAA, 2011), however the role of Alaska in this increase was not accounted for sepa rately.

28 And in the world!

29 Other solutions exist to reduce emissions from gas flares. As they will mainly impact CO2 emissions (and only marginally methane and black carbon), they are not detailed in the report. This includes using inert gas as purge gas, implementing purge reduction devices or using advanced pilot systems with low fuel consumptions.

30 For example, John Zink, Zeeco, Calidus, Tornado, GBA…

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 represent a good alternative option in these conditions (10).

ALTERNATIVE OPTIONS

The design and the maintenance of the knockout drum can also impact the black carbon emissions from a flare. A knockout drum is a separator used to remove liquids from the gas stream prior to being flared. If it is not sized or maintained properly, some liquids droplets may be entrained by a waste gas stream and might be burned incompletely, resulting in smoke formation. The micro condensation units (described above) can be considered as a black carbon emissions reduction option.

EMISSION REDUCTIONS AND COSTS

Despite the increasing number of published test data for emissions from gas flaring, there is currently insufficient information on the mitigation potential of various technologies, particularly regarding black carbon emissions. However, based on only visual assessment (i.e. smoke), proper design and maintenance of flares can have a significant impact on black carbon emissions[31]. Increasing the quantitative understanding of the black carbon emissions from gas flares would support the identification of possibly affordable, short-term, large-scale black carbon abatement options. Flare system costs vary significantly. Depending on the type of flares, the CAPEX for an advanced flare system are 20% to several times higher than for a standard pipe flare. As the replacement of a flare tip usually involves a shut-down of the facility, flare tip lifetime is a key driver for the overall costs of a flare. Frequency of the flare tip replacement varies depending on the flare type[32].

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

Advanced flare systems are used to some extent in all the Arctic countries evaluated. However, for upstream application, systematic methods to reduce black carbon and methane emissions appear to be the exception and a number of interviewees highlighted that flare operations may currently not be optimized, particularly in more dispersed operations[33].

3.3 REDUCE GAS VENTING[34]

DESCRIPTION OF EMISSIONS SOURCES

Venting – direct release of natural gas into the atmosphere without flaring or incineration – has been highlighted as an issue by interviewees. Although the quantities released at any given site are typically small, the total amount may be significant. For example, in Alberta, 381 million cubic meters of gas was vented in 2008 (11)[35] mainly at the oil and bitumen "batteries", where the primary separation of oil, water and associated gas takes place.

OVERVIEW OF EMISSIONS REDUCTION TECHNOLOGIES

Two main options are available to reduce gas venting: (i) utilize the gas (see the sections above) or (ii) flare the gas. Interviewees mentioned a number of reasons for the gas to be vented and not flared:

- The amount of gas available to be directed to the flare was insufficient or too variable to sustain combustion.
- Installing a flare system represents an incremental CAPEX.
- Venting gas is less visible than flaring[36].
- Age of the fields, as some of the fields were developed when there was no regulation related to gas venting.

Venting can also occur during a failure of the flare system (e.g. when the flare is not equipped with a pilot/ignitor, or when the pilot/ignitor fails). To burn the gas instead of venting it, small flare system with one to three pilots or an

31 Abatement costs were estimated using the best figures currently available (Carleton University, 2012).
32 And depending on the flare tip conditions.
33 It is important to note that in some of the area studied, regulations are implemented on combustion efficiency standards, and/or visible smoke emissions
34 In the regions studied, venting is generally not considered an acceptable alternative to flaring by the regulator.
35 Note that the utilization rate in Alberta in 2008 was superior to 95%.
36 When low amounts of hydrogen sulfide is contained in the gas vented.

automatic ignitor could be installed. The different methane emissions sources (tank vents, compressor, separator, relief valves) could all be routed to the flare. If the energy content of the combined gas stream is too low, auxiliary fuel may be needed.

EMISSION REDUCTIONS AND COSTS

Flaring some gas that would have previously been vented will reduce methane emissions but will increase CO_2 emissions (from the combusted gas) and could potentially increase the black carbon emissions[37]. For example, taking into account the different warming potential of CO_2 and methane and the combustion efficiency achieved, flaring gas, instead of venting, can reduce about 75% of the CO_{2eq} emissions[38]. Depending on the flare specificities (number and fuel consumption of the pilots; type of purge gas, purge incremental fuel), the net environmental benefit of each option should be weighted carefully. For a small flare system (a pipe flare with a 4 inch diameter), the investment costs --including ignitor, knock-out drum, piping, shipping and installation -- could be about $75k while a very simple system may costs as little as $10k.

4. METHANE EMISSIONS[39]

This chapter focuses on methane emissions and reviews (i) the current practices of technology application in the different countries, (ii) the best available technologies to reduce methane emissions and (iii) the costs associated to the implementation of the different technologies[40]. The chapter is organized by emission source as follows:

- Dehydration and flow assurance related sources (Section 4.1)
- Pneumatic Control Devices (Section 4.2)
- Storage and loading of hydrocarbon products (Section 4.3)
- Fugitive emissions (Section 4.4)
- Centrifugal Compressors (Section 4.5)
- Reciprocating Compressors (Section 4.6)
- Other sources of methane emissions (Section 4.7)

4.1 DEHYDRATION AND FLOW ASSURANCE RELATED SOURCES

The Arctic poses special challenges related to production, transportation and storage of petroleum and related fluids. Flow assurance[41] under extreme cold temperatures[42] adds complexities to the design and operation of production systems in the Arctic. For example to prevent hydrate plug formation[43], use of additives (e.g. monoethylene glycol (MEG)) and/or dehydration of natural gas[44] may be required with potentially significant methane emission impacts.

Dehydration is conducted to prevent moisture in hydrocarbons from contaminating pipes and vessels downstream (such as corrosion and free-water accumulation). During pipeline transportation, water vapor in the gas can lead to hydrate formation at cold spots or where the pressure is high. In colder climates, the threshold value for acceptable water vapor content in the gas can therefore be lower than in other regions. Dehydration can be accomplished

37 Depending on the flare type and the flaring conditions.

38 Depending on the gas composition and the combustion efficiency achieved. From a climate perspective it is worth noting that methane in the atmosphere is ultimately oxidized to form CO2.

39 The US EPA Natural gas star program is voluntary partnership that encourages oil and natural gas companies to adopt cost-effective technolo gies and practices that improve operational efficiency and reduce emissions of methane. In this section, the work of the program has been leveraged. When relevant, Arctic specific aspects are highlighted.

40 A number of technologies to reduce methane emissions are profitable if the gas recovered can be used or sold. The increased revenue is not presented in each of the sections but is taken into account into the abatement costs calculations.

41 Flow assurance encompasses the thermal-hydraulic design and assessment of oil and gas production and transport systems as well as prediction, prevention and remediation of flow stoppages due to solids deposition (e.g. hydrates).

42 All subsea pipelines in Arctic conditions are not necessarily in an “extreme cold” environment. The minimum seabed temperature is often greater than 4° C.

43 Natural gas hydrates are ice-like solids containing water and methane or other hydrocarbons that can form rapidly and without warning, plug ging pipelines and requiring days or months for remediation. The primary factors influencing hydrate formation include: (i) gas must be at or below its water dew point, (ii) temperature, (iii) pressure, and (iv) composition.

44 For oil systems, hydrate formation can be prevented by keeping fluid warm and/or reducing pressure, while dehydration is normally achieved using emulsion breakers.

through absorption (using various liquid desiccants such as glycols[45] or solid desiccants to absorb water), adsorption[46], or separation (refrigerated separation[47] or separation by electrical coalescence). Each type of dehydrator has its own operating ranges, strengths and weaknesses. The oil and gas industry relies heavily on triethylene glycol (TEG) dehydrators[48] (i.e. absorption using triethylene glycol), but desiccant dehydrators (i.e. solid desiccants), molecular sieve dehydration and refrigerated separation (with injection of hydrate inhibitors) are also used upstream.

Chemical additives (e.g. methanol or MEG) can be added upstream to prevent hydrate formation[49] and meet pipeline specifications, either in addition to or as an alternative to dehydration. Some chemical inhibitors also have good gas dehydration capabilities. MEG (and other glycols) can dehydrate gas to pipeline specification and thus eliminate the need for a TEG contactor/dehydrator. (Methanol does not have this ability)[50] (12).

DESCRIPTION OF POTENTIAL EMISSION SOURCES

TEG dehydrators can lead to significant methane emissions if not designed and operated carefully. TEG absorbs water from wet gas along with methane, non-methane Volatile Organic Compounds (nmVOCs), and HAPs. The absorbed water and hydrocarbons are then boiled off in a reboiler/regenerator. If methane emissions are not controlled, large quantities of methane rich gas (including nmVOCs and HAPs) can be vented to the atmosphere from the reboiler/regenerator. (The emission rate is dependent on the glycol circulation rate). Methane emissions can also be associated with pneumatic glycol circulation pumps and other devices. Desiccant dehydrators do not use glycol, which eliminates most of the methane emissions associated with dehydrators[51].

Regeneration of glycols used as hydrate inhibitors can lead to methane emissions through similar mechanisms as a conventional TEG dehydrator. MEG used as hydrate inhibitor is nearly always recovered, regenerated and reused (for economic reasons). Prior to entering the regeneration facility, the fluid stream is passed through a phase separator, separating the fluid into gases, liquid hydrocarbons and rich MEG. Rich MEG is sent to a reboiler/regenerator, where the vent from the still column (boiled water) is condensed. Non-condensable gases in the vent from the still column would, if vented, lead to emissions of methane.

Chemical injection pumps powered by pressurized natural gas (gas-driven pneumatic pumps) would lead to venting of methane to the atmosphere as part of normal operations.

MEASURES TO REDUCE METHANE EMISSIONS

As presented above, there are alternative technical solutions for flow assurance applicable in the upstream O&G sector in the Arctic. Some of these solutions are associated with methane releases that could lead to atmospheric emissions if not controlled (e.g. use of glycols as hydrate inhibitors or dehydration agent and use of gas-driven chemical injection pumps). The optimal choice of technical design will be site-specific. In terms of controlling methane emissions, the best practice is thus to (i) control emissions through application of adequate control technologies when applying technical solutions associated with vapor releases, or (ii) apply technical solutions with limited methane releases in the first place.

45 Absorption typically uses a dehydration agent (e.g. ethylene, diethylene (DEG), triethylene (TEG) or tetraethylene) to absorb water.

46 Adsorption removes water by passing the wet gas through a vessel with an adsorbent (e.g. silica gel) molecular sieve. Dehydration will adsorb the highest amount of water and simultaneously sweeten and dry gas.

47 Inhibitors (methanol and MEG) can be used to facilitate refrigerated separation (i.e. condensing water out by cooling), which can be considered "dehydration". It should be noted that TEG dehydrators will achieve dew point depression well below what a typical refrigeration process will achieve.

48 To achieve high water dew point depression (relevant in the Arctic), it is important to regenerate the TEG to very high concentrations. This can e.g. be achieved by using solvent stripping instead of conventional gas stripping.

49 This is applicable to upstream pipeline systems that do not have stringent pipeline specifications. When inhibitors are used, additional down stream processing is required (e.g. to remove water and injected methanol or MEG).

50 The selection between inhibitors (alcohols, glycols and salts) involves comparison between many factors including site-specific conditions, capital costs and operating costs. A primary factor in the selection process is whether or not the spent chemical will be recovered, regenerated and re-injected. Glycol is normally recovered and recycled, whereas methanol is used in both once-through systems and but, in other cases, can also be partially recovered. A once-through methanol system can have high operating costs when there are high gas and/or produced water rates (12).

51 During routine cleaning or refilling of desiccant, some gas is typically vented to the atmosphere.

Several well-documented measures to control methane emissions from glycol regeneration facilities are presented in Table 2.

TABLE 2: MEASURES TO CONTROL METHANE EMISSIONS FROM GLYCOL REGENERATION FACILITIES [52]

Measure: (Op. change or technology)	Description of Measure:	Maturity: (Low/Med/High)	Applicability in Arctic: Onshore	Applicability in Arctic: Offshore
SYSTEM DESIGN:				
Install Flash Tank Separator (FTS)	Methane that flashes from rich glycol can be captured/rerouted (requiring outlet for gas[53])	High	X	X
Use electric pump (instead of gas-driven)[54]	Using electric pumps can improve system efficiency (e.g. reduce TEG circulation rates)	High	X	X
OPERATIONS				
Optimize glycol circulation rates	Inlet gas pressure and flow can change over time. Glycol over-circulation leads to emissions	High	X	X

EMISSION REDUCTIONS AND COSTS

The following table summarizes the costs and the emission reductions related to the different measures

TABLE 3: OVERVIEW OF EMISSIONS REDUCTION AND COSTS FOR DEHYDRATION AND FLOW ASSURANCE ABATEMENT OPTIONS (13)

Measure: (Op. change or technology)	Investment Costs	Emissions Reductions
Install Flash Tank Separator (FTS), Optimize glycol circulation rates	$5k to $60k depending on the size and on the location (onshore/offshore)	90%
Use electric pump (instead of gas-driven)	$5k to $20k	80% approx.

Interviewees also highlighted the high costs associated to molecular sieve dehydration units for sour gas applications.

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

The information available on the current practices for flow assurance (upstream) is presented in Table 4.

TABLE 4: CURRENT PRACTICES FOR FLOW ASSURANCE UPSTREAM IN THE ARCTIC

	ALASKA	CANADA	NORWAY	RUSSIA
CURRENT PRACTICE	Glycol dehydrators are common, and flash tank separators are commonly installed in larger dehydrators. Many operators are capturing the gas and flaring it, instead of venting. Desiccant dehydrators are used (but experience is poor).	TEG used for field applications with sweet gas, with condenser systems. TEG dehydrators are controlled, and regulations require optimization of glycol circulation rates (performance curves). Mole sieve dehydrators used for sour applications, with incineration of gas.	TEG dehydrators used both onshore and offshore. Flash gas routed to flare onshore, and recovered offshore. MEG used for hydrate inhibition in sub-sea pipelines. MEG regeneration to flare or back-to-process except at two locations where it is vented.	Confirmation of desiccant dehydrators used offshore. Methanol injection and low temperature separation used in Western Siberia.

4.2 PNEUMATIC CONTROL DEVICES

DESCRIPTION OF EMISSIONS SOURCES

Remote, non-electrified gas production sites often use natural gas powered pneumatic controllers for automatic process control, resulting in significant methane emissions to the atmosphere. Natural Gas (NG) driven control devices emit CH_4 both through continuous bleeding and during actuating (venting). Emissions vary greatly depending

52 Some interviewees highlighted some operational concerns with desiccant dehydrator, and thus desiccant dehydrators are not directly presented as an abatement option.

53 Since fuel is usually needed to heat the regenerator, it is typically easy to find a use for the gas.

54 Also applicable to gas-driven chemical injection pumps.

on the design, the working pressure, type and conditions of the instrument and frequency of actuating. One of the technology providers shared the experience of devices with up to 30 standard cubic feet per hour (scfh) of venting.

OVERVIEW OF EMISSIONS REDUCTION TECHNOLOGIES

Abatement opportunities to reduce methane emissions include:

- Replacement of high-bleed devices with low-bleed design or mechanical controls
- Retrofit the high bleed devices into low bleed ones. Retrofit kits can often be installed without any shutdown required
- Installation of compressed instrument air system including the installation of compressor for air delivery, air dryers, air piping, controller orifices and a volume tank.

All these options are mature and applicable onshore and offshore. However, a retrofit solution is not applicable to all the devices. The Natural Gas Star program indicates that up to 80% of the high-bleed devices could be replaced or retrofitted. Solar powered packages are also currently being commercialized, however snow must be regularly removed from the panels and limitations may be experienced at extremely high latitudes in winter.

EMISSION REDUCTIONS AND COSTS

The following table summarizes the costs and the emission reduction potential of the different options. The material/equipment costs are not different for Arctic conditions though implementation costs may be in some cases. In general, converting/retrofitting high bleed devices into low bleed devices represents a low investment cost abatement option.

TABLE 5: EMISSIONS REDUCTION POTENTIAL AND COSTS FROM PNEUMATIC CONTROL DEVICES

	REDUCTION POTENTIAL	COSTS	DRAWBACKS
Replacement to low bleed devices	Reduce emissions to below 6 scfh	$500 - 1,000, depending on the type and size	•Actuator vents from valve release are not abated
Retrofit of high bleed devices into low bleed	Reduce emissions to below 6 scfh (13)	$300-700 (14)	
Replacement to air-driven instrument	Reduce 100% of the methane emissions[55]	• Varies based on capacity: approx. $6k for 10 Horse Power (HP) & $60k+ for 75 HP • In addition, installation of air delivery piping network may be required; O&M about 10% to 20%. • Converting the control system to compressed air is an expensive option when the number of devices is limited, due to multiple fixed CAPEX and OPEX costs.	•Requires the installation of a new pipe network. •Maintenance issue with the air drying system has been reported

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

In Norway and on the North Slope in Alaska, compressed air control devices are used almost exclusively, while in more dispersed operations (Canada and Russia) (15), NG-driven pneumatic devices constitute a considerable share of the control devices. Most of the new devices are manufactured low-bleed to meet the requirements[56] of maximum 6 sfch[57]. Performing retrofit jobs to minimize the level of venting from the high-bleed devices, although not a standard practice for some of the operators, has also received some attention recently, in particular in North America.

55 But may impact CO2 emissions depending on the fuel used to power the air compressor.
56 Current US regulation.
57 In the abatement cost analysis, the baseline for new equipment is low bleed devices.

4.3 STORAGE AND LOADING OF HYDROCARBON PRODUCTS

DESCRIPTION OF EMISSIONS SOURCES

Vapors, consisting of VOCs[58] (methane and non-methane VOC (nmVOC)) and other hazardous air pollutants (HAPs

e.g. benzene, toluene and H_2S), are released from liquid hydrocarbon products during storage and loading due to three different mechanisms: (i) flashing losses, (ii) working losses, and (iii) breathing losses, also known as standing or storage losses. Flashing losses occur due to a hydrocarbon going from a higher pressure to a lower pressure, for example when crude oil or condensate is transferred from low-pressure production separators or heater equipment into an atmospheric storage tank. While stored, liquid hydrocarbons will continue to evaporate when fluid levels change or tank contents are agitated (working losses), typically occurring during loading and discharging of the tank. Breathing losses are caused by changes in ambient temperature and barometric pressure, resulting in expansion and contraction of the vapor space.

The vapor release rate and composition from a storage tank or loading of a hydrocarbon product will vary over time and depend on fluid characteristics, facility design and operational characteristics[59]. While lower ambient temperatures in the Arctic may have a positive impact on the vapor release rate, the fluid temperature in storage tanks is often controlled in order to ensure sufficiently low viscosity for discharging operations and further transport[60]. Hydrocarbon vapor is often mixed with inert gases present in the tank (e.g. nitrogen and carbon dioxide), and the composition of the resultant gas mixture can vary considerably. The average share of methane can range from <1 Mol % [61] up to >60 Mol %[62] (with nmVOCs, HAPs and inert gases making up the remainder), and can vary considerably over time, e.g. during the loading period of a floating production, storage and offloading units (FPSO) using inert gas as blanket gas. It is relatively common to vent to the atmosphere methane and nmVOCs emitted during storage and loading.

It should be noted that the amount of methane vented as a result of storage and loading operations upstream can be very limited in many instances, and is highly dependent on the production process (e.g. the vapor pressure of the hydrocarbon liquid being stored).

OVERVIEW OF EMISSIONS REDUCTION TECHNOLOGIES AND PRACTICES

Methane (and light hydrocarbons like ethane and propane) have high vapor pressures and are likely to flash out from the liquid hydrocarbon product at some point along the value chain. To minimize the amount of methane vented from storage and loading operations, the best practice is either (i) to use “passive” control measures to reduce evaporation at the storage or loading facility and “move” some of the flashing losses to another place in the value chain where the vapor can be properly handled, or (ii) use a vapor recovery unit and route the gas to a productive use, a flare or an incinerator. The optimal choice of technical design will be site-specific. Routing the hydrocarbon vapor to a flare or incinerator would reduce the methane emissions, but might be challenging with low energy content vapor[63].

The measures considered most relevant under Arctic conditions are presented in Table 6 below.

58 Volatile Organic Compounds (VOCs). VOCs are often split into methane and non-methane VOCs (nmVOCs) due to different regulatory treatment of these components (e.g. in the Kyoto Protocol and UN ECE/the Gothenburg Protocol). nmVOCs comprise ethane and heavier hydrocarbons, such as heptane and pentane.

59 In upstream storage tanks, lighter crude oils will flash more hydrocarbon vapors than heavier crudes, and the vapor release rate will typically show a cyclical pattern where oil is frequently loaded and discharged. Light crude (API 30 and up) can contain up to 5% VOC.

60 Significant amounts of energy are e.g. used in Western Siberia and on crude carriers to heat crude oil prior to transport or discharge.

61 Based on data for the average discharge of VOCs during loading of a 130,000 TDW shuttle tanker in the North Sea (using inert gas as tank blanketing).

62 Upper value of the range presented in http://www.epa.gov/gasstar/documents/ll_final_vap.pdf

63 The Kårstø terminal in Norway requires that VOC released during offloading is burnt in an incinerator. Pilot fuel is required to burn VOC, and the environmental impacts of this practice depend on the fuel used to ensure combustion.

TABLE 6: MEASURES TO CONTROL METHANE EMISSIONS FROM STORAGE AND LOADING OF HYDROCARBON PRODUCTS

MEASURE (Op. change or technology)	DESCRIPTION	MATURITY (Low/Med/High)	APPLICABILITY IN ARCTIC: Onshore	APPLICABILITY IN ARCTIC: Offshore
PASSIVE MEASURES (MEASURES TO REDUCE EVAPORATION):				
Reduce operating pressure upstream	By reducing the operating pressure of separators, flashing losses can be reduced	High	Tanks	Tanks Shuttle tankers
Increase tank pressure (with vapor control)	Flashing losses can be reduced at the tank. Vapor control required upstream/downstream.	Medium/Low	Tanks	Shuttle tankers FPSOs[64]
Change geometry of loading pipes (drop-lines)	Use of increased diameter drop-lines can reduce creation of VOC vapor in loading pipes[64]	Medium	N/A	Shuttle tankers Lightering[66]
ACTIVE MEASURES (VAPOR RECOVERY UNITS – VRUs):				
VRU: Gas compression (scrubber + compressor)	Route vent gas to separator, recycle liquids to tank, compress gas for export or local use	High	Tanks (upstream)	Tanks and FPSOs
VRU: Ejector (e.g. using HP gas)	Use pressure energy of HP gas or other motive fluid to draw in LP VOC for export or local use	High	Tanks (upstream)	Tanks (upstream)
VRU: VOC condensation and gas recovery	Condensing of heavier hydrocarbons (cooling) and use of light fractions (incl. methane) as fuel	Medium/Low	Tanks, loading operations	Shuttle tankers FSOs[67]

Vapor recovery units (VRU) can apply different technologies to recover vapors from storage and loading operations of hydrocarbon products upstream, some of which do not have an impact on vented methane emissions (i.e. adsorption or absorption solutions). Only the measures that can be used to control methane emissions from storage and loading are presented above. Recovered vapors can be utilized productively on-site or exported through existing gas infrastructure where such infrastructure is present. If gas infrastructure is not present or economic to utilize, vapors can be re-absorbed in the product/liquid or condensed to a liquid fuel for on-site use or export[68]. Vapors can also be routed to a flare or incinerator.

EMISSION REDUCTIONS AND COSTS

The attractiveness of VRUs depends on having a sufficient and predictable volume of vapor emissions, the presence of infrastructure to utilize the recovered hydrocarbon vapors, and matching the right technologies with the expected vapor rate and composition, including variations over time. The capacity of a VRU should be optimized, taking into account the variability in vapor release rates and compositions. As a result, some vapor might still be released, e.g. when peak emission rates exceed the capacity limit of the VRU or during start-up of loading operations (due to high inert gas content).

Contractual conditions can often have an impact on the installation of VRUs (e.g. agreements between equipment owners, equipment operators and resource owners)[69]. Difficulties in adequately handling these issues commercially can often explain why otherwise attractive measures are not implemented or are delayed. The costs associated with each of the technologies are reviewed below:

64 Other, more common, technical options exist to reduce VOC emissions. As they do not have a direct effect on methane emissions, they have been excluded from the analysis. In addition, a number of measures exist to reduce breathing losses (for example spray foam, insolation, painting of the tank etc). These techniques are however more relevant in Middle East than in the Arctic and thus are not detailed in this report.

65 A larger diameter drop line, without any moving parts or instrumentation, can prevent most of the VOC formation generated in a conventional drop line. DNV has simulated that increased size of drop lines at a typical Suezmax tanker with drop lines at a height of 22m could yield savings of 85 to 130 tons of VOC per loading, depending on the vapor pressure of the oil (http://www.klif.no/nyheter/dokumenter/vocic_boylelasting_vedl4.pdf). This also has a positive impact on working losses, such as rising gas bubbles from flashing in the piping system and sloshing that can increase surface evaporation inside the tanks. Various estimates of the impact on VOC emission rates from a tank are available, but these are typically presented for the nmVOC portion of the vapor. The potential impact on vented methane emissions is not well known.

66 The process of lightering off-loads cargo from larger vessels to smaller vessels, enabling larger vessels to vary their deliveries.

67 The process of lightering off-loads cargo from larger vessels to smaller vessels, enabling larger vessels to vary their deliveries.

68 Many of the existing implemented technologies do not cover the methane fraction but only the nmVOCs.

69 For example, this could be the case for an FPSO where the oil cargo is owned by one entity, the FPSO and all installed equipment is owned by another, and a third entity is responsible for the operation of the FPSO.

- **Reduce operating pressure upstream of the tank:** While reducing the separator pressure can have minimal direct capital and operational costs, the overall environmental and economic impact is uncertain and site specific. Reduced operating pressure of a production separator will lead to the gas stream leaving the separator having a lower pressure and a richer composition, potentially making it more challenging and costly to utilize[70]. Reducing operating pressure upstream can only lead to reduced methane emissions if additional flashing losses upstream are properly handled.

- **Increase tank pressure:** Increasing the tank pressure can, in some instances, be carried out with minimal direct capital costs[71] but could require investments to increase the design pressure of new storage tanks[72]. This measure would only lead to reduced methane emissions if flashing losses are properly handled downstream in the production chain. (The methane will tend to flash off when the product is brought to atmospheric pressure).

- **Change geometry of loading pipes (drop-lines):** Capital costs for retrofitting the necessary equipment on a 130,000 TDW shuttle tanker is estimated at approximately $2M[73]. There are limited operational and maintenance costs associated with this technology, and its regularity is high (100%).

- **VRU, Compression:** Total capital costs for onshore applications of this type of VRUs range from $43k for a 25 thousand cubic feet unit (MSCFD) unit to $126k for a 500 MSCFD unit[74], while offshore applications are somewhat more expensive. Total installation costs have been reported up to $4M for an FPSO installation with conversion to hydrocarbon blanketing. Capital costs in the Arctic are expected to be 30-40% higher due to need for winterization of equipment and logistics costs[75]. Operating costs (e.g. compression costs) will vary depending on the gas flow rate, efficiency and energy costs. Due to large seasonal variations in Arctic climate conditions, vapor rates could vary more than in other regions, resulting in less optimal capacity utilization of installed equipment. The economic benefits of the VRU will depend on the yield and value of drop-out liquids, the volume and energy content of the recovered gas, and the alternative cost of fuels and/or the net-back value of gas[76].

- **VRU, Ejector:** The capital costs of this technology are comparable to compression for similar range applications, but the technology has the advantage of requiring no maintenance.

- **VRU, Condensation and gas separation:** The first-generation large-scale VRUs were relatively expensive, quite complex and several operational challenges were experienced. Designs have since been optimized to reduce complexity. In terms of co-benefits, the VOC fuel can be used as a substitute for diesel fuel in existing boilers, thus reducing particulate emissions and maintenance related to cleaning of the furnace. In terms of emissions, this technology can completely eliminate methane and nmVOC emissions while in operation. Onshore installations at loading terminals would have capital requirements similar to offshore installations[77].

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70 In Russia, AG from the last stages of oil separation is often flared in remote locations due to its low pressure and high liquid content. Based on analysis by CL, unit cost of gas recovery can exceed $200/000 m3 for very low-pressure gas streams. Where the associated gas is completely recovered, reducing the gas pressure out of a production separator might result in increased compression needs or need for additional treatment upstream to avoid condensation in pipelines.

71 The costs would be marginal as long as the tank pressure is kept within the design pressure adjusted for a deterioration margin. As tanks get old, corrosion and general tear can reduce the acceptable pressure level.

72 Operator Teekay has reported that the additional steel weight for increased tank pressure and increased fatigue standard adds up to 500 tons (~0.5% increase in dead weight, leading to a minor fuel-penalty).

73 In Russia, associated gas from the last stages of oil separation is often flared in remote locations, due to its low pressure and high liquid content. Based on analysis by CL, unit cost of gas recovery can exceed $200/MCM for very low-pressure gas streams. Where the associated gas is completely recovered, reducing the gas pressure out of a production separator might result in increased compression needs or need for additional treatment upstream to avoid condensation in pipelines.

74 Adjusted for inflation and assuming 75% installation costs, as per Natural Gas Star program costs.

75 Interview with Mark Goodyear of COMM engineering

76 The net-back value of gas typically reflects its energy content, the availability of infrastructure and any capacity constraints, and the commercial terms that can be agreed to access downstream gas infrastructure. In remote Arctic conditions, the net-back value could be limited (down to zero/negative if gas is flared).

77 E.g. due to space limitations

The following table summarizes the expected emission reductions and the capital costs in Arctic conditions.

TABLE 7: EMISSIONS REDUCTIONS AND CAPITAL COSTS IN ARCTIC CONDITIONS

MEASURE (Op. change or technology)	REDUCTION OF EMISSIONS[78]		CAPITAL COSTS (examples)	
	Methane	nmVOCs	Onshore:	Offshore:
PASSIVE MEASURES (REDUCED EVAPORATION)				
Reduce operating pressure upstream	Up to 30% for -1 bar	Up to 30% for -1 bar	Highly case specific	Highly case specific
Increase tank pressure	Up to 10-20% for >0.2 bar	Up to 10-20% for >0.2 bar	Can be negligible	Can be negligible
Change geometry of loading pipes (drop-lines)	Poor data available	Up to 50%	N/A	~$2M US (retrofit)
ACTIVE MEASURES (VAPOR RECOVERY UNITS – VRUs):				
VRU: Gas compression (scrubber + compressor)	95%	95%	$60k-120k US (25-500 MSCFD)	$250k US (platform) - $4M US (FPSO)
VRU: Ejector (HP gas or water + pump)	>95%	>95%		

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

The amounts and compositions of VOC emissions from storage and loading of hydrocarbon products vary significantly between the Arctic countries[79]. There are also important differences between onshore and offshore operations and between individual production and storage sites, due to a number of factors such as the production technologies applied, the volatility of the hydrocarbons, and the applicable measures that can be applied to control methane emissions. In the context of this study, it has not been possible to gather sufficient information about the current application of passive measures to control methane emissions associated with storage and loading. Table 8 summarizes the information available on the current practices for control of VOC emissions from storage and loading. Overall, current practices seem to be driven by existing nmVOC and HAP regulations.

TABLE 8: CURRENT PRACTICES FOR HANDLING OF METHANE (IN VOC) FROM STORAGE AND LOADING IN THE ARCTIC

	ALASKA	CANADA	NORWAY	RUSSIA
CURRENT PRACTICE	• VRU installed depending on the local conditions (size, proximity of a city, type of gas). •Vessel with VOC emissions higher than 6 t/y will have to implement reductions measures.	•VRU units required on a case-by-case basis (depending on economics). •But overall uncommon.	•VRUs installed onshore. •Offshore, methane releases from loading is often vented, while some shuttle tankers recover methane.	•VOC from condensate stripping is often flared. •VRU are increasingly used.

4.4 FUGITIVE METHANE EMISSIONS

DESCRIPTION OF EMISSIONS SOURCES

Within oil and natural gas production facilities, a number of components -- such as valves, fittings, pressure regulation equipment, controllers, compressors, open-ended pipes, flanges and other joints -- can develop gas leaks due to the normal wear, process variation and the variety of environmental conditions (e.g., ambient temperature, humidity, corrosion etc.).

78 The baseline emission level is determined as the hydrocarbon vapors emitted without any measures to control VOC emissions. Emission impacts are not adjusted for reliability. While the passive measures will have a high reliability, the active measures can perform poorly if facilities are not properly designed, operated and maintained.

79 Inventories of methane and nmVOC emissions from storage and loading show very different patterns in different regions. In the United States, oil and natural gas condensate storage tank batteries at production and processing facilities have been estimated to emit 23.3 BCF of methane (~490,000 t-CH4) and 22,000 tons of nmVOC per year (http://www.epa.gov/etv/pubs/600s07029.pdf). In Norway, emissions levels are reported at 2,800 tons of methane and 18,600 tons of nmVOC in 2011, after having achieved significant reductions in nmVOC emissions from crude storage and loading (www.norskoljeoggass.no). The ratio of methane vs. nmVOC in the hydrocarbon vapor is reported to be equivalent to 1 to 0.05 in the US and 1 to 6.5 in Norway, a difference of more than a factor of 140. The characteristics of future oil and gas operations in the Arctic remain largely unknown.

OVERVIEW OF EMISSIONS REDUCTION PRACTICES

Establishment of Directed Inspection and Maintenance (DI&M) programs to detect and repair fugitive leaks in oil and gas facilities can significantly reduce this source of emissions. A DI&M program begins with a baseline survey to identify -- and possibly quantify -- leaks. Methane leakages are typically difficult to detect. However, a number of methane leak detection technologies are available, including soap bubble screening, electronic screening, toxic and organic vapor analyzers, ultrasound and acoustic systems, infrared camera and remote methane leak detector). Further, improvements in technology in recent years are helping to increase detection capabilities. For example, infrared (IR) cameras that can be used to see otherwise invisible hydrocarbon emissions have proven to be transformational technologies for raising awareness about methane emission sources and volumes. Repairs can then be made to leaking components. Subsequent surveys are designed based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair. It is important to highlight that IR cameras may have problems operating in very cold conditions (below -20°C or -30°C).

COMMENT ON SUBSEA GAS LEAK DETECTION

Detection and repairs of gas leaks in subsea installations is more challenging, as well as more costly. Mass-balance is an established method to detect the largest leaks. A number of other subsea technologies are commercially available to detect smaller leaks and are briefly summarized in the table below.

TABLE 9: OVERVIEW OF DIFFERENT TECHNOLOGIES TO DETECT AND LOCALIZE GAS LEAKS SUBSEA (16)

	DESCRIPTION	LIMITATIONS
Optical Camera	Video camera for surveillance of the subsea system.	• Sensitive to water turbidity • Needs additional light for detection beyond 3-5 m
Passive Acoustic	Under-water microphones detect the sound generated by a leak	• Sensible to background noise. May not detect small leaks.
Active Acoustic	Sound emitter and receiver. The sound is reflected by boundaries between different medias (including gas bubbles).	• Sensitive to shadowing objects. • Generates significant amounts of data.

EMISSION REDUCTIONS AND COSTS

The magnitude of the leaks within a facility is dependent upon a number of factors including the operating pressure, the amount and age of equipment, the baseline maintenance frequency and environmental conditions. The available reported figures are mainly data from processing plants and transmission facilities. Generally valves and connectors are considered the main leaking components (17). An oil platform has reported around 100 m^3/hour of VOC for equipment leaks (18), and leakages on FPSOs, with significant movement, may be higher. Measurement of the leak rates before the repair is not required but can be performed in order to account for the amount of emission reductions[80]. A service provider stated that typically 90% of the leak volume within a site is due to the top 10% leaking components.

In order to carry out the inspection and measurement operations an IR camera can be used and would cost about $70k. If outsourced, the service typically costs around $2,500 -5,000/day, though a medium sized facility could be surveyed in a few hours. The repair costs vary greatly depending on the type of action that is required. Some leaks can be reduced by tightening the valve stem packing, while some require a replacement of packing materials or, in some cases, replacement of the entire component.

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

Historically, methane leak detection has been mainly motivated by safety and general maintenance concerns. For example, offshore platforms are often equipped with a large number of hydrocarbon concentration detectors to prevent the risk of explosion. These detectors are triggered when methane concentration reaches a certain threshold but, depending on the local conditions and on the specific location of the sensors, many potential leaks may not be detected.

80 Depending on the magnitude of the leaks, several measurements techniques could be employed. For most of the leaks in upstream O&G sector, which are below 10 ft3/min, hi-flow samplers are most widely used. Bagging techniques could be utilized for larger leak rates. The leak identification and measurement technologies have been experienced with several operators in the recent years and have reached a relatively high maturity.

It has been noted during the study that many of the major oil companies are now equipped with infrared leak detection cameras in all of the Arctic regions, and that the DI&M practice is becoming more standard [81]. In Canada, there are also requirements for leak screening upstream (19).

4.5 CENTRIFUGAL COMPRESSORS

DESCRIPTION OF EMISSIONS SOURCE

Centrifugal compressors are widely used in the Oil and Gas industry. These compressors have a rotating shaft with seals that prevent the high pressure gas from escaping. Using high-pressure oil, which circulates between rings around the compressor shaft, as a seal -- also known as a wet seal -- has been common practice, although their use for newly installed centrifugal compressors is significantly declining (20). In the wet seal, the high pressure gas comes into contact with the seal oil, thus resulting in some gas being entrained by the sealing oil. Seal oil is then purged of the entrained gas and re-circulated to the seal area for reuse and the gas purged is commonly vented to the atmosphere (13). The amount of emissions from wet seals varies depending on the operating conditions, ranging from 100 to more than 5,000l/minute (13).

OVERVIEW OF EMISSIONS REDUCTION TECHNOLOGIES

The mechanical dry seal system is an alternative to the traditional wet seal. Using high-pressure gas to seal the compressor, dry seals result in much lower levels of fugitive emissions compared to the wet seals. Dry seals also have lower power requirements, improved compressor performance and require less maintenance. The technology of dry seals could be retrofitted for most of the existing compressors with wet seals[82].

Though dry seals are a very cost-effective option for new compressors, a number of interviewees highlighted that dry seals are not an attractive retrofit option solution due to the important investment needed, the long shutdown time required, and the low value of the recovered gas. An alternative solution has been identified by BP at its North Slope operations: the Seal Oil Vapor Recovery System. This system recovers and separates gas from the sour seal oil before being sent to the degassing tank. Recovered gas can be sent to various outlets, for example flare or the low pressure gas line. According to a recent study, this solution is technically simple and is more cost-effective and applicable as a retrofit solution (1).

EMISSION REDUCTIONS AND COSTS

Implementing a dry seal solution would minimize the amount of methane emissions by more than 95% However, one field expert highlighted that if the dry seal is not maintained properly, it may leak significantly. The capital expenditure for a dry seal system depends on the compressor size and operating conditions. It ranges between $300k-1M and is does not vary for Arctic conditions. The investment costs for an Arctic, onshore Seal Oil Vapor Recovery System (including new intermediate flash drum, fuel filter and pressure regulator)(1) has been evaluated at $30K.

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

The vast majority of new compressors are equipped with dry seals in all the Arctic regions[83]. In Norway, nearly all the centrifugal compressors already use dry gas sealing. An interviewee stated that dry seals retrofitting are picking up in Canada due to stricter regulation but remain marginal. Costs and down-time seems to be important barriers-to-entry. Information is limited regarding penetration rate of wet seals in the upstream oil and gas operations in Arctic Siberia, although a review of the literature indicates the wet seals are common in Russia (15).

81 A number of the companies are currently testing pilot infrared cameras or are implementing DI&M program.

82 However, even with use of dry seals, some leaks can be expected to occur between the seals and the labyrinth. In order to prevent this, an ad ditional emission-free arrangement could be implemented. In this technology, neutral buffer gas is fed between the seals to the labyrinth at higher pressure than the under-compression gas pressure.

83 In the abatement costs, dry seal compressors are considered as the baseline for new centrifugal compressors

4.6 RECIPROCATING COMPRESSORS

DESCRIPTION OF EMISSIONS SOURCE

Though there are a number of leaking points, the highest volume of gas loss within the reciprocating compressors is associated with piston rod packing systems, which are the components ensuring the sealing of the compressed gas (13). Piston rod packing consists of series of cups containing several seal rings side by side, held together by a spring installed in the groove running around the outside of the ring. Considerable leak reduction could be achieved by replacing packing rings and, in some cases, the piston rods.

OVERVIEW OF EMISSIONS REDUCTION PRACTICES

Correctly installed, new packing cases can be expected to leak at about 11 cubic feet per hour when properly aligned and fitted[84] (13). As the system ages, leak rates can increase due to the system's wear. Monitoring and replacing rod packing systems on a regular basis is a viable emission reduction practice. The key issue here is to optimize the frequency of the replacement to avoid high fugitive leaks. Interviewees recommended a three-year period as a reliable industry standard before the rod packing should be replaced.

Some interviewees highlighted that an alternative option consists of collecting and routing the vent to the inlet vacuum air of a natural gas engine, to a tank with a vapor recovery system or to the flare (13).

EMISSION REDUCTIONS AND COSTS

The leak rates for conventional rod packing can range from 60-200 scfh and have been recorded as high as 900 scfh (21). Replacing the old rod packing with new sets could abate up to 90% of the leaks at the time of the replacement[85].

In general, reciprocating compressors cover wider range of operational conditions than for centrifugal compressors. Therefore, the costs of replacing the rod packing system could vary from $360 for a small shaft (0.5 – 1.5 in.) to approximately $1,600 for large sets (3+ in.). Any maintenance on the reciprocating compressor piston rod packing would need a temporary shutdown of a few hours.

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

The practice of optimized replacement of rod packing for the reciprocating compressors has not commonly penetrated oil and natural gas operations in the Arctic, despite the potential economic profitability and the relatively high maturity of the technology. In many cases, the installed gas sensors detect only when major leaks occur. In USA, replacement every 26,000 hours of operation or 3 years is required.

4.7 OTHER SOURCES OF METHANE EMISSIONS

The following section briefly reviews other sources of methane emissions.

Produced water discharge: After treatment and depending on the discharge pressure, produced water may still contain some gas, which will flash out and thus represents a potential source of methane emissions. These emissions can be minimized by reducing the discharge pressure to the lowest possible.

Well Plug and Abandon: Abandoned or suspended wells can also represent a source of gas leakage. The risk of leakage is very much field/basin dependent, as it is determined by the pressure of the geological gas source, the properties of the mitigating geological barriers and the condition of the well at abandonment, including not just the quality of the abandonment but also the quality of the isolation of the annulus. A number of authors have looked at

84 With higher leakage rates, depending upon the correctness of alignment of the packing.
85 Some technology providers claim packing and optimization that could save more than 90% of the gas leaks.

risk of leakage[86], and the proportion of well leaking may be significant, though estimates vary widely[87]. Good practices in well construction and well plugging can reduce this gas emissions source.

Casing head gas: Some gases may be collected in the annulus between the casing (steel pipe cemented in the well bore) and the tubing (pipe in the well to serving as a conduit for the oil and gas). This gas is often vented but could be rerouted to the vapor recovery unit or compressed to be injected in the sale gas line (13).

Well blowdown: The gas flow rate in mature gas wells is reduced when liquids -- water or condensate -- accumulate inside the well tubing. When companies open well heads -- sometime for days -- to unload the liquids, some gas is emitted to the atmosphere. Plunger lift is an artificial-lift method used to unload liquid, using the natural gas pressure in the casing tubing annulus. Automated plunger lift systems significantly reduce the methane emissions but also reduce the number of personnel required and increase the overall productivity of the well (13).

Well test: Well tests are conducted to determine reservoir and reservoir's fluid property and can last from hours to several days. The natural gas produced is generally flared, although it may be vented from some low-volume wells. Different options exist to reduce the emissions from well tests, including reducing the length of the test or performing so-called "in-line testing," where the produced fluids are exported. When the gas is flared, efficient and non-smoking flaring practices can be considered (See section 3.2.).

Hydraulic fracturing: Hydraulic fracturing of tight gas formations may result in significant releases of methane emissions to the atmosphere. These emissions can be reduced either by flaring the gas using a completion combustion device or by capturing the gas using green completions (or "reduced emissions completions").

Gas turbines and engines: Methane emissions result from the incomplete combustion of the NG, which allows some of the methane in the fuel to be emitted with the exhaust stream. Gas engines emit 40 to 150 times more methane than gas turbines.

5. BLACK CARBON EMISSIONS – BEST PRACTICES

5.1 STATIONARY DIESEL ENGINE AND BOILERS

DESCRIPTION OF EMISSIONS SOURCES

Particulate Matter (PM) emissions from diesel engines or boilers are a complex mixture of compounds which are formed through a number of different mechanisms and include soluble organic fraction[88], insoluble fraction[89], and sulfate fraction[90] (22). Older diesel engines, made before 1990, are generally high emitters of black carbon and produce around 0.5 gr black carbon per kWh (and up to 1 gr/kWh). Rates depend on fuel quality and engine performance. However, newer diesel generators produce 0.025 gr/kWh of black carbon (and up to 0.4 gr/kWh) (22) .

OVERVIEW OF EMISSIONS REDUCTION TECHNOLOGIES

A number of options are available to reduce black carbon emissions from engines:

- **Convert to gas power generation:** Using gas, instead of oil products, to generate electricity can represent both a suitable flare reduction/gas utilization route (see section 3.1) and a black carbon abatement option.
- **Import power from a nearby grid source:** Depending on the source of local grid electricity, this solution could present a black carbon and CO_2 abatement option.
- **Implement good combustion practices:** Good combustion practices have a potential impact on PM

86 In particular in the context of CO2 storage. Watson & Bachu and Jordan & Benson

87 The Norwegian Petroleum Safety Authority found in 2006 uncertainty and weaknesses in the integrity of 1/5 of the wells. Schlumberger noted 60% of offshore gas wells presented sustained casing pressure after 30 years. Watson and Bachu (SPE 106817) surveyed 352,000 oil and gas wells and found 5% of wells had gas or oil outside the central borehole. In 1992, the US EPA estimated that of 1.2 million abandoned oil and gas wells in the US, 200,000 may not be properly plugged.

88 From fuel and lubrication oil

89 Dry carbonaceous soot from incomplete fuel combustion

90 from the sulfur in diesel fuel

emissions and may include training of the operating personnel to identify signs of improper operation as well as frequent engine maintenance and inspections (22).

- **Install diesel particulate filter (DPF):** The DPF consists of porous ceramic or cordierite substrate or metallic filter, which can capture black carbon and eliminate it from the exhaust gas. The captured particulate matters go through a process called regeneration[91] in order to reduce it to ash.

As the best available technology and in particular due to their suitablity for remote sites, the DPF is the main focus of this study. DPFs have been used since 1980s and a number of regulatory bodies have established diesel emission standards for some sectors[92], making DPF a requirement (23). DPF technology has evolved over the past 30 years and is very mature[93]. DPFs can be applied both at onshore and offshore operations.

Depending on the engine type, different filter technologies can be employed for example (i) wall-flow filters, made of ceramics and based on physical filtration of the particulate matter through the porous walls of the filter cells or (ii) partial-flow filters, catalysed metal wire, metal foil-based substrates or fibre-based mesh structures.

However, DPFs have some drawbacks:

- **Retrofit time:** It may take up to a week to install the DPF set on an exhaust system.
- **Maintenance:** In most cases, regular maintenance -- typically once per year -- is needed to sustain performance and reduce the risk of any possible blockage.
- **Fuel penalty:** DPFs may lead to additional fuel consumption due to back pressure and regeneration, typically ranging from 1 to 2% (24).
- **Fuel quality:** Ultra low sulphur fuel is required for some DPFs, however many DPFs can be used with high sulphur fuel.

Implementing DPFs for boilers needs more careful design since boilers are more sensitive to back-pressure[94].

EMISSION REDUCTIONS AND COSTS

Wall-flow filters remove black carbon, as fine as 0.01 µm diameter, with an efficiency of up to 90 to 99% in mass of PM[95]. Partial-flow filters offer an option for reducing PM emissions by 30-60%, but can operate with high PM emissions. DPFs can also reduce CO emissions (by 70 to 90%) and hydrocarbon emissions (by 85 to 95%) (25).

The investment cost for a DPF system is higher for retrofitting installations ($75–100/kW of installed capacity for small generation-sets; $40–50/kW for large ones) than for new applications (below $30/kW for large gen-sets). The sizing of the DPF is normally based on diesel engine's make certificates and age. However in Arctic conditions, an exhaust test might be required before designing the DPF. The operating expenditure consists of annual maintenance costs, fuel penalty, and lubricating and maintenance materials and the generated electricity in case of regeneration option.

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

- **Convert to gas power generation:** Gas turbine or engines are extensively used in all the regions of this study, specifically to utilize associated gas. In a number of cases (e.g. North Slope and Norway), the vast majority of the power generation is based on gas, and only stand-by gen-sets or drilling rigs are powered with diesel.
- **Use power from a nearby grid source:** This solution has been implemented in Canada[96] and to a lesser extent in Norway[97].
- **Install diesel particulate filter:** According to interviewees, installation of DPFs is not a standard practice in any of the Arctic regions, and only one actual DPF installation project has been identified.

91 Regeneration is the process through which the accumulated black carbon is discharged from the filter. Regeneration could be either carried out by introducing catalyst to the filter, letting the black carbon to burn by the heat of the exhaust gas itself or by adding extra intensive heat to the exhaust system.
92 Vehicles, some stationary and marine engines, but not in the Oil and Gas sector.
93 Though some research is still on-going, specifically concerning the use of nanotechnologies for filtering
94 DPF is not readily available for small sized boilers.
95 http://www.dieselretrofit.eu/technologies_filters.html
96 When operation are connected to the grid.
97 Further use of grid power in Norway is encouraged by the authorities and will be evaluated on a case by case basis.

It is interesting to note that many interviewees were not familiar with the DPF technology or with the current practices to reduce black carbon emissions from diesel power generation.

5.2 SHIPS AND VESSELS EMISSIONS

DESCRIPTION OF EMISSIONS SOURCES

PM emissions from ships are due to the incomplete combustion or impurities in the fuel and lubrication oil[98]. The mass and type of PM emitted into the air varies depending on engine type, engine age and horsepower, operating conditions, fuel, lubricating oil, and whether or not an emission control system is present. Large ships, such as oil tankers, are typically fuelled with residual oil. The International Marine Organization (IMO) has instituted new regulations for these ships, requiring the use of lower sulfur oil from 2015 in specified Emission Control Areas (ECAs). The coastal areas in USA and Canada (except for Arctic), the North Sea and Baltic Sea have been established as ECAs and others ECAs are currently under consideration.

OVERVIEW OF EMISSIONS REDUCTION TECHNOLOGIES

A recent study[99] shows that fuel quality improvements (from residual to distillate fuels) can reduce black carbon emissions by an average of 30% and potentially up to 80 %, regardless of the engine load[100]. An alternative for complying with the low sulphur fuel regulations is to implement scrubbers, an after-treatment of exhaust stream which washes contaminants out of the gases. Although data are currently very limited, exhaust scrubbing systems could remove 25–70 % of the black carbon (26). Technologies providers are developing different types of scrubbers. The effectiveness of sea water scrubbers can be limited if sea water alkalinity is too low, for example in the northern part of the Baltic Sea and Alaska[101]. The fresh water scrubber is a good alternative to avoid this problem. In such scrubbers, a caustic soda solution is used for neutralizing the sulphur. Hybrid systems can operate both on fresh water as well as sea water. Alternatively, dry scrubber, using granulated limestone, can also be used in these conditions. All the scrubbers can be used with residual fuels, which, on a global scale, need to be disposed.

Other technologies are available to reduce particulates and potentially black carbon emissions from ships[102]:

- Water-in-diesel emulsions increase the combustion's efficiency and reduce soot emissions by up to 90% in particular for old engine types (27) (28).
- Fueling ships with LNG can almost eliminate particulate emissions (29)
- DPF systems can reduce black carbon emissions by 70 to 99%. However the experience on ship engines is limited, and a number of practical challenges have been highlighted (27).
- While docked at the port, ships and vessel use their auxiliary engines to generate power. If high-voltage power is available in close proximity to the quay, supplying power directly to the vessel can reduce PM emissions by 90% and up to 99% (30).
- Slide valves, replacing conventional fuel valves, reduce the amount of unburned hydrocarbons and thus reduce PM emissions by 25% [103] (31) particularly for large older 2-stroke engines (27)

It is also important to highlight that slower operating speed for ships and vessels, which is often presented as a strategy to reduce fuel costs (and CO_2 emissions), can actually increase black carbon emissions by up to 100% if the engines have not been re-tuned accordingly (26). The table below provides an overview of the maturity, the advantages and drawbacks of each technology.

98 Secondary reactions of NOx and SOx can also produce PM

99 Source: Black carbon from ships: a review of the effects of ship speed, fuel quality and exhaust gas scrubbing D. A. Lack and J. J. Corbett

100 However black carbon emissions are not well correlated with sulfur fuel content.

101 Note: The chemistry of the water in coastal areas, ports and rivers can also be variable.

102 Black carbon emissions from marine shipping sector are currently being discussed, in particular at the IMO. Only a few abatement options are mentioned in this report, as ships and vessels represent a small part of the Arctic black carbon emissions in the Oil and Gas sector.

103 Up to 50%; only for large 2-stroke engines

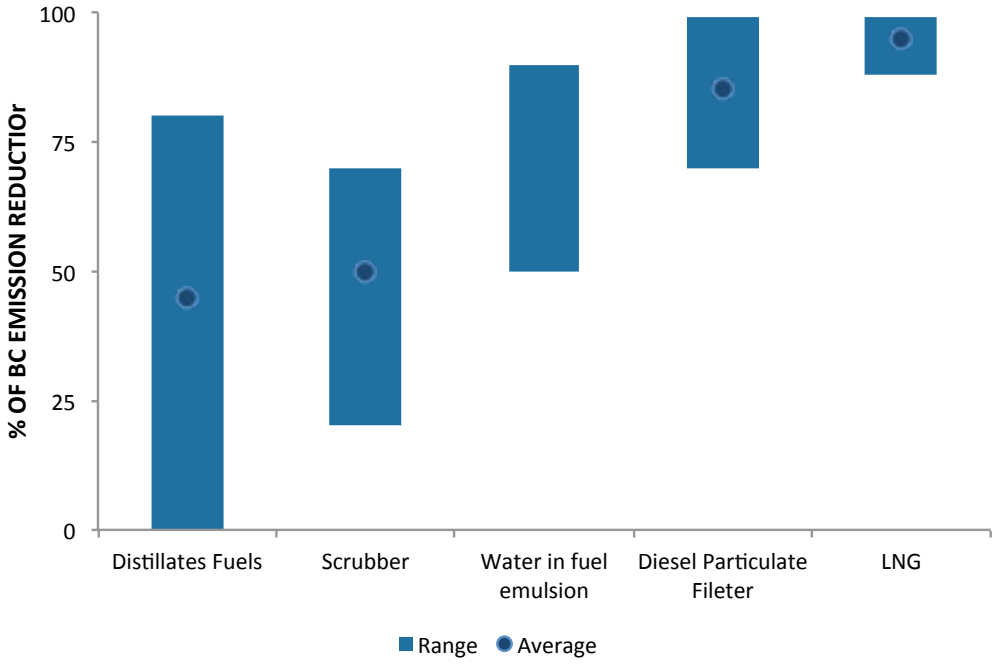
TABLE 10: OVERVIEW FOR THE ABATEMENT TECHNOLOGIES FOR SHIPS/VESSELS[104]

	MATURITY	OTHER ADVANTAGES	DRAWBACKS
Slide Valve (31)(32)(33)	High	Reduce NOx emissions (-20%); fewer engine deposits simple to retrofit	
Distillates fuel	High	Reduce significantly SOx emissions	Price premium, which may increase in the future
Scrubber(31)(32)	Medium to High	Reduce SOx emissions (-90%)	Fuel penalty (2.5%)
Water in fuel emulsion (28)	Medium	Reduce NOx emissions (10 - 50%)	Water used for emulsification needs to be distilled; fuel penalty
DPF + Distillates fuel (31)	Low	Reduce significantly SOx	Fuel penalty (1 to 6%); potential operational problems
LNG	Medium	Reduce NOx emissions; almost eliminate SOx emissions; reduce GHG CO_2 and methane combined by up to 25%	Substantial modifications are required to retrofit; important fuel storage capacity needed; dependant on availability of the fuel in ports; high maintenance costs

EMISSION REDUCTIONS AND COSTS

All these technologies can be retrofitted for existing ship, but the costs may be higher than for a new vessel. Figure 3 presents the impact of the different technologies on black carbon emissions.

FIGURE 3: BLACK CARBON EMISSIONS REDUCTION FOR THE DIFFERENT ABATEMENT TECHNOLOGIES[105]



Finally, the following table summarizes the costs of these technologies. It is important to highlight that cost assumptions are variable depending on the different information sources, and that the economic attractiveness are extremely sensitive to future fuel price assumptions and black carbon emissions factors, which are both quite uncertain.

104 "Improvement of the combustion process" is also discussed as potential abatement measure especially for old engines. However, its potential appears uncertain.

105 Various sources of information including (42)

TABLE 11: COSTS ASSOCIATED WITH DIFFERENT ABATEMENTS OPTIONS - SHIP[106]

	CAPEX	OPEX
Slide Valve (31)(32)(33)	$10k	
Distillates fuel (34)	Small upfront investment ($40k approx.)	Incremental cost of fuel
Scrubber (34)	$5.8 M	Incremental fuel consumption
LNG (34)	$7.5 M	Change in fuel type and consumption

CURRENT PRACTICES ACROSS DIFFERENT REGIONS

Overall, current practices seem to be driven by the existing SO_x regulations. Scrubbers have been proposed and are being implemented in a number of cases in Alaska and Norway. LNG is usually used to fuel LNG tankers, but appears to be extremely rare for other applications[107].

5.3 OTHER SOURCES OF BLACK CARBON

Gas turbines: The primary pollutants from gas turbines are NO_x, CO, and to a lesser extent, VOCs. Gas turbines are also a potential source of PM emissions, when liquid fuels or richer and untreated NG (35) are used as a primary fuel. Very limited research has been identified speaking to the level of black carbon emissions from applications which run on natural gas upstream in the oil and gas sector (i.e. gen-sets, boilers, furnaces and other burners) and many of the oil companies utilize relatively rich associated gas. Water or steam injection can minimize the amount of NO_x emissions while increasing the level of particulates (36).

Road transport: The land transport sector in the upstream O&G sector (for example heavy-hauler mining used to move extracted bitumen, or LPG/LNG trucks) may represent an additional source of black carbon. Black carbon emission depends on the engine type and the fuel and the operating conditions. For example, an emission factor of 0.40 gr black carbon/kg of fuel was calculated for a mining truck (37)[108] and 1.7 gr black carbon/kg for a heavy duty fuel truck (38). DPF[109] is a proven technology that can reduce black carbon emissions by 60 to 95 % (39) on a large range of engine types. However DPF must be used with low sulphur diesel fuel and the fuel penalty associated with retrofit DPF range from zero to a few percent (40).

Small aircrafts with piston engines: Soot emissions from aircraft depend on the type of fuel and on the aircraft specificities and can vary by two orders of magnitude. PM emissions can be reduced through optimization of pilot operations, change of fuel or the installation of a DPF with a catalyst (41)

6. REDUCING BLACK CARBON & CH_4: BARRIERS AND ABATEMENTS COSTS

This chapter focuses mainly on the abatement costs analysis but also describes more generally the existing barriers for technologies/practices implementation.

6.1 ABATEMENT COSTS IN THE ARCTIC

6.1.1 FACTORS INFLUENCING ABATEMENT COSTS IN THE ARCTIC CONDITIONS

As described in the previous sections, all the technologies evaluated can be applied in Arctic conditions, though the performance of some of them may be affected by extreme cold weather. In some cases the Arctic abatements costs can be higher than the existing published ones, due to differences in the implementation costs, but also in expected revenue.

106 All the figures are given for a ship of 8000 kW for the main engine. Note, abatement cost assumptions are based on (42) (31) and (34)

107 New engines manufactured by one of the main engine manufacturers come equipped with slide valves.

108 Note: Environment Canada is currently conducting a study to assess emissions related to surface mining of oil sands.(http://smartmines.com/minutes/may2012/Mike_Lipsett_Emissions_Measurement_System.pdf)

109 Flow Thru Filter (FTF) is an alternative technology and can reduce about 50% of the black carbon emissions.

FACTORS INFLUENCING COST

Based on the interviews, a number of factors influencing technologies' implementation costs have been identified:

- **Installation costs:** Installation costs can vary greatly depending on the site location and may represent a large share of the investment costs.
- **Transport and freight costs:** Due to remoteness of some sites, transport of equipment may be challenging, costly and may only be possible during some parts of the year.
- **Labor costs:** Labor costs are typically 20 to 40% higher in Arctic conditions.
- Design and engineering costs: Additional engineering and design may be required when retrofitting specific equipment.
- **Offshore versus onshore:** For a number of technologies, offshore costs are significantly higher than onshore ones. With a majority of the future prospect in the Arctic situated offshore[110], this may impact the overall abatement costs in Arctic conditions.

In most cases, however, the material/equipment costs reported are fairly similar to the costs in non-Arctic regions.

FACTORS INFLUENCING THE REVENUE

A number of technologies to reduce methane emissions are profitable if the gas recovered can be used or sold. In remote location, gas may have no local value (when excess gas is flared) or have a low netback value (when markets are really distant). This parameter has an important impact on abatement costs for technologies reducing methane emissions.

6.1.2 METHODOLOGY TO CALCULATE THE ABATEMENT COSTS

Abatements costs are derived from the incremental Net Present Value (NPV) of the implementation of the abatement technology and represents the monetary value that must be applied to the pollutant (black carbon or methane) to reach a NPV=0[111].

Economically attractive measures will have negative abatement costs. This means that there is a net financial benefit for the project developer in implementing them at the assumed discount rate. Measures or technologies with a positive abatement cost are not economically attractive unless there is a positive monetary value associated with the emission reductions that can be achieved, where capturing the opportunity would require incremental costs compared to business as usual.

Abatements costs for methane/black carbon in the upstream sector rely on a large number of assumptions, which are country, region and site specific. To reflect these variations, instead of calculating one single abatement cost per technology, a number of different assumptions were used to estimate a realistic range of abatement costs for each technology. The following table summarizes the main sensitivities analysed.

110 USGS

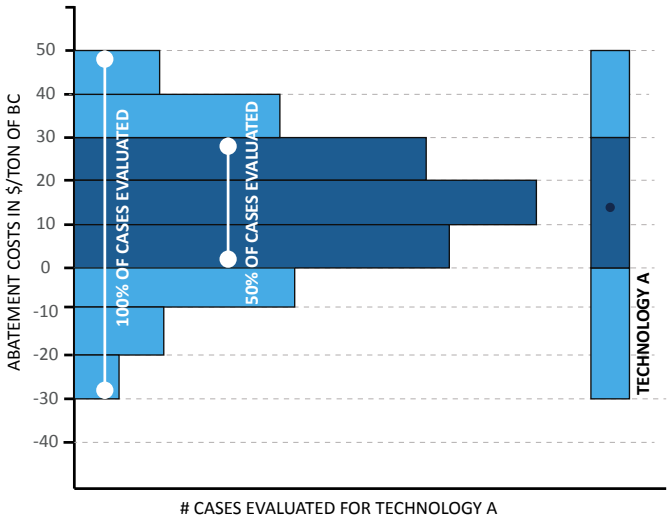
111 For this study, in the abatement costs, the following assumptions have been made:
-Regulatory regime: Some of the countries studied have already emissions regulations in place (in the form of a CO2 tax, CO2 trading system, or technology standard). As the study covers several countries, with very varied regulations, the abatements costs are calculated in the absence of any emissions reduction regulations. When these regulations are already in place, the abatement costs will actually be lower (up to negative) than the one presented. The current presentation allows the comparison of the different technologies with the same baseline.
-Tax regime: the different tax regimes of the different countries have not been considered when assessing the abatement costs.
-Down time (i.e loss of production) has not been considered in the costs analysis. It has always been considered that the retrofit would be performed during a planned maintenance.
-An interest rate of 10% has been assumed.
-Abatement costs are calculated from the perspective of a private investor
-The entire technical lifetime of the abatement technology is considered in the cost analysis.

TABLE 12: OVERVIEW OF DIFFERENT ABATEMENT COSTS CASES ANALYSED[112]

	CASES EVALUATED		
The local net back value of the gas: The local value of gas depends on a number of factors, including regional gas prices, distance to market and costs of alternative energy sources. For remote sites, the local gas value may be very low, except if gas can be used as an alternative fuel for power generation or heat. To reflect this uncertainty, different cases have been assessed.	$0/mscf	$2.5 /mscf ($88 /000 cm)	$5 /mscf ($176/000 cm)
Retrofit versus new installation: In a number of cases, the costs associated to retrofit are higher than the costs for new equipment (e.g. DPF). When relevant, both cases have been assessed.	New	Retrofit	
Onshore versus offshore installation: For some technologies, the costs of implementation offshore are higher than for onshore installation (e.g. VRU)	Onshore	Offshore[113]	
The share of methane in the recovered gas: Methane content of the gas varies widely, depending on reservoir gas composition[114].	55%	70%	80%
Size of installation: The costs and emission reductions will vary depending on size of the site or equipment. When relevant, different cases have been evaluated (e.g. two different stationary engine size have been evaluated)	NA		
Other technology specific key parameters: Finally, some technology-specific parameters vary between sites (e.g. leakage rate of the pneumatic devices, vapor release rates), and thus some technology specific sensitivities have been performed.	NA		

Capital costs, implementation costs and operation expenditure (OPEX) assumptions are based on the results of the interviews and on literature review. Overall, the abatement costs for more than 850 cases were estimated[115] for the 21 technologies or practices covered in the cost analysis. As a result, abatements costs are presented as ranges. A schematic example is presented below to illustrate how the Figure 5 and Figure 6 can be read.

FIGURE 4: PRESENTATION OF THE DISTRIBUTION OF THE ABATEMENT COSTS -- FOR ILLUSTRATIVE PURPOSES ONLY



As this study focuses on methane and black carbon emission reductions, abatement costs per ton of black carbon and per ton of methane have been evaluated, excluding the contribution of any other pollutants. However some of the technical options have other environmental benefits (CO_2, NO_X, SO_X, Organic Carbon, nmVOC), and thus their respective attractiveness should be weighed against their full environmental impact in the Arctic context.

112 The details of the assumptions are available in the appendix

113 Note: Due to insufficient data, it has not been possible to collect information for costs offshore for all the technologies/practices.

114 Note: Rich gas (with low methane content) may have significantly higher value.

115 Note: Not all the combinations of all the parameters were performed. It is important to highlight that all the cases presented are possible but their probability in the Arctic region has not been evaluated and the 850 are not equiprobable.

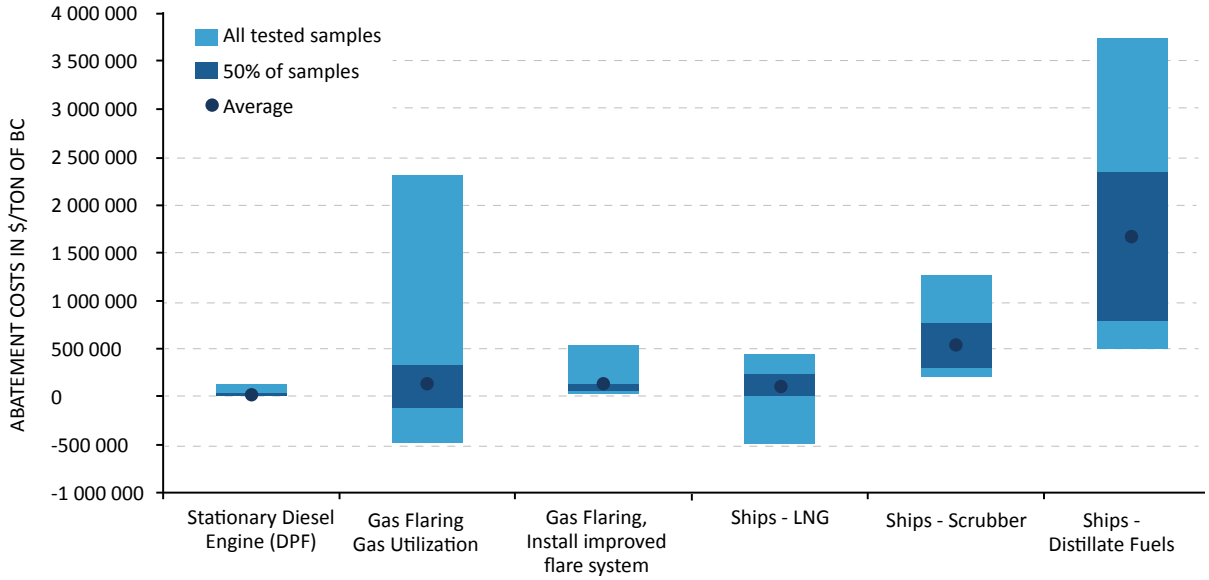
6.1.3 ABATEMENT COSTS

The following two sections present abatement costs for both black carbon and methane emission reduction. It is important to highlight that the impact on climate of reducing one ton of black carbon versus one ton of methane emission is considerably different. Illustrative costs per ton of $CO_{2\ eq}$ are thus also presented.

BLACK CARBON EMISSIONS REDUCTION MEASURES

Figure 5 presents the distribution of the abatement costs for a number of black carbon emissions reduction measures.

FIGURE 5: OVERVIEW OF ABATEMENT COSTS FOR THE BLACK CARBON EMISSION REDUCTION MEASURES[116]



A number of conclusions can be drawn from the abatement costs presented:

- Unsurprisingly, abatement costs are mainly positive, with the exception of gas utilization and LNG conversion, as there is no/limited benefit associated with these measures.
- All the other emission abatement options have abatement costs higher than $25k/t black carbon.
- The installation of DPFs on diesel engines represents a relatively low cost abatement option. The potential of this abatement option is however limited to the areas – mainly remote-- where diesel is used.
- Associated gas utilization may represent a profitable black carbon emission reduction measure in some cases. However, in many of the cases evaluated, the abatement cost of installing an improved flare system is low[117].

METHANE EMISSIONS REDUCTION MEASURES

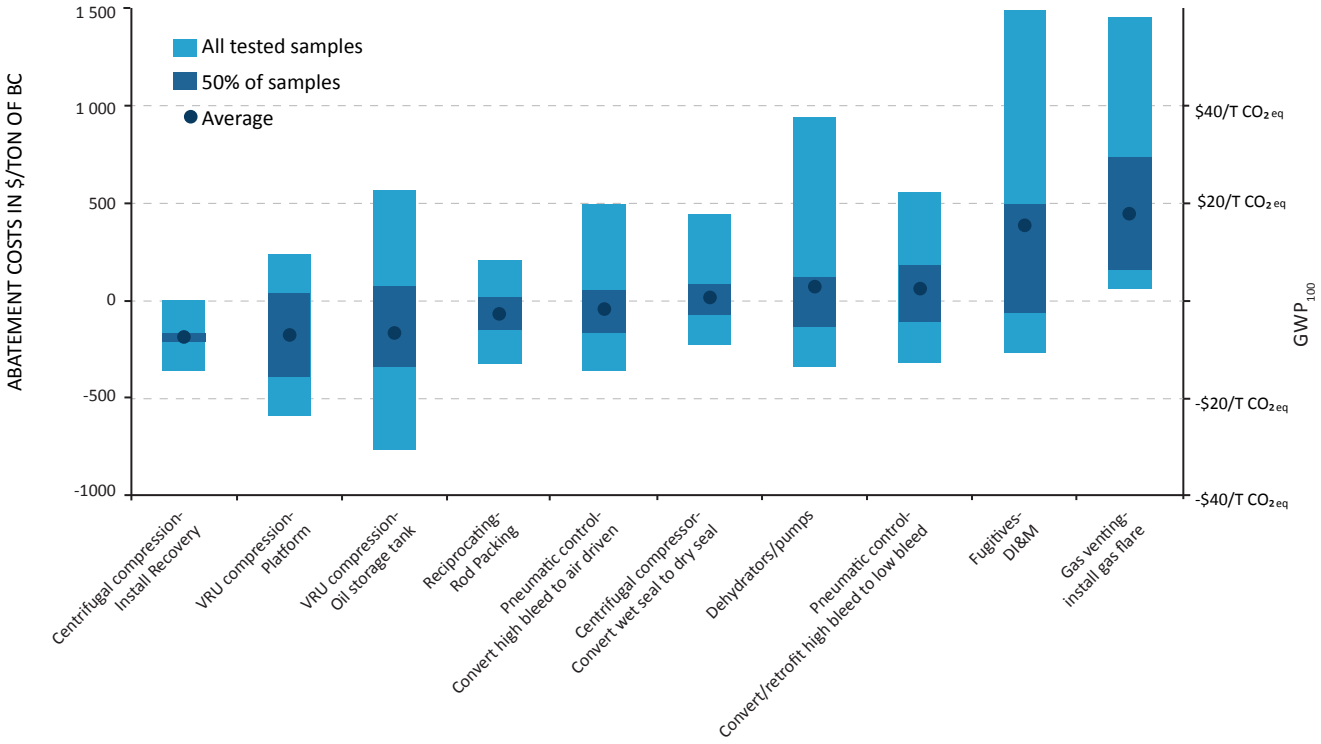
The following graph presents the abatement costs for methane emissions reduction measures. A few technologies with extreme abatements costs have been excluded from the graph to aid the visual comparison[118].

116 Baseline outside of an ECA (current status in the Arctic). Black carbon emission reductions have also a health impact, which is not factored in the abatement costs.

117 Associated gas utilization is presented here only as a black carbon emissions reduction measure (due to the focus of the study), with the understanding that CO2 emissions are also reduced.

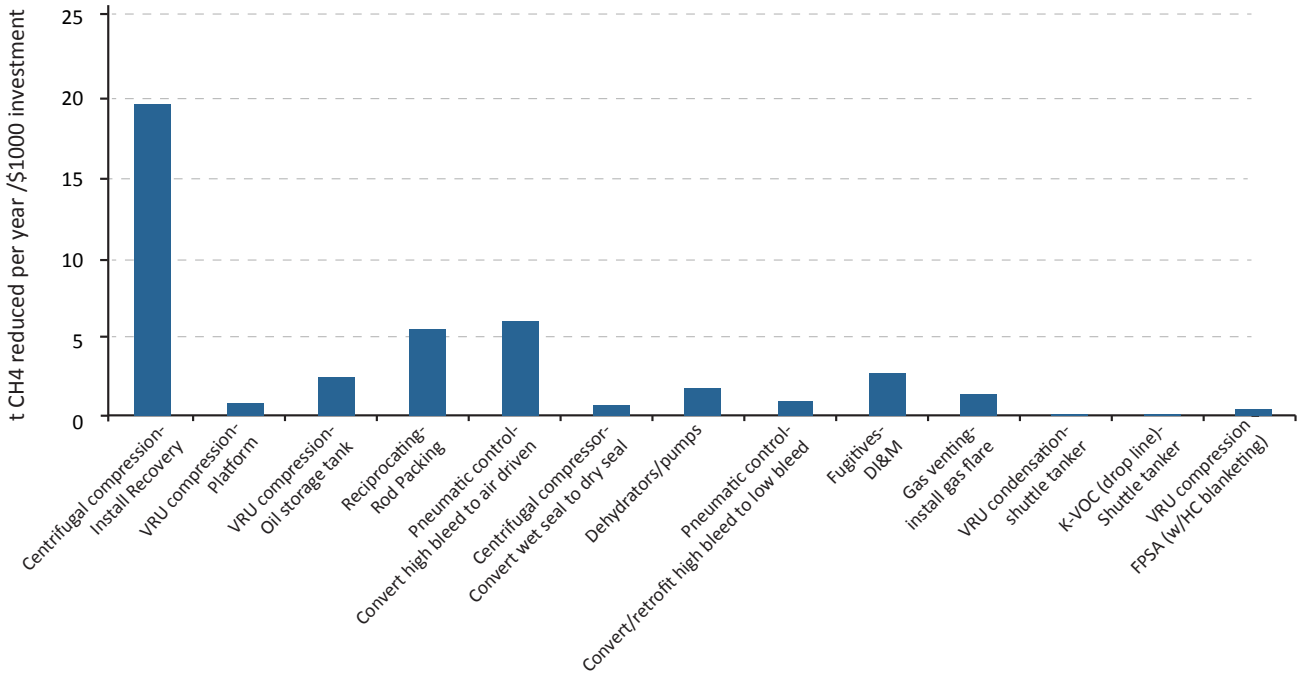
118 Three technologies have been excluded from the graph: "K-VOC (drop line) - Shuttle tanker", "VRU - Compression - FPSO (with hydrocarbon blanketing)" & "VRU - Condensation - Shuttle tanker". In these three cases, abatement costs vary hugely depending on the cases analysed (e.g. by a factor 200). These technologies are primarily implemented to reduce nmVOC. Methane emissions reduction is very small compared to the scale of the investment and is only a positive side effect. In addition, the extreme cases for DI&M have been excluded from the graph for visual comparison. Abatement costs for DI&M can be in the order of $6000/t CH4 for smaller/remote sites.

FIGURE 6: OVERVIEW OF ABATEMENT COSTS FOR THE METHANE EMISSIONS REDUCTION MEASURES



The technologies/practices compared have very different scales, with investment varying from $500 to multimillion US dollar projects. The graph presented below compares annual emissions reduction per thousand dollars of upfront investment, for all the technologies reviewed. It demonstrates that some technologies require significant investment (e.g. technologies to reduce emissions from tanks/loading operation) while a number of technologies/practices (e.g. DI&M; rod packing conversion) require very little investment compared to the amount of emissions saved.

FIGURE 7: EMISSIONS REDUCTION POTENTIAL COMPARED TO THE UPFRONT INVESTMENT[119]



119 The technologies are presented in the same order as in the figure above.

A few key points can be summarized from the analysis:

- The abatement costs for methane emission reduction vary widely depending on the local circumstances
- A large number of cases evaluated present negative abatement costs, i.e. methane emissions reduction can be made at an economic gain.
- Some of the technologies, commonly associated to a net financial benefit, may be less attractive in some situations, particularly due to the low local gas value. As the warming potential of methane does not depend on the location of the emissions, the implementation in Arctic conditions of these technologies may not be the most economically attractive on a global scale.
- Not all of the "inexpensive" abatements measures are widely used currently.
- For a number of the abatement technologies reviewed, retrofitting is more expensive than new systems and is often associated with a number of practical issues. As new development starts in some parts of the Arctic region, there may be opportunities for early uptake of emission reduction solutions.

6.2 OTHER BARRIERS TO PROJECT IDENTIFICATION OR IMPLEMENTATION

The interviews performed shed light on a number of barriers to the identification or implementation of emission reduction practices or technologies in the Arctic region. In this section, these barriers are briefly described:

GAPS IN EMISSIONS DATA OR INSUFFICIENT DATA OPENNESS: As highlighted for some specific technologies, there is currently a gap in emissions data or emissions factors, in particular regarding black carbon emissions. In addition, for the data available, interviewees emphasized the lack of data openness and transparency in some regions of the Arctic. The availability and openness of emissions data is crucial for the identification of emission reduction opportunities.

LACK OF AWARENESS OF ENERGY LOSS: A large number of interviewees were familiar with methane emissions reduction options and their potential economic benefits. However a few interviewees highlighted that some O&G companies still do not fully appreciate the energy/financial loss due to the gas loss in their facilities.

MONITORING: There is a great variety in the monitoring practices across different regions and different O&G companies. In particular, there are differences in terms of monitoring standards, boundaries (which emissions are included), methods applied, measurement technologies[120], traceability, and emissions factors used.

SITE ACCESSIBILITY: Remote sites present additional challenges, as they may be unmanned and also accessible only seasonally. The monitoring of emissions in these sites may be quite challenging and thus restricted, and the maintenance/repair may not be frequent. In addition, the implementation of many of the abatement measures described may be challenging or costly.

SHORT SEASON: As sites may be accessible only in winter (onshore) and some operations may only be accessible in summer (offshore), the time window to implement a technology can be short.

CONTRACTUAL CONDITIONS: Contractual conditions can have an impact on the business decisions regarding some of the technologies reviewed (Ship, FPSO, compressors). Depending on the agreements between equipment owners, equipment operators and resource owners, the company investing in emissions reduction technologies may not benefit from the emission reductions[121].

DOWN TIME: Down time or maintenance of equipment is often quoted as an important barrier to project implementation.

120 In particular for gas flare volume.
121 Note: This issue has not been reflected in the abatement costs presented.

PENETRATION RATE OF TECHNOLOGY: Some of the best practices reviewed are penetrating largely in some regions, either driven by their intrinsic economics, or by regulations. However interviewees highlighted that the rate of penetration appears to be limited by maintenance/replacement schedule (e.g. a compressor may be operating for years without any shut-down).

FIELD DEVELOPMENT CONSTRAINTS: Interviewees highlighted that the development of new fields is often associated with tight budgets and time constraints (particularly in expensive locations, e.g. deepwater, Arctic). In this context, O&G producers often are not able to optimize relatively small value investment (e.g. to maximize the natural gas exported to the market).

POLICY UNCERTAINTY: Interviewees, in general, highlighted the role of regulation in mitigating emissions. In addition, some interviewees underlined that companies tends to be less proactive in a context of an uncertain and unpredictable policy.

SPECIFIC BARRIERS FOR GAS UTILISATION: Interviewees have also emphasized the current challenges, which hinder increasing the share of gas utilized, in particular in Russia. These barriers have been documented over the last few years, and include geographical, regulatory and structural issues.

7. SUMMARY & CONCLUSION

BEST PRACTICES TO REDUCE EMISSIONS

The present study has confirmed that a number of mature technologies are available to reduce black carbon and methane emissions in the upstream O&G sector. In most of the cases, these technologies are suitable for Arctic conditions and, when properly designed and maintained, can achieve significant emission reductions. The abatement options presented have also positive or negative impacts on other pollutants and the full environmental impact should always be considered when reviewing them.

ABATEMENT COSTS IN THE ARCTIC

The business case for the application of the different abatement technologies is site specific and abatement costs vary significantly. In addition, a number of other barriers hinder the implementation of these technologies, e.g. repair down-time, existing contractual situations, and site accessibility/remoteness.

- *METHANE EMISSIONS REDUCTION*

A large number of cases evaluated present negative abatement costs, i.e. methane emissions reduction can be made at an economic gain. However, there are also a range of situations where methane abatement in the Arctic requires incremental costs compared to business-as-usual due to site specific factors, such as low local gas value and high cost for transport, labor and other "logistic" costs. Nevertheless abatement cost for the vast majority of the cases evaluated are below $30/t$CO_{2eq}$.

- *BLACK CARBON REDUCTION*

Despite the relative importance of black carbon climate forcing in the Arctic, information on black carbon emissions is scarce or uncertain and interviewees were much less familiar with black carbon abatement options than with methane. In addition black carbon abatement costs are, in most cases, significant. Gas flaring is most likely one of the largest sources of black carbon emissions in the Arctic upstream O&G sector. Utilizing the gas is, of course, a natural option to reduce black carbon emissions. But in some cases, gas utilisation infrastructure may be costly or take a long time to commission. Though the knowledge on black carbon emissions from gas flaring is very limited, it seems that opportunities exist to reduce soot emissions drastically by improving flaring systems.

CURRENT PRACTICES

Overall, there are important variations on the level of uptake of the best practices or technologies between the different Arctic regions, but also between different sites. More particularly:

- **Gas flaring (both methane and black carbon):** Most of the major international O&G companies have designed and are implementing flaring reduction programs. Large volume of gas is still flared in Russia.
- **Methane emission reductions:** Some of the best practices reviewed have penetrated largely in Norway, North America and, in some cases, in Russia. Some key challenges remain however for smaller or dispersed sites.
- **Black Carbon emission reductions:** Diesel engines are used mainly in remote areas (or on drilling rigs) and gas power is very common in the Arctic regions. When diesel engines are used, the installation of Diesel Particulate Filter seems the exception.

TABLE 13: SUMMARY TABLE OF THE MAIN ABATEMENT OPTIONS

Emission Source	BC/ CH_4?	Technology /Practice	Maturity	Off/ Onshore	Applicable Exploration development?	Emission reduction	Additional Comments/ Other Impacts of Implementation
Centrifugal compressor	CH_4	Dry seal	H	BOTH	YES	94%	Retrofit requires long down-time
		Seal Oil Vapor Recovery System	H	BOTH		95%	(1)
Reciprocating compressors	CH_4	Economical replacement of rod packing	H	BOTH	YES	50%-65%	
		Collecting and using/flaring the vent	M			95%	
Gas Venting	CH_4	Flare instead of vent	H	BOTH	YES	Up to 98%[123]	↗ CO_2 and potentially ↗ BC
		Utilize the gas	H	BOTH	NO	Variable	
Storage and loading of hydrocarbon products	CH_4	Reduce operating pressure upstream	H	BOTH	NA	Up to 30%	↘ nmVOC up to 30% for -1 bar
		Increase tank pressure	L-M			10-20%	↘nmVOC up to 10-20% for >0.2 bar
		Change geometry of loading pipes	M			Poor data	↘nmVOC up to 50%
		VRU: Gas compression	H			95%	↘nmVOC by 95%
		VRU: Ejector	H			>95%	↘nmVOC >95%
		VRU: VOC condensation & gas recovery	M-H			95%	↘nmVOC by 95%
Glycol dehydration and flow assurance	CH_4	Install Flash Tank Separator (FTS) & Optimize glycol circulation rates	H	BOTH	NA`	90%	
		Use electric pump			NA	80%	
		Reroute Glycol Skimmer Gas			NA	95%	
Fugitive emissions	CH_4	Directed Inspection and Maintenance	H	BOTH	YES	60%-80%	
		Subsea leakages detection & repair	M	OFF	NA	Uncertain	
Pneumatic devices	CH_4	Replacement to low bleed devices	H	BOTH	NA	90%	
		Retrofit into low bleed	H		NA	90%	
		Replacement to air driven instrument	H		NA	100%	
Flare - Decrease flare emissions	BOTH	Install advanced flare systems	M-H	BOTH	YES	Uncertain	↗ $CO_2$and possibly ↗ NOx
	BC	Properly size/operate knock out drum	H				
Flare - Increase gas utilization	BC	Maximize local/onsite use	H	BOTH	NO?	Almost 100%	↘ CO2 emissions (& possibly NOx/SOx)
		Gas injection	H		NO		
		Export marketable products	M-H		NO		
		"Near-zero" flaring solutions	H		NO		
Ships/Vessels	BC	Scrubber	M-H	OFF	YES	20-70%	↘ SOx emissions ; ↗ Fuel
		Use Distillates Fuels	H		YES	0-80%	↘ SOx emissions. Fuel premium
		Use LNG	M		YES	88-99%	↘NOx, SOx and GHG
		Water in fuel emulsion	M		YES	50-90%	↘NOx emissions ; ↗CO2
		Slides valves	H		YES	10-50%	↘ NOx emissions; Simple retrofit
		Diesel Particulate Filter	L		YES	70-99%	↘ SOx emission; ↗CO2;
Diesel engines and boilers	BC	Convert to gas	H	BOTH	VARIES	Most	↘ CO_2
		Import power from grid	H	BOTH		Variable	Depends on the local power source
		Implement good combustion practices	M	BOTH	YES	Uncertain	↘ CO emissions and HC emissions
		Install diesel particulate filter	H	BOTH		60-99%	
Diesel land transport	BC	Diesel Particulate Filter	H	ON	YES	60%-99%	(↗CO_2)

122 Depends on the combustion efficiency of the flare

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APPENDIX 1 : COMPANIES/ ORGANIZATIONS INTERVIEWED

Oil and Gas companies
BP
Chesapeake Energy
Sakhalin Energy
Statoil
SUNCOR
Regulators
Environment Canada
EPA
KLIF
NGOs
Bellona
CATF
Earth Justice
NRDC
WWF

Service/Technologies Providers/ Others	
Blair Air	Fluenta
Bluewin	Hamworthy
CanmetENERGY	Hussgroup
CAPP	IMO
Carleton University	Inspectahire
CECO	John Crane
Clearstone Engineering	John Zink
Combustion Resources	Kleven Maritime
Comm Engineering	NOAA
Consilium	REM technologies
CorkenIdex	SIMEK Offshore
Couple Systems	Target Emission Services
EagleBurgmann	Wärtsilä
FLIR	WellMarko

APPENDIX 2: LIST OF ACRONYMS USED

AG	Associated Gas
BAT	Best Available Technology
bcm	billion cubic meters
CAPEX	Capital Expenditures
cm	Cubic Meter
CH_4	Methane
CNG	Compressed Natural Gas
DI&M	Direct Inspection and Maintenance
DPF	Diesel Particulate Filter
ECA	Emissions Control Area
EPA	Environmental Protection Agency (USA)
FGRU	Flare Gas Recovery Unit
FPSOs	Floating Production, Storage and Offloading Units
FSOs	Floating Storage and Offloading units
FTS	Flash Tank Seperator
GTL	Gas to Liquids
GWP	Global Warming Potential
HAP	Hazardous air pollutants
IMO	International Marine Organization
IR	Infrared
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MEG	Monoethylene Glycol
MSCFD	Thousand Cubic Feet
NAMA	Nationally Appropriate Mitigation Actions
NG	Natural Gas
NGO	Non-Governmental Organization
nmVOC	non-methane Volatile Organic Compound
NPV	Net Present Value
O&G	Oil and Gas
OPEX	Operational Expenditures
P&A	Plug and Abandon
PM	Particulate Matter
scfh	standard cubic feet per hour
SLCF	Short-lived Climate Forcers
TEG	Triethylene Glycol
VOC	Volatile Organic Compound
VRU	Vapor Recovery Unit