M-1771|2020

Cold venting and fugitive emissions from Norwegian offshore oil and gas activities

Sub-report 2
Emission estimates and quantification methods

Prepared for the Norwegian Environment Agency

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15 March 2016

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M number	Year	Pages	Norwegian Environment Agency contract number
M-1771 | 2020	2016	76	14088187

Publisher

Norwegian Environment Agency

Financed by

Norwegian Environment Agency

Authors

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Title

Cold venting and fugitive emissions from Norwegian offshore oil and gas activities
Module 2 – Emission estimates and quantification methods

(Translation of Norwegian report M-511I2016)

Summary

The methodology for quantifying emissions from individual sources was assessed on the basis of the emission source survey in module 1 of this project, and principles for future quantifications were recommended. General quantification methods were proposed for most of the emission sources to ensure consistency. Where sources which occur only on one or a few facilities are concerned, it was proposed that the operator prepares facility-specific methods. Such methods were also recommended for emissions sources which are so complex that general methods can be inconsistent. Where sources with very low emissions are concerned, the recommendation was that separate quantification of these emissions be omitted and replaced by a simple percentage mark-up covering all such small sources.

New emissions estimates were prepared. These indicated that the previously reported emissions may be overstated. However, the level of uncertainty is high, particularly for fugitive emissions and minor leaks.

Four subject words

Direct emissions, HC gas, methodology, inventories

Front cover photo

Heimdal. Source: Statoil, Photographer: Øyvind Hagen

Summary

Based on the results from the survey conducted in module 1 of this project and the potential emission-generating processes and sub-processes identified there, new quantification methods have been considered and proposed, and updated emission inventory estimates prepared.

Generic quantification methods are proposed for most of the processes/emission sources, but facility-specific methods are recommended for a few. These represent complex sources and processes which are utilised on only one or a couple of facilities.

A factor-based method is proposed for some processes/sub-processes, using the emission-controlling parameter as the activity factor. This parameter could be the quantity of produced water, the number of wells and so forth. Otherwise, the methods vary widely:

- measurement/sampling
- process simulations/use of special programmes
- utilising recorded measurement data
- registration of events (for non-continuous emissions)
- supplier data.

The survey conducted in module 1 showed that emissions from several of the identified sources are so small that they have no practical effect on the total. The proposal is therefore to drop separate emission calculations for these sources, and to compensate by making a small fixed percentage mark-up to the calculated emissions.

Efforts have been made in module 2 to recalculate/re-estimate total emissions from the sector. This is done partly with reference to the proposed new quantification methods, but not entirely because the necessary reference data are not available. In such cases, other and more uncertain calculation methods have been used. Where some of the sub-processes are concerned, no information has been available which made it possible to estimate the emissions. This is because, in a number of cases, the historical data required to calculate emissions have not been registered. The emission overviews indicate that direct emissions of both methane and nmVOC are below the figures previously reported using the "old" methods.

Uncertainty in the emission estimates and what can be expected with the proposed new quantification methods have been evaluated on a qualitative basis. Lack of access to data has meant quantitative uncertainty estimates could not be made. The uncertainty in the overall estimate is estimated to be in the order of several tens of per cent. Unlike previous emission overviews, however, the estimates have been made in accordance with more consistent methodologies and provide more accurate emission data.

Uncertainty in the emission estimates is particularly high for fugitive emissions and minor leaks. These sources are therefore dealt with in a separate sub-project, as described in sub-report 4.

The proposed new estimation methods will help to ensure better consistency and even more accurate emission overviews than those presented here. Even so, the nature of direct methane and nmVOC emissions means that substantial uncertainty must be accepted. Information reviewed from other countries shows this to be a general problem. Adopting the suggested calculation methods will ensure that the quality of reports on direct emissions from Norwegian offshore facilities will be at least as good as or better than those from some of the other countries used as benchmarks.

Opportunities for measuring the gas quantities emitted have been investigated. Ultrasonic measurement has been identified as the most attractive principle. This also seems to be applicable for breaking down total emissions between methane and nmVOC. Ultrasonic meters can be installed without emptying HC gas from piping systems, known as hot tapping. Ultrasonic measurements can also utilise clamp-on gauges which are installed on the outside of a pipe. This is primarily relevant with feed streams for emission, such as stripping or purge gas. Clamp-on gauges are not currently recommended for emission flows where the pressure is low.

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1 Introduction

Reported emission data represent an important basis for follow-up of the industry by the Norwegian Environment Agency (NEA), including specification of requirements and assessment of measures. This information forms the basis for the national emission inventory as well as for monitoring national goals and international commitments. The NEA therefore considers it important to secure emission figures which are more accurate than those available today.

Offshore petroleum activities involve emissions of methane and non-methane volatile organic compounds (nmVOC) from a variety of sources. The three main ones are:

- unburned gas from gas turbines, gas engines, boilers and flares
- vapour released from shuttle tankers during loading of oil and gas on the field
- cold venting and fugitive emission from the facilities, also known as direct methane and nmVOC emissions.

The direct emissions reported by the oil and gas sector contributed to about 71 per cent of the total methane emissions and about 18 per cent of the total nmVOC emissions from the sector in 2012.

Questions have been raised for several years about whether the methods used to quantify direct methane and nmVOC emissions capture all the sources, and whether the emission estimates are acceptable.

On that basis, the NEA has commissioned Add Novatech AS to improve knowledge about direct emissions of methane and nmVOC from facilities on the Norwegian continental shelf (NCS). The assignment comprises three modules:

- module 1 covers an updated survey of sources for direct emissions of methane and nmVOC
- module 2 covers a review and revision of calculation methods and emission factors to obtain more clarity over the size of emissions
- module 3 will illuminate possible measures to reduce the emissions and assess what is to be considered the best available technology (BAT) for cutting direct methane and nmVOC emissions from offshore petroleum activities.

Work on modules 1 and 2 took place in parallel, while module 3 was completed in 2015. The project was expanded in its final phase with a fourth module to verify (if possible) certain methods for quantifying fugitive emissions with the aid of measurement data from oil and gas treatment plants on land.

This report covers module 2.

Flaring waste gases is often regarded as eliminating the emission. That is not quite correct, since the combustion ratio in the flare is below 100 per cent (about 99 per cent). This component is not taken into account in the emission estimates in this report. Flaring also emits combustion products, with CO_2 as an important greenhouse (GHG) gas.

To secure better emission estimates, the NEA issued an order to the operators in late August 2015. The latter delivered updated emission estimates for 2014 in November 2015. This report has been updated with validated emission figures and waste gas solutions received in response to this order.

2 Emission of HC gases

2.1 Why is attention being paid to HC gas emissions?

Hydrocarbon (HC) gases are reported as methane (CH_4) and nmVOC to meet regulatory requirements and international agreements.

Methane is a GHG with a global warming potential (GWP) 25 times the CO_2 equivalent (CO_2e) in a 100-year perspective. This means that releasing one tonne of methane has the same GWP as 25 tonnes of CO_2. Since methane eventually oxidises to CO_2 in the atmosphere, the GWP of such emissions decreases over time. On the other hand, and for the same reason, the GWP of methane emissions will be higher in a shorter time frame.

In practice, nmVOC embraces all HC gases except methane. It contributes to the formation of ground-level ozone, which has a regional environmental impact. Through the Gothenburg protocol, Norway has undertaken to reduce its nmVOC emissions by 40 per cent from 2005 to 2020 (from 218 000 tonnes/year to 131 000) (ref 17). In mark-up to its regional consequences, which are managed through the Gothenburg protocol, nmVOC is an ozone precursor. Ozone is also a short-lived climate forcer.

The GWP of the short-lived climate forcers is shown in table 1, derived from to the NEA's preliminary sector report (background report for the proposed action plan on short-lived climate forcers - ref 16).

Table 1 GWP in a 10-year perspective for short-lived climate forcers.

Component	Weighting factor for CO_2e (GTP10, Norway)
CO_2	1
Methane, CH_4	86
Nitrogen oxides, NO_X	-28
Carbon monoxide, CO	9
NmVOC	14
BC (black carbon)	2914

2.2 What is direct emission of HC gases?

Direct emission of HC gases can be divided into two categories.

a. **Fugitive emissions.** These are leaks of natural gas directly to the air through valves and seals, hoses and flexible piping, as well as vaporisation from HC liquids and from drill cuttings. They can never be fully eliminated, but can be minimised with good/appropriate materials, equipment, design and operating procedures. Fugitive emissions can occur anywhere on the facility where HC gas is present.

b. **Venting/cold flaring**. These are HC-containing gases released from various processes or sub-processes on a facility and routed to the air as a result of planned and chosen operational solutions. Such operational emissions are often called venting, cold venting or cold flaring. They usually occur through dedicated piping systems, where natural gas is released in a safe location.[1] Venting may be chosen for several reasons, including safety issues, high levels of inert components (mainly nitrogen) in the gas, pressure conditions on the facility, pure cost preferences (very expensive to eliminate/reduce emissions relative to their size) or a combination of these. In many cases, venting can be avoided through good design. Options may be gas recycling or flaring. Environmentally, recycling is the best solution but flaring may be preferable because the GWP of the combustion products is significantly lower than for HC gases. Eliminating some operational emissions of HC gases may be more or less impossible because good technical solutions are unavailable, or because available solutions are very costly.

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[1] To avoid the explosion hazard.

3 Objective and scope of work

Module 2 of the project is based on the survey conducted in module 1. The work has included the following activities:

- develop proposal to update the methodology for quantifying emissions
- assess the uncertainty in the proposed new methods
- update emission estimates
- compare the proposed new emission factors and methods with corresponding practice in other comparable countries
- assess opportunities for determining emissions through measurements.

The survey covered 56 producing facilities on the NCS. Information about planned waste gas solutions was also obtained for 12 facilities still not on stream. Fifteen of the producing facilities were reviewed in detail through all-day meetings with the operator. This resulted in much useful information which had a considerable influence on the work with and results of module 2.

- A total of 48 new emission sources, also called processes generating waste gases, were identified.
- Where most sources are concerned, the survey provided useful information which provides a basis for establishing new targeted, consistent calculation methods and more reliable emission figures.
- However, knowledge about emissions from some of these sources was limited, in part because they are new compared with those previously reported by the industry. This means more work will be needed before new calculation methods can be established for these sources.
- Where some of the larger sources are concerned, facility-specific quantification methods and factors will be required because the processes which generate the emissions are facility-specific. The relevant operators must establish calculation methods and emission factors for these on the basis of their own dedicated process.
- Some of the emission sources show big variations in the data used to calculate the preliminary figures presented in this report. That partly reflects the use of inconsistent and to some extent less relevant calculation methods in certain production organisations. Proposed new calculation methods will ensure more consistent and accurate emissions figures in the future.

These considerations mean that more detailed work is needed for some of the major sources before a new quantification methodology and updated emission figures can be established. This report is structured on that basis. Chapter 4 contains an evaluation of the individual sources on the basis of emission data, quantification methods, uncertainties and the need to strengthen knowledge. Chapter 5 establishes a status for measuring emission streams. Chapter 6 deals with new methods for quantifying emissions, while chapter 7 presents an preliminary and incomplete estimate of emissions.

4 Emission assessments for each source

4.1 TEG regeneration

4.1.1 Introduction

A total of 32 facilities on the NCS use triethyleneglycol (TEG) as the absorbent for reducing water in export gas. This prevents the formation of hydrates in transport pipelines, and is done in an absorption tower – also called a glycol contactor – where dry (anhydrous) TEG flows in the opposite direction to the natural gas and absorbs water during the process. In mark-up to water, some methane and nmVOC are also absorbed by the TEG solution in the contactor. Used (wet) TEG therefore contains water as well as some methane and nmVOC when it emerges. To reuse the TEG, the water must be removed in a regeneration process, as illustrated in figure 1.

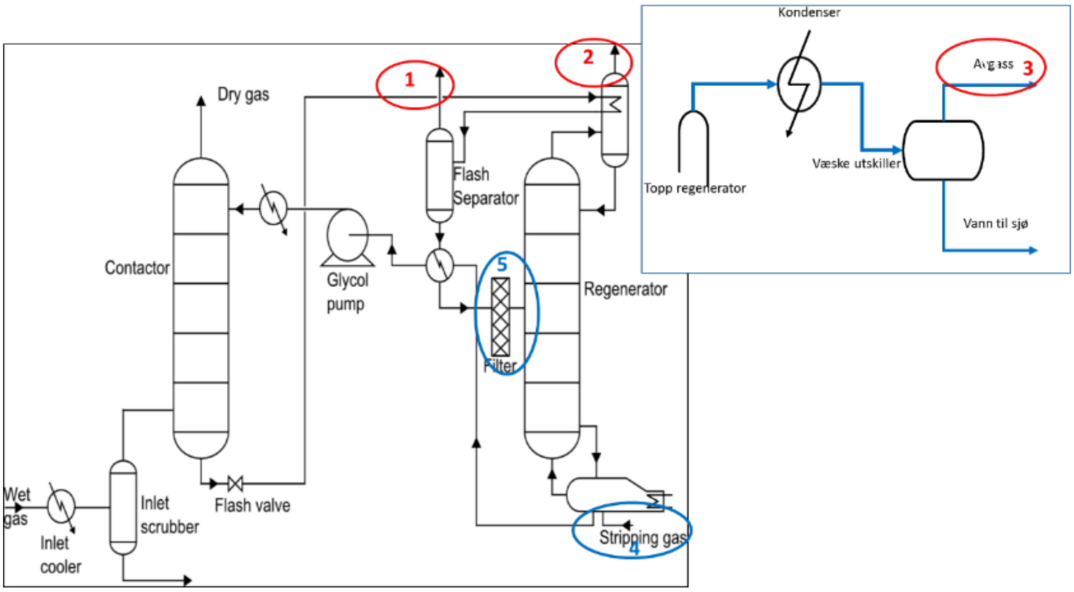

Figure 1 Typical process for TEG regeneration (source: ref 4). How the waste gas is handled in a plant where coolers condense the waste gas is shown at top right.

This process removes not only water from the TEG solution, but also the methane and nmVOC content.

Somewhat simplified, TEG regeneration has two waste-gas sources:

- the degassing tank ("1" in figure 1)
- the regenerator ("2" in figure 1), which is also called a boiler.

Some plants also use stripping gases to extract the final water residues from the TEG solution. Fuel gas is the commonest stripping gas. It flows right through the system, mixes with boil-off gas from the regenerator and emerges with the latter as waste gas. That makes it logical to treat the quantity of stripping gas as a separate emission source when doing the calculations.

In some plants, water in the waste gas is condensed out using a heat exchanger. This is shown in the inset at top right in figure 1. All methane and some nmVOC are emitted as waste gas from the subsequent scrubber, while condensed water and the rest of the nmVOC are led to the drainage water system and on to the produced-water treatment plant before discharge to the sea or reinjection into the sub-surface.

4.1.2 Emissions from the degassing tank

4.1.2.1 Introduction

The absorption tower or contactor operates at high pressure (30-60 barg). That is reduced to about 1.5 bar through a pressure control valve at the outlet from the tower. This causes much of the hydrocarbon gas dissolved in the TEG to be released by outgassing, particularly the methane content. Small amounts of water vapour also degas here. In many cases, the waste gas is extracted in a TEG degassing tank. The TEG from this tank is sent to the regenerator, while the waste gas can be recycled, sent to the flare and burned, or emitted directly to the air. The approach to be taken is selected in in the early design phase. An overview is shown in table 2.

4.1.2.2 Factors affecting the amount of waste gas

Numerous factors influence methane and nmVOC emissions from the TEG degassing tank:

- gas flow through the absorption tower
- TEG circulation rate
- composition of the gas going through the absorber
- pressure and temperature in the absorption tower
- pressure and temperature in the degassing tank
- recycling plant for waste gas from regenerator.

4.1.2.3 Recommended quantification method

At present, only one NCS facility sends gas from the TEG degassing tank for venting to the air. This indicates that a facility-specific quantification method should be used. Moreover, this is a Drizo system without a conventional degassing tank. Depressurised rich TEG is sent to a solvent/water separator, where the waste gas is separated out and released to a common atmospheric vent where the quantity of gas is measured.

That makes it natural for the operator to use a facility-specific quantification method which measures all contributions to the common atmospheric vent using an existing flow meter, supplemented by sampling and analysis of waste gas from the vent. To capture possible changes to the composition over time, it is recommended that the operator evaluates the conditions which could cause such changes and proposes a sampling frequency on that basis.

Where new plants are concerned, it would be natural to send the waste gas for recycling or flaring. Establishing a dedicated quantification method to calculate waste gas from the TEG degassing tank should therefore be unnecessary. Should the need arise, however, it is recommended that the same computer programme proposed for the TEG regenerator be used.

Conclusion:
General quantification method

4.1.2.4 Proportions of methane and nmVOC in the waste gas

Emissions of methane and nmVOC must be derivable from the facility-specific calculation method proposed by the operator.

4.1.2.5 Emissions from the degassing tank

Table 2 Disposal of waste gas from the TEG degassing tank and preliminary emission estimates.

Facilities with TEG degassing tank	*32*
Facilities recycling waste gas from the degassing tank to the main process	*18*
Facilities sending waste gas from the degassing tank to flaring	*14*
Facilities sending waste gas from the degassing tank to direct emission	*0*

As table 2 shows, no facilities have emissions from the degassing tank.

4.1.3 Emissions from the regenerator

A large proportion of the dissolved methane and nmVOC in wet TEG is flashed off in the degassing tank. The residues are boiled-off at about 200°C in the TEG regenerator. The emission point is labelled as “2” in figure 1. All 32 facilities with a TEG dehydration system for gas have waste gas from the regenerator. Twelve of these send the waste gas to an atmospheric vent.

In most of the TEG regeneration plants, waste gas from the regenerator is cooled in a condenser where the bulk of the water vapour and some nmVOC condense and are separated from the gas in a subsequent scrubber. Water and part of the nmVOC are normally sent to the produced-water treatment plant, while the gas phase is extracted as waste gas (“3” in figure 1) and disposed of by recycling, flaring or direct emission. Virtually all the methane content in the waste gas from the regenerator is extracted as waste gas from the scrubber, while part of the nmVOC content is extracted in the liquid phase.

4.1.3.1 Factors affecting the amount of waste gas

Factors affecting the amount of waste gas from the regenerator are the same as for the degassing tank. In mark-up, the waste-gas condensing plant will reduce the nmVOC content in the waste gas.

In a standard TEG regeneration plant, the residual amount of methane and nmVOC in the TEG entering the boiler equals the amount of waste gas going out. This means that the amount of methane is a function of the TEG circulation rate and of the pressure and temperature in the flash tank. The circulation rate normally correlates with the quantity of gas passing through the absorption tower, but will often be somewhat overdimensioned. In that case, the TEG solution will absorb more methane and nmVOC.

4.1.3.2 Assessment of quantification methods

Five methods for determining the amount of methane and nmVOC boiled off from the TEG solution have been identified:

a. measuring waste gas out of the regenerator (flow rate), combined with sampling and analysis of the waste gas
b. simulating the regeneration process
c. sampling and analysis of TEG from the degassing tank combined with measuring the TEG flow rate
d. obtaining data from the plant supplier
e. using the GRI GLYCalc computer programme (see appendix).

4.1.3.3 Recommended quantification methods

It is recommended that the operator can choose between two levels for quantifying emissions from a TEG regenerator.

Alt 1 Use GRI-GLYCalc. This Windows-based programme is specially developed for calculating the amount and composition of waste gases from the various emission sources.

Necessary facility-specific input parameters are:

- volume of natural gas flow through the absorber
- composition of the natural gas
- pressure and temperature in the absorber
- pressure and temperature in the degassing tank
- pressure and temperature in the regenerator (boiler)

  - TEG circulation rate
  - whether the waste gas from the regenerator is condensed
    - if so, pressure and temperature in the scrubber downstream from the condenser.

GRI-GLYCalc calculates emissions of methane and the individual nmVOC components.

Alt 2 Since GRI-GLYCalc is commercial software, an alternative method is also recommended. The content of methane and C_2-C_6 in the TEG solution, measured as mass per unit volume of TEG solution, is determined by sampling and analysing the TEG downstream of the degassing tank. Most plants have a sampling point in/at the TEG filter downstream from the degassing tank.

$U_{CH4} = V_{TEG} \bullet k_{CH4} \bullet t$
$U_{nmVOC} = V_{TEG} \bullet k_{nmVOC} \bullet t$
where:
U_{CH4} = methane emissions in tonnes/year
U_{nmVOC} = nmVOC emissions in tonnes/year
V_{TEG} = TEG circulation rate in m^3/hour
k_{CH4} = concentration of methane in TEG in g_{CH4}/m^3 *TEG*
k_{nmVOC} = concentration of nmVOC in g_{nmVOC}/m^3 *TEG*
t = number of operating hours per year

If the waste gas is sent to a common atmospheric vent with a meter and sampling point, separate quantification of emissions from the regenerator is not required.

Process simulations are not recommended unless they can be verified for the appropriate facility through sampling and analysis as described above. This is because of the very large variations which have arisen through the use of different equations of state.

Conclusion:
General quantification method
1: Alternative analysis of methane and nmVOC in rich TEG downstream from the degassing tank
2: Specially designed and verified computer programme (for example, GRI-GLYCalc).

4.1.3.4 Proportions of methane and nmVOC in the waste gas

Emissions of methane and nmVOC are calculated separately using the proposed calculation methods.

4.1.3.5 Estimated emission quantities from the regenerator

Table 3 Disposal of waste gas from the TEG regenerator and preliminary emission estimates.

Facilities with TEG regeneration	*32*
Facilities sending waste gas to recycling	*9*
Facilities sending waste gas to flaring	*11*
Facilities sending waste gas to direct emission	*12*
Estimated methane emissions from all facilities, tonnes/year	***218***
Estimated nmVOC emissions from all facilities, tonnes/year	***662***

One facility sends the waste gas to a common vent which is measured, and the emissions are included in overall emissions from this. One facility has not quantified the emissions. Ten have quantified the emissions using Hysys and different equations of state. Table 3 shows that only a third of the facilities with TEG regeneration plants send the waste gas from the regenerator to emission.

4.1.3.6 Uncertainty

The emission figures in table 3 are mainly calculated using simulations and various equations of state. As shown in section 4.1.3.2, the results can vary by several orders of magnitude in accordance with the equations of state used. Although different equations of state have been used in the simulations, the results are assumed to be conservative. This is because, when calculating emissions from the facilities with the largest gas volumes, the equations of state which provide the highest solubility of methane and nmVOC in TEG are used. That consequently yields the highest emissions.

The uncertainty is clearly smallest for methane, since good reference data are available and the relationships are simpler. The uncertainty in the estimated nmVOC emissions may be more substantial, but it is very difficult to quantify this. That is partly because the solubility of nmVOC in TEG is very sensitive to the composition of the nmVOC gas.

4.1.4 Emissions from stripping gas

Stripping gas is used on some facilities to remove residual water from the TEG solution. This is shown in figure 1 ("4").The commonest approach is to use fuel gas, but other gases may also be utilised – such as nitrogen (N_2). The stripping gas goes straight through the system and is emitted to the air together with boil-off gas from the regenerator.

4.1.4.1 Factors affecting the amount of waste gas

The quantity of stripping gas supplied to the system is the only factor affecting the waste gas amount emitted from the regenerator. If the stripping gas plus the gas stripped out in the regenerator is condensed through a condenser, some of the heavier components in the gas are separated in the subsequent liquid separator. This will probably play no role for methane.

4.1.4.2 Recommended quantification method

All stripping gas entering the plant is expected to end up as part of the waste gas. Measurement or other reliable quantification of the stripping gas flow rate to the regenerator will therefore be needed to quantify the emission. The amount of stripping gas may differ from one facility to another.

Conclusion:
General quantification method
Measurement/quantification of stripping-gas flow rate

4.1.4.3 Proportions of methane and nmVOC in the waste gas

If fuel gas is used as stripping gas, the waste gas will have a composition similar to the fuel gas.

4.1.4.4 Estimated quantities emitted from the stripping gas

Table 4 Stripping gas in connection with TEG regeneration and preliminary emission estimates.

Facilities using HC stripping gas	*27*
Facilities sending waste gas to recycling	*9*
Facilities sending waste gas to flaring	*10*
Facilities sending the waste gas to emission	*8*
Estimated methane emissions from all facilities, tonnes/year	***311***
Estimated nmVOC emissions from all facilities, tonnes/year	***262***

Stripping gas volumes are provided by the respective operators. Flow data could not be obtained for two of the facilities. Stripping gas was included in waste gas from the TEG boiler on the one, and in measured emissions from the common vent on the other. This indicates that the emission data in table 4 are somewhat underestimated, but that the emission figures are included in other sources. If the waste gas is sent to a common atmospheric vent with a meter and sampling point, separate quantification of emissions from the regenerator is unnecessary.

4.1.4.5 Uncertainties

Uncertainties relate to two factors:

- uncertainty in determining stripping gas volume

- uncertainty over the composition of the fuel gas (content of methane and nmVOC).

Accuracy in measuring the stripping gas flow will depend on how the amount of gas is determined. If flow meters are installed, accuracy will depend in turn on the measurement principle applied and the measuring instrument used. Ultrasonic gas meters operate with an accuracy of +/- three per cent or better. If the flow rate is determined by valve settings and pressure loss calculations, a higher level of uncertainty must be accepted.

The total uncertainty in these calculations must be determined by the operator on the basis of the metering choices made.

4.1.5 Estimated emission quantities from TEG regeneration

Total estimated emissions from TEG regeneration are shown in table 5.

Table 5 Preliminary emission estimates from TEG regeneration.

Contributors	Methane (tonnes/year)	nmVOC (tonnes/year)
Degassing tank	*0*	*0*
Regenerator	*218*	*662*
Stripping gas	*311*	*262*
Total TEG regeneration	***530***	***925***

The figures reflects activity data for 2014 and the assumptions given in the sections above.

Emissions shown in table 5 are substantially lower than those calculated using the old guidelines. This is partly because the methods used in the latter were very imprecise, and partly because a significant proportion of the HC gas dissolved in TEG is recycled through the process.

It is worth noting that emissions of nmVOC from TEG regeneration are significantly higher than for methane. This represents a significant change from the emissions calculated in accordance with the existing guidelines. The explanation is that:

- nmVOC has a much higher solubility in TEG than methane
- while virtually all the methane is boiled off in the degassing tank and sent to recycling or flaring, a far greater portion of the nmVOC remains in the TEG solution and is boiled off in the regenerator before sent to an atmospheric vent on many facilities.

This is confirmed by all the information collected during the study, including literature data (see ref 5).

4.1.6 Comparison with other countries

Compared with other countries (see chapter 8), only the USA seems to have a well-established methodology for calculating methane and nmVOC emissions from TEG regeneration. Emission factors have been developed for the US Environmental Protection Agency (EPA) which correlate with the amount of gas, like the method used in Norway. However, the American approach breaks down the emissions as described in section 4.1.1. The method has been tested in a number of plants, and is approved for emission reporting to the EPA. Emissions of methane and other HC components are calculated using GRI GLYCalc (GTI 2000) for a range of pressure and temperature combinations for both the glycol boiler and the degassing tank. The method is in general use by the US oil and gas industry to calculate emissions from TEG regeneration, both onshore and offshore.

Work on mapping methane emissions, in particular, has been under way in the USA for many years. Both the EPA and the Gas Technology Institute (GTI, formerly the Gas Research Institute (GRI)) have played key roles in this work. A report prepared for the two institutions in 1996 (ref 5) made an important contribution. It was based on a comprehensive study aimed at developing emission factors and extrapolating the data in order to be able to calculate national emissions based on the product of a general emission factor and an activity factor. The work was done using process simulations with

AspenTech Hysys as the simulation tool and with the Peng Robinson equation of state. The TEG system was included with and without emissions from the degassing tank, and with and without the use of HC stripping gas.

The study concluded that methane emissions are directly proportional to the circulation rate of TEG, provided that the ratio between the gas rate through the absorber (glycol contactor) and the TEG circulation rate is constant. Based on the same assumption, the relationship between the gas rate through the absorber and methane emissions is also constant. This confirms that the methodology applied in the Norwegian Oil and Gas Association's guidelines build on the correct correlations, and that the processed gas quantity is a relevant activity factor.

See the appendix for more information.

4.2 Handling produced water

4.2.1 Introduction

Methane and nmVOC emissions occur at three points in the produced water treatment process:

- from the degassing tank
- from the CFU/flotation tank (on facilities with such a tank)
- from the discharge caisson.

In mark-up, oil collected from the hydrocyclones and flotation unit will give off some vapour from the collection tanks and so forth before being led into the oil/gas process for recycling. The amounts are small and normally released through the common atmospheric vent on the facility. Where the common vent has a meter installed, waste gas from the recycled oil will be included there.

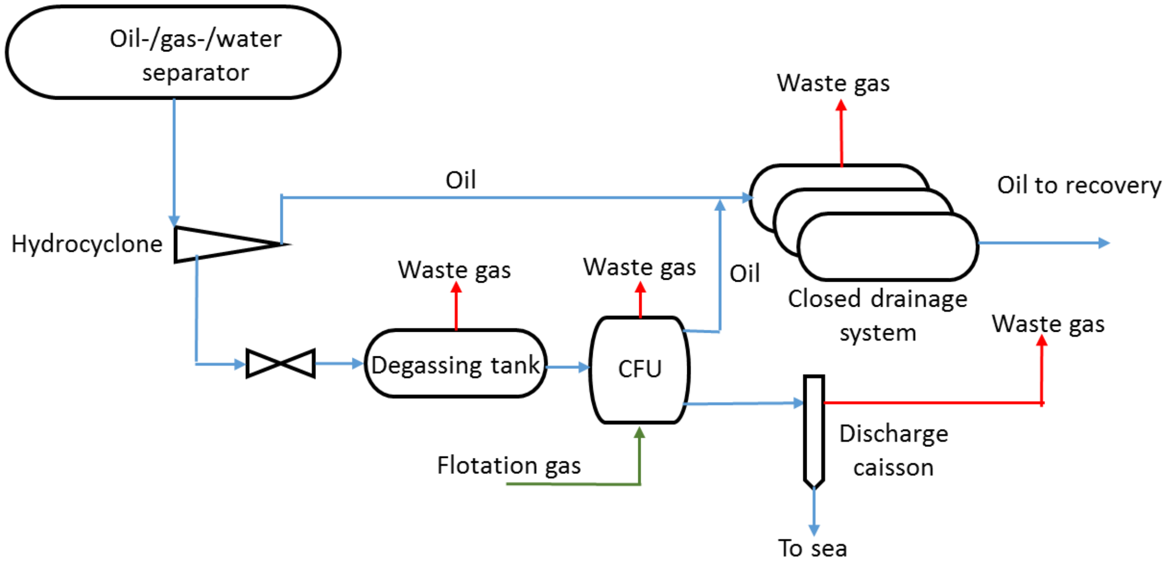

Figure 2 Diagram of a treatment plant for produced water.

Not all facilities have all these sources – their number varies from facility to facility. The degassing tank and discharge caisson are normally found on most. Waste gas from the individual sources can be sent for recycling in the process, for flaring or for direct release to the air.

A total of 43 facilities on the NCS discharge produced water. On most of these, waste gas from the degassing tank and the CFU/flotation tank is sent to recycling or flaring, while waste gas from the produced-water discharge caisson is released to the air. Waste gases released to air are distributed as follows:

Table 6 Facilities where waste gas from produced water treatment is released as direct emissions.

Emission source	Facilities with emissions from this main source
Degassing tank	2
CFU/flotation tank	4
HC flotation gas	1 (emitted to the air)
Discharge caisson	44

The two facilities with emissions from a degassing tank send the waste gas to the low-pressure flare but, since this is inactive, the gas is released as direct emissions.

4.2.2 Factors affecting the amount of waste gas

The amount of waste methane and nmVOC from the produced water system is a direct function of the quantities dissolved in produced water from the first-stage oil/gas/water separator. On facilities discharging produced water to the sea, total waste gas is determined by the difference between the amounts of methane and nmVOC in the water from the separator and when discharged. Since big differences exist between the different facilities over whether the individual waste gas streams are sent for recycling, flaring or direct emission, waste gas quantities must be calculated for each stream.

The following factors affect waste gas amounts:

- amount of produced water to the sea
- pressure and temperature in the first-stage separator (the water is separated out in the second-stage separator on a few facilities)
- pressure and temperature in the degassing tank
- pressure and temperature in the CFU/flotation tank
- amount of flotation gas (where HC flotation gas is used)
- produced water salinity.

The dominant factor affecting discharges to the sea is the amount of water. Pressure in the first-stage separator is also an important parameter. The solubility of methane and nmVOC in water increases more or less in line with pressure within the pressure ranges found on NCS facilities.

4.2.3 Solubility of methane and nmVOC in produced water

All calculations are based on the assumption that the produced water is saturated with methane and nmVOC in the first-stage separator. The amount dissolved is governed by the pressure and temperature in the separator. During depressurisation down to the next emission point, it is assumed that methane and nmVOC are flashed off until the new equilibrium is achieved under the pressure and temperature conditions prevailing in this step. The amount of waste gas at each step in the produced water system can be calculated from the difference in pressure and temperature between this step and the previous one. The end point for the produced water is the sea, with a pressure of one bara and a temperature of 7-12°C, depending on location and season.

A study conducted by Aker Solutions for Add Novatech and the Norwegian Oil and Gas Association in 2014 [ref 3] showed that the amount of methane and nmVOC dissolved in water is more or less proportional to the pressure, as long as the latter is not very high. This is shown in figure 3.

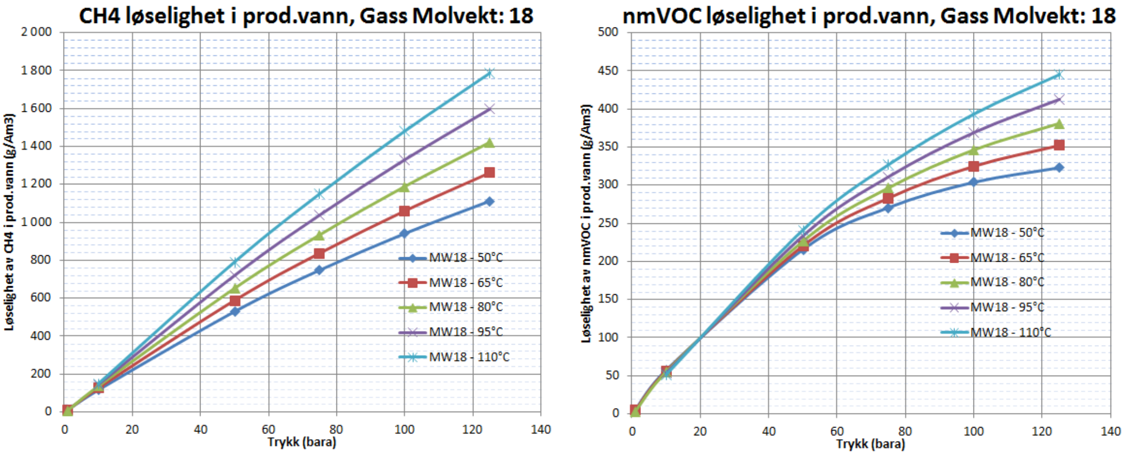

Figure 3 Solubility of methane and nmVOC in water (the mol weight refers to methane and nmVOC combined). (source: ref 3)

The figure shows that the solubility of methane increases with temperature. Produced water from most facilities has a temperature between 50°C and 100°C. The curves in figure 3 are based on simulations using AspenTech Hysys[2] and relate to solubility in water. Similar calculations made with PVTSim[3] showed somewhat lower solubility (down by 15-30 per cent).

Produced water normally contains a quantity of salt. The amount varies from field to field, from a few parts per thousand to several tens of per cent. On fields injecting seawater, this will gradually mix with reservoir water, so that salinity will eventually approach the figure for the seawater (34‰).

The effect of salinity on the solubility of methane was studied by Aker Solutions (ref 3). Figure 4 shows that solubility decreases with a rising salt content in the produced water. This indicates that the solubility t calculated by Hysys may be somewhat conservative (high). Produced water also contains a number of other dissolved inorganic and organic compounds, with large individual variations from field to field. How far these affect the solubility of methane and nmVOC is unknown. This can only be clarified by solubility analysis of produced water on each field. A conservative approach is therefore recommended when quantifying emissions of methane and nmVOC from produced water.

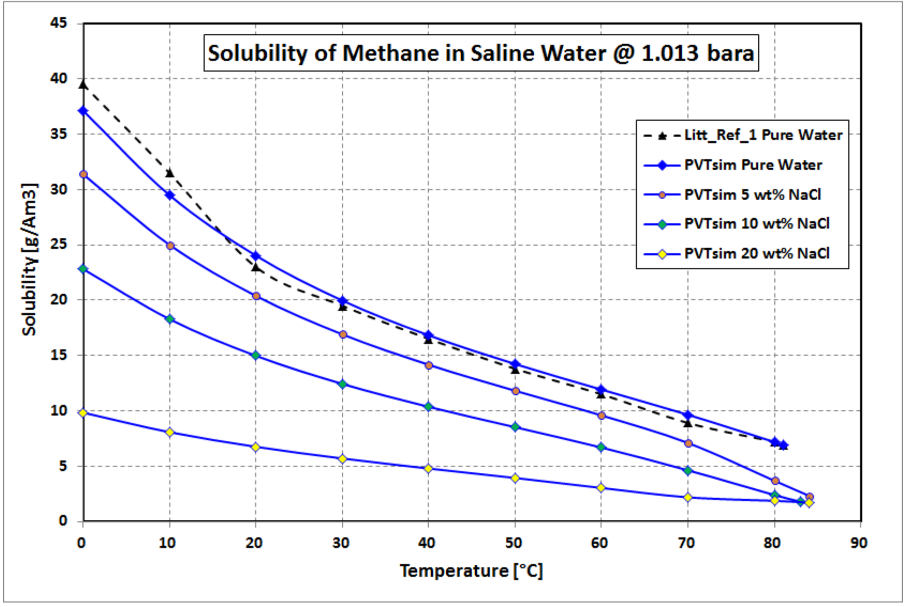

Figure 4 Solubility of methane in water with varying levels of NaCl. (source: Ref 3*)*

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[2] Hysys is a recognised process simulation programme developed by AspenTech.

[3] PVTSim is another recognised process simulation programme developed by the Calsep company.

4.2.4 Recommended quantification method

Based on the simulation results in figure 3, it seems reasonable to calculate the amounts of methane and nmVOC as a direct and linear function of pressure loss for all waste gas sources in the produced water system. In practice, this means fixed emission factors for both methane and nmVOC. Since the produced water has a temperature approaching 100°C on many fields, starting with the curves for 110°C and the highest pressure (120 bar) is recommended in order to be on the conservative side. Activity factors are the amount of produced water and the pressure difference (ΔP). This gives the following generic quantification method.

Methane emissions: $U_{CH4} = f_{CH4} * V_{pw} * \Delta p$
NmVOC emissions: $U_{nmVOC} = f_{nmVOC} * V_{pw} * \Delta p$
where
U_{CH4} = methane emissions, *tonnes/unit time*
U_{nmVOC} = nmVOC emissions, *tonnes/unit time*
f_{CH4} = emission factor, *tonnes methane/10^6 m^3 produced water through the waste point/bar pressure drop*
f_{nmVOC} = emission factor, *tonnes nmVOC / 10^6 m^3 produced water through the waste point/bar pressure drop*
V_{PW} = amount of produced water through the waste point, *10^6 m^3/unit time*
Δp = difference in operating pressure between the waste point and the nearest upstream degassing point, *bar*

The following emission factors are taken from an Aker Solutions report for Add Novatech and Norwegian Oil and Gas in 2014 (ref 3).

f_{CH4} = **14** [**tonnes** CH_4/(10^6 m^3 produced water*bar)
f_{nmVOC} =**3.5** [**tonnes** nmVOC/(10^6 m^3 produced water*bar)

Using the above-mentioned generic method is therefore recommended for calculating all emissions caused by the depressurisation of produced water. Operators should be given the opportunity to use other methods if they can be documented to provide more accurate emission figures.

In mark-up comes the amount of flotation gas where fuel gas is used for this purpose. All flotation gas goes out as waste gas and contributes to emissions in those case where flotation gas is emitted. Its amount will vary from facility to facility and may not correlate with the amount of produced water. This means that emissions of flotation gas should be determined specifically for each facility by measuring the amount of flotation gas into the plant or quantifying it in another reliable way. The operator should be able to document how the flotation gas flow is established.

Conclusion:
General quantification method
Factor calculation for all degassing from depressurisation
Measuring/quantifying the flotation gas into the flotation plant (only where HC flotation gas is used)

4.2.5 Emissions from the degassing tank

Table 7 Disposal of waste gas from the produced-water degassing tank and preliminary emission estimates.

Facilities with degassing tank	*45*
Facilities which send waste gas from the degassing tank to recycling	*25*
Facilities which send waste gas from the degassing tank to flaring	*19*
Facilities which send waste gas from the degassing tank to direct emission	*2*
Estimated methane emissions from all facilities, tonnes/year	**294**
Estimated nmVOC emissions from all facilities, tonnes/year	**43**

One of the two facilities with emissions sends the waste gas to the inactive low-pressure flare. The other sends it to an inert-gas-purged open low-pressure flare, where the waste gas is emitted together with waste gas from several other sources.

4.2.6 Emissions from flotation tank/CFU

A total of 21 NCS facilities have a flotation tank/CFU, and more than 80 per cent of them send the waste gas from the flotation tank/CFU for either flaring or recycling. Four facilities send the waste gas to direct emission via a common vent.

Table 8 Disposal of waste gas from flotation tank/CFU and preliminary emission estimates.

Facilities with flotation tank/CFU	*21*
Facilities which send waste gas from the flotation tank/CFU to recycling	*9*
Facilities which send waste gas from the flotation tank/CFU to flaring	*8*
Facilities which send waste gas from the flotation tank/CFU to direct emission	*4*
Estimated methane emissions, tonnes/year	***47***
Estimated nmVOC emissions, tonnes/year	***51***

The emission figures cover only one facility. Where the others are concerned, these figures are calculated together with those from the discharge caisson and included in the overview in table 10.

4.2.7 Emissions from using HC gas as a flotation gas in a flotation tank/CFU

Fifteen of the 21 facilities with a flotation tank/CFU use HC gas as flotation gas. The others utilise nitrogen. Only one facility sends used flotation gas to the air. This is done via a waste oil tank where HC gas is used as flush and blanket gas. This facility has several systems which send waste gas to the waste oil tank, and total emissions from this tank are estimated and presented under HC purge and blanket gas.

Table 9 Disposal of used HC flotation gas and preliminary emission estimates.

Facilities using HC gas as flotation gas	*15*
Facilities which send used flotation gas to recycling	*8*
Facilities which send used flotation gas to flaring	*6*
Facilities which send used flotation gas to direct emission	*1*
Estimated methane emissions from all facilities, tonnes/year	***206***
Estimated nmVOC emissions from all facilities, tonnes/year	***51***

4.2.8 Emissions from a discharge caisson

A residual amount of methane and nmVOC will always be present in produced water discharged to the sea. Its quantity is determined by the amount of HC gases dissolved in the produced water at the final degassing tank, and by atmospheric pressure. A reasonable assumption is that the gas will vaporise until it reaches equilibrium at atmospheric pressure.

Forty-five facilities on the NCS discharge produced water to the sea. Of these, 43 emitted HC gases through a discharge caisson in 2014. One recycled the waste gas, and another had calculated emissions of zero since there was no pressure difference between upstream degassing and the emission point. Emissions for all these facilities have been calculated using the methodology described in section 4.2.4

Table 10 Disposal of waste gas from a discharge caisson and preliminary emission estimates.

Facilities with discharge caisson	*45*
Facilities which send waste gas from discharge caisson to recycling	*1*
Facilities which send waste gas from discharge caisson to flaring	*0*
Facilities which send waste gas from discharge caisson to direct emission	*44*
Facilities with atmospheric pressure upstream	*2*
Estimated methane emissions from all facilities, tonnes/year	***1 730***
Estimated nmVOC emissions from all facilities, tonnes/year	***439***

4.2.9 Proportions of methane and nmVOC in the waste gas

When applying the general calculation method proposed in chapter 4.2.4, methane and nmVOC emissions are calculated separately using their specific emission factors.

4.2.10 Estimated emission quantities from produced water treatment

Total estimated emissions from produced water treatment are shown in table 11.

Table 11 Preliminary emission estimates from produced water treatment.

Contributors	Methane (tonnes/year)	nmVOC (tonnes/year)
Degassing tank	294	43
Flotation tank/CFU	47	12
Flotation gas	206	51
Discharge caisson	1 730	439
Total produced water	**2 276**	**584**

The figures reflect activity data for 2014 and the assumptions specified in the sections above. They show that produced water treatment is a significant contributor to direct emissions of HC gases, especially methane.

4.2.11 Uncertainty

Uncertainty in the preliminary emission figures given in this section relates mainly to the uncertainty in the calculated solubility of methane and nmVOC. Since conservative assumptions form the basis for the chosen emission factors, the likelihood of underestimation is not regarded as particularly high.

4.2.12 Comparison with other countries

In the USA, emissions from produced water caissons are reported as fixed annual figures of 0.141 tonnes/year of nmVOC and 0.426 tonnes/year of methane for each emission point. The GRI/API have produced a report on calculating emissions from degassing tanks in produced water systems using general emission factors (ref 19). This study estimated emissions from produced water tanks on the basis of process simulations with different salt contents and pressures. No requirement exists in the USA to report anything other than the fixed annual emissions from the produced-water caisson.

4.3 Low-pressure liquid separators

This source was only included in the primary review (15 facilities). The latter showed that liquids and gas from low-pressure liquid separators are sent in many cases to the closed drain system. It also found that operators should carefully survey their facilities to obtain a good overview of where the waste gas is being sent.

Table 12 Disposal of waste gas from low-pressure liquid separators.

Facilities with low-pressure liquid separators	*6*
Facilities which send waste gas to recycling/flaring	*2*
Facilities which send waste gas to direct emission	*4*
Estimated methane emissions, tonnes/year	*2.6*
Estimated nmVOC emissions, tonnes/year	*1.8*

As described in the module 1 report, all four of the facilities with emissions to an atmospheric vent are special cases. Conditions differ from facility to facility, depending on the design of their solutions. In two cases, the gas goes to a common atmospheric vent, where it is mixed with gas from a variety of other sources (measured fiscally on one facility). It is therefore inappropriate to operate with this as a fixed source in the future. The amount of waste gas ranges from almost nothing to about a tonne per year, but may also be somewhat higher. One facility has quantified its emissions using process simulation.

4.3.1 Recommended quantification method

Emissions are so small that it is suggested they are captured using a general mark-up for small emissions.

Conclusion:
General mark-up
Small emissions

4.4 Oil seals in centrifugal compressors

4.4.1 Introduction

When process gas in the compressors comes into contact with seal oil, some gas is dissolved in the latter and must be removed before the seal oil can be reused. Gas is separated from the oil by depressurisation. This usually takes place in two steps.

- Used depressurised seal oil is sent to a degassing pot (also called the sour gas pot), where dissolved gas is released and sent to the air, the flare or recycling. The various compressors on the facility often have separate degassing pots operating at different pressures. Most NCS facilities send the waste gas for recycling or flaring. On some, however, waste gas from certain of the degassing pots goes to emission, in many cases via separate vents. In mark-up, a few facilities have a secondary common degassing tank.

- Oil from the degassing pots continues to an oil tank for storage. This tank is usually at atmospheric pressure with a local vent. From the tank, oil is recycled back to the compressor to repeat the same operation. This is a continuous process.

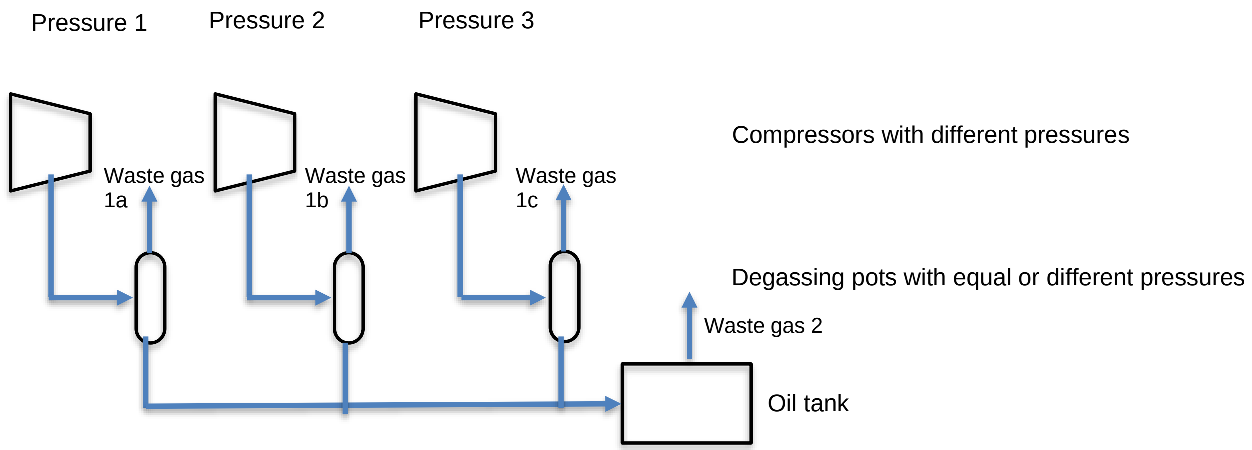

Figure 5 Outline of typical seal oil system.

Compressors with seal oil are used on 18 NCS facilities. Oil was previously the usual sealing method for gas compressors, and is most commonly found on facilities which came on stream before 1995. Newer compressors on the NCS mainly use dry seals. The exceptions are a number of smaller low-pressure compressors using seal oil.

Quantifying emissions from seal oil in centrifugal compressors has been challenging. Operators generally lack emission data or reliable systems for calculating them. Nor has it been easy to secure supplier data (most of these compressor packages were delivered 20-40 years ago).

4.4.1 Degassing pots/tanks

Five facilities on the NCS have reported that they have emissions from this source.

One of these has seal oil in a low-pressure compressor which compresses gas from the flare header for recycling to the closed flaring process. This is a small unit handling minor amounts of gas at low pressure. It is therefore reasonable to assume that its contribution is modest.

Three of the facilities have both degassing pots after the compressors and a common degassing tank downstream of the pots. Waste gas from the common degassing tank is emitted. One facility also emits waste gas from the pots.

Emissions from this sub-source have proved very difficult to quantify. No emission data are so far available. The operators are looking into this in cooperation with the compressor suppliers. Emission figures are expected to be available by 1 May 2016.

Table 13 Disposal of waste gas from seal oil degassing tanks.

Facilities with relevant process	17
Facilities with waste gas to recycling	10
Facilities with waste gas to flaring	3
Facilities with waste gas to direct emission	4

4.4.2 Seal oil in residence tanks

This is the oil tank shown in figure 5. Depressurisation from the degassing pots to the residence tank causes residual gas to separate from the oil.

Fourteen of 16 facilities have emissions from the residence tank.

Table 14 Disposal of waste gas from seal oil degassing tanks and preliminary emission estimates.

Facilities with relevant process	16
Facilities with waste gas to recycling	1
Facilities with waste gas to flaring	1
Facilities with waste gas to direct emission	14
Estimated methane emissions, tonnes/year	154
Estimated nmVOC emissions, tonnes/year	154

4.4.3 Seal oil in storage tank

Most facilities also have a storage tank for seal oil which may generate some waste gas. Thirteen out of 14 facilities emit this gas.

Efforts have been made to calculate the emissions using several methods. Emission data have been obtained from the supplier for a couple of these facilities. In some other cases, they are based on various approaches by the operators. Emissions are so small that this variation does not matter much.

Table 15 Disposal of waste gas from seal-oil storage tank and preliminary emission estimates.

Facilities with relevant process	14
Facilities with waste gas for recycling	1
Facilities with waste gas to flaring	0
Facilities with waste gas to direct emission	13
Estimated methane emissions from all facilities, tonnes/year	**2**
Estimated nmVOC emissions from all facilities, tonnes/year	**2**

4.4.4 Factors affecting emissions

The following factors affect emissions from the seal oil system for centrifugal compressors.

- **Waste gas solution**: HC emissions can be totally eliminated by directing the gas to flaring or recycling. No technical obstacle exists to using this method. More than 70 per cent of the facilities lead the waste gas from the degassing pots to either flaring or recycling.

- **Pressure and temperature of the degassing tanks**: Pressure and temperature affect the solubility of the gas in the oil. The amount of waste gas from the degassing pots/tanks is directly related to the pressure here.

- **How much seal oil comes into contact with compressed gas in the compressor:** The more oil which comes into contact with the gas, the more gas can dissolve in the oil. Some sealing designs exploit this by minimising the amount of oil coming into contact with the gas. That also reduces the total amount of gas which is dissolved in the oil and then released as waste gas in degassing pots and tanks.

- **Solubility of HC gas in seal oil:** nmVOC solubility depends on the composition and concentration of the individual nmVOC components in the compressed gas.

4.4.5 Assessment of quantification methods

This section is only relevant when waste gas is led to the air rather than to flaring or recycling.

The seal oil system is one of the more difficult sources to establish a quantification method for. That is because the industry's knowledge here is limited. The survey has shown that no basis exists for recommending any generic quantification method for methane and nmVOC emissions from sealing oil systems on centrifugal compressors. It also indicated that operators will have difficulty developing reliable facility-specific methods.

A project is therefore recommended to obtain sufficient knowledge and information for a consistent and documentable quantification method to be established. The following ideas and activities could form part of such a project.

a. Systematic collection of information from suppliers of the compressor packages which contribute to emissions. The request should come from the operators themselves. Experience from the survey indicates that such supplier information often comprises warranty figures which are higher – and at times very much higher – than the actual emissions. Such data will nevertheless give a relatively consistent (and probably conservative) indication of emission size.

b. Evaluate the possibility of calculating emissions using process simulations. Since only HC components are included in the oil and gas phases, this may be easier than expected. To create credibility for the simulations, verifying calculated results with measurements is recommended. If the results of such simulations can be verified, they may form the basis for simpler computational programmes which permit quantification of waste gas amounts based on temperatures, pressure levels and circulation rates.

c. Evaluate whether sampling and analysis of used seal oil for methane content and for C_2-C_6 may be a suitable quantification and/or verification method.

This work has started at the relevant operators, and proposals for facility-specific quantification methods are expected to be available by 1 May 2016.

A goal should be that a new quantification method of this kind allows emissions to be calculated within an uncertainty range of +/- 25 per cent.

Conclusion:
Facility-specific quantification method
To be established by each operator

4.4.6 Proportions of methane and nmVOC in the waste gas

Waste gas composition depends on the solubility of methane and nmVOC in seal oil and on how much of the gas is released by pressure changes in pots and tanks. More knowledge is needed in the form of samples and analyses of gas released on the facilities in order to be able to say something about the relative proportions of the two emission gases. This is expected to be available when the operators concerned have their facility-specific quantification methods ready by 1 May 2016.

4.4.7 Estimated emission quantities from seal oil

The survey has shown that no consistent and reliable quantification method exists at present for making credible estimates of methane and nmVOC emissions from sealing systems for centrifugal compressors. An estimate of storage tanks for the seal oil is presented on the basis of uncertain data from the operators. The estimate is very uncertain. Estimating emissions from the degassing pots has not been possible.

Table 16 Preliminary estimates of emissions from seal oil systems for centrifugal compressors.

Contributors	Methane (tonnes/year)	nmVOC (tonnes/year)
Degassing tank/pots	not available	not available
Seal-oil retention tank	66	66
Seal-oil storage tank	1	1

No good data are available on emissions from seal-oil systems, nor are key data or methods available which have made it possible to estimate emissions within the time frame for this assignment. Better data are expected to be available when the operators concerned have established their facility-specific quantification methods, as described in 4.4.5.

4.4.8 Uncertainty

Uncertainty in the emission figures presented is significant. Owing to the lack of data, no basis exists for quantifying this uncertainty. A future quantification method should aim to achieve +/- 25 per cent.

4.4.9 Comparisons with other countries

Generic emission factors in the form of kilograms emitted per hour per source are used in Canada and the USA. Emissions are reported in the fugitive emission category. Canadian guides (CAPP, *Update of Fugitive Equipment Leak Emission Factors*, February 2014) do not distinguish between oil and dry compressor seals. US guides (BOEM, 2011 *Gulfwide Emission Inventory Study*, Nov 2014) distinguish between the two. For information on emission factors, see the table in section 4.5.10.

4.5 Dry seals on centrifugal compressors

4.5.1 Introduction

Compressor seals are used to prevent process gas from leaking between the rotary shaft and the compressor housing. Dry seals are gas seals, with HC gas and nitrogen as common sealants.

Thirty-four facilities on the NCS have compressors fitted with dry seals.

Dry seals are a newer sealing technology, usually fitted to modern centrifugal compressors. Most NCS facilities built after 1990 feature them. The requirement in the Norwegian facilities regulations for two independent security levels is an underlying reason why operators off Norway have generally chosen dry seals with double barriers.

HC gas is commonly used as the primary barrier gas, with nitrogen as a secondary barrier. But the latter could also be provided by HC gas. The primary barrier gas is usually collected from the high-pressure side of the compressor, but fuel gas is also used.

Where the facilities in the primary survey are concerned, it was found that gas flow is measured into and to some extent out of the primary seal in order to monitor the state of the seal. The trend for the seal gas streams is therefore more important than accuracy. Emission calculations are based mainly on data from these measurements. Supplier data were used on some of the facilities.

4.5.2 Primary seal

All compressors with dry seals on the NCS use HC gas as the primary seal gas, whose pressure is roughly 0.3-0.7 bar above the process gas inside the compressor. This pressure difference means the seal gas leaks into the process gas and prevents leakage in the other direction. According to the seal manufacturers, about 90 per cent of the seal gas leaks into the compressor gas while the remainder – roughly 10 per cent – leaks through the seal on the low-pressure side to what the seal suppliers call the primary vent (see figure 6). From there, the waste gas is led to either venting, flaring or recycling.

If the seal has an internal labyrinth, no primary seal gas will leak into the secondary seal (see figure 6). Where the sealing system has no internal labyrinth, some of the waste gas may leak to the secondary gas. The seal suppliers operate here with a maximum 10 per cent of primary gas supplied to the primary vent possibly leaking out to secondary vent (see the diagram). This is a warranty figure, and indicates that a maximum one per cent of the primary seal gas may be emitted from such seals through the secondary vent. This means:

- if the seal has an internal labyrinth, primary seal gas is only emitted in cases where the primary vent is led to emission
- if the seal does not have an internal labyrinth, up to one per cent of primary seal gas may pass through the secondary vent.

Twelve of the facilities on the NCS send waste gas from the primary seal to an atmospheric vent. This is a surprisingly high proportion.

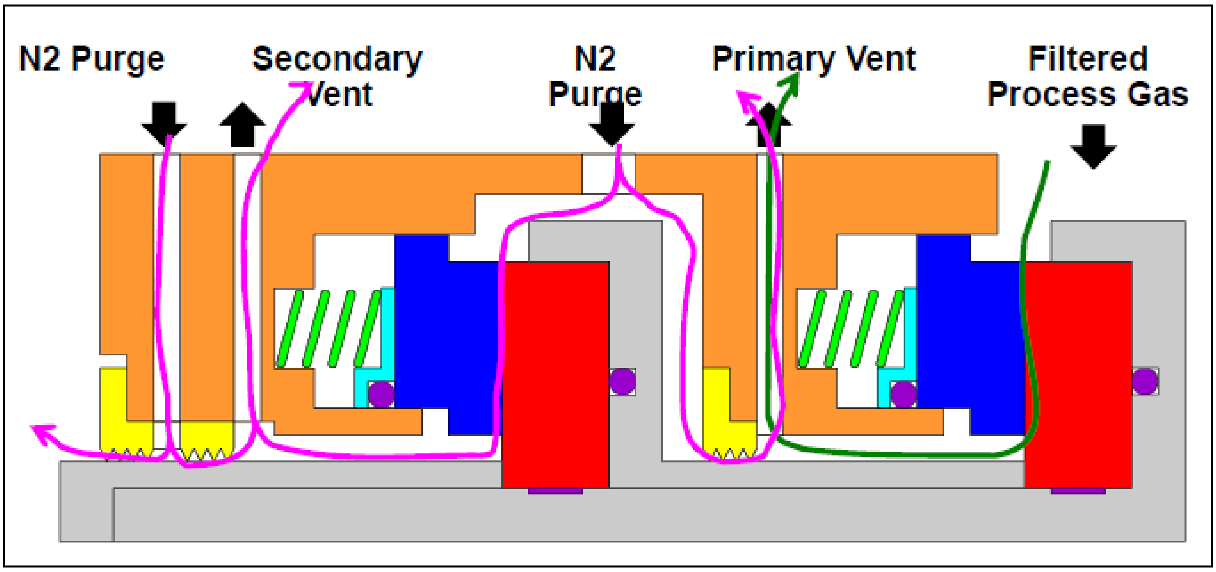

Figure 6 Dry seals. Double barrier using tandem seal and internal labyrinth (source: John Crane).

Table 17 Disposal of primary seal gas – dry compressor seals.

Facilities with dry compressor seals	34
Facilities with waste gas to recycling	4
Facilities with waste gas to flaring	18
Facilities with waste gas to direct emission	12

4.5.3 Secondary seal

Nitrogen is usually used as the secondary seal gas. Part of this leaks to the primary vent to prevent primary seal gas leaking the other way, while the rest flows to the secondary vent. Since the waste gas from the latter will normally consist of pure or almost pure nitrogen, it is sent to emission. Unlike primary seal gas, all secondary seal gas goes to the seal's secondary vent.

But five facilities on the NCS use HC gas as a secondary seal gas and release it through the secondary vent. One reason why HC gas is used in this way is that nitrogen, owing to small amounts of oxygen in the gas, can damage the seal or cause it to wear/corrode.

Only one (new) facility on the NCS recovers secondary HC seal gas, while another sends the gas to flaring. The other three emit it from the secondary vent.

Table 18 HC gas as a secondary seal gas – disposal solutions.

Facilities with relevant process	5
Facilities with waste gas to recycling	1
Facilities with waste gas to flaring	1
Facilities with waste gas to direct emission	3

4.5.4 Leakage of HC gas from primary to secondary vent

Dry seals vary from supplier to supplier and from model to model. Some are designed so that primary seal gas cannot leak from primary to secondary vent – those with an internal labyrinth seal, for example (see section 4.5.2). Leakage can occur from dry seals with different designs. Based on information from sealing suppliers, up to 10 per cent of seal gas flows to the primary vent can leak over to the secondary vent and thereby escape to the air.

Eight facilities report that they have seals with an internal labyrinth, but information from seal suppliers suggests the number may be higher. Some operators have said they have seals which result in leakage of primary seal gas from primary to secondary vent. Facilities where such information is lacking are assumed to experience such leakage.

Where compressors have seals with these leaks, emissions have been calculated as one per cent of primary seal gas (equivalent to 10 per cent of seal gas out of the primary vent).

Table 19 Leakage in HC seal gas from primary to secondary vent – disposal solutions.

Facilities with relevant process	25
Facilities with waste gas for recycling	1
Facilities with waste gas to flaring	3
Facilities with waste gas to direct emission	19
Facilities with uncertain solutions	2

4.5.5 Factors affecting the emissions

The most important factors are the operator's choice of seal gas type and disposal solution for the waste gases.

- **Seal gas type**: used secondary seal gas is released to the air from almost all NCS facilities. Using nitrogen rather than HC gas as the secondary seal gas cuts emissions. Impure nitrogen may damage the seal and could be one reason for selecting HC gas as the secondary seal gas.
- **Waste solution**: HC emissions can be completely eliminated by directing the waste gas to flaring or recycling. About 65 per cent of NCS facilities lead waste gas from the primary seal gas to either flaring or recycling.

The following technical factor affects emissions from the secondary seal (also operator's choice).

- **Internal labyrinth in seal:** an internal labyrinth prevents leakage from primary to secondary seal and thereby the emission of primary seal gas from the secondary vent.

4.5.6 Assessment of quantification methods

Quantification is only applicable if used seal gases containing HC gas are sent to emission.

The following quantification methods are proposed.

Emissions from primary seal
Primary method: Measurement of seal gas flow out of the primary vent. Seal gas gauges are usually not particularly accurate. Waste gas may contain some leaked secondary seal gas. This means the measurement results may be conservative.
Secondary method: If measured waste gas data out from the seal are not available, emissions can be calculated as 10 per cent of the seal gas amount into the seal. This may give rather conservative emission figures (warranty figures).
Tertiary method: If measurement data into the seal are not available, waste gas data will be obtained from the seal supplier.

Emission from secondary seal
HC seal gas: Seal gas into the seal is measured (or quantified in another satisfactory way).
Nitrogen seal gas: If the seal has no internal labyrinth, 10 per cent is considered to leak into the secondary vent as waste gas from the primary seal.
If the seal has an internal labyrinth, emissions are considered to be zero.

Conclusion:
General quantification method
Measurement of seal gas/supplier data

4.5.7 Proportions of methane and nmVOC in the waste gas

Where fuel gas is used as seal gas, it is analysed to determine the relative proportions of methane and nmVOC. Where the seal gas is taken from the compressors, export gas analyses are used to determine the proportions.

4.5.8 Estimated emission quantities from dry compressor seals

4.5.8.1 Primary seal

Emissions have largely been calculated with quantification methods proposed in part by Add Novatech using base data provided by the operators in connection with the survey, and in part by the operators themselves. In both cases, the following principles have largely been applied:

- measurement data for waste gas from primary seal gas are used where available
- where measurement data for waste gas from primary seal gas are not available, the amount of waste gas is calculated on the basis of the input seal gas and 10 per cent waste gas
- where measurement data for primary seal gas flow into the seal are missing, emissions are scaled on the basis of gas volume
- where information about an internal labyrinth is missing, this is assumed to be absent (conservative assumption).

Table 20 Preliminary emission estimates from dry compressor seals (tonnes/year).

Sub-process/emission source	Methane	nmVOC
From primary seal	2 277	1 012
HC gas from secondary seal	19	11
Primary leakage of gas from secondary seal	184	85
Total estimated emissions	**2 480**	**1 108**

Table 20 shows that emissions from dry compressor seals are surprisingly large. That offers the potential to reduce emissions considerably compared with oil seals because of the following.

1. Twelve facilities send used primary seal gas to an atmospheric vent. Emissions can be somewhat overestimated.
2. Five facilities use HC gas as secondary seal gas, with three sending the gas to emission.
3. Estimates of primary seal gas leakage to the secondary vent may be calculated rather conservatively, on the assumption that the seal has no internal labyrinth.

4.5.9 Uncertainty

Uncertainty in the reported emission figures presented in table 20 could be substantial. That reflects several factors.

a. The proposed quantification method is followed only partially owing to the absence of input data for some of the facilities.
b. The accuracy of measured seal gas volumes is poor.

c. The estimated percentage of primary seal gas being vented is uncertain. Deviations from actual leakage quantities may vary over time, while the percentages used are based on warranty figures from the seal supplier and may be conservative.
d. The assumption that compressors without labyrinth information do not contain this component is likely to be conservative.

As a result, the proposed quantification method still contains the uncertainties listed under points b and c above. No data are available for calculating these, but experience obtained from operators and meetings with seal suppliers indicates that the uncertainty can be several tens of per cent.

4.5.10 Comparison with other countries

In Canada and the USA, emissions from dry compressor seals are reported as fugitive emissions. Average emission factors in kilograms/hour per source (per compressor) are used.

The USA distinguishes between compressors for gas, oil, oil/water/gas and oil/ water service. These four service types have different emission factors. Operators report the number of compressors per service type.

Canada distinguishes between oil and gas service types, and operators report the number of compressors per service type.

Emissions from US offshore facilities are regulated by the Bureau of Ocean Energy Management (BOEM). Its *Gulfwide Emission Inventory Study* (ref 20) does not contain specific emission factors for dry compressor or oil seals. Instead, an aggregate emission factor is used which covers dry compressor seals, diaphragms, drains, dump arms, hatches, instruments, meters, depressurisation valves, polished rods, and vents. However, operators are required to indicate the seal type. This suggests that different emission factors are used, depending on compressor seal type. That indicates great uncertainties also exist in the emission figures reported in the USA.

The Canada guide (ref 21) from the CAPP is more detailed.

Table 21 Emission factors used in the USA and Canada.

Country	Unit	Gas	Oil	Oil/water	Oil/ water/gas
US – various sources, including dry compressor seals, diaphragms, drains, etc	lb/component/day	0.47	0.4	0.74	0.74
Canada – dry compressor seals	kg/h/source	0.04669	0.01474		

4.6 Seals on reciprocating compressors

4.6.1 Introduction

Four of the surveyed facilities had reciprocating compressors. A couple of the facilities used reciprocating compressors in the whole gas compression train.

Gas seals in reciprocating compressors are stuffing boxes on the piston rods. Gas leaking past the boxes collects in one or more separator chambers in series. Supplier information indicates that about one per cent of the gas from the first chamber is led to the second. Some gas may also leak from the separator chambers to the crankshaft housing (not normally supposed to occur). This gas is separated from the oil and led away. Where two separator chambers are present, waste gas from the high-pressure chamber can be led to flaring, while waste gas from the low-pressure chamber normally goes to the atmospheric vent.

Two potential emission sources are therefore present – the separator chamber and the crankshaft housing.

4.6.2 Recommended quantification method

Emissions could not be quantified for one facility, but data are available for the other four. Information has been obtained from the supplier in three of these cases, while emissions on the fourth are estimated from pipe dimensions. This facility also operates with radically higher emission data than the other three.

Since the number of facilities with reciprocating compressors is so small, and since different sealing systems are used, two alternative general methods for quantifying emissions are recommended.

1. Where waste gas is sent to a common atmospheric vent equipped with a meter, emissions are quantified in the meter together with those from other contributors.
2. Where waste gas goes to emission, but not through a measured common vent, obtaining the emission data/calculation method from the compressor-package supplier is recommended.

Conclusion:
Facility-specific quantification method
Supplier data

4.6.3 Proportions of methane and nmVOC in the waste gas

Determining the relative proportions of methane and nmVOC can be difficult. The compressor usually contains export gas with a documentable composition and a high methane content. NmVOC is more soluble in oil than methane. It can therefore be assumed that waste gas from depressurisation of seal oil will contain a higher proportion of nmVOC than the gas in the compressor.

To obtain an overview of this, taking a sample of used seal oil from the reciprocating compressor for analysis is recommended.

4.6.4 Estimated emission quantities from reciprocating compressors

Data on waste gas are available for all four facilities with emissions from reciprocating compressors. One of these sends the waste gas to flaring, with the other three sending it to an atmospheric vent.

Table 22 Waste gas from seals on reciprocating compressors and preliminary emission estimates.

Facilities with relevant process	4
Facilities with waste gas to recycling	0
Facilities with waste gas to flaring	1
Facilities with waste gas to direct emission	3
Calculated/estimated amount of methane (tonnes/year)	**750**
Calculated/estimated amount of nmVOC (tonnes/year)	**130**

Figures obtained from the operators vary significantly (by a factor of 200 between lowest and highest). This may be because emissions are calculated from supplier data on some facilities, and on the basis of the capacity of equipment and piping systems for others. This confirms the need to adopt consistent and reliable emission quantification methods.

The estimated total emissions specified in table 22 are probably be too high. That applies particularly for methane. Securing more accurate figures is expected to be possible when all the relevant operators apply the same consistent method.

4.6.5 Uncertainty

Uncertainty in the emission figures in section 4.6.4 is thought to be significant, particularly for methane. Securing better figures is expected to be possible when all the relevant operators apply the same consistent method.

4.6.6 Comparison with other countries

The USA operates with fairly high emissions of methane from reciprocating compressors. Canada makes no distinction between the type of compression seal. Emissions are reported as fugitive emissions. For information on emission factors, see the table in section 4.5.10.

4.7 Seals on screw compressors

4.7.1 Introduction

The survey showed that screw compressors are found on three NCS facilities. One sends waste gas to flaring. The two with emissions have quantified these as well below one tonne per year. Screw compressors are used mainly to compress HC gas from low-pressure sources (closed flare and carpet gas from crude oil tankers (VRU compressors)).

Several types of screw compressors exist. Oil-filled screw compressors are used on two of the facilities. Oil droplets accompanying the gas are separated out in a separator. Compressor seals are flushed with nitrogen. Used oil goes to a drainage pot vented to the air in a safe area.

4.7.2 Recommended quantification method

Since few facilities have screw compressors and emissions are low (see section 4.7.4), the simplest approach should be to include emissions from these compressors in a general pot for small emissions.

Conclusion:
General mark-up

4.7.3 Proportions of methane and nmVOC in the waste gas

Determining the relative proportions of methane and nmVOC is also difficult here. Where the waste gas goes to a measured common vent, the composition in the latter is used. Where emissions are included in a general mark-up, they are incorporated in fixed percentage supplements for methane and nmVOC respectively.

4.7.4 Key data and estimated emission quantities from screw compressors

Emission data are available for both the facilities with emissions from screw compressors.

Table 23 Waste gas from seals on screw compressors and preliminary emission estimates.

Facilities with relevant process	3
Facilities with waste gas to recycling	0
Facilities with waste gas to flaring	1
Facilities with waste gas to direct emission	2
Calculated/estimated emissions of methane (tonnes/year)	**< 1**
Calculated/estimated emissions of nmVOC (tonnes/year)	**< 1**

4.7.5 Uncertainty

Uncertainty in the emission figures in section 4.7.4 is assumed to be relatively substantial, but the amounts are so small that the impact on total emissions is very marginal.

4.7.6 Comparison with other countries

Canada makes no distinction between the types of compression seals, and emissions are reported as fugitive emissions. For information on emission factors, see the table in section 4.5.10.

4.8 Gas freeing in process plants

4.8.1 Introduction

Depressurisation of and gas freeing will occur in all HC process systems. These are found on 54 of the NCS facilities.

As explained in sub-report 1 from this project (ref 1), emissions will occur in connection with depressurisation and gas freeing in all or major parts of the HC process plant on a facility. This usually occurs during a turnaround and otherwise in exceptional circumstances. Turnarounds on most facilities take place every three years, but can also occur every two or four years.

Direct emission of methane and nmVOC occurs during the gas-freeing process where the waste gas is sent to flaring. As the HC gas content in the waste gas gradually decreases during gas freeing, it will become so low at some point that the flame can no longer be maintained. Residual HC gas will then be released to air unburned.

4.8.2 Assessment of quantification methods

As described in section 6.4.5 of ref 1, quantifying emissions will be difficult because the amount of HC gas left in the plant when the flare extinguishes is not known. A conservative method for emission calculation is therefore proposed.

Since the plant is depressurised to atmospheric pressure before gas freeing starts, the standard volume of HC gas in equipment and pipes is roughly equal to their volume. During the gas-freeing process, waste gas still goes to flaring. As the proportions of inert and HC gases in the waste gas increase and decrease respectively, the point comes where the flare goes out because of the low levels of combustible gases present. Residual HC gas will then be released unburned to the air. The time it takes for this to happen will depend on wind and weather, making it difficult (impossible) to calculate how much methane and nmVOC are released.

A conservative approach is therefore proposed. This assumes that all HC gas in the process plant is released to the air when gas freeing starts. Emissions from the activity are small, despite being calculated in accordance with such a conservative method. This approach is therefore regarded as fully acceptable.

A general emission quantification method is therefore recommended:

U_{CH4} = a ● Weight%$_{CH4}$ ● V_{pa} /1000
U_{nmVOC} = a ● Weight%$_{nmVOC}$ ● V_{pa} /1000
a = number of gas-freeing operations per unit of time (eg, per year or three years)
U_{CH4} = Emission methane in tonnes
U_{nmVOC} = Emission nmVOC in tonnes
Weight%$_{CH4}$ = Weight% methane in the gas
Weight%$_{nmVOC}$ = Weight% nmVOC in the gas
V_{pa} = Volume of process plant involved (equipment and pipes) in m^3

Emissions are quantified only for those years when gas freeing take place in the process plant.

Conclusion:
General quantification method
Emissions in scm = volume of process

4.8.3 Proportions of methane and nmVOC in the emission gas

The relative proportions of methane and nmVOC in the waste gas can be difficult to determine. Composition will vary somewhat from one equipment component to another. Equipment and pipes which also contain oil are assumed to have a higher nmVOC content in the gas phase than equipment and pipes in the gas compression plant. Measuring gas composition is also difficult because it will vary over time as the plant fills with inert gas.

It is therefore proposed that fuel or export gas composition be used as a basis for determining the weight ratio between methane and nmVOC emissions. The composition of fuel gas is assumed to be reasonably representative of the gas released by depressurisation for most of the facilities. Analysing the gas emitted during this operation is assumed to be unrealistic.

4.8.4 Estimated emission quantities from depressurisation and gas freeing

The process plant volume has been obtained for 23 facilities, and scaled up linearly to cover all 56 production facilities on the NCS. It is assumed that a third of these are gas-freed annually. Table 24 presents total emissions from the NCS per year.

Table 24 Emissions associated with depressurisation of processing equipment.

Calculated/estimated emission of methane (tonnes/year)	**18**
Calculated/estimated emission of nmVOC (tonnes/year)	**16**

4.8.5 Uncertainty

Since part of the gas will be flared after gas freeing has started, the method is considered to be conservative.

On that basis, uncertainty over annual emissions is assumed to be somewhat skewed. The estimated uncertainty range lies in the order of +20 to -30 per cent.

The uncertainty range can be reduced somewhat once the operators have calculated process plant volumes on all the facilities.

4.8.6 Comparison with other countries

USA: The API compendium provides emission factors for methane with depressurisation of vessels and compressors. “Vessels” include separators, dehydrators, tanks and so forth. The factors are 0.0015 tonnes CH_4 per vessel per annum and 0.162 tonnes per compressor per annum. These recommended emission factors are for use in cases where emission volumes are unknown. Uncertainty in the factors is considered to be high.

Canada: Canadian regulations require emissions associated with depressurisation to be reported, but say nothing about how they are to be calculated.

4.9 HC purge and blanket gas in pipes, equipment and storage tanks

4.9.1 Introduction

Both HC gas (mainly fuel gas) and inert gas (mainly nitrogen) are used for purge and blanket (cover) applications. As described in the module 1 report, only HC blanket and purge gas represent a real source of direct methane and nmVOC emissions.

The survey showed that a total of 14 facilities use fuel gas (or other HC gas) for purging and blanket applications, and six send the waste gas to emission. In most cases, the emission point is the facility’s common atmospheric vent system.

Attention in this section is confined to HC gas (ie, fuel gas) used for purge and blanket. Nitrogen used for these applications does not produce HC emissions other than the HC gas from other sources mixed with the purge/blanket gas, which is covered under other sources.

Blanket gas used in crude oil tanks on FPSOs is covered in section 4.22.

4.9.2 Assessment of quantification methods

The amount of blanket and purge gas used varies greatly from facility to facility on the basis of its area of application and the design of the gas supply. Only two ways exist for quantifying the emissions.

1. **Measuring or otherwise reliably quantifying the flow rate in the supply pipe from the fuel gas system.** If the purge/blanket gas goes to different consumers, which deliver the waste gas to different recipients such as recycling, flaring and emission (vent), the fraction going to emissions should be quantified in as reliable a way as the feed rate.

2. **Measuring and categorising the emission gas, where purge/blanket gas can be emitted with gas from other sources**. This will require a flow meter in the emission pipe and opportunities to determine waste gas composition – by sampling and analysis, for example.

If option 2 is utilised, option 1 will no longer be applicable. This means the operator must choose the quantification method on the basis of the best solution for the particular facility.

Conclusion:
General quantification method
1) Measurement or other quantification of purge gas into the plant
2) Measurement or other quantification of purge gas emitted via the vent

4.9.3 Proportions of methane and nmVOC in the waste gas

Since fuel gas is usually used as a purge and blanket gas, its composition on the specific facility will determine the relative proportions of methane and nmVOC.

4.9.4 Estimated emission quantities from purge and blanket gas

Only three of the six operators with emissions of HC purge and blanket gas were able to estimate these. Total emissions on the NCS were therefore calculated by straight scaling.

Table 25 Use of HC gas as purge and blanket gas and emission estimates.

Facilities with relevant process	14
Facilities with waste gas to recycling	4
Facilities with waste gas to flaring	4
Facilities with waste gas to direct emission	6
Calculated/estimated amount of methane (tonnes/year)	**1 100**
Calculated/estimated amount of nmVOC (tonnes/year)	**1 300**

4.9.5 Uncertainty

Since the base data are insufficient, uncertainty in the estimated emission range shown in section 4.9.4 is large.

4.9.6 Comparison with other countries

The API has a comprehensive compendium describing how emissions from blanket gas can be estimated (ref 18), but there is no requirement to report this.

No indications suggest that other countries used for comparison require emissions from purge and blanket gas to be reported.

4.10 Depressurisation/gas-freeing of instruments and instrument manifolds

4.10.1 Introduction

The survey in module 1 of this project showed that emissions can occur in connection with flushing, maintaining and replacing instruments and instrument manifolds. Operators reported that this was not done frequently. One operator estimated that it had a maximum of 100 such operations annually, with a minority causing emissions.

4.10.2 Assessment of quantification methods

The contribution from this source is negligible compared with others. Emissions are a fraction of ‰ of total direct methane and nmVOC emissions from NCS facilities, and therefore far lower than the level of uncertainty in emission estimates for the larger sources.

Technically, emissions could be measured with a portable flow meter. However, the work and cost involved are not proportionate to the negligible additional benefits of such measurements.

The recommendation is therefore that emissions from this source are not monitored separately, but handled together with other microsources through a general mark-up to the total emissions.

Conclusion:
General mark-up

4.10.3 Proportions of methane and nmVOC in the waste gas

These emissions may occur anywhere in the process, and the composition of the emission gas could vary from place to place. Since the amount involved is very small, an acceptable estimate can be obtained by assuming that the relative proportions of methane and nmVOC in the emission gas are equal to those in the fuel gas.

4.10.4 Estimated emission quantities from maintenance of instruments and instrument manifolds

Four facilities have quantified methane and nmVOC emissions from this source. The average per facility is very small – less than 0.002 tonnes of VOC per annum. Total annual emissions from the NCS are calculated by assuming that average emissions per facility from these four are also representative for those facilities which do not quantify their emissions. In other words, emissions have been scaled up to 56 facilities. Table 26 presents total emissions from the NCS.

Table 26 Emissions associated with maintenance of instruments and instrument manifolds.

Calculated/estimated amount of methane (tonnes/year)	**0.09**
Calculated/estimated amount of nmVOC (tonnes/year)	**0.08**

4.10.5 Uncertainty

Since no measurement data are available, uncertainty cannot be calculated. Given that emission size is considered to be conservative, uncertainty is estimated at +300 to -99 per cent.

4.10.6 Comparison with other countries

Other countries used for comparison provide no indications that emissions from flushing and maintaining instruments are reported or followed up.

4.11 Unburnt flare gas

4.11.1 Emissions from extinguished flares and flare ignition

4.11.1.1 Introduction

As described in the sub-report from module 1, the survey has shown that the flare rarely goes out (hereafter referred to as extinguished flare) on most facilities. Operator personnel on some facilities who participated in the survey had never experienced this or said it had not happened for many years. On a few facilities, however, it was reported to have occurred more often. An extinguished flare may occur as a result of adverse weather and wind conditions and/or a low flow rate.

The survey also showed that, in many cases, it takes some time before the flare or flares can be lit after a shutdown – a turnaround, for example, or when gas for flaring is sent to a normally closed flare.

4.11.1.2 Recommended quantification method

A general emission quantification method is recommended.

Emissions from an extinguished flare can be quantified by introducing manual logging of shutdown and ignition times in a permanent log in the control room. If the exact time when the flare is extinguished cannot be observed, this should be estimated as soon as it has been detected.

The outflow rate is continuously measured by the flare gas meter on every facility. This means that if flare rates are plotted as a function of time, the emissions are represented by the area beneath the flare rate for the period when the flare was extinguished.

The corresponding procedure is used for ignition. The time from opening the flare valve to igniting the flare is logged, and the emission rate during this period is recorded by the flare gas meter.

Conclusion:
General quantification method
Registering the time the flare is extinguished combined with flare gas measurements

4.11.1.3 Proportions of methane and nmVOC in the waste gas

Since it is difficult to analyse the gases sent to emission each time, the recommendation is to determine the relative proportions of methane and nmVOC on the basis of the same flare-gas composition used to calculate CO_2 emissions from flare gas.

4.11.1.4 Estimated emission quantities from an extinguished flare and flare ignition

At present, the time spent before the flare ignites and the number of ignitions per annum are not logged. That means no data are available for calculating the size of emissions from this source.

As mentioned in section 4.11.1.1, a flare going out appears to be very rare. This indicates that an extinguished flare is not a large emission source.

Open flares are continuously lit. Ignition will normally be required only after a turnaround – typically every three years – and is a planned process. In such cases, the flaring rate during ignition will normally be low, Otherwise, the flare will only be ignited every time it has been gone out and/or has been out of service for other reasons.

Closed flares are installed on some facilities. They must be relit whenever flaring is required. The survey indicated that this can occur from several to many times a year on certain facilities, but the number of occasions is unknown since they are not logged.[4] Since the flare is lit when flaring is required, it can be assumed that the flaring rate could be high.

On the facilities providing information here, the time gas has been sent to the flare before ignition varies from 20 minutes to two hours. Flare rates have varied from 1 000 to 25 000 standard cubic metres (scm) per day. Based on this information, a conservative estimate of single emissions from this source can be calculated by applying the highest flare rate and longest time:

$U_{\text{exinguished flare}}$ = 2 h * 25000 scm/day/ 24h/day = 2 083 scm/year ≈ 2 083 kg HC gas ≈ <u>2.1 t HC gas</u>

This figure indicates that emissions from an extinguished flare are unlikely to be a significant contributor to total direct emissions of HC gases by the industry. But they are also not negligible.

Operators for five of the facilities had themselves estimated emissions associated with flare ignition. The average estimate was 3.3 tonnes of HC gas per annum.

4.11.1.5 Uncertainty

Since no historical data are available for these emissions, uncertainty is high for current conditions.

If the recommended quantification method is used, emissions can be calculated with a relatively high degree of accuracy provided relatively accurate timings are available for extinguished flaring. Requirements for flare gas meters are +/- 7.5 per cent. Assuming that logging the emission duration has an uncertainty of +/- 10 per cent, the total uncertainty will be +/- 12.5 per cent. This is low compared with emissions from many of the major sources.

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[4] However, it is possible to calculate backwards with a certain level of uncertainty to determine how many times the closed flare is ignited by analysing flaring data. But this is a fairly time-consuming process.

4.11.1.6 Comparison with other countries

In other countries that have been used for comparison, no indication has been found that emissions from extinguished flare or delayed ignition of flare are reported or followed up.

4.11.2 Non-flammable flare gas

4.11.2.1 Introduction

During the survey, one low-pressure flare was identified which could not ignite owing to high levels of inert gas in the flare gas (the HC content was below the lower ignition limit). As a result, all waste gas from the flare was emitted unignited. Flare gas volume was measured in accordance with Norwegian regulations, but not the methane and nmVOC content.

4.11.2.2 Recommended quantification method

This represents such a special condition that establishing a general methodology for quantifying emissions is considered inappropriate. The proposal is therefore that the operator prepares a facility-specific quantification method.

Conclusion:
Facility-specific quantification method
The operator must come up with the most appropriate method here.

4.11.2.3 Proportions of methane and nmVOC in the emission gas

The relative proportions were determined through simulations performed by the operator. Their quality has not been field-tested. The facility-specific quantification methodology proposed by the operator must include a method for establishing the proportions of methane and nmVOC in the gas.

4.11.2.4 Estimated emission quantities from non-flammable flare gas

The size of the emissions was calculated by the operator using process simulations, and is presented in section 4.18 (amine regeneration).

4.11.2.5 Uncertainty

Since no satisfactory measurement data are available for these emissions, uncertainty is high in current conditions. Uncertainty in a future facility-specific quantification method will be considered when this has become available.

4.11.3 Open flare flushed with inert gas

4.11.3.1 Introduction

Six facilities operating on the NCS today have an open unlit flare. The flare system is flushed with nitrogen. In normal operation, no HC gas is emitted in theory through the flare. In certain specified conditions, a minor depressurisation may occur, with HC gas sent to the flare. This does not happen every year. Gas amounts are continuously measured by a flare gas meter. Monthly overviews are posted by the Norwegian Petroleum Directorate (NPD) on its website. More extensive depressurisation also occurs for such cases as depressurisation of pipelines, when the flare will be ignited.

As pointed out in the module 1 report for this project (ref 1), the safety valves which open when flaring is needed may leak small amounts of gas into the flare header when closed. Although the flare gas is continuously measured (nitrogen purge gas passes through the flare), the HC gas contribution from leaks through the safety valves is too small for detection.

Where smaller facilities with few safety valves are concerned, this is not expected to be a problem. Only one facility is in operation on the NCS. However, the position may be different on facilities with large comprehensive process plants and hundreds of safety valves. When such a flare solution is planned for a new facility, the recommendation is to consider carefully what emissions it would cause. The operator with a large facility in the planning phase who is assessing a flare solution of this kind is aware of the issue.

4.11.3.2 Recommended quantification method

Where flaring with direct emission (venting) of methane and nmVOC is concerned, a generic method is recommended on the basis of flare gas measurements as well as registering venting duration. This is the method used for reporting today.

The proposal for quantifying any leakage through the safety valves is that the operator of the new facility using this solution monitors it once production has started.

Conclusion:
General quantification method
Flare gas meter

4.11.3.3 Proportions of methane and nmVOC in the emission gas

The relative proportions will match the composition of the flare gas.

4.11.3.4 Estimated emission quantities from open flare flushed with inert gas

Operators for five of the six facilities with direct emissions of methane and nmVOC through an inert-gas-flushed open flare have estimated the emissions, largely with the aid of measurements. To cover the entire NCS, emissions are scaled linearly to cover all six facilities.

Table 27 Preliminary emission estimates from open flare flushed with inert gas.

Facilities with relevant process	6
Facilities with waste gas to recycling	0
Facilities with waste gas to flaring	0
Facilities with waste gas to direct emission	6
Calculated/estimated amount of methane (tonnes year)	**1 505**
Calculated/estimated amount nmVOC (tonnes/year)	**585**

The figures in table 27 show that this is a relatively significant emission source.

4.11.3.5 Uncertainty

Emissions from cold venting through the flare are measured by the flare gas meter. Section 8 of the measurement regulations requires that the uncertainty with flare gas meters should be within +/- 5 per cent of the standard volume at the 95 per cent confidence level.

4.12 Process leaks

4.12.1 Large leaks (which give rise to an investigation)

4.12.1.1 Introduction

Large emission leaks are defined as those which prompt an investigation and, as a result, are also quantified and reported in accordance with the HSE regulations. The amounts involved are reported by the operators in their annual emission reports to the Norwegian Environment Agency. Investigations are mainly conducted for emissions with a rate exceeding 0.1 kilograms/second, but may also cover smaller emissions/leaks depending on their criticality.

4.12.1.2 Recommended quantification method

No better way is seen to quantify these emissions than the established system, which means the amount of gas emitted is calculated as part of the investigation into the accident/incident. The amount is calculated on the basis of the emission rate, the time taken to halt the emission, the pressure, and the volume of the equipment and piping which supply gas to the emission point.

Conclusion:
General quantification method
Estimated as part of an investigation, in accordance with current routines

4.12.1.3 Proportions of methane and nmVOC in the emission gas

The relative proportions of methane and nmVOC will vary between the various emission points. They cannot be determined from measurements at individual sources. It is therefore proposed that these be based on the composition of sales or fuel gas on the individual facility.

4.12.1.4 Estimated emission quantities

Emissions can vary significantly from year to year. Reported emissions over the last 12 years are presented in table 28. The relative proportions of methane and nmVOC are not available, but assuming 75 mole% methane and 25 mole% nmVOC is unlikely to represent a large margin of error.

Table 28 Emissions from major leaks 2002 to 2014 (source: EW).

Year	Tonnes	Number of events	Tonnes HC gas per event
2002	8.1	10	0.81
2003	590.0	20	29.50
2004	1371.9	19	72.21
2005	21.4	20	1.07
2006	34.9	28	1.25
2007	2.6	26	0.10
2008	13.3	35	0.38
2009	54.6	19	2.87
2010	11.5	26	0.44
2011	15.4	7	2.20
2012	93.7	8	11.71
2013	2.8	13	0.22
2014	1.7	17	0.10

4.12.1.5 Uncertainty

No data are available which makes it possible to calculate the uncertainty of this emission information. Based on statements from experts at Norwegian Oil and Gas, the uncertainty in the figures is estimated to be +/- a few tens of per cent.

4.12.1.6 Comparison with other countries

Comparison with other countries is difficult since the definition of gas leaks varies from country to country.

Gas emissions on the UK continental shelf (UKCS) are available in the UK hydrocarbon release system (ref 22), where gas emissions are categorised as follows:

- Major:	gas emissions > 300 kg or rate >1 kg/sec and duration > 5 min
- Significant:	gas emissions at rate 0.1-1 kg/sec for 2-5 min
- Minor:	gas emissions < 1 kg or at rate < 0.1 kg/sec and duration < 2 min

In its annual RNNP survey on trends in risk level in the Norwegian petroleum activity for 2013, the Petroleum Safety Authority Norway (PSA) compares aggregated gas emissions with the UKCS north of 59°N in 2000-12.

Table 29 Number of registered gas emissions on the NCS and UKCS (source: ref 23).

Rate	NCS events	UKCS events
> 1 kg/sec	38	24
0.1-1kg/sec	123	53

Table 29 shows that the NCS has had significantly more events than the UKCS. This difference has declined in recent years. Although the UKCS operates with the same leak categories and rates, the figures in table 29 are not necessarily directly comparable since detection routines may differ.

4.12.2 Small gas leaks

4.12.2.1 Introduction

Emissions from leaks have been calculated since the mid-1990s using a default emission factor and total gas throughput as the activity factor. The emission factor was established on the basis of a study by Aker Engineering (ref 7) which drew on the following.

- A report from an API/GRI study in the USA which provides methods for calculating emissions on the basis of the number of emitting components (valves, flanges and so forth) with an emission factor per component (a simplification which has been confirmed to provide realistic emission estimates in the USA (ref 8)).
- A report from the Norwegian Institute for Air Research (Nilu) in 1992 (ref 9) concerning fugitive emissions from Oseberg, which utilised measurements with a trace element (SF_6).

Based on these reports, and especially the one for Oseberg, an overview was established of all the production and riser facilities on the NCS in 1992-93, as well as the emission factors used up to now.

Great uncertainty prevails on whether the current method provides representative total emission data. According to the current quantification method, small leaks are also a relatively significant emission source which contributes a large proportion of total direct emissions of methane and nmVOC.

4.12.2.2 Comparison with other countries

The USA has a significant oil and gas industry and has devoted much work to developing better methods for quantifying leak emissions, and extensive databases have been built up. Since the number of US industrial emitting units with this type of emission is so high, calculations are largely based on generic quantification methods and the use of factors, large databases and statistics. Several calculation methods are also utilised, ranging from general overall factor methods to detailed measurements. The principle is that the more general the method used, the more conservative (high) the emission figures will be. This methodology is described in a protocol prepared by the EPA (ref 11).

Several other countries have developed national standards based on the EPA protocol. The European Committee for Standardisation (CEN) has produced one for quantifying these emissions. It refers to the EPA protocol and builds on some of the same principles. EN 15446 has been adopted by Standards Norway and is available as Norwegian standard NS-EN 15446: 2008 (ref 12).

4.12.2.3 Alternative quantification methods

Leaks are difficult to quantify. The following main methods have been identified.

a. Trace element. This was used in a comprehensive survey by Nilu on the Oseberg field centre in 1992 (ref 9). Measurements were made partly on the facilities and partly from a ship at about 500 and 1 000 metres from the south side of the facilities (Oseberg A and B). Unstable wind conditions and complex geometry on the facilities made this difficult. The uncertainty in the measurements was not specifically discussed in the report, and how representative the measurement results are for the NCS as a whole is also uncertain.

b. Differential absorption Lidar (Dial) measurements. Used at land-based facilities for measuring methane and nmVOC emissions, this is a laser-based method for remote measurement of gas concentrations in the air with detection limits in the order of parts per billion (ppb). As with method (a), two conditions in particular make it difficult to apply for measuring leak quantities on the NCS.
    - The method measures concentrations, which means that emissions from local venting will also be included. Although this is no big problem, it means that the source(s) of the emissions cannot be determined.
    - Distance measurements are difficult on the NCS. On land, a mobile unit (converted bus) is positioned at predetermined points a few hundred metres from the source to be measured. This will be difficult on the NCS. The measuring equipment must be on a ship subject to wave motion. According to information from the industry, this method is seen to present considerable practical difficulties on the NCS.

    Should the Dial method be used, a certain number of facilities ought to be covered so that the measurements can be representative of the NCS as a whole.

c. Sampling and analysis of methane and nmVOC in air samples from vent ducts in artificially ventilated process modules. This will only be possible on facilities which have enclosed process modules with forced ventilation. Such measurements can also be carried out using trace elements. Since only a few facilities on the NCS have closed process modules, the method is primarily suited to verifying emission figures calculated using simpler methods, such as (d) below.

d. Statistical emission data combined with dedicated measurements. As mentioned in section 4.12.2.2, factor estimation methods have been developed in the USA on the basis of comprehensive measurement programmes. In its simplest and most conservative form (level), individual emission factors can be used per type of leak component (valve, flange and so forth). The activity factor is the number of components in each group. More accurate emission data can be obtained by varying the extent of the measurements. Based on statistical methods, the emission factors can be corrected using the measurement data. The US EPA's protocol describes how the method should be used (ref 11).

    The European standard for quantifying fugitive emissions, EN 15446, has been adopted by Standards Norway and is available as Norwegian standard NS-EN 15446: 2008 (ref 12).

4.12.2.4 Recommended quantification method

After this sub-report was completed in June 2015, a separate sub-project looked at methods for estimating small leaks and fugitive emissions (ref 27). The subsequent report recommends that a method called OGI Leak/No Leak be used in the future to quantify these.

This method utilises an IR camera to detect small leaks. Emission amounts are quantified by combining the number of detected leaks with statistically calculated emission factors per component and component type. This now looks like being the best method for quantifying such emissions with a reasonable use of resources. It also meets the requirements for leak detection and repair (LDAR), which has gradually been established as a standard for modern leak control in process plants. This methodology is widely implemented on NCS facilities. The argument for using it is provided in ref 27, which also provides an overall description of the method.

Conclusion:
General quantification method
Use the OGI Leak/No Leak method

4.12.2.5 Proportions of methane and nmVOC in the emission gas

The relative proportions of methane and nmVOC will vary between the different emission points. These proportions cannot be determined by measuring single sources. Basing this on the sales or fuel gas composition for the individual facility is therefore proposed.

4.12.2.6 Estimated emission quantities from small gas leaks

Using an IR camera to detect leaks has been tested and to some extent applied on NCS facilities. However, the OGI Leak/No Leak quantification method has not been used. Estimating methane and nmVOC emissions from small leaks and fugitive emissions with this method is not possible today. The decision has therefore been taken to estimate emissions with the aid of experience-based average factors established by the CAPP on the basis of data from 120 upstream oil and gas production plants in Alberta and British Columbia. These relatively modern facilities use a leak control programme which largely corresponds to the one used on the NCS. Canadian emission factors are therefore also likely to be representative for the NCS.

As a control, the emissions were also calculated using standard default factors from Norwegian standard NS-EN 15446. In reality, these factors should only be used for non-sniffable components.

An overview of the total number of components (valves, flanges and so forth) in HC systems on NCS facilities was estimated. This was done through data collected by the operators for 11 facilities. The number was then scaled up linearly to cover all Norwegian facilities.

The results are shown in table 30.

Table 30 Factor calculations of small gas leaks with CAPP and NS:15446 emission factors.

Method	Methane (tonnes/year)	nmVOC (tonnes/year)
Emissions calculated using CAPP factors	1 233	935
Emissions calculated using NS:15446 default factors	7 114	5 390

Table 30 shows that the methods yield very different results. More precise emission data are likely to be obtained when the OGI Leak/No Leak method is applied, probably from 2017.

4.12.2.7 Uncertainty

As table 30 shows, uncertainty is significant. A comparison shows that these factor methods yield far lower emissions than those found by Dial measurements at four Norwegian land facilities. Similarly, measurements of fugitive emissions and small leaks with soap spray and bubbles on one of the NCS facilities show that the factor calculations yield far higher emission figures. This emphasises that the uncertainty in the calculated emission figures is high. Ref 27 provides a more thorough assessment of these conditions.

4.13 Bleeding gas from the production riser

4.13.1 Introduction

The annulus is the spaces between the tubing and the casing, and between the various casings. These should basically be sealed, which is checked by pressure sensors. If the pressure builds up, the annulus must be depressurised. Pressure build-up can occur for several reasons:

- leaks from production pipes owing to rust or damage
- leaks through screwed connections in the production pipe.
- leaks from the formation through the cement lining at the bottom of the casing
- pressure build-up owing to slow fluid penetration in the annulus.
- gas expansion owing to heat transfer from hot oil in the production pipe.

In all such cases, the pressure must be bled off. This is usually done to the flare or to the process. In some cases, the annulus may have to be bled off to the atmospheric vent. When bleeding-off the pressure, the waste gas is led to recycling in some cases and to emission in others. According to the operators, bleed-off from the annulus is relatively rare.

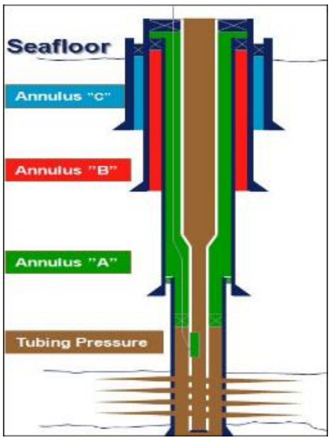

Figure 1 Typical well design (outline downloaded from the web).

4.13.2 Recommended quantification method

Waste gas emitted from bleeding the annulus in production wells in the event of a pressure build-up is not measured. Calculations by some operators show that this can range from almost zero to a few kilograms per bleed-off.

A high level of emissions is accordingly not expected from this source, and it is therefore recommended that emissions are not be quantified separately but included in a general mark-up with other microsources.

Conclusion:
General mark-up

4.13.3 Proportions of methane and nmVOC in the emission gas

The composition of waste gas emitted by bleeding from the annulus will depend on well-specific conditions.

Since the emissions are assumed to be small, the recommendation is to use fuel gas composition as reasonably representative.

4.13.4 Estimated emission quantities from the annulus in production risers

The survey found nothing which could be used to quantify emissions from this source, or anything to suggest that bleeding the annulus in production wells represents a significant contributor to direct methane and nmVOC emissions on the NCS.

4.13.5 Uncertainty

Since it has not been possible to secure better data on emissions from this potential source, assessing uncertainty is difficult. But little evidence indicates that emissions will exceed one per cent of the quantity from the major contributors. The uncertainty will therefore have little significance in the overall context.

4.13.6 Comparison with other countries

No references to this source have been found in the comparisons with other countries.

4.14 Drilling

4.14.1 Introduction

The emission factor used in the Norwegian Oil and Gas guidelines was proposed by Aker Engineering in 1993 (ref 7). According to the Aker report, it was based on an evaluation of data from mud logging during the drilling of three production wells. The gas content in the drilling fluid was logged, and HC gas emissions calculated from relevant flow data for the fluid. This should be a relevant method for calculating emission data. The producers studied by Aker were mainly deviated wells, with a much shorter section in petroleum-bearing layers than is usual with the horizontal wells drilled in some fields today (producers extending up to four kilometres horizontally are drilled through oil- and gas-bearing layers on Troll B and C). Pure gas wells are significantly shorter.

To check Aker Engineering’s emission factor, Add Novatech did a calculation which assumed a pure gas reservoir where all the gas in the cuttings was released. This showed a total gas content of 0.5 tonnes, based on the following assumptions:

drill diameter	8½ inch (= 0.216 metres)
well length in gas-bearing zone	100 metres
leaching factor	30%
pore volume	30%
pressure	300 barg.

That gives a maximum emission of about 500 scm of HC gas. Assuming that the gas contains 30 mole% methane, this corresponds to about 0.25 tonnes of methane and 0.25 tonnes of nmVOC (per well) This indicates that the emission factors given in the Norwegian Oil and Gas guidelines are likely to be reasonably representative of the average for all wells, when taking into account that drilling through oil-bearing layers releases significantly less gas than the amount which forms the basis for the calculations above.

4.14.2 Recommended quantification method

Retaining the general quantification method in the Norwegian Oil and Gas guidelines is proposed, but with adjustments to the emission factors for methane and nmVOC to reflect the calculations in sections 4.14.1 and 4.16.3. A wellbore is proposed as the activity factor rather than a well, since this includes all laterals drilled in HC-bearing layers. If three new laterals, each of 100 metres, are drilled in an existing well, for example, the emissions from each of these will be included. Moreover, the NPD keeps annual statistics over the number of laterals completed in a reporting year.

The emission factors cover amounts released both from handling cuttings and the shale shaker, and from the mud separator in the form of gas.

Proposed emission factors

methane:	0.25 tonnes/wellbore
nmVOC:	0.25 tonnes/wellbore

Conclusion:
General quantification method
Emission factor per wellbore

4.14.3 Proportions of methane and nmVOC in the emission gas

The relative proportions of methane and nmVOC will vary from well to well. Since emissions are so small, a more accurate split between methane and nmVOC will not have a significant impact on total emissions. Assuming that wellbores in gas-filled structures emit more than those in oil-filled structures, a gas composition approaching that for fuel gas should be expected. On that basis, a 50/50 split by weight between methane and nmVOC is proposed.

4.14.4 Estimated emission quantities from drilling

A total of 227 wellbores were completed in 2014. That gives the following emission volumes on the NCS for 2013:

methane: 57 tonnes. NmVOC: 57 tonnes.

Drilling wells on the NCS thereby accounts for less than one per cent of total direct methane and nmVOC emissions.

4.14.5 Uncertainty

Uncertainty is substantial, but the factors are assumed to give conservative emission figures for the NCS as a whole. On average, exploration wells will yield less since most do not penetrate long hydrocarbon-bearing structures.

The uncertainty was considered to range from +40 to -60 per cent in qualitative terms.

4.14.6 Comparison with other countries

Emissions from degassing drilling fluid are reported in the USA. If the separated waste gas is led to the air, the amount released is estimated using generic emission factors based on the number of drilling days. Various emission factors are recommended, depending on the type of drilling fluid. How drilling days are calculated in this respect is not known.

4.15 Gas turbines

4.15.1 Introduction

Fuel gas under pressure was previously used to some extent to start gas turbines. The survey found that this technique was no longer in use.

Gas turbines need to be flushed with fuel gas before start-up. The amounts involved are small.

When gas turbines are shut down, a small amount of enclosed gas must be bled off. This usually goes to a common atmospheric vent.

Both purge and waste gas from depressurisation can be sent for emission through a common atmospheric vent, or for recycling or flaring. How this is done on the facilities was not surveyed because potential emission amounts are so small.
Recommended quantification method

Emissions are so small that it is proposed to include them in the general mark-up for small emissions.

Conclusion:
General mark-up
Small emissions

4.15.2 Proportions of methane and nmVOC in the emission gas

Since fuel gas is the relevant component, the proportions will be the same as for this.

4.15.3 Estimated emission quantities from gas turbines

Flushing at start-up: One operator reports about one scm (roughly one kilogram) of fuel gas per start, with around 50 starts a year. That gives some 50 kilograms of methane and nmVOC per annum.

Bleed-off of enclosed gas at shutdown: The amount was checked on one of the large facilities. The bleed-off volume is well below 10 litres. At 40 bar of pressure, this gives less than 0.4 kilograms of gas emitted per shutdown. The operator estimated turbine shutdowns at about 20 per annum. This indicates annual emissions of about 10 kilograms of HC gas.

On this basis, total methane and nmVOC emissions from the gas turbines found on 45 NCS facilities are calculated to be 0.54 tonnes of HC gas.

Table 31 Distribution of gas emissions from gas turbines and preliminary emission estimates.

Facilities with gas turbines	45
Facilities using fuel gas as start-up method	0
Facilities using fuel gas for purging with direct emission	< 45
Facilities which depressurise fuel gas to the air during turbine shutdowns	< 45
Estimated amount of methane emissions (tonnes/year)	**0.27**
Estimated amount of nmVOC emissions (tonnes/year)	**0.27**

4.15.4 Uncertainty

Uncertainty is high since emission have only been estimated on the basis of a single large facility. The estimate has been conservatively calculated, and the likelihood of emissions exceeding it is considered small.

4.15.5 Comparison with other countries

No references to this source have been found in the comparisons with other countries.

4.16 MEG regeneration

4.16.1 Introduction

Monoethylene glycol (MEG) is an absorption liquid used in part to dewater gas in the same way as TEG on a few NCS facilities. The regeneration process resembles that used for TEG. As described in the module 1 report, however, MEG is primarily used to prevent hydrate formation in multiphase-flow pipelines.

4.16.2 Recommended quantification method

A general quantification method is recommended. Both standard simulation programmes and other specially developed calculation tools are available for quantifying emissions. These include:

- **GRI-GLYCalc**: calculation programme described in detail in the TEG regeneration section
- **MultiProScale**: process simulation programme specifically designed to simulate the chemistry, thermodynamics and equilibrium in oil-gas-water and MEG systems
- **flashSIM**: a three-phase computer programme from Scale Consult using standard equations of state. These are not particularly suitable for this type of calculation, but the supplier claims that a considerable improvement is achieved by using the Huron-Vidal mixing rule.

One operator has had calculations done with both MultiProScale and flashSIM in mark-up to sampling and analysis of the waste gas (ref 13). The report concludes that MultiProScale produces the best results for methane emissions (2.19 versus 1.6 kilograms/day from sampling and analysis). The simulation results for nmVOC were poor (too low). Sampling and analysis showed that methane and nmVOC emissions were about 600 and 7 000 kilograms/year respectively. This was explained as a possible carry-over of heavier components.

Based on the above, the recommendation is that emissions are calculated using programmes such as GRI-GLYCalc or MultiProScale and verified (and corrected if necessary) using measurements and analyses conducted once a year, for example.

On the one facility which uses fuel gas for stripping, the recommendation is that the amount of stripping gas be measured or estimated in a reliable way. That is also recommended for facilities using fuel gas as a blanket in the MEG storage tank.

Conclusion:

General quantification method

- Use of GRI-GLYCalc and MultiProScale calculation software or equivalent, verified by measurements
- Stripping-gas measurement to determine the amount where applicable
- Analysis of the MEG solution

4.16.3 Proportions of methane and nmVOC in the emission gas

Using a calculation programme as proposed will also calculate the amounts of methane and nmVOC components separately. That includes stripping-gas emissions and assumes that the stripping gas (= fuel gas) composition is added to the programme.

Where blanket gas is used, the suggestion is to use the relative proportions in the fuel gas.

4.16.4 Estimated emission quantities from MEG regeneration

From the MEG degassing tank

Table 32 Disposal of emission gas from MEG degassing tank and preliminary emission estimates.

Facilities with MEG degassing tanks	*2*
Facilities which send gas from degassing tank to recycling	*1*
Facilities which send gas from degassing tank to flaring	*1*
Facilities which send gas from degassing tank to emission	*0*
Estimated methane emissions from all facilities (one), tonnes/year	***0***
Estimated nmVOC emissions from all facilities (one), tonnes/year	***0***

No facility has reported that waste gas from the degassing tank goes to an atmospheric vent.

From the MEG regenerator

Table 33 Disposal of waste gas from the MEG regenerator and preliminary emission estimates

Facilities with MEG regeneration plant	*3*
Facilities which send waste gas to recycling	*0*
Facilities which send waste gas to flaring	*0*
Facilities which send waste gas to emission	*3*
Estimated methane emissions from all facilities, tonnes/year	***26***
Estimated nmVOC emissions from all facilities, tonnes/year	***71***

All facilities with MEG regeneration plants send emissions from the regenerator to atmospheric vent, and all have made measurements/calculations to determine the emissions specified in the table above.

Emissions from stripping gas

One plant uses fuel gas for stripping. This passes straight through the system and is emitted with the regenerated gas from the regenerator. Since the amount of stripping gas supplied to the system is the only factor affecting how much gas is released from the regenerator, measurement or other reliable quantification of this input is the sole requirement. The amount will vary from facility to facility.

One facility uses fuel gas for stripping, the others use nitrogen. The fuel-gas user has not differentiated between stripping and regenerated gas. Emissions are recorded under regenerated gas from the regenerator.

4.16.5 Uncertainty

Uncertainty depends on which method is used to determine the emissions. Whether the calculation programme referred to in section 4.16.2 has been verified against field data is unknown, making it hard to say anything about the uncertainty of the emissions specified here. They could be substantial.

4.16.6 Comparison with other countries

As with TEG regeneration, see section 4.1.6.

4.17 Amine regeneration

4.17.1 Introduction

Two of the NCS facilities have an absorption plant which uses an alkylamine solution to remove CO_2 from export gas. Some methane and nmVOC are also absorbed by the amine solution.

a. On one facility, waste gas from the amine regeneration system is injected back to the sub-surface. Methane and nmVOC in the waste gas are thereby also injected.
b. On the other, the waste gas – including methane and nmVOC – is released to the air via the facility's low-pressure flare, which does not burn.

4.17.2 Recommended quantification method

Since the NCS has only two facilities, with totally different technical solutions, facility-specific quantification methods are proposed.

Facility a, where the waste gas is injected into the sub-surface has no emissions in normal operation.

Facility b, where waste gas from amine regeneration is released to the air via an inactive low-pressure flare, it is proposed that the operator establishes a facility-specific calculation model for quantifying methane and nmVOC emissions.

Conclusion:
Facility-specific quantification method
(one facility)

4.17.3 Proportions of methane and nmVOC in the emission gas

The relative proportions of methane and nmVOC in the emitted gas will probably differ between the two facilities. In both cases, the recommendation is that methane and nmVOC content be determined by sampling and analysing the waste gases. Simulating the composition is also possible but, since simulations have proved less reliable, these models should be verified by sampling and analysis.

4.17.4 Estimated emission quantities from amine regeneration

Emissions have been calculated for facility b, where they occur because the CO_2 content in the flare gas is high.

Table 34 Disposal of emission gas from amine regeneration and preliminary emission estimates.

Facilities with amine regeneration	2
Facilities with methane and nmVOC emissions from amine regeneration	1
Estimated emissions of methane (tonnes/year)	**95**
Estimated emissions of nmVOC (tonnes/year)	**40**

Calculated using simulations in Hysys, the emission figures are considered somewhat uncertain.

4.17.5 Uncertainty

Because process simulations have proved unreliable with inadequate verification, uncertainty is estimated to be as high as +100 to -70 per cent.

Sampling and analysing waste gases to verify/calibrate the simulations are recommended to ensure more reliable emission data.

4.17.6 Comparison with other countries

The AmineCalc simulation programme developed by the API in 1999 is used in the USA to estimate methane and nmVOC emissions.

4.18 Gas analysers and test stations

4.18.1 Introduction

Process gas condition is regularly monitored. Gas samples are taken from relevant points in the process for condition monitoring and quality control of fuel, export and injection gases, among others. What is analysed and sampled depends to some extent on conditions on the individual facility.

Gas samples are analysed on the facility or at onshore laboratories. Gas chromatography, H_2S and dew point analysers are the tools most commonly used on NCS facilities. Gas chromatographs are utilised to analyse gas composition, while H_2S analysers are found on facilities which process gas with a high sulphur content. The water content of the gas is checked with a dew point analyser. O_2 and H_2O analysers are other instruments used on the facilities.

On some facilities and with some analysers, gas to be analysed is collected from a sidestream to the pipe which the gas normally passes through. In other cases, the test sample is taken directly from the main stream. On some facilities, the sidestreams are emitted via an atmospheric vent, while on others they go to recycling or flaring. The sidestreams may have a flow rate up to many scm of gas per hour.

Gas for analysis is extracted from the stream in very small quantities at a time (millilitre sizes). Waste gas from the analysers is largely released to the air. Sampling frequency varies from four times per hour, for example, to a couple of times a month. Emissions from the analyser are many times smaller than the amount of gas in the sidestream.

Gas samples for laboratory analysis, including fuel gas analyses, are collected in a pressure cylinder (with a piston to adjust back pressure) holding about 350-500 millilitres. Taken as spot samples at intervals from once a week to once a month, they are analysed at accredited laboratories onshore. The sampling technology used eliminates local flushing to the air, with the gas led to flaring. Gas from pressure cylinders is emitted via a ventilation hood in the lab[5].

Estimated annual emissions, based on two cylinders of 500 millilitres per week per facility, a pressure of 30 barg and 65 facilities, equal to about 100 kilograms/year in all. Based on the information obtained in the survey, the assumptions made here are conservative.

4.18.2 Factors affecting the emissions

The following factors affect emissions from the gas analysers.

- Continuous sidestream: emissions can be reduced by taking the gas for analysis from the main stream rather than the sidestream.
- Discontinuous use of sidestream: emissions can be reduced by restricting flow in the sidestream to periods when the analysis is being conducted.
- Waste gas solution: emissions can be reduced by directing the sidestream to flaring or recycling.

4.18.3 Quantification methods

The survey showed that the sidestream totally dominates emissions from gas analyses and test stations. Other emissions are trivial by comparison.

Two quantification opportunities have been identified.

1. When determining the flow rate through the sidestream by measurement or other reliable method.
2. If the sidestream leads to a common atmospheric vent with a gauge, the amount of gas emitted will be measured through the vent's measurement station. This means the composition of the gas in the common vent can be tested and analysed through or by other reliable methods.

Quantification is only relevant if the sidestream goes to emission.

Conclusion:
General quantification method
Determination of flow rate through the sidestream

4.18.4 Proportions of methane and nmVOC in the emission gas

Where analysers are positioned in the export gas stream, the composition of HC gas released will equal the composition of the export gas. Where analysers are positioned in the fuel gas stream, the composition of HC gas emitted will equal the composition of the fuel gas.

On average, the composition of the emission gas will not vary much from the fuel gas.

4.18.5 Estimated emission quantities from gas analysers and test stations

The primary mapping showed that the flow rate of the sidestream is known. Four of the 16 facilities from the primary mapping had continuous sidestreams with emissions ranging from 0.2 m^3/hour to 0.7 m^3/hour and an average of 0.44 m^3/hour per facility. On the other facilities, the sidestream was not running continuously. Roughly estimated, 25 per cent of the facilities had a continuous sidestream.

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[5] Based on data from the Mongstad PC lab, which performs many of these analyses.

To get the best possible overview of these process contributions to total direct emissions of methane and nmVOC, a simple percentage upscaling has been made to the 54 facilities on the NCS with HC gas handling.

Table 35 Disposal of waste gas from gas analysers and preliminary emission estimates.

Facilities with relevant process	16	of 15 (+1) in primary survey
Facilities with waste gas to recycling	0	of 15 (+1) in primary survey
Facilities with waste gas to flaring	0	of 15 (+1) in primary survey
Facilities with waste gas for direct emission	4	of 15 (+1) in primary survey
Estimated amount of methane emissions (tonnes/year)	**71**	Scaled up to 54 facilities
Estimated amount of nmVOC emissions (tonnes/year)	**54**	Scaled up to 54 facilities

4.18.6 Uncertainty

Uncertainty is relatively high and impossible to quantify because of the limited base data. It could be reduced considerably if a qualified assessment of the flow rate is carried out for all the facilities with continuous use of sidestream and emission of the gas. Since emissions from this process are relatively modest, installing flow meters should be unnecessary.

4.18.7 Comparisons with other countries

Canada only takes account of emissions from gas analysers if a continuous sidestream is involved. Canadian guides also indicate a recommended sidestream rate.

4.19 Turret on FPSOs

Reference is made to the module 1 report from the project (ref 1).This recommends that gas leaks in the turret are treated in the same way as other gas leaks on the facilities. See section 4.12.

4.20 Pig traps

4.20.1 Introduction

Pig traps were considered to be a potential source of HC gas emissions. These are chambers for launching or receiving pigs – tools/instruments pumped through pipelines to scrape wall deposits, remove fluid accumulations, identify deteriorating wall thickness or other inspection tasks.

The primary survey found that 12 of 15 facilities had pig traps. Of these 12, only two had emissions from this source. Both of them depressurised the pig trap to the low-pressure flare, but that was inactive in these cases. Since both facilities had very low emissions, this source was not investigated further in the secondary survey as it is considered negligible.

The two main factors affecting emissions are:

- where the waste gas is routed when gas-freeing the trap
- number of gas-freeing events during the year.

4.20.2 Recommended quantification method

Emissions are so small that it is proposed to include them in a general mark-up for small emissions.

Conclusion:
General mark-up
Small emissions

4.20.3 Proportions of methane and nmVOC in the emission gas

Not assessed, since the emissions from this source are small.

4.20.4 Estimated emission quantities from pig traps

The two facilities with emissions from gas-freeing of pig traps send the waste gas to an inactive flare. To obtain an overview, it is assumed that the three other NCS facilities with the same flaring solution have corresponding annual amounts of waste gas from pig traps.

On all the other facilities, gas freed from pig traps is conducted to an ignited flare – in other words, there are no direct methane and nmVOC emissions from this source.

Table 36 Disposal of waste gas from pig traps and preliminary estimates.

Facilities with waste gas to direct emission	2	of five with a flare
Estimated amount of methane emissions (tonnes/year)	**4**	Scaled up to five facilities
Estimated amount of nmVOC emissions (tonnes/year)	**2**	Scaled up to five facilities

4.20.5 Uncertainty

Emissions are calculable with a relatively high degree of accuracy, since the pig trap volume can be calculated very precisely and the number of gas-freeing events is known (+/-10 per cent). On the other hand, great uncertainty prevails over the scaling-up.

4.20.6 Comparisons with other countries

In the USA, the API compendium (ref 18) distinguishes between pigging in gas and oil pipelines. Where oil pipelines are concerned, it refers to the same calculation methodology recommended for calculating emissions from crude tank flashing. With gas pipelines, emissions are calculated from that part of the pipe which is degassed, plus the volume of the pig trap.

Canada has also conducted some assessments of pig trap emissions, and concluded that this is a negligible source.

4.21 Withdrawal of corrosion coupons

4.21.1 Introduction

A corrosion coupon is a simple and effective tool for monitoring corrosion rates in piping and equipment. It also reveals what type of corrosion is taking place. Coupons comprise pieces of metal in various shapes, sizes and materials. They are installed inside the equipment being monitored and exposed to the same corrosion effects.

Observations from the primary survey indicated that emissions of HC gases to the air on all NCS facilities are very small. On that basis, this source was excluded from the secondary survey.

4.21.2 Factors affecting emissions

The most important factors affecting emissions are:

- the technology used when withdrawing the corrosion coupons
- the number of coupon withdrawn during the year.

4.21.3 Recommended quantification method

Emissions are so small that it is proposed to include them in a general mark-up for small emissions.

Conclusion:
General mark-up
Small emissions

4.21.4 Proportions of methane and nmVOC in the emission gas

Not assessed, since this source is negligible.

4.21.5 Estimated emission quantities from corrosion coupons

Total emissions from corrosion coupon withdrawals on NCS facilities were scaled using data collected in the survey. Emissions are calculated on the basis of the volume of gas released during each withdrawal (volume of gas emitted locally), and the number of retrieval operations per annum. NCS emissions are based on a linear upscaling of the data to 54 facilities.

Table 37 Disposal of waste gas from corrosion coupons and preliminary emission estimates

Facilities with corrosion coupons	54	
Facilities with waste gas to recycling	1	One registered, could be more
Facilities with waste gas to flaring	0	None registered, could be some
Facilities with waste gas to direct emission	about 50	Based on data from the survey. Data lacking from some operators.
Estimated emission of methane (tonnes/year)	0.1	
Estimated emission of nmVOC (tonnes/year)	0.1	

4.21.6 Uncertainty

The amount emitted is probably quite uncertain, but the figures in table 37 have been calculated conservatively and the emissions are very small.

4.21.7 Comparison with other countries

No information has been found regarding reporting of emissions from withdrawing corrosion coupons.

4.22 Flexible risers

4.22.1 Introduction

A number of flexible risers have been installed on the NCS since the 1990s in connection with floating production facilities and subsea-completed wells. Flexible risers consist of alternate layers of steel and elastomers as shown in figure 8.

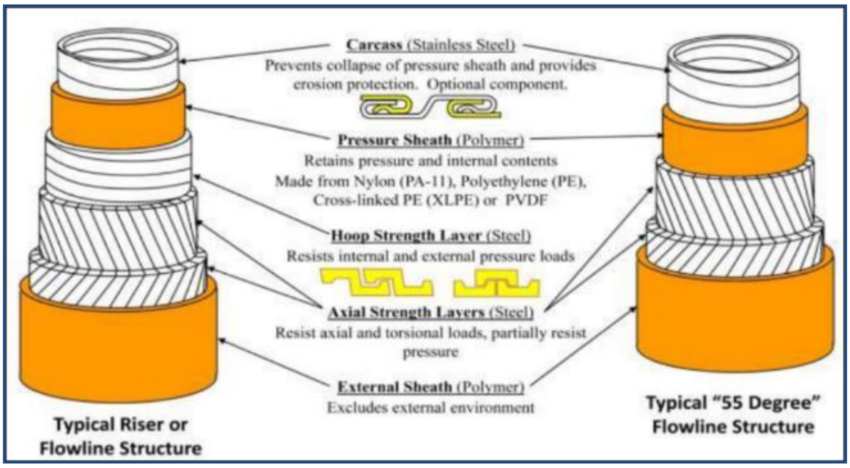

Figure 8 Example of flexible riser structure – simplified diagram (source: 4Subsea AS (from the web)).

Modern flexible risers are equipped with gauges to measure the diffusion rate. These are used for trend measurement in monitoring riser condition and integrity. Older risers do not have meters.

Waste gas from the flexible risers is directed to a valve station at the riser connection point on the topsides. From there, the gas is sent to recycling, flaring, atmospheric venting or locally positioned emission outlets.

4.22.2 Recommended quantification method

Emissions are small (see section 4.22.4). The proposal is therefore to include them in the mark-up for small emissions.

Conclusion:
General mark-up
Small emissions

4.22.3 Proportions of methane and nmVOC in the emission gas

The composition of the diffusion gas depends on the gas in the riser. This will vary between risers tied to production wells, to oil pipelines and to gas pipelines on the same facility. If these emissions are separately quantified, the proposal is that the operator selects the proportions of methane and nmVOC for the appropriate facility on the basis of the flexible risers it has. Given that total emissions are in the range of less than one part per thousand of overall direct emissions from NCS facilities, lack of exactness in gas composition from this source will have negligible effects on total emission quantities for methane and nmVOC from NCS facilities.

4.22.4 Estimated emission quantities from flexible risers

A total of 20 facilities on the NCS have flexible risers. On more than half of these, waste gas from flexible risers is released directly to the air. On seven, the waste gas is led to flaring or recycling. During the survey, data from the operators was collected from 11 facilities with available waste gas information. This included both supplier data on waste gas rates and measurements by operators for single risers. The data have been scaled linearly to include all 13 facilities with emissions to the air.

Table 38 Waste gas emissions from flexible risers and preliminary emission estimates.

Facilities with relevant process	20
Facilities with waste gas to recycling	2
Facilities with waste gas to flaring	5
Facilities with waste gas to direct emission	13
Estimated methane emissions from all NCS facilities with flexible risers (tonnes/year)	**1.8**
Estimated emissions of nmVOC from all NCS facilities with flexible risers (tonnes/year)	**1.5**

4.22.5 Uncertainty

Since the emission figures are calculated by scaling, their uncertainty may be considerable. Based on the figures observed, uncertainty is unlikely to exceed +100 to -50 per cent. Given the size of the calculated emissions, they are not thought to have a big impact on the uncertainty of total emissions from all sources.

4.22.6 Comparisons with other countries

No references have been found to this source in other countries used for comparison.

4.23 Crude oil storage tanks on FPSOs

4.23.1 Emissions from tank inspection

4.23.1.1 Introduction

The regulations require crude oil tanks on floating production facilities to be inspected every five years. This is normally done by inspecting about a fifth of them every year. Since the tanks are at atmospheric pressure and all fuel gas must be removed from the empty tank before inspection, the amount of HC gas (measured in scm) released will be roughly equal to the volume of the tank being gas-freed (see ref 1). Emissions from this source can therefore be calculated from the tank volume and the relative proportions of methane and nmVOC based on fuel gas composition. (Fuel gas is normally used as a blanket. When the tank is emptied of oil before inspection, it is refilled either with fuel or inert gas before full gas-freeing. If fuel gas is used, the HC gas released will be equal to the tank volume. Where inert gas is used, the HC gas emitted will be smaller than the tank volume. If any emissions from gas-freeing are flared, the HC gas will also be smaller than the tank volume).

4.23.1.2 Factors affecting emissions

The most important factor affecting emissions pursuant to today’s regulations is the size of the crude oil tanks.

4.23.1.3 Recommended quantification method

A general emission quantification method is therefore recommended:

$U_{CH4} = V_{tanks}/a_{inspection} * fr_{CH4}$
$U_{nmVOC} = V_{tanks}/a_{inspection} * fr_{nmVOC}$
where,
V_{tanks} = total volume of all storage tanks for crude oil [m^3]
fr_{CH4} = fraction methane
fr_{nmVOC} = fraction nmVOC
$a_{inspection}$ = inspection frequency, minimum every five years per tank

Conclusion:
General quantification method

4.23.1.4 Proportions of methane and nmVOC in the emission gas

Vaporisation from the crude oil will increase the proportion of nmVOC in the gas relative to methane, but obtaining a representative analysis of emission gas composition will be very difficult. The relationship between nmVOC and methane may change, and the waste gas will be enriched by inert gas during gas-freeing. On that basis, fuel gas composition is recommended as the best option.

Emissions are so small that the error will not have a big influence on total emission figures for methane and nmVOC.

4.23.1.5 Estimated emission quantities from gas-freeing of crude oil tanks on FPSOs

The volume of all NCS production facilities with crude oil storage has been obtained and emissions are calculated on that basis. Emissions for some of the facilities are calculated by the operator on the basis of their best knowledge about waste gas composition. On others, emissions are calculated by Add Novatech on the basis that waste gas is 50-50 methane and nmVOC by weight. The figures represent average annual emissions.

Table 39 Waste gas emissions from crude oil tanks on FPSOs and preliminary emission estimates.

Facilities with storage tanks for crude oil	7
Facilities which send waste gas from storage tanks for crude oil to recycling	0
Facilities which send waste gas from storage tanks for crude oil to flaring	0
Facilities which send waste gas from storage tanks for crude oil to emission	7
Estimated methane emissions (tonnes/year)	**55**
Estimated nmVOC emissions (tonnes/year)	**71**

4.23.1.6 Uncertainty

Emissions calculated for this source are considered to have low uncertainty (+/- 10 per cent) since the calculations are based on tank volume, which is considered to provide an accurate approximation.

4.23.2 Emissions associated with abnormal operating conditions

4.23.2.1 Introduction

In normal operating conditions, no emissions will occur from the blanket gas in crude oil storage tanks on FPSOs since the fuel gas used is recycled to the process. However, abnormal operating conditions may occur which make it difficult or impossible to avoid emissions. These could include the following.

- Offloading during a turnaround. A risk might then arise that no fuel or other HC gas is available to refill the tank with blanket gas, so that a neutral gas must be used which cannot be returned to the process (or sent to flaring) after use. This then has to be released to the air with a varying content of fuel gas.
- Problems with the vapour return unit (VRU) compressor may prevent blanket gas being recycled to the process.

4.23.2.2 Recommended quantification method

Such special circumstances may cause significant emissions if they last a long time. It would not be natural or appropriate to calculate emissions from such conditions using generic methods. The recommendation is therefore that the operator concerned establishes/applies facility- and condition-specific methods to calculate methane and nmVOC emissions in such circumstances.

4.23.2.3 Proportions of methane and nmVOC in the emission gas

The relative proportions of methane and nmVOC in the emissions must reflect the relevant emission conditions but. unless otherwise indicated, the same HC gas composition found for tank inspection (section 4.23.1) should be representative for the methane and nmVOC proportions.

4.23.2.4 Estimated emission quantities from abnormal operating conditions

No overview is available of the occurrence or outcome of such emission conditions. That means nothing can be said about the size of the emissions (these are basically assumed to equal zero).

4.23.2.5 Uncertainty

The uncertainty attached to emission calculations in such conditions will reflect the calculation method utilised. Evaluating this is therefore not possible at present.

4.23.3 Comparison with other countries

No references to such emission conditions have been found in other countries used for comparison.

4.24 Storage tanks for diesel and other consumable oils

4.24.1 Introduction

In most cases, diesel tanks and some other storage tanks for oil products do not use blanket gas, and are equipped with local vents which "breathe" to the air. This is also an accepted practice with land-based storage tanks of this type. All facilities in the primary survey have this source.

4.24.2 Recommended quantification method

Calculations are based on a simplified version of AP 42. This standard has been established for large cylindrical storage tanks and takes account of their shape and geometry as well as external temperature and pressure. It can therefore be somewhat uncertain for the more cube-shaped storage tanks found on NCS facilities. Because emissions are very small, however, uncertainty is less important.

Since the emissions are so small (see section 4.24.4), it is proposed that they are not calculated separately but included in a general mark-up for small emissions.

Conclusion:
General mark-up
Small emissions

4.24.3 Proportions of methane and nmVOC in the emission gas

As described above, virtually all waste gas emissions from storage tanks for diesel and other consumable oils will be nmVOC because these oil qualities contains no methane.

4.24.4 Estimated emission quantities

The annual consumption of diesel (and other consumable) oil was acquired for all the facilities, and emissions calculated in accordance with a simplified version of AP 42.

Table 40 Disposal of waste gas from diesel storage tanks and preliminary emission estimates.

Facilities with storage tanks for diesel oil	50
Facilities with waste gas to recycling	0
Facilities with waste gas to flaring	0
Facilities with waste gas to direct emission	50
Calculated/estimated emissions of nmVOC (tonnes/year)	**3.5**

4.24.5 Uncertainty

Some uncertainty prevails about how accurately the simplified AP 42 – used because pressure and temperature fluctuations cannot be accounted for – calculates emissions, but these are small.

4.24.6 Comparison with other countries

A key reference here is the US regulations on *Emission factor documentation for AP-42, section 7.1. organic liquid storage tanks*. This set of very comprehensive calculation models covers all emissions from storage tanks for all types of HC fluids. The models are extensive and complex, and include a number of factors, such as the fluid's Reid vapour pressure (RVP – no problem for diesel), tank and ambient temperatures, internal tank conditions (static filling ratio, filling, discharging, etc) plus a number of correction factors.

4.25 Double block and bleed (DBB) valves

4.25.1 Introduction

Equipment components may need to be isolated from the rest of the process for maintenance and repairs. A double block is two shut-off valves which isolate the equipment when closed. Gas in the pipe between the two valves is bled off to the air or to flaring through a bleed valve.

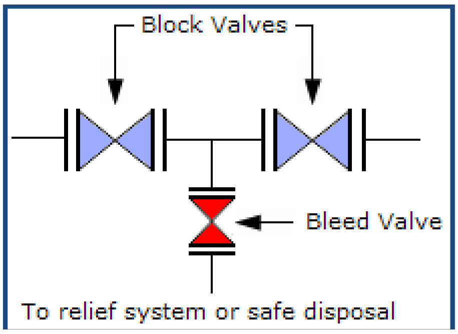

Figure 2 Example of a double block and bleed system (Source: Wermac (from internet))

Data from the primary survey have shown that emissions from this source are very small and that acquiring the necessary information would involve relatively substantial work. It was therefore excluded from the secondary survey.

4.25.2 Factors affecting the emissions

The emissions depend on the waste gas solution, the pipe dimension between the two valves, the pressure, and the frequency of such operations.

- **Waste gas solution**: emissions are eliminated by sending the waste gas to flaring or recycling.
- **Pressure in the pipe**: higher pressure means greater emissions.
- **Pipe dimensions**: emissions will be greater from larger pipes.
- **Bleed frequency**: emissions will depend on how often such operations occur.

4.25.3 Recommended quantification method

Since missions are so small, it is proposed to include them in a general mark-up for small emissions.

Conclusion:
General mark-up
Small emissions

4.25.4 Proportions of methane and nmVOC in the emission gas

Composition is not expected to differ much from fuel gas on the facility.
Estimated emission quantities from DBB valves

The basis for assessment and calculation of emissions was provided for eight facilities during the primary survey. Waste gas from six facilities bleeds off to air (for smaller valves), while the waste gas in all such operations on the other two was found to be led to flare. Six facilities quantified emissions, which ranged from 0.008 tonnes/year to 0.15 tonnes/year with an average of 0.04 tonnes/year. On this basis, emissions were scaled up to all NCS facilities. It is assumed in the calculations that the waste gas from all operations will be directly emitted. In practice, this is not the case. For larger DBB valves, the waste gas is sent to flaring or recycling. It is therefore assumed that the calculations give a conservative estimate.

Table 41 Disposal of waste gas from DBB valves and preliminary emission estimates.

Estimated methane emissions (tonnes/year)	**1.2**	Scaled up to 54 facilities
Estimated nmVOC emissions (tonnes/year)	**1.1**	Scaled up to 54 facilities

4.25.5 Uncertainty

Since the calculations are estimates and the number of DBB valves is large, uncertainty in the total figures is relatively high. However, the estimates are based on conservative assumptions (see section 4.25.5) and it is therefore likely that they are overestimated rather than the reverse.

4.25.6 Comparison with other countries

Emissions from DBB valves are not covered in other countries used for comparison.

4.26 Stripping gas for seawater injection

The survey showed that this source is not found on the NCS. Based on the information provided, no facility there uses HC gas as a stripping gas for seawater injection.

4.27 Emissions from a measured common vent

This is not an emission source but an emission point. It is used for quantification in those cases where the emission rate from the common vent is measured, and contributions from the individual sources are difficult to quantify.

Six NCS facilities collect waste gases from a number of sources at a common vent where the amount emitted is measured. In many of these cases, emissions contain relatively significant amounts of inert gas, mainly nitrogen, which are deducted. Since the amount of inert gas can be difficult to determine, the method is subject to great uncertainty. This is often compensated for by using a conservative subtraction method.

Where it has been possible to quantify emissions from some of the contributory sources, these are deducted and included in the respective emission sources.

Table 42 Disposal of waste gas from common vents.

Facilities which contribute to measured common vents	*6*
Calculated/estimated emissions of methane (tonnes/year)	***1 975***
Calculated/estimated emissions of nmVOC (tonnes/year)	***1 350***

Two facilities in particular dominate these emissions.

5 Determining emissions through measurement

Two types of information are required to determine the emission rates of methane and nmVOC:

- flow rates giving information about the total amounts of gas passing through the emission pipe
- composition of the flow medium to determine the relative proportions of methane and nmVOC.

Should the flow rate be constant over time, it may be advantageous to use methods other than measurement to determine it. Where flow rates vary over time, calculating the emissions is more difficult and flow measurement could be the best option.

If waste gas composition is constant, special meters should not need to be installed to measure this. Composition can be computed or otherwise determined. Should that not be possible, sampling and analysing the gas flow can be utilised. Where the composition varies over time, more advanced meters may be desirable/required. An in-line gas chromatograph could meet the need, but is expensive and simpler measurement methods may suffice.

The survey showed that most facilities had no flow meters installed in pipes to the atmospheric vent. But in-line flow meters were in place on some, particularly newer ones. As far as could be ascertained, no flow meters were installed on local vent piping. Facilities with density or other gauges which could be used to approximate the composition of the waste gas were not identified in the survey.

The type of flow meter was not identified on facilities where they were installed.

Conditions in an atmospheric vent pipe are to a certain extent analogous to those in flare pipes:

- low to medium flow rates
- mixing of multiple components
- variation in the mixing ratio over time.

The main differences are:

- less variation in flow rates (lacks the high rates which may occur in flare pipes)
- significantly smaller temperature variations than in flare pipes
- smaller diameter than in flare pipes.

Ultrasonic gauges have proved suitable for use as flare gas meters and are installed on several facilities. They are said to have a number of properties which make them suitable for such applications:

- large speed range (can measure accurately over large variations in flow rate).
- thereby suitable for low flow rates
- not dependent on calibration after installation (according to suppliers)
- measures molar mass (actually measures speed, but molar mass can be derived from this)
- can separate flush rates from vent rates (claims one of the vendors)
- can be installed without shutting down operation (hot tap)
- supplied with software which can distinguish methane from nmVOC (and CO_2) (claims one supplier).

Of particular interest is the potential opportunity to measure molar mass, which makes it possible to calculate the relative proportions of methane and nmVOC as well as trends over time.

A simplified diagram of an ultrasonic meter is presented in figure 10.

Whether any of the meters installed in common atmospheric vents are of this type has not been investigated. If this is the case, operators are advised to consult their suppliers to investigate whether, and to what extent, it is possible to use these to differentiate between methane and nmVOC.

In most cases, retrofitting in-line flow meters will involve shutting down production – which means in practice that it must take place during a turnaround. However, at least one supplier of ultrasonic gauges claims that it can install them with waste gas in the pipe (hot tapping). That could make it technically feasible to install such equipment without having to wait for the next turnaround.

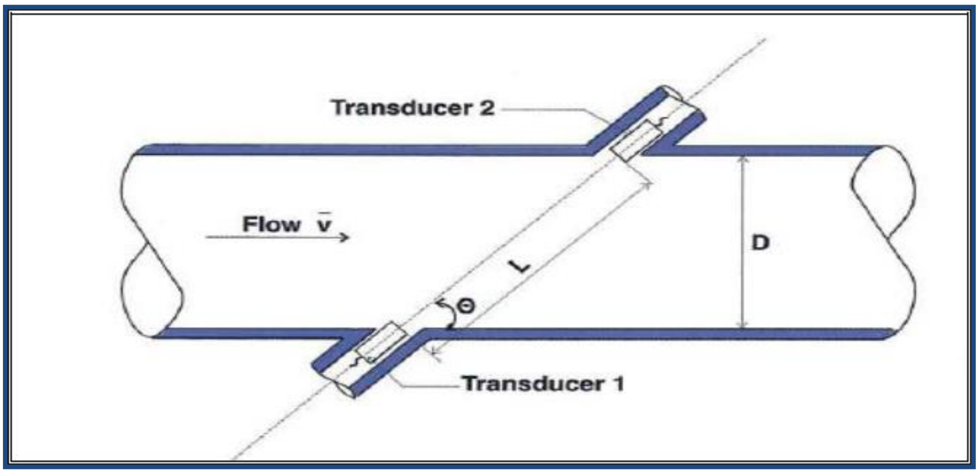

Figure 3 Simplified diagram of an ultrasonic flow meter (source: Fluenta).

Figure 11 Example of clamp-on ultrasonic gas meter (source: Flexim Product Catalogue).

New concepts have emerged on the market during recent years. In particular, the development of ultrasonic flow meters is interesting. Now available are clamp-on ultrasonic gauges which can be mounted on the outside of the pipes. An example is shown in figure 11.

One supplier claims these devices are available in the following dimension ranges:

- measurement accuracy: <+/- three per cent uncertainty
- inner diameter: six mm to more than 2 000 mm
- flow rate: 0.01 m/s to 35 m/s
- temperature: -40°C to above 100°C

They can be delivered in explosion-proof versions and powered by battery (not over long periods) or electricity supply.

Christian Michelsen Research (CRM) reports that ultrasonic meters are used today for measuring both flare and waste (VOC) gases from shuttle tankers during offshore loading of oil. However, these are in-line flange-connected meters (ref 14).

The company believes ultrasonic meters have a big potential. By measuring molar mass indirectly, they allow information on both volume flow and composition to be extracted – providing pressure and temperature are known. If the waste gas contains components which are not HC gas, such as nitrogen, water or CO_2, establishing the proportions may be more difficult. But this can be simplified if the inert gas has a stable flow rate (like nitrogen purge gas, for example).

CMR could confirm that clamp-on gauges can be moved from one pipe to another, but need adjustment to the relevant pipe diameter. Since reinstallation and customisation mean such migration takes some time, they would be unsuitable for measurements on several pipes on the same day. However, clamp-on gauges can be used on a single pipe over a week, for example, and then moved to another pipe.

A challenge for and potential barrier to the use of clamp-on meters with gas pipes is the low gas pressure (about atmospheric). That may make this technology difficult or impossible to use, since a certain pressure (ie, weight) in the gas is usually required for the meter to function efficiently.

Another aspect of ultrasonic gauges is that accuracy declines with decreasing pipe diameter. Suppliers recommend that the latter is at least three inches (ref 15). This is because the further the sound waves travel, the more accurate the time measurements.

Where smaller pipe dimensions are concerned, some suppliers recommend thermal mass meters. These will also make it possible to back-calculate the composition (methane/nmVOC ratio) within certain limits. Such meters must be installed in the pipe itself.

Contacts with the supplier industry indicate that ultrasonic measurement technology currently represents the only commercially available solution for external installation on a pipeline.

Further investigation is recommended into how far ultrasonic gauges or thermal mass flow meters can contribute to sufficiently good characterisation of emission gases. If they permit the proportions of methane, nmVOC and other relevant gases to be determined, such devices may provide a possible method for quantifying methane and nmVOC in emissions without the need for sampling and analysis.

How far clamp-on meters are usable at the pressure levels found in pipes for direct methane and nmVOC emissions should also be investigated in more detail.

6 Methods for quantifying emissions

6.1 Step-by-step methodology

The project has shown that a step-by-step methodology is required to identify and quantify emissions from a facility.

Step 1 Survey sources (plant units and processes/sub-processes) on the facility which can produce emissions.
This is analogous to the old system, where emission sources were checked off. Only the processes/sub-processes found on the facility proceed to Step 2.

Step 2 Determine whether waste gas from sources present goes to emission, recycling or flaring. This is important. Waste gas from many of the sources goes to recycling or flaring on most facilities.
Only sources with waste gas which goes to emission continue to Step 3.

Step 3 Quantify emissions.
If the facility has a metered common atmospheric vent where metering forms the basis for emission reporting, waste gas amounts should not need to be calculated separately for the sources which send waste gas to the common vent. Where processes/sub-processes deliver waste gas to local venting, emissions must be quantified separately.

If the facility does not report measured emissions from common vents, contributions from all sources with waste gas for emission must be quantified separately.

6.2 Quantification method

The survey has shown that it is to some extent very difficult to calculate emissions for some of the processes and sub-processes. Emissions from several of them go to a common vent together with emission gases from other sources. Measurement in the emission pipe could be a solution on facilities with this issue. The challenge is to determine the (sufficiently) correct composition and relative proportions of methane, nmVOC and various inert gases (N_2, CO_2, H_2O, which may collectively represent significant shares). If solutions to this challenge can be found, quantification (measurement) at the emission point may be the best solution for some facilities.

This may involve a split system, where some emissions are measured at the emission point (vent) while others are quantified on the basis of the process/sub-process (source).

The project has shown that different methods must be used to quantify emissions from individual processes and sub-processes if the emission reports are to be representative of the methane and nmVOC amounts released.

Emissions from some sources are quantified by measuring gas going into the process (where gas out equals gas in or a function of it) or using another reliable quantification method. This applies to the following sources:

- stripping gas (HC gas)
- flotation gas (HC gas)
- purge and blanket gas (HC gas)
- seal gas for centrifugal compressors (HC gas)

The equipment available for such measurements will be of varying quality and will not normally meet requirements for fiscal metering. Alternative quantification methods can be used where it can be documented that this gives more accurate results.

Where some processes/sub-processes are concerned, simplified methods are recommended – but that could result in over-reporting (with a high level of probability).

The project has also shown that several of the identified processes/sub-processes yield only very small emissions. Based on sample calculations, these produce less than one per cent of total emissions and it is proposed to cover them through a general mark-up to the overall figure.

Where a few processes are concerned, the project has concluded that insufficient information is available to suggest a quantification method and proposes that the work be continued through dedicated projects. Proposals for these are presented in chapter 9.

The basic aim has been to identify generic methods for quantifying emissions. However, that approach has been found inappropriate for a few processes/sub-processes. This applies to:

- processes/sub-processes where the technical solutions can vary, making generic methods meaningless
- processes/sub-processes which only occur on one or perhaps a couple of facilities.

It is also recommended that an operator should have the option to choose another approach, such as an facility-specific method, if it can be document that this provides more accurate emission figures.

Where some of the processes/sub-processes are concerned, operators can choose between two or more methods – typically a simple but conservative approach or a more demanding option which will nevertheless give more accurate (and in many cases lower) emission figures.

6.2.1 Overview of recommended quantification methods

Table 43 presents proposed quantification methods, either generic or facility-specific, as well as which processes/ sub-processes are recommended for inclusion in a fixed general mark-up.

Table 43 Overview of recommended quantification methods.

Process/sub-process	Recommended quantification method	Comments	Reference
TEG degassing tank	Facility-specific	Specially designed and verified calculation system (eg, GRI GLYCalc)	Sect 4.1.2.3
TEG regenerator	General method	Analysis of TEG solution, alternatively GRI-GLYCalc	Sect 4.1.3.3
Stripping gas TEG regeneration	General method	Based on flow rate of stripping gas	Sect 4.1.4.2
Produced-water treatment degassing tank	General method	Based on pressure reduction and produced-water quantity	Sect 4.2.4
Produced-water treatment flotation tank/CFU	General method	Based on pressure reduction and produced-water quantity	Sect 4.2.4
Produced-water treatment – flotation gas	General method	Based on HC flotation gas	Sect 4.2.4
Produced-water treatment – discharge caisson	General method	Based on upstream pressure and discharge of produced water	Sect 4.2.4
Low-pressure liquid separator	General mark-up	See reference	Sect 5.3
Compressor seal oil – waste gas pots/tanks	Facility-specific	Established by each operator	Sect 4.4.5
Compressor seal oil – holding tank	Facility-specific	Established by each operator	Sect 4.4.5
Compressor seal oil – storage tank	Facility-specific	Established by each operator	Sect 4.4.5
Dry seals – primary seal	General method	Measurement of seal gas/supplier data	Sect 4.5.6
Dry seals – HC as secondary seal	General method	Measurement of seal gas/supplier data	Sect 4.5.6
Dry seals – nitrogen as secondary seal	General method	Measurement of seal gas/supplier data	Sect 4.5.6
Reciprocating compressor – separator chamber	Facility-specific	Simulations, supplier data or equivalent	Sect 4.6.2
Reciprocating compressor –	Facility-specific	Simulations, supplier data or equivalent	Sect 4.6.2

Process/sub-process	Recommended quantification method	Comments	Reference
crankshaft house			
Screw compressor	General mark-up		Sect 4.7.2
Gas-freeing of process equipment	General method	Emission is equal to volume of plant	Sect 4.8.2
Purge and blanket gas	General method	Measurement/determination of purge gas rate	Sect 4.9.2
Instruments and instrument manifolds	General mark-up		Sect 4.10.2
Flare – extinguished flare and flare ignition	General method	Register flare gas rate and time before flare ignites	Sect 4.11.1.2
Flare – non-flammable flare gas	Facility-specific	Established by each operator	Sect 4.11.2.2
Flare – inert-gas-flushed flare	General method	Flare gas measurement	Sect 4.11.3.2
Large gas leaks	General method	Retain today's methodology	Sect 4.12.1.2
Small gas leaks	General method	OGI Leak/No Leak method	Sect 4.12.2.4
Cold vent being measured	General method	Measure (with deduction for inert gas)	Sect 4.27
Bleeding gas from production risers	General mark-up		Sect 4.13
Drilling	General method	Keep todays methodology, but use wellbore instead of well	Sect 4.14.2
Gas turbines	General mark-up		Sect 4.15.2
MEG regeneration waste-gas tank	General method	Recognised calculation programme (GRI-GLYCalc, MultiproScale, etc)	Sect 4.15.9
MEG regeneration – regenerator (boiler)	General method	Recognised calculation programme (GRI-GLYCalc, MultiproScale, etc)	Sect 4.15.9
MEG regeneration – purge gas	General method	Flow rate of purge gas	Sect 4.15.9
Amine regeneration – waste-gas tank	Facility-specific	Must be established by each operator	Sect 4.16.2
Amine regeneration – regenerator	Facility-specific	Must be established by each operator	Sect 4.16.2
Gas analysers and test stations	General method	Measure sidestream. Only if flow is continuous	Sect 4.17.3
Turret on FPSOs	General method	Treated as small gas leaks	Sect 4.18
Pig traps	General mark-up		Sect 4.19.2
Corrosion coupon stations	General mark-up		Sect 4.20.3
Flexible risers	General mark-up		Sect 4.21.2
FPSO storage tanks – tank inspection	General method	Emission is equal to the volume of the tank	Sect 4.22.1.3
FPSO storage tanks – abnormal operating condition	Facility-specific		Sect 4.22.2.2
Oil tanks (diesel, lubricating, etc)	General mark-up		Sect 4.23.2
DBB valves	General mark-up		Sect 4.24.3

7 Total emission overview

7.1 Emission data

An attempt has been made to estimate emissions on the basis of information acquired from the survey. This means emissions, with a number of exceptions, are not calculated in accordance with the quantification methods recommended in chapter 6. That is because data on activity, analysis, the relative proportions of methane and nmVOC and so forth needed for the suggested methods have not been available – in part because it will take time to get these implemented by the operators.

As a result, the emission estimates have been established on the basis of the best available information, where the proposed methods are used or approximated as closely as possible. Chapter 4 describes how emissions from the various sources are estimated. Efforts have been made to base the calculations as far as possible on conservative assumptions. The emission figures are partly calculated by the operators for specific facilities and partly calculated/estimated by Add Novatech on the basis of underlying information from the operators.

A summary of the largest contributors is given in table 44, and presented by main source. Because uncertainty in the emission figures is relatively high, they are rounded to the nearest 50 tonnes. The figures in this table are to be regarded as preliminary estimates.

The emission data presented in this report reflect the status in 2014.

Table 44 Total preliminary overview of emissions by main source.

Main source:	**Methane**	**nmVOC**	**VOC**	**% of total**
Dry compressor seals	2 500	1 100	3 600	18%
Common vent (measured)	1 950	1 350	3 300	17%
Produced water treatment	2 300	600	2 900	15%
HC purge and blanket gas	1 100	1 300	2 400	12%
Gas leaks	1 250	950	2 200	11%
Gas flaring	1 500	600	2 100	11%
Glycol regeneration	550	1 000	1 550	8%
Compressor seal oil	900	300	1 200	6%
Other sources	300	250	550	3%
Total	**12 350**	**7 450**	**19 800**	**100%**

Emissions in table 44 are based on calculating small leaks in accordance with the CAPP method (see section 4.12.2). As shown in section 4.12.2, total emissions are significantly higher if small leaks are calculated in accordance with NS-EN 15446: 2008. The overview is then as presented in table 45.

Table 45 Total preliminary overview of emissions by main source, with fugitive emissions calculated in accordance with NS 15446.

Main source:	Methane	nmVOC	VOC	% av total
Dry compressor seals	2 500	1 100	3 600	12%
Common vent (measured)	1 950	1 350	3 300	11%
Produced water treatment	2 300	600	2 900	10%
HC purge and blanket gas	1 100	1 300	2 400	8%
Gas leaks	**7 100**	**5 400**	**12 500**	**41%**
Gas flaring	1 500	600	2 100	7%
Glycol regeneration	550	1 000	1 550	5%
Compressor seal oil	900	300	1 200	4%
Other sources	300	250	550	2%
Total	**18 200**	**11 900**	**30 100**	**100%**

Contributions from the other sources are more modest. An overview is presented in table 46.

Table 46 Emissions from other sources.

Emission source	Methane	nmVOC	VOC	% of total
Amine regeneration	95	40	135	0.68%
Emissions from gas analysis and sampling	71	54	125	0.63%
Emissions from drilling	57	57	114	0.57%
Gas-freeing of crude oil tanks on FPSOs	71	55	126	0.64%
Gas-freeing of process systems	18	16	33	0.17%
Emissions from DBB valves	1.2	1.1	2.3	0.01%
Emissions from low-pressure liquid separators	2.6	1.8	4.4	0.02%
Gas diffusion through flexible risers	2.3	1.8	4.0	0.02%
Tanks for diesel oil, lubricants and hydraulic oil	-	3.5	3.5	0.02%
Emissions from pig traps	3.6	2.3	6.0	0.03%
Emissions from gas turbines	0.5	0.5	1.1	0.01%
Purging and depressurising instruments and instrument manifolds	0.05	0.04	0.09	0.00%
Emissions from retrieval of corrosion coupons	0.01	0.0	0.02	0.00%
Bleeding off gas from production risers	0.00	0.00	0.00	0.00%
Subtotal	**322**	**232**	**554**	**2.81%**

Sources shown in orange represent those expected to be covered through a general mark-up. In total, these are responsible for about 0.1 per cent of emissions. The proposal is to use a one-per-cent mark-up to take account of them.

Emission data for seal oil systems on compressors may be somewhat inadequate. Operators will continue to work on this up to 1 May 2016, and will hopefully come up with better figures for this source.

Fugitive emissions and small leaks are otherwise the single source with by far the greatest level of uncertainty. Improved emission figures are expected after the operators apply the recommended OGI Leak/No Leak quantification method, probably from 1 January 2017.

7.2 Comparison with emissions calculated in accordance with current methods

As mentioned above, direct emissions of methane and nmVOC from NCS facilities have so far been quantified using methods which are inadequate and based to some extent on inaccurate correlations.

Figure 12 shows emissions over time as reported in accordance with the old method (see sub-report 1 (ref 1)).

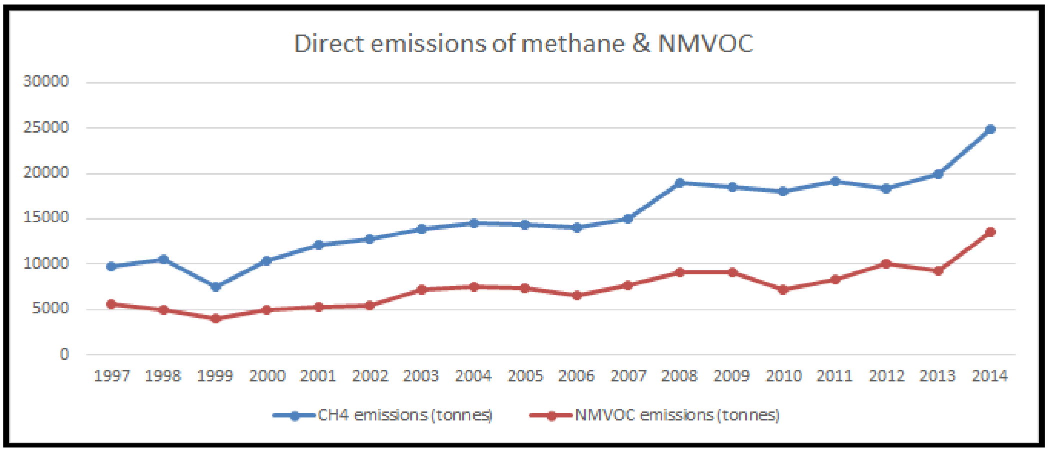

Figure 12 Reported direct emissions of methane and nmVOC from NCS facilities, 1997-2014.

Reported emission figures for 2014 have been compared with the emission estimates presented in this report.

Table 47 Reported 2014 emissions compared with new estimates.

Calculation method	Methane [tonnes]	nmVOC [tonnes]
Reported emissions (old method)	24 922	13 553
New estimate (NS-EN 15446)	18 200	11 900
New estimate (CAPP)	12 350	7 450

8 Comparisons with other countries

Emission sources on the NCS and quantification methods used there have been assessed and compared with those of some other countries, primarily ones with offshore oil and gas production. Reporting requirements and calculation methods have been investigated for the USA, Canada, Australia, the UK, Denmark and the Netherlands.

8.1 USA

Defined reporting requirements, emission sources and calculation methods differ between facilities on land and offshore. Operators of oil and gas production facilities must report greenhouse gas (GHG) emissions to the EPA annually. Offshore facilities are required to observe the reporting rules from the BOEM, while those on land must comply with the EPA guidelines – Federal Regulation 98 Part W.

Emissions are reported to the EPA using the electronic greenhouse gas reporting tool (e-GGRT) under the greenhouse gas reporting programme (GHGRP).

8.1.1 Facilities on the continental shelf

As of 2014, all US offshore facilities have a duty to report emissions of methane (and nmVOC), regardless of the amount. The BOEM has developed a computer programme called the Gulfwide offshore activity data system (Goads) which operators must use to report predefined monthly activity information for selected emission sources in the base (reporting) year to the Gulfwide Emission Inventory (ref 20). The programme generates a PDF report which the operators submit by email to the BOEM. The latter then calculates CH_4 and VOC emissions on the basis of the reported activity data. Emissions are estimated using an Oracle database management system (DBMS).

Offshore facilities report activity data to the BOEM every three years. Emissions in BOEM's *Gulfwide Emission Inventory Study* must be used for reporting to the EPA, and should be adjusted for operating hours in the reporting year (if the Goads report was not published in that year). If the BOEM report is delayed (fails to be produced after the third year), operators must calculate new emission data themselves on the basis of the BOEM guidelines.

Emission sources and corresponding activity data reported to the BOEM are presented in table 48.

Table 48 Fugitive emissions and corresponding activity data reported from offshore oil and gas production facilities in the USA, see the BOEM Goads 2014 guidelines.

Equipment type	Monthly activity data to be reported
Amine units	Hours operated Processed throughput
Drilling operations	Hours operated Total diesel fuel usage Total gasoline fuel usage Total natural gas fuel usage
Fugitives	Stream type VOC weight per cent Component inventory
Glycol dehydrators	Hours operated Processed throughput
Loading operations	Volume loaded Bulk liquid temperature

Equipment type	Monthly activity data to be reported
Losses from flashing	Operating pressure upstream of vessel Operating temperature upstream of vessel Operating pressure of vessel Operating temperature of vessel Oil/condensate throughput Scf of flash/barrel
Mud degassing	Days per month drilling with mud
Natural gas engines	Hours operated Total fuel used
Pneumatic pumps	Hours operated Fuel usage rate
Pressure/level controllers	Hours operated Fuel usage rate
Storage tanks	Average liquid height Bulk liquid temperature API gravity Reid vapour pressure Product throughput Average mole weight of VOC Average% by weight of VOC
Cold vents	Vent gas VOC concentration Hours operated including upsets Volume vented including upsets Vent gas H_2S concentration Average mole weight of VOC

A brief description of methods used to quantify CH_4 and nmVOC emissions from these sources is presented in the following sections.

8.1.1.1 Amine regeneration

Methane and nmVOC emissions from amine regeneration are estimated using the AmineCalc simulation programme provided by the American Petroleum Institute (API 1999).

8.1.1.2 Glycol regeneration

Since emissions from this source depend on the amount of dewatered gas, emission factors correlated with the amount of gas have been developed. Emissions of methane and other hydrocarbon components are calculated using factors established by the GRI-GLYCalc simulation programme for various gas compositions and pressure/temperature combinations, for both glycol boilers and degassing tanks.

8.1.1.3 Fugitive emissions (leaks)

Fugitive emissions of methane and nmVOC are calculated in accordance with the following equation, based on the EPA protocol (ref 11):

$$E_i = e_{comp,stream} \times N_{comp} \times time \times C_i$$

$E_i \quad = Emission\ amount\ of\ gas\ i\ (i = CH4, nmVOC)$

$e_{comp,stream} = Emission\ factor\ for\ unique\ component\ in\ process\ flow$

$N_{comp} \quad = Number\ of\ components$

$C_i \quad = Concentration\ of\ gas\ i$

Table 49 THC fugitive emission factors used in the calculations, (lb/component/day), EIIP 1999.

Service → Component↓	Gas	Natural gas liquids	Heavy oil (API<20)	Light oil (API>=20)	Water/oil	Oil/water/gas
Connector	0.011	0.011	0.0004	0.011	0.0058	0.011
Flange	0.021	0.0058	0.000021	0.0058	0.00015	0.021
Open-end	0.11	0.074	0.074	0.074	0.013	0.11
Other	0.47	0.4	0.0017	0.4	0.74	0.74
Pump	0.13	0.69	0.69	0.69	0.0013	0.13
Valve	0.24	0.13	0.00044	0.13	0.0052	0.24

Compressor seals are included under Other. The guidelines suggest the number of components (by type of processing plant) and VOC gas composition if these data cannot be obtained by the facility's operator.

8.1.1.4 Mud degassing

The emission factors used are from *Atmospheric Emissions from Offshore Oil and Gas Development and Production*, a report prepared by the EPA in 1997. They distinguish between mud types and are based on the number of drilling days. The 1977 report assumes that 83.85 per cent of the waste gas is methane and the rest nmVOC.

Table 50 Emission factors for mud degassing.

Mud type	Discharge factor (kg THC/day)
Water-based mud	405
Oil-based mud	91
Synthetic mud	91

The guidelines say nothing about how drilling days are defined (active drilling, active drilling in HC layers or what).

8.1.1.5 Emissions from degassing

Direct waste-gas emissions from depressurisation (flash gas in the USA) are calculated. Flash gas comes from separators, heat treatment, surge tanks, batteries and atmospheric storage tanks with a fixed roof. Vasquez-Begg's correlation equations are used to estimate the volume of gas vaporised per produced volume of oil in the tanks.

8.1.1.6 Direct venting

The USA requires the volume of gas emitted through common vents to be reported. If any of the contributors to this vent are calculated and reported separately, they must be deducted from volumes measured through common vents.

If an offshore facility processes more than 2 000 barrels of oil per day, federal legislation specifies requirements for measuring outflow through the vent with an uncertainty of less than +/- 5 per cent (ref 24).

8.1.1.7 Minor sources

Table 51 presents emissions per facility in use.

Table 51 Emission factors for methane and nmVOC from minor sources (tonnes/year).

Minor sources	VOC	CH_4
Caisson	0.141	0.426
Other	7.034	2.536

8.1.1.8 Pneumatic pumps and pressure/level controllers

It is not unusual in the USA to use high pressure natural gas for operating pneumatic pumps. Pressurised natural gas is also used in pneumatic control systems (similar to the common use of compressed air in Norway earlier). This is not done on the NCS.

8.1.2 Oil and gas production facilities on land

Onshore oil and gas production facilities must report GHG emissions if these exceed 25,000 tonnes of CO_2 equivalent per annum from specified sources. These emissions include CO_2, CH_4 and N_2O. Generally speaking, sources cover combustion units, including flaring, fugitive emissions and vents.

Methane emissions are reported from the following sources:
- natural gas pneumatic device venting
- natural-gas-driven pneumatic pump venting
- well venting for liquids unloading
- gas-well venting during well completions without hydraulic fracturing
- gas-well venting during well completions with hydraulic fracturing
- gas-well venting during well workovers without hydraulic fracturing
- gas-well venting during well workovers with hydraulic fracturing
- storage-tank-vented emissions from produced hydrocarbons
- reciprocating-compressor-rod stuffing venting
- well-testing venting and flaring
- associated gas venting and flaring from produced hydrocarbons
- dehydrator vents
- centrifugal compressor venting
- equipment leaks from valves, connectors, open-ended lines, depressurisation valves, pumps, flanges, and other sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms and breather caps).

8.2 Canada

GHG emissions from oil and gas production facilities must be reported if they exceed 50 000 tonnes of CO_2 equivalent per annum from specified sources. These emissions include CO_2, CH_4 and N_2O. Among sources are combustion units, including flaring, fugitive emissions and vents.

Environment Canada produced a large and detailed guide in 2014 which includes emission calculation methods and factors for the oil and gas industry. It resembles the US guidelines.

The CAPP published *Best Management Practice for Fugitive Emissions Management* (ref 25) in 2007. Before then, there had been no requirement to perform formal leak programmes. A good many improvements related to leaks have been made since this programme was implemented. The CAPP's *Update of Fugitive Equipment Leak Emission Factors* of 2014 (ref 21) details improvements achieved after 2007. This document also includes the number of components and emission factors for leaks from compressor seals, connectors, flanges, valves, pump seals, open-ended lines and controllers for oil and gas streams.

8.3 Australia

Oil and gas production facilities in Australia must report GHG emissions if these exceed 25 000 tonnes of CO_2 equivalent per annum from specified sources or if energy production or consumption exceeds 100 TJ a year. GHG emissions must also be reported if the operator releases 50 000 tonnes of CO_2 equivalent or more per annum in total from all the facilities it operates or if energy production or consumption exceeds 200 TJ a year. GHG emissions include CO_2, CH_4 and N_2O. Among sources are combustion units, including flaring, fugitive emissions and vents.

Emissions are reported to the federal Department of the Environment under national greenhouse emissions reporting (NGER). The *NGER Technical Guidelines* describe calculation methods for quantifying emissions. They refer to methods described in the API's *Compendium of Greenhouse Gas Emission Estimation Methodologies for the Oil and Natural Gas Industry* (August 2009) (ref 18).

8.4 UK

Methane and nmVOC emissions are reported annually to the environmental emissions monitoring system (EEMS), an electronic reporting solution where environmental data from the UK offshore oil and gas industry are registered. The Department of Energy and Climate Change (DECC), the most important regulatory authority for Britain's offshore oil and gas industry, has ultimate responsibility for the EEMS. Oil & Gas UK, the industry organisation for the British offshore oil and gas industry, has sponsored the EEMS since 1992 on behalf of its member companies.

Methane and nmVOC emissions from direct (non-combustion) sources must be reported under two categories:

- gas venting
- fugitive emissions.

8.4.1 Gas venting

Emissions can be reported either gross or broken down into three sub categories – operation, maintenance and accidental. The method used today is very rough. Generic emission factors for methane and nmVOC emissions (*EEMS – Atmospheric emission calculations*) are used.

8.4.2 Fugitive emissions

Emissions from the following components must be reported:

- flanges (connectors)
- valves
- open-ended pipes
- pumps
- others.

Table 52 shows the generic emission factors used in the UK offshore oil and gas industry for fugitive emissions (leaks). Emission factors are adjusted by a factor of 1.3 for facilities built between 1980-1988 and by 1.5 for those built before 1980.

Table 52 Emission leakages, UK.

Component	Emission factor kg/yr/component
Flanges	0.946
Valves	4.52
Open-ended	8.94
Pumps	1.72
Other	60.9

8.5 Denmark

Information about the Danish regulations is difficult to access. The Danish authorities have not provided feedback on reporting requirements and calculation methods used in Denmark. Online information is very limited.

8.6 Netherlands

The *Methode voor de berekning van broeikasgasemissies* (Method for calculating GHG emissions) (ref 26) was last published in 1997. Little attention has been paid to vented and fugitive emissions. The guide is currently being updated.

9 Recommendations for further surveys

The project has found it difficult to establish specific proposals on quantification methodology for some processes because of inadequate availability of information and knowledge, and because the project's timeframe has been too short. The proposal is therefore that this work continues in the form of specific sub-projects. That applies exclusively to processes/sources with a substantial emission potential.

1. **Seal-oil systems for centrifugal compressors**

   The survey carried out by the project was unable to secure any information or expertise which makes it possible to come up with a representative quantification method. Operators have ongoing activities aimed at establishing a better emission overview and improved facility-specific quantification methods by 1 May 2016.

2. **Purge and blanket gas**

   The primary survey showed that the operators, with a few exceptions, had little overview of purge gas systems, whether in terms of consumption, consumers and emissions.

   To simplify the work of obtaining an overview of existing systems, it is suggested that the operator for each facility creates a small, simple form for the fuel gas blanket gas system which specifies:

   - consumers of fuel gas for purge and blanket
   - consumption of fuel gas for purge and blanket by the individual user, with an overview of how consumption is measured/quantified
   - disposal of waste gas from each user (recycling/flaring/atmospheric vent).

10 Summary and conclusions

Proposals on future methods for quantifying methane and nmVOC have been presented and new emission estimates developed. The suggestion is to use a greater variety of quantification methods than has been the case so far, so that calculated methane and nmVOC emissions will better reflect the actual figures. Generic methods are suggested for most processes, but in some cases the recommendation is to use facility-specific methods. That applies particularly to processes where several technical options are available and to those used on only one or a couple of facilities.

The factor method is proposed for some processes/sub-processes/emission sources, with emission control parameter(s) as the activity factor. Methods otherwise vary widely:

- measurement/sampling
- process simulations/use of special programmes
- utilising recorded measurement data
- registration of events (for non-continuous emissions)
- supplier data.

Where some sub-processes are concerned, it has been found that more information is needed before proposals on a new quantification method can be made.

The survey showed that emissions from several of the identified processes/sub-processes are so small that they have no practical effect on the total. The proposal is therefore that no separate emission calculations are made for nine of the identified processes/sub-processes (collectively representing about one thousandth of total emissions), and to compensate for this by making a small fixed percentage mark-up to the calculated emissions.

Efforts have been made in module 2 to recalculate/re-estimate total emissions from the sector. This is done partly with reference to the proposed new quantification methods, but not entirely because the necessary reference data are not available. In such cases, other and more uncertain calculation methods have been used. Where some of the sub-processes are concerned, no information has been available which made it possible to estimate the emissions. This is because, in a number of cases, the historical data required to calculate emissions have not been registered.

The emission estimates presented contain substantial uncertainties. Unlike earlier overviews, however, they have been established using more consistent methods and yield more accurate data. In the future, the new estimation methods proposed should ensure even better consistency and even more accurate emission overviews than those presented here. However, the nature of direct methane and nmVOC emissions means that a significant level of uncertainty must also be accepted with the proposed new methods. Information from other countries shows this to be a general problem. Adopting the proposed calculation methods will ensure that reports on direct emissions from NCS facilities will be at least as good as or better than those in most of the countries compared with.

An overview of emissions, referenced to 2014, has nevertheless been drawn up. This shows that emissions of both methane and nmVOC are, with a reasonably high probability and to some extent by a good margin, lower than those reported using the former methods.

The level of uncertainty in the emission estimates and what can be expected from the proposed new quantification methods have been assessed on a qualitative basis. Lack of access to data has prevented quantitative calculations. Uncertainty in the total estimate is estimated to be in the order of several tens of per cent.

Opportunities for measuring emissions have been investigated. Ultrasonic measurement has been identified as the most attractive principle. It also appears to allow the relative proportions of methane and nmVOC in the emissions to be calculated. Ultrasonic gauges can be installed by hot-tapping, with gas in the pipe and the process still running. Ultrasonic measurements can also be performed using clamp-on gauges installed on the pipe exterior. However, it remains very uncertain whether this is possible on low-pressure emission flows.

11 Abbreviations and concepts

11.1 Abbreviations

AGR : Acid gas removal
API : American Petroleum Institute
BC : Black carbon
BOEM : Bureau of Ocean Energy Management
CAPP : Canadian Association of Petroleum Producers
CCAC : Climate and Clean Air Coalition
CEN : European Committee for Standardisation
CFU : Compact flotation unit
CH_4 : Methane
CMR : Christian Michelsen Research
CO : Carbon monoxide
CO_2 : Carbon dioxide
DBB : Double block and bleed
DBMS : Database management system (USA)
DECC : Department of Energy and Climate Change (UK)
EEMS : Environmental emissions monitoring system (UK)
EIIP : Emission inventory improvement programme (USA)
e-GGRT : Electronic greenhouse gas reporting tool (USA)
EN : European standard
EPA : Environmental Protection Agency (USA)
FPSO : Floating production, storage and offloading
GHG : Greenhouse gas
GHGRP : Greenhouse gas reporting programme (USA)
Goads : Gulfwide offshore activity data system (USA)
GRI : Gas Research Institute (Gas Technology Institute)
H_2S : Hydrogen sulphide
HC : Hydrocarbon
HP : High pressure
IR : Infrared
LP : Low pressure
MEG : Monoethylene glycol
N_2 : Nitrogen
NCS : Norwegian continental shelf
NGER : National greenhouse emissions reporting (Australia)
Nilu : Norwegian Institute of Air Research
nmVOC : Non-methane volatile organic compounds
NO_x : Nitrogen oxides
NS : Norwegian standard
OC : Overcirculation factor
P&ID : Piping and instrumentation diagram
PSA : Petroleum Safety Authority Norway
RNNP : Trends in risk level in the petroleum activity
TEG : Triethylene glycol
THC : Total hydrocarbons
VOC : Volatile organic compounds
VRU : Vapour recycling/return unit

11.2 Concepts

Extinguished flare:	Flare which is normally intended to burn, but which extinguishes for various reasons.
Closed flare:	Flare which is not normally ignited, where the gas flowing through the flare system is recycled to the process. A closed flare will automatically open if gas flow through the flare manifold rises sharply. The flare must then be ignited either automatically or manually.

12 References

Ref 1 *Surveying installations to identify potential emission sources.* Sub-report 1, Cold venting and fugitive emissions from petroleum activities offshore, Add Novatech, Norwegian Environment Agency, 2015.

Ref 2 Norwegian Oil and Gas Association: *044 Recommended guidelines for discharge and emission reporting* (new version, 23 February 2017).

Ref 3 *Utslippsfaktorer for* CH_4 *and nmVOC fra glykol regenerering og produsert vann*, Add Novatech for Norwegian Oil and Gas, 2014.

Ref 4 *Thermodynamic simulation of the water/glycol mixture*, Dan Laudal Christensen, Aalborg University Esbjerg, 2009.

Ref 5 *Methane Emissions from the Natural Gas Industry*, Volume 14, Glycol Dehydrators, 23 June 1996. http://www.epa.gov/gasstar/documents/emissions_report/14_glycol.pdf

Ref 6 *Glycol Dehydrators*, CCAC technical guidance document number 5, modified 6 August 2014.

Ref 7 *Direct hydrocarbon emissions*, Aker Engineering for the OLF environmental programme, 1993.

Ref 8 *Report on the 1992 API/GRI study on fugitive hydrocarbon emissions from petroleum production operations*, review copy. Prepared by Webb, M: Star Environmental for Martino, P: API and Lott, R: GRI, August 1992.

Ref 9 *Kvantifisering av diffuse utslipp fra Oseberg A og B*. Tønnesen, D (1992), Lillestrøm, Nilu (Nilu OR, 17/92).

Ref 10 *Screening study – Direct emissions of* CH_4 *and nmVOC – Status and mitigation opportunities*, Add Novatech for Norwegian Oil and Gas, 15 November 2013.

Ref 11 *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, November 1995.

Ref 12 *Diffuse utslipp av felles betydning for industrisektoren. Målinger av diffuse utslipp av flyktige forbindelser fra lekkasjer i utslipp og rør*, Norwegian Standard NS-EN 15446:2008.

Ref 13 *Gjøa MEG Unit – Vent Gas*, Scale Consult for GDF Suez, 2015.

Ref 14 Note from phone conversation with Kjell Eivind Frøysa, CMR, 25 March 2015

Ref 15 Phone call with Kjell Vignes, Håland Instruments.

Ref 16 Preliminary sector report – *Underlagsrapport til Forslag til handlingsplan for norske utslipp av kortlevde klimadrivere*.

Ref 17 Environment.no (12 February 2015).

Ref 18 *GHG compendium*, American Petroleum Institute, USA 2009

Ref 19 *1996 GRI/EPA study*, Shires and Harrison, 1996

Ref 20 *Gulfwide Emission Inventory Study*, BOEM, Year 2011, November 2014

Ref 21 *Update of Fugitive Equipment Leak Emission Factors*, CAPP, February 2014

Ref 22 *UK Hydrocarbon Releases Database System* (https://www.hse.gov.uk/hcr3/index.asp)

Ref 23 *RNNP main report – Utviklingstrekk 2013- Norsk Sokkel*.

Ref 24 US Federal state law CFR 30 section 250.1163

Ref 25 *Best Management Practice for Fugitive Emissions Management,* CAPP, 2014

Ref 26 *Methode voor de berekening van broeikasgasemissies,* Principal Inspectorate, Environmental Hygiene.

Ref 27 *Verification of emission quantification methods for fugitive emissions and small gas leaks*. Sub-report 4, Cold venting and fugitive emissions from offshore petroleum activities, Add Novatech, Norwegian Environment Agency, 2015.

Appendix – calculating emissions from TEG regeneration in the USA

Work on mapping methane emissions has been pursued in the USA for many years. Both the EPA and the GTI (formerly the Gas Research Institute (GRI)) have been key players in this work. A central report was prepared for the two institutions in 1996 (ref 5). The basis for this was a comprehensive study aimed at developing emission factors and extrapolating data to calculate national emissions based on the product of a general emission factor and an activity factor. The work was done using process simulations with AspenTech Hysys as the simulation tool using the Peng Robinson equation of state. TEG plants both with and without emissions from the degassing tank, and with and without the use of HC purge gas, were included.

The study concludes that methane emissions are directly proportional to the TEG circulation rate, providing the ratio of gas rate through the absorption tower (also known as a glycol contactor) and the circulation rate of TEG are constant. Based on the same assumption, the ratio of the gas rate through the absorption tower and methane emissions is also constant. (This confirms that the methodology used in the Norwegian Oil and Gas guidelines builds on correct correlations and that processed gas flow is a relevant activity factor.)

The GRI-EPA study shows that emissions from TEG regeneration can be calculated using a general emission factor (f_{TEG}) and an overcirculation factor (OC), which is the ratio between the current circulation rate and the optimal circulation rate – specified in ref 5 as three gallons of TEG per pound of water (equivalent to 25 litres TEG/kilogram water).

Waste methane from the degassing tank and regenerator respectively can then be calculated with the following formulae:

$U_T = V_{KONT} \bullet f_T \bullet OC$
$U_R = V_{KONT} \bullet f_R \bullet OC$

where:
U_T = methane from the degassing tank, tonnes
U_R = waste gas from the regenerator, tonnes
V_{KONT} = gas flow through the absorption column (contactor) in 10^6 scf over the time period
f_T = methane degassing factor from degassing tank, tonnes/V_{KONT}
f_R = methane degassing factor from the regenerator, tonnes/V_{KONT}
OC = TEG recirculation relative to the ideal circulation rate (factor). The average in the USA is a circulation factor of 2.1 (2.1 times above the ideal recommended circulation rate).

The study arrived at the following degassing factors:

$f_T + f_R$ = 175.1 scf methane/10^6 scf processed gas (+101 to -50 per cent)
f_R = 3.57 scf methane/10^6 scf processed gas (+102 to -58 per cent)

(f_T then becomes 173.53 scf/10^6 scf. Uncertainty can be assumed as for ($f_T + f_R$), since f_T is so dominant).

Where uncertainty is concerned, the report points out the following:

> The accuracy is propagated through the EF calculation from each term's accuracy:
>
> 1. ASPEN has been demonstrated to match actual dehydrators within +/- 20 per cent within the calculated confidence intervals obtained from site data.
> 2. Individual EF confidence intervals were calculated from the data used in the calculations.
> 3. Data from site visits has been assigned confidence intervals based upon the spread of the 444 dehydrators from GRI/EPA site data.

In the GRI/EPA study, the OC was found to be 2.1 on average for the US plants. This factor will, of course, vary from facility to facility.

From the literature surveys which have proved possible, this emerges as the most comprehensive and best documented survey of methane emissions from TEG regeneration.

The method has also been adopted by the Climate and Clean Air Coalition (CCAC). In its technical guidance document number 5 (Ref 6), the CCAC refers to a release factor of 275.6 scm of methane emissions/10^6 scm of processed gas, and references the same GRI/EPA report (ref 5). This factor is also referenced in the GRI/EPA report. According to ref 5, however, this is an overall factor for US glycol regeneration and acid gas removal (AGR) plants. The factor also includes emissions from stripping gas in a regenerator, and is not considered representative of TEG regeneration plants on NCS facilities.

Ref 5 includes only methane emissions.

The GTI has later developed GRI-GLYCalc Version 4.0, a Windows-based computer programme built on the work referenced in ref 5 and on further development. Approved by the EPA, it is used by the US gas industry – including oil and gas production facilities on the US continental shelf – for controlling emissions from glycol regeneration and reporting emissions to the US authorities. The programme covers methane, nmVOC and Btex emissions from glycol regeneration, including TEG and other glycol absorbents.

The CCAC states (ref 6):

> The best method for calculating glycol dehydrator methane (as well as VOC and hazardous air pollutants (HAPs, benzene, toluene, ethylbenzene, xylenes)) is GlyCalc®. This model is not expensive and accurately calculates the quantity and composition of the hot vent stream with different dehydrator configurations.