Best Available Techniques to reduce methane emissions from venting and flaring activities in the mid-downstream gas sector

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ABOUT MARCOGAZ

Founded in 1968, MARCOGAZ represents 29 member organisations from 20 countries. Its mission encompasses monitoring and policy advisory activities related to the European technical regulation, standardisation and certification with respect to safety and integrity of gas systems and equipment, rational use of energy as well as environment, health and safety issues. It is registered in Brussels under number BE0877 785 464.

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Introduction

Given the contribution of methane emissions to global warming, the European Commission has identified methane emissions reduction as one of the key priorities of the European Green Deal and the European Methane Strategy, published in October 2020. As part of the strategy, the European Commission adopted a proposal on 15 December 2021 on a Regulation aimed at reducing methane emissions in the energy sector. The Regulation aims for “improved measurement, reporting and verification of energy sector methane emissions and immediate reduction of emissions through mandatory leak detection and repair and a ban on venting and flaring” except “in case of an emergency or malfunction; and where unavoidable and strictly necessary for the operation, repair, maintenance or testing of components or equipment”.

As a contribution to the technical implementation of the requirement to **minimise venting and flaring** and building on the technical experience of its members, MARCOGAZ proposes a concise list of 9 Best Available Techniques (BATs) to reduce, prevent and minimise methane emissions related to Venting and Flaring activities in the mid and downstream gas sector.

Below follows a brief summary of the BATs:

- **BAT 1 - Reduce pressure before venting**
  The first BAT describes how assets can be depressurized and isolated from the total system to prevent the need for venting and flaring. Furthermore, this BAT introduces an evaluation framework for decision making to minimize methane emissions.

- **BAT 2 - Recover and recompress emissions in the process gas: mobile compressor**
  Mobile compressors are introduced to reduce the amount of gas in the to-be-emptied asset section. Although mobile compressors are a proven solution to avoid large amounts of methane to be emitted, also limitations regarding compression ratio, time and environmental impact are addressed.

- **BAT 3 - Recover and recompress emission in the process gas: stationary compressor**
  Stationary recompression is addressed for the recovery of emissions from dry gas seals, process vents and boil off gas at main infrastructure sites. Besides the advantages, from a safety perspective it is also mentioned that emergency process vents could not always be prevented due to time limitations.

- **BAT 4 - Flaring as replacement of venting (to reduce the environmental impact)**
  Mobile venting appliances are proposed in the fourth BAT as a more environmentally friendly solution before venting, after the asset has been depressurised (see other BATs). The BAT addresses two techniques related to flaring, namely natural draught and forced draught burner flaring systems.

- **BAT 5 - High bleed continuous pneumatics mitigation**
  Pneumatic control systems are described which are used as process control instruments to ensure safe operation of the gas networks. High bleed components are reported to be significant emitters and could be replaced by their air or electric counterparts. If due to practical or security of supply reasons this is not possible, also low bleed pneumatic components could be used.

- **BAT 6 - Electrical or pneumatic air starters**
  This BAT describes solutions to avoid vented emissions during the starting phase of gas

turbines. Where traditional starting motors are equipped with expansion turbines and vent the process gas, two low emission solutions are proposed to avoid this. The first solution would be to replace the starting motor by an electric or hydraulic version. The second solution relates to the adaptation of the expansion turbine to handle pressurized air.

- **BAT 7 - Use of nitrogen to purge LNG pipes**
  The seventh BAT introduces nitrogen to purge temporary connections between the LNG receiving terminal and the LNG carrying ship. As a supply of nitrogen is often available at the terminal, implementation is considered good practice for environmental and safety reasons.

- **BAT 8 - LNG truck loading (dry coupling connectors)**
  This BAT addresses a dry cryogenic coupling technique, which enables LNG truck loading with minimal methane emission. The technique is reported to be safe and economically viable.

- **BAT 9 - Excess flow valves in new service lines**
  In the final BAT, excess flow valves (EFVs) are proposed to limit emissions in new distribution service lines. The EFV automatically shuts off the gas flow in the service line when the flow volume exceeds a threshold as in de case of a rupture. Although EFVs are very suitable to minimize emissions, limitations should be considered regarding pressure drop, volume flow and risk of malfunctioning.

In addition to this set of BATs and to comply with the European regulation and OGMP 2.0, operators are advised to **measure operational parameters (pressure, temperature, flow, etc, as relevant)** that allow **quantification of residual and avoided methane emissions for each operation**.

This entails parameters measurement at:

- the start of the operation,
- at any relevant intermediate points during the operation

1. BAT 1 – Reduce pressure before venting

1.1. Introduction

When the content of an asset has to be evacuated for works or decommissioning, the good practice, if possible, consists first in lowering the gas pressure by using the network gas consumptions. Following that, the remaining asset content can be evacuated by using the techniques described in the other BAT documents in this bibliography. Venting is the final activity to remove gas from the asset, but shall be limited to appropriate amounts.
In practice, decompression by dispatching gas to gas appliances is a measure that will be used in combination with other BAT measures. Finding the best solution or combination of solutions is often challenging. Therefore, guidelines are also taking this into account.

1.2. Technical description

First of all, the area in which the asset is embedded shall be reduced in pressure as much as allowed by operational conditions. The next step is to isolate the asset to be depressurised from the total system. Various BAT measurements could be used, also in combination, to remove gas from the pipeline. In practice, a depressurisation measure is part of one or more BAT measures. This results in a complex evaluation framework, where the most optimal combination of measures must be evaluated. Relevant aspects include equipment availability, environmental effects, costs and time available. As an example is a context flow scheme shown in Appendix 1, that can be used in the preparation phase.
Furthermore, an emission and cost calculation tool will be useful when considering measures, see also chapter 5.
Chapter 3 and 4 of this document are considering the depressurising of an asset by dispatching the gas to a gas appliance.

1.3. Applicability and technical limitations

	Transmission	Storage	LNG Terminals	Distribution
Applicability	+	+/-	+/-	+

Table 1 – Applicability of the BAT

The depressurization by dispatching to a gas appliance is technical limited by conditions like:

- Minimum working pressure of (safety) valves and pressure regulators that use natural gas as power gas.
- The minimum working pressure that is allowed in the processes of the downstream gas appliances.

1.4. Impact on safety and secuity of supply

1.4.1. Safety

The safety aspects concerned should be ensured, among other things, such as:

- that no hazardous conditions can occur as a result of the decreasing pipeline pressure, like for safety valves and pressure regulators that use natural gas as power gas
- avoiding backflow of gas
- avoiding any air infiltration

1.4.2. Security of supply

The depressurization measure should be well prepared in advance. It should be carefully prepared and co-ordinated with all relevant parties - including those feeding the gas into the pipeline system - likely to be affected by the measure. It is noted that the customers can only take off the enclosed volume up to a technically minimum pressure.

1.5. Economic impact and methane emissions avoided with the BAT

1.5.1. Economic impact

The depressurization by dispatching to a gas appliance is probably the most economical and effective BAT measure. Because the gas is not "disposed", it is recommended not to calculate the saved emissions by dispatching to gas appliances.
This does not apply if it is necessary to provide financial incentives for related parties to cover their costs for depressurization by gas utilization. One form of compensation could be the free of charge supply of depressurized gas.

1.5.2. Estimation on methane mitigation and costs

Estimating the amount of avoided greenhouse gases is complex for the following reasons:

- Venting gas emissions results in unburned methane being emitted. The volume should be calculated or measured; the environmental impact may be expressed as CO2 equivalent emissions (GWP100 = 28 according to the latest IPCC report).

- Flared gas results in burned CO2 emissions. The volume should be calculated or measured.

- Recompression results in direct or indirect emissions due to the energy used for recompression. The energy consumption must be measured and related to the energy carrier.

- Recompression compressors generate emissions directly or indirectly as a result of energy consumption. Energy consumption needs to be measured and emissions need to be calculated based on the energy source used.

- Both flaring and recompression are technically limited to a lower working pressure. In case of recompression, the minimum pressure is likely to be higher than for flaring. For this reason, flaring can be used additionally after the use of recompression. The remaining gas must be displaced with air or possibly nitrogen with minimal environmental damage.

- Once the pipeline gas has been reduced to atmospheric pressure, it must be displaced with air or nitrogen to create a safe working environment. The energy content and associated emission of greenhouse gasses of the nitrogen gas must also be taken into account.

- If nitrogen is used for displacement, the energy content of the nitrogen gas must be taken into account (preparation and bringing it to a suitable operating pressure).

It is recommended to develop a calculation tool for totalizing the emissions. An example for this is included in Appendix 2.
A cost estimate can be included in the calculation tool for weighing up the most optimal measure, or combination of measures. In practice, this will be a trade-off between environmental effects, costs and available time.

1.6. Appendix 1 – example flowchart decision chart

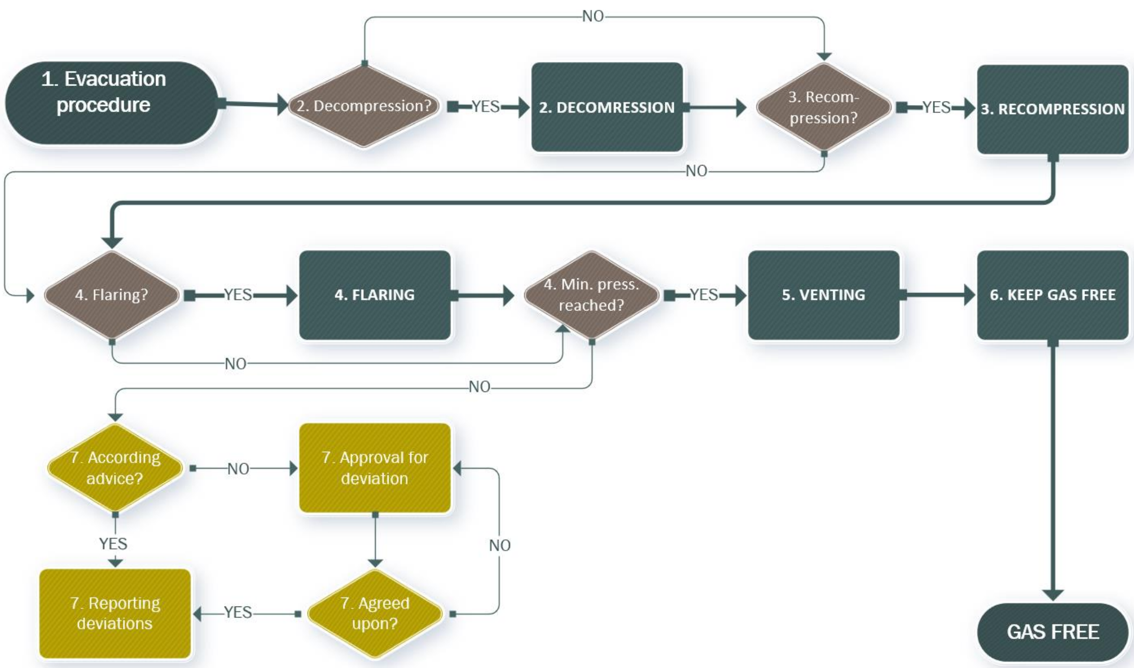

Figure 1 – Example flowchart decision chart

The sequence of BAT measures in the above flow chart has been set up from the perspective of preserving the commodity natural gas in the first place, then making the pipeline gas-free with minimal environmental impact.

Comments to the example chart above:

1. Evacuation procedure: It is recommended to develop company-specific work;

2. Decompression: This step is the topic of the BAT 1;

3. Mobile and stationary recompression: This step is the topic of the BAT 2 and 3. This measure is possible until the final pressure reaches a pressure between ca. 1 and 10 bars.

4. Flaring: This step is the topic of the BAT 4. This measure can be done up to a final pressure of about 100-200 mbar.

5. Venting: When flaring is no longer feasible, residual volume evacuation remains.

6. Keep gas free: This is an air moving procedure to create a safe workplace.

7. Deviations: Field working conditions can sometimes necessitate deviating from the agreed working arrangements. It is recommended to develop an approval procedure for this in order to keep the vented quantities of unburned gas to a minimum.

1.7. Appendix 2 - example emissions calculation tool

		Input data	Recompression and flaring, remaining is vented				Recompression remaining is vented			Flaring			Venting
			Recompres-sion	Flaring	Remaining vented	Total	Recompres-sion	Remaining vented	Total	Flaring	Remaining vented	Total	
Length pipeline	km	20,0											
Diameter pipeline	inch	36											
Geometric volume	m3/km	620											
Upstreum pressure at start	barg	50											
Total volume	m3(n)	620.000											
Amount of compressors required	#	2											
Minimum end pressure recompression	barg	2											
Evacuation time	h	41,0											
Remaining volume after recompression	m3(n)	24.800											
End pressure flaring	barg	0,40											
Remaining volume after flaring	m3(n)	4.960											
Processed volume for each step	m3(n)		2.976.000	409.200	24.800	**3.410.000**	2.976.000	434.000	**3.410.000**	3.385.200	24.800	**3.410.000**	**3.410.000**
Fuel gas recompression	m3(n)/h	50	43.346				43.346						
Gas quality	-	Hgas											
Costs commodity	EUR		10.836	102.300	6.200	**119.336**	10.836	108.500	**119.336**	846.300	6.200	**852.500**	852.500
Environmental costst	EUR		4.375	41.301	23.788	**69.464**	4.375	416.290	**420.665**	341.676	23.788	**365.464**	3.270.848
Total costs	EUR					**188.801**			**540.001**			**1.217.964**	**4.123.348**
Emissions unburned	ton CH4		-	-	17,0	**17**	-	297,3	**297**	-	17,0	**17**	2.336
Emissions burned	ton CO2		87,5	826,0	-	**914**	87,5		**87**	6.833,5	-	**6.834**	
Emission unburned	ton CO2eq		-	-	424,8	**425**	-	7.433,7	**7.434**	-	424,8	**425**	58.408
Total emissions	**ton CO2eq**					**1.338**			**7.521**			**7.258**	**58.408**

Figure 2 – Example emissions calculation tool

It is adviced to develop a tool that aggregates the emissions and environmental costs of the entire pipeline venting procedure. This allows to make justified considerations on the work procedure to choose. One example of this is shown below.

2. BAT 2 – Mobile recompression

2.1. Introduction

Some interventions on gas infrastructures such as: maintenance of a transmission network section or commissioning of new installations on an existing facility, require evacuating important quantities of gas, to empty the concerned asset to intervene safely. This is common on the gas transmission network where pipeline section maintenance is regularly required, in such case ,historically, section of pipeline of sometimes tens of kilometers had to be vented. Mobile recompression is an effective way to mitigate such emissions.

2.2. Technical description

When an asset has to be pumped down, the good practice, if possible, consists first in lowering the gas pressure by using the network gas consumptions. A mobile or portable compressor is connected on the existing facility or pipeline, that temporary connection as to be carefully studied before the work, it can be necessary to perform modifications at the connection point to make it possible.
The pumping work will take place between the facility/pipe section to be emptied which is isolated and an available, in production, section of the asset.
The compression ratio will vary from 1 (at the beginning of the work, when the isolated section will be at process gas pressure) and a high number (sometimes over 50), this will imply most of the time the use of a reciprocating technology (screw compressors can also be suitable for lower compression ratio). As these compressors are volumetric machines, the compressed flow will depend on the suction pressure, which means that the pumped gas flow will dramatically drop when the last bars of pressure will be reached in the isolated section. This will result in an important increasement of the compression needed time that will directly impact the asset section unavailability duration: standard pumping times vary between 24 and 72 hours.
Several solutions can be applied to deal with the low remaining pressure in the isolated section, costly in time and energy to recompress:

- Use 2 sets of compressors when the compression ratio becomes to challenging
- Flare the last bars of pressure for a limited environmental impact

As mentioned earlier, the compressor technology used are reciprocating or screw compressors. They can be driven either by a gas engine or an electrical motor. In the case of an electrical motor, as most of the time a sufficient electrical supply is not available at the pumping site, an auxiliary generator is necessary.
The compressors can be either mobile and mounted on a truck trailer or portable in containers that will be installed at the pumping sites. For the second solution mainly, it can be necessary to build a concrete slab if a stabilized enough ground is not available.
Several compressor manufacturers propose that kind of solution. Mobile compressors and the pumping services can also be rented.

2.3. Applicability and technical limitations

	Transmission	Storage	LNG Terminals	Distribution
Applicability	+	+	+	?

Table 2 – Applicability of the BAT

Mobile recompression is applicable for maintenance and commissioning operations for gas transmission, storage facilities and LNG regasification terminals .
Concerning the LNG terminals mobile recompression can be used during the terminal technical stops where important volumes of boil off gas can be recovered.

2.3.1. Limitations

When small volumes have to be retrieve, the environmental cost of the technology implementation can be higher than the benefit, especially compared to flaring (emissions from the gas engine or the auxiliary generator, emissions during the compressor transportation to the site…)

Technical capabilities of the rental available compressor sets can also be limiting, such as:

- A too high discharge pressure needed
- A compression ratio limit at the end of the pumping

The needed time to pump the gas can also be a limitation as it is impacting the unavailability time of the asset.

2.4. Impact on safety and security of supply

2.4.1. Safety

Compared to venting, the safety impacts are different: the compression arrangement brings additional safety aspects to be covered (rotating equipment, combustion engines, hose pipes, vibrations, temporary connections etc.). An HAZOP process and a 24/7 manned operation are required.

2.4.2. Security of supply

The compression requested time is strongly impacting the asset unavailability time, which has to be considered in terms of security of supply. It can be possible, in case of an issue to use several compressor sets to minimize the pumping time.

2.5. Economic impact and methane emissions avoided with the BAT

2.5.1. Economic impact

2.5.1.1. Subcontracting the pumping services

The cost order of magnitude is from 80’000 to 150’000 Euros per pumping operation.

2.5.1.2. Inhouse pumping activities (compressor owned by the operator)

The Capital Expenditure are up to 2.5 million euro depending on the compressor capabilities.
The Annual maintenance costs for a single compressor are of an order of magnitude of 100’000 euro.
As an example, the average annual operational cost of a mobile compressor for a transmission operator in the CEE region is 410’000 euro – the cost relates to average annual re-compressed gas volume of 13 millions Nm3 and 1900 operating hours per year.

2.5.2. Estimation on methane mitigation costs

The current pumping interventions save between 100 000 and 1M Nm3 per intervention

This can represent millions on Nm3 of gas for a given gas infrastructure operator and the biggest share of its emissions (e.g in gas transmission).

3. BAT 3 – Stationary recompression

3.1. Introduction

Main gas infrastructure sites such as transmission compressor stations, underground storage above surface facilities or LNG regasification terminals, are subject to different kinds of process related vents:

- Vents from technical devices designed to do so (e.g.: dry gas seals)
- Vents of equipment/assets for operational needs (maintenance, tests, etc.)
- Emergency vents done for safety reasons, to avoid any hazardous situation
- LNG tanks boil off gas

If emergency vents are usually not recoverable, technical solutions exist to recover device and operational regular vents using a stationary recompression and can be applicable depending on the site configuration.

Figure 1

3.2. Technical description

The basic principle is:

- to collect the gas at low/atmospheric pressure from the existing venting system,
- or collect it at an higher pressure directly from the concerned equipment/asset that is meant to be vented (e.g. a centrifugal compressor)
- and to recompress it using a dedicated compressor and reinject it in the high pressure process gas system (e.g. suction header of a compressor station).

Reciprocating compressors is the most commonly used technology, as they are well adapted in terms of compression ratio and flow.

3.2.1. Recovery of emissions from dry gas seals

The main example of emission from devices designed to vent that are recoverable, are centrifugal compressors DGS (Dry Gas Seals). Recovery compressors arrangements have been developed in the last decade to do so. They are proposed by the main centrifugal compressor and DGS manufacturers.

DGS primary vents can be recovered, the recovery compressor design will have to be adapted to the vent pressure at the DGS outlet which is low (no more than few bars) at a relatively limited flow. The DGS vent flow will greatly vary between running and pressurized stop conditions of the centrifugal compressor and can also vary depending on the seal condition. The recovery compressor setting must be adapted to such variations: several solutions exist to do so, the most common one being to collect the low pressure vents in a capacity at the compressor inlet. In any case the impact of the recovery device on the vent back pressure and the DGS behaviour must be carefully taken into account and a safety relief device should in any case be installed in the modified vent line, to prevent an over pressure related to a DGS failure.

3.2.2. Recovery of process vents

As for device vent recovery, process vent recovery compressors arrangements are nowadays commonly installed in gas infrastructures. In that case the high-pressure equipment (compressor, pipeline system…) will be emptied, the gas will be pumped and reinjected in an available process gas section of the site. The inlet pressure of the recovery compressor will continuously decrease, and the discharge pressure (process gas) will usually remain stable, resulting in a greatly varying pressure ratio. The recovery compressor is dimensioned accordingly, the reciprocating compressors are particularly adapted to such conditions.

One of the main compressor design parameter to consider will be the allowable time to depressurize. It can vary from few hours to several days. A longer depressurisation will mean less investment in terms of recompression means but can have an important impact in terms of availability (unavailability time to be added to the maintenance time for example) or in terms of process.

Figure 2

3.2.3. Recovery of boil off gas (BOG)

LNG is stored in the tanks of the regasification terminals. When the stored LNG absorbs heat, it is partially vaporized. The increase/decrease in the amount of BOG generated at the terminal is due to the confluence of several phenomena:

- Heat gain from the environment or into the LNG tank. This is a maximum of 0.05% of the tank volume, based on pure methane, or through lines and equipment.
- Heat generated in the dynamic process equipment, generally cooled by the circulating LNG/NG itself (pumps and compressors).
- Vapours generated by unloading LNG from the LNG carrier to the storage tanks. A minor contribution to the system is the decrease of BOG by displacement of LNG pumped from the tanks to the high-pressure system.
- Vapours generated by the LNG carrier during the LNG loading from the storage tanks.
- Changes in atmospheric pressure.

To control the pressure of the LNG tanks, the BOG generated must be removed. Recovery of this BOG is achieved by compressing and recondensing the BOG using LNG before it is vaporized. This system is included in the design of most LNG terminals.
In addition, when the terminal is at zero or low send-out modes, recondensing the BOG is not possible. For this purpose, high-pressure compressors can be installed, to inject otherwise non-recoverable BOG into the transmission grid.

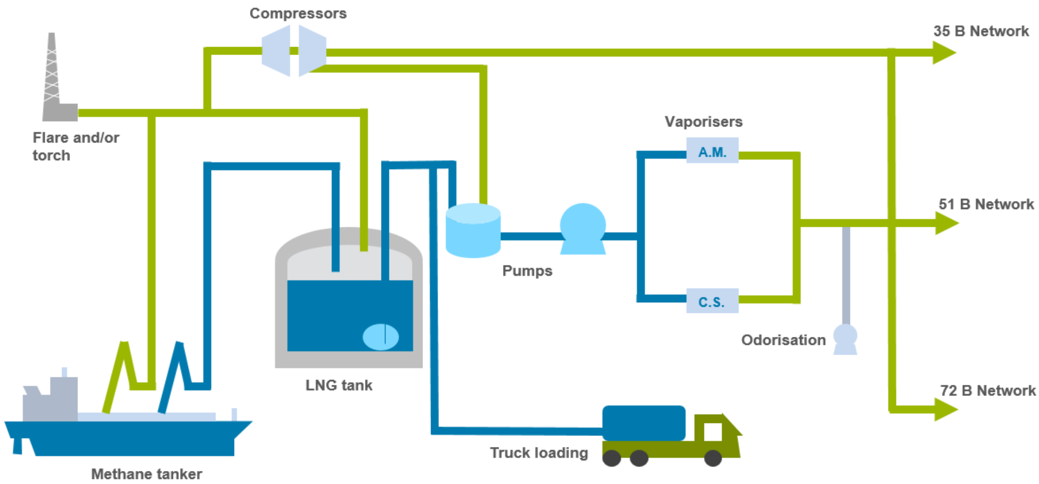

Figure 3 – LNG terminal scheme

The types of BOG compressors are the following:

- BOG Recovery Units - recovering, compressing and sending the BOG to the recondenser (low pressure 8-9 bar) to be converted to LNG.
- High-pressure BOG compressors (Figure 4) - installed to inject non-recoverable BOG into the grid during zero or low send-out modes.

Figure 4 - High pressure BOG compressors

3.3. Applicability and technical limitations

	Transmission	Storage	LNG Terminals	Distribution
Applicability	✚	✚	✚	✖

Table 3 – Applicability of the BAT

The main factors of limitation to stationary recompression are available space and the impact on the vent of the recovery device back pressure (e.g. gas chromatograph vents).
The abatement costs can be disproportionate, especially for some low bleed devices.

3.4. Impact on safety and security of supply

3.4.1. Safety

The time needed to recompress an emergency vent is usually too long to avoid the hazardous situation to happen, making such a recovery impossible.
Moreover, there are examples of sites where depleted pipelines can be used to depressurize in case of an emergency, the "vented" gas in the depleted pipeline can be then pumped and reinjected in the process gas.

3.4.2. Security of supply

The time needed to recompress a process vent prior to a maintenance activity, can significantly impact the unavailability time of the asset and can be incompatible with security of supply.

3.5. Economic impact and methane emissions avoided with the BAT

3.5.1. Economic impact

The economic impact is highly dependent on the recovery compressor size and the complexity of the setting/installation on site.
The capital expenditure could be from 400'000 up to 2 million euros, operational expenditures have also to be considered in terms of energy consumption and maintenance.
The CAPEX associated to a high-pressure BOG compressor are estimated between 7 and 10 million euros.

3.5.2. Estimation on methane mitigation costs

On a general point of view the emission saving will highly depend on the type of process/equipment/asset.

3.5.2.1. Dry gas seals

Depending on:

- the DGS design and size
- the operating conditions (rotating speed, process gas pressure)
- the operation regime (running, pressurized standstill)
- and the seal condition (wear, contamination)

The vent emissions for a single centrifugal gas compressor can vary from 0.5 to 20+ Nm3/h.
If you consider an example of typical conditions for a compressor site with 2 compressor running each 3000 hours per year and remaining pressurized stopped 5000 hours per year. With seals in good conditions emitting per compressors 0.5 Nm3/h when pressurised stopped end 5 Nm3/h when running. The installation of a recovery system on such a site can save 35’000 Nm3 a year, from compressors primary vents.

3.5.2.2. Compressor process vents

The saved gas quantity per event is highly dependent of the site configuration, typically for gas transmission compressor stations it will vary from 1000 to 5000+ Nm3.

3.5.2.3. Boil off gas

The use of high-pressure BOG compressors will depend on the level of gas regasified in a LNG terminal. For periods where the gas regasified and injected into the transmission grid is very low, the compressors can be used continuously. For example, during 2017 and 2018, in a LNG terminal operated by Enagas, HP compressors were in operation around 7.000 hours/year, with a recovered quantity of BOG of around 800 GWh/year (around 72 MNm3). This BOG would otherwise have been burnt.

3.6. Closing remarks

Stationary recompression solutions are more and more developed in the European mid/stream infrastructures. Device vents and process vents recovery can be mutualized in a unique compressor arrangement. Before investing in a recompression solution always consider, alternative, energy free usage of the recovered gas (e.g. plant boilers fuelling).

4. BAT 4 – Flaring as replacement of venting

4.1. Introduction

When the content of an asset must be evacuated for works or decommissioning, the good practice, if possible, consists first in lowering the gas pressure by using the network gas consumptions. Following that, the remaining asset content can be evacuated by using a technique like flaring and other techniques described in the other BAT documents in this bibliography. Venting is the final activity to remove gas from the asset but shall be limited to minimum amounts. This BAT 4 describes the best possible techniques for flaring.

In practice, flaring is a measure that will be used in combination with other BAT measures. Finding the best solution or combination of solutions is often challenging. The role that flaring can play is shown in the general flowchart taken up in Appendix 1 of BAT 1 document.

4.2. Technical description

4.2.1. General

This BAT 4 will be limited to mobile flaring systems with appliance in natural gas pipeline networks during individual maintenance measures on pipeline sections or station piping. These measures can include system modifications, repair and decommissioning.

Flaring systems are developed and available for a wide variety of applications. Therefore, flares can vary in size, thermal power and overall design. Flaring systems can be separated by their basic principle of air supply:

- **natural draught burner** in which the combustion air is entrained at atmospheric pressure, by the buoyancy of a chimney or the fuel velocity and
- **induced draught burner** in which the combustion air is supplied by providing suction in the combustion chamber by mechanical means, usually a fan

The standard EN-ISO 23251 - *Oil and Gas Industries - Decompression and Depressurization Systems* provides useful design information.Flare systems needs to be conform to EN 746-2 Part 2: Safety requirements for fuel handling and combustion systems with respect to their safety devices and design. It covers a wide range of combustion systems and also applies to flaring systems. To ensure complete combustion without methane slip, flaring systems must provide a stable flame free of pulsation with a sufficient temperature and dwell time of the fuel gas. The integrity of the flaring process has to be monitored constantly. This monitoring can be ensured by personal on site or automated flame monitoring systems. In the event of a flameout, the flame must be restored by reignition or the flaring system has to be shut down immediately to prevent unintentional emissions of methane for safety and environmental reasons.

4.2.2. Natural draught burner flaring systems

Flaring systems utilizing the principle of natural draught burners are small and compact systems with rather low process-technical equipment requirements. The combustion air is entrained at atmospheric pressure, by the buoyancy of a chimney or the fuel velocity.

Natural draught flaring systems allow for a relatively high throughput and thermal power, with the drawback of open firing systems which has a high impact on their surroundings. Open firings systems has (see appendix 1) a flame that is visible. These systems will emit high amounts of thermal radiation and possibly visible light. Combined with the noise level of the outlet nozzle, the risk of misconceptions by the public and authorities must be considered before deployment, especially when operating in urban areas or during darkness, as these flames are highly visible over large distances. Due to their

overall smaller size and larger specific flaring capability, these systems are typically used for measures that require short assembly time, where small quantities of gas are to be flared in a short time.
For medium quantities of gas to be flared in a short time, fuel velocity injection burners are used with an enclosed combustion chamber/chimney. See Appendix 2.

4.2.3. Forced draught burner flaring systems

Flaring systems utilizing the principle of premixing burners are monitored equipment that enclose the combustion inside a heat resistant combustion chamber. Prior to entering ignition in the combustion chamber, fuel gas is mixed with the combustion air in a mixing chamber. The required air is supplied by blower fans or thermal convection. These flaring systems will require an external energy supply for controlling and monitoring of the flaring process and the blower fans if present.
Premixing flaring systems allow for a controlled flaring of large volumes of gas. These systems are optimized for long deployment in a wide variety of environments. As the flame is covered and/or operated with a lean air-fuel mixture, no technically relevant thermal radiation or visible light is emitted. Only the area of heated exhaust gas plume is to be considered when planning the installation of such flaring system by maintaining safe distance to surrounding objects. The temperature inside of the combustion chamber and the flowrate of the fuel gas must be monitored and controlled to ensure complete combustion and prevent methane slip.
This type of flaring system is to be generally preferred when performing flaring activities in the pipeline network and on stations, as these flaring activities can take multiple hours to perform. These systems can be stacked in parallel to increase the total flow rate of fuel gas, while internal or external pressure reduction equipment can meet a wide area of gas pressure requirements.
Multiple examples of flaring systems utilizing the principle of premixing burner on the market are included example taken up in Appendix 3.

4.3. Applicability and technical limitations

To judge the applicability of specific flaring systems and further equipment, multiple factors must be considered. The most influential of those are:

- Pipeline pressure
- Nominal gas volume
- Gas quality and composition
- Available setup time
- Local surrounding

In the following table information about the applicability of flaring systems can be found:

	Transmission	Storage	LNG Terminals	Distribution
Atmospheric flaring systems	✖	✖	✖	✚/-
Premixing flaring systems	✚	-	-	✚/-

Table 4 – Applicability of different flaring systems

In the following table the most distinctive limitations per scope of application can be found:

	Transmission	Storage	LNG Terminals	Distribution
Atmospheric flaring systems	Large gas volume High gas pressure	Station surroundings High gas pressure	Station surroundings High gas pressure	-
Premixing flaring systems		Station surroundings	Station surroundings	Small gas volumes

Table 2 – Distinctive limitation per scope of application

4.4. Impact on safety and security of supply

4.4.1. Safety

Safety aspects regarding the design and engineering of the flaring systems are in detail described in EN 746-2 - *Part 2: Safety requirements for combustion and fuel handling systems*. A list of safety hazards is included in this standard. Flare systems are required to meet this standard.

Safety aspects are:

- choice of materials such that the construction and operation of the system are not detrimentally affected. In particular, all the components of the fuel pipework shall be capable of withstanding the mechanical, chemical and thermal loads to which they can be subjected during normal operation
- reliable and correct time for ignition of the fuel/air-mixture at the burner(s);
- prevention of unintentional release of unburned fuels;
- shut-off fuel-supply in case of relevant fault;
- protection of pipeline by precluding the propagation of flame in reverse flow;
- prevent firing when the exhaust of combustion products is not ensured;
- prevent firing when the process conditions are not in the safe state.

Electrical circuits shall be designed in accordance with subclause 5.7 of EN 60204-1:2006.
The combustion and fuel handling for flaring systems shall comply with the safety requirements and/or protective measures, described in chapter 5 of the EN 746-2.
The flare systems shall be designed according to the principles of EN ISO 12100 for relevant but not significant hazards, which are not dealt with in the EN 746-2.
NOTE For guidance in connection with risk reduction by design, see clause 4 of EN ISO 12100-2:2003, and for safeguarding measures see clause 5 of EN ISO 12100-2:2003.
To ensure the safety of personal on site and prevent fire hazards, the specific emission of heat radiation and thermal load contours must be determined for each flaring systems. On this basis the operator must define safety distances to consider when planning the installation location on site.
To prevent misconception of the public and authorities, the noise emissions and visibility (open firing burner(s) should be considered.

4.4.2. Security of supply

The depressurization measure should be well prepared in advance. It should be carefully prepared and coordinated with all relevant parties - including those feeding the gas into the pipeline system - likely to be affected by the measure. It is noted that the customers can only take off the enclosed volume up to a technically minimum pressure.

4.5. Economic impact and methane emissions avoided with the BAT

4.5.1. Economic impact

Properly designed and used flare devices can burn gas cleanly, emitting only the greenhouse gas CO2. However, the energy content of the evacuated gas will be lost.

4.5.2. Estimation on methane mitigation costs

The flared amount of gas must either be measured or calculated based on pipe hydraulic volume and realized pressure reduction. Flared gas results in burned CO_2 emissions, which amount can be calculated based on the gas composition and the total volume of flared gas. As flares will typically require a minimum working pressure for operation, a specific amount of residual gas will remain inside the pipeline and will have to be displaced with air or nitrogen to create a safe working environment. The environmental impact of residual methane should be calculated based on the remaining gas volume and GWP_{100} = 28 (as per IPCC report AR6). The sum of the CO_2 emitted by flaring and the CO_2 equivalent emitted by venting of the residue marks the real emissions generated by the flaring measure. For reference, the CO_2 equivalent of the total gas volume before flaring can be calculated to rate the effectiveness of the flaring measure.
To decrease the residual volume of gas in the pipeline, upstream injection of nitrogen can be used to maintain working pressure and displace the atmospheric gas volume. With this combined measure, the flaring system will receive a mixture of nitrogen and gas, whose influence on the integrity of the flaring system must be considered, as the calorific value of the fuel gas will decrease over time. The energy content and associated emission of greenhouse gasses of the nitrogen gas must also be considered, covering production, transportation and injection.
It is recommended to develop a calculation tool for totalizing the emissions, see also BAT 1. A cost estimate can be included in the calculation tool for weighing up the most optimal measure, or combination of measures.

4.6. Appendix 1

Esders open flame flaring system. The Esders company is marketing a small mobile open flame, see picture below.

Figure 1 – Esders open flame flaring system

4.7. Appendix 2

The Dutch Enwell BV company developed and produced, in cooperation with Gasunie, a mobile flare system with the following scope:

Medium	: Aardgas	
Capaciteit	: 125….500	Nm³/h
Werkdruk	: 42	barg
MOP	: 40	barg
MIP	: 46	barg
CH_4	: 81,29….91,6	vol.%
Temperatuur	: min. 5	°C
MOP	: 4,0	barg
MIP	: 4,6	barg

The mobile flare installation E-HT-500, consists of a hinged combustion chamber (the flare) which can be moved from a horizontal position into a vertical position with a pneumatic press. As soon as the stack is upright, it can be secured. Gas supply is distributed via pre-mixed nozzles over the several burner tubes. The gas is mixed with air drawn in through the bottom of the nozzles. The gas/air mixture is then burned at the top of the burner tubes. Air supply is controlled via a valve system, depending on the continuously monitored combustion temperature. All valves are closed when the flame detection fails. The entire system is on a mobile trailer.

Figure 2 – Enwell BV enclosed mobile flare 500 m³N/h (Gasunie)

The Dutch Enwell BV company developed and produced, in cooperation with Gasunie, a mobile flare system with a capacity up to 1200 m3(n)/h.

Figure 3 – Enwell BV enclosed mobile flare 1200 m³N/h (Gasunie)

In Figure 4 below an example of P&ID mobile flare unit with 1200 KWth.

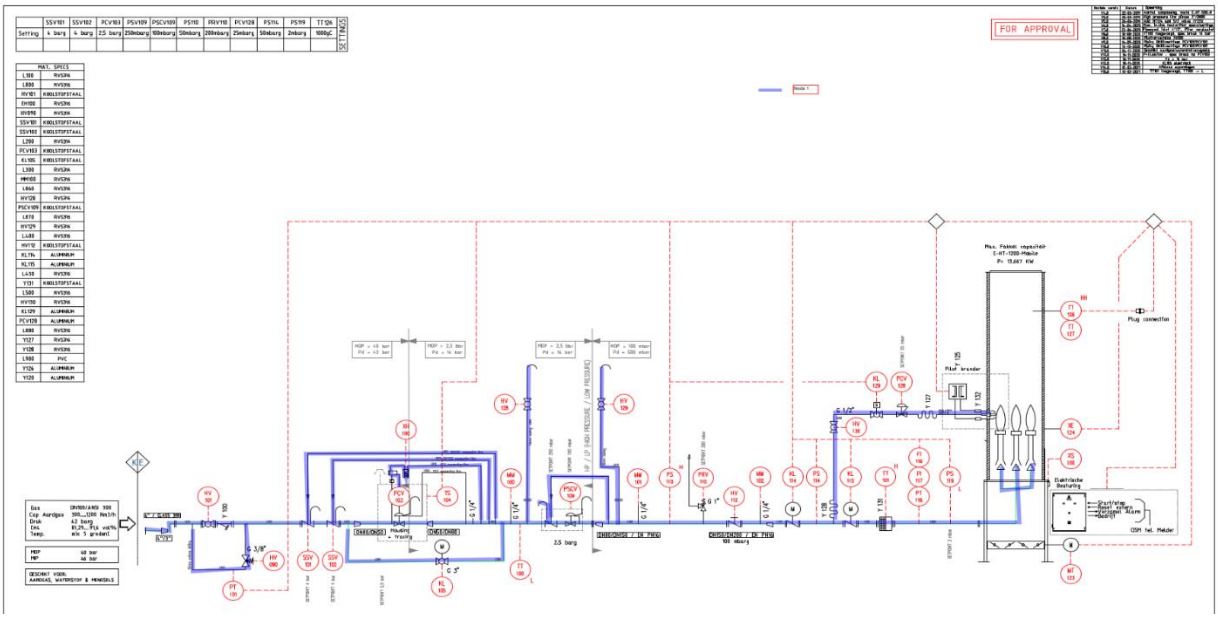

Figure 4 – Example of P&ID mobile flare unit 1200 KWth

In Figure 5 below an example of a flare unit manufactured by Aereon for permanent unattended operation is shown. Such a system can also be made suitable as a mobile unit.

Figure 5 – Aereon flare unit for permanent unattended operation

4.8. Appendix 3

The German Lambda Gastechnik GmbH company developed and produced, in cooperation with OGE, a mobile flare system with the following scope:

Flow rate	**1.000 $m^3{}_N$/h** at > **100 $mbar_g$**
Thermal power	**12.000 kW_{th}**
Outlet height	**6,8 m** above ground
Blower fan	**40 kW_{el}**
	for **19.000 m_3/h** ambient air
Dimensions	**3,5** x **3,5** x **6,8** m
Noise level	**< 80 dB**

The mobile flaring system type *LCHC-2x5000-M, IT TN* is a flaring module consisting of two independent premixing burners. The fuel gas is mixed with the ambient air in separated mixing chambers via forced-air blowers. After controlled mixing, the gas-fuel mixture is ignited at the bottom of the combustion chambers and the exhaust gases exit through the chimney. As the temperature inside the combustion chamber is constantly monitored and used to adjust the air-fuel mixture, a complete combustion is guaranteed. Using a precise lean air-fuel mixture, the flame is completely invisible in daylight and does not emit any noise during combustion. Pressure levels up to 100 barg are possible with external equipment, maintaining a constant flow

rate of 1.000 m^3_N/h up to a minimum operating pressure of 0,1 barg. The system can be operated from its trailer or on pedestals for optimized setup time versus space requirements.	

Figure 6 – Lambda mobile flare system

5. BAT 5 – High bleed continuous pneumatic mitigation

5.1. Introduction

Pneumatic instrument systems powered by natural gas are used across the natural gas infrastructure for process control. Typical process control includes pressure, temperature, liquid level, and flow rate regulation. Gas companies can achieve methane emission reductions by replacing high-bleed devices with low-bleed ones. Another option to achieve emission reductions is to convert natural gas-powered pneumatic control systems to compressed instrument air/electrical systems. Instrument air systems substitute compressed air for the pressurized natural gas, reducing methane emissions.

5.2. Technical description

The pneumatic control system consists of the process control instruments and valves that are operated by natural gas. Pneumatic supply gas is either directed to the valve actuator by the needle valve pinching off an orifice so natural gas pneumatic devices bleed gas to the atmosphere; the bleed rate depends on the design of the device. When a pneumatic controller detects the need to change liquid level, pressure, temperature or flow, it opens or closes a control valve by directing pressurized gas to the control valve. The natural gas used to drive the controller is continuously vented or vented intermittently, depending on the design of the device.

5.3. Applicability and technical limitations

	Transmission	Storage	LNG Terminals	Distribution
Applicability	+	+	+	✖

Table 5 – Applicability of the BAT

Where feasible gas companies make strong efforts to reduce these kinds of emissions. In big installations (e.g. compressor stations) pneumatic devices could be replaced with others operated by compressed air, saving a significant quantity of methane emissions. A rough estimation of the annual save is about 50-200’000 m^3/y for each big plant.

Figure 1 - Air electro-compressor (left) and air tank (right)

In pressure reduction /regulation plant to reduce natural gas pneumatic emissions new criteria could be adopted, such as the use of boilers with electric control in place of heater with pneumatic apparatus, fewer regulating lines but of greater diameter, control valves operated by electric actuator. All these options permit to obtain a significant reduction in natural gas emissions.

Figure 2 - Ball control valve operated by electric actuator (left) and temperature control valves with no emission (right)

Figure 3 - Electric valves instead of gas operated valves

Figure 4 - Electrical actuators

In some cases, where feasible, another option could be to replace high-bleed positioners with low-bleed positioners. A rough estimation of the methane emissions saving of about 7000 m^3/y per device.

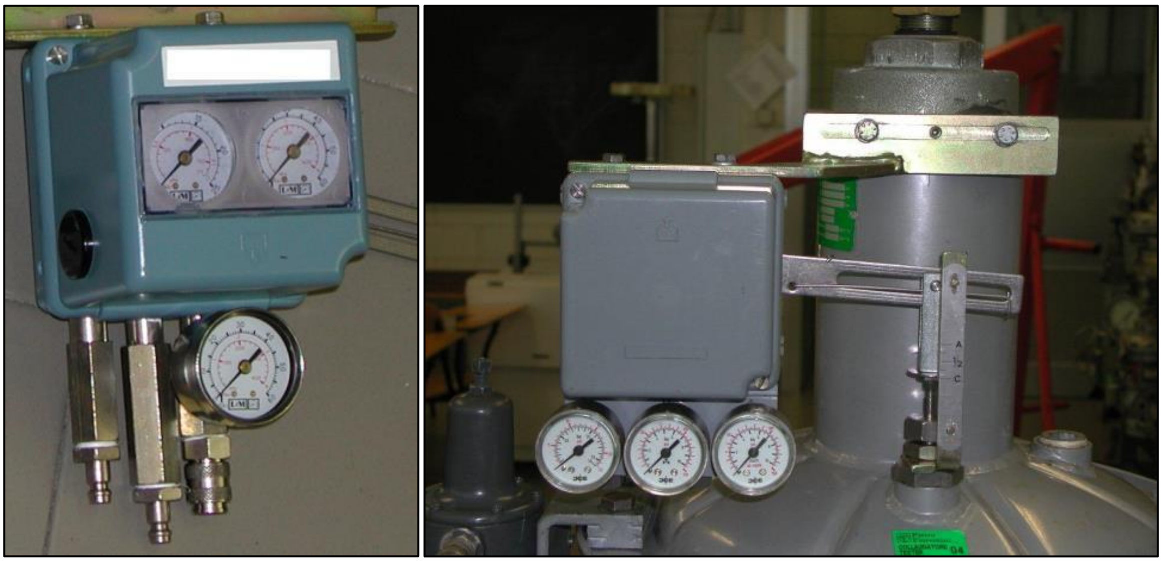

Figure 5 - High-bleed positioner (left) and low-bleed positioner (right)

5.4. Impact on safety and security of supply

To maintain the security of supply on gas infrastructure, pneumatic emission is sometimes unavoidable because gas is the reliable way to ensure continuity of operation (e.g. the security of electricity supply is less than the security of supply of gas).
It is not always possible or acceptable to replace emitting equipment with non-emitting equipment (for example the regulation of the gas installation could be completely dependent on the electrical supply and this could create issues to ensure security of gas supply into the network.

5.5. Economic impact

Below a rough estimation of the cost:

- High-bleed positioners replacement
    - Capital Cost from 1000 to 10'000 € for each device
- To convert pneumatic devices with others operated by compressed air in one compressor stations, considering the engineering update of the plant
    - Capital Cost > 500'000 €

6. BAT 6 – Electrical or pneumatic air starters

6.1. Introduction

Gas turbines are historically used to drive centrifugal compressors of gas transmission and gas storage compressor stations. To be launched and fired the gas turbines are equipped with a starting motor used during their acceleration phase. Some older units (over 20 years) can still be equipped with motors using the high-pressure process gas as an energy. In that specific configuration the high-pressure process gas available in the facility feeds an expansion turbine, used as a launching (starting) motor of the gas turbine. At the exhaust of the expansion turbine the process gas used is vented to the atmosphere, generating an important amount of methane emission. This BAT describes the various solutions that can be used to avoid these emissions.

Figure 1 – Gas turbine with an expansion turbine as starting motor

6.2. Technical description

There are two types of technical solutions:

- It is possible to adapt the expansion turbine feeding system and to replace the process gas supply by a compressed air supply, which can be already available on site. With the interest of minimal modification of the gas turbine on skid equipment.
- It is also possible to replace the gas motor by nowadays state of the art solutions consisting in an electrical motor or a hydraulic motor.

The hydraulic motor system consists in a hydraulic motor fed in high pressure oil (from the gas turbine lubrification system) by a high-pressure lube oil pump.
In the electrical solution, an electric motor is used to launch the gas turbine with potentially the addition of a torque converter or a VFD (Variable Frequency Drive).
The OEM (Original Equipment Manufacturer) of the gas turbines propose as upgrades such modifications.

6.3. Applicability and technical limitations

	Transmission	Storage	LNG Terminals	Distribution
Applicability	✚	✚	✖	✖

Table 6 – Applicability of the BAT

6.3.1. Limitations of the air supply solution

This solution has the advantage to limit the level of modification of the gas turbine of skid equipment, but as a drawback will request to have an important quantity of high pressure air available, this can be challenging and costly (potential necessity to invest in additional air production capabilities) even for the smaller gas turbines.

6.3.2. Electrical or hydraulic motors

Both electrical and hydraulic solutions are corresponding to modern gas turbine state of the art.
The electrical solution can appear to be simpler, but an electric motor will need more available space on the gas turbine skid than a hydraulic motor. In case of a limited available space on the existing gas turbine skid the hydraulic motor solution can be preferred, being possible to install the high pressure oil pump outside of the skid.

6.4. Impact on safety and security of supply

The impact is positive in terms of safety, gas starting motors can lead to safety hazards and are not recommended by modern gas turbine safety standards.

6.5. Economic impact and estimation on methane mitigation costs

The upgrade investment costs are estimated to 300’000€ for an electrical starting motor assuming that sufficient electrical capacities are available on site. The methane emissions saving are estimated to 150 to 350 Nm^3 per start for smaller gas turbines (less than 4MW), gas turbines on European gas network can commonly be started several times a week.

7. BAT 7 – Use of nitrogen to purge LNG pipes

7.1. Introduction

LNG receiving terminals use temporary connections like articulated arms or flexible hoses to empty or fill with LNG different carriers like LNG ships or road tankers. Prior to the disconnection, draining (for the ships), purging and inerting the capacities with nitrogen are good practices for both safety and environmental reasons. As a result the quantities of methane sent to the atmosphere are reduced to an absolute minimum.

7.2. Technical description

LNG receiving terminals can accommodate hundreds of ships per year and receive thousands or even tens of thousands of road tankers per year. Each time the LNG carriers need to be connected either by articulated arms or flexible hoses. On the terminals the facilities are designed and operated to prevent the release of LNG or natural gas to the atmosphere during the connection and disconnection operations. Because gas release could lead to hazardous situations that can threaten safety or environment.
To meet these objectives the receiving terminals are equipped with nitrogen system, the latter being either produced on site or delivered as liquid nitrogen by road or rail. In both case, the liquid comprised in the piping space of the arms or flexible hoses is removed by carrying out a series of purges using pressurized nitrogen to push the liquid.
The purges are usually performed several times. Eventually the concerned section is inserted by nitrogen.
After checking that the methane contain is became extremely low (for example below 2 % by volume) the arms or flexible hoses are disconnected.

7.3. Applicability and technical limitations

	Transmission	Storage	LNG Terminals	Distribution
Applicability	✖	✖	✚	✖

Table 7 – Applicability of the BAT

7.3.1. Limitations

On receiving terminals, there is no limitation about the use of nitrogen to purge and inert the connection facilities meant to fill / empty ships or road tankers.

7.4. Impact on safety and security of supply

7.4.1. Safety

As mentioned above, a disconnection of articulated arms of flexible hoses without the presence of inflammable gas makes the operation safer.
Nevertheless, for these operations to be conducted safely:

- The facilities have to be designed in compliance with the relevant standards (EN/ISO) and the guidelines (SIGTTO…)
- Operational procedures have to be in place specifying what to do and the different responsibilities

- Operational staffs need to be trained and good communication has to be established especially between the ship staff and the terminal staff.

7.4.2. Security of supply

The procedure of purging and inerting requests time and needs to be taken into account in the duration of the slots.

7.5. Economic impact

7.5.1. General

Three elements have to be considered to calculate the economic impact :

- Time and manpower dedicated to the purging and inerting operations
- Supply of nitrogen
- The quantity of natural gas which has not been sent to the atmosphere

The economic impact depends on the type of facilities (diameter, number, etc.) and the local conditions, especially regarding the nitrogen supply.

7.5.2. Estimation on methane mitigation and costs

The purging and inerting procedure can save hundreds or even thousands of Nm3 per years depending on the facilities and the number of connections, with:

- 5 to 10 Nm3 of NG/operation for the marine arms
- A hundred times less operations for the road arms or flexible hoses

8. BAT 8 – LNG truck loading dry coupling connectors

8.1. Introduction

Dry couplings are able to reduce the methane released into the atmosphere during a tank loading operation.

8.2. Technical description

Dry cryogenic couplings (DCC) consist of a tank unit (male unit) or adapter with a spring-loaded poppet and three slots and a hose unit (female unit) or coupler with a valve and three rollers.

- Connecting the couplings: The hose unit is slided easily into the tank unit. Three rollers engage in the three slots. Turning the hose unit clockwise approximately 45° while gently pushing toward the tank unit allows the hose unit to lock and open the valve. It is important when connecting the couplings that there is no moisture between both parts, if there is it should be removed by blowing with air or nitrogen.

- To stop the flow and unlock the units, the procedure is reversed

The dual poppet design shut-off mechanism safely seals liquids and gases behind the valve, eliminating fugitive emissions and the danger of a spill of cryogenic fluids.

Open valve　　　　Close valve

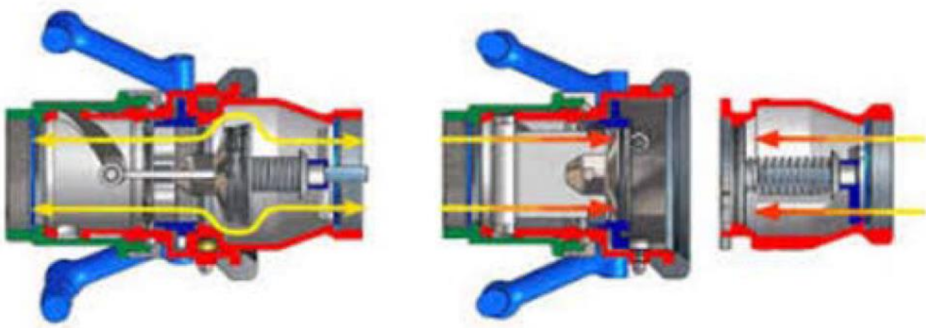

Figure 1 - Valve position

The standard ISO 21593:2019 specifies the design, minimum safety, functional and marking requirements, as well as the interface types and dimensions and testing procedures for dry-disconnect/connect couplings for LNG bunkering systems.

Figure 2 - Tank unit – LNG terminal connections

8.3. Applicability and technical limitations

	Transmission	Storage	LNG Terminals	Distribution
Applicability	✖	✖	✚	✚

Table 8 – Applicability of the BAT

8.3.1. Supplier technical specifications

There are several manufacturers that can provide DCCs in wide range of diameters.

8.4. Impact on safety and security of supply

8.4.1. Safety

The valve has to be made in a material which does not produce sparks and has to comply with EN ISO 21593:2019.

8.4.2. Security of supply

No impact on the security of supply is registered.

8.5. Economic impact

8.5.1. General

The cost of this measure is estimated to be around 30.000 € (each truck loading bay).

8.5.2. Estimation on methane mitigation and costs

It is hard to quantify the amount of methane emissions avoided. It depends on the leakage ratio of the block valves on the LNG and NG lines on each loading bay, the number of daily operations, the tightness of the threaded connection and the number of blanketing cycles after each operation. It can be saved hundreds or even thousands of Nm^3 per year.
DCC prevent leakage of methane during disconnecting and also spillage of LNG.

8.6. Closing remarks

Dry coupling allows to avoid LNG emissions. It is proven to be safe and useful.

9. BAT 9 – Excess flow valves in new service lines

9.1. Introduction

One of the technical options to reduce methane emissions for the DSOs' infrastructure, is the installation of Excess Flow Valves (EFV) into the branch saddle of service lines.

9.2. Technical description

An excess flow valve (EFV) is defined as a device installed in a gas piping system to automatically stop or limit the passage of gas when the gas flow through a device exceeds a predetermined level.
As a safety device, EFVs are designed to automatically shut off the flow of gas when the service line between the gas main and the meter ruptures, thereby mitigating the impact of the rupture, and as a consequence, limiting the amount of methane emission caused by the rupture.

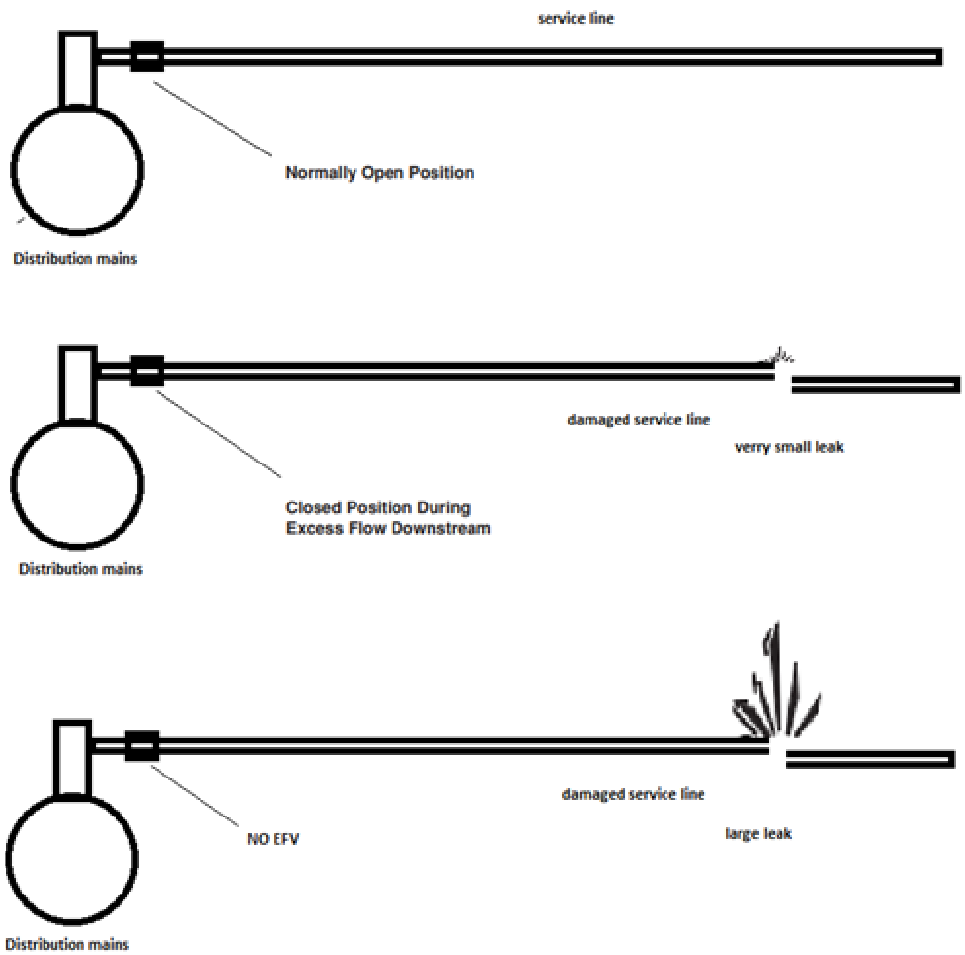

Figure 1 - Application of an EFV (Marcogaz)

An EFV shuts down the gas flow once a certain flow is reached. This flow is typically a factor of around 1.5 times the nominal flow. When third party damage on the service line leads to a large leak, the gas flow is stopped. EFVs come in various forms and sizes but the general working principle is comparable.
The working principle in shown in figure 2. The EFV is in open position as long as the gas flow is below the critical flow. When the gas flow increases, additional force is added to the valve until the point when this force is greater than the opposing force of the spring. When that occurs, the closing valve is pushed into the casing and the gas flow is blocked.

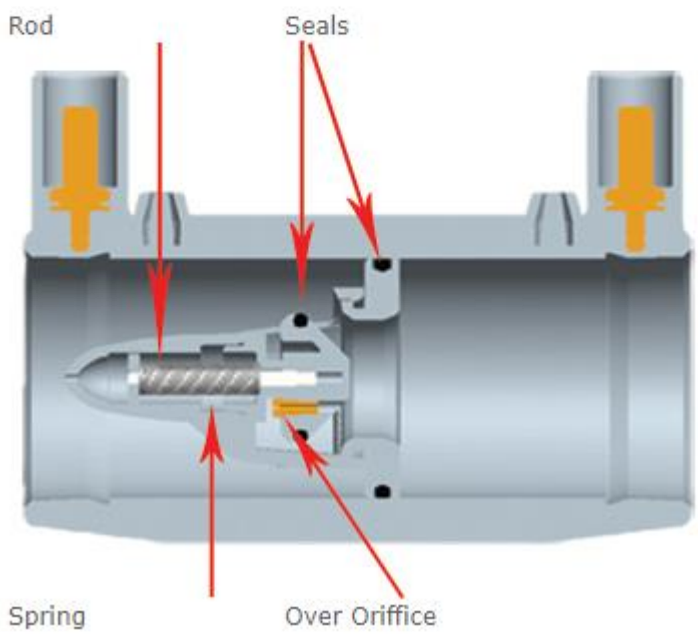

Figure 2 - Working principle of an EFV (Source Plasson)

There are two types of EFV, one that allows bleed by or bypass flow (EFVB) and the other that stops the flow of gas (no bypass) after it is tripped (EFVNB).
The first type (EFVB) allows for bypass flow that is a small predetermined flow through the valve once closed. This bypass flow allows the upstream and downstream pressures to slowly equalize after the leak or rupture has been repaired, allowing the valve to reset automatically.
The second type of valve (EFVNB) does not allow a bypass flow and essentially forms a gas tight seal. This type of valve requires the valve to be reset manually.Both EFVB and EFVNB are considered as mitigation measure for methane emissions.

9.3. Applicability and technical limitations

	Transmission	Storage	LNG Terminals	Distribution
Applicability	✖	✖	✖	✚

Table 9 – Applicability of the BAT

9.3.1. Supplier technical specifications

There are several manufacturers for Excess Flow Valves, providing EFV's in a wide variety of types, diameters and flow ranges.
Diameters vary from 20 to 200 mm, operating pressures range from 0.015 to 5 bar.
Flow ranges are from 9 up to over 1000 m^3/h.

9.3.2. Pressure drop

Installation of the EFV leads to an additional pressure drop in the service line. If the service line is designed close to the minimum requirements, this could lead to the gas being delivered to the customer below the minimum pressure required for the internal gas installation. Except for application in Low Pressure (LP) grids (< 100 mbar), the pressure drop will be low enough and will not lead to any issues. Nevertheless, this risk should always be taken into account before implementing the EFV.

In the case of service lines at MOP[1] equal to or above 1 bar, the experience at DSO's is that the pressure drop caused by EFVs in newly designed service lines is low enough not to require actions, such as an increase of pipe diameter.

9.3.3. Only for large leaks

An EFV will only shut if the pressure drop over the valve is large enough. Therefore, it may not to shut off the flow of gas if the line breaks at the connection of a gas appliance in a residence or in the customer's piping system (interior or exterior) on the customer's side of the meter, nor will they shut off in case of a small leak in a service line or in case of a leak near the end of a very long service line.

9.4. Impact on safety and security of supply

Every additional component in the gas grid is an additional potential source of failure. In the case of an EFV, this failure could be:

- not closing when it was designed to do so (e.g. contamination in the pipelines by dust or sand can cause the EFV's to malfunction) or
- the unintentional closing of the EFV and consequently an interruption of gas supply.

9.4.1. Malfunctioning of the EFV

A few cases have been reported where the EFV did not close in spite of a severe rupture of the service line, mainly due to the presence of debris in the network.
Nevertheless, the incident rate per km for service lines is generally much higher than the incident rate for distribution mains, so, the malfunctioning causes no objection to install EFV's in new or renovated service lines where technically possible (see pressure drop).

9.4.2. Unintentional closing of the EFV

There is no knowledge of a significant number of unintended closures of EFV's.

9.4.3. Secuirty of supply

When dealing with very sensitive commercial and particular industrial customers, requiring continuity of supply, a dedicated risk analysis is necessary in order to evaluate which is the optimal solution.

9.5. Economic impact and methane emissions avoided with the BAT

9.5.1. Economic impact

As for all methane mitigation measures, it is recommended to investigate the costs per saved amount of methane before the decision to implement is made.
The installation of EFV's will lead to extra costs. This is particularly the case when retro-fitting existing service lines with an EFV, which may be very expensive.

9.5.2. Estimation on methane mitigation and costs

[1] MOP: Maximum Operating Pressure (EN 12186)

The average gas loss due to the rupture of a service line in an Medium Pressure (MP) grid at 3.2 bar is estimated at about 190 m^3_N/h. Consequently, if the leakage is fixed within 2 hours (as usually required by most of the National Regulators), we would have an average loss of 380 m^3_N for a regular polyethylene (PE) service line with MOP of 4 bar.
For LP service lines, the methane emission mitigation is negligible and generally technically impossible.

Note: Even with the presence of an EFV, a smaller rupture of a service line results to an equivalent methane emission because EFV are only designed to close when the gas rate $V_{maximum}$ exceeds 1.5 times the design rate V_{normal} of the EFV. It is difficult to calculate this loss because of the lack of sufficient data (duration of the leakage and equivalent diameter of the hole).

In case an EFV closes unintentionally, the DSO has to intervene to reopen the valve. However, experience indicates that the cost of reopening EFVs in the few cases of unintentional shut down, does not outweigh the potential loss of lives, homes, or businesses and the subsequent methane emission due to incidents.

9.6. Closing remarks

While EFV's have proven to be a useful and applicable safety device, they also allow efficient mitigation of methane emissions caused by third party damage in DSO service lines, when technically possible.
They are generally applicable in MP grids, in particular on new PE service lines of limited length.