METHANE GUIDING PRINCIPLES

REDUCING METHANE EMISSIONS

Best Practice Guide: Reducing methane emissions in transmission, storage, LNG terminals and distribution

January 2024

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Disclaimer

Glossary

Blowdown
Removing natural gas from, or de-pressurizing, a pressurized pipeline or vessel. The gas can be released into the atmosphere directly or through control systems.

Centrifugal compressor
Equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seal emissions
Natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing emissions
Emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Customers' meters
The final delivery point from the distribution service line tracking the gas volume to the industrial, commercial or residential customer.

Distribution
The downstream part of the natural gas supply chain which contains mains, service lines, and customers' meters. This segment includes above and below ground piping and other equipment necessary to supply gas to customers.

Distribution mains
Pipelines, in distribution systems, that move gas from inlet gate stations to customers' service lines.

Distribution services
Pipelines, in distribution systems, that move gas from distribution mains to customers' meters.

Hot tap
A method of making a new connection to an existing pipeline or pressure vessel without the need to interrupt the use nor empty the vessel or pipeline.

Inventory
A record of all known sources of emissions and emission rates. An inventory provides a summary of emissions over a given period of time.

Leaks
Unintentional emissions from pressurized equipment used in the natural gas industry. Leaks are usually caused by imperfections in or ordinary wear and tear of sealed joints, such as flange gaskets, screwed connections, valve-stem packing, or by poorly seated valves. Leaks can also come from the wall of a pressurized vessel or pipeline, as a result of corrosion or damage. Leaks are also sometimes called 'fugitive emissions'.

LNG
Liquefied natural gas.

Methane slip
Where some of the natural gas (primarily comprised of methane) that is used as fuel does not burn completely and so some methane is released to the atmosphere. This is sometimes called "unburned methane" or "combustion exhaust methane emissions".

Natural gas compressor
A machine used for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

Pump down
A process where a compressor is used to remove pressurized natural gas from a pipeline or vessel, by pumping it into another pressurized natural gas system.

Purging
A process where air is removed from equipment or pipelines that have been open to the atmosphere, before returning them to service.

Reciprocating compressor
Equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Service lines
The smaller pipes that move gas from distribution mains to individual customers such as residences and businesses.

scf
Standard cubic feet. In Imperial and U.S. customary units, standard cubic foot (scf) is defined as one cubic foot of gas at a temperature of 60°F or 288.7 K or 15.56°C and a pressure of 14.67 pounds per square inch or 1 atmosphere (atm) or 101.325 kilopascals (kPa).

sm^3 (also scm)
Standard cubic meter. In the context of the SI system, it is defined as the quantity of gas contained in a cubic meter at a temperature of 288 K or 15°C and a pressure of 1 atm or 101.325 kPa.

Stopple
A temporary seal, plug or stopper. They are used to repair pipelines, or to isolate (cut off) a section of pipeline where there is no existing shutoff valve.

Storage
The part of the natural gas supply chain that stores natural gas to be used when there is a high demand. Natural gas storage facilities include various types of underground natural gas storage (depleted oil and gas reservoirs, salt formations, water aquifers), as well as above-ground facilities such as liquefied natural gas (LNG) storage.

Supply (Value) Chain
The asset network of equipment and pipelines that allows produced natural gas to reach customers. The supply chain includes production, gathering, gas processing, transmission, storage, and distribution.

Third-party damage
Any accidental damage caused to a natural gas pipeline as a result of activities not associated with the pipeline. Examples are excavations or other private or public works not associated with the natural gas supply (for example, work on water mains). This is different from first-party and second-party damage, which is caused by employees of the pipeline or their direct subcontractors.

Transmission
The midstream part of the natural gas supply chain that contains compressors and large pressurized pipelines that move natural gas from production fields, from entry points to the system (such as international connection points and LNG regassification terminals), or from natural gas processing facilities to industrial customers, distribution systems or storage facilities.

UGS
Underground Natural Gas Storage

Venting
Releasing the gas arising from a process or activity straight into the atmosphere.

Summary

Methane emissions in the natural gas supply chain arise from venting, fugitive emissions, and incomplete combustion (methane slip). Good practice for reducing or eliminating emissions from these sources are described in separate guides developed by the signatories to the Methane Guiding Principles (MGP). However, the technical and economic characteristics of these best practices may vary depending on the characteristics of the segment of the supply chain in which the practice is applied.

This guide describes practices for reducing methane emissions (mitigation measures) from the

natural gas transmission, storage, LNG terminals and distribution segments of the supply chain. This guide does not explore emission mitigation measures for emissions from: downstream of the customer meter, nor to LNG liquefaction and LNG transportation emissions.

Best practice for reducing emissions in transmission, storage, LNG terminals and distribution follows the process described below.

Best practice for reducing methane emissions in transmission, storage, LNG terminals and distribution

Keep an accurate inventory of emissions from all sources

Prevent emissions whenever possible

Reduce emissions that cannot be prevented

Identify and repair equipment that is not working properly

Track emissions and mitigation activities

Because of the large number of mitigation measures that can be used in transmission, storage, LNG terminals and distribution, some practices described in detail in other guides are briefly summarized in this guide, with links to the original guides. Mitigation measures that are unique to transmission, storage, LNG terminals and distribution, or that have different technical or economic characteristics than measures in other parts of the natural gas supply chain, are described in more detail in case studies towards the end of this guide.

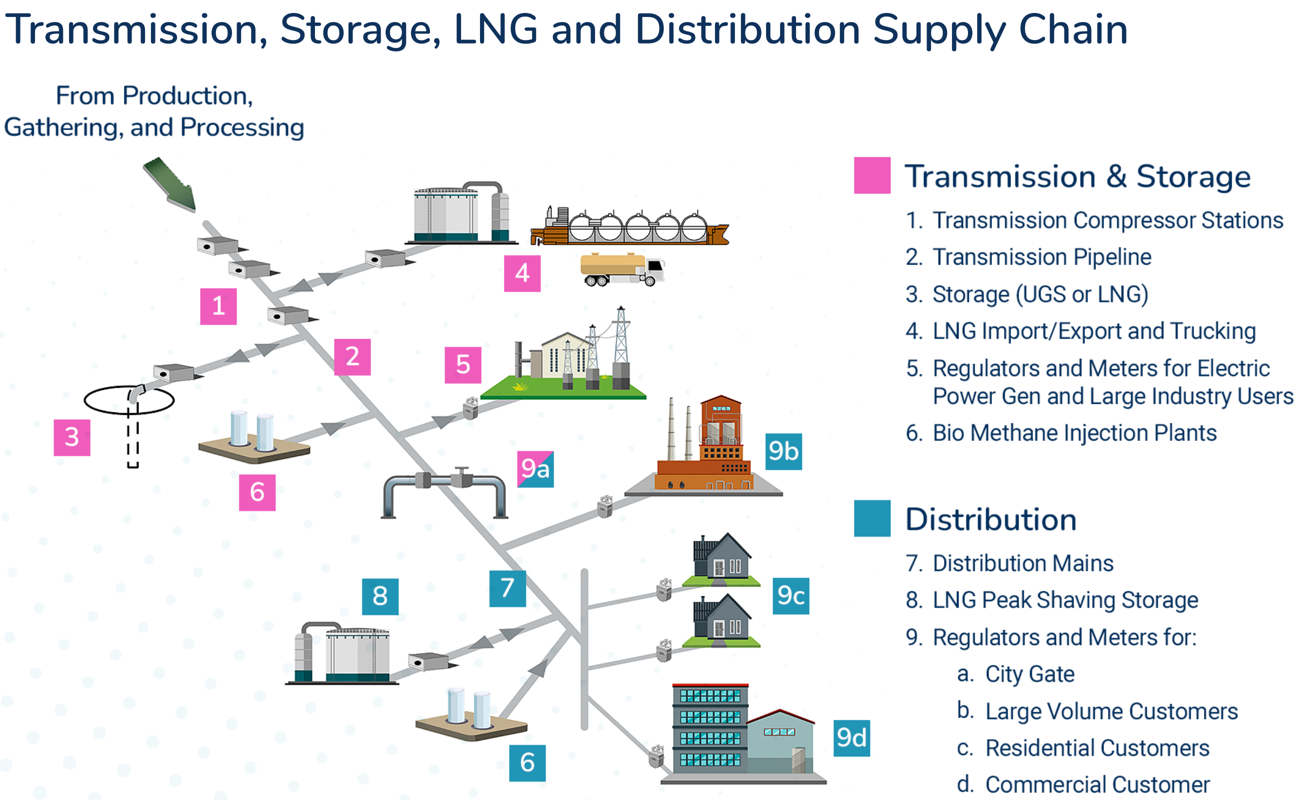
Introduction

The transmission, storage, LNG terminals and distribution sectors of the natural gas supply chain

Natural gas supply chains extend from wellheads to customers in homes, industry, and businesses. Figure 1 shows the portions of the natural gas supply chain that are the focus of this guide. This guide does not explore mitigation options for emissions that occur from the portions of the natural gas supply chain that are outside of the boundaries shown in Figure 1. In addition, this guide does not explore mitigation options for emissions from the following individual components of the natural gas supply chain that fall within the boundaries shown in Figure 1.

- Sources associated with transportation of LNG via ship or vehicle.
- Sources downstream of the distribution customer delivery meter

Figure 1: Segments and boundaries of the natural gas supply chain covered by this guide



Methane emission sources in the transmission, storage, LNG terminals and distribution segments of the natural gas supply chain arise from various sources including venting, fugitive emissions and incomplete combustion (methane slip). According to the Annual European Union (EU) Greenhouse Gas Inventory 1990-2021 and inventory report 2023, methane emissions accounted for 13% of total EU GHG emissions in 2021 and these emissions decreased by 37% since 1990 while the natural gas supply chain's overall contribution to the total methane emissions in the EU was less than 5%.[1] Of this <5% amount, 49% was comprised of fugitives, venting, and flaring methane emissions.[1] Other recent studies suggest that transmission and storage were responsible for approximately 14% of methane emissions from natural gas supply chains in the US, and 23% of emissions of natural gas supply chains in Europe.[2] Information for the net contribution from LNG operations was imited.

Like other segments of the natural gas supply chain, the range in emission rates across sources in transmission, storage and distribution are highly skewed, with small sub-populations of high-emitting sources being responsible for the majority of emissions from a particular site or source type.[3]

Other guides, prepared by the signatories to the Methane Guiding Principles, describe in detail the best practices for reducing methane emissions from venting, fugitive emissions and incomplete combustion.[4] However, reducing emissions from these sources in transmission, storage, LNG terminals and distribution may require different mitigation measures. For example, leaks from buried pipelines can be more difficult to identify and quantify than leaks from above-ground sources, and the cost of accessing a potential leak makes the repair cost higher than for similar above-ground leaks.

Where mitigation measures described in expanded detail in the other MGP guides also apply to similar types of emission sources in transmission, storage, LNG terminals and distribution, this guide only briefly summarizes those measures and provides linkages to the other applicable guides that include greater detail.

Unlike the other MGP guides which focus on individual emission sources and specific mitigation measures to reduce the emissions from those sources, this guide has a broader focus and coverage. This guide encompasses multiple natural gas supply chain segments, multiple emission sources that occur within those segments, and multiple mitigation measures to reduce emissions of the sources within those segments. With this broader coverage, this guide can be used as the starting point for internal and external stakeholders that are seeking to gain a better understanding of this portion of the natural gas supply chain. This updated version of the guide includes a proposed educational resource pathway whereby this guide can be used as an internal and external stakeholder resource tool.

Methane Emission Sources and Mitigation Measures

Methane emission sources and mitigation measures for natural gas transmission, storage, LNG terminals, and distribution are summarized in Tables 1 to 3 as follows:

- **Table 1:** Transmission and storage: facility or equipment type, emission sources, mitigation measures, and other MGP guide(s) with greater detail on the mitigation measure.
- **Table 2:** LNG terminals: facility or equipment type, emission sources, mitigation measures, and other MGP guide(s) with greater detail on the mitigation measure.
- **Table 3:** Distribution: facility or equipment type, emission sources, mitigation measures, and other MGP guide(s) with greater detail on the mitigation measure.

Many of the mitigation measures listed in Tables 1 to 3 are already described in other Methane Guiding Principles (MGP) guides.[4] In this guide, those guides are referred to in the final column of the table. If a measure is unique to transmission, storage, LNG terminals and distribution, or are applied to transmission, storage, LNG terminals and distribution in a specialized way, the table describes which case study to refer to in the next section of this guide for more detail.

Table 1: Methane emission sources and mitigation measures in transmission and storage

Methane Emission Source	Methane Emissions Type	Facility	Emitting Equipment or Emission Event	Mitigation Measures	Other MGP Guide(s) and/ or Case Study References
Compressors	Venting	Transmission (compressor stations) Storage (compressor stations)	Centrifugal-compressor seals	1. Convert wet seals to dry seals 2. Minimize emissions or re-route gas at lower pressure to a recovery unit, flare or low-pressure inlet 3. Capture of compressor dry gas seal for sending to reinjection or recovery units or use as fuel	MGP Venting Guide Case Study 13
			Reciprocating-compressor rod packings	1. Regular replacement of rod packing (ideally based on measured emission rates) 2. Capture and Re-route vented gas to reinjection or recovery units or use as fuel 3. Re-route vents to flare	MGP Venting Guide
			Compressor gas starters	1. Switch to electric motor starters and avoid gas starters in the design phase if possible 2. Minimize starts if possible 3. Capture and Re-route vented gas to reinjection or recovery units (preferred) or to flare (if allowed) or use as fuel	MGP Venting Guide, Pneumatics Guide, MGP Engineering Design and Construction Guide

Table 1: Methane emission sources and mitigation measures in transmission and storage

Methane Emission Source	Methane Emissions Type	Facility	Emitting Equipment or Emission Event	Mitigation Measures	Other MGP Guide(s) and/ or Case Study References
Gas driven pneumatic pumps and controllers	Venting	Transmission (compressor stations and pipelines) Storage (compressor stations, storage pipelines, and wellheads)	Pumps (for example, odorant injection)	1. Use electrically driven chemical pumps	MGP Pneumatics Guide
			Gas-powered pneumatic controllers	1. Avoid during the design phase 2. Eliminate high-bleed devices 3. Switch to compressed air, electric or mechanically driven devices, or very low emitting devices	MGP Pneumatics Guide
Glycol dehydration system	Venting	Transmission (compressor stations) Storage (compressor stations)	Dehydrators	1. Switch to low- or no-emission dehydration (such as low-temperature separation) 2. Optimize glycol circulation and flash tanks 3. Pipe the dehydrator flash gas to 4. vapor-recovery units or use as fuel 5. Route regenerator vent to the flare, if possible	MGP Venting Guide Case Study 6
Pipeline gas releases	Venting	Transmission Pipelines Storage Pipelines	Pipeline repairs Works and maintenance Depressurize and blowdown Purging and commissioning	1. Lower the pressure in the pipeline by allowing consumer drawdown 2. Re-route the gas to an existing network with lower pressure or use it as fuel 3. Recompression 4. Mobile compressor stations 5. Flaring, if allowed and planned. (but not always possible during an emergency) 6. Install plugging equipment to shorten the segment of pipeline involved; use isolation valves to minimize impact 7. Make new connections and repair with a hot tap for small and large diameter pipe 8. Reroute the natural gas to a duct burner, thermal oxidizer or flares if possible 9. Use in-line inspection (ILI), or 'smart pig' technologies instead of hydrotests 10. Pipeline blowdown mitigation with portable thermal oxidizer (incineration)	MGP Operational Repairs Guide, MGP Flaring Guide, and Venting Guide Case Study 1 Case Study 2 Case Study 3 Case Study 4 Case Study 12 Case Study 14

Table 1: Methane emission sources and mitigation measures in transmission and storage

Methane Emission Source	Methane Emissions Type	Facility	Emitting Equipment or Emission Event	Mitigation Measures	Other MGP Guide(s) and/or Case Study References
Equipment Components	Fugitive emissions and venting	Storage Pipelines and Wellheads	Aboveground wellhead equipment, downhole well components, valve and meter stations	1. Monitor the integrity of the well 2. Leak detection and repair (LDAR) programs and directed inspection and maintenance (DI&M) programs	MGP Leaks Guide and Operational Repairs Guide, MGP Identification, Detection, Measurement and Quantification Guide Case Study 5
Equipment Components	Fugitive emissions	Transmission (compressor stations and pipelines) Storage (compressor stations)	Compressor station equipment components, station piping, transmission pipelines, valve and meter stations along pipelines	3. Leak detection and repair (LDAR) programs and directed inspection and maintenance (DI&M) programs 4. Replace leak-prone equipment or pipes.	MGP Equipment Leaks Guide; MGP Operational Repairs Guide, MGP Identification, Detection, Measurement and Quantification Guide
Natural-gas fired combustion sources	Incomplete Combustion (methane slip)	Transmission (compressor stations) Storage (compressor stations)	Reciprocating engines, gas turbines, heaters and boilers	1. Install automated air/fuel ratio controls 2. Minimize the number of start-ups 3. Increase the combustion efficiency of natural gas-powered engines, turbines, heaters, and boilers	MGP Energy Use Guide
Flares	Incomplete Combustion (methane slip)	Transmission (compressor stations and pipelines) Storage (compressor stations and pipelines)	Flares	1. Minimize flaring by using the gas 2. Improve combustion efficiency by changing flare tips or installing flare ignition systems 3. Flare pilot pressure regulation 4. Use nitrogen instead of natural gas if a flare system is continuously purged	MGP Flaring Guide MGP Engineering Design and Construction Guide
All in transmission and storage	All in transmission and storage	All in transmission and storage	All in transmission and storage	1. Achieve continual improvement in methane management	MGP continual improvement

Table 2: Methane emission sources and mitigation measures at LNG Terminals

Methane Emission Source	Methane Emissions Type	Facility	Emitting Equipment or Emission Event	Mitigation Measures	Other MGP Guide(s) and/ or Case Study References
Compressors	Venting	LNG Terminals (liquefaction, regasification, and storage)	Centrifugal-compressor seals	1. Convert wet seals to dry seals 2. Minimize emissions or re-route gas at lower pressure to a recovery unit, flare or low-pressure inlet 3. Install seal oil vent gas recovery (SOVRG) systems	MGP Venting Guide Case Study 11
			Reciprocating-compressor rod packings	1. Regular replacement of rod packing (ideally based on measured emission rates) 2. Re-route vents to recovery units or use as fuel 3. Re-route vents to flare	MGP Venting Guide
			Compressor gas starters	1. Switch to electric motor starters and avoid gas starters in the design phase if possible 2. Minimize starts if possible 3. Route to gas recovery (preferred) or to flare (if allowed)	MGP Venting Guide, Pneumatics Guide, MGP Engineering Design and Construction Guide
Gas driven pneumatic pumps and controllers	Venting	LNG Terminals (liquefaction, regasification, and storage)	Pumps (for example, odorant injection)	1. Use electrically driven chemical pumps	MGP Pneumatics Guide
			Gas-powered pneumatic controllers	1. Avoid during the design phase 2. Eliminate high-bleed devices 3. Switch to compressed air, electric or mechanically driven devices, or very low emitting devices	MGP Pneumatics Guide
Truck loading and unloading	Venting	LNG Terminals (liquefaction, regasification and storage)	LNG truck loading	1. Install dry disconnect couplings 2. Use of nitrogen to purge the LNG hoses 3. Install a system to exchange vapors between tanks and tank vehicles	Case Study 7 MGP Engineering Design and Construction Guide
Equipment Components	Fugitive emissions	LNG Terminals (liquefaction, regasification and storage)	LNG Terminals (equipment components, station piping, and meter stations)	1. Leak detection and repair (LDAR) programs and directed inspection and maintenance (DI&M) programs 2. Replace leak-prone equipment or pipes.	MGP Equipment Leaks Guide; MGP Operational Repairs Guide, MGP Identification, Detection, Measurement and Quantification Guide

Table 2: Methane emission sources and mitigation measures at LNG Terminals

Methane Emission Source	Methane Emissions Type	Facility	Emitting Equipment or Emission Event	Mitigation Measures	Other MGP Guide(s) and/ or Case Study References
Gas releases	Venting and flaring	LNG Terminals (liquefaction, regasification and storage)	Boil-off gas (BOG)	1. Boil-off gas recovery (for example, install high-pressure BOG compressors to inject non-recoverable boil-off gas into the gas network)	See European Standard[5] EN 1473. MGP Engineering Design and Construction Guide, and Venting Guide
Natural-gas fired combustion sources	Incomplete Combustion (methane slip)	LNG Terminals (liquefaction, regasification and storage)	Reciprocating engines, gas turbines, heaters and boilers	2. Install automated air/fuel ratio controls 3. Minimize the number of start-ups 4. Increase the combustion efficiency of natural gas-powered engines, turbines, heaters, and boilers	MGP Energy Use Guide
Flares	Incomplete Combustion (methane slip)	LNG Terminals (liquefaction, regasification and storage)	Flares	1. Minimize flaring by using the gas 2. Improve combustion efficiency by changing flare tips or installing flare ignition systems 3. Flare pilot pressure regulation 4. Use nitrogen instead of natural gas if a flare system is continuously purged	MGP Flaring Guide MGP Engineering Design and Construction Guide
All in LNG Terminals	All in LNG Terminals	All in LNG Terminals	All in LNG Terminals	1. Achieve continual improvement in methane management	MGP continual improvement

Table 3: Methane emission sources and mitigation measures in distribution

Methane Emission Source	Methane Emissions Type	Facility	Emitting Equipment or Emission Event	Mitigation Measures	Other MGP Guide(s) and/ or Case Study References
Pipeline gas releases	Venting	Distribution Pipelines	Pipeline repairs Works and maintenance Depressurize and blowdown Purging and commissioning	1. Lower the pressure in the pipeline by allowing consumer drawdown 2. Re-route the gas to an existing network with lower pressure or use it as fuel 3. Recompression 4. Mobile compressor stations 5. Flaring, if allowed and planned. (but not always possible during an emergency) 6. Install plugging equipment to shorten the segment of pipeline involved; use isolation valves to minimize impact 7. Make new connections and repair with a hot tap 8. Reroute the natural gas to a duct burner, thermal oxidizer or flares if possible 9. Use in-line inspection (ILI), or 'smart pig' technologies instead of hydrotests	MGP Operational Repairs Guide, MGP Flaring Guide, and Venting Guide
Gas purging	Venting	Distribution	Commissioning	1. Vacuum commissioning in distribution	Case Study 8
Pipeline gas releases	Venting	Distribution	Third-party damage and resulting gas release	1. Programs and policies to avoid third-party damage, installing excess flow valves in service lines	Case Study 9 Case Study 10
Equipment Components	Fugitive emissions	Distribution	Distribution system components, distribution pipelines, valve and meter stations, customer meters, odorizer stations	1. Leak detection and repair (LDAR) programs and directed inspection and maintenance (DI&M) programs 2. Replace leak-prone equipment or pipes particularly the replacement of cast iron pipes.	MGP Equipment Leaks Guide; MGP Operational Repairs Guide, MGP Identification, Detection, Measurement and Quantification Guide

Table 3: Methane emission sources and mitigation measures in distribution

Methane Emission Source	Methane Emissions Type	Facility	Emitting Equipment or Emission Event	Mitigation Measures	Other MGP Guide(s) and/ or Case Study References
Natural-gas fired combustion sources	Incomplete Combustion (methane slip)	Distribution	Reciprocating engines, gas turbines, heaters and boilers	1. Install automated air/fuel ratio controls 2. Minimize the number of start-ups 3. Increase the combustion efficiency of natural gas-powered engines, turbines, heaters, and boilers	MGP Energy Use Guide
Flares	Incomplete Combustion (methane slip)	Distribution	Flares	1. Minimize flaring by using the gas 2. Improve combustion efficiency by changing flare tips or installing flare ignition systems 3. Flare pilot pressure regulation 4. Use nitrogen instead of natural gas if a flare system is continuously purged	MGP Flaring Guide MGP Engineering Design and Construction Guide
All in distribution	All in distribution	All in distribution	All in distribution	5. Achieve continual improvement in methane management	MGP continual improvement

MGP Guide Cross-References and Educational Pathway

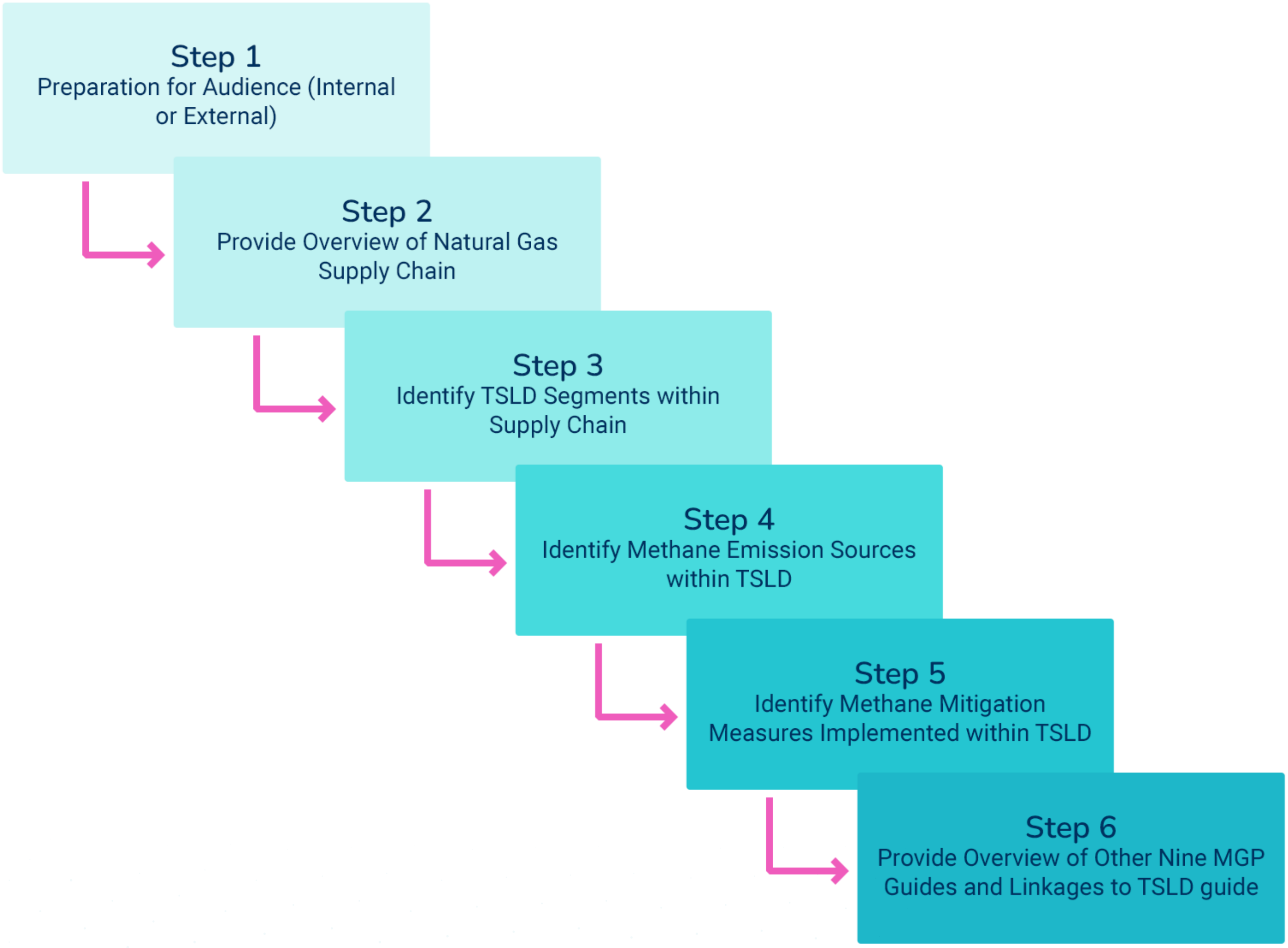
This MGP guide developed for the transmission, storage, LNG, and distribution (TSLD) segments of the natural gas supply chain is unique from the other MGP guides with its broader focus and coverage of multiple emission sources and multiple mitigation measures associated specifically with these segments of the supply chain. This guide is intended to complement the other MGP guides with expanded coverage of TSLD whose primary function is to provide the facilities, equipment, and pipelines needed to transport natural gas to the end use customer. This critical infrastructure allows natural gas to be transported from its points of origin that are scattered widely in regional onshore and offshore production fields and basins spread across the globe. Unlike the hundreds of scattered regional production areas, the TSLD segments of the natural gas supply chain blanket the globe and operate in nearly all countries and continents around the world and these segments are interconnected primarily through pipelines, shipping, and other critical facilities. All of these systems can generate methane emissions so it becomes critical that methane mitigation measures be implemented within these system to reduce or eliminate those emissions due to the global geographic coverage of these systems.

As part of an effort to help educate internal and external stakeholders about the sources of methane emissions and the extensive efforts to mitigate these emissions by the MGP signatory organizations and companies that operate within these segments of the natural gas supply chain, this section of the guide has been included as a starting point for an educational pathway. Table 4 is a summary of cross-references to the other MGP best practices that are contained within this TSLD guide and Figure 2 shows a simple educational pathway diagram that outlines a step by step process to present and educate internal and external stakeholders about the natural gas supply chain, TSLD segments, methane emission sources within TSLD, mitigation measures implemented within TSLD and how this TSLD guide is linked to the other nine (9) MGP guides.

Table 4: **Summary of Cross-References to Other MGP Guides**

Location in TSLD Guide where other MGP Guide(s) are referenced	MGP Guide(s) Referenced (see referenced guide for more information)
Compressors and Flares sources in Tables 1 to 3 of TSLD Guide	Engineering Design and Construction Guide
Pipeline Gas Releases and Flares sources in Tables 1 to 3 of TSLD Guide	Flaring Guide
Natural gas-fired combustion sources in Tables 1 to 3 of TSLD guide	Energy Use Guide
Equipment Component Leak sources in Tables 1 to 3 of TSLD guide	Equipment Leaks Guide
Compressors, Glycol Dehydration Systems, and Gas Release sources in Table 1 to 3 of TSLD guide	Venting Guide
Compressors and Gas-Driven Pneumatic Pumps and Controller sources in Table 1 and 2 of TSLD guide	Pneumatics Guide
Pipeline Gas Releases and Equipment Component sources in Table 1 to 3 of TSLD guide	Operational Repairs Guide
Equipment Component Leak sources in Tables 1 to 3 of TSLD guide	Identification, Detection, Measurement and Quantification Guide
All sources listed in Tables 1 to 3 of TSLD guide	Continual Improvement Guide

Figure 2: MGP Best Practice Guides – Educational Pathway Basic Diagram



Case studies

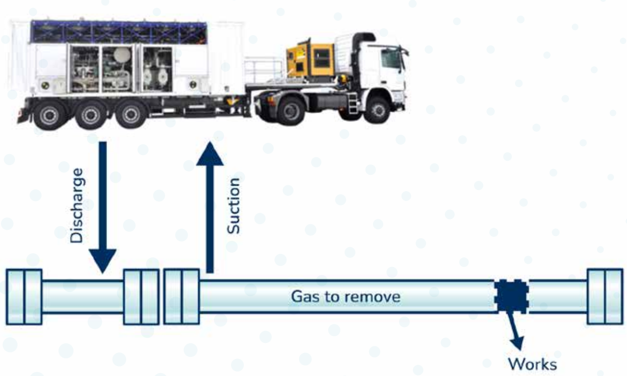
The following case studies describe mitigation measures for large compressor stations; large-diameter, buried, high-pressure pipelines, natural gas storage facilities, LNG regasification terminals, city-gate meter and regulation stations, buried mains (pipelines), service lines, and customer meters.

Case study 1:	Pumping down pipelines with portable compressors before maintenance (transmission)
Case study 2:	Recovering blowdown gas at compressor stations using permanent compressors (transmission and underground storage)
Case study 3:	Flaring instead of venting for maintenance (transmission)
Case study 4:	Hot tapping for pipeline connections (transmission)
Case study 5:	Monitoring underground storage facilities (underground storage)
Case study 6:	Minimizing emissions from dehydrators by using vapor compression and low-temperature separation to remove water (underground storage)
Case study 7:	Minimizing emissions at LNG terminals and LNG truck-loading systems (LNG terminals)
Case study 8:	Commissioning with vacuum pumps (distribution)
Case study 9:	Avoiding emissions caused by third-party damage (distribution)
Case study 10:	Installing excess-flow valves in service lines (distribution)
Case study 11:	Installation of seal oil vent gas recovery (SOVRG) systems on compressors (LNG Terminals)
Case study 12:	Methane Destruction for Pipeline Blowdowns (Portable Incineration) (transmission)
Case study 13:	Capturing and reinjecting compressor dry gas seal methane vents (transmission and underground storage)
Case study 14:	Large Diameter Hot Tapping (transmission)

Case study 1: Pumping down pipelines with portable compressors before maintenance (transmission)

Case study: Large transmission pipelines can pump down, using portable compressors, to lower the pressure in the pipeline pressure before maintenance work. Many companies use this technique.

Description of measures: When maintenance is needed on sections of pipeline, operators block the smallest possible section of the pipeline and depressurize it by venting natural gas to the atmosphere. For a high-pressure large-diameter pipeline, the volume of gas vented may be significant. For example, for each km of a 48” pipeline at 60 bar, 78.000 cubic meters (2,754,544 cubic feet) of gas is vented. Where reasonably possible, pipeline operators can lower gas pressure by blocking a section of the affected pipeline and allowing customers to withdraw gas before venting. For maintenance activities in high-pressure large-diameter pipelines, operators can also reduce venting by using a mobile compressor to remove gas from the section of pipeline to be vented and recompresses it into a nearby section. This is known as the recompression method.



Result: Some portable compressors can pull the line pressure down to 0 bar, reducing the emissions vented by very close to 100%. In 2018, Teréga used the recompression method four times and saved 57,000 sm^3 (2,013,000 scf) of natural gas that would otherwise have been released into the atmosphere. In 2018, Snam used thirteen interventions with mobile compressors, saving 5,360,000 sm^3 (189,286,614 scf) of gas. In 2019, Snam saved 3,380,000 sm^3 (119,363,573 scf) of gas using mobile compressors (eight interventions). GRTgaz uses a combination of three techniques – lowering pipeline pressure through gas consumption, using a mobile compressor, and occasionally, if is too costly in time and energy to recompress the remaining small amount of gas in the pipeline, by flaring. In 2018 and 2019, GRTgaz saved 90% of the gas that would otherwise have been vented, which represents eight million sm^3 (283 million scf) in 2018 and five million sm^3 (177 million scf) in 2019, with 40% of the reduction due to consumption, 45% due to recompression and 5% due to flaring.

Costs: The costs of recompressing gas with a mobile compressor depends on the volume of gas recompressed and the duration of the process. An average cost for using one compressor is reported to be about €70,000. As this process takes time, often several days, it is not suitable for every situation.

Learnings: Using pump down to lower pressure in a pipeline before carrying out maintenance and repairs is an effective way to reduce emissions.

Source: Information provided by Snam, Teréga and GRTgaz.

Case study 2: Recovering blowdown gas at compressor stations using permanent compressors (transmission and underground storage)

Case study: Snam operates a large network of pipelines, including storage facilities. They have introduced a practice which reduces venting for maintenance by using a permanent compressor to deliver gas that might otherwise be vented into a high-pressure system.

Description of measures: When compressors or pipelines in compressor stations are taken out of service for operational or maintenance purposes, gas is depressurized by venting. This emission can be avoided by instead directing the gas to a connected or nearby low-pressure system, or by using an electric-powered compressor to reroute the gas.

Result: Where reasonably possible, Snam installs electric-powered compressors in compressor stations to reroute the majority of gas that might otherwise be vented during blowdown to a temporary storage tank in a high-pressure grid. This reduces venting to a few bars of gas pressure. The reduction in vented gas is about 90% for each intervention. In 2018, the volume of natural gas saved by avoiding venting was about 260.000 m^3 (9,181,813 scf), and in 2019 the gas saved was about 229.000 m^3 (8,087,058 scf) The costs and volume of gas saved depend on the operating conditions (typical gas saved is about 30-50.000 m^3 (1,059,440 - 1,765,733 scf) per year per installation).

Costs: Up to about two million euro.

Learnings: This is an effective way to reduce emissions. However, the cost is high, and this measure is mainly approved for environmental reasons, rather than for the cost of the gas saved. Reductions in methane emissions are site specific and depend on the operating pressure of the compressors or pipelines that are blown down. The suitability of this measure could be limited due to the area needed for the compressor installation and the cost, which could be significant compared against the value of the natural gas saved.

Source: Information provided by Snam.

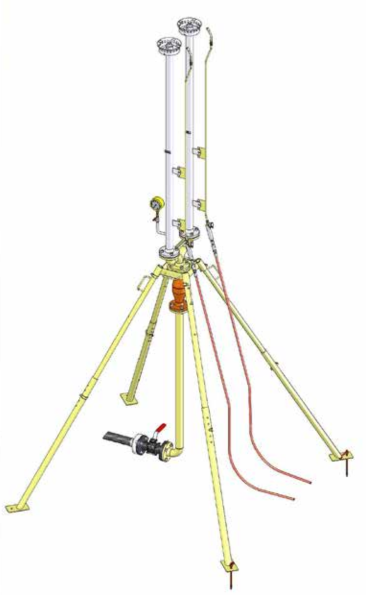
Case study 3:
Flaring instead of venting for maintenance (transmission)

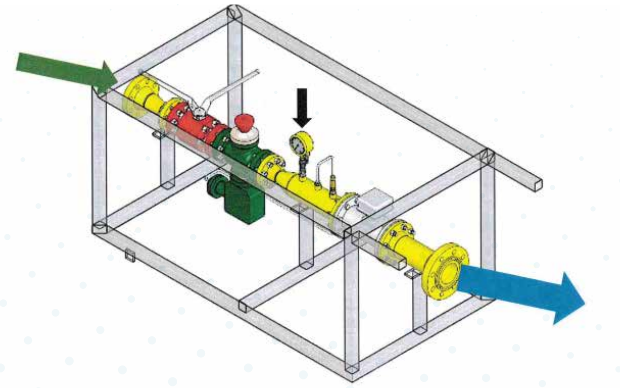
Case study: Teréga flaring best practice

Description of measures: Teréga, a company that operates a transmission system, regularly performs work which requires gas to be vented from pipelines. If gas cannot be moved into another pressurized system, or there is gas left in a pipeline after a recompression, flaring reduces the greenhouse gas impact of the vented gas by converting methane to carbon dioxide.

Teréga has performed several tests to gain experience in flaring. Flaring is noisy and produces a flame several meters high, so it could only be used for small volumes of gas over a short period of time, usually less than two hours.

The mobile flaring system is made up of flexible pipes to connect to the gas network, a pressure reduction line (which expands gas to 8 bar and allows the flaring of 2,800 sm^3 (98,881 scf) of gas per hour), and the flare itself.





Result: In 2018, the Teréga mobile flare was used three times. The total amount of gas flared was 39,800 sm^3 (1,405,523 scf), which is equivalent to approximately 900 metric tons of carbon dioxide equivalent.

Costs: Not reported

Learnings: Other recompression and blowdown methods are limited by a minimum technical pressure (delivery pressure for customers, suction pressure for recompression, etc.). Thus, gas remains in the pipe which may be released to the atmosphere. The tests confirmed that flaring was a way to help Teréga reduce its carbon footprint, and in 2018 Teréga invested in a mobile flare.

Source: Information provided by Teréga.

Case study 4:
Hot tapping for pipeline connections (transmission)

Case study: Snam operates a large network of transmission pipelines and uses hot tapping to avoid the need for venting gas when making new connections to a pipeline.

Description of measures: New connections often need to be made to pipelines to expand or modify the existing transmission network. Historically, this required shutting down a portion of the network and releasing gas to the atmosphere. This procedure, referred to as a shutdown interconnect, results in methane emissions and loss of natural gas. Hot tapping is an alternative procedure that makes a new pipeline connection while the pipeline remains in service. Hot tapping involves attaching a branch connection and valve on the outside of the pipeline before cutting out the wall of the pipeline within the branch. This avoids the loss of natural gas, methane emissions and avoids disruption to customers.

Result: Snam applies hot-tapping techniques where reasonably possible, especially when a high number of customers are connected.

In 2018, six hot-tapping procedures saved 1.700.000 sm^3 (60,034,933 scf) of gas (14% reduction of vented emissions). In 2019, hot-tapping saved 1.030.000 sm^3 (36,374,106 scf) of gas.

Costs: The average total cost for each hot tapping procedure performed by SNAM, including labor costs, was €70,000. However, the cost can vary for each project upon several factors such as pipeline diameter, gas pressure, location of the hot tap, number of personnel required, and other variables.

Learnings: Although this technique is widely applied and considered as common practice in the oil and gas industry, each hot tap has to be evaluated individually for a variety of factors as explained in the Costs section. Specific welding procedures must be used to assure a safe process.

Source: Data provided by Snam.

Case study 5:
Monitoring underground storage facilities (underground storage)

Case study: Implementing a 'well-integrity management system' and mitigation measures.

Description of measures: The well-integrity management system is based on the two-barriers principle, which implies that two barriers (between the gas inside the well and the outside of the well) should be guaranteed thorough all the stages of the well life cycle. This management system takes account of international standards such as NORSOK D-010[6], ISO 16530[7], EN1918[8], API RP 1171[9]. The main objective of well-integrity management is safety, but it also prevents methane emissions. The management system defines roles and responsibilities, standards and policies, and practices and procedures for safely operating wells and minimizing the risk to the environment.

Practices include:

- enhanced monitoring;
- risk management;
- maintenance of the well; and
- LDAR programs at the well head.

Result: The processes involved in well-integrity monitoring and review and enhanced detection of methane emissions include the following.

- Using pressure-monitoring systems to detect downhole problems early
- Optimizing the frequency of well-equipment maintenance to account for corrosion
- Frequent monitoring of emissions from equipment above the ground
- Defining key performance indicators (measures to evaluate performance)
- Compiling all available records relevant to mechanical integrity of the well
- Testing the integrity of the well
- Producing written risk-management plans
- Establishing safe-operating pressures for existing casing and tubing
- Assessing risk before working over wells, or plugging and abandoning wells, and take account of old wells that are no longer in use.

Costs: The cost of implementing a well-integrity management system with external support is €100,000 to €500,000.

Learnings: Many of these monitoring steps are believed to be capable of identifying incipient issues, and so can avoid venting and even prevent catastrophic failures. Many operators already apply these risk-management practices in their operations.

Source: Information provided by Enagás, Snam and Teréga.

Case study 6: Minimizing emissions from dehydrators by using vapor compression and low-temperature separation to remove water (underground storage)

Case study: An alternative way to remove water from the gas withdrawn from an underground-storage facility is to use a condensate-removal process, instead of glycol dehydrators. Vapor-compression refrigeration or a low-temperature separator (LTS process) condenses the liquids and water in natural gas and removes them from the gas stream.

Description of measures: There are two ways to cool the gas stream being withdrawn from an underground facility. The first is a vapor-compression refrigeration process using a circulating refrigerant such as propane. Propane enters the refrigerant compressor as a vapor. The vapor is compressed and exits the compressor superheated. The superheated vapor is condensed into a liquid and the liquid is rapidly expanded, causing flash evaporation and auto-refrigeration. The cold liquid-vapor propane mixture is sent to a heat exchanger where heat is withdrawn from natural gas and the refrigerant is completely vaporized. The cooled gas with condensed water goes through a separator or 'water knockout' that removes water from the natural gas.

The second method is a low-temperature separator process using a Joule-Thomson (J-T) valve (pictured). The process is designed to force the gas stream through the J-T valve, where the gas stream drops in pressure and temperature. After the J-T valve, the cooled gas stream with condensed water flows through a low-temperature separator that removes condensed water from the gas. This process requires a high difference in pressure between the inlet to the J-T Valve and the outlet to the rest of the gas system.

Result: The LTS technique only applies in plants where there is a significant difference in pressure between storage wells and the pipeline (for example, a 120-bar (1,740 psi) well and 20-bar (290 psi) pipeline). Where reasonably possible, Snam uses a refrigeration system with propane, or a low-temperature separator process, instead of glycol dehydrators. Methane emission savings, compared to the use of glycol dehydrators, are estimated to be roughly 10.000 sm^3 (353,147 scf) per year per storage site.

Costs: Not reported

Learnings: This approach is best used in the design phase.

Source: Information provided by Snam.

Case study 7: Minimizing emissions at LNG terminals and LNG truck-loading systems (LNG terminals)

Case study: Enagás used best practices to minimize emissions at three LNG regasification plants.

Description of measures: Enagás classify methane emissions in three categories: fugitive emissions, emissions from venting and incomplete combustion (methane slip). Depending on the type of emission and equipment involved, specific mitigation measures are applied in the LNG terminals.

- **Mitigation for fugitive emissions**
  Since 2020, LDAR programs are conducted every year at all the LNG terminals that Enagás operate in Spain (Barcelona, Cartagena, Huelva). During the LDAR programs, fugitive emissions are repaired in two ways:
  1) Parallel repairs – repairs carried out at the same time as detection and measurement activities (for example, retightening connections and quick adjustments).
  2) Planned repairs – repairs carried out after detection, which could not be repaired at the time and are included in a maintenance plan. These repairs are generally carried out before the end of the year, unless major work is needed.
  Enagás use a portable detector (a point sensor) in the daily operation of LNG terminals, during start-ups, and during maintenance.
- **Mitigation for emissions from venting**
  Enagás apply a large variety of mitigation from the design phase (eliminating pneumatics powered by gas), to optimizing tank pressure, monitoring rod packing (on the boil off gas compressor), LNG truck loading vapor exchange, purging hoses and LNG arms with nitrogen prior to disconnection, and dry disconnecting couplings (pictured) in the LNG truck loading facilities, and use of hot taps.
- **Reducing boil off gas (BOG) venting**
  During the design phase of their three LNG terminals Enagás implemented BOG recovery units to recover, compress and send the BOG to the recondenser to be converted to LNG. In 2015, Enagás installed high-pressure BOG compressors (pictured) to inject non-recoverable BOG into the grid during loading and unloading operations and zero or low send-out modes.

Result: Since 2013, total methane emissions have been reduced by 89%, fugitive emissions have decreased by 55% and emissions from venting by 98%.

Costs: The cost of LDAR projects in each LNG terminal is around €15,000 per year. The costs of equipment needed for the latest mitigation projects in Enagás LNG terminals are 7 to 10 million euro for each high-pressure BOG compressor and an average of €20,000 for the dry-disconnect couplings in each LNG truck-loading facility.

Learnings: In LNG terminals, where equipment operates under large variations of temperature, having annual LDAR programs is the main mitigation measure for reducing fugitive emissions. Mitigation measures to reduce venting and to recover BOG are effective ways to reduce emissions.

Case study 8:
Commissioning with vacuum pumps (distribution)

Case study: NEDGIA (a gas-distribution company in Spain) established a practice for commissioning networks using vacuum pumps. This avoids the need to 'purge' natural gas to the atmosphere to remove air in new pipe sections before they are placed into service.

Description of measures: Constructing and commissioning a new network section gives rise to methane emissions during the purging process prior to pressurizing the new section with gas.

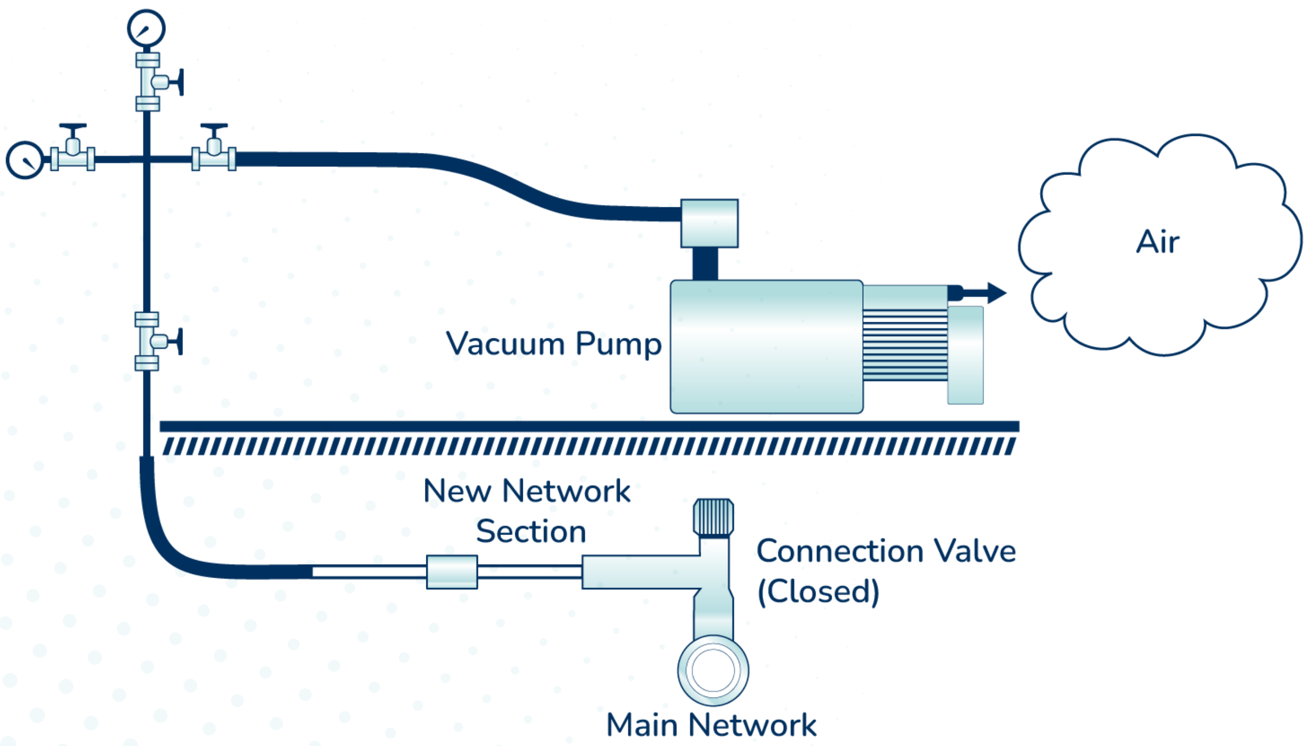
Once the tightness test on a new network section has successfully finished, but before commissioning, the inner air is purged using a vacuum pump, which extracts the air from the new section. Afterwards, the section is pressurized with gas without any gas being released.

Result: As a result of this practice, no methane is released to the atmosphere when a new section of main pipeline is commissioned.

Costs: The costs are low, and are only for the cost of buying vacuum pumps and the operator´s labor costs.

Learnings: New sections of the main pipeline network can be commissioned without releasing methane to the atmosphere. There are important savings in the volume of natural gas that would have otherwise been vented during a purging process.

Source: 'Best Practices for Network Commissioning' presentations by NEDGIA.



Case study 9:
Avoiding emissions caused by third-party damage (distribution)

Case study: Gaz Réseau Distribution France (GRDF) takes preventive actions to avoid methane emissions caused by third-party damage (TPD)

Description of measures: GRDF's distribution mains and services lines can be damaged as a result of unrelated works in close vicinity. Approximatively one third of GRDF's methane emissions each year are linked to third-party damage. For several years GRDF have implemented a plan to reduce third-party damage. The main actions of the plan include the following.

- Implementing analysis and feedback after third-party damage occurs
- Improving the accuracy of maps and geo locations for the network
- Creating partnerships with relevant stakeholders such as the national federation of civil works (Fédération Nationale des Travaux Publics – FNTP) or local authorities
- Raise public awareness of the risk of third-party damage
- Improving the criteria for choosing external contractors to avoid first and second party damage, and sometimes using aspiration engines instead of mechanical shovels
- Monitoring companies responsible for recurrent damage
- Signs to inform third parties about the presence of gas installations
- Defining key performance indicators to assess internal performance; and
- Reducing the impact of methane emissions related to damage on a service line by using protection devices that automatically stop the gas flow

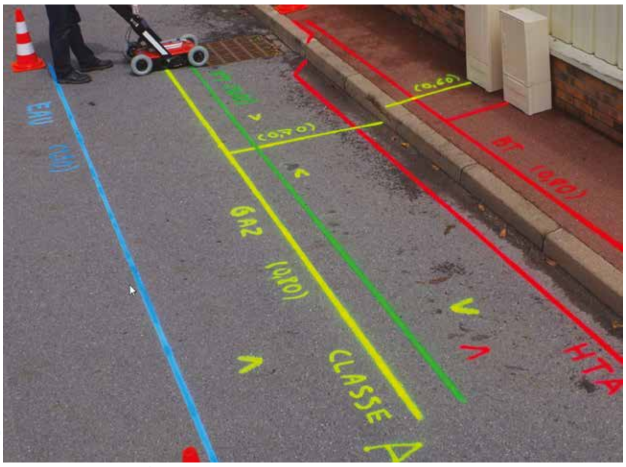
Result: Since 2008, as a result of joint actions implemented by GRDF and stakeholders, the number of incidents of third-party damage on distribution mains and services lines has dropped by 50%. while the number of sites around gas networks increased significantly. The number of TPD incidents decreased to under 3000 in 2019.

Around 18,000 employees of local authorities and 56,000 employees of civil works companies have been trained.

Costs: Not reported

Learnings: GRDF are facing a continuous increase in civil works around the gas network. Although the internal performance ratio 'number of TPD/number of work declarations' significantly decreased as a result of GRDF's actions, the absolute value of TPD remained constant. GRDF pursues its actions on TPD, especially on services which represents 80% of global TPD.

Source: Information provided by GRDF.



Case study 10:
Installing excess-flow valves in service lines (distribution)

Case study: GRDF installs excess-flow valves in existing polyethylene (PE) service lines. These reduce emissions when service lines are damaged.

Description of measures: When a service line is damaged, the faster the flow of gas is cut off, the lower the emissions. An automatic cut-off is faster than sending a technician to respond to the emergency. GRDF installs automatic flow-cutting devices into their PE service lines to stop the flow when damage occurs. Since 2000, all new service lines are fitted with these devices. GRDF have also had a campaign to retrofit the devices in existing lines. This does not require a trench and the gas flow is not interrupted. GRDF selects the areas with the highest likely damage impacts for the first retrofits.

GRDF initially targeted areas of the network that would benefit the most. For example, GRDF chose areas known to be particularly exposed to malicious acts such as vandalism, urban areas with a high density of construction sites, and areas with a high population.

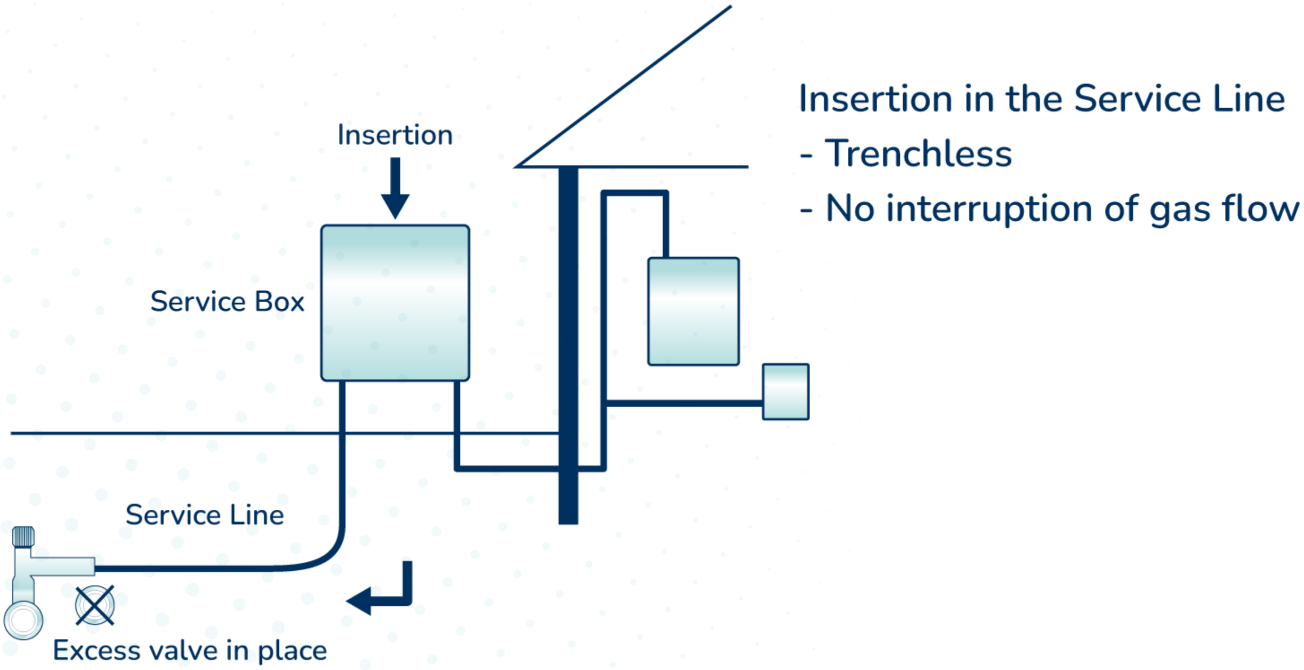
Excess flow valve for existing service lines in polyethylene

Result: In 2019, these devices stopped the flow of gas in 14% of cases of damage to the network. This avoided significant methane emissions, as damage to the network accounts for 30% of GRDF's total methane emissions.

Costs: Not reported

Learnings: GRDF continues to increase its investments on modernizing the network, and focuses on specific types of network to improve security by adding 10,000 new excess-flow valves to existing service lines each year, with an aim to increase to 20,000 per year by 2023.

Source: Information provided by GRDF.

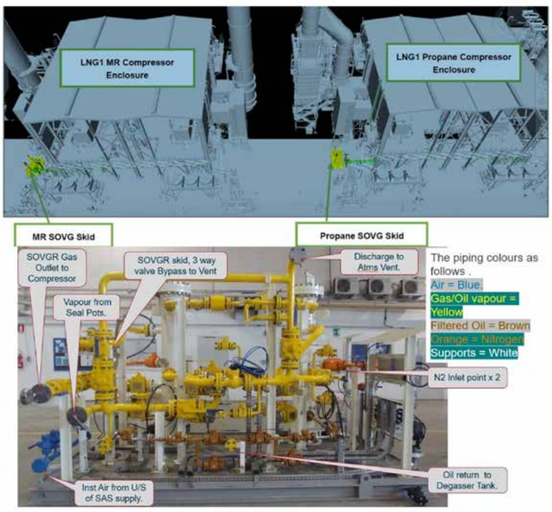


Case study 11: Installation of seal oil vent gas recovery (SOVRG) systems on compressors (LNG Terminals)

Case study: Woodside has installed seal oil vent gas recovery (SOVRG) systems on compressors designed with oil ring wet seals to prevent continuously vented methane emissions.

Description of measures: LNG (Liquefied Natural Gas) production uses large mechanical driven compressors to pressurize refrigerant circuits, enabling methane to be liquified via heat exchangers. The compressor shaft seals are of varying designs. One design uses a wet oil ring to seal the compressor shafts. The LNG train has two wet seal systems per refrigerant circuit: Mixed Refrigerant (MR) and Propane Refrigerant (PR), resulting in continuous venting from a total of four wet seal vents. The compressor seal oil has entrained process gas which vents to atmosphere via sour oil pots.

Depending on the compressor manufacturer, upgrade packages, such as dry gas seals may be available, however our compressor design necessitated an alternative solution. The project involved the installation of seal oil vent recovery coalescing filtration skids and associated pipework to return the gas to the compressor



to ring wet The of

suction and recovery of the entrained seal oil to the degasser tanks. The skids operate in two modes, 'recovery' mode as well as a failsafe 'vent' mode, via a three-way valve. Logging of the valve position enables emission reduction estimates. The installation required replacement of the interconnecting piping and the existing four vent locations, with a single new vent installed dedicated to each skid.

Result: The installation of the seal oil vent recovery systems on the MR and PR compressors are able recover methane emissions as well as atmospheric VOC (Volatile Organic Compound) emissions during normal operations. Engineering calculations based on the seal design estimate the mitigation to be in the order of 280tpa of methane and 2000tpa of VOC emissions. Independent measurements suggest the estimated emission reduction may be conservative. Aside from improved facility emissions, additional benefits included the recovery of vented hydrocarbon streams back into the process for incremental production as well as preventing oil migration, which can impair critical instrumentation.

Costs: The sanctioned cost to deliver the mitigation was > A$15 million, endorsed using our economic assumptions of a GWP (Global Warming Potential) of 84 tCO2e/tCH4 and a carbon price of US$80/tCO2e, i.e. an equivalent price o f US$6720/tCH4.

Learnings:

- SOGVR tie-ins can be aligned to maintenance cycles; this may significantly derisk projects by reducing the skid installation time.
- Validate assumptions made in vendor/contractor calculations in the field.
- Modifying utility systems requires careful consideration for interactive effects on adjacent equipment.
- Functional checks of procured equipment are important to avoid implementation delays.

Source: Information provided by Woodside Energy.

Case study 12:
Methane Destruction for Pipeline Blowdowns (Portable Incineration)

Description of measures: Occasionally, Natural Gas must be evacuated from pipelines to ensure safe execution of repair and maintenance activities. The quickest and easiest way to fully depressurize an isolated pipe segment is to vent the natural gas in the pipeline to atmosphere; however, this results in greenhouse gas emissions. Where possible, TC Energy deploys portable transfer compressors to reduce the volume of natural gas vented to atmosphere by redirecting the natural gas from the isolated pipeline segment to another pressurized system, either to a parallel line or to a separate isolated section of the same line. However, technical, and logistical constraints prevent these compressors from depressurizing the pipeline segment fully and therefore, a residual volume of gas remains in the pipe that has historically been vented to atmosphere.

The use of portable incineration technology is one option for abating the emissions associated with residual gas volumes. As methane has a much higher greenhouse gas (GHG) warming potential than carbon dioxide, high efficiency combustion of the residual natural gas can significantly reduce the GHG intensity of emissions associated with pipeline blowdowns.

TC Energy performed incineration pilots on various projects to test the feasibility of portable incineration technology for pipeline blowdown emissions abatement.

Approach: The size and number of incinerators were determined based on pipeline parameters unique to each blowdown event:

- Available outage duration,
- Internal diameter of pipe,
- Length of pipe isolated, and
- Expected starting pressure following completion of depressurization by a portable transfer compressor.

For each pilot, the incinerators were installed and connected to the blowdown valve riser on the pipeline using temporary piping. A separator tank was installed between the pipeline and the incinerator(s) to remove any liquids or debris in the gas that could cause a safety hazard. During operation, stack testing was performed to determine the combustion and methane destruction efficiencies, and heat radiance and noise testing were conducted to evaluate the heat and noise released from each incinerator. Access matting was used to provide safe access to the valve site; provide a stable, level ground for the incinerator equipment to sit on; and to shield the ground from radiant heat during the incineration activity. Lastly, the incinerators were required to be placed a certain distance away from flammable areas, tanks, and other equipment.

Result: The table below presents the incineration pilots' summary results:

Parameter	Pilot #1	Pilot #2	Pilot #3
Start volume	170 e^3m^3	95 e^3m^3	75 e^3m^3
Start pressure	2,757 kPag	650 kPag	672 kPag
End pressure	5 kPag	5 kPag	0.5 kPag
Depressurization time	35.75 hours	23.5 hours	48.5 hours
Emissions savings	2,730 tCO2e	1,380 tCO2e	1,040 tCO2e

The combustion efficiencies were found to be 99.9% for the units tested. Noise testing indicated increased levels of noise during incineration activity ranging from 65.2 dBA to 102.5 dBA depending on the number and type of incinerators running as well as the distance to the incinerators.

Costs: Not reported

Learnings: Key learnings from the incineration pilot projects are highlighted below.

- **Planning and Stakeholder Engagement:** Executing a successful incineration activity at a pipeline blowdown event takes a significant amount of planning and coordination with both internal and external stakeholders. Project planning should account for the additional time this activity adds to a pipeline blowdown duration. Technical engineering resources should be engaged at the onset of the project to ensure the correct pressure ratings and operating conditions are verified prior to the equipment being deployed. Additionally, hazard identification sessions and risk assessments should be conducted and documented with all relevant stakeholders to ensure that any potential risks and hazards are mitigated as much as possible.
- **Controlling Flow to Incinerators:** Operational experience from previous pilots suggests that it may be possible to achieve faster depressurization by increasing the flow rate to an incinerator. However, this approach impacts noise and heat radiance in the surrounding areas. Both of these factors must be considered prior to increasing the flow rates. Additionally, the flow rates must never exceed the rated capacity of the incinerator units as this could lead to safety concerns, visible flame, and a decrease in combustion efficiency.
- **Safety:** Given the nature of incineration activities, risk of excessive heat and/or fire shall always be considered and planned for. Personnel must stay clear of the high heat exclusion zones unless absolutely necessary for incinerator operation. Only trained personnel familiar with safe gas handling procedures may enter the exclusion zone during operation as required to adjust the incinerator equipment. For each of these pilots, a fire watch crew and additional water trucks were brought to each site to mitigate heat and fire risk. In the event of higher-than-normal temperatures, incinerator units must be shut down until the cause for excessive heat is determined and the site and project teams deem equipment safe to continue incineration.

Author/Source: Brandon Fong, TC Energy.

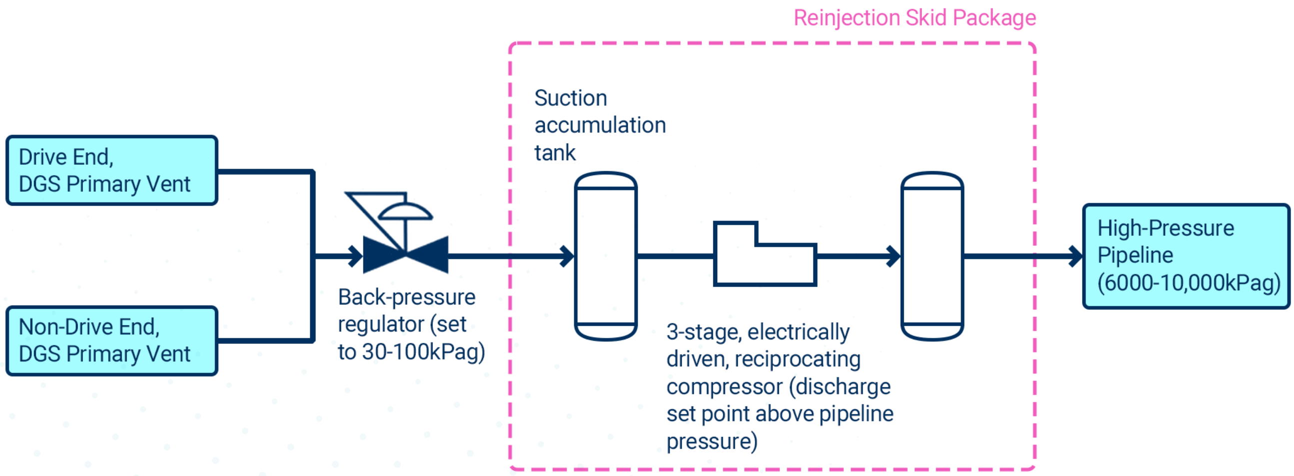
Case study 13:
Capturing and reinjecting compressor dry gas seal methane vents

Issue: Large transmission natural gas pipelines often use centrifugal compressors to boost the pressure of the pipeline and push natural gas downstream to customers. Centrifugal compressors often contain dry gas seals that prevent the product natural gas from escaping the body of the compressor around the rotor shaft. Dry gas seals are comprised of high-pressure natural gas that is injected into a labyrinth around the rotor shaft. A small percentage of the dry gas seal natural gas is then vented to atmosphere by design through the primary vent. The dry gas seal primary vent rate for a typical, large transmission pipeline, centrifugal compressor can be between 2-3 scfm while it is running, which equates to approximately 400-600 tCO_2e worth of methane emissions each year, per compressor. The exact amount of yearly emissions is dependent on how often the compressor is utilized each year.

Description of measures: To stop the dry gas seal primary vent methane from escaping to atmosphere, TC Energy has piloted two options for gas conservation. These options are high- and low- pressure reinjection and are described below.

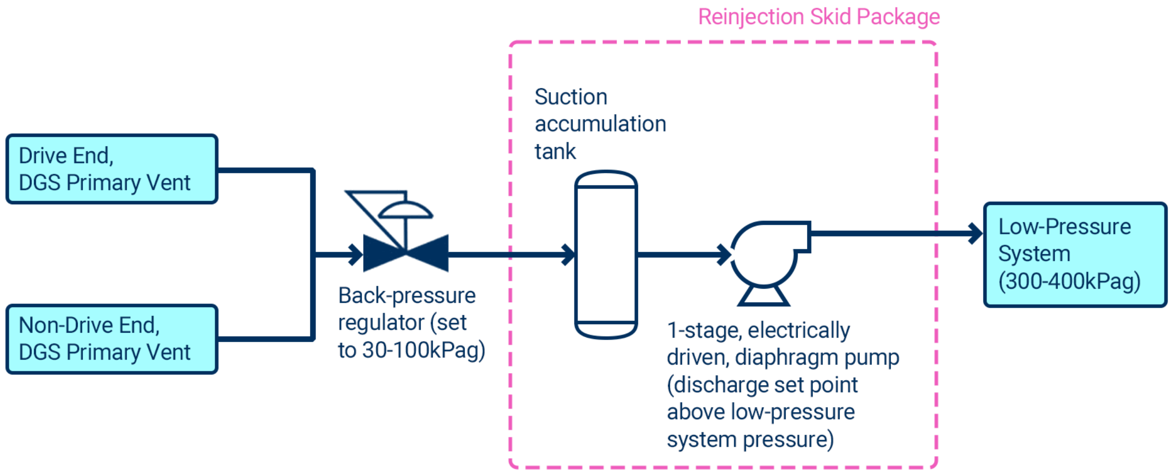
High-pressure reinjection:

High-pressure reinjection systems capture the dry gas seal primary vent gas, recompress it to pipeline pressure and inject it into the pipeline. The primary components and typical pressures for this system are shown in the diagram below:



Low-pressure reinjection:

Low-pressure reinjection systems capture the dry gas seal primary vent gas, recompress it to the pressure of a low-pressure system onsite (such as a utility or fuel gas system) and inject it into the low-pressure system selected. The primary components and typical pressures for this system are shown in the diagram below:



Result: TC Energy has completed three high-pressure reinjection projects and one low-pressure reinjection project. The results from these pilot projects are summarized in the table below:

	Pilot #1	Pilot #2	Pilot #3	Pilot #4
Project Type	High-Pressure	High-Pressure	High-Pressure	Low-Pressure
Number of compressor vents captured	1	2	2	1
Scope 1 Emissions Abated (tCO2e/yr)	~200	~1,190	~900	~510
New Scope 2 Emissions Created* (tCO2e/yr)	~30	~70	~75	~7
Total Emissions Abated (tCO2e/yr)	~170	~1,120	~825	~503
Net Emissions Abatement %	85%	94%	92%	99%
Reinjection Pressure (kPag)	5,520	6,900	10,350	410

**Scope 2 emissions are primarily from electrical power consumption to drive the compressor or pump.*

Costs: Not reported

Learnings: Low-pressure reinjection is the preferred way to conserve dry gas seal primary vent methane emissions, as it has a lower capital investment, maintenance costs, and Scope 2 emissions. However, using this method requires a low-pressure system onsite with enough required flow to consume all the dry gas seal primary vent emissions. If there isn't a suitable low-pressure system onsite, then high-pressure reinjection is a suitable way to conserve dry gas seal primary vent methane emissions.

Source/Author: John Yakielshek, TC Energy

Case study 14:
Large Diameter Hot Tapping (transmission)

Case study: TC Energy operates a multination wide network of natural gas transmission pipelines, with pipe diameters up to NPS 48 in size. TC Energy uses hot tapping to avoid transmission disruption and prevent venting gas to the atmosphere when completing new tie-ins or integrity work; however, hot tapping at large diameters (notionally ≥ NPS 24) presents unique challenges.

Description of measures: Transmission system pipelines occasionally require the addition of new connections or extensions, installation of new equipment, or completion of integrity activities on existing pipeline systems. To complete these activities, the pipeline may need to take an "outage" and have internal gas products removed. Hot tapping is a process through which pipeline modification can be completed while avoiding the requirement to depressure and degas the pipeline, thereby avoiding significant venting of natural gas to atmosphere.

Hot tapping is the process of adding a through pipe-wall hole, of varying size, to a pipeline while the internal product is flowing and/or under pressure. For large diameter activities, engineered reinforced branch sleeves/fittings or split tees are used to replace the material strength that has been lost from the pipe when the hole is created.

When properly reinforced, the hole and reinforcement fitting can be used to serve as a branch connection to another system, eliminating the need to take an outage otherwise required to cut in something like a welded-end tee fitting.

The reinforced hole can also serve as a port through which to add a line stop device, which is commonly a mechanically activated plugging device that can block the flow of the product as though it were a temporary valve. With strategically placed line stop devices and vents, used in tandem with proper gas handling procedures, it is possible to depressure and vent a limited section of a pipeline, allowing for safe completion of integrity work or the addition of new equipment between isolated points. The use of line-stop devices allows the operator to minimize the length of the depressured and vented section, occasionally reducing vented pipe lengths from tens of kilometers (i.e., between isolation valves that may be several kilometers apart) to tens of meters.

While hot tapping is a process that has been used in the pipeline industry for decades, tapping at large diameters offers unique challenges that need to be mitigated through detailed engineering analysis; these include:

- Unique design for large diameter reinforcement fittings as well as specialized material and welding requirements for the fittings.
- Specialized tools to ensure proper alignment of tapping equipment when tapping tools need to cut through extended lengths.
- Thorough analysis of, and support for, the bending loads that large and heavy hot tapping and line stop equipment can place on pipe and tapping fittings.
- Consideration for valves and tools to provide effective and reliable isolation, in combination with robust gas handling practices, to allow for safe work in isolated sections.

Hot tapping is a high-risk activity due to the considerable energy within the system on which work is being performed, proximity of hot work technicians to that system, and potential impact of hot tapping and welding to the strength of the pipe. To ensure work is completed safely, the following safety considerations and mitigations should be employed:

- Robust gas handling practices to prevent loss of product containment and ignition,
- Use of occupational safety mitigations such as fire-resistant PPE, single/double hearing protection, minimizing personnel in the hot zone,
- Pretesting equipment and performing in-service leak checks (i.e., with nitrogen) before tapping,
- Reviewing equipment condition and maintenance to ensure it is fit for service,

- Developing “Management of Change” practices to outline how to, and be prepared for potential need to deviate from original plans,
- Detailed measurements and recording of activities to ensure equipment position is understood,
- Reviewing hot tap equipment and appurtenances, the hot tapping procedure, and orientation to ensure proper functioning of hot tap coupon retention system.

Result: As an example of how effective hot tapping can be at reducing emissions, TC Energy has used a line stop and bypass process to aid in the addition of a new river crossing to an NPS 36 pipeline system. Hot taps were performed upstream and downstream of the river crossing to allow for limited-length cut-outs to permit the addition of new assemblies and crossing connections, as well as bypass systems to ensure product could continue to flow while the additions were completed. Hot tapping to allow the addition of branch connections and line-stop isolation points avoided an outage and the venting of approximately 7,500 tCO_2e of natural gas to atmosphere (following standard practices to minimize venting such as use of transfer compression) on approximately 30km of NPS 36 pipe. With the hot tap, venting was limited to <100 tCO_2e by reducing the vented sections to tens of meters long. It should be noted that this activity took well over a year to plan, design, and procure materials, but was ultimately highly successful at completing the objective, minimizing impact to the pipeline system, and significantly reducing vented emissions.

TC Energy has performed nearly a hundred similar large diameter hot taps on systems of varying size, configuration and for numerous applications (branch connections, tie-ins, pipe replacements, valve additions, threat isolation, etc.), underscoring the flexibility of the application.

Costs: Costs for execution of hot tapping at large diameters is extremely variable and depends on factors including: branch and run pipe diameter; number of connections required; tap orientation; use of line stop devices; use of specialty safety devices like positive retention systems; valves and appurtenances required; structural supports required; use of bypasses; and, the degree of engineering design required. Costs can range from hundreds of thousands of dollars to tens of millions of dollars.

Learnings: Hot tapping is a process that has been used for decades, and combinations of tools and techniques used with hot tapping has been proven to dramatically reduce venting and outage impacts of pipeline system expansion and integrity work. However, hot tapping represents one of the highest risk activities that can be completed on a high-pressure pipeline system, and as size/scale of hot tapping activities increase, there is increased need for detailed engineering and safety practices.

Source/Author: Andy Collard, TC Energy

Checklist

The following example checklist is intended as a simple tool that allows the operator to assess progress in reducing emissions in transmission, storage, LNG terminals and distribution. An operator may choose to follow this checklist or customize it to their assets and implement these activities and measures across some or all of their assets.

	Checklist	Completed	Percentage of facilities involved
General activities	Keep an accurate inventory of emissions from all sources		
	Prevent or avoid emissions whenever possible		
	Reduce emissions that cannot be prevented or avoided		
	Identify and repair equipment that is not working properly		
	Track emissions and mitigation measures		
Specific mitigation measures	Evaluate compressor sources for emission reductions (transmission, storage, LNG terminals)		
	Evaluate gas-powered pneumatics for emission reductions (transmission storage, LNG terminals)		
	Evaluate dehydrators for emission reductions (storage)		
	Evaluate LNG truck-loading for emission reductions (LNG terminals)		
	Implement pipeline maintenance for emissions reductions (transmission, storage, distribution)		
	Implement damage-prevention programs (transmission, storage, distribution)		
	Implement storage-system monitoring (storage)		
	Implement leak detection and repair (LDAR) programs for emissions from above-ground equipment (transmission, storage, LNG terminals, distribution)		
	Evaluate energy use in engines, turbines and other combustion equipment (transmission, storage, LNG terminals, and distribution)		
	Evaluate flaring practices to minimize flaring (storage, LNG terminals, distribution)		
	Evaluate emissions during construction (transmission, storage, LNG terminals, distribution)		
	Evaluate continual improvement in methane management (transmission, storage, LNG terminals, distribution)		

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This series of 10 Best Practice Guides have been designed to improve performance in methane emissions management across the natural gas supply chain. Each Guide provides a summary of current known mitigations, costs and available technologies as of the date of publication. The Guides are available, upon request, in English, French, Arabic, Mandarin, Russian and Spanish.