METHANE
GUIDING
PRINCIPLES

REDUCING METHANE EMISSIONS

Best Practice Guide: Engineering Design and Construction

November 2019

Contents:

Disclaimer

This document has been developed by the Methane Guiding Principles partnership. The Guide provides a summary of current known mitigations, costs, and available technologies as at the date of publication, but these may change or improve over time. The information included is accurate to the best of the authors' knowledge, but does not necessarily reflect the views or positions of all Signatories to or Supporting Organisations of the Methane Guiding Principles partnership, and readers will need to make their own evaluation of the information provided. No warranty is given to readers concerning the completeness or accuracy of the information included in this Guide by SLR International Corporation and its contractors, the Methane Guiding Principles partnership or its Signatories or Supporting Organisations.

This Guide describes actions that an organisation can take to help manage methane emissions. Any actions or recommendations are not mandatory; they are simply one effective way to help manage methane emissions. Other approaches might be as effective, or more effective in a particular situation. What readers choose to do will often depend on the circumstances, the specific risks under management and the applicable legal regime.

Summary

Engineering and design can play a vital role in reducing methane emissions, and are the first line of defense. Also, it is usually substantially cheaper to reduce emissions during the design stage than by adapting systems later or as part of maintenance. In many cases, methane emissions can be eliminated by design. If this is not feasible, venting and leaks may be minimized through the effective design of systems. This may include designs that reduce the amount of methane leaked or vented and fuel used or, as a last resort, incorporating a control device to control methane. General design principles to reduce methane emissions are as follows;

Best practice for reducing methane emissions from energy use in oil and gas operations:

Use electric, mechanical and compressed-air equipment where possible

Centralize facilities

Use pipelines to transport oil and natural gas from facilities

ecover methane for beneficial use

Use alternative low-emission and low-maintenance equipment

Introduction

Engineering and the design of systems can be used to reduce methane emissions before new facilities begin operations or when existing facilities are modified. The design phase provides the best opportunity to identify methane reductions.. It is also usually less expensive to apply reduction strategies in the design phase than to have to modify the facility. The system's engineer should consider the following strategies to reduce methane emissions. The strategies are listed in order of priority.

1. Eliminate sources of methane
2. Reduce the amount of methane emitted and the amount of fuel used
3. Control remaining sources of methane

Most engineering solutions will be specific to a company's operations and facilities, and will evolve as technology does. Any design needs to prioritize integrity, safety, fire-protection and regulatory requirements over reducing emissions. Effective design strategies to reduce methane emissions throughout the natural-gas supply chain are discussed in detail below.

1. **Use electric, mechanical and compressed-air equipment where possible**
   Natural gas pneumatic devices are a significant source of methane emissions in some operations in the oil and gas industry. Using electric, mechanical or compressed-air devices can completely eliminate emissions from pneumatic devices.

   If there is no mains electricity at a remote site, a single gas-fired electricity generator or air compressor can be used instead of several pneumatic devices. Using electric compressors and pumps instead of gas-fired equipment can reduce natural gas used as fuel and increase the amount that can be sold. Electric motors are also more reliable than gas-fired engines, but a gas-fired generator may be needed if the site does not have mains electricity.

2. **Centralize facilities**
   Centralizing facilities may eliminate sources of methane emissions and allow more efficient equipment and processes to be used. For example, a centralized facility may use a single hot-oil heater to provide heat for all equipment in the facility instead of a separate heater for each piece of equipment.

   Centralizing facilities can also make methane-reduction or recovery equipment more economically viable. For example, an oil stabilizer or multi-stage separation system that can take production from surrounding facilities to reduce storage tank emissions. Similar systems at each individual site may not be available or economical on a smaller scale.

3. **Use pipelines to transport oil and natural gas from facilities**
   Using natural-gas pipelines makes sure that methane is sold and reduces or eliminates flaring or venting at production facilities. Liquid pipelines can eliminate methane emissions from storage tanks and truck loading. These pipelines also allow equipment to be centralized.

4. **Recover methane for beneficial use**
   Natural-gas recovery should be prioritized over flaring or venting. The natural gas can be sold or used as fuel on-site. Vapor-recovery units can be installed to boost the pressure of low-pressure gas for sales. Gas can also be directed to a low-pressure fuel system or local gathering line. Some operators will use it to generate electricity to run air compressors or potentially sell electricity to the local grid. Gas can also be injected back into the well to improve recovery. Engineering design should prioritize recovering natural gas if possible.

5. **Use alternative low-emission and low-maintenance equipment**
   Some processes or equipment can be eliminated or replaced with alternative no-emission or low-emission systems. Alternative systems should be considered if they can meet the requirements of the project. For example, methanol injection or dessicant dehydrators are some low-emission alternatives to traditional glycol dehydrators. Low-maintence equipment should also be considered to reduce venting natural gas in order to perform maintenance activities.

Quantifying emissions

Quantification methods for methane emissions deliver a rate, such as mass per time (e.g. kilograms per hour) or volume per time (e.g. standard cubic meters per hour), and can be produced by engineering estimations, by direct measurement of the methane sources, or by use of models. In the design phase there are three basic techniques for quantifying emissions. These are listed below, from most accurate to least accurate.

- Modeling (for tank-flash emissions and glycol dehydrator regenerator emissions) using a process simulation program to predict emissions based on first principles and equations.
- Emission-calculation equations may use a variety of information, from the equipment manufacturer or gathered locally, to estimate the rate from certain processes or activities.

For some sources and processes, commercially available programs and models are widely used to simulate hydrocarbon treating, processing and handling processes. Examples of these programs are ProMax® or Aspen HYSYS®, or simplifications of those models in estimation tools such as E&P Tanks developed by The American Petroleum Institute (API). Models can also be used to characterize methane emissions from glycol dehydrator system vents, and there are simplification tools such as the Gas Technology Institute (GTI) GLYCalcTM program. An advantage to a model is that site-specific conditions can be entered, so that each individual process can be accurately simulated. Some jurisdictions even require certain models to be used. An example is for reporting tank flash emissions under the US EPA's GHG Reporting Rule, or under the US New Source Performance Standard, Subpart OOOOa.

Less-detailed equations for estimating emissions may be used. These equations require site-specific information to be used to characterize emissions. Equations may use a variety of information supplied locally to estimate the rate from certain processes or activities.

The easiest but also least accurate technique for estimating emissions is to use information from the equipment manufacturer and 'emission factors', where emissions per activity (such as a quantity of gas per year per equipment type) is simply multiplied by the number of pieces of equipment.

Example engineering and design strategies

This guide is not intended to detail all design recommendations that could reduce methane emissions, but rather to give some examples of best practice that can be followed to reduce methane emissions. Many of the mitigation strategies detailed in the other best practice guides can be used for design and engineering purposes. Those strategies are not detailed in this guide. The strategies in the table below are covered in this guideline.

Engineering and design strategy	Eliminates sources of methane emissions	Reduces venting, leaks or energy use	Controls methane	Design Strategy Category
1. Siting of utilities and centralization	✔	✔		1, 2, and 3
2. Modular design	✔	✔		5
3. Eliminating fugitive components		✔		5
4. Location of fire-gate valves and isolation valves		✔		4
5. Secondary and tertiary separation		✔		4
6. Tankless design	✔	✔		3 and 5
7. Storage tank design		✔	✔	5
8. Using electric compressors	✔	✔	✔	1
9. Pig ramps and jumper lines		✔		4 and 5
10. Using methanol to prevent hydrates	✔	✔		5
11. Amine unit flash tank		✔		4
12. Acid gas control device		✔	✔	5

Engineering and design strategy 1: Siting of utilities and centralization

Oil and natural gas are produced in remote locations, often with limited gas-gathering pipelines and power supply. Many facilities rely on heaters, engines, and pneumatic devices that use natural gas as fuel and motive gas. Also, they sometimes need to flare or vent natural gas.

Where technically and economically feasible, the decision on where to locate a site should take account of the proximity to existing power supplies and pipelines, and the design of facilities should reduce.

the use of natural gas as a fuel and instead use electrical equipment. If a facility cannot be located near existing infrastructure, power supplies and pipelines should be brought to the facility if this is technically and economically feasible.

Operators should, where practicable, centralize production facilities for large-scale developments. Centralization is where no (or minimal) hydrocarbon treating, processing and handling of liquids occurs at the well pad, and separation, treating, storage and handling are instead carried out at a centrally located facility. The centralized facility can use mitigation measures that may not be economical at smaller facilities.

Operating requirements
Back-up systems – such as emergency generators, flares and transporting liquids by truck – should be considered if frequent interruptions to the power supply are anticipated. Extra treatment processes such as dehydration, acid-gas removal and oil polishing may also be needed on-site to make sure the product meets the specifications necessary to be transported in a pipeline.

Reduction in emissions and economic evaluation
Reductions and economic evaluations for mitigation options that require a power supply are detailed in the other engineering and design strategies.

In continental US in 2017, the cost of pipelines with a diameter of less than 20 inches (500 mm) ranged from US$29,000 per inch-mile to US$167,000 per inch-mile ($710 to $4,086 per mm-km)[1]. In continental US in 2013, the cost of above-ground power lines is estimated to have been between US$285,000 to $390,000 per mile ($177,000 to $242,000 per km)[2].

Engineering and design strategy 2:
Modular design

Well-production rates decline over time, especially for unconventional wells. Production-equipment sized for initial production will not be needed as the production from the well falls. Modular design allows for equipment to be scaled down as production rates decrease. Removing equipment is likely to reduce the number of fugitive leaks, as well as the amount of natural gas used to drive pneumatic devices. Examples of modular design includes using skid-mounted equipment that can be easily removed and replaced, having several smaller storage tanks instead of one large storage tank, and having several smaller compressors instead of one large compressor.

Operating requirements
Facilities need to be large enough to have multiple pieces of equipment rather than one large piece of equipment. Operators should regularly evaluate production rates to decide when equipment should be removed.

Reduction in emissions and economic evaluation
Reductions and costs depends on the equipment. One operator estimated savings of 4,200 Mscf (thousand standard cubic feet) per year (120,000 m^3 (cubic meters) per year) of natural gas for each storage tank removed[3]. Upfront equipment costs may be slightly more than traditional facilities due to extra equipment needing to be bought. For large-scale developments, modular design may also result in cost savings as removed equipment can be used at other facilities.

Engineering and design strategy 3: Eliminating fugitive leaks

Threaded connections and flanges are used to connect piping, equipment and other components such as valves. Threaded connections are commonly used on piping with a diameter of two inches (50 mm) or smaller. Flanges are commonly used on piping with a diameter larger than two inches. There is the potential for natural gas to leak from threaded connections and flanges. These connections can sometimes be replaced with welded connections, which are much less likely to leak.

Operating requirements

Threaded or flanged connections are needed when connecting valves or other components that need to be removed or replaced frequently, in order to avoid having to cut the piping.

Reduction in emissions and economic evaluation

During the design phase, the cost of replacing flanges or threaded connections with welds is minimal. Emissions from flanges are estimated to be between 5.7×10^{-6} and 0.39×10^{-6} kg per hour per flange[4]. Emissions from threaded connections are estimated to be between 1.0×10^{-5} and 0.75×10^{-5} kg per hour per connection[4]. Welded connections are not expected to leak.

Engineering and design strategy 4: Location of fire-gate valves and isolation valves

Isolation valves are used to isolate equipment such as compressors or separation vessels so that they can be depressurized (blowdown) for maintenance and repair purposes. Having the valves as close to the equipment as possible reduces the amount of methane released during blowdowns.

Fire-gate valves are used to isolate a facility during an emergency shutdown. Having the fire-gate valves as close as possible to the first and last piece of equipment in the facility also reduces the amount of methane released during emergency shutdowns.

Operating requirements

The location of the valves may be dictated by safety or fire protection regulations.

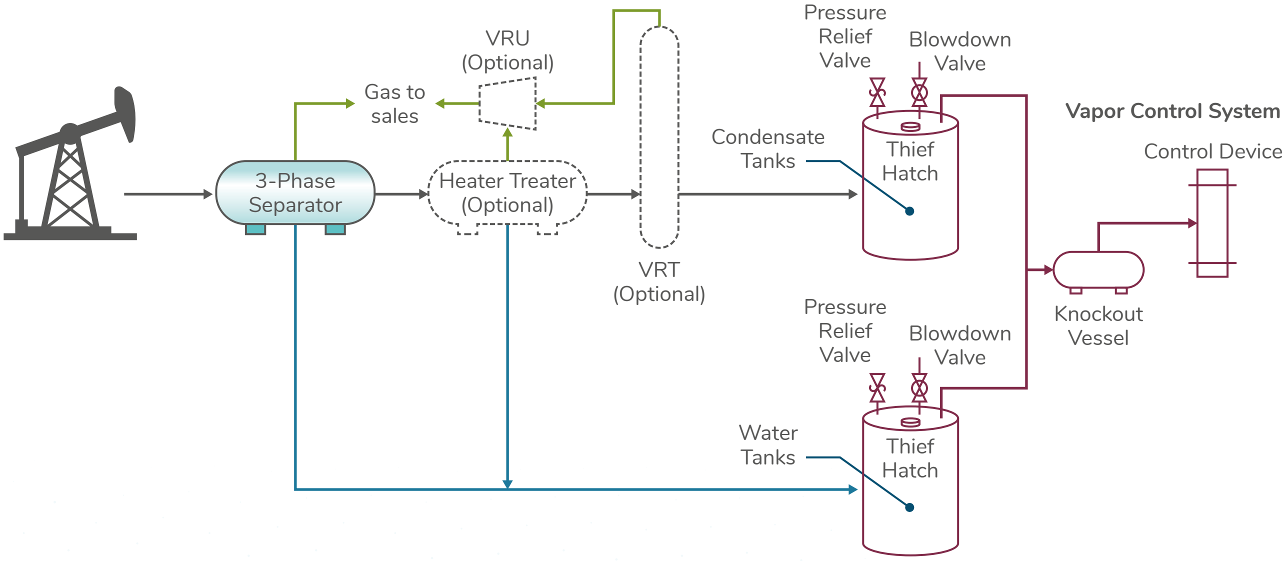
Reduction in emissions and economic evaluation

During the design phase, the cost of relocating valves is minimal. Methane reduction is based on the pressure of the pipeline or equipment and the amount of piping that needs to be depressurized during emergencies or maintenance, and the frequency of blowdown events.

Engineering and design strategy 5:
Secondary and tertiary separation

Oil and condensate need to be separated from natural gas at production facilities, compressor stations and processing plants. This separation usually occurs at high pressure, greater than 100 psig (700 kPa). When the oil or condensate is transferred from high-pressure separators to storage tanks at atmospheric pressure, 'flash gas' is released. The flash gas is typically vented from the storage tank or flared. Secondary and tertiary separation can be used to recover some or all of the flash gas and minimize flashing within storage tanks. Figure 1 shows secondary and tertiary separators represented as a heater treater and vapor-recovery tower (VRT) at a production facility.

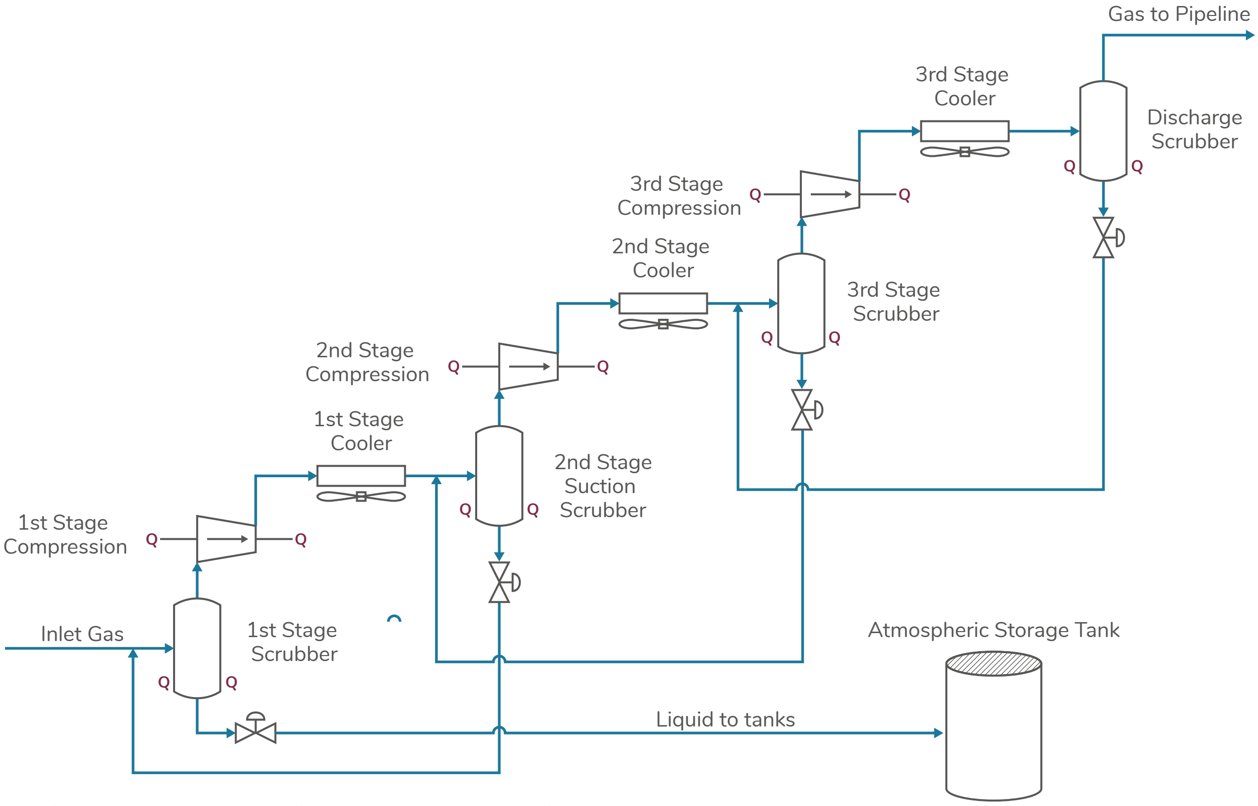
Figure 1: Secondary and tertiary separators at a production facility



Source: Reference[5]

The practice of having secondary and tertiary separation can be used for compressor scrubbers as well where condensed condensate is routed to lower-pressure vessels instead of non-pressurized storage tanks. An example is a configuration of cascading scrubbers, as shown in Figure 2, where the high-pressure condensate is routed to the next lower-pressure scrubber, and only the inlet scrubber is directed to tanks.

Figure 2: Cascading scrubber system on a compressor



Operating requirements

Vapor-recovery units (VRUs) need to be used to recover gas from the low-pressure vessels. The use of electric VRUs is preferred due to their ability to work for a wider range of flow rates than compressors driven by natural gas engines.

Reduction in emissions and economic evaluation

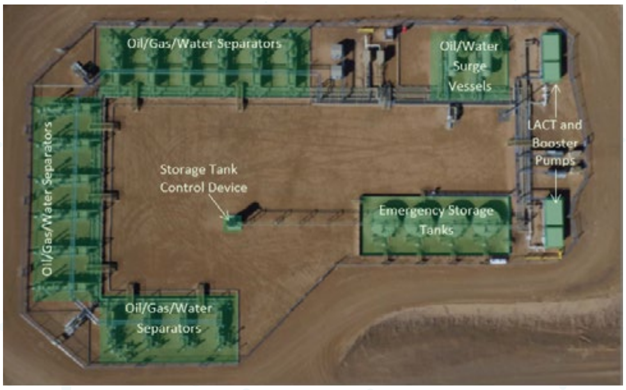
A case study from Occidental Petroleum estimated the cost of a secondary separator and VRT with VRUs to be USD$100,000 to $200,000[6]. Payback periods are typically one to five months[6].

The cost of cascading scrubbers is not known, but is likely to be minimal due to only minimal changes needing to be made to piping. Emission reductions depend on the composition of the gas, but one case study by Kent Pennybaker estimated that cascading scrubber dumps can reduce flash gas from the storage tank by 98.7% and increase the amount of gas that can be sold by 1.2%[7].

Engineering and design strategy 6:
Tankless design

Storage tanks at atmospheric pressure are used to hold crude oil, hydrocarbon condensate and produced water (and mixtures of these) before they are transferred from the site. The EPA estimates that methane from atmospheric storage tanks accounts for about 10% of the methane from the oil and gas industry[8]. One design technique is to eliminate the storage tank altogether. This 'tankless' design can be applied in various ways through production, gathering and processing operations. Examples of tankless design from a production, gathering and processing perspective are as follows.Production – liquid from the separator is transferred directly to a pipeline through an LACT (lease automatic custody transfer) unit or to a surge vessel operating at near atmospheric pressure. The surge vessel is rated for a pressure far above atmospheric pressure. The large operating range allows the vessel to accommodate fluctuations in production and changes to pressure in the tank due to flashing. Vapor generated in the surge vessel is compressed and sent to a pipeline. Figure 3 shows an example production facility using a tankless design.

Figure 3: A production facility using a tankless design



Source: Reference[9]

- Gathering – at a compressor station, liquid from a 'slug catcher' is routed directly to the facility outlet using an electric pump or blow case. The liquids are then processed at a downstream facility such as a natural-gas processing plant.
- Processing – at a natural-gas processing plant, liquid from a slug catcher is stabilized and mixed with natural-gas liquids (NGLs) in pressurized tanks or sent directly to a pipeline for NGLs.

Operating requirements

Tankless design requires access to a pipeline. The liquid may need to meet certain specifications to be transported in a pipeline. A method to re-treat or store liquid that does not meet the specifications may be needed. It may also be necessary to provide emergency storage-tank capacity so wells can produce when the facility is shut out of the pipeline.

Electricity at the facility is also important as it allows electric pumps and VRUs to be used. More frequent 'pigging' of the pipeline may be needed for systems that use the pump-around technique at compressor stations. At natural-gas processing plants, adding condensate to NGLs needs to be evaluated site by site to make sure that the NGLs can still meet the buyer's or the pipeline's specifications.

Reduction in emissions and economic evaluation

Tank emissions can be eliminated almost completely by using a tankless design. One operator reported a reduction of more than 90% in emissions by using tankless facilities[9]. Costs are likely to be less than traditional facilities due to reduced equipment and size of sites.

Engineering and design strategy 7: Storage tank design

The control systems for storage tanks can be difficult to design due to their very narrow operating pressure range, typically less than 1 psig (7 Kpa). Snap-acting valves, plunger-lift systems and pigging can result in variations in liquid and vapor flow rates into the control system. The control system for storage tanks at atmospheric pressure needs to be adequately designed so that the pressure-relief devices do not vent to the atmosphere and all vapors from the storage tank are directed to the control device or VRU during reasonable peak production rates. The design needs to take account for the maximum vapor and liquid flow rates, which may be different from the daily production rates, especially for systems with snap-acting valves or wells on plunger lift. The design should assess the capacity of the control device, and pressure drop through the vapor-collection piping.

Operating requirements
Modeling may be needed to determine the peak storage pressure.

Reduction in emissions and economic evaluation
The cost to carry out a design assessment on storage-tank control systems in continental US is estimated to be $550-$360 per facility[10].

Engineering and design strategy 8: Using electric compressors

Compressors are used to move natural gas through pipelines, as well as to recover gas from low-pressure systems. Engines that run on natural gas are commonly used to drive compressors. An alternative is to use electric motors to drive compressors. Natural-gas engines can only run at a minimum of 50% of their maximum power. Electric motors with variable frequency drives can run at very low loads. Electric motors also need less maintenance than natural-gas engines and so are more reliable.

Operating requirements
A power supply is needed to run electric compressors. Large compressors may need high-voltage lines. A back-up generator may be needed for areas where the power supply is not reliable.

Reduction in emissions and economic evaluation
Electric compressors are estimated to save 2.11 Mscf of gas per horsepower (80,000 m^3 per kilowatt) of the compressor. The cost depends on the size of the compressor. One case study estimated the initial outlay was $1,500,000 for a 1,750 horsepower (1,300 kW) engine. Annual operating costs were approximately equal to the initial capital cost and are mostly due to the cost of electricity[3].

Engineering and design strategy 9:
Pig ramps and jumper lines

A pig (pipe inspection gauge) is used to inspect pipelines and push accumulated liquids through them to downstream facilities. A pig trap at the beginning of the pipeline is depressurized to allow the pig to be inserted into the pipeline. The pig trap is then pressurized to send the pig down the pipeline. The pig is received into another pig trap at the other end of the pipeline (the receiver). In the receiver, some liquid is trapped in front of the pig as well as on the pig itself. When the pig is removed, methane is released due to flashing from the trapped liquid. Pig ramps allow liquids in front of and on the pig to be captured and sent to the pipeline before the pig trap is depressurized, reducing flashing emissions. Jumper lines can partially depressurize the trap to reduce venting from pigging operations.

Operating requirements

Pig ramps are mostly passive devices, but extra time may be needed from the pig being received to it being removed from the receiver to allow the liquids to drain back to the pipeline. A low-pressure system also needs to be available on-site to accept the gas from the pig trap.

Reduction in emissions and economic evaluation

MPLX estimates that using pig ramps and jumper lines can reduce emissions from pigging by up to 85%[11] at a cost of approximately US$8,175 per facility[11].

Engineering and design strategy 10:
Using methanol to prevent hydrates

During cold weather, water can freeze and form hydrates in pipelines, which can inhibit the flow of natural gas. When hydrates are a concern, a glycol dehydrator is typically used to remove water from the natural gas. Glycol also absorbs some methane, which is vented to the atmosphere during glycol regeneration. Methanol can be used instead of glycol dehydration to inhibit the formation of hydrates. Methanol is simply injected into the gas before it enters the pipeline and is removed downstream.

Operating requirements

Methanol needs to be injected from an atmospheric tank into the pressurized natural gas using a pump. The pumps are typically easy to use and are solar-powered. Methanol will need to be delivered to each facility by truck.

Methanol needs to be removed from the natural gas during processing, usually during normal separation and acid-gas removal.

Reduction in emissions and economic evaluation

Emission reductions are estimated at 800 Mscf (22,500 m^3) of natural gas per facility. The cost is estimated at US$2,250 per installation plus operating costs of US$3.45 per MMscf (US$121 per 10^6 m^3) of natural gas[3].

Engineering and design strategy 11:
Amine unit flash tank

Sour gas, which contains high concentrations of sulfur compounds, mainly hydrogen sulfide and carbon dioxide, needs to be treated to remove those compounds. Amine units are one method of removing those compounds. The most common amine used is methyl diethanolamine. The amine is circulated through a tower and absorbs the compounds from pressurized natural gas. Amine also picks up methane from the gas. The amine is then sent to a regenerator to remove the carbon dioxide and sulfur so the amine can be reused. The removed carbon dioxide and sulfur is called acid gas which is normally vented to the atmosphere.

A flash tank can be installed upstream of the regenerator to recover some of the methane picked up by the amine. The flash tank is at a lower pressure than the tower and some of the methane flashes when the amine drops in pressure as it enters the flash tank. The methane can be recovered to a low-pressure system such as the facility fuel system.

Reduction in emissions and economic evaluation
Reductions depend on the system, but are expected to be 90%, similar to that of installing a flash tank on a glycol dehydration unit[3]. Costs vary depending on the size of the tank installed.

Engineering and design strategy 12:
Acid gas control device

Acid gas discharged from treatment with amine is typically very high in carbon dioxide and sulfur, with a small concentration of hydrocarbons. The acid gas may need to be controlled, for safety reasons or to meet environmental standards. Acid gas with a high proportion of carbon dioxide does not have enough heat content (calorific value) to be burned in a flare or combustor. 'Assist gas', typically fuel gas, can be added to the acid gas to bring the heat content up to at least 300 Btu/scf (11.2 MJ/scm)[12]. The assist gas needed may be quite large depending on the volume of acid gas to be recovered. Direct thermal oxidizers may be used to oxidize methane, but traditional thermal oxidizers need a large volume of fuel to keep the combustion chamber at the required temperature.

'Recuperative' or 'regenerative' thermal oxidizers are more fuel-efficient ways of controlling acid gas. These control devices recover waste heat, reducing the amount of fuel needed to keep the combustion chamber at a high enough temperature.

Operating requirements
Thermal oxidizers need a special design for corrosive gases like acid gas. Thermal oxidizers also need power to run fans, controls and valves.

Reduction in emissions and economic evaluation
Reductions depend on the size of the amine unit. One company reported saving up to USD$750,000 per year in fuel costs by replacing a thermal oxidizer with a regenerative thermal oxidizer[13].

Checklist

The following checklist allows you to assess your progress in reducing methane emissions through the design of systems.

Activity	Completed	Percentage of all equipment or processes in this program
Include methane reduction in standard design practice		
Use electric, mechanical and compressed-air equipment where feasible		
Centralize facilities		
Use pipelines to transport oil and natural gas from facilities		
Recover methane where feasible		
Control methane where recovery is not feasible		
Use alternative low-emission equipment and processes		
Use alternative low-maintenance equipment and processes		

Appendix 1: mitigation strategies that can be used with in the design stage

Source of emissions	Description of mitigation strategy	Guide to refer to
1. Gas flaring	**Reinjection** Inject gas back into the oil or gas reservoir to increase recovery.	Flaring
	CNG trucking Compress natural gas to be transported off the site by truck.	Flaring
	Recover NGL Use a system to recover natural-gas liquids.	Flaring
	Gas to power Use gas turbines or a reciprocating engine to generate electricity.	Flaring
2. Storage tanks: flash gas	**Use vapor-recovery units (VRUs)** Install a VRU so gas can be used, sold or flared.	Venting Flaring
	Reduce operating pressure at facilities upstream Install stabilization towers or a vapor-recovery tower (VRT) ahead of tanks to reduce the pressure of gas.	Venting Flaring
	Increase tank pressure Set pressure-relief devices at or near the design pressure of the storage tank.	Venting
	Eliminate tanks at production sites Use lease automatic custody transfer (LACT) systems to transfer liquids directly from separators to the pipeline.	Venting
3. Storage tanks: loading and unloading emissions	**Add automatic-gauging systems** Auto-gauging systems eliminate the need to open the hatch to gauge storage tanks during normal operation and when loading liquids onto trucks for transporting.	Venting
	Introduce a system to balance or exchange vapors between the tanks and tank vehicles Vapor-return lines collect vapors displaced in the truck while liquids from tanks are being loaded and either returns the vapors to the tanks (vapor balance) or sends them to a control device.	Venting

Source of emissions	Description of mitigation strategy	Guide to refer to
4. Compressors: centrifugal	**Use dry seals** Only buy compressors that have dry seals. (About 90% of compressors have dry seals.) Dry seals generally use less power, are more reliable and need less maintenance.	Venting
5. Compressors: starters	**Use electric starters** Emissions can be eliminated by using electric starters instead of pneumatic starters driven by natural gas.	Venting Energy use
	Use compressed-air starters Emissions can be eliminated by using starters driven by compressed air rather than natural gas.	Venting Energy use
	Direct emissions from starters to a vapor-recovery unit (VRU) or flare Natural gas from pneumatic starters are routed to a VRU so they can be used or sold, or sent to a flare.	Venting
6. Glycol dehydrators: regenerator vent	**Use a zero-emissions dehydrator system** Desiccant dehydration systems do not give off any emissions during normal operations.	Venting
	Use electric lean glycol pump Electric pumps eliminate the need to use pneumatic pumps driven by natural gas.	Venting
	Use flash-tank separators Flash tanks separate some methane from rich glycol before the regenerator so that it can be returned to the process or used (for example, as fuel).	Venting
7. Pneumatic devices	**Use electric or mechanical devices** Using mechanical or electric devices eliminates the need for pneumatic devices.	Pneumatic devices
	Use a compressed-air system Used compressed air, rather than natural gas, to drive pneumatic devices.	Pneumatic devices
	Use intermittent-vent or low-bleed devices Intermittent-vent and low-bleed devices use less natural gas than high-bleed devices.	Pneumatic devices

Source of emissions	Description of mitigation strategy	Guide to refer to
8. Fuel usage	**Install electric compressors** Equipment that uses natural gas as a fuel releases some methane that hasn't burned. Electric compressors eliminate the use of natural gas as fuel.	Energy use
	Replace cylinder unloaders Unloaders leak methane through o-rings, covers and pressure packing.	Energy use
	Install air-to-fuel ratio controls The increased use of air-to-fuel ratio controllers on compressor engines to control the amount fuel used has resulted in more efficient combustion engines, which use less fuel.	Energy use

References

1 The Interstate Natural Gas Association of America (INGAA) Foundation Inc, 'North America Midstream Infrastructure through 2035, June 2018

2 Frank Alonso and Carolyn AE Greenwell, 'Underground vs Overhead: Power Line Installation-Cost Comparison and Mitigation', presentation at the Electric Light & Power Executive conference, February 2013, Available at **www.elp.com/articles/powergrid_international/print/volume-18/issue-2/features/underground-vs-overhead-power-line-installation-cost-comparison-.html**

3 Natural Gas Star Program 'Recommended Technologies to Reduce Methane Emissions', a program by the United States Environmental Protection Agency (US EPA), Available at **www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions**

4 Mandatory Greenhouse Gas Reporting Rule (MGGR) for Petroleum and Natural Gas Systems, 40 CFR Part 98, Subpart W

5 Occidental Petroleum Corporation and California Independent Petroleum Association 'Vapor Recover Tower/VRU Configuration ', presented at the Natural Gas STAR Producers Technology Transfer Workshop, August 2007

6 Kent A Pennybaker, 'Optimizing Field Compressor Station Designs', for River City Engineering Inc, Society of Petroleum Engineers, March 1998

7 US EPA, 2017 Greenhouse Gas Reporting Program Industrial Profile: Petroleum and Natural Gas Systems

8 Industry Statewide Hydrocarbon Emissions Reduction (SHER) LACT and Tankless subgroup 'Lease Automatic Custody Transfer (LACT) and Reduced Oil Tank Facilities', July 2018, Available at **www.drive.google.com/open?id=1NMareyGM9jXizG5uXM-mzHuozQrJKM5e**

9 US EPA, Background Technical Support Document for the Proposed Reconsideration of the New Source Performance Standards 40 CFR Part 60, subpart OOOOa, September 2018.

10 MPLX LP, 'Pipeline Launcher/Receiver Emission Reduction Systems, 'Available at **www.mplx.com/content/documents/mplx/markwest/Launcher%20Receiver%20Design%20Detail.pdf**

11 US EPA, 'MarkWest Clean Air Act Settlement Information Sheet', May 2018 Available at **www.epa.gov/enforcement/markwest-clean-air-act-settlement-information-sheet**

12 New Source Performance Standards (NSPS) 40 CFR Part 60.18 General Control Device and Work Practice Requirements

13 Anguil Environmental Systems Inc, 'Amine Tail Gas Treatment', Available at **www.anguil.com/case-studies/natural-gas-processing/amine-tail-gas-treatment**

METHANE
GUIDING
PRINCIPLES

methaneguidingprinciples.org

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.