TECHNICAL GUIDANCE DOCUMENT NUMBER 9: CASINGHEAD GAS VENTING

Introduction

This document provides technical guidance to Partners of the CCAC Oil and Gas Methane Partnership (OGMP). It is one in a series describing a core source of methane emissions from oil and natural gas production operations. The guidance documents introduce suggested methodologies for quantifying methane emissions from specific sources and describe established mitigation options that Partners should reference when determining if the source is "mitigated."[1] The OGMP recognizes that the equipment and processes described in these documents are found in a variety of oil and gas operations, including onshore, offshore, and remote operations, and the way in which the emissions are quantified and mitigated may vary across locations and operational environments. As such, operational conditions, as well as logistical, safety, and cost considerations, must be evaluated on a case-by-case basis. The OGMP assumes that methane emission mitigation actions that require shut-downs of non-redundant equipment/processes (e.g., that would stop operations) would be carried out during regularly scheduled maintenance activities, unless the Partner deems the corrective action to be worthy of an early/additional shut-down.

Description of Source

Casinghead gas is gas that collects in the annular space between the casing and tubing in an oil well. Usually beneficial, casinghead gas forces the produced oil up the tubing. In a mature oil well equipped with a beam pump or electric submersible pump, however, this gas can begin restricting oil flow, decreasing a well's production by vapor locking the pump. Combined with the backpressure of an oil well's surface equipment, pressure from casinghead gas can severely restrict production. Partners must remove casinghead gas pressure build-up in a well's annular space to maintain production. One of the methods to do this is to vent the casinghead gas to the atmosphere at or near the wellhead.
Casinghead gas venting can occur, and may be mitigated, in a variety of ways. Partners are encouraged to identify and deploy appropriate controls for each oil well. Some options include those listed in the following Table 9.1.

For the purposes of the OGMP, Partners will quantify and evaluate for mitigation any configuration presented in Table 9.1 that is identified as "unmitigated" for methane emissions, as described in the sections below. Even for "mitigated" configurations, Partners should evaluate the system to ensure that it is functioning properly and minimizing methane emission levels. Possible equipment failures resulting from improperly functioning systems include a well compressor malfunction, a VRU malfunction, or an extinguished flare. Moreover, Partners should evaluate gases routed to a flare (flow rate, composition) to estimate methane emissions resulting from the flare combustion efficiency.

[1] For reporting purposes as described in the CCAC Oil and Gas Methane Partnership Framework, Section 3.

Table 9.1: Configurations for Casinghead Gas Venting

Configuration	Mitigated or Unmitigated
Casinghead gas is vented directly to the atmosphere, either continuously or periodically to relieve pressure build-up. Exhibit A	Unmitigated
Casinghead gas is recovered by a wellhead compressor/vapor recovery unit (VRU) and routed to sales or for on-site use. Exhibit B	Mitigated (if confirmed to be functioning with low[A] or no emissions) **(OPTION A)**
Casinghead gas is routed to tanks with new or existing VRU systems and routed to sales or for on-site use.	Mitigated (if confirmed to be functioning with low[A] or no emissions) **(OPTION B)**
Casinghead gas is routed to a flare.[2] Exhibit C	Mitigated (if confirmed to be functioning with low[A] or no emissions) **(OPTION C)**

[A] Expected emissions levels if mitigation option is in place and functioning properly (e.g., flare is not extinguished, etc.).

<u>Quantification Methodology</u>

To ensure consistent quantification of annual, volumetric, casinghead gas venting emissions and comparable evaluation of mitigation options, the OGMP recommends that Partners use one of the following two quantification methodologies: direct measurement or engineering calculation. In principle, direct measurement is the most accurate method for quantifying methane emissions.[3] With direct measurement, Partners can be more certain of emissions levels and economic costs and benefits (i.e., value of gas saved). As such, measurement is highly encouraged whenever possible. Individual Partners may choose an alternative quantification methodology if judged to be more accurate by the Partner; in this case, the Partner should document and explain the alternative methodology in the Annual Report.

- <u>Direct Measurement</u>[4]:
  These methodologies give the flow rate for total gas, which is then converted to methane flow rate using the methane content of the gas. The methane flow rate then needs to be extrapolated over the

[2] "Flare" in this document refers to a vertical combustion device using an open or enclosed flame.

[3] Partners should conduct measurements with appropriately calibrated instruments and per the instrument manufacturer instructions. Measurements should also be conducted in different operating conditions, to the extent that those can affect emissions levels. Appendix A to the Technical Guidance Documents includes guidance on instrument use. Partners seeking to generate Emission Factors for their operations should use direct measurement based on a statistically sound number of measurements and gas analyses to understand the content of methane and other valuable hydrocarbons.

[4] Greenhouse Gas Reporting Program. Subpart W – Petroleum and Natural Gas Systems. Section 98.234: Monitoring and QA/QC requirements, 40 CFR 98.234(b). http://www.ecfr.gov/cgi-bin/text-idx?SID=82b3acbd3d06d1ee2c38a34ba97f132b&mc=true&node=sp40.23.98.w&rgn=div6#se40.23.98_1234.

entire year. The annual volume of methane emissions is calculated by multiplying the measured methane flow rate by the operating hours of the well.

Determining the point where the casinghead gas is being vented is essential so that accurate measurements can be taken. Typically, an oil wellhead has a designated gas vent line for casinghead gas. Each wellhead setup is unique, however, and a wellhead could have multiple lines for venting casinghead gas. Partners should confirm the locations of all lines before measuring casinghead gas. Recommended measurement tools include the following:

- Turbine meter.
- Hotwire anemometer.
- Vane anemometer.

Viewing all gas lines with an infrared leak-imaging camera (designed to visually identify hydrocarbon emissions) during venting of casinghead gas will also help to identify potential fugitive leak emissions.

For more details regarding each measurement and detection tool, including applicability and measurement methods, please refer to Appendix A.

- <u>Engineering Calculation</u>:
  An engineering calculation relies on a representative sample of well production taken with no casinghead gas venting: i.e. capture all gas and oil entering the well casing. This may be more costly and less accurate than direct measurement, given the sampling method can affect the production rate and composition. From this sample a gas/oil ratio (GOR) may be determined. For mature wells, Partners should use the estimated well's producing GOR (scf/bbl or scm/bbl) multiplied by the production rate of oil per year (bbl/year) and the methane content of the gas to estimate annual methane emissions. Oil wells with casinghead gas venting are typically mature and thus pump nearly "dead" crude from the reservoir. This crude contains a very small amount of dissolved gas, most of which escapes into the casing before the crude is pumped up the tubing to the surface. Periodic venting the casinghead gas often is necessary to avoid vapor locking the down-hole pump.

<u>Mitigation Option A – Install compressors/VRUs to capture casinghead gas.</u>

Partners have found that using a small wellhead reciprocating compressor can facilitate recovery of previously vented casinghead gas to sell or to use on site as fuel. Drawing down the casing pressure can also increase oil production. Traditionally, companies have used a skid-mounted compressor to recover vented gas. Ideally, the compressor would maintain the casinghead gas pressure as close as possible to zero pounds per square inch gauge (psig) without pulling a vacuum. Maintaining a constant zero pressure helps stabilize the oil line pressure and reduces fluctuations in flow. When feasible, multiple wells can be connected to a single compressor to optimize cost.

Partners can use either a wellhead reciprocating compressor or a VRU to recover casinghead gas. Depending on the characteristics and the destination of the recovered gas, one of these options might make more sense than the other. A typical VRU is designed to maintain a suction pressure near-atmospheric pressure. For wet-screw, rotary-vane, or scroll-type, single-stage compressors, the discharge is limited to about 100 psig (7 kg/cm^2) by the compression ratio. If the gas destination is at a pressure greater than 100 psig (7 kg/cm^2), Partner will need to use two-stage compression with intercooling, which might require a reciprocating compressor.

Operational Considerations

For capturing wet casinghead gas at near-atmospheric pressure, a skid-mounted VRU type wellhead compressor is best. Viable compressor types include rotary-vane, rotary-screw, and scroll. For high compression ratios, such as a strong vacuum on the casing or high discharge pressure or both, Partners can use two- or three-stage compression. Rotary-vane compressors generally have proven to be the most cost-effective when handling small volumes of casinghead gas. Casinghead gas typically is wet because it flashes off from the underground oil reservoir that has a specific gravity of around 0.85 (16 gallons of liquid per Mscf gas)[5] (2.1 liters liquid per scm gas). Both rotary-vane and scroll compressors can handle wet gas effectively, but reciprocating compressors generally cannot, so the first stage in multi-stage compression should be one that handles wet gas effectively. All compressors, and all compression stages in multistage compressors, must have a suction scrubber to handle liquid slugs.

Skid-mounted compressors can be powered by an electric motor or a combustion engine, typically ranging from 10 to 200 horsepower (HP). The availability of a power source, either electricity or fuel gas, primarily determines which option is more viable. If electricity is not available, a beam-mounted compressor is an option. Beam-mounted compressors use the mechanical energy from a well’s rod pumping unit to pull gas from the casing and discharge it into a flow line. These compressors can be single- or double-acting (able to compress on both strokes). Not all wells respond favorably to reduced casinghead pressure, and there is no quick means to predict the response. Companies might want to test some wells in a reservoir before they purchase or lease compression equipment to determine how the wells will respond. If the response is favorable, testing also can confirm whether the increased productivity is temporary or sustained. Every well and reservoir have different characteristics. Specific gravity, gas volume, and pressure of the discharge line for the casinghead gas are some critical factors that Partners should consider when purchasing or designing a wellhead compressor or VRU. Even wells from the same formation can respond differently to casinghead gas capture, which also points to the need for testing. A general guideline is if oil production increases remain constant 30 to 45 days after testing, venting casinghead gas is appropriate.

Experience has shown that casinghead gas capture typically is more successful for wells with water or carbon dioxide floods. Wells with enhanced oil recovery (where produced gas can be reinjected into the reservoir) also are good candidates for casinghead gas capture. One vendor estimated that approximately 65 percent of mature oil wells are appropriate for casinghead gas capture.[6] To avoid a large pressure drop, the compressor or VRU should not be placed too far from the wellhead.

In some situations, a compressor or VRU can be linked to multiple wells. The connected wells should be located near each other and have similar surface pressures. This will help ensure the compressor or VRU pulls on the wells equally, allowing their surface pressures to be closer to zero psig (zero kg/cm^2) gauge pressure. Also, the closer the wells are to each other and to the compressor or VRU, the smaller the pressure drop will be in the suction flow lines. Partners should take into consideration for this option, however, that depending on a single unit could be problematic when the compressor or VRU is down for repair or maintenance, and gas from several wells requires venting.

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[5] Natural Gas STAR Partner Update. Winter 2010. *Technology Spotlight: Casinghead Gas Capture*. https://www.epa.gov/sites/production/files/2016-06/documents/ngspartnerup_winter10.pdf .

[6] Ibid.

The compressor or VRU to capture casinghead gas would be installed when the well is down. When the adequate sales gas line capacity and/or existing infrastructure for recovered gas is available, the installation requires:

- Piping.
- Equipment to treat liquids (e.g., drip pots, suction scrubber, gas/liquid separator).
- Pressure regulators.
- Wellhead compressor or VRU system (includes suction scrubber/separator; compressor[7]; liquid transfer pump; electric programmable logic controller (PLC); associated discharge piping, instruments, valves, and controls).

Methane Emission Reduction Estimate

In general, Partners can reduce methane emission from casinghead gas venting by approximately 95 percent after implementing this project.[8] Theoretically, compressors or VRUs can recover nearly all casinghead vapors, an operating factor of 95 percent allows for 5 percent annual compressor downtime due to maintenance.

Economic Considerations

The major costs associated with this project are:

- Equipment costs of compressor package/VRU system, piping, liquid treatment equipment, pressure regulators.
- Installation costs.
- Annual operating and maintenance (O&M) costs for electricity or fuel.

Costs will vary among well sites and depend on the compressor type/size, piping distance from the wellhead to the compressor, and distance from the compressor to the destination for the gas. The following scenario example is taken from the Natural Gas STAR technical document *Install Compressors to Capture Casinghead Gas*.[9] Capital costs for connecting casinghead gas to a new compressor would be approximately $12,500 for a 30-HP electric rotary compressor capable of delivering up to 200 Mscf (5.7 Mscm) of gas per day[10] into a 100-psig (7 kg/cm^2) sales line.[11,12] Installation costs are assumed to be 1.5 times the equipment cost, bringing the total implementation cost to nearly $32,000.[13] Additional operating costs would include the electricity to power the compressor, which (assuming the compressor operates for half the year and electricity costs $0.075 per kilowatt-hour (kWh)) would bring the annual operating costs to $7,350.[14]

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[7] Typically electric-driven rotary vane, rotary screw, or scroll compressor. For more information, see Technical Document Number 6 for a description of Hydrocarbon Liquid Storage Tanks.

[8] EPA. 40 CFR Part 60, Subpart OOOO: Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. Final Rule. pg. 49526. August 16, 2012. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

[9] EPA. PRO #702: *Install Compressors to Capture Casinghead Gas.* June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/installcompressors.pdf.

[10] Assumes design capacity is double the average vapor recovery rate.

[11] EPA. Lessons Learned: *Installing Vapor Recovery Units on Storage Tanks*. pg. 5. June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/ll_final_vap.pdf.

[12] EPA. PRO #702: *Install Compressors to Capture Casinghead Gas*. pgs. 1, 2. 2016. https://www.epa.gov/sites/production/files/2016-06/documents/installcompressors.pdf.

[13] Ibid.

[14] Ibid.

The primary benefit of this project is the additional revenue received from the increased oil production. Secondary benefits include the sales of previously uncollected associated gas and the reduction in emissions. As illustrated in the example in Table 9.2, the value of the recovered gas would be $104,800 annually based on a gas price of $3 per thousand Standard cubic feet (Mscf) - a quick payback for this project. The value of the increased oil production, however, is likely to be even greater.

Table 9.2: Project Costs and Savings for Casinghead Vent Gas Recovery with a Compressor (Example Scenario)

Project Component	Implementation Costs	Annual Costs
Capital Cost[A]	$12,500	–
Installation Costs[B]	$18,750	–
O&M Costs (Electricity)[C]	–	$7,350
Gas Savings[D]	–	-$104,800
Total	**$31,250**	**-$97,450**

[A] For a 30-HP electric rotary compressor able to deliver up to 200 Mscf (5.7 Mscm) of gas per day to a 100-psig (7 kg/cm^2) sales line.
[B] Assumed to be 1.5 times equipment cost.
[C] O&M = engine horsepower × operating factor × 8,760 hours/year × electricity cost.
[D]Half of design capacity with a 95% operating factor, $3/Mcf gas value.

For more information, see the Natural Gas STAR technical document *Install Compressors to Capture Casinghead Gas* (https://www.epa.gov/sites/production/files/2016-06/documents/installcompressors.pdf).

Mitigation Option B – Connect casing to tanks equipped with vapor recovery units.

Tanks near wells that vent casinghead gas might already have a VRU installed. VRUs can have a wide application at production sites that have crude oil or condensate storage tanks with significant vapor emissions. Partners can take advantage of the similarities in gas composition, pressure, and flow rates between tank emissions and casinghead gas.

Operational Considerations

Partners should take advantage of VRU equipment that is the already available at their sites. Partners also should install pressure regulators if low-pressure casinghead gas is joined with sources having higher pressure (e.g., dehydrator flash tank separator) at the VRU suction point. Connecting casinghead gas to an existing VRU is convenient and cost-effective because only small-diameter piping and pressure regulators are required to join the vent to VRU suction. This project is applicable to wells producing through tubing with packerless completions.[15]

Partners will connect the casinghead gas to a VRU during well downtime to minimize incremental production loss. The connection requires installing:

[15] EPA. PRO #701: *Connect Casing to Vapor Recovery Unit*. pgs. 1, 2. 2016. https://www.epa.gov/sites/production/files/2016-06/documents/connectcasingtovaporrecoveryunit.pdf.

- Piping.
- Pressure regulators.

Methane Emission Reduction Estimate

Theoretically, VRUs can recover nearly all casinghead vapors routed to a storage tank. Based on a VRU operating factor of 95 percent (allowing 5 percent annual downtime of the VRU for maintenance), Partners can expect to reduce methane emissions by up to 95 percent after implementing this technology.[16]

Economic Considerations

Costs for routing casinghead gas to a VRU would be approximately $4,300.[17] Additional operating costs include the increased electricity consumption, reported by Partners to be approximately $3,400 per year (at $0.075 per kWh).[18] As with a newly installed compressor or VRU, cost savings would derive from increased oil production and the capture and sale of previously vented gas. For annual gas savings of 7,800 Mscf (221 Mcm) at $3 per Mscf, the value of the recovered gas would be $23,400. The value of this recovered gas would help pay back the additional electricity and piping costs for this project and the value of the increased oil production is likely to be even greater.

For more information, see the Natural Gas STAR technical document *Connect Casing to Vapor Recovery Unit* (https://www.epa.gov/sites/production/files/2016-06/documents/connectcasingtovaporrecoveryunit.pdf).

Mitigation Option C – Route casinghead gas to flare.

Two possible scenarios for this project are: route to an existing flare or route to a newly installed flare. If an existing flare is within reasonable proximity, however, this scenario is preferred, as routing casinghead gas to an existing flare, provided operational and safety conditions allow, rather than installing a new one is easier and lower cost for Partners. The more casinghead vents that can be routed to a single flare will help improve project viability, in terms of cost versus methane reductions achieved, in addition to other benefits. Partners should route casinghead gas to a recovery outlet whenever possible; sending the gas to a flare should be a last resort. Additionally, in some cases a lit flare might have higher greenhouse gas emissions than an unlit flare, (i.e. taking into account the safety flaring: purge gas and pilot gas burned to ensure the safe operation of the flare), which Partners should take into account when considering implementing this project.

Operational Considerations

A wellhead can have a flare stack for emergency releases, blowdowns, etc. For this project, if a flare is installed, all that would then be required is additional piping to route the casinghead gas vent to the flare. If no flare exists, however, Partners will have to install one. Partners should also consider proximity of the flare to the well(s) when deciding to implement this project.

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[16] EPA. 40 CFR Part 60, Subpart OOOO: Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. Final Rule. pg. 49526. August 16, 2012. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

[17] EPA. PRO #701: *Connect Casing to Vapor Recovery Unit*. pgs. 1, 2. 2016. https://www.epa.gov/sites/production/files/2016-06/documents/connectcasingtovaporrecoveryunit.pdf.

[18] Ibid.

Partners would connect casinghead gas to the flare during downtime to minimize incremental production loss. The connection requires installing:

- Piping.
- Flare stack (if there is no existing flare in proximity).

Methane Emission Reduction Estimate

The methane reductions achieved will depend on the combustion efficiency of the flare. For a typical production flare using a continuous ignition source with an independent external fuel supply, Partners can generally expect to reduce methane emissions from casinghead venting by more than 95 percent after implementing this technology.[19]

Economic Considerations

Costs for routing casinghead gas to an existing flare stack likely would be negligible because the primary cost is for additional piping. The operating cost for supplying additional pilot or fuel gas to the flare, if necessary, might be slightly higher. This incremental cost should also be negligible, however, when compared to a Partner's other costs. If a new flare stack and a continuous ignition source are installed, the cost could be approximately $21,000.[20]

[19] EPA. 40 CFR Part 60, Subpart OOOO: New Source Performance Standards (NSPS). Background Technical Support Document (TSD). §60.5412, page 35897. June 2016. https://www.federalregister.gov/documents/2016/06/03/2016-11971/oil-and-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources

[20] EPA PRO Fact Sheet 904: Install Flares, June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/installflares.pdf

Exhibit A – Manually Venting Casinghead Gas[21]

Exhibit B – Casinghead Gas Recovered by a Wellhead Compressor[22]

[21] Global Methane Initiative, Natural Gas STAR International, Bucaramanga, Colombia, May, 2012: "Ecopetrol Eco-Efficiency, Methane Emission Reduction Opportunities," presented by EPA

[22] Natural Gas STAR Annual Implementation Workshop, Denver, Colorado, April 12, 2012: "Salem Unit Casinghead Gas Project," presented by Citation Oil & Gas Corp. and Hy-Bon Engineering

Exhibit C – Casinghead Gas Routed to a Flare[23]

[23] Natural Gas STAR Annual Implementation Workshop, Denver, Colorado, April 12, 2012: "Salem Unit Casinghead Gas Project," presented by Citation Oil & Gas Corp. and Hy-Bon Engineering