

## OPTIMAL SIZING OF MUD GAS SEPARATORS IN WELL PLANNING FOR EFFECTIVE WELL CONTROL IN DRILLING OPERATIONS

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Received November 28, 2018; Accepted January 18, 2019

### Abstract

Gas kicks are circulated out of the well through mud gas separators by applying well control procedures. The large volumes of gas reaching the surface are directed to the mud gas separator where they are separated from the mud and safely vented out. This paper investigates the optimal capacity (size) of the mud gas separator to effectively separate and vent large gas cuts from mud safely and in a controlled manner. The paper presents a model for the mud gas separation from a functional point of view, and a procedural technique combined with well control data for proper sizing of a mud gas separator. The procedure and simulation illustrated how blow-through can be avoided in any mud gas separator and how to troubleshoot an ineffectively sized separator. A model was developed to effectively size mud gas separators considering the vent line pressure, separation capacity, mud seal leg and other associated parameters. In the case study presented and validated, the optimum mud gas separator internal diameter was found to be 27.3 inches with a mud leg pressure of 3.6 psi under well conditions of peak gas flow rate of 2.74 MMSCF/D using a 230 ft gas vent line with 3 right-sharp bends resulting to a vent line pressure of 1 psi. This model will enhance the sizing and operation of mud gas separators, and will also be a good guide for the upgrade of undersized mud gas separators.

**Keywords:** mud gas separator; Blow-through; vent line pressure; mud seal leg; well control.

### 1. Introduction

As the complexity of exploration of oil and gas in terms of depth, high temperature/high pressure (HT/HP) continually increases, the drilling of these reservoirs and wells have been a challenge in the drilling industry. Pressures of 10,000 psi and above; pore pressures of at least 0.8 psi/ft with associated temperatures greater than 350°F are common in such complex terrain [1].

Severe well control incidents have compelled investigation and re-examination of the equipment and procedures used in drilling these wells. Gas venting rates resulting from kicks in high-pressure wells can approach the equivalent production of a commercial gas well as would be demonstrated in this paper. Gas kicks pose the potentially worst problems encountered during drilling; they occur when formation pressure exceeds the mud hydrostatic pressure. In a situation where nothing is done, the gas kick may go out of hand and become a full blowout. Loss of lives; severe injuries; environmental pollution and a loss in revenue are all consequences of a blowout [2]. As such, the gas is removed by circulating mud and maintaining wellbore pressures to avoid more gas influx.

When a kick is being circulated out of a well, the gas and mud which returns to the surface are both channelled towards the choke line and then goes into the Mud Gas Separator (MGS). Pockets of free gas are separated from the mud in the MGS, which also acts as a venting unit

for the separated gas. In an event where the MGS gets loaded beyond its capacity, the separation may end up being inefficient and thereby resulting in a very dangerous situation where the mud and gas are being returned together into the mud pits and other mud processing facilities.

Separator malfunction can cause live crude, condensate, and drilling mud to be expelled by the gas through the gas vent line. Especially for platforms off shores where the derrick top is the likely point of the gas vent line discharge, it is extremely dangerous as the liquids will most likely fall back on the drilling floor (platform). The volatile condensate/oil mixture will collect close to the deck space and can be ignited by a spark.

Due to the hazards of mud gas separator blow-through, there is a need for gas processing equipment to handle increasing volumes of gas influx in the industry. Typical practice does not consider the MGS limitations, however rather focuses on well control, expecting that the MGS can deal with whatever gas volume is present. The challenge is clear-cut, that as oil and gas exploration continues into deeper and higher pressure reservoirs, the safe operations of the MGS are often exceeded. Although MGS modification and re-design has improved its capacity appreciably, space restrictions, particularly in mobile rigs, have imposed an inherent challenge.

Thus, the importance of proper sizing and design of the separator cannot be overstated. In pursuant to this, this paper considers the separation procedure from a functional point of view, and a procedural technique has been developed to curtail the danger of blow-through in an MGS as well as troubleshooting of a poorly sized MGS.

According to Low and Jansen in [1], regular drilling operations tend to be more focused on well control issues and therefore neglects the shortcomings of the MGS with the assumption that the equipment will deal with whatever gas influx into the well. They added that changes had been made to make the MGS smaller and lighter to save footprint and weight resulting in a reduced gas-handling capacity. However, due to deeper and high pressure drilling, the trend has been reversed. Larger separators, larger-diameter gas vent lines, and longer mud seal legs are now the order of the day and are still affected by the severe space limitations of drilling platforms. They considered the blow-through capacity, calculated the maximum possible casing pressure and developed a kick decision model to determine if a given gas influx could be controlled by the MGS on the rig. The decision model considered the likely risks to be encountered in well control.

Williamson and Dawe in [2] came up with a combination of models which aimed at establishing algorithms that could easily estimate MGS parameters as functions of time while controlling the well. They estimated the liquid and gas entrapment parameters, MGS internal pressure and height of liquid level accordingly. They went on to state that the point when the pressure safety between mud leg seal hydrostatic and internal pressures is minimum is a very critical period for the MGS. They also stated that mud leg seal fluid weight affects the blow-through capacity. They concluded that heating the MGS increases the liquid entrainment, an undesirable condition which can be reduced by using the largest possible MGS diameter.

Lee in [3] carried out a study on MGS design and gas handling system; he stated that the operating capacity of the gas handling system must not be exceeded for efficient separation. In line with this, Lee in [3] highlighted separating, venting, and liquid-entrainment capacities as the performance characteristics or efficiency limitations of a MGS. He modelled and calculated these parameters accordingly to suitably size a MGS.

Butchko *et al.* in [4] stated that the maximum anticipated flow rate of the gas is key when designing the MGS. They suggested an approach to calculate gas pressure and volume and considered vent line and separator sizing. They also added the effects of vessel internals, fabrication, and maintenance on MGS operation.

MacDougall in [5] discussed the evaluation and economical upgrade of MGS to meet design criteria instead of renting or building a new one. He stated that peak gas flow rate, mud leg, separator ID and vent line friction pressure are important factors that influence proper sizing of MGS. He also considered the possible effects of oil-based muds on the sizing and design

requirements. By simulating a kick scenario, he accessed the sizing parameters and also proposed guidelines for possible mud gas separator upgrade to meet sizing criteria. He added that closed-bottom MGS is the preferred configuration to open-bottom and float-type MGS. He carried out further studies to investigate how the minimum separator ID kill rate and effective length affected the friction pressure in the vent line.

## 2. Methods

A typical kick is considered to properly estimate peak gas flow rate. Normally, some factors such as; the well location, the well size, well type and depth will affect the kick [5]. Calculations were made and simulated accordingly in the Splitter program.

The Driller's method [6] was used for calculations since other well control methods would give lower gas peak flow rate values. Driller's method parameters provide worst-case well control scenario values for the separator sizing [7-8]. Normally, the worst case kick (gas kick) is used for the kick data. In this case, we had a 16404-ft. straight hole, 9 5/8 x 8 1/2" casing at 14000 ft., 6 5/8 x 2 13/16" DC at 340-ft, 5"x 50.2 lbm/ft HWDP at 465 ft., 5" 16.6 lbm/ft DP, 5 1/2" x 13" triplex pump at 95% efficiency and 0.091 bbl/stroke output. Slow pump rate at 34 spm, 15 ppg old mud weight, and 20 bbls pit gain were investigated and the optimum MGS sizing parameters were obtained.

Slow pump rate at 810 psi at 34 spm, old Mud Weight was 15 ppg, pit gain was 20 bbls, degree of underbalance was 0.68, initial SIDPP was 580 psi, volume of kick opposite drill collar was 8.8 bbl, volume of kick opposite drill pipe was 11.2 bbl, annular capacity factor was 0.0459 bbl/ft and the Initial SICP was 825 psi

The internal diameter of the MGS has directly related its capacity (The bigger, the better). It is also influenced by the inlet pipe size (the bigger, the better) and on the height between the inlet and the outlet to the vent line. Therefore, blow-through conditions may exist because of insufficient separator cut caused by small vessel internal diameter (ID). The industry standard approach to the sizing of MGS is to use API 12J guidelines. They are simple and non-conservative and do not consider items such as the inlet pipe ID [1,8]. The minimum Separator ID was estimated to be 27.3 inches.

## 3. Equations used for computations

The following equations stated below were used in this study to size the mud gas separator for this case study well. The Slow Circulation Rate, SCR was calculated using Eq. (1). The effective length of the gas vent line was calculated using Eq. (2). The initial SIDPP was calculated using Eq. (3). The initial SICP was calculated using Eq. (4). The annular capacity factor was calculated using Eq. (5). The volume of kick opposite drill collar was calculated using Eq. (6). The volume of kick opposite drill pipe was calculated using Eq. (7). The maximum casing pressure at the surface was calculated using Eq. (8). The volume of gas upstream of the choke was calculated using Eq. (13). The time to pump gas out of the well was calculated using Eq. (14). The volume of gas downstream of the choke was calculated using Eq. (15). The peak gas flow rate was calculated using Eq. (16). The vent line friction was calculated using Eq. (17). The minimum mud leg required was calculated using Eq. (18). The mud droplets falling velocity was calculated using Eq. (19). The minimum separator ID was calculated using Eq. (20).

$$SCR = \frac{Volume}{Displacement} \cdot SPM \quad (1)$$

where SCR is the slow circulation rate in bbls/min; volume is in bbls; displacement in stk; and SPM is the displacement rate in stk/min

$$L_e = L + Equivalent\ length \quad (2)$$

where Le is the effective length of gas vent line in ft., and L is the vent line length in ft.

$$Initial\ SIDPP = Degree\ of\ underbalance \cdot TVD \cdot 0.052 \quad (3)$$

where TVD is the True vertical depth in ft.

$$I.S = Initial\ SIDPP + \frac{DCL+VDP}{ACF} \quad (4)$$

where I.S is the initial SICP in psi; DCL is the Drill Collar length in ft; VDP is the volume of kick opposite drill pipe in bbls; ACF is the Annular Capacity Factor in bbl/ft.

$$ACF = \frac{ID^2 - DP^2}{1029.4} \quad (5)$$

where ACF is the Annular Capacity Factor in bbl/ft, and ID is the casing Internal Diameter in inches, and DP is the diameter of drill pipe in inches.

$$VDC = DCL \times \frac{ID^2 - DC^2}{1029.4} \quad (6)$$

where VDC is the volume of kick opposite drill collar in bbls, and DCL is the drill collar length in ft, ID is the casing Internal Diameter in inches, and DC is the diameter of the drill collar in inches.

$$VDP = PG - VDC \quad (7)$$

where VDP is the volume of kick opposite drill pipe in bbls, and PG is the pit gain in bbls, and VDC is the volume of kick opposite drill collar in bbls.

$$P_{cMAX} = \frac{SIDPP}{2} + \sqrt{\left(\frac{SIDPP}{2}\right)^2 + A \times B \times C \times D} \quad (8)$$

where  $P_{cMAX}$  is the maximum casing pressure at the surface in psi, and SIDPP is the shut in drill pipe pressure in psi, and A, B, C, and D are constants defined by Eqs. (9) to (12).

$$A = SIDPP + 0.052 \times OMW \times TVD \quad (9)$$

where SIDPP is the shut in drill pipe pressure in psi, OMW is the original mud weight in ppg, and TVD is the true vertical depth in ft.

$$B = \frac{PG}{ACF} \quad (10)$$

where PG is pit gain in bbls, and ACF is the annular capacity factor in bbl/ft.

$$C = OMW \times 0.052 - 0.1 \quad (11)$$

Where OMW is the original mud weight in ppg.

$$D = 4.03 - 0.38 \times In(A) \quad (12)$$

$$VGC = PG \times A \times D / P_{cMAX} \quad (13)$$

where VGC is the volume of gas upstream of choke in bbls, and PG is the pit gain in bbls, A and D are constants that have been defined by Eqs. (9) and (12), and  $P_{cMAX}$  is the maximum casing pressure at the surface in psi.

$$TPG = \frac{VGC}{SCR} \quad (14)$$

where TPG is the time to pump gas out of well in minutes, and VGC is the same as in Eq. (13), and SCR is the same as in Eq. (1).

$$VGD = \frac{P_{cMAX} \times VGC}{14.7} \quad (15)$$

where VGD is the volume of gas downstream of choke in bbls, and  $P_{cMAX}$  is same as in Eq. (8), and VGC is the same as in Eq. (13).

$$PGF = \frac{VGD}{TPG} \quad (16)$$

where PGF is the peak gas flow rate in SCF/D, and VGD is same as in Eq. (15), and TPG is the same as in Eq. (14).

$$VLF = 5 \times 10^{-12} \times VEL \times \frac{PGF^2}{ID^5} \quad (17)$$

where VLF is the vent line friction in psi, and PGF is the same as in Eq. (16), and the ID is the gas vent line internal diameter in inches.

$$MMR = \frac{VLF}{0.052 \times OMW} \quad (18)$$

where MMR is the minimum mud leg required in ft., and VLF is the same as in Eq. (17), and OMW is the original mud weight in ppg.

$$MDFV = 0.15 \times \sqrt{\frac{OMW - 0.008}{0.008}} \quad (19)$$

where MDFV is the mud droplets falling velocity in ft/s, and OMW is the same as in Eq. (18).

$$MSID = 15.56 \times \sqrt{SCR} \quad (20)$$

where MSID is the minimum separator ID in inches, and SCR is the same as in Eq. (1).

#### 4. Results and discussion

The performance of the MGS has been depicted in Fig. 1 below; a (purple) vertical line represents the MGS performance, based on API Bulletin 12J and assumed industry empirical numbers for "K" factors. For efficiency in separation, the flow rate of the gas should be less than this vertical line and the horizontal line intersection (left side of the vertical line). If the gas rate is higher than this value, there will be inefficient separation; liquid droplets will be able to flow up the gas vent line and gas will be entrained in the liquid passing through the seal leg. This hampers the overall performance of the separation system. The vent line performance is dependent on gas friction loss calculation.

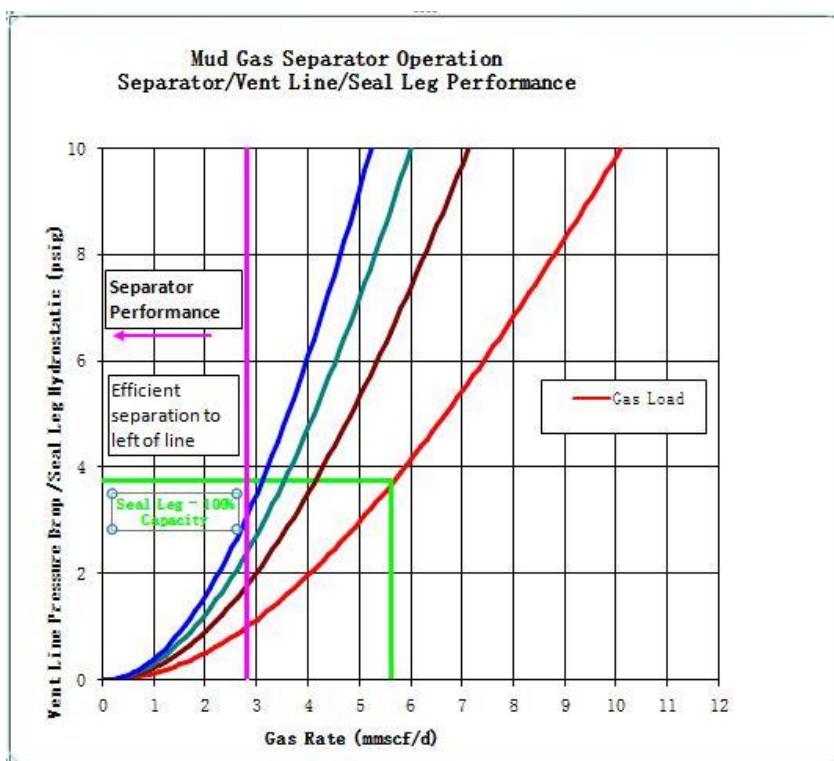


Fig. 1. Mud gas separator operation performance. Purple – MGS performance; Brown, Teal, Blue – Liquid load lines; Green – seal leg capacity line; Red – Gas load line.

For the scenario where there is effective separation (gas rate less than the intersection of the vertical separation capacity line), the (red) Gas Load line can be used.

For the scenario where there is inefficient separation, i.e. the gas rate exceeds the vertical separation capacity line, one of the three Liquid Load Lines is used (Brown, Teal, and Blue). There is no certainty as to how bad the liquid loading is – caution is probably the approach so the worst case condition, which is the blue line, should be considered as the norm.

The intersection of the (Green) Seal Leg Capacity line (equals the hydrostatic pressure of the U-tube full of the selected seal leg fluid density) with the chosen vent line performance line gives the blow-through capacity.

Table 1 below presents the mud gas separator performance data used for this study.

Table 1. Mud gas separator performance data

MGS data			
Temp flowing gas (deg F)	50	Seal Leg Height (ft)	12
Gas Specific Gravity	0.69	Density of Seal Leg Fluid	6
Vent Line ID (in)	7	Mud Density (ppg)	15
Vent Line Length (ft)	230	MGS Height (ft)	22
Other Vent Line Losses (ft -equiv)	210	Separator Diameter (ft)	2.27

From Fig. 1, the separation capacity (see the purple vertical line) is 2.75 MMSCF/D, approximately the value of peak gas flow rate obtained by the Splitter program (2742826 SCF/D). The line intersects gas load line (red line) indicating a vent line friction pressure of 1 psi, the same value obtained by Splitter program (1 psi). If the gas rate is above 2.75 MMSCF/D, signifying inefficient separation, the blue line (vent performance line) must then be used. In this case, this intersects the Seal Leg capacity (green) line at 3.1 MMSCF/D. The blow-through capacity is therefore 3.1 MMSCF/D.

Occasionally, when a MGS is picked for the rig contract, the drilling engineer and supervisor must investigate the suitability of the separator with respect to well location. This analysis is usually done during the process of rig bidding [5]. In a situation where the separator is found to be insufficient, upgrading the separator might make more economic sense instead of building a newly suitable separator. When the hydrostatic pressure of the mud seal leg is less than the friction pressure in the vent line, separation becomes inefficient.

#### 4.1. Reduce the circulating kill rate

Considering excess friction pressures in the vent line and the vessel ID, the MGS operation may be improved by a reduction in the kill rate circulation. Reducing the kill rate makes more economic sense in the face of this sizing challenge. For instance, if we reduce the kill rate from say 3.5 bbl/min to 1.5 bbl/min, there will also be a proportional decrease in the peak gas flow rate. Using Eqs. (14) and (16), the time required to vent gas and the peak gas flow rate were respectively computed as shown below

$$TPG = \frac{69.64}{1.5} = 47 \text{ Minutes} \quad PGF = \frac{7635 \times 8085.6}{47} = 1329464 \text{ SCF / D}$$

We can notice the glaring difference in the peak gas flow rate from the previous value of 2742826 SCF/D. This significant drop in the peak gas flow rate, in turn, decreases the friction pressure in the vent line by approximately 77 percent (77%) and therefore improves the operation as can be seen below: using Eq. (17), the vent line friction was calculated as seen below.

$$VLF = 5 \times 10^{-12} \times 440 \times \left( \frac{1323010^2}{7^2} \right) = 0.23 \text{ Psi}$$

#### 4.2. Increase the mud leg

Increasing the mud seal leg height may be another solution. Let's say if, from our case study, we happen to increase the mud leg from the 12 ft to 15 ft, it invariably means that the hydrostatic pressure in the mud leg will then become 4.5 psi ( $15 \times 0.3$ ), which is a significant increase from the 3.6 psi previously gotten with the 12 ft mud leg, thereby resulting in a more efficient MGS operation.

### 4.3. Gas vent line bends/corners adjustment

The effective length of the vent line and the friction pressure in the vent line are greatly affected by the type and number of bends in the vent line. If the sharp-right bend on separator sized in the case study is replaced with a more rounded-right bend, there will be a significant difference on the effective vent line length and vent line friction pressure values. Using Eqs. (2) and (17) respectively we got the following results

$$L_e = 230 \times (3 \times 1) = 233 \text{ ft.}$$

$$VLF = 5 \times 10^{-12} \times 233 \times \left( \frac{2742826^2}{7^5} \right) = 0.52 \text{ Psi}$$

Hence, changing the type of bend reduced the vent line effective length, and significantly reduced the friction pressure by 50%.

### 4.4. Vent line ID increase

The most expensive alternative may be to increase the vent line ID, but this may just be the only possibility of increasing the separator efficiency [5]. Larger vent line IDs will reduce the vent line friction pressure calculation. Therefore, if an 8-inch vent line ID were used instead of 7, the calculation for vent line friction pressure would change to

$$VLF = 5 \times 10^{-12} \times 440 \times \left( \frac{2742826^2}{8^5} \right) = 0.51 \text{ Psi}$$

The vent line friction pressure decreases from 0.52 to 0.51 psi indicating better separator efficiency.

## 5. Conclusions

The optimal mud gas separator ID and separation capacity obtained in this study were 27.3 inches and 2.74 MMSCF/D respectively. Various solutions were proffered in an attempt to upgrade an existing insufficiently sized MGS in order to meet standard guidelines rather than build or rent an entirely new MGS.

The procedural technique presented will prevent separator blow-through during well control operations, and the following inferences are drawn:

- It is feasible and desirable to control the maximum gas flow rate downstream the choke entering an MGS.
- The kill pump rate is an assessment of the ability of the MGS to handle a kick safely and a basis for optimal well control.
- The severity of bends and corners significantly impact on the friction pressure.
- Increasing the mud seal leg aids effective MGS operation.
- The risk of blow-through in an MGS is reduced greatly if gas is limited to separation capacity.

## Nomenclatures

<i>ACF</i>	<i>Annular capacity factor, bbl/ft</i>	<i>PGF</i>	<i>Peak gas flow rate, SCF/D</i>
<i>DCL</i>	<i>Drill collar length, ft</i>	<i>SCR</i>	<i>Slow circulation rate, bbl/min</i>
<i>I.S</i>	<i>Initial SICP, Psi</i>	<i>SICP</i>	<i>Shut-in circulating pressure, psi</i>
<i>L</i>	<i>Gas vent line length, ft</i>	<i>SIDPP</i>	<i>Shut-in drill pipe pressure, psi</i>
<i>Le</i>	<i>Gas vent line effective length, ft.</i>	<i>TPG</i>	<i>Time to pump gas out of well, min.</i>
<i>MDFV</i>	<i>Mud droplet filling velocity, ft</i>	<i>TVD</i>	<i>True vertical depth, ft</i>
<i>MMR</i>	<i>Minimum mud leg required, ft</i>	<i>VDC</i>	<i>Volume of kick opposite drill collar, bbl</i>
<i>MSID</i>	<i>Minimum separator ID, inch</i>	<i>VDP</i>	<i>Volume of kick opposite drill pipe, bbl</i>
<i>OMW</i>	<i>Original mud weight, ppg</i>	<i>VGC</i>	<i>Volume of gas upstream of the choke, bbl</i>
<i>PcMAX</i>	<i>Maximum casing pressure at the surface, psi</i>	<i>VGD</i>	<i>Volume of gas downstream of choke, bbl</i>
<i>PG</i>	<i>Pit gain, bbl</i>	<i>VLF</i>	<i>Vent line friction, psi</i>

**Abbreviations**

BBL	<i>Barrels</i>	OMW	<i>Original Mud Weight</i>
DC	<i>Drill Collar</i>	PPG	<i>Pounds per gallon</i>
DP	<i>Drill Pipe</i>	SICP	<i>Shut-in Circulating Pressure</i>
HWDP	<i>Heavy Weight Drill Pipe</i>	SIDPP	<i>Shut-in Drill Pipe Pressure</i>
ID	<i>Internal Diameter</i>	SPM	<i>Stroke Per Minute</i>
MGS	<i>Mud Gas Separator</i>		

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