AADE-19-NTCE-050

What Causes Mudlogging Mud Gas Response to Vary?

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This paper was prepared for presentation at the 2019 AADE National Technical Conference, and Exhibition held at the Hilton Denver City Center, Denver, Colorado, April 9-10, 2019. This conference is sponsored by the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individual(s) listed as author(s) of this work.

Abstract

Mudlogging has been used to determine over-pressured zones, balanced mud weight, and gas in the formations while drilling, but the mud gas response varies widely, and the causes are poorly understood. It is not uncommon to see as much as a ten-fold variation in mud gas response while drilling formations that have similar logs. Also, cumulative production has a poor correlation with mudlogging mud gas response in horizontal wells. Mudlogging can be improved and more effective if we understand and account for the mud gas variations.

In the past, mud gas has been normalized using the drilling rate, hole size, and mud pump rate, yet these factors do not fully explain the mud gas response. Propper lagging of mud gas to its depth, drilling mud flushing in front of the bit, gas solubility in drilling mud, surface losses, gas trap, and sampling design will be discussed and quantified.

Two techniques will be presented to quantify the gas in the formation under varying drilling parameters and conditions. Gas Markers and Normalization techniques improve over-pressure detection, help determine the balanced mud weight, and quantify gas in the formation. Using these techniques allows mud gas to be a predictor variable in data mining applications, leads the way to improved well drilling performance, and helps improve well productivity.

Introduction

Mudlogging is a hybrid word. Mud is a commonly used term for drilling fluid, and a log is a record of information over time. “Log” was originally used as a nautical term to measure the progress of a sailing ship. A log on a rope with equally spaced knots was thrown overboard. The distance the ship traveled from the log was calculated by counting the knots traveled in a given period of time and the distance recorded in the log book.

Mudlogging’s focus is on collecting information for formation evaluation and stratigraphic correlation from the drilling fluid circulated through the drillstring. John T. Hayward filed the first patent on mudlogging in 1938.[1] Eight decades later, mudlogging is considered a mature technology, but often perceived as not very reliable by those who don’t understand how to interpret the information. The gas readings presented on the mudlog are not a direct measure of hydrocarbons in the drilled formations but are the amount of gas measured by sensors in the mudlogging unit. However, mudlogging can be a proxy for determining formation gas if the process is understood.

A mudlog is typically presented in a measured depth format: drilling rate (ROP), total gas as measured in the mudlogging unit, its gas constituents, drill cuttings lithology, the presence of oil in the cuttings, and cuttings fluorescence. These measurements and information are gathered periodically on the drilling rig.

Drilling parameters – or their proxies, such as string weight, weight on bit, block height, drillstring length, pump strokes, pump capacity per stroke, pump pressure, mud motor rotation, and drillstring rotation – are measured in real time. In turn, these measurements are used to determine measured depth, the drilling rate/rate of penetration, the location of specific barrels of drilling mud during circulation, the time to circulate drilling mud down the drillstring, and estimate the time the drilling mud takes to travel from the bit to the surface.

Total gas, its constituents, and drill cuttings are transported to the surface by the circulating drilling fluid. Therefore the gas and cuttings seen at the surface are not from the depth being currently drilled, but are from depths previously drilled. A process called “lagging” is used to determine the time and depth at which the cuttings and the gas were drilled. In horizontal wells, the gas lag and the cutting lag rates are not the same. Lagging and a multiplicity of other factors affect the measurement of mudlog gas.

Mud gas is measured at the surface after it traverses from the drill bit up the annulus. At the surface, the mud gas is separated from the mud by a gas trap. During this process, the hydrocarbon gas is mixed with air. Then the air plus hydrocarbon gas mixture is transported via sample lines into the mudlogging unit’s sensors. The air is introduced into the mudlogging unit’s gas trap to prevent the drilling mud from being sucked into the sample lines. Determining how the measured hydrocarbon/air mixture relates to hydrocarbons in the formation, the units of measure, and if the sensors are properly calibrated are major issues. Mudloggers represent they calibrate their mudlogging instruments. They do not; they only calibrate the gas sensors within the mudlogging unit. The gas trap and the sample lines are not part of the calibration.

The mudlog presents hydrocarbon gas measured in “units”. Over time, in various geographical areas and amongst the different mudlogging companies, the “unit” has been defined differently. There is no standard definition of a “unit”. In this presentation percent Equivalent Methane in Air (% EMA) is used for total gas measurement as defined by SPWLA.[2] A “Unit EMA” is 1/100% EMA. Notice this is a percent, not a ratio percent. In a ratio percent, the hydrocarbon gas is the numerator, and the air is the denominator. In the EMA percent, the numerator is the hydrocarbon gas the denominator is the hydrocarbon gas plus the air. Actually, EMA percent is a mole fraction of hydrocarbon gas per mole fraction of hydrocarbon gas and air at standard temperature and pressure (STP). The mudlogger should define what their total units of measure are, how each gas component relates to this measure and the STP base they are using.

Finally, sensors should be calibrated using gas in the range gas is anticipated during mudlogging, the typical ratios of gas components, and the sensor sampling conditions. Often calibration gas used is not in the range of typical mud gas measured. Chromatographs are often calibrated with 1% methane (C_1), 1% ethane (C_2), 1% propane (C_3) and 1% butane (normal (nC_4) or iso-butane (iC_4)) which is not representative of natural gas. Natural gas typically is composed of greater than 90% C_1. Often the calibration gas pressure and temperature are not the same as the measurement inlet pressure and temperature. For this presentation, we are assuming the gas is methane. The methane gas assumption is used to focus on the concepts; more sophisticated analysis techniques have been used with an only slight improvement in results.

Factors Influencing Mudlog Gas

The major purpose of mudlogging is determining the amount of hydrocarbons in the formations being drilled. It is ironic that the direct measurement of hydrocarbons is one of the least predictable methods of formation evaluation. In addition, mudlogging gas response measurement units and presentations are not standardized across the industry adding to the perceived lack of science.

This paper will start with quantifying hydrocarbons in the formation. Then the discussion will follow the gas and cuttings to the surface and review their measurement at the surface. The factors which influence the size of the gas show are: formation gas, flushing in front of the bit, drilling factors (penetration rate, hole size and pump output), lagging, surface losses, gas solubility in drilling fluid, gas trap, and other minor factors.

Formation Gas

Quantifying hydrocarbon resources is the primary goal of all formation evaluation methods including mudlogging. Oil and gas reservoirs contain more gas than gas-saturated water reservoirs. Gas expands as it reaches the surface in accordance with the Laws of Boyles and Charles. Gas solubility in oil field brines has been measured in the laboratory.[3,4]

Table 1 presents the gas released at the surface from one cubic foot of gas or gas-saturated water at different depths. Mud gas measurement can be applied to both conventional volumetric reservoirs and unconventional sorption-type reservoirs. Mud gas is measured at the surface at near standard pressure and temperature conditions. Table 1 also presents the typical amounts of gas found in common water, gas, and oil reservoirs,[5] as well as gas sources from coal, unconventional, gas hydrates, and oil shale at different depths.

A study of Table 1 indicates that the amount of gas found in one cubic foot of the reservoir rock ranges up to 56 standard cubic feet of gas (SCF) at standard temperature and pressure (STP = 60°F and 14.7 psia). Because both temperature and pressure affect gas volume, SCF is the standard measurement unit for gas.

Also, data collected over decades and a perusal of Table 1 indicates that all hydrocarbon reservoirs contain five to eighty times more gas than gas-saturated water reservoirs.

It is difficult to define the quantity of gas in a "typical" reservoir. The range of standard cubic feet of gas per one cubic foot of reservoir ranges from 1.1 to 56.1 SCF in Table 1. The median value in Table 1 is 8.3 and the average value is 13.9. Ten standard cubic feet of gas per one cubic foot of reservoir is arbitrarily chosen to be the amount of gas used in example calculations.

It should be noted the data indicates mudlogging is less effective in oil reservoirs with a gas-oil ratio (GOR) of less than 200 SCF/bbl and conventional gas reservoirs under 500 feet vertical depth. Mudlogging also has difficulty determining if oil and gas is moveable or immovable (residual or depleted).

Not only does mudlogging measure the magnitude of gas in the mud, but it also measures the chemical composition of the gas. The following hydrocarbon molecules are the lighter part of the alkane series – C_1, C_2, C_3, nC_4 and iC_4. The gas molecules are measured by chromatography, Fourier Transform Infrared Spectroscopy (FTIR) and Mass Spectrometry at the mud gas unit.

The difficulty with this type of analysis is oil and gas reservoirs have similar C_1 to C_4 characteristics, thus their ratios are very similar.[6-8] Table 2 presents the C_1-C_4 characteristic gas profiles for oil, condensate, and dry gas reservoirs. Each gas component has a different solubility in drilling mud, boiling point, and gas mixtures affect the components solubility. Heavier hydrocarbons in the drilling mud may not be gas vapors at surface conditions. Another factor which is not well understood is the rate at which soluble gases exit the drilling fluid.

New spectrofluorometry technology is being developed to distinguish residual oil reservoirs from productive oil reservoirs. A further discussion is beyond the scope of this paper. However, it is recommended that every cuttings sample caught be examined under a UV light and cut with a solvent to determine if oil is present. Often UV light examination will not detect oil that can be seen as a fluorescing residual ring when cut with solvent.

New technology which can capture and quantify the heavier hydrocarbons (with high carbon chains) is being developed but is not the focus of this presentation. This presentation will focus on total mud gas and its major constituent methane.

Table 1 – Gas at Surface in One Cubic Foot of Water, Gas or Reservoirs at Certain Depths

STANDARD CUBIC FEET OF GAS PER ONE CUBIC FOOT WATER OR GAS	SURFACE GAS VOLUME (SCF/CF)	GAS PER 20-ft SECTION (BCF/SEC*20 FT)
ONE CUBIC FOOT OF GAS SATURATED WATER AT 500 FEET (POROSITY 100%, Sw 100%, 500 FT)	0.5	0.25
ONE CUBIC FOOT OF GAS AT 500 FEET (POROSITY 100%, Sw 0%, 500 FEET)	16.0	8.82
ONE CUBIC FOOT OF GAS SATURATED WATER AT 1,000 FEET (POROSITY 100%, Sw 100%, 1,000 FT)	0.9	0.48
ONE CUBIC FOOT OF GAS AT 1,000 FEET (POROSITY 100%, Sw 0%, 1,000 FEET)	31.6	17.42
ONE CUBIC FOOT OF GAS SATURATED WATER AT 5,000 FEET (POROSITY 100%, Sw% 100, 5,000 FT)	2.4	1.33
ONE CUBIC FOOT OF GAS AT 5,000 FEET (POROSITY 100%, Sw 0%, 5,000 FEET)	160.8	88.64
ONE CUBIC FOOT OF GAS SATURATED WATER AT 10,000 FEET (POROSITY 100, Sw100%, 10,000 FT)	3.2	1.75
ONE CUBIC FOOT OF GAS AT 10,000 FEET (POROSITY 100%, Sw 0%, 10,000 FEET)	263.7	145.36
GRAPH REFERENCE RESERVOIRS		
WATER FILLED POROSITY AT 5,000 FEET (POROSITY 30%, Sw 100% 5,000 FT,)	0.7	0.40
GAS RESERVOIR AT 5,000 FEET TOTALLY FILLED WITH GAS (POROSITY 5%, Sw = 0% 5000 FT)	8.0	4.43
TYPE OF RESERVOIR		
WATER FILLED POROSITY AT 500 FEET (POROSITY 30%, Sw 100% 500 FT)	0.1	0.08
WATER FILLED POROSITY AT 1,000 FEET (POROSITY 30%, Sw 100% 1,000 FT)	0.3	0.15
WATER FILLED POROSITY AT 5,000 FEET (POROSITY 30%, Sw 100% 5,000 FT)	0.7	0.40
WATER FILLED POROSITY AT 10,000 FEET (POROSITY 30%, Sw 100% 10,000 FT)	1.0	0.53
COAL WITH 25 SCF/TON GAS CONTENT	1.1	0.58
GAS RESERVOIR AT 1,000 FEET (POROSITY 10%, Sw 55%, 1,000 FT)	1.4	0.78
GAS RESERVOIR AT 1,000 FEET TOTALLY FILLED WITH GAS (POROSITY 5%, Sw 0%, 1,000 FT)	1.6	0.87
COAL WITH 50 SCF/TON GAS CONTENT	2.1	1.16
SHALE LEWIS WITH 30 SCF/TON GAS CONTENT	2.4	1.34
OIL RESERVOIR AT ANY DEPTH (POROSITY 10%, Sw 60%, 500 GOR)	3.6	1.96
GAS RESERVOIR AT 1,000 FEET (POROSITY 20%, Sw 35%, 1,000 FT)	4.1	2.26
COAL WITH 100 SCF/TON GAS CONTENT	4.2	2.32
SHALE ALBANY WITH 60 SCF/TON GAS CONTENT	4.9	2.68
SHALE ANTRIM WITH 70 SCF/TON GAS CONTENT	5.7	3.13
SHALE OHIO WITH 80 SCF/TON GAS CONTENT	6.5	3.58
GAS RESERVOIR AT 5,000 FEET (POROSITY 10%, Sw 55%, 5,000 FT)	7.2	3.99
OIL SHALE WITH 100 SCF/TON GAS CONTENT	7.5	4.13
GAS RESERVOIR AT 1,000 FEET (POROSITY 30%, Sw 15%, 1,000 FT)	8.1	4.44
COAL WITH 200 SCF/TON GAS CONTENT	8.4	4.64
UNCONVENTIONAL BAKKEN (OIL)(POROSITY 9%, Sw 35%, 1,000 GOR)	10.4	5.74
UNCONVENTIONAL MANCOS (OIL)(POROSITY 10% Sw 45%, 1,300 GOR)	12.7	7.02
OIL RESERVOIR AT ANY DEPTH (POROSITY 10%, Sw 60%, 1,800 GOR)	12.8	7.07
WOLFCAMP (COND)(POROSITY 9% Sw 30%, 5,000 GOR)	15.6	8.58
OIL RESERVOIR AT ANY DEPTH (POROSITY 30%, Sw 20%, 500 GOR)	15.6	8.59
COAL WITH 400 SCF/TON GAS CONTENT	16.8	9.29
UNCONVENTIONAL NIOBRARA (CONDENSATE) (POROSITY 12% Sw 35%, 7,000 GOR)	19.3	10.63
UNCONVENTIONAL HAYNESVILLE (GAS)(POROSITY 8%, Sw 32%, 20,000+ GOR)	19.9	10.94
GAS RESERVOIR AT 5,000 FEET (POROSITY 20%, Sw 35%, 5,000 FT)	20.9	11.52
SHALE BARNETT WITH 325 SCF/T GAS CONTENT	26.4	14.53
UNCONVENTIONAL EAGLE FORD (OIL)(POROSITY 12%, Sw 25%, 2,000 GOR)	26.7	14.73
HYDRATE GAS AT ANY DEPTH (160 *.25 = 40SCF/FT RESERVOIR)	40.0	22.05
GAS RESERVOIR AT 5,000 FEET (POROSITY 30%, Sw 15%, 5,000 FT)	41.0	22.60
OIL RESERVOIR AT ANY DEPTH (POROSITY 30%, Sw 20%, 1,800 GOR)	56.1	30.93

Coal and Shale reservoirs with gas content reported in Standard Cubic Feet of gas per Ton of coal or shale are not depth dependent
Oil reservoirs with gas oil ratios reported in Standard Cubic Feet of Gas per Oil Barrel are not depth dependent
Reservoirs reported at depth assume a 0.433 psi/feet pressure gradient, a 1.0 degree per 100 feet gas gradient and
Methane pseudo critical pressure, pseudo-critical temperature and z factor were used to calculate gas volumes
(SCF/CF) is standard cubic feet of gas per cubic foot of reservoir rock. (BCF/SEC*20 ft) is Billion SCF of gas per 1 section of 20-foot reservoir rock
Gas solubility of water from Amyx, Bass, and Whiting

Table 2 –Properties of Dry Gas, Condensate, and Oil*

Molecular Properties of Dry Gas, Condensate and Oil

Name	Formula	Boiling Point (STP)	Dry Gas Mole %	Condensate Mole %	Oil Mole %
Methane	C1H4	-258	91.32	87.07	57.83
Ethane	C2H6	-127	4.43	4.39	2.75
Propane	C3H8	-43	2.12	2.29	1.93
Butane	C4H10	31	1.36	1.74	1.60
Pentane	C5H12	96	0.42	0.83	1.15
Hexane	C6H14	155	0.15	0.60	1.59
Heptane+	C7H16+	209	0.20	3.08	33.15
		Total	100.00	100.00	100.00
		Frick	ABW	ABW	ABW

Mudlog gas chromatography response To Dry Gas, Condensate and Oil

Name	Dry Gas Mole %	Condensate Mole %	Oil Mole %
Methane	92.03	91.18	90.20
Ethane	4.46	4.60	4.29
Propane	2.14	2.40	3.01
Butane	1.37	1.82	2.50
Total	100.00	100.00	100.00

*Includes data assembled from various sources.[3,9]

Flushing in Front of the Bit

During drilling, oil or gas from the reservoir can be "pushed" into the pore space ahead of the bit; this is known as "flushing". Many techniques can determine the magnitude and importance of flushing in front of the bit.[10-18] Some of the techniques to determine the magnitude and importance of flushing in front of the bit are: micro drilling laboratory measurements, API filtration tests, time-lapsed LWD, Diagnostic Fracture Injection Test (DFIT), unstimulated completion tests, computer modeling, transient spherical flow mathematical solutions, analog electrical modeling, and open-hole log evaluation. Flushing is de minimus in reservoirs below 100 to 10 millidarcies depending on which source in the technical literature is referenced.[16-18]

With the current rapid improvement in drilling rates, flushing has become less of an issue. The worst case for flushing can be estimated using initial and residual hydrocarbon saturation. Residual hydrocarbon saturations can be used to determine the mud gas response and can be compared to initial reservoir saturations mud gas response to judge the maximum loss of mud gas due to flushing. Open-hole log calculations presented often show initial reservoir water saturation of about 30% and residual hydrocarbon saturation of about 25%. Using these worst-case estimates, a mud gas show at the surface would be reduced by 64% if all other factors are the same. Using our example of 10 standard cubic feet of gas per one cubic foot of unflushed reservoir and flushing occurs under these worse case scenarios, 3.6 SCF of gas per one cubic foot of flushed reservoir would be measured and the other 6.4 SCF of gas would be pushed ahead of the bit.

Drilling and Mud Circulation Factors

In recent years mud gas calculations have been normalized based on bit size, the rate of penetration, and the mud circulation rate.[19-22] Mud gas increases by the square of the bit diameter. Mud gas is directly proportional to the rate of penetration and is inversely proportional to the mud circulation rate. All these variables are quantifiable and have small margins of error. Bits are gauged before and after they are run. The rate of penetration is recorded on the Electronic Drilling Recorders (EDR) and are verified against the pipe strap (measured length of each drillpipe and bottomhole assembly) during connections. Pump rates are calculated by using pump stroke counters and estimating efficiency factors. The pump rates are verified using the pump pressure, downhole turbine revolutions, sonic flow meters, lag, pills, sweeps, and Coriolis meters. Typically, the error of all these factors is 10% or less. However, normalized mud gas calculations fail to explain the variability of response seen on typical mudlogs.

Figure 1 shows the rock volume drilled in cubic feet per minute at different bit sizes and ROP. The typical volume of rock drilled is between 0.5 to 2.0 ft^3/min. The amount of mud gas liberated into the drilling mud can be calculated using the volume of rock drilled, pump rate and reservoir hydrocarbon saturation.

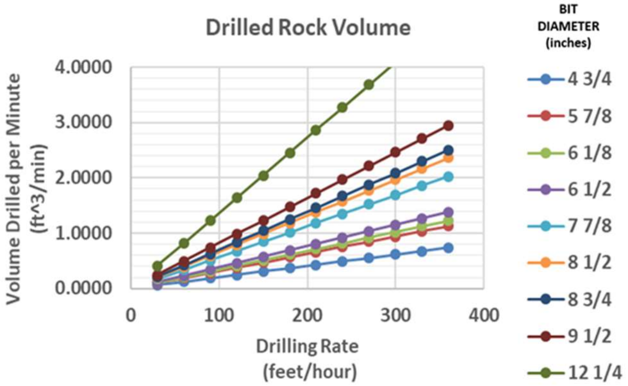


Figure 1 – Impact of ROP and bit size on cubic feet of rock drilled per minute.

Assume one cubic foot of rock is drilled per minute, the pump rate is 13.6 bbl/min (76.3 cubic feet per minute), and our typical reservoir holds 10 SCF of gas. These assumptions would calculate to 0.13 cubic feet of gas, at STP, per cubic foot of water-based drilling mud at the surface.

It also should be noted from Table 1, that one cubic foot of water at 10,000, 5,000, 1,000 and 500-feet depth can store 3.2, 2.4, 0.9, and 0.5 SCF respectively. These solubilities would indicate that the WBM at typical mud circulation rates can hold all the gas in solution. Thus the gas would travel up the hole at the same rate as the drilling mud until it reaches the surface. Assuming the pump rate is 13.6 bbl/min (76.3 cubic feet per minute), with 3% drill solids in the WBM, at 10,000, 5,000, 1,000, and 500-feet depth this 13.6 bbl/min circulating mud can store 237, 178, 67, and 37 SCF of gas in solution respectively.

Figure 2 presents the maximum soluble gas in barrels at STP for typical circulation rates compared to the typical range of gas in barrels at STP for cuttings combinations of reservoir gas in Table 1 and drilling rates in Figure 1. Notice the vertical axis scale is logarithmic and is in barrels of gas at STP, not cubic feet at STP. The reason for this unit change is that most mud circulation rates are presented in barrels per minute. Four circulation rates are presented; 5, 10, 15, and 20 barrels per minute. Four cuttings gas volumes are presented as horizontal lines, that is constant lines of 10, 30, 50, and 70 SCF per minutes presented on a barrel of gas at STP per minute gas scale. Notice that until very near the surface 4 to as much as 80 times more gas can be solubilized in the drilling mud than is created by the mud gas liberated by drilling the reservoir. The ratio of cuttings generated gas per minute and the drilling mud maximum solubility per minute depends on the depth; mud circulation rate in barrels per minute; and the cubic feet of reservoir rock volume drilled per minute times its reservoir gas volume per cubic foot.

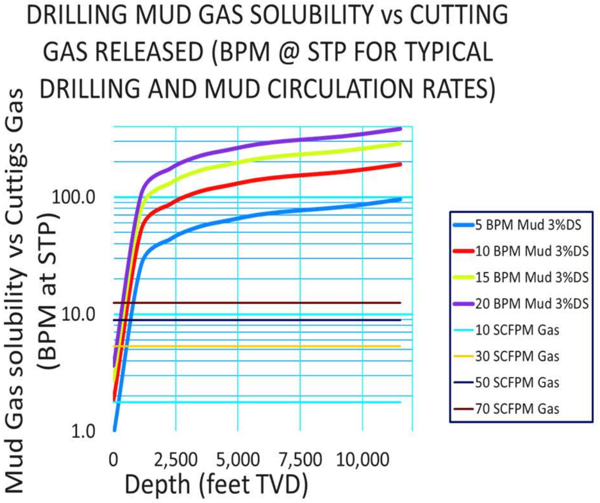


Figure 2 – Drilling mud gas solubility for four mud circulation rates versus cuttings gas released for four typical gas volumes released.

The volume of water in WBM and the circulating volumes indicate all of the gas in the reservoirs in Table 1, being drilled at rates in Figure 1, are in solution and thus travel with the drilling mud and do not come out of solution until at or near the surface. Gas is more soluble in oil-based muds. Thus the mud gas should be in solution in the OBM drilling mud until very close to the surface.

Lagging, Smearing, and Gas Migration

Lagging is a method used to determine the time or pump strokes it takes for drill cuttings or mud gas to arrive at the surface. It takes time for the gas and cuttings at depth to travel from the bit to the surface (Figure 3). Lagging is considerably more complex in directional and horizontal holes as compared to vertical holes.[23-25]

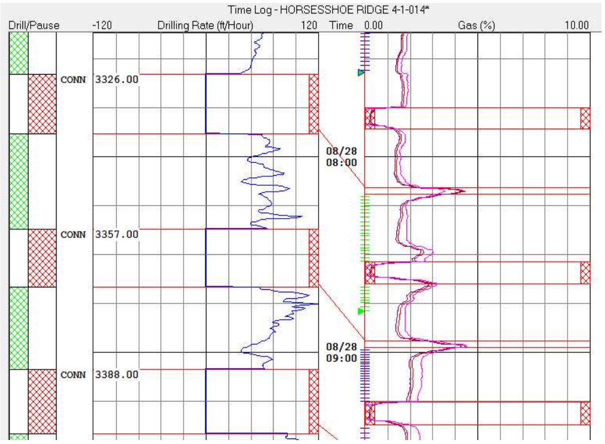


Figure 3 – Portion of Time Log. Gas Lag is shown by a diagonal line linking time drilled and time gas shows up at the mudlogging unit.

Figures 4 and 5 illustrate a comparison of Pump Stroke to Carbide or Connection Lagging of mud gas and Cutting Lagging. Note that pump stroke lagging is the benchmark measurement for mud logging. However, if other lagging methods are not considered, mud/gas would be at the wrong depth up hole by ~20% and the drill cuttings downhole by ~50%.

In deviated holes, the mud/gas travels above the cuttings bed. The mud gas lag time is faster than the pump stroke calculated lag time by often as much as 20% in long horizontal holes where the propensity is for the heavier cuttings to settle on the low side of the horizontal section.[25] The cuttings bed on the low side of the hole reduces the annular flow volume, thus the mud/gas travels faster up the hole than indicated by pump stroke calculations. The settling of cuttings on the low side in horizontal wells can “flow” in dunes and is called “saltation flow”. The cuttings lag time is often 50% less than the pump stroke lag time.

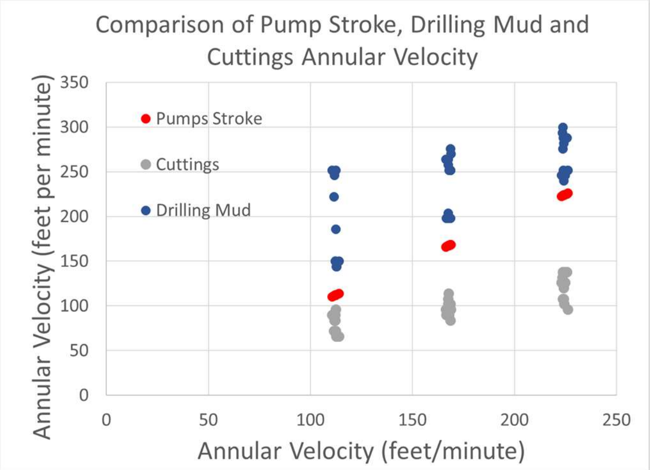


Figure 4 – Annular velocity of mud and cuttings compared to pump stroke to show the impact of lagging at three velocities. Note the mud/gas flows faster than the pump stroke velocity and the cuttings flow slower.

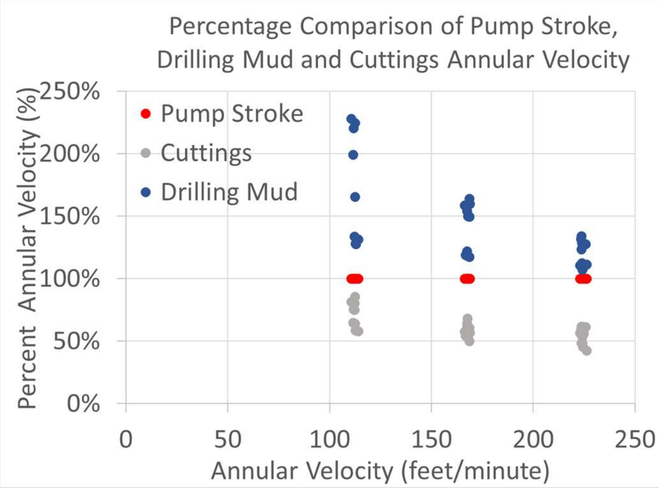


Figure 5 – Annular velocity as a percentage of annular velocity for mud and cuttings (data from Figure 4) compared with pump stroke to show the impact of lagging as a percentage of velocity.

Cuttings are pumped to the surface in the drilling mud. During the time the cuttings are being pumped to the surface gravity settling causes "smearing" that is the mixing of cuttings from different depths.[27] Cuttings smearing is acerbated by saltation flow in horizontal wells.[28]

Various methods can be used to calculate mud/gas and cuttings lags. These methods are pump strokes, connection gas, calcium carbide, propylene, lithology changes, pills of gelled mud and lost circulation material (LCM) sweeps. The three mud/gas lag-rate methods commonly used by mudloggers are:

1. Pump Stroke Lagging – theoretical volumetric lagging using pump strokes
2. Connection Lagging – matching the connection gas to the appropriate connection
3. Carbide Lagging – using calcium carbide or propylene introduced at the surface

Cuttings lagging is difficult to measure at the drill site, but can be determined by matching cutting sample descriptions to ROP changes and the LWD Gamma Ray response. Cuttings bed modeling and pills with LCM particles of a cutting size and cutting density are other alternatives for calculating the cutting lag rate.

Pump Stroke Lagging is the simplest lag-rate method to implement and is continuous. Note pump stroke lagging is not a measurement, but a computation. The internal volume of the drillstring is used to calculate the surface-to-the-bit volume. The annular volume of the drillstring in the borehole, liner and/or casing is used to calculate the bit-to-the-surface volume. The pump stroke volume is measured, and an efficiency factor is applied to the pump stroke volume, then the pump strokes from the surface to the bit and the pump stroke from the bit to the surface can be calculated.

Numerous errors are introduced in this process. The pump stroke counter must be accurate. The pump stroke efficiency is seldom measured and is variable depending on the pump pressure and pump condition. The borehole diameter is assumed to be in gauge, or a washout correction factor is applied. No correction for cuttings bed and cutting bed build up is applied, adding to a potential error in the calculation. The length, internal and external diameter of the drillstring, as well as the casing/liner length and internal diameter, are all assumed to be the same as the API published information.

For example, let us assume the following:

Drilling rate = 240 ft/hr
Pump output = 0.10 bbl/stroke with a typical 10% pump efficiency already included at 136 strokes/min
Bit = 8.5-in. diameter
Drillpipe = 4.0-in., 14-lb/ft
Measured depth (MD) = 15,000 ft

Assume the Pump Stroke Lag, the bit-to-surface time, is 60 minutes. If the pump efficiency decreases just 10%, the lag rate now is 67 minutes. At a drilling rate of 240 ft/hr, that minor change in efficiency loss translates into 27 ft of lag depth.

The impact of the error in the calculation of lag depth is important to other calculations. If perforation clusters are chosen by Pump Stroke Lag and it is assumed the mud/gas lag is Pump Stroke Lag, perforations may not be at the depth expected.

Connection Lagging and simply timing using a fix pump stroke rate were used by early mudloggers when pump stroke counters were not available. The technique is very useful even in this age of instrumentation. Connection gas is the gas liberated at the bottom of the hole during a connection. The connection gas is caused by a reduction of Equivalent Circulating Density (ECD) when the pumps are stopped. Swabbing the well when pulling off bottom during the connection also contributes to the influx of gas. Figure 3 is the "WYSIWYG" method of lagging connection gas to its proper connection. It is a graphical method of presenting mudlog raw data versus time, also known as a Time Log. The tracks presented left to right in Figure 3 are:

1) Drill/Pause (Drilling operations = green hatchured marks; Paused operations = red hatchured marks)

2) Operation (text)
3) Drilling Rate (ft/hr)
4) Time and Date
5) Pumps Off indicator (red hatchured marks)
6) Red diagonal lines indicate the lag time in connection gas reaching the surface/mudlogging unit.
7) Alternating blue and green horizontal ticks indicate the footage where the gas is lagged.
8) Sensor total gas readings in percent equivalent methane in the air (% EMA). There are three sensor gas readings shown in Figure 3.

The typical mudlog depth presentation is difficult to audit, but the drilling rate and mud gas should be the same before and after a connection. The drilling rate should be continuous with no unexplained off bottom times. Gas shows, before or after a connection that do not correspond to drilling breaks, often indicate improper lagging. In the Time Log (Figure 3), the red line from the bottom of a connection to the connection gas peak and the alternating blue and green footage ticks on the left side of the gas curve track visually show how this connection is lagged.

The Time Log display of Connection Gas Lagging can be compared to Pump Stroke Lagging. The pump stroke, pump time, and total time from the pumps on at the bottom of the connection to the gas peak are used to determine which lagging method is accurate. The duration of the connection gas peak is an indication of smearing[27] of the cuttings from different lithologies and depths. The connection gas peak will appear skewed if the hole is packed off or severely washed out. A sharp symmetrical connection gas peak indicates a good hole with minimal hole cleaning issues.

Note that some gas readings which are shown in the Time Log will not be presented in the Mud Log. After bottoms up, gas is not presented in a mudlog. If a Carbide Lag (the introduction of calcium carbide into the drillstring during a connection) is run, it will be a separate peak just after the connection gas peak. The time between the two peaks is the surface-to-bit time.

Carbide Lagging is the introduction of a small amount of foreign hydrocarbon gas or chemical producing a foreign hydrocarbon gas into the drillstring, typically at a connection, and then counting the pump strokes, time, or volume for the gas to arrive at the surface mudlogging sensors. In water-based muds, calcium carbide is used. A measured amount of calcium carbide is inserted downhole and reacts with water to produce acetylene gas and lime water. In oil-based muds, propylene is used.

As with Pump Stroke Lagging, the pump output, casing and drillstring lengths, and both internal and external diameters must be accurate. The gas flow time from the gas trap to the gas sensors in the mudlogging unit should be known. A trap check is run by putting butane in the gas trap and timing the response to the sensors in the mudlogging unit.

Pump strokes between the on-bottom connection gas peak and the surface-introduced carbide lag can be used to verify the pump stroke volume or if the connection gas is coming in the hole at the bit. A record of all three lag method should be kept and plotted. Any inconsistent trends indicate either the pump efficiency is changing or the connection gas is not coming from the bottom of the hole. If the Connection Gas Lag and the Carbide Lag agree, then the connection gas is coming from the hole's measured depth and the Pump Stroke Lag needs to be adjusted.

Carbide Lags and pills can also be run prior to drilling out the casing shoe to check the pump output volume. It is a common misconception that mud gas breaks out of the drilling mud and rises up the hole faster due to buoyancy. Mud gas does not have the volume of a gas kick and does not behave like a gas kick in the annulus. The conclusion that mud gas travels with the drilling mud is based on years of mudlogging experience, previously discussed computations based on water solubility in Table 1, Figure 2, and the technical literature.[18] Mud gas travels in solution at the same rate as the drilling mud. Near the surface, some gas comes out of solution. This phenomenon will be examined later in this paper.

Cuttings Lagging is very difficult in deviated holes. Lithology changes matched to drilling rate changes, lithology changes matched with LWD Gamma Ray changes, and pills with coarse marble (250 to 600 µm) are good sources to verify the cuttings lag time. Course marble has the density of cuttings. However, if the ROP is fast, the bit rpm is high; and if a multiple blade PDC bit is used, the coarse marble may be smaller than the cuttings. A ROP of 240 ft/hr, a bit rpm of 120, and a five-blade PDC bit give a cutting height of 0.080 in. or 2,032 µm. The size difference will influence cuttings transport. Cutting height can be estimated using the following formula:

$$CH = \left[\frac{12.0}{(60/ROP)*(ROT)*(CUT)}\right] \qquad \textit{Eq. 1}$$

Where

CH = Cuttings height (inches)
ROP = Rate of Penetration (feet/hour)
ROT = Bit speed (revolutions/minute)
CUT = number of cones or blades on bit

Figures 4 and 5 present the modified work of Augusto Garcia-Hernandez and others.[23,25] The thesis and paper detail the cutting transport in a flow loop. The flow loop is 100-ft long and had 4.5-in. outside diameter drillpipe in an 8.0-in. diameter borehole. The flow loop experiments compared three different annular velocities (110, 179 and 225 ft/min), water to viscofied drilling mud (plastic viscosity (PV) of 12 cP, yield point (YP) of 15 lb_f/100 ft^2), two drillpipe rotations (sliding, 0 rev/min, and 40 rev/min) and two hole inclinations (70 and 90 degrees). Although Garcia-Hernandez did not compare his data to pump stroke volume, charts showing that comparison (Figures 4 and 5) are illuminating with regards to Cuttings Lag. Figure 4 shows the mud and thus the mud/gas flows faster than the Pump Stroke velocity, and the cutting flow is slower than the Pump Stroke velocity. Figure 5 presents the same data as a percentage of Pump Stroke annular velocity. The Pump Stroke annular velocity is calculated assuming no cuttings bed or washouts.

The drilling mud annular velocity can be measured either by Connection Gas or Carbide Lagging. The comparison of Pump Stroke and Connection Gas/Carbide Lag is a practical method for determining the effective hole cleaning. The ratio or percent change in the different lagging methods is a real-time monitor of changing hole cleaning conditions. It is also interesting that cuttings traveling in saltation flow in horizontal holes have a lag rate compared to pump strokes of about 50% less. Another paper also demonstrated that cuttings are smeared by saltation flow and cuttings of different bed lithologies are distributed when sampled in a log-normal fashion.[28]

Gas Solubility in Drilling Fluids at the Surface

Hydrocarbon gases are soluble in oil-based and water-based drilling fluids. The solubility of the hydrocarbon gas components is determined experimentally and follows Henry's Law. The solubility of many hydrocarbon gases in water, diesel, oil-based, and water-based drilling fluids have been published.[29-31] Figure 2 shows the solubility of hydrocarbon gases varies with temperature and pressure. One cubic foot methane-saturated water at 77°F contains 0.0325 SCF of methane. Figure 6 charts some gas solubilities from 40 to 200°F as reported by Yaws.[30-31] Note solubility varies six-fold over this temperature range.

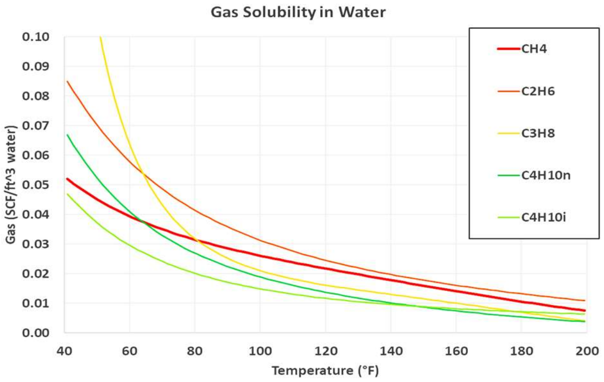


Figure 6 – Gas solubilities from 40 to 200°F, after Yaws. [30-31]

The solubility ratio for methane and acetylene is fairly constant over a wide range of temperatures (Figure 7). For this reason, acetylene is a good gas to benchmark methane because although it does not have the same solubility, it behaves similarly over a wide range of temperatures.

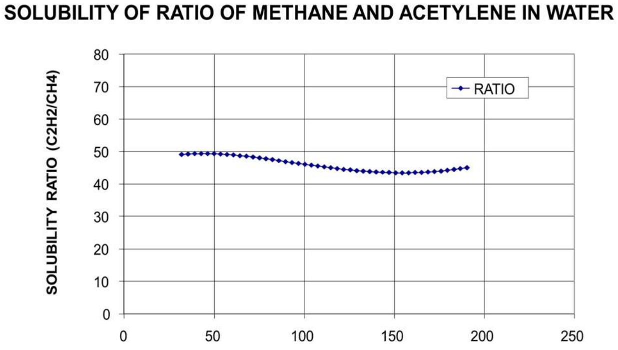


Figure 7 – Solubility ratio for methane and acetylene.

In a previous section, the assumption was made that the drilling rate was 1 ft^3/min, the pump rate is 13.6 bbl/min or 76.3 ft^3/min, and our typical reservoir contains 10 SCF of gas. These assumptions would calculate 0.13 SCF of gas per cubic foot of water-based drilling mud at the surface. Assuming 3% drill solids, then 0.13 SCF of mud/gas is in one cubic foot of water-based mud at the surface That is 0.0325 SCF in solution, and 0.0945 SCF is in a gaseous state at 77°F. About 75% of the gas at the surface is in vapor form.

Surface Losses

All of the factors discussed so far are deterministic. Gas in the formation, flushing, drilling factors, and gas solubility can be quantified. Surface losses on a drilling rig are difficult to quantify. Some rigs drill with a rotating head, some allow gas to escape out the bell nipple, and some rig use a gas buster prior to running the drilling mud over the shale shaker. Gas Research Institute[32-33] and Elder[34] attempted to quantify surface losses and showed they could be as high as 40% of the gas in the drilling mud.

Gas Trap

The mud gas is typically sampled by using a gas trap or by sampling the air/mud gas mixture in the flow line. The gas trap is placed in the possum belly. Figure 8 shows a gas trap and its location in the possum belly. Cavitation is the formation of bubbles in a liquid by the movement of a propeller through it. The rapid propeller rotation reduces the pressure near the propeller to such an extent that the hydrocarbon liquids or gas in solution boils out of the liquid at ambient temperature. The propeller in the gas trap is called the agitator. The gas trap draws the drilling mud into a port at the bottom of the trap, cavitates the mud with an agitator, and the mud exits a side port. The gas liberated from the drilling mud rises to the headspace in the trap where it is mixed with air. The headspace gas is conditioned to remove water vapor and particulates and is drawn via a small diameter tube to the mudlogging unit's gas sensors.

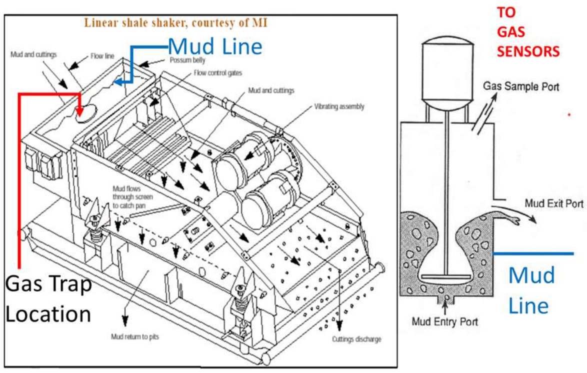


Figure 8 – Location of the typical gas trap in relation to the possum belly's mud line.

Williams and Ewing wrote an excellent paper on gas trap design and performance.[35] GRI attempted to standardize the gas trap design.[36] The gas trap is the Achilles heel of mudlogging. There is no standard gas trap or laboratory performance testing of gas traps. Figure 9 shows the performance characteristics of nine commercially available gas traps.[35] 1% methane in the drilling mud can read as little as 0.03% in the headspace or as much as 2.0% in the headspace depending on the design of the gas trap.

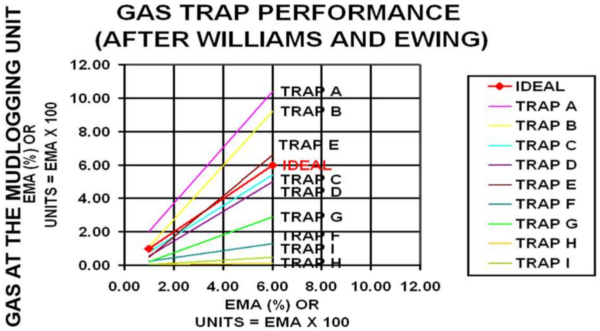


Figure 9 - Gas Trap performance (after Williams and Ewing).[35]

Two of the gas traps, A and D in Figure 9, were further tested to see how the mud level in the possum belly relative to the base of the mud exit port influenced head gas readings. Figure 10 shows the variations graphically in headspace gas response.[35] Gas Trap A and Gas Trap D measured 1% methane in the drilling mud. In Gas Trap A, a two-inch change in the relative mud level caused the headspace gas reading to vary from 0.35% to 2.00%. In Gas Trap D, a four-inch change in the relative mud level caused the headspace gas reading to vary from 0.35% to 1.00%. Variations in gas trap positioning relative to the mud level in the possum belly can cause the headspace gas to vary. The stable region in both gas traps A and D is about 1 inch of possum belly mud level. This one inch is the maximum mud level variation for reliable readings. With the advent of mud motors which rely on a constant mud rate, the possum belly mud level is typically stable and this is not as large of an issue as it was decades ago.

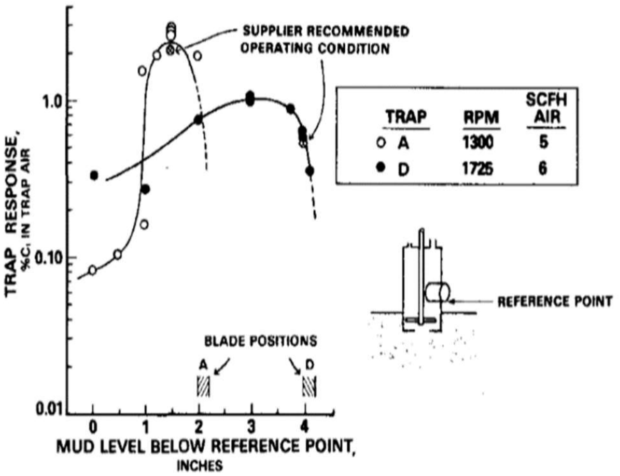


Figure 10 – Change in Gas Traps A and D in response to mud level in the possum belly. Graph from Williams and Ewing.[35]

Elder[34] studied mud properties and rheology factors such as mud weight (MW), PV and YP and found no change in gas trap performance due to mud weight or rheology. The experiments were conducted in a laboratory using a flow loop. The MW varied from 9.8 to 14.0 lb_m/gal, the PV varied from 8 to 33 cP, and the YP varied from 2 to 24 lb_f/100 ft^2. Many mudloggers dismiss this study because weighting up tends to reduce the mud gas readings. The addition of mix water to WBM, circulating while building mud, and jet mixing may be the cause of the drop in mud gas, not changes in mud properties.

A major factor which has not been studied in detail is the amount of oil or diesel in the WBM. Mud gas response in oil-based mud (OBM) and WBM does vary and may be due to the differences in gas solubility between water, synthetics, oil, and diesel. Diesel and other common base fluids for OBM contain methane in concentrations below the sensor's lower threshold. OBM can contain a measurable amount of volatile, heavy hydrocarbon depending on the base oil used; clues to this contamination can be determined by watching the mixing schedule of new mud.

If we apply gas trap variations to our base case of 0.1270 SCF of methane per cubic feet of drilling mud with 3% drilling solids, there are major variations in mud gas readings. In mudlogging gas readings, 0.1270 SCF methane per cubic feet of drilling mud is equivalent to 12.7% EMA or 1,270 units EMA or 127,000 ppm. The working assumption is the volume of gas in the drilling mud is minor and that gas-free drilling mud is the denominator. If the denominator included the gas volume then 11.27% EMA is the reported value, not 12.70% EMA.

With the advent of faster drilling rates, prior studies with less mud gas volumes per volume of drilling mud may not be valid for higher drilling rates. Gas solubility becomes less of a factor with higher ROP, thus cavitation gas traps become less relevant.

Williams and Ewing's work on gas traps[35] is the only published commercial gas trap performance data. If extrapolated beyond the data to the case presented, the choice of gas traps would cause the gas readings to range from 0.38 to 25.4% EMA. Gas Trap A's reading would range from 4.45 to 25.4% EMA depending on the mud level relative to the base of the exit port. If the mud level in the possum belly varies by less than 1 inch, then the gas reading varies less than 10%. A simple quality control check is to monitor the drilling mud exit volume. If it is stable, then the gas trap readings are stable. The GRI gas trap,[36] (never widely accepted due to licensing fees) is designed to have an exit port flow of about 12.7 gal/min.

Today's mud pumps are better maintained than years ago and mud motors require a constant volume of drilling mud to perform well; these factors improve the quality of mudlogging data by keeping the level in the possum belly stable.

Other Minor Factors

Other factors influence the size of the mud gas response. The factors are considered minor but should be touched on in this discussion. These factors can be grouped into poor drilling practices, poor mudlogging practices, or indeterminant factors. Poor drilling and mudlogging factors can easily be ameliorated.

Good Drilling Practices and modern rig function monitoring have helped improved mudlogging. Good mud properties, fast drilling, high annular velocities, and good solids control equipment help minimize cavings, minimize smearing, and minimize recycled gas response. Drilling mud contamination from gasoline, waste engine oil, and waste diesel affects mud gas response. Waste hydrocarbons should be disposed of off-site and not mixed with the drilling mud. Recycled gas or drilling with high gas-cut mud can be remedied by using proper solid control equipment, degassers, mud gas monitoring in the suction pit, and circulating bottoms up.

Occasionally cementing companies will run gasoline through their mix pumps to prevent cement from setting up; the practice does impact the mud gas response.

Poor Drilling Practices. Drilling severely underbalanced, which allow kicks or the well to flow, will adversely affect the quality of mudlogging and in most cases is not considered a good drilling practice. Drilling blind or with severe mud losses will also adversely affect the quality of mudlogging and in most cases is also not considered good drilling practice.

Poor Mudlogging Practices. Miscalibrated gas sensors, wind blowing in the gas trap exit port, the gas sampling system, and untrained mudloggers are other minor factors which can be easily remedied. Today's gas sensors have a wide dynamic range, and are seldom poisoned, cross-contaminated, or saturated. Older catalytic bead sensors become saturated and do not work when hydrocarbon gas is over 7.00% EMA due to the lack of oxygen for catalytic combustion. However, even the best sensors need to be calibrated and maintained. A downspout can be installed on the gas trap to minimize the effect of wind if the possum belly does not have walls. Watching the steam rise from the mud can be used to determine if the wind is an issue. Long sampling lines, sampling lines that are not insulated/heated, sampling lines with water or oil-based liquid build up which caused slugging in the lines, drying agents which are used to dewater but sorb hydrocarbon gases, and vent holes in lines to prevent mud sucking are all bad mudlogging practices. Ethylene glycol antifreeze is used to dewater lines and prevent freezing in cold weather, but ethylene glycol sorbs hydrocarbon gases and, when the temperature rises, releases these sorbed gases in an indeterminant fashion. Poorly trained mudloggers who do not properly follow procedures, fail to catch samples correctly, and fail to calibrate equipment are another poor mudlogging practice, but one that can be corrected.

Indeterminate Factors are numerous. Cuttings which do not fully release all their gas into the mud is an indeterminate factor. An old mudlogging technique of pulverizing cuttings in a blender has been and can be used to measure the amount of gas left in cuttings. Some mud additives for product anti-caking and polymer muds that sorb hydrocarbons are difficult to monitor and quantify. Very rarely do drilling mud polymers or anti-caking materials influence mud gas response. Monitoring the suction pit mud gas and watching the mud mixing schedule can help minimize the effect of drilling mud additives.

Some indeterminate factors could also be characterized as poor drilling practices. An open bell nipple, which allows gas to escape before it is measured, is another factor which is difficult to quantify. This factor is not considered a minor factor and has been discussed previously in this paper.[34] Using a rotating head with a good rubber element helps improve mudlogging. Gas escaping from the top of a gas buster while drilling is another indeterminate factor. Sampling the gas vent on a gas buster is a good practice. Swapping shakers or swapping manifolded flowlines upstream of the possum belly causes the mud level at the possum belly to fluctuate. A lockout tagout procedure can be implemented to prevent starving or bypassing the gas trap. A shroud with a constant volume lip can be built in the possum belly to prevent gas trap level fluctuations. Removing the shaker screens instead of bypassing the shaker when running LCM is a method that can be used to keep the flow level constant in the possum belly. The amount of oil in the water-based mud can be remedied by proper disposal of oily waste.

Most, if not all, of these minor factors which affect mud gas response can be quantified if Gas Markers are used. It is assumed that what influences the magnitude of the mud gas response also influences the Carbide Lagging response magnitude.

Gas Marker and Normalization Techniques to Quantify Mud Gas

Two techniques are presented which have improved mud gas interpretation. These are Gas Markers[37-38] and Normalization[39] techniques.

The Gas Markers technique was developed for interpreting Coal Bed Methane in the Powder River Basin, Wyoming, USA. The operator drilled a vertical pilot well on a pad through five coals. The productive coals shallowest to deepest are the Anderson, Dietz 2, Dietz 3, Monarch, and Carney. Then the operator logged and completed the vertical pilot well in the Carney. Next, the operator would top set the other four coals by drilling four more vertical wells on the pad each well exploiting the next shallower coal. The wells were about 20 feet apart. The shallowest, Anderson coal, was penetrated four times on the pad and partially penetrated once.

Sixteen pads of five wells were drilled in a section and all were mudlogged. The mud gas varied wildly. A three-fold range of mud gas response was not uncommon. The results were very disheartening. Years before when I introduced my new computerized mudlogging units, a driller told me mudlogging helped, but he, the driller, never knew if a certain gas reading would portend a gas kick or just a gas show.

A Gas Marker using one-half cup of calcium carbide was run before and after the coals. A half cup of calcium carbide was run because it had a response on the lower economic range of the coal mud gas responses. The amount of calcium carbide used was a trial-and-error process to gauge the commercially marginal mud gas response. I was aware that certain mudlogging companies always recorded both the magnitude of the carbide lag and the amount of carbide used. Randal Amen had just published a paper where a considerably small amount of acetylene or propylene was continually fed into the mud system to prove the gas trap was working.[40]

The normalization technique was presented in a thesis by Ty Taylor.[39] Walsh and Donovan[41] suggested the technique Taylor used but had no data to support the technique. I helped Ty Taylor evaluate mudlogs, suggested various methods to evaluate mudlogs and watched his progress to find the best relationship between mud gas and reserves. Normalization is a method that can be used if no Carbide Lag data is available.

Gas Markers and Normalization techniques are not mutually exclusive; they both can be run on the same mudlogged hole. Gas Markers can be considered an improvement over conventional Carbide Lagging which is a common mudlog practice. The only differences between Carbide Lagging and Gas Markers are that the calcium carbide's yield must be known, the sensor must be calibrated for both methane and acetylene, the amount of calcium carbide used must be recorded on the mudlog and the peak gas reading must be recorded on the mudlog. All other data used is data typically provided on a mudlog. The cost of implementing Gas Markers is minimal, especially if Carbide Lags are being run.

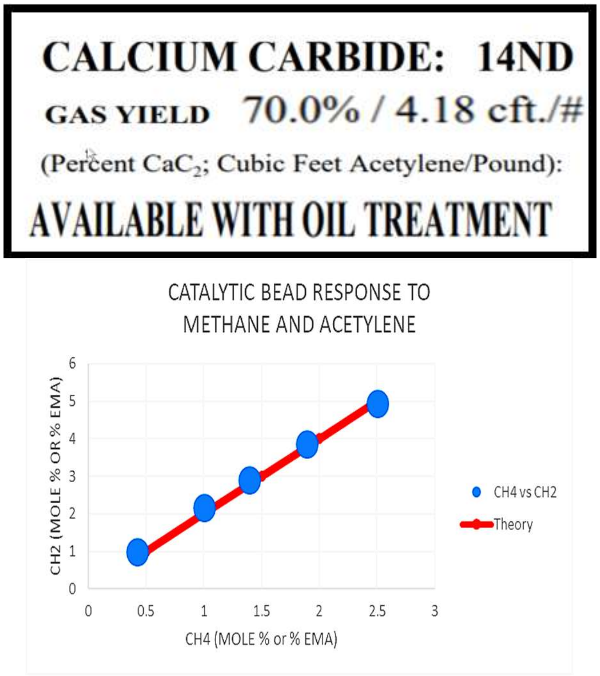
The Gas Marker technique is safe, low cost, and easily implemented. The Normalization technique proposed uses data already available and the correction factor can be applied prior to drilling the target reservoir.

Gas Markers

Mudloggers represent they calibrate their mudlogging instruments. They do not; they only calibrate the gas sensors within the mudlogging unit. The equipment is not calibrated to compensate for the effects of gas solubility, the gas losses at the surface, the gas trap, or the sample line losses. The gas trap is the major cause of mud gas response variations, yet it is never calibrated. The mudlogging calibration procedure is analogous to calibrating the equipment in the open-hole logging truck, then assuming the cable and downhole sonde were good.

Gas Markers compares the mud gas liberated by an oil and gas reservoir to a known amount of acetylene introduced in a connection above and below the reservoir. Only one Gas Marker lag is required, but more Gas Marker lags give a sense of consistency to the mud gas measurements. The volume of reservoir gas liberated is measured per minute and the bulk volume of rock drilled per minute is calculated from the bit diameter and penetration rate. The reservoir gas is the numerator, and the bulk volume of rock is the denominator.

Before using Gas Markers in a well, the calcium carbide yield must be known, and the mud gas sensors need to be calibrated for both acetylene and methane. The calcium carbide yield is the standard cubic feet of acetylene per pound of calcium carbide. In this example, the carbide yield from the manufacturer is 4.18 SCF of acetylene per pound of calcium carbide. Figure 11 shows the yield for calcium carbide and the calibration response for both methane and acetylene. The sensor used in this example is a catalytic bead (CB aka hot wire) which is a carbon counter. Acetylene has twice the response per mole percent as methane. All common mudlogging sensors – Flame Ionization Detectors (FID), FTIR, and Thermal Conductivity (TC) have all been used in Gas Marker computations, but their response to both methane and acetylene must be determined prior to mudlogging a well.



CALCIUM CARBIDE: 14ND

GAS YIELD 70.0% / 4.18 cft./#

(Percent CaC_2; Cubic Feet Acetylene/Pound):

AVAILABLE WITH OIL TREATMENT

Figure 11 – Calcium carbide yield and methane/acetylene sensor response.

At the wellsite a Gas Marker Lag is run before the zone of interest is drilled. From the calcium carbide yield information, sensor calibration for both methane and acetylene, the size of the Gas Marker, and the Gas Marker's response a conversion factor for mud gas response in hydrocarbon reservoirs can be determined. Figure 12 presents the computations and data sources for determining the gas conversion factor (Gas Factor) in this example.

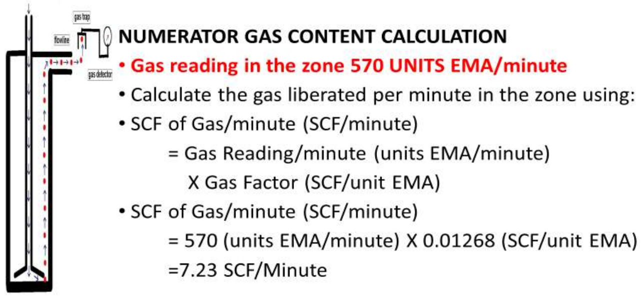
$$\overset{\text{CARBIDE YIELD}}{\left(\frac{1.268\ \cancel{SCF\ C_2H_2}}{0.5\ \cancel{CUPS\ CaC_2}}\right)}\times\overset{\text{AVOGADRO'S LAW}}{\left(\frac{1.268\ SCF\ CH_4}{1.268\ \cancel{SCF\ C_2H_2}}\right)}\times\overset{\text{CARBIDE LAG}}{\left(\frac{0.5\ \cancel{CUPS\ CaC_2}}{200\ \cancel{Units\ C_2H_2}}\right)}$$

$$\times\underset{\text{SENSOR CALIBRATION}}{\left(\frac{250\ \cancel{Units\ C_2H_2}}{125\ \cancel{Units\ CH_4}}\right)}\times\underset{\text{DEFINITION}}{\left(\frac{1\ \cancel{Units\ CH_4}}{1\ Units\ EMA}\right)}=\underset{\text{GAS FACTOR}}{\left(\frac{0.01268\,SCF\ CH_4}{1\ Unit\ EMA}\right)}$$

Figure 12 – Calculation for converting Carbide yield to Mud Gas Response (Gas Factor).

The Gas Factor is 0.01268 SCF of methane per one mud gas EMA unit. In this example, the calcium carbide yield is 1.268 SCF of acetylene per half cup of calcium carbide.

When the reservoir is drilled, the numerator in the Marker Gas equation can be computed. In this example, a 570-unit EMA gas show was drilled, pumped to the surface while drilling ahead, measured and lagged to the proper depth. Using the Gas Factor of 0.01268 SCF of methane per one mud gas EMA unit, calculations showed 7.23 SCF methane per minute is liberated from the reservoir into the drill cuttings. Figure 13 presents the numerator calculations. In this case, it was a coal reservoir, but the lithology of the reservoir does not affect the calculations.

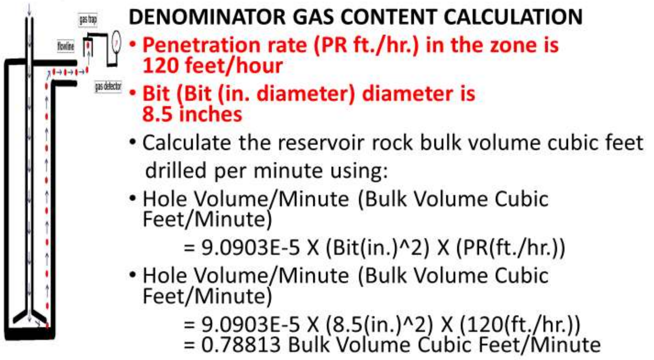


NUMERATOR GAS CONTENT CALCULATION

- Gas reading in the zone 570 UNITS EMA/minute
- Calculate the gas liberated per minute in the zone using:
- SCF of Gas/minute (SCF/minute)
  = Gas Reading/minute (units EMA/minute)
  X Gas Factor (SCF/unit EMA)
- SCF of Gas/minute (SCF/minute)
  = 570 (units EMA/minute) X 0.01268 (SCF/unit EMA)
  =7.23 SCF/Minute

Figure 13 – Calculation of Gas Content Numerator

In this example and presented in Figure 14, an 8.5-in. diameter bit drills at a penetration rate of 120 ft/hr. That calculates to 0.78813 cubic feet of bulk volume rock drilled per minute. The reservoir bulk volume of rock drilled per minute is the denominator in the Gas Marker equation.

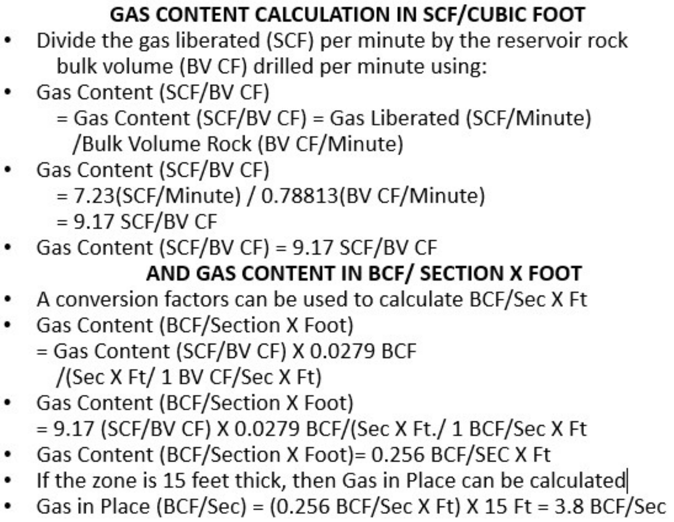


DENOMINATOR GAS CONTENT CALCULATION

- Penetration rate (PR ft./hr.) in the zone is 120 feet/hour
- Bit (Bit (in. diameter) diameter is 8.5 inches
- Calculate the reservoir rock bulk volume cubic feet drilled per minute using:
- Hole Volume/Minute (Bulk Volume Cubic Feet/Minute)
  = 9.0903E-5 X (Bit(in.)^2) X (PR(ft./hr.))
- Hole Volume/Minute (Bulk Volume Cubic Feet/Minute)
  = 9.0903E-5 X (8.5(in.)^2) X (120(ft./hr.))
  = 0.78813 Bulk Volume Cubic Feet/Minute

Figure 14 – Calculation of Gas Content Denominator

Figure 15 presents the gas content in both SCF per cubic foot of reservoir rock and BCF per section-foot. 7.23 SCF methane per minute is liberated from 0.78813 ft^3 bulk volume of rock drilled per minute. That is 9.17 SCF per one cubic foot of reservoir rock. Using the SCF of methane per cubic foot bulk volume of reservoir rock calculates to 0.256 BCF/section-foot. If the zone is fifteen feet thick with mud gas response of 0.256 BCF/section-foot throughout, then there would be 3.8 BCF per section.



GAS CONTENT CALCULATION IN SCF/CUBIC FOOT

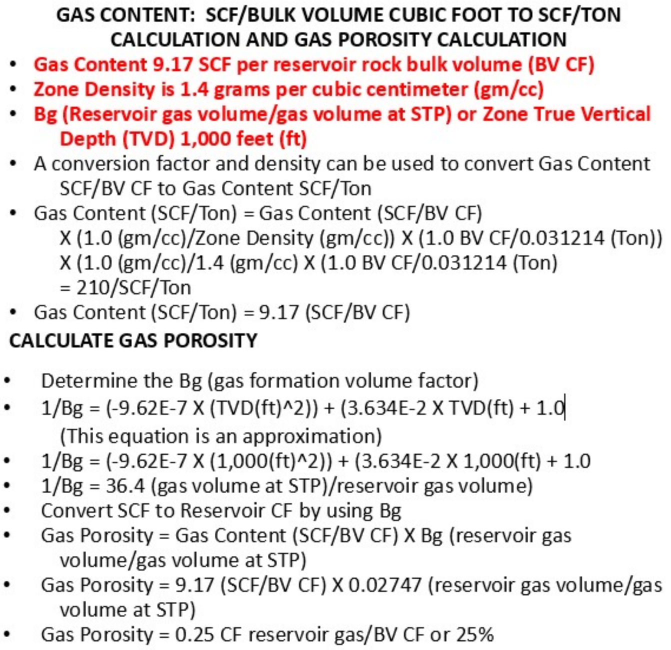
- Divide the gas liberated (SCF) per minute by the reservoir rock bulk volume (BV CF) drilled per minute using:
- Gas Content (SCF/BV CF)
  = Gas Content (SCF/BV CF) = Gas Liberated (SCF/Minute)
  /Bulk Volume Rock (BV CF/Minute)
- Gas Content (SCF/BV CF)
  = 7.23(SCF/Minute) / 0.78813(BV CF/Minute)
  = 9.17 SCF/BV CF
- Gas Content (SCF/BV CF) = 9.17 SCF/BV CF

AND GAS CONTENT IN BCF/ SECTION X FOOT

- A conversion factors can be used to calculate BCF/Sec X Ft
- Gas Content (BCF/Section X Foot)
  = Gas Content (SCF/BV CF) X 0.0279 BCF
  /(Sec X Ft/ 1 BV CF/Sec X Ft)
- Gas Content (BCF/Section X Foot)
  = 9.17 (SCF/BV CF) X 0.0279 BCF/(Sec X Ft./ 1 BCF/Sec X Ft
- Gas Content (BCF/Section X Foot)= 0.256 BCF/SEC X Ft
- If the zone is 15 feet thick, then Gas in Place can be calculated
- Gas in Place (BCF/Sec) = (0.256 BCF/Sec X Ft) X 15 Ft = 3.8 BCF/Sec

Figure 15 – Gas Content Calculations for both SCF/BV CF and BCF/Section-Feet.

If the reservoir is coal with a bulk density of 1.4 grams per cubic centimeters the gas content of the coal would be 210 SCF per ton. If the coal was at 1,000 feet and the gas expansion factor (1/Bg) is known to be 36.4 SCF per reservoir cubic feet. Then the coal would have an equivalent gas porosity of 25%. Computations in this paragraph are summarized in Figure16.



GAS CONTENT: SCF/BULK VOLUME CUBIC FOOT TO SCF/TON CALCULATION AND GAS POROSITY CALCULATION

- Gas Content 9.17 SCF per reservoir rock bulk volume (BV CF)
- Zone Density is 1.4 grams per cubic centimeter (gm/cc)
- Bg (Reservoir gas volume/gas volume at STP) or Zone True Vertical Depth (TVD) 1,000 feet (ft)
- A conversion factor and density can be used to convert Gas Content SCF/BV CF to Gas Content SCF/Ton
- Gas Content (SCF/Ton) = Gas Content (SCF/BV CF)
  X (1.0 (gm/cc)/Zone Density (gm/cc)) X (1.0 BV CF/0.031214 (Ton))
  X (1.0 (gm/cc)/1.4 (gm/cc) X (1.0 BV CF/0.031214 (Ton)
  = 210/SCF/Ton
- Gas Content (SCF/Ton) = 9.17 (SCF/BV CF)

CALCULATE GAS POROSITY

- Determine the Bg (gas formation volume factor)
- 1/Bg = (-9.62E-7 X (TVD(ft)^2)) + (3.634E-2 X TVD(ft) + 1.0
  (This equation is an approximation)
- 1/Bg = (-9.62E-7 X (1,000(ft)^2)) + (3.634E-2 X 1,000(ft) + 1.0
- 1/Bg = 36.4 (gas volume at STP)/reservoir gas volume)
- Convert SCF to Reservoir CF by using Bg
- Gas Porosity = Gas Content (SCF/BV CF) X Bg (reservoir gas volume/gas volume at STP)
- Gas Porosity = 9.17 (SCF/BV CF) X 0.02747 (reservoir gas volume/gas volume at STP)
- Gas Porosity = 0.25 CF reservoir gas/BV CF or 25%

Figure 16 – Gas Content SCF/BV CF to SCF/Ton Calculations and Gas Porosity Calculations.

If the reservoir is an oil reservoir, then the GOR is required to calculate oil reservoir volume. The working assumption in the Gas Marker method is calcium carbide behaves similarly to methane as they travel up the hole. Another working assumption is that all the gas is liberated from the cuttings. If this assumption is not true, then these calculations would underestimate the reservoir gas volume. Also, it is assumed no gas is entering from the undrilled reservoir into the borehole either because the reservoir has low permeability or the drilling is balanced.

Gas Markers were used to calculate Mudlog Gas Content (Mudlog GC) in the Powder River Basin, Wyodak coals near Sheridan, WY, USA. All gas content results are presented in SCF of natural gas per ton of coal reservoir. The client wanted to keep the exploration ramifications of the data confidential, so the results (Figure 17) are labeled Wells 1 to 55. The wells were all in a contiguous area drilled on 40-acre pads as discussed before. The range of Mudlog GC is from 25 to 300 SCF/ton, with over half above a gas content of 100 SCF/ton.

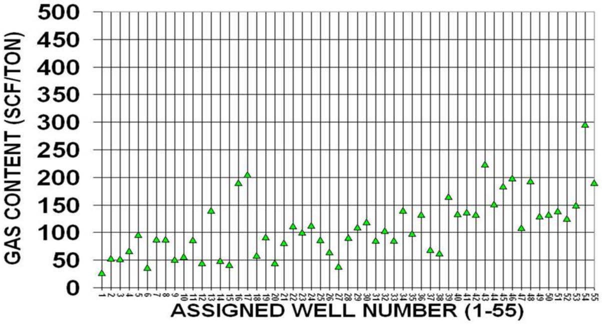


Figure 17 – Mudlog Gas content of 55 wells.

For this presentation, the Mudlog GC was compared to the “back-calculated” gas content based on cumulative thirty months of gas production and the EUR projected from the cumulative production. Below is the equation along with defined variables used to make the calculation.

$$GC = \left(\frac{G}{(1.3597\, X\, H\, X\, A\, X\, \rho_b)} \right) \qquad \text{Eq. 2}$$

GC = Gas Content (SCF/Ton)
G = Cummulative Production or Estimated Ulitimate Reserves (MCF)
A = Drainage Area (Acres)
H = Reservoir Height (Feet)
ρ_b = Bulk Density (Grams/Cubic Centimeter)

Figure 18 compared the Mudlog GC to the cumulative production back-calculated gas content (Cumulative GC), and the Estimated Ultimate Recovery back-calculated gas content (EUR GC). The anticipated order of gas content should be the Mudlog GC higher than the EUR GG, and the EUR GC higher than the Cumulative GC. Most samples follow this order. The wells with the higher Mudlog GC tend to have a higher Cumulative GC and EUR GC. This unanticipated order may be due to higher fracture permeability coals flushing gas in front of the bit, thus lowering the Mudlog GC. Alternatively, this unanticipated order may be due to the higher permeability coals draining more than the 40-acre spacing unit. Suffice it to say the correlation between Mudlog GC and well performance is good.

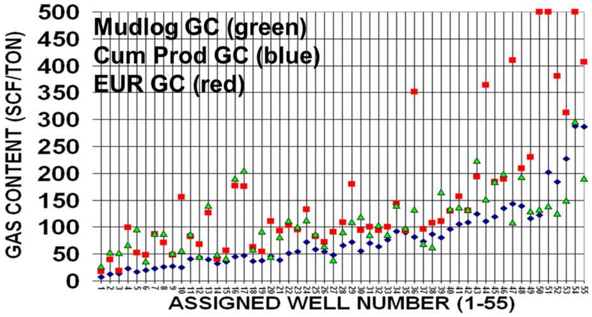


Figure 18 – Gas Marker examples from Figure 17 compared to 30 months of production and EUR estimates.

These Mudlog GC readings were considered high when compared to Cannister Desorption Gas Content (Cannister Desorption GC). Mudlog GC gas content was dismissed early on because the data did not agree with Cannister Desorption Gas Content data gathered in the area. The wells presented did not have cannister desorption data because the measurements are not operationally mutually compatible. The Canister Desorption Gas Content data presented here are from a correlation derived from numerous measurements in all directions within a three-mile radius of the area. The reservoir engineers viewed Cannister Desorption GC as valid and extrapolatable to the wells with Mudlog GC. The Cannister GC data are plotted in Figure 19. Notice the Cannister GC was lower than the Cumulative GC in over 80% of wells indicating the Cannister GC underestimated well performance. To summarize Mudlog GC is a good predictor of production performance in coal gas unconventional reservoirs.

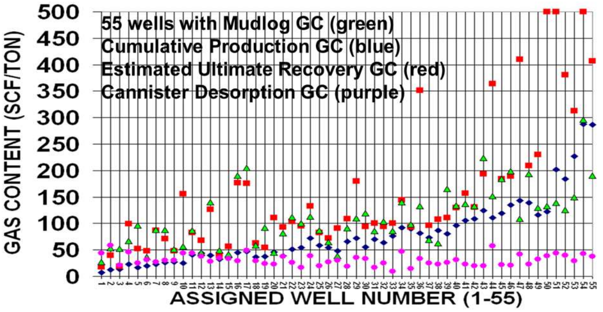


Figure 19 – Gas Marker data and production data from Figure 18 plus the Cannister Desorption GC data.

Normalization Technique

The next example is from Ty Taylor’s Master Thesis.[39] The example quantifies mud gas and relates it to production performance from the Marcellus unconventional shale reservoir in Westmoreland County, Pennsylvania, USA. Normalization does not require Gas Markers but does require a statistically significant number of wells to be mudlogged. The data is from one operator, and the well completions were similar. The well completions were intentionally similar in an attempt to relate reservoir properties to well performance. The operator provided both the eighteen-month cumulative production data and the EUR estimates. Figure 20 shows the stratigraphic formations and Figure 21 presents the Gamma Ray (GR) log response of the formations. The mud gas was normalized in the Mahantango Shale and a correction factor was then applied to the productive Union Springs member of the Lower Marcellus Formation. This process is similar to benchmarking open-hole logs based on their reading in a specific lithology or formation. Benchmarking is a common technique used in open-hole logging. Two examples of benchmarking are using an Anhydride to check for density log calibration or Passey delta T log R baseline for unconventional Total Organic Carbon (TOC) determinations.

MARCELLUS STRATIGRAPHIC COLUMN

Age	Formation		Member
Upper Devonian	Harrell Shale		
Middle Devonian	Tully Limestone		
	MAHANTANGO SH		
	MARCELLUS SH	upper interval	
		middle interval	Purcell Limestone
		lower interval	
	Onondaga Limestone		
	Huntersville Chert		
	Needmore Shale		
	Oriskany Sandstone		

Figure 20 – Stratigraphic formations discussed in Ty Taylor's thesis.[39]

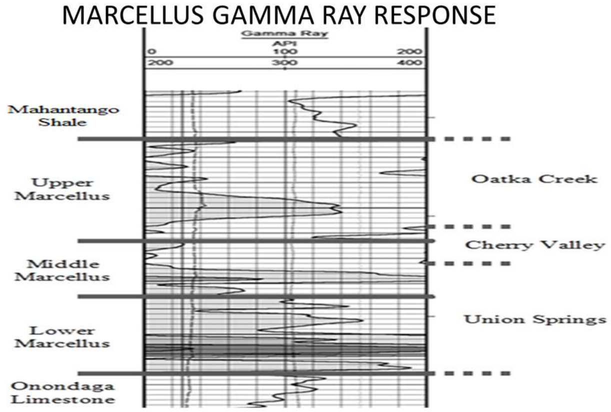


Figure 21 – Marcellus gamma ray response as discussed in Ty Taylor's thesis.[39]

Twelve horizontal geosteered wells were used in this study. Log ASCII Standard (LAS) file format of the mudlog data were available on a half-foot basis from surface casing to total measured depth. A fifty-foot correlative interval within the Mahantango Shale was chosen to normalize the mud gas response. This fifty-foot interval was chosen because it had similar open-hole log curve and core characteristics. The interval also had low and consistent Total Organic Carbon (TOC) from geochemistry data. It was assumed if the lithology was similar, the variation in mud gas response was due to measurement and instrumentation issues previously outlined in this presentation.

The mud gas for the fifty-foot Mahantango Shale interval was summed and averaged for each well. The well's average ranged from 25 to 550 units with an average value of about 350 units. The gas readings were normalized to an arbitrary 350 units. Each well had its own correction factor that was either added or subtracted from the mud gas reading to get a normalized mud gas reading. The normalized mud gas readings read an average value of 350 units in the fifty-foot Mahantango Shale normalization depth interval. Figure 22 is a graphical presentation of the process. Well 5, which averaged 50 units, was shifted up to 350 units by adding a correction factor of 300 units. Whereas Well 11 average readings of 550 units was shifted down to 350 units by subtracting a correction factor of 200 units. Notice the data has an eleven-fold difference in gas reading for similar lithology. These corrections are major corrections and demonstrate the vagaries of mud gas readings.

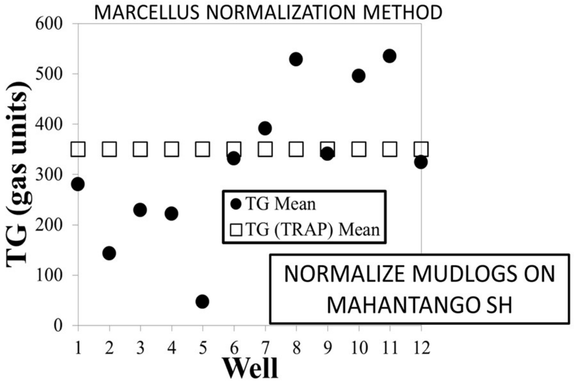


Figure 22 – Normalized Mud Logs on Mahantango Shale.

Every half-foot mud gas reading in the well was normalized using their well's correction factor. The normalized mud gas was summed in the Marcellus completed interval. The completed interval was from the toe to heel perforation intervals. Figure 23 plots the normalized mud gas data against the 18-month cumulative gas production. The sum of the normalized gas units range from 1 million to five million and the range of cumulative production is from 0.4 to 1.9 BCF; the coefficient of determination (R^2) is 0.87.

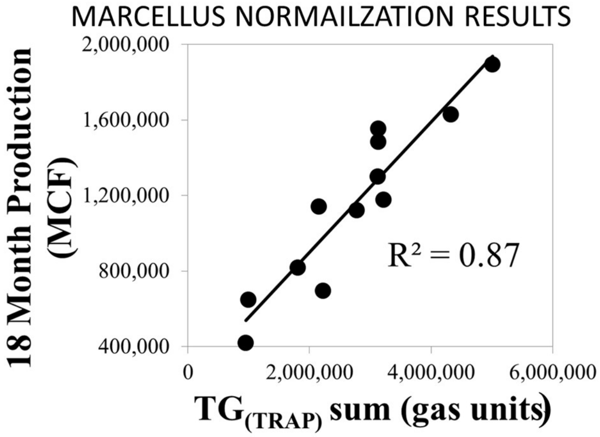


Figure 23 – Normalization results for Marcellus Shale.

A similar graph, Figure 24, plots the raw API GR readings against the 18-month cumulative gas production resulting in a correlation with a coefficient of determination of 0.73. Multiple regression on independent variables, normalized mud gas and normalized API GR, against the dependent variable 18-month cumulative gas production is beyond the scope of this presentation.

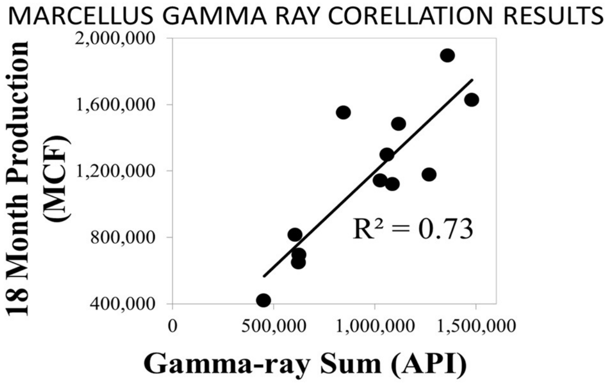


Figure 24 – Marcellus Gamma Ray correlation results.

A simple data shift gave the best result and indicates that mud gas behaves linearly over the measurement range. This would suggest that the gas trap does have a linear response. The normalizing of mud gas on drilling rate, hole size, and circulation rate did not provide a satisfactory correlation with production. This lack of correlation demonstrated the drilling rate, hole size, and circulation rate are not major factors influencing the size of the gas show. There typically are not wide variations in rig pump output, drill pipe and bit sizes among drilling contractors in mature plays. Other mud log variables and the combination of mud log variables did not yield a better correlation.

Conclusions

With the advent of horizontal drilling in unconventional plays mudlogging has been overlooked as a source of valuable information.

Factors influencing mud gas response have been presented. Surface losses and gas trap variations are major factors that influence mud gas response. The variations are not minor and can be over ten-fold.

Three different mud/gas lagging techniques have been presented; 1) Pump Stroke Lagging, 2) Connection Lagging and 3) Carbide Lagging. It has been demonstrated that mud gas, in the volumes drilled and circulated, is solubilized in water-based mud and thus is a proxy for drilling mud circulation.

In horizontal wells, the mud/gas lag, pump stroke lag, and cuttings lag are not the same and should be treated differently to relate lag gas and cuttings to their proper depth.

Gas Markers, a simple improvement on Carbide Lagging, demonstrate the predictive value in mud gas analysis. Normalization has shown to improve mud gas interpretation in wells without Gas Markers.

Gas Marker and Normalization techniques are more predictive than using raw mud gas data in data mining applications. These techniques show mud gas analysis can be correlated to production performance.

Acknowledgments

I would like to acknowledge Roy Gallup, Core Lab, Jim Jacobs, and Tom Dugan, Dugan Production Corporation for mentoring me when I broke out. Drs. Hilchie and Pickett at the Colorado School of Mines taught me the techniques I applied to mudlogging. Thanks to Ty Tayor, Warren Walsh, and Randal Amen for engaging in mudlogging discussions. Also thanks to Jack McDermott, Vincent "Red" McHoes, Phil Jacobs, and Ryan Weller, the backbone of Automated Mudlogging Systems, for their diligent collection of mudlogging data and my operator clients who supported this work by employing me. Mary Dimataris, thank you for editing and proofreading this paper. Last but not least, acknowledgments to my wife and family who accepted a three-week-on and one-week-off schedule for decades.

Nomenclature

BCF = *Billion cubic feet of gas at STP (MMMCF)*
EMA = *Equivalent Methane in Air (%)*
EUR = *Estimated Ultimate Recovery*
GC = *Gas Content*
GOR = *Gas-oil ratio (SCF/Bbl)*
LAS = *Log ASCII Standard*
ROP = *Rate of penetration or drilling rate (ft/hr)*
SCF = *Standard cubic feet of gas* (ft^3)
STP = *Standard temperature and pressure (60°F, 14.7 psia)*

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