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Réaliser par :

GARRI Brahim ,GHOCHI Abdennasser et ARBAOUI Bachir

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L'encadreur :

M. BARI Mohamed Abdou

Jury:

Abidi S Elfakeur

président

Univ. Ouargla

Moulay Khalil

Examineur

Univ. Ouargla

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DEDICATE

Than to be able to share the best moments of your life with the beings you love.

Arrived at the end of my studies, I have the great pleasure to dedicate this modest work:

To my mother, who always gives me hope to live and never stopped praying for me.

To my father, for his encouragement, his support, above all for his love and his sacrifice that nothing hinders the progress of my studies.

To my dear Sisters and my brother.

To all my big family,

To my teachers for their helps.

To my best friends as all my class friends.

To All those I love and respect.

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Praise be to Allah who has guided us to this. We were not guided, if Allah had not guided us.

*Then a big thanks to all the teachers who supervised our teaching during the period of our studies in the Faculty of Hydrocarbons and Geology, also thank you to the supervisor **D.Bari Mohamed Abdou** for all the help both in terms of providing lectures and lessons and providing us with*

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List of Symbols

Abriviation	Definition	Abriviation	Definition
Wh	Wetness Ratio	SMOW	Standard Mean Ocean Water
Bh	Balance Ration	MD	Measured depth
Ch	Character Ration	TD	Total Depth
GOR	Gas Oil Ratio	OCR	Oil Character Ratio
GOC	Gas Oil Contact	LHR	Ligh to Heavy Ratio
OWC	Oil Water Contact	GLR	Gas Liquid Ratio
CGR	Condensate Gas Ratio	GWR	Gas Wetness Ratio
API	American Petroleum Institut	NGL	Natural Gas liquid
LWD	Logging While Drilling	RFID	Radio frequency Identification
TVD	True Vertical Depth	DST	Drill Stem Test
ROP	Rate Of Penetration.	CVT	constant volume trap
ECD	Equivalent Circulation Density	QGM	Quantitative gas measurement
MDT	Modular formation Dynamic Test	NW	Normalized isotopic composition Well
IRM	Isotope Logging Device		

INTRODUCTION

GENERAL INTRODUCTION

Allowing for the lag time required to circulate the drilling fluid from the bottom of the hole back to surface, analysis of formation gas released and entrained in the drilling fluid provides an immediate appraisal of reservoir potential.

This short program demonstrates how real-time chromatographic analysis of light hydrocarbons can provide effective fluid characterization with the identification of fluid changes, zones and contact points, as the reservoir is being penetrated.

The clear advantage of this is that reservoir fluids are analyzed immediately, before contamination by mud invasion can alter the characteristics of formation fluids adjacent to the borehole, which can often be detrimental to subsequent electrical analysis. In addition to such reservoir analysis, high speed chromatographic analysis also provides the necessary resolution for the techniques to be applied to the steering of horizontal wells. While Logging While Drilling (LWD) is an effective technique, it is also an expensive one and costs can be dramatically reduced by the application of gas analysis to geosteering. A further benefit is often realized through more rapid course corrections (depending on the relationship between lag time and penetration rate versus tool placement, and when changes are recognized at surface) minimizing the amount of missed pay. ^[3]

However, predictions based on gas analysis have, on occasion, proved to be misleading or even false. This has led to some skepticism and lack of trust in this source of data. Understanding the processes involved in gas extraction and analysis helps to alleviate this mistrust, so this program also aims to characterize some of the possible problems that can be encountered and how they can be taken into consideration to provide effective analysis. ^[1]

Unfortunately, one of the major sources of error is in the equipment itself. Agitation based gas extraction is subject to many variables and produces many unknowns in the resulting gas measurement. This is well recognized in the industry and techniques have been developed to try to improved the qualitative nature of the gas data. The final part of this program analyzes the development of a new extraction technique, utilizing a gas permeable membrane, rather than physical agitation, that provides a fully quantitative gas measurement. This removes virtually all of the inconsistencies and sources of error in present gas analysis, resulting in consistent, repeatable, quantitative gas data that can be reliably applied to the applications described above. ^[1]

CHAPTER I : FLUID
CHARACTERIZATION
USING GAS RATION

INTRODUCTION

Fluid characterization can be made with a number of different ratio techniques. The chromatographic gas ratios most applicable to real-time analysis and geosteering are the Wetness, Balance and Character ratios.

These ratios are calculated and plotted real-time, providing an immediate appraisal of the formation fluid character, as the well is being drilled. The values, relationships and separation of these ratio curves are used to determine the hydrocarbon fluid type. Relative changes in oil gravity and gas wetness can be determined, as well as the actual gas/oil and oil/water contact points. ^[6]

1. Generalized definition of gas ratio

- ❖ Chromatograph analysis of the C1-C5 fraction of the hydrocarbons released at the ditch
- ❖ Mathematical treatments on the light alkane series to assist in hydrocarbon show evaluation
- ❖ Reservoir characterization by analysis of light hydrocarbon shows. ^[5]

2. The Wetness Ratio (Wh)

The wetness ratio shows an increasing trend as gas and oil density increases, i.e. as the amount of heavy gas components increase proportionally against the lighter gases. ^[6]

$$Wh = \left(\frac{C2+C3+C4+C5}{C1+C2+C3+C4+C5} \right) \times 10$$

Wh	Fluid Type
< 0.5	non-productive, non-associated dry gas
0.5 – 17.5	gas, increasing in density, or wetness, as Wh increases
17.5 – 40	oil, increasing density (decreasing gravity) as Wh increases
> 40	low gravity or residual oil

3. Balance Ratio (Bh)

The balance ratio is a direct comparison of light to heavy hydrocarbons and, for interpretative purposes, is used together with the wetness ratio. ^[6]

$$Bh = \left(\frac{C1+C2}{C3+C4+C5} \right)$$

Bh reacts inversely to Wh so that it decreases as the fluid density increases. It is used to determine, or confirm, gas production potential. The value will be very high with very dry methane for example, then fall rapidly as soon as there is a trace of the heavy hydrocarbons associated with a productive source. ^[5]

Table 1 shows exactly how the two ratios are used, numerically, to determine these zones.

In practice, a very simple “egg-timer” type profile (Figure I.1), or relationship, between the wetness and balance ratios is used to determine changing fluid type and contact points.

If the balance ratio is greater than the wetness ratio, gas is being predicted. The closer the curves are to each other, then the denser the gas and the more likely it is to be productive. ^[6]

Table I. 01: Fluid characterization using the wetness and balance ratios

Balance Ratio	Wetness Ratio	Reservoir Fluid and Production Potential
> 100		Very light, dry gas Typically non-associated and non-productive such as the occurrence of high pressured methane, metagenic cracking below the oil window, bacterial methane etc
< 100	< 0.5	Possible production of light, dry gas
Wh < Bh < 100	0.5 – 17.5	Productive gas, increasing in wetness as the curves are closer together
< Wh	0.5 – 17.5	Productive, very wet gas or condensate or high gravity oil with high GOR (Bh < Wh indicates liquid, but Wh still indicates gas)
< Wh	17.5 – 40	Productive oil with decreasing gravity as the curve separation increases
<< Wh	17.5 – 40	Lower production potential of low gravity, low gas saturation oil
	> 40	Very low gravity or residual oil

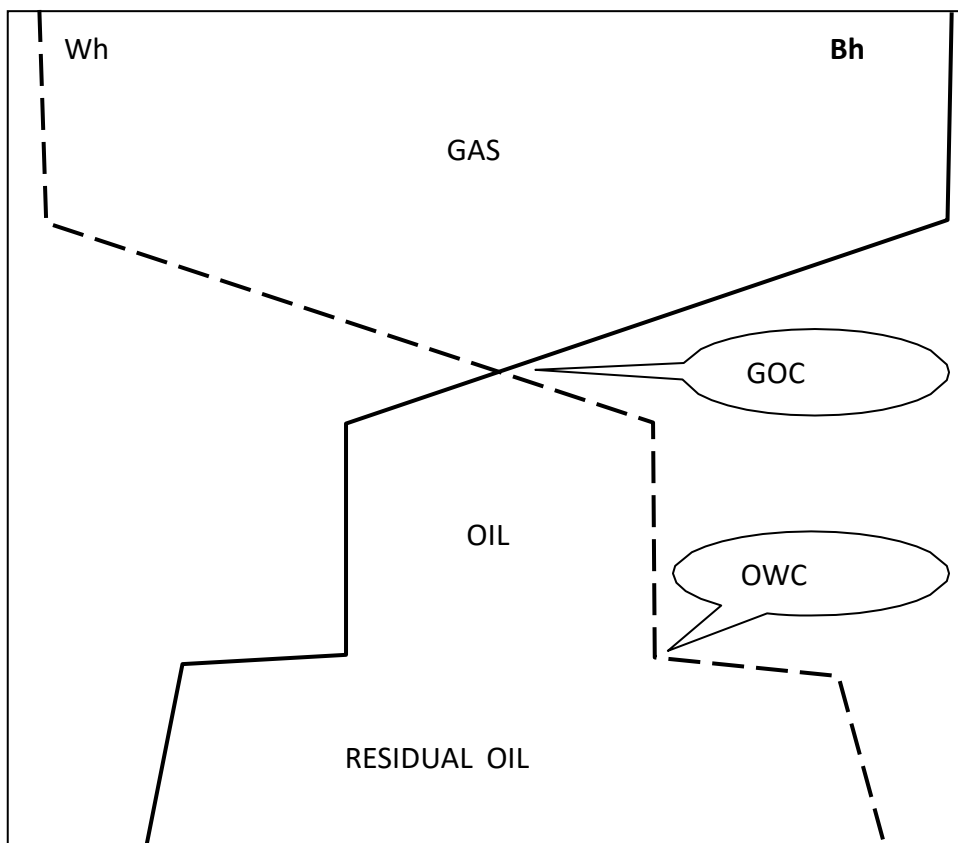


Figure I.1: Typical fluid and contact profiles of the Wh and Bh Ratio

If the wetness ratio is greater than the balance ratio, oil is being predicted. The closer the curves are to each other, then the lighter the oil. The greater the separation of the curves, then the heavier the oil and the more likely it is to be unproductive or residual.

The gas-oil-contact (GOC) is therefore defined by the cross-over point of the two curves.^[6]

The oil-water-contact (OWC) is typically determined when a sharp increase in the wetness ratio, accompanied by a greater separation of the two curves, reflects a greater proportion of heavier hydrocarbons associated with residual oil traces.^[6]

4. Character Ratio (Ch)

By comparing the heavier compounds (propane – pentane), the character ratio is used to qualify a gas prediction from the wetness/balance ratios. The character ratio confirms whether a gas prediction is indeed a gas zone, or whether the gas is associated with oil.

The significance of comparing these three compounds is that C3 will typically be more predominant in a gas reservoir, with lower amounts of C4/C5. All the heavier components will increase as the fluid density increases, but C4 and C5 will increase proportionally in the case of light oils. ^[5]

$$Ch = \left(\frac{C4+C5}{C3} \right)$$

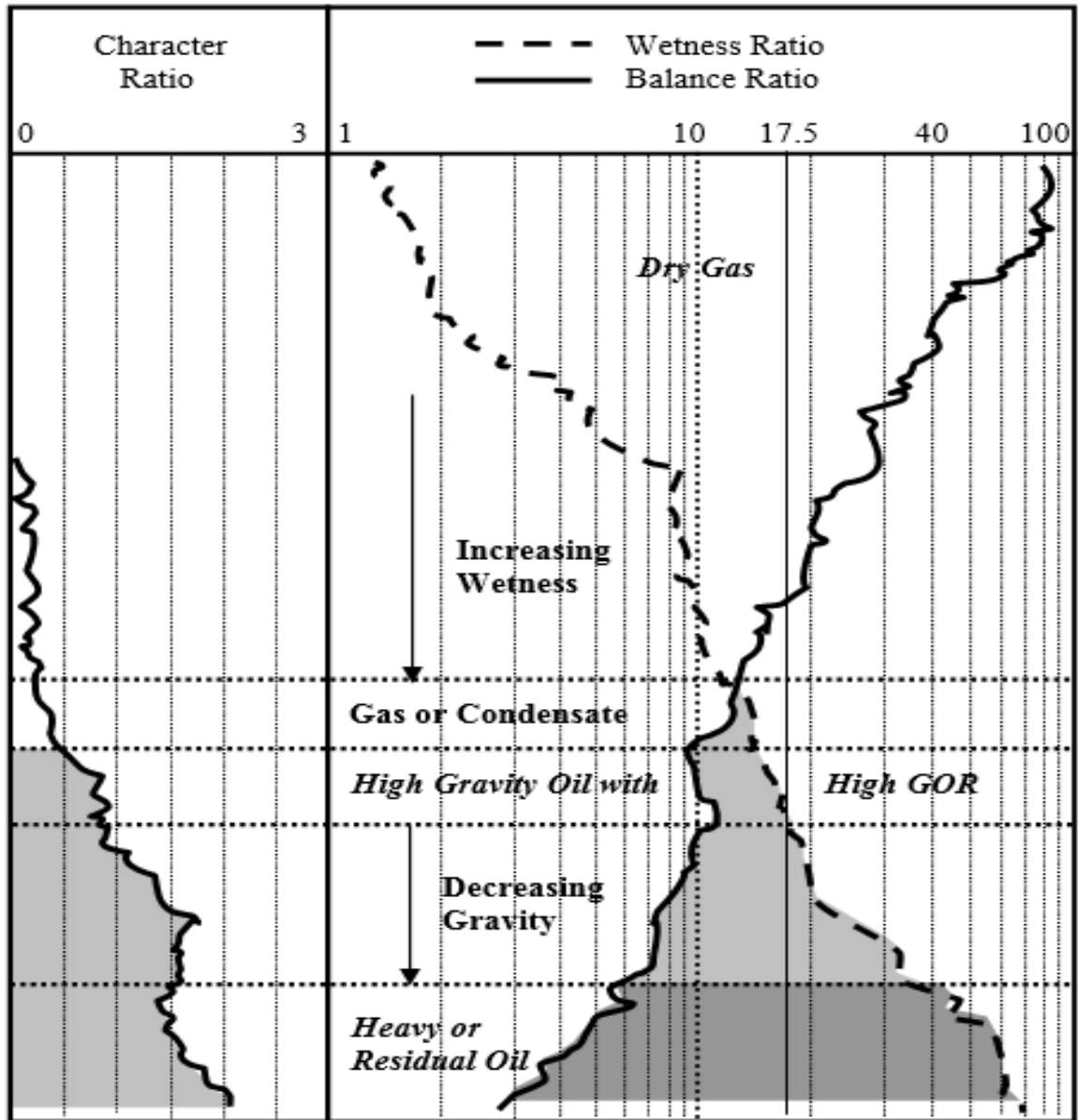
If $Ch < 0.5$ With C3 the major component, the presence of a productive gas phase is confirmed, indicating either wet gas or gas condensate.

If $Ch > 0.5$ The presence of a productive liquid phase is confirmed, so that the gas . indicated by the wetness ratio is associated with light oil. ^[6]

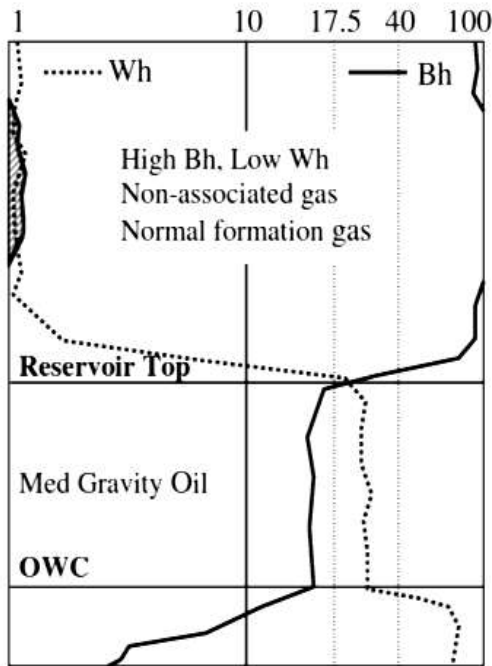
The character ratio should be used to qualify all Wh/Bh ratio gas predictions, but it is most useful in a very specific situation. When the wetness and balance ratio curves are close together, it is difficult to be specific about the fluid type. A wet gas, gas condensate and light oil can, compositionally, be very similar, so that they will yield very similar ratio values. By only considering the heavy components, the character ratio helps to determine whether the productive phase is gas or oil. ^[6]

5. Reservoir Profiling

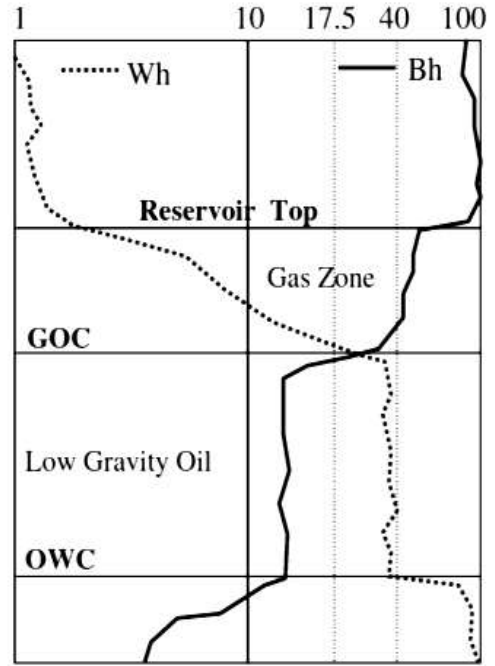
5.1. How the gas ratios determine fluid variations and contact points



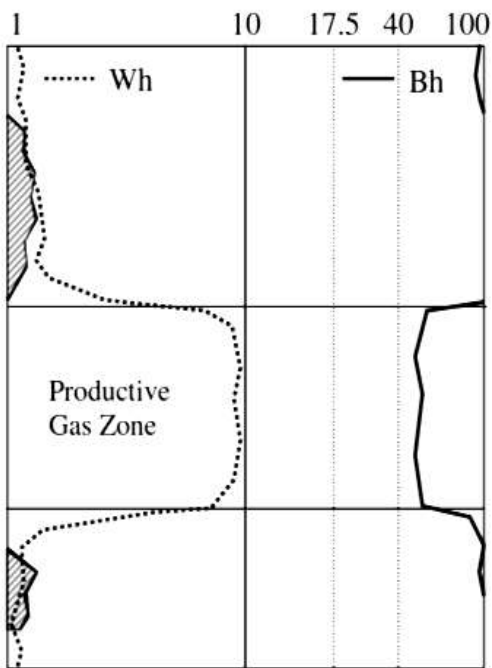
FigureI. 2: Fluid characterization of a reservoir section, with gas ratios.



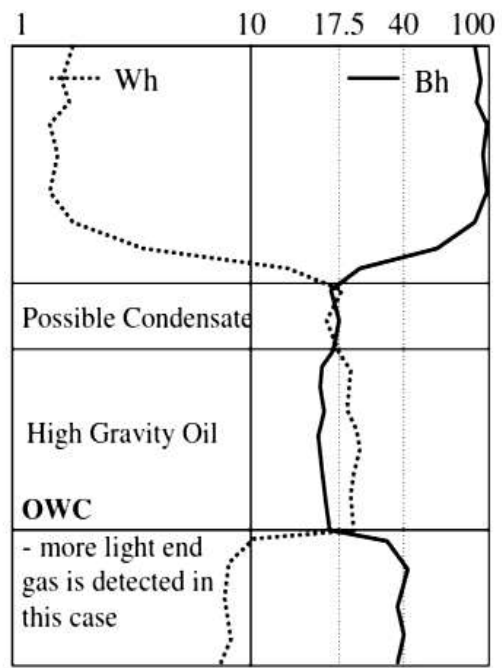
A Oil bearing zone and oil-water contact



B Gas-oil and oil-water contacts



C Gas zone



D "Complications"

Figure I. 3 (A-B-C-D) shows gas ratio trends for typical reservoir profiles.

5.2. Example A

Here, the Wetness/Balance cross-over is lithological, as well as fluid based, with the well entering straight into an oil bearing reservoir with no true gas-oil contact.

The curve separation through the zone suggests medium gravity oil and the oil water contact is determined when there is a greater degree of separation resulting from heavier, residual oil. ^[6]

5.3. Example B

In this example, the top of the reservoir is identified when the balance ratio drops to show a more productive gas. The top of the reservoir is a gas cap as the curves gradually come together, indicating an increasingly heavier gas as the oil zone is approached. The gas-oil contact is seen when the two curves finally cross.

With the higher wetness and greater separation from the balance, a lower gravity oil is predicted in this example. ^[6]

5.4. Example C

Productive gas zones are indicated when the balance ratio falls (below 100) in relation to the background formation gas level. At the same time, the wetness ratio increases and converges on the balance ratio – the closer the curves come together, the heavier the gas.

Typically, any gas-water contact will be evident from the ratios returning to a light, normal formation type gas composition. ^[6]

5.5. Example D

When Wh and Bh cross, in this example, to indicate the top of the reservoir, they remain very close together. In this situation it is very difficult to determine the fluid type between condensate, gas or oil, although the character ratio can be used as an extra indicator.

With lower Wh, and the curves quite close together, the main zone is a high gravity oil. The oil-water contact acts inversely to what is normally expected – in this case, more light gas is evident from water than heavier gas from any residual oil. ^[6]

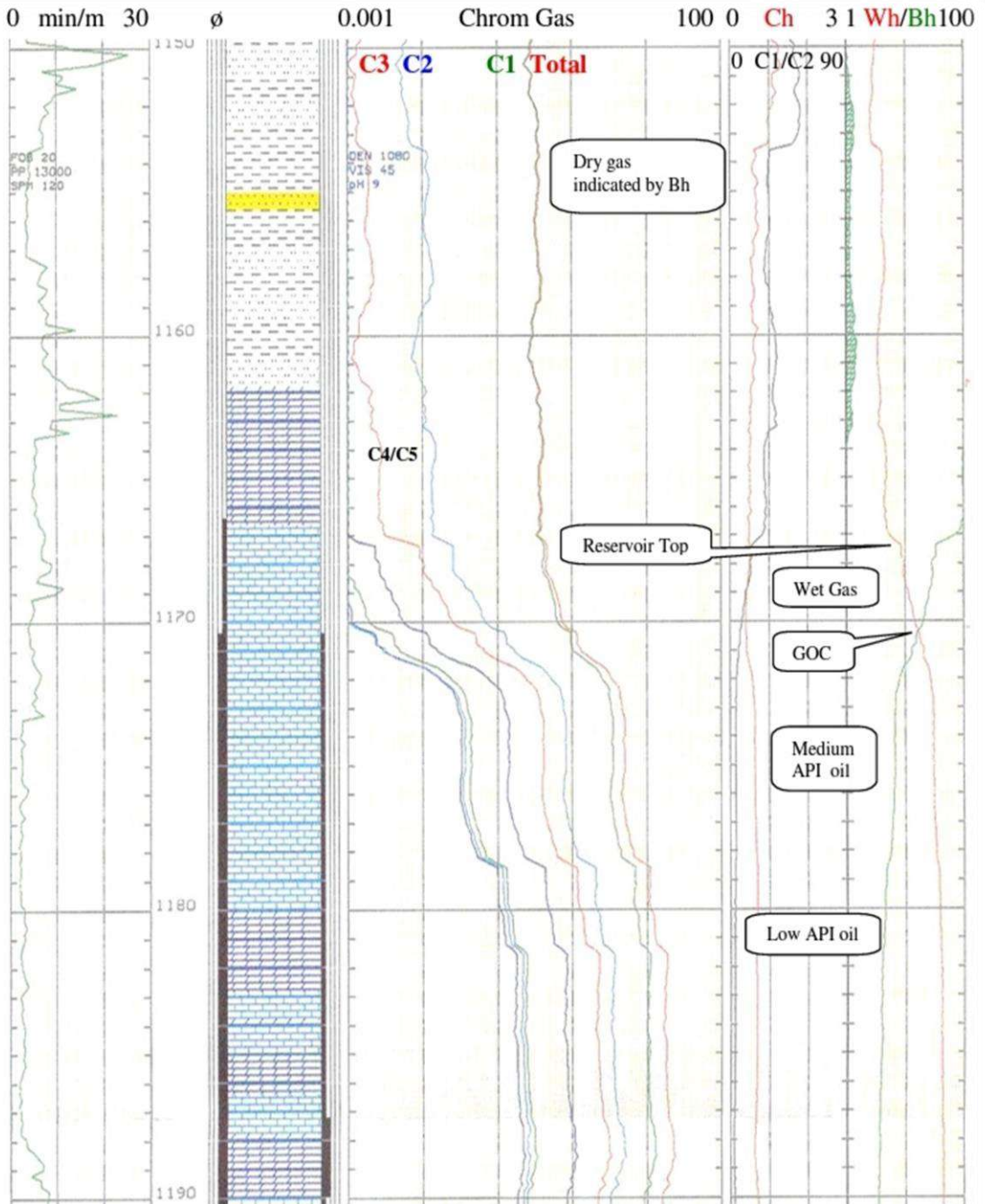


Figure I. 4 : Ratio determination of a high gravity oil bearing sand, with gas response [6]

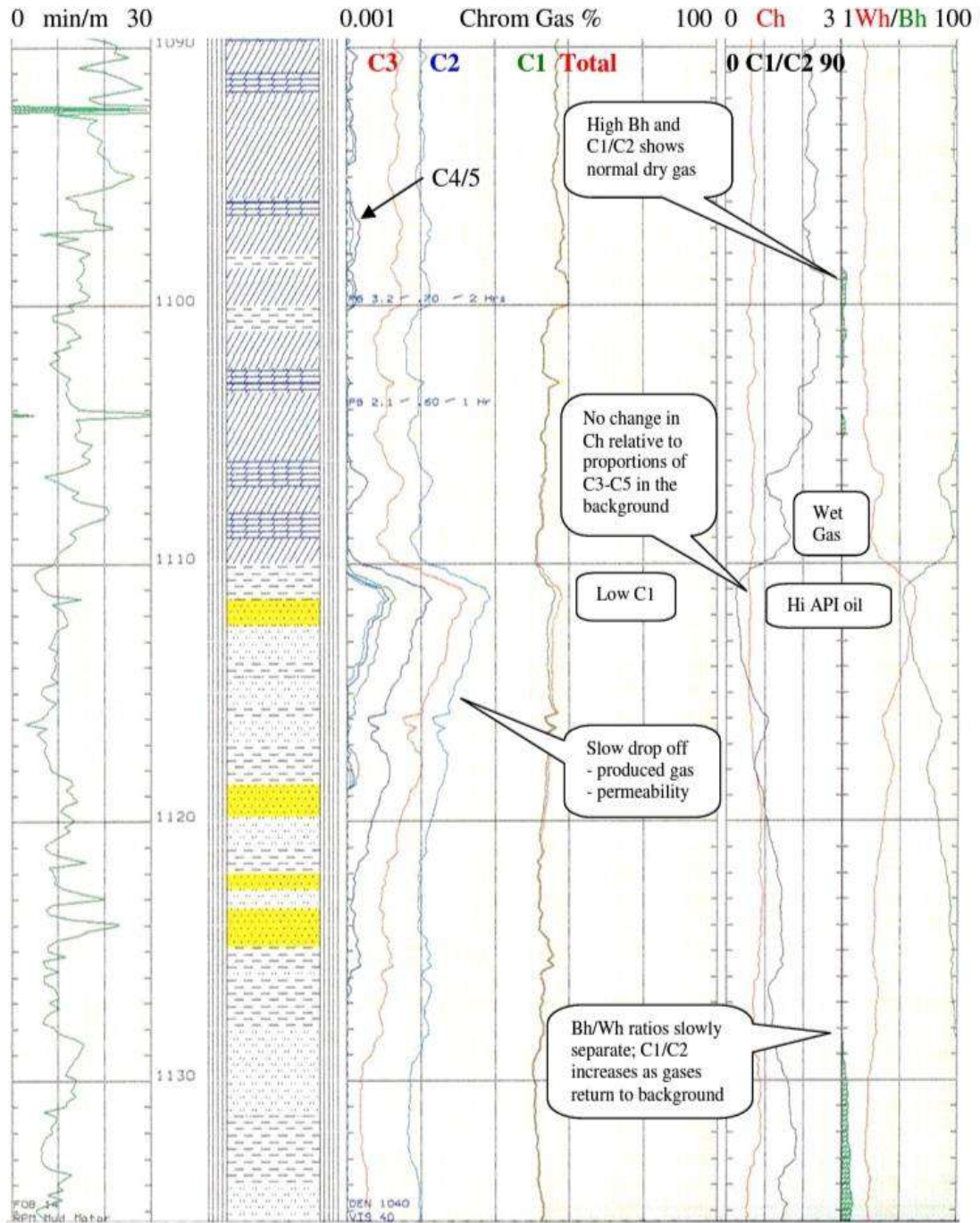


Figure I. 5 : Gas ratio determination of gas-oil contact and changing oil gravity. ^[6]

CHAPTER II : THE
.....
GEOSTEERING
.....
APPLICATION
.....

1. Introduction

Accurate fluid characterization and determination of contact points through real-time high speed gas chromatography provides the mechanism by which to steer horizontal wells laterally through zones of interest.

Ideally, the gas ratios and curve profiles, for a particular zone of interest, should be known before steering a horizontal section, either through a vertical pilot hole or reliable offset data.

The ratio signatures through the zone can therefore be established and contact points determined, thus establishing “controls” for steering the lateral sections of horizontal wells.

[6]

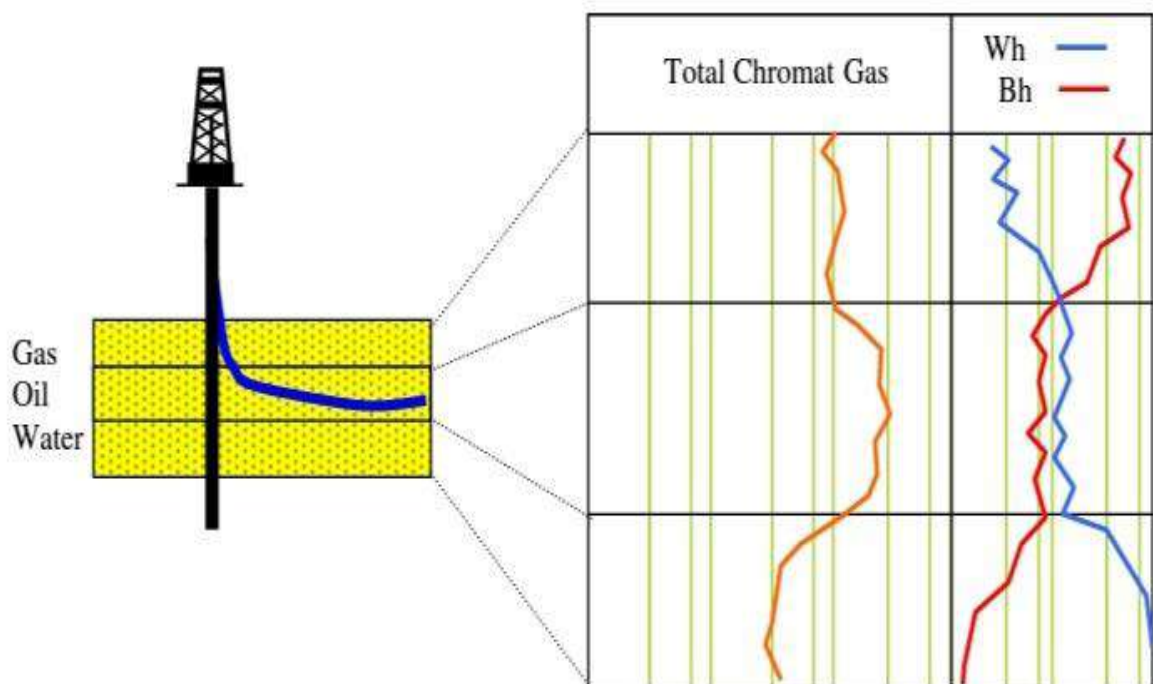


Figure II.1 : Establishing ratios for geosteering

Explication

- In figure II.1, the zone of interest, with high gravity oil, is defined by the higher gas levels recorded and by the balance ratio being slightly less than the wetness ratio.

A lateral section can be drilled within this zone by maintaining this ratio profile and separation (as demonstrated in figure II.2).^[6]

- If the balance ratio was to start increasing and cross over to be greater than the wetness ratio, then it is clear that the bit has come up out of the oil, into the gas zone, and the well course needs to be corrected in a downward direction.
- If the balance ratio was to decrease and wetness ratio increase, with the curves showing a rapid separation, then it is clear that the bit has passed through the oil-water contact, and the well course needs to be corrected in an upward direction.^[6]

In addition, course corrections can often be made faster through analysis of gas data, maximizing the well's trajectory within the pay zone. For example, the well is being drilled at a penetration rate of 5 m/hr and the LWD tool is located 10m behind the bit:

- 2 hours are required for the LWD tool to catch up with the bit depth and by the time that fluid changes are seen at surface, the bit is 10m beyond the zone, requiring a larger course correction.
- With a typical lag time of 1 hour, halve the time is required for the same fluid change to be seen at surface (figure I.1), leading to an earlier course correction and reduced by passed pay.^[6]

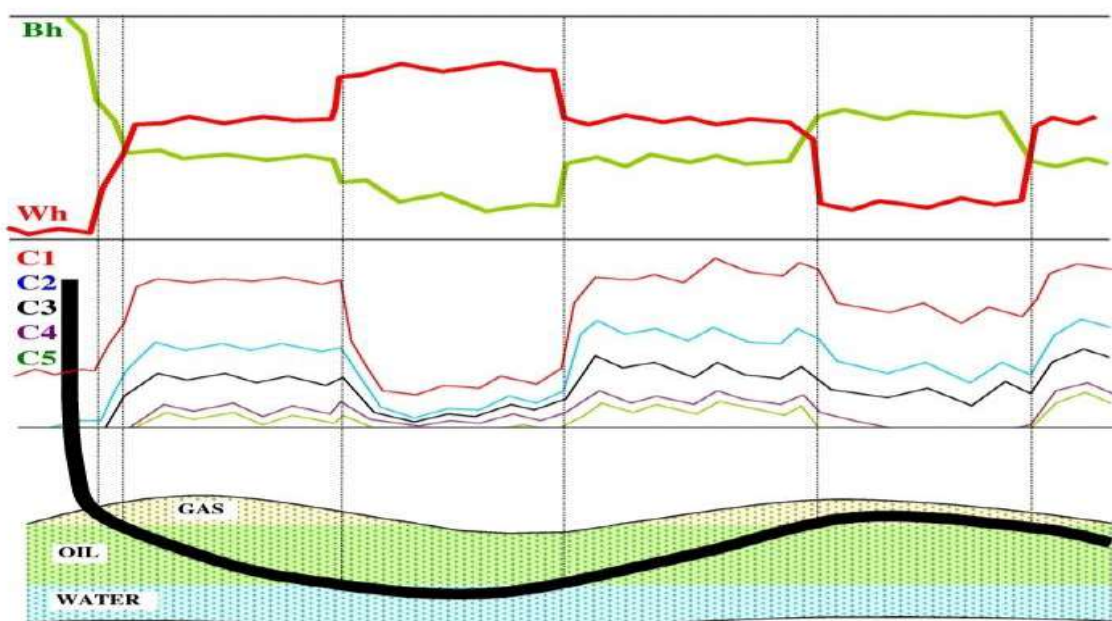


Figure II.2; Fluid contact identification and course correction

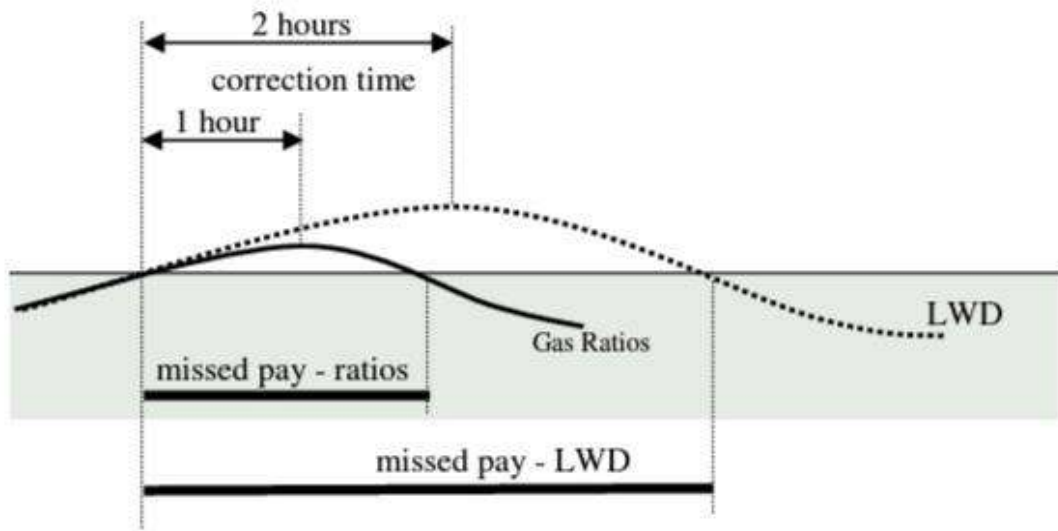


Figure II. 3: Gas ratio geosteering often leads to faster course corrections

2. Geosteers

2.1. Geosteer I

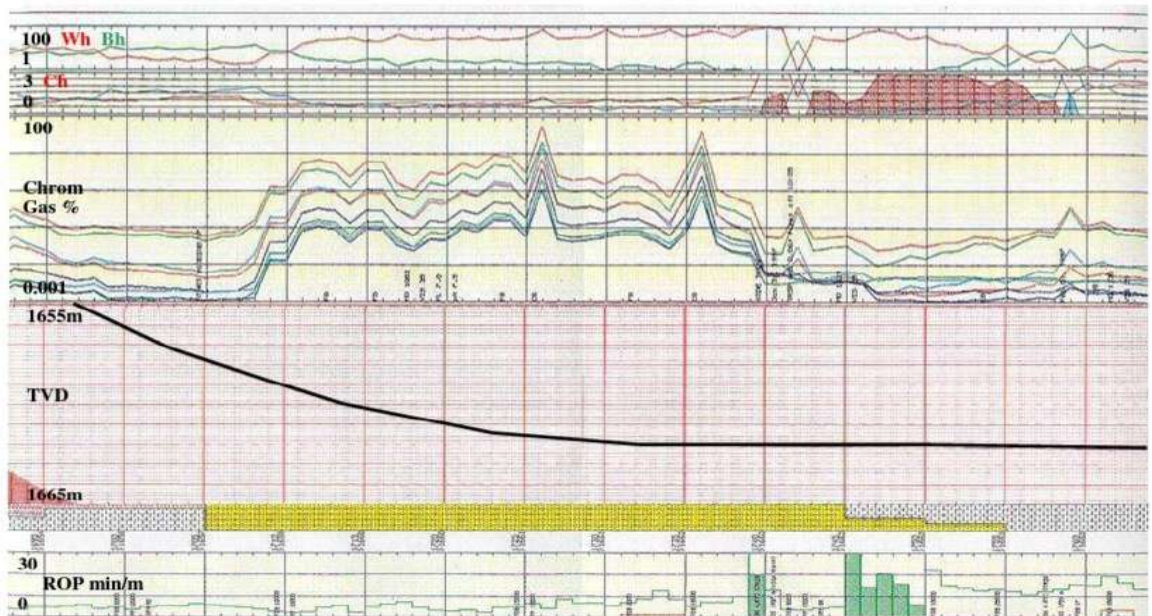


Figure II.4: Log for Geosteer Example I

(Figure II.4) shows the profile of a well that is being steered around to the horizontal, at the beginning of a lateral section, passing through an oil bearing sand section into basal shale. ^[6]

The reservoir top is determined at 1710m (1659 TVD) where all chromatographic gases show an increase above background and where the wetness and balance ratios cross over. This pin-points the gas/oil contact, above which, there is a metre interval where the two ratios overlap. This could suggest a shallow interval of wet gas, condensate or lighter oil with a high gas oil ratio. With the character ratio, at this point, hovering just above 0.5, it is not definitive but would suggest oil with a higher gas saturation at the top of the main zone. ^[6]

The well is steered around to the horizontal with the intention of drilling laterally through the oil zone. As the well passes vertically through the reservoir, the gradual separation of the wetness and balance ratios shows a medium to heavy oil with slightly decreasing API gravity with depth. Throughout, the character ratio ranges between 0.5 and 1 confirming an oil bearing reservoir.

At 1739m (1662m TVD), all of the chromatographic gas levels drop, the wetness and balance ratios show a greater degree of separation, the character ratio increases dramatically and the penetration rate slows. The changes in ratios are characteristic of a heavy, residual oil, indicating that the oil-water contact has been passed through.

In this case, it is not strictly a contact since it coincides with a transitional change into shale. The top of the clean shale is clear, at 1756m (1662.2m TVD), where the wetness and balance ratios cross back over to indicate a normal formation gas ratio profile. ^[6]

The cross-over of the wetness and balance ratio curves at 1742m result from a trip gas peak, where there is a characteristic proportional increase in light end hydrocarbons caused through swabbing. ^[6]

2.2. Geosteer II

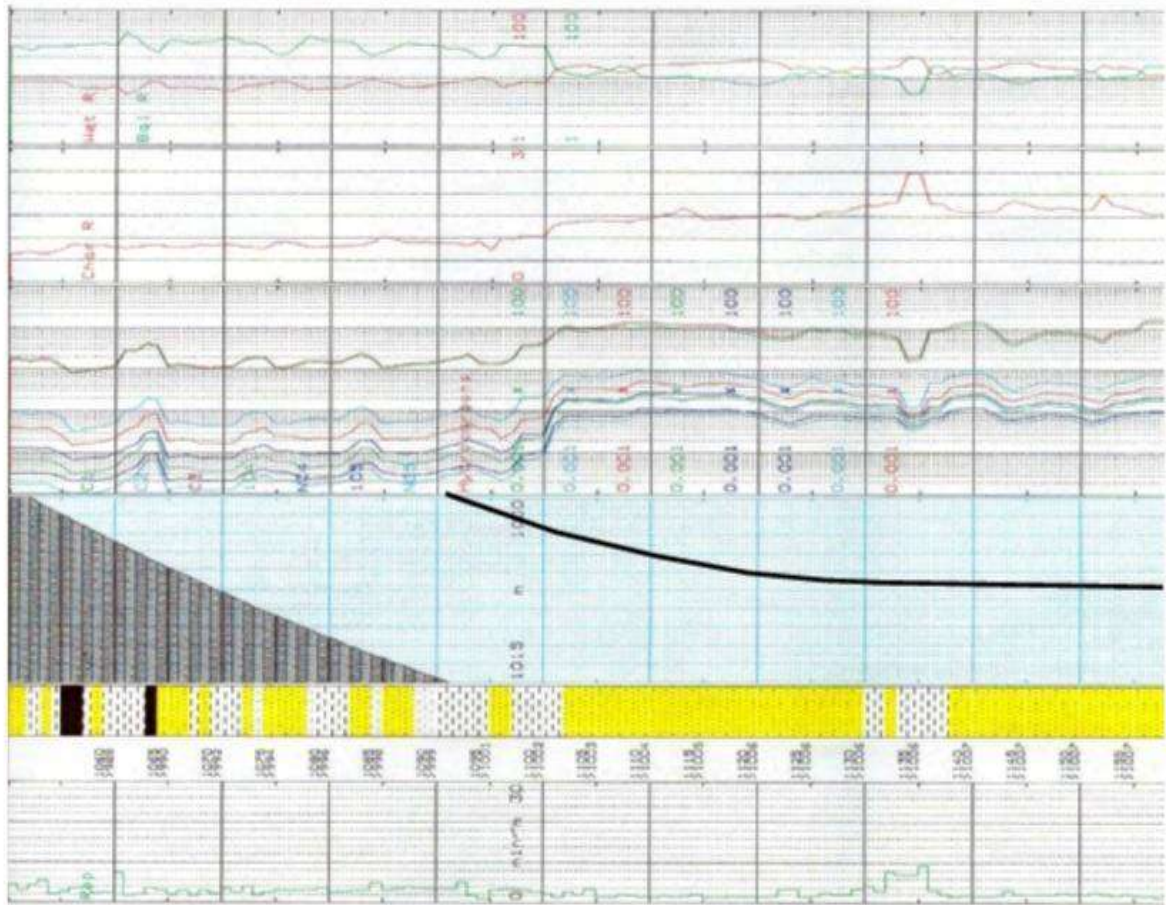


Figure II. 5: Log for Geosteer example II

The top of the reservoir (figure II. 5) is identified where the wetness and balance curves cross over at 1101m (1003m TVD), indicating a change from gas to a light oil. The two curves then remain closely separated through the section, as the well comes round to a horizontal, sometimes criss-crossing. This pattern, as explained previously, could indicate either light oil with a high GOR or a condensate type fluid or a wet gas, but in this case, the high character ratio value confirms that the gas is associated with light oil.

The relatively high character ratio in the gas zone above 1101m should not lead to confusion. This is resulting from the heavier gas components present in the background gas readings, a proportion of which is recycled or contamination gas. ^[6]

Shaly basal laminations are seen at 1034m (1007m TVD), initially indicated by the drilled cuttings and slower ROP. They are confirmed as the chromatographic gas values drop off and the gas ratios predict a heavier fluid composition at the base of the reservoir. [6]

2.3. Geosteer III

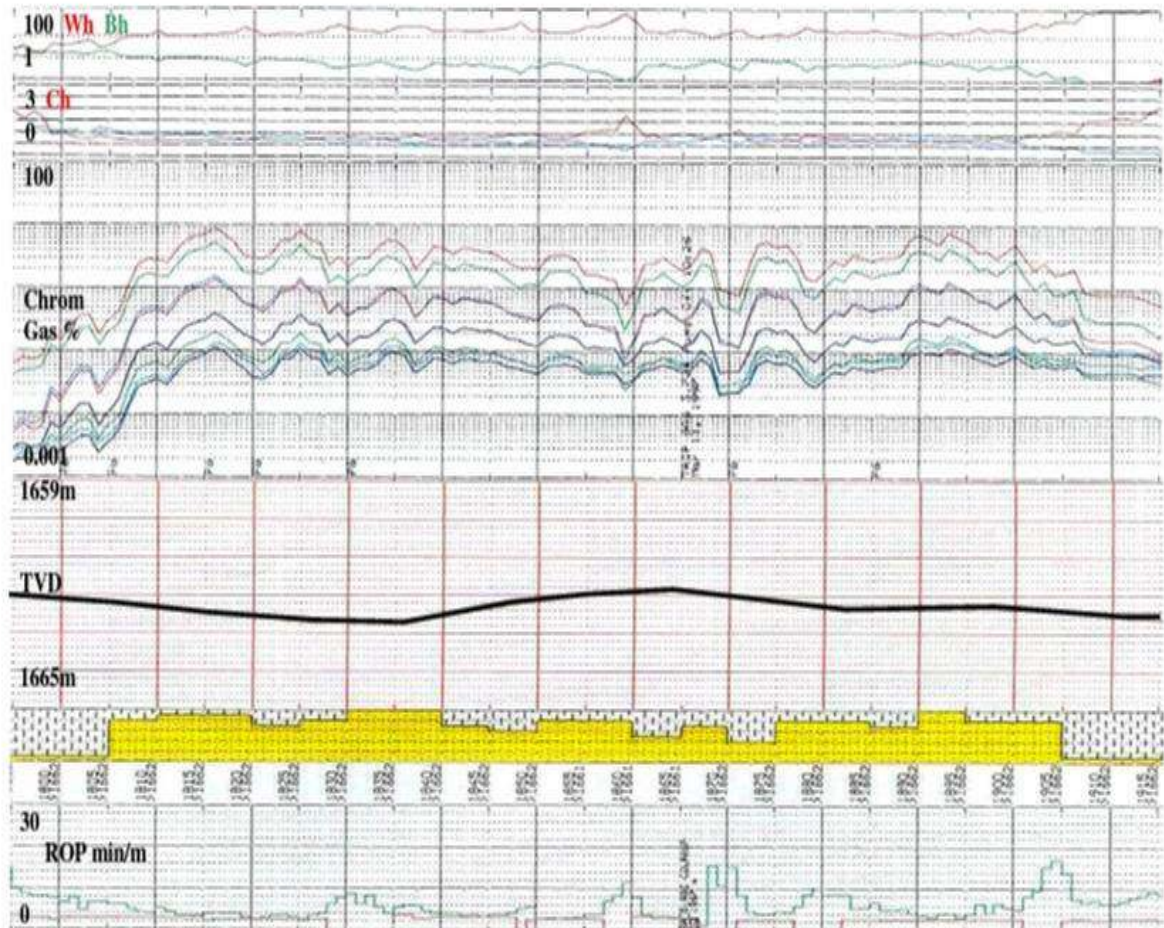


Figure II. 6 : Log for Geosteer example III

Here (figure II.6), the top and base of a dipping sandstone reservoir can be clearly distinguished from the gas ratios, allowing for effective geosteering.

Gas levels start to increase immediately above the reservoir contact, with the wetness and balance ratios close together and criss-crossing indicating a wet gas/light oil transition. The top of the reservoir is evident at 1806m (1662.2m TVD), where gas levels increase

significantly and the wetness and balance ratios show a definite separation indicating a medium gravity oil. ^[6]

The separation of the curves is maintained throughout this lateral section until the base is penetrated at 1907m (1662.5m TVD). Entry into basal shale is defined by the drop in gas levels, and by the wide divergence of the ratio curves showing a more residual fluid. Note that shale laminations are frequently encountered, for example at 1860 and 1870m. These are identified, first, from the cuttings and ROP changes. They are confirmed by momentary drops in gas levels, accompanied by a separation of the wetness and balance ratios indicating a heavier fluid composition. ^[6]

3. Limitaion to Gas Ratio Analysis

3.1. Definition

Rather than the specific ratio values defining fluid types being taken as absolute, the ratios are used more effectively if these are taken as a guide only. Far more important, especially in the geosteering application, are the trends and relationships between the curves that clearly define fluid changes and contact points.

Precise ratio values can vary for a number of reasons and, if used as absolutely defining points, erroneous evaluations can result. If used correctly, however, these limitations actually provide additional information in terms of reservoir evaluation. ^[6]

3.2. Variations in hydrocarbon composition

- Heavier oils may contain proportionally less of the light hydrocarbons (principally methane, sometimes ethane) leading to higher wetness values and lower balance ratios. Therefore, Wetness Ratios in excess of 40 can still result in a productive zone, especially considering that, what was classed as non-productive in the mid-80's may be far easily produced nowadays.
- Dry productive gases can result in Balance Ratios in excess of 100, so again, the defining point of what is, and what is not, productive, has to treated with care. ^[6]

3.3. Processes affecting the release of different gas

- If a zone is underbalanced and producing, a proportional increase in the light hydrocarbons is very typical, leading to lower wetness and higher balance ratios.
- Depending on the size of drilled cuttings and the efficiency of gas liberation, a tight formation may see a *greater* retention of heavier components by the cuttings, leading to lower wetness and higher balance ratios.
- If permeable zones are prone to flushing prior to, and during, penetration, then any hydrocarbons flushed away from the zone ahead of the bit will, clearly, not be liberated into the formation. This would clearly have an impact on any subsequent analysis and even result in potential zones being missed. ^[6]

3.4. Extraction of the gas from the drilling fluid

- Low viscosity mud may result in poorer retention of the light end gases, especially methane, which may be lost in the surface system prior to sampling.
- Heavy, viscous drilling fluid may reduce gas trap efficiency so that, proportionally, less of the heavier gases are extracted, resulting in lower wetness and higher balance ratios.
- Mud type, gas composition, phase and solubility – see next section.
- Gas trap extraction efficiency and inconsistencies – see next section. ^[6]

CHAPTER III :
THE PROBLEM
WITH GAS TRAPS

I. THE PROBLEM WITH GAS TRAPS

1. Gas Behavior

Gas can exist in two distinct phases in a drilling fluid, either in solution or as an emulsion of bubbles. The behavior of methane (for example) in solution differs greatly from the behavior of methane in an emulsion. Different types of fluids (including air) exhibit different solubility factors and thus different characteristic curves of gas concentration by volume. ^[5]

The gas trap is an extremely non-linear device which has been the principle method used in the extraction of gas in drilling fluids. Unfortunately, it's behavior is quite different for the two states of gas in drilling fluid.

The characteristic curves for all fluids will meet at two common points, at 0% concentration, and 100% concentration. At 0% concentration, there is obviously no gas to measure and the reading will be zero regardless of the fluid type. At 100% gas concentration, there is only gas present, so again, the reading is unaffected by fluid type, since there is no fluid.

Between these two points, a complex mathematical relationship exists where some gas is dissolved in the fluid, and some is present as bubbles (an emulsion). ^[2]

2. Gas Trap Non-Linearity

Current gas-trap based measuring systems exhibit large non-linearity in response due mainly to the crossover between gases in solution and gases in bubble form. A gas trap is, in effect, a mechanical converter that converts a percentage of gas in the mud, which cannot be directly measured, to a percentage of gas in air, which can be directly measured. ^[2]

Dissolved gas will be broken out by the mechanical agitation, and removed at a fixed rate by the gas sampling equipment through the sample line. Air will be re-introduced into the trap at the same rate, thus, the percentage of gas measured will approximate the actual percentage in solution. From this, it can be seen that the sample flow rate will influence the gas reading of the trap.

As the gas percentage in the mud increases, however, it will reach a point where the mud is saturated with all the gas that can be held in solution, and the remaining gas will exist as free bubbles in the mud. These bubbles will displace air in the trap canister, thus falsely

increasing the apparent concentration at the sampling point, not by increased percentage of gas, but by decreased percentage of air. This phenomenon is known as trap saturation or loading.^[2]

At some point, the amount of gas released from bubbles will exceed the amount of gas drawn out by the sampling system (as well as the amount of air drawn in). At this point, the apparent gas concentration soars to 100% and becomes totally non-representative of the actual concentration in the mud, since no more air is being drawn into the canister. This is precisely why current gas trap designs can indicate an abnormally high gas concentration when there is no noticeable bubbling at the flowline, or reduction of mud density. If the gas concentration were indeed as high as is often indicated, a well blowout would be well underway.^[2]

3. Trap Limitations

Conventional traps break gas out of solution from the drilling mud, when it returns from the wellbore to surface, by rapidly rotating blades literally beating the mud as it passes through the trap assembly. The extracted gas collects in a vessel surrounding the blades, from where it is drawn off and carried to the actual gas detector by an air pump. This type of arrangement has several limitations and drawbacks that prevent it from being a wholly reliable source of gas sampling.^[2]

As well as the trap saturation described above, traps also have the following limitations:

- Any variations in the mud level at the trap location (normally restricted to the shaker box) result in varying volumes of mud being sampled. At the same time, the air volume in the trap varies inversely. This leads to inconsistent levels of gas extraction and changes in apparent gas concentration.
- The efficiency of gas extraction decreases as mud density and viscosity increase, making comparisons and correlation of data difficult.
- The efficiency of gas extraction varies as the gas composition changes. Lighter hydrocarbons (methane and ethane) are easier to extract whereas heavier components (propane, butane and pentane) are more difficult, resulting in greater proportions of heavy gas remaining in the mud and going undetected. This is illustrated in (figure III.1), where it can be seen that much of the gas, dissolved in water, goes undetected.^[2]

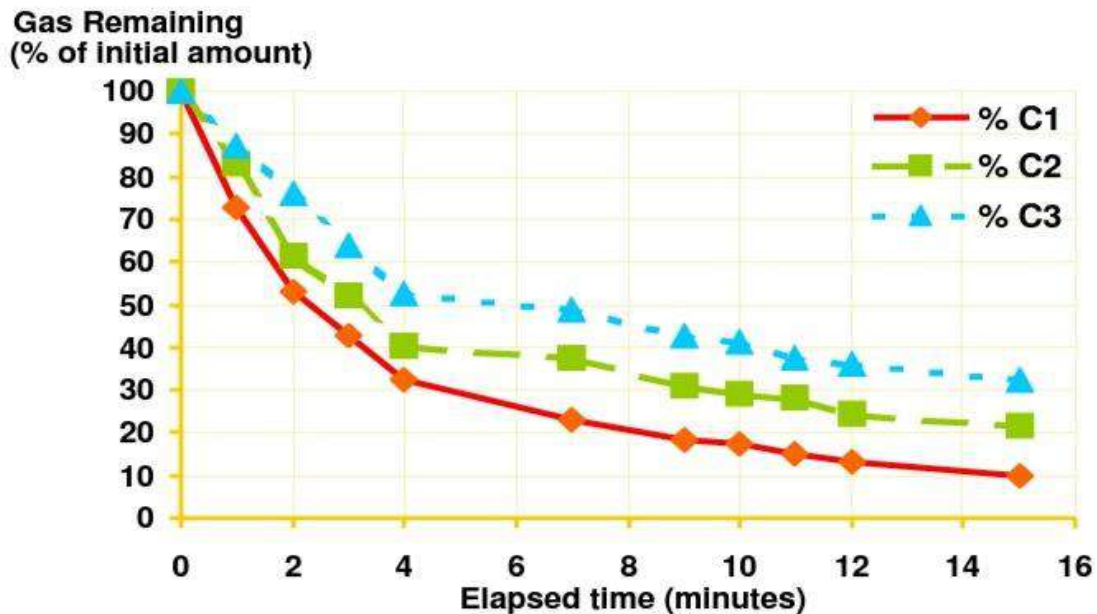


Figure III. 1: Gas remaining dissolved in water after prolonged agitation

- Extracted gas is diluted in a large volume of air within the trap, sample line and drying vessels. Such dilution results in extended gas responses and poorer definition of small changes in gas levels.
- At high gas concentrations, gas may be extracted from the mud at a greater rate than is being drawn off by the sample pump. This leads to an increased concentration and volume of gas within the trap vessel, which takes a longer period of time to be exhausted. Such trap loading leads to erroneously high gas measurements with delayed and dampened gas responses.
- All of the limitations described above result in an extremely qualitative gas-in-air measurement. The relationship between this measurement and the actual volume of gas entrained within the drilling mud is an unknown.
- The sample line carrying the gas from trap to detector can lead to a delay in analysis of several minutes depending on the distance and on the efficiency of the pump.

- Sample lines are prone to freezing in cold temperatures and to the heavier gases condensing to a liquid phase, so going undetected.
- To minimize freezing, the gas sample requires drying. Unfortunately, drying agents may absorb some of the hydrocarbons, reducing measurements. Should the drying agent become saturated, hydrocarbons may be released at a later time, effectively contaminating current gas measurements with gas from an unknown source.
- Conventional dryers and filters require constant maintenance with replacements required at least daily, often even more frequently.
- The trap is mechanical and therefore prone to changes in efficiency and to breakdown. ^[2]

I. THE MEMBRANE PRINCIPLE

1. General definition

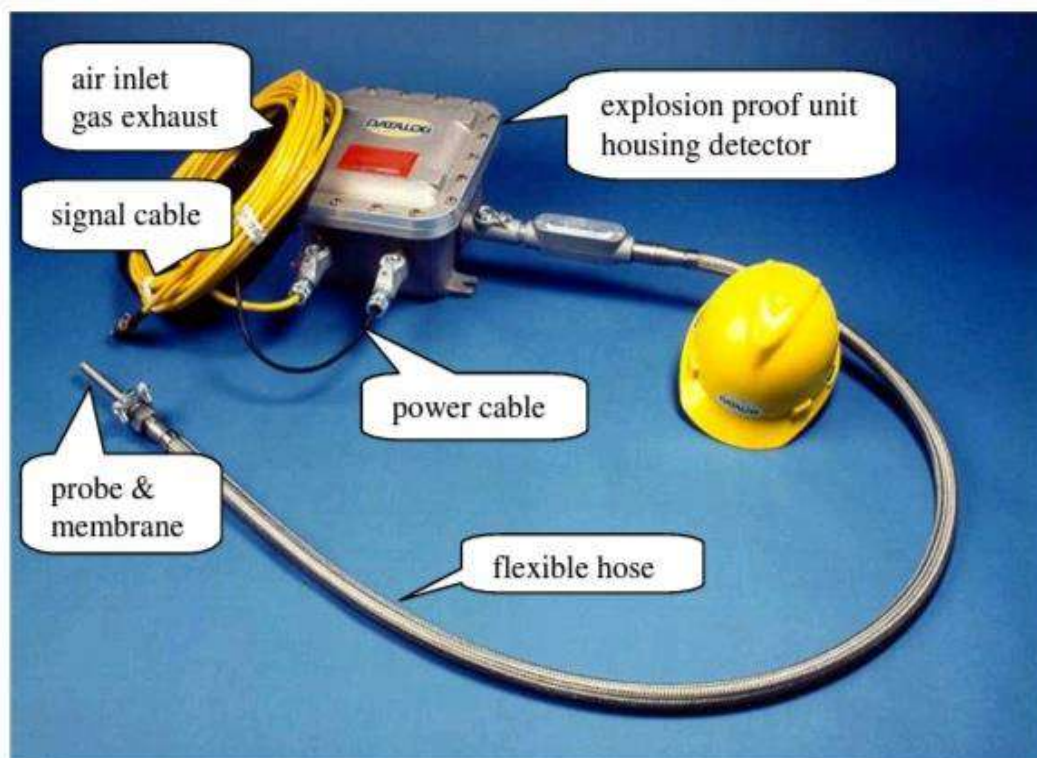


Figure III.2: Gas Wizard TM, using membrane extraction of gas

A new extraction and detection system developed by Datalog (figure III.2) utilizes a semi (gas) permeable membrane, a passive device that facilitates the transfer and extraction of gas from any drilling fluid .

Very simply, this device eliminates the conversion step from gas-in-mud to gas-in-air, making it possible to determine the gas concentration, in percentage by volume, entrained in the mud system. This enables the quantitative measurement of gas concentration, over the full range of possible concentrations, in various drilling fluids. ^[4]

Gas permeation through the membrane wall is driven by the difference in partial pressures (in other words, the gas concentration) on either side of the wall. In other words, if gas concentration is kept to a minimum, by continual evacuation, on the inside, then any gas on the outside of the membrane will generate a positive partial pressure gradient, and transfer across the membrane is facilitated. ^[2]

The volume of gas that passes through the membrane is directly proportional to the actual gas concentration, by volume, in the drilling fluid. Therefore, the quantitative gas value can be determined from the actual volume measured and the permeation rate of the gas through the membrane.

This requires modeling of the gas behavior, whether dissolved or free, in different fluids. This is illustrated in (figure III.3) for the solubility of methane, for which the system is currently operational as a detector. The user simply selects the appropriate mud type so that the right correction factor is applied to the algorithm. ^[2]

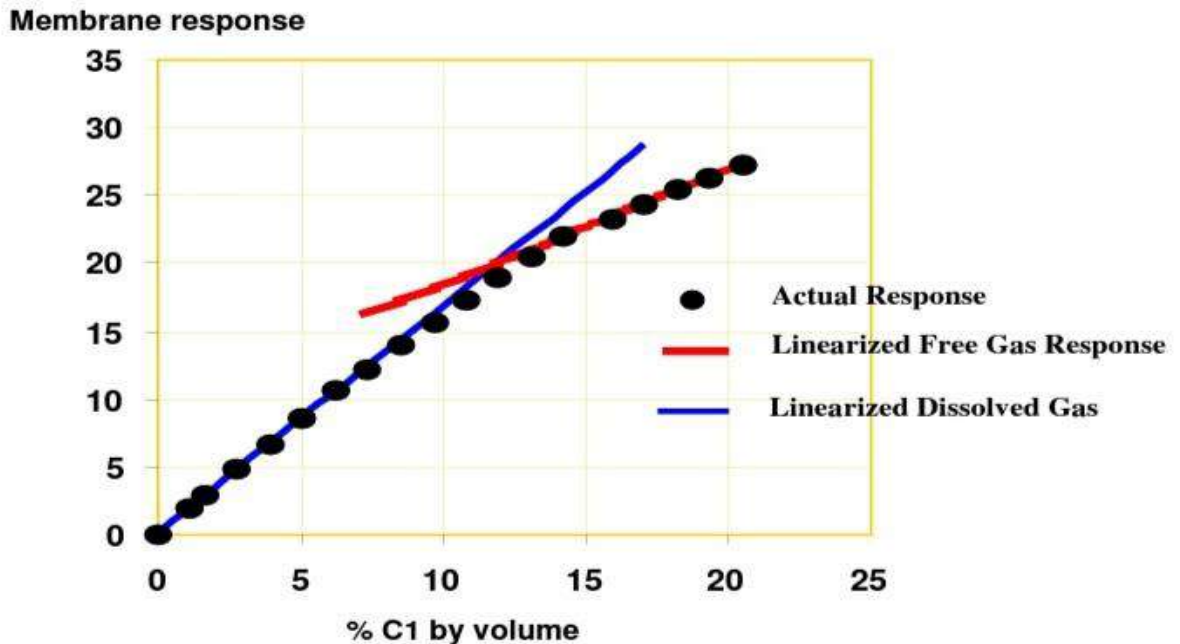


Figure III.3 : Membrane response modeling

The system is currently operational as a methane detector, with a chromatographic version underdevelopment and trials. ^[2]

1. Evaluation Differences and Advantages

2.1. Quantitative Measurement

Values recorded are a true measurement of gas volume in mud, providing much better data for the geologist and engineer. ^[3]

Erroneously high gas values, maybe in the order of 70, 80%, or even higher, are not be recorded. These large values result from trap loading, where gas bubbles displace air from the trap and/or where gas is extracted from the mud at a quicker rate than it is being vacated from the trap (Figure III.4). The concentration therefore builds up in the trap, leading to erroneously high values that will take a longer period of time to be completely vacated from the trap. ^[3]

2-1. Response Time and Sensitivity (Figure III.5)

Since the detector is located at the point of installation, there are minimal transit delays between gas extraction and gas measurement. This rapid response time leads to much better depth resolution and more accurate determination of formation tops and contact points for example. ^[1]

Greater sensitivity results from the small quantities of gas and air required, so that there is no overdilution of the gas sample in large air volumes resulting in ‘dampened’, poorly defined responses. This degree of sensitivity provides more effective formation evaluation in situations such as the identification of thin beds or fractures and in the determination of minor changes in porosity or permeability, contact points, etc. ^[1]

2-2. Connections

One thing that every well site operator is familiar with, from agitator traps, is the gas reading falling to zero when connections are made. This is simply due to the fact that the mud level drops in the header box so that the trap is no longer in the mud.

This will not, necessarily, be seen with the GasWizard measurement. Although the gas level will fall, it will not go to zero if there is still ambient gas in the flowline surrounding the probe, since the gas will still pass through the membrane. It is also probable that the mud will not completely drain from the flowline over the duration of the connection, so that gas is still measured from the static mud. ^[3]

3-4. Unaffected by flow changes

Unlike a gas trap, the mandrill carrying the membrane is not affected by changes in mud level or flowrate (although a minimum mud velocity of around 0.25m/sec is required). ^[4]

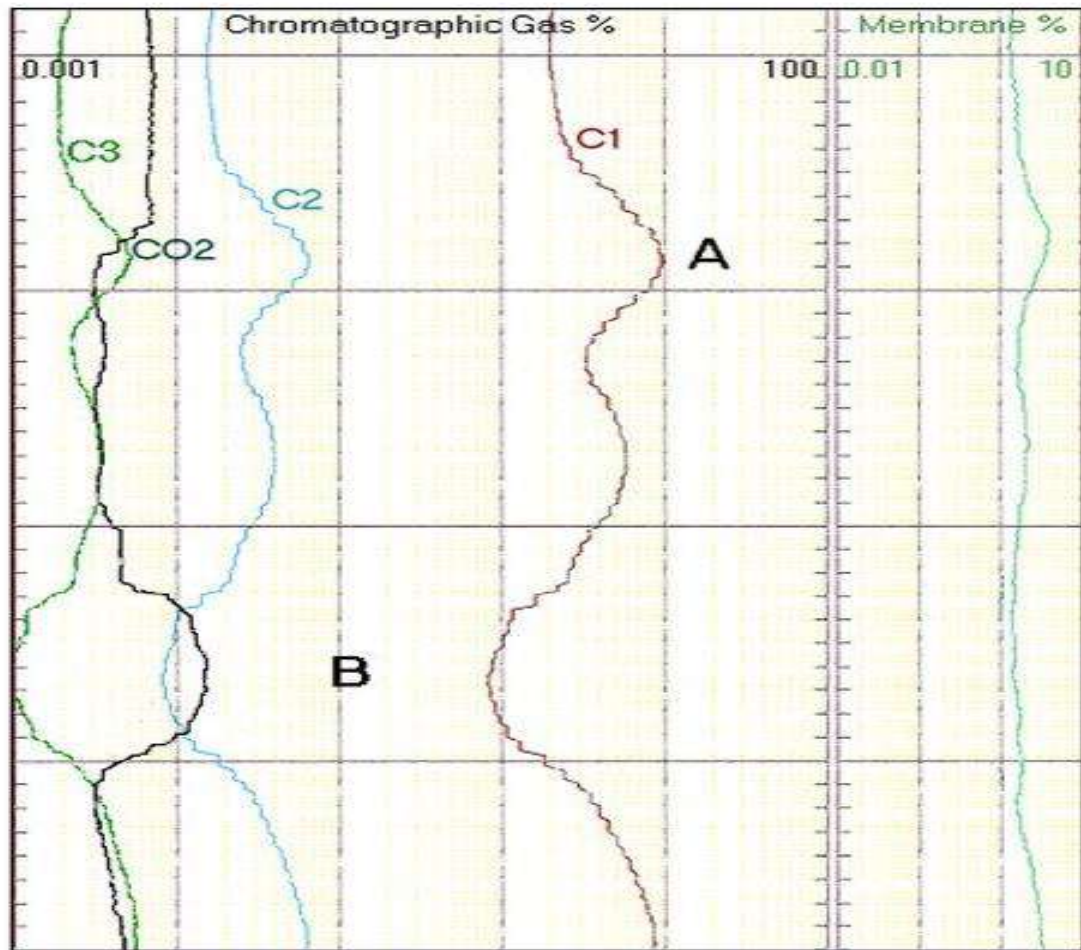


Figure III. 4 : Trap Loading

This example (figure III.4) from a water-base mud system, illustrates the process of air displacement leading to trap saturation and erroneously high gas measurement. Note, with the gas response at A, the CO₂ component decreases. The CO₂ results principally from the air inside the trap, which decreases as the volume of hydrocarbon bubbles increase, displacing the air.

The total hydrocarbons, measured from the trap, increase from 2.0% to 9.9% (X4.9). The hydrocarbons measured through the membrane increase from 1.3% to 3.9% (X3). This illustrates the erroneous increase caused by air displacement from the trap. ^[1]

At point B, the increase in CO₂ measurement results from an increase in air volume within the trap due to a temporary drop in mud level. Correspondingly, the trap samples a reduced mud volume and the chromatographic gases all show a decrease. At the same time,

note that no such drop in the gas measured through the membrane is detected, since it is unaffected by changes in mud level. ^[1]

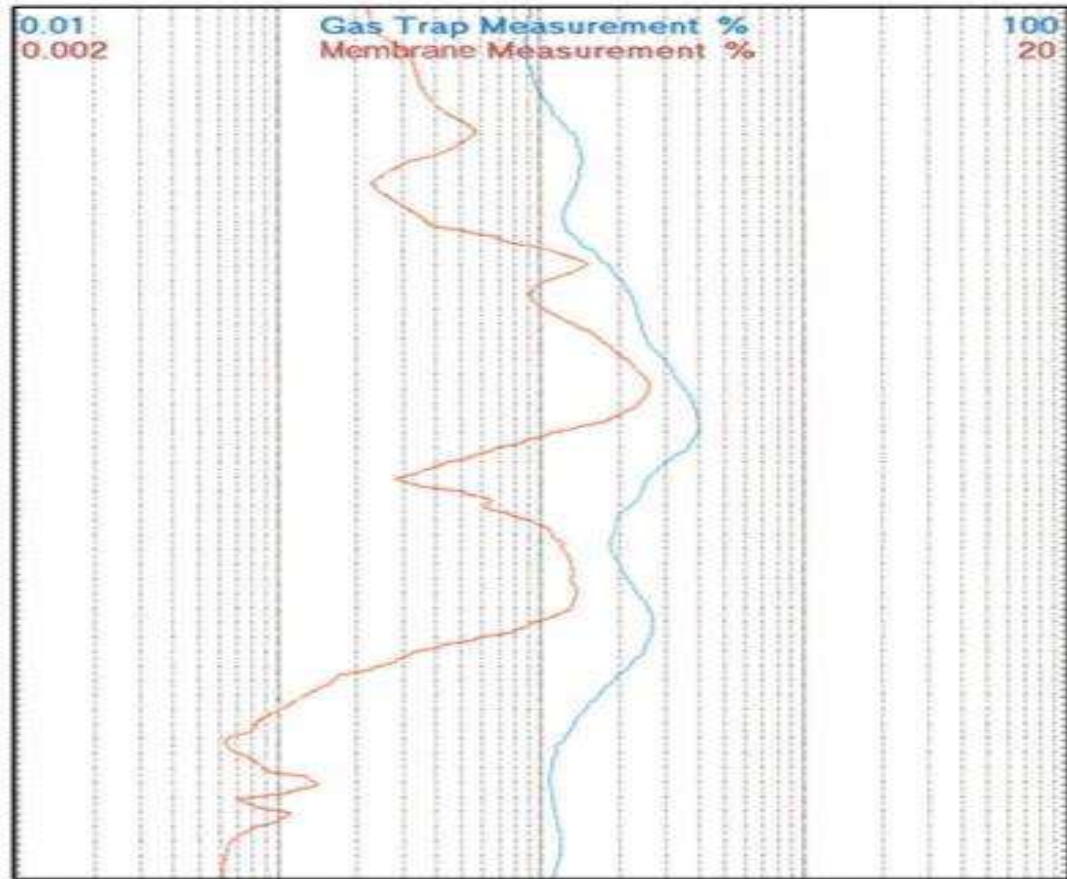


Figure III. 5: Speed and Resolution

This example (figure III.5) illustrates several of the differences normally experience with measurement of gas extracted through the membrane:

- Lower values in water base mud, where methane is present as free gas bubbles and displacing air from gas traps.
- Rapid response time, here around 2 minutes before the same responses are seen in the conventional system.
- Better resolution since there is minimal dilution in air, which can dampen the trap responses note the sharper definition and greater number of responses seen from the gas extracted through the membrane. ^[1]

3. Water-Base Mud

- Gas values are typically lower than those recorded by the agitator trap as a result of the trap loading described above. This is particularly true for where free gas is more predominant in the mud. This transition (dissolved to free) may be as low as 2 or 3% methane concentration in the mud.
- For lower gas concentrations (below the dissolved-free gas transition), and when dealing with principally methane, gas values are likely to be very similar to standard traps which work fairly efficiently in this range.
- Gas composition may also cause a difference in response. If heavier oil is being sampled with a greater proportion of heavier end gases (propane through pentane) present, the response will typically be higher with the membrane. This is because a greater proportion of these components will be dissolved and not efficiently extracted by agitator traps.^[1]

4. Oil Base Mud

- Readings from the membrane are typically higher than those recorded by conventional agitator traps. This is simply a result of gas phase. Oil has a much lower bubble point than water so that gas does not break out of solution to the same degree. Oil base mud arriving at surface therefore has a far greater proportion of dissolved gas. This, as we have seen, does not affect the membrane, but does lead to inefficient extraction and lower measurements with the agitator trap.
- At higher concentrations, trap loading may result in higher recordings by the gas trap. But we are now talking significant gas concentrations before we see the dissolved-free gas transition. This may be as high as 10% in a typical diesel or oil-base mud, and even higher, maybe 15% in certain mineral oils.^[2]

CHAPTER IV:
Reducing
Exploration and
Development Risk

1. Reducing Exploration and Development Risk Using Mud Gas and Isotopic Data

1-1. Mud Gas definitions

For definition purposes the level of gas in the mud is due to one or a combination the following:

- **Background Gas :** The general level of gas carried by the mud purely as a function of circulating in open hole.
- **Drilled Gas :** Gas which has entered the mud due to the actual drilling of the formation. i.e. the gas contained in the matrix of the rocks which have been drilled.
- **Connection Gas :** The gas which enters the mud when a connection is made due to reduction in hydrostatic due to loss of ECD and due to swabbing while pulling back.
- **Swabbed Gas :** The gas which enters the well due to swabbing. This may be caused by tripping or by simulating tripping.
- **Trip Gas :** The gas which enters the mud during a trip which is measured after a trip has taken place.
- **Pump Off Gas :** The gas which enters the mud due to turning off the mud pumps and removing ECD from the hydrostatic pressure on the bottom of the well.

It is imperative for pore pressure estimation that the gas levels in a drilling mud are correctly interpreted and the above definitions adhered to.

Pore pressure can only be definitively assessed on the basis of observations of trip gas , connection gas swab gas and pump off gas. If any of these are observed then pore pressure levels are close to mud hydrostatic.

Increasing background gas levels can indicate increasing pore pressure if correctly determined and analysed it is important that drilled gas level content of background gas is understood. ^[3]

2. Conventional Reservoir Applications of Mud Gas Isotope

- Determine genetic origins of gas (thermogenic, bacterial, mixed).
 - Implications for associated hydrocarbon liquids.
- Determine maturity of thermogenic gases.
 - Implications for associated hydrocarbon liquids.

- Prevention of “Missed Pay” - Identify oil and gas reservoirs even when over-balanced drilling sweeps the near-well-bore area causing the absence of a gas kick on the total gas log (isotope values are not dependent on gas concentration).
- Determine hydrocarbon type (gas, oil, water).
- Predict fluid properties (GOR, Saturation Pressure).
- Evaluate reservoir continuity, vertically within a single well and laterally between wells.
- Data serve as a contingency for failed down-hole MDT sampling. ^[7]

2-1. Isotech RT™ Isotope Logging Device

- **Applications**

- Identifying new oil and gas deposits
- Logging mud-gas isotopes
- Differentiating biogenic gas from thermogenic gas
- Determining gas-oil-source rock correlations-
- Correlating gas and oil deposits between wells
- Evaluating the maturity of fluids and source rocks
- Identifying seals.

- **Features and Benefits**

- Enables real-time analysis of $\delta^{13}\text{C}$ methane
- Continuously cycles samples from the gas extraction system
- Automatically calibrates using a methane of known isotopic value that has been diluted in air to mirror typical mud-gas concentration
- Provides a significant quantity of data for analysis
- Can be controlled locally or remotely via an Internet connection (required).

- **Tool Description**

The Weatherford Isotech RT (IRT) isotope logging device offers high-precision, real-time carbon isotopic analysis at the wellsite. The device consists of a

patent-pending sampling system and a laser-activated cavity ring-down spectrometer for isotopic analysis. ^[10]

The IRT logging device is installed in the mud logging cabin. A standard gas trap (QGM) or a constant volume trap (CVT) separates the gas from the drilling fluid, and a sample pump draws gas into the device. Users at the wellsite can control the device through a local laptop with an Internet connection, and trained Isotech scientists or Weatherford surface logging technicians can monitor and operate the device remotely. ^[10]



Figure IV .1: Isotech RT™ Isotope Logging Device

3. Types of Gas Samples

- Drill Stem Test (DST)
 - ‘Single stage flash’: gas is separated from the fluid sample in the lab into a pressurized cylinder
- Wireline Formation Test.
 - Sub-sampled as with DST
- Flow line / separator
 - Field or laboratory sub-sampling
- Mud gas
 - From the gas trap
- Headspace gas
 - Evolved from cuttings
- Surface samples (seeps; groundwater). ^[3]

3-1. Headspace gas

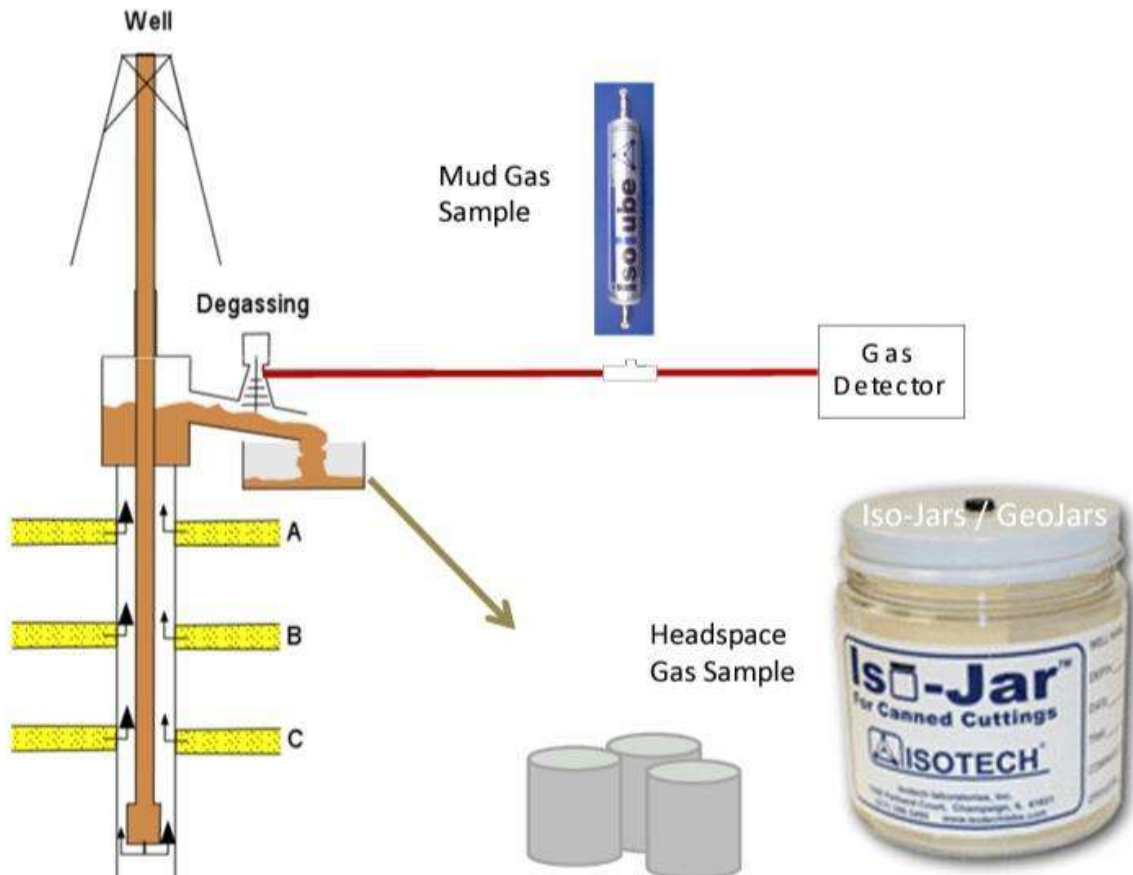


Figure IV.2: Headspace gas.^[3]

4. Collecting Mud Gas Samples During Drilling (IsoTubeR Autoloader)

4-1. IsoTube® AutoLoader™ System

- Applications

- Collecting gas samples from the wellbore
- Determining the isotopic composition and the origin (biogenic or thermogenic) of sample gases, and identifying their association with oils

- **Features**

- The automated, embedded control system provides several options for triggering the device
- A user-defined hysteresis window helps prevent the device from triggering multiple times during total-gas sampling
- Tube-mounted tags store the date, time, depth, gas concentration, and serial numbers of the tube and device
- All job/well files are stored in the internal memory of the device and can be downloaded to a computer through the web-based interface. Downloadable job/well files include comprehensive data on each sample, including date, time, time zone, tube and device serial numbers, trigger method, sample depth, and total gas concentration

- **Benefits**

- Offers several options for triggering loading: independent triggers by time, depth returns, and total gas; continuous triggering by depth intervals; and smart triggering using a peak-detection algorithm
- Enables the user to independently activate and disable triggers at any point using the web-based interface
- Provides downloadable job/well files in text and Excel formats, which enables the user to import all sample data, including isotopic analysis, into a single file
- Receives data from third-party devices in WITS0 via Serial RS-232 or Ethernet (active or passive)

- **Tool Description**

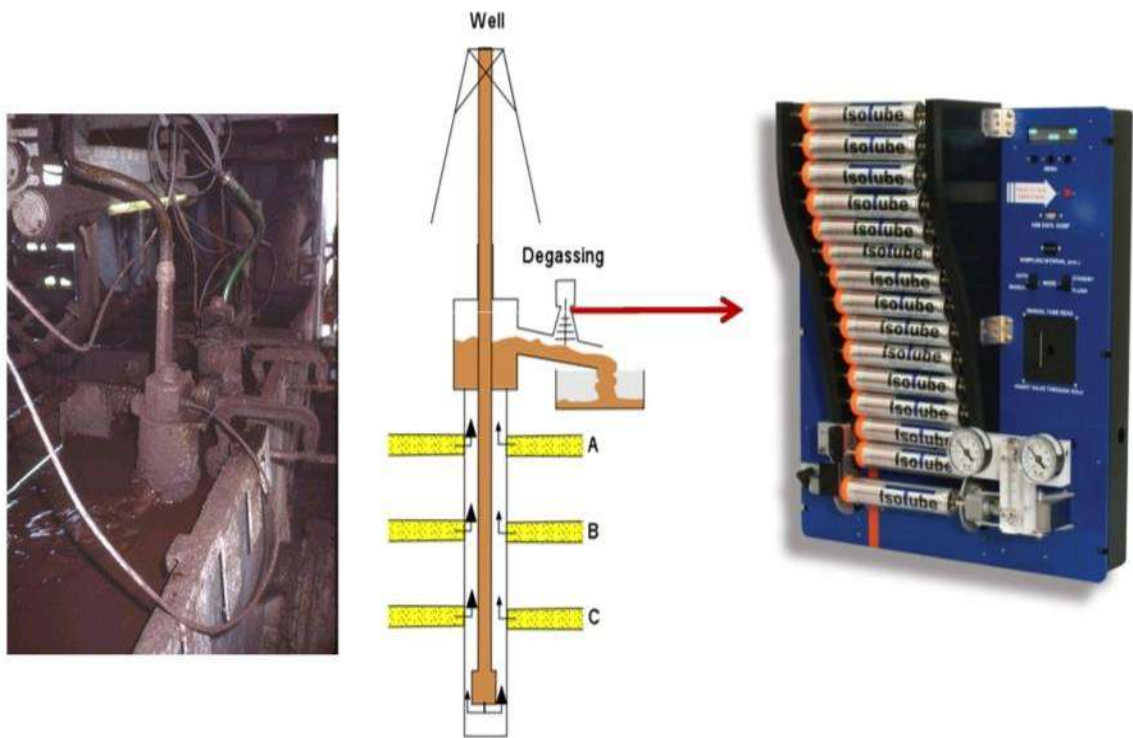
The IsoTube AutoLoader system is an automated device that collects gas for isotopic analysis. The device loads durable aluminum tubes into a hopper and, when triggered, automatically captures and stores mud-gas stream samples. After taking a sample, the device automatically loads a new tube in preparation for collecting the next sample.

The device records data—including the depth, time, and gas concentration—for each sample and stores it in a job/well file. A radio-frequency identification (RFID) tag mounted directly on the tube stores the sample time and the serial numbers of the tube and device.

Users can activate and deactivate triggers, manage data connections to other devices, create new job/wells, and download job/well files through the web-based interface.

The IsoTube AutoLoader can be used in conjunction with other gas-sampling devices to collect isotopes. Isotopic analysis is available through Weatherford at IsoTech Laboratories.

[9]



**Figure IV.3 : Collecting Mud Gas Samples During Drilling:
IsoTubeR Autoloader [9]**

5. Basic Components Natural Gases

Inorganic

Organic

Carbon Dioxide (CO₂)

Methane CH₄

Hydrogen Sulfide (H₂S)

Ethane C₂H₆

Nitrogen (N ₂)	Propane C ₃ H ₈
Noble Gases (He, Ar, etc.)	Butanes nC ₄ H ₁₀ iC ₄ H ₁₀
Hydrogen (H ₂)	Pentanes nC ₅ H ₁₂ iC ₅ H ₁₂ . ^[7]

6. Major Stages of Hydrocarbon Generation

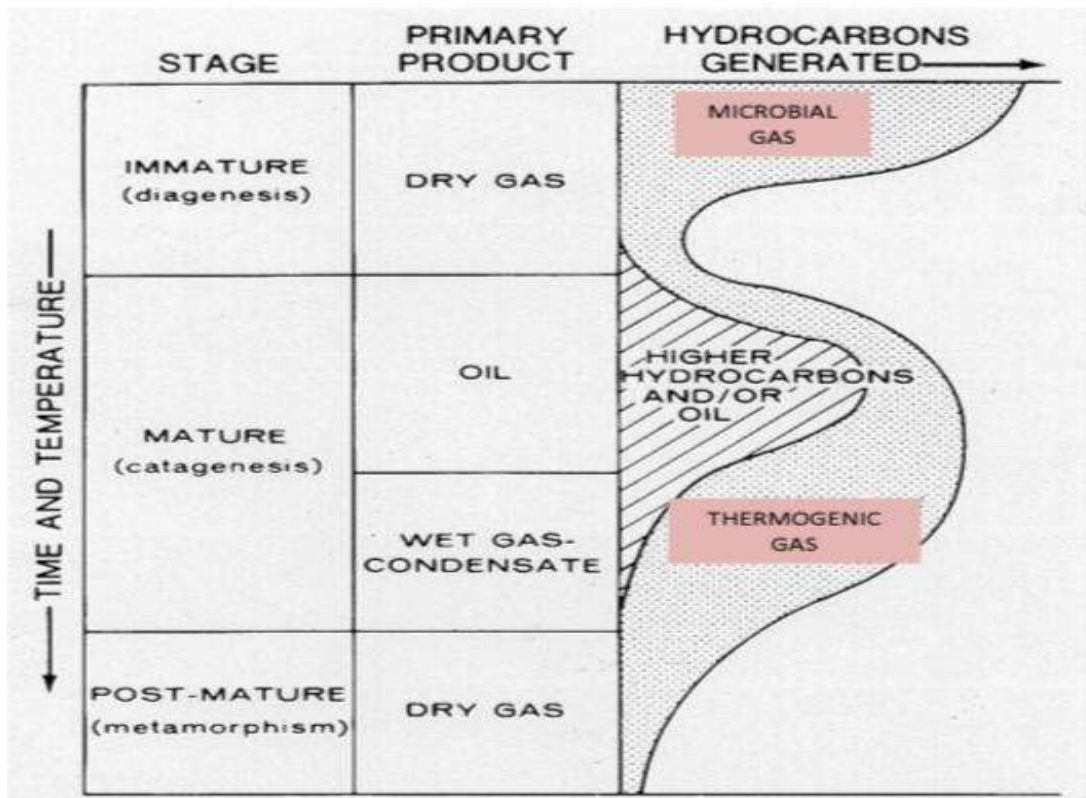


Figure IV.4: Major Stages of Hydrocarbon Generation ^[6]

7. Thermogenic Gas Generated from Kerogen in Source Rocks

Gas abundance, GOR, and NGL content depends on:

- Kerogen quality.
- Organic matter type (e.g., higher plant vs. algal components).

- Organic matter preservation (oxidation, reworking).
- Source richness .
- Thermal maturity.
- Expulsion efficiency. ^[7]

8. Identifying Natural Gas Sources

Gas-source correlations are based on two types of geochemical information:

- Molecular composition
 - Relative abundance of CH₄ and C₂+ components (gas “wetness”)
 - Non-hydrocarbon gases (CO₂, N₂, H₂S)
- Stable isotope ratios
 - Carbon (of individual hydrocarbons and CO₂)
 - Hydrogen (of hydrocarbons)
 - Helium (to assess CO₂ origin). ^[7]

9. Gas From Oil Cracking in Conventional Reservoirs

Above temperatures of ~160°C oil begins cracking to natural gas and pyrobitumen:

Oil = Gas + Pyrobitumen



About 50% yield as natural gas Thermal stability depends on oil composition:

NSOs < C₁₄+ aromatics < C₁₄+ saturates < C₆-C₁₄ saturates. ^[7]

10. Tools Based on Gas Composition

10.1. Molecular Ratios

“Wetness”: Amount of heavier gases relative to methane :

$$\% \text{C}_{2+} = \frac{\text{C}_2 + \text{C}_3 + \text{C}_4}{\text{C}_1 + \text{C}_2 + \text{C}_3 + \text{C}_4} \times 100$$

“Dryness”: Amount of Methane relative to heavier gases :

$$\%C_1 = \frac{C_1}{C_2+C_3} \times 100. [7]$$

10.2. ‘Haworth ‘ Parameters

GWR $100 \cdot S(C_2 \rightarrow C_5) / S(C_1 \rightarrow C_5)$

LHR $(C_1 + C_2) / (C_3 + SC_4 + SC_5)$

OCR $(SC_4 + SC_5) / C_3$.

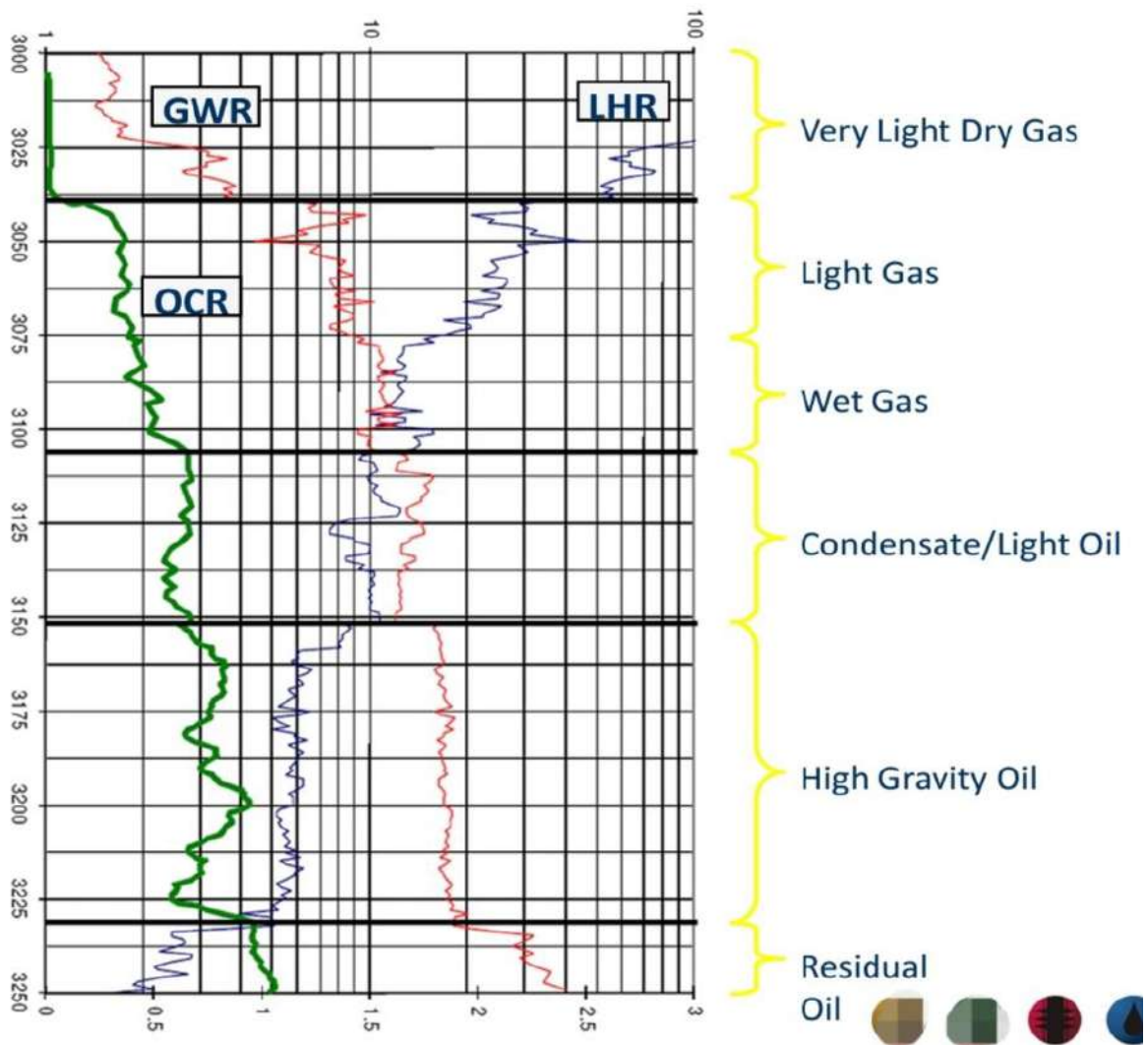


Figure IV. 5: “Haworth Parameters”.^[7]

10.3. Horizontal Drilling

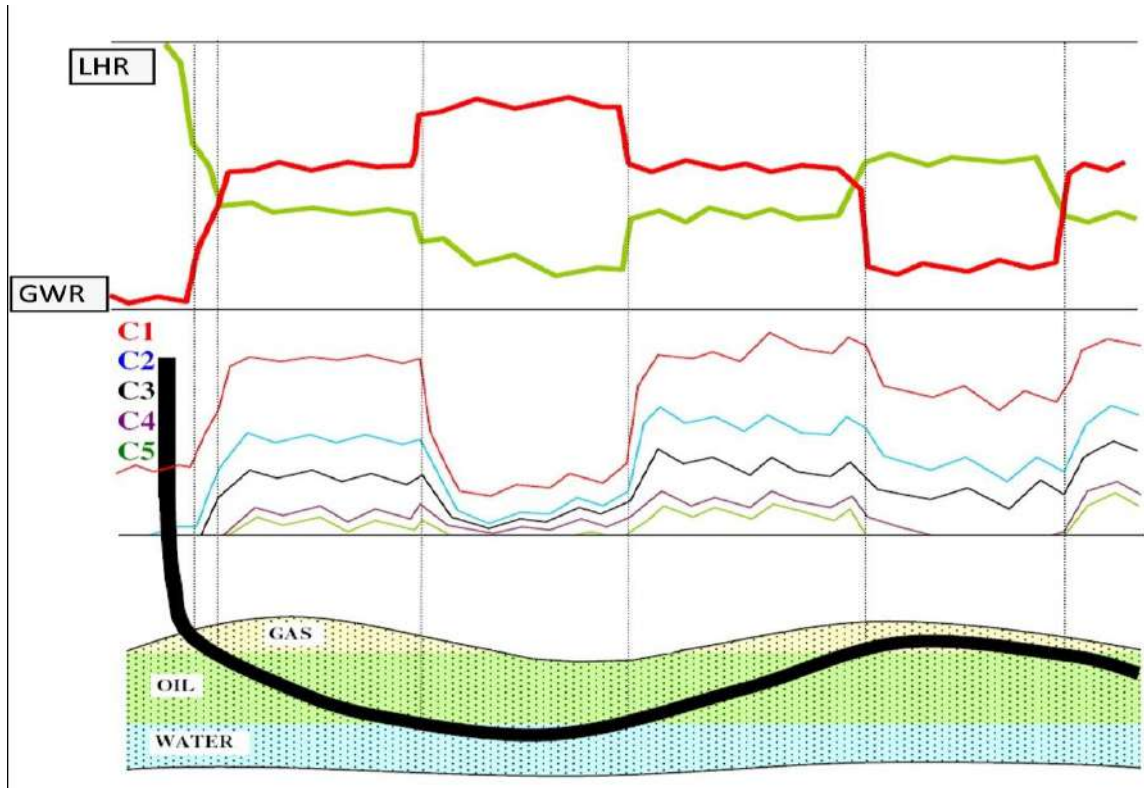
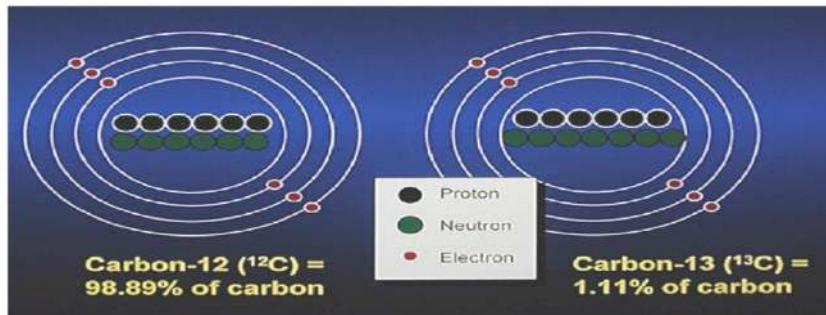


Figure IV.6: Horizontal Drilling ^[5]

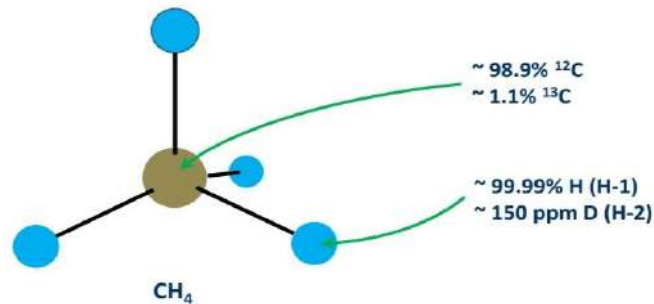
11. Tools Based on Gas Isotopes

11.1 . Characterization of Hydrocarbon Gases Using Stable Isotopes

- The Isotopes of Carbon Differ by 1 Neutron



• **Stable Isotopes Example: Methan**



• **Isotopic Measurements**

Isotopic ratios are measured relative to a standard

Deviations from the standard are reported as positive (+) or negative (-) enrichments of the heavier isotope

Values are reported in parts per mil (thousand): ‰

$$d^{13}CSAMPL = \frac{(^{13}C/^{12}C)SAMPLE - (^{13}C/^{12}C)STANDARD}{(^{13}C/^{12}C)STANDARD}$$

International standards:

-Carbon: Pee Dee Belemnite (“PDB”)

-Hydrogen: Standard Mean Ocean Water (“SMOW”).^[7]

11.2. Different Types of Natural Gas Have Distinct Isotopic Compositions

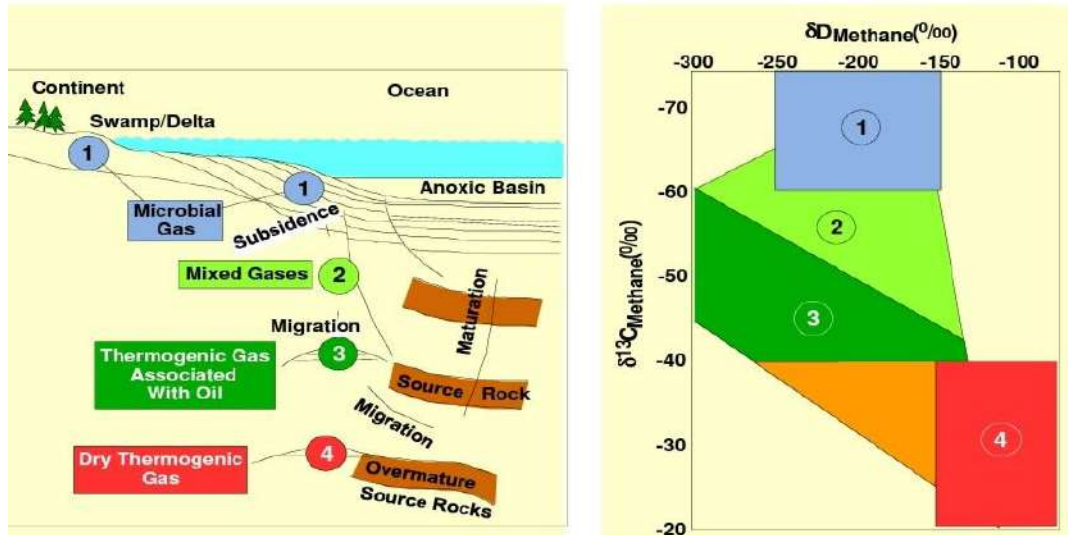


Figure IV.7: Different Types of Natural Gas Isotopic.^[11]

11.3. “Schoell Plots”

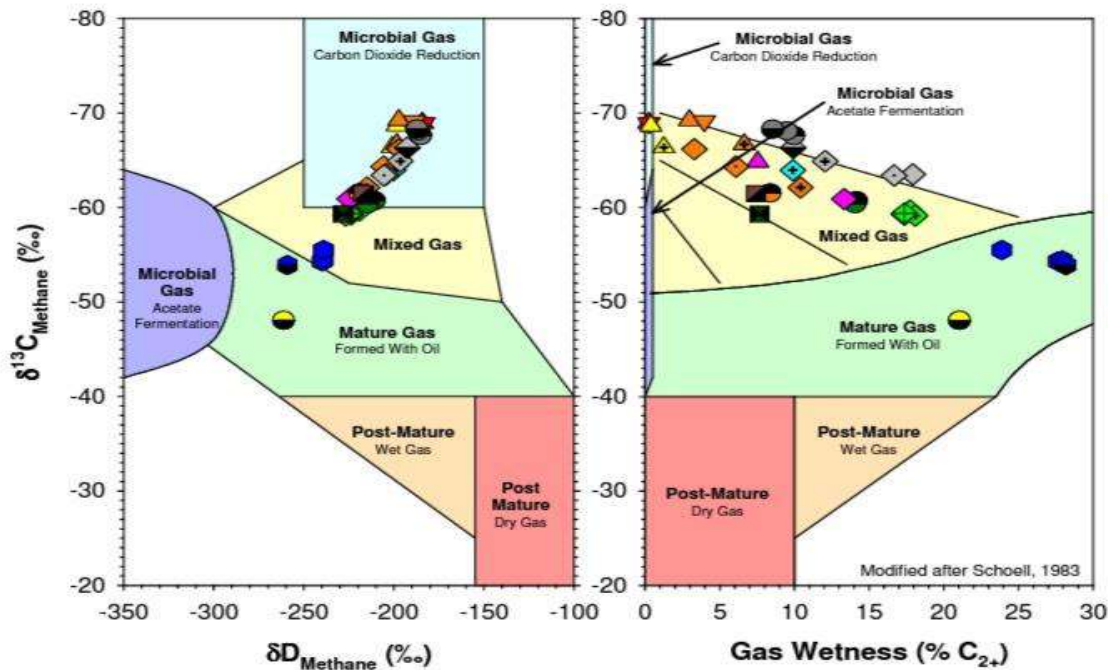
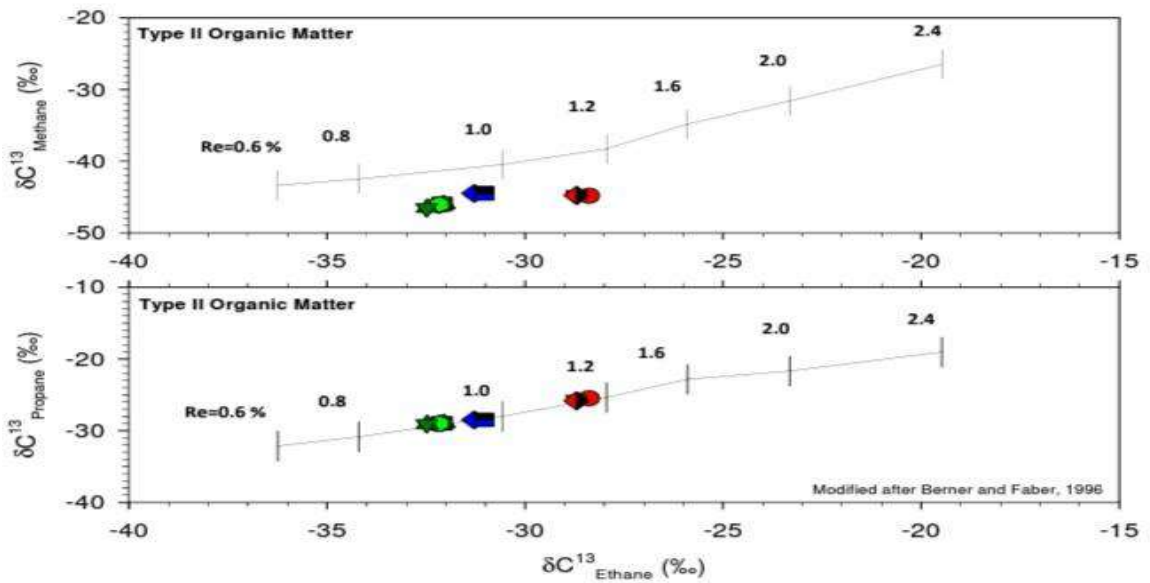


Figure IV.8 : Genetic Characterization of Natural Gas^[11]

11.4. “Faber Plots”



1. Knowledge of kerogen type
2. Knowledge of kerogen carbon isotopic composition.

Figure IV.9 : Thermal Maturity from Stable Carbon Isotope Data .^[11]

11.5 “Bernard Plot”

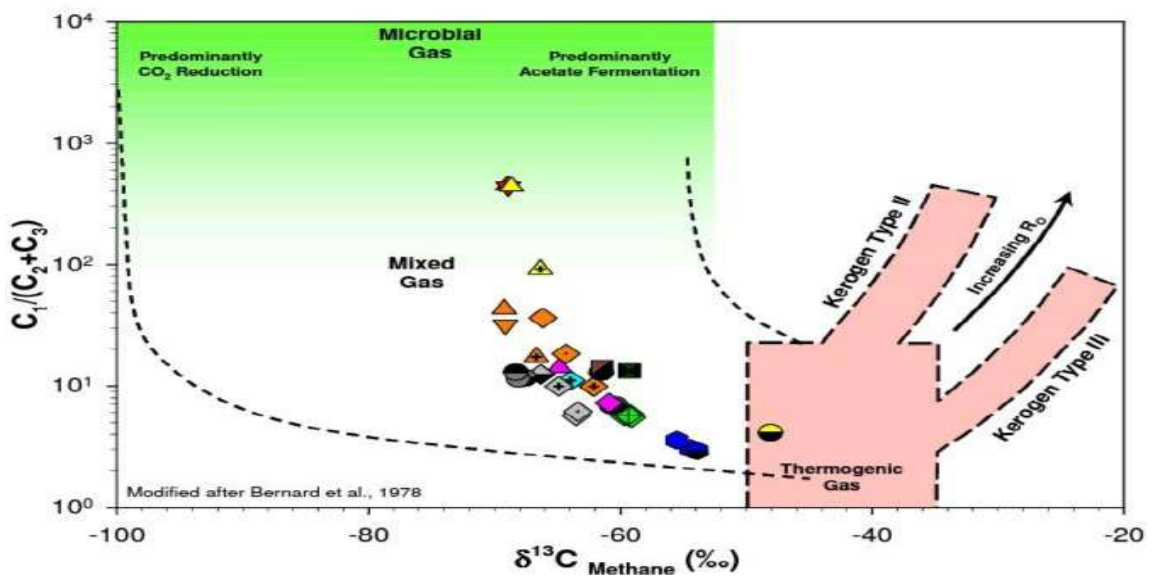


Figure IV.10 : Genetic Characterization of Natural Gas Bernard plot. ^[11]

11.6 “Chung Plot”

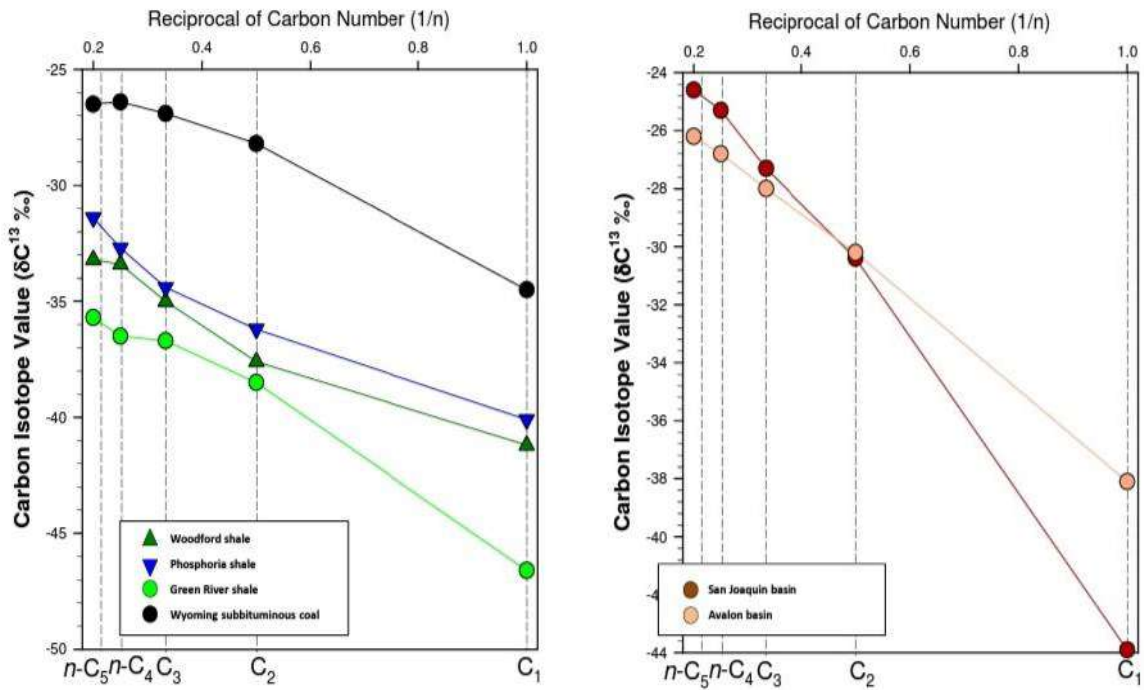


Figure IV.11 : Carbon Isotope Value “Chung Plot” .^[11]

CHAPTER V:

CASE STUDY

1. Case Study I: Exploration Well

1.1. Haworth Ratio Plot Characterization Hydrocarbon Type

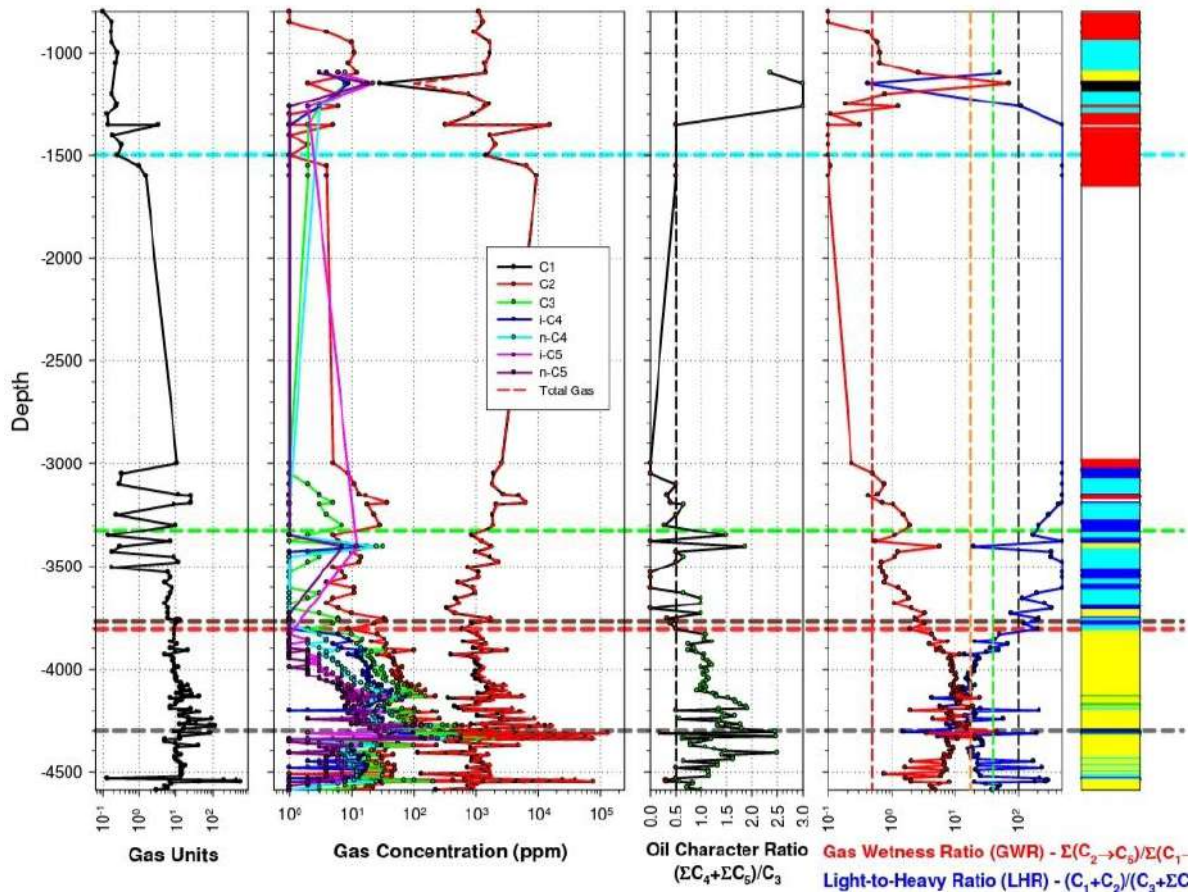


Figure V.1 :Haworth Ratio Plot Characterization Hydrocarbon Type

Table V.1 : Haworth Ratio Plot Characterization Hydrocarbon Type

GWR	LHR	OCR	Fluid Type	Comments
< 0.5	> 100	=0	Very Dry Gas	Background gas or microbial and possibly productive
$0.5 \leq \text{GWR} < 17.5$	< 100	< 0.5	Wet Gas: Non Associated	Gas density increases as GWR and LHR curves approach each other
$0.5 \leq \text{GWR} < 17.5$	< 100	≥ 0.5	Wet Gas: Condensate	Same as above; OCR indicates Condensate
$17.5 \leq \text{GWR} < 40$	< 100	< 0.5	Very Wet Gas: Condensate/Light-Oil	Increasing gas density as GWR and LHR curves cross
$17.5 \leq \text{GWR} < 40$	< 100	≥ 0.5	Very Wet Gas: Medium Gravity Oil	Oil density increases with increasing GWR and LHR curve separation
$0.5 \leq \text{GWR} < 17.5$	≥ 100	≥ 0.5	Mixed Gas: Thermogenic/Microbial	Microbial gas Lowers GWR, increases LHR and leaves OCR unchanged
< 40	≥ 100	< 0.5	Coal-Bed Gas, Organic Rich Shales	Predominantly methane and ethane
$\text{GWR} > 40^*$	$\ll 17.5$	≥ 0.5	Residual Oil	Low-volatile immobile hydrocarbon; may indicate oil/water contact
			No Values or Outside Range	The concentration of one or more of the hydrocarbon gases is zero

Down-hole log-plots: Gas Units, Gas Concentration, and the Haworth ratios GWR, LHR and OCR are provided. Based on the results summarized in Figures V.1 and table V.1 a colored log is presented that identifies fluid compositional zones based on the Haworth ratios. The horizontal colored dashed lines indicate stratigraphic tops identified in the right margin. [8]

1.2. Genetic Characterization of Natural Gas (Modified after Schoell, 1983)

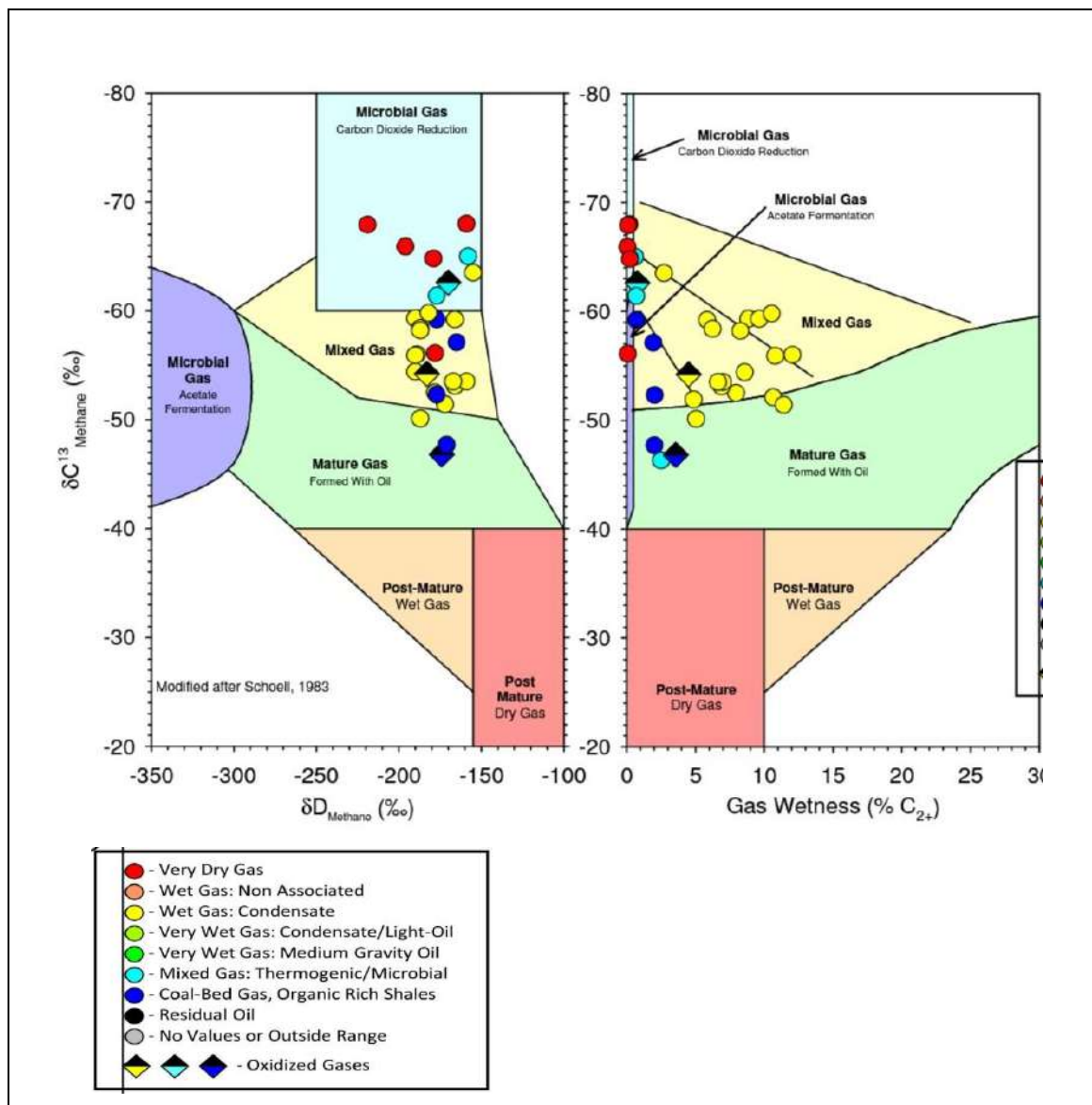


Figure V.2 : Genetic Characterization of Natural Gas Schoell, 1983 ^[11]

1.3. Genetic Characterization of Natural Gas (Modified after Bernard, 1978)

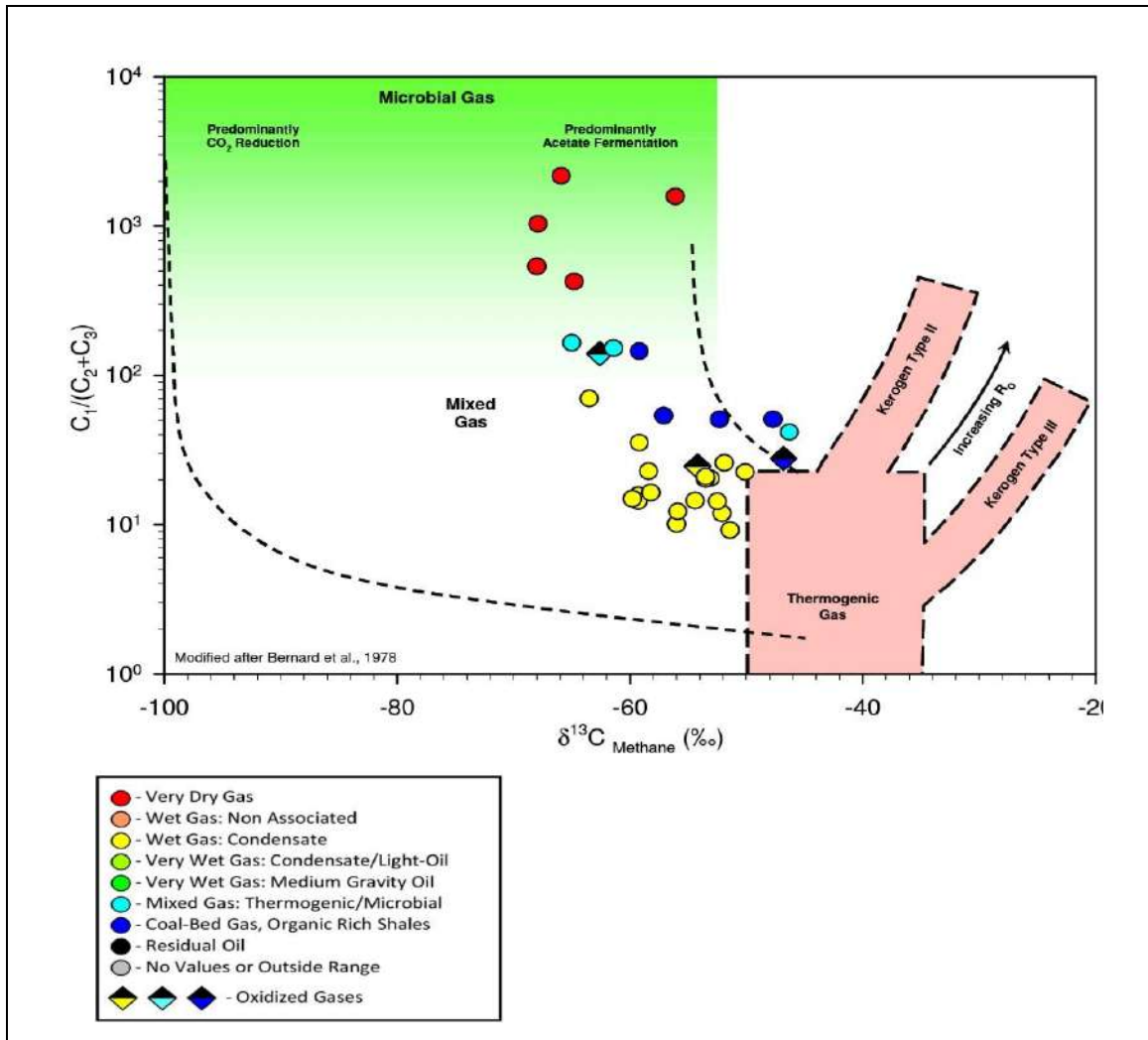


Figure V.3 Genetic Characterization of Natural Gas, 1978 [11]

2. Case Study II: Misc. Applications

2.1. Visund Field (N. North Sea)

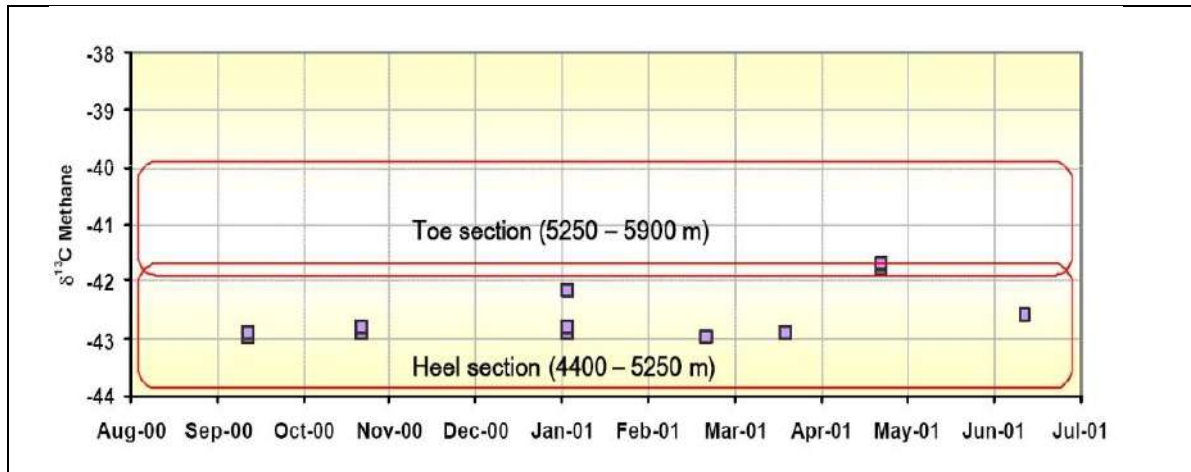


Figure V.4 Produced gas isotopes toe section not contributing to production

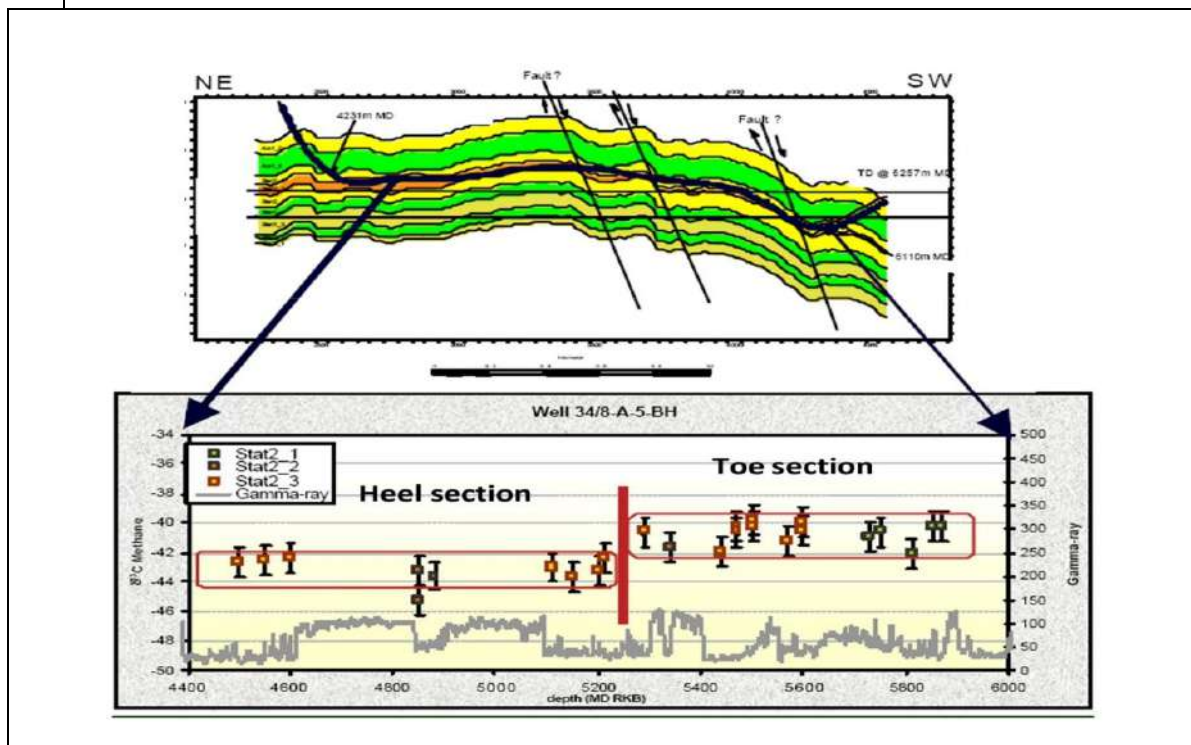


Figure V.5 Mud gases suggest a flow barrier at 5250 MD [6]

2.2. Germany Rotliegend Gas Field

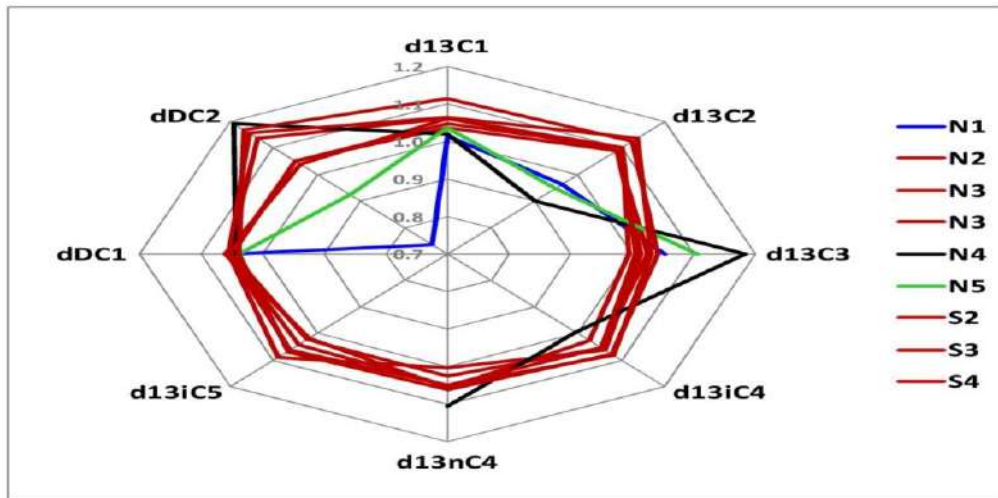


Figure V.6 Normalized isotopic composition of produced gases

Normalized isotopic composition of produced gases showing pronounced differences between N1, N4 and N5 gases and other gases in NW Germany Rotliegend Gas Field. [8]

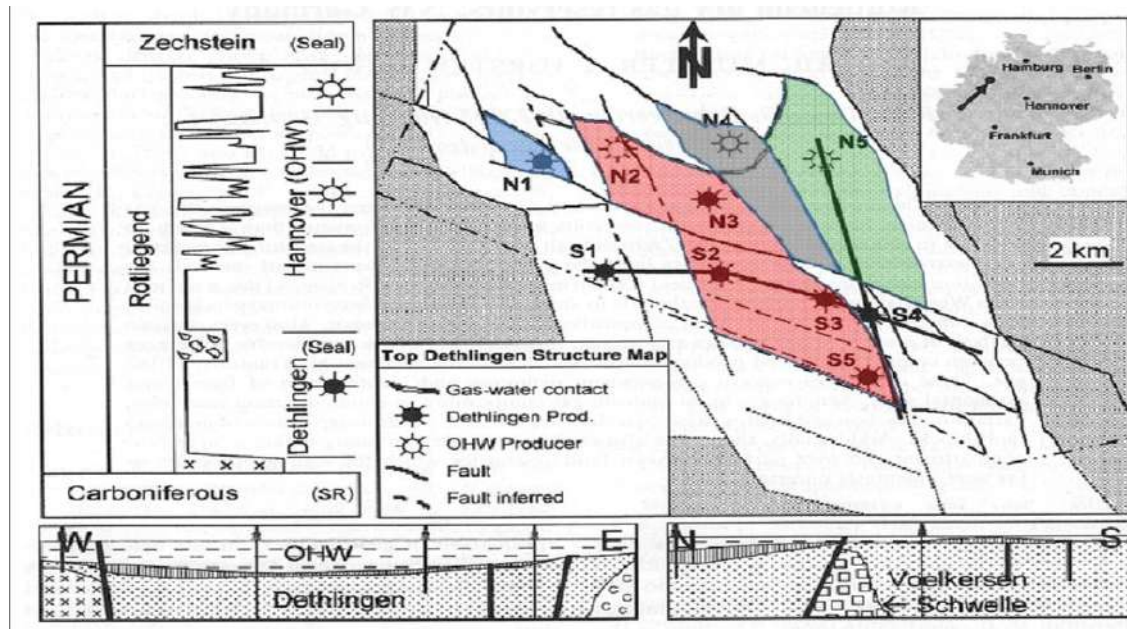


Figure V.7 gas and condensate geochemistry NW Germany Rotliegend Gas Field

A significant degree of compartmentalization is suggested by gas and condensate geochemistry well NW Germany Rotliegend Gas Field (After Mueller and Scholz (2004)). [8]

2.3. Predicting Saturation Pressures

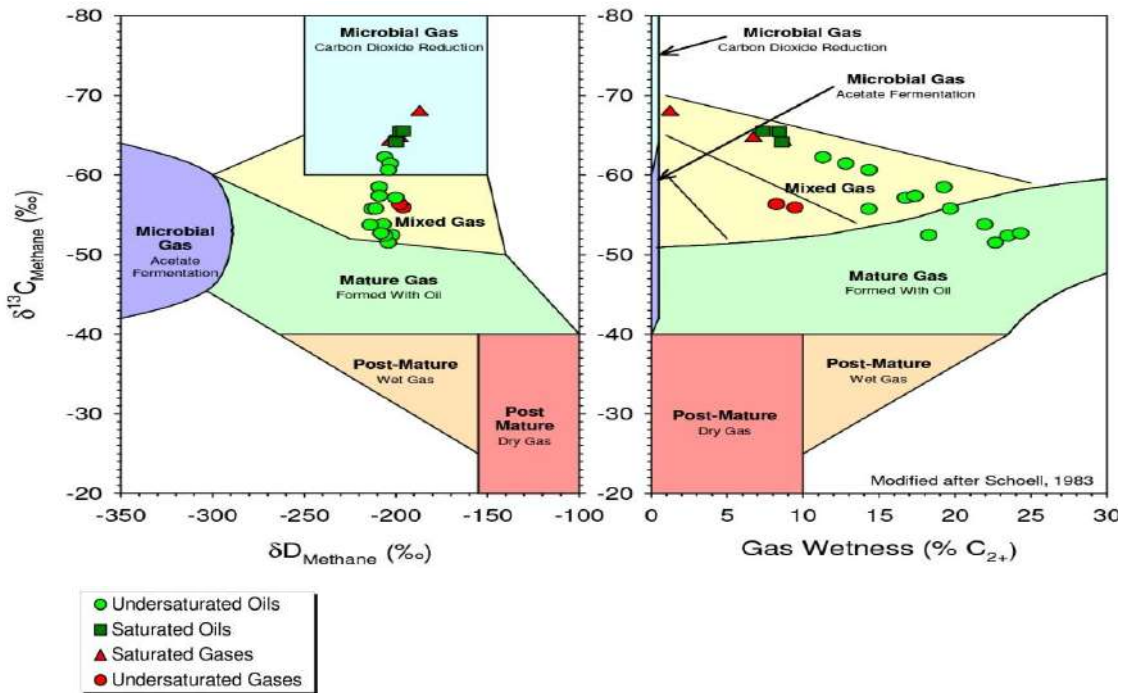


Figure V.8 Genetic Characterization of Natural Gas.^[11]

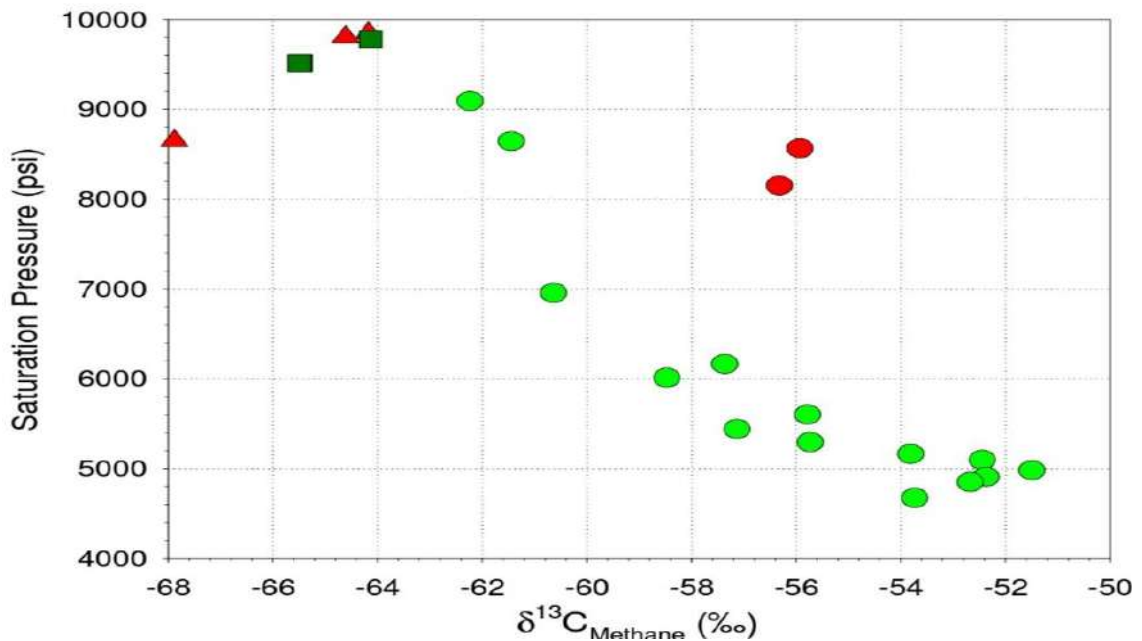


Figure V.9 Saturation Pressures Germany Rotliegend Gas Field.^[11]

2.4. Related Applications of Geochemistry

Geochemistry solves problems throughout the lifespan of a field

Exploration :

- Characterizing charge Risk (source, maturity, timing, gas vs oil potential)

Development

- Assessing reservoir compartmentalization
- Oil/gas property prediction (API, viscosity)
- Identifying missed pay
- Identifying fluid contacts
- Identifying induced fracture geometry
- Flood monitoring –Assessing sweep

Production

- Production Allocation
- Identifying completion problems (tubing string leaks, poor cement jobs, ineffective stimulations)
- Flow Assurance: Prevent Sludge/Asphaltene/ Wax Deposition

Field Abandonment

- Environmental site assessment and remediation. ^[8]

2.5. Shale Gas/ Shale Oil Applications

- Predicting hydrocarbon gas vs hydrocarbon liquid abundance variations with depth
- Identifying migrated gas vs. gas sourced in-situ
- Predicting relative permeability
- Characterizing fracturation height
- Production Allocation from multiple frac stages
- Constraining source maturity in vitrinite-poor intervals
- Characterizing gas in shallow non-pay zones that may be source of stray gas in aquifers. ^[8]

3. Case Study III : Shale Gas/ Oil Well**3.1. Shale Gas/Oil Example :**

- An emerging shale gas and shale oil play
- Source rock facies uniform throughout the core play area
- Maturity variations the dominant control on produced fluid type

- Exploration phase: relationship established between mud gas molecular and isotopic characteristics and whole-core source rock maturity
- Appraisal/delineation/production phase: used to infer maturity and probable character of produced fluids (e.g., GOR, CGR, CO₂ content, etc.)

From mud gas data

- - near real time fluid property prediction
- - confirm or replace core-based data. [8]

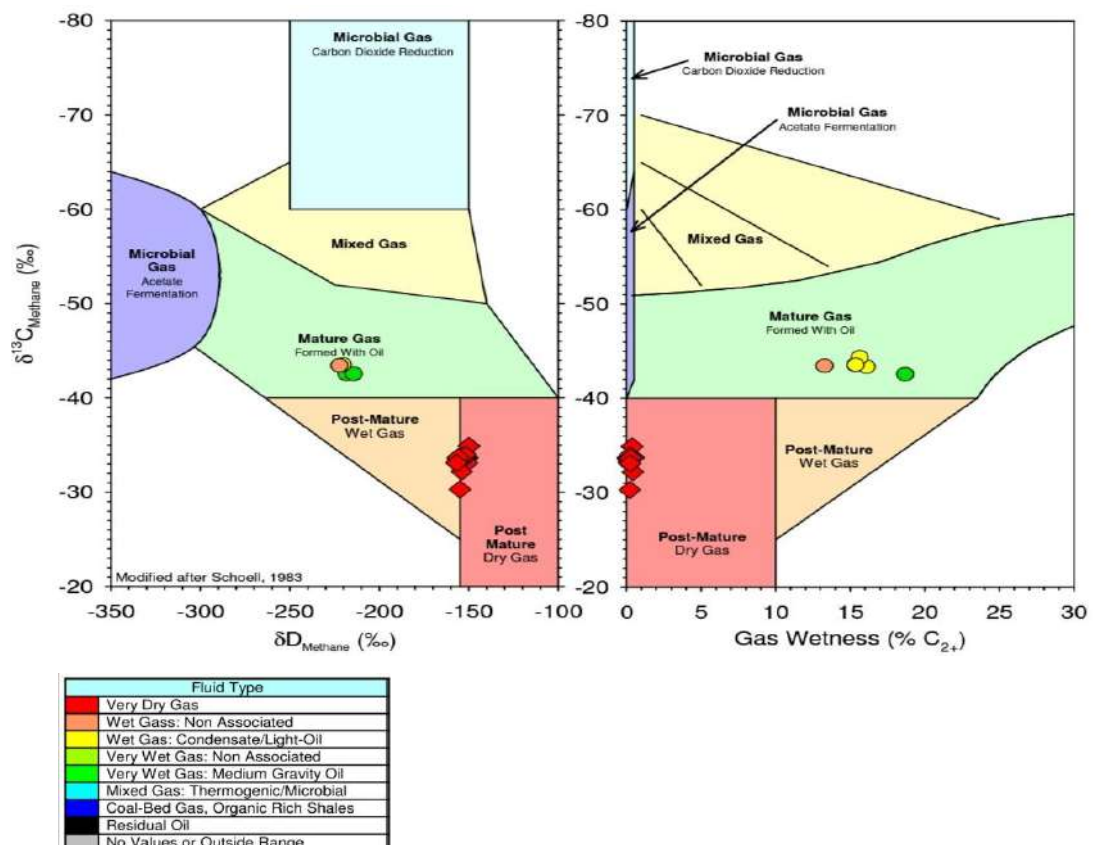


Figure V.10 Genetic Characterization of Natural Gas Shal gas

Symbols Colored by Fluid Type Inferences Using Haworth et al (date) ratios and interpretation guidelines. [8]

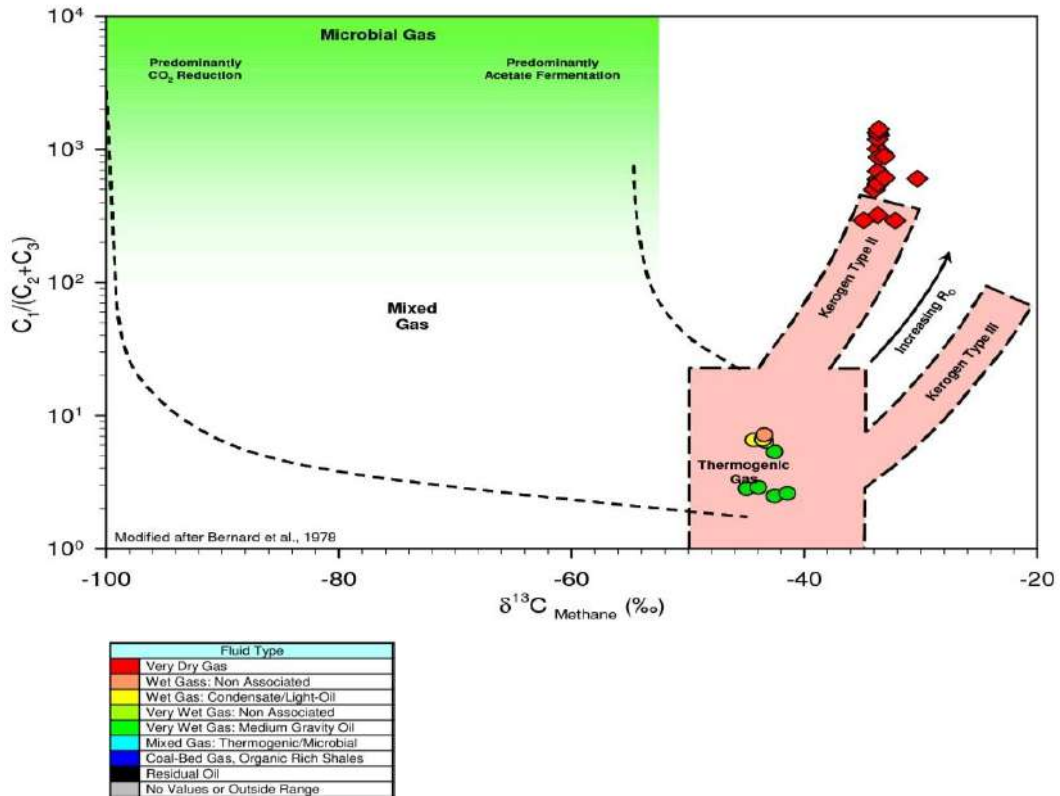


Figure V.11 Genetic Characterization of Natural Gas Shal gas.^[8]

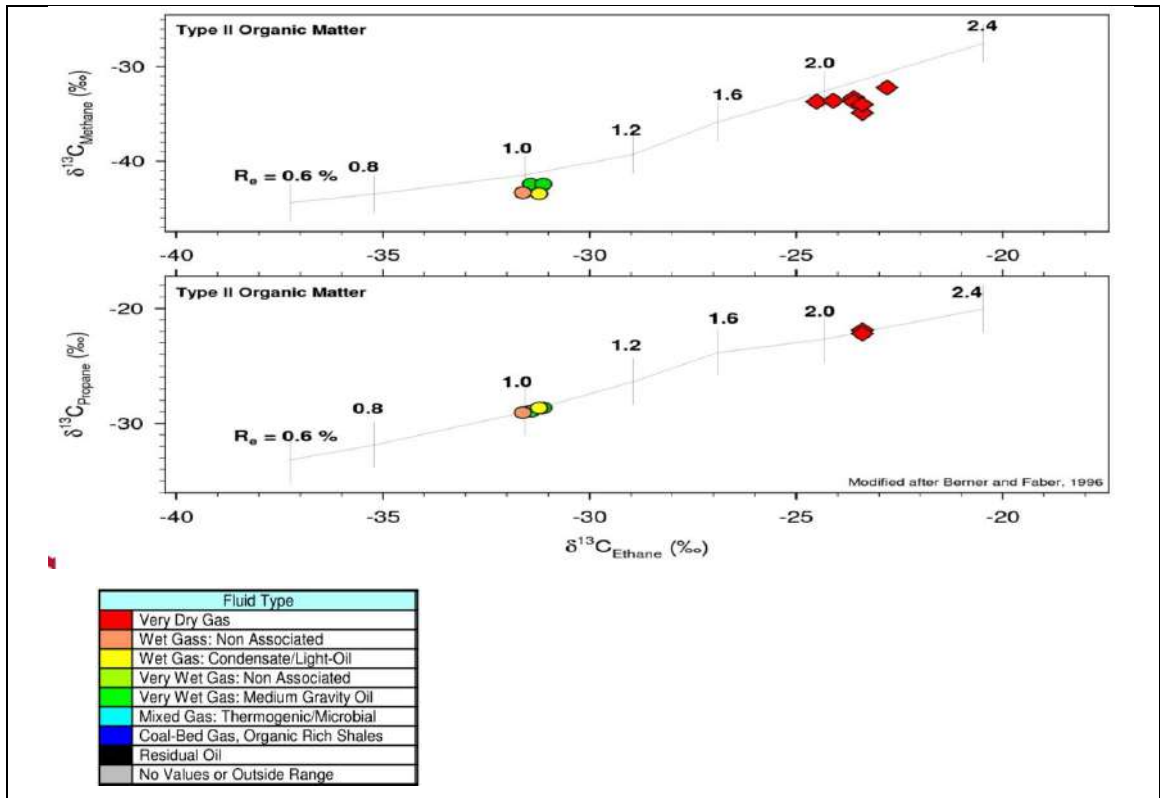


Figure V.12 Thermal Maturity from Stable Carbon Isotope Data.^[8]

3.2. Carbon isotope Value Niorara oil shale play

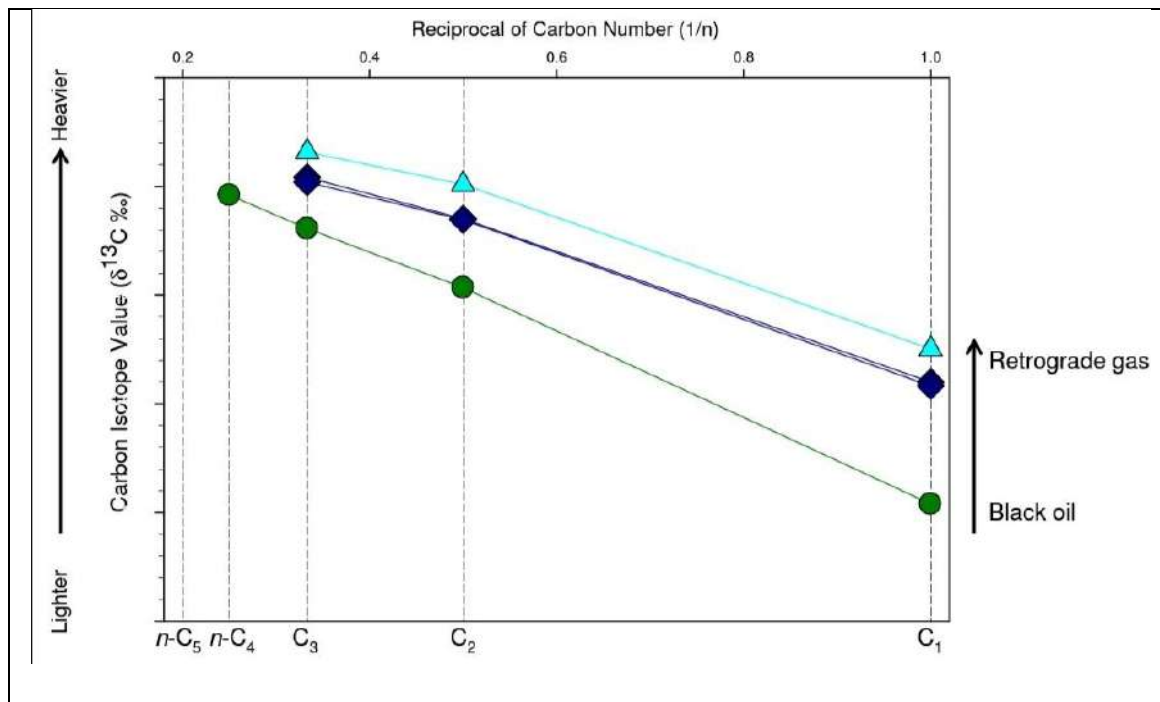


Figure V.13 Carbon isotope Value Niorara oil shale play

- As Niobrara source rock maturity increases, gas isotopes become heavier
- As Niobrara source rock maturity increases, gas-liquid ratio of Niobrara fluids increases
- Empirical relationships established with separator samples
- Applied to mud gas samples for GOR and fluid property predictions. ^[8]

CONCLUSION

GENERAL CONCLUSION

As explained in this work and since its introduction, following analysis of data, the program chromatography, were confirmed as a powerful tool and important method in the analysis of hydrocarbon which have complex composition and it use for the quantitative analysis of total petroleum hydrocarbon, gas contamination Oil Base Mud and water base mud while drilling. In contrast to mud logging cabine, based geochemical analyses, the advanced mudlogging-derived interpretation is obtained in near real time and can influence data collection and sampling programs while the drilling rig is still on site Surface data are always available while drilling, whatever the hole conditions, drilling challenges, well type, unlike any downhole measurement

In particular, the analysis of the data obtained has enabled the identification of reservoir sweet spots, fluid contacts within reservoir sections and fractures in carbonate reservoirs. Such data enabled precise and optimized sampling points for further mud logging cabine analysis. It was also found that data quality enabled direct comparison between mud gas data, mud flow data and core, well test and wireline data, when available. Rock properties such as porosity and permeability can be modelled by advanced mud gas, advanced mud flow detection and geochemical data obtained on surface while drilling; this new modelling approach is currently qualitative and is under development by the authors for further quantification

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- [10] <http://www.weatherfordlabs.com/Pss/Isotech> RT™ Isotope Logging Device
- [11] from Schoell et al. (1983) "Genetic characterization of natural gas", Berner and Faber, 1996, Data Moses Chung et al., 1988 "modeling thermogenic using carbon isotope ratio of natural gas"

Abstract

This short program demonstrates how real-time chromatographic analysis of light hydrocarbons can provide effective fluid characterization with the identification of fluid changes, zones and contact points, as the reservoir is being penetrated.

The clear advantage of this is that reservoir fluids are analyzed immediately, before contamination by mud invasion can alter the characteristics of formation fluids adjacent to the borehole, which can often be detrimental to subsequent electrical analysis. In addition to such reservoir analysis, high speed chromatographic analysis also provides the necessary resolution for the techniques to be applied to the steering of horizontal wells. While Logging While Drilling (LWD) is an effective technique, it is also an expensive one and costs can be dramatically reduced by the application of gas analysis to geosteering. A further benefit is often realized through more rapid course corrections (depending on the relationship between lag time and penetration rate versus tool placement, and when changes are recognized at surface) minimizing the amount of missed pay.

Key words :time chromatographic analysis, mud invasion, formation, lag time, penetration rate

Résumé

Ce programme court montre comment l'analyse chromatographique en temps réel des hydrocarbures légers peut fournir une caractérisation efficace des fluides avec l'identification des changements de fluides, des zones et des points de contact, au fur et à mesure que le réservoir est pénétré.

L'avantage évident de ceci est que les fluides du réservoir sont analysés immédiatement, avant que la contamination par l'invasion de boue ne puisse altérer les caractéristiques des fluides de formation adjacents au trou de forage, ce qui peut souvent être préjudiciable à l'analyse électrique ultérieure. En plus de cette analyse de réservoir, l'analyse chromatographique à grande vitesse fournit également la résolution nécessaire pour les techniques à appliquer au pilotage de puits horizontaux. Bien que la diaggraphie pendant le forage (LWD) soit une technique efficace, elle est également coûteuse et les coûts peuvent être considérablement réduits par l'application de l'analyse des gaz au géoguidage. Un autre avantage est souvent réalisé grâce à des corrections de trajectoire plus rapides (en fonction

de la relation entre le temps de latence et le taux de pénétration par rapport au placement de l'outil, et lorsque les changements sont reconnus à la surface) minimisant le montant de la paie manquée.

Mots clés : analyse chromatographique en temps, la contamination, l'invasion de boue, formation, le temps de latence, le taux de pénétration

الملخص

يوضح هذا البرنامج القصير كيف يمكن للتحليل الكروماتوغرافي في الوقت الفعلي للهيدروكربونات الخفيفة أن يوفر توصيفًا فعالًا للسوائل مع تحديد تغيرات السوائل ومناطق ونقاط التلامس عند دخوله الى الخزان. الميزة الواضحة لهذا هي أن سوائل المكمن يتم تحليلها على الفور ، قبل أن يؤدي التلوث الناتج عن غزو الطين إلى تغيير خصائص سوائل التكوين المجاورة لحفرة البئر ، والتي يمكن أن تكون ضارة في كثير من الأحيان للتحليل الكهربائي اللاحق. بالإضافة إلى تحليل الخزان هذا ، يوفر التحليل الكروماتوغرافي عالي السرعة أيضًا الدقة اللازمة للتقنيات التي سيتم تطبيقها على تجريب الآبار الأفقية. على الرغم من أن التسجيل أثناء الحفر (LWD) هو أسلوب فعال ، إلا أنه مكلف أيضًا ، ويمكن تقليل التكاليف بشكل كبير من خلال تطبيق تحليل الغاز على التوجيه الجغرافي. غالبًا ما يتم تحقيق فائدة أخرى من خلال تصحيحات المسار الأسرع (اعتمادًا على العلاقة بين وقت التأخير ومعدل الاختراق لوضع الأداة ، مع التعرف على التغييرات على السطح) لتقليل مبلغ الأجر الفائت.

الكلمات المفتاحية : التحليل الكروماتوغرافي في الوقت الفعلي ، التلوث ، غزو الطين ، وقت التأخير ، معدل الاختراق