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NEW PETROPHYSICAL MODEL FOR UNCONVENTIONAL HIGH-CO_2-CONTENT OIL RESERVOIRS

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ABSTRACT

It is known the existence of unquantified amount CO_2 produced from some fields in the Caguán Putumayo basin in Colombia. The effect of CO_2on resistivity and porosity open hole logs have not been evaluated yet; then, it is proposed to build a new petrophysical interpretation model from available open hole logs in order to quantify the CO_2 concentration in the Caballos formation in the Caguán Putumayo basin to facilitate a better understanding of the thermodynamic behavior of the reservoir fluids. Knowing CO_2significant subsurface concentration allows evaluating not only the impact in hydrocarbon reserves and production costs but also alternative management strategies for produced $CO_2$to reduce environmental pollution. Reservoir CO_2quantification resulted feasible by using porosity and neutron open hole logs superposition only if filtrate invasion is low or moderate. This method detects the residual CO_2 saturation; however, special drilling muds with null or low filtrate permits estimating virgin zone porosity. The method applies with no additional costs to all under saturated reservoirs containing CO_2 if density and neutron porosity logs are available. Neutron porosity can be replaced by NMR porosity.

Keywords: CO_2 saturation, porosity logs, NMR logs, depth of investigation.

INTRODUCTION

In the opinion of ecologists, CO_2 is the gas greenhouse gas causing warming global effect and represents a severe environmental problem, but, for experts, this resource can be no longer a problem and becomes an important energy source.

CO_2 flooding as an enhanced oil recovery technique was successfully started in 1972 in the Nelly-Snyder field in Texas. Currently, there exist more than some hundred active CO2 injection projects in USA, Canada, Venezuela, Mexico, Trinidad, Libya and Turkey.

Due to the general concern on global warming, in the last decade, there have been undertaken several research projects related to CO_2 sequestration and injection CO_2 in depleted oil reservoirs or aquifer traps generally formed by sandstone. There are numerous references dealing with liquid CO_2 injection in brine-saturated cores to measure resistivity and acoustic velocity at high pressure and temperature conditions for simulating subsurface conditions. For instance, Onishi (2009) injected gas, liquid and supercritical CO_2 in brine-saturated coresat three different flow rates (0.5, 3 y 10 ml/min) and monitoredthe resistivity increase during injection. He calculated CO_2saturation by applying Archie's equation knowing previously the formation resistivity factor (F), brine resistivity (Rw) and measuring true resistivity (Rt) for the reservoir rock-fluid set.Onishi (2009) concluded that the calculated water saturation agreed well with the amount of water displaced byCO_2 and the amount of CO_2 entering the reservoir rock can be accurately estimated by Archie's equation by measuring resistivity increase.

Nakatsuka (2010) presented a model for quantification CO_2 saturation injected in the sandstone core and utilized the resistivity index (IR) and the shale index (V_{sh}) measured by the gamma ray log.

Kim, Xue, Z. and Matsouka (2010) measured resistivity using an array of four electrodes along cores with injected CO_2at supercritical state and concluded that seismic velocity and resistivity are useful for monitoring $CO_2$by utilizing the fluid substitution theory and the resistivity index theory, respectively.

From the above experiences can be concluded that the CO_2entrance in the reservoir rock increases significantly resistivity and decreases the acoustic velocity and, as a consequence CO_2 injection process can be monitored from Surface applying some categories of the electric method and/or seismic method by comparing measurement along the reference sections but with time lapse.

No information on petrophysical interpretation evaluating quantitatively the CO_2effect on resistivity and porosity measurement during open well logging was found. Therefore, in this work, two core holder devices were built with the purpose of understanding the CO_2effect on resistivity and sonic porosity in oil reservoirs. One device was used for measuring resistivity and the other one for acoustic velocity at reservoir conditions.The analysis of the measurement data allowed for the generating a new petrophysical model for correcting porosity and saturation due to high CO_2 content.

FIELD STUDY BACKGROUND

It is recognized that several oil fields in the Caguán Putumayo basin produce CO_2 in unmeasured amounts. However, it is believed that in the foothill, in the western sector of the same basin, a higher CO_2 content is produced. For this reason, a study focused on determining the CO_2 concentration in nine wells, five of which belonging to the western sector and four to the south of basin was conducted.

Franco *et al*. (2012) mentioned that there exists the highest CO_2 amount in the western area fields based upon the chromatography results given in CO_2 molar percentage: Caribe = 60.9%, Sucio = 60.9%, Quriyana = 93.6%, Churuyaco = 51.8%, San Antonio= 33.6%and Sucumbíos=72.8%. These results do not resolve the given problem since they do not permit the determination of the existing CO_2 amount in the different sandstones producing from the Caballos formation since the analyzed samples were collected from the production battery to which converges the production from different wells. The generalized stratigraphic column for the Caguán-Putumayo basin is given in Figure-1.

The Caballos formation is the main producing source from the basin. It consists of sandstone with interbedded shale and some thin carbon layers. The sandstone is formed primary by quartz grains; feldespar are less than 5% and other minerals in minimum amounts. The formation top is composed by gluconitic sandstone. Four different sandstone units can be differentiated in The Caballos formation. They are named from bottom to top: U1, U2, U3 and U4, Franco *et al*. (2012).

Table-1 presents reservoir and bubble point pressures for each one of the studied well; six wells belonging to the western area and 3 to the south. In all the cases, the reservoir is under under saturated conditions, then, by the time the well logs were run the reservoir rock contained only liquid hydrocarbon. On the other side, the production history reports very low GOR, compatible with under saturated fluids.

Table-1. Initial reservoir and bubble-point pressures for the studied well. After: Ecopetrol. Datos técnicos. Auditoria de reservas, año 2013.

Well	**PR** (psi)	**Pb** (psi)
Sucumbíos 5	3300	1577
San Antonio 14	3900	482
Churuyaco 7	3900	1530
Quriyana 1	3200	915
Caribe 5	3037	1168
Caribe 7	3037	1168
Acaé 12 D	4705	1600
Acaé 6	4705	1600
Loro 7A	4705	1600

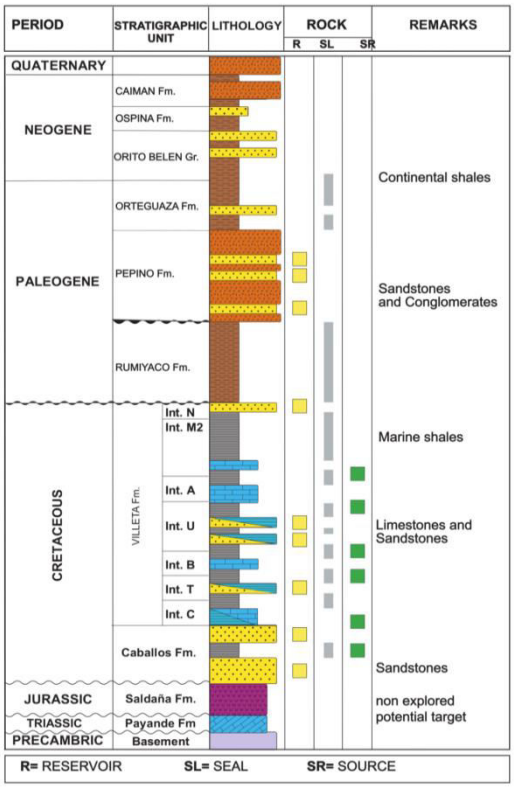

Figura-1. Generalized stratigraphic column for the Caguán-Putumayo basin.Takenfrom: Agencia Nacional de Hidrocarburos. ColombianSedimentaryBasins. Bogotá, 2007.

CO_2 EFFECT ON OPEN HOLE WELL LOG MEASUREMENTS

Conventional resistivity tools are devised for measuring rock-fluid resistivity at three levels: wash or flushed zone (Rxo), transition zone (Ri) and virgin zone (Rt) farther than the invaded zone by mud filtrate which reflects the true resistivity of rock and original fluids. The deep resistivity log (Rt) is very sensitive to the presence of such non-conductive fluids in the virgin zone as hydrocarbons; Rxoand Rimeasure resistivities which resulted very influenced by the mud filtrate which displaces the original fluids. Like hydrocarbons, gas, liquid or supercritical $CO_2$is a non-conductive substance; then, it is not possible to differentiate in the deep resistivity log (Rt) between hydrocarbon or CO_2 formations; moreover, the interpretation becomes harder in in oil reservoirs with high- CO_2 content.

Porosity logs

Measurements of sonic porosity, neutron, density magnetic resonance logs are subjected to the mud-filtrate invasion because their depth of investigation (DOI) is very low; then, their response is affected by the flushed and virgin zones. These tools respond differently depending upon lithology and gas or light fluids in the pore space. In high gas-contain reservoirs, porosity measured from

density logs is very high, while sonic porosity in well-compacted rocks has no influenced by gas, Hilchie (1962). However, there are small differences related to the tool design depending on the manufacturing company.

Density log

The density tool measures the density of electrons in the rock and a pore fluid which is related to total or bulk density of the rock-fluid set (ρ_b):

$$\rho_b = \phi\rho_f + (1-\phi)\rho_{ma}$$
$$\rho_f = S_w.\rho_w + S_o.\rho_o + S_g.\rho_g$$

If matrix density (ρ_{ma}) and fluid density (ρ_f) are known, then, the density tool allows estimating accurately the porosity.

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

When there exists residual oil in the flushed zone the total (ρ_b) from the density log is slightly affected since oil and water densities are fairly close. In such case, it is reasonable to assume ρf=1. in contrast, when residual hydrocarbon gas exists with density ranging from 0.1-0.3 g/cc, the resulting total density is very low; then, estimated porosity will be higher than the actual value. Customary, in gas zones the fluid density (ρ_f) is taken as the mud-filtrate density and it is accepted that the apparent porosity obtained from density tool is overestimated. In order to correct this effect, Hilchie (1982) suggested using a fluid density value of 0.7 g/cc in the above equation when gas density is unknown. It is deduced that residual oil having high CO_2 content has a density going from 0.6 to 0.9 g/cc at the Caballos formation depth. It produces an intermediate effect (between oil effect and hydrocarbon gas effect). Porosity from density log is slightly overestimated. Unfortunately in high-CO_2 -content oil reservoirs, it is not possible to estimate fluid density (ρ_f) because saturations and densities of oil and CO_2 are unknown; therefore, quantification of CO_2 is impossible from total (ρ_b) provided by the log.

Neutron log

The neutron log mainly responds to the amount of hydrogen atoms which are presented in the pore and fracture fluids (including clay water). This means that clean rocks with pores filled of liquid (water or oil), the apparent porosity from the neutron tool is a good indicator of total rock porosity whether or not pores are connected. The equation for the neutron log tool is:

$$\emptyset_N = \emptyset * IH_f + (1-\emptyset) * IH_{ma} - \Delta\emptyset_{exc}$$

where IH is the hydrogen index which is found from:

$$IH_f = S_{xo} * IH_{mf} + S_o * IH_o + S_g * IH_g$$

The amount of hydrogen per formation unit volume is expressed by the hydrogen index (IH) which by definition is the unity for sweet water and less than one for hydrocarbon gases. This leads to clarify the existence of residual gas in the invaded zone causes less apparent porosity than the actual value. This minor hydrogen concentration is not corrected by the processing software of the neutron tool (Asquith and Krigowsky, 2007). Since CO_2 has no hydrogen in its structure, then, the neutron tool does not detect it. As a consequence, in oil reservoirs with CO_2 content, the hydrogen deficit is big and the apparent porosity is much less than the actual one.

Sonic log

It measures the transit time Δtused by a compressional wave to go throughout a foot of formation. Porosity is estimated by Willye equation, Bassiouni (1994):

$$\phi_s = \frac{\Delta t_c - \Delta t_{ma}}{\Delta t_{ma} - \Delta t_f}$$

Where, $\Delta t_c = \phi.\Delta t_f + (1-\phi)\Delta t_{ma}$

The fluid transient time is estimated by:

$$\Delta t_f = S_{xo} * \Delta t_{mf} + So * \Delta t_o + S_g * \Delta t_g$$

Since the investigation depth of the sonic tool is very low, it is assumed that the pore fluid is basically mud filtrate, then$\Delta t_f$is 189 o 185 µsec/ft,if dealt with sweet-water or salt-water based mud, respectively. The sonic tool responds well in clean rocks with intergranular uniform porosity. However, it only measures primary porosity. In theory, the transient time Δtc is higher in reservoirs with high gas residual saturation and low invasion. Then, sonic porosity is higher than the actual value. The gas effect is corrected by multiplying by a factor of 0.7, Hilchie (1982). In practice, the sonic log only detects gas in unconsolidated rocks. It does not detect gas presence in compacted or consolidated rocks, like the Caballos formation.

NMR log

It is used only to study atomic nucleus having odd numbers of protons or neutrons as the case of a hydrogen atom $_1H$, which behaves as a small magnet. The NMR tools are calibrated at the hydrogen magnetic resonance frequency. Analogous to the neutron tool, the NMR tool responds to the hydrogen amount or hydrogen index IH of the fluid in the pore space. It does not detect hydrogen in either rock matrix or clay minerals. The NMR equation (Hamada, 2008) is:

$$\emptyset_{NMR} = \emptyset * S_{gxo} * IH_g * P_g + \emptyset * IH_L * (1 - S_{gxo})$$

Assume a hydrogen index.IH_L= 1

$$\emptyset_{NMR} = \emptyset * \left[1 - S_{gxo} * \left(1 - IH_g * P_g\right)\right]$$

Since CO_2does not content hydrogen, then, the NMR does not detect it. Therefore, apparent porosity from NMR logs in oil reservoirs with $CO_2$is less than the actual value.

APPLICATION TO THE STUDIED FIELD

Gas detection is currently detected with the called "gas effect" using both neutron and density logs. The neutron tool was calibrated with sandstone matrix density (2.65 g/cc) in the nine studied wells and the porosity calculated from the density log used this density value. Oil has less density than water but about the same hydrogen index, but CO_2 –compared to water- has less density and its hydrogen index is zero. Therefore, oil rich in CO_2 has a less density than water and the hydrogen index is very low as the dissolved CO_2 content increases. When the density and neutron logs are superposed in compatible porosity scale of clean aquifers, they read equal porosity values. In oil reservoirs the neutron log reads a porosity value slightly lower than the density log. But, in gas reservoirs, the neutron reading is smaller than the density leading to a pattern known as "gas effect". The two logs crosses towards the high extreme value of the scale while the neutron goes towards the lower values. It is concluded for the studied field that if CO_2 is dissolved in oil crude, then density and neutron logs should display gas effect.

Notice that the neutron log reads all the hydrogen in the formation, including in clay minerals. This means that in reservoirs with clay the apparent porosity read by the tool is higher than the effective porosity and if gas exists, this can be undetected since they alter the sonic porosity in opposite directions. With the purpose of avoiding masking the existing CO_2 in oil reservoirs, there is a need of correcting density and neutron porosities due to clay content –convert them into effective porosities- before evaluating the magnitude of the gas effect by log superposition.

The combination of NMR and density logs responds for either gas presence or low density fluid similar to neutron-density crossover, this means that in front of a gas reservoir this superposition also shows gas effect. This combination allows to easily detect CO_2 presence since the NMR log has higher investigation depth than the neutron log and only detects hydrogen in the pore fluids and it is no sensitive to hydrogen in the clay minerals. It means that apparent porosity from NMR tool and the effective porosity are equal.

PROPOSED METHODOLOGY

The proposed method for CO_2 quantification uses neutron and density log superposition. Then, true porosity is estimated using any proposed equation for gas zones (DasGupta, Gaymard or Hilchie). This method applies to undersaturated reservoirs constituted by clean or clayly rocksin any formation (Caballos, Villetaand Pepino) if neutron and density logs are provided and invasion zone is low. Neutron log can be replaced by NMR log which is only sensitive to fluids, eliminating the hydrogen effect in clay minerals which tends to mask the gas effect in the neutron log. This method detects either residual or minimum CO_2 saturation which was not displaced by the invaded fluid. The estimated saturation by this method would be the same to the virgin zone saturation in wells with special muds leading to low or zero.

Acoustic velocity measurement

Acoustic velocity throughout a fully saturated core was measured. First, a brine with 10000 ppm was used, second, brine concentration was increased to 30.000 pm; then, the core was saturated with $CO_2$and crude. In both cases, temperature ranged between 77 ºF to 220 ºF and pore pressure from 0 to 3000 psi, respectively. It was observed that acoustic velocities in crude and CO_2 decreases as the pressure increases. Also, temperature increment causes a reduction in acoustic velocity in crude and an increase of acoustic velocity CO_2.

Wanand Amos (1989) found that "velocity reduction of the compressive wave depend upon the pore pressure, temperature, porosity, among other factors. The pore pressure increment at constant confining pressure not only keeps pore and crack open and cancels the confining pressure effects but also increases CO_2 density; therefore, greater pore pressures cause a higher descend in both P and S waves. In well consolidated sandstones, the increment of porosity tends to reduce CO_2 effect".

Since the DOI of the Sonic tool is very low, measurements are mainly affected by wash zone fluids (mud filtrate and oil with dissolved CO_2). The fluid transit time for this case are represented by the following equation:

$$\Delta tf = S_{xo} * \Delta t_{mf} + S_o * \Delta t_o + S_{CO2} * \Delta t_{CO2}$$

At pressure and temperature conditions CO_2 and oil has net transit time 180 and 250 $\mu sec/ft$ respectively. CO_2transient time compared to the filtrate transient time in theory is 189 $\mu sec/ft$ results to be very close so there is no enough contrast to determine CO_2 presence with the sonic log.

Resistivity measurements

Resistivity measurement in a 100% oil saturated core was infinite. Then, 25%, 50% and 75% of oil was successively displaced by CO_2 injection. In all cases resistivity was infinite. It was proved that CO_2, like oil, is a no polar and non-conductive fluid. This experiment leaded to conclude that because the lack in resistivity contrast of crude and CO_2, resistivity logs do not differentiate crude and CO_2 in the reservoirs, even, when CO_2 is dissolved in crude oil as for the case of the studied field.

Table-2. Petrophycal parameters for well Sucumbíos 5. Source: Ecopetrol-ICP.

Depth (ft)	Ø (%)	**K** (md)	**Ro** (Ω.m)	**F** (Ro/Rw)
8869.83	6.9	1.8	89,11	171,27
8892.29	6.2	1.3	133,32	256,24
8894.50	5.8	3.8	141,15	271,28
8898.38	9.2	176	46,31	89,01
9050.50	10.8	152	36,01	69,21
9058.50	10.8	300	36,94	70,99
9079.08	8.4	270	56,72	109,02
9092.50	10.2	248	40,49	77,82
9101.42	10.0	72	44,76	86,03

Available information

Information of nine (out of 20) wells was used to build a model of petrophysical interpretation for quantifying CO_2 content. The remaining 11 wells had no complete information. The selected wells are: Sucumbíos 5, San Antonio 14, Quriyana 1, Churuyaco 7, Caribe 5, Caribe 7, Acaé 6, Acaé 12D, Loro 7A. A recent PLT log for well Sucumbíos 5 was also receivedalong with along with a nuclear magnetic resonance log (MRIL) log (8784-9155 ft) and spectral gamma ray log of recovered cores from the caballos formation sandstone (8717-9107 ft) with their corresponding petrophysical analysis: porosity and permeability measurements, cementing coefficient mof 1.93, saturation exponentnof 1.79 and tortuosity coefficient aof 1.

Since Caballos formation has very thick sandstones drilled with a 6-in diameter bit, only correction by invasion depth with tornado charts was applied. Neutron log was corrected by well diameter and temperature.

Water sampled from production battery was not used since water saturation depends exponentially on formation water resistivity (Rw). In all the wells chosen to build the petrophysical model the spontaneous potential (SP) has poor resolution possibly due to low filtrate-formation water resistivity contrast and high rock-fluid resistivity. This log was then not used for determining formation top, formation base and Rw. On the other hand, the gamma ray log shows an excellent definition. U1 sandstone has a growing-grain sequence from bottom to top. It is clean in the base and slightly clayl in top. For its evaluation, it can be classified as clean sand.

Mud invasion and gas effects

The commercial package used for data processing corrects Rxo and Rt resistivities by invasion effects using special charts. It provides invasion diameter which was converted to invasion depth by:

$$DOI = \frac{Di - ID\ well}{2}$$

Tabla-3. Invasion diameter for well Sucumbios 5.

Depth (ft)	**ID** (in)	**Rxo**	**Ri**	**Rt**	**Di** (in)	**DOI** (in)	**CO_2 effect**
9013	6.28	6.0	692	605	20	7	Yes
9030	6.29	124	520	814	36	15	No
9060	6.22	61	165	458	55	24.5	No
9080	6.22	124	274	567	55	24.5	No

Table-4. Invasion diameter for well Caribe 7.

Depth (ft)	**ID (in)**	**Rxo**	**Ri**	**Rt**	**Di (in)**	**DOI (in)**	**CO_2 Effect**
7808	5.88	130	915	1113	23	8.5	Yes
7830	5.88	257	458	458	18	6	No
7890	5.92	152	1368	2856	35	14.5	No
7920	5.92	143	303	303	18	6	Si

Rxo, Ri, Rt, and Di were read at different depths in front of sandstone U1. The DOI and the gas effect demonstration ratios for four wells are given in Table-3 through 7. In the first two wells; mud filtrate invasion was deep enough that causes a significant reduction to gas effect. In the remaining two wells, with low invasion, the gas effect caused by CO_2 is evident.

Table-5. Invasion diameter for well San Antonio 14.

Depth (ft)	ID (in)	Rxo	Ri	Rt	Di (in)	DOI (in)	CO_2 Effect
7808	5.88	130	915	1113	23	8.5	Yes
7830	5.88	257	458	458	18	6	No
7890	5.92	152	1368	2856	35	14.5	No
7920	5.92	143	303	303	18	6	Si

Table-6. Invasion diameter for well Acaé 6.

Depth (ft)	ID (in)	Rxo	Ri	Rt	Di (in)	DOI (in)	CO_2 Effect
10544	10.45	437	343	353	20	5	Yes
10590	8.15	744	934	864	20	6	Yes
10620	8.33	409	471	451	20	6	Yes
10676	8.12	146	163	119	120	56	Yes
10720	8.20	54	53	43	120	56	Yes

As observed in Tables 3 through 6, in front of U1 sandstone, the DOI varies between6”and56”; intervals with DOI > 14” do not evidence gas effect (wells Sucumbíos 5 and Caribe 7). DOI < 12”, low or moderate DOI’s show gas effect.

Wiley and Patchett (1994) affirm that Invasion depths >18” reduce oreliminate the density and thermal neutron logs separation due to gas. The DOI difference is also reflected in the separation of virgin zone (Rt) and transition zone (Ri) resistivity logs. Wells Churuyaco 7 and Acaé 12D showing gas effect were included in the nine-well group for evaluating CO_2content although do not possess the three resistivity logs.

“Gas Effect” interpretation in density and neutron logs

The observed gas effect is the result of CO_2 concentration in the pore space fluid and does not obey the hydrocarbon gas presence since undersaturated reservoirs do not have free hydrocarbon gas. In the gas effect zones, the density and neutron log separation varies between 4 and 9 porosity units. The gas effect is observed by a left deviation of the density log while neutron log slightly -or nothing- deviates to the right. This pattern asymmetry due to gas effect suggests that porosity tools were affected at different levels by mud filtrate since DOI’s are different.

In front of the CO_2 sandstones, the apparent porosities registered by the three logs after clayly correction are related in the following way:

$$\emptyset_D > \emptyset_N > \emptyset_S$$

Since sonic logs measure primary porosity and density and neutron tools measure total porosity including secondary porosity, so it is expected that sonic porosity to be the least. The following logs correspond to wells Sucumbíos 5, San Antonio 14, Caribe 7 and Acaé 6, in the zone corresponding to U1 basal sandstone of the Caballos formation which the most promising reservoir which constituted by quartzic clean sandstone with thick grain and porosities between 12-15 % and permeabilities between 200 and 300 md.

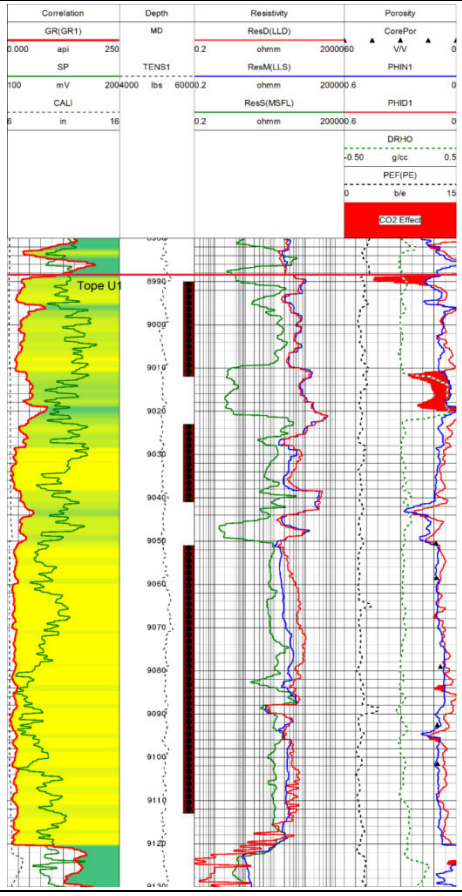

Figure-2. Logs of well Sucumbíos 5 in front of U1 sandstone.

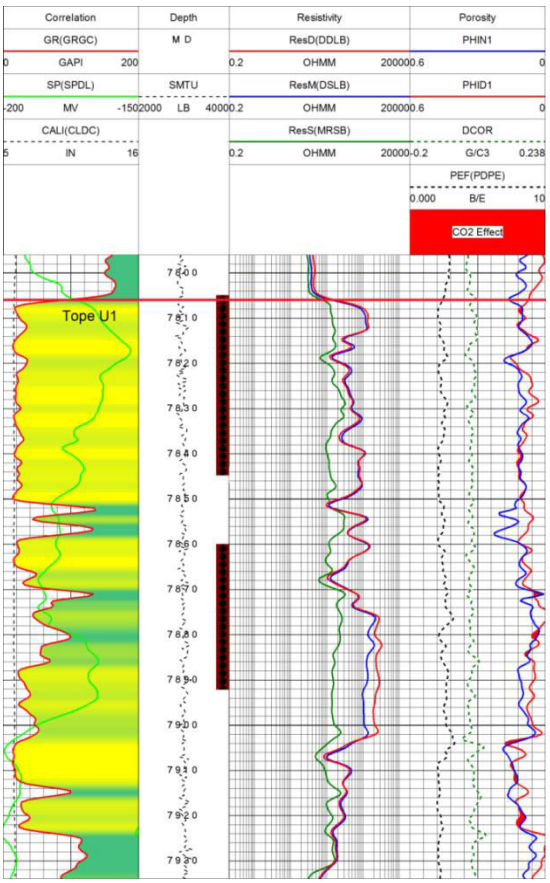

Figure-3. Logs of well Caribe 7 in front of U1 sandstone.

In well Caribe 7 the invasion was deep and eliminated almost the complete gas effect. In the 9010-9020ft interval a false gas effect is seen due to a bad contact of the density tool pad. In well San Antonio 14 invasion was deep and completely eliminated gas effect except in some specific zones. In well Acae-6 invasion was low and the CO_2 generated gas effect continuously, excepting the shale zones.

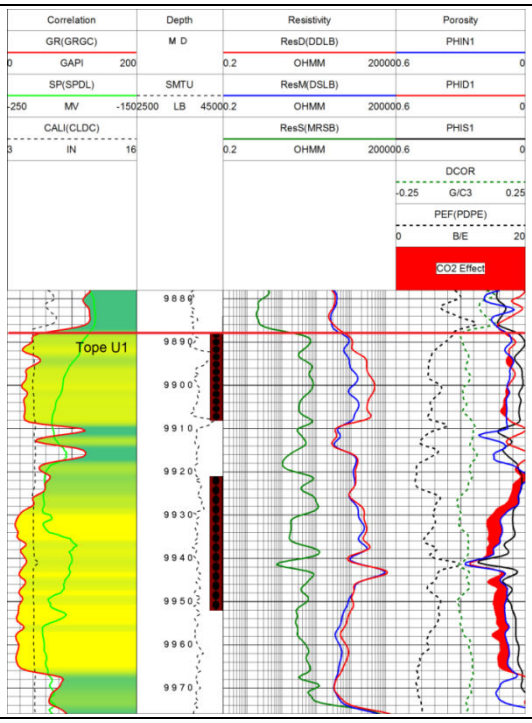

Figure-4. Logs of well San Antonio 14 in front of U1 sandstone.

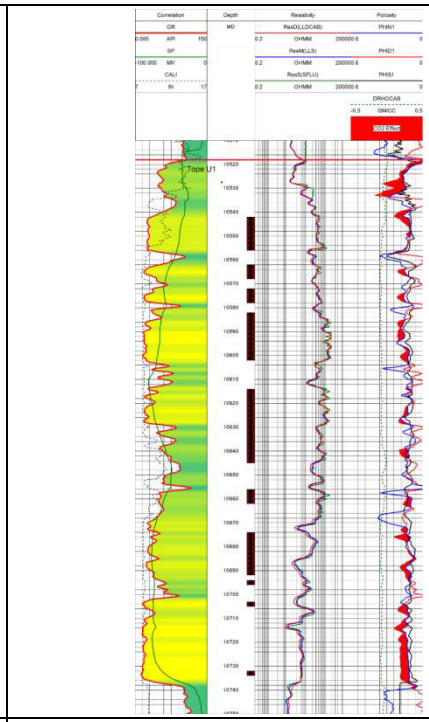

Figure-5. Logs of well Acaé 6 in front of U1 sandstone.

Clayly model

Clayly calculation was performed from the gamma ray log using Larionov method for ancient or consolidated rocks.

$$V_{sh} = 0.33 * (2^{2*I_{sh}} - 1)$$

Where,

$$I_{sh} = \frac{GRlog - GRmin}{GRmax - GRmin}$$

The estimated values matched well with DRX lab test son cores of well Sucumbíos 5. According to these results the clay volume is less than 10% and the most abundant mineral is kaolinite. In lower amounts are found: chlorite, hilite and quartz powder, Franco *et al*. (2012) as illustrated in Figure-6.

Matrix density identification

The information taken from the well head logs indicates that the dominant matrix in Caballos formation corresponds to sandstone; then, a 2.65 g/cc density and 55,5 $\mu s/ft$ are used to estimate porosities. The photoelectric log (Pe) in front of the sandstone reads a value of 1.8 b/e that confirms that the reservoir rock is, in fact, a sandstone. In well Churuyaco 7 this log provided a higher value due to barite used in the drilling mud.

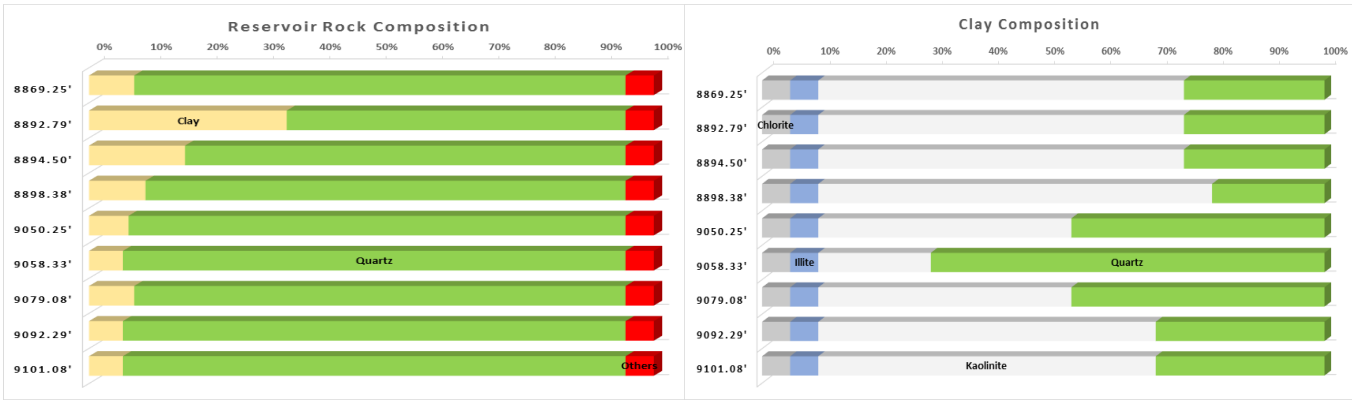

Figure-6. Matrix and clayly mineral composition of U1 Sandstone in well Sucumbíos 5. Taken from Franco *et al*. (2012).

Porosity model

Correction to neutron, density and sonic logs were applied by shale effect according to the following expressions proposed by Bassiouni (1994):

$$\emptyset'_N = \emptyset_N - Vshl * \emptyset_{Nshl}$$
$$\emptyset'_D = \emptyset_D - Vshl * \emptyset_{Dshl}$$
$$\emptyset'_S = \emptyset_S - Vshl * \emptyset_{Sshl}$$

Porosities from cores and well Sucumbíos 5 logs were compared as reported in Table-7. Values are fairly close. There is a need of determining true porosity from well logs since core information from other wells in unavailable. The true porosity ($\emptyset_T$) in reservoir rocks saturated with gas or with a fluid of lower density than mud filtrate is conventionally estimated Gaymard equation.

$$\emptyset_T = \sqrt{\frac{\emptyset_N^2 + \emptyset_D^2}{2}}$$

However, other researchers, among them Ijasan (2013), state that porosities calculated from Gaymard equation especially in clean gas formations are very approximated and proposed different methodologies to estimate more accurate the true porosity from density and neutron logs. In this study, a direct and easy method proposed by Das Gupta (1997) to estimate true porosity,

$$\emptyset_T = \frac{2}{3}\emptyset_D + \frac{1}{3}\emptyset_N$$

Table-7. Porosities of Well Sucumbíos 5.

Depth (ft)	$\emptyset_{\mathbf{Core}}$	$\emptyset_{\mathbf{D}}$ (%)	$\emptyset_{\mathbf{N}}$ (%)	$\emptyset_{\mathbf{S}}$ (%)	$\emptyset_{\mathbf{NMR}}$ (%)
9050.50	10.8	12.4	13.9	11.5	5.0
9058.50	10.8	9.0	9.73	7.2	10.5
9079.08	8.4	6.8	6.7	6.0	6.1
9092.50	10.2	4.0	8.2	9.6	7.0
9101.42	10.0	6.6	11.4	9.1	8.0

It is considered that this model provides better results under moderate invasion conditions since it takes into account that neutron and density tools are unequally affected by mud filtrate since DOI is different.

Water saturation model

Archie's equation was used for water saturation calculation using a = 1 m = 1.93, and n = 1.79 for all wells.

$$S_{WA} = \left(\frac{a}{\emptyset^m} * \frac{R_W}{R_t}\right)^{\frac{1}{n}}$$

Other water saturation models were considered since not all the Caballos formation sandstones are as clean as unit U1 and formation water salinity covers a wide range. Simandoux modified model produces good results in shaly sands saturated with salt water:

$$S_{WMS} = \left(\left(\frac{V_{sh}}{R_{sh}}\right)^2 + \frac{4{\emptyset_e}^m R_t}{aR_W * (1 - V_{sh})} - \frac{V_{sh}}{R_{sh}}\right)^{\frac{1}{2}} * \frac{aR_w * (1 - V_{sh})}{2{\emptyset_e}^m}$$

The Indonesia modelproduces good results in sands saturated with sweet water.

$$S_{WI} = \sqrt{\frac{1}{R_t}} * \frac{\sqrt{R_{sh}}}{(V_{sh})^{(1-0.5*V_{sh})}} + \sqrt{\frac{{\emptyset_e}^m}{aR_W}}$$

Table-8 shows saturation values for U1 sandstone obtained from Archie, Simandouxand Indonesia models.

It was concluded that water saturation by Archie's method is the most optimistic. Simandouxand Indonesia model estimate similar Swvalues. Simandoux method was chosen for estimation of water saturation in the interpretation model.

Comparison of water saturation with production data

Tabla-9 allows comparing water saturation estimated from Simandouxmethod and water cut according to recent production history for each studied well. Sw for wells in Caribe field correlates well with water cut presented in the year 2013 production potential estimate. In the remaining wells the observed differences suggest that water saturation for those wells has increased during the well productive life.

Table-8. Sw summary calculated by each model.

Well	Rw	Rt	SwA	SwMS	SwI
Sucumbíos 5	0.134	374.06	16.60	19.54	19.73
Quriyana 1	0.185	239.55	26.96	27.88	28.87
Churuyaco 7	1.06	4551.87	11.33	15.13	15.39
San Antonio 14	0.25	2700.83	7.26	9.34	9.43
Caribe 5	1.55	3902.55	17.44	18.78	19.98
Caribe 7	2.24	1310.39	40.93	40.17	42.70
Acaé 12D	0.133	205.95	24.92	28.71	28.80
Acaé 6	0.12	539.36	13.35	13.41	14.88
Loro 7A	0.569	1034.39	30.28	27.04	30.80

Table-9. Saturation and water cut for the studied wells.

Pozo	SwMS	% Water cut
Sucumbíos 5	19.54	7.5
Quriyana 1	27.88	60
Churuyaco 7	15.13	60.7
San Antonio 14	9.34	50
Caribe 5	18.78	12
Caribe 7	40.17	30
Acaé 12D	28.71	-
Acaé 6	13.41	80
Loro 7A	27.04	73

Estimation of CO_2 saturation

If oil chemical composition shows high amounts of non-hydrocarbon components, there is a need of quantifying in the reserve estimation process to avoid overestimating hydrocarbon net volume. The existing CO_2in the reservoirs under study lead to quantify the volumetric ratio between $CO_2$and initial reservoir fluid. Two methods are proposed for the determination of CO_2saturation from PVT analysis and open hole logs.

Method-1. From PVT analysis

This is more accurate for the determination of CO_2Saturation. It was applied to Acaé 2, Quriyana 1 and Sucumbíos 5 wells. It starts from the fluid composition obtained from PVT analysis, preferably from bottom sampling which are more representative that surface recombination. The methodology covers the following steps:

1) Find the total moles for an arbitrary reservoir fluid:

$$nt = \frac{P * Vt}{Z * R * T}$$

2) ObtainCO_2 moles from:

$$n_{CO2} = Z_{CO2} * nt$$

3) Find the equivalent mass of CO_2moles:

$$m_{CO2} = n_{CO2} * MW_{CO2}$$

4) Using the reservoir-condition density finds the volume occupied by the CO_2mass:

$$V_{CO2} = \frac{m_{CO2}}{\rho_{CO2}}$$

5) Find the volume fraction of CO_2in crude oil from the following expression:

$$f_{CO2} = \frac{V_{CO2}}{V_t}$$

6) CO_2saturation is calculated from:

$$S_{CO2} = f_{CO2} * (1 - Sw)$$

Z compressibility factor was provided by a phase-behavior simulator. CO_2density was found with Ouyang (2011) correlation. Table-10 includes the CO_2saturations calculated from PVT analysis.

Table-10. CO_2 Saturations.

Well	CO_2 (% mol)	CO_2 (%Vol)	Sw (%)	S_{CO2} (%)
Sucumbíos 5	47.25	19.64	18	16.10
Quriyana 1	22.17	6.75	25	5.06
Acaé 2	0.51	0.16	25	0.12

Method-2. From Porosity Logs Superposition

Considering in CO_2 rich reservoirs that neutron porosity decreases with respect to true porosity since the neutron tool ignores the CO_2 volume, then, the difference between true and neutron porosities correspond to the volume occupied by CO_2. NMR porosity can be utilizedinstead of neutronporosity,

$$\emptyset_{CO2} = \emptyset_T - \emptyset_N$$
$$\emptyset_{CO2} = \emptyset_T - \emptyset_{NMR}$$

CO_2saturation is calculated bytaken the porosity occupied by CO_2divided by the rock true porosity estimated by Das Gupta method. Results for U1 sandstoneare reported in Table-11.

$$S_{CO2} = \frac{\emptyset_{CO2}}{\emptyset_T} * 100$$

Table-11. Summary of true porosities and CO_2 saturtions for U1 sandstone.

			True porosity			CO_2 Saturation		
			Dasgupta	Gaymard	Hilchie	Dasgupta	Gaymard	Hilchie
WELL	$\emptyset_D$ (%)	$\emptyset_N$ (%)	$\emptyset_T$ (%)	$\emptyset_T$ (%)	$\emptyset_T$ (%)	S_{CO2} (%)	S_{CO2} (%)	S_{CO2} (%)
Sucumbíos 5 *	9.79	6.49 **	8.69	8.41	9.22	24.29	22.20	26.20
Quriyana 1	10.70	8.70	10.04	9.76	10.01	13.34	10.91	12.54
Churuyaco 7 *	16.03	10.08	14.04	13.43	14.81	29.12	25.86	32.30
San Antonio 14	13.57	9.22	12.12	11.62	12.39	22.26	19.15	23.80
Caribe 5	10.73	8.22	9.89	9.58	10.01	17.85	15.17	15.85
Caribe 7	12.81	10.97	12.20	11.93	12.10	10.29	8.26	7.20
Acaé 12D	14.49	5.83	11.60	11.10	13.47	50.54	48.21	57.05
Acaé 6	17.91	11.86	15.90	15.21	18.33	25.62	22.29	34.71
Loro 7A	10.82	6.33	8.58	8.89	10.27	26.88	29.40	38.63

* CO_2saturation decreased by Deep filtrate invasion
** NMR porosity.

As observed in Table-11, the higher CO_2 concentration is found in wells: Acaé 12D (50.54%), Loro 7A (26.88%) and Acaé 6 (25.62%). The least CO_2concentration is found in wells: Caribe 7(10.29%), Quriyana 1 (13.34%) and Caribe 5 (17.85%). It is known from well Sucumbíos 5 that $CO_2$is high but the estimated concentration resulted decreased probably due to mud filtrate invasion.

CO_2saturations found by this method for wells Sucumbíos 5 and Quriyana 1 resulted to be higher than 8% than CO_2saturation found from PVT analysis. This difference may be due to PVT test reflects a local CO_2 saturationwhile saturations from logs separation correspondto an average of 7 porosity readings taken in each well at different depths in U1 sandstone.

In undersatured reservoir with CO_2 contain, the logs separation method provide the minimum or residual saturation which was not displaced by mud filtrate. However, using special drilling mud with very low or zero invasión, this method could provide CO_2 in the virgin zone.

ADVANTAGES OF THE PROPOSED METHOD

CONCLUSIONS

1. CO_2detection in reservoir is feasible by neutron and density logs superposition if mud invasion is low or moderate. This method detects the minimum or residual CO_2saturation which was not displaced by mud filtrate. In special drilling muds with low or null invasion, the estimated saturation by this method should be equal to the saturation of virgin zone. This method applies to undersaturated reservoirs constituted by clean or clayly sandstones in any formation (Caballos, Villetaor Pepino) if neutron and density logs are available. Neutron log can be replaced by NMR log.

2. Although, the proposed method is approximated as are the log measurements, it is continuous and allows the evaluation of all the reservoirs in Caballos, Villeta and Pepino formations in any field of the basin.

Nomenclature

a	Tortuositycoefficient
Di	Invasiondepth
DOI	Depth of investigation
ID	Internaldiameter
IR	Resistivityindex
I_{sh}	Shaleindex
F	Formation factor
GR_{min}	Minimum Gamma Ray
GR_{max}	MaximumGamma Ray
GR_{log}	InterestzoneGamma Ray
IH_L	Fluid hydrogenindex
IH_{ma}	Matrixhydrogenindex
IH_g	Gas hydrogenindex
IH_{mf}	Filtratehydrogenindex
m	Cementationexponent
n	Watersaturationexponent
Pb	Bubble-pointpressure
P_g	Gas pressure
PR	Reservorpressure
R_w	FormationwaterResistivity
R_{xo}	WhasedzoneResistivity
R_i	TransitionzoneResistivity
R_{sh}	Shaleresistivity
R_t	Virgen or true zone Resistivity
S	Saturation
S_{WA}	Watersaturationby Archie
S_{WMS}	WatersaturationbySimandoux
S_{WI}	Watersaturationby Indonesia
S_o	Oilsaturation
S_g	Gas saturation
S_{gxo}	Flushedzonesaturation
S_{CO2}	CO_2saturation
V_{sh}	Shalevolume
m	Cementationexponent
n	Watersaturationexponent

Greek

$\emptyset$	Porosity
$\emptyset_D$	Densityporosity
$\emptyset_N$	Neutronporosity
$\emptyset_N$	Sonic porosity
$\emptyset_{NMR}$	NMR porosity
$\Delta\emptyset_{exc}$	Cave effectcorrection
Δt_{mf}	Filtratetransient time
Δt_{ma}	Matrixtransient time
Δt_o	Oiltransient time
Δt_g	Gas transient time
Δt_c	Compressional wave transient time
$\emptyset'_N$	Neutron porosity corrected by shale
$\emptyset'_D$	Density porosity corrected by shale
$\emptyset_T$	True porosity
ρ_b	Total orbulkdensity
ρ_f	Fluid density
ρ_{ma}	Matrixdensity

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