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EFFECT OF HIGH CO_2 CONTENT ON FORMATION DAMAGE OF OIL FIELDS: A FIELD CASE IN A SOUTH WESTERN COLOMBIAN FIELD

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ABSTRACT

Such factors as fines migration, mud invasion, high gas phase saturation, organic and inorganic deposition and bacterial growing are among the causes of formation damage. Reservoirs with high CO_2 content present a particular thermodynamic behavior leading to increase formation damage by both organic and inorganic deposition. This work deals with a field case in a Colombian field in which CO_2 content is very high. CO_2 content increases asphaltene destabilization and alters wettability which leads to a severe reduction of the near-wellbore permeability causing a tremendous loss of the well potential. A thermodynamic evaluation of fluid samples coming from this reservoir was analyzed and results for a single well are presented.

Keywords: high CO_2 content, oil fields, skin factor, asphaltene deposition, mixture stability.

1. INTRODUCTION

Organic material deposition is one of the most common and difficult problems presented in the oil production processes of the hydrocarbon industry. Precipitation takes place because of changes in both chemical composition and temperature-pressure environment provide conditions for asphaltenes and paraffins to precipitate out of the carrying fluid. This leads to such problems as plugging which causes reduction in the area available for fluid flow; then, decreasing of the production rate is attained. Leontaritis and Mansoori (1988) presented a collection of field cases with asphaltene problems during primary production. The amount of asphaltenes itself is not the problem, but asphaltene precipitation causes a great concern. Extreme cases include the crude of the Hassi Messaoud field in Algeria which contains about 0.15 % wt of asphaltenes.

In some Colombian fields, the high CO_2 content associated to the produced fluids (crude-water-gas) is not caused by CO_2 injection. In the field case treated in this study, the originally associated CO_2 constitutes 88.75 % of molar composition of the associated gas and 47.26 % molar composition of the hydrocarbon fluids.

Due to the high operational costs involved by the above-mentioned problems presented in the oil industry, many authors have addressed their researches to analyze and understand the behavior of paraffins and asphaltenes to be able to generate predictive models to perform precipitation predictions. It is required to account with an accurate predictive model, since it allows the performance of operations to avoid or mitigate the precipitation conditions.

Asphaltene precipitation in the porous media causes pore-throat plugging which alters rock's petrophysical properties decreasing both rock porosity and permeability and increasing progressively the skin factor in the near-wellbore zone affecting seriously the well potential; therefore, it is so important that the engineer count on a prediction model of the mention depositional behavior for oil fields having asphaltene problems so they help to anticipate the problem so the preventive actions may be undertaken. This allows to optimize and reduce the economic impact.

2. WELL, ROCK AND FLUID INFORMATION

The studied well, Well A, was drilled in a faulted anticline completed at a depth of 9242 ft (TVD: 9006 ft) in February 23rd, 2010. The well is deviated and was hydraulically fractured just before production initiated. At the same time the well was successfully treated for removing organic deposition and fine migration control. The initial production was 800 STB/D with 4 % water cut. Its production history is summarized in Figures 1, 2 and 3. A PVT report was conducted on January 13 with the purpose of assessing the fluids' thermodynamic behavior. Figure-4 provides a total composition of the recombined fluid and Figure-5 presents the thermodynamic behavior of liquid-vapor equilibrium for the fluid of Well A. Other relevant information related to the test is given below:

GOR: 515.9 SCF/STB
Sample type: Recombined
CO_2 content : 47.2582 % Mol
Bubble-point pressure, P_b: 1577 psia
Reservoir temperature: 200 °F
Initial reservoir pressure, Pi: 3680 psia
Live oil density: 35.5°API

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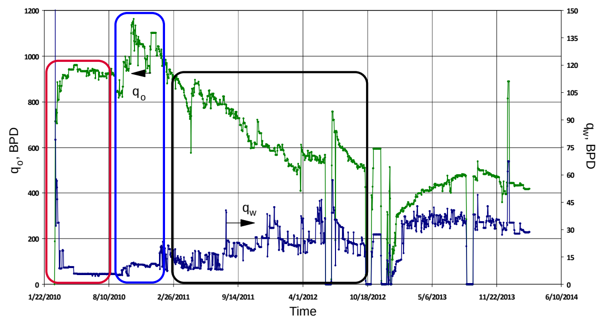

Figure-1. Oil and water production of Well A.

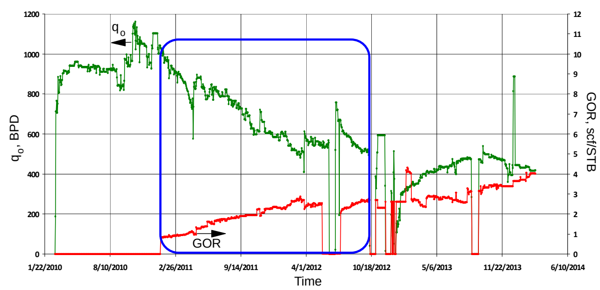

Figura-2. Oil production and GOR for Well A.

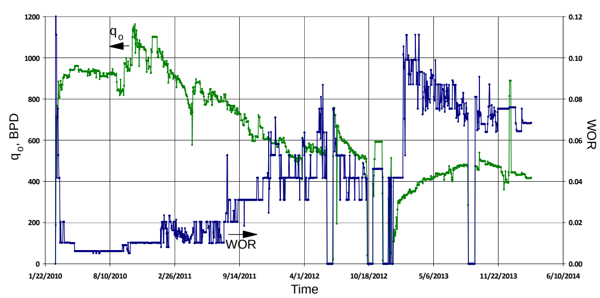

Figure-3. Oil production history and WOR for Well A.

3. ASPHALTENE STABILITY

As observed in the PVT analysis, CO_2 content is so high. This generates such several particular behaviors in the rock-fluid system as swelling, viscosity reduction, interfacial tension reduction, residual oil saturation reduction, wettability changes, asphaltene precipitation, and soluble salt formation that acts as emulsion stabilizer. CO_2 dissolved in the formation water reacts with the rock and creates fine migration. Some other analyses at a temperature of 200 °F are:

Oil viscosity = 1.25 cp
Emulsion viscosity = 681.8 cp
Water viscosity = 0.309 cp

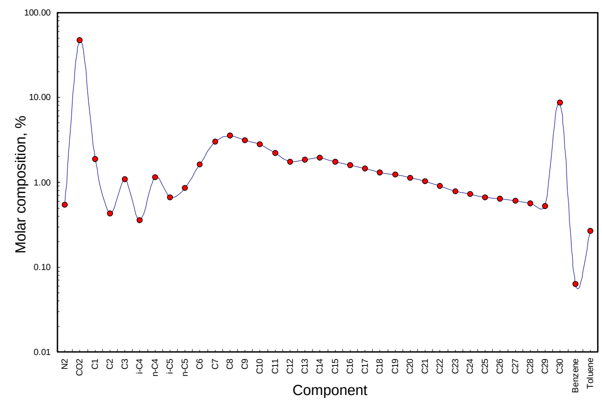

Figure-4. Total composition of the recombined fluid.

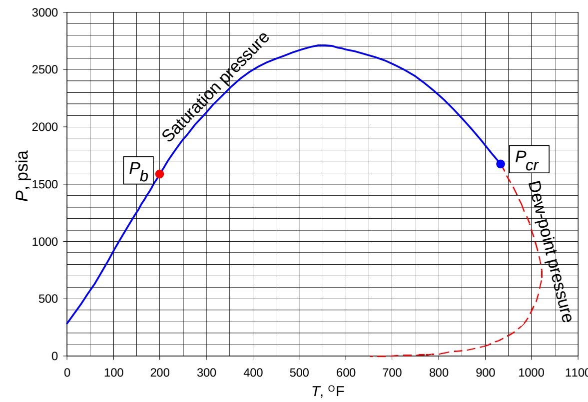

Figure-5. P-T diagram for fluid of Well A, after Patio and Gutierrez (2013).

The sampled fluid presents a very strong and stable normal emulsion. This aspect is very important when analyzing formation damage since emulsion blocking has to be taken into account.

The SARA analysis for Well A as reported in March 07, 2014:

Saturated	70.469 %
Aromatic	9.507 %
Resins	13.464 %
Asphaltenes	6.560 %

A high content of saturated hydrocarbons is noticeable. This represents an unfavorable condition for asphaltene stability. This last parameter was evaluated using the methods presented by Leontaritis (R/A) - Leontaritis (1989)- colloidal instability index (CII), - Hirschberg *et al.* (1984)- Stankiewicz - Stankiewicz *et al.* (2002)- and stability cross plot (SCP)- Medina and Bonilla (2010).

Figure-6 provides stability results according to Leontaritis' criterion. It can be observed that Well A is under instability condition since R/A = 2.05. This criterion indicates that there is not enough amounts of resins for

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asphaltene stabilization in the crude for Well A. The ranges of the plot are:

R/A > 3.0	Steady state
2.0 < R/A < 3.0	Meta-steady state
R/A < 2.0	Unsteady state

The second applied criterion is the colloidal instability index (CII) which is used to measure asphaltene instability in crudes. It is defined by:

$$CII = \frac{\text{Saturates+Asphaltenes}}{\text{Resins+Aromatics}}$$

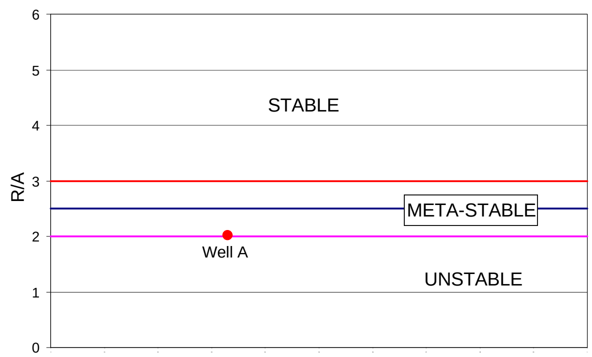

Figure-6. Stability analysis by Leontaritis' criterion for Well A.

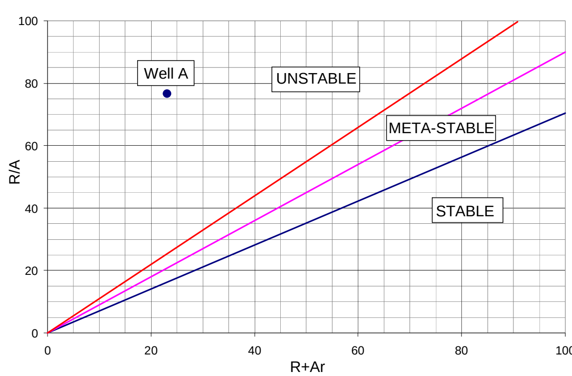

Figure-7. Stability analysis by CII criterion for Well A.

Figure-7 contains the results from applying CII; it can be seen that the crude from Well A is unstable with CII = 3.35.
The ranges in Figure-7 are:

CII > 1.1	Unsteady state
0.7 < CII < 1.1	Meta-steady state
CII < 0.7	Steady state

The CII value is strongly affected by the high saturated content in the simple, the low concentration of aromatics and the low resin/asphaltene ratio.

The third method of analyzing asphaltene stability is the Stankiewicz Plot. This correlates saturated and asphaltene. Figure-8 presents results of the application of this criterion which provides instability condition resulting from the effect of the high amount of saturated and the high asphaltene/resin ratio.

The last method for analyzing asphaltene stability is the stability cross plot (SCP) which is grouped in four plots. Each plot handles different relationships formed by combining the parameters obtained from SARA analysis. Analysis of Figures-9(a), 9(b), 9(c) and 9(d) allows concluding that asphaltene condition is unstable in all the plots.

De Boer *et al.* (1995) presented different criteria for distinguishing crudes with asphaltene deposition problems and those which do not. Field experiences indicate that asphaltenes are more stable in heavy oil with low asphaltene content. In general terms, De Boer (1995) found instability problems in light oils with high C1-C3 concentration, low C7+ content, high bubble-point pressure and high compressibility. These crudes generally have low asphaltene content.

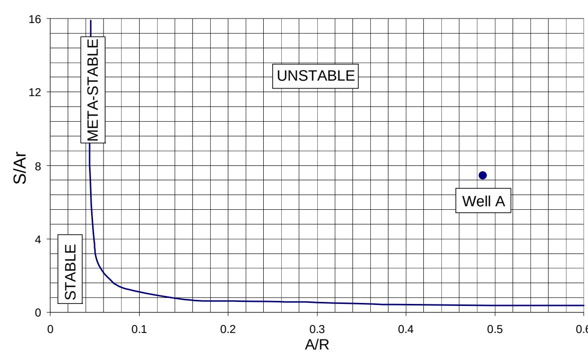

Figure-8. Stability analysis by Stankiewicz plot for Well A.

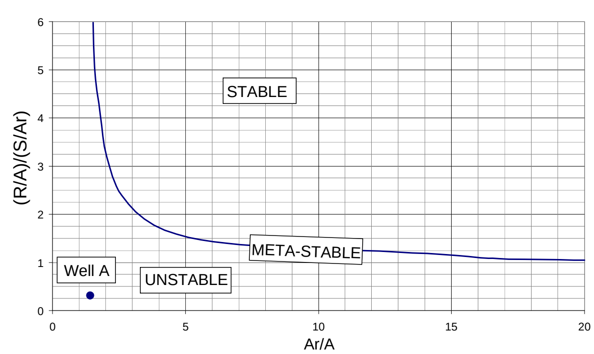

Figure-9(a). SCP1 stability analysis for Well A.

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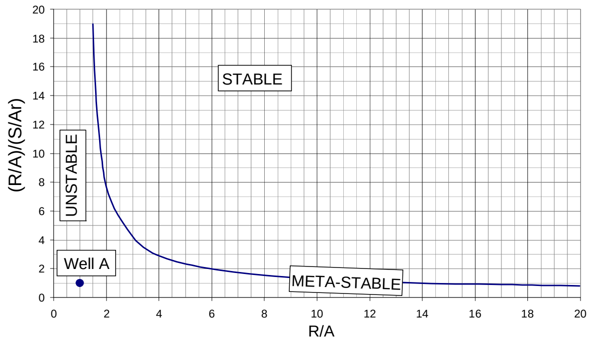

Figure-9(b). SCP2 stability analysis for Well A.

For the studied case, Well A was drilled in a reservoir having a light oil (35.5 °API), high concentration of light compounds which goes to the order of 51.19 % mol (N_2, CO_2, C1-C3), a C7+ content of 44.17 %, a bubble-point pressure of 1577 psia. These observations indicate that, possibly at reservoir conditions, asphaltenes are unstable. From the former analysis plus including the SARA analysis, we can tell:

- Asphaltenic compounds in the oil simple from Well A are unstable at reservoir conditions.
- According to the SARA analysis, crude oil from Well A has a high saturated content, low aromatic content and a resin/asphaltene ratio of about 2.0 %; these conditions are very appropriate for having unstable asphaltenic compounds.
- If we take into account that the crude samples were obtained at the wellhead, these fluids have lost light compound. The oil crude has a higher dissolved light compounds at reservoir conditions, which will destabilize, even more, the asphaltenic compounds. In other words, asphaltenes would be more unstable at reservoir conditions.
- Besides, Well A produces an oil crude with high CO_2 content which makes more severe the instability problem. Asphaltenes are more unstable in crudes with high dissolved CO_2 content.

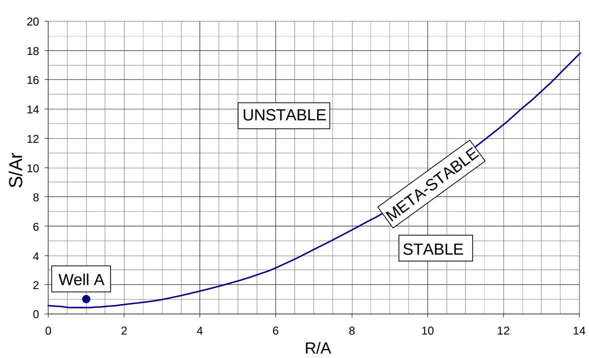

Figure-9(c). SCP3 stability analysis for Well A.

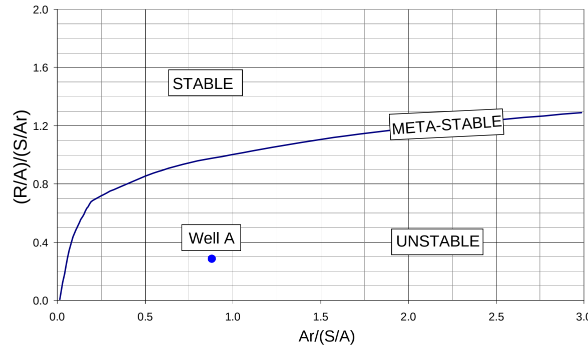

Figure-9(d). SCP4 stability analysis for Well A.

4. STABILITY EVALUATION OF PARAFFINS AND ASPHALTENES. ESTIMATION OF FORMATION DAMAGE

Since PVT and SARA analyses indicate asphaltene instability condition for the oil simple from Well A, the next step consists of evaluating the behavior of paraffinic compounds, determinate the precipitation envelope for asphaltene deposition (onset) and the formation damage caused by the deposition of these compounds.

4.1. Paraffin stability

For this purpose a computer tool was developed along this work for the evaluation of paraffin stability. From the point of view of stability of paraffinic compounds, using the de fluid composition (PVT) the equilibrium vapor-liquid-solid is simulated and the point at which wax appear is determined (WAP=Wax Appearance Point), T_{WAP} = 106.5 °F. The developed computer tool also simulates the wax deposition envelope (WDE) as shown in Figure-10.

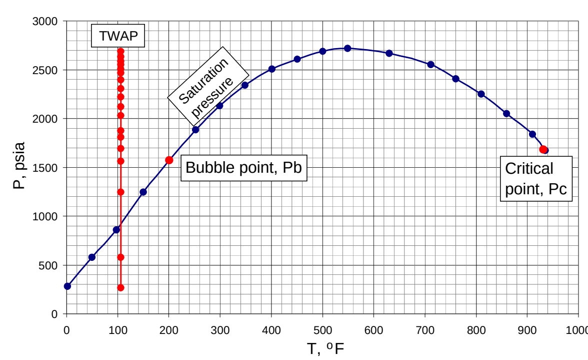

Figura-10. Wax deposition envelope (WDE) – Well A.

Paraffin deposition is not a serious problem in oil reservoirs since the system is isothermal. Paraffin deposition is a function of temperature. Temperature of Well A is 200 °F and is greater than the cloud point temperature which is 106.5 °F; then, paraffins will always be in liquid state.

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Now, if the effect of CO_2 on the solubility of wax-paraffin in crude oils is analyzed, from the solubility point of view, CO_2 is more or less equivalent to a 50-50 mixture of propane-Butane. Therefore, if CO_2 is in solution in crude, it could act as wax dissolvent. Since CO_2 is a non-polar fluid, its impact is much higher on asphaltene solubility than wax-paraffin, Leontaritis (2013). The above-mentioned analysis leads to conclude that paraffinic compounds in the oil crude from Well A are under stable condition, and paraffinic waxes remain in liquid phase as well.

4.2. Asphalthene stability

The same computer program mentioned before was used for the determination of the asphaltene precipitation envelope. For this purpose, it is required an experimental datum: amount of deposited asphaltene at a given pressure and temperature. Since, we do not count with the needed information and considering that the treated crude has high CO_2 concentration at reservoir conditions, a sensitivity analysis was carried out with variation of the deposition onset pressure. For this case, 3000 4000 and 5000 psi were employed, respectively, as verified in Figure-11.

A conservative case is the condition of P_{onset} = 3000 psia, with a máximum precipitation at the bubble-point pressure (1577 psia) of 0.0516 % wt, see Figure-12. Now, the impact of these organic compounds is evaluated when they are deposited in the reservoir with the consequent formation damage around the wellbore. For these conditions, if the well-flowing pressure, P_{wf}, is kept above P_{onset} there are no formation damage problems associated to asphaltene deposition. The effect in Well A is evaluated at the beginning of its productive life, as given below;

Date: April 11, 2010
Average reservoir pressure: 3308 psia
well-flowing pressure, P_{wf} = 2400 psia
Oil rate, q_o = 941 STB/D
P_{onset} = 3000 psia

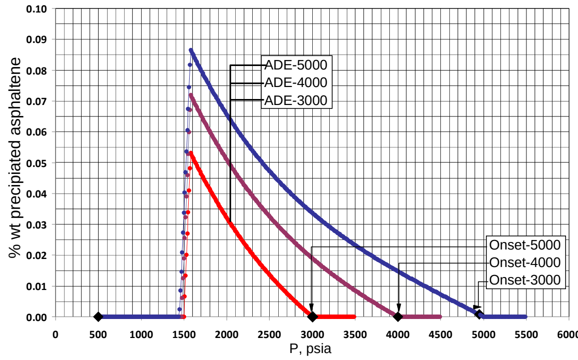

Figure-11. Asphaltene deposition envelopes - Well A.

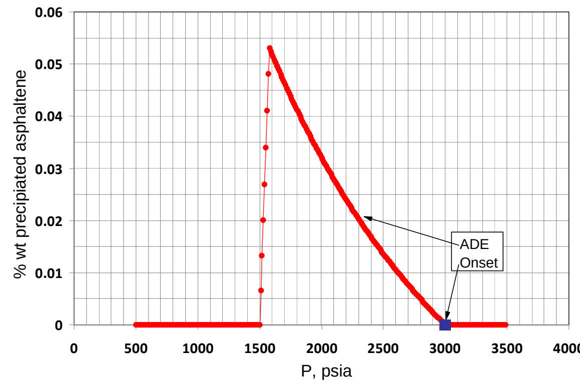

Figure-12. Asphaltene deposition envelope, Well A.

Figures-13 through 16 are presented as a result of modeling formation damage caused by asphaltene deposition. They contain the respective behaviors of pressure, porosity, permeability and skin factor with time. The skin radius is also estimated.

Since P_{wf} is lower than P_{onset}, a damage is growing around the wellbore until a stabilization of the altered zone reaches a radius, r_{asf}= 1.313 ft with a permeability of the altered zone, k_s = 2.11 md, a total stabilized skin s= 12.83. As indicated in Figures-14 and 15, there exist strong reductions in both porosity and permeability in the altered zone due to pore-throat plugging which leads to a high pressure drop, ΔP_s, to be able to maintain the production potential of Well A of 941 STB/D.

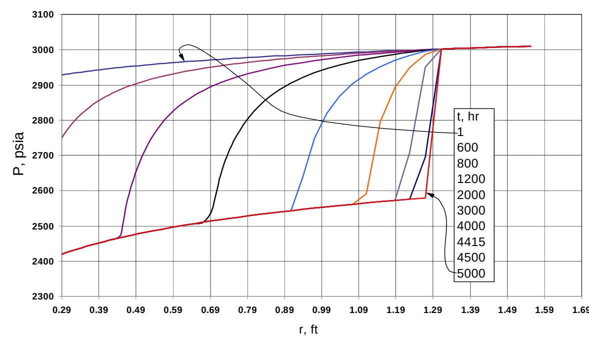

Figure-13. Pressure behavior, Well A.

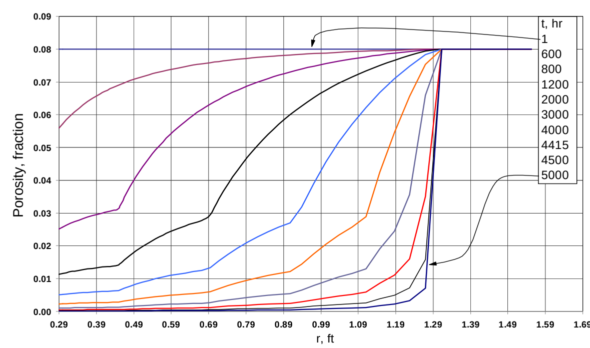

Figure-14. Porosity behavior, Well A.

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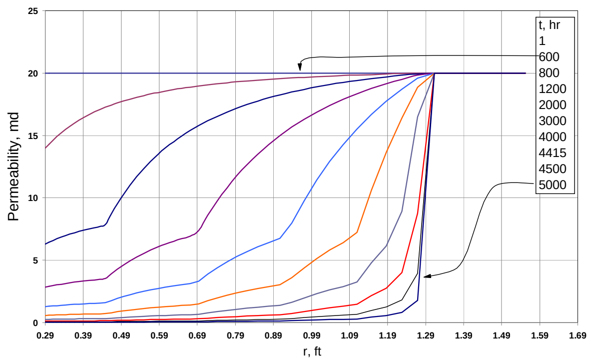

Figure-15. Permeability behavior, Well A.

Figure-1 contains the production history of Well A during its early life. Oil production is stable and water cut is low.

An estimative of both real and ideal pressure drops were achieved using rock and fluid properties for Well A at early lifetime, April 11, 2010, Pinzon-Torres, Charry, and Chavarro (2014),

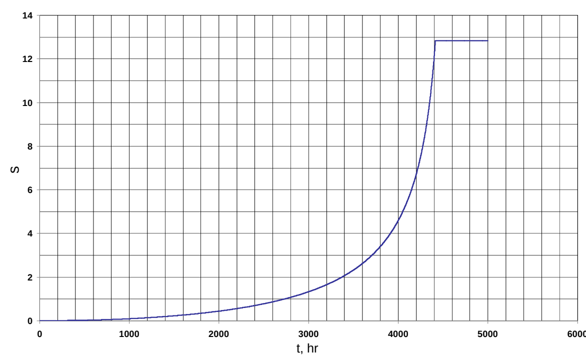

Figure-16. Skin factor behavior, Well A.

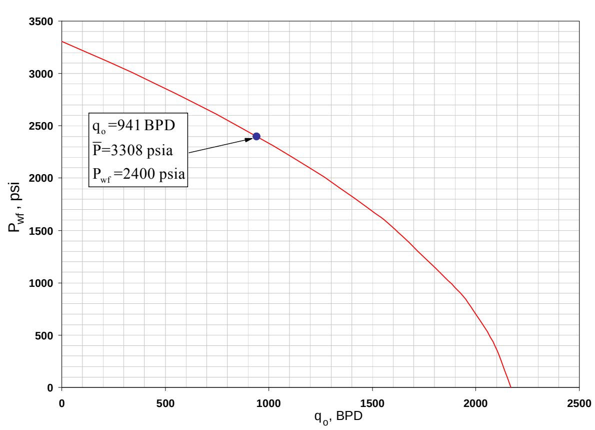

Figure-17. IPR for Well A @ April 11, 2010.

k = 43.8 md	ΔP_{ideal} = 190.0 Psi
r_e = 1500 ft	q_o = 941 STBD
h = 246 ft	ΔP_s = 718.0 Psi
r_w = 0.29 ft	q_w = 9.5 STBD
μ_o = 1.436 cp	J = 1.036 STBD/Psi
B_o = 1.2549 bb/STB	q_t = 950.5 STBD
$\overline{P}$ = 3308 psia	J_{ideal} = 4.945 STBD/Psi
ΔP_t = 908.0 psia	s = 32.3
P_{wf} = 2400 psia	

Figure-17 presents the IPR curve at the above conditions. The well has a high formation damage level with ΔP_s = 718.0 psi which corresponds to 79.1 % of the total pressure drop. The pressure drop due to asphaltene deposition was estimated to be 525 psi which reflects 57.8 % of the total pressure drop. The remaining 193 psi of pressure drop may be caused by either stimulation/completion fluid or fines migrations or emulsion which corresponds to 21.3% of the total pressure drop.

During the period between April to September 2010, Well A presented stabilized conditions with a smooth reduction in oil production and a constant water rate of 6 STB/D. We can observe such behavior in the IPR behavior given in Figure-18. There is no increase in water cut and skin factor increases probably due to fines migration or emulsion blocking. Well A presents a BSW of 2.6%, a normal water-in-oil emulsion (very strong) with fines production of 1.0%.

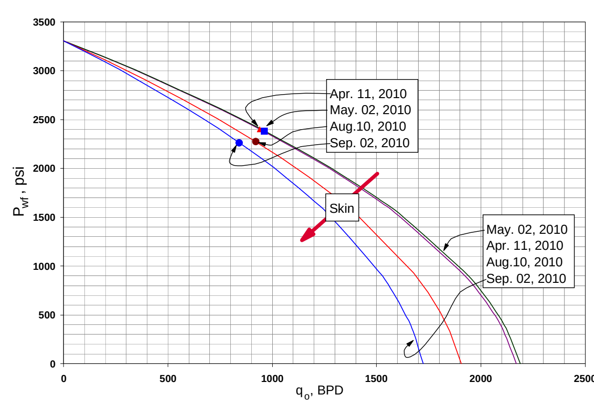

Figure-18. IPR for Well A, April-September, 2010.

Between September and December 2010, while trying to increase well productivity mechanical changes in the artificial lifting system (ESP) were applied; then, Well A initially responds with an increase in the oil rate of 1162 STB/D but water cut also increases with an average of 10 STB/D. Afterwards, well production declined at a rate of 7.5% per year, see Figure-1. If the IPR behavior is analyzed for this period, Figure-19, it can be observed that well skin factor increases; it may be due to water production which reduces oil relative permeability, and also, water reacts with the rock matrix generating fines migration and emulsion blocking.

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For the period between February/2011 to October/2012, besides occurring an increase in water production, the well-flowing pressure level went below the bubble-point pressure (P_b= 1577 psia); then, free gas is released in the reservoir and it starts flowing, Figure-2. If the IPR behavior form this period is studied, Figure-20, we can notice the existence of an accelerated increase in the well skin factor which may be caused by handling levels of well-flowing pressure between 1340 and 883 psia which are below the reservoir bubble-point pressure (P_b=1577 psia). Under these conditions the low oil productivity responds to such factors as: increase in water cut with consequent reduction of oil relative permeability, water reacting with rock matrix causing fines migration, formation plugging by asphaltene deposition and emulsion blocking.

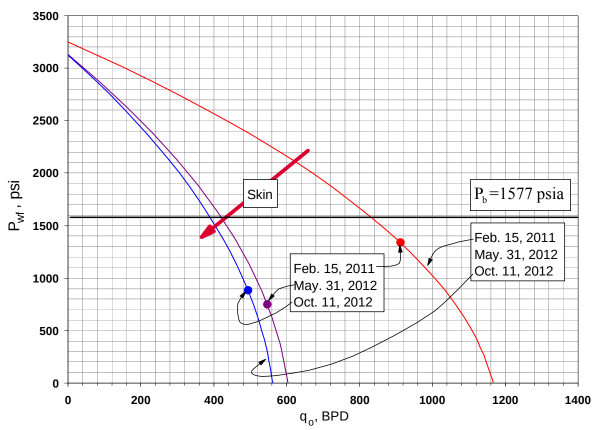

Figure-20. IPR for Well A, February/2011-October/2012.

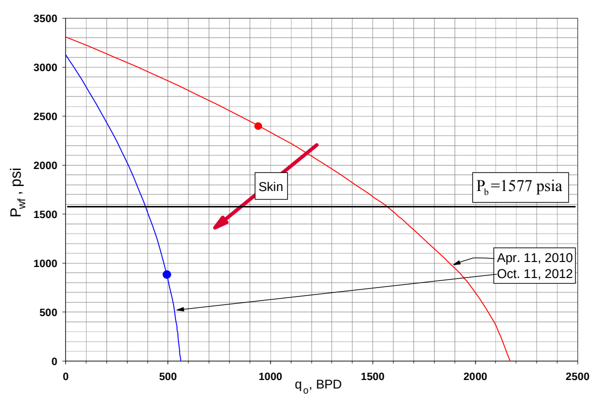

Figure-21. IPR for Well A, April/2010-October/2012.

The IPR behavior between April/2010 and October/2012 is given in Figure-21 where both the skin factor magnitude and the formation damage evolution during 2.5 years of productive life are observed. Well A presents a huge formation damage with ΔP_s = 2144 psi which represents 95.5 % of total pressure drop generating a skin factor in the near-wellbore zone which reached a stabilized radius of the altered zone r_{asf}= 273 ft, with an affected permeability k_s = 2.32 md, a stabilized total skin, s = 5.44. See Figures 22 to 25.

An asphaltene deposition formation damage was estimated to be 838 psi (37.3 % of the total pressure drop) and the remaining damage - oil permeability reduction due to an increment of water and gas production, besides, water reaction with matrix rock to generate fines migration and emulsion blocking - a value of 1306 psi (58.2 % of the total pressure drop).

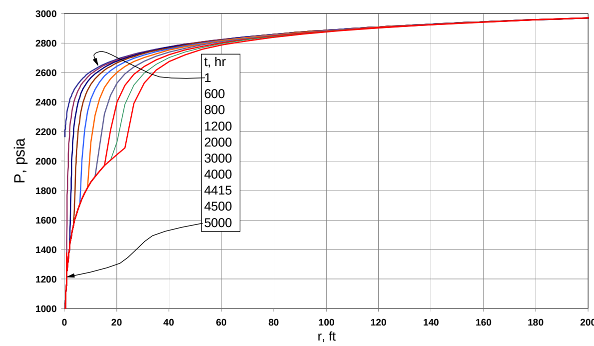

Figure-22. Well pressure behavior at Oct./12, Well A.

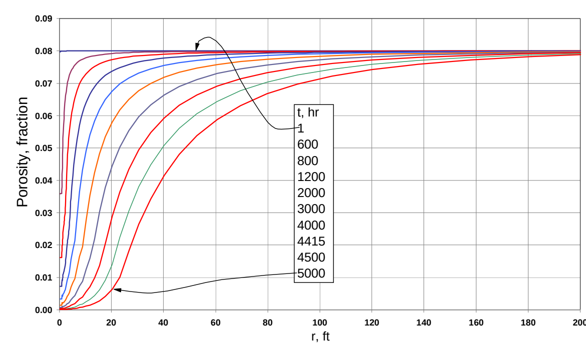

Figure-23. Near-wellbore porosity behavior at Oct./12, Well A.

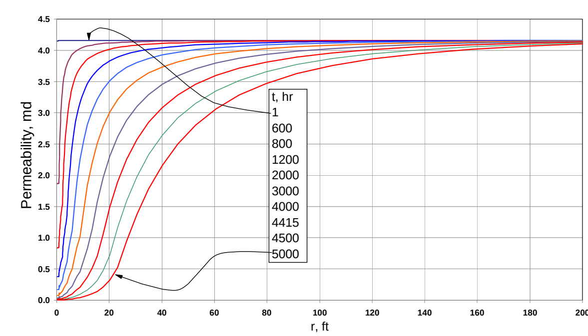

Figure-24. Near-wellbore permeability behavior at Oct./12, Well A.

In December 2012, Well A was treated with a matrix stimulation, Bahamon (2013), with the purpose of reducing the formation damage in Unit U1 of the Caballos formation. PLTs, Table-1, before and after the stimulation job proofs that the treatment effect based on EDTA for scale dissolution was effective so production level was kept.

The fluid contribution (oil-gas-water) comes from the intervals 9051 ft - 9113 ft and 9030 ft - 9040 ft which correspond to San U1. Intervals U2, U3 and U4 do not present any fluid contribution. This confirms the existence of a severe damage in Well A which may be caused by precipitation and deposition of asphaltenes in the pore throats, soap formation by naftenates, emulsion blocking, wettability changes, fines migration and inorganic scale deposition.

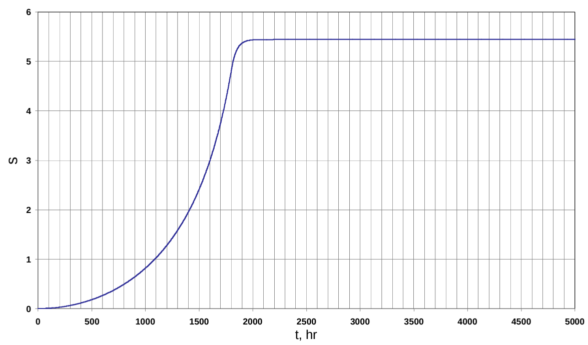

Figure-25. Skin factor behavior at Oct./12, Well A.

Table-1. Stimulation results.

	PLT PRE-Treatment (December 19/2012		
Interval, ft	**q_o, STB/D**	**q_w, STB/D**	**q_g, Mscf/D**
9030-9040	143.5	0	220
9051-9113	369.2	105.1	1871
Interval, ft	**PLT POST-Treatment (December 25/2012)**		
(9030-9040)	85	6	1238
(9051-9113)	435.4	102.4	1571

According to the study by Pinzon-Torres *et al.* (2014) can be concluded that calcite, barite and siderite have a high deposition potential at reservoir pressure and temperatura condictions, while there is no deposition potential halite, gypsum, basinite and anhydrite. Franco *et al.* (2012) determined that scale minerals are the second most important formation damage mechanism.

5. CONCLUSIONS

a) Crude from well A is unstable at reservoir conditions. It has a high saturated content, a low aromatic content and a resin/asphaltene ratio of 2%. These conditions are appropriate for instability of Asphaltenes. However, since the sample was taken at the wellhead, some of the light compounds were lost before sampling; then, higher instability would be given in the reservoir. Moreover, the western zone of the reservoir in which Well A is located has a high CO_2 content which makes the instability problem more severe. Asphaltenes in crude from Well A are under unstable conditions since the crude contains a light oil (35.5 °API), high concentration of light compounds (51.19 % molar of N2, CO_2, C1-C3), high content of C7 (44.17 %) and a bubble-point pressure of 1577 psia. The high CO_2 content (47.3%) in the fluids sample in Well A produces a particular thermodynamic behavior. It causes formation damage around the wellbore caused by asphaltene instability. Paraffins are always in liquid phase. The dissolved CO_2 in crude oil acts as a wax dissolvent.
b) Formation damage in Well A has several origins; then, it is needed to perform detail analysis and assessment of each skin pseudo-compound (organic deposits - asphaltenes and naftenates, scale deposits, emulsion blocking, fines migration, wettability changes, and oil relative permeability reduction) for an optimal stimulation treatment.
c) The fluid presents a very stable strong normal emulsion. These crudes with high CO_2 content, depending on naphtenic acid, have the tendency to form insoluble salts and calcium naftenate which generate plugging of the pore throat and also produce stable emulsions causing formation damage around the wellbore.
d) Formation water is an acid water with high amount dissolved CO_2, rich in carbonic acid. This water reacts and destabilizes clay and rock cementing material causing fines migration (re-deposition and bridging) causing formation damage by permeability reduction.
e) The dealt reservoir is very sensitive to water due to increase in water saturation causes a high reduction of the oil relative permeability. Besides, if precipitation of asphaltene and naftenates occurs then oil wettability increases with a consequent reduction of recovery factor due to an accelerated loss of well flow potential.

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Nomenclature

A	Asphaltene
ADE	Asphaltene deposition envelope
Ar	Aromatic
CII	Colloidal instability index
B	Volumetric factor, rb/STB
k	Permeability, md
GOR	Gas-oil ratio, scf/STB
h	Formation thickness, ft
J	Productivity index, bbl/psi
$\bar{P}$	Average reservoir pressure, psia
P	Pressure, psi
q	Flow aret, STB/D
t	Time, hr
r	Radius, ft
R	Resines
s	Skin factor

Greeks

Δ	Change, drop
ϕ	Porosity, fraction
μ	Viscosity, cp

Suffices

b	Bubble-poin
e	External
i	Initial
$ideal$	Ideal
o	Oil
$onset$	Deposition onset
s	Skin
t	Total
w	Well
wf	Well flowing