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Integrative approach for formation damage diagnosis in a Colombian brownfield: a comprehensive methodology

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Received: March 14th, 2024. Received in revised form: August 21st, 2024. Accepted: August 30th, 2024.

Abstract
Formation damage is the reduction of a well's productivity due to the alteration of the permeability of the subsurface rock, leading to economically inefficient operations. This research established a methodology to diagnose such damage, which is divided into: 1) Identification of operational problems, 2) Field sampling and analysis of geological and engineering data, 3) Adaptation of API standards for the study of fluid-fluid and rock-fluid interactions, 4) Identification of damage mechanisms and recommendations. This methodology was applied to two depleted wells in a brown oilfield with reduced productivity to address scale deposition and casing corrosion issues. Finally, the application of control and stimulation fluids must satisfy technical and environmental requirements, with the objective of inducing destabilization of the identified formation damage mechanisms.

Keywords: formation damage diagnosis; workover; rock-fluid interaction; fluid-fluid interaction; emulsion.

Enfoque integrador para el diagnóstico de daño de formación en un campo maduro colombiano: una metodología integral

Resumen
El daño de formación es la reducción de la productividad de un pozo debido a la alteración de la permeabilidad de la roca subsuperficial, conduciendo a operaciones económicamente ineficientes. Esta investigación estableció una metodología para diagnosticar dicho daño, la cual se divide en: 1) Identificación de los problemas operativos, 2) Toma de muestras de campo y análisis de datos geológicos e ingenieriles, 3) Adaptación de las normas API para el estudio de las interacciones fluido-fluido y roca-fluido, 4) Identificación de los mecanismos de daño y recomendaciones. Esta metodología se aplicó a dos pozos depletados en un yacimiento con baja productividad para abordar los problemas de deposición de incrustaciones y corrosión. Finalmente, la aplicación de fluidos de control y estimulación deben cumplir los requisitos técnicos y medioambientales, con el objetivo de inducir la desestabilización de los mecanismos de daño a la formación identificados.

Palabras clave: diagnóstico de daños en la formación; reacondicionamiento; interacción roca-fluido; interacción fluido-fluido; emulsión.

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1. Introduction

In relation to the energy demand levels of the year 2020, it is expected that global energy demand will escalate by 14% in the more moderate scenarios to as much as 53% in the more ambitious scenarios by the year 2050. Nevertheless, despite the incorporation of renewable energies, the energy matrix will remain reliant on fossil fuels such as coal, oil, and

How to cite: Rueda-Cortés, L.F., Torres-Cortecero, B.D., Jiménez-Caballero, M.A., Archer-Martínez, F.I., Gómez-Cepeda, E.A., León-Bermúdez, A.G., and Calvete-González, F.E., Integrative approach for formation damage diagnosis in a Colombian brownfield: a comprehensive methodology. DYNA, 91(233), pp. 120-129, July - September, 2024.

natural gas [1]. The rate of discovery of giant reservoirs reached its zenith in the late 1960s, among which approximately thirty account for half of the world's reserves, with the majority classified as brown fields. Consequently, the efficient development of these fields needs the application of economically practical techniques, alongside proper reservoir management [2]. Prevention and diagnosis of formation damage are imperative in well operations, as the economic viability of any project hinges upon the capability to produce hydrocarbon volumes at proper rates [3,4]. Technically defined, formation damage encompasses any process responsible for inducing localized alterations in the initial permeability characteristics, resulting in diminished performance of productive or injector wells [3-8], potentially leading to the complete shutdown of wells [9]. Formation damage can occur at any stage of a well's lifecycle, whether during drilling, completion, stimulation, or workover/service operations [4,8].

The comprehension of formation damage mechanisms and their origins holds paramount significance, as the formulation of strategies and remediation treatments for achieving the restoration of original or near-original well productivity hinges upon them. Various methodologies have been proposed for the assessment and determination of formation damage mechanisms affecting reservoir operability [10-12]. Nevertheless, no single test or tool exists that can comprehensively supply the necessary information for identifying and evaluating formation damage, underscoring the value of a systematic approach [5]. The rationale behind the paramount importance of the know & how of professionals conducting formation damage diagnosis.

In line with the context, the purpose of this study is to present a systematic methodology for the evaluation and diagnosis of formation damage within a brownfield situated in the Middle Magdalena Valley Basin, Colombia. The study aims to document the identified formation damage mechanisms after each intervention process in two designated wells, referred to as A and B, located within the study field. Furthermore, the study aims to supply recommendations for the remediation of the encountered formation damage in a brownfield.

2. Experimental section

Identification of causes behind well injection or production decline, known as formation damage diagnosis, requires a multidisciplinary approach [13], integrating geological and engineering information [7,10,14], as well as the incorporation of various knowledge fields, such as organic/inorganic chemistry, physicochemistry, colloid and interfacial sciences, chemical kinetics, mineralogy, diagenesis, and porous media flow [8].

Initially, formation damage was detected through a reduction in the water injection rate or oil well productivity index. Subsequently, well samples were collected, including crude oil, formation water, precipitates (carbonate, asphaltene, wax), injection water and fluids used in operations. Additionally, a pre-diagnosis was performed by analyzing available geological and engineering information, encompassing lithostratigraphy, reservoir structural configurations, facies analysis, diagenetic processes, reservoir fluid properties, petrophysical properties, drilling history, well service and intervention records, well logs, production history, and pressure analysis results. After that, laboratory tests were done, adapted from API-RP 42B and API-RP 13B standards, which were categorized into basic fluid and rock characterization, and the study of rock-fluid and fluid-fluid interactions [15,16]. Finally, the formation damage was diagnosed based on the pre-diagnosis analysis and laboratory results obtained in the earlier steps.

To comprehensively diagnose formation damage, it was essential to have well-specific information such as petrophysical data, geological context, mechanical conditions, intervention history, production history, and prior studies. Additionally, knowledge of rock mineralogy and basic characterization of reservoir and external fluids was vital. This collective information yields an overarching perspective on potential formation damage mechanisms [3,7,10,17].

2.1 Materials and reagents

For compatibility and emulsion tests, it was necessary to have samples of native reservoir fluids taken at the wellhead. In the absence of formation water, it was possible to synthesize it in the laboratory based on physicochemical characterization results, following standard methods for the examination of water and wastewater (methods: S.M 2540 D, S.M 2540 C, and S.M 2540 B).

2.2 Geological and engineering information

Formation damage assessment requires a systematic approach encompassing research, planning, and comprehensive analysis of all available information [3,18]. This information may encompass geological and engineering data such as lithostratigraphy, structural configurations, facies analysis, and diagenetic processes [7,10,18], reservoir fluid properties, petrophysical characteristics, well history, production records, well logs, and pressure analysis results [7,11,21,17]. In this study, geological, petrophysical, reservoir, and fluid characteristics data were compiled and interpreted. The well's life history, including mechanical status, drilling logs, completions, and intervention history, was also scrutinized.

2.3 API gravity

The API gravity of the examined crude oil samples was determined following the procedures outlined in the ASTM standard D287 – 22, employing the hydrometer method [19].

2.4 Micrograph acquisition

High-quality microscopic images were captured using a Nikon SMZ445 C-PSC stereoscope, enhancing the precision and detail of crude oil-in-water, water-in-crude, and mixed emulsions, as well as in exploring their destabilization dynamics.

2.5 Basic Sediment and Water measurement (BSW)

The estimation of water and sediment content was done using the centrifuge method by the procedure outlined in ASTM standard D4007–22 [20].

2.6 Viscosity

Viscosity measurements were assessed using a Brookfield DV2T® viscometer adapted to a temperature-controlled circulating bath with a propylene glycol solution. Each viscosity measurement used 50 mL of the sample to assess the temperature effect between 25 to 80 °C.

2.7 Cation Exchange Capacity (CEC)

The test procedure for determining the CEC was modified from the API RP 13B-1 2014 standard for field evaluation of water-based drilling fluids and is described as follows [21]: A 0.01 N methylene blue (MB) solution was prepared with deionized water. After that, 10 g of rock was mixed with 30 mL of deionized water. The rock suspension was then treated with methylene blue (MB) solution in 0.5 mL increments. Following each 0.5 mL addition of MB, the rock mixture underwent magnetic stirring for 1 minute and a small aliquot was extracted and deposited onto Fisher brand filter paper. The development of a persistent blue halo around the rock aggregate spot on the filter paper signified the displacement of cations in the double layer by MB, coating the entire surface.

The cation exchange capacity was calculated using eq. (1), where CEC is the cation exchange capacity, C_h is a volumetric constant equivalent to 100, V_m is the volume of methylene blue solution in mL, C_m is the concentration of methylene blue (0,01 meq/mL), and W_s is the weight of the rock sample used.

$$\mathrm{CEC} = \frac{C_h \times V_m \times C_m}{W_s} \tag{1}$$

2.8 X-ray diffraction

Rock samples were analyzed using powder X-ray diffraction (XRD) technique. For this purpose, the sample was homogeneously ground using a mortar and pestle until a grain size capable of passing through a 400-mesh sieve was achieved. Subsequently, the prepared sample was placed onto a sample holder and positioned in the Bruker D8 Advance® diffractometer.

The analysis covered a 2θ measurement range from 3.5° to 70°, with a sampling time of 0.6 s, using CuKα1 radiation. The resulting diffractogram was processed and analyzed using the DIFFRAC.EVA software with the 2022 database.

2.9 Visual wettability

API RP-42 outlines a qualitative visual wettability test designed for the rapid assessment of a fluid's inclination to wet a solid surface. The test used a sample extracted from the reservoir, introducing 10 mL of the clean reservoir sample into a 50 mL test solution. Following a half-hour contact period, the mixture underwent decantation, and a specific quantity was applied to two glass slides—one with formation water and the other with varsol filtered through silica gel.

The reservoir sample was then deposited onto the glass slides, and the relative dispersion of particles, or their propensity to form clusters in the aqueous and oil phases, was seen. The presence of dispersion showed that the sand was wetted by the medium, while the formation of clusters suggested non-wettability by the medium [15].

2.10 Fluid – fluid/rock compatibility

Compatibility test supplies a qualitative analysis of the interactions between fluids and rock formation, allowing the study of the generation or absence of precipitates, formation of new phases, emulsions, and undesired phenomena. During the test, different proportions of fluids (crude oil - production brine or crude oil - injection brine) were mixed in 100 mL Schott bottles at ratios of 20:80, 50:50, and 80:20. Additionally, solids such as formation sand, inorganic scales, and metal coupons were introduced. Once the compatibility mixtures were prepared, testing were conducted at the reservoir temperature of 68°C. The compatibility between fluid - fluid and rock - fluid was examined at initial time intervals of 0, 0.5, 1, 2, 4, 6, and 24 hours to identify phase changes. As the test is qualitative, the results indicate abnormal phases. A total of 17 experiments were carried out, including compatibility between injection water - synthetic formation brine, crude oil - formation water, crude oil - (synthetic formation brine + injection water) - sand, and crude oil - (synthetic formation brine + injection water + scale inhibitor, corrosion inhibitor) - sand - organic scales. The nomenclature to describe the results is as follows:

✔ Compatible
✖ Incompatible

2.11 Emulsion formation

In evaluating emulsion tendencies, a mixer was employed to combine crude oil, formation/production waters, and sand at 1,800 rpm for 60 s. The occurrence of any form of emulsion after 24 hours at room temperature is considered indicative of unfavorable performance.

3 Results and discussion

3.1 Depositional environments and lithostratigraphy

The study area is in the Middle Magdalena Valley Basin in Colombia, which covers an area of 30,000 km² [22]. It is situated in the northern part of Colombia along the middle portion of the valley, traversed by the Magdalena River, between the Central and Eastern Cordilleras of the Colombian Andes [22-24], spanning the departments of Boyacá, Santander, Cundinamarca, and Antioquia [23].

To the north, its boundary is defined by the presence of the Espíritu Santo fault system. In the northeastern direction, its limit is proved in relation to the Bucaramanga-Santa Marta fault system. To the southeast, its border is marked by the Bituima and La Salina fault systems. To the south, its extent is in proximity to the Girardot fold belt. Finally, on its western boundary, it contacts the Neogene deposits of the Serranía de San Lucas, as well as the basement of the Central Cordillera [22,24].

The uplift of the Central and Eastern Cordilleras gave rise to the opening where the Middle Magdalena Valley Basin was deposited during the Mesozoic [25]. The basin's filling is characterized by calcareous and siliciclastic sediments, resulting from the development of an epicontinental transgression process from the Triassic to the early Cenozoic. The Paleogene sequence is primarily composed of siliciclastic rocks deposited under continental conditions with some marine influence [22,24-26]. The stratigraphic sequence of the Middle Magdalena Valley Basin is shown in Fig. 1, supplying a visual representation of the geological layers.

3.2 Engineering data

In this study, the mechanisms of formation damage in two wells, named A and B, were investigated in a brown oil and gas producing field. The mechanical states of the wells, along with pressure logs and analyses, indicate the presence of gas in the upper production intervals and oil in the lower intervals, showing a pronounced depletion over time since the start of their production life. Fig. 2 provides a schematic representation of the mechanical states, highlighting the depths of the perforated intervals. The wells are characterized by gas production from the upper intervals through the annulus and oil production from the lower intervals through tubing with mechanical pumping, in a dual production scheme. The main difference between the evaluated wells lies in the depth of their completed production zones.

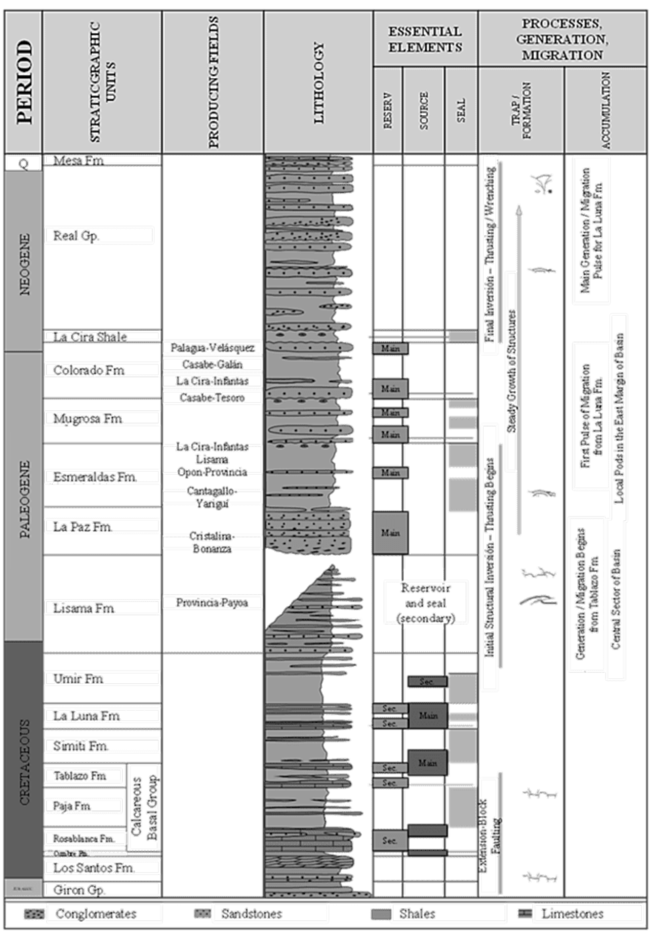

Figure 1. Stratigraphic Column of the Middle Magdalena Valley Basin.
Source: Authors.

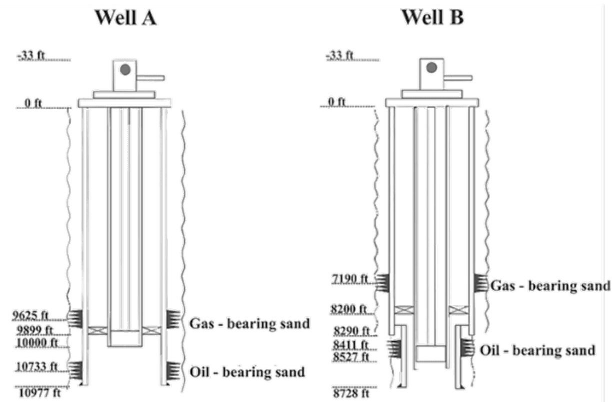

Figure 2. Schematic Representation of the Mechanical States of Wells A and B.
Source: Authors.

Table 1.
Relevant production data from wells A and B.

Well	ALS	API gravity (°)	Q_o (Bbl/ day)	W_{cut} (%)	Q_g (MSCF/ day)	Note
A	BP	21	12	60	N/A	High water cut
B	BP	23	5	20.5	620	Low water cut

Source: Authors.

Throughout their productive life, the wells have been intervened for cleaning or stimulation operations. However, they show adverse behaviors in terms of decreased productivity following the completion of interventions [27,28]. Similarly, at the laboratory level, damage to the formation at the pore scale caused by acid stimulation processes during well interventions has been identified.

Table 1 presents initial production data of the wells under evaluation, emphasizing that well A exhibits significantly higher water production, which has had a negative impact on gas extraction. As a proposed hypothesis, it could be set up that the fluids used in workover, control, and/or completion operations in the wells (such as production water and/or crude oil intended for sale) could be the cause of this impact.

3.3 Identification of pseudo damage following information analysis

Following the comprehensive analysis of data pertinent to the study field, encompassing geological interpretation, petrophysical properties, detailed drilling records, completion parameters, historical intervention records, earlier production patterns, and subsequent mechanical states, the correct identification of detrimental mechanisms that lead to the impairment of formation integrity was achieved.

3.4 Inorganic scales

Throughout the production cycle of the wells, and during conventional operational activities, the occurrence of organic deposits in the production tubing has been documented, with a significant presence of calcium carbonates. Different studies have reported that scale precipitation is one of the most common formation damage mechanisms during the production stage of wells [29]. The formation of carbonate scales is a direct function of factors that affect the thermodynamics, kinetics, and hydrodynamics of the environment, which can include changes in pressure, temperature, pH, concentration of calcium and bicarbonate ions, and ionic strength [12,30,31]. Fig. 3 displays the compositional characterization of ions present in the formation water, revealing a tendency for scaling ions, which may have been accelerated by the natural decline in reservoir pressure.

3.5 Organic scales

Detection of waxes and asphaltenes has been regularly documented, recorded in the historical records of interventions carried out in the wells. Similarly, during the evaluation of the previously conducted crude composition analyses, the asphaltic and paraffinic nature of these samples becomes clear. These elements are prone to precipitate and/or flocculate if destabilization processes occur, because of changes in pressure and temperature throughout the production history of the field, especially in wells where the upper gas sands are cooling the liquid stream within the well due to Joule-Thompson effect [32-34].

3.6 Emulsions

Emulsions can be generated due to incompatibilities between fluids present in the formation and exogenous fluids [5]. These emulsions can lead to permeability reduction by plugging pore throats [35]. The primary evidence lies in the reported BSW values in production records, which reflect heavily emulsified crudes with high water production. Additionally, the use of significant amounts of demulsifier in treatment schemes further supports this observation.

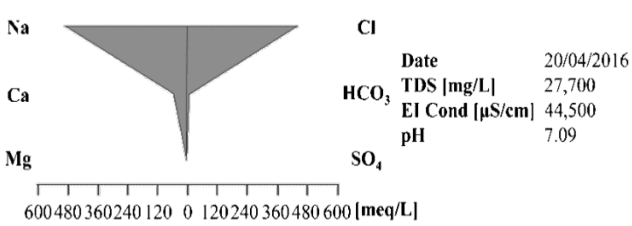

Figure 3. Compositional characterization of formation water ions.
Source: Authors.

Table 2.
Experimental values of °API and %BSW for the crude oils from wells A and B.

Well	API gravity (°)	BSW (%)
A	16.5	40
B	24.9	14

Source: Authors.

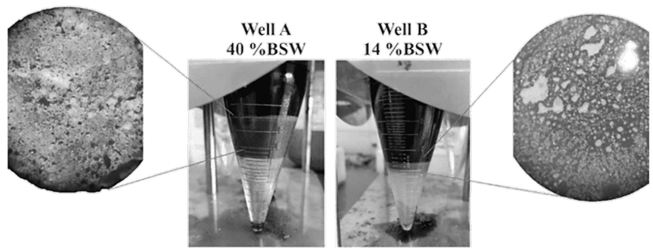

Figure 4. Micrographs of the emulsions, post-centrifuge method, for wells A and B.
Source: Authors.

3.7 Basic fluid characterization

The quantified values of API gravity and the percentage of water and sediment (%BSW) are presented in Table 2. These measurements align with the production data recorded for the wells. Undoubtedly, despite the similarity in the origin of the produced fluids, their nature differs. The crude oil from well A shows higher density, a phenomenon attributed to emulsification, in comparison to the crude oil from well B. Different authors reported that the density of emulsified crudes can increase by up to 28.75% [36,37].

To gather evidence of emulsion formation in each of the crude oils, micrographic images of the emulsified fluids were taken for analysis. The captured micrographs of both emulsions are shown in Fig. 4.

These images reveal a lower percentage of emulsified fluid for crude oil B, further confirming the disparity in emulsifying nature between the two studied crude oils. Both fluids show the formation of multiple emulsions of the crude-oil-water-crude type (O/W/W), which are characterized by a strong tendency towards stability.

3.8 Study of reactivity of present clays

In a preliminary phase, cation exchange capacity (CEC) tests were done on sand samples extracted from the gas-generating and oil-producing formations. These tests were done in two contexts: one with the inclusion of formation water and another with injection water. The results are

Table 3.
Results of CEC for ditch samples from the gas – bearing sand and oil – bearing sand.

Sample	Cation Exchange Capacity (CEC) [meq/100 g]	
	Presence of formation water	Presence of injection water*
Gas – bearing sand	12	10
Oil – bearing sand	10	8

* Note. Injection water refers to the water used to prepare control and stimulation fluids.
Source: Authors.

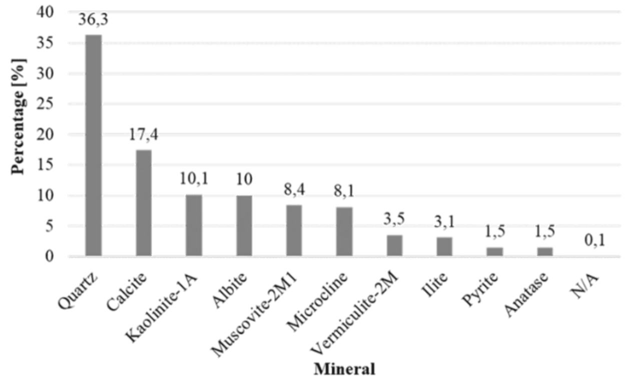

Figure 5. Quantitative characterization of minerals by XRD analysis in gas-producing formation core sample.
Source: Authors.

presented in Table 3, showing a low cation exchange capacity for both soils. Swelling tendency for soils with a cation exchange capacity of less than 20 meq/100 g is low [38]. Additionally, the results reveal a slightly higher degree of reactivity for the gas-producing formation.

Rock samples extracted from the gas-producing formation underwent X-ray diffraction (XRD) analysis, which is presented in Fig. 5. As observed, most of the present minerals show low reactivity or swelling tendency, except for vermiculite-2M and illite; however, their weight percentages were low, 3.50% and 3.10%, respectively.

Furthermore, minerals associated with fines migration are identified, such as quartz, kaolinite, illite, albite, microcline, and muscovite-2M1 [5,39-41]. Nevertheless, due to the presence of polar compounds in the crude oil, these clays demonstrate the ability to form "water-bridging" bonds, facilitating clay hydration [42]. This process may potentially lead to a pseudo-affectation of the formation.

3.9 Visual wettability

For this test, a sample of sand from the oil-producing formation was taken and brought into contact with formation water and injection water systems. All tests demonstrated a water-wet behavior, as reflected in Fig. 6.

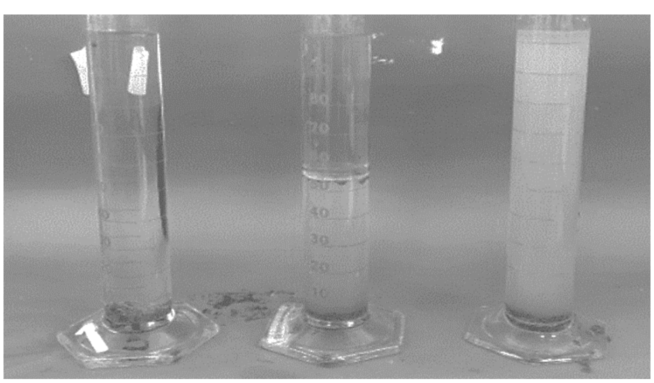
Figure 6. Visual wettability tests, with a test tube containing varsol on the left, a mixture of 50% varsol and 50% distilled water in the middle, and distilled water on the right.
Source: Authors.

Table 4.
Results of compatibility between injection water and synthetic brine.

Fluids	Mixture ratio		
	20:80	**50:50**	**80:20**
Injection water : synthetic brine	✔	✖	✖

Source: Authors.

3.10 Fluid – fluid/rock compatibility

In this test, the presence of emulsions, precipitates, detergency, and/or other adverse phenomena is evaluated. Table 4 shows the results of compatibility between injection water and synthetic brine (formation brine).

For the 20:80 proportion, the water is slightly turbid, indicating the presence of suspended particulate matter, while the coloration is opaque, denoting impurities. As the concentration of injection water is increased to 50% and 80%, it can be observed that a solubility limit has been reached and the suspended particulate matter precipitates, indicating incompatibility between the fluids.

Table 5 presents the compatibility results for the crude oils from wells A, B, and synthetic formation brine. For well A crude oil, regular compatibility is observed at any of the proportions. In the case of well B crude oil, only regular compatibility is seen between fluids at proportions of 20% crude: 80% synthetic brine and 50% crude: 50% synthetic brine.

For both crude oils at the mentioned concentrations, detergent action and adherence to internal surfaces are clear. Likewise, significant dehydration of the crude oils is observed, due to temperature variations during the test. In the case of well A crude oil, approximately 25% of previously emulsified water was released, while in well B crude oil, the release was approximately 10%.

The previous analysis was subjected to a more detailed examination, in which original crude oil samples and samples after compatibility were subjected to viscosity characterization. The resulting curves are depicted in Fig. 7, clearly illustrating how the dehydration of the crude oils led to a substantial reduction in viscosity.

Particularly noteworthy is the case of well A crude oil, where a significant 49% decrease in original viscosity was seen, highlighting the inherent flow restriction imposed by the natural emulsification of the crude oils. This finding reinforces the concept that hydrocarbon flow is inherently constrained.

Table 5.
Fluid-fluid compatibility tests for wells A and B; base matrix: crude oil with synthetic formation brine.

Fluids	Mixture ratio		
	20:80	**50:50**	**80:20**
Well A crude oil : synthetic brine	✔	✔	✔
Well B crude oil : synthetic brine	✔	✔	✖

Source: Authors.

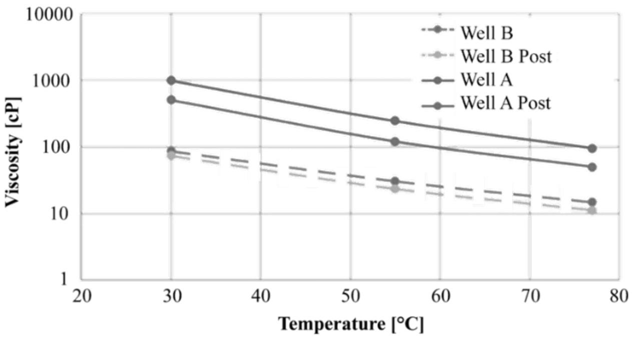

Figure 7. Viscosity curves of the crude oils from wells A and B before and after the fluid-fluid compatibility test.
Source: Authors.

Table 6.
Compatibility test results for fluid-rock for wells A and B.

Fluids	Mixture ratio		
	20:80	50:50	80:20
Well A crude oil + (injection water + synthetic brine) + sand	✖	✖	✖
Well B crude oil + (injection water + synthetic brine) + sand	✔	✖	✖

Source: Authors.

Table 6 presents the compatibility results for systems that include crude oil, injection water, synthetic formation brine, and formation sand. For the aqueous phase, a proportion of 80% injection water and 20% synthetic brine was used, and the compatibilities were performed with a base of 20%:80%, 50%:50%, and 80%:20% of crude oil and aqueous phase, respectively.

For Well A crude oil, incompatibilities across all specified proportions are existing. It is noteworthy that phenomena of adherence to the glass surface by the crude oil are observed, despite the turbidity, no suspended solids or impregnation of the sand by the crude oil are discerned. However, the formation of a fine tissue near the crude oil-water interface is notably presented in Fig. 8. This phenomenon stems from the incompatibility between the polar constituents within the crude oil and the adhesion of micrometer-sized particles found in the injection water and synthetic formation brine, manifesting as suspended solids.

Figure 8. Close-up view of the tissue formed at the interface.
Source: Authors.

Table 7.
Results of compatibility tests for 50% crude oil + 50% (injection water + corrosion inhibitor, scale inhibitor + synthetic brine) + carbonates + sand.

Fluids	Mixture ratio
	50:50
Well A crude oil + (injection water + corrosion inhibitor + inorganic scale inhibitor + synthetic brine) + carbonate scale + sand	✖
Well B crude oil + (injection water + corrosion inhibitor + inorganic scale inhibitor + synthetic brine) + carbonate scale + sand	✖

Source: Authors.

Recent studies by various researchers have characterized the interfacial rag layer formed between water and toluene, containing a fraction of interfacially active asphaltenes (IAA). This layer comprises asphaltenes and fine clays, collectively termed an interfacial membrane [43,44]. It is suggested that the cohesion of these systems arises from inorganic fines and clay material, which facilitate the formation of water bridges and localized hydrations, potentially involving cationic exchanges. Consequently, such interactions lead to flow restrictions within gas and/or crude layers during operations employing aqueous and/or oil-based fluids in wells.

For Well B crude oil, no incompatibilities are evident at 20%:80% concentration. However, at the 50%:50% ratio, there is a discernible emergence of the previously identified fine structure in the bottle tests. Additionally, at the 80%:20% ratio, identification of the aqueous phase in the bottle becomes impracticable.

Finally, Table 7 show compatibility results for bottles containing crude oil, synthetic brine, injection water, inhibitors, inorganic scales, and sand. The test reveals a clear incompatibility, with a visual worsening of the aqueous phase and the adherence of crude oil to the bottle walls.

An illustrative case arises when contrasting the well B crude oil against a blend comprising formation water, synthetic brine, injection water, corrosion inhibitors, scale inhibitors, sand, and carbonates. This comparison is exemplified in Fig. 9, which displays a notable O/W/O (oil-in-water-in-oil) emulsion, prominently stabilized by solid constituents.

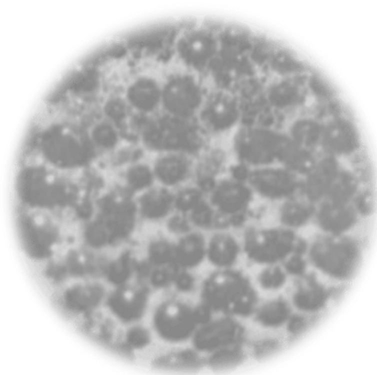

Figure 9. Micrograph of the emulsion formed in the system of crude oil B 50% + 50% (injection water + corrosion inhibitor, scale inhibitor + synthetic brine) + carbonates + sand.
Source: Authors.

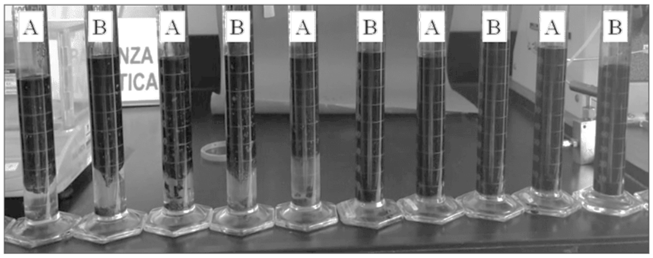

Figure 10. Emulsion bottle tests.
Source: Authors.

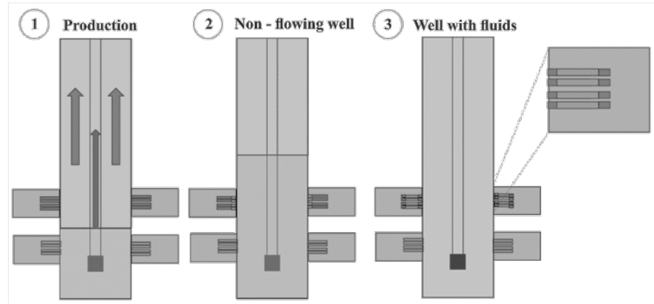

Figure 11. Diagram depicting the stages of interaction during well control.
Source: Authors.

3.11 Emulsion test

Emulsion tests were conducted using analogous systems established for evaluating crude oil's compatibility with formation brine, injection water, and varying proportions of injection water and synthetic brine (80%, 50%, and 20%), each incorporating sand. These systems underwent agitation in a shaker operating at 1800 rpm for around 1 minute. The results obtained from the 24-hour evaluations are depicted in Fig. 10.

The findings from the tests highlight the emulsions' remarkable stability and plugging efficacy, particularly evident under lower temperatures. At ambient room temperature (~25°C), there was no observed breakdown of the existing emulsion. For Well A crude oil, the tests revealed structures reminiscent of icebergs, underscoring the robust solid stabilization at the interface. Conversely, Well B crude oil exhibited significantly lower water content in the emulsion, displayed enhanced water retention capability. Notably, the interface remained imperceptible throughout the test duration, demonstrating continuous emulsion development.

3.12 Diagnosis

Once all the information and laboratory test results were compiled, a diagnosis of the damage to the formation in the wells under study was prepared. For this purpose, a comprehensive assessment of the conditions and events occurring in the well during each intervention or control was initiated. In this analysis, three essential phases were identified that encompass various interactions at the level of the perforations in the gas-producing areas of the formations:

1. During the production phase of the well, only the presence of gas is detected.
2. After the well is shut in, a rise in liquid level (either crude oil and/or formation water) to the gas perforations is seen, leading to the coexistence of gas, oil, and formation water.
3. Injected fluids are introduced, resulting in a final interaction between this fluid, oil, formation water, and gas.

The interplay of these factors is combined with the presence of various clay components, as identified in the studies, some of which are hydratable or migratory. This combination of factors leads to the manifestation of the observed phenomena in the results phase. These stages and their interactions are visually represented in Fig. 11.

The presence of asphaltic compounds in the crude oil, even without precipitation, triggers the impregnation of both matrix-bound and suspended minerals by the oil. This impregnation fosters cohesive forces surrounding water droplets, thereby stabilizing the O/W/O emulsions via the mechanism recognized as “interfacial membranes”. Moreover, this phenomenon is bolstered by the collaboration of inorganic fines and clay compounds, which establish water connections and prompt localized hydration reactions.

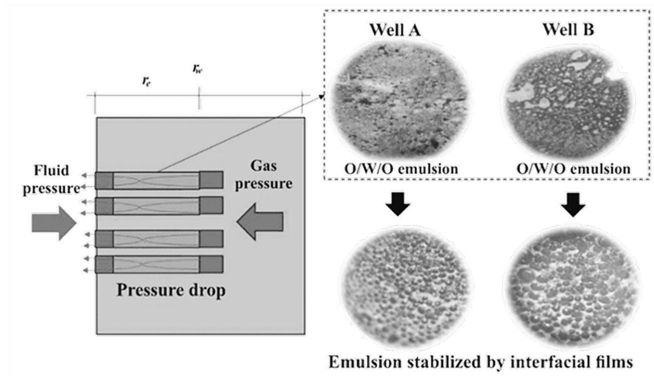

Figure 12. Diagram of the formation damage diagnosis in the wellbore.
Source: Authors.

This collective interplay of factors results in flow restrictions within gas and/or oil layers during fluid-based processes within wells, be it aqueous or oily. Fig. 12 delineates a schematic representation of the associated damage and its impact on producing formations.

4. Conclusions

The comprehensive working methodology presented here consists of four steps, beginning with the recognition of operational issues, the collection of samples and geological and engineering information to perform a pre-diagnosis, laboratory tests including basic fluid and rock characterization, fluid-fluid and rock-fluid interaction studies, and finally, relating the pre-diagnosis results to those obtained in the laboratory to determine associated formation damage mechanisms and suggest solutions.

The presented methodology allowed the identification of the presence of organic and inorganic scales, minerals sensitive to swelling and migration through X-ray diffraction, and interfacial phenomena such as the formation of plugging emulsions and interfacial membranes strengthened by the presence of clay-like particles with a strong tendency to alter their wettability due to interactions with polar components of the crude. Thus, it enables obtaining a representative diagnosis of formation damage mechanisms during Workover or well servicing operations.

In intervening in these wells, it is important to consider the existing physicochemical mechanisms and interactions between the injected and native fluids, as proved, significant incompatibilities arise that lead to various synergistic formation damage mechanisms at the wellbore face. It is from this point that conventional treatments do not yield satisfactory results, and the productivity of gas intervals is severely affected after these field interventions. This damage is further accentuated and strengthened with each intervention.

Finally, conducting formation damage studies in fields of this nature is crucial to decide the behaviors and/or interactions of the elements composing the fluid flow in the petroleum system. This is essential for implementing necessary measures to recover and/or enhance productivity by designing remediation treatments that address pseudo damage.

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