

Análisis integrado para identificar y prevenir el daño causado por la formación de salmueras de terminación: una aplicación en campos de Colombia

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Resumen

Después de realizar varios trabajos de reacondicionamiento de pozo se ha evidenciado una reducción considerable en la producción de aceite, la cual es causada por el daño de formación creado por el uso de salmuera de completamiento inadecuadas. El mecanismo de daño puede ser:

- 1) Bloqueo en la cara de la formación, producido por la tendencia a formar emulsiones entre el aceite del pozo y la salmuera de completamiento
- 2) Producción de incrustaciones inorgánicas en el medio poroso, durante el contacto del agua de formación con la salmuera de completamiento
- 3) Bloqueo por sólidos suspendidos presentes en las salmueras de completamiento
- 4) Aumento de la actividad bacteriana en la vecindad del pozo
- 5) Incompatibilidad roca-fluido debido a la sensibilidad de los minerales de formación a la salmuera de completamiento, causado por alto intercambio iónico que genera hinchazón de arcillas y reducción de la permeabilidad
- 6) Aumento de la permeabilidad relativa al agua.

Teniendo en cuenta lo anterior, este documento se centra en el análisis integrado de selección de salmueras de completamiento adecuadas, basadas en un análisis de laboratorio y producción. Los análisis de laboratorio incluyen:

- 1) Evaluación de las interacciones fluido-fluido,
- 2) Análisis físico-químico del agua producida,
- 3) Definición de la tendencia a formar incrustaciones del agua producida con la salmuera de control a nivel de cabeza del pozo y a condiciones del yacimiento a través de un software de simulación,
- 4) Filtración del fluido base de la salmuera de control y análisis SEM de residuos sólidos encontrados.

- 5) Análisis microbiológico del agua base de la salmuera de completamiento,
- 6) Compatibilidad entre salmuera-roca a través de una prueba de core-flooding,
- 7) Determinación de salinidad crítica. El análisis de producción incluye un diagrama de diagnóstico con una evaluación de la historia de producción, niveles de fluido, eventos, condiciones de extracción, etc.

El análisis integrado se aplicó en 12 pozos en los campos A-G en Colombia, para determinar la causa raíz de las pérdidas de producción, después de los trabajos de reacondicionamiento. La evaluación económica mostró la pérdida de productividad, cuantificado en más de un millón de dólares por pozo.

Este trabajo presenta los resultados de la evaluación en los pozos del G-11 y A-21, junto con las conclusiones y recomendaciones.

Palabras clave: Daño de formación, salmuera de completamiento, Intercambio Iónico, permeabilidad, análisis SEM, prueba de Coreflooding, tendencia Scale, presión fondo fluyente, valor presente neto.

Integrated analysis to identify and prevent formation damage caused by completion brines. A Colombian field application

Abstract

After workover jobs, many oil-producing wells have reduced their production, which is caused by formation damage created by using inadequate completion brine. The damage mechanism may be:

- 1) Block in the face of the formation, produced by the tendency to form emulsions between the oil of the well and the completion brine ,
- 2) Production of inorganic scale in the porous medium during the contact of the formation water with the completion brine,
- 3) Blockage by suspended solids present in the completion brines,
- 4) Increased bacterial activity in the wellbore vicinity,
- 5) Rock-fluid incompatibility due to sensitivity of the formation minerals to the completion brine, caused by high ion exchange, causing swelling of clays and reduction of the permeability,
- 6) Increase of the water relative permeability.

Given the above, this paper focuses on integrated analysis for selecting appropriate completion brines, based on an analysis of laboratory and production. Laboratory analysis includes:

- 1) Evaluation of fluid-fluid interactions,
- 2) Physical-chemical analysis of produced water,
- 3) Definition of Scale tendency of produced water and the mixture with control brine at the wellhead and at reservoir conditions through a simulation software,

- 4) Filtration of the base fluid of the control brine and analysis SEM of solid waste found,
- 5) Microbiological analysis of the base water of the completion brine,
- 6) Compatibility brine-rock through test of core -flooding,
- 7) Determination of critical salinity, The production analysis includes a diagnostic diagram with an assessment of the production history, fluid levels, events, extraction conditions, etc.

The integrated analysis was applied in 12 wells in the fields A, and G in Colombia, to determine the root cause of production losses, after workover. The economic evaluation showed loss of productivity, quantified in more than one million dollars per well. This paper presents the results of the evaluation in the wells G-11 and A-21, along with the conclusions and recommendations.

Keywords: Formation damage, completion brine, ion exchange, permeability, sem analysis, Core-flooding test, scale tendency, bottom hole pressure, net present value.

Introduction

The use of completion and well control fluids based on halides brines with low solids in the 1970's meant a breakthrough in reducing the damage to reservoirs and access to all the economic benefits of the open-hole horizontal wells completions. However, these brines were not appropriate for all wells. For example, shortly after, it was discovered that higher bromide brines density had certain disadvantages as drilling fluids. One of these drawbacks is the incompatibility with the sensitive fluid reservoirs containing divalent cations. In this context, the "sensitive reservoirs" are those with SO_4 or HCO_3 in dissolved in formation water and those containing H_2S in the gas phase.

Shell and Mobil were the first companies to try and use formate brine with low levels of solids as non-damaging completion and well control fluids. At present, of sodium and potassium formate based brines are routinely used as completion and well control fluids in development of fields where density requirements do not exceed 1.60 g/cm^3 (13.35 lb/gal).

In these times many workover operations continue using halide brines or inadequate well completion fluids, that generates formation damage due to the incompatibility between brine and formation fluids. This incompatibility may occur due to adverse reactions between invasive

filtered completion or well control fluid and in situ (oil or brine formation) fluids to form scales, insoluble precipitates, asphaltic sludge or stable emulsions.

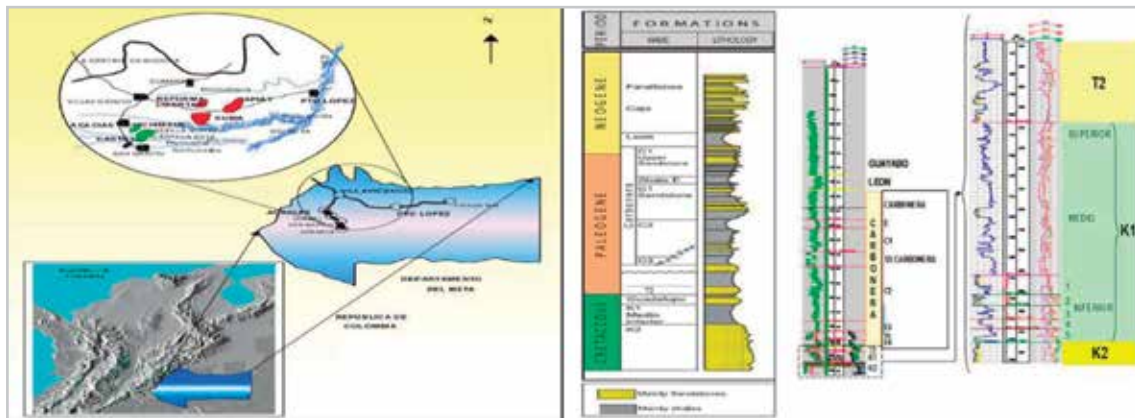
Formation damage generated in the wells cause a reduction of the production, increasing the costs of lifting and lowering its profitability.

Field of study and characterization of the problem

Field of Study

To carry out this work the S-A field, located in the eastern Llanos Basin, with high potential heavy oil was selected as a study pilot.

The A Block is located in the southwestern sector of the eastern Llanos basin in the department of Meta, 32 km SE of the city of Villavicencio. It is bordered by the Llanero Piedmont and the fault system Upia-Guicaramo to the west, the high Paleo of Cumaral to the north, and the Serrania of the Macarena to the south, defining an area of approximately $30,000 \text{ km}^2$. A, S y L-Reforma oilfields belong to this sub basin (see **Figure-1** left).



SOURCE: THE AUTHORS

Figure 1. Geographic Location of the A. Block (left) & Stratigraphic Column of the A. Block (right).

The stratigraphic section of the A-A block is formed by sedimentary rocks ranging in age from Paleozoic to Quaternary. The total thickness of the lithological column reaches 18,000 feet. Sedimentary rocks of Cretaceous and Tertiary age are the main reservoir in the area. The producing formations are: Une (Unit K2), Chipaque (Unit K1), San Fernando (Unit T2) and Carbonera (Unit T1). **Figure 1** Right shows the stratigraphic column respectively.

The discovery by Ecopetrol of structures in Block A-A began in the A field in 1981 with the drilling of the well A-1, with an initial production of 1700 BOPD of the K2 unit with oil of 25°API. In 1985 it was discovered S field with the drilling of the well Suria-1, which produced the K2 and K1 units showing oil of 34 ° API. Due to high oil prices, the imminent decline in reserves and low success exploratory in the country, the unit T2 (San Fernando formation) took an important place in the development of these fields from the previous decade.

Characterization of the problem

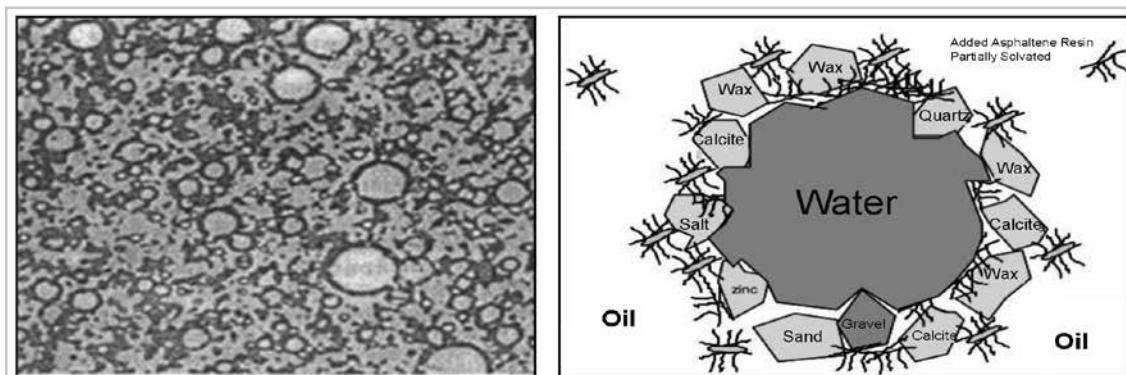
In order to characterize the problem of low productivity caused by a possible formation damage fluid incompatibility between completion / well control brine and reservoir fluids and minerals, an experimental protocol and analysis of the production history was followed which will be described later.

Formation damage

The use of brine for completion or well control can generate the following damage mechanisms: 1) Block in the face of the formation, produced by the tendency to form emulsions between the oil of the well and the completion brine , 2) Production of inorganic scale in the porous medium during the contact of the formation water with the brine of completion, 3) blockage by suspended solids present in the completion brines, 4) Increased bacterial action in the well, 5) Incompatibility rock-fluid by sensitivity of the formation minerals to the completion brine, caused by high ion exchange, causing swelling of minerals and reduced permeability, 6) increased the relative permeability to water.

Blockage due to emulsions

One of the most common formation damage types is the blockage the face of the formation by the tendency to form emulsions between oil and well completion or well control brine. For purposes of this study the water-in-oil emulsions (W/O) formed by water droplets dispersed in oil is considered, see **Figure-2** Left.



SOURCE: MARTELL, J. 2011

Figure 2. Micrograph of a W/O Emulsion (Left) & Stabilized Emulsion, (Right).

There is a mutual insolubility of many liquid hydrocarbons and water. The presence of carbon-carbon double bonds (e.g., alkenes, dialkenes and aromatic) increases the solubility of water in the crude oil. Water is far to be soluble in saturated hydrocarbons (e.g. paraffins or alkanes) and water solubility decreases with increasing molecular weight of the hydrocarbons.

An emulsion is a quasi- stable fine droplets of a liquid dispersed in another liquid, as shown in **Figure-2 Right**. The liquid in form of droplets is the dispersed or internal phase, while the surrounding liquid is the continuous or external phase. For purposes of this study, the dispersed phase is water, which may be accompanied by solids such as sand, mud, carbonate, and solid corrosion products precipitated or dissolved, which help stabilize the emulsion. The emulsions are sometimes classified according to the size of the dispersed droplets; regarded as macro - emulsion when the droplet range is 10 to 150 microns and as mini and nano-emulsion when the droplet size ranges from 0.5 to 10 microns.

There are three requirements to form an emulsion: 1. Two immiscible liquids; 2. enough agitation to disperse a liquid into small droplets; 3. an emulsifier to stabilize the dispersed droplets.

The W/O emulsions formed can be classified as hard and soft. By definition a hard emulsion is very stable and difficult to break, mainly because the dispersed droplets are very small. In the other hand, a soft emulsion is unstable and easy to break.

Emulsifiers

An emulsifying agent must be present in order to stabilize an emulsion. The typical emulsifier is a surface active agent or surfactant.

In the oil industry, the emulsifying agents are numerous and can be classified as follows:

- Natural surfactant compounds such as asphaltenes and resins containing organic acids and bases, naphthenic acids, carboxylic acids, sulfur compounds, phenols, cresols and other natural high molecular weight surfactants.
- Finely divided solids such as sand, clay, formation fines, shale, drilling muds, stimulation fluids, mineral scale, corrosion products (for example iron sulfide, oxides), paraffins, asphaltenes precipitated. Well stimulation fluids can contribute to form very stable emulsions.
- Production chemicals added such as corrosion inhibitors, biocides, cleaners and wetting agents.

Natural surfactants are defined as interface-active macromolecules having a high aromatic content and which can be stacked in the form of micelles. They are formed of acidic fractions of asphaltenes, resins, and naphthenic acids porphyrin materials. A second stabilizing mechanism occurs when emulsifiers consist in very fine solid particles. In order to act as emulsifiers, solid particles must be smaller than the suspended drops and must be wetted by the oil

and water phases. Then these fine solid particles or colloid is collected on the surface of the drop, forming a physical barrier. Common examples of this type of emulsifier are iron sulfide and clays. In **Figure 2** Right, the adsorption of different particles acting as emulsifiers is shown around a water droplet.

The salinity of the brine is an important factor when forming stable emulsions. Fresh water or brine with a low concentration of salt promotes emulsion stability. Conversely, high salt concentrations generally cause loss in the stability of emulsions.

Paraffinic crude oil do not normally form stable emulsions, whereas naphthenic and mixed based crude oils do form stable emulsions. Waxes, resins, asphaltenes and other solids can influence the stability of the emulsions. In other words, the type of oil determines the amount and types of natural emulsifiers.

Incompatibilities between the rock and the fluid

Adverse reactions between filtered water-based invasive fluids and sensitive clays surrounding the pores, causes the movement of fines and it's associated to reductions in near well-bore permeability. Smectite clays which surround the pores can swell and disintegrate when in contact with a filtered fluid of lower salinity than the native reservoir brine. When low salinity brines invade the reservoir, the clays which surround the pores are exposed to a separation process and movement through the porous system, which results in clogging of the pore entrances.

Invasion of solids

Penetration and blocking access reservoir porous by suspended solids in completion fluids or well control. Permanent housing of solids at the formation porous radii can severely reduce its permeability. If particles are required in the brine in order to form filter cakes or as sealing agents, it is recommended to select them depending on their ability to minimize the potential for formation damage.

Phases retention

Invasion and permanent retention of leaked oil or water in the near wellbore region. These retained fluids can greatly reduce the relative permeability to oil.

Chemisorption / alteration of wettability

It is referred to the alteration of the permeability to oil due to changes in the wettability of the surfaces of the porous media. It is possible that completion or well control fluids contain conventional chemical surfactants (e.g. emulsifiers, oil wetting agents and corrosion inhibitors), which are deliberately added to enhance the performance of the fluid or to mitigate performance deficiencies. The adsorption of these chemicals in the reservoir rock can change the wettability and the permeability to hydrocarbons.

Biological activity

Reduced formation permeability as a result of microbial activity promoted by the use of microbiologically contaminated completion and well control brines. These brines can introduce new microorganisms into reservoirs, stimulate the activity of native microorganisms or contain nutrients that promote bacterial growth.

Evaluation methodology to identify and prevent formation damage

Given the above and the productivity losses that have been shown in some wells of the SOA after subsurface maintenance, an integrated analysis was performed in order to properly select completion brines.

This methodology was designed with the goal of conducting a comprehensive analysis to select, evaluate and optimize the completion or well control brine, based on laboratory and production analysis.

This methodology is described below:

1. Experimental evaluation

- a. Fluid-fluid interactions
- b. Produced water physical-chemical analysis
- c. Defining scale tendency of produced water and the mix with the completion or well control brine at wellhead and reservoir conditions through simulation software.
- d. Filtering the completion of well control brine and SEM analysis of the solid residues.
- e. Microbiological analysis of water-based completion or well control brine
- f. Compatibility of completion or well control brine with reservoir rock, through core flooding tests.
- g. Determination of critical salinity

The parameters evaluated for physicochemical analysis of produced waters are divided into two groups according to where they are collected:

1. "In situ": once a sample of interest in the well the parameters pH, conductivity, alkalinity, dissolved gases are measured (H_2S , CO_2 y O_2) y dissolved iron (Fe^{+2}). pH and conductivity are determined using an Horiba® pH and conductivity meter; alkalinity is determined by potentiometer.
2. A sample is taken at the wellhead is preserved with 2-3 drops of HNO_3 for lately assessed in the laboratory by measuring metals Na^+ , K^+ , Ca^{+2} , Mg^{+2} , Si^{+2} , Ba^{+2} , Sr^{+2} and total iron by plasma spectroscopy ICP-OES, Cl-by potentiometric method, SO_4^{2-} by turbidimetric method and sulfate reducing bacteria count (BSR) and acid producing bacteria (BPA) following standard ASTM D-4412-02 method.

Using specialized software, it can be predicted whether a certain mineral at a any time may precipitate, given certain conditions of pressure, temperature, flow rate or depth. This simulation is based on the physic-chemical analysis of produced water obtained as mentioned above. The tendency of a mineral to precipitate or remain in solution

is determined by the scale index (SI) or the scale tendency (ST). In general, positive values of SI (>0) indicate trends for precipitation and negative for dissolution. Values > 1 of ST indicate the number of folds that water is supersaturated so theoretically the mineral may precipitate.

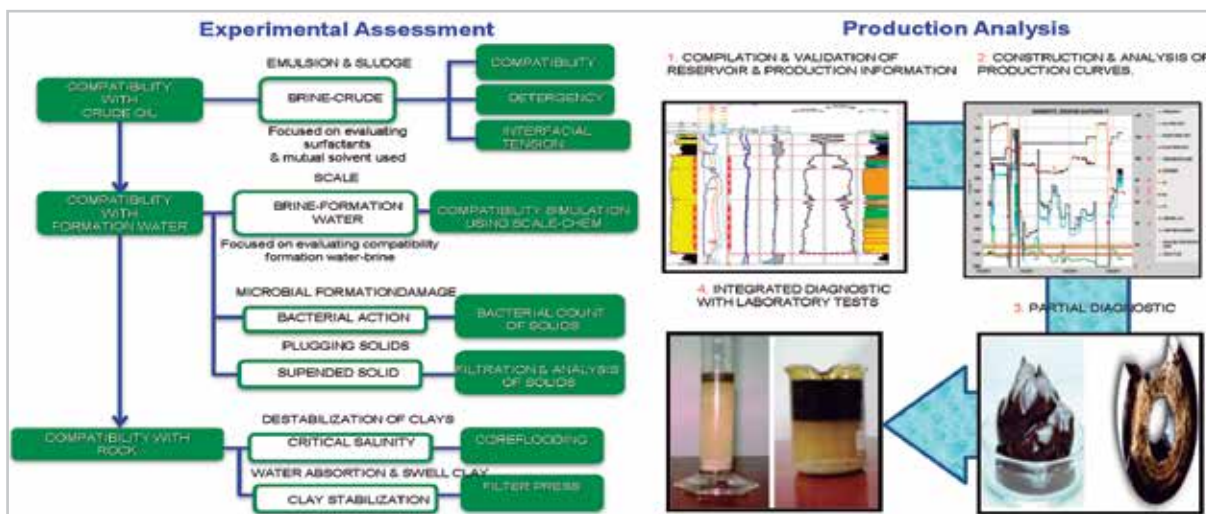
This prediction is based on thermodynamics. Kinetically it is considered that in order to have physical evidence of the presence of mineral precipitate, ST must be greater than 4. Additionally, an estimated amount of scale that could precipitate at specific conditions, which serve as reference data to establish the criticality of the problem at each point is calculated. This amount depends on the flow rate handled in the process, the pressure and the temperature^[1, 2].

In order to determine the compatibility of the treatments with the formation fluids, a fluid - fluid interaction test based on the standard AP RP 42 is performed. For this assessment usually oil and formation water taken from the well being tested is used. The oil must contain a %BS&W < 15 , measured under the ASTM D4007 standard.

If formation water is not available or the amount is insufficient, a synthetic equivalent brine can be prepared based on the physicochemical analysis data of it obtained as mentioned in previous paragraphs. For the test, oil and aqueous brines/treatments mixtures are performed in 50/50, 20/80 and 80/20 ratios, in flasks hermetically sealed.

The mixtures are shaken manually for approximately 60 seconds and subjected to heating for 2 hours at maximum test temperature, which corresponds to the temperature of the formation of interest, in a convection oven. After operating for 2 hours, the flasks are taken out of the oven and observations on the percentage of phase separation, the appearance of the interface and of each phase separately, the presence/absence of stable emulsions and the formation of precipitates are performed.

Finally, a photographic record of each of the results is made, which are tabulated along with the formulation of treatment/brine assessed. When the phases are immiscible (e.g. , aqueous - oil) , a phase separation of at least 80% , defined interface without any precipitates or stable emulsion free of oil and aqueous phase is expected. When the phases are miscible (e.g., treatment or treatment organic - aqueous oil - water training), a single phase without the presence of any precipitate is expected.



SOURCE: THE AUTHORS

Figure 3. Experimental evaluation methodology (Left) & Integrated analysis methodology, (right).

Production analysis

The methodology for assessing productivity losses includes a diagnostic diagram with an analysis of the production history, fluid levels, pump inlet pressures, events, extraction conditions, etc. This analysis complements the experimental evaluation (see **Figure 3** right).

The integrated analysis was applied in 10 wells of A, S and G oilfields in Colombia, after underground maintenance work, in order to determine the causes of production

losses and to design the appropriate completion brines and stimulation treatments.

Selection of wells

Wells selected for this study, were those which after maintenance work, have reduced their production, (see **Table-1** left), which as mentioned was caused by formation damage generated completion brine, (**Table-1** right).

Table 1. Wells of the A-S field with productivity loss (left) & completion brine or control fluid used in the A-S field (right).

| WELL | FORMATION | BSW (%) | OBSERVATION |
|---------|-----------|---------|---|
| A-21 | K1 | 92 | |
| A-6 | T2 | 80 | Shut off , was sampled A9 & A18 |
| G-11 | K1 | 60 | |
| L.N-11 | K1 | 97 | Shut off , was sampled L2 |
| SSur-4 | K2 | 72 | |
| SSur-7 | T2 | 30 | |
| SSur-8 | K1 | 70 | |
| SSur-14 | K1 | 46 | |
| A-5 | K1 | 2 | Detergency Problems Presented in Previous Assessments |
| T-1 | K1 | 49 | Not Sampled |

| BRINE COMPAÑY 1 | | | |
|-----------------|-----------------|------|------------|
| ADDITIVE | FUNCTION | UNIT | FORMULA A1 |
| Water A-13 | Fluid Base | GPT | 993 |
| NaCl | Sodium Chloride | % | 4 |
| 10A | Mutual Solvent | GPT | 5 |
| 65A | Surfactant | GPT | 2 |

SOURCE: THE AUTHORS

Case study

As case study, the evaluation and appropriate selection of completion brines and analysis of production wells where formation damage is caused by the use of an inadequate completion / well control brine is presented.

Selection and evaluation of completion / well control brines

Following the described methodology of experimental analysis (Figures-3 Left), completion / well control brine used for S-A oilfield where, A-13 produced water was used as a base fluid to prepare the brine was evaluated.

Rating completion / well control brines

Compatibility, detergency and interfacial tension assessments between completion / well control brine from company 1 (baseline) and crude oil produced by 17 S-A wells in K1, K2 and T2 strata (including those that experienced productivity losses) were performed. Given the incompatibility of brine from company 1 with crude oil 14 out of the 17 wells tested, six (6) formulations of completion / well control brines from company 2 and four (4) formulations of completion / well control brine from company 3 were evaluated. **Table 2** shows 11 formulations of the completion brines, and **Table 3** shows the results of evaluation of these formulations.

Table 2. Completion brine formulations evaluated for S-A field.

| BRINES | | | COMPANY 1 | | COMPANY 2 | | | | | COMPANY 3 | | | |
|-------------|------------------|------|-----------|-------|-----------|-------|-------|--------|-------|-----------|-------|-------|-------|
| ADDITIVE | FUNTION | UNIT | Fm A1 | Fm A2 | Fm B2 | Fm C2 | Fm D2 | Fm E2 | Fm F2 | Fm A3 | Fm B3 | Fm C3 | Fm D3 |
| A. Water 13 | Fluid Base | GPT | 993 | 993,5 | 994,25 | 992 | 998,5 | 999,25 | 997 | 993 | 991 | 993 | 991 |
| KCl | Potasio Chloride | % | - | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 |
| NaCl | Sodium Chloride | % | 4 | - | - | - | - | - | - | - | - | - | - |
| 10A | Mutual Solvent | GPT | 5 | - | - | - | - | - | - | - | - | - | - |
| 65A | Surfactant | GPT | 2 | - | - | - | - | - | - | - | - | - | - |
| 3004 | Mutual Solvent | GPT | - | 5 | 5 | 5 | - | - | - | - | - | - | - |
| 226 | Surfactant | GPT | - | 1,5 | 0,75 | 3 | 1,5 | 0,75 | 3 | - | - | - | - |
| 5 | Surfactant | GPT | - | - | - | - | - | - | - | 2 | 4 | - | - |
| 282 | Surfactant | GPT | - | - | - | - | - | - | - | - | - | 2 | 4 |
| 200 | Mutual Solvent | GPT | - | - | - | - | - | - | - | 5 | 5 | 5 | 5 |

SOURCE: THE AUTHORS

Table 3. Evaluation results for completion Brines, for S-A field.

| FM / YEAR | WELL | COMPANY 1 | | COMPANY 2 | | | | | COMPANY 3 | | | | |
|-------------|------------|-----------|-------|-----------|-------|-------|-------|-------|-----------|-------|-------|----|----------|
| | | Fm A1 | Fm A2 | Fm B2 | Fm C2 | Fm D2 | Fm E2 | Fm F2 | Fm A3 | Fm B3 | Fm C3 | D3 | FM D3 Op |
| 2011 | A5(K1) | | | | ✓ | | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| | A9(T2) | | | ✓ | | | | | ✓ | ✓ | ✓ | ✓ | ✓ |
| | A18(Y2) | | | | | | | | ✓ | ✓ | ✓ | ✓ | ✓ |
| | AP21 (K1) | | | | | | | ✓ | | | ✓ | ✓ | ✓ |
| | G11(K1) | | | | | | | | | | | ✓ | |
| | L2(K2) | | | | ✓ | | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| | SSur-4(K2) | | ✓ | ✓ | ✓ | ✓ | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| | SSur-7(K2) | ✓ | | | ✓ | | | | ✓ | ✓ | ✓ | ✓ | |
| | SSur-8(K1) | ✓ | | ✓ | | | | | ✓ | ✓ | ✓ | ✓ | |
| SSur-14(K1) | ✓ | ✓ | | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | |
| T2 / 2012 | A9 | | | | | | | | | | | ✓ | |
| | A31 | | | | | | | | | | | ✓ | |
| | AE2 | | | | | | | | | | | ✓ | |
| | G6H | | | | | | | | | | | ✓ | |
| | G19H | | | | | | | | | | | ✓ | |
| | S8 | | | | | | | | | | | ✓ | |
| SSur-10 | | | | | | | | | | | ✓ | | |

SOURCE: THE AUTHORS

Completion / well control brine vs formation water

A physicochemical analysis of the water for preparing the brine (A- 13) and wellhead samples produced water of some of the wells with loss of productivity, as noted in **Table 4** were performed.

Table 4. Physical-chemical analysis of brine base and produced water horizons K1, K2 and T2.

| DATE | WELL | FORMATION | Na ⁺ | K ⁺ | Ca ⁺⁺ | Mg ⁺⁺ | Ba ⁺⁺ | Sr ⁺⁺ | Fe ⁺⁺ | STD | SALINITY | I. S. | SiO ₂ |
|-------------|--------|-----------|-----------------|----------------|------------------|------------------|------------------|------------------|------------------|--------|----------|-------|------------------|
| | | | mg/l | mg/l | mg/l | mg/l | mg/l | mg/l | mg/l | | | | |
| May-18-11 | A -13 | K1 | 136 | 1,158 | 1,738 | 0,063 | 0,020 | 0,024 | 0 | 524 | 1760 | | 50,4 |
| April-30-09 | A-6 | T2 | 1543,6 | 64,5 | 174,3 | 15,8 | 0,2 | 6,5 | 0,4 | 5150 | 4344 | 2,119 | 107,2 |
| May-28-11 | L-2 | K2 | 35,7 | 10,2 | 21,5 | 1,9 | 1,1 | 0,5 | 11,2 | 393,2 | 162,0 | -0,1 | 107,1 |
| May-27-11 | SSur-4 | K2 | 62,0 | 13,9 | 38,2 | 3,5 | 1,6 | 1,4 | 0,2 | 510,4 | 258,6 | 0,4 | 92,7 |
| May-25-11 | SSur-8 | K1 | 295,2 | 21,8 | 65,6 | 6,8 | 71,5 | 2,0 | 0,2 | 1256,0 | 1022,8 | 0,5 | 99,6 |
| May-18-11 | A-21 | K1 | 50,9 | 3,6 | 8,3 | 1,0 | 0,2 | 0,1 | 0,5 | 325,3 | 127,6 | -0,6 | 115,3 |

| DATE | WELL | FORMATION | pH/°C | RESIST. | H ₂ S | O ₂ DIS. | CO ₂ | HCO ₃ ⁻ | CO ₃ ⁺⁺ | SO ₄ ⁺⁺ | Cl ⁻ | CONDUCT |
|-------------|---------|-----------|-------------|-----------|------------------|---------------------|-----------------|-------------------------------|-------------------------------|-------------------------------|-----------------|---------|
| | | | | Wm @ 25°C | mg/l | ppb | mg/l | mg/l | mg/l | mg/l | | |
| May-18-11 | A -13 | K1 | 8.22/ 18.9 | 19,12 | ND | N.R. | <10 | 312,8 | 7,5 | 7,7 | 6,74 | 0,523 |
| April-30-09 | A-6 | T2 | 7.41 / 41.2 | 1,48 | ND | NA | 15 | 869 | 0 | 483 | 1892 | 6,75 |
| May-28-11 | L-2 | K2 | 7.24/38.8 | 31,35 | N.D | N.R. | <10 | 152,5 | 0 | 13,3 | 27 | 0,319 |
| May-27-11 | S Sur-4 | K2 | 7.52/38.3 | 24,15 | N.D | N.R. | <10 | 244 | 0 | 10,4 | 42,3 | 0,414 |
| May-25-11 | S Sur-8 | K1 | 7.68/40 | 6,51 | N.D | N.R. | <10 | 213,5 | 0 | 32,7 | 447 | 1,537 |
| May-18-11 | A-21 | K1 | 7.45/33.4 | 62,85 | N.D | N.R. | <10 | 122 | 0 | 16,1 | 6,8 | 0,1591 |

SOURCE: ECP

The ions present in higher concentrations in formation water (Ca, Fe, Ba, HCO₃⁻, etc.). Under certain conditions of pressure, temperature and saturation, decrease their solubility in the system and can be precipitated as inorganic scale.

With the help of a simulation software and physicochemical analysis presented on Table 5, it was possible to predict

the scaling tendency of produced water alone and mixed with completion / control brine at wellhead and reservoir conditions.

The conditions used for modeling were, (Table 5), the criteria or thresholds for determining the tendency to form scale (ST) are shown in Table-5 right.

Table 5. Modeling conditions (left) & definition of scale tendency - ST (right).

| DATE | WELL | FORMATION | P RESERVOIR (psi) | T RESERVOIR (°F) | P WELLHEAD (psi) | T WELLHEAD (°F) |
|-------------|------|-----------|-------------------|------------------|------------------|-----------------|
| May-04-09 | A-13 | K1 | 4079 | 260 | 147 | 110 |
| April-30-09 | A-6 | T2 | 3334 | 260 | 105 | 113 |
| May-28-11 | L-2 | K2 | 3667 | 245 | 76 | 111 |
| May-27-11 | SS-4 | K2 | 3615 | 260 | 245 | 115 |
| May-25-11 | SS-8 | K1 | 2454 | 245 | 123 | 95 |
| May-18-11 | A-21 | K1 | 4260 | 245 | 137 | 144 |

| Scale Tendency (ST) | Brine | Condition |
|---------------------|----------------|-----------|
| ST < 1 | Low Saturation | Low |
| ST = 1 | Saturated | Moderate |
| ST > 4 | Supersaturated | Critical |

SOURCE: THE AUTHORS

The results of the modeling and simulation to determine the tendency to form scale (ST) of produced water at wellhead and reservoir conditions are shown in **Tables 6 and 7**.

Table 6. Inorganic scale trend at wellhead (left) & scale trend by saturation at wellhead (right).

| DATE | WELL | FORMATION | SCALE TENDENCY | | | | SATURATION CONDITION FOR WELL | BaSO4 | CaCO3 | Fe ⁺² CO3 | |
|-------------|---------|-----------|----------------|--------|----------------------|----------------|-------------------------------|---------------------------------------|-----------------------------------|----------------------|-----|
| | | | BaSO4 | CaCO3 | Fe ⁺² CO3 | BaCO3 | | | | | |
| May-4-09 | A-13 | K1 | 0,040 | 1,630 | 1,200 | Low Saturation | A-13 A-21 | A-21 L-2 | A-6 S sur-4 S sur-8 A-21 | | |
| April-30-09 | A-6 | T2 | 3,694 | 11,268 | 1,009 | | Saturated | L-2 S sur-4 A-6 | A-13 S sur-4 S sur-8 | A-13 | |
| May-28-11 | L-2 | K2 | 2,903 | 0,400 | 10,187 | | | Supersaturation Critical Condition | S sur-8 | A-6 | L-2 |
| May-27-11 | S Sur-4 | K2 | 2,986 | 2,011 | 0,475 | | | | | | |
| May-25-11 | S Sur-8 | K1 | 352,008 | 2,484 | 0,222 | | | | | | |
| May-18-11 | A-21 | K1 | 0,582 | 0,370 | 1,027 | | | | | | |

SOURCE: THE AUTHORS

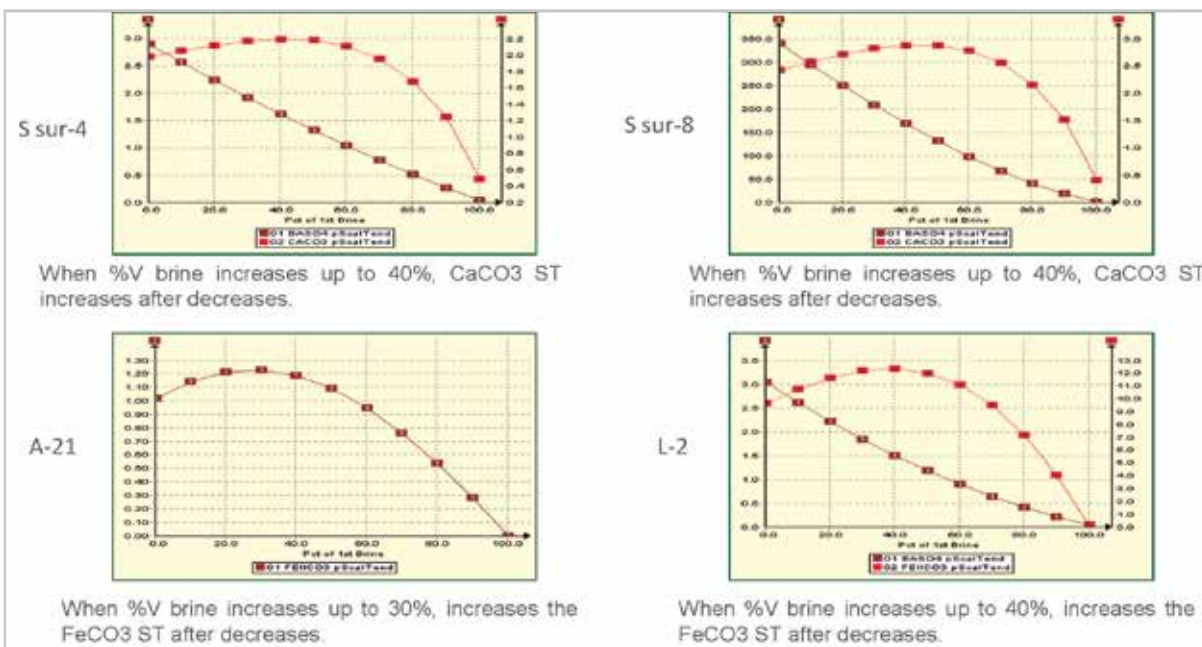
Table 7. Inorganic scale trend at reservoir (Left) & Scale trend by saturation at reservoir, (right).

| DATE | WELL | FORMATION | SCALE TENDENCY | | | | SATURATION CONDITION FOR WELL | BaSO4 | CaCO3 | Fe ⁺² CO3 | |
|-------------|---------|-----------|----------------|--------|----------------------|----------------|---------------------------------------|---------------------------------------|-------------|---------------------------|------------|
| | | | BaSO4 | CaCO3 | Fe ⁺² CO3 | BaCO3 | | | | | |
| May-4-09 | A-13 | K1 | 0,011 | 2,470 | 2,649 | Low Saturation | A-13 A-6 L-2 S sur-4 A-21 | A-21 | S sur-8 | | |
| April-30-09 | A-6 | T2 | 0,597 | 71,657 | 5,154 | | Saturated | | A-13 L-2 | A-13 S sur-4 A-21 | |
| May-28-11 | L-2 | K2 | 0,915 | 3,151 | 56,952 | | | Supersaturation Critical Condition | S sur-8 | A-6 S sur-4 S sur-8 | A-6 L-2 |
| May-27-11 | S sur-4 | K2 | 0,803 | 13,644 | 2,037 | | | | | | |
| May-25-11 | S sur-8 | K1 | 74,348 | 13,403 | 0,956 | | | | | | |
| May-18-11 | A-21 | K1 | 0,244 | 1,085 | 2,321 | | | | | | |

SOURCE: THE AUTHORS

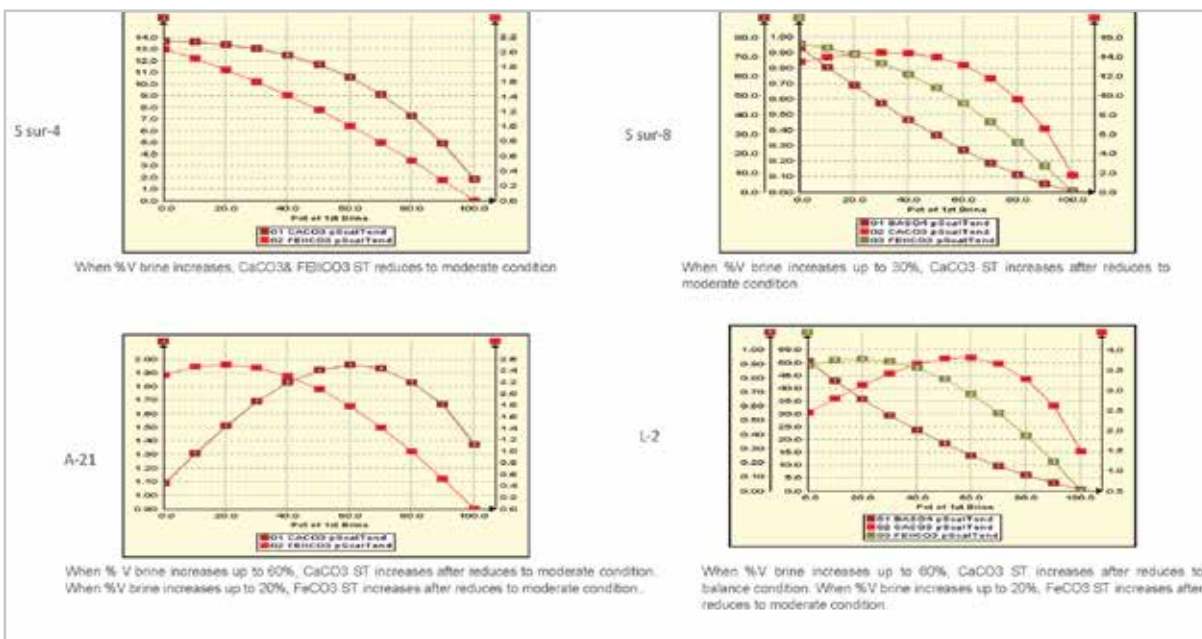
The results of modeling and simulation to determine the tendency to form scale (ST) of the mixture of produced water and completion / well control brine at wellhead and

reservoir conditions are shown in **Figures 4, 5 and 6**. This modeling is focused on predicting favorable mix ratios for non-scaling.



SOURCE: THE AUTHORS

Figure 4. Scale tendency of the brine - formation water mixture at wellhead conditions.



SOURCE: THE AUTHORS

Figure 5. Scale tendency of the brine- formation water mixture at reservoir conditions.

| Mixture | Site | CaCO ₃ | Fe+2CO ₃ | BaSO ₄ | SrCO ₃ |
|-----------------|-----------|-------------------|---------------------|-------------------|-------------------|
| A-13 vs A-6 | Reservoir | ↓ | ↓ | | ↓ |
| | Wellhead | ↓ | ↓ | ↓ | |
| A-13 vs S sur-4 | Reservoir | ↓ | ↓ | | |
| | Wellhead | from 50% ↓ | | ↓ | |
| A-13 vs S sur-8 | Reservoir | from 40% ↓ | ↓ | | |
| | Wellhead | from 50% ↓ | | ↓ | |
| A-13 vs A-21 | Reservoir | to 60% ↑ | from 30% ↓ | | |
| | Wellhead | | to 30% ↑ | | |
| A-13 vs L-2 | Reservoir | to 60% ↑ | from 20% ↓ | | ↓ |
| | Wellhead | | to 40% ↑ | | ↓ |

SOURCE: THE AUTHORS

Figure 6. Scale-forming tendency of the brine-formation water mixture at wellhead and reservoir conditions.

Plugging by solids

In order to quantitatively determine the suspended solids in the aqueous vehicle used in the preparation completion / well

control brine, a sample of A-13 produced water was filtered using a 0.45µm membrane. SEM analysis of elemental composition of the solid of the cake was performed, see Figure-7.

| Element | Relative Abundance (%) |
|----------|------------------------|
| Carbono | 44.3 +/- 0.4 |
| Oxygen | 55 +/- 1 |
| Aluminum | Traces |
| Silicon | 0.5 +/- 0.1 |
| Iron | Traces |



SOURCE: THE AUTHORS

Figure 7. SEM Analysis of solids in water. Well A-13 & Micrograph, particle detail.

Particles larger than 2 microns of the following elements and compounds were found Si, Al, Ca, Fe, K, Na, iron oxides (Fe₂O₃), silica (SiO₂), Barium Sulfate (BaSO₄), fragments of organic material with size between 57 and 350 microns, pyrite (FeS₂) and calcium carbonate CaCO₃. It is worth noting that these larger-than-2-microns particles can cause obstruction of pore throats.

Bacterial action

A microbiological analysis was conducted on the completion/well control brine (A-13), with the aim of identifying the presence of bacteria and thus define if the use of a bactericide or biocide is necessary for control, **Table 8**.

Table 8. Microbiological analysis of water, Well A-13.

| Identification | Bacteria Count | | |
|--------------------|------------------|-----------------------|--|
| | Sulfate Reducing | Acid Production (BPA) | Total Anaerobes(ANT, Broth Tioglicolate) |
| Fresh water sample | **BSR/mL | BPA/mL | ANT/mL |
| A-13 | <10 | 10 | 10 |

SOURCE: ECP

Compatibility between rock and completion / well control fluid

An assessment of clay swelling inhibitors in the completion / control brine was performed, in order to determine whether the brine when in contact with the reservoir rock, causes swelling and / or flocculation of clays in the formation.

As inhibitors of clays, 2 w% KCl and additionally two liquid substitutes of KCl, were evaluated through a filter press, see formulations in **Table 9**.

Table 9. Brine formulations evaluated with different clay controllers.

| ADDITIVE | FUNTION | UNIT | Fm A | Fm B | Fm C | Fm D |
|------------|--------------------|------|------|------|------|------|
| Water A-13 | Base Fluid | GPT | 995 | 995 | 998 | 1000 |
| KCl | Potassium Chloride | % | | | 2 | |
| 226 | Surfactant | GPT | 3 | 3 | | |
| 3C | Clays controller | GPT | 2 | | | |
| 2011 | Clays controller | GPT | | 2 | | |

SOURCE:
THE AUTHORS

Table 10 shows the results of the evaluation of clay swelling inhibitors.

Table 10. Results of clay inhibitors evaluation.

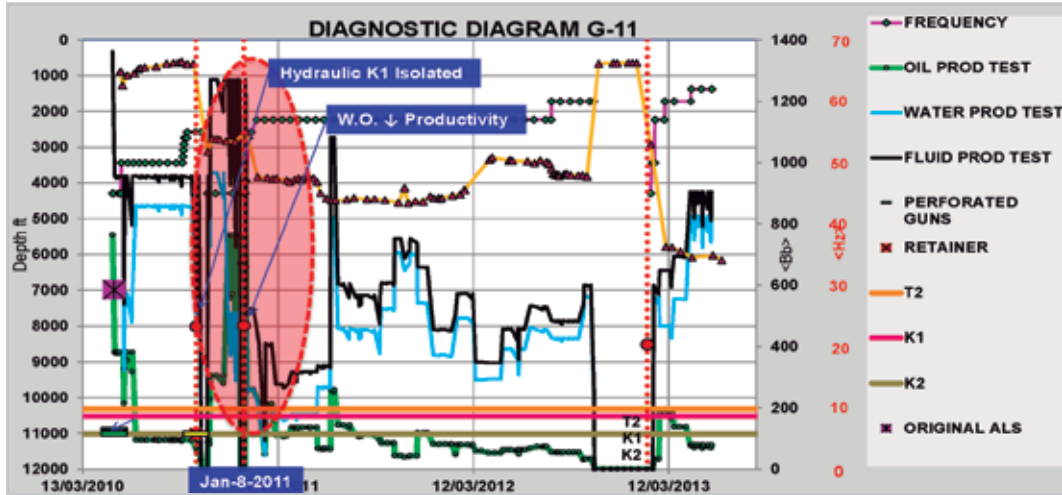
| Filtration time | Filtering Volume (ml) | | | |
|-----------------|--|---|---|--|
| | Water A-13 | Water A-13 + KCl 2% | Brine A + Clay tread 3C | Brine B + ESP 2011 |
| 0 minutes | 6,8 | 25,5 | 17,8 | 20 |
| 1 minutes | 44 | 169 | 225 | 160 |
| 3 minutes | 85 | 218 | 226,5 | 213 |
| 5 minutes | 114 | | | |
| 10 minutes | 168 | | | |
| Observations | By applying pressure 20psi vol filter increased, the total vol was taken in 10min. | By applying pressure 20 psi vol filter increased, and 218 ml was taken in 3min. | By applying pressure 20psi vol filter increased, and 226.5 ml were taken at 3min. | By applying pressure 20psi vol filter increased, and 213ml were taken in 3min. |

SOURCE:
THE AUTHORS

Productivity analysis

In this section, a case study (the G-11 oil-well) is shown, where a reduction in production happened after a maintenance

work made in January 2011, caused by formation damage due to the use of inadequate completion/control brine. For the analysis of loss of productivity, a diagnostic diagram and an economic evaluation are considered, see **Figure 8**.



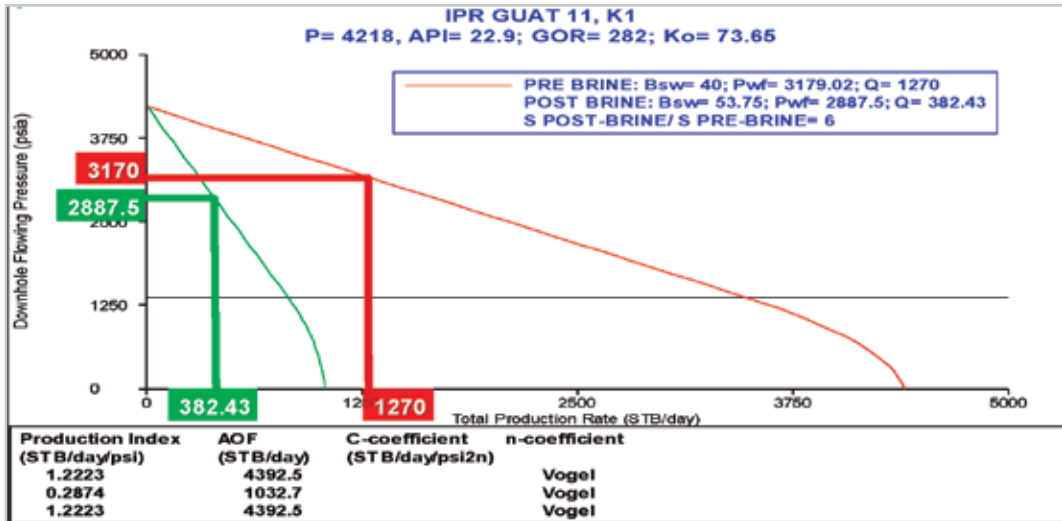
SOURCE: THE AUTHORS

Figure 8. Diagnostic diagram of G-11 oil-well.

The diagnostic diagram is a graph allowing visualizing and analyzing the history of producing strata, fluid levels or pump’s inlet pressure, events, extraction conditions, etc. In **Figure 8** it can be seen that after the maintenance work, the G-11 oil-well production was significantly reduced, that was caused by the formation damage generated during the respective work.

Production modeling

From **Figure 8** and considering conditions with or without damage caused by completion brine, the nodal analysis was performed on G-11 oil-well, as shown in **Figure 9**.



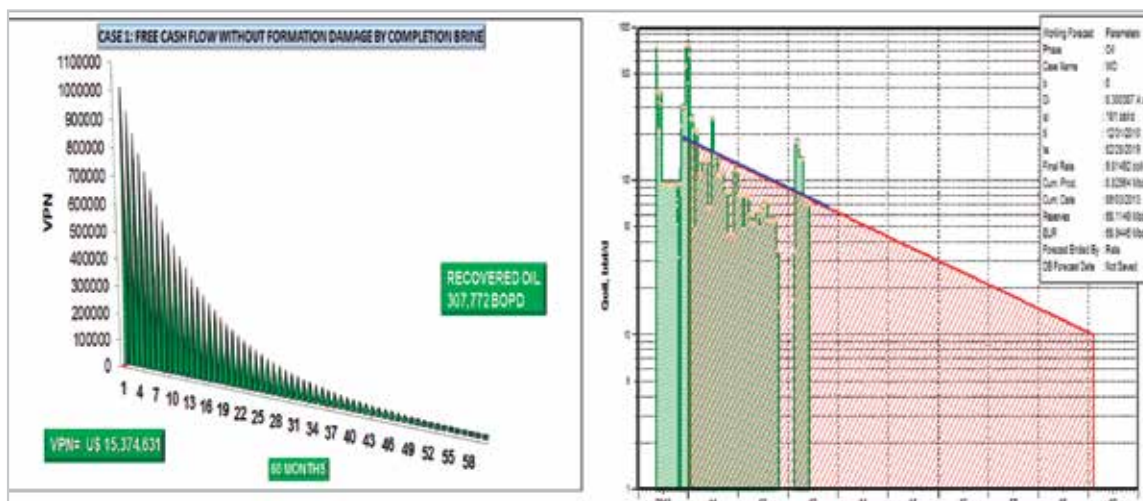
SOURCE: THE AUTHORS

Figure 9. Nodal analysis with and without damage caused by completion brine on G-11 oil-well.

Economic assessment

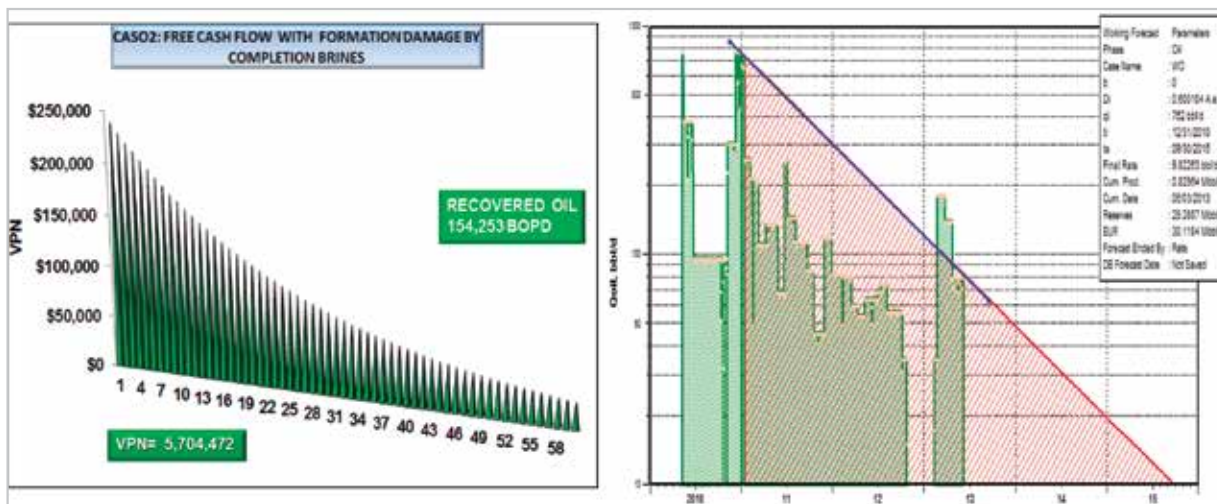
Figures 10 and 11 show the economic evaluation (VPN) for two production scenarios with and without formation

damage caused by completion brine, taking into account the loss of productivity that was presented in G 11 after a job done in January 2011.



SOURCE: THE AUTHORS

Figure 10. Economic assessment without damage caused by completion brine, G-11 oil-well.



SOURCE: THE AUTHORS

Figure 11. Economic assessment with damage caused by completion brine, G-11 oil-well.

Conclusions and recommendations

An improper selection of the completion brine can generate a level of formation damage and loss of productivity in the oil-wells, to the point of making them unproductive.

For proper selection of the completion brine it is required making a comprehensive evaluation at laboratory and at the field, such as the one developed in this paper.

In the case of completion brine used in a well area (sands T2, K1 and K2), a possible formation damage was established by the incompatibility of the completion brine and the fluids and minerals of the formation.

Among the main damage types of damage caused by incompatibility between the completion brine and crude oil there are: emulsion formation and tendency to formation of inorganic deposits (BaSO_4 , CaCO_3 , Fe_2CO_3), plugging solids, etc.

When mixing completion brine and produced water, the tendency of formation of inorganic deposits is higher at reservoir level than at surface, for CaCO_3 and Fe_2CO_3 . In the case of scaling tendency of BaSO_4 , it increases more at the surface than at reservoir level.

On the surface, a 6 oil-well has the critical condition as to the tendency of formation of CaCO_3 , the S South-8 oil-well is the most critical condition as to the tendency of formation of BaSO_4 and well L-2 has the condition most critical in terms Fe_2CO_3 forming tendency.

At the reservoir level, the A 6, S Sur-4 and S Sur-8 oil-wells are the most critical in terms of the tendency of formation of CaCO_3 ; S Sur-8 oil-well has the most critical condition as to the tendency of formation of BaSO_4 . L-2 and A-6 oil-wells are the most critical in the formation tendency of Fe_2CO_3 .

In relation to the analysis of production, in the case study presented in this paper (G11), after the maintenance work performed in January 2011, a loss of productivity was due to formation damage generated by the use of inadequate completion/control brine.

A nodal analysis for the well G-11, showed a damage ratio of 6 (post brine damage / pre brine damage).

The economic analysis showed that G-11 oil-well productivity losses represents close to USD 10 million for the assessment of a 6-year scenario.

Nomenclature

| | |
|------------------------------------|--------------------------------|
| SEM | = Scanning Electron Microscope |
| Unit K1 | = Producing formations K1 |
| Unit T2 | = Producing formations T2 |
| Unit K2 | = Producing formations K2 |
| g/cm³ | = grams/cubic centimeter |
| lb/gal | = pounds/gallon |
| W/O | = water in Oil emulsion |
| NH4Cl | = Ammonium chloride |
| NaCl | = Sodium chloride |
| NaBr | = Sodium Bromide |
| KCl | = Potassium chloride |
| CaCl | = Calcium chloride |
| CaBr | = Calcium bromide |
| ZnBr₂ | = Zinc bromide |
| AFQ | = Physical Chemical Analysis |
| ST | = Tendency to form scale |
| BaSO₄ | = Barium Sulfate |
| CaCO₃ | = Calcium Carbonate |
| Fe₂O₃ | = Iron oxide |
| BaCO₃ | = Barium Carbonate |
| μm | = micro meter |
| AOF | = Absolute Open Flow |
| VPN | = Net Present Value |

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