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Prediction of Thermal Induced Fracture during Waterflooding in a High Pressure High Temperature Field in Offshore Brazil

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SUMMARY: Waterflooding is still the most used method to keep pressure and improve oil recovery from petroleum fields. One important phenomenon to be considered during the water injection project is the possible occurrence of a thermal induced fracture in a injection well due to the difference between reservoir and injected water temperatures. This difference reduces the initial stress state of the reservoir, also decreasing the fracture pressure, and the induced fracture will propagate at a lower pressure than those calculated by isothermal methods. This work describes a methodology to estimate the impact of a fracture propagation in a waterflooding project in an offshore brazilian High Pressure High Temperature (HPHT) field. The object is to study the possible conditions that a thermal induced fracture can occur and estimate the main parameters that affect the process, like horizontal and vertical penetration of the fracture and propagation pressure. The results indicates that the probability of thermal induced fracture is very high and, due to the reservoir depth and geological environment, it is quite possible to have benefits from its application.

KEYWORDS: Fracture Propagation, Cold Water Injection, Thermal Induced Fracture.

1 INTRODUCTION

Reservoir Geomechanics has become a relevant subject for the petroleum industry during the last decades. There are many benefits on improving geomechanics understanding, including: better characterization of reservoir volume deformation and impact on rock permeability (compaction and dilation); prediction of surface subsidence; reducing risks of fault reactivation; and fracture propagation during waterflooding or other improved oil recovery process.

In Petrobras, Reservoir Geomechanics is a fundamental tool to develop fields with large number of faults/fractures, which is the case of several offshore sandstone and carbonate reservoirs.

By the other hand, waterflooding is still the most used method to keep pressure and improve oil recovery from petroleum fields.

One important phenomenon to be considered during a water injection project is the possible occurrence of a thermal induced fracture in the injection well due to the difference between reservoir and injected water temperatures.

This difference reduces the initial stress state of the reservoir, also decreasing the fracture pressure, and the induced fracture will propagate at a lower pressure than those calculated by isothermal methods.

In this case, the system operates with Injection with fracture propagation pressure, a technique widely used by petroleum operators in order to keep the predicted injection rate, but sometimes also avoided to minimize geomechanical risks, like an impact in sweep efficiency (Souza et al, 2005) or communication between different layers or even exudation (Pereira et al, 2014).

In this work, a methodology to estimate the impact of a fracture propagation in a waterflooding project in an offshore brazilian

High Pressure High Temperature (HPHT) field is presented.

The object is to study the possible conditions that a thermal induced fracture can occur and estimate the main parameters that affect the process, like horizontal and vertical penetration of the fracture, propagation pressure and so on.

The Mechanical Earth Model (MEM) was developed in two stages: the main geomechanical parameters were obtained by lab and log data and correlations available in the literature; and the initial stress state was calculated by data available from density logs and field tests like leak-off (LOT) and mini-fracs.

A set of reservoir data was supplied by the asset and two in-house programs were used for the simulations.

2 INJECTION WITH FRACTURE PROPAGATION PRESSURE

Injection with fracture propagation pressure (IFPP) occurs when a fluid, normally water, is injected in the reservoir and the pressure reaches the formation breakdown pressure. After that, a fracture is opened and the injected fluid propagates the fracture with a speed that depends on the injection rate and several other parameters, like water quality, reservoir permeability, etc.

The technique is normally used to keep the injection rate without the need of water cleaning and well interventions, and Petrobras has used it in the past with this objective. However, the lack of information on how the fracture grows throughout the formations above the reservoir made its application to be reduced.

In fact, some injection wells in onshore fields still use IFPP as they started this technique in the 1990's and there is no clear evidence that the fractures created are closed now. Some offshore wells are probably also injecting at fracture conditions due to thermal induced fracture effect (Perkins and Gonzalez, 1982). A recent internal work showed that the break-down pressure reduction due to thermal effect in some carbonate fields could reach up to 500 psi.

3 FIELD X DESCRIPTION

Field X is a sandstone reservoir located in water depth of 2500 m with its top being at 5544 m. Its initial reservoir pressure is 581 bar and the temperature is 114 ºC, making it a HPHT field. It will be developed by vertical wells. The main reservoir characteristics are showing in Table 1.

Table 1. Reservoir characteristics of Field X.

Parameter	Value
Top depth (m)	5544
Oil thickness (m)	42
Oil API	38
Oil viscosity (cp)	0.23
Porosity (%)	14
Permeability (D)	0.14
Reservoir Pressure (bar)	581
Reservoir Temperature (ºC)	114
Rock Thermal Expansion Coefficient (1/ºC)	7.5×10^{-6}

A waterflooding project is planned using sea water with a SRU to start together with the field development. IFPP will probably happen some time during the production due to the high difference between reservoir and injection water temperatures.

In order to give a fast response on how a fracture propagation will behave in such conditions, a study was carried using two in-house simulators. These simulators are based on both finite elements method and from analytical solutions given by Carter (Howard And Fast, 1957), PKN method (Perkins and Kern, 1961, Nordgren, 1972) and Perkins and Gonzalez (1981, 1982) models. A description of the equations used in this paper can be found in Souza et al (2005).

Injection data are given in Table 2. Geomechanical data were obtained from logs, LOT, mini-frac and lab tests and are presented in Table 3.

Table 2. Injection data for waterflooding in Field X.

Parameter	Value

Injection Rate (m^3/day)	5000
Injectivity Index (m^3/day/bar)	29
Water density (kg/m^3)	1000
Water temperature (ºC)	30
Water viscosity (cp)	0,79
Distance between wells (m)	1500

Table 3. Geomechanical data for Field X.

Parameter	Value
Young Modulus (GPa)	12
UCS (MPa)	42
Biot Coeficient	0.79
Traction Resistance (bar)	21.4
Poisson Coefficient of Reservoir	0.22
Poisson Coefficient of Shale	0.32
Vertical Stress (bar)	894
Minimum Horizontal Stress (bar)	769
Maximum Horizontal Stress (bar)	894

From those data, isothermal fracture pressure for permeable formation and good quality water is given by (Yew, 1997):

$$P_f = \frac{3\sigma_h - \sigma_H - \eta P_r + T}{2-\eta} \quad (1)$$

Where:

$$\eta = \alpha \frac{1-2\nu}{1-\nu} \quad (2)$$

Which gives the value of 771 bar.

The reduction due to temperature difference between reservoir and injected water is given by (Peerkins and Gonzalez, 1981):

$$\Delta\sigma_T = \frac{E\beta\Delta\theta}{(1-\nu)} F_0 \quad (3)$$

With F_0 given by:

$$F_0 = 0,5\left[1 + \frac{1}{1+1,45(h_o/d)^{0,9} + 0,35(h_o/d)^2}\right] \quad (4)$$

Where d is the diameter of cold region.

For temperature difference of 90 ºC between reservoir and injected water, fracture pressure reduces to 720 bar.

Initial injection pressure for the given II, reservoir pressure and rate is calculated as:

$$P_i = P_r + Q / II \quad (5)$$

Given the value of 754 bar, which is higher than Pf, meaning that, for the base case, the initial injection pressure must be set to Pf and the fracture starts at the beginning of the injection.

3 FRATURE PROPAGATION

In order to study the behavior of fracture propagation, some uncertainty should be included in parameters that may have a high impact in the results, which are the rate, water temperature and rock thermal expansion coefficient.

In this way, a base case was chosen with Q = 5000 m^3/day, θ_w = 30 ºC and β_r = 7.5 x 10^{-6} ºC^{-1}.

For these data, the pressure behavior is presented in Figure 1. It decays with time due to the temperature difference between reservoir and injected water.

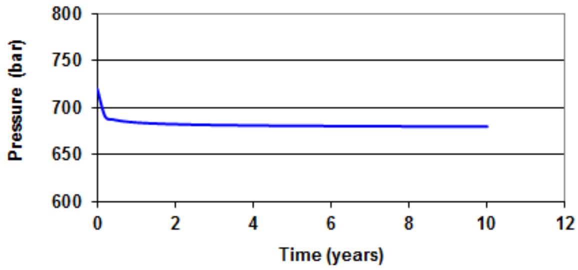

Figure 1. Pressure with time for base case.

The length of the fracture with time is shown in Fig. 2. It reaches almost 400 m after 10 years of injection.

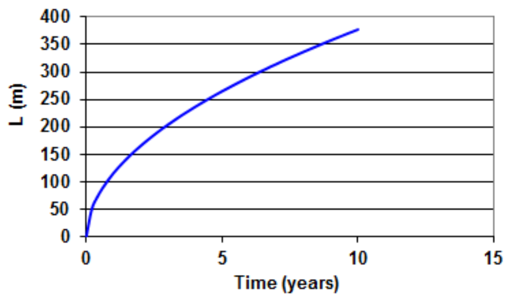

Figure 2. Fracture length with time for base case.

Vertical penetration above the reservoir is presented in Fig. 3. It is practically negligible for this situation.

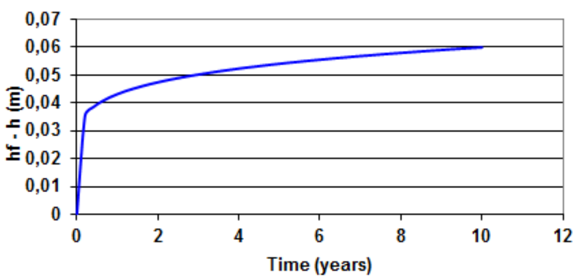

Figure 3. Vertical penetration of Fracture with time for base case.

Figure 4 shows the behavior of Injectivity Index (II) with time for both situations where the injection is with fracture conditions (blue line) and when it is below fracture pressure, that is, matrix injection (green line). It can be seen the great advantage of using IFPP: while II decays with time for matrix injection, it grows and stabilizes in a higher value for IFPP.

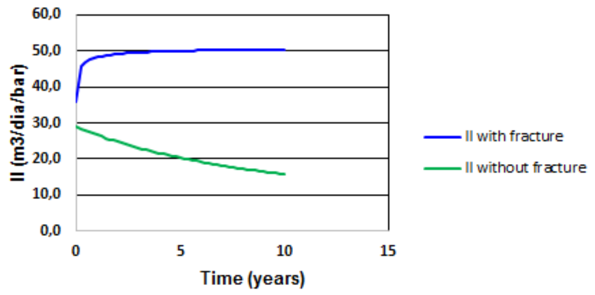

Figure 4. Injectivity Index with time for base case.

Figure 5 shows a schematic plot of the elliptical water and temperature fronts at the end of the simulation, that is, after 10 years of injection.

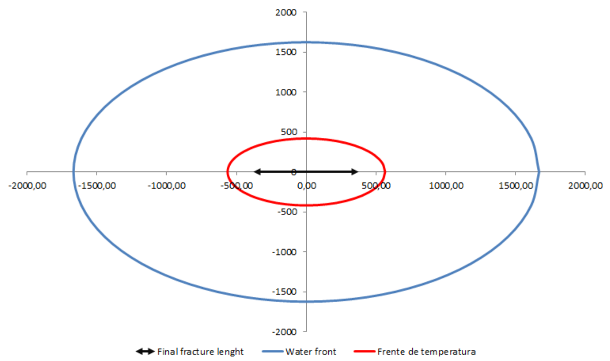

Figure 5. Water and temperature fronts after 10 years of injection (distances in meters).

4 PARAMETERS VARIATION

The parameters chosen of the base case were varied creating a range for each of then. After some runs, it was realized that the variations in water temperature and in rock thermal expansion coefficient would lead to similar results, so that the variations in parameters were summed up to rate and rock thermal expansion coefficient.

In this way, the values for rate were defined as 3500, 5000 and 6500 m^3/day and for rock thermal expansion coefficient as 1 x 10^{-6}, 7.5 x 10^{-6} and 1 x 10^{-5} ºC-1.

Figures 6, 7 and 8 shows the variation of pressure, fracture length and vertical penetration with time for the three selected rates. As expected, the higher is the rate, the deeper is the penetrations. For the lowest rate (3500 m3/day), fracture starts more than 2 years after the beginning of injection, which explains why the pressure increases and then drops after reaching the fracture pressure.

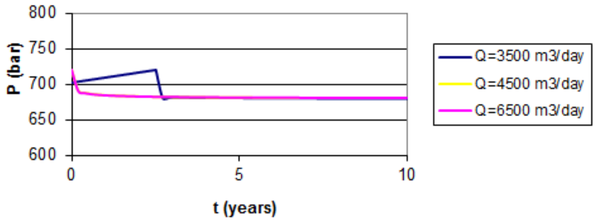

Figure 6. Pressure with time for the selected rates.

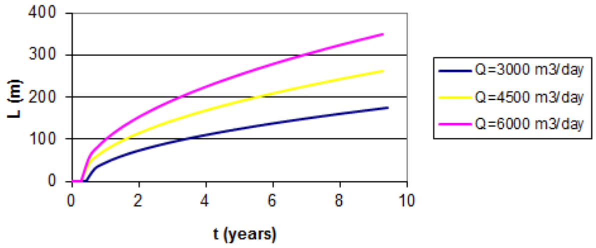

Figure 7. Fracture length with time for the selected rates.

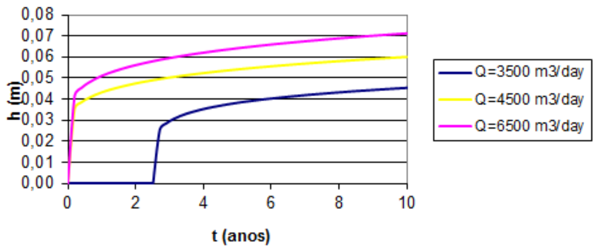

Figure 8. Vertical penetration of Fracture with time for the selected rates.

Figures 9, 10 and 11 shows the variation of pressure, fracture length and vertical penetration with time for the three selected rock thermal expansion coefficients. For the lowest β ($1x10^{-6}$ $^oC^{-1}$), the impact of temperature difference is low and fracture starts later, with the pressure remaining higher than the other two values. One important point to emphasize for this situation is the fact that the vertical penetration starts later but is higher, since the stress contrast with the surround formation is lower due to the higher reservoir pressure.

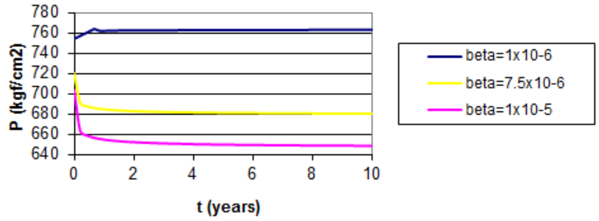

Figure 9. Pressure with time for the selected betas.

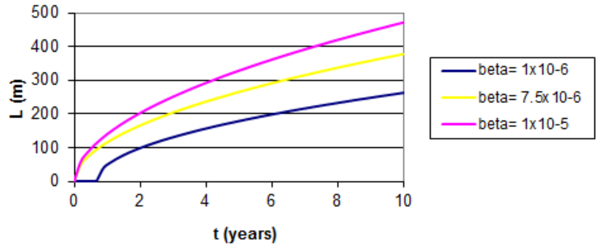

Figure 10. Fracture length with time for the selected betas.

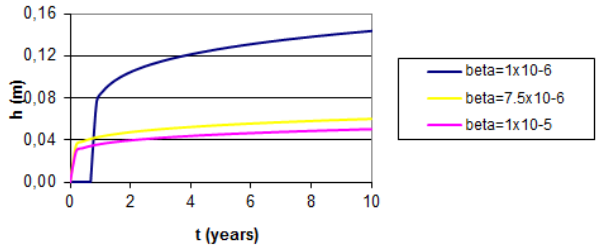

Figure 11. Vertical penetration of Fracture with time for the selected betas.

4 CONCLUSIONS

The probability of thermal induction fracture for field X is very high, due to the temperature difference between reservoir and injected water.

The horizontal length of the fracture is high but should not have an impact in sweep efficiency due to the large distance between wells.

The vertical penetration of the fracture throughout the overburden is very low and is also mitigated by the temperature effect, which reduces the stress in the reservoir, increasing the stress contrast with the surrounding formation.

It is recommended to start the injection with low rates and increases it slowly in order to postpone the fracture induction.

Some practical recommendations should be implemented, such as collect more geomechanical data during well drilling, measure water temperature at bottom conditions and use of anticorrosive material in the well column.

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NOMENCLATURE

Latin:

E – Young Modulus (bar)
HPHT – High Pressure High Temperature
h – Thickness
II – Injectivity Index (m3/day / bar)
L – Length (m)
LOT – Leak-off Test
MEM – Mechanical Earth Model
Q – Rate (m3/day)
SRU – Sulfate Removal Unit
T – Traction resistance (bar)
t – Time (years)
UCS – Unconfined Compressive Strength (MPa)

Greek:
α - Biot Coefficient
β (beta) - Thermal Expansion coefficient
ν - Poisson coefficient
σ - Stress (bar)
θ - Temperature

Subscripts:

h – Minimum
H - Maximum
w – Water
o – Oil
r – Rock or Reservoir
f - Fracture

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