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Research on the Optimisation of Hydraulic Fracturing Operations

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Abstract

Fracturing fluids can be classified in terms of basic components into the following categories: hydrocarbon-based fluids; water-based fluids; emulsion-type combined fluids; foam-based fluids [1, 2]. The main role of the fracturing fluid is to transmit the necessary pressure to the layer that is to be subjected to the operation and to carry the agent that maintains the fracture open during well operation. The present paper analyses two important properties of fracturing fluids, i.e., viscosity and filtration. Furthermore, three fracturing fluid compositions are detailed for three vertical wells. Two case studies on fluid lost through fracture cracks (estimated via overall filtration coefficient) aim to complete this study on the optimisation of hydraulic fracturing operations.

Key words: *fracturing fluids properties, fracturing fluids composition, fracturing fluids loss, total filtration fluid loss coefficient*

Fracturing Fluid Types and Their Main Properties

Viscous oil products (refined oils), light petroleum products (kerosene, diesel) thickened or processed into gel via additive treatment, as well as plain or thickened crude oil belong to the *hydrocarbon fluid category*.

Water-based fracturing fluids can be linear gels (non-crosslinked) or crosslinked gels, based on freshwater, seawater, or KCl brine. This category also includes water and acid solutions – in usual or gel state – and is particularly suitable for the fracturing of water injection wells.

Emulsion-type fracturing fluids include kerosene in hydrochloric acid, water in oil, etc. System stability is ensured by an emulsifier, which has the role of breaking emulsions upon layer entry [1, 2, 5, 6].

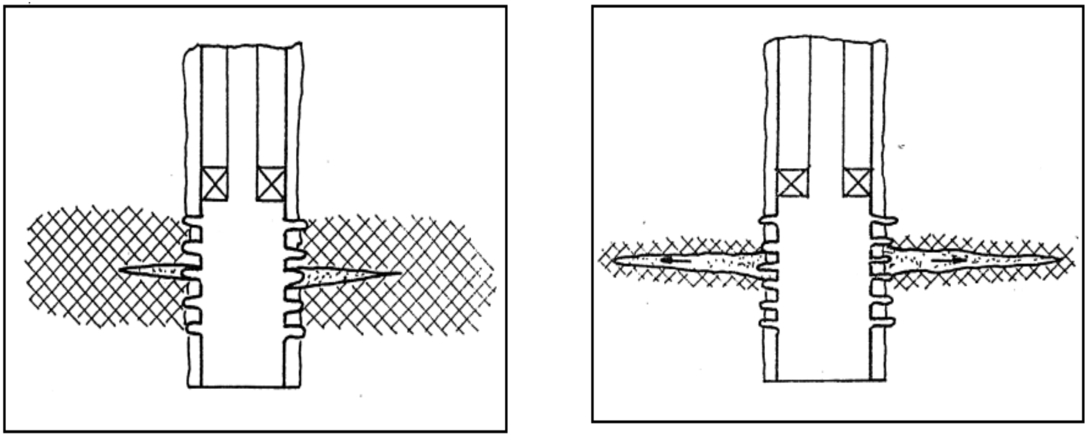
Most *foams* used in fracturing operations consist of 20 - 40% liquid volume and 60 - 80% gas volume. The liquid can be water, a mixture of water and methanol, acids or crude oil.

Among the properties of fracturing fluids, the most important ones are viscosity and filtration, properties that are important to the geometry of the layer fracture.

High viscosity fluids are excellent when it comes to transporting and maintaining the fracturing support material suspended and do not require large pumping volumes. Low viscosity fluids require large pumping volumes in order to provide the necessary transportation velocity of the fracturing support material.

A crucial role regarding the extension degree of the initial fracture is played by the characteristics of the layer fracturing fluids (figure 1).

Generally, the following fracturing fluid additives are used: *gel stabilizers* (used to prevent gel degradation at a temperature of about 93°C); *buffer solution*s (added to the fracturing fluid to maintain the pH at the required value); *gel breakers* (used to eliminate the gel upon well operation); *bactericide* (viscosity loss prevention as a result of degradation under the influence of bacteria); *surfactants* (surface active agents that are absorbed upon immiscible substance interference); *clay stabilizers*; *fluid loss control additives*, etc. [1.5].



a) b)

Fig. 1. Fracturing fluid effect: a – with high filtration; b – with low filtration

Choosing fracturing fluid type is conditioned by the lithology of the treated layer, by the physical properties of the collector rocks (table 1) and by the properties of the fluid, which saturate the pores of the collector rocks. Fracturing fluid types used in 3 production wells Table 1 [7, 8].

Table 1. Fracturing fluid types used in 3 production well

Well characteristics	**Well 1**	**Well 2**	**Well 3**
Column	$5^{1/2}$ in	$8^{5/8}$ in + liner $5^{1/2}$ in	7 in
Mirror	3053 m	988 m	1293 m
Perforated Interval	20 m	10 m	12 m
Lithology	Coarse sandstone with mixed cement, micro-conglomerated in places	Alternation of marls, sands and sandstones with rare conglomerate intercalation	Sandstones with marly intercalation
Layer temperature	157^0C	72^oC	81^oC
Porosity	7-15%	7 – 11%	5 – 13%
Permeability	0.95 mD	0.92 mD	0.86 mD
Fracture fluid	Polialcogel with Carbolite-type support agent	Acid emulsion	Romfrac-type neutral emulsion
Used fracturing fluid volume	80 m^3 of Polialcogel and 9 tons of Carbolite	60 m^3	80 m^3
Fracturing fluid injection flow	2400 l/min	2700 l/min	1700 l/min
Fracturing fluid injection pressure	700 bar	405 bar	400 bar

Table 2. Fracturing fluid composition [7, 8].

No.	Fracture fluid type	Composition	m^3 fluid quantity
1	Polialcogel	Freshwater E-96 (SP 15-75) Polyvinyl alcohol (dust sort 120-88) Methanol Borax Sodium Hydroxide	797.5 l 2.5 l 2.5 kg 200 l 2.5 kg 0.5 kg
2	Acid emulsion	Turnu E (Calacea) crude oil Bodrog (Sânpetru) crude oil Xylem Romamid DT Acetic acid Acid solution	74 l 112 l 14 l 7 l 3 l 790 l
3	Romfrac-type neutral emulsion	Sânpetru crude oil Saltwater Romamid DT	200 l 793 l 7 l

Fracturing Fluid Loss Case Studies

Filtration fluid loss during fracturing treatment is a process controlled by a number of factors such as: fracturing fluid composition, pumping pressure, reservoir properties (permeability, porosity and saturation), microcrack presence.

Total filtration fluid loss coefficient C_L is treated as a function of these parameters and is given by relation [1, 2, 5]:

$$\frac{1}{C_L} = \frac{1}{C_v} + \frac{1}{C_d} + \frac{1}{C_t}, \tag{1}$$

where: C_v represents the filtration fluid loss coefficient controlled by viscosity;
C_d – diffusion filtration coefficient (or the coefficient of fluid loss controlled by formation fluid compressibility C_c);
C_t – cake filtration coefficient (or fluid loss coefficient controlled by the filter cake).

The viscosity-controlled filtering coefficient C_v is determined using the following relation: [1, 3, 4, 6].

$$C_v = \sqrt{\frac{km\Delta p}{2\mu_f}}, \tag{2}$$

where: k is the absolute permeability of the productive layer rocks;
m – absolute porosity of the productive rock layer;
Δp – pressure difference between input fluid pressure and reservoir pressure;
μ_f – fracturing fluid viscosity while in reservoir.

The diffusion filtration coefficient C_d, also known as the fluid loss coefficient determined by formation fluid compressibility, is calculated using the following relation:

$$C_d = \Delta p\sqrt{\frac{km\beta}{\pi\mu}}, \tag{3}$$

where: μ represents the formation fluid dynamic viscosity (crude oil);
β – formation fluid dynamic compressibility.

The cake filtration coefficient is calculated using the following equation [1, 3, 4, 6]:

$$C_t = \sqrt{\frac{C k_t \Delta p}{2\mu_f}}, \tag{4}$$

where: *C* represents the ratio coefficient;
k_t – cake permeability;
μ_f – formation fluid dynamic viscosity.

The cake filtration coefficient C_t is determined in the laboratory, is specific to each fluid and is dependent on fluid composition as well as collector rock characteristics.

Knowing the physical properties of the collector rocks and of the fracturing fluids, the overall filtration coefficient of *well 1* can be estimated using calculation models (1) - (4) upon hydraulic fracturing operation (see table 3).

Table 3. Reservoir and fracture fluid characteristics [7]

Collector rock and fracturing fluid properties	Measurement unit	Value
Productive formation *k* permeability	mD	1
Formation fluid viscosity	cP	1
Δp formation pressure drop	Pa	30
Production formation *m* porosity		0.15
Fracture fluid μ_f viscosity	cP	15
Cake filtration coefficient C_t	$m/\sqrt{s}$;	$3.95\cdot.10^{-5}$
Crude oil compressibility coefficient β_t	Pa^{-1}	$1.37\cdot 10^{-9}$

Table 4 showcases the influence of the cake filtration coefficient on the overall fluid loss coefficient.

Table 4. Fluid loss coefficients

Filtration coefficients	**Initial data values ($m/\sqrt{s}$)**	**Values after C_t halving ($m/\sqrt{s}$)**	**Values after C_t doubling ($m/\sqrt{s}$)**
C_v	$3.87\cdot10^{-4}$	$3.87\cdot10^{-4}$	$3.87\cdot10^{-4}$
C_d	$2.42\cdot10^{-4}$	$2.42\cdot10^{-4}$	$2.42\cdot10^{-4}$
C_t	$3.95\cdot10^{-5}$	$1.97\cdot10^{-5}$	$7.9\cdot10^{-5}$
C_L	$3.12\cdot10^{-5}$	$1.73\cdot10^{-5}$	$5.16\cdot10^{-5}$

A four-fold increase in cake filtration coefficient leads to a three-fold increase in overall coefficient. Variation of CL with Ct is presented in Figure 2.

The influence of fluid viscosity on the overall fluid loss coefficient was observed. The values of the viscosity control coefficient and overall filtering coefficient are listed in Table 5 and Figure 3.

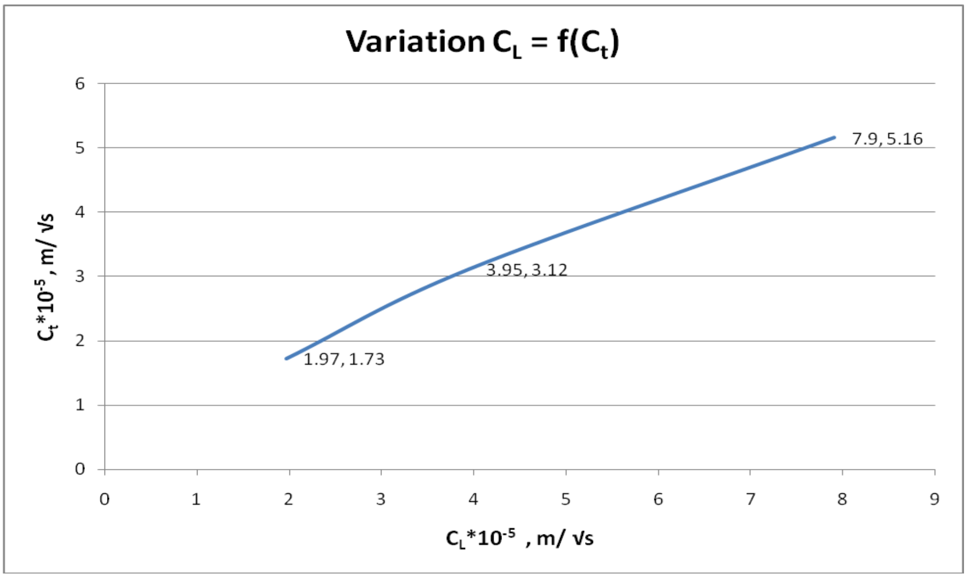


Fig. 2. Variation overall coefficient with cake filtration coefficient

Table 5. Fluid loss coefficients

Parameters	**Measurement unit**	**Initial value**	**Recalculated value**
μ_f	cP	**15**	**1.5**
C_v	$m/\sqrt{s}$	**$3.87 \cdot 10^{-4}$**	**$1.22 \cdot 10^{-3}$**
C_d	$m/\sqrt{s}$	$2.42 \cdot 10^{-4}$	$2.42 \cdot 10^{-4}$
C_t	$m/\sqrt{s}$	$3.95 \cdot 10^{-5}$	$3.95 \cdot 10^{-5}$
C_L	$m/\sqrt{s}$	$3.12 \cdot 10^{-5}$	$3.30 \cdot 10^{-5}$

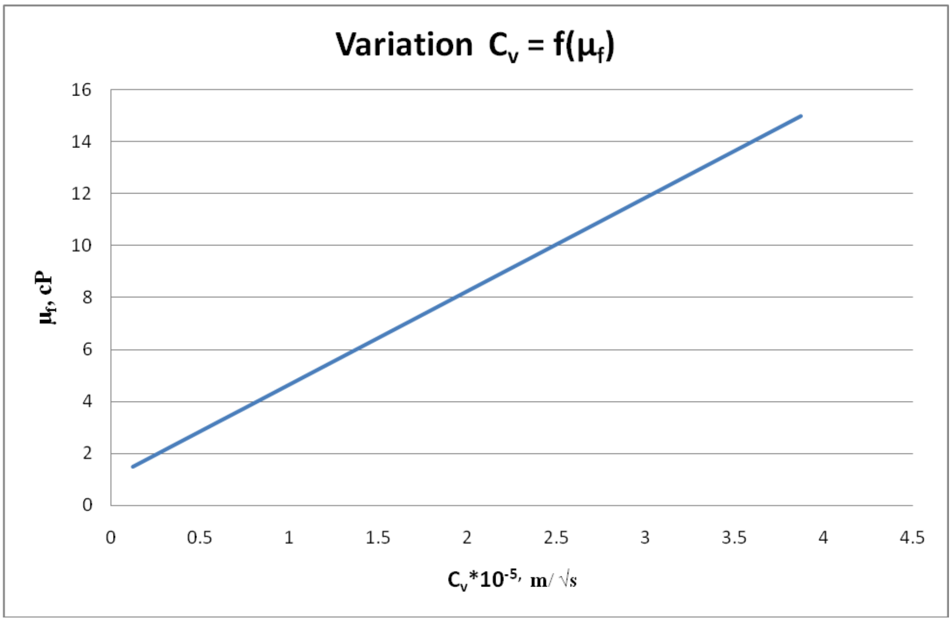


Fig. 3. Variation of viscosity-controlled filtering coefficient with fluid viscosity

Conclusions

The present study reveals the impact of the cake filtration coefficient on the overall fluid loss coefficient and the need for determining under laboratory conditions the physical properties of the fluids contained by the layer that is to be subjected to hydraulic fracturing, as well as the properties of the fracturing fluids and collector rocks.

The exact requirements of each reservoir and well must be observed if the correct fracturing fluid is to be chosen for a particular operation.

The 10-fold decrease of fracturing fluid viscosity (from 15 cP to 1.5 cP) leads to a 3-fold increase in the viscosity control coefficient, whereas the overall loss coefficient barely increases (almost remains constant).

The 1.5 cP viscosity of the considered fracturing fluid is very close to crude oil viscosity values in the layer (1 cP), which leads to an increase in fracture fluid lost through fracture cracks. It is for this reason that crude oil must not be used as fracturing fluid, but only gelled oil for viscosity increase leading to reductions in fluid loss through the fracture cracks (as shown in figure 1).

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Asupra unor elemente de eficientizare a operaţiei de fisurare hidraulică

Rezumat

Fluidele de fisurare pot fi clasificate din punct de vedere al componentului de bază în următoarele categorii: fluide pe bază de hidrocarburi; fluide pe bază de apă; fluide combinate de tipul emulsiilor; fluide pe bază de spume [1, 2]. Rolul principal al fluidului de fisurare este acela de a transmite presiunea necesară asupra stratului care urmează a fi supus operației, respectiv de a transporta agentul care va menţine fisura deschisă în timpul funcţionării sondei. În cazul lucrării de faţă sunt analizate două proprietăţi importante ale fluidelor de fisurare: vâscozitatea şi filtraţia. De asemenea, sunt prezentate trei rețete de fluide de fisurare, pentru trei sonde verticale. Două studii de caz privind pierderile de fluid prin fețele fisurii (estimate printru coeficient global de filtrare), vin să completeze elementele de eficientizare a unei operaţii de fisurare hidraulică.