25th ABCM International Congress of Mechanical Engineering
October 20-25, 2019, Uberlândia, MG, Brazil

COB-2019-1384
THE LOST CIRCULATION EFFECT IN A SINGLE FRACTURE ON A WELLBORE TEMPERATURE PROFILE

James Luigi Romano
Fernando Cesar De Lai
Silvio Luiz de Mello Junqueira
Research Center for Rheology and Non-Newtonian Fluids – CERNN, Graduate Program in Mechanical and Materials Engineering – PPGEM, Federal University of Technology – Paraná – UTFPR, Curitiba-PR 81280-340, Brazil
james@alunos.utfpr.edu.br, fernandodelai@utfpr.edu.br, silvio@utfpr.edu.br.

Abstract. *During drilling operations, the wellbore temperature profile is used when selecting well casing materials, making cementation related decisions, and, most importantly, identifying loss zones. In this work, a transient heat transfer mathematical model for a fractured wellbore is proposed. The well has its geometry simplified to a concentric annular cylinder that presents one discrete fracture in its external wall (well-formation interface). The thermal model is obtained with the first law of Thermodynamics, focusing the heat interactions between the pipe, the annular region and the formation. The key characteristic of the model is the fracture detection through thermal gradient graphical analysis. The thermal gradient is an output of the solution of the discretized energy equation in all domains, obtained through the finite volume method. The investigated parameters were the loss circulation and drilling fluid viscosity profile. Results discussion relies on the analysis of the transient annular region temperature profile and its gradient. It is verified that increasing loss rate favors fracture detection, since the discontinuity in the annular region thermal gradient profile is intensified. In addition, it provokes cooling in the whole annulus extension.*

Keywords: *loss zone location, temperature profile, drilling fluid*

1. INTRODUCTION

The eventual leakage of drilling fluid from the wellbore to the formation occurring through the discontinuities in the wellbore walls is called the lost circulation. This phenomenon occurs when highly fractured, porous or cavernous zones present pressure values higher than the one observed in the adjacent substrate (Cook et al., 2011). Since it is an undesirable phenomenon, one expects to control it through different processes and techniques. One corrective way to control the fluid loss and to enable the flow to return to its original state inside the wellbore consists in adding particles with selected granulometry along with the drilling fluid (Whitfill, 2003). Such particles are nominated lost circulation materials – LCM.

According to Chen et al. (2014), corrective measures involving LCM can be improved knowing the number of fractures and their respective positions. Understanding such process can help evaluating not only the need of additional coating and estimating the depth at which wall cementation will be done, but also to assist the drill, valves and equipment selection (Santoyo, 1997). There are multiple ways to measure lost circulation: Radioactive or electromagnetic methods (Firminhac, 1956), diffraction tomography (Tura et al., 1992), microseismic analysis (Dai et al., 2011) and multifocal diffraction (Bloch et al., 2003). Methods such as nuclear magnetic resonance, diffraction tomography and electromagnetics have practical issues locating fractures (Rauch-Davies et al., 2014). Meanwhile, microseismic analysis is not suitable for low thickness fracture detections (Maxwell, 2009), since it cannot assimilate such limited dimensions.

An alternative method to the fracture detection, developed by Chen et al. (2017), consists in locating the fractured zone location while drilling is in course. According to their numerical approach, the temperature measurements throughout the wellbore extension can be used to determine the fracture locations. This work proposes a generalization of the Chen et al. (2014) model, by considering viscosity as a function of temperature, aiming to improve the heat transfer coefficients accuracy.

2. PROBLEM FORMULATION

Consider Fig. 1 as a simplified representation of a wellbore that consists of two concentric cylinders with height L. The drillpipe has a radius r_c and the distance between the formation interface and the center of the wellbore is represented by r_p. The figure also presents 5 regions identified as the drillpipe itself (1), the transition zone between the drillpipe and the annulus (2), the annular section below the fracture (3), the annular section above the fracture (4) and the surrounding formation (5). The drillpipe inlet temperature is prescribed as T_0 and a continuity boundary condition is imposed at the bottomhole, where the drillpipe and the annular temperatures are equal. Moreover, at the fracture depth temperature continuity is imposed in the transition between subdomains 3 and 4 (T^U=T^L). From a radial distance that is far enough from the center of the wellbore, the rock formation is considered thermally undisturbed and a linear geothermal temperature profile is assumed. In addition, a fully developed condition is imposed and the loss rate through the discrete fracture is constant. The thermophysical properties are assumed constant, except the viscosity, which is a function of temperature, and the heat generated by viscous dissipation is neglected.

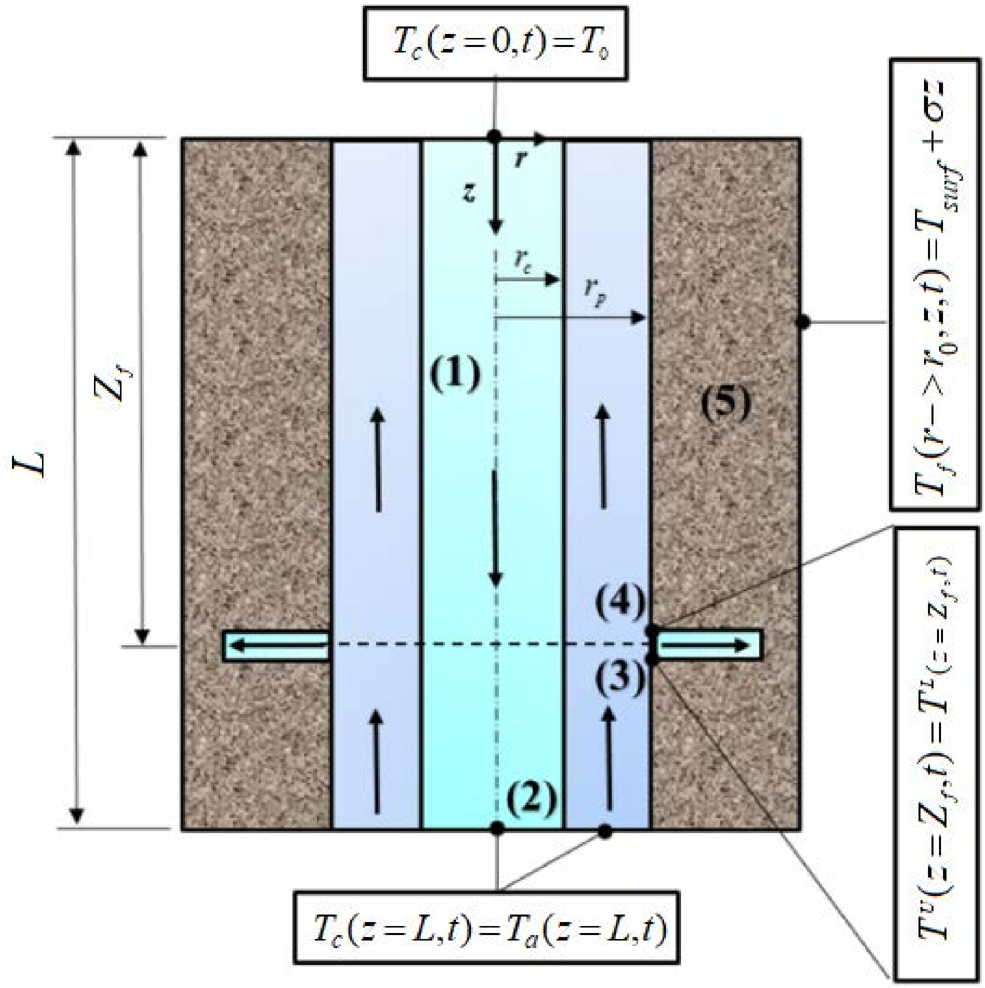

Figure 1. Schematic representation of a single fracture wellbore and its boundary conditions

In the axial direction, one considers convection heat transfer as the dominant regime. For the radial direction, only conduction in the annular region is considered. At the borehole, heat exchange between the fluid and the formation is also neglected.

Besides the convection along the flow direction in the annular region, conduction exists between the annulus and both the drillpipe and the formation. Along the formation, the dominant regime is heat conduction.

Obtaining energy equations for the drilling fluid in the drill pipe, annulus and formation is done through control volume energy balance for a small interval Δz as shown in Fig. 2. Hence, the following equations are obtained for the drillpipe, annulus and formation, respectively:

$$c_m \dot{m}_c T_c(z+\Delta z,t) - c_m \dot{m}_c T_c(z,t) = 2\pi r_c U_{ac}(T_a - T_p)\Delta z - c_m \rho A_c \Delta z \frac{T_c(z)}{t} \quad (1)$$

$$c_m \dot{m}_a T_a (z+\Delta z,t)\Delta t - c_m \dot{m}_a T_a (z,t)\Delta t + 2\pi r_p \Delta z h_{af} (T_p - T_a) - 2\pi r_c \Delta z U_{ac} (T_a - T_c) = \\ = c_m \rho_m A_a \Delta z \frac{\partial T_a (z)}{\partial t} \quad (2)$$

$$\frac{\partial T_f(z,r,t)}{\partial t} = \alpha_f \left(\frac{\partial^2 T_f(z,r,t)}{\partial r^2} + \frac{1}{r} \frac{\partial T_f(z,r,t)}{\partial r} \right) \quad (3)$$

where $\dot{m}_a$ and $\dot{m}_c$ are the annulus and drillpipe flow rates, respectively; c_m is the fluid specific heat, h_{af} is the heat transfer coefficient between the annulus and the formation, ρ_m represents the fluid specific mass, T_a, T_p, and T_c are the annulus, wall and drillpipe temperatures respectively, U_{ac} denotes the global heat transfer coefficient, α_f is the thermal diffusivity and A_a and A_c are the annulus and column areas, respectively.

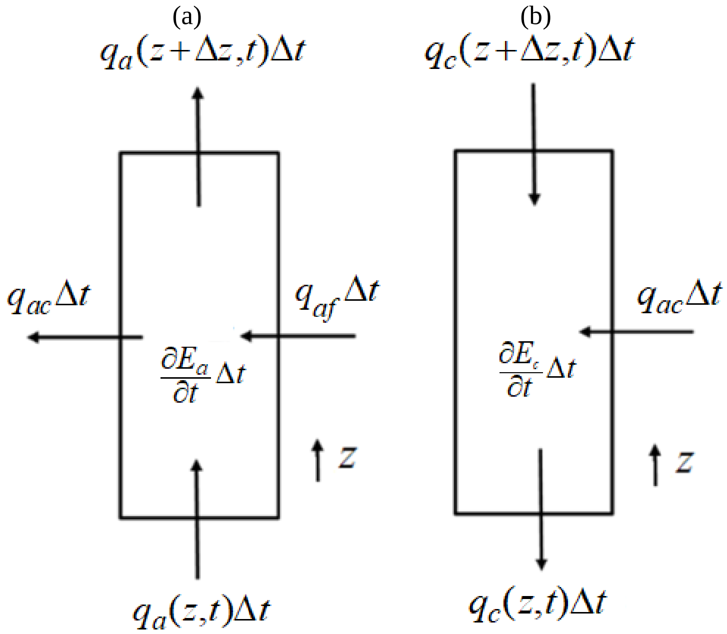

Figure 2. Energy balance for control volumes in the (a) annulus and (b) drillpipe.

The heat transfer function coefficient h is a function of the thermophysical and transport properties of the drilling fluid and the wellbore geometry and its obtainment is a complex task. Therefore, numerical correlations, which are dependent on the flow dimensionless groups, are utilized, as shown in Table 1.

Table 1. Heat transfer coefficient correlations

Correlation	Conditions
$Nu = 4,364$	$Re < 2300$
$Nu = 0.023 Re^{0.8} Pr^{0.333} \left(\frac{\mu}{\mu_w} \right)^{0,14}$	$\begin{bmatrix} 0.7 \le Pr \le 160 \\ 10000 \le Re \\ L/D \ge 10 \end{bmatrix}$
$Nu = \frac{f/8(Re-1000)Pr}{1+12,7(f/8)^{1/2}(Pr^{2/3}-1)}$ $f = (0,79 \ln(\mathrm{Re}) - 1,64)^{-2}$	$\begin{bmatrix} 0.5 \le Pr \le 2000 \\ 3000 \le \mathrm{Re} \le 5*10^6 \\ L/D \ge 10 \end{bmatrix}$

In Table 1, Nu, Pr and Re are the Nusselt, Prandlt and Reynolds number, respectively, L and D are the pipe length and diameter, respectively, f is the friction factor and μ and μ_w are the drilling fluid viscosities evaluated at the center and the wall of the pipe.

The finite volume method is used to discretize Eqs. 1-3 through an implicit transient formulation. In addition, the heat transfer advective terms are approximated by the upwind scheme (Versteeg et al., 2007).

The criterion for choosing drilling fluids is picking the most different viscosity behavior with the temperature changes. Figure 3 shows the temperature effect on viscosity for fluids f1, f2, f3, f4 and f5. Generating viscosity-temperature correlations for the drilling fluids is a complex task and the data utilized in this work comes from the experimental and numerical work by Cook et al. (2012) and Santoyo et al. (2003). It is worth noting that fluid f1 is a hypothetical fluid, and its viscosity does not change with temperature.

The wellbore conditions, as well as the thermal properties from both the drilling fluid, formation and the well itself were chosen based on the work developed by Chen et al. (2017). The program input data is shown in Table 2.

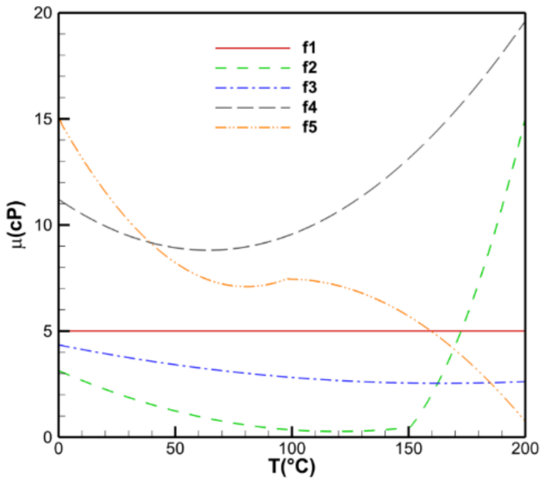

Figure 3. Viscosity profile as a function of temperature for the chosen drilling fluids (Chen et al., 2017).

Table 2. Wellbore and drilling fluid conditions and properties.

Parameter		Value	Unit
Well depth	Z	4500	m
Drillpipe diameter	D_c	0,084	m
Well diameter	D_p	0,156	m
Flow inlet	λ	0,02	m³/s
Temperature inlet	T_0	45	°C
Geothermal gradient	σ	3,311	°C/100m
Formation thermal diffusivity	α	$1{,}2.10^{-6}$	m²/s
Surface temperature	T_{surf}	15,28	°C
Wellbore thermal conductivity	k_p	50	W/m.K
Mud thermal conductivity	k	0,6	W/m.K
Formation thermal conductivity	k_f	1,3	W/m.K

3. RESULTS

The well and fluid conditions from Chen et al. (2017) were chosen to evaluate the results here presented and to illustrate the effect of the drilling fluid viscosity over the thermal profile. Figure 2 shows the effect of the lost circulation intensity (Q = 0.05, 0.10, 0.20) on both the temperature and its gradient profiles along the annular region, for 5 different fluids (f1 to f5).

The effect of the total lost circulation Q on the wellbore annular temperature profile for $z_f = 0.75$ and $t_c = 12h$ is shown in Figure 4. As expected, the temperature profile distortion caused by the fracture is more evident when the lost circulation intensity is raised. Similarly, a higher fluid invasion in the formation decreased the temperature of the entire annular region. The explanation for that is: since there is a decrease in the mass flow after the fracture depth, there will be less heat transfer between the annulus and the drillpipe. The drillpipe will then be at a lower average temperature because it will suffer less influence from the formation, and contribute directly to a lower temperature profile in the annulus.

Fluids f1, f3, f4 and f5 show similar behavior in their temperature profiles. On the other hand, fluid f2 exhibits an increasing temperature gradient as the depth in the annular region decreases near the outlet. For every fluid, the average temperature profile decreases with an increase in the lost circulation from $z_f = 0.75$ (Fig. 4a) to $z_f = 0.20$ (Fig. 4c).

It is important to note that fluid viscosity also plays a big role on fracture detection. Fluids f2 and f3, for example, which have the least average viscosity, suffer the biggest temperature profile changes, especially near the fracture position.

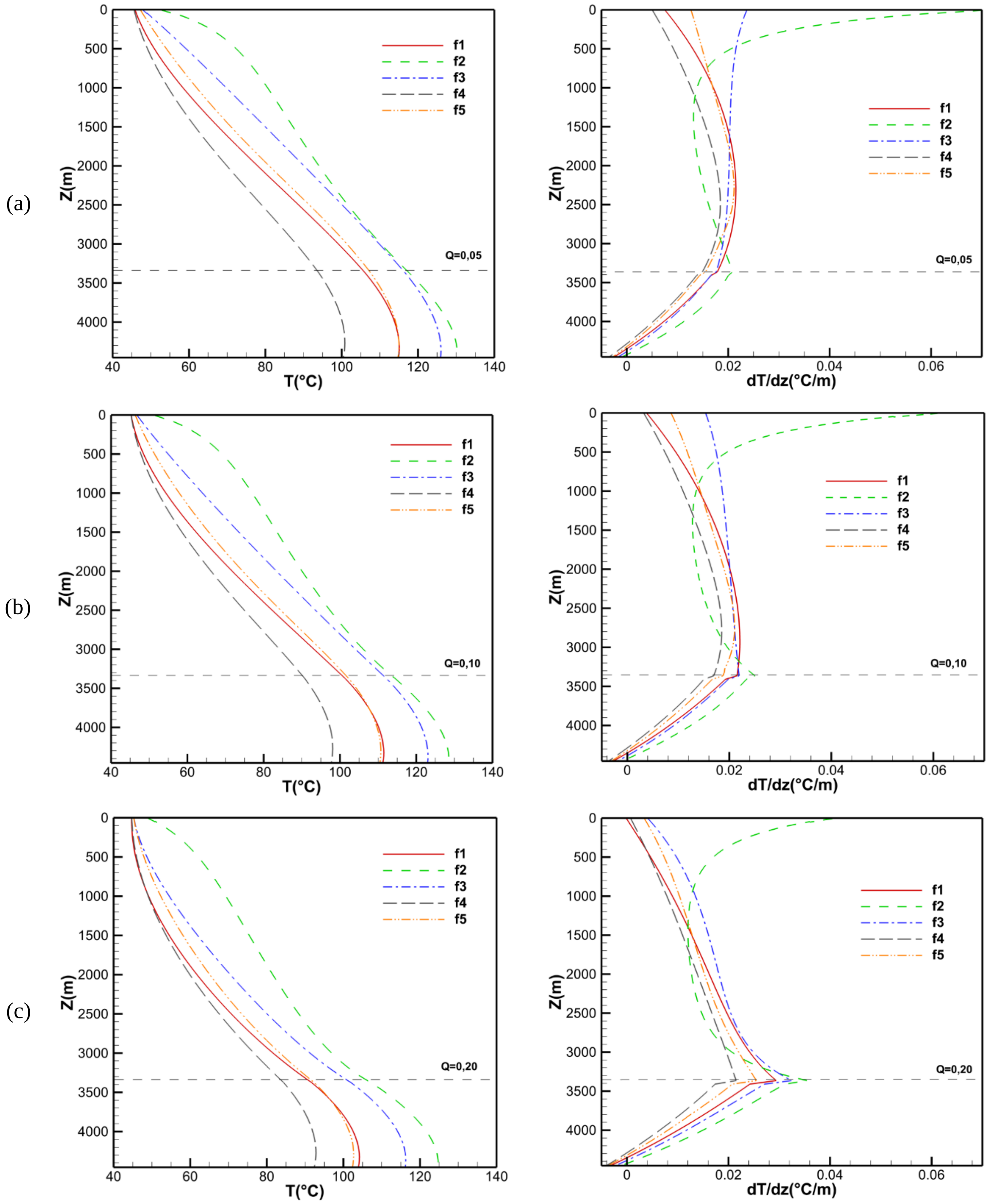

Figure 4. Temperature profile (left) and its corresponding gradient profile (right) in the annular region for different values of total lost circulation Q = (a) 0.05, (b) 0.10 and (c) 0.20.

Comparing the thermal and its correspondent gradient profiles, it is shown that fracture visual detection is facilitated if you observe the gradient temperature profiles, since the discontinuity is present and coincident with the fracture.

Furthermore from Fig. 2, an increase in the lost circulation implicates in a higher level of discontinuity on the gradient temperature profile. Hence, fracture detection easiness is increased with higher levels of mud loss.

4. CONCLUSIONS

In this work the effects of the lost circulation intensity over the annulus temperature and its gradient profile for vertical oil and gas wells containing a single fracture were analyzed.

Preserving the well parameters and increasing the lost circulation, a decrease in the annulus temperature profile was observed. At the same time, an increase in the lost circulation led to a measurable difference in the outlet temperature, in addition to the cooling of the well. Consequently, since the monitoring of the outlet temperature in a field operation is an easy task, it can be used when making decisions related to corrective measures.

The effect of the mud viscosity on the temperature outlet requires further investigation, but its importance was demonstrated in the present results, since fracture detection easiness was linked to the drilling fluid viscosity profile.

Considering the importance of localizing loss zones in the rock formation, the necessity of new techniques in methodologies to detect fractures with higher precision is clear. Since new temperature sensors were developed in the last decade and wellbore temperature profile measurement is becoming a viable method, the developed methodology can aid in field decisions. The provided results may aid in field when deciding if the drilling process should be stopped entirely or not. For example, a corrective measure may be the best option if multiple fractures are recognized in the gradient temperature profile, while shutting down the well might be necessary if there is a single fracture with significant lost circulation. In this situation the operator can decide between multiple corrective techniques. As an example, a common process consists of the injection of lost circulation materials (LCM), aiming to plug these fractures without the necessity of completely stopping the process.

5. ACKNOWLEDGEMENTS

The authors are grateful to the Brazilian Petroleum Agency (ANP), the Human Resources Program for the Petroleum and Gas Sector PRH-ANP (PRH10 – UTFPR) and CENPES-PETROBRAS for the provided financial support.

6. REFERENCES

Bloch, G., El Deeb, M., Badaam, H., Cailly, F., Meunier, A., 2003. Seismic facies analysis for fracture detection: a powerful technique", *Middle East Oil Show*. Society of Petroleum Engineers.

Chen, Y., Yu, M., Miska, S., Ozbayoglu, E., Al-khanferi, N., 2014. "Modeling Transient Circulating Mud Temperature in the Event of Lost Circulation and its Application in Locating Loss Zones", *33rd International Conference on Ocean, Offshore, and Arctic Engineering*, San Francisco, USA. pp 8-11.

Chen, Y., Yu, M., Miska, S., Ozbayoglu, E., Zhou, E., Al-khanferi, N., 2017. "Fluid flow and heat transfer modeling in the event of lost circulation and its application in locating loss zones", *Journal of Petroleum Science and Engineering*, vol. 148, pp. 1-9.

Cook, J., Growcock, F., Gui, Q., Hodder, M., Van Oort, E., 2011. "Stabilizing the wellbore to prevent lost circulation." *Oilfield Review*, vol. 2012, pp. 4.

Dai, H., Ford, R., Yu, C., Wang, J., 2011. "Fracture detection using PS converted waves: A case study." *Daqing oil field, SEG Technical Program Expanded Abstracts. Society of Exploration Geophysicists*, pp. 1318-1322.

Firminhac, R., 1956. "Location of Fractures and Channel by Radioactive Methods, Drilling and Production Practice". *American Petroleum Institute.*

Maxwell, S. C., 2009. "Assessing the Impact of Microseismic Location Uncertainties On Interpreted Hydraulic Fracture Geometries", *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.

Rauch-Davies, M., Pelman, D., Deev, K., 2014 "Fracture Detection Through MultiFocusing Diffraction Imaging", *Case Studies.*

Santoyo, E. R., Garcia, A., Espinosa, G., Santoyo-Gutierrez, S., Gonzalez-Partida, E., 2003. "Convective heat-transfer coefficients of non-Newtonian geothermal drilling fluids", *Journal of Geochemical Exploration*, vol. 78, pp. 249-255.

Santoyo, E. R., 1997. "Transient numerical simulation of heat transfer processes during drilling of geothermal wells", PhD Thesis, University of Salford.

Tura, M. A. C., Johnson, L. R., Majer, E. L., Peterson, J. E., 1992. “Application of diffraction tomography to fracture detection”, *Journal of Geophysics*, vol. 57, pp. 245-257.

Versteeg, H. K., Malalasekera, W., 2007. “An introduction to computational fluid dynamics: the finite volume method.” *Pearson Education.*

Whitfill, D. L., 2003. “All lost-circulation materials and systems are not created equal”, *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.

7. RESPONSIBILITY NOTICE

The authors are the only responsible for the printed material included in this paper.