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Real-Time Fracture Aperture Identification Using Mud Loss Data and Solution for LCM Combination

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Abstract

Managing server lost circulation is a major challenge of drilling operation in naturally fractured formations and it causes much nonproductive rig time. When encountered with loss, the fracture aperture intersecting the wellbore is not well-identified in time, which has a significant impact on the decision of drilling operation and the undesired result of loss curing. Therefore, the onset of fracture is identified in a timely manner and evaluated comprehensively to formulate an appropriate strategy over time. However, the mud loss date, which is the primary source of information retrieved from the drilling process, was not properly used in real-time prediction of fracture aperture. This article provides a detailed mathematical study to discuss the mechanism of mud invasion in the near-wellbore region and prediction of fracture aperture. The fracture aperture can be calculated from mud-loss data by solving a cubic equation with input parameters given by the well radius, the overpressure ratio, and the maximum mud-loss volume. It permits the proper selection of loss-circulation material (LCM) with respect to particle size distribution and fiber usage. The case study illustrates the applicability of this methodology with a discussion on LCM particle distribution in different scenarios and the result demonstrates the outcome of inappropriate LCM usage and the advantages of the novel fiber-based LCM treatment.

Keywords

Mud loss, Fracture Aperture, LCM Selection, Particle-Size Distribution

1. Introduction

Lost circulation, defined as the uncontrolled escape of drilling mud into the formation, presents a significant challenge during drilling operations. However, this problem becomes particularly complex in naturally fractured formations. Unlike induced fractures with more predictable geometries, naturally occurring fractures can exhibit intricate networks, with dominant flow paths often difficult to identify. Conventional lost-circulation materials (LCMs) designed for uniform openings may prove ineffective due to the irregular nature of these fractures. The consequences of lost circulation in fractured formations are multifaceted. Wellbore instability, where the formation weakens and collapses around the wellbore, can occur due to the loss of mud pressure support [1]. Differential sticking, the inability to retract the drill pipe due to pressure imbalances caused by lost circulation, can lead to costly fishing operations [2]. Moreover, lost circulation can compromise well control by allowing formation fluids to enter the wellbore, potentially leading to a blowout scenario. Additionally, the environmental impact of uncontrolled mud loss into the formation cannot be ignored. On the other hand, costs associated with losses are non-productive time (downtime spent controlling lost circulation), additional rig mobilization and operation costs and potential well abandonment due to severe lost circulation. So, the complexity of diagnosing lost circulation arises for the reason on the limited knowledge of a loss mechanism when it occurs. Therefore, the estimation of fracture aperture is the key factor on how to cure lost circulation despite natural or induced mechanism.

Managing lost circulation has historically been simply adding favorite lost-circulation material (LCM) into the drilling fluid and pumping them downhole in hopes of delivering it to the loss zone and waiting for serendipity to occur. Huang and Griffiths [3] briefly surveys more than 200 different solutions presented for lost circulation issues based on different systems and materials. Savari and Whitifill [4] proposed the innovative LCMs based on the concept of a multimodal particle-size distribution (PSD) to plug a range of fracture sizes. The right LCM combination with an appropriate particle-size distribution should be carefully engineered to achieve the capability of efficient fracture plugging [5]. Therefore, knowledge of fracture's apertures in a well of lost occurrence has a strong technical and economic effect on LCM combination selection.

The fracture's width is normally calculated with the fracture stress-intensity factor and the crack with three distinct symmetrical pressurized regions [6]. However, three principal *in-situ* stresses are not easily or accurately obtained once loss occurs from real-time data. Whitfill [7] demonstrated rock mechanics modeling to calculate fracture width with rock elastic properties around the wellbore. However, Young's modulus, Poisson's ratio and *in-situ* stress are arduous to obtain during drilling operation once losses occur [8]. Dyke *et al.* [9] demonstrated that losses through the fractures can be identified by examining the characteristics of losses and fracture aperture can be estimated from analytical solution and type curve, which has become the dominating tool in the past decades. Sanfillippo *et al.* [10] proposed a model for the prediction of the invasion of Newtonian mud propagation within a single constant fracture aperture width, which can be utilized to find the aperture of the natural fracture from mud loss data. However, the assumption of a Newtonian mud leads to the limitation on the infinite invasion radius by the rheological behavior of the drilling fluid influenced volume of losses to the fracture system, which is clearly unrealistic [11]. In order to assumption of a non-Newtonian Bingham plastic fluid, Lavrov [12] demonstrate a model of radial flow into an unlimited-extension fracture. It is described that the drilling fluid loses into a slot of fracture width by the local pressure drop from laminar flow. And it also provides the estimation of hydraulic fracture aperture through a curve matching technique that describes mud loss volume against time with field data. Based on Lietard's model, Civan and Rasmussen [13] provided an effective and simple solution by assuming no fluid leak-off and fracture deformability. In addition, Lavrov *et al.* [14] theoretically developed a simplified elasticity equation related to fracture aperture variation through fracture stiffness parameter in borehole ballooning phenomenon. It simulated a fracture surface by adopting fractal geometry to prove Lavrov's theory [15]. It developed a methodology by coupling the impacts of formation matrix and the fracture to detect fracture aperture in naturally fractured formation by using mud loss data [16].

In this paper, a simpler and more direct way of determining the fracture width is proposed by upgrading previous Lietard's model instead of curve matching technique. The real-time analysis of mud loss data delineated its dependence on main factors of the wellbore diameter, the overpressure ratio, and the fracture width. The approach demonstrated in this paper briefly discussed the mathematical formulation of estimating effective fracture aperture and validated with the analytical solution for the mud loss invasion problem in study area. Moreover, the remedy of fluid loss issue was discussed through the proper selection of loss-circulation material on particle size distribution and fibrous usage. In the case of Shell China Changbei project, the effect of different LCMs was discussed in different induced fracture apertures.

2. Methodology

Mud will occur propagation into wellbore when the differential pressure between bottom hole pressure and pore pressure exceeds the yield value of drilling fluid. This process is normally described as a volume fluid induced through the membrane driven by the pressure difference [17]. Mud fluid flowing into formation through fractures is sketched in **Figure 1**. The model relies on the relationship between pressure drop within the fracture and the mud invasion rate. Moreover, **Figure 2** depicts pore pressure distribution at different circulation moments. The drilling fluid intruding into the formation caused the pore pressure to build up around the wellbore with time-based stages and the maximum pore pressure appeared in the near-wellbore region. Eventually, the propagation will settle when the different pressure reduces under the yield value of drilling fluid and the distance ultimately depends on the invasion radius, which is demonstrated in Figure 2(c) as the pressure profile.

We assume laminar flow of the drilling fluid encountering resistance due to the mud's inherent viscosity and the geometrical constraints of the fracture. The equation defines the rheological behavior of the non-Newtonian drilling mud using the Bingham plastic model. It relates the shear stress (τ) within the fluid to its shear rate (γ) through the plastic viscosity (μ_p) and the yield stress (Y_P) of the mud:

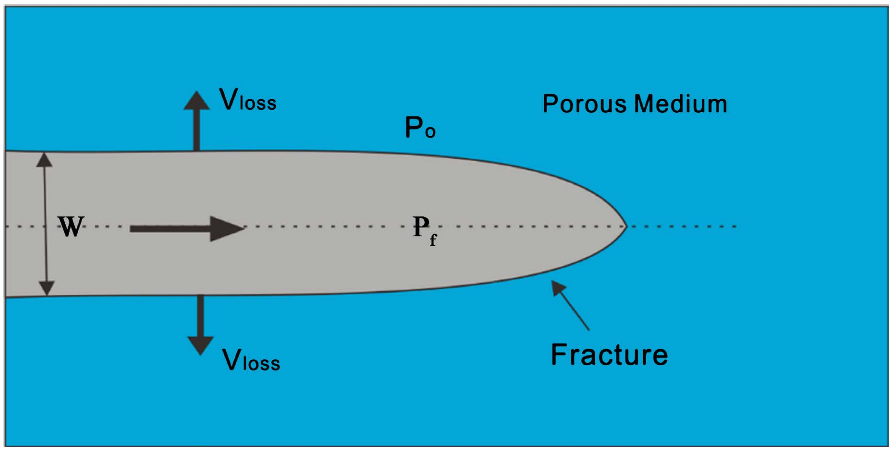

Figure 1. Schematic of fluid flow in the cohesive fracture (cross section of the fracture viewed from the fracture-height direction).

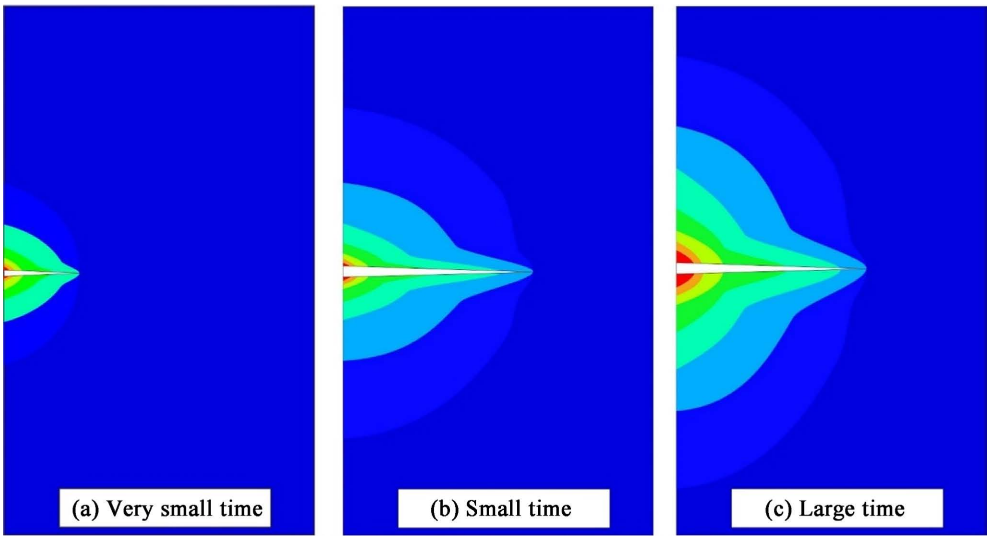

Figure 2. Pore pressure distribution around the fracture during lost circulation. (a) The mud fluid just starts to move into formation. Thus, momentum is transferred in the formation direction and overload pressure is propagated. (b) The mud fluid has been intruded into formation in small time and the stage of pressure reduce has been formed. (c) At large values of time, steady state is established and a pressure reduce profile the formation direction is reached.

$$\tau = \mu_p * \gamma + Y_P \tag{1}$$

So, the equation expresses the pressure drop (ΔP) experienced by the drilling mud as it flows through the fracture [18]. It utilizes the concept of shear stress and relates it to the geometric parameters and flow characteristics:

$$\Delta P = \left(2 * \mu_p * v\right) / w \tag{2}$$

which v represents the intruding velocity of the drilling mud along the fracture, and w represents the fracture aperture (the unknown we aim to solve for).

Building upon the previous equations, we can establish a relationship between the mud loss volume (V_m) and the fracture aperture (w). Here's a simplified outline of the derivation:

- Integrate Equation (2) over the distance traveled by the mud within the fracture (which depends on the mud loss volume).
- Combine this expression with the definition of volumetric flow rate ($Q = v * A$, where A is the cross-sectional area of the flow path).
- Utilize the relationship between mud loss volume ($V_m = Q * t$, where t is the invasion time) to express V_m in terms of model parameters.
- Substitute Equation (1) for the shear stress term to account for the Bingham plastic behavior of the mud.

This process leads to a cubic equation in terms of the fracture aperture (w). Solving this cubic equation using numerical methods provides the estimated value of w based on the measured mud loss volume (V_m), wellbore radius (r_w), overpressure ratio ($\Delta P / Y_P$), and drilling mud rheological properties (μ_p and Y_P). Therefore, the pressure drop within the fracture can be expressed through equation:

$$\frac{\mathrm{d}p}{\mathrm{d}r} = \frac{12\mu_p V_m}{w^2} + \frac{3\tau_y}{w} \tag{3}$$

which μ_p is the plastic viscosity, V_m denotes the intruding velocity of drilling fluid in fractures around wellbore under radial flow conditions, w is a hollow cylindrical aperture of fracture and τ_y is the drilling-mud yield value. On the other hand, V_m represents the cumulative volume of mud loss at a given time as:

$$V_m(t) = \frac{\mathrm{d}V_m(t)}{\mathrm{d}t} \Big/ (2\pi r w) \tag{4}$$

Thus, substituting Equation (3) into Equation (2) results in:

$$\frac{\mathrm{d}p}{\mathrm{d}r} = \frac{6\mu_p}{\pi r w^3} \frac{\mathrm{d}V_m(t)}{\mathrm{d}t} + \frac{3\tau_y}{w} \tag{5}$$

The loss volume equation can be assumed that the mud was purely accumulated in the near-wellbore region of the formation. This region is simplified to the right circular hollow cylinder with the height as fracture width and the circular ring as fracture length and wellbore length. Therefore, the cumulative volume of mud loss V_m is given by:

$$V_m\left(t\right)=\pi w\left(r_i^2-r_w^2\right) \tag{6}$$

which r_i is the depth of mud invasion at time (t) and r_w is the distance along the direction of fracture. Following Lietard equation, Equation (6) can be substituted with the fluid invasion radius $r_D=r_s/r_w$ and dimensionless time $t_D=t/r_c$ as:

$$\frac{\mathrm{d}r_D}{\mathrm{d}t_D}=\frac{w\Delta p-3r_w\tau_y\left(r_D-1\right)}{4w\Delta pr_D\ln\left[r_D\right]} \tag{7}$$

At eventual stage, the propagation of drilling fluid settles when the different pressure reduces under the yield value of drilling fluid. Therefore, the ultimately intruding distance theoretically depends on the wellbore radius:

$$r_{D_{\max}}=1+\frac{w\Delta p}{3r_w\tau_y} \tag{8}$$

The maximum mud-loss volume is given by:

$$V_{m_{\max}}=\pi w\left(r_{s_{\max}}^2-r_w^2\right) \tag{9}$$

Substituting Equation (8) into Equation (9) gives:

$$\left(\frac{\Delta p}{\tau_y}\right)^2 w^3+6r_w\left(\frac{\Delta p}{\tau_y}\right)w^2-\frac{9}{\pi}V_{m_{\max}}=0 \tag{10}$$

which is an equation in the fracture aperture w, the wellbore radius r_w, the overpressure ratio by differential pressure divided by yield value of drilling fluid ($\Delta p/\tau_y$), and the ultimate mud-loss velocity at certain time $V_{m_{\max}}$. Discarded physically meaningless roots, the fracture aperture w can be calculated through Equation (10) in a simpler and more direct way. The physically meaningful of the aperture w is a real and positive value. While the aperture $w=0$, Equation (7) is converted to $-\frac{9}{\pi}V_{m_{\max}}=0$ and then the mud-loss volume $V_{m_{\max}}$ equals zero. It means that there would be no mud-loss in the formation without fracture, which is matching the realistic case.

While mud loss data analysis offers a valuable tool for estimating fracture aperture, it is crucial to acknowledge the inherent limitations of this approach. Non-uniform fracture geometries, with varying widths and interconnected pathways, can lead to discrepancies between the estimated and actual aperture size [19]. Additionally, variations in drilling fluid rheology due to temperature and pressure changes can affect the flow behavior within the fracture. Furthermore, the model assumes constant overpressure, neglecting potential pressure fluctuations during drilling operations [20]. Wellbore ballooning, a phenomenon where the wellbore expands due to high pressure, can also introduce uncertainties in the interpretation of mud loss data. It discussed the simulation model of constant fracture aperture with fracture stiffness determined variation of the fracture deformation as a function of applied normal stress [21]. However, the fracture stiffness parameter is variable and difficulty to obtain and the model did not significantly improve the accuracy of fracture estimation compared with Equation (10). Therefore, the correct values of rheological parameter are critical to use in the model to eliminate this imperfect assumption. The selection of wellbore radius (r_w), overpressure ratio ($\Delta P/Y_P$), and maximum mud loss volume (V_m) as input parameters for the model is based on their direct influence on the mud loss behavior within the fracture. The wellbore radius is a fundamental geometric parameter defining the flow path for the mud. The overpressure ratio represents the driving force for mud invasion into the fracture, with higher ratios leading to increased mud loss. Finally, the maximum mud loss volume reflects the total volume of mud lost before the pressure drop stabilizes.

3. Analysis of Mud Losses for the Well Case

The well case was selected in study area by the operator in the second campaign. Losses were expected in the 12 1/4" sections, which was drilled in the weak formation. The section TD originally was planned to be at 3641 m MD and 2871 m true vertical depth with a deviation of 84 deg. During drilling at 2064.5 m, total losses were experienced with no returns to surface. As an immediate mitigation, topped up annulus with water and two LCM pills with mud were pumped unsuccessfully because the formation strength was not reached to the expected 12 kPa/m. Considering the total losses and lost time, it was recommended to pump loss circulation cement plug, but this practice still failed again. The following three LCM pills with mud and high fluid-loss LCM pill were pumped unsuccessfully. Eventually, the loss was successfully cured by the engineered LCM pill with fiber and the formation strength has been increased to 12.01 kPa/m, as shown in **Table 1**.

In this case, the drill bit was 12-1/4" in diameter, thus

$$r_w = 0.311\,\text{m} \tag{11}$$

The initial situation is described with a total of 110 m^3 of mud losses during 2.5 hours over 2064.5 m of drilling across the weak formation. The average mud loss was:

$$V_{m_{\max}} = \frac{110}{2.5} = 44\ \text{m}^3 \tag{12}$$

The drilling fluid in that moment was water base mud. The density of mud was 11.8 kPa/m and the drilling-mud yield value was 23 mPa·s. Therefore, the overpressure ratio in total loss scenario at 2064.5 m MD and 2053 m true vertical depth was:

$$\frac{\Delta p}{\tau_y} = \frac{(11.8-11.5)\times 2053\times 1000}{23} = 26778 \tag{13}$$

Substituting Equations (11)-(13) into Equation (10) gives the cubic solution:

$$26778^2 w^3 + 6 \times 0.311 \times 26778 w^2 - \frac{9}{\pi} 44000 = 0 \tag{14}$$

The only real root of the cubic after solution is $w = 559.95 \times 10^{-4}$ m (559.95 μm). Therefore, the analytical solution to the fractured-wellbore problem at the pre-LCM state was determined by this method. The initial action was taken to diluted drilling fluid to 11.0 kPa/m and the first two LCM pills has been determined to use different combinations with the particle size of 44 μm and13 μm due to the limitation of site LCM storage. As expected, loss was not cured at all and formation strength was remaining the same at 11.5 kPa/m. The configuration of this problem at this situation is shown in **Figure 3**. As the schematic demonstrated that the small LCM particle was distributed in the wide fracture as the normal drilling fluid and they were not able to seal this fracture at all [22].

After the first two trials, the operator desperately decided once for all that cement plug was pumped and squeezed to cure the loss and increase formation strength. Unfortunately, the loss was still not cured after dressed off cement plug. But formation strength slight increased to 11.75 kPa/m.

The situation is described with a total of 8.2 m^3 of mud losses during 0.5 hours across the weak formation. The average mud loss was:

$$V_{m_{\max}} = \frac{8.2}{0.5} = 16.4 \text{ m}^3 \tag{15}$$

The drilling fluid in that moment was 11.0 kPa/m of density and 14 mPa·s of the drilling-mud yield value. And the equivalent circulating density obtained from measurements-while-drilling tool was 12.1 kPa/m during circulation with lowest pumping rate. Therefore, the overpressure ratio was:

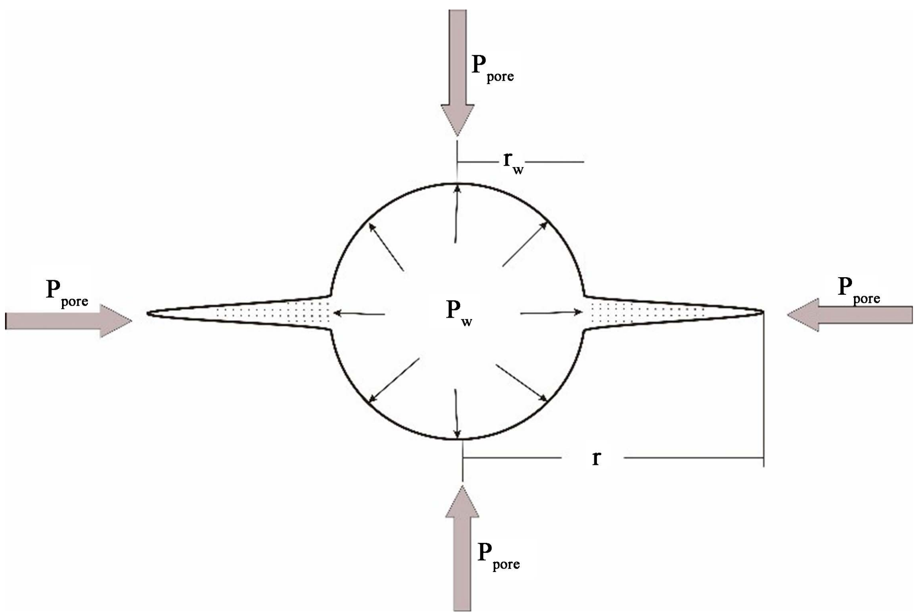

Figure 3. Schematic of the fractured wellbore and small LCM particle distribution in the post-LCM problem.

$$\frac{\Delta p}{\tau_y} = \frac{(12.1 - 11.75) \times 2053 \times 1000}{14} = 51325 \tag{16}$$

Substituting Equations (11)-(13) into Equation (10) gives the cubic solution:

$$51325^2 w^3 + 6 \times 0.311 \times 51325 w^2 - \frac{9}{\pi} 16400 = 0 \tag{17}$$

The only real root of the cubic after solution is $w = 261.15 \times 10^{-4}$ m (261.15 μm). Therefore, the analytical solution to the fractured-wellbore problem at the post-cement state was determined by this method. The configuration of this problem at this situation is shown in **Figure 4**. The cement plug was successfully isolated the weak zone once cement set. However, the cement plug was dressed off and the cement inside of fracture was also damaged as well. There was only a small piece of cement plug successfully isolated the tip of fracture [23]. The fracture can be seen as two fractures separated by cement plug and the equivalent fracture aperture was calculated by this analytical solution. Therefore, the formation strength was increased due to the equivalent fracture aperture was smaller.

The regulations did not allow running the casing with losses and the abandonment of this well is not an option. Therefore, the following three LCM pills in mud with 11.4 kPa/m density and one high fluid-loss LCM pill were pumped to control the losses without success again [24]. The formation strength was even lower than before, especially when pumped and squeezed the first LCM pill.

The analytical situation in the fractured wellbore at the post-LCM state was determined by this method separately. The calculated fracture apertures in different stages were 396.15 μm at the post of the first LCM pill, 307.45 μm at the post of the second LCM pill and 292.67 μm at the post of the third LCM pill. The

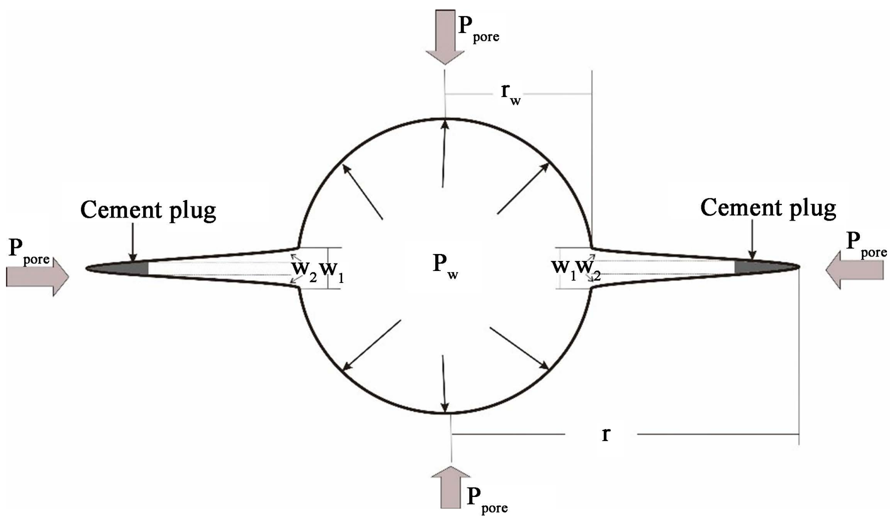

Figure 4. Schematic of the fractured wellbore and cement plug isolated the tip of fracture in the post-cement situation. W_1 stands for the previous fracture aperture of 559.95 μm and W_2 stands for the equivalent fracture aperture of 261.15 μm after cement plug.

configuration of this problem at this situation is shown in **Figure 5**. The cement plug isolated in the tip of fracture was broken during squeeze the first LCM pill and it caused the formation strength getting worse. The second and third LCM pills were squeezed into the secondary fracture in the cement plug and it generated the isolation in the cement plug instead of fracture itself due to the small LCM particle size. Therefore, these three LCM pills were not able to increase the formation strength to previous value of cement plug.

The operator was aware that the high fracture aperture would be not able to plug with normal size LCM particle as their desire. Therefore, one type of high fluid-loss LCM pill was mobilized on site. This LCM was introduced with the ability to isolated fractures aperture less than 2500 μm. Unfortunately, this new LCM was not able increase formation strength at all in this case as **Table 1** shows. In reality, high fluid-loss LCM pill was only fulfilling the secondary fracture

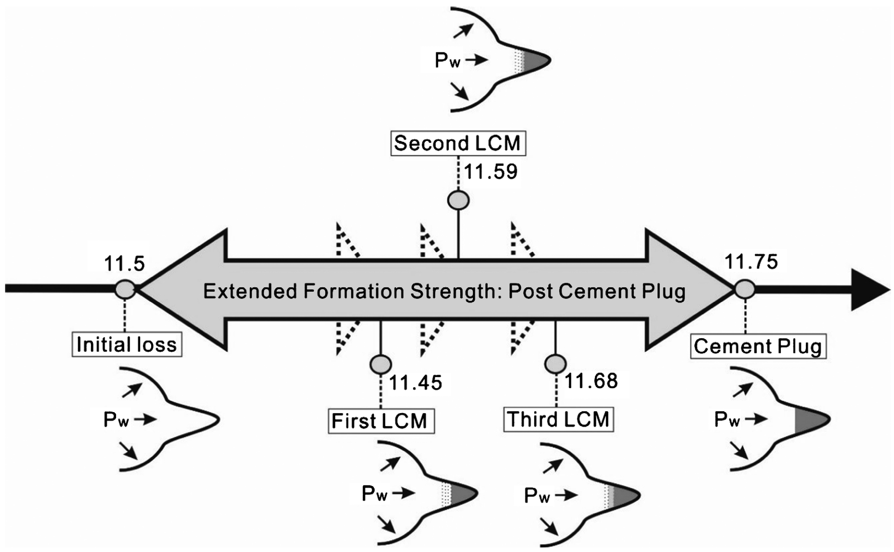

Figure 5. Formation strength of the fractured and LCM treated wellbore.

Table 1. Drilling report for losses and wellbore strengthen operation in 12-1/4” section.

Operation	Volume lost (m^3)	Formation strength (kPa/m)
Lost return when drilling to 2064.5 m with RSS BHA. Topped up annulus with water.	110	11.5
Perform wellbore strengthening, squeezed in 29.6 m^3 LCM pill.	26.9	11.5
Perform second wellbore strengthening, squeezed in 19.7 m^3 LCM pill.	16.2	11.5
Set cement plug from 2117 m to 1917 m.	8.2	11.75
Squeezed in 21 m^3 of LCM pill in hesitation mode to record pump off pressure after every 100 litre.	21	11.45
Squeezed in 23.5 m^3 of LCM pill in hesitation mode to record pump off pressure after every 100 litre.	23.5	11.59
Squeezed in 38.5 m^3 of LCM pill in hesitation mode to record pump off pressure after every 100 litre.	38.5	11.68
Pumped and spot 15 m^3 high fluid-loss LCM pill.	12.3	11.64
Pumped 30 m^3 engineered LCM pill with 335 kg/m^3 concentration and fiber.	20.5	12.01

in cement plug as normal LCM did.

The decision was made to squeeze another LCM with fiber by creating an interlocking network of fibers with sealing material of various sizes to provide solution to loss circulation. Low relative stiffens factor allows fibers to penetrate deep inside the fracture. Due to radial flow conditions fluid velocity drops with increasing distance from the wellbore. At low velocity flow conditions fiber accumulate and form a 3 d matrix. This matrix acts as a barrier for granular material reducing its invasion into the formation. Therefore, the strength of the plugging zone consists of the strength formed with particles and the strength increment after the addition of fiber. The relationship between formation strength and aspect ratio of fiber is discussed as Figure 6 shows.

The LCM pill with fiber plugged in fracture zone as Figure 7 shows. As the result, LCM pill with fiber was successfully plugged the fracture and increase formation strength to 12.01 kPa/m as desired.

4. LCM Selection Guidelines and Cementing Conditions in Fractured Reservoirs

The LCM particle distribution should be selected in extreme careful way to minimize failure of squeezed LCM pills. In addition, the LCM particle should be not only fine enough to squeeze into fracture, but also coarse enough to prevent deep invasion. Therefore, the prerequisite of particle distribution is an accurate estimate of the fracture aperture, which is the main subject of this paper. Therefore, LCM selection should be more caution and advised by the calculated fracture aperture. Moreover, the next important design step is to determine the particle-size distribution (PSD) of the LCM to be used to effectively plug the flow paths. The most acceptable methodology of the correlations between the fracture

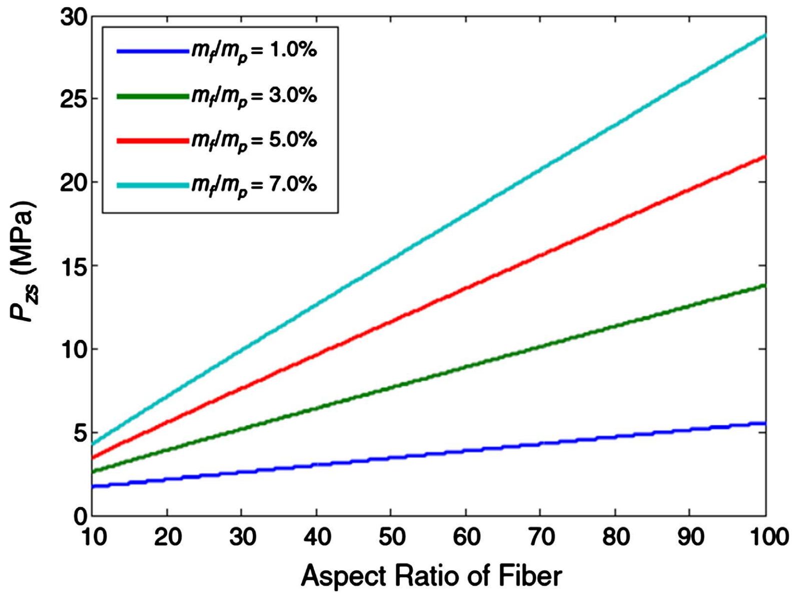

Figure 6. Relationship of formation strength in loss zone and aspect ratio of fiber at different mass ratios of fiber to particle. m_f/m_p presents mass ratio of fiber to particle [22].

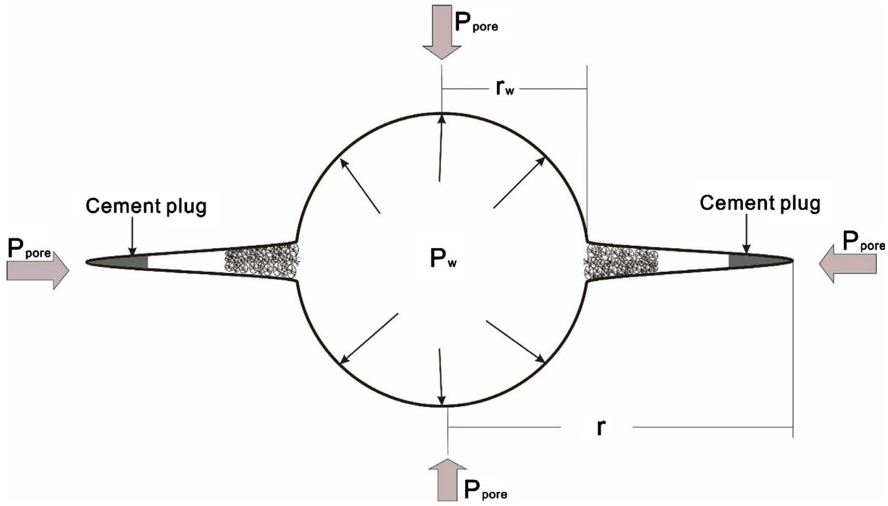

Figure 7. Schematic of the fractured wellbore and fiber LCM particle distribution in fracture. LCM generates interlocking network by fibers to form large size particles and they plug wide fracture.

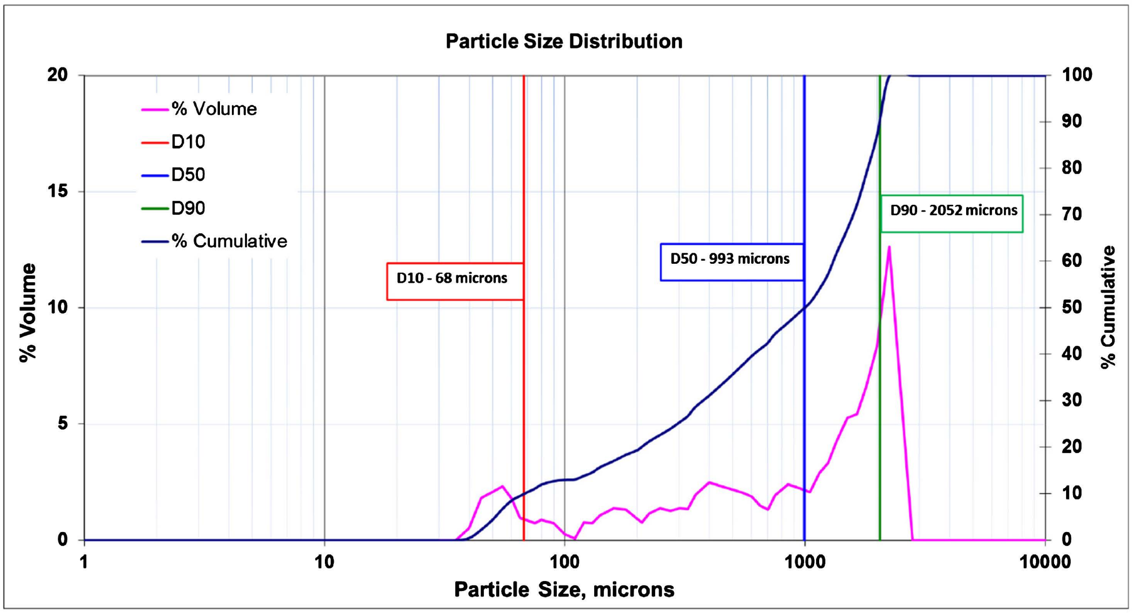

Figure 8. Example PSD for composite product (reference from Savari and Whitifill, 2016 [4]).

size and LCM PSD is the Abram's rule, which advocates that the median size of LCM should be at least 1/3 of the flow path being plugged. Savari and Whitifill [4] proposed that an important point when selecting an LCM combination as a preferred solution is to consider the entire PSD curve rather than focusing on just the median size of the LCM combination as **Figure 8** shows. The distribution curve will actually provide important information on how narrow or broad the PSD is. Moreover, it is suggested to choose an LCM combination that has a broad PSD with the D50 equal to the fracture aperture and the example of a composite LCM PSD is shown in **Figure 8**.

On the other hand, once the severe losses encountered with calculated high fracture aperture and the selection of PSD was not able to match the fracture aperture, the fiber should be added into LCM pill. Comparison of the performance of various pills with the performance of fibrous LCM in the example demonstrates that the fibrous LCM is able to control the loss circulation problems as desired.

5. Conclusion

The fracture aperture in wellbore can be estimated by the analysis of the mud loss data and it can be indicated by the selection of LCM pill. It has been shown in this paper that the fracture aperture can be real-time determined from mud loss data by solving the approach with input parameters given by the well radius, the overpressure ratio, and the maximum mud loss volume. The findings of the estimation on fracture aperture in this paper are relevant to reduce non-productive time by optimizing the selection of lost-circulation material pills. As the analysis of example, the fracture aperture can be obtained to discuss the result of sealing treatments and determine the optimum sealing option for lost circulation. The particle-size distribution of the lost-circulation material combined fibers is a good solution to address server lost circulation issue with the evidence for effective wellbore-strengthening. The proposed model and fibrous lost-circulation material are successfully applied to the field case study in the Shell China Changbei project.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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