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Root Cause Analysis of Loss Circulation Problem and Designing/Customizing Wellbore Strengthening Materials in One of the Middle East Oil Fields- A Case Study

Mahdi Nazarisaram

Faculty of Civil and Earth Resources Engineering, Islamic Azad University, Central Tehran Branch, Tehran, Iran

Abstract

In the drilling industry, one of the most important parameters to improve the drilling of new wells is studying the previously-drilled wells to find major common problems and use new methods to prevent them. This article has aim to discover the root cause of loss circulation and its consequences problems right in one of the Middle East oil fields. Also, it will be discussing customizing solutions to cure or prevent such problems. Previous problems are interpreted based on lithology, hydraulic and rheological parameters. Loss circulation volume and rheological parameters (eg gel strength) were analyzed in 12 drilled wells in the specific field. Based on the results, in 5 wells, the loss problem was severe, and the cause was the creation of induced fractures due to the high volume of gel strength. Also, using the geo-mechanical models revealed that induced fracture was expected to develop approximately 36 microns through drilled formations. that the reducing gel strength is sometimes not affordable due to hole cleaning issues. Hence, it has been customized for loss prevention. Accordingly, the wellbore strengthening materials with a mean size of 36 microns were proposed to increase the fracture gradient of formations pressure to drill with high-density muds. By implementing recommended materials in two new wells with high-gel strength, fluid losses, and related problems were considerably showed a reduction. Thereafter, Nonproductive time compared with previously-drilled wells was reduced between 71 to 89%. Also, fluid loss volume dropped from 511 bbl to 75-100 bbl in each nominated well. Meaning an 80-85% reduction in fluid loss, indicating reasonable achievements.

Keywords: Drilling Operation Optimization, Mud Loss Circulation, Drilling Problems, Drilling Fluids, Induced Fracture, Loss Preventative Material.

Introduction

In the drilling industry, loss circulation is defined as losing drilling fluids into the formations underneath the earth (while or after drilling) [1]. Losses are categorized into two distinct types based on the path that fluids can get lost into, natural and induced [2-7]. Natural loss circulation is the entrance of fluids to formations with natural pores, fractures, vugs, high permeability, or even caverns. In contrast, induced loss circulation is defined as the ones involved with creating induced fractures while drilling by using over-pressure drilling fluids in a drilling operation. This type of loss is mainly related to the narrow mud weight window zones, which is the pressure range between pore pressure and fracture pressure versus depth. Lost circulation may create problems such as fluid inflow (well kick), wellbore collapse, differential stuck pipe and increasing nonproductive rig time, extra operational expenses, and environmental damages. Mainly the most important parameters affecting lost circulation pressure are as follows: pore pressure, the minimum in situ stress, near-wellbore rock geomechanics properties, etc.

Equivalent Circulating Density (ECD) (Mud density considering extra frictional pressures) must be optimized to control lost circulation and provide a balance between the risk of fluid influx and wellbore instability (as it was previously mentioned as mud window). It is considered that high ECDs results in an increment of the risk of loss circulation, and low ECDs result in an increment of influx (kick) risk and wellbore instability problems. In other words, if the bottom hole pressure (BHP) is chosen to be in a lower level of formation pore pressure, an influx (mud kick) or physical wellbore stability problems can occur. The relation of calculating ECD is given below by Equation 1:

**Corresponding author:* Mahdi Nazarisaram, Faculty of Civil and Earth Resources Engineering, Islamic Azad University, Central Tehran Branch, Tehran, Iran
E-mail addresses: mah.nazari_sarem@iauctb.ac.ir
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$$Equivalent\ Circulating\ Density\ \left(ECD\right)=\frac{annular\ pressure\ loss}{0.052TVD}+mud\ density \quad (1)$$

In Equation 1, ECD stands for Equivalent Circulating Density of mud in ppg (pound per gallon), and TVD stands for true vertical depth in feet. Also, units of annular pressure loss and mud density are psi and ppg, respectively.

If lost circulation is occurred due to induced fractures, the lost circulation pressure is equal to the fracturing pressure. Mentioned fracturing pressure is determined by minimum near-wellbore and in situ stresses that do not contain natural fractures. In zones with natural fractures, the fracturing pressure will be lowered [3].

Extended leak-off tests (XLOT) or mini-frac tests should be done to identify the formation fracture pressure gradient. In the leak-off test, fluid volume is pumped slowly with a constant flow rate into 2-3 feet below the formation or casing shoe.

The pressure and volume readings will be drawn until the linear pressure versus volume response shows a specific untrendy break in the plot.

The difference between the mini-frac or XLOT test and with leak-off test is that these tests will continue until a clear formation break is observed to find the fracture propagation pressure.

After that, as pressure is stopped, the frictional dynamic loss for the pumping fracture is lost, and pressure would bleed off [3-9].

For a mini-frac or extended leak-off test, the fracture closure pressure could be used for determining the minimum horizontal stress in the studied formation. The leak-off point is also the start point of fracture initiation (and not where the ultimate fracture breakdown pressure is reached), and it can be calculated for non-penetrating fluid by the Kirsch equation (by Equation 2):

$$P_{frac} = 3\tau_h - \tau_H - P_p - T_0 \quad (2)$$

In Equation 2, Pfrac and τh stand for fracture pressure (psi) and minimum horizontal stress (psi), respectively. In addition, τH stands for maximum horizontal stress (psi), and Pp is pore pressure (psi).

Mud losses are also categorized into different types based on the severity of mud decrement while drilling, named "Loss Severity". Again, based on the type of drilling fluid using OBM or WBM, the classification may be different, but as a general classification, the following categories are generally acceptable by industries: Seepage losses (loss severity is less than 10 bbl./hour), Partial losses (loss severity is in range of 10 to 100 bbl/hour), Severe losses (loss severity is more than 100 bbl./hour), and Total losses (when there is no return of mud to the surface and all the fluid is lost) [4].

Classification of mud losses based on the severity will not define all the required information about losses for finding the best treatment method or identifying the cause of the problem. Moreover, the mechanism of loss, type of drilled formation, and geological properties must be defined and considered to find the best effective method [5].

Different treatment or prevention methods have been applied in the past based on the type and severity of the problem. None of the mentioned methods are successful in all conditions and scenarios, meaning for each problem, the cure/prevent method must be customized and optimized. One of the most common treatment and preventative actions is using Loss Circulation Materials (LCM) and Loss Preventative Materials (LPM). Each mentioned material has its merits and disadvantages that must be considered before any field application. Depending on the type and severity of the problem and the estimated width of the fractures, the suitable materials will be chosen and added with drilling fluids in the form of a pill (small separated volume of drilling fluid) or to the active mud to treat/prevent losses in thief zones.

Dyke et al in 1995 proposed an effective method to understand the type of loss circulation based on the estimating types of fractures [6-11]. They considered the changes in mud pit level versus time while lost circulation was happening. Therefore, they concluded that in induced fracture losses the mud pit level would be reduced and then slightly increase to a higher level with time. Still, in natural fractures, the decrease in mud pit level was continued but it was not along with increments. Most of the nominated literature suggested the importance of fluid loss analysis within the drilling category.

The purpose of this article is to a depth analysis to investigate the fluid loss phenomena based on the Wellbore strengthening materials. Hence, to cover the goals, a vast investigation to relate such a parameter to the fluid loss problem will be expanded in detail.

Wellbore Strengthening and Loss Prevention

Wellbore strengthening is a methodology that minimizes the probability of loss problems by increasing the required pressure to break formations and prevent the creation of induced fractures. Research shows that if wellbore strengthening is effective, formation breakdown pressure can be raised by 8.0 ppg and fracture propagation pressure by 3.0 to 6.0 ppg. Therefore, wellbore strengthening is considered an actual process to prevent losses caused by natural/induced fractures in formations with sufficient permeability. These increments in breakdown pressure can prevent many formations from breaking and the induced losses while drilling a probable thief zone and optimize drilling operations [9].

Managing the wellbore stresses is one of the most important methods to prevent/cure lost circulation. It can be defined as designing and applying treatments to increase the hoop stress around the wellbore using Wellbore Strengthening Material (WBS) to plug/seal induced fractures tips with used materials and neutralize pressure transition into the formation by isolating fluid and the fracture pressure and also increasing the near-wellbore hoop stress. This treatment applies to different formation types, such as carbonates and sandstone formations. In addition, mentioned increase in the fracture gradient is affected by the physical properties of LPM/WBS (such as the size, strength, and, resiliency).

WSMs or loss prevention materials (LPM) are particulate materials that are used for wellbore strengthening.

In the history of drilling, materials such as calcium carbonate or walnut shells are used as WSM [9-10]. In Table 1, the wellbore strengthening mechanisms and their related type of materials and physical properties are summarized.

Table 1 Wellbore Strengthening Methodologies Summary.

Mechanism	Type of Material	Size of Material	Material Strength	Tip Isolation	References
Fracture Pressure Inhibitor	LPM	Important	Selected Strength	Required	[10-11]
Stress Cage	Calcium Carbonate	Important (Equal to or larger than the frac-(ture aperture at the borehole wall	Considerable	Not Required	[11]
Fracture Stress Closure	DSF (Drill and Stress Fluid) water-based systems	Important (narrow particle size distribution to maximize fluid loss through the fracture (.wall	Not Considerable	Required	[11-15]
Fracture Propagation Resistance		Unimportant (Broad particle size distribu-(tion to maximize the sealing efficiency	Not Considerable	Required	[16]
Fracture Healing	High Strength Materials	Important	Considerable (Very (Important		[2]

Based on the data in Table 1, one of the studied mechanisms is "the fracture closure stress" which declares that wellbore strengthening materials are capable of plugging the newly-created fractures into a space adjacent to the borehole and as a result, the fracture closure stress increases. Also, in "stress cage" theory, for induced fractures and permeable formations, the insertion of WSM at or close to the tip of the induced fractures will plug them and keep the induced fractures open which results in making balance between fluid pressure in the wellbore from the fracture network. The dissipation of the fluid which was entering the fracture will lead to pressure release in the fracture. Stress cages will increase near-wellbore effective tangential stress and lower the possibility of losses. According to the stress cage theory, the fractures must be short and wide [11].

The researchers proposed a model, named FROP, which relates the effect of fracture sealing to the reopening pressure of plugged fractures.

Based on this model, more effective wellbore strengthening can be achievable in the depleted sections during drilling in a fractured zone with lower pressure [12].

Karimi Rad et al. proposed using fibers, sized bridging agents, and resilient materials to achieve the most efficient sealing fractures and hoop stress increment. Based on this study, the surface covering of fibers helps to seal off the fractured zone and prevent fracture propagation [13].

In 2020, researchers proved Wellbore strengthening approach had a favorable in-field application with an increasing 2 ppg (pound per gallon) mud window in a sandstone formation [14].

Generally, to estimate the concentration of WSMs needed for wellbore strengthening a dimensionless parameter so called the Wellbore Strengthening Index or WSI is being used. WSI relates solids percentage to the length of an induced fracture while pluggings are formed using integrated geomechanics and drilling fluids aspects and are less demanding of large WSM compared to the conventional methods approach [5,6].

In 2018, researchers tried a wellbore strengthening in the deep-water Gulf of Mexico to achieve zonal isolation. Based on the authors' analysis of several wellbore strengthening showed a successful wellbore strengthening treatment demonstrates the potential for achieving adequate annular cement placement and zonal isolation in narrow pore pressure fracture gradient environments [15].

According to researchers, walnut particles were engineered to be used as wellbore-strengthening materials in both laboratory studies and field experiments, instead of coarse-grade of marble. Authors claimed newly-engineered materials were more effective due to having a lower tendency of settling. The concentration of the optimum mixture was 20-39 kg/m^3 [6,7].

In Table 2, important parameters which affect the wellbore strengthening mechanism are discussed:

Table 2 Parameters Affecting Wellbore Strengthening Application.

Main Parameter	Parameters	References
Fluid properties	Drilling fluid rheological and filtration properties	[12, 13]
WSM properties	Concentration, Particle size distribution, resiliency, crushing pressure, length (for fibers)	[12, 13]
Fracture dimension	Length, Width,	[12]
Filter-cake properties	Thickness, the strength of filter-cake in shearing forces	[13]
Formation properties	Fracture pressure, Permeability	[13]

Materials and Methods

To meet the purpose of this research, an enhanced understanding of WSM/LPM Materials and pressure consideration will be needed. Accordingly, those will be discussed in follow for a better understanding of fluid loss concerning some kinds of materials.

Calculation of Pressure to Break the Gel

Gel strength can be defined as the measure of interparticle forces in drilling fluid and indicates the amount of gelling that will occur when circulation is stopped and is measured in pounds per 100 square feet (lbs/100 sq.ft.). The reading is obtained by noting the readings of the viscometer when the rotator is rotated at 3 rounds per minute (rpm) after allowing to stand for 10 seconds, 10 minutes, and 30 minutes [16]. The optimum gel strength prevents cuttings from settling in the borehole.

The pressure required to break mud's gel strength inside the drill string and annulus is explained below:

Step 1: pressure required to break the mud's gel strength inside the drill string can be calculated using Equation 3 [16]:

$$P1=(\frac{(Lds)(\tau gs)}{300Di}) \quad (3)$$

where P1 stands for the pressure required to break gel strength inside the drill string (psi), τgs stands for gel strength of drilling fluid (lb/100 ft^2), Di is the Inside diameter of drill pipe in (inches) and Lds stands for Length of the drill string (ft).

Step 2: pressure required to break the mud's gel strength in the annulus using Equation 4 [16].

$$P2=(\frac{(Lds)(\tau gs)}{300(Dh-Di)}) \quad (4)$$

P2 stands for the pressure required to break gel strength in the annulus (psi) and Dh stands for the diameter of the annulus in inches.

Step 3: The total pressure required to break circulation can be calculated by using Equation 5:

$$Ptotal=P1+P2 \quad (5)$$

where P_{total} is the pressure required to break circulation in the well (in psi) [16].

Importance of Fracture Geometry in Wellbore Strengthening Applications

According to research, fracture length has insignificant effects on wellbore strengthening issues. The fracture length prognosis is not as crucial as fracture width estimation [2-7]. Also, other studies confirm plugging the fracture tip increases the fracture propagation pressure [7-8]. Furthermore, the permeability of formation has a direct effect on the wellbore strengthening mechanism meaning higher permeability leads to faster and easier plug forming due to the higher tendency of WSMs to be placed into the fracture tips and wellbore surface [13].

WSM/LPM Materials

When the drilling fluid comes in contact with the permeable layer, a filtrate (base fluid) and part of the solid particles in the fluid will enter the formation pores. Solid particles in fluid have different sizes. Particles larger than the average diameter of the pores cannot penetrate the porous medium. So, those kinds of particles settle on the wall of the well. That causes a low permeability layer on the surface of the well and prevents further penetration of the filtered and solid particles. filter cake removal is difficult and even if penetration depth is low and limited, it will still have a great impact on reducing permeability and increase in losses.

The lower the permeability of the mud cake is, the faster it is formed and the better its quality is. On the other hand, its thickness should also be controlled to avoid problems such as drill pipe sticking.

The pressure required to start the flow depends on the (1) type, (2) size, and (3) concentration of the additive particles, (4) the strength of mud cake, (5) the permeability of the formation, and (6) the mud cake; in addition, the parameters affecting the thickness/strength of the mud cake are pressure difference and solid particles in the mud.

Adding WBS materials to the drilling fluid reduces mud cake density and reduces the onset pressure of the flow. For instance, the high-pressure difference can increase the thickness of the mud cake and also would increase the solid cake density and increases its solid content, and yield strength.

In former studies, cellulose fiber materials are widely used to control and prevent partial and moderate loss from1980's [17]. Cellulose materials should be used as soon as possible before the problems begin, to prevent/minimize unnecessary drilling formations losses due to their flexibility and compressibility [17]. If properly sized, these particles can prevent the drilling fluid from losses. The rock has a complex fluid-rock system, and it is very important in understanding the type, size distribution, and how the pores are connected and can prevent fractures from occurring during the drilling phase. Because of uncertainty in the size and shape of the fracture's sizes or pore throats, the selection of LCM/LPM type and particle size distribution has an undeniable role to reach an applicable and efficient loss circulation treatment [17].

The effect of fibrous pills in curing loss circulation problems in formations with natural fractures was studied by [1]. Also, the effectiveness of loss treatment utilizing two kinds of fibers (with different physical properties) was investigated in the study of Yili et al. [18].

Based on this study, it was concluded that using high-strength fibers and also low-strength (soft) types of fiber following granular bridging agents can effectively plug fractures.

Filter-cake covering was also studied by Cook et al. [7]. Based on their result, the importance of the filter cake in stopping the growth of fractures and also increasing the sustainable pressure of the wellbore was explained. It was claimed that the filter cake itself could seal off the small induced fractures and then it could prevent the fluid entrance to the fractures/pores of formations. It has been claimed by authors that the filter-cake forms on the wellbore surface before initiation of any induced fracture, and, so optimum filter-cake is capable of sealing off the pores/fractures as early as their creation arresting losses at the first momentum of occurrence. [7]. Authors also studied the capability of the filter-cake and rock properties to form a blockage over the tip of the fractures such as filter-cake thickness, the fracture characteristics, and the filter-cake strength [7].

Field Introduction

In this article, the largest middle east oil field was chosen for the case study analysis and to verify the analysis context. In that oil field, the folding mechanism is considered as a combination of two mechanisms. Thos are bending-sliding folding and neutral surface folding. In addition, there is a thrust fault in the north and south edges and possibly uplifts of the blocks.

Also, the eastern zone has the most potential for drilling fluid loss due to the maximum slope gradient and the frequency of fractures in such a section.

On the other hand, the western zone has the least potential for drilling fluid loss. The central zone is also considered the intermediate state of the eastern and western zones.

Moreover, in the eastern part where the height of the anticline and slope has the highest value followed by high fracture density. In that area, it seems that increasing the fracture density can raise the possibility of drilling fluid losses.

Therefore, the focus of this manuscript was to select the east zone of the field for better comparison and raising more challenges with the most potent part of the field.

According to surveys, most wells did not suffer from loss circulation problems. Wells 8, 9, 10, 11, and 12 in the east zone of the studied field faced high-loss circulation problems. Studies have shown that most of the fractures are closed in the center of the studied field, and also there are very few open fractures in the west of the fields.

According to seismic geophysical information, the studied oil field can be structurally zoned into three relatively eastern, central, and western parts.

Also, the names of the wells are not real and they are selected for this paper.

Analysis Methods

This paper describes the historical loss circulation and related problems in one of the onshore Middle East fields and presents a field-studied solution to prevent/cure these problems by predicting induced fractures and optimizing a loss preventive material to prevent their creation.

This section briefly describes the methodology used in this study:

Step 1) Collection of information on the previously-drilled wells in the studied field

Step 2) Find the root cause of problems in the formations layer C (member 3) in the studied field

Step 3) Prognosis of loss problem in future wells and the possibility of creating induced fractures

Step 4) Estimating induced fracture widths

Step 5) Customizing methods and wellbore strengthening materials to treat the problems

The root cause of the problem, with aspects of geology, lithography, hydraulic, drilling conditions, and hole cleaning is investigated in 12 wells in the same geological zone in this paper and then it is tried to customize the right type of prevention method in future wells to reduce problems and optimize drilling operation. To bring engineering to LCM design, we should consider the following points must be considered:

• Diagnosis of the type of Lost Circulation
• Diagnosis of fracture types
• Choosing the best mechanism to cure/prevent Lost Circulation
• Choosing the best WBS/LPM type(s)

At last in field operations, two wells were drilled using a newly developed methodology with successful results (given in this paper).

Approximation of Fracture Opening Estimate Fracture or Pore Size

To apply preventive methods such as wellbore strengthening or bridging, estimation of the induced fracture width to find the optimum size of the LCM, for sealing the created fractures is crucial [1, 14, 20].

Researchers presented fracturing theories for estimating the fracture width for rock type and pressure regime. Rock mechanics modeling has been developed, which enables the fracture widths to be estimated. This model uses the change in stress state around the wellbore and can relate the fracture width to the rock elastic properties for a given set of conditions [11,14,15,19,20]. The following model, which is a kind of rock mechanics modeling, can relate the fracture opening to the rock's elastic properties (as seen in Equation 6]:

$$w(x)=\frac{(4*(1-v^2)}{E})(P_w-S_H)\sqrt{(L+R)^2-x^2)} \quad (6)$$

where w(x) stands for the width or aperture of fracture at a distance x from the wellbore, R is wellbore radius, Pw is wellbore pressure, and SH is maximum horizontal stress. Also, L and x stand for fracture length and distance from the wellbore center respectively. Moreover, Young's modulus (v) and Poisson's ratio (E) are geomechanical constants of the studied formation in this formula.

An equation (Equation 7) for a penny-shaped fracture to demonstrate the strengthening effect is as follows [19]:

$$Deiita(P)=\frac{\pi}{8}*\frac{W}{R}*\frac{E}{(1-v^2)} \quad (7)$$

where $W(x)$ is the width or aperture of fracture at a distance x from the wellbore, R stands for wellbore radius, E stands for formation Young's modulus, ϑ stands for formation Poisson's ratio, Pw is wellbore pressure and S_H is maximum horizontal stress. Also, L stands for fracture length is assumed to be 6 inches based on the authors' idea [19] Delta (P) stands for fracture pressure or pressure difference between formation and wellbore.

Results and Discussion

In this paper, the methods to deal with the loss circulation problem by designing and engineering the materials for controlling the problem will be studied. According to the conditions in the studied field, and recommending the best way to cure or prevent the problem by root cause analysis of the problem. This design and optimization include investigating factures width estimation methods, optimizing material type and size selection, selecting the appropriate material, and making non-invasive filter cakes in boreholes surface.

The goal of the current analysis is for the LPM/WSM materials in the active drilling fluid to seal fractures as possibly close as the fracture tip to isolate pressure transmit between fracture and wellbore to prevent any losses into newly created fractures. Based on this scenario, the required pressure for fracture propagation will be increased and so the extra wellbore hoop stress will reduce the possibility and volume of losses into the thief zone.

So, the BHP exactly should be calculated during drilling for keeping bottom-hole pressure below the formation fracture pressure. The rheological drilling fluid properties (i.e. yield point when fluid is dynamic and gel strength) determine the annulus pressure loss. So, their effect on bottom-hole pressure must be considered as extra pressure. In zones with the possibility of induced fractures, drilling fluid rheology must optimize as high yield point and gel strength would result in higher frictional pressure losses and cause an increase in the possibility of lost circulation. By that, the first and most applicable method to prevent losses will be to keep the bottom-hole pressure below the lost circulation pressure.

It is recommended that to improve the treatment for lost circulation caused by low-fracture gradients, specially designed materials in the mud system should be used to instantly seal off the induced fractures around the wellbore. As a result, no further losses will occur.
Sufficient particles both larger and smaller than the estimated fracture width also will be needed for LPM optimization. In the current research, particle size criteria are selected based on the Fracture Stress Closure theory already mentioned in the literature [20]. In addition, the physical properties of the LPM may have a crucial effect on the effectiveness of the use of LPMs. The resiliency and hardness of LPMs help to withstand the fracture closure stresses without any major size reduction. That can reduce tolerate changes in extra exerted pressures due to the gel strength of drilling fluid.
In addition to mechanical properties, like crush resistance and resiliency, LPM/WBS also have a prominent role in capturing mud losses and in strengthening the wellbore. In terms of wellbore strengthening, the mechanical strength of the LCM could play an important role. Fibers undergo elastic deformation and regain their actual shape once confining pressure has been removed with a lower reduction in size. That is in comparison with other common loss circulation materials. Those achievements will be illustrated within this section in more features.
Only data for 12 wells were provided for this study. All wells are selected from the east side of the field for similarity in fractures and geological depths. All wells are selected in the same zone; thus, they can be assumed similar in the aspect of natural fractures and geological formation depths. Wells were sorted based on gel strength forces increase and then named from 1 to 12 for this paper.
Locations of studied wells of one of the Middle East fields in this paper are given in Figure 1.

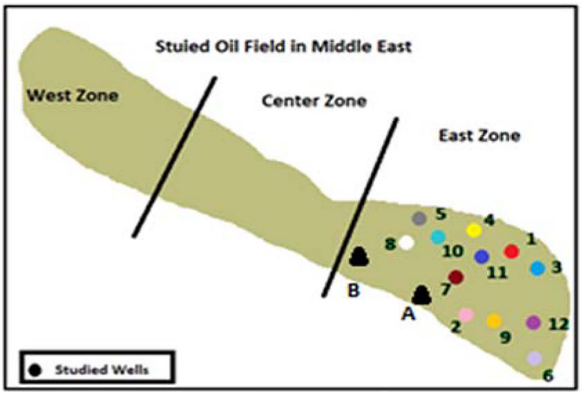

Fig. 1 Locations of Studied Wells in the Eastern Part of One of the Middle East Oil Fields.

Lithology data, common hole problems, and casing design of wells in the studied field are given in Table 3. Also, the required data from the studied well are given in Table 4. The following data are mainly used for finding the probability of losses and also estimating induced fracture sizes (in case of having induced losses). Gel Strength comparison in 12 wells (2500-meter TVD) is given in Figure 2. As mentioned, wells were sorted based on gel strength forces increase and then named from 1 to 12 for this paper.

Table 3 Geological and casing design of wells in the studied field.

Depth (meters) (MD)	Casing Size and Depth	Hole Size	Formation	Member	Lithology Description	Top True Vertical Depth (meter)	Problem
101	18 5/8 "@ 100 Mt MD	26"	A		Marl, Sand-shale	surface	Seepage losses while drilling
1900	13 3/ 8 @1900 Meter MD	17 1/2"					
			B		Marl	1437	-
3200	9 5/8" @3200 Meter MD	12 1/4"	C	Member 7	Marl	1774	-
				Member 6	Marl-Anhydrite	1891	-
				Member 5	Anhydrite-Marl	2075	Losses while drilling, Stuck pipe
				Member 4	Salt	2319	
				Member 3	Anhydrite-Gray Marl-Limestone/Salt-Anhydrite-Gray Marl	2585	
				Member 3		2903	-
				Member 2		3114	-
3500	7" Liner@ 3500 Meter MD	8 3/8 "		Cap Rock	Salt-Anhydrite-Gypsum	3277	-
			D		Limestone	3312	-

Table 4 Data of Previously Drilled Wells in Studied Oil Field (in Formation Layer C-member 3).

Items	Available Data	Data (unit)
1	Average Drilling Fluid Gel Strength	As given in Figure 2
2	Average Drilling Fluid Yield Point (while drilling with losses)	21 lb/bbl
3	Average Drilling Fluid Plastic Viscosity (while drilling with losses in formation)	20 cp
4	ROP (while drilling with losses) in Formation	8 (m/hour)
5	Poisson's Ratio of formation	0.26
6	Young Modulus of formation	4205000 (psi)
7	Common Mud Weight (Density)	14.9 (ppg)
8	Minimum Horizontal Stress of formation rock	6250 psi
9	Hole diameter in formation	12 ¼ (inches)
10	Depth of Drilling (TVD of formation)	2500-2600 (meters)
11	Hole Inclination	30 degrees
12	Pump Rate	700-800 GPM
13	Drill Pipe Rotation	120-130 (RPM)

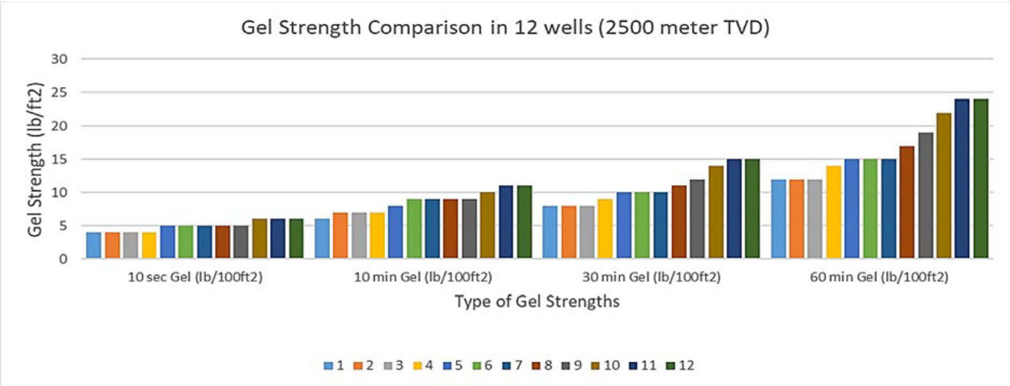

Fig. 2 Gel Strength Comparison in 12 Wells (2500-meter TVD).

Gel Strength Comparison in 12 wells and 1-hr estimation (2500-meter TVD) are given in Figure 3. Based on results, losses have occurred in problematic wells as pumps were shut done for one hour or more. 10-second, 10-minute, and 30-minute gel strengths were reported in daily well reports, and a 1-hour gel strength is not commonly reported. For this research,12 fluids were experimentally tested in the laboratory to find the gel forces behavior of drilling fluids as it is static in well condition for up to 1 hour.

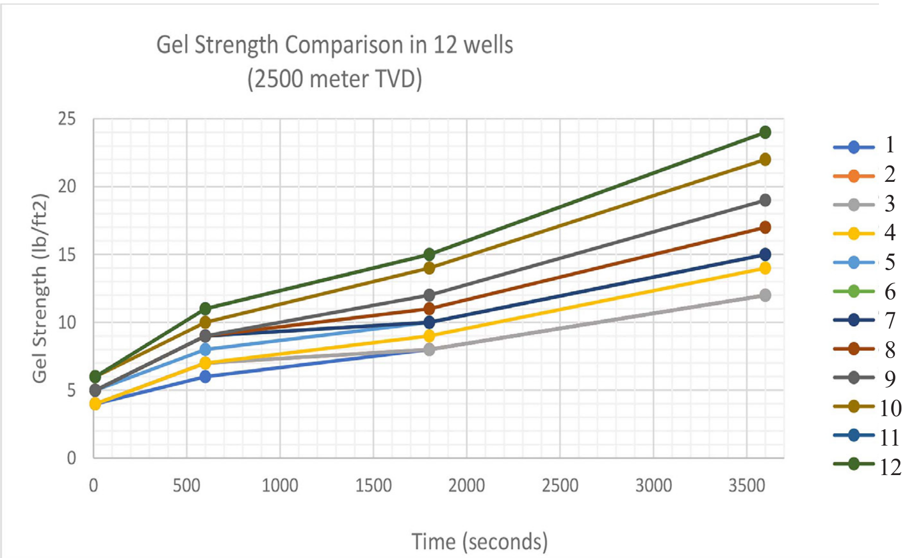

Fig. 3 Gel Strength Comparison in 12 Wells (2500-meter TVD).

Total volume losses in 12 studied wells (layer C (member 3)) are given in Figure 4, and as it is obvious in 5 wells (8,9,10,11 and 12) losses were severe.

High gel strength (while pumps are off for a couple of hours) can exert extra pressure on the wellbore surface and create induced fractures, so losses will be severe and extra NPT due to losses and related problems such as differential sticking will be inevitable. Successful cleaning of wells is achievable by increasing the gel strength, but this gel force can cause induced fracture and loss of circulation.

The important performed analysis in this report was to investigate the density of drilling fluid in different layers to determine whether the hydrostatic pressure of the used drilling fluid is capable of breaking the formation.

According to the obtained data on pore pressure, fracture pressure, and mud hydrostatic pressure in each formation, it was confirmed that one of the most important causes of losses was high mud hydrostatic pressure in wells 8, 9, 10, 11 and 12 in (layer C (member 3)).

Losses are caused by induced fractures or high fluid gel when pumps are switched off for one hour or more. To be more precise, in the mentioned field at a depth of 2500 meters, the sum of mud hydrostatic pressure and pressures (applied by pumps) to break gel strength of mud (as pumps are switched off for approximately 1 hour) exceeds fracture pressure and creates induced fractures and induced losses. But in wells 1 to 7, due to the lower gel strength of muds, these types of problems (induced fractures, severe losses, or related problems) were not reported.

Pore pressure, fracture pressure, and mud density in the studied field are given in Figure 5 for 12 studied wells.

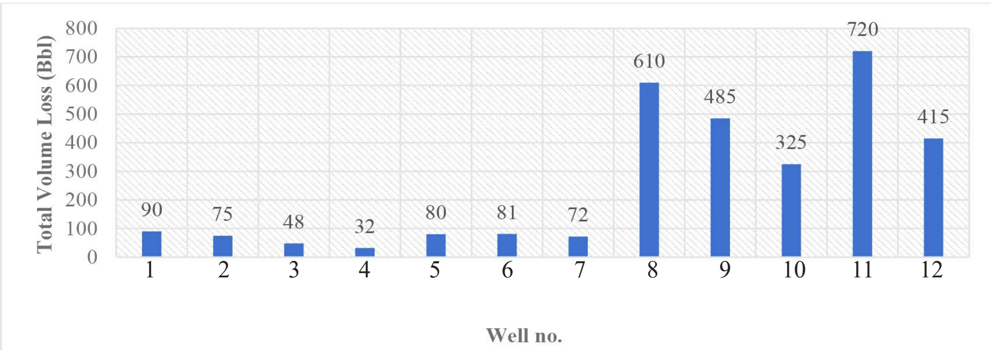

Fig. 4 Total Volume Loss Comparison in 12 Studied Wells.

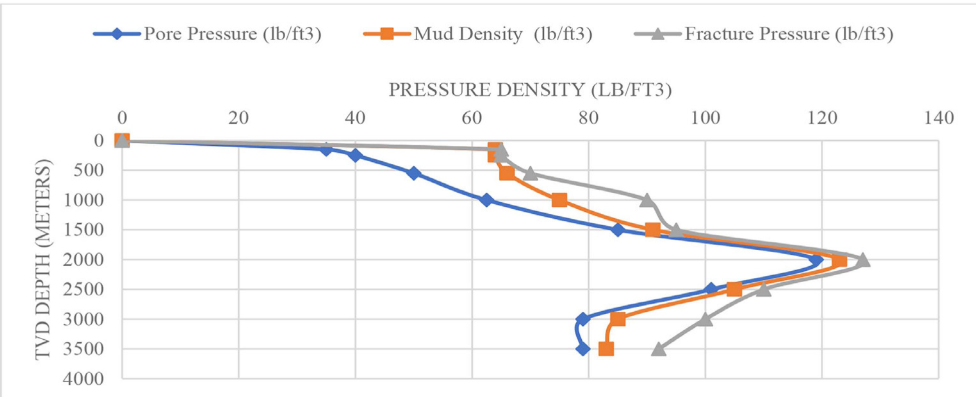

Fig. 5 Pore pressure, fracture pressure, and mud density in the studied field.

The ECD pressure was calculated in mentioned wells. The ECD pressure would not exceed fracture pressure for all those 12 wells. Moreover, no induced fractures were created. The ECD for mentioned wells had a value from 145 psi to 215 psi. That is in the range in which pressures would not exceed fracture pressure in studied cases.

However, in previous pieces of literature, the pressure exerted on the formation due to gel strength (when pumps are switched off for hours and switched on after that) would not be considered.

Required pressure to break gel strength after the 1-hour static condition is given in Figure 6.

According to the results, the main problem in the studied case was the high hydrostatic pressure of drilling fluid in the lower parts of layer C (member 3) and also the lower fracture pressure in the layers below member 3. Increasing density to prevent fluid kicks can result in penetration of fluid breaking the formation and occurring losses. In addition to overpressure drilling fluid density, other main, mud density itself cannot break formation. Even investigating calculated ECDs showed that ECD is not that high which case induced losses, but the main cause of the problem in the studied field is the high amount of fluid gel strengths as it is given in Figure 6.

Extra pressure for breaking gel forces pushed mud hydrostatic pressure, and based on calculation, the pressure exceeded fracture pressure which was reported with severe losses in five cases.

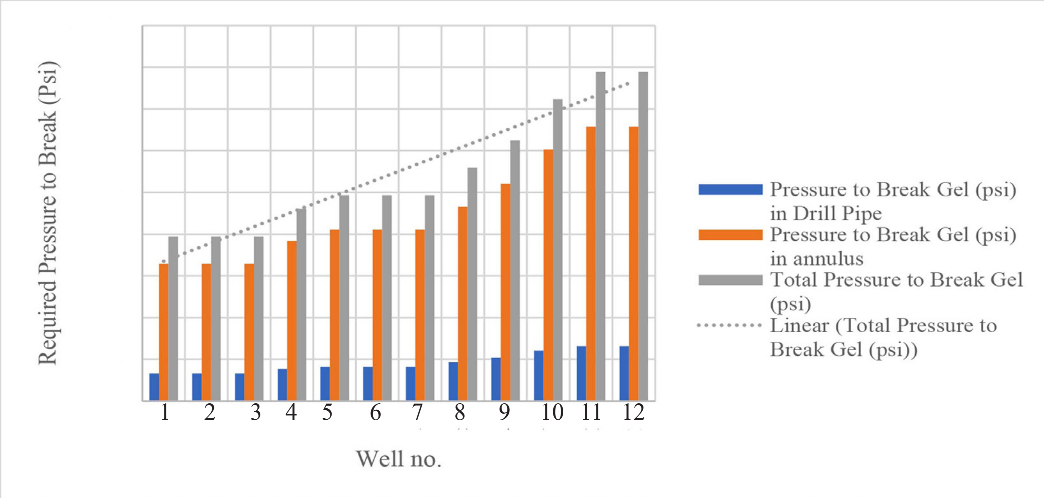

Fig. 6 Required Pressure to Break Gel Strength After 1-Hour Static Condition).

Above the mentioned issues about rheological and hydraulic parameters, layer C (member 3) consists mainly of anhydrite and carbonate formations, which are suspected to have natural fractures and also can be easily fractured if exerted pressure on them exceeds their minimum horizontal stress. The type of lithology eases the conditions for inducing fractures and losses. Carbonate formations in this field are suspectable of fracturing as fluid pressure exceeds the fracture pressure.

The next step for finding the best solution for preventing or curing a loss circulation problem is estimating average fracture/pore sizes. There are different ways to find the mentioned value as using SEM images of formation cores. The maximum or average pore size in microns can be obtained from thin section analysis and a scanning electron microscope (SEM) which these kinds of data were not provided in the studied field.

According to Equations 6 and 7 and data provided in Table 4, the average width of induced fractures of the formation layer C (member 3) was estimated to be approximately 36 microns (like the phenomenon was observed in wells 8, 9, 10, 11 and 12), which is schematically presented in Figure 7.

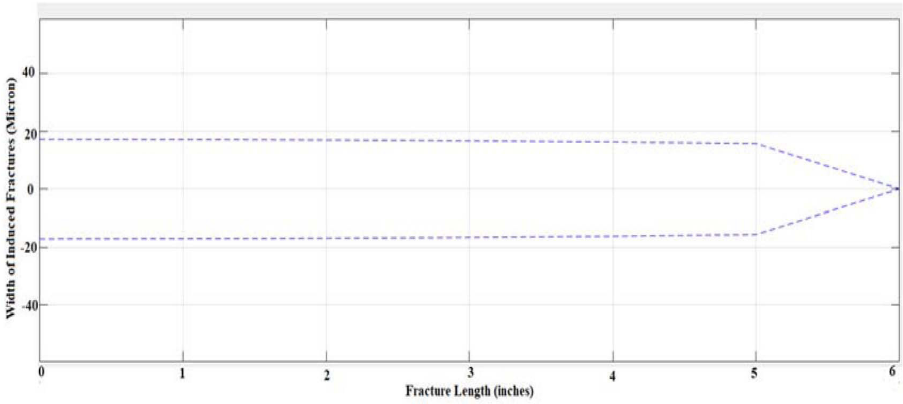

Fig. 7 Schematically Induced Fracture of Layer C (Member 3).

The solution to the problem of loss circulation in the mentioned field can be described as follows:

• Strengthening the wellbore of wells by Wellbore-Strengthening Materials (WSM) and LPMs to create an ultra-low permeable filter cake

• Change casing-shoe depths (which this method is not applicable due to the high cost most of the time)

Mentioned LPMs are micronized common cellulosic fibers which are effective in sealing filter cake pores and strengthening the wellbore by keeping it intact, as the drilling fluid is adjacent to drilled formation. These LPMs are enforced with bridging agents such as calcium carbonate particles with the same PSD to bridge remaining unsealed pores/fractures on the wellbore surface.

Material Explanation

In this study, based on the condition of studied wells, WSMs, and LPMs to create an ultra-low permeable filter cake were proposed with a size distribution of between 20 to 50 microns (with a median size of 36 microns equal to calculated induced fracture sizes of studied wells) based on Fracture Stress Closure theory [20]. That recommended narrow particle size distribution to maximize fluid loss through the fracture wall.

Field Application- Case Study

In one of the middle east fields, the most common problem in formation layer C (member 3) is loss circulation. Because of high mud hydrostatic pressures, sometimes stuck pipe incidents, severe mud losses, sidetracks, and high NPT were reported. The high mud hydrostatic pressures are unavoidable in some of the intervals due to high pore pressure and wellbore stability issues. Consequently, the composition of mud materials and properties were the main tool against the mentioned problems. A solution was to prevent differentially stuck pipes by using optimized LPMs to minimize pore pressure transmission and seal off low-pressured zones. The required data for two new wells are given in Table 5.

The main mechanisms which are considered in designing LPMs are creating filter cake that exhibits low-thickness, ultra-low permeability, and high strength in shearing forces. A mixture of pore-plugging (resilient-type of materials) and "fibers covering" forms a barrier on the formation walls, which reduces the invaded zone and improve stability by increasing hoop stress through induced/natural fractures and preventing losses efficiently in problematic zones. If used fibers do not contain customized particle size distribution according to induced fracture width, they will not be capable of plugging fracture tips.

Using fibrous LPMs helped with the strength of filter cake, due to having sufficient strength. Also, resilient materials are perfect for plugging induced fractures, because instantly plugging the newly-created fractures (while drilling) and penetrating through them, will increase hoop stress in boreholes with suspectable thief zones. This mechanism proved to be very efficient while drilling normally pressured and over-pressured formations in the same drilling sequence and prevented losses into exposed under-pressured zones.

In conclusion, by adding optimized LPMs, a non-invasive filter cake was created and fluid loss was reduced, so the thickness of the filter cake was reduced and differential sticking probability was lowered.

Drilling fluids used in this section contained LPMs with concentrations of 20-28 kg/m^3, based on the size of fractures (calculated in Figure 7 based on fracture closure stress theory). The selected LPM materials (with a mean size of 36 microns) were designed based on thief zone properties based on the methodology explained in this paper as a preventative action to evade drilling fluid losses.

Table 5 The Provided Data for Drilled Wells (A, B) in Layer C (member 3).

Well no	Lithology	Inclination @ Final depth of Member 3	Measured Depth @ Final depth of Member 3	1-hour Gel Strength (1b/100ft2)	Pressure to Break Gel (psi) in Drill Pipe	Pressure to Break Gel (psi) in the annulus	Total Pressure to Break Gel (psi)
A	Carbonate, Anhydrite and Chert	15 degrees	2005 meters	25	68.6	342.4	411.0
B	Carbonate, Anhydrite and Chert	9 degrees	1996 meters	26	71.3	356.1	427.5

Based on Abrams's rule [1], a minimum concentration of LPMs must be 5% (volume/volume) in the drilling fluid. As the density of used LPMs and WBMs were approximately between 0.4 to 0.6, the concentration of used materials required to be adjusted to 20 to 28 kg/m^3.

Using mentioned LPMs proved to be highly effective in minimizing seepage losses and differential sticking problems. Based on drilling results, NPT in comparison with other drilled wells was reduced by 25 hours (89% reduction) in well A and 20 hours in well B (71% reduction). Also, the Volume of drilling fluid losses was reduced from 511 bbl. (average from previously drilled wells) to 100 bbl. well, A (80% reduction) and 75 bbl. in well B (85% reduction). Small fractures were sealed using customized LPM that isolated the fracture tip from fluid pressure and controlled the fracture propagation and resulted in formation integrity increment. NPT comparison of studied wells with average previously drilled wells is given in Figure 8.

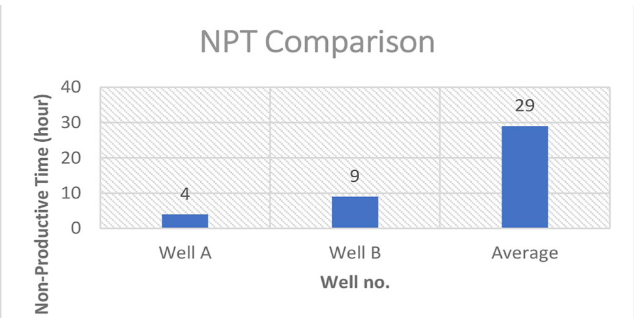

Fig. 8 NPT Comparison of Studied Wells with Average Value of Previously Drilled Well.

The total volume loss comparison of studied wells with average previously drilled wells is given in Figure 9.

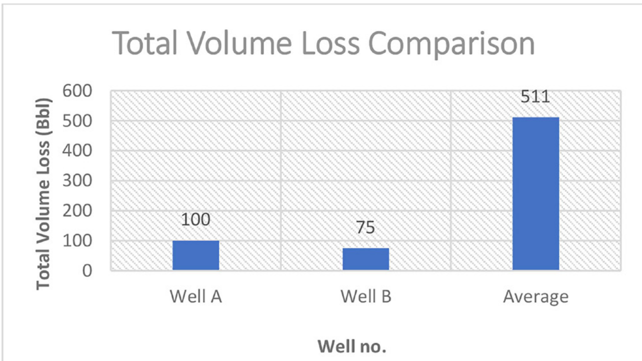

Fig. 9 Total Loss volume comparison of studied wells with an average value of previously drilled well.

Considering the results, it should be mentioned that well B is two advantages in comparison with well A. The first one is that due to the lower inclination of well B in member 3 (layer C), it has lower length and surface contact in mentioned layer compared with well A. Secondly, the location of well B is closer to the border of the eastern/central block of the studied field (Figure 1), and it was previously explained, in the central block, losses are less severe comparing the eastern section. These two facts justify a considerable difference in losses and NPT values of well B as it is compared to well A. It should be mentioned that wells A and B were the same in the aspect of depth, lithology, and drilling practices as given in Table 5.

Due to a lack of hydraulic fracturing and leak-off test data in the Asmari Formation of the Shadeghan Oil Field, to calculate minimum horizontal stress, mud losses information of the formation was used. Thus, if the mud weight leads to the fracture initiation and/or reopening of the pre-existing fractures in the formation, the total mud weight can be considered equivalent to the minimum horizontal. Based on mud weight information in the daily drilling reports, pore pressure in member 4 of the Asmari Formation up to the cap rock (member 1) in the Shadeghan Oil Field would be about 0.023 MPa/m. This value implies the presence of a large amount of saline water at this depth and thus overpressure of the Formation. In this way, pore pres-sure at failure depths of Shadeghan 12, 131, and 31 wells was estimated to be 65.8, 73.74, and 71.65 MPa, respectively. Drilling in members 4–2 of the Asmari Formation in Shadeghan 133 well shows that mud weight has increased up to 145.5 pcf, which was declined to 140.2 pcf by the mud loss of 22.6 barrels. The mud column weight pressure (i.e., well pressure at the depth of failure) was calculated to be 75.89 MPa. Since the fracture gradient of the Asmari Formation was 0.025 MPa/m, due to the pre-existing fractures, the 146 pcf mud weight can initiate or propagate fracturing at the failure depth. Since the fracturing induced by mud weight increase up to the formation strength must occur along the direction of horizontal stress, by converting mud weight unit (pcf) to pressure unit (MPa), it is seen that mud column weight at failure depth is almost equivalent to Shmin. At the failure depth of the Shadeghan 130 well, mud weight increased up to 149 pcf, by which the well pressure was increased to 80.42 MPa, while mud weight declined to 145.6 pcf (as seen in Figure 10).

In Figure 11, the methodology of preventing losses in formations with a probability of losses by using LPM and WSM presented in this paper is given.

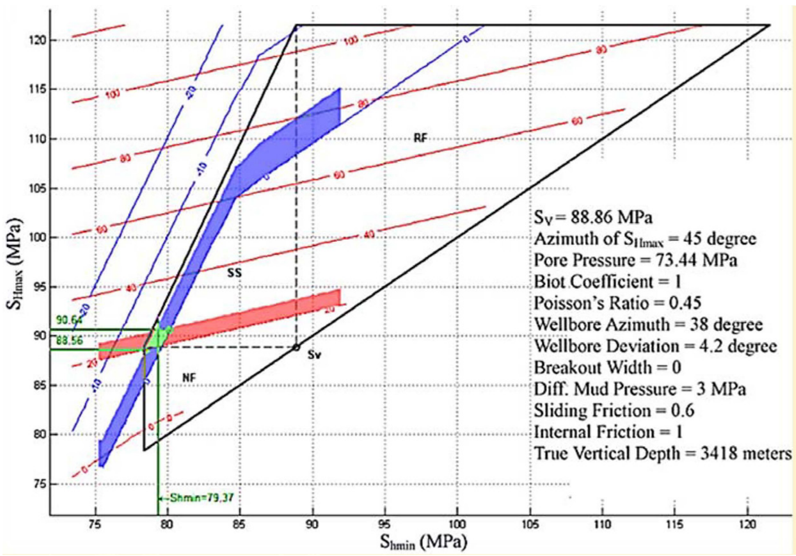

Fig. 10 Stress polygon based on the Mohr-Coulomb failure criterion for Shadeghan 21 well.

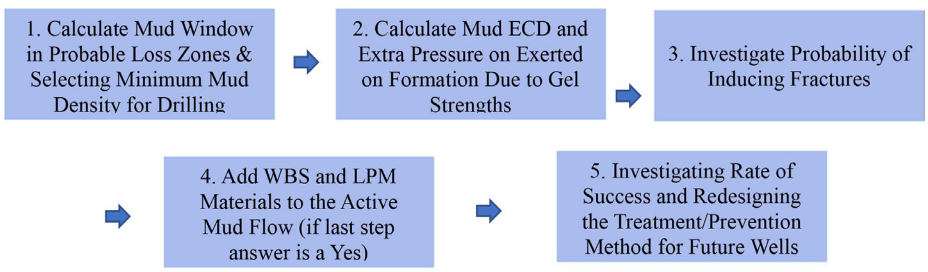

Fig. 11 Methodology of Preventing Losses in Formations with Probability of Losses by Using LPM and WSM.

Conclusions

This paper provides a case study of preventing lost circulation, including a brief review of lost circulation basics, and a discussion of the best preventive and remedial methods of mitigating losses and related problems. The process used in this paper can simply be explained as finding the root cause of loss problems and induced fractures of layer C (member 3) in the studied field (in the Middle East).

Also, a customized LPM was used to create an effective seal at the tip of the induced fracture of the formation.

The most effective method to prevent lost circulation is to keep the BHP below the lost circulation pressure and consider ECD and Gel Strength parameters as extra exerted pressure on formations.

In the studied formation, based on provided data, an important analysis was to investigate the density of drilling fluid in different layers to determine whether the density of the mud is capable of breaking the formation. According to the obtained data on pore pressure, fracture pressure, and mud weight in each field formation, it was confirmed that one of the most important causes of loss circulation was high fluid pressure in some parts of layer C (member 3). They are caused due to high fluid gel when pumps are switched off for a few hours which results in induced fractures.

Also, induced fracture width in studied wells, using geo-mechanical and drilling fluid data was calculated at approximately 36 microns through porous media in the near-wellbore region.

In two new wells, using optimized LPMs proved to be highly effective in minimizing seepage losses and differential sticking problems. Small fractures were sealed using customized LPM (with a median size of 36 microns based on Fracture Stress Closure theory) that isolates the fracture tip from fluid pressure and controls the fracture propagation and results in formation integrity increment. Using recommended materials in two new wells (with high-gel strengthens same as before), losses and related problems were considerably reduced, as NPT in comparison with previously-drilled wells was reduced between 71 to 89%. Also, loss volume was reduced from 511 Bbl (average from previously drilled wells) to 75-100 Bbl in each well (80-85% reduction). Based on successful wellbore strengthening, LPM plugged the fractures immediately and prevent mud losses. For reaching the best results, an estimation of the fracture opening to define the proper size of the LPM to seal the fracture most effectively as the "fracture propagation resistance" theory claims, was done. Based on this theory, fracture gradient improvement happens due to blockage of WSM the induced fracture near its tip so that the tip gets hydraulically isolated from the borehole. Therefore, the fracture can tolerate higher wellbore pressures without propagating further.

Nomenclatures

API= American petroleum institute
Bbl.= Barrel
BHP= Bottom-hole pressure
ECD=Equivalent circulating density
FL= Filtration loss
IPS= Ideal Packing Sequence
IPT= Ideal Packing Theory
LCM= Loss circulation material
LPM= Loss prevention material
NPT=Non-Productive Time
OBM= Oil-based mud
PCF=Pound per cubic feet
PPG=Pound per gallons
PSD= Particle size distribution
PV= Plastic viscosity
SEM= Scanning electron microscope
WBM= Water-based mud
WSM= Wellbore strengthening material
YP= Yield point

Article Highlights

• The historical seepage, partial and severe loss circulation, and related problems in one of the onshore Middle East fields are described.

• A field-studied solution to prevent/cure loss circulation problems by predicting induced fractures and optimizing loss preventive materials is presented.

• One of the most important causes of loss circulation was high fluid pressure in some parts of layer C (member-3) resulting from induced fractures due to high fluid gel strength when pumps are switched off and switched on for a few hours.

• The induced fractures are estimated to be due t high gel strength, with a calculated width of approximately 36 microns in the near-wellbore region.

• In two new wells, using LPM materials (with a size distribution of 20 to 50 microns with a median size of 36 microns equal to calculated induced fracture sizes) proved to be highly effective in minimizing seepage losses and differential sticking problems.

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Conflicts of Interest

No conflicts of interest exist.

Ethical Statement for Solid-State Ionics

Hereby, Authors consciously assure that for the manuscript / insert title/ the following is fulfilled:

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3- The paper reflects the authors' own research and analysis in a truthful and complete manner.

4- The paper properly credits the meaningful contributions of co-authors and co-researchers.

5- The results are appropriately placed in the context of prior and existing research.

6- All sources used are properly disclosed (correct citation). Literally copying of text must be indicated as such by using quotation marks and giving proper reference.

7- All authors have been personally and actively involved in substantial work leading to the paper, and will take public responsibility for its content.

SI Metric Conversion Factors

cP×1.0* E–03 = Pa·s
ft ×3.048* E-01= m
ºF(°F–32)/1.8= ºC
in. ×2.54* E+00 = cm
lb ×4.545* E-01 =Kg
bbl ××1.59*E-01 =m^3
psi ×6.894757 E+00 = kPa

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