International Journal of Innovative Technology and Exploring Engineering (IJITEE)
ISSN: 2278-3075, Volume-8, Issue-4S February, 2019

Oil Well Stimulation for Carbonate Reservoir using Acidizing Techniques

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Abstract: Matrix acidizing is one of the oldest well stimulation methods that has been used for the past few decades to resolve the formation damage issue. However, stimulation in carbonate reservoir rocks is considered difficult due to the high degree of challenge faced during the stimulation process. An efficient matrix acidizing system for carbonate reservoir. This paper mainly focuses on designing as operational excellence approach in diagnosis of the type of formation damage, selection and formulation of suitable stimulation fluid and designing a complete acidizing system for carbonate reservoirs. In this work, crude and deposit samples from two different wells of a carbonate oil field named Bukit Tua field located in the East Java region of Indonesia was used as case studies to quantify and analyse the type of formation damage. Various analytical tests such as dissolution test, modified SARA analysis, pH of the crude sample, on the samples were conducted in the laboratory to understand and affirm the occurrence of formation damage. Based on the analytical results and studies, it was concluded that the deposition of organic and inorganic scales in and around the wellbore caused the majority problem in carbonate wells. Hence, a micro emulsion formulation and a heat generating formulation were designed in order to simultaneously dissolve and disperse the deposits and also make the heavy viscous crudes to flow. The customized stimulation fluid had a controlled reaction kinetics, low density and the ability to simultaneously treat multiple formation damage issues in carbonate wells that gives them an edge over the conventional acidizing systems. Following the most crucial stage of proper stimulation fluid selection, an efficient treatment plan has been designed in order to scale up for field applications.

Keywords: carbonate reservoir rocks, Matrix acidizing, SARA analysis

I. INTRODUCTION

Carbonate reservoirs contain almost two-third of the remaining oil reserves in the world. Carbonate formations exhibit extremely high heterogeneity and complex production problems which results in decrease in the productivity of the well [1]. Among them, production formation damage is one of the major causes for decline in production in many oil fields causing restrictions in flow of fluid in and out of the wellbore [2]. The flow restriction is caused due to the reduction in permeability in the near wellbore region, changes in the relative permeability to the hydrocarbon phase, unintended flow restriction in the completion and various other factors. This flow restriction can adversely affect the production rate and the well performance [3]. This problem can be solved by the acidizing method which is a process of well stimulation widely used in the petroleum industry, that involves pumping acid solution into the formation under fracture pressure. The primary aim of acidizing is to stimulate the formation and thereby increase the productivity of the well by restoring the permeability of the near wellbore region. [4]

When a decrease in productivity of a well in a carbonate reservoir is encountered as a result of formation damage causing reduction in permeability, attempts are taken to increase productivity through various methods such as well intervention and other appropriate treatments [5]. If the production team decide to work over the well, they should initially determine the cause for the damage and design a treatment program that could create effective wormholes or flow conduits between the reservoir and the borehole [6].

The mechanism that causes the increase in permeability in the carbonate formations is the dissolution of the rock by reacting the carbonate and acid. This dissolution process would lead to the formation of “wormholes” that facilitates the flow through the near wellbore region resulting in an increment in production as well as injection [7]. HCl & HF are commonly used acids for matrix acidizing treatment which rapidly reacts with the formation to form wormholes [8]. However HCl or weaker acids are preferred over HF in order to avoid further precipitate [8]. HF possess more sever HSE concerns too. Various organic acids and combination of acids can be used for stimulation jobs too. Carbonate matrix acid stimulation can also be useful in treating carbonate cemented sandstone, deposition of inorganic scales, naphthenate and organic depositions, damage from various acid soluble species such as calcium carbonate ($CaCO_3$) and lost circulation material [9].

The screening criteria for the stimulation fluid for carbonate formations are also distinct from the other types. It is necessary for the stimulation engineer to understand the extent, type and origin of the damage, the reservoir mineralogy and properties, and the compatibility of the treating fluid with the formation in the process of designing an efficient carbonate stimulation design system [10]. It is also crucial to determine the ideal reservoir temperature for the application, safe pumping rates and the fluid type as these parameters have a direct influence on the reaction between the treating fluid and the carbonate reservoir rock.

Hence designing a very well planned acidizing is very crucial. For an efficient stimulation, the wormhole network should penetrate deeply and uniformly throughout the production interval.

Revised Manuscript Received on February 05, 2019.

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Achieving a uniform stimulation can be challenging in particular due to the existence of large permeability variation within the treatment interval. Most of the times, the stimulation acid that penetrates the formation tent to flow into the most permeable pathways resulting in waste of acid.

Thus, in this work, crude and deposit samples from two different wells of a carbonate oil field named Bukit Tua field located in the East Java region of Indonesia was used as case studies to quantify and analyse the type of formation damage. Various analytical tests such as dissolution test, modified SARA analysis, pH of the crude sample, SEM and XRD on the samples were conducted in the laboratory to understand and affirm the occurrence of formation damage.

II. METHODOLOGY

Case Study

Bukit Tua field is located in the East Java region having an area of about 3.32 km^2. The mature field is expected to contain recoverable reserve of about 65 million barrels of oil and around 110 billion cubic feet of gas. The oil and gas are located within the Oligo-miocene carbonate reservoirs of the kujung formations.Five different crude samples from different wells (A & B) along with two types of deposit samples were received for analysis. As a result of adverse skin and deposition in and around the wellbore and along the tubing string adversely effected the production of those wells.

Sample Analysis

To get a better understanding of the nature of the sample and to design an effective treatment method, the samples were assessed for, compositional analysis and characterized by dissolution tests. The test conducted were, deposit Physical Appearance and Properties, Dissolution Test on the deposit sample , Tests on crude/water sample and SARA Analysis.

Proposed Treatment

Conventional treatment methodologies are insufficient in order to treat the problems caused due to the deposition both, organics and the inorganics. The recovered crudes from Bukit Tua field are highly waxy in nature and solidifies at ambient condition. These crudes are also having high free water content ranging from 46.-92 % resulting in thick deposit of inorganic scale along with some corrosion products as oxide/ sulphide of Iron.

By chemical analysis of the inorganic deposit samples, it is observed that there is very small amount of organic embedded into them. This indicates that in & around well bore there may mainly be deposition of organic and Inorganic scale embedded with little organics may be in the tubing. The deposits are thick and compacted with cylindrical shape of tubing.

Two formulation were prepared. Formulation I, a heat generating formulation that has the tendency to generate heat upon reaction between Active 1 and Active 2. This formulation is intended to treat organics, inorganics or combination and heavy crudes with a high pour point.Formulation II, a specialty micro-emulsion formulation that is almost 40% organic acid and 60 % solvent, was designed as per the compositional analysis of the deposit sample and the crude. This formulation is intended to treat both organics and inorganics. Upon addition of surfactants it also could break strong emulsion and reduce the viscosity of the crude that has a relatively lower pour point.

III. RESULT AND DISCUSSION

Deposit Physical Appearance and Properties

For the samples from Well A as shown in Figure 1 (a), it was observed that Greyish with some brown layer on upper surface , hard thick solid layered deposit. As for the sample in Well B as shown in Figure 1(b), it was observed that Deposit Solid Sample, Greyish brown , very thick, compacted , cylindrically deposited and hard to break.

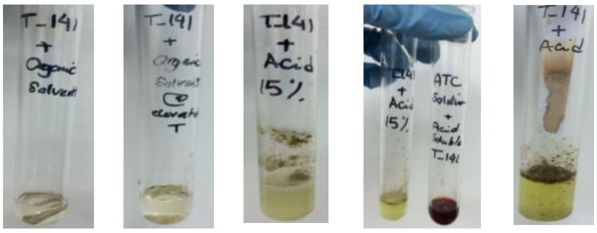
(a) (b)

Fig. 1 Sample Well A (a) Sample Well B (b)

Deposit Physical Appearance and Properties

For the dissolution test on Sample Well A in organic solvent at ambient and at elevated temperature, it was observed that as shown in Figure 2 (a) and 2(b), there was no development of color and no dispersion / dissolution of sample. Thus, it is deduced that absence of organic content in the sample and the sample is predominantly in-organic in nature. As for 15% HCL test, it was observed as shown in Figure 2(c) that vigorous reaction and effervescence took place with development of yellowish color of solution on standing and some sludge around in the tube. Thus it indicates the existence of in-organic scale, predominantly Calcite along with some embedded organics and yellow color indicates the existence of iron/ferric as corrosion product.

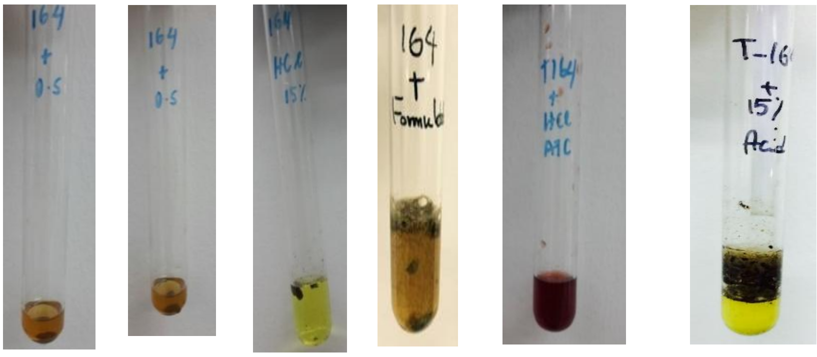
For the Ferric iron test, it was observed that as shown in figure 2(d), Colorless ATC solution turned blood red upon adding the dissolved sample in 15% HCl. As for H_2S detection, it was observed as shown in Figure 2 (e) that lead acetate paper color turned dark in vicinity of reaction of sample with acid. Thus this indicates that the blackening of lead acetate paper indicates the existence of sulphide which on reacting with HCl liberates H_2S gas.



(a) (b) (c) (d) (e)

Fig. 2 Sample Well A dissolution test outcome

For the dissolution test on Sample Well B in organic solvent at ambient, it was observed that as shown in Figure 3 (a) Development of light brownish color occurred and it indicates that existence of minor amount of lower organics. For the test in organic solvent at elevated temperature, it was observed as shown in Figure 3(b) that no darkening of the color /further dissolution of the sample, it indicates that organic component of the deposit is low. For the 15% Hcl and modified formulation , it was observed in Figure 3(c) and 3 (d) that bubbles of gas are made on the surface of deposit but no brisk effervescence with development of yellow color of solution on standing. Also brisk effervescence observed with modified formulation. It indicates organic may be embedded into the inorganic/calcite along with corrosion productsand organic embedded must be hindering the reactivity with 15% Hcl. It confirms the presence of calcite. For the Ferric iron test, it was observed that as shown in figure 3(e), development of blood-red color on addition of colorless ATC solution. This indicates existence of corrosion products. As for H_2S detection, it was observed as shown in Figure 3 (f) that no development of color on Lead Acetate paper after the sample is treated with modified 15% HCl. This indicates there may not be any sulphide content present in the composition.



(a) (b) (c) (d) (e) (f)

Fig. 3 Sample Well B Dissolution Test Outcome

Test on crude/water sample

For sample Well A, it exhibited free Water of 46% and crude solidifies at ambient temperature as dark brown lump. For sample Well B, it exhibited free water of 90.91% and Crude solidifies at ambient temperature as dark brown lump. SARA Analysis was conducted on the crude sample in order to determine the detailed composition of the sample and it is shown in Table 1 and Table 2 respectively. As per the chemical analysis conducted, the deposit samples from well A & B were mostly calcite in composition along with some corrosion products as Iron oxide /sulphide. It was noted here that there is very little organic embedded content in the deposit. This could be due to high free water in the crude. Thus, also suggested that the sample was predominantly inorganic in nature, mainly calcite along with little corrosion products and insoluble. As per compositional analysis, the crude samples from well A & B were found to be waxy in nature with high content of Macro-crystalline wax (low molecular weight/low melting point) along with other higher organics as Asphaltene & Naphthenates. Because of high content of Macro-crystalline wax along with some micro-crystalline wax which have high molecular weight/high melting point, pour point of the crude is high as 39 0C.The CII of the crude is high 1.4 - 2.3 for crude samples A & B respectively which indicated that there is high likelihood of precipitation of Asphaltene forming nucleation for deposit along with waxes.

Table. 1 Sara Analysis Results on Crude Sample of Well A

Crude Sample Well A		
Pour Point : 42.0° C		Standard Test Method : ASTM D5853
SARA ANALYSIS		Standard Test Method : Modified SARA [IP 143/90, (ASTM D-3279-90),(ASTM D-4124)] Sample basis (%)
Volatiles		43.14
Saturates	Macro crystalline wax (low molecular weight)	28.71
	Micro-crystalline wax (high molecular weight)	0.89
Total Saturates		29.60
Asphaltenes		2.58
Resin		2.16
Aromatics		20.34
Naphthenates		0.66
*Total		98.48
CII		1.46

Table. 2 SARA Analysis results on crude sample of Well B

Crude Sample Well B		
Pour Point : 39.0° C		Standard Test Method : ASTM D5853
SARA ANALYSIS		Standard Test Method : Modified SARA [IP 143/90, (ASTM D-3279-90),(ASTM D-4124)] Sample basis (%)
Volatiles		47.01
Saturates	Macro crystalline wax (low molecular weight)	24.07
	Micro-crystalline wax (high molecular weight)	1.14
Total Saturates		25.21
Asphaltenes		2.45
Resin		2.82
Aromatics		19.58
Naphthenates		1.36
*Total		98.42
CII		1.30

Dissolution test of the samples using the customized formulation

1 gram of the sample was taken in a test tube and 5 ml of designed formulation was added to it and allowed to soak overnight. Next, the tube was gently shaken to observe dissolution or dispersion. It was observed to dissolve or disperse. 5 ml of water is then added, mixed with the contents and kept undisturbed for 3-4 hours to observe any settling at the bottom. The tube was tilted and no settling at bottom was observed. Based from the chemical analysis such as the dissolution test, SARA analysis, , deposit sample of well A was found to be predominantly organic in nature with Asphaltenes deposition along with other soluble or insoluble inorganics and naphthenate deposits. It was detected to dissolve/disperse in the designed formulation. Therefore, well A is recommended for treatment with this formulation for dissolution or dispersion of the deposit in tubing and around well bore for improved productivity as shown in Figure 4.

Fig. 4 Dissolution test on the deposit sample from well A

1.5 g of the deposit sample (T-164) was taken in a tube. 5ml of designed formulation was added to the deposit. The tube was kept for 1 hour. It was observed that the deposit sample was dissolved and dispersed in the formulation fully.

The colour change of lead acetate paper was used as an indicator for any H_2S release. No blackening of the paper was observed. Water was added to the tube to check if there is any residue at bottom of the tube or rag at interface. No evidence of rag or residue at bottom of the tube was observed as shown in Figure 5. Very similar positive results were obtained when the formulation was used to treat the deposits from well A.

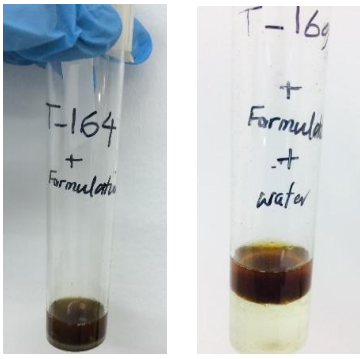


Fig. 5 Well B Deposit Sample Tested With Formulation II

Test of solidified crude of well A with formulation 1 shows that temperature rise to above 110°C with some generated heat lost to the surroundings. However higher temperature up to 125 0C can be achieved in the well.The sample dissolved/dispersed in the formulation fully. The contents of the beaker were transferred to another beaker after cooling, No residue was left behind and no re-solidification of sample happened after cooling as shown in Figure 6. Very similar positive results were obtained when the formulation was used to treat the crude oil from well B.

Dissolution test of the samples using the customized formulation

A unique methodology of treatment is designed to treat both organic deposit in & around well bore and Inorganic scale in the tubing. It consists of combination of Formulation I and Formulation II. First, Formulation I is added to dissolve and disperses the organics and then it is followed by Formulation II to dissolve the inorganic scale. The proposed treatment on small scale was conducted in lab. In this experiment, organic deposit was added to the bottom of the tube while the scale deposit was hanged inside the tube. This arrangement was made to replicate the well condition. Active 2 and Active 1 of Formulation I was added to the tube followed by Formulation II. The organic solid was dissolved while hanged inorganic deposit also dissolved/dispersed completely as shown in Figure 7. No formation of any precipitation or rag is observed. It also tests the compatibility of the designed formulation with the crude.

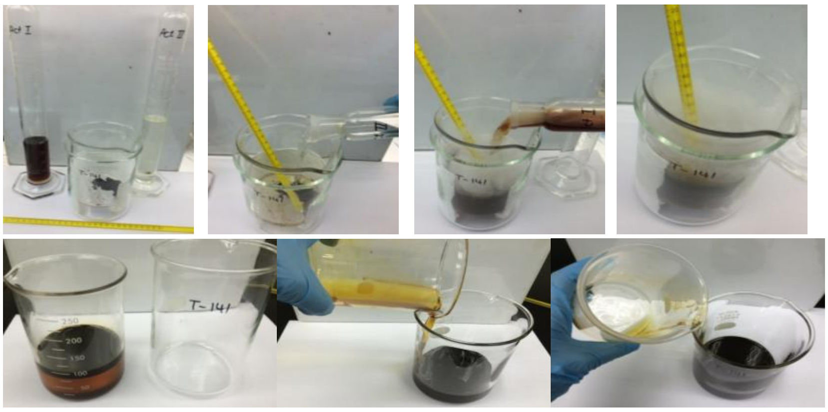


Fig. 6 Test of Solidified Crude of Well A with Formulation 1

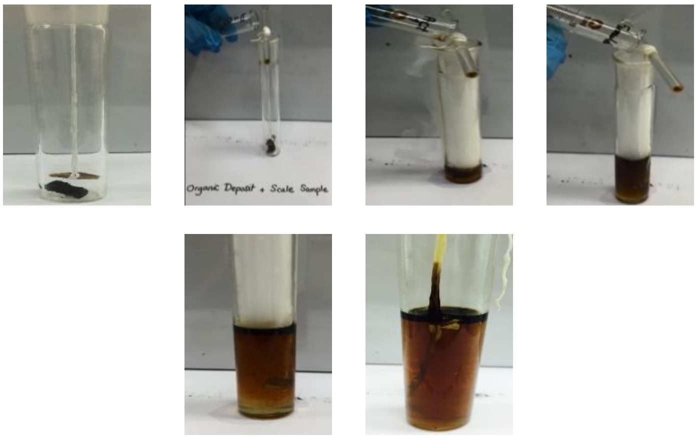


Fig. 7 Treatment for Bukit Tua Wells

IV. CONCLUSION

For the organic and inorganic deposit as are identified to be deposited separately in & around well bore and in the tubing, well is recommended to be treated with Formulation Ifor remediation of organic in & around well bore followed by Formulation II as post flush for dissolution/dispersion of deposited inorganics/calcite in the tubing. Any H_2S released will be scavenged in the formulation. This will remediate the well for improved productivity. For wells with similar problems, a combination of the formulations or the formulations individually can be used to treat the wells efficiently compared to the conventional acidizing method.

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