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Evaluation of the performance of acids for effective stimulation of a sandstone formation

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Abstract

Optimum acid selection based on reservoir condition is one of the key elements in achieving a successful treatment in sandstone matrix acidizing. This work will investigate the effectiveness of several type of acid in sand stone reservoir stimulation. PROSPER well modeling package was utilized for the model development. Pre- acid job analysis was carried out to establish the well performance before acidization. Acid stimulation was implemented with Hydrochloric (HCl), Formic, Acetic, Propionic and ChloroAcetic acids. Thereafter, post-job analysis was done to ascertain the improvement in well productivity index for each of the acids. Result shows that the reservoir will deliver 11296.5 STB/day of liquid into the wellbore for a production index of 3-STB/day-psi without acid stimulation and the well will produce 6726.05 STB/day of liquid. Results reveals a decrease in productivity index as the treatment acid was change from HCl acid to formic acid, acetic acid and propionic acid. A productivity index values of 3.07074STB/day-psi, 3.0375 STB/day-psi, 3.01038 STB/day-psi, 3.00791 STB/day-psi were obtained when the formation was acidized with HCl acid, formic acid, acetic acid and propionic acid. A percentage increase of 15.1973%, 7.5731%, 1.95684% and 1.47001% in permeability was observed as the formation was treated with HCl acid, formic acid, Acetic acid and Propionic acid. Results reveals that HCl acid resulted in highest permeability increase. It was therefore concluded that the formation should be acidized with HCl acid since it gave the highest productivity index, percentage increase in permeability, porosity and the highest improvement in skin factor.

Keywords: Stimulation; Acid; Sandstone; Permeability; Porosity; Productivity Index.

1. Introduction

Well operations like drilling, completion, workover and production operations often result in formation damage. Formation damage is one of the most difficult problems encountered by engineers in the oil and gas industry (Leong and Ben Mahmud, 2017). This common problem usually give rise to significant decline in oil and gas well productivity especially after many years of production (Williams *et al.,* 1979). In order to solve this problem, acid stimulation has come into play for its role in reducing formation damage by increasing the porosity and permeability of the formation, hence recovering the production profile of a well (Schechter, 1992; Economides *et al.,* 2013).

In sandstone reservoirs, this operation is expected to only remove the formation damage around the wellbore, and its desired outcome is usually to only restore the original reservoir permeability around the well. However, in carbonate reservoirs, as the reservoir rock itself is highly soluble in the injected acid, the outcome of matrix acidizing is usually much better. If injected at the right conditions, the acid dissolves the carbonate rock forming highly conductive preferential paths called wormholes (McDuff *et al.,* 2010). Ideally, these channels are very thin, but have very high conductivity. As only a small fraction of the rock is dissolved to form the thin channels, the usual volumes of acid used in the field treatments can extend the wormholes to considerable distances into the reservoir, as much as 10 to 20 ft

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(Economides *et al.,* 2013). Wormholes make the connection between formation and wellbore. Therefore, hydrocarbons can flow to the wellbore through new created flow channels. The creation of wormholes in carbonate reservoir that penetrate beyond the damaged zone, can result in a negative skin (Glasbergen *et al.,* 2009). The lowest skin factors will be achieved when the acidizing treatment is conducted at optimum injection rate, and consequently the longest wormholes are created (Akanni and Nasr-El-Din, 2015). Decreasing the skin factor depends on the dissolution pattern which influences the invasion of the acid into the reservoir (Fredd, 2000). The highest acid penetration occurs when the dominant wormhole is formed and this is will lead to the highest reduction in the skin factor. For this purpose, fluid type, injection flow rate, and fluid volume must be investigated (Glasbergen *et al.,* 2009). The importance of the injection rate on wormhole formation has also been pointed out by McDuff *et al.,* (2010). The optimum injection rate of acid was determined and it was shown that at a specific temperature, the acid injection rate is an important parameter to form wormholes. As highlighted by Akanni and Nasr-El-Din (2015), an optimum acid injection rate in matrix acidizing treatments is very important to achieve deep acid penetration. Suitable acid selection for high-temperature tight reservoirs. Several researchers have investigated the positive effect of acid stimulation on production rates (King, 2010; King, 2014; Allix, *et al.,* 2011; Baihly, *et al.,* 2010; Manchanda, *et al.,* 2014). Their evaluation of acid fracturing was an increase in the production rate, which is also confirmed by the study of Kalfayan, (2008). Previous works about acid fracturing of sandstone reservoir are very limited and are merely confined to feasibility studies or primary candidate well selection (Bale *et al.,* 2010; Shadizadeh *et al.,* 2010; Heydarabadi *et al.,* 2010). Therefore, this work fills the gap by presenting an optimization design of acid stimulation of tight sandstone reservoir. Laboratory and hypothetical field data will be used to examine the production trend of different acid type and the improvement of the skin that reduced the production sandstone formation using PROSPER software.

2. Materials and Methods

2.1. Materials

Petroleum Experts PROSPER well modelling simulator and Fluid properties data (solution gas/oil ratio, water salinity, oil API gravity and gas gravity), reservoir and inflow data(productivity index, reservoir pressure and temperature), deviation survey (measured depth versus true vertical depth), downhole equipment (casing and tubing strings, SSSVs etc.), geothermal gradient (formation temperature versus measured depth, overall heat transfer coefficient), well parameters, well test data, rock properties, formation composition were used and presented in Table 1 to Table 10

Table 1 Model setup data

Property	Specification
Fluid type	Oil and Water
Fluid model	Black Oil
Separator	Single-stage separator
Flow type	Tubing flow
Well type	Producer
Well completion type	Cased hole

Table 2 Fluid properties data

Property	Values
Gas Gravity	0.75
Water salinity	25000 ppm
Solution gas/oil ratio	800 SCF/STB
Oil gravity	37°API

Table 3 Reservoir and inflow data

Property	Value
Inflow Model	PI Entry
Reservoir Pressure	5200 psig
Reservoir Temperature	210°F
Productivity index	3 STB/day/psi
Water cut	40%
Total GOR	800 SCF/STB

Table 4 Deviation survey

Measured Depth (ft)	Total Vertical Depth (ft)
0	0
600	600
1005	1000
4075	4000
7700	7500
9275	9000

Table 5 Downhole equipment data

Type	Measured Depth (ft)	Inside Diameter (inches)	Inside Roughness (inches)
Xmas Tree	0	-	-
Tubing	1000	4.052	0.0006
SSSV	-	3.72	-
Tubing	9000	4.052	0.0006
Casing	9275	6.4	0.0006

Table 6 Geothermal gradient

Measure Depth (ft)	Temperature (°F)
0	60
9275	210

Table 7 Well parameters

Property	Value
Borehole diameter	8.496inch
Perforated interval	100ft
Shot density	8 per ft
Perforation tunnel diameter	0.62inch

Table 8 Well test data

Property	Value
Liquid production rate	10627.8STB/day
Test water cut	0%
Permeability from test	50mD

Table 9 Rock properties

Property	Value
Porosity	0.2 fraction
Rock bulk density	166lb/ft^3
Rock tensile strength	500psi
Poisson's ratio	0.2 fraction

Table 10 Formation composition

Property	Value
Dolomite	25wt%
Calcite	60wt%
Mixed clays	12wt
Mixed Feldspar	1wt%
Muscovite (Mica)	2wt%

2.2. Simulation Procedure

The Petroleum Experts PROSPER was used to develop a well bore model consists of well type, completion type, fluid type and method of calculating fluid properties with the model set up in Table for configuration. The black oil fluid properties data in Table 2 were entered in the PVT section. The current reservoir properties such as reservoir pressure and temperature, water cut and producing GOR in Table 3.3 were entered in the reservoir data section of inflow performance relationship model section. Then the well bore configuration was described with the deviation survey shown in Table 4. The down-hole equipment section was installed with the data in Table 5 and the geothermal gradient data shown in Table 6 were populated in the temperature input interface. An overall Heat Transfer Coefficient (OHTC) value of 8-Btu/h/ft^2/°F was also entered which account for the heat transfer from the fluid to the surroundings. The well performance for the un-acidized well with a productivity index of 3-STB/day-psi was determine with the Nodal Analysis simulation tasks against a wellhead pressure of 500psig. It combined the VLP and IPR curves to find the system point at which the well will flow. Later the screening tool was used to design the acid job (Hydrochloric (Hcl) acid, Formic acid, Acetic acid, and Propionic acid) using the data in Table 7 – Table 10. For all the acid type considered, a volume of 10000 gallons of acid was used. For each of the acid type, the base case productivity index was updated with the productivity index and the well performance re-evaluated. The simulation workflow is presented in Figure 1.

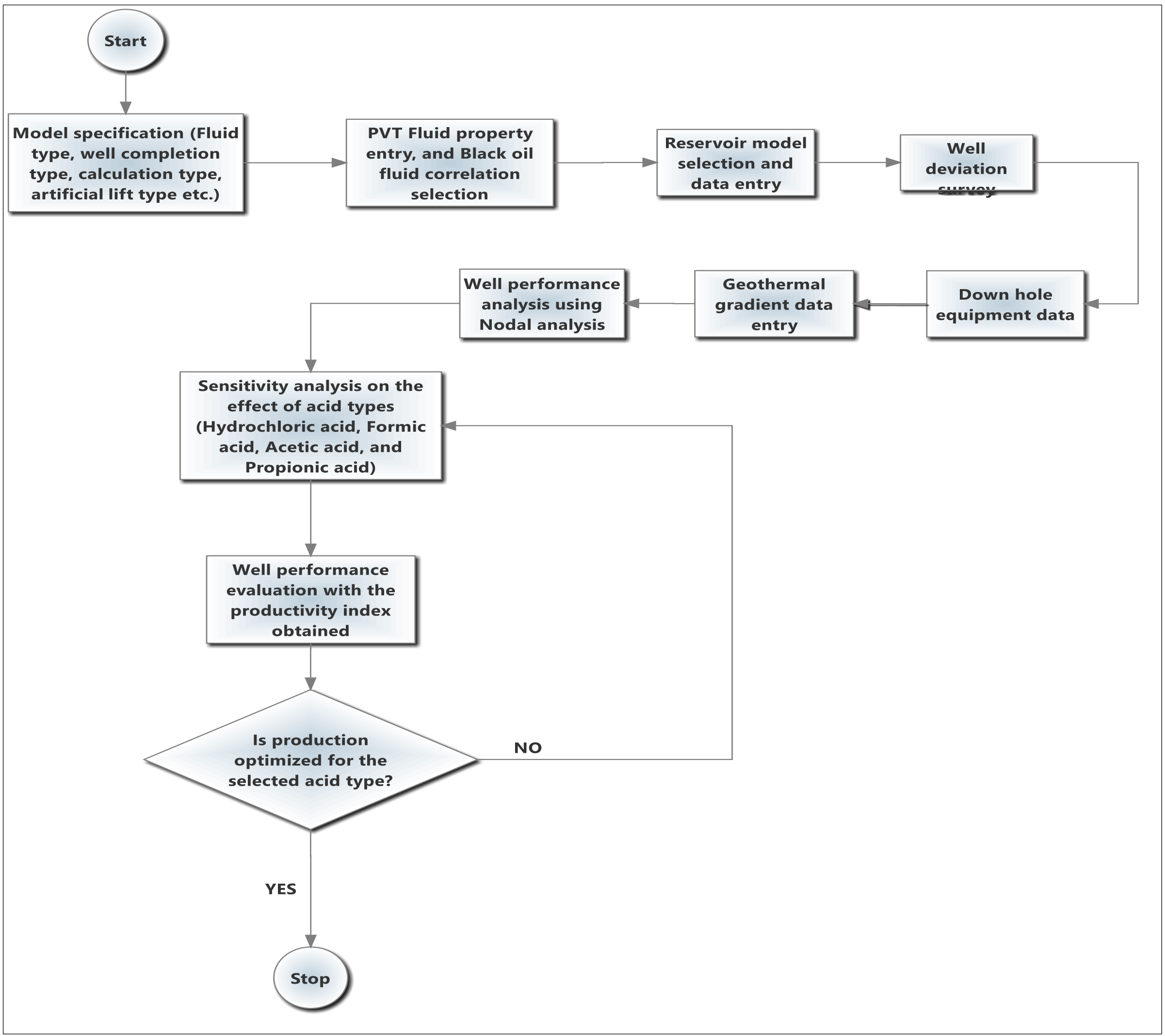

Figure 1 Simulation workflow

3. Results

3.1. Acid Treatment for Post job Analysis

The results of the acid stimulation treatment is presented in Table 11. It shows the formation porosity, permeability, productivity index and skin factors before and after treatment. Results reveals a decrease in the formation porosity, permeability and productivity index as the treatment acid was change from HCl to formic acid, acetic acid, and propionic acid.

Figure 2 shows a comparison of the formation permeability before and after acidization for each of the acid considered. The trend shows a decrease in formation permeability as the treatment acid was change from HCl to formic acid, acetic acid, and propionic acid. A percentage increase of 15.1973% in permeability was observed as the formation was treated with HCl acid. A percentage increase of 7.5731% was observed in formation permeability as the formation was treated with formic acid. A percentage increase of 1.95684% was observed in formation permeability as the formation was treated with Acetic acid. A percentage increase of 1.47001% was observed in formation permeability as the formation was treated with Propionic acid. Results reveal that HCl acid resulted in highest permeability increase.

Table 11 Acid treatment

Variable	Hcl acid	Formic acid	Acetic acid	Propionic acid
Porosity before treatment	0.2	0.2	0.2	0.2
Porosity after treatment	0.2120	0.2061	0.2016	0.2012
Permeability before treatment (mD)	50	50	50	50
Permeability after treatment (mD)	57.5987	53.7866	50.9784	50.735
Productivity index before treatment (stb/d-psi)	3	3	3	3
Productivity index after treatment (stb/d-psi)	3.07074	3.0375	3.01038	3.00791
Skin factor after treatment	-0.2043	-0.1091	-0.0297	-0.0224

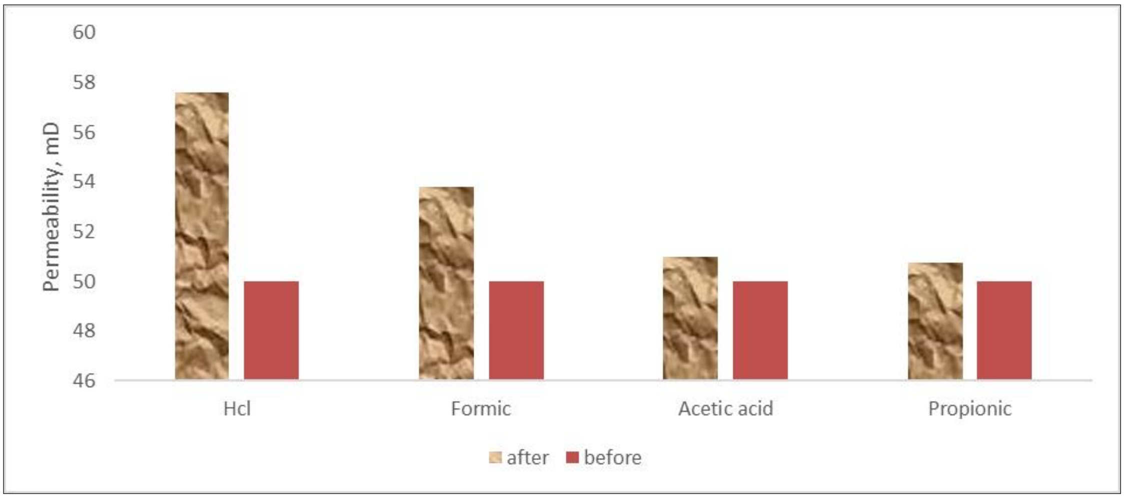

Figure 2 Comparison of permeability before and after treatment

The relationship between the formation porosity before and after acidization for each of the acid is presented in figure 3. The trend shows a decrease in formation porosity as the treatment acid was change from HCl to formic acid, acetic acid, and propionic acid. A percentage increase of 6.04105% in formation porosity was observed as the formation was treated with HCl acid. A percentage increase of 3.08043% was observed in formation porosity as the formation was treated with formic acid. A percentage increase of 0.81019% was observed in formation porosity as the formation was treated with Acetic acid. A percentage increase of 0.60959% was observed in formation porosity as the formation was treated with Propionic acid. Results report that HCl acid resulted in highest porosity increase.

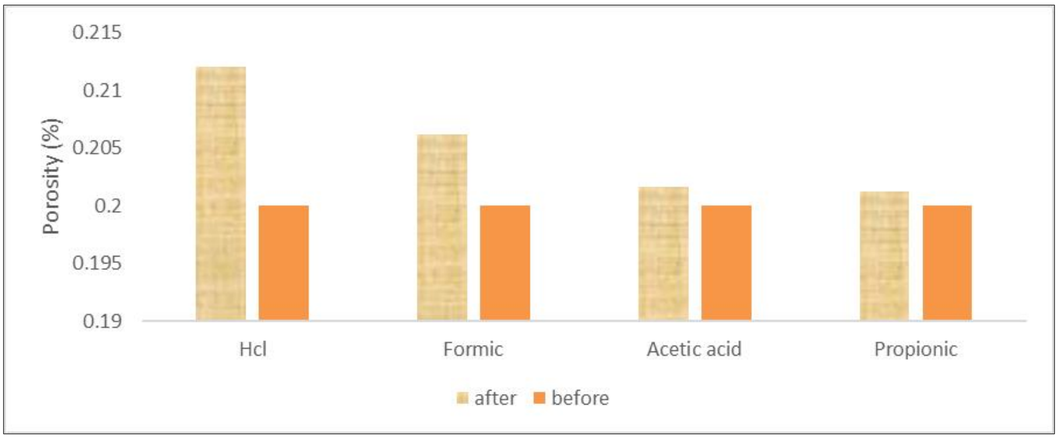

Figure 3 Comparison of porosity before and after treatment

Figure 4 shows a comparison of the productivity index for HCl acid, formic acid, acetic acid, and propionic acid before and after acidization. Results reveals a decrease in productivity index as the treatment acid was change from HCl acid to formic acid, acetic acid and propionic acid. A productivity index values of 3.07074 STB/day-psi, 3.0375 STB/day-psi, 3.01038 STB/day-psi, 3.00791 STB/day-psi were obtained when the formation was acidized with HCl acid, formic acid, acetic acid and propionic acid.

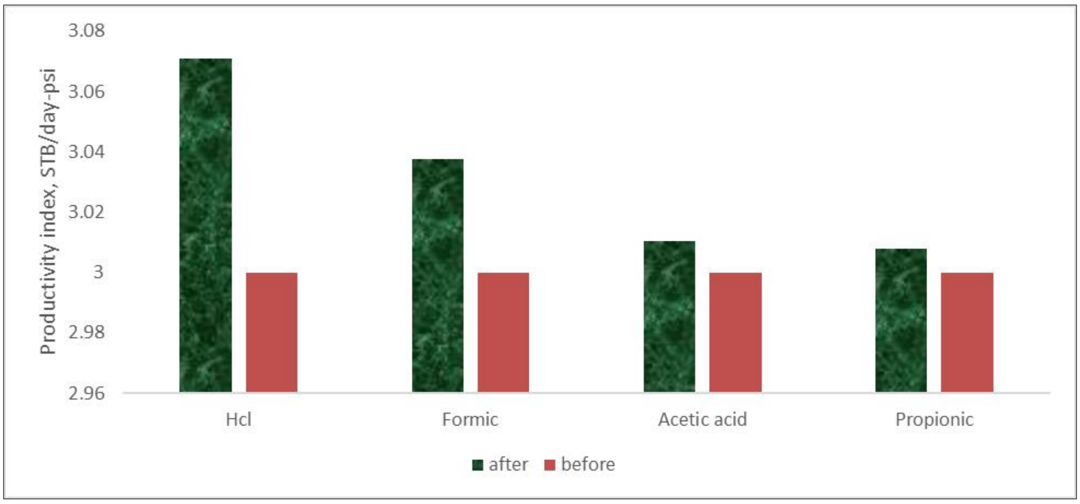

Figure 4 Comparison of productivity index before and after treatment

3.2. Reservoir deliverability and production assessment after acidization

The well inflow performance relationship curve for a well acidized with HCl is shown in figure 5. Results reveals that the reservoir will deliver 11563.2STB/day of liquid into the wellbore if the bottom hole pressure is reduced to 0psig(maximum pressure drawdown).

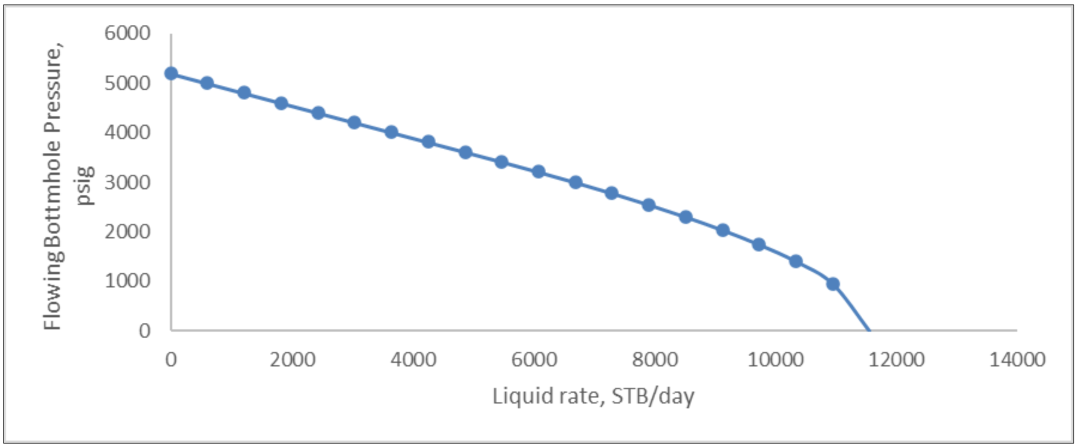

Figure 5 Reservoir inflow for HCl acid

Figure 6 shows the system performance curves (inflow and outflow curves) for the case in which the formation was acidized with HCl. Results reports a liquid production rate of 6865.36 STB/day at a flowing bottom hole pressure of 2921.75psig.

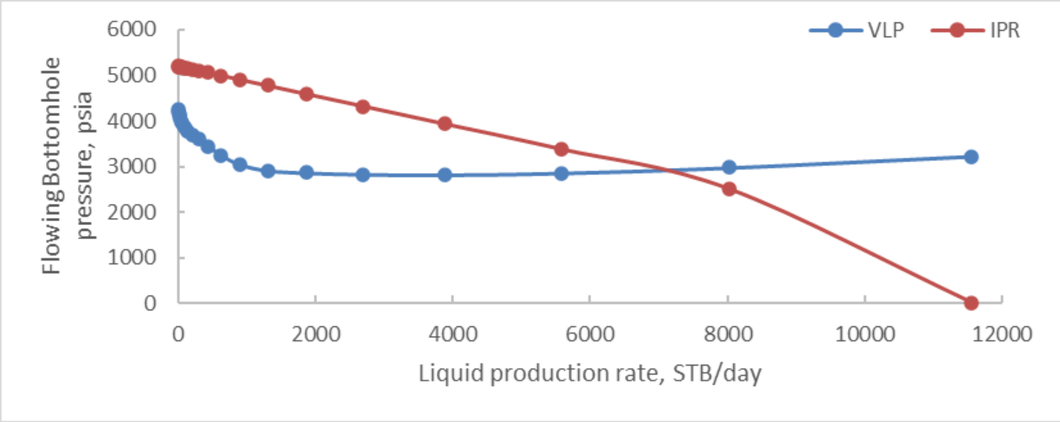

Figure 6 Production performance with HCl acid

The well inflow performance relationship curve for a well acidized with formic acid is shown in figure 7. Results reveals that if the formation acidized with formic acid, the reservoir will deliver 11438.1STB/day of liquid into the wellbore if the bottom hole pressure is reduced to 0psig(maximum pressure drawdown).

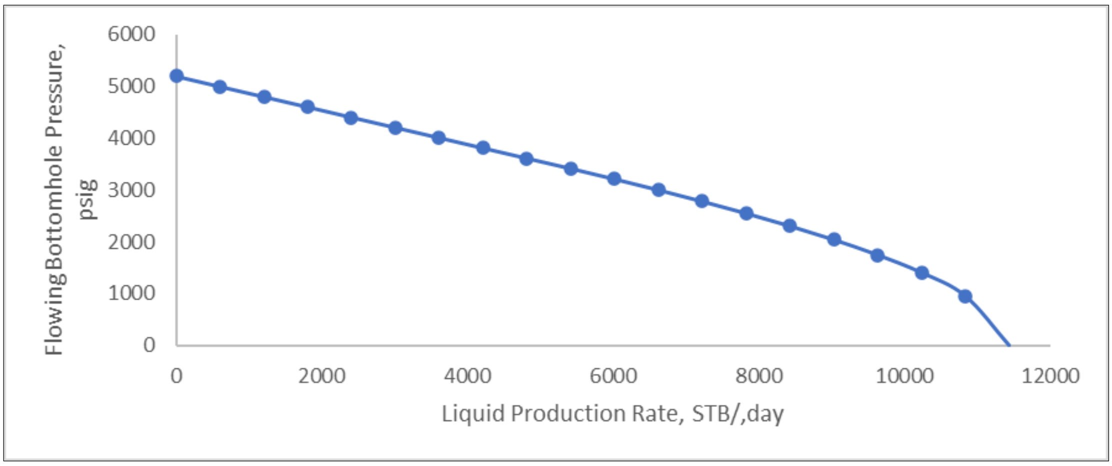

Figure 7 Reservoir deliverability for formic acid stimulation

Figure 8 shows the inflow and outflow performance curves for the case in which the formation was acidized with formic acid. Results reports a liquid production rate of 6800.05STB/day at a flowing bottom hole pressure of 2918.49psig.

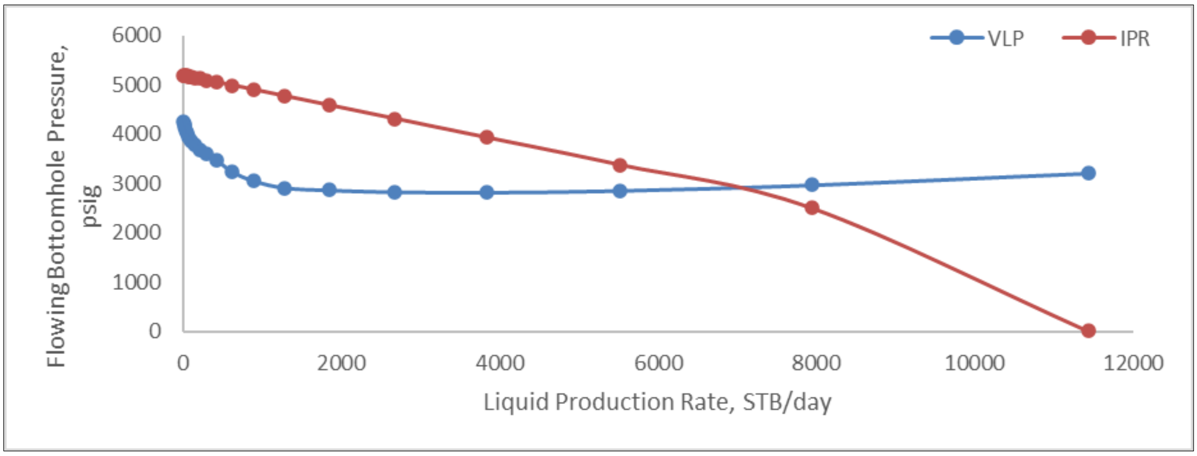

Figure 8 Production performance for formic acid stimulation

The well inflow performance relationship curve for a formation acidized with acetic acid is presented in figure 9. Results reveals that the reservoir will deliver 11335.5STB/day of liquid into the wellbore if the bottom hole pressure is reduced to 0psig(maximum pressure drawdown).

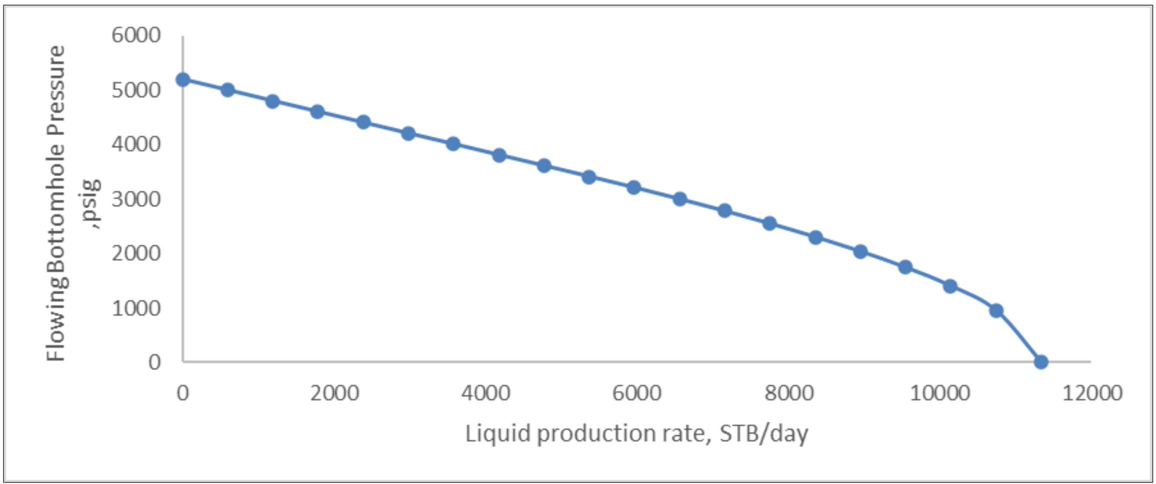

Figure 9 Reservoir deliverability for acetic acid stimulation

Figure 10 shows the well performance curves for the case in which the formation was acidized with acetic acid. Results reports a liquid production rate of 6746.57STB/day at a flowing bottom hole pressure of 2915.85psig.

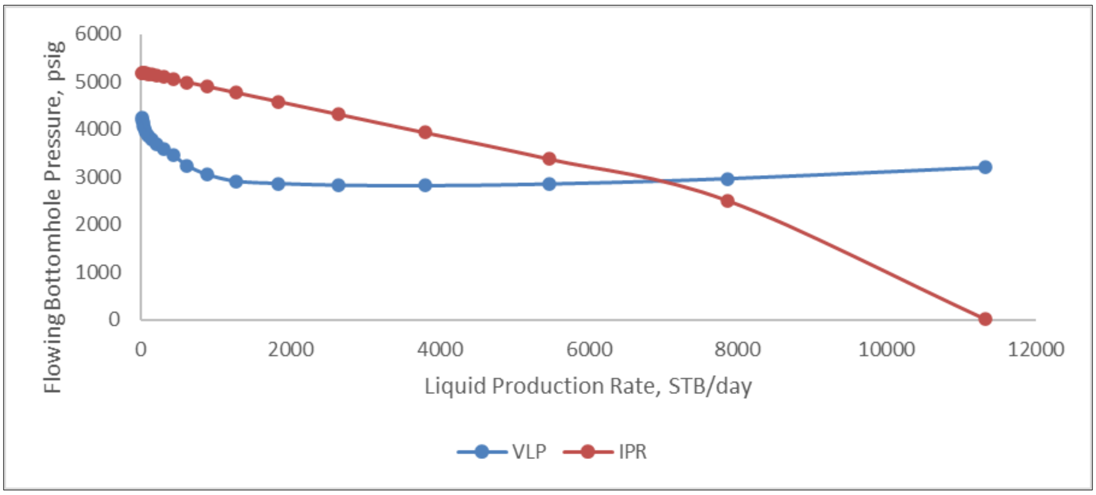

Figure 10 Production performance for acetic acid stimulation

The well inflow performance relationship curve for a formation acidized with propionic acid is shown in figure 11. Results reveals that the reservoir will deliver 11326.4STB/day of liquid into the wellbore if the bottom hole pressure is reduced to 0psig, i.e., at maximum pressure drawdown.

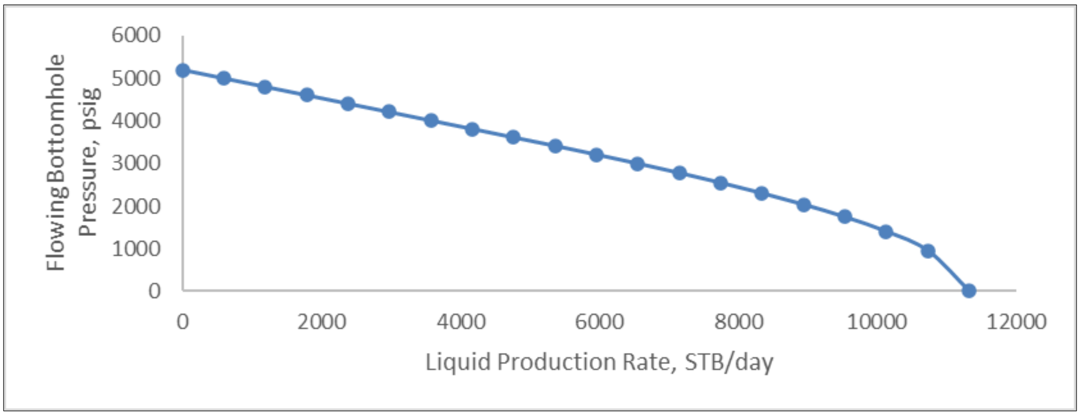

Figure 11 Reservoir deliverability for propionic acid stimulation

Figure 12 shows the well performance curve for the case in which the formation was acidized with acetic acid. Results reports a liquid production rate of 6741.69STB/day at a flowing bottom hole pressure of 2915.61psig.

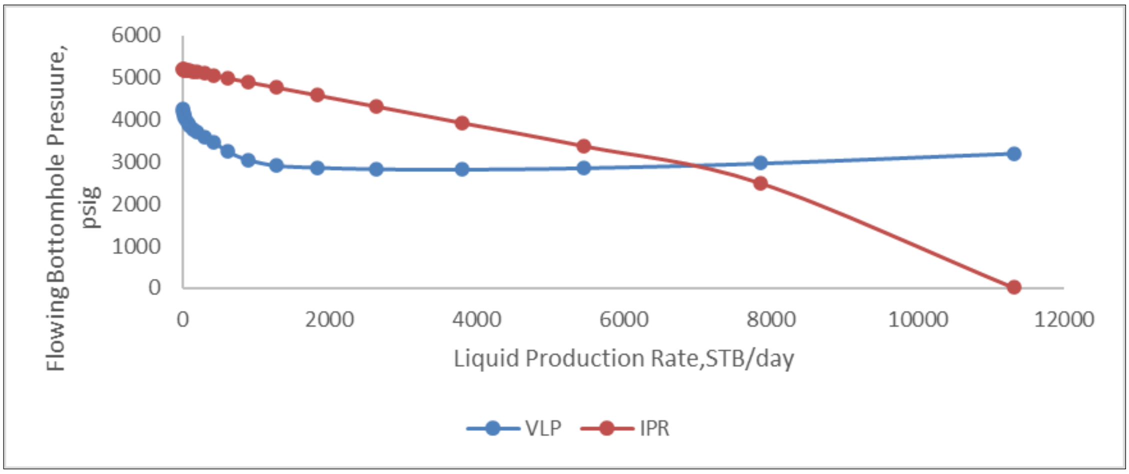

Figure 12 Production performance for Propionic acid stimulation

4. Conclusion

This work evaluates impact of acid type for effective stimulation on production performance in sandstone formation. Hydrochloric (HCl), Formic, Acetic, Propionic and ChloroAcetic acids were injected into the formation. PROSPER well modelling package was utilized for the model development. Pre-acid well model was constructed based on well test data before acid job to determine current well skin. Acid stimulation was then implemented and thereafter, post-acid job analysis was implemented to determine the oil gain and actual skin reduction after acidizing.

The following conclusion was drawn from the study;

- There was a decrease in productivity index as the treatment acid was change from HCl acid to formic acid, acetic acid and propionic acid
- Porosity of the treated sand stone formation decreases in the order of the acid type from HCl acid to formic acid, acetic acid and propionic acid
- Permeability of the treated sand stone formation decreases in the order of the acid type from HCl acid to formic acid, acetic acid and propionic acid
- The liquid production rate increases after acid treatment with a shift in the cross between the vertical lift performance and inflow performance relationhip.

Compliance with ethical standards

Disclosure of conflict of interest

No conflict of interest to be disclosed.

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