OTC 21151

An Integrated Approach to Selecting and Optimizing Demulsifier Chemical Injection Points using Shearing Energy Analysis: A Justification for Downhole Injection in High Pressured Well

Adekunle Opawale, SPE, African University of Science and Technology, Abuja, Nigeria
Samuel Osisanya, SPE, University of Oklahoma, Norman, USA
Appah Dulu, SPE, Petroleum Training Development Fund (PTDF), Nigeria
Solomon Otakoro, SPE, Clariant Oil Services, Aberdeen, UK

This paper was prepared for presentation at the Offshore Technology Conference held in Houston, Texas, USA, 2–5 May 2011.

Abstract

Chemical demulsifiers are routinely injected into the petroleum production system at several points to effectively resolve water-in-oil emulsion issues. Point of injection varies from downhole through wellhead and manifolds to stocktanks (Batch treatment). Selection of the best injection points during oilfield practices still remains a very challenging task for both operators and chemical vendors. Many researches have not been done on this subject matter, and hence remains the focus of this study.

In this paper , models to carefully analyze and study the relationship between shearing energy and pressure drops at various points in a production system is developed. It analyses the Shearing action as the reservoir fluid flows through formation pores, perforations, tubing, wellhead chokes and the surface flowline. This program determines the best injection points for demulsifier chemicals to ensure their adequate mixing, mobility and strong partitioning at the water-oil interfaces where their actions are needed. This novel approach applies to several well geometry and completions, ranging from open to cased wells. Developed models were tested and validated with real data from a known oilfield in Nigeria. Wellhead and downhole injection (through gas lift valves) appear to be one of the best practicable injection points selected by the program. This selection already considered the current conditions of the field and produced fluid and also the nature of demulsifier chemical in use, in terms of its residence time of action. Results obtained vary with changes in these factors as the reservoir becomes depleted and workover operations are performed.

This paper emphasises the impact of shearing energy and pressure drops on the effectiveness of demulsifier chemicals. Determination of appropriate injection points combats lots of operational and economical problems such as over-treating and re-emulsification. It reduces unnecessary high budgets for demulsifier chemicals as injection rates will be optimized. This paper also discusses the benefits that can be realized by breaking emulsions downhole, and contributes to the existing literature in the design and construction of production chemical injection program for a green field development. The authors anticipate that the new concept of shearing energy analysis presented in this paper would contribute more to improving the technology of chemical-demulsification.

Keywords: Emulsion, Demulsification, Shearing energy, Demulsifier chemical injection.

Introduction

Crude oil is produced from petroleum reservoirs mostly in the form of an intractable emulsion. A regular oilfield emulsion is a dispersion of water droplets in oil (w/o).[1] The problem of resolving water-in-oil emulsion has been approached in a number of ways over the years (including Mechanical, Electrical, Chemical and Thermal methods)[2]. Today, the chemical demulsification method is by far the most widely used in the oil industry, both from an environmental and technical point of view. Successful chemical formulations (Demulsifiers) are able to drop emulsified water rapidly, provide relatively clean interfaces, and produce dry, saleable oil.[3]

Chemical demulsifiers are surface-active agents capable of partitioning to the water-oil (w/o) interface and providing steep interfacial tension gradients that allow rapid drainage of the continuous phase between water droplets.[4] They are usually in anionic, cationic or non-ionic form.[5] However, majority of the demulsifiers used in oil-and gas-condensate fields are of the non-ionic type because they have a higher surfactancy. Some common examples of modern demulsifier bases are polyglycol esters, resin derivatives, sulphonates, Alkanolamine condensates, oxyalkylated phenols, polyamine derivatives etc. They preferentially adsorb at the water/oil interface and totally or partially displace the natural indigenous stabilizing components of the interfacial film surrounding the emulsion droplets as described in **Fig.1.** Also, they act as a wetting agent and alter the wettability of the stabilizing particles. These phenomena bring about changes in properties such as interfacial viscosity and elasticity of the protecting film. It leads to the rupture and weakening of the rigid films of emulsifiers and thus enhances destabilization of the emulsion. Several Interfacial and rheological studies confirm that these mechanisms do operate.[6-10]

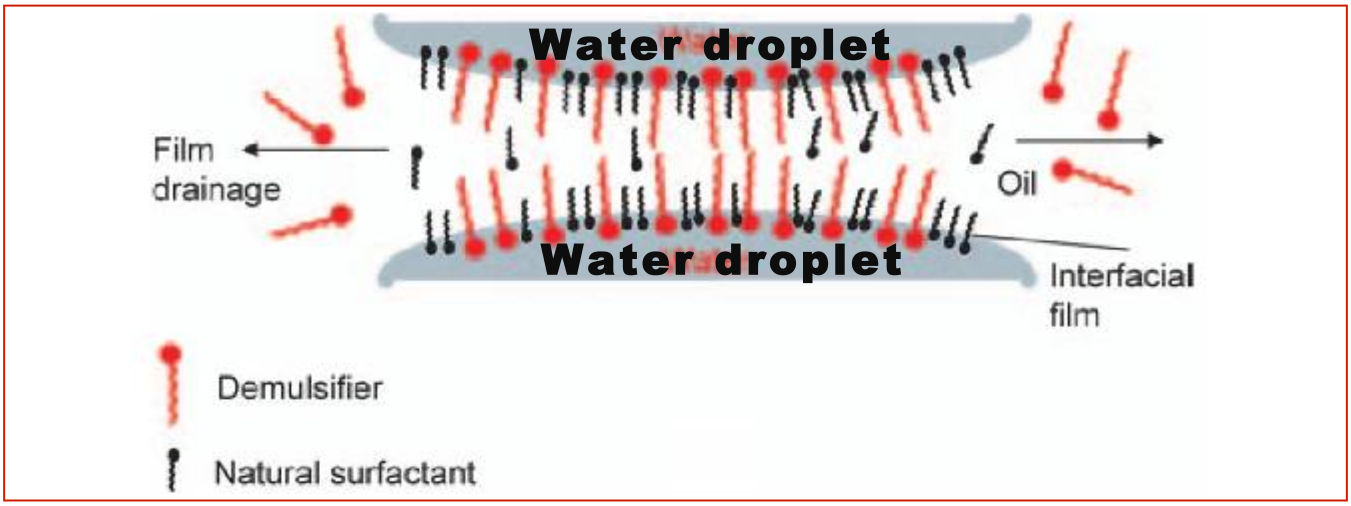

Figure 1: Film drainage in the presence of a demulsifier. Demulsifier displaces indigenous surfactant in the interfacial film.[11]

However, practical applications of chemical demulsifiers in oilfields to ensure an optimum emulsion breaking process always follow the procedure below.[11, 12]

- A properly selected chemical for the produced emulsion.
- Optimum quantity of the choice chemical.
- Adequate mixing of this chemical in the emulsion (Function of the injection point).
- Sufficient retention time in emulsion treaters.
- Combination of other methods (heat, electricity, coalescers, etc. to facilitate or completely resolve the emulsion.

Compatible demulsifier chemicals should be injected into the production system and allowed to mix evenly with the emulsion. If the mixing is poor, the demulsifier will tend to be ineffective. Turbulence and shear accelerates the diffusion of the demulsifiers through the emulsion especially to the oil-water interface where their actions are needed. It also increases the number and intensity of impacts between water droplets, and hence promotes coalescence of emulsified water.

Although bottle tests, laboratory simulations and actual plant trials are usually used to test the compatibility of demulsifiers with crude oil and optimize its dosage, selection of their best point of injection in real field application is still practised as an art rather than a science. Wrong selection of injection points could cause further re-emulsification and produce tougher emulsions that would even be more difficult to treat. There have been several efforts [6, 13-16] to understand the mechanism of demulsification of crude oil emulsions and develop high performance emulsion breakers, but only few[17-19] studies have been done on getting production chemical injection right. Expert's advice from vendors of chemicals is currently used to accomplish this task. This paper introduces a new twist on improving the technology of injecting demulsifier chemical during production. Studying the phenomenon of demulsifier mobility and partitioning to the w/o interface, is quite challenging, due to the dynamic nature of the petroleum system during production. The methodology demonstrated in this paper reveals a novel approach that relates the demulsifier effectiveness with the shearing (agitation) energy experienced at different regions in a production system. Shearing energy at a particular region is described as a function of the pressure drop (ΔP) along a characteristic length D in the region, and the total surface area available for shearing as flow occurs. The regions taken into consideration in this study are the formation pores, perforation, tubing, wellhead chokes, manifolds and the surface facilities piping. Our assumption is that the intensity of shear is seen as the main factor that determines how stable and tight the emulsion produced will be, hence points of emulsification are those regions with relatively high shearing energy. High shearing energy is being correlated with turbulence in the petroleum system where adequate mixing of the chemicals is ensured. Hence injecting demulsifiers upstream of such points gives a great potential of demulsifier effectiveness[20] and further re-emulsification may be prevented.

Although the primary goal of this study is to select the best point for injecting demulsifier chemicals, which will facilitate the thorough mixing of chemicals, providing the cleanest separation of water from oil in the shortest time, and even at the lowest cost per barrel of emulsion produced, the paper also discuses benefits of implementing downhole injection of demulsifier chemicals in high pressured wells. Example of such is the field analyzed, where sufficient shearing is encountered at the near wellbore formation and production tubing by the produced fluid.

Model of shearing Energy

Considering two immiscible fluids of known properties flowing through a circular pipe of length D_o and known internal surface area, as shown in **Fig.2**. According to Abdel-Aal et al [21] the shearing energy responsible for dispersion of one phase of the liquid into the other as the fluid flows through the pipe is dependent on the turbulence available in the pipe, due to the shearing force per unit area of the pipe exposed to flow.

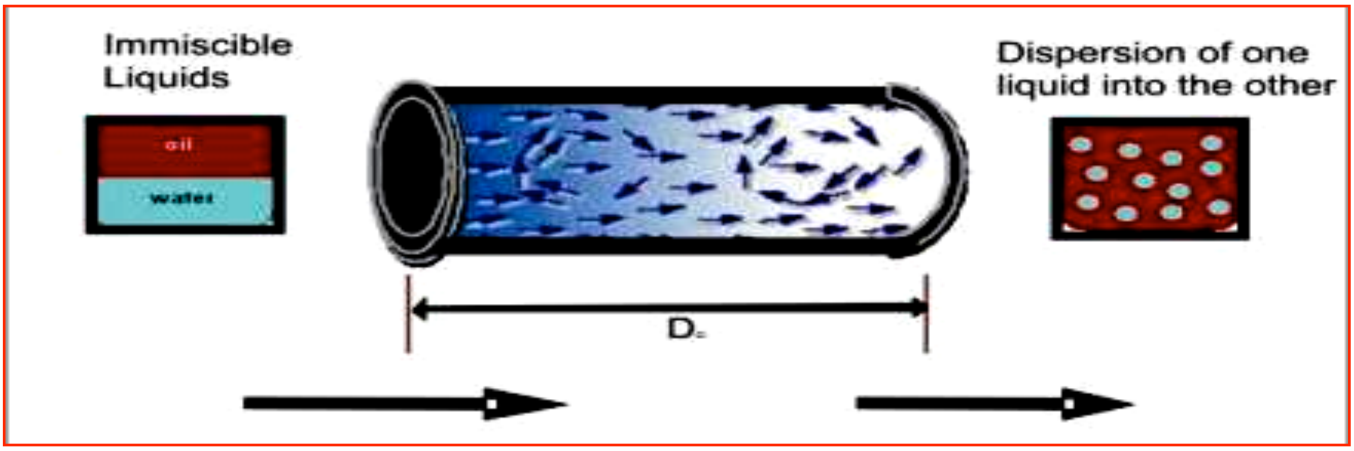

Figure 2: Shearing energy experienced by immiscible fluids flowing through a circular pipe

It is a function of the pressure drop along the characteristic length D_o of the pipe, and its total internal surface area available for shear as flow occurs. The shearing energy is given as follows:

$$Shearing\ Energy, SE_p = \Delta P_p . A_{sp} . D_p \tag{1}$$

Pressure drop in a pipe could be associated to lots of factors as described in literatures.[22] These factors include roughness of the pipe, change in property of flowing fluid, sudden reduction in flow area etc. Shearing energy overcomes the viscous force between the liquid layers, leading to their separation into thin sheets or parts, and, formation of ''surface energy'', which occurs as a result of the separation of the molecules at the plane of cleavage. This principle is applied to the regions where high turbulence is expected in the petroleum production system, and hence emulsions formed. Regions considered in this study are the near wellbore formation pores, perforation, tubing, wellhead chokes, manifolds and the surface facilities layout.

1. Shearing Energy Analysis of flow through near wellbore formation pores and perforation.

The near wellbore formation pores and perforation is a region of high pressure gradient and temperature where emulsions have been observed to form.[23]As reservoir fluids (oil and water mixture) flow here (**Fig.3),** they are exposed to shear, in the presence of emulsifiers, hence stable emulsions are formed. The shearing energy experienced in this region is thus analyzed and compared with the results from other regions.

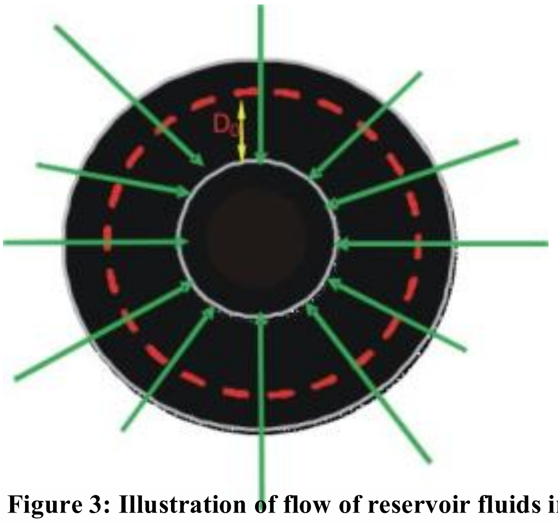

Figure 3: Illustration of flow of reservoir fluids in the formation and perforation to the wellbore.

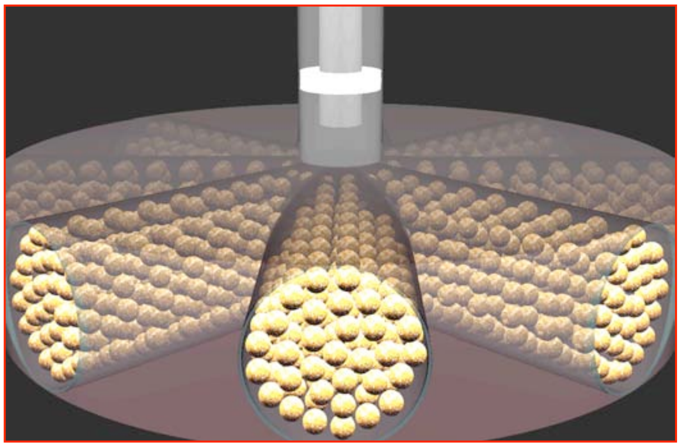

Figure 4: Idealized set of pipes used to analyze shearing energy in the formation.

This case is approached by idealizing the near wellbore region as some 8-set of large circular pipes that are geometrically arranged and packed with reservoir grains. Their diameter equals to the perforation interval. The flow into the wellbore through the perforation are assumed to be through each of the pipes as shown in **Fig4**. Considering a perforation depth D_f into the formation, and analyzing the shearing energy as the fluid flows.

$$Shearing\ Energy, SE_{nw,perf} = \Delta P_{perf} . A_s . D_f \tag{2}$$

The bulk of the pressure is assumed to be lost as the fluid moves through the perforations. A correlation describing the pressure in this scenario has already been established.[24] It considers the diameter and the number of perforations in the system.

$$\Delta P_{perf} = 0.2369 \left(\frac{Q^2 \rho_b}{n^2\, d_{perf}^4\, C^2}\right) \tag{3}$$

However, C the coefficient of discharge could vary from 0.56 to 0.86. A value of 0.7 is assumed in this study.

The specific pore surface area per unit volume, A_s of each pipe is described using the Carman Kozeny equation[25]. This is assumed to be the flow area available for the shearing action in this region. It is also referred to as wetted area, and analysed as below. All terms used are defined in the nomenclature.

$$A_s = \sqrt{\frac{\varphi\, \Delta P}{Q.\ t\, .\, \mu\, .\, L}}$$

However, t which is defined as the kozeny constant is assumed as 2.5 in this study. Also L is the perforation depth into the formation and it's also defined as D_f .

Hence the shearing energy is:

$$S.E_{nw,perf} = \left(0.2369 \left(\frac{Q^2 \rho_b}{n^2\, d_{perf}^4\, C^2}\right)\right)\left(\sqrt{\frac{\varphi\, \Delta P}{Q.\ t\, .\mu\, .L}}\right)\left(D_f\right) \tag{4}$$

This analysis applies to cased vertical well. In an open-hole well, reservoir fluid flows directly from the reservoir into the casing, and so the analysis of its shear starts from the tubing.

2. Shearing Energy Analysis of flow through the production tubing length.

Production tubings are steel pipes designed by considering tension, collapse, and burst loads under various well operating conditions to prevent their mechanical failure. The walls of the tubing constitute a high degree of shear which adds to the formation of emulsions as the fluid is being produced. A sketch of tubing installed in a production system is shown in **Fig.5** Shearing energy along the tubing length is as analyzed below:

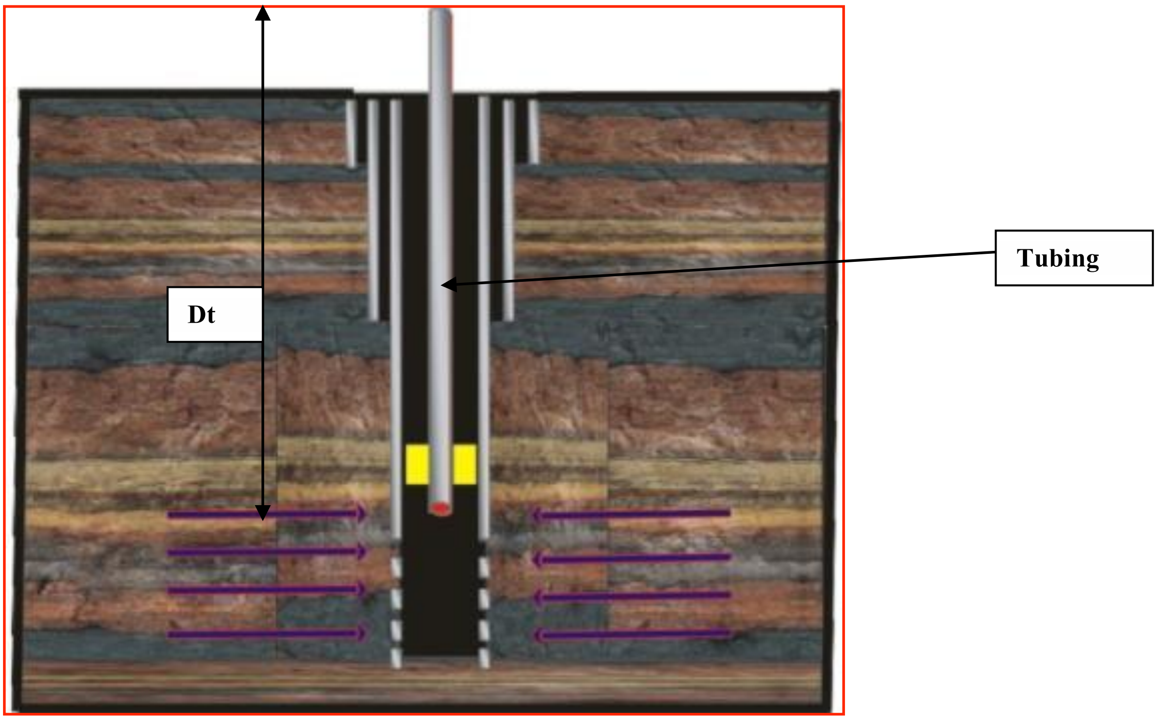

Figure 5: Shearing energy experienced by immiscible fluids flowing through the production tubing

$$Shearing\ Energy,\ S.E_{tl} = (\Delta P_t).(A_{st}).(D_t) \tag{5}$$

Many correlations have been developed for predicting multiphase flow pressure gradient in vertical pipes[26-28]. Poetman and Carpenter's correlation[29] is used for this study. It assumes the following: There is no slip at the pipe wall, no flow regime consideration, mixture density is based on the input gas-liquid ratio, gas and liquid are travelling at the same velocity in the pipe.

$$\left(\frac{dP}{dZ}\right)_z = \frac{1}{144}\left[\frac{g}{g_c}\rho_n + \frac{fw^2}{2.9652\times10^{11}\ \rho_n\, d_t^5}\right] \tag{6}$$

$$\rho_n = \rho_l\lambda_l + \rho_g\lambda_g\ \ and\ \lambda_l = \frac{V_{sl}}{V_{sl} + V_{sg}}$$

The surface area, A_s is simply calculated as:

$A_s = 2\pi R_t D_t$, Where R_t is the radius of the tubing and D_t is the entire length of the production tubing.

Hence the shearing energy is:

$$S.E_{tl} = \left[\frac{1}{144}\left[\frac{g}{g_c}\rho_b + \frac{f_v {m_t}^2}{2.9652\times10^{11}\ \rho_b\, d_t^5}\right]D_t\right].2\pi R_t D_t\,.D_t \tag{7}$$

3. Shearing Energy Analysis of flow through the wellhead choke

Production choke also constitute another region of high turbulence due to sudden reduction in flow area, and hence causes a vigorous shearing action which promotes emulsion formation. Extreme mixing conditions are hence experienced as the fluid mixtures flow through the wellhead. New water/oil interfaces are thus formed which contributes to the formation of tight emulsions. The shearing energy experienced by the oil/water mixture as it leaves the tubing hanger and flow through the wellhead to the flowline is as analyzed below:

$$Shearing\ Energy, SE_c = \Delta P_c . A_{sc} . D_c \tag{8}$$

Achong's choke performance correlation[30] is used in this study to analyze the pressure drop, ΔP accross the wellhead, and also considers the multiphase nature of the produced fluid.

$$P_u = \frac{3.829\, q_1 {R_p}^{0.65}}{d_b^{1.88}} \tag{9}$$

Let P_d be the choke downstream pressure. Hence pressure drop, $\Delta P_{\ choke} = (p_u - p_d)$. The choke area is taken to be circular and d_b is the choke size (bean size) used for production. D_c is the characteristic length of flow in the choke.

$$S.E_{wc} = \left(\left(\frac{3.829\, q_1 {R_p}^{0.65}}{d_b^{1.88}} \right) - P_d \right) . \left(\frac{\pi}{4} (d_b)^{\,2} \right) . D_c \tag{10}$$

It is also assumed that only the choke area and the pressure drop are assumed to change significantly, and hence contribute to the turbulence.

4. Shearing Energy Analysis of flow through the surface flowlines and manifolds

Fluid from the wellheads flow into surface flowlines and co-mingle at a common gathering point (manifold) before flowing into a trunkline which leads to the central processing facilities. The surface piping and its fittings also constitutes some forms of turbulence and stabilizes emulsion. Shearing energy is being analyzed on the surface piping network, to evaluate the best points where demulsifiers can be injected.

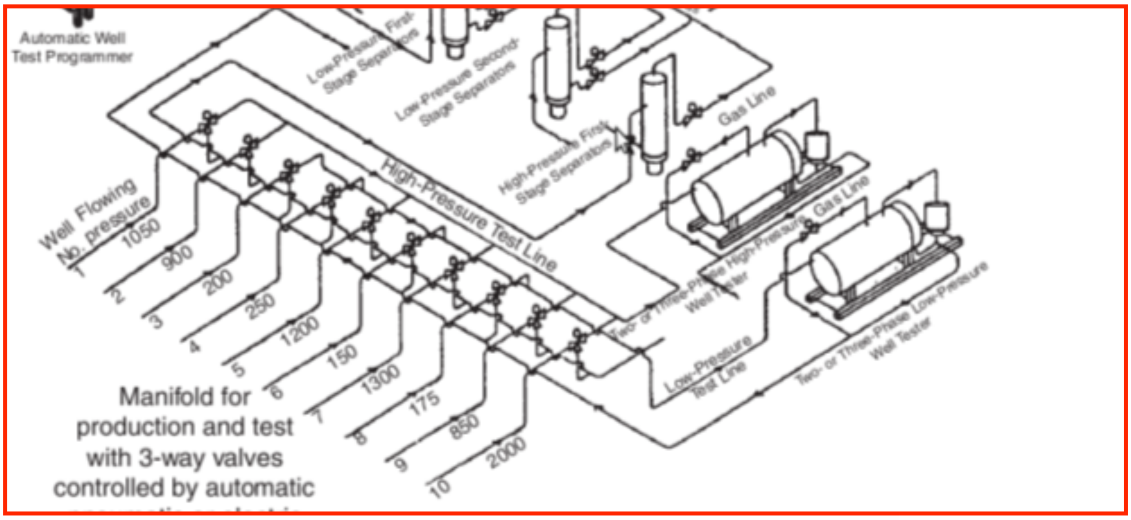

Figure 6: Schematic layout of surface piping facilities and

Multiphase flow is considered through them. Practical analysis will depend on the layout of the surface piping. Applying shearing energy equation:

$$Shearing\ Energy, SE_{fp} = \Delta P_{fp} . A_{sfp} . D_{fp} \tag{11}$$

Where ΔP , is the pressure drop in each pipe segment and fittings, and are analyzed independently. Equivalent length and hence shear area are assumed for the fittings. A procedure described by Eaton's[31] is used in this study to estimate the pressure gradient in the horizontal flow.

$$\left(\frac{dp}{dx}\right)_f = \frac{f\,\rho_b V^2}{2\,g_c\,d_{fp}} \quad (12)$$

The friction factor, f is computed as: $\frac{0.057(\,m_g\,.m_l\,)^{0.5}}{\mu_g\,d_{fp}{}^{2.25}} = f\,\left(\frac{m_l}{m_m}\right)^{0.1}$

If D_{fp} is the length of flowline, and internal surface area, A_{sfp} is $\left(2\,\pi\,\frac{d_{fp}}{2}D_{fp}\right)$, shearing energy through this region is modeled as below:

$$S.E_{fp} = \left(\frac{f_h\,\rho_b V^2}{2\,g_c\,d_{fp}}D_{fp}\right)\left(2\,\pi\,\frac{d_{fp}}{2}D_{fp}\right)\,D_{fp} \quad (13)$$

For the fittings, soopprasong et al's approach[32] is used to calculate pressure drops, and assumes equivalent diameter and hence shear area.

$$\Delta p_{ff} = \frac{k\,\rho_{b\,V^2}}{2g_c}$$

$$S.E_{ff} = \left(\frac{k\,\rho_{b\,V^2}}{2g_c}\right)\left(\frac{\pi d_{fp}^2}{4}\right)\,D_{fe} \quad (14)$$

Table 1: Developed equations for estimating shearing energy in the petroleum system.

Regions in the production system	**Developed Model equations for Shearing Energy**
Near wellbore & Perforation	$S.E_{nw,perf} = \left(0.2369\,\left(\frac{Q^2\rho_b}{n^2\,d_{perf}^4\,C^2}\right)\right)\left(\sqrt{\frac{\varphi\,\Delta P}{Q.\;t\,.\mu\,.D_f}}\right)(D_f)$
Tubing	$S.E_{tl} = \left[\frac{1}{144}\left[\frac{g}{g_c}\rho_b + \frac{f m_t{}^2}{2.9652\times 10^{11}\;\rho_b\;d_t^5}\right]D_t\right]\,.2\pi R_t D_t\,.D_t$
Wellhead Choke	$S.E_{wc} = \left(\left(\frac{3.829\;q_1 R_p{}^{0.65}}{d_b^{1.88}}\right) - \;P_d\right).\left(\frac{\pi}{4}(d_b)^{\,2}\,\right)\,.D_c$
Flowline Pipe	$S.E_{fp} = \left(\frac{f\;\rho_b V^2}{2\;g_c\;d_{fp}}D_{fp}\right)\left(2\;\pi\;\frac{d_{fp}}{2}D_{fp}\right)\;D_{fp}$
Flowline fittings	$S.E_{ff} = \left(\frac{k\;\rho_{b\,V^2}}{2g_c}\right)\left(\frac{\pi d_{fp}^2}{4}\right)\;D_{fe}$

Field Application of Models

Developed models of shearing energy were used to analyze the turbulence experienced by a typical production system in an oilfield located in Niger delta, Nigeria. **Table 3** shows a summary of the production data from the field. The shear experienced by the produced fluids (i.e. gas, oil and water) as they flow through the near wellbore region of the formation, casing perforations, tubing length, wellhead choke and surface flowline piping of the field was analyzed. The pressure drop along a characteristic length of flow, and the area of the flow path available for shear were first calculated, and then shearing energy was computed following **Eqns. 4,7,10, 13 and 14**. A Spreadsheet program was developed to compute the shearing energy for all the 5 regions analyzed in this study. The program identifies the region where more turbulence is encountered and hence determines the best injection points for demulsifier chemicals to ensure their adequate mixing and strong partitioning at the water-oil interfaces where their actions are needed. The program also considered the current conditions of the field and fluid and the nature of demulsifier chemical in use, in terms of its residence time of action. Results obtained vary with changes in these factors as the reservoir becomes depleted and workover operations are performed. Although for a cased wellbore, turbulence will be analyzed for all the 5 regions, shearing energy through perforation holes will not be considered in an open hole. Also, for a horizontal wellbore, the multiphase flow through the horizontal section can be analyzed using shearing energy models for horizontal flowlines in **Eqn. 13**.

Discussion of Results

Modeling results of pressure drop, shearing area and shearing energy obtained for all the 5 regions of the production system analyzed in this study are presented in **Table 1**. The near wellbore region and tubing string show relatively high pressure drop of 177psi and 902 psi, shearing area of 5.1E+4 in^2 and 6.51E+5 in^2 and hence shearing energy of approximately 1.5E+6KJ and 9.4E+11 KJ respectively. Multiphase flow through these region experience high turbulence. As reservoir fluids are forced to flow under high pressure gradient through the pores of the formation grains, a high pressure drop is experienced due to the tortuous nature of flow through them. Also the casing perforation holes are flow restrictions, hence a significant pressure drop are experienced at their entrance. Although the near wellbore has a higher pressure drop, the tubing length has more shearing area due to the large internal surface area of the tubing length (~6000ft). Frictions on the wall of this pipe induces more turbulence during production and hence produces higher energy available for shearing.

The wellhead choke is another region that is believed to produce high shearing energy and demulsifiers are usually injected there. Although it also shows a high pressure drop of 339 psi, it has a small shear area of 0.442 in^2. The shear area strictly depends on the nominal choke size in use as correlated in **Eqn. 10**. A choke size of 48 is used in this analysis, which is responsible for the relatively small shearing energy obtained in this study (see **Table 2**). Use of larger choke sizes would further increase the shearing energy experienced in this region.

The surface piping layout also shows a high shearing energy, and this explains while injection at the surface still works in oilfields. However, the downhole and tubing region shows a relatively higher magnitude of shearing energy as compared to the entire production system analyzed. Injection downhole also gives the demulsifier a higher potential of intimate mixing with the produced emulsion at the connate temperature.

Table 2: Spreadsheet programme estimating shearing energy at 5 regions in the production system

CALCULATED RESULTS							
		Near well, perforation	Tubing	Wellhead choke	Flowline pipes	Flowline fittings	
Pressure drop, Δp	(psi)	902	177	339	32	11	
Shear area, As	(sq inches)	51,751.8	651,440.7	0.442	1613	149	
Characteristic length, D	(ft)	24	6000	1.25	1100	892	
Shearing energy	(lb_f ft)	1.12 E+9	6.92 E+11	1.88 E+3	5.68 E+7	1.46 E+6	
Shearing Energy	(KJoules)	1.52 E+6	9.40 E+11	2.54 E-1	7.70 E+4	0.98 E-3	

Furthermore, injecting demulsifier chemicals downhole of this well has the following benefits.[18-19]

- It reduces produced well fluid viscosity to cause increased pressure drawdown.
- It reduces the frictional losses in the production tubing
- It increases well productivity and profitability by reducing tubing flow pressure loss
- It reduces the volume of unbreakable emulsion going to the produced water at the surface.

Conclusion

The shearing energy, S.E parameter developed in this study appears to be very useful in the improvement of demulsifier chemical injection technology. For the first time, models of shearing energy, describing the turbulence experienced at different regions of the petroleum production system is developed. S.E and pressure drop $\Delta\mathbf{p}$ are directly related, and both vary with the change in nature of the fluid produced and the condition of the production system.

The downhole, tubing regions of the well in this study experienced the highest intensity of shearing energy as analyzed by the developed program in **Table 2.** The turbulence present would relatively enhance adequate mixing, mobility and strong partition of the chemicals to the water-oil interface where their actions are needed. Also since downstream of these points are regions with lower shearing energy, possibility of re-emulsification after treatment will be reduced.

In summary, with all observation of the intensity of shearing energy downhole, coupled with other factors favourable for emulsion resolution (e.g. high downhole temperature) based on the current production data available, this study recommends downhole demulsifier injection for the field being analyzed. However, the wellhead choke could be considered as an alternate point of injection if a small nominal size of choke is used during production. This increases the turbulence encountered in this region.

Nomenclature

A_p = Cross sectional area of idealized pipe, ft2
C = Coefficient of discharge
d_{perf} = Perforation diameter, ft
d_t = Tubing diameter, ft
d_b = Choke size (Nominal), in
d_{fp} = Flowline diameter, in
D_t = Tubing length, ft
D_o = Length of flow in idealized formation pipe, ft
D_{fp} = Characteristics flowline length, ft
D_{fe} = Equivalent Characteristics flowline length, ft
D_f = Characteristic length of perforation depth into the formation, ft
D_c = Characteristics choke length, ft
g = Acceleration due to gravity, ft/sec2
g_c = Gravitational conversion factor, $lb_m.s/lb_f.ft$
K = Resistance coefficient
M_t = Total mass flowrate, lb_m/s
M_l = Liquid mass flowrate, lb_m/s
M_g = Gas mass flowrate, , lb_m/s
n = Number of perforations
P_d = Flowline pressure FLP, psi
Q = Total Flowrate, bpd
Q_l = Liquid Flowrate, bopd
Q_w = Water flowrate, bpd
Q_g = Gas flowrate, mmscfd
r_w = Wellbore radius, ft
R_p = Gas to Liquid ratio GLR, scf/bbl
S.E = Shearing energy, J
SPF = Perforation shot density, shots/ft
V_{sg} = Gas superficial velocity, ft/s
V_{sl} = Liquid superficial velocity, ft/s
V = Total superficial velocity, ft/s

Greek Symbols
t = Kozeny constant
ρ_b = bulk density, $lb_m/ft3$
ρ_l = Liquid density, $lb_m/ft3$

ρ_g = Gas density, $lb_m/ft3$
Φ = Porosity
Δp = Pressure drop in the near wellbore region as used in the Carman Kozeny equation
f_v = Two-phase frictional factor in vertical flowlines
f_h = Two-phase frictional factor in horizontal flowlines
λ_g = Gas volumetric fraction
λ_l = Liquid volumetric fraction
μ = Viscosity of produced fluid.

Subscripts
nw, perf = near wellbore and perforation region
tl = Tubing length
wc = Wellhead choke
fp = Flowline pipe
ff = Flowline fittings

Acknowledgement

The authors would like to thank African University of Science and Technology, Abuja for all supports on this paper.

References

1. Kokal,S.L., Al-Ghamdi,A. and Meereanpillai.N.S., ''An Investigative Study of Potential Emulsion Problems Before Field Development,'' SPE paper 102856 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, September, 2006.

2. Opawale, A.O., ''Oilfield Emulsion Control: A major issue during; A major issue during heavy crude oil production,'' SPE paper 128352 presented at the SPE annual conference and Exhibition, Abuja, August, 2009.

3. Michael, K., Shaokun, C., Robert, A,M., and Samuel, C.M., ''Classifying Crude oil emulsions using Chemical Demulsifiers and Statistical Analyses,'' SPE paper 84610 presented at the SPE Annual Technical Conference and Exhibition, Colorado, October, 2003.

4. Janaka, B.P., and Shamal, M.M., ''A New family of Demulsifiers for Treating Oilfield Emulsions'' SPE paper 37269 presented at the SPE International Symposium on Oilfield Chemistry, Houston, 1997

5. Chilingarian, G.V., Robertson, J.O., and Kumar, S., "Surface operations in petroleum production, part 1, Elservier Science, Newyork, NY, 1987

6. Bhardwaj, A. and Hartland, S., '' Dynamics of Emulsification and Demulsification of water-in-crude Oil Emulsions,'' Industrial and Engineering chemistry Research, 33, 1271-1279, 1994.

7. Chen, G., and Towner, J.W., ''Study of Dynamic interfacial Tension for Demulsification of crude oil Emulsions'' SPE paper 65012 presented at the SPE International Symposium on Oilfield Chemistry, Houston, 2001.

8. Salager, J.L., '' The Fundamental Basis for the Action of a Chemical Dehydrant: Influence of physical and chemical Formulation on the stability of an emulsion,'' Intl. Chemical Engineering, 103-116, 1990.

9. Breen, P, '' Adsorption Kinetics of Demulsifiers to an Expanded Oil/Water Interface,'' Surfactant Adsorption and Surface Solubilization, R. Sharma(ed.), ACS symposium series 615,ACS Washington DC,268-279, 1995.

10. Kim, Y.H. and Wasan, D.T., '' Effect of Demulsifier Partitioning on the Destabilization of water-in-oil Emulsions'' Ind. Eng. Chem. Res., 114-1149, 1996.

11. Kokal, S.L. ''Crude-Oil Emulsions,'' Petroleum Engineering Handbook, SPE, Richardson, Texas, 2005.

12. Kokal, S.L., ''Crude Oil Emulsions: A state-of-the-art Review,''SPE paper 77497 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, 29 September – 2 October 2002.

13. Schubert, H., and Armbroster, H., ''Principles of Formation and Stability of Emulsions,'' International Chemical Engineering Series, No. 1, 14-28, 1992

14. Opawale.A.O., An Experimental Model to Predict and Control Oilfield Emulsion tightness: A Novel Approach, M.Sc thesis, African University of Science and Technology, AUST, Abuja, 2010.

15. Tambe, D.E. and Sharma.M.M. ''Factors Controlling the stability of Colloid-Stabillized Emulsions,'' Journal of Colloids and interface Science, No.157, 244-253, 1993.

16. Jones,T.J., Neustadter, E.L., and Wittingham, K.P., ''Water-in-crude Oil Emulsion Stability and Emulsion Destabilization by chemical Demulsifiers, '' Journal of Canadian Petroleum Technology, 100-108, 1978.

17. Willmon, J.G. and Edwards, M.A., ''From Pre-commissioning to startup: Getting Chemical Injection Right,'' SPE paper 96144 presented at the SPE Annual Technical Conference and Exhibition, Dallas, October, 2005.

18. Dutta, B.K. and Ahmed, H.H., '' Production Improvement by Downhole Demulsification- A simple and Cost Effective Approach,'' SPE paper 81568 presented at the SPE 13th Middle East Oil show and conference, Bahrain, 2008.

19. Lagerlef, D.L., Sindelar, S.T., Mc Lelland, W.G., Blumer, D.J., '' Downhole Emulsion Breaker injection into the gas lift stream,'' SPE paper 29487 presented at the 1995 Production Operations Symposium, Oklahoma, April, 1996.

20. Treating Oilfield Emulsions, 4th edition; Petroleum Extension service at The University of Texas at Austin: Austin, 1990.

21. Abdel-Aal, H.K., Mohamed, A. And Fahim, M.A., ''Petroleum and Gas Field Processing, '' 3rd Ed., Mercel Dekker, New York, 2003.

22. Cengel, Y.A., Cimbala, J.M., '' Fluid Mechanics: Fundamentals and Applications,'' 1st Edition, MCGraw-Hill Publisher, New York, 2006.

23. HTS consultants, Workshop on oilfield Production chemicals and Microbiology, Aberdeen, 17-26, September, 2007

24. Jean, R., Mack, M.G. and Elbel, J.L.,'' Theoretical Model and Numerical investigation of Near-Wellbore Effects in Hydraulic fracturing'', SPE paper 63009 presented at the Annual Technical Conference and Exhibition, Dallas, 22- 25 October, 2005.

25. Walter, D.R., "Rock Properties and Well logging," Course Notes, University of Ibadan, Nigeria, Nigeria, 1975

26. Brill, J.P., and Beggs, H.D., Two phase flows in pipes, University of |Tulsa, Tulsa, OK, 1978.

27. Fancher, G.H.Jr. and Brown, K.E., ''Prediction of Pressure gradients for Multiphase flow in tubings, ''SPE Journal, March 23, 1963.

28. Baxendell, P.B. B and Thomas, R., ''The calculation of pressure Gradients in High-Rate flowing wells, '' JPT, October, 1961.

29. Poettman, F.H., and Carpenter, P.G., ''The multiphase flow of Gas, Oil and water through vertical flow strings with application to the design and Gas-lift Installation,'' Drilling and Production Prac., 1952.

30. Achong, I., '' Revised Bean performance formular for Lake Maracaibo wells,'' internal company report, shell Oil Co., Houston, October, 1961.

31. Eaton, B.A., Andrews, D.E., Knowles, C.E., SIlberterg, I.H., and Brown, K.E., '' The prediction of Flow patterns, liquid holdup, and pressure losses occurring during continuous two-phase flow in Horizontal pipelines, Trans. AIME, 240: 815-828, 1967.

32. Sookprasong, P., Brill,J.P., and Schmidt, Z., '' Two phase flow in piping components,'' Journal of Energy Res. Tech, September, 1986

Table 3: Data from an oilfield in Niger delta for testing the developed model

Near Wellbore and perforation data:	
Reservoir pressure, p_r, psia	3200
Reservoir Temperature, T_r, o_F	198
Permeability, K, md	8.2
**Kozeny constant	2.5
Porosity, φ, %	22
* length of flow in idealized formation pipe, D_f, ft	3
API, ^{o}	28
Produced fluid viscosity, μ_f, cp	0.23
Gas viscosity, μ_g, cp	0.0131
Liquid flow rate, Q_l, bbl/day	1550
Gas flowrate, Q_g, mmscf/day	0.21
Density of oil, ρ_l, lb_m/ft^3	54.76
Density of gas, ρ_g, lb_m/ft^3	2.84
*Density of fluid mixture, ρ_n, lb_m/ft^3	4.916
Radius of wellbore, R_w, ft	0.328
*Characteristic length of flow from formation to wellbore, D_{fw}, ft	3.328
Perforation interval, H, ft	44
Perforation shots density, SPF, *shots/ft*	6
*Number of perforation, *n*	264
Diameter of perforated hole, d_{perf}, *ft*	0.019
** Coefficient of discharge in perforation, *C*	0.7
Tubing Tubing correlation- Poetman &Carpenter correlation for multiphase flow in vertical pipe	
Casing Internal Diameter, d_{casing}, *ft*	0.43
Tubing Internal Diameter, d_t, *ft*	0.24
*Cross-sectional area of tubing, A_p, ft^2	0.0451
* Superficial velocity of gas flow in tubing, V_{sg}, *ft/sec*	53.89
* Superficial velocity of liquid flow in tubing, V_{sg}, *ft/sec*	2.233
* Total Superficial velocity of fluid flow in tubing, V_{sg}, *ft/sec*	56.12
* Volumetric fraction of liquid in flow, λ_l	0.04
* Volumetric fraction of gas in flow, λ_g	0.96
*** Two phase frictional factor, f	0.012
* Mass flow rate of liquid, M_l, lb_m/sec	5.514
* Mass flow rate of gas, M_g, lb_m/sec	6.9012
* Total mass flow rate , M , lb_m/sec	12.42
Choke Choke Correlation - Achong's choke performance correlation	
Gas-Liquid ratio produced through choke, GLR, *scf/bbl*	135
Choke size, d_b, *in*	0.75
*Choke area, A_c, in^2	0.442
Choke downstream pressure, p_d, *psia*	305
Characteristic choke length, D_c, *in*	6.5

Flowline Flowline correlation: Eaton correlation for predicting pressure gradient in horizontal pipes	
Diameter of flowline, d_{fp}, ft	0.208
Length of flowline, D_{fp}, ft	4300
*** Frictional factor, f	0.0614
Flowline fittings Flowline correlation – Sookprason et al pressure drop for multiphase flow through pipe fittings	
*** Resistance coefficient, K	36
Fitting length equivalent, D_{fe}, ft	1000
* Data calculated ** Data assumed. ***Data read from chart.	