Experiences Of Downhole Scale Squeeze Treatment To Solve Problem Of $Caco_3$ Scale In Zamrud Field, Indonesia

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ABSTRACT

Operational problem of $CaCO_3$ scale has been experienced for many oil-wells in Zamrud field. Some $CaCO_3$ scales encountered in tubing and other in artificial lift. This problem increased operating cost of work over job to pull out the artificial lifts which were stuck by $CaCO_3$ scale. In order to clean up the perforation zone with high skin effect contributed by $CaCO_3$ scale, acidizing using 15% HCl was conducted, but the production time was very short and the oil-wells were needed to be re-acidized. In order to get longer production life of treatment, the growth of $CaCO_3$ scale is needed to be inhibited after acidizing job. Downhole scale squeeze treatment (DSST) has good performance with step of crystal growth retardation, crystal nucleation inhibition, and crystal dispersion. Scale inhibitor which was pumped is 10% Gyptron IT-256, with active content of bis-hexamethylene triamine penta(methylene phosphonic acid) tested using dynamic scale loop to determine minimum inhibitor concentration, which is necessary step in the evaluation process. For many oil-wells, DSST show a good performance indicated by longer production with almost constant watercut. Good understanding of type of scale inhibitor which was used and the characteristic of content of positive and negative ion in formation water as well as mineralogy of perforated zone in oil wells enables of remedy other oil wells in different fields with variety of mineralogy and bottom-hole temperature.

Key Words: *Downhole scale squeeze treatment, $CaCO_3$ scale, high bottomhole temperature, BHMT-P, minimum inhibitor concentration, ESP*

1. INTRODUCTION

The problem of $CaCO_3$ scale is encountered in Zamrud field. Scale formation is the deposition of soluble inorganic salts from aqueous solution. The key problem causing $CaCO_3$ scale is not coming from incompatibility of produced water and injection water for waterflood which was started on December 1993. The problem

is caused by the incompatibility of formation water coming from different sands since the perforated zones are commingled production.

Surface facility both oil treating plant and water cleaning plant, which is used to re-use produced water as injection water, are not accomplished with ion exchanger to deionize the produced water for waterflood. Water cleaning plant is operated to filter the suspended solid to reach 10 NTU as the requirement of injection water standard and to reduce the oil content for minimizing oil loss. The operation of produced water and injection water is in closed loop type and there is no water is wasted to surrounding.

Acidizing with 15% HCl, which is strong acid, is a good solution to solve the $CaCO_3$ scale near wellbore (James, 2009). Unfortunately, the reaction of HCl and $CaCO_3$ is very fast, so that most of sand are coming out perforated zone and accumulating in the wellbore when the oil-well is produced. Retarding agent which is added to the acidizing as an additive can reduce the amount of sand accumulation. As the oil-wells are commingled-produced, the life time of production is no longer and the same problem is encountered. Re-acidizing is the best solution, but the cost of work over is needed to pull out tubings to avoid corrosion during pumping 15% HCl and repairing Electrical Submercible Pump (ESP) with full of scale deposition on it. From the continuity of production stand point of view, re-acidizing will be potential to cause formation damage if not carried out correctly resulting in losing compressive strength of near wellbore triggerred by fine migration due to repeatation or excessive volume and concentration. In order to avoid frequent repeatation of acidizing job, the lifetime of production is needed to be extended by another remedy. The technique of Downhole Scale Squeeze Treatment (DSST), wherein scale inhibitor in aqueous solution is injected by bullhead pumping into the near-wellbore area, is common on upstream of oil and gas industry. Although this technique has been developed, the selection of active content of scale inhibitor become key point since different reservoir has different mineralogy and characteristic of formation water and crude oil. Case of DSST for light oil and waterflood as secondary enhanced oil recovery is discussed this paper.

(a) (b)

Figure 1. Deposit of $CaCO_3$ scale. (a) Gas separator of electrical submersible pump, which was fullfilled by in well name Example #02 producing 51 days (ESP, brand EJP, type KGS, series 540, shaft size 1,18), (b) outer 3 5/8 inch tubing

Wylde and McAra (2004) reported the application of water free crude oil scale inhibitor to solve the problem of usage of water-based scale inhibitor for water sensitive formation such as formation damage to clay hydrolysis followed by swelling and constriction of pore throats. In this paper, field tests were conducted using commercially available product of aqueous based-inhibitor, but the reducing of flow rate due to constriction of pore throats and alternation of near well bore wettability indicated by increasing watercut DSST was also discussed.

Product

The product used in this field application is described in Table 1. We applied Gyptron IT-256 which has active content of bis-hexamethylene triamine penta(methylene phosphonic acid) (BHMT-P) with the concentration of 10% diluted with formation water before pumping downhole. BHMT-P ($C_{17}H_{44}N_3O_{15}P_5$), which works at maximum temperature of 400 ^oF and is soluble in water, is able to inhibit scale growth of $CaCO_3$, $CaSO_4$, dan $SrSO_4$ with high pH. BHMT-P with concentration of 100 ppm has high tolerance to content of 2,500-10,000 ppm Ca^{2+} in water at temperature ranging 75-200 ^oF.

Phosphonate type was used since high accuration of phosphonate residual content at low contentration and its stability at temperature higher than 300 ^oF. BHMT-P ($C_{17}H_{44}N_3O_{15}P_5$) has functional group of amines which bond to phosphonate. Amine, which is oil-miscible, has ability to adsorption on rock matrix and act to inhibit scale formation. Over time the inhibitor is gradually washed from

the rock matrix as oil production continues until a further descaling treatment is required.

The performance of scale inhibitor was tested prior to field application using parameter of Minimum Inhibitor Concentration (MIC), required to prevent scale growth. The laboratory test protocol adopted throughout the industry are based upon dynamic scale loop (DSL) inhibitor performance test.

DSL was used instead of the conventional static “bulk” or “jar” test procedures adopted are related to NACE standard TM 0197-97 since the ability testing system under pressure with relavant bottom hole temperaturem in the presence of bicarbonate ion without loss of pH control. In addition, “jar” test has the weakness, which is limited in temperature (<100 ^{o}C), pressure, pH, and bicarbonate content (Halvorsen et al., 2009). The apparatus for experiment is shown in Figure 2. MIC was determined by pressurizing the apparatus within certain time and dosage of scale inhibitor until pressure gradually decreased resulting in increasing pressure drop due to blocked by scale formation. The point of pressure drop started to increase, is noted as MIC which would be further used for field application with three times of MIC value.

Figure 3 shows the result of running DSL. The test consisted of the individual injection of two scaling brines, cation (i.e. 32.4 mg/L calcium) and anion (i.e. 3,179.2 mg/L bicarbonate), which was doubled (x2 severity) of actual calcium and bicarbonate content of Example-01, resulting in scaling index of 1.9. Therefore, the MIC obtained shall be divided two for determining the actual MIC. Gyptron IT-256, which is 2.5 time of blank scaling time, is able to inhibit the propagation of scale formation within minimal holding time of 180 minutes with MIC of 5 ppm dosage rate. It can be concluded that actual MIC for Example-01 as typical Zamrud field is half of 5 ppm which is 2.5 ppm.

(a)

(b)

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Figure 2. Picture of apparatus of the scale inhibition test experiment located in NALCO Champion Singapore, (a) Dynamic scale loop contains cation and anion container, (b) Capillary tube (L=1 m ; ID=1/8 inch) in the oven heated up to bottom hole temperature

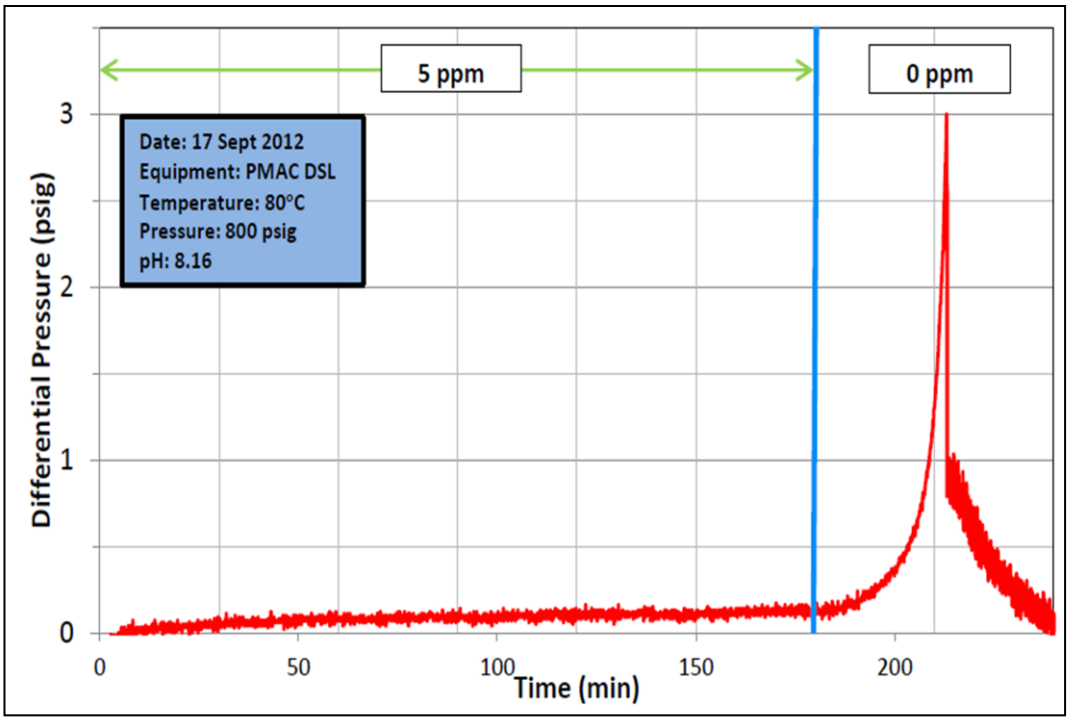

Figure 3. A plot of differential pressure vs time for MIC determination of scale inhibitor Gyptron IT-256 with synthetic water as similar as produced water from Zamrud field (Perng, 2012). DSL was running for 3 hours with flow rate brine water of 10 mL/minute

2. EXPERIMENT

The problem of formation damage near well bore can be caused by many factors such as emulsion blockage and invasion of pulverized formation rock grains, resulting in reducing permeability (Jan et al, 2009). This paper is focused on formation damage caused by scale formation of calcium carbonate only, while other factors can be neglected since DSST is conducted following acidizing, which is able to reduce skin factor. The emulsion problem, which is due to pumping scale inhibitor, can be minimized because of the usage of emulsion preventer as pre-flush prior to pumping scale inhibitor.

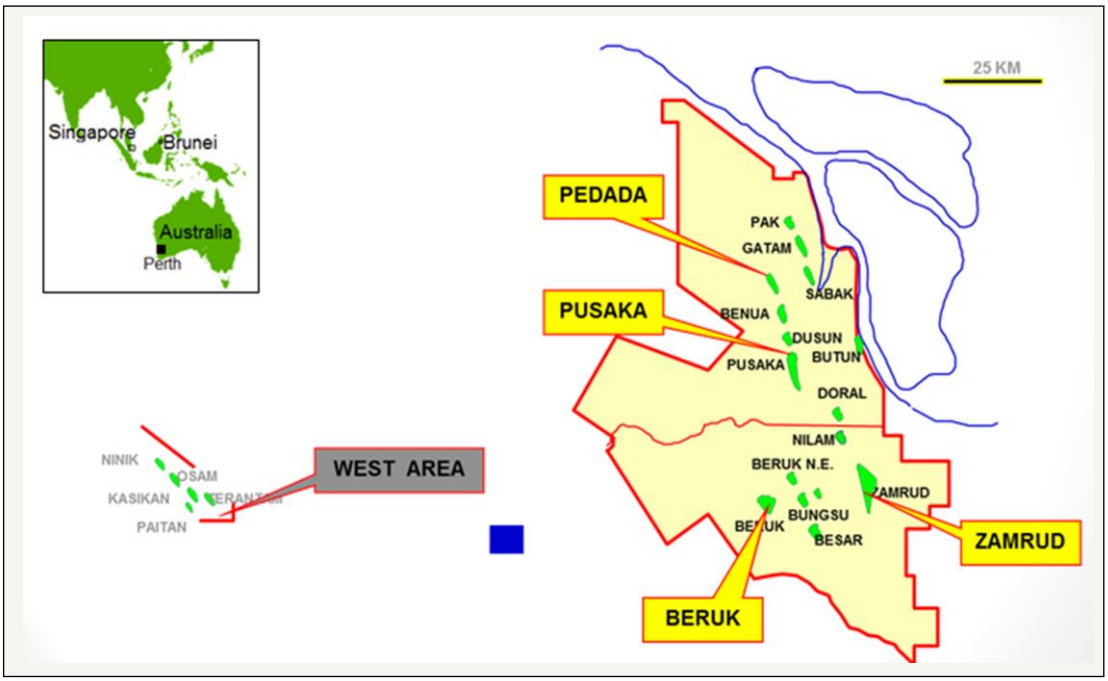

Figure 4. Map of Coastal Plain Pekanbaru (CPP) blok

The discussion on the following was based on the field data, which were tested in Zamrud field, one of fields in CPP block as shown in Figure 4. Active production-wells of CPP block are 600, comprised of Zamrud field, consisted of 107 production wells and 49 injection wells, and other fields. The produced water comes out the reservoir are handled by closed-loop operation mode when the water are re-injected as waterflood and the excess of water are pumped to reservoir on disposal wells.

Table 1. Opened perforated intervals of oil-wells found scale buildup

Well No.	Identification of Scale Deposit	Scaling Index	Opened Perforated Intervals (ft)
Example #01	Twenty five joints tubings above REDA ESP	2.86 3.81	86 86
Example #02	Gas separator of ESP		
Example #03	One joint tubing	2.86	43

Example #04 Instance #01	Body of REDA ESP (type D285, series 400) 20 joints 3 5/8 inch tubings	1.28 2.81	50 20

The field tests were conducted for oil-wells which had quite high Scaling Index (SI) based on Stiff-Davis's correlation as shown in Table 1. Tendency of scale deposition, based on Stiff-Davis index, which is a method to correlate calcium and alkalinity concentrations to saturation pH (*pHs*), temperatures, and total dissolved solids, can be indicated by SI higher than zero (Kemmer and McCallion, 1979). Table 1 also shows the number of opened perforated intervals, which are 5, 5, 5, and 3 intervals for Example #01, #02, #03, and #04, respectively.

The result of laboratory test, using X-Ray Diffraction (XRD), showed the scale deposit was calcium carbonate or sometimes called calcite as shown in Figure 5. The calcium carbonate scale was also proved by dissolving the scale using HCl resulting in changing color of solution to yellow and releasing gas CO_2.

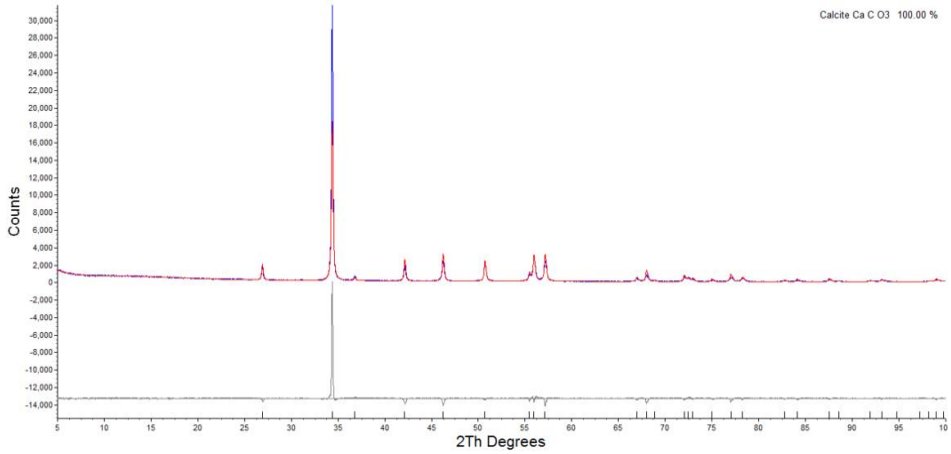

Figure 5. Calcium carbonate scale tested using XRD

2.1 Design of DSST

DSST, is comprised of three stages of job, which is preflush using 1,000-10,000 ppm emulsion preventer, a squeeze pill, and overflush (Reizer et al. 2002). The squeeze pill is defined as injection of 10% scale inhibitor in formation in KCl or brine water into the oil-well above formation pressure. Overflush is aimed at displacing the squeeze pill 3-5 ft radius of well bore exposing to inhibitor, before 24 hours soaking, allowing inhibitor retained onto rock matrix.

2.2 Technique of pumping

The sequences of pumping for Example #01, was started from preflush (A), squeeze pill (B), and overflush (C), as shown in Figure 6. Preflush, which was pumped prior to squeeze pill, was 7.53 litres emulsion preventer diluted with 94.75 barrels formation water. Squeeze pill consisted of 1 drum of scale inhibitor mixed with 7 barrels formation water. Overflush was 0.1% emulsion preventer (12.73 litres) diluted with 160 barrels formation water, pressurized to obtain 3 ft displacement.

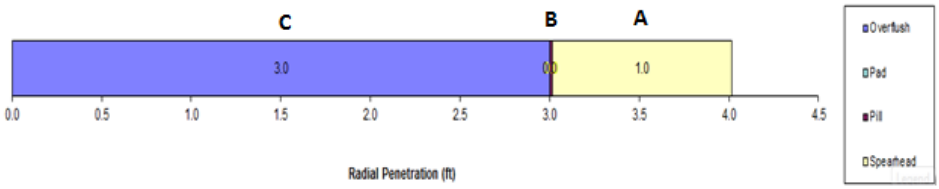

Figure 6. Design of DSST for Example #01: preflush (A), squeeze pill (B), and overflush (C)

All these stages was performed after acidizing stimulation using 15% HCl and soaking time of 30 minutes. The characteristics of reservoir of Zamrud field are shown in Table 2.

Table 2. Reservoir characteristics of fields

RESERVOIR PARAMETER	ZAMRUD	BEKASAP
Depth (ft)	2500-4000	1668-1744
Watercut (%)	97	93
Brine salinity (as NaCl) (ppm)	5000-6000	1900-2000
Oil gravity (^{o}API)	37.4	37.7
Kinematic viscosity @122 ^{o}F (cSt)	15.55	23.15
Pressure Initial (Psi)	1250	560
Reservoir temperature (^{o}F)	170-220	200

3. RESULTS AND DISCUSSION

The production performance of well -DSST was discussed for each well. Phosphonate Residual Content (PRC) for each well was periodically monitored. The successfull of the DSST was PRC which was higher than 5 ppm as recommended by DSL test discussed above.

3.1 Zamrud field

3.1.1 Case of Example #01

Figure 7 shows the well schematic of Example #01 for job of DSST for first, second, and third time, which were conducted on November 15th, 2011, October 30th, 2013, and October 2nd, 2014, respectively. All these jobs of DSST were

conducted on the same perforated intervals without re-perforated new interval and followed acidizing 15% HCl.

Figure 8 shows that before-DSST, production was ranging 120-175 BOPD within 2009-2010. In 2009 there was 300 BFPD and then decreased to 200 BFPD in 2010 due to low efficiency of ESP. DSST, the production was 95 BOPD by using ESP capacity of 300-550 BFPD (i.e. DN 450/113 stages/PRDB/30 HP) on pump set of 3264 ft. Before-DSST on October 2010, the ESP which was installed, was D 285/224 stages/PSDB/30 HP with capacity of 150-350 BFPD. Although the ESP capacity -DSST at the first time, which was installed almost the same capacity with ESP capacity installed on November 2009 (i.e. D 440/213 stages/PSDB/50 HP), but the stages was more higher. On November 6th, 2011, DSST was conducted first time in this well. The result of DSST at first time was stable production for 9 months, so that it could be concluded that DSST was successful on well of Example #01 which contained 16 mg/L calcium, 5 mg/L magnesium and 0.1 mg/L Fe^{3+} at Bottom Hole Temperatur (BHT) of 245 ^{o}F and bottom hole pressure of 819 psia. On April 16th, 2012, there was pump failure indicated by high ampere, so that the ESP was re-installed with another one with the same capacity, resulting in reducing watercut and increasing production. DSST was not re-performed since the life-time treatment was designed for one year.

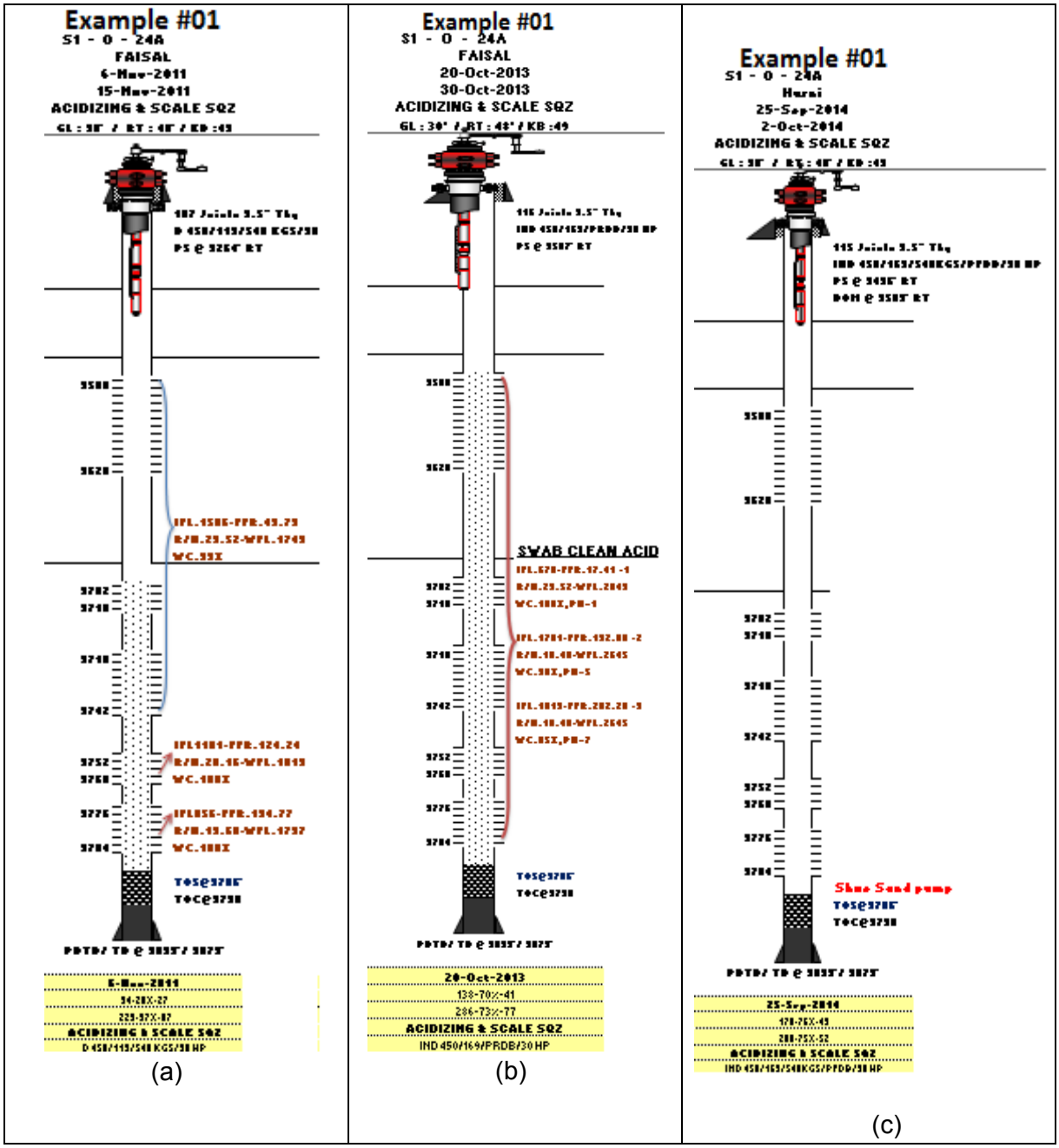

Figure 7. Well schematic of Example #01 with 5 opened perforated intervals in commingled production for DSST program. (a) First-time, (b) Second-time, (c) Third-time

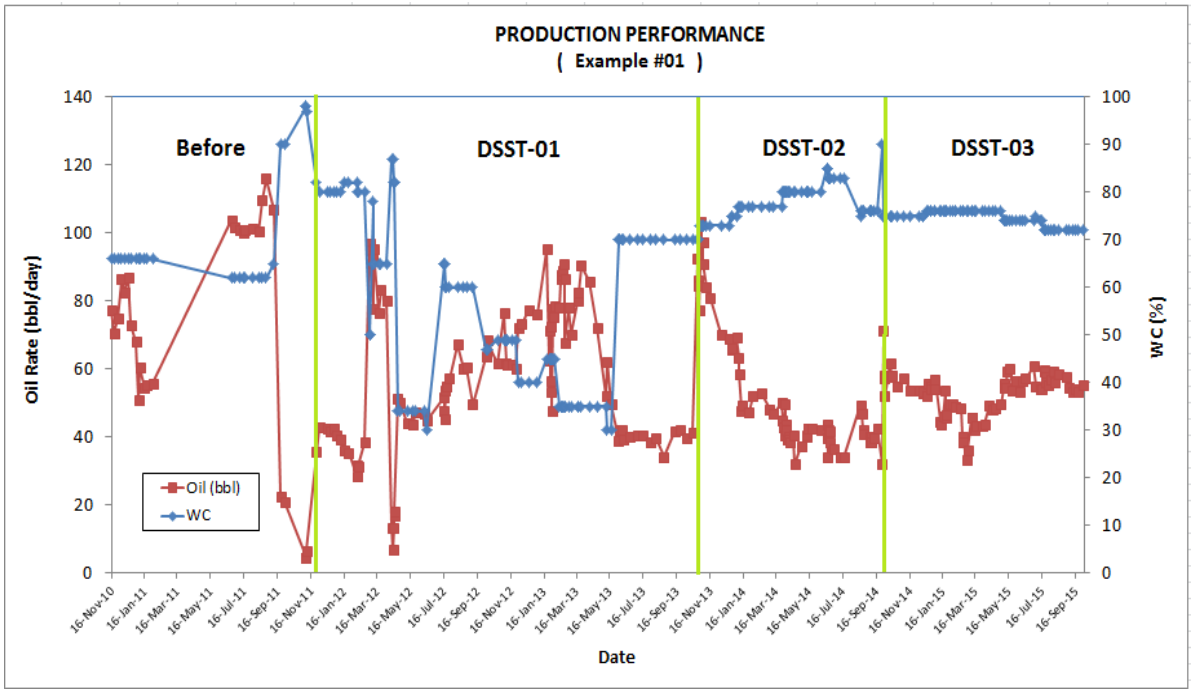

Figure 8. Production performance of Example #01, before- and after-DSST for first-, second-, and third- time following acidizing on November 6th, 2011, October 20th, 2013, and September 25th, 2014, respectively

3.1.2 Case of Example #02

Well of Example #02 prior to acidizing 15% HCl and DSST, the program was putting on hole low capacity of ESP (i.e. 440/101 stages/50 HP) due to low influx of the formation. On October 12th, 2012, ESP was found high ampere, caused by scale formation. On October 26, 2012, the pump was changed to IND 440/213 stages/ 30 HP and the production increased 60 BOPD with 25% watercut (on October 4th, 2012) and 82 BOPD with 25% watercut (on October 6th, 2012) to 105 BOPD with 45% watercut (on October 27th, 2012). At this time of production, there was no treatmeant of scale squeeze inhibitor.

DSST, conducted on January 10th, 2013, the production was back to its potensial production as shown in Figure 9. BHMT-P, which has five double bond phosphonates, bond to amine group, is working by “threshold effect”. Double bond phosphonate reacts to calcium ions and keep them in solution, which prevent $CaCO_3$ scale formation between Ca^{2+} and CO_3^- in formation water. The calcium is dissolved in formation water due to content of calcium in mineralogy of rock matrix as shown in Table 4. In addition, Table 5 shows the complete water analysis cations including calcium in formation water. BHMT-P was working with calcium in formation water to minimize the scale growth around six months and five montsh for first time and second time, respectively. The monitoring of PRC can be seen in Table 6. At the beginning of treatment life, there was high content of PRC and its content gradually started to decrease. Since scaling index is 3.81,

the PRC was significantly reduced in shorter time rather than its design. If the PRC value reached MIC, DSST was re-conducted. The well was re-squeezed after 4 months life time treatment, shorter than its design due to assumption of scaling index 1.9 used in DSL test.

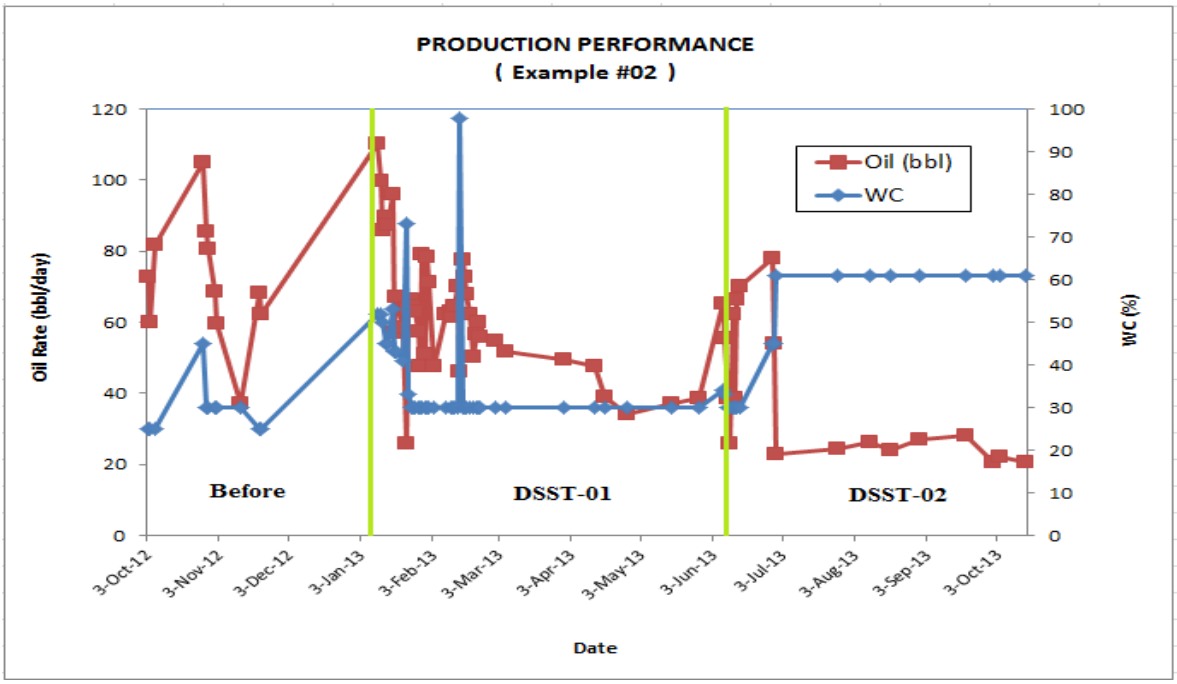

Figure 9. Production performance of Example #02 before- and after-DSST for first- and second-time following acidizing 15% HCl on January 7th, 2013 and June 6th, 2013, respectively

Table 4. The mineralogy of formation for Example #02

			Sand					
			W'			X'	Y'	Z'
			W1'	W2'	W3'	X1'	Y1'	Z1'
Clay Mineral (vol %)	Illite	$K_{0.6}(H_3O)_{0.4}Al_{1.3}Mg_{0.3}Fe^{2+}_{0.1}Si_{3.5}O_{10}(OH)_2.(H_2O)$	37	48	26	25	66	40.4
	Kaolinite	$Al_2Si_2O_5(OH)_4$	-	-	-	-	-	-
	Chloride		-	-	-	-	-	-
Carbonate (vol %)	Calcite	$CaCO_3$	13	0.1	0.9	2.2	-	5.4
	Dolomite	$CaMg(CO_3)_2$	-	-	-	-	-	-
	Siderite	$FeCO_3$	-	-	-	-	-	-
Other Mineral (vol %)	Quartz	SiO_2	26	25	42	45	6.3	27.4
	Orthoclase	$KAlSi_3O_8$	-	0.1	3	0.4	-	-
	Feldspar		24	26.8	28.1	27.4	27.7	26.8
	Plagioclase							
	Muscovite							
	Hematite	Fe_2O_3						
	Barite	$BaSO_4$						
	Pyrite	FeS_2						

Table 5. Water analysis of formation water of Example #02 for scale inhibitor field test

CONSTITUENTS	Example #02
Sodium (mg/L)	2,175.3
Calcium (mg/L)	24.2
Magnesium (mg/L)	3.7
Iron (mg/L)	0.1
Barium (mg/L)	3.0
Chloride (mg/L)	2,499.4
Sulfate (mg/L)	0.0
Bicarbonate (mg/L)	1,565.2
Carbonate (mg/L)	0.0
pH (-)	8
Bottom Hole Temperature (^{o}F)	247
Bottom Hole Pressure (psia)	856

Table 6. Monitoring of phosphonate residual content after DSST of Example #02

Well Name :		Example # 02		Example # 02	
Injection of Scale Inhibitor		6-Jan-13		5-Jun-13	
Production		7-Jan-13		6-Jun-13	
Monitoring Period		Sampling Date	PRC (ppm)	Sampling Date	PRC (ppm)
Before Squeeze		4-Jan-13	0.00	5-Jun-13	2.80
After Production	Day 1	8-Jan-13	61.67	7-Jun-13	52.00
	Day 2	9-Jan-13	59.61	8-Jun-13	46.92
	Day 3	10-Jan-13	57.93	9-Jun-13	45.66
	Day 4	11-Jan-13	52.97	10-Jun-13	44.39
	Day 5	12-Jan-13	43.55	11-Jun-13	43.12
	Day 6	13-Jan-13	37.91	12-Jun-13	38.05
	Day 7	14-Jan-13	17.54	13-Jun-13	31.71
	Day 8	15-Jan-13	16.87	14-Jun-13	25.36
2nd week	Day 9	16-Jan-13	16.49	16-Jun-13	22.83
	Day 11	18-Jan-13	15.22	18-Jun-13	17.75
	Day 13	20-Jan-13	15.14	20-Jun-13	12.68
3rd week	Day 21	28-Jan-13	13.95	28-Jun-13	6.14
4th week	Day 28	4-Feb-13	12.90	5-Jul-13	6.02
5th week	Day 35	11-Feb-13	7.90	12-Jul-13	6.30
6th week	Day 42	18-Feb-13	5.59	19-Jul-13	7.30
7th week	Day 49	25-Feb-13	4.67	26-Jul-13	3.04
8th week	Day 56	4-Mar-13	4.53	2-Aug-13	2.83
3rd month	Day 90	7-Apr-13	3.30	5-Sep-13	2.09
4th month	Day 120	7-May-13	2.80	5-Oct-13	1.38
5th month	Day 150	6-Jun-13	**Re-Squeezed**	4-Nov-13	**Re-squeezed**
6th month	Day 180	6-Jul-13		4-Dec-13	

3.1.3 Case of Example #03

Job of acidizing and DSST for Example #03, which have BHT=277 ^{o}F and Bottom Hole Pressure (BHP)=1105 psia, were conducted on April 20th and 22nd, 2012, respectively. The same capacity of ESP (i.e. REDA IND 450/113 stages/30 HP) was installed prior to before DSST (DN 450/113 stages/ 66L/30 HP). There was an increasing production to 356 BOPD with 83% watercut (July 12th, 2012) compared to before treatment dated January 4th, 2012 with 188 BOPD and 94% watercut, as shown in Figure 10. Therefore, acidizing was catagorized successfull. As shown in Table 7, PRC was lower than MIC since June 2013 when scaling index of this well was 2.81, which was higher than DSL running scaling index of 1.9. The PRC seems very low concentration since the first day of well reactivated, it was caused by dilution of breakthrough water injection from one of injection well with flow rate of 2,048 BWPD.

January 29th, 2013, ESP was changed to new one with the same capacity due to zero Meg, resulting in production ranging 77-87 BOPD. If oil gain is compared

before and after ESP re-changing, there was decreasing gain oil, caused by increasing watercut. It was believed that breakthrough waterflood from injection well pressurized Example #03 during shut-in Example #03 for re-changing ESP. Injection well could not be shut-in because this injection well supply water injection in irregular pattern of waterflood. It seems PRC below MIC did not give longer inhibition to scale growth. After first DSST, which had 7 months life time treatment, Example #03 was re-acidized and re-squeezed scale inhibitor. The result of acidizing on November 2013 could not increase the oilcut to its potential.

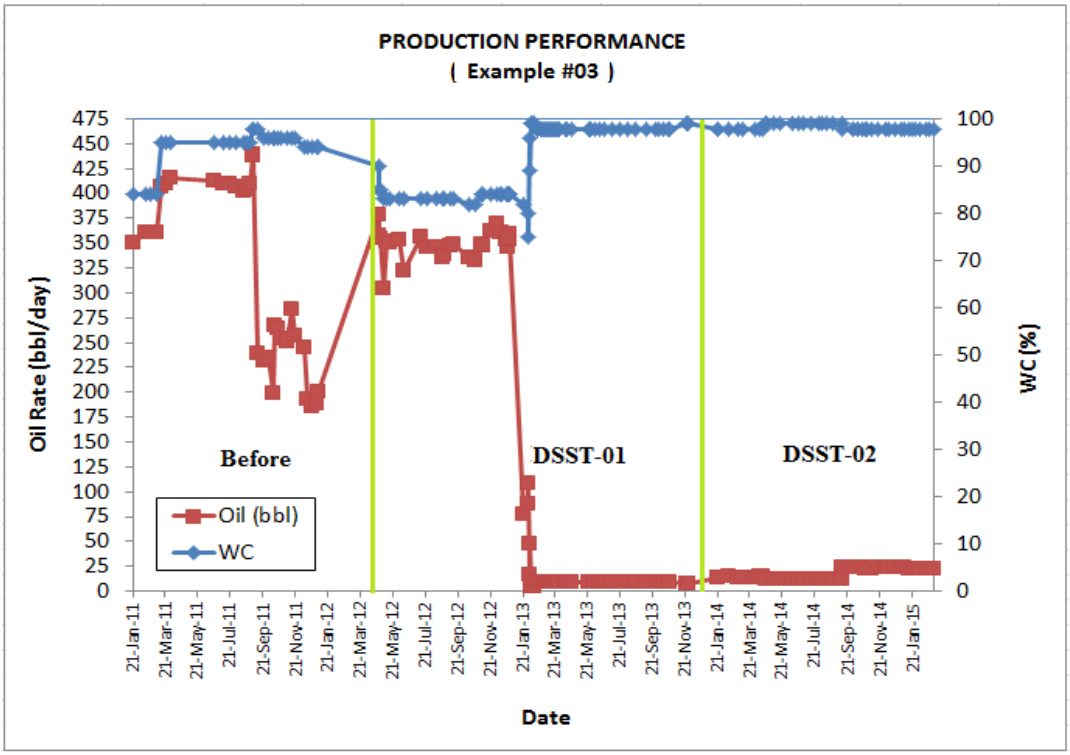

Figure 10. Production performance of Example #03 before- and after-DSST for first and second time following acidizing 15% HCl on April 22nd, 2012 and November 30th, 2013, respectively

Table 7. Monitoring of phosphonate residual content after DSST of Example #03

Well No.		Example #03		Example # 03	
Squeeze Date		25-Apr-12		21-Nov-13	
Re-produce date		26-Apr-12		22-Nov-13	
Monitoring Period		Sampling Date	PRC (ppm)	Sampling Date	PRC (ppm)
Before Squeeze		-	0.00	-	0.00
	Day 1	27-Apr-12	9.51	23-Nov-13	26.61
	Day 2	28-Apr-12	9.13	24-Nov-13	21.53
	Day 3	29-Apr-12	8.62	25-Nov-13	19.15
	Day 4	30-Apr-12	7.74	26-Nov-13	15.95
	Day 5	1-May-12	6.34	27-Nov-13	14.56
-	Day 6	2-May-12	4.27	28-Nov-13	10.59
	Day 7	3-May-12	4.92	29-Nov-13	8.32
	Day 8	5-May-12	3.59	1-Dec-13	6.26
2nd week	Day 9	7-May-12	3.58	3-Dec-13	4.36
	Day 11	9-May-12	2.50	5-Dec-13	3.12
	Day 13	17-May-12	2.40	13-Dec-13	2.56
3rd week	Day 21	24-May-12	2.35	20-Dec-13	2.54
4th week	Day 28	31-May-12	2.28	27-Dec-13	1.89
5th week	Day 35	7-Jun-12	2.19	3-Jan-14	0.61
6th week	Day 42	14-Jun-12	1.85	10-Jan-14	0.33
7th week	Day 49	21-Jun-12	1.66	17-Jan-14	0.16
8th week	Day 56	25-Jul-12	1.31	20-Feb-14	0.14
3rd month	Day 90	24-Aug-12	0.82	22-Mar-14	0.10
4th month	Day 120	23-Sep-12	0.49	21-Apr-14	0.05
5th month	Day 150	23-Oct-12	0.49	21-May-14	0.00
6th month	Day 180	22-Nov-12	0.48	20-Jun-14	0.00
7th month	Day 210	22-Dec-12	0.24	20-Jul-14	0.00
8th month	Day 240	21-Jan-13	0.00	19-Aug-14	0.00
9th month	Day 270	20-Feb-13	0.00	18-Sep-14	0.00
10th month	Day 300	22-Mar-13	0.00	18-Oct-14	0.00
11th month	Day 330	21-Apr-13	0.00	17-Nov-14	0.00
12th month	Day 360	21-May-13	0.00	17-Dec-14	0.00
		20-Jun-13	Not Monitored	16-Jan-15	Not Monitored
		20-Jul-13	Not Monitored		
		19-Aug-13	Not Monitored		
		18-Sep-13	Not Monitored		
		18-Oct-13	Not Monitored		
		17-Nov-13	Not Monitored		
			Re-squeezed on 21 Nov 2013		

3.1.4 Case of Example #04

During January to September 2013, when DSST was not performed, steady production decline was observed after acidizing stimulation only. Subsequently, program of DSST following acidizing 15% HCl was conducted on October 1st, 2013. Example #04 was produced on October 2nd, 2013 at 11.00 am using 1-3/4 inch Hydraulic Pumping Unit (HPU) with pump set on 3600 ft. At first day of production, 50 BOPD was obtained, then suddenly decreased to 29 BOPD a day production with PRC of 2 ppm as shown in Figure 11.

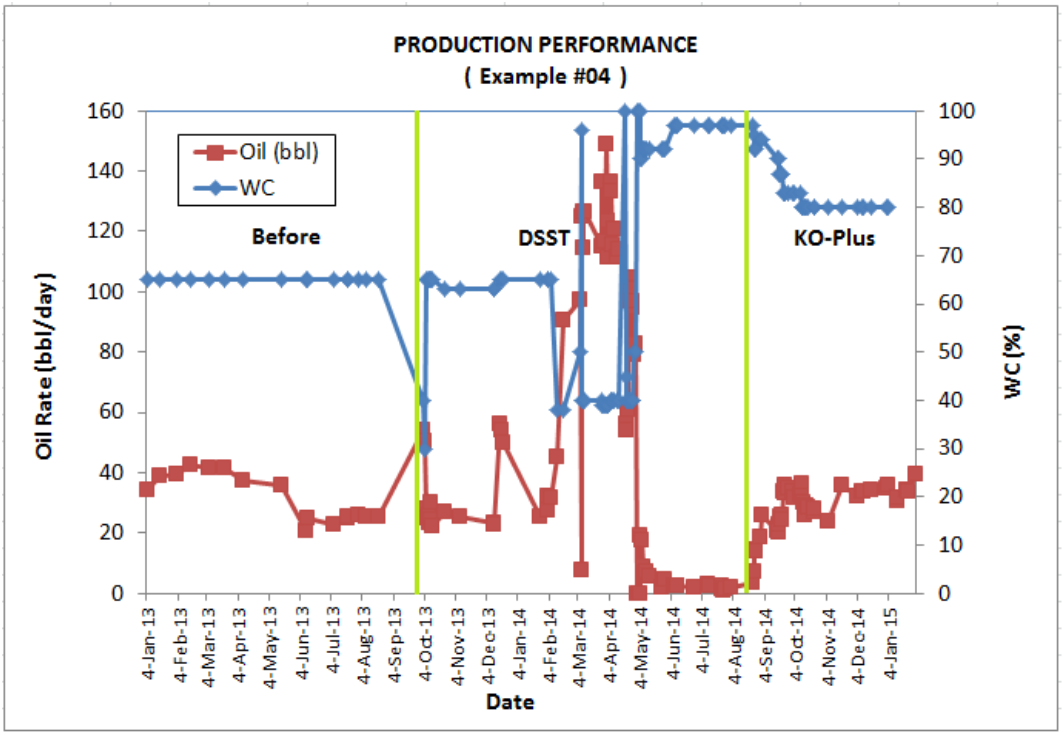

Figure 11. Production performance of Example #04 before- and after-DSST following 15% HCl acidizing. After DSST, there was acidizing using KO-Plus (i.e. organic acid), which is scale dissolver, on August 22nd, 2014

3.2 Bekasap field

3.2.1 Case of Instance #01

Before-DSST, acidizing stimulation only gave increasing of oil maintaining for 4 months with production ranging 18-100 BOPD. Performance of Bekasap #02 after DSST without 15% HCl acidizing showed only 4 months successful as shown in Figure 12. The life time performance was very short compared to the design, which was calculated for one year treatment. This well, which was re-activated on November 19, 2011, had production of 44 BOPD with watercut 10% on August 20th, 2011. The production seems stable only for 5 months until March 24th, 2012. It can be concluded that pumping scale inhibitor, eventhough 4 months after acidizing, could prolong the life time of production.

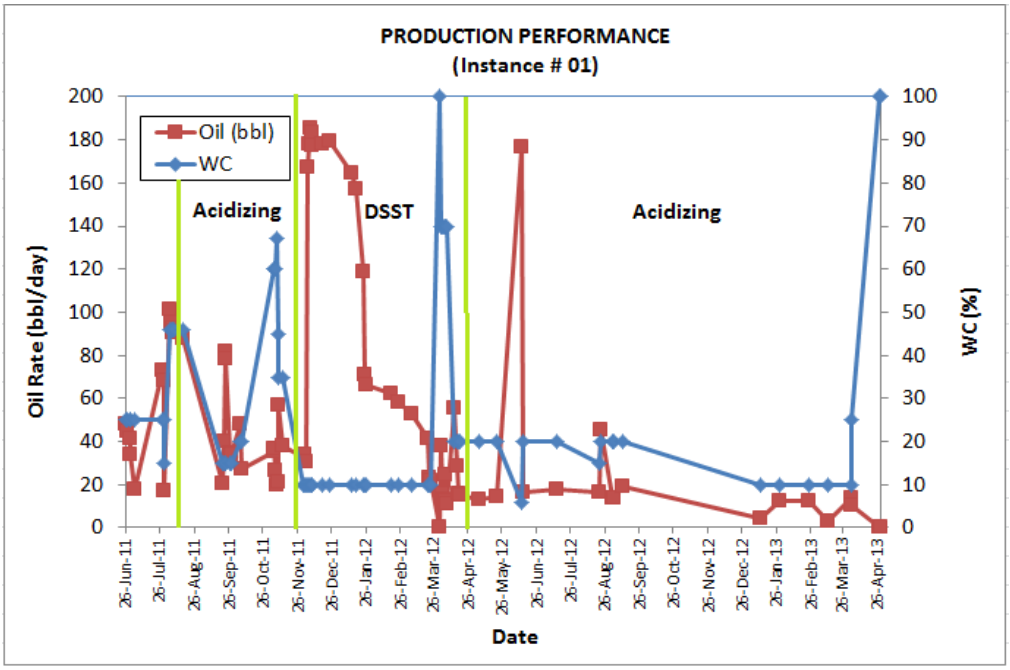

Figure 12. Production performance of Instance #01 before- and after-DSST without 15% HCl acidizing on November 2nd, 2011. Before-DSST, only 15% HCl Acidizing was conducted on July 27th, 2011. After-DSST, only 15% HCl Acidizing was conducted on March 31st, 2012. All these jobs were performed on the same intervals, namely 1668-1678 ft, 1790-1794 ft, and 1798-1804 ft

Table 8 shows that BHMT-P is suitable for Instance #01 with content of 12.12 mg/L Ca^{2+} in formation water and Bottom Hole Temperature (BHT) and Bottom Hole Pressure (BHP) are 200°F and 560 psia.

Table 8. Water analysis of formation water of Instance #01 for scale inhibitor field test

CONSTITUENTS	Instance #01
Sodium (mg/L)	1,625
Calcium (mg/L)	12.12
Magnesium (mg/L)	6.89
Chloride (mg/L)	2,499.2
Sulfate (mg/L)	1.0
Bicarbonate (mg/L)	947.5
Carbonate (mg/L)	362.9
pH (-)	8
Bottom Hole Temperature (°F)	560
Bottom Hole Pressure (psia)	200

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4. CONCLUSIONS

- Well name Example #01, #02, #03, and #04 show a good production performance. After DSST, the oil-wells have longer production life in spite of the wells are being shut-in and reactivated numerous times.
- BHMT-P is suitable for Zamrud field in general and especially well name Example #01 with content of 24 mg/L Ca^{2+}, 5 mg/L Mg^{2+}, and 0.1 mg/L Fe^{3+} in formation water and Bottom Hole Temperature (BHT) and Bottom Hole Pressure (BHP) are 247 ^{o}F and 856 psia, respectively. BHMT-P is not precipitate when it mixed with divalent and multi-valent cation in formation water.
- DSST in Bekasap field was also evaluated based-on the successful of DSST in Zamrud field and showed a quite good result.

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