Empirical Study of Thermochemical for Heavy Oil in Production Wells

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ABSTRACT: *The 'X' well is an oil well located in South Sumatra, Indonesia, the well began production (on stream) in June 2017 and is still in production today. Fluid characteristics of heavy oil with a value of 24.6 ºAPI and a high pour point of 48ºC originating from the Talang Akar Formation reservoir. The analysis problem shut-in well after two months of production, and the results of laboratory analysis of oil samples are oils with asphalts problems so that the oil freezes before it reaches the surface. The analysis is carried out in the production well has been done twice with a chemical injection of xylene (C_8H_{10}) + toluene (C_7H_8) and the 'X' well is back in production for 9 days but has decreased oil production by 16% per day until the 'X' well shut in on 18 January 2018, due to indications of heavy oil deposits in production tubing. Based on data from the EMR (Electric Memory Recorder) starting at a depth of 400 m from the surface the temperature is below the pour point (48ºC) of oil produced. On July 22, 2018, a thermal stimulation project with thermochemical by injecting (HCl 15% + NH3 5% + Ester) was carried out to overcome the asphaltenes problem in the 'X' well. Thermochemical stimulation succeeded in turning on the 'X' well with Qoi 325 BOPD and raising the wellhead temperature from 30ºC / 86ºF to 50ºC / 122ºF for 100 days and then production lasts 58 BOPD for 120 days. This research was successful in handling production problems at a mature oil field for 230 days (almost 8 months) economically and can operate at low oil price conditions*

KEYWORD: *Thermochemical; Heavy Oil; Asphalts; Mature oil Field.*

INTRODUCTION

The characteristics of oil produced in well 'X' are heavy oil with high pour-point / HPPO (high pour-point oil). Based on the characteristics of the oil produced, there will be freezing of oil deposits in the production tubing before it reaches the surface because has a production problem in the form of asphaltenes problem. A study on handling thermal stimulation has been carried out in the field with the problem of heavy oil in oil wells in 1994. The problem of wax and asphalt deposition in the PETROBRAS oil field, Brazil, was overcome by research conducted by the PETROBRAS Production Dept. Campos Research Centre. This study uses an esterification reaction with Nitrogen (N2) and produces heat, which can melt wax and asphalt deposition [8]. Along with the advancement of research and technology progresses, paraffin and asphalt removal develop with esterification formation reactions using chemicals that can generate heat with higher temperatures up to 200ºC [13]. The heavy oil field that

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implementation of thermochemical stimulation treatment is the Albacora field, Brazil, is succeeded increase oil production by 32% and generating USD 200,000 / day [8]. Thermochemical stimulation research to overcome the asphalt problem is also applied in the marginal field of West Malaysia, and it can be concluded that this method is more profitable [2].

Research conducted at Well X used a thermochemical method by injecting HCl 15% and NH_3 5% as a result of the most sensitive components in the laboratory. This thermochemical reaction can increase the temperature of production fluid up to 160ºC. Then it is observed that the temperature can last until it reaches the pour point of the production fluid at 48ºC. The fluid composition of thermochemical is very effective to maintain well production for up to 230 days. At first, there were doubts about using HCl for injection fluid due to its corrosive nature to casing and tubing, but by adjusting the proper concentration it will cause a heat reaction and produce a solvent fluid that will be produced with the production fluid. If the concentration of HCl after reaction stability in reach on the surface, it can be anticipated in the separation equipment or in water treatment with the addition of NaOH can produce salt and water.

THEORETICAL SECTION

Asphaltenes problems

Asphalt crystallization in crude oil produces non-Newtonian flow characteristics, including time-dependent (thixotropic) yield stress at the temperature of crude oil. Asphalt crystallization depends on the low temperature and the rate of temperature decrease. Crystallization in crude oil can cause three problems: high viscosity, pressure, high-stress yield, and crystalline deposits. High viscosity (>150 cp) and deposits are the leading causes of production problems, such as high pressures and increased pumping rates due to deposits, but oil production decreases. Besides, high viscosity in the presence of sediment will cause damage to pipes and production facilities.

These asphalt crystals settle to production facilities such as tubing, flow line, storage tanks, pumps, and other equipment will cause this production fluid cannot to flow [9]. The crystal can settle even though crude oil is at a temperature above its freezing point. This happens because oil has a high pour point value. Asphalt crystals will settle to a slower fluid flow compared to a faster fluid flow rate.

***Table1 :.Asphaltenes Oil Characteristic Proble*m**

Viscosity	Pour point	Specific Gravity (SG)	Color
Cp	ºC		
>150	>40	>0.9	Dark Brown

Low flow rates affect asphalt deposition, mainly due to longer residence times on the pipe.

This increase in residence time allows more heat loss and results in lower crude oil temperatures, which can cause precipitation and precipitation of asphalt crystals.

The characteristic of oil with an asphalts problem is that it has a high SG value (> 0.9) and a high pour point (> 40ºC) compared to oil with paraffin problem oil color with dominant brownish dark asphalts in the presence of shiny films. The following are the characteristics of oil with the asphalts problem shown in Table 1.

In Table 1 above, the oil with asphaltenes problem has characteristics with a dark brown color, a viscosity above 150 cp, SG value is high (> 0.9) so that the value API Gravity into a low/heavy oil.

Indications of deposition of heavy oil

The first step to organic diagnosis deposit is to analyze samples of crude oil. There are some routine laboratory tests conducted on samples of crude oil such as dissolution tests and SARA(Saturates, Asphaltene, Resins, and Aromatics) Analysis [13].

a) Dissolution test

In examining the nature of the sample, one of the routine tests is to analyze the sample solubility in an organic solvent, organic acid, and water.

Dissolution testing is not a quantitative test, but a useful method to examine the nature of the deposit samples. Samples with dominant fraction soluble organic solvent while the non-dominant samples dissolved in acid and water. This step is one of the first steps to characterize organic sediment, therefore, needed further tests to determine the organic deposits in crude oil. Here is a sample of the dissolution process of oil with solvent and acid + water is shown in Fig. 1.

Fig. 1 above, section A shows a sample of oil with an acid + water, while in B visible oil sample with a solution of the solvent resulted in a dark brown color precipitate. This indicates that oil sample B is the dominant part of the asphalt.

Table 2 : Types of Deposits Based On Melting Points.

Type of Wax	Melting Point
Asphaltenes	(120-150ºC)
Resins	(120-150ºC)
Aromatics	(60-100ºC)

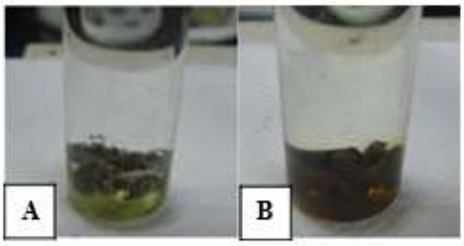

Fig. 1: Dissolution Test.

b) Analysis of SARA (Saturates, Asphaltenes, Resins, and Aromatic)

Analysis of SARA (saturates, asphaltenes, resins, and aromatics) is an analysis performed to determine the levels of saturation, asphalt, resins, and aromatic content in petroleum. Analysis SARA detected by the Colloidal Instability Index (CII), is the ratio between the saturation and the asphalt with resin and aromatic, if the value of CII is below 0.7, then the level of SARA is stable, whereas if the value of CII ranges above 0.9 then the oil or the sample tends to be unstable with predominantly content asphalt therein.

The higher the value of CII (Colloidal Instability Index), the higher the content of asphalt in the oil, with this, the oil will tend to be easier to freeze and cause problems of production and the resulting decrease in oil production due to the deposition of organic oils that usually accumulate in the tubing production and zones of perforation. Based on the description of saturates, asphalts, resins, and aromatics above, it can be grouped types of organic sludge by melting in Table 2 below. In Table 2 above, groups of asphaltenes and resins is a type of sediment that has a high melting point compared with other sediment type group.

SARA in crude oil fraction can indicate the level of asphaltene stability. High asphaltene content of which is not the reason for the problem of asphaltene, but the fraction of high saturation can cause asphaltene instability. In addition, the resin concentration affects the stability of asphaltene, when the ratio of resin to high asphaltene, there will be no problem in the hydrocarbon fraction, whereas when the ratio decreased, asphaltene become unstable. The Colloidal Instability Index (CII) is another approach to identifying the stability of asphaltene. CII is the ratio of total asphaltenes and saturation of the total aromatics and resins. Crude oil is was teady if CII value under 0.7, and then crude oil is considered unstable when CII value is higher than 0.9. Determine levels of CII, and then use the following equation:

$$CI1 = \frac{Sat + asp}{res + aro} \times 100 \qquad (1)$$

Explanation:
sat : saturates
asp: asphaltenes
res: resins
aro: aromatic

The data used to calculate the CII on the oil sample is total saturation, levels of asphalt, resins, and aromatics obtained on test samples in the laboratory.

c) Thermochemical stimulation

Thermochemical stimulation is a method of injecting chemicals into production wells as heat-producing / exothermic reactions with temperatures generated in the range (125ºC-175ºC) and then soaking/soaking for 12-24h The purpose of thermochemical stimulation is to clean the production tubing due to organic deposition or freezing due to the oil produced being heavy oil with high asphalt content, after thermochemical stimulation is expected to increase well production.

The chemicals injected are HCL 15% and amine (NH_3) 5% which can produce high temperatures + esters (NH_4Cl), this high temperature produced will melt/melt frozen oil deposits in the production tubing, while chemicals resulting from the exothermic reaction in the form of an ester which is a solvent so it cannot be mixed with the oil to be produced.

The following is the equation of the thermochemical stimulation reaction shown in the equation below.

$$HCl + NH_3 = HEAT + NH_4Cl \qquad (2)$$

Thermochemical stimulation process

Stimulation thermochemical is divided into three main parts: the injection of chemicals into the well to be stimulated, then an immersion process or chemical soaking wells for 12-24 hours in this process is the longest process

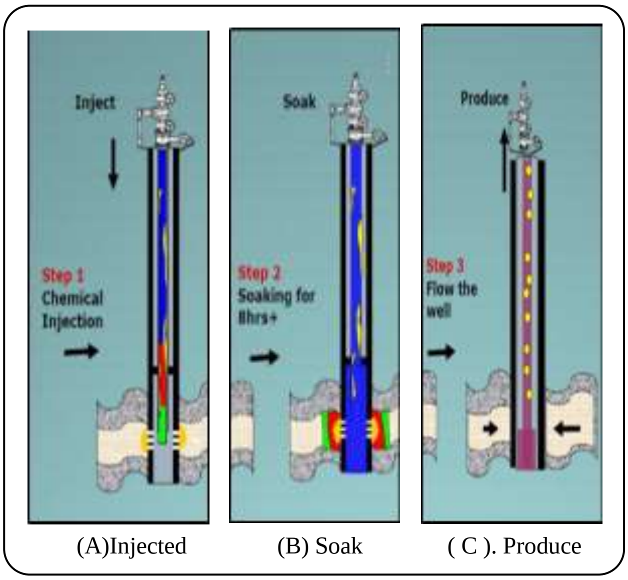

Fig. 2: Thermochemical Injection Process.

of stimulation segment thermochemical and chemical production process back to the surface, In the process injection of stimulation is divided into three segments, namely the segment of pre-flush, flush, and post-flush which is a different part in the type of chemical that is injected. The chemical segment has a different function in the part of stimulation.

The stimulation process is performed on the same production wells, for more details, it is shown in Fig. 2 show for the chemical injection section.

Figure 2 (A**)** above is a chemical injection, first of chemicals injected into the wells in the order of injection pre-flush, flush (thermo-A + thermo-B), and post-flush. The following is a function of the chemical in thermochemical stimulation operations:

A) Pre-Flush: a *chemical* that serves as the entrance of the chemical thereafter by breaking the thin films in the organic pour point inside the production tubing with chemical surfactants. The injection volume is 10% pre-flush of the total volume of production tubing.

B) Flush

a. Thermo-A: Chemical Thermo-A is a chemical that reacted with the chemical Thermo-B to generate heat. The heat generated will dissolve heavy oil deposits that are still settled on the production tubing, perforation zones, and several feet in formation. Volume thermo-A injected into the well is 40% of the total volume of the casing perforation zone and a few feet from the wellbore.

b. Thermo-B: a *chemical* that is reacted with the chemical Thermo-B to generate heat. The heat generated will dissolve sludge deposits of oil in the production tubing, casing perforation zone, and a few feet after the wellbore. Volume thermo-B was injected into the well is 60% of the total volume casing perforation zone and a few feet from the wellbore.

C) Post flush: The chemical used is a surfactant that is used to push in thermo-A and thermo-B into the casing and perforated zone, the volume of which is used to inject the chemical post flush as much volume of production tubing.

Furthermore, the well is capped and soaked/soaked for 12-24 hours to completely dissolve the heavy oil, in a process of soaking time graphics to be displayed in Fig. 2 (B). Soaking in thermochemical stimulation. Soaking aims to optimize the chemical reaction and produce the optimum temperature.

Further wells in the open again and produced up to 1.5 times the volume of chemical is injected to ensure the entire chemical that is injected has been completely out of the wellbore as shown in Fig. 2(C). The production process well after stimulation as shown in Figure 4 above, do injection and soaking, then performed to produce back well after stimulation does thermochemical. Once all the stimulation fluid is reproduced and then well testing is to determine the performance of the wells. Research methodology is a combination of experimental in the well performance injection thermos chemicals, and analytical in laboratories to physical and thermal properties bellow and after injection thermochemical.

EXPERIMENTAL SECTION

Experiment Stimulation

Well 'X' produced 504 bopd after that for 58 days the well experienced a fairly rapid decline in production until shut-in. The 'X' well can produce again in November 2017 by stimulating xylene + toluene so that the well can return to production with 90 bopd, but the well will return/shut in within 22 days, then xylene + toluene will be stimulated again in January 2018 and the well returned to production for 9 days after which the well was shut-in again due to the heavy oil produced. On January 18, 2018 well 'X' decreased by 16% per day until the well shut down in 9 days so that the well could not be reproduced until production was handled. Following is the production data on well 'X' displayed graphically in Fig. 3.

Table 3: Fluid Properties Well 'X'.

Specific Gravity @60/60 ºF	0.9067	
API Gravity @ 60 F	24.6	
Kinematic Viscosity at 140 ºF	159.3	cp
Kinematic Viscosity at 180 ºF	51.24	cp
Kinematic Viscosity at 210 ºF	26.98	cp
Pour Point	48	ºC
Flash Point "ABEL"	90.5	ºC
Oil Type	HPPO-Heavy Oil	

Table 4: SARA Analysis Result Well X

		Sample basis (%)	Dry basis (%)
Volatiles		43.7	
Saturates	Macro crystalline wax (low molecular wt.)	21.49	38.23
	Micro crystalline wax (low molecular wt.)	2.35	4.18
Total saturates		23.84	42.41
Asphaltenes		2.98	5.3
Resin		8.68	15.44
Aromatics		17.56	31.24
Napthenes		2.5	4.46
* Total		99.35	98.85

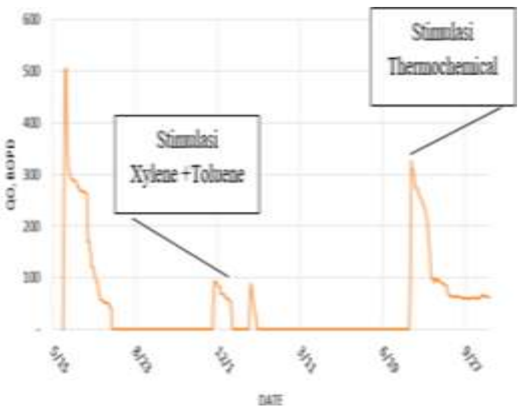

Fig. 3: Production data well 'X'

In Fig. 3 above, Well 'X' is indicated by the presence of frozen oil along the production tubing. The following is the result of the fluid properties in Laboratory of the Well Oil 'X' displayed in Table 3.

Based on the fluid properties of the 'X' well above, where the well 'X' is a heavy oil with low API Gravity at 24.6 ºAPI and is a high pour point oil (48ºC), then further laboratory analysis is performed by analyzing more hydrocarbon fractions in the analysis of saturates, asphaltenes, resins, and aromatics. In this condition, the crude oil has frozen in the tubing so that it cannot flow to the surface of the well.

SARA (Saturates, Asphaltenes, Resins, and Aromatics) Analysis

SARA analysis (Saturates, Asphaltenes, Resins, and Aromatics) is an analysis of oil samples used to diagnose the dominant heavy oil deposits in the oil hydrocarbon fraction in well 'X'. Laboratory results on oil samples produce saturates, asphalt, resins, and aromatics, as shown in Table 4. below this.

From the laboratory results in the SARA analysis above, which is macro saturation because the value of

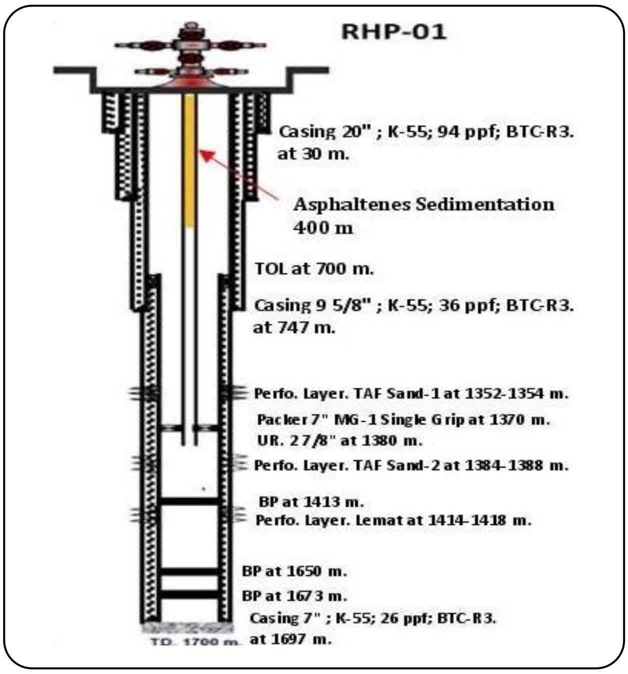

Fig. 4: Well Diagram RHP-01 with Deposition Indications Analysis.

macro saturation is greater than micro saturation. Furthermore, it can be determined the value of CII (Colloidal Instability Index), CII is the ratio between saturation and asphalt with aromatics and resins in the macro hydrocarbon fraction.

The CII value in the good oil sample can be determined by the equation:

$$CII = \frac{23.84 + 2.98}{8.68 + 17.56}$$

$$CII = 1.022$$

CII value in Well X 'from the calculation result is 1,022 which means crude oil is indicated as dominant asphaltenes sediment because CII value> 0.9, and the hydrocarbon fraction is stable if the value CII <0.7. With this SARA analysis, it proves the assumption that oil in the 'X' well has asphaltenes problems with oil freezing in the production tubing and perforation zone

Static pressure and temperature analysis well X

Analysis of static pressure and temperature in the 'X' well by using Electric Memory Recorder data) is shown in Table 5.

Based on the EMR data above, where at 400 m from the surface the temperature is below the pour point of the oil produced, so the oil settles/solidifies from a depth of 400 m to the surface. Graphically it can be shown in Fig. 4 below.

In Fig. 4 above, visible heavy oil deposits freeze at 400 m from the surface in the production tubing. Asphaltic deposition problems a fluid flow blocking as an effective oil is not produced to the surface, although artificial lift (Electric Submersible Pump) performance is normal.

Planning thermochemical stimulation

A) Determination of chemical stimulation

Based on the asphaltenes problem in the well 'X', the chemical used for the thermochemical stimulation in Table 6 below is determined. Table 6, is a chemical determination used for thermochemical stimulation where the resulting temperature must be higher than the melting point of asphaltenes 120ºC-150ºC. So the chemicals used for stimulation are thermochemically consisting of 15% HCl, amine (NH_3) 5%, and esters (125ºC - 175ºC). The Determinate of Easter Specific Head can be followed in Table 7.

B) Enthalpy of thermochemical reaction

The following is the determination of the enthalpy generated from the thermochemical stimulation reaction process with heat generated from the reaction at temperatures of 125ºC and 175ºC.

Enthalpy Final temperature 175ºC

SH = 2.259 J/g ºC

m = 53.5 g (HCl + NH_3)

ΔT = (30ºC – 175ºC)

= -145ºC

$\Delta H = m \times SH \times \Delta T$ …. (3)

$\Delta H_{@175OC}$ = -17520 Joule

Next is the determination of the enthalpy of the thermochemical stimulation reaction with the final temperature produced at 125ºC, obtained :

$\Delta H_{@125OC}$ = -11008 Joule

Based on the enthalpy calculation in the thermochemical stimulation reaction above, the enthalpy produced at the final temperature of 175ºC is $\Delta H_{@175OC}$ = -17520 Joule and the reaction with the final result of 125ºC is$\Delta H_{@125OC}$ = -11008 joule. The negative sign of the enthalpy result is that the reaction produces an exothermic process where heat is generated from the system (thermochemical stimulation reaction) to the environment (boreholes).

Table 5- Static Pressure and Well Temperature 'X' Before Stimulation.

No	Depth	Depth	Pressure	Temperature, ºF	Temperature, ºC
	Meters	Feet	psi		
1	1375	4511	1134.09	185.35	85.160
2	1350	4429	1116.08	184.24	84.570
3	1300	4265	1081.02	181.26	82.900
4	1250	4101	1046	177.7	80.900
5	1200	3937	1011.13	174.03	78.800
6	1150	3773	976.26	171.1	77.200
7	1100	3609	940.77	167.83	75.400
8	1050	3445	905.75	164.51	74.000
9	1000	3281	870.34	161	71.600
10	950	3117	835.18	157.77	69.800
11	900	2953	799.72	154.19	67.880
12	850	2789	764.2	150.52	65.800
13	800	2625	728.6	147	63.800
14	750	2461	692.95	143.9	62.000
15	700	2296.7	657.30	140.60	60.300
16	650	2132.65	621.25	136.75	58.190
17	600	1968.6	585.33	133.40	56.330
18	550	1804.55	549.36	129.79	54.320
19	500	1640.5	513.15	125.79	52.100
20	450	1476.45	476.72	122.00	50.000
21	400	1312.4	440.30	118.55	48.000
22	350	1148.35	404.30	114.34	45.700
23	300	984.3	368.29	110.16	43.400
24	250	820.25	331.60	105.61	40.800
25	200	656.2	294.21	100.77	38.100
26	150	492.15	256.88	95.07	35.000
27	100	328.1	219.50	90.98	32.700
28	50	164.05	182.32	87.54	30.850
29	0	0	148.05	86.55	30.200

Table 6- Chemical Stimulation Based on Temperature.

Chemical Stimulation	Temperature
Xylene	(<40ºC)
Xylene + Toluene	(<60ºC)
HCl	(<100ºC)
HCl+ Xylene	(<100ºC)
Thermochemical (HCL 15%+NH3 5%+Ester)	(125-175ºC)

Table 7- Final temperature Vs Easter- specific heat.

Final Temperature (ºC)	Specific Heat (J/g. K)
25	2,028
75	2,082
125	2,166
175	2,259

Table 8- Determination of chemical concentration percentage.

No	Concentrations (%)		Temperature (ºC)
	HCl	NH_3	
1	5	5	83
2	7	5	85
3	10	5	112
4	10	10	115
5	12.5	10	125
6	15	5	160
7	15	10	160

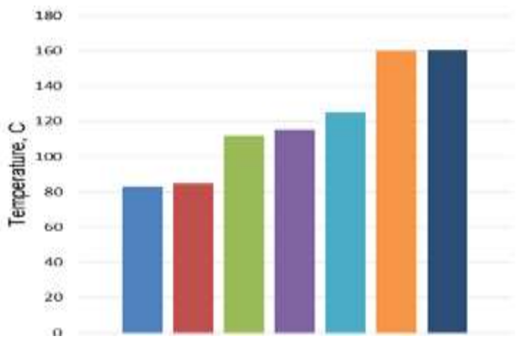

Fig. 5- Determination of optimum chemical concentrations.

C. Determination of chemical concentration

In thermochemical stimulation planning the concentration of the chemical and its solvent is important, so the chemical content and the solvent are in accordance with the concentration needed to produce the temperature needed to dissolve the deposits of oil deposits.

Following are the results of laboratory experiments on the percentage of optimal chemical concentration on thermochemical stimulation shown in Table 8 below.

Based on the results of laboratory experiments in Table 8, optimal concentrations of HCL and NH3 to produce high temperatures are with HCL concentrations of 15% (32% base) and NH3 5% (20% base) so as to produce temperatures of up to 160ºC, with temperatures of 160ºC thermochemical has been able to melt heavy oil deposits asphaltenes problem. The percentage concentration of HCL 15% and NH3 5% is the sensitivity of laboratory experiments, then it is graphically from Table 8, shown in Fig. 5 below. In Fig. 5 above as a determination of chemical concentration used in thermochemical stimulation by reacting 'X' well oil samples with 15% HCl, Amine (NH_3 =35%) is the optimum chemical concentration to produce high temperatures (160ºC) sufficient to dissolve sediment

Asphalts heavy oil problem. The next step is to determine the ratio/percentage volume of HCl and NH_3 to the solvent (water) using the dilution equation as follows.

Base HCl (M_1)= 32%

HCl 15% (M_2)= 15%

V_2 = 2,9 bbl.

$$n_1 = n_2 \tag{4}$$

$$M_1 \times V_1 = M_2 \times V_2 \tag{5}$$

0.32 x V_1 = 0.15 x 2,9 bbl.

V_1 = 1,36 bbl.

$V_2 = V_1$ + V solvent

V solvent = 1,54 bbl.

% solvent = 53%

Based on the calculation of the dilution reaction above, where the base HCl 32% is diluted to 15%, the concentration ratio of HCl to its solvent (water) becomes ratio (47:53). Next is determining the percentage of NH_3 with the following Eqs (4) and (5)

Base NH_3 (M_1) = 20%

NH_3 15% (M_2) = 5%

V_2 = 4,3 bbl.

$n_1 = n_2$

M_1 x V_1 = M_2 x V_2

0.2 x V_1 = 0.05 x 4,3 bbl.

V_1 = 1,075 bbl

$V_2 = V_1$ + V solvent

V solvent = 3,225 bbl.

% solvent = 75%

Table 9 : Chemical concentration laboratory results.

Chemical	Concentration
HCl 15%	152.542 ppm
Amine (NH_3) 5%	47.619 ppm
Surfactant 30%	230.769 ppm

The process of diluting NH_3 with its solvent (water) from base 20% to 5% used in thermochemical stimulation is to be (25:75). Next is the determination of concentration (ppm) obtained in the following Table 9.

Based on Table 8 above, thermochemical stimulation in 'X' wells with chemical flush concentrations with 15% HCl at concentrations of 152,542 ppm. Furthermore amine (NH_3) 5% with a concentration of 47,619 ppm. The results of this laboratory produce a temperature of 160°C where this reaction has dissolved heavy oil deposits in the asphalts problem. Furthermore, chemical pre-flush and post-flush use surfactant 30% at 230,769 ppm.

D. Determination of injection volume

The determination of thermochemical injection volume in the 'X' well is determined by observing the well 'X' profile. The following are the data used to calculate the injection volume:

ID Tubing Production = 2,441 in
OD Tubing = 2.875 in
Depth of Tubing Production = 1380 m
Depth of Tubing-Casing=(1413- 1370) m= 43 m
Depth of Perforation = 1384 – 1388 m
ID Casing = 6,456 in
Ø = 16,5 %

Calculation of the injection volume of the thermochemical tubing segment (VT) in the X'well with the following equation (6) ;

$$VT = \left[(IDt)2 \Big/ (1029.45) \right] \times Dt \times (3.281) \quad (5)$$

$$VT = \frac{(2.441)^2}{1029.45} \times 1380 \times 3.281$$

$$VT = 26.2068 \text{ bbl}$$

The above calculation is a volume calculation for production tubing, then the thermochemical volume calculation for the perforated casing zone (VC) with the following Eq. (7) ;

$$\mathbf{VC} = \left\{ \left[(ID_C)^2 \Big/ (1029.45) \right] \times \text{Depth}_{(C-T)} \right] - \quad (7)$$

$$\left[(ODt)^2 \Big/ (1029.45) \right] \times \text{Depth}_{(dT)} \Big] \Big\} \times (3.281)$$

$$VC = \left(\frac{6.456^2}{1029.45} \times 43\text{m} - \frac{2.875^2}{1029.45} \times 10\text{m} \right) \times 3.281$$

$$VC = 5.7121 \text{ bbl} - 0.2634 \text{ bbl}$$

$$VC = 5.4487 \text{ bbl}$$

The injection volume calculation for 2 ft (VW) around the well uses Eq. (8) below.

$$VW = (\text{Radius Well bore in Perfo.}) - \quad (8)$$

$$(\text{V.Casing in Perfo}) \times Ø$$

For the value of Ø = 0.165, then the value of VW, can be calculated:

$$VW = \left(\frac{30.456^2}{1029.45} \times 43\text{m} \times 3.281 \right) \left(\frac{6.456^2}{1029.45} \times 4\text{m} \times 3.281 \right)$$

x (0.165)

VW = (11,82 bbl – 0,53 bbl) × 0,165 = 1,8628 bbl.

Total volume = VT + VC + VW

Total volume = (26,2068 + 5,4487 + 1,8628) bbl

Total Volume = 33,5183 bbl.

The total volume of thermochemical injected in thermochemical stimulation is the sum of the volumes of the production tubing segment, the casing zone, and the near wellbore zone. The following are the results of the calculation of the thermochemical injection volume shown in Table 10 below.

The above calculation is a determination of the amount of thermochemical volume to be injected into the X well. Furthermore, the volume determined for each type of thermochemical consists of pre-flush, flush, and post-flush.

- Pre-Flush = 10% x Tubing Volume

= 10% ‘X’ 26,2068 bbl.
= 2,62068 bbl.

- Flush

Thermo-A = 40% x (5,4487 + 1,8628) bbl.
= 2,9246 bbl.
Thermo-B = 60% x (5,4487 + 1,8628) bbl.
= 4,3869 bbl.

- Post Flush = Production Tubing Volume

= 26,2068 bbl.

Table 10: Thermochemical Injection Volume Calculation Results.

Segment	ø	ID (in)	Depth (a), m	Depth (b), m	Depth (b-a), m	Volume, bbl.
Tubing		2.441	0	1380	1380	26.2068
Casing		6.456	1370	1413	43	5.4487
Near Wellbore	0.165	24	1384	1388	4	1.8628
Volume Total					33.5183 bbl	

E. Determination of injection rate

Thermochemical injection in well 'X' is pumped with a Triplex pump. The thermochemical injection process is by reacting thermo-A and thermo- B as a high-temperature producer (120ºC-175ºC), for that in the injection process set the pump rate so that thermo-A and thermo-B can react well by minimizing heat loss when pumping so that it can produce optimal heat.

Following are the Triplex Pump specification data and other data used to inject chemicals into X wells.

Stroke Length = 12 in
SPM = 90/min
ID tubing = 2.441 in
η = 80%

Based on these data, it can be determined the amount of injection rate/pump output from the triplex pump using the following equation (9).

$$PO = 3\times\left[(IDt)2\ \times Tcap\right]\times SL\times Lcap\times SPM\times\eta \tag{9}$$

$$PPO = \left(3\times(2.4412\ \times 0.7854)\times 12\right)\times 0.00411\times 90\times 80\%$$

Pump Output = 49.85 gpm = 1.18 bpm

So the magnitude of the chemical injection rate of 1.18 bpm with a pump efficiency of 80%.

F. MASTP (Maximum Allowable Surface Tubing Pressure)

Maximum Allowable Surface Tubing Pressure (MASTP) is the maximum injection pressure that can be received by the tubing. The MASTP determination is determined for each injection segment because the chemical injection density is not the same for each segment.

The following is the determination of MASTP for pre-flush and post-flush segments.

Fluid Density = 7,3 ppg
Mid Perfo = 4547,5 ft
Frac Gradient = 0,7 psi/ft

The determination of MASTP is done by knowing the magnitude of the hydrostatic pressure and the fracture pressure of the formation first, using the following MASTP as equation (10) ;

$$MASTP = (Prf - Ph) \tag{10}$$

Frac.Pressure =0.7psi/ft x 4547.5 ft = 3183.2 psi

Hydrostatic Pressure (Pf) = 0.052x 7.3 ppgx 4547.5 ft = 1726.2 psi.

MASTP = (3183,2 – 1726,2) = 1457 psi

Next is the determination of MASTP in the flush injection segment at fluid density = 7.9 ppg, is :

MASTP = (3183,2 – 1868,1)psi = 1315,1 psi

Based on known MASTP data, it can be determined the amount of pump pressure used, pump pressure must not exceed MASTP.

By knowing the rate of chemical injection, the estimation of chemical injection time into the wellbore can be determined. The following is the result of the chemical injection time calculation in Table 11. Based on the calculation of the estimated time in Table 11 above, the thermochemical injection process into the X well is 31 min or less than 1 hour.

Stimulation operation evaluation

Thermochemical stimulation operations are divided into chemical injection, soaking time or immersion, and running Electric Memory Recorder (EMR) to determine the static pressure and temperature wells thermochemical x subsequent to stimulation.

A. Chemical injection

Chemical injection is the first phase of stimulation thermochemical operations, the number of chemicals that is used by 33.5 bbl consisting of 2.6 bbl segment pre-flush, flush segments 2.9 thermo-A, 4.3 flush thermo-B segment, and 26 bbl segment post-flush. Chemical injection of the stimulation process used a thermochemical Triplex pump for the injection speed is needed to minimize heat loss. The chemical injection process carried out in stages with three

Table 11: Estimated Thermochemical Injection Time.

No	Description		Volume, bbl.	Pumping rate, bpm	Pumping Pressure, psi	Time, min
1	Pre-Flush		2.6206	1.18	1300	2.220
2	Flush	A	2.9246	1.18	1200	2.478
		B	4.3869	1.18	1200	3.717
3	Post Flush		26.206	1.18	1300	22.20
Injection Time Estimation						30.62

segments with sequence injection pre-flush, flush, and post-flush. Pre-flush is injected at the first stage to pave the way for other segments pre-flush is injected at a rate of 1:18 bpm with a pump pressure of 1300 psi. Furthermore, injected segment flush consisting of thermo-A and thermo-B was injected simultaneously with two pump rates of 1:18 bpm with pump pressure 1200 psi of each pump, the last injected segment of post-flush to encourage chemical flush into the zone of the casing and into formation with 1:18 bpm injection rate and pressure of 1300 psi pump.

The estimated time spent in planning thermochemical stimulation to inject the entire chemical into the well is 31minutes. Subsequently, the wells were closed for 12 hours for the period of immersion/soaking time. Thereafter the well produced back as much as 1.5 times the volume of injection to ensure the entire fluid injection/chemical has been removed entirely from the wells in the stimulation.

B. Running Electric Memory Recorder (EMR)

Following stimulation thermochemical wells X was running EMR (Electric Memory Recorder) in wells X 36 h to determine the static pressure and temperature. Here are the results of running EMR (electric memory recorder) wells x subsequent to stimulation shown in Table 12 below.

Based on Table 12 above, in which the results of running the EMR (Electric Memory Recorder) wells thermochemical x subsequent to stimulation, the resulting magnitude of temperature and pressure at the bottom of the well at 122ºC and 1600 psi, while the temperature and pressure wellhead at 50°C and 188 psi. The EMR data, then the magnitude of the temperature at the well head temperature remained above Pour-point oil produced so that the oil can flow to the surface without experiencing a pour point along the production tubing.

RESULTS AND DISCUSSION

Based on the well production problems X with asphaltenes problem, the type of chemical used is a thermochemical consideration resulting in temperature (125ºC-175ºC) and thermochemical containing HCl 15% (32% base), and amine / NH3 5% (20% base). Enthalpy is required to produce a high temperature in the well with a final temperature of H =-11008 Joule at 125ºC, and at the final temperature175ºC of H = -17 520 Joules.

Planning injection thermochemical the well X with a total volume of 33.5 bbl, and the injection is done at a rate of injection 1:18 bpm (80% efficiency) for 31 minutes of injection and pressure pumping segment pre-flush and post-flush of 1300 psi, while pressure pump on a segment flush of 1200 psi. Well X is back into production after stimulation and does thermochemical with Qoi 325 bopd.

Furthermore, based on the data EMR (Electric Memory Recorder) following thermochemical stimulation, the magnitude of the temperature and pressure at the bottom of a well at 122ºC / 252ºF and 1600 psi. While the temperature and pressure at the wellhead at 50ºC / 122ºF and 188 psi, so the magnitude of the wellhead temperature is still higher than in Pour-point (48ºC) oil that is produced, so that, subsequent to stimulation of wells thermochemical X can be returned to production. The stimulation effect on the rate of production and the length of time of production in the ‘X well can be seen in Table 13.

From Table 13, it can be seen that without well stimulation Well X only produced 58 days, with initial production 504 bopd, and then continue to fall to 0 bopd on day 59. By using solvent stimulation (Xylene + Toluene) the first injection was produced for 22 days with peak production of 90 bopd. On the second injection, this Well X only produced 9 days, with peak production at 75 bopd. The stimulation with thermochemical wells can produce for 230 days with peak production at 325 bopd

Table 12 : Static Pressure and Well Temperature Data 'X' After Thermochemical Stimulation.

Measured Depth	Pressure	Temperature	
Meters	psi	ºF	ºC
0	188.021	122.957	50.532
50	200.901	125.717	52.065
100	227.554	127.936	53.298
150	259.556	130.631	54.795
200	301.664	134.706	57.059
250	313.631	138.169	58.983
300	325.312	140.395	60.219
350	367.959	144.024	62.236
400	391.520	147.793	64.330
450	454.624	151.413	66.341
500	517.774	154.624	68.124
550	562.508	157.681	69.823
600	611.642	160.399	71.333
650	633.159	164.488	73.604
700	654.298	169.606	76.448
750	694.289	173.0489	78.360
800	746.392	178.398	81.332
850	777.566	184.3824	84.657
900	808.400	189.6549	87.586
950	830.020	194.8833	90.491
1000	861.510	200.2809	93.489
1050	902.168	206.8359	97.131
1100	972.674	212.5085	100.283
1150	1042.893	219.764	104.313
1200	1113.871	224.6153	107.009
1250	1223.808	229.7225	109.846
1300	1354.088	236.1675	113.426
1350	1523.570	245.8232	118.791
1375	1600.541	252.2602	122.367

Table 13 : Well 'X' Production Rate and History.

Stimulation	Production Rate	Production Time
Non Stimulation	504 bopd	58 days
Xylene + Toluene	90 bopd	22 days
Xylene + Toluene	75 bopd	9 days
Thermochemical Stimulation (HCl 15%+NH3 5%+ Ester)	325 bopd 58 bopd	100days 230 days
Average Production	82.81 bopd	

then decrease slowly production to 58 bopd , or the average daily rate production is 82.81 bopd.

Production result analysis

The wells X with this problem, an analysis of indications of freezing oil deposits in the tubing was carried out, the fluid properties analysis showed that RHP-01 well oil is a type of heavy oil-HPPO (High Pour point oil) with 24.6°API and 48°C pour point. Analysis of hydrocarbon / SARA fractions (saturates, asphaltenes, resins, and aromatics) shows a CII value of 1.02 which is an asphaltenes problem (CII > 0.9). Static temperature data shows that at 400 m from the surface, the tubing temperature is the same as the oil pour point (48°C), so there has been a freeze.

Based on these problems, thermal stimulation is carried out to melt oil deposits in the tubing, an optimal chemical selection is done to melt asphalts (120°C-150°C). To produce high temperatures, the chemicals used are HCl 15% (from 32% base acid) and NH3 / amine 5% (20% base) with the resulting temperature of 160°C and produced ester / NH_4Cl as a thinner. The HCl concentration used is 43:57 with the solvent (water), while the ratio of NH3 concentration with the solvent (water) is the ratio (25:75)

Thermochemical stimulation in wells X is done by injecting chemicals which are divided into 3 parts, first is the pre-flush injection of 2.6 bbl surfactant 30% to open oil deposits in tubing, then injected thermo-A flush as HCl 15% 2.9 bbl and flush thermo-B NH3 5%, 4.3 bbl. Furthermore, post-flush surfactant 30% 26 bbl injection was to push oil deposits in the melting tubing into the wellbore. The injection rate is 1.18 bpm with a pump pressure of 1200 psi for flush, and 1300 psi for pre-flush and post-flush. After injection, the X well is closed/soaked for 12 hours to produce an optimum reaction. The well was again produced 1.5 times the volume of injection to ensure all chemicals were produced and a well test and running EMR (Electric Memory Recorder) were performed to determine the static pressure and temperature after stimulation.

Stimulation thermochemical on wells ray done on 19 July 2018, and began to be produced on July 22, 2018 with a magnitude of Qoi production of 325 bopd. Until the final data obtained ie on October 31, 2018, Well x is still producing at 58 bopd, then made forecasting/forecasting production method based on the decline curve with the gradient of temperature decreases wellhead at 0.011°C/days. The. average daily rate production is 82.81 bopd for 230 days of production.

Economies analysis investment

The following is a calculation using the production forecast decline curve method. Determining the type of curve used by the calculation annexed to the Attachment. Below are the results of the type used in the determination of tortoise forecast production at well X.

Tipe Kurva = harmonics

b = 1

qi = 61,91 bopd

dT= 20 days (Oct, 11 – 31, 2018)

Determination dT (decline Temperature) is a period of decline curve analysis used to forecast production on well X Fields HERA. Furthermore, the determination of the value decline rate per day (DI) using the following equation.

$$Di = \frac{\left(\frac{qi}{q1}\right) - 1}{dT} \quad (11)$$

$$Di = \frac{\left(\frac{61.91}{58.47}\right) - 1}{20}$$

Di= 0.002941 / days

Decline rate (Di) in the well of X by 0.002941 / day using harmonic curve type (b = 1). Here is the well production data X, subsequent to stimulation thermochemical and forecast production and the amount of temperature decrease wellhead displayed graphically in Fig. 8 below.

In Fig.8, a forecast of production wells thermochemical, subsequent to stimulation, the well began production back on July 22, 2018 with a production of 325 bopd, further production wells continue to decline due to the effect of the heat generated from the stimulation began to decrease. Until the last production data obtained ie October 31, 2018, Well x still producing at a rate of 58 bopd of oil production. Furthermore, in the forecasting of the production wells X, the parameter next is the gradient drop in temperature wellhead at 0,011°C/day, and during the 230 days of production, namely the March 9, 2019 wells X back shut in due to temperature wellheads having to be the same as the pour point of oil produced (48°C).

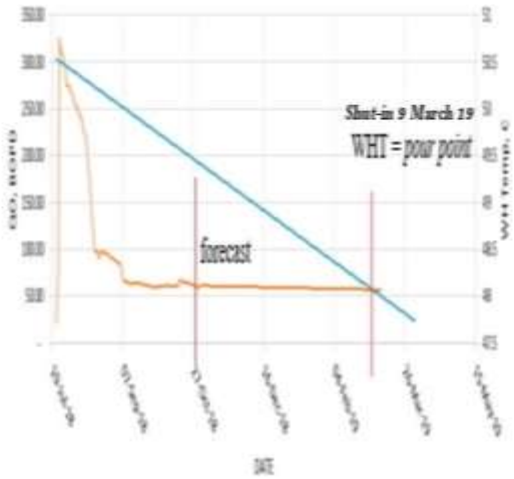

Fig. 8: Forecast Oil Production Well 'X' After Stimulation.

Following an economic determination of stimulation X Well thermochemical with oil price data as follows.

Oil Price = USD 60/BBL

Lifetime = 230 days

(22 July 2018 – 9 March 2019)

The calculated value of cumulative production

(Np-i) = 19047.87 bbl.

If the cumulative total production of X Wells after thermochemical stimulation is 19047.87 barrels, for 230 days, then the average daily production rate is 82.81 bopd. The following economic calculations are revenue or the Gross Revenue (GR) on Well X in the stimulation thermochemical wells using the following :

GR = (82,81 bopd x 320 days x 60 (USD/bbl)

Gross Revenue = 1142872 USD

Gross income or revenue from the success of well stimulation thermochemical on X amount of USD 1,142,872 for 230 days (July 22, 2018 - March 9, 2019). Thermochemical stimulation requires no small cost, the cost of chemical and equipment rental costs are the most expensive cost of this thermochemical injection operation and coupled with the cost of personnel and specialized in the field of chemical used in this stimulation.

Based on the result economical analysis investment (Table 14) above, in which the size of the investment required for the stimulation of thermochemical with the cost of USD 195061. Having in mind the amount of investment made then the next can be determined the amount of profit/profit from thermochemical stimulation is determined using the following equation.

Profit =(1142872-195061) USD

Profit = 497811 USD

The amount of net profit /profit the thermochemical stimulation operations on wells X obtained at USD 947811 for 230 days from the wells back into production (July 22, 2018 - March 9, 2019), the greater the revenue or gross income, the greater the profit obtained

Here is a budget of stimulation thermochemical on wells X displayed in Table 14 below. Furthermore, the determination of the pay out time (POT) of investments made in thermochemical stimulation on the well X. Here is the determination pay out time (POT) on the stimulation of wells thermochemical X by using the following :

POT = (195.061 (USD) / 82.81 (BOPD)) /60 (USD/BBL)

POT = 39 days

So that pay out time (POT) investments in thermochemical stimulation for 39 days after Well x back into production after stimulation does thermochemical, on August 30, 2018.

The amount of revenue / gross income from the investment of this thermochemical stimulation during the 230 days is USD 1,142,872 with the amount of investment issued USD 195,061 for the cost of chemical, personnel, and equipment support, so the magnitude profit obtained is of USD 947 811. Here is the result of the calculation economics of thermochemical stimulation wells X displayed in Table 15 below. Based on Table 15 above, with average oil production of 82.81 bopd during the exothermic stimulation at 230 days, resulting in revenues amounting to USD 1,142,872 at an investment cost of USD 195 601, making a profit of USD 947 811 from the stimulation thermochemical.

And future investment returns or Pay Out Time (POT) for 39 days from the wells X back into production after stimulation of wells in thermochemical.

Stimulation thermochemical on wells ray done on 19 July 2018, and began to be produced on July 22, 2018 with a magnitude of Qoi production of 325 bopd. Until the final data obtained ie on October 31, 2018, Well x are still producing at 58 bopd, then made forecasting/forecasting production method based on the decline curve with the gradient of temperature decrease wellhead at 0,01° C / day. Total infestation 195061 USD, POT 39 days, and Net profile as 947811 USD is a very profitable project.

Table 14 : Cost of thermochemical stimulation.

No	Chemical		Total IDR
1	Pre-Flush		Rp66.553.200
2	Flush	Thermo-A	Rp129.874.500
3		Thermo-B	Rp213.518.200
4	Post Flush		Rp665.053.200
Sub Total			Rp1.074.999.100
No	Personal		Total IDR
5	Project Coordinator		Rp133.000.000
6	Chemical Field Specialist		Rp159.600.000
7	Field Technician		Rp139.650.000
Sub Total			Rp432.250.000
No	Equipment		Total IDR
8	Triplex' Pump		Rp931.000.000
9	Chemical Pump		Rp146.300.000
10	Generator set		Rp146.300.000
Sub Total			Rp1.223.600.000
Total IDR (Chemical + Personal + Equipment)			Rp2.730.849.100
Total USD			$195.061

Table 15: Calculation of POT (Pay Out Time), Revenue, and Thermochemical Stimulation Profit.

Qo, BOPD	Revenue, USD	Infestation, USD	Profit, USD	POT, days
82,81	1.142.872	195.601	947.811	39

CONCLUSIONS

Thermochemical stimulation carried out at well 'X' to overcome the asphaltenes problem is a reaction of 15% HCl with 5% amine (NH_3), by producing an ester product (NH_4Cl) and the resulting temperature of 160ºC. Well performed at a rate of 1.18 bpm in the pre-flush segment of 2.6 bbl with a pump pressure of 1300 psi, and flush segment with a pump pressure of 1200 psi at 7.2 bbl, and injection of 26 bbl post-flush with a pump pressure of 1300 psi. Well stimulation, as succeeded, raise the temperature of the well-produced to 147ºC, and can turn on the 'X' well that previously died with Qoi 325 bopd and the effect of exothermic reaction for 230 days, with an average oil production of 82.81 bopd with temperature well head 50ºC / 122ºF. Pay Out Time (POT) from cost analysis on thermochemical well stimulation project, within 39 days by generating 230 days production of revenue of USD 1,142,872, investment of USD 195,601, and profit of USD 947,811.

Nomenclature

CII	Colloidal Instability Index
POT	Pay Out Time
bopd	Barrel Oil per Day
DI	Decline rate per day
SARA	Saturates, Asphaltenes, Resins, and Aromatic
SG	Specific Gravity
EMR	Electric Memory Recorder
MASTP	Max.Allowable Surface Tubing Pressure
OD	Outset Diameter
ID	Inset Diameter
sat	Saturated
asp	Asphaltenes
res	Resins

aro	Aromatic
Ph	Hydrostatic Pressure
Pf	Fracture Pressure
USD	US Dollar
VT	Tubing Vole
VC	Casing Volume
VW	Wellbore Volume

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