Full-Length Research Paper

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Full-Length Research Paper showing the performance of the Petro Corrosion Control System formally known as the “Silver Hawg” on horizontal well 59 T for Shell Nigeria.

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Full Length Research Paper

A proactive approach for predicting and preventing wax deposition in production tubing strings: A Niger Delta experience

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A proactive approach for managing wax deposition problems during production operation is presented. A predictive thermodynamic model is employed to determine the onset condition(s) for wax precipitation in hydrocarbon mixtures. The parameters of a continuous distribution function are used to establish the nature of hydrocarbon mixtures while a fluid temperature distribution model enables the determination of the potential wax precipitating point in the production tubing. A field case study was conducted on 17 reservoirs in a field located in (Niger Delta, Nigeria). Results show that the thermodynamic model predicted Wax Appearance Temperature (WAT) decreases with reservoir depth. The WAT ranged between 21 and 46°C from the deepest (8,000 ft) to the shallowest (5,000 ft) reservoir. Field observation shows that wax formation is effectively prevented when the Wax-Inhibiting-Tool (WIT) is installed 100 - 500 ft below the tubing depth corresponding to the predicted WAT. Proper placement of the WIT has substantially reduced wax precipitation and potential problems that might have occurred due to wax deposition.

Key words: Thermodynamic model, wax appearance temperature, fluid temperature distribution, wax inhibiting tool, gamma distribution parameters.

INTRODUCTION

The identification, diagnosis, and alleviation of the problems caused by heavy organic compounds deposition are as old as the oil industry. The combined mass of major petroleum deposits are generally referred to as wax (Leontaritis, 2007) and past efforts by operators were limited to reactive or curative measures rather than preventive approaches to solving depositional problems. However, proper identification and characterization as well as accurate description of the behaviour of various deposits are essential for appropriate field development planning and design of effective mitigation strategies.

Current research efforts are geared towards developing strategies to predict, prevent and/or mitigate the formation of heavy organic compounds during petroleum production and processing (Baker, 2003; Weispfennig, 2006; Dalirsefat and Feyzi, 2007). The most effective proactive approach to forestall heavy organics' precipitation or flocculation is to develop efficient predictive tools or mathematical models that can predict the onset conditions for organic deposition. It is equally important to devise a means of establishing the location of the precipitation point or nucleation sites within the production and processing system using an appropriate fluid temperature distribution model (Sagar et al, 1991; Hassan and Kabir, 1994).

Studies (Erickson et al., 1993; Hammami and Raines, 1999) have shown that the wax appearance temperature (WAT) measured by cross polar microscopy (CPM) compare favourably with field measured temperatures at which wax deposition starts in the corresponding well. Similarly therefore, a good thermodynamic model's WAT prediction should agree fairly well with the field observations.

FIELD CASE STUDY

A major oil producing company in Nigeria's Niger Delta (ND) was faced with the challenges of managing wax

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Figure 1. Wax inhibiting tool (WIT).

Table 1. ND field waxy strings.

Reservoir	Well(S)
D1.000X	Well 32S Well 5S Well 33S – Wax problems in flow-line
D2.000X	Well 12S Well 23L Well 25L Well 33L Well 37L Well 4T Well 51L Well 5L Well 28L – Closed in due to wax problem
D3.000C	Well 59T – Monthly pigging
D3.000X	Well 12L
D6.000N	Well 30S

deposition problems in its operations. A WIT (Figure 1) was designed to prevent or reduce wax deposition inside the production tubing or along the flow line. The equipment was tested in some wax-prone wells but with mixed success. It was subsequently discovered that the tool works better if installed very close to the wax nucleation point. Therefore, there was a need for an approach, which could predict the wax precipitation point in the production tubing, and a clear definition of the WIT depth of installation.

Challenges in ND field

ND field has a history of wax deposition problems. Fifteen wells producing from D1.000X, D2.000X, D3.000C, D3.000X, and D6.000N reservoir sands were identified as waxy wells but the wax problem is most severe in Wells 33S, 28L and 59T (Table 1). Well 28L was closed in due to wax problem, while Well 59T undergoes monthly pigging also as a result of wax deposition. In 2007, 1500BOPD was deferred due to wells closed in as a result of wax problems.

A number of reactive measures have been adopted in the past to resolve the problems caused by wax deposition in ND field. Some of these methods included pigging, solvent soaking, and wax cutting. These techniques had yielded little positive results as their application was characterized by sudden increase in production with subsequent gradual production loss. This called for a more effective mitigation strategy.

Figure 2 shows the high frequency of well interventions occasioned by wax cutting exercises followed by increase in production and subsequent gradual rate decline for a well in a different AG field. The periodic wax cutting operations was maintained throughout 1997 -1999 but could not be sustained from 2000 due to increase in host community hostilities. The WIT was arbitrarily installed (at any convenient point) after wax cutting and tubing wash in December 2003 while production had averaged 600 BOPD. Although, the well has been producing consistently with little decline, production could have been significantly improved if the WAT and the corresponding nucleation point had been predicted before setting the WIT at the most appropriate point. This is because the WIT performs more efficiently when set close to the predicted wax nucleation point.

In this work, we present an approach based on the application of three-phase thermodynamic model (Won, 1985; Sulaimon, 2009) and fluid temperature model (Sagar et al, 1991; Hassan and Kabir, 1994; Sulaimon, 2009) to respectively predict the WAT and generate fluid temperature profiles inside the production tubing string. The objective is to locate potential wax nucleation points inside the tubing, where a WIT can be installed to prevent wax formation.

Thermodynamic model

When vapour, liquid and solid phases coexist at equilibrium, the following thermodynamic equilibrium

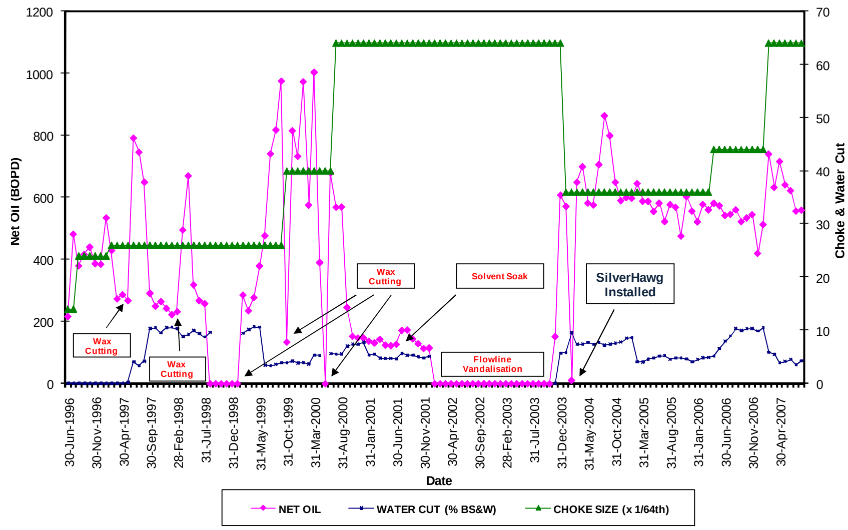

Figure 2. Typical intervention for well 39L in AG field.

condition must be satisfied:

$$f_i^V = f_i^L \tag{1}$$

$$f_n^V = f_n^L = f_n^S \tag{2}$$

Where

f_i = fugacity of component i
n = number of components in the mixture
V, L, S = Vapour, Liquid, Solid phases

A detailed description of the three phase thermodynamic model has been presented (Won, 1985; Sulaimon, 2009). However, Sulaimon (2009) has recently developed a new set of thermodynamic properties' correlations that afford better comprehensive estimation of the solid-liquid equilibrium constant. The thermodynamic model has been validated (Sulaimon, 2009) with experimental data from 32 major oil fields with an average absolute deviation (AAD) of 0.75%. This makes it a reliable tool for predicting the onset of wax precipitation in the Niger Delta.

Fluid temperature distribution model

Fluid and wellbore temperature profiles for a naturally flowing or gas lifted well are determined by modifying the Temperature Distribution Model (TDM) developed by Sagar et al. (1991). The Ramey's time function (Ramey, 1962) used in the model was replaced by the algebraic approximation developed by Hassan and Kabir (1994) which offers better dimensionless time solution.

MODEL APPLICATION PROCEDURES

A computer package which combines both the thermodynamic model and temperature distribution model (TDM) was used to predict the onset conditions and generate temperature profiles inside the wellbore respectively. The following are the steps involve in running the computer program:

1. Feed in the input parameters (hydrocarbon components' mole fractions and molecular weights) for the three-phase thermodynamic model.
2. The temperature value that corresponds to the least amount of 'precipitated wax (%)' is the cloud point or Wax Appearance Temperature (WAT).
3. Initialize the Temperature Distribution Model (TDM) subroutine using production and well parameters.
4. Generate earth (formation) temperatures and fluid's temperatures at different depth at specified regular intervals.
5. Create the temperature distribution profiles by plotting 'Depth (ft)' against 'Temperature (°F)'; trace the WAT from the horizontal axis to the fluid temperature profile and find the corresponding precipitation depth on the vertical axis.
6. From the well status diagram, establish the nearest possible point that is closest to the estimated precipitation depth for hanging the WIT.

Data gathering

To facilitate a comprehensive study and analysis of the problem of wax deposition potential in ND field, it is imperative to uniformly select representative candidate wells (identified waxy and non-waxy wells) from every reservoir in the field. This would afford a means of generating a broad database from the field and laboratory investigations of sampled wells. It is assumed that the initial fluid composition is the same at every drainage points (wells) within a given reservoir.

Originally, a well was selected from each of the 28 hydrocarbon-bearing blocks found in 21 reservoir sands. Table 2 shows the reservoir sands, blocks and all wells in the field from which the 29 candidates were chosen. The compositional data obtained from 17 wells (in bold letters) producing from different blocks were used as input data for the thermodynamic model.

Crude oil samples were collected from the 17 of the 29 selected candidate wells and analysed. The results of the laboratory analyses are shown in Table 3. Pour point is an important parameter in flow assurance studies and can provide an indication for partial or total plugging of flowlines. Therefore, due to their relatively high pour point values, the most susceptible wells to wax deposition problems are those producing from D4.000X, D8.000N and E2.000X reservoir sands. The observed variations in the measured pour points (Table 3) for wells producing from the same reservoir (D1.000X, D2.000X and D3.000X) are due to changes in fluid compositions and differences in well depth, bottom-hole temperatures and pressures.

DISCUSSION OF RESULTS

WAT predictions for ND oils

The validated thermodynamic model (Sulaimon, 2009) was deployed to study the wax deposition tendencies of wells in the ND field. Table 4 shows the WAT predictions for the 17 well fluids' samples collected from different reservoirs. The depths at the Oil-Water-contact (OWC) or Oil-Down-To (ODT) were used as the reference point.

Study results have revealed that wells producing from D8.000A, D9.000A, E2.000A, F2.700N, F4.100 and F4.200 reservoir sands are less likely to have wax deposition problems. This is because there were no wax precipitations at all temperatures and pressures after several computer runs. Nevertheless, similar computer runs performed using other reservoirs' fluids' analytical data (D2.000N, D2.000X, D4.000X, D3.000X, D3.000C, D4.000P, D6.000N, D6.000A, D9.000N, E3.800A, and E5.000A) show that they are all prone to wax deposition but at different WATs.

Fluid temperature distributions

To determine the point or depth where precipitation would start in the production tubing strings, the fluid temperature model was run for the 11 reservoirs' fluids identified to have high potential for wax deposition in the ND field. Analysis of the temperature profiles revealed that wax precipitation could occur in five conduits (Table 5). These include Well 6S (D2.000X), Well 19L (D4.000X), Well 25S (D2.000N), Well 57S (D4.000P), and Well 59T (D3.000C). The remaining six wax prone wells: Well 19L (D3.000X), Well 30S (D6.000N), Well 6L (D6.000A), Well 20L (D9.000N), Well 53L (E3.800A) and Well 45L (E5.000A), would most likely experience wax deposition in the surface equipment as also shown in Table 5.

Wax deposition tendency

D2.000N reservoir fluid

The D2.000N reservoir sand is the shallowest of all the reservoirs under study and Well 25S with completion interval within 5,814 - 5,823 ft (1,772.1 - 1,774.9 m) was used for analysis. Modelling results showed that wax precipitation would occur when the fluid's temperature drops below the predicted WAT of 107.6°F (42°C). This corresponds to a tubing depth of 1,490 ft (454.2 m) as illustrated on the temperature distribution profile for Well 25S (Figure 3). Thus, it suffices to install the wax-inhibiting tool (WIT) below this depth to prevent precipitation inside the production tubing. Therefore, a tubing depth of 2,000 ft (609.6 m) would be appropriate.

D2.000X reservoir fluid

The D2.000X reservoir is characterized by complex geologic features and has the highest concentration of wells (44 wells) in ND field. The fluid's compositional data for Well 6S was used as input data for the model runs. The well was completed with perforations through 7" casing with interval 5,906.6 - 5,912.5 ft (1,800.8 - 1,802.6 m) open to production.

Model predictions have indicated that the WAT is 111.2°F (44°C) and this corresponds to a tubing depth of 2,000 ft (609.6 m) as highlighted on the temperature profiles in production tubing (Figure 4). A placement depth of 2,500 ft (762.0 m) is recommended on the temperature profile.

It was observed that well 6S has been closed-in since April 1, 1999, due to wax problems as depicted by the sudden increase in the tubing head pressure from 280 - 450 psi with subsequent decline in oil production from 4,988 - 203 bbls (Figure 5). Therefore, it is necessary to identify the corresponding wax precipitation depths in all producing wells in D2.000X reservoir to ascertain probable wax nucleation points using the predicted WAT as a benchmark. Thereafter, the well status diagrams can be used to locate the most practicable depth for the WIT installation.

Table 2. Selection of candidate wells.

S/N	Reservoir	Block	All wells	Selected wells
1	D1.000	X	5S, 10S, 20S, 21S, 23S, 25S, 28S, 29S, 32S, 33S, 37S, 43T, 51S, 55S	25S
		N	25S	
2	D2.000	X	1L, 1T, 3L, 4T, 5L, 5S, 6S, 9S, 10L, 11T, 12S, 16T, 18S, 19S, 21C, 21L, 22S, 23L, 23S, 24S, 25L, 26S, 28L, 29L, 30L, 32L, 33L, 37L, 39C, 39T, 40T, 43T, 48S, 49L, 50L, 51L, 54T, 55L, 58T, 60T, 61T, 63T, 64L, 64S	6S
		C	59T	59T
3	D3.000	X	5L, 12L, 13C, 13S, 19L(1), 21T, 22L, 23L, 25L, 26L, 48L, 65S, 66T	19L
		P	57S	57S
4	D4.000	X	19L(2), 31C, 36S, 38S	19L(2)
		N	20S	20S
5	D5.000X	X	13T, 20L, 26L, 36L, 38L, 57S	57S
		A	2C, 6L, 7C, 8S, 9L, 10L, 12L, 13L, 36L, 45S	6L
6	D6.000	N	30S	30S
		P	57L	57L
7	D7.000	A	14S	14S
		N	24L	24L
8	D8.000	A	7S, 56S	7S
		N	30L	30L
9	D9.000	A	7L, 53S	7L
		N	20L, 44S	20L
11	E2.000	A	53L	53L
		X	18L, 20L, 24L, 34S, 65L	65L
12	E3.000	A	18L, 56L	56L
13	E3.800	A	31S	31S
14	E4.000	A	31L	31L
15	E5.000	A	45L	45L
16	E6.000	N	30S, 34L	30S
17	E9.400	N	14L	14L(1)
18	F2.000	N	31L	31L
19	F2.700	N	14L, 31L	14L(2)
20	F4.100	N	47S	47S
21	F4.200	N	47L	47L

Table 3. Laboratory results.

Sand	Well	TAN (MgKOH/g)	Dry S.G @ 15/15°C	API gravity	Kinematic viscosity @ 40°C	Pour point	
						°C	°F
D1.000 X	5S	0.4	0.9182	22.6	24.7	-7	19.4
	1T	0.3	0.9224	21.9	27.3	-3.9	24.98
	4T	0.6	0.9248	21.5	28.9	-1.1	30.02
D2.000 X	12S	0.3	0.9564	16.5	26.1	-7	19.4
	18S	0.5	0.9463	18	26.2	-7	19.4
	43T	0.3	0.9216	22	22.6	-1.1	30.02

Table 3. Contd.

D3.000 X	12L	0.3	0.8904	27.4	7.7	-1.1	30.02
	22L	0.2	0.9058	24.7	13.4	-7	19.4
D3.000 C	59T	0.2	0.8834	28.7	10.5	1.7	35.06
D4.000 X	36S	0.2	0.8696	31.2	22.3	4.4	39.92
D8.000 N	30L	0.3	0.8571	33.6	4.3	4.4	39.92
E2.000 X	65L	0.1	0.8267	39.7	2.8	4.4	39.92
E3.000 A	56L	0.1	0.8329	38.4	3.2	-1.1	30.02
E3.800 A	31S	0.1	0.827	39.6	3.2	1.7	35.06

Table 4. ND field WAT predictions.

S/N	Well	Sand	OWC/ODT (ft-ss)	Predicted WAT	
				(°F)	(°C)
1	25S	D2.000N	5814	107.6	42.0
2	06S	D2.000X	5900	111.2	44.0
3	19L2	D4.000X	6185	114.8	46.0
4	19L1	D3.000X	6190	91.4	33.0
5	59T	D3.000C	6254	114.8	46.0
6	57S	D4.000P	6420	98.6	37.0
7	30S	D6.000N	6457	102.2	39.0
8	06L	D6.000A	6560	89.6	32.0
9	07S	D8.000A	6720	No wax	No wax
10	20L	D9.000N	6723	100.4	38.0
11	07L	D9.000A	6780	No wax	No wax
12	53L	E2.000A	7132	No wax	No wax
13	31S	E3.800A	7657	69.8	21.0
14	45L	E5.000A	8073	80.6	27.0
15	31L	F2.700N	9619	No wax	No wax
16	47S	F4.100N	9811	No wax	No wax
17	47L	F4.200N	9851	No wax	No wax

Table 5. Characterization of hydrocarbon mixtures in ND field.

S/N	Sand	Well no.	API gravity	Gamma distribution parameters			Fluid type
				Alpha (α)	Beta (β)	Variance (η)	
1	D6.0A	6L	36.4	1.0061	103.97	10,874.80	Light oil/Condensate
2	D2.0X	6S	24.2	1.0028	207.43	43,144.53	Asphaltenic oil
3	D9.0A	7L	43.4	1.0268	28.42	829.14	Gas
4	D8.0A	7S	41.3	1.0143	29.83	902.37	Gas

Table 5. Contd.

5	D3.0X	19L1	24.7	1.0034	127.37	16,277.56	Waxy oil
6	D4.0X	19L2	34.2	1.0038	110.38	12,229.88	Light oil/Condensate
7	D9.0N	20L	41.6	1.0022	91.00	8,299.29	Waxy condensate
8	D2.0N	25S	24.9	1.0021	93.40	8,742.37	Waxy condensate
9	D6.0N	30S	36.4	1.0131	117.03	13,875.32	Waxy condensate
10	F2.7N	31L	40.3	1.0441	95.20	9,462.57	Light oil/Condensate
11	E3.8A	31S	39.6	1.0488	91.91	8,859.50	Waxy condensate

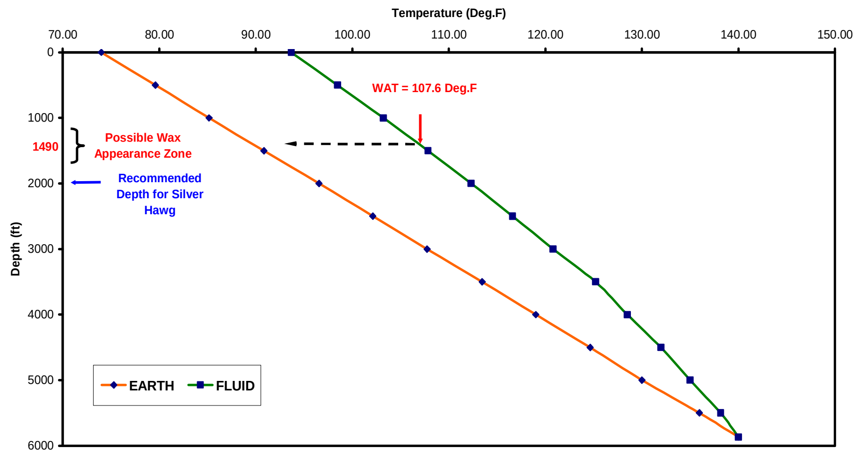

Figure 3. Temperature distribution profiles in production tubing for well 25S.

D3.000X reservoir fluid

There are a total number of 13 wells producing from D3.000X sand horizon but the analytical data for Well 19L1 were used as input data for analysis. The well was completed with 7" casing at 6,813 ft (2,076.6 m) b.d.f (below derrick floor) and interval 6,182 - 6,188 ft (1,884.3 - 1,886.1 m) open to production.

The predicted wax appearance temperature for this fluid is 91.4°F (33°C). This value does not correspond to any fluid temperature in the production tubing as shown in Figure 6. Thus, wax formation is unlikely inside the production tubing but precipitation may occur in the surface equipment (flowlines, separators, or storage tanks) when the fluid temperature drops below 91.4°F. Field observation has corroborated model prediction as no wax deposit has been found inside the tubing or surface flowline.

D3.000C reservoir fluid

The horizontal Well 59T is the only drainage well producing from D3.000C reservoir sand. The original reservoir static pressure was 2,675 psi while the initial bottom-hole temperature was 142°F. The well was completed in 1998 with 7" predrilled liner and 4½" tubing. Model predictions indicated that wax precipitation would start when the fluid temperature decreases from the initial bottom-hole temperature of 142°F to the predicted WAT, 114.8°F (46°C). This corresponds to a tubing depth of 835 ft (254.5 m) as illustrated on the temperature distributions plot (Figure 7). Allowing for a clearance or a depth interval of 500 ft (152.4 m), it suffices to install the wax-inhibiting tool at 1,300 ft (396.2 m). However, the closest profile for hanging the tool is the Baker sliding sleeve located at 6,008 ft (1,831.2 m). Therefore, it is recommended that the tool be set at this depth.

In 2002, the steel flowline was replaced with 'glass reinforced epoxy (GRE)' pipe to prevent wax formation in the pipeline and the WIT was installed inside the tubing at a depth of 6,008 ft (1,831.2 m). Production increased from 570 bbls/d in February 2002 to 3,155 bbls/d after the installation (Figure 8). A well entry with wireline in May 2003 indicated that the tubing was mostly wax-free but a3.74" gauge cutter had some wax cutting up to 700 ft (213.4 m). This is in line with the model prediction of 835 ft (254.5 m), which represents the depth at which the first wax crystal appears or separates from the crude. The

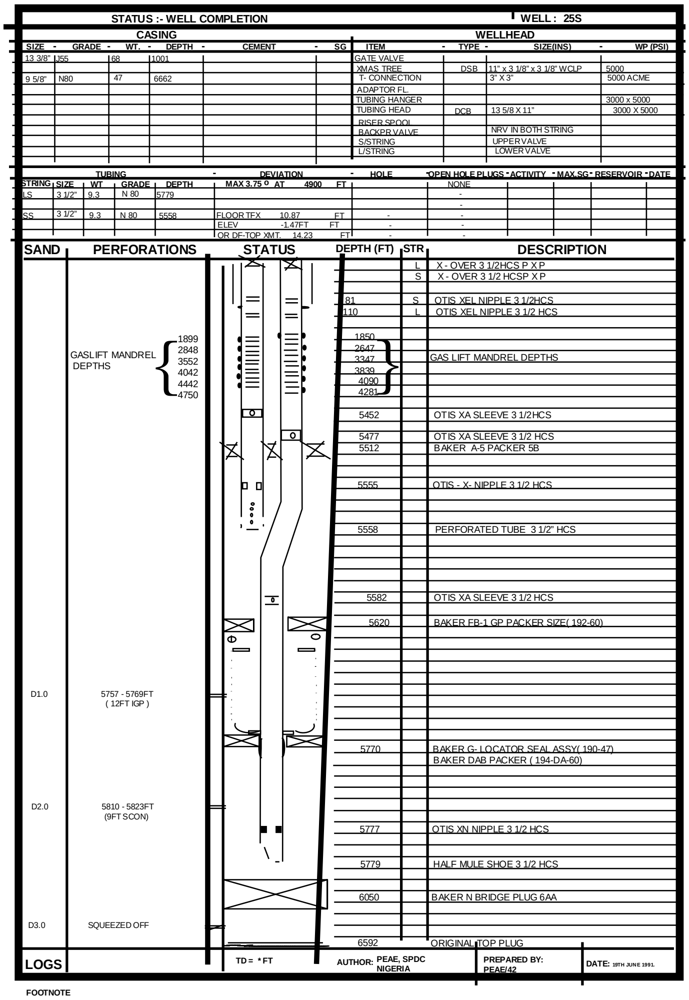

Figure 4. Completion diagram for well 25S.

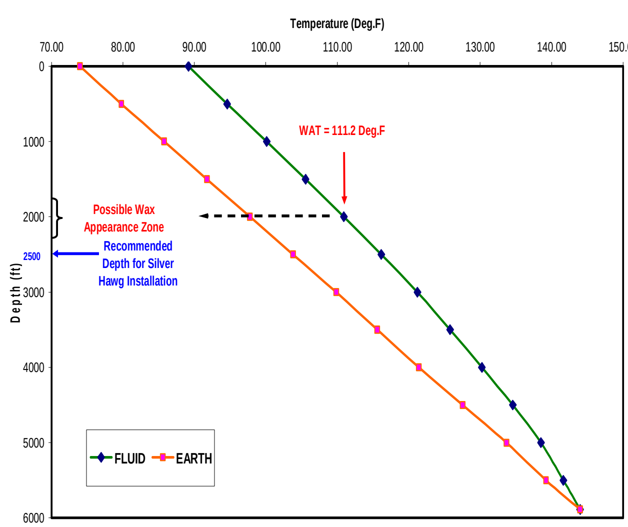

Figure 5. Temperature distribution profiles in production tubing for well 6S.

well was closed-in between August 2003 and October 2004 due to community problems.

Wax-free reservoir fluids

Model results have shown that some reservoir fluids in ND field are wax-free. The reservoirs containing wax-free crude oils are: D8.000A, D9.000A, E2.000A, F2.700N, F4.100N and F4.200N. Several model runs did not give any indication of possible wax formation at any pressure and temperature conditions. Field observation has shown that none of these reservoir fluids contain wax.

WAT variation with depth

Investigations have shown that shallow reservoir oils exhibit relatively higher WAT values than deeper reservoir fluids and thus, may experience more precipitations. This may be attributed to heat loss to the formation, loss of volatile components, or bacteria action (biodegradation). Although there is no direct relationship between 'Depth' and 'WAT', the trendline indicates that the WAT decreases with depth (Figure 9).

Conclusion

A proactive approach for dealing with wax deposition problems during petroleum production and processing operations is presented. The technique is based on the development of a robust computer algorithm based on the basic thermodynamic concepts to predict the onset conditions for wax precipitation, and application of a modified fluid temperature model to determine potential wax formation region within the production system.

The combined thermodynamic and fluid temperature distribution models can be used to reliably predict and locate potential wax precipitation point inside the production tubing. When appropriately installed within the predicted wax precipitation depth, the WIT can effectively prevent wax deposition. The ND field consists of more light/volatile oil and condensate reservoirs than black or heavy oil reservoirs. Moreover, the tendency of a reservoir fluid to precipitate wax decreases with depth.

RECOMMENDATIONS

Analysis to determine paraffin and asphaltene constituents in crude oil should be conducted during the early development of a reservoir in order to predict deposition problems and to develop methods of minimizing deposition. The WAT should be experimentally determined to validate and if necessary, fine-tune the thermodynamic model. The fluids from the wells producing from the identified waxy reservoir fluids should be monitored for

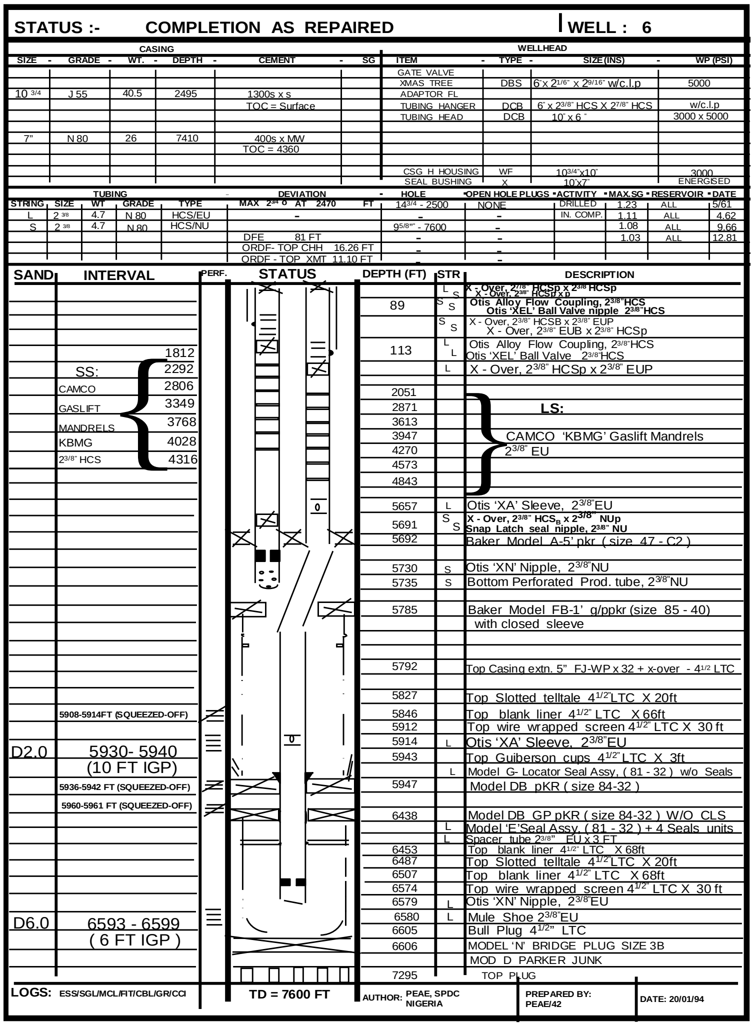

Figure 6. Completion diagram for well 6S.

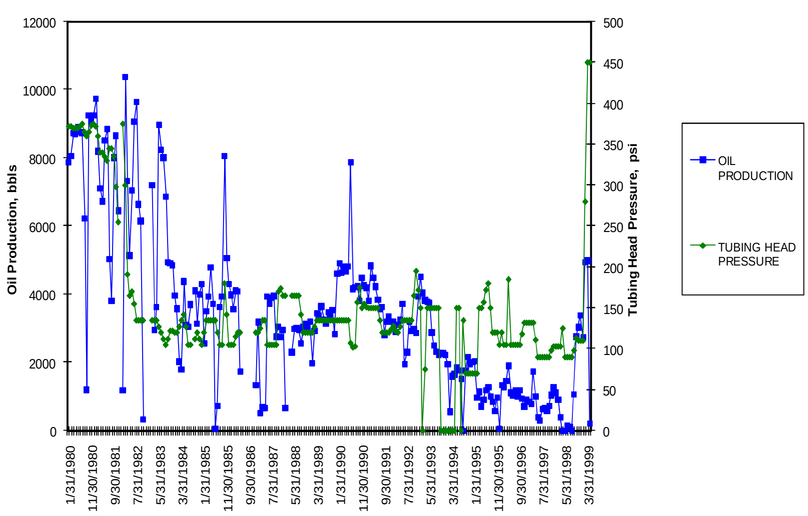

Figure 7. Monthly production and pressure profiles for well 6S.

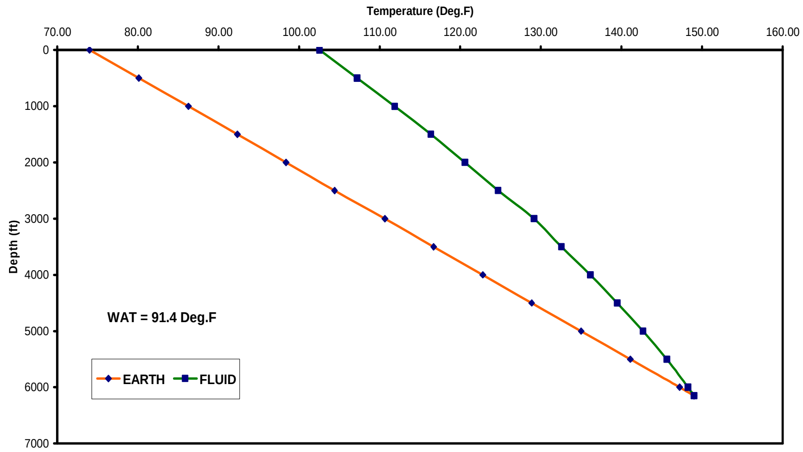

Figure 8. Temperature distribution profiles in production tubing for well 19L1.

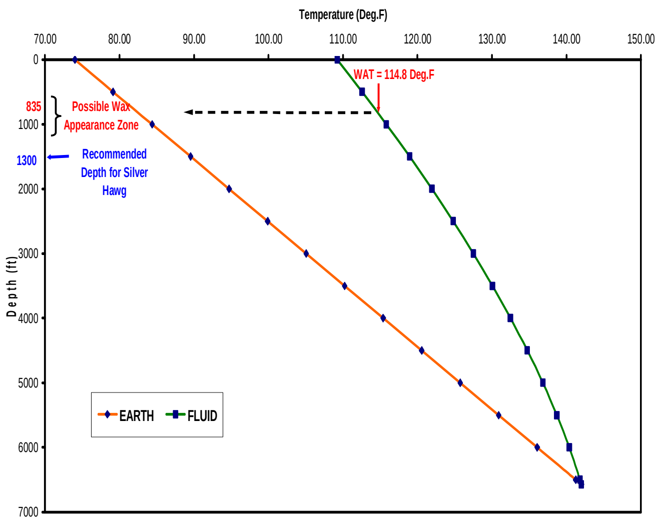

Figure 9. Temperature distribution profiles in production tubing for well 59T (D3.000C sand).

the following indicators of an imminent wax deposition:

1. Change in crude appearance.
2. Accumulation of paraffin in stock tanks.
3. Paraffin build-up in surface flowline and tubing.
4. Production loss.
5. Gradual increase in tubing or wellhead pressure.
6. Sharp increase in the Gas-Oil-Ratio (GOR).

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APPENDIX

Principle of operation of a WIT

Silver-Hawg is an alloy comprised of dissimilar metals. Its operation is based on scientific knowledge that physical characteristic of a flowing liquid changes or is modified by contact with a particular alloy (Figure 1). During oil production, crude oil is sucked up through the open lower end of the tool's inner tube by pressure into the inner tube. This causes multiple streams or jets of crude oil to emanate from the radically bored holes in the wall of the tube to bombard the copper nickel walls of the annular chamber and the center insert (WEAFRI, 2005). Electrons released from the copper in the walls of the chamber combine with molecules of the hydrocarbons and other minerals, thereby altering certain physical characteristics of the crude oil, produced water and the other entrained minerals which otherwise clog the tubing and impede the upward flow of the crude.

The crude oil and its entrained minerals treated in the Silver-Hawg pass through the string of tubing to the surface. The treated crude oil not only keeps paraffins and other waxes in suspension, but it also breaks up the long chain hydrocarbon molecules thereby making the oil "slicker". On high paraffin low gravity crudes, the treatment increases the API gravity of the resulting crude by at least two or three points, thus, increasing the marketability of the treated crude.

Design methodology for Silver-Hawg installation

When cloud point indicates that the precipitation is in the flowline, a flowline Silver-Hawg would be most appropriate and effective when placed before the nucleating point. If cloud point combined with fluid temperature predictions indicated wax/paraffin formation in the tubing, a specific Silver-Hawg design for tubing suspension would be appropriate. The tool should not only be installed a few feet below the cloud point but must also posses a flow area that will not reduce oil production. It is essential to locate the nearest profile such as ''X'', ''XN'', ''Sleeve'' that is closest to the nucleating point for hanging the tool. The closer the tool is to the nucleating point, the more effective is its performance.