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Development and Application of CLOGEN-Polymer Slug as Enhanced Oil Recovery Agent in the Niger Delta Marginal Oil Fields

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Abstract: - Mathematical models for the application CLOGEN Polymer Slug (CPS) was successfully designed for chemical flooding in the Niger Delta. Estimation of cumulative oil recovery or additional oil recovery after secondary recover method was done using development and application of CLOGEN-Polymer slug as enhanced oil recovery agent in the niger delta marginal oil fields. Draw-dip and down-dip solution gas was designed to enhance the recovery. A double line drive pattern was employed with chemical flooding simulation using CLOGEN-Polymer slug injection at one end of the reservoir to maintain the reservoir pressure above the bubble-point pressure and as well as to displace the level of the oil to the perforation section. Pressurized injection was equally done at the other end to achieve miscibility pressure and enhance the fluids lifting to the surface. The producers placed in between them, for effective drainage. The water and gas produced recovered in a separation process and sent to water-plant and gas-plant respectively, for treatment and re-injection. The water treatment and injection skid conditioned the water for CPS and the pressurized stream before re-injection. In addition to cutting down the cost, the production system was designed to ensured water and pressurized streams requirement availability. A total of nine (9) wells was estimated, three (3) injecting wells for CLOGEN-Polymer-injection at the lower dip, three (3) injecting wells for pressurized stream-injection at the upper dip and three (3) producing wells for fluids production in between the injectors. It was found out that 72 to 83% reserves would be recovered in new fields and additional 10 to 25% recovery in old wells, after secondary methods. *That was possible through the reduction of the interfacial tension (IFT) between oil and water to low tension, which converted macro-emulsion from higher droplets to a micro-emulsion of lower droplets and total voidage out replacement by Water soluble polymer solution.*

I. INTRODUCTION

CLOGEN Polymer Slug (CPS) is an improved (Combination of Polymer Augmented Water and Micro-emulsion) chemical flooding. The objective of the design is to improve the recovery efficiency and surmount most of the problems common in the chemical flooding, an agent for enhancing oil recovery. The application of CLUGEN-Polymer-Slug is an advanced EOR process, because it is a method/technique which recovers oil more efficiently than plain water flooding or gas injection methods. It is an attempt to recover oil beyond primary and secondary methods. Chemical flooding methods involve mixing chemicals and sometimes other substances in water prior to injection in low to moderate viscosity and moderate to high permeability. Lower mobility fluids are injected in chemical flooding with adequate injection. Active water drive reservoirs are not good candidates for chemical flooding, because of low residual oil saturation be low limit, after primary recovery and gas-cap reservoirs mobilized oil might re-saturate the gas-cap fluids. High clay contents formations increase adsorption of the injected chemicals. Moderate salinity with low amount of divalent ions are preferred, since high divalent ions interact negatively with the chemicals.

The polymer augmented water flooding is a chemical flooding technique used to improve the mobility ratio for good displacement and sweep efficiencies (areal & vertical). The resultant effect is high oil recovery. The ultimate oil recovery at a given economic limit may be from 4% to 10% higher with a mobility controlled flood than in plain water flooding. More efficient displacement, since less injected water is required for a given oil value recovered. Polymer flooding is an improved waterflooding technique, but it does not recover residual oil trapped in pore spaces and isolated by water. It produces additional oil by improving the displacement efficiency and increases reservoir volume contacted. Dilute aqueous solution of water-soluble polymers have the ability to reduce the mobility of water in the reservoir, then improves the flood efficiency. Partially hydrolyzed polyacrylamides (HPAM) and zanthan gum (XG) polymers are good chemicals for reducing the mobility of water by increasing its viscosity. In addition HPAM has ability to alter the flow path by reduction of the permeability to water and leave that of oil unchanged. A resistant factor of 10 makes it 10 times more difficult for polymer solution to flow through the system. Meaning that the mobility of the augmented waterflooding is 10 folds, since for water with the viscosity of 1cp, polymer solution flows with an apparent/effective viscosity of 10cp, even though the viscometer reading is a lower value. ***[Chang, 1978]***

Oil and gas are some of the gifts of nature which contribute much to an economic development or growth of a Nation, so advancement in the recovery techniques is an added advantage. The Pilot oil fields used were the reservoirs fields with low recoverable target reserves between 6.0 to 20.0MMstb. The target reserves/oil ($\boldsymbol{N_T}$) could be any value, but the recoverable value ($\boldsymbol{N_R}$) is paramount, at least 6MMstb. The economic models in this work were designed to estimate the profit margins from the proceeds of the oil recovery value, revenue generation and taxes values. It uses Visual Studio (Basic Programming Language) to show the Target-oil, recoverable-oil, recovery value, revenue from the proceeds and taxes value. The economic models solutions use the revenue value and effects of Petroleum Production Taxes (PPT) on the NPV in low recoverable oil reserves field development. This gives an investor good idea about the business, so that he can make decision whether to invest on the development of the field or not and the government to formulate the agreement or contractual terms. The outstanding advantage in the research work is that it gives an investor the value of the target reserves ($\boldsymbol{N_T}$), recoverable value ($\boldsymbol{N_R}$), the CAPEX and OPEX values as well as the profit before and after PPT by government (Technical and Economic Feasibilities). Many paper publications on oil recovery using EOR are based on the principle of chemical oil recovery/flooding, fluids (HCS, Water or Gas) injections and thermal (heating) oil recovery techniques.

1.1 Chemical Oil Recovery or Flooding

The chemical flooding for oil recovery is based on 3-main principles polymer augmented water flooding, alkaline /caustic or surfactant flooding.

Craig, (1971) designed a better correlation of water mobility determination at the average water saturation behind flood front at water breakthrough. He found out that the relative mobility to water ($\boldsymbol{K_{rw}}$) at average water saturation ($\boldsymbol{S_w}$) at breakthrough using Weldge graphical approach for mobility ratio (**M**) expression. He equally found out that the mobility ratio of waterflooding ($\boldsymbol{M_w}$) remained constant before the breakthrough, it increased after the water breakthrough corresponding to the increase in water saturation and the relative water saturation in the connected portion of the reservoir. He concluded that unless stated otherwise, the term mobility ratio is the value prior to water breakthrough, so it is important in the determination of the waterflooded. He defined mobility ratio of a fluid as the ratio of the permeability of a fluid (absolute permeability, K) to the fluid viscosity ($\boldsymbol{\mu}$). Mathematically:

$$\boldsymbol{M = \lambda = \frac{K}{\mu}} \qquad 1.1$$

Where

$\mathrm{M} = \lambda = \text{Mobility ratio, md/cp}$

$\mathrm{K} = \text{Effective fluid permeability, md}$

$\mu = \text{fluid viscosity, cp}$

In a multi fluid flow reservoir system

$$\boldsymbol{M = \frac{K_{rw}/U_w}{K_{ro}/U_o} = \frac{K_{rw}\,U_o}{K_{ro}\,U_w}} \qquad 1.2$$

API-Report, (1984), defined recovery efficiency as the fraction of oil in place that can be economically recovered with a given process. The API research work showed that the efficiency of primary recovery mechanism varies with reservoir, but the efficiency is normally greatest in water drive, intermediate in gas-cap and least in solution gas drive. The results obtained using waterflooding confirmed their findings. They concluded that generally primary and ultimate recoveries from carbonates reservoirs tends to be lower than from sandstones. For pattern waterflooding the average ratio of secondary to primary oil recovery ranges from 0.3 in Califonia sandstones to greater than 1.0 in Texas carbonates. For edge water injection the $\mathbf{2^o : 1^0}$ the ratio ranged from 0.33 in Louisiana to 0.64 in Texas. By comparison secondary recovery for gas injection into a gas-cap reservoir averaged only 0.23 in Texas sandstones and 0.49 in Califinia sandstones. They recommended that solution gas drive reservoirs are the better candidates for waterflooding, because generally they have higher residual oil after primary recovery than any other one. They also pointed out that displacement of oil by waterflooding is controlled by oil viscosity, relative permeability, rock heterogeneity, formation pore size distribution, fluids saturations, capillary pressure and injection wells locations relative to the producers. These factors contribute to the overall oil recovery efficiency ($\boldsymbol{E_R}$) by waterflooding and it is the product of displacement efficiency ($\boldsymbol{E_D}$) and the volumetric efficiency ($\boldsymbol{E_V}$). This mathematical definition was based on the fluid mobility ($\boldsymbol{\lambda = \frac{K}{\mu}}$). Mathematically:

$$\boldsymbol{E_R = E_D\, E_V = E_D\, E_p\, E_I} \qquad 1.3$$

Where

$E_R = {}^{V_D}/_{V_I} = \text{Recoverable Reserves, \%pv}$

$E_D = \text{Displaced fluids from the pv, \%}$

$E_V = \text{Volumetric sweep efficiency, \%}$

$E_p = Pattern\ sweep\ efficiency, \%$

$E_I = pore\ spaces\ invaded\ by\ injected\ fluid$

Muskat and Wyckoff, (1934) presented analytical solutions for direct-line drive, Staggered-line drive, 5-spot, 7-spot and 9-spot patterns.

Craig, et al, (1955) worked on 5-spot and line drive.

Kimbler, et al, (1964) worked on 9-spot pattern flood.

Prats, et al, (1959) worked on 5-spot flood pattern. All their results showed that the areal sweep efficiency is low when mobility ratio is high. They concluded that sweep efficiency is more important for considering rate vs time behaviours of waterflooding rather than ultimate recovery, because at the economic limit most of the interval flooded has either had enough water throughput to provide 100% areal sweep or the water bank has not yet reached the productivity well, so that no correction is needed for areal sweep.

Fassihi, (1986) provided correlation for the calculation of areal swep efficiencies and curved fitted with the data of Dyes and Caudle resulting to the eqn1.5.

$$\boldsymbol{\frac{1-E_p}{E_p} = [a_1 ln(M + a_2) + a_3]f_w + a_4 ln(M + a_5) + a_6} \quad \mathbf{1.4}$$

$$\boldsymbol{E_p = Areal\ swepp\ efficiency\ by\ water\ pattern}$$

$$\boldsymbol{E_V = \frac{E_p/V_d}{\left[M^{0.5} - \left(\frac{(M-1)(1-E_p)}{V_d}\right)^{0.5}\right]^2}} \qquad 1.5$$

Willhite, (1986) used material balance and derived a mathematical model called MBE for estimation of oil recovery by waterflooding. MBE/models are:

$$\boldsymbol{N_{pw} = \frac{7758Ah\emptyset[S_{op} - E_V S_{or} - (1-E_V)S_{oi}]}{B_o}} \qquad \mathbf{1}.6$$

$$\boldsymbol{N_{pw} = N - N_p - N\frac{B_{oi}}{B_o}\left[1 + E_V\left(\frac{S_{or}}{S_{oi}} - 1\right)\right]} \qquad 1.7$$

Where
$\mathbf{N_{pw}}$ = Potential oil recoverable by waterflooing
$\boldsymbol{N} = $ *Initail oil in place, stb*
$\boldsymbol{S_{op}} = $ *Saturation at the start of waterflooding*
$\boldsymbol{N_p} = $ ***Oil produced at operations, stb***
$\boldsymbol{B_{oi}} = $ *Initial FVF*

Dyes, et al, (1954) experimentally studies showed that if the M of waterflooding with a 5-spot pattern is 5, the areal sweep efficiency is 52% at breakthrough. If the economic limit is a producing water-oil ratio of 100:1 ($f_w = \frac{100}{101} = 99\%$), the sweep efficiency at floodout is 97%. If the polymer lowers the mobility ratio from M = 5 to M = 2, the sweep efficiencies are 60% at breakthrough and 100% at the economic water-oil ratio of 100:1. They concluded that a proper size polymer treatment requires 15 – 25% pv and polymer concentration of 250 **-** 2000mg/L injection over 1 t0 2 years and then revert to normally waterflooding.

Martin, (1986) used aluminium citrate process: consisted of the injection of HPAM polymer solution slug, Al^{3+} and citrate ions and a second polymer slug. The first polymer slug was adsorbed or retained on the surface of the reservoir, the Al^3 attached to the adsorbed polymer and acted as a bridge to the second polymer layer. The process was repeated until a desired layering was achieved. The disadvantage in his work was that the transport of Al^{3+} through the reservoir may be limited to near wellbore, whicvh needed another treatment further than that.
Gogarty, (1983) in the reduction of chromium ions ($\boldsymbol{Cr^{+6}}$) to permit crosslink of HPAM or XG polymer molecules, a polymer slug was used. The polymer slug contained $\boldsymbol{Cr^{+6}}$ was injected, followed by a polymer slug that contained a reducing agent ($\boldsymbol{Cr^{+6} \rightarrow Cr^{+3} + 3e^-}$) a gel was formed with the polymer. The amount of permeability reduction is controlled by the number of times each slug is injected, the size of each slug or concentration used. His alternate treatment involved placing a plain water pad between the first and the second polymer slug. A cationic polymer is injected first since reservoir surfaces are often negatively charged, and can highly adsorb the cationic polymer. The injection of this treated slug or cationic polymer adsorbent slug generate a strong attraction between the adsorbed cationic polymer and the anionic polymer that followed. The advantage is that polymer concentration used in these variations are normally low: 250mg/L and with low molecular weight polymer or if a very stiff gel is desired 1 to 1.3% addition to those used in conventional polymer flooding, but the products used for gelation command a higher price. These could be used in fractured treatment, example: acetate **($\boldsymbol{Cr^{3+}}$),** polyacrylamides, colloidal silica and resorcinol-formaldehydes**.**

II. SURFACTANT AND ALKALINE FLOODING

Alkaline flooding like surfactant flooding improves oil recovery by lowering the interfacial tension (IFT) between the crude oil and the displacing water. The surfactants for alkaline flooding are generated in-situ when alkaline materials react with crude oil. This is possible if the crude oil contains sufficient amount of organic acids to produce natural surfactant or emulsification of the oil for the alteration in the preferential wettability of the reservoir rock. Surfactant flooding involves the mixing of surface active agent with other compounds (***cpds***) as alcohol and salt in water and injected to mobilize the crude oil. Polymer thickened water is then injected to push the mobilized oil-water bank to producing wells. Water soluble polymer can be used in a similar fashion with alkaline flooding. Alkaline flooding consist of injection of aqueous solution of sodium hydroxide ($\boldsymbol{NaOH_{(aq)}}$), sodium carbonate solution ($\boldsymbol{NaHCO_{3(aq)}}$), sodium silicate solution ($\boldsymbol{Na_2SiCO_{3(aq)}}$) or potassium hydroxide solution **($\boldsymbol{KOH_{(aq)}}$).** The alkaline chemicals react with organic acids in certain crude oil to produce surfactant in-situ that dramatically lower the IFT between water and oil. The alkaline agent also reacts with reservoir rock surfaces to alter the wettability from oil-wets to water-wets or vice versa. Other mechanisms include emulsification and entrainment of oil to aid mobility control. The slug size of the alkaline solution is often 10 – 15%pv. The concentrations (conc.) of alkaline chemical are normally 0.2 to 5% dosage, a pre-flush of fresh or softened water often proceed the alkaline slug and a drive fluid, which is water or polymer solution after the slug. [**William, 1996**]

Surfactant/Polymer Flooding

Fassihi, (1986) postulated the present-day methods for designing surfactant flooding for enhancing oil recovery, which include: A small slug of about 5%pv and high conc. of the surfactant 5 to 10% of the total chemical solution. In many cases of micro-emulsion, the combination included surfactant, HCS, water, electrolytes (salt) and a solvent (alcohol). This mixture uses a slug size of 30 to 50%pv of polymer thickened water to provide mobility control in displacing the producing wells. The advantage in his work was that low cost petroleum sulfonate or blends with other surfactant could be used.

Alkaline/Surfactant/Polymer Flooding (ASP)

Martin, et al, (1986) used the combination of chemicals to lower process cost by lowering the injection cost and reducing the surfactant adsorption value. ASP solution permits the injection of large slug of injecting, because of lower cost.

Hydrocarbons (HCS) or Gas Injection

Taber, (1982) worked on gas injection. He generally classified hydrocarbon or gas injection into: Miscible solvent (LPG-propane), enrich gas drive, high pressure gas drive, carbon dioxide ($\boldsymbol{CO_2}$), flue gas (smoke) or inert gas ($\boldsymbol{N_2}$) application to improve oil recovery value. Gas injection recently has been coming from non-hydrocarbons application ($\boldsymbol{CO_2}$), $\boldsymbol{N_2}$ **or flue** gas. Miscible flooding (HCS) can be subdivided into 3-techniques LPG-slug/solvent flooding, enrich (condensing) gas drive and high pressure (vaporizing) gas drive. The miscible flooding depends on pressure and depth ranges to achieve fluids miscibility in the system. The disadvantages of his work include: Early breakthrough and large quantity of oil-bypass in practice and hydrocarbons deferment, meaning gas needed for processes are valuable, so to this most operators prefer non-HCS gases such as $\boldsymbol{CO_2}$, $\boldsymbol{N_2}$ **or flue** gas that are less valuable. The disadvantage in using non-HCS gases is that $\boldsymbol{N_2}$ **or flue** gas does not recover oil as much as the HCS gases or liquid, due to low compressibility and poor solubility at reservoir conditions in them.

Carbon Dioxide (CO_2) Flooding

Haynes, et al, (1976) stated numbers of reasons, why CO_2 gas is an effective EOR agent, which are:

i. Carbon dioxide is very soluble in crude oil at reservoir conditions, hence it swells up the net volume of oil and it reduces the oil viscosity before miscibility is achieved.
ii. As the reservoir fluids and $\boldsymbol{CO_2}$ miscibility approaches, both oil and CO_2 phases containing oil-intermediate (C_{2-6}) can flow together due to low IFT and the relative increase of the oil volume by the combination of CO_2 and oil phases, compared to waterflooding.
iii. Miscibility of oil and CO_2 is high in crude oil system when pressure is high enough, so the target is for the system or steam to attain the minimum miscibility pressure (MMP).

Their report showed that there is a rough correlation between API gravity and the required MMP. They also stated that the MMP increases with temperature.

Holm and Jesendal, (1982) showed that a better correlation is obtained with the molecular weight of that $\boldsymbol{C_6}^+$ fraction of the oil than with the API gravity.

Orr and Jensen, (1982) work showed that the required pressure must be high enough to achieve minimum density in the CO_2 phase. At this variable CO_2 density with oil composition, the $\boldsymbol{CO_2}$ becomes a good solvent for the oil, especially the C_{2-6} HCS and the required miscibility can be developed to provide the efficient displacement normally observed in CO_2. To this effect at high temperature, corresponding high pressure are equally needed to increase $\boldsymbol{CO_2}$ density value to match up the ones at MMP at low temperature.

Helier and Taber, (1986) studied the mechanism for $\boldsymbol{CO_2}$ flooding and found out that CO_2 mechanism appeared to be similar to that of HCS miscible flooding, but CO_2 flooding gave better oil recoveries even if both systems are above their required MMP, especially in tertiary flooding. This is so, because $\boldsymbol{CO_2}$ is much more soluble in water and it has been experimentally shown that it diffuses in water phase to swell up by-passed oil until the oil becomes mobile, but the ultimate recovery may be higher than with HCS when above MMP.

Miscible Flooding Design and Performance Prediction

General miscible flooding design and performance prediction showed that the accuracy is affected by pore volume of solvent and drive fluid injected, pressure distribution, size of the solvent, type of drive fluid, mobility of the solvent, drive fluid and reservoir fluids and the displacement efficiencies in both miscible and immiscible swept areas.

- Laboratory test is used to determine the miscibility performance.
- Physical and numerical models are used to predict the computational fluids dynamics (CFD), this considers whether the displacement is miscible or immiscible and flows vertical or horizontal. In medium to light gravity crude oil and deep to medium depth reservoirs miscible displacement is considered. In medium to shallow depth with medium to heavy gravity crude oil the miscibility pressure (if exists) surpasses the formation parting pressure. Here displacement is immiscible, with beneficial effects of viscosity reduction and oil swelling. The direction of displacement depends on reservoir geometry and characteristics. It is horizontal in non-dip and thin pay-zones. It is controlled by the displacing fluid/oil mobility ratio. To avoid or reduce the displacing fluid fingering, gas/water alternating injections (WAG) are employed. It is vertical in pinnacle reef or salt-dome reserve controlled by gravity. For gravity stable process, upward vertical displacement is achieved, using water as a chasing fluid. Downward displacement is accomplished by using gas as a chasing fluid.

Initial phase of the miscible fluid flooding is reservoir pressurization using water in the primary pressure depletion or others. The total amount of injected water, W and time, t necessary for reservoir pressurization are estimated. The total amount of the displacing fluid required is estimated in pinnacle reef for vertical, downward and gravity-stabilized displacement. The displacing fluid injected static wellhead pressure is estimated and parasite tubing of the displacing fluid injection pressure is also estimated. The compressor horsepower that would be required to compress 1MM scf/d of the displacing gas from the given pressure and temperature to the required pressure plus wellhead loss and surface choke must be estimated. [***Stalkup, 1984]***

Conventional EOR Performances Predictions

National Petroleum Council (NPC) US, (1984) studied the general EOR methods compared to conventional performances in four categories.

A is 5 to 10%: Tight oil reservoirs slightly fractured or heavy oil reservoirs.
B is 10 to 25%: Oil reservoirs producing mainly by solution gas drive
C: 25 to 40%: Oil reservoir producing under water-drive and gas injection
D is 40 to 55%: Oil reservoir produced by conventional waterflooding

Table 1.1: EOR-methods compared to conventional

EOR Methods	***Performance Predictions***			
	A	***B***	***C***	***D***
In-Situ Combustion	40-45	40-55	40-45	50-65
Steam Injection	30-35	30-45	35-50	-
Polymer Injection	-	35-50	40-55	-
Solvent Injection				
- Dry or Rich Gas	-	-	37-52	48-63
- LPG or Alcohol	-	35-50	40-45	-
- Surfactant Flooding	-	40-55	40-55	50-65
Gas/CO_2 Injection				
- Immiscible Flooding	-	30-45	35-50	-
- Miscible Flooding	-	-	40-55	50-65
Improved Conventional				
- Infill drilling	-	-	2-4	-
- Water-Gas Injection	-	7	5	-

-	Gas-Cap Water Inj.	-	-	5	-
-	Waterflooding-gas inj	-	-	-	5
-	Pressure Pulsing	-	3 – 5	3	-
-	Attic Oil –Gravitational	-	-	5	-
-	Gross Flooding	2 – 4	2 – 4	2 – 4	2 – 4

Source [***National Petroleum Council (NPC) Study US, 1984]***

Adsorption of Surfactants on Grains Surface

Studies showed that although petroleum sulphonates with high equivalent weight cause the greatest reduction in an interfacial tension, but are insoluble in water, so are readily adsorbed. Lower equivalent weight sulfonates show very little adsorption and are water soluble. More, so when these sulfonates are mixed with those of high equivalent weights. In addition the chemical system is provided with various mineral compounds which are adsorbed in preference to the surfactant. Other mineral additives (NH_3 or Na_2CO_3) protect the surfactant slug against mineral in the formation water. [***Carlos, et al, 2003***]

Santoso, (2003) worked on effects of divalent cations and dissolved oxygen on hydrolyzed polyacraylamides (HPAM) polymers and found out that HPAM polymers are unstable on elevated temperature in the presence of divalent cations (Ca^{2+} or Mg^{2+}) and dissolved oxygen.

Moradi-Araghi and Doe, (1987) worked on effects of divalent cations on HPAM using divalent cations concentration of 2000ml/L at 75℃, 500ml/L at 88℃, 270ml/L at 96℃, 250ml/L at 120℃, 200ml/L at 160℃, 150ml/L at 180℃, 100ml/L at 200℃, 50ml/L at 220℃ and less than 20ml/L at 240℃. They found out that for brine concentration less than 20ml/L divalent cations polymer hydrolysis and precipitation (ppt) will not be a problem in a temperature elevation of 200℃ or above. They concluded that two known chemicals which can impact critical stability for partially hydrolyzed polyacralamide (HPAM) are divalent cations (Ca^{2+} or Mg^{2+}) and dissolved oxygen. They equally showed that HPAM polymer in absence of divalent cations (Ca^{2+} or Mg^{2+}) or dissolved oxygen are stable for at least eight (8) years at 100℃ and in brine concentration of 0.3 to 2%NaCl or 0.2%NaCl + 0.1%$NaHCO_3$ at 160℃ and more stable above 160℃ in brine concentration of 2%NaCl+1%$NaHCO_3$ than orders without antioxidant or chemical oxygen scavenger. They recommended water pre-flushing to remove or reduce effects of projected dissolved oxygen in the reservoir or if any leak at surface facilities or piping, this prevents aggravation of HPAM degradation.

Emulsion Problem in Oil Recovery Efficiency

Emulsion is the dispersion of one liquid in another, with one as continuous phase and the other as discontinuous phase. There are two main types of emulsion oil-in-water (O/W) emulsion and water-in-oil emulsion (W/O). The O/W is commonly in pipeline and surface tanks or facilities while W/O is mainly in the reservoir near the wellbore. In reservoir conditions emulsion in macro-droplets of the dispersed phase tends to plug a reservoir pore spaces or permeability thereby reduces a well-inflow performance. The disadvantage is fluid recovery efficiency reduction. Emulsion in micro-droplets of the dispersed phase tends to flow with ease in the pore spaces than macro-emulsion. This is because micro-emulsion phase is similar to crude oil and behaves just like its droplets. The advantage of this micro-emulsion is that it mobilizes residual oil in a reservoir, thus improving the recovery efficiency. Any agent that can enhance attainment of micro-emulsion with droplets sizes ranging from $1\ x\ 10^{-6}$ to $1\ x\ 10^{-4}$mm is an enhancement chemical for high oil recovery efficiency. Residual oil saturation is the total volume of irreducible oil in a reservoir. It acts as a displacing agent for the recoverable oil. If the residual oil saturation is high, it means low oil recovery efficiency and if it is low it means small volume of oil is left in the reservoir or high recovery efficiency.

Obah, et al, (1998) worked on ***''Micro-Emulsion Phase in Equilibrium with Oil and Water''*** and showed that when maximum adsorption of oil is attained it becomes thermodynamically stable. Any additional oils begin to build an oil bank as a third equilibrium phase and this phase has relatively low viscosity with Newtonian flow ability at low pressure flooding. Micro-emulsion can equally reduce IFT to a low value with minimal inter facial energy. The advantage of low tension force is that it reduces both the capillary and viscous forces, which are frictional forces to oil recovery in a reservoir. Any agent that reduces both capillary and viscous forces enhances oil recovery efficiency. They equally showed that Oil phase viscosity can be reduced using miscible flooding (surfactants) and thermal process (heating). Fully miscible oil and water phases simultaneously reduce both frictional forces (capillary and viscous). Capillary force is reduced when IFT is reduced to minimum while viscous force is reduced in a miscible phase and flow as a phase. The viscosity of water phase is increased using polymer and interfacial tension (IFT) is reduced through the addition of surfactant. An experimental procedure was carried out on three primary oil production based terminals in the Niger Delta (Escravos, Forcados and Que Iboe) by ***Obah, et al, 1998.*** Four categories of emulsion phases were used for the study.

i. Equilibrium of oil and oil/water emulsion phase
ii. Equilibrium of water and water/oil emulsion phase
iii. Equilibrium between oil-water and emulsion phase
iv. Exclusive availability of a micro emulsion phase as a control experiment

They found out that the addition of co-surfactant as alcohols favour the formation of micro emulsion. They equally carried out model tests using hydrocarbons as toluol, n-octane and cyclohexane to ascertain the influential factors for micro emulsion phases. They found out that the surfactant Carboxymethylated nonphenolyethylate (5 EO/mole) with a co-surfactant isopropanol favored micro emulsion formation and stability based on aqueous solution within a given range of salt concentration (1 to 22 wt %NaCl). They concluded that Micro emulsion volume increases with surfactant concentration and decreases with temperature. Paraffinic oil needs a higher temperature to form stable micro emulsion than others. Toluol formed middle phase emulsion between 12 & 13 wt % NaCl, cyclohexane between 19 & 22 %, but n-octane did not even form emulsion at 22%wt. Escravos and Que Iboe oils salinity is 17 and 23 while Forcados oil is between 19 and 24. The range increased to 6%. They stated here that the tendency for developing a middle phase micro emulsion phase is highest with aromatic hydrocarbons and the reverse is in oil with high percentage of alkanes (saturated hydrocarbons) while cycloalkanes are in between them. The oil composition, formation water ions content and temperature are fixed parameters, so the choice of surfactant and co-surfactants must be based on individual system.

Table 1.2: Influence of Temperature on Phase Behaviour

Temp °C	Toluol Water [ml]	Aqueous Volume, [ml]	Micro emulsion [ml]	Oil Phase Volume, [ml]
48	25	5.5	7.5	12.0
54	25	8.0	7.0	10.0
60	25	8.5	5.5	11.0
66	25	9.0	0.0	16.0*

Source [***Obah, et al, 1998***]

*The upper phase micro emulsion was observed. They concluded that a closed oil bank developed in a pilot test and can be produced. Micro emulsion flows at optimal flooding velocity till the end of the flooding tube.

Interfacial Tension Maintenance

Laboratory study method reported that it would be necessary to reduce and maintain the interfacial tension in 0.01 to 0.001dyne/cm. This would have an effect on the residual oil saturation. To obtain this low interfacial tension value in petroleum, sulphonate derived from crude oil was used. This was successful, because sulphonates have high interfacial activity, are less expensive and potentially available in large supply. The challenge here is selecting the component in order to reduce or displace the residual oil saturation. ***[Atkinson, 1927]***

Wettability and Capillary Pressure **Synergy**

The wettability of a fluid on rock depends on a capillary number. A reservoir will be MP/EOR candidate if the capillary number is greater than 10^{-5} for water wetting critical and/or 10^{-4} for oil wetting critical. ***[Gupta and Trushenski, 1979]***

Water Displacement in Linear series Beds

The displacing fluid cut in each zone of a reservoir depends on milidarcy-foot (md.ft) of oil flowing capacity at any time that break to production. The distance of advanced flood front is proportional to the absolute permeability (K). In linear beds geometry all beds undergo the same oil saturation change due to displacement effect by the displacing fluid, more so if all beds have similar porosity, relative permeability of oil and water. Under constant pressure drop across the beds with mobility ratio greater than unity the total flow through all the beds will increase. This is because less mobile oil phase is replaced by the more mobile displacing fluid phase. ***[Stile, 1949]***

Petroleum Profit Taxation (PPT)

The current or past fiscal regime relating to oil fields development only offers a reduction of 19.25% from 85% in PPT, giving 65.75% for new comers in the 1st 5-years. This does not adequately pay for the use of unconventional equipment and technology, which are much more expensive. ***[David and Decree 23, 1996]***

Legal Framework for Oil Reserve Fields

The acquisition of an oil reserve in the Niger Delta (Nigeria), is to have a right to effectively exploit the existing assigned oil fields in Nigeria, it is necessary to consider the methods or procedures by which these fields are transferred and acquired (Farm-out and Farm-in) by the intending investors. This is done within the existing and pending legislation. The petroleum Act of 1969 Decree, No.23 of 1996 (Amendment) deals with the exploration, drilling (evaluation) and production of oil and gas in Nigeria. An additional or new paragraph 16A of the Act provides guidelines for the development and production of these fields. Many of these fields lie within the existing OPL and OML portfolios of the major oil companies and as in joint venture operations with NNPC. The fact that some of these fields are the low reserves and smaller portion of the OPL and OML granted area, methods of acquisition must be in accordance with methods prescribed or allowed under the oil and gas Act or Decree granted by the OPL and OML. ***[Decree-23, 1996]***

CPS2

Memorandum of Understanding (MOU)

Adepetun, et al, (1996) worked on the MOU and stated that is was another major fiscal incentive on profit, which was given to enhance export, encourage exploration & production activities, increase investment volume, promote crude oil lifting operations and to enhance reserves base. In addition a mechanism was introduced to ensure that producers actually realized equity share of the crude oil recovered. Actual market prices are the basis used for computing of government take values (***PPT & royalty***).

Contractual Arrangements:

1. Concession Arrangement (sole risk)
2. Joint Venture
3. Production sharing contract (***PSC***). Government preference*
4. Service Contract
5. Joint Operating Sharing Holdings
6. Contract, (current in use and government interest)

2. Research Methodology

Research Work Plan

In this research work a surfactant was designed called *CLOGEN-Polymer* slug (***CPS***). The second part of the design used pressurized polymer injection. Mathematical definitions and calculations procedures of the materials, reagents and proceeds of the investment incorporated. The third part of the research covers an economic evaluation procedure for effective cost control. A mathematical evaluation is used here to study both the total oil recovery and the cost to recover it, estimating the profit margin before and after petroleum profit tax (PPT) by government.

Project Case Design

Draw-dip and down-dip solution gas was designed to enhance the recovery. A double line drive pattern was employed with chemical flooding simulation using CLOGEN-Polymer slug injection at one end of the reservoir to maintain the reservoir pressure above the bubble-point pressure and as well as to displace the level of the oil to the perforation section. Pressurized injection is equally done at the other end to achieve miscibility pressure and enhance the fluids lifting to the surface. The producers placed in between them, for effective drainage. The water and gas produced recovered in a separation process and sent to water-plant and gas-plant respectively, for treatment and re-injection. The water treatment and injection skid conditioned the water for CPS and the pressurized stream before re-injection. In addition to cutting down the cost, the production system was designed to ensured water and pressurized streams requirement availability. A total of nine (9) wells was estimated, three (3) injecting wells for CLOGEN-Polymer-injection at the lower dip, three (3) injecting wells for pressurized stream-injection at the upper dip and three (3) producing wells for fluids production in between the injectors. Figure 2.1 shows the schematic view of the converted field for EOR methods.

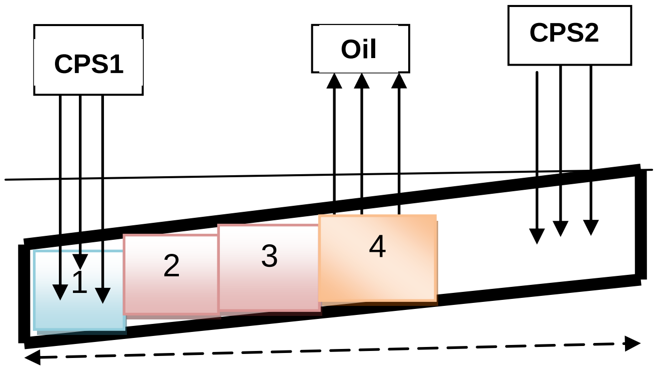


Fig. 2.1: ***Mechanism of CPS Operation***

1. Chase Water Bank
2. Polymer slug (CPS)
3. *CLOGEN-Surfactant Solution (CSS)*
4. Miscible Displacement Bank (*CPS*, oil and Gas)
CLOGEN-Polymer Slug (CPS) Design

Table 2.1: CLOGEN Surfactant Solution (CSS) Composition

CLOGEN-2A Components	***Conc % wt***
Active Surfactant (***HPAM***)	10.0
Crude Oil	15.0
fresh water	70.0
Co-Surfactant (***hexyls or isopropyl alcohol)***	2.0
Inorganic Salt (2%$\boldsymbol{NaCl} + \mathbf{1}$%$\boldsymbol{NaHCO_3}$)	3.0
Total	**100.0**

In each of the surfactant solution preparation about 100g (10%) of active surfactant was placed in an anaerobic Chamber and about 700ml (70%) of fresh water, steered and 170ml $\left(\frac{M_0}{\rho_0} = \frac{15}{0.8550}\right)$ crude oil was added to the mixture, steered again vigorously. About 20ml of co-surfactant (1.12 $moles\ of\ RCH_2COHCH_2R$) was added then shaken properly and 30g of inorganic salts (2%$\boldsymbol{NaCl} + \mathbf{1}$%$\boldsymbol{NaHCO_3}$) was finally added to the mixture in an anaerobic Chamber. The complete solution was transferred into Teflon wrapped plugs (CLOGEN-Polymer Storage tool). The objective of CLOGEN-Polymer slug injection is to reducing and maintaining IFT between 0.01 and 0.001 dyne/cm and it is less expensive and potentially available in large supply. Surfactants in water solutions recover more of the oil, because proportionate composition assures a gradual transition from displacement of water to the oil displacement without significant interface. Another advantage is to converts macro-emulsion to micro-emulsion which enhances high recovery. Inorganic salt is used to prepare the surfactant solution in order to gain better solution viscosity control. The surfactant solution is driven by a polymer slug in order to control its mobility called CLOGEN surfactant polymer (CSP) flooding. The CSP solution is miscible with reservoir fluids (oil and water) without phase separation, assuring lower residual oil after displacement. The percentage of a fluid displacement depends on rock uniformity, areal sweep efficiency and the injection fluid invasion efficiency. The surfactant solution is similar to emulsion except that the discontinuous phase in the solution is smaller in size (more microscopic).

CLOGEN Mechanism of Operation

The 3 principal components of ***CLOGEN*** are surfactant (sulfonate), oil and water in oil and water region. Oil and water are in equilibrium and external to the CLOGEN each lying at the opposite ends of the miscible-line AB. In the miscible region all the components are present with little or no interfaces. The pseudo-critical diagram for practical CLOGEN-Polymer Slug (***CPS***) displacement in the field of study is the oil and water region. The surfactant-slug moves through the reservoir, changing its composition after absorbing oil and water thereby attaining miscible displacement in present of the injected pressurized stream.

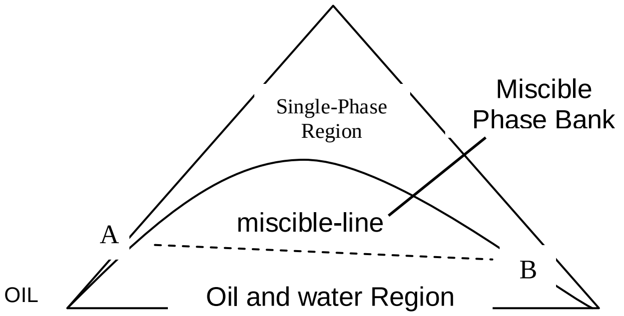


Fig 2.2 Pseudo-critical saturation diagram

[Source: Niger Delta Oil Sample Analysis]

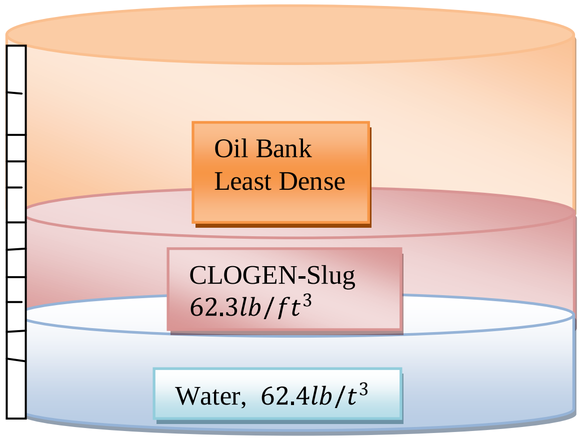


Fig 2.3 Volume of Oil Bank Observed

Experimental Procedure and Observations

About 25ml of each CLOGEN solution was pipette into a boiling tube containing 50ml of macro oil emulsion. The mixture was agitated and exposed to direct sun heating from 60 to 240°F and left to settle down. The volume of oil bank observed in each of the CLOGEN types was recorded in every 30°F increased. Table 2.2 shows detailed recorded values. In this case hydrolyzed polyacrylamide (*HPAM, **called CLOGEN-2A)*** was selected, be cause fresh water HPAM solution can provide efficient sweep with minimum mixing saline brine if polymer mobility is sufficiently low. In the absence of O_2 and/or divalent cat-ions ($Ca^{2+} or\ Mg^{2+}$), HPAM polymer viscosity remains unchanged at 100°C (212°F) for many years and in EOR is stable up to 120°C (248°F) even if it contacts O_2 and/or divalent cat-ions ($Ca^{2+} or\ Mg^{2+}$). More so most reservoirs produce water with little or no detectable dissolved oxygen and it can be controlled in the field by preventing leakages.

Table 2.2 Temperature effect on Micro Emulsion

T °F	CLOGEN-1		CLOGEN-2		CLOGEN-3	
	Micro Phas [ml]	**Oil Phase V [ml]**	**Micro Phase [ml]**	**Oil Phase V [ml]**	**Micro Phase [ml]**	**Oil Phase V [ml]**
60	5.2	8.3	5.2	10.5	5.0	10.7
90	10.3	12.7	15.1	20.1	15.3	17.9
120	14.9	30.2	15.0	37.4	15.0	20.4
150	10.4	38.6	9.2	43.0	10.3	40.3
180	6.7	40.7	7.5	51.7	8.5	50.4
210	2.3	41.8	5.3	62.1	5.3	58.9
240	0.4	43.1	0.0	68.8	0.5	60.0

[Source: Experimental Results from the field of study]

Technical Evaluation and Modelling

Assumptions:

The assumptions are necessary to drive the equations and make reasonable calculations.

Variable Permeability in Series/parallel Beds

1. Linear geometry and the distance (Δx) of the advanced flood front is proportional to the absolute permeability (K). $\rightarrow \ \Delta x \propto K$
2. Production in each zone changes from oil to displacing fluid (CLOGEN)
3. The displacing fluid (water or CLOGEN) cut in each zone depends on Milidarcy.foot (md.ft) of oil flowing capacity at any time that breaks to water production.
4. There is negligible cross flow between zones
5. All beds have the porosity, relative permeability to oil ($K_{ro} = KK_o$) ahead and to water ($K_{rw} = KK_w$) behind the flood front.
6. All beds undergo similar oil saturation change (ΔS_o) due to CLOGEN displacement (Δh_j).
7. The given zone thickness is Δh_t and permeability is K_i
8. The velocity of the flood front is proportional to the permeability of the beds
9. When the mobility ratio (M) is equal to 1.0, there is a constant velocity and pressure drop: Meaning uniform permeability (K) beds
10. When M ≥1.0 there is variable velocity and pressure drop (non-uniform permeability beds).
11. The total pressure drop equals the sum of the individual drop in the zone
12. Total length of bed is the sum of individual length ($L_W + L_o$) in the zone
13. The flow is a single phase since miscible and two-dimension (2D), since small cross-flow

Permeability in Linear Beds or Layers

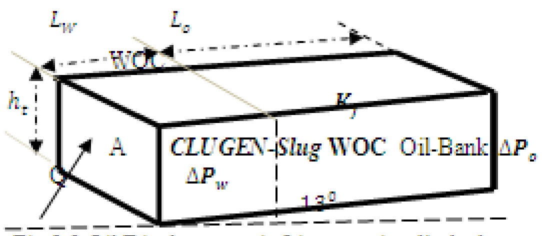
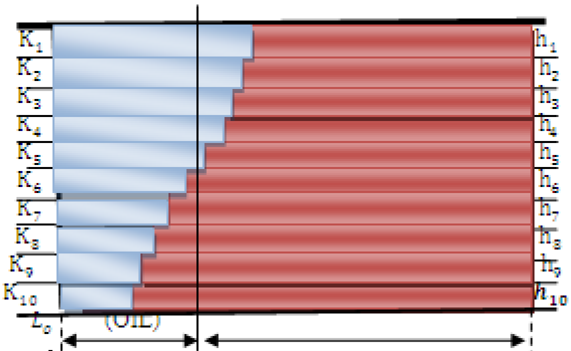


Fig 2.3 Oil Displacement in Linear series dip beds



L_w

Fig 2.4 Oil Displacement in Linear parallel beds

$$\begin{bmatrix}\textbf{Recovery Efficience}\\ \textbf{at } K^{th} \textbf{ Term}\end{bmatrix} = \begin{bmatrix}\textbf{Fraction of}\\ \textbf{Flooded Zone}\end{bmatrix} + \begin{bmatrix}\textbf{Fraction of}\\ \textbf{Producing}\\ \textbf{Capacity}\end{bmatrix}$$

$$E_R = \frac{h_j}{h_t} + \frac{K_h - \sum_1^j K_j}{h_t} \qquad 2.1$$

where

h_j = Total height swept at the given E_v

$= \Delta h_1 + \Delta h_2 + \ldots + \Delta h_j$ 2.2

$h_t = h_1 + h_2 + \ldots . + h_n$ Reservoir Thickness 2.3

$K_h = Total\ formation\ capacity, md.ft$

$\sum_1^j K_j$ = Complete flooded capacity, md. ft

$K_h - \sum_1^j K_j$ = Producing capacity, md. ft

$\frac{\Delta h_k}{j} = Recoered\ fraction\ at\ K^{th}$

Substituting these in eqn2.1 gives eqn2.4

$$E_R = \frac{h_j + \frac{1}{K_j}\left[K_h - \sum_1^j K_j\right]}{h_t} \qquad 2.4$$

Multiplying eqn2.4 by $\frac{K_j}{K_j}$ gives eqn2.5, the recovery efficiency. $E_R = \frac{h_j K_j + \left[K_h - \sum_1^j K_j\right]}{h_t K_j}$ 2.5

Cumulative Oil recovery (N_p) Modelling

$$\begin{bmatrix}\textbf{Cumulative}\\ \textbf{Oil Recovery}\end{bmatrix} = \begin{bmatrix}\textbf{recovery}\\ \textbf{Efficiency}\end{bmatrix}\begin{bmatrix}\textbf{Recovered}\\ \textbf{Oil at } K^{th}\end{bmatrix}$$

$$N_p = E_R \Delta S_o \qquad 2.6$$

but $\Delta S_o = NE_V$ 2.7

Substituting this in eqn2.6 giveseqn2.8

$$N_p = NE_R E_V = \frac{NE_v\left[h_j K_j + \left(\left[K_h - \sum_1^j K_j\right]\right)\right]}{h_t K_j} \qquad 2.8$$

Actual Oil recovery Factor (% N_p)

$$\% N_p = \frac{N_p}{N} = \frac{E_V\left[h_j K_j + \left[K_h - \sum_1^j K_j\right]\right]}{h_t K_j} \qquad 2.9$$

or Using the Graphical Table % $N_p = f(E_v)$

$$\% N_{p(E_V)} = \frac{\left[h_j K_j + \left[K_h - \sum_1^j K_j\right]\right]}{h_t K_j} \qquad 2.10$$

Total Surfactant Requirements (G_{Ts}) Estimation

$$\begin{bmatrix} Surfactant \\ Required \end{bmatrix} = \begin{bmatrix} Active \\ Slug \end{bmatrix}\begin{bmatrix} Retened \\ Slug \end{bmatrix}\begin{bmatrix} Slug \\ Size \end{bmatrix}\begin{bmatrix} Slug\ to \\ Retn\ Ratio \end{bmatrix}\begin{bmatrix} floodable \\ Pore\ Volume \end{bmatrix}$$

$$G_{Ts} = 10^{-3}\left(\frac{1-ø}{ø}\right)\left(\frac{\rho_r \sigma W_{clay}}{\rho_s}\right)\left(\frac{V_{ps}}{D_s}\right)\left(\frac{NE_V B_{oi}}{S_{oi}}\right) \qquad 2.11$$

where

$C_s = \frac{1-\emptyset}{\emptyset}$ = active surfactant in the injected slug

$D_s = \left(\frac{\rho_r \sigma W_{clay}}{\rho_s}\right) =$ Surfactant retention

$V_{ps} = slug\ particle\ size\ F_{PV} = F_{pv\,x}\,\rho_{pB}$

$\frac{V_{ps}}{D_s}$ = Slug size to surfactant retention ratio

$F_{PV} = \frac{N_T B_{oi}}{S_{oi}} = \frac{NE_V B_{oi}}{S_{oi}}$ = Unit floodable pore volume

Total Polymer Requirement (G_{Tp}) Estimation

When relative permeability data are available, a plot of $\frac{\mu_o}{\mu_w}$ against C_{pB} could be made. The initial mobility of the polymer buffer (C_{pB}) is made equal to the minimum mobility ratio of water and oil ($M_{PB} = \frac{K_w \mu_o}{K_0 \mu_w}$). Then the viscosity of the mobility in buffer is graded down to that of the chase fluid. Or a simplified plot of polymer concentration in initial portion of drive against the ratio of oil to water viscosity is made. Applying the US Department of Energy, 1980 model values

Table 2.3 Polymer conc. based on oil-water viscosity ratio

$\frac{\mu_0}{\mu_w}$	1.0	2.0	3.0	5.0	5/0	6.0	7.0	8.0	9.0	10.0
C_{pB}	300	417	550	689	825	900	1082	1200	1260	1500

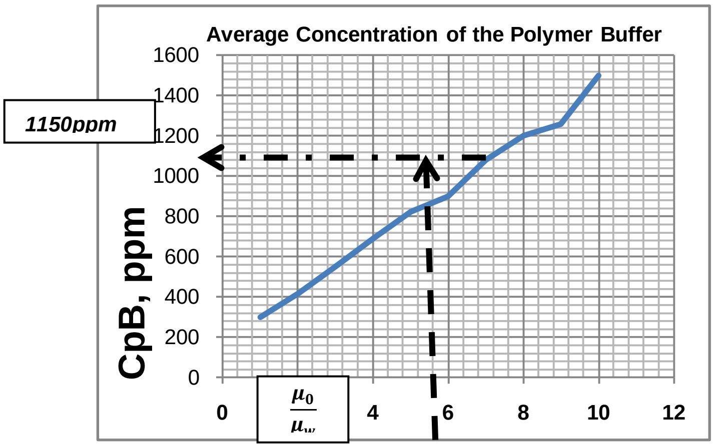


Fig 2.5 Polymer and CLOGEN Viscosity Ratio Synergy

$$V_{pB} = \frac{2.807\ x\ 10^{-9} C_{pB}\rho_{pB} NE_V B_{oi}}{S_{oi}} \qquad 2.12$$

Project Life (t_{life}) Estimation

The reservoir pressure gradient must be 0.1psi/ ft^3 less than the injector pattern drive pressure gradient to maintain the elastic limit, so that the total underground withdrawal at the producing end equals to the surfactant invasion rate at the other end of the reservoir block. This prevents free gas saturation from exceeding the critical fluid saturation for proportionate volume flow. The resultant effect is that double line-drive mechanism provides normal condition for proportionate phase (oil & gas) separation. Using the US Department of Energy, 1980 Mathematical model total injection volume in PV (V_R) is:

$$V_R = V_{ps} + V_{pB} + V_{dg} = 1.45 \approx 1.5 \qquad 2.13$$

$$t_{life} = \frac{9430A\emptyset\ \mu_o V_R (4.56 + 0.73(logA))}{\frac{dp}{dD} K\, D} \qquad 2.14$$

Field Development Study and Estimation

This must be based on the number of wells pattern in the given field (injectors and producers) and the CPS required in sweeping the area in a given period. The total area needed to be developed (D_A) is a function of the floodable pore volume (F_{PV}) and reservoir effective porosity (7758øh) and the total number of wells (N_W) for the project depends on the reservoir area ($\boldsymbol{D_A}$). The function of the number of wells is to increase the surface area for sweeping efficiency.

$$N_W = \frac{F_{PV}}{D_A} = \frac{F_{PV}}{7758A\text{ø}h} = \frac{1.289 \times 10^{-4} N E_v B_{oi}}{A\text{ø}hS_o} \qquad 2.15$$

Economic Data and Mathematical Modelling

The revenue ($\$_o$ or ₦) depends on the market price (S_{M1}/bbl) and the recoverable fluids (N_p). It equally depends on the market modifier factor, (X_S). About 80% of current market price is used to minimize the inflation and fluctuation effects. X_S = 1.0 for sweet (non-acid) crude or 0.9 for sour crude. Nigerian crude is predominately sweet, but 0.95 the average value is preferred for conservative reason. Using the OPEC oil market price model: [$\boldsymbol{S = (S_M - 0.02(40 - API))X_s}$] by US, Department of Energy 1980 the current oil buying price would be estimated.

Revenue from the Proceeds

$$\begin{bmatrix} Revenue\ from \\ the\ Proceeds \end{bmatrix} = \begin{bmatrix} Total\ Oil \\ Recovered \end{bmatrix} \begin{bmatrix} The\ OPEC \\ Market\ Price \end{bmatrix}$$

$$\boldsymbol{Rev = N_p X_s \left(S_M - 0.02(40 - API)\right)} \qquad 2.16$$

Development Costs Data Estimation

This part of the model covers the expenses incurred in the application for licenses, field exploration bills, drilling new-wells, purchasing equipment, conversion and workover jobs on old wells to suit EOR project, called CAPEX.

$$\boldsymbol{CAPEX = W_{SB} + W_{DC} + W_{CPT} + W_{WC} + W_{skid} + W_{EH} + G_{TS} + G_{TP}} \quad 2.6$$

Development cost Recovery Value (CAPEXRV)

$$\boldsymbol{Amotization = CAPEXRV = \frac{CAPEX + Bank\ Inerest}{t_{life}}} \qquad 2.17$$

Yearly Project Operations Costs (Investment)

$$\boldsymbol{INV = OPEX = W_a + W_{FH} + W_{MO}} \qquad 2.18$$

Operation Costs/Investment Recovery value $\quad$ **INVRV** $= \frac{\textbf{INV}}{\boldsymbol{t_{life}}} = \frac{\boldsymbol{W_a + W_{FH} + W_{MO}}}{\boldsymbol{t_{life}}}$ $\qquad$ 2.19

Annual Overhead (OHDC) is 10% of Investment

$$\boldsymbol{OHDC = 0.1(W_a + W_{FH} + W_{MO})} \qquad 2.20$$

Annual Overhead Cost Recovery value $\boldsymbol{OHDCRV}$

$$\boldsymbol{OHDCRV = \frac{OHDC}{t_{life}} = \frac{0.1(W_a + W_{FH} + W_{MO})}{t_{life}}} \qquad 2.21$$

Yearly Operations Information Flow Calculation

i. Yearly Crude Oil production

$$\boldsymbol{N_{p1} = N_p / t_{life}} \qquad 2.22$$

ii. Revenue, Per Year (Only round down)

$$\boldsymbol{Rev1 = \frac{N_R S}{t_{life}} = \frac{N_p X_s \left(S_s - 0.02(40 - API)\right)}{t_{life}}} \qquad 2.23$$

iii. **Royalty Interest, Royalty** $= \frac{1REV1}{8}$ **2**.24

Royalty $= \frac{0.125 N_p X_s (S_s - 0.02(40 - API))}{t_{life}}$ 2.25

iv. **Working Interest,** $WI = \frac{7}{8} REV1$ **2.26**

v. **State Tax** $(Stax = 8\% \, INV)$ 2.27

Substituting eqn2.19 into eqn 2.27 gives eqn2.28

$$Stax = 8\% \, INV = \frac{0.08(W_a + W_{FH} + W_{MO})}{t_{life}} \quad 2.28$$

vi. **Yearly Net cash flow before tax (NCF)**

$$NCF = Rev - Royalty - STAX - OPEX - CAPRX - OHD$$

vii. Cumulative cash flow before tax (CUM)

$$CUM = t_{life}(Rev - Royalty - STAX - OPEX - CAPRX - OHD)$$

viii. Income Tax, the Petroleum Profit Tax (PPT)

Government fixed the petroleum profit tax (PPT_1) at 65.75% for New Comers in the first five years into the business and (PPT_2) 85% there after or old members. The mathematical definition is:

$$PPT = NCF(5PPT_1 + PPT_2 (t_{life} - 5)) \quad 2.29$$

Net Pay Value: $NPV = NCF - PPT$ 2.30

$$NPV = NCF \left(t_{life} - \left(5PPT_1 + PPT_2(t_{life} - 5)\right)\right) \quad 2.31$$

Equation 2.31 is the general net pay value mathematical definition. The percentage of net cash flow (%**NPV**) gives the investor an idea on how much he is getting in the end of the contract.

$$\%NPV = \frac{NPV}{CAPEX + OPEX} \quad 2.32$$

Evaluated Model Equations Applications

This section presents the application of the models on 89 reservoirs in 4-categories (Tab 2.4), with the reserve of 1.24MMMstb. About 80% of these reserves showed that 65% to 72% of the reserves were recovered using GLOGEN-Slug compared to 48% recovered using conventional methods (gas dissolved drive and waterflooding). The economic models equally showed good NPV after PPT.

Table 2.4: A cross section of 4-Categories of Reservoirs

Fields	Reservoir capacity N MMstb	Number of Reservoir f	Reserves Nf, MMstb
I	0.1 – 5.0	18	90.0
ii	5.1 – 10.0	16	160.0
iii	10.1 – 15.0	22	330.0
iv	15.1 – 20.0	33	33
Total		89	1240.0

Probability, P (N < 5.0) = 18/1240 = 0.015 or 20% Probability, P (N > 5.1) = 71/1240 = 0.057 or 80%

Example Application:

Table 2.5 Initial, Production and Laboratory data

Reservoir Depth, D	60000ft
Reservoir thickness, h	24ft
Porosity, ø	28%
Irreducible water saturation, S_{wi}	30%
Average Permeability, K	400md
Dykstra Permeability variation, V_{Dk}	0.5
Oil Gravity, ^oAPI	34^oAPI
Oil Viscosity, μ_o	3.4cp
Initial Reservoir Temperature, Ti	102^oF
Oil FVF Boi & Bof, rb/stb	1.15/1.10
Average Reservoir Area, A	80acres

Cumulative (Gas&Water Drives), Np (48%)	17.2MMstb
Water – Oil Ratio, WOR	21
Residual Oill Saturation (Swept Zone) S_{orw}	26%
Oil Saturation in the Un-swept Zone, Sor	65%
Salinity content of the Water, Ws, $ppmT_{DS}$	$6.5x10^4$
Water Viscosity, μ_w	0.55cp
Clay content of the Rock, W_{clay}	0.05
Rock Density, P_r	156 lbm/ft^3
Surfactant Density, P_s	62.3 lbm/ft^3
Injection Pressure Gradient, Cp	$0.5psi/ft^3$
IFT tension, £ Dyne/cm	$3.33x10^{-3}$
Initial Oil In Place N (17.2 x 100/48 x 10^3)	35.8MMstb
MP Displacement Efficiency, E_{mp}	77.39%
Volumetric Sweep Efficiency, E_V	80%
Vertical Swept Efficiency, E_D	65%

A field was abandoned due to high gas after 17.2MMstb (48%) recovery. Then it was selected for reconsideration as a pilot reservoir for study. A rectangular reservoir boarded all sides by faults, except one, which was boarded by an aquifer in a monocline with 13° dip to the faults. After a short period of production using gas dissolved drive mechanism, the reservoir was converted to water-flooding. This took place in selected single-line drive area of 80acres pattern. The cumulative oil production under solution gas drive and water-flooding was 17.2MMstb 48% of the pore volume. Table 2.5 is the collated history, production and laboratory test data of the field..

Solution:

Technical Evaluation Procedures (Table 3.2)

Column – 1: Volumetric sweep efficiency

Column – 2: $\sum_i^n \Delta h_j \ \ ft$ Beds thickness delineation

Column – 3: $K_j \ \ md$ Absolute permeability (capacity) in each of the beds

Column – 4: $\sum_i^n K_j \ \ md$ Cumulative capacity of the beds

Column – 5: $\sum_i^n \Delta h_j \ x \ K_j \ \ md.ft$ Cumulative capacity

Column –6: Using the table 3.2 the 80% sweep efficiency in the most permeable part of the formation has a total permeability of 331md and contains $331/400 = 83\%$ of the total formation capacity. When the 22.4th footage has been completely flooded the recovery efficiency (E_R) was estimated using eqn2.5 as:

$$E_R = \frac{h_j K_j + [K_h - \sum_1^j K_j]}{h_t K_j} = \frac{19.6 \ x \ 37 + (400 - 331)}{28 \ x \ 37} = 87\ \%$$

Column – 7: **Cumulative**

Applying eqn2.8 in column-7 table 3.2 gives actual cumulative oil recovery (N_p) at 80% volumetric sweep efficiency.

$$N_p = \frac{NE_V[h_j K_j + [K_h - \sum_1^j K_1]]}{h_t K_1}$$

$$= \frac{[illegible]}{[illegible]} = [illegible]\text{MMstb}$$

Column – 8: Actual oil recovery factor ($\%N_p$)

Applying eqn2.10 in column- 8 on table 3.1 gives actual oil recovery factor: $\% N_{p(80\%)} = 72.20\%$

Additional Oil recovery:

$\Delta N_p = (25.87 - 17.2) MMstb \quad = 8.67 MMstb$

III. RESULTS AND DISCUSIONS

Technical Feasibility Results: About 89 reservoirs in 4-categories with the sum reserves of 1.24MMMstb. Table 3.1 shows the confirmed evaluation models. Table 3.3 shows the technical feasibility results and tables 3.4 to 3.6 show the economic results.

Table 3.1 Technical and Economic evaluation Models

Eqn	*Evaluation Models*	*remarks*
	Technical Models	
2.8	$N_p = \frac{NE_v[h_j K_j + (K_h - \sum_1^j K_j)]}{h_t K_j}$	Cumulative Recovery
2.9	$\% N_p = \frac{E_V[h_j K_j + [K_h - \sum_1^j K_j]]}{h_t K_j}$	Recovery Factor
	$\% N_{p(E_V)} = \frac{[h_j K_j + [K_h - \sum_1^j K_j]]}{h_t K_j}$	Using Tab 2.5
2.10	G_{Ts}	
2.11	$= 10^{-3} \left(\frac{1 - ø}{ø}\right)\left(\frac{\rho_r \sigma W_{clay}}{\rho_s}\right)\left(\frac{V_{ps}}{D_s}\right)\left(\frac{NE_V B_{oi}}{S_{oi}}\right)$	Surfactant Needed
		Required Polymer
2.12	$V_{pB} = \frac{2.807 \ x\ 10^{-9} C_{pB} \rho_{pBN} E_V B_{oi}}{S_{oi}}$	Project Duration
2.14	t_{life}	
2.15	$= \frac{9430A \ \emptyset \mu_o V_R (4.56 + 0.73 (logA))}{\frac{dp}{dD} K D}$	Total Well Required
	$N_W == \frac{1.289 \ x\ 10^{-4} NE_v B_{oi}}{[illegible]}$	
	Economic Models	
2.16	$Rev = N_p X_s (S_M - 0.02 (40 - API))$	Total revenue Yearly Revenue
2.23	$Rev1 = \frac{N_p X_s (S_s - 0.02 (40 - API))}{t_{life}}$	**Royalty**
2.25	$Royalty = \frac{0.125 N_p X_s (S_s - 0.02 (40 - API))}{t_{life}}$	Yearly Capital Net Cash Flow
2.26	Working Interest, $WI = \frac{7}{8} REV1$	Govt Tax
	NCF	**Net Pay Value:**
2.29	$= Rev - Royalty - STAX - OPEX - CAPRX - OHD$	
2.31		
2.32	$PPT = (NPPT_1 + PPT_2 (t_{life} - 5)$	
	$NPV = NCF (t_{life} - (5 PPT_1 +$ □□□□(□□□□□−□))	
	$\% NPV = \frac{NPV}{CAPEX + OPEX}$	

Table 3.2 CLOGEN –Slug Flooding Performance Prediction

1	2	3	4	5	6	7	8
E_v %	h_j ft	K_j md	$\sum K_j$ md.ft	$h_j K_j$ md.ft	E_R Eff	N_p MMstb	$\%N_p$
10	*2.8*	*45*	*45*	*125.0*	*0.38*	*11.30*	*31.54*
20	*5.6*	*44*	*89*	*246.4*	*0.45*	*13.38*	*37.34*
30	*8.4*	*43*	*132*	*361.2*	*0.52*	*15.46*	*43.15*
40	*11.2*	*42*	*175*	*470.4*	*0.59*	*17.55*	*48.98*
50	*14.0*	*41*	*215*	*574.0*	*0-66*	*19.63*	*54.79*
60	*16.8*	*40*	*255*	*672.0*	*0.73*	*21.71*	*60.59*
70	*19.6*	*39*	*294*	*764.4*	*0.80*	*23.79*	*66.40*
80	*22.4*	*37*	*331*	*828.8*	*0.87*	*25.87*	*72.20*
90	*25.2*	*35*	*366*	*882.0*	*0.93*	*27.66*	*77.20*
100	*28.0*	*34*	*400*	*952.0*	*1.00*	*29.74*	*83.00*

Table 3.3 T*echnical Feasibility Results*

Studied Parameters	Data
Oil Initially in place (OIIP), N	35.83MMstb
Cumulative oil production, N_p (48% PV)	17.2MMstb
Additional recovered oil, N_R (24.20% PV)	8.67MMstb
Total recovery factor, E_R (48 + 24.20)	72.20%PV
Capillary number, N_{cap}	2-67x10^{-3}ppm
Total surfactant required, G_{TS}	75.00Mstb
Total polymer required, G_{PM}	11.0x10^{6}lbm
Project life or duration, t_{life}	6 years
Total field for development, D_A	874acrees
Total number of wells (6 old + 3 new)	9 wells
Wells for conversion and workover jobs	6 wells
Total new to drill, N_{DA}	3 wells
Distribution , 6 injectors & 3 producers	3wells each

[Calculated using technical feasibility equations]

Table 3.4 Yearly Operations Information flow

Yr	N_p MMbbl	Rev 10^6	WI 10^6	Roy 10^6	S/T 10^6	OPCR 10^6	OHCR 10^6	DVCR 10^6
0	0.00	0.000	0.000	0.00	0.00	0.00	0.00	0.00
1	1.445	118.3	103.51	14.79	1.28	16.00	9.60	33.60
2	1.445	118.3	103.51	14.79	1.28	16.00	9.60	33.60
3	1.445	118.3	103.51	14.79	1.28	16.00	9.60	33.60
4	1.445	118.3	103.51	14.79	1.28	16.00	9.60	33.60
5	1.445	118.3	103.51	14.79	1.28	16.00	9.60	33.60
6	1.445	118.3	103.51	14.79	1.28	16.00	9.60	33.60
	8.67	709.8	621.06	88.72	7.68	96.00	57.60	201.6

Source [Calculated Using Economic Feasibility Models]

Table 3.5 Six Year Cash Flow at 65% and 85% PPT

Rev/Time	Operations ($Years of Op x 10^6)					
	1^{st}	2^{nd}	3^{rd}	4^{th}	5^{th}	6^{th}
Revenue	**118.3**	**118.3**	**118.3**	**118.3**	**118.3**	**118.3**
WI ($\frac{7}{8}Rev$)	**103.51**	**103.51**	**103.51**	**103.51**	**103.51**	**103.51**
Roy($\frac{1}{8}Rev$)	**14.787**	**14.787**	**14.787**	**14.787**	**14.787**	**14.787**
STax 8%inv	**1.280**	**1.280**	**1.280**	**1.280**	**1.280**	**1.280**
CAPEX	**16.00**	**16.00**	**16.00**	**16.00**	**16.00**	**16.00**
OPEX	**33.60**	**33.60**	**33.60**	**33.60**	**33.60**	**33.60**
OHCR	**9.600**	**9.600**	**9.600**	**9.600**	**9.600**	**9.600**
Taxable	**28.240**	**28.240**	**28.240**	**28.240**	**28.240**	**28.240**
PPT	**(18.36)**	**(18.36)**	**(18.36)**	**(18.36)**	**(18.36)**	**(24.00)**
NPV	**9.884**	**9.884**	**9.884**	**9.884**	**9.884**	**4.236**
OPEXCRV	**16.00**	**16.00**	**16.00**	**16.00**	**16.00**	**16.00**
CAPEXCRV	**33.60**	**33.60**	**33.60**	**33.60**	**33.60**	**33.60**
OHCRV	**9.600**	**9.600**	**9.600**	**9.600**	**9.600**	**9.600**
NCF	**69.084**	**69.084**	**69.084**	**69.084**	**69.084**	**63.436**

Source [Calculated Using Economic Feasibility Models]

The research result shows that in the pilot reservoir 25.87MMstb (72.20%) was estimated recovered compared to 17.20MMstb (48%) in the conventional methods used. Thus an economic additional recovery factor ($\%N_p$) of 24.20% pore volume was achieved in this field, because the CPS used effects on the oil displacement efficiency.

Table 3.6 Effect of PPT on Net profit (NPV)

PPT %	*(NPV)* $\$ x\ 10^6$	%(NPV
10/29.25	55.8582	29.06
15/34.25	52.0725	27.09
20/39.25	48.2969	25.13
25/44.25	44.5211	23.16
30/49.25	38.3228	19.94
35/54.25	36.9700	19.24
40/59.25	33.1943	17.27
45/64.25	29.4186	15.21
50/69.25	25.6300	13.34
55/74.25	21.8673	11.38
60/79.25	19.0917	9.41
65/84.25	14.3132	7.45
70/89.25	10.5404	5.43
75/94.25	6.7647	3.52

[Calculated:* Economic Feasibility *equations]

Source [Generated from Table 3.6]

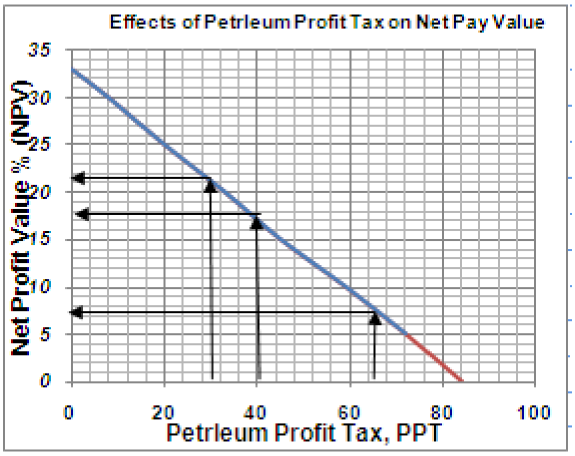


Fig 3.1 Net Profit Value against Petroleum Profit Tax

This graph shows that when the PPT is 30% the NPV is 21% and when PPT is 40%, NPV is 17%. This implies that at 65% and 85% the NPV is 5%. The only remedy is the MOU between the Government and investor.

IV. DISCUSIONS

The primary advantage of these models result is to identify and select the chemical flooding technique for all or high oil recovery in the Niger Delta fields. This would enhance the prediction of the fluid production value in a given period using the chemical flooding mechanisms. At any stage of production, the designed slug controls the oil displacement from the pore spaces and sweeping to the producers. The principal mechanisms of CLOGEN-Polymer Slug is the ability of preventing free gas saturation from exceeding the critical fluid saturation, maintaining the reservoir pressure above the bubble point pressure, very high displacement of the oil level and lifting to the surface. The effective fluid recovery using CLOGEN-Polymer Slug ranges from 65% to 72% of the reserves compared to 15% - 48% common in the conventional methods (gas dissolved drive and waterflooding).

V. CONCLUSION

Mathematical evaluation models were successfully derived for preparing CLOGEN-Polymer slug that effectively displaces oil from the pore spaces and sweeping it to the producers in practice. The principal advantage is that 10% to 25% addition to conventional method recovery of the recoverable reserves would be achieved. This is possible since the surfactant-oil phase activity and the changes in the CLOGEN-Polymer will cause a reduction in the interfacial tension required for a miscible displacement. The Surfactant-brine-oil phase measurement can control any difficulty of interfacial tension and also provides a basis for CLOGEN-surfactant flooding design.

VI. RECOMMENDATIONS

a. The CLOGEN-Polymer density must be $62.3\ lb\ /ft^{3}$ in formation water of $62.4\ lb\ /ft^{3}$ (meaning: $0.1 lb\ /ft^{3}$ less than the formation water). This maintains proportionate adsorption profile. The recovery in this case is between 65 and 75% if the volumetric sweep efficiency is up to 80%.
b. These principles are achieved only in a very narrow range of salt concentration) in the CLOGEN-solution. The salinity of the brine influences the phase behaviour of CLOGEN-surfactant solution, so it needs a good correlation with the interfacial tension.
c. The wells (producers) location must be determined using principle of moment. The advantage of using the principle is that fluids miscibility pressure attainment and micro-emulsion are possible with vertical oil displacement assurance.
d. Injection gradients must be slightly above the reservoir pressure gradients, for controlled flowing, but is best determined in practice.
e. Amortization must be spread throughout the contract duration and not at once like in the conventional

production operation contract. This favours the business viability and stability.

f. The best way to determine PPT should be based on individual contract for fair consideration. In this pilot reservoir I recommend a PPT of 40% for new comers and 60% in the subsequent years with NPV of 42%. This would entice small scale investors, since the profit is good. This equally increases indigenous firms' chances or opportunities to participate in oil upstream sector.
g. Enhanced oil recovery technology can maintain the potential of the declining proven elephant reserves of a country, so developing special methods for advancement in the recovery efficiency is recommended. Government should do all that is necessary to encourage advancement in fluids recovery efficiency research.
h. The development of low oil fields enhances technical knowledge exchange or transfer. It equally gives the citizens employment opportunities. It increases both domestic oil base and foreign reserves or exchange. It generates additional revenue for a nation.
i. The most assured philosophy or best program for high recovery in a reservoir is to recognize early the proper techniques to use in that reservoir. This guides the development program of the reservoir towards maximum use in the exploration and exploitation programs best suited for high recovery.
j. To successfully farm-out and farm-in low oil fields for development, government, fields' owners and interested investors (OPL/OML license holders) have to come together and reformulate the terms of agreement. Or the government should used its veto power and formulate a farm-out and farm-in policy.

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