

Evaluation of Temperature Effect on Scale Deposition on Oil Production Tubing in Niger Delta

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Abstract

Scale deposition along the tubing is one of the major problems in the petroleum industry and water production pipelines. Corrosion attack produced by scale deposition can impair production tubes and other facilities. Oil production is reduced to the surface as a result of such assault. The effects of scale deposition on oil production tubing in the Niger Delta and control measures are discussed in this research, which outlines the various types of scale and effective control measures. In this study, experiments were conducted using formation and sea water. The amount of strontium, calcium, and barium were determined after been synthesized. The solubility of several types of scales was computed, and their tables demonstrates the trend in temperature ranges, as well as how solubility declines with increasing temperature or increases with decreasing temperature in the various forms of scales both at high and regular salinity. Scale is more likely to be deposited in formations with high salt or concentrations, as obtained from the test. The experimental results conducted at temperature of 50°C - 90°C showed an increase in BaSO₄ solubility but a decrease in CaCO₃, CaSO₄ and SrSO₄ solubility. When synthetic seawater containing sulfate was mixed with formation water that contained dissolved calcium, strontium and barium ions, in-situ precipitation of calcium, strontium and barium sulfates occurs, depicting scale tendency.

Keywords: Scale deposition, Calcium carbonate, Tubing, Solubility, Temperature, Oilfield

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1. Introduction

Petroleum resources provide the majority of the world's energy. Petroleum industry is critical to the creation of jobs and the growth of nations. Oil firms all over the world are expanding their operations to cold locations such as offshore deep sea and onshore for more environmental reserves due to the global demand for energy (Theyab, 2018). Due to high pressure, lengthy distances, and financial losses resulting from production interruption and damages to pipeline or surface facilities such as production tubing, flow assurance has recently been deemed the most crucial responsibility in Deepwater energy production (due to solid deposits). Flow assurance is a major issue in the oil and gas industry, and it is used to control petroleum flow. This covers system selection, comprehensive design, surveillance, troubleshooting, operational issues, and improved late-life recovery, among other things. Scale deposition, hydrate formation, emulsion, wax deposition, asphaltenes, slugging, and corrosion are

some of the flow assurance issues. Flow assurance has an impact on oil flow, particularly deep offshore. Scale deposition is a mineral deposit that forms in tubing and other production facilities when the water solution equilibrium is disrupted by pressure and temperature fluctuations, dissolved gases, and, most importantly, when incompatible waters are mixed (i.e formation water from the producing well and sea water from injection well in the agbada formation). Understanding the mechanism of scale creation at the surface of facilities, particularly the surface of production tubing, provides a better strategy to manage scale concerns. The deposition of inorganic scales such as CaCO₃, BaSO₄, and SrSO₄ in oil and gas production in the Niger Delta is the subject of this research.

In the Niger Delta complex basin, the Agbada formation is the most important oil-producing formation. Oil and gas are predominantly produced in the Niger Delta from sandstones and unconsolidated sands, notably in the Agbada

formation. Wells at the Delta fields were drilled to the Agbada formation's lower levels. Some wells are drilled in the field to resolve water coning concerns in the producing well, some of the wells are producing ones, while others are water injection wells that are used for pressure support and enhance oil recovery (EOR) (Weber, 1971; Weber and Daukoru, 1975; Doust and Omatsola, 1990; Evamy et al., 1978; Haack et al., 2000). Out of many Wells drilled, some are enhanced oil recovery wells (EOR). But due to EOR operations, scale deposition on oil facilities is extremely high.

Scales of BaSO₄ and SrSO₄ are formed when saltwater is injected into the reservoir, where it meets formation water and the two are incompatible. The presence of these scales in an oilfield can cause a variety of problems, fouling of equipment and, as a result, a reduction in output. Experiments in the oil industry have shown that scale deposition inside the oil producing formation matrix and down-hole equipment has caused flow limitation in several oil wells. Statoil published a summary of their scale deposition experience during several operations. Scale prevention is critical in the oil and gas industry to avoid the cost of scale removal, which can cost up to 2.5 million dollars, and the cost of deferred production can be significantly greater (Wigg and Fletcher, 1995).

In order to improve oil recovery operations from offshore reservoirs where pressure is maintained by injecting seawater, various scales are established. The differing water composition (formation water and injection water) causes significant scaling in the reservoir, resulting in the precipitation of barite, celestine, and gypsum. These compounds diminish the porosity of the surrounding rocks while also slowing the flow in the production tubing and equipment.

2. Materials and methods

2.1 Seawater and the formation water

The seawater and the formation water were prepared synthetically in the lab, the composition of the seawater prepared is as follow:

Sodium chloride (NaCl)	19.41g/l
Magnesium chloride (MgCl ₂)	3.64g/l
Sodium sulfate (Na ₂ SO ₄)	1.64g/l
Calcium chloride (CaCl ₂)	0.52g/l
Potassium Chloride (KCl)	0.07g/l
Sodium Bicarbonate (NaHCO ₃)	0.04g/l
Potassium Bromide (KBr)	0.01g/l
Boric Acid (H ₃ BO ₃)	0.0034g/l
Strontium Chloride (SrCl ₂)	0.0015g/l
Sodium Fluoride (NaF)	0.0010g/l

Water (H₂O) 495.670g/l

2.2 Experimental procedures

The experimental procedure used to determine the solubility of common oilfield scales from seawater and formation water at both high salinity and normal salinity of high concentration of Calcium, Barium and Strontium at various temperature, ranging from (50-90) °c and 1 atm were as follow:

- For each oilfield scales (CaCO₃, BaSO₄ & SrSO₄), 100ml of filtered seawater and formation water were measured and poured simultaneously into a beaker.
- The synthetic brines inside the beaker were heated on hot plate, and the solution was stirred by magnetic stirred and filtered through 0.45-3um filter paper.
- After the filtration, 5 ml of the filtrate was taken into a 50ml volumetric flask and was diluted with distilled water to make up 50 ml of solution. This instantaneous dilution of CaCO₃, CaSO₄, SrSO₄, and BaSO₄ containing brines was performed in order to prevent the precipitation between filtering and analytical determination of the Ca, Sr, and Br concentration
- The calcium, strontium and barium determinations were calibrated by measuring five standard solutions. The Standard solutions were prepared from CaCl₂, BaCl₂ and SrCl₂ solutions.
- Calcium, strontium and barium concentrations in the diluted filtrates were determined by Atomic Absorption Spectrometry. After multiplying with the dilution factor, the exact concentrations of each were computed.

3. Results and discussion

Atomic absorption spectrometry was used to determine the concentrations of Strontium, Calcium and Barium. The solubility of their salts (CaCO₃, CaCO₄, SrSO₄, and BaSO₄) at different temperatures were calculated as shown in Tables 1-4. There is trend in the temperature ranges, CaCO₄ and SrSO₄ solubility decreases with increasing temperature because of dissociation of CaSO₄ and SrSO₄ which are exothermic reaction. The phenomenal is dissimilar as compared to that of BaSO₄ whose solubility increases with increasing temperature due to its endothermic reaction. The sulfate ion content in the sea water brine was reacted with brine ions content in the formation

water instantaneously but it was a reaction of both Calcium and Strontium ions during heating. The more precipitation of CaCO_3 , CaSO_4 , SrSO_4 and BaSO_4 results from the presence of a large concentration of calcium, Strontium and barium ions as compared to less precipitation at normal concentration of calcium, strontium and barium ions. Calcium carbonate scale can be formed by combination of calcium and bicarbonate ions, and this reaction is the major cause of calcium carbonate scale deposition in oilfield tubing. This study had shown that bicarbonate ions dissociated at the pH values in most Injection-waters to form H^+ and CO_3^{2-} .

Solubility of CaCO_3 is greatly influenced by the carbon dioxide content of the water and

temperature increase. CaCO_3 becomes less soluble as temperature decreases. During heating, CO_2 comes out of solution and precipitation of calcium carbonate takes place. Supersaturation is the most important reason behind mineral precipitation. Increased supersaturation would result in a more rapid rate of scale precipitation. The experimental results confirmed the general trend in solubility dependencies for common Oilfield scales with temperature.

From the study, it can be inferred that the less scale potential occurs by lowering the salinity of injected water. The low salinity water injection that has been established recently, offers not only the significant oil enhancement but also lower scaling potential than high salinity water injection.

Table 1: Solubility of CaCO_3 at various temperatures

Temperature (°C)	Solubility of CaCO_3 at high salinity (Ca= 30,000ppm)	Solubility of CaCO_3 at normal salinity (Ca=7,000ppm)
50	23301.335	5849.312
55	22999.740	5058.279
60	22698.144	4267.225
65	22600.179	4081.114
70	22502.213	3895.003
75	22335.647	3771.540
80	22045.203	3648.076
85	21878.637	3494.700
90	21712.070	3341.304

Table 2: Solubility of CaSO_4 at various temperatures

Temperature (°C)	Solubility of CaSO_4 at high salinity (Ca= 30,000ppm)	Solubility of CaSO_4 at normal salinity (Ca= 7000ppm)
50	26918.523	5410.185
55	25019.282	5253.198
60	23120.041	5096.211
65	21637.148	5023.742
70	20154.255	4951.272
75	19538.711	4394.642
80	18923.166	3838.011
85	16847.584	3701.549
90	14772.001	3565.087

Table 3: Solubility of BaSO₄ at various temperatures

Temperature (°C)	Solubility of BaSO ₄ at high salinity (Ba=2200ppm)	Solubility of BaSO ₄ at normal salinity (Ba=250ppm)
50	900.615	137.178
55	1100.358	153.208
60	1300.100	169.237
65	1415.275	172.329
70	1530.450	175.420
75	1575.419	178.205
80	1620.388	180.989
85	1680.044	186.334
90	1739.699	191.679

Table 4: Solubility of SrSO₄ at various temperatures

Temperature (°C)	Solubility of srso ₄ at high salinity (Sr = 1100ppm)	Solubility of SrSO ₄ at normal salinity (Sr =500ppm)
50	851.150	363.011
55	778.092	357.092
60	705.034	351.172
65	692.658	322.247
70	680.282	293.322
75	650.261	276.954
80	620.240	260.585
85	525.131	250.918
90	430.021	241.250

4. Conclusion

At high concentration of 30,000ppm and 1,100ppm for Ca and Sr respectively, the solubility of CaCO₃, CaSO₄ and SrSO₄ decreases with increasing temperature. So, as the precipitation of CaCO₃, CaSO₄ and SrSO₄ increases scales deposition occurs in the tubing. While at high concentration of 2200ppm for Ba, the solubility of BaSO₄ increases with increasing temperature signifying that as the temperature increases, BaSO₄ becomes more soluble but less soluble at decreasing temperature. These simply denote that at normal salinity or concentration of Ca and Sr, precipitation of inorganic scale is not that a problem compared to high concentration or salinity.

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