PHYSICAL PROPERTIES, CHARACTERIZATION AND INTERACTION MECHANISM STUDY BETWEEN BARIUM SULPHATE AND *DIETHYLENETRIAMINEPENTAACETIC* ACID PENTAPOTASSIUM SALT

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ABSTRACT

The scale formation of inner pipe was a common problem in oil and gas production industries. This problem resulted in decreasing in the amount of oil and gas produced and production efficiency, formation damage, emergency shutdown, equipment failure and increase the maintenance cost. The deposition of scale often resulted from the incompatibility between injected saline water and reservoir water. The common scales formed in the oil field are $CaCO_3$, $CaSO_4$ (anhydrite, gypsum), $BaSO_4$ (barite), $SrSO_4$ (celestite) and ferrous scale. Among the scales, $BaSO_4$ was the hardest scale and difficult to remove chemically or mechanically. Thus, a suitable chelating agent needs to be identified in order to overcome this problem. In this present study, the physical properties, characterization and interaction mechanism between $BaSO_4$ and *Diethylenetriaminepentaacetic* acid pentapotasium salt (DTPA) used as solvent were investigated. Based on the findings, the pH value of pure DTPA and DTPA-$BaSO_4$ mixture were same which were 14.00. On the other hand, the pure DTPA viscosity was 7.28 mPa.s and based on the observation, the DTPA-$BaSO_4$ mixture was identified less viscous than the pure DTPA. The density for pure DTPA was 1.787 g/ml and the mixture of DTPA and $BaSO_4$ were expected to increase as the mass of solute increase. The amount of water content for both samples did not change which was 54.10 %. Besides that, the CHNS and ICP-MS results represented the structure of DTPA. In addition, the interaction mechanism study based on the FTIR and NMR analysis showed that DTPA and $BaSO_4$ having hydrogen bonding interaction at CH_2 functional group.

ABSTRAK

Pembentukan mendapan di dalam paip adalah masalah biasa dalam industri pengeluaran minyak dan gas. Masalah ini menyebabkan penurunan dalam pengeluaran minyak dan gas dan kecekapan pengeluaran, kerosakan formasi, penutupan kecemasan, kegagalan peralatan dan meningkatkan kos penyelenggaraan. Pemendapan sering terjadi akibat daripada ketidakserasian di antara air masin dan air dipam ke dalam telaga minyak dan gas. Mendapan yang biasa terbentuk dalam adalah $CaCO_3$, $CaSO_4$ (anhidrat, gipsum), $BaSO_4$ (barit), $SrSO_4$ (selestit) dan mendapan ferus. Antara pembentukan mendapan ini, $BaSO_4$ adalah mendapan yang paling sukar dan susah untuk dihapuskan sama ada menggunakan bahan kimia atau pun secara mekanikal. Oleh itu, ejen pelarut yang sesuai perlu dikenal pasti untuk mengatasi masalah ini. Dalam kajian ini, ciri-ciri fizikal, penyifatan dan kajian mekanisme interaksi antara $BaSO_4$ dan *Diethylenetriaminepentaacetic* asid pentapotasium garam (DTPA) yang digunakan sebagai ejen pelarut telah dianalisa. Berdasarkan kajian ini, nilai pH DTPA asli dan campuran DTPA- $BaSO_4$ adalah sama iaitu 14.00. Sebaliknya, kelikatan DTPA yang tulen adalah 7.28 mPa.s dan berdasarkan analisa yang dijalankan, campuran DTPA-$BaSO_4$ telah dikenal pasti kurang likat daripada DTPA tulen. Ketumpatan tulen DTPA adalah 1.787 g / ml dan campuran DTPA dan $BaSO_4$ dijangka meningkat kerana peningkatan jisim bahan larut. Jumlah kandungan air bagi kedua-dua sampel tidak berubah iaitu 54.10%. Di samping itu, CHNS dan ICP-MS keputusan diwakili struktur DTPA. Di samping itu, kajian mekanisme interaksi berdasarkan FTIR dan NMR analisis menunjukkan bahawa DTPA dan $BaSO_4$ mempunyai ikatan hidrogen interaksi di kumpulan berfungsi CH_2.

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LIST OF ABBREVIATIONS

Ba	Barium
Ba^{2+}	Barium ion
Ca	Calcium
Ca^{2+}	Calcium ion
g	Gram (unit of weight)
K'_S	Molal concentration solubility product
m	Mass
M	Molarity
m	Molality
ml	Milliliter (unit of volume)
s	Activity coefficient
SO_4	Sulphate
SO^{2-}	Sulphate ion
Sr^{2+}	Strontium ion
Sr	Strontium
v	Volume
Z	Charge on the ion in solution
%	Percentage

Greek

μ	Kinematic viscosity
ρ	Density
γ	Unity at zero ionic strength

Subscripts

m	Ionic molality
s	Ionic strength
v	Viscosity

LIST OF ABBREVIATIONS

C	Celcius (unit of temperature)
CHNS	Carbon, Hydrogen, Nitrogen, Sulphur
CO_2	Carbon dioxide
CO_3	Carbonate
DTPA	*Diethylenetriaminepentaacetic acid*
EDTA	*Ethylenedinitrilotetraacetic acid*
Exp.	Experimental
F	Ferenheit (unit of temperature)
FTIR	Fourier Transform Infrared Spectroscopy
HCO_3	Bicarbonate
H_2O	Water
ICP-MS	Inductively Coupled Plasma Mass Spectrometry
NaCl	Sodium chloride
NMR	Nuclear Magnetic Resonance
ppm	Parts per million
ZnS	Zinc sulphide

1 INTRODUCTION

1.0 Background

Current study merely refers to the physical properties, characterization and mechanism study between $BaSO_4$ and DTPA. $BaSO_4$ is one of the scales that formed in an oil and gas industries. It became a big problem to the production because the deposition of this scale is hard to remove, whether chemically or mechanically. It is due to $BaSO_4$ has low solubility. DTPA is one type of chelating agent, recently being used to remove the $BaSO_4$ scale. The study regarding the physical properties of DTPA, characterization of DTPA and interaction mechanism study had been conducted to identify the ability of DTPA to dissolved $BaSO_{4.}$

1.1 Motivation

The deposition of insoluble mineral salts or scales in production facilities is a relatively common problem in the oil and gas industry. This problem is resulting in a decrease in oil and gas production; while in the meantime, there were a significant increase in demand for oil and gas. Many oil wells have suffered flow restriction, generally in primary, secondary and tertiary oil recovery operation, because of scale formation within the oil producing formation matrix and the down holes equipment as well as the scale deposition on the surface of the production equipment. Precipitation of mineral salts has been also recognized as a major cause of formation damage either in injection or producing wells (Amiri & Moghadasi, 2010).

Others consequence could be emergency shutdown, increased maintenance cost and decrease in production efficiency (Blanco, Tang, Shuler, & Goddard III, 1997). Besides that, the scale can be also deposited in plug lines and equipment that will lead to equipment failure. The failure of these equipments could risk the production system. The deposition of scales also can be in the pores of the formation and eventually results in injectivity decline with time (Yuan & Todd, 1991).

Scale deposition also leads to formation damage. Loss of well performance because of formation of scale has been discussed in several of articles. The oil recovery was strongly affected by permeability of reservoir, whether the reservoir permeability can be kept intact or even improved. Changes in permeability of petroleum wells had a great deal of concern by the oil and gas industry. This problem was called as formation damage and it could happen during almost at any stage of petroleum exploration and production operations.

There are a few types of scale that commonly found in the oil and gas production system as shown in Table 1-1.

Table 1-1: Common oilfield scales (Amiri & Moghadasi, 2010)

Name	Chemical Formula	Primary Variables
Calcium Carbonate	$CaCO_3$	Partial pressure of CO_2, temperature, total dissolved salts, pH
Calcium Sulphate:		
Gympsum	$CaSO_4.2H_2O$	Temperature, total dissolved salts, pressure
Hemihydrate	$CaSO_4.1/2H_2O$	
Anhydrite	$CaSO_4$	
Barium Sulphate	$BaSO_4$	Temperature, pressure
Strotium Sulphate	$SrSO_4$	Temperature, pressure, total dissolved salts
Iron Compounds:		
Ferrous Carbonate	$FeCO_3$	Corrosion, dissolved gases, pH
Ferrous Sulfide	FeS	
Ferrous Hydroxide	$Fe(OH)_2$	
Ferrous Hydroxide	$Fe(OH)_3$	

The deposition of scale often resulted from the incompatibility between injected saline water and reservoir water (Todd & Yuan, 1992). Sea water was injected into the reservoir in order to maintain the pressure and improve the secondary recovery in offshore production system. Two waters are called incompatible if when mixed them, they interact chemically and results in minerals precipitation.

Typically, sea water contain high concentration of SO_4^{2-} and low concentration of Ca^{2+}, Ba^{2+} and Sr^{2+}, while formation or reservoir water contain very low concentration of SO_4^{2-} but high concentration of Ca^{2+}, Ba^{2+} and Sr^{2+}. When these two waters mixed, supersaturated brine was created and $CaSO_4$, $BaSO_4$ and $SrSO_4$ deposited.

During the production, the water was drained to the surface. This water suffered from significant pressure drop at various temperatures. The pressure drop leaded to release the carbon dioxide that resulted an increase in pH value of produced water and precipitation of $CaCO_3$ (Mackay, 2003).

Precipitation of mineral salts including the solids depositing on the pore walls reduced the permeability of reservoirs due to the attractive forces between the particles and the surface of the pore, the pore blocking by a single particle, several particles bridging across the pore throat. The formation damage was influenced by the characteristics of the precipitation. The characteristics were the large degree of supersaturation, the presence of impurities, the changes in temperatures and the rate of mixing that controlled the quantity and morphology of the deposited minerals (Aliaga et al., 1992).

The production problem that caused by the deposition of mineral scale in oil production operations had been recognized long ago. Among the problems was caused by sulphate scale, particularly $BaSO_4$ scale. The deposition of this scale was a difficult problem due to the low solubility of $BaSO_4$ in the most type of fluids. Besides that, most acids were commensurate low reactivity with $BaSO_4$ scale. The continuous deposition of $BaSO_4$ on the surface of production tubular exposed very little surface area for chemical treatment and thus, this scale was almost impossible to remove once it was deposited.

1.2 Problem statement

Scale deposition has been recognized as a major problem in oil and gas production industries. It contributes to pipeline formation damage, emergency shutdown, increased maintenance cost and decrease in production efficiency. As a result, they decreased the amount oil and gas production while the demand for oil and gas significantly increase. Among the scales formed as shown in Table 1-1, $BaSO_4$ scale is the hardest scale to remove, whether mechanically or chemically (Guimaraes et al., 2007). Thus, a potential solvent needs to be applied in order to remove the $BaSO_4$ scale to ensure the continuity of oil and gas supply.

1.3 Objectives

The following are the objectives of this research:

- To study the dissolution ability of DTPA toward $BaSO_4$
- To investigate the physical properties of DTPA and DTPA-$BaSO_4$ mixture in term of pH value, water content, density and viscosity
- To characterize the DTPA based on the results of ICP-MS and CHNS
- To identify the interaction mechanism between DTPA and $BaSO_4$ based on the NMR and FTIR analysis

1.4 Scope of this research

The following are the scope of this research:

i) The correlation of results obtained from characterization tests with the chemical formula of DTPA

ii) Experimental analysis of the amount of $BaSO_4$ ranging from 0.01 to 0.06 g that can be dissolved in DTPA at mild condition (temperature of 25^oC and atmospheric pressure)

iii) The difference between the pure DTPA and DTPA-$BaSO_4$ mixture to identify the interaction mechanism between DTPA and $BaSO_4$.

1.5 Organisation of this thesis

The structure of the reminder of the thesis is outlined as follow:

Chapter 2 consists of review regarding the scale deposition, type of scales in the oil and gas production system, the variable that effected the scale formation, and current methods for removal of scales. In addition, the general review for DTPA pentapotassium salt included in this paper.

Chapter 3 told about the laboratory work to analysis the physical properties of DTPA pentapotassium salt such as analysis of pH value, density, viscosity, water content and solubility of $BaSO_4$ in DTPA. Besides that, the method for characterization and interaction mechanism study between $BaSO_4$ and DTPA pentapotassium salt briefly explained in this section.

Chapter 4 consists of the results and discussion of laboratory work and analysis study. Those results were summarized. The explanation for the results was briefly discussed. Besides that, the results from the previous works were also compared with the result from the experimental work and analysis study.

Chapter 5 concluded the findings and results that obtained from the laboratory work and analysis. This conclusion contained also some explanation for the results. In addition, some recommendation was made in order to improve the experimental work and analysis study. The future work also stated in this section.

2 LITERATURE REVIEW

2.0 Overview

The formation of mineral salts in oil production system is a relatively common problem. Scale deposition can occur due to the mixing of incompatible injection and formation waters in the well as well as in the tubing.

2.1 Type of scales

The common scales formed in the oil field are $CaCO_3$, $CaSO_4$ (anhydrite, gypsum), $BaSO_4$ (barite), $SrSO_4$ (celestite) and ferrous scale (Merdhah & Yassin, 2009).

2.1.1 Calcium carbonate scale

Calcium carbonate or calcite scale was frequently encountered in oil and gas production system. The calcite had a greatest stability in oilfield circumstances. Therefore, it was the most common scale faced in the oilfield. The $CaCO_3$ crystals were large. However, the scale appeared uniformly when the scale was found together with the impurities in the form of finely divided particles. Deposition of $CaCO_3$ scale could be summarized as below:

$$\mathrm{Ca^{2+} + {CO_3}^{2-} \rightarrow CaCO_3} \tag{2.1}$$

Besides that, the $CaCO_3$ scale also formed by combination of calcium and bicarbonate ions and this was a major cause of the $CaCO_3$ scale deposition. This was due to only a small percentage of the bicarbonate ions dissociated at the pH values found in the most injection waters to form H^+ and CO_3^{2-} (Moghadasi et al., 2004b).

In addition, the $CaCO_3$ scale also formed when there was a significant pressure drop and temperature variations. The water was drained to the surface and suffered from the significant pressure drop and temperature variations during the production operation. The continuous pressure drops leaded to degassing of CO_2 with an increased in the pH value of the produced water and precipitation of $CaCO_3$ (Rousseau et al., 2003).

When connate or acquifer water passed through the bubble point, the CO_3 was evolved. As the gas evolved, the solubility declined rapidly with the respect to carbonate and formed the precipitation with divalent ions, commonly calcium, as outlined (Mackay & Jordan, 2005):

$$\mathrm{Ca(HCO_3)} \leftrightarrow \mathrm{CaCO_3} + \mathrm{CO_2} + \mathrm{H_2O} \tag{2.2}$$

2.1.2 Calcium sulphate scale

Calcium sulphate was a unique problem in oilfields because it occurred with one of three different phases. Calcium sulphate existed in several crystalline forms, which were gypsum ($CaSO_4.2H_2O$), hemihydrate ($CaSO_4.1/2H_2O$) and anhydrate ($CaSO_4$). These compounds might be stable depending on temperature and ionic strength.

Gympsum was the most common scale deposited at relatively low temperature, while at higher temperature (above 100^{o}C), the more stable phase of calcium sulphate than gypsum predicted was anhydrite. However, hemihydrate had been studied to form at 100 to 121^{o}C, especially in non-turbulent system and in high ionic strength of brines (Moghadasi et al., 2003). Besides that, they have decreasing solubility with increasing temperatures.

The mixing of incompatible brines leaded to the formation of these sulphate scale when the injection water contains sulphate ions (Mackay & Jordan, 2005).

$$\mathrm{Ca^{2+}} + \mathrm{SO_4}^{2-} \leftrightarrow \mathrm{CaSO_4} \tag{2.3}$$

2.1.3 Barium sulphate scale

Barium sulphate or barite was a disaster in the water flood projects formed by mixing of incompatible injected and formation waters. Barite scale was typically grayish in colour but the pure barite was white. The scales might have impurities or organic material trapped in the barite scale that gave them a blackish tinge. The specific gravity of $BaSO_4$ scale was around 4.5 and the Mohr hardness was in the range of 2.5 to 3.5.

Usually, the consequent of this formation of scale was the reduction of reservoir permeability and eventually, decreased the well production. $BaSO_4$ could be deposited easily related to the thermodynamics condition and kinetics of precipitation. Formation of $BaSO_4$ scale could be described as:

$$\mathrm{Ba}^{2+} + \mathrm{SO_4}^{2-} \leftrightarrow \mathrm{BaSO_4} \qquad (2.4)$$

$BaSO_4$ was the most insoluble scale, which it was a hard scale and extremely hard to be removed. The solubility of barite scale was about a thousand times less than of $CaSO_4$, at the surface conditions. The $BaSO_4$ solubility also increased when the temperature, pressure and salt content in the brine was increased. Since the pressure, temperature or salt content drop would increase precipitation, thus, the prediction of $BaSO_4$ scale was much easier than the other scales.

Besides that, the $BaSO_4$ scale treatment focussed mainly on its prevention through the usage of scale-control chemicals. Thus, the severity of the scaling problem was determined both by the scaling rate and the efficiency of the chemical inhibitors.

2.2 Deposition of scales

Precipitation of solid minerals, which might form scales, would occur if:

i) The water contained ions capable of forming compounds of limited solubility.

ii) There were changes in the physical conditions or water composition, which lowered the solubility.

The severity of scale formation may be divided into the following stages (Fan et al., 2012): (1) nucleation and precipitation of scales; (2) attachment of scales to tubing surfaces; and (3) crystal growth. The formation of scale grows from solution. The first development is a formation of unstable clusters of atoms within a saturated fluid (Crabtree et al., 1999). The process is called homogeneous nucleation (Figure 2-1).

The seed crystals, a catalyst for scale formation, grow by ions absorbing on the crystal surfaces and subsequently, extending the crystal size. The large seed crystals favor continuing the growth, while small seed crystals may re-dissolve (Harry Y., Steven M., & Maria E., 2003) and give a large degree of saturation. Thus, the formation of any seed crystal will encourage the growth of scale deposits to increase.

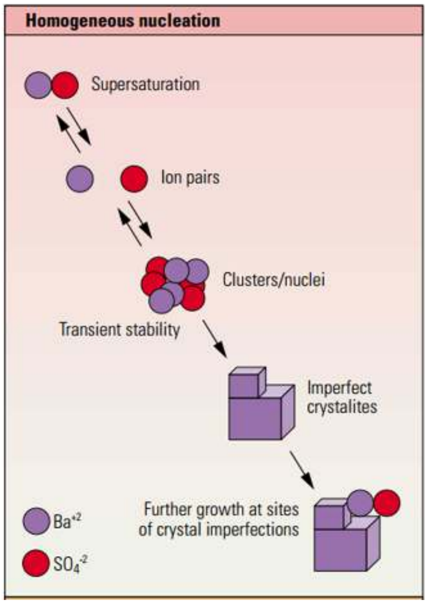

Figure 2-1: Homogeneous nucleation process is where ion pairs forming single crystals in solution (Crabtree et al., 1999)

Scale growth also initiates on a pre-existing fluid-boundary surface and this process is called heterogeneous nucleation as shown in Figure 2-2. The sites for heterogeneous nucleation are including the surface defects such as pipe surface roughness or perforations in production liners, or joints and seams in tubing and pipelines. Besides that, the accumulation of scale can occur in the flowing system at the position of the bubble point pressure that cause by a high degree of turbulence that catalyze the scale deposition (Crabtree et al., 1999).

When producing oil and gas there will in most cases also be produced some water, which contains dissolved salts. These salts may precipitate and they tend to deposit on surfaces. Deposition of inorganic minerals from brine is called scale, and its formation causes flow reduction or even blocking of pipes, valves and other equipment.

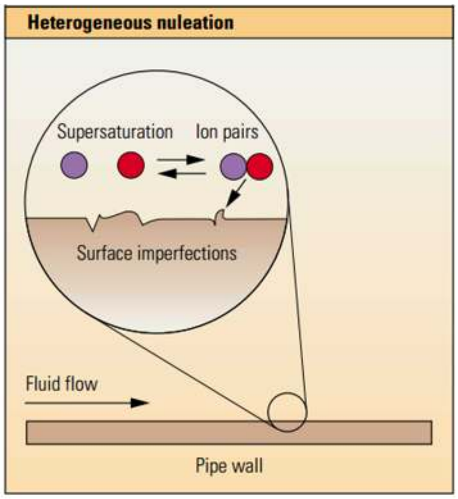

Figure 2-2: Heterogeneous nucleation process is growth of scales on pre-existing surface defects (Crabtree et al., 1999)

Common types of scale during oil and gas production are $CaSO_4$, $SrSO_4$, $BaSO_4$ and $CaCO_3$. Flow reduction can lead to a severe decrease in production rate, and may also lead to safety problems, for example, if scale forms in the down hole safety valve. The economical impact for both prevention and removal of scale can be serious. In some cases the scale may even be radioactive due to small amounts of radium, and must therefore be treated as radioactive waste (Sandengen, 2006). Figure 2-3 shows scale formation in tubing that obviously will constitute a serious flow restriction.

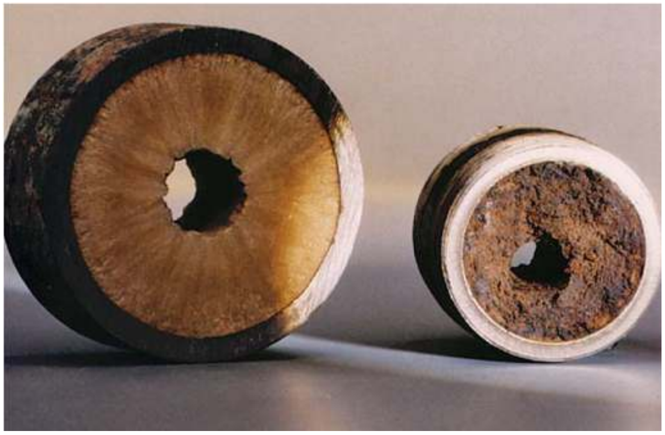

Figure 2-3: Scale in tubing (Sandengen, 2006)

Scale deposition can cause by the mixing of incompatible injection and formation waters in the well as well as in the tubing. Seawater, typically rich in SO^{2-} anions, is often injected into reservoirs during secondary to maintain the reservoir pressure and therefore increase oil recovery. When this encounters the formation water containing Ca^{2+}, Ba^{2+} and Sr^{2+} it may lead to sulphate precipitation; $CaSO_4$, $SrSO_4$ and $BaSO_4$. This type of scale is usually fairly easy to predict, but $BaSO_4$ is one of the most serious scale forming minerals in the oil industry. The SO_4^{2-} concentration in sea water is therefore frequently reduced prior to injection to avoid such problems (Sandengen, 2006).

An overview of all possible scale formation environments for sea water, aquifer, natural depletion and produced water re-injection is shown in Figure 2-4 (Jordan, Collins, & Mackay, 2008; Jordan & Mackay, 2005).

a) For example, before injection, if seawater injection is supplemented by produced water reinjection (PWRI)
b) Around the injection well, as injected brine enters the reservoir contacting formation brine
c) Deep in the formation, owing to displacement of formation brine by injected brine, or owing to converging flow paths
d) As injection and formation brines converge towards the production well, but beyond the radius of a squeeze treatment
e) As injection and formation brines converge towards the production well, and within the radius of a squeeze treatment
f) In the completed interval of a production well, as one brine enters the completion, while another brine is flowing up the tubing from a lower section, or as fluid pressure decreases
g) At the junction of a multilateral well, where one branch is producing a single brine and the other branch is producing incompatible brine
h) At a subsea manifold, where one well is producing one brine and another well is producing a different brine

i) At the surface facilities, where one production stream is flowing one brine and another production stream is flowing another brine

j) During aquifer water production and processing for reinjection, with the possibility of scale formation within a self-scaling brine or mixing with an incompatible formation brine as in b)

k) During pressure reduction and/or an increase in temperature within any downhole tubing or surface processing equipment, leading to the evolution of CO_2 and to the generation of carbonate and sulfide scale if the appropriate ions are present. Temperature reduction could lead to the formation of halite scales if the brine is close to saturation under reservoir conditions

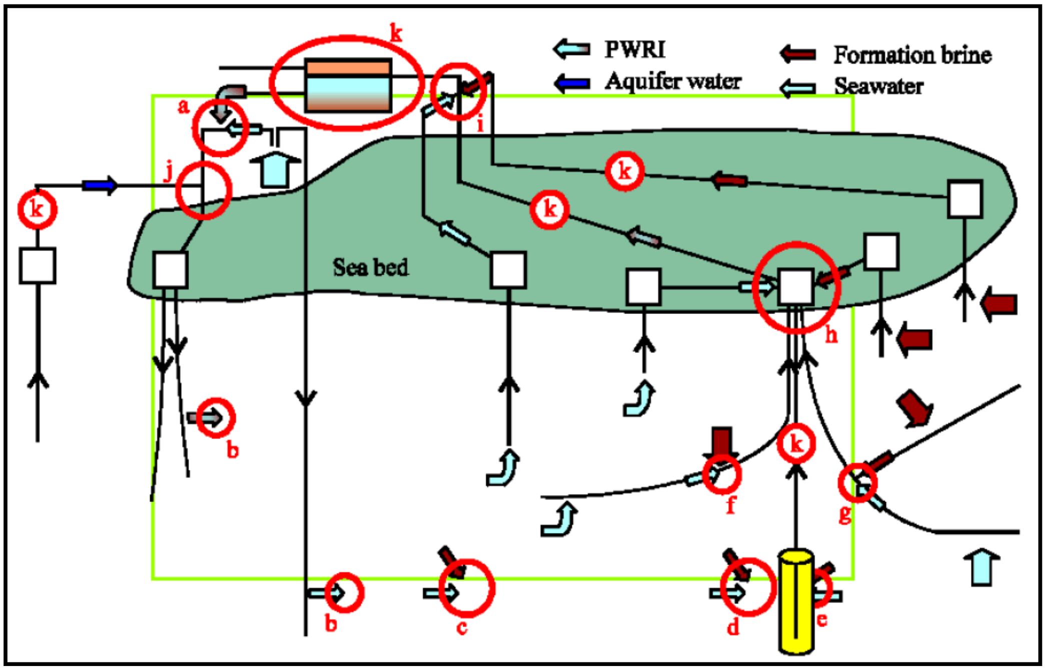

Figure 2-4: Location throughout the flow system where the scale deposition may take place (Jordan et al., 2008)

In oilfield system, for both offshore and onshore, there are three principal mechanisms of scale formation (Amiri & Moghadasi, 2010; Mackay & Jordan, 2005):

a) Decrease in pressure and/ or increase in temperature of a brine, goes to a reduction in the solubility of the salt which is most commonly lead to precipitation of carbonate scales, such as $CaCO_3$.

$$Ca(HCO_3)_2 \leftrightarrow CaCO_3 + CO_2 + H_2O \qquad (2.5)$$

b) Mixing of two incompatible brines where most commonly formation water rich in cations such as Ca^{2+}, Sr^{2+} and Ba^{2+} mixing with sulphate rich seawater, precipitating the sulphate scales, such as $BaSO_4$.

$$\mathrm{Ca^{2+}\ (or\ Ba^{2+}\ or\ Sr^{2+}) + SO_4{}^{2-} \rightarrow CaSO_4\ (or\ BaSO_4\ or\ SrSO_4)} \tag{2.6}$$

Other fluid incompatibilities include sulphide scale where hydrogen sulphide gas mixes with iron, zinc or lead rich formation water.

$$\mathrm{Zn^{2+} + H_2S \leftrightarrow ZnS + 2H^+} \tag{2.7}$$

c) Brine evaporation which is resulting in salt concentration to increase above the solubility limit and form salt precipitation as it may occur in high pressure/high temperature gas wells where a dry gas stream may mix with a low rate brine stream, resulting in dehydration and most commonly the precipitation of NaCl.

The extensive use of water injection for oil displacement and pressure maintenance, many oil and gas reservoirs experienced the problem of scale deposition when the injection water began to breakthrough. The consequence was the formation damage. According the Moghadasi et al. (2004a), formation damage was a terminology that referred to the impairment of the permeability of bearing formations of various adverse processes.

The formation damage was an undesirable operational and economic problem that occurred during the oil and gas recovery. The recovery from the subsurface reservoirs involved drilling, production, hydraulic fracturing and work over operations. The fundamental processes that cause the damage in the petroleum bearing formations were hydrodynamics, physico-chemical, chemically, thermally and mechanically.

The formation damage mechanisms can be categorized into three major processes (Leone & Scott, 1988):

1) Hydrodynamics

During the fluid flow, a mechanical force, by exerting a pressure gradient, mobilized loosely attached fine particles from the pore surface. The movement of many different types of fine particles, such as clay minerals, quartz, amorphous silica, feldspars and carbonates, might cause mechanical fine migration damage.

2) Physico-chemical

   This mechanism was due to the water sensitivity clays. In equilibrium, the clays existed with the formation brines until the ionic composition and concentration of the brine was altered (Crowe, 1986). Decrease of permeability was caused by the swollen clay that occupied the pore space. However, permeability decline more often happened because of the fines that released by the swelling.

3) Geochemical

   The injected fluid might not be compatible with the native pore fluid during treatment of wells or water flooding. As a result, there would be no equilibrium chemical in the porous system. The ions in the source water might react with the ions in the reservoir fluids in order to form precipitation of solid downstream in the porous system. This precipitation would plug the pore throats or deposit onto the pore wall that resulting in the porosity reduction.

2.3 Solubility of scales

Solubility is defined as under a given set of physical conditions, the limiting amount of solute that can be dissolved in a solvent. When a sufficiently amount of solute was contacted with a limited amount of solvent, dissolution occurred until the mixture solution reached one state when the reverse process in equilibrium. This reverse process was the return of dissolved species to the undissolved state and the process was called precipitation.

Dissolution and precipitation occurred continuously and at the same rate. The amount of dissolved solute presented in a given amount of solvent remained constant with time, where the process was in dynamic equilibrium. This state of equilibrium was known as a saturated solution. In addition, the solution that contained less solute was called an unsaturated solution, while the solution with higher concentration of solute than the amount required for the solvent said to be a supersaturated solution.

2.3.1 Effect of temperature

Salt solubility is generally highly temperature dependent, thus temperature changes throughout the productions system is usually a critical factor for scale prediction. Some salts have a lower solubility at high temperature and are therefore particularly troublesome on surfaces of heat exchangers and in the hot zone of a well. Others can be troublesome at low temperature. The water solubility of a mineral is increased with the increasing of temperature. Figure 2-5 shows the solubility of some common oilfield scales of injection water.

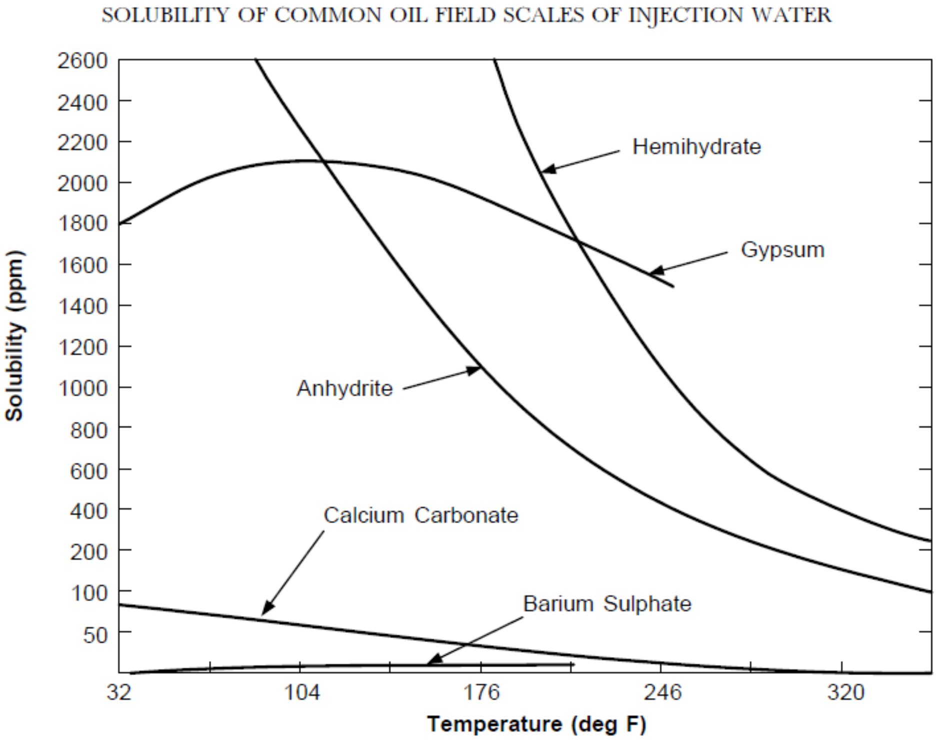

Figure 2-5: Solubility of common oilfield scales at various temperatures (Connell, 1983).

2.3.2 Effect of pressure

Commonly, $CaSO_4$, $BaSO_4$ and $SrSO_4$ had high solubility at higher pressure. The precipitation of sulphate scales by the formation water usually occurred when the pressure was reduced during the production. $BaSO_4$ was commonly precipitate at the perforations or downstream of chokes, where the pressure was reduced considerably