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INVESTIGATION OF THE RISKS OF INTRODUCING PRODUCED WATER INTO FRESHWATER INJECTION SYSTEM

INVESTIGASI RESIKO PENAMBAHAN AIR TERPRODUKSI KE SISTEM INJEKSI AIR TAWAR

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ABSTRAK

Penggunaan air injeksi dari berbagai sumber potensial memperburuk resiko kerusakan formasi dan dapat berdampak pada perolehan minyak. Sebuah studi kasus bagaimana menilai resiko tersebut dibahas dalam makalah ini. Studi berdasarkan pada percobaan laboratorium. Material, metode, dan prosedur uji yang tepat untuk mendapatkan kualitas data sebagai acuan teknis interpretasi potensi resiko diuraikan secara detail. Telah diidentifikasi resiko penyumbatan, pengendapan, penurunan permeabilitas, dan kehilangan perolehan minyak disebabkan penggunaan air terproduksi. Penyumbatan disebabkan keberadaan bakteri dan partikel padatan dalam air terproduksi. Pertumbuhan bakteri tergolong tinggi. Konsentrasi padatan juga tinggi dengan diameter rata-rata lebih besar dibandingkan diameter partikel yang dianggap tidak merusak. Pengendapan $CaCO_3$ potensi terjadi pada temperatur reservoir akibat konsentrasi HCO_3^- dalam air terproduksi tinggi. Penggunaan air terproduksi bersama air tawar menyebabkan penurunan permeabilitas secara signifikan. Untuk komposisi 25% air terproduksi dan 75% air tawar, penurunan permeabilitas berkisar 80% dari permeabilitas awal. Penambahan 2000 ppm biosida dan penggunaan kertas saring 11 mikron dapat meningkatkan kualitas air terproduksi. Dengan komposisi air injeksi yang sama, permeabilitas hanya turun 47%. Analisa ukuran diameter pori batuan dan partikel padatan ikutan dalam air menunjukan perlu penggunaan saringan kurang dari 11 mikron untuk mencegah penurunan permeabilitas akibat penyumbatan partikel padatan. Percobaan dengan injeksi air tawar menunjukan perolehan minyak sebesar 46.1%. Bila menggunakan campuran 50% air terproduksi dan 50% air tawar, terjadi penurunan perolehan minyak sebesar 16% dibandingkan hasil injeksi hanya air tawar. Potensi kehilangan perolehan minyak tersebut merepresentasikan efek kuantitatif kerusakan formasi terhadap produksi minyak. Informasi ini sangat bermanfaat untuk evaluasi keekonomian pengembangan lapangan.

Kata Kunci: *Air terproduksi, air tawar, kerusakan formasi, penyumbatan, pengendapan, penurunan permeabilitas, kehilangan perolehan minyak*

ABSTRACT

Mixing of waters from different sources may exacerbate the risk of formation damage and can impact on oil recovery. A case study is presented to demonstrate how to assess these risks. The study relies on laboratory-based work. Appropriate materials, methods, and procedures to assure the quality of test data and derive technically valid risks potential interpretations are discussed. The risks for potential plugging, *scaling, permeability reduction, and oil recovery loss caused by introducing produced water are identified. Plugging is caused by bacterial growth and solid particles present in produced water. Bacterial growth is categorized as high. Solids Concentration is also high with its mean diameter larger than the non-damaging particle size. The $CaCO_3$ scale is likely at reservoir temperature due to high concentration of HCO_3^- in the produced water. Mixing of untreated produced water and treated freshwater caused significantly reduction in permeability. For the 25% PW and 75% FW mix, the permeability decreases by about 80% of its initial permeability. Adding 2000 ppm of biocide and filtered using 11 micron filter paper improved the quality of produced water. For the same mixing fraction, the permeability decreases only 47%. Analysis of pore throat size in conjunction with particle size of water samples suggests the need for using a filter less than 11 micron to avoid permeability decline imposed by solid particles. Waterflood experiments showed an ultimate recovery factor of 46.1% of original oil in place obtained from freshwater injection. Introducing 50% of produced water caused an oil recovery loss of 16% compared to freshwater injection alone. This lost oil recovery represents a quantitative effect of formation damage on oil production and may be valuable from the economic viewpoint.*

Keywords: *Produced water, freshwater, formation damage, plugging, scaling, permeability reduction, oil recovery loss*

I. INTRODUCTION

Injection of water for pressure maintenance and sweeping oil towards production wells is a common practice in the oil industry. The main reason behind using this technique has been that it offers high efficiency in displacing light to medium gravity crude oils, ease of injection into oil-bearing formations, availability and affordability of water, and lower capital and operating costs, leading to a favorable economic outcome compared to other improved oil recovery methods. The possible sources of injected water are produced water from a reservoir that is brought to the surface along with oil production and a suitable source from an external reservoir. External sources range from seawater, lake water, river water, to shallow aquifer freshwater. A successful water injection project can increase oil recovery from 5% to 25% normally seen under primary recovery, up to typically a 45% recovery of original oil in place.

At the start of a water injection project, all the injected water is sourced from an external reservoir. As oil production continues, the volume of water produced by a well and a field will increase. Then, the percentage of produced water reinjected is also increased. This does come without risks because both surface and produced waters are usually different in composition. Mixing of waters from different sources may exacerbate the risk of formation damage and can impact oil recovery. Evans (1994) provides a good description of the different activities required during produced water reinjection project to avoid any risk associated with the project. They are produced water characterization, plugging, scaling, souring studies, microbiology, corrosion, coreflooding tests, and injectivity evaluation.

Most of the recent studies of mixing produced water with surface water concern the formation damage caused by plugging, scaling, souring, and permeability reduction. Ba-Taweel *et al.* (2006) investigated the risks of injectivity decline in water injectors caused by mixing produced water with seawater using core samples from Arab-D. Experimental results showed that introducing different ratios of produced water to the seawater resulted in permeability loss in core samples. Bedrikovetsky *et al.* (2006) has shown that mixing of cation-rich produced water and seawater with sulfate anions resulted in a significant decrease in injectivity even for barium levels at decimal fraction of parts per million (ppm). Mackay (2007) studied the scaling risks at production wells due to injection of mixture of seawater and produced water. The scaling tendency at the production well through precipitation of barium and sulphate was investigated using the STARS reactive transport finite difference reservoir simulator. Zuluaga *et al.* (2011) studied the risk of both scaling and souring when produced water reinjection is supplemented by seawater in a field scale. Mahmoud (2014) investigated the damage caused by deposition of calcium sulfate precipitation by use of the material-balance method. Core flood experiments were performed to assess the damage and a computed-tomography scan used to locate the damage inside the core. The results of experimental data showed reduction of permeability of 20% from its initial value after seawater injection, caused by calcium sulfate precipitation.

Plugging risk is controlled by bacterial growth, oil content, and solid material in the water injected. Bacteria can plug rock pores by liberating H_2S, which causes precipitation of iron sulfide flocs, and by creation of bacterial slimes (Lappan and Fogler, 1995). The severity of plugging by oil will depend on oil droplet size and concentration. Large oil droplets can plug the pore throats. Increased oil saturation around the wellbore results in lowering the relative permeability to water and reduces injectivity (Ba-Taweel *et al.* 2006). Factors which control the plugging by suspended solid particles are particle size and solid concentration (Ochi *et al.* 2007). Suspended solids with large size will create an external filter cake and cause face plugging. The accumulation of the deposited particles inside the core reduces the pore sizes, blocks thin pore throats, and leads to permeability reduction.

Scaling may be induced by incompatible fluids. Two waters are called incompatible if they are mixed and interact chemically to form a solid that precipitates minerals. Mineral scales can be both calcium carbonate and or iron sulphide formation arising from produced water itself and sulfate scales arising from the comingling of barium, strontium, and calcium contained in produced water with freshwater (Zuluaga *et al.* 2011). Another mechanism of scaling is induced by pressure or temperature changes. Decrease in pressure and or increase in temperature of water leads to a reduction in the salt solubility, leading to precipitation of carbonate.

Proper mitigation of formation damage requires knowing the type of damage occurred, since treatment is damage-specific. A case study is presented to demonstrate how the potential risks of plugging, scaling, permeability reduction, and oil recovery loss caused by mixing produced water with freshwater are assessed. Loss in oil recovery is provided to get insight into how the damage affects economic field life. The field is a sandstone reservoir with current production supported mainly by freshwater injected into main zone reservoir for pressure maintenance and reservoir sweeping. The freshwater is taken from shallow aquifer formations in the same structure of the oil reservoir through several dedicated water producer wells. Currently, the produced water is disposed in the river after being treated to reduce oil content below the maximum allowable by the government requirement. Having high produced water disposed in the river, replacing freshwater with produced water for water injection has emerged from the water management strategy viewpoint.

II. METHODOLOGY

This work relies on a laboratory-based study. Appropriate materials, methods, and to procedures are needed to assure the quality of test data and to derive technically valid risks potential interpretations. Details of these issues are described in the following subsections.

A. Experimental Materials

Water Properties. Water samples representing both freshwater and produced water were collected from different sampling points. Freshwater samples were taken from three points: one at the gathering network and two samples collected at freshwater producer wellheads. Produced water samples were collected at the Oily Water Treatment Unit (OWTU) outlet flotator. Sampling was conducted daily for ten days at different times, namely morning, afternoon, and evening. There was no sampling on the seventh day owing to rain. The samples were stored in a lab fridge to prevent bacterial growth over time.

Reconciliation of water properties were obtained by averaging over the geochemical analysis of samples taken during ten consecutive days. Table 1 gives the average value and corresponding properties for each type of water. Produced water is warmer and contains higher concentration of total dissolved solids (TDS) compared to freshwater. Given TDS of 1,644 and 2,920 mg/L for freshwater and produced water, both waters are classified as brackish slightly saline water.

Cores Selection and Preparation. Four tubes of full diameter cores were obtained from a sandstone reservoir. Different laboratory tests were performed to select consistent core samples in terms of petrophysical properties as well as homogeneity. These include full diameter core X-ray computerized tomography (CT) scan, core plug CT scan, and routine core analysis. The analysis of X-ray CT scanning was performed on the well-site core tube to provide an initial non-destructive control over internal geological features before further analysis. The full diameter cores were scanned at 0° and 90° to help in selecting core-plug samples that have sedimentary bedding planes parallel to the flow direction.

Ten horizontal core plugs have been cut from full diameter cores based on the results of full diameter CT scan. Core plug dimensions are 1.5 inch in diameter and 3 inch in length. The core plugs were then CT scanned to screen out any core with fractures or permeability barriers. Routine core analysis includes porosity, air permeability, and grain density determinations were carried out for the selected cores at 4292 psig of confining pressure and temperature of 80°C. Brief lithology descriptions were also provided. Porosity was measured using helium gas porosimeter. Permeability was determined through the use of nitrogen gas permeameter. Table 2 lists the porosity permeability measurements and lithology description of the selected cores. Core plugs are grouped according to their porosity permeability and lithology characteristics for further coreflooding experiments. The first group consists of core plugs #1 and #2 will be used to assess the risk of injected water on reservoir permeability. The second group of core plugs #3, #4, and #5 are for an oil recovery study.

Mineral composition of rock samples were also investigated with the help of X-ray diffraction (XRD). XRD chipped samples were taken at the end site of core plugs #1 and #2. The sample materials are composed of approximately 81% quartz, 9% kaolinite, 3% illite, 3% siderite, and less than 5% for other minerals such as plagioclase, pyrite, and gypsum.

Table 1
Geochemical analysis and corresponding properties for sources of water

Ions	Concentration, mg/L	
	Freshwater	Produced Water
Na^+	522.4	1,039.7
Ca^{2+}	9.4	9.7
Mg^{2+}	4.3	6.0
Fe^{2+}	1.9	0.2
Ba^{2+}	0.2	0.4
Sr^{2+}	0.5	0.1
Cl^-	461.3	321.4
OH^-	0.0	0.0
CO_3^-	0.0	0.0
HCO_3^-	892.0	2,717.2
SO_4^{2-}	1.1	0.7
T °C	22.0	48.3
TDS	1,644	2,920
Oil Content	-	1.89
SG @ 60°F	1.0010	1.0028
pH	6.9	7.2

Table 2
Basic properties for core plugs used for coreflooding experiments

Core Plug#	Length (cm)	Diameter (cm)	Porosity (%)	Air Permeability (mD)	Grain Density (gr/cc)	Lithology Description
1	7.772	3.801	22.0	246	2.650	SS: gry, med hrd, fgr, sb ang – sb rdd, well srtd, sli shale, qz
2	7.773	3.800	20.7	187	2.650	SS: gry, med hrd, fgr, sb ang – sb rdd, well srtd, sli shale, qz, carb flaks
3	7.627	3.784	25.9	1827	2.649	SS: light brn, med hrd, mgr, sb ang – sb rdd, mod srtd, qz
4	7.231	3.779	25.6	4280	2.649	SS: light brn, med hrd, mgr, sb ang – sb rdd, mod srtd, qz
5	7.356	3.781	25.2	2647	2.648	SS: light brn, med hrd, mgr, sb ang – sb rdd, mod srtd, qz

B. Methods and Procedures

Methods and procedures of laboratory testing to investigate any risks associated with water injection scenarios are described below.

Plugging. Formation plugging can be impaired over time by injecting produced water with higher population of bacteria, oil content, and solid mineral. All of these can increase the risk of plugging pore throat in the near-well region where the injected water first enters the formation.

Bacterial growth was determined using most probable number (MPN) method by distributing and separating the microorganisms in liquid dilution tubes. The MPN for injection water is based on the API RP-38 method. Optimal growth medium, incubation temperature, and period are required to allow any single viable cell to grow and become quantifiable. Bacteria identification was carried out by means of purifying monocultures isolates from bacterial colonies within a dish containing nutrient agar and then observed using Bergey's manual. Oil content in produced water was determined utilizing the Concawe – 1/72 method. Total suspended solid (TSS) was measured by use of membrane filter according to NACE TM-01-73. The sample is pressed through the filter of 0.45 μm at constant pressure until a certain volume has passed the filter or for a set time. Test involves determination of the value of membrane filter test slope number (MTSN).

Degree of plugging potential is expressed by relative plugging index (RPI) with the following relationship:

$$RPI = TSS - MSTN \quad (1)$$

As MTSN always has a negative value, then the RPI is the sum generated from TSS with MTSN. A guide developed by AMOCO Production Co. Research Center is used to relate RPI with degree of plugging as presented in Table 3.

Scaling. Laboratory experimental was carried out for produced water sample to see the scale risk if produced water is introduced in the freshwater injection system. The risk for potential scale precipitation was investigated at ambient and reservoir temperatures of 74°F and 94°F, respectively.

Scaling risks induced by calcium sulfate ($CaSO_4$), barium sulfate ($BaSO_4$), and strontium sulfate ($SrSO_4$) are based on solubility calculation using the following equation, providing values of K_{sp} are known for each compound:

$$S = 1000 \times \left[\left(X^2 + 4K_{sp} \right)^{1/2} - X \right] \quad (2)$$

Here S is solubility expressed in milliequivalents/Liter (meq/L), K_{sp} is the solubility product, and X is excess ion concentration in moles/L. The S is related to scale formation as follows:

- S > the actual concentration, water is undersaturated with $CaSO_4$, $BaSO_4$, or $SrSO_4$ and scale is unlikely.
- S = the actual concentration, water is saturated or in equilibrium with $CaSO_4$, $BaSO_4$, or $SrSO_4$. Scale layer is neither precipitated nor dissolved.
- S < the actual concentration, water is supersaturated with $CaSO_4$, $BaSO_4$, or $SrSO_4$ and scale is likely.

where the actual concentration of sulfate compound in solution is equal to the smaller of the Ca^{2+} / Ba^{2+} / Sr^{2+} or SO_4^{2-} concentrations in the water of interest.

The risks posed by calcium carbonate ($CaCO_3$) scales were investigated by the Stiff Davis Method. Scaling risk indicated by scaling index (SI) as follows:

$$SI = pH\ (measured) - pHs \quad (3)$$

with the pHs is the condition at which water is saturated in calcium carbonate. Interpretation of SI is:

- For SI > 0, water is supersaturated and tends to precipitate a scale layer of $CaCO_3$.
- For SI = 0, water is saturated (in equilibrium) with $CaCO_3$. A scale layer of $CaCO_3$ is neither precipitated nor dissolved.
- For SI < 0, water is undersaturated and tends to dissolve solid $CaCO_3$.

Different ratios of produced water to the freshwater were tested for compatibility assessment

Table 3
Water quality rating guide by AMOCO

RPI	Quality Rating	Remarks
< 3	excellent	suitable for all formations
3 – 10	good – fair	good to fair
10 – 15	questionable	can cause plugging in sandstones
> 15	poor	can be used for dolomite fracture injection, but generally need treatment

using the hot rolling method. Water samples are first filtered through a 0.45 μm filter paper. Put the samples into the 500 cc sized of stainless steel cell. Place the cell in a hot roll oven for 24 hours at reservoir temperature with rotational speed of 50 rpm. After being cooled sample are re-filtered: then compare TSS formed from the testing of mixed water with TSS of 100% freshwater and 100% produced water. If the weight of precipitate minerals of mixed water is less or equal to the comparator, then the mixed water is considered compatible and vice versa.

Permeability Reduction. Core plugs #1, #2, and #3 were used to research the risk of permeability reduction resulting from injecting the mixed produced water with freshwater at various volume ratios. Two tests were undertaken. First, the produced water without any biocide treatment and filtration was used with freshwater for the water injection system. The experiment was done using core plug #1. Second, the produced water was treated by adding biocide and filtered using 11 micron filter paper before being mixed with the freshwater and injected into the core plugs #2 and #3. All experiments were performed under reservoir pressure and temperature conditions, which are 3600 psi and 60 ^{o}C respectively. The experimental procedures include:

- Load a freshwater saturated core plug into core holder and put it in the 60 ^{o}C oven and applying confining pressure of 4100 psi.
- Inject freshwater that has been filtered using 11 micron filter paper at pressure of 3600 psi up to several pore volume (PV) to get stabilized differential pressure (dP) between inlet and outlet of injection fluid.
- Inject mix of 25% of freshwater with 75% of production water up to several PVs and investigate the reduction trend of both differential pressures.
- If the permeability damage is not severe, then inject mix of 50% of freshwater with 50% of production water, 75% of freshwater with 25% of production water, and finally 100% of production water.
- Perform a post freshwater injection to see whether the permeability damage could be recovered back to its original.

Oil Recovery Loss. Quantitative effect of risks related formation damage caused by commingling produced water with freshwater to oil production is expressed by loss of oil recovery. Three waterflood experiments were conducted to assess the risks. They are 100% freshwater, 50% freshwater and 50% produced water mix, and 100% produced water injections. Core plugs #4, #5, and #6 were used in those experiments. The experimental procedure is described below:

- Inject freshwater of 3 PV and heat the cell and core at reservoir temperature of 60^{o}C.
- Measure initial permeability to water, $k_w@S_{oi}$.
- Inject Marcol 52 until the pressure drops across the core plug is stabilized and no more water production.
- Measure initial permeability to oil at irreducible water saturation, $k_{o1}@S_{wi}$.
- Measure the displaced water volume accurately,
- Inject toluene of 1 PV.
- Inject filtered crude oil of 5 PV and measure initial permeability to oil at irreducible water saturation, $k_{o2}@S_{wi}$.
- Shut-in the cell with pressure and temperature to restore rock and fluids wettability for one week.
- Perform core waterflooding and calculate the oil recovery factor versus water injection volume.

III. RESULTS AND DISCUSSION

Risks which arise when introducing produced water into the freshwater injection system for pressure maintenance and sweeping oil in a sandstone oil field studied are discussed below.

A. Plugging

Table 4 gives the average RPI values for freshwater and produced water measured during the ten consecutive days both onsite and in the laboratory. Test results shown that produced water rated poorly in term of RPI, indicating faster plugging of the filter. It means that a high potential plugging may arise when produced water is introduced into the freshwater water injection system without any treatments. The RPI becomes more severe when it tested again in the laboratory due to the increase in value of MTSN and TSS as seen in Figure 1. Meanwhile the fresh water in general rated as excellent with a few having a quality rating good to fair. MTSN and TSS measured in laboratory and onsite are relatively unchanged as depicted in Figure 2.

The variation of MTSN and TSS is controlled by bacterial growth, oil content, and solid particles material. Microbiological analysis indicated that both produced water and freshwater generally contain insignificant anaerobic bacteria with population less than 10 cell/mg. Specific anaerobic bacteria include sulfate-oxidizing bacteria (SOB) and sulfate-reduction bacteria (SRB) were also found in an insignificant number. But aerobic bacteria in the produced water were generally found to be high density of 10,000 – 99,999 cell/ml. Oil content in produced water measured during the ten consecutive days ranged from 0.5 up to 5.0 mg/L with the average value is 1.9 mg/L, a very low level compared with the standard dischargeable value of less than 30 mg/L (Arthur *et al.* 2005). Bacteria can produce biofilm. Oil and solids particles entrained in produced water may be trapped by the developing bacterial biofilm. This explains higher MTSN value from the laboratory tests compared with the onsite tests. The increasing of TSS was triggered by the bacterial content since they add the actual weight of filter paper.

Another source of plugging comes from the particle size and solids concentration on waters related to the pore throat distribution. Non-damaging particle size distribution should not be larger than $1/10^{th}$ – $1/7^{th}$ of pore throat size (Ba-Taweel *et al.* 2006). Table 5 gives a summary of pore size distribution measured from four core samples. It showed that pore aperture diameter of 10-30 μm around 39% and 1-10 μm about 25%. For an average (D_{50}) pore throat size of 10 μm, the non-damaging diameter for the invading particle has to be less than 1.0-1.4 μm using the $1/10^{th}$ – $1/7^{th}$ rule. Table 6 provides particle size distribution and solid concentration on four water samples. The mean diameter of solids in produced water and freshwater are 5.4 and 5.5 μm, respectively, which

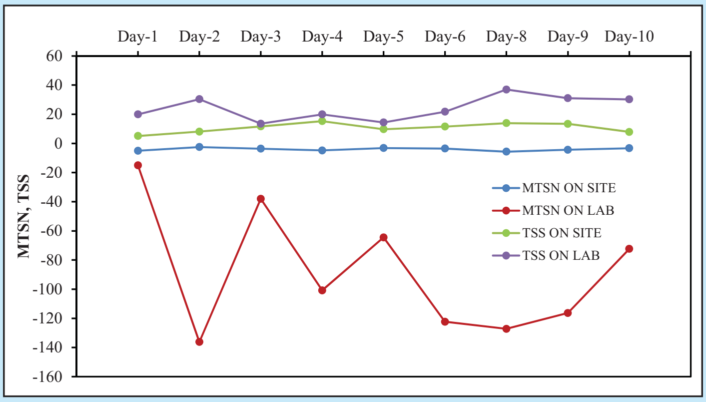

Figure 1
MTSN and TSS values of produced water obtained from laboratory and onsite tests

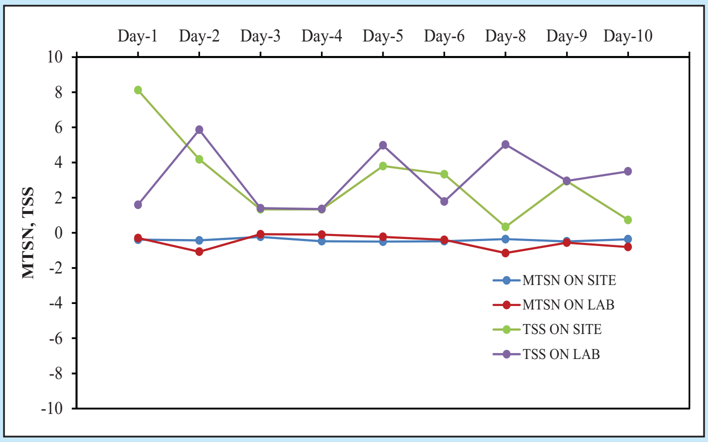

Figure 2
MTSN and TSS values of freshwater obtained from laboratory and onsite tests

Table 4
RPI analysis of water samples

Water Sample	Onsite				Laboratory			
	MTSN	TSS	RPI	Rating	MTSN	TSS	RPI	Rating
Morning produced water	-4.95	10.12	15.07	poor	-81.16	24.08	105.24	poor
Afternoon produced water	-3.98	15.10	19.09	poor	-61.57	20.28	81.85	poor
Evening produced water	-3.08	6.98	10.06	fair	-121.54	28.30	149.84	poor
Freshwater gathering line	-0.48	3.92	4.40	good	-0.67	1.17	1.84	excellent
Freshwater Well 1	-0.48	2.42	2.90	excellent	-0.18	7.35	7.53	fair
Freshwater Well 2	-0.28	2.36	2.64	excellent	-0.73	0.96	1.69	excellent

is larger than the non-damaging particle size. Solid concentration in produced water is also much higher than freshwater. The increase in solid concentration will increase the risk of plugging.

The above results indicate that plugging risk will increase by injecting produced water into the freshwater injection system, but levels are expected to be manageable through the use of suitable biocide and filters. Appropriate biocide with optimal concentration is generally effective in reducing the number of bacterial cells. Waters should be screened using filter below 10 μm to ensure removal of fine particles greater than 5 μm in order to reduce the risk of plugging.

Table 5
Pore size distribution from core samples

Permeability (mD)	Porosity (%)	Pore Size Distribution, % PV				
		<0.1 μm	0.1-1.0 μm	1-10 μm	10-30 μm	>30 μm
267	25	5.4	12.9	27.4	35.9	5.0
205	25	5.1	11.4	21.4	41.7	5.6
173	26	4.3	12.7	23.2	39.1	4.5
2,102	29	3.1	7.0	11.1	21.1	49.6

Table 6
Particle size distribution of solids in water samples

Water Sample	3-12 μm		5-20 μm		10-40 μm	
	Count	D50%	Count	D50%	Count	D50%
Morning produced water	5,072	4.8	844	8.7	102	17.0
Afternoon produced water	4,849	4.7	629	8.8	95	16.9
Evening produced water	3,223	5.1	757	9.2	140	16.5
Freshwater gathering line	1,624	5.1	502	8.5	38	16.6

Table 7
Scaling index tendency calculations for produced water

Scale	Actual Concentration, meq/L	77 °F		94 °F	
		S, meq/L	Tendency	S, meq/L	Tendency
$CaSO_4$	0.0135	29.4496	unlikely	30.4456	unlikely
$BaSO_4$	0.0052	0.0422	unlikely	0.0474	unlikely
$SrSO_4$	0.0043	1.6744	unlikely	0.7761	unlikely
		SI		SI	
$CaCO_3$		-0.6230	unlikely	1.0867	likely

B. Scaling

Table 7 presents the average values of scaling index tendency calculations from 27 produced water samples that were taken three times a day for nine days. The highlighted cell indicates a condition that is interpreted high risk for potential scale precipitation. Precipitation of $CaSO_4$, $BaSO_4$, and $SrSO_4$ are not likely because the produced water is under saturated with those sulfate mineral scales. The S values calculated for $CaSO_4$, $BaSO_4$, and $SrSO_4$ are higher than actual concentration both at the ambient and reservoir temperatures. Cation and anion levels present in the produced water are found not sensitive to the temperature change in forming precipitation of sulfate mineral scales.

The risk for potential sulfate mineral scales is further investigated through compatibility test. Different ratios of produced water to freshwater are tested. Table 8 presents the results for the mixing fraction that were used in the compatibility test. PW refers to produced water, while FW refers to freshwater. The results show that the weight of precipitation formed after mixing according the scenarios is below the average weight of proportional precipitate. It means that no precipitation from the mixing of two waters is expected. Scaling index calculations and compatibility tests are found consistent with the geochemical analysis reported in Table 1. Less amounts of sulfate mineral scale-associated ions in the produced water leads to a low risk for potential scale precipitation.

The laboratory testing of 27 water samples indicated that there is a tendency for $CaCO_3$ to precipitate at ambient temperature, although unlikely on average. At reservoir temperature, the tendency for $CaCO_3$ scale is likely. In other words, $CaCO_3$ scaling risk increases with temperature. Increases in temperature leads to a reduction in the solubility of the salt. Decreasing solubility caused the compounds precipitate from solution as solids. Level of dissolved bicarbonate HCO_3^- concentration which appeared in the produced water samples is likely sensitive to the temperature change in forming $CaCO_3$ scale. Cooling the injected water temperature by increasing fraction of freshwater may

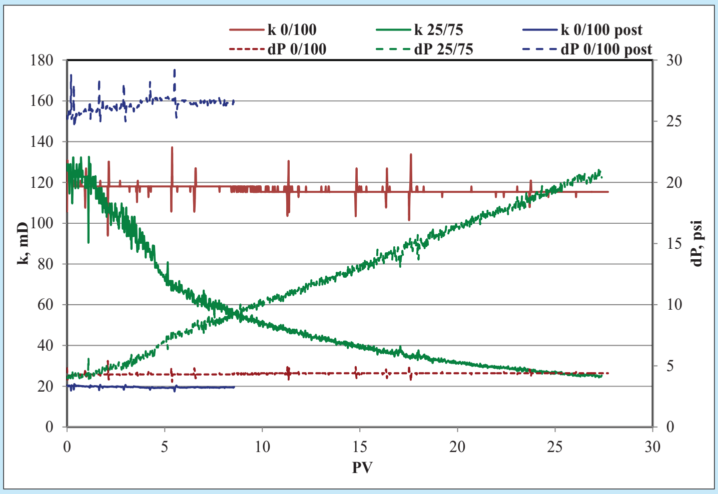

Figure 3
Differential pressure and permeability profile as a function of PV injected for mixture of untreated produced water and filtered freshwater

Table 8
Compatibility of produced water (PW) versus freshwater (FW)

Mixing Fraction PW/FW	Compatibility mg/L	Proportional Precipitate mg/L	Remark
100/0	3.0500	3.0500	
75/25	2.5500	2.5875	Compatible
50/50	1.5500	2.1250	Compatible
25/75	1.1000	1.6625	Compatible
0/100	1.2000	1.2000	

decrease the risk of $CaCO_3$ scale. Mitigation through scale inhibitor squeeze treatments can also be performed to remove accumulations of this type of scale.

C. Permeability Reduction

Two tests were conducted to assess permeability loss of core samples when introducing produced water into the freshwater injection system. Results of each experiment are detailed below.

Test 1: Untreated production water

Core plug #1 was used in this experiment. The base permeability was first established using filtered freshwater. Then, the mixed produced water and freshwater were injected into the core sample. A post freshwater injection was performed at the end of the experiment. Figure 3 reveals the differential pressure and permeability profile as a function of PV injected for various mixing of fraction produced water to freshwater (PW/FW). The injection of freshwater did not cause any damage to the core permeability. The water permeability is relatively constant with an average of 116 mD after 27 PV freshwater being injected. A stabilized pressure drop of around 4 psi was observed during the injection also indicating there is no any damage to the flow system along the core.

After finishing freshwater injection, the mixed of 25% produced water and 75% freshwater began to be introduced into the core. Results are shown by green lines in Figure 3. The differential pressure is inversely proportional to the permeability. Sharp increases of differential pressure up to 5 PV injected resulted in sharp decline in core permeability. Average permeability decreases quickly and sharply from 125 mD to 72 mD after 5 PV of injection. This suggested a fast damaging rate in the core. Then, the differential pressure decline is proportional to the cumulative volume injected and permeability reduction decreases gradually to finally stabilize at around 25 mD after 27.4 PV of injection. It means that the core loses 80% of its initial permeability. This severe reduction in permeability is probably caused by high bacterial counts and TDS present in the produced water. Since the core suffered substantial permeability reduction, injection with mix of water containing more than 25% of produced water was not further evaluated.

A post freshwater injection was carried out to further evaluate the damage characteristic. Results are depicted by blue lines in Figure 3. No improvement is observed after injecting 8.5 PV of freshwater shown by relatively constant differential pressure and permeability. Average permeability of around 20 mD suggested that the permeability losses cannot be recovered. Untreated produced

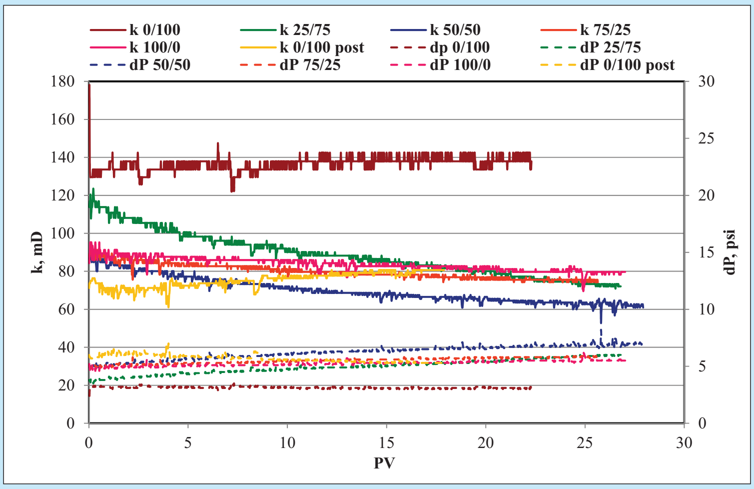

Figure 4
Differential pressure and permeability profile as a function of PV injected for mixture of treated produced water and filtered freshwater

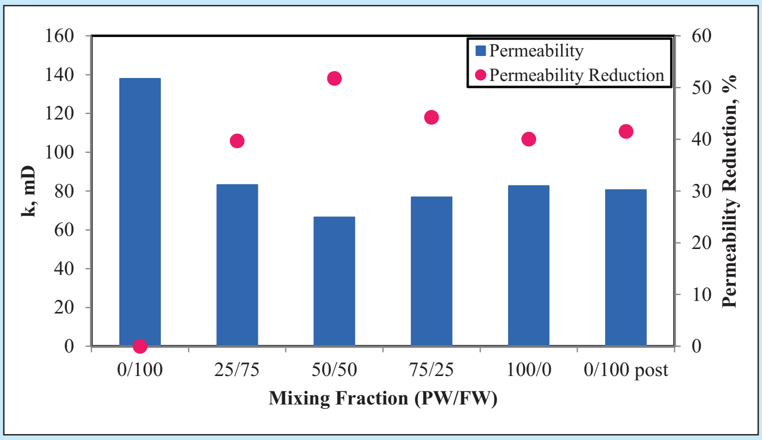

Figure 5
Permeability reduction after injecting 17 PV of various mixtures of treated produced water and filtered freshwater

water caused permanently permeability impairment, which is attributed to the entrainment of bacteria and solid particles with high concentration in the produced water. The in-situ secretion of bacterial slimes can be a cause of substantial permeability impairment.

Test 2: Treated production water

Produced water was treated by adding 2000 ppm of biocide and filtered using 11 micron filter paper. Figure 4 depicts the differential pressure and permeability profile as a function of PV injected for mixture of treated produced water and filtered freshwater using core plug #2. Increasing differential pressure resulted in decreasing permeability.

Results of freshwater injection show a similar trend observed in Figure 3. Both differential pressure and permeability are relatively constant during the injection. An average permeability is around 135 mD after 22 PV freshwater being injected. However, a different trend was observed for the mixed water injection. Introducing produced water caused a gradual decline in core permeability and the decline is linear to the PV injected. The permeability impairment is significantly improved using treated produced water. Mixing 25% volume of produced water with freshwater resulted in the improvement of core permeability losses from 80% for the untreated to 47% for the treated produced waters after injecting the same PV of mixed water. This improvement is attributed to the effectiveness of biocide in suppressing the bacterial growth. The observation for 28 days shows that there was no bacterial growth in the produced water after added 2000 ppm of biocide.

Figure 5 shows the reduction in permeability which resulted from mixing freshwater with different fraction of produced water after injecting 17 PV. Increasing the fraction of produced water causes an increase in the severity of permeability reduction. However, the permeability reduction was observed to reach a saturated value when the fraction of produced water increased more than 50% of PV. A higher permeability reduction of 55% was reached when 50% of produced water was injected. The severity of permeability reduction decreased when the volume of produced water increased more than 50% volume. For example, 75% and 100% volume of produced water caused reduction in core permeability by 44% and 40%, respectively. Post freshwater injection at the end of the experiment did not show significant improvement in permeability. After 17 PV mixed water was injected, the permeability is relatively constant at 80 mD or corresponding to 42% in permeability loss.

The major source of permeability impairment for this test 2 was induced by the solid particles. The solid particles passed the 11 micron filter paper migrate and block mechanically within the pore throats, which have the size less than 11 μm. The mean diameter of solids in produced water and freshwater are 5.4 and 5.5 μm, respectively. Therefore, there is a high risk for the potential bridging of solids within the core and caused permeability reduction. In addition, high concentration of TDS in produced water resulted in more severe permeability reduction imposed by mixing waters compared to the freshwater alone.

The severity of permeability reduction observed in both tests can be related to the fraction of pore throats having a diameter of less than 11 μm. When the fraction becomes larger, the water permeability tends to decrease. This is supported by the results obtained from the freshwater injection into the core plugs #1 and #2. Even though the core plug #1 has higher absolute permeability, its average water permeability is less compared to the core plug #2.

Table 9
Basic data for oil recovery determination

Core Plug #	Fluid Injected	Core Properties (%) PV	S_{oi}	S_{wc}	k_w (mD)	$k_w@S_{oi}$ (mD)	$k_{o2}@S_{wi}$ (mD)
3	FW	22.64	19.29	3.35	836	109	551
4	50 PW/50 FW	21.42	16.29	5.13	2270	372	1041
5	PW	21.03	14.44	6.59	808	279	670

This is due to the fact that the core plug #1 contains pore throat size of 1-10 μm about 27.4% of PV, while the core plug #2 has only 21.4%, as revealed in Table 5. It means that with the same concentration of solid particles less than 11 μm, reduction in permeability for core plug #1 tends to be higher than core plug #2. Using a 5 micron filter paper is expected to reduce permeability reduction induced by solids particles. Unfortunately, no injection of freshwater that has been filtered by filter paper of less than 11 micron was performed on both tests.

D. Oil Recovery Loss

The risk of oil recovery loss induced by mixing produced water with freshwater presented was evaluated through three waterflood experiments performed on core plugs # 3, 4, and 5. The basic data for those experiments derived during coreflooding are given in Table 9. The permeability varied from 808 to 2270 mD representing the reservoir heterogeneity. Produced water and freshwater were treated the same as that used in test 2 of the permeability measurement.

Figure 6 depicts the oil recovery factor which resulted from the waterflood experiments. The results show a higher ultimate recovery factor of 46.1% of original oil in place obtained from freshwater injection as expected. When the 50% PW/50% FW mix is considered, the ultimate recovery factor decreases to 38.7%. The recovery factor of produced water injection reaches 30.6%. Contrary to permeability reduction, the 50% PW / 50% FW mix gives a good result compared to the 100% produced water. This is probably due to the fact that permeability of core plug #4 used in the 50% PW / 50% FW mix experiment is significantly higher compared to permeability of core plug #5 used in the 100% produced water. Knowing that the average permeability used in the freshwater injection is approximately 836 mD, the waterflood result that consider the permeability of 2270 is very conservative in terms of oil recovery loss. An important result from this experiment is to demonstrate the quantitative effect of risks related formation damage to oil production caused by introducing produced water into the freshwater injection system. Introducing 50% of produced water caused oil recovery loss of 16% compared to freshwater injection alone. This reduction of oil recovery is consistent with the previous experiment results.

IV. CONCLUSIONS

Risks which arise when introducing produced water into the freshwater injection system were investigated through laboratory experiments. The field case study demonstrated that there is a risk for potential plugging, scaling, permeability reduction, and oil recovery loss. Plugging is caused by bacterial growth and solid particles present in produced water. Bacterial growth is categorized high. Solids Concentration is also high with its mean diameter larger than the non-damaging particle size. The $CaCO_3$ scale is likely at reservoir temperature due to high concentration of HCO_3^- in the produced water. Plugging and scale resulted in permeability reduction as well as oil recovery loss, even though that scale plug was considerably less due to the fact both waters are compatible. Mixing of untreated produced water and treated freshwater caused significant reduction in permeability. For the 25% PW and 75% FW mix, the permeability decreases by about 80% of its initial permeability. Adding 2000 ppm of biocide and filtered using 11 micron filter paper improved the quality of produced water. For the same mixing fraction, the permeability decreases only 47%. This improvement attributed to the effectiveness of biocide in suppressing the bacterial growth. The permeability decline is triggered by high concentration of solids with particle size greater than non-damaging particles size. Analysis of pore throat size in conjunction with particle size of water samples suggests the need

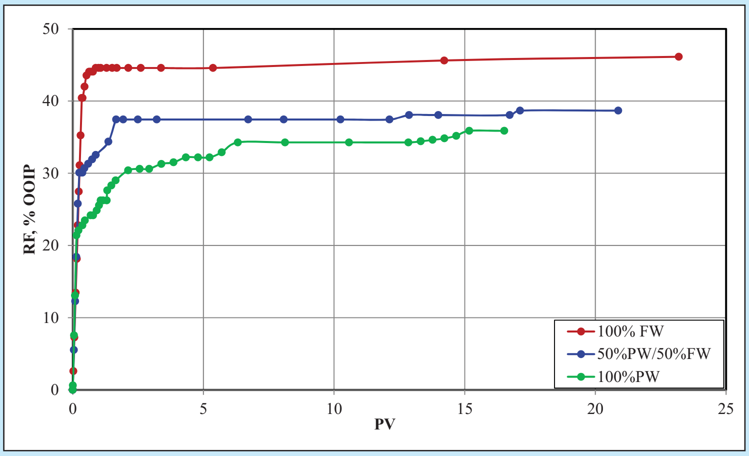

Figure 6
Oil recovery factor obtained from injecting different waters

for using a filter paper less than 11 micron to avoid permeability decline imposed by solid particles. Risk of using produced water on the oil production is assessed through waterflood experiments. The results show an ultimate recovery factor of 46.1% of original oil in place obtained from freshwater injection. Introducing 50% of produced water caused an oil recovery loss of 16% compared to freshwater injection alone. This loss of oil recovery represents a quantitative effect of formation damage on oil production and may be valuable from the economic viewpoint.

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